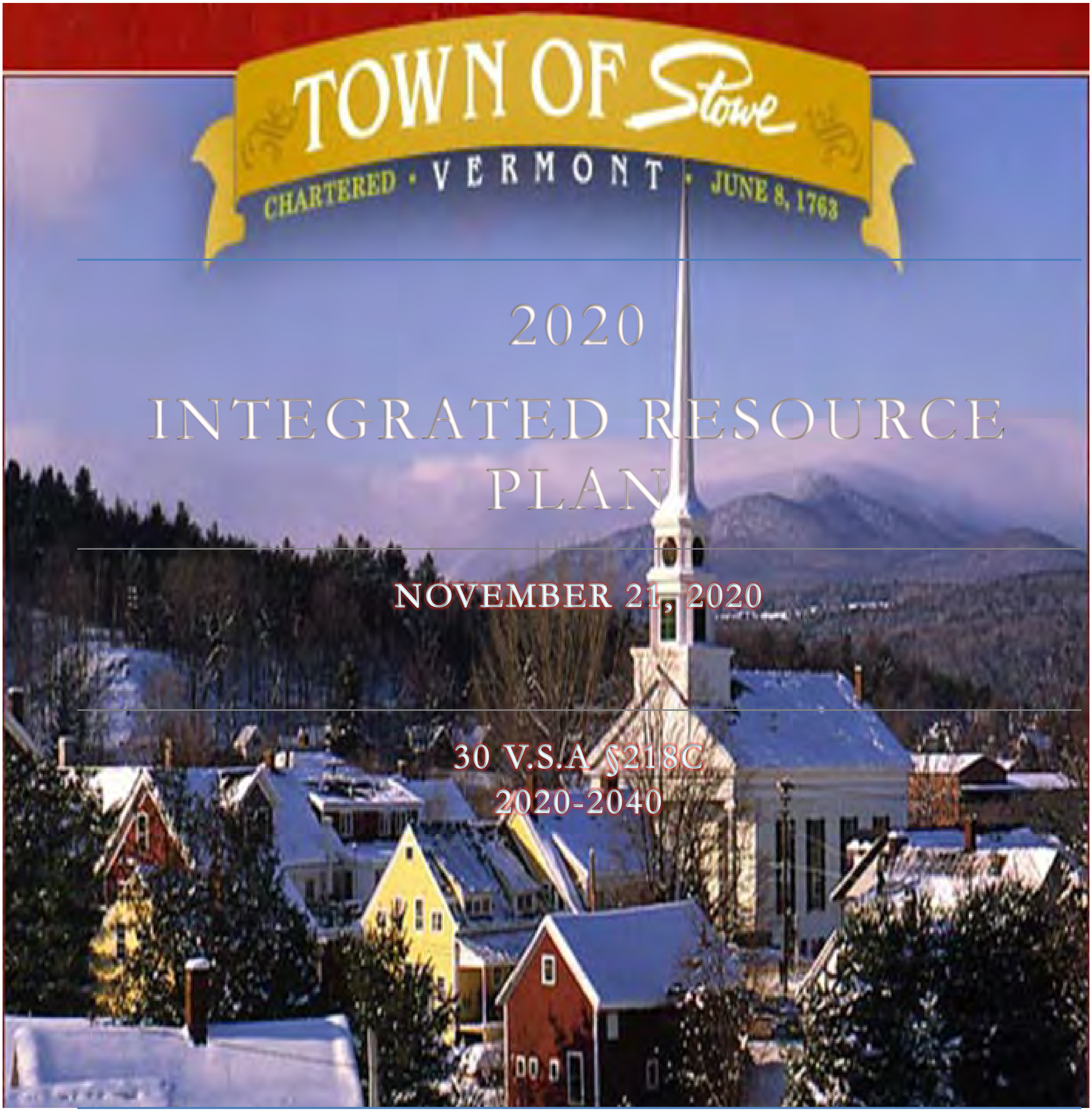

2020
INTEGRATED RESOURCE PLAN

NOVEMBER 21, 2020

30 V.S.A §218C
2020-2040

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) 2020 Optimal Integrated Resource Plan (IRP) is filed pursuant to Vermont Statute 30 V.S.A. § 202. Stowe, ITRON Inc., and Energy New England, LLC (ENE) prepared this IRP. Stowe filed its previous IRP in 2017 (revised filed July 6, 2018). Stowe consults with (ENE) for guidance on the ISO New England markets and structuring of short and long-term power contracts. ENE has offered Stowe opportunities to leverage existing power generation sources that are carbon-neutral and carbon-free, which helps Stowe decarbonize its distribution system. ITRON provides Stowe and ENE forecasting and modeling to inform Stowe's decision-making.

The New England wholesale energy market continues to evolve to meet the demands of customer electrification needs and updated decarbonization mandates. While, an evolving energy market brings challenges and opportunities to Stowe and its customers, it also creates uncertainty and volatility. Adding to these factors is the short-term and long-term impacts caused by the covid-19 pandemic and Governor's emergency orders. The intent of this IRP is for Stowe to account for these metrics and provide reliable, resilient, and least-cost service to our customers.

The IRP as 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. Stowe understands there will always be tradeoffs to consider when deciding on various issues concerning future projects and contracts.

This IRP considers several key influencers to 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. Currently, more than half of Stowe's portfolio is carbon free or carbon neutral and with the new Renewable Energy Standard (RES), 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 seek flexible pricing that will work to mitigate current commitment to substantially 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 will be priority for analysis, as they will enable Stowe to fill RES standards that began in 2017.

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. Forecasts and Scenarios provides Stowe's load forecasts and scenarios.

Section D. Assessment of Environmental Impact explains the significant environmental attributes of the resources in Stowe's portfolio.

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

Section F. Assessment of Resources explains a review of alternatives and comparison of those alternatives to the preferred portfolio.

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

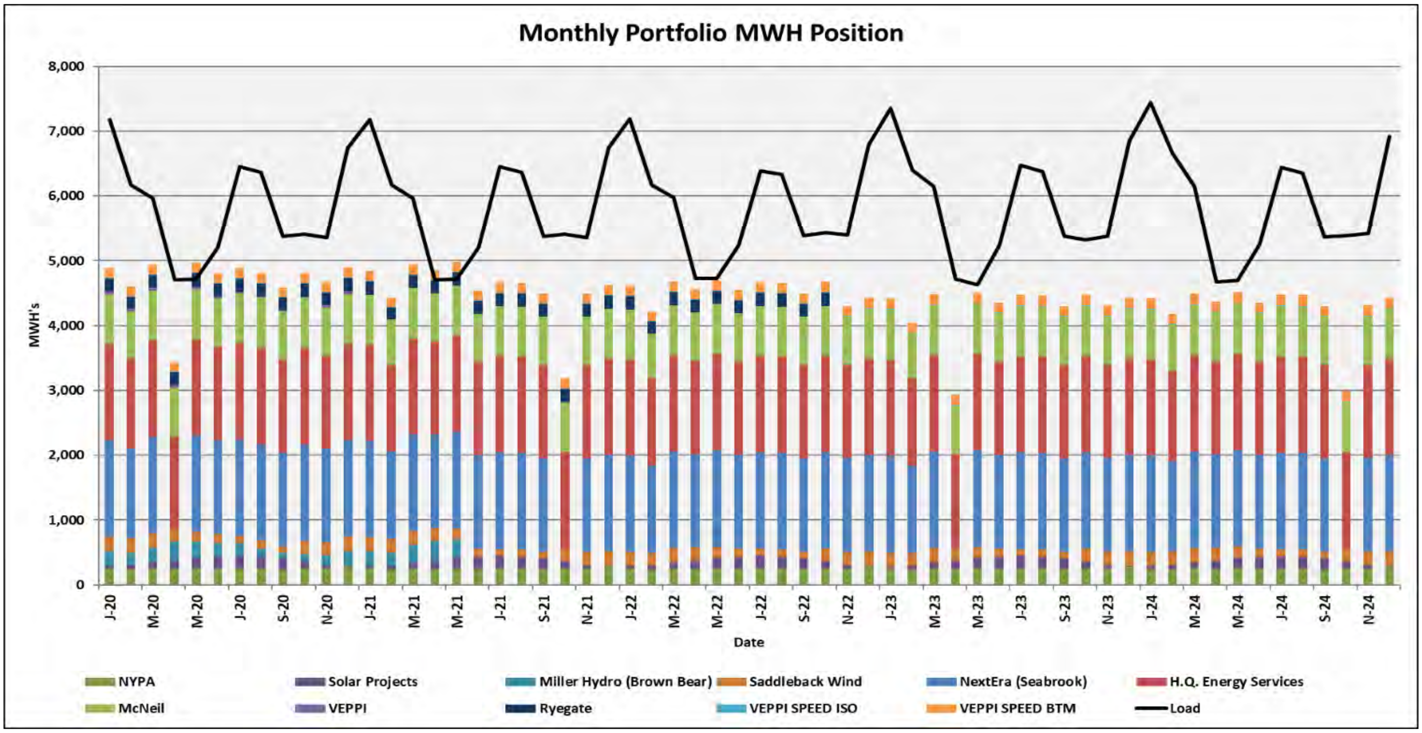
Section H. Assessment of the Transmission and Distribution System evaluates system improvement of efficiency and reliability for bulk transmission, grid modernization, underground damage prevention plan, and vegetation management.

Section I. Integrated Analysis and Plan of Action provides an assessment of demand, supply, finances, transmission, and distribution to find the least-cost portfolio and preferred plan of action.

A.2.1 Resources Requirements

Stowe has seen a change in sales numbers, with an 1.73% reduction in retail sales (Stowe Mountain not included) from 2016 to 2019. 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 Stowe'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

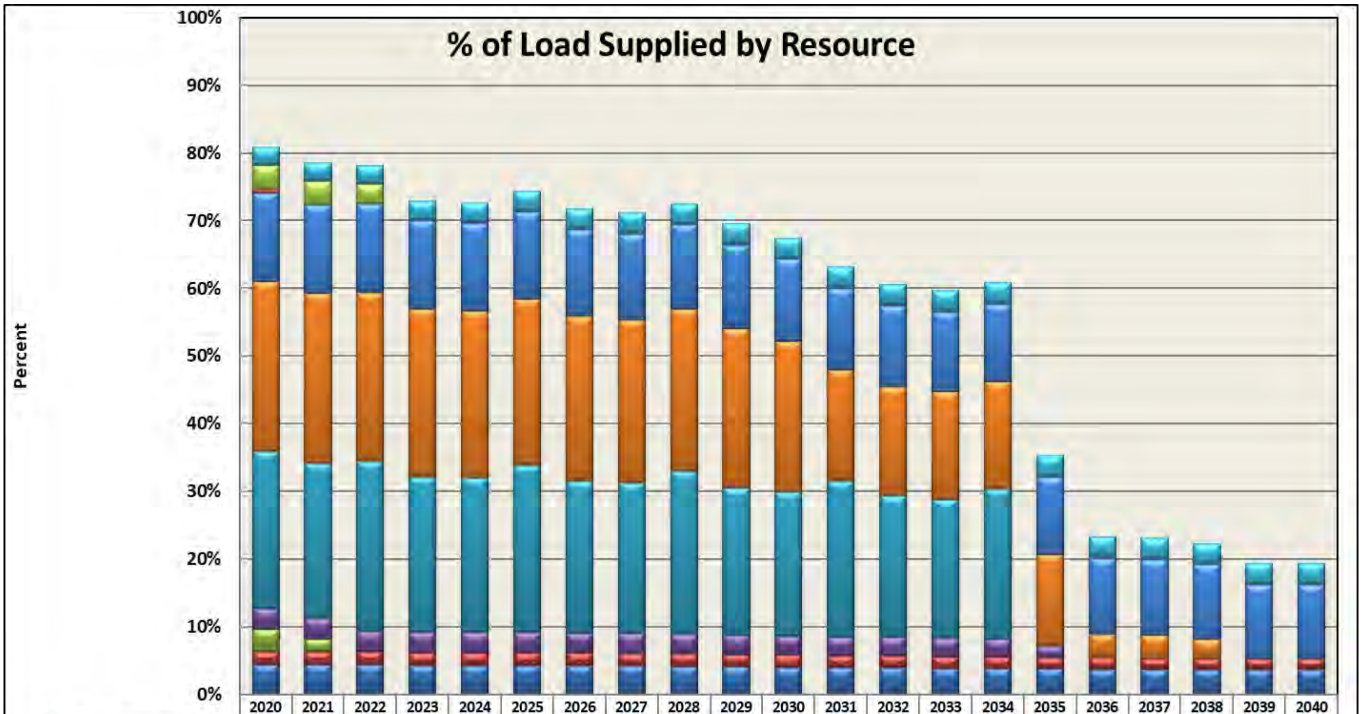


The "Base Case" load forecast (black line in Figure 1) has load maintaining steady. This includes adjustments for expected future energy efficiency improvements, impacts of solar, electric vehicles, and heat pump penetration. This forecast removes the variable mountain load, only because all mountain 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. 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 shows the base caseload applied and matches it to the forecasted output of Stowe's renewable resources. Stowe's generation portfolio is largely carbon neutral. The Seabrook offtake contract does not count towards RES compliance but is a carbon neutral energy source. When focusing on alternative resources, Stowe will continue to search out renewable generation and remain committed to bringing customers utility rates that are the least cost possible. As Stowe continues to meet the RES compliance through renewable and carbon-neutral generation, the Stowe portfolio will offset RES compliance costs.

Figure 2: Stowe's Resource Portfolio



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
VEPPI SPEED BTM	2.59%	2.64%	2.69%	2.72%	2.76%	2.80%	2.83%	2.87%	2.89%	2.91%	2.93%	2.95%	2.97%	2.98%	3.01%	3.03%	2.99%	2.96%	2.93%	2.92%	2.91%
VEPPI SPEED ISO	0.18%	0.19%	0.19%	0.19%	0.20%	0.20%	0.20%	0.20%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.22%	0.21%	0.21%	0.21%	0.21%	0.21%
Ryegate	3.40%	3.39%	2.82%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
VEPPI	0.55%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
McNeil	13.12%	13.08%	13.06%	12.96%	12.91%	12.84%	12.72%	12.62%	12.50%	12.31%	12.14%	11.98%	11.84%	11.67%	11.52%	11.37%	11.24%	11.11%	11.03%	10.96%	10.94%
H.Q. Energy Services	25.14%	25.07%	25.02%	24.85%	24.75%	24.61%	24.39%	24.20%	23.95%	23.59%	22.16%	16.40%	16.21%	15.97%	15.77%	13.55%	3.48%	3.44%	2.84%	0.00%	0.00%
NextEra (Seabrook)	23.16%	23.02%	25.11%	22.89%	22.73%	24.69%	22.46%	22.22%	24.03%	21.73%	21.37%	23.05%	20.91%	20.54%	22.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Saddleback Wind	3.06%	3.03%	3.03%	3.00%	3.00%	2.98%	2.95%	2.93%	2.90%	2.85%	2.81%	2.78%	2.75%	2.70%	2.67%	1.71%	0.00%	0.00%	0.00%	0.00%	0.00%
Miller Hydro (Brown Bear)	3.34%	1.85%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Solar Projects	1.93%	1.92%	1.92%	1.91%	1.90%	1.89%	1.87%	1.86%	1.84%	1.81%	1.79%	1.76%	1.74%	1.72%	1.70%	1.67%	1.65%	1.63%	1.62%	1.61%	1.61%
NYPA	4.37%	4.36%	4.35%	4.32%	4.30%	4.28%	4.24%	4.21%	4.16%	4.10%	4.04%	3.99%	3.95%	3.89%	3.84%	3.79%	3.74%	3.71%	3.68%	3.66%	3.65%

A.2.3 Resource Alternatives

Stowe will always seek resources for its portfolio that lower costs to its customers and are beneficial to State and Independent System Operator New England (ISO-NE) energy sector costs. With RES targets beginning in 2017, Stowe increased its 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 twelve scenarios using an optimization algorithm, which is explained in section I.2. ENE's simulation models can be found in section Data Models and Information tested 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 based on each scenario

A.2.4 Comparative Tradeoff Analysis and Risk

The ENE Portfolio Simulation Model used a couple of simulation-based models that estimate 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.

The RES was a large weight within each scenario model. The RES section of Stowe's energy portfolio has the largest risk if left unhedged.

The I.1 Evaluation of Portfolio Scenarios section describes the details of all nine scenarios. Table 1 below shows a few scenarios the IRP process analyzed.

Table 1: Comparative Portfolio

	Scenario	***NPV Total Cost***	***NPV Total RES***	***Std Dev***	***Hedged Target Average***
Least Cost	Scenario #8	$ 68,657,311	$ 1,276,167	$ 6,376,784	71%
High Cost	Scenario #1	$ 65,342,181	$ 8,257,049	$ 9,225,943	59%
Optimal Scenario	Scenario #3	$ 69,579,560	$ 937,217	$ 5,926,564	74%

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

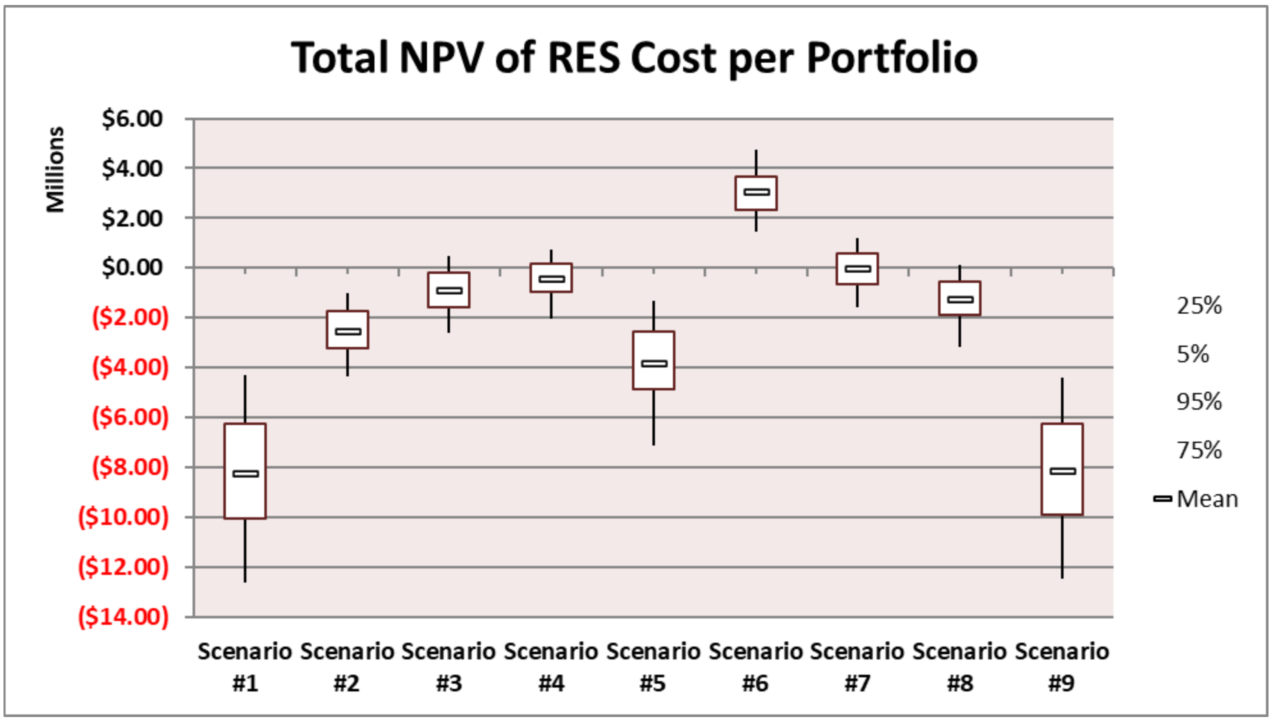
I. Scenario #8 = Current Portfolio, PPA for an existing Hydro 2.5% of load, HQ extension, 5 MW VT based solar project, and 100 kW Moscow Mills Hydroelectric Unit
II. Scenario #1 = Current Portfolio with no additional resource procurement. In the current market environment, this approach can be effective, but has the most risk to spot market exposure, as well as RES compliance costs. This scenario is the highest cost scenario.
III. Scenario #3 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, and 5 MW VT based solar project

The scenarios provide an analysis of net present value of each portfolio regards 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 cognizant of the fact that with more renewables, although helpful towards RES, there is a reliability risk and risk of higher prices to Stowe's energy cost. In this IRP, Stowe viewed benefits and risk of new and existing fuel sourced projects with respect to cost to each portfolio.

The following figure shows 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.

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

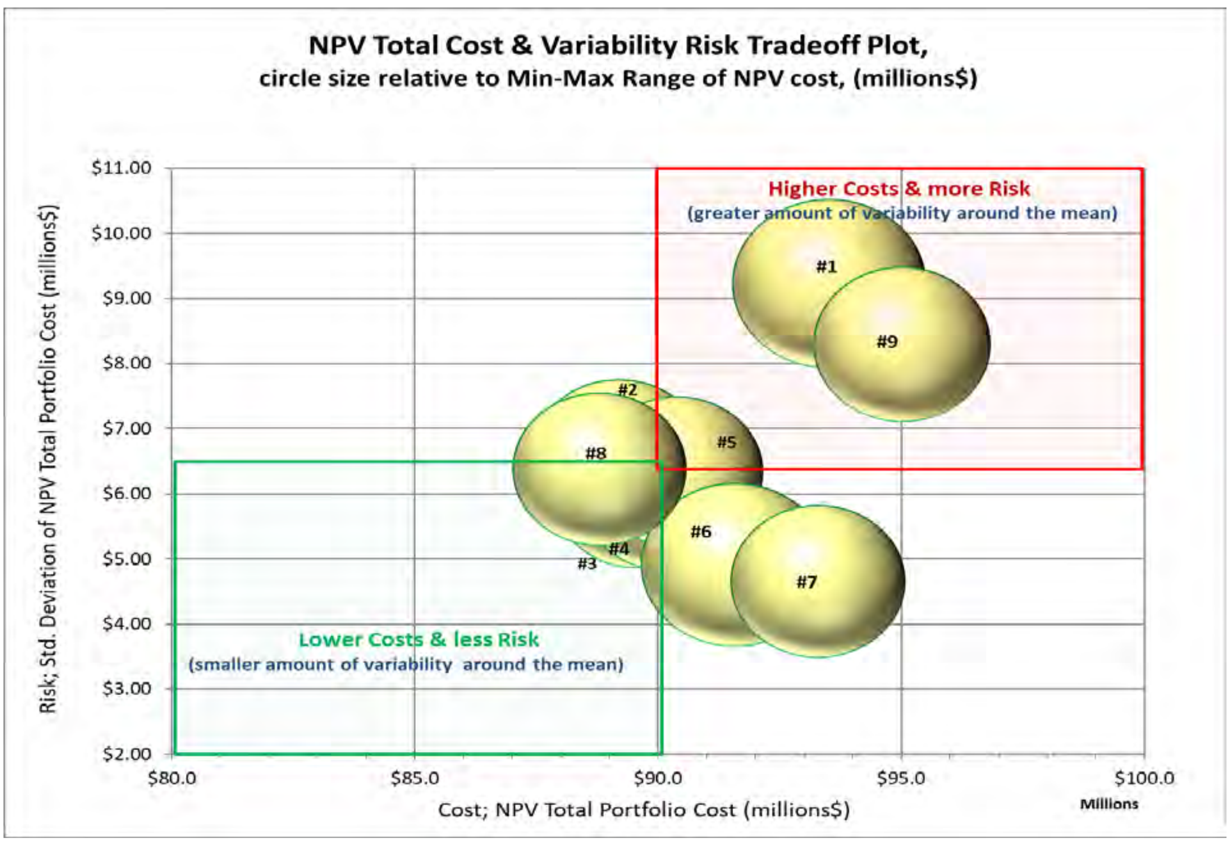


[1] "Box-and-Whisker" diagram, the white area, or the "box," represents the upper and lower quartiles (25th and 75th percentiles) of values, the black line is the 50th percentile of the data, and the thin black lines, or the "whiskers," represent the minimum and maximum values of the sample data.

Another method for comparative tradeoff analysis is to rank the portfolios by their standard deviations and then plot them in "risk/return"[2] 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" 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 show a portfolio's merit but displays the size of a portfolio's bubble according to its relative risk. Figure 4 shows the bubble plot comparison for least cost and risk.

Figure 4: Risk/Cost Tradeoff Bubble Plot



[2] "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".

A.2.5 Stowe's Target Resource Portfolio

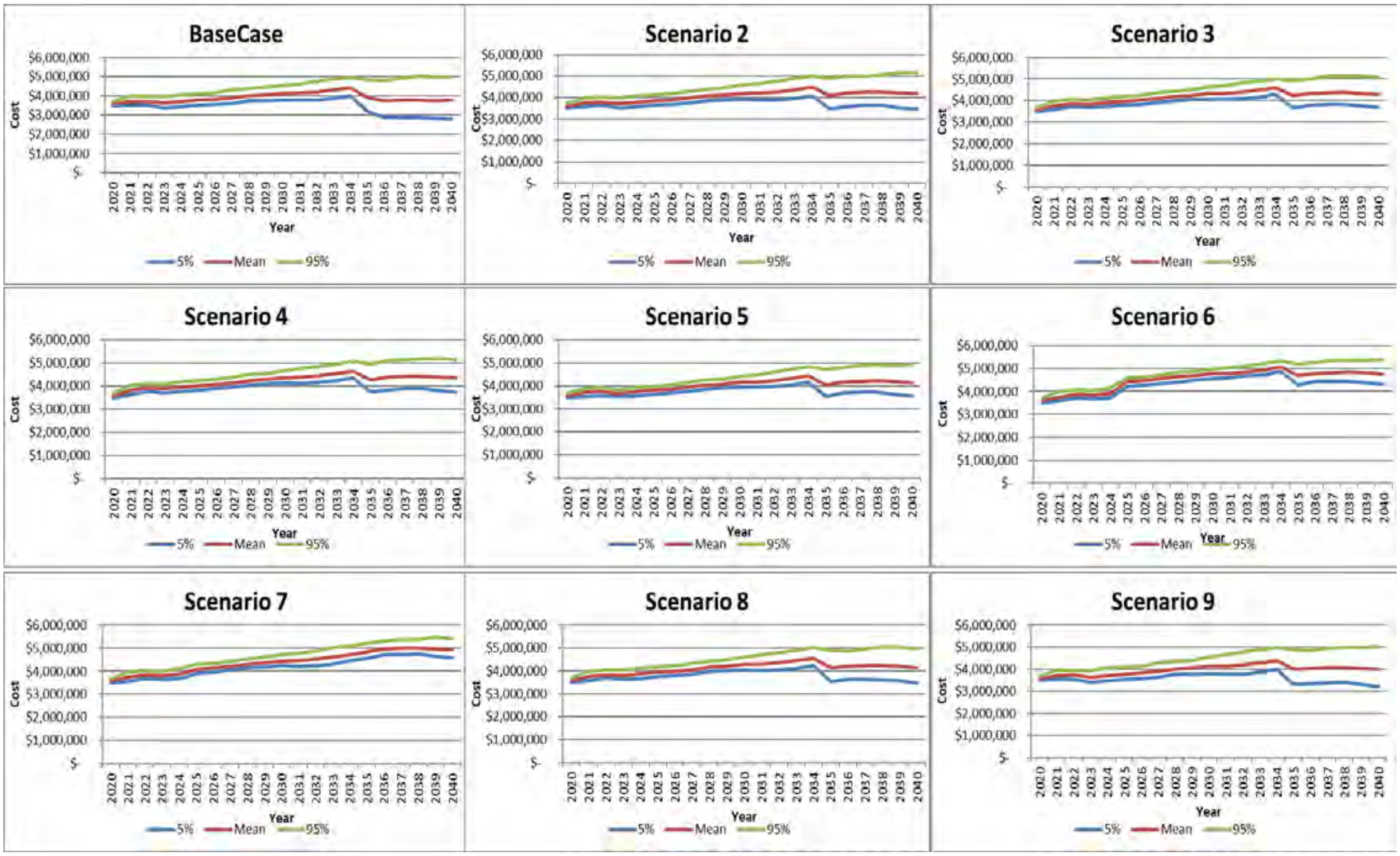
Based on the comparative analysis, the optimal portfolio is Scenario #3 for Stowe's IRP. Scenario 3 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, and 5 MW VT based solar project.

The caveat is that specific resource volumes will be 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 not, will have an impact on the volume and nature of new resources pursued.

Stowe's position for choosing Scenario 3 has to do with the economic and environmental performance of the balance this option provided and the feasibility of obtaining the scenario. Three of the six resources modeled are current contract extensions. Because HQ, Miller Hydro, and Saddleback Wind are current resources in Stowe's portfolio, they have an expected performance that allows for a more reliable estimation of output because Stowe has historical data.

The three new resources added into Scenario 3 are a new purchase power agreement for existing hydro for 2.5% of load, a purchase power agreement for a new a 5 MW solar project within the state of Vermont and a rebuild of what was the Moscow Mills hydro project. These resources are currently in the process of providing contract terms to Stowe. 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 5: 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. This is especially important in the near term because of the Corona Virus restrictions on people's lives
3. Continue market purchases as needed in a low commodity price environment over the next several years. This is especially relevant for the Stowe Mountain Snow Making contract, as well as exposure from unit outages
4. Continue to investigate adding in-state renewable resources
5. Continue to review renewable resource alternatives, including wind both on and offshore, and hydro both existing and new, 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 most 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 residents and businesses within the Town of Stowe. Over 4,000 year-around residential and commercial customers rely on Stowe to provide energy at affordable prices. The Town of Stowe also has a 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[3]

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 Country Project. This upgrade consisted of 10 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 a more efficient electrical usage by creating greater reliability to the system.

Stowe consistently looks to the future and investigates additional carbon reducing alternatives to build on the reductions already achieved, including installing utility owned and managed electric charging stations, commissioning a solar farm, and installing smart meters so customers can make informed decisions on energy usage. Stowe is committed to exploring all avenues, which will give the most reliable energy and service at the most affordable cost to its consumers.

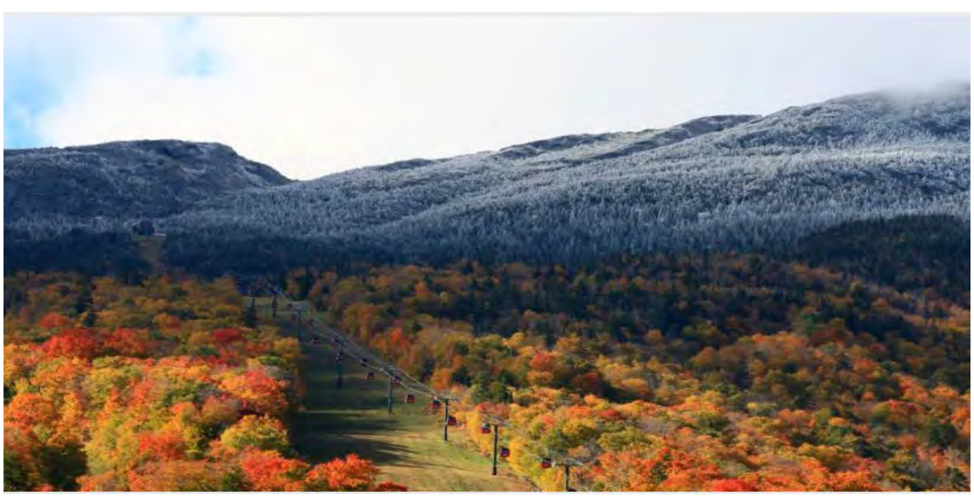
Stowe's Board of Electric Commissioners is engaged and involved within the community. Stowe's ratepayers are always first in mind and customer service, grid safety, and reliable electric service are foundational to Stowe's operation. Stowe supports environmentally viable and economical power from local sources and evaluates all contracts for purchased power from renewal sources that fall within its budget.

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

B.1.1 Overview of Town of Stowe

Agriculture and logging dominated the early economy of the Village of Stowe. Stowe had over 100 farms and a strong timber production economy. 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 establish itself as a recreational pastime capable of driving economic growth, and skiing remains an important 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 revenues derived from Stowe Mountain Resort.

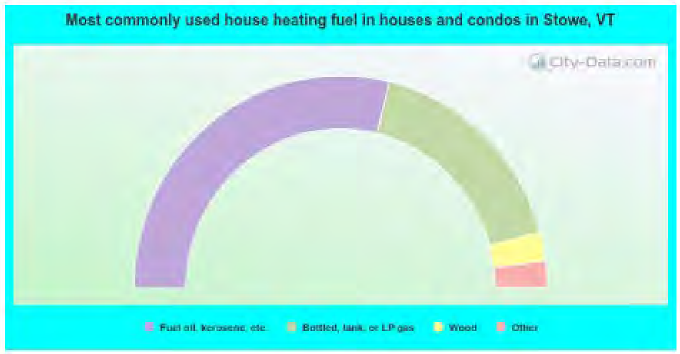
The Town of Stowe also capitalizes on the landscape's exceptional beauty and scenery, enabling an extensive year-round tourist economy. The annual transition from summer to fall brings a beautiful foliage spectrum that is a popular tourist attraction. With the COVID-19 pandemic still in effect in the U.S., the Town of Stowe is uncertain how the tourism will change and if Stowe will see a continued load loss as they did in the Spring and early Summer of 2020.



photos by Scott Braatten

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 housing and condominium heating source representation is found in Figure 6 below. These facts will become important when Stowe looks for ways to implement energy efficiency within the service territory for Tier III compliance.

Figure 6: Stowe's most used house-heating fuel[4]



Fuel oil, kerosene, etc.	57.6%
Bottled, tank, or LP gas	33.9%
Wood	4.5%
Electricity	3.0%
Utility gas	1.0%

VELCO's2008's capital improvement investment in the Lamoille county reliability project upgraded 10 miles of new 115kW lines and added a new 115/34.5 kV substation. This also helped Stowe increase dependability of electricity service to its customers; and, to plan future projects. This upgrade also benefited the Mt. Mansfield snow making usage, which also has a positive effect on the Town of Stowe and Stowe's customers.

B.1.2 Stowe Demographics

As of 2010[5], the population in Stowe, VT was 4,314, with the median residential age of 44.9 years. Within the occupied residential housing market, 72% owner occupied while 28% are renter occupied.[6] Condominiums comprise approximately 26% of the residential housing in Stowe.

[4] http://www.city-data.com/city/Stowe-Vermont.html
[5] http://www.city-data.com/city/Stowe-Vermont.html
[6] http://www.city-data.com/housing/houses-Stowe-Vermont.html

Stowe's main industry for jobs, for both male and female in 2015 was within the accommodation and food services industry as shown below in Figure 7, this is due to the heavy importance of tourism for the town. The second common industry is technical and educational services. Both sectors have been dramatically impacted by the COVID-19 pandemic and Stowe has remained engaged with both the commercial owners and the workers employed in these industries.

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

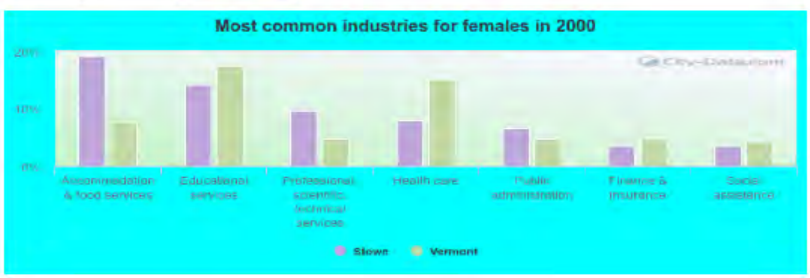
Most common industries in Stowe, VT (%)

Both | **Males** | Females

- Accommodation & food services (20.8%)
- Professional, scientific, technical services (11.2%)
- Educational services (5.8%)
- Finance & insurance (5.1%)
- Construction (5.0%)
- Sporting goods, camera, hobby & toy stores (4.0%)
- Public administration (3.4%)

Most common industries in Stowe, VT (%)

Both | Males | **Females**

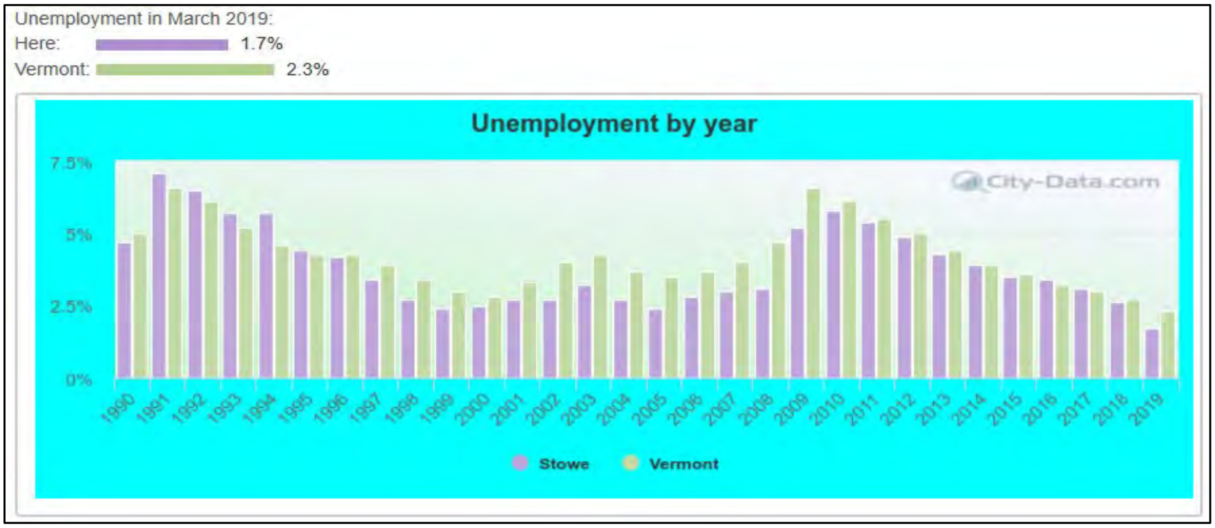


- Accommodation & food services (19.1%)
- Educational services (14.3%)
- Professional, scientific, technical services (9.6%)
- Health care (7.9%)
- Public administration (6.6%)
- Finance & insurance (3.5%)
- Social assistance (3.5%)

[7] http://www.city-data.com/city/Stowe-Vermont.html

The Town's 2019 unemployment rate was 1.7% (vs. 2.3% for Vermont) and the unemployment history is found in Figure 8 below. Since the economic impact of the COVID – 19 Pandemic unemployment has been on the rise both in Vermont and the United States. As of April 2020, the U.S. Bureau of Labor Statistics posted Vermont's rate as 15.6 a large increase from just one year ago.

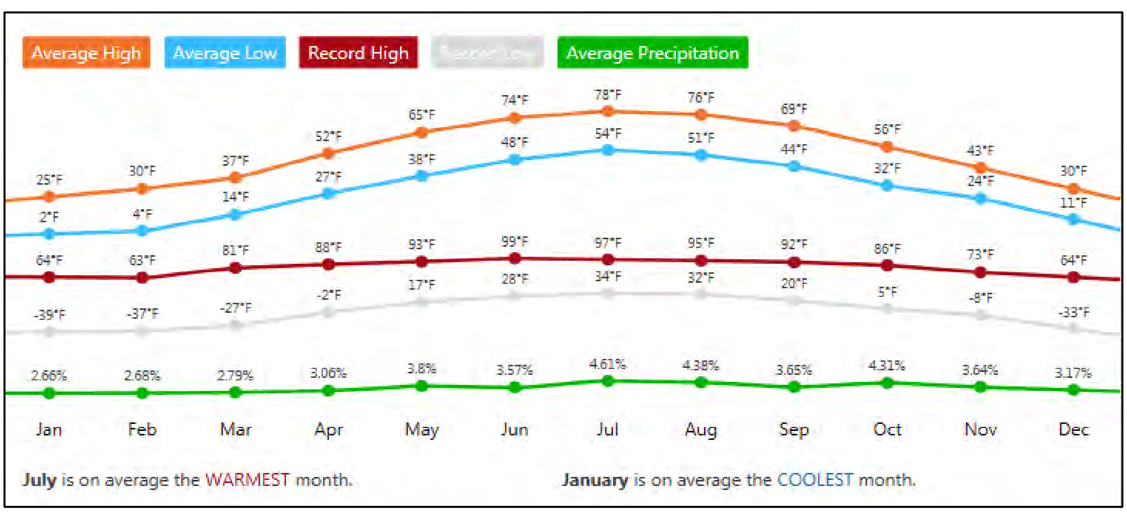
Figure 8: Stowe's Unemployment History



B.1.3 Stowe Climate

The Town and State's climate are important factors to consider when planning future generation and/or location of generation. The average climate, found below in Figure 9: Stowe's Average Temperatures, provides insight into which months are the highest heating and cooling driven months.

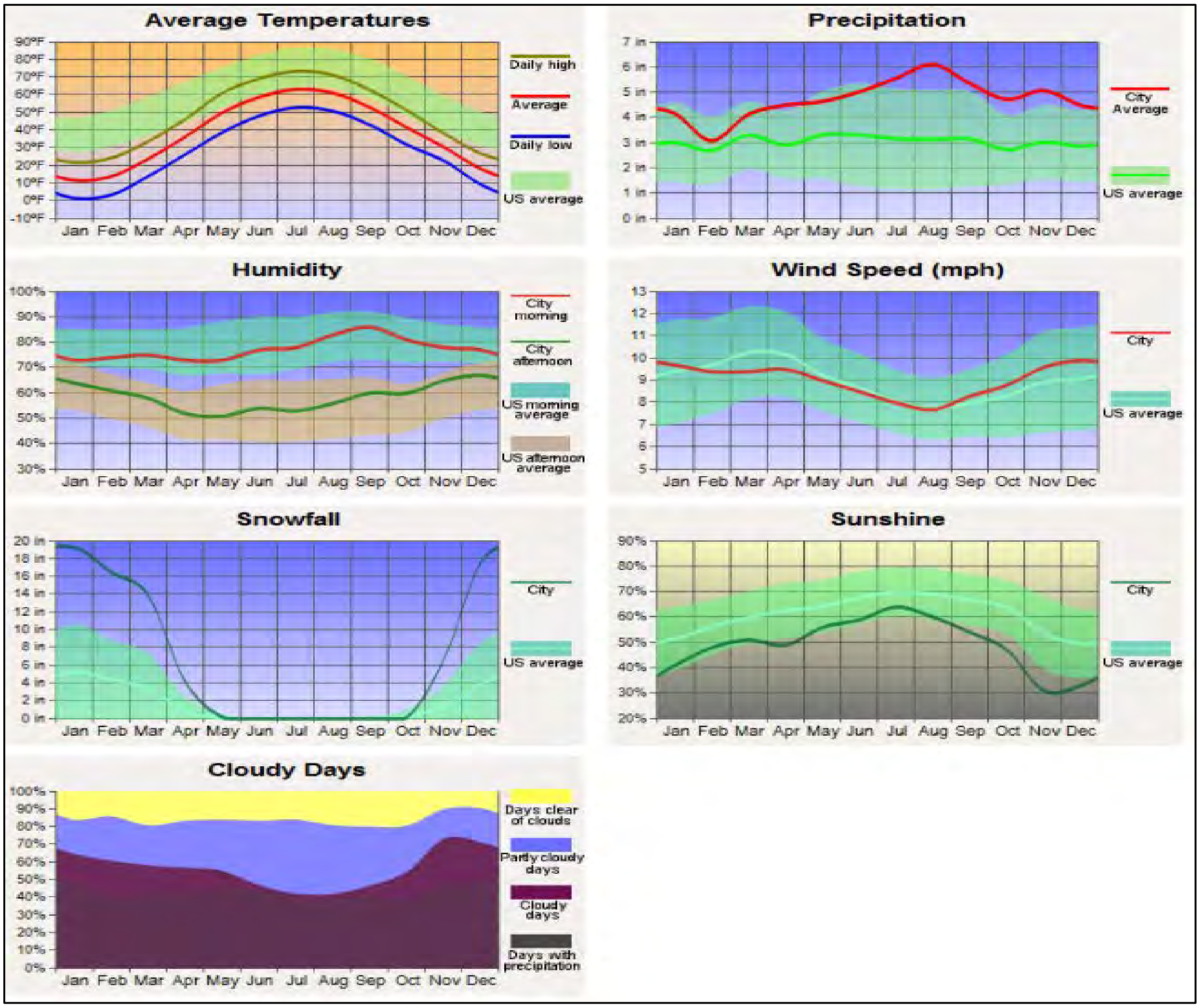
Figure 9: Stowe's Average Temperatures[8]



[8] https://weather.com/weather/monthly/l/USVT0233:1:US

The data compiled by the city-data.com website, which uses over 4,000 weather stations, shown below in the graphs of Figure 10: Average Climate in Stowe provides additional information. By analyzing wind speed and cloud coverage, Stowe can make educated assumptions of resource optimization within Stowe. 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 the greatest output.

Figure 10: Average Climate in Stowe[9]



[9] http://www.city-data.com/city/Stowe-Vermont.html

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

Stowe contracted ITRON through 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 3,500 residential customers and 80 commercial customers, including the Stowe Mountain Resort (Mountain). Stowe has a relatively large commercial customer base with the commercial sector accounting for approximately 58% of system sales. The residential sector accounts for 32% of sales and mountain resort the remaining 10% of system sales.

