Barton Village, Inc.

2019 Integrated Resource Plan

Filed with the Public Utility Commission

VPPSA
Vermont Public Power Supply Authority

Executive Summary:

Barton Village, Inc. (BVI) has operated an electric utility system since 1894 in the northern part of Vermont, located close to the Canadian border, in Orleans County and part of Caledonia County in the Northeast Kingdom. BVI 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 BVI is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

BVI's 95 square mile service territory encompasses the Village of Barton as well as portions of six of the surrounding towns: Barton Town, Charleston, Westmore, Brownington, and parts of Sutton and Irasburg. About 53% of BVI's customers are served within the village and town portions of Barton. In total, BVI serves approximately 2,100 customers.

BVI's distribution system serves a mix of residential and small commercial customers. Residential customers make up over 90% of the customer mix while accounting for three-quarters of BVI's retail kWh sales. One-hundred-and-eighty-three small commercial customers make up approximately 18% of retail usage with the remaining 7% of retail sales going to public authority customers, and public street and highway lighting.

Consistent with regulatory requirements, every 3 years BVI is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan, or IRP) for provision of energy services to its Vermont customers. BVI'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

BVI is facing a period of relatively flat demand influenced by several competing factors, all of which carry some uncertainty. Continued adoption of solar net metering reduces demand although the pace at which net metering will grow in BVI'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.

While no significant change in the demand associated with BVI's largest customers is currently anticipated, the potential does exist. BVI 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

BVI'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 market contracts, hydro, and other renewable sources. BVI owns and operates the Barton Village Hydroelectric Project, delivering a clean reliable source of power located on the Clyde River, within its service territory. The Barton Village Hydroelectric Plant has been a dependable source of power for the evolving energy needs of northeastern Vermont and is certified by the Low Impact Hydro Institute (LIHI).

When considering future electricity demand, BVI seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. BVI 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. BVI 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 BVI 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, BVI 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 BVI 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.

BVI faces three major energy resource decisions over the 2020 – 2039 period covered by this Integrated Resource Plan (IRP).

The major resource decisions faced by BVI occur in 2020 and 2024, respectively, which in total, will affect about 38% of BVI's energy supply between 2020 and 2024. The first is the expiration of a contract at the end of 2022, which represents about 30% of BVI's energy supply. The second is the expiration of a group of current market contracts in 2024, which represent about 8% of BVI's energy supply. The next resource expirations don't occur until the 2030's.

Options being evaluated by BVI to replace these two contracts include renegotiating the contract expiring in 2022 and extending its term, signing a PPA for an existing hydro plant to provide capacity, energy, and Tier I RECs, signing a PPA for a solar plant to provide energy and Tier II RECs, or signing a PPA for market energy supplies.

The main sources of uncertainty expected to impact these decisions are potential changes in load and load growth, followed by capacity market prices and energy prices. Other important variables are peak coincidence factor, the cost of regional transmission service and REC prices.

BVI's capacity supplies are only expected to fulfill about half of its capacity obligation in the 2020's. As a result, a long-term capacity resource that is prices at or below today's market prices would be beneficial.

Analysis of these major resource decisions also addresses one load-related questions: what is the rate impact of 1% compound annual load growth?

RENEWABLE ENERGY STANDARD

BVI is subject to the Vermont Renewable Energy Standard which imposes an obligation for BVI to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into three categories, TIER I, TIER II and TIER III. BVI'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 BVI's TIER III obligation involves energy transformation, or reduction of fossil fuel use within its territory. TIER III programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on diesel generation to electric service, among other things. By providing incentive programs to encourage conversion of traditional fossil fuel applications BVI receives credits toward its TIER III obligation. More information regarding BVI's approach to meeting its TIER III obligation is available in Appendix B to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

BVI has a compact service territory as a result of being a small, municipal-owned electric utility and has consistently pursued upgrade initiatives each year in order to maintain a reliable and efficient system. BVI has just over 200 miles of distribution lines in a radial feed configuration with two 13.2kV Y/7.6kV feeders from the Heath substation serving customers in the Village of Barton, Sutton, Westmore, Brownington, Town of Barton, Charleston, and Irasburg. Some older areas of the system step down further to 2.4kV delta.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, BVI is examining the need to modernize in order to support beneficial electrification and additional distributed generation on the system and to provide more customer oriented services, including load management programs that reduce costs for both BVI and its customers. BVI is currently engaged with VPPSA in a multi-phased process designed to assess its readiness for AMI, guide it through an RFP process culminating in vendor and equipment selection and ultimately resulting in implementation of an AMI system, provided the resulting cost estimates gained through the RFP process are not prohibitive.

BVI sees potential value to customers from utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison. Implementation of an AMI system is expected to enhance BVI's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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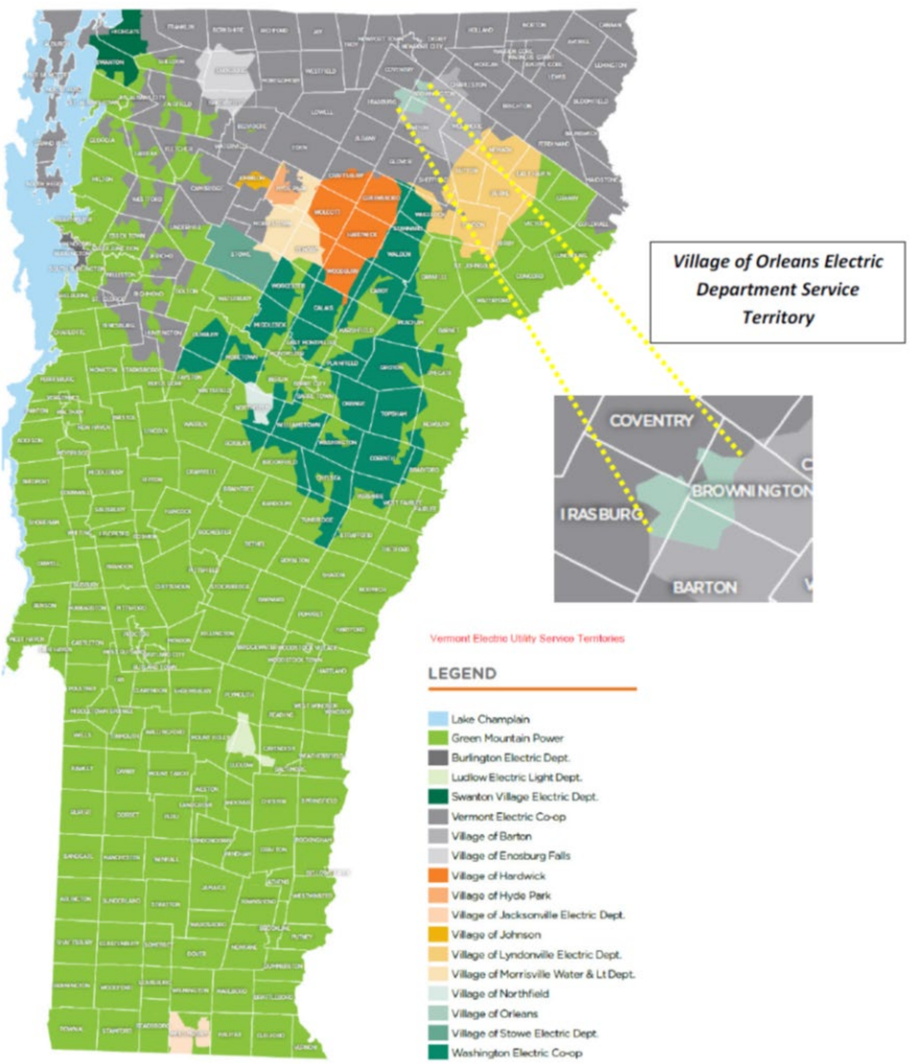
Introduction:

Incorporated in 1894. Barton Village, Inc. (BVI)'s service territory is located in Orleans County and part of Caledonia County in the Northeast Kingdom of Vermont. Its approximately 95 square mile service territory can be seen on the Vermont Utility Service Territory map found below, and it encompasses the Village of Barton as well as portions of six of the surrounding towns: Barton Town, Charleston, Westmore, Brownington, and parts of Sutton and Irasburg. About 53% of BVI's customers are served within the village and town portions of Barton. BVI serves approximately 2,100 retail customers. Like most of Vermont's smaller municipal utilities, many of its utility functions, such as office staffing, are carried out by employees who also have responsibilities in other aspects of village municipal operations. BVI remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. Well-established practices keep BVI operating safely, efficiently, and reliably.

Figure 1: BVI'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.

BVI is one of twelve member utilities of VPPSA, who 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:

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

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

System Overview

In 2018 BVI's peak demand in the winter months was 2,987 kW and 2,956 kW during the summer and shoulder months. Annual energy retail sales for 2018 were 13,646,122 kWh and the annual load factor was 60.1%.

BVI is connected to the Vermont Electric Cooperative (VEC) transmission system.

Table 1: BVI's Retail Customer Counts

Data Element	2014	2015	2016	2017	2018
Residential (440)	1,948	1,891	1,952	1,949	1,945
Small C&I (442) 1000 kW or less	193	192	180	186	183
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	3	3	3	3	3
Public Authorities (445)	14	14	15	14	15
Interdepartmental Sales (448)	12	12	14	14	15
Total	**2,170**	**2,112**	**2,163**	**2,166**	**2,162**

Table 2: BVI's Retail Sales (kWh)

Data Element	2014	2015	2016	2017	2018
Residential (440)	10,571,355	10,311,643	10,162,644	10,057,047	10,185,244
Small C&I (442) 1000 kW or less	2,688,013	2,753,528	2,854,503	2,619,983	2,513,736
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	66,118	66,118	73,152	73,195	127,277
Public Authorities (445)	572,454	539,110	540,614	527,614	573,016
Interdepartmenta l Sales (448)	194,516	203,859	220,626	234,666	246,849
Total	**14,092,456**	**13,874,258**	**13,851,539**	**13,512,505**	**13,646,122**
YOY	0%	-2%	0%	-2%	1%

Table 3: BVI's Annual System Peak Demand (kW)

Data Element	2014	2015	2016	2017	2018
Peak Demand kW	3,074	2,935	3,483	3,020	2,987
Peak Demand Date	01/02/14	01/08/15	02/14/16	12/28/17	01/01/18
Peak Demand Hour	19	18	19	18	19

Structure of Report

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

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

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

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

IV. Electricity Transmission and Distribution
This chapter describes BVI's distribution system and discusses how it is being maintained to provide reliable service to its customers.

V. Financial Analysis
This chapter presents a high-level forecast of BVI's power supply costs and cost of service.

VI. Action Plan
This chapter outlines specific actions the BVI expects to take as a result of this Integrated Resource Plan.

A. Appendix: Letters List
The appendix includes a series of supporting documents and reports, as listed in the Table of Contents.

B. Glossary

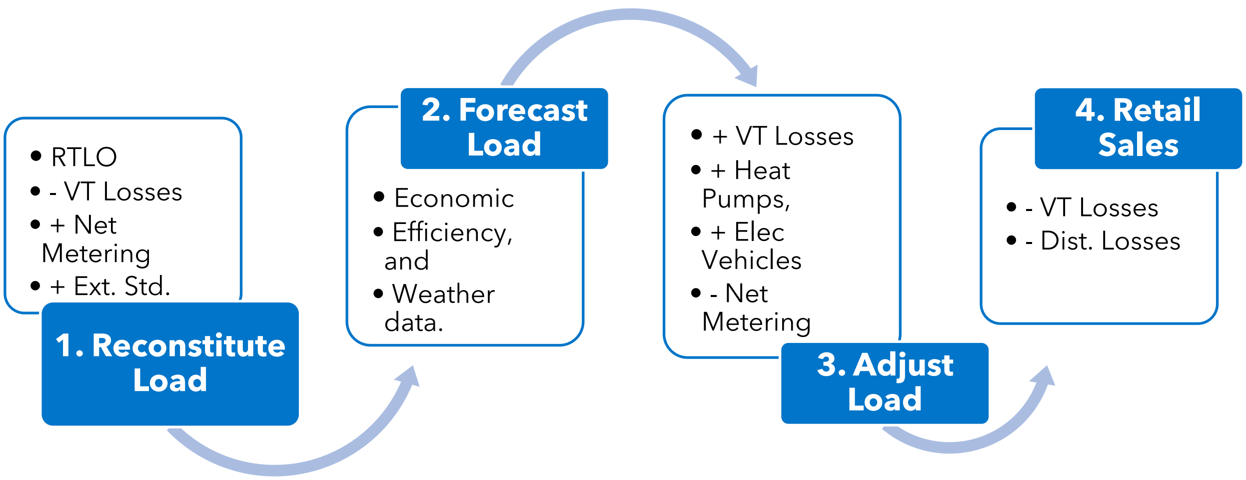
Electricity Demand

I. Electricity Demand

Energy Forecast Methodology: Regression with Adjustments

VPPSA uses Itron's Metrix ND software package and a pair of multiple regression equations to forecast BVI's peak and energy requirements. Importantly, the peak and energy forecasts are based on the same underlying data sets and the same methodologies that are used to set BVI's annual power budget. As a result, the forecasts are updated annually, and variances are evaluated monthly as actual loads become available. The forecast methodology follows a four-step process.

Figure 2: Forecasting Process



1. Reconstitute Load

In the past, metered load at the distribution system's tiepoints (boundaries) was used as the 'dependent' variable in the regression equations. However, the growing impact of the net metering and Standard Offer Programs has effectively obscured the historical trends in this data, and this would cause the accuracy of the regression equations to decrease. To preserve the accuracy of the regression forecast, VPPSA "reconstitutes" the Real-Time Load Obligation (RTLO) data by 1.) adding back generation from the net metering and Standard Offer Programs, and 2.) subtracting Vermont's transmission losses. This results in a data set that can be accurately modeled using multiple regression, and creates consistency with the historical data.

The resulting, reconstituted load is used as the dependent variable in the regression equations and forms a historical time series data that the regression equations use to predict future loads. The following table summarizes the data that is used to reconstitute the load.

Table 4: Data Sources for Reconstituting RTLO

Data Element	Source
RTLO	ISO-NE
– Vermont Transmission Losses	VELCO[1]
+ Net Metering Program Generation	VPPSA
+ Standard Offer Program Generation	VELCO
= Reconstituted Load	

2. Forecast Load

The regression equations use a series of independent or "explanatory" variables to explain the trends in the reconstituted load data. The equations themselves consist of the explanatory variables that are listed in Table 5.

Table 5: Load Forecast Explanatory Variables

Data Category	Explanatory Variable	Source
Dummy Variables	These variables consist of zeros and ones that capture seasonal, holiday-related, and large, one-time changes in electricity demand.	Not applicable. Determined by the forecast analyst.
Economic Indicators	Unemployment Rate (%)	Vermont Department of Labor
	Eating and Drinking Sales ($)	Woods and Poole
Energy Efficiency	Cumulative EE Savings Claims (kWh)	Efficiency Vermont Reports and Demand Resource Plan
Weather Variables	Temperature – 10-year average heating & cooling degree days.	National Oceanic and Atmospheric Administration (NOAA)

The forecast accuracy of the regression model is very good. Based on monthly data, it has an R-squared of 98%, and a Mean Absolute Percent Error (MAPE) of 1.47%.

3. Adjust Load

Once the regression models are complete and the forecast accuracy is maximized, the load forecast is adjusted to account for the impact (both historical and forward-looking) of cold climate heat pumps (CCHP), electric vehicles (EV), and net metering. As new electricity-using devices, CCHPs and EVs increase the load. However, by its nature, net metering decreases it[2].

Because the historical trends for these three items are still nascent, they cannot be effectively captured in the regression equations. In the case of net metering, VPPSA used the most recent three-year average to determine the rate of net metering growth in BVI. For CCHPs and EVs, we used the same data (provided by Itron) that the

[1] Vermont Electric Power Company

[2] For more information on net-metering, please refer to https://vppsa.com/energy/net-metering/.

Vermont System Planning Committee (VSPC) used in VELCO's 2018 Long Range Transmission Plan.

Notice that the adjusted load does not account for the presence of the Standard Offer Program. This is a deliberate choice that enables the resource planning model to treat the Standard Offer Program as a supply-side resource instead of a load-reducer.

4. Retail Sales

A forecast of retail sales is required to estimate compliance with the Renewable Energy Standard (RES), and is calculated by subtracting Vermont transmission and local distribution losses from the Adjusted Forecast.

Energy Forecast Results

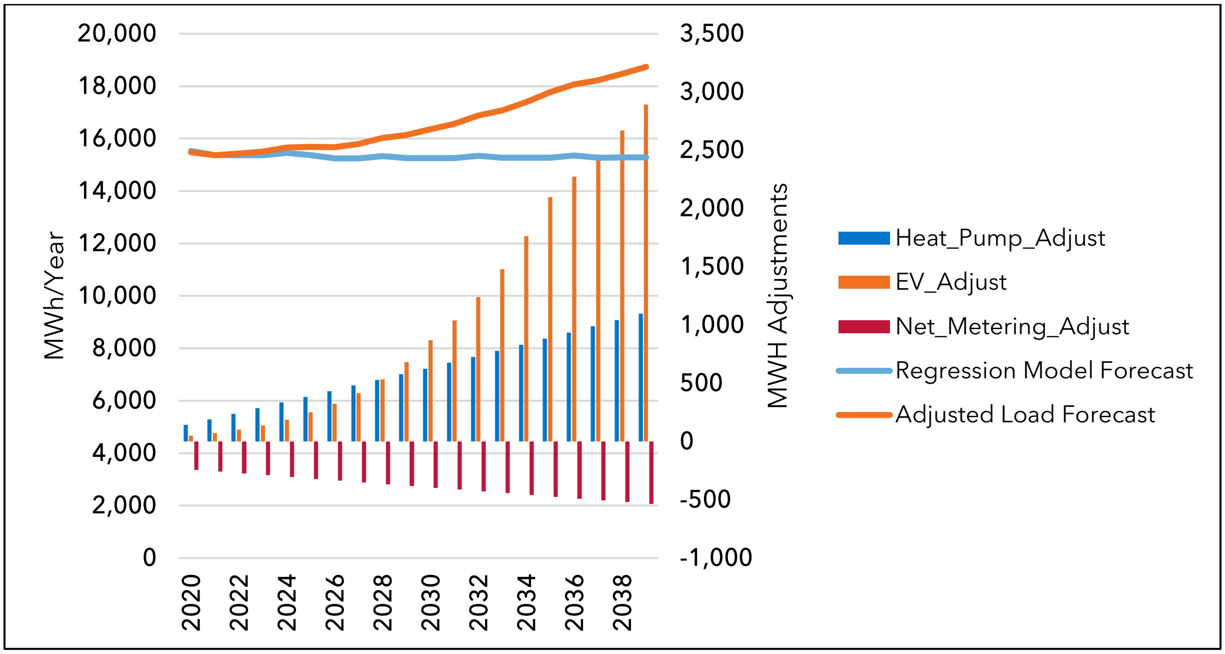
Table 6 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is declining by 0.1% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 1.0% per year.

Table 6: Adjusted Energy Forecast (MWh/Year)

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	**1**	15,528	142	50	-244	15,477
2025	**6**	15,373	384	251	-320	15,688
2030	**11**	15,258	625	870	-397	16,357
2035	**16**	15,271	883	2098	-474	17,778
2039	**20**	15,281	1097	2892	-535	18,736
CAGR		**-0.1%**	**10.7%**	**22.5%**	**4.0%**	**1.0%**

The Adjusted Forecast is the result of high CAGRs for CCHPs (10.7%) and EVs (22.5%). But during the first three years of the forecast, these two trends are mostly offset by the net metering program, which grows by the historical three-year average of 4.0% per year. By 2023, the impact of CCHPs and EVs is greater than the impact of net metering, and the load begins to grow from that year forward.

Figure 3: Adjusted Energy Forecast (MWh/Year)



The accuracy of the underlying regression model is excellent at 95.5% adjusted R-squared, and the mean absolute percent error (MAPE) is low at 1.19%. While all of the trends in the adjustments are uncertain, they are expected to cause significant load growth after 2030.

Energy Forecast – High & Low Cases

To form a high case, we assumed that the CAGR for CCHPs and EV's about doubles to 25% and 40% respectively. Simultaneously, we assume that net metering penetration stops at today's levels. At these growth rates, 2039 energy demand rises by over 300% compared to 2020 electricity use, a result that is driven by the 40% CAGR for EVs. Because of the nature of compound growth, the increase in energy demand does not start to snowball until after 2030. As a result, there is ample opportunity to monitor these trends during the annual budget cycles and the tri-annual IRP cycles.

Table 7: Energy Forecast – High Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	**1**	15,528	142	50	-244	15,477
2025	**6**	15,373	435	267	-244	15,832
2030	**11**	15,258	1,326	1,436	-244	17,777
2035	**16**	15,271	4,048	7,726	-244	26,801
2039	**20**	15,281	9,883	29,678	-244	54,599
CAGR		**-0.1%**	**23.6%**	**37.7%**	**0.0%**	**6.5%**

To form a low case, we assumed that the CAGRs for CCHPs and EVs decreases by more than 50% from the base case. In addition, we assumed that the CAGR for net metering doubles. This combination of trends is a plausible worst-case scenario, and results in a forecast that *decreases* by 0.2% per year.

Table 8: Energy Forecast - Low Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	**1**	15,528	142	50	-244	15,477
2025	**6**	15,373	182	80	-358	15,277
2030	**11**	15,258	232	129	-526	15,093
2035	**16**	15,271	296	207	-773	15,002
2039	**20**	15,281	360	304	-1051	14,894
CAGR		**-0.1%**	**4.7%**	**9.5%**	**7.6%**	**-0.2%**

Peak Forecast Methodology: The Peak & Average Method

The peak forecast regression model forecasts the load during the peak hour each day. Because utility loads are strongly influenced by temperature, this peak usually occurs during an hour of relatively extreme temperatures. In winter, this is during a very cold hour, and in summer it is during a very hot hour.

Unlike the energy forecast model, using average weather in the peak forecast model is not appropriate. Why? By definition, the coldest day and hour is always colder than average, and the hottest day and hour is always hotter than average. As a result, using average weather in the peak forecast model would result in a forecast that is biased and too low. In this context, the key question is, "How can historical weather data be used to develop an accurate representation of future weather, while still maintaining the extremes?"

The answer is the rank-and-average method, which is widely accepted[3] and effectively represents the random, real-life extremes in average historical weather. This method assigns a temperature to each day of the year that is representative of the average of the coldest (or hottest) days. It is important to highlight that the rank and average method produces a "50/50" forecast. While one may expect this to be a method for forecasting extreme weather conditions, in reality extreme weather *is* normal.

Finally, the accuracy of the peak forecast regression model is good. Based on daily data, it has an R-squared of 75%, and a MAPE of 3.34%.

[3] For a more in-depth discussion of the method, please refer to Itron's white paper on the topic. https://www1.itron.com/PublishedContent/Defining%20Normal%20Weather%20for%20Energy%20and%20Peak%20Normalization.pdf

Peak Forecast Results

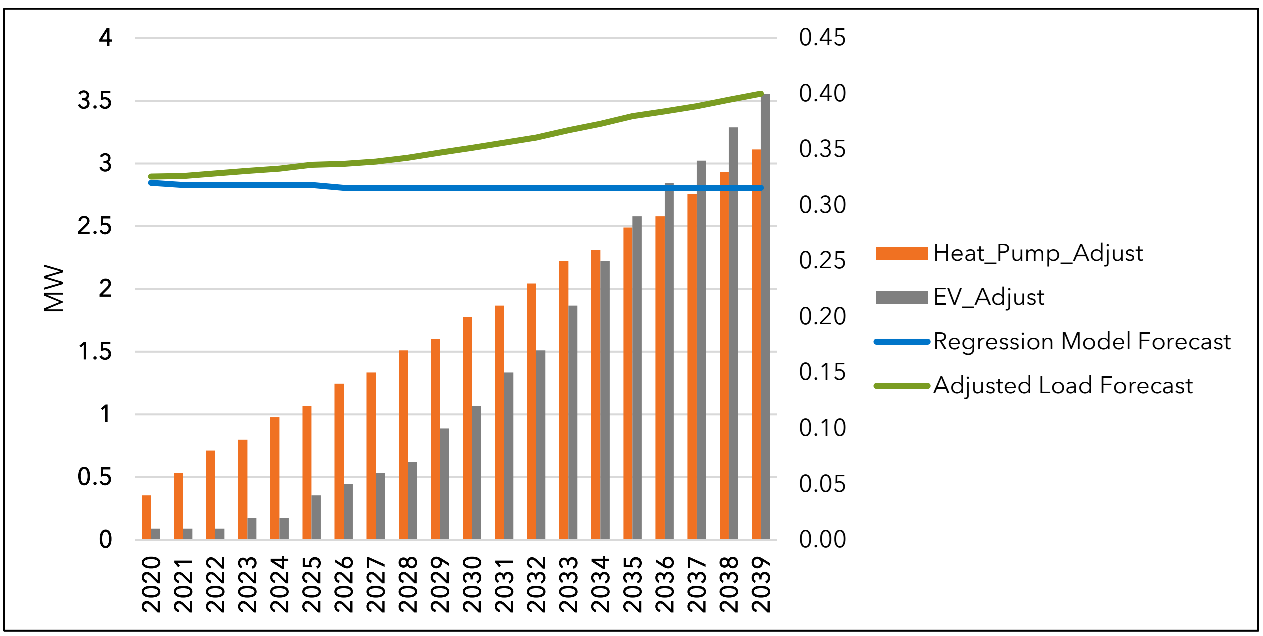
Table 9 shows the results of the Regression Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is flat. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 1.0% per year. Finally, the table shows that the timing of BVI's peak load is forecast to stay in January at 1900 (7:00 PM).

Table 9: Peak Forecast (MW)

MMM-YY	Peak Hour	Regression Forecast	EV Adjustment	CCHP Adjustment	Net Metering Adjustment	Adjusted Forecast
Jan-20	1900	2.8	0.01	0.04	0.00	2.9
Jan-25	1900	2.8	0.04	0.12	0.00	3.0
Jan-30	1900	2.8	0.12	0.20	0.00	3.1
Jan-35	1900	2.8	0.29	0.28	0.00	3.4
Jan-39	1900	2.8	0.40	0.35	0.00	3.6
CAGR		**0%**	**20.3%**	**11.5%**		**1.0%**

The Adjusted Forecast exceeds the Regression Forecast starting in 2020 due to high CAGRs for CCHPs (12.2%). By 2035, EV's are forecast to be responsible for as much peak load growth as CCHP's. The peak load forecast starts at 2.8 MW and ends at 3.6 MW. This amounts to a 1% CAGR, and can be seen in Figure 4.

Figure 4: Adjusted 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 CAGR assumptions from the high case as in the energy forecast. Even under these assumptions, peak load growth does not start to materially impact the system until 2030. Absent a step change in consumer adoption of CCHPs and EVs, electrification is not likely to produce any peak load growth for the next ten years. However, we will continue to monitor these trends annually during our budget forecasting process.

Table 10: Peak Forecast – High Case

MMM-YY	Peak Hour	Regression Forecast	CCHP Adjustment (MW)	EV Adjustment (MW)	Net Metering Adjustment (MW)	Adjusted Fcst. (MW)
Jan-20	**1900**	2.8	0.01	0.04	0.00	2.9
Jan-25	**1900**	2.8	0.04	0.12	0.00	3.0
Jan-30	**1900**	2.8	0.22	0.37	0.00	3.4
Jan-35	**1900**	2.8	1.16	1.14	0.00	5.1
Jan-39	**1900**	2.8	4.44	2.78	0.00	10.0
CAGR		**-0.1%**	**35.6%**	**23.6%**		**6.4%**

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

Forecast Uncertainties & Considerations

Because of strong growth in CCHPs and EVs, BVI's electricity demand is expected to grow by 1% annually over the forecast period. The uncertainties facing BVI stem from the growth rate of net-metering, CCHPs and EVs all of which are nascent trends that will almost certainly progress at different rates than forecast.

Net Metering

BVI presently has 25 residential scale (< 15 kW) net metered customers with a total installed capacity of about 160 kW. In addition, there is one customer who has a 31 kW array. As solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If state policy continues to be supportive of net metering in this event, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for BVI to monitor, especially if larger net metered projects are proposed. For example, a 100 kW net metered solar projects built in 2020 would represent a 50% increase in the base of installed, net metered capacity on the system. In this event, the impact would be captured in interconnection and annual power budgeting processes, and managed accordingly.

Electricity Supply

II. Electricity Supply

BVI'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 BVI 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 11 power supply resources in BVI's portfolio.

Existing Power Supply Resources

1. Barton Village Hydro Project

BVI owns and operates a 1.4 MW hydro facility on the Clyde River in Charleston, Vermont. The project provides about 20% of BVI's energy, and is certified by the Low Impact Hydro Institute (LIHI). Finally, it qualifies for Massachusetts Class II Renewable Energy Credits.

2. Fitchburg Landfill

BVI holds a 5.55% (248 kW) entitlement of a landfill gas-fired generator at the Fitchburg Landfill in Westminster, MA. The 15-year PPA started in 2012, and provides nine participating VPPSA members with 3 MW of firm energy, capacity and renewable attributes for five years. Between 2017 and 2021, the contract supplies 3 MW of firm energy, capacity and renewable attributes plus 1.5 MW of unit contingent energy, capacity and renewable attributes. From 2022 to 2026, the participants will receive 4.5 MW of unit contingent energy, capacity and renewable attributes. The contract includes an option to extend deliveries for an additional five years (2027-2031).

3. Kruger Hydro

The Kruger Hydroelectric Facilities consist of six small facilities in Maine and Rhode Island; Barker Lower, Barker Upper, Blackstone, Brown's Mill, Gardiner and Pittsfield. Their output was purchased by VPPSA under three long-term purchased power agreements signed in February 2017. BVI has an agreement with VPPSA to purchase 5.76% of their collective output. Finally, these contracts do not include RECs.

4. NextEra 2018-2022

BVI has a PPA with VPPSA to purchase firm, fixed price energy with NextEra, which provides energy from Seabrook Station, a nuclear facility in Seabrook, New Hampshire. BVI has an 3.8% (646 kW) share of the on-peak energy and a 3.6% (432 kW) share of the off-peak energy, which expires on December 31, 2022. While this resource is not qualified under any state RPS, it is tracked separately due to its carbon-free emission profile. Finally, it represents almost 30% of BVI's energy supplies in 2020.

5. New York Power Authority (NYPA) – Niagara

NYPA provides power to utilities in Vermont under two contracts: Niagara and St. Lawrence. BVI's share of the Niagara facility is 303 kW, and ends on September 1, 2025. We assume that the contract is renewed through 2039. Finally, the Niagara contract energy qualifies as a Vermont RES Tier 1 resource though the resource does not generate marketable RECs at this time.

6. New York Power Authority (NYPA) – St. Lawrence

BVI's share of the St. Lawrence facility 6 kW. The contract ends on April 30, 2032 but we assume that the contract is renewed through the rest of the forecast period.

7. Project 10

BVI has an agreement with VPPSA to purchase a portion of the power produced by Project 10, an oil-fired peaking generator located in Swanton, VT. BVI's share of Project 10's benefits and costs is 2.16%, and we assume that Project 10 is available throughout the forecast period.

8. Public Utilities Commission (PUC) Rule 4.100

BVI is required to purchase power from small power producers through Vermont Electric Power Producers, Inc. (VEPP Inc.), in accordance with PUC Rule 4.100. BVI's share of VEPPI power in 2018 was 0.2495%, and the current contracts between VEPP Inc. and its power producers will expire in 2020. We assume that there are no new participants in the 4.100 program for the rest of the forecast period. This is consistent with the relatively recent changes to Rule 4.100 that returned PURPA purchasing obligations to the host utility.

9. Public Utilities Commission (PUC) Rule 4.300

BVI is required to purchase power from small power producers through the Vermont Standard Offer Program, in accordance with PUC Rule 4.300. Some of the Standard Offer resources are configured as load-reducers and are not settled in the wholesale markets, resulting in lower reported loads. BVI's share of Standard Offer power in 2018 was 0.27%.

10. Ryegate Facility

BVI receives power from the Ryegate biomass facility, a 20.5 MW generator in East Ryegate, Vermont. In 2018 BVI received 0.2658% of the energy from the plant. Under Vermont statutes, Ryegate is the only plant eligible to meet 30 V.S.A. § 8009, and at this time, we have assumed that there may be a renewal of the current contract upon expiration. As a result, we assume that the generator is available throughout the forecast period. Currently BVI is entitled to a portion of the RECs produced by the facility.

11. Market Contracts

BVI meets the remainder of its load obligations through ISO New England's day-ahead and real-time energy markets, and through contracts (physical and financial) that are less than five years in duration. Market purchases range in size, duration, and counterparty, and are designed to balance BVI's supply resources with its load obligations in ISO New England's markets.

Table 11 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) are shown to show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed-price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits[4] (RECs), that is indicated in the seventh column, followed by the resource's expiration date and whether we assumed that it would be renewed until 2039.

Table 11: Existing Power Supply Resources

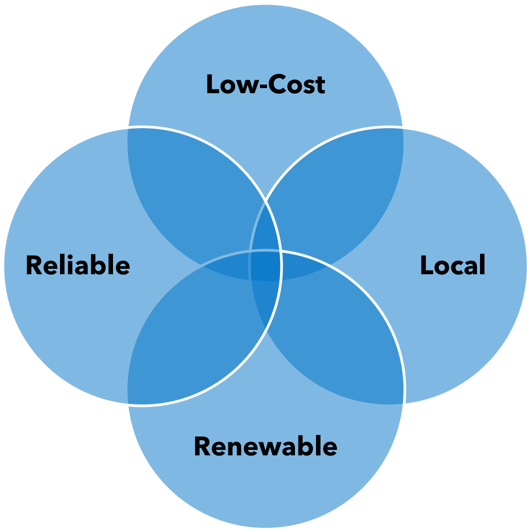
Resource	2020 MWH	% of MWH	2020 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2039
Barton Hydro	3,693	23%	0.000	Intermittent	Fixed	✓	Life of unit.	Yes
Fitchburg Landfill	1,874	12%	0.186	Firm	Fixed	✓	12/31/31	No
Kruger Hydro	1,458	9.2%	0.091	Intermittent	Fixed	✓	12/31/37	No
NextEra 2018-22	4,675	30%	0.0	Firm	Fixed	✓	12/31/22	No
NYPA – Niagara	1,756	11%	0.303	Baseload	Fixed	✓	09/01/25	Yes
NYPA – St. Law.	128	0.8%	0.008	Baseload	Fixed	✓	04/30/32	Yes
Project 10	13	0.1%	0.835	Dispatchable	Variable		Life of unit.	Yes
PUC Rule 4.100	71	0.5%	0.010	Intermittent	Fixed		2020	No
PUC Rule 4.300	407	2.6%	0.003	Intermittent	Fixed	✓	Varies	No
Ryegate Facility	433	2.7%	0.051	Baseload	Fixed	✓	10/31/21	Yes
Market Contracts	1,317	8.3%	0.0	Firm	Fixed		< 5 years.	N/A
Total MWH	**15,825**	**100%**	**1.487**					

[4] Note that RECs are defined broadly in this table, and that the "emissions attributes" from non-renewable (but also non-carbon emitting) resources such as nuclear are included in this table.

Future Resources

BVI 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 and stabilize electric rates.
- ✓ **Local** resources are located within the Northeastern Vermont Development Association (NVDA) area or within Vermont.
- ✓ **Renewable** resources meet or exceed RES requirements
- ✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

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

Category 1: Extensions of Existing Resources

This plan assumes that three existing resources are extended past their current expiration date. These include NYPA, Project 10, and Ryegate. The most crucial of these is Project 10, which supplies over 95% of BVI's capacity. Where resource needs remain, market contracts will be used to supply them.

1.1 Market Contracts

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

Category 2: Demand-Side Resources

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

Category 3: New Resources

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

3.1 Wind Generation (On and Off-Shore)

On-shore wind projects continue to be developed in New England, and entitlements to such projects can often be negotiated at competitive prices. RECs are often bundled into the PPA, making this resource a good fit for the low-cost and renewable criteria. Off-shore wind projects are in development, but the costs remain substantially higher than for on-shore wind. As a result, BVI would approach such projects with more reserve.

3.2 Gas-Fired Generation

As Project 10 approaches an investment in a major overhaul and the requirements for reserves, voltage support and other ancillary services shift, BVI will investigate simple and combined cycle (CC) generation. This includes entitlements to new or existing plants in New England, and to traditional peaking generation which continues to provide reliable peak-day service to the New England region. It should be noted that as a participant in ISO New England's markets, the marginal cost of supply is set by these same resources, and that the benefit of owning an entitlement in one is primarily to reduce heat rate risk.

