STOWE ELECTRIC DEPARTMENT

ESTABLISHED 1911

2023 INTEGRATED RESOURCES PLAN

Stowe Electric Department | Stowe, VT | StoweElectric.com

November 21, 2023 | VSA §218C | 2023-2043

SUBMITTED BY:
Energy New England, LLC on behalf of Stowe Electric Department

CONTRIBUTORS:
Energy New England, LLC; ITRON Inc.; and Stowe Electric Department

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A Executive Summary

A.1 Overview

Stowe Electric Department's (Stowe) 2023 Optimal Integrated Resource Plan (IRP) is filed pursuant to Vermont Statute 30 V.S.A. § 202. Stowe (SED), ITRON Inc., and Energy New England, LLC (ENE) prepared this IRP. Stowe filed its previous IRP in 2020. Stowe consults with (ENE) for guidance on the ISO New England markets and structuring of short and long-term power contracts. ENE offers ISO New England (ISO) market participation services to SED. ENE has offered SED opportunities to leverage existing power generation sources that are carbon-neutral and carbon-free, which helps SED decarbonize its distribution system. ITRON provides forecasting and modeling to inform Stowe's decision-making.

The IRP is a key tool in developing Stowe's strategic plan, which is to optimize Stowe's generation portfolio with a cost structure that stabilizes rates and improves financial health, services, and environmental indicators for the utility and its customers. The 2022 Comprehensive Energy Plan (CEP) provides guidance to ensure Stowe incorporates the State goals within decision making of this 2023 IRP. Stowe understands there will always be tradeoffs to consider when deciding on various issues concerning future projects and contracts.

This IRP considers various key influences on the energy market and several strategies that Stowe could utilize when continuing to build its long-term resource portfolio. Such concepts include:

- Incorporate future resources that balance low present value costs while reducing the environmental footprint of the portfolio. Stowe aims to construct a portfolio that is both fiscally and environmentally responsible for its customers. For the Renewable Energy Standard (RES) requirements, Stowe intends to seek out future resources that serve to fill RES needs while being economical.
- Consider long-term resources that provide protection against adverse market conditions. Stowe will pursue pricing that will work to mitigate current commitment to out-of-market resources.
- Stowe will seek out and review Vermont-based resources to help it comply with RES. In addition, behind-the-meter generation projects that will reduce emissions in Stowe are priority for analysis, as they will enable Stowe to fill RES standards that began in 2017.
- Stowe will participate in the Vermont Climate Action Plan that follows the Global Warmings Solutions Act to achieve a reduction of greenhouse gas emissions to net zero by 2050. Stowe will encourage climate adaptation and smart growth strategies with the guidance of the VT Plan.

Since filing the 2020 IRP, SED would like the recognize the following achievements:

- Selected as a partner utility in the US Department of Energy, Clean Energy Innovator Fellowship program to host a fellow.
- Received an Energy Innovator Award from the American Public Power Association's (APPA) DEED R&D program for its research partnership with University of Vermont.
- Named a Smart Energy Provider by APPA.
- Established a utility owned tree crew to complete right of way maintenance and respond to storm damage.
- Awarded more than $1.6MM in grant funding for resiliency and infrastructure modernization, including funding for a microgrid feasibility study and distribution automation loop scheme.
- Engaged Argonne National Laboratory, Idaho National Laboratory, Oak Ridge National Laboratory, and National Renewable Energy Laboratory on technical assistance research programs focused on grid modernization and resiliency planning.
- Increased Tier III participation through increasing rebated products from 59 products in 2019 to 290 products in 2023.
- Completing transition to an enterprise management system by early 2024 will bring customer service, billing, finance, inventory, GIS, and operations systems under one platform.
- Signed PPAs for additional carbon free. Completed a grant funded pilot program that installed over 200 window inserts to improve weatherization in homes located in Stowe and Lamoille County.
- Onboarded Jackie Pratt as SED's new General Manager upon retirement of Ellen Burt, SED's General Manager since April 2005).

A.2 IRP Outline

Section A. Table of Contents provides titles and page numbers per section of this report.

Section B. Executive Summary provides an overview of the report.

Section C. Resource Requirement with Forecasts and Scenarios.

Section D. Portfolio of Existing Resource and environmental impact.

Section E. Resources alternatives and comparison of those alternatives to the preferred portfolio.

Section F. Data Models and Information provides an explanation of the modeling used to guide Stowe's decision-making in this IRP.

Section G. Renewable Energy Standard Analysis provides an overview of the regulatory scheme driving decarbonization.

Section H. Assessment of the Transmission and Distribution System evaluates system improvement of efficiency and reliability for bulk transmission, grid modernization, underground damage prevention plan, and vegetation management.

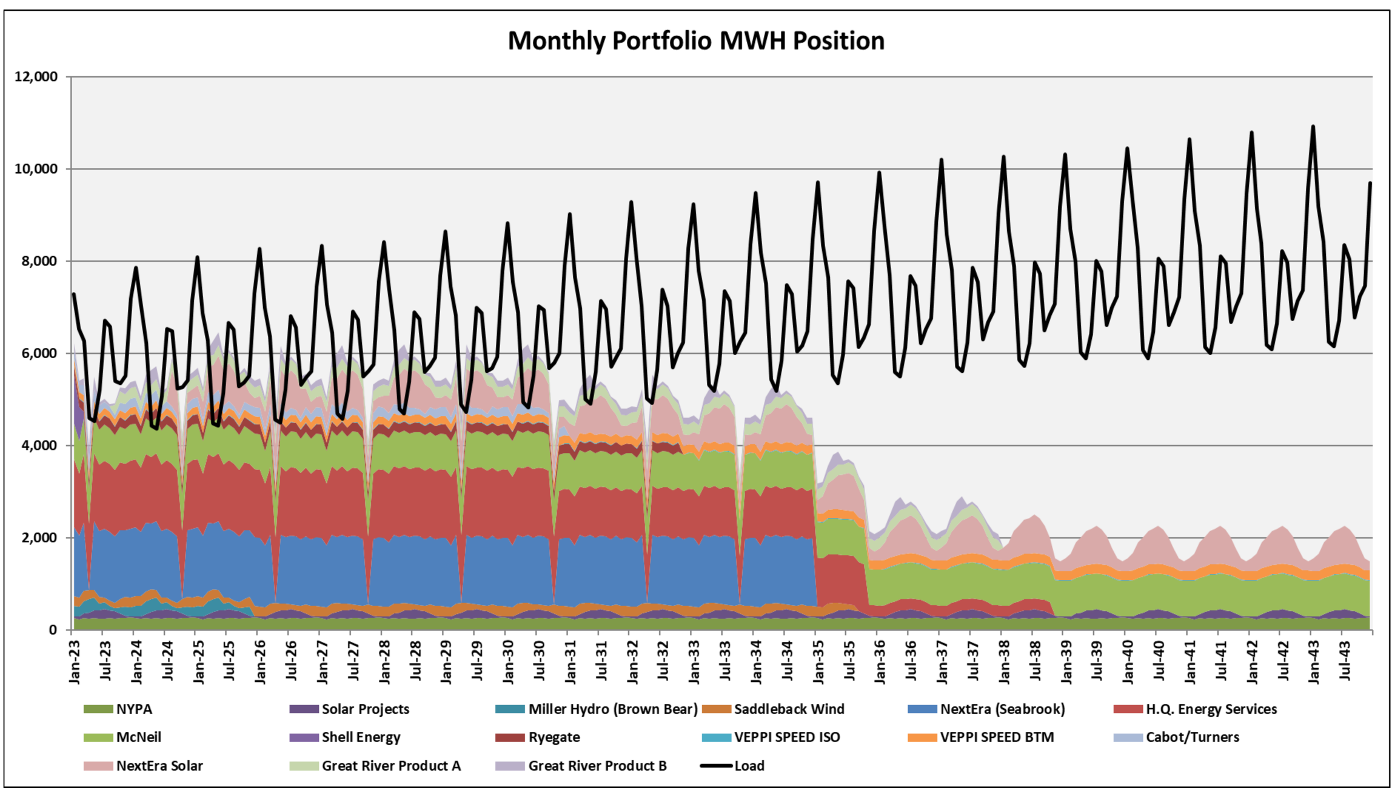
Section I. Evaluations to assess the economics and technical feasibility where appropriate. Development and adoption of any necessary procedures to meet the following standards.

Section I. Integrated Analysis and Plan of Action provides an assessment of demand, supply, finances, transmission, and distribution to find a target portfolio.

A.2.1 Resources Requirements

Stowe's 2022 sales (Stowe Mountain not included) have rebounded from the sharp decline in 2020 (COVID-19) by 10.3%. Comparing 2022 and 2019 sales have increased by 3.4%. Although Stowe has life of unit contracts in their portfolio, there is a supply gap to address in future planning years. While this IRP analyzes various portfolio options, it also addresses both coverage and Renewable Energy Standard (RES) requirements. The benefits of certain resources in the RES program will have greater implications to SED's overall power costs. Therefore, assessment of resources is based on not only potential cost, but RES offset as well.

Figure 1: Energy Supply Gap

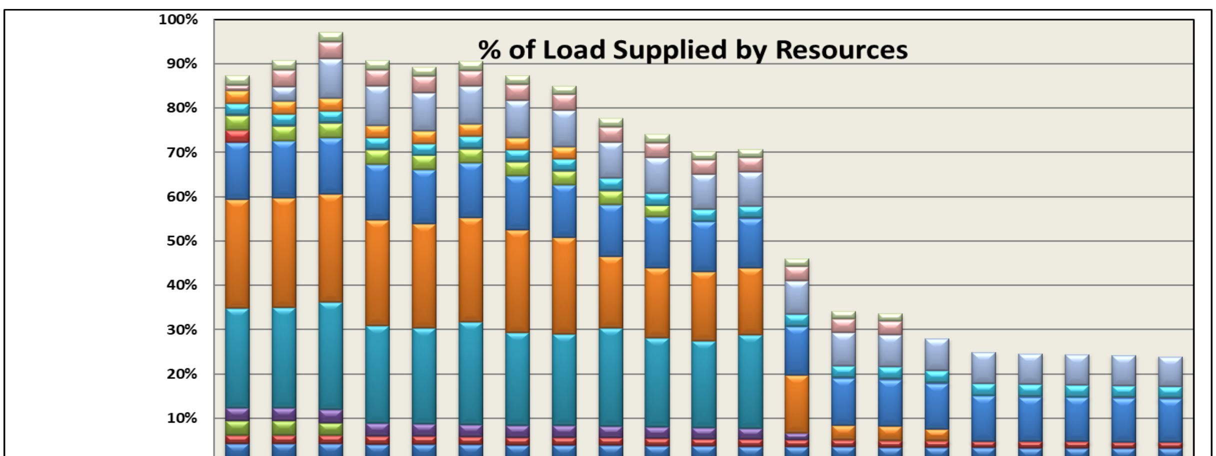


The "Base Case" load forecast (black line in Figure 1) has load maintaining steady. This includes adjustments for expected future energy efficiency improvements, impacts of solar, electric vehicles, and heat pump penetration. This forecast removes the variable mountain load, only because all mountain costs are billed back, and never become a cost detriment to Stowe's ratepayers. Stowe intends to continue to explore ways to supply its portfolio with renewable best benefit solutions.

A.2.2 Stowe's Renewable Supply Portfolio

Currently, Stowe has over 80% carbon free generation supply portfolio throughout the year 2030. This includes unit entitlements and Purchase Power Agreements (PPAs) that have qualified Renewable Energy Certificates (RECs) and/or State-approved RECs for RES compliance. Figure 2 illustrates the base case load applied and matches it to the forecasted output of SED's renewable resources. Stowe's generation portfolio is carbon neutral. The Seabrook offtake contract does not count towards RES compliance but is a carbon neutral energy source. When focusing on alternative resources, SED will continue to search out renewable generation and remain committed to bringing customers utility rates that are the least cost possible. As SED continues to meet the RES compliance through renewable and carbon-neutral generation, the SED portfolio will offset RES compliance costs.

Figure 2: Stowe's Resource Portfolio



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Great River Product B	2.19%	2.20%	2.17%	2.13%	2.10%	2.06%	2.03%	2.00%	1.97%	1.94%	1.90%
Great River Product A	1.28%	3.84%	3.78%	3.72%	3.66%	3.60%	3.54%	3.49%	3.44%	3.38%	3.32%
NextEra Solar	0.00%	3.19%	8.96%	8.82%	8.67%	8.53%	8.39%	8.28%	8.16%	8.02%	7.86%
Cabot/Turners	2.95%	2.97%	2.92%	2.87%	2.82%	2.78%	2.74%	2.70%	0.00%	0.00%	0.00%
VEPPI SPEED BTM	2.48%	2.54%	2.56%	2.56%	2.57%	2.62%	2.64%	2.66%	2.67%	2.67%	2.68%
VEPPI SPEED ISO	0.18%	0.18%	0.17%	0.17%	0.17%	0.17%	0.17%	0.16%	0.16%	0.16%	0.16%
Ryegate	3.32%	3.34%	3.29%	3.23%	3.18%	3.18%	3.13%	3.09%	3.05%	2.49%	0.00%
Shell Energy	2.71%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
McNeil	12.81%	12.87%	12.67%	12.46%	12.26%	12.27%	12.09%	11.93%	11.75%	11.53%	11.33%
H.Q. Energy Services	24.55%	24.67%	24.29%	23.89%	23.50%	23.51%	23.17%	21.77%	16.09%	15.78%	15.50%
NextEra (Seabrook)	22.60%	22.65%	24.37%	22.00%	21.57%	23.21%	20.94%	20.59%	22.18%	20.03%	19.56%
Saddleback Wind	2.96%	2.97%	2.93%	2.88%	2.83%	2.79%	2.74%	2.70%	2.66%	2.62%	2.57%
Miller Hydro (Brown Bear)	3.18%	3.20%	2.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Solar Projects	1.88%	1.89%	1.86%	1.83%	1.80%	1.77%	1.74%	1.72%	1.70%	1.67%	1.64%
NYPA	4.26%	4.29%	4.22%	4.16%	4.09%	4.02%	3.95%	3.90%	3.84%	3.78%	3.70%

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Great River Product B	1.86%	1.83%	1.79%	1.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Great River Product A	3.25%	3.19%	3.13%	3.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NextEra Solar	7.72%	7.56%	7.42%	7.29%	7.17%	7.07%	6.99%	6.91%	6.84%	6.77%
Cabot/Turners	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
VEPPI SPEED BTM	2.68%	2.68%	2.67%	2.69%	2.70%	2.71%	2.67%	2.65%	2.62%	2.60%
VEPPI SPEED ISO	0.15%	0.15%	0.15%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.13%
Ryegate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Shell Energy	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
McNeil	11.12%	10.89%	10.67%	10.50%	10.33%	10.18%	10.04%	9.96%	9.85%	9.76%
H.Q. Energy Services	15.21%	12.99%	3.30%	3.25%	2.67%	0.00%	0.00%	0.00%	0.00%	0.00%
NextEra (Seabrook)	20.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Saddleback Wind	2.52%	1.60%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Miller Hydro (Brown Bear)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Solar Projects	1.60%	1.57%	1.54%	1.52%	1.49%	1.47%	1.45%	1.44%	1.42%	1.41%
NYPA	3.63%	3.56%	3.50%	3.43%	3.38%	3.33%	3.29%	3.26%	3.22%	3.19%

A.2.3 Resource Alternatives

Stowe's 2023 IRP is a tool used to evaluate purchases and resources. Stowe's IRP researched supply balance, generation, load control, technology, and storage. Stowe will seek resources for its portfolio that lowers costs to its customers and that are beneficial to the State of the Vermont and Independent System Operator New England (ISO-NE) energy sector. Stowe is mindful of policy obligations such as the Renewable Energy Standard (RES) that began 2017. RES compliance has enhanced Stowe's focus on fair and equitable ways to promote energy efficiency. Stowe also formed a strong partnership with Efficiency Vermont (EVT), community action groups (most often Capstone Community Action), Town of Stowe employees and Committees, and the Lamoille County Planning Commission to increase outreach and dissemination of energy efficiency technologies to its customers.

The IRP process selected combinations of potential resources for evaluation. Together, Stowe and ENE chose five scenarios using an optimization algorithm, which is explained in section I.4. ENE's simulation models can be found in section E Data Models and Information evaluated each portfolio for performance within simulated in market environments.

The evaluation review chose the ideal scenario using four major criteria:

1) Least Cost: Mean of the Net Present Value (NPV) of the total portfolio; this includes energy cost of both current resources and potential scenario resources.
2) Renewable Energy Standard: Mean of the Net Present Value (NPV) of each scenario based on current and proposed RES coverage and resources for each scenario.
3) Standard Deviation: Risk of each scenario relative variation of the expected NPV of Total Portfolio Cost and RES, as measured by the standard deviation and various tradeoff considerations.
4) Spot Market Exposure: The relative spot market exposure to Stowe is based on each scenario.

A.2.4 Comparative Tradeoff Analysis and Risk

The ENE Portfolio Simulation Model used simulation-based models that estimated future values of the input variables. The simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Stowe's resource portfolio under different market conditions and identifies the factors to which the performance is most sensitive. Simulated data sets include VT to MA Hub basis, AGT Delivered Gas Price, Around the Clock MA Hub LMP, Around the Clock VT Hub LMP, Total Annual Cost for the portfolio, Coverage, and Unit capacity factor.

In creating and cultivating the IRP scenario, Stowe will consider aspects of operational impact. Resource cost, environmental impacts, fuel, Transmission and Distribution challenges as well as reliability will all weigh heavily on the choosing of the potential plan of action.

The Evaluation of Portfolio Scenarios section describes the details of all five scenarios. Table 1 below lists the least and high-cost scenarios along with the optimal scenario.

Table 1: Comparative Portfolio

	Scenario	NPV Total Cost	NPV Total RES	Std Dev	Spot Exposure Target Deviation
Least Cost	Scenario #1	$ 90,192,297	$ 2,050,015	$ 19,999,017	61%
High Cost	Scenario #3	$ 100,429,469	$ (3,502,271)	$ 7,042,235	86%
Optimal Scenario	Scenario #2	$ 95,605,453	$ (304,696)	$ 10,619,225	80%

Here are the highlights of the most competitive resource combination along with Stowe's current resource portfolio:

I. Scenario #1 = Current Portfolio, and Ryegate extended through 2032.
II. Scenario #3 = Current Portfolio, Moscow Mills Hydroelectric Unit, Ryegate extended through 2032, Offshore Wind option, Hydro with small water storage capability, and Hydro Quebec extension.
III. Scenario #2 = Current Portfolio, Moscow Mills Hydroelectric Unit, Ryegate extended through 2026, Hydro Quebec extension, Existing Wind offtake, Existing hydro extension.

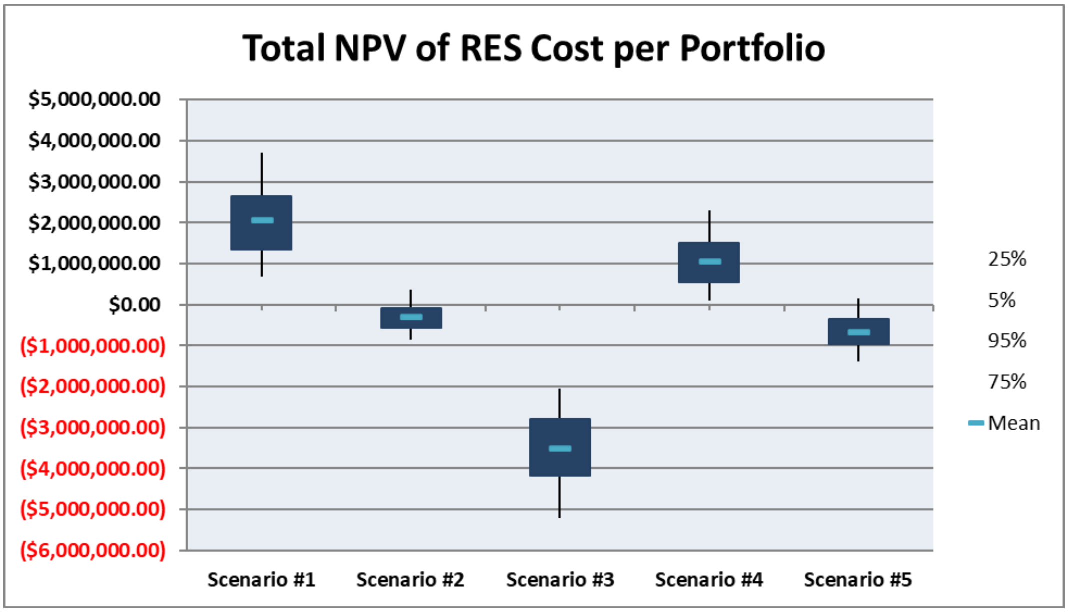
The scenarios provide an analysis of net present value of each portfolio compared to energy and RES along with respected hedged amount each scenario would provide Stowe.

Using the previously mentioned four major criteria as guideposts allows Stowe to fulfill its goals of compliance and risk coverage to help provide reliable, reasonably priced energy to its customers. However, one must be aware that more renewables, although helpful towards RES, increases reliability risk and the risk of higher prices to Stowe's energy costs. In this IRP, Stowe viewed the benefits and risks of new and existing fuel sourced projects with respect to the cost of each portfolio scenario.

The following figure displays the results of the simulations in a "box plot"[1] format, which provides a quick visual summary of the mean value, the minimum and maximum values, and the relative amount of variation around the expected cost of RES to Stowe for each scenario.

[1] "Box-and-Whisker" diagram, the white area, or the "box," represents the upper and lower quartiles (25th and 75th percentiles) of values, the black line is the 50th percentile of the data, and the thin black lines, or the "whiskers," represent the minimum and maximum values of the sample data.

Figure 3: 20-year Total Portfolio Cost Comparison for each Portfolio's RES NPV



A.2.5 Stowe's Target Resource Portfolio

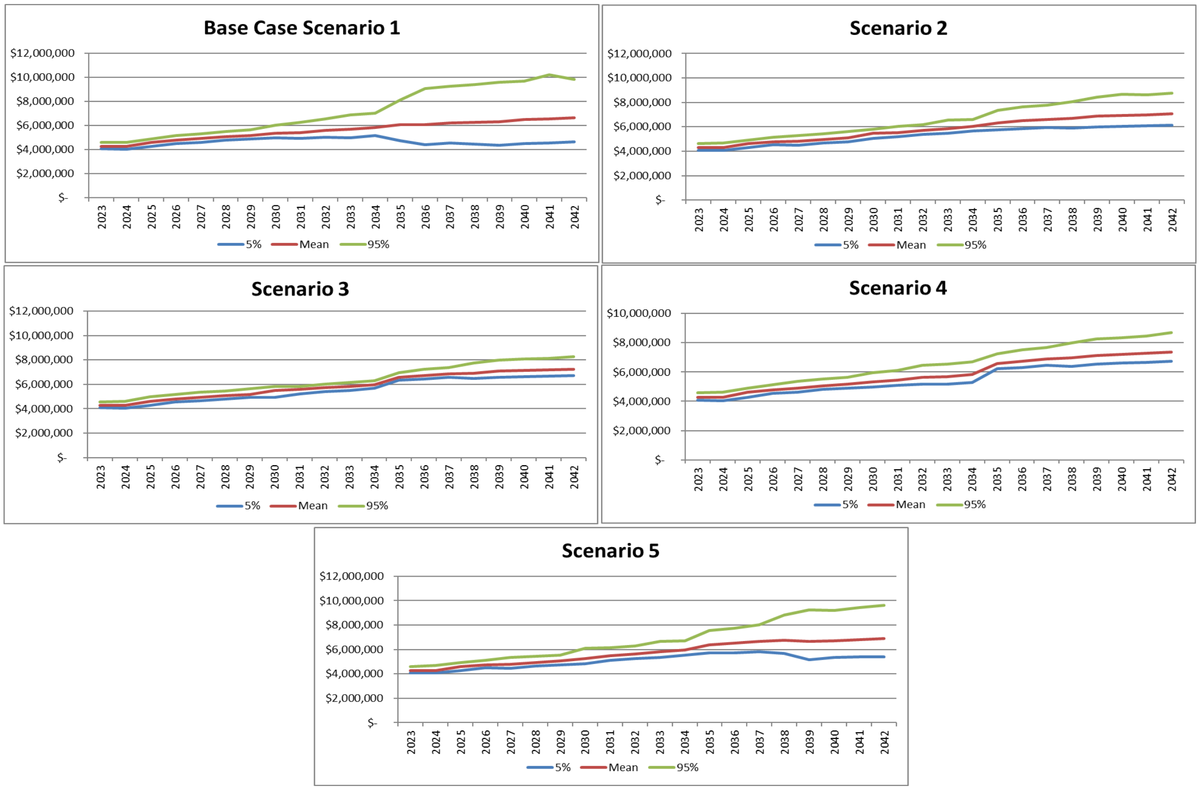
Based on the comparative analysis, the optimal portfolio is Scenario #2 for Stowe's IRP. Scenario 2 = Current Portfolio, Moscow Mills Hydroelectric Unit, Ryegate extended through 2026, Hydro Quebec extension, Existing Wind offtake, Existing hydro extension.

The caveat is that specific resource volumes are determined relative to Stowe's load requirements as well as renewable capacity factor adjustments throughout the term of this plan. These volumes will need adjusting to effectively balance the cost and environmental performance while avoiding the purchase of too many resources at certain times of the year. Material changes to Stowe's load, whether efficiency driven, or electrification will have an impact on the volume and nature of new resources pursued.

Stowe's position for choosing Scenario 2 has to do with the economic and environmental performance of the balance this option provided and the feasibility of obtaining the scenario. The resource extensions are modeled at current potential rates that are transactable in the market. Ryegate forecasted through 2026 assumes the resource will not achieve requested requirements set forth in 8009 Section (8009 (k)(1)) Case 22-3944. The new resources added into all the scenarios is the Stowe rebuild of what was the Moscow Mills hydro project. SED purchased the historic Moscow Mills parcel in Stowe, VT in 2016. The hydro project is set on Smith's Falls dam, a rock and timber dam built on ledge in 1822. SED is finalizing the stabilization of the dam to enhance flood control and hydropower generation at the site.

The most competitive portfolios strike a balance with resources that improve the environmental performance towards Vermont's RES and take advantage of the current market environment, which provide lower costs over time and across various market environments.

Figure 4: 20 Year Annual Energy and RES Compliance Costs



The plan incorporates the following timeline and action points:

1. Continue to explore ways to promote energy efficiency and conservation for Tier III compliance purposes.
2. Monitor load growth or contraction on an ongoing basis.
3. Continue market purchases as needed in a low commodity price environment over the next years. This is especially relevant for the Stowe Mountain Snowmaking contract, as well as exposure from unit outages.
4. Continue to investigate adding competitively priced renewable power within New England.
5. Continue to review renewable resource alternatives, including offshore wind, and distributed generation, to build diversify and comply with RES within Stowe's portfolio. Technology improvements, the relative cost of market power and renewable energy credit prices will make resources more attractive or deter incorporating into a portfolio.

B Introduction

B.1 Overview of Stowe Electric Department

The Village of Stowe was chartered in March of 1763, and the first settlement took place in 1794. As the Village of Stowe grew, it added a portion of the Town of Mansfield in 1840. In 1855, the rest of Mansfield and the Town of Sterling became part of the Village.

The first electric department was established in 1911 as the Village of Stowe Electric Light and Power System. In 1996, the Village of Stowe and the Town of Stowe merged, and the Town of Stowe Electric Department ("Stowe") became an enterprise division of the Town. Currently, Stowe's consumer base consists of residents and businesses within the Town of Stowe. Using updated information provided by the 2020 Census, Stowe's population has grown 21% since 2010, reaching 5,223 people in 2020. Stowe Electric's service territory does not cover the entire Stowe census block, but SED serves 4,445 meters. Approximately 80% of the meters in our territory are residential meters, and 70% of these meters serve residences that are primarily second homes or short-term rentals. Stowe Area Association reported that the daily occupancy rate during the 2023 foliage season reached 85%. Estimates show that between 75,000 – 100,000 people visit Stowe during the summer and fall and the Town of Stowe reports a winter seasonal daily population of approximately 8,000 people. This makes Stowe's system planning and electric service reliability valuable to the local economy and Town planning[2].

Beginning in 2008, Stowe contracted with ENE to manage its wholesale power supply entitlements. In recent years, Stowe and VELCO collaborated on the transmission expansion and upgrade called the Lamoille County Project. This upgrade consisted of ten miles of new 115kV lines installed between the towns of Duxbury and Stowe. Stowe also benefited from the construction of a new 115/34.5kV substation. The entire upgrade resulted in more efficient electrical usage by creating greater reliability to the system.

In 2012 Stowe Electric Department implemented AMI technology throughout its service territory. This allows customers to access meter data through the Stowe Electric Website. Stowe's goal is to keep customers informed of their usage to allow for more informed energy related decisions. Stowe also installed electric vehicle charging stations to help minimize carbon emissions. Stowe is committed to exploring all avenues of cost effectiveness while reducing carbon. Stowe wants to provide reliable energy and service at the most affordable cost to its consumers.

Stowe's Board of Electric Commissioners is engaged and involved within the community. Stowe's ratepayers are always first in mind and customer service, grid safety, and reliable electric service are foundational to Stowe's operation. Stowe supports environmentally viable

[2] Town of Stowe Statistics: https://www.townofstowevt.org/vertical/Sites/%7B97FA91EA-60A3-4AC6-8466-F386C5AE9012%7D/uploads/statistics.pdf

and economical power from local sources and evaluates all contracts for purchased power from renewal sources that fall within its budget.

CUSTOMER SURVEY

Stowe Electric Department commissioned GreatBlue Research to conduct a comprehensive customer survey among residential customers to gain a deeper understanding of their perception of the utility, satisfaction with the service provided, and identification of areas for future growth and improvement. The outcome of this research enables Stowe to understand and set customer expectations, act on near term opportunities for improvement, and create strategic roadmap to support customer adoption of electrification measures more clearly. The survey took place in May 2023.

92.7% of survey respondents had a net-positive rating (12.3% Advocate + 29.2% Loyal + 51.2% Satisfied) for Stowe Electric, compared with the national average of 80.2% for public power utilities. 79.4% of respondents said community ownership of the utility is important. 61.4% said SED effectively represents community interests and meets local needs. In addition, 95.1%* of customers who reported experiencing a power outage in the past year said the amount of time to restore power was acceptable and 58.5% found SED's outage communications acceptable. (*Excludes "Don't Know" responses.)

61.9% of Stowe customers ranked "Reliability" as their number one priority, whereas 26.3% ranked "Cost of Power," and 11.8% ranked "Carbon Reduction" as their top priority respectively. 53.4% of customers indicated Stowe's cost of service is "About Right."

More than half of customers (56.4%) reported being aware of beneficial electrification, with 26.5% being "very aware" and 28.4% being "moderately aware." 41.6% of Stowe Electric customers indicated they plan to purchase an electric vehicle in the next 5 years. An additional 27.6% said they anticipate purchasing an EV more than five years from now. 16.9% said they plan on installing solar in the near future, with 84.2% of those indicating they plan to take action within the next five years. 13.4% said they plan to purchase heat pumps for their home, with 40% planning to act this year and another 48% taking action within the next 5 years.

B.1.1 Overview of Town of Stowe

Agriculture and logging dominated the early economy of the Village of Stowe. Stowe had over one hundred farms and a strong timber production industry. However, as early as the middle of the 19th Century, the Village of Stowe was recognized as a preeminent destination for its scenic vistas and outdoor experiences. The Mt. Mansfield Toll Road was completed in 1870 and an electric railroad linked Stowe and Waterbury by 1897. After World War I, skiing established itself as a recreational pastime capable of driving economic growth, and skiing remains a crucial element in the Town of Stowe's economy and identity. Stowe's winter sport availability is a substantial revenue generator for the town, with a significant amount of its revenue derived from Stowe Mountain Resort.

 [3]

The Town of Stowe also capitalizes on the landscape's exceptional beauty and scenery, enabling an extensive year-round tourist economy. The annual transition from summer to fall brings a beautiful foliage spectrum that is a popular tourist attraction. COVID-19 pandemic affected Stowe's tourism negatively. Thankfully, as restrictions and mandatory lockdowns were lifted, Stowe has had a quick recovery of energy usage.

 [4]

Since winter is a strong tourist season for the Town of Stowe, it is important to understand the main fuel source that residences are using. The Town's occupied housing heating source representation is found in Figure 5 below. These facts become important when Stowe looks for ways to implement energy efficiency within the service territory for Tier III compliance.

[3] https://www.stowe.com/the-mountain/about-the-mountain/mountain-info.aspx?tc_1=2

[4] Photo Album - Official Website of the Town of Stowe, Vermont (townofstowevt.org)

Figure 5: Stowe's most used house-heating fuel[5]

ACS 2021 5-year

Table universe: Occupied Housing Units

Column	Stowe, VT	
Utility gas	0%	±2.2%
Bottled, tank, or LP gas	36.7%	±16.5%
Electricity	11.4%	±15.8%
Fuel oil, kerosene, etc.	43.2%	±27.9%
Coal or coke	0%	±2.2%
Wood	0%	±2.2%
Solar energy	0%	±2.2%
Other fuel	0%	±2.2%
No fuel used	8.7%	±8.6%

B.1.2 Stowe Demographics

As of 2020[6], the population in Stowe, VT was 5,223, with the median age of 47.8 years and 28% of the population 65 years and older. The Lamoille County average age is 40 and 17% of the population is 65 years and older. Within the housing market, the home ownership rate is 72%. 6.5% of homeowners and 16% of renters moved to Stowe in 2021 or later. Stowe does have a high rental sector due to the tourist location, and around 17% of the housing units are considered short-term rentals.

The median household income in Stowe is $74,065, as compared to $66,016 in Lamoille County, and $67,674 statewide. The poverty level in Stowe is reported at 8.1%, while the rest of Lamoille County reports a 10.5% poverty rate. These numbers show that Stowe residents are, on average, wealthier than the rest of Vermont.

Stowe's main industry for jobs in 2021 were education and health care at 30.9% with food service and entertainment (recreation) as the second largest sector at 27%.

[5] Grid View: Table B25040 - Census Reporter

[6] Stowe town; Lamoille County; Vermont - Census Bureau Profile

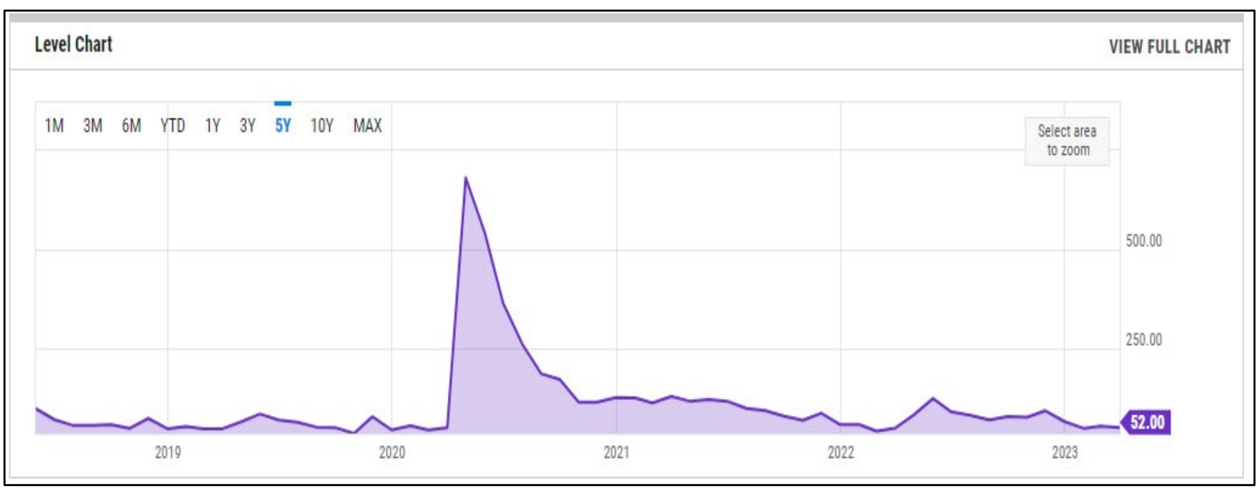
Figure 6: Common Industries for Males and Females in Stowe vs. Vermont [7]

Industry for the Civilian Employed Population 16 Years and Over
in Stowe town, Lamoille County, Vermont
DP03

Measure	Value
Agriculture, Forestry, Fishing and Hunting, and Mining	2.0%
Construction	6.9%
Manufacturing	1.9%
Wholesale Trade	2.4%
Retail Trade	8.7%
Transportation and warehousing, and utilities	0.0%
Information	0.7%
Finance and insurance, and real estate and rental and leasing	4.2%
Professional, scientific, and management, and administrative and waste management services	3.7%
Educational services, and health care and social assistance	30.9%
Arts, entertainment, and recreation, and accommodation and food services	27.4%
Other services, except public administration	5.6%
Public administration	5.5%

The Town's 2021 employment rate was 54.1% (vs. 65.6% for Lamoille County, Vermont). Stowe's unemployment history is found in Figure 7 below. COVID – 19 Pandemic shutdowns drastically impacted the first half of 2020. It was not until regulations and guidelines were lifted towards the middle of 2021 that you can notice the market rebound in unemployment data.

Figure 7: Stowe's Unemployment History[8]

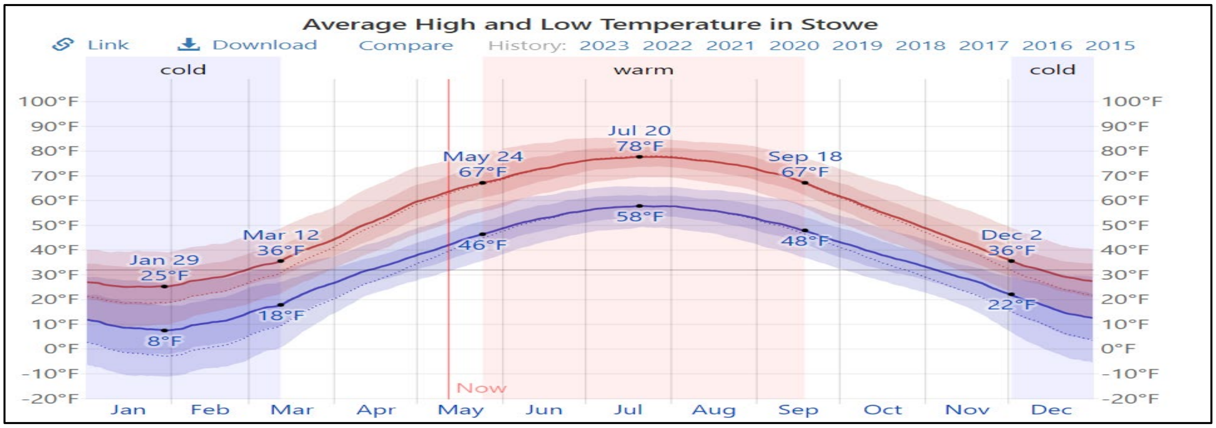


[7] Stowe town; Lamoille County; Vermont - Census Bureau Profile
[8] https://ycharts.com/indicators/stowe_vt_unemployment

B.1.3 Stowe Climate

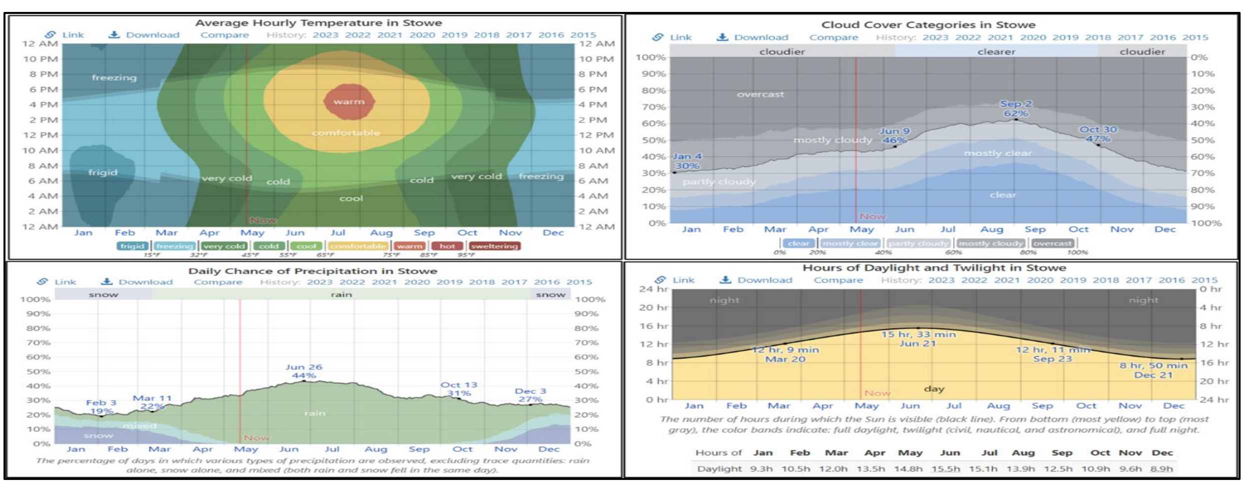
The Town and State's climate are key factors to consider when planning future generation and/or location of generation. The average climate, found below in Figure 8: Stowe's Average Temperatures, provides insight into which months are the highest heating and cooling driven months.

Figure 8: Stowe's Average Temperatures[9]



The data compiled by the Weather Spark, averages 9 years of weather data, depicted below in the graphs of Figure 9: Average Climate in Stowe provides additional information. By analyzing the amount of daylight hours and cloud coverage, Stowe can make educated assumptions of resource optimization. Although renewable generation has benefits to Stowe, it is important to choose the resource that will have the greatest value to Stowe by providing the most output.

Figure 9: Average Climate in Stowe[10]



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[9] Stowe Climate, Weather By Month, Average Temperature (Vermont, United States) - Weather Spark

[10] Stowe Climate, Weather By Month, Average Temperature (Vermont, United States) - Weather Spark

C Long Term Energy and Demand Forecasts and Scenarios –Submitted by ITRON, Inc

The Town of Stowe Electric Department (Stowe) contracted Itron, Inc. (Itron) through Energy New England (ENE) to develop a twenty-year energy and demand forecast to support the IRP planning process. This document provides an overview of the sales and energy trends, forecast results, forecast assumptions, and methodology.

C.1 Background

Stowe serves approximately 3,600 residential customers and 830 commercial customers, including the Stowe Mountain Resort (Mountain). Stowe has a relatively large commercial customer base with the commercial sector accounting for approximately 54% of system sales. The residential sector accounts for 34% of sales and the Stowe Mountain resort (the Mountain) the remaining 11% of system sales. As a result of state COVID mandates, 2020 commercial sales fell 14.5%. Sales since then have recovered with 2022 electric sales close to pre-COVID levels. COVID had the opposite impact on residential sales; residential sales jumped 8.4% with a 3.3% gain in customers. Stowe added 111 new customers in 2020, the highest number of new customers in over ten years. Stowe continues to see strong customer growth adding an additional 125 customers since 2020. Residential sales have also stayed elevated with 2022 sales 14% higher than 2019 sales; there does not appear to be any trend back to pre-COVID usage levels. We expect to see relatively strong growth (when compared with the rest of the state) with annual residential sales growth of 0.7%, customer growth 0.9%, and annual commercial sales growth of 0.4% over the next ten years.

Stowe is a winter-peaking utility with significant load variation in the winter months; this variation is largely driven by Mountain snowmaking. Figure 10 shows projected 2023 system hourly demand for normal weather and Figure 11 shows the 2023 Town load; Town load excludes the Mountain.

Figure 10: 2023 System Projected Hourly Demand (MW)

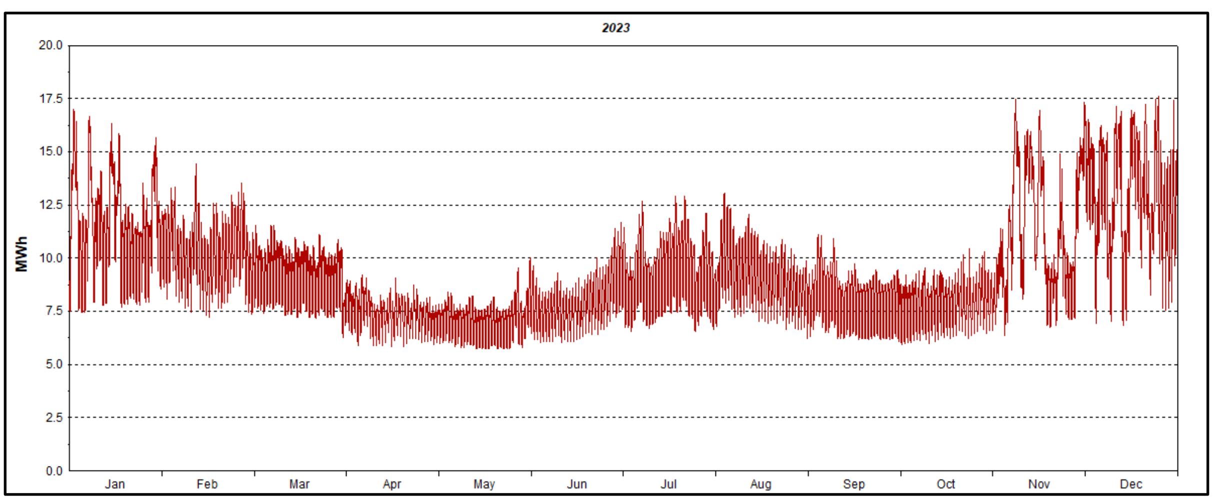
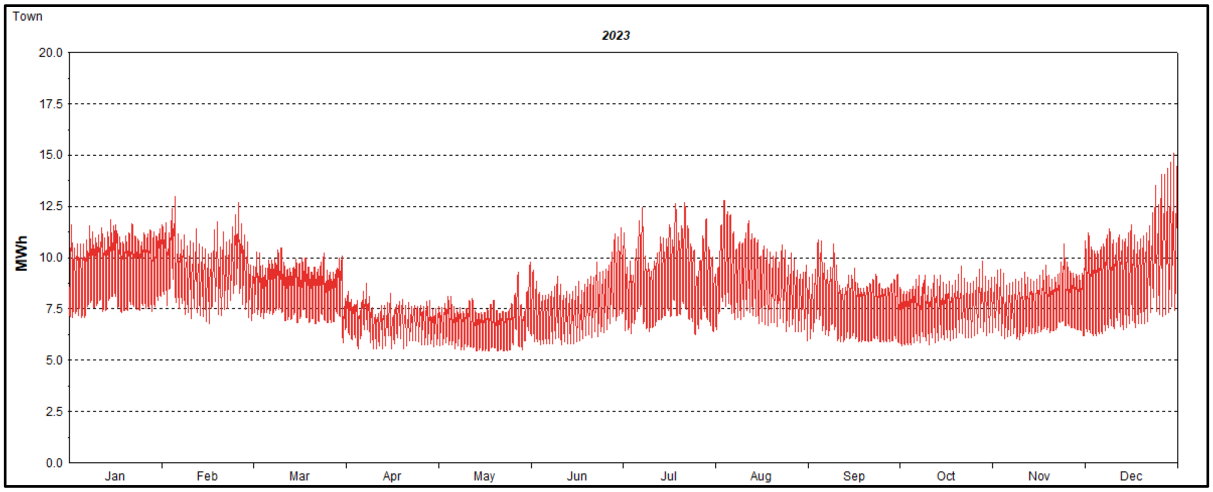


Figure 11: 2023 System (Excluding Mountain) Hourly Demand (MW)

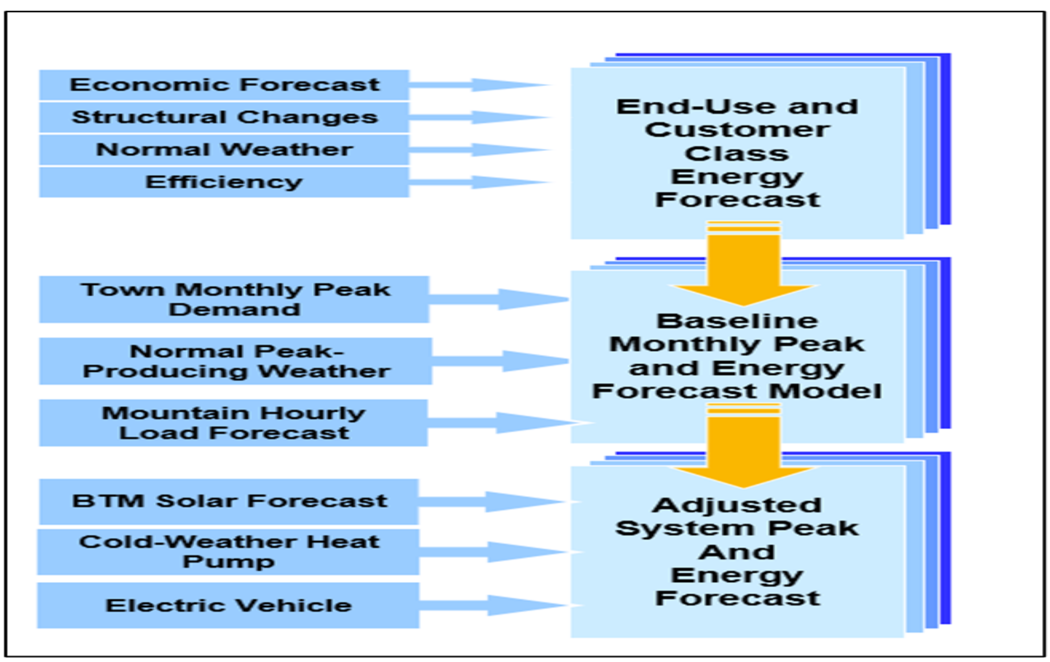


For modeling, system and town loads are adjusted for historical solar generation as our objective is to start with modeling customer demand regardless of the power source. Historical and future solar generation is then subtracted out of system and town loads for resource planning.

C.2 Forecast Summary

The forecast is derived using a bottom-up approach that starts with forecasts of residential and commercial sales that in turn are used in projecting baseline energy, peak demand, and hourly loads. The baseline forecast is then adjusted for new solar generation, electric vehicles, and heat pumps that are incentivized as part of the State's greenhouse gas reduction goals. Figure 12 illustrates the bottom-up forecast approach.

Figure 12: Forecast Framework



The baseline forecast captures customer growth, state economic activity, end-use saturation and efficiency trends, temperature trends, and state energy efficiency (EE) program savings. Table 2 and Table 3 show the baseline class sales and customer forecast.

Table 2: Sales Forecast

Year	Res_MWh	chg	Com_MWh	chg	Total_MWh	chg
2023	27,470		41,631		69,101	
2024	27,748	1.0%	41,030	-1.4%	68,778	-0.5%
2025	27,840	0.3%	41,505	1.2%	69,345	0.8%
2026	28,057	0.8%	42,009	1.2%	70,066	1.0%
2027	28,299	0.9%	42,443	1.0%	70,742	1.0%
2028	28,585	1.0%	42,864	1.0%	71,448	1.0%
2029	28,705	0.4%	43,027	0.4%	71,732	0.4%
2030	28,894	0.7%	42,997	-0.1%	71,891	0.2%
2031	29,084	0.7%	42,941	-0.1%	72,025	0.2%
2032	29,351	0.9%	43,046	0.2%	72,397	0.5%
2033	29,499	0.5%	43,007	-0.1%	72,506	0.1%
2034	29,670	0.6%	43,074	0.2%	72,744	0.3%
2035	29,930	0.9%	43,175	0.2%	73,106	0.5%
2036	30,250	1.1%	43,442	0.6%	73,693	0.8%
2037	30,456	0.7%	43,491	0.1%	73,947	0.3%
2038	30,727	0.9%	43,667	0.4%	74,394	0.6%
2039	31,030	1.0%	43,858	0.4%	74,888	0.7%
2040	31,400	1.2%	44,081	0.5%	75,481	0.8%
2041	31,619	0.7%	44,109	0.1%	75,728	0.3%
2042	31,953	1.1%	44,281	0.4%	76,234	0.7%
2043	32,301	1.1%	44,508	0.5%	76,809	0.8%
2023 - 33		**0.7%**		**0.3%**		**0.5%**
2033 - 43		**0.9%**		**0.3%**		**0.6%**

Table 3: Customer Forecast

Year	Residential	chg	Commercial	chg
2023	3,662		839	
2024	3,687	0.68%	846	0.83%
2025	3,716	0.79%	856	1.18%
2026	3,751	0.94%	866	1.17%
2027	3,787	0.96%	875	1.04%
2028	3,823	0.95%	884	1.03%
2029	3,859	0.94%	892	0.90%
2030	3,896	0.96%	899	0.78%
2031	3,932	0.92%	905	0.67%
2032	3,968	0.92%	912	0.77%
2033	4,005	0.93%	919	0.77%
2034	4,041	0.90%	925	0.65%
2035	4,077	0.89%	932	0.76%
2036	4,114	0.91%	938	0.64%
2037	4,150	0.88%	945	0.75%
2038	4,186	0.87%	951	0.63%
2039	4,223	0.88%	957	0.63%
2040	4,259	0.85%	963	0.63%
2041	4,295	0.85%	969	0.62%
2042	4,332	0.86%	975	0.62%
2043	4,368	0.83%	981	0.62%
2023 - 33		**0.90%**		**0.92%**
2033 - 43		**0.87%**		**0.66%**

Heating, cooling, and base-use energy requirements are derived from the class sales models. This data is combined with peak-day weather conditions and used in estimating Town baseline monthly peak demand. The baseline energy forecast is derived by applying line losses to the sales forecast.