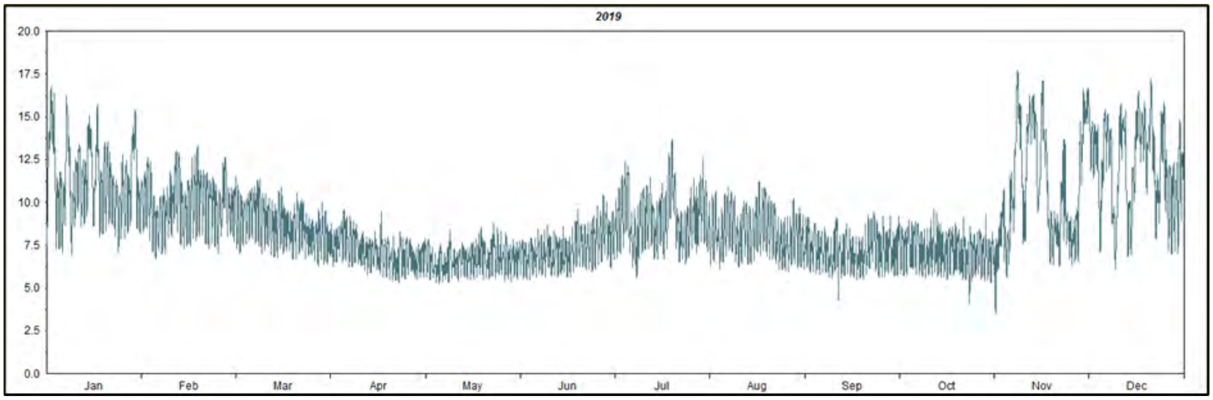
Stowe electric sales are heavily influenced by activity at the Mountain, directly through snowmaking and indirectly through tourism. Stowe experienced strong growth starting in 2015 and lasting through 2017. The infrastructure and lodging expansions at the Mountain largely drove this growth. The expansion at the Mountain coupled with the economic recovery in all sectors also helped spur growth. Tourism and visitation also increased significantly over the last five years contributing to hotel and restaurant sales growth. Increased occupancy rates in the second-home market plays an important role in the Town of Stowe economy, and roughly half of the residential housing stock in Stowe are second-homes. Residential customers increased on average 1.3% annually and commercial customers 1.6% annually over the 2015-17 period.

Since 2017, sales growth has slowed but has remained positive. The recent uptick in behind-the-meter (BTM) solar has contributed to slower electricity sales. Going forward, the state-wide promotion of cold climate heat pumps and electric vehicles are expected to contribute to positive sales growth outweighing further sales loss due to BTM solar adoption.

The COVID-19 induced economic shutdown has had a significant impact on sales with year-to-date sales (through July 2020) down 8.2% over the same period last year. The drop in sales is largely due to shutdown of hotels, restaurants, and other business, which dependent heavily upon tourism; commercial sales are down nearly 18% on a year-to-date basis. Year-to-date residential sales are up 8.7%. Moody's analytics projects COVID-19 to impact economic activity through 2021 with a strong recovery beginning in 2022 and full recovery by 2024.

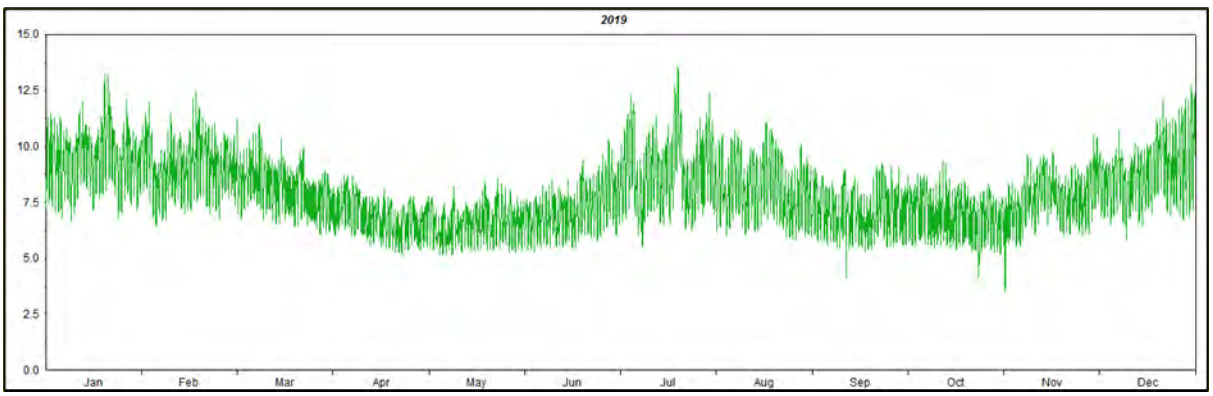
Stowe is a winter-peaking utility with significant load variation in the winter months; this variation is largely driven by snow-making Figure 11 shows 2019 system hourly demand.

Figure 11: 2019 System Hourly Demand (MW)



For forecasting purposes, the Mountain is separated from residential and commercial sales (Town Load); most of the Mountain load is for snowmaking. Figure 12 shows the 2019 Town hourly load demand.

Figure 12: 2019 Town Hourly Demand (MW)



The 2019 Town load profile is somewhat atypical of past years. Stowe generally peaks during the Christmas holiday period; in 2019 the town load peaked in July.

C.2 Forecast Summary

The forecast is based on a bottom-up approach. Separate forecasts are generated for residential, commercial, and mountain sales. The baseline forecast is the sum of these sectors excluding additional BTM solar, incentivized heat-pumps, and electric vehicles. The baseline forecast has two parts – the Town load, which is the sum of the residential and commercial forecast and System load, which also includes the mountain load.

Stowe has experienced modest sales growth over the last five years, with relatively strong regional economic and tourism growth. COVID-19, however, has thrown a wrench in recent growth with the state mandated economic-shutdown having a significant negative impact on 2020 sales and likely continuing impacts over the next couple of years.

Table 2 shows projected annual energy and peak demand. The Baseline Forecast reflects current state economic and household projections, end-use intensities derived from the EIA 2020 Annual Energy Outlook, and VEIC current efficiency program savings projections. The Adjusted Forecast incorporates the expected impact of BTM solar load growth, cold-climate heat pump adoption through the state incentive program, and electric vehicles.

Table 2: System Energy and Demand Forecast

	Baseline			Adjusted	
Year	Energy (MWh)	Peak (MW)		Energy (MWh)	Peak (MW)
2015	77,511	19.0		77,511	19.0
2016	84,323	19.0		84,323	19.0
2017	80,849	19.6		80,849	19.6
2018	83,718	18.1		83,718	18.1
2019	79,340	17.7		79,340	17.7
2020	74,427	17.2		74,546	17.2
2021	77,527	16.9		77,603	16.9
2022	77,903	16.5		77,736	16.6
2023	78,449	17.1		78,232	17.1
2024	79,094	16.8		78,745	17.0
2025	79,216	17.5		78,921	17.6
2026	79,577	17.4		79,555	17.7
2027	79,856	17.2		80,127	17.7
2028	80,379	17.0		81,111	17.9
2029	80,581	17.0		81,977	17.9
2030	80,936	17.3		82,995	18.0
2031	81,214	17.7		83,984	18.4
2032	81,665	17.6		85,151	18.7
2033	81,584	17.0		86,029	19.0
2034	81,645	17.4		87,015	18.7
2035	81,734	17.1		88,095	19.4
2036	82,079	17.4		89,295	19.3
2037	81,906	17.7		89,968	20.2
2038	81,862	17.4		90,563	19.8
2039	81,766	16.9		91,056	20.4
2040	81,795	17.3		91,473	19.8
2015-19	0.6%	-1.8%		0.6%	-1.8%
2021-40	0.3%	0.1%		0.9%	0.8%

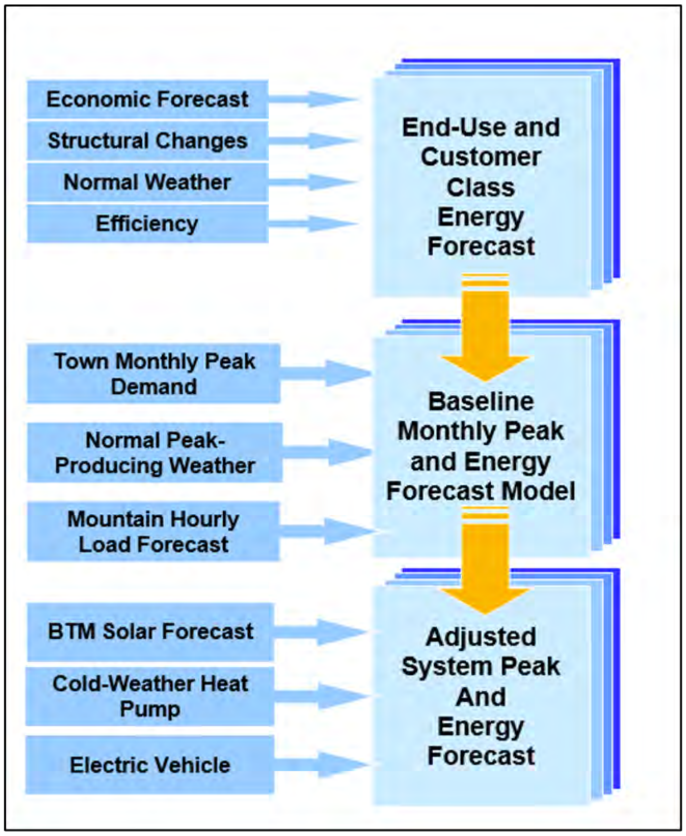
In the Baseline Forecast, strong efficiency gains counter customer and economic growth resulting in low energy and peak demand growth sales growth. With Mountain usage held constant, total baseline energy requirements are projected to increase 0.3% annually and baseline winter peak demand 0.1%.

In the early years (through 2025), the Adjusted Forecast is lower than the baseline forecast as solar adoption outpaces near-term sales gains from incentivized heat-pumps and electric vehicles. This flips after 2025 as adoption of incentivized heat-pump and electric vehicles accelerates and solar adoption slows.

C.3 Forecast Approach

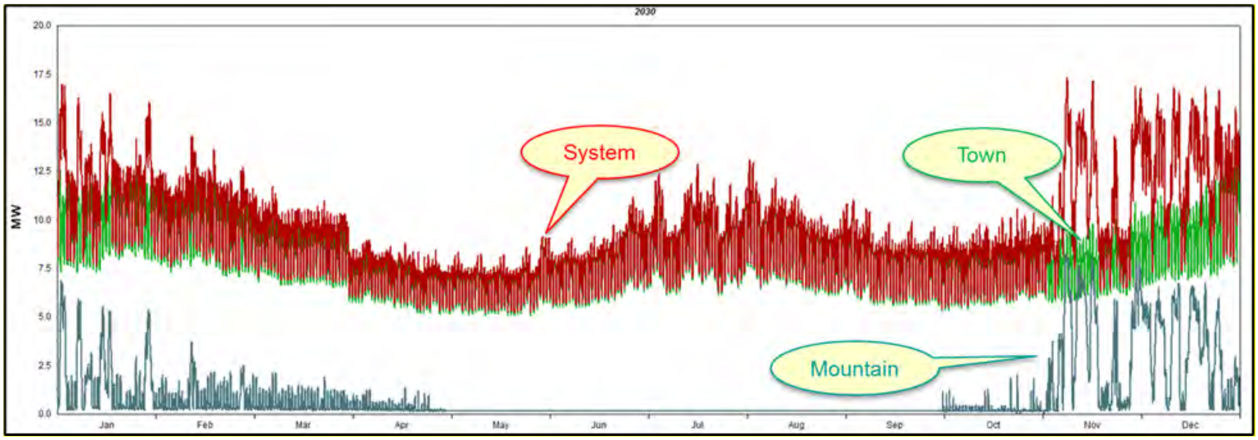
The IRP forecast is based on the same approach as that used in the VELCO state long-term energy and demand forecast. Energy and demand forecasts are derived using a bottom-up framework as depicted in Figure 13 which shows the 2030 Baseline system hourly load forecast.

Figure 13: Forecast Framework



The process entails first developing residential and commercial sales forecasts, derived from the estimated models, then estimate heating, cooling, and base-use energy requirements. End-use energy requirements are combined with peak-day weather conditions to drive Town-level peak demand. Energy requirements are calculated by applying a loss factor to the class sales forecast. The baseline hourly load forecast is then calculated by combining peak, energy, and system hourly load profile forecast. The *Baseline System* hourly load forecast is derived by adding the Town and Mountain hourly load forecasts.

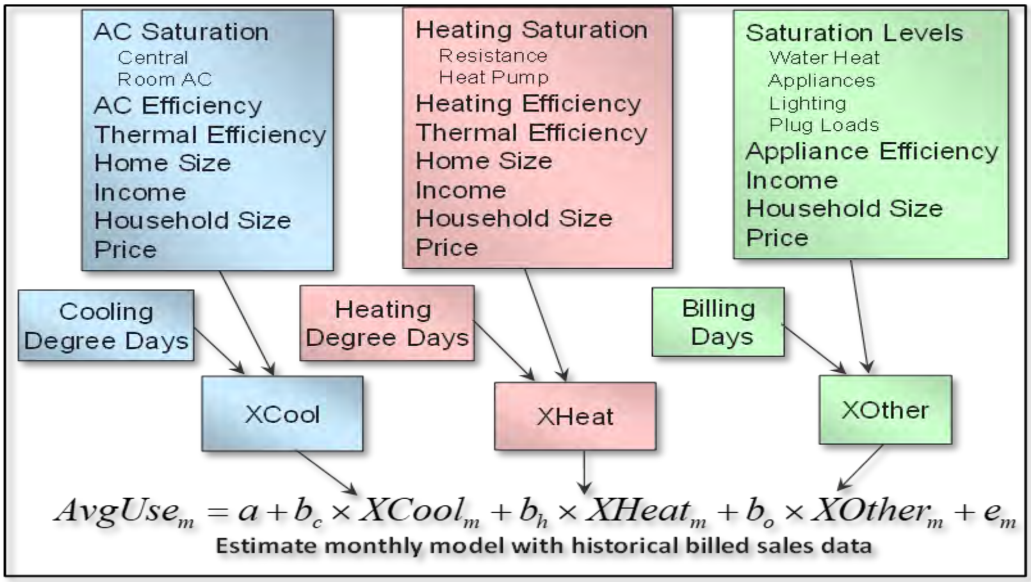
Figure 14: Baseline System Hourly Load Forecast - 2030



C.3.1 Customer Class Sales Forecast

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 15 shows the residential average-use SAE model specification.

Figure 15: Residential SAE Model Overview

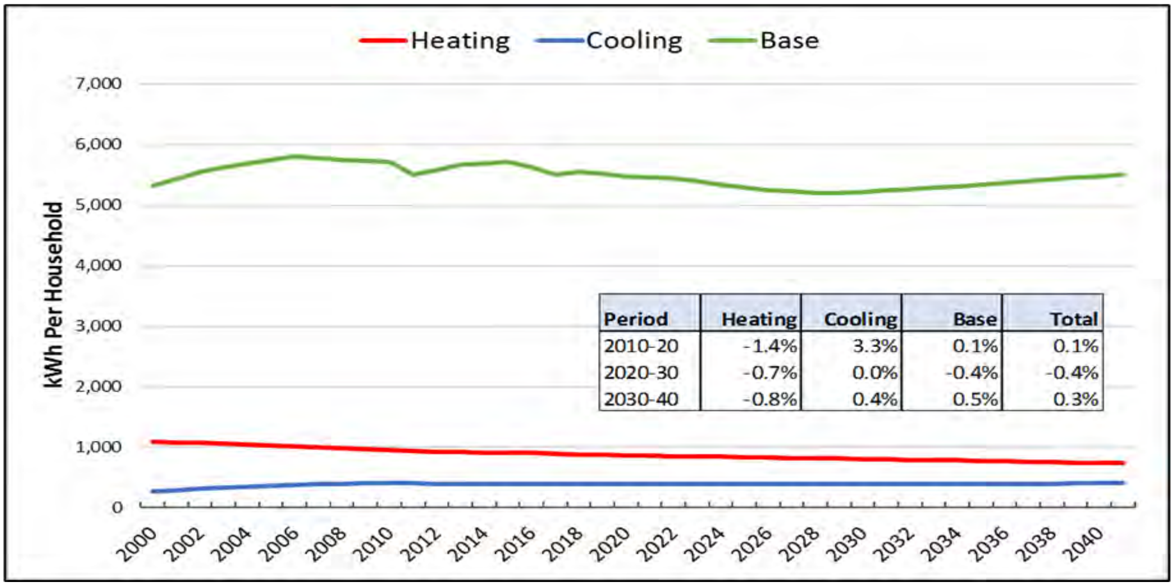


C.3.1.1 Residential Average Use Model

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 significant decline in overall end-use intensities measured in kWh per household. For most end-uses, increase in stock efficiency has 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 16 shows aggregated end-use intensity trends when mapped to cooling, heating, and base use (non-weather sensitive end-uses).

Figure 16: Aggregated End-Use Energy Intensities



Period	Heating	Cooling	Base	Total
2010-20	-1.4%	3.3%	0.1%	0.1%
2020-30	-0.7%	0.0%	-0.4%	-0.4%
2030-40	-0.8%	0.4%	0.5%	0.3%

Across all end-uses, energy intensity declines through 2030 largely a result of new energy efficiency appliance standards and continued state efficiency goals. 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; this changes 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 Moody's May 2020 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 results in fewer HDD (contributing to the decline in heating use) and more CDD (driving the cooling use higher). Figure 17 through Figure 19 show the model variables.

Figure 17: XHeat (kWh per customer)

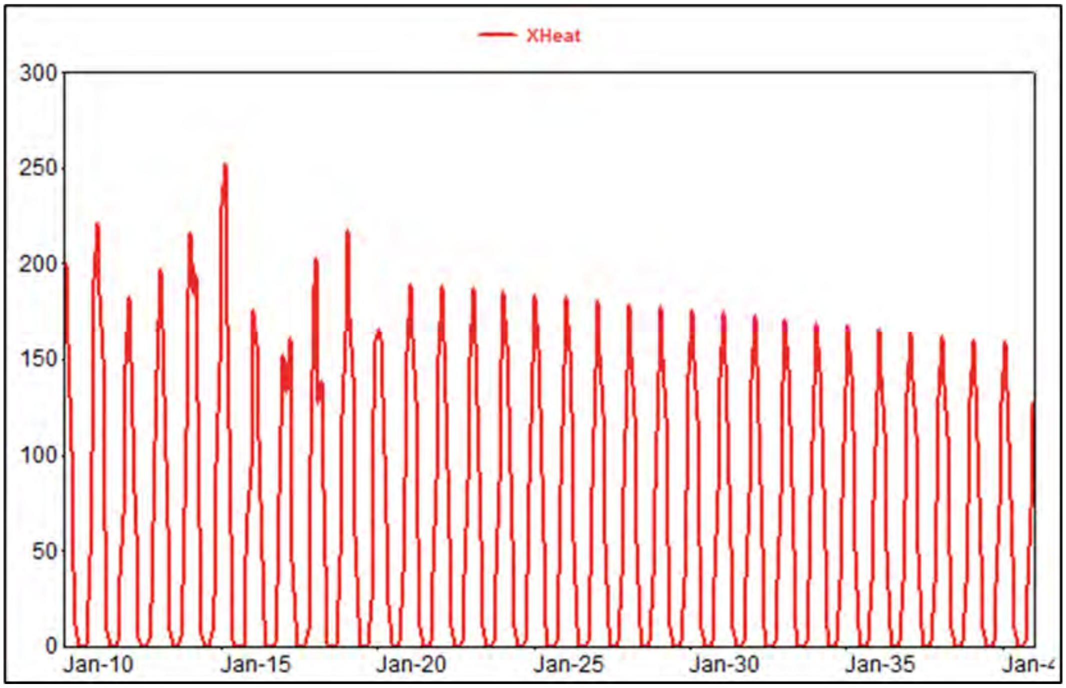


Figure 18: XCool (kWh per customer)

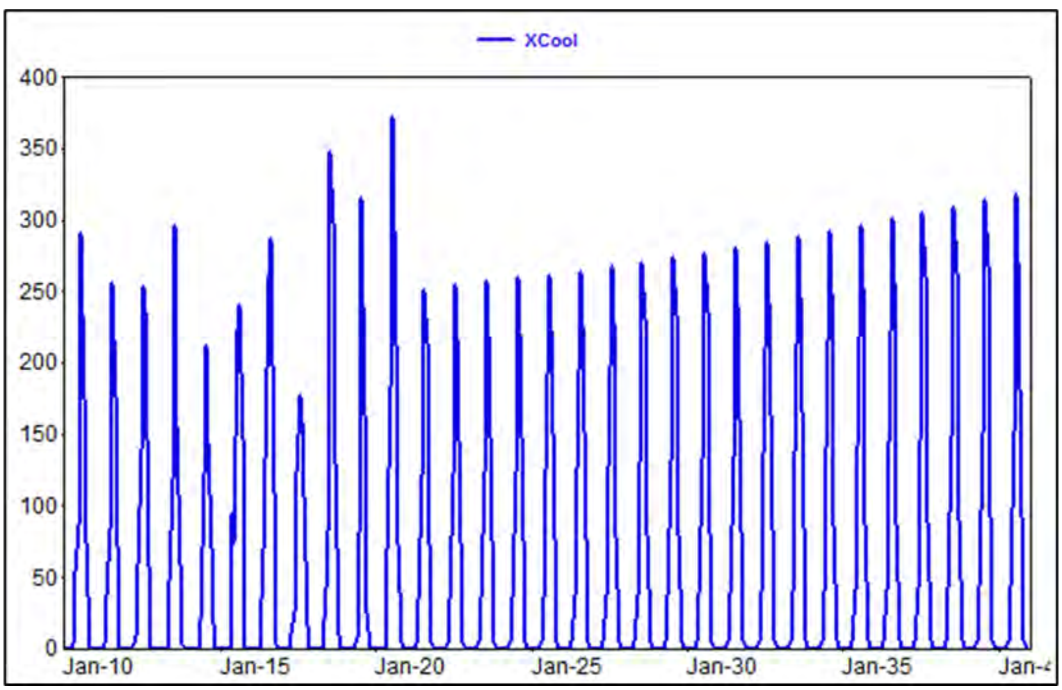
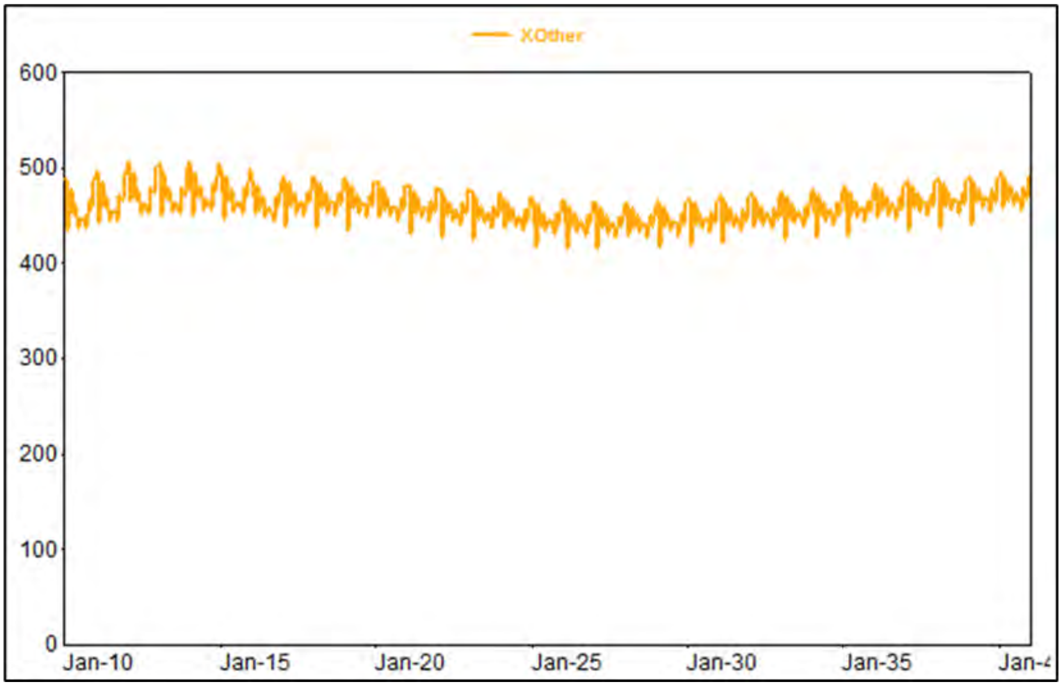


Figure 19: XOther (kWh per customer)



The constructed end-use variables are incorporated into an average-use regression model. The model is estimated with reconstituted average use from January 2010 to July 2020. Reconstituted average use is derived by adding estimates of historical solar-generation for own-use to residential sales. Model results are summarized in Figure 20.

Figure 20: Residential Average Use Model

Variable	Coefficient	T-Stat	P-Value
XHeat	0.923	9.844	0.00%
XCool	0.328	4.347	0.00%
XOther	1.131	31.833	0.00%
COVID_Impact	71.504	4.093	0.01%

Model Statistics	
Iterations	1
Adjusted Observations	127
Deg. of Freedom for Error	113
R-Squared	0.92
Adjusted R-Squared	0.91
Std. Error of Regression	28.72
Mean Abs. Dev. (MAD)	20.73
Mean Abs. % Err. (MAPE)	3.59%
Durbin-Watson Statistic	1.667

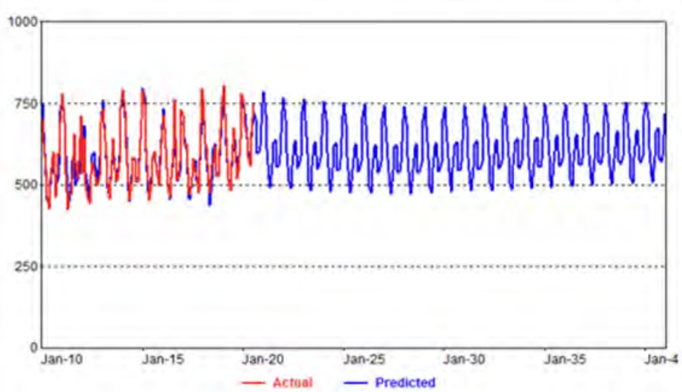


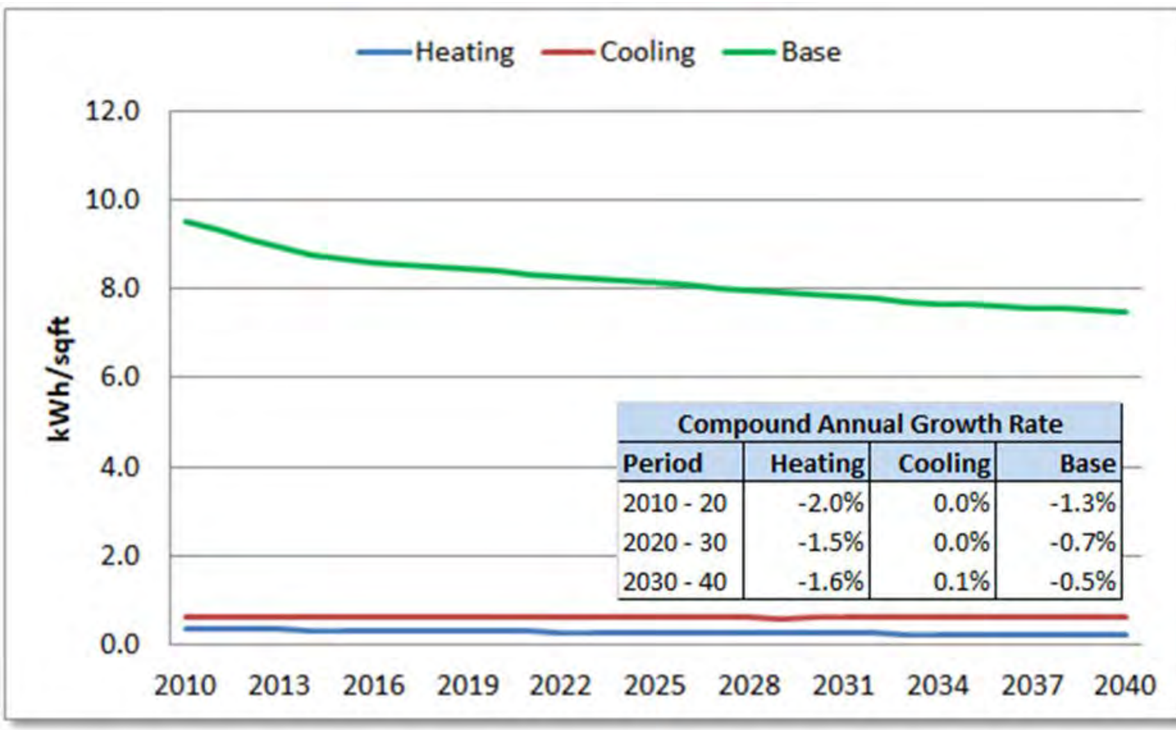
Figure 20 shows the coefficients for the primary model variables. All the variables are statistically significant as indicated by the T-Statistic and P Values. Again, the historical average-use data has been adjusted to include solar own-use consumption; the average-use forecast includes what is purchased from Stowe and is self-generated. COVID-19 has had a positive impact on residential sales, reflecting stay-at-home orders and increase in customers now working from home. We assume the structural impact of COVID-19 fades over time and is back to normal by June 2021.

C.3.1.2 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 resulting from improvements in end-use efficiency; therefore, kWh per square foot have steadily declined. Figure 21 shows commercial end-use energy intensity forecasts for heating, cooling, and non-weather sensitive use (base).

Figure 21: Commercial End - Use Energy Intensity



Compound Annual Growth Rate			
Period	Heating	Cooling	Base
2010 - 20	-2.0%	0.0%	-1.3%
2020 - 30	-1.5%	0.0%	-0.7%
2030 - 40	-1.6%	0.1%	-0.5%

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 22 through Figure 24 show the commercial end-use model variables.

Figure 22: Commercial XHeat (kWh per Square Foot)

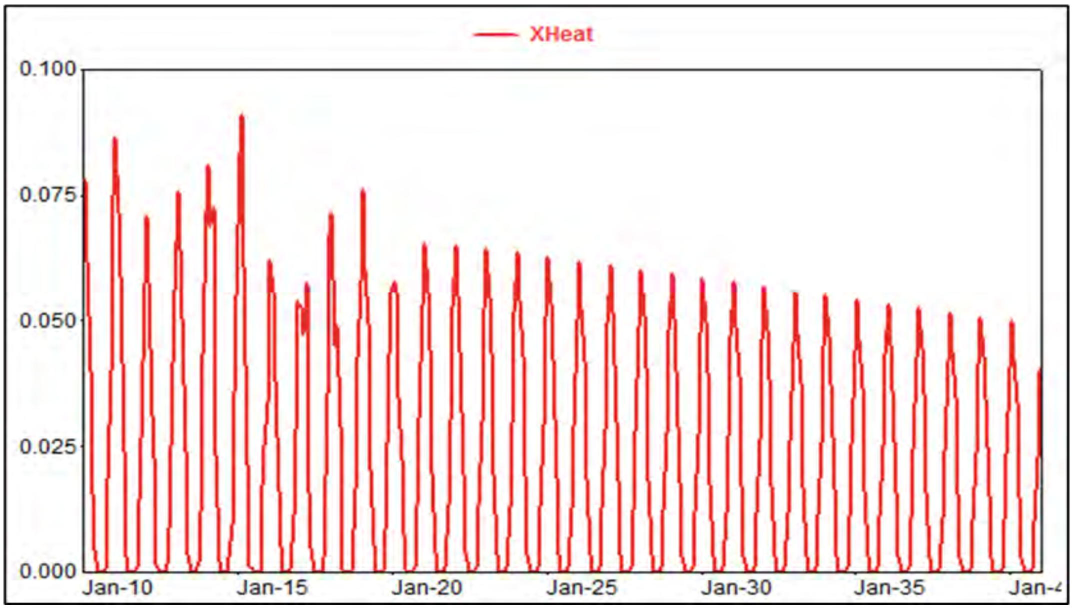


Figure 23: Commercial XCool (kWh per Square Foot)

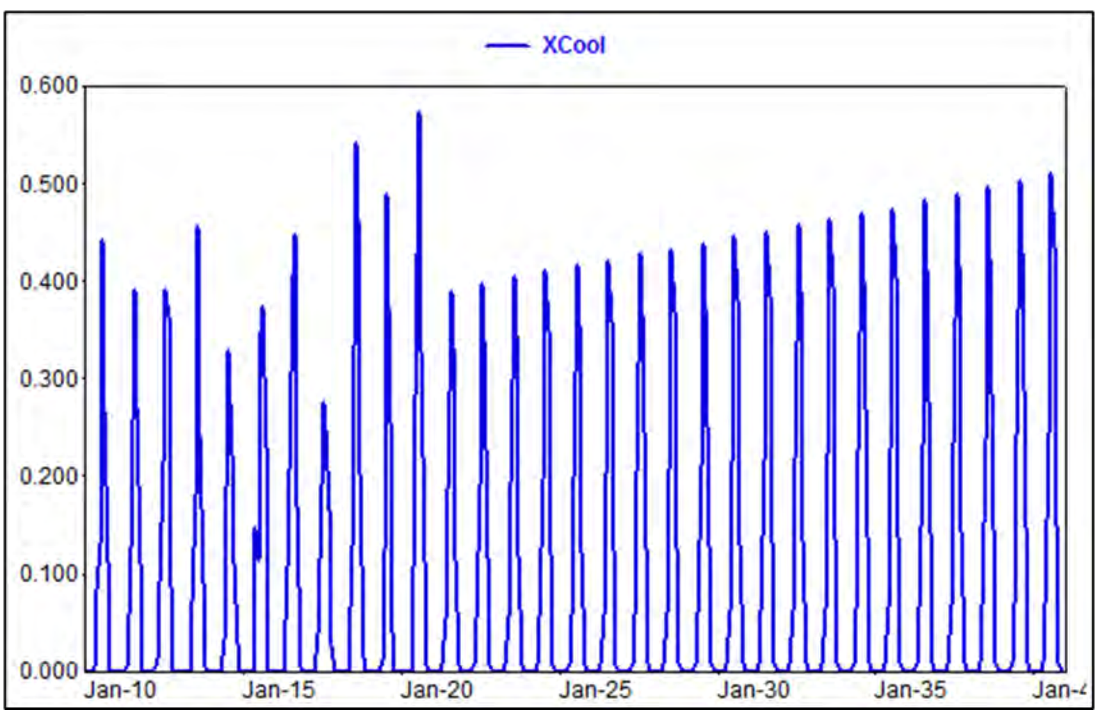
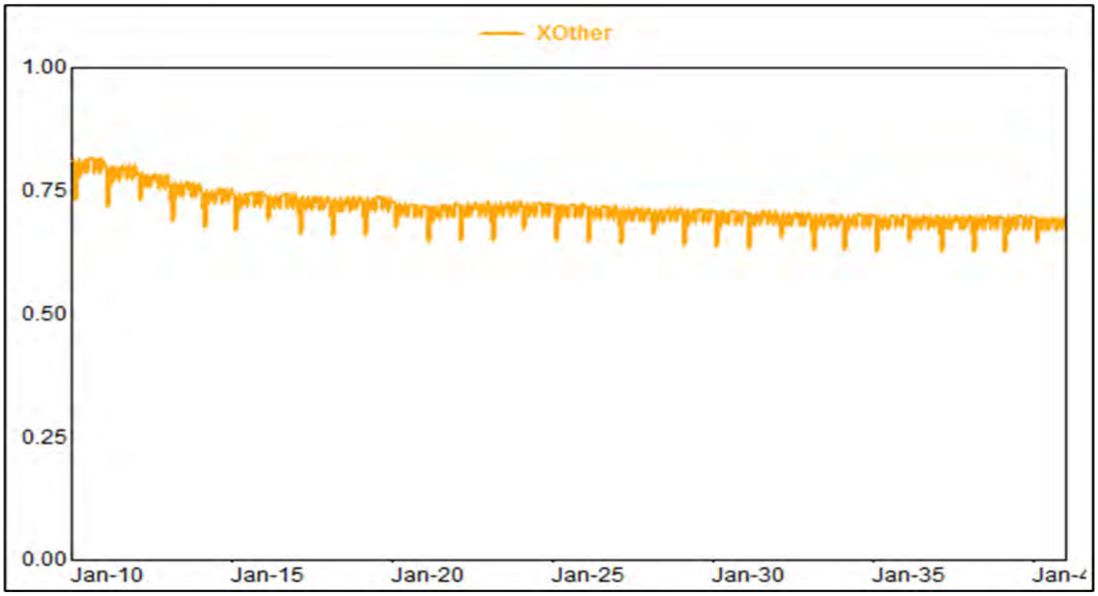


Figure 24: Commercial XOther (kWh per Square Foot)



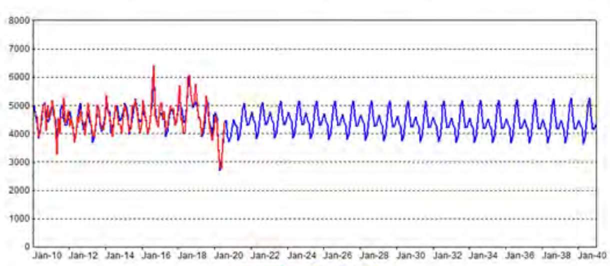
Increasing temperatures contribute to declines in heating requirements and increases in cooling requirements. The impact, however, is relatively small as commercial cooling and heating use are small in comparison with non-weather sensitive commercial use; non-weather-sensitive uses account for nearly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

XHeat, XCool, and XOther are used in estimating a commercial monthly average use sales model; the estimation period is January 2010 through July 2020. Figure 25 shows the commercial average use model results.

Figure 25: Commercial Average Use Model

Variable	Coefficient	T-Stat	P-Value
XHeat	10338.567	7.558	0.00%
XCool	2791.831	9.33	0.00%
XOther	5148.303	51.463	0.00%
COVID_Impact	-1155.404	-8.2	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	127
Deg. of Freedom for Error	117
R-Squared	0.788
Adjusted R-Squared	0.771
Std. Error of Regression	265.6
Mean Abs. Dev. (MAD)	198.02
Mean Abs. % Err. (MAPE)	4.40%
Durbin-Watson Statistic	1.873



The primary model variables are all 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. By 2022, commercial sales eventually get back to 2019 sales level.

C.3.1.3 Customer and Baseline Sales Forecast

The sales forecast is derived by combining the average-use forecast with customer forecast. Stowe experienced strong residential and commercial customer growth in the 2015-2017 period. Growth has slowed since then, however. COVID-19 will contribute to slow near-term customer growth.

Customers are forecasted using a monthly regression model that relates number of customers to forecasted state households. The model is estimated with monthly customer count data from January 2010 through July 2020. Customer growth slows over the forecast period with slowing state economic growth. Figure 26 shows Stowe's customer forecast.

Figure 26: Customer Forecast (forecast begins August 2020)

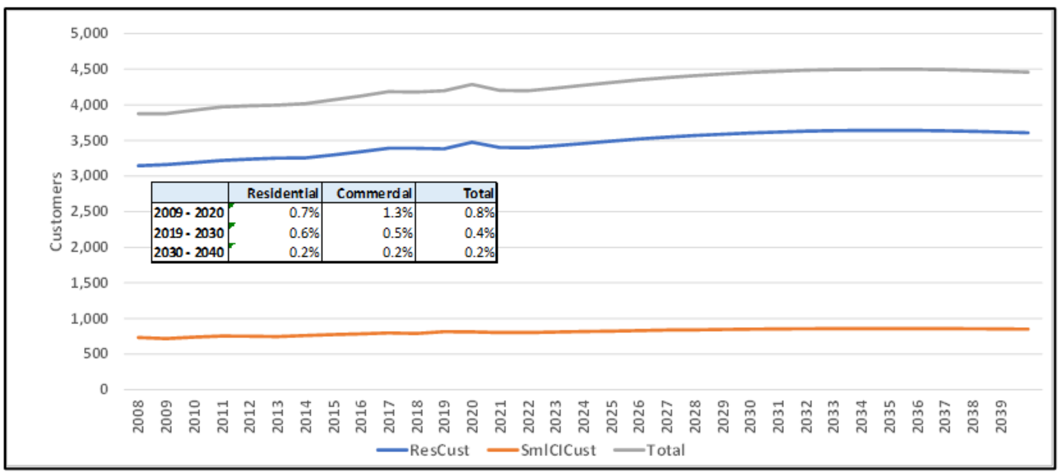


Table 3 summarizes baseline customer class sales and customer forecast.

Table 3: Baseline Customer Class Forecast

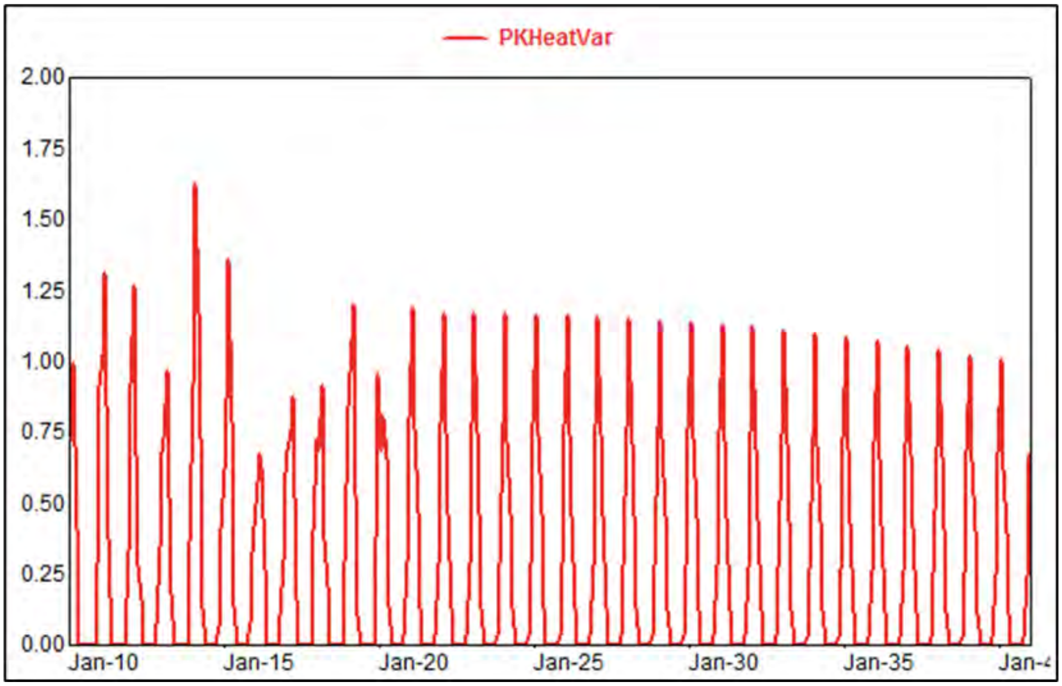
	Residential			Small Commercial			Total
Year	Avg Use (kWh)	Customers	Sales (MWh)	Avg Use (kWh)	Customers	Sales (MWh)	Sales (MWh)
2020	7,432	3,476	25,837	45,944	812	37,305	63,143
2021	6,957	3,400	23,655	52,956	802	42,475	66,130
2022	6,871	3,397	23,341	53,843	801	43,146	66,487
2023	6,832	3,425	23,401	53,975	808	43,605	67,006
2024	6,801	3,458	23,517	54,028	816	44,062	67,579
2025	6,727	3,490	23,476	53,782	823	44,259	67,735
2026	6,706	3,521	23,612	53,562	830	44,465	68,077
2027	6,684	3,547	23,706	53,380	836	44,637	68,343
2028	6,702	3,569	23,919	53,348	841	44,881	68,800
2029	6,718	3,587	24,097	53,148	845	44,936	69,033
2030	6,746	3,605	24,319	53,024	850	45,051	69,370
2031	6,777	3,619	24,529	52,875	853	45,105	69,634
2032	6,822	3,631	24,768	52,885	856	45,254	70,022
2033	6,829	3,638	24,845	52,649	857	45,140	69,986
2034	6,855	3,640	24,955	52,556	858	45,090	70,044
2035	6,891	3,642	25,093	52,477	858	45,035	70,129
2036	6,945	3,641	25,289	52,590	858	45,127	70,416
2037	6,966	3,637	25,335	52,454	857	44,956	70,291
2038	6,994	3,629	25,383	52,454	855	44,867	70,250
2039	7,023	3,619	25,419	52,445	853	44,739	70,158
2040	7,072	3,608	25,518	52,476	850	44,629	70,146
2021-30	-0.3%	0.7%	0.3%	0.0%	0.6%	0.7%	0.5%
2030-40	0.5%	0.0%	0.5%	-0.1%	0.0%	-0.1%	0.1%

C.3.2 Baseline Energy and Demand Forecast

The Town Baseline energy forecast is calculated by applying historical monthly average loss factors to the Town monthly 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 year. Adjusted for line losses, Mountain energy is approximately 8,000 MWh per year.

System peak requirements are expected to change as underlying heating, cooling, and non-weather sensitive (base-use) energy requirements change. To capture the impact of changing end-use sales growth on peaks, the 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. 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 27 shows estimated peak-day heating requirements. The forecast data series begins in August 2020.

Figure 27: Peak-Day Heating Requirements (MW)



Similar peak-day load estimates are generated for cooling and non-weather sensitive use (base-use). Constructed variables are shown in Figure 28 and Figure 29.

