

Lyndon Electric Department 2025 Integrated Resource Plan



As Filed with the Public Utility Commission

EXECUTIVE SUMMARY

Located in rural Caledonia and Essex Counties in the Northeast Kingdom of Vermont, the Village of Lyndonville Electric Department has operated an electric utility system since 1896. By Act No. M-14 effective July 1, 2023, the Village of Lyndonville merged with the Town of Lyndon, with the Town of Lyndon being the surviving entity. Pursuant to Section 81(a) of the Charter, the official name of the electric department is now the Town of Lyndon Electric Department (LED). The Town of Lyndon Electric Department serves approximately 6,900 retail customers in the Town of Lyndon as well as portions of twelve surrounding towns: Burke, East Haven, Glover, Kirby, Newark, Sheffield, St. Johnsbury, Sutton, Victory, Westmore and Wheelock. Approximately half of LED's customers are served within the village and town portions of Lyndon. LED's two largest customers are Northern Vermont University (formerly known as Lyndon State College) and Burke Mountain. LED remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. As a small municipal utility LED is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

LED's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up over 80% of the customer mix while accounting for about half of LED's retail kWh sales. Forty-one large commercial customers (less than 1%) make up almost 20% of retail usage with the remaining 30% of retail sales going to small commercial, public authority and streetlight customers.

Consistent with regulatory requirements, every three years LED is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan or IRP) for the provision of energy services to its Vermont customers. LED'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

LED 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 has reduced demand. At this time, the pace at which net metering will grow in LED'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 LED's largest customers is currently anticipated the potential does exist. LED monitors the plans of large customers in order to anticipate necessary changes to the existing resource plan and system infrastructure. In the case of a significant expansion by one or more customers, detailed engineering studies may be needed to identify necessary system upgrades.

ELECTRICITY SUPPLY

LED'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 prices, the portfolio is heavily weighted toward hydro, solar and other renewable sources. Located within its service territory, LED currently owns and operates two hydro stations, Vail and Great Falls, comprised of four turbines with LED utilizing all of their output. Combined, these clean and renewable, power stations provide LED with approximately 6% of its energy supply.

When considering future electricity demand, LED seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. LED 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. LED anticipates regional availability of competitively priced renewable resources including solar, wind, and hydro. In addition to playing a role in meeting future electricity requirements, this category of resource contributes to meeting Renewable 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 LED 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, LED employs an integrated financial model that incorporates impacts on load and subsequent effects on revenue and power supply costs, as well as effects of 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 LED relies on to evaluate resource decisions on an individual or portfolio basis, there are other more subjective factors to consider, including resource diversity or exposure to major changes in market rules.

There are three major resource decisions facing LED over the next five to ten years, beginning with the option for a five-year extension of the Fitchburg Landfill Contract beginning in 2027 and running thru 2031. With the expiration of two significant hydro and wind contracts representing about 36% of LED's energy resources at the end of 2027, LED will need to evaluate options to replace the bundled energy and REC products associated with the Brookfield and Stetson contracts. The third evaluation facing LED is whether to commit to a utility scale storage contract in the near future; recent experience of other VPPSA members indicates that evaluation of the economic viability of a utility scale storage project may have potential.

The main sources of uncertainty expected to impact these decisions include the potential loss of any large customer load, uncertainty in market energy prices that may be influenced by the price of natural gas and pipeline transportation prices, uncertainty regarding electrification related load growth, and the cost of regional transmission service. Because LED is largely hedged for the long run in the capacity market, capacity prices are not a large source of uncertainty.

RENEWABLE ENERGY STANDARD

LED is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for LED to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into four categories, TIER I, TIER II, TIER III and TIER IV. LED'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 LED'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. TIER IV obligations may be met with RECs from new renewable resources. By providing incentive programs to encourage conversion of traditional fossil fuel applications LED receives credits toward its TIER III obligation.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

LED's municipal-owned electric utility has twelve miles of 34.5kV sub-transmission interconnecting four of its five substations with VELCO's 115kV substation and a connecting tap to a connection point with GMP's 34.5 sub-transmission line. GMP's line is the previous sole feed to LED and can be used to receive or to feed power on to GMP's grid.

LED has four hundred miles of distribution line. Given LED's rural service territory, the majority of LED's lines are off road and inaccessible from a street or highway. LED operates a total of nine regulated 12.47 kV distribution feeders. All of the distribution mainline is overhead. The distribution system has been fully converted to 12.47/7.2 kV (four-wire) operation. The

distribution system is in good physical condition and has been adequately maintained. The minimum conductor size that is now used is 1/0 ACSR. Some older, smaller diameter copper conductor is still present on some of the fused branch lines, where the thermal loading is generally quite small.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, LED is examining the need to modernize in order to enhance distribution system management in the face of growing system complexities related to climate change, energy market changes, distributed generation and the effects of intensifying electrification. LED is currently engaged with VPPSA to install AMI and GIS systems. In addition, LED is currently collaborating with VPPSA and its members to develop a Tech Roadmap that will guide and lead to implementation, over the next few years, of more sophisticated distribution system management capabilities. Potential additions to the GIS and AMI systems include SCADA and DERMS systems. LED sees potential value to customers from utilizing rate design along with other incentive or load control programs as tools to manage both system and customer peak loads in unison.

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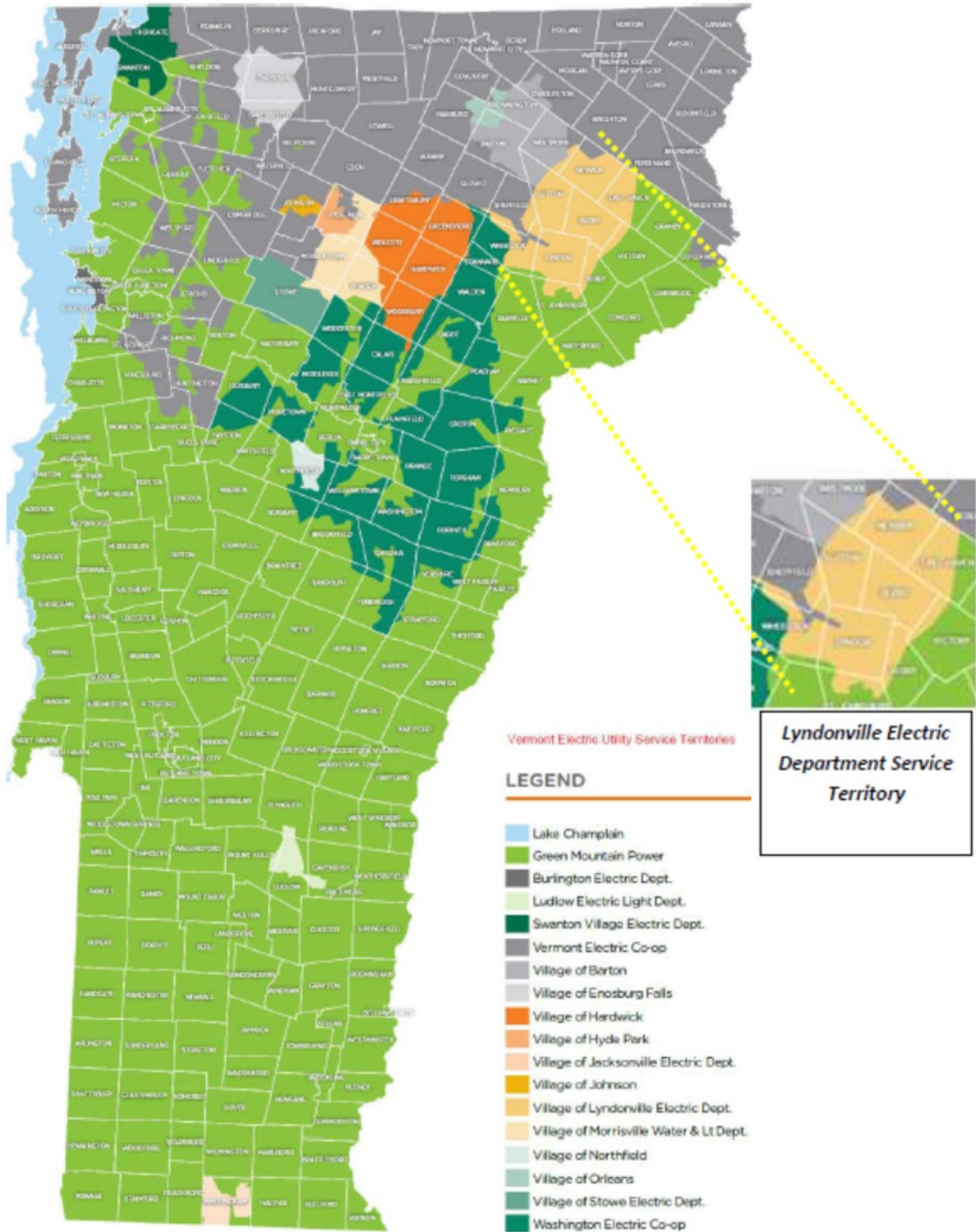
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INTRODUCTION

Located in rural Caledonia and Essex Counties in the Northeast Kingdom of Vermont, the Village of Lyndonville Electric Department has operated an electric utility system since 1896. By Act No. M-14 effective July 1, 2023, the Village of Lyndonville merged with the Town of Lyndon, with the Town of Lyndon being the surviving entity. Pursuant to Section 81(a) of the Charter, the official name of the electric department is now the Town of Lyndon Electric Department (LED). LED serves approximately 6,900 customers. LED's service territory encompasses the Town of Lyndon as well as portions of twelve surrounding towns: Burke, East Haven, Glover, Kirby, Newark, Sheffield, St. Johnsbury, Sutton, Victory, Westmore and Wheelock. About 48% of LED's customers are served within the town portions of Lyndon. Northern Vermont University (formerly known as Lyndon State College) and Burke Mountain are similar in load demand and are LED's two largest customers. LED remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual, National Electric Code (NEC) and the National Electric Safety Code (NESC). Well-established practices keep LED operating safely, efficiently, and reliably.

Figure 1: LED'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.

LED 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:

- Lyndon 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
- Morrisville Water & Light Department
- Northfield Electric Department
- Orleans Electric Department
- Swanton Village, Inc. Electric Department

LED and VPPSA are parties to a broad Master Supply Agreement (MSA). Under the MSA, VPPSA manages LED'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 LED's loads and power supply resources in the New England power markets.

SYSTEM OVERVIEW

LED serves a balanced mix of residential and commercial load with approximately 53% residential, 36% commercial and 11% for municipal and streetlights.

LED receives its power from a ring bus configuration within VELCO's 115kV substation located in Lyndon. LED's primary source of power, prior to construction of the Vermont Electric Power Company (VELCO) 115kV Substation, was a sub transmission line connection with Green Mountain Power (GMP). This sub-transmission line remains in place and can be used as a redundant feed to LED or as a source to GMP.

Table 1: LED's Retail Customer Counts

Data Element	2019	2020	2021	2022	2023
Residential (440)	4,836	4,866	5,884	5,935	5,984
Small C&I (442) 1000 kW or less	888	908	938	956	963
Large C&I (442) above 1,000 kW	41	41	40	41	44
Total	5,765	5,815	6,862	6,932	6,991

Table 2: LED's Retail Sales (KWh)

Data Element	2019	2020	2021	2022	2023
Residential (440)	30,677,778	32,187,261	32,753,090	33,945,487	34,057,491
Small C&I (442) 1000 Kw or less	11,585,413	11,528,733	11,903,747	12,206,560	12,263,484
Large C&I (442) above 1,000 Kw	16,886,147	15,791,850	16,943,526	18,199,703	17,646,800
Street Lighting (444)	477,867	476,968	476,514	474,318	472,786
Total	59,627,205	59,984,812	62,076,877	64,826,068	64,440,561
YOY	2%	1%	3%	4%	-1%

Table 3: LED's Annual System (¹NCP) Peak Demand (²TLEL)

Data Element	2019	2020	2021	2022	2023
Peak Demand kW	12,977	12,921	12,574	13,561	13,788
Peak Demand Date	01/30/19	12/29/20	01/24/21	12/11/22	12/06/23
Peak Demand Hour	19	18	18	18	18

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 LED's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION

This chapter describes LED'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 LED's power supply costs and cost of service.

ACTION PLAN

This chapter outlines specific actions the LED 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

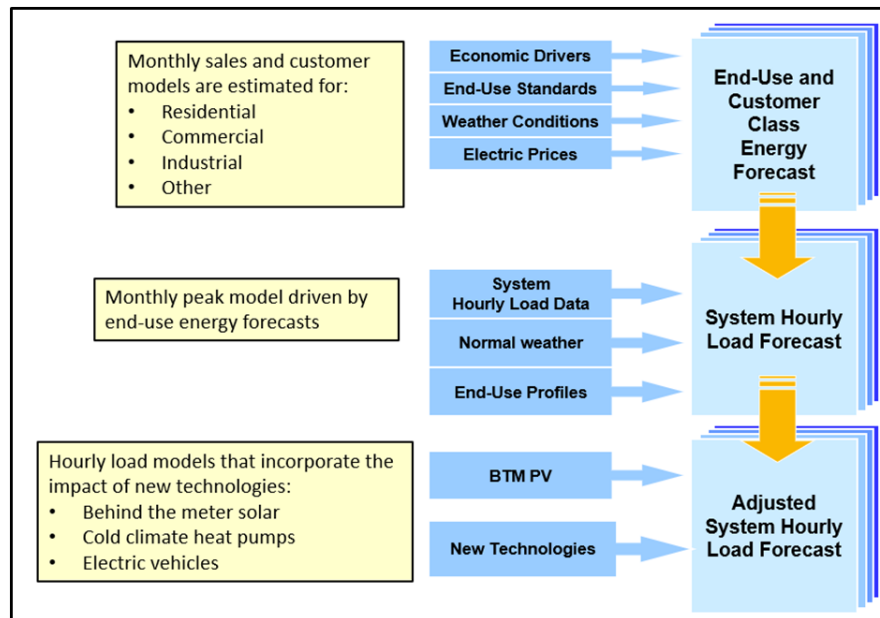
ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast LED'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 in connection with development of VELCO's 2022 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 uses). The impact of new technologies is then layered on top of the baseline forecast as shown in Figure 2.³ Note that, the Itron forecast does not extend through the entirety of the IRP range. Therefore, the various values that comprise the Itron forecast were extrapolated to include 2044 for the purposes of this IRP.

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

Figure 2: Forecasting Process



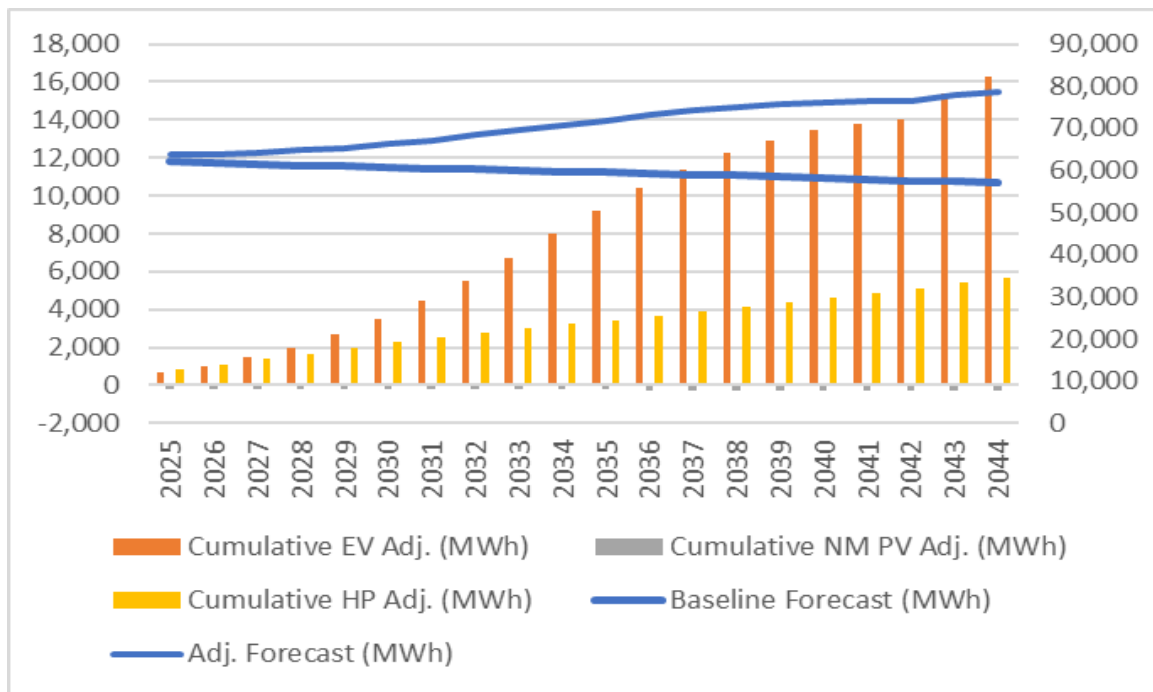
ENERGY FORECAST RESULTS

Table 4 shows the Baseline Forecast, as well as the adjustments that are made to arrive at the Adjusted Forecast. The effect of the electrification and net metering measures on the decreasing retail sales is an increasing adjusted forecast. The compound annual growth rate of the adjusted forecast is about 1.1%. This percentage is depicted in Figure 3.

Table 4: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	62,317	713	-169	862	63,722
2029	5	60,937	2,667	-207	1,990	65,386
2035	11	59,476	9,222	-239	3,454	71,912
2039	15	58,525	12,929	-248	4,385	75,591
2044	20	57,043	16,251	-301	5,670	78,662
CAGR		-0.5%				1.1%

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST - HIGH & LOW CASES

To form a high case, we assumed that the increase in penetration per year for EVs and CCHPs doubles compared to the base case. We assume that net metering penetration continues as forecast in the base case. At these growth rates, the market penetration for EVs and CCHPs reaches approximately 156% and 88% each in 2044. This rough estimate assumes that most households will have a CCHP and more than one electric vehicle. This is a reasonable high case given the fact that most homes require more than one CCHP if the entire home is to be served by the CCHP and the average Vermont household currently has two vehicles. With these increases in electrification the CAGR increases to 2.3%. This growth rate results in a 54% increase over 2025 electricity use.

Table 5: Energy Forecast - High Case (MWH)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	62,317	1,426	-169	1,723	65,297
2029	5	60,937	5,334	-207	3,980	70,043
2035	11	59,476	18,443	-239	6,908	84,588
2039	15	58,525	25,858	-248	8,769	92,904
2044	20	57,043	32,501	-301	11,339	100,583
CAGR		-0.5%				2.3%

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 0.4% per year.

Table 6: Energy Forecast - Low Case (MWH)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	62,317	356	-169	431	62,935
2029	5	60,937	1,333	-207	995	63,058
2035	11	59,476	4,611	-239	1,727	65,575
2039	15	58,525	6,464	-248	2,192	66,934
2044	20	57,043	8,125	-301	2,835	67,702
CAGR		-0.5%				0.4%

PEAK FORECAST RESULTS

Table 7 and Table 8 show the results of the Baseline Forecast of peak loads for Summer and Winter periods, as well as the adjustments that are made to arrive at the Adjusted Forecast. The baseline forecast is decreasing by 0.5% per year for the Summer period. After adjustments for CCHPs, EVs and net metering, the Adjusted Forecast increases by 1.5% per year. The Winter peak is decreasing by 0.8% per year. After making the same adjustments the forecast increases by 1.6% per year.

Table 7: Summer Peak Forecast (MW)

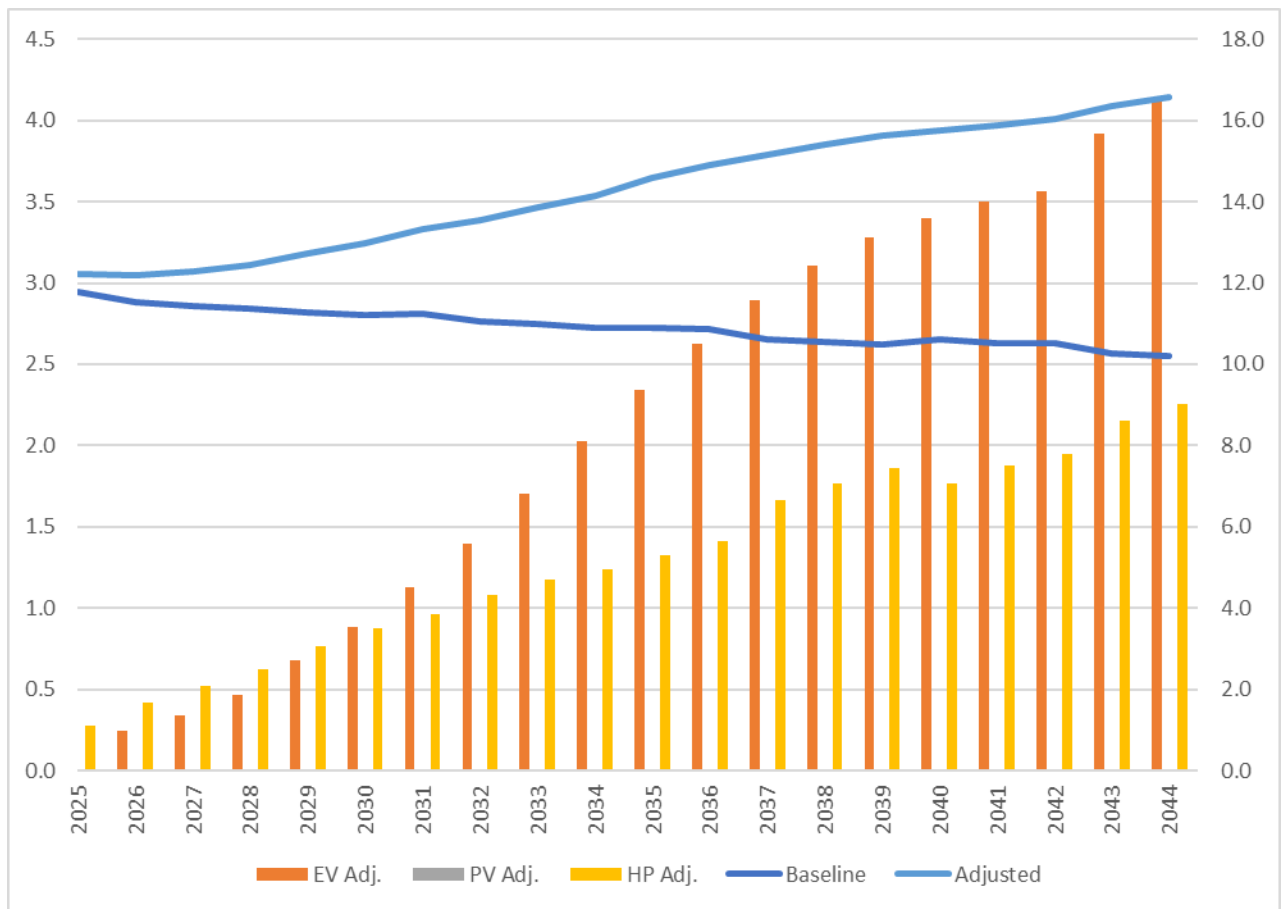
Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	8.7	0.1	0.0	0.1	8.9
2029	5	8.6	0.5	0.0	0.2	9.4
2035	11	8.4	2.0	0.0	0.3	10.6
2039	15	8.2	2.7	0.0	0.4	11.4
2044	20	7.9	3.5	0.0	0.5	11.8
CAGR		-0.5%				1.5%

Table 8: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	11.8	0.2	0.0	0.3	12.2
2029	5	11.3	0.7	0.0	0.8	12.7
2035	11	10.9	2.3	0.0	1.3	14.6
2039	15	10.5	3.3	0.0	1.9	15.6
2044	20	10.2	4.1	0.0	2.3	16.6
CAGR		-0.8%				1.6%

The size of the adjustments can be seen in Figure 4, which shows the winter peak forecast net of adjustments.

Figure 4: Adjusted Winter 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 the peak reaches 23 MW by 2044.

Table 9: Winter Peak Forecast – High Case (MW)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	11.8	0.3	0.0	0.6	12.7
2029	5	11.3	1.4	0.0	1.5	14.2
2035	11	10.9	4.7	0.0	2.7	18.2
2039	15	10.5	6.6	0.0	3.7	20.8
2044	20	10.2	8.3	0.0	4.5	23.0
CAGR		-0.8%				3.2%

A plausible low case for the peak forecast would involve applying TOU electric rates and load control devices on all 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 the Tier III 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 is greater than the electrification that is budgeted through Tier III programs which include numerous measures. This difference represents a deviation between the load forecast and the Tier III Annual Plan.

Table 10 shows the budgeted measures from VPPSA’s 2025 Tier III plan, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Eighty-six percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles. Table 10 shows Lyndon’s share of VPPSA’s Tier III budget, and it indicates 156 MWH of new electric loads are likely in 2025.

This number is lower than the heat pump and electric vehicle adjustments from Itron. The work papers supporting Table 4 show that Itron forecasted a 495 MWH increase in electric loads for 2025 as a result of these technologies. The forecasted increased load is about 0.8% of the adjusted forecast in 2025. This is well within the forecast error⁵ of the forecast itself.

⁴ PUC Rule 4.415 (6)(A)

⁵ The Mean Absolute Percentage Error (MAPE) in Itron’s energy model was 3.83%.

Table 10: Program Year 2025 Tier III Measures & Their Expected Impact on Load

Measure	# of Measures (rounded)	Added MWh/Unit/Yr	Total New MWh/Yr
Electric Vehicles	21	2.4	50
Heat Pumps	16	5.3	84
Heat Pump Water Heater	6	1	6
Other	15	1.1	16
TOTAL	58		156

TIER III LOAD MANAGEMENT

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 management control. From a technical perspective, there are many credible options for managing 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 11: 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
\$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 11.

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. However, large devices can become cost-effective as shown in the green shaded areas. Additionally, LED does not believe that the intensity of electrification is currently, or in the near future, at a point where active load management is reasonable nor are there systems in place at this time to be able to perform active load management.

Innovative rates are a potentially cost-effective way to manage load. In addition to helping with peak demand, this option allows customers to maintain their autonomy as opposed to imposing restrictions with active load management. As a result, VPPSA is exploring innovative software platforms to be used for implementing innovative rates that may include market based, Time-of-Use (TOU) rates. This effort may inform rates applicable to both residential electric vehicle chargers and public charging stations, as well as providing rate research that can carry over into more generalized load management efforts.

VPPSA sends out capacity and transmission peak notifications to all members. With these notifications LED is able to adjust department use and notify customers. VPPSA also attends the Delta Climb program on behalf of its members. In more recent years this program has focused heavily on load management, specifically in rural settings such as those of the VPPSA member service territories. Lastly, AML, once implemented, can be used to help identify when charging and discharging a battery will be most useful and it will help inform and implement Time-Of-Use rates. In short, the overarching approach to load control for LED is dynamic rates with supplementation from battery storage, behind-the-meter generation, searching for and partnering with innovative technology and AML.

FORECAST UNCERTAINTIES & CONSIDERATIONS

LED presently has one hundred seventy residential scale (< 15 kW) net-metered customers with a total installed capacity of about 1,098 kW. In addition, there are fifteen customers who have arrays between 15 and 500 kW with a total capacity of 1,834 kW. 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 steep change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

Electrification, particularly in the form of electric vehicles and cold climate heat pumps, has been accounted for in the load forecast. However, actual adoption of these measures will likely vary. While there is the potential for adoption rates to vary substantially from the current forecast, particularly given the statewide push toward electrification, this variation will likely be at a rate that would allow LED to adjust power supply resources so that the utility is not too short or too long on energy compared to load. Once AMI has been implemented, LED will have the ability to obtain much more granular, time-varying load and behind-the-meter generation data, which will then inform more granular load forecasting in the future.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

LED'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 LED and its customers from the cost and volatility of buying electricity from ISO New England on the spot market at the Vermont Zone. The following sections describe each of the power supply resources in LED portfolio.

EXISTING POWER SUPPLY RESOURCES

1. Brookfield Hydro 2023-2027

- Size: 10 MW On Peak, 8.5 MW Off Peak
- Fuel: Hydro
- Location: Varies
- Entitlement: 1.7 MW On Peak, 1.3 MW Off Peak
- Products: Energy, VT Tier I RECs
- End Date: 12/31/27

2. Chester Solar

- Size: 4.8 MW
- Fuel: Solar
- Location: Chester, MA
- Entitlement: 29.8%, PPA
- Products: Energy, capacity
- End Date: 6/30/39

3. Fitchburg Landfill

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 24.8%, PPA
- Products: Energy, capacity, renewable energy credits (MA I)
- End Date: 12/31/31

4. Hydro Quebec US (HQUS)

- Size: 212 MW
- Fuel: Hydro
- Location: Quebec
- Entitlement: 0.603 MW, PPA
- Products: Energy, renewable energy credits (Quebec system mix)
- End Date: 10/31/38

5. Kruger Hydro

- Size: 6.7 MW
- Fuel: Hydro
- Location: Maine and Rhode Island
- Entitlement: 25.5%, PPA
- Products: Energy, capacity
- End Date: 12/31/37

6. McNeil Station

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 3% (1.5 MW), joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit

7. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 0.594MW (Nia. PPA), 0.0367MW (St. Law PPA)
- Products: Energy, capacity, VT Tier I RECs
- End Date: 4/30/2032

8. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 19.6%, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit

9. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 1.3% PPA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2032

10. Standard Offer Program

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas and micro-hydro
- Location: Vermont
- Entitlement: 1.3% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies

11. Stetson Wind 2023-2027

- Size: 57MW
- Fuel: Wind
- Location: Maine
- Entitlement: 9.2% (PPA)
- Products: Energy, VT Tier I RECs
- End Date: 12/31/27

12. Stonybrook

- Size: 352 MW
- Fuel: Natural Gas, Oil
- Location: Ludlow, MA
- Entitlement: 0.44%, (1.55 MW), PPA
- Products: Energy, capacity, reserves
- End Date: Life of Unit

13. Vail & Great Falls Hydro

- Size: 2.4 MW
- Fuel: Hydro
- Location: Lyndon, VT
- Entitlement: 100%, Owned
- Products: Energy, capacity, renewable energy credits (VT Tier I & II)
- End Date: Life of Unit

Table 12 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) show the relative size of each resource.

