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Town of Hardwick Electric Department

2019 Integrated Resource Plan



Executive Summary:

The Town of Hardwick Electric Department (HED) was incorporated in 1897. Its approximate 174 square mile service territory, located in north central Vermont, encompasses the towns of Hardwick, Woodbury, Wolcott, Craftsbury, Greensboro as well as small portions of the surrounding towns of East Calais, Elmore, Hyde Park, Eden, Stannard, and Walden. Approximately 4,500 retail customers are served. HED remains guided by the Vermont Public Utility Commission (PUC) rules, the American Public Power Association's (APPA) safety manual, as well as standard utility practices and applicable standards as defined by ANSI, the NESC, and the IEEE. Well-established past practices keep HED operating safely, efficiently, and reliably.

Hardwick's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up almost 90% of the customer mix while accounting for almost three-quarters of HED's retail kWh sales. Twenty-nine (less than 1%) large commercial customers and 358 small commercial customers each make up approximately 15% of retail usage, with the remaining less than 1% of retail sales going to public authority, and public street and highway lighting customers.

Consistent with regulatory requirements, every 3 years HED 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. HED'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

Hardwick 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 HED'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 HED's largest customers is currently anticipated, the potential does exist. HED 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.

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Finally, the impact of COVID-19 has thus far been temporary. During the spring months of 2020, the quarantine caused demand to drop. Since then, demand has recovered to what appears to be normal levels, and any long-term impacts to demand remain to be seen.

ELECTRICITY SUPPLY

Hardwick'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. HED owns and operates the Wolcott Hydroelectric Facility, delivering a clean reliable source of power located on the Lamoille River, within its service territory. The Wolcott Hydroelectric Facility has been a dependable source of power for the evolving energy needs of north central Vermont.

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

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

The first decision is in 2023, when HED must decide how to replace a firm, shaped, fixed energy contract, that is set to expire 12/31/2022. The volume needed is consistent through 2027. For the second resource decision, also during this 2023–2027-time frame, HED must decide how to fill their Tier I REC requirement. The third resource decision spans the 2028–2040 timeframe, after the Brookfield Hydro contract expires at the end of 2027 and when the Fitchburg Landfill contract expires in 2032, when HED needs increased volumes of both energy and RECs. Rather than model a series of five-year decisions to replace these expiring PPAs, we are choosing to model the impact of HED becoming 100% renewable in 2028 and contracting for those volumes through 2040.

Options being evaluated by HED to replace these contracts include signing a 5-year energy only PPA, procuring a 5-year contract to provide Tier I RECs, signing a PPA to provide energy plus Tier 1 RECs, and becoming 100% renewable in 2028 and contracting for those volumes through 2040.

The main sources of uncertainty expected to impact these decisions are the price of natural gas, the price of Class I Renewable Energy Credits (RECs), followed by the rate of load growth or decline, the rate of inflation in Regional Transmission Service (RNS), natural gas transportation to New England via pipelines, peak coincidence with ISO-NE, and Tier 1 REC prices, and capacity market prices. Other important variables are Tier II REC prices and reserve market risks.

HED's capacity supplies are forecast to be about 1MW less than its requirements (10% deficit). The deficit is contingent on both HED's annual coincident peak with ISO-NE and the generation of HED's Wolcott Hydroelectric (load reducing hydro) at the coincident peak hour. Wolcott Hydro's capacity rating is almost 1 MW.

Analysis of these major resource decisions also addresses one load-related question: what is the rate impact of 1% compound annual load growth? If this level of load growth were to occur between 2021 and 2032, for example, 1% compound annual load growth could reduce rates by about 7% in 2032 as compared to the reference case.

Additionally, the analysis evaluates the potential value of storage based on Round 2 of VPPSA's storage RFP. The value of storage appears to be about \$12/kW-month, and a 3 MW battery priced at \$10/kW-month could reduce HED's rates in 2023 by about 1.2%.

RENEWABLE ENERGY STANDARD

Hardwick is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for HED 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. HED'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

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purchasing RECs from renewable resources located within Vermont. Satisfaction of HED'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 and space heating sectors, 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 HED receives credits toward its TIER III obligation. More information regarding HED's approach to meeting its TIER III obligation is available in Appendix B to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

Hardwick has consistently pursued upgrade initiatives each year in order to maintain a reliable and efficient system.

Hardwick's distribution system includes approximately 325 miles of line all operating on a 12.47 kV distribution system and two substations. Hardwick also owns approximately five miles of the 34.5 kV transmission facilities serving its distribution system. This line segment is from Morrisville Water & Light's Green River switch running easterly to HED's Wolcott Substation. GMP's 3319 line continues from this point to HED's Hardwick Substation, and from there to the GMP Marshfield Substation.