Both rate class sales and system load are "reconstituted" for solar generation; past solar generation estimates are added back to sales and load. The baseline forecast is adjusted for additional solar loads, electric vehicles, and heat pumps.

Table 4 and Table **5** show the town energy and peak forecast.

Table 4: Town Energy (MWH)

Year	Town_Reconstituted	Chg	HtPmps	EV	Solar	Total	Chg
2023	72,694.10		257.66	247.09	-1,906.34	71,292.51	
2024	72,353.99	-0.5%	551.69	665.57	-2,132.33	71,438.92	0.2%
2025	72,950.44	0.8%	868.82	1,370.96	-2,276.34	72,913.89	2.1%
2026	73,709.65	1.0%	1,209.06	2,320.94	-2,343.23	74,896.43	2.7%
2027	74,420.75	1.0%	1,574.81	3,484.02	-2,437.61	77,041.98	2.9%
2028	75,163.41	1.0%	1,964.91	4,733.38	-2,496.10	79,365.61	3.0%
2029	75,461.89	0.4%	2,379.23	6,240.53	-2,501.04	81,580.61	2.8%
2030	75,629.48	0.2%	2,785.33	7,813.05	-2,549.97	83,677.89	2.6%
2031	75,769.72	0.2%	3,155.01	9,466.82	-2,610.64	85,780.91	2.5%
2032	76,161.83	0.5%	3,501.51	11,154.15	-2,710.64	88,106.86	2.7%
2033	76,275.98	0.1%	3,822.84	12,761.30	-2,720.79	90,139.33	2.3%
2034	76,526.50	0.3%	4,101.38	14,420.72	-2,765.66	92,282.94	2.4%
2035	76,906.91	0.5%	4,294.88	15,842.52	-2,777.19	94,267.12	2.2%
2036	77,524.77	0.8%	4,491.79	17,013.36	-2,829.31	96,200.62	2.1%
2037	77,792.41	0.3%	4,658.34	17,987.96	-2,834.17	97,604.54	1.5%
2038	78,262.29	0.6%	4,825.05	18,838.39	-2,879.98	99,045.76	1.5%
2039	78,782.39	0.7%	4,965.95	19,577.13	-2,891.74	100,433.74	1.4%
2040	79,405.92	0.8%	5,083.65	20,319.49	-2,944.53	101,864.54	1.4%
2041	79,666.21	0.3%	5,178.11	20,930.04	-2,943.52	102,830.84	0.9%
2042	80,197.79	0.7%	5,247.96	21,015.92	-2,943.52	103,518.16	0.7%
2043	80,802.93	0.8%	5,293.17	21,072.83	-2,943.52	104,225.42	0.7%
2023 - 2033		**0.5%**					**2.4%**
2033 - 2043		**0.6%**					**1.5%**

Table 5: Town Peak (MW)

TownPk Date	BaselineCPk	HtPmpCPk	EVCPk	SolarCPk	TownPeak	Chg
12/30/2023 17:00	15.11	0.05	0.04	-	15.21	
12/28/2024 17:00	15.22	0.10	0.12	-	15.44	1.6%
12/27/2025 17:00	15.35	0.16	0.24	-	15.75	2.0%
12/26/2026 17:00	15.45	0.23	0.41	-	16.09	2.1%
12/31/2027 17:00	15.55	0.40	0.58	-	16.53	2.8%
12/30/2028 17:00	15.62	0.50	0.82	-	16.94	2.5%
12/29/2029 17:00	15.67	0.45	1.09	-	17.21	1.6%
12/28/2030 17:00	15.68	0.53	1.36	-	17.56	2.1%
12/27/2031 17:00	15.69	0.60	1.64	-	17.92	2.1%
1/20/2032 18:00	14.09	1.83	2.73	-	18.65	4.0%
12/31/2033 17:00	15.74	1.04	2.20	-	18.98	1.8%
1/24/2034 18:00	13.95	2.15	3.51	-	19.62	3.4%
1/23/2035 18:00	13.99	2.25	3.83	-	20.07	2.3%
1/22/2036 18:00	14.03	2.34	4.06	-	20.44	1.8%
1/20/2037 18:00	14.08	2.44	4.25	-	20.77	1.6%
12/31/2038 18:00	15.69	1.32	3.82	-	20.84	0.3%
1/18/2039 18:00	13.67	2.60	4.47	-	20.75	-0.4%
1/24/2040 18:00	14.21	2.65	4.53	-	21.39	3.1%
1/22/2041 18:00	14.25	2.72	4.59	-	21.56	0.8%
1/21/2042 18:00	14.30	2.75	4.61	-	21.66	0.5%
1/20/2043 18:00	14.36	2.77	4.61	-	21.75	0.4%
2023 - 2033						**2.2%**
2033 - 2043						**1.4%**

The system load forecast is derived by combining the adjusted town and Mountain hourly load forecasts. Table 6 shows system peak and energy forecast. The time is shown for hour beginning.

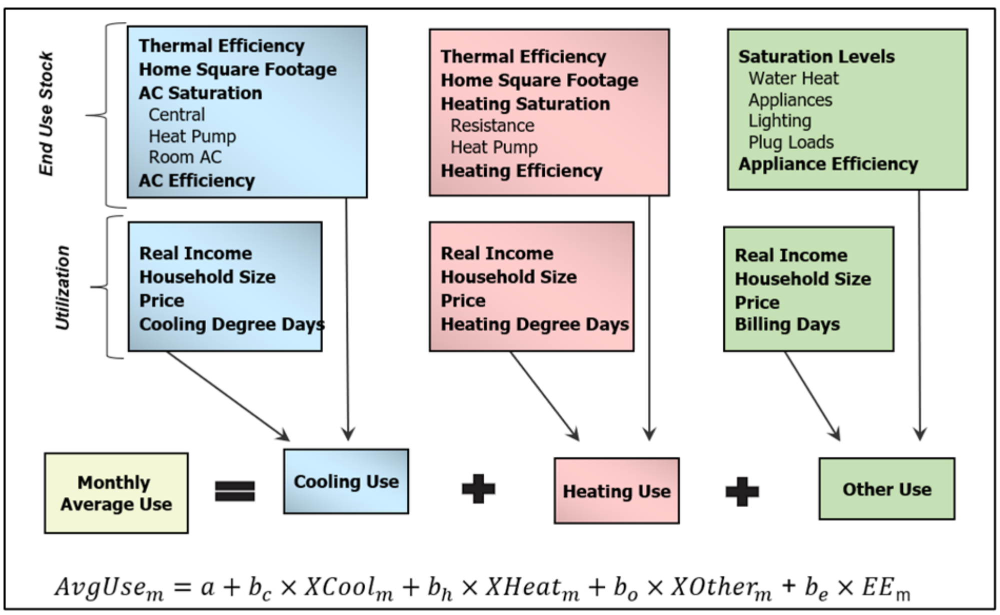
Table 6: System Peak and Energy

SystemPk Date	MW	Chg	Town_CPeak	Mtn_CPeak	MWh	Chg
12/25/2023 17:00	17.54		12.80	4.74	79,252	
1/2/2024 10:00	17.52	-0.1%	10.83	6.69	79,440	0.2%
1/2/2025 10:00	18.54	5.8%	11.85	6.69	80,873	1.8%
1/2/2026 10:00	18.99	2.4%	12.30	6.69	82,856	2.5%
12/25/2027 17:00	19.15	0.8%	14.41	4.74	85,001	2.6%
1/14/2028 20:00	19.50	1.8%	14.51	4.99	87,367	2.8%
12/11/2029 19:00	19.41	-0.5%	13.02	6.39	89,540	2.5%
12/11/2030 19:00	19.52	0.6%	13.13	6.39	91,637	2.3%
1/7/2031 18:00	20.66	5.8%	16.04	4.62	93,740	2.3%
1/14/2032 20:00	21.80	5.5%	16.81	4.99	96,108	2.5%
1/14/2033 20:00	22.11	1.4%	17.12	4.99	98,098	2.1%
1/28/2034 18:00	21.98	-0.6%	18.87	3.11	100,242	2.2%
1/29/2035 18:00	22.01	0.1%	18.68	3.33	102,226	2.0%
1/29/2036 18:00	22.14	0.6%	18.81	3.33	104,202	1.9%
1/14/2037 20:00	23.68	6.9%	18.69	4.99	105,564	1.3%
1/14/2038 20:00	23.64	-0.2%	18.65	4.99	107,005	1.4%
1/14/2039 20:00	24.08	1.9%	19.09	4.99	108,393	1.3%
1/28/2040 18:00	23.52	-2.3%	20.41	3.11	109,866	1.4%
1/29/2041 18:00	23.17	-1.5%	19.84	3.33	110,790	0.8%
1/7/2042 18:00	24.03	3.7%	19.41	4.62	111,477	0.6%
1/14/2043 20:00	24.58	2.3%	19.59	4.99	112,185	0.6%
2023 - 2033		**2.4%**				**2.2%**
2033 - 2043		**1.1%**				**1.4%**

C.3 Forecast Approach

The forecast process begins with developing long-term residential and commercial sales forecasts. Customer heating, cooling, and base-use energy requirements are then used to calculate energy requirements and drive system peaks through a monthly peak-demand regression model. Over the long-term, structural changes as well as changes in economic and weather conditions drive customer usage. Improvements in end-use efficiency resulting from new appliance and business equipment efficiency standards and state energy efficiency programs have had a significant impact on customer usage across the state. The impact of end-use efficiency improvements is captured through monthly customer average use models estimated using a Statistically Adjusted End-Use (SAE) model framework. The SAE model is estimated using a linear regression specification that relates customer average-use to estimates of heating (XHeat), cooling (XCool), and base-use (XOther) energy requirements. The end-use variables are constructed by combining structural elements such as end-use saturation, average end-use stock efficiency, and index for housing thermal shell improvements with economic drivers, weather conditions, and price. Figure 13 shows the residential average-use SAE model specification.

Figure 13: Residential SAE Model Overview

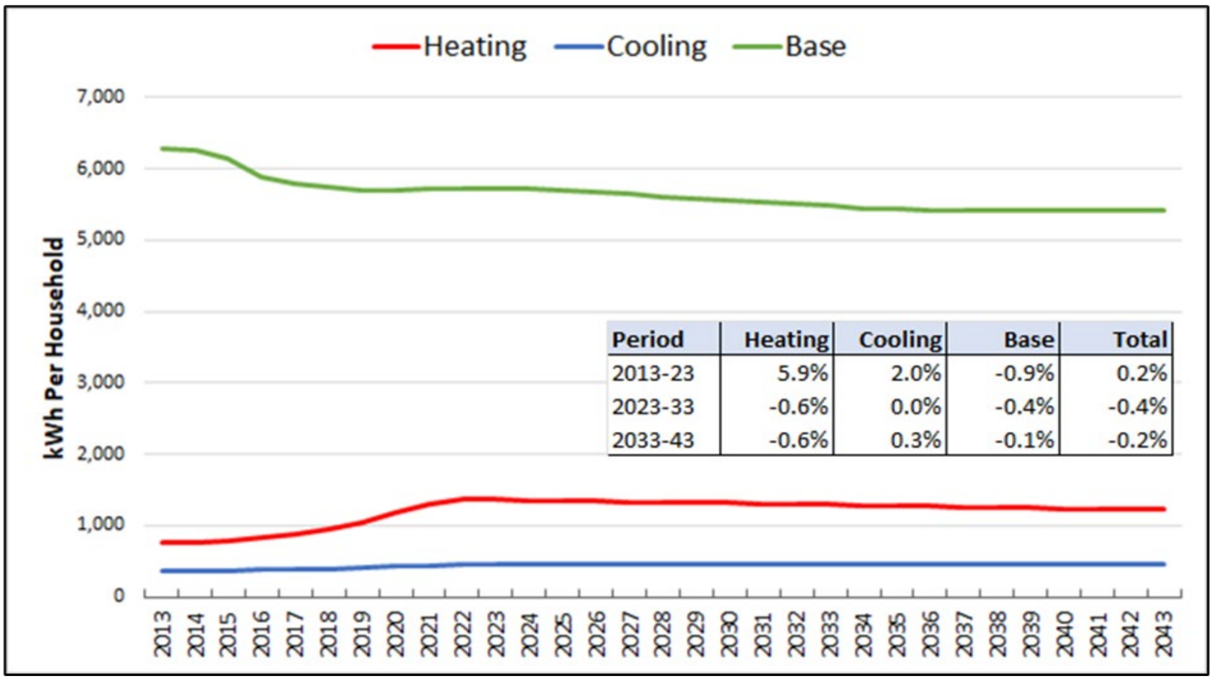


C.3.1 Residential Class Sales Forecast

The residential sales forecast is derived as the product of monthly average-use and customer forecasts. Models are estimated from reported monthly sales and customers. Because a significant amount of residential energy use is self-generated through rooftop and community-based solar systems, estimated monthly self-generation is added back to the historical sales data; models are estimated for the reconstituted data series. The baseline forecast is then adjusted for past solar generation.

End-Use Intensities. Over the last ten years, there has been a significant decline in overall end-use intensities measured in kWh per household. For most end-uses, increases in stock efficiency have been greater than increase in saturation. Cooling is an exception where saturation has been increasing faster than equipment efficiency. Miscellaneous is the other end-use where sales continue to increase. Miscellaneous includes everything from home computer equipment, electric lawnmowers, plug loads to spas. Figure **14** shows aggregated end-use intensity trends when mapped to cooling, heating, and base use (non-weather sensitive end-uses).

Figure 14: Aggregated End-Use Energy Intensities



Period	Heating	Cooling	Base	Total
2013-23	5.9%	2.0%	-0.9%	0.2%
2023-33	-0.6%	0.0%	-0.4%	-0.4%
2033-43	-0.6%	0.3%	-0.1%	-0.2%

For most end-uses, energy intensity declines through 2030 largely because of new appliance standards and continued state efficiency activity. Base use intensity shows moderate increase after 2030 as miscellaneous intensity continues to increase, and impact of current appliance standards slow. Historically, cooling intensity has been increasing as strong increases in cooling saturation have outweighed efficiency gains; intensities flatten out over the forecast period as efficiency begins to outweigh further air conditioning purchases.

Economic Drivers. Economic and demographic impacts are captured through the interaction of end-use intensities with household size and household income in the constructed XHeat, XCool, and XOther model variables. Household size and income projections are derived from January 2023 Vermont economic forecast.

Weather Drivers. XHeat also includes monthly heating-degree-days (HDD) to capture temperature-driven heating sales and XCool incorporates monthly cooling degree-days (CDD) to account for cooling sales variation. HDD and CDD projections reflect expected increases in average temperature. Increases in temperature result in fewer HDD (contributing to the decline in heating use) and more CDD (driving the cooling use higher). Figure 15 through Figure 17 show the model variables.

Figure 15: XHeat (kWh per customer)

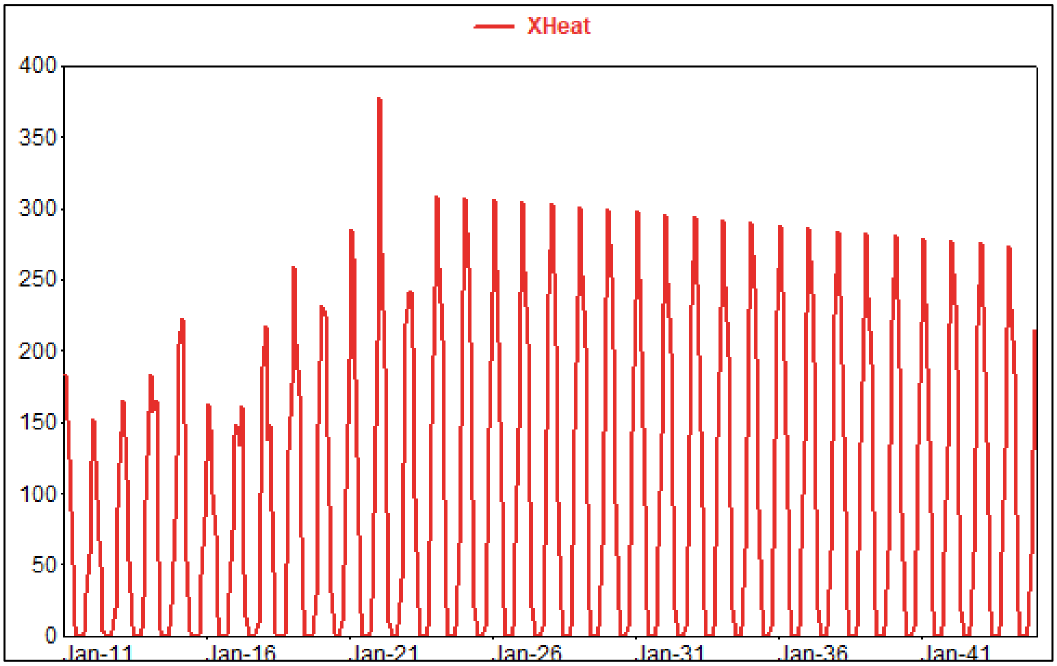


Figure 16: XCool (kWh per customer)

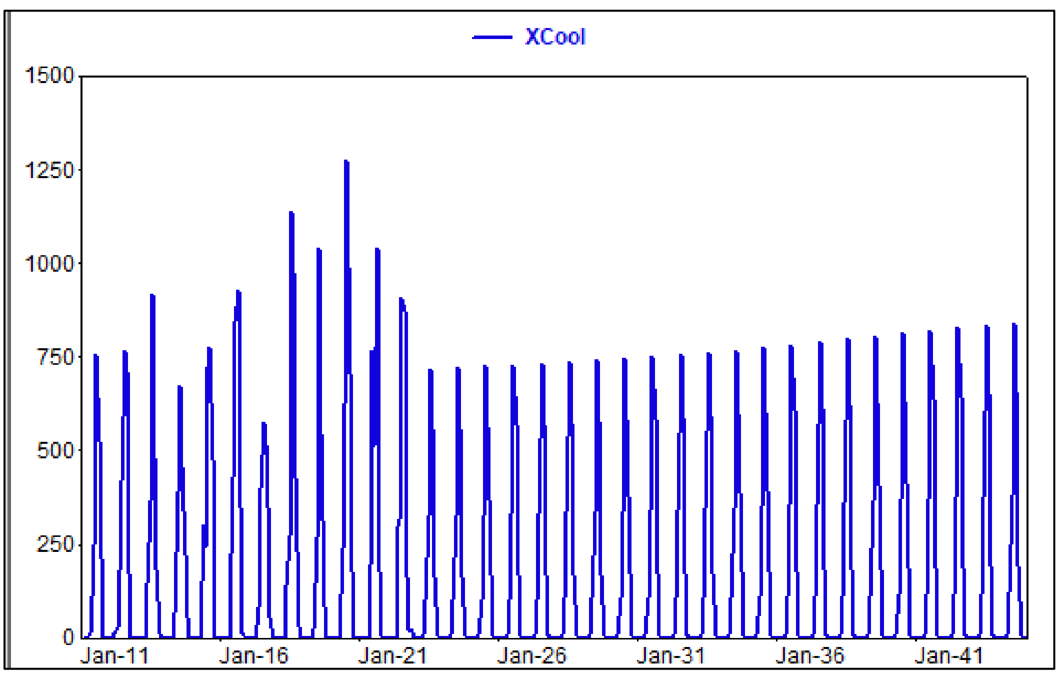
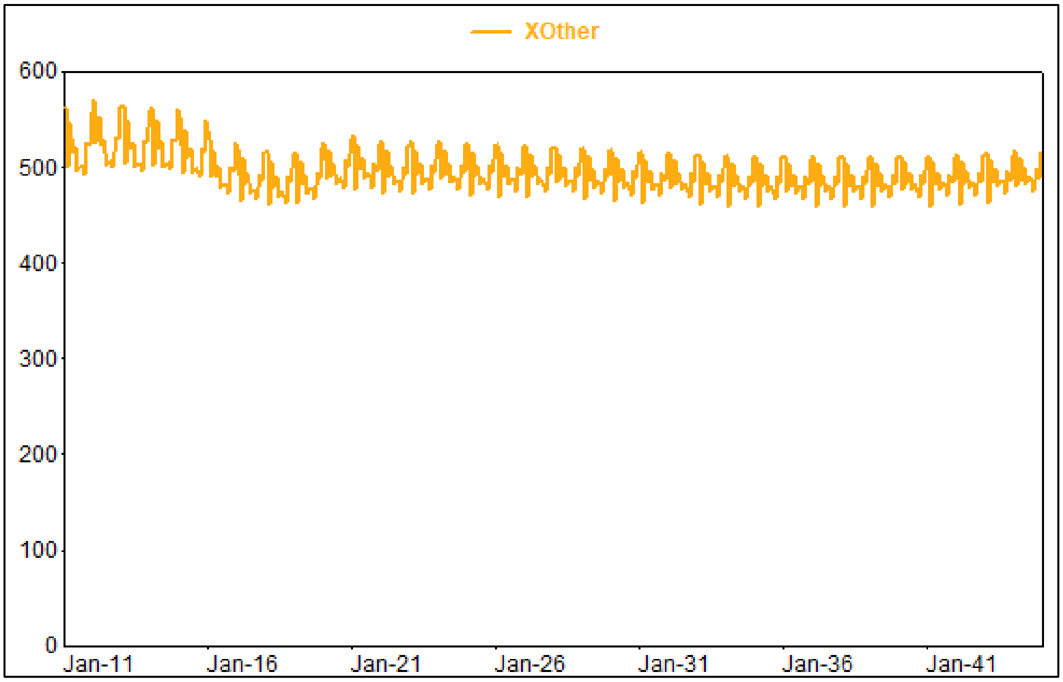


Figure 17: XOther (kWh per customer)



The constructed end-use variables are incorporated into an average-use regression model. The model is estimated with reconstituted average use from January 2012 to March 2023. Reconstituted average use is derived by adding estimates of historical solar-generation for own-use to residential sales. Model results are summarized in Figure 18.

Figure 18: Residential Average Use Model Update

Variable	Coefficient	T-Stat	P-Value
XHeat	0.689	9.552	0.00%
XCool	0.081	4.141	0.01%
XOther	1.11	43.114	0.00%
COVID_Impact	2.992	1.967	5.15%

Model Statistics	
Iterations	16
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.939
Adjusted R-Squared	0.932
Std. Error of Regression	27.2
Mean Abs. Dev. (MAD)	20.16
Mean Abs. % Err. (MAPE)	3.34%
Durbin-Watson Statistic	1.875

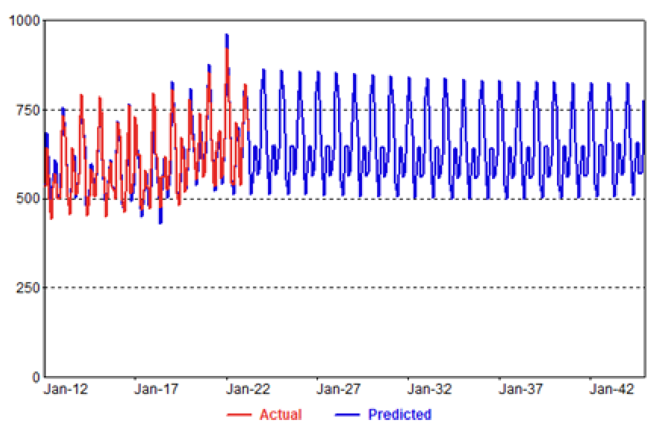


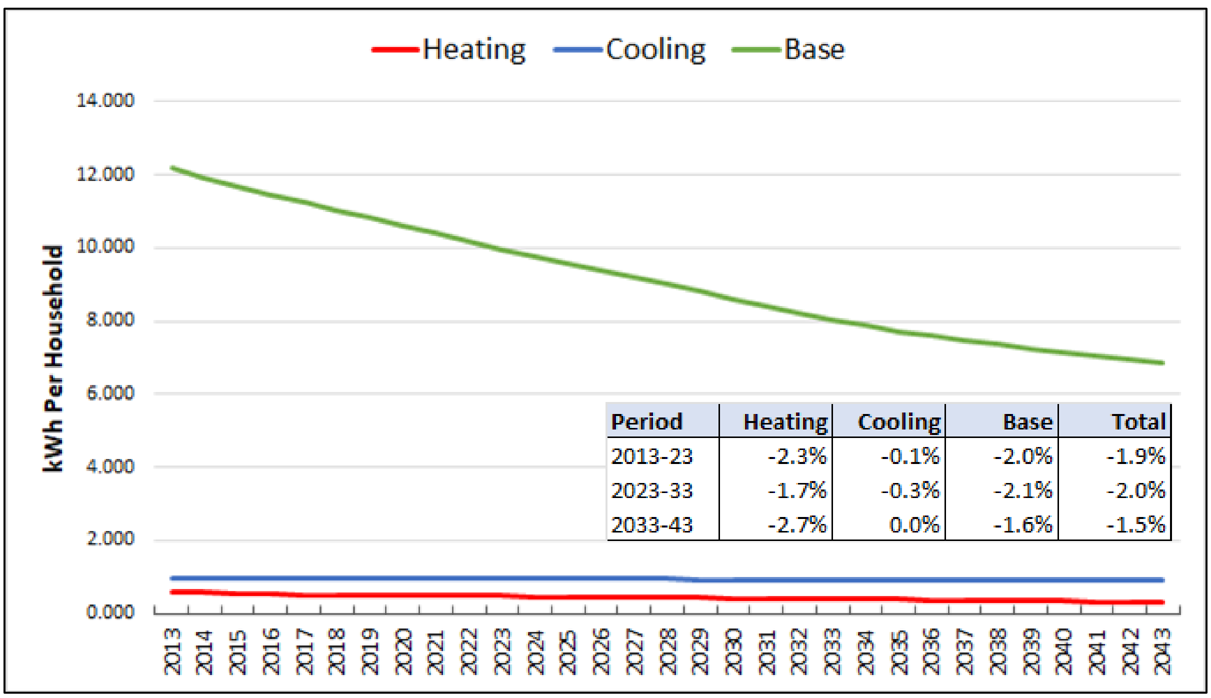
Figure 18 shows the coefficients for the primary model variables. All the variables are statistically significant as indicated by the T-Statistic and P Values. Again, the historical average-use data has been adjusted to include solar own-use consumption; the average-use forecast includes what is purchased from Stowe and is self-generated. COVID-19 has had a positive impact on residential sales, reflecting stay-at-home orders and an increase in customers now working from home.

C.3.2 Commercial Average Use Model

Commercial average-use is also modeled using an SAE model specification where commercial average-use is defined as a function of monthly heating requirements (XHeat), cooling requirements (XCool), and non-weather sensitive use (XOther). The model variables incorporate end-use intensities (measured in kWh per square-foot), state GDP, and monthly HDD and CDD.

As in the residential sector, there have been significant declines in commercial end-use intensities because of improvements in end-use efficiency; kWh per square foot have steadily declined. Figure 19 shows commercial end-use energy intensity forecasts for heating, cooling, and non-weather sensitive use (base).

Figure 19: Commercial End-Use Energy Intensity



Given temperate summer and low saturation of electric heat, commercial heating and cooling intensities are relatively small. It is largely the decline in the non-weather sensitive end-uses (Base) that is driving commercial sales lower. The end-uses showing the strongest decline are commercial lighting and ventilation. Figure 20 to Figure 22 show the commercial end-use model variables.

Figure 20: Commercial XHeat (kWh per Square Foot)

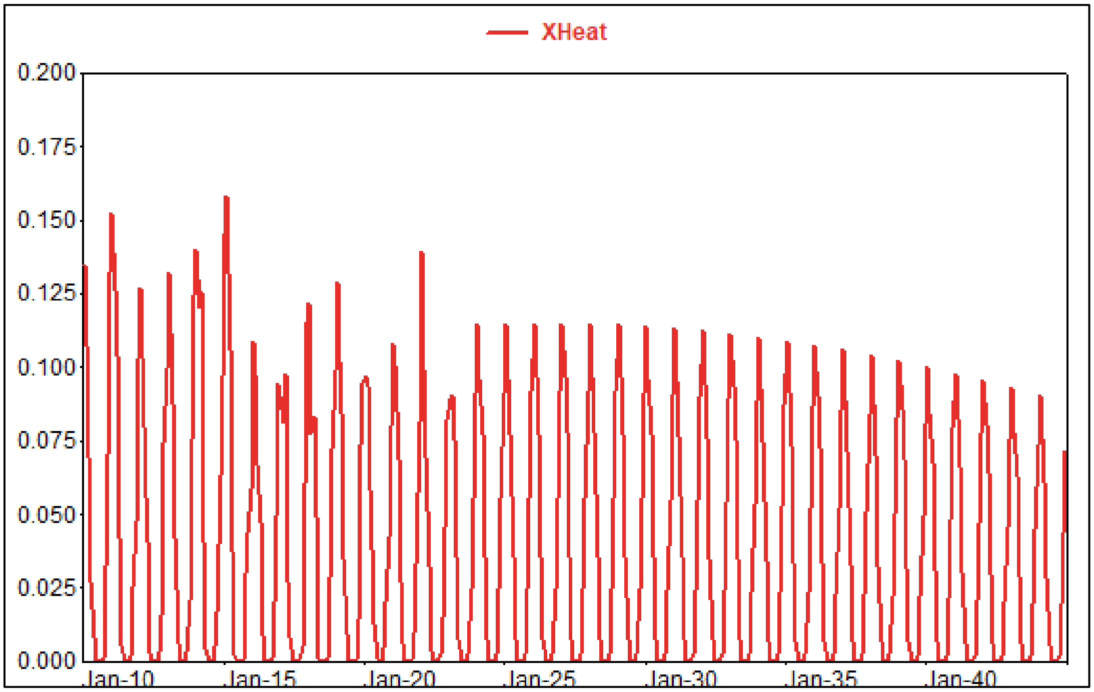


Figure 21: Commercial XCool (kWh per Square Foot)

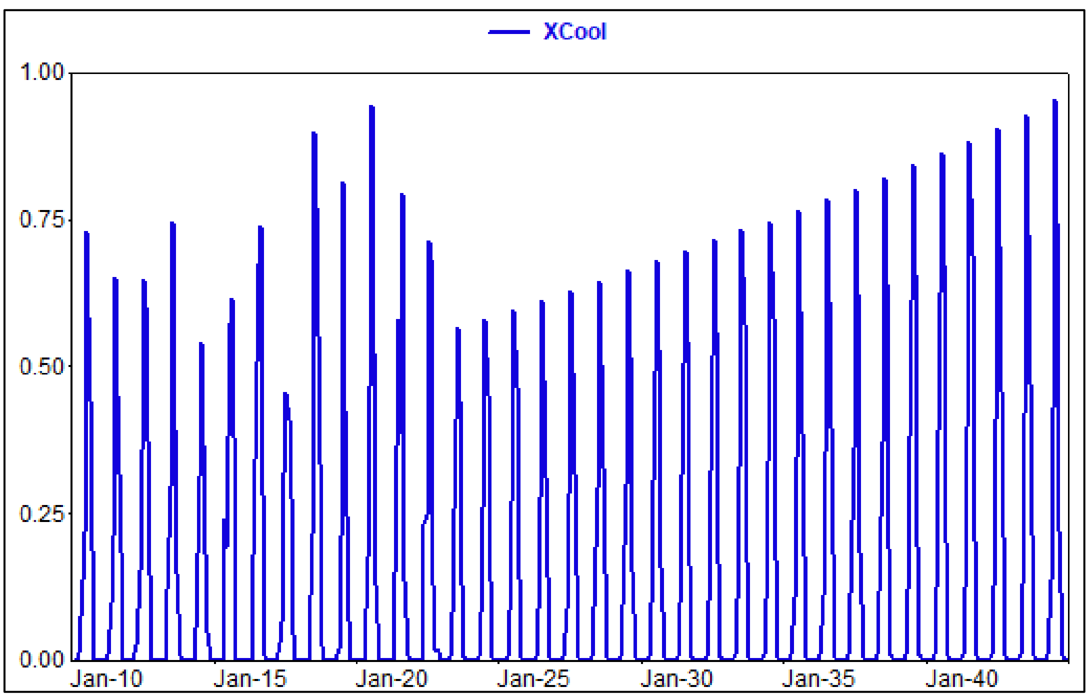
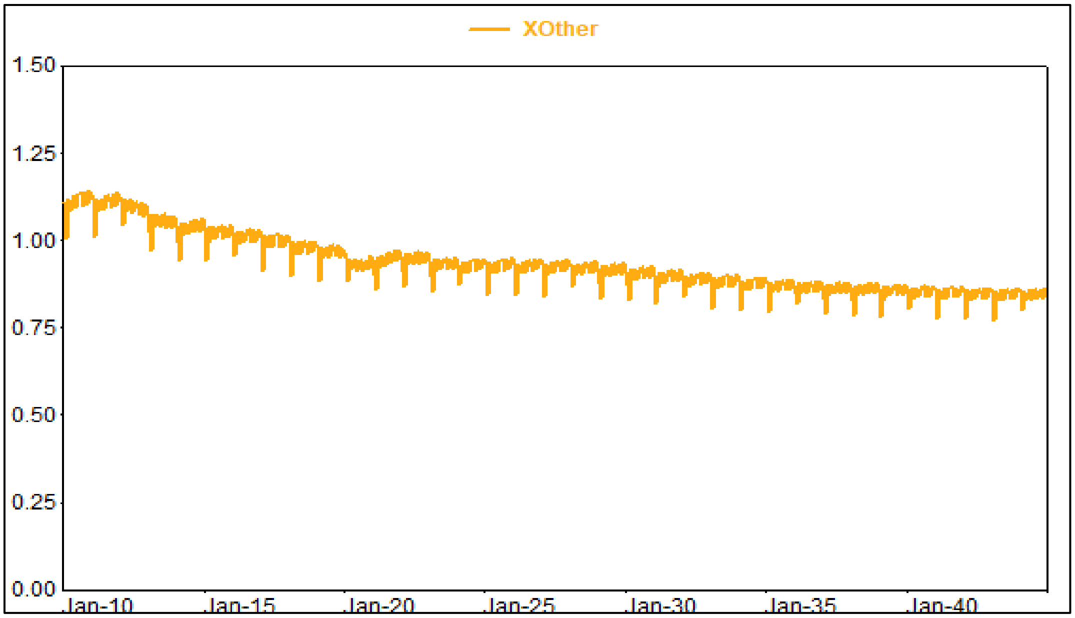


Figure 22: Commercial XOther (kWh per Square Foot)

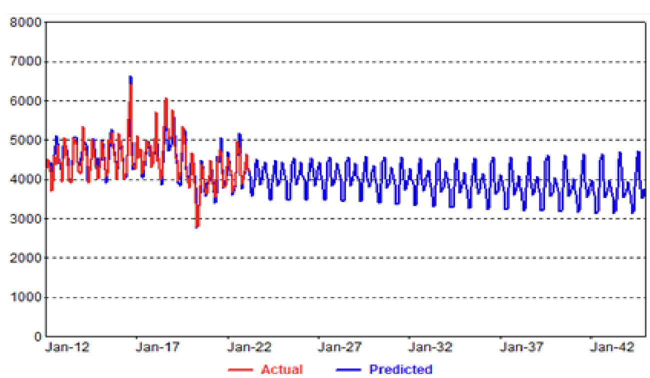


Increasing temperatures contribute to declines in heating requirements and increases in cooling requirements. The impact, however, is relatively small as commercial cooling and heating use are small in comparison with non-weather sensitive commercial use; non-weather-sensitive uses account for nearly 90% of commercial usage.

XHeat, XCool, and XOther are used in estimating a commercial monthly average use sales model; the estimation period is January 2012 through March2023. Figure 23 shows the commercial average use model results.

Figure 23: Commercial Average Use Model

Variable	Coefficient	T-Stat	P-Value
XHeat	4042.13	41.95	0.00%
XCool	6992.295	7.333	0.00%
XOther	1709.83	9.823	0.00%
COVID_Impact	17.347	2.779	0.63%



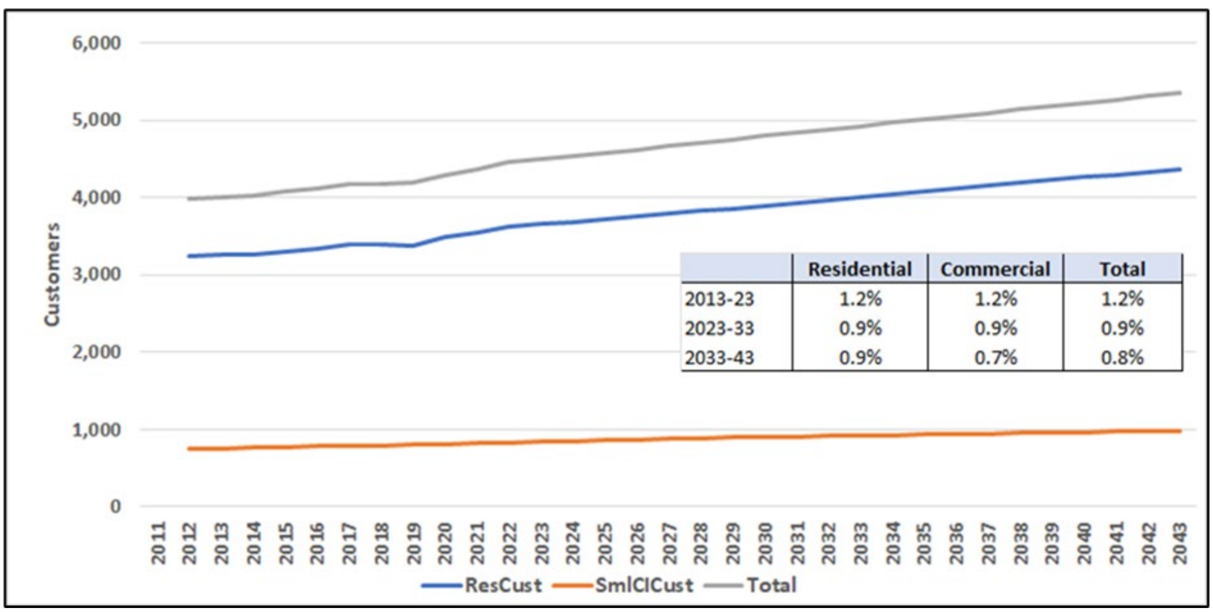
Model Statistics	
Iterations	10
Adjusted Observations	134
Deg. of Freedom for Error	123
R-Squared	0.806
Adjusted R-Squared	0.79
Std. Error of Regression	257.01
Mean Abs. Dev. (MAD)	191.48
Mean Abs. % Err. (MAPE)	4.25%
Durbin-Watson Statistic	2.209

The primary model variables are statistically significant. The model fit (as measured by the adjusted R-Squared) is weaker than the residential model as there is significant monthly variation in the historical data that cannot be explained by weather or state-level economic activity. The unexplained variation could be the result of billing adjustments or simply timing of the monthly data collection and billing process. COVID-19 has a significant impact on sales as illustrated in the graph. Sales are still running below the pre-COVID level. With employees continuing to work from home at least part of the time, we do not expect to get back to pre-COVID consumption levels.

C.3.3 Customer Forecast

Residential customers are forecasted using a simple trend model; we could not statistically tie the strong customer growth with slower state household projections. The trend model indicates that we can expect to add approximately 36 new customers per year. Commercial customers are derived from a regression model that weights state GDP and households. We project on average 6 new commercial customers per year over the forecast period. The model is estimated with monthly customer count data from January 2012 through March 2023. Figure 24 shows Stowe customer forecast.

Figure 24: Customer Forecast (forecast begins April 2023)

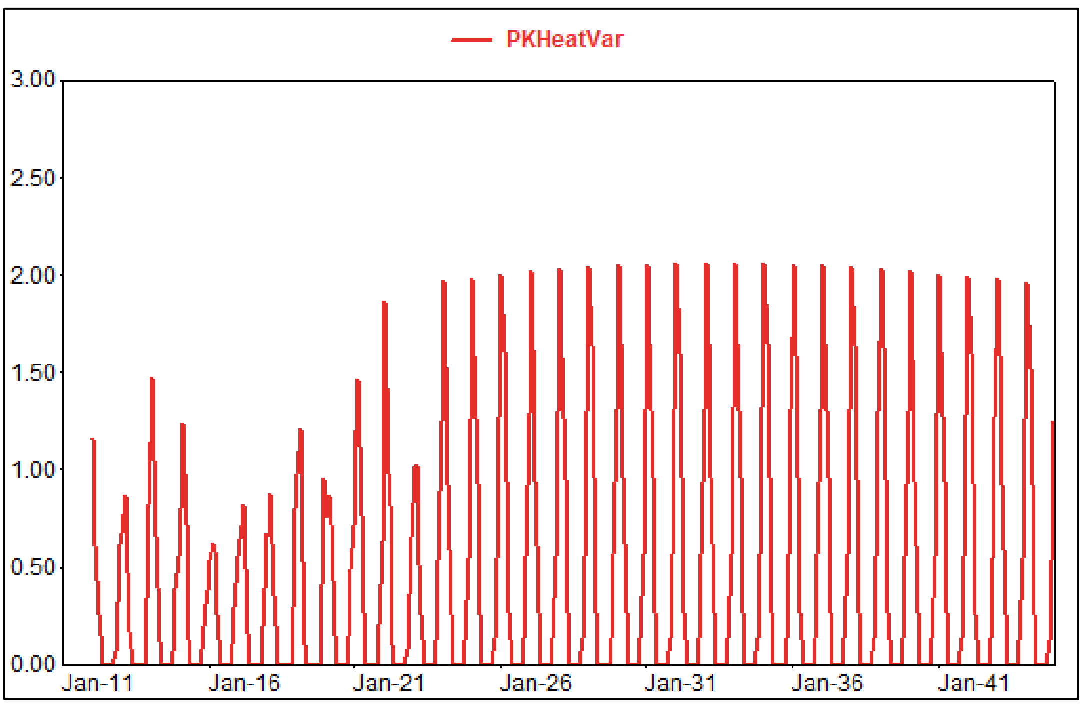


C.3.4 Baseline Energy and Demand Forecast

The Town Baseline energy forecast is calculated by applying historical loss factors to the Town reconstituted sales forecast. Total system energy forecast is the sum of the Town energy and Mountain energy forecasts. Mountain energy use is primarily sales for snowmaking. The Mountain sales forecast is based on average sales over the last five years. Adjusted for line losses, Mountain energy is approximately 9,000 MWh per year.

System peak demand is driven by heating, cooling, and non-weather sensitive (base-use) energy requirements. Baseline peak demand is estimated with a monthly regression model that relates monthly peak-demand to peak-day HDD and CDD, and system heating, cooling, and base-use load requirements derived from the class sales models. The peak model variables are defined as the interaction of peak-day CDD and HDD with cooling and heating energy requirements and estimated baseload requirements. Figure 25 shows estimated peak-day heating requirements. The model is estimated through March 2023 with the forecast beginning April 2023.

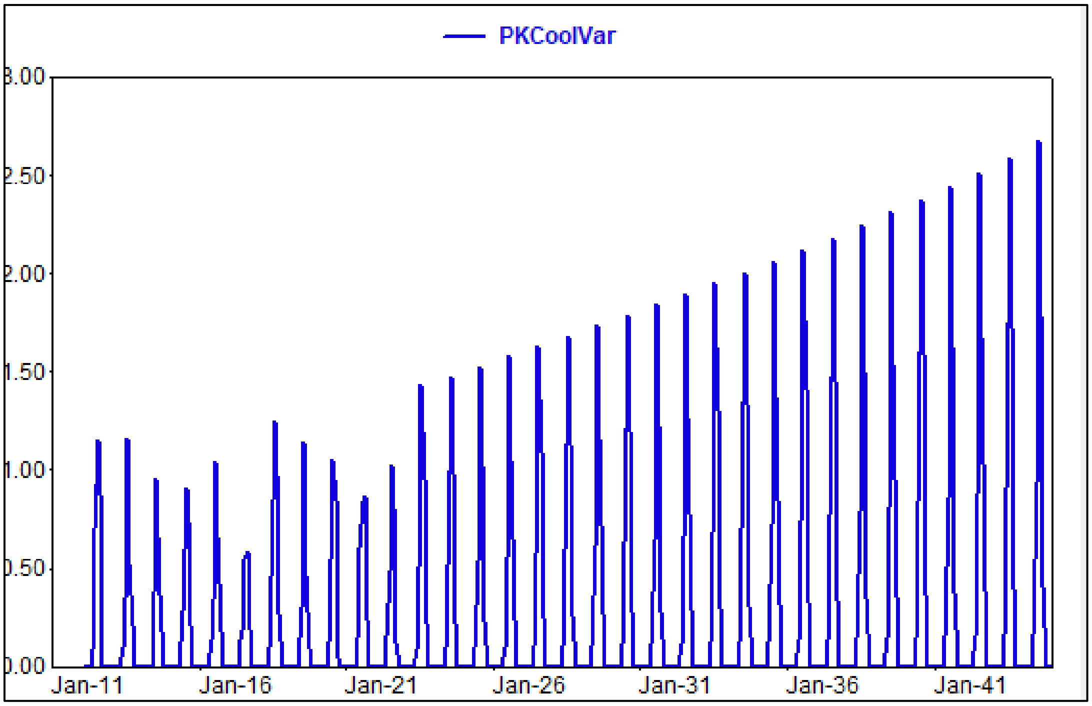
Figure 25: Peak-Day Heating Requirements (MW)



The heating variable excludes the impact of future heat pump market penetration as heat pumps are treated as an adjustment to the baseline energy and peak forecast. The baseline heating variable declines over time as a result of heating efficiency improvements (both end-use and home thermal shell integrity) and warming temperature trend (fewer HDD).

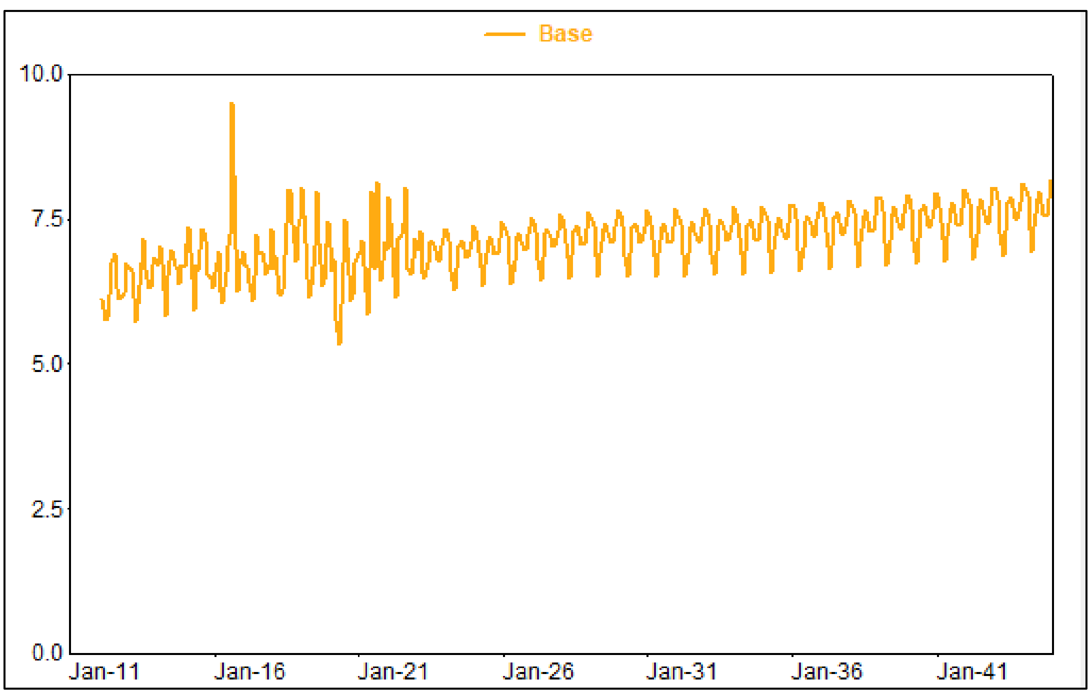
Similar peak-day load estimates are generated for cooling and non-weather sensitive use (base-use). Constructed variables are shown in Figure 26 and Figure 27.

Figure 26: Peak-Day Cooling Requirements (MW)



While cooling intensities are relatively flat, customer growth and increasing temperatures contribute to increase in peak day cooling requirements.

Figure 27: Peak-Day Base Load Requirements (MW)



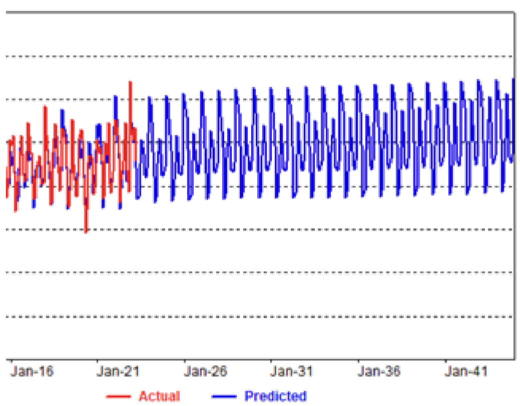
The peak base use model increases moderately over time largely driven by customer growth and increase in miscellaneous energy consumption.

The peak demand model is estimated as a function of the peak-day heating, cooling, and base use variables. The model is estimated over the period January 2013 to March 2023. Figure 28 shows the model results.

Figure 28: Town Peak Model (MW)

Variable	Coefficient	T-Stat	P-Value
Base	1.029	7.001	0.00%
Base_Apr	-0.189	-5.096	0.00%
Base_May	-0.14	-4.314	0.00%
Base_Nov	-0.084	-2.678	0.84%
Base_Dec	0.24	7.847	0.00%
PkHeat	2.029	11.027	0.00%
PkCool	1.432	5.602	0.00%

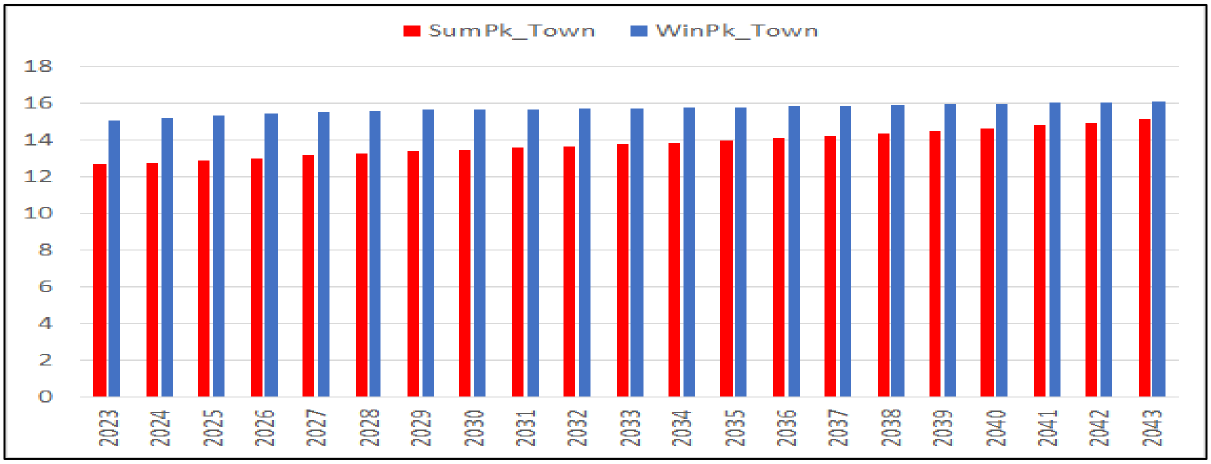
Model Statistics	
Iterations	1
Adjusted Observations	134
Deg. of Freedom for Error	122
R-Squared	0.878
Adjusted R-Squared	0.867
Std. Error of Regression	0.61
Mean Abs. Dev. (MAD)	0.46
Mean Abs. % Err. (MAPE)	4.22%
Durbin-Watson Statistic	1.424



The COVID-19 impact is captured in the model base variable. The primary model variables are statistically significant. The model fit is improved by interacting monthly binaries for April, May, November, and December with the peak-day nonweather sensitive load variable Base.

Figure 29 shows the Baseline summer and winter peak demand. Summer baseline peak is increasing faster than winter baseline peak, but Stowe remains a winter peaking utility through the forecast period particularly after adjusting for EV charging and heat pumps.

Figure 29: Baseline Town Peak Demand Forecast



C.3.5 Adjusted Energy and Demand Forecast

The forecast expected case was developed with VELCO and the VSPC forecast subcommittee as part of the 2023 VELCO IRP forecast. The expected case is based on recent state policy designed to lower state CO2 emissions through reduction in fossil fuel for heating and transportation. The primary activity is through incentives to encourage heat pump adoption, a new program to reduce fossil fuel heating through a clean heat credit market, and adoption of California EV standards that require all new light-duty vehicle sales to be electric by 2035. In addition, the state is promoting fleet electrification (e.g., electric city and school buses) and working to build electric charging infrastructure across the state.

The forecast assumes strong heat pump saturation reaching 50% by 2043. Light-duty EV adoption is expected to near 100% by 2035, with additional electrification in the fleet vehicle market. Solar load also continues to increase but slows over time as reflected in actual adoption data and expected system costs. Energy efficiency programs are expected to continue to be funded at current funding levels adjusted for inflation.

