Village of Swanton Electric Department

2022 Integrated Resource Plan

Vermont Public Power Supply Authority

Filed with the Public Utility Commission

EXECUTIVE SUMMARY

Located in northern Franklin County in northwestern Vermont, the Swanton Village Electric Department (SED) has operated an electric utility system since 1894. SED remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. Well-established practices keep SED operating safely, efficiently, and reliably.

SED serves approximately 3,780 customers, within approximately 56 square miles, spanning across the Village of Swanton and portions of three of the surrounding towns: Swanton, Highgate, and St. Albans. About 70% of SED's customers are served within the village and town portions of Swanton. In addition to the retail customer load served within its service territory, SED provides transmission service to an island of customers in Highgate, which is in Vermont Electric Cooperative's (VEC) retail franchise territory.

SED's distribution system serves a mix of residential and small commercial customers. Residential customers make up over 86% of the customer mix while accounting for almost half (49%) of SED's retail kWh sales. Approximately 500 commercial customers (less than 14%) make most of the other half (49%) of retail usage with the remaining 2% of retail sales going to interdepartmental and public street and highway lighting customers.

Consistent with regulatory requirements, every 3 years SED is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan, or IRP) for provision of energy services to its Vermont customers. SED's Integrated Resource Plan (IRP) is intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

ELECTRICITY DEMAND

SED is facing a period of relatively flat demand influenced by several competing factors, all of which carry some uncertainty. Continued adoption of solar net metering reduces demand although the pace at which net metering will grow in SED's territory is uncertain. As various incentives aimed at transitioning from fossil fuels to cleaner electricity are made available, increasing acceptance of cold climate heat pumps and similar appliances will likely increase demand, as will an expected increase in the use of electric vehicles. Forecast increases in the adoption of cold climate heat pumps, other appliances, and electric vehicles is expected to overtake demand reductions associated with solar net metering in the next 5 to 10 years, resulting in modest projected load growth in the longer term.

While no significant change in the demand associated with SED's largest customers is currently anticipated, the potential does exist. SED monitors the plans of these large customers in order to anticipate necessary changes to the existing resource plan and system infrastructure. Significant expansion by one or more customers may require detailed engineering studies to identify necessary system upgrades.

ELECTRICITY SUPPLY

SED's current power supply portfolio includes entitlements in a mixture of baseload, firm and intermittent resources through ownership or contractual arrangements of varying duration, with most contracts carrying a fixed price feature. Designed to meet anticipated demand, as well as acting as a hedge against exposure to volatile ISO-New England spot market prices, the portfolio is heavily weighted toward hydro, solar and other renewable resources. Delivering a clean, reliable source of power located within is service territory, SED proudly owns and operates their Orman Croft Hydroelectric Plant, i.e. "Highgate Falls." The Highgate Falls power dam has been a dependable source of power for the evolving energy needs of northwestern Vermont since 1894 and is currently SED's primary source of energy and renewable energy credits.

When considering future electricity demand, SED seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. SED believes that in addition to working with financially stable counterparties, it is important for new resource decisions to balance four important characteristics: new resources should be low cost, locally located, renewable and reliable. Market contracts have the advantage of being both scalable and customizable in terms of delivery at specific times and locations. SED anticipates regional availability of competitively priced renewable resources including solar, wind, including offshore wind as it becomes competitively priced, and hydro. In addition to being a factor in meeting future electricity requirements, this category of resources contribute to meeting Renewal Energy Standard goals. Gas fired generation may have a role to play in the future portfolio for reliability purposes. As battery storage technology matures and proves economically feasible, SED sees potential for storage to play an important load management role and to enhance the local impact of distributed generation.

RESOURCE PLANS

Looking ahead to evaluating major policy and resource acquisition decisions, SED employs an integrated financial model that takes into account impacts on load and subsequent effects on revenue and power supply costs, as well effects on investment, financing and operating costs. Use of the integrated model allows for evaluation of uncertainty related to key variables, on the way to identifying anticipated rate impacts over time. While rate trajectory is the primary metric SED relies on to evaluate resource decisions on an individual or portfolio basis there are other more subjective factors to consider, including resource diversity, intermittence, or exposure to major changes in market rules.

There are four resource related decisions within the next 5 years, three of which revolve around the Highgate Falls hydro unit. As part of SED's FERC relicensing process, proposed changes to the Water Quality Certificate (WQC) and restricted peak shaving opportunities along with aesthetic flows over the bladder must be considered during the relicensing process. The potential impact of these changes could affect SED's production, 100% renewable status and raise costs to the rate payers along with impacts to taxes being paid to the Highgate community. The Highgate Falls unit is also subject to fluctuations in hydrological conditions; upcoming resource decisions must address mitigation of the potential for prolonged low water conditions which may lead to financial stress in any given year. In addition to potential variability and/or reductions in hydro production capability, SED faces load growth related to increasing electrification as heat pumps and electric vehicles become the norm. In order to meet the challenges posed by expected load growth and the presence of intermittent resources over the next decade, SED will evaluate a combination of potential renewable resources including solar, on and offshore wind, firm hydro, and wood resources. SED's resource decisions will need to consider renewable resources that complement the intermittent nature of the Highgate Falls hydro unit, contribute to RES compliance, are competitive with market prices, and fit well with SED's seasonal and monthly load shape.

RENEWABLE ENERGY STANDARD

SED is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for SED to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into three categories, TIER I, TIER II, and TIER III. SED' s obligations under TIER I can be satisfied by owning or purchasing RECs from qualifying regional resources. TIER II obligations must be satisfied by owning or purchasing RECs from renewable resources located within Vermont. Satisfaction of SED's TIER III obligation involves energy transformation, or reduction of fossil fuel use within its territory. TIER III programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on diesel generation to electric service, among other things. By providing incentive programs to encourage conversion of traditional fossil fuel applications such as space heating, water heating, or internal combustion engine vehicles to electric power, SED receives credits toward its TIER III obligation. More detail regarding SED's plans to meet its TIER III obligation is available in Appendix A to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

SED has a compact service territory as a result of being a small, municipal-owned electric utility and has consistently pursued initiatives each year in order to maintain a reliable and efficient system. The distribution system includes approximately 120 miles of line operating at 12.5 kV and contains three substations. SED also owns approximately 6 miles of 46 kV transmission line, which provides a valuable loop feed, creating the flexibility for SED to have two different sources feed the substations.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, SED is looking at the need to update its system to support additional distributed generation and beneficial electrification on the system and to provide customers with targeted services including load management supported by more innovative programs and rate designs that reduce costs for both SED and its customers. SED is currently engaged, with VPPSA, in the final stages of a multi-phased process that is expected to result in implementation of an AMI system beginning in early 2023. SED sees potential value to customers by utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison. Implementation of an AMI system is expected to enhance SED's ability to deliver these benefits and capture economic development/retention opportunities where possible.

SED is also working with VPPSA on implementing a centralized GIS mapping system that will coordinate with the AMI system and benefit situational awareness of infrastructure, asset life cycles, preventive maintenance, and vegetation management. These new systems will also enhance SED's ability to identify developing concentrations of load, distributed generation, and "hot spots" related to intensifying electrification.

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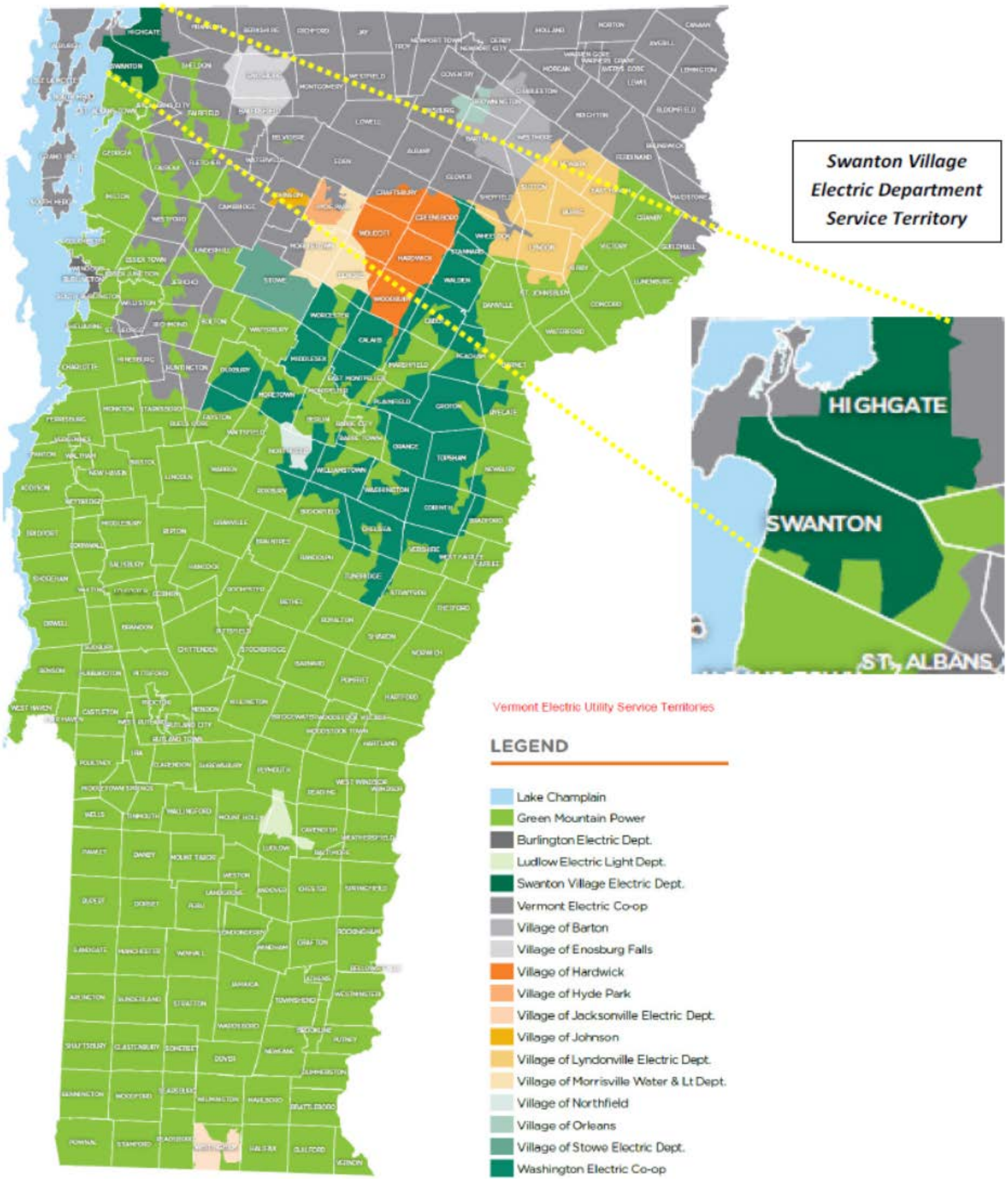
INTRODUCTION

Located in northern Franklin County in northwestern Vermont, the Swanton Village Electric Department (SED) has operated an electric utility system since 1894. Consisting of approximately 120 miles of electric distribution lines within approximately a 56 square mile service area, the boundaries of SED's service territory can be seen on the map below.

Figure 1: SED's Distribution Territory



VERMONT PUBLIC POWER SUPPLY AUTHORITY

The Vermont Public Power Supply Authority (VPPSA) is a joint action agency established by the Vermont General Assembly in 1979 under Title 30 VSA, Chapter 84. It provides its members with a broad spectrum of services including power aggregation, financial support, IT support, rate planning support and legislative and regulatory representation. VPPSA is focused on helping local public power utilities remain competitive and thrive in a rapidly changing electric utility environment.

SED is one of eleven member utilities of VPPSA, which is governed by a board of directors that consists of one appointed director from each member. This gives each municipality equal representation. VPPSA's membership includes:

- Swanton Village Electric Department,
- Barton Village Inc.,
- Village of Enosburg Falls Electric Light Department,
- Hardwick Electric Department,
- Village of Jacksonville Electric Company,
- Village of Johnson Electric Department,
- Ludlow Electric Light Department,
- Lyndonville Electric Department,
- Morrisville Water & Light Department,
- Northfield Electric Department, and
- Village of Orleans

SED and VPPSA are parties to a broad Master Supply Agreement (MSA). Under the MSA, VPPSA manages SED's electricity loads and power supply resources, which are pooled with the loads and resources of other VPPSA members under VPPSA's Independent System Operator – New England (ISO-NE) identification number. This enables VPPSA to administer SED's loads and power supply resources in the New England power markets.

SYSTEM OVERVIEW

SED's distribution system serves a mix of residential and commercial customers, with residential making up the vast majority of their total customer count.

In 2021, SED's peak demand in the winter months was 9,233 kW and 11,281 kW during the summer and shoulder months, making SED a summer peaking utility. Annual energy retail sales for 2021 were 52,571,052 kWh.

Table 1: SED's Retail Customer Counts

Data Element	2017	2018	2019	2020	2021
Residential (440)	3,195	3,192	3,220	3,255	3,319
Rural	68	67	69	72	72
Small C&I (442) 1000 kW or less	472	509	421	414	503
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	3	3	3	3	3
Public Authorities (445)	0	0	0	0	0
Interdepartmental Sales (448)	10	10	10	10	15
Total	3,748	3,781	3,723	3,754	3,912

Table 2: SED's Retail Sales (kWh)

Data Element	2017	2018	2019	2020	2021
Residential (440)	22,951,321	24,598,750	24,134,713	25,597,220	25,432,493
Rural	2,072,047	2,100,805	2,009,004	1,864,218	1,837,041
Small C&I (442) 1000 Kw or less	26,946,217	26,848,517	25,850,209	25,143,039	24,176,979
Large C&I (442) above 1,000 Kw	0	0	0	0	0
Street Lighting (444)	135,290	126,643	126,916	127,115	126,928
Public Authorities (445)	0	0	0	0	0
Interdepartmental Sales (448)	895,442	945,075	1,017,721	1,005,540	997,611
Total	53,000,317	54,619,790	53,138,563	53,737,132	52,571,052
YOY	-3%	3%	-3%	1%	-2%

Table 3: SED's Annual System ([1]NCP) Peak Demand ([2]TLEL)

Data Element	2017	2018	2019	2020	2021
Peak Demand kW	10,198	11,035	10,384	11,053	11,281
Peak Demand Date	09/27/17	08/06/18	07/30/19	07/27/20	08/26/21
Peak Demand Hour	14	18	16	18	15

[1] Noncoincident Peak (NCP)

[2] Total load excluding losses (TLEL)

STRUCTURE OF REPORT

This report is organized into six major sections plus an appendix and a glossary.

ELECTRICITY DEMAND

This chapter describes how SED's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

ELECTRICITY SUPPLY

This chapter describes SED's electricity supply resources, and the options that are being considered to supply the electricity needs of SED's customers.

RESOURCE PLANS

This chapter compares SED's electricity demand to its supply and discusses how SED will comply with the Renewable Energy Standard.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

This chapter describes SED's distribution system and discusses how it is being maintained to provide reliable service to its customers.

FINANCIAL ANALYSIS

This chapter presents a high-level forecast of SED's power supply costs and cost of service.

ACTION PLAN

This chapter outlines specific actions the SED expects to take as a result of this IRP.

APPENDIX

The appendix includes a series of supporting documents and reports.

GLOSSARY

ELECTRICITY DEMAND

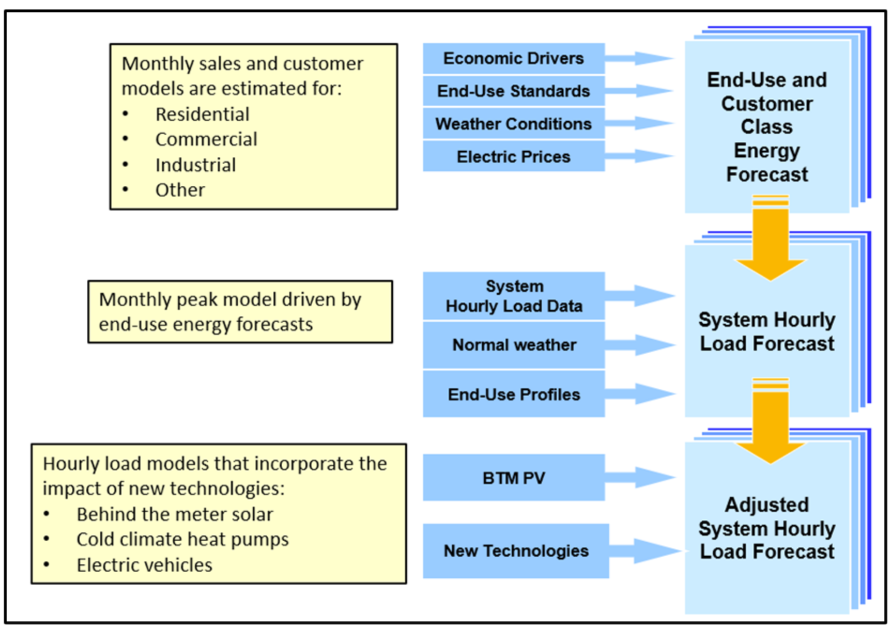
I. ELECTRICITY DEMAND

ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast SED's peak and energy requirements. Using the SAE (Statistically Adjusted End Use) methodology, the Itron team used the same electrification inputs and assumptions that were developed by the Vermont System Planning Committee during VELCO's 2021 Long-Range Transmission Plan (LRTP). Specifically, the adoption rates for heat pumps and electric vehicles (also known as "electrification") are shared with the LRTP.

The 2022 long-term forecast includes energy and peaks underpinned by forecasts of customer class sales and adjusted for the impact of electrification technologies. The forecast is based on a bottom-up framework where long-term demand is driven by underlying customer class sales (residential, commercial, industrial, street lighting, and other use). The impact of new technologies is then layered on top of the baseline forecast as shown in Figure 2.[3]

Figure 2: Forecasting Process



[3] VPPSA 2022 Long-Term Load Forecast Report, Itron, 2022, page 2

ENERGY FORECAST RESULTS

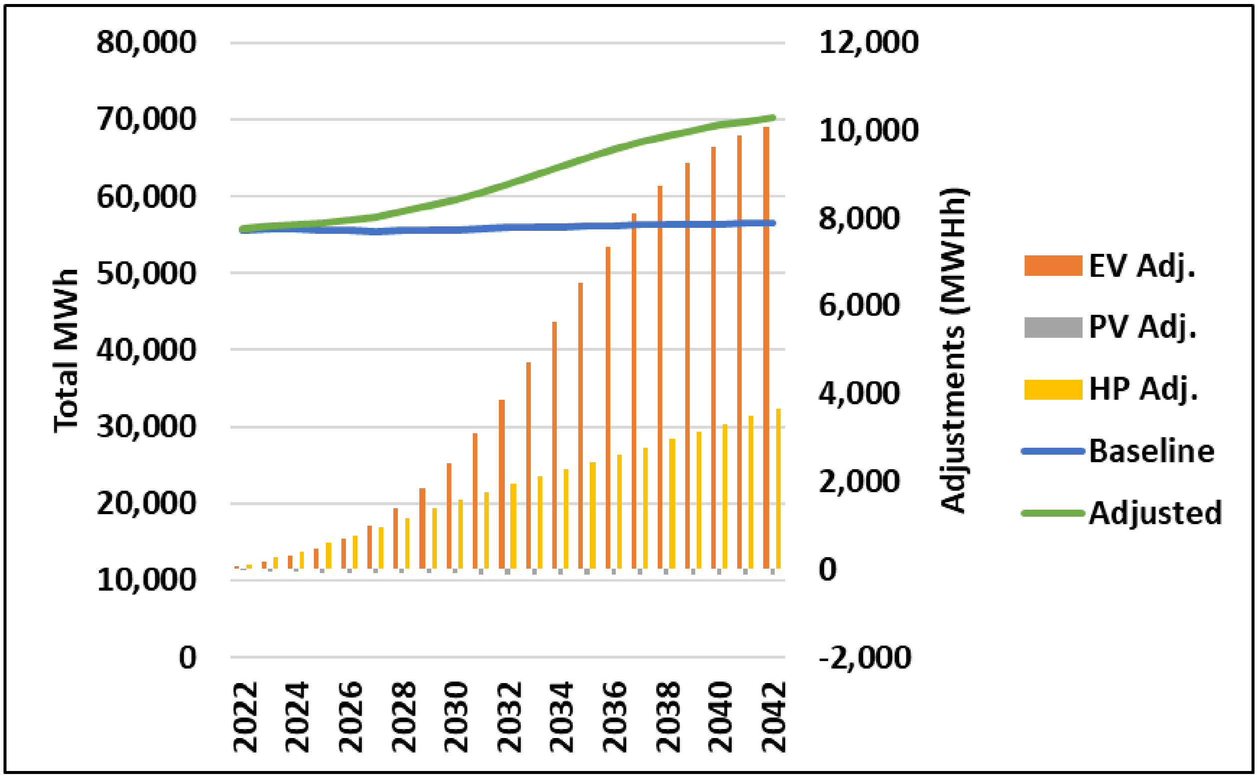
Table 3 shows the Baseline Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is increasing by 0.1% per year. After making adjustments for electric vehicles (EV), net metered solar (NM PV) and heat pumps (HP) the Adjusted Forecast increases by 1.1% per year.

Table 3: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast (MWh)	EV Adj. (MWh)	NM PV Adj. (MWh)	HP Adj (MWh)	Adj. Forecast (MWh)
2022	1	55,674	76	-18	129	55,862
2027	5	55,464	1,013	-90	960	57,347
2032	10	55,947	3,875	-107	1,945	61,660
2037	15	56,263	8,112	-114	2,786	67,047
2042	20	56,544	10,084	-122	3,678	70,183
CAGR		0.1%	26.2%	9.4%	17.3%	1.1%

The Adjusted Forecast is the result of high CAGRs for HPs (17.3%) and EVs (26.2%). The impact of CCHPs and EVs can be seen in the green line and the orange and yellow bar in Figure 3.

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES

To form a high case, we assumed that the market saturation rate for EVs and HPs rises from the base case in 2023 (Year 1) to 200% in 2042 (Year 20). This equates to having two EVs and two HPs per residential customer in 2042. Because net metering would decrease the impact of electrification, we assume that net metering penetration continues as forecast in the base case.

This pace of electrification is significantly faster than in the reference case, and although it may be unlikely to unfold smoothly, it does give a reasonable indication of the kind of growth in energy use that is possible: 3.7% per year. By 2042, this growth rate results in a 215% increase over 2022 electricity use.

Table 4: Energy Forecast – High Case 1 (MWH)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	55,674	76	-18	129	55,862
2027	5	55,464	5,570	-90	2,305	63,250
2032	10	55,947	21,310	-107	4,668	81,819
2037	15	56,263	44,618	-114	6,687	107,453
2042	20	56,544	55,460	-122	8,826	120,708
CAGR		0.1%	36.8%	9.4%	22.3%	3.7%

To form a low case, we assumed that the penetration for CCHPs and EVs is half of the base case, and we kept the net-metered PV penetration rate the same as the base case. This results in a forecast that increases by 0.6% per year.

Table 5: Energy Forecast - Low Case (MWH

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	55,674	76	-18	129	55,862
2027	5	55,464	506	-90	480	56,361
2032	10	55,947	1,937	-107	973	58,750
2037	15	56,263	4,056	-114	1,393	61,598
2042	20	56,544	5,042	-122	1,839	63,303
CAGR		0.1%	22.1%	9.4%	13.5%	0.6%

PEAK FORECAST RESULTS

Table 6 and Table 7 shows the results of the Baseline Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast grows in the summer and declines in the winter. After making adjustments for CCHPs, EVs, and net metering, both the winter and summer peaks grow by 1.4-1.8% per year. The summer peak is much higher than the winter peak and the timing of the peak hour is expected to be remain in the late afternoon hours between 4:00 PM and 6:00 PM.

Table 6: Summer Peak Forecast (MW)

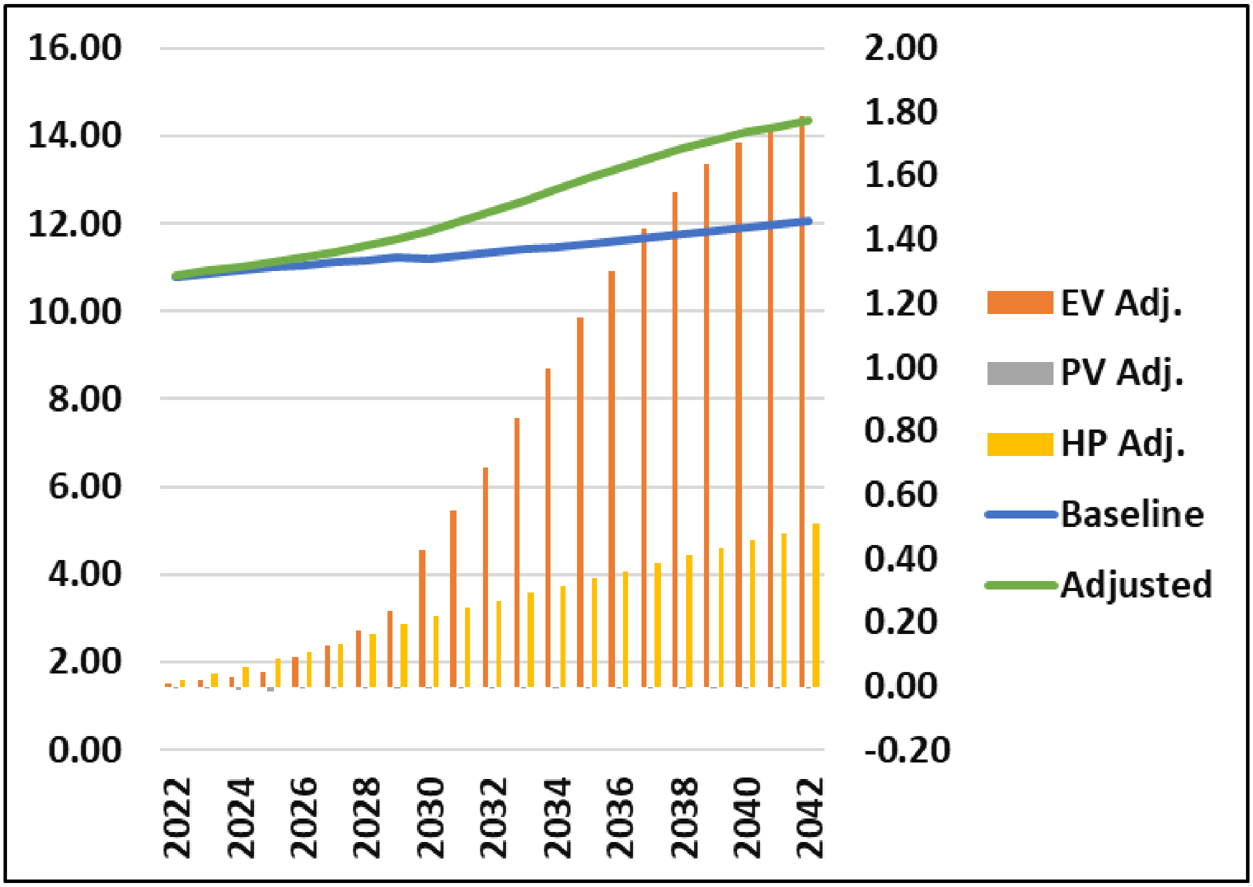
Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	10.8	0.0	0.0	0.0	10.8
2027	5	11.1	0.1	0.0	0.1	11.4
2032	10	11.3	0.7	0.0	0.3	12.3
2037	15	11.7	1.4	0.0	0.4	13.5
2042	20	12.1	1.8	0.0	0.5	14.3
CAGR		0.5%	30.2%	1.1%	17.2%	1.4%

Table 7: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	9.0	0.0	0.0	0.0	9.0
2027	5	8.9	0.2	0.0	0.5	9.6
2032	10	8.6	1.1	0.0	1.0	10.7
2037	15	8.5	2.3	0.0	1.5	12.3
2042	20	8.3	2.8	0.0	2.0	13.1
CAGR		-0.3%	26.9%		20.4%	1.8%

The size of the adjustments can be seen in Figure 4, which shows the summer peak forecast net of adjustments. The Adjusted Forecast exceeds the Baseline Forecast immediately as a result of high CAGRs for HPs and EVs.

Figure 4: Adjusted Summer Peak Forecast (MW)



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we assume that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same assumptions from the high case as in the energy forecast. Under these assumptions, peak loads double by 2042. However, 9.8 MW of this growth is due to EV charging, and if 75% of this load is controlled, as assumed in VELCO's 2021 Long Range Transmission Plan, then 7.4 MW of this load will not materialize at the peak hour, and the adjusted peak will drop from 23.1 MW to 15.8 MW.

Table 8: Summer Peak Forecast – High Case (MW)

Year	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	10.8	0.0	0.0	0.0	10.8
2027	11.1	0.7	0.0	0.3	12.2
2032	11.3	3.8	0.0	0.6	15.8
2037	11.7	7.9	0.0	0.9	20.5
2042	12.1	9.8	0.0	1.2	23.1
CAGR	0.5%	41.2%	1.1%	22.2%	3.7%

A plausible low case for the peak forecast would involve applying TOU electric rates and load control devices on all of the major end uses, especially CCHPs and EVs. In theory, this strategy could completely offset any peak load growth resulting from CCHPs and EVs. As a result, it is not necessary to quantify a low case scenario. Peak loads would simply match the Baseline Forecast without any adjustments.

TIER III IMPACTS ON THE FORECAST

The provisions of Tier 3 Best Practices and Minimum Standards state:

"For a Retail Electricity Provider implementing Energy Transformation Projects that increase the use of electric energy, the Provider's Tier III annual plan shall include: (A) reference to the load forecast developed in the Provider's most recently Commission approved Integrated Resource Plan and any relevant updates to or major deviations from the assumptions used in that load forecast."[4]

Based on the following analysis, the load forecast adjustments for heat pumps and electric vehicles are in alignment with the electrification that is budgeted through Tier III programs. As a result, we do not observe any major deviations from the assumptions used in the load forecast at this time.

Table 9 shows the budgeted measures from VPPSA's 2022 Tier III budget, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Ninety-five percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles.

Table 9 shows Swanton's share of VPPSA's Tier III budget, and it indicates 220 MWH of new electric loads are likely in 2022. This number is in alignment with the heat pump and electric vehicle adjustments from Itron. As shown in Table 3, a 206 MWH increase in electric loads is expected in 2022 as a result of these technologies.

[4] PUC Rule 4.415 (6)(A)

Table 9: Program Year 2022 Tier III Measures & Their Expected Impact on Load

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
Electric Bicycle	3	0.03	0.1
Electric Vehicle - New	4	2.8	11.0
Electric Vehicle - New, Income Qualifying	1	2.8	2.8
Electric Vehicle Used	1	2.8	2.8
PHEV - New	1	1.7	1.7
PHEV- New, Income Qualifying	1	1.7	1.7
PHEV - Used	1	1.7	1.7
Heat Pump - ductless	45	3.4	151.6
Heat Pump - ductless, Weatherized	1	3.4	3.4
Heat Pump - ductless, Income Qualified	2	3.4	6.7
Integrated Controls (with Heat Pump)	1	3.4	3.4
Ground Source Heat Pump	1	3.4	3.4
WBHP - Ducted	4	4.2	16.7
WBHP - Air to Water	1	4.2	4.2
Heat Pump Water Heater	4	1.0	3.8
Golf Carts	6	0.8	4.5
Residential Lawn Mower	3	0.01	0.0
	80		**220**

TIER III LOAD CONTROL

Rule 4.417 requires "a discussion of the available options for controlling load and their effectiveness and costs, the options the Provider is implementing and why, and whether the projected volume of Energy Transformation Projects warrants demand management activities; strategies to be used for encouraging the installation of technologies in buildings that meet minimum energy performance standards, as applicable; and strategies to be used for Customer education, outreach, and marketing."

VPPSA continues to investigate options for load control and is piloting both GridFruit for controlling refrigeration loads and open-source Electric Vehicle Supply Equipment (EVSE). The

EVSE pilot is particularly promising because it is attempting to gain cost-effective access to the data without having to pay for proprietary, subscription-based access.

From a technical perspective, there are many credible options for controlling load. However, they all must scale up to be economically competitive. Based on quotes from various vendors to date, the subscription cost of data acquisition and reporting can be prohibitive as shown in the following table.

Table 10: Cost and Size Ranges of Typical Pay-Per-Device Load Control Programs ($/kW-mo)

	kW Savings					
$/Yr/Device	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**5.0**
$250	$41.67	$20.83	$13.89	$10.42	$8.33	$4.17
$200	$33.33	$16.67	$11.11	$8.33	$6.67	$3.33
$150	$25.00	$12.50	$8.33	$6.25	$5.00	$2.50
$100	$16.67	$8.33	$5.56	$4.17	$3.33	$1.67

Many vendors offer a pay-per-device subscription fee as shown in the first column of Table 10. For devices that are 1.5 kW and smaller, the fees are far too large to justify the cost. For example, a $250 per device charge for a one kW device would cost $20.83/kw-month. This compares to avoided capacity costs that are about $2.50/kW-month and transmission avoided costs that are about $12/kW-month. As a result, this business model does not work for small devices, at least not at low levels of participation. However, large devices can quickly become cost-effective as shown in the green shaded areas.

Innovative rates are likely to be a cost-effective way to control load. As a result, VPPSA is exploring innovative rates that will be Time-of-Use (TOU) based. It would apply to both residential electric vehicle chargers and public DC fast charging stations and will provide rate research that can carry over into more generalized TOU rates for other end uses.

VPPSA will continue to pilot promising load control technologies and work to gain cost-effective access to the devices and the data they can provide. From a load forecasting perspective, we will continue to use load shapes that reflect best practices, as determined by the Technical Advisory Group (TAG).

FORECAST UNCERTAINTIES & CONSIDERATIONS

NET-METERING

SED presently has 39 residential scale (< 15 kW) net metered customers with a total installed capacity of about 290 kW. It also has two 500 kW community scale arrays. As solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If state policy continues to be supportive of net metering in this event, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for SED to monitor, especially if larger net metered projects are proposed. For example, two more 500 kW net metered solar projects built in 2023 would almost double the base of installed, net metered capacity on the system. In this event, the impact would be captured in interconnection and annual power budgeting processes and managed accordingly.

ELECTRIFICATION

Because most of SED's customer base is connected to Vermont Gas's distribution system, electrification of its heating loads is likely to follow a slower path than other rural parts of Vermont.

II. ELECTRICITY SUPPLY

SED's power supply portfolio is made up of generation resources, long-term contracts, and short-term contracts. The portfolio acts as a diversified, financial hedge that buffers SED and its customers from the cost and volatility of buying electricity from ISO New England. The following sections describe each of the power supply resources in SED's portfolio.

EXISTING POWER SUPPLY RESOURCES

1. Highgate Falls Hydro

- Size: 11.392 MW
- Fuel: Hydro
- Location: Swanton, Vermont
- Entitlement: 100%, owned
- Products: Energy, capacity, renewable energy credits (VT Tier I and NH I)
- End Date: Life of Unit
- o Notes: Highgate Falls provided 49.3% of SED's energy in 2021. The generation reduces load in ISO markets, is qualified as VT Tier I (#1-4) and NH Class I (#5) RECs.

2. Market Contracts

- Size: Varies
- Fuel: New England System Mix
- Location: New England
- Entitlement: Varies (PPA)
- Products: Energy, renewable energy credits
- End Date: Varies, less than 5 years.
- o Notes: SED purchases system power from various entities under short-term (5 years or less) agreements. These contracts are also labeled as Planned and Market Purchases and comprised 24.2% of SED's supply in 2021.

3. McNeil Station

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 3.7% (1.85 MW), joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit
- Notes: As the joint-owner, VPPSA has agreements with SED to pay for and purchase 3.7% of the unit's output.

4. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 0.478 MW (Niagara PPA), 0.01 MW (St. Lawrence PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 9/1/25 (Niagara), 4/30/32 (St. Lawrence)
- Notes: NYPA provides hydro power to SED under two contracts, which will be extended at the end of their term.

5. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 7.3% (2.9 MW) MW, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with SED to pay for and purchase 7.3% of the unit's output.

6. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 1.04% (PPA)
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2032

7. Stony Brook Station

- Size: 352 MW
- Fuel: Natural Gas, Oil
- Location: Ludlow, MA
- Entitlement: 0.352% (PPA)
- Products: Energy, capacity, reserves
- End Date: Life of unit

Table 11 summarizes the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed-price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits (RECs), that is indicated in the seventh column, followed by the resource's expiration date and whether we assumed that it would be renewed until 2042.

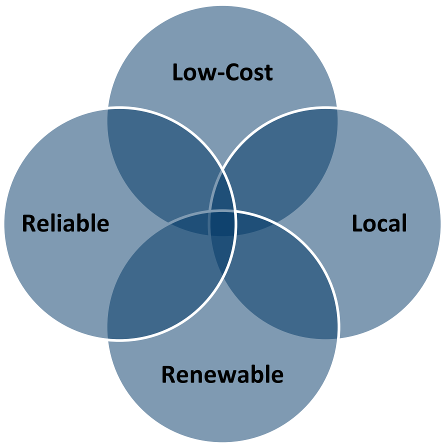
Table 11: Existing Power Supply Resources

RESOURCE	2021 MWH	% of MWH	2021 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2042
Highgate Hydro #1-4	27,410	45.5%	11.392	Run of River	O&M Only	✓	Life of Unit	
Highgate Hydro #5	2,318	3.8%		Run of River	O&M Only	✓	Life of Unit	
Market Contracts	14,583	24.2%	0.0	Firm	Fixed		< 5 years	
McNeil	10,114	16.8%	1.85	Intermediate	Variable	✓	Life of Unit	
NYPA Niagara	3,800	6.3%	0.478	Baseload & Peaking	Fixed	✓	9/1/25	Yes
NYPA St. Lawrence	73	0.1%	0.01	Baseload & Peaking	Fixed	✓	4/30/32	Yes
Phase I/II	0	0.0%	1.3	N/A			Life of Unit	
Project #10	29	0.0%	2.9	Peaking	Variable		Life of Unit	
Ryegate	1,697	2.8%	0.205	Baseload	Fixed	✓	10/31/32	No
Stony Brook	186	0.3%	1.24	Peaking	Variable		Life of Unit	
TOTAL	**60,209**	**100%**	19.4					

FUTURE RESOURCES

SED will seek out future resources that meet as many of the following criteria as possible. Ideally, future resources will meet four criteria by being low-cost, local, renewable and reliable.

Figure 5: Resource Criteria



✓ **Low-Cost** resources reduce or stabilize electric rates.

✓ **Local** resources are located within SED's Regional Planning Commission area or within Vermont.

✓ **Renewable** resources meet or exceed RES requirements.

✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

These criteria enable SED to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that SED may consider fall into three categories: 1.) Existing resources in Table 11, 2.) demand-side resources, and 3.) new resources that meet the criteria in Figure 5.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that two existing resources are extended past their current expiration date. These include Project 10 and NYPA. Depending on how contract negotiations align with the resource criteria, other existing resources may be extended including the Brookfield Hydro and Howard Wind resources. Where resource needs remain, market contracts will be used to supply them.

1.1 MARKET CONTRACTS

Market contracts are expected to be the most readily available source of electric supply for energy, capacity, ancillary services and renewable attributes (RECs). By conducting competitive solicitations through VPPSA, SED can not only get access to competitive prices (low-cost), but it also can structure the contracts to reduce volatility (stable rates) and potentially include contracts for RECs for RES compliance. Market contracts are also scalable and can be right-sized to match SED's incremental electric demands by month, season and year. In many cases, the delivery point for market contracts can be set to the Vermont Zone reducing potential price differential risks between loads and resources. Finally, the financial strength of the suppliers in the solicitation can be predetermined. The combination of these attributes makes market contracts a good fit for procuring future resources.

CATEGORY 2: DEMAND-SIDE RESOURCES

The lowest cost, most local source of energy is often energy that is conserved or never consumed. As a result, SED will continue to welcome the work of the Efficiency Vermont (EVT) and Capstone Community Action in its service territory. SED will also continue to work with its customers, both large and small, to uncover demand response opportunities. This includes best practices for demand management as SED continues to implement its energy transformation programs under RES.

VPPSA has several pilot projects that are in progress with Efficiency Vermont. This includes a Behavioral Demand Response program where VPPSA sends notices of potential transmission and capacity peaks to member utilities with recommendations to maximize generation and minimize electric demand during the forecast peak window. VPPSA also provides public notice of potential capacity peaks via social media, Front Porch Forum, and press releases. This includes recommendations to minimize electric demand during the forecast peak window.

VPPSA is also collaborating with Efficiency Vermont to install forty residential EV chargers. The chargers will be programmed to avoid charging during peak hours and customers will be provided with information about how this benefits the electric grid and the cost of electricity.

CATEGORY 3: NEW RESOURCES

VPPSA regularly meets with developers throughout New England, and through VPPSA staff, SED will continue to monitor and evaluate new generation resources in the New England region.

3.1 BATTERY STORAGE

VPPSA conducted a Request for Information (RFI) process in 2020 to better understand the business case for short duration (<4 hours) storage. Nine companies responded, including four that were based in Vermont and two that are among the largest developers in the US. The pricing was used to develop a net-present value positive business case for peak shaving that is congruent with other storage projects that have already been built in Vermont. Based on this peak shaving business case and the strength of the responses to the RFI, VPPSA conducted a Request for Proposals (RFP) process in 2021 and selected a development partner.

VPPSA is also monitoring the development of long-duration storage technology (>4 hours), and expects to conduct a similar process as the technology becomes commercially available.