Hardwick's sub-transmission provider presently is GMP, but HED is working on purchasing the portion of GMP's 3319 line between Wolcott/Hardwick Substations.

Located on the Lamoille River just off of VT RT 15 between Hardwick and Wolcott, is the HED owned and operated Wolcott Hydroelectric generating station. Originally constructed in 1912, this generation station presently has one hydroelectric turbine generator.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, HED 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 HED and its customers. HED 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.

Hardwick 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 HED's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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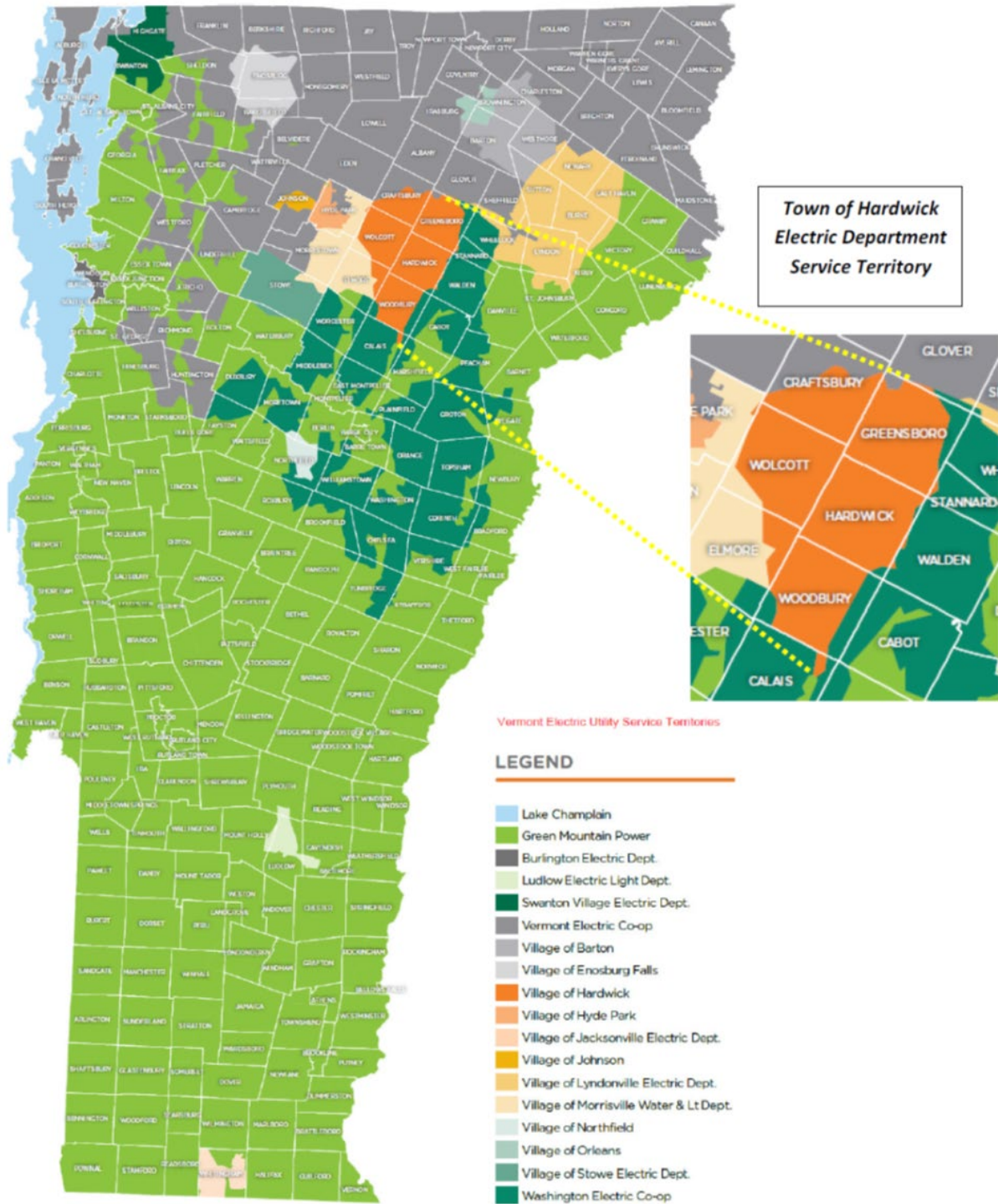
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Introduction:

The Town of Hardwick Electric Department (HED) was incorporated in 1897. HED's service territory is in north central Vermont. Its approximate 174 square mile service territory can be seen on the Vermont Utility Service Territory map found below, and it encompasses the towns of Hardwick, Woodbury, Wolcott, Craftsbury, Greensboro as well as small portions of the surrounding towns of East Calais, Elmore, Hyde Park, Eden, Stannard, and Walden. Approximately 4,500 retail customers in total are served. HED remains guided by the Vermont Public Utility Commission (PUC) rules, the American Public Power Association's (APPA) safety manual, as well as standard utility practices and applicable standards as defined by ANSI, the NESC, and the IEEE. Well-established past practices keep HED operating safely, efficiently, and reliably.