Lyndon Electric Department - 2025 Integrated Resource Plan

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 have a 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.

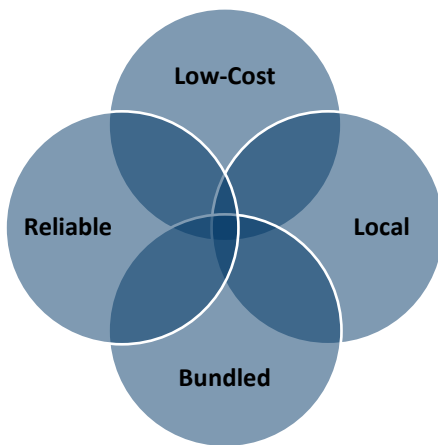
Table 12: Existing Power Supply Resources

Resource	2024 MWh	% of MWh	2024MW	Delivery Pattern	Price Pattern	REC	Expiration Date
2019 Planned Purchase	709	1.1%	0.60	Firm	Fixed	No	03/31/2024
Brookfield 2023-2027	12,238	19.4%	2.80	Firm	Fixed	Yes	12/31/2027
Chester Solar	1,852	2.9%	1.43	Intermittent	Fixed	No	06/30/2039
Fitchburg Landfill	7,910	12.5%	1.12	Intermittent	Fixed	Yes	12/31/2031
HQUS Contract	3,531	5.6%	0.60	Firm	Fixed	Yes	10/31/2038
Kruger Hydro	5,489	8.7%	1.71	Intermittent	Fixed	No	12/31/2037
McNeil Facility	5,911	9.4%	1.50	Baseload	Fuel Cost	Yes	Life of Unit
NYPA Niagara Contract	4,821	7.6%	0.59	Baseload	Fixed	Yes	04/30/2032
NYPA St. Lawrence Contract	158	0.2%	0.04	Baseload	Fixed	Yes	04/30/2032
Project #10	228	0.4%	7.84	Peaking	Fuel Cost	No	Life of Unit
Ryegate Facility	1,907	3.0%	0.27	Baseload	Fixed	Yes	10/31/2032
Short Term Coverage	1,438	2.3%	Varies	Firm	Fixed	No	Varies
Standard Offer Program	1,723	2.7%	Varies	Intermittent	Fixed	Yes	Varies
Stetson Wind 2023-2027	10,668	16.9%	4.79	Intermittent	Fixed	Yes	12/31/2027
Stony Brook Station	181	0.3%	1.55	Peaking	Fixed	No	Life of Unit
Vail & Great Falls Hydro	4,392	7.0%	2.40	Run of River	O&M Only	Yes	Life of Unit
TOTAL	63,156	100.0%					

FUTURE RESOURCES

LED 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 ISO NE region.
- ✓ **Bundled** resources meet or exceed RES requirements with bundled energy and RECs.
- ✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

Resources that LED may consider fall into three categories: (1) Existing resources in Table 12, (2) demand-side resources, and (3) new resources that meet the criteria in Figure 5 whenever possible.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that NYPA Niagara and NYPA St. Lawrence are extended past their current expiration dates. It is possible that existing resource, such as Brookfield and Stetson, could be extended. This IRP is exploring the possibility of entering into a contract for firm bundled energy and VT Tier I RECs, similar to the existing Brookfield contract.

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, LED will not only get access to competitive prices (low-cost), but it also can structure the contracts to reduce volatility (stable rates and volumes). Market contracts are also scalable and can be sized to match LED's incremental electric demands by month, season and year. 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 and lowest environmental impact source of energy is energy that is conserved or never consumed. LED participates in VPPSA's 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 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 and maintains communications with developers throughout New England. Through VPPSA staff, LED will continue to monitor and evaluate new generation resources in the New England region.

Vermont [Public Power](#) Supply Authority

3.1 BATTERY STORAGE

VPPSA conducted a Request for Information (RFI) process in 2020 to better understand the business case for storage. Nine companies responded, including four that were based in Vermont and two that are among the largest developers in the US. The pricing that was received 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 a 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 continues to work directly with this partner but has also begun working with additional developers in several member territories. Currently no storage project has been proposed for LED territory, however, this is something VPPSA is actively pursuing for all members.

LED has had very preliminary discussions with a storage developer. No location or contract have been proposed. An economic analysis of the value of an energy storage system will be included in this IRP.

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. Hydro generators often create RECs that are qualified for VT Tier I so entering into bundled contracts is a possibility.

3.3 SOLAR GENERATION

While LED has an out of state solar resource in the portfolio, no solar projects within the state have been proposed for LED. Given the increased Tier II obligation for the Renewable Energy Standard it is possible that a solar project will be pursued in the future but a location suitable for a utility scale system in the LED territory has yet to be identified by developers. However, due to Lyndon’s small size, it may be difficult to achieve the economy of scale that helps these solar projects become economically viable.

3.3.1 NET METERING

LED has 185 net-metered customers and an installed base of solar capacity of 2,932 kW. LED 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. RECs are often bundled into the PPA, making this resource a potential fit for the renewable criteria. LED already has Stetson Wind in its portfolio. This is a unit contingent resource that includes Tier I RECs. A downside to wind resources is the high level of intermittency that makes reliable energy prices more difficult to achieve. VPPSA is currently working with Pecos Wind, a company that has developed a very small-scale turbine. Given the increase in Tier II obligation in Act 179, LED will need additional Tier II resources and these small-scale wind projects could be a good opportunity to both diversify their portfolio as well as increase the number of Tier II RECs procured.

3.5 GAS OR OIL-FIRED GENERATION

Project 10 underwent 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.

3.6 NUCLEAR GENERATION

LED's contract for nuclear energy expired in 2022, and has been replaced by renewables (hydro, solar and wind) to comply with the RES. However, LED supports all forms of low-carbon energy, and will consider nuclear power in the future if it is feasible particularly given its high reliability compared to renewables.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Northeastern Vermont Development Association (NVDA), LED is part of a Regional Plan that was updated in 2023. The intent of the plan is to further “two broad state energy goals: reduce greenhouse gas emissions and meet energy needs using renewable sources.” Future resource decisions will be made with this plan in mind.

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 either 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, such as unit availability and adjustments to load.
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:** If internal transactions cannot bring LED 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 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.

ENERGY RESOURCE PLAN

Both Brookfield and Stetson contracts expire at the end of 2027 leaving a large gap in coverage. This IRP will evaluate a bundled energy and REC purchase.

Figure 6 compares LED's energy supply resources to its adjusted load. The supply resources closely match demand through 2027. After 2027 new resources will be necessary.

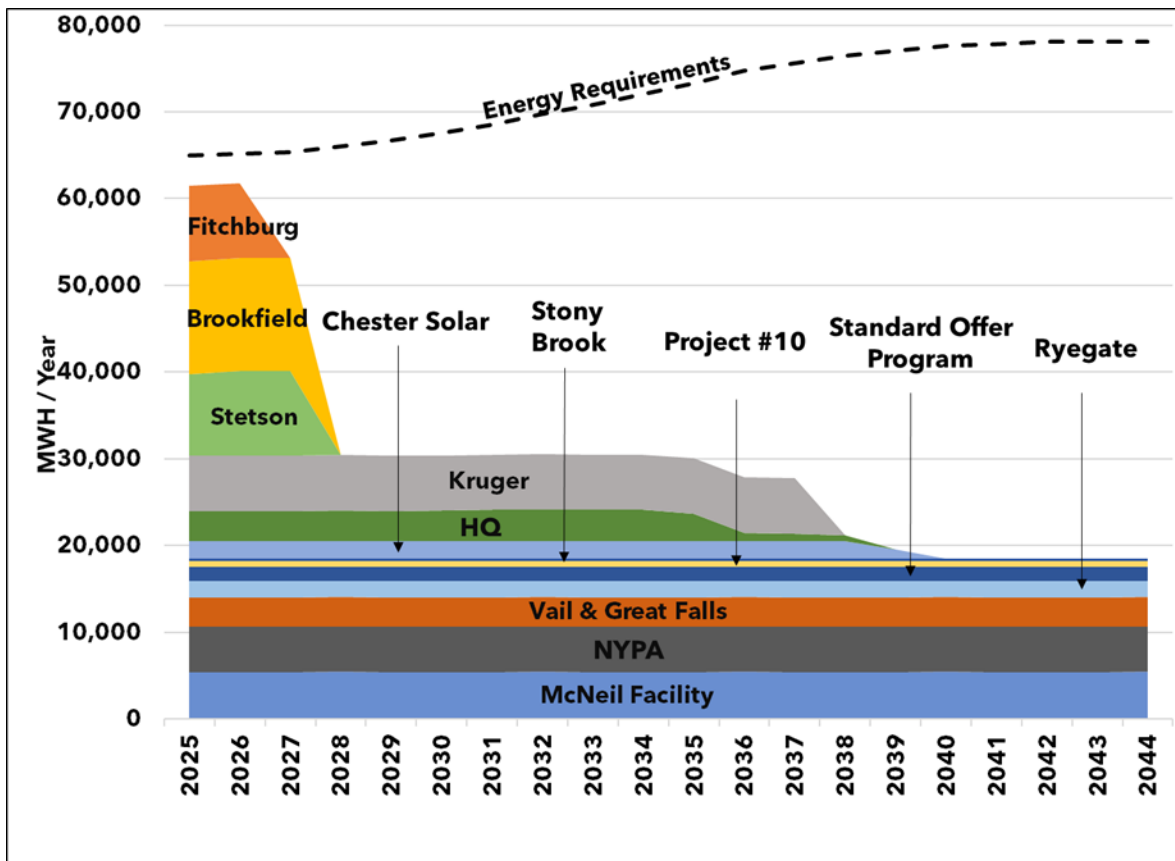
DECISION 1: WHETHER TO EXTEND FITCHBURG LANDFILL CONTRACT

This PPA includes an option to extend the term by five years at a predetermined price. The reference case assumes the contract is extended. Notice must be given by the middle of 2025 for an extended term that would begin on 1/1/27. The extension goes through 2031.

DECISION 2: ENERGY PURCHASE 2028-2032

Both Brookfield and Stetson contracts expire at the end of 2027 leaving a large gap in coverage. This IRP will evaluate a bundled energy and REC purchase.

Figure 6: Energy Supply & Demand by Fuel Type



DECISION 3: BATTERY STORAGE CONTRACT (ESSA)

Utility scale battery storage is an excellent way to manage transmission costs and address load control. LED is in the very early stages of discussions with a storage developer therefore this economic evaluation is based on an approximate Energy Storage Solution Agreement (ESSA) rate from other ESSA's VPPSA has worked with. This is an important first step in determining if this is an appropriate solution for LED.

Table 13 summarizes the energy resources decisions LED faces in the coming five to ten years.

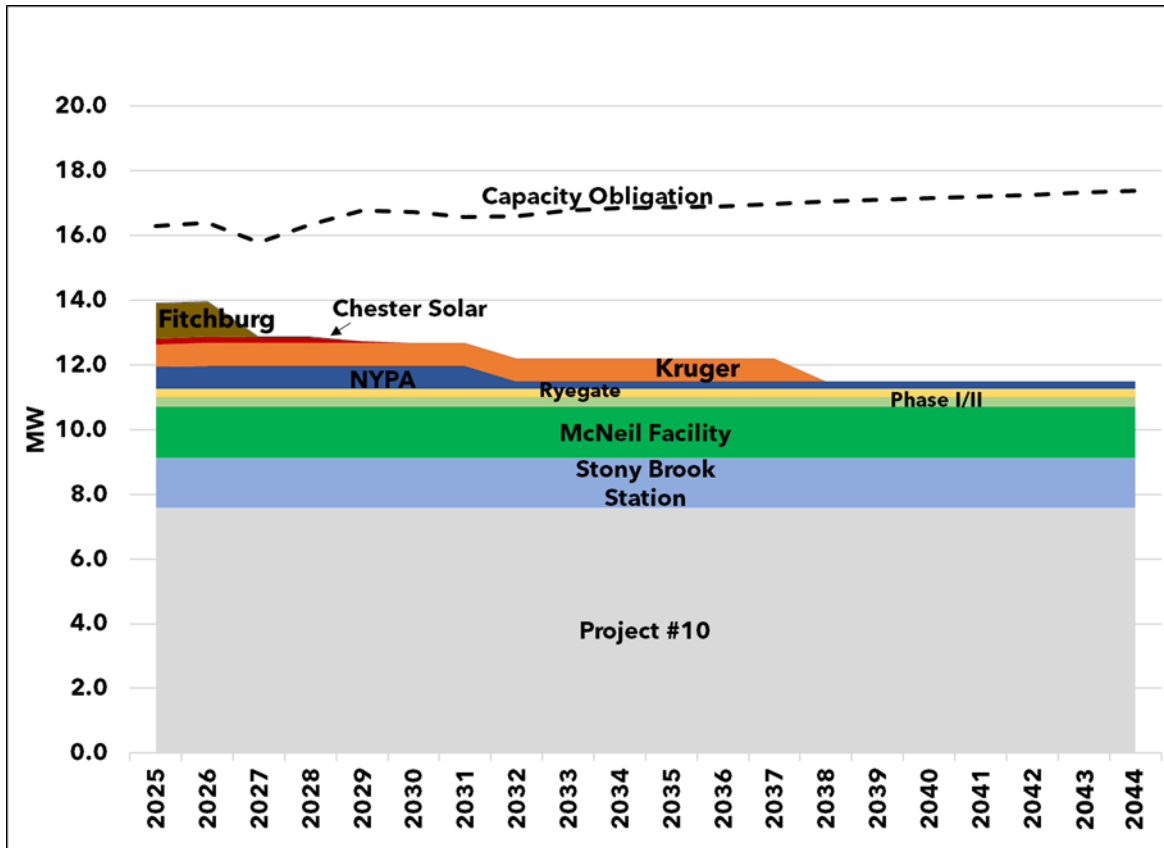
Table 13: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact
Bundled Energy & REC Contract	2028 - 2032	45%	Decrease
Fitchburg Landfill PPA	2027 - 2031	13%	Decrease
Storage ESSA	2025 - 2044	100% of Peak	Decrease

CAPACITY RESOURCE PLAN

Figure 7 compares LED's capacity supply to its capacity supply obligation (CSO). The CSO is equal to LED's coincident peak demand with ISO New England plus a reserve margin. As a result, the CSO is higher than the Adjusted Peak Load Forecast. Most of LED's CSO is covered by existing resources into 2027. After that the gap reaches about 1/3 of the total CSO.

Figure 7: Capacity Supply & Demand (Summer MW)



Vermont Public Power Supply Authority

Project 10 represents about half of LED's capacity supply, and as a result, the reliability of this resource will be the key to minimizing LED's capacity costs, as explained in the next section.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because LED 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 is not available, LED will be provided with capacity by ISO New England. However, ISO New England's Pay for Performance⁶ (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 LED'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, LED could receive up to a \$27,977 payment or pay up to a \$31,549 penalty during a one-hour scarcity event. To date, Project 10 has performed well during capacity scarcity conditions and, therefore, has performed well as a hedge against such market conditions that would have otherwise cost LED more money.

Table 14: Pay for Performance Ranges for One Hour of Project 10 Operation⁷

ISO Load	0%	50%	100%
10,000	-\$13,691	\$7,143	\$27,977
15,000	-\$19,643	\$1,191	\$22,024
20,000	-\$25,596	-\$4,762	\$16,072
25,000	-\$31,549	-\$10,715	\$10,119

⁶ For an overview of the PFP program, please visit <https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project>.

⁷ 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>

RENEWABLE ENERGY STANDARD (RES 1.0) REQUIREMENTS

A new Renewable Energy Standard (RES) was recently passed. The obligations for a municipal utility are shown in Table 15. This table only shows information through 2035 as this plan assumes obligations remain the same in subsequent years.

Table 15: RES Requirements (% of Retail Sales)

Year	VT_1	Net VT_1	VT_2	VT_3	VT_4
2025	63.00%	57.20%	5.80%	6.00%	0.00%
2026	63.00%	55.70%	7.30%	6.67%	0.00%
2027	63.00%	54.20%	8.80%	7.34%	0.00%
2028	67.00%	56.70%	10.30%	8.00%	0.00%
2029	67.00%	55.20%	11.80%	8.67%	0.00%
2030	67.00%	48.70%	13.30%	9.34%	5.00%
2031	71.00%	51.20%	14.80%	10.00%	5.00%
2032	71.00%	49.70%	16.30%	10.67%	5.00%
2033	71.00%	48.20%	17.80%	10.67%	5.00%
2034	75.00%	50.70%	19.30%	10.67%	5.00%
2035	100.00%	70.00%	20.00%	10.67%	10.00%

Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tiers I, II and IV requirements. Unlike the Tier I, Tier II and Tier IV requirements, which count only electricity that is produced and consumed in an individual year, Tier III programs account for the “lifetime” of the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2025, the fossil fuel savings from that CCHP are counted such that the full thirteen-years of the CCHP’s expected useful life accrue to the 2025 Tier III requirement.

Table 16: ACP Prices⁸ (\$/MWH)

Year	TIER I	TIER II & III	TIER IV
2025	\$12.72	\$76.35	\$40.00
2026	\$13.06	\$78.41	\$41.08
2027	\$13.42	\$80.53	\$42.19
2028	\$13.78	\$82.70	\$43.33
2029	\$14.15	\$84.94	\$44.50
2030	\$14.53	\$87.23	\$45.70
2031	\$14.92	\$89.58	\$46.93
2032	\$15.33	\$92.00	\$48.20

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, Tier III, or Tier IV 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).

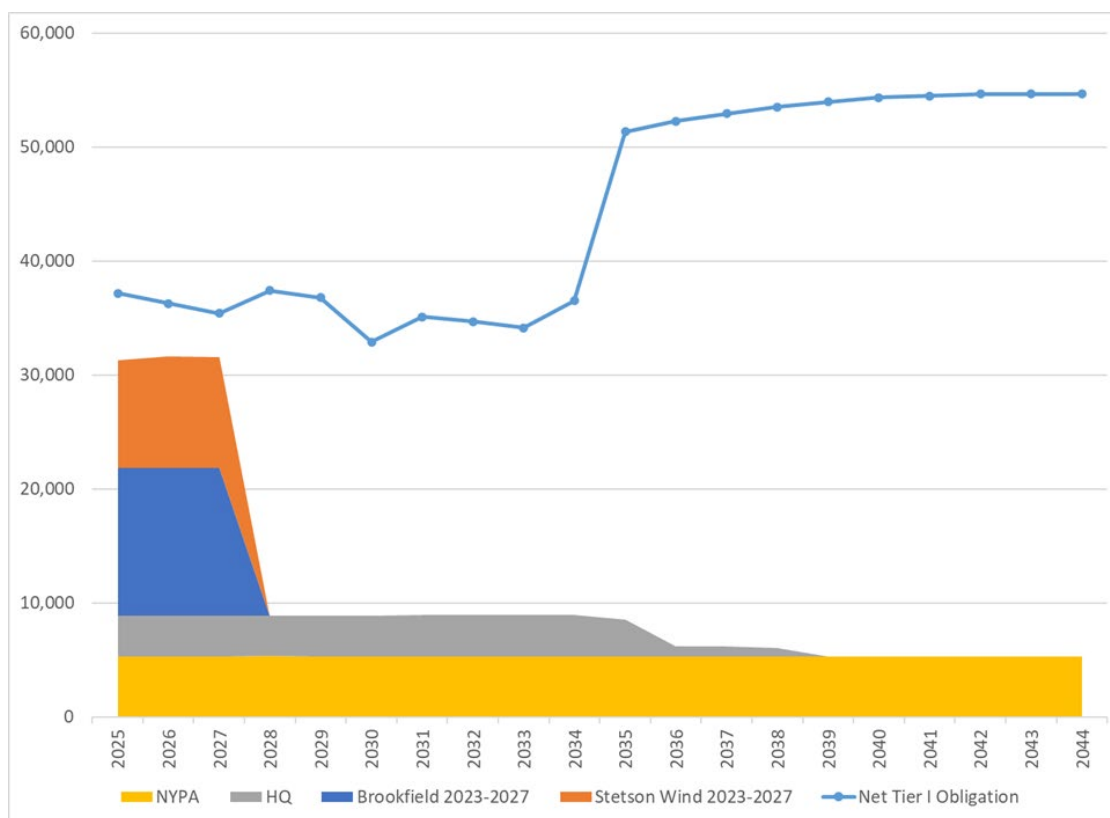
However, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP, or they may petition the PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

TIER I - TOTAL RENEWABLE ENERGY PLAN

In 2025 LED's Net Tier I requirement is approximately 37,165. The primary energy resource contributors to Tier I are the Brookfield and Stetson Wind contracts with NYPA and HQ providing smaller volumes. Brookfield and Stetson Wind contracts expire at the end of 2027 which means LED will need to purchase a larger volume of Tier I RECs, and/or enter into a bundled energy and REC contract. The deficit hovers in the 20-30,000 REC range until the obligation reaches 100% in 2035 at which point the deficit increases to over 40,000. The price of Tier I RECs has varied substantially from \$0.25 to over \$11 per REC over the last several years. Current prices for 2025 vintage are about \$4.50. At those prices, assuming gradual increases year on year, complying with net Tier I throughout the forecast period could be as little as about \$4.1 million or as much as \$9.2 million.

⁸ Please note that 2025 is known but following years are estimates and grow at inflation.

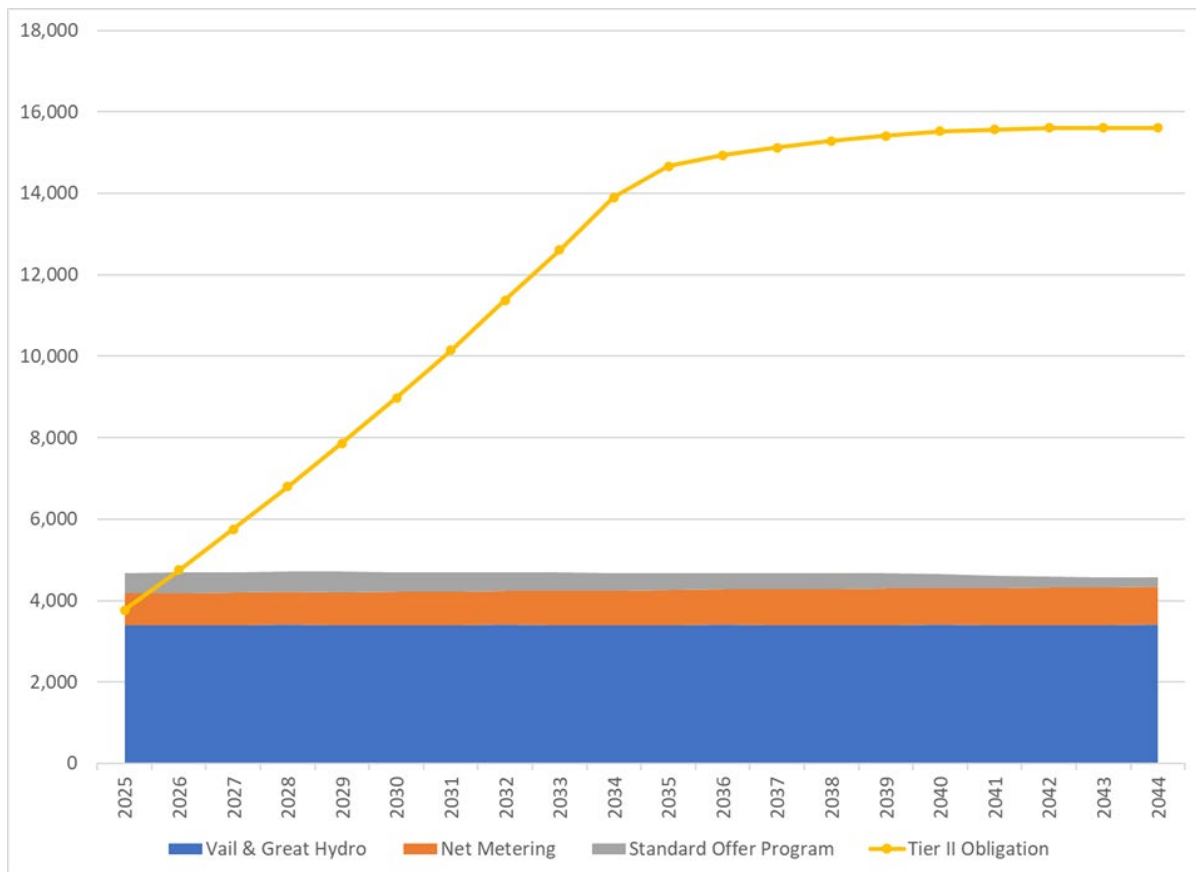
Figure 8: Tier I - Total Renewable Energy Supplies



TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The line in Figure 9 shows LED's Distributed Renewable Energy (Tier II) requirement, which increases from 3,768 MWh in 2025 to almost 15,610 MWh in 2044. LED's Tier II resources are Vail & Great Falls Hydro, Standard Offer and Net Metering. These resources are enough to satisfy LED's obligation until 2027 when the utility will need to purchase Tier II RECs and/or procure another Tier II resource. The current cost of Tier II RECs is approximately \$40 in 2025 with prices generally dropping to \$36 through 2030. Using these assumptions, it will cost LED about \$6.4 million throughout the forecast period to comply with the Tier II portion of RES.

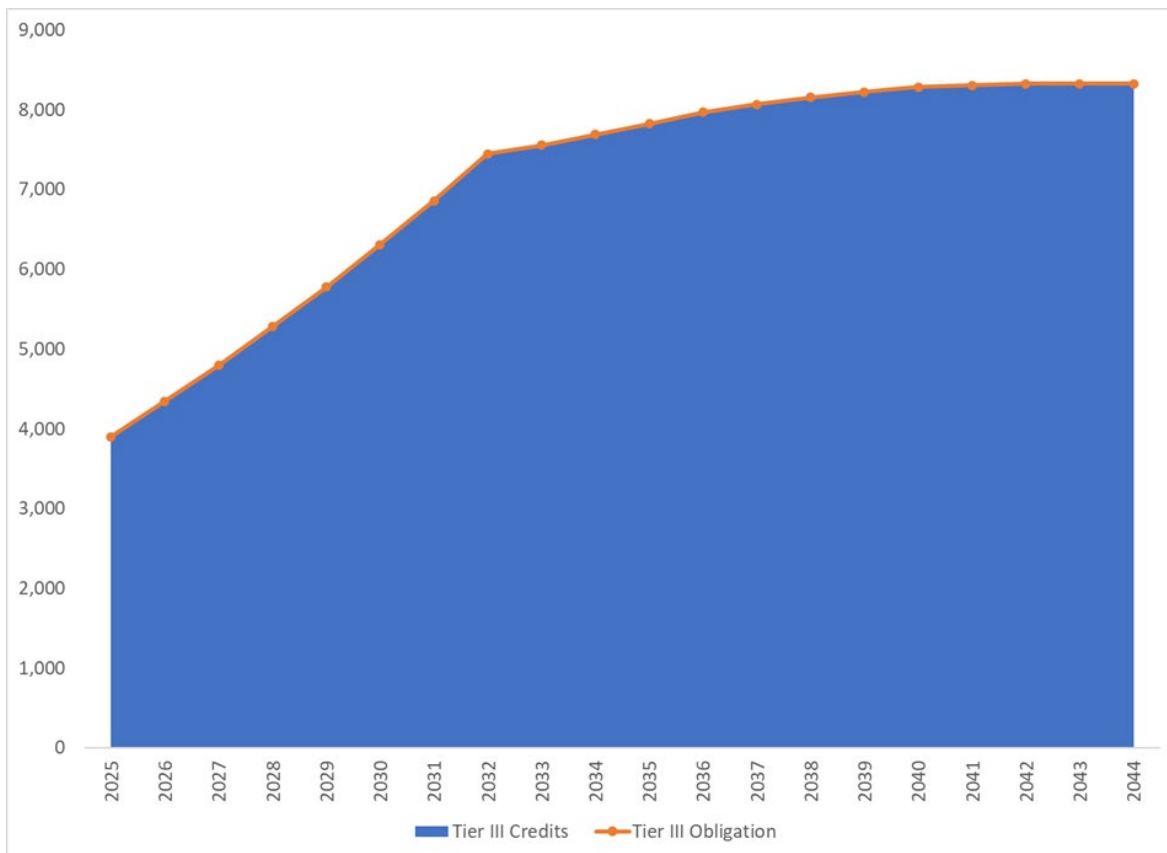
Figure 9: Tier II - Distributed Renewable Energy Supplies



TIER III - ENERGY TRANSFORMATION PLAN

The orange line in Figure 10 shows LED's Energy Transformation (Tier III) requirements, which rise from about 4,000 MWH in 2025 to about 8,000 MWH in 2044. Prescriptive programs are presently budgeted to fulfill the entire requirement and are shown in the orange area. 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 2025 Tier 3 Annual Plan) and in the following section. Note that VPPSA is monitoring the Clean Heat Standard proceeding, which could have an effect on VPPSA's Tier III approach moving forward.