3.2 HYDROELECTRIC GENERATION

Hydroelectric generation is widely available in the New England region, and can be purchased within the region or imported from New York and Quebec. Furthermore, it can be sourced from either small or large facilities, and can sometimes be purchased "firm", meaning that the seller is willing to guarantee delivery regardless of hydrological conditions. Like all existing resources, price negotiations begin at or near prevailing market prices. As a result, existing hydro generation could be both low-cost (or at least at market) and renewable.

3.3 SOLAR GENERATION

As a 100% renewable utility, SED has no Tier II requirement except to retire net-metered RECs. However, solar is a good fit for SED because its production peaks in the summer months when hydroelectricity is at its lowest point of the year. As a result, SED will investigate solar developments within its service territory.

3.3.1 NET METERING

SED has 37 residential scale net-metered customers and two 500 kW community arrays. Its installed base of solar capacity is 1,280 kW. SED will monitor the participation rate closely as solar costs approach grid parity. Should grid parity occur, not only would net metered solar penetration be expected to increase but the costs of the existing program would likely cause upward rate pressure. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 WIND GENERATION (ON AND OFF-SHORE)

On-shore wind projects continue to be developed in New England, and entitlements to such projects can often be negotiated at competitive prices. RECs are often bundled into the PPA, making this resource a good fit for the low-cost and renewable criteria. Off-shore wind projects are in development, and the costs are becoming competitive. As a result, SED will consider both on and off-shore wind PPA's as those opportunities arise.

3.5 GAS OR OIL-FIRED GENERATION

Project 10 completed a major overhaul in 2022, and the expected life of the unit spans the planning period. As a result, no new sources of gas or oil-fired generation are being planned for in this IRP.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Northwest Regional Planning Commissions (NRPC), SED is part of a Regional Energy Plan[5] that was created in 2017. The intent of the plan is "to complete in-depth energy planning at the regional level while achieving state and regional energy goals—most notably, the goal to have renewable energy sources meet 90% of the state's total energy needs by 2050 (90 x 50 goal)."[6]

The plan gives municipalities "substantial deference" before the PUC for applications that seek a Certificate of Public Good (CPG)." The full plan is included in the appendix, and all future resource decisions will be made with this plan in mind. Specifically, SED will consult with the NRPC on resource decisions that involve potential siting of new resources in Vermont.

[5] The full plan can be found at https://www.nrpcvt.com/energy-planning.

[6] Northwest Regional Energy Plan 2017, Page 5

RESOURCE PLAN

III. RESOURCE PLANS

ENERGY PROCUREMENT PROCESSES

MONTHLY PROCESS

VPPSA's Power Supply Authorities Policy requires that energy supplies be within +/-5% of the forecasted demand in each month of the year. The ratio of supply to demand is known as the hedge ratio. Any imbalances between supply and demand are hedged to these levels before the operating month begins. In practice, changes in weather, generator availability and other factors often combine to push the actual percentage outside of the +/-5% threshold.

VPPSA evaluates supply and demand every month and purchases or sells energy to refine the energy hedge ratio. The following three-step process is used to balance supply and demand.

1. Update Budget Forecast
    a. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply (unit availability and hydro conditions).
2. Hydroelectric Adjustment
    a. Supply is sometimes reduced by one standard deviation from the long-term average in order to avoid making sales that could end up being unhedged by supply in the event of a drier-than-normal month.
3. Execute Purchases or Sales
    a. **Internal Transactions**: VPPSA seeks first to make internal transactions between its members to balance supply and demand. The transactions are designed to result in a hedge ratio that falls within the +/-5% range that is required by VPPSA's Power Supply Authorities Policy.
    b. **External Transactions**: In the event that internal transactions cannot bring SED into the +/-5% range, external transactions are placed with power marketers, either directly or through a broker.
    c. **Price:** For Internal Transactions, the price of the transaction is set by an average of the bid-ask spread as reported by brokers on the date of the transaction. For External Transactions, the price is set through a negotiation with the counterparty.

ANNUAL PROCESS

Known within VPPSA as "planned purchases", these transactions are almost always purchases. They typically take place no more than once a year, usually carry a 1-5 year term, and if possible, are executed at a time when market prices are at or below budgeted levels.

These purchases are designed to fit the on and off-peak energy needs in each month of the year as precisely as possible. As a result, they minimize the need for monthly 7x24 hedging transactions under VPPSA's Power Supply Authorities Policy.

The solicitation method is an informal Request for Proposals (RFP), and follows a three-step process.

1. **Pre-Approval Term Sheet:** First, the proposed purchase volumes and anticipated prices are documented in a standardized term sheet. This document is distributed to each VPPSA member for their pre-approval, and it defines their share of the total purchase.
2. **Issue RFP:** Once all of the pre-approvals are received, the term sheet is distributed to three or more power marketers, who are asked to make their best offer by a deadline, typically within 5 business days.
3. **Evaluate & Execute:** When all of the bids are received, VPPSA evaluates them to determine the lowest cost bid, and executes the purchase with that counterparty. The purchase is allocated to each VPPSA member according to their pre-approved term sheet, and the data is entered into VPPSA's database for scheduling and invoice tracking.

LONG-TERM PROCESS

VPPSA evaluates long-term Purchased Power Agreements (PPAs) for bundled energy, capacity, renewable energy credits, and/or ancillary products on an ongoing basis. Because long-term contracts are subject to PUC approval, the acquisition strategy is simply to negotiate the best terms and to make the contract execution contingent on PUC approval.

DECISIONS FACING SED

As the following sections will explain, SED is focused on a series of potential resource events in the coming five years. These events all revolve around Highgate Falls, and can be condensed into four questions.

1. **Highgate Falls Peak Shaving Impacts:**
   Q1: What is the financial impact of the proposed Water Quality Certificate (WQC) on peak shaving operations, and what can be done to mitigate it?

2. **Highgate Falls Aesthetic Impacts**
   Q2: What would be the financial impact of a 1,000 MWH/year reduction in generation?

3. **Low Hydrological Conditions**
   Q3: What is the financial impact of a single dry hydro year on SEDs cost of service, and what resources can best mitigate it?

4. **Renewable Resource to Meet Electrification Growth**
   Q4: What renewable resource is the least cost and most diversifying for SED's electrification-driven load growth?

Highgate Falls Peak Shaving Impacts: In June 2021, Highgate Falls retired from ISO-NE's capacity market and is now a load reducer. This has reduced capacity and transmission costs by reducing coincident peak loads with ISO-NE. The reference case includes the expected peak shaving impacts, which reduce SED's costs. The new WQC that has been proposed would require run-of-river operations, which would eliminate peak shaving operations. This impact is quantified in the Financial Analysis chapter in the context of replacing it with a battery storage resource.

Highgate Falls Aesthetic Impacts: The proposed WQC also includes a requirement to spill water over the dam to improve aesthetics. The impacts on generation are likely to be non-linear and dependent on seasonal stream flows. As a result, this IRP models the impacts using monthly average generation profiles. The value of this lost generation is quantified in the Financial Analysis chapter.

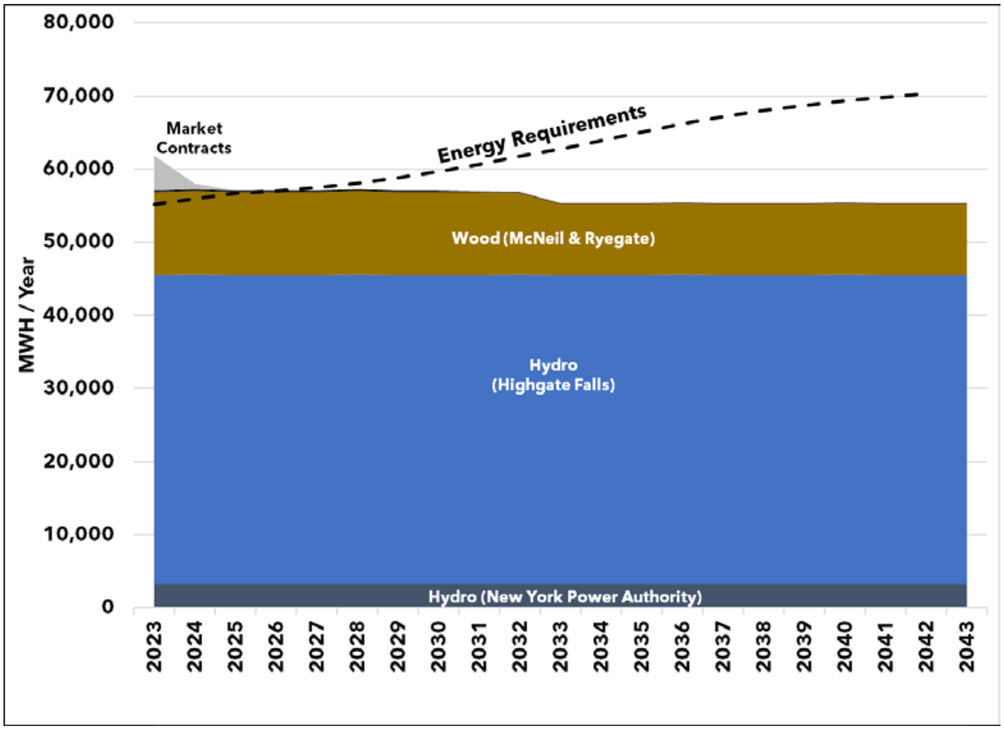
Low Hydrological Conditions: This analysis quantifies the impact of a single dry year by reducing: (1) the annual capacity factor by 30%, which is two standard deviations from the mean, and (2) the annual peak coincidence with ISO to zero, which is an event that has already occurred and may happen again in the future.

Renewable Resource to Meet Electrification Growth: As electrification grows SED's load, a new resource will be needed to maintain SED's 100% renewable power supply. The following sections evaluate how renewable resources fit the load, and the Financial Analysis chapter will quantify the costs.

ENERGY RESOURCE PLAN

Figure 6 compares SED's annual energy supplies to its adjusted load. Under normal hydrological conditions and with typical availability of McNeil and Ryegate, SED's energy requirements are fully hedged into the mid 2020s. However, a dry hydrological year such as 2021 can result in much tighter supplies. Furthermore, to keep pace with the expected load growth from electrification, a new renewable resource is needed this decade.

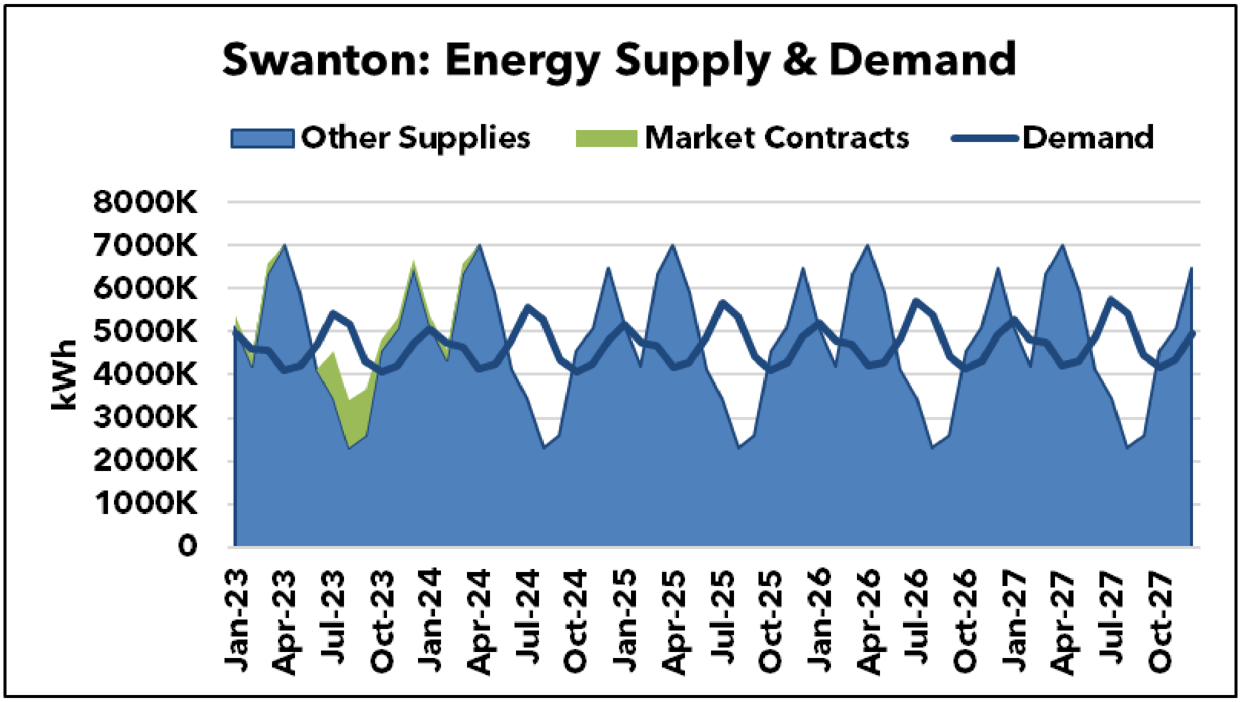
Figure 6: Annual Energy Supply & Demand by Fuel Type



This picture is quite different when viewed on a monthly basis. As shown in Figure 7, there is seasonality in both demand and supply. On the demand side, twice-a-year peaks in energy demand occur in July and January. On the supply side, Highgate Falls creates a surplus in energy supplies during the spring and again in the fall, just prior to the winter freeze up.

Conversely, in the late summer and early fall, there is not enough water in a typical year to fulfill all of SED's energy requirements. This can be seen in the troughs of Figure 7. These troughs are where market contracts have been purchased historically, but the troughs could be filled by a renewable resource later this decade.

Figure 7: Monthly Energy Supply & Demand by Fuel Type: 2023 - 2027



RENEWABLE ENERGY PROCUREMENT OPTIONS

Hydrological conditions can swing Highgate Falls annual generation by +/-15%. This is equal to one standard deviation or 6,900 MWH/Year in any year. This variation represents the most immediate resource need; to procure a resource that can replace this volume of energy during a dry year. The full array of renewable options includes hydro, solar, wind and wood energy. Any one (or a combination) of these resources would hedge SED's forecast loads in a normal hydro year into the early 2030s. The pros and cons of each is discussed below.

First, firm hydro energy and Tier I RECs can be procured in-region at prevailing market prices. The advantage of this product is that it can be shaped to match Swanton's seasonal needs (summer primarily). The disadvantage is that it will be priced to match other firm market products and may even carry a premium to account for the firmness of the product. Because this product is priced seasonally and at prevailing market prices, it is not analyzed in the Financial Analysis. The financial results will look the same as in the reference case.

Second, solar has three advantages going for it. First, a 4.4 MW solar project can generate about 6,900 MWH/year at an 18% capacity factor. This size project would hedge SED during a dry year and be small enough to avoid an ISO-NE interconnection. Second, dry (low) hydro conditions are likely to coincide with a good (high) solar generation, which makes hydro and solar complementary in the event of a dry year. Finally, solar generation peaks in the summer when Highgate Falls generation is at its minimum, so it can help fill a seasonal energy deficit even during normal hydro years.

The seasonal generation profile of solar is not a perfect fit for SED, however. A 3 MW wind resource or an additional 1.4 MW of McNeil would also produce the same 6,900 MWH/year. Their daily and seasonal generation profiles are different though. Both wind and wood produce well during the winter, but wood has the advantage of producing *less* during the spring when hydro conditions are reliably good. Furthermore, wood generation increases through the summer due to dry soil conditions (good wood harvesting weather), while wind reaches it annual minimum in the summer. As a result, wood is likely to be a better fit than wind for SED. The following Figures show how these levels of solar, wind and wood energy would change SED's annual and monthly resource mix compared to its load.

Figure 8: Annual Supply & Demand with Solar

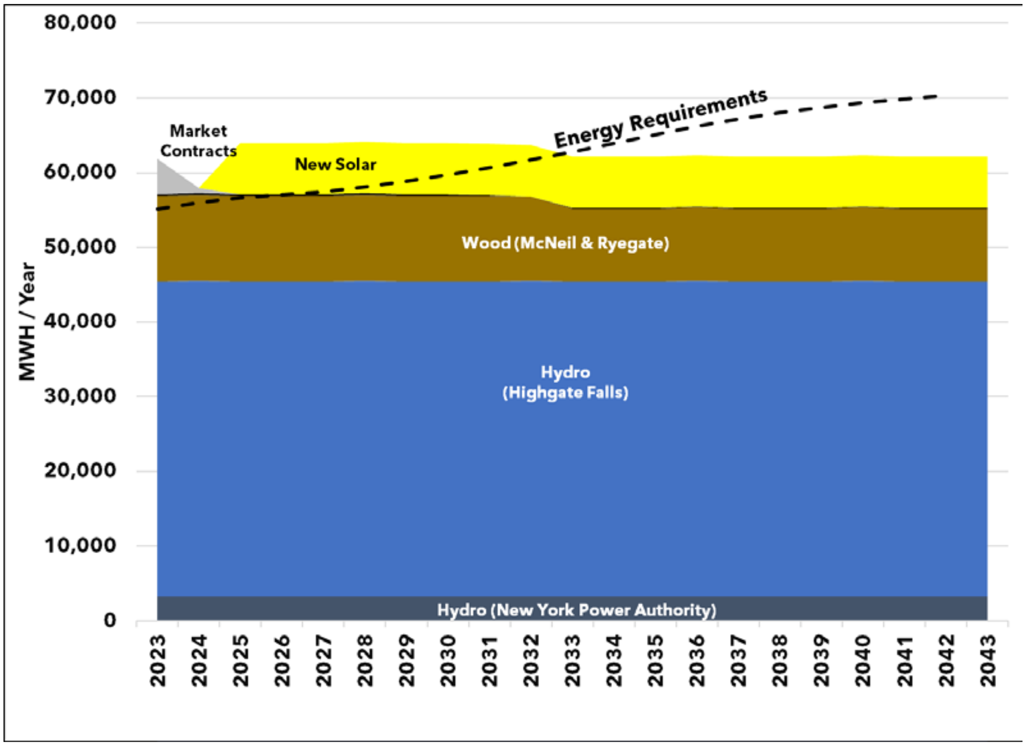
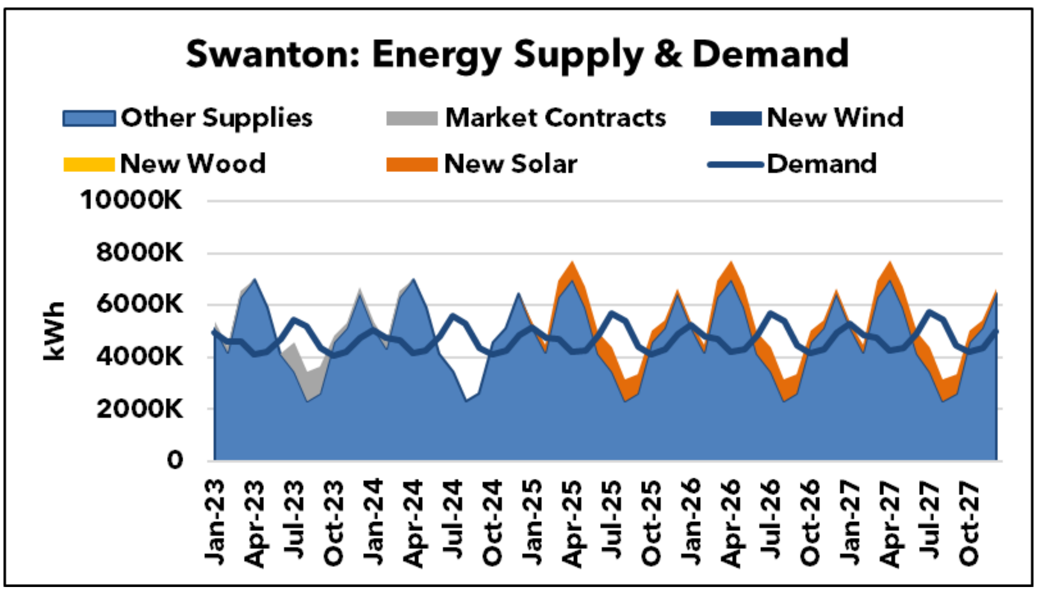


Figure 9: Monthly Supply & Demand with Solar



Solar energy exacerbates SED's spring energy surplus, and does little to fill in the summer energy supply deficit.

Figure 10: Annual Supply & Demand with Wind

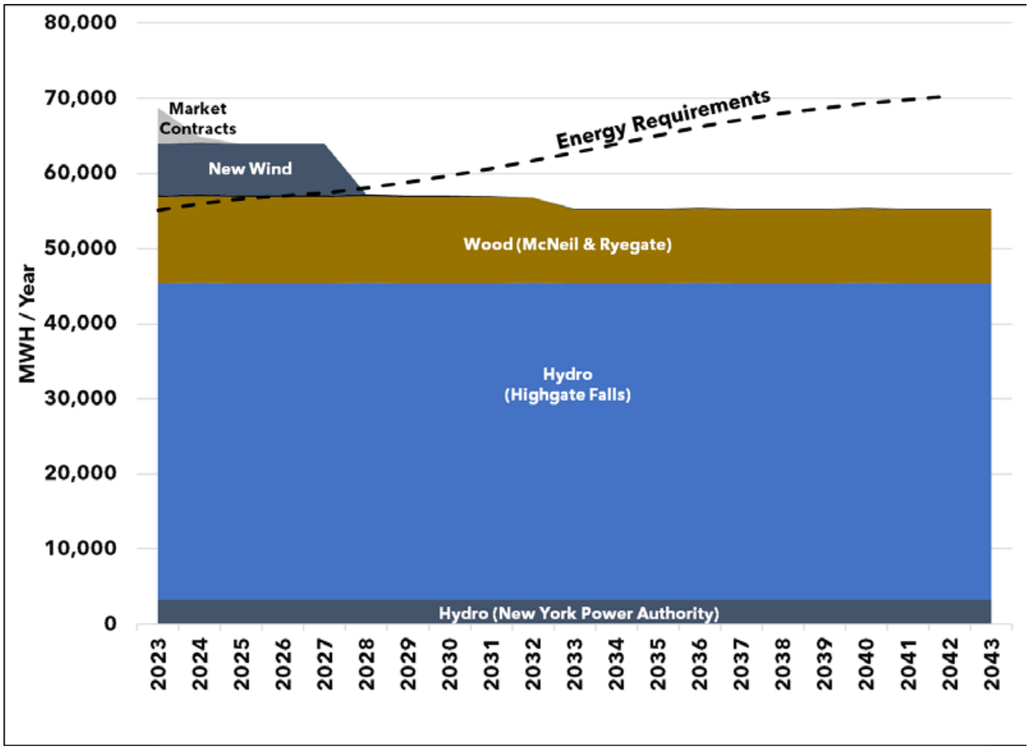
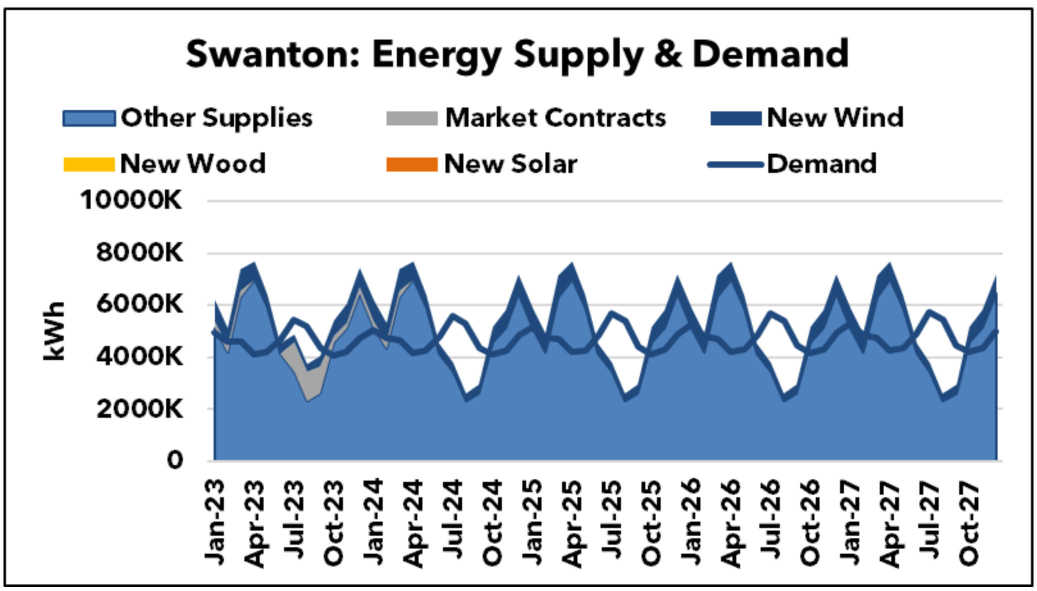


Figure 11: Monthly Supply & Demand with Wind



Wind energy adds supply year-round, especially in the winter months. This is advantageous in the event of a cold winter. However, wind does little to hedge summer energy needs.

Figure 12: Annual Supply & Demand with Wood

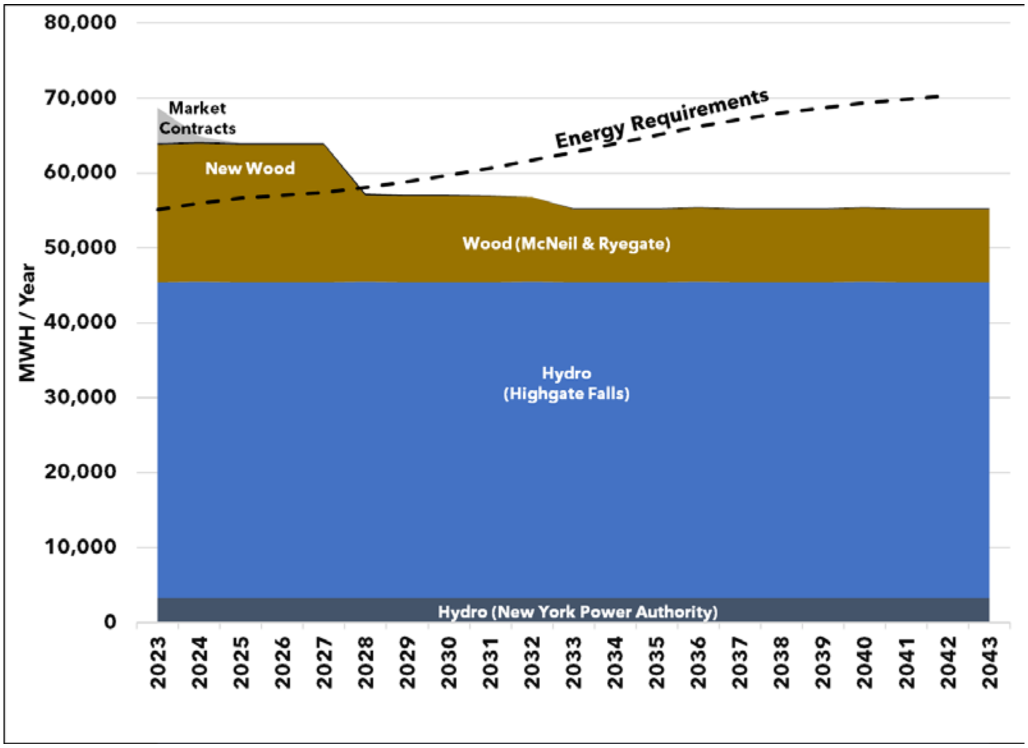
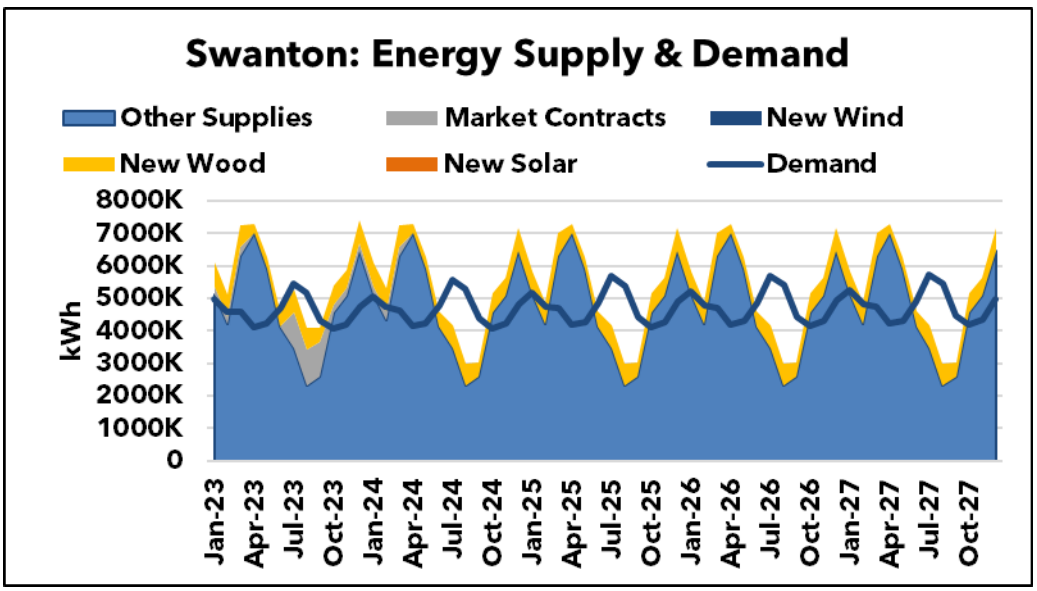


Figure 13: Monthly Supply & Demand with Wood



Wood energy also adds supply year around, especially in the winter. It supplies more energy than wind in the summer, but adds to SED's surplus in the fall.

RENEWABLE ENERGY PROCUREMENT DISCUSSION

Because Highgate Falls is an intermittent resource, SED is accustomed to the month-to-month variability in its output and in its power supply costs. As a result, managing annual costs is the first priority, and monthly misalignments in supply volumes and power supply costs can be tolerated. In this context, diversifying new supplies away from intermittent hydro and toward firm or baseload supply sources is a beneficial strategy.

This can be accomplished with almost any combination of renewable resources.

- Firm hydro,
- Intermittent solar,
- Intermittent wind,
- Baseload wood

The key question is, "Which combination is least cost and lowest risk?"

Because firm hydro and wood resources are in the New England region, they will be priced at New England market prices. As a result, no financial benefit can be attributed to them through a life-cycle cost analysis. The cost will be determined by the market at the time the resource is contracted, and the economic benefit will be determined by future market price fluctuations from the contract price. However, solar energy will be priced at the cost of new construction and could (in theory) be a cost saving resource. Finally, the wind resource that is modeled in this IRP is an import from NYISO, where prices are substantially lower than in New England. As a result, some cost savings is attributable to this resource in the Financial Analysis chapter.

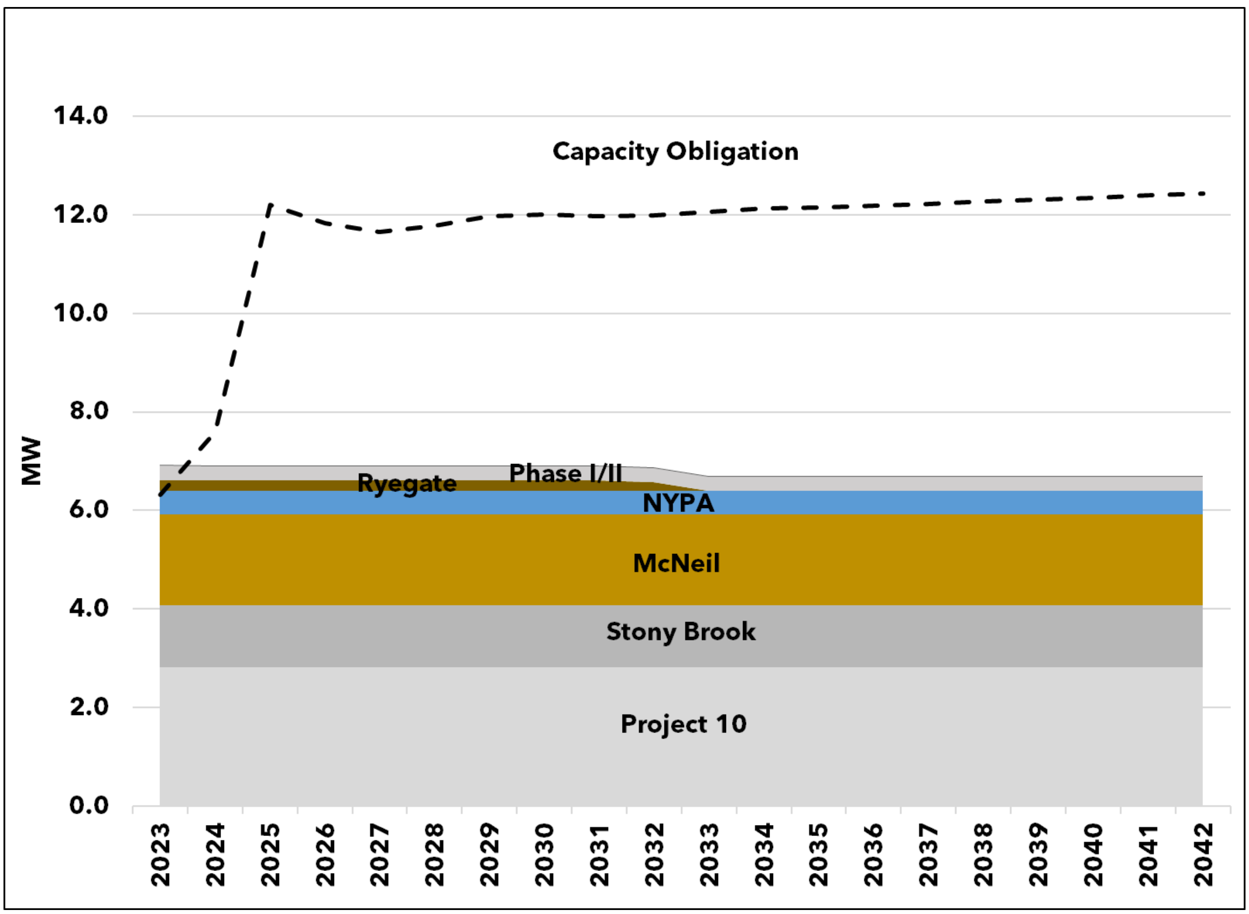
In terms of risk, firm and baseload resources are naturally lower risk than intermittent ones, which makes firm hydro and baseload wood attractive compared to wind and solar. Finally, another way to manage SED's intermittent hydro risk is to sell some of it and replace it with a different resource whose generation is more firm or at least less correlated with generation at Highgate Falls. The challenge with this strategy is that SED's surplus energy from Highgate Falls is concentrated in the spring months, when the New England region also has a surplus. As a result, selling Highgate Falls is not likely to garner an attractive market price that is high enough to offset the cost of buying replacement power in more expensive months of the year.

CAPACITY RESOURCE PLAN

Figure 14 compares SED's capacity supply to its demand. Note that SED's capacity obligation in 2023 is expected to be low. This is because Highgate Falls was able to generate during the annual peak hour this past summer. This is not likely to continue in future years for two reasons. First, water is not always available during the summer months when the peak hour occurs, and second, the new WQC is likely to eliminate Highgate's ability pond water for peak shaving. As a result, we expect that SED's capacity obligation will increase in 2024 and beyond.

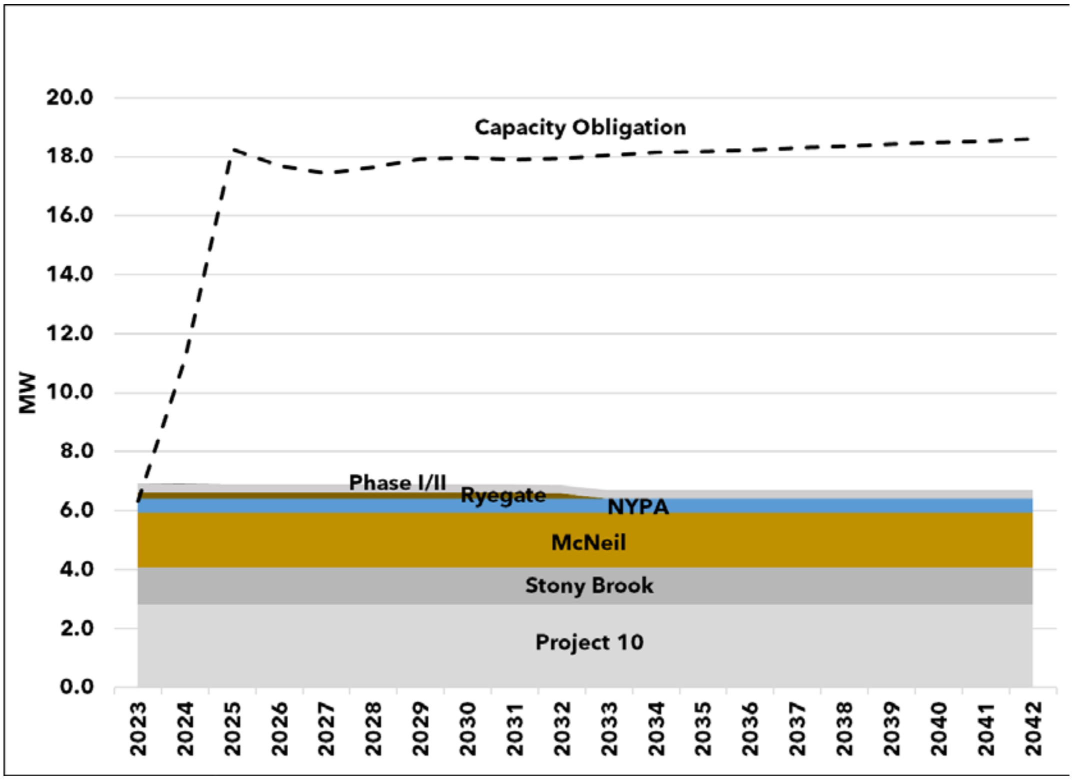
Under the current WQC, Highgate Falls is expected to shave 3.5 MW off the annual peak in a typical year. This is the six-year average from Table 12 and it explains the gap between capacity supply and demand. It should be noted that this is an average, and the actual coincident generation will determine Highgate's (avoided) capacity value in any single year.

Figure 14: Capacity Supply & Demand (Summer MW)



In the event that Highgate Falls can no longer shave peaks, the capacity obligation is increased as depicted in the following Figure.

Figure 15: Capacity Supply & Demand (No Peak Shaving)



A history of Highgate's coincident generation with the ISO annual peak appears in Table 12. The average is 3.5 MW, which excludes the zero in 2018 because the unit was on scheduled maintenance in that year.

Table 12: Highgate Falls Coincident Generation with ISO-NE's Annual Peak

Date	Hour Ending	MW
06/13/2017	17	5.2
08/29/2018	17	0.0
07/30/2019	18	1.6
07/27/2020	18	0.8
06/29/2021	17	0.3
07/20/2022	19	9.3
Average		3.5

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because SED is part of ISO New England, its capacity requirements are pooled with all of the other utilities in the region. As a result, if Project 10 or McNeil are not available, SED will be provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance[7] (PFP) program creates financial payments (and potential penalties) for generators to perform when the grid is experiencing a scarcity event.

The following table illustrates the range of performance payments that SED's share of Project 10 creates in ISO New England's PFP Program. Depending on ISO-NE's load at the time of the scarcity event and Project 10's performance level, SED could receive up to a $10,400 payment or pay up to a $11,800 penalty during a one-hour scarcity event. This represents a range of plus or minus sixteen to 15% of SED's monthly capacity budget. However, such events are not expected to occur more than a few times a year (if at all), and frequently last less than one hour.