Figure 28: Peak-Day Cooling Requirements (MW)

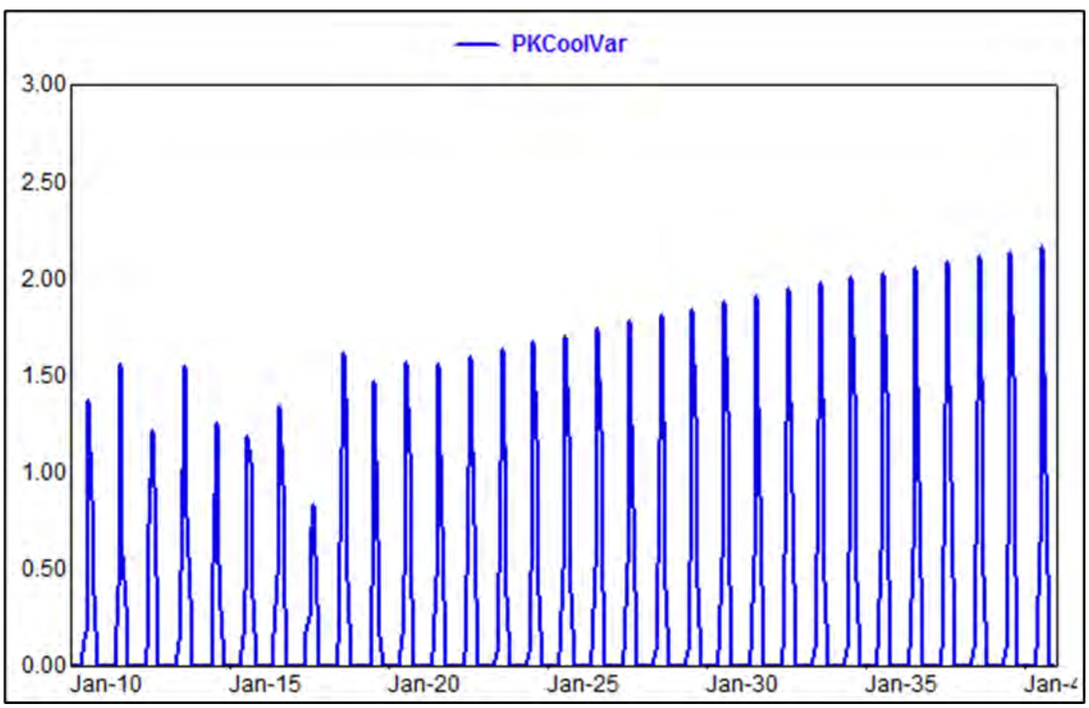
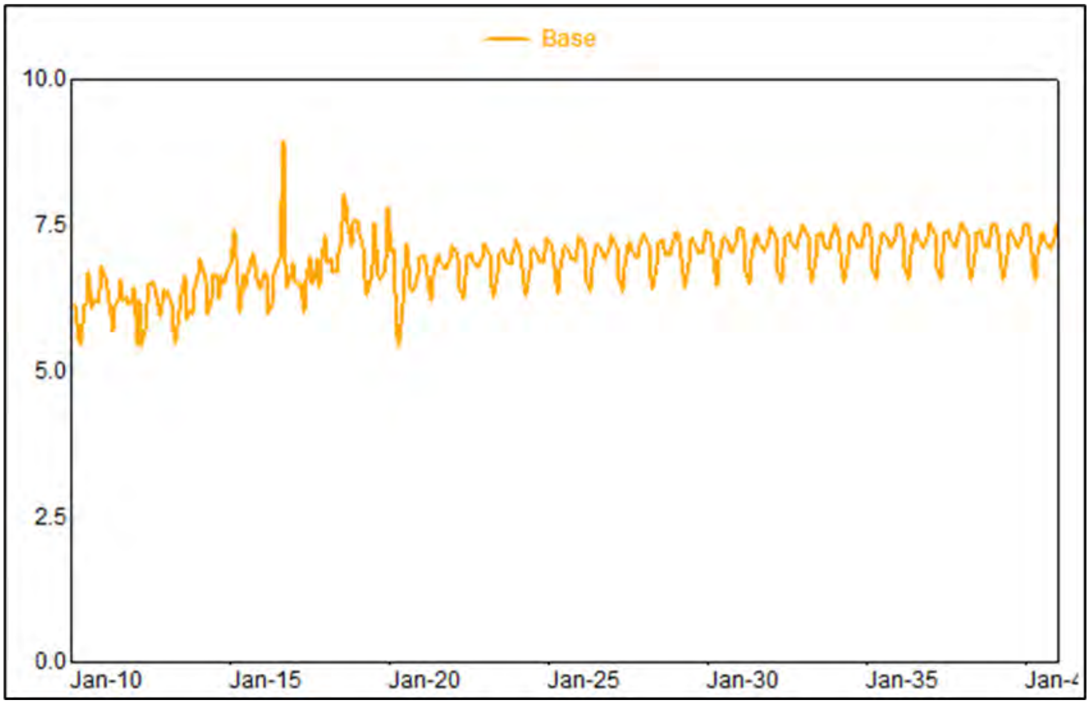


Figure 29: Peak-Day Base Load Requirement (MW)

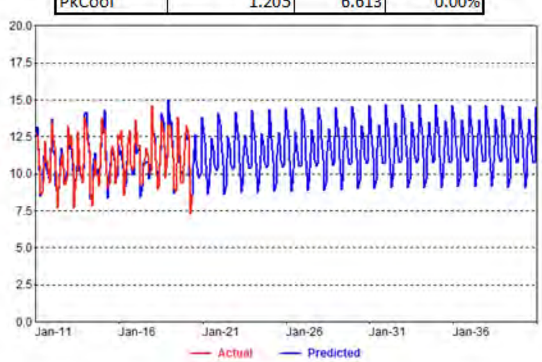


A monthly peak demand regression model is estimated as a function of the peak-day heating, cooling, and base use variables. The model is estimated over the period January 2011 to May 2020. Figure 30 shows the model results.

Figure 30: System Peak Model (MW)

Variable	Coefficient	T-Stat	P-Value
Base	1.577	62.239	0.00%
Base_Apr	-0.157	-4.356	0.00%
Base_May	-0.135	-3.879	0.02%
Base_June	-0.104	-3.122	0.23%
Base_Dec	0.221	6.379	0.00%
PkHeat	2.344	12.375	0.00%
PkCool	1.205	6.613	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	113
Deg. of Freedom for Error	102
R-Squared	0.876
Adjusted R-Squared	0.864
Std. Error of Regression	0.6
Mean Abs. Dev. (MAD)	0.46
Mean Abs. % Err. (MAPE)	4.20%
Durbin-Watson Statistic	1.528



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

Figure 31 shows the Baseline summer and winter peak demand. Summer peak is increasing faster than winter peak, but Stowe remains a winter peaking utility through the forecast period.

Figure 31: Baseline Town Peak Demand Forecast

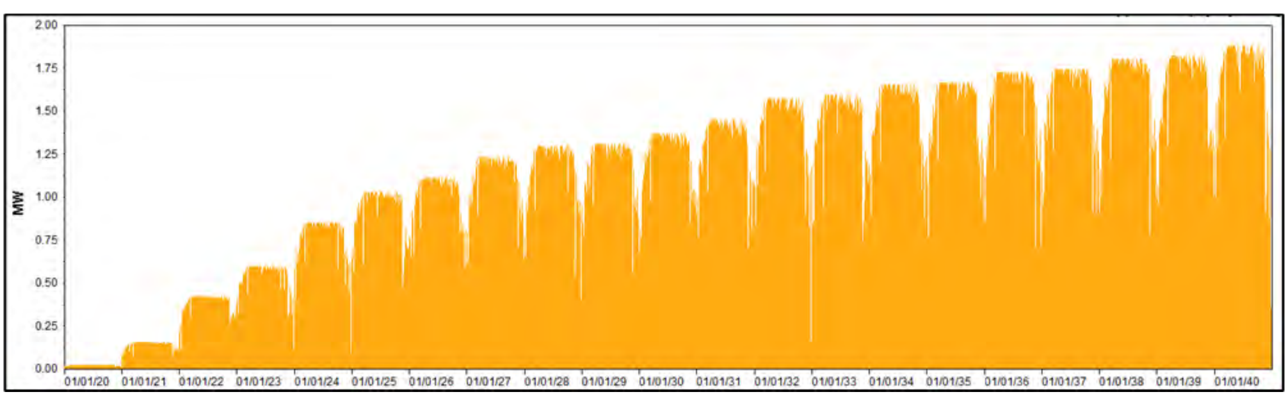
C.3.3 Adjusted Energy and Demand Forecast

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

C.3.3.1 Solar Load Forecast

Figure 32 shows the incremental 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 32: Solar Hourly Load Forecast (2020-2040)



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

C.3.3.2 Cold Climate Heat Pump Impact

Vermont Energy Investment Corporation (VEIC) recently launched a program to promote the adoption of cold climate heat pumps. The program is intended to help utilities meet the Vermont Tier III goals under the RES. Program-driven heat pump loads are added to the Baseline Forecast. The heat pump program is expected to significantly impact winter peak as it adds to electric heating loads. Figure 33 through Figure 35 show program-induced heat-pump hourly load impacts.

Figure 33: Heat Pump Program Hourly Load Impacts 2020-2040

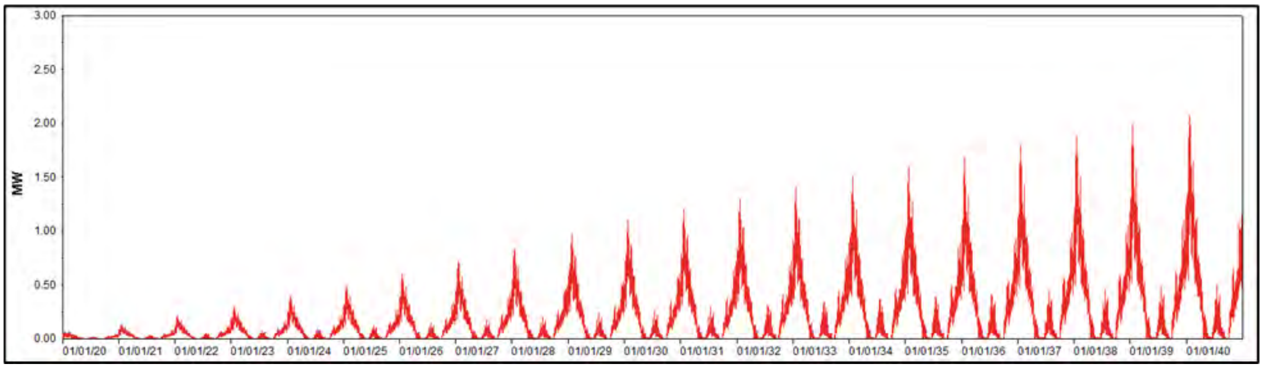


Figure 34: Heat Pump Program Impact 2030

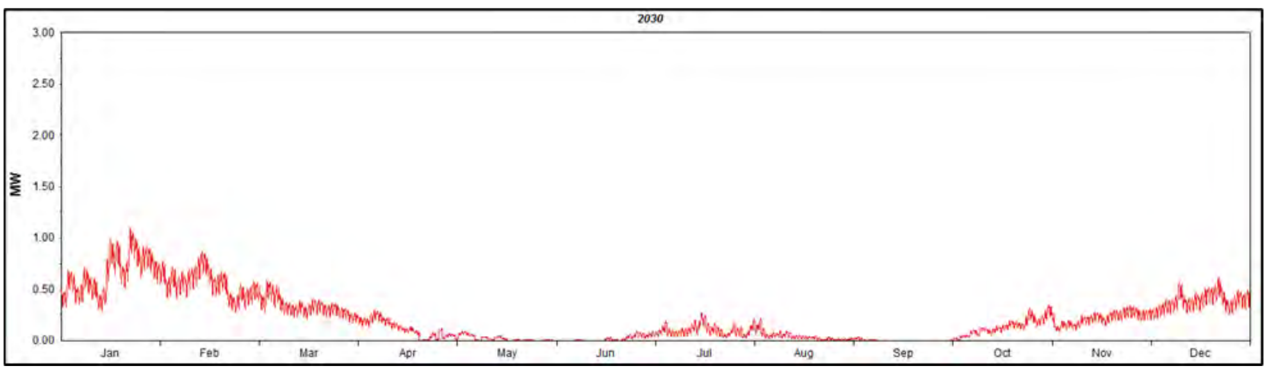
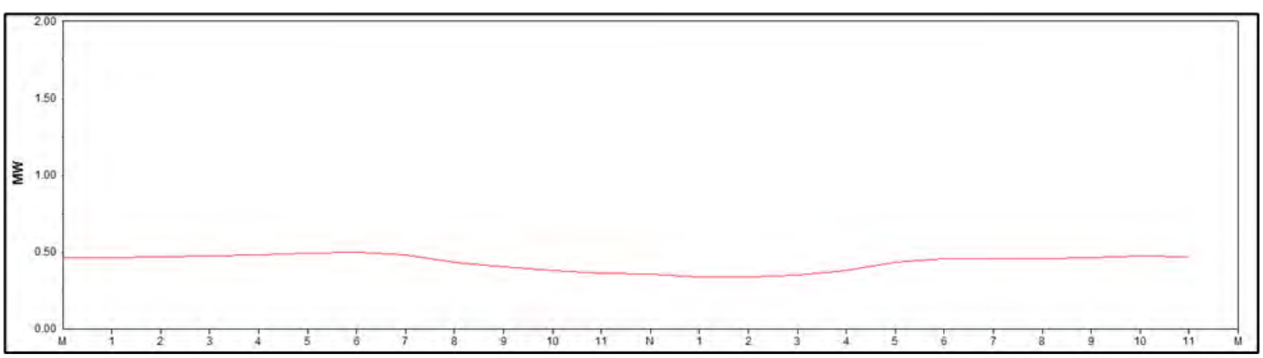


Figure 35: 2030 Heat Pump Hourly Load Peak-Day



C.3.3.3 Electric Vehicle Impact

The electric vehicle (EV) forecast was developed by VEIC. 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 2040, electric vehicles are projected to account for nearly 55% of all registered vehicles. Figure 36 through Figure 38 show the electric vehicle load impacts.

Figure 36: Electric Vehicle Load Impacts 2020-2040

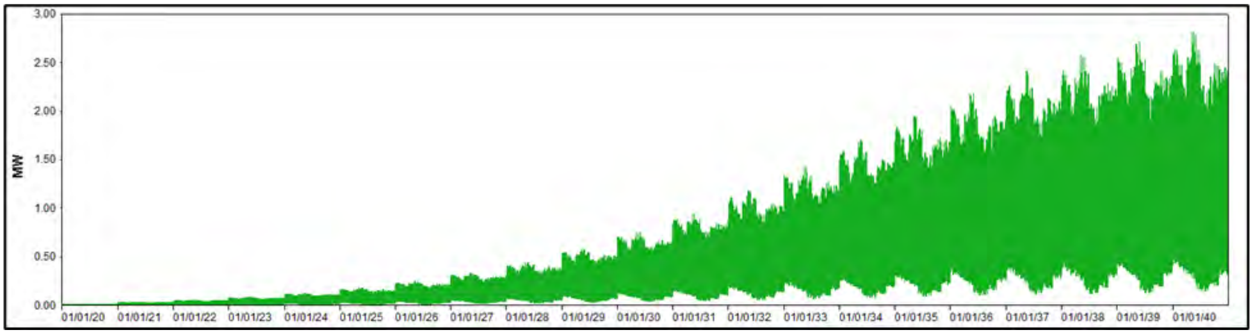


Figure 37: Electric Vehicle Load Impacts 2030

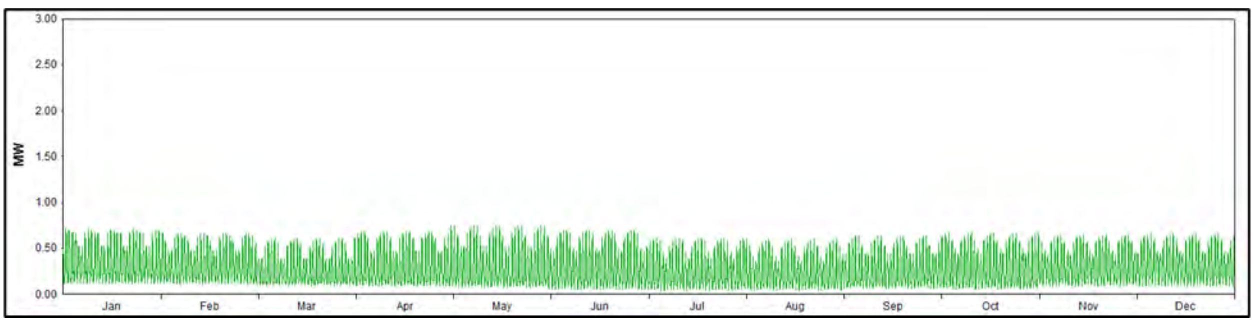
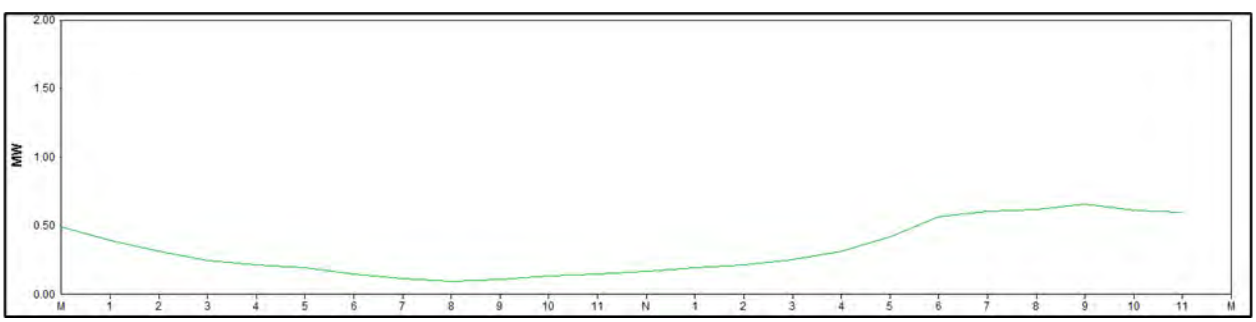


Figure 38: Electric Vehicle Load Impacts Peak Day



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 39 and Figure 40 compare the 2027 Baseline and Adjusted system hourly load forecasts.

Figure 39: Baseline and Adjusted Forecast Comparison – Winter Week, 2030

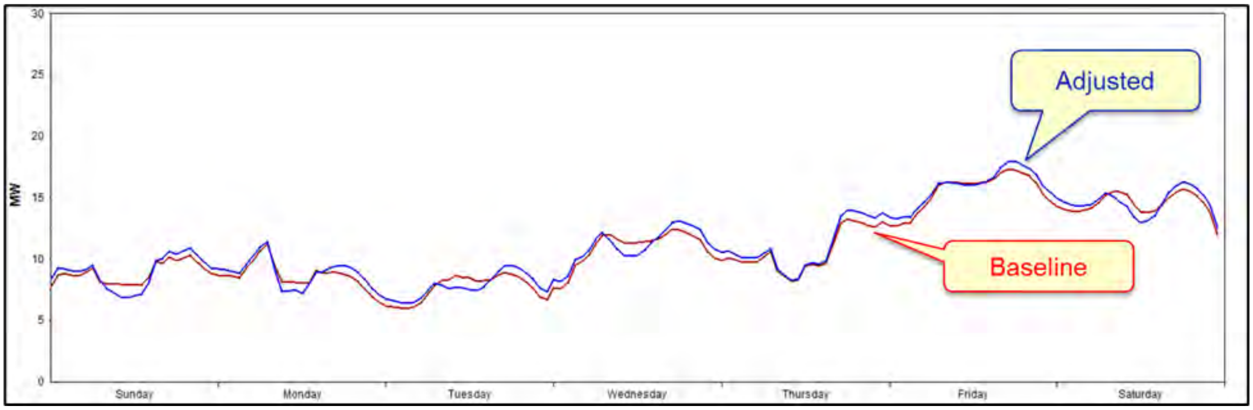
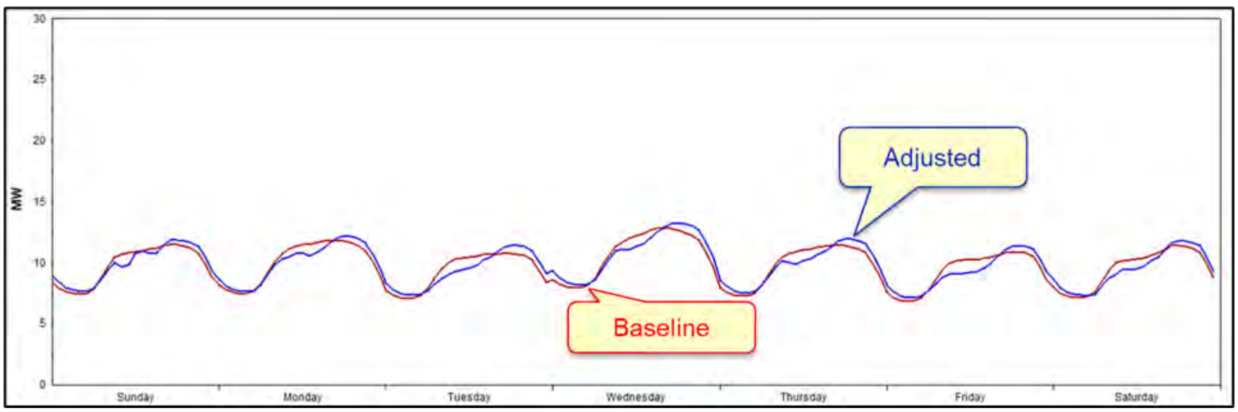


Figure 40: Baseline and Adjusted Forecast Comparison – Summer Week, 2030



The winter adjusted hourly load forecast is higher than the Baseline Forecast with the addition of heat pumps and vehicle charging. Solar impacts can be seen in the summer load profile. Specifically, the adjusted summer hourly load profile is lower than the Baseline profile during daylight hours. The impact of solar load, however, is somewhat mitigated by heat-pump cooling load increases and some daytime vehicle charging.

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 2010 to July 2020. The peak demand model is based on monthly peak demands derived from Stowe's hourly load data over the period January 1, 2011 to May 31, 2020.

Town hourly load data is also used in estimating the Baseline Town hourly load profile. A separate hourly load profile model is estimated for Mountain hourly loads.

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 have a positive value when temperatures are below a specified temperature reference point and CDD are 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 the Burlington International Airport. Monthly HDD and CDD are calculated as the sum of the daily degree days during the month:

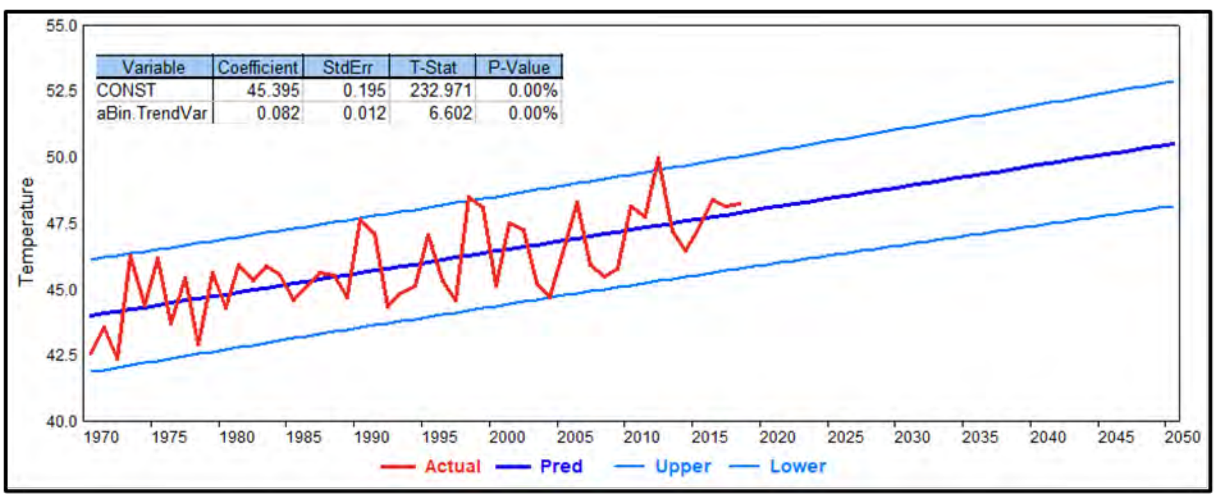
〖HDD55〗_m=∑Max(〖55-Temperature〗_d,0)

〖CDD65〗_m=∑Max(〖Tempature〗_d-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 41 shows the long-term temperature trend for Burlington Airport.

Figure 41: Burlington Airport Temperature Trend



The estimated model shows, that since 1970, 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 translates into a 0.2% annual decrease in number of HDD and 1.0% annual increase in the number of CDD. Figure 42 and Figure 43 show historical and projected HDD and CDD.

Figure 42: Annual HDD (trend normal start in 2020)

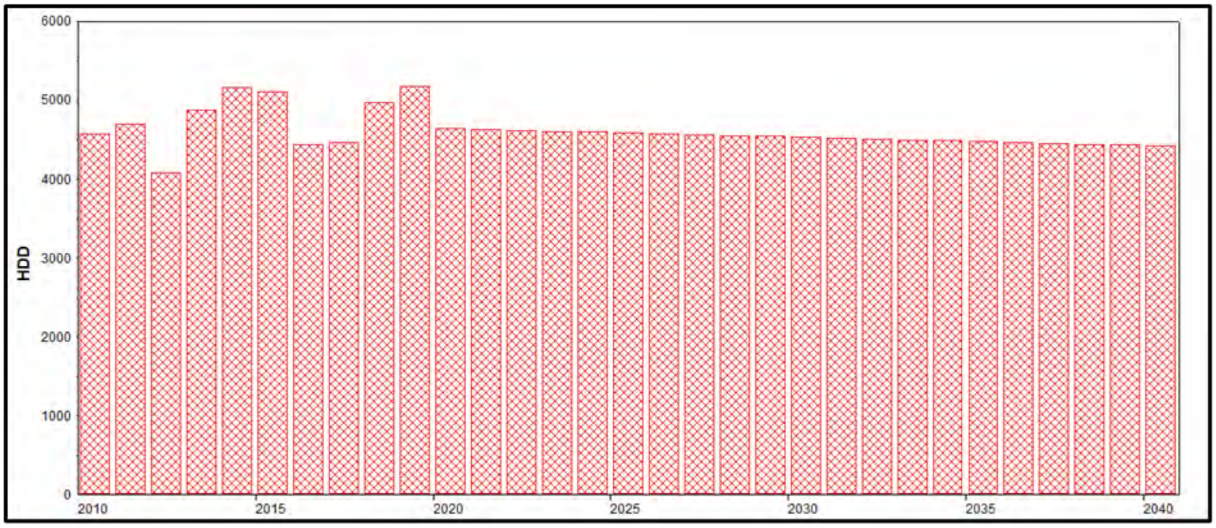
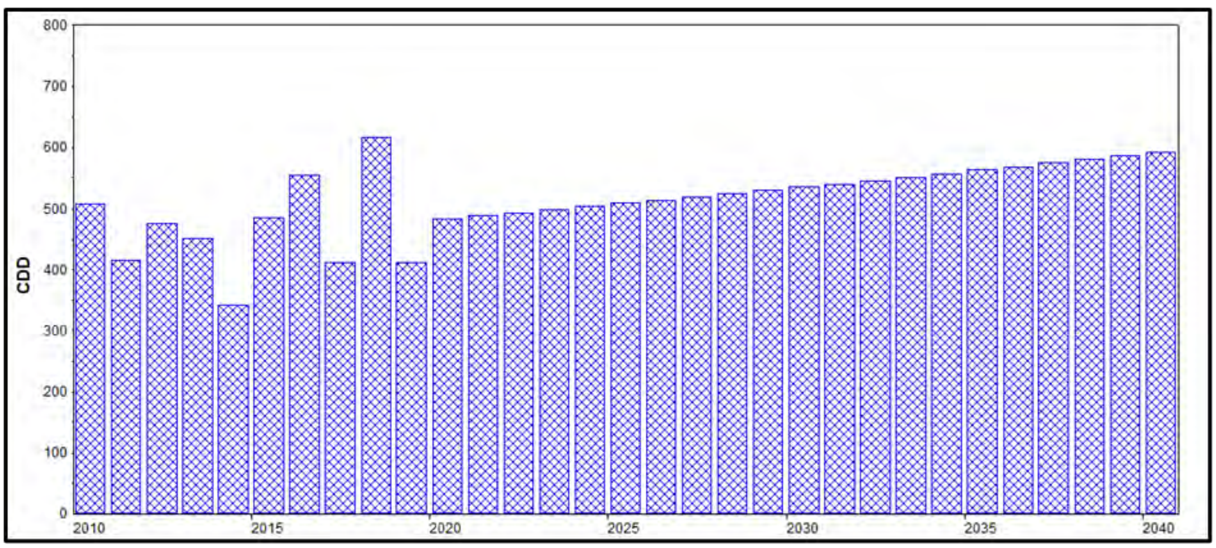


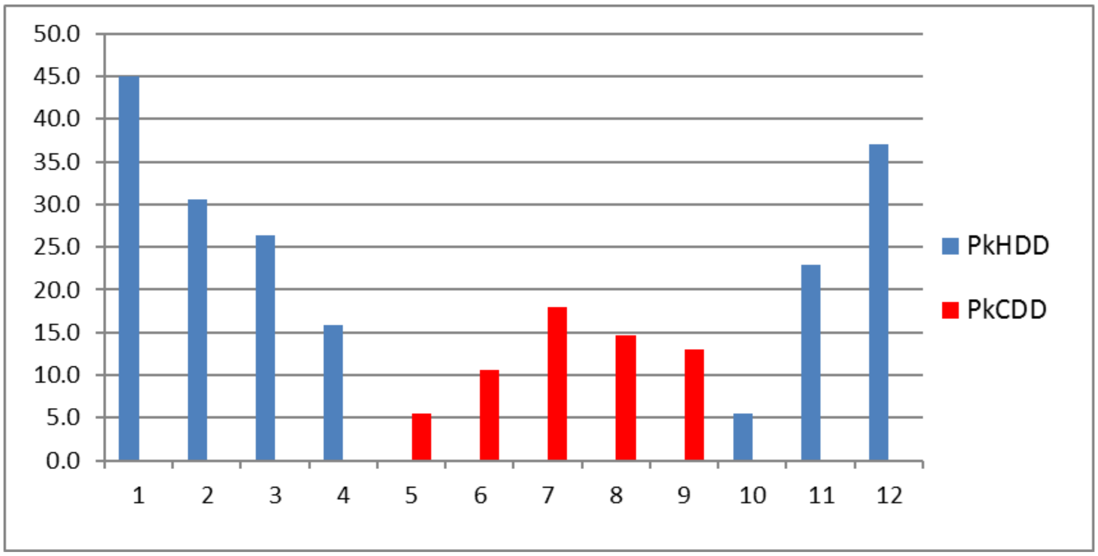
Figure 43: Monthly CDD



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 ten-year period (2010 to 2019). 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 44 shows the result of this process.

Figure 44: 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 May 2020 economic forecast for Vermont. Table 4 summarizes the primary economic drivers.

Table 4: Moody Analytics May 2020 Vermont Economic Forecast

Year	Households (Thou)	Real Household Income ($)	GSP (Mil $)	Employment (Thou)
2010	256.8	105.6	28,025	298.0
2011	258.9	107.8	28,693	300.9
2012	260.2	108.9	28,954	304.5
2013	262.1	108.5	28,455	306.7
2014	263.4	110.2	28,498	309.6
2015	264.1	113.8	28,954	312.1
2016	264.2	115.2	29,322	313.3
2017	264.5	115.9	29,414	315.0
2018	264.7	118.5	29,771	316.0
2019	264.9	121.4	30,341	315.4
2020	266.0	119.7	29,117	296.7
2021	264.9	118.2	29,407	296.1
2022	265.3	119.6	31,049	302.4
2023	266.4	121.8	32,308	308.5
2024	267.5	122.9	33,027	311.5
2025	268.5	123.2	33,547	312.4
2026	269.5	123.8	34,075	313.2
2027	270.4	124.6	34,639	313.8
2028	271.1	125.7	35,258	314.6
2029	271.7	126.7	35,859	315.6
2030	272.3	127.4	36,445	316.7
2031	272.7	128.2	37,031	317.7
2032	273.1	128.8	37,616	318.6
2033	273.3	129.1	38,199	319.5
2034	273.4	129.3	38,773	320.2
2035	273.5	129.6	39,342	320.9
2036	273.4	129.8	39,914	321.6
2037	273.3	130.0	40,475	322.4
2038	273.1	130.2	41,038	323.2
2039	272.7	130.4	41,621	324.0
2040	272.4	130.5	42,216	324.8
2010-20	0.4%	1.3%	0.4%	0.0%
2021-40	0.1%	0.5%	1.6%	0.4%

In 2020, Moody Analytics shows a significant drop in Gross State Product (GSP) and employment from the COVID-19 economic shutdown. COVID-19 impacts are expected to continue into 2021 with a relatively strong drop in number of state households and no employment growth until 2022. The economy is expected to recover after 2022 with strong economic growth through 2024. 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) 2020 New England Census Division forecast. End-use saturation and stock efficiency estimates are used in constructing end-use intensity estimates. Residential heating and cooling saturations are calibrated to Vermont-specific heating and cooling saturation data derived from state-sponsored efficiency potential studies. 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.

A significant share of energy efficiency (EE) program impacts is captured in the end-use intensities. EE program impacts are captured two ways. First, EIA updates the end-use saturations based on appliance shipment data. EE programs that promote adoption of more efficient technologies are reflected in this data. Second, EIA directly models the impact of EE programs through the end-use technology choice models. Costs associated with the most efficient technology options are "rebated" lowering the cost of these options. In turn, the model selects a greater share of the more efficient technology options.

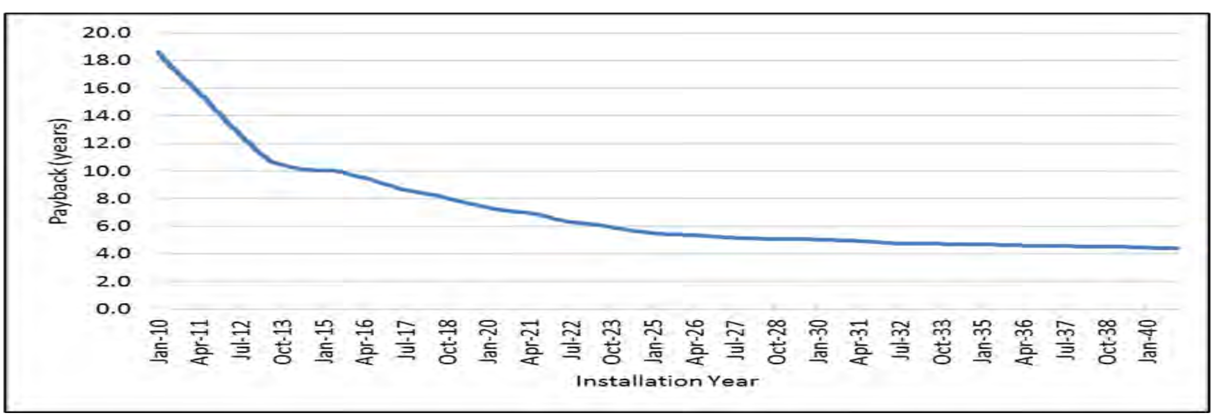
C.4.5 Solar Load Forecast

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 45.

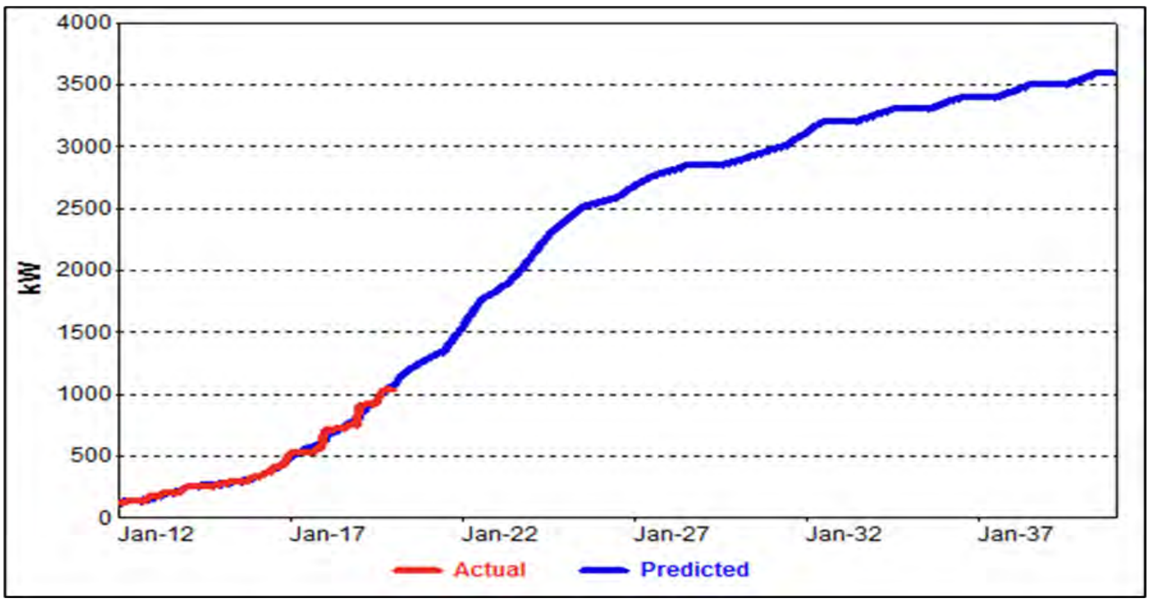
Figure 45: Payback Curve



Current system payback is roughly 7 years. By 2030, payback is expected to fall to 5 years. The most significant factor driving the payback trend downwards is system costs (expressed on an installed dollar per watt basis). System costs have been declining rapidly over the last five years. In 2014, the average residential solar system cost $4.24 per watt; by 2019 costs have dropped to $3.02 per watt. For the forecast, we assume that system costs continue to decline on average 5% per year through 2028, at which point costs continue to decline at 1% a year.

The capacity model relates the installed capacity to simple payback using a cubic specification. A cubic model specification is chosen to impose an S-shaped adoption curve. Figure 46 shows the resulting customer share forecast.

Figure 46: Solar Share Forecast



The energy forecast is adjusted for incremental new solar capacity beginning in July 2020. 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 for Burlington. The PV shape is an engineering estimate of a typical generation profile for the state. Table 5 shows solar capacity and generation forecasts.

Table 5: Solar Capacity and Generation Forecast

Year	Capacity (MW)	Generation (MWh)
2020	1.2	1,492
2021	1.4	1,716
2022	1.8	2,145
2023	2.0	2,427
2024	2.3	2,832
2025	2.5	3,106
2026	2.6	3,235
2027	2.8	3,420
2028	2.8	3,533
2029	2.9	3,547
2030	2.9	3,645
2031	3.0	3,769
2032	3.2	3,971
2033	3.2	3,997
2034	3.3	4,091
2035	3.3	4,115
2036	3.4	4,221
2037	3.4	4,236
2038	3.5	4,334
2039	3.5	4,359
2040	3.6	4,470

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

C.4.6 Cold Climate Heat Pump (CCHP) Forecast

As part of state efforts to reduce CO2 emissions, Efficiency Vermont (EVT) and the distribution utilities have an aggressive program to promote the adoption of cold climate heat pumps (CCHP). The primary target market are homes that heat with oil or propane. EVT along with input from the Department of Public Service developed a long-term forecast of CCHP units for low, medium, and high case. The Adjusted forecast uses the medium CCHP forecast.

The CCHP program incentivizes adoption through cost rebates. EVT expects sales of around 6,000 units in the near-term, rising to 10,000 units by 2030 for the entire state. The state level forecast is apportioned to Stowe based on the ratio of Stowe customers to total state customers; Stowe has approximately 1.0% of the state population.

EIA includes heat pumps in the end-use intensity projections. To avoid double-counting program impacts, Baseline heat pump forecast (based on the EIA forecasted saturation rate) are subtracted from the incentivized heat pump unit projections. The difference is program-induced adoption.

Program-related energy gains are calculated as the product of net number of units adopted through the program and annual unit energy consumption (UEC). 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 6.

Table 6: Heat Pump Sales (MHW)

Year	Heating	Cooling
2020	100	7
2021	205	14
2022	323	22
2023	454	31
2024	596	41
2025	749	51
2026	913	63
2027	1,089	75
2028	1,276	87
2029	1,476	101
2030	1,666	114
2031	1,829	125
2032	1,984	135
2033	2,131	145
2034	2,277	155
2035	2,423	164
2036	2,572	174
2037	2,720	184
2038	2,867	194
2039	3,015	204
2040	3,161	214

C.4.7 Electric Vehicle Forecast

The electric vehicle (EV) forecast was developed by VEIC and Drive Electric, which provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The forecast is based on achieving target EV saturation rates by 2050; the saturation rate is the percent of all registered vehicles that are electric. The low case is 35%, the medium case is 60%, and the high case is 90%. VEIC assumes that adoption will follow an S-shape path and fits a logistic curve starting with current level of electric vehicle saturation and reaching target-level saturation by 2050.

The 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 2020, there were 3,716 registered electric vehicles; in the medium case this reaches 250,000 EVs by 2040. The forecast is allocated to Stowe based on the ratio of Stowe customers to the number of state electric customers. The forecasted number of vehicles and sales is shown in Table 7.

Table 7: Electric Vehicle Forecast

Year	Vehicle Count	Vehicle Consumption (MWh)
2020	52	169
2021	69	224
2022	91	299
2023	121	399
2024	160	531
2025	211	705
2026	277	930
2027	361	1,220
2028	467	1,586
2029	600	2,042
2030	760	2,597
2031	949	3,255
2032	1,165	4,006
2033	1,401	4,831
2034	1,647	5,690
2035	1,890	6,543
2036	2,117	7,339
2037	2,316	8,038
2038	2,480	8,614
2039	2,609	9,065
2040	2,705	9,400

The impact of EVs on system load and peak depends on the EV charging profile. The charging profile is constructed from Green Mountain Power (GMP) measured vehicle charging load data. 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 because of colder weather.

C.5 Forecast Scenarios

C.5.1 Forecast Scenarios

The Adjusted load forecast represents the most likely long-term energy and demand outcome. Low and high case forecast are based on state CCHP and EV projections. These technologies have the largest impact on long-term demand and the highest uncertainty factor due to the level (number of units) and adoption timing. The low case is based on the state low-case heat pump and electric vehicle forecasts and the high case on the high-case heat pump and EV forecast. High and low case forecast for these technologies were developed by VEIC. The technology forecasts are derived by scaling down the state-level forecast to Stowe, based on the number of customers. Figure 47 and Figure 48 show the three forecast scenarios.

Figure 47: Electric Vehicle Scenarios: Sales (MWh)

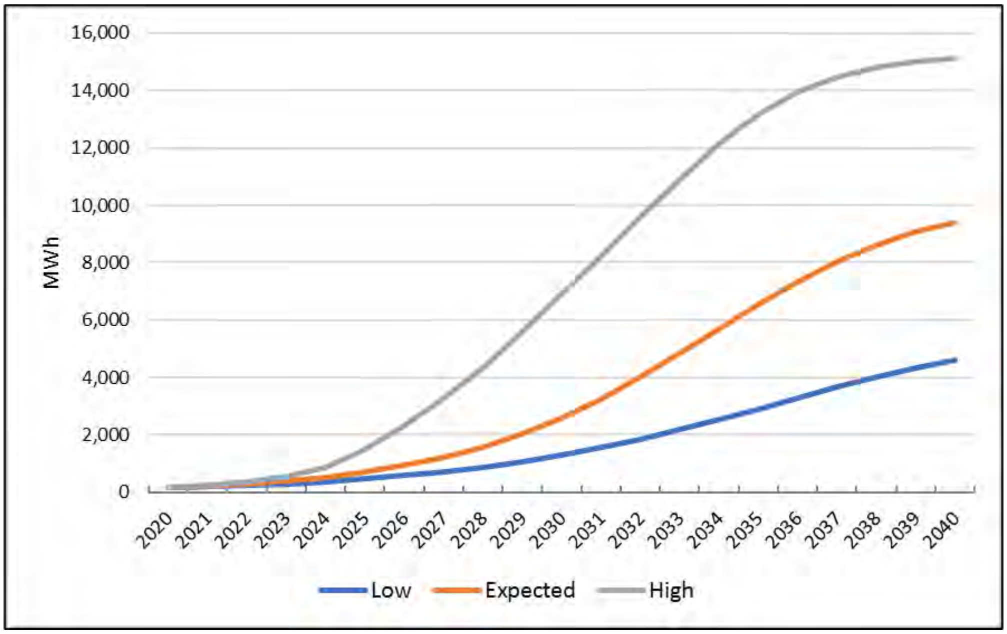


Figure 48: Heat Pump Scenarios: Sales (MWh)

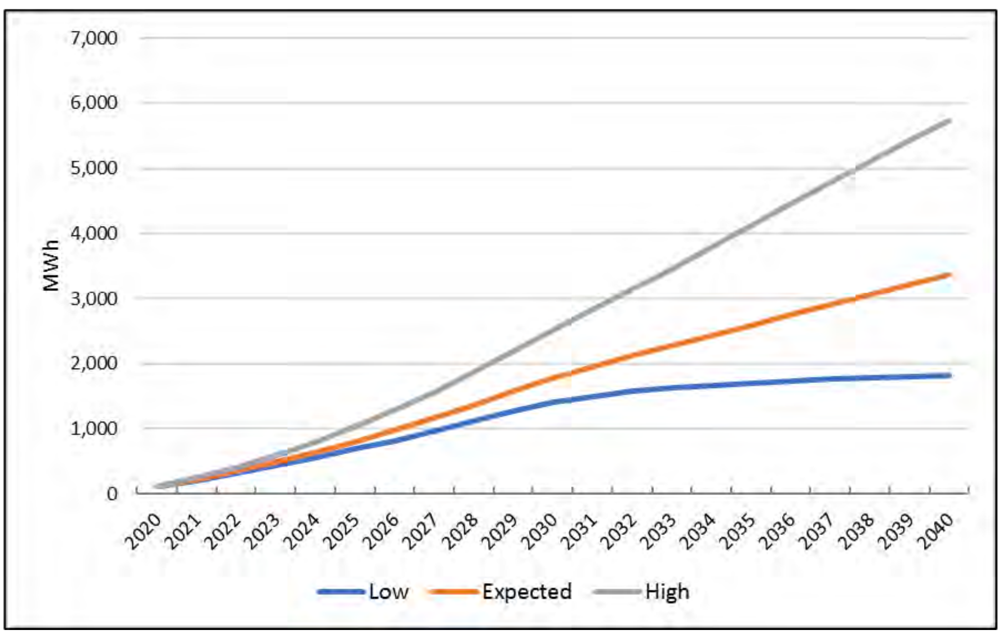


Table 8 and Table 9 compare energy and peaks for the three scenarios.