Figure 10: 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. LED will follow a three-part strategy to fulfill its Tier III requirements:

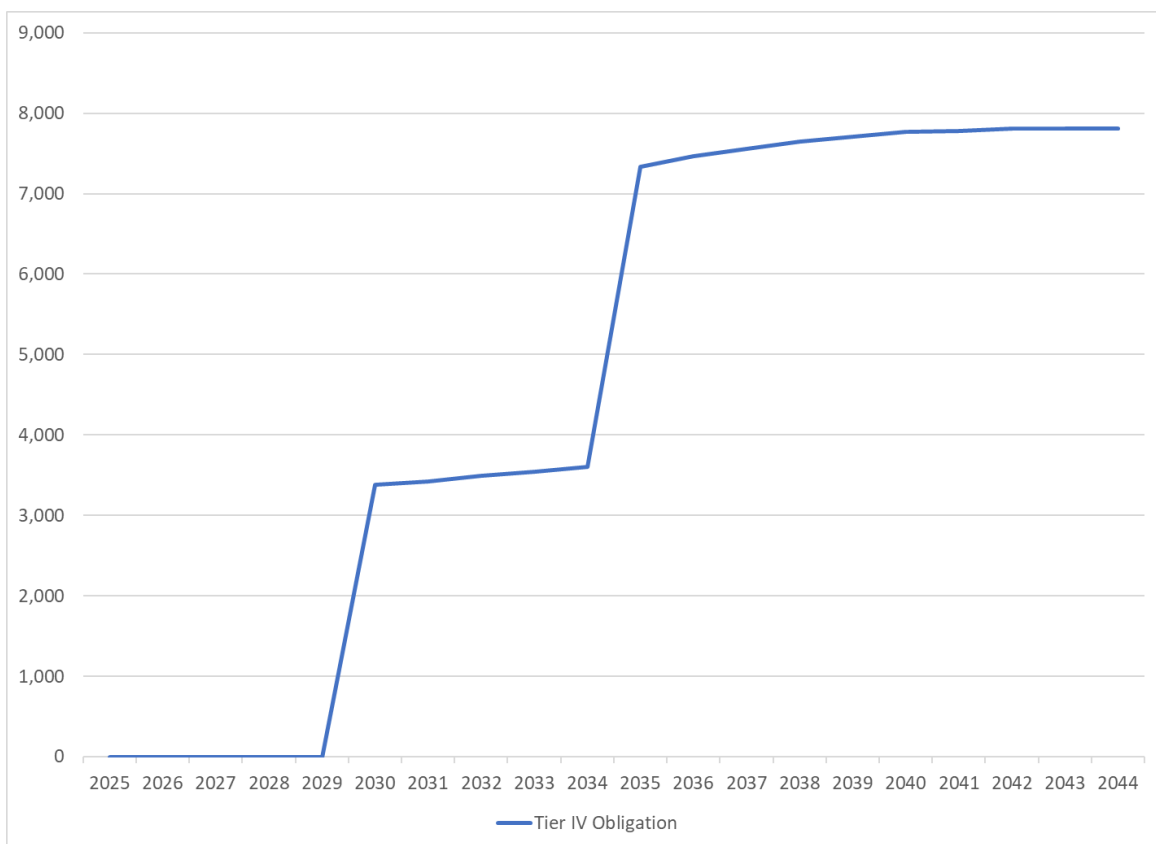
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1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Manage Tier II credits to maximize value across both Tier II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

TIER IV - NEW RENEWABLE ENERGY

LED's Tier IV obligation begins in 2030 at 3,378 RECs and increases to 7,805 by the end of the forecast period. Currently LED has no Tier IV resources. LED will need to either enter into a bundled energy and REC contract for Tier IV RECs and/or enter into a REC only purchase.

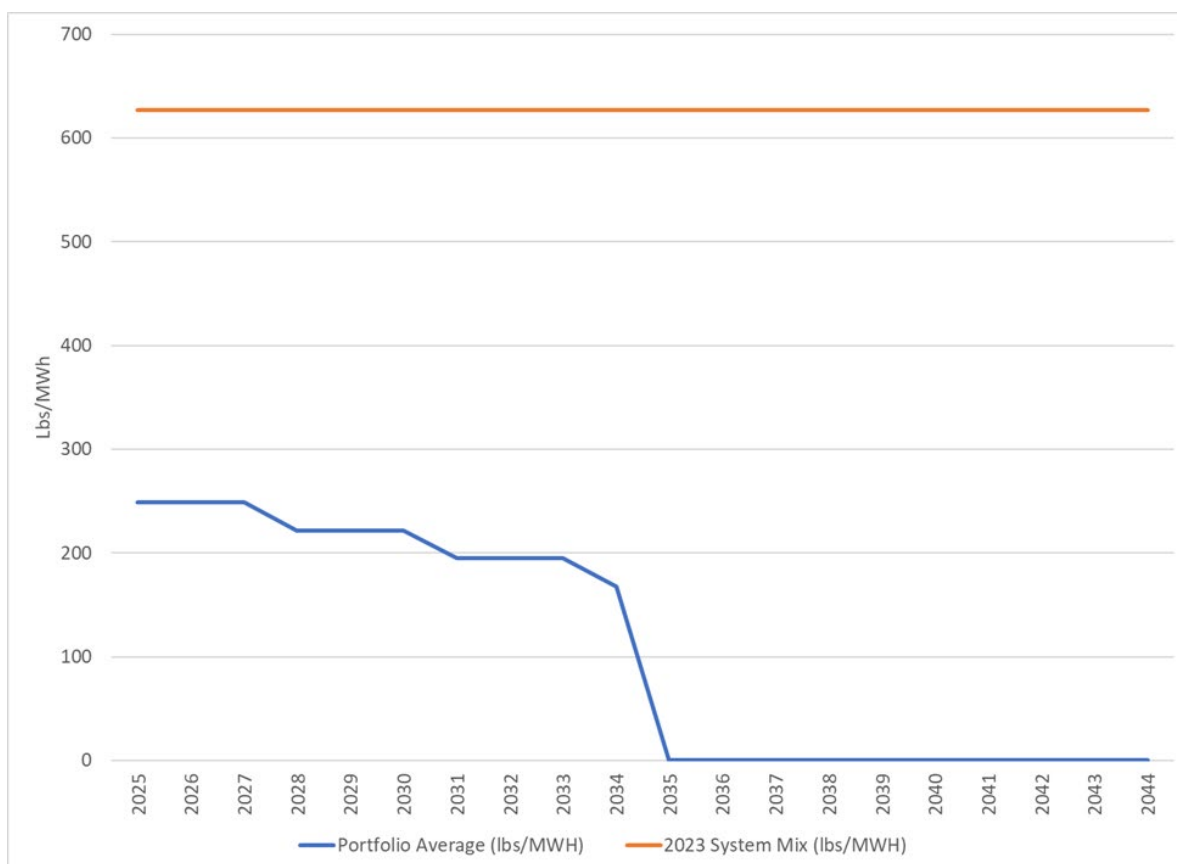
Figure 11: New Renewable Energy Obligation



CARBON EMISSIONS AND COSTS

Figure 12 shows an estimate of LED's carbon emissions rate compared to the 2023 system average emissions rate from New England and imported resources⁹. The emissions rate in 2025 is about 249 lbs/MWH.

Figure 12: Portfolio Average Carbon Emissions Rate (lbs/MWH)



The emissions rate declines through 2035 as a result of increasing RES requirements and eventually reaches zero at 2035 due to the RES obligation reaching 100% renewable.

These emissions rates were multiplied by the load forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that

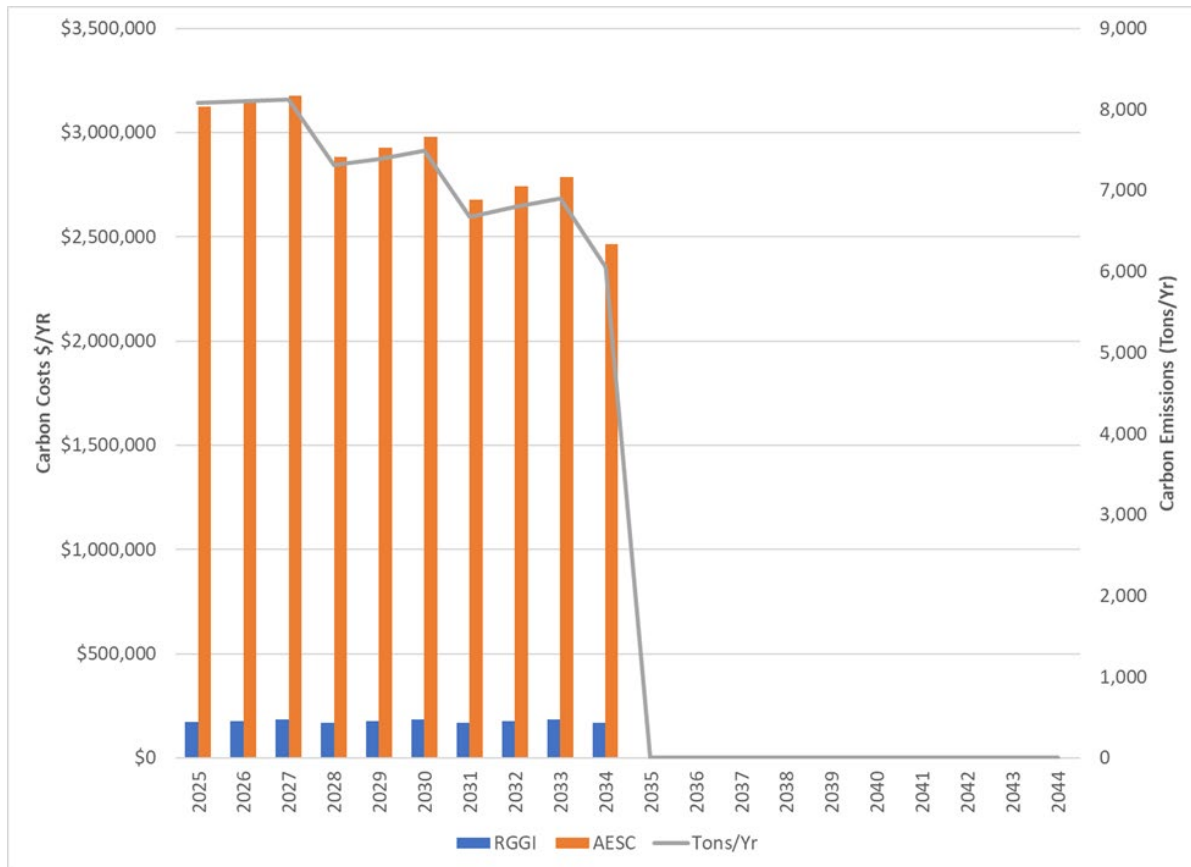
⁹ The source of this data is the NEPOOL GIS. <https://www1.nepoolgis.com/>

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carbon emissions range from about 8,078 tons/year in 2025 down to 0 tons per year in 2035 and beyond.

The costs of these emissions were calculated using two sources, the Regional Greenhouse Gas Initiative Auction (RGGI) results for the most recent auction (\$25.75 per ton) and the update to the 2021 Avoided Cost of Energy Supply (AESC) study (\$387 per ton in 2025 and escalating). Using RGGI prices plus inflation, the cost of carbon emissions averages about \$177,061 per year until 2035. Using updated AESC prices, the average cost through 2034 is about \$2.9 million per year.

Figure 13: Carbon Emissions (Tons/Year) and Costs (\$)



PROCUREMENT PLAN FOR RES 1.0

LED will need minimal additional VT Tier I RECs from 2025 through 2027 until the Brookfield and Stetson contracts expire. After that point the utility will have a large gap. The two main options are to enter into another bundled energy and REC contract and/or buy RECs only. VPPSA will need to evaluate which option is more cost effective as the time gets closer. To obtain VT Tier II RECs LED will likely continue to purchase those from other VPPSA members. LED will also need to procure VT Tier II and IV RECs. VPPSA has an existing relationship with a company that has generators that are eligible for Tier IV qualification and will follow up with them to discuss REC purchases only or bundled energy and REC purchases to fulfill the Tier IV obligation.

RESOURCE PLAN OBSERVATIONS

TIER I

LED is meeting its Tier I requirements primarily with existing resources as well as annual REC only purchases. With the new RES law passed, the volumes of the existing bundled contracts will not be enough to meet Tier I obligations throughout the planning horizon of this IRP. Therefore, it's likely that REC only purchases will need to be made and/or another bundled energy purchase procured. The final decision in this regard would depend on REC and energy market prices and how the indicative pricing from bundled contracts compare to market contracts.

TIER II

LED will continue to purchase Tier II RECs from other VPPSA members. It is likely that the utility will develop a solar project in the future to help with its Tier II obligation.

TIER III

Tier III requirements continue to be met with prescriptive programs. In addition, LED continues to investigate custom projects to supplement these programs.

TIER IV

Tier IV requirements will be met either by purchasing RECs only or by entering into a bundled contract. As stated previously, VPPSA has a relationship with an entity that has Tier IV eligible resources. VPPSA has already begun the conversation with that entity about the possibility of a REC only or bundled energy purchase.

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

TRANSMISSION & DISTRIBUTION SYSTEM PLANNING

LED is in the early stages of developing a structured approach to integrate load management into its broader distribution system planning. Rather than viewing load management in isolation, LED believes it is most effective when integrated into the planning cycle, helping target strategies that enhance distribution efficiency.

The planning process begins with a load forecast that informs a distribution system study. This study identifies system weaknesses and the costs of necessary upgrades. At this stage, load management strategies are considered as alternatives to costly existing or future equipment upgrades. These strategies vary, targeting system peaks, specific devices, or sections of the distribution network. Their goals range from reducing wholesale costs to deferring or optimizing distribution investments and managing local constraints due to increased electrification and distributed generation.

Load management can take passive forms, such as rate design, or active forms like using storage assets or device-specific approaches. However, it must be balanced with expected load growth and future equipment needs. Since these upgrades and strategies unfold over time, planning must account for uncertainties, particularly as electrification accelerates. Recent cost benefit analyses included in the planning for LED's upcoming AMI implementation indicated that implementation of Time-of Use and peak penalty pricing rate design strategies could yield an NPV of about \$200,000 in avoided costs.

As the planning cycle repeats, each iteration of the load forecast incorporates previous decisions, leading to ongoing refinements in both distribution investment and load management. With increasing distributed generation, the need for more granular system management will grow. LED, along with other VPPSA members, is working on a technology roadmap to improve distribution management and load measurement, with a report on new software systems expected in early 2025. Advanced technologies like SCADA, ADMS, and DERMS, along with existing AMI and GIS systems, are being considered.

As these systems come online, LED expects better data on localized load behavior, leading to more precise forecasts and the ability to evaluate alternatives. By modeling the effects of these alternatives, LED will be able to develop a structured analysis framework that tracks penetration of electrification and distributed generation impacts and compares the effect of applying alternate load management strategies over time. LED can make informed decisions on upgrades and load management strategies, considering factors like cost, rate impact, effectiveness, and flexibility. The utility is also open to collaboration with DPS and other utilities to share knowledge and insights.

TRANSMISSION & DISTRIBUTION SYSTEM DESCRIPTION

Detail regarding LED's sub-transmission and distribution facilities is provided below

SUB-TRANSMISSION SYSTEM DESCRIPTION

LED has twelve miles of 34.5kV sub-transmission interconnecting four of its five substations with VELCO's 115kV substation and a connecting tap to a connection point with GMP's 34.5 sub-transmission line. GMP's line is the previous sole feed to LED and can be used to receive or to feed power on to GMP's grid.

DISTRIBUTION SYSTEM DESCRIPTION

LED has four hundred miles of distribution line. Given LED's rural service territory, the majority of LED's lines are off road and inaccessible from a street or highway. LED operates a total of nine regulated 12.47 kV distribution feeders. All of the distribution mainline is overhead. The distribution system has been fully converted to 12.47/7.2 kV (four-wire) operation. The distribution system is in good physical condition and has been adequately maintained. The minimum conductor size that is now used is 1/0 ACSR. Some older, smaller diameter copper conductor is still present on some of the fused branch lines, where the thermal loading is generally quite small.

LED-OWNED INTERNAL GENERATION

LED owns two “run of the river” hydro stations comprising four generators with LED utilizing all of their output. In 2023 the two hydro facilities produced a total of 4,306 MWh. The five-year average output for the stations is 3,017 MWh.

Great Falls Hydro Station

Located at 76 Great Falls Drive, Lyndon on the Passumpsic River and is a run of the river facility having three turbines: one 1,350kW Leffel turbine; and two smaller GE 350 kW turbines.

Vail Hydro Station

Located at 166 Light Plant Drive, Lyndon on the Passumpsic River and is a run of the river facility having a single 350 kW GE turbine.

LED SUBSTATIONS

LED owns and operates five substation facilities. Each substation is briefly described below.

Great Falls Substation (#1)

Unlike other LED substations, Great Falls is a low-voltage substation. Generation from both hydro stations is fed into the low-side of the substation bus at 2400 volts through a 12470/2400 grounded wye transformer and distributed to the Industrial Park Substation. Metering for hydro generation is located in this substation, however there is no SCADA communication with this substation.

Industrial Park Substation

The high-side voltage of the Industrial Park Substation is 34.5kV and is lowered to 12470 volts via 3.7 MVA grounded wye step down transformer. Voltage regulation is governed by 167kV GE regulators via the bus. At the time of construction, the sub was to be utilized only

for the load developed within the Industrial Park. However, development in the park fell short of expectations so to make the most of substation capacity it was decided that residential distribution would concurrently be served therefrom. Circuit 1 is the only circuit originating out of the substation and is protected by a Cooper oil filled breaker. There is no SCADA communication with this substation.

Hill Street Substation (#2)

Number Two Sub, as it is sometimes called, is LED's largest substation in regard to load and footprint. Hill Street Sub consists of a 7.5 MVA with a 34.5kV high side and a 12470/7200 grounded wye low side. Circuits originating from this substation are lines 4 and 8. All circuits are protected by Cooper VWEs oil filled breakers. Voltage regulation is via the bus governed by Siemens 250kVA regulators. There is no SCADA communication with this substation

Pudding Hill Substation

Pudding Hill is comprised of 34.5kV high side to 5MVA 12,740/7200 ground wye low side. Voltage regulation is via the bus regulated by 167kVA regulators. Circuits out of the sub are lines 2, 3 and 42. All circuits are protected by Cooper oil filled breakers. There is no SCADA communication with this substation.

Burke Mountain Substation

Burke Mountain Substation is the only LED substation outside of the town of Lyndon. As with all other substations, Burke Mountain Substation has a 34.5kV high side, a 5MVA grounded wye transformer to 12470/7200 low side. Voltage regulation, also like other LED substations, is via the bus governed by 167kVA regulators. Circuits emanating from the substation are 6 and X6. These circuits are protected by Cooper oil filled breakers. There is no SCADA communication with this substation.

CIRCUIT DESCRIPTION

Table 17: LED Circuit Description

Circuit Name	Description	Length (Miles)	# of Customers by Circuit	Outages by Circuit (2023)
Line: 1	Broad St., South Wheelock, Kirby	62.5	1,013	61
Line: 2	Rt. 122, Sutton Wheelock	18.88	208	13
Line: 3	Lyndon Center, Lyndon St. College	13.91	531	3
Line: 4	Lyndon, Burke, Newark, Westmore	107.06	1,517	81
Line: 6	East Burke, East Haven	77.83	1,113	58
Line: X6	Burke Mountain	1.87	172	4
Line: 7	Lyndon, Kirby	23.64	310	12
Line: 8	Lyndonville Village, Broad St.	3.78	359	2
Line: 42	Lyndon, Sutton, Wheelock, Glover	62.08	623	60

LED has nine feeder circuits in total. LED does not consider any of its circuits to be particularly long. LED operates its system to maintain 114 to 126 volts at the customer's metering point.

T&D System Evaluation:

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

Outage Statistics

LED evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. The evaluations include the review of the Public Utility Commission Rule 4.900 Outage Reports and data collected from load loggers. In addition, LED periodically completes long term system planning studies to develop overall strategies for improving the performance of the T&D facilities. The cost of the improvements recommended in the study are developed into a 5-year budget and approved by the LED Electric Board of Commissioners based upon the financial position of LED's electric department.

Tree contact from severe weather events is the primary cause of service interruptions for distribution facilities. To prevent future outages and maintain reliability, LED continues to trim trees on an 11-year rotation and add animal guards to equipment. LED also takes out danger trees as necessary subject to landowner cooperation.

LED's Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years (2019-2023) in their entirety, can be found in Appendix C, at the end of this document.

LED has committed to performance standards for reliability that measure the frequency and duration of outages affecting its customers. There are two primary measures for the frequency and duration of outages. The Public Service Board's Rule 4.900 defines them as:

System Average Interruption Frequency Index (SAIFI): Customers Out, divided by Customers Served. SAIFI is a measure of the average number of times that the average customer experienced an Outage.

Customer Average Interruption Duration Index (CAIDI): Customer Hours Out, divided by Customers Out. CAIDI is a measure of the average length of time, in hours, that was required to restore service to customers who experienced an Outage.

LED has committed to achieve performance levels for its distribution system below an index of 3.0 for SAIFI and 2.6 for CAIDI. LED maintains a record of and reports on all its system outages, including the root cause of an outage. While some outages cannot be prevented, there are a number of specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

The following table summarizes LED's SAIFI and CAIDI values, excluding major storms, for the years 2019 - 2023.

Table 18: LED Outage Statistics¹⁰

	Goals	2019	2020	2021	2022	2023
SAIFI ¹¹	3.0	2.0	2.8	2.4	2.4	2.9
CAIDI ¹²	2.6	2.9	3.2	1.8	2.7	2.2

LED will continue to evaluate all circuits on a basis that considers cost-efficiency, impact to rate payers, reliability, and safety measures. LED will also continue to look at ways to bring lines closer to roads while weighing the costs of doing so.

LED has several initiatives underway to improve reliability. Each of these initiatives is described below.

ANIMAL GUARDS

All aerial pathways into LED's substation bus work are covered by animal guards. Additionally, it is LED's practice to install animal guards on all new distribution transformer installations or change outs.

FAULT INDICATORS

LED has installed fault locators on the out feed of LED's underground distribution enclosures to help in identifying de-energized conductor. Aerially, LED relies on fusing to indicate downstream issues.

AUTOMATIC RECLOSURES/FUSING

¹⁰ SAIFI and CAIDI statistics shown are net of major storm outages

¹¹ System Average Interruption Frequency Index

¹² Customer Average Interruption Duration Index

All circuits originating from a substation are protected by oil filled reclosers. Only line 4 has a recloser at its origin outside of a substation. None of LED reclosers have communication integrated; all reclosers operate per programmed settings. The bulk of LED's lines are protected by aerial fusing.

FEEDER BACK-UP

The design of LED's distribution system allows for feeder backup only within the limits of Lyndon. Where possible LED has installed fusing and solid cutouts to re-route power from different substations in the event that a feeder is lost.

POWER FACTOR MEASUREMENT AND CORRECTION

As of an August 2010 Transmission and Distribution System Study LED had a power factor of 94%. With new management in place, LED has recently begun investigating options to improve power factor and will include further analysis of improvement opportunities in the next system study.

DISTRIBUTION CIRCUIT CONFIGURATION

VOLTAGE UPGRADES

LED completed its system wide voltage conversion in 2000 from 4800/2800 to 12470/7200.

PHASE BALANCING/ FEEDER BACK-UPS

Each of LED's distribution feeders have been checked for load balance between phases. It should be noted that limited options exist for load balancing on certain feeders (Pudding Hill B-17 and B-18), as these feeders each feed a long single phase branch that load one phase of the circuit more heavily. Where balancing was possible, losses were slightly reduced and end of line voltage was improved

As stated previously, due to the design of LED's distribution grid, only feeders in the vicinity of Lyndon have been altered to allow for feeder back-up.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

PROTECTION PHILOSOPHY

LED has system protection that covers transmission, substations and distribution plant. Each protection methodology is discussed individually below.

Transmission Protection:

The VELCO Lyndon substation has a single 115 to 34.5 kV transformer and a 5-breaker 34.5 kV ring bus. One position in the ring bus is used for the transformer connection. The other four positions are used as terminals for LED's 34.5 kV lines. The 34.5 kV circuit breakers that supply LED's 34.5 kV transmission lines have state of the art relay protection and control packages connected to VELCO's SCADA system.

Substation Protection:

At No. 2 Substation (Hill St.), transformer high side protection at the Village substation is accomplished using a 34.5 kV circuit recloser. The recloser has been configured to monitor the transformer neutral CT, which allows it to sense ground faults on the 12.47 kV side of the transformer. This provides fast acting backup capability in the event of a stuck feeder recloser.

At Pudding Hill Substation, transformer high side protection at the Village substation is accomplished using power fuses. The fuse size has been selected to provide transformer protection as well as to coordinate with the source side devices.

At Burke Mountain Substation, transformer high side protection is accomplished using power fuses. The fuse size has been selected to coordinate with the source side devices.

At Industrial Park Substation, transformer high side protection at the Industrial Park substation is accomplished using power fuses. The fuse size has been selected to coordinate with the source side devices.

Distribution Protection:

At No. 2 Substation (Hill St.), distribution feeder protection for the B-8, B-9, and B-10 feeders is accomplished using circuit reclosers, with automatic line reclosing. Additional automatic line sectionalizing of the B-9 feeder is accomplished via the mid feeder B-22 line recloser, which is located near the fairgrounds.

At Pudding Hill Substation, distribution feeder protection for the B-16, B-17, and B-18 feeders is accomplished using circuit reclosers with automatic line reclosing.

At Burke Mountain Substation, distribution feeder protection for the B-19 and B-20 feeders is accomplished using circuit reclosers, with automatic line reclosing.

At Industrial Park Substation, distribution feeder protection for the B-24 feeders is accomplished using a circuit recloser.

LED utilizes branch fusing on all of its distribution feeders to ensure that line faults are sectionalized in a manner that affects the fewest number of customers.

SMART GRID INITIATIVES

PLANNED AMI

Beginning in 2018, LED 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 LED. This is an electric AMI assessment; the Town of Lyndon Water Department did not participate in this evaluation. 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 19: 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. LED 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. The Readiness Evaluation is summarized in the table below:

Table 20: AMI Readiness Evaluation

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

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,

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- 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 Vermont [Public Power](#) Supply Authority

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.

LED 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 \$1,800,000, with a positive cost-benefit ratio of 2.3 and a 4.9-year payback, providing LED with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are inclusive of the Vermont state funding opportunity. The final contract with Aclara has been recently signed and LED is optimistic that it will begin implementation of a new AMI system in either late 2026 or early 2027, to be completed no later than the end of 2027.

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. VPPSA's 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. LED is mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While LED is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and LED's membership in VPPSA provides LED with knowledge and insight regarding ongoing cybersecurity developments and risks.

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. Since May of 2024, LED has been working directly with VPPSA to provide the service.

LED 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. LED conducts ongoing vulnerability assessments and LED recently completed its most current assessment.

OTHER SYSTEM MAINTENANCE AND OPERATION:

RECONDUCTORING FOR RELIABILITY OR SYSTEM LOSS REDUCTION

A section of 34.5 sub-transmission from the VELCO 115 kV substation to LED's connection point with GMP has been reconductored with larger 477 mcm (Pelican) conductor to strengthen the connection between VELCO/LED/GMP.

The distribution system is in good physical condition and has been adequately maintained. The minimum conductor size that is now used is 1/0 ACSR. Some older, smaller diameter copper conductor (#4 or #6 copper) is still present on some of the fused branch lines, where the thermal loading is generally quite small.

Thermal loading is a minor consideration in the upgrading of the small conductor; however, upgrading to our standard 1/0 ACSR benefits thermal loading. Poor conductor condition, loss reduction, and product end of life cycle are the major considerations for conductor upgrading.

TRANSFORMER ACQUISITION

As a practice, LED requires load loss data from vendors when quoting distribution transformers. LED considers manufactures such as ABB, Cooper, and Ermco as trusted brands, and multiple factors, such as load losses, cost, brand, delivery in relation to available storage space, and total ownership cost, are considered in LED's purchasing decision.

CONSERVATION VOLTAGE REGULATION

LED does not have conservation voltage regulation.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

On a rural system such as LED's, most of the transformers are fairly lightly loaded and many serve single residences. It is unlikely that a DTLM program would be cost effective, given the relatively small number of transformers that are expected to be heavily loaded. More detailed evaluation of DTLM may become more practical following implementation of AMI equipment, making implementation of a limited DTLM program more feasible.

SUBSTATIONS WITHIN THE 100- AND 500-YEAR FLOOD PLAINS

None of LED's substations fall within a flood plain.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

The bulk of LED lines are aerial; however, LED does own a small amount of underground primary. All customers own their underground service lateral and a small number of customers own primary underground. LED utilizes the Vermont Utilities Electric Service Requirements manual as its Underground Facilities Standards. LED follows and will continue to adhere to the Vermont Dig Safe Law. LED 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 July 2019.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

LED purchases small distribution equipment from well-known, reliable vendors. These purchases are made based on criteria including equipment that is UL approved or certified by other industry standards and are subject to consideration of quality, cost, and timely delivery. Larger substation equipment is bid via a spec developed by our engineering consultant (PLM) that takes into consideration life-cycle-cost, loss reduction and energy efficiency.