Table 13: Pay for Performance Ranges for One Hour of Project 10 Operation[8]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWH	-$5,100	$2,700	$10,400
15,000	$5,500/MWH	-$7,300	$400	$8,200
20,000	$5,500/MWH	-$9,500	-$1,800	$6,000
25,000	$5,500/MWH	-$11,800	-$4,000	$3,800

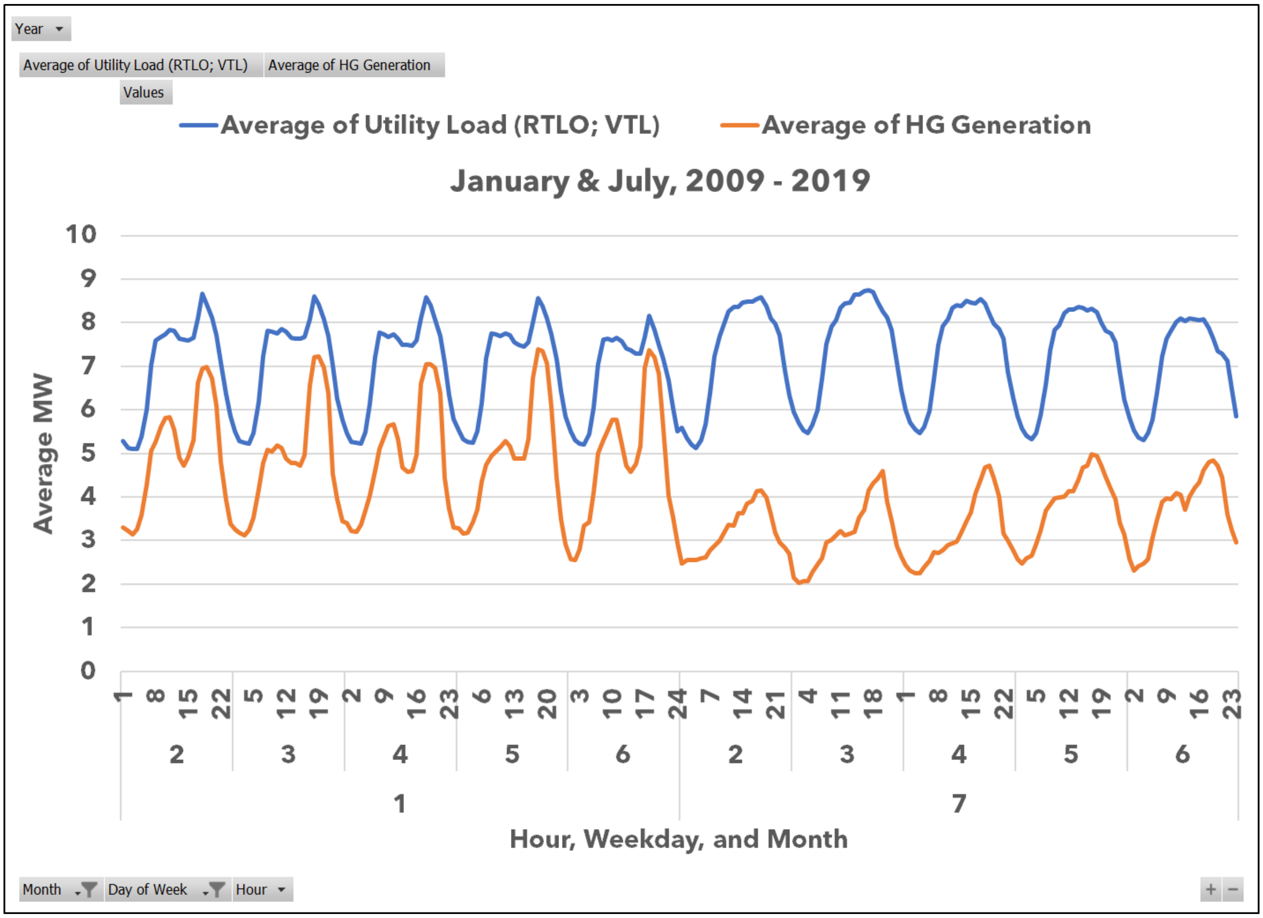
[7] For an overview of the PFP program, please visit https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project.

[8] Please refer to the following presentation from ISO-NE for the details of how the performance payments are calculated. https://www.iso-ne.com/static-assets/documents/2018/06/2018-06-14-egoc-a4.0-iso-ne-fcm-pay-for-performance.pdf

HIGHGATE FALLS OPERATIONAL PLAN

Highgate Falls historically has operated on a diurnal pattern where water is ponded overnight and released during the day. Then the daytime releases are timed to follow SED's load as shown in Figure 16. This strategy was used to maximize generation during the daytime hours when energy prices are at their highest.

Figure 16: Highgate Falls Average Weekday Generation Compared to SED's Load



Now that Highgate Falls is a load reducer, this operational pattern is shifted slightly to reduce SED's coincident peaks with ISO and VELCO, which occur in the late afternoon and early evening hours. This strategy emphasizes reducing transmission and capacity costs over reducing energy costs, and has already been effective at lowering SED's power supply costs since it retired from ISO markets in June 2021.

STORAGE RESOURCE PLAN

Highgate Falls is an effective storage resource that is well matched to SED's load in most months of the year. However, in the event that the new WQC is adopted as proposed, Highgate Falls may lose its ability to operate as a storage resource that can shave coincident peaks. In this event, SED could invest in a short duration battery storage resource. Unfortunately, this resource will come at an increased cost as compared to Highgate Falls, and it will be too small to shave all of SED's load. This is because storage resources have to be less than 5 MW in size to avoid interconnecting with ISO-NE and participating in its markets. For context, Highgate Falls can produce up to 9.1 MW when hydrological conditions permit. Nevertheless, the cost of investing in a 5 MW battery storage resource will be quantified in the Financial Analysis.

RENEWABLE ENERGY STANDARD REQUIREMENTS

SED's obligations under the Renewable Energy Standard (RES) are shown in Table 14. Under RES, SED must maintain a 100% renewable supply. Tier II requirements are met by retiring net-metered RECs, and there is no further obligation to develop Tier II resources.

Table 14: RES Requirements (% of Retail Sales)

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: Net Total Renewable Energy (A) - (B)	Tier III: Energy Transformation
2022	100%	0% (NM only)	100%	4.00%
2027	100%	0% (NM only)	100%	7.34%
2032	100%	0% (NM only)	100%	10.67%
2033-42	100%	0% (NM only)	100%	10.67%

The final column shows the Energy Transformation (Tier III) requirement. Note that the Tier III requirement is held constant from the 2033 to 2042 period. This is due to the fact that the RES statute does not define an obligation during these years. Given the current push for electrification, we assume that the 10.67% requirement holds steady through these years.

Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tier I and Tier II requirements. Tier III is unlike the Tier I and Tier II requirements, which count only electricity that is produced and consumed in an individual year.

The RES statute provides a second way to comply with its requirements, the Alternative Compliance Payment (ACP). In the event that a utility has not achieved the requisite amount of Tier I, Tier II or Tier III credits in a particular year, then any deficit is multiplied by the ACP, and the funds are remitted to the Clean Energy Development Fund (CEDF).

However, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP, or they may petition the PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

Table 15: ACP Prices[9] ($/MWH)

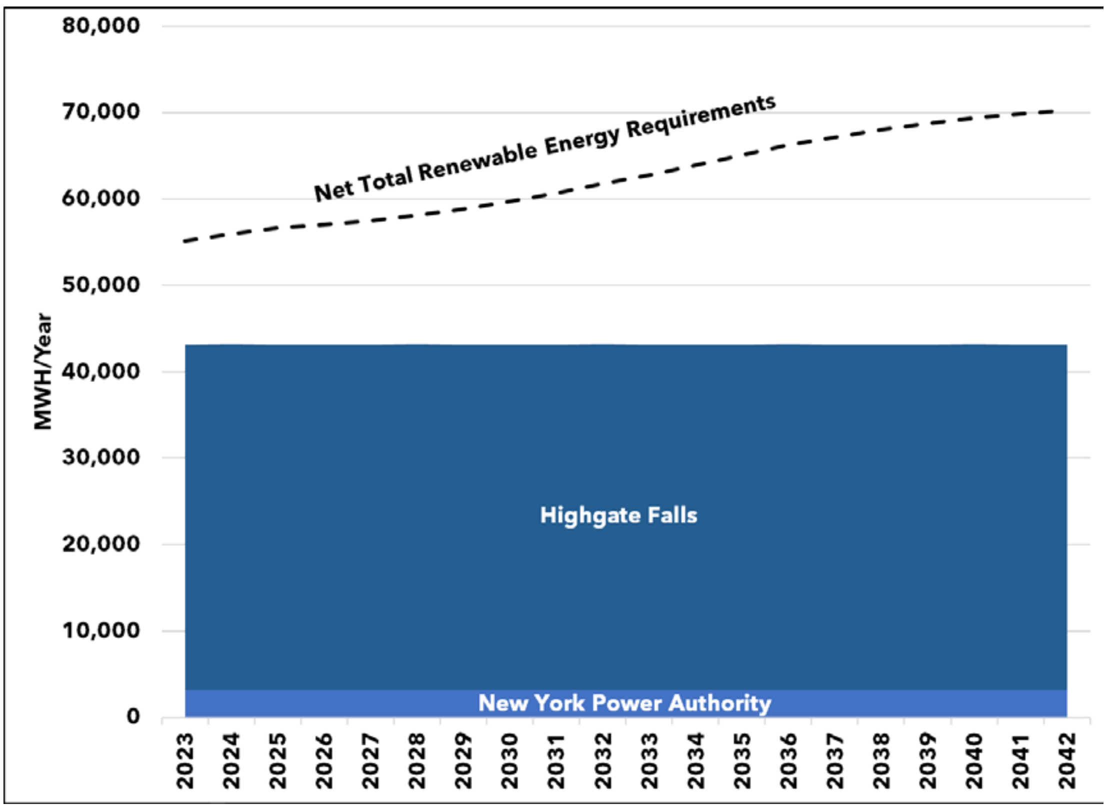
Year	TIER I	TIER II & III
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

[9] Please note that these are estimates, and grow at inflation.

TIER I - TOTAL RENEWABLE ENERGY PLAN

SED has two hydroelectric resources that contribute to meeting the Net Tier I requirement; NYPA and Highgate Falls. These resources add up to about 43,000 MWH per year or 80% of SED's Tier I requirement in 2023. The gap between these resources and a 100% renewable power supply is fulfilled by McNeil and Ryegate, but because their RECs are sold to load serving entities in Connecticut, they are not depicted here. The sale of those RECs creates a revenue stream that is used to fund the purchase of Vermont Tier I RECs.

Figure 17: Tier I - Total Renewable Energy Supplies



SED is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). Their price has ranged from a low of \$1.00 to a high of \$10.00 per MWH over the past five years. At the current price of \$10/MWH, the cost of complying with Net Tier I between 2023 and 2027 with ME II RECs would be about \$120,000-\$160,000 per year.

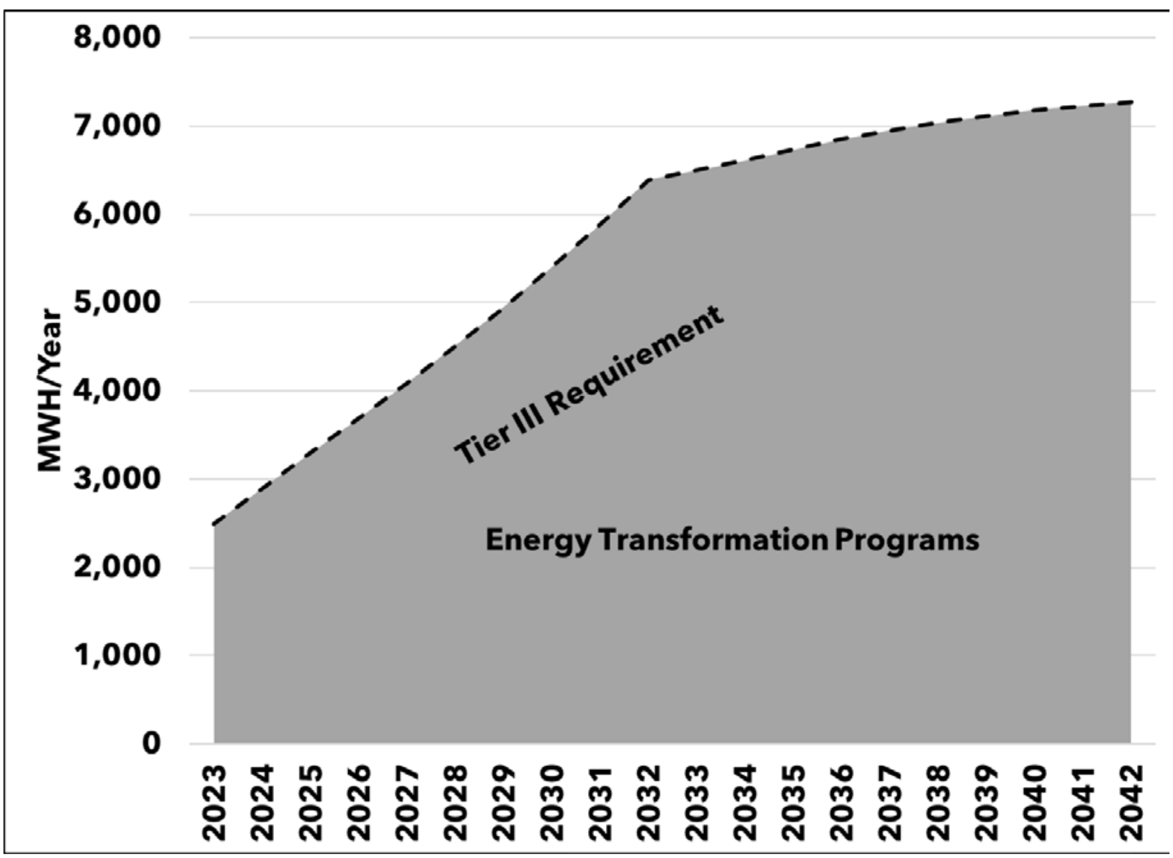
TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

Because SED is already 100% renewable under Tier I, it has no Tier II requirement except to retire net-metered RECs, which it will continue to do throughout the planning period.

TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 18 shows SED's Energy Transformation (Tier III) requirements, which rise from about 2,500 MWH in 2023 to 6,500 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 18. These programs cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. More detail on these programs can be found in Appendix A (VPPSA's 2022 Tier 3 Annual Plan) and in the following section.

Figure 18: Energy Transformation Supplies



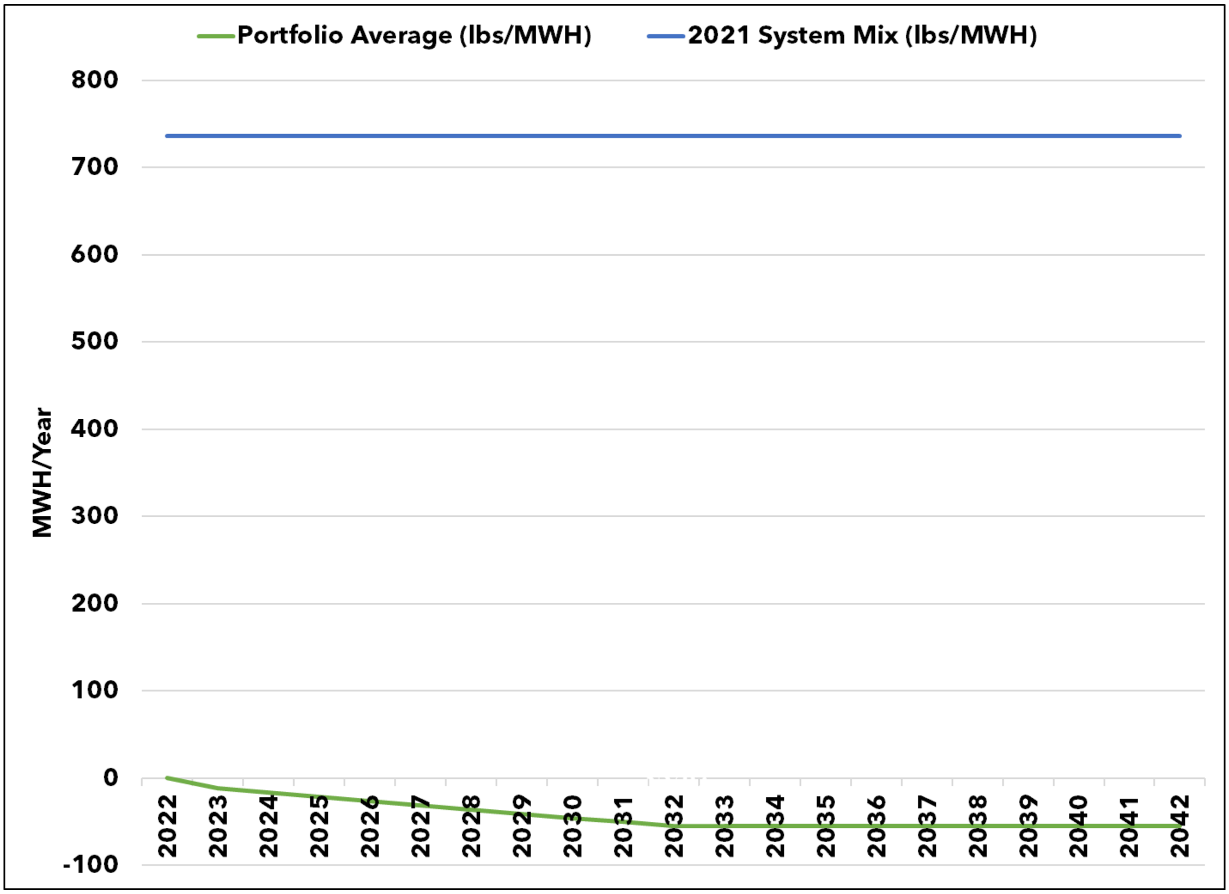
If prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. SED will follow a three-part strategy to fulfill its Tier III requirements.

1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Manage Tier II credits to maximize value across both Tier II and Tier III requirements.

CARBON EMISSIONS AND COSTS

Figure 19 shows an estimate of SED's carbon emissions rate compared to the 2021 system average emissions rate in New England[10]. The emissions rate is negative because SED must maintain a surplus of renewable energy to maintain it's 100% renewable portfolio.

Figure 19: Portfolio Average Carbon Emissions Rate (lbs/MWH)



[10] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

RESOURCE PLAN OBSERVATIONS

The resource plans in this section have led to several observations. First, a battery can only partially compensate for the loss of peak shaving operations at Highgate Falls. This is due to the fact that a load reducing battery would need to be less than 5 MW in size, and Highgate Falls can presently shave up to 9.1 MW when the water is available. This net loss in peak shaving capability would increase SED's costs.

Second, the aesthetic impacts of the proposed WQC are likely to be non-linear and dependent on seasonal stream flows. As a result, modeling the financial impact of the aesthetic impacts of the proposed WQC is limited to using seasonal averages, and is probably not additive.

Third, low hydrological conditions represent a significant risk to SED's 100% renewable supply. In dry years like 2021, additional sources of renewable energy are necessary to maintain 100% renewability.

Finally, no single resource aligns perfectly with SED's monthly and seasonal need for renewable energy in the coming decade. Both solar and wood have some seasonal advantages, but neither one fills the summer deficit without also creating a surplus in other seasons. The addition of wind energy can reduce costs at today's market prices, but its seasonal generation profile merely creates more surplus energy in months when Highgate Falls already generates surplus supplies. This leaves firm hydro as an option that can be purchased in different quantities throughout the year. This product could be made to fit the load, but it would almost certainly command a price premium for being firm and renewable.

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

TRANSMISSION SYSTEM DESCRIPTION

SED owns approximately 6.2 miles of 46 kV transmission line. This line connects Highgate Substation, Elm Street Substation, and Leader Substation and has a feed to the Swanton Peaking generator unit. This line connects the Highgate Substation and the Elm Street Substation to the VELCO Highgate Substation at the east end and can also make a connection to the VEC Island circuit at the western end. The SED system can also be configured and split up so that the Elm Street Substation can be on the VEC Island circuit, and the Highgate Substation can be connected to the VELCO Substation. This dual feed into the SED system creates the ability for SED to have two different sources feed these substations. The transmission line is located in the towns of Highgate and Swanton. The circuit consists of 4 miles of 336 ACSR conductor with an additional 0.4 miles of 336 ACSR conductor connecting the Swanton Peaking generating project's transformer. There are also 1.8 miles of 4/0 ACSR conductor connecting the 46 kV lines on Route 78 to the Leader Substation mainly via a cross-country path.

SED has a SCADA (Supervisory Control and Data Acquisition) control over both the transmission switches and the substation reclosers.

DISTRIBUTION SYSTEM DESCRIPTION

The distribution system includes approximately 120 miles of line operating at 12.5 kV located in the Village of Swanton, towns of Swanton, Highgate, and St. Albans.

SED-OWNED INTERNAL GENERATION

History of the Orman Croft Hydroelectric Plant – "Highgate Falls":

The Highgate Falls power dam has been a dependable source of power for the evolving energy needs of northwestern Vermont since 1894. By the early 1900's, the facility played an important role in providing electricity to the citizens of Swanton and Highgate, and through regular maintenance and equipment upgrading, has retained that position.

The first dam at Highgate Falls was built during the late 1700's by private entrepreneurs to power the saws, mill stones, and forges of the various businesses occupying the Highgate Falls site. In 1894, Swanton Village purchased the rights to develop the site for hydroelectric power.

In 1915, the Vermont General Assembly authorized Swanton Village to develop its water power at Highgate Falls and for that purpose to build, construct, and maintain a suitable power plant or improve its present plant with all buildings, dams, flumes, and other equipment necessary and to borrow money or issue bonds for that purpose. Numerous improvements were made to the project and by 1920, the project structures included a concrete dam, woodstave penstock, concrete surge tank, and powerhouse. The powerhouse contained two 900 kw generating units, necessary switchgear, and transmission terminal equipment. The original dam was constructed to elevation 164.8 feet above sea level and had provisions for five feet of flashboards, giving the dam the potential for a maximum power pool at elevation 169.8 ft asl.

The flood of November 1927 brought waters 17 feet over the dam. There came a period of modification and refurbishment which began with the installation of a 900 kW Westinghouse generator (initially operated in 1928) in the unit # 2 position. During the early thirties, a steel surge tank was built inside the existing tank, and butterfly valves were installed between the generating units and the surge tank. The addition of a General Electric 900 kW generator (initially operated in 1932) in the powerhouse unit # 1 position completed the configuration until the 1950s.

The 1952-1954 changes included reshaping the dam cross section, raising the pond level from elevation 169.8 ft. (above sea level) to 170.8, construction of a new intake facility and conduit system, raising the height of the steel surge tank and expanding the powerhouse to enable the 1954 installation of a Westinghouse 2,800 kW generating unit.

In 1986, the three generating units went through a major overhaul to improve their generating performance. In 1990, another phase of powerhouse improvement was completed. The powerhouse was once again increased in size and a National Industrial generating unit with a capacity to produce 5,800 kW was installed in the new area, as well as new switchgear, and computerized controls. This phase of the project was dedicated to Orman E. Croft who, at the time, was the Village Manager for the Village of Swanton. A few years later, another major change at the dam site would take place. In 1994, the most recent phase of improvement was completed. The intake structure was raised to elevation 193 ft. also, a new trash rake was installed, a new dam site powerhouse was built, and as for the dam; the elevation of concrete was brought up to elevation 175 ft. and an inflatable rubber dam provided by Bridgestone was installed on top of the concrete. The addition of the rubber dam brought the pond level up to elevation 190 ft. as it remains today. In August 2018, the Bridgestone rubber dam was replaced by one manufactured by HydroTech.

In 2011, a 5th turbine and generator was installed into the overflow power house. The installation of this unit was the final step of the upgrades started in 1994 but was halted due to budget restrictions. The 5th turbine went into production on March 13, 2012.

About the Orman Croft Hydroelectric Plant:

The Orman Croft Hydroelectric Plant consists of five hydroelectric generators with the following characteristics as a combined operating system:

Capacity: 9.85 Megawatts (total of all units generating simultaneously).

2018 Annual Production: 33,062 MWH.

Water Flow: 1,800 cubic feet of water per second.

Minimum Flow at bypass: 35 cfs, 200 cfs at the tailrace

Head Water Elevation: 190 feet above sea level.

Tailwater Elevation: 105 feet above sea level.

The whole is less than the sum of its parts. In other words, when the units are generating simultaneously, the maximum total output is lower than that maximum total output of each unit if each unit were generating separately.

Output Capacity for each Generator:

"Rated kW" signifies the actual output kW capacity of the generator, not the kW nameplate rating.

Unit # 1: General Electric AC Generator installed in 1930. Excitation is provided by a Basler static exciter. Voltage: 7200 volts, Speed: 360 revolutions per minute, Cycles: 60hz., Phase: 3, Power Factor: 0.8, rated kW: 1,170 Kilowatts. The Turbine unit is a Francais type, Rated Horsepower: 1,340 hp, Discharge: 224 cubic feet of water per second.

Unit # 2: Westinghouse AC Generator installed in 1928. Excitation is provided by a Basler static exciter.

Voltage: 7200 volts, Speed: 360 revolutions per minute,

Cycles: 60 hz., Phase: 3, Power Factor: 0.8, rated kW: 1,012 Kilowatts. The Turbine unit is a Francais type.

Rated Horsepower: 1,340 hp, Discharge: 224 cubic feet of water per second.

Unit # 3: Westinghouse AC Generator installed in 1954. Excitation is provided by a Basler static exciter.

Voltage: 7200 volts, Speed: 257 revolutions per minute.

Cycles: 60 hz., Phase: 3, Power Factor: 0.8, rated kW: 3,420 Kilowatts. The Turbine unit is a Francais type,

Rated Horsepower: 4,070 hp, Discharge: 558 cubic feet of water per second.

Unit # 4: National Industrial AC Generator installed in 1990. Excitation is provided by a Basler static exciter.

Voltage: 7200 volts, Speed: 211.8 revolutions per minute, Cycles: 60hz, Phase: 3, Power Factor: 1.0, performed kW: 4,994 Kilowatts. The Turbine unit is a Francais type, Rated Horsepower: 7,600 hp, Discharge: 900 cubic feet of water per second.

Unit #5: OSSBERGER turbine, Hitzinger generator: construction and installation into minimum flow building in September 2011, and in production on March 13, 2012. Unit is a horizontal intake, horizontal shaft double cell, cross flow design impulse type turbine, with draft tube effect. Rated at static Head =44.6ft=13.6m. Full flow= 200cfs, partial flow= 35cfs. Normal speed 900 rpm with an over speed of 2010 rpm. Apparent power is 650 kVA at full flow with a frequency of 60Hz. Rated kW: 484 Kilowatts.

SED SUBSTATIONS

SED owns and operates three substation facilities. Each substation is briefly described below.

Elm street Substation:

The Elm Street Substation consists of a 10,000 kVA step down transformer from 46 kV primary to 12,470/7,200 volt grounded secondary. There are three reclosers that feed the load normally fed from this substation. The reclosers are ABB vacuum units that also have potential transformers tied to them to take advantage of their microprocessors for data gathering. SED downloads the load data monthly to see what the load balance is as well as what the system power factor on each circuit is. This allows for the correct sizing of capacitor banks for each circuit. SED presently maintains each circuit power factor range between 92 and 97 percent. As stated before, the controls of these reclosers are self-standing but also are operated by remote control by SCADA.

Highgate Substation:

Highgate Substation is located at the Highgate Falls generating station. The transformer at this site is a 15,000 kVA step down with a 46 kV primary and 12,470/7200 volt grounded secondary. There are three remotely-controlled load circuits. The load data is recorded from this location as well. In addition to these three load circuits, the power plant generation is connected to this bus by way of an underground circuit that goes to a 10,000 kVA transformer with a primary voltage of 12,470/7,200 volt grounded primary with a 7,200 volt delta secondary. The operational voltage for the five hydro generators at this location is 7,200 volts delta.

Leader Substation:

The Leader Substation was originally built by Vermont Fasteners for their heat treat hardening process of their product. It was later purchased by SED from Leader Evaporator Co. when it purchased the building from Vermont Fasteners. The transformer is rated at 49.2 kV delta to 13.8Y/7.968 kV with a 7,500 kVA base load capacity. The transformer was configured to operate as close as possible to SED's system requirements and three GE VR1 voltage regulators were added to the step-down side to maintain the proper system voltage requirement. Located between the transformer step down points and the regulators is an ABB vacuum recloser that provides fault protection and data collection which is all accessible and remote controlled by SCADA. This load circuit has a power factor range of 98 to 100 percent.

CIRCUIT DESCRIPTION

Table 16: SED Circuit Description

Circuit Name	Description	Length [11](Miles)	# Customers by Circuit	Outages by Circuit 2021
1200	12.4 kV three-phase branching to 7,200 Volt single-phase	17.3	258	1
1201	12.4 kV three-phase branching to 7,200 Volt single-phase	16.8	876	6
1202	12.4 kV three-phase branching to 7200 Volt single-phase	4.3	783	7
1203	12.4 kV three-phase branching to 7,200 Volt single-phase	27.6	512	10
1204	12.4 kV three-phase branching to 7200 Volt single-phase	35.6	448	9
1205	12.4 kV three-phase branching to 7200 Volt single-phase	5.7	352	3
L50	12.4 kV three-phase branching to 7200 Volt single-phase	12.9	539	2

There are seven circuits in total. The voltage of the circuits is regulated at the substation bus. SED does not consider any of its circuits as particularly long.

The circuit with the greatest frequency of outages on it, in 2021, was circuit 1203, where there were ten outages in total. Animals caused seven of the ten outages. Accidents, trees, equipment failure each caused one outage.

T&D SYSTEM EVALUATION

System reliability is important to SED and its customers. SED has a number of initiatives underway to improve reliability. Each of these initiatives is summarized below.

[11] Estimated from circuit maps

Outage Statistics

SED tracks all outage statistics as part of its Service Quality Reliability Plan (SQRP). These outage statistics allow us to examine causes by circuit and develop plans for the most cost-effective reliability improvements. The following table summarizes SAIFI and CAIDI results for the past 5 years. SED's Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years in their entirety, can be found at the end of this document.

Table 17: SED Outage Statistics

	Goals	2017[12]	2018	2019	2020	2021
SAIFI[13]	**2.4**	0.3	1.0	1.4	0.5	0.4
CAIDI[14]	**2.5**	1.0	1.5	0.7	1.5	1.7

RELIABILITY

SED added a 48 kV motor operated air switch between the VELCO and Highgate substations, improving reliability by greatly reducing the length of outages on the transmission system, reducing dependence on external systems and enhancing the ability to back-feed the Highgate circuits from the Elm Street Substation following a disturbance on the transmission.

ANIMAL GUARDS

SED believes that animal guards are a cost-effective means of reducing animal contact and the associated service interruptions. SED utilizes animal guards on its system to protect

[12] SAIFI and CAIDI statistics shown are net of major storm outages

[13] System Average Interruption Frequency Index

[14] Customer Average Interruption Duration Index

against outages. Animal guards are installed in all new installations, where appropriate and animal guards are retrofitted on existing equipment after an incident has occurred.

FAULT INDICATORS

SED currently uses fault indicators in the industrial park underground. SED typically utilizes them for developments where there is more than one transformer. One of the benefits of fault indicators is a quicker response time for troubleshooting and repair. As a result, SED's system reliability and customer satisfaction improves.

AUTOMATIC RECLOSERS

SED uses automatic reclosers to attempt to re-establish service after short-duration outages. Also, SED fuses all its tap lines.

POWER FACTOR MEASUREMENT AND CORRECTION

SED monitors the power factor on each individual circuit on a weekly basis. The individual distribution circuits and the system maximum, minimum, and average power factors are calculated from the monthly downloading of data from the distribution feeder controls at SED's substations. SED maintains a power factor of 95 percent or higher. There is no need for power factor correction at this point in time.

DISTRIBUTION CIRCUIT CONFIGURATION

VOLTAGE UPGRADES

SED is not planning any voltage upgrades at this time.

PHASE BALANCING

SED monitors each circuit's neutral current and phase current and also physically moves load from one phase to another.

FEEDER BACK-UPS

All of SED's circuits are able to be fed from multiples directions because of gang-operated 3-phase distribution switches which allows for connecting from one circuit to another.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

PROTECTION PHILOSOPHY

SED's sub transmission is protected by fuse protection. The three-phase main feeders are protected by reclosers and by the presence of down system protection fuses. If SED observes that load is growing in a specific area of the system, it monitors with load loggers and adjusts fuse sizes as necessary. SED displays the values of the fuses at bottom of the poles. Presently, fuse coordination occurs on the individual circuits at the time of modification. Fuse values are traced back to the feeder, current readings on the circuit are measured over a period of time and then the correct fusing that coordinates with the upstream values are chosen. SED is currently in the process of implementing a system-wide GIS mapping application which will enhance SED's ability to optimize protection systems and fuse coordination. SED has a contract with MPower to "resurrect" SED's old GIS system and overlay it onto a newer, more functional and user-friendly version. SED needs to verify accuracy of the data and fine tune the GIS coordinates, pole attachments and transformer data. SED is working with VPPSA's GIS Technician to continue to update the data and schema to match the other VPPSA member utilities.

SMART GRID INITIATIVES

PLANNED AMI

Beginning in 2018, SED began participating in a multi-phased, VPPSA joint-action project intended to assess individual member readiness for AMI, guide participating members through an RFP process culminating in vendor and equipment selection and implementation.

Vermont Public Power Supply Authority (VPPSA) contracted with Lemmerhirt Consulting to evaluate its member utilities readiness for an Automated Meter Infrastructure (AMI) in its territory. This effort was to provide a current assessment of business processes, systems, and equipment in place that would be impacted by AMI and evaluate the suitability, uses, challenges, and benefits for AMI at SED. Since the Village of Swanton provides both electric and water services, this evaluation covered an AMI implementation for both services. AMI is a major technical and business transition for any utility and provides a platform to improve operational efficiency, reliability, and customer service, including new functionality such as time-of-use or dynamic rate plans for customers, demand response programs, grid management improvements, and greater customer engagement.

Lemmerhirt Consulting visited and interviewed each member utility, gathering data from utility staff and driving around the service territory to assess challenging geographic areas for AMI suitability. The Readiness Assessment addressed ten functional areas in some detail, rating the member system's readiness for each functional area according to the following criteria:

Table 18: AMI Readiness Assessment Criteria

Readiness	Definition
Good	The effort, cost, IT, business change, and training requirements are all low and achievable by the utility. The benefits to the utility of AMI surpass the challenges.
Fair	There is some effort, cost, business change, or training required; one or more areas may require significant change.
Difficult	The effort, cost, change to the business and IT, and training requirements are all significant for the utility. There are not many benefits of AMI to the utility.

The rating is an indication of the level of potential challenge associated with each functional area for an AMI implementation. Awareness of the effort, potential cost, and requirements can inform the utility in its business decision to pursue an AMI implementation.

For a successful AMI project, the utility team and staff must be interested and receptive to adopting new technology and new ways of doing business. SED recognizes emerging requirements and value for AMI in offering more customer services such as time-of-use rates and self-service options; measuring and monitoring new technology - electric vehicles, distributed generation; distribution grid improvements by adopting programs like

Conservation Voltage Reduction or Volt/Var Reduction. Since the Village of Swanton provides water service, there is the benefit of adding water metering to the solution, ultimately strengthening an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 19: AMI Readiness Evaluation

Overall AMI Readiness	Rating
Electric Meter Readiness	Fair
Water Meter Readiness	Fair
Meter Reading Readiness	Good
Billing and IT Readiness	Fair
Customer Engagement Readiness	Fair
Electric Distribution Readiness	Good
Outage Management Readiness	Fair
Water Distribution System Readiness	Good
Telecommunications Readiness	Good
Asset Data Readiness	Fair
Overall	Fair

Following the Readiness Assessment, an RFI was developed and issued to multiple vendors with an eye toward learning more about potential available solutions and identifying well qualified partners. The Respondents to the RFI were required to describe the general AMI solution(s) being proposed, the respondent's experience with AMI systems and whether their proposed solution(s) included functionality for water system operation and could be shared by all VPPSA members and centrally operated. Further detail regarding the respondent's experience, contract negotiation process, product roadmap and project management/professional services capability was also requested.

In broad terms the "must have" features for proposed solutions included the following features:

- Support both Electric & Water meter operations,
- Support multiple meter manufacturers,
- Multiple communication options to address hard to reach areas,

- Service level agreement,
- Hosted software solution for required Head End, Meter Data Management System (MDM) etc.,
- Multi-tenant software – segregate multiple members data in central database
- Support distribution automation/management capabilities

In support of these goals respondents were asked to respond to a series of detailed technical questions (See Appendix D – AMI RFI Technical Requirements) with respect to:

- Electric & Water Meters
- The AMI network/communication
- Head end software, MDM capabilities and other system tools
- Water system functionality and
- Project Plan & pricing

VPPSA received responses from 7 vendors which were evaluated by a team made up of a mix of about 20 VPPSA /Member management, staff, and consulting personnel. Members of the evaluation team reviewed the RFI responses to the detailed technical questions for completeness and "fit" and assigned a numerical ranking to each. Ultimately, the rankings were aggregated, and the three highest scoring vendors were selected to participate in the subsequent RFP.

Subsequent to evaluation of the responses to its RFI, VPPSA issued an RFP to three chosen vendors; Aclara Technologies (Aclara), Hometown Connections Inc, and Landis & Gyr. Respondents were asked to "…fully address the requirements of this solicitation related to performing all required work, including site assessment, drawings and document submittals, manufacturing, testing, delivery, and technical support during and after installation. This general statement of scope aligned with the RFP's stated selection criteria:

Proposals will be reviewed, evaluated, and ranked utilizing the following criteria:

- Price (20%)
- Experience Qualifications (15%)
- Technical and Non-Technical Requirements (30%)

- Project Delivery (15%)
- Ongoing Support (20%)

VPPSA reserved the right to award this contract to the Proposer providing the best overall match to the RFP requirements and which best serves the interest of VPPSA and its members.

Key requirements for the RFP were similar to those mentioned above for the prior RFI with emphasis on a hosted software solution that included functionality for both electric and water meters to be centrally purchased and share the same network with no collector device being a single point of failure, have one set of software licenses and have all data in a common, multi-tenant database with the ability to view individual member data and also access data as a group. In addition, the AMI solution was required to deliver data to each member's CIS. The detailed technical requirements are provided for reference in Appendix E (AMI – RFP Technical Requirements).

During the evaluation phase the three vendor responses were reviewed, discussed and scored by a group of about 20 staff and management personnel drawn from both VPPSA and individual VPPSA members. Early in that process the proposal from Landis & Gyr was eliminated from further consideration because it did not include the required MDM feature. Ultimately the Aclara proposal was selected for final contract negotiation; key factors in the Aclara proposal's favor included its fully integrated, single vendor aspect and its ability to meet several key requirements including:

- Single License (not separate licenses for individual VPPSA members)
- A hosted multi-tenant head end and MDM
- Inclusion of propagation study – confidence around cost estimates
- Licensed RF communication system; better penetration
- Reporting flexibility
- Customer support

The proposed Aclara system relies on a two-way, fixed base RF network that provides its meter-reading solutions through a secure, long-range wireless network using private licensed radio channels in the 450 - 470 MHz band. Built-in redundancy through multiple collection and processing paths without the use of repeaters prevents single-point failures from disrupting normal operation of the entire network. A failure of one DCU network device does not affect the entire network. The Aclara RF network uses conservative design, built-in redundancy, and continuous operation of multiple communication routes to prevent single-point failures from disrupting normal operation. The Aclara ONE headend and meter data management (MDM) system is hosted, multi-tenant software that will allow VPPSA members to see only their own data while providing VPPSA with an overview of the entire network and total distribution of electric and water across all members.

SED expects to benefit from AMI implementation in a number of ways:

- Collection of interval data to support cost of service and innovative rate design
- Offer energy programs for customers to promote beneficial load management
- Increase customer engagement in their use of electricity and water resources,
- Planning of future capital/T&D system investment strategies
- Comply with future regulatory and legislative requirements
- Reduction of overall meter reading impacts on staff and time
- Improve re-read needs and billing errors
- Reduce cost of non-pay disconnect/reconnect, move-in/out (off-cycle reads)
- Improve billing and customer care services
- Identify and reduce theft of service
- Improve accuracy of electric and water metering
- Optimize electric metering benefits such as transformer right-sizing
- Improved system planning capabilities and water resource management
- Improved water distribution system asset performance
- Reduced carbon footprint

In terms of business case, a cost benefit assessment, looking at about 20 areas of potential benefit, spanning field operations, metering and meter operations, billing, and customer and related rate programs was performed. This assessment indicates a positive NPV benefit of more than $1,700,000, with a positive cost-benefit ratio of 1.88 and a 5.7-year payback, providing Swanton with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of any anticipated, but unconfirmed, state funding opportunity. While negotiation of a final contract with Aclara is ongoing at this time, Swanton is optimistic that it will begin implementation of a new AMI system in early 2023, to be completed by year end 2023.

GEOGRAPHIC INFORMATION SYSTEM

Recently, VPPSA has taken major steps forward in developing centralized geographic information system (GIS) utility mapping and data management programs. A new service offered in 2020, centralized GIS mapping maximizes efficiencies by standardizing data across member utilities and reducing the amount of time required to maintain map data. It additionally allows VPPSA to develop analytics, mapping deliverables, applications and field data collection tools. Through these assets each member utility empowers VPPSA to proactively manage their data and mapping capabilities. The VPPSA GIS program kicked off with hiring a GIS Administrator to join the Technology and Security Services Department. VPPSA's new administrator worked with each utility to identify strengths and short comings with their existing data and to plan for further data collection and/or updates where needed. Three categories of GIS maturity were identified across the membership, and a plan was developed to advance each group's status such that all VPPSA's members will have consistent capabilities and data standards. VPPSA GIS is in the process of implementing new and exciting GIS capabilities to allow affordable mapping solutions. Helped by a combination of partnerships with mPower innovations and the use of ESRI technologies, the final result culminates in a highly accurate, user friendly and affordable mapping solution for VPPSA's current and future members. These capabilities ensure that VPPSA members' GIS capable data solutions and mapping tools are connected to a variety of utility data such as AMI meter readings, spatially aware billing records, geospatially based load/voltage analysis, interconnection studies, and other insights into energy use trends. VPPSA members will also benefit from an enhanced situational awareness of infrastructure, asset life cycles, preventive maintenance, and vegetation management via real-time updates to data using VPPSA created mobile collection tools.

CYBER SECURITY

2020 was a cybersecurity turning point for many industries around the globe as nefarious digital attacks threatened to hold organizations hostage and utility regulators at the state and federal level increased focus on cybersecurity. SED is mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While SED is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and SED's membership in VPPSA provides SED with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, SED endeavors to purchase and protect its IT systems (with assistance from VPPSA as needed), in a manner intended to minimize security risks to the system and its ratepayers.

VPPSA has initiated a cyber program that all members have access to and is working with each member individually to determine what the best approach is given individual member resources. VPPSA's Technology and Security Services team continues to work with its vendor consultants, developing cybersecurity hygiene and best practices to protect VPPSA and those of its members who choose to take advantage of it.