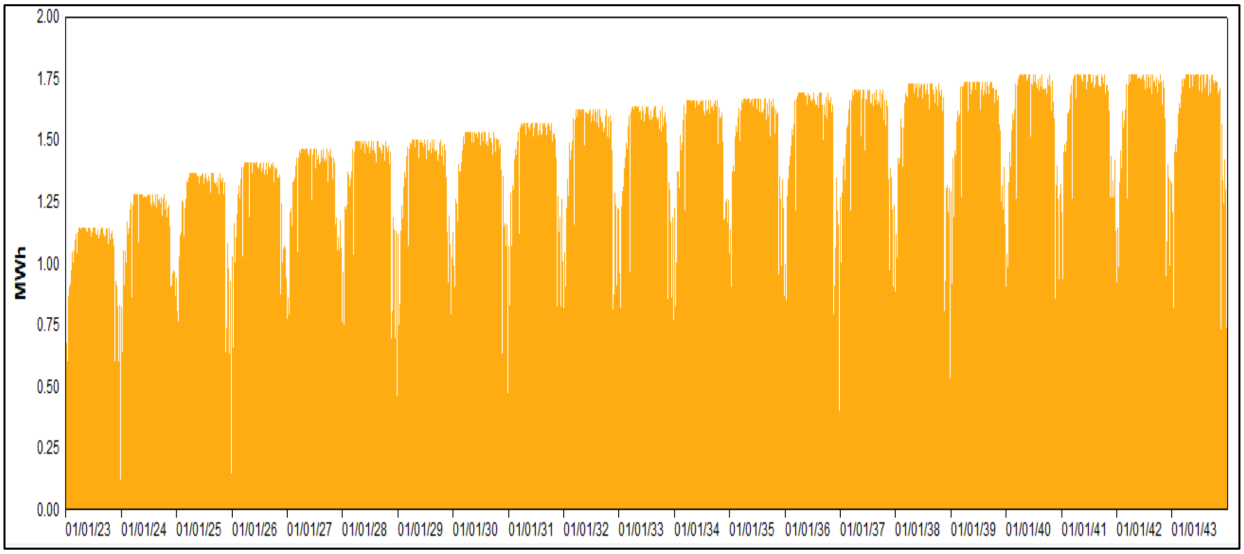
State-level projections of heat pumps, electric vehicles, and energy efficiency savings are allocated to Stowe based on Stowe's percent of the state electric customers.

The Adjusted hourly load forecast is derived by combining the Baseline hourly load forecast with the solar, heat pump, and EV hourly load forecasts.

C.3.5.1 Solar Load Forecast

Figure 30 shows BTM hourly solar load forecast. The BTM solar capacity forecast is based on a regression model that relates installed capacity to simple payback. The capacity forecast is translated to monthly generation and hourly load forecasts based on a typical solar load profile for Stowe.

Figure 30: Solar Hourly Load Forecast (2023 - 2043)



Given that Stowe peaks at night in January, solar adoption has no impact on system peak demand.

C.3.5.2 Cold Climate Heat Pump Impact

Over the last four years there have been over 50,000 heat pumps that have been installed statewide as part of the VEIC incentive program; heat pump saturation has increased from 10% of homes to 20%. While we don't know the specific number of heat pumps that have been adopted in Stowe, we can see from the sales data that it has been measurable; it is part of the reason residential usage is not trending back to pre-COVID levels. In the base case, VEIC expects the number of heat pumps sold through the program to ramp up to 18,000 per year by 2029; after that the number of new heat pumps adopted through the program slows. We assume that Stowe will see similar heat pump growth scaled to number of Stowe electric customers; Stowe accounts for approximately 1.2% of State electric customers. Heat pumps are expected to add significant load. Figure 31 show the heat pump sales forecast. By 2043 heat pump energy requirements (after adjusting for line losses) reach 5,200 MWh with maximum peak demand of 3.2 MW and coincident peak demand of 2.8 MW. Figure 32 shows expected 2043 heat pump loads.

Figure 31: Heat Pump Load Forecast

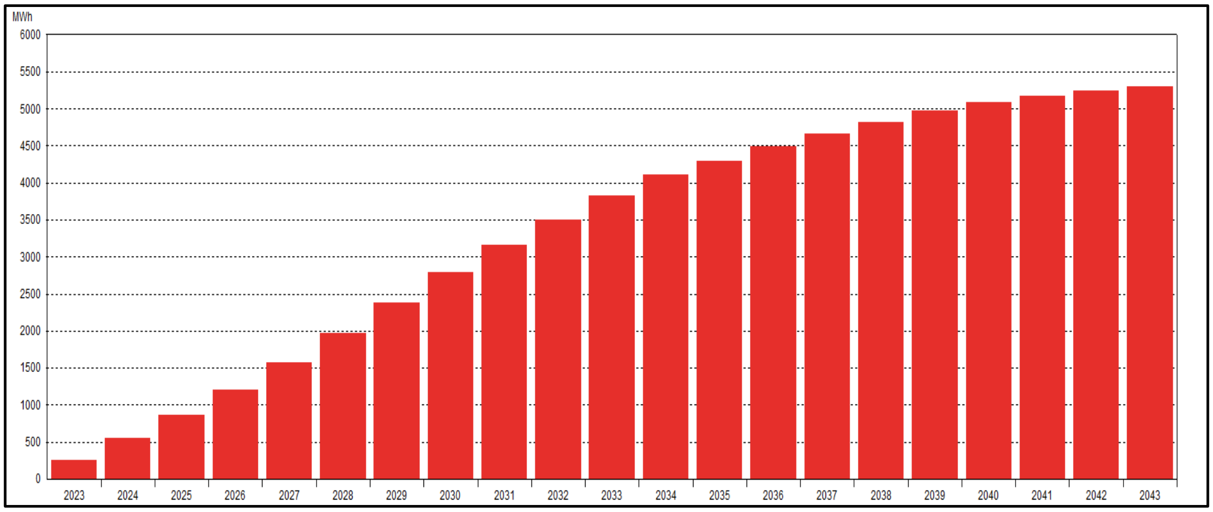
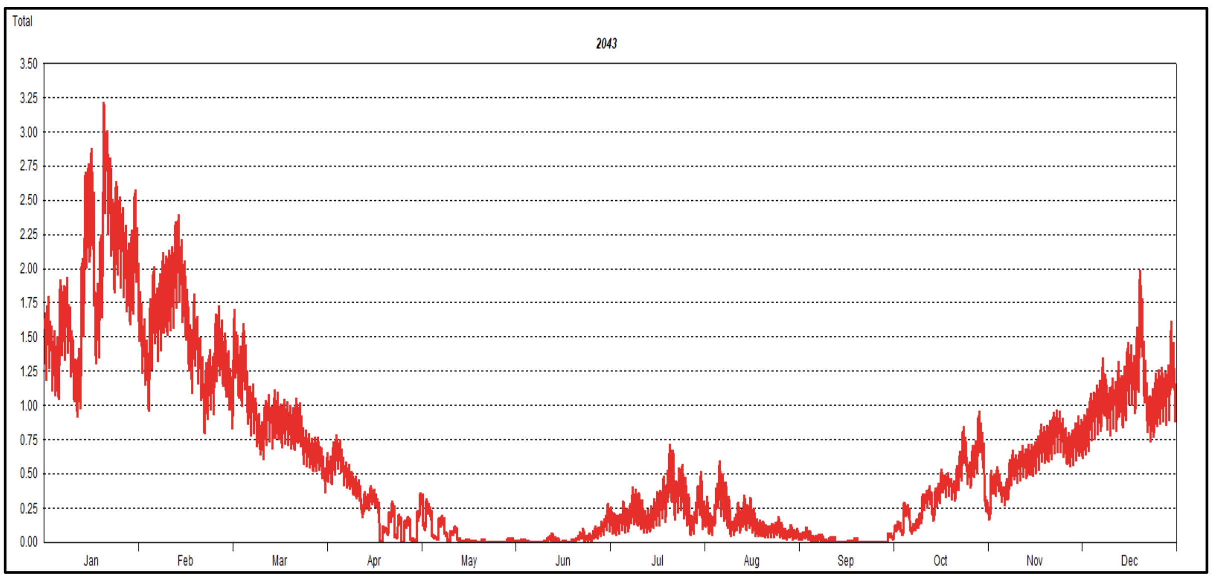


Figure 32: Heat Pump Loads 2043



C.3.5.3   Electric Vehicle Impact

The electric vehicle (EV) forecast was developed in conjunction with the 2023 VELCO Long-Term forecast. The forecast captures the increased adoption of electric vehicles and the charging requirements of these vehicles. While relatively small now, EVs are forecasted to increase significantly after 2030. By 2043, electric vehicles are projected to account for nearly 90% of all registered vehicles.

Figure 33 through Figure 35 show the electric vehicle load impacts.

Figure 33: Electric Vehicle Load Impacts 2023 to 2043

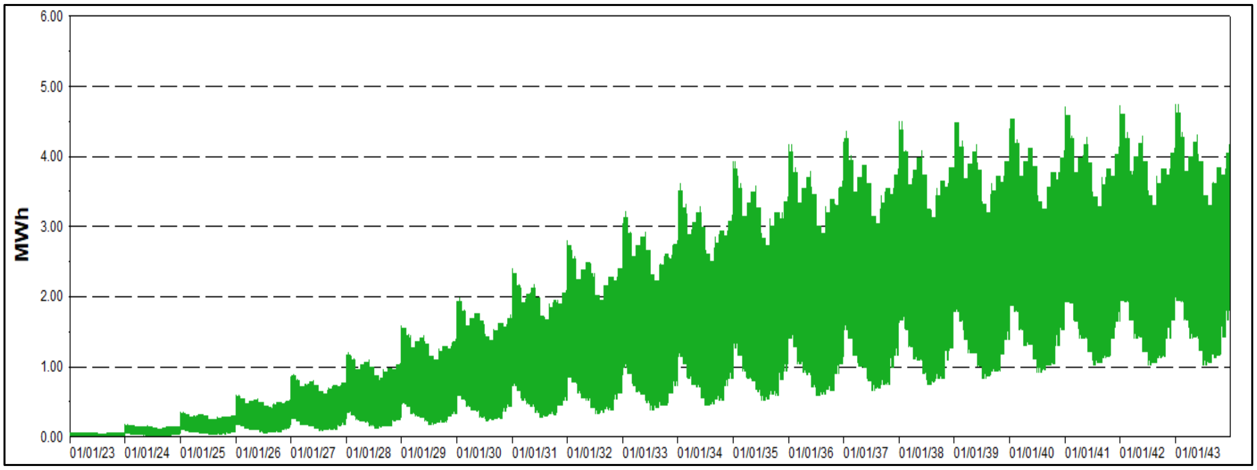


Figure 34: Electric Vehicle Load Impacts 2043

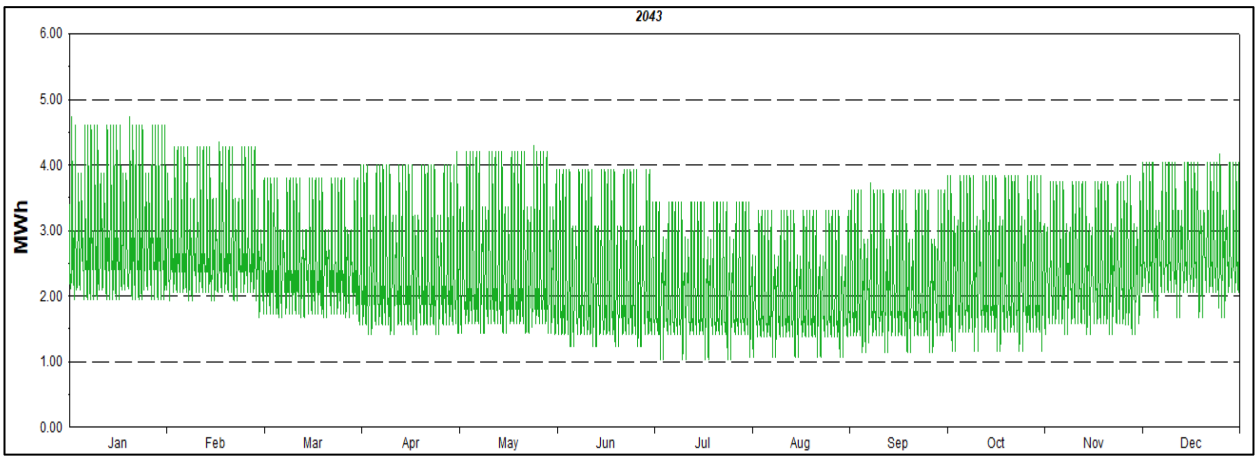
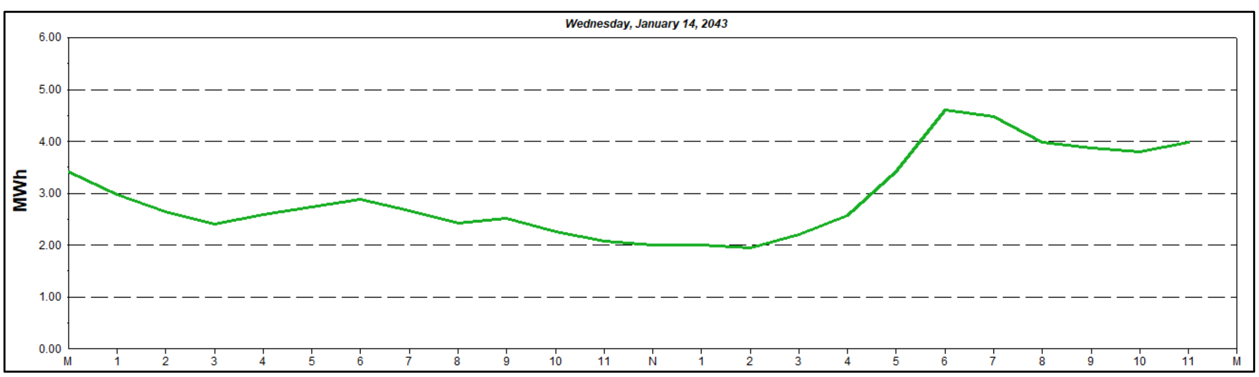
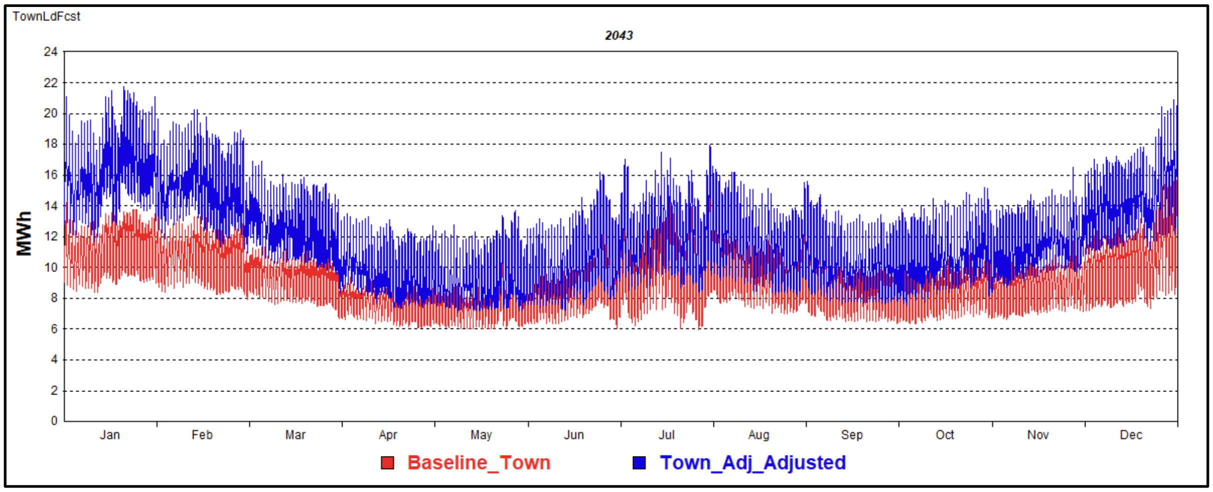


Figure 35: Electric Vehicle Load Impacts Peak Day 2043



The *Adjusted* system load forecast is derived by subtracting the solar forecast from the *Baseline* forecast and adding the heat pump and hourly electric vehicle load forecasts. Figure 36 compares baseline and adjusted town-level load forecast.

Figure 36: Baseline and Adjusted Forecast Comparison – Winter Week, 2043



Without adjustments baseline peaks at 16 MW in 2043; adjustments contribute an additional 5.8 MW - a 37% increase in winter peak demand.

C.4 Forecast Data and Assumptions

C.4.1 Sales, Customer, and Load Data

Monthly residential and commercial average use models are estimated from historical billed sales and customer counts. These models are estimated using data from January 2012 to March 2023. The peak demand model is based on monthly peak demands derived from Stowe's system hourly load data over the period January 1, 2013, to March 31, 2023.

C.4.2 Weather Data

Monthly variation in winter usage is captured by heating degree-days (HDD) while changes in monthly cooling requirements are associated with monthly cooling-degree-days (CDD). HDD has a positive value when temperatures are below a specified temperature reference point and CDD is positive when temperatures are above a temperature reference point. For Stowe, HDD with a temperature base of 55 degrees and CDD with a base of 65 degrees result in the best model statistical fit. HDD and CDD are calculated from daily average temperature data from Burlington International Airport. Monthly HDD and CDD are calculated as the sum of the daily degree days during the month:

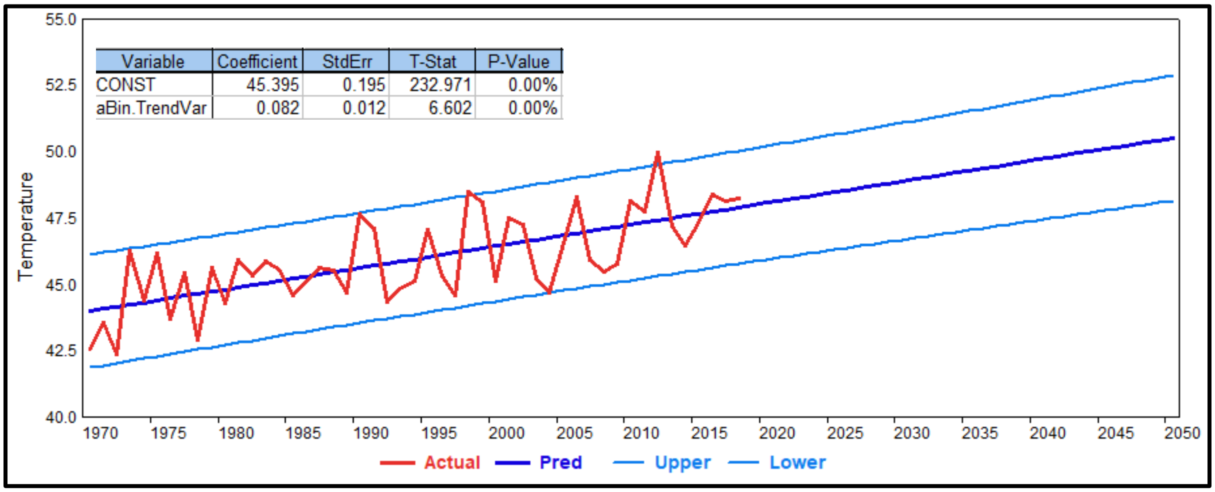
$$〚HDD55〛\_m=\sum Max(〚55\text{-}Temperature〛\_d,0)$$

$$〚CDD65〛\_m=\sum Max(〚Tempature〛\_d\text{-}65,0)$$

Sales forecasts are generally based on normal HDD and CDD where normal degree-days are calculated by averaging historical temperature data. What we have found, however, is that average temperatures have been increasing. Due to increasing greenhouse gases, temperatures are likely to continue to increase over the next fifty years. With increasing temperatures, a forecast based on normal degree-days will likely over forecast winter-heating usage and under forecast summer- cooling usage.

Figure 37 shows the long-term temperature trend for Burlington Airport.

Figure 37: Burlington Airport Temperature Trend



The estimated model shows that since 1970, the average annual temperature has been increasing 0.082 degrees per year, or 0.82 degrees per decade. The trend coefficient is highly statistically significant. Increases in temperature at 0.82 degrees per decade translate into a 0.3% annual decrease in the number of HDD and 1.2% annual increase in the number of CDD. Figure 38 and Figure 39 show historical and projected HDD and CDD.

Figure 38: HDD (trended normal starts in 2023)

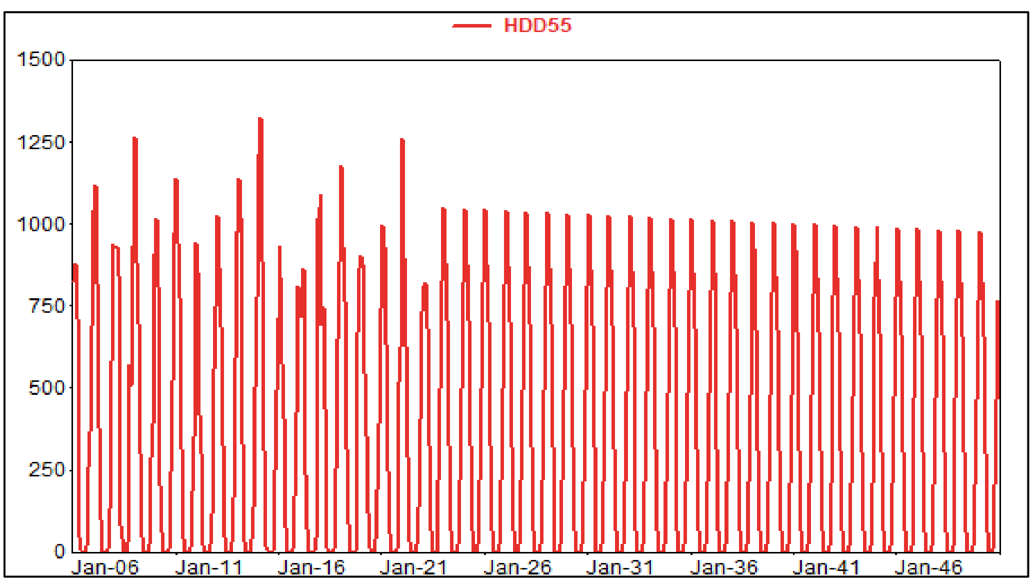
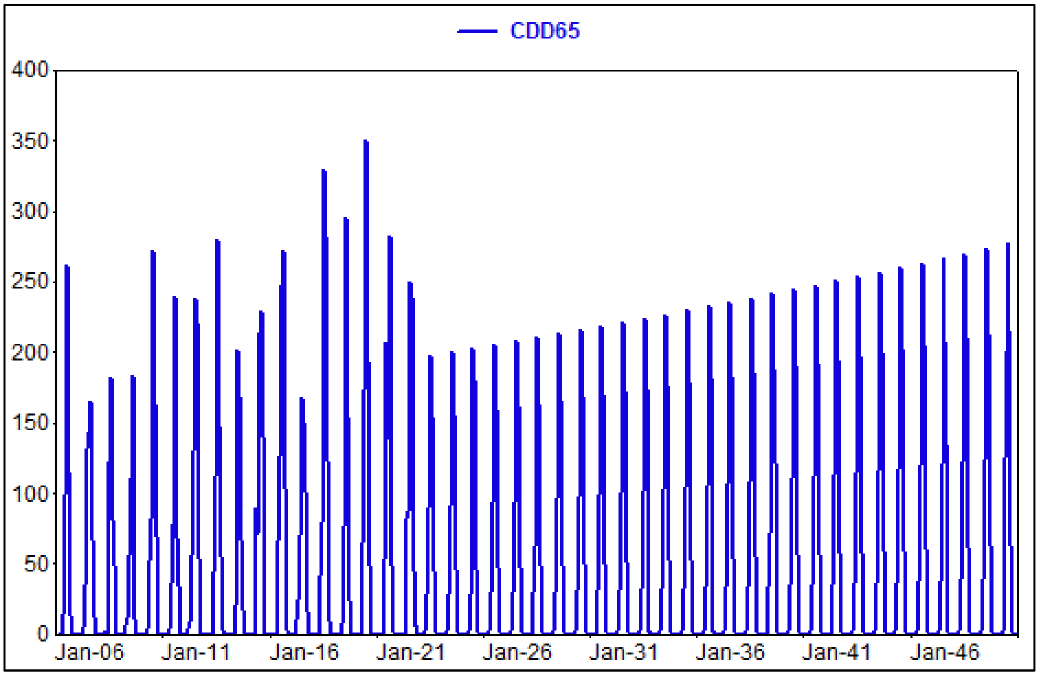


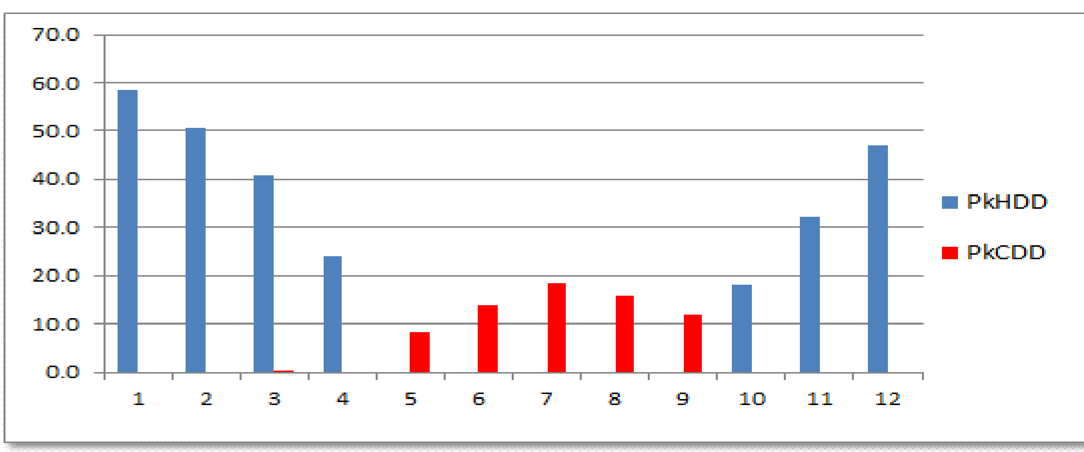
Figure 39: CDD (trended normal starts in 2023)



C.4.2.1 Peak-Day Weather Variables

Normal peak-day CDD and HDD are based on temperature data from the Burlington Airport and are calculated by evaluating peak-month HDD and CDD over a twenty-year period (2003 to 2022). The process entails finding the coldest and hottest days in each historical month and averaging these values using a using a rank and average approach (the most extreme temperatures are averaged, then the next extreme, to the least extreme). Figure 40 shows the result of this process.

Figure 40: Peak-Day Normal HDD and CDD



The impact of long-term temperature changes is reflected in the heating and cooling requirements that are incorporated in the peak model variables.

C.4.3 Economic Data

State economic forecasts drive the energy and demand forecasts. While Stowe is a small part of the state, in terms of economic activity and energy consumption, sales and customer growth are strongly correlated with state economic activity. The energy and demand forecasts are based on Moody's Economy.com January 2023 economic forecast for Vermont. Table 7 summarizes the primary economic drivers.

Table 7: Moody Analytics January 2023 Vermont Economic Forecast

Year	Households (Thou)	Real Household Income ($)	GSP (Mil $)	Employment (Thou)
2013	263.2	108.8	28,671	306.7
2014	264.7	110.7	28,868	309.6
2015	265.6	113.5	29,172	312.1
2016	265.7	114.2	29,378	313.3
2017	266.0	114.9	29,499	315.0
2018	266.2	116.7	29,630	316.1
2019	264.3	122.3	29,831	315.4
2020	259.0	132.9	29,174	289.3
2021	256.2	133.8	30,491	293.4
2022	258.8	128.1	31,328	300.5
2023	259.1	128.4	31,575	303.6
2024	260.0	129.6	32,083	305.4
2025	260.9	131.7	32,884	307.0
2026	261.7	134.0	33,726	307.6
2027	262.2	136.3	34,527	308.0
2028	262.7	138.5	35,311	308.6
2029	263.1	140.6	36,053	309.2
2030	263.5	142.5	36,708	309.5
2031	263.9	144.1	37,313	309.6
2032	264.3	145.8	37,932	309.6
2033	264.7	147.6	38,584	309.7
2034	265.1	149.4	39,234	309.7
2035	265.5	151.1	39,867	309.6
2036	265.9	152.7	40,488	309.4
2037	266.3	154.3	41,095	309.1
2038	266.7	155.9	41,686	308.8
2039	267.1	157.4	42,279	308.5
2040	267.5	158.9	42,870	308.2
2041	267.9	160.4	43,461	308.1
2042	268.3	161.9	44,060	307.9
2043	268.7	163.5	44,675	307.6
2013-23	-0.2%	1.7%	1.0%	-0.1%
2023-43	0.2%	1.2%	1.8%	0.0%

Over the long-term, Moody Analytics projects relatively slow household and economic growth for Vermont. It is important to note that the number of residential customers will likely increase faster than state households as the secondary home market is significant.

C.4.4 Appliance Saturation and Efficiency Trends

Residential and commercial end-use intensities are derived from the Energy Information Administration's (EIA) 2022 New England Census Division forecast. End-use saturation and stock efficiency estimates are used in constructing end-use intensity estimates. Saturations are adjusted to reflect recent state residential housing surveys and Vermont ResStock and ComStock output from the National Renewable Energy Laboratory (NREL). ResStock and ComStock provide detailed housing and building-type hourly end-use simulations for each state and other micro areas.

Heat pump saturations are also adjusted to capture the impact of the recent state heat pump incentive programs; for the forecast period, we hold heat pump saturation constant as new heat pump sales and load impact are treated as a separate adjustment. The residential sector incorporates saturation and efficiency trends for seventeen end-uses across three housing types – single family, multi-family, and mobile home. The commercial sector includes end-use intensity projections for ten end-uses across ten building types.

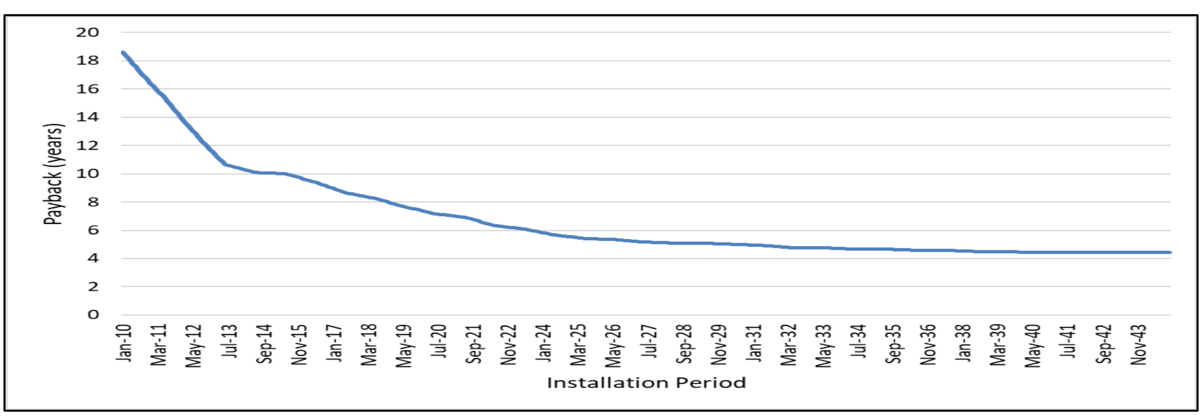
C.4.5 Solar Load Forecast

The energy and peak forecasts incorporate the impact of expected photovoltaic (PV) adoption. Although relatively small in magnitude compared to the rest of Vermont, Stowe has experienced a steady increase in BTM solar load growth. This growth is expected to increase over time as solar system costs continue to decline.

C.4.5.1 Solar Capacity Model

The primary factor driving solar system adoption is the favorable economics from the customer's perspective. Simple payback is used to reflect customer economics. The simple payback reflects the length of time needed for a customer to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. The payback calculation is a function of the total installed cost, annual savings from reduced energy bills, and incentive payment for generated power. Payback is calculated for a typical 5 kW residential solar system. The resulting payback curve can be seen in Figure 41.

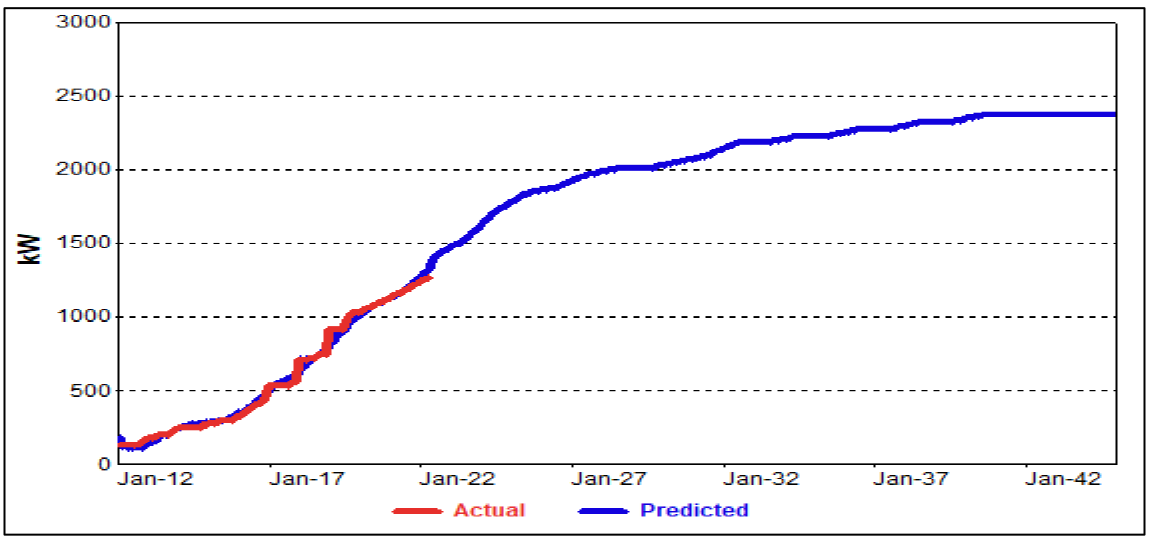
Figure 41: Payback Curve



Currently, system payback is roughly 6 years. By 2040, payback is expected to fall to 4.5 years. The most significant factor driving the payback trend downwards is system costs (expressed on an installed dollar per watt basis. In 2015, the average residential solar system costs approximately $3.50 per watt; by 2022 costs have dropped to $2.60 per watt. For the forecast we assume system costs continue to decline 5% annually through 2024, 3% decline annually 2025-2027, and 1% annually after 2027.

The capacity model relates the total installed capacity to simple payback using a cubic specification. A cubic model specification is chosen to impose an S-shaped adoption curve. Figure 42 shows the resulting capacity forecast.

Figure 42: Solar Capacity Forecast



The capacity forecast is translated into a monthly generation forecast by applying monthly solar load factors to the capacity forecast. The monthly load factors are derived from a typical PV load profile. The PV profile is an engineering estimate of a typical generation profile for the state. Table **8** shows solar capacity and generation forecasts.

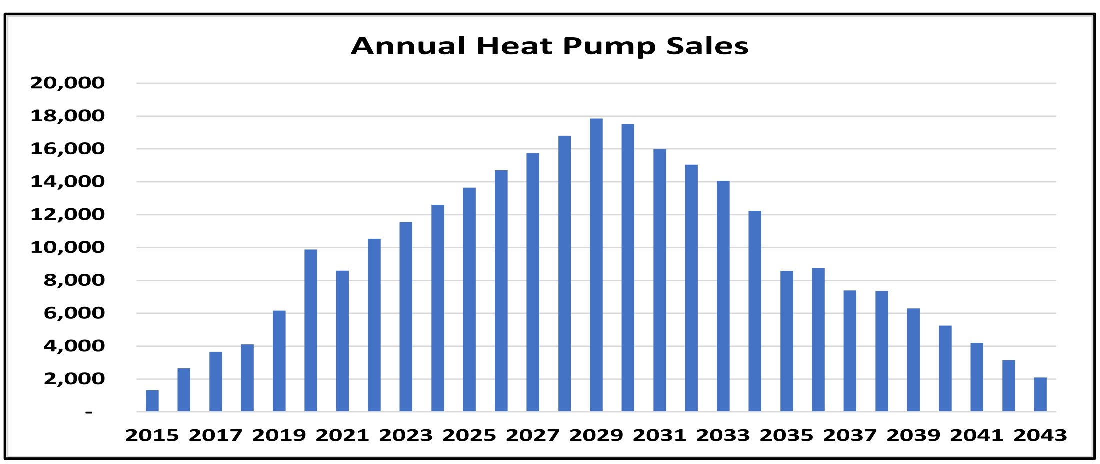
Table 8: Solar Capacity and Generation Forecast

Year	Capacity (MW)	Generation (MWh)
2023	1.5	1,906
2024	1.7	2,132
2025	1.8	2,276
2026	1.9	2,343
2027	2.0	2,438
2028	2.0	2,496
2029	2.0	2,501
2030	2.1	2,550
2031	2.1	2,611
2032	2.2	2,711
2033	2.2	2,721
2034	2.2	2,766
2035	2.2	2,777
2036	2.3	2,829
2037	2.3	2,834
2038	2.3	2,880
2039	2.3	2,892
2040	2.4	2,945
2041	2.4	2,944
2042	2.4	2,944
2043	2.4	2,944

As the system peaks during winter evening, solar adoption has no impact on system peak.

C.4.6 Cold Climate Heat Pump (CCHP) Forecast

The cold-climate heat pump (CCHP) forecast is based on VEIC's mid-case forecast developed as part of this year's DER filing. Figure 43 shows the VEIC state heat pump forecast. Figure 43: State Annual Heat Pump Sales (Units)



The forecast is scaled to Stowe based on Stowe's share of state electric customers (1.2%). Heat pump sales are derived as the product of net number of units and annual unit energy consumption (UEC) for both heating and cooling. Based on recent regional CCHP studies, we assume starting annual heating UEC of 2,085 kWh and cooling UEC of 146 kWh. CCHP UEC declines over time with projected CCHP efficiency improvements. The resulting energy requirements are summarized in Table 9.

Table 9: Heat Pump Sales (MWh)

Heat Pump Sales (MWh)			
Year	Heating	Cooling	Total
2023	229	16	245
2024	491	34	524
2025	773	53	826
2026	1,075	74	1,149
2027	1,400	97	1,497
2028	1,747	121	1,868
2029	2,116	146	2,262
2030	2,477	171	2,648
2031	2,805	194	2,999
2032	3,114	215	3,328
2033	3,399	235	3,634
2034	3,647	252	3,899
2035	3,819	264	4,083
2036	3,994	276	4,270
2037	4,142	286	4,428
2038	4,290	296	4,587
2039	4,416	305	4,720
2040	4,520	312	4,832
2041	4,604	318	4,922
2042	4,666	322	4,989
2043	4,707	325	5,032

Heat pump heating and cooling sales are combined with heating and cooling load profiles that have been estimated from Vermont residential and commercial AMI load data. Heat pump loads are adjusted for line losses.

C.4.7 Electric Vehicle Forecast

The Stowe electric vehicle (EV) forecast is derived from the state-level forecast which was developed as part of the 2023 VELCO Long-Term forecast. The forecast includes the impact of personally owned (non-fleet) and fleet electric vehicles. The forecast aligns with Vermont's goal of not allowing the sale of new gas-powered light-duty vehicles after 2035.

The non-fleet forecast is based on achieving target EV saturation rate of 90% by 2050; the saturation rate is the percent of all registered vehicles that are electric. The non-fleet EV vehicle forecast is derived by applying saturation projections to forecasted number of total vehicles. Total vehicles are based on the number of vehicles per household and state household projection. As of January 2023, there were 8,875 registered electric vehicles; this reaches 417,000 EVs by

2043. The forecast is allocated to Stowe based on the ratio of Stowe customers to the number of state electric customers, which is approximately 1.2%.

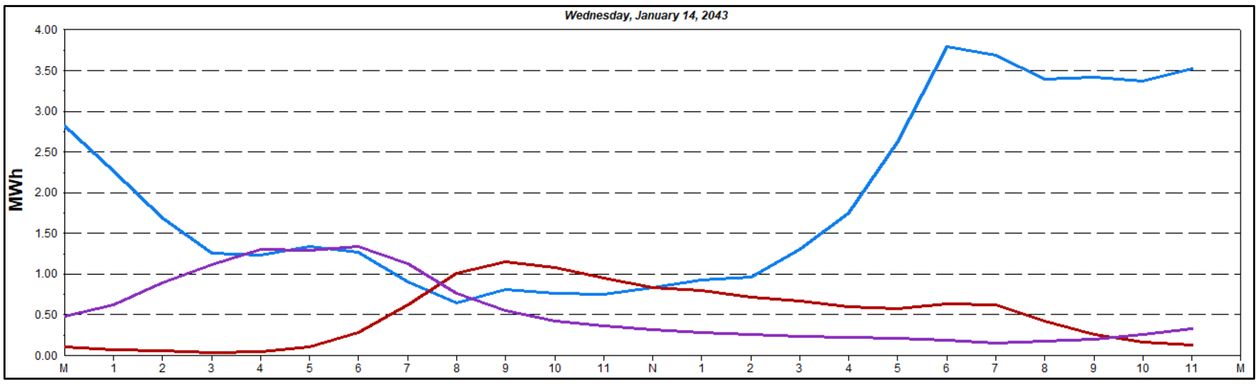
The fleet forecast is based on ISO New England's 2023 Transportation Electrification Forecast for Vermont. The ISO forecast provides a breakdown of light-duty fleet, medium-duty fleet, school bus, and transit bus counts annually through 2032. The forecast assumes 100% electrification by 2038-2045, depending on fleet electric vehicle type. Vehicle counts are combined with kWh per vehicle, based on the ISO forecast, to calculate total charging MWh. The forecast is then allocated to Stowe based on the ratio of Stowe customers to the number of state electric customers, which is approximately 1.2%. The forecasted non-fleet and fleet charging sales are shown in Table **10**.

Table 10: Electric Vehicle Forecast

Year	Non-fleet Consumption (MWh)	Fleet Consumption (MWh)
2023	234	13
2024	631	35
2025	1,301	70
2026	2,204	117
2027	3,307	177
2028	4,477	256
2029	5,888	353
2030	7,344	469
2031	8,863	603
2032	10,394	760
2033	11,840	921
2034	13,304	1,117
2035	14,487	1,356
2036	15,368	1,646
2037	15,989	1,999
2038	16,409	2,430
2039	16,675	2,902
2040	16,843	3,477
2041	16,946	3,984
2042	17,003	4,013
2043	17,026	4,047

The impact of EVs on system load and peak depends on the EV charging profile. Three charging profiles are utilized: non-fleet at home, non-fleet public, and fleet. The non-fleet at home charging profile is constructed from Green Mountain Power (GMP) measured vehicle charging load data. The non-fleet public and fleet are based on the National Renewable Energy Laboratory's Electric Vehicle Infrastructure Projection Tool, a publicly available dataset of electric charging shapes. We assume 80% of non-fleet charging occurs at home and 20% away from home at public charging stations or work. The EV charging profile assumes there is no incentivized EV rate; other studies have shown that incentivized charging rates can shift EV charging to off-peak hours. The charging profile also reflects the impact of weather variation over the year. Winter month charging requirements are nearly 30% higher than summer as a result of colder weather. Figure 44 shows the charging profiles for a January weekday in 2043.

Figure 44: EV Charging Profiles



D Portfolio Planning Approach and External Influences

D.1 Regional Resource Portfolio and Marginal Supply

The New England Independent System Operator (ISO-NE) meets a majority of both its base load and its peak load with natural gas fueled units. Although ISO-NE is moving toward renewable generation resources, natural gas fueled generation still sets the hourly electric price in most instances. The ISO-NE's 2023 Capacity, Energy, loads, and Transmission (CELT) Report maintains Natural Gas as the largest fuel source through 2032.

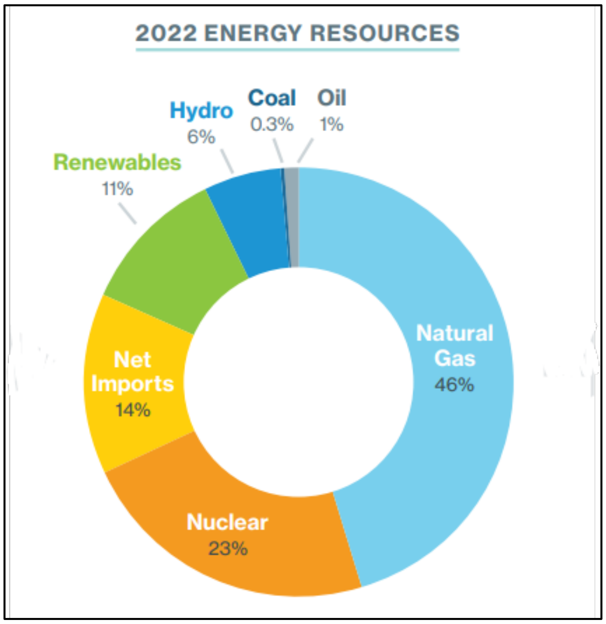
Figure 45: Summer by Fuel-Unit Class

	CSOs based on FCA and ARA Results					Projected CSOs based on FCA 17 Results					
Fuel/Unit Classification	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Battery, energy storage (1, 2)	10	91	765	659	1,048	1,048	1,048	1,048	1,048	1,048	1,048
Co-located, PV/battery (1, 2)	73	341	306	414	415	415	415	415	415	415	415
Coal (1, 2)	438	438	438	310	0	0	0	0	0	0	0
Fuel cell (1, 2)	31	32	24	22	22	22	22	22	22	22	22
Hydro (1, 2)	1,390	1,199	1,208	1,198	1,210	1,210	1,210	1,210	1,210	1,210	1,210
Landfill gas/other biomass gas (1, 2)	48	56	46	48	46	46	46	46	46	46	46
Natural gas (1, 2)	14,523	14,980	13,857	13,894	13,486	13,486	13,486	13,486	13,486	13,486	13,486
Nuclear (1, 2)	3,339	3,333	3,326	3,331	3,352	3,352	3,352	3,352	3,352	3,352	3,352
Oil (1, 2)	5,765	5,205	5,664	4,959	4,941	4,941	4,941	4,941	4,941	4,941	4,941
Photovoltaic (1, 2)	216	297	330	326	479	479	479	479	479	479	479
Pumped storage (1, 2)	1,528	1,859	1,859	1,859	1,845	1,845	1,845	1,845	1,845	1,845	1,845
Refuse (1, 2)	359	336	350	343	338	338	338	338	338	338	338
Wind (1, 2)	82	97	273	275	361	361	361	361	361	361	361
Wood (1, 2)	404	312	336	335	320	320	320	320	320	320	320
ISO New England generation capacity subtotal (1, 2)	28,205	28,578	28,781	27,972	27,864	27,864	27,864	27,864	27,864	27,864	27,864
Demand capacity resources (1, 2)	4,122	3,818	3,862	3,198	2,940	2,940	2,940	2,940	2,940	2,940	2,940
Imports (3)	1,115	958	1,297	1,504	567	84	84	84	84	84	84
Total capacity	33,443	33,354	33,941	32,675	31,370	30,887	30,887	30,887	30,887	30,887	30,887

As displayed below in Figure 46 natural gas is 46% of the resource fuel type used to address New England electricity demand. Natural gas has contributed to lower regional carbon rates overall because natural gas fueled power plants played a key role in the retirement of oil and coal fossil fuel plants. Decarbonization in the region further increased with the decommissioning of coal plants, such as Salem Harbor in Salem MA and Brayton Point in Somerset MA, and Bridgeport Harbor 3 in Bridgeport CT. Also, older coal and oil units have a longer range start up time when compared to natural gas generation units, which made the older oil and coal units more difficult to rely on during critical demand condition periods. As the region moves to noncarbon sources of energy, natural gas fueled units are retiring. The gas fueled Mystic generation station located in Charlestown MA was scheduled to be retired, but ISO-NE determined it was needed for reliability purposes. The costs related to its continued operation are now shared by all pool participants.

New England is on track to lower carbon emissions by increasing the amount of renewable energy. The major transformation of renewable energy has begun; and the ISO is looking to the future as increased amounts of wind, solar, and battery storage are connected to the New England Grid. "Today, the ISO continues to fulfill its historic mission of using competitive markets to secure a reliable supply of electricity for New England's households and businesses."[11]

Figure 46: Supply Obligation by Fuel Type [12]



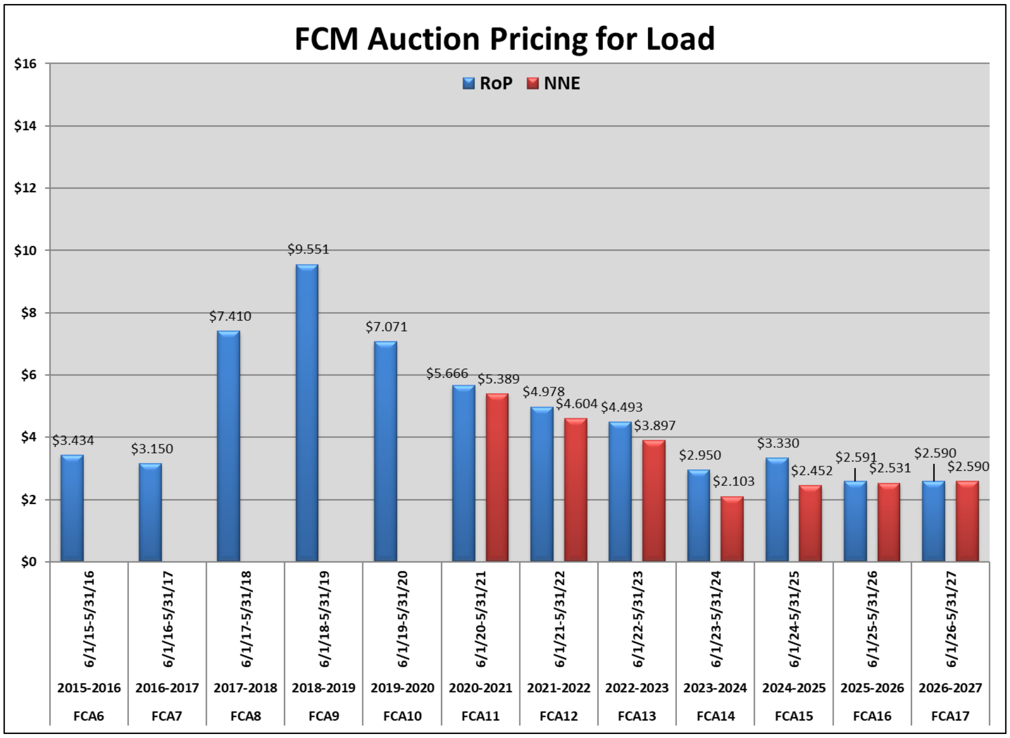
D.2 Market Conditions

D.2.1 Capacity Market

The Forward Capacity Market (FCM) began on June 1, 2010. The FCM's goal is to acquire enough generation resources to meet future demand. The FCM auctions take place three years in advance of actual settlement. The FCM auction designs clearing prices that will attract new generation units and demand response assets as well as support the existing resources. The evolution of FCM began with zonal classifications. Initially, there was Rest of Pool and Maine. Currently, in the latest auction #17, there was Rest of Pool and Northern New England (NNE). Stowe was in Rest of Pool until auction 11 and now Stowe is in the Northern New England zone. Historically, price separation occurs from zone to zone. The zones that are "import" constrained have higher overall clearing prices. Figure 47 illustrates the clearing prices for the Rest of Pool and NNE Locations that impact Stowe's capacity costs.

[11] 20+ Years of ISO New England (iso-ne.com)
[12] new_england_power_grid_regional_profile.pdf (iso-ne.com)

Figure 47: Rest of Pool and Northern New England's Capacity Auction Clearing Prices



Zone location affects resource capacity compensation, meaning where the generation unit resides determines the compensation. Note, capacity costs are not "one for one" on the load charge rates because load charge rates incorporate capacity resource credits the ISO must collect to distribute to resources. Load rates are greater than the resource credit rates and therefore if Stowe can self-supply a resource in their obligation zone, the resource will receive the same rate Stowe's load will pay to offset those MW's. This brings up the importance of qualified self-supplying generation resources. In FCM 17, Stowe has self-supplied Stony Brook, NextEra's Seabrook, NYPA and McNeil generating units. This does provide a one-to-one offset of Stowe's load charges. Stowe's capacity portfolio can be found in Figure 75: Stowe's Capacity Forecast.

The most recent Capacity auction occurred on March 6, 2023, for Forward Capacity Auction (FCA) 17, which is implemented on June 1, 2026, and goes through May 31, 2027. The latest self-supply designation window was completed on December 13, 2022, for FCM 17. The auction for FCM 17 closed after round 4 having an adequate number of resources to meet the ISO-NE forecasted peak demand.

FCA 17 was composed of three separate Capacity Zones and resulted in clearing prices of $2.590 KW-month except for New Brunswick that cleared at $2.551 KW-month. The division of FCA 17 Capacity Zones are Rest of Pool Zone "RoP" (encompassing Load Zones, of NEMA, SEMA, WMASS/Central MASS, CT, RI, H.Q. Phase I/II, and the NY AC Ties), and Export Constrained

Northern New England "NNE" (encompasses Loads Zone of VT and NH), and Maine "Maine" as "nested" Export Constrained Capacity Zones with NNE.