MAINTAINING OPTIMAL T&D EFFICIENCY

Conductor

The analysis that is used is a comparison of the differential cost of the cumulative present worth of construction carrying charges and any increased annual O&M costs to the cumulative present worth of the avoided purchase power costs at the projected forward capacity market clearing price (demand), plus the annual energy savings, that would result from the anticipated reduction in system losses. Projects that break even within 20 years are deemed to be viable candidates. The net reduction in system losses due to a specific project is calculated using the system computer model. The model is Vermont [Public Power](#) Supply Authority

also useful to be able to identify those line sections that are the largest contributors to overall system losses.

LED's standard distribution conductor size is 1/0 aluminum, which is installed on most of our feeder lines; side taps can be copper conductor of smaller size. As time and resources allow, LED replaces copper conductor on tap lines.

Pole Inspection

Ongoing development of its GPS/GIS program, enables LED to "mine" the resulting database to identify equipment that is fully depreciated and/or noted as being in poor condition and needing replacement. Transmission lines are patrolled on a quarterly basis and condition of conductors, poles, and vegetation are noted and prioritized for repair or replacement.

Equipment

Substation equipment and Gang Operated Switches in the field are inspected on a monthly basis. Reclosers and regulators are tested annually. Infra-red testing is also done annually on all substation equipment and components as well as selected components in the field.

Actual System Losses

In efforts to reduce losses, LED completed conversion to 12,470/7200 voltage system wide in 2000. To further minimize line losses, LED has standardized on 1/0 AAAC (Azusa) conductor for all new distribution construction. Older tap lines with lower capacity conductor are being upgraded on a prioritized basis. LED distribution system losses have averaged 2.8% since 2019 and have been gradually decreasing; 2023 actual distribution losses were 1.9%

System Maintenance

LED's system maintenance includes a very active vegetation management plan as discussed in detail below.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

LED utilizes the NJUNS database to initiate and track pole activities between LED and other pole partners.

Relocating cross-country lines to road-side

LED does believe in relocating cross-country lines to road-side to build system resiliency. LED will continue to do so as time and finances allow, providing ROWs can be obtained.

DISTRIBUTED GENERATION IMPACT:

LED presently has one hundred seventy residential scale (< 15 kW) net-metered customers with a total installed capacity of about 1,098 kW. In addition, there are fifteen customers who have arrays between 15 and 500 kW with a total capacity of 1,834 kW.

Interconnection of Distributed Generation

LED recognizes the unique challenges brought on by increasing penetration levels of distributed generation. LED 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 that 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 LED 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, and
- Increased incident energy exposure (arc flash)

In addition, recognizing that the aggregate of many smaller installations that individually pass Rule 5.500 screening criteria can present problems that would otherwise go unnoticed, LED will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow LED 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). LED 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 LED's service territory, LED 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 LED. As a reasonable compromise, LED 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, LED 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. LED 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

LED 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. LED is focused on identifying and developing technical systems that help with the challenge of identifying, tracking and managing “hot spots” on the system as they develop. This includes keeping an eye toward formulating timely responses, whether those be load-management efforts, equipment upgrades, or the addition of generation/storage at key locations.

The LED distribution system currently has sufficient capacity for the foreseeable future. LED’s four substations, as shown below in Table 21, are fed from one transformer in the VELCO substation via four reclosers. The aggregate nameplate capacity of LED’s four substations is 21.2 MVA. LED’s 2024 peak distribution load was 65,955 MWH, indicating average loading of about 36% of nameplate capacity. With a 13.68 MW peak in December of 2024, maximum aggregate transformer loading was about 65%.

Table 21: LED Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity (MVA)	Peak % of Nameplate (2)	Avg Load % of Nameplate (1)	CIRCUIT/ FEEDER ID/NAME	Circuit Voltage (kV)	Distributed Generation # of Units	Nameplate AC Output Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
Industrial Park Substation	1	3.7 MVA			Circuit 1	12470	24	188		456	1,521,348
					Circuit 7	12470	11	74			
					INDUSTRIAL SUB. TOTAL		35	262	-	456	1,521,348
Hill Street Substation (#2)	1	7.5 MVA			Circuit 4	12470	57	1,896			
					Circuit 8	12470	2	11			
					HILL STREET SUB. TOTAL		59	1,907	-	-	-
Pudding Hill Substation	1	5 MVA			Circuit 2	12470	10	68		-	-
					Circuit 3	12470	7	56		528	2,857,620
					Circuit 42	12470				-	-
					PUDDING HILL SUB. TOTAL		17	2,030	-	528	2,857,620
Burk Mountain Substation	1	5 MVA			Circuit 6	12470	48	358		1,958	5,053,402
					Circuit 6x	12470	4	34		-	-
										-	-
					BURK MT. SUB. TOTAL		52	2,422	-	1,958	5,053,402
Aggregate			65%	36%							

(1) Estimated Annual kWh / (transformer capacity * 8760)

(2) Estimated Peaks by Circuit are Derived from Connected kVA on each Feeder

We know from the Demand Chapter¹³ that the transformers at the Lyndon 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 rating. Furthermore, because conductor size is calculated based on the transformer rating, it is also unlikely that conductor size is going to be a constraint. While substation transformer capacity appears adequate for the foreseeable future, LED recognizes that the addition of one or more EV charger(s), heat pump(s), or storage device(s) at some locations may stress transformers at the service drop level, necessitating unanticipated upgrades.

While the anticipated, immediate 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 regulator level. In recognition of the potential stress on its system, LED 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, and develop concentrations of electrification-driven load.

Currently, LED 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. LED can track installed electrification measures associated with incentive programs, by street address, within the LED 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, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to LED's responses to expected electrification impacts on its distribution system.

As discussed earlier, LED anticipates through the tech roadmap project that phased implementation of AMI, GIS, SCADA and DERMS systems over the next few years will provide

¹³ See 'Peak Forecast Results.'

the ability for more sophisticated measurement, tracking and analysis frameworks that will support implementation of more sophisticated, and forward looking, load forecasting and distribution system planning. As the anticipated distribution system management implementations reach maturity, LED will be able 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 LED'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 LED's planning for appropriate distribution system development by enhancing LED'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 for appropriate load management including innovative rate designs and optimal location of storage facilities.

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 LED to commission a full T&D study to take stock of current system conditions and identify/prioritize required improvement projects.

VEGETATION MANAGEMENT/TREE TRIMMING

ROW maintenance has been moved to the forefront of concerns for the utility; the annual funding for this effort has been increased to \$250,000. Revamping its vegetation management program has allowed LED to achieve an eleven-year trim cycle within what it believes to be a sustainable budget that won't create rate pressure.

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LED anticipates trimming an average of 27+ miles of ROW per year; as heavily overgrown sections are reclaimed in the next few years, LED hopes to be able to subsequently increase the annual miles trimmed thus shortening the trimming cycle.

Resulting from increasing the vegetation management budget and moving the vegetation management to the forefront of our utility's concerns in 2019, we have seen a change in the trend with decreasing tree caused outages. By utilizing a trifecta of approaches comprised of the local Corrections Department Work Camp, the tried-and-true use of aerial trimming and mechanized equipment for remote ROWs, LED has consistently met its annual goal of miles trimmed being in the high twenties. We see this as a financially sustainable combination that is producing positive results. The Work Camp with LED onsite supervision is utilized for those areas where the terrain will not allow mechanized equipment or in the proximity of dwellings where the machines would not be welcome or have a high potential to damage ground cover. Trimming contractors are utilized for aerial roadside trimming and off-road locations where the only option for aerial removal is via climbing and additionally to supplement ground trimming. Lastly, mechanized equipment is used for those long stretches of cross-country ROWs, which are numerous, where proximity to houses is limited and aesthetic not closely scrutinized. We do a limited amount of trimming using in-house resources; however, we have determined that our crews are the most expensive option for trimming. At this time, herbicide use for vegetation management is not a means we want to consider.

In addition to its vegetation and brush management program, LED has a program to identify danger trees. Danger trees are identified by all of our utility personnel while patrolling the lines or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within LED's right-of-way. For danger trees outside of the right-of-way, LED contacts the property owner, explains the hazard, and with the owner's cooperation removes them. Where permission is not granted, LED will periodically follow up with the property owner to attempt to obtain permission.

The emerald ash borer has very recently become an active issue in Caledonia County. LED 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 LED's territory, affected trees will be cut down, chipped and properly disposed of.

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Table 22: LED Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Distribution	Approximately 400 miles	300	11-year average cycle
Transmission	Approximately 12 miles	6	11-year average cycle

Table 23: LED Distribution Vegetation Management Costs

	2021	2022	2023	2025	2026	2027
Amount Budgeted	\$151,339	\$190,000	\$170,000	\$250,000	\$250,000	\$250,000
Amount Spent	\$232,395	\$235,112	\$204,387	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	27.8 miles	28.2 miles	24.5 miles	27.3 miles to be trimmed	27.3 miles to be trimmed	27.3 miles to be trimmed

Table 24: LED Transmission Vegetation Management Costs

	2021	2022	2023	2025	2026	2027
Amount Budgeted	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000
Amount Spent	\$0	\$5,468	\$0	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	0 miles	1.3 miles	0 miles	.57 miles to be trimmed	.57 miles to be trimmed	.57 miles to be trimmed

Table 25: LED Tree-Related Outages

	2019	2020	2021	2022	2023
Tree Related Outages	91	177	98	110	79
Total Outages	164	286	149	235	294
Tree-related outages as % of total outages	55%	62%	66%	47%	27%

STORM/EMERGENCY PROCEDURES:

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

RESILIENCE PLANNING:

LED recognizes the need to actively address system resilience as electrification increases customers' dependence on the electric system at the same time as climate, cybersecurity, and other threats to that system are increasing. LED supports the development of a systematic approach to defining, valuing, and planning for resilience, including the use of metrics for measuring and tracking system quality beyond the standard reliability metrics of SAIDI, SAIFI, and CAIDI. Toward this end LED plans to follow the development of relevant metrics and planning frameworks being explored through resilience proceedings at the PUC and engage in resilience initiatives convened by the PUC or DPS and its partners.

PREVIOUS AND PLANNED T&D STUDIES:

FUSE COORDINATION STUDY

A fuse coordination study has not been conducted nor implemented. LED is not experiencing any issues with fuse coordination at this time and fuse configuration is updated as significant changes to the system occur.

SYSTEM PLANNING AND EFFICIENCY STUDIES

LED completed a Transmission and Distribution System Study just prior to the VELCO/Lyndon 115kV Substation coming online in 2010. The system has seen little growth and has remained stable since the last study.

LED intends to complete an engineering study in 2025 - 2026 to replace the approximately 5.5 mile long 34.5kV transmission line that supplies the Burke substation. Consideration of replacing or rebuilding the Burke Sub will also be a part of the engineering study. Future anticipated load, operational efficiency, State of Vermont permitting requirements, and environmental conditions will also be included in this planning study. The intent is to construct the final approved project in 2027.

CAPITAL SPENDING

HISTORICAL CONSTRUCTION COST 2021-2023

Table 26: LED Historic Construction Costs 2021-2023

Lyndon Electric Department			
Historic Construction	2021	2022	2023
Functional Summary:			
Production	\$ 154,933	\$ 198,258	\$ -
General	\$ 28,006	\$ -	\$ -
Distribution	\$ 329,494	\$ 388,294	\$ 260,636
Transmission	\$ -	\$ -	\$ 17,091
Total Construction	\$ 512,433	\$ 586,552	\$ 277,727

PROJECTED CONSTRUCTION COSTS 2025-2027

Table 27: LED Projected Construction Costs 2025-2027

Lyndon Electric Department			
Projected Construction	2025	2026	2027
Functional Summary:			
Production	\$ 42,699	\$ 43,638	\$ 44,598
General	\$ 54,354	\$ 55,549	\$ 95,795
Distribution	\$ 358,177	\$ 366,057	\$ 374,111
Transmission	\$ -	\$ -	\$ -
Total Construction	\$ 455,230	\$ 465,245	\$ 514,503

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of resource procurement scenarios as well as an analysis of battery storage to illustrate the cost saving potential of a peak-shaving battery. The characteristics of these scenarios are summarized in Table 28.

Table 28: Scenarios

#	Resource Scenario	Description
0	Reference Case	Open position starting in 2028. Fitchburg extended.
1	Fitchburg Evaluation	No extension of Fitchburg
2	Energy Purchase	Bundled energy and REC purchase
3	Battery Storage	4.9MW Battery

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 increase by 18% within the forecast period. Transmission charges are growing more at 71%. This has been the trend over the past decade. Administrative costs grow 44%. RES cost grows 93%. Loads grow at 17%. Finally, the coverage ratio drops as contracts expire.

Table 29: Reference Case Financial, Load and Coverage Ratio Outcomes (\$ Million)

Cost Item	2025	2029	2035	2039	2044	% Increase
Net Resource/Load Charges & Credits	\$5.10	\$5.47	\$4.79	\$5.59	\$6.21	18%
Transmission Charges	\$2.38	\$2.95	\$4.39	\$5.77	\$8.18	71%
Administrative/Other Charges & Credits	\$0.21	\$0.24	\$0.29	\$0.33	\$0.38	44%
Total Charges	\$7.70	\$8.66	\$9.46	\$11.69	\$14.77	48%
RES Cost	\$0.12	\$0.41	\$1.19	\$1.45	\$1.72	93%
Total Load - Including Losses (MWH)	64,974	66,670	73,325	77,075	78,050	17%
Coverage Ratio	95%	59%	33%	18%	17%	

To stabilize net resource costs, long-term, fixed price contracts can be entered at or below the embedded cost of the existing (or expiring) resource. Stabilizing costs in a least cost way requires ongoing monitoring of both market prices and embedded costs and then procuring resources during those times when it is cost-minimizing to do so.

To reduce transmission costs, a peak-shaving storage resource is being studied. The system evaluated is sized at 4.9 MW 100% revenue retention with an assumed commissioning year of 2025. With a high degree of accuracy of hitting the peaks, a battery would reduce transmission costs from present day costs due to lower coincident peaks. However, due to the year-on-year increase in transmission rates, the transmission costs likely wouldn't stabilize; instead, their cost would be reduced from what the cost would have been without a battery. The next section quantifies the relative cost of each procurement scenario.

PROCUREMENT SCENARIOS

Table 30 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and the three scenarios evaluated.

Table 30: Financial Outcomes of each Procurement Scenario (\$ Million)

#	Resource Scenario	PVRR	% Change
0	Reference Case	\$208.83	
1	Fitchburg Evaluation	-\$1.44	-0.7%
2	Energy Purchase	-\$0.46	-0.2%
3	Battery Storage	-\$4.90	-2.3%

The reference case assumes Fitchburg is extended. The first scenario is modeled as if Fitchburg is extended as included as an option in the PPA. The volume remains the same but the PPA rate increases to \$95.

The second scenario of bundled energy purchase is based on market energy prices plus a slight premium, which is based on VPPSA's experience in obtaining indicative pricing from the counterparty that offers bundled contracts, and an assumption that REC values will mirror market values. The price decrease from the reference case is about \$456,000.

Finally, the third scenario reflects the impact of the battery storage option which is a 100% revenue retention with a high base payment rate. This reduces costs from the reference case by about \$4.9 million.

CONCLUSIONS

All scenarios reduce costs. The smallest reduction in cost is the bundled energy and REC purchase at just a 0.2% reduction in present value revenue requirement. Not extending the Fitchburg contract has a reduction of 0.7%. These are such small percentage changes that slight changes to markets could swing the value proposition to a negative value. It will be important to continue to reevaluate the projects scenarios as the deadlines approach to ensure the most advantageous decisions are made for LED. Particularly for a bundled energy purchase it will be important to get indicative pricing and reevaluate.

Lastly, the battery storage project at 100% revenue retention saves 2.3% and is much more obviously a beneficial project. Lyndon is currently in talks with a storage developer but these discussions are still in their infancy and there are very few specifics.

ACTION PLAN

VI. ACTION PLAN

Based on the foregoing analysis, LED envisions taking the following actions:

- Advanced Metering Infrastructure
 - Implement an AMI system as reflected in the recent RFP within the 2026-2027-time frame.
- Energy Resource Actions
 - At this time there is a slight benefit to a bundled transaction. Further review will need to take place in the future including indicative pricing.
- Capacity Resource Actions
 - Manage and monitor the reliability of Project 10 to minimize Pay-for-Performance (PFP) risk and maximize PFP benefits.
- Tier I Actions
 - Most likely a combination of bundled energy and REC purchases as well as REC only purchases will be needed to achieve 100% renewability by 2035.
 - Make forward purchases, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk. Follow broker price marks to ensure lowest price possible using REC banking when appropriate.
- Tier II Actions
 - Continue to purchase Tier II RECs from other VPPSA members that have excess.
 - Pursue construction of a Tier II resource.
- Tier III Actions
 - Identify and deliver prescriptive and/or custom Energy Transformation programs.

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- Tier IV Actions
 - Maintain open lines of communication with the counterparty that has resources that will qualify for Tier IV to ensure those resources are qualified as quickly as possible and to enter into contracts when those resources are officially qualified.
- Storage
 - Continue discussions with a storage developer to site and develop a battery.
- Load Management
 - Work with VPPSA to develop innovative rates to achieve effective load management.
 - Pursue battery storage.
- Net Metering
 - Monitor the penetration rate and cost of net metering for future grid parity, and advocate for appropriate policies to mitigate potential upward rate pressure.

APPENDIX

APPENDIX A: 2025 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA 2025 TIER 3 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B - LED Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – LED 2019-2023 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 – LED IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

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

APPENDIX H: LED PROJECTED CAPITAL INVESTMENT

This appendix is provided separately in a file named:

Appendix H – LED Projected Capital Investment.pdf

APPENDIX I: LED PROJECTED FINANCIAL RESULTS

This appendix is provided separately in a file named:

Appendix I – LED Projected Financial Results-live.pdf

GLOSSARY

Glossary

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
AEO	Annual Energy Outlook
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
CSO	Capacity Supply Obligation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
DTLM	Distribution Transformer Load Management
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
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

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kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LED	Town of Lyndon Electric Department (Formerly known as the Village of Lyndonville Electric Department)
L RTP	Long-Range Transmission Plan
MAPE	Mean Absolute Percent Error
MDMS	Meter Data Management System
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NOAA	National Oceanic and Atmospheric Administration
NRPC	Northwest Regional Planning Commission
NYPA	New York Power Authority
OMS	Outage Management System
PFP	Pay for Performance
PPA	Power Purchase Agreement
PSD	Public Service Department or "Department"
PUC	Public Utility Commission
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
SQRP	Service Quality & Reliability Performance, Monitoring & Reporting Plan
TAG	Technical Advisory Group

Lyndon Electric Department - 2025 Integrated Resource Plan

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
VPPSA	Vermont Public Power Supply Authority
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTrans	Vermont Agency of Transportation
WBHP	Whole Building Heat Pump
WEC	Washington Electric Cooperative
WQC	Water Quality Certificate

Community is at the Heart of VPPSA.



Vermont Public Power Supply Authority

2025 Renewable Energy Standard: Tier III Annual Plan

Case No. 24-3273-INV 2025 RES Tier III Annual Plans

Filed via ePUC

November 1, 2024

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Introduction

In accordance with the Public Utility Commission (“PUC”) Rule 4.400, Vermont Public Power Supply Authority (“VPPSA”) is filing its 2025 Renewable Energy Standard: Tier III Annual Plan describing the proposed strategy to meet its members’ energy transformation program compliance.

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 III”) projects or purchase additional Renewable Energy Credits (“RECs”) from new, small, distributed renewable generators (“Tier II”). In 2024, the Vermont General Assembly passed H.289 (Act 179), *An act relating to the Renewable Energy Standard* which incorporates several revisions to the Renewable Energy Standard¹.

Act 179 created two new Tiers in the RES: Tier 4 (new regional renewable energy) and Tier 5 (load growth). It consolidates RES reporting requirements into the Comprehensive Energy Plan.

Providing safe, reliable, and affordable electricity is a critical factor in supporting the State’s renewable energy goals and expanded offerings must be evaluated to ensure cost-effectiveness. Further, the emerging and rapidly evolving landscape of systems to optimize grid modernization and energy transformation initiatives continues to expand opportunities for VPPSA and its members to design and develop innovative energy services programs.

VPPSA members continue to prioritize strategic electrification that minimizes cost-shifting or upward rate pressures. These issues remain top-of-mind as cost-of-living expenses continue to rise and geopolitical conflicts once again strain the global economy. Responsiveness to the needs of all customer classes remains a priority to ensure sustainable growth and promoting the values of local energy democracy.

In consideration of all these factors, VPPSA submits its 2025 Tier III Annual Plan which aims to support mutually beneficial statewide programs with Vermont’s Energy Efficiency Utilities, while also strengthening opportunities to increase access to sustainable, clean, and cost-effective energy transformation solutions for residential, commercial, and industrial customers.

¹ See: <https://legislature.vermont.gov/bill/status/2024/H.289>



VPPSA Tier III Obligation Requirements

VPPSA Member Utilities’² Tier III obligation 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.”³ Tier III requirements increase by two-thirds of a percent annually.

The new RES policy requires that VPPAS obligation be based off of load which was interpreted as total load including losses. Total load including losses includes all energy purchased in addition to internal generation and losses incurred through transmission and distribution. The definition of load is pending and may change because there has not yet been a ruling by the PUC defining load.

Figure 1 illustrates that since 2019, VPPSA’s member utilities have recorded modest load growth patterns, with a decrease observed between 2019 – 2020.

For 2025, VPPSA has estimated a 2.0% load growth that aligns with industry and statewide forecasts, while taking into consideration increased priority being placed on equitable access to electrification in more rural service territories. These assumptions are made with the acknowledgement that some member utilities may not trend precisely in alignment with these estimates.

Based on the proposed forecast of Total Load Including Losses (TLIL), VPPSA estimates its 2025 compliance requirement to be 22,455 MWh equivalent (MWh_e) in savings, representing 5.34% of members’ 2023 estimated Annual Retail Sales (kWh), per the statute.

² VPPSA Members include Barton Village; Village of Enosburg Falls; Hardwick Electric Department; Village of Jacksonville; Village of Johnson; Ludlow Electric Light Department; Lyndon Electric Department; Morrisville Water & Light; Northfield Electric Department; Village of Orleans; and Swanton Village.

³ 30 V.S.A. § 8005(a)(3)(B)



Figure 1: VPPSA Annual RES Compliance Obligation Calculations & Projects (2019 - 2025)

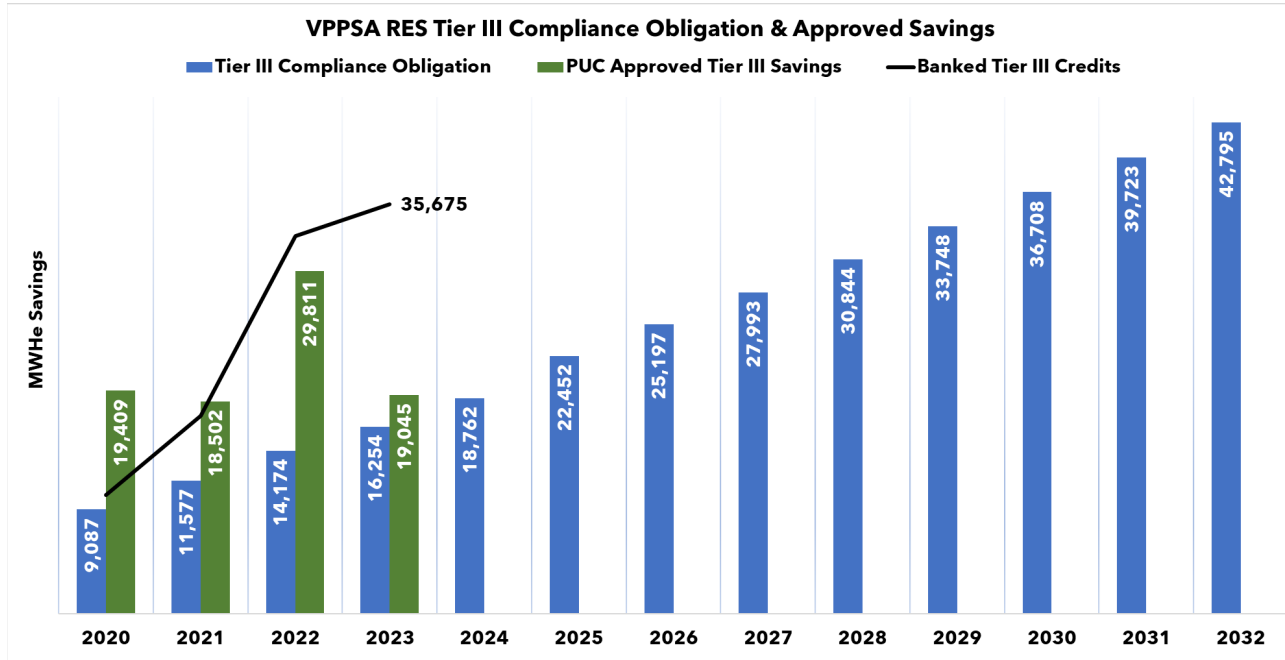
VPPSA Annual RES Compliance Obligation Calculations								Estimates & Projections	
% of Retail Sales	2017	2018	2019	2020	2021	2022	2023	2024	*2025
Tier I	55.00%	55.00%	55.00%	59.00%	59.00%	59.00%	63.00%	63.00%	63.00%
Tier I - Tier II	54.00%	53.40%	52.80%	56.20%	55.60%	55.00%	58.40%	57.80%	57.20%
Tier II	1.00%	1.60%	2.20%	2.80%	3.40%	4.00%	4.60%	5.20%	5.80%
Tier III	0.0%	0.0%	2.00%	2.67%	3.33%	4.00%	4.67%	5.33%	6.00%
Retail Sales	2017	2018	2019	2020	2021	2022	2023	2024	2025
VPPSA Total (kWh)			344,106,701	340,727,482	347,253,486	354,352,447	348,300,088	351,783,089	
Retails Sales Growth				-1.0%	1.9%	2.0%	-1.7%	2.0%	
Total Load Including Losses (TLIL)									374,207,000
TLIL Growth									
kWh/Yr	2017	2018	2019	2020	2021	2022	2023	2024	2025
Tier I				201,029,214	204,879,557	209,067,944	219,429,055	221,623,346	235,750,410
Tier I - Tier II				191,488,845	193,072,938	194,893,846	203,407,251	203,330,625	214,046,404
Tier II				9,540,369	11,806,619	14,174,098	16,021,804	18,292,721	21,704,006
Tier III				9,087,202	11,577,431	14,174,098	16,254,004	18,767,628	22,454,915
MWh/Yr	2017	2018	2019	2020	2021	2022	2023	2024	2025
Tier I				201,029	204,880	209,068	219,429	221,623	235,750
Tier I - Tier II				191,489	193,073	194,894	203,407	203,331	214,046
Tier II				9,540	11,807	14,174	16,022	18,293	21,704
Tier III (MWh)				9,087	11,577	14,174	16,254	18,768	22,455
PUC Approved Savings			8,553	19,409	18,502	29,811	19,045		
*2025 Obligations are based off percentages of Total Load Including Loses (TLIL)									

The 11 VPPSA member utilities plan to meet their Tier III 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.”

Figure 2: VPPSA Tier III Annual Obligation illustrates VPPSA’s projected Tier III annual MWh equivalent (MWh_e) savings obligations through 2032 and approved compliance performance.



Figure 2: VPPSA Tier III Annual Obligation





Summary of 2024 Projects

VPPSA is on track to meet its 2024 Tier III requirements of 18,862 MWh through a portfolio of prescriptive and custom energy transformation measures.