SED and VPPSA remain mindful of the balance between the levels of cyber security risk protection and the associated costs to its ratepayers. VPPSA assists its members in pursuing and coordinating funding opportunities for various purposes, such as cyber security assistance and many other programs, to help its members reduce costs to their customers.

OTHER SYSTEM MAINTENANCE AND OPERATION:

RECONDUCTORING FOR LOSS REDUCTION

SED's strategy for improving system efficiency involves monitoring actual system losses and implementing system improvements to reduce system losses. After the ice storm of 1998, SED's full system was re-conductored with lower loss conductors.

When it comes to re-conductoring lines with lower loss conductors the advantages of the costs associated with lower loss conductors must be balanced against the higher costs associated with their purchase. SED assesses system performance vs. the cost of system reconductoring in making these equipment choices.

TRANSFORMER ACQUISITION

SED replaced many of its transformers after the major ice storm of 1998. It is SED's practice to always buy new transformers, rather than used transformers. In its transformer purchase analysis, SED compares the transformers of three manufacturing companies. Price is a primary factor; efficiency is taken into account. SED tries to buy U.S.A made transformers where possible. When SED gets a quote for a transformer, the vendor provides data on no load losses, load losses, and total losses. SED factors in this data with the cost of the transformer before making the selection. SED does not use the Department's life-cycle cost spreadsheet, but it would be willing make use of it if the Department wanted to share it with them.

CONSERVATION VOLTAGE REGULATION

Elm Street Substation and Leader Substation both have voltage regulation equipment. The Highgate Substation currently does not have conservation voltage regulation equipment on it. SED has evaluated the cost/benefit analysis of installing conservation voltage regulation in the Highgate Substation, and it has determined that it would be cost prohibitive to do so.

The goal for end-of-line voltage is to stay within the bandwidth of 2.5% on either side of the 120 Volts. It's monitored by the regulators, LTC, and by VELCO, and by taking voltage readings at different intervals.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

SED monitors distribution transformer load management via SCADA and makes changes as necessary.

SUBSTATIONS WITHIN THE 100- AND 500-YEAR FLOOD PLAINS

None of SED's three substations fall within the 100- and 500-year flood plains.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

The majority of SED's lines are overhead lines. As the quantity of SED's underground lines increase, SED will become increasingly more involved with the Damage Prevention Plan. SED requires inspection of all underground lines prior to burial. This will be performed by SED's employees. SED does the same thing for itself (internally) as it does for Dig Safe. SED follows and will continue to follow the Dig Safe rules.

SED has collaborated with the Department of Public Service and VPPSA to develop a draft Damage Prevention Plan and filed it with the Department of Public Service in April 2018.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

When replacing transmission and distribution equipment, SED solicits multiple quotes before making a purchase. SED installs equipment that is tried-and-true. These purchases are based on pricing and reliability.

MAINTAINING OPTIMAL T&D EFFICIENCY

System Maintenance

SED performs annual oil checks on transformers, weekly substation inspections, and has thermal imaging devices in the field.

Substation Maintenance

SED performs annual oil checks on transformers and substation regulators as well as weekly inspections (using the form, below) of the substation in its entirety.

Figure 20: SED's Substation Inspection Form

SWANTON VILLAGE ELECTRIC DEPARTMENT SUBSTATION INSPECTION REPORT

DATA DATE:	RECORDED BY:	INSPECTION DATE:	INSPECTED BY:

RECLOSER DATA:

	INSTANTANIOUS CIRCUIT CURRENT				MAXIMUM CIRCUIT CURRENT				INSTANTANIOUS CIRCUIT VOLTAGE			COUNTER	PF	DMD.	BATTERY		NO PHYSICAL PROBLEMS
VR	PHASE A AMPS	PHASE B AMPS	PHASE C AMPS	NEUTRAL AMPS	PHASE A AMPS	PHASE B AMPS	PHASE C AMPS	NEUTRAL AMPS	PHASE A KV	PHASE B KV	PHASE C KV	READS OPS.		RST?	UPS OK?	Δ Vdc	
S-50																	
1200																	
1201																	
1202																	
H-50																	
1203																	
1204																	
1205																	
L-50																	
SOLAR RECLOSER DATA:																	
SANDPIT																	
CC500																	

TRANSFORMER AND AREA INSPECTIONS:

XFMR	LIQUID TEMP:	MAXIMUM LIQUID TEMP:	LIQUID LEVEL:	GAS GA.:	LTC LIQUID LEVEL:	LTC TAP POSITION:	LTC TAP MIN.:	LTC TAP MAX.:	LTC COUNTER:	WINDING TEMP.:	MAXIMUM WINDING TEMP.:	BUSHINGS CLEAN & OK ?	RESET MAX TEMP. INDICATORS?	TAP POS		FANS ON AUTO?
2665														3		
1715														3		
1505														2		
2548														1		

XFMR	FAN HOURS METER:	HEATERS IN OP. ?	SUBS.:	LIGHTNING ARRESTORS GOOD ?	ALL SWITCHES CLOSED?	DISCONNECT CONTACTS CLOSED?	INSULATORS IN GOOD COND.?	TANK OIL FREE?	SNOW PLOWING REQUIRED?	GATES CLOSE OK?	TRANS. FUSES OK ?	SPARE FUSES STORED OK?	PROBLEMS AND CONCERNS:
2665			ELM ST.										
1715			HG-UPPER										
1505			HG-LOWER										
2548			LEADER										

LEADER SUBSTATION REGULATORS:

PHASE:	#:	TAP POS.:	MIN TAP POS.:	MAX TAP POS.:	RESET HANDS ?	TOTAL OPS COUNT:	LOCAL VOLTS:	SOURCE VOLTS:	POWER FACTOR:	TANK OIL FREE ?	BUSHINGS OK ?	DOOR SEAL GOOD ?	PROBLEMS AND CONCERNS:
A	2552												
B	2551												
C	2550												

COMMENTS:

Pole Inspection

SED has an informal pole inspection program to assure that poles in its service territory are in good and reliable condition. Also, SED always inspects poles that are in the vicinity of normal field work. Due to the size of the system, SED has a good understanding of the age and condition of the poles. The implementation of SED's system-wide GIS mapping application will facilitate a more formal and systematic pole inspection tracking mechanism.

Equipment

SED evaluates its equipment through inventory stock. SED looks at trending and overall system performance.

Under SED's procurement & purchase policy, as previously mentioned, SED solicits three different quotes, before making a purchase. Also, under this policy, multiple quotes are required before making any planned purchase that exceeds ten thousand dollars.

Actual System Losses

In order to reduce line losses, SED converted the system voltage of three circuits in the village in early 2000. From 2001 to present, reconductoring has helped SED reduce line losses from just over 5% to 2.44% in 2018. SED has recently completed reconductoring the last two sections of its system that needed to be reconductored. At this point SED's lines are all fairly new and opportunities to further reduce losses are limited. SED will monitor system losses, with an eye toward identifying further loss reduction opportunities in the short term. In the longer-term SED seeks to proactively identify the point at which initiating another full-scale reconductoring process is warranted.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

SED currently uses the NJUNS database to track transfer of utilities and dual pole removal.

Relocating cross-country lines to road-side

SED relocates cross-country lines to road-side locations, where cost-effective, in order to reduce maintenance and outage costs as well as in order to reduce impacts. It is SED's plan to continue with this process.

DISTRIBUTED GENERATION IMPACT:

Currently, SED has in excess of 41 solar net metering customers, with a combined total installed capacity of 1,290 kW. There are also two projects of more than 500 kW each, with no direct regulation from SED. These net metered installations provide energy credits for municipalities within Highgate and Swanton, such as schools.

Interconnection of Distributed Generation

SED recognizes the unique challenges brought on by increasing penetration levels of distributed generation. SED adheres to the procedures set forth in Rule 5.500 for the interconnection of new generation. Per rule 5.500, a fast-track screening process is utilized to expedite the installation of smaller generators which are less likely to result in issues that affect existing distribution customers. If a proposed installation fails the screening criteria, a Feasibility Study and/or System Impact Study is performed to fully identify and address any adverse effects that are a direct result of the proposed interconnection. These studies, performed by SED or their representatives, typically include a review of the following issues that may arise as a result of a new generator interconnection:

- Steady state voltage (per ANSI C84.1)
- Flicker (per IEEE 1453)
- Temporary overvoltage due to load rejection and/or neutral shift

- Effective grounding (per IEEE 1547 & IEEE C62.91.1)
- Overcurrent coordination
- Equipment short circuit ratings
- Effect of distributed generation on reverse power and directional overcurrent relays
- Voltage regulator and load tap changer control settings (bi-directional operation)
- Unintentional Islanding
- Thermal loading of utility equipment
- Power factor and reactive compensation strategy
- Impact to underfrequency load shed
- Increased incident energy exposure (arc flash)

In addition, recognizing that the aggregate of many smaller installations which individually pass Rule 5.500 screening criteria can present problems that would otherwise go unnoticed, SED will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow SED to periodically review how much generating capacity is installed on a particular feeder or substation transformer and identify any concerns as penetration increases over time.

For example, one issue of growing concern is the aggregate of smaller distributed generators being large enough to require voltage sensing on the primary side of substation power transformers for ground fault overvoltage protection. If a transmission (or sub-transmission) ground fault occurs and the remote terminals operate to clear the fault, an overvoltage due to neutral shift can occur when the ratio of generation to load in the islanded portion of the system is greater than 66% (presumes a standard delta primary, grounded-wye secondary substation power transformer). SED continues to monitor trends for interconnection protection for abnormal conditions. Supplementing the process outlined in Rule 5.500 with detailed recordkeeping and periodic reviews of how much distributed generation is installed by feeder will help member utilities identify these types of issues before they occur.

As distributed generation penetration increases within SED's service territory, SED may consider performing a system-wide hosting capacity study and/or providing hosting capacity maps as a tool to steer development of future medium to large-scale distributed generation to the most suitable locations. This type of hosting study can result in significant up-front costs that must be borne by SED. As a reasonable compromise, SED may suggest that potential developers locate facilities within reasonable proximity to an existing substation and within portions of the system with low penetration levels of existing distributed generation, both of which should increase the likelihood that the facility will be able to successfully interconnect.

Inverter Requirements

Consistent with ISO New England requirements related to inverter "ride-through" settings, SED now requires owners/developers of all new DER installations to self-certify installation of inverters compliant with the Inverter Source Requirement Document (SRD) of ISO New England, with settings consistent with IEEE 1547-2018 and UL 1741 SA. SED recognizes the need to standardize efforts aimed at certifying inverter compliance with the ISO SRD and will work with VPPSA and the PSD to achieve use of common forms and process in this regard.

DISTRIBUTION-LEVEL IMPACT OF ELECTRIFICATION

SED recognizes that developing and maintaining a distribution system capable of integrating both distributed generation and developing load concentrations resulting from beneficial electrification is a coming challenge. As electric vehicles, heat pumps, heat pump water heaters, electric mowers and other measures become more common, the need to upgrade or proactively manage portions of the distribution system is expected to increase. SED is focused on the challenge of identifying and tracking "hot spots" on the system as they develop, with an eye toward formulating timely responses, whether those be load management efforts, equipment upgrades, or addition of generation/storage at key locations.

The SED distribution system currently has sufficient capacity for the immediate foreseeable future. Table 20 indicates, SED has a moderate number of small solar projects on its system along with two large 500 kW units attached to the Elm St Substation. Maximum loading on the Highgate substation transformer is currently about 26% of it's nameplate capacity and about 19% on average. The Elm Street and Leader substations show maximum loading of 42% and 22% of nameplate capacity, respectively, and average loading between 17% and 31% of nameplate.

Table 20: SED Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity	Peak % of Nameplate	Avg Weekly Peak % of Nameplate	CIRCUIT/ FEEDER	Circuit Voltage Kv	Solar/Hydro Dist. Generation # of Units	Solar/Hydro Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
Highgate Substation	1	16.0 MVA	26%	19%	1203	12.47	12	95		114	60,680
					1204	12.47	6	51		468	206,200
					1205	12.47	3	20		80	21,440
					Highgate Falls 1-4	12.47	4	9,800			
					Highgate Falls 5	12.47	1	479			
Elm St Substation	1	14.9 MVA	42%	31%	1200	12.47	2	1,000		664	247,030
					1201	12.47	4	25		2,216	653,980
					1202	12.47	4	19		79	26,350
Leader Substation	1	11.2 MVA	22%	17%	L50	12.47	8	70		2,217	702,520
Prescriptive (HP,HPWH,etc) TIER 3 has limited availability											

We know from the Demand Chapter[15] that the transformers at SED's Substations are not likely to become a constraint. Even when EV and HP penetration reaches high levels in the early 2040s, the peak load is forecast to be well below the transformer ratings. Furthermore, because conductor size is calculated based on the transformer rating, it is also unlikely that conductor size is going to be a constraint. One of the primary lessons learned from Washington Electric Cooperative's (WEC) ongoing PowerShift Electric Vehicle Charging Equipment (EVSE) pilot with Efficiency Vermont (EVT) was that addition of one or more uncontrolled EV charger(s), heat pump(s) or storage device(s) could stress transformers at the service drop level, necessitating

[15] See 'Peak Forecast Results,' pages 23-24.

an unanticipated upgrade. It was also a conclusion that was reached by GMP in their 2021 Integrated Resource Plan.

While the anticipated pressure point is at the service drop level, the upstream distribution system is adequate for the near future; electrification impacts have yet to become a critical issue at the substation level. In recognition of the potential stress on its system, SED is exploring sources of data readily available in the short term, that will help identify locational trends, facilitate early identification of and inform proactive responses to, developing concentrations of electrification-driven load.

At the present time SED tracks customer adoption of electrification measures based on data captured from past and current incentive programs. This incentive-program driven dataset provides a significant amount of information regarding the magnitude and approximate locational trends of electrification driven load. SED is able to track installed electrification measures associated with incentive programs, by street address, within the SED system. Use of this dataset in the short run assists the development and analysis of historic deployment patterns as well as anticipating penetration patterns. While this data currently shows a very limited level of penetration that is evenly scattered across the SED system, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to SED's responses to expected electrification impacts on its distribution system.

The current incentive program tracking effort is relatively simple and while it provides limited information, it serves a current need. SED anticipates that implementation of integrated AMI and GIS systems over the next couple years will provide the ability for implementation of more sophisticated, timely and location-targeted distribution system planning, rate driven load management responses, including load control programs where appropriate, and development of forward-looking distribution system improvements designed to take advantage of opportunities to encourage cost-efficient and balanced load growth. As the anticipated AMI and GIS implementations reach maturity, SED will be in a position to systematically track and analyze transformer, circuit and substation loading on a locational basis and focus on exploiting the new system's abilities. The current incentive tracking effort will become less critical as SED's ability to measure and analyze load, in something close to real time, from substation down to customer delivery points, comes into play. The improved data availability and analytical capability will facilitate SED's planning for appropriate distribution system development by enhancing SED's ability to:

- Monitor physical limits at substation, circuit and transformer levels,
- Identify areas of growing load concentration,
- Discern apparent penetration and deployment patterns of electrification measures based on actual metered load information at the customer level
- Identify developing spatial patterns of load growth that highlight opportunities to target distribution system upgrades that are cost effective, shape efficient system load growth, and further resiliency efforts.
- Develop effective strategies to implement appropriate load management programs including amount of and optimal location of storage facilities, innovate rate designs, and active load control/management programs.

As data from the new AMI/GIS systems becomes available, and detailed patterns of loading on the distribution system become more readily available, the time will be right for SED to commission a full T&D study to take stock of current system conditions and identify/prioritize required improvement projects.

VEGETATION MANAGEMENT/TREE TRIMMING

SED has a vegetation and brush management program with a schedule to routinely clear under its distribution lines. SED will undertake to review that program, utilizing inspections and feedback from its outage reports, to assure that the program maintains the vegetation and brush within its rights-of-way appropriately and to make modifications to the management program in the event that the program is not maintaining adequate clearances of brush from the lines.

First and foremost, SED visually inspects the system to determine the problem areas that need immediate attention. SED monitors its vegetation along the distribution and transmission lines annually. SED trims along its transmission lines approximately every three to five years and trims along the distribution lines about every five to seven years. SED has a spreadsheet that lists where and when it trims. SED's outage reports show that the trimming plans have been working successfully.

All lines are trimmed to the edge of the legal right-of-way. The trimming width on either side of the line is fifty feet.

SED has a firm budget on trimming, which is approximately $100,000 per year; the miles of trimming are determined during the inspections and are dependent on growth due to climate conditions. Eighty percent of the system is roadside, so monitoring is fairly simple. The other twenty percent is monitored on foot.

The trimming cycle used to be much longer, but Swanton shortened it in order to maintain adequate clearances of brush from the lines. Since the ice storm of 1998, SED has become much more aggressive with its tree trimming. SED's ratepayers have also become more in favor of tree-trimming, as it has seen first-hand the effects of what untrimmed trees can do to reliability of the system during an ice storm.

In addition to its vegetation and brush management program, SED has a program to identify danger trees within its rights-of-way and to either prune or remove those trees. Again, the success of this program is measured by whether danger trees are a root cause of system outages. Danger trees are identified by utility personnel while patrolling the lines, reading meters, or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within SED's right-of-way. For danger trees outside of the right-of-way, SED contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, SED will periodically follow up with the property owner to attempt to obtain permission.

Occasionally, SED finds that some trees are out of its reach. In those cases, SED hires a contractor to do the trimming work. The majority of tree species in SED's service territory are conifers, ash, white birch and maple.

The emerald ash borer has not yet become an active issue in SED's territory. SED is monitoring developments and coordinating efforts with VPPSA and VELCO and will make use of any guidance that becomes available as a result. If and when the emerald ash borer does surface in SED's territory, affected trees will be cut down, chipped and properly disposed of.

Table 21: SED Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Sub-Transmission	6.2 miles	0	3-5 year average cycle
Distribution	120 miles	20	5-7 year average cycle

Table 22: SED Distribution Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$100,000	$100,000	$105,000	$105,000	$105,000	$105,000
Amount Spent	$80,829	$86,338	$92,324	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	3.6 miles, 7 trees	1.9 miles, 24 trees	2.1 miles, 25 trees	5 miles to be trimmed	5 miles to be trimmed	5 miles to be trimmed

Table 23: SED Transmission Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$0	$10,000	$5,000	$5,000	$5,000	$5,000
Amount Spent	$5,600	$4,200	$0	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	12,500 sq. ft., partial span	0.1 miles, 1 tree	0 miles	miles to be trimmed	miles to be trimmed	miles to be trimmed

Table 24: SED Tree-Related Outages

[16]	2017	2018	2019	2020	2021
Tree Related Outages	4	8	13	5	6
Total Outages	47	65	42	47	38
Tree-related outages as % of total outages	9%	12%	31%	11%	16%

STORM/EMERGENCY PROCEDURES:

Like other Vermont municipal electric utilities, SED is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows SED to coordinate not only with public power systems in Vermont, but with those throughout New England. A SED representative is also on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties. SED uses the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. SED believes it is beneficial to inform the Department of Public Service if it is experiencing these types of outages.

PREVIOUS AND PLANNED T&D STUDIES:

Fuse Coordination Study

In 2008, John Askew of L.N. Consulting, Inc. assisted SED in the coordination of their electric circuit feeders and fusing. Final reporting was informal, and correspondence was carried out using email. Technical one-line diagrams and associated fault curves as well as recommended recloser control settings were included within the correspondence. Some fine adjustments have been made to recloser response settings, since the major coordination effort, to satisfy FERC, NERC, and ISO-NE requirements. Copies of the emails (12 pages) and technical drawings (13 pages) are available if desired.

[16] Statistics shown are net of major storm outages

System Planning and Efficiency Studies

Two twenty-year system studies have been conducted for SED. The first study was done in 1968, by Burns and Roe, Inc., and the second was done in 1996, by PLM Electric Power Engineering. The content of these two studies is available upon request.

At this point, SED does not have any system study plans. However, when renewable projects are proposed, a system study may be initiated to determine the impact. When a solar project is proposed, SED preforms a system study from the desired location to the VELCO/VEC connection. Any future studies will depend on growth resulting from additional loads and from generation projects.

CAPITAL SPENDING

HISTORICAL CONSTRUCTION COST 2019-2021

Table 25 Swanton Historic Construction Costs 2019-2021

Swanton Village Electric Department		**Historic Construction**		
Historic Construction		**2019**	**2020**	**2021**
Hydro	Prod	-	-	-
Station Equipments	Dist	-	-	13,367
Pole Replacements	Dist	27,468	19,656	56,433
Conductors	Dist	33,964	23,573	654
Transformers	Dist	43,471	20,851	16,204
Services	Dist	6,140	1,747	11,107
Meters	Dist	1,610	615	1,175
Security/Streetlighting	Dist	15,082	2,909	4,929
Office Equipment	Gen	6,838	-	-
EV Chargers	Gen	-	-	-
Vehicles	Gen	91,173	24,897	287,949
Misc Equipment	Gen	-	-	
	Trans	67,969	10,086	38,911
Total Construction		**$ 293,715**	**$ 104,334**	**$ 430,729**
Functional Summary:				
Production		-	-	-
General		98,011	24,897	287,949
Distribution		127,735	69,351	103,869
Transmission		67,969	10,086	38,911
Total Construction		293,715	104,334	430,729

PROJECTED CONSTRUCTION COSTS 2023-2025

Table 26 Swanton Projected Construction Costs 2023-2025

Village of Swanton Electric Department		Projected Construction		
Projected Construction		2023	2024	2025
Hydro	Prod	225,000		
Bucket Truck	Gen			
1 Ton	Gen	55,000		
Pole & Line Replacements	Dist	82,650		
Distribution Air Switch	Dist	11,500		
Transformers	Dist	35,000		
Transmission Air Switch & Operator	Trans	75,000		
Hydro	Prod		235,000	
Office & computing Equipment	Gen			
Pole & Line Replacements	Dist		103,960	
Distribution Air Switch	Dist		11,500	
Transformers	Dist		35,000	
Transmission Air Switch & Operator	Trans		-	
Hydro	Prod			185,000
Office & computing Equipment	Gen			
Pole & Line Replacements	Dist			217,193
Distribution Air Switch	Dist			11,500
Transformers	Dist			47,000
Transmission Air Switch & Operator	Trans			
AMI	Gen	637,507		
Routine/Recurring/Misc plant & General		5,000	5,000	5,000
Total Construction		**$ 1,126,657**	**$ 390,460**	**$ 465,693**
Functional Summary:				
Production		225,000	235,000	185,000
General	25%	693,757	1,250	1,250
Distribution	75%	132,900	154,210	279,443
Transmission		75,000	-	
Total Construction		1,126,657	390,460	465,693

FINANCIAL ANALYSIS

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of procurement scenarios that would maintain SED's 100% renewable supply as discussed in the Resource Plans chapter. It also includes a storage-only procurement to illustrate the cost saving potential of a MW-scale, peak-shaving battery. The characteristics of these scenarios are summarized in Table 27.

Table 27: Scenarios

0	Reference Case	Spot market prices & volumes.	N/A	Monthly DALMP
1.1	Highgate Falls No Peak Shaving	Peak shaving operations end 1/1/25.	N/A	N/A
1.2	Highgate Falls - Aesthetic Impacts	Impact of 1,000 MWH/Yr reduction.	1,000 MWH/Yr	N/A
1.3	Highgate Falls Low Hydro Year	30% less generation in 2023.	12,000 MWH/Yr	N/A
2.1	Add Wind 2023-2027	Energy + MAI RECs	3.0 MW & 6,900 MWH/Yr	Contract + Inflation
2.2	Add McNeil 2023-2027	Energy + CTI RECs	1.4 MW & 6,900	Equal to Mkt. Prices
2.3	Add Solar 2023-2027	Energy + MAI RECs	4.4MW & 6,900 MWH/Yr	$110/MWH Levelized
2.4	Add Solar 2025-2042	Energy + MAI RECs	4.4MW & 6,900 MWH/Yr	$110/MWH Levelized
3	Add Storage	Battery Storage	5 MW & 15 MWH	$15/kW-Month Levelized

The sizes and terms were chosen to maintain a 100% renewable supply if Highgate Falls has a one standard deviation decrease in generation. The pricing is set to the most currently available levels, and to further enable easy comparisons, the term of the wood, solar and wind procurements is held to five years so that the near-term financial impacts can be assessed.

The wood PPA is priced at current energy and REC market prices. Howard Wind priced using an inflation factor, and the solar PPA is priced at $110/MWH levelized, which is in alignment with VPPSA's recent solar development costs. Finally, storage is priced at $15/kW-month, which is a lower than recent values due to the passage of the Inflation Reduction Act (IRA).

REFERENCE CASE

The results of the reference case reflect the underlying trends in the price and volume of serving load. The Net Resource and Load Charges and Credits are growing at about 6.7%, which is a result of decreasing energy revenues. Two trends explain this growth rate. First as SED's load grows, it has less surplus MWH to sell to the energy market. Second, the value of Highgate Fall's energy surplus is declining because this past year's energy prices are forecast to moderate over time. Transmission charges are growing at 6% per year, which matches the trend over the past decade. Administrative costs grow more slowly (0.9%), and the load grows at 1.3% per year after accounting for electrification trends. Finally, the coverage ratio drops as electrification increases SED's load over time.

Table 28: Reference Case Financial, Load and Coverage Ratio Outcomes ($ Million)

Cost Item	2022	2027	2032	2037	2042	CAGR
Net Resource and Load Charges & Credits	$1.10	$1.72	$2.44	$3.30	$4.00	6.7%
Transmission Charges	$0.80	$0.97	$1.34	$1.85	$2.58	6.0%
Administrative and Other Charges & Credits	$0.16	$0.16	$0.17	$0.18	$0.19	0.9%
Total Charges	$2.06	$2.85	$3.95	$5.33	$6.78	6.1%
Total Load - Including Losses (MWH)	53,808	57,447	61,766	67,162	70,302	1.3%
Coverage Ratio	111%	99%	92%	82%	79%	

PROCUREMENT SCENARIOS

Table 29 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and for the procurement scenarios. The first series of scenarios shows the impact of the new Water Quality Certificate (WQC). Notice that the PVRR increases by about $22.2 million if Highgate Falls can no longer shave peaks. This is by far the largest risk that SED faces over the planning horizon. Replacing part of that peak shaving capability with a 5 MW battery can lower the impact by $6.8 million (Scenario 3.0), but the net cost to SED would still be an increased cost of $15.4 million or 13%.

For comparison, this is equivalent to having Highgate Falls experience a 30% reduction in annual generation every year for the next 20 years. That outcome that is shown in Scenario 1.3 and is illustrative only. SED does not expect this outcome to occur, but in any given year, it is a possibility. For example, 2021 was an exceptionally dry year, and if that were to reoccur in 2023, SED's power supply costs would increase by $1.5 million. This is about double the cost of SED's 2023 power supply costs in the Reference Case. Finally, the cost of losing generation for aesthetic flows is comparatively modest at 1.3% PVRR per 1,000 MWH/year of reduction.

Table 29: Financial Outcomes of each Procurement Scenario ($ Million)

#	Procurement Scenario	PVRR	Unit	% Change
0	Reference Case	$116.3	PVRR	
1.1	Highgate Falls - No Peak Shaving	$22.2	Versus Ref. Case	19.1%
1.2	Highgate Falls - Aesthetic Impacts	$1.5	Versus Ref. Case	1.3%
1.3	Highgate Falls – 30% Lower Gen.	$17.3	Versus Ref. Case	14.9%
2.1	Add Wind 2023-2027	($3.7)	Versus Ref. Case	-3.2%
2.2	Add McNeil 2023-2027	$0.0	Versus Ref. Case	0.0%
2.3	Add Solar 2023-2027	$0.4	Versus Ref. Case	0.3%
2.4	Add Solar 2025-2042	($4.1)	Versus Ref. Case	-3.6%
3.0	Add Storage	($6.8)	Vs. Ref. Case + No Peaking	-4.9%

The second series of scenarios shows the financial costs of different renewable resources. In the next five years, the lowest cost option is to import wind from NYISO. As already discussed, there is no expected financial benefit of purchasing wood or hydro power because they would be priced at prevailing market prices. Although solar increases costs slightly in the next five years, it could be expected to reduce costs over a planning horizon.

STORAGE

Round 2 of VPPSA's storage RFP revealed indicative pricing for peak shaving batteries that ranged from about $8.00 to $12.00/kW-month, levelized over 20 years. This price range was applicable to batteries whose capacity was between 1-5 MW and whose energy output was between two and four hours in duration. At this scale, batteries have several advantages.

- They are size appropriate for the loads at SED's substations.
- They are small enough to operate behind-the-meter with respect to ISO markets.
- They can be cycled 100 times per year to shave monthly and annual peaks.

Inflation and supply chain challenges have undoubtedly increased the cost of storage since the RFP was conducted. If SED were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, the cost to SED would be between $720,000 and $1,080,000 per year.

Figure 21: Annual Cost of a 5 MW AC Battery ($/Year)

($/kW-mo)	5 MW AC
$12.00	$720,000
$15.00	$900,000
$18.00	$1,080,000

To determine the value of a peak shaving battery, VPPSA modeled the avoided cost of capacity and ISO transmission. Because our storage partner is offering a performance guarantee that ensures 90% accuracy of operating the battery during peak hours, we assumed a 90% success rate for shaving the monthly and annual peaks. Based on a Monte Carlo analysis of 1,000 different randomly generated results, the value of a peak shaving battery averaged $25/kW-month (levelized) between 2023 and 2042. As a result, any BESS agreement that is priced less than this should generate net present value and reduce costs over the life of the agreement. Specifically, a BESS agreement for $15/kW-month would be expected to reduce annual costs by $540,000 and PVRR by $6,800,000.

CONCLUSIONS

The financial analysis can be summarized by two primary points. First, maintaining the ability for shaving peaks with Highgate Falls is the single most important factor affecting SED's cost of service. Although a 5 MW battery resource could mitigate some the costs of losing this ability, it is only a partial offset, both in terms of volume and in terms of PVRR.

The next largest risk SED faces is a dry hydro year. If the dry conditions from 2021 recurred in 2023, SED can expect its power supply costs to increase by $1.5 million. Mitigating this risk can be accomplished by diversifying away from run-of-river hydro in favor of more predictable resources such as firm hydro or baseload wood. Solar and wind resources can also provide diversity, and despite their intermittent nature, they were shown to be the least-cost options for SED at this time.

ACTION PLAN

VI. ACTION PLAN

Based on the foregoing analysis, we envision taking the following actions.

- Automated Metering Infrastructure (AMI)
  - Pursue implementation of an AMI system as reflected in the recent RFP within the 2022-2023 time frame.

- Energy Resource Actions
  - Manage year to year energy market requirements using fixed-price, market contracts that are less than five years in duration.
  - Consider acquiring a new renewable resource (firm hydro, solar, wind, and/or wood) to reduce energy costs and increase diversity.

- Capacity Resource Actions
  - Manage and monitor the reliability of Project 10 and McNeil to minimize Pay-for-Performance (PFP) risk and maximize PFP benefits.
  - Maintain the ability to shave peaks with Highgate Falls.

- Tier I Actions
  - Consider buying a firm, fixed price hydro resource to hedge Tier I REC costs.
  - Make forward purchases and sales, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk.

- Tier II Actions
  - Retire net-metered RECs.

- Tier III Actions
  - Identify and deliver prescriptive and/or custom Energy Transformation programs.

- Storage
    - Maintain the ability to pond and shave coincident peaks with Highgate Falls.
    - Develop battery to replace Highgate Falls peak shaving ability if necessary.

- Transmission
    - Maintain the ability to pond and shave coincident peaks with Highgate Falls.

- Active Load Control Pilot Program
    - Investigate options for engaging customers in active load control programs and tariffs, including end-uses such as electric thermal storage, CCHPs, and HPWHs.

- Innovative TOU Rates Program
    - Work with VPPSA to explore development and implementation of innovative, Time-of-Use (TOU) rates for residential electric vehicle chargers, public DC fast charging stations and more generalized (whole house) TOU and other innovative rate structures as a cost-effective way to supplement active load controls.

- Net Metering
    - Monitor the penetration rate and cost of solar net metering for future grid parity, and advocate for appropriate policies to mitigate potential upward rate pressure.

APPENDIX

APPENDIX A: 2022 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA Tier 3 2022 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B – SED Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – SED 2017-2021 Rule 4.900 Electricity Outage Reports.pdf

APPENDIX D: AMI RFI TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix D – AMI_RFI_Technical_Requirements.pdf

APPENDIX E: AMI RFP TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix E – AMI_RFP_Technical_Requirements.pdf

APPENDIX F: ITRON'S LOAD FORECAST REPORT

This appendix is provided separately in a file named:

Appendix F – Swanton IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

Appendix G – Swanton Tier III Life-Cycle Cost Analysis.pdf

APPENDIX H: NRPC REGIONAL ENERGY PLAN

Appendix H - https://www.nrpcvt.com/energy-planning

GLOSSARY

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
AESC	Avoided Energy Supply Cost
AMI	Advanced Metering Infrastructure
APPA	American Public Power Association
BESS	Battery Energy Storage Service Agreement
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
CEDF	Clean Energy Development Fund
CEP	Comprehensive Energy Plan
CRC	Cooperative Response Center
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
DTLM	Distribution Transformer Load Management
EIA	U.S. Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems
GMP	Green Mountain Power
HP	Heat Pump
HPWH	Heat Pump Water Heater
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO-NE	ISO New England (New England's Independent System Operator)
kV	Kilovolt
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LIDAR	Light Detection and Ranging

LIHI	Low Impact Hydro Institute
LMP	Locational Marginal Price
LRTP	Long Range Transmission Plan
MAPE	Mean Absolute Percent Error
MSA	Master Supply Agreement
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MDMS	Meter Data Management System
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NJUNS	National Joint Utilities Notification System
NOAA	National Oceanic and Atmospheric Administration
NYPA	New York Power Authority
NRPC	Northwest Regional Planning Commission
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
PVRR	Present Value of Revenue Requirement
R^2	R-squared
REC	Renewable Energy Credit
RES	Renewable Energy Standard
ROW	Right-of-way
RTLO	Real-Time Load Obligation
SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SED	Swanton Village Electric Department
SQRP	Service Quality & Reliability Performance, Monitoring & Reporting Plan
TAG	Technical Advisory Group
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)

TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)
VEC	Vermont Electric Cooperative
VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VFD	Variable Frequency Drive
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTrans	Vermont Agency of Transportation
WQC	Water Quality Certificate

Vermont Public Power Supply Authority
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Vermont Public Power Supply Authority
2022 Tier 3 Annual Plan

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing this Annual Plan describing its proposed 2022 Energy Transformation programs. Vermont's Renewable Energy Standard ("RES"), enacted through Act 56 in 2015, requires electric distribution utilities to either support fossil fuel savings by encouraging Energy Transformation ("Tier 3") projects or purchase additional Renewable Energy Credits ("RECs") from new, small, distributed renewable generators ("Tier 2").

VPPSA's Requirement

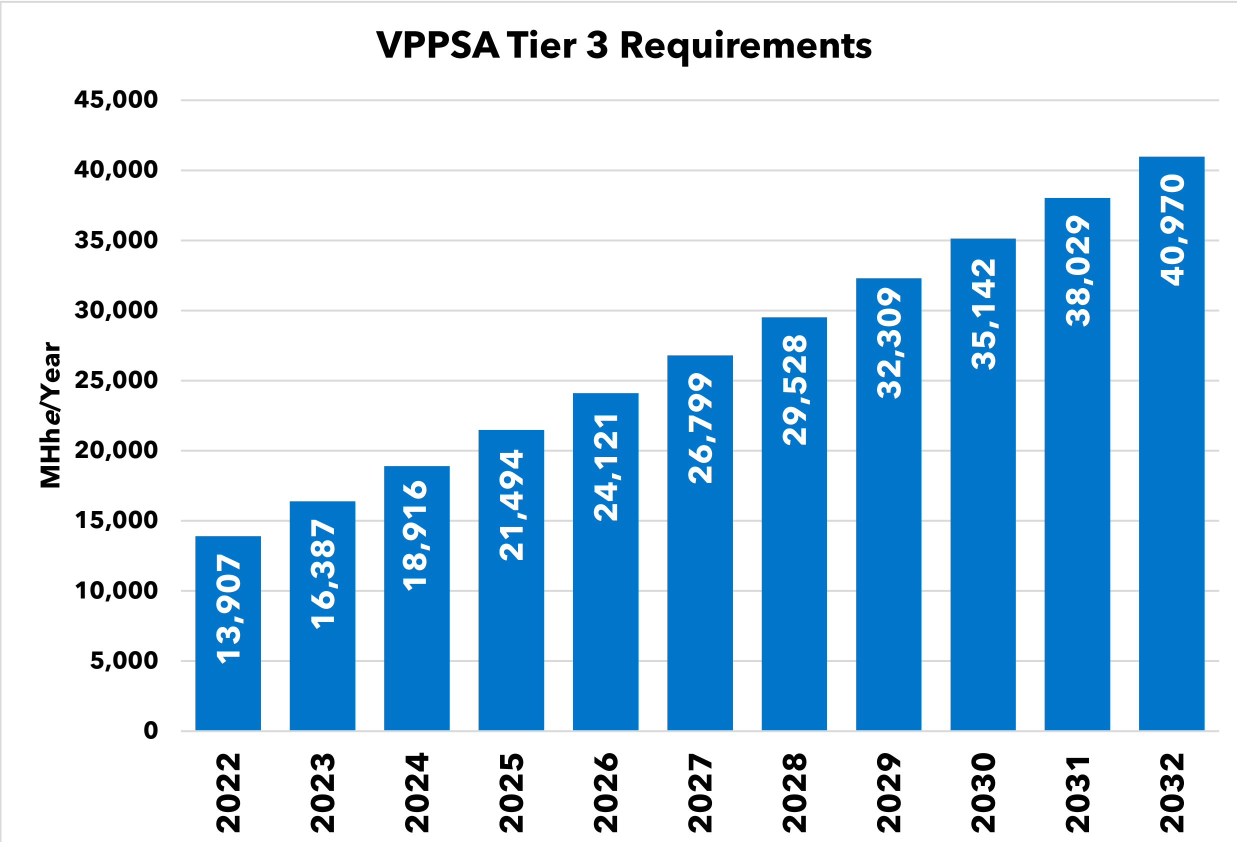
Utilities' Tier 3 requirements are established by 30 V.S.A. § 8005(a)(3)(B), which states that "in the case of a provider that is a municipal electric utility serving not more than 6,000 customers, the required amount shall be two percent of the provider's annual retail sales beginning on January 1, 2019.[1]" Tier 3 requirements increase by .67% annually.

In 2022, VPPSA's aggregate requirement is estimated to be 13,907 MWh equivalent in savings, representing 4% of annual retail sales. The 11 VPPSA member utilities plan to meet their Tier 3 requirements in aggregate, as permitted under 30 V.S.A. § 8004 (e), which states "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate."

VPPSA Members:
- **Barton Village**
- **The Village of Enosburg Falls**
- **Hardwick Electric Department**
- **Village of Jacksonville**
- **Village of Johnson**
- **Ludlow Electric Light Department**
- **Lyndonville Electric Department**
- **Morrisville Water & Light**
- **Northfield Electric Department**
- **Village of Orleans**
- **Swanton Village**

[1] 30 V.S.A. § 8005(a)(3)(B)

The below chart represents VPPSA's projected annual MWh equivalent in savings through 2032.



Summary of 2021 Projects

VPPSA expects to meet its 2021 Tier 3 requirements of approximately 11,605 MWh through a combination of prescriptive and custom measures. Prescriptive measures included post-purchase rebates or instant discounts for:

1. Cold Climate Heat Pumps
2. Heat Pump Water Heaters
3. Electric and Plug-In Hybrid Vehicles
4. Electric Vehicle Chargers
5. Electric Forklifts
6. Electric Golf Carts
7. Residential Electric Lawn Mowers
8. Commercial Electric Lawn Mowers
9. Ebike and Retrofit Kits
10. Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers

Of the prescriptive rebates offered, cold climate heat pumps have had the greatest uptake. VPPSA's strategy continues to focus on cost-effective prescriptive and custom Tier 3 measures. VPPSA continues to observe that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is lower than both prescriptive incentives and Tier 2 RECs. Custom projects include incentives for line extensions and service upgrades that removed the need for diesel generators. Several custom projects were identified in 2021 but likely will not be completed until 2022 or later.

2022 Program Overview

VPPSA proposes meeting 2022 Tier 3 requirements in a manner that mitigates costs that could put upward pressure on electric rates. This includes a combination of prescriptive and custom measures and use of Tier 2 RECs if needed. The focus of VPPSA's offerings is on electrification measures that will benefit all ratepayers by bringing in additional revenue to the host utilities.

Prescriptive Measures

VPPSA intends to maintain its current portfolio of prescriptive measure offerings with a few additions. Savings are calculated using measure characterizations created by the Tier 3 Technical Advisory Group ("TAG.")

Electric Vehicles and Plug-In Hybrids

VPPSA will continue to offer customer incentives for the purchase or lease of EVs and PHEVs in 2022. The customer incentive for purchasing or leasing a new electric vehicle will be $1000 and the customer incentive for purchasing or leasing a new plug-in hybrid electric vehicle will be $500. Low-income customers[2] will receive an additional $400 towards the purchase or lease of an EV or PHEV.

VPPSA plans to continue incentives for purchasing used EVs and PHEVs. The customer incentive will be $500 for the purchase of a used EV and $250 for the purchase of a used PHEV.

Upfront cost has been identified as a major barrier to purchasing an electric vehicle. Beginning July 1, 2021, VPPSA piloted a point-of-sale incentive with two auto dealerships: Burlington Cars and Lamoille Valley Chevrolet. These dealerships were chosen due to their willingness to participate in a pilot and their proximity to VPPSA members.