FCA 17 represents year one of the Two-Year Minimum Offer Price Rule (MOPR) transition period. The total of cleared resources for FCA 17 were 31,370 MW against a net Installed Capacity Requirement "NICR" of 30,305 MW. FCA 17 approved 2,457 MWs of Dynamic De-list Bids from the eighty-three generation resources that submitted a de-list bid. New entries totaled 1,232 MW as noted in Table 1. FCA 17 had a 300 MW cap for state sponsored new resources under the Renewable Technology Resources (RTR) MOPR exemption. All 300 MWs of the cap were qualified for FCA 17 with only 108 MW staying in the auction at the closing price. FCA 18, the last year of the MOPR transition, will have 192 MW of FCA 17 carryover added to the 400 MW FCA 18 RTR CAP for total of 592 MW of RTR MOPR exempt capability. The auction concluded with 1,065 MW of surplus supply.

Table 11: New Cleared Capacity FCA 17[13]

Type	FCA 17 MW	FCA 16 MW	Change MW
Solar	91	184	(93)
Energy Storage	400	98	302
Co-located Solar & Storage	28	29	(1)
Wind	99	0	99
Natural Gas	0	0	0
Hydro	1	0	1
Generator Total[1]	**619**	**311**	**308**
Passive Demand	123	129	(6)
Active Demand	7	101	(94)
Demand Total	**130**	**230**	**(100)**
Import	483	1,504	(1021)
Grand Total	**1,232**	**2,045**	**(813)**

ISO's two-settlement FCM design began with FCA 9 (June 2018-May 2019). The two-settlement design includes an FCM payment for Capacity Resources that are awarded a Capacity Supply Obligation (CSO) in an FCA and Pay-For-Performance (PFP) incentives. PFP provides a payment or charge for a resource performance during Capacity Scarcity Conditions (CSC), when the system is short real-time reserves. The PFP rate paid or charged was $2,000/MWH for FCA 9 through FCA 11, $3,500/MWH for FCA 12 through FCA 14, $5,455/MWH for FCA 15, and $9337/MWH FCA 16 and thereafter. With MOPR elimination in FCA 19 (June 2028-May 2029) ISO will evaluate a new PFP rate. Table 12 is a summary of forecasted Load charge rates for Stowe Electric Department's capacity obligation. Recall Load capacity charges are a function of the FCA price, subsequent Annual Reconfiguration Auction (ARA) prices and quantities, shifts

[13] Forward Capacity Auction (FCA) 17 for Capacity Commitment Period 2026–2027: Summary of Results -Reliability Committee 4/19/2023

in the total Peak Allocation MW, Multi-year Capacity Price Lock paid to Resources, and other factors.

Table 12: ISO Auction Results of the Annual Forward Capacity Auction[14]

AUCTION COMMITMENT PERIOD	TOTAL CAPACITY ACQUIRED (MW)	NEW DEMAND RESOURCES (MW)[1]	NEW GENERATION (MW)[2]	CLEARING PRICE ($/KW-MONTH)[3]
FCA #1 in 2008 for CCP 2010/2011	34,077	1,188	626	$4.50 (FLOOR PRICE)
FCA #2 in 2008 for CCP 2011/2012	37,283	448	1,157	$3.60 (FLOOR PRICE)
FCA #3 in 2009 for CCP 2012/2013	36,996	309	1,670	$2.95 (FLOOR PRICE)
FCA #4 in 2010 for CCP 2013/2014	37,501	515	144	$2.95 (FLOOR PRICE)
FCA #5 in 2011 for CCP 2014/2015	36,918	263	42	$3.21 (FLOOR PRICE)
FCA #6 in 2012 for CCP 2015/2016	36,309	313	79	$3.43 (FLOOR PRICE)
FCA #7 in 2013 for CCP 2016/2017	36,220	245	800	$3.15 (FLOOR PRICE) NEMA/Boston: $14.99
FCA #8 in 2014 for CCP 2017/2018	33,712	394	30	$15.00/new & $7.025/existing
FCA #9 in 2015 for CCP 2018/2019	34,695	367	1,060	System-wide: $9.55 SEMA/RI: $17.73/new & $11.08/existing
FCA #10 in 2016 for CCP 2019/2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020/2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021/2022	34,828	514	174	$4.63
FCA #13 in 2019 for CCP 2022/2023	34,839	654	837[4]	$3.80
FCA #14 in 2020 for CCP 2023/2024	33,956	323	335	$2.00
FCA #15 in 2021 for CCP 2024/2025	34,621	170	950	ROP: $2.61 NNE: $2.48 & SENE: $3.98
FCA #16 in 2022 for CCP 2025/2026	32,810	230	311	ROP: $2.59 NNE: $2.53 & SENE: $2.64
FCA #17 in 2023 for CCP 2026/2027	31,370	2,940	619	$2.590

[14] https://www.iso-ne.com/about/key-stats/markets#fcaresults

ENE utilized a Monte Carlo simulation technique to estimate future capacity clearing prices in the Northern New England capacity zone. Simulation results are found in section F.3 Capacity modeling. Appendix F contains the simulation output using historical year weighting.

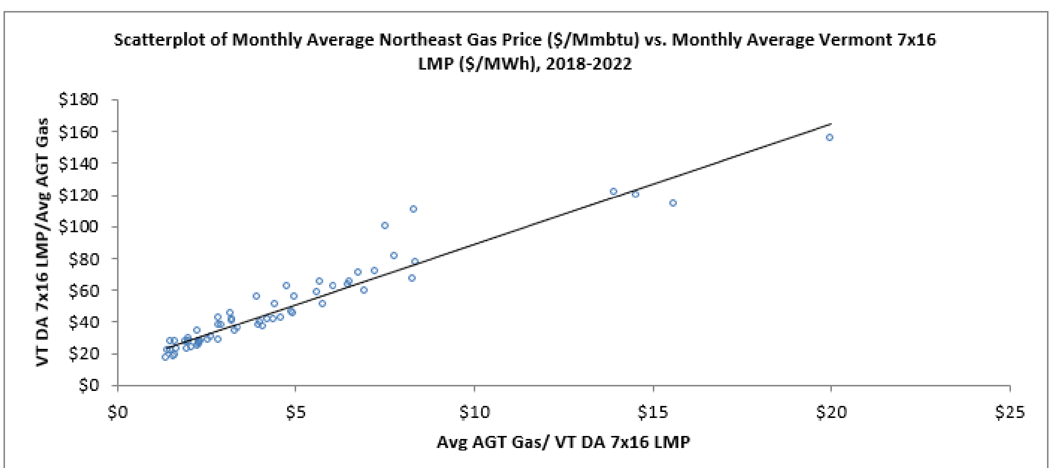
D.2.2 Energy Market

The ISO-NE determines the cost of the energy market's power prices. Providing reliable and competitive prices are the goals of the operation. Using economic dispatch and clearing prices to cover the region's demand allows ISO-NE to run units in economic merit. The marginal resource or last unit to turn on sets the market price for the hour.

The New England wholesale energy market continues to evolve to meet the demands of customer electrification needs and decarbonization mandates. The ISO-NE 2023 CELT report predicts an increase in demand of 23%. The report uses economic forecasts as well as increases in electric vehicles, heat pumps and other electric technologies as part of the demand projections.

Within Stowe's scenario modeling, the Vermont load zone Locational Marginal Prices (LMP), where Stowe must purchase its load charges, are projected based on assumptions. These assumptions include natural gas and oil prices, as well as future implied heat rates. Calculations utilize regional delivered natural gas prices and implied heat rates due to the high frequency of natural gas fired resources setting marginal energy prices in New England. The link between energy prices in New England, specifically the Vermont Zone, is captured in Figure 48, which calculates a .960 correlation between Vermont Zone 5x16 monthly average LMPs with monthly average northeast delivered natural gas prices.

Figure 48: Vermont LMP Scatterplot Correlation to Northeast Natural Gas Prices

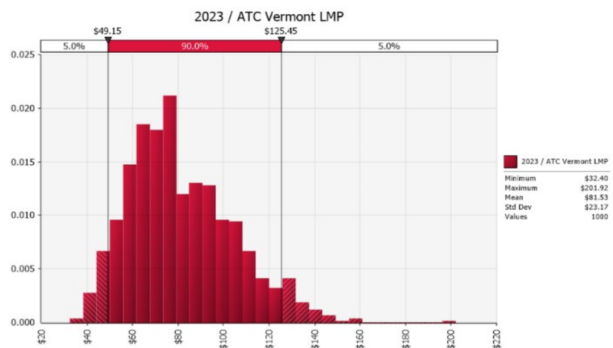


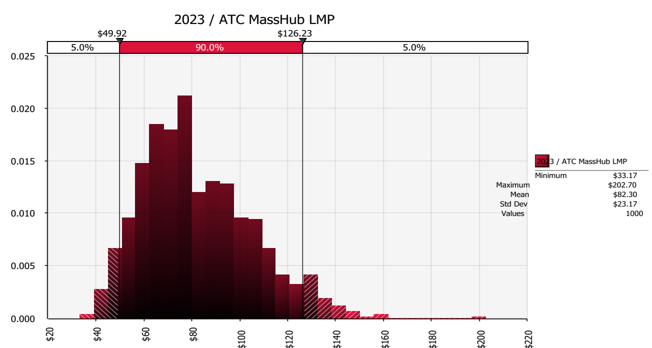
Correlation	0.9600485

In the portfolio optimization model, this forward curve is set to a mean (*expected* outcome); then set by modeling the historical periodic movement of LMP at the Mass Hub and the Vermont nodal basis. The model produces 1000's of simulations of LMP at the Vermont Load Zone. The simulations become a range of probabilistic outcomes (bucketed into percentiles) of simulated

LMPs around the forward curve (the mean) to determine the probabilistic costs for open market purchases. Stowe's chosen portfolio scenario and future resource decisions will influence the nature of its interaction with the spot market. Stowe can reduce its spot market activities by procuring renewable resources and short and longer-term market purchases. Below Figure 49 illustrates the simulation results for Vermont and Mass Hub Around the Clock's Locational Marginal Price used in the base case data set.

Figure 49: ATC Vermont and Hub LMP futures





Below in Figure 50 through Figure 53 contain forward energy curves and simulations.

Figure 50: ISO New England Hub Peak FWD Curve History

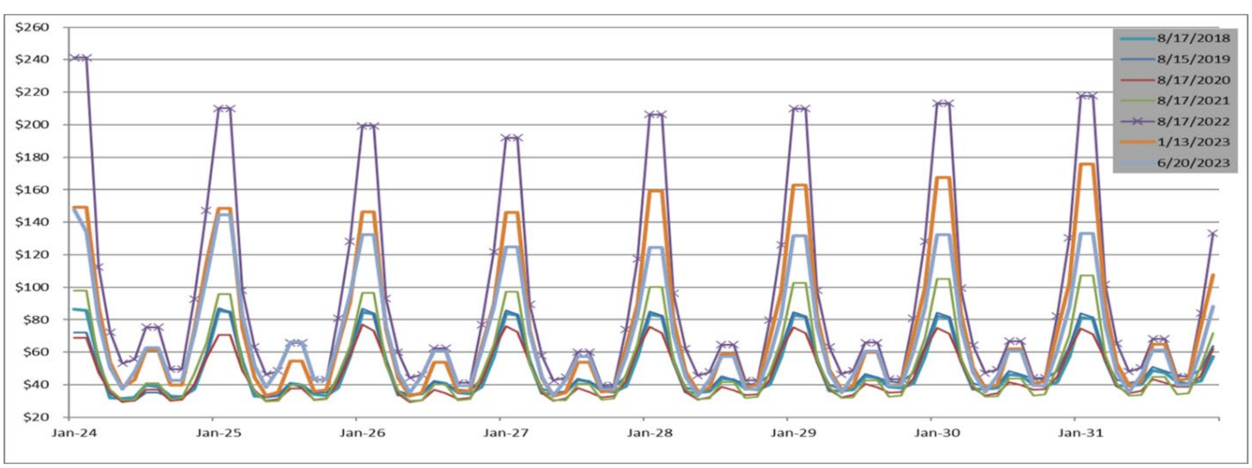


Figure 51: Mass Hub ATC LMP, Monthly Simulated Range Jan 2025 to Dec 2044

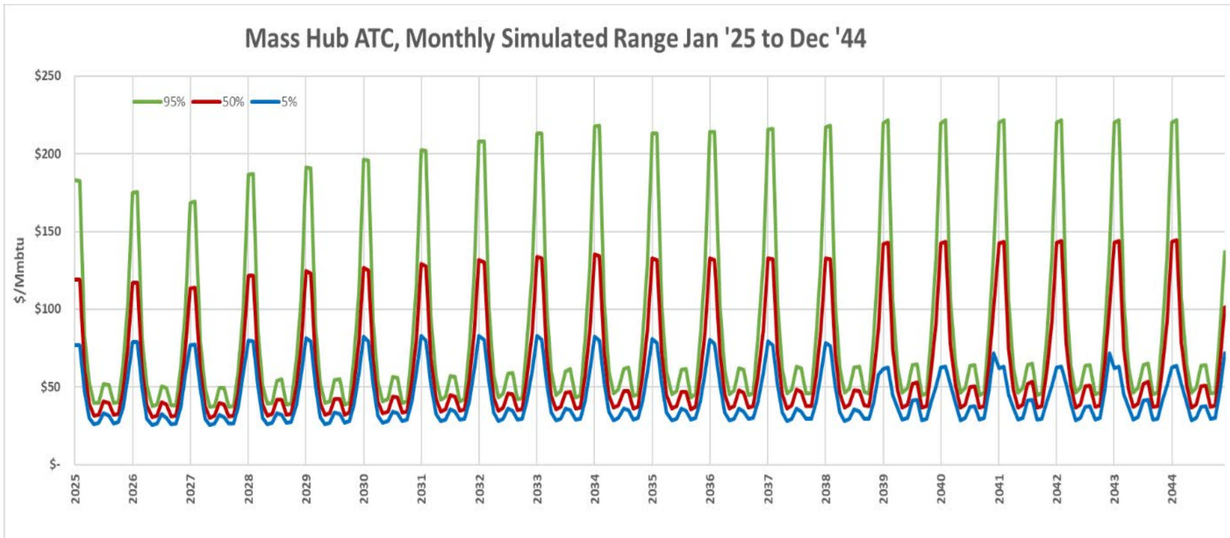


Figure 52: Vermont Zone ATC, Monthly Simulated Range Jan 2022 to December 2042

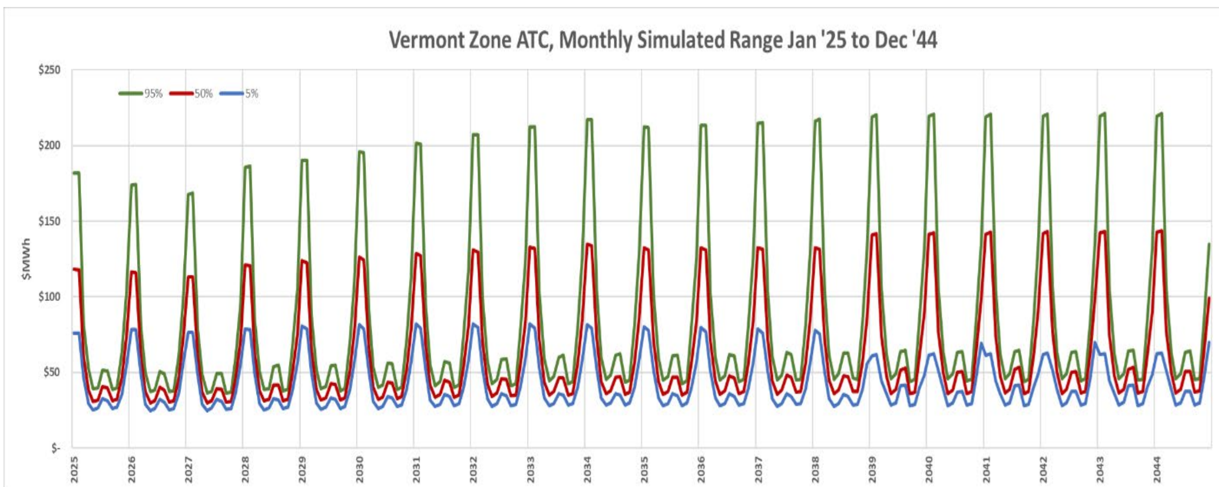
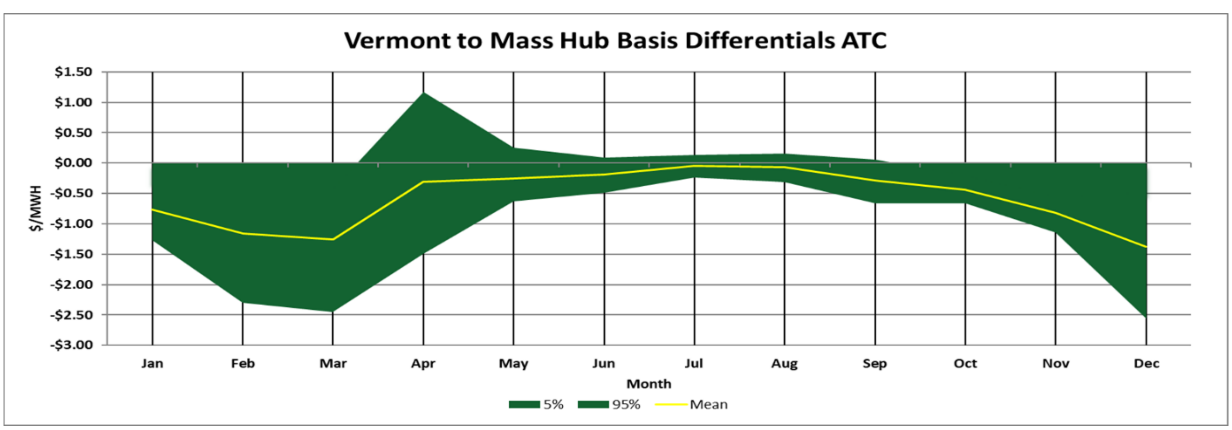


Figure 53: Vermont to Mass Hub Basis, Monthly Simulated Range, ATC



D.2.3 Natural Gas in New England

D.2.3.1 Reliance on Natural Gas for Electricity Generation in the Northeast

Over the past 20 years, the reliance on natural gas for electricity generation has grown significantly in the Northeast. The development of natural gas fired power plants was due to technological advancements in efficient production, as well as the option for a lower carbon content than coal and oil plants.

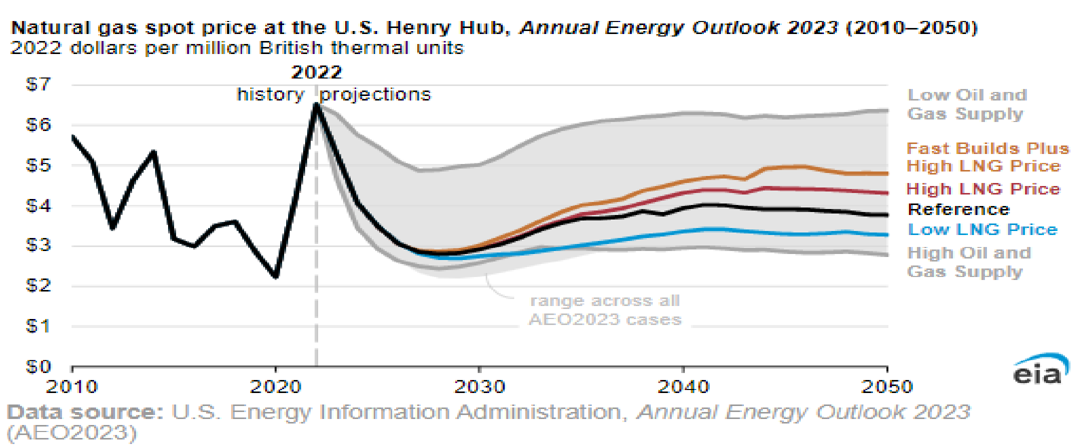
Forty six percent of New England's generators operate on natural gas. Gas units have a significant impact on the resulting market price. With the development of increased access to low-cost natural gas (resulting from improvements in drilling technologies: horizontal drilling and hydraulic fracturing) from the Marcellus Shale and other regional shale locations such as the Appalachian Basin, electricity prices decreased almost 50% from a decade ago.

"In 2020, the COVID-19 pandemic and the continuation of regional industry trends led to historically low consumer demand for grid electricity in New England in 2020, setting the stage for the lowest average wholesale market prices since the inception of the region's competitive markets in 2003."

Additionally, environmental policies such as the Regional Greenhouse Gas Initiative and the state-driven renewable portfolio standards contribute to the dwindling reliance on coal throughout the region.

Energy Administration Association's (EIA) annual 2023 Outlook have included assumptions based on projections for post COVID-19 as well as the Russia-Ukraine war when forecasting natural gas exports and average gas prices. as seen below in Figure 54.

Figure 54: Natural Gas spot prices[15]



15 U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

D.2.3.2 Market Fundamentals Influencing Spot and Forward Pricing of Natural Gas and Wholesale Electricity in New England

ISO New England uses a method called economic dispatch where they dispatch units in economic order (lowest price first). As demand increases higher priced units are dispatched. With natural gas positioning itself as the popular fuel source for electricity generation in the Northeast, it has subsequently become the marginal fuel source for wholesale electricity pricing. When low-cost natural gas delivered from the Algonquin City Gate is readily available and not in exceptionally high demand, this relationship between wholesale electricity prices and low-cost natural gas is favorable to wholesale electricity consumers. However, natural gas remains one of the most volatile commodities in which its price can change frequently and materially based on weather and socioeconomic factors. The market fundamentals of supply and demand, which are mostly driven by seasonal weather cycles and production/storage data, influence the spot and forward market pricing of natural gas. Further augmenting the volatility of natural gas prices in the Northeast are seasons that induce significant heating/cooling demand, during which the availability of natural gas is not a certainty.

The preeminent issue in the Northeast, which most notably reared its head in the winter of '13/'14 (due to the Polar Vortex), is that of natural gas pipeline capacity constraints and their ability to plague the region's wholesale energy markets. When pipeline constraints and/or periods of exceptionally high demand hit the region, the basis price (the value a commodity between point A to B - in New England's case, price of natural gas at Henry Hub relative to the Algonquin City-Gates) increases, thus causing wholesale electricity prices to increase as well. Historically, the Northeast has experienced its most notable pipeline capacity constraints in the winter. However, the last several winters in New England have brought relatively mild weather, and in turn, the price spikes in the Algonquin City-Gates basis are lower than in previous years, as illustrated in Figure 56. Presently, we can see how world affairs affected the price of gas, on February 24, 2022, when Russia invaded Ukraine. The invasion resulted in European countries adding sanctions on Russian oil. These sanctions on Russian oil led to United States (US) suppling more LNG overseas. The US supply inventory is below the five-year average and the rise in European demand has increased Henry Hub prices while decreasing the US storage. Figure 55 depicts the increase in European imports from the U.S. Details provided by NextEra fundamentals forecast presentation.

Figure 55: LNG Exports by Region

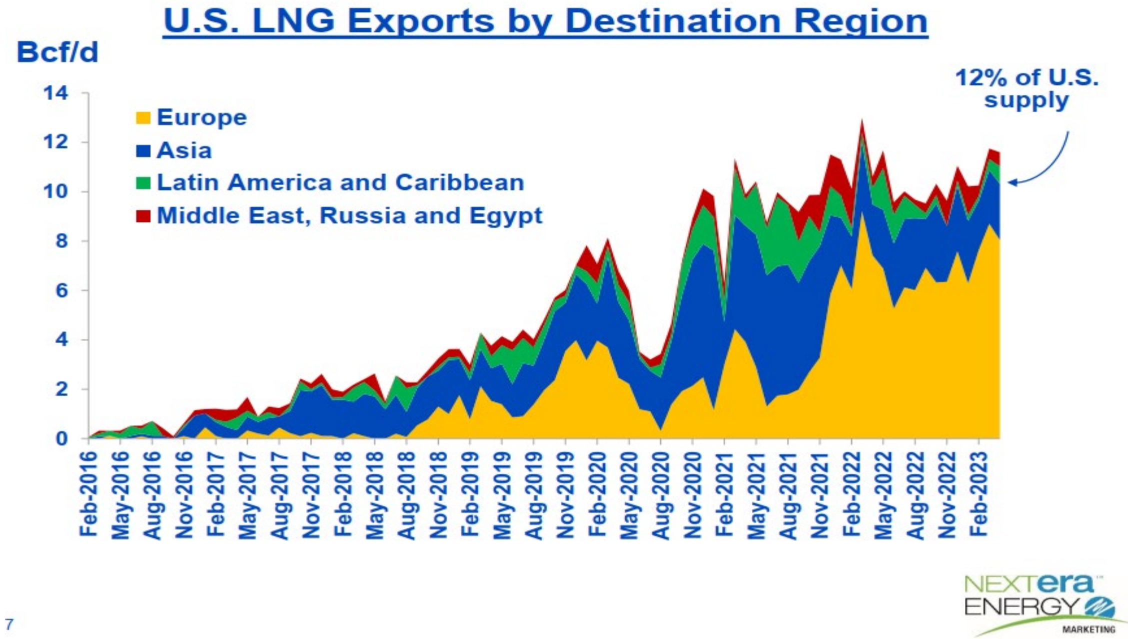
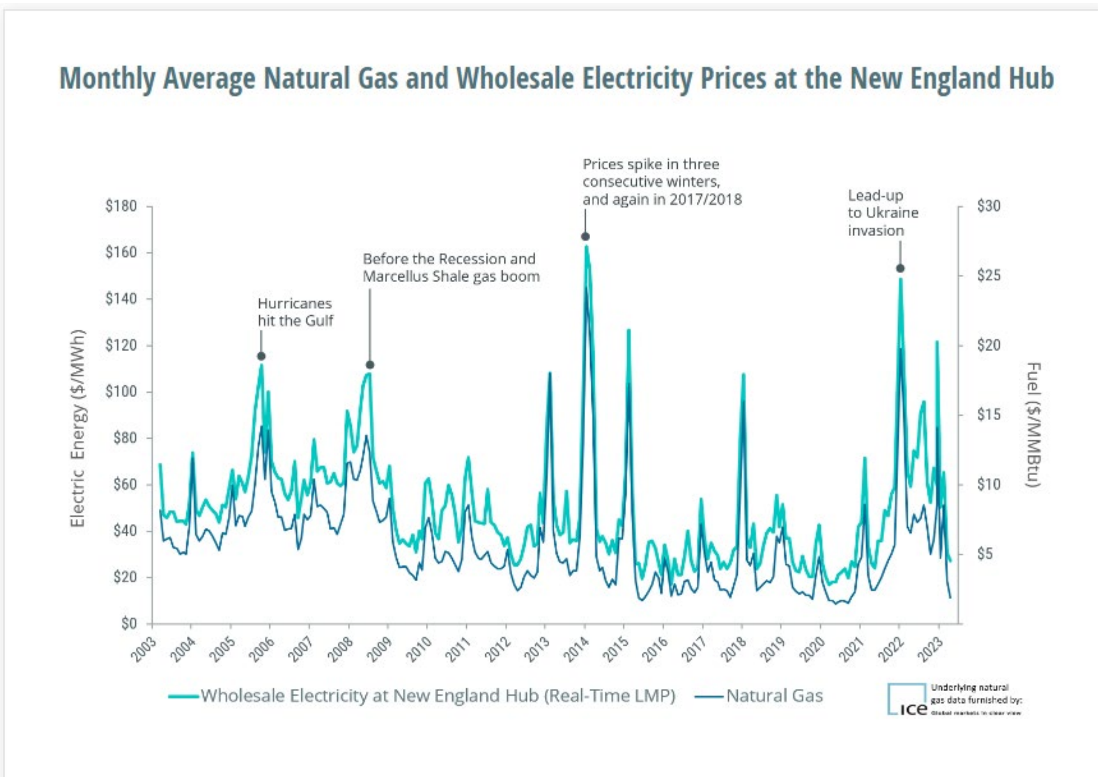


Figure 56: Link between Regional Prices for Natural Gas and Wholesale Electricity[16]



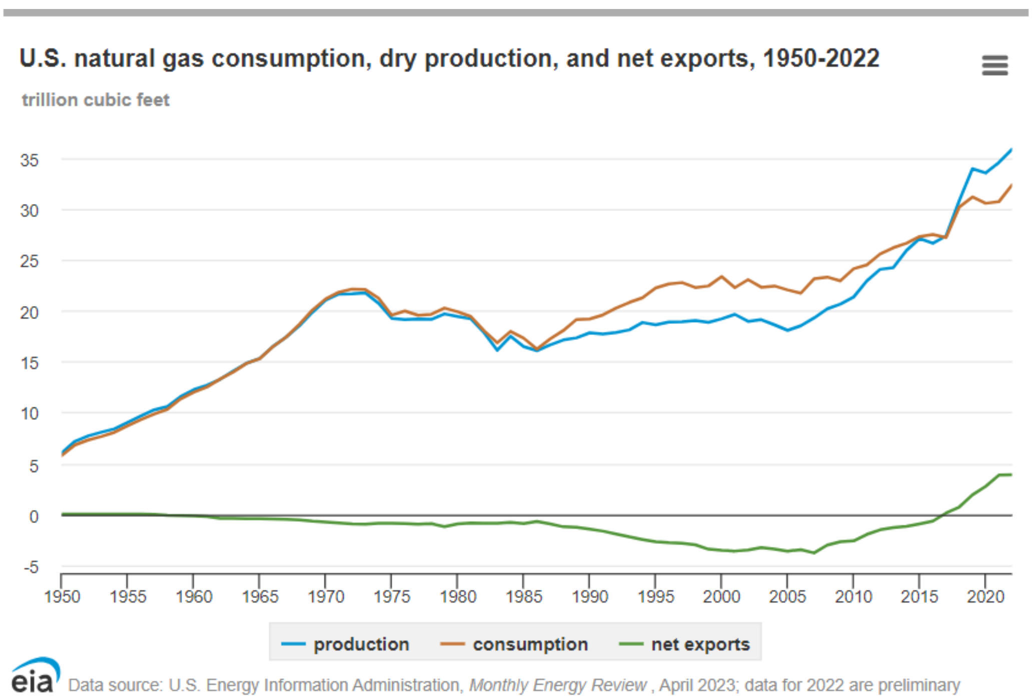
[16] https://www.iso-ne.com/about/key-stats/markets

D.2.3.3 Natural Gas in New England - Summary

The Northeast had additional pipeline capacity built as recently as 2018. The key question is whether this pipeline capacity buildout can keep pace with demand. Increasing demand has come in several forms, for example, heating demand in the Northeast continues to be more reliant on natural gas as Local Distribution Companies (LDCs) continue to place customers on the preferred fuel. Demand increases are negatively impacted by supply constraints. "Natural gas pipeline constraints limited the amount of natural gas that could be delivered to power plants, leading to the reactivation of several power plants that burn fuel oil to help meet electricity demand."[17] New England is subject to natural gas pipeline constraints that result in increased gas prices as well as locational marginal price increases. There are changes to the natural gas demand as incentives push for electrification (example heat pumps) that will help lower the demand of natural gas to end users.

Natural gas production in 2020 was 10% greater than consumption. As the COVID-19 pandemic hit, drilling declined, this was a contributing factor in decreased demand. Natural gas production (displayed in Figure 57). is projected to have a steady incline vs expected production.

Figure 57: EIA Dry Natural Gas Production History/Projections



Below in Figure 58 ENE included a Natural Gas forward curve. It is hard to predict the levels at which natural gas spot and forward market pricing will reside since pricing will remain sensitive to advancements in E&P technology, the availability of resources, and seasonal weather cycles. However, ENE took into consideration market forces and various scenarios when creating

[17] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

natural gas simulations. Gas prices are affected by the inclusion of enhancements in exploration and advancements in production technologies, increased supply, and resources (i.e., Marcellus Shale play).

Figure 58: Natural Gas Forward Curve History

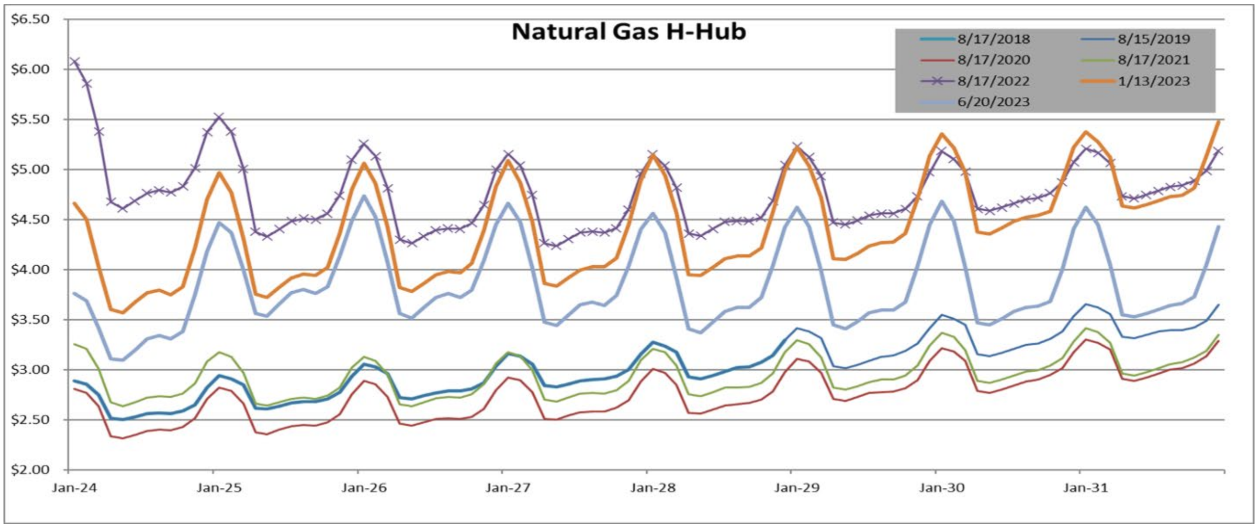
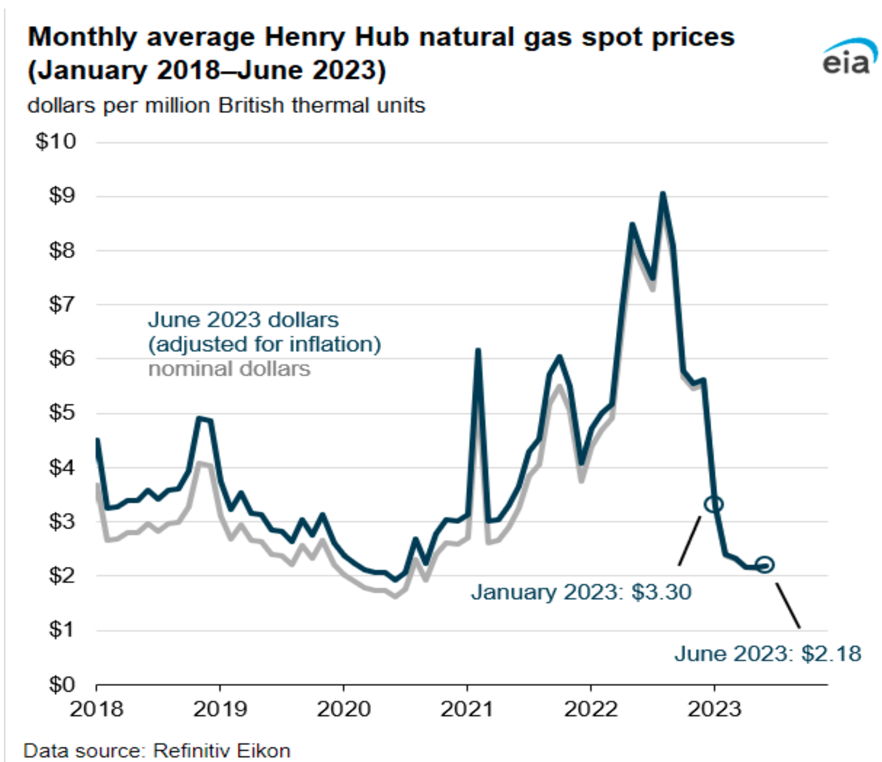


Figure 59: Natural Gas Historical Spot Prices[18]



[18] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/07_06/

Figure 60: Natural Gas, Algonquin Citygate, Monthly Simulated Range Jan 2021 to Dec 2040

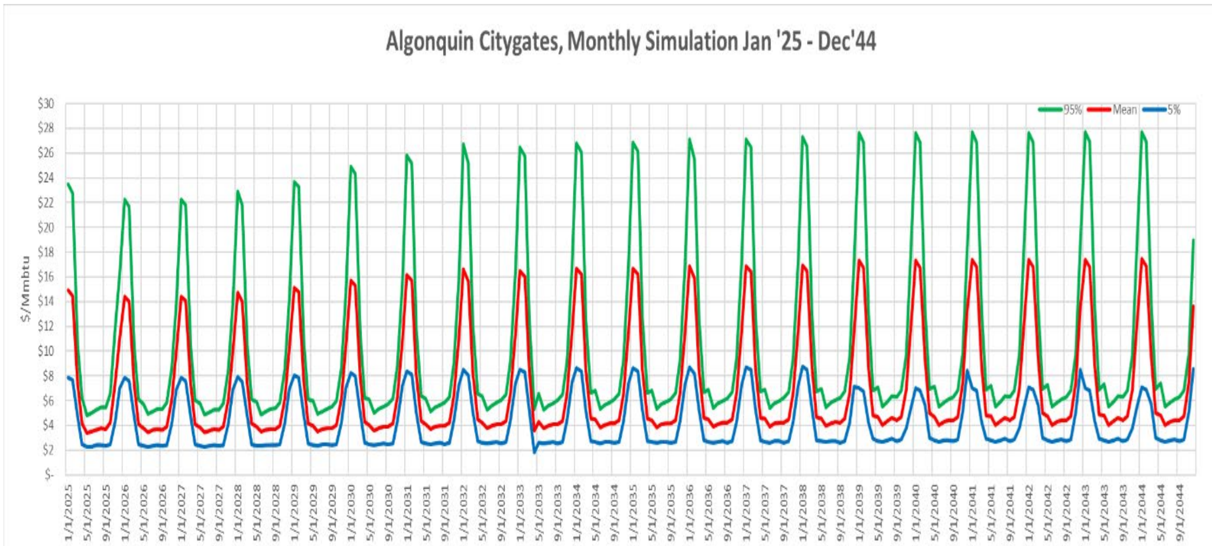
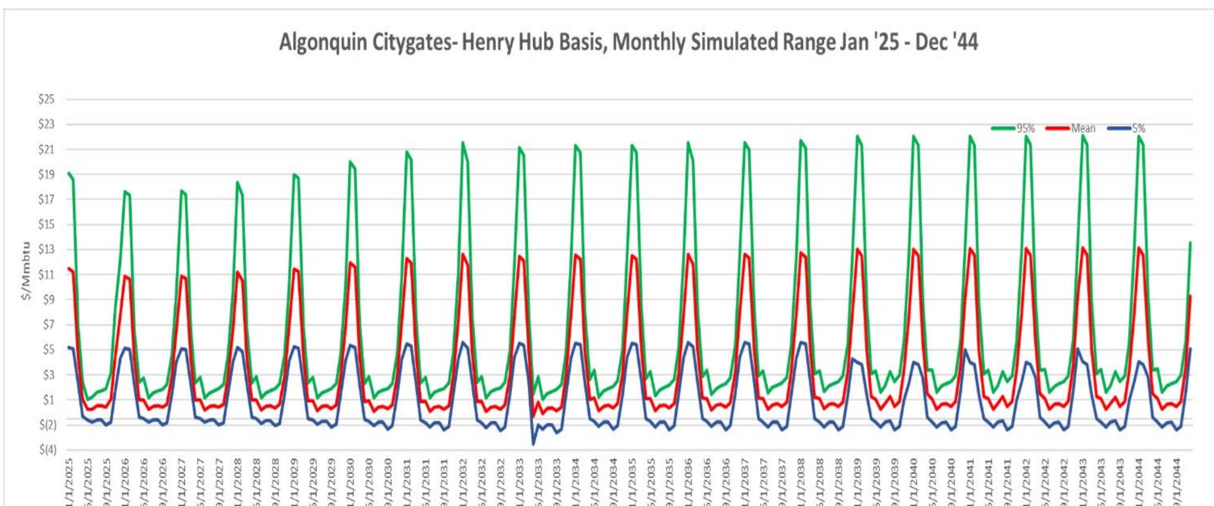


Figure 61: Algonquin to Henry Hub Basis, Monthly Simulated Range Jan 2021 to Dec 2040



D.2.4 Transmission Market

One of the largest contributing factors to Stowe's ISO-NE costs is the Open Access Transmission Tariff (OATT). Within the transmission category are various ancillary charges, the largest of those being the Regional Network Service (RNS). RNS is the service over the Pool Transmission Facilities, which the ISO provides to transmission customers to serve their loads. These are monthly charges based on Stowe's regional network load value at Vermont Electric Company's (VELCO) peak usage. During the summer months, the ISO will publish a presentation from the Reliability Committee/Transmission Committee of the Rates Working Group for the RNS rate. RNS historically was June to May but beginning in 2022 this has changed to a calendar year. If Stowe can reduce consumption during the critical coincident peak of VELCO, it could potentially save on its transmission charges to the ISO. Using the most recent forecasted rates and Stowe's three-year monthly peaks, ENE created a forecast of Stowe's transmission impact, displayed below in Figure 62. Transmission costs are likely to increase due to the increasing dependence on intermittent generation resources in New England.

Figure 62: RNS Forecasted Rates

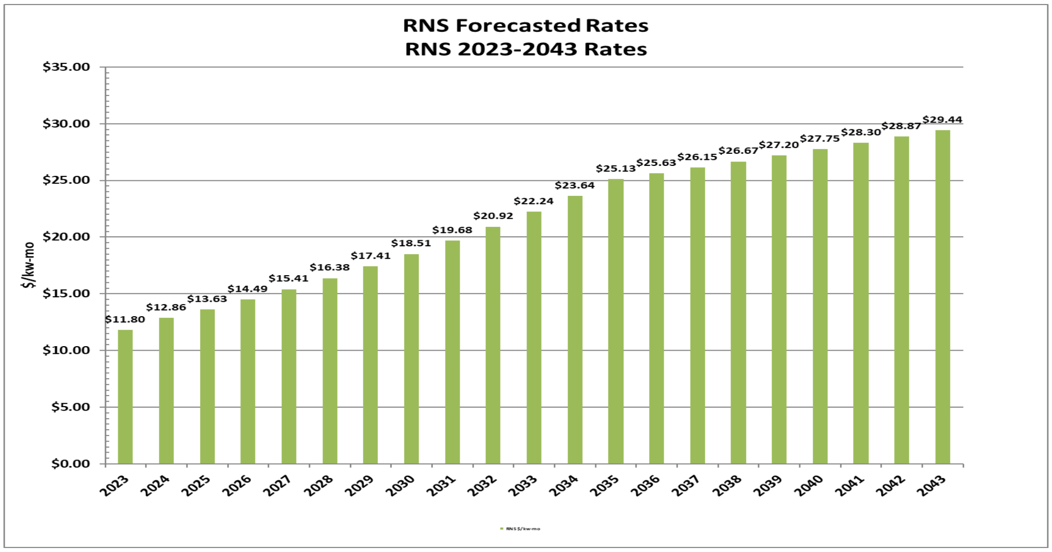


Table 13: Stowe's RNS Forecast

SED		
RNS Forecast		
Rate Year	RNS Rate $/kw-mo	Projected RNS Cost
1/1/2023	$ 11.804	$ 1,717,232
1/1/2024	$ 12.863	$ 1,871,195
1/1/2025	$ 13.634	$ 1,983,467
1/1/2026	$ 14.494	$ 2,108,537
1/1/2027	$ 15.408	$ 2,241,492
1/1/2028	$ 16.379	$ 2,382,832

D.3 Assessment of Environmental Impact

The New England Independent System Operator (ISO) is "responsible for the reliable and economical operation of New England's electric power system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system."19 The power sector is affected with new Federal Environmental actions. From

[19] 2021 Regional System Plan

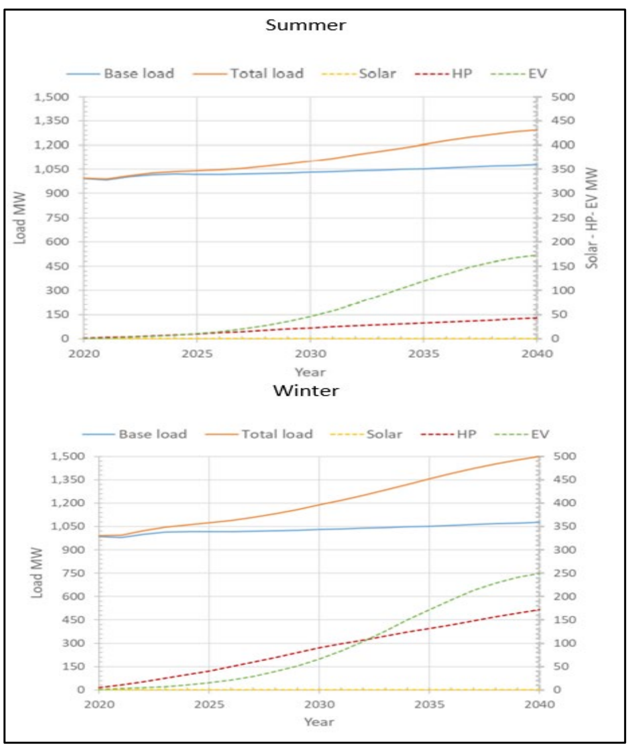
Pollution strategy and air quality standards, added resources are being assessed to comply and control air toxins.

D.3.1 Emerging Technologies

Vermont Electric Power Company (VELCO) creates a long-range transmission plan, which within the analysis is a discussion of how emerging technologies can affect the future load of the state. VELCO manages transmission lines, substations, switching stations, terminal facilities, emergency radio system, and fiber optic network which is used to monitor and control the Vermont electric system and broadband. VELCO's 2021 long range plan has carefully reviewed potential impacts for electric vehicles, PV, storage, and distributed generation and how these products will impact the VT grid. Future policies "recommended load management, which is sometimes referred to as load flexibility. Storage has a role to play if designed, operated, and located properly." The planning forecasts are used to help with reliability standards along with federal and regional reliability plans.

Vermont has an estimated 145 MWs of peaking resources, as well as 80 MWs of Standard Offer, with plans to increase the volume to 127.5 MW's. In Figure 63 , VELCO assesses the summer and winter MW impacts energy efficiency, and each technology, along with weather effects. After analyzing the trends, it can be safe to assume Stowe's load will increase or decrease at the same rate, when Stowe is impacted by these emerging technology enhancements.

Figure 63: VT Summer and Winter Peak Load and Components[20]

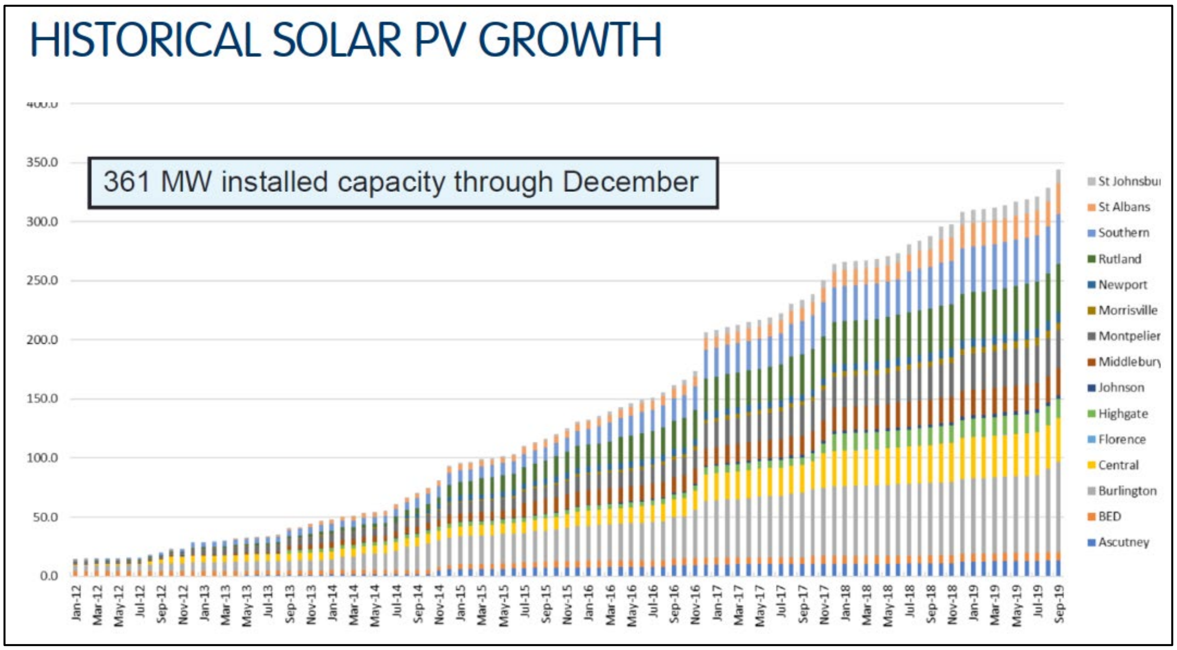


[20] *2021 Vermont Long-Range Transmission Plan*

VELCO publishes a long-range transmission plan, which provides a discussion of how emerging technologies can affect the future load of the state. VELCO's 2021 Plan reinforces the success of renewable growth in Vermont. "Vermont public policies have been successful at encouraging. investment in small-scale distributed generation, which has been primarily solar PV."[21]

In Figure 64, VELCO assesses the MW summation of the current solar installation. VELCO must monitor the Vermont equipment due to load shifting due to solar and possible overloading transformers as PV grows.

Figure 64: Vermont Historical Solar Data



D.3.1.1 Distributed Generation (DG)

ISO-NE describes distributed generation ("DG") as "generation provided by relatively small installations directly connected to distribution facilities or retail customer facilities. A small (24 kilowatt) solar photovoltaic (PV) system installed by a retail customer is an example of distributed generation."[22]

ISO-NE requested each distribution owner provide detailed projects information with respect to installed and operational PV projects within each territory. Vermont utilities include Burlington, GMP, Stowe, VEC, VPPSA, and WEC. All the VT utilities provided data as of December 31, 2022.[23] Vermont's installed projects totaled 468 MW, and Stowe's contribution was 3 MW. In

[21] *2021 Vermont Long-Range Transmission Plan*
[22] https://www.iso-ne.com/participate/support/glossary-acronyms#d
[23] https://www.iso-ne.com/static-assets/documents/2023/04/2023_pv_forecast_final.pdf

Figure 65 below are the survey results from all the New England States PV data along with the Vermont data.

Figure 65: ISO-NE Total PV Installed Capacity Survey Results

December 2022 Cumulative PV Totals

State-by-State

The table below reflects statewide aggregated PV data provided to ISO by regional Distribution Owners. The values represent installed nameplate as of 12/31/22.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	3,289	150,020
Connecticut	912	73,553
Vermont*	468	19,348
New Hampshire	183	14,427
Rhode Island	326	17,034
Maine	295	8,583
New England	**5,473**	**282,965**

* Includes values based on MA SREC data or VT SPEED data

As of March 31, 2023, Stowe has sixty-five installed net-metered solar projects on residential accounts. The total installed kW is 987.685. Stowe's internal PV net-metered customers and the Standard Offer resources (DG resources amongst the Vermont utilities) reduce Stowe's load.

With the Standard Offer Program as of February 24, 2023, there are 69.597 MWs of PV projects accepted as well as 10.728 MWs of Wind, Biomass, Farm and Landfill Methane, and Hydroelectric online. The Standard offer projects reduce the Vermont Utility load for each municipal's pro rata share per hour. Stowe's share percentage beginning in 11/1/2022 is 1.558%. DG within both Vermont and within Stowe will help count towards Stowe's RES compliance obligation.

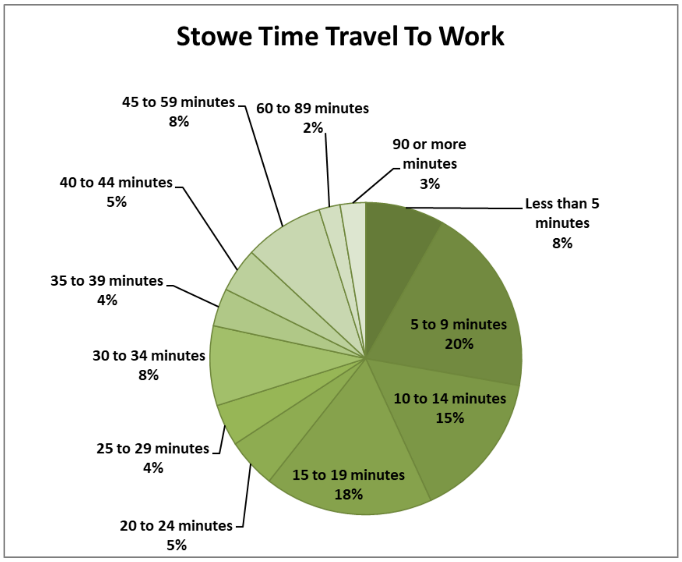
D.3.1.2 Electric Vehicle Penetration

The average travel time for Stowe residents is 17.3 minutes. 63.5% of the workers are commuting by car alone. 17% of workers are fully remote.[24] Over half of Stowe residents live in single family homes meaning they likely already have easy access to charge a vehicle at home.[25] Given the shorter commute times in theory and without constraints, Stowe's residents could use electric vehicle (EV) or plugin hybrid electric vehicle (PHEV) technology to reduce gas usage. Stowe is increasing EV infrastructure in town to accommodate a charging network.