Table 8: Forecast Scenarios – Energy (MWh)

Year	Low Case	Expected	High Case
2021	77,563	77,603	77,650
2025	78,570	78,921	79,934
2030	81,310	82,995	88,073
2035	83,528	88,095	96,352
2040	85,064	91,473	99,691
2021-30	0.5%	0.7%	1.4%
2030-40	0.5%	1.0%	1.2%

Table 9: Forecast Scenarios – Peak (MWh)

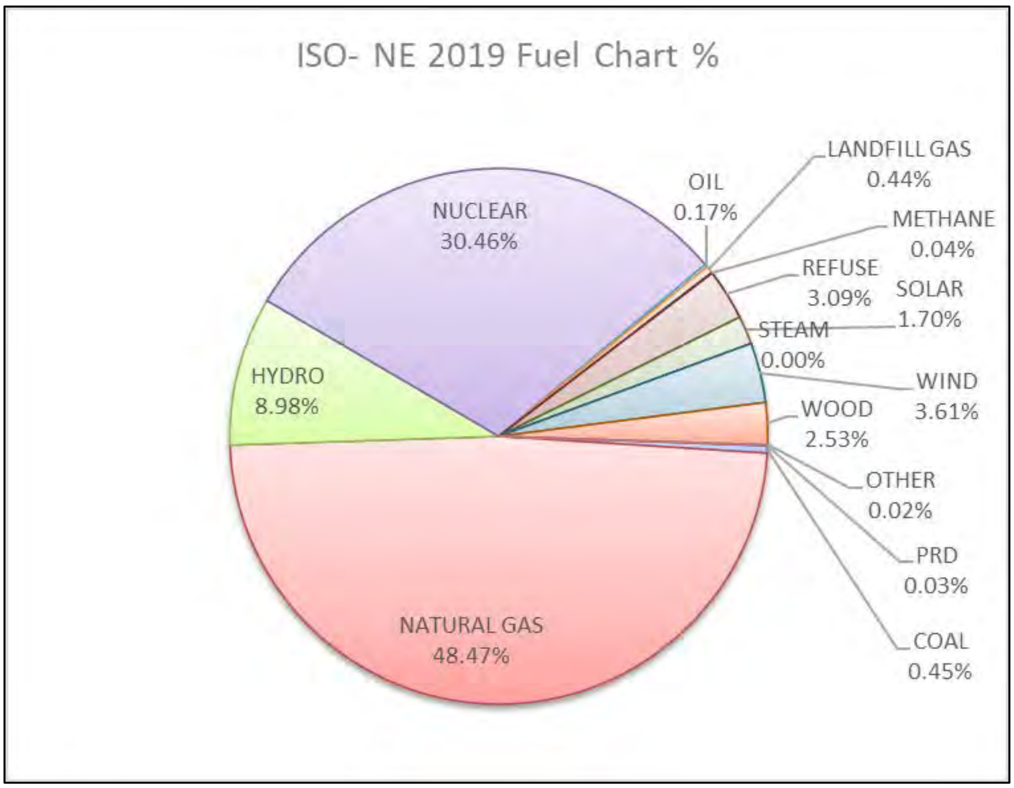
Year	Low Case	Expected	High Case
2021	16.9	16.9	16.9
2025	17.6	17.6	17.8
2030	17.6	18.0	19.0
2035	18.2	19.4	21.6
2040	18.3	19.8	21.8
2021-30	0.4%	0.6%	1.3%
2030-40	0.4%	1.0%	1.4%

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. As seen below in Figure 49 natural gas is about 48.5% of the resource fuel type used to cover the New England demand. Natural gas has helped New England realize lower carbon rates from the retirement of fossil fuel plants. Decarbonization in the region further increased with the shuttering coal plants, such as Salem Harbor in Salem MA and Brayton Point in Somerset MA, Mystic 7, 8, and 9 in Charlestown MA, Bridgeport Harbor 3 in Bridgeport CT. In ISO-NE "[n]atural Gas has become the dominant fuel used to produce electricity in New England, displacing higher emitting and less economic power plants. With supply from the nearby Marcellus Shale and relatively low construction costs, natural gas continues to be a top fuel choice for new generators."[10]

Figure 49: Supply Obligation by Fuel Type for Claimed Capability [11]



[10] https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints

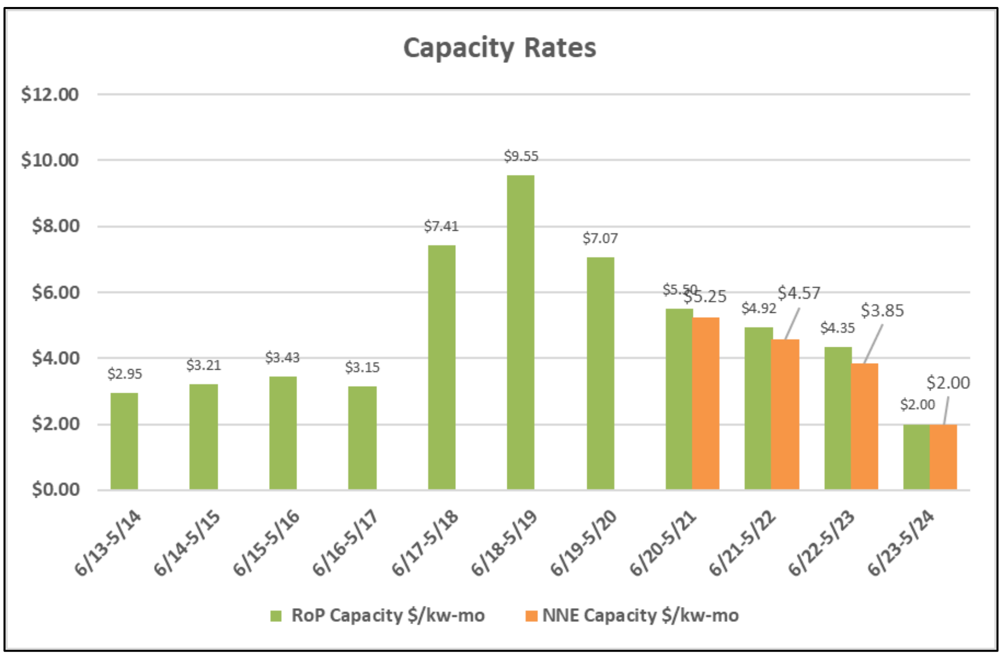
[11] https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load

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 a sufficient amount of resources to meet the 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 and demand response assets as well as support the existing resources. The evolution with FCM has been within the zonal classifications. In the beginning, there was Rest of Pool and Maine. Beginning on June 1, 2016 there were Rest of Pool, Maine, Connecticut, and NEMA/Boston capacity zones. Currently, in the latest auction #14, there were Rest of Pool, Northern New England (NNE), and Southeast New England (SENE). Stowe has been in Rest of Pool until auction 11, where they now are under Northern New England. Historically, there has been price separation from zone to zone. The zones that were import constrained (NEMA) had larger clearing prices. Seen in Figure 50 are the clearing prices for the Rest of Pool and NNE Locations that have and will affect Stowe's capacity charges.

Figure 50: Rest of Pool and Northern New England's Capacity Auction Clearing Prices



The zone location affects resource compensation, meaning where the unit resides will determine the compensation, which will not be a one for one on the load charge rates. This brings up the importance on self-supplying resources that are qualified to do so. In FCM 14, Stowe has self-supplied Stony Brook, NextEra's Seabrook, and McNeil. This will guarantee a 1 to 1 offset of Stowe's load charges. Stowe's capacity portfolio can be found in Figure 77: Stowe's Capacity Forecast

The most recent Capacity auction began on February 3, 2020 for Forward Capacity Market (FMC) 14, which will begin on June 1, 2023 through May 31, 2024. The latest self-supply designation window was completed on October 28, 2019 for FCM 14. The auction for FCM 14 had an abundance of resources to meet the peak demand, which resulted in the lowest clearing price in Forward Capacity Auction (FCA) history.

There were 516 new resources qualified in the FCM 14. 33,956 megawatts (MW) of resources with commitments will be available, but the regional target was only 32,490 MW. The region can secure additional capacity beyond the target to ensure reliability and cost-effective prices. 317 MW of new resources were under the renewable technology resource designation (RTR). These resources included both land and offshore wind, solar and solar paired with battery systems.

The sophomore program Competitive Auctions with Sponsored Policy Resources (CASPR), which allows for a substitution auction where resources retiring can trade their capacity supply obligation to new state-sponsored resources had no trades this year.

FCM 14 had four locations the Southeast New England "SENE" (encompassed NEMA, SEMA, and RI), the Northern New England "NNE" (encompasses ME, VT, and NH), and the Rest of Pool Zone (CT, and WMASS), and Maine. In this auction, all locations cleared at the same price of $2.001/kW-month, which is the lowest price the FCM has cleared. This auction had no price separation in any zone.
Pay for Performance incentive began in FCA 9 (June 2018- May 2019). The rate paid and rewarded is the same $2,000/MWH. This rate will increase in FCA 12 to $3,500/MWH, then to $5,455/MWH in In FCA 14. There has been one Scarcity Event on September 3, 2018.

Stowe will assess the capacity market when researching different portfolio scenarios. Placement of generation and settlement of generation will come into play. Resources that directly offset peak usage for Stowe will be most attractive, because it will lower Stowe's obligation and give them the largest benefit. When forecasting the future capacity rates of the cost relations to portfolio scenarios for Stowe's IRP, the process included the analyzation of historical clearing prices and what factors drove those prices. Table 10 below shows how much capacity was needed and how much the clearing prices were affected by new Demand resources and New Generation. In the auctions where new resources were needed the most, the clearing prices were greater. Currently the system has sufficient resources to meet electric demand in 2020-2021 and therefore it caused the lowest price settlement of the past three auctions.

Table 10: ISO Auction Results of the Annual Forward Capacity Auction[12]

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[3]	$3.80
FCA #14 in 2020 for CCP 2023/2024	33,956	323	335	$2.00

ENE utilized a Monte Carlo simulation technique to estimate future capacity clearing prices Northern New England capacity zone. Simulation results are found 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 markets power prices. Providing reliable and competitive prices are the goals of the operation. Using economic dispatch and clearing prices to cover the region's

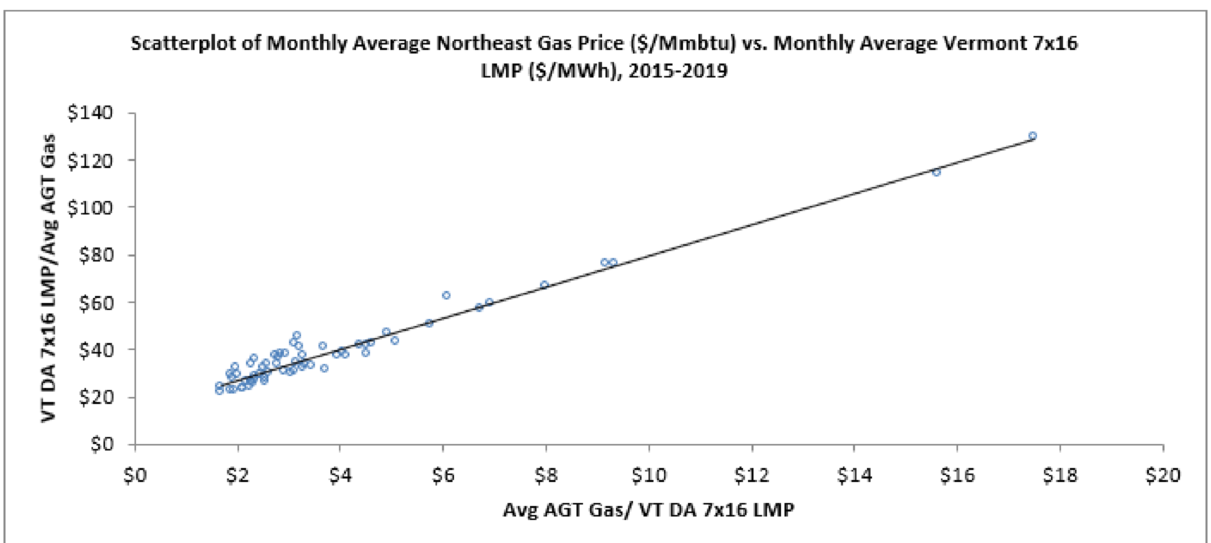
[12] https://www.iso-ne.com/about/key-stats/markets#fcaresults

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.

Stowe's dispatchable resources Stony Brook, which ISO-NE dispatches in either the day-ahead or the real-time spot markets for each operating day. This unit will protect Stowe from high price market power because if bid at prices below market at their locations, they will be dispatched, and thus offset spot market energy purchases for Stowe. If they do not dispatch, then Stowe will purchase greater amounts of energy that day from the spot market. The benefit of the dispatchable resources is that if they are not economically dispatched, Stowe will buy those remaining megawatts at a lower cost through spot market purchases.

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 implied heat rates for the future. 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 51, which shows a .981 correlation between Vermont Zone 5x16 monthly average LMPs with monthly average northeast delivered natural gas prices.

Figure 51: Vermont LMP Scatterplot Correlation to Northeast Natural Gas Prices



Correlation	0.9810058

The assumptions construct ENE's forward curve of power prices in New England. In the portfolio optimization model, this forward curve is set to a mean (*expected* outcome); then, 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 in Figure 52 through Figure 56 contain forward energy curves and simulations.

Figure 52: ISO New England HUB PEAK FWD CURVE HISTORY

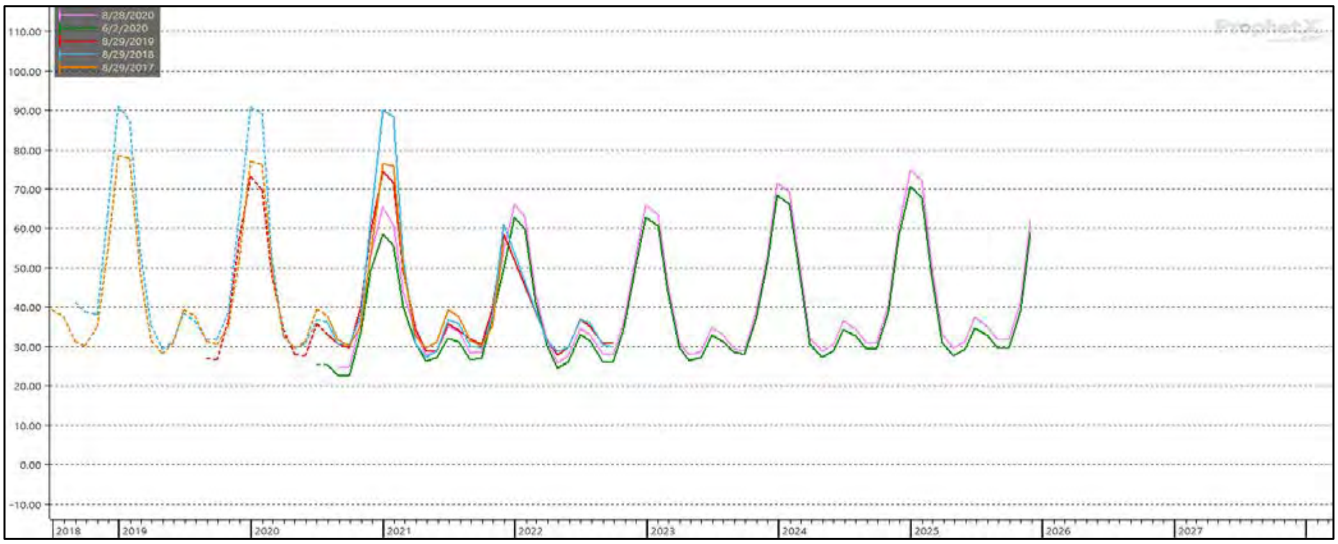


Figure 52 displays the path of the forward curve since 2017. Overall forward prices peaked during 2018 and hit 20-year lows in June of 2020. Forward prices have moved up during the summer of 2020 but are still within 4% of all-time lows.

Figure 53: Mass Hub ATC LMP, Monthly Simulated Range Jan 2021 to Dec 2040

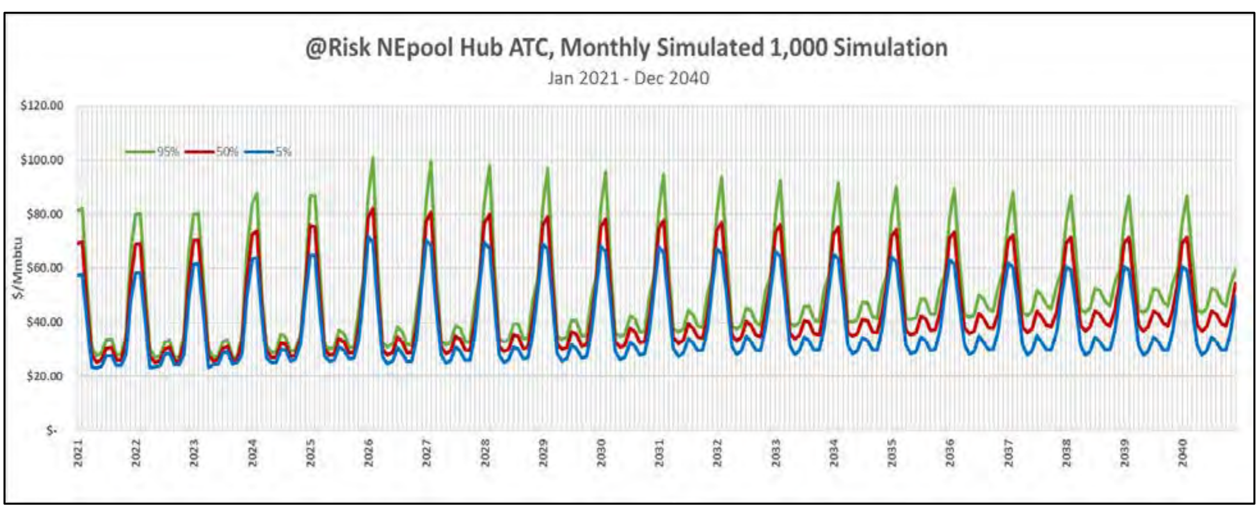


Figure 53 is a probabilistic simulation of New England Hub Around-The-Clock pricing through 2040. Winter pricing exhibits a significant standard deviation from the rest of the year. During a cold winter when natural gas pipelines are constrained, monthly winter pricing can jump as high as $100 MWH. During a warm winter prices can be lower around $60/MWH. This creates a probabilistic range of $40/MWH.

Figure 54: Vermont Zone ATC, Monthly simulated Range Jan 2021 to December 2040

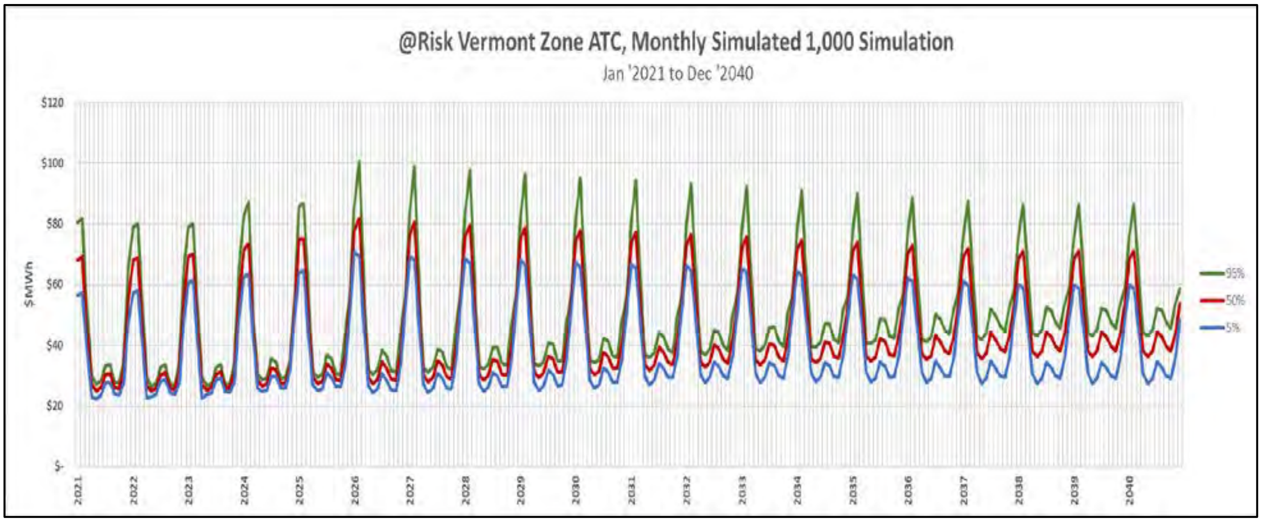


Figure 54 is a probabilistic simulation of Vermont Around-The-Clock pricing through 2040. Like New England pricing, Vermont zone can exhibit significant range of pricing in the winter months. The summer months have a narrower range since there is less volatility in the price of gas paid by generators.

Figure 55: Vermont to Mass Hub Basis, Monthly Simulated Range, ATC

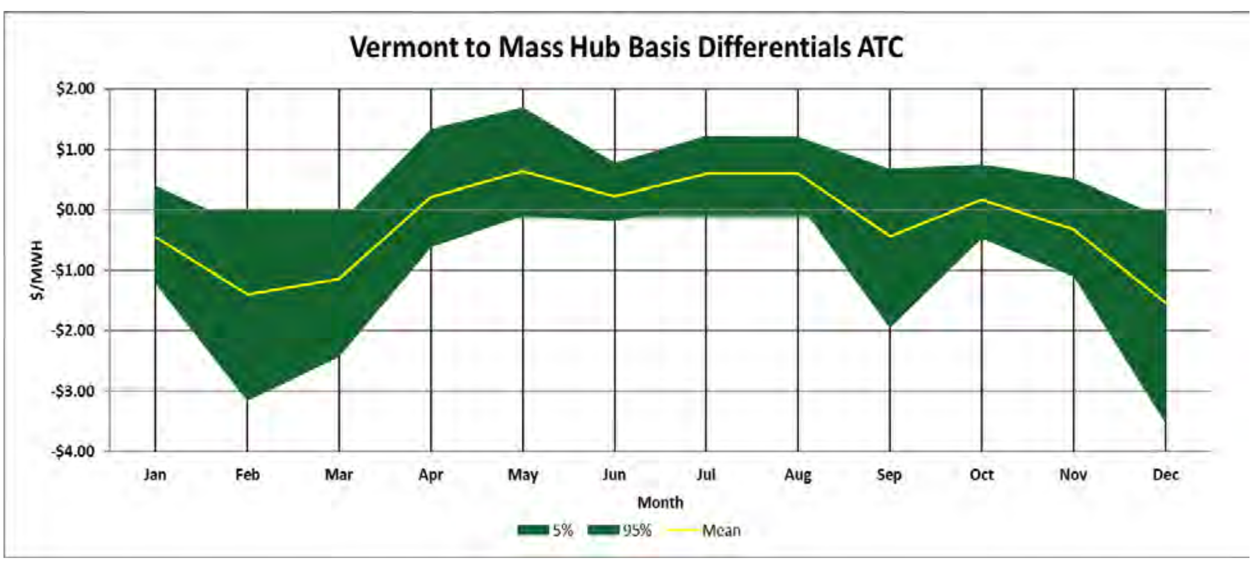


Figure 55 displays a simulated range in the ATC price differential (Basis) between the Vermont Load Zone and the Mass Hub. On average Vermont pricing is slightly above Mass Hub in the spring-summer months, and then Vermont is cheaper than hub in the winter months. This pricing trend is because VT has high wind/hydro generation in the winter-spring months, which reduces VT prices relative to Hub.

D.2.3 Natural Gas in New England

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

Over the last two decades, the reliance on natural gas for electricity generation has grown significantly in the Northeast; going from 13% to 40% share of the region's total electricity generation. As of 2019, over 40% of regional electricity generation was reported to be fueled primarily by natural gas as seen below in Figure 56.

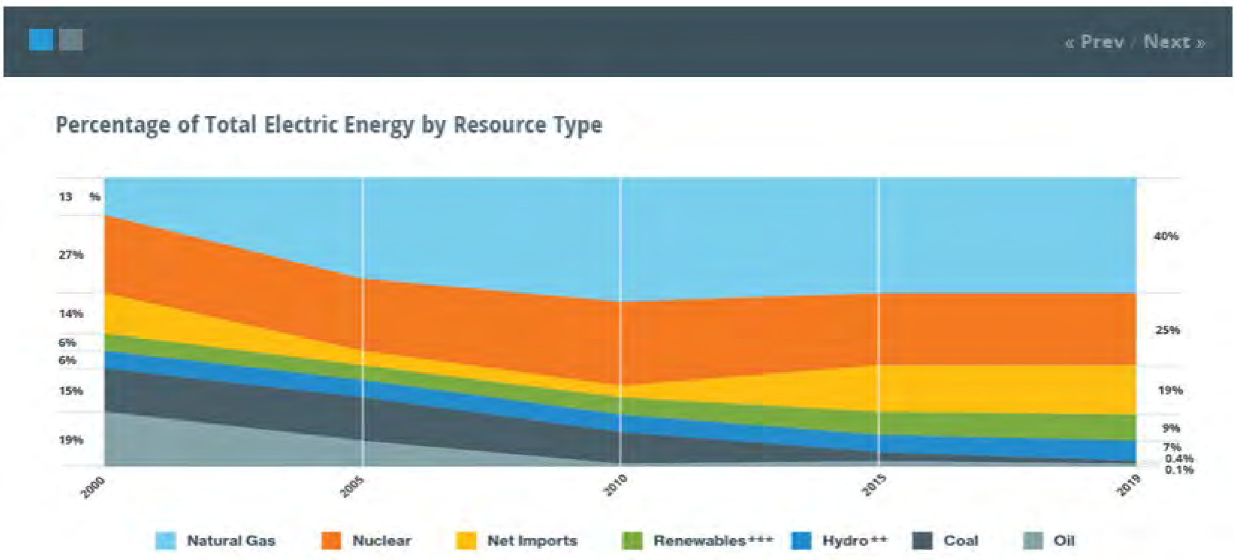
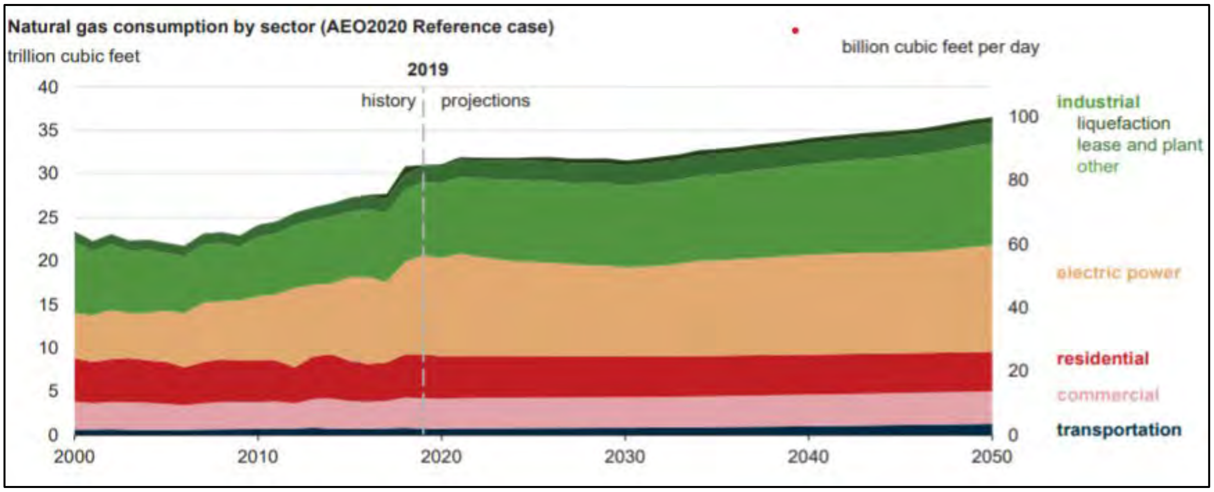


Figure 56: New England Resource Mix – Percent of Total System Capacity by Fuel Type[13]

The predominant reason for natural gas surpassing coal as the fuel of choice for a majority of electricity generation regionally has been due to the development of increased access to low-cost natural gas (resulting from improvements in drilling technologies such as horizontal drilling and hydraulic fracturing) from the Marcellus Shale and other regional shale plays within the Appalachian Basin. Furthermore, environmental policies such as the Regional Greenhouse Gas Initiative (RGGI) as well as state-driven renewable portfolio standards have also contributed to the dwindling reliance on coal throughout the region. With the "Relatively low U.S. natural gas prices in the AEO2020 Reference case lead to continued growth in natural gas consumption in the near term, particularly in the electric power sector. However, through 2050, only the industrial sector shows markedly increased natural gas consumption", as seen below in Figure 57. Although usage increases in the outward years, United States will remain a large exporter of natural gas.

[13] https://www.iso-ne.com/about/key-stats/resource-mix

Figure 57: Industrial and electric power demand[14]



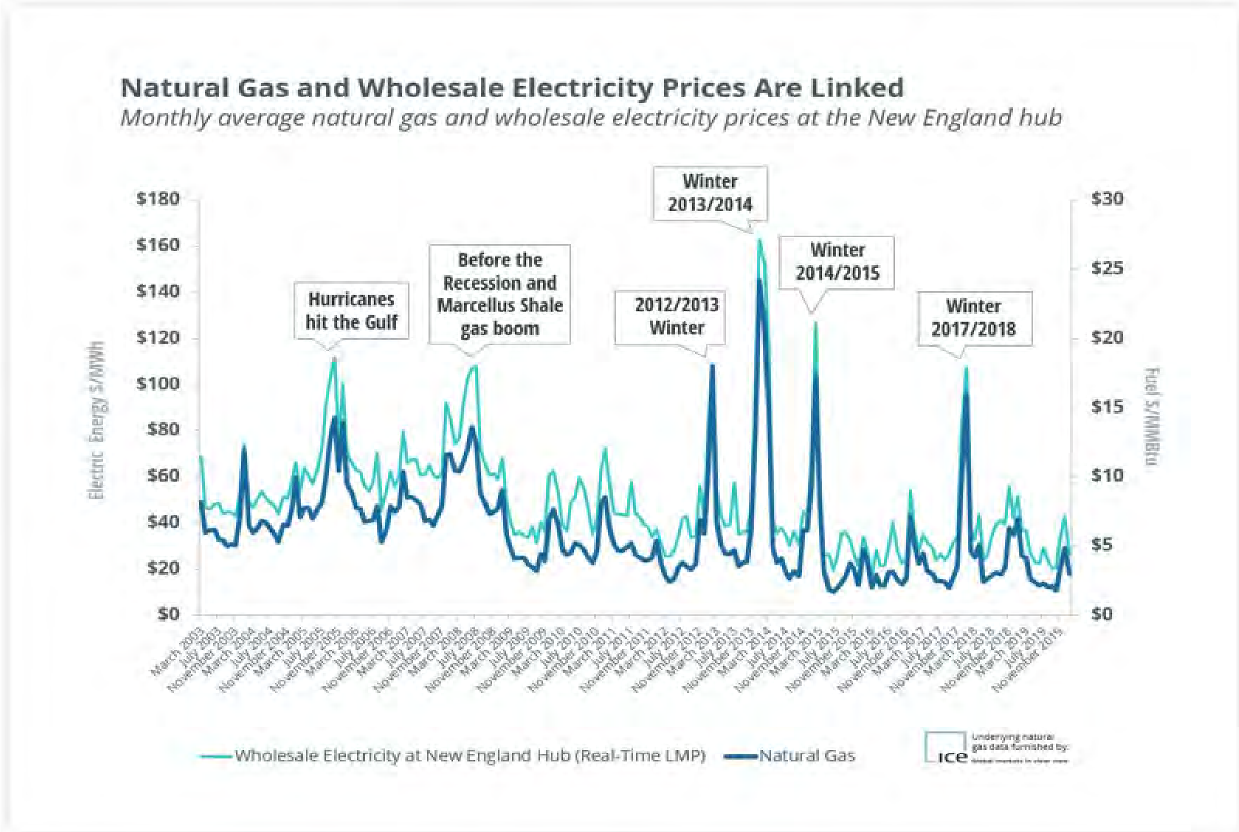
D.2.3.2 Market Fundamentals Influencing Spot and Forward Pricing of Natural Gas and Wholesale Electricity in New England

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 relatively 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. The market fundamentals of supply and demand, which are mostly driven by seasonal weather cycles and production/storage data, largely 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) and the winter of '17/'18 (due to the Bomb Cyclone), 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 cost of moving a commodity from point A to B - in New England's case, moving natural gas from Henry Hub 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 have been lower than in previous years, as shown in Figure 58.

[14] https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Natural%20Gas.pdf

Figure 58: Link between Regional Prices for Natural Gas and Wholesale Electricity[15]



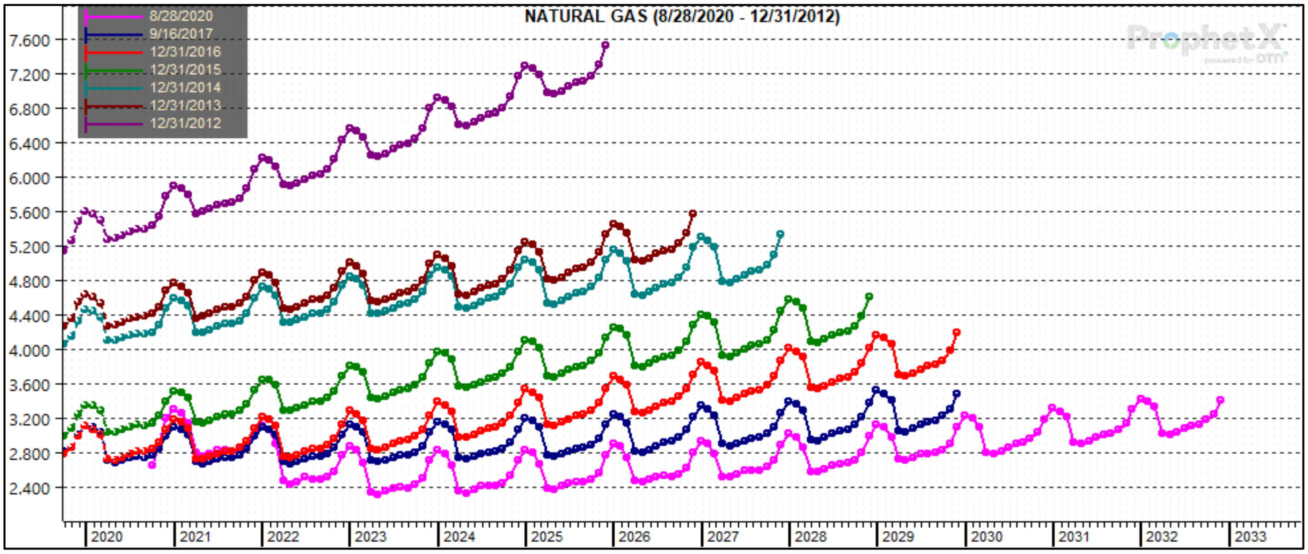
D.2.3.3 Natural Gas in New England - Summary

The Northeast saw an additional pipeline capacity built in 2018 and anticipates more expansion. The question is whether the capacity buildout can keep pace with the pipeline infrastructure. “In 2000, natural gas fueled just 15% of the region’s electricity. Since then, it has become the dominant fuel used to produce electricity in New England, displacing higher emitting and less economic power plants.”[16] Natural gas power has helped the region overall in reducing air emissions and reducing cost of power.

Natural gas prices have come down over the last several years, as seen in the “flattening” of the forward curve shown in Figure 59. These price decreases are the result of enhancements in exploration and production technologies, increased supply, and resources (i.e. Marcellus Shale play), and warmer-than-normal temperatures experienced over the past several winters.

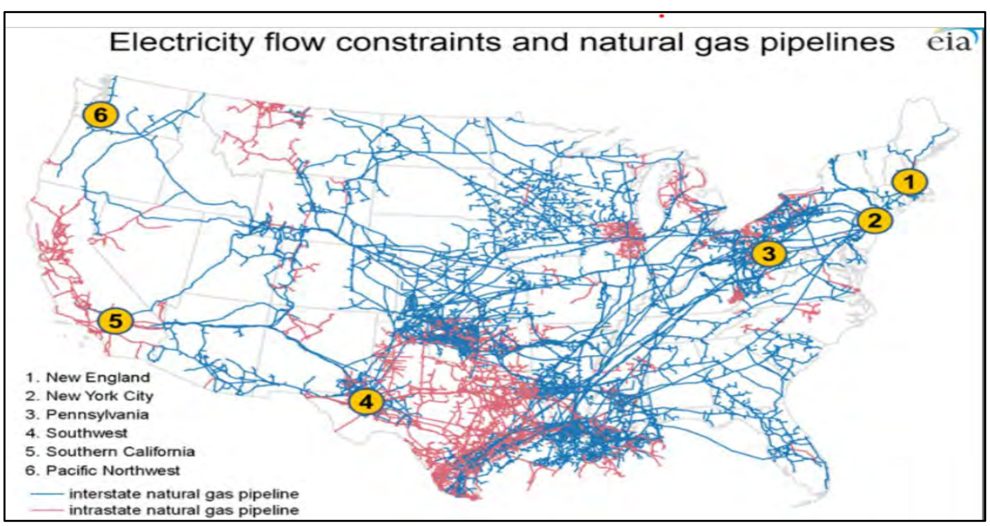
[15] https://www.iso-ne.com/about/key-stats/markets
[16] https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints

Figure 59: Natural Gas Forward Curve History



With more generators reliant on gas deliveries, New England could have price spikes due to the constrained pipelines. This scenario occurred in the winter of 2017-2018 during the Bomb Cyclone when generators had to resort to oil and residual fuel. Below in Figure 60, shows where in the United States localities have natural gas pipeline restrictions. Because New England is located at the end of the pipeline, the expected impacts to the system are small and access to the North American pipeline network limited. With the cold winters, the ISO- NE implemented markets (Winter Reliability Program and Pay for Performance measures) to help pay generators to store and retain fuel on site, which helps maintain reliability and reduce fuel risk.

Figure 60: Constraints and Natural Gas Pipelines[17]



[17] https://www.eia.gov/electricity/monthly/update/archive/june2020/

Below figures are simulated Natural Gas, Algonquin and Henry Hub prices used to support the open position market prices that Stowe would purchase their spot need against.

Figure 61: Natural Gas, Algonquin Citygate, Monthly Simulated Range Jan 2021 to Dec 2040

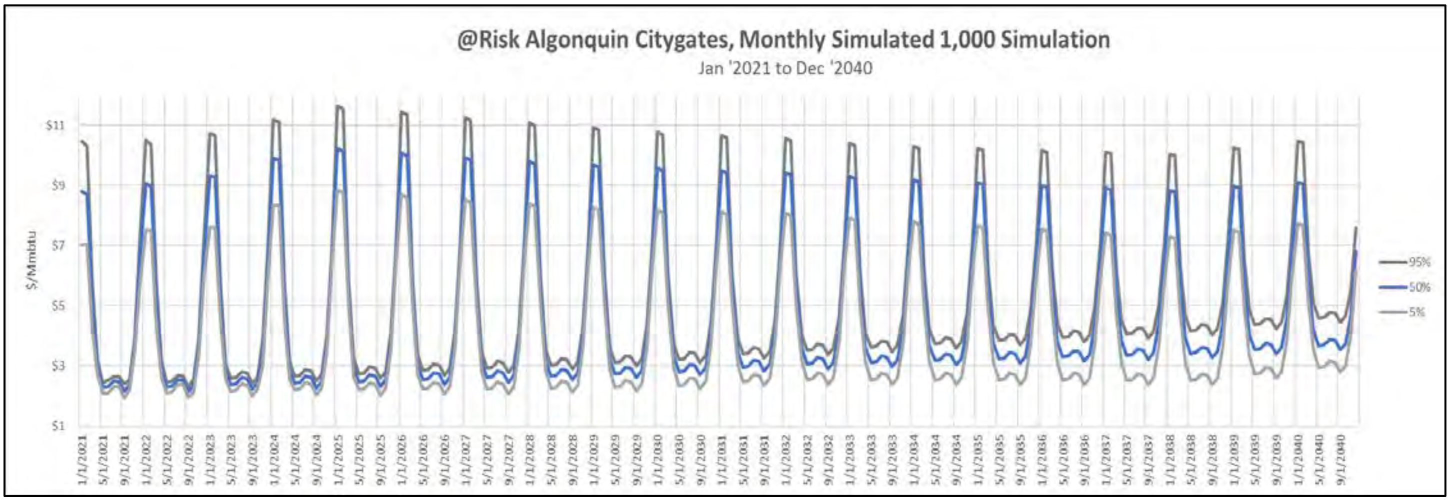
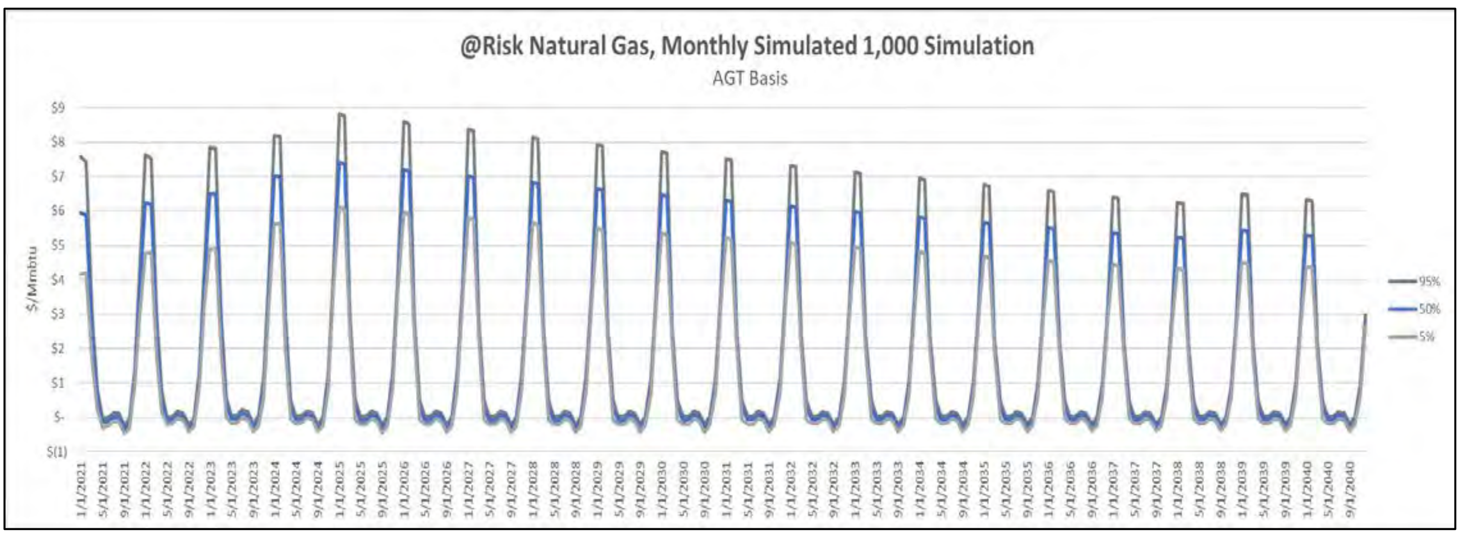


Figure 62: Algonquin to Henry Hub Basis, Monthly Simulated Range Jan 2021 to Dec 2040

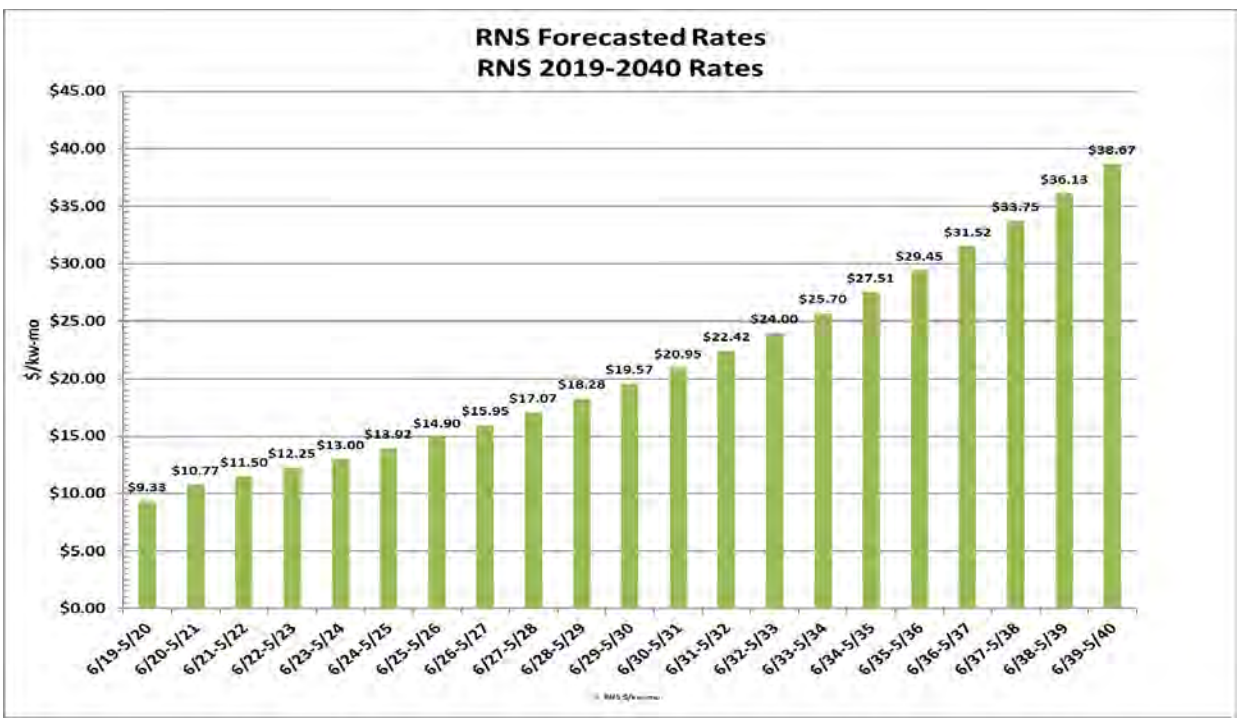


D.2.4 Transmission Market

The third largest piece of Stowe's ISO-NE costs are the Open Access Transmission Tariff (OATT) charges. 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.[18] These are monthly charges based on Stowe's regional network load value at VELCO's peak. Every summer, the ISO publishes the presentation from the Reliability Committee/Transmission Committee of the Rates Working Group for the RNS PRT Forecast. These going forward rates include current transmission projects.