3.3 Solar Generation

Solar development is increasingly common and cost-effective, particularly at utility scales. Plus, it can be deployed locally. Furthermore, solar is expected to be the primary technology that is employed to meet its Distributed Renewable Energy (Tier II) requirements under RES. For these reasons, solar is likely to be a leading resource option, and BVI will continue to investigate solar developments both within its service territory and outside of it.

3.31 Net Metering

While net metering participation rates are presently modest and are forecast to grow modestly, BVI 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 take off but the costs of the existing program would likely cause upward rate pressure[5]. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 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. Like all existing resources, price negotiations begin at or near prevailing market prices. As a result, existing hydro generation could be both low-cost (or at least at market) and renewable.

3.5 Battery Storage

Any discussion of future resources would be remis without including battery storage. While still in its initial phase of commercialization, there are six use cases where storage is being installed. According to a recent analysis by Lazard[6], use cases fall into two categories:

1. **In-Front-of-the-Meter**
    a. Wholesale (Used as a replacement for peaking generation.)
    b. Transmission and Distribution (Used to defer or replace traditional T&D investments.)
    c. Utility-Scale (Solar + Storage)

2. **Behind-the-Meter**
    a. Commercial & Industrial (Used as a standalone way to reduce demand charges.)
    b. Commercial & Industrial (Solar + Storage)
    c. Residential (Solar + Storage)

All of the In-Front-of-the-Meter use cases are large-scale, and small public power utilities like BVI may be best served by participating in such projects as a joint owner or entitlement holder, not the lead participant. However, where local T&D constraints are present or when utility-scale solar plus storage sites are being developed, BVI will work through VPPSA to quantify the business case. Similarly, the business case for Behind-the-Meter applications will be quantified as those opportunities are identified.

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[5] An excellent discussion of net metering and rate-design policy issues by Dr. Ahmad Faruqui can be found in the October 2018 issue of Public Utilities Fortnightly. https://www.fortnightly.com/fortnightly/2018/10/net metering-faq

[6] For a current analysis and list of use cases, please refer to the "Levelized Cost of Storage Analysis – Version 4.0", Lazard, November 2018. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

Regional Energy Planning (Act 174)

As part of the Northern Vermont Development Association (NVDA), BVI is part of a Regional Energy Plan[7] that was certified by the Department of Public Service on June 26, 2018. According to NVDA's Energy Plan, the aim is "to guide the region's energy development for the next eight years in 24 support of Vermont's 2016 Comprehensive Energy Plan (CEP), which contains the following goals:

- Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 26 2050.
- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 28 90% by 2050.
- Achieve three renewable end-use sector goals for 2025: 10% transportation, 30% buildings, 30 and 67% electric power."[8]

The full plan is included in the appendix, and all future resource decisions will be made with this plan in mind. Specifically, BVI will consult with the NVDA on resource decisions that involve potential siting of new resource in Vermont.

[7] The full plan can be found at http://www.nvda.net/regional-plan.php.

[8] NEK Regional Plan, Chapter 2: Energy, NVDA 2018, Page 2

Resource Plan

III. Resource Plans

Decision Framework

BVI will generally evaluate major policy decisions, such as resource acquisitions, using the integrated financial model developed in this IRP. The primary quantitative evaluation metric will be the impact that a decision has on BVI's retail cost of service per kWh over time. (i.e the effect on the rate trajectory)

When evaluating significant decisions, BVI will identify the key variables whose potential range of possible outcomes (due to uncertainty) has the largest impact on the retail costs of service per kWh. BVI will consider the impacts on potential decisions of changes from the base case assumptions to assist in evaluating the risks associated with the decision. This analysis could include evaluating ranges of potential values for the key variables either via simple replacement of the base assumptions in either the power supply or the integrated financial model as appropriate. Another potential (and similar) evaluation would be to review the decision under extreme (but improbable values) to consider how sensitive the decision is to unexpected outcomes.

Some decisions, such a simple or short-term resource acquisitions, may not have integrated effects. In such cases, the impact of the resource decision on power costs may be used as a proxy for the relative impact on overall retail costs per kWh.

For example, a simple choice between two resources could be evaluated in this streamlined manner. (Assuming that the resources do not impact non-power supply costs, retail sales volumes, or are not needed under all load forecast cases.) Decisions with small relative impacts may not warrant detailed evaluation at all. It is important to scale the effort spent evaluating a decision, to its potential impact on the utility. Larger decisions that impact power supply costs, as well as non-power-supply costs and/or sales volumes would generally require the use of the full financial model to evaluate.

Any quantified potential impact on rates, determined either through the power supply or integrated financial model, will be considered in conjunction with other metrics that are less easily converted to numerical values in the final decision-making process. Such factors might include resource diversity, risk of fundamental changes in market rules, and other factors.

Major Decisions

As the following sections will explain, BVI faces a series of potential risks and accompanying resource decisions that can prudently fulfill its energy, capacity and RES obligations in the coming years. These include:

1. **Extend the NextEra Contract:** The expiration of the NextEra contract on 12/31/2022 not only represents over 30% of BVI's energy supply, but also its largest source of emissions free electricity. As a result, the analysis quantifies the cost of a long-term (2023-2039) PPA at the same volumes, but at levelized market prices.

2. **Long-Term Hydro and REC PPA:** The following analysis will illustrate how a 1.5 MW hydro PPA with Tier I eligible RECs could reduce market price risk and cost.[9]

3. **Long-Term PV and REC PPA:** The following analysis will illustrate how a 0.5 MW PV PPA with Tier II eligible RECs could reduce market price risk.

[9] This size PPA would equate to the size of the NextEra contract, and is deliberately undersized compared to the Tier I RES requirements so as not to make BVI long on energy supplies. For additional information, please read ahead to the Tier I – Total Renewable Energy Plan.

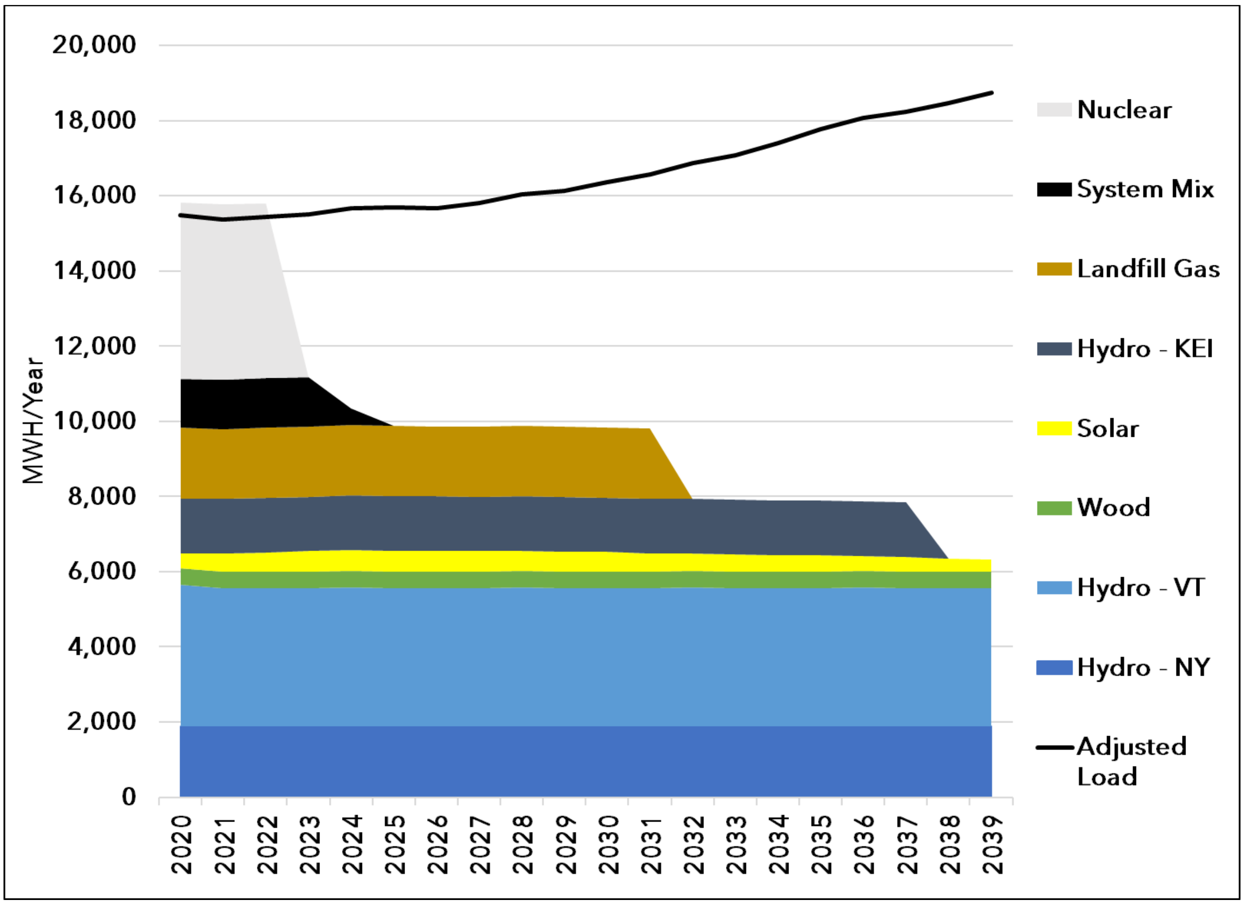
Energy Resource Plan

Figure 6 compares BVI's energy supply resources to its adjusted load. The most immediate resource decision is the expiration of the NextEra contract on 12/31/2022, which represents about 30% of BVI's energy supply. The next resource decision occurs as current market contracts expire is the expiration of the current market contracts on 3/31/2024, which represent about 8% of BVI's energy supply. The next resource expirations don't occur until the 2030s.

Leading options to replace these two contracts include:

- NextEra: Renegotiate the NextEra contract and extend its term,
- Solar: Sign a PPA for a solar plant to provide energy and Tier II RECs,
- Existing Hydro: Signing a PPA for an existing hydro plant to provide energy and Tier I RECs, and
- Market Contracts: Signing a PPA for market energy supplies.

Figure 6: Energy Supply & Demand by Fuel Type



The impact of these two resource expirations on the portfolio is summarized in Table 12. Because the price of the NextEra contract is presently above the market price forecast, its expiration could potentially reduce rate pressure. It will have no impact on RES compliance, but because it includes emissions free nuclear attributes, it will increase BVI's emissions rate if it is not replaced with another emissions free resource. The impact of the market contracts' expiration is not expected to impact rates because they are priced very close to today's market price forecast.

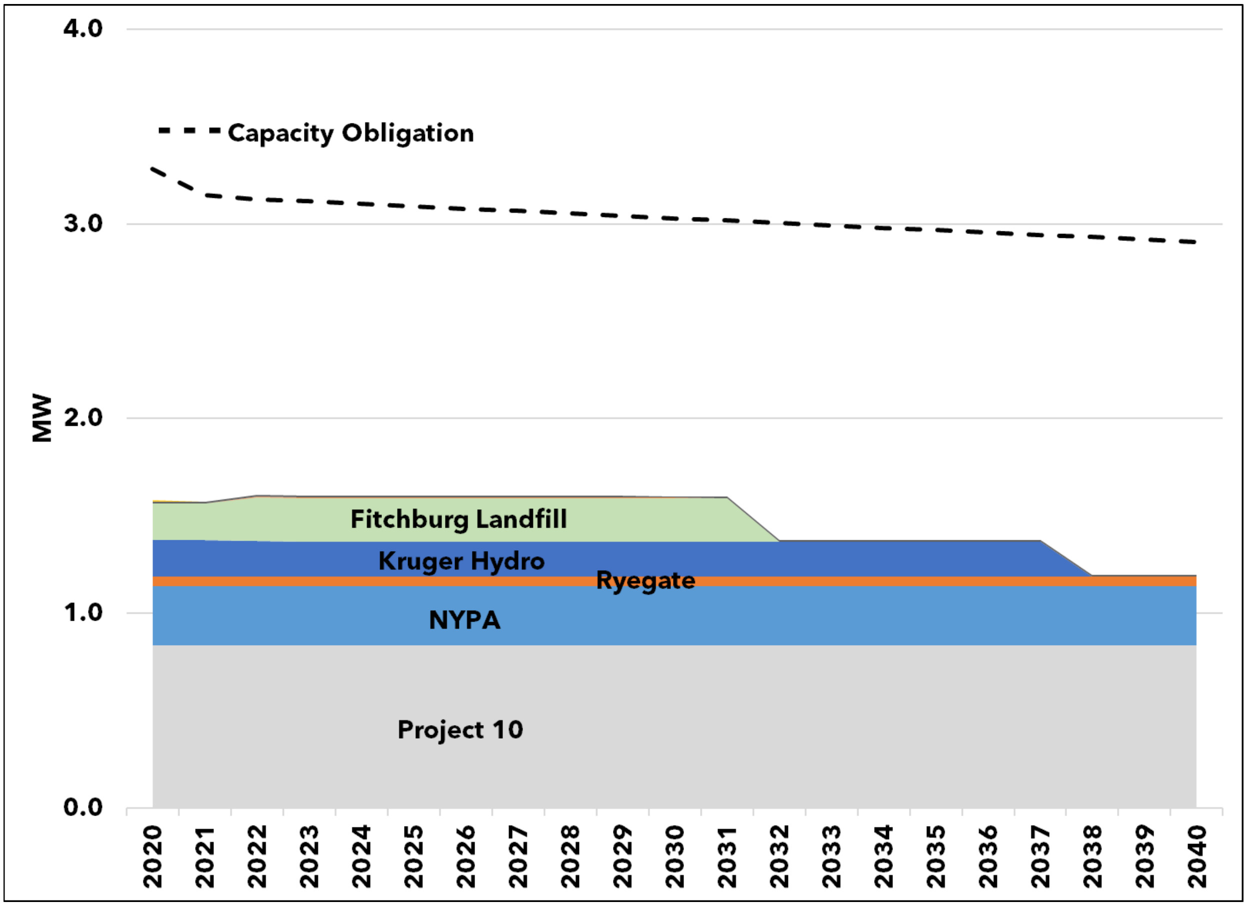
Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
1. NextEra 2018-2022	2023+	30%	Beneficial	None
2. Market Contracts	2024+	8%	Neutral	None

Capacity Resource Plan

Figure 7 compares BVI's capacity supply to its capacity obligation. Project 10 provides about half of BVI's capacity, but NYPA, Ryegate, Kruger Hydro and the Fitchburg Landfill also produce some capacity.

Figure 7: Capacity Supply & Demand (Summer MW)



Because the Barton Hydro has not produced any energy at ISO-NE's annual peak in three of the past four years, it does not appear here as a capacity resource. Depending on hydrological conditions, it has produced up to 500 kW at the coincident peak, but this does not appear to be likely based on recent experience.

BVI's capacity supplies are only expected to fulfill about half of its capacity obligation in the 2020s. As a result, a long-term capacity resource that is priced at or below today's market prices would be beneficial. This can include the hydro PPA from the previous section or a conventional peaking resource like Project 10.

Absent a new resource acquisition, maintaining the reliability of BVI's largest capacity resource, Project 10, will be the key to minimizing BVI's capacity costs, as explained in the following section.

ISO New England's Pay for Performance Program

Because BVI is part of ISO New England, its capacity requirements are pooled with all of the other utilities in the region. As a result, BVI is provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance[10] (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 BVI'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, BVI could receive up to a $1,300 payment or pay up to a $1,300 penalty during a one-hour scarcity event. This represents a range of plus or minus 5% of BVI's monthly capacity budget. However, such events are not expected to occur more than a few times a year (if at all), and frequently last less than one hour.

Table 13: Pay for Performance Ranges for One Hour of Project 10 Operation[11]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$2,000/MWH	-$500	$300	$1,300
15,000	$2,000/MWH	-$800	$0	$1,000
20,000	$2,000/MWH	-$1,000	-$200	$800
25,000	$2,000/MWH	-$1,300	-$400	$600

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

[11] 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 Requirements

BVI's obligations under the Renewable Energy Standard[12] (RES) are shown in Table 14. Under RES, BVI must purchase increasing amounts of electricity from renewable sources. Specifically, its Total Renewable Energy (Tier I) requirements rise from 59% in 2020 to 75% in 2032, and the Distributed Renewable Energy[13] (Tier II) requirement rises from 2.8% in 2020 to 9.4% in 2032. Note that this IRP assumes that the RES requirements are maintained at their 2032 levels throughout the rest of the study period.

Table 14: RES Requirements (% of Retail Sales)

Year	Tier I (A)	Tier II (B)	Net Tier I (A) - (B)	Tier III
2020	59%	2.80%	56.20%	2.67%
2021	59%	3.40%	55.60%	3.33%
2022	59%	4.00%	55.00%	4.00%
2023	63%	4.60%	58.40%	4.67%
2024	63%	5.20%	57.80%	5.34%
2025	63%	5.80%	57.20%	6.00%
2026	67%	6.40%	60.60%	6.67%
2027	67%	7.00%	60.00%	7.34%
2028	67%	7.60%	59.40%	8.00%
2029	71%	8.20%	62.80%	8.67%
2030	71%	8.80%	62.20%	9.34%
2031	71%	9.40%	61.60%	10.00%
2032	75%	10.00%	65.00%	10.67%
2033-2039	75%	10.00%	65.00%	10.67%

Under RES, Tier II is a subset of Tier I. As a result, we subtract the Tier II percentage from the Tier I percentage to get the Net Tier I requirement in the fourth column. Notice that the net Tier I requirement declines every 2nd and 3rd year until the Tier I requirement increases. When these percentages are multiplied by the forecast of retail sales, the result is a seesaw effect where the Net Tier I requirement declines every 2nd and 3rd year. This can be seen more clearly in Figure 8 in the next section.

The final column shows the Energy Transformation (Tier III) requirement. Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tier I and Tier II requirements. And unlike the Tier I & II requirements…which count only electricity that is produced and consumed in an individual year[14]…Tier III programs account for the "lifetime" the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2020, the fossil fuel savings from that CCHP are counted such that the full ten-years of the CCHP's expected useful life accrue to the 2020 Tier III requirement.

[12] For more information on the RES program, please visit https://vppsa.com/energy/renewable-energy-standard/.

[13] Distributed Renewable Energy must come from projects that are located in Vermont, are less than five MW in size, and are built after June 30th, 2015.

[14] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

Table 15: Alternative Compliance Payment[15] ($/MWH)

Year	Tier I	Tier II & III
2020	$10.00	$60.00
2021	$10.22	$61.32
2022	$10.44	$62.67
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

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, II or III credits in a particular year, then any deficit is multiplied by the ACP, and the funds are remitted to the Clean Energy Development Fund (CEDF).

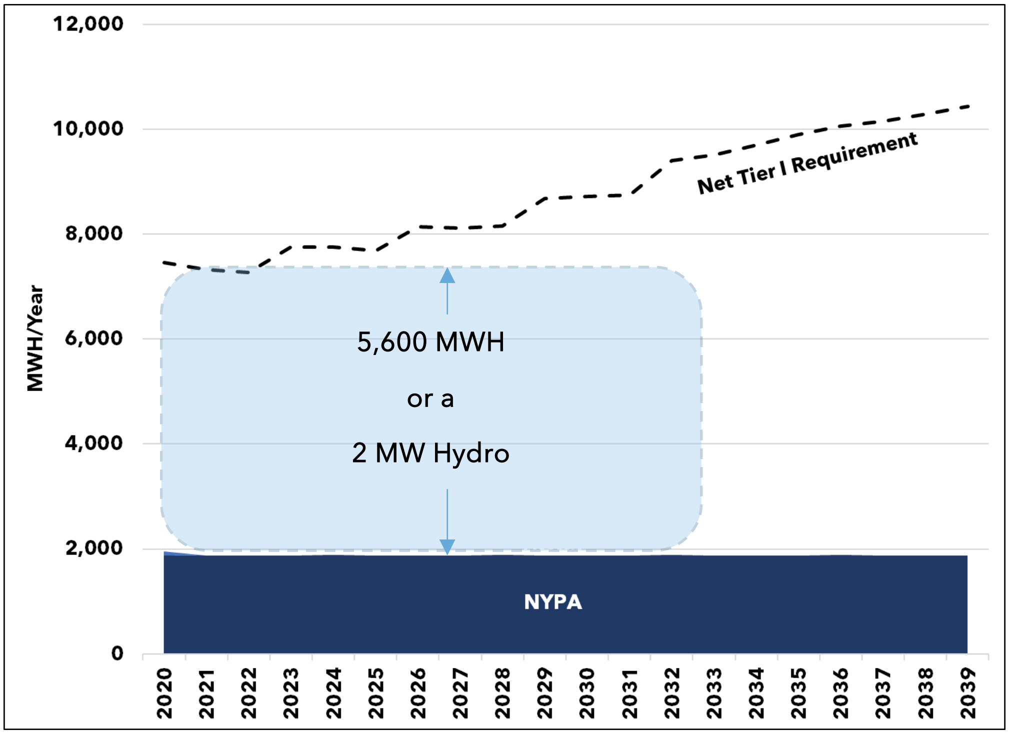
Finally, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP. Alternatively, utilities may petition PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

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

Tier I - Total Renewable Energy Plan

Between 2020 and 2024, BVI's Net Tier I requirement is about 7,500 MWH per year. The only resource that contributes to meeting it is NYPA, and the (miniscule) remainder of PUC's 4.100 program. NYPA represents about 1,900 MWH per year or 25% of BVI's Net Tier I requirement. Through 2024, the Net Tier I deficit is about 5,600 MWH per year.

Figure 8: Tier I - Demand & Supply (MWH)



In the early years of the 2020s, BVI is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). These are presently the lowest cost source of Tier I compliant RECs in the region, and their price has ranged from a low of $0.25 to a high of $2.50 per MWH over the past four years. At the current price of $1.50/MWH, the cost of complying with Net Tier I in the 2020 to 2024 period would be about $8,800 per year.

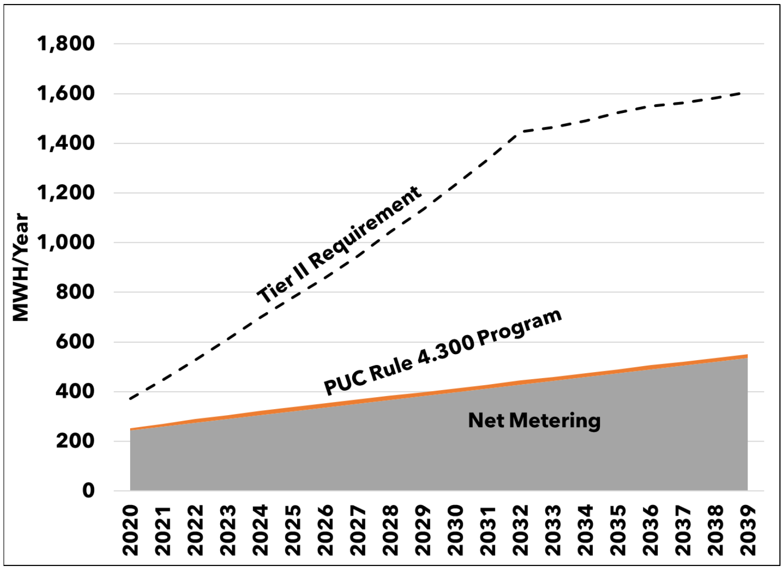
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 PPA creates an opportunity to purchase a resource that provides both energy and RECs. The 5,600 MWH per year deficit is equivalent to a 2.0 MW hydro facility[16], which is 33% larger than the hydro that would be necessary to replace the NextEra MWH. As a result, we have sized the hydro PPA to meet BVI's energy requirements, not it's Tier I requirements. This volume is 1.5 MW. If the output from a hydro resource of this size and capacity factor was purchased (including RECs), the Net Tier I deficit between 2020 and 2024 would fall to about 1,000 MWH per year. To fulfill the entire Net Tier I requirement through 2032, a 2.5 MW hydro facility (7,200 MWH per year) would be necessary. This size hydro resource would almost maintain 65% Net Tier I after 2032.

[16] We have assumed a 32% capacity factor, which results in roughly 5,600 MWH per year.

Tier II - Distributed Renewable Energy Plan

The dashed line in Figure 9 shows BVI's Distributed Renewable Energy[17] (Tier II) requirement, which rises steadily from 350 MWH in 2020 to 1,300 MWH in 2032. Between 2020 and 2024, the net metering program (plus a small contribution from PUC's 4.300 Program) is expected to fulfill 14% of BVI's Tier II requirement. As a result, another Vermont-based renewable resource(s) will be required[18].

Figure 9: Tier II – Demand & Supply (MWH)



The size of the solar resource that is required to fulfill Tier II starts at 100 kW in 2020 and rises to about 600 kW in 2032. As part of a partnership between VPPSA and Encore Renewable Energy[19], BVI is planning to enter into a PPA for a share of a 1 MW solar project that is being developed in Jacksonville, VT. In the event that this project is built, BVI plans to have enough RECs to fulfill its Tier II requirement in the early 2020s, plus a surplus that can be used toward its Energy Transformation requirement.

A second solar project will be required during the second half of the decade, but we will leave this resource assessment to a subsequent IRP.

In the event that the Jacksonville solar project is not built, then BVI will most likely work with other VPPSA members to develop a solar project elsewhere in Vermont. In any years where there is a deficit, BVI plans to purchase qualifying RECs to meet its TIER II requirement. In recent years, the cost of these RECs has been 60% to 90% lower than the ACP.

[17] The TIER II requirement is also known as "Tier 2".

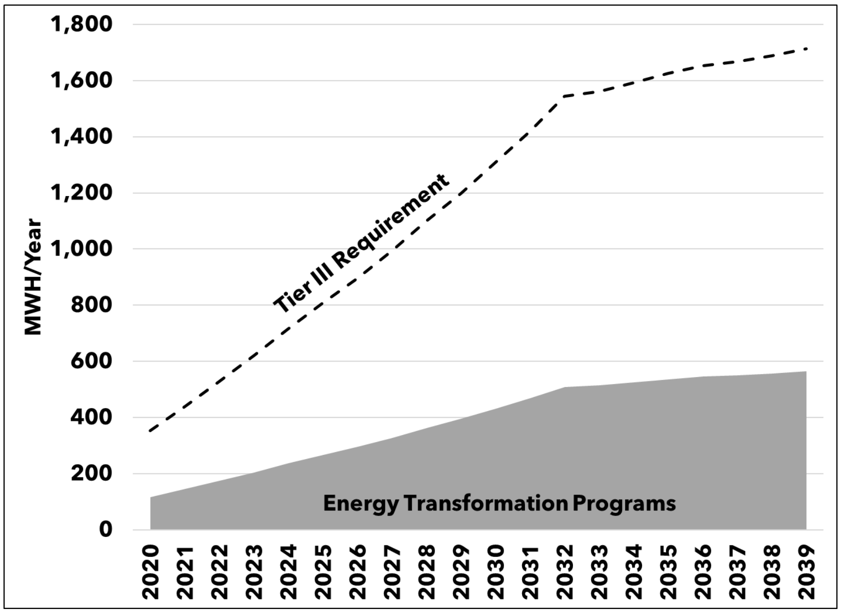
[18] We assume that any surplus MWH are not banked, and are instead applied to BVI's Energy Transformation requirement.

[19] https://encorerenewableenergy.com/vermont-public-power-supply-authority-and-encore-renewable-energy-partner-to-increase-solar-generation-for-member-communities/

Tier III - Energy Transformation Plan

The dashed line in Figure 10 shows BVI's Tier III requirements, which rise from about 225 MWH in 2020 to about 925 MWH in 2032. Energy Transformation programs are presently budgeted to fulfill about a third of the requirement, and are shown in the gray-shaded area of Figure 10. These programs[20] cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. For perspective, the Tier III requirement is equivalent to installing 20-50 CCHP[21] per year between 2020 and 2025.

Figure 10: Energy Transformation Supplies



BVI is expected to have a substantial deficit which is illustrated in Figure 10. This deficit is equivalent to 16 – 69 CCHP's per year or 140 – 620 kW of solar PV. Alternatively, the deficit could be fulfilled by a custom Tier III project.

Whatever the deficit or surplus position, BVI will follow a four-part strategy to fulfill its Tier III requirements.

1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Develop and complete the Jacksonville Solar or a comparable, Vermont-based solar project, and/or
4. Purchase a surplus of Tier II qualifying renewable energy credits.

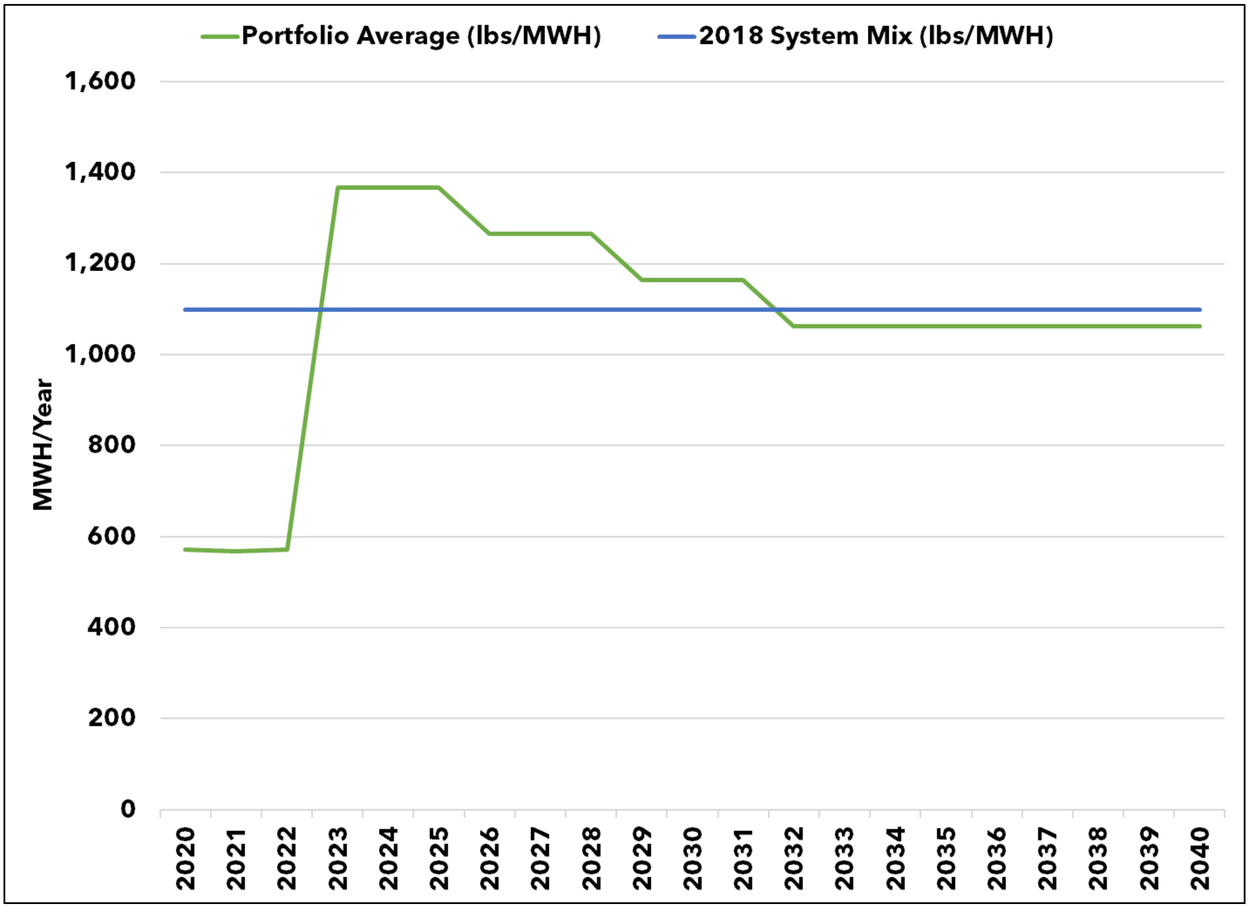
[20] More detail on these programs can be found in Appendix B (VPPSA's 2019 Tier 3 Annual Plan) and on VPPSA's website.

[21] This estimate is based on 15 MWH/CCHP of net lifetime savings, which is an average of all listed single-zone CCHP measures in the 'Act 56 Tier III Planning Tool FINAL PY2019.xls' spreadsheet.

Carbon Emissions and Costs

Figure 11 shows an estimate of BVI's carbon emissions rate compared to the 2018 system average emissions rate in the New England region[22]. The emissions rate between 2020 and 2022 is just under 600 lbs/MWH, but it rises steeply to 1,367 lbs/MWH in 2023 because the NextEra PPA expires, and its MWHs are being supplied by fossil fuels. We assume that the carbon emissions rate of these MWH will be equal to the 2018 NEPOOL Residual Mix which is a proxy for the fossil fuel emissions rate in the region.[23]

Figure 11: Portfolio Average Carbon Emissions Rate (lbs/MWH)



The carbon emissions rate starts to decline in 2024 as a result of increasing RES requirements and drops below the system average by 2028. This decline continues until 2032, when the RES requirements end. After 2032, the emissions rate remains stable because this plan assumes that the RES requirements will be maintained.

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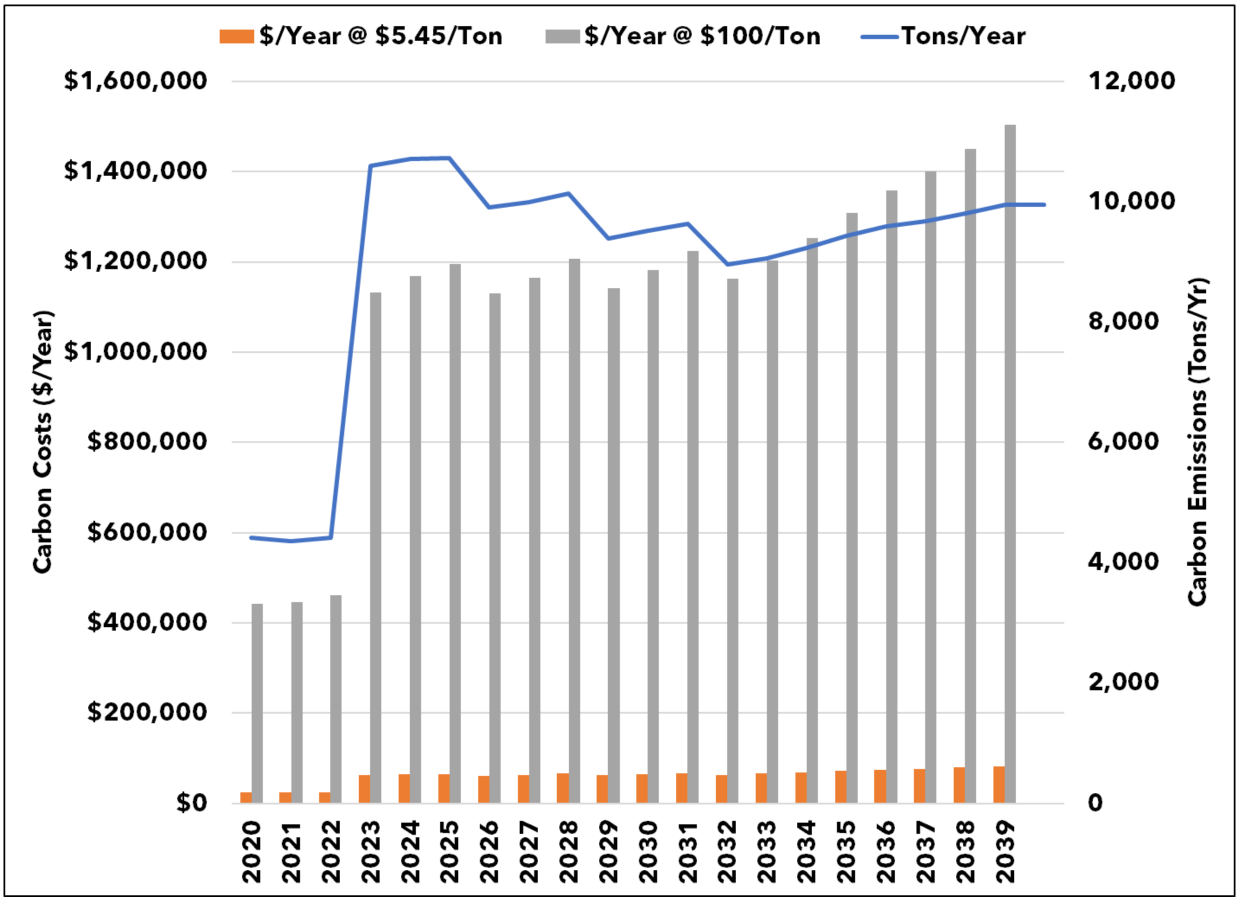
[22] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

[23] For the current value of the NEPOOL Residual Mix, please visit https://www.nepoolgis.com/public-reports/.