[24] https://data.census.gov/profile?g=060XX00US5001570525

[25] townofstowevt.org)

Figure 66: Stowe's Time Traveled to Work



With state-sponsored energy efficiency programs promoting solar and electrification the demand for electric vehicles (EV) and air source heat pumps will increase. There are more consumer options for EVs due to the increase in production within the automobile industry. Increase in production will create more EV options for the secondhand market (used vehicles). The used EV market may help SED increase the adoption of vehicle electrification; outlined in the 2021 Vermont Comprehensive Energy Plan.

Since the first all-electric Nissan LEAF and plug-in hybrid Chevy Volt both hit the market in 2011 the electric vehicle space has expanded exponentially. "These days, everyone from Hyundai to Porsche to Hummer is throwing its hat in the ring with an EV of their own"[26]. The top EV models include the Tesla Model 3, Chevrolet Bolt EV, Nissan LEAF, GMC Hummer EV, and the Ford Mustang Mach-E. Each car offers enough daily gasoline-fee free driving range to meet the needs of most consumers on electric power alone, and/or in the case of the plug-in hybrids, for most annual miles traveled.

The Tesla Model 3 travels 358 miles on a single charge, (single 15-minute recharge at a supercharger will yield another 180 miles). This option will (primarily) appeal to the middle to upper middle-class due to its price tag. A more economically priced EV would be the Chevy Bolt at $26,500 with an EPA rated range of 259 miles. Tesla, Ford, Chevrolet, Volvo, Kia, Nissan, Audi, BMW models can go 200-400 miles between charges. One must keep in mind temperatures, as on a freezing day with temperatures around -4°F (Typical VT winter), the average EV's range may be reduced by 25% or more.

[26] https://www.menshealth.com/technology-gear/g19535983/best-electric-cars

EV energy consumption is measured in kilowatt-hours (kWh). . . "Let's say you drive about 1,183 miles per month (Americans drive an average of about 14,200 miles annually). For an average EV consuming 1 kWh per three miles, you will use about 394 kWh in that time. Using the U.S. household average from January 2022 of fourteen cents per kWh, it would cost about $55 per month to charge an electric car."[27]

Figure 67: Stowe's Energy Consumption from EV charging 2019 vs. 2022 and monthly 2022 data

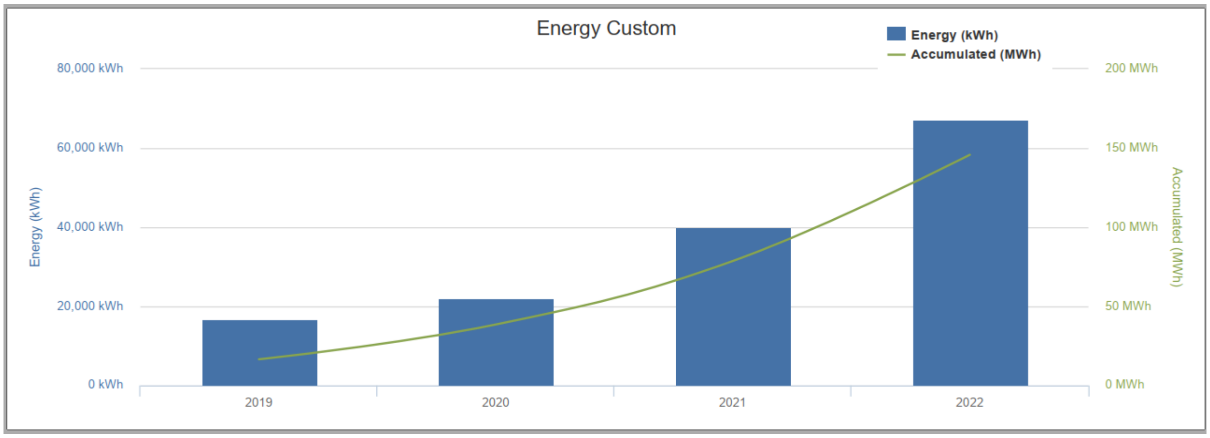


Table 14 Efficiency Vermont's Energy Usage and Savings summary has complied Stowe's EV statistics.

Table 14: Stowe's EV Registrations from Efficiency Vermont's 6/20/23 Report

Vehicle Type	2017	2018	2019	2020	2021	2022	2023
All Electric	9	11	12			12	10
Plug In Hybrid	28	26	20			9	11
Total	37	37	32	10	12	21	21

Assumptions for this IRP include 1) the average speed of the Stowe driver is 35 MPH, 2) there are an average of 250 work travel days a year, and 3) the use of a discharge rate of three miles per kWh, for a conservative average approach.

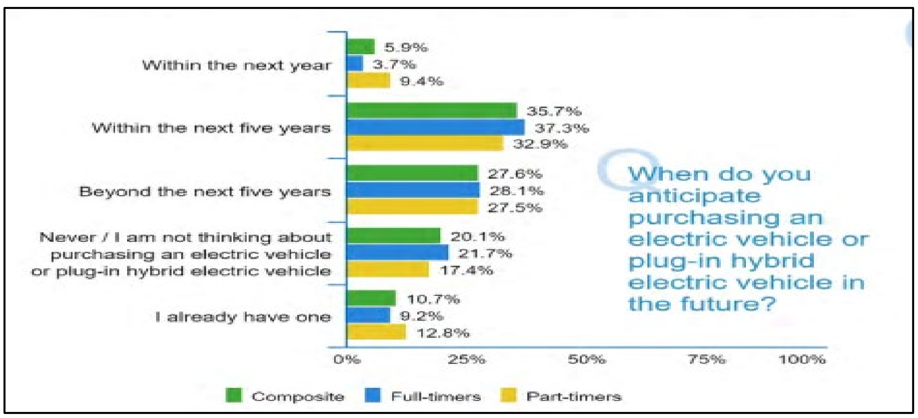
Table 15 below depicts the impact of potential EV penetration. With 100% penetration, Stowe's average annual load may increase by 5,718 MWhs, whereas a low case of 25% penetration might add 1,429 MWhs. Stowe's charging stations are also increased by tourism. Stowe's 2023

[27] https://www.kbb.com/car-news/how-much-does-it-cost-to-charge-an-ev/

survey[28] results on anticipated EV or Hybrid Vehicle purchase increasing to 30% within the next five years. It is feasible Stowe will see a low to medium energy increase due to this indication.

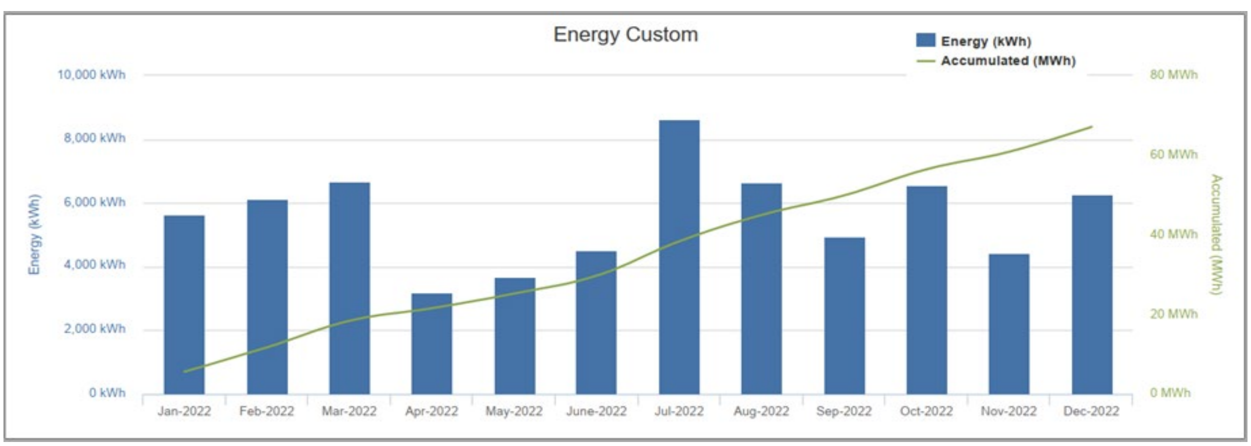
Table 15: Impact of Potential EV penetration in Stowe's work force and Survey Results

Time Traveled to Work	#	%	Miles using AVG 35 MPH	kWh round trip	kWh used for the year	EV Usage 100%	EV Usage 50%	EV Usage 25%	
Less than 5 minutes	180	8%	2.9	1.94	87,443	87,443	43,722	21,861	
5 to 9 minutes	429	20%	5.2	3.50	375,131	375,131	187,566	93,783	
10 to 14 minutes	337	15%	8.2	5.44	458,397	458,397	229,198	114,599	
15 to 19 minutes	384	18%	14.0	9.33	895,418	895,418	447,709	223,855	
20 to 24 minutes	113	5%	16.9	11.27	318,390	318,390	159,195	79,598	
25 to 29 minutes	95	4%	16.9	11.27	267,673	267,673	133,837	66,918	
30 to 34 minutes	181	8%	19.8	13.21	597,917	597,917	298,959	149,479	
35 to 39 minutes	86	4%	22.7	15.16	325,872	325,872	162,936	81,468	
40 to 44 minutes	101	5%	25.7	17.10	431,775	431,775	215,888	107,944	
45 to 59 minutes	181	8%	34.4	22.93	1,037,562	1,037,562	518,781	259,390	
60 to 89 minutes	48	2%	51.9	34.59	415,064	415,064	207,532	103,766	
90 or more minutes	58	3%	52.5	34.98	507,170	507,170	253,585	126,793	
	2193			180.72	5,717,813	5,717,813	2,858,906	1,429,453	kWh/yr
						0.65	0.33	0.16	MW/hr



Below in Figure 68 is the consumption from calendar year 2022 of EV charging stations.

Figure 68: Stowe's Energy Consumption from EV charging 2022 annual total



[28] [Rates & Filings | Stowe Electric]

The US Energy Information Administration (EIA) estimates car usage, of both conventional and alternative fuels, in a forecast that extends through the year 2050.[29] When necessary, Stowe can increase their current EV station fleet in an effort to promote and accommodate electric vehicles. EV will remain of high interest for Stowe because EV stations and usage will count towards Stowe's compliance of the Tier III Renewable Energy Standard.

[30]

D.3.1.3 Energy storage

Stowe received a grant to develop a microgrid feasibility study, which includes the feasibility of adding battery energy storage (BESS) to our system. As staff work to complete the study and determine the most viable use case for BESS, Stowe is focused on a battery that can meet multiple use cases. This could include absorbing surplus solar generation on our system, operating reserves, peaking capacity, and outage restoration. Storage technology offers users the ability to meet demand whenever needed and, more importantly, enables the user to call upon it during peak energy events. Stowe could use this energy to reduce their load during these events and help reduce peak load. Energy storage could not only save Stowe on load cost, but it could also reduce their transmission and capacity charges within ISO-NE. Table 16 below illustrates

[29] http://www.eia.gov
[30] https://www.stoweelectric.com/

how a system using a one MW storage capability at the critical peak times can result in large yearly savings. See section Market Conditions D.2 for the forecasted rates used to calculate a one MW reduction. ENE also forecasted capacity reduction using an estimated 40% reserve adder. With these assumptions, Stowe would not only reduce its peak by 1 MW, but it would also ultimately reduce it by the storage amount plus the ISO reserve adder, making storage a more appealing tool for cost savings.

Table 16: Capacity and Transmission Savings

Project Assumptions	
MW	1
Commerical Operation Date	1/1/2023
Load Zone	VT
Est Reserve Margin	40%
RNS Ratio (8/12 months etc)	67%

Row Labels	Total ISO Capacity Savings	Sum of Total ISO RNS Savings	Total Savings
2023	$ -	$ 100,898	$ 100,898
2024	$ 22,888	$ 107,961	$ 130,849
2025	$ 39,972	$ 115,518	$ 155,490
2026	$ 40,968	$ 123,604	$ 164,573
2027	$ 41,788	$ 132,257	$ 174,044
2028	$ 42,624	$ 141,514	$ 184,138
2029	$ 43,476	$ 151,420	$ 194,897
2030	$ 44,346	$ 162,020	$ 206,365
2031	$ 45,232	$ 173,361	$ 218,594
2032	$ 46,137	$ 185,497	$ 231,634
2033	$ 47,060	$ 198,481	$ 245,541
2034	$ 48,001	$ 212,375	$ 260,376
2035	$ 48,961	$ 227,241	$ 276,202
2036	$ 49,940	$ 243,148	$ 293,089
2037	$ 50,939	$ 260,169	$ 311,108
2038	$ 51,958	$ 278,380	$ 330,338
2039	$ 52,997	$ 297,867	$ 350,864
2040	$ 54,057	$ 318,718	$ 372,775
2041	$ 55,138	$ 341,028	$ 396,166
2042	$ 56,241	$ 341,028	$ 397,269
Grand Total	**$ 882,724**	**$ 4,112,486**	**$ 4,995,209**

The greatest benefit of energy storage is its ability to heighten the capacity factor of renewable generation, such as solar. "These devices can also help make renewable energy, whose power output cannot be controlled by grid operators, smooth and dispatchable." [31] When solar production is low and a peak event is on the horizon, energy storage can supplement the solar output, and thereby, enable load reduction during the critical time.

[31] https://www.energy.gov/oe/services/technology-development/energy-storage

D.3.1.4 Fuel Switching

American Rescue Plan Act distributed to the State of Vermont (reported by Agency of Administration in October 2022[32]) over $1 billion in State Fiscal Recovery Funds from the pandemic. These funds were allocated to VT programs but included in the list were heating and renewable efficiency assistance. Other utility programs included energy resilience assessments.

Other funding sources were discussed in the H.518 bill that was passed by the House on March 18, 2022, and then by the Senate on June 2, 2022. This proposal was to establish fuel switching grant programs and expand municipalities to State Energy Resource Funds for energy efficiency improvements.

Generally understood, "heat pumps are powered by electricity, but they are much more efficient than electric resistance heating familiar to most homeowners (such as space heaters and baseboard heating). Rather than directly converting electrical energy into heat with electric resistance heating or converting heat from fossil fuels through combustion, heat pumps redistribute heat that is already present in the outside environment."[33] Heat pump switching is efficient, and due to this, the technology can help with Stowe's RES Tier III energy transformation compliance. However, Stowe's demographics include a sizable percentage of second and third homeowners that are part-time residents, meaning that Stowe homeowners might hesitate in switching to heat pumps because of the upfront costs. In 2023 Stowe issued a customer satisfaction survey (which can be found on the Stowe Electric Department Website).[34] Some key statistics that were uncovered were:

- EV Adoption - 41.6% of Stowe Electric customers indicated they plan to purchase an electric vehicle in the next 5 years. An additional 27.6% said they anticipate purchasing an EV more than five years from now.
- Solar Adoption - 16.9% said they plan on installing solar soon, with 84.2% of those indicating they plan to act within the next five years.
- Heat Pump Adoption - 13.4% said they plan to purchase heat pumps for their home, with 40% planning to act this year and another 48% acting within the next 5 years.

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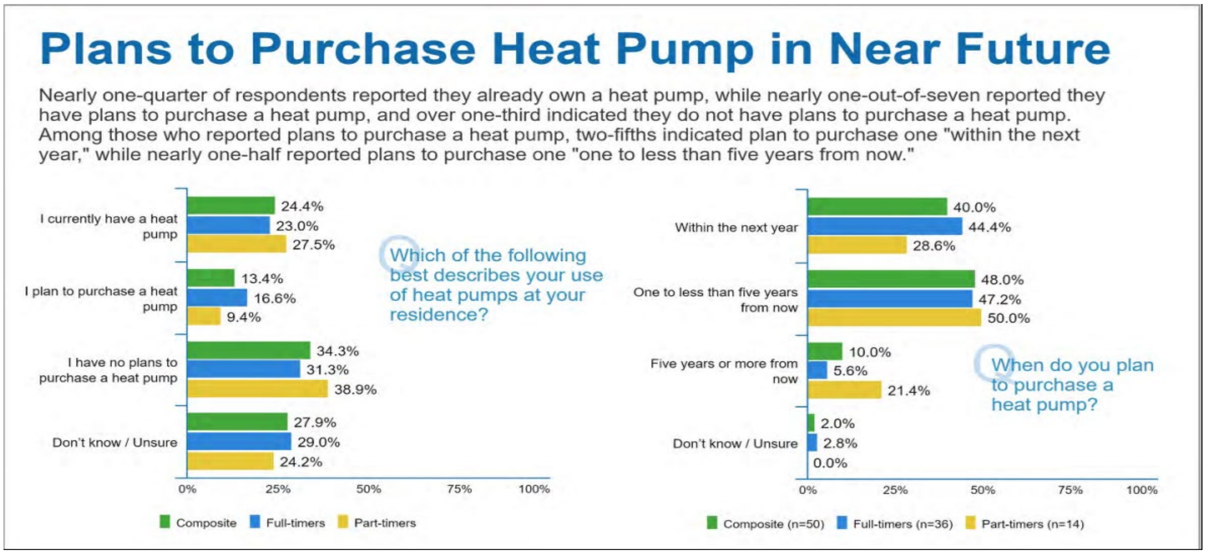
[32] PowerPoint Presentation (vlct.org)
[33] https://www.synapse-energy.com/about-us/blog/switch-savings-heat-pump-cost-effectiveness-study
[34] Rates & Filings | Stowe Electric



Stowe will continue to partner with EVT to offer incentives and consumer education to encourage the installation of CCHPs.

The conversion to heat pumps offers an energy efficient alternative to fuel switching. Although heat pumps can offer additional benefits to homes and buildings, they do increase electricity usage. Stowe does promote these switching options; Stowe Electric provides different rebates for Heat Pump technology. Going forward, Stowe will have to decide if time of use rates would benefit or be a detrimental option. Time of use may be beneficial for EV plug-ins to motive charging during off-peak times but if the household is using heat pumps, this option may have negative impact to the customer's electric bill.

D.3.2 Environmental attributes

Environmental attributes are defined as "characteristics of a program or project (such as particulate emissions, thermal discharge, waste discharge) that determine the type and extent of its short-term and long-term impacts on its environment".[35] Projects qualify their attributes in different state classifications, based on year, fuel type, and emissions to name a few. These attributes are then marketable on a current platform called the New England Power Pool Generation Information System (NEPOOL GIS). Projects with qualifying attributes trade them to participants within ISO-NE, who apply them towards their renewable portfolio to meet compliance rules.

D.3.3 Assessment of Carbon Impacts

Energy New England initiated the carbon assessment by reviewing the historical carbon intensity of SEP's power mix from 2010 through 2022 and then compared the results against the forecasts for the given years. ENE quantified SED's yearly non-emitting MWH totals by compiling

[35] http://www.businessdictionary.com/definition/environmental-attributes.html

resources such as NYPA, Hydro Quebec, FirstLight, Standard Offer, McNeil, Seabrook, Nebraska Valley, and Saddleback. allocations and REC retention totals and then comparing the results against their total yearly retail sales data. ENE collected ISO-NE's final emission reports to incorporate the carbon impact of the regional system for each year.[36] Even though there are other components of GHG (such as CH_4 and N_2O), ENE chose to primarily focus on CO_2 because "in the U.S., CO_2 emissions represent more than 99 percent of the total CO_2-equivalent GHG emissions from all commercial, industrial, and electricity generation combustion sources."[37]

D.3.3.1 *Emission Calculation*

ENE calculates SED's emission rates using ISO-NE's yearly ISO New England Electric Generator Air Emissions Report. Although the report was published after a delay, the methodology used to create the emission rate best aligns with SED's portfolio emission estimates. The ISO utilizes a total system emission rate calculation method that is based on all ISO New England generators emissions for a calendar years' worth of production. They use actual run time for on and off-peak generation at the emission rate for each month. The primary source of data is from the US EPA's Clean Air Market Division (CAMD) database, as well as the Regional Greenhouse Gas Initiative (RGGI). If any information is not available, EPA's eGRID annual emission rates are used to obtain rates from similar unit types.

All units that are dispatched are included in the emission rate calculation. The calculation is:

$$\text{Annual System Emission Rate (lb/MWh)} = \frac{\text{Total Annual Emissions (lb) all generators}}{\text{Total Annual Energy (MWh) all generators}}$$

Using ISO data is important because not all the generation is operational at the same time or all the time. The ISO tracks the air emissions from the NE system Grid while taking into consideration:

- Forced and scheduled maintenance outages
- Fuel and emission allowance costs
- Imports and exports to and from NE region
- System energy consumption
- Water availability, etc.

Incorporating these factors set ISO emissions methods apart from those of other data sources (such as eGRID). EPA's eGRID states "Emissions and emission rates in eGRID represent emissions and rates at the point(s) of generation . . .they do not consider any power purchases, imports, or exports of electricity into a specific state or any other grouping of plants. and They also do not account for any transmission and distribution losses between the points of generation

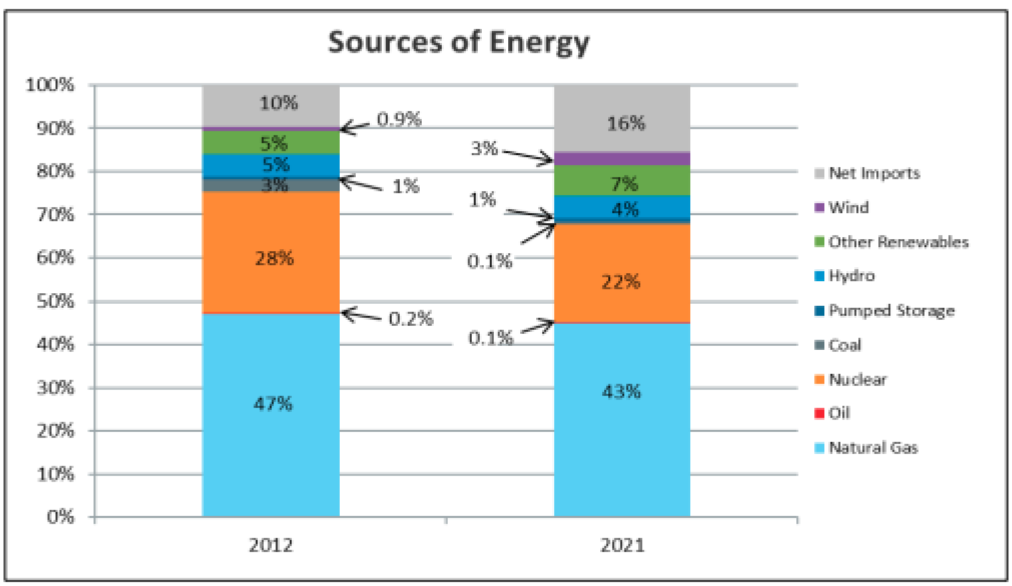
[36] https://www.iso-ne.com/about/key-stats/air-emissions
[37] https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

and the points of consumption. EGRID does not account for any pre-combustion emissions associated with the extraction, processing, and transportation of fuels and other materials used at the plants or any emissions associated with the construction of the plants."

D.3.3.2 Emission Trends

Figure 69 displays the fuel mix in the ISO-NE control area in 2012 compared to 2021. ENE selected 2021 data, because this is the most recent period for which the ISO regional emissions report is available. Coal has decreased the most over the period, dropping from 3% to .1%. Oil generation decreased by .1%. These changes resulted from a combination of tightening emission requirements, higher operating and maintenance expenses of solid fuel and older thermal generating facilities compared to natural gas, and market forces, such as low natural gas prices in the past several years. The latter is due to the merchant generator boom that occurred in the late 1990's and early 2000's. This resulted in the building out of thousands of MWs of high efficiency natural gas fired generating capacity. This moved natural gas to the dominant marginal fuel in New England, where it now sets the marginal wholesale electricity price 43% of the time or more. This means that all generating technologies are affected by the price and availability of natural gas. In renewable energy "Wind often displaced gas as the price-setting fuel. Though wind was marginal 13% of the time in 2021, it was usually marginal for only a small share of total system load."[38]

Figure 69 ISO-NE System Energy Generation Percentage by Fuel Source[39]



[38] 2021-air-emissions-report.pdf (iso-ne.com)
[39] 2021-air-emissions-report.pdf (iso-ne.com)

Table 17 lists ISO New England's average yearly CO_2 emission rates. These rates were used to determine Stowe's supply emission profile for its open position and bilateral commodity energy contracts since these purchases are not tagged to a particular generator.

Table 17: Regional Annual CO_2 Emissions in lb./MWH[40]

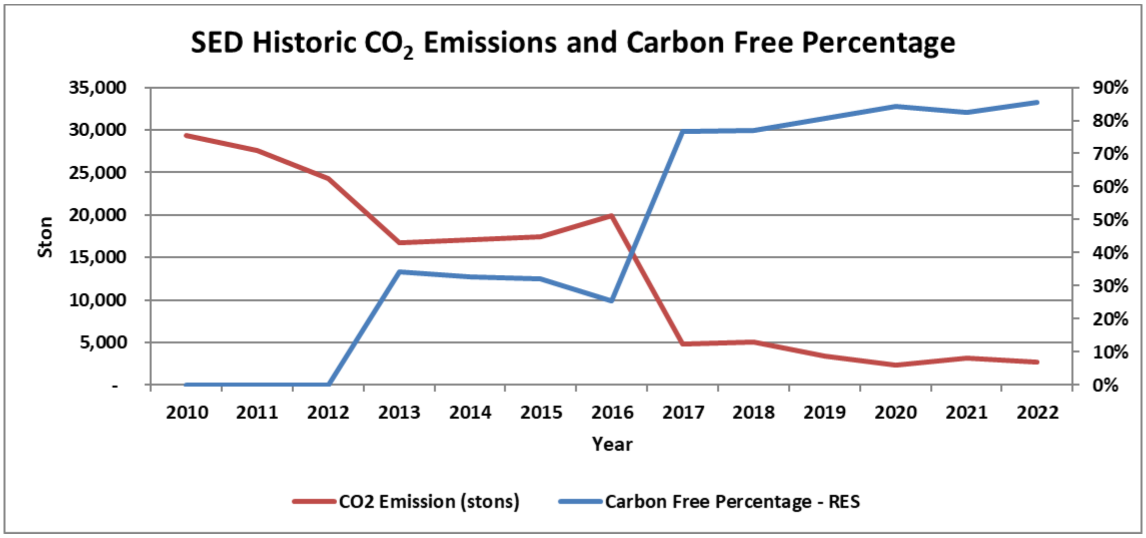
Appendix Table 6
ISO New England
Annual Average Generator Emission Rates, 2001 to 2021 (lbs/MWh)

Year	Total Generation (GWh)	NO_x	SO_2	CO_2	CO_2 with Net Imports
2001	114,626	1.05	3.51	930	
2002	120,539	0.94	2.69	909	
2003	127,195	0.93	2.75	970	
2004	129,459	0.78	2.31	876	
2005	131,874	0.88	2.27	919	
2006	128,046	0.67	1.59	808	
2007	130,723	0.54	1.66	905	
2008	124,749	0.52	1.51	890	
2009	119,282	0.46	1.29	828	
2010	126,383	0.46	1.28	829	
2011	120,612	0.42	0.95	780	708
2012	116,942	0.35	0.28	719	645
2013	112,040	0.36	0.32	730	643
2014	108,356	0.38	0.22	726	643
2015	107,916	0.35	0.17	747	657
2016	105,570	0.31	0.08	710	630
2017	102,562	0.30	0.08	682	592
2018	103,740	0.30	0.10	658	577
2019	97,890	0.26	0.05	633	547
2020	94,945	0.25	0.04	654	561
2021	101,692	0.24	0.04	658	574
Percent Reduction, 2001 - 2021		77	99	29	

Stowe's current carbon reduction power supply portfolio includes NYPA, and all retained RECs such as Hydro Quebec, and Seabrook. Figure 70 represents SED's total portfolio created about 30,000 tons of CO_2 in 2010 and drops to about 2,650 tons of CO_2 in 2022.

[40] 2021-air-emissions-report.pdf (iso-ne.com)

Figure 70 SED CO_2 Emissions and Carbon Free Portfolio

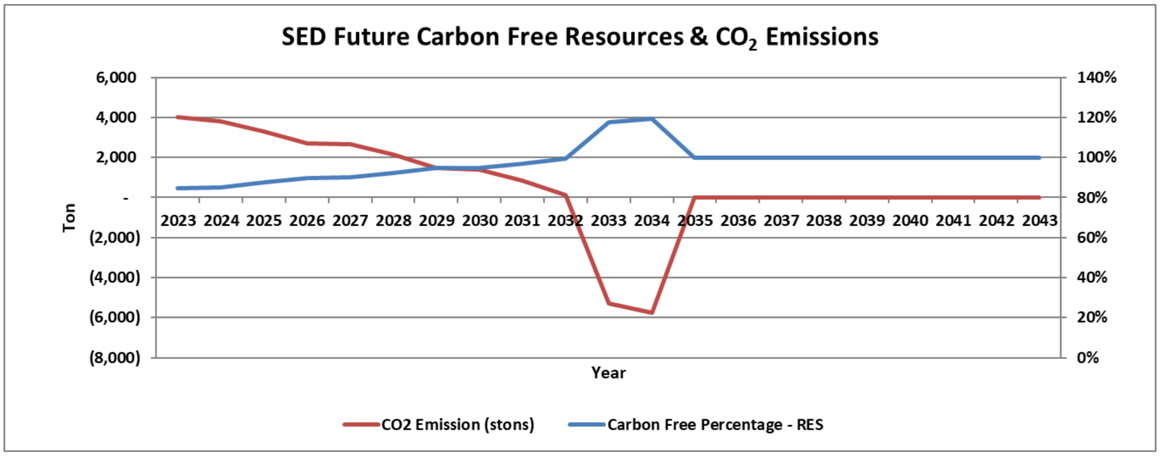


As a result of the RES, Stowe will increase their non-emitting portfolio by retaining and retiring RECs. ENE projected the emission rates for beyond 2022 with the most recent rate in 2021 of 658 CO_2 lbs./MWH. ENE also assumed Stowe would be 100% carbon free within the year 2032, this is the final year of the current RES program. Figure 71 illustrates that these assumptions maintain Stowe's carbon footprint Achieving the RES targets reduces Stowe's carbon emissions by 87% from 2016 levels in 2022. By 2032 the final year of RES, Stowe will have reduced CO_2 by -99% from 2016 levels. This decrease directly follows the State goals set in the Vermont Climate Action Plan "Vermont must get ready for a changing climate and cut its climate pollution, such as carbon and methane emissions, in half by 2030 to meet the target in Vermont's Global Warming Solutions Act."[41]

In December 2021, the Final Vermont Climate Council's Climate Action Plan was finalized[42]. The plan requires net zero emission by 2050. Stowe is in line to achieve this goal well before 2050, Stowe will have net zero by 2033 barring some unforeseen circumstances. Stowe's carbon goal accomplishes the 2016 Paris Agreement to reduce GHG emission by 26% below 2005 levels by 2025, as well as the 2016 Comprehensive Energy Plan to reduce GHG by 40% below 1990 emission by 2030.

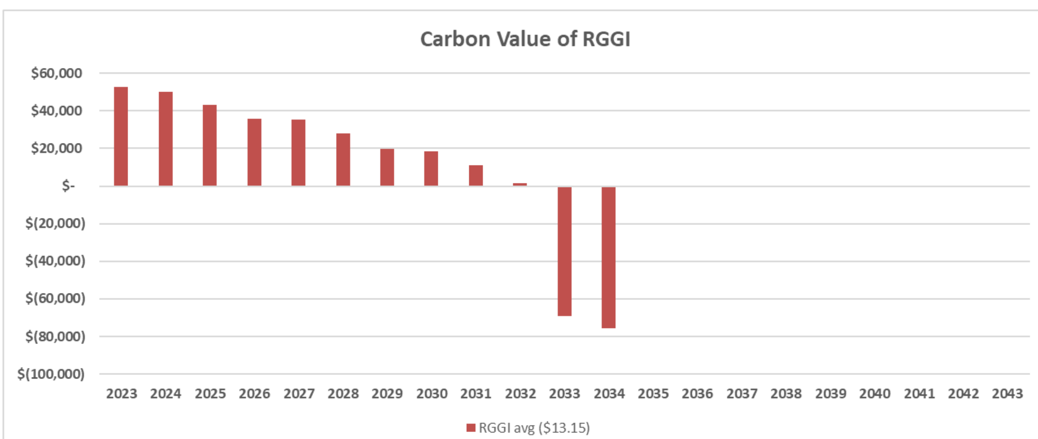
[41] VT CAP Summary FINAL.pdf (vermont.gov)
[42] Climate Action Plan - Final - 12/1/21 | Climate Change in Vermont

Figure 71 SED CO_2 Emissions for RES



Carbon pricing is a way to value the externalities of carbon emitted by human causes into the environment. RGGI is a market-based program for reducing greenhouse gases. There is a rate associated to the carbon allowance emitted in short tons of CO_2. Generators purchase RGGI credits to emit CO_2. RGGI rates average around $13.15. below Figure 72 is the carbon cost if Stowe were to buy RGGI credits for each ton of carbon at an average rate of $13.15. Once Seabrook terminates, Stowe will maintain 100% renewable compliance set in the RES obligation.

Figure 72 SED Carbon Value of RGGI



E Data Models and Information

E.1 RES Optimization Model - @Risk®

In performing the RES portfolio integration and identifying an optimal REC position, Energy New England performed Monte Carlo simulations using the @RISK® commercial statistical software package to extrapolate optimal algorithms that identify the percentile of each outcome to SED's portfolio.

The Energy New England Portfolio Simulation Model is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables. This method allows insights into the probability distribution of outputs. The reason for the quantitative modeling is to determine the sensitivity of Stowe's portfolio cost when faced with changes in market conditions. Also, to identify an optimal combination of resources that will provide Stowe with the highest probability of having a competitive and low-cost resource portfolio. The model allows the use of inputs that will represent extreme and mild cases per resource. ENE reviewed and analyzed the extreme cases during the stress testing (results).

ENE used this model for the Energy Portfolio, Capacity Market and the RES modeling sections within the IRP. The RES base case model result can be found in G.2 RES modeling. The Capacity results can be found F.3 Capacity modeling.

F Assessment of Resources

F.1 Existing Energy Resources

Stowe's portfolio consists of existing resources, including long-term contracts and entitlements, which provide suppliers, fuel source, and term diversity. See Table 18 for a brief description of each resource. Each resource includes annual production, fuel, location, and termination date.

Table 18: Stowe 2022 Resources

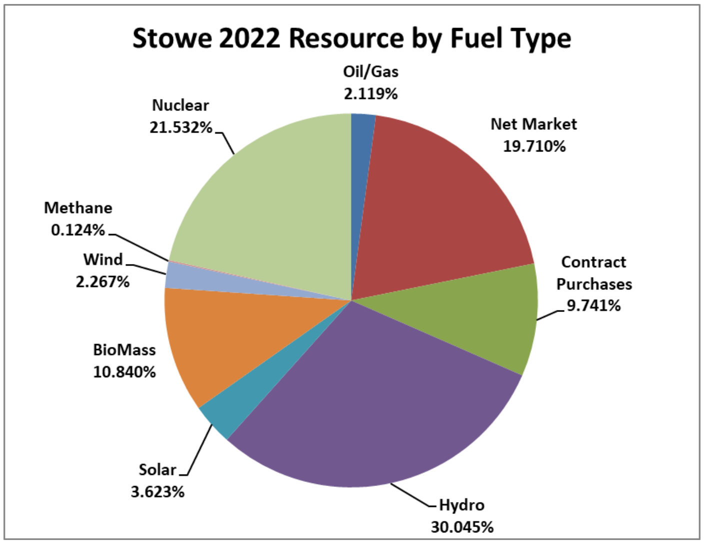
2022 Total KWH's by Resource								
Resource		Type	MWH	KWH	% of Load	Fuel	Location	Termination
Niagara		Block	3,095	3,094,891	3.8%	Hydro	Roseton	9/1/2025
St. Lawrence		Block	80	79,995	0.1%	Hydro	Roseton	4/30/2032
HQ Contract		ISO Bilateral	17,462	17,461,600	21.5%	Hydro	HQ Highgate 120	10/31/2038
Ryegate	1.550	Wood Unit	1,948	1,947,655	2.4%	Wood	RYGT	11/1/2032
McNeil		Wood Unit	6,869	6,869,206	8.4%	Wood	Essex	Life of Unit
Standard Offer ISO			101	101,129	0.1%	Methane	VT Nodes	
Cabot/Turners		ISO Bilateral	1,705	1,704,552	2.1%	Hydro	Mass hub	Exp. 2030
Stony 1A/1B/1C	4.916	Dispatchable	1,724	1,723,616	2.1%	Natural Gas/Oil	Stonybrk 115	Life of Unit
Seabrook Offtake		ISO Bilateral	17,514	17,514,058	21.5%	Nuclear	Seabrook 545	Exp. 2034
Miller Hydro		PPA	2,097	2,097,394	2.6%	Hydro	TopSham.Milr	Exp. 2025
Saddleback Ridge	0.21	PPA	1,844	1,843,606	2.3%	Wind	LUDDN_LN	Exp. 2035
Shell Bilateral		ISO Bilateral	546	545,600	0.7%		VT Zone	3/31/2023
Bilateral Purchase - Mtn		ISO Bilateral	7,378	7,377,534	9.1%		Mass hub	4/30/2024
ISO Energy Net Interchange			16,032	16,031,706	19.7%			
Totals			78,393	78,392,544				
Standard Offer BTM		Load Reducer	1,671	1,671,226	2.1%		Behind meter	
Nebraska Valley Solar Project		Load Reducer	1,276	1,275,966	1.6%	Hydro	Behind meter	Life of Unit
		Reconstituted	81,340	81,339,736	100.0%			

Table 19: Stowe 2022 Current Resources Energy Cost

2022 Energy Cost by Resource			
Resource			$/MWH
Niagara			$ 4.92
St. Lawrence			$ 4.92
HQ Contract			$ 58.44
Ryegate			$ 110.40
McNeil			$ 64.28
Standard Offer ISO			$ 191.83
Standard Offer BTM			$ 143.87
Cabot/Turners			$ 42.33
Stony 1A/1B/1C			$ 110.24
Seabrook Offtake			$ 54.71
Miller Hydro			$ 48.46
Saddleback Ridge			$ 94.17
Shell Bilateral			$ 170.21
Bilateral Purchase - Mtn			$ 202.82
ISO Energy Net Interchange			$ 98.46

Figure 73, below, represents Stowe's resources by fuel type format. This pie chart shows 19.7% of Stowe coverage was from market purchases within 2022.

Figure 73: Energy Resources in 2022



F.1.1 J.C. McNeil Generating Station

The McNeil wood-fired generation station is in Burlington, Vermont and has a maximum capability of 53 MW. Stowe's unit entitlement for energy, capacity, and ancillary products stems from a power purchase agreement with the Vermont Public Power Supply Authority for the life of the unit. Wood is the primary fuel source, with natural gas as an alternate. Plant startups utilize either natural gas or fuel oil. With the NOx improvement, McNeil renewable credits are qualified in Connecticut Class I category. This has increased McNeil's running time as well as lowering the overall cost of the unit. With the McNeil's bonds paid off in June 2015, fixed costs for the plant have decreased. The variable cost structure is due to ISO-NE dispatching the unit regularly when the price of wood is competitive with natural gas.

F.1.2 New York Power Authority (NYPA)

The New York Power Authority provides hydroelectric power to New York's neighboring states. Two contracts provide this power to Vermont: a) 1 MW entitlement to the Saint Lawrence project in Massena, New York; and b) a 14.3 MW entitlement in the Niagara project located in Niagara Falls, NY. The Saint Lawrence contract was renegotiated after its most recent end date of April 30, 2032, and the Niagara contract through September 1, 2025.The energy, capacity, and transmission payments required to deliver this entitlement to Vermont are at prices that are competitive to the New England power markets. The NYPA Renewable Energy Credits are allowed to be used toward Stowe's RES compliance as stated in the 8550 final order, which can be found in Appendix E.

F.1.3 Ryegate

Ryegate is a 20 MW wood-fired unit, which was once within the VEPPI 4.100 projects. The VEPPI contract expired on October 31, 2012. The utilities negotiated a 10-year contract for power through VEPPI. The contract is for both power and renewable energy credits. As the extension terminated on April 30, 2023, the contract was renegotiated through a maximum date of November 1, 2032. The contract timeline is subject to earlier termination if Ryegate Associates fails to meet the requirements of Section 8009(k) in the petition.

"Under Section 8009(k), Ryegate Associates must increase the plant's overall efficiency by at least 50%, relative to the 12-month period preceding July 1, 2022. Sections 8009(k)(2) and (3) establish a schedule for Ryegate Associates to demonstrate that the plant will meet the efficiency requirements by November 2026."

F.1.4 Sustainably Priced Energy Enterprise Development "SPEED" or Standard Offer

SPEED Standard Offer is a program established under Vermont Public Service Board Rule 4.300. The program's goal is to achieve renewable energy and long-term stable price contacts. Vermont utilities will purchase power from the SPEED projects. These projects are behind the meter and each utility will have their percent shared. Stowe's share for November 1, 2020, through October 31, 2021, was 0.2418% and increased to 0.2536 % for November 1, 20121 through October 31, 2022. Stowe receives a modest capacity credit, and renewable energy credits for these resources. The cost paid to the SPEED projects are set based on the generation type. SPEED began in the fourth quarter of 2010.

Section 4.304 of Rule 4.300 defines Speed Projects (those that qualify to serve a Vermont utility's SPEED requirement) as:

"(SPEED projects are new electric generating projects that produce renewable energy. A "new" project means a project brought on-line after December 31, 2004. A SPEED project must use a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate. Obvious examples of SPEED projects are utility scale wind farms, hydroelectric projects less than 200 MW, wood-to-energy projects, landfill gas-to-energy projects, etc. Combined Heat and Power (CHP) projects are SPEED projects if they meet certain efficiency standards or if they are fueled with a renewable resource.

Projects that use a mix of fossil fuels and renewable fuels, such as a diesel generator that is partially fueled with biodiesel, may qualify as SPEED in proportion to the amount of renewable fuel (in this case biodiesel) that is used.

The incremental energy produced by an expansion or modification of a pre-existing renewable energy project are considered as a SPEED project."

In May of 2009, as the SPEED Program progressed and implemented modifications, it changed into the Standard Offer program. This change began a feed-in-tariff to encourage the development of SPEED resources by making contracts long term and fixed prices that qualified renewable energy projects. By May of 2012, the Vermont Energy Act of 2012 expanded the program to 127.5 MW over a 10-year span with a new pricing mechanism for qualified projects. The Standard Offer Program within the Public Utility Commission Docket No. 8817 contained avoided cost price caps.

These prices are found below in Table 20. Each CAP is subject to a location and a fuel type. Figure 74 lists the current fuel source breakdown of the Standard Offer Projects. The complete list of projects is in Appendix C.

Table 20: 2022 Avoided Cost Price CAPS for Standard Offer

TECHNOLOGY- SPECIFIC PRICE CAPS

The following will serve as price caps for the 2022 RFP:

- Biomass – $0.125 per kWh (fixed over 20 years)
- Landfill Gas – $0.090 per kWh (fixed over 15 years)
- Wind > 100 kW – $0.116 per kWh (fixed for 20 years)
- Wind ≤ 100 kW – $0.258 per kWh (fixed for 20 years)
- New Hydroelectric – $0.130 per kWh (fixed for 20 years)
- Food Waste Anaerobic Digestion – $0.208 per kWh (fixed for 20 years)
- Solar – $0.0982 per kWh (fixed for 25 years)

Figure 74: Energy Provided by Standard Offer Projects

Program Technology Summary

Technology	Online (MW)	Pending (MW)	Total (MW)
Solar PV	63.567	43.450	107.017
Solar PV – Utility	6.030	0.000	6.030
Wind – Large	0.000	2.200	2.200
Wind – Small	0.050	0.738	0.788
Farm Methane	1.965	0.000	1.965
Hydroelectric	4.939	2.350	7.289
Biomass	0.865	0.000	0.865
Landfill Methane	0.000	0.000	0.000
Food Waste	0.000	2.988	2.988
Total	77.416	51.726	129.142
Farm Methane Outside Program Cap	2.909	0.000	2.909

Updated 2/24/23

F.1.5 Stony Brook Combined Cycle

Stowe is entitled to slightly under 6 MW of the Stony Brook combined cycle facility. This facility is a natural gas and #2 oil fired generation facility located in Ludlow, Massachusetts. The total capacity is 350 MW in the winter. During the winter months, the unit is challenged with sourcing natural gas; it will run on fuel oil during that time. Fuel scarcity limits unit generation to non-winter months, concentrated around the summer New England peak load season. The development of new, high efficiency combined cycle facilities in the past 10 years has served to limit Stony Brook's operational time. Built as an intermediate unit in 1981, it now generally provides peak availability. The unit heat rate is in the 8,500 BTU/KWH range, and the fact that the unit runs little during the year is a testament to the impact that merchant generation has had in New England. While power prices have been falling due to natural gas storage increasing, this has caused a reduction of run time for peaking units, because locational marginal prices have been far below bid price.

Stated in MMWEC's 2021-22 Budget the operating reserve is used to help mitigate cost increases. The funds are used for any unforeseen events or capital expenditures.

ENE did not include Stonybrook as a cost or coverage among Stowe's scenarios because of the low amount of output from the unit. In addition, the times Stonybrook is used to hedge peak hours where it can run in the money, can be a benefit for Stowe.

F.1.6 New -Hydro Quebec Contract

This contract began on November 1, 2012, for energy and renewable credits. The contract calls for 218 MW, with Stowe's portions vary during different periods as listed below in Table 21. The contract pricing is flexible and competitive in relation to the market price because it will follow the defined Energy Market index and the cost of power on the forward market. The pricing is based on market prices and inflation. The contract structure carries limits on year-to-year price fluctuations. Given the greater degree of market price volatility exhibited since the original Hydro Quebec (HQ) contract was agreed, this pricing approach should be beneficial to Stowe as the contract is limited to how "out of market" it might become for both HQ and Stowe. This is an important contract quality in the current market environment, and it reduces potential rate pressure for Stowe. In addition to price flexibility, this will continue to provide extremely low carbon energy to Stowe, helping it maintain a market price based green energy procurement strategy. The HQ RECs are allowed to be used toward Stowe's RES compliance as stated in the 8550 final order, which can be found in Appendix E.

Table 21: Contract based on 218 MW.

Schedule	Start Date	Final Delivery Date	Stowe Entitlement (MW)
Period 1	11/1/2012	10/31/2015	1.032
Period 2	11/1/2015	10/31/2016	2.884
Period 3	11/1/2016	10/31/2020	2.984
Period 4	11/1/2020	10/31/2030	2.984
Period 5	11/1/2030	10/31/2035	2.251
Period 6	11/1/2035	10/31/2038	0.399

Highgate has completed an upgrade to increase the transfer capability. The schedule was approved by the ISO-NE; the MW's increased to 255 MW. With this adjustment, the contract shifted to the second option of bilateral amounts beginning in November 2016. Table 22 below lists the new portion for Stowe.

Table 22: Contract based on 255 MW.

Schedule	Start Date	Final Delivery Date	Stowe Entitlement (MW)
Period 1	11/1/2012	10/31/2015	1.238
Period 2	11/1/2015	10/31/2016	2.890
Period 3	11/1/2016	10/31/2020	2.990
Period 4	11/1/2020	10/31/2030	2.990
Period 5	11/1/2030	10/31/2035	2.135
Period 6	11/1/2035	10/31/2038	0.483

F.1.7 Brown Bear II Hydro (Old Miller Hydro Contract)

Stowe signed a purchase power agreement (PPA) for 2.613% of the Worumbo (Miller Hydro) Project. The contract price is for delivery of energy to the resource node in Maine, and capacity to be settled at the Maine location. The PPA terminated on May 1, 2016.

Brown Bear Hydro purchased Miller Hydro and a PPA was renegotiated beginning on June 1, 2016. The contract was extended for the same allotment of 2.613% of unit. The negotiation of the PPA now includes energy and renewable energy credits (RECs). This PPA terminated on May 31, 2021.

Brown Bear Hydro PPA was renegotiated beginning on June 1, 2021, and will terminate on November 30, 2025. The contract was extended for the same allotment of 2.613% of unit. The negotiation of the PPA includes energy and RECs.

F.1.8 Saddleback Ridge Wind Project

Stowe purchased 2.172% of the Saddleback Wind Project, a 33 MW project with a 20-year PPA. This is 3% of Stowe's load. The project allows Stowe to buy energy, capacity, and RECs. Saddleback Wind went full Commercial on September 2015.


[43]

F.1.9 FirstLight (Cabot/Turners Falls Hydro)

Beginning on January 1, 2021, Stowe will receive an estimated 2.6% of their load from a Purchase Power Agreement for a bilateral percentage amount from the Cabot and Turners Fall Hydro Plants. Stowe will also receive renewable energy credits that are Vermont Tier I qualified. This PPA will expire on December 31, 2030. This transaction is part of a larger transaction involving a group of municipal light plants throughout New England. It is in both the supplier and the buyers' interests to explore an extension of this power purchase agreement prior to its termination in 2030.

F.1.10 Short Term Bilateral

Beginning on December 1, 2022, Stowe purchased shaped block power from a counterparty. This purchase was to lock in coverage for Stowe's position during the month of December 2022 through March 2023.

F.1.11 NextEra – Seabrook offtake

Beginning January 1, 2015, and going through December 31, 2034, Stowe will receive .16% (or a max of 2 MW) of around the clock from the NextEra Seabrook Resource. This contract provides Stowe with the same PPA percentage of capacity as well. Stowe also receives the Emissions Free Energy Certificates ("EFECs").

F.1.12 Great River Hydro Project

Stowe contracted a PPA for generation and RECs from the Moore Dam and Great River Hydro projects. Four of the five hydro units began on January 1, 2023. The new generator was scheduled to begin on January 1, 2023; however, supply chain and steel worker availability

[43] https://www.patriotrenewables.com/projects/saddleback-ridge-wind/

delayed it until November 1, 2023. It will terminate on December 31, 2037. Stowe's share is estimated to be 7.1% of the PPA output.

F.1.13 Nebraska Valley Solar Farm
Stowe built a 1 MW AC ground mounted solar electric generation project. Estimated output is approximately 1,568 MWh per year. This is about 1-2% of Stowe's annual energy requirement. The greatest benefit to Stowe from this project is the ability to use the renewable energy credits towards Tier II of the RES. Considered as distributed generation, or behind Stowe's meter, additional benefits include energy, capacity, and transmission. The project began operation in August 2016.


[44]

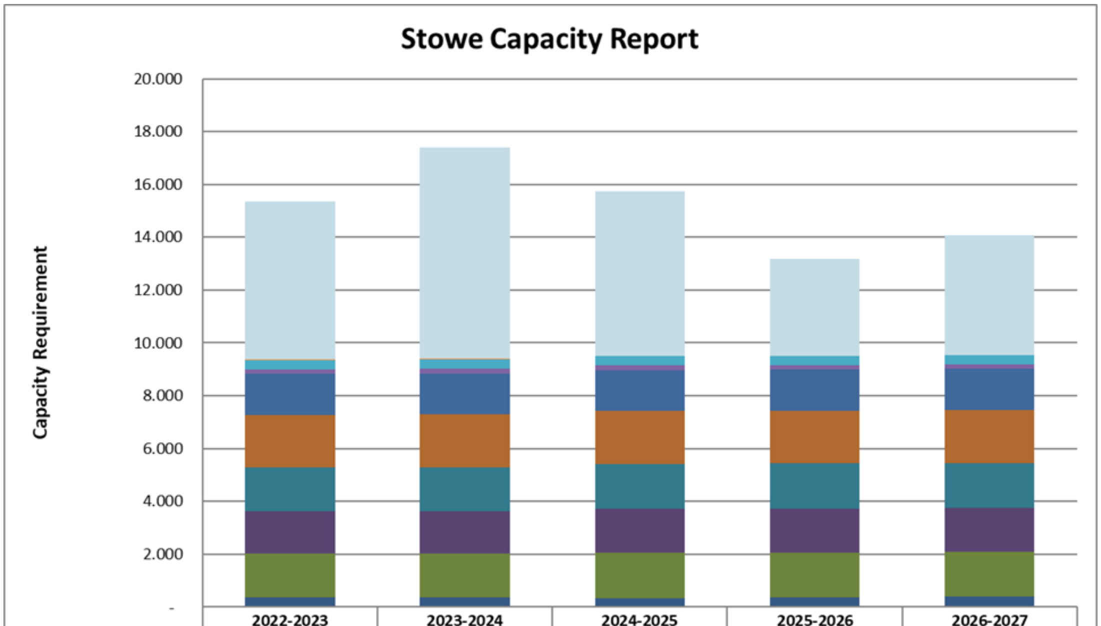
F.1.14 Snowmaking Procurement – Energy Only Load Following
Stowe's snowmaking load requirements are intermittent due to the nature of snowmaking demands at Stowe Mountain. Load-following energy products provide Stowe with a coverage solution. It reduces Stowe's price risk for the probable increase of load during the winter. A load-follow energy product also can protect other Stowe customers from the Mountain's snowmaking load requirements.

[44] encorerenewableenergy.com

F.2 Existing Capacity Resources

Figure 75 is a stack chart of Stowe's capacity position through-out the next five years. Please note if a resource has multiple lines, it is to determine different price points of the generation per capacity year, meaning self-supply rate, payment rate, or new generation rate.