Figure 63 shows the latest published forecast on August 18 & 19, 2020 ISO presentation. The rate year 19-20 and 20-21 are actual rates. The forecasts of RNS rates are steadily increasing, and therefore, Stowe's resource and efficiency become a larger importance. If Stowe can reduce consumption and do so at 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, shown in Table 11. With projected RNS costs totaling over 1.5 million a year, Stowe's desired portfolio will have a mix of load reduction resources and energy efficiency load savings.

Figure 63: RNS Forecasted Rates



18 https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/oatt-schedule9-rns

Table 11: Stowe's RNS Forecast

SED		
RNS Forecast		
Rate Year	RNS Rate $/kw-mo	Projected RNS Cost
6/20-5/21	$ 10.772	$ 1,489,608
6/21-5/22	$ 11.500	$ 1,590,307
6/22-5/23	$ 12.250	$ 1,694,023
6/23-5/24	$ 13.000	$ 1,797,738
6/24-5/25	$ 13.917	$ 1,924,502

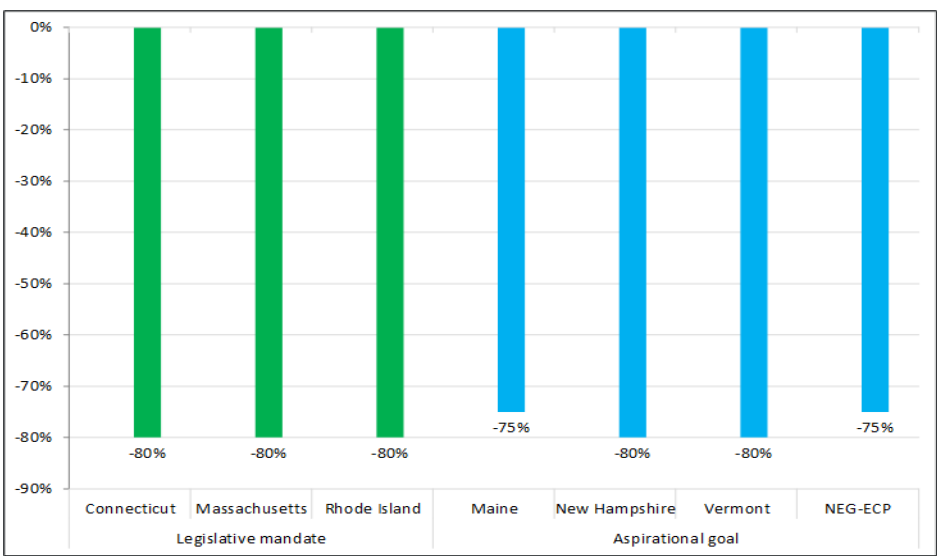
D.3 Assessment of Environmental Impact

ISO-NE is "the not-for-profit corporation 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] Stowe can use the information with the ISO-NE's Regional System Plan for its own planning purposes.

D.3.1 Emerging Technologies

The ISO-NE's plan references emerging technology growth in the system due to greenhouse gas reduction mandates and goals. Everything from behind the meter (BTM) solar to electrification initiatives to allow for adoption of EVs and CCHPs have introduced new demand for electricity. Below in Figure 64 is the New England states' goals for reducing GHG emissions. Vermont's goals are the results of emerging technology expansion for the Vermont Utilities.

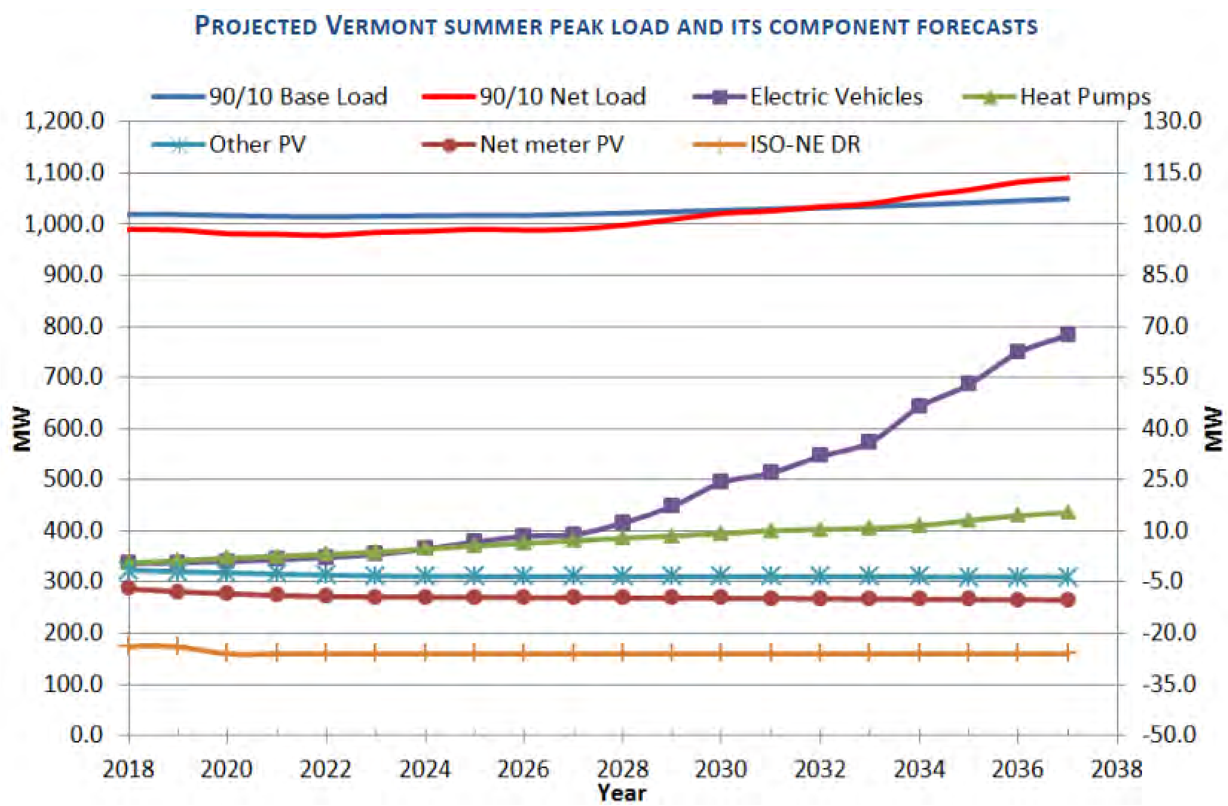
Figure 64: ISO 2019 Regional System Plan



[19] 2019 Regional System Plan (https://www.iso-ne.com/system-planning/system-plans-studies/rsp)

VELCO creates a long-range transmission plan, which provides a discussion of how emerging technologies can affect the future load of the state. VELCO used a new component in this report due to distributed generation and state policies effecting trends. VELCO's 2018 Plan states it was updated with "[p]redicting future demand relies on assumptions about economic growth, technology, regulation, weather, and many other factors. In addition, forecasting demand requires projecting the demand-reducing effects of investments in energy efficiency and small-scale renewable energy."[20] In Figure 65, VELCO assesses the MW impacts each technology can do to the Summer Peak load. Analyzing the trends, it can be reasonably assumed Stowe's load will increase or decrease at the same rate, if within Stowe, any technology enhancements include these same components.

Figure 65: VT Summer Peak Load Forecast[21]



[20] https://www.velco.com/assets/documents/2018%20LRTP%20Final%20_asfiled.pdf

[21] *2018 Vermont Long-Range Transmission Plan—6/29/2018*

D.3.1.1 Distributed Generation (DG)

ISO-NE describes distributed generation ("DG") as "[g]eneration 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 reached out for PV data within the Vermont utilities to help determine the DG affect and Burlington, GMP, Stowe, VEC, VPPSA, and WEC provided data as of December 31, 2019.[23] Vermont's data totaled 364.24 MW, and Stowe's contribution was 2.68 MW. In Figure 66 below are the survey results from all the New England States PV data along with the Vermont data.

Figure 66: ISO-NE Total PV Installed Capacity Survey Results

December 2019 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 12/31/19.

State	Installed Capacity (MW_{AC})	No. of Installations
Massachusetts*	2,180.45	102,381
Connecticut	566.53	44,514
Vermont*	364.24	13,863
New Hampshire	105.24	9,587
Rhode Island	159.75	7,776
Maine	56.32	5,387
New England	**3,432.53**	**183,508**

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

As of December 31, 2019, Stowe has 35 installed net-metered solar projects on residential accounts. The total installed kW is 594.625. 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 April 28, 2020, there has been 82.397 MW's of PV projects accepted as well as 14.230 MW's of Biomass, Farm, Food Waste and Landfill Methane, and Hydroelectric. Lastly there are 0.811 MW of small wind generation that reduces the Vermont Utility load for each municipal's pro rata share per hour. Stowe's share percentage beginning in 1/1/2020 was 1.4849%. Going forward, DG within both Vermont and within Stowe will help count towards Stowe's RES compliance obligation.

[22] https://www.iso-ne.com/participate/support/glossary-acronyms#d

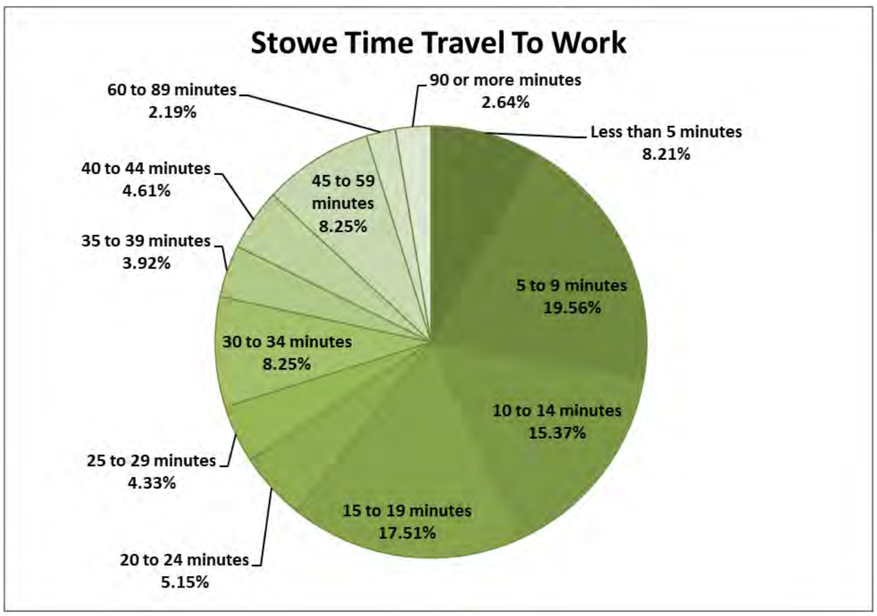
[23] https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_pv_forecast.pdf

D.3.1.2 Electric Vehicle Penetration

Many Stowe residents (74%) travel to work by mode of a car, with 8% of the population carpooling to work. Of the people surveyed 8.5% of the people working stated they work from home[24]. This percentage most certainly has shifted upwards since March of 2020 when COVID restrictions and shutdowns had begun. A Global Workplace analysis has stated their "best estimate is that 25-30% of the workforce will be working-from-home multiple days a week by the end of 2021."[25] This virus may change the amount of time people report to the office for an extended time period.

The typical time traveled for the majority of the Town of Stowe residents is greater than a 25-minute commute to work. This could lead one to believe that, in theory and without constraints, Stowe's residents could use the current plugin electric vehicle (EV) or plugin hybrid electric vehicle (PHEV) technology in order to reduce gas usage due to longer commutes to work.

Figure 67: Stowe's Time Traveled to Work



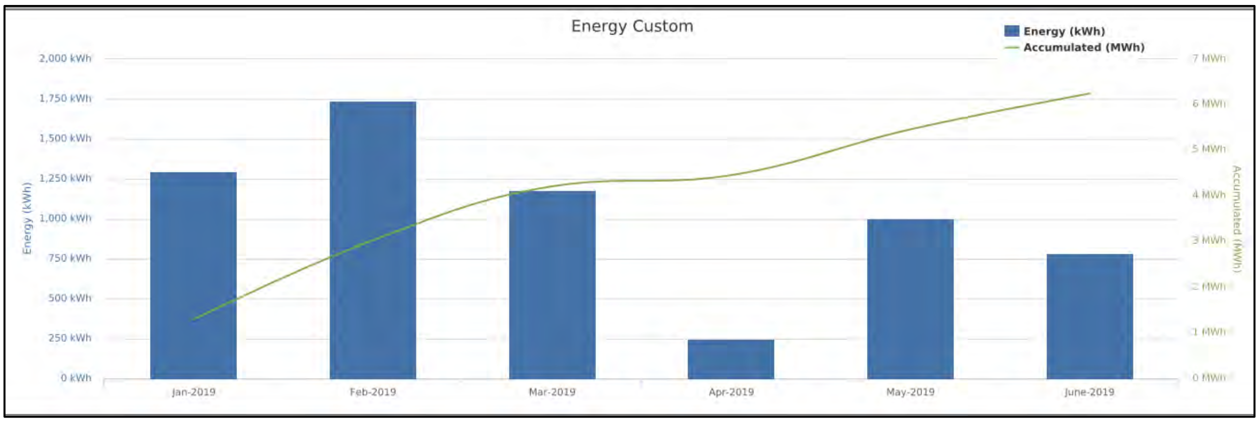
Kelley Blue Book lists the many different electric car options[26], such as a Tesla Model 3, a Ford Fusion Energi, a Honda Clarity Plug-in hybrid, a Nissan LEAF, and a Toyota Prius Prime. These each offer enough daily gasoline-fee free driving range to meet the needs of many consumers on electric power alone, and/or in the case of the plug-in hybrids, for many annual miles traveled.

[24] http://www.city-data.com/housing/houses-Stowe-Vermont.html#ixzz1jGktKvzD
[25] https://globalworkplaceanalytics.com/work-at-home-after-covid-19-our-forecast
[26] https://www.kbb.com/electric-car/

The Tesla Model 3 travels up to 310 miles on a single charge. With a car like this, one can recharge for 15 minutes at a supercharger for another 180 miles. The 2019 Clarity (Plug-in Hybrid) gets 47 miles of battery power and total range of 340 miles combined if the hybrid system is also used. With a car like this, one would have to expect a full recharge to take 2.5 hours with a 240-volt charger or up to 12 hours with a standard 120-volt plug. This vehicle charges at a rate of up to 6.6 kW; the Clarity uses up to 15 kWh per charge, including charging losses.

Currently, Stowe owns and maintains 10 EV charging stations with a total of 19 ports. 9 are level 2 and 1 is a DC Fast Charger. Stowe uses ChargePoint to track the electrical consumption for the EV charging stations. Figure 68 is the usage of January through June 2019 vs 2020. 2020's usage is greater in the months January through March. April through June does not have the increase as the prior months. COVID impacts probably have been affecting charging amounts due to lack of driving.

Figure 68: Stowe's Energy Consumption from EV charging 2019 vs. 2020



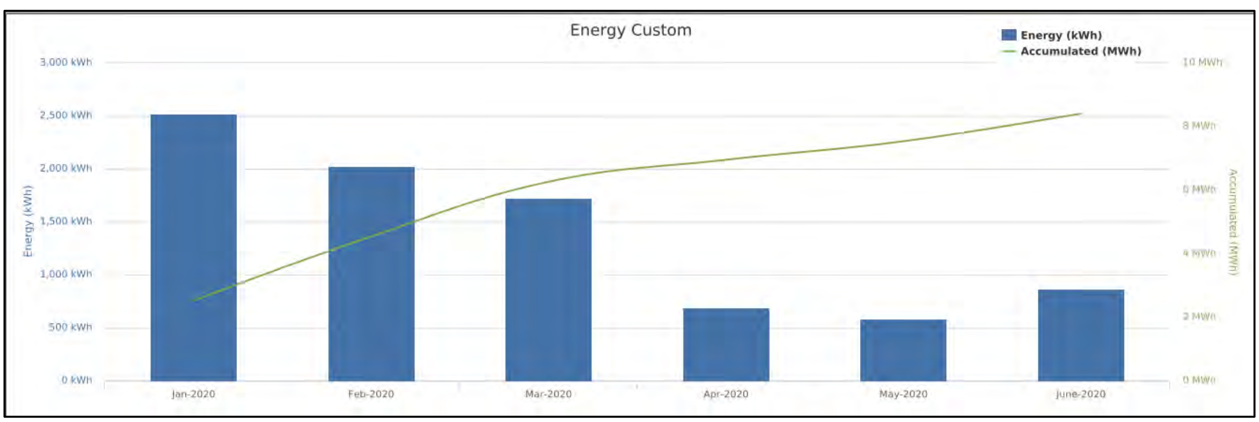


Table 12 Efficiency Vermont's Energy Usage and Savings summary has complied Stowe's EV statistics.

Table 12: Stowe's EV Registrations from Efficiency Vermont's 6/4/20 Report

Stowe	**Vehicle Type**	**2017**	**2018**	**2019**
	All Electric	9	11	12
	Plug In Hybrid	28	26	20
	Total	**37**	**37**	**32**

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.

"Electric car's energy consumption is measured in kilowatt-hours per 100 miles (kWh/100 miles). If an EV requires 40 kWh to recharge a fully depleted battery, and the rate is 18 cents per kWh, that's $7.20 for a fill-up." For a 2019 Nissan Leaf, its average rated efficiency of 150 MPGe translates to 40 kilowatt-hours per 100 miles. Just multiply that by your electric cost."[27]

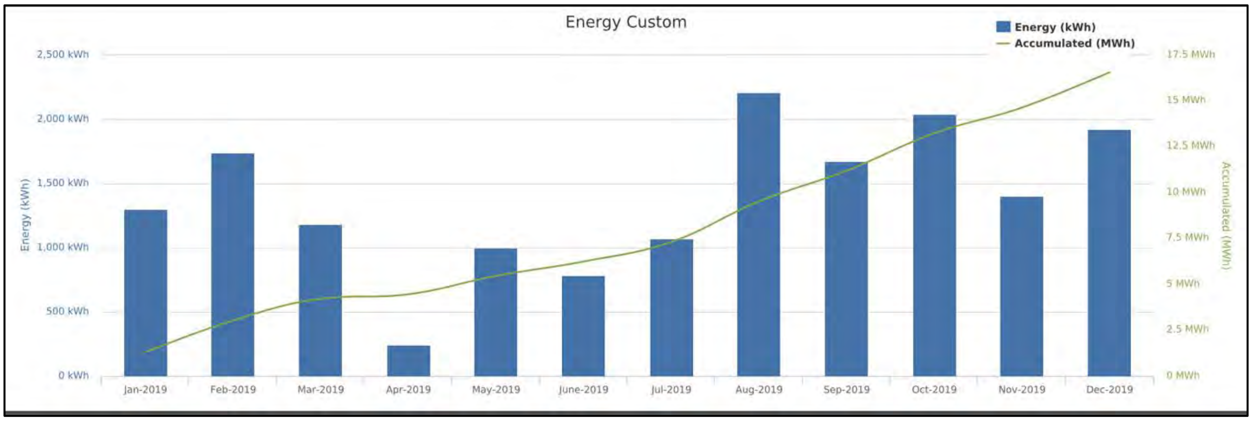
Table 13 below shows the impact of potential EV penetration. With 100% penetration, Stowe's average annual load may increase by 5,718 MWhs, whereas a low case of 25% penetration might add 1,429 MWhs. Stowe's charging stations are also increased by tourism. Although tourism is at an extreme low with the COVID restrictions on travel, Stowe's load will also increase above any Stowe residential drivers. Below, in Figure 69 shows the consumption of 2019 that equated to an accumulation of MWHs of 97.15 MWH for the year.

Table 13: Impact of Potential EV penetration in Stowe's work force

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

[27] https://www.edmunds.com/fuel-economy/the-true-cost-of-powering-an-electric-car.html

Figure 69: Stowe's Energy Consumption from EV charging 2019 annual total



The US Energy Information Administration (EIA) estimates car usage, of both conventional and alternative fuels, in a forecast that extends through the year 2050.[28] When necessary, Stowe has and can increase their current EV station fleet in an effort to promote and accommodate electric vehicles. EV will remain as high interest for Stowe because EV stations and usage will count towards Stowe's compliance of the Tier III Renewable Energy Standard.

[29]

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

D.3.1.3 *Energy storage*

Storage technology for electrical energy is growing in popularity. This technology offers users the ability to meet demand whenever needed and, more importantly, enables 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 14 below shows 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 the capacity reduction using an estimated 40% reserve adder. With these assumptions, Stowe would not only reduce its peak by the 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 14: Capacity and Transmission Savings

Project Assumptions	
MW	**1**
Commerical Operation Date	**1/1/2021**
Load Zone	**VT**
Est Reserve Margin	**45%**
RNS Ratio (8/12 months etc)	**67%**

Row Labels	Total ISO Capacity Savings	ISO RNS Savings	Total Savings
2021	$ -	$ 70,171	$ 70,171
2022	$ 39,189	$ 72,625	$ 111,814
2023	$ 49,324	$ 75,668	$ 124,993
2024	$ 41,409	$ 78,513	$ 119,922
2025	$ 63,224	$ 81,465	$ 144,689
2026	$ 93,401	$ 84,527	$ 177,928
2027	$ 133,249	$ 87,705	$ 220,953
2028	$ 106,610	$ 91,002	$ 197,612
2029	$ 71,019	$ 94,423	$ 165,443
2030	$ 47,854	$ 97,973	$ 145,827
2031	$ 38,805	$ 101,656	$ 140,462
2032	$ 49,521	$ 105,478	$ 154,999
2033	$ 65,084	$ 109,443	$ 174,527
2034	$ 91,532	$ 113,558	$ 205,089
2035	$ 98,499	$ 117,827	$ 216,326
2036	$ 94,439	$ 122,256	$ 216,695
2037	$ 65,438	$ 126,852	$ 192,290
2038	$ 56,548	$ 131,621	$ 188,169
2039	$ 115,303	$ 136,569	$ 251,873
2040	$ 110,519	$ 141,704	$ 252,223
Grand Total	**$ 1,430,968**	**$ 2,041,037**	**$ 3,472,004**

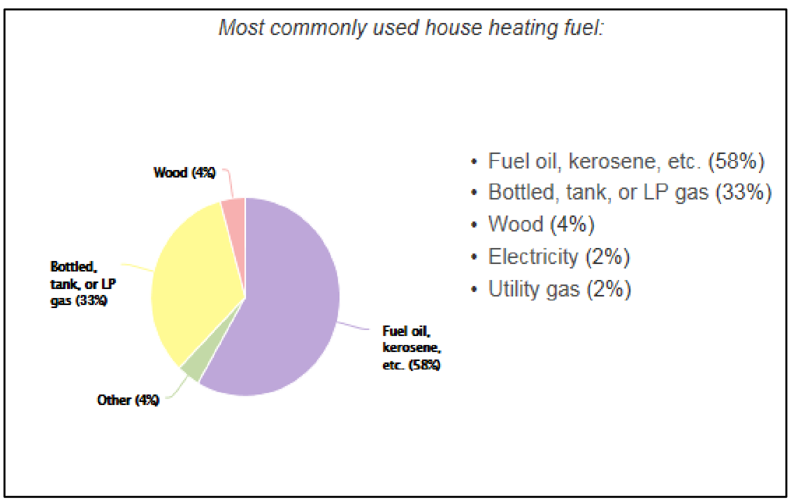
The greatest benefit of energy storage is its ability to heighten the capacity factor of renewable generation, such as solar. "These devices can also help make renewable energy, whose power output cannot be controlled by grid operators, smooth and dispatchable." [30] When solar production is low and a peak event is on the horizon, energy storage can supplement the solar output, and thereby, enable load reduction during the critical time.

D.3.1.4 Fuel Switching

Home fuel switching in Stowe could largely be accomplished using heat pumps. Generally understood, "[h]eat 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".[31] 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 and a large percentage of second and third homeowners that are part-time residents, means that Stowe homeowners might hesitate in switching to heat pumps because of the upfront costs. Stowe will continue to partner with EVT to offer incentives and consumer education to encourage the installation of CCHPs.

Beyond the home and business fuel switching there are generator fuel switching. "Unfortunately, owners of coal-fired power plants cannot easily switch fuels. A coal boiler is designed to burn coal, not natural gas. Even if a coal plant were modified to accept natural gas, the resultant fuel efficiency would be the resultant fuel efficiency would be horrible and production costs would remain elevated."[32]

Figure 70: Stowe Commonly Used Heating Fuel



[30] https://www.energy.gov/oe/services/technology-development/energy-storage
[31] https://www.synapse-energy.com/about-us/blog/switch-savings-heat-pump-cost-effectiveness-study
[32] http://breakingenergy.com/2012/10/15/fuel-switching-is-not-so-easy/

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".[33] 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 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

Beginning in 2017, Vermont created the Renewable Energy Standard (RES) to require utilities to meet various obligations of renewable attributes. The original State goal is to "obtain 90% of its energy from renewable sources by 2050."[34] The S.267 Bill that was introduced will require the renewable energy to increase to 100% by 2030. Additional RES information is found in the Renewable Energy Standard (RES) section G below.

D.3.3 Assessment of Carbon Impacts

ENE began the carbon assessment by reviewing the historical carbon intensity of Stowe's power mix from 2010 through 2019 and comparing it to the forecasts for the given years. ENE quantified Stowe's yearly non-emitting MWH totals by combining its New York Power Authority (NYPA) allocations and REC retention and compared this total against their total yearly retail sales data, which includes snowmaking loads. ENE collected ISO-NE's final emission reports to incorporate the carbon impact of the regional system for each year.[35] Even though there are other components of GHG such as CH_4 and N_2O, ENE chose to 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 sourcesCO_2 emission rates."[36]

D.3.3.1 *Emission Calculation*

ENE chose to calculate Stowe's emission rates using ISO-NE's yearly ISO New England Electric Generator Air Emissions Report. Although the report is published on a lag, the methodology used to create the emission rate best suits Stowe's portfolio emission estimates. ISO-NE uses a total system emission rate calculation method that is based on the emissions by all ISO-NE generators during 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 emission rate uses 76% of the reported CO_2 from actual US EPA's Clean Air Market Division (CAMD) database, as well as RGGI. They also use EPA's eGRID annual emission rates as a means of accounting for units for which this information is not available.

[33] http://www.businessdictionary.com/definition/environmental-attributes.html
[34] http://publicservice.vermont.gov/renewable_energy
[35] https://www.iso-ne.com/about/key-stats/air-emissions
[36] https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

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 generation is operational at the same 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-NE emissions methods apart from those of other data sources such as eGRID. EPA's eGRID states,

> "[e]missions and emission rates in eGRID represent emissions and rates at the point(s) of generation…they do not take into account any power purchases, imports, or exports of electricity into a specific state or any other grouping of plants, and they do not account for any transmission and distribution losses between the points of generation and the points of consumption. Also, 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"[37]

D.3.3.2 Emission Trends

Figure 71 shows the fuel mix in the ISO-NE control area in 2009 compared to 2018. ENE selected 2018 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 12% to 1%. Oil generation has stayed around 1%. These changes resulted from a combination of tightening emission requirements, relatively 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 MW of high efficiency natural gas fired generating capacity or 49% of the generation pool. This moved natural gas to the dominant marginal fuel in New England, where it now sets the marginal wholesale electricity price 60% of the time or more. This means that all generating technologies are affected by the price and availability of natural gas.

[37] https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_technicalsupportdocument_v2.pdf

Figure 71 ISO-NE System Energy Generation Percentage by Fuel Source[38]

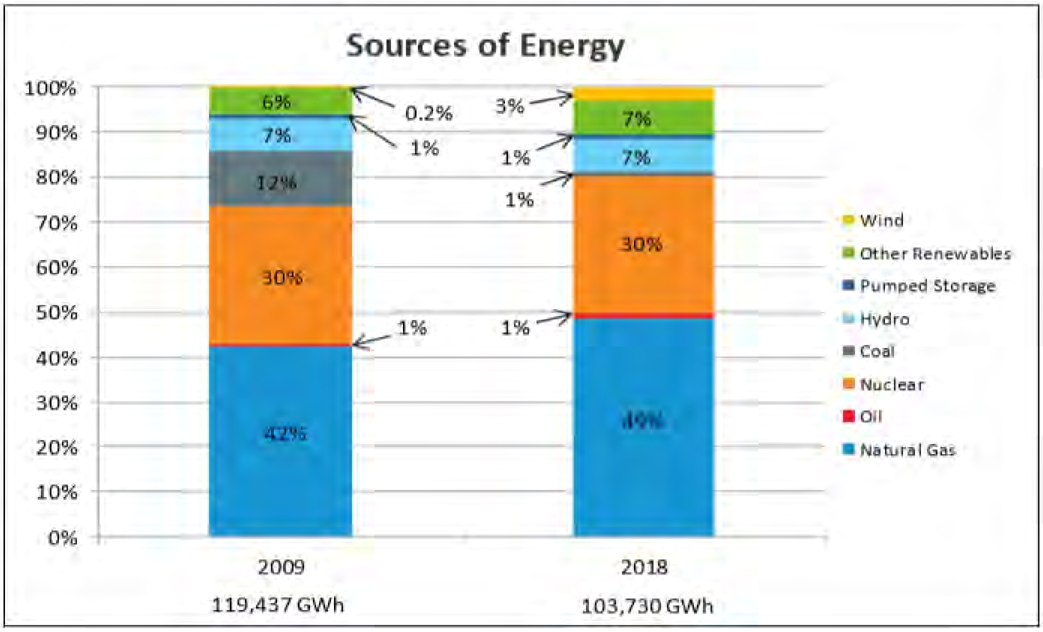


Table 15 shows New England's average yearly CO_2 emission rates. Following the build out of merchant, gas fired generating capacity in the late 1990's and early 2000's, these rates continue to trend downward slightly as the underlying resource mix changes with less reliance on coal and oil generation. 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.

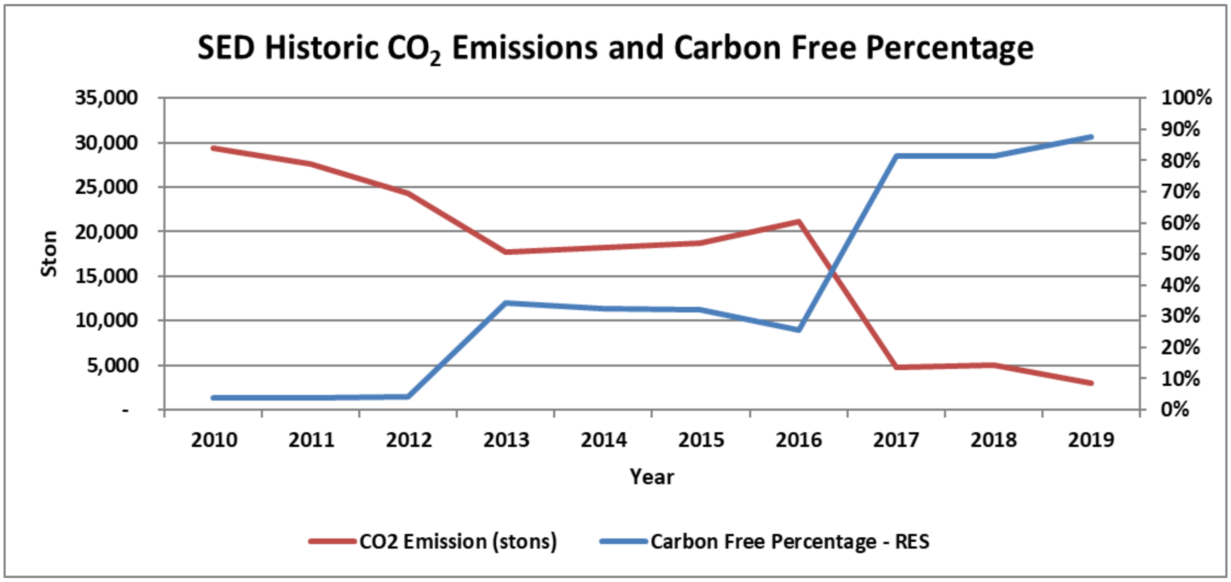
Table 15: Regional Annual CO_2 Emissions in lb./MWH

Annual System (NE)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
ISO CO2 Emission lb/MWH	905	890	828	829	780	719	730	726	747	710	682	658

Stowe's current carbon reduction power supply portfolio includes NYPA, and all retained RECs such as Hydro Quebec, and Seabrook. Figure 72 shows that Stowe's total portfolio represents about 30,000 tons of CO_2 in 2010 and drops to about 3,500 tons of CO_2 in 2019.

[38] https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf

Figure 72 Stowe CO_2 Emissions and Carbon Free Portfolio

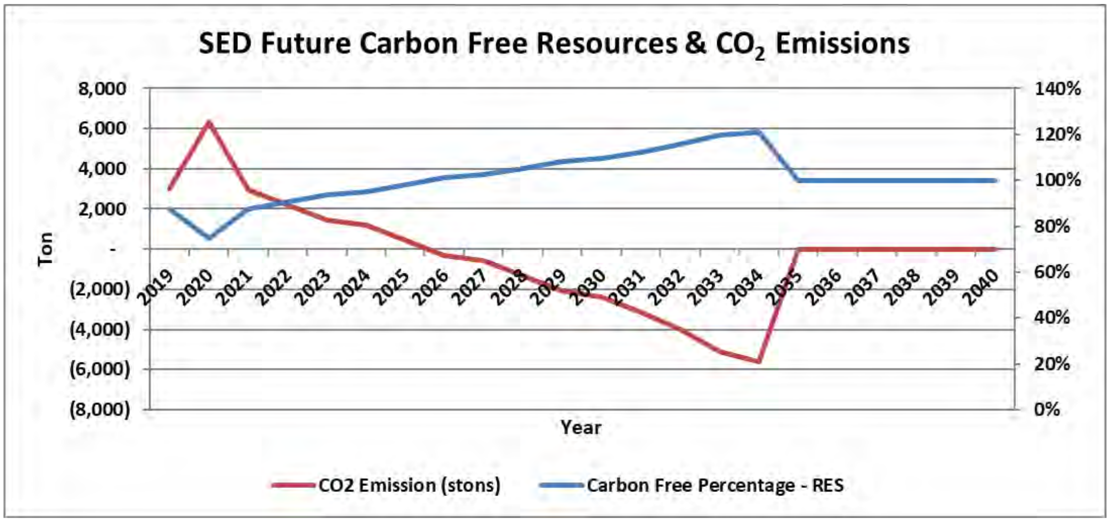


As a result of the RES, Stowe will increase their non-emitting portfolio by retaining and retiring RECs. ENE projected the emission rates for 2019 through 2025. By applying the average percent change from the past five years (2015-2019), which was a decrease of 2.0% and held it consent throughout the IRP timeline. ENE also assumed Stowe would be 100% compliant with Tier I, II, and III. Figure 73 shows that these assumptions maintains Stowe's carbon footprint around 3,000 tons of CO_2 in 2019. Achieving the RES targets reduces Stowe's carbon emissions by 77% from 2016 levels in 2017. By 2032 the final year of RES, Stowe will have reduced CO_2 by -118% from 2016 levels. This decrease directly follows the State goals set in August 2015 at the New England Governors and Eastern Canadian Premiers to set targets of decreasing carbon in the region by 35% to 45% from 1990 levels by 2030.[39] In for the remaining IRP years, CO_2 emissions reduction total 100%. This exceeds the target established by the Vermont Comprehensive Energy Plan of meeting 25% of energy needs using renewable sources by 2025.[40] Stowe's carbon footprint is negative in year 2028 through 2034 because of the 100% Tier I compliance plus Seabrook.

[39] http://climatechange.vermont.gov/climate-pollution-goals

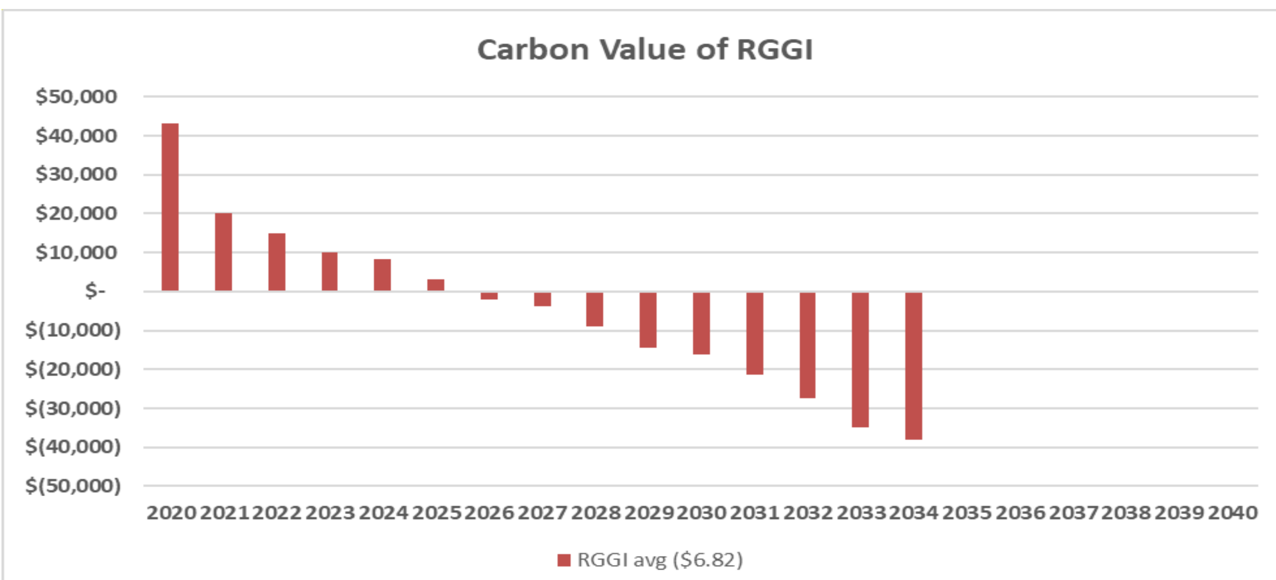
[40] https://outside.vermont.gov/sov/webservices/Shared%20Documents/2016CEP_Final.pdf

Figure 73 Stowe 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. that generators purchase RGGI credits to emit CO_2. RGGI rates average around \$6.82. below Figure 74 is the carbon cost if Stowe were to buy RGGI credits for each ton of carbon at an average rate of \$6.82. Once Seabrook terminates Stowe will maintain 100% renewable compliance set in the RES obligation.

Figure 74 Stowe 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, ENE performed Monte Carlo simulations using the @RISK® commercial statistical software package to run optimization algorithms that identify the percentile of each outcome to Stowe'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 a view into the probability distribution of outputs. The reason for the quantitative modeling is to determine the sensitivity of Stowe's portfolio cost to the change in market conditions and 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 cases as well as mild cases per resource. ENE reviewed and analyzed these extreme cases in 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 several existing resources, including long-term contracts and entitlements, which provide supplier, fuel source, and term diversity. See Table 16 for a brief description of each resource. Each resource includes annual production, fuel, location, and termination date.

Table 16: Stowe 2019 Resources

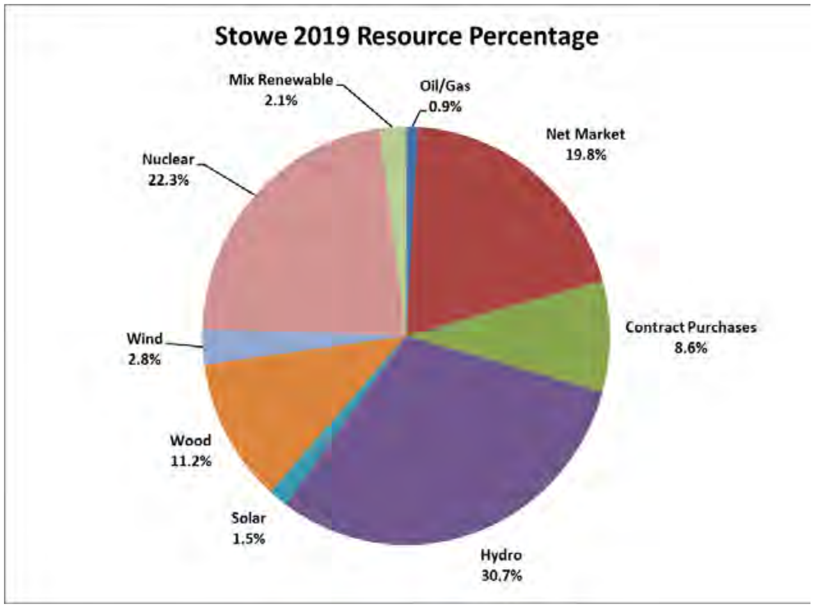
2019 Total KWH's by Resource							
Niagara	Block	3,628	3,628,097	4.8%	Hydro	Roseton	9/1/2025
St. Lawrence	Block	73	72,884	0.1%	Hydro	Roseton	4/30/2032
VEPPI 4.1	PURPA	399	398,962	0.5%	Hydro	VT Nodes	12/14/2020
Ryegate	Wood Unit	1,956	1,956,297	2.6%	Wood	RYGT	11/1/2022
VEPPI-Standard Offer ISO Settlement	Standard Offer	119	118,506	0.2%	Farm Methane	VT Nodes	
HQ Contract	ISO Bilateral	17,462	17,461,600	23.1%	Hydro	HQ Highgate 120	10/31/2038
McNeil	Wood Unit	6,817	6,817,190	9.0%	Wood	Essex	Life of Unit
Stony 1A/1B/1C	Dispatchable	741	741,293	1.0%	Natural Gas/Oil	Stonybrk 115	Life of Unit
Saddleback Ridge	Wind	2,175	2,175,066	2.9%	WInd	LUDDN_LN	Exp. 2035
Bilateral Purchase - Mtn	ISO Bilateral	6,747	6,747,055	8.9%			
Miller Hydro	Run of River	2,498	2,497,646	3.3%	Hydro	TopSham.Milr	5/31/2021
Seabrook Offtake	ISO Bilateral	17,496	17,496,257	23.1%	Nuclear	Seabrook 555	Exp. 2034
ISO Energy Net Interchange		15,527	15,526,742	20.5%			
Totals		75,638	75,637,595	100%			
Nebraska Valley Solar Project	Load Reducer	1,332	1,331,806	1.7%	Solar	Behind meter	Life of Unit
VEPPI Standard Offer BTM	Load Reducer	1,540	1,540,242	2.0%	Mix	Behind meter	

Table 17: Stowe 2019 Current Resources Energy Cost

2019 Energy Cost by Resource		
Resource		**$/MWH**
NYPA - Niagara		$ 4.98
NYPA - St. Lawrence		$ 4.92
Nebraska Solar Project		$ -
VEPPI 4.1		$ 119.91
Rygate		$ 101.80
VEPPI Standard Offer BTM		$ 188.11
VEPPI-Standard Offer ISO Settlement		$ 367.09
HQ PPA Contract		$ 55.45
McNeil		$ 59.28
Stonybrook 1A/1B/1C		$ 28.36
Bilateral Purchase - Seabrook		$ 51.02
Miller Hydro Purchase		$ 50.40
Saddleback Ridge		$ 92.68
Bilateral Purchase - Mtn		$ 65.82
ISO Energy Net Interchange		$ 37.94

Figure 75, below, represents Stowe's 2019 resources by fuel type format. This pie chart shows that 19.8% of Stowe coverage was from market purchases.

Figure 75: Energy Resources in 2019



In Stowe's resource forecast, found in Figure 2 , ENE uses specific resource knowledge to estimate generation. In the long-term bilateral purchases, such as Brown Bear Hydro, the estimate is an average of historical run times. ENE conservatively estimated the HQ bilateral at the lower MW value of 218. ENE expects McNeil to run between a 47-67% annualized capacity factor due to the NOx upgrade. The Saddleback Ridge Wind, VEPPI, and NYPA forecasts are each calculated using an average of historical generation, with VEPPI adjusted for expiring units. Seabrook offtake is a steady bilateral that makes up about 20% of Stowe's portfolio. ENE used a generic solar forecast when estimating the solar projection for Stowe. Once the Solar project has been in operation for a year, ENE will review actual data against the forecasted output and make necessary changes to the forecast then.

This resource forecast results in very modest exposure to the spot market for Stowe, see Figure 1 Furthermore, that exposure is limited to the pricing of Stowe's Stony Brook entitlements, so long as the units are available for dispatch in high LMP times, Stowe will have a great coverage percent when it needs it most.

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 startup utilizes 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 run time as well as lower 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 preference 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 very competitive to the New England power markets. The Niagara 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.

With the extension of Saint Lawrence, after December 23, 2017 VT utilities were no longer entitled to NYPA St. Lawrence Renewable Energy Credits. This reduces the amount of coverage Stowe can declare for RES compliance through the NYPA contract.