These emissions rates were multiplied by the Adjusted Load Forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 4,000 tons/year in 2020 up to 10,000 tons/year in 2023, and then decline as the RES requirement increase through 2032. Thereafter emissions remain stable, and only rise with load growth.

The costs of these emissions were calculated using two sources, the 2019 Regional Greenhouse Initiative Auction[24] (RGGI) results ($5.45/ton) and the 2018 Avoided Cost of Energy Supply[25] (AESC) study ($100/ton). Using RGGI prices (plus inflation), the cost of carbon emissions in 2020 is $24,000 per year and about $63,000 per year in 2032. Using AESC prices, the range is $440,000 per year in 2023 up to almost $1,200,000 per year in 2032.

Figure 12: Carbon Emissions (Tons/Year) and Costs ($)



24 https://www.rggi.org/auctions/auction-results/prices-volumes

25 https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf

Conclusions

There are three decisions facing BVI that the financial analysis will quantify.

1. New Long-Term Hydro PPA
   Q1: What are the costs and benefits of a 1.5 MW Hydro PPA at levelized market prices?

2. New Long-Term Solar PPA
   Q2: What are the costs and benefits of a 500 kW Solar PPA?

3. Extension of the NextEra PPA
   Q3: What are the costs and benefits of extending NextEra volumes through 2039 at levelized market prices?

In addition, we quantify one load related question.

4. 1% CAGR

   Q4: What is the rate impact of 1% compound annual load growth?

Transmission & Distribution

IV. Electricity Transmission & Distribution

Transmission and Distribution System Description:

BVI has entered an interim contract arrangement with Vermont Electric Coop (VEC) to provide field operations, system maintenance and 24-7 on-call service for emergency, restoration and safety related issues. This agreement allows BVI to temporarily operate with somewhat reduced staffing levels while it evaluates the most appropriate operational structure for maintaining infrastructure and providing quality customer service going forward. BVI continues to staff administrative, billing and customer service functions from its Barton offices, with support from Trustees and VPPSA, as needed.

Transmission System Description:

BVI co-owns, with the Village of Orleans Electric Department (OED), approximately 5.5 miles of 46 KV transmission line that connects the Heath Substation to a side tap on a co-owned BVI/OED/VEC transmission line. This side tap is located approximately ¼ mile south of I-91 on Route 16 in Barton. The rebuild of this transmission line was completed in 2014.

BVI also co-owns, with OED and VEC, approximately 10 miles of 46 kV transmission line which extends from the VELCO Irasburg Substation to the aforementioned side tap located on Route 16.   BVI's pole ownership share for this line is approximately 12%; VEC has managed the pole replacement process during the past few years.   Sixty remaining poles are expected to be replaced during 2020 and 2021.

Distribution System Description:

BVI has just over 200 miles of distribution lines in a radial feed configuration with two 13.2kV Y/7.6kV feeders from the Heath substation serving customers in the Village of Barton, Sutton, Westmore, Brownington, Town of Barton, Charleston, and Irasburg.   Some older areas of the system step down further to 2.4kV delta.

BVI-Owned Internal Generation:

BVI owns and operates an internal hydro-electric generation resource.

Barton Village Hydroelectric Project:

The Barton Village Hydroelectric Project located in West Charleston operates on FERC License 7725-000—Vermont.

BVI created a new position in 2019 for a hydro-electric manager who also provides part-time operational control. The manager also utilizes other village staff and contractors as needed.

The facility can be monitored remotely, and the facility can automatically shut down if river levels do not meet minimum flow requirements.

Barton Village Hydroelectric Project is a two-turbine project. Turbine one was constructed and put into service in 1930 then rebuilt in 2008. This unit is a Francis vertical turbine manufactured by James Leffel & Co. coupled to a General Electric generator. It operates at 514 r.p.m 950 rated horsepower, 74 rated head, 2400 volts, frequency 60, 875 kva, with a 700kW nameplate rating.

The second unit was put into service in 1948 then rebuilt in 2009. This unit is a Francis vertical turbine manufactured by S. Morgan Smith coupled to a General Electric generator. It operates at 360 r.p.m, 950 rated horsepower, 74 rated head, 2400 volts, frequency 60, 875 kva, with a 600kW nameplate rating.

BVI replaced the majority of its penstock in 1991 and monitors the pipelines serving each turbine following the bifurcation structure for replacement. The penstock and the dam are monitored in part by following a Dam Safety Surveillance and Monitoring Plan (DSSMP) last updated in 2019.

BVI continues to invest in the hydro-electric facility. These investments include major hardware and software upgrades, a downstream fish passage added in 2015, and replacement of a low flow slide gate in 2018-2019. BVI understands that continued reinvestment in the Project is necessary. BVI qualified for a Low Impact Hydropower Institute (LIHI) Certification in 2019. The certification allows BVI to sell REC credits to markets that are looking for high quality projects. This effort is expected to provide additional revenue for facility reinvestment.

The most recent 10-year average annual production of the Barton Village Hydroelectric project is 3,990,616 kWh.

The following table summarizes the actual generation output of the hydroelectric plant for the past 10 years.

Table 16: Barton Village Hydroelectric Project Generation

Year	Total Annual Hydroelectric Generation (kWh)
2009	5,101,367
2010	4,701,286
2011	5,187,248
2012	2,769,928
2013	4,061,110
2014	3,411,541
2015	4,330,701
2016	4,091,374
2017	4,704,459
2018	3,371,743

Table 17: Barton Village Hydroelectric Project Nameplate Ratings

Unit Name	Hydroelectric Unit Nameplate Rating (kW)
West Charleston Hydro Unit 1	700
West Charleston Hydro Unit 2	600
Total	**1,300**

Barton Village Diesel Generation:

BVI has recently decommissioned a standby diesel generation system originally constructed in 1956. The building and equipment remain but fuel is no longer stored onsite.

BVI Substations:

BVI currently operates two substations. One is a jointly owned substation and the other is a substation at the Barton Village Hydroelectric Project facility.

BVI also owns approximately 15 smaller step-downs that reduce voltage from 13.2kV/7.6kV Y to 2.4 kV, which is currently the primary distribution voltage level. The substations are briefly described below.

Heath Substation:

BVI's entire load is served through the BVI-/OED co-owned Heath Substation located on Baird Road in Barton Town. The transformer has a high side voltage of 46.5kV, a low side of 13.2kv Y and a maximum transformer capacity of 10/12.5MVA. The Heath Substation has three feeders, two serving the entirety of BVI and one serving the entirety of OED. Feeder 1 for Barton serves south to the Barton Village area and feeder 2 services north to Brownington and the majority of Westmore.

Figure 13: Heath Substation

Barton Hydroelectric Substation:

BVI's hydroelectric plant is stepped up to 13.2kV Y/7.6kV from 2.4kV at the Barton Hydroelectric Substation. The transformer has a maximum transformer capacity of 2/2.3MVA. BVI has reinvested in the substation recently by replacing transformer oils.

Figure 14: Barton Hydroelectric Substation

A complete list of 7.6Kv to 2.4Kv step-downs are included below:

1. Roaring Brook, Barton Village
2. May Pond, Barton
3. Route 16, Barton
4. Elm Street, Barton Village
5. Lake Region Road, Barton
6. Chamberlain Road, Barton
7. Hinton Hill, Westmore
8. Route 5A (Westmore Main Street), Westmore
9. Telfur Hill Road, Barton
10. Lake View Road, Westmore
11. Route 5A (Snack Bar), Westmore
12. Sanderson Hill, Brownington
13. Route 5A (Hudson Road), Brownington
14. Ticehurst Road, Brownington

Circuit Description:

There are two circuits in total, the West Charleston branch and the Barton branch. The voltage of the circuits is regulated at the substation bus with 333 kVa voltage regulators. These regulators were replaced in August of 2016.

T&D System Evaluation:

System reliability is important to BVI for its customers. BVI currently relies on VEC for identification and evaluation of necessary safety and repair work and related reliability issues. VEC has been reviewing structures and equipment with BVI's part-time lineman during the past 6 months and will continue to inspect the system to identify reliability issues.

Outage Statistics

BVI evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. BVI reviews the Public Utility Commission Rule 4.900 Outage Reports, system reviews, as well as annual budgets in order to correct and/or prevent any issues that may materialize.

BVI has committed to performance standards for reliability that measure the frequency and duration of outages affecting its customers. There are two measures for the frequency and duration of outages. The Public Utility Commission'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.

BVI has committed to achieve performance levels for its distribution system below an index of 1.8 for SAIFI and 2.5 for CAIDI. BVI 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.

Table 18: BVI Outage Statistics

	Goals	2014[26]	2015	2016	2017	2018
SAIFI[27]	1.8	3.5	2.9	4.3	2.9	0.7
CAIDI[28]	2.5	3.2	6.4	5.6	5.1	2.6

BVI has a number of initiatives underway to improve reliability. Each of these initiatives is described below.

Animal guards are installed on all new services and on rebuilds. Additionally, whenever maintenance is done on existing services, animal guards are installed if they are not already in place.

Fault Indicators

BVI uses flashing light fault indicators on its transmission lines.

Other

BVI Trustees have directed staff during the past few months to evaluate budget changes since contracting with VEC to support additional vegetation management. Budget changes have moved available funds to additional contract tree trimming work. BVI staff is evaluating historic vegetation management and prioritizing high risk areas. In the short run, trimming in these high-risk areas may be limited to the most critical sections rather than undergoing complete vegetation removal. As a result, line sections containing these critical areas are expected to see a reduced trimming burden on the subsequent maintenance cycle.

Distribution Circuit Configuration

Voltage Conversion

Major system voltage upgrades from 2400 to 7620 were completed in the 1990's and early 2000's to reduce line loss. BVI continues to look for opportunities to upgrade lines from 2400 to 7620 to reduce line loss and 2400/7620 line duplications. BVI

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

[27] System Average Interruption Frequency Index

[28] Customer Average Interruption Duration Index

completed a voltage conversion to remove segments of 2.4kV delta in Brownington in 2019.

Phase balancing

BVI has no immediate plans for existing phase balancing, BVI's load is not growing. BVI is looking at phase balancing for a proposed line extension for agricultural projects in south Barton.

System Protection Practices and Methodologies;

Protection Philosophy

BVI's system protection includes transmission, substation and distribution protection. BVI has different settings because these reclosers can be used to protect a segment of the line or the entire line. Also, they can feed an adjacent circuit Each protection practice is discussed briefly below.

Transmission Protection:

BVI's transmission system is protected by multiple devices. Primarily, OED/BVI/VEC co-own an H16 breaker at the VELCO Irasburg Substation. Also, a Supervisory Control and Data Acquisition (SCADA) controlled motorized switch is located where BVI and OED's co-owned 5.5 46kV mile transmission line side taps off of the VEC/BVI/OED co-owned line on Route 16. Fuses are also located between switches that isolate the Heath Substation from the 5.5 mile 46kV line and the Heath main power transformer.

Substation Protection:

Equipment at the Heath Substation is protected by high side fuses just downstream of the Heath switches and upstream of the Heath main transformer. Additionally, reclosers are located on both West Charleston and BVI circuits.

Distribution Protection:

The distribution system protection involves a combination of distribution circuit reclosers and fuses. All side taps of the main line distribution feed are fused.

Smart Grid Initiatives

Planned Smart Grid

Beginning in 2018, BVI began participating in a multi-phased, VPPSA joint-action project intended to (1) assess individual member readiness for AMI, (2) guide participating members through an RFP process culminating in vendor and equipment selection and (3) guide members through the implementation phase. At the end of the initial assessment phase individual members will make the choice to go forward with the RFP process, or not. Upon completion of the RFP phase of the project, individual members will have the information needed to examine the business case and make a decision to commit to implementation of an AMI system, or not.

At this time BVI is participating in the initial readiness assessment phase of the project, gaining information pertaining to its initial readiness, potential required changes to staffing and operating processes, as well as potential benefits to municipal electric, water and wastewater systems. As the assessment phase wraps up later in 2019, BVI will decide whether to proceed to the RFP phase of the process.

BVI is mindful of the many facets of the evolving grid and their impact on the value of implementing AMI. Advanced metering may play a key role in taking advantage of more sophisticated rate design and load management/retention opportunities as we see continued expansion of net metering, heat pump installations, and adoption of electric vehicles.

BVI recognizes the potential value of utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison to create value for both the utility and the customer. In the absence of an AMI system, or pending development and implementation of an AMI system, BVI will explore the use of pilot programs or tariffs that may be implemented using currently available technology. Initial efforts in this area will focus on larger customers with the greatest opportunity to manage loads in a way that will reduce both system and customer costs, capture economic development/retention opportunities and reduce carbon footprint where possible.

Working with VPPSA, Efficiency Vermont, and other stakeholders, BVI stays abreast of these developments and the strategies needed to maintain a safe, reliable, and economically viable distribution system.

BVI is also mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While BVI is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and BVI's membership in VPPSA provides BVI with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, BVI endeavors to purchase and protect its IT systems (with assistance from VPPSA as needed), in a manner intended to minimize security risks to the system and its ratepayers. BVI remains mindful of the balance between the levels of cyber security risk protection and the associated costs to its ratepayers.

Other System Maintenance and Operation:

Reconductoring for Loss Reduction

BVI has been gradually replacing small conductor over the last twenty years and plans to continue to replace small aged conductors over the next ten years. Most conductors being used now are 1/0 aluminum AAAC.

Transformer Acquisition

BVI exclusively buys new and rebuilt transformers from major distributors such as WESCO. BVI will begin to look at transformer efficiencies with WESCO and other retailers to focus on life-cycle cost.

Conservation Voltage Regulation

BVI's voltage setting is done with voltage regulators at the Heath Substation. These regulators were just replaced with new units in August of 2016.

BVI does not have conservation voltage regulation.

Distribution Transformer Load Management (DTLM)

BVI does not have a formal DTLM program. BVI consults experts which make recommendations on transformers used for different applications when there are questions.

Substations within the 100- and 500-YEAR Flood Plains

There are no current plans for relocation of step-downs out of flood plains however some units that are in flood plains were elevated around the year 2000. Step-downs will be re-evaluated in the future to assess the current risks associated with each step-down/transformer.

The Utility Underground Damage Prevention Plan (DPP)

Less than 1% of BVI's customers have primary lines underground. When damage occurs, BVI handles each incident on a case by case basis. BVI 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

BVI purchases standard certified transmission and distribution equipment from established trusted vendors. The majority of the equipment is purchased from WESCO. BVI prioritizes quality equipment and following utility standards over low purchase prices.

Maintaining Optimal T&D Efficiency

System Maintenance

BVI's system maintenance includes a number of components. Each is discussed briefly below.

Substation Maintenance

BVI inspects each major substation (Heath Substation and Barton Hydroelectric Substation) on a weekly basis. Oil tests on transformers are performed once a year. BVI uses infer-red technology to inspect the system annually, and any hot spots found are taken care of as soon as possible.

Pole Inspection

BVI inspects its poles on an annual cycle and regularly while conducting field work. In addition, BVI, in conjunction with VEC, has started to create a database of pole locations. Pole location and pole identification will be the foundation of a database which tracks pole condition, size, weight, class, age, pole preservative and other relevant information for equipment replacement planning. Other relevant information captured in this database will include factors such as the importance of the pole weighted by the number of customers impacted by failure. BVI recognizes a formal organized electronic method of monitoring pole condition is the only way to manage asset replacement and is fully committed to tracking and replacing poles in this way.

Equipment

BVI performs oil testing on its main transformers once a year. Additionally, thermal imaging tests are conducted on transformers in the system with heavy loads and cutouts. BVI continues to replace ceramic cutouts on an ongoing basis even if they seem to be in good condition. BVI also performs gas testing annually on the Heath Substation transformer.

Finally, under BVI's procurement & purchase policy, BVI solicits three different quotes before making a purchase above a certain dollar threshold.

System Losses

BVI is committed to providing efficient electric service to its customers. BVI's plan for improving system efficiency involves two actions. The first action involves monitoring actual system losses. The second action is to complete projects to reduce system losses. Each of these tasks is discussed briefly below.

Actual System Losses:

BVI and OED replaced their co-owned 5.5 mile major transmission line stretching from the VEC/BVI/OED co-owned split off to the Heath Substation. This activity involved replacing poles with taller ones, as well as changing wire, conductors and metering and switching components. This upgrade was completed in order to improve the overall efficiency of the transmission system.

It is expected that the replacement of the transmission line, described above, will reduce overall line losses. BVI will also continue to look for opportunities to upgrade conductor sizes where appropriate to further reduce system losses.

Efforts to Reduce Losses:

As mentioned previously BVI continues to look for opportunities to convert outlying lines from 2400 to 7620 in order to reduce losses as well as to have unified

13,200/7620 grounded system. Voltage upgrades like this will have a significant impact on system efficiency

Transmission Losses:

As mentioned previously, the main transmission line which feeds BVI was recently replaced. It is expected that the replacement of that line will have a positive impact on system level efficiency compared to historical levels.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

BVI is starting to use NJUNS and will continue to implement this practice over the next couple of years.

Relocating cross-country lines to road-side

BVI recognizes the significant cost associated with maintaining off-road assets. BVI has a policy in place where every attempt shall be made to make all new construction road-side. Additionally, when rebuilding off-road infrastructure BVI looks carefully at relocating assets to road-side when possible. On the transmission line, where some of the lines cannot be relocated to road-side, BVI works with landowners to improve its ability to access the line and improve restoration time.

Distributed Generation Impact:

Currently, BVI has 26 solar net metering customers, with a combined total installed capacity of 191 kW. BVI had a surge of new customers in 2018, but otherwise the number is growing slowly, about 2 customers per year.

Interconnection of Distributed Generation

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

- Steady state voltage (per ANSI C84.1)
- Flicker (per IEEE 1453)
- Temporary overvoltage due to load rejection and/or neutral shift
- Effective grounding (per IEEE 1547 & IEEE C62.91.1)
- Overcurrent coordination
- Equipment short circuit ratings
- Effect of distributed generation on reverse power and directional overcurrent relays
- Voltage regulator and load tap changer control settings (bi-directional operation)
- Unintentional Islanding
- Thermal loading of utility equipment
- Power factor and reactive compensation strategy
- Impact to underfrequency load shed
- Increased incident energy exposure (arc flash)

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

Vegetation Management/Tree Trimming:

BVI has made efforts to address long-term vegetation management strategies. BVI now has the majority of the system mapped with Google Earth for aerial evaluation of field cover/roadside and cross-country areas. BVI has been able to evaluate that approximately 30 miles of the 50 miles of 7620V distribution. is located within mowed or field areas that do not require active cycles for management. Approximately 20 miles are on a 10-year cycle, however BVI estimates that fewer than 10 miles remain for the current cycle, with about 5 miles of priority 7620V feeders. The majority of this high priority trimming is not on BVI's main feeders except for sections serving remote areas of Brownington and Westmore. The 7620V areas are the arterial feeders to smaller fused step downs to BVI's 2400V system. Therefore, outages are not expected to be system wide unless there are trouble trees that disrupt service during a wind or ice event.

Starting in 2019 BVI has for the first-time used contractors that employ mechanical trimmer attachments to tracked excavators. This method of clearing was successful and BVI expects to expand this use in 2020 and beyond. The mechanical trimming method will be used at all non-roadside locations to the extent possible.

BVI will work during the next few years to evaluate the best approach to developing a trimming plan for the older segments of 2400V areas. Approximately 70-80 miles of the 150 miles will need hand trimming, specifically roadside trees that continue to age that develop canopies with branches over lines. BVI will need to evaluate its ability to apply financial resources for this work.

During the prior three years, BVI has identified that bidding tree trimming projects is challenging due to its limited size. BVI has found that contractors prefer to work for larger utilities with larger projects. BVI is considering bidding a large project every other year in order to more reliably attract the larger commercial contractors that have the capacity to complete large projects.

Since BVI has struggled with attracting contractors to complete projects, staff has been instructed to triage the system by trimming the worst areas impacting the most customers. While this work may not be considered a thorough trim of the entire width of the right-of-way, it is intended to reduce the most immediate dangers until the routine trimming cycles have addressed the entire system.

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

BVI has not used herbicides in the recent past and does not have any concrete plans to use them in the future.

The emerald ash borer has recently become an active issue in Orleans County this year. BVI is monitoring developments and coordinating efforts with VPPSA, danger tree contractors 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 BVI's territory, affected trees will be cut down, chipped and properly disposed of.

Table 19: BVI Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Sub-Transmission	Approximately 5.5	3	7-year average cycle
Distribution 7600 V	Approximately 50	20	10-year average cycle
Distribution 2400 V	Approximately 150	75	10-year average cycle

Table 20: BVI Distribution Vegetation Management Costs

	2016	2017	2018	2019	2020	2021
Amount Budgeted	$65,000	$65,000	$50,000	$40,000	$50,000	$50,000
Amount Spent (FY)	$54,000	$6,400	$22,765	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	5.4	0.64	2.3	9.5 miles to be trimmed	9.5 miles to be trimmed	9.5 miles to be trimmed

Table 21: BVI Tree Related Outages

	2014	2015	2016	2017	2018
Tree Related Outages	6	17	10	22	18
Total Outages	30	40	34	54	50
Tree-related outages as % of total outages	20%	43%	29%	41%	36%

Storm/Emergency Procedures:

BVI's storm/emergency outages are all being handled under the contract with VEC. VEC reports BVI's outages on the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. BVI believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. BVI has a representative on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties.

Previous and Planned T&D Studies:

BVI does not have any pending formal T&D studies. Distribution studies were last conducted in the 1990's and transmission studies were performed prior to the 5.5 mile 46kV upgrade. BVI will evaluate the appropriate timing and expenditure of the next study.

Fuse Coordination Study

There are no fuse coordination studies currently under way or planned for the short-term future. However, BVI continues to install fuses on side taps in order to isolate side taps to improve system robustness.

System Planning and Efficiency Studies

System Operation

BVI does not have any system operation studies currently underway nor does it have any planned. BVI will be looking at the needs of the system and the timing of conducting such studies.

Distribution System Planning

BVI does not have any pending formal T&D studies. Distribution studies were last conducted in the 1990's and transmission studies were performed prior to the 5.5 mile 46kV upgrade. BVI will evaluate the appropriate timing and expenditure of the next study.

Transmission System Planning

As already mentioned in this document, BVI and OED have completed the upgrade to the 5.5 mile 46KV line. BVI continues to work closely with OED and VEC to plan for future load growth. Structure upgrades continue on the VEC/OED/BVI co-owned transmission lines.

Capital Spending:

Construction Cost (2016-2018):

Table 22: BVI Historic Construction Costs

Barton Village, Inc.		Historic Construction		
Historic Construction		**2016**	**2017**	**2018**
Hydro	Prod	**14,656**	**6,479**	**28,168**
Land and land rights	Dist			**2,716**
Structures and improvements	Dist		**5,806**	
Station equipment	Dist	**12,738**		**2,250**
Poles, towers, and fixtures	Dist			
Overhead conductors & devices	Dist			**137,450**
Underground conduit	Dist			
Underground conductors & devices	Dist			**18,244**
Line transformers	Dist			**69,974**
Services	Dist	**292,100**		**48,772**
Meters	Dist			**63,184**
Street light & signal systems	Dist			**13,628**
Structures & improvements	Gen			
Offiice furniture & equipment	Gen			
Transportation equipment	Gen			**38,000**
Tools, shop, & garage equipment	Gen			
Power operated equipment	Gen			
Land and land rights	Trans	**114,712**		
Station equipment	Trans			
Towers & fixtures	Trans			
Poles & fixtures	Trans	**383,650**	**21,317**	**21,249**
Overhead conductors & devices	Trans	**431,478**	**12,253**	**11,539**
Construction WIP			**17,147**	**37,497**
Total Construction		**$ 1,249,334**	**$ 63,002**	**$ 492,670**
Functional Summary:				
Production		14,656	6,479	28,168
General		-	17,147	75,497
Distribution		304,838	5,806	356,217
Transmission		929,840	33,570	32,788
Total Construction		1,249,334	63,002	492,670

Projected Construction Cost (2020-2022):

Table 23: BVI Projected Construction Costs

Barton Village, Inc.		Projected Construction		
Projected Construction		2020	2021	2022
Hydro	Prod	16,000		
Poles & Wires	Dist	25,000		
Station Structures	Dist	2,500		
Transformers, Services & Meters	Dist	20,000		
H-16 Rebuild	Trans	60,000		
Hydro	Prod		16,352	
Office & computing Equipment	Gen		3,000	
Poles & Wires	Dist		25,550	
Station Structures	Dist		2,555	
Transformers, Services & Meters	Dist		20,440	
H-16 Rebuild	Trans		60,000	
Routine updates	Trans		10,000	
Hydro	Prod			16,712
Office & computing Equipment	Gen			
Poles & Wires	Dist			26,112
Station Structures	Dist			2,611
Transformers, Services & Meters	Dist			20,890
Routine/Recurring/Misc plant & General	25%/75%	3,000	3,066	3,133
Total Construction		**$ 126,500**	**$ 140,963**	**$ 69,458**
Functional Summary:				
Production		16,000	16,352	16,712
General	25%	750	3,767	783
Distribution	75%	49,750	50,845	51,963
Transmission		60,000	70,000	-
Total Construction		126,500	140,963	69,458

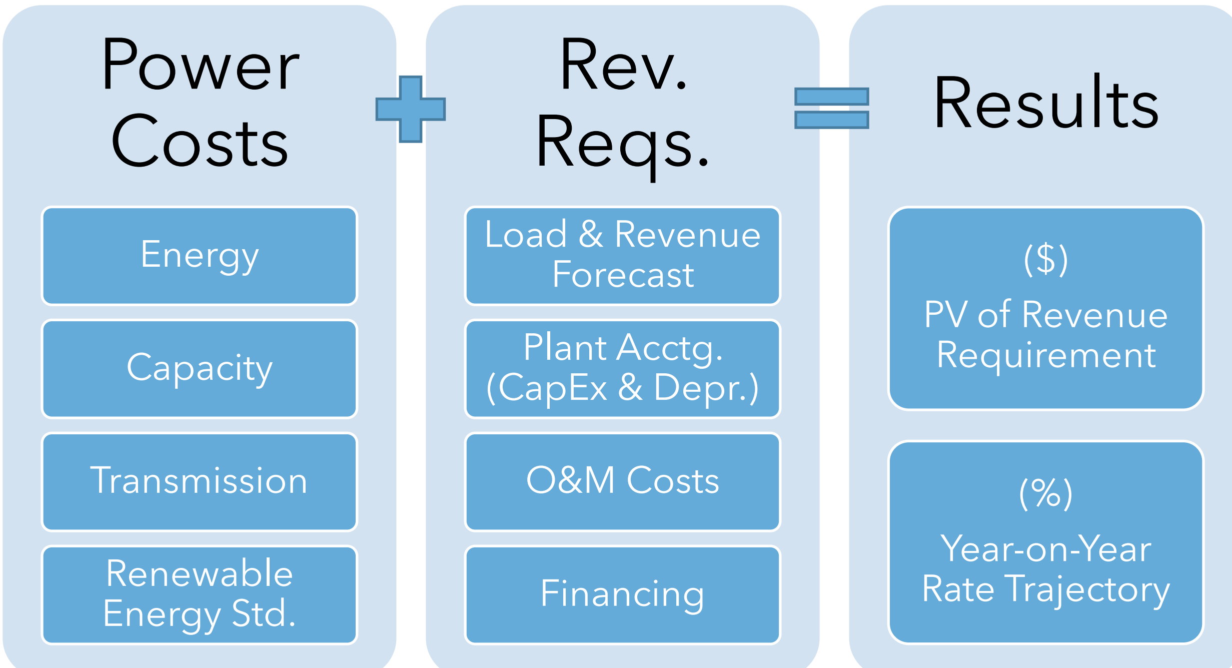
Financial Analysis

V. Financial Analysis

Components

The financial analysis represents an integrated analysis of BVI's power supply costs and its revenue requirements. The results include the present value of BVI's revenue requirements (a proxy for least cost) and the annual change in retail rates. The following figure illustrates the primary components of the analysis.

Figure 15: Primary Components of the Financial Analysis



The power supply cost models consist of four primary spreadsheets that estimate the cost of energy, capacity, transmission, and the costs of complying with the Renewable Energy Standard. The power supply models are monthly, and roll up to annual numbers for integration with the revenue requirements model. The revenue requirements model contains annual estimates of BVI's load, revenue, plant accounting activity (including capital expenditures and depreciation), O&M costs, and ultimately, a profit and loss statement. Its outputs are annual revenue requirements, average rates, and the annual change in rates.

Importantly, the power cost spreadsheets are the same models that are used to create BVI's annual power cost budget, and are formatted to be consistent with the spreadsheets that are used for monthly budget to actual analysis. As a result, they are operational as well as planning tools.

Methodology

The financial analysis estimates the costs and benefits of three major decisions that were identified in Section III. Resource Plans, and one load-related uncertainties. These include:

Decisions

1. Extension of the NextEra PPA
   Q1: What are the costs and benefits of extending NextEra volumes through 2039 at levelized market prices?

2. New Long-Term Hydro PPA
   Q2: What are the costs and benefits of a 1.5 MW Hydro PPA at levelized market prices?

3. New Long-Term Solar PPA
   Q3: What are the costs and benefits of a 500 kW Solar PPA?

4. 1% CAGR
   Q4: What is the rate impact of 1% compound annual load growth?

Pathways

There are six possible combinations of the three resource decisions, as shown in Table 24.

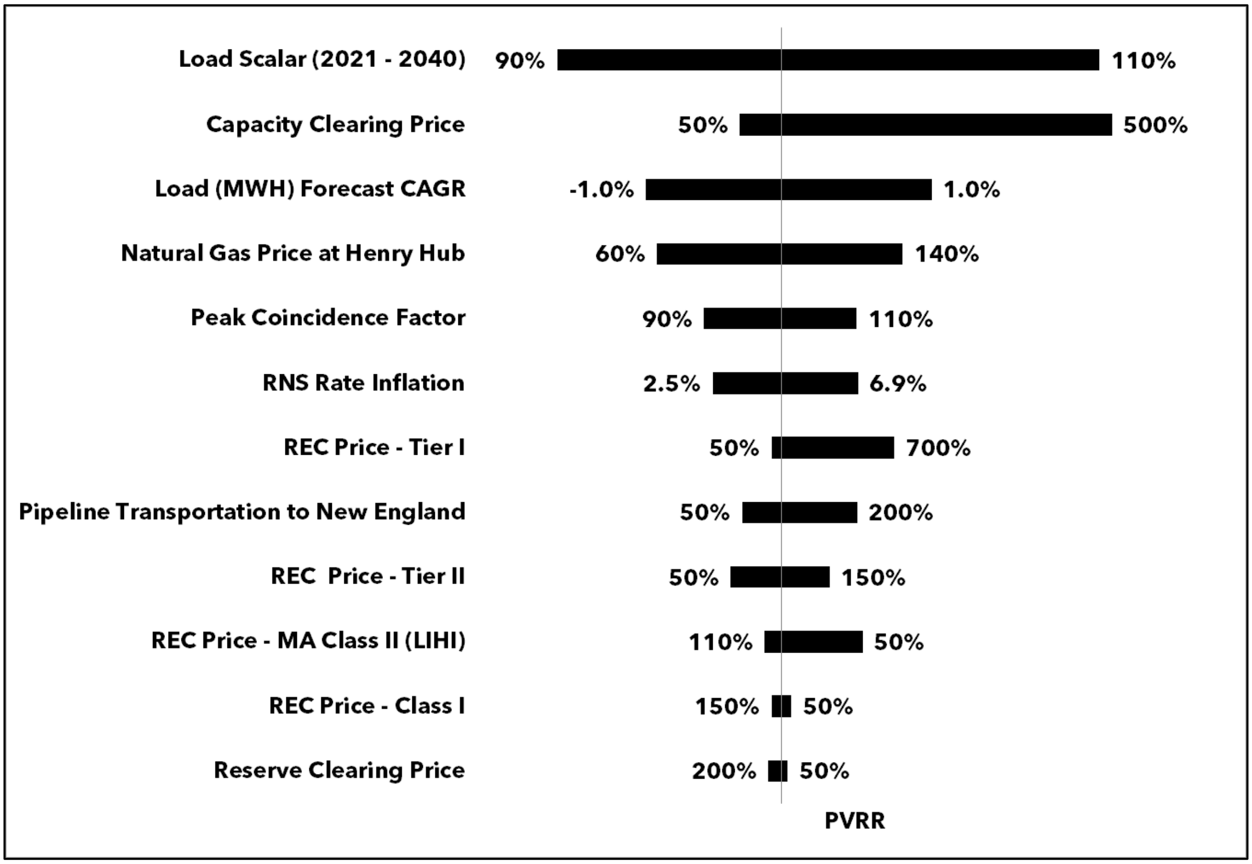
- Pathway 1 is the reference case.
- Pathways 2-4 show the costs and benefits of using long-term contracts to hedge BVI's short position in energy and RECs.
- Pathways 5-6 show the cost and benefits of extending the NextEra contract to hedge BVI's short position in energy and using a solar PPA to hedge JEC's Tier II requirements.

Table 24: Event / Decision Pathways

Pathway	Name	Extend NextEra PPA to 2039	1.5 MW Hydro PPA in 2023	500 kW Solar PPA in 2021
1	Reference Case			
2	Hedge Tier I with Hydro PPA		✓	
3	Hedge Tier II with Solar PPA			✓
4	Hedge Tier I & II with PPAs		✓	✓
5	Hedge Energy w/ NextEra PPA Extension	✓		
6	Hedge Energy w/ NextEra PPA Extension + Solar PPA	✓		✓

The financial analysis estimates the cost of each of these pathways, and then runs sensitivity analysis on 12 different variables that are known to have a material impact on BVI's revenue requirements. Low, base and high ranges were set up using historical data for each of these variables, as shown in Figure 16.

Figure 16: Sensitivity Analysis of Key Variables – Pathway 1 (Reference Case)

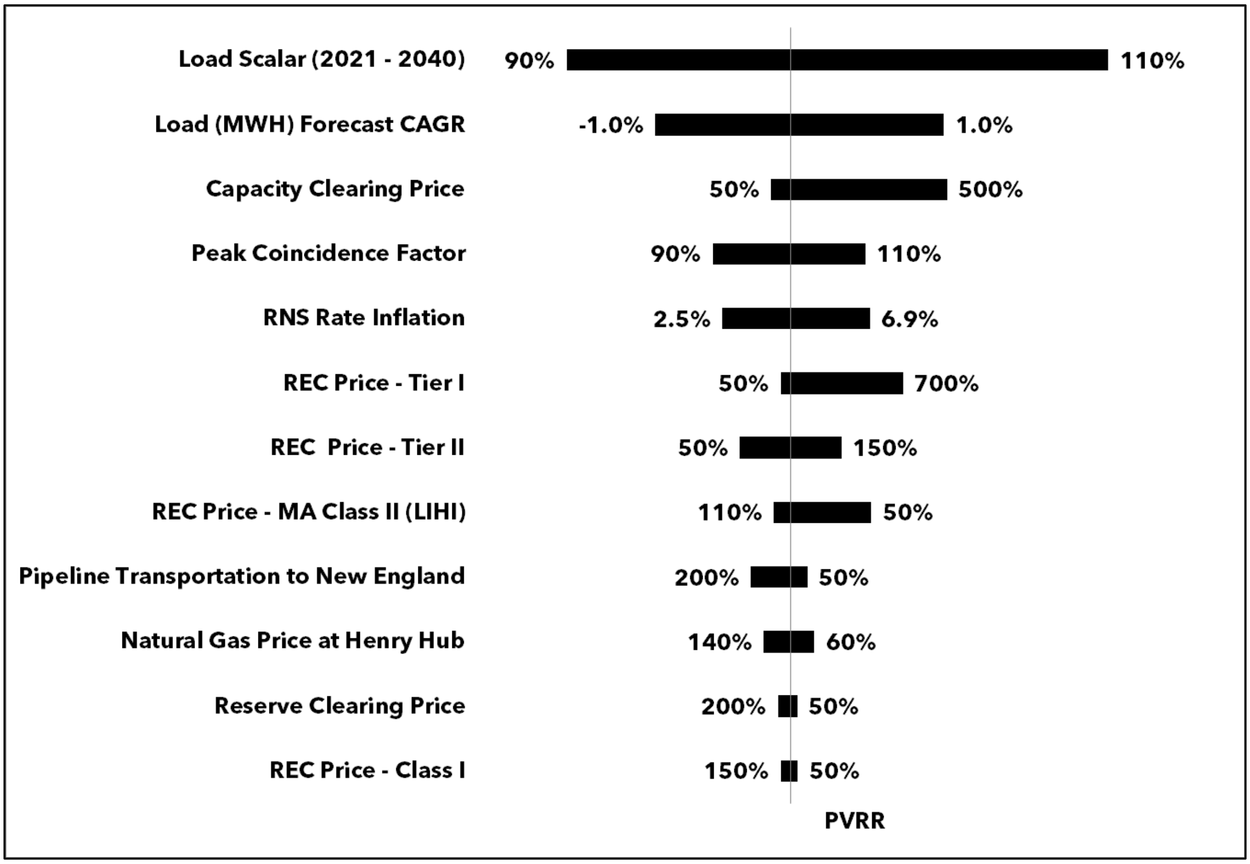


Over the 20-year time horizon of the financial analysis, the three largest uncertainties that BVI faces are changes in load and load growth, capacity market prices and energy market prices. Changes in load are always foundational, so this result is no unexpected. Similarly, BVI's capacity requirements are only half hedges, which means that capacity market prices would be expected to impact BVI's revenue requirements. Finally, energy market prices directly impact the cost of managing changes in load (the most important variable), so this uncertainty too is not unexpected.