Figure 75: Stowe's Capacity Forecast



	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Market	5.979	8.002	6.244	3.650	4.537
VEPPI SPEED	0.021	0.021	-	-	-
NYPA	0.354	0.354	0.354	0.354	0.354
Saddleback	0.175	0.175	0.175	0.175	0.175
McNeil	1.560	1.560	1.560	1.560	1.560
Seabrook - Bilateral	1.995	1.999	1.999	1.999	1.999
Stony Brook GT1C	1.656	1.656	1.709	1.709	1.709
Stony Brook GT1B	1.607	1.607	1.655	1.655	1.655
Stony Brook GT1A	1.656	1.656	1.709	1.709	1.709
HQICC	0.354	0.369	0.340	0.355	0.385

F.3 Capacity modeling

The Energy New England Portfolio Simulation Model, which is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables, was used to assess SED's Capacity positions.

The process then uses the ranges of estimated values to find the key drivers of the Capacity portfolio performance. The stochastic simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Stowe's Capacity portfolio under different conditions and analyzes the factors to which the performance is most sensitive. A major benefit of using a simulation method is the ability to apply thousands of different scenario conditions across all the model inputs, which produces a distribution of outcomes.

F.3.1 Model Assumptions

The IRP's capacity forecast is illustrated in the Capacity Market section. Below are the $/kw-mo. forecasted charges that ENE's simulation exported for each IRP year. The historical data (June 2018 through May 2027) used includes clearing prices and payment rate percentages of the historical clearing price to the payment rates. ENE used a risk simulation table that weighed five scenarios based on the percentage of the past three-year FCM clearing prices. Using FCA 15 through FCA 17 was the most ideal because they are the results from the most recent capacity parameters. Figure 76 are the simulation results from the model. The prices are trending downward but the uncertainty in the market leaves room for average prices to range from $5.50 to $7.50 $/KW-month.

Figure 76: Forward Capacity Price Simulation Range

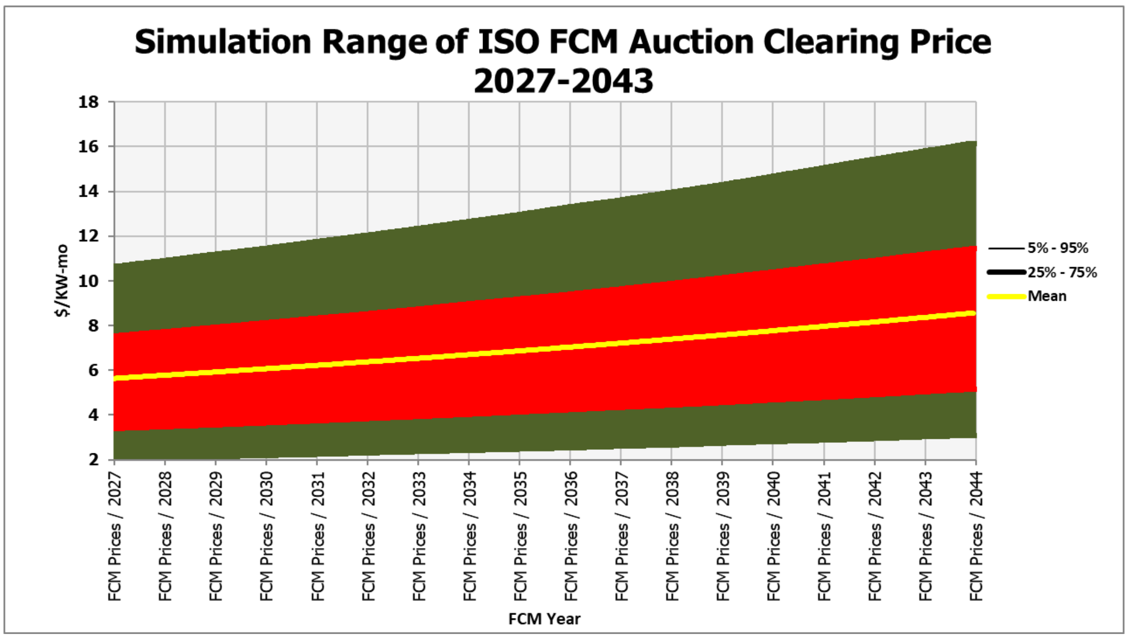
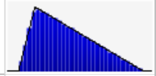
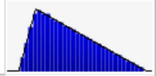
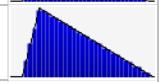
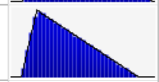
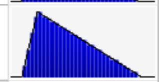
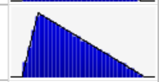
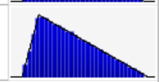
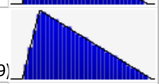
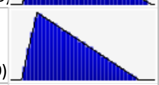
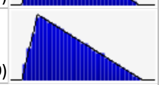
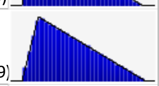
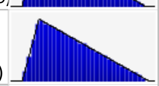
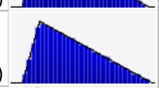
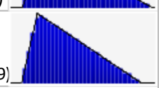
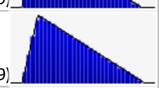
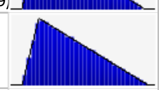
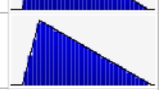
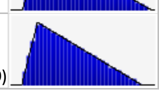


Figure 77: @Risk Model Prices for Capacity Forecast

@RISK - Results Summary
Performed By: Michelle Coscia
Date: Friday, March 31, 2023 3:52:28 PM

Name	Function	Graph	Minimum	Maximum	Mean
Worksheet: FCM					
Category: Stochastic Spot FCM Price, $kw-mo					
Stochastic Spot FCM Price, $kw-mo / 5/31/2028	RiskTriang(T11,T10,T9)		1.091	13.100	5.635
Stochastic Spot FCM Price, $kw-mo / 5/31/2029	RiskTriang(U11,U10,U9)		1.205	13.200	5.776
Stochastic Spot FCM Price, $kw-mo / 5/31/2030	RiskTriang(V11,V10,V9)		1.257	13.607	5.921
Stochastic Spot FCM Price, $kw-mo / 5/31/2031	RiskTriang(W11,W10,W9)		1.164	13.967	6.069
Stochastic Spot FCM Price, $kw-mo / 5/31/2032	RiskTriang(X11,X10,X9)		1.231	14.179	6.220
Stochastic Spot FCM Price, $kw-mo / 5/31/2033	RiskTriang(Y11,Y10,Y9)		1.354	14.665	6.376
Stochastic Spot FCM Price, $kw-mo / 5/31/2034	RiskTriang(Z11,Z10,Z9)		1.339	14.891	6.535
Stochastic Spot FCM Price, $kw-mo / 5/31/2035	RiskTriang(AA11,AA10,AA9)		1.403	15.262	6.698
Stochastic Spot FCM Price, $kw-mo / 5/31/2036	RiskTriang(AB11,AB10,AB9)		1.433	15.681	6.866
Stochastic Spot FCM Price, $kw-mo / 5/31/2037	RiskTriang(AC11,AC10,AC9)		1.498	16.284	7.037
Stochastic Spot FCM Price, $kw-mo / 5/31/2038	RiskTriang(AD11,AD10,AD9)		1.488	16.769	7.214
Stochastic Spot FCM Price, $kw-mo / 5/31/2039	RiskTriang(AE11,AE10,AE9)		1.426	16.903	7.394
Stochastic Spot FCM Price, $kw-mo / 5/31/2040	RiskTriang(AF11,AF10,AF9)		1.437	17.319	7.578
Stochastic Spot FCM Price, $kw-mo / 5/31/2041	RiskTriang(AG11,AG10,AG9)		1.632	17.857	7.769
Stochastic Spot FCM Price, $kw-mo / 5/31/2042	RiskTriang(AH11,AH10,AH9)		1.579	18.262	7.963
Stochastic Spot FCM Price, $kw-mo / 5/31/2043	RiskTriang(AI11,AI10,AI9)		1.582	18.972	8.161
Stochastic Spot FCM Price, $kw-mo / 5/31/2044	RiskTriang(AJ11,AJ10,AJ9)		1.749	19.124	8.366
Stochastic Spot FCM Price, $kw-mo / 5/31/2045	RiskTriang(AK11,AK10,AK9)		1.791	19.956	8.575

G Renewable Energy Standard (RES)

In July 2015, using the 2011 Vermont Comprehensive Energy Plan, the State of Vermont established Act 56 (H. 40) that detailed the State's energy requirements and provide direction on how utilities can participate. The RES requires utilities to buy or retain renewable energy credits and encourages energy transformation projects. The obligation is calculated using a yearly percentage of retail sales. In lieu of renewable credits or transformation projects, a utility can meet required obligations by paying an alternative compliance payment (ACP) rate set forth by the State. The compliance rates adjust annually for inflation (using CPI). The Vermont Energy Plan was updated in January 2017 and is intended to meet greenhouse gas emissions reductions and stay consistent with both the 10 V.S.A § 578 and the Vermont Climate Action.

Plan adopted and updated pursuant to 10 V.S.A. § 592.

G.1 The Three Tiers to the RES program:

- Tier I: Establishes the first requirement of renewable energy in Stowe's portfolio. Stowe can claim any class of REC that has a New England qualification.
  - Requirement to reach 75% of Tier I classification by 2032.
    - Total renewable energy requirement started in 2017 at 55%.
    - Requirements increase by 4% every three years.
    - The Hydro Quebec bilateral and NYPA contracts that have been executed by the State of Vermont also qualify although the power originates outside of New England.

- Tier II: Is for distributed generation. Tier II helps support the reliability of the electric system and helps with transmission constraints. Resources must be 5 MW or less and directly connected to the Vermont utilities sub transmission or distribution system. Stowe's 1 MW solar project supplies qualification requirements for Tier II. Projects that are greater than 5 MW name plate must receive State approval to qualify for this category.
  - Required to reach 10% of Tier II classification by 2032.
    - Total renewable energy requirement started in 2017 at 1%.
    - Requirements increasing by three-fifths of a percent each year.

- Tier III: Is for energy transformation projects. Tier III encourages projects that will help reduce fossil fuel consumption and greenhouse gas emissions. The Public Utility Commission approves a conversion method (developed by the Department of Public Service) that utilities can use the exchange of fossil fuel reduction into compliance MWHs of electric energy.
  - Requirements to reach 10 & 2/3 percent of Tier III classification by 2032.
    - Total renewable energy requirements started in 2019 at 2%.

- Increasing by two-thirds of a percent each year.
- Excess Tier II-qualifying distributed generation are eligible for Tier III compliance.

In 2017 Vermont Statue Title 30, Chapter 89 (30 V.S.A. § 8002-8005) created the RES for the Vermont distribution utilities. Stowe will meet all three tiers under the RES through either renewable energy credits, energy transformation projects, or compliance payments. Using Stowe's current portfolio, ENE estimated the cost impact to Stowe's retail sales forecast, as depicted below in

Figure **78**. Compliance of RES heavily influenced the selection of portfolio scenarios for the IRP. This analysis is based on Stowe's load, excluding Stowe Mountain's snowmaking load. The snowmaking load is addressed as a pass through, whereas all obligations to RES are billed back to the Mountain.

On January 14, 2022, the Vermont Department of Public Service distributed the 2022 Annual Report on the Renewable Energy Standard. The cost compliance year of 2020 was approximately $21 million across the Distribution Utilities (DU). "The Department estimates the net cost of continuing to meet RES obligations over the next ten years will have a net present value (NPV) cost of roughly $168 million (assuming a 6% discount rate).[45]" The Departments finding do coincide with the RES modeling for Stowe with a current portfolio NPV (for the 20 year IRP) for RES estimating to be $2,050,000.The Department does expect RES to help contribute to a large reduction of carbon dioxide emissions throughout the State, but it is not come without an impact to electric utility rates.

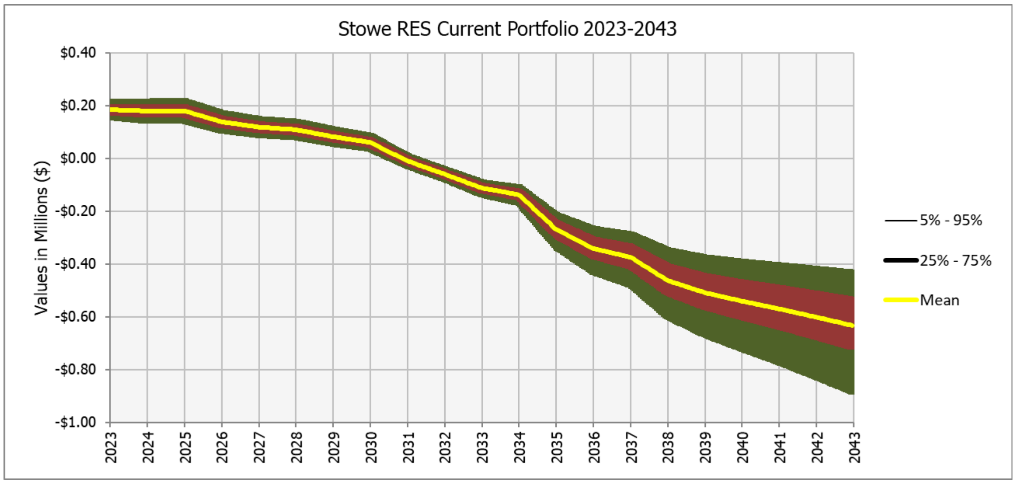
When modeling the RES impact Stowe used the amended Tier I with 100% renewable by 2030 while retaining the original Tier II and Tier III obligation from the original Statue.

The was a proposed amendment that included increasing the RES to 100% by 2030 and increasing the distributed renewable obligations (Tier II) to 20% by 2032. Under the proposal purchasing Tier I RECs cannot exceed more than 33% coverage from hydroelectric facilities that are greater than 200 MW.

In March 2020, the rules were suspended & bill committed to Committee on Natural Resources and Energy with the report of Committee on Finance intact, on motion of Senator Cummings. Senator Cummings moved that Senate Rule 49 be suspended to commit the bill to the Committee on Natural Resources and Energy with the report of the Committee on Finance

[45] 2022 CEP AppendixC Renewable Energy Standard Report.pdf (vermont.gov)

Figure 78: Stowe's Potential RES Cash Flow with Proposed Alternative Obligations

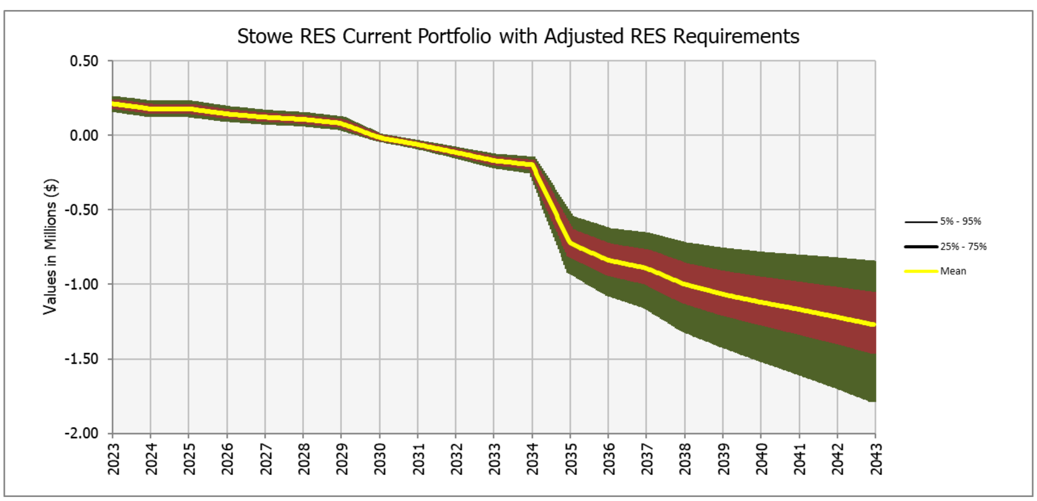


Renewable Energy Vermont currently has a 2023 RES Reform Bill that will expand on the Vermont greenhouse gas reduction goals. Updates to the RES include:[46]

- Replace current renewable energy requirements by capping existing renewable energy sources at 40% by 2035.
- Increase in state renewables from 10% to 20% by 2030 and 30% by 2035.
- Include a new renewable energy requirement of 30% new renewable of any size within New England by 2035.

Below is the potential RES cash flow of the potential Reform Bill. The net present value is an increase in costs of $3 million over the IRP timeline.

Figure 79: Stowe's Potential Cash Flow with new RES Reform Bill

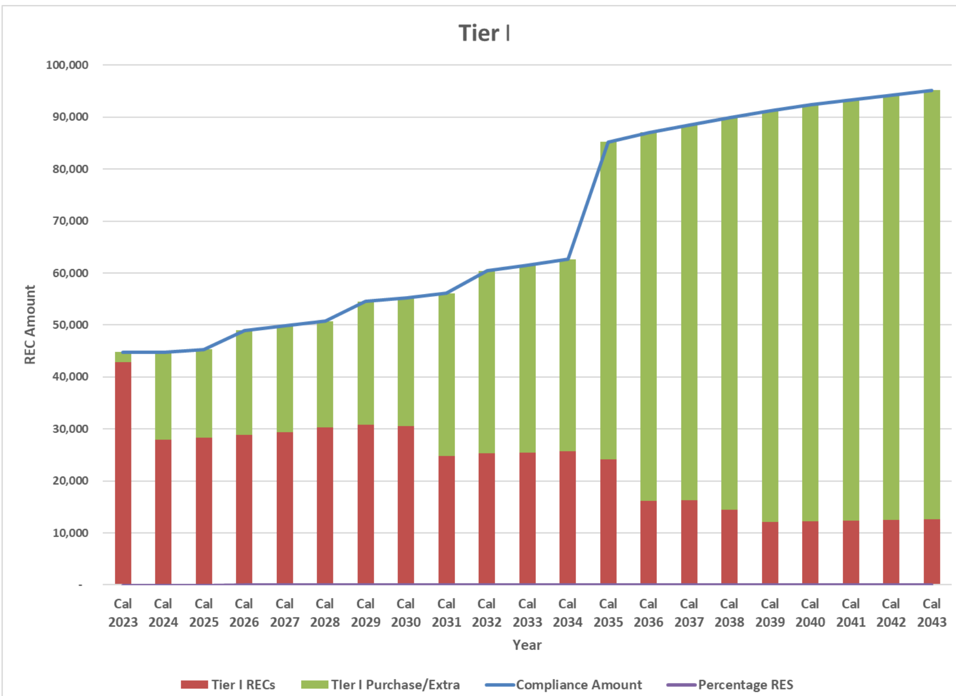


[46] www.revermont.org

G.1.1 Tier I

Currently, Stowe's Tier I portfolio contains 63% of the obligation needed by retiring RECs. Stowe's compliance is met by State approved RECs, such as HQ and the New York Power Authority, retiring Tier I owned RECs or purchasing tradeable RECs. Figure 80 below depicts Stowe's Tier I forecast. As the percentage requirement increases, the need for Tier I purchases increases. The compliance is based on the original portfolio. When analyzing resources Stowe will assume retaining a project's renewable energy credits against probable future Alternative Compliance Payment (ACP) rates.

Figure 80: Stowe's Tier I Forecast



G.1.2 Tier II

Stowe's distributed generation resource portfolio is largely made up of Stowe's Nebraska Valley Solar project, which is 1 MW of distributed generation behind SED's transmission system. Stowe also retains RECs from their distributed generation projects as well as their share of Standard Offer Tier II Classified RECs. "The Commission shall allow a provider that has met the required amount of renewable energy in a given year, commencing with 2017, to retain tradeable renewable energy credits created or purchased in excess of that amount for application to the provider's required amount of renewable energy in one of the following three years."[47] With this three-year banking policy, Stowe is able to maintain Tier II compliance until 2029. As the compliance percentage increases, Stowe will have to address the shortfall with either REC purchases and or entering new distributed generation projects. Analyzing this shortage is

[47] 30 V.S.A. § 8004(c)

important when determining new distributed generation. Stowe will balance what the potential compliance payment charges may be against building or purchasing from a Tier II qualified project. Stowe has a contract for a Vermont based solar project, due to be online in 2024 as well as the reconstruction of the Moscow Mill Hydro dam that will qualify for Tier II. Stowe's short position of Tier II is priced within the model simulation at forecasted Class I RECs within the market.

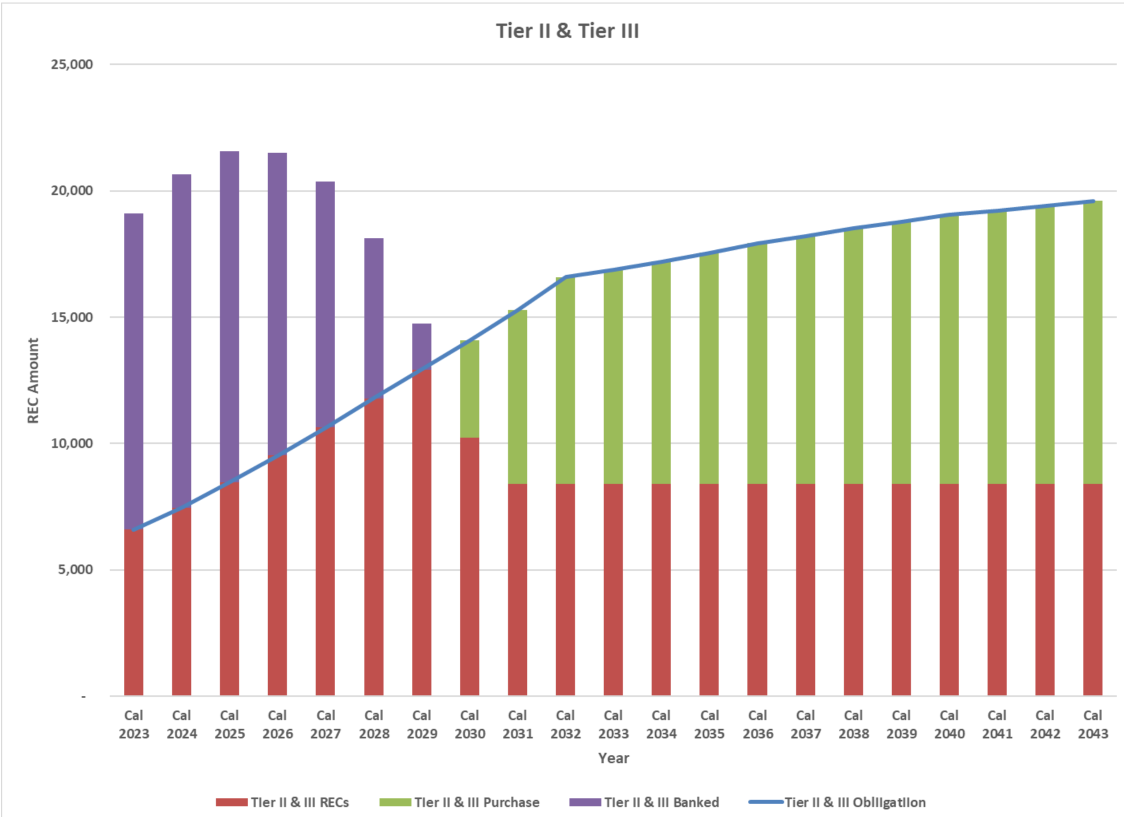
G.1.3 Tier III

Tier III compliance is attained by implementing energy transformation projects. This category is set to encourage projects that will help reduce fossil fuel usage and reduce greenhouse gas emissions. Currently, Stowe has an extensive fleet of Electric Vehicle charging stations, which have qualified for Tier III compliance. The Public Utility Commission approved a conversion methodology developed by the Department of Public Service that utilities will use to equate fossil fuel reduction into MWHs of electric energy. The conversion uses the most recent year's approximate heat rate for electricity net generation from the total fossil fuels category as reported by the U.S. Energy Information Administration in its Monthly Energy Review.[48] Vermont's Climate Action Plan's work in publishing a climate change assessment with the GUN Institute and the Nature Conservancy address the greenhouse entrapment within the Earth atmosphere. "The rate of human-induced greenhouse gas emissions has increased far faster than forests, oceans, and other natural processes can remove them from the atmosphere."[49] With the current state of the global warming, Tier III initiatives are needed for the Vermont Utilities to participate in the Vermont Climate goals.

Stowe collaborates with Efficiency Vermont in sharing the savings with EV programs that are within Stowe's territory. "Examples of these projects could include building weatherization; air source or geothermal heat pumps and high-efficiency heating systems; industrial process fuel efficiency improvements; increased use of biofuels; biomass heating systems; electric vehicles or related Infrastructure; and infrastructure for storage of renewable energy on the electric grid."[50] Stowe enables energy efficiency programs to help decrease fossil fuel usage and comply with this RES requirement. Stowe's short position of Tier III requirements is priced at the forecast alternative compliance rates.

[48] Docket No. 8550
[49] [VCA-Chapter-1-11-4-21-1.pdf (uvm.edu)](VCA-Chapter-1-11-4-21-1.pdf)
[50] http://legislature.vermont.gov/assets/Legislative-Reports/RES-SO-Report-2017-final.pdf

Figure 81: Stowe's Tier II and III Forecast

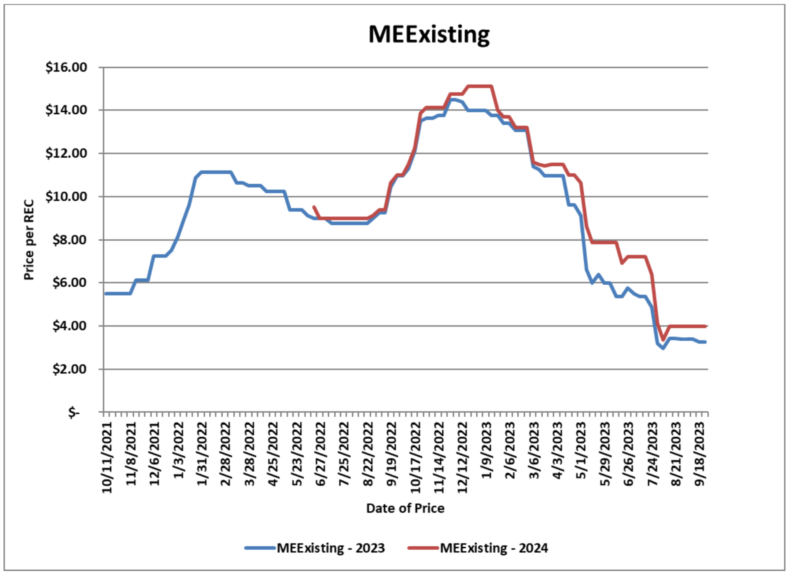


G.1.4 Renewable Energy Credit Arbitrage

The rules regarding Tier I qualification is that a provider, such as Stowe, "may use renewable energy with environmental attributes attached or any class of tradeable renewable energy credits generated by any renewable energy plant whose energy is capable of delivery in New England." (Act 56 of 2015). Because of this rule, Stowe can create REC arbitrage. The meaning of arbitrage is "the simultaneous purchase and sale of the same securities, commodities, or foreign exchange in different markets to profit from unequal prices."[51] Stowe can assess the market, and if its renewable energy credits are more valuable to sell in its qualified markets than buying other class RECs, Stowe has the option of selling the RECs it owns and buy back another class or state REC that is available at lower prices. This option can help SED buy down their RES compliance payments in other Tiers, where they may have a deficit. SED is also aware of the price increase for existing hydro RECs which in the past were heavily discounted. As the 2022 REC has progressed these RECs have increased by 500%. In (Figure 82 below) is the historical REC prices for existing hydro Maine (ME) Class II for Cal 2022 and 2023.

[51] http://www.dictionary.com/browse/arbitrage

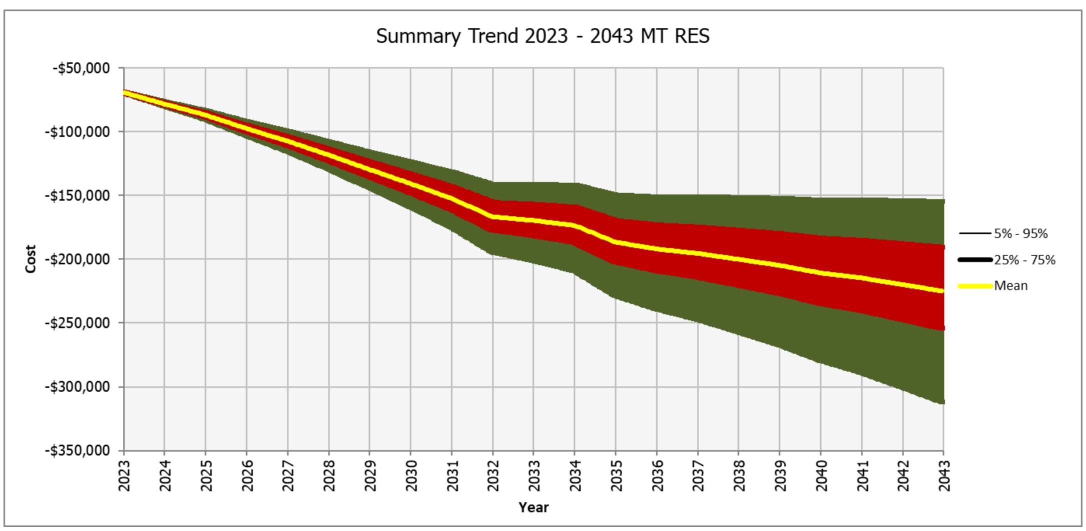
Figure 82: Historical Broker Prices for ME II RECs for Cal 2022 and 2023



G.1.5 Snowmaking Potential RES Cost

Because ENE did not model the snowmaking load into Stowe's energy or RES portfolio, ENE has modeled their impact as a separate entity. All snowmaking charges are a pass through in their rate structure.

Figure 83: Snowmaking Potential RES Cost Cash Flow



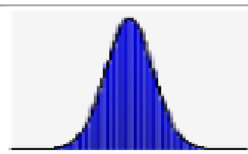
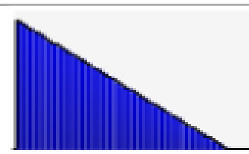
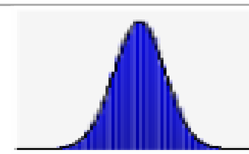
G.2 RES modeling

The Energy New England Portfolio Simulation Model, which is a stochastic simulation-based model that utilizes the Monte Carlo simulation technique to estimate future values of the input variables, was used to assess Stowe’s RES positions.

The process then used the ranges of estimated values to identify the key drivers of the REC portfolio performance. The stochastic simulation approach to portfolio modeling provides a powerful, unbiased, and dynamic tool to measure the future performance of Stowe’s REC portfolio under different conditions and identifies the factors to which the performance is most sensitive. A major benefit of using a simulation method is the ability to apply thousands of different scenario conditions across all the model inputs, which produces a distribution of outcomes.

G.2.1 Model Assumptions

Table 23: @Risk Model Inputs for RES Net Present Value

Detailed Statistics			
Input	REC Percentage	Discount Rate	CPI
Function	RiskNormal(0.3,0.03,RiskStatic(0.3))	RiskTriang(0.00089167,0.00089167,0.072498,RiskName("Discount Rate"))	RiskNormal(0.021967,0.010836,RiskName("CPI"))
Graphs			
Cell	'RES Breakdown'!B26	CPI!S12	CPI!T12
Statistic			
Minimum	18.823%	0.0894%	-2.1474%
Maximum	42.075%	7.2408%	6.2305%
Mean	30.000%	2.4760%	2.1967%
Mode	30.038%	0.1071%	2.2375%
Std. Deviation	3.000%	1.6879%	1.0836%

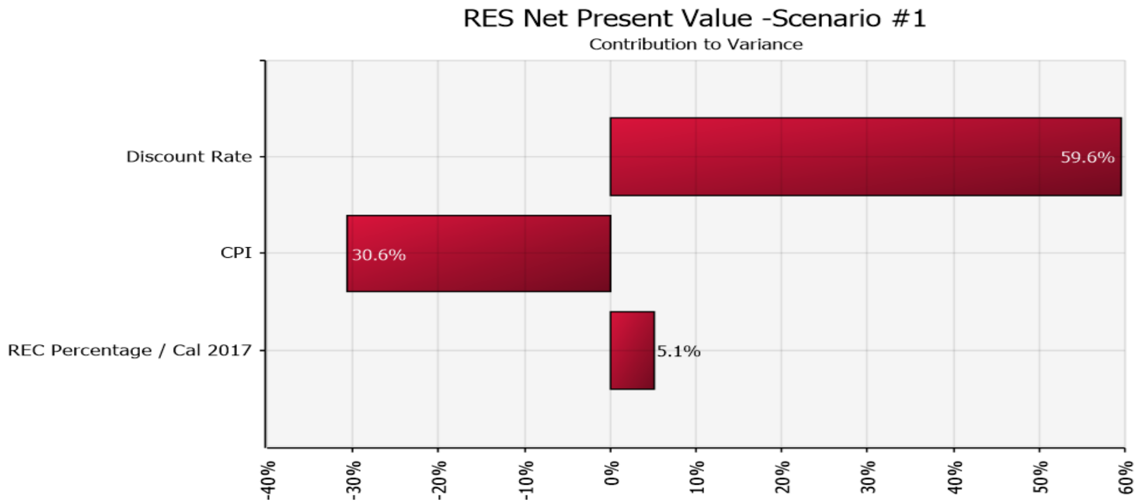
G.2.1.1 RES Tier Compliance rates use the CPI adder.

G.2.1.2 Existing REC Market uses the CPI adder.

G.2.1.3 Class I MA REC Market uses the MA compliance rate (using the CPI adder), and the REC market is a percentage of the compliance rate.

G.2.1.4 Net Present Value of each year uses the discount rate.

Figure 84: RES Tornado Chart of Inputs

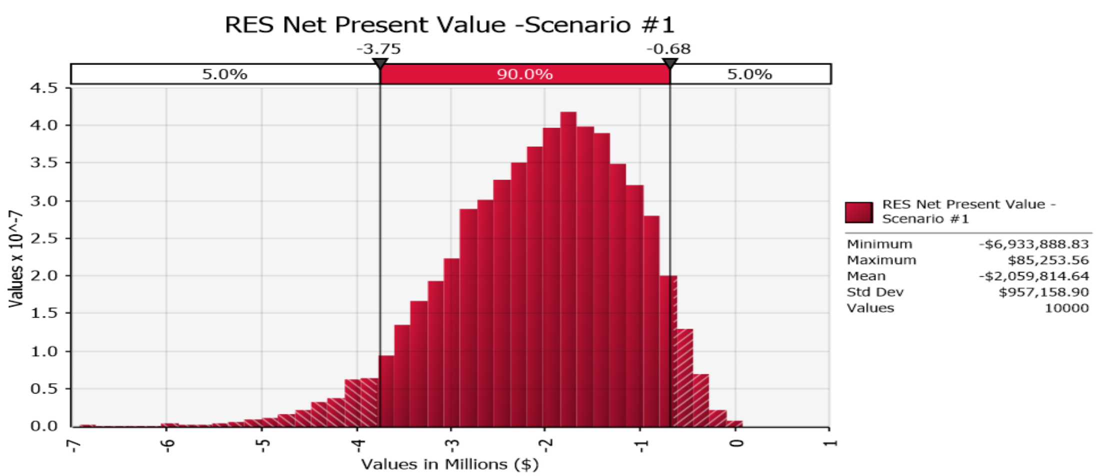


G.2.2 Model Outputs

Appendix B contains the modeling report for the RES base case Net Present Value.

Appendix D contains the modeling report for the RES snowmaking load Net Present Value.

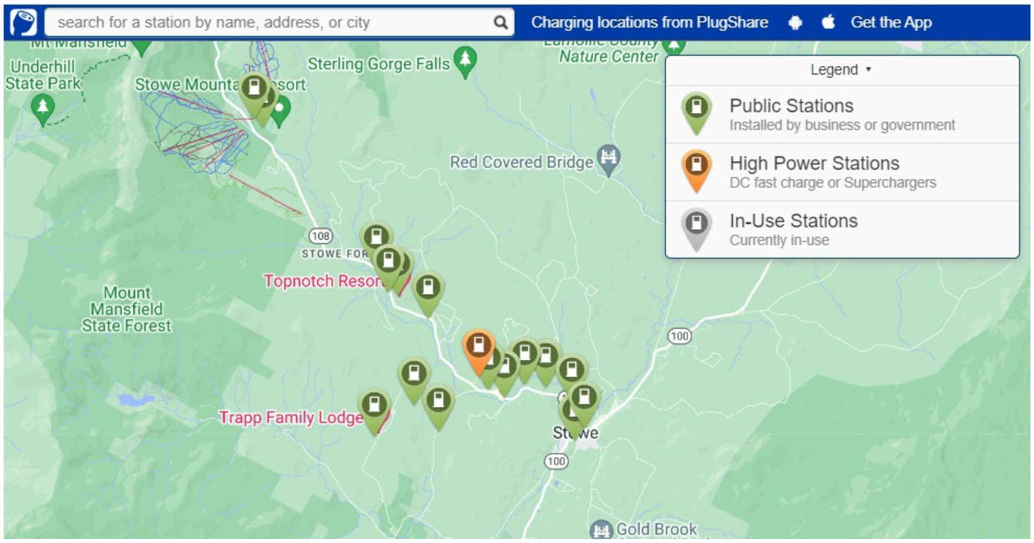
Figure 85: Net Present Value of RES for Stowe



G.3 Smart Rates

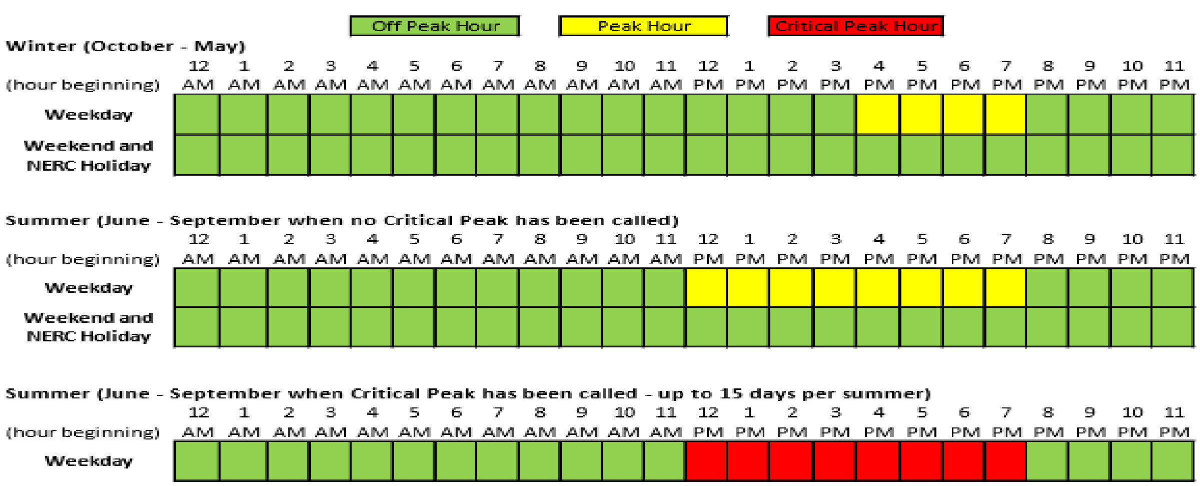
Stowe implemented rate thirty-five for EV charging stations, the current rate was set on September 8, 2023. This rate is for all public EV charging stations owned by Stowe Electric Department. The energy charge is set at $0.2010 per KWH. There is a session fee (i.e. cost to initiate the charging session) and a kWh cost. The session fee is set to the minimum charge (varies per level 2 or 3). The remaining cost for the charging session is tied to kWh consumed. . The map of Stowe's EV charging stations can be found below Figure 86, and on the SED's website [Public EV Charging | Stowe Electric].

Figure 86: Stowe EV Stations



In 2015, Stowe introduced a residential time of use rate with a critical peak pricing component. This rate was set to entice customers to become more energy efficient at costly times of the day while simultaneously communicating the dynamics of the wholesale electricity marketplace from which Stowe secures its power. By reducing usage, these customers would see reductions in their electric bills. This option became possible after Stowe implemented its fleet of AMI smart meters. In addition, by collecting 15-minute meter data, Stowe can view load patterns. The TOU is set seasonally from summer (June-September) in hour's noon to 8pm and winter (October-May) in hours 4pm to 8pm as seen below in Figure 93. Critical peak periods can be called on a day-ahead basis for the peak hours for up to 15 days during a given summer season.

Figure 87: Stowe TOU Hourly Description



Participating customers are contacted when peak events occur through a combination of email, text, and phone. Figure 88 below shows Stowe's TOU and CPP rates. Voluntary curtailment of usage by TOU customers during peak hours has the potential to help Stowe save on coincident peak costs.

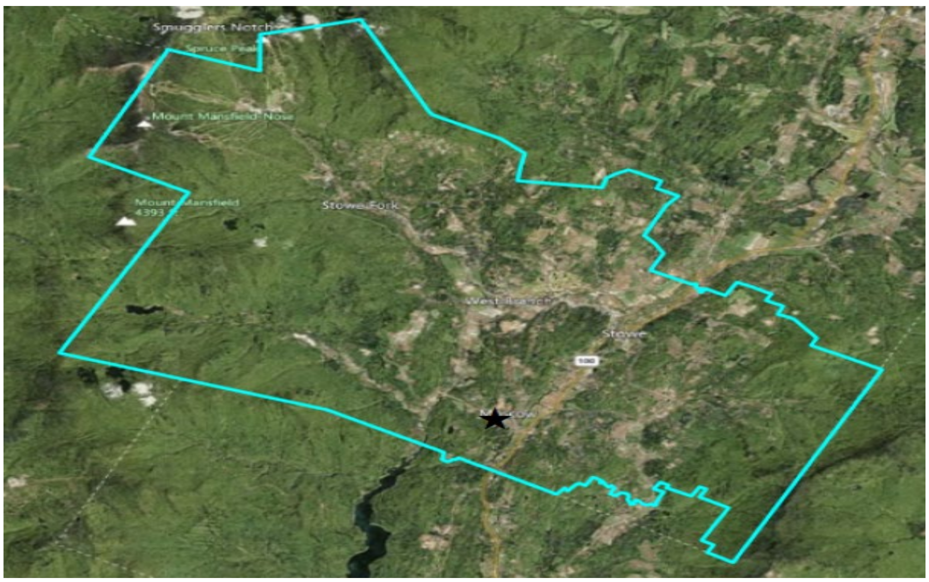
Figure 88: SED TOU Rate Energy Charge

Energy Charge:	
During Winter Peak hours:	$0.2455/kWh
During Winter Off-Peak hours:	$0.1431/kWh
During Summer CPP Peak hours:	$0.6447/kWh
During Summer Non-CPP Peak hours:	$0.1852/kWh
During Summer Off-Peak hours:	$0.1168/kWh

H Assessment of the Transmission and Distribution System (SED)

H.1 T & D System Evaluation

Stowe Electric Department ("Stowe") is a municipally owned electric utility providing service to 4,445 customers in the Town of Stowe, Vermont. The service territory spans 63 square miles. Some areas within the Town of Stowe are served by Vermont Electric Coop or Morrisville Water & Light. The primary make-up of the customer base is residential and small commercial with some larger vacation resorts as well as Stowe Mountain Resort (Mount Mansfield) making up the balance.



Stowe's system consists of 8.1 miles of 34.5kV transmission line, 120 miles of overhead distribution and twenty-five (25) miles underground distribution lines. SED serves an average of twenty-nine (29) customers per mile of distribution line. SED owns three (3) substations and receives our primary service through a VELCO 115kV interconnection but can also receive service through a backup interconnection with GMP's 34.5kV subtransmission line.

Since the filing of the 2020 IRP, Stowe operation staff and lineworkers have replaced condemned poles, complete several new service applications, completed make-ready work for new broadband service and a new traffic light in Stowe, removed hazard trees, and relocated about 2,400 feet of off-road line to roadside.

H.2 T & D Substations

Stowe has three primary 12.47kV distribution substations that are fed from the 34.5kV transmission system and can tie and back-up each other supporting 75-80% of our customers. Stowe is currently planning to upgrade the Wilkins Substation and add a new feeder that would pick up some of the loading on Circuit 5 and Circuit 2. This would add redundancy to the circuits and allow for the development of a distribution automation loop feed that would serve the Stowe High School and Middle School. Stowe is also planning to evaluate strategies to harden the

Houston and Lodge substations, and the 34.5kVa line (aka the Mountain Line) through a feasibility study, partially funded by a FEMA "Building Resilient Communities" grant. This study can help improve future implementation projects to make Stowe's substations and off-road 34.5kVa more resilient to storm-related outages.

Table 24: Substation List

Location	L.S. Voltage	H.S. Voltage	Transformer Sizes
Wilkins	12,470	34.5kV	2 x 5 MVA
Houston	12,470	34.5kV	2 x 7.5 MVA
Lodge	12,470	34.5kV	1 x 7.5 MVA
		TOTAL:	32.5 MVA

H.2.1 Wilkins Substation

This substation was built in 1996 and consists of two 12.47kV distribution feeders (Circuit 1 and Circuit 2). Each circuit is regulated by three 167kVA voltage regulators and each protected by a separate circuit recloser. The station transformer sizes are 2 x 5 MVA, which are fed underground from the VELCO/Stowe 34.5kV ring bus through a circuit switcher. The substation was designed low profile, and all equipment is housed in metal ground mounted equipment and is not located in the flood plain. It is in good condition and has good working clearances.

Figure 89: Wilkins Substation

H.2.2 Houston Substation

This substation was built in 1992-93 and consists of two 12.47kV distribution feeders (Circuit 5 & Circuit 6). Both circuits consist of three 333kVA voltage regulators and both are protected by circuit reclosers. Both station transformers for each circuit were upgraded in 2015 from 5MVA to 7.5MVA units pursuant to PUC Docket 8466. The substation is of wooden pole and cross arm construction, is in good condition, and has good working clearances. The pole structures for the distribution lines leaving the substation were re-built in April 2017. Both circuits originally shared common pole structures but are now separated and on individual poles. A new three-gang switch was also incorporated so that each circuit can be easily back fed through this switch and the buses isolated. A redundant station service transformer and transfer switch were installed so secondary equipment can remain energized during bus outages. This substation is not located in the flood plain (NOTE: See T & D System Evaluation, Statement 9).

Figure 90: Houston Substation

H.2.3 Lodge Substation

This substation has two 12.47kV distribution feeders (Circuit 7 and Circuit 8) which share three 333kVA voltage regulators and one 7.5MVA station transformer. Each feeder is protected by a circuit recloser. Lodge substation also contains a 34.5kV bus where the transmission line continues and feeds Stowe Mountain Resort. This 34.5kV circuit includes three 500kVA voltage regulators, a grounding transformer bank, and is protected by a circuit recloser. Two 3600kVAR capacitor banks are in place for the 34.5kV transmission line in the substation as well. The substation is wood pole and cross arm construction. The 34.5kV bus was re-built in 2003, is in good condition, and with desired working clearances. The 12.47kV bus clearance will be studied in 2021 for a rebuild. This substation is not located in the flood plain.

Figure 91: Lodge Substation

H.3 T & D Equipment Selection and Utilization

The Vermont Department of Public Service updated the Vermont Comprehensive Energy Plan ("CEP") in 2022. The 2022 CEP included Guidance for Integrated Resource Plans and 202(f) Determination Requests. Relevant to this section of Stowe's IRP, the updated guidelines provide a general set of questions utilities can use to evaluate their transmission and distribution systems. Stowe's assessment per those questions follows below.

1) The utility's power factor goal(s), the basis for the goals(s), the current power factor of the system, how the utility measures power factor, and any plans for power factor correction.

Stowe currently does not have the equipment to accurately measure and monitor power factor within our system. A distribution system study was performed in 2020 by Control Point Technologies and the overall system power factor was estimated to be 95.3%. The six individual distribution circuits were estimated to be between 94% to 98% on each circuit. Control Point has recommended the installation of additional capacitors in several locations. Stowe will evaluate the cost and implementation of installing additional capacitors.

Table 25: Capacitor Banks, Sizes, and Locations

Cap Bank #	Location	Pole #	Switched	Circuit	Size	Voltage
C1	Lodge Sub	Sub	Y	34.5kV Line	3600 kVAR	34.5KV
C2	Lodge Sub	Sub	Y	34.5kV Line	3600 kVAR	34.5KV
2-87-1	Moscow Rd	2-87	Y	2	600 kVAR	12470V
5-42-C1	Mountain Rd	5-42	Y	5	600 kVAR	12470V
1N-ED-11-C1	Weeks Hill Rd	1N-ED-11	Y	5	600 kVAR	4160v
5-D2-C1	Cottage Club Rd	5-D2	N	5	300 kVAR	12470V

2) Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for backup.

Each of Stowe's six 12.47kV feeders have been reconfigured to back up other feeders with bus ties at the substations or tie points on the lines. Many of the main feeder lines have been re-conductored in the past 10-15 years during 4kV conversions to the system and new transformers were also installed at which point phase balancing was done during those upgrades. Loads are recorded monthly at the substation reclosers and reviewed for phase balancing. During the 2020 Distribution System Study, Control Point Technologies determined that each of Stowe's six circuits meets phase balancing criteria and that no further action is necessary at this time. Control Point also determined that the total decrease in losses to convert the majority of remaining 4kV line segments was less than a kW and that it would not be cost effective to convert most of those segments. Stowe will complete those segments already started during 2021.

3) Sub transmission and distribution system protection practices and philosophies.

Protection for the 34.5kV transmission line is provided at the breakers on the VELCO/Stowe 34.5kV substation ring bus and are maintained and monitored by VELCO.

Stowe has recloser protection on all utility owned distribution circuits. Recloser settings are found below in Table 26.

Table 26: Stowe Recloser Settings

Circuit	Control Form		Min Trip	TCC1	TCC2	Operations to Lockout	TCC Sequence
1	4C	Phase	480	101	133	3	2-2-2
		Ground	240	102	165		
		ALT Phase	120				
		ALT Ground	60				
2	F6	Phase	480	101	133	3	2-2-2
		Ground	240	102	165		
5	4C	Phase	280	101	162	3	1-1-2
		Ground	140	102	142		
		ALT Phase	110				
		ALT Ground	60				
6	4C	Phase	280	101	162	3	1-1-2
		Ground	140	102	142		
		ALT Phase	110				
		ALT Ground	60				
7	3A	Phase	480	A	K	3	1-2-2
		Ground	240	1	13		
8	F6	Phase	500	163	117	3	1-1-1
		Ground	150	151	135		
WCAX-URD	F6	Phase	150	163	117	1	1
		Ground	100	151	101		

Stowe uses fusing on all main lines, side taps, and transformers to minimize the number of customers affected by system faults. Arresters are used to protect all aerial transformers, capacitors, and primary underground equipment. In the 2020 Distribution System Study, Control Point Technologies provided a complete protection and coordination analysis of the distribution system and found several areas with fuse-to-fuse coordination issues. In November 2023, Stowe applied for federal funding to help pay for the costs of a fusing coordination study, which will update Control Point's recommendations and provide an implementation plan to update fuse changeouts and relay setting changes.

4) The utilities planned or existing "smart grid" initiatives such as advanced metering infrastructure, SCADA, or distribution automation.

Stowe implemented smart grid initiatives including AMI and MDM systems, and automated CSI systems. In Q3 2023, Stowe hired Davey Resource Group to full map and GIS Stowe's system, including over 25 miles of underground line. When completed, Stowe will have more information about our system and can consider how to implement sensing and communication infrastructure. Stowe does not have the financial resources or staffing to add SCADA, but Stowe is engaged with Oak Ridge National Laboratory to determine a pathway to add a sensing, controls, and monitoring system appropriate for a rural municipal utility. This could lead to Stowe adding fiber to enhance communications at our substations and gatekeepers within our existing AMI infrastructure.

In 2023, Stowe applied for funding to restore a vacant residential building on our campus into an emergency operations and distribution system control and monitoring center. This would allow Stowe to create a unified command room for system monitoring, dispatch, and outage management.

Stowe also received a grant to complete the Barrows Road distribution automation loop feed, which will harden and add resiliency to a section of our system that supports Stowe High School and Middle School, the Town's emergency shelter.

5) Re-conductor lines with lower loss conductors.

Stowe's main feeder lines have been re-conductored during the 4kV conversions to the system over the past 10-15 years. Standard conductor sizes are 336 AAC for three phase main lines, 1/0 AAAC or ACSR for all branched side taps. SED uses 1/0 URD jacketed primary cable with full neutral placed in conduit for all underground-branched side taps.

6) Replacement of conventional transformers with higher efficiency transformers.

The 2020 Distribution System Study created a tool for use by Stowe to run a cost benefit analysis when purchasing transformers. The tool was developed using the RUS Bulletin 1724D-107. This bulletin provides a way to calculate costs over a transformer's lifetime based on several variables entered by Stowe. The results were mixed between the various sizes of transformers in both single phase and three phase and in pole mounted and pad mounted versions. Control Point Technologies recommends that Stowe obtains pricing for both low loss and high loss transformers when purchasing new transformers. Stowe now utilizes this tool when purchasing stock transformers.

7) The utility's distribution voltage settings (on a 120V base) and whether the utility employs, or plans to employ, conservation voltage regulation or volt/VAR optimization.

All circuits are bus regulated with a set point of 122V-124V, +/-1.0V-1.5V volts at the substation and our AMI meters monitor customer voltage and provide alarms when voltage does not meet Stowe requirements. Capacitor banks have been installed on our system to provide volt/VAR support where needed.

Control Point Technologies analyzed conservation voltage regulation (CVR) during the 2020 Distribution System Study and determine that two of our six circuits are not eligible for CVR. The remaining four circuits from our Houston and Lodge substations could have CVR implemented. However, the resulting reduction in losses would be minimal. Additionally, the varying settings between substations and the need to switch back and forth between CVR and normal operating modes during feeder backup scenarios adds complications during critical operations. Another complicating factor is the increasing amount of distributed generation (DG) on the Stowe system which reduces the amount of current seen by the regulators. Based on these factors and the many system upgrades that would be required ahead of implementing CVR, Control Point recommends that Stowe not implement CVR on our system.