VPPSA has chosen to expand this approach in 2022. VPPSA is currently engaging with vehicle dealerships around the state to offer a point-of-sale incentive. Customers who

[2] According to Rule 4.413, "A low-income customer shall be defined as a customer whose household income is at or below 80% of Vermont statewide median income."

purchase or lease a vehicle from a participating dealership will receive their incentive as an instant discount. The dealership will then submit to VPPSA for reimbursement.

Should an eligible customer purchase or lease a vehicle from a non-participating dealership, the option will still be available to receive a post-purchase rebate.

Electric Vehicle Charging

VPPSA will continue to offer a $500 rebate for customers installing electric vehicle chargers at a workplace and/or available for the public to use.

VPPSA is planning an EV Charging pilot for 2022 in conjunction with Efficiency Vermont ("EVT"). The pilot will provide free Level 2 charging equipment to some residential utility customers who purchase electric vehicles. The chargers that are provided will be equipped with Open Charge Point Protocol ("OCPP") meaning that they can be integrated with multiple control platforms through open-source technology. These EV chargers will initially be programmed to provide charging during off-peak hours and will facilitate direct control of EV charging in the future. This pilot will be offered in a subset of the VPPSA members' service territories in which VPPSA and EVT are conducting tailored programs in 2022.

Cold Climate Heat Pumps

VPPSA will continue to offer incentives on ductless and whole building heat pump technology. Efficiency Vermont will continue to administer point-of-sale heat pump incentives on VPPSA's behalf.

Ductless Heat Pumps:

VPPSA began offering downstream, post-purchase incentives for ductless heat pumps in 2019. Upon installation the customer would complete the rebate form, submit the application and supporting documents to VPPSA, and receive a check in the mail upon approval.

VPPSA collaborated with Efficiency Vermont and other Vermont distribution utilities to change the administration of the heat pump incentive beginning January 2021. In 2022, Efficiency Vermont will continue to administer the ductless heat pump incentive as an instant discount at the point-of-sale. The $250 utility incentive will be applied when a customer works through a participating contractor or distributor. Efficiency Vermont will batch the incentives applied in VPPSA member territories and invoice VPPSA monthly for reimbursement. VPPSA expects a similar volume of ductless heat pump incentives to what was offered in 2021.

VPPSA is also engaged in discussions with Efficiency Vermont and other Vermont electric utilities around the potential to offer ductless heat pumps to income-qualifying households at no cost to the utility customer. These incentives would be offered in tandem with weatherization services provided through the Weatherization Assistance Program ("WAP") to income eligible customers. The cost of the heat pumps will be split 50-50 between the distribution utilities and Efficiency Vermont through use of Act 151 funds. Consistent with the requirements of Act 151, the distribution utilities will claim the entire thermal savings for these CCHPs and EVT will claim the electric savings. This pilot envisions providing ductless CCHP to 150 Vermont households and VPPSA anticipates 11 of these will be installed in its member utility territories in 2022. Conversations with Efficiency Vermont and the WAPs are ongoing.

VPPSA will also be participating in an Efficiency Vermont pilot to promote integrated controls that are installed to ensure customers' ductless CCHPs are working efficiently with the buildings' central heating systems and thermostats. This is a downstream rebate offering up to $600 for integrated controls. VPPSA will fund $400 of this incentive and claim the thermal savings resulting from more efficient operations of the CCHP and central system. Efficiency Vermont has developed a custom savings tool to evaluate the electric and thermal savings values attributable to integrated controls and this tool will be shared with the Department of Public Service ("Department") in order to verify Tier 3 savings.

Whole Building Heat Pumps:
VPPSA will continue to offer incentives on centrally ducted heat pumps and air-to-water heat pumps. Beginning January 1, 2022, VPPSA will offer prescribed custom incentives for ground source heat pumps. Efficiency Vermont administers all whole building heat pump incentives on behalf of VPPSA and several other Vermont utilities.

The centrally ducted heat pump incentive will continue to be offered as an instant discount at the point-of-sale. The incentive amount ranges from $750 – $1,500 depending on the size of the heat pump.

Efficiency Vermont will continue to administer the post-purchase rebate available for air-to-water heat pumps. In most cases, VPPSA and Efficiency Vermont will each offer 50% of the $1,000/ton incentive and claim 50% of the thermal savings. When an air-to-water heat pump is installed in VGS territory, VPPSA will offer the full incentive and claim the full savings. This is equivalent to how the incentive was managed in 2021.

VPPSA will offer the statewide ground source heat pump ("GSHP") incentive beginning in 2022. The incentive offered will be $2,100/ton. Because ground source heat pumps are not characterized by the TAG, VPPSA is approaching these incentives on a prescribed custom basis. The incentive offering will remain constant at $2,100/ton while savings will be calculated using a tool developed by Efficiency Vermont that has been shared with the Department through the TAG.

Efficiency Vermont will batch the incentives and invoice VPPSA monthly for reimbursement.

Heat Pump + Weatherization:
VPPSA will continue to offer a $200 downstream incentive to customers who are installing heat pump technology in a weatherized building. The incentive applies to ductless, centrally ducted, and air-to-water heat pump technology.

If the customer wishes to receive the additional weatherization incentive, then they must fill out the Heat Pump + Weatherization rebate application form and submit it to VPPSA along with the necessary supporting documents. The additional incentive serves to highlight the importance of overall building performance. To be eligible for the higher incentive amount, customers will need to demonstrate that their homes were weatherized according to a list of standards developed and circulated by the Department during the CCHP measure characterization by the TAG.

VPPSA claims the incremental savings associated with a heat pump installed in a weatherized building. Currently there is a distinct measure characterization for ductless CCHP installed in a high performing (weatherized) building. VPPSA will advocate through the TAG to get distinct measure characterizations for WBHP (ducted, air to water, and GSHP) that are installed in weatherized buildings.

Heat Pump Water Heaters

VPPSA will continue to provide a $600 discount to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. This incentive is administered by Efficiency Vermont.

There are two pathways a customer can take to receive the incentive. The first scenario applies to customers working through a contractor. These customers may be eligible for an instant discount at the time of purchase. Efficiency Vermont provides a $650 discount at the distributor level. $600 is passed down through the contractor to the end use customer while $50 remains with the distributor as a stocking incentive. Efficiency Vermont batches incentives provided to distributors and end-use customers and bills VPPSA monthly.

In the second pathway the customer purchases a qualifying HPWH from a retail provider. The customer then completes and submits the appropriate Efficiency Vermont rebate form. VPPSA is billed monthly by EVT.

Approximately 75% percent of customers installing a new heat pump water heater are doing so to replace an electric water heater. In this instance, Efficiency Vermont pays the entire incentive and claims the electric efficiency savings. The remaining 25% of customers are replacing fossil fuel fired water heaters. VPPSA claims all the thermal savings associated with these energy transformation projects.

Forklifts

VPPSA continues to offer a $2,500 rebate incentive for customers that purchase a new electric forklift.

Golf Carts

VPPSA continues to offer a $100 rebate incentive for customers that purchase new electric golf carts.

Lawn Mowers

VPPSA will continue to offer both commercial and residential lawn mower incentives. The rebate for a residential lawn mower will continue to be $50. VPPSA will continue to offer a $1,000 incentive for commercial lawn mowers in 2022.

E-Bikes

VPPSA will continue to offer a rebate incentive of $100 for the purchase of a new e-bike or e-bike conversion kit.

Residential Yard Care

VPPSA introduced several new incentives in July 2021 through an amendment to the 2021 Annual Plan. The following rebates were added in 2021 and will be continued in 2022.

Leaf Blowers:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric leaf blower.

Trimmers:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric trimmer.

Chainsaws:

VPPSA will continue to offer a rebate incentive of $25 for the purchase of an electric chainsaw.

Custom Measures

Commercial and industrial ("C&I") customers will continue to be served on an individual, custom basis in 2022. VPPSA continues to explore cost-effective Tier 3 custom projects. Identified custom projects with estimated completion in 2022 include electric buses, commercial heat pump units for a new-construction multifamily unit, electric bucket trucks, and an industrial heat recapture project.

Due to the relatively lower cost of MWh savings from custom projects, VPPSA continues to focus on identifying opportunities and working with utility customers to engage in energy transformation. VPPSA has launched a Key Accounts program that will better enable identification of custom projects with C&I customers. Additionally, VPPSA continues to partner with Efficiency Vermont to identify C&I customers that have potential Tier 3 and electric efficiency projects. Incentives for custom measures are typically paid for by the host utility rather than through VPPSA, with the host utility retaining the associated Tier 3 credits. Upon approval of the VPPSA Board of Directors, VPPSA may fund custom projects through its Tier 3 budget and allocate the Tier 3 savings among its members.

VPPSA is currently partnering with WexEnergy to pilot their new product, WindowSkins. WexEnergy was a participant in the 2020 DeltaClime business accelerator program, which VPPSA sponsors. VPPSA staff mentored DeltaClime participants throughout the accelerator program as they pitched their innovative products designed to minimize heat loss through windows. The pilot program involves testing the WindowSkin product in municipal buildings and one industrial customer through the 2021/2022 heating season. The WindowSkins should assist the municipalities and industrial customer in lowering the amount of fossil fuel used to heat their buildings and meet internal energy goals.

VPPSA will continue to work with the Department on custom projects to ensure savings claims are verified and the Department is able to adequately budget for verification activities.

Tier 2 RECs

To the extent that there is a shortfall in savings from the prescriptive and custom measures, VPPSA may utilize excess Tier 2 RECs from its growing solar project portfolio and/or purchase Tier 2 RECs when prices are low as a hedge against a deficit in savings from Tier 3 programs. To the extent that Tier 2 RECs are less expensive than implementing Tier 3 programs, VPPSA may exercise this strategy to benefit its members. For VPPSA members that own Tier 2 eligible generating resources, Tier 2 RECs may be the primary strategy for Tier 3 compliance.

VPPSA is managing member Tier 3 compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier 2 RECs. Under this approach the Tier 2 REC price acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings. Should Tier 2 REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier 3 planning document.

Best Practices and Minimum Standards

Over the long-term, Tier 3 programs have the potential to significantly increase loads for Vermont utilities. VPPSA members have identified that their systems remain robust, and the expected growth in annual and local peak demand associated with proposed measures can generally be sustained if monitored and deployed carefully.

VPPSA's most recent, Commission-approved IRP used the same underlying assumptions as VELCO's Long-Range Transmission Plan ("LRP"). As a result, they incorporate the State's latest outlook for EVs and CCHPs. These technology trends are still nascent and are significant inputs to the load forecast. However, according to the IRP load forecast analysis, they are not likely to cause any major deviations to the IRP, either this year or in the next three years.

VPPSA continues to monitor COVID-related load impacts, as well as the potential impacts of large, custom Tier 3 projects. To date, VPPSA has not identified any major deviations from its IRP load forecasts, especially in light of the high and low forecast cases that were analyzed in the IRPs.

VPPSA has established a partnership with Virtual Peaker, allowing us to assist our members in demand-response programming. In 2022, VPPSA will continue to use the platform for an internal utility behavioral demand-response program to strategically maximize load-reducing generation during high-cost time periods.

VPPSA's memorandum of understanding ("MOU") with Efficiency Vermont, which the PUC approved under Case 19-3272, continues through 2023. The VPPSA/Efficiency Vermont MOU includes the potential for an active demand response pilot. The utility economics of active load control remain a challenge, and involvement from Efficiency Vermont could help lower utility costs. VPPSA and Efficiency Vermont are in the early stages of discussing a load management program that would enable VPPSA member utilities to control multiple technologies through one integrated platform in order to overcome the cost barriers of utilizing distinct, proprietary platforms to manage each technology (e.g. EV chargers, CCHP, smart thermostats.) The OCPP pilot discussed above is a component of this demand management strategy and will mitigate the grid impacts of EV charging.

As discussed in the CCHP section of this plan, VPPSA is partnering with EVT on a pilot to promote integrated controls for CCHP. This pilot is expected to increase the fossil fuel savings from CCHP installations through more efficient integration with the buildings' central heating systems. This technology will also lay the groundwork for future load management of CCHP electric demand.

In addition, VPPSA is pursuing utility-scale storage as a cost-effective means of achieving demand reductions for its members. A Request for Proposals to install storage facilities sized between 100 kW and 4.9 MW within the VPPSA member utilities' service territories was issued in October 2020 and VPPSA has narrowed the selection down to a final vendor.

Finally, as noted in the discussion on prescriptive rebates, VPPSA provides an additional $200 heat pump incentive for units that are installed in weatherized buildings as a mechanism to encourage the installation of heat pumps in buildings that meet established performance standards.

Equitable Opportunity

VPPSA strives to ensure that Tier 3 programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier 3 incentives described in the Plan will be available to all VPPSA member utility customers. Commercial and Industrial customers have the ability to access VPPSA's prescriptive measures and are also served through custom incentives.

With some measures, such as EVs, VPPSA is providing a significantly higher incentive to income-eligible customers to help offset the upfront cost barrier of purchasing these vehicles. VPPSA also provides incentives on used EVs and PHEVs which come with a lower upfront cost to the customer.

Additionally, VPPSA is engaging with Efficiency Vermont and other electric utilities to offer ductless cold climate heat pumps to income-qualifying households at no cost to the utility customer. Please refer to the Cold Climate Heat Pump section of this plan for more details on this low-income program offering.

Financing is another tool that can be used to make Tier 3 measures accessible to customers. VPPSA is co-chairing an Energy Action Network subgroup to develop an on-bill tariff efficiency program through which customers could pay for their efficiency and Tier 3 measures on their electric bill. This program, which is being financed by Vermont Housing Finance Agency, will include robust incentives to low-income customers. The program is being structured such that participating customers' total monthly energy costs, including the on-bill tariff payment, will be the same or lower after making the efficiency upgrades than they were previously. This "revenue neutrality" is seen as a critical element for reaching lower income households.

In compliance with Rule 4.413 VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. Participation and spending are monitored and reviewed each year to inform program planning for future years.

Finally, VPPSA's Tier 3 programs have a deliberate emphasis on electrification. The ability to bring financial benefits to all customers, rather than just participating customers, makes electrification an attractive Tier 3 option from an equity perspective. If additional kWh can be procured at costs at or below the costs embedded in a utility's rates, increasing the number of kWh delivered through the utility's system allows the fixed costs of operating the utility to be recovered over a larger number of units, driving the per kWh rate down for all customers. In this way both participants and non-participants stand to benefit from VPPSA's Tier 3 programs and cost-shifting among customers is minimized.

VPPSA's analysis shows that the incentive dollars paid to customers in rebates for electrification measures will typically be recovered through increased sales over the life of the measures, making these programs revenue neutral or beneficial for non-participating ratepayers.

Consistent with Commission Rule 4.413 (c), VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. This data is included in VPPSA's Tier 3 savings filed in March and RES Compliance Filing in August. Over the life of the RES, VPPSA intends to provide equitable opportunities to its customer sectors in rough proportion to each customer sector's annual retail sales.

Partnership, Collaboration, and Marketing

VPPSA plans to continue actively working with both public and private partners to execute our Tier 3 plan in the most cost-effective way.

VPPSA continues to administer the VTrans income-qualifying electric vehicle incentive. The VTrans incentive is offered on the sale of any electric vehicle registered in Vermont. The value of the VTrans incentive is dependent upon the owner's household income level. Participating car dealers sell vehicles at a price reduced by the statewide incentive for eligible customers. Each dealer then submits the customer's information and vehicle details to VPPSA. VPPSA batches the incentives each month and sends the information to VTrans with a summary report and invoice. VTrans will pay VPPSA for the state incentive, which VPPSA will then remit to the dealer. In 2021 there was an increase in uptake of the income-qualifying VPPSA electric vehicle incentive.

The VPPSA/Efficiency Vermont MOU approved in 2019 has strengthened the partnership between the two organizations. In many cases, this partnership involves VPPSA providing incentives for electrification measures, which can provide benefits to all VPPSA utility customers, while Efficiency Vermont provides incentives for electric efficiency measures. With the exception of air-to-water heat pumps, there will be no prescriptive measures offered by VPPSA in 2022 for which costs and savings will be allocated between VPPSA and EVT. The allocation of savings and costs for joint custom commercial and industrial projects will be determined on a case-by-case basis. In general, savings allocated to each entity will be in proportion to the financial contribution to the specific project.

Under the MOU structure, VPPSA and Efficiency Vermont will implement tailored efforts in three VPPSA member communities each year of EVT's current performance period (2021-2023.) Morrisville Water & Light, Lyndonville Electric Department, and Hardwick Electric Department have been identified for 2022 Tailored Efforts. Additionally, as previously mentioned, VPPSA and Efficiency Vermont plan to partner on load management pilots.

VPPSA continues to take on a greater role in utility customer interaction. Historically, the individual VPPSA member utilities were responsible for customer outreach. With the addition of Tier 3 projects, VPPSA will educate utility customers on the available incentives through use of the following:

- VPPSA member utility bill stuffers
- VPPSA member utility staff training
- VPPSA website
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops

- Car dealer outreach
- EVT contractor and distributor outreach
- Direct outreach to Key Account customers

Cost-Effectiveness

VPPSA's Tier 3 planning included consideration of the suite of measures in the 2022 Tier 3 Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA analyzed the inclusion of wood pellet stoves for 2022. This measure would have been delivered in conjunction with Efficiency Vermont and necessitated a 50/50 split of the thermal savings. The incentive and Tier 3 savings values for pellet stoves are included in the table below. Ultimately VPPSA decided not to include pellet stoves as a measure in 2022 because projections of electrification measures show that VPPSA's entire Tier 3 requirement is likely to be met through existing prescriptive programs. As described in the Equitable Opportunity section above, VPPSA's Tier 3 strategy prioritizes electrification measures that have the potential to bring financial benefits to all customers. VPPSA will re-visit the inclusion of pellet stoves in future Tier 3 planning cycles.

Measure	Incentive	MWh	Cost/MWh
Residential Pellet Stoves, Existing Home	$225.00	90.05	$2.50
Residential Pellet Stoves, New Construction	$225.00	40.46	$5.56

VPPSA has completed lifecycle cost analysis for its Tier 3 measures. Cost-effectiveness was evaluated based on both the Utility Cost Test ("UTC") and Societal Cost Test ("SCT"). Lifetime utility net costs are presented in the Summary Table of the Tier 3 Reporting template that accompanies this plan. Results of the SCT analysis are presented below. In future years, lifecycle analysis of VPPSA's Tier 3 programs will be included in the VPPSA members' Integrated Resource Plans.

Measure	Budgeted Incentive	Incremental Cost	Life (Years)
EV	$1,022	$15,708	8
PHEV	$650	$7,301	8
CCHP	$381	$3,293	15
WBHP	$1,535	$10,159	18

Utility Cost Test	Societal Cost Test
0.9	0.5
0.9	0.8
1.1	1.6
1.0	1.1

- EV
  - Both the UCT and the SCT are less than one.

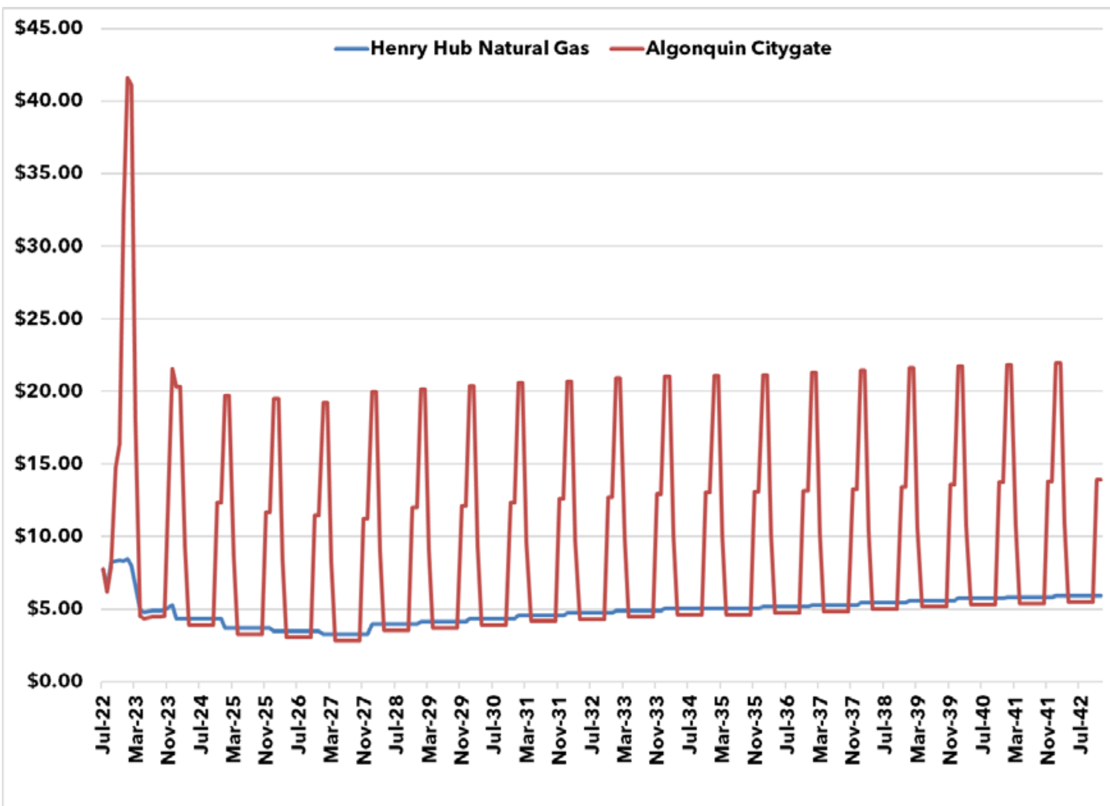
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- PHEV
    - Both the UCT and the SCT are less than one.
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- CCHP
    - Both the UCT and the SCT are greater than one.
    - This is due to a combination of a relatively low incremental costs and a relatively long measure life.
- WBHP
    - Both the UCT and the SCT are greater than one.
    - Incremental costs are relatively high for this measure, but the long measure life offsets it.
- Assumptions
    - Incentive levels match the VPPSA Tier III Budget.
    - Incremental costs and measure lives match the Tier III Planning Tool for 2022.
    - Seasonal on and off-peak load shapes (MWH and MW) are based on a combination of Itron, Cadmus and TAG working documents. Total MWH match the Tier III Planning Tool.
    - Avoided Costs for wholesale energy, capacity, transmission and RECs align with VPPSA's 2022 power budgeting assumptions.
    - Avoided fuels and carbon costs are from the AESC 2021 report.
    - The methods for calculating the UCT and SCT are from the EPA's National Action Plan for Energy Efficiency, 2009.

APPENDIX B: PRICING METHODOLOGY

ENERGY PRICING

Energy prices are forecast using a three-step method. First, a monthly natural gas price forecast is taken from broker quotes for the first two years of the forecast period. This includes both Henry Hub (HH) and Algonquin Citygate (AGT) prices, as well as NEPOOL electricity prices. Second, the AGT price is added to the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) HH forecast for the period 2025 to 2042. The forecast of HH and AGT prices can be seen in Figure 1.

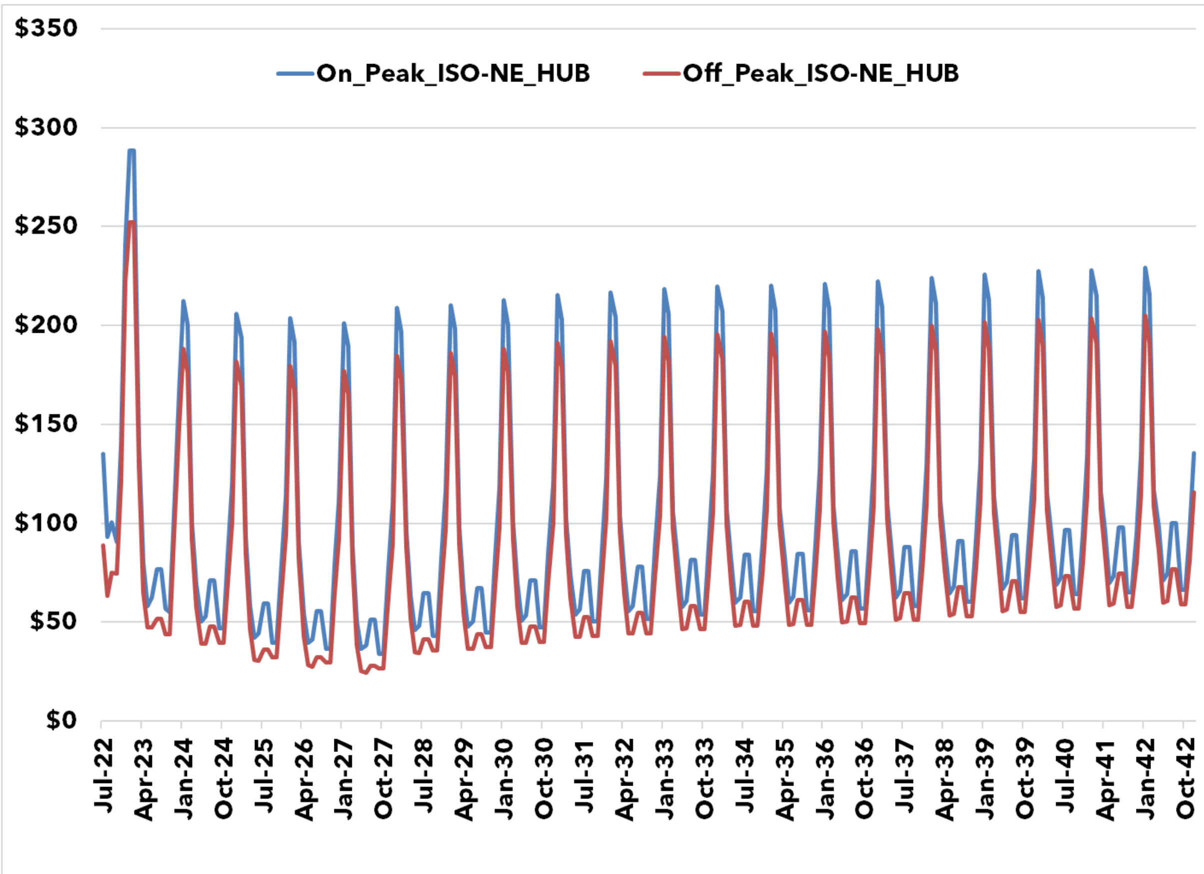
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Notice that the Henry Hub price is stable and inflationary, while the Algonquin Citygate price is high and volatile. This is due to the fact that New England's marginal gas supply is imported Liquified Natural Gas (LNG) during the winter months. LNG's price is subject to international supply and demand balances, and is the cause for the very high winter-time price outlook.

Third, we multiply the natural gas price forecast by the implied heat rate in the broker quote to get the on-peak electricity price. From this value, we subtract the spread between the on and off-peak prices to get the off-peak price. The results can be seen in Figure 2.

Figure 2: Electricity Price Forecast (Nominal $/MWH)

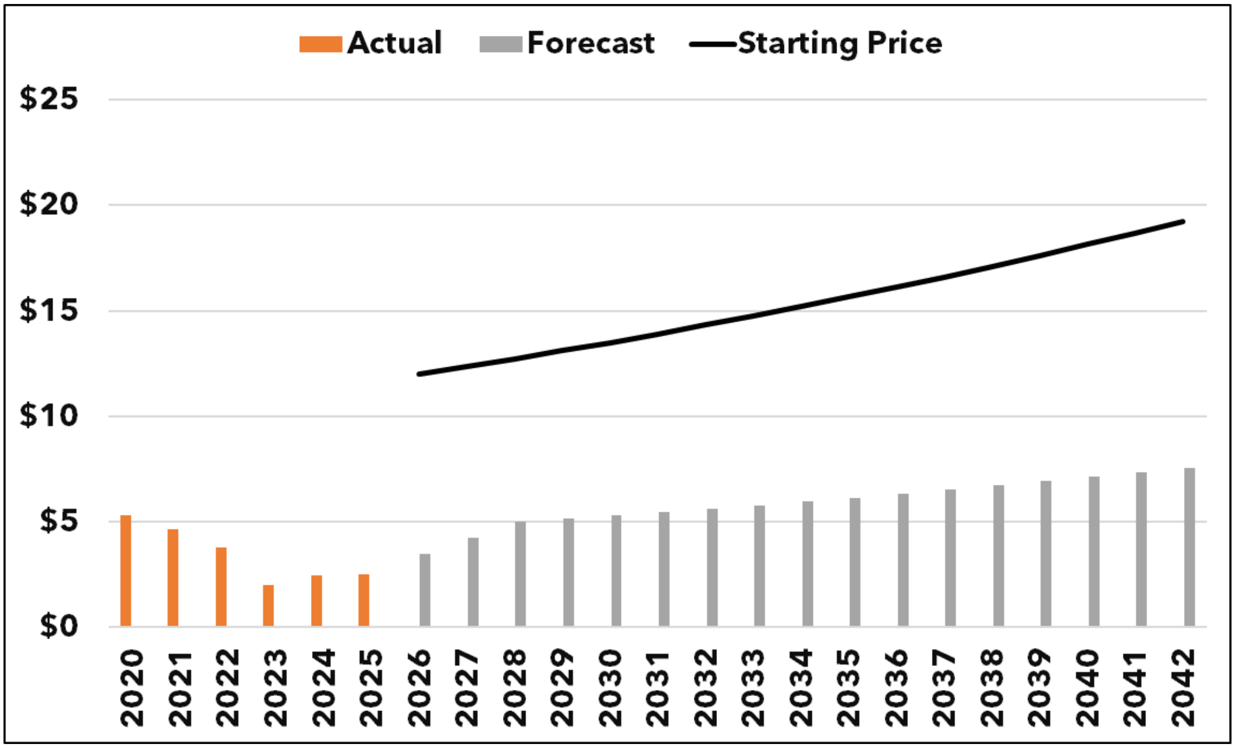


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of SED's load and resources.

CAPACITY PRICING

The capacity price forecast starts at $3.50/kW-month, which is the average of the last six years of actual auction results for the Northern New England Zone. Inflation is added to this value, which grows the capacity price to about $7.50/kW-month in 2042. Significant upside price risk does exist, as shown by the Maximum line in Figure 3. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 3: Capacity Price Forecast (Nominal $/kW-Month)



SWANTON VILLAGE ELECTRIC 2017

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	SWANTON VILLAGE ELECTRIC
Calendar year report covers	2017
Contact person	REGINALD R. BELIVEAU
Phone number	(802) 868-3397
Number of customers	3,670

System average interruption frequency index (SAIFI) = 1.4
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.5
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	4	19
2	**Weather**	23	12,663
3	**Company initiated outage**	1	0
4	**Equipment failure**	4	34
5	**Operator error**	0	0
6	**Accidents**	8	187
7	**Animals**	12	66
8	**Power supplier**	0	0
9	**Non-utility power supplier**	1	2
10	**Other**	1	4
11	**Unknown**	2	93
	Total	56	13,069

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

SWANTON VILLAGE ELECTRIC 2018

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	SWANTON VILLAGE ELECTRIC
Calendar year report covers	2018
Contact person	REGINALD R. BELIVEAU
Phone number	(802) 868-3397
Number of customers	3,701

System average interruption frequency index (SAIFI) = 1.0
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.5
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	8	533
2	**Weather**	22	1,660
3	**Company initiated outage**	1	5
4	**Equipment failure**	5	2,117
5	**Operator error**	0	0
6	**Accidents**	3	133
7	**Animals**	21	424
8	**Power supplier**	1	286
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	4	48
	Total	65	5,206

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

SWANTON VILLAGE ELECTRIC 2019

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	SWANTON VILLAGE ELECTRIC
Calendar year report covers	2019
Contact person	REGINALD R. BELIVEAU
Phone number	(802) 868-3397
Number of customers	3,790

System average interruption frequency index (SAIFI) =	**1.4**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**0.7**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	13	668
2	**Weather**	12	1,625
3	**Company initiated outage**	0	0
4	**Equipment failure**	2	12
5	**Operator error**	0	0
6	**Accidents**	4	175
7	**Animals**	8	262
8	**Power supplier**	1	628
9	**Non-utility power supplier**	0	0
10	**Other**	1	27
11	**Unknown**	1	9
	Total	42	3,406

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

SWANTON VILLAGE ELECTRIC 2020

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	SWANTON VILLAGE ELECTRIC
Calendar year report covers	2020
Contact person	REGINALD R. BELIVEAU
Phone number	(802) 868-3397
Number of customers	3,750

System average interruption frequency index (SAIFI) = 0.5
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.5
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	5	605
2	**Weather**	5	397
3	**Company initiated outage**	1	133
4	**Equipment failure**	5	19
5	**Operator error**	0	0
6	**Accidents**	3	1,101
7	**Animals**	18	117
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	5	27
11	**Unknown**	5	72
	Total	47	2,471

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

SWANTON VILLAGE ELECTRIC 2021

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	SWANTON VILLAGE ELECTRIC
Calendar year report covers	2021
Contact person	REGINALD R. BELIVEAU
Phone number	(802) 868-3397
Number of customers	3,762

System average interruption frequency index (SAIFI) = 0.4
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.7
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	6	2,061
2	**Weather**	1	75
3	**Company initiated outage**	0	0
4	**Equipment failure**	2	6
5	**Operator error**	0	0
6	**Accidents**	2	207
7	**Animals**	24	295
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	2
11	**Unknown**	2	51
	Total	38	2,696

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

1. TECHNICAL REQUIREMENTS

Please answer all questions and provide detail on any specific capabilities of your AMI technology in your response.

1.1 Electric Metering

The purpose of this section is to understand capabilities of the electric meters that work with the AMI solution.

1. Provide details of meters available with your AMI solution, e.g. meter type, manufacturer, etc.
2. List all the meters and manufacturers that your AMI solution will support.
3. Does your AMI solution support meters from more than one manufacturer in a single AMI implementation?
4. What compliance standards do your meters meet, e.g. ANSI, UL, IEC, etc.?
5. Meters will be installed in Vermont and be subject to a wide range of weather (ice, heat, snow, temperature) and environment considerations. Please provide details on the performance of meters given these details. This includes compliance with an outdoor installation. This includes UV resistance.
6. Describe the service life of the electric endpoint, including internal batteries, given weather/environment considerations.
7. Provide details regarding the failure rate of the electric meter and communications technology in a Pareto analysis format.
8. Provide details of the alerts, alarms, and configurations, i.e. tamper, temperature, reverse energy, voltage etc.
9. Describe the electric meter disconnect capability including support for remote disconnect, load limiting, disconnect security, etc.
10. Provide meter identification details including barcode, labeling and meter security keys. Describe how meter identification is handled if a single central AMI system is used across all Members.

11. Describe the measurement parameters available on all meter types, e.g. energy, demand, voltage, power factor, including interval data measurements.

12. Describe data storage capacity within the meter.

13. Provide details regarding the meter's ability to support Time-of-Use, Critical Peak Pricing and other rate designs.

14. Describe the meter display and any visual indicators, e.g. disconnect indicator.

15. Describe the meter's ability to support net energy metering installations.

16. Provide details regarding the meter data security, along with associated hardware considerations from field to back-office systems, including encryption/decryption.

17. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

18. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi, etc.).

19. Describe the process for meter firmware upgrades or configuration changes.

20. Describe any other functionality available in the meter.

1.2 Water Meters and Endpoints

The purpose of this section is to understand capabilities of a water AMI solution including water meter capabilities and/or the integration of an AMI water endpoint with existing water meters.

1. Describe features of the proposed system relating to water meters:

   a) Meter interface unit connection & mounting options. Address solutions for existing 6-digit touch read meters located in the basement with touchpad on the outside wall. There are a few meters in pits with a touchpad through the lid.

   b) Alarm and tamper alert features, e.g. reverse flow, tamper, battery life, etc.

   c) Read data and interval operations; describe the measurements available for each type of meter.

2. Provide a list of water meters and registers compatible with the AMI solution.

3. Explain power output and two-way communication functionality. Does the meter interface unit (MIU) have the ability to "hop" information to/from the electric meters or other water meters?

4. Explain the process of installation and commissioning of the meter and interface unit. Include any issues or concerns associated with communication devices. Address any issues of access to indoor meters. Most will be replacement of touchpad that is mounted on outside wall of the structure.

5. What industry compliance standards do your meter interface units meet, e.g. ANSI, UL, IEC, etc.?

6. What is the service life of the meter interface unit, including internal batteries, given weather/environment considerations?

7. Provide details regarding the failure rate of the water meter and meter interface unit in a Pareto analysis format.

8. Describe the capability of the system, meter interface unit and meter to support for remote disconnect, disconnect security, etc.

9. Provide details of meter identification including barcode, labeling, meter security keys. Describe implementation of meter identification/discretion if one central AMI system is used for several Member utilities.

10. Describe the meter data storage capacity within the meter interface unit.

11. Provide details regarding security of meter, interface unit and associated hardware considerations for back-office systems including encryption/decryption.

12. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

13. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi).

14. Describe the process for MIU firmware upgrades or configuration changes.

15. Describe any other functionality available in the meter.

16. Provide description of clock/calendar in the MIU including drift limits and synchronization intervals.

1.3 AMI Network

The purpose of this section is to understand the AMI network capabilities and operation as well as the equipment used for the network.

1. Describe the types of communications available with your AMI solution, e.g. RF, PLC. Include options for a mixed communication AMI solution.

2. Provide details regarding the metering communication network including types of equipment and backhaul options. Explain the alternative network backhaul options if cellular service is unavailable.

3. Explain the latency of your system for each communication and backhaul option used in your solution.

4. Explain the installation requirements for each type of network equipment, e.g. locations, mounting, height, power, protection from surges/lightning.

5. Describe the network architecture. Include the option of a shared AMI system for all Members. Does the configuration support common collection devices across Members, e.g. neighboring Members?

6. Describe the capacity of your AMI network, e.g. bandwidth, collector/repeater capacity (meters per network device), etc.

7. Describe the network security e.g. encryption, breach identification.

8. Provide an overview of how meters communicate with each type of collection device.

9. Describe how electric and water meters can be read concurrently through the network.

10. Describe how the network solution reaches hard-to-read meters (encumbered by terrain, foliage, etc.) or geographically dispersed meters.

11. Describe how the proposed system is managed over time, e.g. resource skill, training, remote management and maintenance, replacement process.

12. What service level agreement is supported by your solution and capabilities? Can the solution provide 99% of daily reads every day?

13. What is the success rate of last gasp messages for outages?

14. What is the success rate of on-demand meter interrogations or pings?

15. Provide a preliminary outline describing network solutions for VPPSA Members as a group and then also having each Member as an individual network.

16. Describe the procedure for AMI network component firmware upgrades.

17. Explain network disaster recovery processes specific to each proposed solution. Provide details regarding redundancy and failover of collection devices.

1.4 Software

In this section, provide a description of the AMI head end software, tools and software to operate the network and meter data management (MDM) capabilities. In addition, provide the options for implementation of the software and delivery of the solution.

1. Describe the software required to operate the AMI system. Provide product names of all software required for the solution. Include a MDM in your solution; third party solutions are acceptable.

2. Provide an architectural overview of the software solution provided with the AMI system.

3. Identify the software required to operate and troubleshoot the network.

4. Identify the software required to retrieve and manage all meter data.

5. What tools or software are available for field programming, data download and troubleshooting?

6. Does your company offer Meter Data Management (MDM) software?

7. Describe the following functionality and identify the software product performing the function:

    a) Meter Data Interrogation

    b) Meter Disconnect/Connect, Pinging

    c) Meter Data Validation, Estimation and Editing

    d) Reports

    e) Analytics

8. Describe how meter reads can be transferred to billing systems, include manual and automated processes.

9. Describe the options for software delivery including on-premise, hosted, managed services or others.

10. Can one central system serve all Members but have the data segregated and accessed by the Member owning the data, i.e. multi-tenant database

11. Can each VPPSA Member have their own separate system?

12. Describe the advantages and disadvantages of a single central system versus separate systems for each Member.

13. Has your system been integrated to the following systems and describe the type of integration, e.g. standard API, Multispeak, manual entry:

    a) SEDC

    b) NEMRC

    c) Harris Northstar

    d) Harris Spectrum

    e) Harris Select

    f) MUNIS

    g) Cogsdale

    h) Creative Technologies

    i) mPower

14. Does your company offer software for customer engagement such as a web portal? If not, what are your recommendations for a customer portal solution?

15. Does your company offer software for data analytics?

16. Does your software provide any mapping or GIS functionality? If so, describe any 3rd party products.

17. Provide al list of 3rd party products used in your AMI solution. Identify any product that requires a separate license.

1.5 Other Electric Capabilities

The purpose of this section is to understand the additional capabilities supported by the electric AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those capabilities. Include any third-party solutions or partners that work with the AMI solution or network.

1. Describe your company's offerings for Demand Side Management (DSM).
2. Describe the AMI solution's capability to support Demand Response Programs.
3. Describe your AMI solution support for Home Area Networks (HAN).
4. What protocols are available to support DSM or HAN technologies, e.g. OpenADR, Zigbee, Multispeak?
5. What support does your AMI solution offer for outage management?
6. Describe the AMI solution's support for voltage reduction programs, e.g. CVR, VVR.
7. What support does your AMI solution offer for transformer sizing or transformer load management?
8. Describe the AMI solution's ability to support Distribution Automation.
9. Describe the AMI solution's support for net metering.
10. How does the AMI solution support new customer electric technologies, e.g. electric vehicles, power walls, etc.?
11. Describe methods of exporting data from your system.
12. Are there other functions available and supported by your AMI network e.g. streetlight control, security cameras, active shooter, propane tank monitoring?
13. Is there a customer pre-pay solution integrated with the AMI solution?