Peak coincidence is the fourth most important variable, followed by the cost of transmission (aka RNS rate inflation). While REC prices do impact the analysis, they are more than halfway down the list. Interestingly, this includes the price of Massachusetts Class II RECs. If those prices fall by 50%, BVI does have some financial risk, but it is on part with the risk of Tier I RECs, and does not rise past the 50% mark on the list of uncertainties.

The risks that BVI's faces in Pathway 2 are markedly different from Pathway 1, even though the range of financial outcomes is quite similar[29]. In this pathway, the hydro PPA hedges BVI against changes in natural gas and pipeline transportation costs, and as a result, those risks drop from #4 and #8 in Pathway 1 to #9 and #10 in Pathway 2. What rises to the top in Pathway 2 are changes in load, load growth and capacity prices. The primary takeaway from this case is this. The hydro PPA is an effective hedge against energy prices, but does comparatively little to hedge against capacity and REC prices. This is due to its low coincidence with the ISO peak, and the dominance of the load-related uncertainties in the analysis.

Figure 17: Sensitivity Analysis of Key Variables – Pathway 2 (Hedge Tier I with a Hydro PPA)



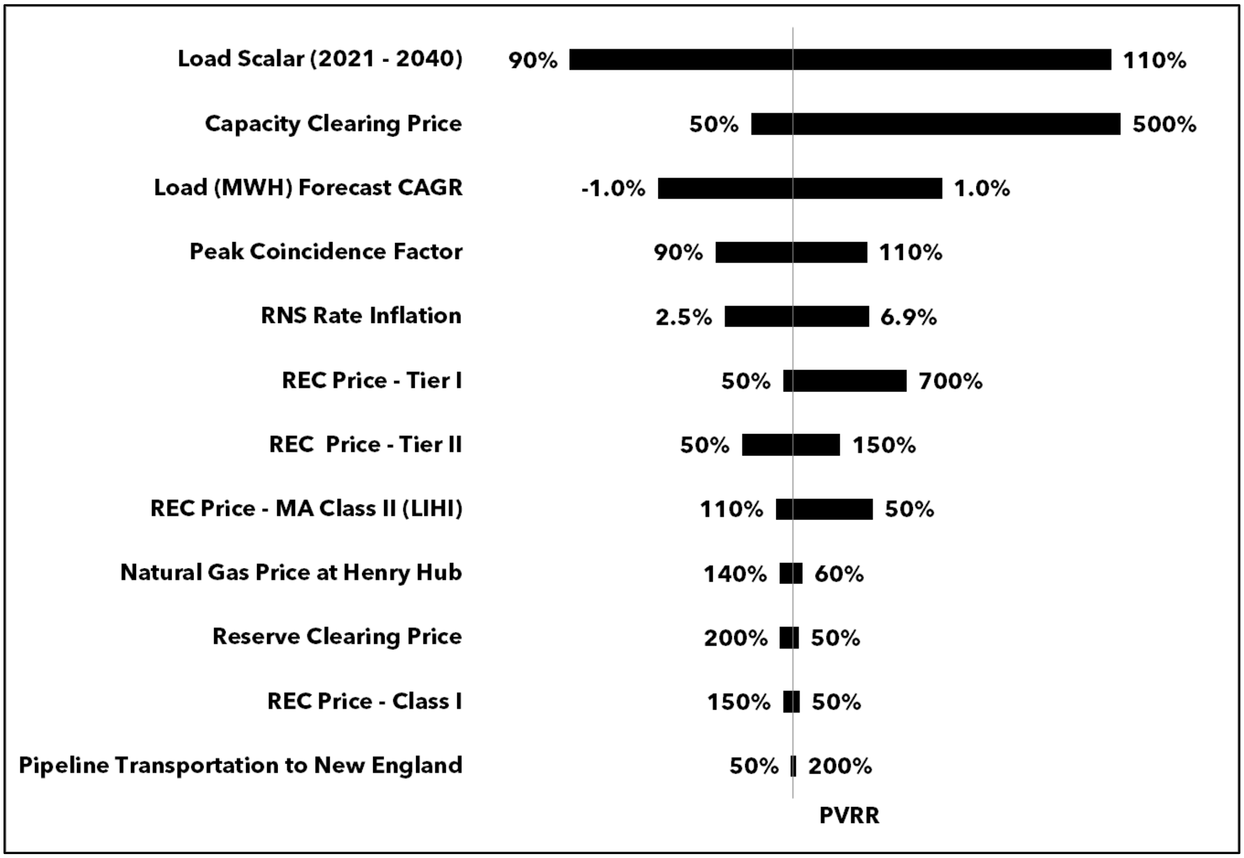
The risks of Pathway 3 are very similar to Pathway 1 because the solar PPA does very little to hedge energy requirements. Similarly, the risks of Pathway 4 are very similar to Pathway 2 because the hydro PPA effectively hedges energy price risks. As a result, their sensitivity analysis charts are not shown.

Figure 18 shows the risks of extending the NextEra PPA from 2023-2039 at today's market prices. Changes in load, capacity market prices, and load growth top the list, followed by the peak coincidence factor and the growth rate of Regional Network Service (RNS) transmission costs. This mix of risks is distinct from Pathway 2 (Hydro PPA) because it doesn't impact the

[29] Please refer to Figure 19 for a scatter plot of financial outcomes by pathway.

risk of changes in capacity market prices at all. It is, however, even more effective at heading energy market prices because the seasonal shape of the NextEra MWH more closely fits BVI's load than the MWH production of the hydro PPA. In addition, BVI already has a substantial source of hydroelectricity in its portfolio, Barton Hydro. The addition of another small hydro with high spring and low fall production isn't actually a good fit for BVI. Large hydro, however, could remedy this situation by providing a more steady monthly supply of energy. This is the primary conclusion from this pathway.

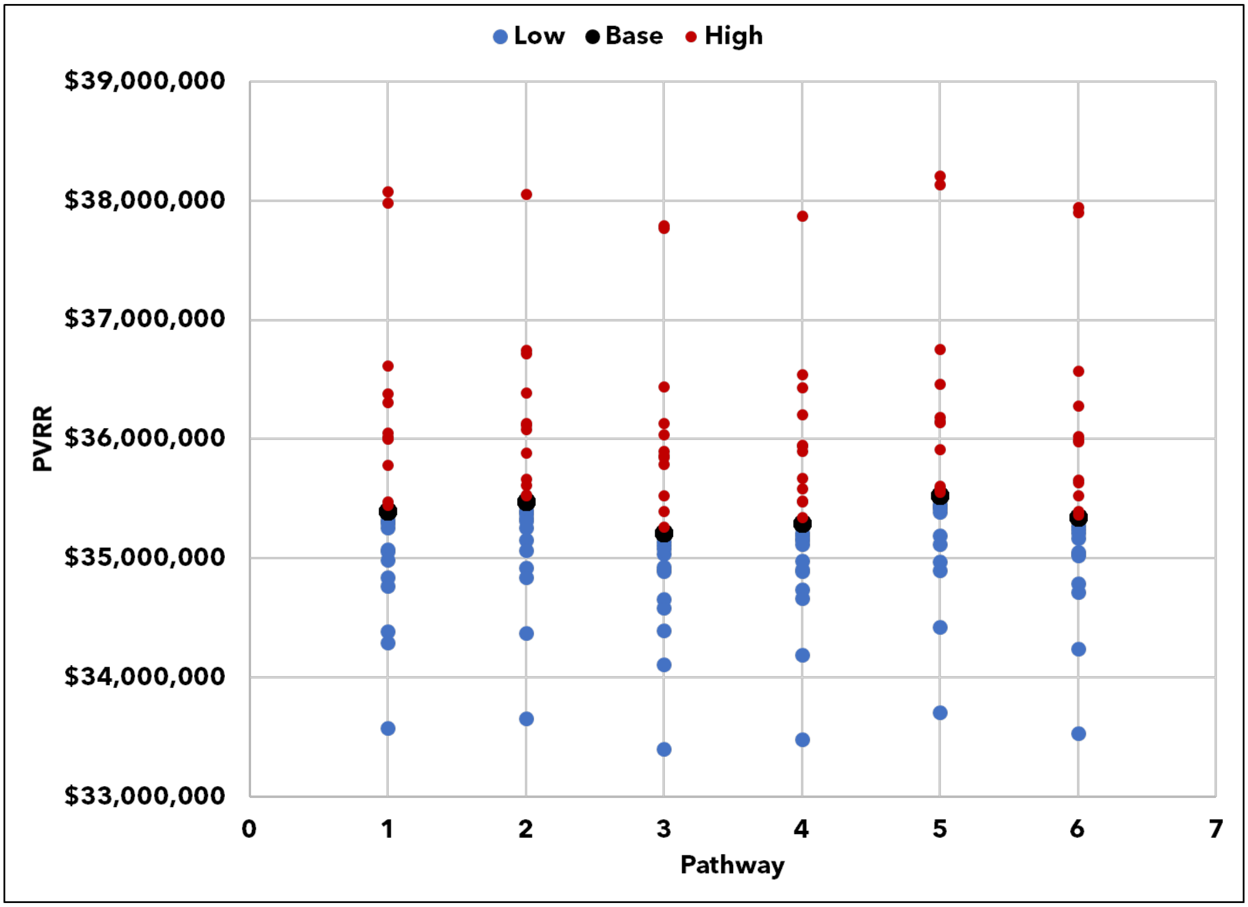
Figure 18: Sensitivity Analysis of Key Variables – Pathway 5 (Hedge Energy with NextEra PPA Extension)



Revenue Requirement Results

The high-level results of the financial analysis appear in Figure 19. The first pathway shows the range of results when the NextEra contract is allowed to expire in 2023. The second through the fourth pathways show the range of results when the NextEra contract is replaced with a combination of a hydro and a solar PPA. Finally, the last two pathways show the impact of extending the NextEra contract through 2039, both with and without a solar PPA.

Figure 19: Scatter Plot of Financial Analysis Results (PV of Revenue Requirement)



- **Pathway 1:** This range of outcomes is the reference case and it shows how much variability BVI can expect from changes in market conditions over time.

- **Pathway 2**: The overall cost and the range of costs in Pathway 2 are similar to Pathway 1. However, the risks that BVI faces are different. Because the long-term hydro PPA effectively hedges BVI from both energy, capacity and REC price risk, these uncertainties drop. In the case of energy price risks, they drop substantially. The impact on capacity and REC price is noticeable but not large. In any event, the financial outcomes are dependent on negotiating a PPA whose price is at or lower than the levelized cost of energy plus Tier I RECs in the price forecast.

- **Pathway 3-4:** The range of Pathway 3 is shifted downward slightly from Pathways 1 and 2, and it is marginally less costly. This indicates that the 500 kW solar PPA reduces price risk and costs. The magnitude of the savings and risk reduction in Pathway 4 is similar to, but slightly higher than Pathway 3. Hedging both energy and RECs reduces costs slightly, but the range of financial outcomes is largely the same due to the dominance of the load related uncertainties.

- Pathway 5-6: These pathways show the impacts of extending the NextEra contract at forecast market prices, and adding a solar PPA to hedge Tier II requirements. The range of financial outcomes narrows from the reference case, but the risks that BVI faces change as shown in Figure 18.

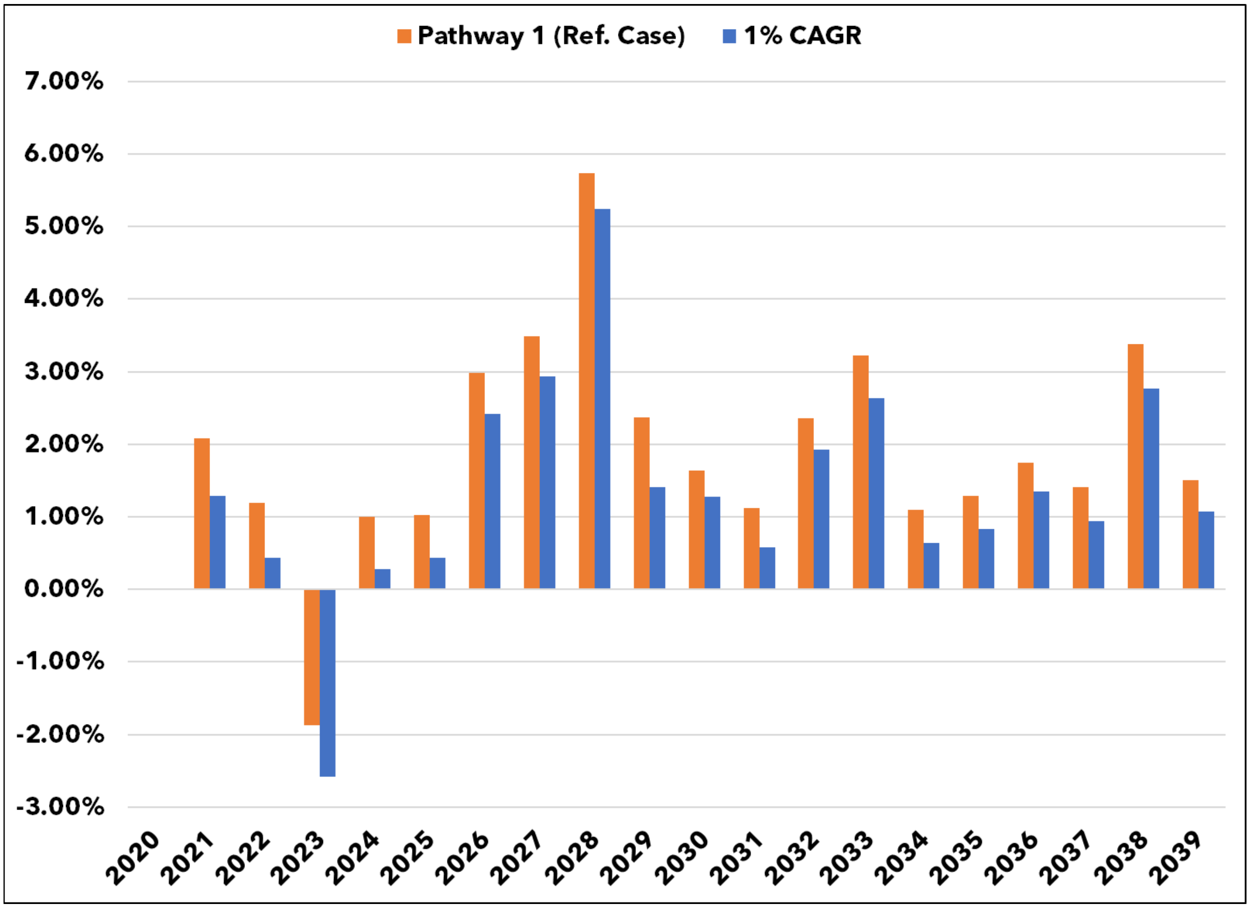
Preferred Pathway

The lowest cost and least risk pathway appears to be Pathway 3 – Hedge Tier II with Solar PPA. However, this pathway produces similar cost outcomes to the other pathways, and it doesn't minimize energy and capacity market price risks. As a result, the preferred pathway is likely to be a variation on Pathways 4 or 6, where energy and capacity are hedged with a firmer (less seasonally variable) energy and capacity resource such as large hydro or nuclear PPA.

Impact of 1% Compound Annual Load Growth (CAGR)

Promoting energy-efficient load growth is an implied goal of the RES's Energy Transformation (Tier III) requirements. This section quantifies the impact that a 1% increase in annual load growth would have on retail rates. As Figure 20 shows, the impact is uniformly to lower rates except in 2023 when the NextEra PPA expires. This is intuitive but is an important outcome to quantify. If this level of load growth were to occur between 2020 and 2032, for example, the 1% compound annual load growth could reduce rates by about 7% in 2032 as compared to the reference case.

Figure 20: Rate Impact of 1% CAGR Load Growth



Summary and Conclusions

The answers to the questions that were posed at the beginning of this chapter are now evident.

1. Extension of the NextEra PPA
   Q1: What are the costs and benefits of extending NextEra volumes through 2039 at levelized market prices?
   A1: Extending the NextEra PPA is a very effective hedge against energy market prices, but without capacity or RECs, has no impact on those uncertainties. As a result, and extension of the NextEra contract should be negotiated to include capacity.

2. New Long-Term Hydro PPA
   Q2: What are the costs and benefits of a 1.5 MW Hydro PPA at levelized market prices?
   A2: The long-term hydro PPA does reduce energy market price risk, but it is not as effective as the NextEra PPA at hedging energy prices. This is due to the fact that BVI already has exposure to a small hydro production profile in Barton Hydro. Additional seasonal hydro creates a seasonal mismatch between supply and demand. In addition, small hydro resources do comparatively little to hedge capacity market price risk because their run-of-river production profile is not often highly coincident with the ISO peak. As a result, we recommend seeking out larger hydro resources that can provide a firmer energy and capacity product throughout the year.

3. New Long-Term Solar PPA
   Q3: What are the costs and benefits of a 500 kW Solar PPA?
   A3: While the 500 kW solar PPA doesn't fulfill all of BVI's Tier I and Tier II requirements, it does fulfill them well into the mid-2020s and reduces costs. As a result, we recommend pursuing the 500 kW solar PPA now, and another solar PPA in the mid 2020's are load requirements and state renewable policy becomes more clear.

4. 1% CAGR
   Q4: What is the rate impact of 1% compound annual load growth?
   A4: An addition 1% annual growth in load could reduce the retail average rate by 7% by 2032. As a result, BVI should support electrification programs in the immediate future.

These and other conclusions are carried into the Action Plan in the following section.

Action Plan

VI. Action Plan

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

1. Automated Metering Infrastructure (AMI)

- BVI will participate in an evaluation of AMI readiness which, if results are positive, will lead to preparation of an RFP leading to vendor and equipment selection and ultimately to implementation of an AMI system. Upon completion of the RFP phase of the project, BVI will have the information needed to examine the business case and make a decision to commit to implementation of an AMI system, or not. BVI recognizes that cost reduction, while desirable, is but one of many factors that must be weighed in making the decision to go forward with AMI BVI sees the potential for a number of future benefits that, while difficult to quantify in cost/benefit terms, will clearly be desirable to various stakeholders. These benefits include (but may not be limited to) improved system control/optimization, ability to deliver/administer more creative customer and load management initiatives, and ability to accommodate emerging initiatives such as EV charging. BVI also notes that unanticipated initiatives may emerge over time that positively impact the perceived value of having an AMI system in place. BVI is considering the potential benefit of a staged implementation that would initially focus on limited areas of high load or customer concentration.

2. Energy Resource Actions

- Manage year to year energy market requirements using fixed-price, market contracts that are less than five-years in duration.
- Consider a 1.5 MW hydro PPA from a large resource that includes bundled energy, capacity, and renewable energy credits. This can reduce energy, capacity and Tier I costs and risks. Importantly, the hydro resource should be large enough to provide energy and capacity that is more firm than a typical small, run-of-river hydro plant.

3. Capacity Resource Actions

- Manage and monitor the reliability of Project 10 to minimize Pay-for-Performance (PFP) risk and maximize capacity, reserves, and PFP benefits.
- Seek out long-term sources of capacity to hedge BVI's capacity requirement, preferably from a large hydro resource as recommended above.

4. Tier I Requirements

- Consider a 1.5 MW hydro entitlement that includes bundled energy, capacity, and renewable energy credits to reduce both energy, capacity and Tier I costs and risks.
- Make forward purchases of qualifying RECs on the regional market to manage REC price and ACP risk.

5. Tier II Requirements

- Develop and complete the Jacksonville Solar or other comparable, Vermont-based solar projects.
- Make forward purchases of qualifying RECs on the Vermont market to manage REC price and ACP risk.
- Investigate adding battery storage to upcoming solar projects to increase their value and decrease overall project costs.

6. Tier III Requirements

- Identify and deliver prescriptive and/or custom Energy Transformation programs, and/or
- Develop and complete the Jacksonville Solar or other comparable, Vermont-based solar projects, and/or
- Purchase a surplus of Tier II qualifying renewable energy credits.

7. Active Load Control Pilot Program

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

8. Peak Load Management Pilot Program

- Explore ways to align reductions in customer demand charges with utility coincident peak costs through use of a pilot tariff.

9. Net Metering

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

10. Storage

- Monitor cost trends and potential use cases, and
- Identify Behind-the-Meter use cases and sites, and
- Develop project-specific cost-benefit analysis.

Appendix

Appendix A: NVDA Regional Energy Plan

This appendix is provided separately in a file named:

Appendix A - NVDA Regional Energy Plan.pdf

Appendix B: 2020 Tier 3 Annual Plan

This appendix is provided separately in a file named:

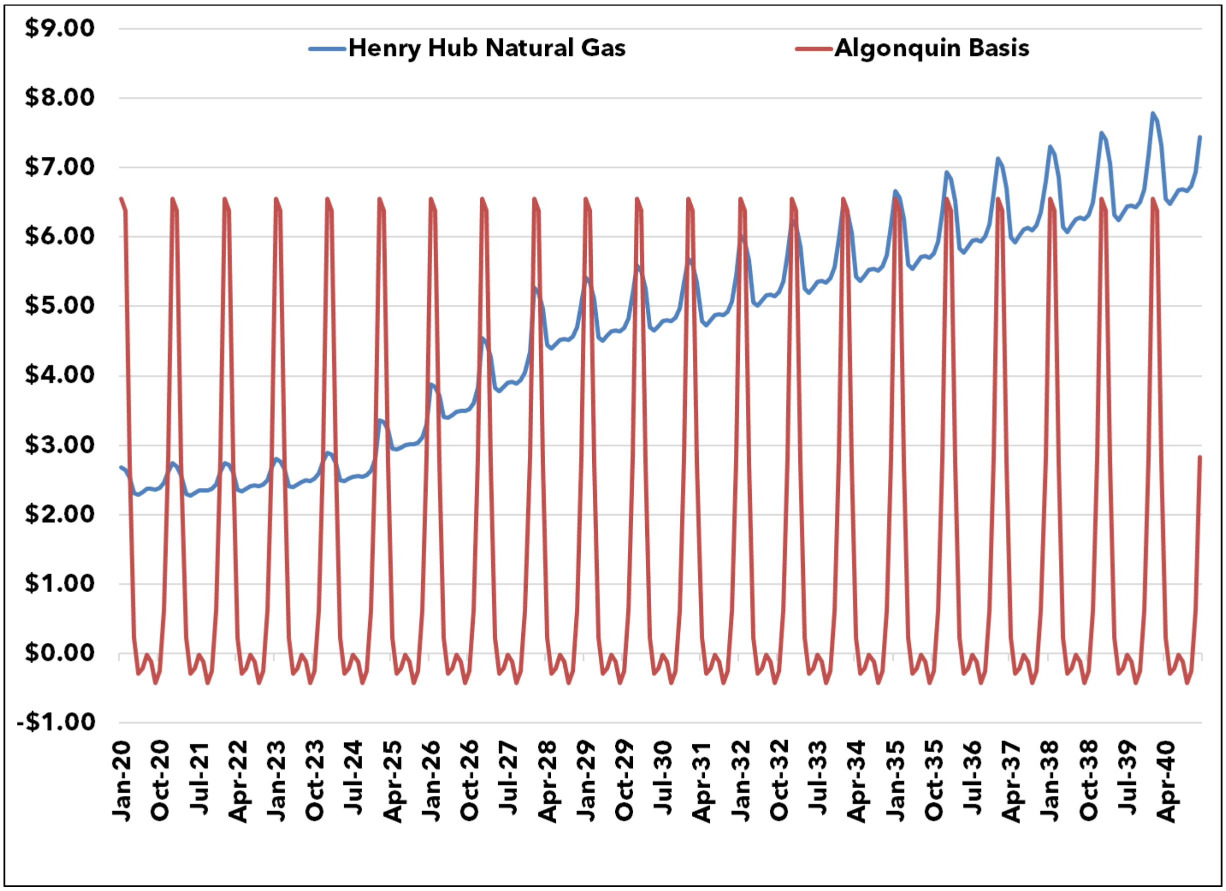
Appendix B - VPPSA Tier 3 2020 Annual Plan.pdf

Appendix C: Pricing Methodology

Energy Pricing

Energy prices are forecast using a three-step method. First, a natural gas price forecast is formed by combining a 3-month average of NYMEX Henry Hub futures prices for the period 2020 to 2021 with the Energy Information Administration (EIA) Annual Energy Outlook (AEO) Henry Hub forecast for the period 2022 to 2039. The forecast of Henry Hub Natural Gas prices can be seen in Figure 21.

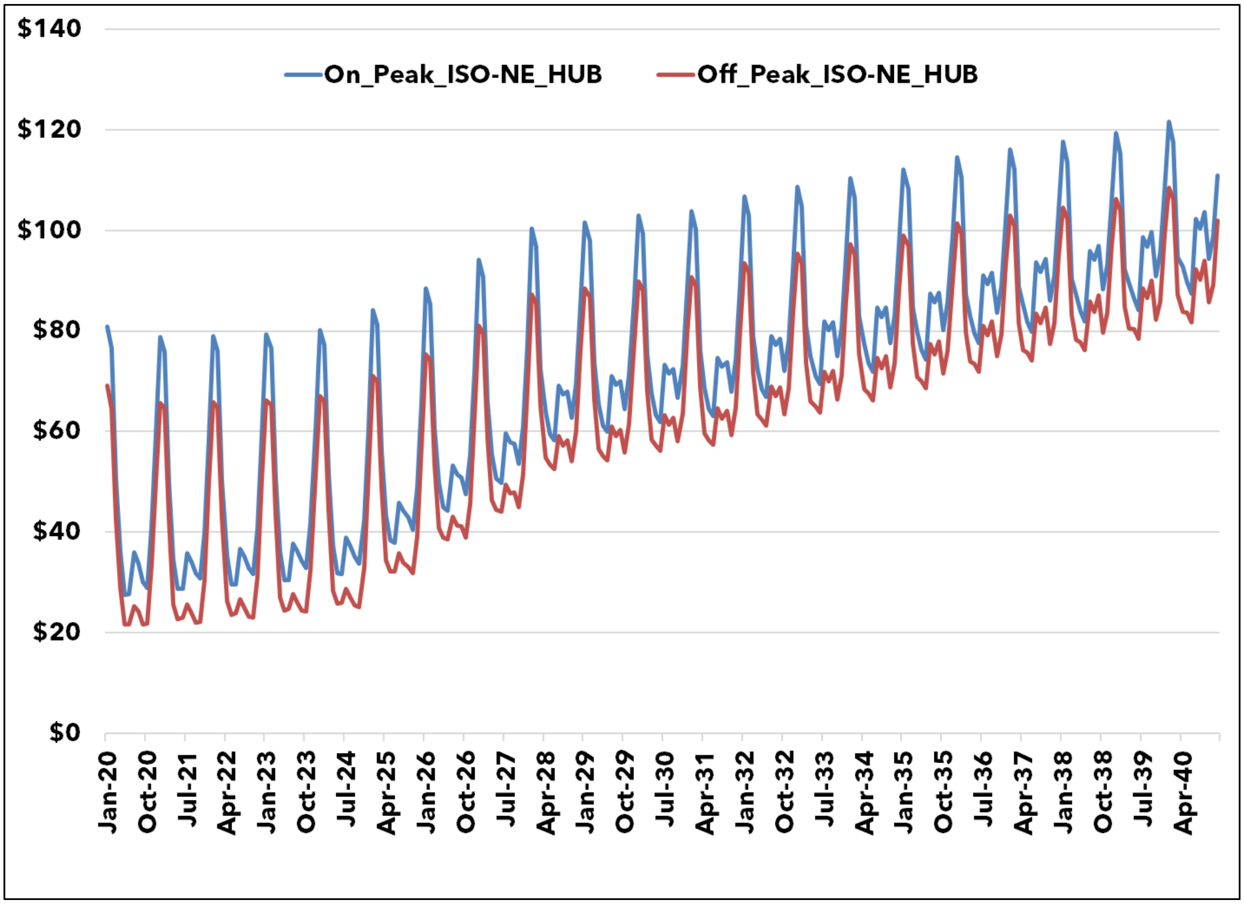
Figure 21: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Second, we use NYMEX futures prices (between 2020-2021) to find 1.) the cost of transportation (basis) to the Algonquin Hub and 2.) the cost of on and off-peak energy at the Massachusetts Hub (MA Hub). These prices are used to calculate an implied heat rate (MMBtu/MWH) and a spread between on and off-peak electricity prices. These values (sometimes called shapes) are used for the remainder of the forecast period.

Third and finally, we multiply the natural gas price forecast by the implied heat rate 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 22.

Figure 22: Electricity Price Forecast (Nominal $/MWH)

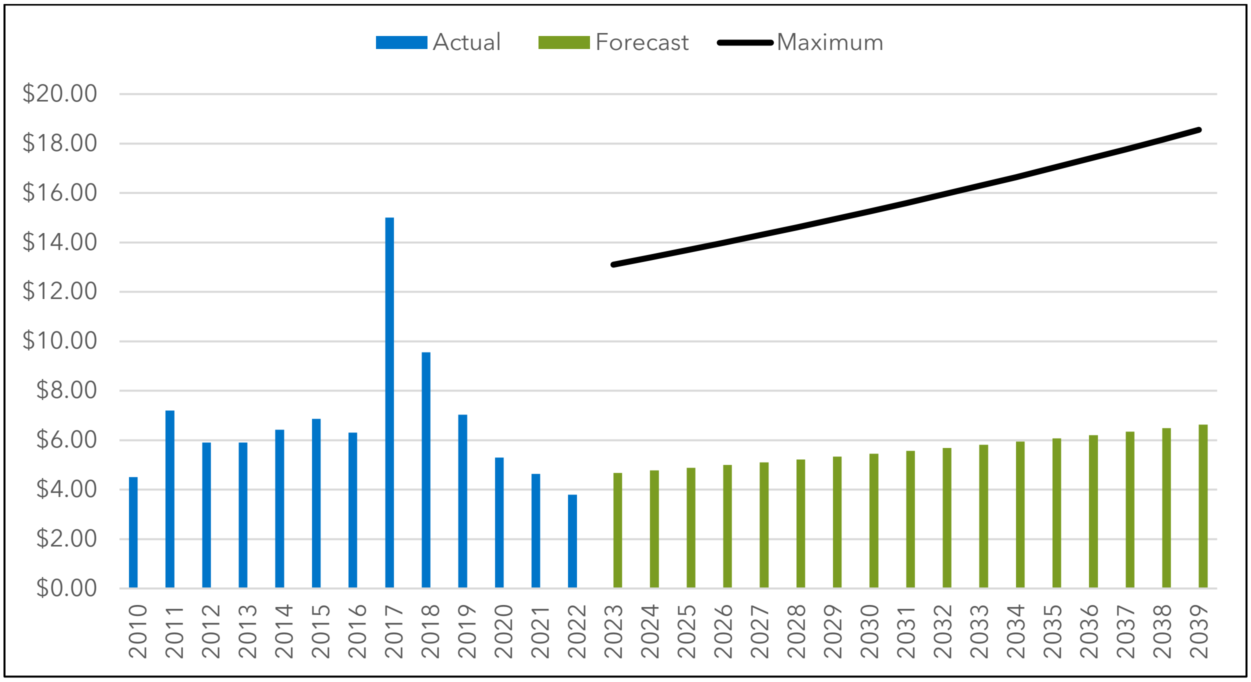


Finally, and in keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between LMP nodes to adjust the price forecast at the MA Hub to the location of BVI'Ss load and resources.

Capacity Pricing

The capacity price forecast is an average of the last three years of actual auction results plus inflation, and it grows from $4.68 per kW-month in 2023 to $6.77 per kW-month in 2039. Significant upside price risk does exist, as shown by the Maximum line in Figure 23. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 23: Capacity Price Forecast (Nominal $/kW-Month)



Appendix D: PUC Rule 4.900 Outage Reports

Barton Village Inc. **2014**

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village Inc.
Calendar year report covers	2014
Contact person	Malcolm McCormick
Phone number	802-525-4747
Number of customers	2,181

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**3.5**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**3.2**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	6	1,111
2	**Weather**	12	4,037
3	**Company initiated outage**	3	15,005
4	**Equipment failure**	5	2,625
5	**Operator error**	0	0
6	**Accidents**	1	4
7	**Animals**	2	12
8	**Power supplier**	1	1,628
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	30	24,422

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

Barton Village Inc. 2015

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village Inc.
Calendar year report covers	2015
Contact person	Malcolm McCormick
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**2.9**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**6.4**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	17	5,400
2	**Weather**	8	17,007
3	**Company initiated outage**	3	17,922
4	**Equipment failure**	7	330
5	**Operator error**	0	0
6	**Accidents**	2	43
7	**Animals**	2	134
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	33
11	**Unknown**	0	0
	Total	40	40,869

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

Barton Village, Inc. 2016

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village, Inc.
Calendar year report covers	2016
Contact person	Malcolm McCormick
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) = 4.3
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 5.6
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	10	1,774
2	**Weather**	4	531
3	**Company initiated outage**	5	15,267
4	**Equipment failure**	4	105
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	1	9
8	**Power supplier**	1	30,450
9	**Non-utility power supplier**	0	0
10	**Other**	6	4,142
11	**Unknown**	3	225
	Total	34	52,504

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

			Barton Village, Inc.			**2017**

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village, Inc.
Calendar year report covers	2017
Contact person	Evan Riordan
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) =	**2.9**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**5.1**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	22	5,596
2	**Weather**	2	2,518
3	**Company initiated outage**	2	144
4	**Equipment failure**	20	2,551
5	**Operator error**	1	1
6	**Accidents**	1	0
7	**Animals**	2	11
8	**Power supplier**	1	20,662
9	**Non-utility power supplier**	0	0
10	**Other**	2	704
11	**Unknown**	1	6
	Total	54	32,194

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

			Barton Village, Inc.				**2018**
Revised Calculation - Removed Major Storm Outages of 10/15/18 & 11/27/18-11/29/18							
This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.							
Electricity Outage Report -- PSB Rule 4.900							
	Name of company	Barton Village, Inc.					
	Calendar year report covers	2018					
	Contact person	Evan Riordan					
	Phone number	802-525-4747					
	Number of customers	2,175					
	System average interruption frequency index (SAIFI) =			**0.7**			
	Customers Out / Customers Served						
	Customer average interruption duration index (CAIDI) =			**2.6**			
	Customer Hours Out / Customers Out						
	Outage cause	**Number of Outages**	**Total customer hours out**		Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.		
1	**Trees**	18	3,398				
2	**Weather**	16	113				
3	**Company initiated outage**	1	13				
4	**Equipment failure**	8	203				
5	**Operator error**	0	0				
6	**Accidents**	1	1				
7	**Animals**	3	14				
8	**Power supplier**	0	0				
9	**Non-utility power supplier**	0	0				
10	**Other**	0	0				
11	**Unknown**	3	48				
	Total	50	3,790				

Appendix E: Inverter Source Requirements

Inverter Source Requirement Document of ISO New England (ISO-NE)

This Source Requirement Document applies to inverters associated with specific types of generation for projects that have applied for interconnection after specific dates. These details will be described in separate document(s). This document was developed with the help of the Massachusetts Technical Standards Review Group and is consistent with the pending revision of the IEEE 1547 Standard for Interconnection and Interoperability of Distributed Resources with Associated Electrical Power Systems Interfaces. All applicable inverter-based applications shall:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings
- have the abnormal performance capabilities (ride-through)
- comply with other grid support utility interactive inverter functions statuses

These specifications are detailed below and are consistent with the amended IEEE Std 1547a-2014.

1. **Certification per UL 1741 SA as grid support utility interactive inverters**

In the interim period while IEEE P1547.1 is not yet revised and published, certification of all inverter- based applications:

a. shall be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std 1547-2018 (2nd ed.)1 that can be certified per the type test requirements of
UL 1741 SA (September 2016). IEEE Std 1547-2018 (2nd ed.) in combination with this document

replaces other Source Requirements Documents (SRDs), as applicable;

b. may be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawai'ian Rule 14H as the SRD. Such inverters are deemed capable of meeting the requirements of this document.