8) Implementation of a distribution transformer load management (DTLM) or similar program.

Stowe does not have a DTLM program currently. Instead, Stowe applies traditional transformer sizing methods and uses Load Data Loggers to monitor customer loading where necessary.

In the third quarter of 2023, Stowe started the transition to a new outage management system which utilizes a new GIS system that is integrated with our AMI and CSI systems. Included in the new OMS is a load manager module that enables staff to review the load on a transformer and evaluate its performance. Using the load manager module requires us to link each meter with its service transformer in the GIS. Although the linking process has already begun, we estimate it will continue throughout most of 2024 to accurately finish that process.

9) A list of the location of all substations that fall within the 100- and 500-year flood plains, and a plan for protection or relocation of these facilities.

None of Stowe's three substations are located within any flood plain. During an upgrade of the Houston Substation station transformers in 2014 and 2015 per Docket 8466, it was determined by the Vermont Department of Environmental Conservation (DEC) Watershed Management Division after a survey of the facility that the Houston Substation elevation was above the 100- and 500-year flood elevations. No additional flood proofing measures were required by the DEC Watershed Management Division at that time. However, a recommendation was made for Stowe to work with the Watershed Management Division to take protective steps if Stowe decides to rebuild or relocate this substation in the future. See Docket No. 8466. Stowe will work closely with the Watershed Management Division should the utility decide to rebuild or relocate this substation in the future.

10) A discussion of whether the utility has Damage Prevention Program (DPP), or plans to develop and implement a DPP, if none exists.

Stowe completed its Damage Prevention Plan in December 2018. *See Appendix N*. Stowe, as a member utility in the Dig Safe program, requires customers and contractors to contact Dig Safe for all underground construction activity. All Stowe facilities are located and marked by Stowe personnel (who are trained to use the equipment), and Stowe uses company-owned underground locating equipment.

Additionally, this equipment has GPS capability and is used to capture and store GPS coordinates of the underground system during the locating of cables. The coordinates are then uploaded into a GIS mapping system for future reference.

11) The location criteria and extent of the use of animal guards.

Stowe's policy is to install animal guards on all new construction and line rebuilds. Animal guards are also installed on existing services whenever maintenance is done on these services. Stowe evaluates outages on a regular basis to determine if animal guards in those areas would be beneficial.

12) The location criteria and extent of use of fault indicators, or the plans to install fault indicators, or a discussion as to why fault indicators are not applicable to the specific system.

Stowe requires all primary underground developments with more than three pad mount transformers, particularly long underground, or loop feed systems, to install fault indicators at each transformer or elbow cabinet. Fault indicators have been installed on the overhead transmission line in strategic locations, such as road crossings and before underground risers. No fault indicators are currently installed on overhead distribution lines. Stowe's overhead distribution lines are relatively small and well protected by reclosers and fusing and faults can usually be easily located. Stowe evaluates outages on a regular basis to determine if fault indicators in those areas would be beneficial. Additionally, Stowe's new outage management system has been integrated with our AMI system to receive "last gasp" outage notifications directly from meters in the field and meter outages are instantaneously displayed on our GIS map. All Stowe personnel can access and load outage information, and field personnel are equipped with tablets to help locate faults based on the information displayed on the map.

13) A Pole inspection program, the plans to implement a pole inspection program, or a discussion as to why a pole inspection program is not appropriate to the specific utility.

As of this IRP, Stowe Electric maintains an informal pole inspection program. Because Stowe does not own all the poles in Stowe and does not have any jointly owned poles with Consolidated Communications (CCI), Stowe has maintained an informal inspection program. CCI solely owns approximately 778 poles within Stowe that are generally along route 100 and 108 corridors: 535 of these poles are fully depreciated (294 are 33 years – 50 years in age and 241 are more than 50 years in age) and there are approximately 82 double sets that CCI needs to remove in SED's service territory. Most of the Stowe's solely owned distribution poles have been replaced during voltage conversion and re-conductoring projects in the last 10 years. Stowe line maintainers patrol the lines and conduct surveys on a weekly basis to determine which poles may need to be replaced and/or may need work. Stowe's Operations staff maintains a spreadsheet to keep track of pole replacements and prioritize replacement.

In 2023, Stowe hired Davey Resource Group to complete the mapping and GIS of our system. This project includes gathering information on the poles within our system. This information will be added into the new OMS and GIS system for staff to track information and prioritize pole replacements. Stowe feels that the database effectively serves the utility's needs to keep track of its poles and in time will help to identify those areas of Stowe's system which may command specific attention.

Stowe has also seen several poles replaced during the make ready work that is part of new construction and the advancement of broadband in Vermont. In particular, the broadband buildout has made it possible for Stowe to harden the poles and areas along the end of feeders that are previously unserved by broadband and have aging infrastructure.

In 2022, CCI hired Osmose Utilities Services Company to complete a pole survey within Stowe's service territory. Because CCI and Stowe do not jointly own poles in Stowe's territory, for the past several years Stowe and CCI have been in negotiations for Stowe to acquire all CCI owned poles in Stowe's service territory. This would give Stowe the opportunity to own and maintain all electric utility poles in Stowe, which would allow Stowe to consider implementing a more formal pole inspection program.

14) The impact of distributed generation on system stability.

Stowe's total installed distributed generation capacity as of November 20, 2023, is 3MW. Stowe's total installed net-metering capacity as of November 20, 2023, is 2MW, there is an additional 616kW solar net-metering projects that have a CPG or filed an application.

In December 2018, during the interconnection process of a 500kW DG facility on SED's circuit 2, Control Point Technologies was hired to perform a protection and coordination analysis and develop settings for the new PCC and line reclosers purchased for that project. During that analysis, they determined that the load to generation ratio for circuit 2 would be below Stowe's required 3:1 ratio after interconnection. Stowe's 34.5/19.9kV Delta-12.47/7.2kV Grounded-Wye supply transformer configuration can cause overvoltages to occur on the unfaulted transmission phases during line to ground faults on the supply system putting our substation transformers at risk. Stowe subsequently had to develop and implement a Transmission Ground Fault Overvoltage (TGFOV) protection solution for circuit 2 at considerable cost to allow interconnection.

During the 2020 Distribution System Study, Control Point evaluated Stowe's remaining circuits to determine their load to generation ratios. Their final analysis shows that the ratios for both circuit 5 and 6 at our Houston substation are at 3:1 and any additional DG would push it below the threshold. Stowe, with the assistance of VELCO, completed a TGFOV protection solution, which removed the distributed generation constraint on these circuits. As of this filing, there are no distributed generation constraints within Stowe's distribution system.

Stowe solicits quotations from three sources before making purchases for all major equipment. Purchase decisions are made on price and reliability. Stowe also evaluates the functionality and suitability of equipment before a decision is made to purchase.

Stowe will conduct a cost-benefit analysis using our new transformer cost comparison tool to ensure that our transformer purchases remain consistent with least-cost principles.

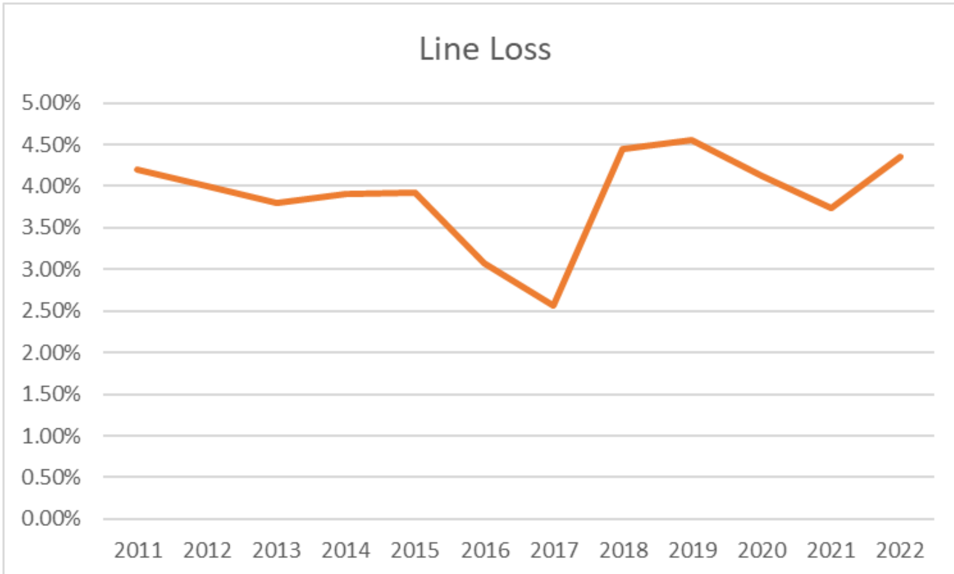
Stowe maintains a substantial inventory of distribution transformer sizes, both pole and pad mounted on hand for new installations and replacements. An inventory of critical units, such as step downs and voltage regulators, is also available for emergency replacements. Inventory is reviewed periodically to keep counts at suitable levels. Stowe, like most electric distribution utilities, experienced significant delays in receiving transformers due to the ongoing supply chain constraints. Early in the pandemic, Stowe ordered sufficient transformers and moved transformers around the system from points of low loading to points where larger transformers were needed to meet the demand from new residential customers.

Currently Stowe uses traditional transformer sizing methods based on the size of the home. We also request anticipated load information with applications for new services and seek assistance from outside engineers when the anticipated load is larger than a typical service. Stowe will also use Load Data Loggers to monitor customer loading where necessary.

H.4 Implementation of T & D Efficiency Improvements

Stowe continues to experience low line losses since a decrease from 2010 levels, with the most recent five-year average of 2.47%.

Figure 92: SED's Annual Percentage Line Loss



Stowe's main feeder lines have been re-conductored over the past 10-15 years during 4kV conversions to the system. Standard conductor sizes are 336 AAC for three phase main lines, 1/0 AAAC or ACSR for all branched side taps and 1/0 URD jacketed primary cable with full neutral, in conduit, for all underground branched side taps.

Capacitor banks have also been installed in specified areas to maintain voltages.

H.5 Maintenance of T & D Efficiency

Stowe continues to convert the few remaining sections of our distribution system that are still operating at 4kV to 12.47kV. Poles, equipment, and wires are evaluated before the start of a project to determine if full, partial, or no replacement is required. Typically, Stowe will replace conductor types and sizes that do not conform with our current standards, with a particular focus on aging conductors that are reaching the end of their useful life, such as copperweld.

During the 2020 Distribution System Study, Control Point Technologies determined that the total decrease in losses to convert the majority of remaining 4kV line segments was less than a kW and that it would not be cost effective to convert most of those segments.

Substation inspections are completed on a monthly basis and equipment problems are documented and addressed as they occur. Oil samples are drawn from substation transformers on an annual basis and analyzed.

A system wide infrared study is conducted on an annual basis as well. Results are analyzed and questionable equipment is repaired or replaced where needed.

Stowe completed the replacement and installation of fifteen new three gang ground operated switches in strategic locations across the system. The witches are located at circuit tie points and heavy concentrated load areas and are used for sectionalizing and isolating lines during outages and maintenance operations. The new switches will have the capability of having motorized operators installed in the future for remote monitoring.

H.6 Other T & D Improvements

H.6.1 Bulk Transmission

The VELCO 115kV line and VELCO/Stowe substation was completed in December 2009 and energized in January 2010. The line provides a stronger feed into SED's system and greatly improves reliability to the Stowe Mountain Resort. Before the 115kV line was installed, Stowe frequently had to have the Mountain limit snowmaking to stabilize the system but has not had to do so since. No further upgrades are being considered by Stowe at this time.

H.6.2 Sub-Transmission

Stowe's 34.5kV transmission line is fed from the VELCO 34.5kV ring bus in the new Stowe/VELCO substation. Two existing 34.5kV feeds remain on the 34.5kV ring bus as back up to the 115kV feed.

In August 2019, Stowe completed the replacement of three underground conductors on the Shaw Hill section of our 34.5kV sub-transmission line. This 1800' section was originally installed in the 1980s and Stowe experienced a conductor failure in 2018. Fortunately, Stowe had planned for this contingency and had installed a spare conductor three years prior to the failure and was able to switch to the back up and use it until all three old conductors were replaced. Stowe is preparing to replace and upgrade the primary underground of the 34.5kV on the segment starting at the Toll Road between 2024-2026.

Starting in 2018, Stowe increased the tree clearing width along the 8-mile-long 34.5kV sub-transmission to widen and re-establish the 100' width. By the end of 2022, Stowe tree crews completed trimming along the entire line. In 2022, Stowe received a grant from FEMA to develop a plan to harden this line from wind, ice and snow loading, and tree damage. During Winter Storm Elliot in December 2022, Stowe experienced outages along this line from trees and ice loading, which reiterated the need to harden this line. Stowe will complete the planning study for the line hardening and develop a plan to pay for the line hardening project. Stowe anticipates that by reducing the span lengths, adding tree wire, and installing sensing and communication equipment, the utility can limit storm caused outages and reduce the duration of outages.

In October 2020, Stowe and VELCO completed the installation of new backup 34.5kV underground conductors from the VELCO/Stowe substation to SED's Wilkins substation. The new conductors replaced the old overhead backup conductors that were left in place during the VELCO/Stowe 115kV conversion but were not connected to the Stowe's system. Restoration during an outage on the underground feed to Wilkins would have taken at least a day due to having to complete wire runs, make terminations, etc. The new backup conductors are in place and can be switched over in less than 30 minutes.

In June of 2019 and September of 2022 Stowe completed the installation of a Transmission Ground Fault Overvoltage (TGFOV) protection relay system at the Wilkins and Houston substations. Because of the amount of distributed generation on this substation, the relay system is designed to coordinate between the Stowe and VELCO substations and protect the station transformers and 34.5kV bus from damage during a fault.

H.6.3 Distribution

During the second half of 2023, Stowe started the installation of a new outage management system utilizing a new GIS system integrated with our AMI and CSI systems. This system will also include the ash tree identification completed by the Electric Department and Town of Stowe in 2021, which will track ash trees near or within the utility right of way that could be preemptively removed to avoid damaging distribution equipment. Stowe anticipates the operation of a new OMS/GIS system at the end of the first quarter of 2024, which will show the complete system information.

Stowe completed upgrades on the two major circuits fed from our Houston Substation. In 2015/16 the two 5MVA stations transformers were replaced and upgraded to two 7.5MVA units. Stowe line-maintenance staff has rebuilt the pole structures that deliver power from the substation. The two circuits originally shared single pole structures, in March 2017, line work was completed, and Circuits 5 and 6 were separated on individual poles. Stowe also added switching flexibility with the installation of a new switch between both feeders to further enhance the load serving capabilities at this substation by creating a new tie point.

Stowe is taking a proactive approach for handling direct burial primary cable failures. As of 2024, Stowe will have digitally mapped the underground system and identified the age of the cables in those areas. Stowe has purchased new equipment and trained our line maintainers on fault locating to help decrease our restoration times in such an event. Stowe also purchased a CAT305 mini excavator and trailer. This will not only help reduce our response time as we will no longer need to rent such equipment, but it also means that Stowe has the in-house ability to replace larger sections of this aging underground when needed. We will continue with our practice of installing new cabling in conduit for added protection and ease of replacement in the future. Stowe identified in the 5-year capital plan the replacement of two-direct buried primary underground line segments at Stonybrook and Robinson Springs. Because of the cost of replacing these segments, Stowe will continue to seek state and federal funding to defray the financial impact on our customer base for these projects.

In October 2020, Stowe completed the installation of the conduit system for the new circuits 6 & 7 tie point and the new underground conductors will be installed in the spring of 2021. This section of line is located where poles and aerial lines cannot be installed. The new 2000-foot cable route has been relocated roadside and will replace a failed 3-phase segment that was originally installed through the woods with very limited access. In addition to faster restoration times during outages, this new tie point will also give Stowe the ability to bypass our Lodge substation and keep the mountain resorts energized during future substation upgrades.

Stowe has several areas along our distribution feeders that are off-road and cross-lots that make access difficult and more costly to treat. Historically these areas were maintained less frequently because consultant costs made it difficult to prioritize. In 2023, Stowe created a utility owned tree crew to trim lines and address overgrown portions of our distribution system. Stowe has been able to prioritize off-road segments that need their utility right of way reestablished and address hazard trees that might threaten distribution equipment. Stowe has identified the relocation of a line segment along Gold Brook Road as a priority project in our 5-year capital plan, which will help reduce the off-road distribution lines within our system.

Stowe is a member utility with NJUNS and utilizes the online portal to coordinate pole transfers with telephone and cable utilities. Stowe has expressed to Consolidated Communications an interest in purchasing their poles in Stowe – which is approximately a third of the total poles in our territory. This will give Stowe better control over coordinating pole transfers and removing existing double sets.

H.6.4 Grid Modernization

Stowe is committed to grid modernization that is properly sized for our service territory. Our goal is to make our system reliable, resilient, and secure for our customers as it is flexible and manageable for our workforce. The modernization of our workspaces and infrastructure is part of this effort and in 2016 Stowe purchased the historic Moscow Mills property to build a new utility headquarters. The site was home to a machine shop, sawmill, a residence, and storage for construction materials. Starting in 2017, Stowe finalized site and building plans, demolition of two buildings, and worked closely with Efficiency Vermont to develop modern lighting, heating, and cooling for the new buildings. Construction of the new buildings was completed in 2019 and is now home to 12 administrative staff, 5 linemen, and 3 right of way tree crew members. In 2020, one (1) Level 2 EV charging station was added for use by our customers and employees.

A rooftop photovoltaic system will be installed on the garage building and the redeveloped Millwright's Office to add additional renewable energy to our generation portfolio. A combination saw and grist mill built in 1820s utilized waterpower for its operations and was later adapted to produce electricity from a run of river hydroelectric facility. Stowe is finalizing designs to restore and modernize the mill with a new powerhouse located adjacent to the mill. Stowe has received funding for the hydroelectric modernization project from a $1.2MM congressionally directed spending earmark and a grant from the Vermont Low Income Trust for Electricity and American Public Power Association's Demonstration of Energy & Efficiency Developments. The modernized hydroelectric facility and new solar generation will form the basis of an on-bill generation credit program for income-qualifying customers. The project will also allow Stowe to partner with stakeholder groups to further enhance the shoreline of the Little River, provide riverbank restoration and stabilization, and allow safe public access to the river.

This project will highlight the role of rivers in Vermont history and the need to modernize Vermont's electricity generation with renewable distributed generation projects.

During the second half of 2023, Stowe started the migration to a new outage management system utilizing a GIS system that integrated with our AMI and CIS systems. Stowe's OMS/GIS system has complete system information and is available to all SED personnel. Field crews are also outfitted with tablets that have cellular capabilities that allow real time access to GIS information and real time outage data. Customers can also report outages and check the location of outages in real time. The new OMS system is integrated with Vtoutages.com and automatically updates outage information. Stowe completed the installation of AMI meters and AMI and MDM systems in 2013. The AMI meters communicate over a mesh RF network back to collectors placed in strategic locations throughout our system. The MDM and customer billing systems were replaced with our transition to NISC. A new IP based phone system was installed in February 2023.

Fiber optic cable has been installed from our Wilkins substation along our 34.5kV transmission line with terminations at Houston and Lodge substations. It then continues to the top of Mt. Mansfield and terminates in the WCAX building. Stowe will also replace the reclosers at each substation with units utilizing digital relaying that will provide feeder status, voltages, load data, and power factor back to the new headquarters. Fiber has been installed at our new headquarters.

Stowe's 5-year capital plan has identified priority projects to modernize our distribution system, sensing and controls, and IT infrastructure. This includes upgrading the Wilkins substation, restoring a vacant building into an emergency operations center and control room, and distribution system upgrades that include relocating off-road line to roadside and line conversions. Stowe is also considering how to improve the visibility and communications within our system by adding fiber to the gatekeepers, substations, and important node centers, CISCO ISR routers at all nodes, and weatherproof enclosures. These projects will add to the resiliency and reliability of our system and reduce both the number and duration of outages.

In June 2020, Control Point Technologies completed a study of Stowe's distribution system. In Phase One of the study, Control Point Technologies modeled the existing distribution system including: substations, supply transformer, voltage regulation, capacitors, reclosers and lines. The system was first evaluated in both its normal state and during peak loading conditions. Then a contingency analysis was performed on each circuit to determine the preferred tie points for restoration. The analysis included voltage drop, overloading, loss evaluation, regulator/capacitor placement, power quality, TGFOV and protective device coordination.

Phase Two developed mitigation strategies, options to alleviate any voltage issues and thermal overload, TGFOV and protective device coordination strategies. Additionally, assessments on transformer load loss, CVR and conversion of 4kV line segments were completed. Stowe will evaluate Control Point's recommendations and design a 10-year plan for system improvements and upgrades.

Technology and Cybersecurity Innovation

Stowe is committed to modernizing and hardening our distribution system. Stowe's right of way tree crew is focused on increasing the mileage trimmed each year. In 2023, the crew focused on make-ready work for broadband and new service applications, and reclaiming the full right of way width on distribution lines that have off-road lines. Our tree crew will improve the reliability of our system and improve response time to outages caused by tree damage.

In the near term, Stowe is focused on transitioning from several software vendors into one enterprise platform provided by National Information Solutions Cooperative, Inc (NISC). This will create a unified system for customer service, operations, finance, outage management, meter data management, and GIS. The NISC platform will allow Stowe to communicate with customers through an online portal, text, email messaging, and phone calls. Stowe also updated and streamlined our website, which provides customers with more information on our system, rebates, and regulatory filings. Stowe will continue to seek ways to improve and streamline communications with our customers.

Stowe will continue to research and plan for software and hardware system updates that can automate processes and provide customers with a modern experience. Stowe is working on a distribution automation loop scheme for a segment of a high-priority feeder, which will give staff the opportunity to work with technical experts and develop a framework to add more sensing and automation equipment to our system. Stowe has advanced metering infrastructure (AMI), and Stowe will continue to work with our AMI provider to improve the flow of information between the metering infrastructure and the enterprise software. Stowe has experienced communication challenges in gathering metering data because of spotty and unreliable cellular service in the region.

As we move into 2025-2026, Stowe will look to improve system visibility and communications with fiber at the gatekeepers, substations and important nodes, upgrade to Cisco ISR routers at all nodes, and add weatherproof enclosures. These measures will improve our visibility and communication capabilities that could allow Stowe to consider implementation a supervisory control and data acquisition type system that is appropriately sized for a small rural municipal utility.

Stowe, in partnership with VELCO, is also planning to bring fiber to distributed generation on our system over 150kW in nameplate capacity and bring our substations into the VELCO Pi system. This will improve the data that VELCO receives from Stowe and will offer Stowe improved visibility into our feeders and substations. With this data sharing, Stowe can begin to plan for more advanced analytical tools, automation, flex load management, and system planning.

In the next IRP, Stowe will use the recommendations in the Vermont Comprehensive Energy Plan and guidance from the Department of Public Service when addressing and setting a path to helping Vermont meet its goals. Stowe will "use the IRP process to demonstrate the underlying methodology and a set of specific tools they will use to evaluate options for balancing supply and demand at the lowest present value life cycle cost as they arise – a utility's "decision-making framework". [52] Stowe will also seek to utilize the Initiative Flowcharts provided by the Department of Public Service in Attachment 1 to the Guidance for Integrated Resources Plans and 202(f) Determination Requests as Stowe considers how to implement grid modernization projects, rate restructuring, and bringing more technology onto our system.

H.7 Vegetation Management Plan

Winter Storm Elliot highlighted the importance of regular tree trimming for ongoing reliability as well as the benefits of having a tree crew on-site during outage operations. Without a tree crew on-hand for the December 2022 storm, SED's lineworkers spent a significant amount of time during restoration efforts clearing downed trees. Contract tree crews are in high demand by utilities and are often difficult to secure. To overcome this obstacle, Stowe Electric established an in-house tree crew in April 2023.

Thanks to the new in-house tree crew, Stowe Electric will be able to consistently meet PUC reliability trimming standards and provide an on-site tree crew for outages. SED's tree crew has trimmed 9.7 miles of right-of-way (ROW) since May 2023. We are currently on target to hit 11 miles by the end of 2023. The milage cut by our crew does not capture their time spent removing danger trees or maintaining road right of ways for the Town of Stowe. Our current pace for vegetation management will ensure SED meets 12 miles of ROW clearing per year, putting the utility on track for a five-year distribution and transmission clearing cycle. It is important to note that Stowe does not apply herbicides to any utility ROW but does use herbicides through a licensed applicator within the fence line of each substation. Line and tree crews continually monitor our overhead lines for danger trees. Danger trees may also be brought to our attention by customers and landowners.

Lands within the Stowe ROWs are owned either by private individuals or by the State of Vermont. A perpetual easement is the most common type of utility right-of-way document, and most easements are 50 feet on aerial distribution and 100 feet on aerial transmission. Many Stowe owned distribution lines are located near roadways, which provides different challenges for tree trimming crews than those lines running through timbered areas. Vegetation along Stowe ROWs ranges from open agricultural land, low- growing shrubs and brush, as well as full grown trees. The most common forest types in wooded areas along Stowe ROWs are northern hardwoods, spruce-fir, eastern hemlock, yellow birch, and white pine.

[52] Guidance for Integrated Resource Plans and 202(f) Determination Requests - April 2023.pdf (vermont.gov)

These varying conditions, as well as the considerable efforts of the last few years to achieve a consistent vegetation management cycle, means that some areas of Stowe's network have had higher tree-trimming costs, as is reflected in the table below. This also means that the utility's anticipated future tree trimming budgets may be able to cover more miles of Stowe's distribution system as fully-grown, high cost-per-mile areas are addressed.

Stowe has mapped our entire system by year to help coordinate pre-season line surveys with tree trimming assignments for the year. Tree trimming activities are conducted by qualified line clearing employees that adhere to the American National Standard Institutes (ANSI) Standard A300. Stowe line-clearing personnel work closely with Stowe line-workers to conduct routine inspections of our right of ways, remove hazard trees in advance of electrical and broadband communication work, and maintain Stowe's right of way line clearance standards.

Stowe is aware that emerald ash borer (EAB) infested areas have been identified to the south and west of Lamoille County. The State of Vermont has not identified EAB as active in Stowe's service territory, Stowe has monitored EAB's spread and takes all precautions identified in State guidance. Stowe's line crews evaluate ash trees within the utility ROWs for threats to the utility lines and remove trees when needed to protect lines. Stowe also remains apprised of reporting completed by the Town of Stowe, which provides prospective review of potential threats to public right of ways.

H.8 Studies and Planning

Stowe Electric staff are working with Oak Ridge National Laboratory, National Renewable Energy Laboratory, Idaho National Laboratory, Argonne National Laboratory, Boise State University, and University of Vermont on several technical assistance and feasibility studies designed to modernize and harden our distribution system and research modern rate design principles. Stowe will complete these projects between 2023-2024 and seek funding opportunities to implement the recommendations in the reports. Two of the more significant projects are a microgrid and distribution automation. These projects will add carbon-free generation to our system and make our system more resilient to climate change. The current 5-year capital plan for Stowe is as follows:

	Category
Upgrade Wilkins Substation	Distribution
Express circuit to Mountain Road from Wilkins	Distribution
Emergency Operations Center	Distribution
Replace Failed Meters	Distribution
Distribution Automation Loop Feed	Distribution
Tree Trimming Bucket Truck	Distribution
Tree Trimming Chipper	Distribution
Tree Trimming Tools & Equipment	Distribution
Weeks Hill 3-Phase to Percy Farm Pole Rebuild	Distribution
Weeks Hill 3-Phase to Percy Farm Line Conversion	Distribution
Gold Brook Rd - Relocate 3-phase	Distribution
Dewey Hill Rd - Pole Replacements	Distribution
Rebuild Distribution side of Lodge Substation	Distribution
New reclosers and controllers at each substation	Distribution
Install URD Fault Indicators	Distribution
Replace Primary Underground at Stonybrook	Distribution
Replace Primary Underground at Robinson Springs	Distribution
Replace 34.5kV Underground at Toll Road	Distribution
Build new storage garage at Cady Hill substation	Distribution
NISC Software & Hardware	IT
NISC Pole Survey & System Mapping	IT
2012 r2 Server OS Upgrades (Domain/Veeam/Field & Net Sense)	IT
Firewall	IT
2016 Server OS Upgrades (SQL/mPower/Domain WLS)	IT
2017 SQL Server	IT
2019 Server OS Upgrades	IT
Moscow Garage Solar Install of 60kw AC	Solar
Moscow Microhydro 168kW	Hydro

H.9 Emergency Preparedness and Response

Customers have 24/7 access to Stowe for all emergencies by calling our main phone number. After hours, calls are handled by Stowe's answering service, which has direct phone contact with on-call lineworkers, the Director of Operations, and General Manager for a response.

Additionally, customers now can report outage information via Stowe Electric's website. Outages are directly loaded into our new Outage Management System and displayed on Stowe's territory map for customers to view the affected area. Stowe has also created a link from our new OMS to VToutage.com to automatically update outage information on that site.

The on call lineworker will call in additional Stowe personnel if needed, depending on the severity of the situation. Customers with significant loading also have direct 24/7 cell contact with the General Manager and the Director of Operations.

In the event Stowe crews require additional outside help, SED can rely on members of the Northeast Public Power Association's (NEPPA) and APPA's mutual aid programs. This gives Stowe access to local, regional, and national Municipal utility crews. Further help is available from Green Mountain Power, Washington Electric Coop, and Vermont Electric Coop.

For planned outages, Stowe uses several forms of communication to inform customers in advance: phone calls, emails, and door hangers. Information is also posted on Front Porch Forum, Stowe's website, X (Twitter), and Facebook page, as well as in the local newspaper when time permits. With the new enterprise system implemented in late 2023, Stowe Electric will also be able to send out text messages, emails, and automated phone calls ahead of time to customers impacted by planned outages.

Stowe participates in the Fall Vermont Joint Utilities/State Agencies Emergency Prep Program and the Lamoille County Emergency Response Tabletop Exercise. Stowe also participates in the VELCO statewide emergency preparation conference calls when scheduled. In addition, Stowe Electric is the NEPPA mutual aid coordinator for northern New England and engages in several mutual aid exercises through NEPPA each year.

H.10 Reliability

Stowe serves over 92% of residents and 100% of businesses located within Stowe, Vermont. As of 2023, Stowe serves 4,445 customer meters, which includes net of voltage and current meters, station service meters, and any meters at a retail customer's premises beyond the customer's first meter.

In 2022, Stowe experienced 112 outages and a total of 4,971 customer hours without service. Company initiated outages, trees, equipment failure, and weather were the leading causes of customer outages. Because of the size and intensity of the December 2022 storm, which was considered a major storm, those customers' hours without electricity were not included in the 2022 SAIFI and CAIDI numbers show below. At the height of the December Winter Storm Elliot event, SED had approximately 2,700 customers without power.

Code	Outage cause	2022 No. of Outages	2022 Cust. Hrs.
1	Trees	19	708
2	Weather	10	3,235
3	Company initiated outage	54	537
4	Equipment failure	10	155
5	Operator error	0	0
6	Accidents	3	42
7	Animals	7	125
8	Power supplier	0	0
9	Non-utility power supplier	0	0
10	Other	1	1
11	Unknown	8	167
	Total	112	4,971
	SAIFI	0.7	
	CAIDI	1.6	

Table 27: SED's 2022 reliability indices reflect improvements in system performance.

	Target	2020	2021	2022
SAIFI	0.9	0.8	1.7	0.7
CAIDI	3.3	1.9	1.2	1.6

H.11 Assessment of Outage Events and Trends

Stowe's system experienced several weather events between 2020-2023. One of these events, the December 2022 Winter Storm Elliot, which qualified as a Major Storm as defined in the Service Quality Reliability Plan ("SQRP"). SED's SQRP includes two criteria that a weather event must meet to be considered a Major Storm: (1) more than 10% of the customers in the service territory are without of service, and (2) at least 1% of the customers in the service territory are without service for at least 24 hours. Three of these events met the first criterion but none met the second criterion.

Number of Outage Events 2020-2022

Code	Outage cause	2020 No. of Outages	% of total 2020	2021 No. of Outages	% of total 2021	2022 No. of Outages	% of total 2022
1	Trees	28	25%	41	30%	19	17%
2	Weather	4	4%	3	2%	10	9%
3	Company initiated outage	44	39%	63	46%	54	48%
4	Equipment failure	13	11%	11	8%	10	9%
5	Operator error	0	0%	0	0%	0	0%
6	Accidents	4	4%	5	4%	3	3%
7	Animals	14	12%	4	3%	7	6%
8	Power supplier	0	0%	0	0%	0	0%
9	Non-utility power supplier	1	1%	0	0%	0	0%
10	Other	1	1%	4	3%	1	1%
11	Unknown	5	4%	5	4%	8	7%
	Total	114	100%	136	100%	112	100%

In 2022, SED experienced fewer outages and total customer hours without service as compared to 2020 and 2021. The trend shows: 1) company initiated outages for equipment replacement, new service, service upgrades, and make-ready work for broadband and cellular providers are a primary source of outages and customer hours without power in SED's territory; 2) trees and weather remain the most significant challenge to system reliability and the utility remains committed to proactively mitigating these impacts, and 3) SED's commitment to prioritizing off-road right-of-way vegetation management has reduced hours customers were without power.

Since 2021, SED experienced increased failure of chance cut-outs and failure of direct buried primary lines. SED has completed a survey to locate all remaining chance cut-outs on our system and prioritize their replacement. SED continues to seek technical solutions and funding to map remaining primary underground lines and develop a plan to replace aging direct bury underground lines with new lines withing underground conduits.

In 2020 and 2021, SED contracted with an engineering firm to continue an in-depth analysis of the Utility's distribution system. The results continue to inform long-term grid planning and identify feeders, circuits, substations, and other portions of the system that need particular attention. The study results and recommendations will help reduce outage events caused by equipment failures and prioritize future grid improvements. These may include traditional improvements such as substation redesign and improvements necessary to accommodate new customer-side technology, such as solar net-metering, cold-climate heat pumps, and electric vehicles.

The implementation of a new outage management system ("OMS") will provide enhanced operational capabilities for Stowe personnel and help to prioritize line-clearing, identify hazard trees, and improve operations within our system.

The staff at Stowe are committed to maintaining a safe, reliable, and modern utility. Stowe staff and Board of Commissioners remain focused on improving our customer service, employee training, distribution system infrastructure, and engaging the broader Stowe and Lamoille County community. Our energy efficient headquarters and garage completed in February 2019 is part of our commitment that has seen Stowe Electric install a state of the art behind the meter solar generation facility safely interconnected to our distribution system, a new Outage Management System, an 80% renewable purchase power portfolio, and 16 public charging stations installed throughout the town. Stowe is committed to coupling new and innovative ideas with hard work and expertise to bring the best possible service at the least cost practicable to our customers.

I Integrated Analysis and Plan of Action

I.1 Risk and Uncertainty Analysis

I.2 Evaluation of Portfolio Scenarios

ENE's portfolio simulation models evaluated five (5) scenarios that consisted of varying amounts of resources, fuel type and renewal of existing contracts. Scenario #1 is the base case, which is the "do nothing" current portfolio. ENE analyzed each scenario from both the energy perspective and the RES contribution to compliance perspective. Below are all the scenarios, categorized by number for clarification.

Portfolio Scenarios:

- Scenario # 1 = Current Portfolio with no additional resource procurement There were projections within scenario 1. Stowe assumed NYPA contract for both Niagara and St. Lawrence are extended. Also Stowe extended Ryegate through 2032. The Ryegate assumption follows the Ryegate Case No. 23A-2194 the plants Efficiency requirement filing, and completion coupled with the purchase power agreement Case No. 22-3944 whereas if Ryegate meets the requirements set on Section 8009(k) the recommendation is to contract until the end of November 2032.
  "Under Act 155, the obligation of each Vermont retail electricity provider to purchase the provider's pro rata share of the baseload renewable power portfolio requirement is extended until November 1, 2032, unless terminated earlier pursuant to the collocation and efficiency requirements of 30 V.S.A. § 8009(k). Under Section 8009(k), Ryegate Associates must increase the plant's overall efficiency by at least 50%, relative to the 12-month period preceding July 1, 2022. Sections 8009(k)(2) and (3) establish a schedule for Ryegate Associates to demonstrate that the plant will meet the efficiency requirements by November 2026. Section 8009(k)(2) requires that, on or before July 1, 2023, Ryegate Associates must sign a contract for the construction of a facility that uses the Ryegate Plant's excess thermal heat for a beneficial purpose and provide a certification by a qualified professional engineer that the construction of the facility will meet the efficiency requirement."

- Scenario #2 = Current Portfolio, including NYPA contract for both Niagara and St. Lawrence are extended. Additions include, the rebuild of the 168 kW Moscow Mills Hydroelectric Unit set at standard offer rates, Ryegate extended through 2026 (assuming Ryegate does not meet the requirements set on Section 8009(k), extension of HQ are current prices continuing escalating rates of the current contract, extension and increase of existing onshore wind (Saddleback) 4MW or 13% of portfolio at current market rates of $79/MWH, and extension and increase of existing hydro (FirstLight) 3MW or 14% of portfolio at current market rates of $77/MWH.

- Scenario #3 = Current Portfolio, including NYPA contract for both Niagara and St. Lawrence are extended. Additions include, the rebuild of the 168 kW Moscow Mills Hydroelectric Unit set at standard offer rates, Ryegate extended through 2032 (assuming Ryegate does meet the requirements set on Section 8009(k), extension of HQ are current prices continuing escalating rates of the current contract, offshore wind 5MW or 13% of portfolio at current market rates of $96/MWH) Appendix H, and hydro contract with storage control 4MW or 10% of portfolio at current market rates of $81.50/MWH.

- Scenario #4 = Current Portfolio, including NYPA contract for both Niagara and St. Lawrence are extended. Additions include, the rebuild of the 168 kW Moscow Mills Hydroelectric Unit set at standard offer rates, Ryegate extended through 2032(assuming Ryegate does meet the requirements set on Section 8009(k), extension of HQ are current prices continuing escalating rates of the current contract, piece of a large solar project 1MW or 2% of portfolio at current market rates of $62/MWH, extension and increase of existing hydro (FirstLight) 3MW or 14% of portfolio at current market rates of $77/MWH, lastly an extension of Seabrook 3MW or 30% of portfolio at current market rates of $77.50.

- Scenario #5 = Current Portfolio, including NYPA contract for both Niagara and St. Lawrence are extended. Additions include, the rebuild of the 168 kW Moscow Mills Hydroelectric Unit set at standard offer rates, Ryegate extended through 2026 (assuming Ryegate does not meet the requirements set on Section 8009(k), new build of a solar project 4% of portfolio at standard offer rates of $98.20/MWH (Appendix), potential new onshore wind project 4% of portfolio at standard offer rates of $116/MWH (Appendix) and potential landfill 12% of portfolio at current market rates of $90/MWH.

The NPV of each scenario cost and the risk tradeoff is below in Table . With the stochastic models of @Risk, ENE was able to rank each portfolio by the NPV of each scenario using energy cost and RES value. Using the Monte Carlo simulation allowed ENE the use of multiple variables, such as compliance payment rates, LMP, and hedged position. ENE then performed iterations of these inputs and developed a probability of returns.

Next, ENE analyzed these returns to determine the optimal scenario for Stowe that stabilize costs and maintain healthy coverage while allowing room for future projects.

Table 28: Scenario Display.

	NPV Total Cost	Rank	Total RES NPV	Rank	Std Dev	Rank	Spot Exposure Target Deviation	Rank	Weighting on Cost	Total Rank
Scenario #1	$ 90,192,297	1	$ 2,050,015	5	$ 19,999,017	5	61%	5	$ 92,242,313	1
Scenario #2	$ 95,605,453	3	$ (304,696)	3	$ 10,619,225	3	80%	2	$ 95,300,757	3
Scenario #3	$ 100,429,469	5	$ (3,502,271)	1	$ 7,042,235	1	86%	1	$ 96,927,199	5
Scenario #4	$ 95,713,688	4	$ 1,052,353	4	$ 9,122,712	2	79%	3	$ 96,766,041	4
Scenario #5	$ 94,955,129	2	$ (666,702)	2	$ 14,149,830	4	70%	4	$ 94,288,427	2

I.3 Assessment of Environmental Impact

The analytical process determined the optimal scenario for Stowe that maintained energy costs with reasonable renewable alternatives and helped curb the large cost impact of RES to Stowe. The ranking per category is based solely on the most optimal of that category. ENE chose to consider more than category rank to determine the best solution for Stowe. To determine the scenarios that would financially benefit Stowe, ENE analyzed how each scenario ranked in each category, the mean cost of each portfolio, and the risk to Stowe for each scenario. ENE's integration models were used to run 1,000 iterations of each potential portfolio for both energy and RES impact. ENE determined how the cost, stability, and environmental impact to Stowe would be for each scenario. There were no scenarios that resulted in the best rank in all categories, so finding the optimal choice was determined not only by cost and impact but also by feasibility. ENE wanted to present a scenario that was obtainable to SED to include in their portfolio.

I.4 Preferred Plan

I.4.1 Optimal Scenario

The IRP process found the optimal scenario to be scenario #2. Scenario #2 was assessed at the current portfolio, including NYPA contract for both Niagara and St. Lawrence are extended. Additions include, the rebuild of the 168 kW Moscow Mills Hydroelectric Unit, Ryegate extended through 2026 (assuming Ryegate does not meet the requirements set on Section 8009(k), extension of HQ, extension and increase of existing onshore wind (Saddleback) 4MW or 13% of portfolio, and extension and increase of existing hydro (FirstLight) 3MW or 14% of portfolio.

For the energy price of the new construction of Moscow Mills hydro project the model was based on Appendix G, Ryegate is priced at the existing contract rate of $100/MWH plus fuel, HQ are current prices continuing escalating rates of the current contract, extension of onshore wind was priced at current market prices, as well as extension of existing hydro projects.

The stochastic model data is below in Figure 93. The Output for the RES impact is found in Appendix I. Scenario 2 offers Stowe a multitude of benefits from resource diversity to RES benefits in Tiers I and II. The open position to this forecast is marketed at forward prices that are generated from the @Risk modeling and represent both spot prices and bilaterals.

This scenario helps SED's RES requirement in the most expensive tiers, Tier II, and Tier III. With the REC arbitrage, Stowe can fill the minimal shortfall with the extra benefit from selling high and buying low at the beginning of the program. Figure 94 and Figure are the RES resulting coverage from scenario #2.

Figure 93: Optimal Scenario #2

	NPV Total Cost	Rank	Total RES NPV	Rank	Std Dev	Rank	Spot Exposure Target Deviation	Rank	Weighting on Cost	Total Rank
Scenario #1	$ 90,192,297	1	$ 2,050,015	5	$ 19,999,017	5	61%	5	$ 92,242,313	1
Scenario #2	$ 95,605,453	3	$ (304,696)	3	$ 10,619,225	3	80%	2	$ 95,300,757	3
Scenario #3	$ 100,429,469	5	$ (3,502,271)	1	$ 7,042,235	1	86%	1	$ 96,927,199	5
Scenario #4	$ 95,713,688	4	$ 1,052,353	4	$ 9,122,712	2	79%	3	$ 96,766,041	4
Scenario #5	$ 94,955,129	2	$ (666,702)	2	$ 14,149,830	4	70%	4	$ 94,288,427	2

Figure 94: Tier I with Scenario #2

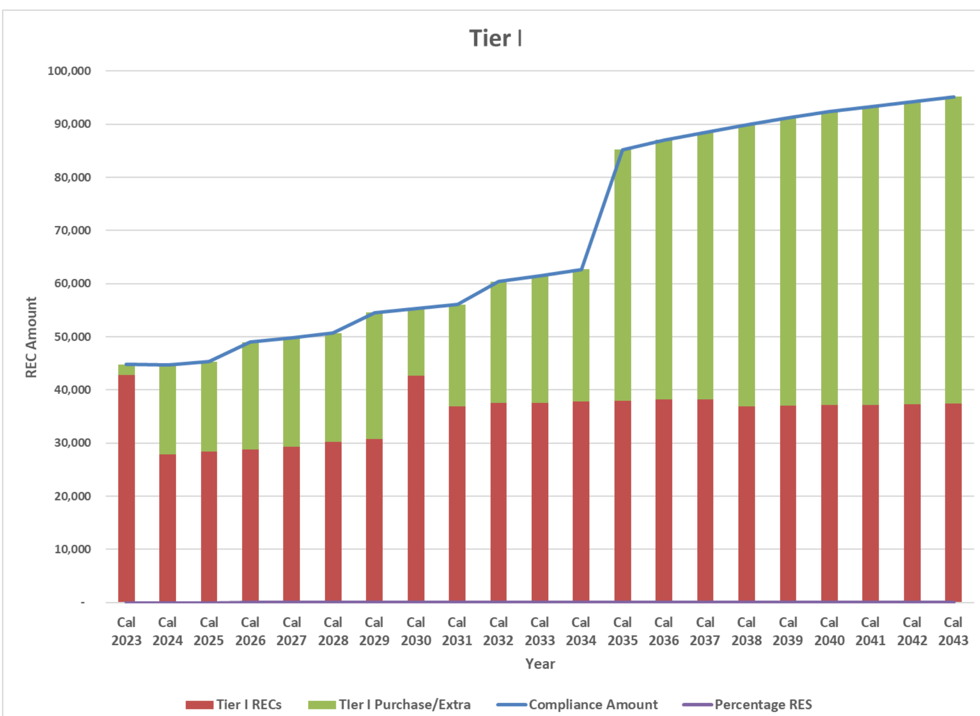
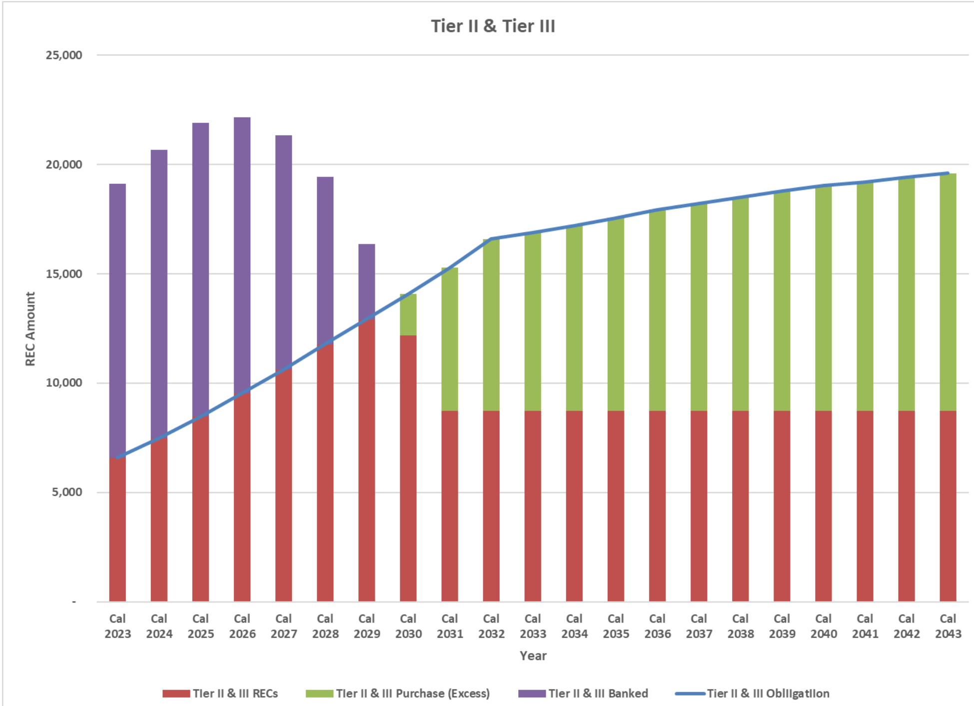


Figure 95: Tier II and Tier III with Scenario #2



I.4.2 Least Energy Cost Scenario

The least cost scenario is #1. This is Stowe's current portfolio, with no additional hedging or building of renewable projects, the only inclusion is extending NYPA throughout the term of the IRP. The reason for this outcome is due to the low forward price curves, seen in Figure 52 verses project prices with a purchase agreement. The @Risk model is mapping the open position to forward prices. Although the current energy NPV of scenario #1 is the lowest option, this scenario has the complete opposite effect to NPV of the RES cost to Stowe. The "do nothing" approach is not an option for Stowe because it leaves them exposed to REC price risk as well as Alternative Compliance Price risk (ACP) if they are short compliance in all three Tiers. Also, the risk of choosing scenario 1 is that SED cannot depend on the forward market costs to remain stable, although the model examines 1,000 iterations choosing this option leaves Stowe the most exposed to the market. The market risk exposure is depicted in the size of Scenario 1's graphed circle seen within Figure 95.

I.5 Risk and Uncertainty Evaluation

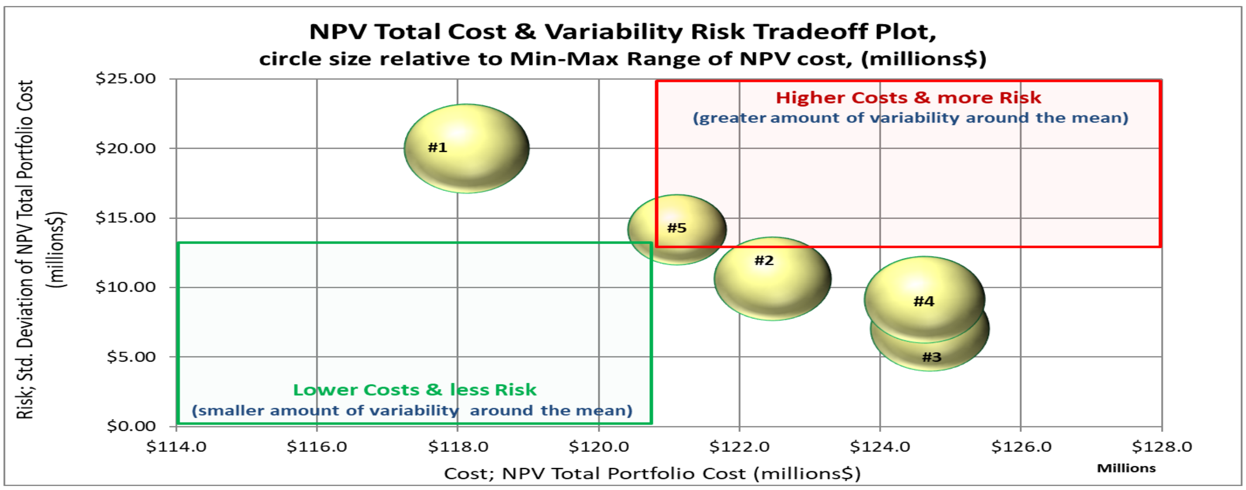
Another method for comparative tradeoff analysis is to rank the portfolios by their standard deviations and then plot them in "risk/return"[53] space. This plots the expected values along the x-axis and the risk on the y-axis. For this analysis, a "bubble" chart was used, where each "bubble"

[53] "risk/return space" is term used in Portfolio Theory when finding the Min-Variance portfolio, where "return" is term used when portfolio consists of equity assets; in the IRP context we use the implied improvement (savings/benefit) in Total Cost metrics by pursuing an alternative resource portfolio as a proxy for "return."

is a point on the chart and represents a portfolio's relative position based on its respective expected value, X, and standard deviation, Y.

This allows for a comparison and evaluation of portfolios based on their location on the chart – namely, which quadrant they fall within from the output of the modeling. For example, if comparing portfolios on risk vs. least cost, the lower left quadrant should contain the portfolios with both lower costs and risk, and the upper right quadrant should hold the higher cost and higher risk portfolios. The additional benefit of using a bubble chart is that the relative size of each bubble also represents that relative variation of each portfolio. Not only does the quadrant display a portfolio's merit but includes the size of a portfolio's bubble according to its relative risk. Figure 95 demonstrates the bubble plot comparison for least cost and risk.

Figure 95: Risk/Cost Tradeoff Bubble Plot



To minimize uncertainty Stowe's ideal scenario allowed for an estimated coverage of 80%. With less market exposure Stowe can set rates for power at know and reasonable prices. As Stowe's portfolio is stacked with projects that include RECs Stowe is also able to monetize RECs per resource. Large portions of scenario #2 include renewals of existing contracts. The benefit of this strategy is Stowe can use historical output of such projects and create realistic capacity factors. By incorporating existing projects Stowe is not exposed to the current supply chain and price increases that new projects are facing.

I.6 Implementation or Action Plan

Stowe is diligently collaborating with developers and counterparties for the resources set forth in scenario 2. The resources examined in optimal scenario are the most feasible options, as well as reasonably priced in the market today. Stowe is cognizant of RES compliance as well as energy hedged positions while evaluating the different scenarios. There are trade-offs to each scenario one may provide more coverage but less financial stability around market prices and RES risk. The component of the optimal scenario is to maintain Stowe at a hedged position that is risk adverse. Stowe's purchase plan is to maintain at least 80% coverage. This still allows space for future renewable options or bilateral purchases. Stowe's risk tolerance at 80% coverage also includes the potential of Stonybrook coverage. When the market prices increase high enough Stowe has Stonybrook as an intermediate unit that will help mitigate price spikes.