1.6 Water System Functionality and Leak Detection

The purpose of this section is to understand the additional capabilities of the water AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those

capabilities. Include any third-party solutions or partners that work with the water AMI solution or network.

1. Describe leak detection features of the meter interface unit using existing meters

2. Describe distribution leak detection device, capabilities, and requirements.

3. Describe system capabilities for district (zone) metering

4. Describe other features available for use with the proposed AMI system such as:

   a) Pressure loggers

   b) Water quality monitoring

   c) Other water system monitoring features

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Request for Proposal (RFP)

for an

Advanced Metering Infrastructure Solution

Deadline for Submission: March 4, 2020

Issued by Vermont Public Power Supply Authority
PO Box 126
5195 Waterbury-Stowe Road
Waterbury Center, VT 05677

Release Date: December 20, 2019

1. TECHNICAL REQUIREMENTS

1.1 Electric Meter Endpoints

This section defines the functional and technical requirements for new solid-state electric AMI revenue meters (AMI Meters) that shall be provided and deployed as part of this AMI project. VPPSA reserves the right to purchase one meter type or more than one meter type based on negotiations with the Vendor.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 6

Question	**Response:** Comply, No Comply or Alternative
1. AMI Electric Meters shall be new, solid state with no moving parts except for the minimum number of required to support service disconnect switching, tamper detection, and/or "hard" demand reset.	
2. Functional features of the new meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming is to be done at the factory according to utility specifications.	
3. AMI Electric Meters shall have a 20-year life.	
4. AMI Electric Meters shall be capable of recording total delivered and received energy measurement data in dedicated registers. Net energy is to be recorded in a dedicated register.	

5. AMI Electric Meters shall be capable of recording and storing interval data in interval lengths of 15, 30, or 60 minutes.	
6. AMI Electric Meters shall be capable of recording Time-of-Use (TOU) data.	
7. Demand quantity recorded in each register shall be configurable through programmable meter settings. Values stored in demand registers shall continuously increase until they are reset locally or via the AMI Network by an authorized AMI user.	
8. Meters registering peak demand shall support local resetting of the value (to zero) in any demand register.	
9. Meters shall feature security provisions that prevent local demand register resets by anyone other than authorized personnel.	
10. Programming of the AMI Electric Meters shall include an option to record either "rolling" or "block" interval demand values. Rolling demand subintervals shall include resolution of five (5) minutes, three (3) minutes, two (2) minutes or one (1) minute.	
11. AMI Electric Meters shall support KYZ data pulse (Form C) output.	
12. AMI Electric Meters must have the ability to provide "last gasp" notification of power outages within 30 seconds or less.	
13. All polyphase AMI meters shall auto-range when connected to services in the range of 120-277 Volts RMS, ± 20% with the exception that Form 12S must	

auto-range when connected to services in the range of 120-480 Volts RMS, ± 20%.	
14. The AMI Electric Meter shall be equipped with an industrial grade display capable of presenting at least five (5) reading digits, along with status enunciators and ID code numbers. The display shall include an easily interpreted graphic representing the magnitude and direction of energy quantities passing through the meter.	
15. Meters with an integrated service disconnect switch shall have an indicator that shows the status of the switch. The indicator shall be easily recognized, readily interpreted, and clearly visible to an observer viewing the meter.	
16. Meters equipped with a service switch shall perform reliably during continuous operation at the maximum load indicated on the meter's nameplate, while at minimum rated ambient temperature and humidity.	
17. Meters equipped with a service switch shall continuously monitor the service voltage on the customer side (load side) of the switch regardless of switch state. The meter shall generate an alert if voltage is present on a load terminal when the service switch is open.	
18. AMI Electric Meter display shall have an easily interpreted indicator showing the current status of the AMI Meter's AMI network connection. For example, the indicator may show the following states: • Network detected – connected • Network detected – not connected • No network detected • Transmitting	

• Receiving	
19. Meter displays may have an indicator that shows the TOU rate that is governing current TOU consumption registration in the meter.	
20. The meter nameplate shall include all applicable meter identification information. This information shall include a unique alphanumeric meter ID code (company number) specified by VPPSA, the manufacturer’s name, the manufacturer’s serial number, manufacturing date, bar coding, etc.	
21. Prior to delivery from the factory, the meter manufacturer shall test each meter to certify the accuracy and proper operation of the meter.	
22. A file with meter attribute information and test results shall be provided to VPPSA electronically prior to every shipment from the manufacturer.	
23. AMI Electric Meters provided shall not require any special equipment for shop or field-testing procedures. All testing should be capable of being conducted using standard, commercially available test equipment in both the field and the shop.	
24. All AMI Meters proposed shall feature a “test mode” that suspends normal meter operation so that consumption and demand measurements from tests are not recorded in the billing registers and/or interval data. All energy measurements and other measurements stored in the meter shall be unaffected by energy passing through the meter while in test mode.	

Provide detailed responses for the following questions:

1. Identify the specific make and model of AMI Electric Meters that support replacement of 100% of the meter population shown in Table 3. Note: actual number of meters to be ordered will be updated at the time of contract negotiations.
2. Provide a list of all alternate AMI Meters, by make and model, which currently work with the proposed AMI solution. Include a roadmap for future AMI Electric Meters that will be compatible with the AMI system.
3. Identify the electric quantities on all meter forms that the AMI meters are capable of measuring.
4. Provide a table that shows the relationship between number of channels, interval length, and days of storage in the proposed AMI Electric Meters. Describe the options to collect data in intervals shorter than 15-minutes.
5. Specify the number of TOU registers available.
6. Describe the process to perform a local demand reset in each proposed meter type.
7. Describe how the day/date/time of AMI Electric Meter is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Electric Meters time synchronized after an outage.
8. Describe the abilities of the proposed AMI Electric Meters and the AMI system to provide time-stamped voltage data, maximum and minimum voltage data, sag and swell events or counts, loss of voltage, etc. Describe the method of measuring voltage, average or RMS. Include the frequency of data retrieval from the AMI Meter by the AMI system (real time, daily, scheduled, or on request).
9. Describe if any meter components (service switch, display, communication board) are serviceable and/or replaceable by VPPSA and/or the Vendor.
10. Vendors shall describe how the "last gasp" notifications occur, or if they may be impeded by the loss of power to a Meter Collection Point (MCP).
11. Vendors shall describe how the "test mode" feature is activated and suspended on each of the proposed models of AMI Electric Meters
12. Provide a list and description of all alerts, events and notifications provided by the AMI Electric Meter. This should include tamper, outage and deviations from nominal AC voltage, frequency, and waveform.
13. Describe if power quality functions are running all the time, or how the AMI Electric Meter can be remotely reconfigured to turn on power quality monitoring when needed.
14. Describe the following service disconnect and reconnect features:

a. Describe both remote and local operation of the service switch, including "arming" features, if any, available with the proposed solution.

b. Specify the number of disconnect/reconnect cycles that the switch is rated to perform at full meter load.

c. Identify if the AMI Meters and/or Head-End System has a duty cycle monitor for the service switch.

d. What features are in place in the AMI Meter to keep the switch from repeatedly cycling open and closed.

e. Describe whether a "demand limiting" capability can be enabled via the AMI Network. This means that control of the switch can be configured to disconnect the service if demand exceeds a threshold value. Service shall be re-connected after a predetermined time interval or when the demand drops below the threshold value. Specify if and how the proposed solution allows the threshold and time interval values to be securely set locally and/or remotely over the network using the AMI Head-End System.

f. Describe at what voltage level the service switch will not close, if the service has been disconnected. Vendor shall describe if this voltage level can be specified by the utility and how it is set.

15. Describe the local communication software and methods between the AMI meters and staff who locally read and/or service the meter. Local communications may be with a radio interface, WiFi or an optically isolated connection accessible on the outside of the meter cover.

16. Describe the AMI Meter's internal memory. Vendor shall describe how the proposed AMI performs in the event of a communication failure and the AMI meter's ability to store data until communication has been re-established.

17. Describe the meter's program security provisions including but not limited to the following information:

a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

c. Explanation of the provisions securing communication with the meter via the meter's local communications portal(s) (optical and/or RF.

18. Describe the use of batteries, if any, in proposed AMI Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures.

19. Provide details of all metering compliance (ANSI, UL, IEC, etc.) and certifications.

20. Provide details of the failure rate for the proposed AMI Meters.

1.2 Water Meter Endpoints & Water System Features

VPPSA intends to place priority on utilizing existing water meters that already have touch-type registers and converting them to the AMI system being proposed. Where meters do not have AMI-compatible registers, proposer may elect to either replace registers with AMI-ready registers or replace entire meter with new AMI Water Meters which meet the standards and specifications outlined in this section.

The functional and technical requirements for the new AMI endpoints, known hereon as Meter Interface Units (MIUs). These MIUs shall be used to convert existing compliant water meters to AMI Water Meters. And, where necessary, new water meters shall be provided by the Vendor as part of this AMI project, inclusive of compatible MIUs. VPPSA reserves the right to purchase one meter type or more than one meter type based upon project needs and negotiations with the Vendor.

VPPSA members having water metering as part of this project generally have mechanical meters currently in place. These include, but not limited to, positive displacement, turbine and compound meters. Meters proposed in response to this RFP should be similar in size and measurement technology. More modern technologies, such as magnetic resonance, ultrasonic, or others, may be proposed and will be considered by VPPSA Members for use in this project.

For those VPPSA Members that have water meters as part of this project, the meters are generally located inside basements, utility closets, etc. Few will be located outdoors in meter pits or vaults. Vendor shall provide propagation analysis and outline installation considerations for proper operation and to maximize radio performance between the AMI Water Meter MIU and AMI MCPs.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 7

Question	**Response:** Comply, No Comply or Alternative

1. The AMI Water Meters provided as part of this solicitation shall be new meters meeting applicable AWWA and ANSI standards relative to type.	
2. Functional features of the new AMI Water Meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming shall be done at the factory according to utility specifications.	
3. AMI Water Meters and MIUs provided by vendor as part of this project shall have a 20-year life.	
4. All AMI Water Meters and MIUs together shall record total water delivered, detect reverse flow, and provide notification of alert conditions to the Head End system.	
5. The AMI Meters shall have the capability to record and store interval data in interval lengths of 15, 30, or 60 minutes.	
6. The AMI Water MIUs shall feature security provisions to prevent local reading, configuration or programming by anyone other than authorized personnel.	
7. New AMI Water Meter supplied for this project shall be equipped with registers capable of presenting at least eight digits, either digital or mechanical, and provide electronic features for scale output resolution.	
8. The meter nameplate shall include all applicable meter identification information. This information shall include, at minimum, a unique 8-digit numeric meter/register ID, manufacturer’s name, FCC data, manufacturing date, bar coding, etc.	

9. Prior to shipment from the factory, the meter manufacturer shall test each meter and certify the accuracy and proper operation of the meter to AWWA/ANSI standards for the specific type of water meters.	
10. A file with meter attribute information and test results shall be electronically provided to VPPSA prior to every shipment from the manufacturer that includes the following information about the delivery: 1) Water meter type 2) Water meter size 3) Water meter serial numbers 4) Water meter test results 5) Meter register types 6) Meter register ID numbers	
11. The meter shall not require any special equipment for shop or field-testing procedures. All standard test equipment can be used for testing in both the field and the shop.	
12. AMI Water Meter MIU has ability to be retrofitted to existing water meters that have touch pads (external on wall for indoor/basement meters).	
13. AMI Water Meter register output to the MIU is ASCII-based, serial communication, no pulse-based registers will be allowed.	
14. Communication from the AMI Water Meter register shall include the meter register's unique ID and current meter reading, at minimum.	
15. The Vendor shall provide clear instructions for the wiring connection between the radio transmitter and encoder registers. All wiring connectors or splices	

shall be tamper resistance providing signs that the wire has been tampered with or disconnected.	
16. AMI Water Meter registers shall record usage in US Gallons or Cubic Feet as determined during negotiations.	
17. New AMI Water Meter encoder registers shall display a minimum of eight digits (high resolution). The register shall be shipped factory programmed encoding all digits, a minimum of eight digits.	
18. New AMI Water Meter encoder registers should be programmable so that Member personnel may alter the meter reading configuration. This includes, but is not limited to, the number of digits in the reading.	
19. New AMI Water Meter encoder registers shall be attached to the meter body by a method that will prevent or discourage customers from tampering with the meter and register. The register terminal screw cap shall allow for the sealing of the terminal screws.	
20. The register shall have permanently stamped on the dial face the manufacturer, meter size, meter type, register type and unit of measure.	
21. The register shall have a low flow indicator visible on the face of the meter for use by the customer in the detection of a leak within the property.	
22. For new AMI Water Meters and MIUs, the Vendor shall supply a wire connector that is certified as an IP 68 connection, tamper proof and can be connected and disconnected without having to cut the wire or destroy the connector itself. There shall be no manual connections (e.g. gel caps) and there must	

be consistency among connectors across all meter brands provided. Where the connector needs to be installed or potted to the water meter register, it is the Vendor's responsibility to handle all communications, carrying costs and shipping costs imposed by the water meter register manufacturer(s).	

Provide detailed responses for the following questions:

Meter Interface Units (MIUs)

1. Identify the specific makes and models of MIUs that support conversion and/or replacement of 100% of the water meter population shown in Table 4. Note: actual number of MIUs and/or meters to be ordered will be updated at the time of contract negotiations.
2. Outline whether or not the proposed MIU has a multi-port option that will allow a multi-register AMI Water Meter to be read from a single MIU.
3. Provide a table that shows the relationship between datalogging interval and days of storage in the proposed AMI Water Meters. Describe the options to collect data in varying intervals, such as hourly, 30-minute, 15-minutes, etc.
4. Describe how the day/date/time of AMI Meters is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Meters time synchronized after a network outage, firmware updates, demand reads and commands (remote shut off, etc.).
5. Provide a list and description of all alerts, events and notifications provided by the AMI Water Meter. This should include battery level, wire tamper, reverse flow, register removal, magnetic tamper, leak detection.
6. Describe the leak detection functionality of the water meter MIU and how it will work with 6-digit registers that are part of the existing meter inventory.
7. Describe the local communication software and methods between the AMI Water Meters, MIUs and staff who locally read and/or service the water meter. Local communications shall be done using a wireless interface.

8. Describe the use of batteries in proposed AMI Water Meter MIUs. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures (if applicable). Describe how the low battery flag triggered, by a time-based calculation or by monitoring voltage?
9. Provide details regarding the typical and maximum expected failure rate for the proposed AMI Water Meters, registers and MIUs.
10. Describe the internal memory of the MIU. Vendor shall describe how the proposed AMI system performs in the event of a communication failure and the AMI Water Meter MIU's ability to store data until communication has been re-established.
11. Describe the MIU's programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.
    b. Explanation of how program access and change events are recorded by the MIU.
12. For indoor/basement water meter products, provide:
    a. Preferred mounting method of MIU (wall enclosure or flange).
    b. Two-wire and three-wire capability
    c. Describe how the MIU is to be connected to the AMI Water Meter register (e.g. splice, connector, etc.).
13. For pit-installed products, provide:
    a. Preferred mounting method.
    b. Minimum requirements of the meter pit lid (material construction, maximum thickness, depth of through the lid antenna recess necessary to make the antenna flush with the top of the lid and diameter of hole).
    c. Minimum clearance needed between the top of meter to bottom of pit lid.
    d. Describe how the radio is wired to the register (e.g. splice, connector).
14. Explain the provisions for securing communication with the meter via the meter's local communications portal(s) – optical and/or RF.
15. Provide MIU battery life warranty (in years). Describe the conditions of the warranty, such as if On-Demand Reads affect warranty terms, and if so to what extent.
16. Describe any other non-metering devices the AMI radio transmitter is compatible with.

<u>New AMI Water Meters & Registers</u>

17. Provide a table listing all AMI Water Meters being proposed by Vendor as part of this project. Include a listing of compatible AMI Water Meters indicating manufacturer, model and sizes, approved for use with the proposed AMI solution. Include any roadmap for future AMI Water Meters to be compatible with the proposed AMI system.
18. Provide details regarding the failure rate for the proposed AMI Water Meter registers.
19. Describe any provision for water service disconnect and reconnect options which may be incorporated in the water service:
    a. Describe both remote and local operation of the service disconnect functions.
    b. Specify the number of disconnect/reconnect cycles that the meter and MIU are capable of performing.
    c. Identify if the AMI Water Meter, MIU and/or Head-End System have a duty cycle monitor for the water service disconnect.
    d. What features are in place in the AMI Water Meter to keep the valve from repeatedly cycling open and closed or sticking.
    e. Describe whether a “flow-limiting” capability can be enabled via the AMI Network. This means that control of the service disconnect valve can be configured to provide limited water flow and be securely set locally and/or remotely over the network using the AMI Head-End System.
20. Describe the use of batteries in proposed AMI Water Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management practices and battery replacement procedures (if applicable).
21. Provide details of all meters regarding compliance with industry standards such as AWWA, ANSI, etc. Include any additional industry certifications.
22. Provide details regarding the failure rate for the proposed AMI Water Meters.
23. Describe the internal memory of the AMI Water Meter. Vendor shall describe how the proposed meter performs in the event of a communication failure between the meter register and MIU.
24. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.
25. Describe the meter’s programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

26. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

Remote Disconnect Water Meters & Leak Detection

27. Provide AMI Water Meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

1.3 AMI Network

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 8

Question	**Response:** Comply, No Comply or Alternative
1. AMI Solution shall use the same network for electric and water endpoints. The same MCPs will be used for both as well.	
2. AMI Network shall include two-way transport of data and commands between AMI endpoints and their respective AMI MCPs, which transfer the messages to/from the AMI Head-End System via the Vendor's proposed backhaul network.	
3. AMI System shall not rely on any collector device which may become a single point of failure for data retrieval of any specific endpoints.	

4. Authorized utility personnel shall be able to remotely access and modify all configurable AMI Meter programming/configuration parameters via the AMI Network.	
5. AMI System shall be IPv6 compliant.	
6. All elements of the proposed AMI Network shall support industry best practices for protection of data confidentiality, data integrity, and operational security.	
7. AMI Radio transmitters shall have multiple pathways to the Head End System with the intent of eliminating any single point of failure (redundancy).	

The following section includes the functional and technical requirements for interoperation of the AMI Head-End System, AMI Network, MCP's, and AMI MIU endpoints. If applicable, responses must include information for both AMI Electric Meters and AMI Water Meters. Please be sure that all responses cover both commodities (electric and water) where differentiation is necessary. VPPSA requires an AMI Network that will transport data and commands which support the proposed AMI functions at all AMI endpoints, in accordance with the functional and performance requirements specified throughout this RFP.

Provide detailed responses for the following questions:

1. Describe the proposed AMI Network and backhaul network provisions that will serve AMI endpoints. AMI endpoints will communicate with MCPs, and the MCPs will communicate directly with the Vendor's proposed backhaul network. Available fiber take-out points owned by VPPSA members are available, see Section 3 for background. Use of fiber for backhaul is preferred, wherever available.
2. Provide a network design showing the number and approximate location of MCP and/or Repeaters (if necessary) on a map of VPPSA member service territories. Use the GIS data provided in the files listed in Section 3.0. For purposes of sizing and configuring the network, assume the following baseline system activity:
    a. On-demand reading requests shall have an average response time of 30 seconds or less at least 90% of the time.

b. All polyphase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System three times within a 24 hour period.
c. All single-phase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System once every 24 hours.
d. The AMI Head-End System shall daily send 100 individual control message commands to AMI Meters with an integrated service switch to perform 50 connections or disconnections a day.
e. All AMI Meters will send outage notifications to the Head-End System as they occur.

3. Provide the percentage of total usable AMI network communication capacity Vendor expects to be used in the proposed AMI system under the baseline operating conditions described above. Additionally, Vendors shall predict the percent of network capacity utilized at the point in the AMI system with the least communication capacity and shall also recommend the maximum percentage loading that Vendor considers acceptable for VPPSA's intended uses of the AMI system.

4. Provide a proposed installation diagram that shows spacing requirements and where the MCP and associated equipment is to be placed on power poles, towers or other structures.

5. Provide the specification sheet for the MCP and associated equipment. Specifications must include how the MCPs will be powered and if there are any battery requirements or remote antennas needed. If multiple MCPs or external antenna versions are prescribed, then specification sheets will be included for each model variant.

6. All AMI firmware in the AMI Meters, Network devices, and customer premise devices, shall be remotely accessible for review, modification, and replacement over the AMI Network.

7. Describe how personnel will perform firmware upgrades (patches) using either the Head-End System or remote meter management software with the AMI Network. Clearly describe the AMI Meter's ability to sense, reverse, and report unauthorized or unsuccessful firmware replacements.

8. Describe how the AMI Radio transmitters will be read by more than one AMI data collector, providing MCP redundancy).

1.4 Head End System, Meter Data Management and Operations Software

VPPSA is seeking hosted software for both the Head-End System (HES) and Meter Data Management System (MDMD) functionality. The Proposer shall provide day to day support for the AMI solution. Seamless integration between HES and MDMS functions is expected.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 9

Question	**Response:** Comply, No Comply or Alternative
1. The Head End and Meter Data Management systems shall be established, well-proven, commercially available products based on widely adopted technology standards.	
2. The Head End Software shall manage all meter interrogations and communications for the AMI Network.	
3. The HES shall: • Accept and schedule readings based on the billing system scheduled reads file • Perform scheduled demand meter resets based on the billing system scheduled reads file • Provide a meter reading file for the billing system of scheduled reads • Report unread meters in scheduled routes/cycles • Reschedule unread scheduled readings for following day reading file for the billing system • Report on exceptions.	
4. The HES shall gather the billing data from 99% of the meters successfully read each day without estimation.	

5. The AMI System shall not fail to retrieve billing data from any single meter more than 15 consecutive days in the absence of a permanent AMI communication failure.	
6. Data stored in the AMI Meters and/or in the AMI Network shall be stored for a minimum of five-years from the day the data is first stored.	
7. The Head End Software and Meter Data Management Software shall be located in a Tier 3 datacenter, at minimum.	
8. The MDMS shall be capable of Validation, Estimation and Editing (VEE) prior to delivering data to a member's billing system.	
9. The MDMS shall provide a dashboard and reports showing the status of data by Member and aggregated for all VPPSA members.	
10. A Service Level Agreement for the defined Tier 3 datacenter 99.982% datacenter uptime availability shall be provided.	
11. The HES and MDM shall have disaster recovery services.	
12. The MDMS shall calculate Time-Of-Use billing determinants by rate class or for individual customers.	
13. The MDMS shall support any billing calculations required by VPPSA members, e.g. Critical Peak Pricing, Dynamic Pricing, Aggregated Load, Net Billing for solar groups.	
14. Support for the AMI Network and Wide Area Services shall be included in the support services.	
15. Backup services of all software, data and configurations shall be performed at least daily.	

16. Backups shall be stored off site in a geographic region different from the hosting data center.	
17. The HES and MDM databases must be encrypted.	
18. The Head End Software supports a multi-tenant solution where each tenant has its own separate data and application set, independent of other tenants.	
19. The Head End Software shall support each tenant executing the same application set, but shared among the various tenets	
20. The HES shall provide software keys to separate individual member's data, in addition to security built into meters.	
21. The Meter Data Management System shall provide software keys to separate individual members data, in addition to security features that are built into the proposed meters.	
22. User access shall be limited to individual member system's database.	
23. VPPSA Administrator's user credentials shall be configured to allow access all Member's system data.	
24. Individual VPPSA Members shall be allowed access to only individual member's meter and system data.	
25. For VPPSA Administrators, reporting shall be set to report on combination of individual Members system data, i.e. VPPSA wide statistics.	
26. Policies, safeguards, parameters and monitoring shall be in place to prevent unacceptable interference (performance, high workload) problems among tenants.	

Provide detailed responses for the following questions:

1. Provide a description of the features and functionality of the HES and MDMS (maximum of 2-pages for each system).
2. Provide screen shots of the Head-End System dashboard and key screens or reports available from the proposed Head-End system.
3. Provide details of daily procedures to manage meters, collectors, and network.
4. Provide details of procedures when there is failure of meters, collectors, and network.
5. Describe the Validation, Editing and Estimation available in the MDMS.
6. Describe the types of billing determinant calculations available in the MDMS.
7. Provide screen shots of the Meter Data Management System dashboard and key screens or reports available from the proposed MDMS.
8. Describe the Data Center(s) hosting the HES and MDMS. Include ownership, location, physical facilities, tier and security.
9. Provide a copy of the Service Level Agreement with the hosting data center.
10. Describe the type of hosting services provided such as: Infrastructure as a Service (IaaS), Platform as a Service (PaaS), Software as a Service (SaaS)
11. Describe the disaster recovery services and process.
12. Describe separately the multi-tenant features of the HES and the MDM including login levels, data security and encryption capabilities of the proposed system.
13. Describe the data protection and operational security provisions in the HES and MDMS.

1.5 Other Capabilities with the AMI System

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 10

Question	Response: Comply, No Comply or Alternative
1. The AMI System shall support a customer pre-payment function.	

2. The AMI System shall support the measurement of load from electro-technologies such as electric vehicles.	
3. The AMI System solution shall provide load control capabilities integral to the AMI system and software.	

Provide detailed responses for the following questions:

1. Explain any additional system functionality available today which would add value to the project.

2022 Long-Term Forecast Report

VERMONT PUBLIC POWER SUPPLY AUTHORITY

SWANTON VILLAGE, INC.

Prepared For:
VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared By:
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2022 LONG-TERM DEMAND FORECAST SUMMARY – SWANTON VILLAGE, INC.

The Swanton Village Inc. (Swanton) serves 3,300 customers in the Village of Swanton and Towns of Swanton, St. Albans, and Highgate. Residential customers account for approximately 50% of sales and small and medium commercial for the remainder.

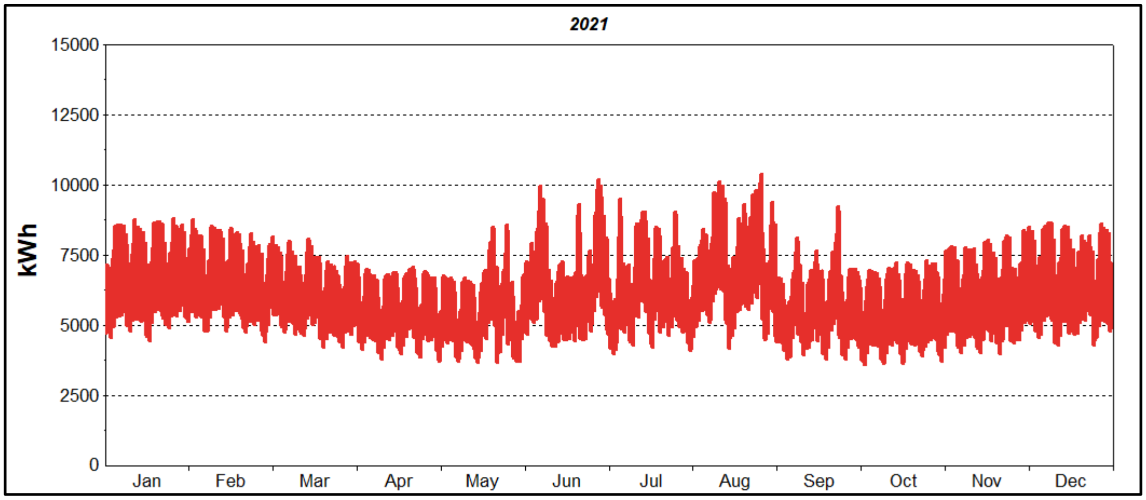
Over the last ten years, Swanton's electric load has averaged 0.4% annual growth. Increase in the residential sales has largely been driven by relatively strong customer growth (when compared with other Vermont utilities) and a small increase in average use; customer growth has averaged 0.4% per year and average use 0.2% per year. Combined this translates into 0.6% average annual residential sales growth. Non-residential sales (Small and Large C&I revenue classes) have been increasing at slower 0.2% annual rate; this includes as 7.7% jump in 2012 sales a 5.2% drop in sale in 2020. The 2020 decline is largely attributable to the business response to COVID-19: 2021 sales are still below 2019 levels. The residential sector saw the opposite with a 4.1% jump in 2020 sales; residential sales are still trending at a more elevated level. Table 1 shows historical customer and sales.

TABLE 1: SWANTON HISTORICAL CALENDARIZED SALES AND CUSTOMERS

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2011	25,655		3,202		8,012		25,813		51,467	
2012	25,732	0.3%	3,194	-0.2%	8,056	0.6%	27,801	7.7%	53,533	4.0%
2013	26,124	1.5%	3,208	0.4%	8,143	1.1%	28,028	0.8%	54,152	1.2%
2014	26,279	0.6%	3,202	-0.2%	8,207	0.8%	27,988	-0.1%	54,266	0.2%
2015	26,742	1.8%	3,232	0.9%	8,274	0.8%	27,990	0.0%	54,732	0.9%
2016	26,010	-2.7%	3,236	0.1%	8,038	-2.9%	27,892	-0.4%	53,903	-1.5%
2017	25,835	-0.7%	3,263	0.8%	7,918	-1.5%	27,362	-1.9%	53,197	-1.3%
2018	26,774	3.6%	3,259	-0.1%	8,215	3.8%	27,514	0.6%	54,288	2.1%
2019	26,227	-2.0%	3,278	0.6%	8,001	-2.6%	27,518	0.0%	53,745	-1.0%
2020	27,309	4.1%	3,306	0.9%	8,260	3.2%	26,084	-5.2%	53,393	-0.7%
2021	27,275	-0.1%	3,340	1.0%	8,166	-1.1%	26,198	0.4%	53,473	0.2%
11-21		**0.6%**		**0.4%**		**0.2%**		**0.2%**		**0.4%**

Swanton peaks in the summer months. System peak is approximately 10 MW. 10 MW Figure 1 shows the 2021 system hourly load.

FIGURE 1: SWANTON SYSTEM LOAD 2021



Forecast Approach

The Swanton long-term forecast is constructed using a bottom-up modeling approach where the forecast starts at the revenue-class (e.g., residential, commercial, and industrial) and with heating, cooling, and base-use sales derived from the sales models used in constructing and forecasting peak demand. System energy is based on the historical relationship between total monthly sales and monthly system delivered energy. A similar modeling approach has been used for all the VPPSA members, GMP, Burlington Electric, and VELCO. A detailed description of the modeling approach is included in the 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For Swanton, this includes residential, small commercial, large C&I, and other (other is primarily street lighting and is relatively small). Models are estimated using monthly linear regression models with historical billed sales and customer counts from January 2011 to December 2021. Model estimated coefficients, statistics and actual and predicted and results are included in APPENDIX A.

The baseline forecast captures expected load growth before adjustments for new PV adoptions, electric vehicle (EV), and cold climate heat pumps (CCHP). Baseline sales are driven by customer growth projections, state economic forecasts, end-use efficiency and saturation projections and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model integrates end-use saturation and efficiency trends that change slowly over time with variables that impact month-to-month sales variation and capture economic growth; this includes temperatures (HDD and CDD), economic conditions (household income, employment, and state output), and demographic trends (population, number of households, household size).

Economic Drivers

Historical and forecasted economic data is provided by Moody's Analytics. Forecasts are based on the January 2022 economic forecast. Model inputs include number of households, household income, gross state product, and employment. Economic data is provided in 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Efficiency and End-Use Saturations

End-use efficiency and saturations are derived from the 2020 Annual Energy Outlook (AEO) for the New England Census Division. Historical and projected residential saturations are adjusted to reflect Vermont where data is available. We assume commercial building energy intensities (measured in kWh per sq. ft.) for Vermont are like those of New England. The forecast is further adjusted for state energy efficiency program savings derived from the current state Demand Resource Plan (DRP). Swanton accounts for 1.4% of state residential sales and 0.2% of commercial sales.

Weather

Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are based on Burlington International Airport temperature data. Since 1970, average temperatures have been increasing 0.08 degrees per year (0.8 degrees per decade). This is reflected in the number of cooling degree-days (CDD) which are increasing 1.3% per year on a relatively low base (there are not many CDD in Vermont) and decrease in heating degree-days (HDD) of 0.3% per year. We assume average temperature continues to increase at the current rate through the forecast period with decline in HDD contributing to lower heating requirements and increase in CDD to higher cooling requirements.

COVID-19

The "work at home" and closure of most retail businesses had a significant sales impact starting in late March 2020. The commercial sector saw a significant decline in sales while residential a large increase. Through 2021 sales began to normalize as more people went back to work. While there has been continued *sales normalization*, recent data from Burlington Electric and GMP has shown the trend through mid-July 2022 has slowed. We are seeing permanent structural change as many businesses transition to hybrid work environment (part-time at home and part-time at the office) and increasing number of workers that are and will continue to be working on a fully remote basis. COVID residential and nonresidential model variables are based on Vermont Google mobility data through the end of 2021. The mobility data measures the cellphone call volume variance from March 2020 (the month before COVID's load impact). In residential call volume increased and in the nonresidential workplaces call volume decreased. For the forecast we trend the mobility variables back to base value in March 2020. By 2023 we hold the COVID variables at 90% of pre-COVID level to capture what we believe will be some permanent shift in residential average use (up slightly from pre-COVID levels) and commercial sales (down slightly from pre-COVID levels).

A detailed description of the baseline model structure, and model inputs are included in 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Results

Slow state household and economic growth projections coupled with expected efficiency improvements (both due to appliance purchases and state EE programs) and temperature trends results in flat baseline sales growth. Baseline sales are expected to reach 53,925 MWh in 2032 compared with expected year-end sales (2022) of 53,662 MWh – a 0.5% increase. Table 2 shows Swanton baseline customer and sales forecast.

TABLE 2: SWANTON BASELINE SALES FORECAST

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2022	26,852		3,355		8,004		26,810		53,662	
2023	26,662	-0.7%	3,384	0.9%	7,879	-1.6%	27,097	1.1%	53,759	0.2%
2024	26,644	-0.1%	3,407	0.7%	7,821	-0.7%	27,104	0.0%	53,749	0.0%
2025	26,477	-0.6%	3,426	0.6%	7,727	-1.2%	27,085	-0.1%	53,562	-0.3%
2026	26,462	-0.1%	3,444	0.5%	7,682	-0.6%	27,062	-0.1%	53,524	-0.1%
2027	26,422	-0.2%	3,461	0.5%	7,635	-0.6%	27,038	-0.1%	53,459	-0.1%
2028	26,509	0.3%	3,476	0.4%	7,626	-0.1%	27,022	-0.1%	53,530	0.1%
2029	26,583	0.3%	3,491	0.4%	7,615	-0.1%	26,997	-0.1%	53,580	0.1%
2030	26,698	0.4%	3,505	0.4%	7,617	0.0%	26,976	-0.1%	53,675	0.2%
2031	26,818	0.4%	3,518	0.4%	7,623	0.1%	26,952	-0.1%	53,770	0.2%
2032	26,987	0.6%	3,530	0.3%	7,645	0.3%	26,938	-0.1%	53,925	0.3%
2033	27,012	0.1%	3,541	0.3%	7,629	-0.2%	26,908	-0.1%	53,919	0.0%
2034	27,084	0.3%	3,549	0.2%	7,631	0.0%	26,886	-0.1%	53,970	0.1%
2035	27,190	0.4%	3,557	0.2%	7,644	0.2%	26,864	-0.1%	54,054	0.2%
2036	27,363	0.6%	3,565	0.2%	7,676	0.4%	26,856	0.0%	54,219	0.3%
2037	27,399	0.1%	3,571	0.2%	7,673	0.0%	26,831	-0.1%	54,229	0.0%
2038	27,449	0.2%	3,576	0.1%	7,676	0.0%	26,814	-0.1%	54,263	0.1%
2039	27,500	0.2%	3,580	0.1%	7,681	0.1%	26,796	-0.1%	54,295	0.1%
2040	27,617	0.4%	3,584	0.1%	7,706	0.3%	26,778	-0.1%	54,396	0.2%
2041	27,665	0.2%	3,587	0.1%	7,713	0.1%	26,747	-0.1%	54,412	0.0%
2042	27,776	0.4%	3,589	0.1%	7,739	0.3%	26,725	-0.1%	54,500	0.2%
22-32		0.1%		0.5%		-0.5%		0.0%		0.0%
32-42		0.3%		0.2%		0.1%		-0.1%		0.1%

Adjusted Forecast

The baseline forecast is adjusted for new behind-the-meter (BTM) solar projections starting in 2022, electric vehicles, and cold climate heat pumps (CCHP). Future electricity sales and demand growth will largely be driven by these technologies that are being promoted as part of the state's electrification programs designed to reduce greenhouse gas emissions. Two of the primary targets are heating – converting fossil fuel heat to cold climate heat pumps (CCHP) and Electric Vehicles (EV). The state, through VEIC and state utilities are promoting the adoption of CCHP and EVs with rebates, low-interest loans, and building out electric vehicle infrastructure. Expected increase in behind the meter solar adoption (PV) mitigates some of the long-term energy growth. The statewide forecast of these technologies (CCHP, EV, and PV) were developed through a collaborative process as part of the *Vermont Electric Power Company (VELCO) 2021 Long-Term Transmission Plan*. Forecast contributors include the Department of Public Service (DPS), the Vermont Energy Investment Company (VEIC), state utilities, and other state stakeholders. We are beginning work to update these assumptions as result of the recently passed *Vermont Climate Action Plan*.

CCHP, EV, and PV forecasts are derived by allocating the state forecast based on Swanton's share of state residential and commercial customers. Table 3 shows the resulting forecast.

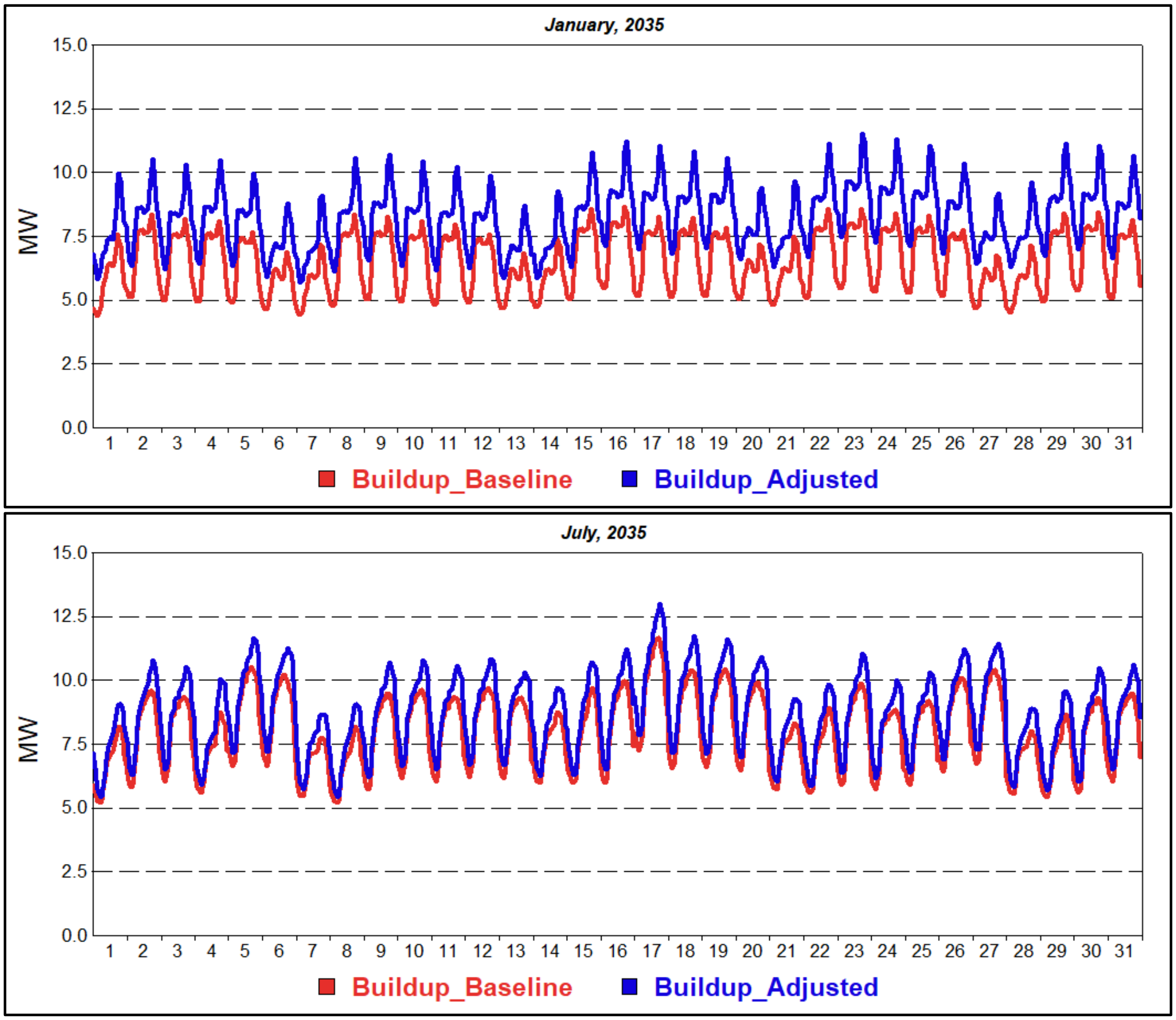
TABLE 3: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	23	13	59
2023	53	29	125
2024	93	45	196
2025	144	55	273
2026	211	60	355
2027	297	65	444
2028	406	68	539
2029	541	69	641
2030	705	71	739
2031	900	74	823
2032	1,122	77	904
2033	1,367	78	981
2034	1,624	80	1,059
2035	1,879	80	1,137
2036	2,120	82	1,218
2037	2,333	83	1,299
2038	2,513	84	1,381
2039	2,657	84	1,463
2040	2,768	86	1,547
2041	2,845	87	1,627
2042	2,900	88	1,707

Technology annual energy forecasts are estimated by combining technology characteristics such as average historical load profile, heating and cooling unit energy consumption, average miles driven, and technology efficiency trends with unit forecasts. Hourly (8,760) technology forecasts are then generated by combining technology annual energy forecast with technology hourly profiles that reflect seasonality, solar load patterns, and expected HDD and CDD.