2. **Voltage and frequency trip settings for inverter based applications**

Applications shall have the voltage and frequency trip points specified in Tables I and II below.

3. **Abnormal performance capability (ride-through) requirements for inverter based applications**

The inverters shall have the ride-through capability per abnormal performance category II of IEEE Std 1547-2018 (2nd ed.) as quoted in Tables III and IV.

The following additional performance requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

1

7.3 as a proxy, subject to minor

editorial changes.

Consistent with IEEE Std 1547-2018 (2nd ed.) the following shall apply:

a. DER tripping requirements specified in this SRD shall take precedence over the abnormal performance capability (ride-through) requirements in this section, subject to the following:
    1. Where the prescribed trip duration settings for the respective voltage or frequency magnitude are set at least 160 ms or 1% of the prescribed tripping time, whichever is greater, beyond the prescribed ride-through duration, the DER shall comply with the ride-through requirements specified in this section prior to tripping.
    2. In all other cases, the ride-through requirements shall apply until 160 ms or 1% of the prescribed tripping time, whichever is greater, prior to the prescribed tripping time.
b. DER ride-through requirements specified in this section shall take precedence over all other requirements within this SRD with the exception of tripping requirements listed in item a. above. Ride-through may be terminated by the detection of an unintentional island. However, false detection of an unintentional island that does not actually exist shall not justify non- compliance with ride-through requirements. Conversely, ride-through requirements specified in this section shall not inhibit the islanding detection performance where a valid unintentional islanding condition exists.

4. Other grid support utility interactive inverter functions statuses

Other functions required by UL 1741 SA shall comply with the requirements specified in Table V. For functions not activated by default, the inverter is compliant if tested to the manufacturers stated capability.

5. Definitions

The following definitions which are consistent with IEEE Std 1547-2018 (2nd ed.) and UL 1741 SA shall apply:

cease to energize: Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange. This may lead to momentary cessation or trip.

clearing time: The time between the start of an abnormal condition and the DER ceasing to energize the utility's distribution circuit(s) to which it is connected. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device (used to interconnect the DER with the utility's distribution circuit).

continuous operation: Exchange of current between the DER and an EPS within prescribed behavior while connected to the utility's distribution system and while the applicable voltage and the system frequency is within specified parameters.

mandatory operation: Required continuance of active current and reactive current exchange of DER with utility's distribution system as prescribed, notwithstanding disturbances of the utility's distribution system voltage or frequency having magnitude and duration severity within defined limits.

momentary cessation: Temporarily cease to energize the utility's distribution system while connected to the utility's distribution system, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate restore output of operation when the applicable voltages and the system frequency return to within defined ranges.

permissive operation: operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the applicable voltages or the system frequency.

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ISO-NE PUBLIC **Table I: Inverters' Voltage Trip Settings**

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	**Required Settings**		**Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II**		
	Voltage (p.u. of nominal voltage)	**Clearing Time(s)**	**Voltage**	**Clearing Time(s)**	**Within ranges of allowable settings?**
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)	Comparison to IEEE Std 1547-2018
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: T = 3 s + 8.7 s (V − 0.65 p.u.)	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A	See footnote b
V < 0.30	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

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Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.)
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF[2]
Q(V), Volt-Var Function with Watt	OFF
SS, Soft-Start Ramp Rate	ON Default value: 2% of maximum current
FW, Freq-Watt Function OFF	OFF

2

with unity PF.

Glossary

Glossary

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
APPA	American Public Power Association
BVI	Barton Village, Inc.
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
DPS	Department of Public Service or "Department"
DSSMP	Dam Safety Surveillance and Monitoring Plan
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
HPWH	Heat Pump Water Heater
IRP	Integrated Resource Plan
ISO-NE	ISO New England (New England's Independent System Operator)
kV	Kilovolt
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LIHI	Low Impact Hydropower Institute Certification
MAPE	Mean Absolute Percent Error
ME II	Maine Class II (RECs)
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NVDA	Northeastern Vermont Development Association
NYPA	New York Power Authority
OED	Village of Orleans
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
R^2	R-squared
RES	Renewable Energy Standard
RTLO	Real-Time Load Obligation
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)

VEC	Vermont Electric Cooperative
VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VFD	Variable Frequency Drive
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources

Chapter Two: Energy

I. INTRODUCTION

Traditionally, Northeastern Vermont Development Association has approached energy planning from a strictly "supply-and-demand" perspective, and this has generally supported the traditional systems that have continued to meet our regional energy needs. The energy trends of the past decade, however, have presented NVDA with the challenge of addressing a much broader perspective, one that transcends current energy production and usage. During this time, several factors created a contentious climate for the future planning of our energy systems. The region has had to contemplate the effect of utility-scale wind development on our mountains; identify ways to ensure forest sustainability as wood-fuels grow in popularity; and seek means to secure long-term affordability of our energy resources for the general public and business communities. In response, NVDA expanded its approach to energy planning and its role in regional energy policy with the intent of seeking a stronger voice in formulating energy policy for NVDA and its member municipalities.

NVDA's statutory role in energy planning is outlined in V.S.A. Title 24, Chp.117 §4348a (3), which stipulates that a regional plan include:

> "… an analysis of energy resources, needs, scarcities, costs and problems within the region across all energy sectors, including electric, thermal, and transportation; a statement of policy on the conservation and efficient use of energy, and the development of renewable energy resources; a statement of policy on patterns and densities of land use likely to result in conservation of energy; and an identification of potential areas for the development and siting of renewable energy resources and areas that are unsuitable for siting those resources or particular categories or sizes of those resources."

The approval process for siting energy generation projects is largely under the jurisdiction of Section 248 of Title 30. The Vermont Supreme Court has expressly exempted projects subject to Section 248 from local permitting. At this time municipalities have only the power to regulate "off-grid" renewables – and must do so in accordance with Vermont Statute.

In accordance with Section 248, energy developers must obtain a Certificate of Public Good (CPG) from the Public Utility Commission (PUC) before beginning site preparation or construction of electric transmission facilities, electric generation facilities, and certain gas pipelines within Vermont[1]. Prior to issuance, the PUC takes into account the environmental, economic, and social impacts of a proposed facility. Municipalities and other groups are allowed to participate in the Section 248 review process, but many find doing so to be difficult and expensive. Moreover, the PUC is only obligated to give "due consideration" to the recommendations of the municipal and regional planning commission in determining if the project "will not unduly interfere with the orderly development of the region."[2] The process has also been complicated by the fact that Vermont statute does not define "due consideration", nor does it indicate whether the courts or the PUC should be the ultimate arbiter.

Previous versions of this plan have been prepared in anticipation of receiving "due consideration" in the Section 248 process. To support the PUC's consideration, NVDA has defined what constitutes a 'substantial regional impact' with regards to development (24 V.S.A. Chp.117 §4345a (17)). This

[1] Vermont Public Service Board. "Citizens' Guide to the Vermont Public Service Board's Section 248 Process.
[2] City of S. Burlington, 133 Vt. at 447, 344 A.2d at 25

definition is provided within Land Use section of the *Proposed Regional Plan for the Northeast Kingdom 2018* (Chp.1, pg. 24).

Act 174 of 2016 establishes a new set of municipal and regional energy planning standards. If these standards are met, regional and municipal plans may carry greater weight – "substantial deference" – in the Section 248 process. Unlike "due consideration," "substantial deference" is codified in statute to mean:

> "…that a land conservation measure or specific policy shall be applied in accordance with its terms unless there is a clear and convincing demonstration that other factors affecting the general good of the State outweigh the application of the measure of policy."

This regional plan has been revised to meet substantial deference under Act 174. It is important to note, however, that substantial deference does not carry the weight of zoning. Projects that fall under the jurisdiction of Section 248 are still exempt from local zoning and permitting. Nevertheless, this plan reflects our attempt to have a greater say in where energy projects should – and should not – be sited, and it is structured as a resource who municipalities who also wish to seek substantial deference for their local plans. Substantial deference is voluntary for municipalities. Duly adopted local plans that do not meet the enhanced energy planning standards of Act 174 but otherwise meet all the requirements of Chapter 117 will continue to receive due consideration from the PUC in the Section 248 review process. Whether or not a municipality choses to pursue substantial deference, it is hoped that this regional plan will help our municipalities to think comprehensively about energy use, resulting in strategies that conserve existing resources and reduce our reliance on fossil fuels.

Strategy Outline

NVDA's Energy Plan aims to guide the region's energy development for the next eight years in support of Vermont's 2016 Comprehensive Energy Plan (CEP), which contains the following goals:

- Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 2050.
- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050.
- Achieve three renewable end-use sector goals for 2025: 10% transportation, 30% buildings, and 67% electric power.

The basic components of the Energy Strategy are organized into five main sections:

State and Regional Overview

This section provides an estimate of local consumption across the transportation, thermal, and electrical energy sectors.

Generation and Distribution

This section analyzes the existing framework by which our utilities generate and distribute power, as well as legislation and incentives that will impact future generation.

Future Energy Use and 2050 Projections

This section analyzes the ambitious 2050 goals for Vermont's CEP and how it may impact future energy use in the Northeast Kingdom. Efficiency and conservation are also addressed in support of meeting statewide energy goals.

Energy Resource Analysis and Recommendations

In this section resources are analyzed for their current and future potential as part of the overall energy portfolio in support of 2050 goals. This section includes a region-wide GIS-based analysis, which identifies potential areas for the development and siting of renewable energy resources, areas that are unsuitable for siting those resources or particular categories or sizes of those resources, and potential generation from siting areas.

Regional Goals & Strategies

This section identifies the primary regional challenges for meeting 2050 goals and identifies pathways for meeting them.

II. STATE AND REGIONAL OVERVIEW

Statewide Energy Use

Vermont's total energy consumption is the lowest in the nation and has traditionally ranked among the lowest per capita. As of 2014, Vermont ranks 43rd in per capita consumption (about 223 MM BTUs). However, the state ranks 13th in total energy expenditures per capita (at $5,225). Throughout the U.S., energy prices are rising due to the stress on traditional resources and increasing consumption levels. To address rising energy costs, Vermonters are turning more and more towards supplemental fuels, renewables, co-generation facilities, and efficiency/conservation efforts.

Energy consumption has grown steadily since the 1960s. Historically, leaps in consumption are associated with major economic growth, low energy prices, population growth, and an overall increase in the number of vehicle miles driven. Vermont has limited generation capacity and has relied on Quebec to fulfill part of its energy needs since the early 1980s. With the permanent closure of the Vermont Yankee Nuclear Plant at the end of 2014, the state lost 55% of its generation capacity and now produces less than one-third of the energy it consumes. In addition to Canada, the state relies on the ISO-NE grid for power from neighboring states. Energy use is dominated by transportation and by heating in the frigid winters. About three-fifths of the energy consumed in Vermont are petroleum-based products, which are transported into the state by rail or truck from neighboring states and Canada. The state has limited access to natural gas. There is a natural gas pipeline in the Northeast Kingdom (which is shown on the regional energy maps), but we lack infrastructure to access it. Vermont is the second smallest natural gas consumer per capita, among the states. In 2015, nearly all of Vermont's in-state net electricity generation was produced by renewable energy, including hydroelectric, biomass, wind, and solar resources.[3]

What is a BTU?

BTU stands for **British Thermal Unit**, and it is defined by US Energy Information Administration as the measurement of the quantity of heat required to raise the temperature of one pound of liquid water by 1° F at the temperature that water has its greatest density (approximately 39 °F.

Fuels come in a variety of measurements – by cord, by gallon, by kilowatt – so this plan converts units of measurement into BTUs in order to compare their energy output consistently.

One BTU is a miniscule amount, so BTUs are often measured in the thousands, millions (MM BTUs), or even trillions.

Table 2.1 represents the total primary energy consumption in the state from 2009 to 2014 Petroleum products are by far the leading source of fuel in the state, most of which is used in the transportation and residential heating sectors.

Table 2.1: Primary Energy Consumption Estimates, 2009-2014 (Trillions of BTUs)

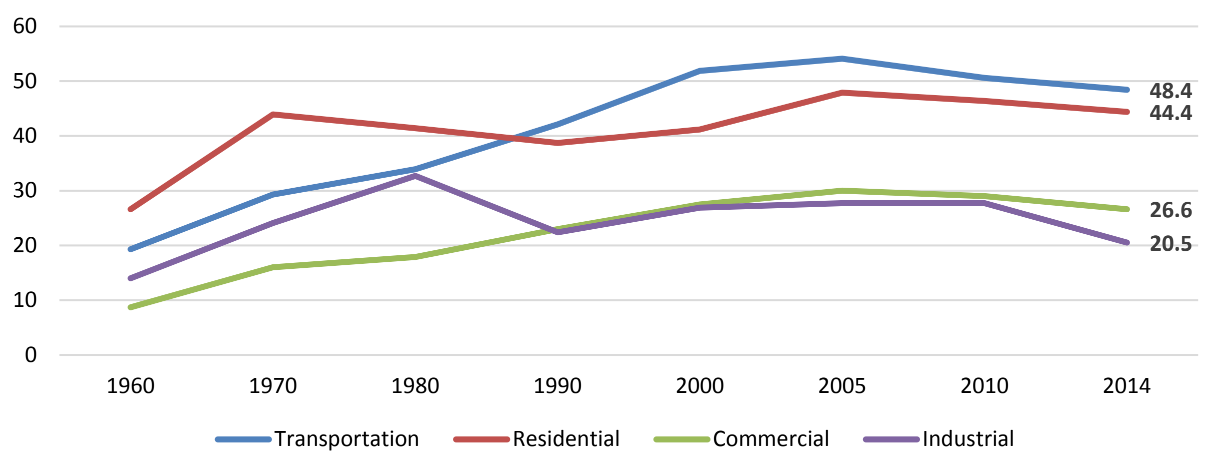
	2009	2010	2011	2012	2013	2014

[3] US Energy Information Administration: Vermont State Energy Profile and Estimates

Coal	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	8.7	8.5	8.7	8.3	9.7	10.8
Total Petroleum	84.6	81.8	80.2	75.9	79.4	79.5
Distillate Fuel Oil	27.8	26.6	27.7	24.4	25.3	26.5
Jet Fuel	2.9	1.3	1.3	1.3	1.3	1.2
LPG	9.3	9.0	8.3	9.2	10.4	10.1
Motor Gasoline, excluding fuel ethanol	38.0	37.6	36.2	35.1	35.7	35.3
Residual Fuel Oil	1.2	1.0	0.9	0.6	0.8	0.5
Other	5.4	6.3	5.7	5.4	5.9	8.5
Nuclear Electric Power	56.1	50.0	51.4	52.3	50.6	52.9
Hydroelectric Power	14.5	13.1	13.8	10.6	12.3	11.2
Biomass	19.4	19.0	17.2	16.1	20.8	20.3
Solar/PV	0.1	0.2	0.3	0.5	0.7	0.9
Wind	0.1	0.1	0.3	1.0	2.3	3.0
Net Interstate Flow of Electricity	-35.5	-27.4	-30.0	-73.4	-78.3	-76.9
Net Electricity Imports	8.7	8.3	8.6	39.2	40.1	38.1
Source: U.S. Energy Information Administration, State Energy Consumption Estimates, 1960-2014, released June 2016						

Figure 2.1 outlines Vermont's energy use by sector between 1960 and 2014. While transportation energy use has grown at a faster pace than any other energy sector since 1960, it has dropped by more than 10% since 2000, most likely a result of an increase in fuel efficiency and conservation efforts. Residential sector consumption has grown by nearly 15% since 1990. Residential fluctuations are considered to be normal - resulting from general population growth, an increase in the average house size, and additional modern conveniences. While the drop from 2005 levels may be attributed in part to the great recession, it may also reflect more efficient building practices, such as more efficient heating equipment and better insulated building shells. According to the Energy Information Administration's 2013 Residential Energy Consumption Survey, U.S. homes built in 2000 and later consume only 2% more energy on average than homes built prior to 2000, despite being on average 30% larger.

Figure 2.1: Statewide Energy Use by Sector, 1960-2014
(trillions of BTUs)



Source: U.S. Energy Information Administration, State Energy Consumption Estimates, 1960-2014

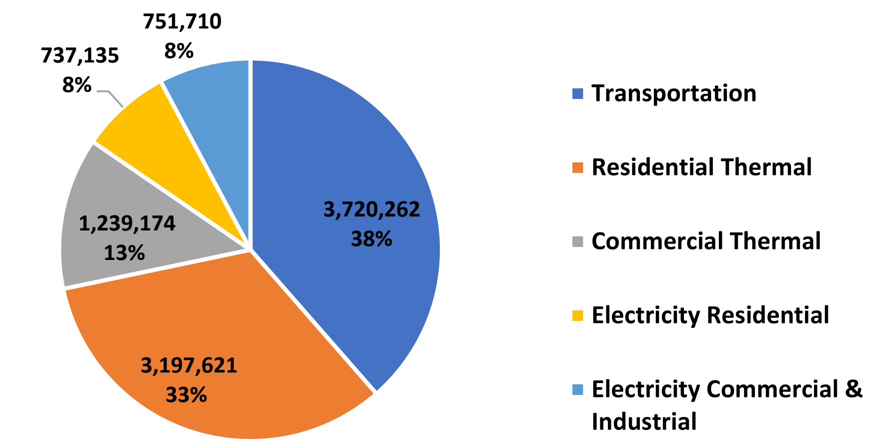
The industrial sector has seen the most significant decrease in consumption since 2010; however, it is unclear as to how much of this reduction is attributed to new energy efficiency measures employed by manufacturers, reduced production levels, or plant closings in Vermont.

Regional Energy Use by Sector

Note: The following regional estimates were developed using multiple sources, including the Department of Public Service, American Community Survey, Vermont Department of Labor. For more information about how these estimates were developed, please see Appendix A.

According to NVDA estimates, residential and commercial thermal use (heating space and water) is the largest energy use at 46%. Transportation[4] is the second largest energy use in the Northeast Kingdom, accounting for 38% of total usage measured in MM BTUs,, followed by electricity at 16%. (Figure 2.2)

Figure 2.2: Regional Energy Use by Sector (MM BTUs), NVDA Estimates



Residential Thermal

On average, a Vermont residence uses 110 MM BTUs annually for heating space and water.[5] Annual usage, however, can vary from as low as 70 MM BTUs to 150 MM BTUs, depending on a number of factors such as total square footage, seasonal use, and age of structure. The age of the Northeast Kingdom's housing stock is likely the most significant contributor to the overall usage. According to most recent American Community Survey Five-Year Estimates (ACS), nearly one-third of owner occupied housing units and nearly one-half of renter-occupied housing units were built prior to 1940.[6] Older homes are likely to be poorly insulated and leakier, driving up consumption and costs.

There are 26,133 occupied and heated households in the Northeast Kingdom, which collectively account for more than 3.2 billion BTUs and $40 million in various heating fuels. (Table 2.2)

Table 2.2: Residential Heating Fuels Used in the Northeast Kingdom

Fuel Type: Space Heating	Number of Households	Avg. Use (Annual)		Percent of Use: (All HHs)	Percent of Use: Owner	Percent of Use: Renter	Percent of Cost (All HHs)
Tank/LP/etc. Gas	3,782	3,713,828	Gallons	14.4%	12.4%	21.1%	23.5%

[4] Transportation data only includes light-duty vehicles, and commercial transportation data is not available.
[5] Vermont Department of Public Service. "Guidance for Regional Enhanced Energy Planning Standards" March 2, 2017
[6] The American Community Survey (ACS) data differs from Census data in that it utilizes annual survey figures, from a smaller cross-section of the population, across a rolling 5-year timeframe to provide data estimates for a given year. The estimates used for this update were from 2011-2015.

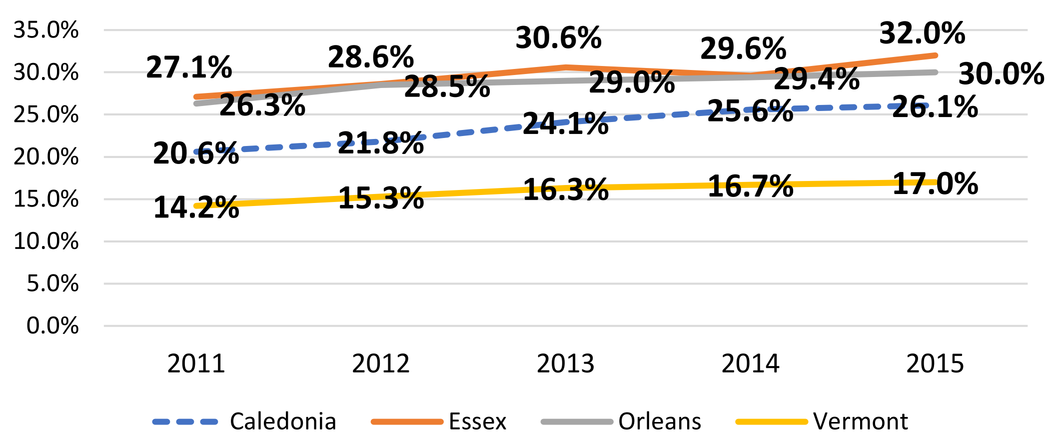
Electricity	454	11	GWh	1.7%	0.8%	4.7%	4.0%
Fuel Oil	13,997	9,252,413	Gallons	53.4%	50.6%	62.5%	51.4%
Wood	7,441	36,446	Cords	28.4%	34.1%	10.2%	20.6%
Coal/Coke	115	529	tons	0.4%	0.4%	0.6%	0.5%
Other	344	-		1.3%	1.6%	0.4%	0.0%
Source: NVDA (See Appendix A)							

The region lacks natural gas distribution infrastructure, so oil is the most widely consumed residential heating fuel. Propane -- which is cleaner burning and less expensive than oil but tends to produce less heat per gallon – is the second most used heating fuel for rental stock.

Another contributor to residential thermal usage patterns in the Northeast Kingdom is the high concentration of seasonal homes. According to the 2010 Census, more than one of every five housing units in the NEK is a vacant housing unit intended for "seasonal, recreational, or occasional use". The Vermont Department of Public Service has estimated that "summer" seasonal housing stock – i.e. lake cottages -- may use as little as 5% of a year-round residential structure, while "winter" seasonal housing – like in Burke and Jay – could use as much as 10%. In reality, the seasonal usage lines are blurred, as many communities have seasonal populations that visit throughout the year. NVDA estimates that the region's approximately 8,800 seasonal units accounts for about 45,398 MM BTUs annually in thermal energy.

Wood is used by more than one-third of owner occupied homes, but only about one-tenth of renter-occupied homes. Two affordable housing developments in the region use wood pellets – Maple Street Senior Housing in Hardwick with 16 units, and Mathewson Block in Lyndonville with 6 units. The region's homeowners maintain a strong tradition of burning wood and do so at a much higher rate than the rest of the state. (Figure 2.3). In the late 2000s, instability of fuel prices compelled more homeowners to install wood-pellet stoves and furnaces, as well as outdoor wood boilers for heating water in recent years. Despite a recent drop in fuel oil prices in recent years, combined with a significant shortage of wood pellets during the 2014-2015 heating season, homeowners remain committed to wood. In many cases, fuel oil is actually used as a back-up source to wood.

Figure 2.3: Wood Use in the NEK and Vermont, 2011-2015



Source: American Community Survey

Table 2.3: Cost of Fuels, 2011-2016									
		November 2011			*November 2016*				
Types of Energy	**BTU/Unit**	**Adj. Effic.**	**$/Unit**	**$/MM BTU**	**Typical Effic.**	**$/Unit**	**$/MM BTU**	***High Effic. ****	***High Efficiency$/MM BTU***
Fuel Oil, gallon	138,200	80%	$4.08	$36.89	80%	$2.23	$20.14	*95%*	*$16.96*
Kerosene, gallon	136,600	80%	$4.45	$40.71	80%	$2.80	$25.65		
Propane, gallon	91,600	80%	$3.37	$46.05	80%	$2.54	$34.64	*95%*	*$29.17*
Natural gas, Ccf	100,000	80%	$1.78	$22.22	80%	$1.41	$17.67	*95%*	*$14.88*
Electricity, kWh (resistive)	3,412	100%	$0.16	$46.37	100%	$0.15	$43.46		
Electricity, kWh (heat pump)**	n/a					$0.15	n/a*	*240%*	*$18.32*
Wood (cord-green)	22,000,000	60%	$192.03	$14.55	60%	$227.00	$17.21		
Pellets (ton)	16,400,000	80%	$263.51	$20.09	80%	$275.00	$20.96		

Source: Department of Public Service, Vermont Fuel Price Report (2011 figures are adjusted for Inflation)
* n/a because heat pumps can only burn in one mode.

Table 2.3 demonstrates the change in heating fuel prices in the last few years. Only the least used fuel – resistance type electricity – has remained stable. Meanwhile the cost of fossil fuels has dropped, while the cost of wood has risen slightly. When oil prices were high, many NEK residents turned to alternative fuels, especially wood pellets, which are cleaner burning, more efficient than cord wood, and relatively easy to use. Stoves and furnaces can be controlled by a thermostat. Their prices have remained relatively stable, although there have been some shortages in recent heating seasons. Wood pellet stoves and furnaces may be a significant investment for most homeowners, so they have continued to use pellets even after the price of heating oil dropped.

In 2015 the Vermont Fuel Price report was amended to account for "High Efficiency" ratings of furnaces, which are manufactured to meet higher efficiency standards can result in savings on energy for the customer.

Heat Pump Technologies:

The Fuel Price Report now includes information on electric-powered heat pump systems, which can deliver up to three times more heat energy than the energy required to operate them. This high return rate – called a coefficient of performance (COP) – offsets the increased electricity usage. All air – even frigid Vermont winter air – contains a significant amount of heat energy. The air source heat pump captures the heat energy from the outside, compresses it, and circulates it into the house at a high temperature. (In hot summer months, the technology operates in reverse, acting as an air conditioner.) Because a heat pump *transfers* heat rather than *generates* it, it requires significantly less energy to operate than a traditional electric, propane, or oil system.

Geothermal or "ground source heat pump systems" operate on the same principle: They extract natural low-temperature thermal energy from the ground during colder months for heating, and transfer thermal energy from the building to the ground in warm months for cooling. A geothermal system in Vermont can save roughly $1,000 to $2,000 annually in heating costs and have a "simple payback time" of between 10-20 years. This technology operates much like a refrigerator, utilizing a heat pump, heat exchanger, and refrigerant.

There are two main types of geothermal systems, open-loop and closed-loop. Open-loop systems utilize a deep rock well or pond to draw water to the heat exchanger where heat flows from the water into cold refrigerant. The refrigerant is then compressed, which greatly raises its temperature and converts it to vapor. Refrigerant vapors then transfer heat to water in a second heat exchanger that is then circulated to heat the building. The process operates in reverse for cooling. Closed-loop systems are slightly different in that they utilize piping in the ground or a pond that can be placed closer to the surface, but then require refrigerant or water with antifreeze to circulate in the piping.

Open-loop systems are more efficient than closed-loop systems and are often cheaper to install because they require less excavation. Open-loop systems are also a good fit for Vermont, since standing column wells can be constructed virtually everywhere. While existing well systems can have geothermal systems installed, installation of this technology is often cheapest during construction of a new building and development of a new well site. A geothermal well resource map is provided at the end of the chapter and identifies existing wells with a high potential for geothermal heating and cooling applications.

Traditionally, geothermal systems have been more efficient than air-sourced heat pumps (ones that just utilize outside air), because the ground/well source systems can take advantage of relatively constant temperatures below the frost line. In recent years, however manufacturers have developed air-sourced "cold climate" pumps that operate more consistently over Vermont's vast temperature ranges. Unlike geothermal units, they do not require excavation or duct work and can be much less expensive to install. Cold climate heat pumps have the capacity to heat about 50% to 70% of a building, depending on the size and layout of the structure. Older homes with multiple ells or wings may be difficult to heat with heat pumps alone, but the pumps may be effective for boosting colder underserved zones. They also may be useful in outdoor workspaces. Despite recent improvements in effectiveness on cold days, a backup heating source is usually required for sub-zero temperatures.

Commercial/Industrial Thermal

Most of the region's commercial/industrial energy usage can be attributed to space heating and process heating. Table 2.4 identifies average heating load per establishments and total MM BTUs consumed annually[7] Heating loads vary significantly and may be highly specific to type of industrial processes. NVDA's estimates were developed using assumptions about business patterns. For example, types of businesses that tend to employ more workers per establishment can be expected to be the larger consumers of heat energy – schools, hospitals and clinics, hotels and restaurants. On the other hand, businesses that have few on-site employees – like real estate agencies – use significantly less.

To combat high heating costs, RadianTec, a radiant-floor heating manufacturing company in Lyndon, utilizes solar hot water panels and passive solar design to reduce their heat loads. Other commercial operations and institutions have turned to wood. Wood chips - either bole chips or whole tree chips - are well suited for combustion to supply heat, hot water, or steam in institutional, commercial, and industrial settings. The Vermont Fuels for School Program has been very successful

Table 2.4: Commercial Thermal Energy Use

	# of Commercial Establishments	Average Heating Load (MMBTUs)	Total MMBTUs
Caledonia	722	829	598,292
Essex	103	1,118	115,174
Orleans	631	833	525,708
TOTAL	1,456	851	1,239,174

Source: Department of Public Service, Vermont Department of Labor

[7] Vermont Department of Public Service. "Guidance for Regional Enhanced Energy Planning Standards" March 2, 2017

implementing wood heating in schools. Six schools in the Northeast Kingdom currently heat with wood: Burke Mountain Academy, Craftsbury Elementary, Danville School, Hazen Union School, and Lyndon Town School currently heat their facilities with wood. Ryegate and Groton students attend the Blue Mountain School in Wells River, which has been heated with wood chips since 1998.

Industrial and commercial enterprises in the state are also moving towards wood-based heating systems, and in some cases co-generation. In the Northeast Kingdom, the North Country Hospital, and Lyndon Furniture utilize wood-chip Combined Heat and Power (CHP) systems to meet partial heat and power needs.

Thermal Efficiency and Weatherization

Regional thermal efficiency and weatherization efforts are spearheaded through four organizations: **Efficiency Vermont**, **Northeast Employment and Training Organization (NETO), 3E Thermal, and Heat Squad**.

Efficiency Vermont, the energy efficiency utility for the state, was established by the Vermont Public Service Board in 1999. The utility is funded by an energy efficiency charge on consumer electric bills, similar to a system benefits charge. Efficiency Vermont offers energy and money-saving programs to consumers that allow them to install and use energy-efficient construction designs, products and equipment. They also offer low-income energy assistance programs.

NETO was incorporated in 1978 as a 501(c)3 agency for the purpose of delivering weatherization programs to low income residents of the Northeast Kingdom. NETO receives most of its funding from the State of Vermont Weatherization Program and receives additional funding from the Department of Energy. Residents who do not qualify for low-income weatherization assistance can still contact NETO for energy audits.

3E Thermal (formerly known as Vermont Fuel Efficiency Partnership) is a statewide program that provides consulting, technical support, and incentives to owners of affordable apartment housing. Since 2010, 3E Thermal has collaborated on several multifamily energy-improvement projects around the NEK, representing a total of more than 250 apartments, each saving more than 6,000 MMBTUs annually. 3E is funded by a thermal efficiency fund created by the legislature that uses revenues from the regional Greenhouse Gas Initiative, a cape-and-trade system covering nine states in the Northeast, and the forward-capacity market, where Efficiency Vermont sells future electric savings through ISO-New England.

Heat Squad, an energy efficiency organization, founded by NeighborWorks of Western Vermont, is actually based in the Rutland area. However, in August of 2017, Heat Squad received $250,000 in grant funding from the Northern Border Regional Commission to expand their services to the Northeast Kingdom. The expansion is expected to result in 233 home energy retrofits over the next three years.

According to Efficiency Vermont, 6,061 efficiency projects have reduced thermal energy consumption in the Northeast Kingdom by more than 37,000 MM BTUS annually. (Table 2.5)

Table 2.5: Thermal Savings in the NEK (MM BTUs), 2014-2016

	2014	2015	2016	Total
Residential	2,986	1,774	2,722	7,481
Commercial & Industrial	3,015	19,982	6,590	29,587
TOTAL	6,001	21,756	9,312	37,069

Source: Vermont Energy Investment Corporation

The Vermont Department of Public Service seeks to optimize thermal performance on all new residential and commercial construction through the enforcement of energy codes. Although codes have been in place since the late 1990s, they have not always been enforced consistently. In 2013, the Vermont legislature passed Act 89, which ties documentation of compliance with energy codes to the local zoning process. Zoning administrators are now required to provide all applicants with Residential Building Energy Codes (RBES) and Commercial Building Energy Codes (CBES). If a municipality issues a certificate of occupancy, the developer must produce certification of compliance with the codes. Act 89 also authorizes the Department of Public Service to adopt "stretch" codes that exceed baseline efficiency, and municipalities have the option to adopt these codes as they become available. The Department of Public Service adopted a stretch code for RBES, and a stretch code for CBES is in development. The Natural Resources Board presumes compliance with stretch codes to meet the energy efficiency criterion of the Act 250 review.

Transportation

The EIA estimates that statewide, the transportation sector alone consumes about three-fifth of all petroleum products, mainly because rural residents drive long distances to work and errands. Regional estimates show transportation to be the second-largest overall energy use, and this estimate does not even include commercial and industrial vehicles. While Vermont ranks 50th in carbon dioxide emission, transportation accounts for more than half of all greenhouse gas emissions.

Table 2.6: Transportation Energy Use in the Northeast Kingdom

Total Light Duty Vehicles	49,676
Total Internal Combustion Engine (ICE) Vehicles	49,542
Average Miles per gallon for ICE	22
Average annual Vehicle miles travelled ICE	14,000
Total annual VMTs ICE	693,588,00
Total Gallons ICE	31,526,727
Trillion BTUs, Fossil fuel	3.5
MM BTUs, Ethanol	240,357
Trillion BTUs Total ICE	3.7
Total Electric vehicles (EVs) (as of Jan. 2017)	134
Average annual VMT for EVs	7,000
Total annual VMTs for EVs	938,000
Average fuel economy for kWh	3
Total kWh for EVs	312,667
MMBTUs for EVs	1,067

Sources: American Community Survey, Department of Public Service, and NVDA estimates.

Energy use in transportation is most greatly influenced by the development patterns of the region. Given that the Northeast Kingdom consists of a rural landscape with small pockets of concentrated development, there are minimal avenues in which energy consumption as part of the transportation sector can be effectively reduced. Long commutes and incidental trips require NEK residents to drive an average of 14,000 miles per year, collectively accounting for more than 693 million vehicle miles travelled, which represents nearly $71 million in fuel costs. (Table 2.6) Nearly all of this energy is non-renewable. Ethanol currently accounts for the vast majority of renewable transportation energy use – about 6.5% of total BTUs – while electricity accounts for a mere .03%.

Plug-in electric vehicles (EVs) have the greatest potential to reduce Vermont's statewide greenhouse gas emissions. "Refueling," which is as simple as plugging into an electric outlet, costs the equivalent of about $1.00 per gallon. According to Vermont Energy Investment Corporation, there are 1,595 EVs registered in Vermont as of April 2017, marking a 37% increase from the previous year.

There are two types of EVs:

- **All-Electric Vehicles (AEVs)**: An AEV can range as far as 80 miles on a single charge, but on very cold days, this range can be cut in half. AEVs are therefore best used as a second car.

- **Plug-in Hybrid EVs (PHEVs)**: A PHEV generally does not range as far as an AEV, but it can switch over to gasoline when the battery charge runs low, making it a more likely choice for those with longer drives and greater distance from public charging stations. About 75% of EVs registered in Vermont are PHEVs.

Not surprisingly, Chittenden County has the highest concentration of EVs on the road – about one-third of all EVs in the state. Nevertheless, Northeast Kingdom residents are beginning to use them as well. As of January 2017, there were 134 EVs registered in the region. The highest use is found in the region's population centers – St. Johnsbury, Lyndon, Hardwick, Derby, and Newport. There are three EV dealerships in the region – Lamoille Valley Ford in Hardwick, and Twin State Ford and Quality Mitsubishi, both in St. Johnsbury. A limited number of public charging stations have been established around the region (Table 2.7), and more will be needed to support expanded EV use, particularly if more drivers switch to AEVs. All but two of the existing public charging stations are level 2, which can be ideal when a driver can park for at least an hour for work, shopping, or dining. A level 2 is about six times faster than a level 1, which requires several hours of charge time. Only one location currently offers a DC fast charge, which can provide up to 80% battery charge in only 20 minutes. Unfortunately, many hybrids are not equipped to connect to the DC fast charge.