F.1.3 Vermont Electric Power Producers, Inc. (VEPPI)

Stowe receives power from a group of independent power producer projects (IPPs) under Order 4.100 of the Vermont Public Utility Commission. The power is generated by several small hydroelectric facilities. There were 19 Vermont Electric Power Producers (VEPPI) units, as of December 31, 2019, 16 have expired, leaving 3 remaining. VEPPI assigns the energy generated by these facilities using a load ratio basis that compares Stowe's electric sales to other utilities in Vermont on an annual basis. The VEPPI contracts have varying maturities, with the last VEPPI contract scheduled to end in 2020.Stowe's current pro rata share of the VEPPI production is 1.3616%, which started November 1, 2019 and will run through October 31, 2020. The prior percent which ran from November 1, 2018 through October 31, 2019 was 1.4072%%. The VEPPI contracts are priced with relatively high energy rates.

F.1.4 Ryegate

Ryegate is a 20 MW wood-fired unit, that 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. Stowe's allocation for the November 1, 2019 through October 31, 2020 contract year is 1.4493%. This contract will terminate on November 1, 2022.

F.1.5 Sustainably Priced Energy Enterprise Development "SPEED" or Standard Offer

SPEED Standard Offer is a program established under Vermont Public Utility Commission Rule 4.300. The program's goal is to achieve renewable energy and long-term, stably priced contacts. Vermont utilities will purchase power from the SPEED projects, which are projects that are behind the meter and four additional ISO-NE settlement only generators. Each utility will have their percent share of each project. Stowe's share for November 1, 2018 through October 31, 2019 was 1.5197% and decreased to 1.4691% for November 1, 2019 through December 31, 2020. 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.

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 bio-diesel, may qualify as SPEED in proportion to the amount of renewable fuel (in this case bio-diesel) that is used.*
>
> *The incremental energy produced by an expansion or modification of a pre-existing renewable energy project will be considered as a SPEED project."*

The Vermont Energy Act of 2009 changed into the Standard Offer program to include a feed-in-tariff to encourage the development of SPEED resources by making contracts long term and at fixed prices to qualified renewable energy projects. 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. In 2013 the PUC issued a mechanism to solicit new projects into the program beyond the 127.5 MWs. The 2020 RFP for the Standard Offer Program within the Public Utility Commission through Orders in Dockets 7523, 7533, 7780, 7873, 7874, 8817, Case 173935-INV, Case 18-2820-INV and most recently Case No. 19-4466-INV, contained the avoided cost price caps. These prices are found below in Table 18. Each CAP is subject to a location and a fuel type. Figure 76 shows the current fuel source breakdown of the Standard Offer Projects. The complete list of projects is in Appendix C.

Table 18: 2020 Avoided Cost Price CAPS for Standard Offer

The following avoided costs will serve as price caps for the 2020 RFP for the Provider Block and Developer Block:

- Biomass: $0.125 per kWh (levelized over 20 years)
- Landfill Gas: $0.090 per kWh (levelized 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: $0.130 per kWh (fixed for 25 years)

The following table contains avoided-cost price schedules for biomass and landfill gas plants.

	Biomass	Landfill Gas
Year 1	0.121	0.088
Year 2	0.122	0.088
Year 3	0.122	0.089
Year 4	0.123	0.089
Year 5	0.124	0.090
Year 6	0.124	0.090
Year 7	0.125	0.091
Year 8	0.126	0.091
Year 9	0.126	0.092
Year 10	0.127	0.092
Year 11	0.128	0.093
Year 12	0.129	0.093
Year 13	0.130	0.094
Year 14	0.130	0.094
Year 15	0.131	0.095
Year 16	0.132	NA
Year 17	0.133	NA
Year 18	0.134	NA
Year 19	0.135	NA
Year 20	0.135	NA

Figure 76: Energy Provided by Standard Offer Projects [41]

Program Technology Summary

Technology	Online (MW)	Pending (MW)	Total (MW)
Solar PV	56.967	19.400	76.367
Solar PV – Utility	1.830	4.200	6.030
Wind – Large	0.000	0.000	0.000
Wind – Small	0.000	0.811	0.811
Farm Methane	2.529	0.000	2.529
Hydroelectric	4.939	0.000	4.939
Biomass	0.865	0.000	0.865
Landfill Methane	0.000	0.000	0.000
Food Waste	0.000	2.988	2.988
Total	**67.130**	**27.399**	**94.529**

Updated 5/28/20

[41] https://vermontstandardoffer.com/standard-offer/technologies/

F.1.6 Stony Brook Combined Cycle

Stowe is entitled to just under 6 MW of the Stony Brook combined cycle facility. This is a natural gas and #2 oil fired generation facility located in Ludlow, Massachusetts. Its total capacity is 350 MW in the winter. During the winter months, the unit is challenged in sourcing natural gas, so it generally will run on fuel oil during that time. That typically limits unit generation to non-winter months, concentrated around the summer New England peak load season. The build out of newer, high-efficiency combined cycle facilities in the past 10 years has served to limit Stony Brook's run time. Built as an intermediate unit in 1981, it now generally provides peaking duty. The unit heat rate is in the 8,500 BTU/KWH range, and the fact that the unit runs relatively 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 increases, it has reduced the run time for peaking units, because locational marginal prices have been far below bid price.

Stated in Massachusetts Municipal Wholesale Electric Company's (MMWEC) 2009 audited financials, the Stony Brook Intermediate Series A Bonds were paid in full as of July 1, 2008. This has helped reduce Stowe's fixed cost obligation for its entitlement.

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.1.7 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 shown below in Table 19. The contract pricing will be flexible and competitive 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 will be 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 to Stowe. In addition to the price flexibility, this will continue to provide very 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 19: 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 20 below shows what will be the new portion for Stowe.

Table 20: 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.1.8 Brown Bear II Hydro (Old Miller Hydro Contract)

Stowe recently signed a purchase power agreement (PPA) for 2.613% of the Brown Bear's Worumbo (Miller Hydro) Project. The contract states that Stowe will receive their allocation of the Miller hydro output per month. The contract price is for energy to be delivered to the Maine Zone, and capacity to be settled at the Maine location.

The PPA terminated on May 1, 2016. Subsequently, the Miller Hydro was purchased by Brown Bear Hydro and a PPA was renegotiated beginning on June 1, 2016. It is the same 2.613% of unit, but it is for energy and RECs going forward. This will terminate on May 31, 2021.

Brown Bear Hydro is a run of river unit that has an average annual production of 90,000 MWH per year, over the past 3 to 5 years. This resource equates to roughly 3% of Stowe's energy and Stowe is considering negotiating a contract extension.

F.1.9 Saddleback Ridge Wind Project

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

[42]

F.1.10 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.1.11 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.

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

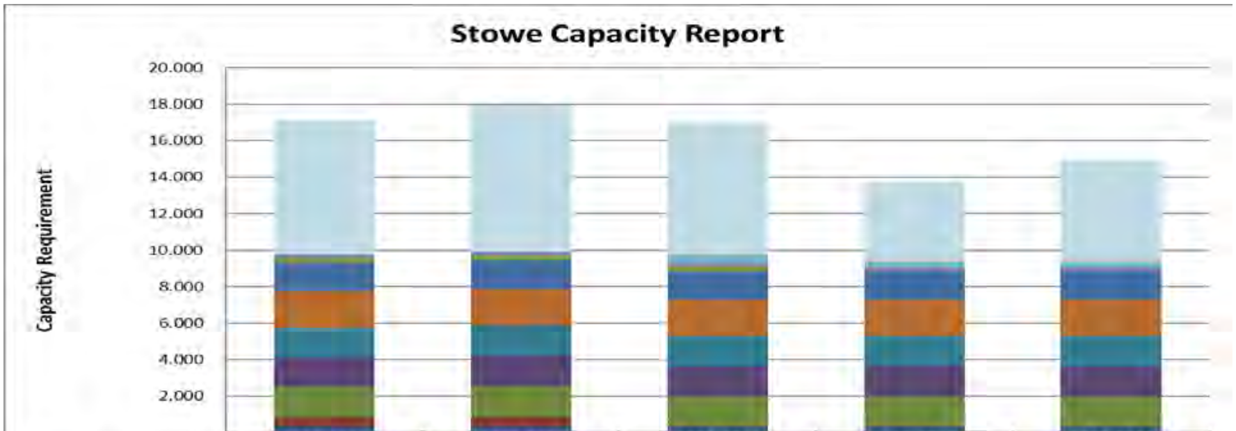
F.1.12 Snowmaking Procurement – Energy Only Load Following

The snowmaking load requirements are intermittent due to the nature of snowmaking demands at Stowe Mountain. ENE's analysis showed a load-following energy product provides the best solution for the utility, the Mountain, and the remaining utility customers. It reduces Stowe's price risk for what can be a significant load during the winter months and provides a vehicle to mitigate potential true-up payments that may be made from Stowe to the Mountain or vice versa. A load-follow energy product also can insulate other Stowe customers from the Mountain's snowmaking load requirements and has the potential to allow a lower overall cost to the Mountain as the energy markets continue to fall.

F.2 Existing Capacity Resources

Stowe currently has around 57% of their 19-20 Forward Capacity Market Obligation covered with capacity resources, as seen below in Figure 77.

Figure 77: Stowe's Capacity Forecast



	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Market	7.373	8.048	7.262	4.325	5.598
VEPPI SPEED	-	0.021	0.021	0.021	0.021
NYPA	-	-	0.418	0.354	0.354
Saddleback	0.175	0.175	0.175	0.175	0.175
VEPPI SPEED	0.007	-	-	-	-
Ryegate	0.270	0.270	0.291	-	-
McNeil	1.560	1.560	1.560	1.560	1.560
Seabrook - Bilateral	1.995	1.995	1.995	1.995	1.999
Stony Brook GT1C	1.656	1.709	1.657	1.656	1.656
Stony Brook GT1B	1.607	1.655	1.607	1.607	1.607
Stony Brook GT1A	1.656	1.708	1.656	1.656	1.656
NYPA	0.473	0.451	-	-	-
HQICC	0.365	0.367	0.367	0.371	0.367

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 Stowe's Capacity positions.

The process then uses the ranges of estimated values to identify 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 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 ultimately produces a distribution of possible outcomes

F.3.1 Model Assumptions

The IRP's capacity forecast is shown 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 2010 through May 2024) used includes clearing prices and payment rate percentages of the historical clearing price to the payment rates. ENE used a risk simulation table that weighted five scenarios based on the percentage of the past three-year FCM clearing prices. Using FCA 12 through FCA 14 was the most ideal because they are the results from the most recent capacity parameters. Figure 78 are the simulation results from the model. The prices are reding downward but the uncertainty in the market leaves room for prices to range from $1.50 to $7.00 $/KW-month.

Figure 78: Forward Capacity Price Simulation Range

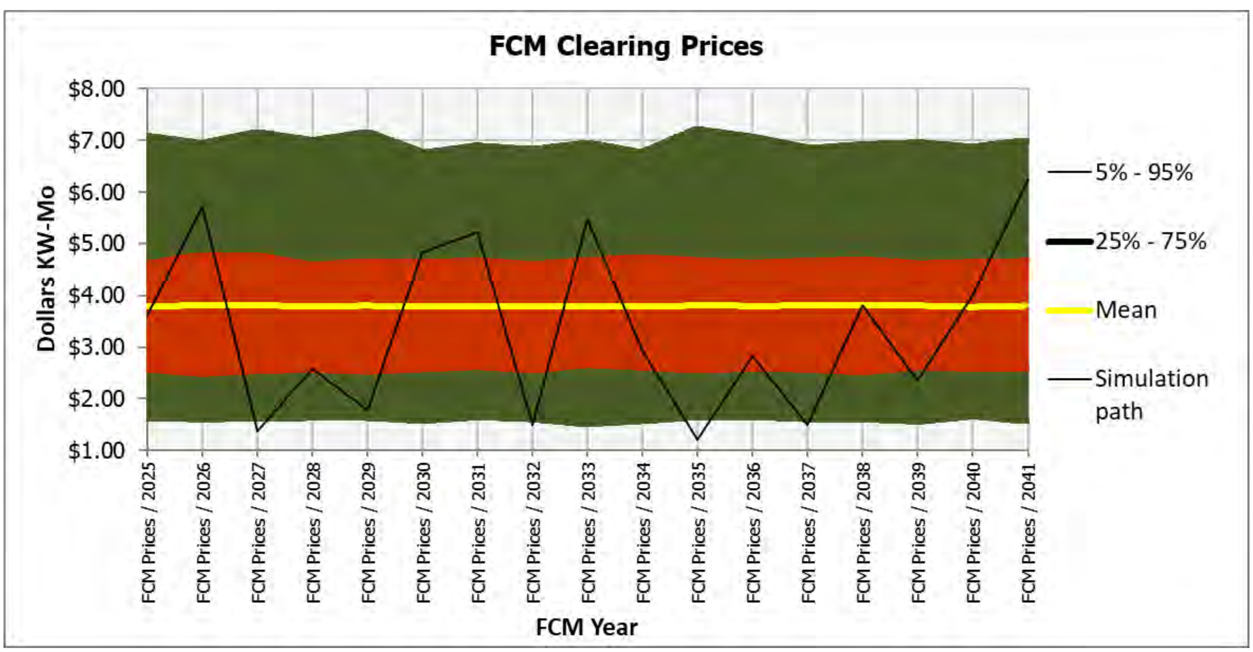
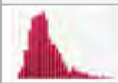
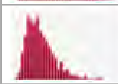
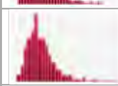
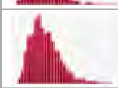
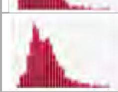


Figure 79: @Risk Model Prices for Capacity Forecast

Outputs

Report:
Performed By:
Date:

Summary Statistics

Output	Cell	Graphs	Function	Minimum	Maximum	Mean	Std Dev	5%	95%
FCM Prices / 2025	J18		RiskOutput(,$I $18,1)	0.6921	11.7741	3.7820	1.6670	1.6257	7.0743
FCM Prices / 2026	K18		RiskOutput(,$I $18,1)	0.4796	11.9969	3.8099	1.7529	1.6074	6.9328
FCM Prices / 2027	L18		RiskOutput(,$I $18,1)	0.6993	15.5080	3.8049	1.7407	1.6173	7.1458
FCM Prices / 2028	M18		RiskOutput(,$I $18,1)	0.4988	12.4233	3.7909	1.7053	1.6346	6.9880
FCM Prices / 2029	N18		RiskOutput(,$I $18,1)	0.7813	13.1658	3.8003	1.7403	1.6346	7.1444
FCM Prices / 2030	O18		RiskOutput(,$I $18,1)	0.7625	12.2932	3.7842	1.6852	1.5788	6.7457
FCM Prices / 2031	P18		RiskOutput(,$I $18,1)	0.6983	13.9785	3.7870	1.6776	1.6493	6.8872
FCM Prices / 2032	Q18		RiskOutput(,$I $18,1)	0.4814	14.0762	3.7860	1.6897	1.6095	6.8182
FCM Prices / 2033	R18		RiskOutput(,$I $18,1)	0.6423	13.9520	3.7983	1.7081	1.5163	6.9380
FCM Prices / 2034	S18		RiskOutput(,$I $18,1)	0.6743	11.4277	3.7807	1.6276	1.5759	6.7511
FCM Prices / 2035	T18		RiskOutput(,$I $18,1)	0.6490	17.2908	3.8051	1.7543	1.6486	7.1992
FCM Prices / 2036	U18		RiskOutput(,$I $18,1)	0.6737	15.8393	3.7968	1.7484	1.6511	7.0532
FCM Prices / 2037	V18		RiskOutput(,$I $18,1)	0.7512	14.8564	3.8010	1.7425	1.6101	6.8371
FCM Prices / 2038	W18		RiskOutput(,$I $18,1)	0.6479	12.7917	3.8089	1.7453	1.6059	6.9146
FCM Prices / 2039	X18		RiskOutput(,$I $18,1)	0.8283	13.0721	3.8024	1.7358	1.5637	6.9511
FCM Prices / 2040	Y18		RiskOutput(,$I $18,1)	0.5648	11.1669	3.7760	1.6455	1.6688	6.8656
FCM Prices / 2041	Z18		RiskOutput(,$I $18,1)	0.5559	12.0287	3.8013	1.7139	1.5662	6.9893

G Renewable Energy Standard (RES)

In July 2015, the State of Vermont established Act 56 (H. 40) to detail the State's goals and provide guidance to the utilities on reaching these goals. The RES requires utilities to buy or retain renewable energy credits and energy transformation projects, and it set yearly percentage goals of retail sales to be covered by them. In lieu of renewable credits or transformation projects, a utility can meet its obligation by paying an alternative compliance payment at rates set by the State. The compliance rates adjust annually for inflation using CPI.

G.1 RES Details

There are three tiers to the RES program:

- Tier I: Meet a 75% by 2032 total renewable energy requirement (55% in 2017)
    - Any class of tradeable renewable attributes that are delivered in New England qualify
    - Approved Unit generations that will qualify towards compliance are McNeil, Hydro Quebec bilateral, and NYPA.
- Tier II: Meet 10% of sales with distributed generation in 2032 (1% in 2017)
    - New Vermont based unit that is 5 MWs or less or renewable generation
- Tier III: Municipal utilities must meet $10^{2/3}$% of sales with "energy transformation projects" in 2032 (2% in 2019)
    - Excess Tier II-qualifying distributed generation or project that reduces fossil fuel consumed by their customers and emission of greenhouse gases qualifies for compliance

Vermont Statue Title 30, Chapter 89 (30 V.S.A. § 8002-8005) began the RES for the Vermont distribution utilities in 2017. 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 shown below in Figure 80. 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 will be addressed as a pass through, whereas all obligations to RES will be billed back to the Mountain.

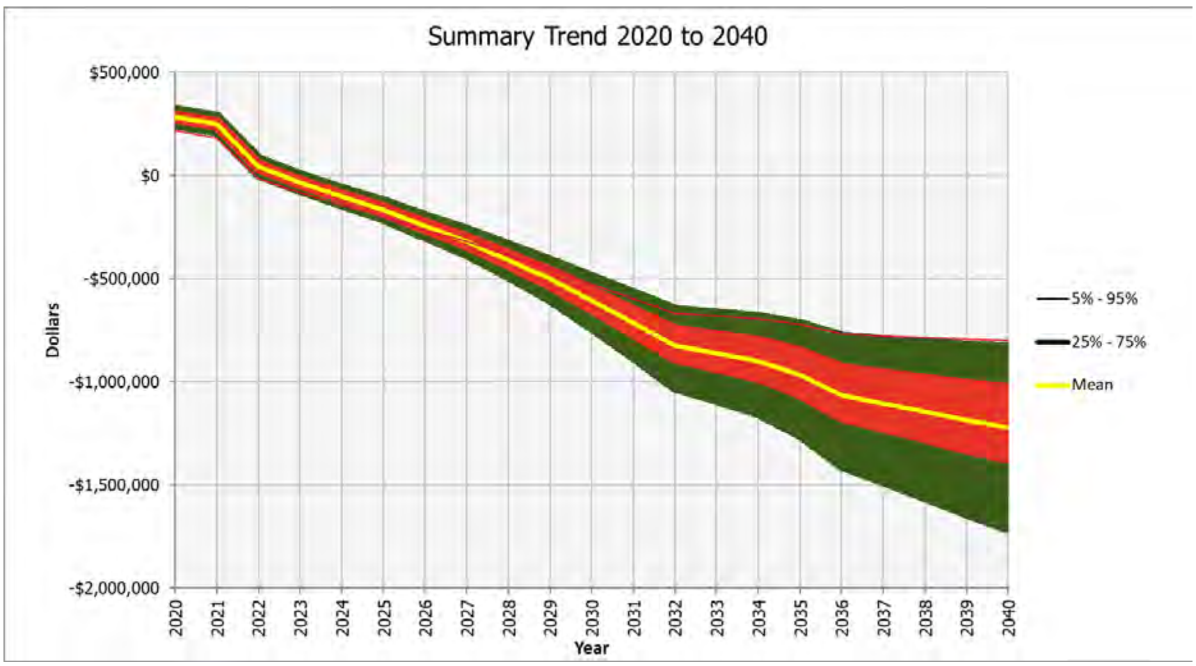
On January 15, 2019, the Vermont Department of Public Service distributed the 2019 Annual Report on the Renewable Energy Standard. The net present value was analyzed for the next 10 year from 2017. The cost of between $10,000,000 to $174,000,000, these findings coincide to the results of Stowe's potential RES costs. Both short positions and REC price increases will have an impact on rates, although it will also help reduce the fossil-fuel usage and greenhouse gas emissions. 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.

Proposed legislation changes in 2020 under the 2020 bill S.267 were reviewed by the Senate Committee of Natural Resources and Energy. The proposed amendments 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. The Commission with the Department of Public Service are due to give recommendations by January 20, 2021. The State Legislature will also new into a new biennium in 2021.

S.267 Introduced Bill amendment for Tier I:

"Required amounts. The amounts of total renewable energy required by this subsection shall be 55 59 percent of each retail electricity provider's annual retail electric sales during the year beginning on January 1, 2017 2020, increasing by an additional four 8.2 percent each third second January 1 thereafter, until reaching 75 100 percent on and after January 1, 2032 2030."

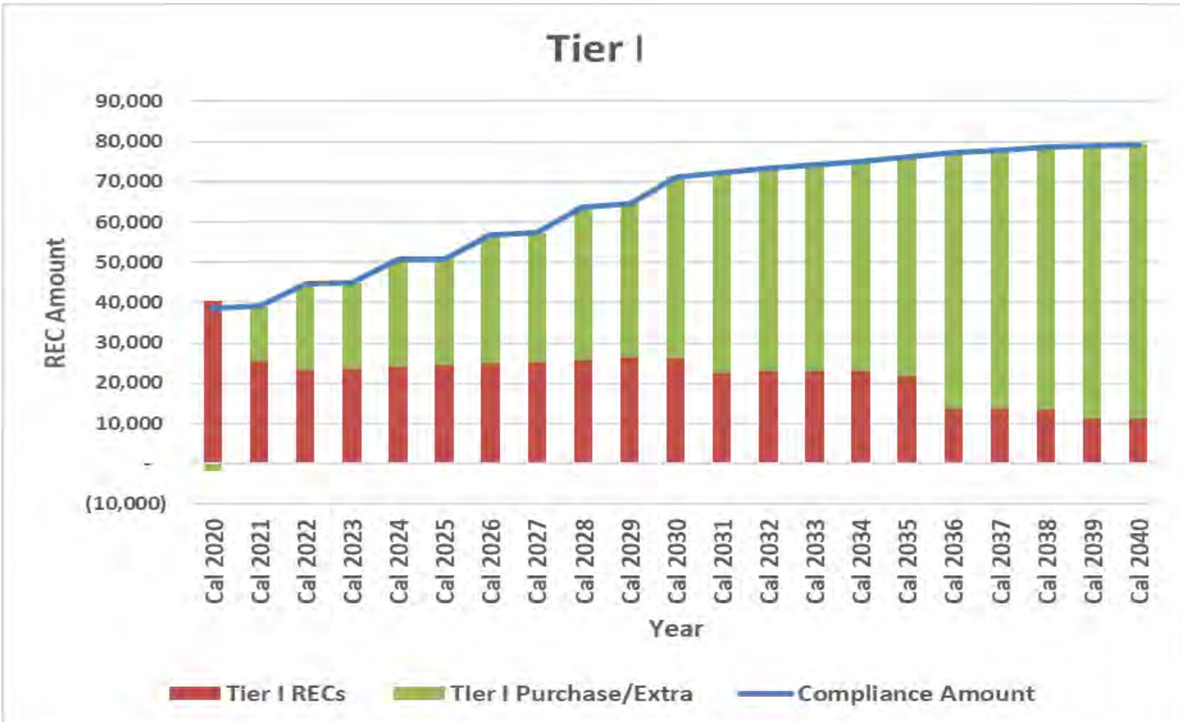
Figure 80: Stowe's Potential RES Cash Flow with Proposed Alternative Obligations for Tier I



G.1.1 Tier I

Currently, Stowe's Tier I portfolio contains 59% of the obligation needed by retiring existing generation RECs. This percentage comes from qualified generation that is either State approved, such as HQ and the New York Power Authority contract for RES, or as generation, that has tradeable renewable energy credits. Figure 81 below shows Stowe's Tier I forecast. As the percentage requirement increases, the need for Tier I purchases increases. Using this forecast of current contracts, one can assess new projects. When looking forward to future purchases, Stowe can analyze the cost of retaining a project's renewable energy credits against possible future Compliance payment rates.

Figure 81: Stowe's Tier I Forecast



G.1.2 Tier II

Currently, Stowe's distributed generation resource portfolio is about 107% of the obligation requirement. This mostly made up by Stowe's Nebraska Valley Solar project, which is 1 MW of distributed generation behind Stowe'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."[43] With this three year banking policy, Stowe is able to maintain Tier II compliance until 2022. 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 important when determining new distributed generation. Stowe will need to balance what the potential compliance payment charges may be against building or purchasing from a Tier II qualified project. Stowe's short position of Tier II is priced at the model's simulation of VT's alternative compliance cost. This assumes Tier II RECs will be unattainable.

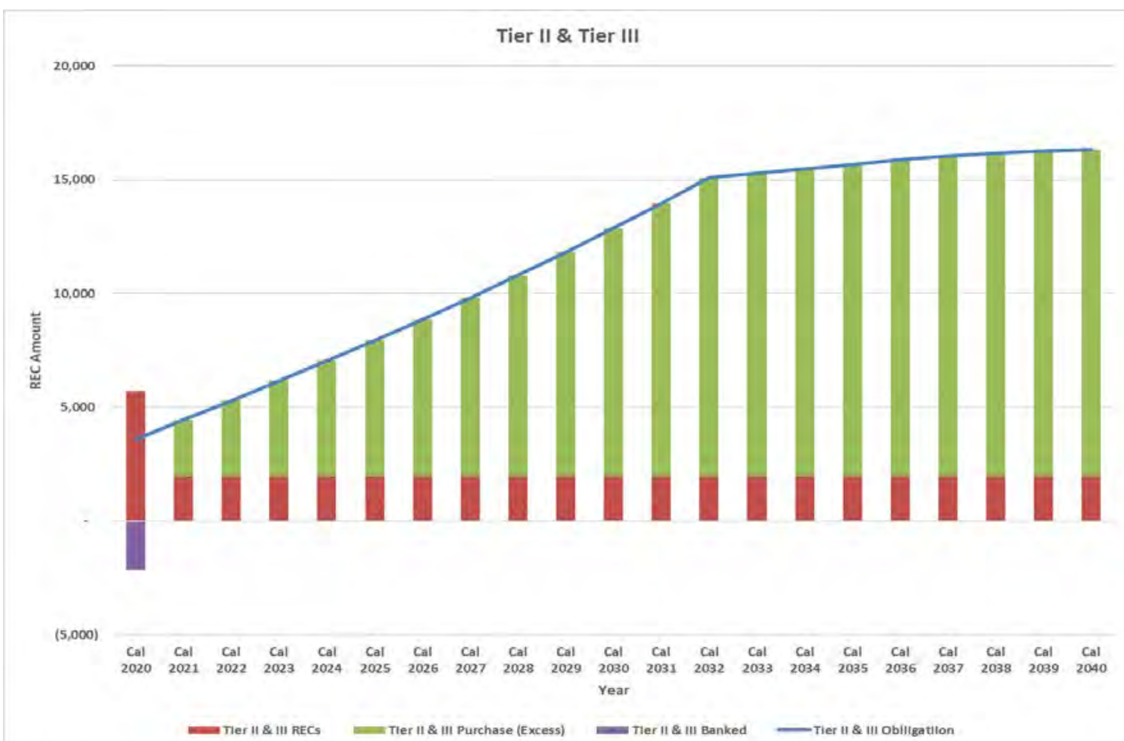
[43] 30 V.S.A. § 8004(c)

G.1.3 Tier III

Tier III is for energy transformation projects. This category is set to encourage projects that will help reduce fossil fuel usage and reduce greenhouse gas emissions. Currently, Stowe currently has an extensive fleet of Electric Vehicle charging stations, many of which had 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.[44]

Stowe can collaborate 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."[45] Stowe is enabling energy efficiency programs to help decrease fossil fuel usage and comply with this RES requirement. We will begin with the base case as being open for purposes of modeling to not overestimate transformation projects.

Figure 82: Stowe's Tier II and III Forecast



44 Docket No. 8550

45 http://legislature.vermont.gov/assets/Legislative-Reports/RES-SO-Report-2017-final.pdf

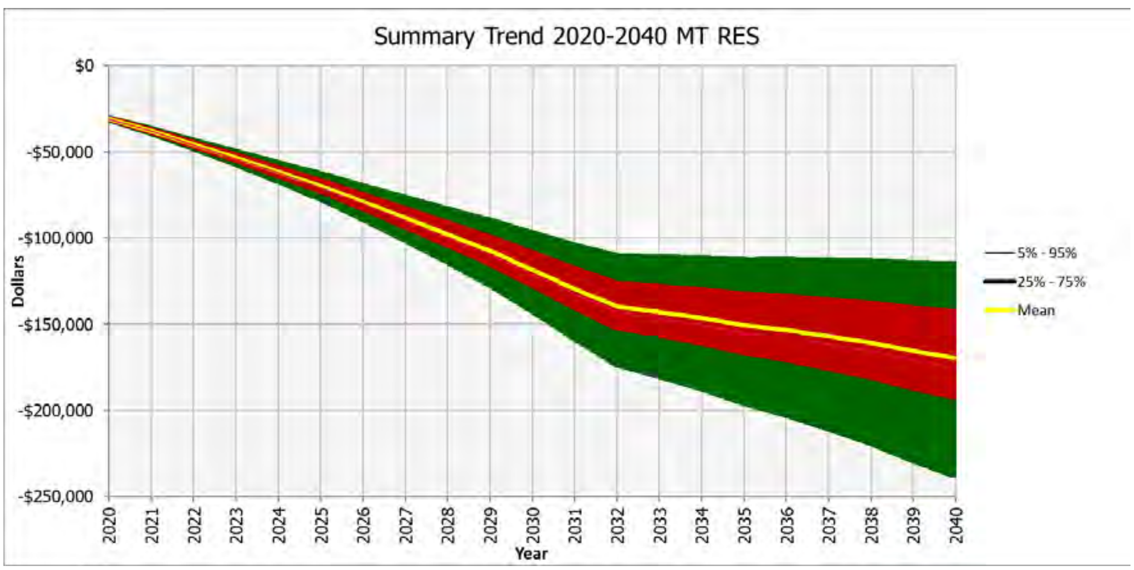
G.1.4 Renewable Energy Credit Arbitrage

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."[46] 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 will sell the RECs it owns and buy back another class or state REC that is available at lower prices. This ability can help Stowe buy down RES compliance payments in other Tiers where it may have a shortfall.

G.1.5 Snow Making 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 will be a pass through in their rate structure.

Figure 83: Snowmaking Potential RES Cost Cash Flow



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

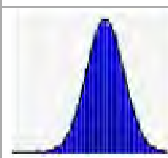
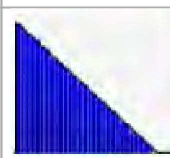
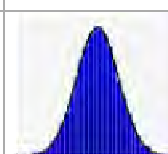
G.2 RES modeling

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 ultimately produces a distribution of possible outcomes.

G.2.1 Model Assumptions

Table 21: @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	B26	S12	T12
Statistic			
Minimum	18.693%	0.0918%	-1.2146%
Maximum	39.868%	7.0465%	5.8715%
Mean	29.999%	2.4759%	2.1969%
Mode	29.887%	0.1429%	1.9364%
Std. Deviation	3.005%	1.6883%	1.0838%

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

G.2.2 Model Outputs

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

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

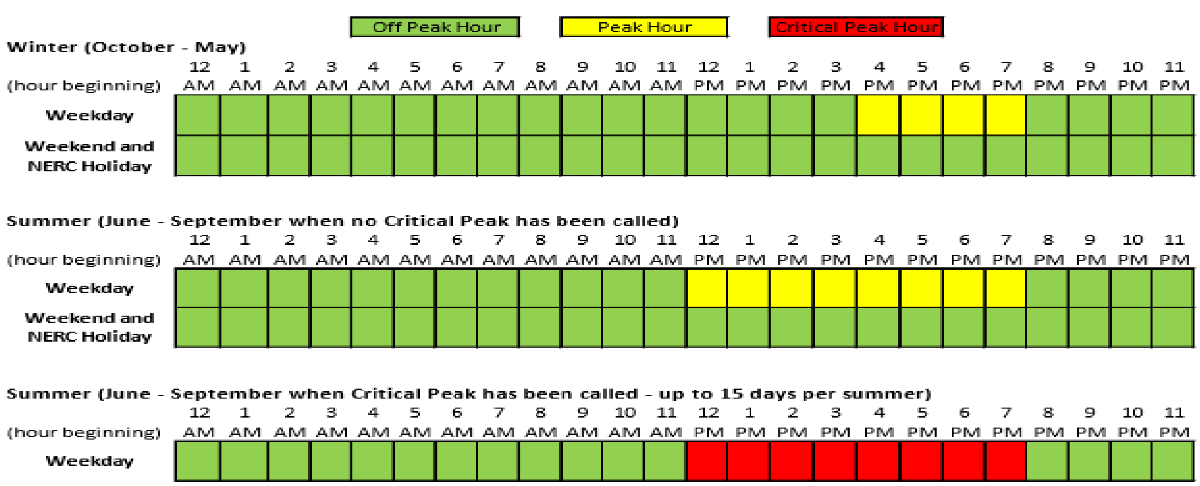
G.3 Assessment of Alternative Resources

When assessing different portfolio strategies, Stowe's focus is RES compliance. Therefore, the scenarios that were heavily focused on were to include either one or a combination of wind, solar, and hydro. We analyzed small Tier II compliant resources against Tier I compliant resources to see which suited Stowe's portfolio the best. The IRP removed the interruptible snowmaking load from the scenarios due to the unique fact that the snowmaking tariff is a cost pass-through. Stowe addressed the impact of RES to the mountain load but do not include it when making portfolio decisions for the net Stowe load. The load-following contract for the Mountain flows directly to Stowe Mountain Resort. Stowe will continue to assist Stowe Mountain Resort (owned by Vail Resorts, Inc.) to meet the RES goals and Vail's stated corporate goal to have zero net emissions by 2030. The Mountain's compliance goals, and Stowe's RES targets align to serve as an important driver to meet compliance goals and stimulate the local economy.

G.4 Smart Rates

After its last cost of service study, completed 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 84. 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 84: Stowe TOU Hourly Description



Participating customers are contracted through a combination of email, text, phone call to be made aware of the event. For the rates mentioned, see Table 22 below. These peak hours have the potential to help Stowe directly in saving on coincident peak load with the ISO-NE and VELCO.

Table 22: Stowe’s TOU Rate Energy Charge

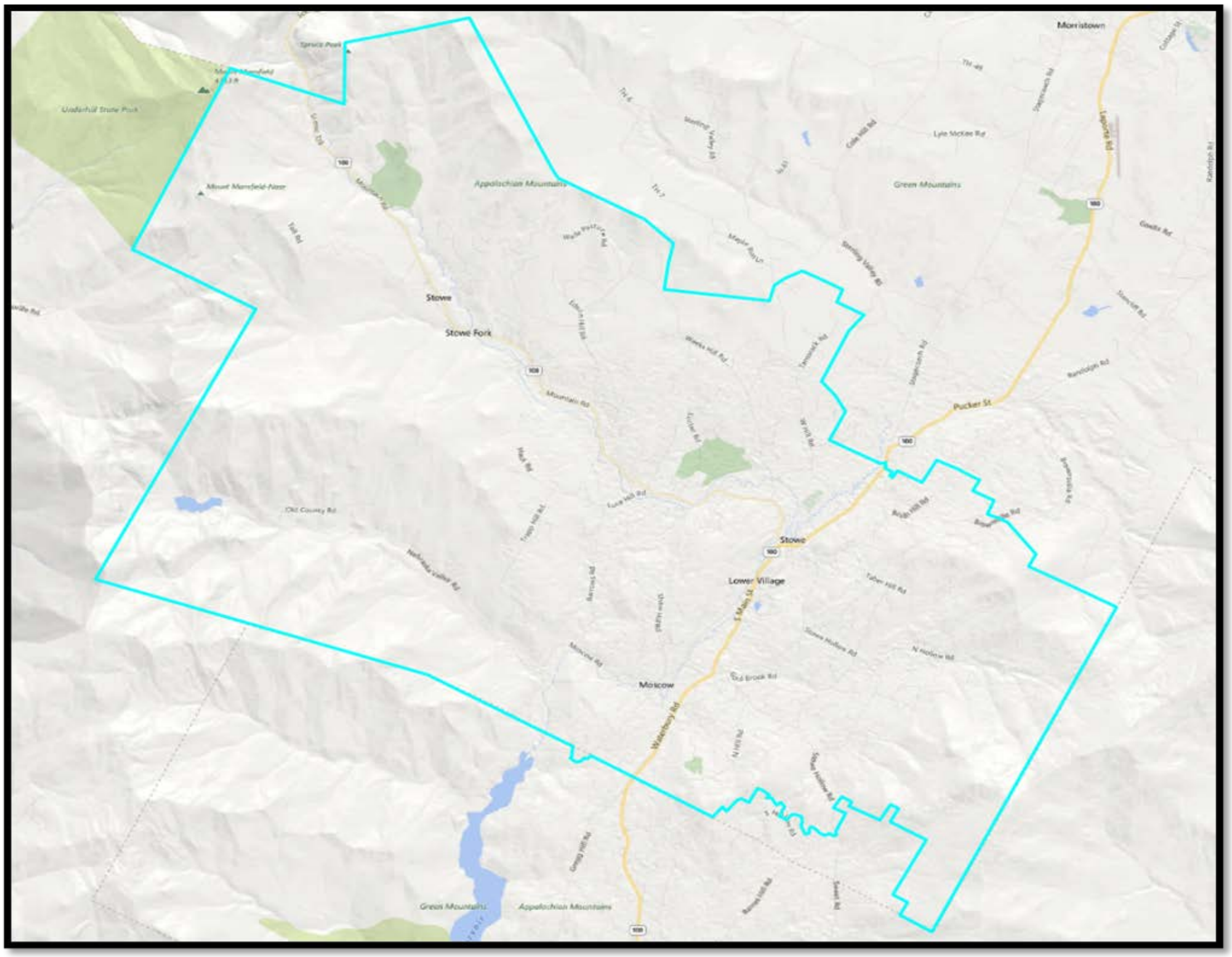
Energy Charge:	
During Winter Peak hours:	$0.2455/kWh
During Winter Off-Peak hours:	$0.1431/kWh
During Summer CPP Peak hours:	$0.6447/kWh
During Summer Non-CPP Peak hours:	$0.1852/kWh
During Summer Off-Peak hours:	$0.1168/kWh

H Assessment of the Transmission and Distribution System

H.1 T & D System Evaluation

Stowe Electric Department (“Stowe”) is a municipally owned electric utility providing service to 4,267 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.

Figure 85: Territory Currently Served by Stowe Electric Department



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. Stowe serves an average of twenty-nine (29) customers per mile of distribution line. Stowe 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 if needed

H.2 T & D Substations

Substations:

Stowe has three primary 12.47kV distribution substations that are fed from the 34.5kV transmission system and are able to tie and back-up each other supporting 75-80% of our customers.

Table 23: 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

Figure 86: 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.

H.2.2 Houston Substation

Figure 87: 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).

H.2.3 Lodge Substation

Figure 88: 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 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.

The Vermont Department of Public Service updated the Vermont Comprehensive Energy Plan ("CEP") in 2016. The 2016 CEP included guidance for IRPs. Relevant to this section of Stowe's IRP, the CEP included specific questions that utilities are to 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 factorcorrection.

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 study the cost and implementation of their recommendations in 2021. Table 24 Stowe Capacitor Banks, Sizes, and Locations

Table 24: 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. Much 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 25.

Table 25: 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. Stowe will review their recommendations and cost implications on fuse changeouts and relay setting changes and implement those changes throughout 2021.

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.

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. Stowe 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.

It has been an established Stowe practice to purchase rebuilt transformers from T & R Electric Supply Co. out of South Dakota at a fraction of the cost of new transformers. The cost of new units is at least double the cost of re-built units, carries a shorter warranty period, and is not readily available. This information, coupled with the fact that Stowe is an at-cost provider and is not allowed a rate of return like investor- owned utilities, has always supported our judgement to continue purchasing rebuilt transformers.

However, during the 2020 Distribution System Study, Control Point Technologies 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 first half of 2020, Stowe completed the installation of 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 2021 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 own 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.

Stowe has an informal pole inspection program. Many of the distribution poles have been replaced during voltage conversion and re-conductoring projects in the last 10 years leaving just a few outlying areas where maintenance is being conducted. 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. This information is added to Stowe's GIS system. Stowe is also using this tool to keep track of pole replacements. As line maintainers consistently work to supplement the data currently contained in the system, 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.

14) The impact of distributed generation on system stability.

Stowe's total installed net metering capacity as of October 20,2020 was 2639.5kW compared to 490.4kW on December 31, 2016. As of October 2020, there is an additional 257.6kW currently permitted or with a filed application. In December 2018, during the interconnection process of a 500kW DG facility on Stowe'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 has therefore placed a hold on interconnecting any new DG to these two circuits until a TGFOV protection solution has been implemented.

Figure 89: Stowe's Nebraska Valley Solar Farm (1MWAC)

H.3 T & D Equipment Selection and Utilization

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 continue to purchase rebuilt transformers from T & R Electric Supply Co. out of South Dakota at a fraction of the cost of new transformers. Stowe will also conduct a cost-benefit analysis using our new transformer cost comparison tool to ensure that our transformer purchases remain consistent with least-cost principles.

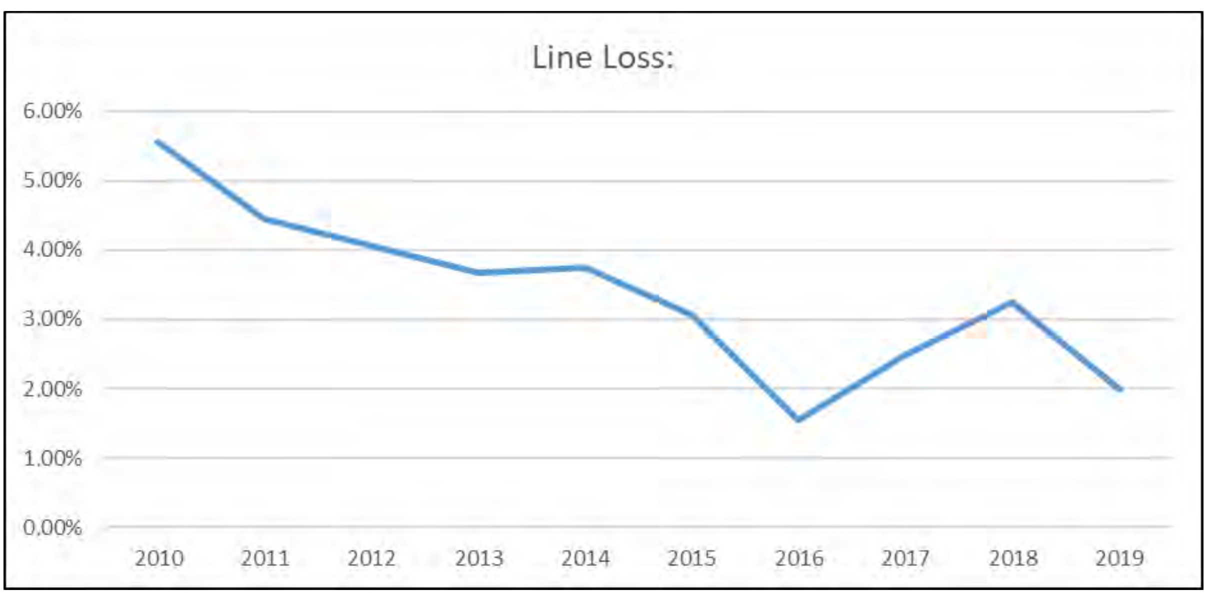
Stowe maintains a substantial inventory of distribution transformer sizes, both pole and pad mounted, on hand for new installations and replacements. An inventory of critical units, such as step downs and voltage regulators, is also available for emergency replacements. Inventory is reviewed periodically to keep counts at suitable levels.

Currently Stowe uses traditional transformer sizing methods based on the size of the home. We also request anticipated load information with applications for new service 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 90: Stowe'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. Any segment already started will be completed before the next IRP.

Substation inspections are completed monthly 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 over the last three years. Located at circuit tie points and heavy concentrated load areas, they will be 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 new VELCO 115kV line and new VELCO/Stowe substation was completed in December 2009 and energized in January 2010. The new line provides a stronger feed into Stowe'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 increased targeted tree clearing on our 8-mile-long sub-transmission line over the last three years with a focused effort on widening right of ways to re-establish the 100' width. By the end of 2020, Stowe tree crews will have cut, widened and trimmed approximately 99% of this line leaving the last 1800' to be completed in 2021.

In October 2020, Stowe and VELCO completed the installation of new backup 34.5kV underground conductors from the VELCO/Stowe substation to Stowe'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 Stowe completed the installation of a Transmission Ground Fault Overvoltage (TGFOV) protection relay system at our Wilkins substation. 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 first half of 2020, Stowe has completed the installation of a new outage management system which utilizes a new GIS system that has been integrated with our AMI and CSI systems. Our new OMS/GIS system has our complete system information, lines, poles, transformers, and meters. Field crews are outfitted with tablets that have cellular capabilities that allows access to all GIS information and real time outage data.

Stowe completed upgrades on the two major circuits fed from our Houston Substation. In 2015/16 the two 5MVA stations transformers were replaced and upgrade 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. Work replacing the six 250kVA voltage regulators with six 333KVA units was completed in 2019.