The system adjusted hourly load forecast is calculated by subtracting PV hourly load forecast and adding EV and CCHP load forecasts to the baseline hourly load forecast. Figure 3 shows the baseline and adjusted hourly load forecast for January and July 2035.

FIGURE 2: BASELINE AND ADJUSTED HOURLY LOAD FORECAST



By 2035, EVs and CCHP add significant load. In the summer adjustments add 1.3 MW to baseline demand forecast and in the winter 2.2 MW. The winter load adjustments are much higher than summer adjustments as both EV charging and CCHP winter peak hour load impacts are higher. Adjusted energy is calculated by adding the hourly adjusted load forecasts and winter and summer peak demands are derived by finding the highest hourly load in each season and year. Table 4 shows the adjusted energy and demand forecasts.

TABLE 4: SWANTON ENERGY FORECAST (MWH)

Energy and Peak										
Year	Energy (MWh)	Chg	Energy WN (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2011	56,312		56,417		10.32		7/21/11 5:00 PM	9.29		12/28/11 5:00 PM
2012	57,184	1.5%	57,274	1.5%	10.66	3.3%	6/21/12 2:00 PM	9.40	1.3%	12/27/12 5:00 PM
2013	56,608	-1.0%	56,696	-1.0%	10.66	0.0%	7/19/13 3:00 PM	9.72	3.4%	1/24/13 5:00 PM
2014	56,764	0.3%	56,846	0.3%	10.36	-2.8%	7/1/14 12:00 PM	9.61	-1.2%	1/7/14 5:00 PM
2015	57,967	2.1%	57,478	1.1%	10.96	5.8%	8/19/15 3:00 PM	9.71	1.0%	1/8/15 9:00 AM
2016	57,469	-0.9%	57,198	-0.5%	10.94	-0.2%	8/11/16 4:00 PM	9.25	-4.7%	12/19/16 5:00 PM
2017	56,342	-2.0%	56,698	-0.9%	10.20	-6.8%	9/27/17 1:00 PM	9.68	4.7%	12/28/17 5:00 PM
2018	56,356	0.0%	55,669	-1.8%	10.75	5.5%	7/2/18 4:00 PM	9.62	-0.6%	1/2/18 5:00 PM
2019	54,737	-2.9%	54,983	-1.2%	10.38	-3.4%	7/30/19 3:00 PM	9.68	0.6%	1/21/19 5:00 PM
2020	55,271	1.0%	55,163	0.3%	10.78	3.8%	7/27/20 5:00 PM	9.50	-1.8%	12/15/20 5:00 PM
2021	54,483	-1.4%	54,492	-1.2%	11.28	4.7%	8/26/21 2:00 PM	9.23	-2.8%	1/25/21 5:00 PM
2022	55,862	2.5%			10.80	-4.2%	7/19/22 4:00 PM	9.01	-2.4%	2/14/22 6:00 PM
2023	56,185	0.6%			10.92	1.1%	7/18/23 4:00 PM	9.16	1.7%	2/13/23 6:00 PM
2024	56,440	0.5%			11.02	0.9%	7/16/24 4:00 PM	9.14	-0.2%	2/12/24 6:00 PM
2025	56,575	0.2%			11.12	0.8%	7/15/25 4:00 PM	9.51	4.0%	2/10/25 6:00 PM
2026	56,935	0.6%			11.24	1.1%	7/21/26 5:00 PM	9.46	-0.5%	1/20/26 5:00 PM
2027	57,347	0.7%			11.36	1.1%	7/20/27 5:00 PM	9.60	1.5%	1/19/27 5:00 PM
2028	57,996	1.1%			11.50	1.2%	7/18/28 5:00 PM	9.73	1.3%	1/18/28 5:00 PM
2029	58,731	1.3%			11.65	1.3%	7/17/29 5:00 PM	9.92	2.0%	2/12/29 6:00 PM
2030	59,605	1.5%			11.84	1.7%	7/16/30 6:00 PM	10.20	2.8%	2/11/30 6:00 PM
2031	60,555	1.6%			12.05	1.7%	7/15/31 6:00 PM	10.47	2.6%	2/10/31 6:00 PM
2032	61,660	1.8%			12.29	2.0%	7/20/32 6:00 PM	10.72	2.4%	1/20/32 6:00 PM
2033	62,672	1.6%			12.53	2.0%	7/19/33 6:00 PM	11.05	3.0%	1/18/33 6:00 PM
2034	63,786	1.8%			12.79	2.1%	7/18/34 6:00 PM	11.24	1.8%	1/24/34 6:00 PM
2035	64,934	1.8%			13.02	1.8%	7/17/35 6:00 PM	11.54	2.6%	1/23/35 6:00 PM
2036	66,116	1.8%			13.28	2.0%	7/15/36 6:00 PM	11.91	3.2%	1/22/36 6:00 PM
2037	67,047	1.4%			13.50	1.7%	7/21/37 6:00 PM	12.29	3.2%	1/20/37 6:00 PM
2038	67,884	1.2%			13.72	1.6%	7/20/38 6:00 PM	12.55	2.1%	1/19/38 6:00 PM
2039	68,596	1.0%			13.91	1.3%	7/19/39 6:00 PM	12.73	1.4%	1/18/39 6:00 PM
2040	69,264	1.0%			14.07	1.2%	7/17/40 6:00 PM	12.79	0.5%	1/24/40 6:00 PM
2041	69,722	0.7%			14.21	1.0%	7/16/41 6:00 PM	12.94	1.2%	1/22/41 6:00 PM
2042	70,183	0.7%			14.35	0.9%	7/15/42 6:00 PM	13.11	1.3%	1/21/42 6:00 PM
11-21		**-0.3%**		**-0.3%**		**1.0%**			**0.0%**	
22-42		**1.1%**				**1.4%**			**1.9%**	

Projected EV, CCHP, and PVs have a significant impact on load; over the next twenty years, delivered energy is expected to average 1.1% annual growth. This compares with baseline annual sales growth of 0.1%. Winter adjusted peak averages 1.9% annual demand growth and summer 1.4% average annual growth. While winter peaks increase at a faster rate, Swanton remains a summer peaking utility through the forecast horizon.

Table 5 and Table 6 summarizes the demand forecast by base load and technologies.

TABLE 5: SWANTON SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	10.78		0.01	0.00	0.02	10.80	
2023	10.87	0.9%	0.02	-0.01	0.04	10.92	1.1%
2024	10.95	0.7%	0.03	-0.01	0.06	11.02	0.9%
2025	11.01	0.5%	0.05	-0.02	0.08	11.12	0.8%
2026	11.05	0.4%	0.09	-0.01	0.11	11.24	1.1%
2027	11.11	0.6%	0.13	-0.01	0.13	11.36	1.1%
2028	11.17	0.5%	0.18	-0.01	0.16	11.50	1.2%
2029	11.23	0.5%	0.24	-0.01	0.19	11.65	1.3%
2030	11.20	-0.3%	0.43	0.00	0.22	11.84	1.7%
2031	11.26	0.5%	0.55	0.00	0.25	12.05	1.7%
2032	11.34	0.7%	0.68	0.00	0.27	12.29	2.0%
2033	11.40	0.6%	0.84	0.00	0.29	12.53	2.0%
2034	11.48	0.6%	1.00	0.00	0.32	12.79	2.1%
2035	11.53	0.5%	1.16	-0.01	0.34	13.02	1.8%
2036	11.62	0.8%	1.30	-0.01	0.36	13.28	2.0%
2037	11.69	0.5%	1.44	0.00	0.39	13.50	1.7%
2038	11.77	0.7%	1.55	0.00	0.41	13.72	1.6%
2039	11.84	0.6%	1.64	0.00	0.43	13.91	1.3%
2040	11.92	0.6%	1.70	0.00	0.46	14.07	1.2%
2041	11.99	0.6%	1.75	-0.01	0.48	14.21	1.0%
2042	12.06	0.6%	1.79	-0.01	0.51	14.35	0.9%
22-42		**0.6%**					**1.4%**

TABLE 6: SWANTON WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	8.95		0.02	0.00	0.04	9.01	
2023	9.02	0.8%	0.04	0.00	0.10	9.16	1.7%
2024	8.92	-1.2%	0.08	0.00	0.15	9.14	-0.2%
2025	9.18	2.9%	0.12	0.00	0.21	9.51	4.0%
2026	8.92	-2.8%	0.14	0.00	0.40	9.46	-0.5%
2027	8.92	-0.1%	0.20	0.00	0.49	9.60	1.5%
2028	8.87	-0.5%	0.27	0.00	0.59	9.73	1.3%
2029	8.97	1.2%	0.46	0.00	0.49	9.92	2.0%
2030	9.04	0.7%	0.60	0.00	0.57	10.20	2.8%
2031	9.07	0.3%	0.77	0.00	0.63	10.47	2.6%
2032	8.60	-5.1%	1.07	0.00	1.04	10.72	2.4%
2033	8.59	-0.1%	1.32	0.00	1.14	11.05	3.0%
2034	8.45	-1.7%	1.57	0.00	1.23	11.24	1.8%
2035	8.41	-0.5%	1.81	0.00	1.32	11.54	2.6%
2036	8.46	0.7%	2.04	0.00	1.40	11.91	3.2%
2037	8.53	0.8%	2.26	0.00	1.50	12.29	3.2%
2038	8.52	-0.1%	2.43	0.00	1.60	12.55	2.1%
2039	8.46	-0.7%	2.57	0.00	1.69	12.73	1.4%
2040	8.34	-1.4%	2.67	0.00	1.78	12.79	0.5%
2041	8.30	-0.5%	2.75	0.00	1.89	12.94	1.2%
2042	8.32	0.2%	2.81	0.00	1.99	13.11	1.3%
22-42		**-0.4%**					**1.9%**

Baseline summer system peak averages 0.6% per year largely driven by projections of strong air conditioning saturation. Winter baseline demand declines as result of improving energy efficiency across all the non-weather sensitive end-uses excluding miscellaneous. PV has a limited to no impact on peak demand as the system peak has been moved out to later hours from past solar adoption. Most of the load growth is driven by EV charging and CCHP.

2022 LONG-TERM FORECAST MODEL OVERVIEW

INTRODUCTION

Vermont Public Power Supply Authority (VPPSA) serves 11 members located across Vermont. Combined VPPSA members serve 50 communities and over 30,000 customers.

The VPPSA members include:

- Barton
- Enosburg
- Hardwick
- Jacksonville
- Johnson
- Ludlow
- Lyndonville
- Morrisville
- Northfield
- Orleans
- Swanton

Long-term sales, energy, and demand forecasts have been developed for each member.

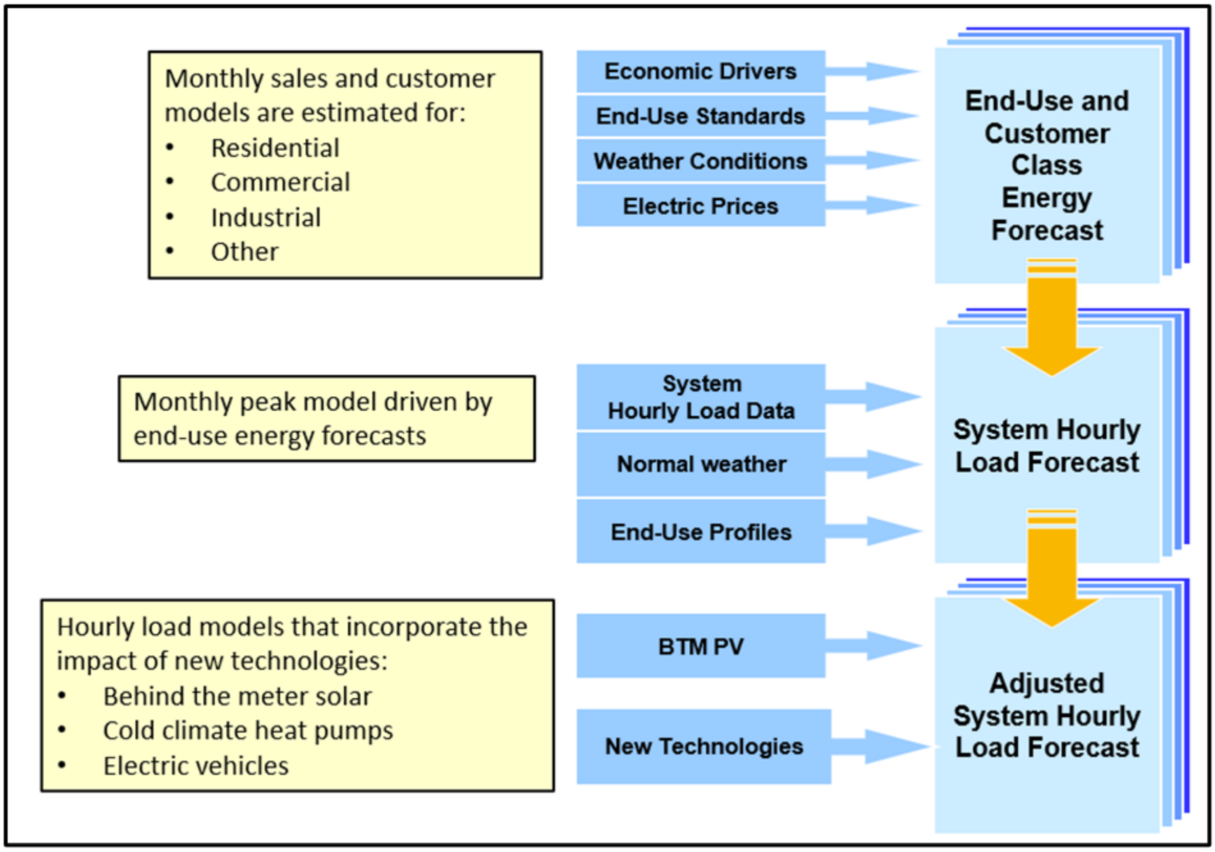
Forecast includes:

- Residential, commercial, industrial, and other classification sales and customers
- Baseline energy and peak demand
- Adjusted energy and peak demand. Adjusted for the impacts of new technologies including electric vehicles, photovoltaic solar, and cold-climate heat pumps.

FORECAST METHOD

The long-term forecasts are based on a bottom-up approach were baseline energy, demand, and hourly load is first developed from underlying customer class heating, cooling, and base-use energy requirements. The baseline hourly load forecast is then adjusted for the long-term load impacts of electric vehicles (EV's), solar (PV's), and cold-climate heat pumps (CCHP). Figure 3 shows the general forecasting approach.

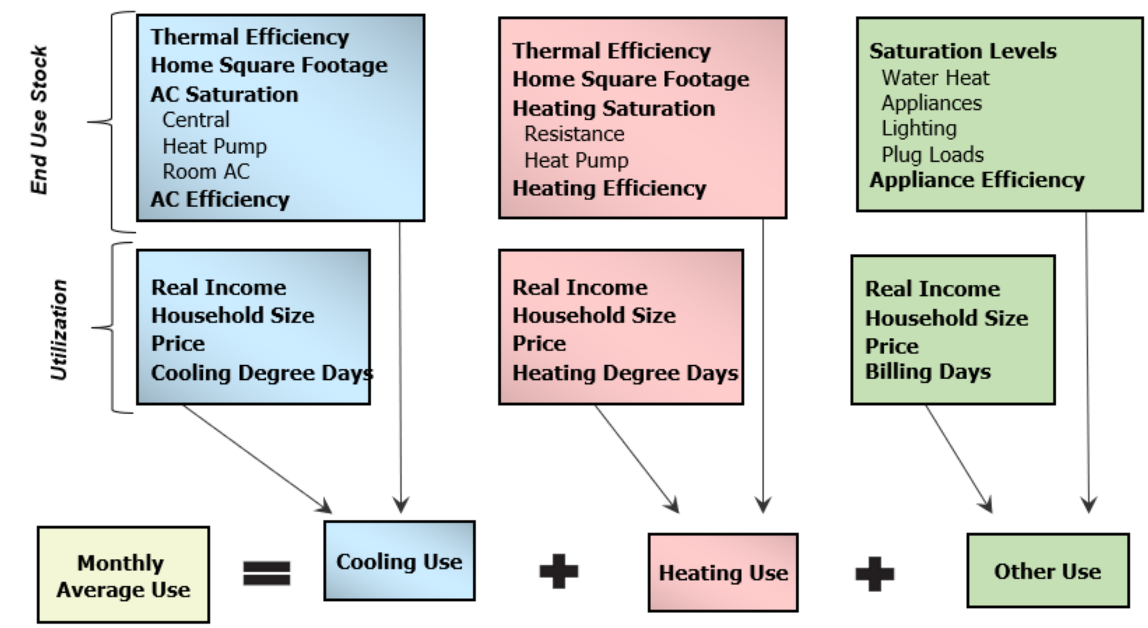
FIGURE 3: FORECASTING FRAMEWORK



Customer Class Sales Forecast

The forecast process starts with estimating sales models for residential, small commercial, large commercial, industrial, and other (mostly street lighting) classes. The residential forecast is derived as the product of the residential average use and customer forecast. Commercial, industrial, and other revenue classes are estimated as total sales models. Models are estimated with monthly billed sales data from January 2011 through December 2021 using linear regression. Models are used to forecast sales and customers based on projected demographic and economic growth, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), and trended normal heating degree-days (HDD) and cooling degree-days (CDD). Where supported by the data, models are estimated using a modeling structure called a Statistically Adjusted End-Use (SAE) model. The SAE model specification integrates the forecast drivers into three primary model variables that include heating (XHeat), cooling (XCool), and other uses (XOther) variables. Figure 4 shows the SAE model specification.

FIGURE 4: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL

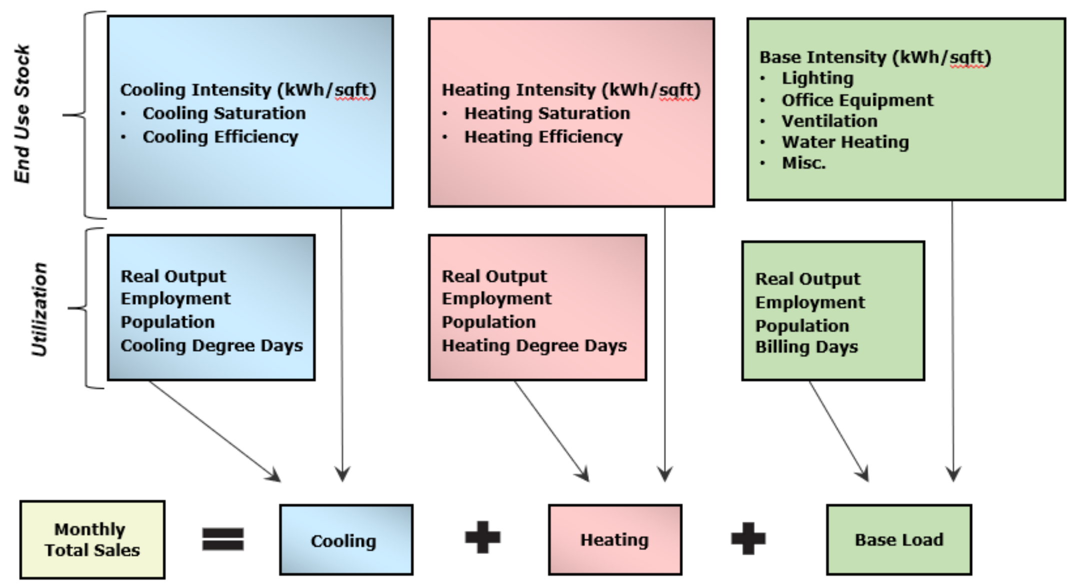


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Residential forecast is the product of the customer forecast and average use forecast. Average use is defined as the sum of average monthly cooling (XCool), heating (XHeat), and other non-weather energy use (XOther). Historical EE estimates are also included in the model to account for any state efficiency savings that are not captured on the primary end-use variables. In most models the variable proved to be statistically insignificant largely as the number of customers and noise in the billing data proved to be too few to pick up much of an impact. A monthly average use regression model is used to estimate the coefficients a, b_c, b_h, and b_o,, and b_e which effectively *statistically adjust* the end-use model variables to actual customer usage. End-use sales estimates are then derived by combining the estimated model coefficients with the model variables (XCool, XHeat, and XOther) for normal weather conditions. The specification is theoretically strong and appropriately captures the impact and interaction of structural model variables (e.g., end-use saturation, efficiency, and thermal shell integrity) with monthly utilization variables – weather conditions, household size, and household income.

A similar SAE model specification is used for the commercial customer classes. Figure 5 shows the commercial model specification.

FIGURE 5: COMMERCIAL SAE MODEL



$$kWh_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d$$

In the commercial model end-use energy intensities are expressed on a kWh per square foot basis. Intensities for cooling, heating, and base-use are derived from EIA's Annual Energy Outlook for the New England Census Division. Annual end-use intensities are combined with monthly utilization variables that include monthly HDD and CDD, and constructed economic driver based that incorporates state economic output, employment, and population. Model variables are used in estimating monthly sales models. Commercial end-use energy requirements are derived as the product of the estimated model coefficient and initial end-use energy estimates (XCool, XHeat, and XOther).

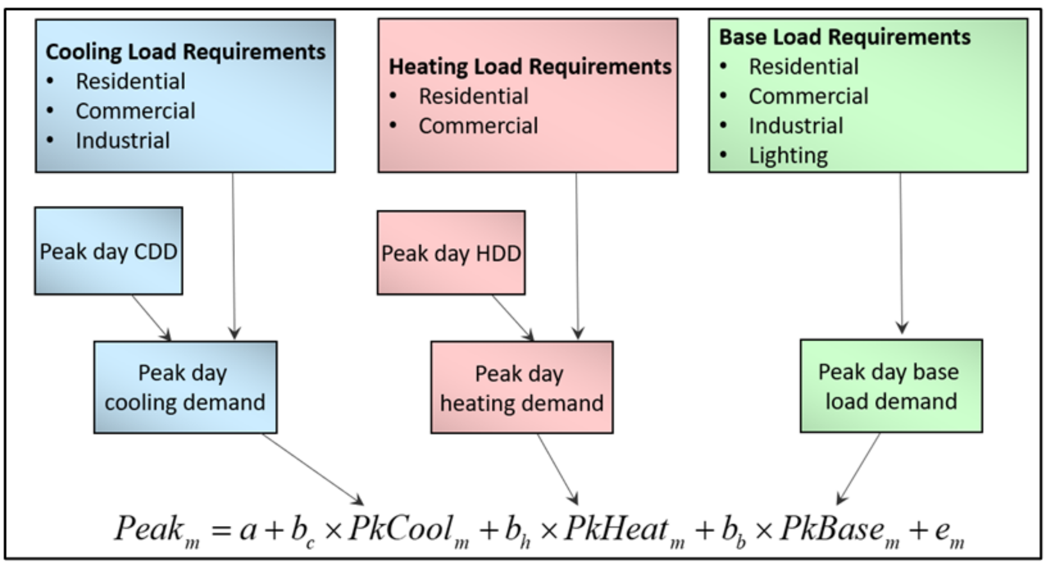
For many of the municipalities the larges C&I customer class is dominated by a few companies. The is often significant variation in month-to-month sales making it difficult to fit with an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is also true for the *other* customer class that is generally street lighting and municipal own use.

Baseline Energy, Peak, and Hourly Load Forecast

The baseline energy forecast is derived from the customer-class sales forecasts. For most members, the energy forecast is derived by aggregating the customer class sales forecasts and adjusting for line losses. In some case where billed sales data (used in estimating class sales) are too noisy due to the billing process, separate monthly energy regression models are estimated where the total sales forecast is the primary driver.

Monthly peak regression models are estimated based on underlying heating, cooling, and base-use loads derived from the customer class sales models. Heating and cooling load requirements are combined with peak-producing weather to generate peak-day heating and cooling variables; the impact of peak-day temperatures changes over time with changes in heating and cooling load requirements. In general baseline heating requirements are declining as traditional resistant heat saturation falls and cooling requirements are increasing with increasing air conditioning saturation. The expected growth due to CCHP program turns around the baseline decline in heating load and adds to cooling demand growth. Figure 6 shows the baseline peak demand model.

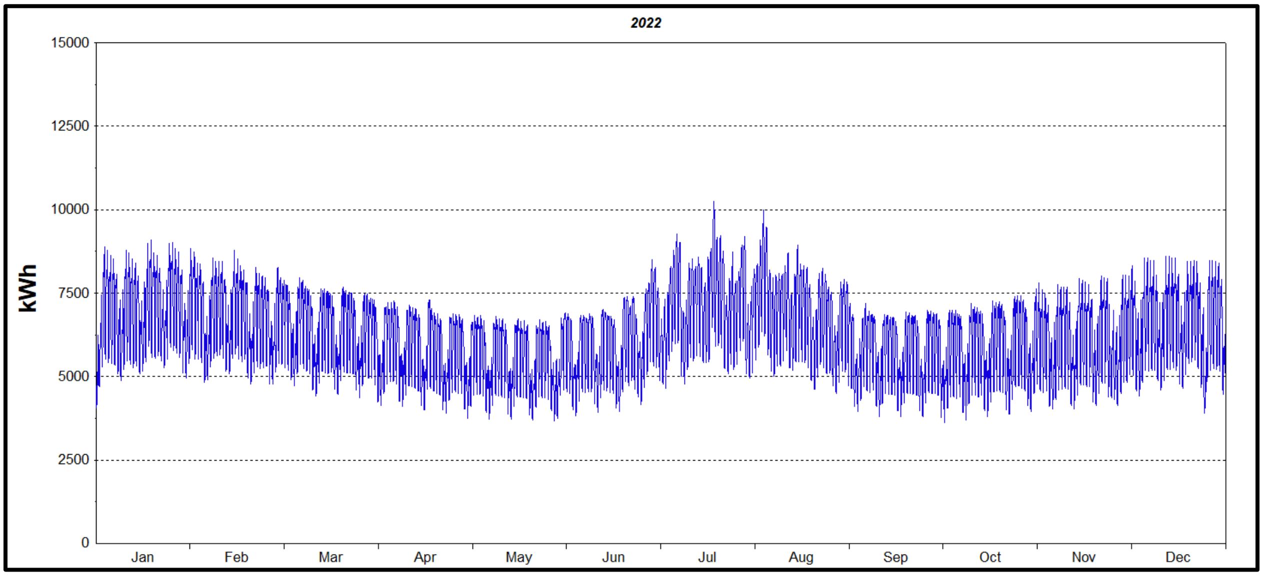
FIGURE 6: BASELINE PEAK MODEL



The peak model is estimated using linear regression that relates the monthly peak to peak-day CDD and HDD, combined with cooling, heating, and base load requirements at time of peak.

A baseline hourly load profile is derived from historical hourly system loads. Models are designed to capture expected hourly loads for typical weather conditions, day of the week, season, and holidays. Figure 7 shows the baseline profile for Swanton.

FIGURE 7: SWANTON HOURLY BASELINE PROFILE



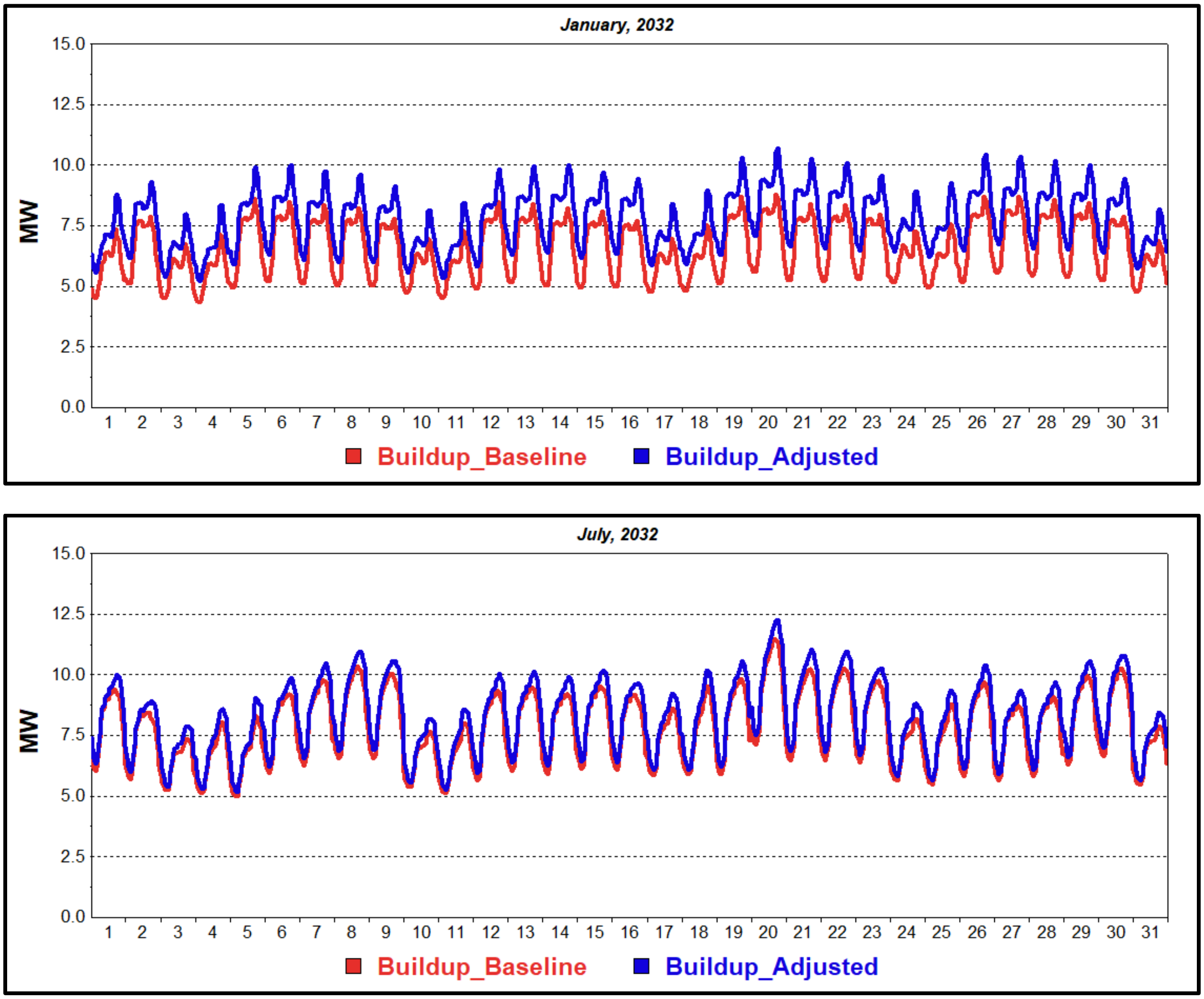
The baseline profile is constant over the estimation period. The baseline hourly load forecast is then derived by combining the baseline energy and peak forecast with the profile. Increase in energy requirements and peak demand lift the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

Adjusted Load Forecast

For the most part, baseline loads are either flat or declining as efficiency gains have outweighed customer and economic growth. The long-term peak demand drivers are expected market penetration of CCHP and EV purchases. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV market penetration is projected to continue to increase, capacity projections slow from current pace and have minimum impact on peak demand; PV capacity has already shifted peaks into the later summer hours and has no impact on winter peak demand.

The expected increase in PV adoption, CCHP, and EVs reshape system load over time and as a result the timing and level of peak demand. Incremental PV energy savings, and new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast. Figure 8 compares the Swanton baseline and hourly load forecast for 2032.

FIGURE 8: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)



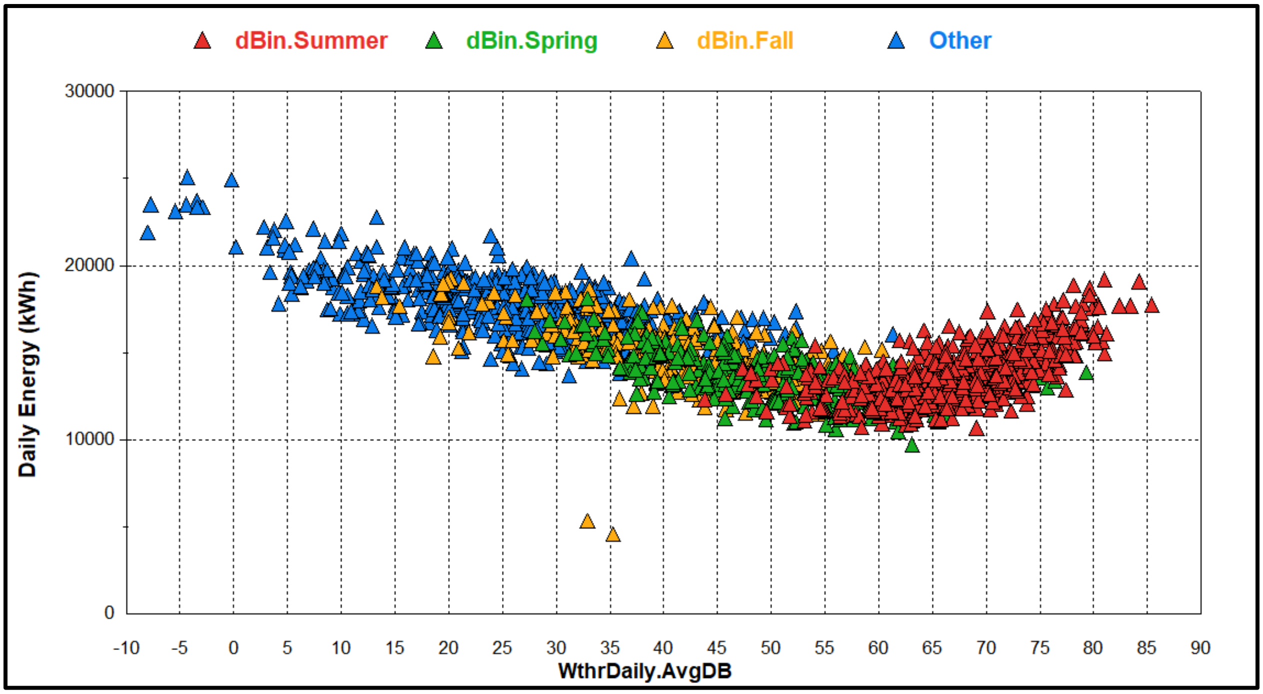
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight of VPPSA members that are clustered in north-central Vermont and Rutland weather data for the three large municipals in the central and southern regions of the state. The temperature/load relationship is evaluated at the system level. Figure 9 illustrates what this relationship looks like at the system level for Jacksonville.

FIGURE 9: LOAD-TEMPERATURE RELATIONSHIP (JACKSONVILLE)



Each point represents the daily average use (in kWh) and the average temperature for that day. The curve shows us a long heating curve with heating starting at 55 degrees, and a short cooling curve with cooling starting at around 60 degrees.

Historical temperature data is used to generate daily and monthly heating-degree days (HDD) and cooling degree-days (CDD). HDD are derived using a base temperature of 55 degrees; this is the temperature point where we begin to see heating load. HDD are positive when average daily temperature falls below 55 degrees and 0 when temperatures exceed 55 degrees. CDD are defined for a 60 degree-day. CDD are positive when temperatures are above 60 degrees and 0 when average daily temperature falls below 60 degrees.

Normal or expected degree-days are used to drive the forecast. The general approach is to calculate normal degree-days as an average of past temperature or degree-days over a historical time; most utilities will use a 30-year or 20-year period. The implied assumption is that future temperatures is best represented by the average of the past. Given climate change, however, this is probably not the best assumption.   Our analysis and that of others shows that average temperatures are increasing. An analysis of last 50 years of weather data for the Burlington airport shows average temperatures are increasing roughly .08 degrees per year or 0.8 degrees per decade. This is consistent with temperature trends we found in New York. Temperature trend studies have shown average temperatures increasing from 0.4 degrees to over 1.0 degrees per decade depending on geographic location. Temperature trends tend to be the lowest in cities near the ocean.

Increasing temperatures result in fewer HDD and increasing number of CDD. This is illustrated in Figure 10 and Figure 11 that show 20-year degree-day moving average against actual degree days.

FIGURE 10: HEATING TREND

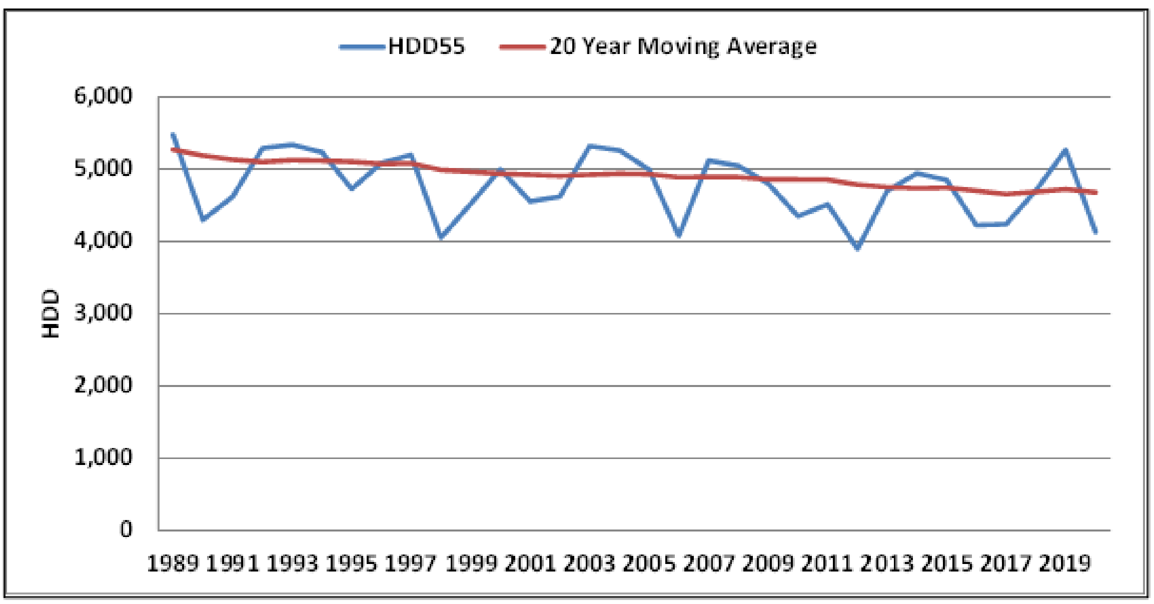
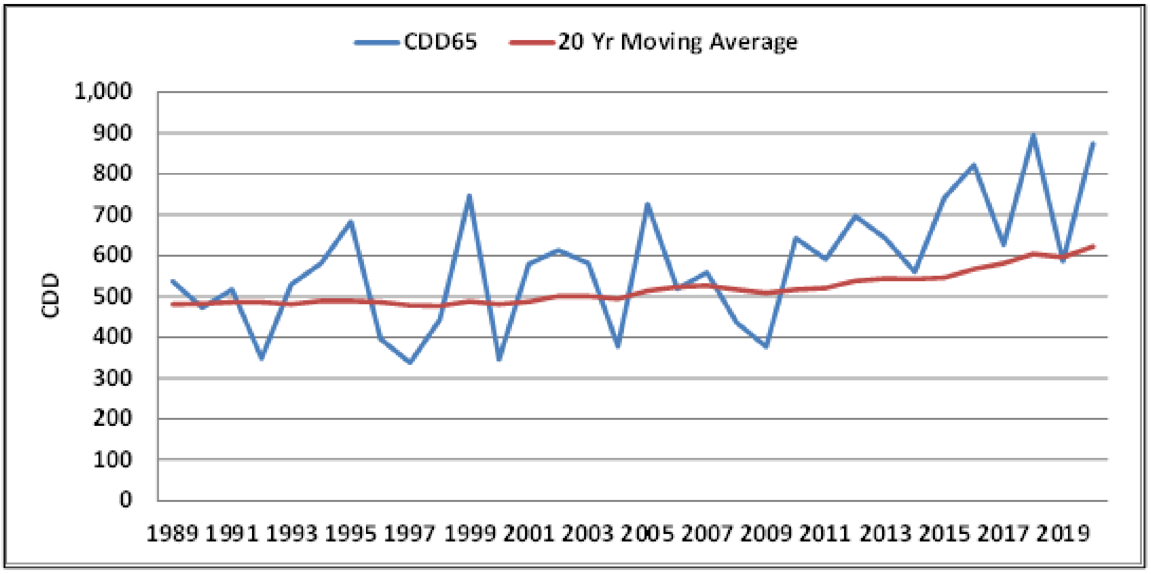


FIGURE 11: COOLING TREND



Recent climate studies show that we can expected temperatures to continue to increase. We assume HDD and CDD trends to persist through the forecast period.