Table 2.7: Public Charging Stations for EVs in the Northeast Kingdom

Town	Location	Charge Type
Barton	Barton Village Offices	Level 2
Danville	Marty's First Stop	Level 2 and DC fast
Derby Line	Derby Line Unitarian Universalist Church	Level 2
Hardwick	Lamoille Valley Ford	Level 2
St. Johnsbury	Twin State Ford	Levels 1 and 2
St. Johnsbury	Pearl Street Parking Lot	Level 2
St. Johnsbury	Northeastern Vermont Regional Hospital	Level 2
Source: US Department of Energy's Alternative Fuel Locator		

Ethanol, currently the primary source of renewable fuels for light-duty transportation vehicles, can be blended up to 10% with gasoline to form E10. It can be used in any engine that takes regular gasoline. Corn is the most common element used to produce ethanol, even though it can be produced from a variety of elements, including wood. Ethanol burns cleaner than gasoline and is very effective in lowering fuel emissions. Unfortunately, the fuel also has significant problems in cold-weather, which make it less useful for Vermont's climate. While E10 is required in many urban areas that do not meet federal air emission guidelines, this is not the case in Vermont. Many of the blends available in this area are 9% ethanol.

One area in which Vermont is seeing growth in fossil fuel usage is via compressed natural gas. With a reduction in natural gas prices, compressed natural gas is now economical for large industrial applications (utilizing over 150,000 gallons fuel oil annually) and as a transportation fuel. Both the Burlington Department of Public Works and Vermont Gas maintain vehicle fleets fueled with compressed natural gas. Liquified petroleum gas (LPG) can also be used a transportation fuel and produces fewer CO2 tailpipe emissions than conventional gasoline-powered vehicles. The region has one LPG fueling station at the Pick and Shovel in Newport.

Price volatility of gasoline in the first half of the past decade helped to spur an interest in the development of biofuels. Biodiesel is commonly made from soybeans, rapeseed (canola), and sunflowers; all of which can be grown in Vermont. Biofuel can be blended with diesel up to 5% (B5) to be safely used for on-road vehicles. Higher blends, including pure biodiesel (B100) can be used in off-road equipment and farm vehicles, although farm equipment manufacturers have approached the use of biodiesel with caution. Black Bear Biodiesel, located just outside of the region in Plainfield, is a B100 fueling station.

Research has found that oilseed crops, when grown in rotation with other crops, can help to support sustainable, diversified, and profitable agricultural enterprises. The Vermont Bioenergy Initiative, a program of the Vermont Sustainable Jobs Fund, provides early-stage grant funding, technical assistance, and loans to producers. Currently North Hardwick Dairy produces oilseed crops for use as fuel and food-grade. Although the recent drop in fuel prices has reduced some incentive for farmers to enter biofuel production, NVDA encourages further innovation and research into this area as a long-range economic opportunity.

Commercial shipping is one of the highest consumers of transportation fuels and another area in which the region can reduce consumption. As gas prices started to climb in the past decade area, businesses looked for alternative shipping methods and inquiries into the region's rail infrastructure grew. Railroad shipping is most desirable for non-perishable commodity goods. Upon further review it was found that regional rail infrastructure has the potential for growth, with room for increased traffic and a number of underutilized sidings. The Kingdom may also be able to attract additional rail usage if rail beds are upgraded to meet the 286,000 lb. weight limit standard and bridge heights are increased. Both improvements will allow rail cars to be filled to capacity and allow for the double stacking of rail cars, which is now standard across the country. NVDA also supports the re-establishment of the Twin State Line as a means to better connect the Kingdom with greater rail markets in New England.

Development Patterns and Transportation Use

Understandably rural development patterns directly impact transportation energy usage, especially in regards to individual behaviors. With limited transit infrastructure, the region is dominated by single-occupancy light-duty vehicles. Residents typically commute to disparate labor market areas, reducing opportunities for carpooling. VTrans offers grant assistance to municipalities who wish to establish park and rides on municipal, state, or leased property on or near state highways. Mixed-use, higher density neighborhoods encourage more pedestrian use. The following land use principles encourage reduced transportation energy consumption[8]:

1. Encourage the location of new development in or near traditional village and city centers to reduce both sprawl and the number of vehicle miles driven.
2. Support transit-oriented development that fosters the expansion of public transportation and rail use.
3. Encourage the construction of Park and Ride facilities to support carpooling efforts.
4. Encourage the expansion of bicycle and pedestrian facilities such as sidewalks and bike lanes.

Additionally, improved telecommunications infrastructure in this region has the potential to reduce annual VMTs by allowing more workers to telecommute.

Electricity Use

With respect to simply how much electricity is generated here relative to what is consumed, the Northeast Kingdom is a net exporter of energy. This is a major shift from more than a decade ago, when the region relied heavily on Canada, New Hampshire, and the rest of Vermont to meet its electricity demand. In 2016, the total electric usage for the region was 436,355 MWHs, representing a total of roughly 1.48 trillion BTUs. (Table 2.8). Despite the increase in customer counts in the C&I sector since 2014, total usage dropped by .4% over the same period. The number of residential customers increased slightly over the same period, but total residential usage decreased by a fraction

[8] See the Transportation, Land-Use, and Housing Sections of the *Regional Plan for the Northeast Kingdom* for additional energy-related recommendations.

of a percentage point, as did the average residential usage. Similar data on average commercial and industrial use is not available.

Table 2.8: Annual Electricity Use in the NEK			
Usage by Sector (In MWHs)	2014	2015	2016
Commercial & Industrial	221,395	229,877	220,313
Residential	216,757	218,962	216,042
Total	438,152	448,840	436,355
Avg. Residential Use (in KWHs)	6,323	6,372	6,295
Count of Customer Premises (Customers)			
Sector	**2014**	**2015**	**2016**
Commercial & Industrial	5,808	5,871	5,977
Residential	34,279	34,363	34,317
Total	40,087	40,234	40,294
Source: Vermont Energy Investment Corporation			

Although the commercial and industrial sector only accounts for about 15% of all electrical utility customers, they account for slightly more than half of all usage. Electric costs are a major factor in attracting and retaining major commercial/industrial operations in the region. New England retains the highest electric costs in the lower 48 states for both sectors. In April 2017, the state's average electric retail price was 14.14 cents/kWh in the commercial sector and 10.12 cents/kWh in the industrial sector. These rates are the second lowest in the New England, but still considerably higher than national rates of 10.38 cents/kWh and 6.63 cents/kWh respectively (U.S. Energy Information Administration, Electric Power Monthly). When most large manufacturers are speaking in terms of megawatt-hours (thousands of kilowatt-hours) for power consumption, those price differences are considerable. The former Dirigo Paper Mill utilized on-site hydro and waste steam for electrical generation. Ampersand Gilman Hydro continues to operate the site. Ethan Allen has studied the feasibility of a combined heat-and-power plant with Orleans and Barton Electric for their Orleans facility; and Lyndon Furniture in St. Johnsbury has employed a diesel-fueled electric generator to stabilize their electric costs for several years.

According to Efficiency Vermont, 6,061 efficiency projects have achieved savings electrical use in the Northeast Kingdom by 82,324 MM BTUs from 2014 to 2016. (Table 2.9).

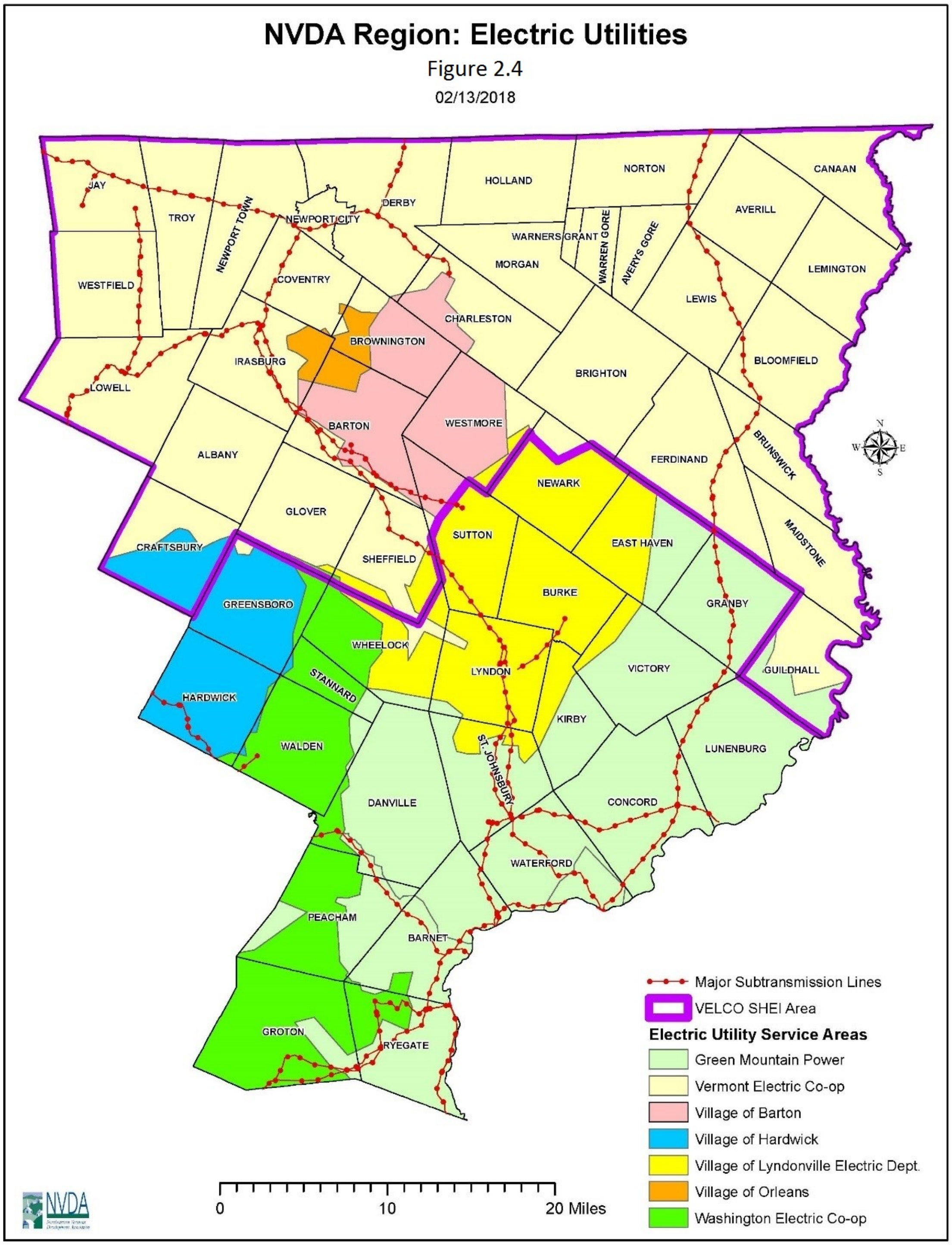
Table 2.9: Electricity Savings Achieved in the NEK, in MWh				
Sector	**2014**	**2015**	**2016**	**Total**
Residential	2,951	3,569	3,286	9,806
Commercial & Industrial	3,953	5,178	4,990	14,122
Total	6,904	8,748	8,276	23,928
Source: Vermont Energy Investment Corporation				

III. GENERATION AND DISTRIBUTION

Electric systems are part of large regional networks that extend beyond state boundaries. Vermont belongs to a network that encompasses the six states of New England. These regional networks are responsible for the general organization and operation of the electric businesses and market territory. However, the vast diversity in state-to-state infrastructure can influence the energy climate in surrounding network states. For Vermont, this translates into major effects on the affordability, cost, and reliability of electrical systems.

Regional Utilities

The Northeast Kingdom is served by seven electric utilities. Figure 2.4 depicts the coverage areas of the region's utilities and the subtransmission lines. Vermont Electric Co-Op serves the largest area, covering over 19 towns in Northern Essex and Orleans Counties. Green Mountain Power also covers a large area in Caledonia and Southern Essex Counties, with the remainder of the region served by Washington Electric Co-Op, and four municipal-owned electric companies. The NEK's municipal electric utilities include Barton Electric, Orleans Electric, Lyndonville Electric, and Hardwick Electric. Together the municipal utilities provide service to 19 different towns and villages (Figure 2.4[9]).



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[9] Latest version of mapped Utility Service Territories (VCGI ArcGIS) data available.

All the municipally owned utilities throughout the state are represented by the Vermont Public Power Supply Authority (VPPSA). VPPSA acts on behalf of the utilities in the regional buying and selling of power and provides rate studies, central computer services, load forecasting, tax-free financing of certain capital projects, and exploration of new generation options. VPPSA is a part owner in the McNeil Station in Burlington, a 50 MW generator that primarily uses wood, as well as the Highgate Interconnection facility, which is used to bring in power from Hydro Quebec. In 2010, VPPSA completed a 40MW peaking facility in Swanton, Vermont. The facility runs during peak price times to mitigate price spikes that typically occur in the summer and winter.

The region's utility power supply portfolios are made up of a mixture of generation resources, long-term contracts, and short-term contracts. Three of the municipal utilities generate some of their own power through hydro (Hardwick has a facility in Wolcott, just outside of the region.) Orleans Electric's portfolio also includes long-term and short-term contracts; however, it is without generation resources of its own. Figure 2.4 demonstrates the aggregated power supply by fuel type for all utilities serving the Northeast Kingdom. (This power supply mix will vary among each member utility of VPPSA.)

Table 2.10: 2016 Fuel Mix (Before Sales of Renewable Energy Certificates)							
VPPSA*		Washington Electric Coop		Vermont Electric Coop		Green Mountain Power	
%	Source	%	Source	%	Source	%	Source
40	Market Purchases	66	Coventry Landfill	59.6	Hydro	34.7	Large Hydro
33	Hydro	13	NYPA (Large Hydro)	19.4	Wind/Solar/Farm Methane/Wood	27.4	Market Purchases
15	Biomass	10	Sheffield (Wind)	17.9	Nuclear	13.8	Nuclear
7	Landfill Gas	5	Small Hydro	3.2	Natural Gas/Oil	5.6	Existing VT Hydro
2	Solar	3	Ryegate (Wood)			8.2	Wind
2	Standard Offer	3	Market Purchase			4.9	Hydro
1	Fossil	<1	GMP System			2.6	Wood
						2.1	Solar
						0.3	Methane
						0.4	Oil & Natural Gas
Source: Integrated Resource Plans, Utility reports, and web sites *Fuel mix will vary among municipal utility members.							

Until it shut down in 2014, Vermont Yankee supplied roughly one-third of Vermont's electric supply. Central Vermont Public Service and Green Mountain Power were the lead owners of the facility. (GMP and CVPS merged in 2012.) . While a large share of this replacement power has come from Hydro Quebec GMP, there is still some nuclear power in the mix from Seabrook, NH. While much of the utilities' power originates from Hydro Quebec, there are other sources from New York Power Authority, as well as smaller facilities throughout the state. Market purchase are power contracts purchased without any known environmental attributes and the fuel mix may change over time.

Green Mountain Power estimates that as of 2016, the market purchase mix is more than half natural gas, followed by nuclear, and oil.[10]

Although the NEK is a net exporter of energy, Vermont has traditionally been a net importer. Technically, the state produces enough generation; however, due to the performance characteristics of the in-state generation, Vermont has relied heavily on its transmission network to import power from neighboring states. When Vermont Yankee shut down, Vermont's net import rate rose significantly, making the state a net importer of power at virtually all hours from New York, New Hampshire, Massachusetts and Canada in order to meet the state's load requirements. Without significant new in-state generation, this situation will be a long-term operating condition.[11]

Purchase & Distribution

The state of Vermont belongs to the ISO-New England Regional Transmission Organization (RTO). The ISO-New England RTO operates all of New England's bulk electric power system and works in coordination with the New England Power Pool (NEPOOL). NEPOOL is Vermont's regional representative of the electric power businesses, including utilities, independent power producers (IPP), suppliers, end-users, and transmission providers. In 1997, the RTO was developed as a means to create competitive wholesale electricity markets. Their responsibilities include developing, overseeing and operating the New England wholesale electric market, as well as managing and planning for regional electric needs.

The RTO wholesale electric market operates on a per-hour bid system that incorporates some short-term and long-term contracts. The bid system requires generation units to bid into the system based on what it costs them to produce for that hour. The hourly price is then set based on the most expensive facility needed to meet demand. As demand increases, the higher-priced facilities are pulled online to meet the increasing load. In Vermont, many of the "peaking" plants utilize diesel fuel. New England is also heavily dependent on natural gas generation facilities, which set the hourly price 85% of the time. Even though natural gas prices have dropped recently, New England households retain the highest electric costs in the country. As part of the RTO, Vermont is subject to these higher electric costs, even though there is only one natural gas generation facility in the state. According to the Public Service Department, the higher pricing is caused by existing long-term contracts and restrictive pipeline infrastructure. In other words, New England is still paying natural gas pricing that was set in a multi-year contract, plus its limited pipeline capacity means it cannot access additional volumes of natural gas outside of those contracts. Massachusetts is currently pursuing the expansion of a major pipeline to be able to utilize larger volumes of natural gas.

Transmission

A majority of Vermont's electric transmission system is operated by the Vermont Electric Power Company (VELCO), which was established by Vermont's utilities in 1956. VELCO is responsible for bulk transmission lines with a voltage rating of 115kV and above. Lines with a rating of 34.5kV, 46kV, and 69kV are considered sub-transmission lines. The Northeast Kingdom has roughly 325 miles of transmission and sub-transmission lines (Figure 2.3) and serves as an important gateway for electricity coming from both Canada and New Hampshire.

VELCO is responsible for planning and constructing upgrades that ensure system reliability and maintain the grid. Several upgrades in recent years should significantly increase transmission capacity

[10] Green Mountain Power: Our 2016 Fuel Mix Information
http://www.greenmountainpower.com/2016/12/01/fuel-mix/

[11] VELCO: 2015 Long-Range Transmission Plan
https://www.velco.com/assets/documents/2015Plan_Final_toPSB.pdf

on existing lines: new lines between Irasburg and Newport; upgrades to the St. Johnsbury, Irasburg, and Newport substations; and the reconfiguration of the Hydro Quebec interconnection at Highgate. In 2010 VELCO upgraded the Hill Street substation in Lyndonville, which provided a secondary connection between Lyndonville Electric's grid and the larger VELCO transmission lines. In 2011, a new substation in Jay established redundancy in transmission paths and increased capacity to delivery power to the Jay area.

VELCO maintains a long-range transmission plan that must be updated every three years for the PUC. The plan and subsequent updates are vetted through a stakeholder group called the Vermont System Planning Committee (VSPC), which is made up of VELCO, electric distribution utilities, the Department of Public Services, representatives of demand and supply resources, and representatives of the general public. The most recent Long-Range Transmission Plan (June 2015) acknowledges that a profound transformation of the electric grid is already underway. The grid must become more agile and diverse by retiring traditional base load generation, increasing distributed renewable generation, and investing in demand-side resources, such as energy efficiency and demand response. Emerging technologies, such as heat pumps and electric vehicles, are reflected in the load forecast of the 2015 Plan, but their full impact cannot yet be quantified with confidence.

One ongoing VPSC initiative of particular concern to the Northeast Kingdom is grid congestion in the Sheffield Highgate Export Interface (SHEI), the northwestern area of our region where generation exceeds load. (Figure 2.4) In essence, the region generates far more power than it consumes, causing generation to exceed the capacity of the export line. The continued addition of new sources of generation, like solar, forces existing resources, like Kingdom Community Wind and Sheffield Wind to curtail their output due to the lack of capacity to export power. Adding more renewables to an already full grid at this point can simply mean replacing other renewables. While modest transmission upgrades may help to alleviate some congestion in the short-term, the situation will require robust, long-term solutions that are complex and possibly costly.[12] Utilities, clean energy advocates, regulators and other stakeholders are currently discussing ways that the SHEI limitations can be addressed to reduce or eliminate curtailments of generation located within the interface.

Regional Generation Facilities

(Note: For municipal-level generation estimates, see Appendix B.)

The Northeast Kingdom has a very large share of generation resources compared to other regions of the state. (Table 2.11) The region is home to four major renewable generation facilities: the Ryegate Wood-Chip Plant, the Coventry Landfill methane-generator, the Sheffield Wind Farm, and Kingdom Community Wind in Lowell. Collectively, these facilities produced 80% of the region's total electricity generation that is not net-metered (i.e. grid-tied). 2005 saw the first major jump in regional generation growth with the development of the Coventry Landfill methane generator, which doubled its output in 2009. The region also produces a significant amount of hydro power. Collectively, hydro power (excluding Connecticut River production, which is technically in New Hampshire), the Northeast Kingdom's hydro resources account for 18% of regional generation.

[12] Frank Ettori, SHEI Overview, VSPC, July 12, 2017 v. 2

Table 2.11: Generation Facilities in the Northeast Kingdom					
Owner/Operator – Facility Name	**Location**	**Utility**	**Facility Type**	**kW Capacity**	**Annual Output MWh**
Kingdom Community Wind	Lowell	GMP	Commercial Wind	63,000	*191,174*
Sheffield Wind	Sheffield	WEC	Commercial Wind	40,000	*121,380*
Passumpsic Hydro	Barnet	GMP	Hydro	700	3,851
East Barnet Hydro	Barnet	GMP	Hydro	2,200	7,442
Barnet Hydro	Barnet	GMP	Hydro	490	1,814
Great Bay Hydro Corp. (IPP) – West Charleston (Standard Offer)	Charleston	VEC	Hydro	675	2,655
Barton Village Hydro	Charleston	Barton Village Electric	Hydro	1,400	4,210
Fairbanks Mill	Danville	GMP	Hydro	18	73
West Danville #15	Danville	GMP	Hydro	1,000	3,700
Ampersand Gilman Hydro	Lunenburg	GMP	Hydro	4,850	28,000
Great Falls	Lyndonville	LED	Hydro	1,900	9,600
Vail	Lyndonville	LED	Hydro	350	1,850
Newport 1, 2, 3	Newport	VEC	Hydro	4,000	15,735
Dodge Falls	Ryegate	GMP	Hydro	5,000	27,000
Emerson Falls	St. Johnsbury	GMP	Hydro	230	700
Arnold Falls	St. Johnsbury	GMP	Hydro	350	1,588
Gage	St. Johnsbury	GMP	Hydro	700	2,878
Pierce Mills	St. Johnsbury	GMP	Hydro	250	1,544
North Troy	Troy	VEC	Hydro	460	2,600
Troy Mills Hydroelectric (Standard Offer)	Troy	VEC	Hydro	816	3,210
Maxwell's Neighborhood Energy, LLC (IPP) (Stanard Offer)	Coventry	VEC	Methane	225	1,508
WEC – Coventry Landfill	Coventry	WEC	Methane	8,000	50,506
Maplehurst Farm (Standard Offer)	Greensboro	HED	Methane	150	1,005
Chaput Family Farms (Standard Offer)	Troy	VEC	Methane	300	2,010
Sun CSA 73 (Community Solar)	Barnet	GMP	Solar	150	184
Sun CSA 59 (Community Solar)	Barnet	GMP	Solar	150	184
Barton Solar LLC (Standard Offer)	Barton	VEC	Solar	1,890	2,401
SolarSense VT (Community Solar)	Concord	GMP	Solar	500	613
Coventry Solar (Standard Offer)	Coventry	VEC	Solar	2,200	2,794
Sun CSA 27 (Community Solar)	Lowell	VEC	Solar	150	184
Solaflect Community Solar Park	Lunenburg	GMP	Solar	150	235
Sun CSA 53 (Community Solar)	Lunenburg	GMP	Solar	150	184
Ira Rentals (Standard Offer)	Newport	VEC	Solar	37	47
Bobbin Mill (Standard Offer)	Newport	VEC	Solar	50	64
Ryegate Power Station (IPP)	Ryegate		Wood Chip	167,627	154,785

TOTAL	310,118	647,708
Source: VEPP, Vermont Renewable Energy Atlas. Some outputs were calculated because actual output was not available, including KCW and Sheffield Wind, which are curtailed due to grid congestion.		

There are also three very large generation assets located on the border of the region that deserve to be mentioned. The Comerford Dam, McIndoe Falls Dam, and the Moore Dam are all located on the Connecticut River, which is owned by New Hampshire. Table 2.12presents their generation figures. According to the Department of Public Service, they are not considered Vermont generation assets, but their mere proximity to the region may pose a future benefit to our area.

Table 2.12: State-Line Generation Facilities (Technically located in New Hampshire) in MWhs/year			
TransCanada - Moore Dam	Hydro	271,000.00	Waterford, VT & Littleton, NH
TransCanada - Comerford Dam	Hydro	315,000.00	Barnet, VT & Monroe, NH
TransCanada - McIndoe Falls Dam	Hydro	52,000.00	Barnet, VT & Monroe, NH
Total		**638,000.00**	

SPEED and Standard Offer

In June 2005, Vermont enacted the Sustainably Priced Energy Enterprise Development (SPEED) Program and Renewable Portfolio Goal to provide financial incentives for the development of new renewable generation facilities under 2.2 MW. The program encourages development by providing feed-in tariffs, which pay a set incentive rate/kWh above current market retail prices for power that meets program criteria and agrees to long-term contracts. Specific types of renewable generation were initially assigned different tariff amounts, and the program had a total cap of 50 MW. In the 2012, the legislature increased the cap to a total of 127.5MW that will be rolled out in set allotments over the course of 10 years to limit the impact on rate payers. Changes to the program also addressed how tariff rates are established, with the legislature promoting a reverse auction process to ensure competitive rates. Northeast Kingdom renewable energy development projects with standard offer contracts are noted in Table 2.13 and include all the farm methane generators, as well as hydro and solar, producing in excess of 15,000 MWh a year. In 2015, VPPSA was awarded two Standard Offer contracts for two solar projects (475 kW and 500 kW) to be located in Lyndonville. A contract has also been awarded to Dairy Air, a large wind project in Holland, although that project is still under review by the Public Service Board. Act 56, which established the renewable energy standard for electric utilities (see below), eliminated the SPEED Program, except for the standard offer component.

Net-Metering

In 1998 the Vermont State legislature passed a bill allowing the practice of net-metering. Net-metering requires electric utilities to permit customers to interconnect on-site renewable electricity systems with the grid (e.g. a photovoltaic system with proper DC-AC conversion equipment) and to be billed only for the net amount of power they consume. This effectively creates an incentive equal to the customer's electric rate for the kWh of renewable electricity that they create. There have been several revisions to the net-metering rules over the past several years, including expanding production limits, simplifying permitting, and increasing peak load capacity, making it easier to establish individual and group run net-metered systems.

Although it is approved for a variety of systems -- solar, small wind, combined heat and power, farm methane, and bio-gasification facilities generating up to 500 kW – net metering has been most popular with solar. This has been largely due to the “solar adder,” which increased the average price per kWh of solar net-metered generation.

Act 99, which became effective in January of 2017, raised the cap on Vermont’s utilities from 4% to 15%, meaning that the utilities have to take on net-metered systems on a first-come, first-served basis to all its customers until the cumulative generating capacity of all net-metered systems equal 15% of the utility’s peak demand. New net-metering customers will be compensated at a reduced rate, although the rate is still well above retail electric rates. Instead of applying a solar adder, the new net-metering rule applies a series of adjustments for siting solar on statewide **preferred** sites that have already been disturbed: rooftops, parking lot canopies, brownfields, and gravel pits. There is no site adjustment for installations of 150 kW or more, so the new net metering has the potential – at least in theory – to site small developments away from open fields and other undeveloped areas. To date, utilities serving the Northeast Kingdom have reported a sharp uptick in the number of net metering applications, and in some instances, at double the rate of previous years. In testimony to the Senate Natural Resources and Energy Committee, VEC has noted that since January of 2017 66% of the 2017 net metering capacity is for projects greater than 150kW. This service area (the SHEI) already has significant system constraints, so new net-metered generation will displace existing generation which is less expensive.[13]

The region currently generates nearly 13,000 MWh through net metering. (Table 2.13). There has also been growth in group net metering and community solar programs, which allow individual customers within one utility service territory to invest in a solar project and receive distributed net metering credits. This off-site option can be cost-effective for residents, particularly renters and home owners where solar installations are not possible. Currently, such net metering projects in the area generate 11,792 MWh annually. Utility customers are also able to “sponsor” solar panels in community solar projects outside of the region.

Table 2.13: Annual Output Net metering in the Northeast Kingdom (MWh)

	Caledonia	Essex	Orleans	NEK
Solar Net-Metering	5,415	452	3015	8,882
Group Net Metered	836	275	209	1320
Community Solar Array	368	1032	184	1584
Small Wind	489	8	613	1,110
Total	7,108	1767	4021	12,896

Source: Vermont Renewable Energy Atlas

Renewable Energy Standard

Until 2015, Vermont had a renewable energy portfolio goal for its utilities to meet growth in electricity demand by using energy efficiency and new renewable generation sources. When Act 56 was passed in 2015, this goal was replaced by a mandatory Renewable Energy Standard (RES) for the portfolios of Vermont’s electric utilities. The RES has three tiers:

Tier I: 55% starting in 2017, existing total renewables will rise 4% every three years to reach 75% in 2032. A utility can meet this requirement by owning renewable energy or renewable energy certificates (RECs) from any plant, as long as the plant’s energy can be delivered in New England.

Tier II: A subset of Tier I RECs, utilities now have a distributed generator requirement connected to Vermont’s electric grid. Starting in 2017, 1% of the utility’s portfolio must be *distributed renewable generation*, rising .6% each year to reach 10% in 2032. (Unlike energy produced in a large power plant, *distributed* energy is produced on-site or in a decentralized manner, such as district generation,

[13] Vermont Electric Cooperative: Testimony to the Senate Natural Resources and Energy Committee-March 23, 2017

through smaller grid-tied devices.) Utilities can meet this requirement by through the production of distributed renewable energy or through RECs that have come into service after June 30, 2015, are 5 MW or less, and are directly connected to Vermont's grid (i.e. in state generation.)

Tier III: This is an energy *transformation* requirement that starts from 2% in 2017 and rises to 12% in 2032. Utilities meet this requirement either through additional distributed renewable generation or "transformation projects" that replace or reduce fossil fuel consumption. Such projects include home weatherization, installation of heat pumps, the use of biofuels, or incentives to purchase EVs. The municipal utility members of VPPSA are exempted from this requirement until 2019, but VPPSA's program will likely include weatherization and heat pumps, biofuels, energy storage, and EVs and charging infrastructure.

Renewable Energy Certificates (RECs)

Tiers 1 and 2 of the Renewable Energy Standard require utilities to hold Renewable Energy Certificates (RECs) to satisfy their requirements. RECs track how much renewable energy is produced from a project, and they have been a major supporting factor in the development of renewable energy. Because Vermont did not have mandatory renewable energy portfolio standards prior to the passage of Act 56, RECs were less likely to be "retired" (used) in state. Rather, they were often sold to Massachusetts, Connecticut, Rhode Island, Maine, and New York, which already had mandatory standards. Utilities and generators buy and sell RECs on an open regional market. Utilities cannot claim electricity is renewable if the REC from that electricity has been sold. Conversely, a utility can claim 100% renewability if it holds sufficient RECs to offset retail sales, even if it generates with fossil fuel. Act 99 affects the sale of RECs from small and mid-size generation. Under the new net metering rule, customers who keep their RECs (either to sell out of state or to keep for themselves) will be subject to a $0.03 penalty per kilowatt-hour (kWh). By contrast, customers who transfer their RECs to the utility will receive a $0.03 incentive per kWh for the first ten years of their operation. Even for a small residential-scale system, this penalty can amount to thousands of dollars. Although the law is intended to help Vermont utilities meet their renewable energy goals, critics of the legislation argue that it could stymie new solar development once utilities have met their 10% Tier II goals. Also, because energy consumers cannot claim to use renewable energy unless they retain the RECs, it does not support energy consumers who have made a conscious decision to avoid the use of fossil fuel and nuclear power.

Incentives and Subsidies

There are considerable federal incentives that support the market for renewable energy development in Vermont. Without the tax credits and Renewable Energy Credits (RECs), some renewable technologies, such as utility-scale wind, would not be an economically viable resource. There are currently three major federal tax credits supporting the development of renewable energy facilities. Table 2.14 below lists the current federal subsidies and their eligible renewable technologies:

Table 2.14 Federal Subsidies for Renewable Energy Development

Program Name	Applicable Technology
Business Investment Tax Credit (ITC)	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, CHP/Cogeneration, Solar Hybrid Lighting, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use. This credit has been amended several times, most notably in 2015 in the Consolidated Appropriations Act, when the expiration date for these technologies was extended with a gradual step-down of the credits between 2019 and 2022. An investment tax credit is also available to home owners (such as for solar installations) through 2021.

Modified Accelerated Cost-Recovery System (MARCS)	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Hybrid Lighting, Anaerobic Digestion, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use. Also amended in the Consolidated Appropriations Act, the "placed in service" deadline for bonus depreciation was extended to January 2018.
Renewable Energy Production Tax Credit (PTC)	Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, Hydrokinetic Power (i.e., Flowing Water), Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal. This credit phases down for wind commencing construction after December 2016 and expires for other technologies.

Vermont provides a tax credit that investors can claim in addition to the federal credit. Efficiency Vermont provides a link to rebates and incentives for small-scale renewables and efficiency improvements. https://www.efficiencyvermont.com/rebates). With regards to municipal tax, Vermont law allows municipalities to waive the property taxes for solar facilities and any land, not to exceed one-half acre, on which it is built.

Property-Assessed Clean Energy (PACE) Districts allow property owners to borrow money to pay for such things as energy efficient water heaters, lighting, furnaces, boilers, windows, programmable thermostats, and insulation, as well as solar heating, PV, wind and biomass systems. The amount borrowed is typically repaid via a special assessment on the property over a period of up to 20 years. In Vermont, local governments are authorized to create PACE Districts to provide financing. Participating property owners must agree to a special assessment and lien on the property and pay a one-time, non-refundable fee to support the reserve fund created to cover losses in the event of foreclosure of participating properties. The district may release a lien on a property once the property owner has met the terms of the loan. At this time only a few towns are implementing PACE Districts. Municipalities may have been slow to adopt PACE because of a perceived administrative burden. Since 2011, VEIC has received funding to provide most of the administrative support to town. More outreach and education about PACE may be necessary.

Other Energy Facilities

The electricity system is the major energy network in the region. However, it is important to mention the Northeast Kingdom's other major energy infrastructure. The Portland Pipeline is a major crude oil pipeline that stretches from Portland, Maine into Canada. In our region, the pipeline runs from Guildhall northwest to Jay before crossing into Canada. While Vermont doesn't tap into the pipeline, its existence in our region as major transporter of oil is important for potential future use.

The Portland Natural Gas Transmission system also just touches the region. The transmission line also runs from Portland, Maine into Canada and is owned by TransCanada, a major Canadian energy supplier. The line just barely passes through the state in Canaan, Vermont before reaching Canada. A spur has recently been created from this line, but only serves the Ethan Allen Manufacturing Plant in Beecher Falls. Future potential to expand this transmission system into the region remains possible.

Granite State Power Link (GSPL)

Plans have been announced for the development of a new electric transmission line in Vermont and New Hampshire that will deliver up to 1,200 MW of hydro power to southern New England. The infrastructure will consist of two converter stations (one in Vermont), 59 miles of high-voltage direct current line (used for transmitting large amounts of power over great distances), 109 miles of alternating-current line, and a switching station in New Hampshire. The line is proposed to be built adjacent to an existing VELCO transmission corridor and will require a 150 foot expansion. About 53 miles of GSPL will be high-voltage direct current line running through the towns of the Essex County. (Table 2.15) Because the NEK portion of the line is direct-current only, the line will not expand the region's transmission capacity to host new energy development (like wind or solar). The project is located alongside an existing transmission corridor, so visual impacts are expected to be minimal. Project developers are currently working with Vermont Association of Snow Travelers (VAST) to explore recreation opportunities, and the project will bring revenues and other financial benefits into the region and affected communities. The project has been found to be in conformance with NVDA's regional plan

Table 2.15: Vermont Communities in the GSPL

Community	Approximate miles
Norton	4.6
Avery's Gore	0.7
Averill	1
Lewis	6.7
Bloomfield	5.1
Brunswick	3
Ferdinand	5.7
Granby	8.5
Victory	2.4
Lunenburg	3.8
Concord	8.8
Waterford	2.1

IV. FUTURE ENERGY USE AND 2050 PROJECTIONS

(Note: for municipal targets in support of these goals, see Appendix A.)

NVDA's Regional Energy Plan was developed in support of Vermont's 2016 Comprehensive Energy Plan (CEP), which contains the following goals:

- Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 2050.
- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050.
- Achieve three renewable end-use sector goals for 2025: 10% transportation, 30% buildings, and 67% electric power.