Stowe is taking a proactive approach for handling direct burial primary cable failures. Stowe has digitally mapped approximately 90%of our underground system and has identified the age of the cables in those areas. Stowe has purchased new equipment in anticipation of potential failures of old underground primary. We have purchased new underground locating equipment and have 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

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.

Much of Stowe's distribution lines are located along the roadside and much of those that are cross-country cannot be relocated because of the remoteness. Currently Stowe has relocated two cross-country sections to roadside existing poles and right of ways. Stowe works with the telephone and cable TV utilities on utilizing and maintaining their existing infrastructure.

Stowe is a member utility with NJUNS and utilizes the online portal to coordinate pole transfers with telephone and cable utilities. Stowe is currently reviewing our in-house procedures to better document pole replacements in the field and to better coordinate transfer work in NJUNS. Stowe is also in negotiations with Consolidated Communications to purchase the poles they own in Stowe, approximately a third of the total. This will give Stowe better controls on coordinating pole transfers and removing existing double sets.

H.6.4 Grid Modernization

In October 2016, Stowe purchased the old Moscow Mills property, which is now the location of Stowe's new headquarters. This old industrial site was home to a machine shop, a sawmill, several outbuildings, a residence, and site storage for construction materials. Throughout the first half of 2017, Stowe finalized site and building plans, and demolition of two buildings began in September 2017. Construction of the new buildings began in November 2017 and state of the art headquarters building and garage were completed using energy efficient technologies. Stowe worked closely with Efficiency Vermont on lighting, heating, and cooling for the buildings. A rooftop photovoltaic system will be installed to provide energy needs. In 2020, one (1) Level 1 EV charging station for use by our customers and employees was installed at the location.

Stowe feels that our efforts to clean up and re-develop this dilapidated industrial site have significantly improved historic Moscow District. A grist mill built in 1800s that recently housed a run of the river hydroelectric generator are located next to the new headquarters building. Stowe is researching the stabilization and restoration of the historic mill and will look to install a new turbine and generator to produce electricity. The restored mill and hydro facility will 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.

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 in the first quarter of 2017. A new IP based phone system was installed in June 2017.

During the first half of 2020, Stowe completed the installation of a new outage management system which utilizes a new GIS system that has been integrated with our AMI and CSI systems. Stowe's OMS/GIS system has complete system information and is available to all Stowe personnel. Field crews are also outfitted with tablets that have cellular capabilities that allows 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.

Fiber optic cable has been installed from our Wilkins substation along our 34.5kV transmission line with terminations at Houston and Lodge substations, then continues to the top of the 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 to our new headquarters.

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 was completed.

Throughout 2021 Stowe will evaluate the Control Point's recommendations and design a 10-year plan for system improvements and upgrades.

H.7 Vegetation Management Plan

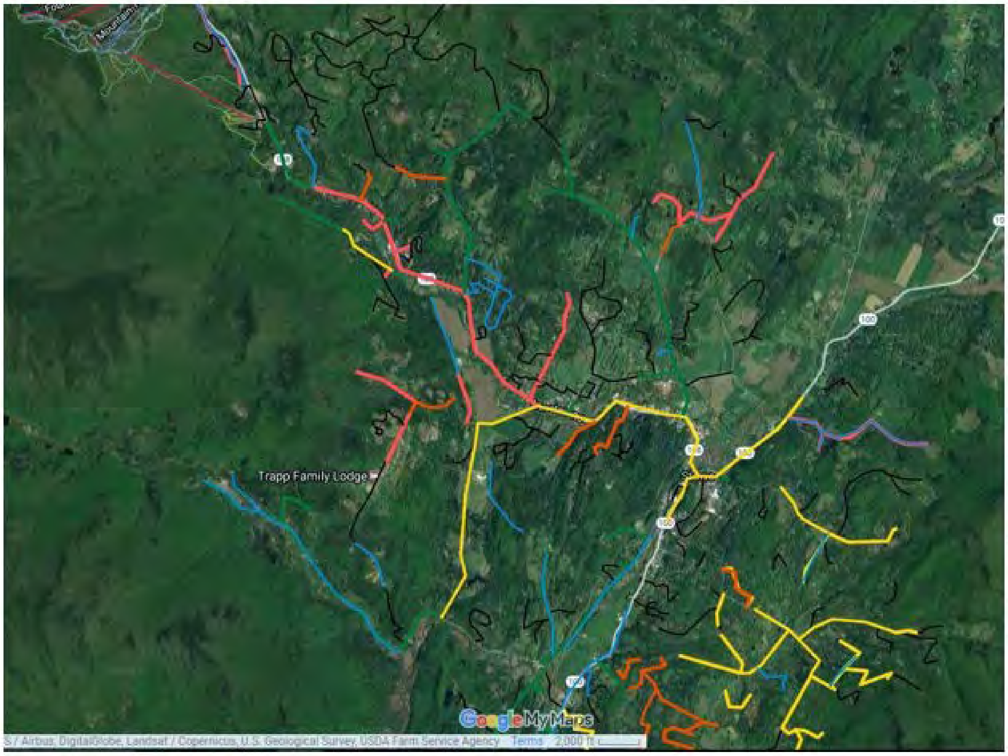
Stowe continues to see positive results from our vegetation management program. Stowe does not apply herbicides[47] to any utility right-of-way (ROW) but does use herbicides through a licensed applicator within the fence line of each of substation. Stowe developed a tree trimming program to trim ROW corridors on a five-year cycle for both transmission and distribution. Stowe continues to strive to improve our annual results, and Stowe exceeds the goals stated in the 2014 IRP, which aimed to achieve a 5-year tree-trimming cycle for subtransmission lines and a 7-year cycle for our distribution system.

Lands within the Stowe ROWs either are owned by private individuals or are by the State of Vermont. A perpetual easement is the most common type of utility right-of-way document and most easements at Stowe are 50 feet on aerial distribution and 100 feet on aerial transmission. Many of Stowe owned distribution lines are located near roadways, which provides different challenges for tree trimming crews than those lines running through timbered areas. A variety of vegetation along Stowe ROWs range 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. 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 more fully-grown areas, and therefore those areas with a higher cost per mile, have already been addressed.

Stowe has mapped our entire system by year to help coordinate pre-season line surveys with tree trimming assignments for the year.

[47] Stowe continues to follow all customer notification and reporting requirements pursuant to Vermont Public Utility Commission Rule 3.600 on herbicide application.

Figure 91: Stowe Tree Trimming, 2013-2017 (Note: Underground facilities in black)



2017 2016 2015 2014 2013

Stowe Tree Trimming, 2018-2020

Tree trimming activities are conducted by qualified line clearing contractors who are bound by contract to adhere to the American National Standard Institutes (ANSI) Standard A300. Stowe staff conducts routine maintenance inspections and contract administration to ensure that maintenance activities are conducted in accordance with established standards. The contract work is augmented by Stowe line maintainers cutting danger trees and some trim work during the slower winter months.

Line crews continually monitor our overhead lines for danger trees. Danger trees may also be identified by contracted tree crews or brought to our attention by customers and landowners. In the event that there are no contracted tree crews currently working in Stowe's territory that can be redirected to evaluate and deal with a danger tree, line maintainers will be diverted as soon as practicable to remove danger trees.

Table 26: Tree Maintenance Budget and Amount Spent

	Total Miles	Miles Needing Trimming	Trimming Cycle (years)
Subtransmission	8.1	6.1	5
Distribution	120	63.9	7

	2017	2018	2019	2020	2021	2022
Amount Budgeted	$83,000.00	$83,333.00	$175,000.00	$175,000.00	$175,000.00	$175,000.00
Amount Spent	$120,459.00	$82,288.00	$149,735.00	$171,500.00		
Miles Trimmed	5.9	2.96	6.17	6.5	7.5	7.5

Stowe is aware that emerald ash borer (EAB) infested areas have been identified to the south and west of Lamoille county[48]. While, 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[49]. Stowe also works closely with contracted tree-trimmers to identify and remove ash trees within Stowe's ROW.

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[48] https://vtanr.maps.arcgis.com/apps/PublicInformation/index.html?appid=cfda013ad1464b7b9103a3d7806f0cc5

[49] https://www.townofstowevt.org/vertical/Sites/%7B97FA91EA-60A3-4AC6-8466-F386C5AE9012%7D/uploads/EAB_Plan_03-11-19_FINAL.pdf; https://vtcommunityforestry.org/sites/default/files/pictures/stowe_summary_report_with_maps_8.16_0.pdf; https://vtcommunityforestry.org/sites/default/files/pictures/Resilient_ROW/stowe_resilientrowactionplan_final20191230small.pdf;

H.8 Studies and Planning

The following are Stowe's distribution system future upgrades.

Table 27: Distribution Upgrades

Job	Location	Estimated	Priority
Replace Cap Bank Controller at Lodge Sub	Lodge Sub	$5,000.00	3-5 years
Install new tie point for Circuits 6 & 7	Mountain Rd	$250,000.00	>1 years
New reclosers and controllers at substations	All Subs	$200,000.00	3-5 years
New transformer (Circuit 1) at Wilkins Sub	Wilkens Sub	$150,000.00	1-3 years
Rebuild Lodge Substation - 12KV Structure	Lodge Sub	$50,000.00	1-3 years
Complete 1Ø Aerial Primary Brook Rd (Circuit 6B)	Brook Rd	$15,000.00	1-3 years
River Rd. - replace poles and crossarms (Maintenance)	River Rd.	$0.00	3-5 years
Barrows Rd. - replace poles and crossarms (Maintenance)	Barrows Rd.	$0.00	1-3 years
Barrows Rd H.S. Riser Pole - replace and re-configure	High School	$0.00	1-3 years
Convert Sanborn Rd. to 3Ø up to Robinson Springs	Sanborn Rd	$15,000.00	1-3 years
Move main line out to Mountain Rd. (across from Rusty Nail)	Mountain Rd	$15,000.00	3-5 years
Weeks Hill 3Ø to Percy Farm Conversion - Phase 1	Weeks Hill	$20,000.00	1-3 years
Weeks Hill 3Ø to Percy Farm Rebuild - Phase 2	Weeks Hill	$30,000.00	3-5 years
Birch Hill - Winterbird Rd. URD replacement	Birch Hill Rd.	$10,000.00	1-3 years

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 linemen, 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 lineman 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, Stowe can rely on members of the Northeast Public Power Association's mutual aid program. This gives Stowe access to local Municipal utility crews. Further help is available from Green Mountain Power and Vermont Electric Coop.

For planned outages, Stowe uses several forms of communications to inform customers in advance: phone calls, emails, and doorknockers. Information is also posted on Front Porch Forum, Stowe's website, Twitter, and Facebook page, as well as in the local newspaper and radio stations when time permits.

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.

H.10 Reliability

Stowe serves over 92% of residents and 100% of businesses located within Stowe, Vermont and currently serves 4,267 customer meters, net of voltage and current meters, station service meters, and any meters at a retail customer's premises beyond the customer's first meter.

Stowe's system experienced several extreme weather events in 2019. Though none of them qualified as a "major storm" as defined in the Stowe Service Quality and Reliability Plan ("SQRP"), they had a considerable impact on the outage data. In total, there were 4 wind events which were major negative contributors to Stowe's SAIFI ("System Average Interruption Frequency Index") and CAIDI ("Customer Average Interruption Duration Index") numbers. These events and their impacts on Stowe's reliability indices are addressed more thoroughly later in this assessment.

Stowe's SQRP reliability goals: SAIFI .9 and CAIDI 3.3

Stowe's Indices for 2019 With All Outages Included: SAIFI 1.8 and CAIDI 2.4

Stowe's 2019 reliability indices reflect short-term improvements in system performance. In 2018, Stowe reported a SAIFI of 2.8 and a CAIDI of 2.6. In 2019, Stowe had 98 outage events and 18,639 customer hours out. Stowe recorded 110 outage events and 31,315 customer hours out in 2018.

However, there has been a trend in recent years of high intensity, short duration weather systems featuring high winds and other adverse weather. Stowe's system has been regularly subjected to events like these and they typically lead to a high number of damaging tree outages. This trend continued in 2019, and Stowe's system experienced four (4) significant weather events. Without these four (4) major events, Stowe's 2019 SAIFI and CAIDI numbers would have been 0.6 and 2.5, respectively.

Figure 92: Long Term SAIFI Performance

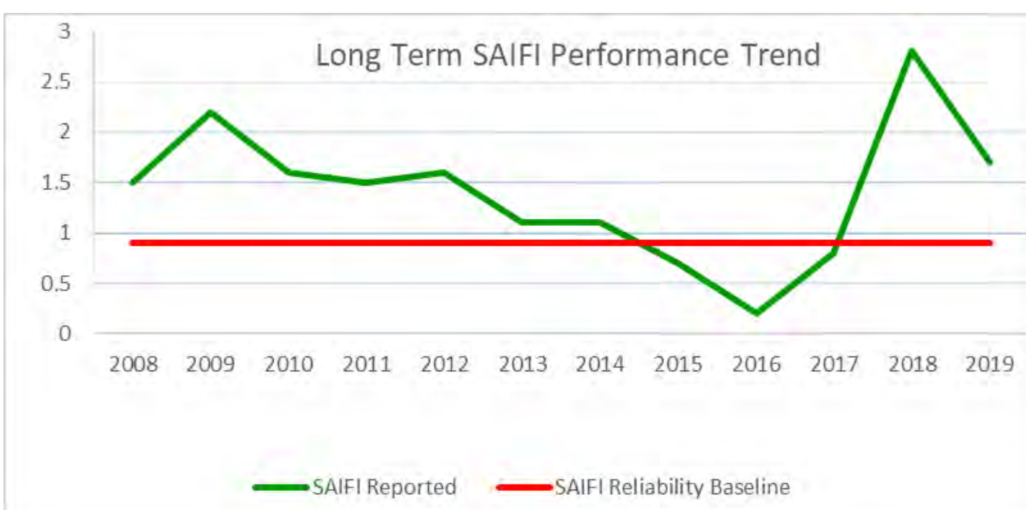
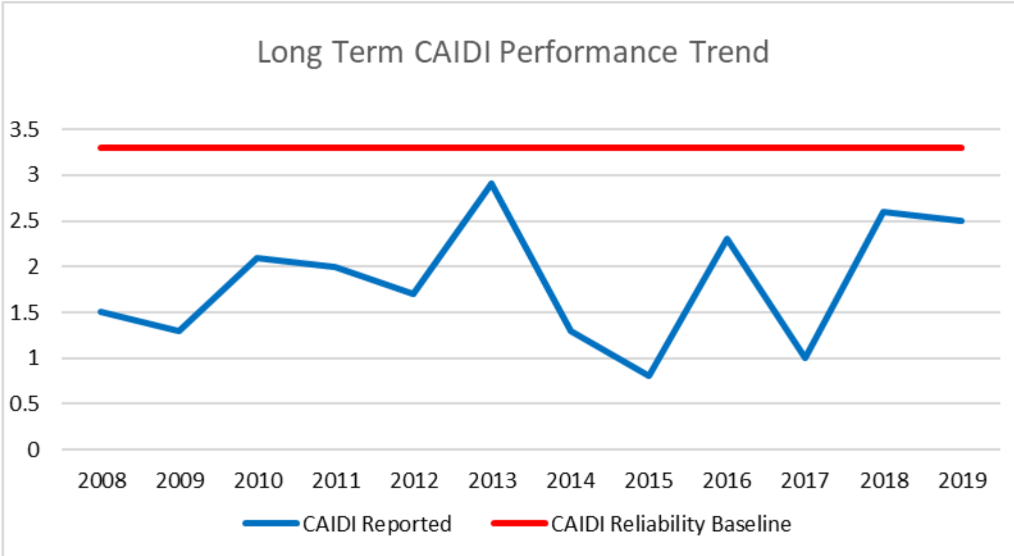


Figure 93: Long Term CAIDI Performance



H.11 Assessment of Outage Events and Trends in 2019

As mentioned above, Stowe's system experienced several significant weather events during 2019. None of these events qualified as a Major Storm as defined in the Service Quality Reliability Plan ("SQRP"). Stowe's SQRP includes two criteria that a weather event must meet in order 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[50]. Three of these events met the first criterion but none met the second criterion.

- July 28 – A weather event featuring thunderstorms, heavy rain, and wind caused three separate outages from trees and impacted 1,654 customers leading to 1,938 customer hours out.

- July 30 – A weather event featuring thunderstorms and strong wind gusts caused 5 separate outages from trees and impacted 151 customers out for a total of 199 customer hours out.

- October 18 – A wind event led to 1 outage caused by a tree and impacted 1,019 customers for a total of 1,454 customer hours out. A small pine branch broke off a tree and fell onto the crossarms of a pole and across two phases of a three-phase section of our system. This caused both conductors to burn up and fall to the ground.

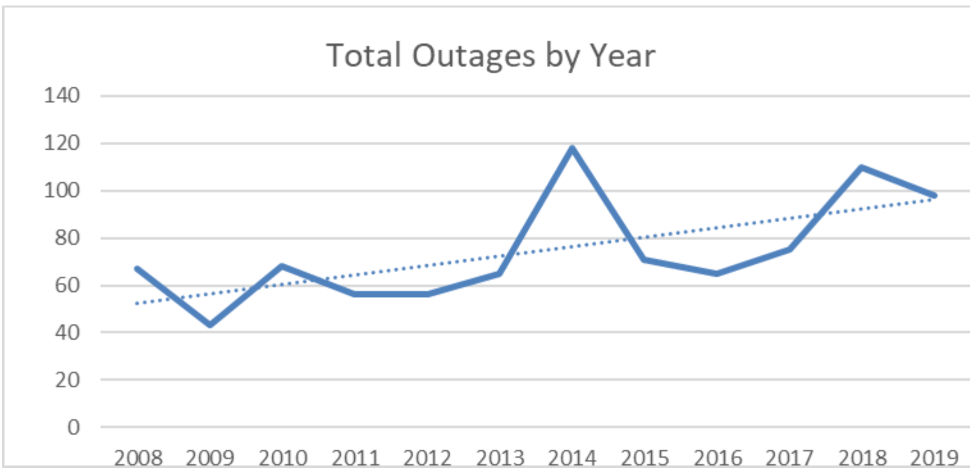
- November 1 – Stowe suffered 22 outages during a storm featuring heavy winds and flooding. 2,073 Stowe customers experienced a loss of power with a total 8,069 customer hours out. This single storm accounts for 22% of Stowe's annual outages and 43% of Stowe's annual customer hours out. It

[50] *Stowe Service Quality and Reliability Plan,* p8, November 6, 2006.

was also the only event that lead to service interruptions longer than 24 hours. But only 22 customer meters, or less than 0.5% of Stowe's total customer meters, were disrupted for that long.

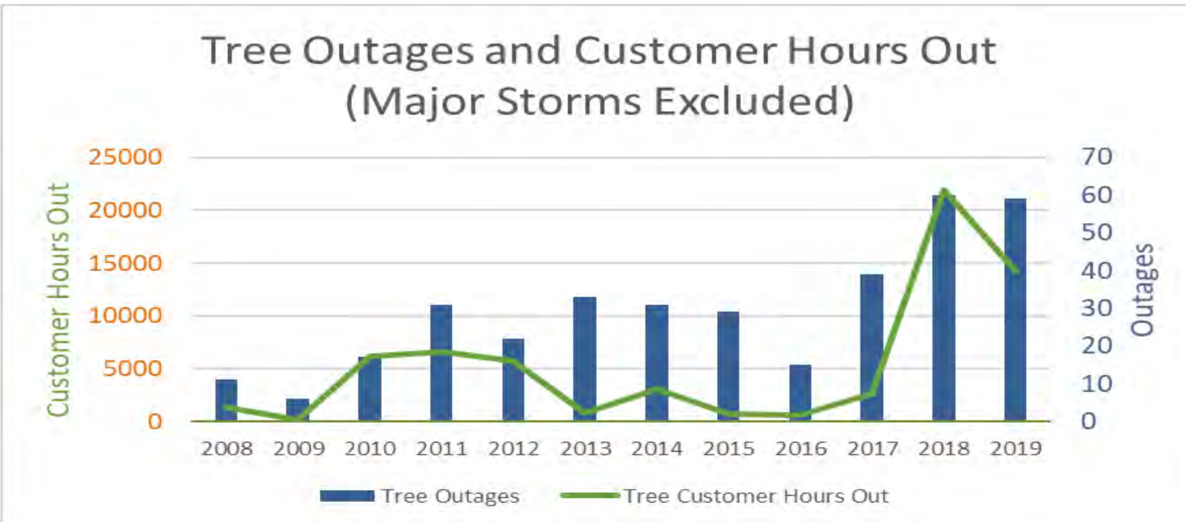
The number of customers affected, and the total number of customer hours out speak to the severity of these events. Three (3) of these events would have qualified as major storms if not for Stowe's line crews who worked quickly, efficiently, and safely to restore service. It is also worth noting that the November 1 windstorm was so severe and widespread that the state of Vermont and Lamoille County qualified to receive assistance from the Federal Emergency Management Agency.

Figure 94: Annual Outages



Consistent with past trends, trees were the most common cause of outages in 2019 and resulted in 59 outages and 14,161 customer hours out. Many of these outages, including some of the severe events highlighted above, were caused by trees that fell from outside the Utility's ROWs and otherwise appeared to be healthy. The 2019 data shows that, excluding Major Storm events, Stowe's system experienced the second highest number of individual tree outages and the second highest number of customer hours out caused by trees since at least 2008. Intense, straight line winds, especially those that originate from the south-southeast, are particularly damaging and are becoming more common. Stowe has allocated additional financial resources to help counter this trend, but storms continue to have a dramatic impact on our distribution system, especially from trees that are located outside of the Utility's ROWs.

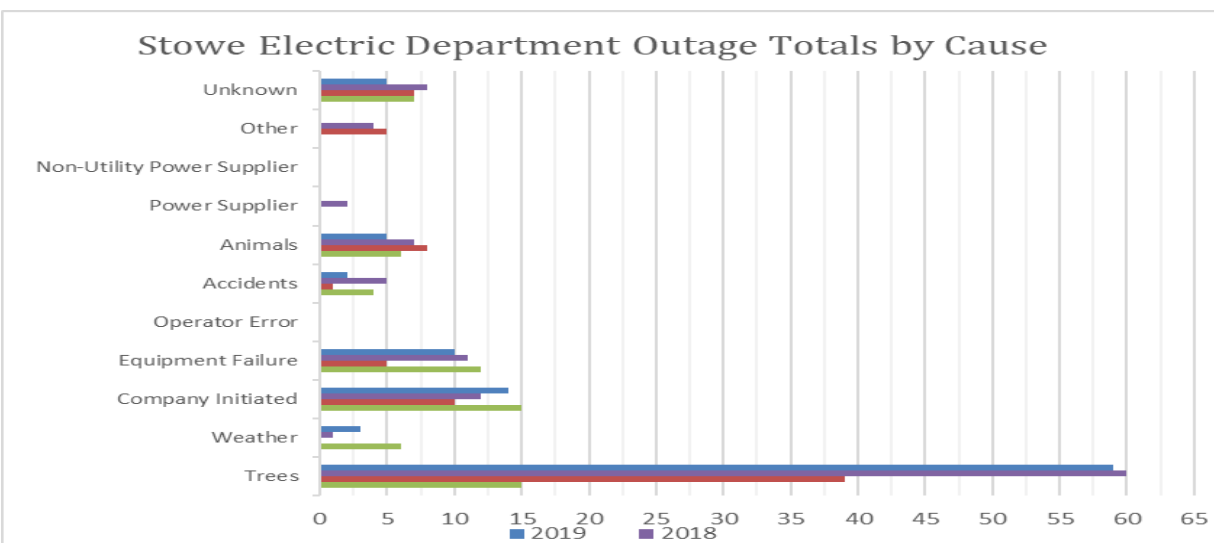
Figure 95: Tree Outages and Number of Hours Out



The second highest cause of outages in 2019 was company-initiated disruptions for a total of 14 that accounted for 3,481 customer hours out. The number of customer hours out was higher than normal. The main driver was major system work on Stowe's 34.5 kV subtransmission line that will not need to be repeated for some time. A portion of the line runs underground, and one of the three underground conductors failed in 2018. Stowe was able to maintain normal service while replacement conductors were procured. Stowe elected to proactively replace all three conductors to limit the likelihood of another failure. This required lengthy planned outages for a significant portion of our service territory.

Equipment failures were the third highest cause of outages. As shown in the chart below, the number of outages from equipment failures in 2019 was generally consistent with what we have seen in recent years. Equipment failures only accounted for 10 events and 615 hours out.

Figure 96: Outage Totals by Cause



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 were completed in February 2019 and are part of this commitment, which also 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.

Stowe Village Sidewalks and Main Street Utility Relocation Project

Stowe Electric Department Administration Building

I Integrated Analysis and Plan of Action

I.1 Evaluation of Portfolio Scenarios

ENE's portfolio simulation models evaluated nine (9) 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.

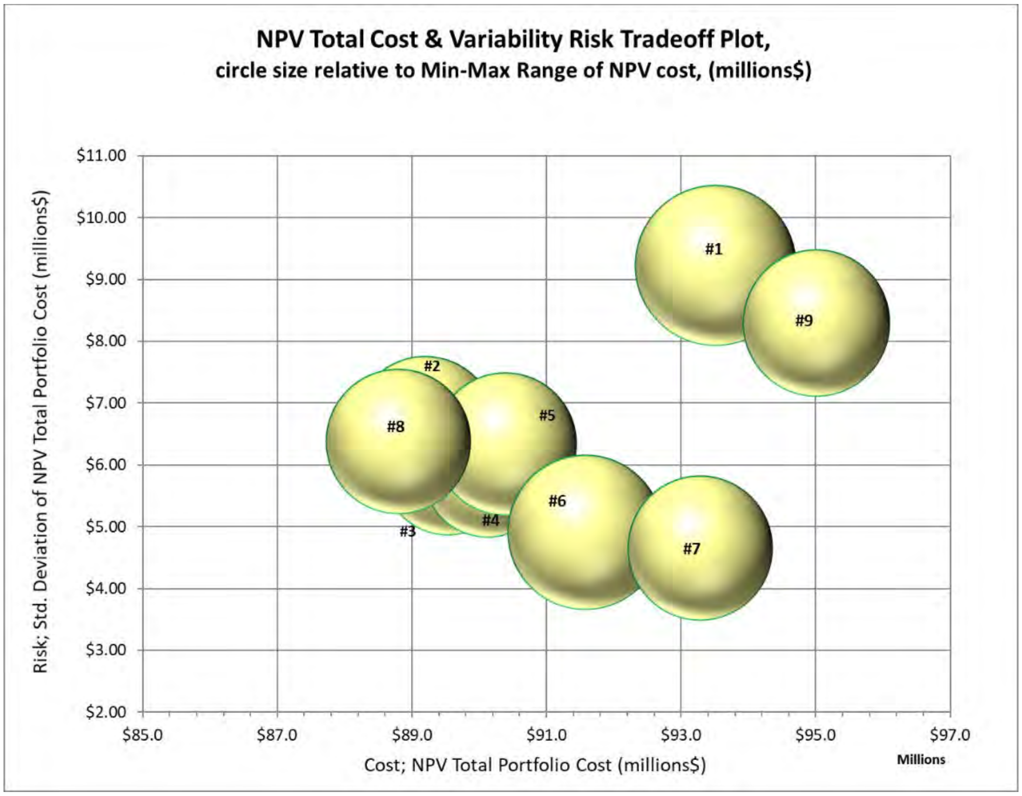
Portfolio Scenarios:

- Scenario # 1 = Current Portfolio with no additional resource procurement
- Scenario #2 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, and HQ extension
- Scenario #3 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, and 5 MW VT based solar project
- Scenario #4 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, 5 MW VT based solar project, and 150 kW Farm Methane project in Stowe
- Scenario #5 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for increased percentage to 4% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, and 7 MW of a 50 MW solar project
- Scenario #6 = Current Portfolio, with 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, 5 MW VT based solar project, and 3 MW of Off Shore Wind
- Scenario #7 = Current Portfolio, Existing Hydro (Miller extension) PPA for roughly 3% of load, new PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, Seabrook extension, 5 MW VT based solar project, and 1 MW of Off Shore Wind
- Scenario #8 = Current Portfolio, new PPA for an existing Hydro 2.5% of load, HQ extension, 5 MW VT based solar project, and 100 kW Moscow Mills Hydroelectric Unit
- Scenario #9 = Current Portfolio, new PPA for an existing Hydro 2.5% of load, HQ extension,

The NPV of each scenario cost and the risk tradeoff is below in Figure 97. 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 would not largely increase costs and maintain a healthy coverage while allowing room for future projects.

Figure 97: Cost and Risk Tradeoff Bubble Plot



The four primary factors that used for comparative analysis are: (Also found in A.2.3 Resource Alternatives)

Table 28: Scenario Simulation Summary Statistics by Ranking

	NPV Total Cost	Rank	NPV Total RES	Rank	Std Dev	Rank	Hedged Target Average	Rank	Total Weighted NPV Cost	Total Rank
Scenario #1	$ 65,342,181	1	$ 8,257,049	9	$ 9,225,943	9	59%	9	$ 73,599,230	8
Scenario #2	$ 67,783,639	4	$ 2,539,505	6	$ 6,601,527	7	67%	7	$ 70,323,144	2
Scenario #3	$ 69,579,560	6	$ 937,217	4	$ 5,926,564	4	74%	5	$ 70,516,777	3
Scenario #4	$ 70,572,621	7	$ 447,985	3	$ 5,886,636	3	75%	4	$ 71,020,605	5
Scenario #5	$ 67,173,426	3	$ 3,824,169	7	$ 6,339,180	5	78%	3	$ 70,997,595	4
Scenario #6	$ 75,206,322	9	$ (3,020,853)	1	$ 4,908,654	2	86%	1	$ 72,185,469	6
Scenario #7	$ 73,099,155	8	$ 57,594	2	$ 4,651,198	1	83%	2	$ 73,156,749	7
Scenario #8	$ 68,657,311	5	$ 1,276,167	5	$ 6,376,784	6	71%	6	$ 69,933,478	1
Scenario #9	$ 66,411,663	2	$ 8,154,417	8	$ 8,296,354	8	63%	8	$ 74,566,080	9

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 choose was determined not only by cost and impact but also by feasibility. ENE wanted to present a scenario that was obtainable to Stowe to include in their portfolio.

I.2 Preferred Plan

I.2.1 Optimal Scenario

The IRP process found the optimal scenario to be scenario #3. The portfolio included all current resources along with 100 kW Moscow Mills Hydroelectric Unit, Miller extension PPA for roughly 3% of load, PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, and 5 MW VT based solar project.

The projected cost used in ENE's @Risk modeling for a PPA of existing hydro was based on Appendix H, Standard offer pricing. Because Stowe is currently working with a supplier for a contract the model did contain yearly escalating prices based on projected contract costs. For the energy price of the new construction of Moscow Mills hydro project the model was based on Appendix I, Standard offer 7533 Standard Offer Hydro Model. Stowe is currently working with a developer and was able to use estimated pricing in the analysis, the pricing correlates to the standard offer pricing found in Appendix L. The stochastic model data is below in Figure 98. The Output for the RES impact is found in Appendix K. Scenario 3 offers Stowe a multitude of benefit from resource diversity to RES benefits in all three Tiers. 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 Stowe's RES requirement in the most expensive tiers, Tier II and Tier III. With the REC arbitrage, Stowe will be able to fill the minimal shortfall with the extra benefit from selling high and buying low at the beginning of the program. Figure 99 and Figure 100 are the RES resulting coverage from scenario #3.

Figure 98: Optimal Scenario #3

	NPV Total Cost	Rank	NPV Total RES	Rank	Std Dev	Rank	Hedged Target Average	Rank	Total Weighted NPV Cost	Total Rank
Scenario #3	$ 69,579,560	6	$ 937,217	4	$ 5,926,564	4	74%	5	$ 70,516,777	3

Figure 99: Tier I with Scenario #3

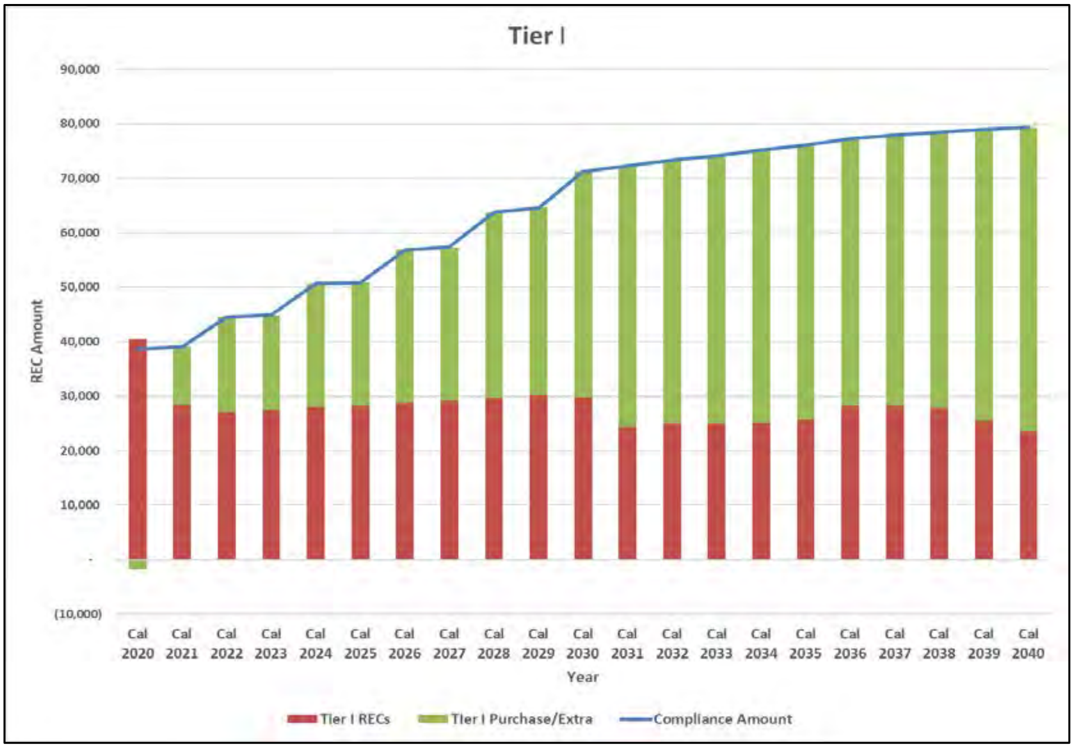
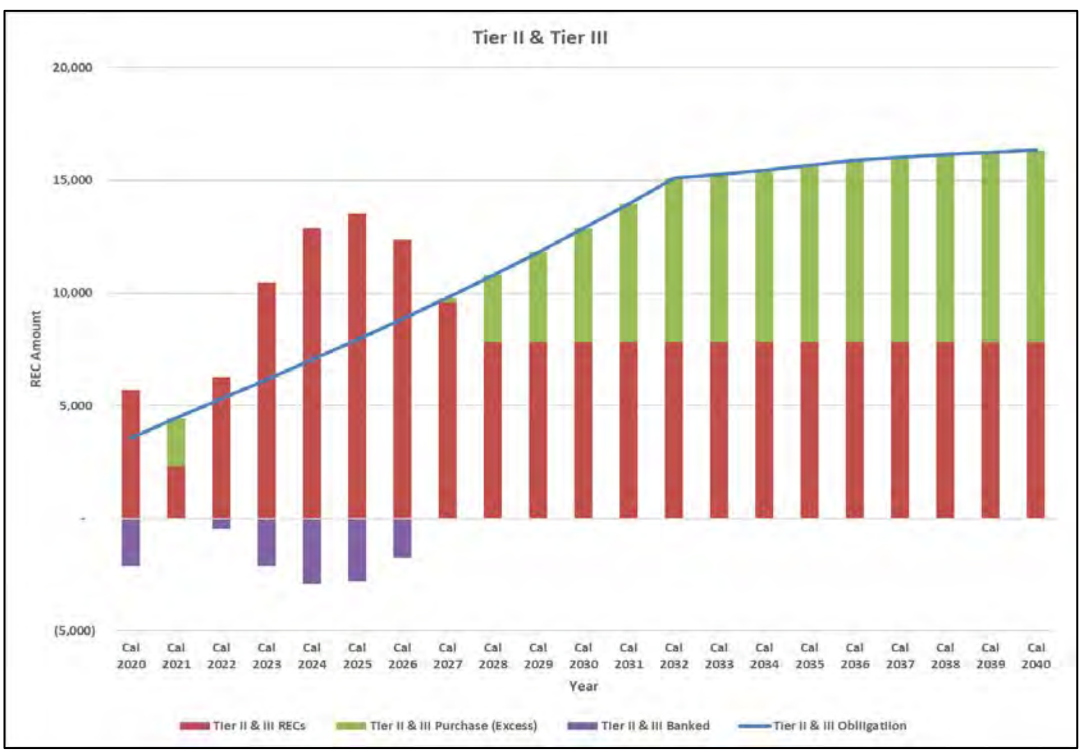


Figure 100: Tier II and Tier III with Scenario #3



I.2.2 Least Energy Cost Scenario

The least cost scenario is #1. This is Stowe's current portfolio, with doing no additional hedging or building of renewable projects. The reason for this outcome is largely due to the low forward price curves, seen in Figure 54. The @Risk model is mapping the open position to forward prices that are reasonably low compared to historical actual 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 to be 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 Stowe cannot depend on the forward market costs, although the model examines 1,000 iterations choosing this option leaves Stowe the most exposed to the market. The market risk exposure is shown in the size of Scenario 1's graphed circle seen within Figure 97.

I.2.3 Greatest Energy Cost Scenario

The greatest cost scenario is #6. This portfolio included the 100 kW Moscow Mills Hydroelectric Unit, Existing Hydro (Miller extension) PPA for roughly 3% of load, PPA for an existing Hydro 2.5% of load, Saddleback Wind extension, HQ extension, 5 MW VT based solar project, and 3 MW of Off Shore Wind. The scenario obtained all the resources that were included in the optimal scenario but with one difference, a large amount of offshore wind. Stowe's scenarios revolved around the most feasible options and then added situations that would stress the ranking. The pricing used to model offshore wind can be found in Appendix J, which is based on the Mayflower Wind Project off the coast of Martha's Vineyard and Nantucket. The amount of energy was forecasted to be about 14% of Stowe's portfolio. This option narrowed Stowe 's open position on average to 14%. This option had the greatest hedged option and a large benefit to RES costs. The largest downfall to this option is the high-risk exposure Stowe would have to the Class I REC market in New England. With a large amount of energy and RECs coming from a Class I resource the REC arbitrage mitigated the next 20 years of RES exposure to compliance payments. Not only was the risk large to Stowe's cost the price of Offshore wind remains to be above market, therefore causing this scenario to have the largest NPV cost to the energy portion of the Stowe. The cost of new offshore wind does not offset the RES benefit, and therefore, does not make this option appealing to Stowe if it wants to maintain low cost rates for its customers.

I.2.4 Other optional Scenario

Stowe's scenarios were largely based on the premise of feasibility so most include the main contracts Stowe is currently working on due diligence for contract completion. These include the 5MW VT solar and existing hydro PPA's. Besides analyzing offshore wind as an extra resource Stowe also reviewed replacing a VT solar PPA with a MW allotment of a large-scale solar project outside of VT. A larger scale project's benefit is economies of scale to the energy price. Scenario 5 included a 7MW PPA of large solar. Although the energy NPV of the scenario was low, the RES NPV was much too high to help offset the energy price reduction of large scale vs. small VT solar. Viewing the outcomes of the simulations of each scenario it was clear the best option for Stowe would be the one that would provide the most balance to both energy prices and the RES compliance cost. These VT based resources are a good value based on their benefits to both, towards RES, and to portfolio stability with locked-in long-term contract rates. Stowe searches for options that will help stabilize costs just as much as trying to find low cost resources. With the compliance of RES now a large driver of decision making, more expensive renewable resources are more valuable, and Stowe can now justify adding these to its portfolio because there are other benefits to Stowe's overall business costs.

I.3 Implementation or Action Plan

Stowe is diligently working with developers and counterparties for the resources set forth in scenario 3. Most of the resources examined are similar in most portfolio's because Stowe wanted to create feasible options. 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 for RES. While one scenario has the most risk depending on REC prices verses risk in generation output. The components of the optimal and other ideal scenarios are balanced to maintain Stowe at a hedged position that still allows space for future renewable options or bilateral purchases. Stowe's risk tolerance for an open position less than 60% is large, because the municipal knows if market prices increase high enough it has Stonybrook as a Peaker unit that will help mitigate price spikes. This scenario allows benefits to Stowe beyond coverage and cost, it allows them to transact for a large solar project outside their territory and still retain Tier II benefits and scheduling ease. Although Stowe will have opportunity cost with this solar PPA such as load and ISO-NE charge reductions the benefits of not owning and operating the project is more appealing. These options of Vermont based resources will be the most sought after for the RES compliance. Stowe will evaluate each potential resource on cost and benefit to both energy and RES. The most feasible scenarios purposively have Stowe coverage at an average of 70% to 80% this allows Stowe to have options to investigate additional products to comply with any new regulations. Reviewing Vermont based resources will be the key to Stowe's RES compliance and reducing their environmental impact. This option reduces 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 so it can monitor rate impact more efficiently if needed. Lastly, it will provide Stowe a RES compliance that will reduce its exposure to any compliance payments, which could increase costs to the ratepayers.

I.4 Ongoing Maintenance and Evaluation

Stowe will update this IRP 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.