The portfolio of eligible prescriptive measures diversified the 2024 program year and continue to be administered using a combination of mid- and downstream incentive models. VPPSA directly administers a broad portfolio of eligible measures including:

- 1) E-Bikes and Electric Scooters
- 2) Electric Golf Cart and Utility Vehicles
- 3) Electric Forklifts and Stock Chasers
- 4) Electric Motorcycles
- 5) Electric Snowmobiles
- 6) Electric Vehicles (All Electric, Plug-In Hybrid, Fleet Electrification)
- 7) Electric Vehicle Supply Equipment (EVSE) Charging
- 8) Electric Lawnmowers (Residential & Commercial)
- 9) Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers
- 10) Weatherization and Window Inserts

VPPSA members also help sustain the statewide midstream incentive programs administered through Efficiency Vermont (EVT). In 2024, VPPSA members' incentivized the following measures through the midstream program administered by Efficiency Vermont (EVT):

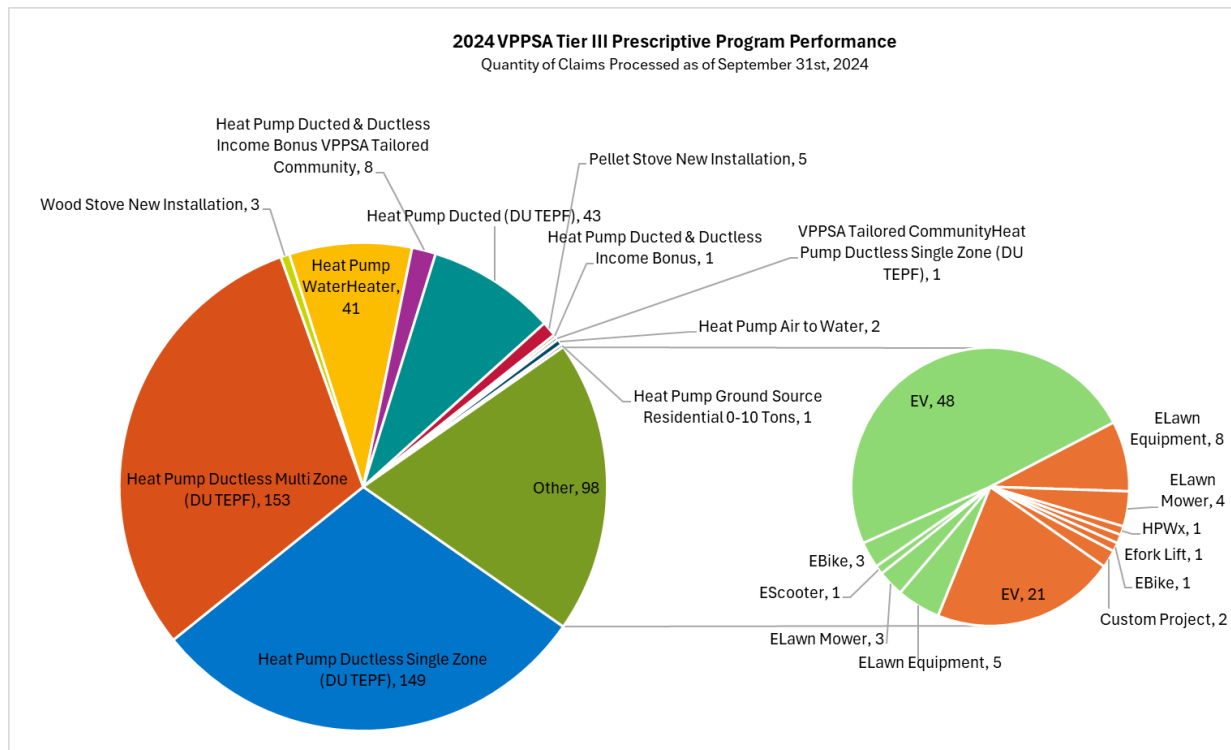
- 11) Cold Climate Heat Pumps
 - a) Single Zone
 - b) Multi-Zone
 - c) Ducted
 - d) Ductless (Additional Incentives offered for integrated controls)
- 12) Heat Pump Water Heater
- 13) Air-to-Water Heat Pumps
- 14) Ground Source Heat Pumps (aka Geothermal)
- 15) Advanced Wood Heating (Cord Wood/Pellet)



Figure 3: 2024 Tier III Prescriptive Program Performance reflects processed claims as of September 31, 2024 and is intended for illustrative purposes only⁴.

This data is not reflective of the total or expected claims for the entire 2024 Tier III Compliance year.

Figure 3: 2024 Tier III Prescriptive Program Performance



⁴ Figure 3 represents the quantity of completed prescriptive rebate claims processed as of September 31, 2024 and is intended for illustrative purposes only. This data does not reflect the entirety of 2024 Tier III Compliance claims, nor does it represent expected compliance performance by year-end.



VPPSA recognizes that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is, on average, lower than both prescriptive incentives and Tier II RECs.

Custom Energy Transformation Projects, typically for commercial and industrial customers, include incentives for line extensions, service upgrades, or other energy transformation projects that reduce greenhouse gas emissions and reliance on fossil fuels.

VPPSA continues to seek and support a robust pipeline of custom projects at various stages in their development. In 2024 VPPSA finalized the program design and development of its Business Energy Repayment Assistance Program, a grant-funded initiative that provides an on-bill repayment structure for C&I customers of member utilities to implement eligible energy transformation projects.⁵

⁵ See WCAX [Cabot Hosiery invests in efficiency upgrades at Northfield factory](#), October 23, 2024



2025 Tier III Program Overview

The focus of VPPSA's 2025 Tier III Program is to support Vermont's electrification transition while ensuring rates are affordable and maintaining reliability of service. It is important for distribution utilities to prioritize reliability as an assurance for customers during the decision-making process to adopt new electrification measures.

First and foremost, VPPSA's strategy for the 2025 Program Year continues to focus on cost-effective prescriptive and custom Tier III measures which meet member and customer needs. This strategy includes monitoring market saturation, external funding sources, potential grid infrastructure impacts, and external socio-economic factors that may affect supply chains and future compliance.

For the past several years, VPPSA has executed annual MOUs with EVT related to statewide programs and services. These MOUs have been beneficial in articulating clear roles and responsibilities to support increased collaboration and coordination with Vermont's Energy Efficiency Utilities, as required under the Renewable Energy Standard. For example, Efficiency Vermont's statewide EEN network of participating suppliers and distributors expands access to potential savings at the point of purchase.

Evaluation of the midstream program's shared savings model shows that VPPSA members' contributions for eligible measures accounts for, on average, 76% of the total incentive available to an end-use customer in the midstream program. Beginning in 2024, midstream incentive program partners are also subject to an additional 9.7% Cost-Recovery Fee⁶ on every incentive administered through EVT on behalf of the distribution utility.

VPPSA continues to research innovative program opportunities for customers to participate in flexible load management programs for electric vehicles (EV) and electric vehicle station equipment (EVSE). VPPSA anticipates a new prices-to-devices program piloting in late 2024-early 2025 and ready for full implementation in early 2025.

Ongoing progress continues to be made to deploy Advanced Metering Infrastructure (AMI) for its eleven (11) member utilities, with installation occurring in tranches over a 3-year project period. As an enabling technology, AMI will support time-based energy

⁶ 2024 Cost Recovery Fees = 9.7% (General Support-Indirect, 6.7% + Core IT, 3%).
2025 Cost Recovery Fees = 8.7% (General Support -Indirect, 6.7% + Core IT, 2%)



usage monitoring, data analytics, and customer behaviors for sustainable distribution grid modernization and electrification.

In addition to traditional incentives, VPPSA plans to evolve the program to meet customer needs and increase accessibility, while simultaneously adjusting to market and compliance conditions. VPPSA continues to seek strategic partnerships that support economic development for grid modernization while continuing to align with the core values of local energy democracy, affordability, and reliable service.

As in previous years, VPPSA plans to meet its 2025 Tier III requirements by further diversifying its portfolio of offerings at costs that mitigate pressure on electric rates. This portfolio includes a combination of prescriptive and custom measures and use of Tier II RECs, if needed.

VPPSA intends to maintain its current portfolio of directly administered prescriptive measure offerings. Prescriptive Measure Savings are calculated using the Net Lifetime MWh Saved measure characterizations created by the Tier III Technical Advisory Group ("TAG").

To ensure a diversity of offerings that promotes equity in accessibility and customer participation, VPPSA's 2025 Tier III Program measures into four main categories, by type of electrification (aka energy transformation):

- a) Transportation
- b) Thermal
- c) Commercial Equipment & Appliances
- d) Residential Equipment & Appliances

Incentive offerings are explained in greater detail below.

Transportation

State and Federal funding and policy making decisions continue to support the expansion of the electric vehicle market and electric vehicle charging infrastructure. VPPSA plans to continue incentive offerings that encourage customer adoption, with a focus on equity and strategic monitoring of potential changes in load management, ideally with the approval of our tariff rider program currently under development.

Electric Vehicles (EV) and Plug-In Hybrids (PHEV)

VPPSA will continue to offer customer incentives for the purchase or lease of new and used EVs and PHEVs in 2025 as both point-of-sale or post-purchase rebates.



The incentive levels for the 2025 Tier III Transportation measures are shown in Figure 4: 2025 Electric Vehicle Incentive.

Electric Vehicle Fleets

VPPSA's 2025 program will continue to include incentives for electric vehicle fleets to support electrification of class 8 trucks, paratransit shuttles, school buses, garbage trucks, delivery trucks, mail trucks, and transit buses. These types of projects can be quite expensive, but the environmental benefits are quite high. VPPSA is offering a \$5000 incentive for fleet conversion projects in 2025.

Electric Vehicle Charging

In 2024, VPPSA increased its rebate for customers installing Level 2 electric vehicle chargers at a workplace and/or available for the public to use to \$950.

Using insights gained from the 2023 EVSE Powershift Pilot Program with Efficiency Vermont (EVT), VPPSA hopes to develop a more robust EV charging network and program through expanded access as part of its strategy to offer customers EV/EVSE rates in 2025. These programs will optimize EVSE charging to monitor grid impacts from this added load. EV Charging will be incentivized during off-peak hours and may facilitate direct control of EV charging in the future.

Figure 4: 2025 Electric Vehicle Incentive Levels

MEASURE TYPE	BASE INCENTIVE	INCOME QUALIFYING INCENTIVE ADDERS
ELECTRIC VEHICLE (NEW)	\$ 1,250	\$ 400
ELECTRIC VEHICLE (USED)	\$ 500	\$ 400
PLUG-IN HYBRID VEHICLE (NEW)	\$ 500	\$ 400
PLUG-IN HYBRID VEHICLE (USED)	\$ 250	\$ 400
ELECTRIC VEHICLE FLEETS	\$ 5,000	N/A

In its fourth year of partnering with vehicle dealerships around the state to offer point-of-sale incentives, VPPSA again seeks to expand its program to additional dealerships and increase awareness of incentive availability to member customers. Customers



who purchase or lease a vehicle from a participating dealership will receive an instant point- of-sale incentive discount. Dealerships then submit the required application and documentation to VPPSA for reimbursement.

Post-purchase rebate applications will continue to be accepted from eligible customers who provide all necessary documentation. There are enhanced incentives for income-qualifying customers in our ongoing efforts for equity in energy transitions. These include a used all electric and used plug-in hybrid low-income adder that we have added this year.

e-Lite Transportation

New in 2024, we have added a new category of alternative, “e-Lite” electric transportation offerings. These include electric bikes, scooters, motorcycles, and snowmobiles (commercial and recreational)

MEASURE TYPE	BASE INCENTIVE
E-LITE BIKE	\$ 100
E-LITE SCOOTER	\$ 250
E-LITE MOTORCYCLE	\$ 500
COMMERCIAL SNOWMOBILE	\$ 500
RECREATIONAL SNOWMOBILE	\$ 500

Thermal

As described above in relation to transportation, VPPSA recognizes that alleviating energy burden of its customers must also include supporting thermal, or heating and cooling electrification technologies such as cold climate heat pumps. We have added pellet stoves, wood stoves, and window inserts into our offerings for 2025.

In collaboration with Efficiency Vermont (EVT) and other Vermont distribution utilities, beginning January 2021, EVT began administering state-wide utility heat pump incentive programs. This partnership and collaboration have expanded the adoption and installation of these fuel-saving technologies, particularly in VPPSA member



service territories which had been historically underrepresented in state-wide adoption metrics.

Cold Climate Heat Pumps

In 2025, VPPSA will continue to incent ducted cold-climate heat pumps through the midstream program administered through Efficiency Vermont, however, no longer incentivize purchases of ductless heat pumps.

Efficiency Vermont will batch midstream claims and invoice VPPSA monthly for reimbursement, inclusive of their cost-recovery fees.

Centrally Ducted Cold Climate Heat Pumps

VPPSA will continue to offer incentives on centrally ducted heat pumps, air-to-water heat pumps, and ground-source heat pumps. Efficiency Vermont administers these incentives through the statewide program.

Incentive levels vary by the units' size and range anywhere from \$1,025 to \$2,025.

Air-to-Water Heat Pumps

Efficiency Vermont will continue to administer midstream incentives 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. This is equivalent to how the incentive was managed in previous years.

Ground-Source Heat Pump

VPPSA also anticipates coordinating with Efficiency Vermont for ground source heat pump incentives which vary based on tonnage, but range anywhere from \$2,100 - \$1,000/ton.

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 including acceptable forms to prove weatherization. The additional incentive serves to highlight the importance of overall building performance.



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 continue to 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 \$650 incentive to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. This incentive is administered by Efficiency Vermont and would also include the 10% administrative processing fee.

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.

Advanced Wood Heating (Pellet Stoves / Wood Stoves)

New in 2024, EVT and partner utilities have promoted a statewide midstream program for advanced wood heating (i.e. pellet and wood stoves). Both EVT and VPPSA contribute \$200 to the offered incentive and MWhe savings are split based on the type of installation (new or replacement).

Commercial Equipment & Appliances

As key fixtures and economic drivers in member communities, VPPSA is pleased to continue offering specific prescriptive incentive measures to support the electrification of commercial equipment and appliances.

Electric Forklifts & Stock Chasers

In support of the various business customers throughout VPPSA's member territories, VPPSA intends to continue offering a \$2,500 rebate incentive for new electric forklifts.



Increased marketing and outreach will be conducted to various businesses to inform and encourage the electrification of this equipment.

Electric Golf Carts & Utility Vehicles

VPPSA will continue to offer a \$100 rebate incentive for customers that purchase new electric golf carts. As with forklifts, VPPSA intends to increase marketing and outreach to the various businesses which may benefit from the investment in new, electric golf carts.

Commercial Property Maintenance

Commercial Lawn Mowers

VPPSA will be offering a \$1,500 incentive for the purchase of an electric, commercial ride-on lawn mower. A \$100 incentive will be offered for the purchase of an electric, commercial push mower.

Commercial Leaf Blowers

The 2025 rebate incentive remains \$50 for the purchase of a new commercial electric leaf blower.

Commercial Chainsaws, Trimmers, Edgers and Cultivators

The 2025 rebate incentive remains at 2024 levels, \$50 for the purchase of a new commercial electric chainsaw, trimmer, edger, or cultivators.

Residential Equipment & Appliances

VPPSA recognizes the enormous impact that local, state, and federal policies can have on the average residential customer and is pleased to offer the following suite of prescriptive incentives in 2025.

Residential Property Maintenance

VPPSA continues to observe steady customer claims for yard care rebates which will continue to be offered in 2025. Although these measures often have a high \$/MWh cost, they are often a lower cost, entry level, and electrification of equipment for the average customer.



Residential Lawn Mowers

VPPSA will continue to offer a \$50 incentive for the purchase of a residential push and a \$100 incentive for the purchase of a ride-on electric lawn mower.

Residential Leaf Blowers

VPPSA will continue to offer a \$50 rebate incentive for the purchase of a new residential electric leaf blower in 2025.

Residential Chainsaws, Trimmers, Edgers, and Cultivators

VPPSA will continue to offer a \$50 rebate incentive for the purchase of a residential electric chainsaw, trimmer, edgers or cultivators.

Custom Measures

For commercial and industrial (“C&I”) customers seeking more sophisticated energy transformation projects, VPPSA intends to continue offering Custom Measures, where appropriate. VPPSA maintains and tracks a pipeline of customers exploring potential Tier III customer projects, in collaboration with the work of Efficiency Vermont (EVT).

Due to long lead times and complex project implementation schedules VPPSA continues support these projects where feasible and promote custom incentive opportunities, in addition to the grant-funded BERAP program previously referenced.

VPPSA members’ strong community relationships for economic development inform project leads, in addition to coordination with Efficiency Vermont to identify qualifying Tier III energy transformation and electric efficiency projects.

Incentives for custom measures are typically paid for either by the host utility directly or by the approval of the VPPSA Board of Directors, customer incentives can be issued through its Tier III budget and allocate savings across its members.

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

Tier II RECs

VPPSA manages its member Tier III compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier II RECs. Under this approach the Tier II REC price



acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings.

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

Should Tier II REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier III planning document.



Best Practices & Minimum Standards

Load Growth & Management

Over the long-term, energy transformation programs have the potential to increase loads for all Vermont utilities, however load impact potential is a complex scenario influenced by several factors. VPPSA members systems remain robust, and the expected growth in annual and local peak demand associated with proposed measures are supported and sustained through monitoring deployment.

In alignment with industry best practices, underlying assumptions used in VELCO's Long- Range Transmission Plan ("LRP") are used to develop members' Integrated Resource Plans (IRP). As a result, IRPs incorporate the State's latest outlook for Electric Vehicle (EV) and Cold Climate Heat Pump (CCHP) adoption. Additionally, State and Federal investments in electrification technologies for the thermal and transportation sectors are important factors that contribute to forecasting models in relation to consumer trends and adoption of electrification measures.

From a technical perspective, there are many credible options for controlling load which VPPSA continues to monitor, pilot, and deploy where shown to be economically competitive.

As part of VPPSA's long-term IT/OT plans, member utilities will soon have the capacity to further refine analytics around load monitoring and forecasting correlating to energy transformation programs. This is particularly important as state policies continue to support electrification of transportation and thermal sectors. In the interim, VPPSA is negotiating an agreement with a platform as a service provider while maintaining its existing partnership with Virtual Peaker. Virtual Peaker supports internal utility behavioral demand-response programs that strategically maximize load-reducing generation during high-cost time periods.

As previously stated in the Transportation Electrification section, VPPSA and Efficiency Vermont partnered on the PowerShift Pilot in 2023. VPPSA anticipates its proposed EVSE Tariff Rider program will optimize EVSE charging to monitor grid impacts from this added load. EV Charging will be incentivized during off-peak hour. VPPSA is also kicking off the project planning and implementation of its Energy Storage Access Program (ESAP) grant award for in-home and community-scale battery storage for municipal and income qualifying customers. Further, VPPSA continues to pursue utility-scale storage as a cost-effective means of achieving demand reductions for its members.



Lastly, as a method to encourage participation in buildings which meet established performance standards, thereby helping to manage load control, VPPSA also continues to provide additional incentives for measures installed in weatherized buildings.

Minimum Standards: Program Administration

As previously stated, VPPSA administers its Tier III Program in aggregate, on behalf of all members. As such there are a number of standards and processes which are employed to meet minimum standards and compliance.

In administering prescriptive measures, VPPSA maintains standard customer privacy and data security procedures to protect sensitive information. VPPSA also implements necessary internal controls to ensure the integrity of the Program. This requires a segregation of duties in the receipt, processing, and approval of incentive applications.

Equitable Opportunity

VPPSA strives to ensure that Tier III energy transformation programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier III incentives described in this Plan are available to all VPPSA member utility customers. Commercial and Industrial customers can access VPPSA's prescriptive measures and are also served through custom incentives.

Consistent with Rule 4.413(c), each year VPPSA tracks and reports Tier III participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income). For incentives administered directly by VPPSA, customers must answer a tracking question related to their household income.

Participation and spending are monitored and reviewed each year to inform program planning for future years. This data is included in VPPSA's Tier III savings filed in March and RES Compliance Filing in August. Each year, and over the life of the RES, VPPSA intends to provide equitable opportunities for its customer sector in rough proportion to each customer sector's annual retail sales.

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



VPPSA's Tier III 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 III 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 III programs and cost-shifting among customers is minimized.

VPPSA's Utility Present Value Life Cycle Cost 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 these measures, making these programs revenue neutral or beneficial for non-participating ratepayers.

Coordinated Delivery of Energy Transformation Projects

In 2025, VPPSA plans to continue actively working with both public and private partners to execute our Tier III plan in the most cost-effective way without sacrificing the customer experience, or cost-shifting to non-participating customers.

Under the revised MOU filed within case 22-2954-PET VPPSA and Efficiency Vermont anticipate continuing to collaborate on enhancing offerings to members' customers. In many cases, this partnership involves VPPSA providing incentives for energy transformation measures, which can provide benefits to all VPPSA utility customers, while Efficiency Vermont provides incentives for electric efficiency measures.

Through the MOU, VPPSA and Efficiency Vermont have developed a comprehensive program with enhanced benefits for its member utility customers⁷. These offers will be available in all eleven-member utility communities beginning for the duration of their DRP performance period (2024- 2026).

⁷ See www.efficiencyvermont.com/vppsa



Marketing & Communications

VPPSA continues to engage in utility customer interaction, marketing and communications. With the addition of Tier III projects, VPPSA will educate utility customers on the available incentives through use of the following:

- VPPSA member utility bill inserts
- VPPSA member utility staff training
- VPPSA website and streamlined rebate processing platform
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops
- Electric Vehicle/e-Lite product distributor and supplier outreach
- EVT contractor and distributor outreach
- Direct outreach to key community representatives and regional planning commissions

Cost-Effectiveness & Equity

VPPSA's Tier III planning included consideration of the suite of measures in the 2025 Tier III Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA has initiated an overall analysis of the Tier III portfolio's diversity to ensure both cost-effectiveness and equity for customers at varying levels of spending ability while still meeting regulatory compliance.

Utility Present Value Life Cycle Cost

VPPSA estimated the utility's net revenue for each of the 2025 Tier III measures. The analysis was conducted to provide a key input to the 2025 Tier III reporting template, specifically the 'Present Value Net Revenue' column. These estimates, when combined with other inputs to the template, calculate the 'Utility Present Value Life Cycle Cost Net' in \$/MWh.



The methodology followed a five-step process that netted utility costs from utility revenues.

First, the Tier III Planning Tool was used to gather several key inputs:

- Measure Life,
- Added kWh new system,
- Existing System MMBtu Displaced, and
- Assumed Fuel.

Second, seasonal load shapes were assumed for each measure. Specifically:

- Winter Peak MWH
- Winter Off-Peak MWH
- Summer Peak MWH
- Summer Off-Peak MWH
- Winter Peak MW
- Summer Peak MW

Third, current estimates of avoided costs were gathered. Energy, capacity, REC and transmission costs were sourced from VPPSA's budget models, and the cost of fossil fuels and non-embedded carbon were gathered from the AESC 2021 report.

Fourth, the volumes (MWH and MW) were multiplied by the appropriate avoided costs to arrive at an avoided cost estimate from the utility's perspective.

Fifth, the utility revenues were calculated using blended average retail rates as forecast during the 2019-2020 IRP cycle.

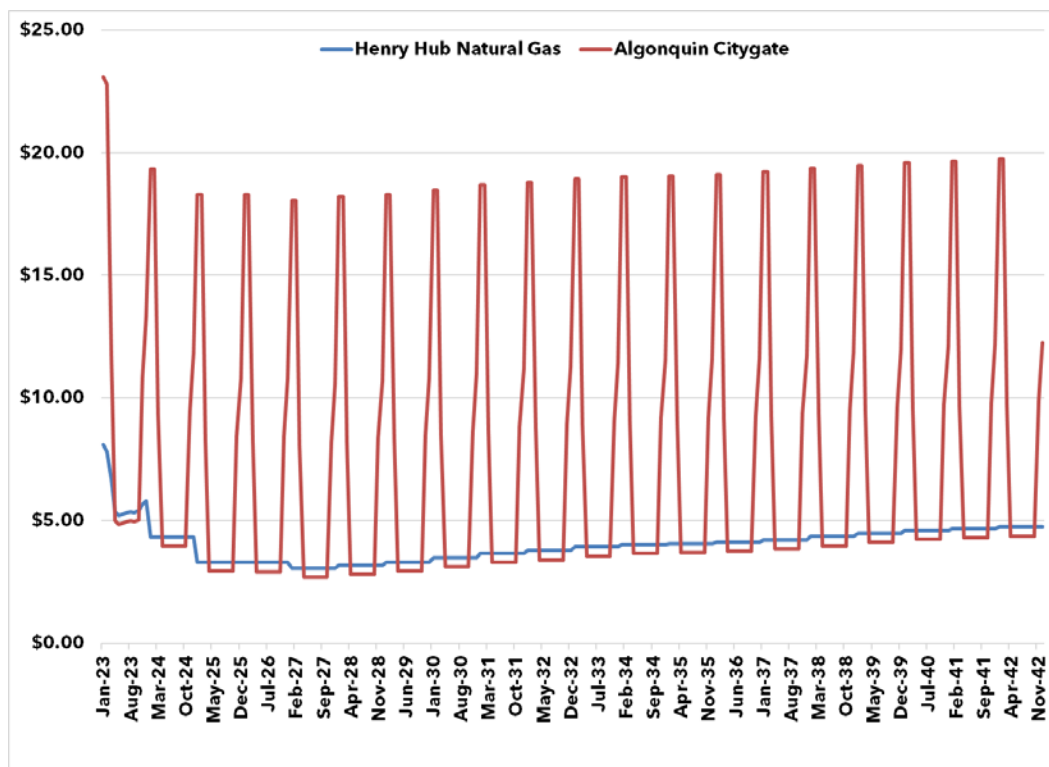
Finally, the 'Present Value Net Revenue' was calculated by subtracting the costs from the benefits and discounting the cash flows back to 2025 at a 5% discount rate.

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.

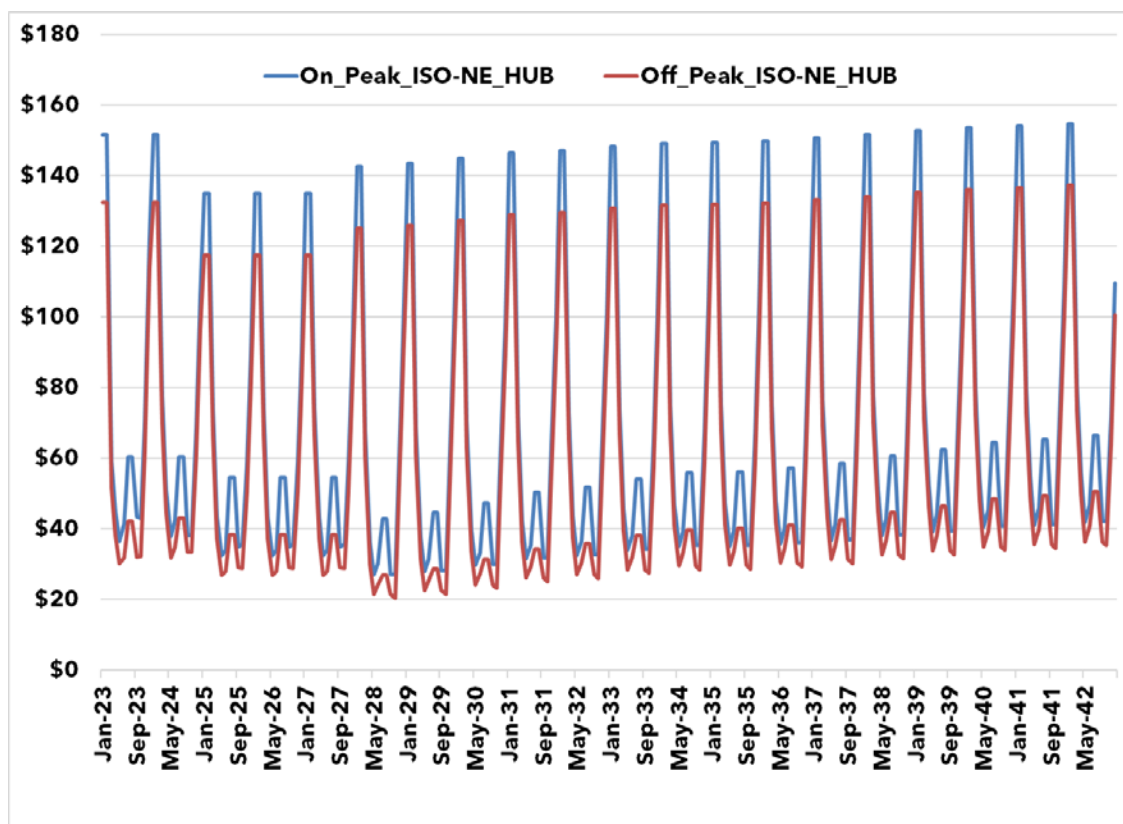
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal \$/MMBtu)



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 Liquefied 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)

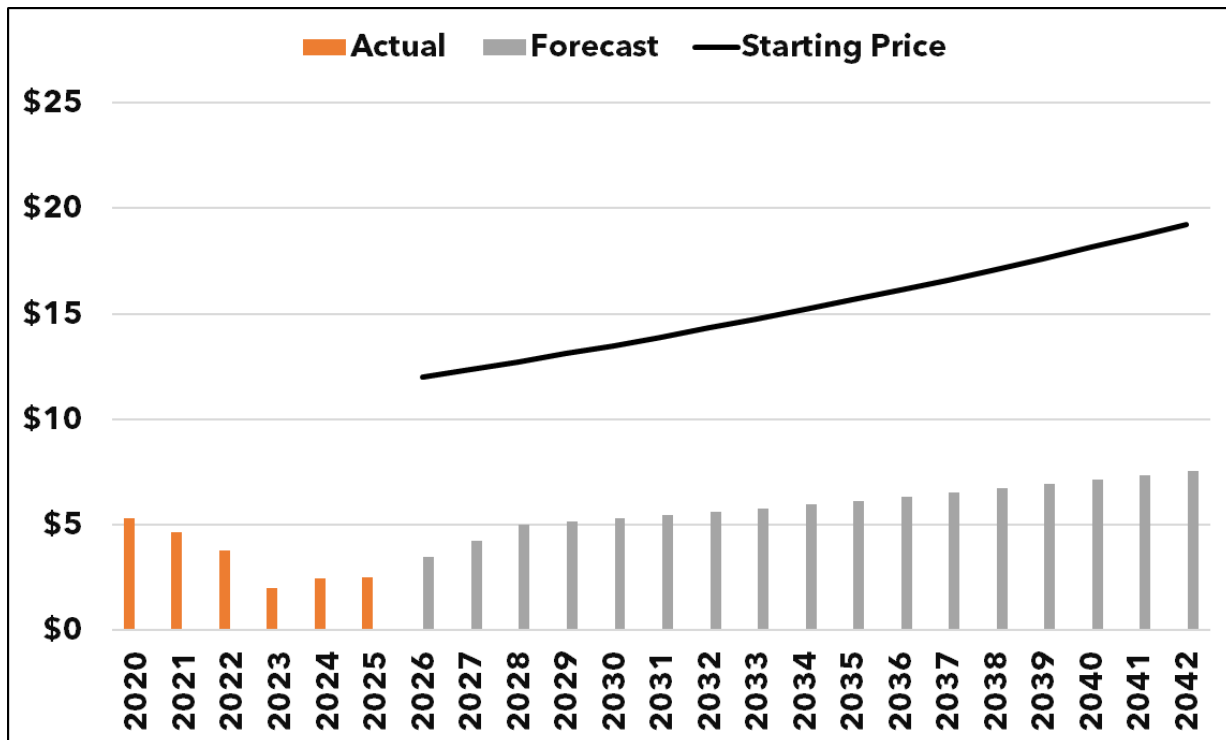


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of VOEF's load and resources.