What follows below is one possible strategy, developed by Vermont Energy Investment Corporation, which uses a regionalized scenario of the statewide Long-Range Energy Alternatives Planning (LEAP) model. Historic information was primarily drawn from the Public Service Department's Utility Facts 2013 and U.S. Energy Information Administration data. Projections came from the Vermont Public Service Department's Total Energy Study (TES), and Integrated Resource Plans from the utility companies.

The "90x2050" approach has two major underlying concepts:

1. **Reducing energy use**: Aggressive weatherization, efficiency, and conservation measures are critical in reducing total energy demand to the point where it can be primarily met through renewable sources. Conservation involves reducing or eliminating unnecessary energy use and waste (e.g. lowering thermostats, limiting hours of operation, etc.). Efficiency also involves reducing the total amount of energy consumed, but the reduction comes from improving equipment or operating processes that use energy. Weatherization improvements are energy efficiency measures such things as insulating walls and ceilings, installing programmable thermostats, and replacing inefficient machinery. The net result is that less energy is used, while the overall costs needed for energy are reduced as well. Energy efficiency improvements typically have a cost, but the payback periods will vary depending upon the cost of the improvement and the amount of energy that is saved.

2. **Replacing traditional fuel sources**: The 90x205 model replaces traditional fossil-fuels with electricity, which can come from clean renewable sources like hydro and solar. Fuel switching primarily occurs by providing residential heating units with heat pumps, but efficient wood burning systems (like wood pellet furnaces) and bio fuels play an important role as well. Fuel switching also occurs by gradually replacing fossil-fuel burning automobiles with EVs. Electrification of heating and transportation has a large effect on the total demand because the electric end uses are three to four times more efficient than the combustion versions they replace. Even if the region's population grows and the economy expands, overall energy use declines because of efficiency and electrification.[14]

Regional end-use models (Figures 2.5 through 2.8) are derived from two scenarios:

1. The "**reference" scenario** assumes a business-as-usual continuation of today's energy use patterns but does not reflect the Vermont's renewable portfolio standard or renewable energy or greenhouse gas emissions goals. The main changes over time in the reference scenario are more fuel-efficient cars because of CAFE standards.

[14] Vermont Energy Investment Corporation: NVDA Modeling, Summary Results and Methodology

2. The “**90% x 2050 scenario”** is designed to achieve the goal of meeting 90% of Vermont’s total energy demand with renewable sources.

What follows below shows 2015 usage according to the reference scenario, and then displays energy use from subsequent years based on the 90x2050 scenarios. “Avoidance” is the energy that is no longer needed because of aggressive weatherization, efficiency upgrades, and fuel switching.

Residential and Commercial Heating by 2050

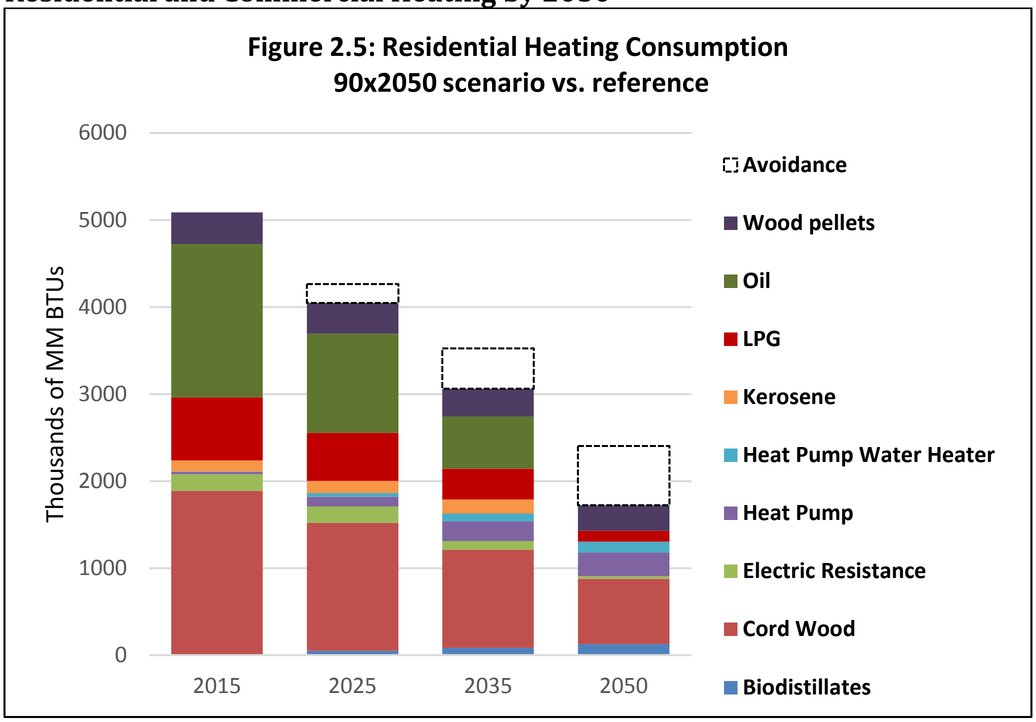
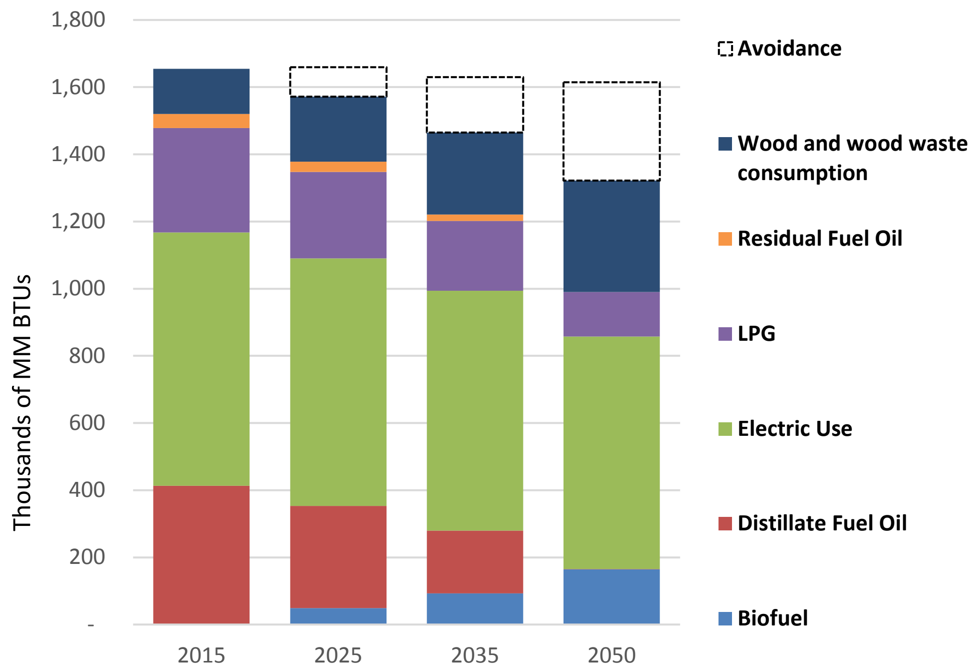


Figure 2.5: Residential Heating Consumption 90x2050 scenario vs. reference

Figure 2.6: Commercial Heating Consumption 90x2050 vs. reference



Residential demand was based on counts of housing units from American Community Survey and assumed a constant population growth rate of 0.21%, based on calculations from Vermont Population Projections 2010-2030. Residential demand also assumed that household size would decrease from 2.4 in 2010 to 2.17 in 2050. (More about the declining household size can be found in NVDA's Housing Plan.)

Projected change in the energy demand from the commercial sector was based on commercial sector data in the Total Energy Study, which showed commercial building square footage growing by almost 17% from 2010 to 2050.

In these scenarios, the use of electricity for residential heating nearly doubles. This increase offsets a slight decrease in electricity for the commercial sector, where wood and wood scraps and biofuels play a more significant role. Neither estimate accounts for the use of solar in water heating. According to the Vermont Renewable Energy Atlas, there are nearly 40 solar powered water heating systems in the Northeast Kingdom.

Table 2.16 establishes weatherization and fuel switching targets in support of the 90x2050 targets for residential and commercial heating in the Northeast Kingdom. These targets were developed with assistance from the Department of Public Service using the assumptions from the regionalized model from VEIC.

Table 2.16: Weatherization and Fuel Switching Targets for the Northeast Kingdom

By Year	2025	2035	2050
Estimated number of households	28,050	30,044	32,180
% of households to be weatherized	22%	35%	60%
# of households to be weatherized	6,073	10,568	19,323
Estimated number of commercial establishments	1,571	1,692	1,822

% of commercial establishments to be weatherized	5%	8%	14%
# of commercial establishments to be weatherized	75	130	248
% of households with efficient wood heat systems (e.g. pellet furnaces, stoves)	56%	43%	31%
# of households with efficient wood heat systems	15,648	12,863	9,992
% of households with heat pumps	17%	14%	31%
# of households with heat pumps	4,642	9,814	13,352
% of commercial establishments with efficient wood heat systems	15%	17%	22%
# of commercial establishments with efficient wood heat systems	229	291	401
% of commercial establishments with heat pumps	6%	10%	13%
# of commercial establishments with heat pumps	87	162	239

These projections assume a constant increase in the number of housing units and commercial establishments of about 0.6% and a weighted average heat load derived from existing municipal-level energy consumption estimates from by NVDA. (See Appendix B for a full explanation of municipal estimates.) Weatherization targets assume an average savings of 25% for residential heat load and 20% for commercial heat load.

Targets in Table 2.16 use methodology from the Department of Public service. Overall efficiencies achieved through the use of heat pumps (particularly in the residential sector) will reduce the use of supplemental heat. Nevertheless, we anticipate a continued need for efficient wood heating systems, particularly in older structures with multiple heating zones. The commercial sector is less likely to see a reliance on heat pumps, partly due to the relative lack of commercial development pressure in the region, not to mention the fact that a number of commercial establishments are already using efficient biomass systems.

Electricity use is expected to increase dramatically by 2050 so demand-side management and upgrades, such as hardwiring, lighting fixtures, and appliances is also an important part of this scenario, especially since electricity is replacing other fuel-burning thermal applications. Table 2.17 establishes targets for electrical equipment upgrades.

Table 2.17: Electrical Equipment Upgrade Targets for the Northeast Kingdom			
By Year	2025	2035	2050
Estimated number of customers	41,551	44,055	46,487
# of customers to upgrade equipment	10,769	16,923	24,808
% of customers to upgrade equipment	26%	38%	53%

This estimate assumes an average savings of 400 kWh per project and assumes a projected number of customers by multiplying the number of housing units by 1.5 (to account for multi-units and non-residential customers.

Table 2.18 provides some historical data on weatherization, fuel-switching, and equipment upgrades accomplished to date. Measures that achieve thermal savings and electrical efficiency are often inextricably linked because they have *interactive* effects. For example, the installation of a cold climate heat pump may produce thermal savings, but it may also increase electrical use because it is replacing a fuel-oil system (thus making demand-side management critical). Also, in industrial settings a switch from incandescent bulbs (which emit a substantial amount of heat) to LED bulbs (which emit very little heat) can actually require additional energy to heat the space. A heat pump water heater in a finished basement collects heat from the space and delivers the heat to the water, meaning the basement requires additional heat.

Individuals and businesses can access a variety of resources, both public and private, for services ranging from energy audits to financing to contracting. Local energy committees have led successful campaigns to replace lighting with LED bulbs, encourage the purchase of Energy Star appliances, and educate consumers about incentives for more efficient options such as heat pumps. Additionally, improvements to battery storage may reduce peak demand. The development and use of real-time monitoring technology will also make customers more efficient users of electricity.

Table 2.18: Efficiency Measures by Count in the Northeast Kingdom

	2014		2015		2016		Total	
	Res.	C & I	Res.	C&I	Res.	C&I	Res.	C&I
Air Conditioning Efficiency	63	81	90	196	71	28	**224**	**305**
Compressed Air	0	57	0	10	0	12	**0**	**79**
Cooking and Laundry	323	1	265	76	244	0	**832**	**77**
Design Assistance	0	29	0	12	0	9	**0**	**50**
Health and Safety	9	0	12	0	8	0	**29**	**0**
Hot Water Efficiency	1,059	9	696	4	617	8	**2,372**	**21**
Hot Water Fuel Switch	1	0	0	0	0	0	**1**	**0**
Hot Water Replacement	2	0	2	2	2	0	**6**	**2**
Industrial Process Efficiency	0	40	0	8	0	15	**0**	**63**
Light Bulb/Lamp	70,113	14115	61,755	17,859	51,767	16,837	**183,635**	**48,811**
Lighting Efficiency/Controls	38	800	2	722	20	144	**60**	**1,666**
Lighting Hardwired Fixture	3,886	4185	5,030	6,764	4,484	7,139	**13,400**	**18,088**
Motor Controls	3	21	0	57	1	22	**4**	**100**
Motors	229	0	243	3	387	1	**859**	**4**
Office Equipment, Electronics	1,773	34	1,492	0	751	1	**4,016**	**35**
Other Fuel Switch	0	0	0	5	0	0	**0**	**5**
Refrigeration	461	129	320	317	238	83	**1,019**	**529**
Space Heat Efficiency	162	9	116	14	129	7	**407**	**30**
Space Heat Fuel Switch	27	1	27	6	19	5	**73**	**12**
Space Heat Replacement	4	10	43	38	113	9	**160**	**57**
Thermal Shell	225	1	152	11	156	7	**533**	**19**
Ventilation	194	93	66	88	32		**292**	**181**
Water conservation	0	0	0	1	0	1	**0**	**2**
Source: Vermont Energy Investment Corporation								

Transportation Energy Use by 2050

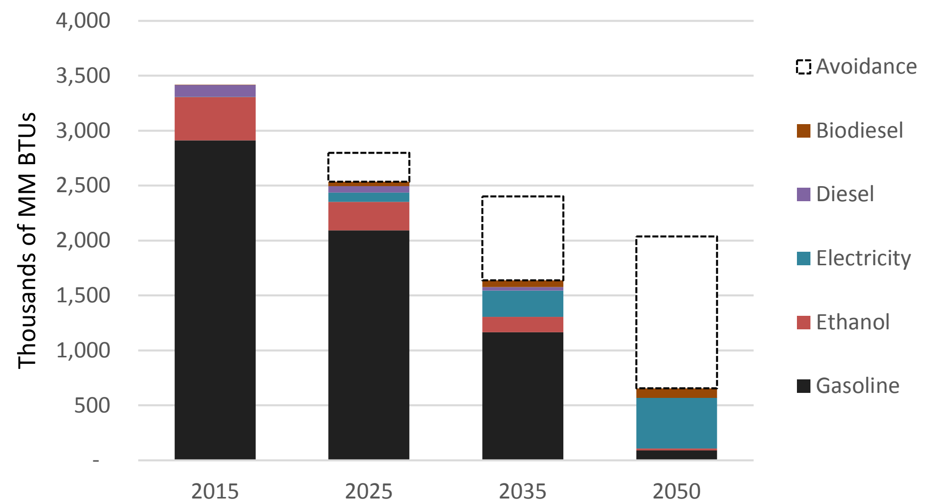


Figure 2.7: Regional Light Duty Vehicle Consumption 90x2050 Scenario vs. Reference

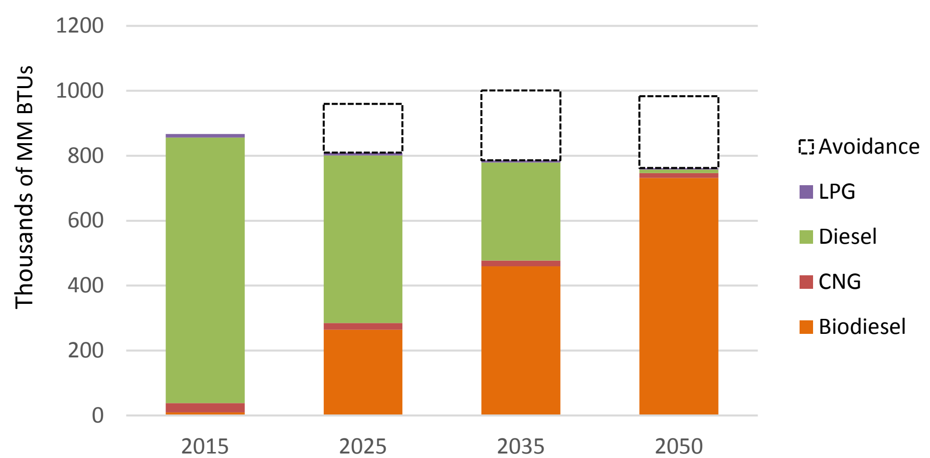


Figure 2.8: Regional Heavy Duty Vehicle Consumption 90x2050 Scenario vs. Reference

Biodiesel, which is currently being sources from oilseed grown in the Northeast Kingdom, is the most significant agent of change in use among heavy-duty vehicles and farm equipment. Among light-duty vehicles (LDVs), the gradual conversion from fossil fuel to EVs is expected to have a dramatic impact on electricity use in the Northeast Kingdom. These estimates assume gradual gains in fuel efficiencies from 3 miles per kWh to 4 miles per kWh, which helps to reduce total energy use by more than two-thirds from 2015 levels, even though the number of light duty vehicles on the road increase. In 2050, end-use electricity consumption in LDVs increases by more than 153 times, or more than 15,000%.

Clearly, the switch to EVs in the rugged Northeast Kingdom is a tall order, requiring significant investment in charging infrastructure, not to mention performance improvements on steep terrains and in cold temperatures, battery storage, and affordability. Table 2.19 uses vehicle counts from American Community Survey to identify targets for achieving fuel switching goals for LDVs.

Table 2.19: Fuel Switching Targets for Light-Duty Vehicles in the Northeast Kingdom			
By Year	2025	2035	2050
Estimated number of light-duty vehicles	53,153	56,874	60,855
# of EVs	5,618	17,937	38,603
% of LDVs	11%	32%	63%

V. ENERGY RESOURCE ANALYSIS AND RECOMMENDATIONS

The 90x2050 projections – which will nearly eliminate the use of fossil fuels—will require transferring many of our uses to electricity. Therefore, even while electrical systems, appliances, and vehicles will likely continue to increase in efficiency, more electricity will need to be produced. Some of that will come from imported sources, such as hydroelectricity from Hydro Quebec and other providers, but much of it will also need to be generated by in-state renewable facilities as well.

90x2050 projections indicate that residential non-thermal electrical use alone could exceed 614,000 MWh by 2050. Additionally, conversion to light-duty EVs could require more than 135,000 MWh over that same period. Understandably, these projections counter earlier regional estimates, which showed only modest increases in regional electrical consumption to 462,353 MWh by 2020.[15] It is important to remember that the 90x2050 projections incorporate sweeping and long-range changes to the way we live and work.

Where – and how -- would energy generation occur? In support of the 90x2050 goals, each region has a set of generation targets. Because our region already generates a disproportionate share of energy relative to our low population, the Northeast Kingdom's new generation targets are the lowest in the state. (Table 2.19) While generation targets can be met through a variety of renewable technologies, the Northeast Kingdom does not have any generation targets specific to wind. Nevertheless, great care and consideration shall be given to the siting of new generation.

Table 2.19: In-state Generation Targets	
Regional	New MWh
Addison	172,978
Bennington	293,182
Central Vermont	418,530
Chittenden	845,236
Lamoille	185,927
Northeastern	18,680
Northwest	260,438
Rutland	439,276
Southern Windsor	194,612
Two Rivers	396,631
Windham	97,716

Policy Statements

This region has a responsibility to plan for adequate supply of energy to meet local energy demand. Planning activities may include the production, storage, siting, and distribution of energy. Individuals, businesses, organizations, and communities are encouraged to explore emerging energy supply, efficiency, and net-metering opportunities that meet accepted environmental standards in order to satisfy their power demand.

New industrial/utility energy development shall meet the highest standards required by law. Permitting authorities shall first consider current and historical land use and the culture of the region, community opinion, economic benefit, as well as the land owner's rights. Any development shall to the extent possible be done so as to mitigate adverse impacts to the region. Any utility-scale energy generation project deemed acceptable by the Public Utility Commission shall

[15] NVDA Wind Study Report, March 26, 2015

include a plan for distributing benefits to the towns in the region proportional to the adverse effects experienced by that town. Long term maintenance, safety issues, decommissioning, and land reclamation procedures required at the end of the energy project's life must also be included in the project plan.

This plan aims to balance environmental quality and important natural resources with energy production. Significant local and regional support and clearly demonstrated benefits should exist in any energy proposal. This is especially relevant when siting commercial- or utility-scale wind facilities, which could have impacts on neighboring communities. "Commercial" and "utility" are defined in this plan as:

Commercial-scale: facilities with a capacity of more than 10 kW (which would be considered residential), but less than 100 kW. These structures typically have a height of just over 120 feet. (The wind tower at Burke Mountain is 123 feet high.) These structures are referred to as "business-scale" in the Vermont Renewable Energy Atlas.

Utility-scale: Wind turbines with a capacity of 1MW or more. These structures are referred to "commercial scale" in the Vermont Renewable Energy Atlas.

The region has recently experienced a sharp increase in the number of renewable energy applications which will worsen already congested transmission, particularly in the Sheffield-Highgate Export Interface (SHEI), where several existing generators are frequently curtailed by the ISO. While NVDA encourages appropriately scaled renewable energy development, NVDA has a commitment to ensure that such development is sustainable and feasible and does not merely substitute one renewable resource with another. NVDA supports energy development that will not exacerbate curtailment at issue within the SHEI. It is unlikely that any single solution will solve congestion within the SHEI and, as such, it is anticipated that incremental progress will be achieved as partial solutions are implemented. In the meantime, NVDA will support projects that are consistent with the land use and conservation measures in this plan and in duly adopted plans of impacted municipalities. Additionally, we will expect project developers to work with utilities and other stakeholders to explore innovative strategies that shift generation away from the hours when generation exceeds load within the SHEI area or otherwise avoids exacerbating congestion on the grid. An example of such a project would pair a battery with a solar facility to control when the project's power is exported to the grid. In determining support for such a measure, NVDA will seek guidance from the long-range Transmission Plan and Integrated Resource Plans in the region and will consult with utilities, VELCO, and other stakeholders.

Siting Potential

This plan is accompanied by a series of maps (Appendix C) that can assist in the process of identifying potential areas for siting and quantifying generation output. Underlying assumptions were made about suitability factors, such as slope and direction of land, elevation and wind speeds, and access to three-phase power. Additional statewide layers identified *known* constraints and *possible* constraints, and a third layer has identified *regional* constraints:

<u>Known constraints</u> are areas not likely to be developed for renewable energy because they contain one or more of the following: vernal pools; river corridors; FEMA floodways; significant natural communities; rare, threatened and endangered species, national wilderness areas, wetlands (Class 1 and Class 2).

<u>Possible constraints</u> are areas that would likely require mitigation because they contain the one or more of the following: agricultural soils; special flood hazard areas (outside of the floodway); protected (conserved) lands; deer wintering areas; Act 250 mitigated agricultural soils; hydric soils, and highest priority forest blocks.

Regional constraint: NVDA's regional plan has long held that rural areas should receive very little commercial or industrial development unless it occurs in an established industrial park, or in an area specifically designated in the local bylaw or plan as being well suited to such uses. Lands with an elevation of 2,000 feet or more merit consideration as a special class of rural lands that should be protected from any large-scale commercial or industrial development characterized by a constructed height of 100' or more, and an acre or more of permanent site disturbance, such as clear-cutting. These lands, as indicated on attached siting potential maps, contain one or a combination of factors that make them unsuitable to such development – contiguous forest cover; sensitive wildlife and plant habitat; conservation lands and recreational assets; managed forestland; and headwaters and ephemeral surface waters, which are highly vulnerable to erosion and man-made disturbance. This high-elevation forest cover must be kept unfragmented for the attenuation of flood flows, the benefit of wildlife habitat and linkage, and public enjoyment through passive recreation.

The maps accompanying this plan do not carry the weight of zoning, and the siting of renewables on prime acreages (i.e. without known constraints) is not a foregone conclusion. Rather regional maps should be viewed as a starting point for our member municipalities to determine suitable and unsuitable locations for renewable energy development. This plan's siting considerations for each specific energy technology on the following pages should not be considered exclusive. They too should be seen as a starting point for creating effective local specification and constraints.

Our estimates for potential generation outputs are therefore deliberately conservative to account for the designation of local siting constraints. In most instances, only ***prime*** acreage (areas with no constraints at all) were used to calculate output potential. Even with a highly conservative estimate, potential generation vastly exceeds the regional generation target. This plan strongly encourages municipalities to conduct additional site investigations to identify local constraints (as well as preferred sites in addition to existing statewide preferred sites) in order to address the environmental, aesthetic, civic, economic, and cultural concerns unique to each community.

Table 2.20: Estimated Potential Energy Generation in the Northeast Kingdom

	MW	MWh
Residential rooftop solar generation	15.0	18,412.2
Small commercial rooftop solar generation	3.0	3,343.2
Large commercial rooftop solar generation	5.9	7,225.9
Ground mounted solar	652.6	800,340.3
Wind (residential scale only)	13.6	23,405.2
Methane Digesters	430.0	2,260,080.0
Hydro	2.9	10,238.6
Total Generation	1,123.0	3,123,045.4

Solar

Total output potential:	**829,321.6 MWh**
Rooftop assumptions:	NVDA assumed one out of every 10 residential structures (including seasonal, many of which are inhabited part-time year-round). The region has relatively few commercial structures, so NVDA determined small commercial suitable for solar (less than 40,000 sq. ft.) for solar to be 10% of all commercial structures, and large commercial

	structures suitable for solar (more than 40,000 sq. ft.) to be just 3% of all commercial structures. The number of commercial structures was determined with NAICS classification counts used for determining commercial thermal energy use. (See Appendix B.)
Ground mounted assumptions:	Approximately eight acres of land are required to produce one MW of solar energy. In order to account for contingencies (property owners not interested in leasing their land, interconnection costs that may be too high, and unsuitability of specific sites) NVDA estimated only 1MW for every 60 prime solar acres. Acres with possible constraints were not included in the calculation.

Overall solar resources in Vermont are quite good, and solar energy can be harnessed effectively for primary and secondary energy needs. The two main types of solar energy systems are photovoltaic (PV), which generates electricity, and solar thermal, which generates hot air or hot water for water and/or space heating. For some homeowners in our region, solar electricity systems have proven more cost effective than extending power lines to the home. A typical off-grid system consists of photovoltaic (PV) modules that convert solar energy to electricity, batteries that store the electricity (if off-grid), and an inverter that converts DC power to AC for use in conventional electric appliances. As a rough rule of thumb, a 1 kilowatt photovoltaic system can be expected to produce 3-3.5 kWh/day on average in Vermont.

Solar water heating systems typically utilize collectors to capture the sun's energy, a pump to circulate a solution through the collectors to extract heat energy, and a well-insulated storage tank to hold the heated water for use as needed (this can be integrated with an existing water-heating system). An appropriate size solar water-heating system can provide one-half to two-thirds of a household's annual hot water needs – typically 100% in summer, but as little as 25% in winter. In Vermont, these types of systems tend to pay themselves off in less than two decades.

Solar energy can also be harnessed through passive solar design (day-lighting and space heating) with Green Building Design. This includes orienting buildings close to true south, as well as using appropriate windows on the south wall, installing thermal mass (brick, concrete, or water) to store the sun's energy, and using appropriate levels of insulation. Through these designs, as much as 60% of a building's space heat can be derived from the sun. This type of heating is termed "passive solar" because no moving parts are needed, the collection and storage system is built into the structure. Green Building Design principles also attempt to maximize the amount of natural light a building receives, in order to reduce the energy costs associated with daytime lighting.

Active and passive solar systems are custom built based on the building site, building and purpose of the solar system. There are many factors that bear on siting solar systems. Many homes and businesses have good rooftop sites, or good sites nearby for ground mounted systems. Unfortunately, some do not, such as properties where there is limited southern exposure. One way to address this situation is through the development of "community-sized" PV projects or co-operative systems on the order of a few hundred kilowatts up to a few megawatts. There are a number of community solar sites in our region, which also allow renters and homeowners where rooftop solar will not work to take advantage of solar by "sponsoring" an off-site panel. Utility-scale PV developments are also becoming popular in other areas of the U.S. Often referred to as solar parks, farms, or ranches, these utility-scale PV installations are designed for the sale of merchant power (MWh) into the electric grid and can utilize several acres of land. Public concerns surrounding solar installations of this size usually focus on aesthetics and transmission line development.

Siting policies for solar:

- NVDA has determined that the following types of locations in the region should be prioritized for future solar generation. Even though these locations are not shown on the regional solar maps due to a lack of GIS data, these sites should be considered "preferred locations" for siting solar:

- Rooftops of structures, residential and commercial. (Our conservative estimates show the region's total potential output from rooftop solar alone could amount to 23.9 MW, or 6.3% of the high end of the LEAP model projections for solar for 2050 of 377.2 MW).
- Brownfield sites not located in a designated downtown or village center
- Earth extraction sites (e.g. gravel pits, quarries), active or abandoned
- Parking lot canopies and surface parking lots
- Farms, where more than 50% of the power generated is used by the farm
- Industrial parks, where more than 50% of the power generated is used by the tenants of the industrial park
- Undersized lots and otherwise undevelopable land in existing industrial parks

- The Northeast Kingdom has a robust agricultural economy, and NVDA discourages siting ground-mounted solar in a manner that fragments productive agricultural soils, effectively removing farmland from production for decades. To this end, NVDA encourages municipalities to explore and identify local constraints that minimize farmland fragmentation. These measures may include agricultural overlays (regulatory), as well as conservation easements (non-regulatory). A number of land exploration tools, such as land evaluation and site analyses (LESAs) can help municipalities prioritize agricultural lands for protection. NVDA will assist local planning commissions to identify local constraints as appropriate.
- Notwithstanding the above concern, NVDA recognizes that successful integration of solar into active agricultural uses can help farms reduce expense, generate extra income, and remain viable. NVDA encourages on-farm solar that, to every extent feasible, uses existing farm structures, or is sited in a manner that supports grazing, the establishment of pollinator crops, or simply to create buffers between organic and non-organic production areas. NVDA will showcase best on-farm generation practices in the region and will cite "Guide to Farming Friendly Solar," produced by the Two Rivers Ottauquechee Regional Planning Commission, as a vital resource.

Wind

Total output potential:	**23,405.2 MWh**
Assumptions:	In accordance with Act 174 guidelines published in March of 2017, regional plans are allowed to submit plans to the Department of Public Service that do not establish targets for utility scale wind. This is especially important for the Northeast Kingdom, which has no targets for wind generation due to the existing level of production. When accounting for NVDA's regional constraint, the balance of prime wind acreages is just over 38,000. We estimate that new generation will be primarily farm- and residential-scaled. Even though no significant acreage is required for a farm- or residential scaled turbine, NVDA's estimate

	assumed a contingency of 1 turbine for every 25 prime acres, with an average capacity of 9.5 kW. Some towns have no prime acres. For these towns, we assumed a broader contingency of 1 turbine every 75 acres. The purpose of the contingency was similar to that of solar: to account for property owners not interested in leasing their land, prohibitive interconnection costs, and unsuitability of specific sites (including neighbor objections.

Wind energy has recently been on the forefront of the renewable energy movement. The U.S. Department of Energy has announced a goal of obtaining 5% of U.S. electricity from wind by 2020, a goal consistent with the current rate of growth of wind energy nationwide. Vermont is currently ranked 34th out of the lower 48 states for wind energy potential.

The Northeast Kingdom, the region that the NVDA serves, has considerable experience with utility-scale wind turbines. Caledonia County is home to First Wind's Sheffield turbines. Green Mountain Power's Kingdom Community Wind turbines are located in Lowell (Orleans County). Three additional projects were proposed, but not carried out: The East Haven Wind Farm (Essex County), Seneca Mountain Wind (Caledonia and Essex Counties), the Encore Redevelopment project in Derby (Orleans County). It follows that the NVDA's Board of Directors has become quite familiar with arguments both for and against industrial wind complexes.

The siting of wind turbines has raised concerns about aesthetic impacts, erosion, water quality impacts, noise, land scarring, and effects on wildlife, property values, public health, and local economic drivers, such as tourism. Because of our region's mountainous terrain, the ideal location for utility-scale wind turbines is on North-South oriented ridgelines with elevations between 2000 and 3500 feet above sea level. Each utility-scale tower can range in height from 135 feet to 500 feet tall, requiring specified FAA lighting for towers over 200 feet. For purposes of this plan, smaller non-utility scale wind systems are defined as turbines under 200 feet in height, including the length of the blades. Larger (utility-scale) ridgeline generation facilities may contain as few as 1 to as many as 40 or more turbines. Because of the variations in wind speed, the output of a wind facility is considered intermittent power, and the energy generated is generally 20-30% of what a conventional power generation facility of the same rated peak capacity would produce. Wind speeds need to be within an optimum range specific to the tower technology. If any wind speeds or gusts are registered over the optimum range the wind tower is usually shut down for safety purposes.

Siting policies for wind:

- The NVDA has first-hand experience with the divisiveness that accompanies wind projects and the damage that the projects visit upon communities. In 2012, the NVDA Board of Directors voted 39 to 3 in favor of a resolution calling for a suspension of development of new industrial wind projects in the region. The Board called for the formation of a committee to study industrial wind energy in the region and develop findings and recommendations. The committee's findings and recommendations would be reviewed by the NVDA's Executive Committee and then by the full Board of Directors. As a result of this effort, the NVDA has developed the following position on industrial wind energy:

  "The NVDA sees one clear benefit to industrial wind energy, one clear problem, and a host of troubling questions. The clear benefit is the tax relief that industrial-scale wind turbines bring to their host towns. The clear problem is the bitter divisions that wind brings to our communities. The troubling questions involve the unreliability of wind energy, the amount of energy produced versus the social and environmental disruption, the costliness of the electricity, and the dubiousness of the claims of environmental benefit. We are even more troubled by the potential impacts on human health, essential wildlife habitat, water quality, aesthetics, property values, and our tourism industry. We are also

troubled by the state's energy policies, the state's permitting process, and the ease with which the public good as expressed in our municipal and regional plans can be overridden by people who may never have even visited our region.

It is the position of the NVDA that no further development of industrial-scale (sic[16]) wind turbines should take place in the Northeast Kingdom.

- Existing small turbines in the region are sited in very low-density areas and on farmland. NVDA strongly urges municipalities to consider density in their specifications, as even small wind turbines can produce noise that is incompatible with many residential areas. This can be established through the use of noise ordinances or through required distances from nearby residential uses, as specified in a locally adopted municipal plan with Substantial Deference.

- The Northeast Kingdom has no new generation targets for wind due to the large amount of energy generation currently coming out of the region. In keeping with the policies and recommendations in the Land Use Plan, the regional wind generation maps in Appendix C do not show many wind generation areas with high generation potential. This is due to the existence of known constraints, including upland areas of 2,000 ft or more, headwaters, forest coverage of site class 1, 2, or 3, priority forest habitat blocks, and state natural areas and fragile areas.

Hydro

Total output potential:	**10,238.7 MWh**
Assumptions:	NVDA's analysis takes into account only existing dams not being accessed for hydropower. Generation information comes from a 2008 Agency of Natural Resource study of small hydropower resources.

Existing hydro-power facilities in the Northeast Kingdom collectively produce more than 118,000 MWh annually, accounting for more than 18% of our regional generation. (Table 2.13) The three Connecticut River Dams, though not considered part of our regional generation, are three of the largest hydro facilities in the Northeastern U.S. Together the Moore, Comerford, and McIndoe Falls Dams produce an additional 638,000 MWh of electricity annually (double what the region consumes).

Hydro facilities can be a good source of base-load power when regular rainfall is received. For river-run facilities, power generation is dependent upon continuous levels of rainfall and must run when the flow is at optimum levels. This can mean producing electricity when it might not be needed. Dams, on the other hand, have the advantage of storing their resource for later use. Unfortunately, drought can severely limit the production capacity of dams as well. Hydro power facilities can also alter the ecosystem of a waterway. Both reservoir and river-run systems can increase water temperature, decrease water speed, limit oxygen and increase nitrogen levels, and alter riparian areas. These changes to the ecosystem cause stress to fish populations and riparian-habitat wildlife[17]. Today, new hydro facility design and upgrades are engineered to mitigate or lessen negative impacts on the ecosystem.

Overall hydro-power is considered a long-term resource and is relatively secure and stable. Generation costs for hydropower vary considerably between facilities. Many of the facilities in the

[16] The language regarding "scale" of renewable energy development has since evolved. For all intents and purposes the preferred term is "utility-scale," although in context of the 2012 wind study, the terms "industrial" and "utility" may be used interchangeably.
[17] Foundation for Water Energy and Education

region were built in the early 1900's and have needed significant upgrades over the years. Upgrading existing hydro and permitting new hydro can prove to be very costly and consequently raises the production costs for the facility.