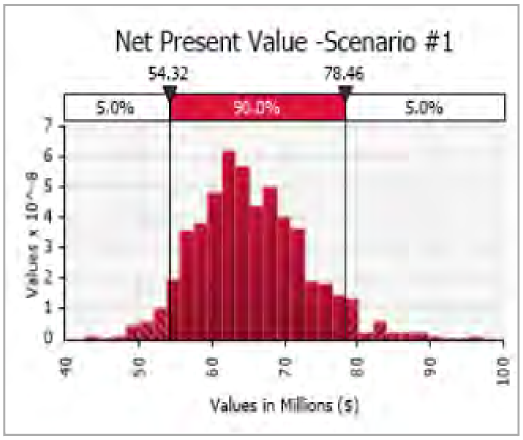
In the next IRP, Stowe will use the recommendations in the Vermont Comprehensive Energy Plan and guidance from the Department of Public Service when addressing and setting a path to helping Vermont meet its goals. V.S.A. § 8001 states the RES program is to promote renewable energy goals of "Balancing the benefits, lifetime costs, and rates of the State's overall energy portfolio to ensure that to the greatest extent possible the economic benefits of renewable energy in the State flow to the Vermont economy in general, and to the rate-paying citizens of the State in particular".[51]

[51] http://legislature.vermont.gov/statutes/section/30/089/08001

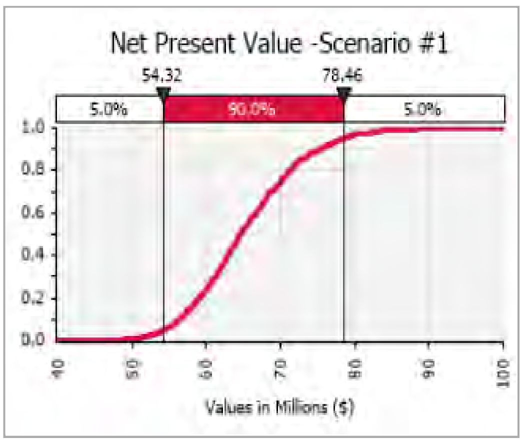
A Appendix A

Net Present Value -Scenario #1 - B26

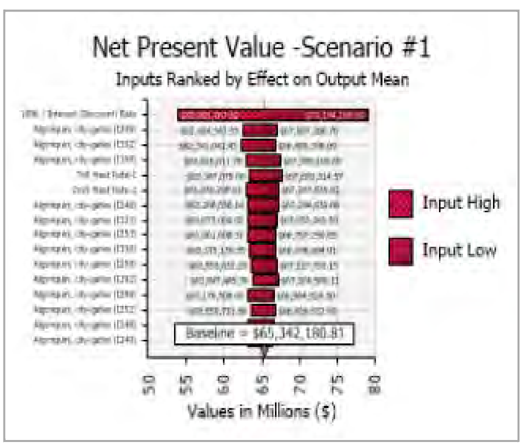
Report: Compact Output Report
Performed By: mcoscia
Date: Tuesday, October 6, 2020



Summary Statistics		
Statistic		Value
Minimum	$	42,498,562.17
Maximum	$	97,246,019.97
Mean	$	65,342,180.81
Std. Deviation	$	7,411,873.94
Variance		5.494E+013
Skewness		0.4468
Kurtosis		3.3675
Median	$	64,653,793.07
Mode	$	64,695,020.62
Left X	$	54,316,350.60
Left P		5%
Right X	$	78,457,187.04
Right P		95%



Percentiles		
Percentile		Value
1%	$	49,891,473.46
2.5%	$	52,411,235.13
5%	$	54,316,350.60
10%	$	56,321,003.85
20%	$	59,011,336.18
25%	$	60,245,682.64
50%	$	64,653,793.07
75%	$	70,024,148.02
80%	$	71,366,287.83
90%	$	75,363,548.72
95%	$	78,457,187.04
97.5%	$	81,088,641.94
99%	$	84,770,430.18

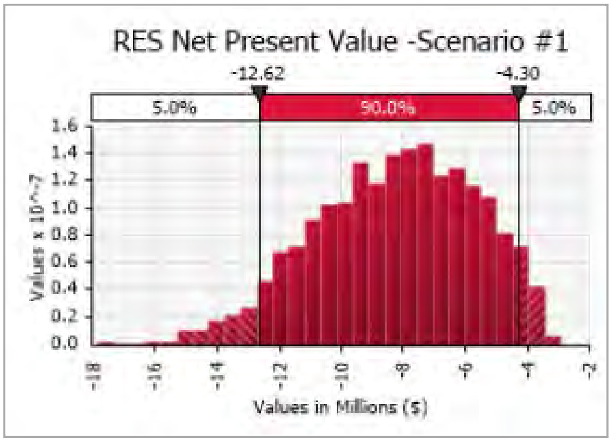


Change in Output					
Rank	Name		Lower		Upper
1	1996 / Interest (Discount) Rate	$	53,893,767.62	$	79,194,195.09
2	Algonquin, city-gates (I209)	$	62,424,343.53	$	67,107,266.76
3	Algonquin, city-gates (I302)	$	62,341,041.43	$	66,880,398.09
4	Algonquin, city-gates (I188)	$	63,016,611.78	$	67,385,100.65
5	7x8 Heat Rate-1	$	63,347,078.06	$	67,681,314.57
6	2x16 Heat Rate-2	$	63,030,208.61	$	67,167,839.62
7	Algonquin, city-gates (I246)	$	63,268,856.14	$	67,294,939.06
8	Algonquin, city-gates (I121)	$	63,073,099.02	$	67,053,245.59
9	Algonquin, city-gates (I253)	$	63,061,608.31	$	66,757,250.85
10	Algonquin, city-gates (I136)	$	63,315,130.35	$	66,938,604.01
11	Algonquin, city-gates (I258)	$	63,553,032.29	$	67,127,701.15
12	Algonquin, city-gates (I192)	$	63,847,485.76	$	67,304,580.11
13	Algonquin, city-gates (I286)	$	63,178,508.65	$	66,564,524.30

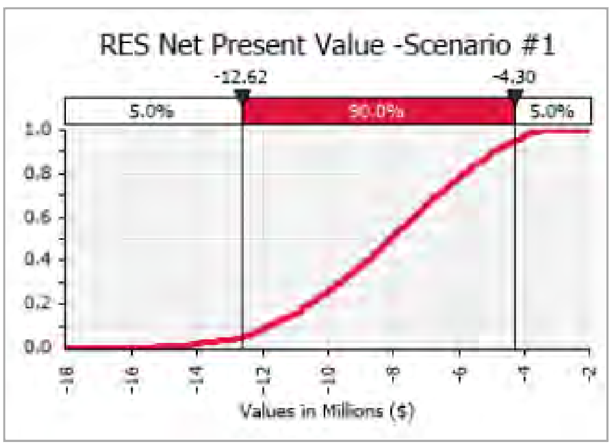
B Appendix B

RES Net Present Value -Scenario #1 - B127

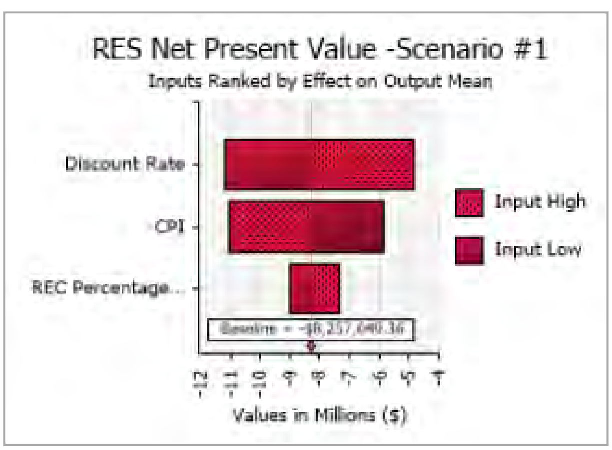
Report: Compact Output Report
Performed By: mcoscia
Date: Wednesday, October 14, 2020



Summary Statistics	
Statistic	Value
Minimum	($17,896,076.15)
Maximum	($2,919,111.85)
Mean	($8,257,049.36)
Std. Deviation	$2,586,852.82
Variance	6.692E+012
Skewness	-0.3373
Kurtosis	2.6321
Median	($8,076,231.52)
Mode	($8,056,563.44)
Left X	($12,618,655.67)
Left P	5%
Right X	($4,300,809.14)
Right P	95%



Percentiles	
Percentile	Value
1%	($14,691,263.62)
2.5%	($13,578,406.27)
5%	($12,618,655.67)
10%	($11,823,228.53)
20%	($10,587,829.83)
25%	($10,075,147.28)
50%	($8,076,231.52)
75%	($6,274,575.96)
80%	($5,826,496.54)
90%	($4,951,724.95)
95%	($4,300,809.14)
97.5%	($3,953,570.36)
99%	($3,702,771.08)



Change in Output			
Rank	Name	Lower	Upper
1	Discount Rate	($11,164,062)	($4,804,114)
2	CPI	($11,061,908)	($5,851,321)
3	REC Percentage / Cal 2	($9,000,761)	($7,319,639)

C Appendix C

STANDARD OFFER PROJECTS OPERATING

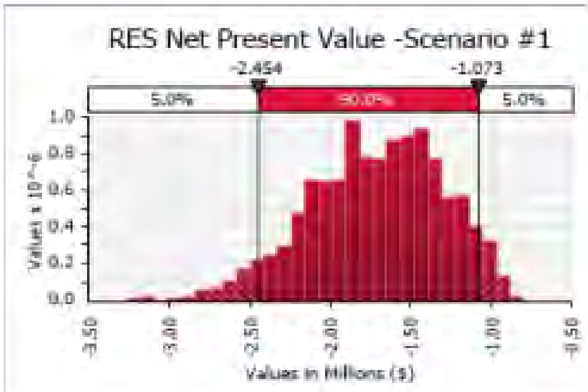
PROJECT NAME	PROJECT FUEL	ESTIMATED ANNUAL OUTPUT MWH
Audet's Cow Power	Farm Methane	4,557
Berkshire Cow Power	Farm Methane	4,021
Chaput Family Farms	Farm Methane	2,010
Dubois Energy	Farm Methane	3,016
Four Hills Farms	Farm Methane	3,016
Gervais Digester	Farm Methane	1,340
Green Mountain Dairy	Farm Methane	2,010
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
Riverview Farms	Farm Methane	1,267
Westminster Energy	Farm Methane	3,016
Vermont Technical College	Farm Methane	2,513
Advance Transit	Solar	41
Barton Solar Farm	Solar	2,401
Battle Creek 1 Solar	Solar	2,794
Bobbin Mill	Solar	64
Bridport West Solar Farm	Solar	2,540
Butternut Farm Solar	Solar	131
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
IRA Rentals Solar	Solar	47
Kingsbury Solar	Solar	61
Leunig's Building	Solar	33
Limerick Solar	Solar	2,751
Lyndonville Solar West (1)	Solar	480
Lyndonville Solar East (2)	Solar	495
MartinbrookPV	Solar	1,905
Next Generation Solar Farm	Solar	2,794
Northshire	Solar	20
Otter Valley Solar	Solar	2,769
Pownal Park 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	855
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
Townshend Hydro	Hydroelectric	3,776
Troy Hydro Project	Hydroelectric	3,210
West Charleston	Hydroelectric	2,655
Cersosimo Lumber Biomass	Biomass	6,441
TOTAL ESTIMATED ANNUAL OUTPUT		136,698

D Appendix D

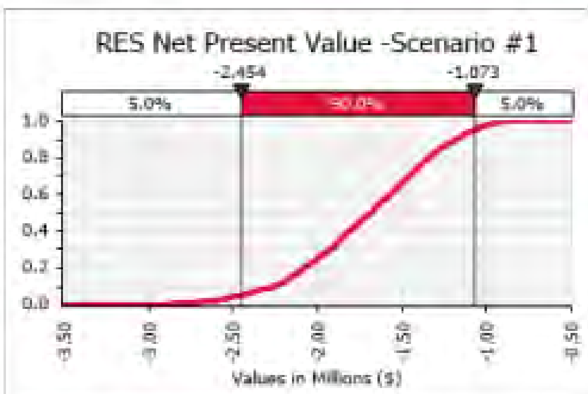
RES Analysis Base Case for the Mountain

RES Net Present Value -Scenario #1 - B127

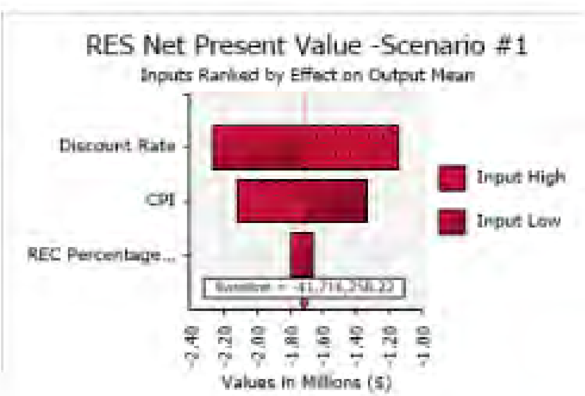
Report: Compact Output Report
Performed By: mcoscia
Date: Wednesday, October 14, 2020



Summary Statistics	
Statistic	Value
Minimum	-$3,269,018.42
Maximum	-$794,961.75
Mean	-$1,716,258.22
Std. Deviation	$418,325.85
Variance	1.750E+011
Skewness	-0.3922
Kurtosis	2.8797
Median	-$1,680,234.86
Mode	-$1,658,511.13
Left X	-$2,453,581.65
Left P	5%
Right X	-$1,072,869.54
Right P	95%



Percentiles	
Percentile	Value
1%	-$2,790,371.50
2.5%	-$2,587,722.30
5%	-$2,453,581.65
10%	-$2,261,614.32
20%	-$2,081,029.09
25%	-$1,999,386.70
50%	-$1,680,234.86
75%	-$1,411,212.54
80%	-$1,345,070.36
90%	-$1,175,277.57
95%	-$1,072,869.54
97.5%	-$1,013,907.94
99%	-$949,833.44



Change in Output			
Rank	Name	Lower	Upper
1	Discount Rate	-$2,263,757.16	-$1,150,127.53
2	CPI	-$2,119,530.42	-$1,333,119.41
3	REC Percentage / C...	-$1,797,682.12	-$1,664,682.39

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

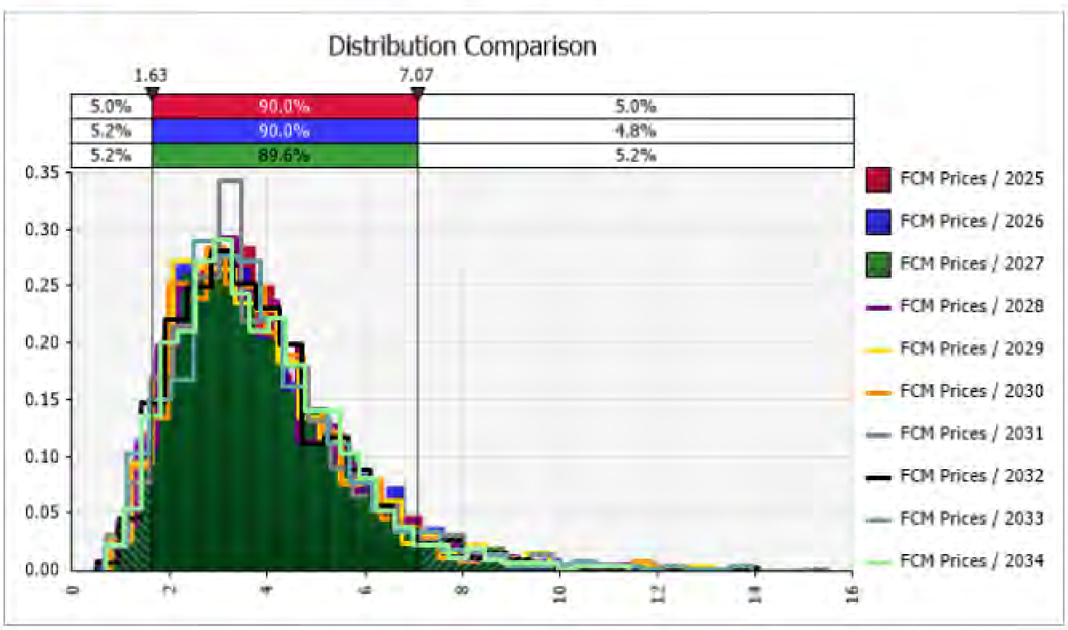
Capacity Simulation Statistics of Outputs

Summary Statistics for Outputs

Statistic	FCM Prices / 2025	FCM Prices / 2026	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	FCM Prices / 2036	FCM Prices / 2037	FCM Prices / 2038	FCM Prices / 2039	FCM Prices / 2040	FCM Prices / 2041
Minimum	$ 0.69	$ 0.48	$ 0.70	$ 0.50	$ 0.78	$ 0.76	$ 0.70	$ 0.48	$ 0.64	$ 0.67	$ 0.65	$ 0.67	$ 0.75	$ 0.65	$ 0.83	$ 0.56	$ 0.56
Maximum	$11.77	$12.00	$ 15.51	$ 12.42	$ 13.17	$ 12.29	$ 13.98	$ 14.08	$ 13.95	$ 11.43	$ 17.29	$ 15.84	$ 14.86	$ 12.79	$ 13.07	$ 11.17	$ 12.03
Mean	$ 3.78	$ 3.81	$ 3.80	$ 3.79	$ 3.80	$ 3.78	$ 3.79	$ 3.79	$ 3.80	$ 3.78	$ 3.81	$ 3.80	$ 3.80	$ 3.81	$ 3.80	$ 3.78	$ 3.80
Std. Deviation	$ 1.67	$ 1.75	$ 1.74	$ 1.71	$ 1.74	$ 1.69	$ 1.68	$ 1.69	$ 1.71	$ 1.63	$ 1.75	$ 1.75	$ 1.74	$ 1.75	$ 1.74	$ 1.65	$ 1.71
Variance	$ 2.78	$ 3.07	$ 3.03	$ 2.91	$ 3.03	$ 2.84	$ 2.81	$ 2.86	$ 2.92	$ 2.65	$ 3.08	$ 3.06	$ 3.04	$ 3.05	$ 3.01	$ 2.71	$ 2.94
Skewness	$ 1.10	$ 1.17	$ 1.25	$ 1.20	$ 1.23	$ 1.24	$ 1.19	$ 1.22	$ 1.24	$ 0.92	$ 1.42	$ 1.47	$ 1.34	$ 1.15	$ 1.28	$ 1.09	$ 1.11
Kurtosis	$ 4.64	$ 5.12	$ 6.18	$ 5.22	$ 5.32	$ 5.69	$ 5.59	$ 5.67	$ 5.97	$ 4.29	$ 7.62	$ 7.18	$ 6.54	$ 5.06	$ 5.89	$ 4.81	$ 4.87
Median	$ 3.51	$ 3.48	$ 3.46	$ 3.49	$ 3.50	$ 3.48	$ 3.46	$ 3.49	$ 3.52	$ 3.52	$ 3.52	$ 3.48	$ 3.45	$ 3.48	$ 3.48	$ 3.51	$ 3.52
Mode	$ 3.97	$ 2.31	$ 2.41	$ 1.87	$ 2.31	$ 2.28	$ 3.38	$ 3.95	$ 3.37	$ 2.94	$ 3.04	$ 2.64	$ 2.52	$ 2.28	$ 4.25	$ 2.79	$ 4.41
1%	$ 1.07	$ 1.15	$ 1.12	$ 1.21	$ 1.18	$ 1.15	$ 1.00	$ 1.20	$ 1.11	$ 1.08	$ 1.08	$ 1.11	$ 1.11	$ 1.02	$ 1.07	$ 1.08	$ 1.11
2.5%	$ 1.42	$ 1.45	$ 1.38	$ 1.38	$ 1.41	$ 1.33	$ 1.31	$ 1.42	$ 1.27	$ 1.36	$ 1.31	$ 1.44	$ 1.36	$ 1.33	$ 1.29	$ 1.40	$ 1.31
5%	$ 1.63	$ 1.61	$ 1.62	$ 1.63	$ 1.63	$ 1.58	$ 1.65	$ 1.61	$ 1.52	$ 1.58	$ 1.65	$ 1.65	$ 1.61	$ 1.61	$ 1.56	$ 1.67	$ 1.57
10%	$ 1.95	$ 1.90	$ 1.90	$ 1.94	$ 1.92	$ 1.96	$ 1.95	$ 1.92	$ 1.87	$ 1.93	$ 1.95	$ 1.95	$ 1.90	$ 1.95	$ 1.90	$ 1.95	$ 1.91
20%	$ 2.39	$ 2.30	$ 2.33	$ 2.36	$ 2.32	$ 2.36	$ 2.42	$ 2.39	$ 2.45	$ 2.38	$ 2.37	$ 2.40	$ 2.39	$ 2.36	$ 2.39	$ 2.43	$ 2.39
25%	$ 2.57	$ 2.49	$ 2.54	$ 2.56	$ 2.53	$ 2.58	$ 2.62	$ 2.56	$ 2.66	$ 2.61	$ 2.55	$ 2.59	$ 2.57	$ 2.52	$ 2.62	$ 2.58	$ 2.57
50%	$ 3.51	$ 3.48	$ 3.46	$ 3.49	$ 3.50	$ 3.48	$ 3.46	$ 3.49	$ 3.52	$ 3.52	$ 3.52	$ 3.48	$ 3.45	$ 3.48	$ 3.48	$ 3.51	$ 3.52
75%	$ 4.60	$ 4.77	$ 4.76	$ 4.58	$ 4.66	$ 4.63	$ 4.67	$ 4.59	$ 4.68	$ 4.73	$ 4.67	$ 4.63	$ 4.66	$ 4.69	$ 4.61	$ 4.64	$ 4.66
80%	$ 4.97	$ 5.10	$ 5.09	$ 5.03	$ 5.07	$ 5.00	$ 4.96	$ 5.01	$ 5.00	$ 5.08	$ 4.99	$ 4.94	$ 5.09	$ 5.07	$ 5.03	$ 4.95	$ 5.01
90%	$ 5.99	$ 6.11	$ 6.15	$ 6.00	$ 6.12	$ 5.94	$ 6.01	$ 5.95	$ 5.92	$ 5.88	$ 6.04	$ 6.04	$ 6.11	$ 6.26	$ 6.09	$ 5.84	$ 6.09
95%	$ 7.07	$ 6.93	$ 7.15	$ 6.99	$ 7.14	$ 6.75	$ 6.89	$ 6.82	$ 6.94	$ 6.75	$ 7.20	$ 7.05	$ 6.84	$ 6.91	$ 6.95	$ 6.87	$ 6.99
97.5%	$ 8.01	$ 7.81	$ 7.97	$ 7.98	$ 8.16	$ 7.75	$ 7.82	$ 7.93	$ 7.79	$ 7.58	$ 7.96	$ 7.96	$ 7.71	$ 7.96	$ 8.10	$ 7.98	$ 7.93
99%	$ 8.86	$ 9.67	$ 8.71	$ 9.07	$ 9.38	$ 9.30	$ 9.28	$ 9.03	$ 9.13	$ 8.66	$ 9.12	$ 9.60	$ 9.41	$ 9.46	$ 9.39	$ 8.80	$ 9.28

Outputs

Report: Overlay Outputs Report
Performed By: mcoscia
Date: Wednesday, September 30, 2020



G Appendix G[52]

Standard offer 7874 Farm Methane less than 150 KW

The Economics of On-Farm Dairy Methane Digesters on Vermont Dairy Farms	
	Farm X
System Costs:	
Estimated Size of Farm by Number of Milking Cows	500
Generator Nameplate Capacity (kWh)	150
Total System Cost Per Generator Nameplate Capacity ($/kWh)	$13,108
Total System Cost	$1,966,220
Percentage of Cost Applied to Digester/Building/ect	75%
Total Cost of digester/bldg/etc.	$1,474,665
Expected Years of Life of Digester/Building/Ect	20
Percentage of Cost Applied to Equipment/Genset/Separator/ect	25%
Total Cost of Equipment/Genset/Separator/ect	$491,555
Expected Years of Life of Equipment/Genset/Separator/ect	7
Cost of Replacement Genset/Equipment after 7 Years	$216,600
Summary of System Funding:	
Total System Cost (Installed)	$1,966,220
Total Grant Funding	$491,555
Net System Cost (Installed)	$1,474,665
Percentage of System Costs Covered By Farm	75.00%
Senior Debt Percentage	60%
Senior Debt	$884,799
Equity Percentage	40%
Equity	$589,866
Capacity Factor:	
Total Output	100%
Parasitic Load	-20%
Degridation of Equipment and Fuel Stream Restrictions	-20%
Total Capacity Factor	**60%**
Annual Figures:	
Total Hours in Period	8,760
Net Electrical Production (kWh)	788,400
Standard Offer Program Electrical Rate ($/kWh)	**$0.1988**

[52] https://puc.vermont.gov/document/7874-standard-offer-farm-methane-less-150kw-2015

H Appendix H[53]

Standard Offer Prices for existing Hydroelectric Plants

2015 Price Elements for Existing Hydroelectric Plants				
	10-Year Contract LIHI certified	10-Year Contract	20-Year Contract LIHI certified	20-Year Contract
Energy	5.83 cents/kWh	5.83 cents/kWh	5.83 cents/kWh	5.83 cents/kWh
Capacity	TBD	TBD	TBD	TBD
Avoided Line Losses	3% or 5%	3% or 5%	3% or 5%	3% or 5%
Environmental Attributes	2.3 cents/kWh	0.1 cents/kWh	2.6 cents/kWh	0.1 cents/kWh
Contract Adder Value	5%	5%	10%	10%
Note: The capacity price element for each hydroelectric unit shall be calculated by multiplying the ISO-NE capacity rating by the FCM payment price and dividing that revenue value by the kWh the plant generates. The capacity rating for an ISO-SOG is the FCM-qualified winter and summer capacity rating. The capacity rating for a load-reducer is its generation at the time of the ISO-NE peak for the previous two years. The FCM payment price for use in 2015 contracts is $2.69 per kW-month. For load reducers a 15 percent adder shall be made to the capacity revenue value.				

[53] https://puc.vermont.gov/sites/psbnew/files/doc_library/standard-offer-7874-order-hydro-pricing-2015.pdf

I Appendix I[54]

Standard offer 7533 Standard Offer Hydro Model

Assumptions:		Notes:
Operating Inputs:		
Generator Capacity (MW)	1.278	
Energy Production:		
Gross Project Capacity Factor	44.9%	
Project Availability Factor	100.00%	
Loss Factor/Other Adjustments	0.00%	
Net Capacity Factor	44.9%	
Output in MWhs	5,027	
Annual Output Degradation	0.00%	
Inverter Replacement (total value year 10)	0	
Annual Operating Expenses:		
Maintenance Cost	See Schedule Below	
Labor		
Hours of Labor	0	
Labor Rate ($/hour)	0	
Payroll Overhead Adder	0.0%	
Property Tax		
Amount	EBITDA x WACC x Tax Rate	
Property Tax Rate	1.78%	
Property Tax Depreciation rate	3.33%	
Insurance	0.40%	
Recurring Maintenance Reserve	20,000	per year escalating by inflation
Wheeling Charges	0	
FERC Charges	0	
ISO-NE Charges	0	
Revenue Assumptions:		
RECs:		
REC and Carbon Value ($/MWh)	0.00	
REC inflation Factor	2.00%	
Other Revenues (increases with inflation)	0	
Base Year Energy Price ($/MWh)	118.84	
Return Metrics:		
Average Debt Service Coverage Ratio	1.50	
Minimum Debt Service Coverage Ratio	1.45	
Internal Rate of Return	9.75%	
Maintenance Schedule		
Years 1(escalates at inflation)	129,078	$101/kW

[54] https://puc.vermont.gov/document/7533-standard-offer-hydro-model

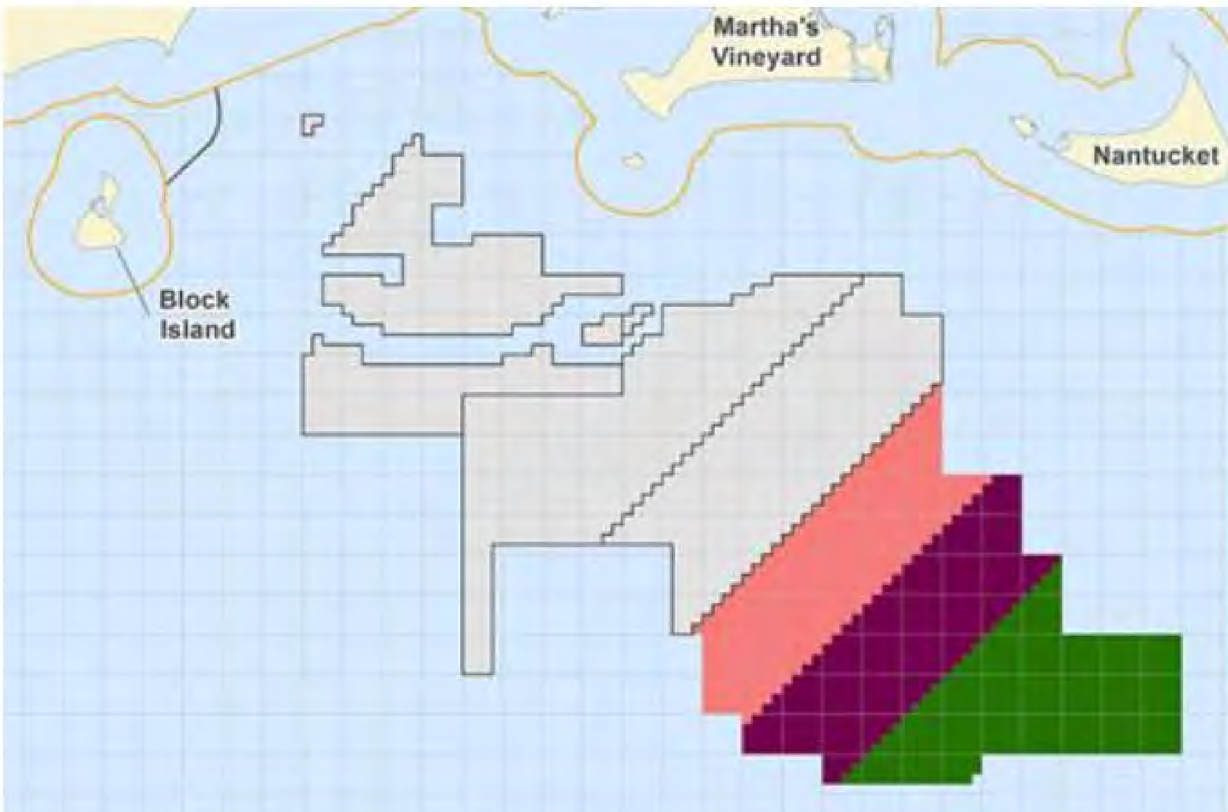
J Appendix J[55]

Offshore wind is modeled after the cost of the Mayflower Wind Project of 804 MW's. The levelized NPV of the price is $58.47/MWH. The project has a 20year cost contracts of $77.76/MWH that will include Renewable Energy Credits. For the Stowe's cost scenario, the offshore wind is priced at the contract price of $77.76/MWH.

Mayflower lowers US offshore to $58/MWh

12 February 2020 by Craig Richard

Shell and EDP Renewables' 804MW Mayflower Wind project will generate electricity for $58.47/MWh over its 20-year lifetime, marking a new benchmark for US offshore wind.



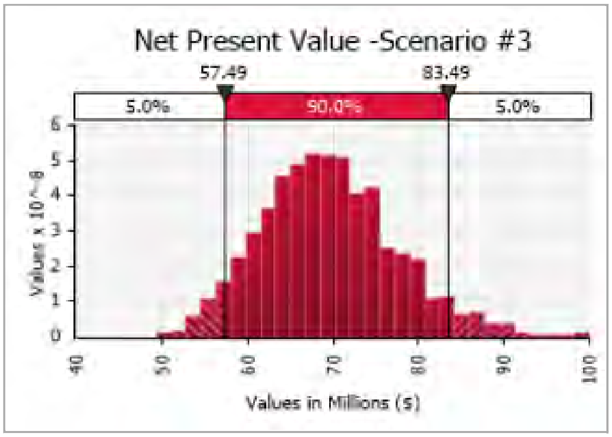
Mayflower Wind will be built in the purple lease area (pic credit: BOEM)

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

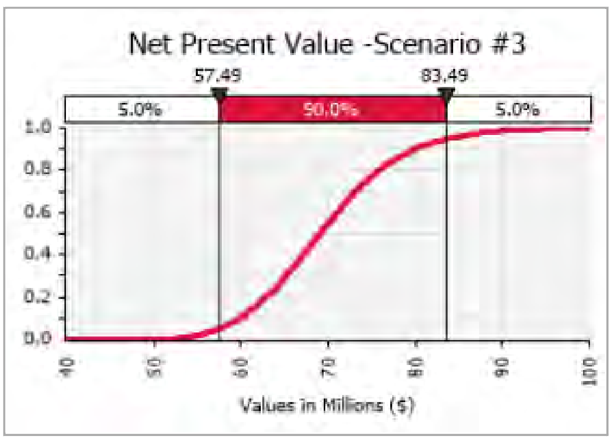
K Appendix K

Net Present Value -Scenario #3 - B26

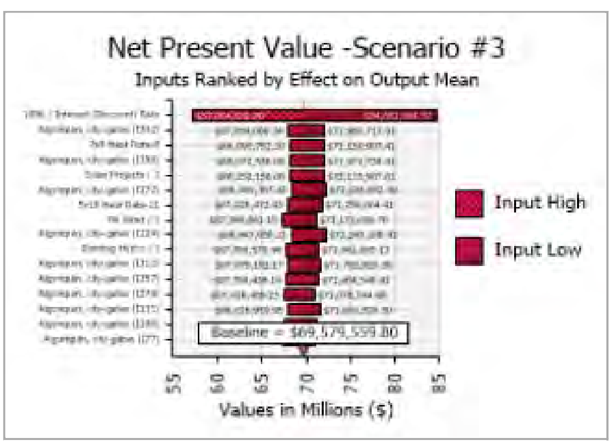
Report: Compact Output Report
Performed By: mcoscia
Date: Tuesday, October 13, 2020



Summary Statistics		
Statistic		Value
Minimum	$	49,315,815.87
Maximum	$	99,919,745.57
Mean	$	69,579,559.80
Std. Deviation	$	7,919,544.72
Variance		6.272E+013
Skewness		0.4551
Kurtosis		3.3533
Median	$	69,074,267.81
Mode	$	70,750,859.19
Left X	$	57,490,799.68
Left P		5%
Right X	$	83,485,348.86
Right P		95%



Percentiles		
Percentile		Value
1%	$	53,359,356.38
2.5%	$	55,686,107.59
5%	$	57,490,799.68
10%	$	59,758,882.31
20%	$	62,860,851.75
25%	$	64,218,131.15
50%	$	69,074,267.81
75%	$	74,383,127.05
80%	$	75,676,923.25
90%	$	79,754,975.78
95%	$	83,485,348.86
97.5%	$	86,860,903.97
99%	$	90,508,859.07



Change in Output			
Rank	Name	Lower	Upper
1	1996 / Interest (Discou	$ 57,064,037	$ 84,681,995
2	Algonquin, city-gates (I	$ 67,854,000	$ 71,986,714
3	7x8 Heat Rate-8	$ 68,095,752	$ 72,130,907
4	Algonquin, city-gates (I	$ 68,072,536	$ 71,971,734
5	Solar Projects / 3	$ 68,252,156	$ 72,133,908
6	Algonquin, city-gates (I	$ 68,349,367	$ 72,228,892
7	5x16 Heat Rate-11	$ 67,928,473	$ 71,756,064
8	Mt Wind / 2	$ 67,348,842	$ 71,171,700
9	Algonquin, city-gates (I	$ 68,447,658	$ 72,243,208
10	Existing Hydro / 3	$ 67,704,575	$ 71,441,693
11	Algonquin, city-gates (I	$ 67,970,182	$ 71,702,826
12	Algonquin, city-gates (I	$ 67,784,438	$ 71,464,548
13	Algonquin, city-gates (I	$ 67,418,488	$ 71,078,145

L Appendix L

Solar Pricing Model

Assumptions:			Notes:
General Inflation Facto	1.89%		From http://www.clevelandfed.org/research/data/inflation_expectations/
% of Base Price Escalati	0%		
Uses of Funds			
Debt Reserve	73,800		($73,739)
Maint. Reserve	0		$60.00
Decommissioning Fun	0		$60/kW avg decommissioning costs from Dockets 8302, 8248, 8234, 8225
Working Capital	41,063		6 months of working capital
Total Working Capital &	114,863		
Financing Costs & IDC	362,925		3% of approximate debt amount (E17) + (5%/12 months * Installation Costs * 4.5 months = IDC) + $ (E18) for Tax equity
Installation Cost (Hard	5,500,000		$2.50
Total Uses of Funds	5,977,788		Insall cost per watt from recent docket
Total Project Cost ($/kW	2,717		
Sources of Funds			
Grants	0		
Debt	3,586,673		$3,660,000
Equity	2,391,115		$150,000
Total Sources of Funds	5,977,788		
Grants:			
State and Federal Ince	0		
Net Value of Grants	0		
Asset Life (Years)	25		
Loan Lif Long Term Loan	18		
Short-Term Loa	6		
Tax Rates:			
Federal Income Tax	35.0%		
State Income Tax	8.5%		
Income tax rate	40.53%		
Capital structure:			
Debt Long Term Loan	30.00%		
Debt Short-Term Loa	30.00%		
Equity	40.00%		
Debt costs: Long Ter	4.50%		
Debt costs: Short Ter	3.00%		
Weighted Average Co	6.09%	9.60%	
Tax Rates and Incentives:			
Investment Tax Credi	97.5%		
Income Tax Basis Adj	50.0%		
Federal Income Tax Credit			
ITC Rate	30.0%		
ITC Realization Pe	1		
ITC Amount			
Total Amount	1,608,750		Federal ITC Value Loss
Percent Realize	100.0%		0
Total Amount F	1,608,750		
State Income Tax Credit			
ITC Rate			
Amount of Fed	24.00%		
Effective State	7.20%		
ITC Realization Pe	1		
ITC Amount			
Total Amount	250,965		State ITC Value Loss
Percent Realize	100.0%		0
Total Amount F	250,965		

Assumptions:		Notes:
Operating Inputs:		
Generator Capacity (MW)	2.2	
Energy Production:		
Gross Project Capacity Factor	14.50%	
Project Availability Factor	100.00%	
Loss Factor/Other Adjustments	0.00%	
Net Capacity Factor	14.5%	
Output in MWhs	2,794	
Annual Output Degradation	0.50%	
Inverter Replacement		per watt cost inflated from p.10 conservative estimate using commercial scale system http://www1.eere.energy.gov/solar/pdfs/47927_chapter4.pdf, plus $3000 labor
Value Year 12	400,000	0.2
Annual Operating Expenses:		
Maintenance Cost	25,528	$6.67/kW
Labor		
Hours of Labor	0	
Labor Rate ($/hour)	0	
Payroll Overhead Adder	0.0%	
Property Tax		
Amount	EBITDA x WACC x Tax Rate	
Property Tax Rate	0.56%	Tax Rate approximately $12/watt.
		14
Depreciation Rate	4.00%	
Insurance (% of Installation Cost)	0.40%	
Other Operational Expenses	0	6.8
Lease	14,960	1000
		lease acres X price per X plant size
FERC Charges	0	
ISO-NE Charges	0	
Revenue Assumptions:		
RECs:		
REC and Carbon Value ($/MWh)	0.00	
REC inflation Factor	2.00%	
Other Revenues (increases with inflatio	0	
Base Year Energy Price ($/MWh)	155.43	
Return Metrics:		
Average Debt Service Coverage Ratio	1.95	
Minimum Debt Service Coverage Ratio	1.79	
Internal Rate of Return	9.60%	

M Appendix M (ITRON, Inc)

Residential Use per Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.WtXHeat	0.923	0.094	9.844	0.00%
mStructRes.WtXCool	0.328	0.076	4.347	0.00%
mStructRes.WtXOther	1.131	0.036	31.833	0.00%
mBin.Mar	-67.615	10.791	-6.266	0.00%
mBin.Apr	-96.744	15.497	-6.243	0.00%
mBin.May	-85.891	16.82	-5.107	0.00%
mBin.Jun	-31.675	13.653	-2.32	2.21%
mBin.Sep	-42.467	12.213	-3.477	0.07%
mBin.Oct	-50.901	14.25	-3.572	0.05%
mBin.Nov	-67.245	11.653	-5.771	0.00%
mBin.Jan12	-204.151	29.253	-6.979	0.00%
mBin.Aug16	156.506	30.002	5.216	0.00%
mBin.Yr19Plus	46.854	8.197	5.716	0.00%
COVID_Shift.Shift	71.504	17.469	4.093	0.01%

Model Statistics	
Iterations	1
Adjusted Observations	127
Deg. of Freedom for Error	113
R-Squared	0.92
Adjusted R-Squared	0.91
AIC	6.819
BIC	7.133
Log-Likelihood	-599.22
Model Sum of Squares	1,067,168
Sum of Squared Errors	93,234.65
Mean Squared Error	825.09
Std. Error of Regression	28.72
Mean Abs. Dev. (MAD)	20.73
Mean Abs. % Err. (MAPE)	3.59%
Durbin-Watson Statistic	1.667

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.HHs	30.79	8.049	3.825	0.02%
mBin.Jan	-4777.921	2119.621	-2.254	2.61%
mBin.Feb	-4782.708	2119.395	-2.257	2.60%
mBin.Mar	-4795.702	2119.25	-2.263	2.56%
mBin.Apr	-4783.42	2119.196	-2.257	2.59%
mBin.May	-4785.976	2119.208	-2.258	2.59%
mBin.Jun	-4773.731	2119.28	-2.253	2.62%
mBin.Jul	-4770.375	2119.349	-2.251	2.63%
mBin.Aug	-4774.255	2119.203	-2.253	2.62%
mBin.Sep	-4777.334	2119.137	-2.254	2.61%
mBin.Oct	-4769.162	2119.154	-2.251	2.64%
mBin.Nov	-4778.942	2119.244	-2.255	2.61%
mBin.Dec	-4765.879	2119.398	-2.249	2.65%
AR(1)	0.898	0.044	20.285	0.00%

Model Statistics	
Iterations	15
Adjusted Observations	126
Deg. of Freedom for Error	112
R-Squared	0.94
Adjusted R-Squared	0.933
AIC	6.288
BIC	6.603
Log-Likelihood	-560.91
Model Sum of Squares	847,197
Sum of Squared Errors	54,269.36
Mean Squared Error	484.55
Std. Error of Regression	22.01
Mean Abs. Dev. (MAD)	15.13
Mean Abs. % Err. (MAPE)	0.45%
Durbin-Watson Statistic	2.624

Commercial Use per Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructSmlCI.WtXHeat	10338.567	1367.953	7.558	0.00%
mStructSmlCI.WtXCool	2791.831	299.238	9.33	0.00%
mStructSmlCI.WtXOther	5148.303	100.039	51.463	0.00%
mBin.Yr14Plus	391.06	49.724	7.865	0.00%
mBin.Apr	-446.792	92.116	-4.85	0.00%
mBin.May	-221.023	96.948	-2.28	2.44%
mBin.Aug16	997.34	278.01	3.587	0.05%
mBin.Nov19	-743.902	268.763	-2.768	0.66%
mBin.Yr2018	425.44	84.576	5.03	0.00%
COVID_Shift.Shift	-1155.404	140.736	-8.21	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	127
Deg. of Freedom for Error	117
R-Squared	0.788
Adjusted R-Squared	0.771
AIC	11.239
BIC	11.463
Log-Likelihood	-883.91
Model Sum of Squares	30,606,408
Sum of Squared Errors	8,253,308
Mean Squared Error	70541.1
Std. Error of Regression	265.6
Mean Abs. Dev. (MAD)	198.02
Mean Abs. % Err. (MAPE)	4.40%
Durbin-Watson Statistic	1.873

Commercial Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mFcst.ResCust	0.232	0.001	332.269	0.00%
AR(1)	0.395	0.082	4.805	0.00%

Model Statistics	
Iterations	5
Adjusted Observations	126
Deg. of Freedom for Error	124
R-Squared	0.623
Adjusted R-Squared	0.62
AIC	5.533
BIC	5.578
Log-Likelihood	-525.35
Model Sum of Squares	50,985
Sum of Squared Errors	30,862.81
Mean Squared Error	248.89
Std. Error of Regression	15.78
Mean Abs. Dev. (MAD)	8.32
Mean Abs. % Err. (MAPE)	1.07%
Durbin-Watson Statistic	1.92

Town Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEndUse.Base	1.577	0.025	62.239	0.00%
mEndUse.PKHeatVar	2.344	0.189	12.375	0.00%
mEndUse.PKCoolVar	1.205	0.182	6.613	0.00%
mEndUse.Apr_Base	-0.157	0.036	-4.356	0.00%
mEndUse.May_Base	-0.135	0.035	-3.879	0.02%
mEndUse.Nov_Base	-0.104	0.033	-3.122	0.23%
mEndUse.Dec_Base	0.221	0.035	6.379	0.00%
mBin.Yr14Plus	-0.511	0.131	-3.897	0.02%
mBin.Aug16	-1.775	0.617	-2.877	0.49%
mBin.Jan18	1.058	0.613	1.726	8.74%
mBin.Dec19	-2.964	0.653	-4.537	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	113
Deg. of Freedom for Error	102
R-Squared	0.876
Adjusted R-Squared	0.864
AIC	-0.915
BIC	-0.65
Log-Likelihood	-97.64
Model Sum of Squares	264
Sum of Squared Errors	37.25
Mean Squared Error	0.37
Std. Error of Regression	0.6
Mean Abs. Dev. (MAD)	0.46
Mean Abs. % Err. (MAPE)	4.20%
Durbin-Watson Statistic	1.528

Solar Capacity Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	12320.49	834.396	14.766	0.00%
Payback.Payback	-2841.781	248.333	-11.443	0.00%
mAdopt.Payback_Sq	221.497	24.204	9.151	0.00%
mAdopt.Payback_Cb	-5.769	0.772	-7.473	0.00%
MA(1)	0.534	0.09	5.959	0.00%

Model Statistics	
Iterations	17
Adjusted Observations	96
Deg. of Freedom for Error	91
R-Squared	0.993
Adjusted R-Squared	0.993
AIC	6.318
BIC	6.452
Log-Likelihood	-434.49
Model Sum of Squares	7,095,643
Sum of Squared Errors	47,969.85
Mean Squared Error	527.14
Std. Error of Regression	22.96
Mean Abs. Dev. (MAD)	14.4
Mean Abs. % Err. (MAPE)	3.38%
Durbin-Watson Statistic	1.587

N Appendix N (Stowe's 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

Stowe

ELECTRIC

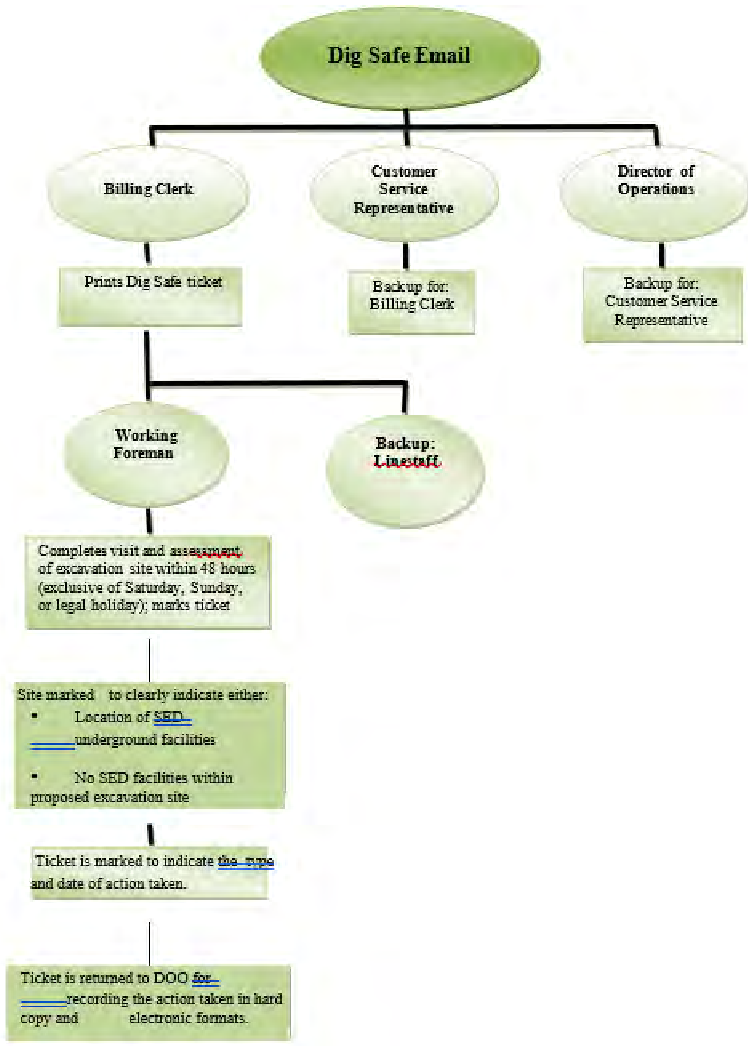
Scope and Purpose of this Document

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.

1) 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


Dig Safe Email
Billing Clerk
Customer Service Representative
Director of Operations
Prints Dig Safe ticket
Backup for: Billing Clerk
Backup for: Customer Service Representative
Working Foreman
Backup: Linestaff
Completes visit and assessment of excavation site within 48 hours (exclusive of Saturday, Sunday, or legal holiday); marks ticket
Site marked to clearly indicate either:
• Location of SED underground facilities
• No SED facilities within proposed excavation site
Ticket is marked to indicate the type and date of action taken.
Ticket is returned to DOO for recording the action taken in hard copy and electronic formats.

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

- 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. Emergency Dig Safe Request

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 oncall 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. Pre-marking of Excavations by SED

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.

3) SED'S Investigation Procedure for Damage to its Underground Facilities

- 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.

- 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 assure that the appropriate documentation is completed.

4. <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 paper work per PUCR 3.805(C).

- 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.

5) <u>Marking and Documenting New Underground Installations</u>

- 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.

6) <u>SED's Contact Information</u>

- 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.

Director of Operations

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