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)



Village of Lyndonville Electric Department SQRP

2019

Original

System average interruption frequency index (SAIFI) =	2.5
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	3.2
Customer Hours Out / Customers Out	

Village of Lyndonville Electric Department SQRP

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 calender year. Electricity Outage Report -- PSB Rule 4.900

Electricity Outage Report -- PSB Rule 4.900

Company: Village of Lyndonville Electric Department
Calendar Year: 2020
Contact Person: Jason Lefebvre
Phone Number: (802) 626-9252
Customers Served: 6,256

SAIFI (System average interruption frequency index) = Customers out / Customers served	2.82
CAIDI (Customer average interruption duration index) = Customer hours out / Customers out	3.18

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

Outage Code	No. of Outages	Total Hours Out
Accidents -r-	1	34.23
Animals -r-	3	36.64
Equipment Failure -r-	5	4389.03
Major Storm	18	1403.01
Other -r-	2	8.48
Service Call_Tree	2	16.11
Trees -r-	176	36664.52
Unknown -r-	27	913.53
Weather -r-	51	8939.9
Total	285	52405.45

Village of Lyndonville Electric Department SQRP

2021

Original

System average interruption frequency index (SAIFI) =	2.9
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	2.0
Customer Hours Out / Customers Out	

Village of Lyndonville Electric Department SQRP

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

Electricity Outage Report -- PSB Rule 4.900

Company: Village of Lyndonville Electric Department

Calendar Year: 2022

Contact Person: Jason Lefebvre

Phone Number: (802) 626-9252

Customers Served: 5,949

SAIFI (System average interruption frequency index) = Customers out / Customers served	3.13
CAIDI (Customer average interruption duration index) = Customer hours out / Customers out	5.37

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

Outage Code	No. of Outages	Total Hours Out
Accidents -r-	4	397.77
Animals -r-	8	331.57
Equipment Failure -r-	11	759.55
Major Storm	58	61892.16
Trees -r-	110	33492.34
Unknown -r-	25	1346.8
Weather -r-	19	1797.55
Total	235	100017.74

Lyndon Electric Department

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 -- PUC Rule 4.900

Name of company	Lyndon Electric Department
Calendar year report covers	2023
Contact person	Jason Lefebvre
Phone number	(802) 626-9252
Number of customers	5,995

System average interruption frequency index (SAIFI) =	5.89
Customers Out / Customers Served	

Customer average interruption duration index (CAIDI) =	3.43
Customer Hours Out / Customers Out	

Outage cause	Number of Outages	Total customer hours out
Accidents	7	1,485
Animals	6	61
Department initiated outage	2	976
Equipment failure	9	12,257
Operator error	1	1
Other	1	159
Trees	79	48,530
Unknown	17	3,887
Weather	172	53,824
Total	294	121,178

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 a 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

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, $\pm 20\%$ with the exception that Form 12S must	

auto-range when connected to services in the range of 120-480 Volts RMS, $\pm 20\%$.	
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).	
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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.

New AMI Water Meters & Registers

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 tenants	
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 DEMAND FORECAST SUMMARY

Town of Lyndon

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2022 LONG-TERM DEMAND FORECAST SUMMARY

THE TOWN OF LYNDON

The Lyndon forecast was completed in August 2022 and reflects state economic and household projections in December 2022, and state efficiency projections, heat pump, and EV forecasts developed as part of the VELCO 2021 IRP forecast.

Lyndon serves approximately 4,900 residential customers and 960 commercial customers within the town and surrounding Towns of Lyndonville, Burke, East Haven, Glover, Kirby, Lyndon, Newark, Sheffield, St. Johnsbury, Sutton, Victory, Westmore, and Wheelock. The utility has seen small but positive customer growth, adding on average 20 new residential customers per year – a 0.3% annual customer growth rate. Customer growth slows to a -0.5% annual rate over the next ten years as customer growth is tied to state population projections. Residential sales account for approximately 53% of sales and nonresidential sales 47%. Total 2021 sales are 61,149 MWh compared with sales of 67,768 MWh in 2011 representing a 1.0% decrease over ten years. COVID-19 had a significant impact on commercial sales that fell 6.8% in 2020; there was a small recovery in 2021, but as of 2021 commercial sales were still well below pre COVID levels. A jump in residential sales in 2020, somewhat countered commercial sales loss. Table 1 shows historical residential customers and class sales.

TABLE 1: LYNDON HISTORICAL CALENDARIZED SALES AND CUSTOMERS

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Total Sales (MWh)	Chg
2011	32,451		4,782		6,787		35,316		67,768	
2012	32,022	-1.3%	4,787	0.1%	6,689	-1.4%	34,124	-3.4%	66,146	-2.4%
2013	31,449	-1.8%	4,793	0.1%	6,562	-1.9%	32,183	-5.7%	63,632	-3.8%
2014	32,082	2.0%	4,793	0.0%	6,694	2.0%	31,858	-1.0%	63,940	0.5%
2015	31,999	-0.3%	4,784	-0.2%	6,689	-0.1%	30,793	-3.3%	62,792	-1.8%
2016	30,805	-3.7%	4,813	0.6%	6,400	-4.3%	30,421	-1.2%	61,226	-2.5%
2017	31,072	0.9%	4,824	0.2%	6,441	0.6%	29,970	-1.5%	61,043	-0.3%
2018	31,615	1.7%	4,845	0.4%	6,526	1.3%	30,473	1.7%	62,088	1.7%
2019	31,830	0.7%	4,836	-0.2%	6,582	0.9%	30,590	0.4%	62,420	0.5%
2020	32,611	2.5%	4,866	0.6%	6,702	1.8%	28,504	-6.8%	61,115	-2.1%
2021	32,082	-1.6%	4,915	1.0%	6,527	-2.6%	29,066	2.0%	61,149	0.1%
11-21		-0.1%		0.3%		-0.4%		-1.9%		-1.0%

Given the relatively large residential customer base, Lyndon has been winter peaking with a system peak of around 13 MW. Table 2 shows historical system energy and peak demand.

**TABLE 2: HISTORICAL SYSTEM ENERGY AND DEMAND**

Year	Energy (MWh)	Chg	Summer Peak (MW)	Chg	Winter Peak (MW)	Chg
2011	72,281		11.21		12.89	
2012	70,540	-2.4%	10.21	-8.9%	12.61	-2.2%
2013	69,705	-1.2%	10.19	-0.1%	13.47	6.8%
2014	68,807	-1.3%	9.80	-3.9%	13.31	-1.2%
2015	65,688	-4.5%	9.80	0.0%	12.26	-7.9%
2016	65,453	-0.4%	9.45	-3.6%	12.76	4.0%
2017	63,100	-3.6%	9.69	2.5%	13.16	3.1%
2018	64,799	2.7%	10.16	4.9%	12.73	-3.3%
2019	63,916	-1.4%	9.49	-6.6%	12.98	2.0%
2020	62,071	-2.9%	10.18	7.3%	12.92	-0.4%
2021	64,489	3.9%	11.08	8.8%	12.57	-2.7%
11-21		-1.1%		0.0%		-0.2%

Reflecting class sales trends, system energy has declined on average 1.1% with flat summer peak demand and 0.2% annual average decline in winter peak demand.

Forecast Approach

The Lyndon long-term forecast is based on a bottom-up modeling framework where the forecasts start with projected residential and commercial and industrial (C&I) heating, cooling, and base-use (nonweather-sensitive end-uses) energy requirements. that then drives system energy and peak demand. The baseline peak demand (which excludes adjustments for solar, cold-climate heat pumps, and electric vehicles) is based on a demand model that relates monthly peak demand to heating, cooling, and base-use energy requirements and peak-day weather conditions. The peak modeling approach is used for all VPPSA members, GMP, Burlington Electric, and VELCO. A detailed description of the modeling approach is included in the *2022 Long-Term Forecast Model Overview*.

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For Lyndon, this includes residential, small commercial, large commercial, industrial, and other (other is primarily street lighting and is relatively small). Forecasts are derived from linear regression models that are estimated using 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 sales forecast captures expected load growth before adjustments for new solar (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 (both due to standards and state EE program activity) 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 activity (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 the *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). Lyndon accounts for 1.6% of state residential sales and 1.6% 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 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 impacted sales starting in late March 2020. The commercial sector saw a significant decline in sales while the residential sector saw a measurable increase. Through 2021 sales began to normalize as more people went back to work. Recent GMP sales have shown that residential average use has leveled out at a somewhat higher level than pre-COVID use, and commercial usage has settled at a lower level. We are likely to see permanent structural change as many businesses transition to hybrid work environment (part-time at home and part-time at the office) and large number of workers that continue to be work remotely on a full-time basis.



Baseline Results

Reflecting state population projections, for the next ten years we expect residential customer growth to average 0.2% annually. Improving efficiency counters customer growth, contributing to a 0.4% annual decline in baseline sales. Commercial baseline sales decline 0.6% annually over the next ten years as commercial efficiency improvements outweigh sales gains associated with economic activity; we continue to see this trend across the state. In total, baseline sales are expected to decline from 61,149 MWh in 2021 to 58,298 MWh in 2032 and 55,624 in 2042. Table 3 shows Lyndon baseline customer and sales forecast.

TABLE 3: LYNDON BASELINE SALES FORECAST

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Total Sales (MWh)	Chg
2022	31,824		4,943		6,439		29,517		61,341	
2023	31,375	-1.4%	4,967	0.5%	6,317	-1.9%	29,534	0.1%	60,909	-0.7%
2024	31,190	-0.6%	4,982	0.3%	6,261	-0.9%	29,547	0.0%	60,737	-0.3%
2025	30,820	-1.2%	4,993	0.2%	6,173	-1.4%	29,344	-0.7%	60,163	-0.9%
2026	30,651	-0.5%	5,002	0.2%	6,128	-0.7%	29,109	-0.8%	59,760	-0.7%
2027	30,451	-0.7%	5,009	0.1%	6,079	-0.8%	28,866	-0.8%	59,317	-0.7%
2028	30,416	-0.1%	5,016	0.1%	6,064	-0.2%	28,705	-0.6%	59,120	-0.3%
2029	30,365	-0.2%	5,022	0.1%	6,047	-0.3%	28,465	-0.8%	58,831	-0.5%
2030	30,372	0.0%	5,027	0.1%	6,041	-0.1%	28,242	-0.8%	58,614	-0.4%
2031	30,379	0.0%	5,032	0.1%	6,038	-0.1%	28,007	-0.8%	58,386	-0.4%
2032	30,447	0.2%	5,034	0.1%	6,048	0.2%	27,851	-0.6%	58,298	-0.2%
2033	30,337	-0.4%	5,035	0.0%	6,025	-0.4%	27,564	-1.0%	57,901	-0.7%
2034	30,287	-0.2%	5,033	-0.1%	6,018	-0.1%	27,346	-0.8%	57,633	-0.5%
2035	30,278	0.0%	5,030	-0.1%	6,020	0.0%	27,142	-0.7%	57,420	-0.4%
2036	30,350	0.2%	5,027	-0.1%	6,037	0.3%	27,029	-0.4%	57,379	-0.1%
2037	30,254	-0.3%	5,021	-0.1%	6,025	-0.2%	26,781	-0.9%	57,035	-0.6%
2038	30,175	-0.3%	5,014	-0.1%	6,018	-0.1%	26,595	-0.7%	56,769	-0.5%
2039	30,096	-0.3%	5,006	-0.2%	6,012	-0.1%	26,407	-0.7%	56,502	-0.5%
2040	30,101	0.0%	4,998	-0.2%	6,023	0.2%	26,228	-0.7%	56,329	-0.3%
2041	29,981	-0.4%	4,988	-0.2%	6,011	-0.2%	25,919	-1.2%	55,900	-0.8%
2042	29,936	-0.2%	4,976	-0.2%	6,016	0.1%	25,688	-0.9%	55,624	-0.5%
22-32		-0.4%		0.2%		-0.6%		-0.6%		-0.5%
32-42		-0.2%		-0.1%		-0.1%		-0.8%		-0.5%

Adjusted Forecast

Future load growth will come from state electrification efforts (primarily through cold climate heat pump, CCHP, adoption) and projected electric vehicle (EV) market penetration. Expected solar (PV) growth will mitigate some of the sales growth from CCHP and EVs but have no impact on peak demand as peaks have already shifted out to the evening and nighttime hours. is growth mitigated by additional PV growth. The baseline forecast is adjusted for new PV capacity additions, EVs, and CCHP. The statewide forecast of these technologies (PV, CCHP and EV) were developed through a collaborative process as part of the *Vermont Electric Power Company (VELCO) 2021 Long-Term Transmission Plan*. The technology forecasts are then allocated to Lyndon service area based on Lyndon's share of state electric customers. Table 4 shows the resulting forecast.

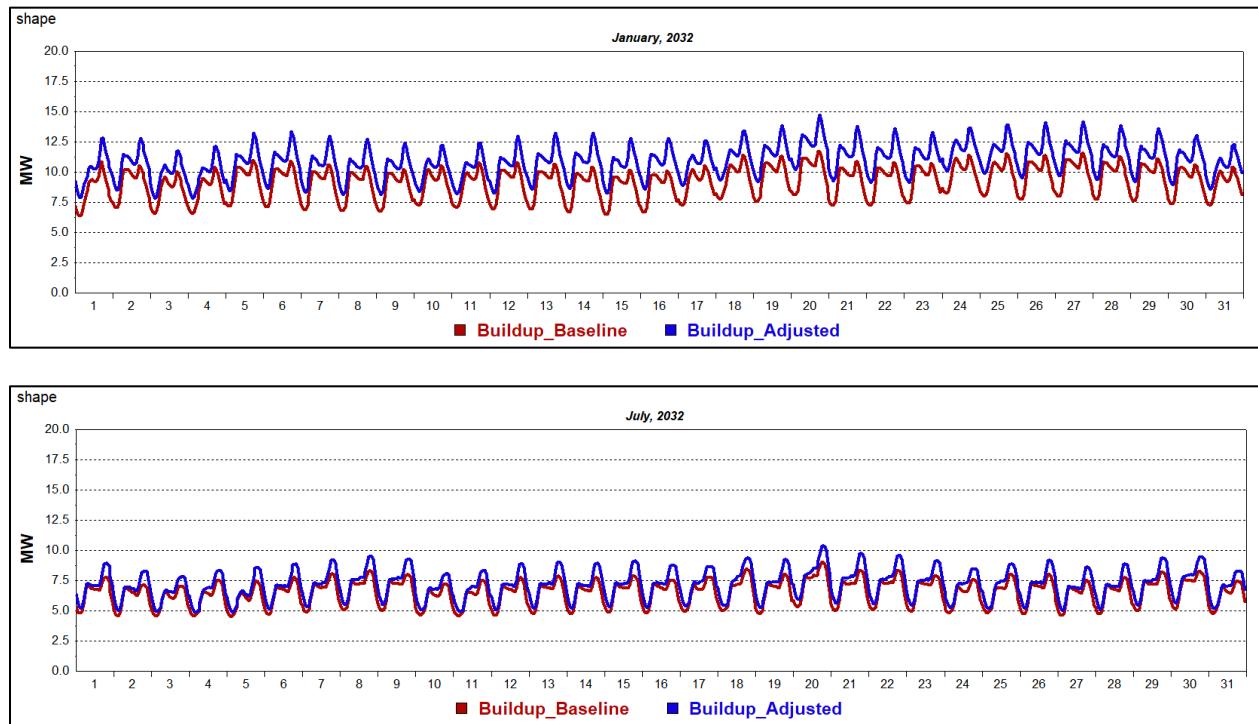
TABLE 4: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	34	29	87
2023	78	65	183
2024	136	100	286
2025	211	122	397
2026	307	132	516
2027	430	142	643
2028	586	148	778
2029	778	150	922
2030	1,012	154	1,059
2031	1,287	160	1,177
2032	1,601	167	1,289
2033	1,944	169	1,395
2034	2,303	171	1,502
2035	2,658	173	1,608
2036	2,989	175	1,717
2037	3,281	176	1,826
2038	3,523	178	1,936
2039	3,715	179	2,046
2040	3,860	181	2,157
2041	3,968	183	2,268
2042	4,044	185	2,380

Annual energy forecasts are estimated for each technology, 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 1 shows the baseline and adjusted hourly load forecast for January and July 2032.

FIGURE 1: BASELINE AND ADJUSTED HOURLY LOAD FORECAST (2032)



All future load growth is driven by EV and CCHP adoption with both EVs and CCHP adding significant electric sales and peak demand growth. Table 5 shows the adjusted energy and demand forecasts.



TABLE 5: LYNDON ENERGY FORECAST (MWH)

Energy and Peak								
Year	Energy (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2022	63,799		9.70		7/19/22 6:00 PM	12.79		1/18/22 5:00 PM
2023	63,660	-0.2%	9.57	-1.3%	7/18/23 6:00 PM	12.57	-1.8%	1/17/23 5:00 PM
2024	63,852	0.3%	9.57	0.0%	7/16/24 6:00 PM	12.66	0.7%	1/16/24 6:00 PM
2025	63,722	-0.2%	9.55	-0.1%	7/15/25 6:00 PM	12.71	0.4%	1/14/25 6:00 PM
2026	63,877	0.2%	9.66	1.2%	7/21/26 6:00 PM	12.98	2.2%	1/20/26 6:00 PM
2027	64,100	0.3%	9.69	0.2%	7/20/27 6:00 PM	13.14	1.3%	1/19/27 6:00 PM
2028	64,714	1.0%	9.75	0.6%	7/18/28 6:00 PM	13.38	1.8%	1/18/28 6:00 PM
2029	65,386	1.0%	9.85	1.1%	7/17/29 6:00 PM	13.52	1.0%	1/23/29 6:00 PM
2030	66,257	1.3%	9.97	1.2%	7/16/30 6:00 PM	13.84	2.4%	1/22/30 6:00 PM
2031	67,222	1.5%	10.12	1.4%	7/15/31 6:00 PM	14.18	2.4%	1/21/31 6:00 PM
2032	68,453	1.8%	10.39	2.6%	7/20/32 6:00 PM	14.70	3.7%	1/20/32 6:00 PM
2033	69,465	1.5%	10.57	1.8%	7/19/33 7:00 PM	15.08	2.6%	1/18/33 6:00 PM
2034	70,665	1.7%	10.77	1.9%	7/18/34 7:00 PM	15.33	1.7%	1/24/34 6:00 PM
2035	71,912	1.8%	10.98	1.9%	7/17/35 7:00 PM	15.74	2.7%	1/23/35 6:00 PM
2036	73,260	1.9%	11.19	1.8%	7/15/36 7:00 PM	16.13	2.5%	1/22/36 6:00 PM
2037	74,157	1.2%	11.43	2.2%	7/21/37 7:00 PM	16.62	3.0%	1/20/37 6:00 PM
2038	74,963	1.1%	11.56	1.1%	7/20/38 7:00 PM	16.91	1.7%	1/19/38 6:00 PM
2039	75,591	0.8%	11.66	0.8%	7/19/39 7:00 PM	17.15	1.4%	1/18/39 6:00 PM
2040	76,150	0.7%	11.71	0.5%	7/17/40 7:00 PM	17.19	0.2%	1/24/40 6:00 PM
2041	76,320	0.2%	11.75	0.3%	7/16/41 7:00 PM	17.36	1.0%	1/22/41 6:00 PM
2042	76,547	0.3%	11.78	0.2%	7/15/42 8:00 PM	17.50	0.8%	1/21/42 6:00 PM
22-32		0.7%		0.7%			1.4%	
32-42		1.1%		1.3%			1.8%	
22-42		0.9%		1.0%			1.6%	

With the addition of EVs and CCHP less solar growth impact, system energy averages 0.7% through the first ten years and even faster annual growth of 1.1% through the following ten years. This compares with the baseline annual sales decline of 0.5%. Winter adjusted peak averages 1.6% annual demand growth and summer 1.0% average annual growth.



Table 6 and Table 7 summarizes the demand forecast by base load and technologies.

TABLE 6: LYNDON SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	9.65		0.02	0.00	0.03	9.70	
2023	9.47	-1.9%	0.05	0.00	0.06	9.57	-1.3%
2024	9.41	-0.7%	0.08	-0.01	0.09	9.57	0.0%
2025	9.31	-1.0%	0.13	-0.01	0.12	9.55	-0.1%
2026	9.33	0.2%	0.19	-0.01	0.16	9.66	1.2%
2027	9.24	-1.0%	0.26	-0.01	0.19	9.69	0.2%
2028	9.17	-0.8%	0.35	-0.01	0.23	9.75	0.6%
2029	9.11	-0.6%	0.47	-0.01	0.28	9.85	1.1%
2030	9.05	-0.7%	0.62	-0.01	0.32	9.97	1.2%
2031	8.99	-0.7%	0.79	-0.01	0.35	10.12	1.4%
2032	9.04	0.5%	0.98	-0.01	0.38	10.39	2.6%
2033	8.89	-1.6%	1.27	0.00	0.41	10.57	1.8%
2034	8.83	-0.7%	1.51	0.00	0.44	10.77	1.9%
2035	8.77	-0.6%	1.75	0.00	0.47	10.98	1.9%
2036	8.73	-0.5%	1.96	0.00	0.50	11.19	1.8%
2037	8.74	0.2%	2.16	0.00	0.53	11.43	2.2%
2038	8.68	-0.7%	2.32	0.00	0.56	11.56	1.1%
2039	8.62	-0.7%	2.45	0.00	0.59	11.66	0.8%
2040	8.55	-0.8%	2.54	0.00	0.62	11.71	0.5%
2041	8.48	-0.8%	2.61	0.00	0.66	11.75	0.3%
2042	8.30	-2.2%	2.82	0.00	0.66	11.78	0.2%
22-42		-0.8%					1.0%

TABLE 7: LYNDON WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	12.67		0.02	0.00	0.10	12.79	
2023	12.37	-2.4%	0.05	0.00	0.15	12.57	-1.8%
2024	12.29	-0.7%	0.13	0.00	0.24	12.66	0.7%
2025	12.17	-0.9%	0.20	0.00	0.33	12.71	0.4%
2026	12.09	-0.7%	0.29	0.00	0.60	12.98	2.2%
2027	11.98	-0.9%	0.41	0.00	0.75	13.14	1.3%
2028	11.92	-0.5%	0.56	0.00	0.90	13.38	1.8%
2029	11.70	-1.9%	0.74	0.00	1.07	13.52	1.0%
2030	11.64	-0.5%	0.97	0.00	1.24	13.84	2.4%
2031	11.58	-0.5%	1.23	0.00	1.37	14.18	2.4%
2032	11.68	0.9%	1.53	0.00	1.49	14.70	3.7%
2033	11.59	-0.8%	1.87	0.00	1.62	15.08	2.6%
2034	11.37	-1.9%	2.22	0.00	1.74	15.33	1.7%
2035	11.31	-0.5%	2.57	0.00	1.86	15.74	2.7%
2036	11.28	-0.3%	2.88	0.00	1.98	16.13	2.5%
2037	11.34	0.5%	3.17	0.00	2.12	16.62	3.0%
2038	11.26	-0.7%	3.41	0.00	2.24	16.91	1.7%
2039	11.19	-0.7%	3.60	0.00	2.37	17.15	1.4%
2040	10.99	-1.8%	3.73	0.00	2.48	17.19	0.2%
2041	10.89	-0.9%	3.84	0.00	2.63	17.36	1.0%
2042	10.82	-0.7%	3.91	0.00	2.77	17.50	0.8%
22-42		-0.8%					1.6%

Adjusted summer system peak averages 1.0% growth driven by EV charging and heat pump air conditioning growth; peaks move out to the evening hours with solar have little to impact on peak demand Winter demand sees even stronger growth averaging 1.6% over the forecast horizon. Both EV charging and heat pump have larger winter load impacts than summer impacts.

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
- Lyndon
- Morrisville
- Northfield
- Orleans
- Swanton

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

Forecast includes:

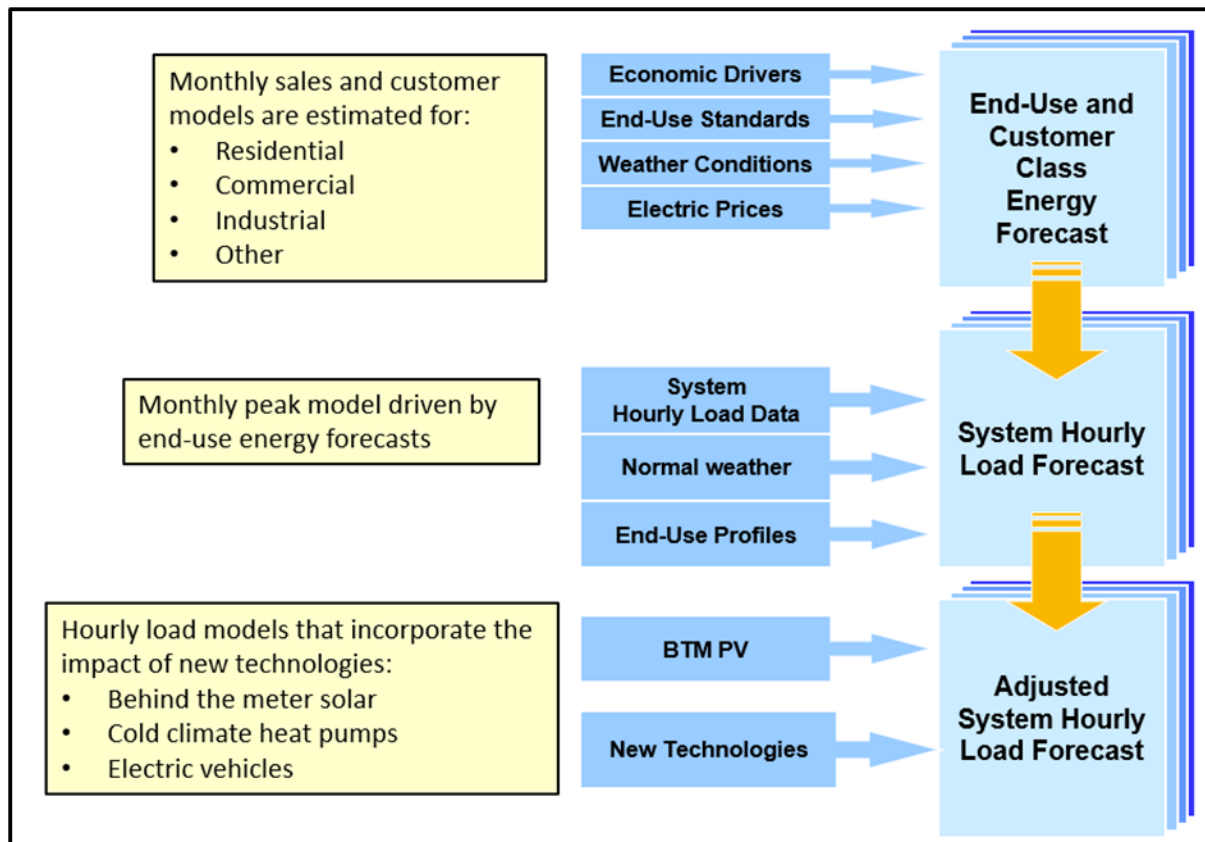
- Residential, commercial, industrial, and other classification sales and customers
- Baseline energy and peak demand
- Adjusted energy and peak demand. Adjusted for the impacts of new technologies including electric vehicles, photovoltaic solar, and cold-climate heat pumps.

FORECAST METHOD

The long-term forecasts are based on a bottom-up approach where 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 2 shows the general forecasting approach.