Siting policies for hydro:

- While this energy source is renewable, the ability to create new hydro-power generation is limited. Some of the best hydro resources in the region are already generating, while permitting new facilities has been a long and difficult process. At this time, facilities in other regions of the state are facing some significant challenges in relicensing. Our focus for regional hydro-power should be focused on maintaining our existing generation infrastructure, upgrading aging infrastructure, and improving safety standards. The development of new facilities should be pursued where practical.

Methane

Total output potential:	**2,260,000 MWh**
Assumptions:	NVDA's estimate used the Farm to Plate Atlas for a count of dairy farms in the region. The waste from 4 to 6 cows can produce about 1 kW of energy. On-site systems were only considered, so farms known to have small herds were excluded from the estimate. Because digesters are a significant investment in equipment and maintenance, NVDA assumed a contingency of about 1 in every 8 farms.

Methane, a common gas found in the environment, can be burned to produce electricity. Large amounts of methane are produced through the anaerobic digestion of manure, agricultural wastes, and other organic wastes. Both large farms and landfills offer the best potential to utilize this resource. The only large-scale landfill in the region is already being utilized for methane generation, but there are at least 20 dairy farms with enough capacity to sustain a manure-methane generation facility. In agricultural practices, manure is collected in various containment systems, where it can be heated up for methane gas production and collection. The remaining manure by-product can be spread on fields as fertilizer, the dry solids can be used for animal bedding, and the excess heat can be used for other purposes such as greenhouse heating.

In agricultural practices, the procedure also destroys harmful pathogens, reduces water quality impacts, reduces manure odors, and provides a new source of income to local farmers. The Blue Spruce Farm in Bridport, Vermont was the first farm in the state to develop a manure-methane generation system. In the Northeast Kingdom the Maplehurst Farm, Maxwell Farm, and Chaput Family Farms have installed anaerobic digester systems and collectively produce more than 4,500 MWh annually. All three are enrolled in the Standard Offer program, which offers long-term fixed prices for generation without having to go through the program's reverse auction process.

Food scraps and food residuals (byproducts from processing) can also be used to produce energy in a similar manner. The expansion of the region's agricultural processing sector, paired with Act 148's mandatory diversion of food scraps from the waste stream, creates additional opportunity to generate energy. Research with food waste is already underway at Vermont Technical College, but additional exploration is needed to make this feasible here in the NEK.

Siting policies for methane:

- Manure methane generation should be expanded in the region's energy mix. As with farm-friendly solar generation, manure methane generation may protect the viability of working farms by reducing production expense and generating extra income for the farmer. NVDA encourages municipalities to identify potential production sites in their plans and provide appropriate guidance for siting with regard to screening, noise, and odors.

- Existing on-site technologies are costly and only make economic sense for larger farms. (In Europe, central methane digestion systems do allow smaller farmers to process animal wastes, but trucking is involved.) Emerging technologies in Europe may prove to be more cost-effective for smaller farms. NVDA encourage the ongoing use state and federal grants, tax credits, incentives, and technical assistance to combat the high start-up costs of methane generation for the region's farmers.
- NVDA should work with the region's food system leadership group, as well as other proponents of the Regional Food System Plan, to ensure that the region's agricultural producers have access to technical services, grants, and other incentives to refine and maximize digester technologies.
- Food scraps and residuals may play a role in the region's energy generation portfolio as well. NVDA supports energy recovery that supports the highest and best use of waste materials, namely the food recovery hierarchy that prioritizes the reduction of waste. This policy is consistent with NVDA's Utility and Facilities Plan.

Biomass

Biomass has significant potential to reduce the region's fossil fuel consumption. The majority of our fossil fuel consumption is for transportation and home heating uses, only a small portion of fossil fuels are used in electricity generation for the region. Wood chips, wood pellets, and biodiesel hold the greatest potential for Vermont to transition these uses towards renewable energy. The expansion of these resources will also offer strong support for our traditional economy (forestry and agriculture) and stabilize regional fuel costs. In the next few years, biomass usage should be promoted and expanded as a significant resource to diversify the region's energy portfolio and meet future energy needs.

The region already supports a large-scale wood-chip fueled electric generation facility. The Ryegate Power Station is the second largest electric generation facility in the region. Capable of generating 172,367 MWh annually; the plant operated at 100% capacity in 2009, but was idle in the spring of 2012. New power purchase agreements have been drafted and the plant resumed production in June 2012. Ryegate Power Station is a good example of the difficulties in making an electric-only wood generation plant profitable and competitive. Overall, the ease of handling, local availability, low emissions, and general low-costs of wood resources will allow the region an opportunity to expand this resource if fossil fuel prices climb.

One of the most efficient uses for wood-fuels is co-generation, the simultaneous production of both heat and power, such as the system in North Country Regional Hospital that generates a third of its electric needs and heats the entire hospital. Recent studies looking at co-generation opportunities in the region indicate that it works best when there is an equal need for heat and power[18]. Balanced heat and power loads are easier to provide for on the small scale, such as for an individual business but larger plants are more desirable, since they can secure more renewable energy incentives and the capital cost/kWh improves. Large co-gen applications (10+MW) may make sense if an equally large heat user can be found, such as a manufacturer that requires tremendous heat loads. Some engineers propose developing district heating systems along with co-gen plants in areas where a considerable industrial heat user is not available. District heating systems are utilized throughout Europe and one will soon come on-line in Montpelier. Unfortunately most of Vermont's communities do not have

[10] *Town of Sutton - Burke Lumber Site Redevelopment: Wood Supply Assessment & Wood Pellet Manufacturing Facility Feasibility Study/Business Plan* (June 2009, Innovative Natural Resource Solutions for NVDA), St. Johnsbury-Lyndon Industrial Park Energy Study (2007).

the density to support nor afford the $400/linear foot installation cost district heating requires for distribution. In addition, the average connection cost for district heating is around $5,000 per homeowner. In other words, district heating is not an easy sell to tax payers.

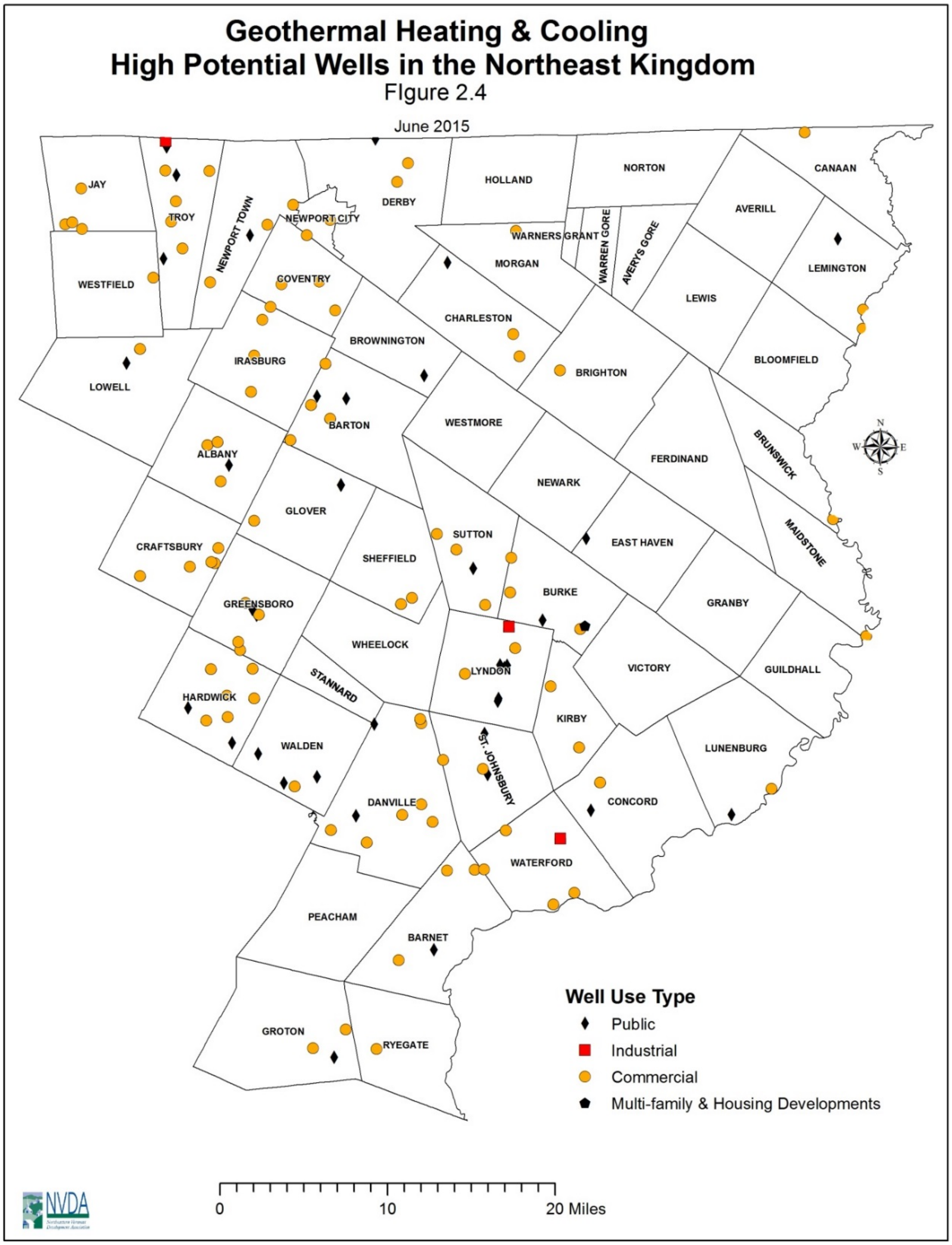
Siting policies for biomass:

- Siting wood-generation and co-generation facilities can be fraught with challenges. Noise, emissions, truck traffic, and unsightly smoke stacks are concerns when siting facilities near residential neighborhoods. Municipalities are strongly encouraged to develop performance standards for industrial uses.

- These facilities use a renewable fuel that grows at a specific rate, so overharvesting of the regional woodshed is a concern. The plan strongly urges a commitment to responsible stewardship of the region's forestry resources, accomplished through the use of forestry overlays that minimize fragmentation (regulatory), or enrollment in Vermont's Current Use Program and conservation easements (non-regulatory). A number of planning tools are available to municipalities, including forestry land evaluation and site analyses (FLESAs), that can help municipalities prioritize lands for protection. NVDA encourages local planning commissions to seek technical assistance.

Geothermal

Geothermal has great potential for expansion in the Northeast Kingdom, with the most promising systems being open-loop well systems. This technology is also one of few renewable resources that can directly reduce fuel oil consumption used for space heating and should be encouraged in both existing and new construction in the region. There are numerous sites throughout the region where geothermal can be used. (Figure 2.4)


Geothermal Heating & Cooling
High Potential Wells in the Northeast Kingdom
FIgure 2.4
June 2015
JAY
TROY
NEWPORT TOWN
NEWPORT CITY
DERBY
HOLLAND
NORTON
CANAAN
AVERILL
WESTFIELD
COVENTRY
WARNERS GRANT
WARREN GORE
AVERY'S GORE
MORGAN
LEMINGTON
LEWIS
CHARLESTON
BROWNINGTON
IRASBURG
LOWELL
BRIGHTON
BLOOMFIELD
BARTON
WESTMORE
ALBANY
BRUNSWICK
FERDINAND
NEWARK
GLOVER
MAIDSTONE
SUTTON
EAST HAVEN
CRAFTSBURY
SHEFFIELD
BURKE
GREENSBORO
GRANBY
WHEELOCK
VICTORY
GUILDHALL
LYNDON
STANNARD
HARDWICK
KIRBY
WALDEN
ST. JOHNSBURY
LUNENBURG
DANVILLE
CONCORD
WATERFORD
PEACHAM
BARNET
GROTON
RYEGATE
Well Use Type
Public
Industrial
Commercial
Multi-family & Housing Developments
0
10
20 Miles
NVDA

A Healthy and Sustainable Regional Food System

The food we eat has a profound impact on our region's energy use and carbon footprint. The complexity of processes and practices along every point in our food system -- from production, to processing, to distribution, to waste – has significant environmental and ecological implications, making food the number one cause of global warming.[19] Fortunately, the region's vibrant agriculture sector has helped to make Vermont a leader in access to local food. The Northeast Kingdom is the only region of Vermont to adopt a comprehensive Food System Plan, one that is built on a "soil to soil" model that seeks to localize the production, processing, distribution, consumption, and composting of our region's agricultural resources. The emerging Food System Leadership Group, is responsible for overseeing the implementation of the five-year plan. Their work can intersect with regional energy planning efforts in a number of ways, including:

The reduction of food waste: There has been a concerted effort to divert discarded food and food scraps from landfilling, as evidenced by the many schools, institutions, and municipalities that have established programs for collecting and composting food scraps. However, perfectly edible food often gets discarded as well. Food waste is a serious economic and environmental problem that persists, even in the face of rising food insecurity. Food waste is any food product that gets discarded, at any point along the supply chain: from produce left to rot in the fields, from expired foods discarded by the retailer, to leftovers scraped from dinner plates into the garbage bin. Anywhere from 25% to 40% of our nation's food ultimately goes to waste, nearly all of which ends up in landfills, where it produces methane that is 21 times more potent that CO2 as a greenhouse gas. Food waste contributes 4.4 gigatons of carbon dioxide equivalent into the atmosphere every year. If food waste were a country, it would be ranked just behind the U.S. and China as the third largest emitter of greenhouse gas emissions.[20] The NEK Food System Plan is focused on redirecting waste, both edible food to food secure populations, and food scraps and residuals to appropriate composting facilities and to digesters. The region has limited infrastructure for handling organic wastes, so a successful and efficient system will likely be a combination of trucking/hauling and on-site management.

Shared distribution and warehousing: In theory, a more localized food system reduces energy because it entails fewer "food miles" in getting the food from farm to table. Unfortunately, much of the region's agricultural product is currently distributed in and out of the region in a less-than-truckload capacity. Among the smallest of producers, the distribution system could be a Subaru. The NEK Food System Plan has identified a number of opportunities for shared distribution and storage, all of which can reduce transportation miles and greenhouse gas emissions. Coordination and oversight of these shared opportunities is needed to make this distribution system efficient.

Conservation and Regenerative Agricultural Practices: An array of practices that feed the soil can also increase the rate of carbon sequestration. While there is no single blueprint for success, a number of farmers in the region are implementing techniques such as diversified cover cropping and conservation tillage to mitigate the loss of topsoil and stem erosion. Grass farming and rotational grazing can reduce energy inputs, reduce erosion, and improve water quality as well. The NEK Food System Plan seeks to promote practices that improve environmental stewardship and overall soil health. It is imperative that farmers can access the technical assistance and resources that will help them achieve this.

[19] Paul Hawken. *Drawdown: The Most Comprehensive Plan Ever Proposed to Reduce Global Warming*, Penguin (2017)
[20] Ibid.

REGIONAL ENERGY GOALS & STRATEGIES

An adequate, reliable, diverse, and secure energy supply will benefit the region.

- Promote a diversified energy portfolio for the region.
- Support the upgrade of regional transmission systems to continue to reduce constraints.
- Support the maintenance and upgrade of existing energy generation facilities and related infrastructure.
- Encourage local responders to plan for emergency energy resources (VEM Emergency Generator Grant Program generators).

Affordable energy alternatives will be available for the region's users that decrease the region's reliance on fossil fuel.

- Assist in the development of businesses that support alternative energy use.
- Work with Tier 3 energy service providers to promote the installation of cold climate heat pumps and geothermal systems by facilitating outreach and education on their benefits.
- Partner with Efficiency Vermont and Tier 3 energy service providers to increase the use of efficient wood heat and biomass systems.
- Support the development of small-scale renewable resources, such as wind and solar, and the use of supplemental sources (wood) to stabilize energy costs.
- Promote and support rail infrastructure as a cost-effective transportation resource for the energy industry.
- Encourage and support agricultural production of biofuels and oilseed crops and explore ways to broaden access to processing infrastructure.
- Identify potential users of district heating and wood heating systems and provide assistance to communities seeking to develop them.
- Encourage the legislature to increase incentives and rebates for efficient wood heat systems.
- Provide outreach and education among vendors, contractors, and the general public through venues such as tradeshows and workshops.
- Provide communities with an analysis of potential areas that are suitable for ground source heat pumps.
- Support upgrade and trade-out programs and incentives for older, higher emission wood burning stoves and boilers.

Decrease the region's reliance on single occupancy vehicle trips and gas/diesel powered vehicles.

- Continue to advocate for better telecommunications infrastructure so employees can work from home.
- Encourage local employers to reduce VMTs through programs such as ride sharing and Go Vermont.

- Support and expand access to liquid biofuels for use in commercial vehicles and heavy equipment.
- Support and expand the use of electric powered busses and vans among the public transportation providers serving the region.
- Work with cycling advocacy groups such as Local Motion by hosting safe on-road cycling workshops.
- Provide training to local zoning and development review boards to consider infrastructure for alternative transportation in their review of site plans.
- Provide technical and grant writing assistance to local planning commissions who plan for multi-modal circulation and better connectivity with alternative transportation modes.
- Promote the use of the region's cycling infrastructure such as the Cross Vermont Trail and the Lamoille Valley Rail Trail and support the efforts of local groups who work to maintain them.
- Support municipalities and local businesses to install EV charging stations at convenient locations, such as in front of restaurants, stores, businesses, or entertainment or recreational facilities, where users would want to park for periods of two to four hours. Explore and pursue incentives to defray the cost of installation and administration so that users pay only for electricity.

Net-metering capacity in the region will be maximized.

- Encourage municipalities to become "clean energy districts" and participate in the PACE program (Property Assessed Clean Energy). This would provide consumers with options to more affordably implement grid tied renewable energy systems.
- Support solar panel safety training programs for fire fighters and first responders.

Energy efficiency and weatherization will be an integral part of the energy portfolio.

- Assist municipalities in reducing their energy costs through conservation, efficiency, and weatherization programs.
- Support and promote the Energy Action Network (EAN) energy dashboard and educate communities about its use and benefits. Support crowdsourcing on efficiency and weatherization efforts at the local level (e.g. Vermont Community Energy Dashboard).
- Support Local Energy Committee/Coordinator efforts to reduce energy consumption, improve efficiency and weatherization, and develop new generation resources.
- Encourage municipalities to conduct energy audits and weatherization programs.
- Encourage businesses to make energy efficiency investments and develop energy efficient production methods.
- Promote energy efficient building design and construction methods (e.g. Green Building Design, LEED certification, and Passive Design).
- Promote Energy Efficiency Utility program resources by making web links available on municipal/regional web sites.

- Work with partner organizations and Energy Efficiency Utilities EEUs to offer workshops and educational opportunities to businesses on efficiency in new construction, retrofits, and conservation practices.
- Identify large energy usage customers (including large businesses, manufacturing facilities, and schools) as a target audience and encourage participation in commercial and industrial EEU programs.
- Facilitate strategic tree planting to maximize energy benefits by encouraging communities to participate in the ArborDay Energy Saving Trees Program.
- Support local zoning initiatives that incent the development of small and/or net-zero homes.
- Ensure that developments subject to Act 250 consider new energy requirements by encouraging the compliance with commercial energy stretch codes, particularly among proposed commercial uses that are high energy consumers.
- Showcase the cutting-edge work of local architects and contractors who incorporate green building practices through NVDA's web site and newsletters.
- Promote the use of the Vermont Home Energy Profile among prospective buyers and sellers of homes. Work with local contractors to become BPI certified in energy-efficient retrofit work in order to assist with these profiles.
- Ensure that local zoning administrators have information on Residential Building Energy Standards and Commercial Building Energy Standards (RBES and CBES). Host and facilitate training sessions for local officials. Encourage communities with zoning to require Certificates of Occupancy. Encourage the local adoption of "stretch codes".
- Work with local affordable housing organizations to promote and improve the supply of the region's net-zero and near-net zero housing supply, such as Vermod homes.
- Review local zoning bylaws and offer technical assistance to development review boards when evaluating the energy efficiency implications of site plans for proposed developments.

Weatherize at least 25% of the region's housing stock by 2020.

- Actively advocate for the continuation and expansion of funding programs that support thermal efficiency and renewable energy improvements, especially programs that are targeted to middle- and low-income households.
- Coordinate with and promote efficiency programs and weatherization assistance programs (such as Efficiency Vermont, NE TO, 3E Thermal, and Heat Squad) for low-income households and apartment buildings.
- Cosponsor and organize weatherization workshops for home and businesses with EEUs.
- Facilitate or sponsor a workshop for owners of rental housing (including farm labor housing) to encourage implementation of energy efficiency.
- Encourage residents to hire Efficiency Excellence Network (EEN) contractors when completing energy efficiency projects by including links to the EEN on municipal/regional websites.
- Make information available about lending programs that can improve the efficiency of older housing stock, such as Efficiency Vermont's "Heat Saver" loan and USDA Direct and Guaranteed Loan Programs, for single homes and multi-family homes.

Energy generation that provides the best cost-benefit to the region will be promoted.

- Promote wood-based energy generation to support the region's forest industry.
- Encourage the development of energy facilities and resources that help sustain local agriculture and forestry (i.e. grass/wood-pellets, small-wind, solar, farm-methane, wood-chip, biodiesel).

Environmental and aesthetic impacts of energy generation and usage will be considered.

There will be broad public participation in the decision-making process.

- Encourage the Vermont Legislature to develop policies that support the development of solar, small-wind, hydro-electric, farm methane, biodiesel and biomass generation facilities, while respecting current local land use and the culture of the region.
- Encourage the PUC to examine the long-term sustainability of proposed facilities.

Assessment of local needs and values on new energy development will be encouraged.

- Encourage towns to address energy development in town planning and zoning.
- Provide assistance to businesses/municipalities to develop cogeneration and other alternative energy strategies.

Reduce the region's carbon footprint through the expansion of a closed loop soil-to-soil regional food system that sustains and feeds the people of the Northeast Kingdom.

- Coordinate movement and storage of goods to achieve maximum efficiency.
- Redirect food scraps and other organics from the waste stream in a manner that maximizes efficiency and minimizes hauling.
- Support and further the goals and strategies of the NEK Food System Plan through its Leadership Group.
- Identify and publicize opportunities for shared truck space among existing growers and producers.
- Generate better awareness of existing distribution resources, such as freight service.
- Identify and publicize opportunities for shared storage space among existing growers and producers.
- Explore the feasibility of establishing a leased storage facility.
- Assess market demand for products and existing shippers and distributors already moving to external (New York and Boston) markets (including opportunities for backhauling).
- Identify infrastructure needed to maximize inbound, outbound, and internal freight movement.
- Promote the use of and increase the amount of on-farm power and community energy generation and the use of renewable energy for farming and food production (such as

anaerobic digesters, solar, wind, biomass, and biodiesel, in accordance with local and regional planning priorities).

- Support local incentives for siting solar installations away from most productive agricultural soils.
- Explore the use of compost heat recovery; identify challenges, opportunities, and funding sources.
- Provide and increase opportunities for onsite and commercial composting training and education, sustainable farming methods focused on reduction and reuse of wastes (closed-loop nutrient systems), and shared facilities and infrastructure to transfer and store compost.
- Establish a coordinated marketing campaign that dispels the perceptions around local food costing more and extols the long-range benefits of staying local (e.g. dollars re-circulated into the economy, food miles travelled).
- Explore the feasibility of a developing a "food miles" measurement that can be used in marketing local foods.

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Vermont Public Power Supply Authority
2020 Tier 3 Annual Plan

In accordance with the Public Utility Commission's ("PUC") *Final Order in Docket 8550*, Vermont Public Power Supply Authority ("VPPSA") is filing this Annual Plan describing its proposed 2020 Energy Transformation programs. Vermont's Renewable Energy Standard ("RES"), enacted through Act 56 in 2015, requires electric distribution utilities to either generate fossil fuel savings by encouraging Energy Transformation ("Tier 3") projects or purchase additional Renewable Energy Credits ("RECs") from small, distributed renewable generators ("Tier 2").

VPPSA's Requirement

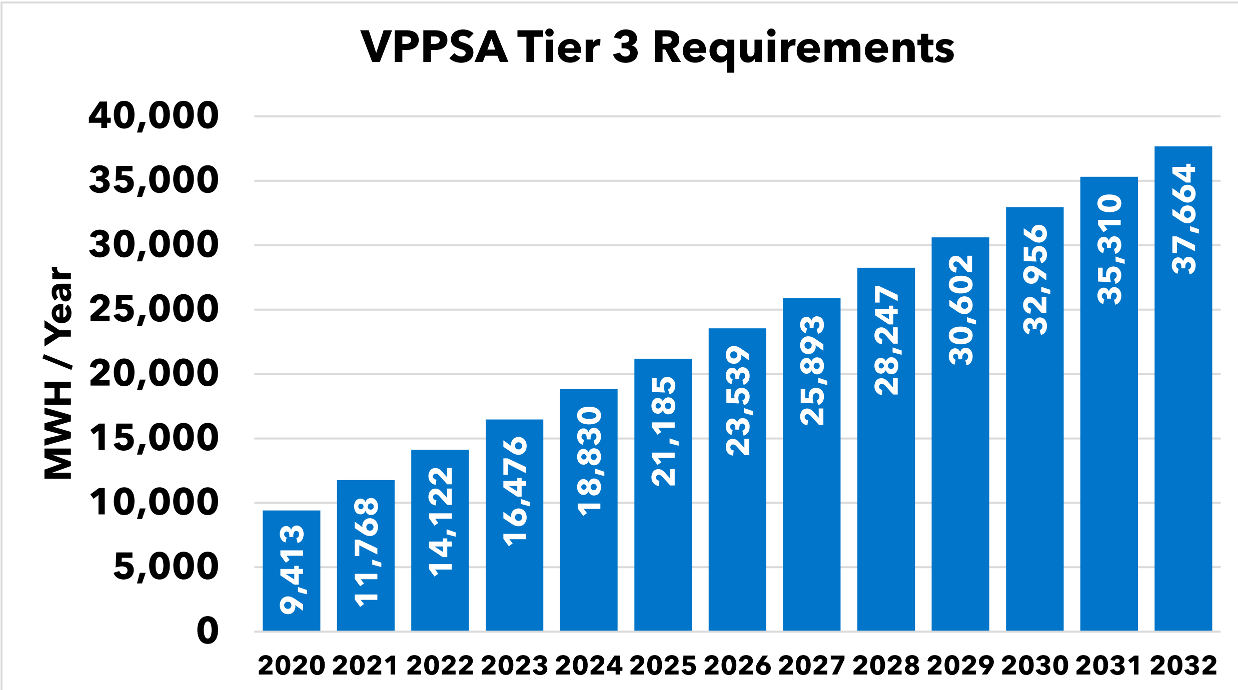
Utilities' Tier 3 requirements are established by 30 V.S.A. § 8005(a)(3)(B), which states that "in the case of a provider that is a municipal electric utility serving not more than 6,000 customers, the required amount shall be two percent of the provider's annual retail sales beginning on January 1,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

Under 30 V.S.A. § 8004 (e) "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate." The 11 VPPSA member utilities plan to meet Tier 3 requirements in aggregate. In 2020, VPPSA's aggregate requirement is estimated to be 9,413 MWh equivalent in savings, representing 2.67% of annual retail sales.

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

[1] 30 V.S.A. § 8005(a)(3)(B)

Tier 3 requirements increase by .67% annually. The below chart represents VPPSA's projected annual MWh equivalent in savings through 2032.



Summary of 2019 Projects

VPPSA expects to meet its 2019 Tier 3 requirements of 7,059 MWh through a combination of prescriptive and custom measures and through employing excess Tier 2 RECs as needed.

Prescriptive measures included post-purchase rebates for:

1. Cold Climate Heat Pumps
2. Heat Pump Water Heaters
3. Electric and Plug-In Hybrid Vehicles

Of the three prescriptive measures, we found cold climate heat pumps to be the most successful. We additionally found that custom measures, while providing a greater return in MWh savings at a lower cost, tend to have a longer ramp-up time. We identified and began working on multiple custom measures in 2019, but completion will likely not take place until a later date. Because the pricing of Tier 2 RECs was lower than the cost of implementing Tier 3 programs, purchasing excess Tier 2 was an effective strategy for keeping the Tier 3 compliance cost low. However, to accommodate the changing REC market prices, we have preemptively employed a Tier 3 marketing strategy to raise customer awareness around Energy Transformation Projects and increase uptake in the coming years.

2020 Program Overview

VPPSA proposes employing a similar strategy to meet the 2020 Tier 3 requirements while mitigating costs that could put upward pressure on rates. This includes a combination of prescriptive and custom measures and use of excess Tier 2 RECs.

Prescriptive Measures

VPPSA intends to expand its prescriptive measures offerings. Savings are estimated using measure characterizations created by the Tier 3 TAG. VPPSA's budget and estimated savings for prescriptive Tier 3 Programs is summarized below.

Cold Climate Heat Pumps

VPPSA will continue to offer customer rebates for the purchase of cold climate heat pumps ("CCHP".) In 2020 the rebate amount will be increased to $400. For customers that can demonstrate a defined level of building performance, the CCHP rebate will be increased to $500. The additional incentive serves to highlight the importance of overall building performance. In order to be eligible for the higher incentive amount, customers will need to demonstrate that their homes were weatherized according to a list of standards developed and circulated by the Department of Public Service ("DPS") during the CCHP measure characterization by the TAG.

Heat Pump Water Heaters

VPPSA will provide rebates to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. In 2019, our incentives were provided in conjunction with Efficiency Vermont ("EVT"). VPPSA and EVT are currently negotiating a Memorandum of Understanding to implement the 2020 program and define the "savings split" between VPPSA utilities and EVT.

Electric Vehicles and Plug-In Hybrids

Despite lower operating and maintenance costs associated with electric vehicles ("EVs") and plug-in hybrid electric vehicles ("PHEVs"), the upfront cost continues to be a major barrier to greater EV penetration in the state. EVs and PHEVs remain a relatively low percentage of overall vehicle sales in the state. According to Drive Electric Vermont, the number of plug-in vehicles (EVs and PHEVs) in the state increased by 676 vehicles, or 26%, over the past year. These vehicles comprised 4.1% of new passenger vehicle registrations over the past quarter. Nonetheless, there were only 3,288 plug-in vehicles registered in Vermont as of July 2019.

VPPSA is working to raise awareness of the benefits of plug-in vehicles and help alleviate the financial barriers to EV and PHEV adoption. VPPSA will continue to offer customer rebates for the purchase or lease of EVs and PHEVs and raise the rebate levels in 2020. The customer incentive for purchasing or leasing a new electric vehicle will be $1000 and the customer incentive for purchasing or leasing a new plug-in hybrid electric vehicle will be $500. Low-income customers[2] will receive an additional $400 towards the purchase or lease of an EV or PHEV.

To further expand on this program, VPPSA is adding incentives for purchasing used EVs and PHEVs. The customer incentive will be $500 for the purchase of a used EV and $250 for the purchase of a used PHEV. We are also adding a $500 incentive for the purchase of a Level 2 Charger.

Forklifts

Several industrial customers in VPPSA Members' territories utilize forklifts in their operations. Because the potential fossil fuel savings from converting diesel forklifts to those powered by electricity is significant VPPSA will actively work with these customers to determine whether a conversion is feasible. We are adding a rebate incentive of $800.

Golf Carts

VPPSA has identified opportunities to switch golf carts from fossil fuel to battery powered. We are adding a rebate incentive of $50.

Lawn Mowers

VPPSA will be adding both commercial and residential lawn mower incentives. A rebate of $25 for a residential lawn mower and $1,000 for a commercial lawn mower will be available in 2020.

E-Bikes

Utility customers have expressed interest in e-bikes, which has led VPPSA to add a rebate incentive of $100 for the purchase of a new e-bike.

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[2] According to the PUC's *Order Implementing the Renewable Energy Standard* dated 6/28/2016, "A low-income customer shall be defined as a customer whose household income is at or below 80% of Vermont statewide median income.

Measure	Savings/Unit (MWh)	Incentive Amount	Admin Cost	Total Cost	Volume	Cost/MWh	Credit (MWh)	Budget
EV	29.50	$1,000	$414	$1,414	20	$47.92	590	$28,275
PHEV	23.08	$500	$324	$824	20	$35.69	462	$16,474
EV (Low Income)	29.50	$1,400	$414	$1,814	5	$61.48	148	$9,069
PHEV (Low Income)	23.08	$900	$324	$1,224	5	$53.02	115	$6,119
EV (Used)	14.75	$500	$207	$707	4	$47.92	59	$2,828
PHEV (Used)	11.54	$250	$162	$412	4	$35.69	46	$1,647
Level 2 Charger	15.27	$500	$214	$714	4	$46.77	61	$2,857
CCHP	13.57	$400	$190	$590	42	$43.50	570	$24,794
CCHP (Weatherized)	16.96	$500	$238	$738	8	$43.51	136	$5,903
HPWH	12.50	$650	$175	$825	10	$66.03	125	$8,253
Level 2 Charger	15.27	$500	$214	$714	4	$46.77	61	$2,857
Forklift	72.96	$800	$1,023	$1,823	5	$24.99	365	$9,117
Golf Cart	2.6	$50	$36	$86	25	$33.26	65	$2,162
Lawn Mower (Residential)	1.24	$25	$17	$42	20	$34.19	25	$848
Lawn Mower (Commercial)	52.35	$1,000	$734	$1,734	2	$33.13	105	$3,469
E-Bike	5.2	$100	$73	$173	10	$33.11	52	$1,735
TOTAL					**184**	**$42.27**	**2923**	**$123,549**

Custom Measures

Commercial and industrial ("C&I") customers will be served on an individual, custom basis in 2020. VPPSA continues to explore cost-effective Tier 3 custom projects, including converting utility customers from diesel generators to electric service. In addition, C&I customers that have potential Tier 3 projects are being identified by Efficiency Vermont through a joint arrangement with VPPSA to ensure that these customers receive comprehensive efficiency services. To date, opportunities have been identified at ski resorts, a furniture maker, a quarry, and a candy manufacturer. Due to the long ramp-up time expected for these projects, completion will likely take place after 2020. The Tier 3 savings would be claimed in the year the project is completed. VPPSA will continue to work with the DPS on custom projects to ensure savings claims are valid and able to be evaluated.

Tier 2 RECs

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

Should REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would re-file its annual Tier 3 planning document.

Demand Management

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

VPPSA has established a partnership with Virtual Peaker, allowing us to assist our members in demand-response programming. In 2020, VPPSA will be piloting the following demand-response programs to keep peak load and the cost of electricity at a minimum:

1. Internal utility behavioral demand-response program to strategically maximize load-reducing generation
2. Active demand-response programs to control electric devices including CCHPs, HPWHs, and Level 2 chargers

VPPSA is also exploring partnerships outside of Virtual Peaker to best deploy demand-response programming.

Equitable Opportunity

The Tier 3 incentives described above will be available to all VPPSA member utility customers. The ability to bring financial benefits to all customers, rather than just participating customers, makes electrification an attractive Tier 3 option from an equity perspective. If additional kWh can be procured at costs at or below the costs embedded in a utility's rates, increasing the number of kWh delivered through the utility's system allows the fixed costs of operating the utility to be recovered over a larger number of units, driving the per kWh rate down.

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

Partnership, Collaboration, and Marketing

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

VPPSA is participating in administering the VTrans electric vehicle incentive. The VTrans incentive is offered on the sale of any vehicle registered in Vermont. The value of the VTrans incentive is dependent upon the owner's household income level. Participating car dealers will sell the vehicle at a price reduced by the statewide incentive. The dealer will then submit the customer's information and vehicle details to VPPSA. VPPSA will batch the incentives on a monthly basis and send the information to VTrans with a summary report and invoice. VTrans will pay VPPSA for the state incentive, which VPPSA will then remit to the dealer. We anticipate that stacked incentives and collaboration with car dealers will help to increase participation in VPPSA's electric vehicle rebate program.

VPPSA and EVT are working together to define how the two entities can provide holistic efficiency services to residential, commercial, and industrial customers. In many cases, this partnership involves VPPSA providing incentives for electrification measures, which can provide benefits to all VPPSA utility customers, while EVT provides incentives for thermal and electric efficiency measures.

VPPSA and EVT are also working closely on the Energy Savings Account pilot, which involves Ethan Allen and the Village of Orleans. This pilot allows Ethan Allen to engage in electrical efficiency measures and helps to identify opportunities for strategic energy transformation projects.

Two VPPSA member utility areas have been selected for EVT's 2020 Targeted Communities. The Village of Johnson and the Village of Orleans will both receive enhanced services from EVT for efficiency. This is yet another opportunity to explore strategic electrification for customers while reducing overall energy burden. The 2020 Targeted Communities effort is designed to have the greatest impact on low-income households.

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

- VPPSA website
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops
- Car dealer outreach
- EVT contractor and distributor outreach