Figure 12 and Figure 13 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 12: NORMAL AND TRENDED NORMAL HDD

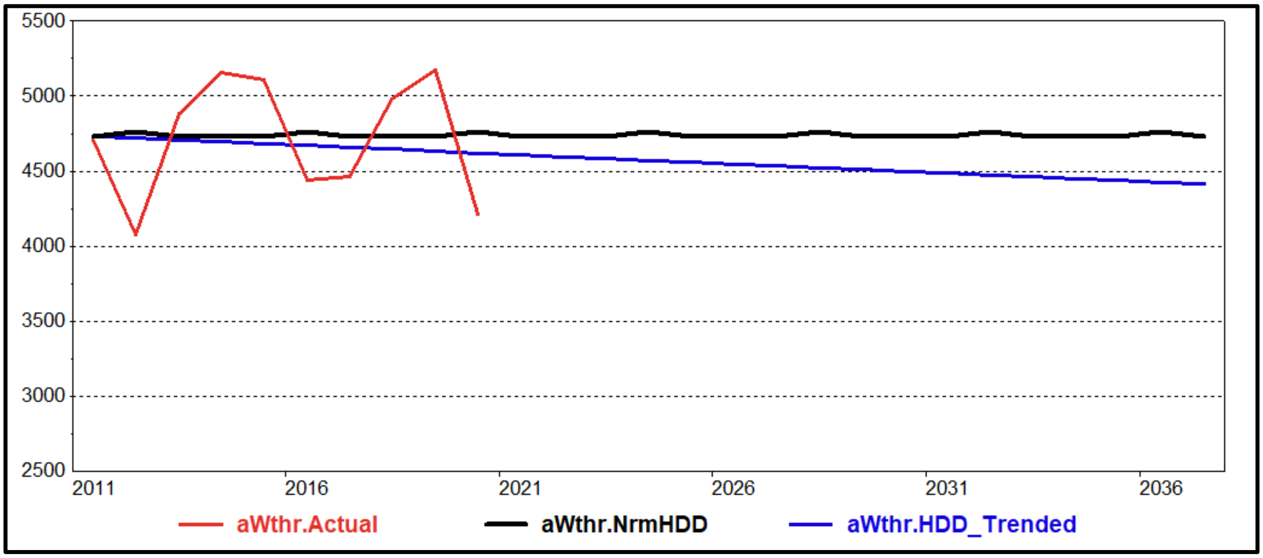
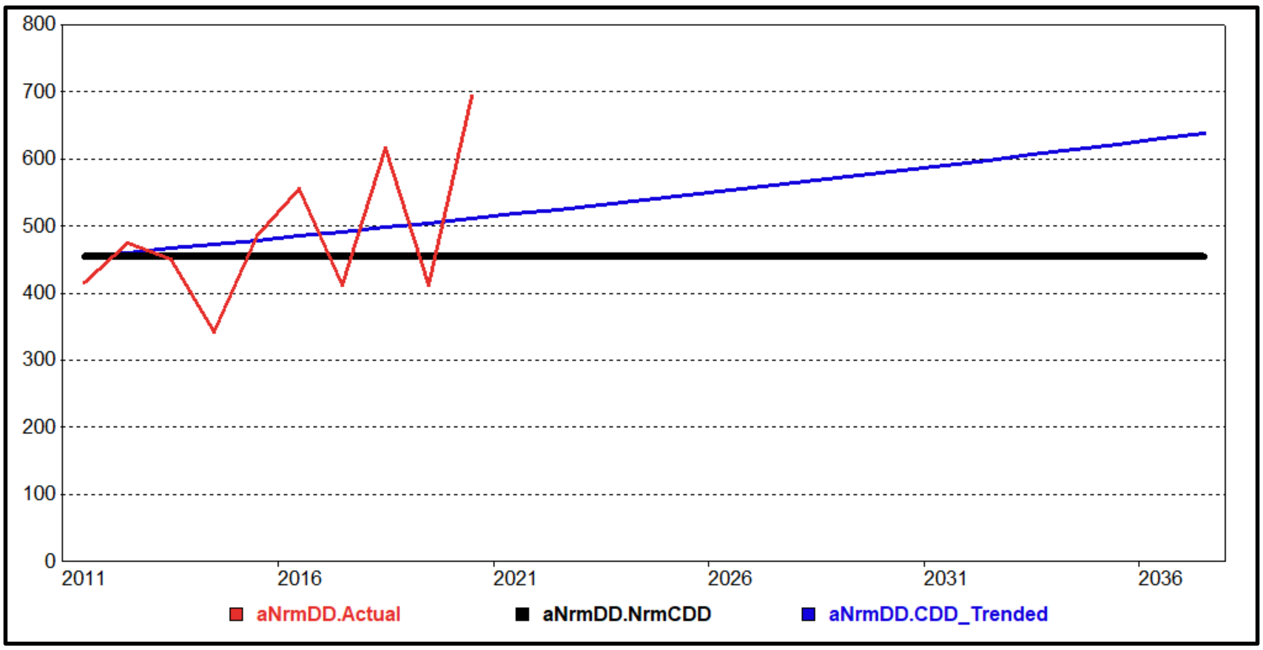


FIGURE 13: NORMAL AND TRENDED NORMAL CDD



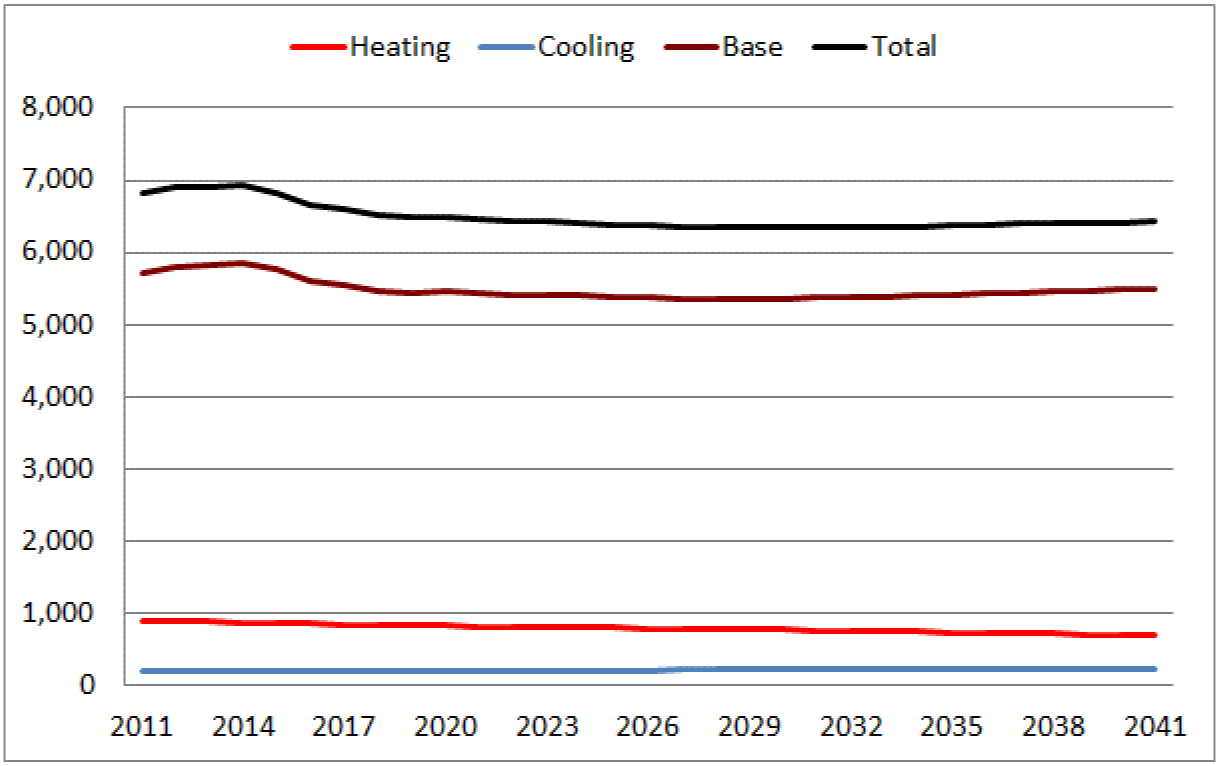
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

End-Use Intensities

Overall, sales have been flat to declining across the state. The decline is largely attributable to behind-the-meter solar adoption and end-use and efficiency gains resulting from new standards and state-incentivized energy efficiency programs. The impact of efficiency improvements is captured in the end-use intensities that reflect both changes in end-use ownership (saturation) and end-use efficiency. End-use intensities are derived for ten residential and nine C&I end-uses by combining saturation and efficiency projections. In the residential sector, intensities are measured on a kWh per household basis and in the commercial sector on a kWh per square-foot basis. End-use intensities are based on EIA 2020 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available.

For most end-uses, increasing efficiency outweighs increase in saturation contributing to declining customer average use. The exception is miscellaneous use (e.g., plug loads, appliances, electric equipment) and residential cooling; in residential cooling saturation continues to trend positive at a rate faster than improvements in air conditioning stock efficiency. Increasing CDD and incentivized heat-pumps are also expected to contribute to additional cooling-related sales. Still, aggregate cooling consumption is relatively small given temperate summer weather conditions. Figure 14 shows residential end-use intensities aggregated into heating, cooling, base, and total intensity.

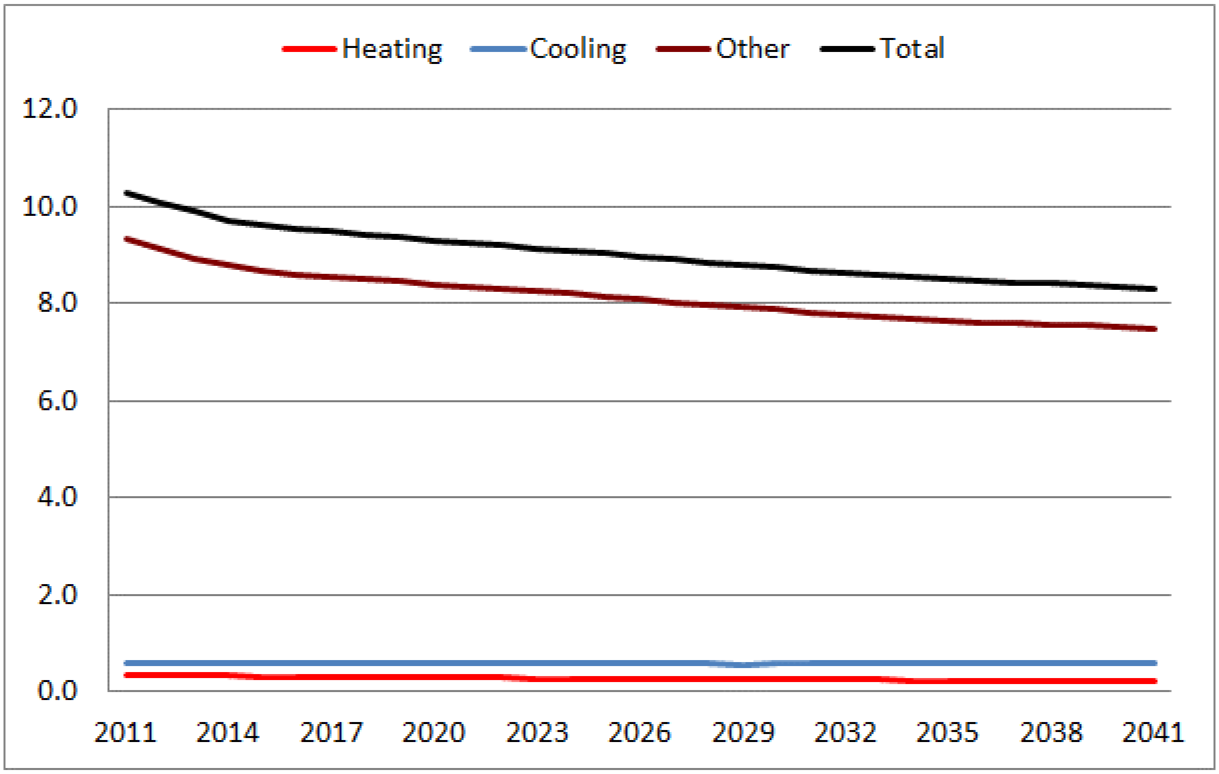
FIGURE 14: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has declined 0.7% annually with the conversion from incandescent and florescent to LED being a major contributor. The energy intensity still declines but at a much slower rate over the next ten years (-0.2% per year) as the lighting savings have been realized and the impact of new appliance standards begins to slow.

Commercial energy intensities are measured on a kWh per Sq. ft. basis. Figure 15 shows commercial heating, cooling, and other use intensity trends. Heating and cooling are a relatively small part of commercial energy use. The non-weather sensitive use (Other) is composed of seven end-uses where the largest end-uses include ventilation, lighting, refrigeration, and miscellaneous use.

FIGURE 15: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

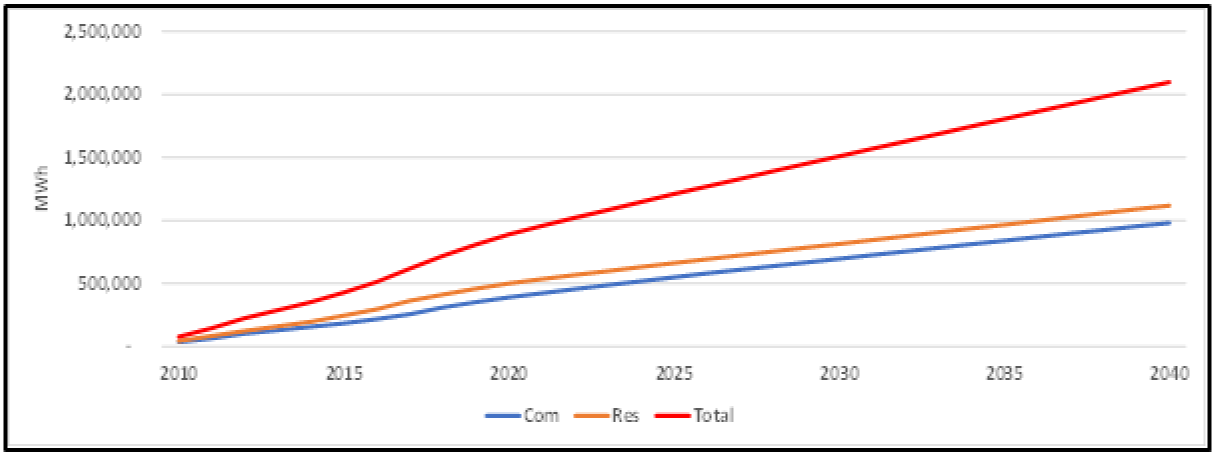


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial intensity has averaged 1.2% decline over the last ten years and is projected to decline another 0.7% over the next ten years.

EE Program Impacts

State efficiency programs have also had a significant impact on sales. At the state level, most of the impact is captured in the end-use intensities. EIA adjust end-use efficiencies to reflect New England EE program savings. Forecasts are further adjusted for Vermont-specific savings by incorporating VEIC measured and projected savings as an additional model variable. Where the variable is statistically insignificant, sales are adjusted based on allocated state EE savings projections. State savings projections are allocated to utilities based on customer class sales. Figure 16 shows the current state Demand Resource Plan (DRP) cumulative historical and projected savings.

FIGURE 16: VEIC HISTORICAL AND PROJECTED EE PROGRAM SAVINGS



Economic Outlook

The 2022 forecast is based on Moody's January 2022 state economic projections. The primary economic drivers include number of state households, population, real personal income, employment, and real economic output (GDP). Table 7 shows historical and projected economic outlook.

TABLE 7: ECONOMIC FORECAST

Year	Households (Thou)	Chg	RPI (Mil $)	Chg	GDP (Mil $)	Chg	Emp (Thou)	Chg
2011	258.9		28,119		28,981		300.9	
2012	260.2	0.5%	28,505	1.4%	29,281	1.0%	304.5	1.2%
2013	262.1	0.7%	28,624	0.4%	28,671	-2.1%	306.7	0.7%
2014	263.4	0.5%	29,295	2.3%	28,868	0.7%	309.6	0.9%
2015	264.1	0.3%	30,121	2.8%	29,163	1.0%	312.1	0.8%
2016	264.2	0.1%	30,316	0.6%	29,368	0.7%	313.3	0.4%
2017	264.5	0.1%	30,530	0.7%	29,506	0.5%	315.0	0.5%
2018	264.7	0.1%	30,895	1.2%	29,629	0.4%	316.1	0.3%
2019	265.0	0.1%	31,477	1.9%	29,775	0.5%	315.3	-0.3%
2020	263.9	-0.4%	33,348	5.9%	28,807	-3.2%	289.1	-8.3%
2021	265.1	0.5%	32,911	-1.3%	29,819	3.5%	293.5	1.5%
2022	266.6	0.6%	31,845	-3.2%	30,849	3.5%	301.9	2.9%
2023	268.3	0.6%	32,674	2.6%	31,788	3.0%	306.8	1.6%
2024	269.5	0.4%	33,550	2.7%	32,650	2.7%	309.1	0.7%
2025	270.3	0.3%	34,325	2.3%	33,439	2.4%	310.0	0.3%
2026	271.1	0.3%	35,042	2.1%	34,151	2.1%	310.2	0.1%
2027	271.7	0.2%	35,772	2.1%	34,760	1.8%	310.5	0.1%
2028	272.2	0.2%	36,583	2.3%	35,369	1.8%	310.9	0.1%
2029	272.7	0.2%	37,422	2.3%	35,986	1.7%	311.4	0.2%
2030	273.2	0.2%	38,226	2.1%	36,577	1.6%	311.8	0.1%
2031	273.5	0.1%	38,971	2.0%	37,168	1.6%	311.9	0.0%
2032	273.7	0.1%	39,711	1.9%	37,791	1.7%	311.9	0.0%
2033	273.9	0.0%	40,446	1.9%	38,443	1.7%	312.0	0.0%
2034	273.8	0.0%	41,147	1.7%	39,100	1.7%	312.1	0.0%
2035	273.7	0.0%	41,830	1.7%	39,757	1.7%	312.1	0.0%
2036	273.6	0.0%	42,494	1.6%	40,405	1.6%	311.9	-0.1%
2037	273.4	-0.1%	43,150	1.5%	41,042	1.6%	311.7	-0.1%
2038	273.0	-0.1%	43,783	1.5%	41,671	1.5%	311.5	-0.1%
2039	272.6	-0.2%	44,387	1.4%	42,302	1.5%	311.3	-0.1%
2040	272.2	-0.2%	44,973	1.3%	42,933	1.5%	311.1	-0.1%
2041	271.6	-0.2%	45,540	1.3%	43,570	1.5%	311.0	0.0%
2042	271.0	-0.2%	46,117	1.3%	44,215	1.5%	310.9	0.0%
11-21		0.2%		1.6%		0.3%		-0.2%
22-32		0.3%		2.2%		2.1%		0.3%
32-42		-0.1%		1.5%		1.6%		0.0%

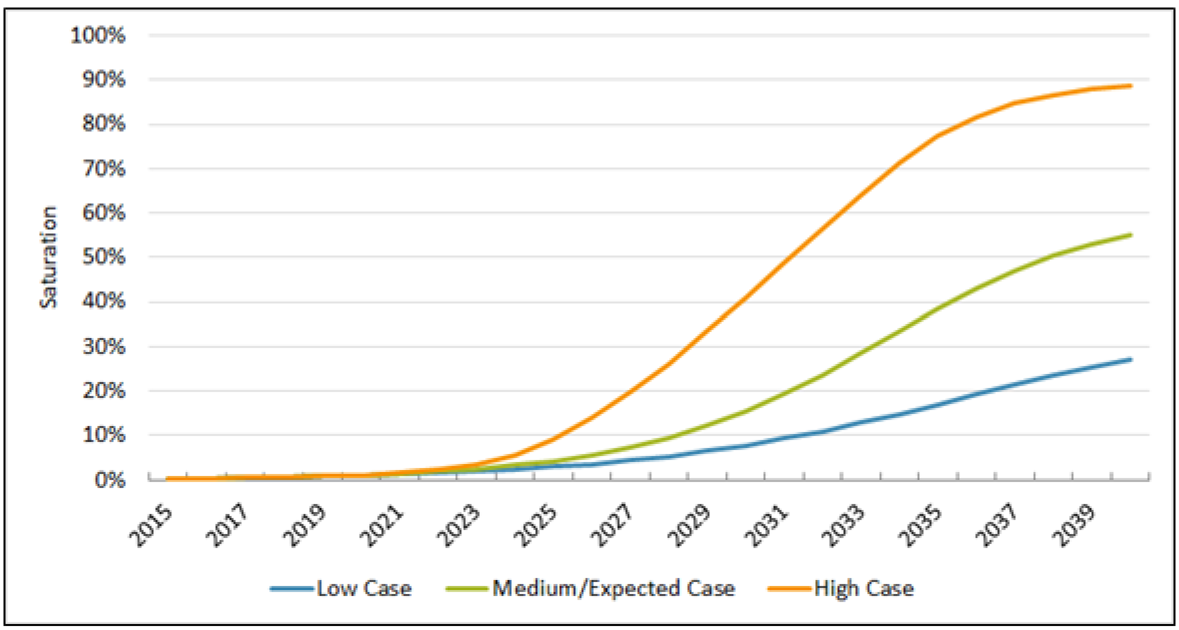
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022 with strong economic growth coming out of the COVID-driven recession.

Over the long-term, number of households is expected to average 0.3% with employment increasing at roughly the same rate. GDP averages 2.1% per year largely driven by improvements in productivity and a jump in GDP coming out of the pandemic.

Electric Vehicles

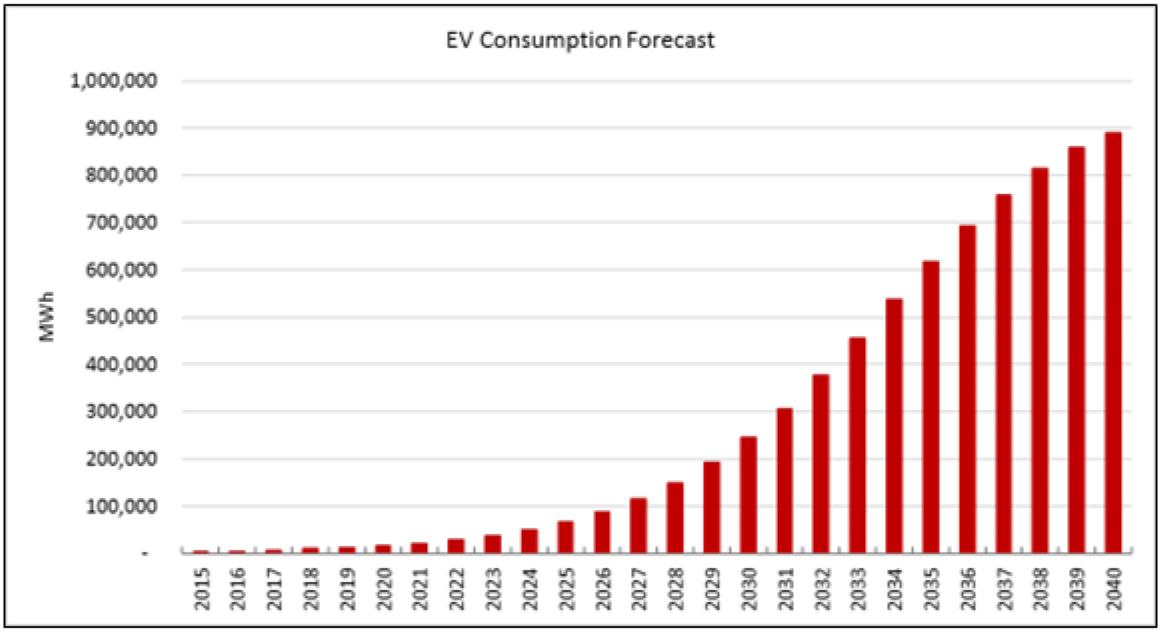
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over 15% of all vehicles are electric by 2030 and by 2050, 60% of vehicles are electric. In the high case, 90% of all vehicles are electric by 2050 with a 50% market share by 2030. In the low case 35% of all vehicles are electric by 2050. Figure 17 shows the projected adoption paths.

FIGURE 17: ELECTRIC VEHICLE SATURATION PROJECTIONS



EV saturations are translated into number of vehicles and then total charging energy requirements based on estimated annual miles driven and kWh per mile driven. Figure 18 shows state EV electric consumption for the expected case.

FIGURE 18: EXPECTED CASE STATE EV ELECTRICITY FORECAST

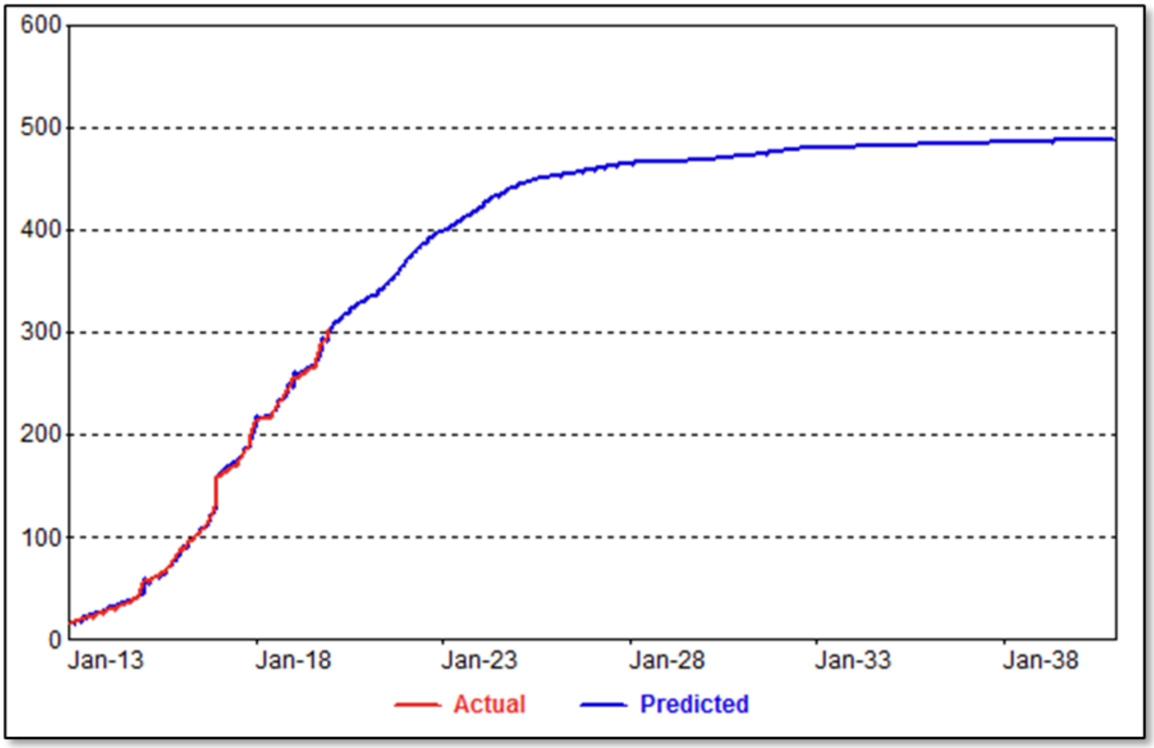


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

Solar

The solar forecast is based on Itron's behind-the-meter (BTM) solar forecast developed also as part of the 2021 VELCO long-term forecast. BTM solar capacity is derived from an investment return-based model that relates installed capacity to average system payback (number of years before investment costs are recovered). Figure 19 shows state capacity forecast.

FIGURE 19: STATE SOLAR CAPACITY FORECAST (MW)

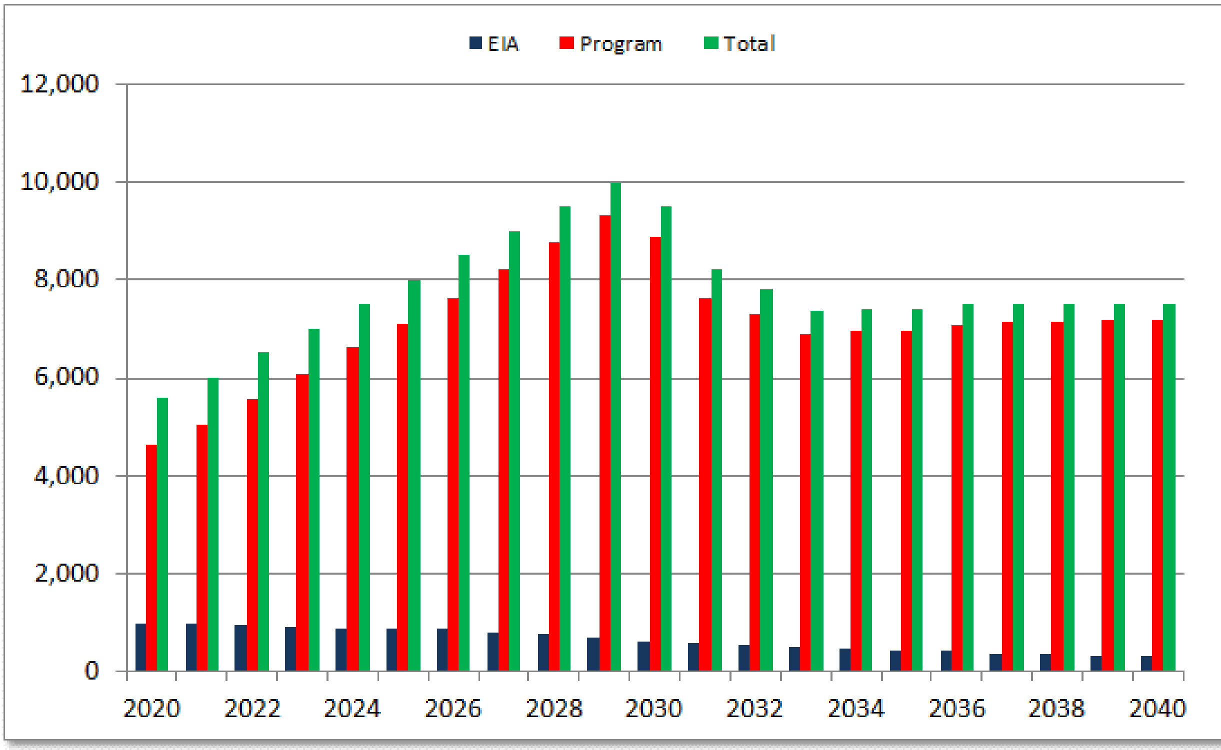


We expect the growth of BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation profile data. Our default assumption is VPPSA member BTM solar is proportional to total state generation based on number of member customers.

Cold Climate Heat Pumps

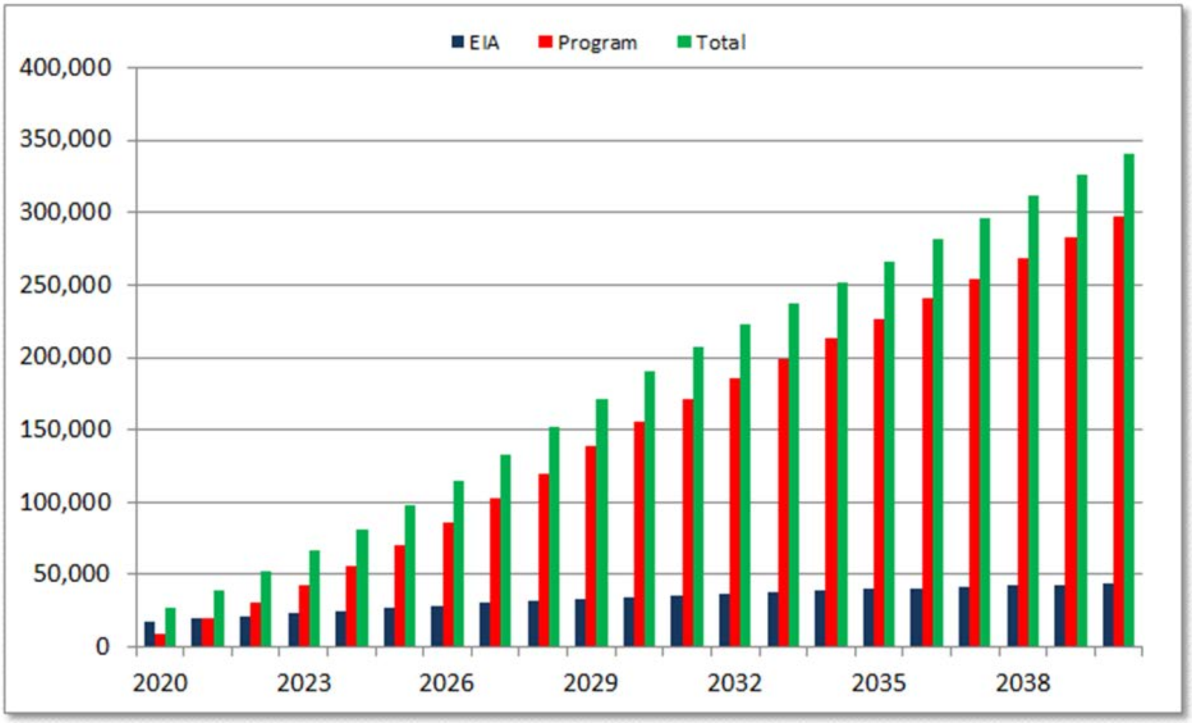
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary targets are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term forecast of CCHP units for low, medium, and high case. The reference case is based on the medium CCHP forecast with sales of around 6,000 units in the near-term, rising to 10,000 units by 2030. EIA projections are considerably more conservative with heat pumps primarily displacing electric resistant heat. Figure 20 shows state CCHP unit projections.

FIGURE 20: STATE CCHP FORECAST (UNITS PER YEAR)



VEIC further translated unit projections into electricity use based on recent CCHP measurement studies. Figure 21 shows projected state-level CCHP energy forecast.

FIGURE 21: STATE CCHP ENERGY PROJECTIONS (MWH)



CCHP sales are allocated to VPPSA members based the number of customers relative to state-level customer counts.

APPENDIX A

MODEL RESULTS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.861	0.089	9.726	0.00%
mStructRes.LagXHeat	0.633	0.085	7.473	0.00%
mStructRes.XCool	2.741	0.225	12.178	0.00%
mStructRes.LagXCool	2.457	0.226	10.851	0.00%
mStructRes.XOther	1.026	0.019	53.904	0.00%
mCovid.ResIndex	21.966	8.6	2.554	1.18%

Model Statistics	
Iterations	1
Adjusted Observations	130
Deg. of Freedom for Error	124
R-Squared	0.818
Adjusted R-Squared	0.811
AIC	7.242
BIC	7.375
Log-Likelihood	-649.21
Model Sum of Squares	745,595.19
Sum of Squared Errors	165,619.06
Mean Squared Error	1,335.64
Std. Error of Regression	36.55
Mean Abs. Dev. (MAD)	29.08
Mean Abs. % Err. (MAPE)	4.29%
Durbin-Watson Statistic	2.216

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	9.062	2.901	3.124	0.22%
mBin.Aft20	29.646	5.118	5.793	0.00%
mEcon.HHs	11.843	0.162	73.288	0.00%
AR(1)	0.938	0.023	40.397	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	131
Deg. of Freedom for Error	127
R-Squared	0.988
Adjusted R-Squared	0.988
AIC	3.249
BIC	3.337
Log-Likelihood	-394.72
Model Sum of Squares	261,352.27
Sum of Squared Errors	3,176.64
Mean Squared Error	25.01
Std. Error of Regression	5
Mean Abs. Dev. (MAD)	2.3
Mean Abs. % Err. (MAPE)	0.07%
Durbin-Watson Statistic	2.056

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	798597.554	116073	6.88	0.00%
mStructCom.LagXHeat	1041860.274	112317.9	9.276	0.00%
mStructCom.XCool	287305.565	38789.84	7.407	0.00%
mStructCom.LagXCool	354834.178	39097.29	9.076	0.00%
mStructCom.XOther	30431.513	585.82	51.947	0.00%
mCovid.NResIndex	-7665.185	4310.561	-1.778	7.79%
mBin.Yr12	85353.043	5777.316	14.774	0.00%
mBin.Bef17	-63513.465	3791.772	-16.75	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	129
Deg. of Freedom for Error	121
R-Squared	0.852
Adjusted R-Squared	0.843
AIC	19.672
BIC	19.849
Log-Likelihood	-1,443.89
Model Sum of Squares	228,593,824,938.09
Sum of Squared Errors	39,827,914,539.49
Mean Squared Error	329,156,318.51
Std. Error of Regression	18,142.67
Mean Abs. Dev. (MAD)	14,063.12
Mean Abs. % Err. (MAPE)	4.42%
Durbin-Watson Statistic	1.481

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	1872874.877	37940.9	49.363	0.00%
mBin.Feb	1759703.982	37905.86	46.423	0.00%
mBin.Mar	1816891.24	38365.88	47.357	0.00%
mBin.Apr	1787873.174	40521.11	44.122	0.00%
mBin.May	1818462.144	39836.81	45.648	0.00%
mBin.Jun	1880354.195	38011.44	49.468	0.00%
mBin.Jul	2012736.725	38013.93	52.947	0.00%
mBin.Aug	2085208.721	37885.15	55.04	0.00%
mBin.Sep	1871038.011	37884.59	49.388	0.00%
mBin.Oct	1869846.881	37742.35	49.542	0.00%
mBin.Nov	1660701.326	38376.92	43.273	0.00%
mBin.Dec	1805461.483	38442.04	46.966	0.00%
mCovid.NResIndex	-98232.531	28070.72	-3.499	0.07%
mBin.Bef13	-198251.425	29944.85	-6.621	0.00%
mBin.Bef17	171820.083	24774.68	6.935	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	130
Deg. of Freedom for Error	115
R-Squared	0.659
Adjusted R-Squared	0.617
AIC	23.431
BIC	23.762
Log-Likelihood	-1,692.47
Model Sum of Squares	2,984,586,742,264.29
Sum of Squared Errors	1,547,598,351,798.27
Mean Squared Error	13,457,376,972.16
Std. Error of Regression	116,005.94
Mean Abs. Dev. (MAD)	88,544.89
Mean Abs. % Err. (MAPE)	4.72%
Durbin-Watson Statistic	1.749

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.152	0.067	2.274	0.027
Seasonal	0.182	0.147	1.245	0.218

Model Statistics	
Iterations	22
Adjusted Observations	60
Deg. of Freedom for Error	58
R-Squared	0.416
Adjusted R-Squared	0.406
AIC	18.076
BIC	18.146
Log-Likelihood	-625.42
Model Sum of Squares	2,830,674,299
Sum of Squared Errors	3,976,584,449
Mean Squared Error	68,561,800.85
Std. Error of Regression	8,280.21
Mean Abs. Dev. (MAD)	6,030.98
Mean Abs. % Err. (MAPE)	6.40%
Durbin-Watson Statistic	1.899

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	3150.487	882.833	3.569	0.05%
mWthr.HeatVar55	21.901	3.214	6.813	0.00%
mWthr.CoolVar60	112.976	7.678	14.713	0.00%
mCPkEndUses.BaseVar	0.711	0.132	5.403	0.00%
mBin.Bef13	-282.987	129.068	-2.193	3.03%
mBin.Bef17	486.65	127.493	3.817	0.02%
mBin.Apr	438.62	158.969	2.759	0.67%
mBin.Oct	275.445	165.31	1.666	9.84%
mBin.Nov	299.853	149.554	2.005	4.73%
mBin.Dec	360.99	127.667	2.828	0.55%
MA(1)	0.384	0.09	4.242	0.00%

Model Statistics	
Iterations	19
Adjusted Observations	128
Deg. of Freedom for Error	116
R-Squared	0.842
Adjusted R-Squared	0.827
AIC	11.898
BIC	12.165
F-Statistic	56.35
Prob (F-Statistic)	0
Log-Likelihood	-931.08
Model Sum of Squares	83,315,127.22
Sum of Squared Errors	15,591,630.50
Mean Squared Error	134,410.61
Std. Error of Regression	366.62
Mean Abs. Dev. (MAD)	265.1
Mean Abs. % Err. (MAPE)	2.90%
Durbin-Watson Statistic	1.807

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

The Tier III Rule states that:

"4.410 (3) The Energy Transformation Project shall meet the need for its goods or services at the lowest present-value life-cycle cost, including environmental and economic costs. This evaluation shall include an analysis of alternatives that do not increase electric consumption. If a Retail Electricity Provider's Integrated Resource Plan includes an analysis of alternatives, the Provider's Tier III annual plan shall reference the analysis in the Integrated Resource Plan and shall include any significant changes. If a Provider's Integrated Resource Plan does not include an analysis of alternatives, the Provider's Tier III annual plan shall include the analysis."

Because ninety-five percent of the savings from SED's Tier III programs are from four measures, we summarize the life cycle costs for electric vehicles and heat pumps in Table 1. In terms of avoided costs, these ratios are based on the forecast of electricity, capacity and transmission prices that support the financial analysis section. The measure savings (lifetime kWh) are consistent with the averages in the Tier III Planning Tool for Program Year 2022, and the value of avoided emissions is consistent with the 2021 Avoided Energy Supply Cost (AESC) study. Finally, the retail rates are based on a forecast of SED's residential rate.

Table 1: Life-Cycle Cost-Benefit Ratios

Measure	Utility	Customer	Society
EV	0.8	0.4	0.5
PHEV	0.8	0.5	0.8
CCHP	1.0	1.1	1.3
WBHP	0.9	1.6	1.8

Heat pumps are the least-cost measure, and provide net benefits to both the customer and to society. They are break-even to the utility, however. Electric vehicles have much higher incremental costs as well as shorter measure lives. As a result, their cost-benefit ratios are less attractive.

The Tier III Planning Tool does include some measures that do not increase electric consumption. These measures include the use of biodiesel, the use of wood pellets, telecommuting, bicycle commuting, using public transportation and installing smart thermostats. SED will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.