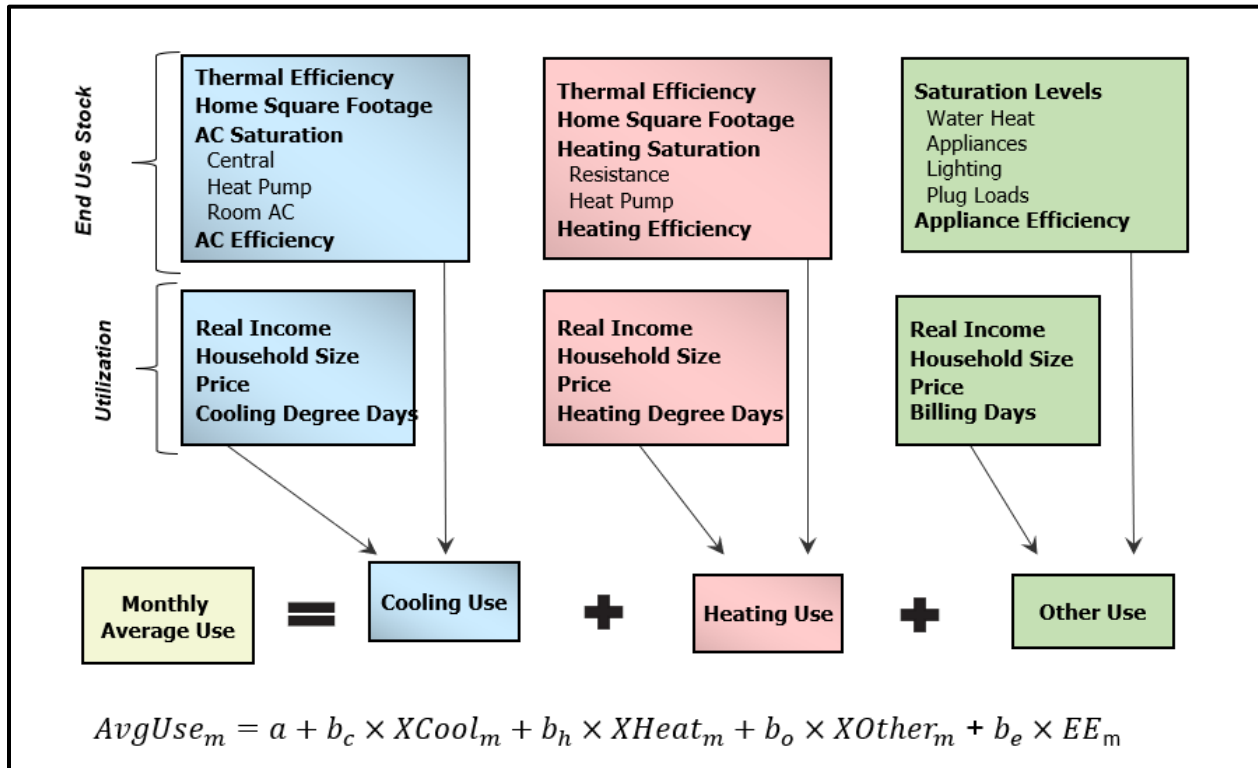
FIGURE 2: FORECASTING FRAMEWORK



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 household, employment and state output, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), state energy efficiency activity, and trended normal heating degree-days (HDD) and cooling degree-days (CDD) that reflect measured temperature trends. 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 3 shows the SAE model specification.

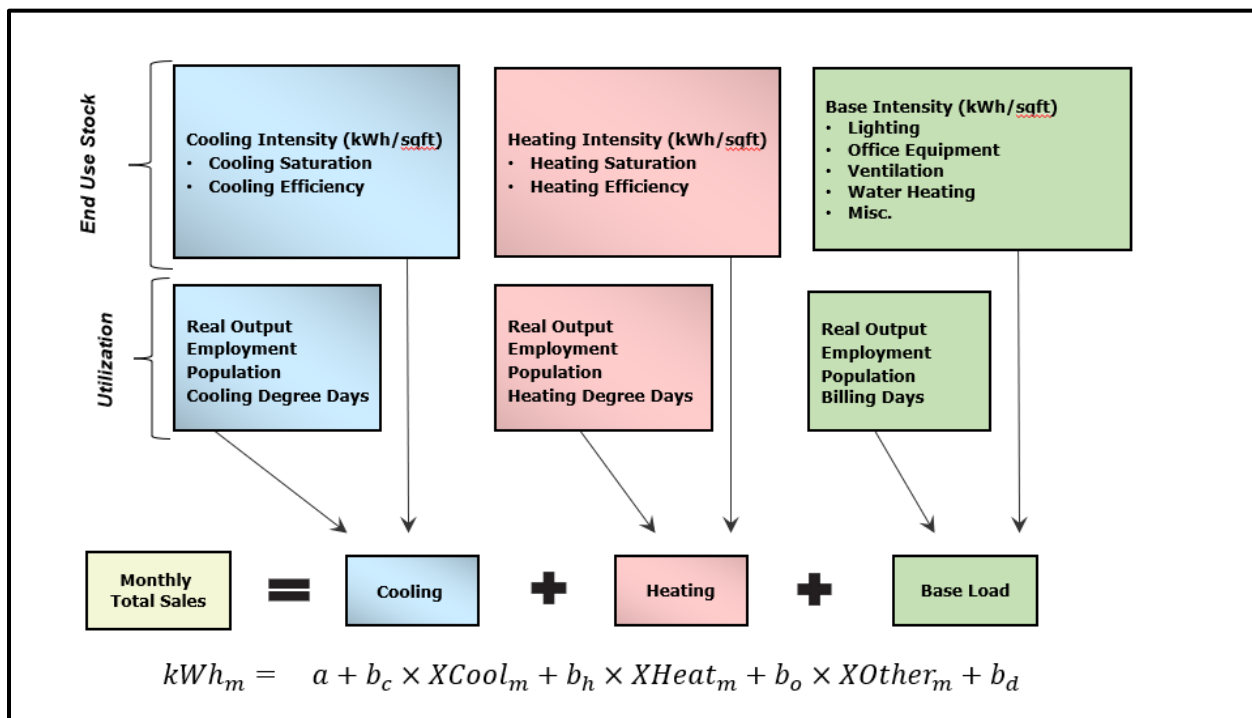
FIGURE 3: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL



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 EE variable proved to be statistically insignificant largely because long-term efficiency trends are already captured in the constructed end-use variables. A monthly average use regression model is used to estimate the coefficients a , b_c , b_h , and b_o , and b_e that effectively *statistically adjust* the initial estimates of monthly heating, cooling, and base-use to actual customer usage. 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. Historical and forecasted end-use energy requirements can be calculated by combining the estimated model coefficients with the cooling (XCool), heating (XHeat), and other use (XOther) where XCool and XHeat are constructed using normal weather.

A similar SAE model specification is used for the commercial customer classes. Figure 4 shows the commercial model specification.

FIGURE 4: COMMERCIAL SAE MODEL



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 that incorporate state economic output, employment, and population. The end-use 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 the end-use model variables where XHeat and XCool incorporate normal weather.

For many of the municipalities the large C&I customer class is dominated by a few companies; there is often significant variation in month-to-month sales data making it difficult to fit 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.

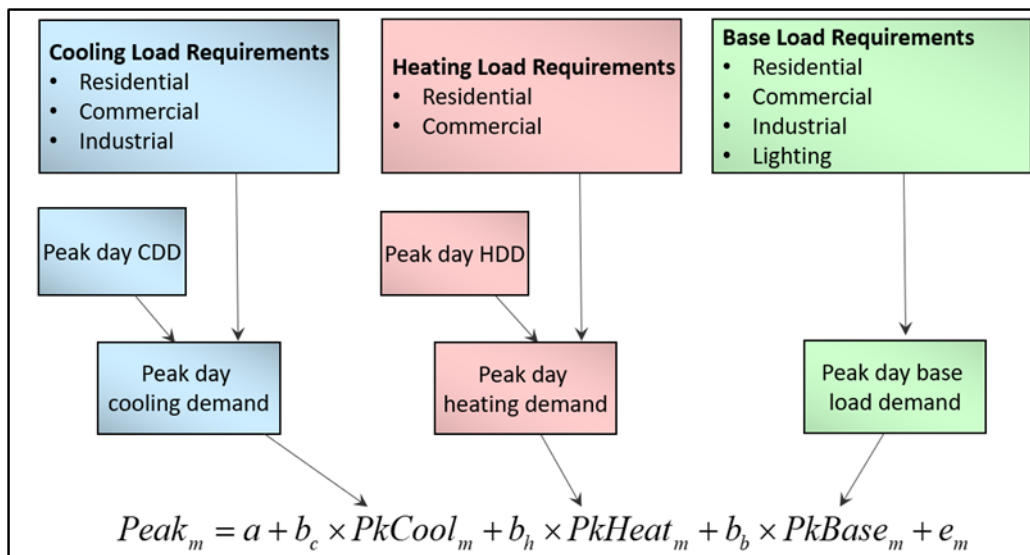
Baseline Energy, Peak, and Hourly Load Forecast

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 from the 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 the CCHP incentive program turns heat loads positive and also adds some cooling load (a significant share of heat pump cooling is displacing room air conditioning). The baseline peak model excludes CCHP, PV, and EV charging loads. Figure 5 shows the baseline peak demand model.

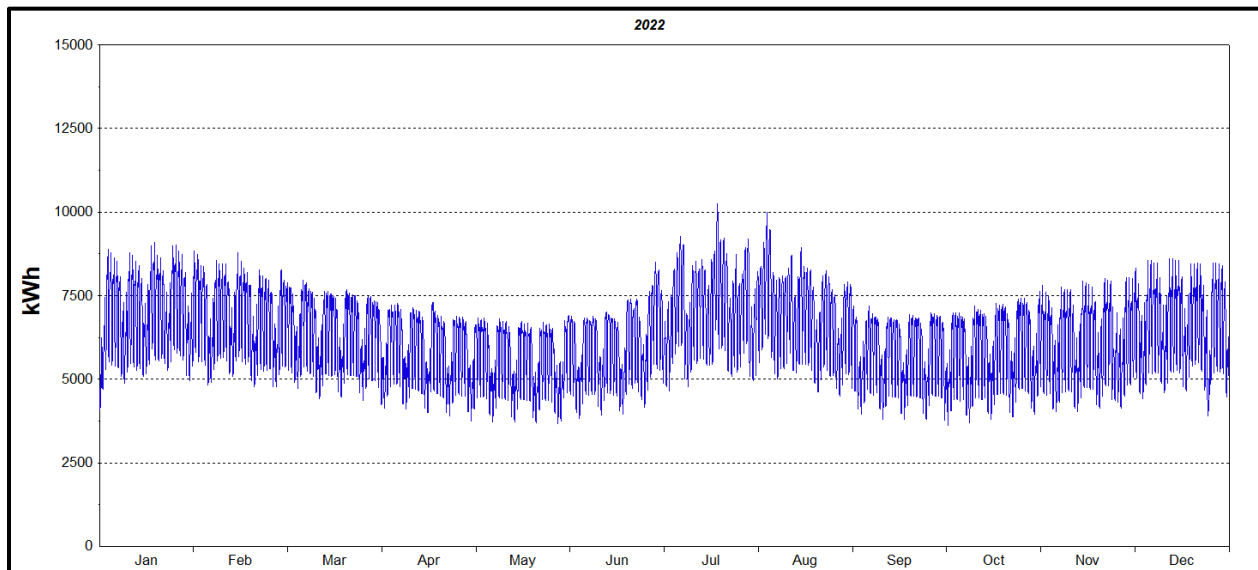
FIGURE 5: BASELINE PEAK MODEL



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. Hourly profile models are estimated at the gross level – that is, estimated hourly solar generation is added back to measured system hourly loads. The profile model captures expected hourly loads for typical weather conditions, day of the week, season, holidays, and hours of light. Figure 6 shows the baseline profile for Swanton.

FIGURE 6: SWANTON LOAD PROFILE



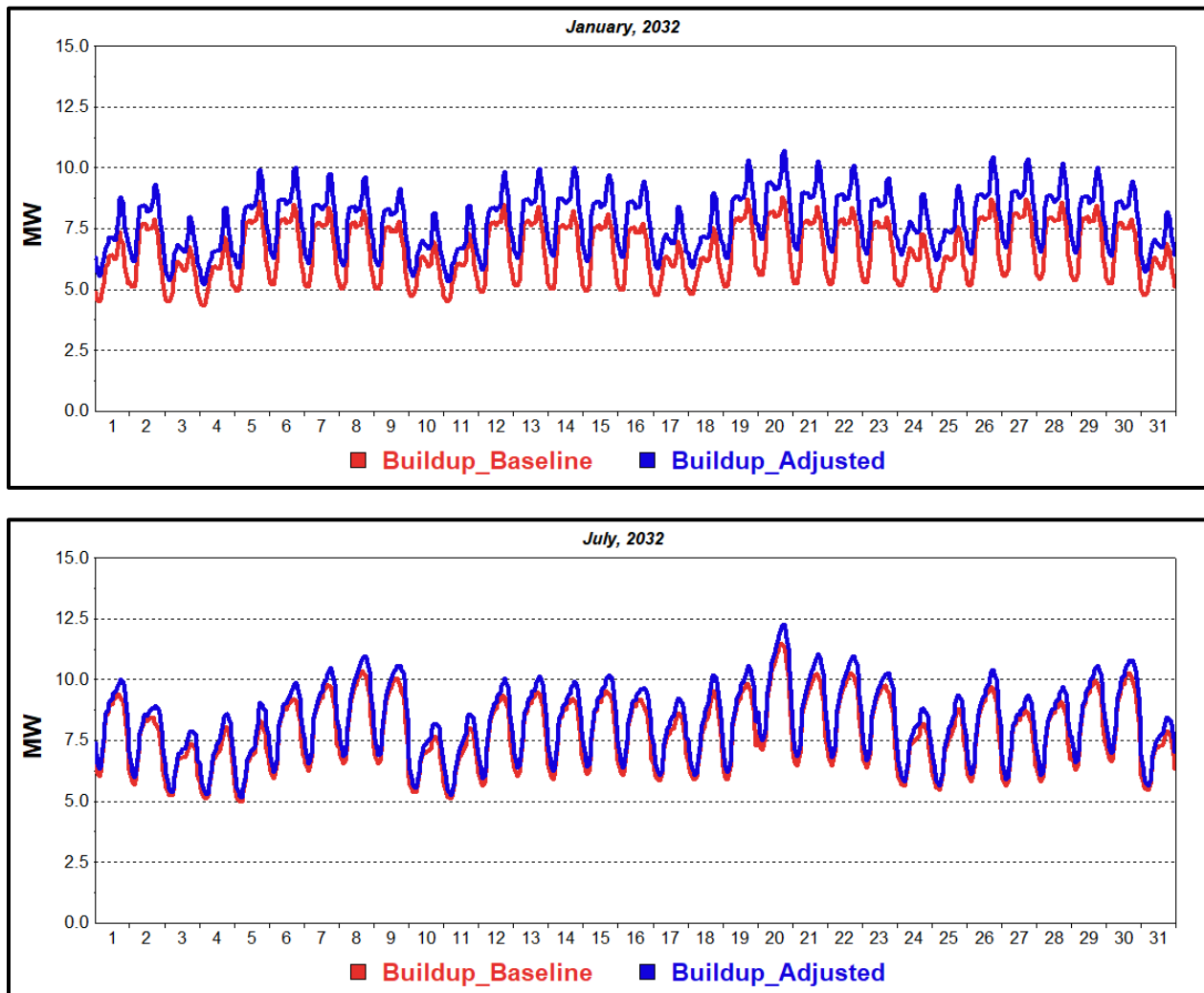
The baseline hourly load forecast is derived by combining the baseline energy and peak forecasts with the system hourly load profile. Increase in energy requirements and peak demand lifts the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

Adjusted Load Forecast

For the most part, baseline loads are flat to declining as efficiency gains have outweighed customer and economic growth. What is driving forecast growth is the expected market penetration of CCHPs and EVs. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV generation continues to increase, capacity projections slow from the current pace. Further, PV has a minimum impact on peak demand as PV 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. PV generation, new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast. Figure 7 compares the Swanton baseline and hourly load forecast for 2032.

FIGURE 7: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)



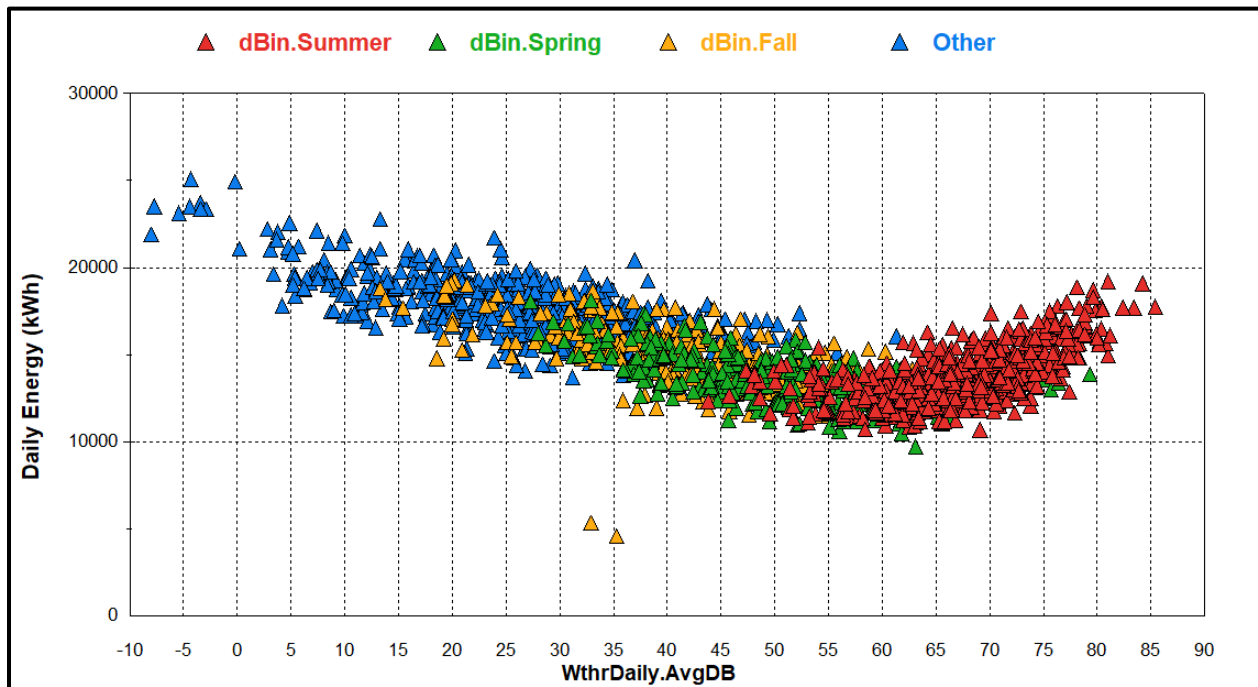
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight VPPSA members that are clustered in north-central Vermont and Rutland weather data for the three large municipalities in the central and southern regions of the state. The temperature/load relationship is evaluated at the system level. Figure 8 illustrates what this relationship looks like at the system level for Jacksonville.

FIGURE 8: 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 the 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 9 and Figure 10 that show 20-year degree-day moving average against actual degree days.

FIGURE 9: HEATING TREND

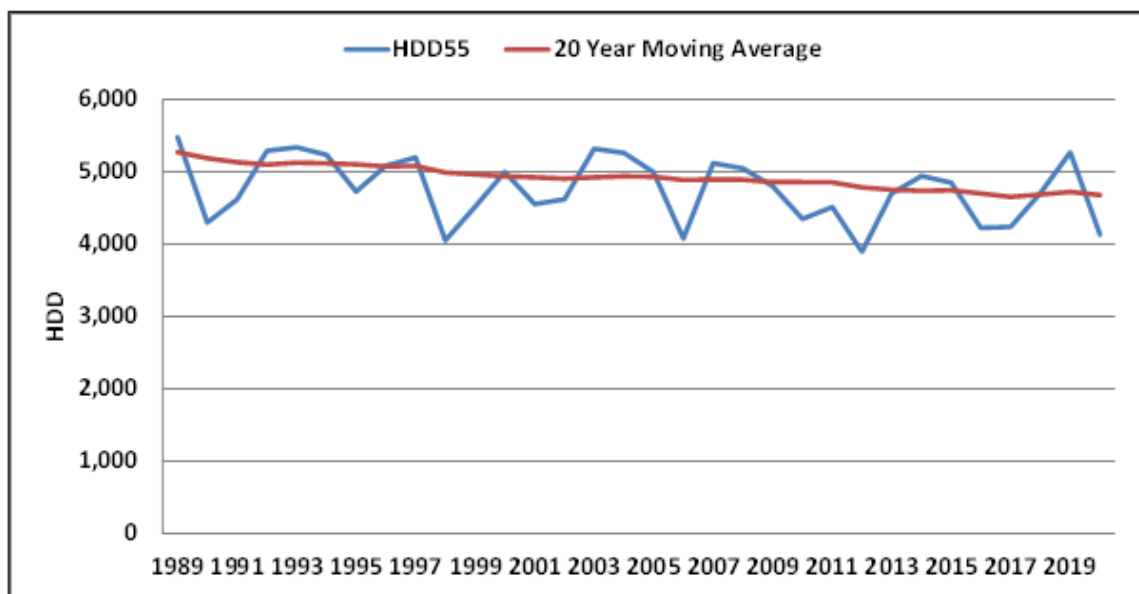
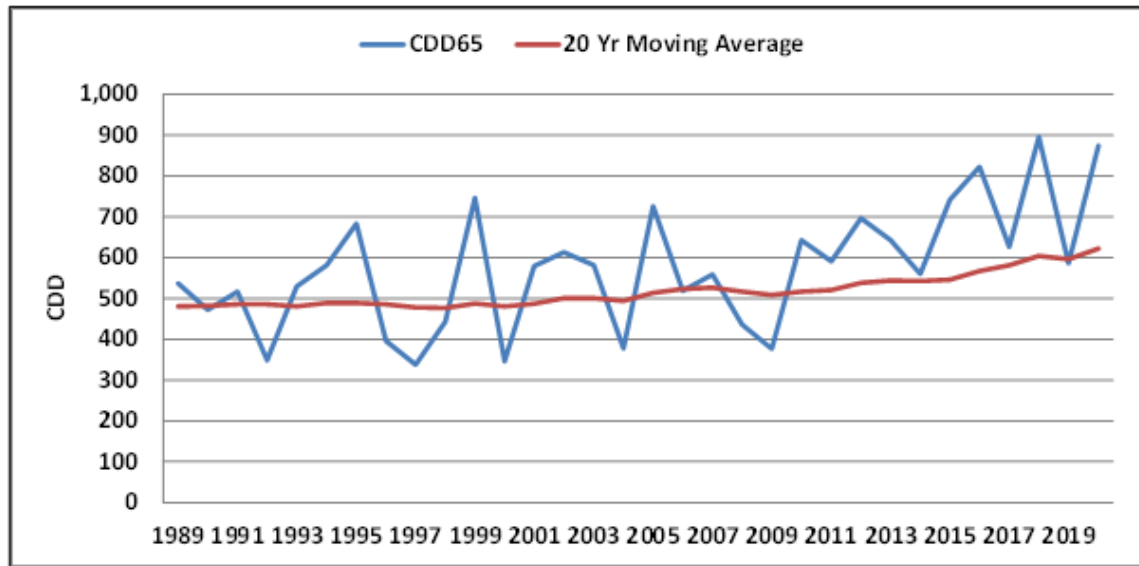


FIGURE 10: COOLING TREND



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

Figure 11 and Figure 12 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 11: NORMAL AND TRENDED NORMAL HDD

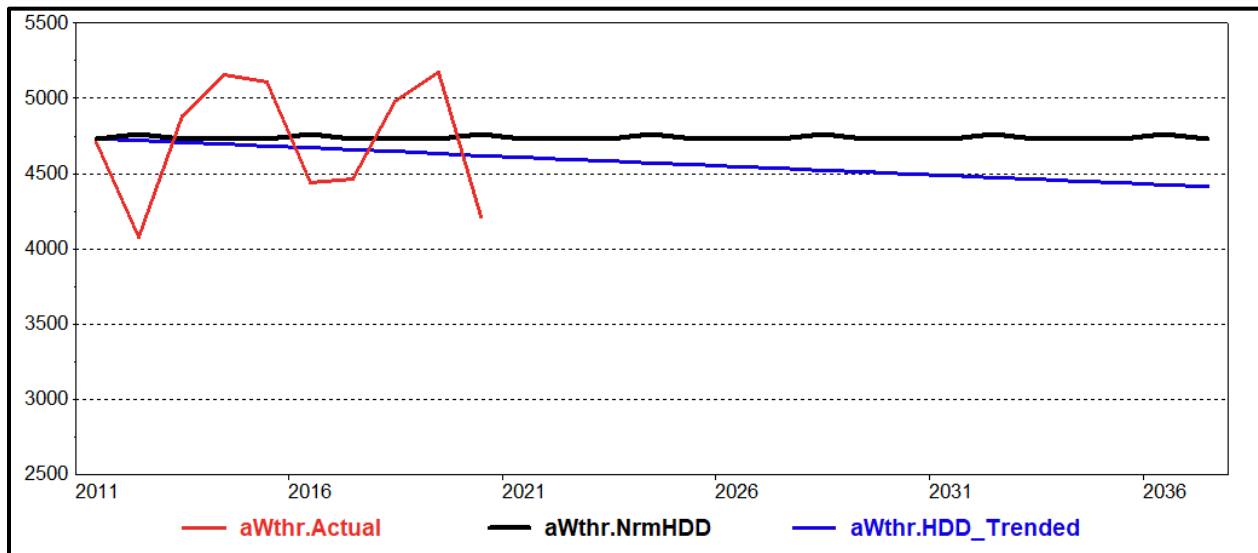
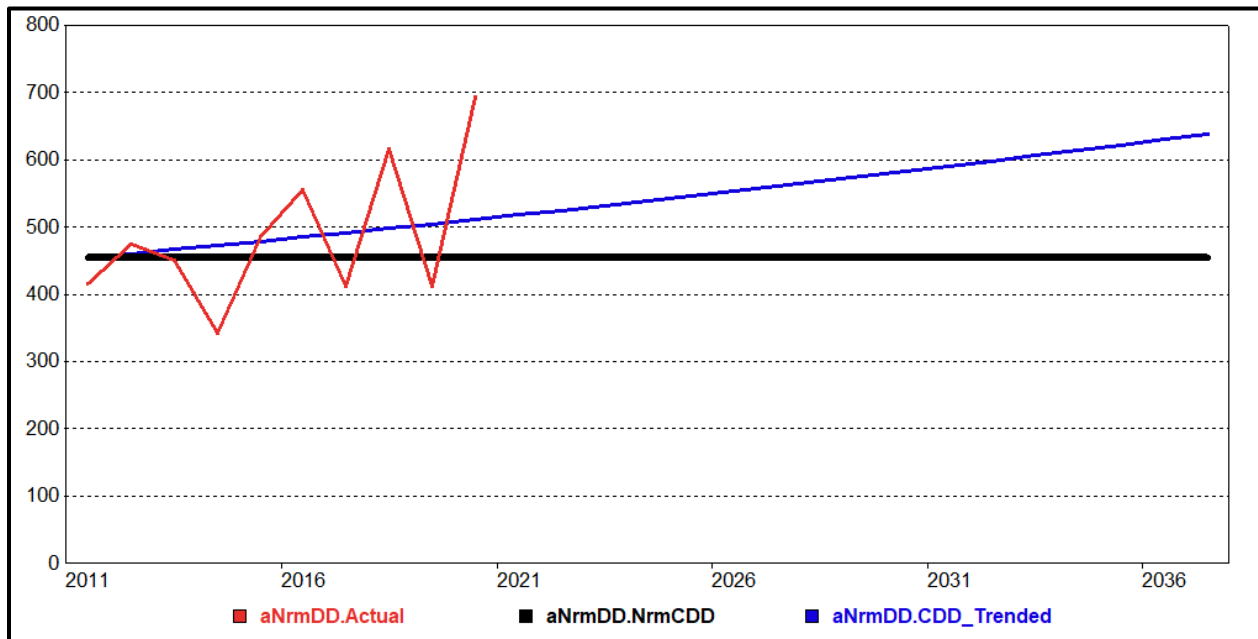


FIGURE 12: NORMAL AND TRENDED NORMAL CDD



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

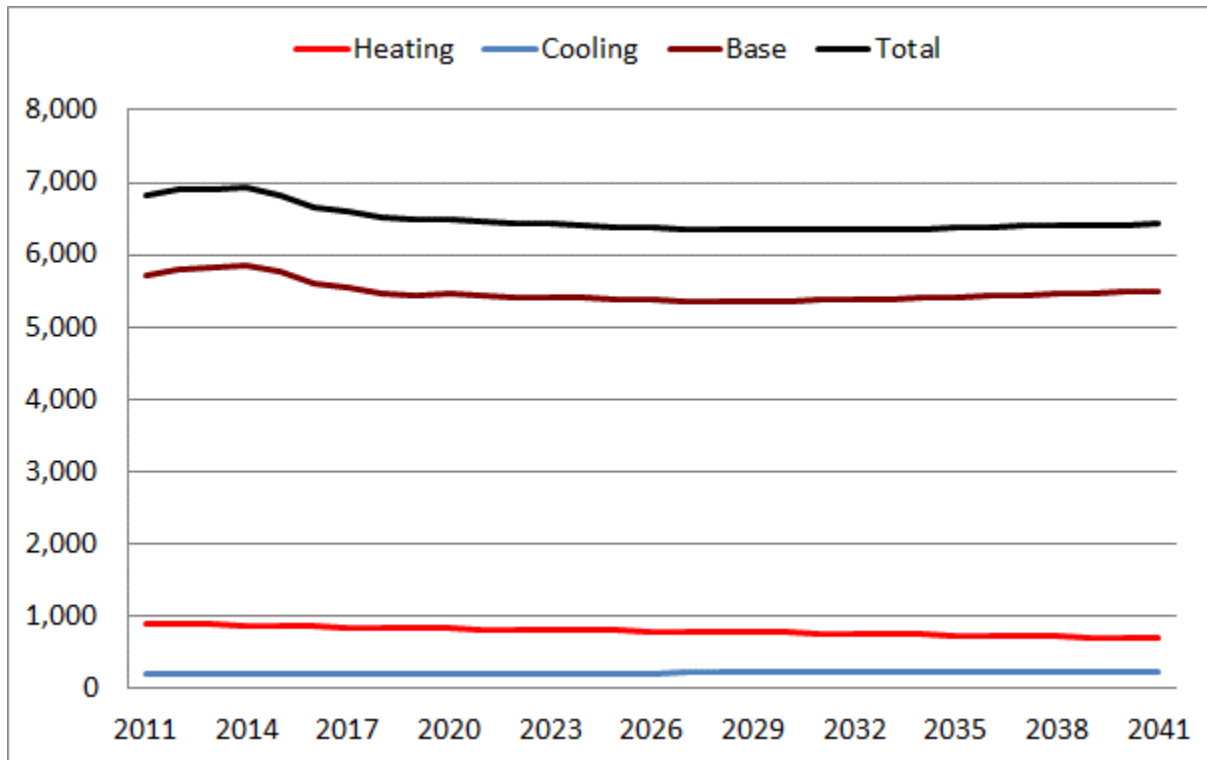


End-Use Intensities

Overall, sales have been flat to declining across the state. The decline is largely attributable to behind-the-meter solar adoption and end-use 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 13 shows residential end-use intensities aggregated into heating, cooling, base, and total intensity.