This scenario allows benefits to Stowe beyond coverage and cost, it allows them options to investigate additional products to comply with any new regulations. Reviewing renewable resources is the key to Stowe's RES compliance and reducing their environmental impact. This option reduces the environmental carbon footprint for Vermont and Stowe's customers. It would provide a long-term energy price point that Stowe can lock into its rates. Stowe remains diligent when monitoring rate impact, on their customers. Lastly, it will provide Stowe with RES compliance that will reduce its exposure to any compliance payments, which could increase costs to the ratepayers.

I.7 Financial Assessment

I.7.1 Financial Transparency and Accountability

Stowe Electric's finances are discussed quarterly at open meetings of the Stowe Electric Commission. The Commission, appointed to directly represent the interests of ratepayers and the Stowe Community, approves SED's annual budget and five-year capital plan, sets rates, and guides organizational policy. In addition to regular open discussion of finances, seven years of audited financial statements are available for public review on Stowe Electric's website at www.StoweElectric.com/financials.

The Stowe Electric Commission approved an updated five-year capital plan in February 2023 (Appendix L). This document also includes a five-year debt ratio and cash flow forecasts. Additionally, the five-year capital plan details outstanding and anticipated debt instruments. The Commission reviews and updates the rolling five-year plan annually to provide a clear vision for upcoming capital investments and to support sound financial planning. Projects are identified along with estimated costs and anticipated or preferred sources of funding.

The FY2024 operating budget shows anticipated expenses and revenue, with a projected net income of $231,430 in FY2024.

Figure 96: 5-year projection – FY2024 + Inflation

	FY24 Approved Budget	FY25 Projected Budget	FY26 Projected Budget	FY27 Projected Budget	FY28 Projected Budget
Estimated Additional Load		1.0%	1.0%	1.0%	1.0%
30 VSA 218d(n) Anticipated Increase		2.0%		2.0%	2.0%
Estimated Rate of Inflation *		3.1%	2.6%	2.6%	2.6%
Opererating Revenue:					
Electric Sales to Customers ^	$ 15,929,770	$ 16,407,663	$ 16,571,740	$ 17,068,892	$ 17,580,959
Sales of Labor & Supplies ~	$ 940,530	$ 969,686	$ 994,898	$ 1,020,766	$ 1,047,306
Rental Income	$ 67,596	$ 67,596	$ 67,596	$ 67,596	$ 67,596
Total Operating Revenues	$ 16,937,896	$ 17,444,946	$ 17,634,234	$ 18,157,254	$ 18,695,860
Operating Expenses:					
Purchased Power ~	$ 11,685,603	$ 12,047,857	$ 12,361,101	$ 12,682,490	$ 13,012,234
Transmission & Distribution ~	$ 2,259,624	$ 2,329,672	$ 2,390,244	$ 2,452,390	$ 2,516,152
Customer Accounts ~	$ 496,061	$ 511,439	$ 524,736	$ 538,379	$ 552,377
Admin & General ~	$ 1,896,486	$ 1,955,277	$ 2,006,114	$ 2,058,273	$ 2,111,788
Depreciation	$ 814,752	$ 814,752	$ 814,752	$ 814,752	$ 814,752
Taxes ^	$ 163,637	$ 168,546	$ 170,232	$ 175,339	$ 180,599
Total Operating Expenses	$ 17,316,163	$ 17,827,543	$ 18,267,179	$ 18,721,623	$ 19,187,903
Net Income/(Loss) from Operations	$ (378,267)	$ (382,598)	$ (632,945)	$ (564,369)	$ (492,043)
Non-Operating Revenue/(Expense):					
Investment Income '	$ 984,242	$ 1,041,691	$ 1,099,140	$ 1,156,588	$ 1,214,037
Interest Expense	$ (395,145)	$ (395,145)	$ (395,145)	$ (395,145)	$ (395,145)
Gain/(Loss) on Disposals	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
Other Income	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000
Total Non-Operating Revenue/(Expense)	$ 609,697	$ 667,146	$ 724,595	$ 782,043	$ 839,492
Net Income/(Loss)	$ 231,430	$ 284,548	$ 91,650	$ 217,674	$ 347,449

*** Based on the Consumer Price Index Growth published by the Vermont Legislative Joint Fiscal Office on July 31, 2023**
^ Increased by estimated additional load each year and the 2% allowed by the PUC when noted above
~ Increased by rate of inflation
' Increased by 12% anticipated ROI for VT Transco Equity Purchase in December 2023

I.7.2 Rates, Power Supply & Cost of Service

Stowe Electric applied for a rate increase on December 15, 2022, which was implemented February 1, 2023. The PUC ultimately approved a 7.95% increase. An extensive review of supporting financial documentation was performed by both PUC and DPS throughout the rate approval process.

To ensure rate classes are designed to equitably allocate costs across customers, SED is planning to engage in a comprehensive cost-of-service study during the first quarter of 2024. This Cost-of-service study will ensure revenue requirement recovery, equitable apportionment of cost allocation and revenue recovery, cost-based rates, and rate design that will incentivize or disincentivize customer behaviors for the benefit of all customers. The cost-of-service study will also contemplate creation of new rate classes for electric vehicles, low-income customers, and short-term hospitality rentals in addition to evaluating existing time of use, residential, commercial, and interruptible load tariffs.

The optimal power supply portfolio as outlined in section A.2.5, Scenario #2, positions Stowe to fulfill its goals of compliance and risk coverage to help provide reliable, reasonably priced energy to its customers. Stowe's position for choosing Scenario #2 has to do with the economic and environmental performance of the balance this option provides and the feasibility of obtaining the scenario. The resource extensions are modeled at current potential rates that are transactable in the market. The most competitive portfolios strike a balance with resources that improve the environmental performance towards Vermont's RES and take advantage of the current market environment, which provide lower costs over time and across various market environments.

I.7.3 Metrics & Ratios

In addition to the five-year capital plan and five-year operating projection (Appendix L), the American Public Power Association (APPA) recommends these high-level financial metrics to provide a snapshot of financial health of public power utilities. These metrics are calculated from areas of the balance sheet and operating income to help show the health of the utility.

Metric	Ratio
Current	1.82
Quick	2.28
Days Cash on Hand	164
Capitalization	39%
Debt Service Coverage	1.53
Moody's Issuer Level Rating	Aa3

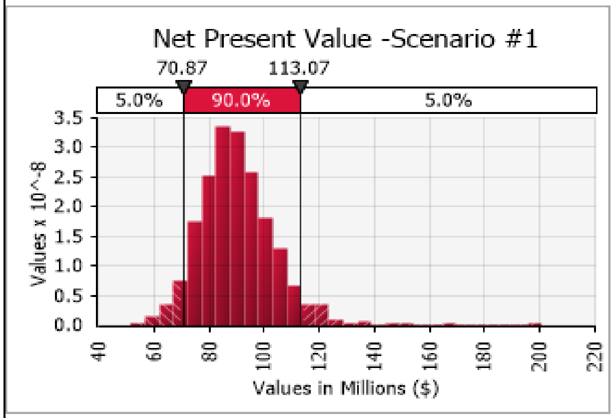
I.8 Ongoing Maintenance and Evaluation

Pursuant to 30 V.S.A. §218c,2 each regulated electric, or gas company is required to prepare and implement a least-cost integrated plan, Stowe will update their IRP requirement on a scheduled basis per regulatory requirement and make any necessary adjustments. The implementation of the plan will include an annual review of factors that could initiate an adjustment, such as major shifts in the New England supply stack, new generation and carbon capture technology, fundamental changes to the natural gas market, and regulatory changes, including ISO New England market design.

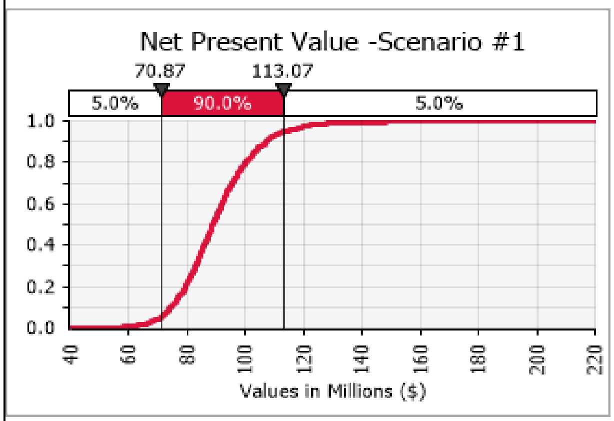
A Appendix A

Net Present Value -Scenario #1 - 'Annual Summary'!B26

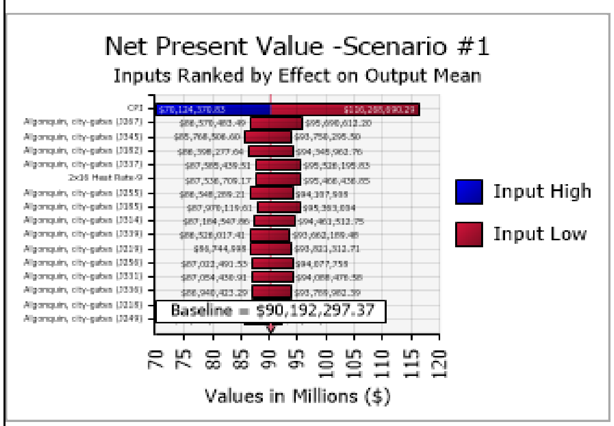
Report: Compact Output Report
Performed By: mcoscia
Date: Thursday, August 31, 2023



Summary Statistics	
Statistic	Value
Minimum	$ 51,686,634.69
Maximum	$ 200,645,465.75
Mean	$ 90,192,297.37
Std. Deviation	$ 14,042,237.79
Variance	1.972E+014
Skewness	1.2280
Kurtosis	8.5204
Median	$ 88,751,941.90
Mode	$ 83,613,834.45
Left X	$ 70,874,279.37
Left P	5%
Right X	$ 113,073,644.21
Right P	95%



Percentiles	
Percentile	Value
1%	$ 62,279,826.42
2.5%	$ 66,706,027.30
5%	$ 70,874,279.37
10%	$ 74,383,387.70
20%	$ 79,320,433.34
25%	$ 81,068,931.53
50%	$ 88,751,941.90
75%	$ 97,504,922.48
80%	$ 100,083,144.39
90%	$ 107,025,315.29
95%	$ 113,073,644.21
97.5%	$ 119,867,977.85
99%	$ 131,557,192.14

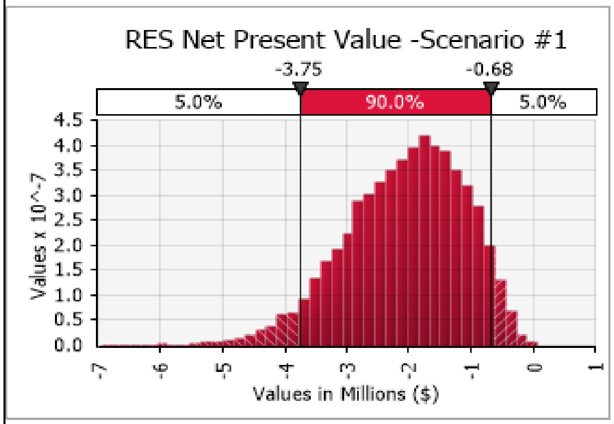


Change in Output			
Rank	Name	Lower	Upper
1	CPI	$ 70,124,370.83	$ 116,268,690
2	Algonquin, city-gates (	$ 86,570,483.49	$ 95,690,612
3	Algonquin, city-gates (	$ 85,768,506.60	$ 93,750,295
4	Algonquin, city-gates (	$ 86,398,277.64	$ 94,345,963
5	Algonquin, city-gates (	$ 87,585,439.51	$ 95,526,196
6	2x16 Heat Rate-9	$ 87,536,709.17	$ 95,466,437
7	Algonquin, city-gates (	$ 86,548,289.21	$ 94,107,908
8	Algonquin, city-gates (	$ 87,970,119.61	$ 95,363,004
9	Algonquin, city-gates (	$ 87,184,547.86	$ 94,461,513
10	Algonquin, city-gates (	$ 86,526,017.41	$ 93,662,189
11	Algonquin, city-gates (	$ 86,744,998	$ 93,821,313
12	Algonquin, city-gates (	$ 87,022,491.53	$ 94,077,758
13	Algonquin, city-gates (	$ 87,054,430.91	$ 94,088,477

B Appendix B

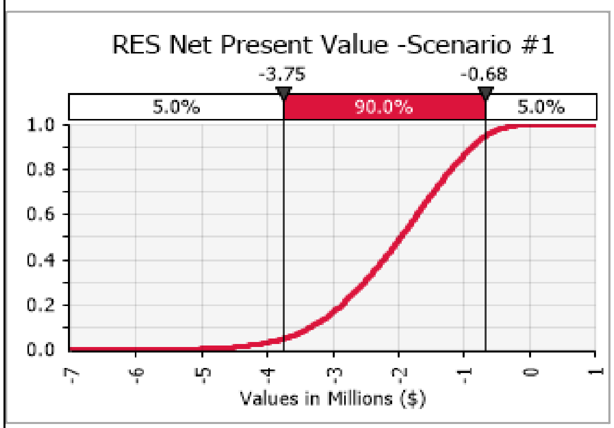
RES Net Present Value -Scenario #1 - Stowe!B127

Report: Compact Output Report
Performed By: mcoscia
Date: Wednesday, September 13, 2023



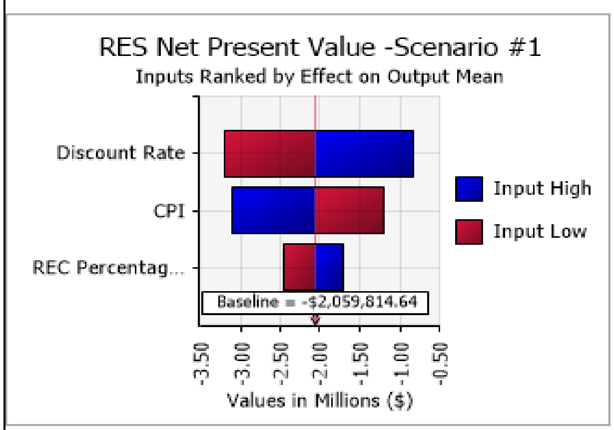
Summary Statistics

Statistic	Value
Minimum	-$ 6,933,888.83
Maximum	$ 85,253.56
Mean	-$ 2,059,814.64
Std. Deviation	$ 957,158.90
Variance	9.162E+011
Skewness	-0.5506
Kurtosis	3.2180
Median	-$ 1,969,151.68
Mode	-$ 1,324,972.16
Left X	-$ 3,747,113.37
Left P	5%
Right X	-$ 678,098.92
Right P	95%



Percentiles

Percentile	Value
1%	-$ 4,616,665.50
2.5%	-$ 4,125,703.87
5%	-$ 3,747,113.37
10%	-$ 3,346,168.58
20%	-$ 2,857,937.25
25%	-$ 2,689,796.04
50%	-$ 1,969,151.68
75%	-$ 1,335,052.69
80%	-$ 1,205,555.77
90%	-$ 882,827.02
95%	-$ 678,098.92
97.5%	-$ 518,635.77
99%	-$ 349,383.73



Change in Output

Rank	Name	Lower	Upper
1	Discount Rate	-$ 3,197,429.06	-$ 824,062.34
2	CPI	-$ 3,096,542.70	-$ 1,195,371.06
3	REC Percentage / Cal 2	-$ 2,445,644.29	-$ 1,701,971.02

C Appendix C

STANDARD OFFER PROJECTS OPERATING

Plant Name	Technology	Est. Annual Output MWH
Audet's Cow Power	Farm Methane	4,557
Berkshire Cow Power	Farm Methane	4,021
Chaput Family Farms	Farm Methane	2,010
Dubois Energy	Farm Methane	3,016
Four Hills Farms	Farm Methane	3,016
Gervais Digester	Farm Methane	1,340
Gervais Digester 2	Farm Methane	1,340
Green Mountain Dairy	Farm Methane	4,021
Kanes Cow Power	Farm Methane	1,508
Maplehurst Farms	Farm Methane	1,005
Neighborhood Energy	Farm Methane	1,508
Rail City Cow Power	Farm Methane	2,010
Westminster Energy	Farm Methane	3,016
Highgate Digester	Farm Methane	295
Greenwich Wind	Small Wind	50
Advance Transit	Solar	41
Barton Solar Farm	Solar	2,401
Battle Creek 1 Solar	Solar	2,794
Bobbin Mill	Solar	64
Northshire	Solar	20
Otter Valley Solar	Solar	2,769
Pownal Park Solar	Solar	2,794
Salvage Yard Solar	Solar	2,667
Sand Hill Solar	Solar	2,794
Sheldon Springs Solar	Solar	2,794
South Burlington Solar	Solar	2,802
Southern VT Energy Park	Solar	2,540
Springfield Solar Alliance	Solar	1,270
St. Albans Solar Farm	Solar	2,540
Sudbury Solar	Solar	2,540
SunGen1 Solar	Solar	2,667
Technology Drive Solar	Solar	2,540
Trombley Hill Solar	Solar	1,086
Wallingford Solar	Solar	2,794
Whitcomb Farm	Solar	2,794
White River Junction	Solar	2,751
Williamstown	Solar	2,540
Ball Mountain Hydro	Hydroelectric	8,653
Factory Falls	Hydroelectric	590
North Hartland	Hydroelectric	543
Bridport West Solar Farm	Solar	2,540
Butternut Farm Solar	Solar	131
Center Road Solar	Solar	2,667
Champlain Valley Solar Farm	Solar	2,540
Charlotte Solar	Solar	2,540
Chester Solar	Solar	2,540
Claire Solar	Solar	2,794
Clarendon Solar	Solar	2,540
Clarke Solar Center, LLC	Solar	1,016
Coventry Solar	Solar	2,794
Cross Pollination One	Solar	2,540
Ferrisburgh Solar Farm	Solar	1,330
Golden Solar	Solar	2,794
IRA Rentals Solar	Solar	47
Kingsbury Solar	Solar	61
Leunig's Building	Solar	33
Limerick Solar	Solar	2,751
Lyndonville Solar West (1)	Solar	610
Lyndonville Solar East (2)	Solar	629
MacKinnon Solar	Solar	2,794
Martinbrook Solar	Solar	1,905
Next Generation Solar Farm	Solar	2,794
Townshend Hydro	Hydroelectric	3,776
Troy Hydro Plant	Hydroelectric	3,210
West Charleston	Hydroelectric	2,655
Cersosimo Lumber Biomass	Biomass	6,441
Total Estimated Annual Output		146,982

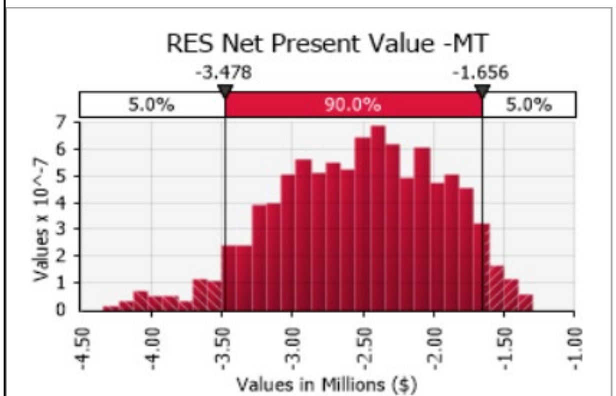
Updated 10/31/22

D Appendix D

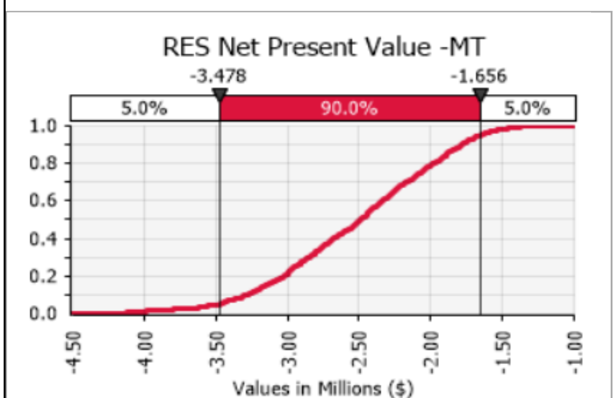
RES Analysis Base Case for the Mountain

RES Net Present Value -MT - MT!B127

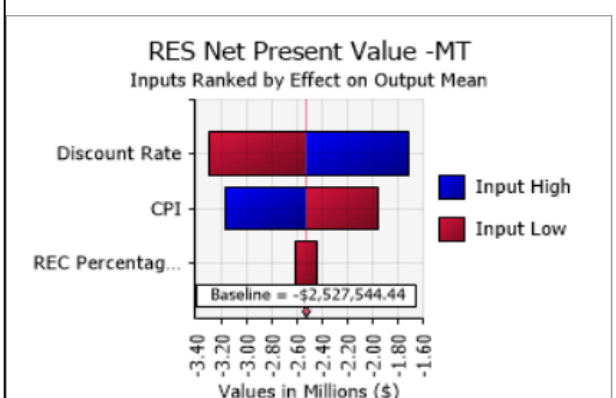
Report: Compact Output Report
Performed By: mcoscia
Date: Monday, October 2, 2023



Summary Statistics	
Statistic	Value
Minimum	-$ 4,342,235.00
Maximum	-$ 1,290,939.25
Mean	-$ 2,527,544.44
Std. Deviation	$ 578,974.56
Variance	3.352E+011
Skewness	-0.3045
Kurtosis	2.6488
Median	-$ 2,487,882.19
Mode	-$ 2,756,939.27
Left X	-$ 3,477,514.28
Left P	5%
Right X	-$ 1,655,874.37
Right P	95%



Percentiles	
Percentile	Value
1%	-$ 4,035,718.56
2.5%	-$ 3,702,641.67
5%	-$ 3,477,514.28
10%	-$ 3,279,278.01
20%	-$ 3,022,462.08
25%	-$ 2,948,315.57
50%	-$ 2,487,882.19
75%	-$ 2,069,568.56
80%	-$ 1,981,168.90
90%	-$ 1,785,896.14
95%	-$ 1,655,874.37
97.5%	-$ 1,555,379.23
99%	-$ 1,424,845.72



Change in Output			
Rank	Name	Lower	Upper
1	Discount Rate	-$ 3,295,557.96	-$ 1,711,852.87
2	CPI	-$ 3,176,680.21	-$ 1,953,900.20
3	REC Percentage / Cal 201	-$ 2,613,289.66	-$ 2,440,869.49

E Appendix E

Renewable Energy Standard Oder 8550

Tiers I & II

1. **Use of GIS.** Pursuant to 30 V.S.A. § 8006(a), the Board adopts the Generation Information System operated by the New England Power Pool ("GIS") as its principal mechanism for the tracking and monitoring of renewable energy credits ("RECs") qualifying for the Renewable Energy Standard program ("RES").

(a) Distribution utilities ("DUs") shall demonstrate their compliance with Tiers I and II of the RES through ownership and retirement of renewable energy credits ("RECs") in the GIS.

(b) Should a DU wish to demonstrate its compliance with the RES by means of environmental attributes that are not monitored on the GIS, the DU shall submit with its annual RES compliance filing documentation demonstrating that it owns the attributes in question, that the attributes are eligible for the RES, and that the attributes have not been claimed in any other jurisdiction.

(c) In the case of energy procured from Hydro-Quebec or the New York Power Authority ("NYPA"), DUs may demonstrate their compliance with the RES through the mechanism described in 1(b), above. However, in this instance, DUs shall also demonstrate their ownership of the attributes associated with energy from Hydro-Quebec or NYPA through ownership and retirement of those attributes as they are tracked within GIS, even if the DU claims a different value for the environmental attributes than that displayed in the GIS.

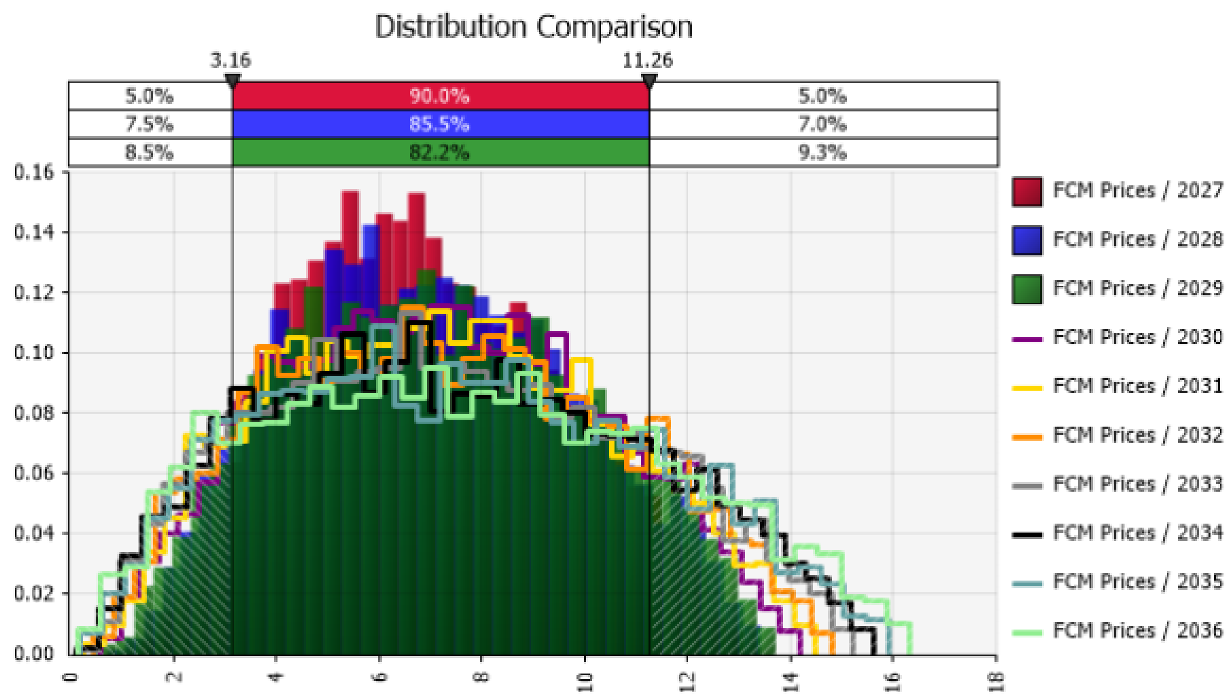
F Appendix F

Capacity Simulation Statistics of Outputs

Summary Statistics for Outputs

Statistic	FCM Prices / 2027	FCM Prices / 2028	FCM Prices / 2029	FCM Prices / 2030	FCM Prices / 2031	FCM Prices / 2032	FCM Prices / 2033	FCM Prices / 2034	FCM Prices / 2035
Minimum	1.374	0.724	0.520	0.598	0.247	0.454	0.124	0.117	0.171
Maximum	13.085	13.431	13.717	14.172	14.481	14.821	15.214	15.599	15.916
Mean	6.923	7.036	7.101	7.176	7.206	7.279	7.382	7.473	7.525
Std. Deviation	2.479	2.704	2.878	3.010	3.130	3.259	3.426	3.533	3.607
Variance	6.146	7.311	8.284	9.060	9.795	10.62	11.74	12.48	13.01
Skewness	0.2263	0.1429	0.1148	0.0947	0.1267	0.1260	0.1388	0.1612	0.1750
Kurtosis	2.2676	2.2229	2.1623	2.1638	2.1688	2.1234	2.1171	2.1151	2.1319
Median	6.724	6.939	6.972	7.093	7.138	7.148	7.212	7.294	7.385
Mode	5.506	5.819	7.645	7.217	6.218	8.814	6.596	6.763	7.347
1%	2.280	1.869	1.582	1.392	1.371	1.253	1.123	1.068	1.014
2.5%	2.706	2.334	2.112	1.892	1.825	1.710	1.570	1.510	1.490
5%	3.163	2.776	2.576	2.422	2.330	2.161	2.059	2.071	2.033
10%	3.788	3.507	3.367	3.191	3.033	2.975	2.791	2.828	2.796
20%	4.611	4.470	4.371	4.288	4.205	4.098	4.100	4.068	4.013
25%	4.990	4.973	4.786	4.802	4.686	4.656	4.686	4.666	4.585
50%	6.724	6.939	6.972	7.093	7.138	7.148	7.212	7.294	7.385
75%	8.768	9.057	9.291	9.456	9.596	9.781	9.988	10.179	10.286
80%	9.238	9.539	9.848	9.984	10.109	10.400	10.687	10.886	10.967
90%	10.446	10.787	11.119	11.399	11.586	11.797	12.176	12.468	12.651
95%	11.261	11.755	11.945	12.210	12.507	12.792	13.204	13.479	13.601
97.5%	11.844	12.243	12.514	12.804	13.209	13.418	13.817	14.184	14.422
99%	12.313	12.692	12.974	13.342	13.702	13.968	14.458	14.774	15.059

Statistic	FCM Prices / 2036	FCM Prices / 2037	FCM Prices / 2038	FCM Prices / 2039	FCM Prices / 2040	FCM Prices / 2041	FCM Prices / 2042	FCM Prices / 2043	FCM Prices / 2044
Minimum	0.154	0.0701	0.245	0.107	0.0548	0.109	0.0966	0.179	0.131
Maximum	16.329	16.754	17.246	17.638	18.075	18.588	19.013	19.284	19.956
Mean	7.644	7.778	7.895	7.934	8.130	8.220	8.391	8.552	8.707
Std. Deviation	3.766	3.874	3.950	4.110	4.290	4.368	4.456	4.600	4.727
Variance	14.18	15.01	15.60	16.89	18.40	19.08	19.86	21.16	22.34
Skewness	0.1673	0.1900	0.1685	0.2293	0.2076	0.2427	0.2388	0.2307	0.2411
Kurtosis	2.1221	2.1003	2.1469	2.1321	2.0952	2.1186	2.1283	2.1152	2.1237
Median	7.462	7.564	7.699	7.641	7.836	7.906	8.048	8.219	8.325
Mode	2.593	5.858	8.122	5.246	4.527	5.249	3.591	5.290	6.728
1%	0.898	0.907	0.858	0.838	0.673	0.735	0.741	0.790	0.638
2.5%	1.362	1.379	1.290	1.197	1.160	1.158	1.165	1.150	1.054
5%	1.889	1.919	1.787	1.702	1.664	1.706	1.741	1.649	1.602
10%	2.635	2.703	2.659	2.621	2.519	2.540	2.600	2.592	2.570
20%	3.973	4.065	4.069	3.970	3.961	4.023	4.010	4.023	4.110
25%	4.596	4.618	4.744	4.609	4.579	4.669	4.714	4.746	4.847
50%	7.462	7.564	7.699	7.641	7.836	7.906	8.048	8.219	8.325
75%	10.552	10.784	10.853	11.040	11.485	11.544	11.816	12.080	12.266
80%	11.225	11.517	11.622	11.880	12.330	12.447	12.626	12.933	13.216
90%	12.905	13.264	13.482	13.748	14.218	14.567	14.710	15.033	15.444
95%	14.118	14.390	14.627	15.044	15.542	15.730	16.215	16.544	16.972
97.5%	14.813	15.143	15.496	15.892	16.405	16.697	17.158	17.508	17.856
99%	15.513	15.863	16.211	16.706	17.039	17.411	17.743	18.276	18.645



G Appendix G

TECHNOLOGY- SPECIFIC PRICE CAPS

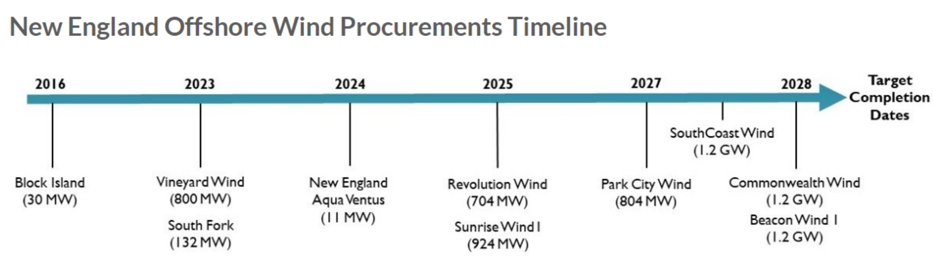
The following will serve as price caps for the 2022 RFP:

- Biomass – \$0.125 per kWh (fixed over 20 years)
- Landfill Gas – \$0.090 per kWh (fixed over 15 years)
- Wind > 100 kW – \$0.116 per kWh (fixed for 20 years)
- Wind ≤ 100 kW – \$0.258 per kWh (fixed for 20 years)
- New Hydroelectric – \$0.130 per kWh (fixed for 20 years)
- Food Waste Anaerobic Digestion – \$0.208 per kWh (fixed for 20 years)
- Solar – \$0.0982 per kWh (fixed for 25 years)

H Appendix H[54]

After a delay, the Vineyard Wind project has finally begun construction within the summer of 2023. The project is the start of the seven-year delay of continuing off-shore wind projects. The current economic landscape has impacted all the offshore wind projects. With supply chain issues, as well as production costs increasing with inflation, project costs have increased substantially from the original expected contract prices.

Originally RFPs had the potential of rates of the around $77/MWH, and since COVID Orsted (offshore wind developer) has stated the impairments amount to about half of the $4 billion, that Orsted said it had invested in its offshore portfolio in the United States. If projects costs are increased $2B or 20% a $77/MWH contract is at least $88/MWH and include RECs and estimated $96/MWH is a reasonable rate to use within the IRP modeling.



[55]

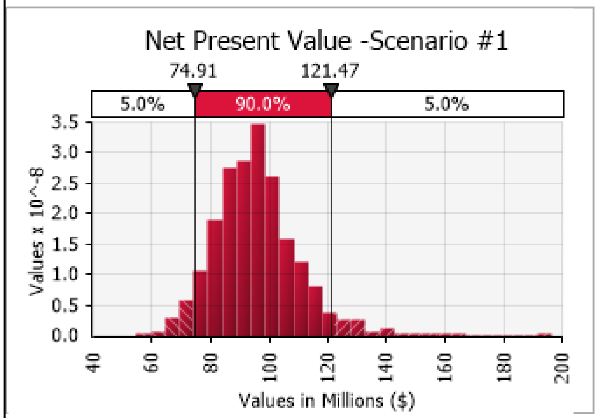
[54] https://www.windpowermonthly.com/article/1673776/mayflower-lowers-us-offshore-58-mwh

[55] New England for Offshore Wind | Overview

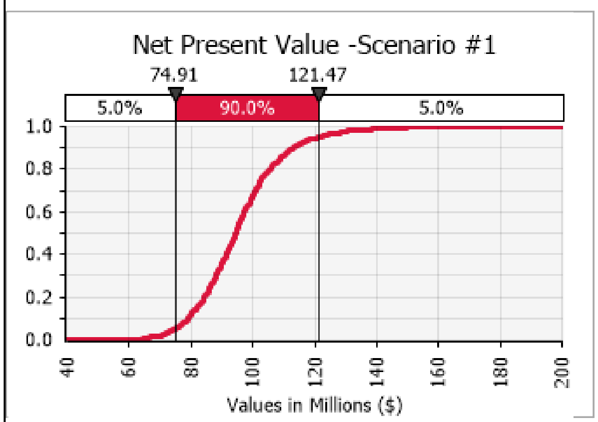
I Appendix I

Net Present Value -Scenario #2 - 'Annual Summary'!B26

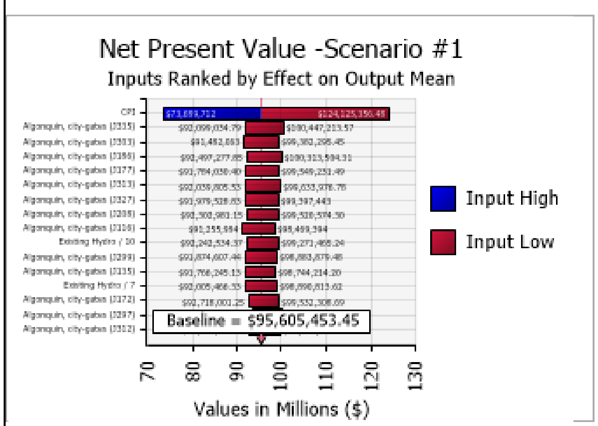
Report: Compact Output Report
Performed By: mcoscia
Date: Wednesday, September 20, 2023



Summary Statistics	
Statistic	Value
Minimum	$ 54,609,693.40
Maximum	$ 196,376,761.31
Mean	$ 95,605,453.45
Std. Deviation	$ 14,475,998.35
Variance	2.096E+014
Skewness	1.0001
Kurtosis	6.5806
Median	$ 94,553,116.37
Mode	$ 95,159,452
Left X	$ 74,908,679.11
Left P	5%
Right X	$ 121,474,659
Right P	95%



Percentiles	
Percentile	Value
1%	$ 65,996,555.55
2.5%	$ 71,596,584.15
5%	$ 74,908,679.11
10%	$ 79,119,808.72
20%	$ 84,138,023.77
25%	$ 86,201,922.71
50%	$ 94,553,116.37
75%	$ 102,717,393
80%	$ 105,461,380.25
90%	$ 113,185,093.49
95%	$ 121,474,659
97.5%	$ 128,523,302.27
99%	$ 140,355,568



Change in Output			
Rank	Name	Lower	Upper
1	CPI	$ 73,689,712	$ 124,125,356.48
2	Algonquin, city-gates (J33	$ 92,099,034.79	$ 100,447,213.57
3	Algonquin, city-gates (J30	$ 91,482,063	$ 99,382,295.45
4	Algonquin, city-gates (J18	$ 92,497,277.85	$ 100,313,504.31
5	Algonquin, city-gates (J17	$ 91,784,030.40	$ 99,549,231.49
6	Algonquin, city-gates (J31	$ 92,039,805.53	$ 99,633,976.78
7	Algonquin, city-gates (J32	$ 91,979,528.83	$ 99,397,443
8	Algonquin, city-gates (J20	$ 92,302,981.15	$ 99,520,574.30
9	Algonquin, city-gates (J11	$ 91,255,984	$ 98,469,394
10	Existing Hydro / 10	$ 92,242,534.37	$ 99,271,465.24
11	Algonquin, city-gates (J29	$ 91,874,607.44	$ 98,883,879.48
12	Algonquin, city-gates (J13	$ 91,766,245.13	$ 98,744,214.20
13	Existing Hydro / 7	$ 92,005,466.33	$ 98,890,813.62

J Appendix J (ITRON, Inc)

Residential Use per Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.WtXHeat	0.689	0.072	9.552	0.00%
mStructRes.WtXCool	0.081	0.02	4.141	0.01%
mStructRes.WtXOther	1.11	0.026	43.114	0.00%
mBin.Mar	-57.777	9.012	-6.411	0.00%
mBin.Apr	-112.96	14.106	-8.008	0.00%
mBin.May	-108.123	14.848	-7.282	0.00%
mBin.Jun	-51.909	11.193	-4.638	0.00%
mBin.Sep	-54.52	10.47	-5.207	0.00%
mBin.Oct	-79.357	13.32	-5.958	0.00%
mBin.Nov	-84.981	9.537	-8.911	0.00%
mBin.Jan12	-192.056	24.261	-7.916	0.00%
mBin.Aug16	149.449	24.595	6.076	0.00%
mBin.Yr19Plus	48.699	9.66	5.041	0.00%
COVID_Shift.Res_Shift	2.992	1.521	1.967	5.15%
MA(1)	0.486	0.087	5.561	0.00%

Model Statistics	
Iterations	16
Adjusted Observations	135
Deg. of Freedom for Error	120
R-Squared	0.939
Adjusted R-Squared	0.932
AIC	6.711
BIC	7.033
Log-Likelihood	-629.53
Model Sum of Squares	1,364,014.88
Sum of Squared Errors	88,763.49
Mean Squared Error	73970.00%
Std. Error of Regression	27.2
Mean Abs. Dev. (MAD)	20.16
Mean Abs. % Err. (MAPE)	3.34%
Durbin-Watson Statistic	1.875

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-876.083	399.943	-2.191	3.00%
mBin.TrendVar	0.1	0.009	10.649	0.00%
AR(1)	0.864	0.043	20.075	0.00%

Model Statistics	
Iterations	8
Adjusted Observations	158
Deg. of Freedom for Error	155
R-Squared	0.975
Adjusted R-Squared	0.975
AIC	6.153
BIC	6.212
F-Statistic	3044.205
Prob (F-Statistic)	0
Log-Likelihood	-707.31
Model Sum of Squares	2,810,214.09
Sum of Squared Errors	71,543.00
Mean Squared Error	461.57
Std. Error of Regression	21.48
Mean Abs. Dev. (MAD)	15.44
Mean Abs. % Err. (MAPE)	0.46%
Durbin-Watson Statistic	2.577

Commercial Use per Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructSmlCI.WtXOther	4042.13	96.357	41.95	0.00%
mStructSmlCI.WtXHeat	6992.295	953.566	7.333	0.00%
mStructSmlCI.WtXCool	1709.83	174.072	9.823	0.00%
mBin.Apr	-354.648	78.54	-4.516	0.00%
mBin.May	-271.847	79.285	-3.429	0.08%
mBin.Aug16	905.171	217.629	4.159	0.01%
mBin.Nov12	-598.665	214.021	-2.797	0.60%
mBin.Nov19	-402.2	214.228	-1.877	6.28%
COVID_Shift.NRes_Shift	17.347	6.242	2.779	0.63%
mBin.Nov20Plus	289.26	189.592	1.526	12.97%
AR(1)	0.652	0.066	9.841	0.00%

Model Statistics	
Iterations	10
Adjusted Observations	134
Deg. of Freedom for Error	123
R-Squared	0.806
Adjusted R-Squared	0.79
AIC	11.177
BIC	11.415
Log-Likelihood	-927.98
Model Sum of Squares	33,695,593.97
Sum of Squared Errors	8,124,385.36
Mean Squared Error	66,051.91
Std. Error of Regression	257.01
Mean Abs. Dev. (MAD)	191.48
Mean Abs. % Err. (MAPE)	4.25%
Durbin-Watson Statistic	2.209

Commercial Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
COVID_Shift.NRes_Shift	-0.453	0.189	-2.396	1.81%
mBin.Jan18	-98.008	7.886	-12.427	0.00%
mBin.Nov19	94.7	8.083	11.715	0.00%
mBin.Dec19	84.03	9.03	9.306	0.00%
SmlCICust.LagDep(1)	0.169	0.055	3.089	0.25%
mEcon.ComCust_Var	627.85	43.612	14.396	0.00%
AR(1)	0.98	0.017	57.586	0.00%
MA(1)	-0.697	0.083	-8.428	0.00%

Model Statistics	
Iterations	23
Adjusted Observations	134
Deg. of Freedom for Error	126
R-Squared	0.93
Adjusted R-Squared	0.925
AIC	4.335
BIC	4.508
Log-Likelihood	-472.58
Model Sum of Squares	117,884.63
Sum of Squared Errors	9,075.82
Mean Squared Error	72.03
Std. Error of Regression	8.49
Mean Abs. Dev. (MAD)	6.31
Mean Abs. % Err. (MAPE)	0.80%
Durbin-Watson Statistic	1.992

Town Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	3.296	0.94	3.507	0.06%
mEndUse.Base	1.029	0.147	7.001	0.00%
mEndUse.PKHeatVar	2.029	0.184	11.027	0.00%
mEndUse.PKCoolVar	1.432	0.256	5.602	0.00%
mEndUse.Apr_Base	-0.189	0.037	-5.096	0.00%
mEndUse.May_Base	-0.14	0.032	-4.314	0.00%
mEndUse.Nov_Base	-0.084	0.031	-2.678	0.84%
mEndUse.Dec_Base	0.24	0.031	7.847	0.00%
mBin.Aug16	-1.085	0.71	-1.527	12.93%
mBin.Dec19	-1.965	0.644	-3.052	0.28%
mBin.Jan18	1.515	0.612	2.477	1.46%
mBin.Nov22	5.61	0.636	8.825	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	134
Deg. of Freedom for Error	122
R-Squared	0.878
Adjusted R-Squared	0.867
AIC	-0.917
BIC	-0.657
F-Statistic	79.636
Prob (F-Statistic)	0.00
Log-Likelihood	-116.73
Model Sum of Squares	32167.00%
Sum of Squared Errors	44.8
Mean Squared Error	0.37
Std. Error of Regression	0.61
Mean Abs. Dev. (MAD)	0.46
Mean Abs. % Err. (MAPE)	4.22%
Durbin-Watson Statistic	1.424

K Damage Prevention Plan

Damage Prevention Plan

Procedures for Compliance with the State of Vermont Requirements for Underground Utility Damage Prevention 30 V.S.A. Chapter 86 and Vermont Public Service Board Rule 3.800

Town of Stowe Electric Department

PO Box 190

435 Moscow Road

Stowe, VT 05672

December 2018

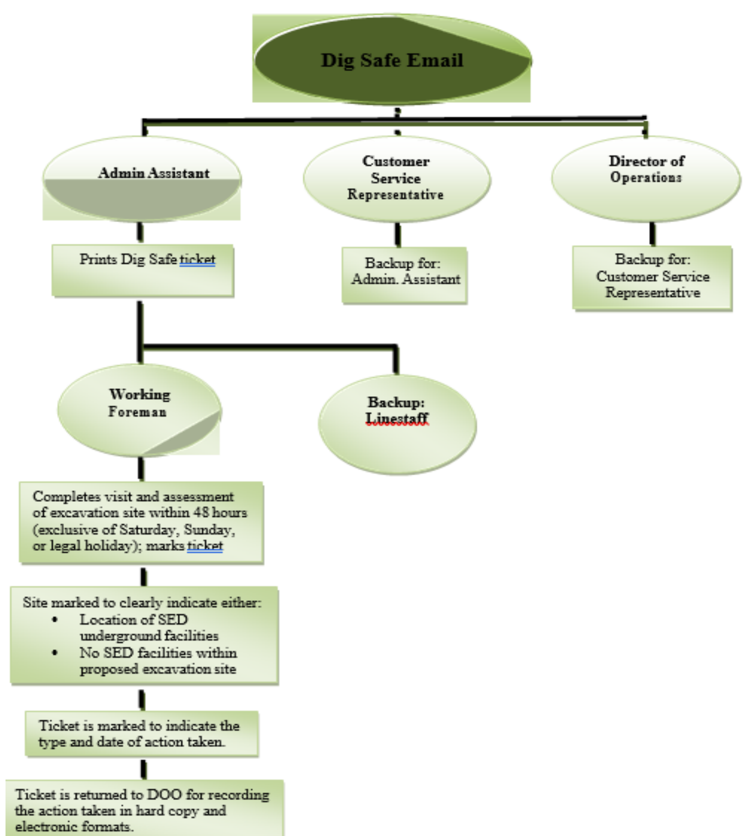
Scope and Purpose of this Document

This document outlines the general underground facility damage prevention procedures used by the Town of Stowe Electric Department (SED) within the State of Vermont. These guidelines help ensure compliance with PUC Rule (PUCR) 3.800 and 30 V.S.A. Chapter 86. The document focuses on the requirements to locate underground facilities upon notification to Dig Safe Systems, Inc. (Dig Safe), manage SED's own excavation efforts, and prevent damage to underground infrastructure with an elevated emphasis on Customer Service Restoration and System Integrity. This document will be utilized by SED supervisors and employees responsible for locating underground facilities, performing underground excavation and construction, and repair of SED's underground facilities. This document is to be reviewed annually and updated as necessary.

Procedures for Handling Requests from Dig Safe Systems, Inc.

Upon receiving notice of excavation activities in SED's service territory, Dig Safe will notify SED's Director of Operations (DOO), Billing Clerk, and Customer Service Representative. This notice is an email generated by Dig Safe to the named individuals and processed as shown in Diagram 1.

Diagram 1 – Notification of Dig Safe Email



Locating and Marking Underground Facilities

A. URD Mapping

Detailed maps of SED's Underground facilities (URDs) are maintained in a GIS mapping system at a secure offsite location and are accessible to authorized individuals only. The GIS mapping is updated by SED's Working Foreman annually or after any new construction of underground occurs.

B. Procedures for Locating and Marking the URD for Others

Once a Dig Safe request ticket is received notifying of excavation that may impact SED's facilities, the following steps are taken by the Working Foreman or other SED personnel trained to identify and perform locates to facilitate Dig Safe's request:

- The Working Foreman or their backup is given a Dig Safe request ticket and map page of the identified primary URD facility. Since secondary low voltage URDs are owned by the individuals they serve and are not part of SED's system, SED will only locate secondary facilities at the request of the customer and for an additional fee.

- Any nearby underground cable is located with an underground locater. A signal generator is used to inject a fixed frequency signal onto the cables to be located. The electronic locator is turned to the generated signal frequency and the area where the signal is strongest is marked with red flagging and/or red paint, depending upon the time of year and length of the cable run. Markings that need to be left in place for a long period of time or due to location may be marked with wooden stakes painted red and marked "SED" to ensure they are in place when needed by the excavator.

- If the proposed site of the excavation is not pre-marked with white paint, a telephone call should be placed to the contractor to determine why. An on-site meeting may be necessary to verify the location of the proposed excavation. In some cases where extensive excavation is proposed in proximity to SED's underground facilities, SED may generate a telephone call to the appropriate contractor warning him verbally of the potential hazard and request an on-site meeting. All verbal communications shall be followed up in writing.

- After SED staff visit the excavation site the DigSafe ticket is marked indicating what action was taken. It is then given to the DOO and recorded. In the case of a request by the customer to locate secondary service, the ticket is also delivered to SED's accountant for billing purposes. The DOO's records are maintained and submitted on an annual basis by SED's Financial Controller.

- If it is determined that there are no primary underground facilities at the excavation site, SED will mark the site as such. The ticket will also be marked to indicate that there were no SED facilities. These tickets will also be recorded according to the above procedure.

C. <u>Emergency Dig Safe Request</u>

When an Emergency Dig Safe request is received, either through a request form or a call into SED's after hours call center, the SED's scheduled on- call line staff will be the primary contact, followed by the DOO. The on call linestaff will follow the same marking and recording procedure outlined above.

D. <u>Pre-marking of Excavations by SED</u>

SED will pre-mark any of its own excavations by use of white paint, white stakes, or other appropriate means before it calls DigSafe for a Ticket for its work.

<u>SED'S Investigation Procedure for Damage to its Underground Facilities</u>

- When SED becomes aware of or is notified of damage to its underground facilities, the Working Foreman and the DOO shall be notified. After normal working hours, the on-call linestaff and the DOO will be notified and will coordinate with other SED personnel as needed.

- The first employee arriving at the scene of any suspected or reported damage shall assess the situation and contact the Working Foreman and DOO and provide all essential information including: actions required to restore service, if necessary, extent of damage to SED's system and names/contact information for any witnesses. If possible, pictures of the damage and surrounding site shall be taken. Prior to commencing restoration efforts, all necessary and required work area protection shall be established by the employee(s) at the site. If required, an emergency ticket from Dig Safe shall be generated.

- As part of the damage investigation the Working Foreman and DOO will attempt to validate whether 30 V.S.A. Chapter 86 procedures were followed prior to the damage occurring.

- The Working Foreman or DOO shall ultimately be responsible for assessing any suspected or reported damage to its facility. They will ensure that the appropriate documentation is completed.

<u>SED's Underground Facilities Damage Report (UFDR)</u>

- The Working Foreman or DOO shall be responsible for the investigation of the damaged underground facility and will collaborate to review the report to help ensure its accuracy before it is submitted to the State agencies. The DOO will send the UFDR to the Vermont Public Utility Commission (PUC) and the Department of Public Service (DPS), as required per PUCR 3.805(C). The preferred method of submitting the UFDR form is by using the online form at the DPS web site at http://publicservice.vermont.gov.

- The responsibilities of the Working Foreman or DOO will include, but are not limited to, the following:
  - Service restoration
  - Investigation of the incident including, but not limited to:
    - Photographing and/or video recording the damage and mark outs (paint, flags) and area landmarks
    - Verifying to the extent possible if all hand digging regulations, within the 18 inches of the marked location, were adhered to.
    - Initiation of required paperwork per PUCR 3.805(C).
- Per PUCR 3.807, upon receiving the UFDR, the DPS may open an investigation of the facility damage event. SED will be notified directly by the DPS of a Notice of Probable Violation (NOPV) detailing its responsibility in the damage event, or SED will receive a copy of the NOPV issued to the excavator indicating their level of responsibility.

- If the NOPV indicates SED is responsible, the Working Foreman or DOO shall review the NOPV and respond to the PUC and the DPS per PUCR 3.807(C).

- Pursuant to PUCR 3.807 (F), SED may request a Hearing if it does not concur with the DPS's findings or recommendations on the NOPV.

- In all events where the actions of an excavator caused subsequent damage to SED's facilities, SED may seek restitution from the excavator for the repairs.

- All damage to SED's underground infrastructure shall be billed to the responsible party if applicable.

Marking and Documenting New Underground Installations

- Upon completion of a new SED owned underground installation the location and details of the installation shall be entered into SED's GIS mapping system.

SED's Contact Information

- SED is responsible for updating Dig Safe, the DPS and the PUC with appropriate contact information (see Attachment A).

- Dig Safe shall issue all tickets directly to SED via its electronic notification system. The Billing Clerk, Customer Service Representative, and DOO shall be the recipients of the notification.

- The DPS or the PUC should address any questions regarding SED's Underground Damage Prevention Plan procedures to the DOO via the contact information in Attachment A.

- Questions regarding damage documentation or the UFDR should be addressed to the DOO, with a copy to the Working Forman via the contact information in Attachment A.

- All notices by the DPS and/or the PUC should be addressed to the DOO with a copy to the Working Forman via the contact information in Attachment A.

Attachment A – Stowe Electric Contact Information for DigSafe Matters

Director of Operations

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