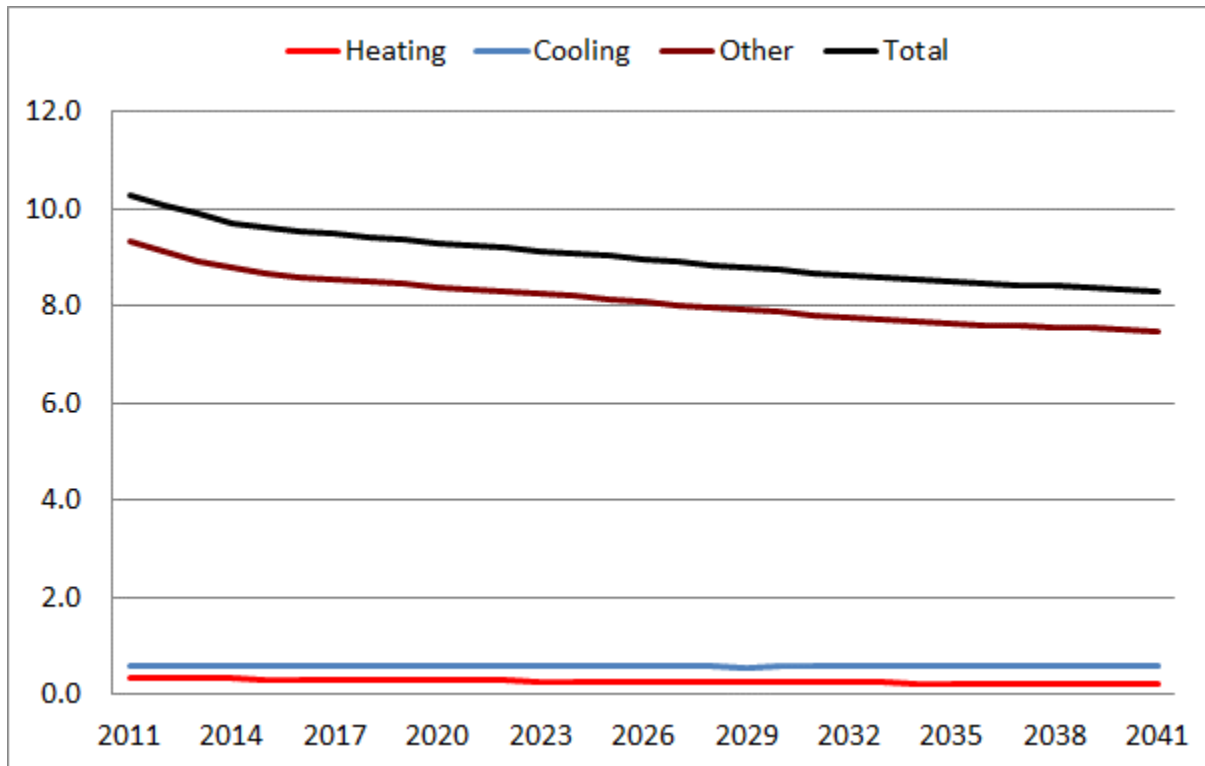
FIGURE 13: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has declined 0.7% annually with the conversion from incandescent and fluorescent 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 14 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 14: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

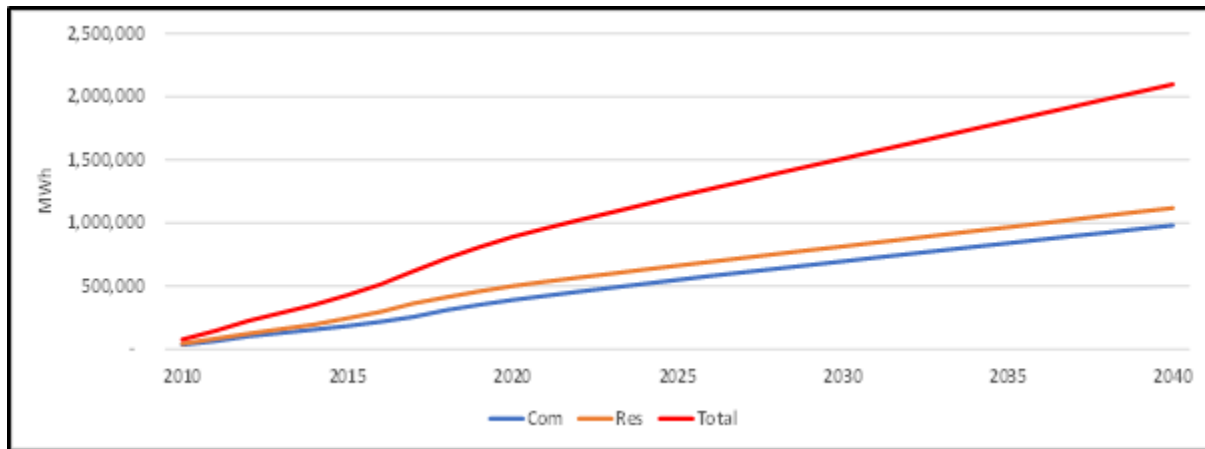


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial energy intensity has declined 1.2% annually over the last ten years; commercial intensity is projected to decline another 0.7% over the next ten years.

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 adjusts 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 15 shows the current state Demand Resource Plan (DRP) cumulative historical and projected savings.

FIGURE 15: 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 8 shows historical and projected economic outlook.

TABLE 8: 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%

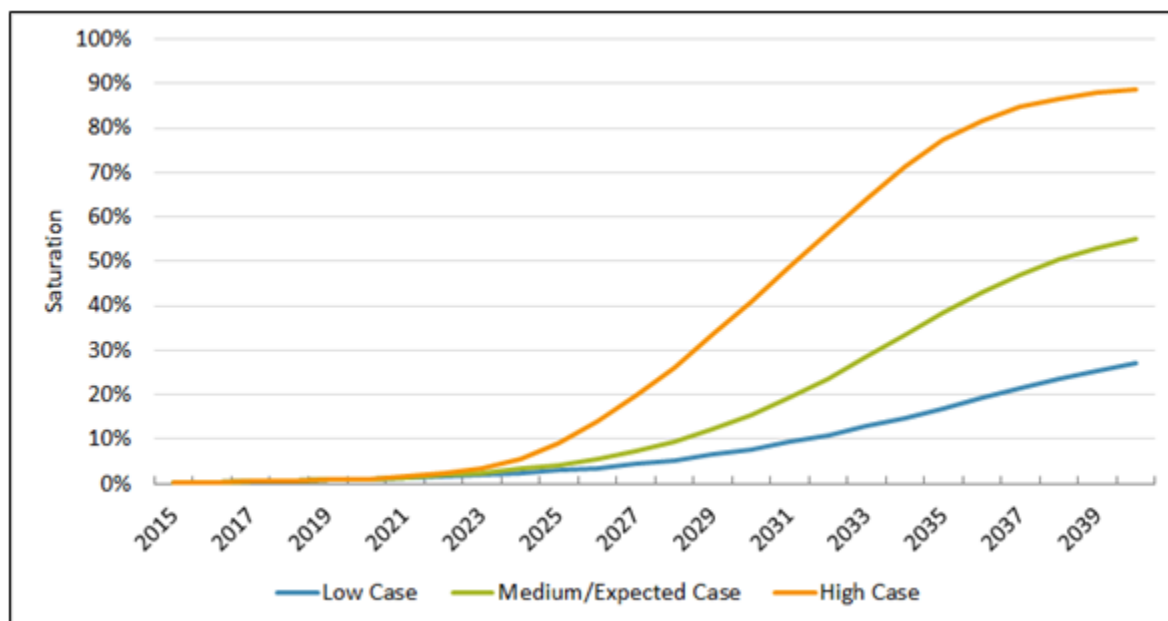
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022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

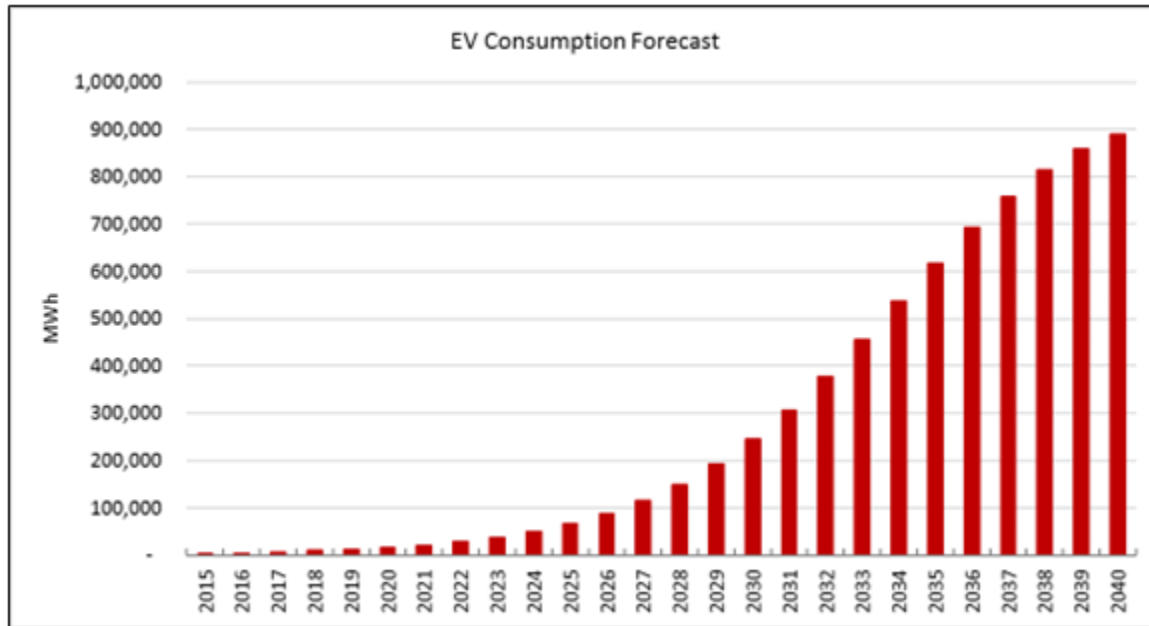
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over 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 16 shows the projected adoption paths.

FIGURE 16: 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 17 shows state EV electric consumption for the expected case.

FIGURE 17: EXPECTED CASE STATE EV ELECTRICITY FORECAST

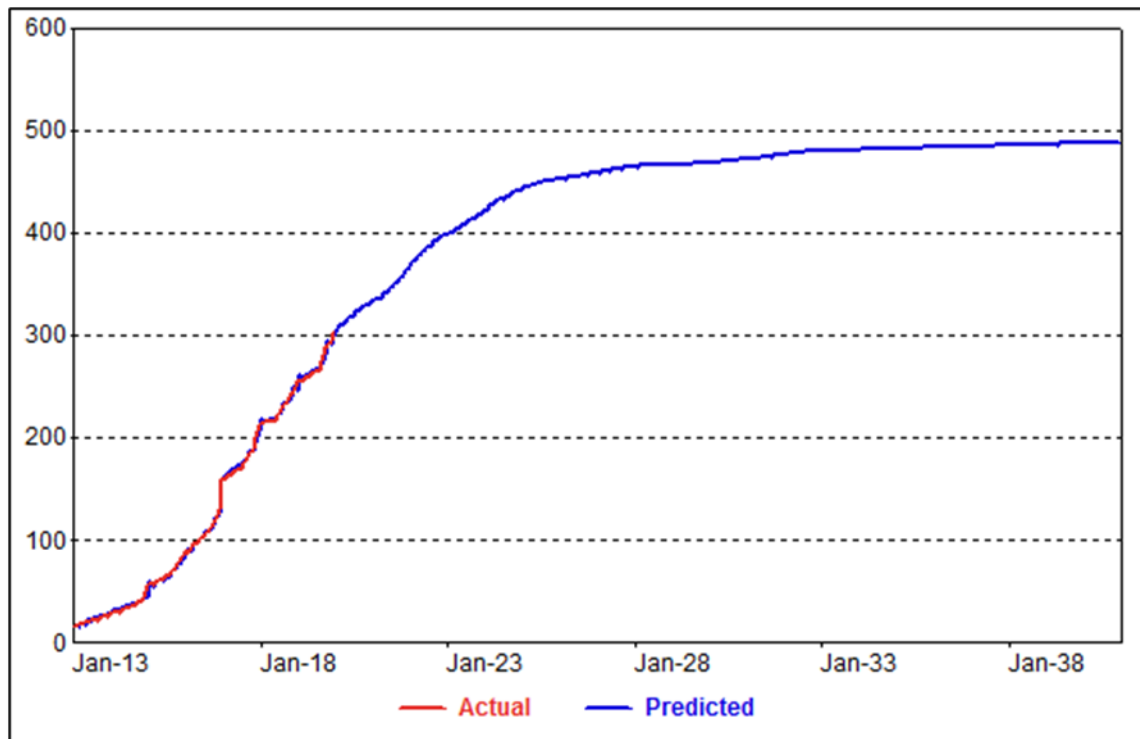


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

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 18 shows state capacity forecast.

FIGURE 18: STATE SOLAR CAPACITY FORECAST (MW)

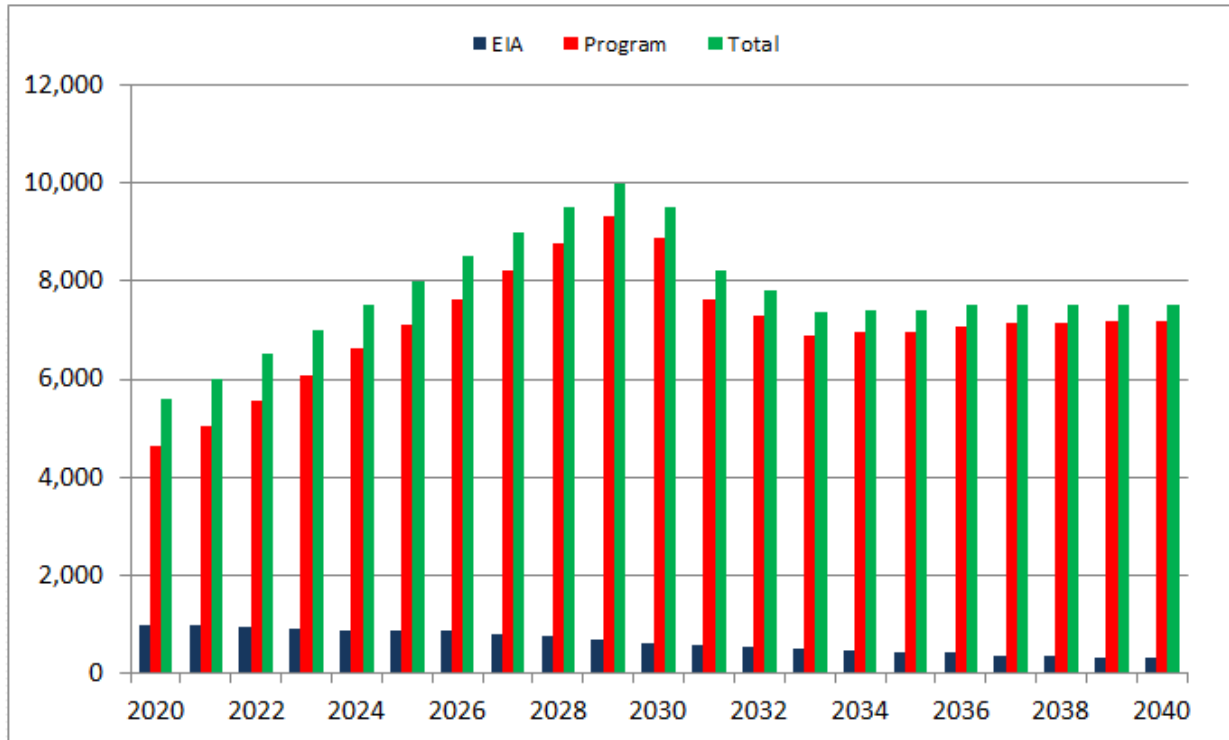


We expect BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out and the number potential solar customers slows. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation 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

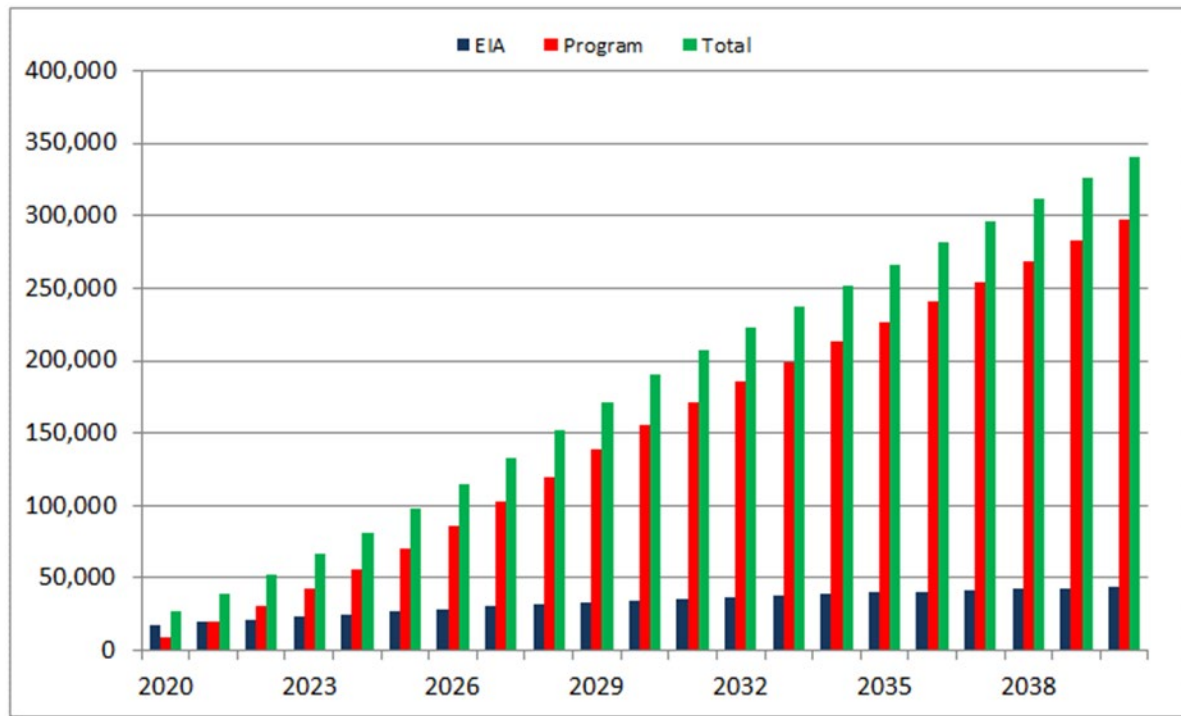
As part of state efforts to reduce CO₂ emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary target are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term 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 19 shows state CCHP unit projections.

FIGURE 19: STATE CCHP FORECAST (UNITS PER YEAR)



VEIC further translated unit projections into electricity use based on recent CCHP measurement studies. Figure 20 shows projected state-level CCHP energy forecast.

FIGURE 20: STATE CCHP ENERGY PROJECTIONS (MWH)



CCHP sales are allocated to VPPSA members based on 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	0.808	0.081	9.997	0.00%
mStructRes.LagXHeat	0.53	0.086	6.184	0.00%
mStructRes.XCool	0.624	0.172	3.631	0.04%
mStructRes.LagXCool	1.086	0.165	6.59	0.00%
mStructRes.LagXOther	0.909	0.014	62.89	0.00%
mCovid.ResIndex	24.897	4.961	5.019	0.00%
mBin.Yr11	22.094	6.314	3.499	0.07%
mBin.Yr12	17.151	6.372	2.692	0.81%
mBin.Feb	-58.265	13.361	-4.361	0.00%
mBin.Apr	-24.714	13.756	-1.797	7.49%
MA(1)	-0.312	0.089	-3.511	0.06%

Model Statistics	
Iterations	13
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.859
Adjusted R-Squared	0.847
AIC	6.819
BIC	7.061
Log-Likelihood	-621.53
Model Sum of Squares	617,129.33
Sum of Squared Errors	101,351.14
Mean Squared Error	844.59
Std. Error of Regression	29.06
Mean Abs. Dev. (MAD)	22.65
Mean Abs. % Err. (MAPE)	4.16%
Durbin-Watson Statistic	1.997

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	18.351	0.189	96.916	0.00%
AR(1)	0.987	0.02	48.572	0.00%
MA(1)	-0.672	0.073	-9.24	0.00%

Model Statistics	
Iterations	25
Adjusted Observations	131
Deg. of Freedom for Error	128
R-Squared	0.785
Adjusted R-Squared	0.782
AIC	6.071
BIC	6.137
Log-Likelihood	-580.54
Model Sum of Squares	197,869.06
Sum of Squared Errors	54,204.18
Mean Squared Error	423.47
Std. Error of Regression	20.58
Mean Abs. Dev. (MAD)	13.82
Mean Abs. % Err. (MAPE)	0.29%
Durbin-Watson Statistic	2.292



Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.LagXHeat	2884022.092	269025.6	10.72	0.00%
mStructCom.LagXCool	1371800.487	127009.9	10.801	0.00%
mStructCom.LagXOther	98707.128	1373.559	71.862	0.00%
mBin.Yr11	-77176.719	18778.77	-4.11	0.01%
mBin.Yr12	-65781.379	18692.35	-3.519	0.06%
mBin.Mar	60210.382	20396.38	2.952	0.38%
mBin.Aug	-51719.957	26227.86	-1.972	5.09%
MA(1)	-0.256	0.09	-2.841	0.53%
MA(2)	0.296	0.09	3.29	0.13%

Model Statistics	
Iterations	19
Adjusted Observations	130
Deg. of Freedom for Error	121
R-Squared	0.573
Adjusted R-Squared	0.545
AIC	22.109
BIC	22.307
Log-Likelihood	-1,612.52
Model Sum of Squares	607,747,436,606.53
Sum of Squared Errors	452,321,967,500.23
Mean Squared Error	3,738,198,078.51
Std. Error of Regression	61,140.81
Mean Abs. Dev. (MAD)	46,800.37
Mean Abs. % Err. (MAPE)	4.79%
Durbin-Watson Statistic	1.807



Large Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	4019374.485	1869612	2.15	3.36%
mStructCom.LagXHeat	7004735.773	1640793	4.269	0.00%
mStructCom.XCool	-1261640.331	509660.7	-2.475	1.47%
mStructCom.XOther	163375.783	7872.06	20.754	0.00%
mBin.Yr11	282707.856	79237.1	3.568	0.05%
mBin.Yr12	278929.178	78767.75	3.541	0.06%
mBin.Mar	-433989.442	70407.72	-6.164	0.00%
mBin.Apr	-323331.221	92066.17	-3.512	0.06%
mBin.May	-211013.191	75921.42	-2.779	0.63%
mBin.Oct	-236497.981	63484.58	-3.725	0.03%
MA(1)	0.349	0.087	4.03	0.01%

Model Statistics	
Iterations	13
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.791
Adjusted R-Squared	0.774
AIC	24.463
BIC	24.705
Log-Likelihood	-1,777.23
Model Sum of Squares	17,649,689,013,922.70
Sum of Squared Errors	4,662,699,631,373.66
Mean Squared Error	38,855,830,261.45
Std. Error of Regression	197,118.82
Mean Abs. Dev. (MAD)	145,430.71
Mean Abs. % Err. (MAPE)	9.49%
Durbin-Watson Statistic	1.835

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	-0.05	0.008	-6.403	0.00%

Model Statistics	
Iterations	0
Adjusted Observations	12
Deg. of Freedom for Error	10
R-Squared	1
Adjusted R-Squared	1
AIC	1.#Q0
BIC	1.#Q0
Log-Likelihood	1.#R
Model Sum of Squares	0
Sum of Squared Errors	0
Mean Squared Error	0
Std. Error of Regression	0
Mean Abs. Dev. (MAD)	0
Mean Abs. % Err. (MAPE)	0.00%
Durbin-Watson Statistic	0

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthr.HeatVar55	39.546	6.157	6.422	0.00%
mWthr.CoolVar60	8.874	10.426	0.851	39.64%
mCPkEndUses.BaseVar	1.714	0.036	47.354	0.00%
mBin.Feb	-657.417	195.534	-3.362	0.10%
mBin.Mar	-429.792	222.365	-1.933	5.56%
mBin.Apr	-921.5	217.963	-4.228	0.00%
mBin.May	-1731.153	236.08	-7.333	0.00%
mBin.Jun	-1032.15	201.549	-5.121	0.00%
mBin.Sep	-714.845	202.387	-3.532	0.06%
mBin.Oct	-1457.828	208.297	-6.999	0.00%
MA(1)	0.372	0.086	4.345	0.00%

Model Statistics	
Iterations	9
Adjusted Observations	132
Deg. of Freedom for Error	121
R-Squared	0.869
Adjusted R-Squared	0.858
AIC	12.783
BIC	13.023
Log-Likelihood	-1,019.98
Model Sum of Squares	264,354,035.12
Sum of Squared Errors	39,794,535.14
Mean Squared Error	328,880.46
Std. Error of Regression	573.48
Mean Abs. Dev. (MAD)	431.93
Mean Abs. % Err. (MAPE)	4.14%
Durbin-Watson Statistic	1.901

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 LED'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 LED'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. LED will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.

Lyndon Electric Department

		<u>Projected Construction</u>																			
<u>Projected Construction</u>		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Hydro	Prod	42,699	43,638	44,598	45,579	46,582	47,607	48,654	49,724	50,818	51,936	53,079	54,247	55,440	56,660	57,906	59,180	60,482	61,813	63,173	64,562
Bucket Truck (10 yr cycle?)	Gen							248,622										309,064			
Digger Truck	Gen																				
1 Ton	Gen																				
3/4 TON Pickup	Gen																				
Utility pickip Truck (5 y cycle?)	Gen			39,023					43,509					48,510					54,086		
Office furniture & computing Equipment	Gen	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809	40,685	41,580	42,495	43,430	44,385	45,362	46,360	47,379	48,422	49,487	50,576
pole & Line rebuild?	Dist	139,369	142,435	145,569	148,771	152,044	155,389	158,808	162,301	165,872	169,521	173,251	177,062	180,958	184,939	189,007	193,166	197,415	201,758	206,197	210,733
Line Reconductor?	Dist	44,598	45,579	46,582	47,607	48,654	49,724	50,818	51,936	53,079	54,247	55,440	56,660	57,906	59,180	60,482	61,813	63,173	64,562	65,983	67,434
Transformers, Services,meters	Dist	55,747	56,974	58,227	59,508	60,817	62,155	63,523	64,920	66,349	67,808	69,300	70,825	72,383	73,975	75,603	77,266	78,966	80,703	82,478	84,293
Misc Distribution	Dist	55,747	56,974	58,227	59,508	60,817	62,155	63,523	64,920	66,349	67,808	69,300	70,825	72,383	73,975	75,603	77,266	78,966	80,703	82,478	84,293
Transmission	trans																				
Routine/Recurring/Misc plant & General	25%/75%	83,621	85,461	87,341	89,262	91,226	93,233	95,284	97,381	99,523	101,712	103,950	106,237	108,574	110,963	113,404	115,899	118,449	121,055	123,718	126,439
Total Construction		\$ 455,230	\$ 465,245	\$ 514,503	\$ 485,941	\$ 496,631	\$ 507,557	\$ 767,345	\$ 573,644	\$ 541,798	\$ 553,718	\$ 565,900	\$ 578,350	\$ 639,583	\$ 604,077	\$ 617,367	\$ 630,949	\$ 953,893	\$ 713,102	\$ 673,514	\$ 688,331
<u>Functional Summary:</u>																					
Production		42,699	43,638	44,598	45,579	46,582	47,607	48,654	49,724	50,818	51,936	53,079	54,247	55,440	56,660	57,906	59,180	60,482	61,813	63,173	64,562
General	25%	54,354	55,549	95,795	58,021	59,297	60,602	310,556	106,806	64,690	66,113	67,568	69,054	119,083	72,126	73,713	75,334	386,055	132,772	80,417	82,186
Distribution	75%	358,177	366,057	374,111	382,341	390,753	399,349	408,135	417,114	426,290	435,669	445,253	455,049	465,060	475,291	485,748	496,434	507,356	518,518	529,925	541,583
Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Construction		455,230	465,245	514,503	485,941	496,631	507,557	767,345	573,644	541,798	553,718	565,900	578,350	639,583	604,077	617,367	630,949	953,893	713,102	673,514	688,331