Figure 1: HED'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.

HED is one of eleven 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:

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

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

System Overview

In 2018 HED's peak demand in the winter months was 7,039 kW and 6,548 kW during the summer and shoulder months. Annual energy retail sales for 2018 were 33,545,766 kWh and the annual load factor for 2018 was 60.3%.

HED's transmission system is connected to those of Green Mountain Power (GMP) to the east and Morrisville Water & Light (MW&L) to the west.

Table 1: HED's Retail Customer Counts

Data Element	2014	2015	2016	2017	2018
Residential (440)	4,028	4,027	4,019	4,061	4,066
Small C&I (442) under 30 kW	419	419	401	385	381
Large C&I (442) 30 kW or more	26	28	30	30	29
Street Lighting (444)	9	8	7	9	9
Public Authorities (445)	0	0	0	0	0
Interdepartmental (448)	10	11	11	11	11
Total	4,492	4,493	4,468	4,496	4,496

Table 2: HED's Retail Sales

Data Element	2014	2015	2016	2017	2018
Residential (440)	23,402,447	23,265,827	23,259,517	23,141,723	23,528,620
Small C&I (442)	4,867,165	4,876,507	4,887,653	5,006,241	4,990,052
Large C&I (442)	4,285,382	4,563,615	4,666,302	5,072,305	4,846,138
Street Lighting (444)	149,218	174,777	160,353	124,620	122,710
Public Authorities (445)	0	0	0	0	0

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Interdepartmental (448)	58,471	53,970	61,422	59,900	58,246
Total	32,762,683	32,934,696	33,035,247	33,404,789	33,545,766
YOY	1%	1%	0%	1%	0%

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

Data Element	2014	2015	2016	2017	2018
Peak Demand kW	7,032	6,687	6,695	7,120	7,039
Peak Demand Date	01/02/14	02/15/15	02/14/16	12/28/17	01/02/18
Peak Demand Hour	18	19	19	18	18

Structure of Report

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

I. Electricity Demand

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

II. Electricity Supply

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

III. Resource Plans

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

IV. Electricity Transmission and Distribution

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

VI. Action Plan

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

A. Appendix

The appendix includes a series of supporting documents and reports, as listed in the Table of Contents.

B. Glossary

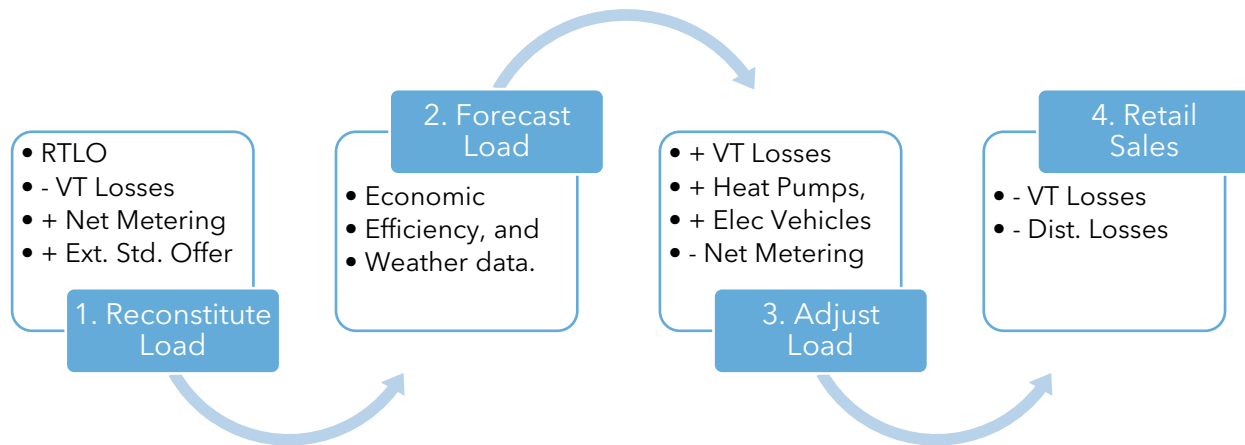
Electricity Demand

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 HED'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 HED'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 tie points (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 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 adjusted R-squared of 95.6%, and a Mean Absolute Percent Error (MAPE) of 0.99%.

¹ Vermont Electric Power Company

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 it².

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 HED. For CCHPs and EVs, we used the same data (provided by Itron) that the Vermont System Planning Committee (VSPC) used in VELCO's 2021 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.

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

Energy Forecast Results

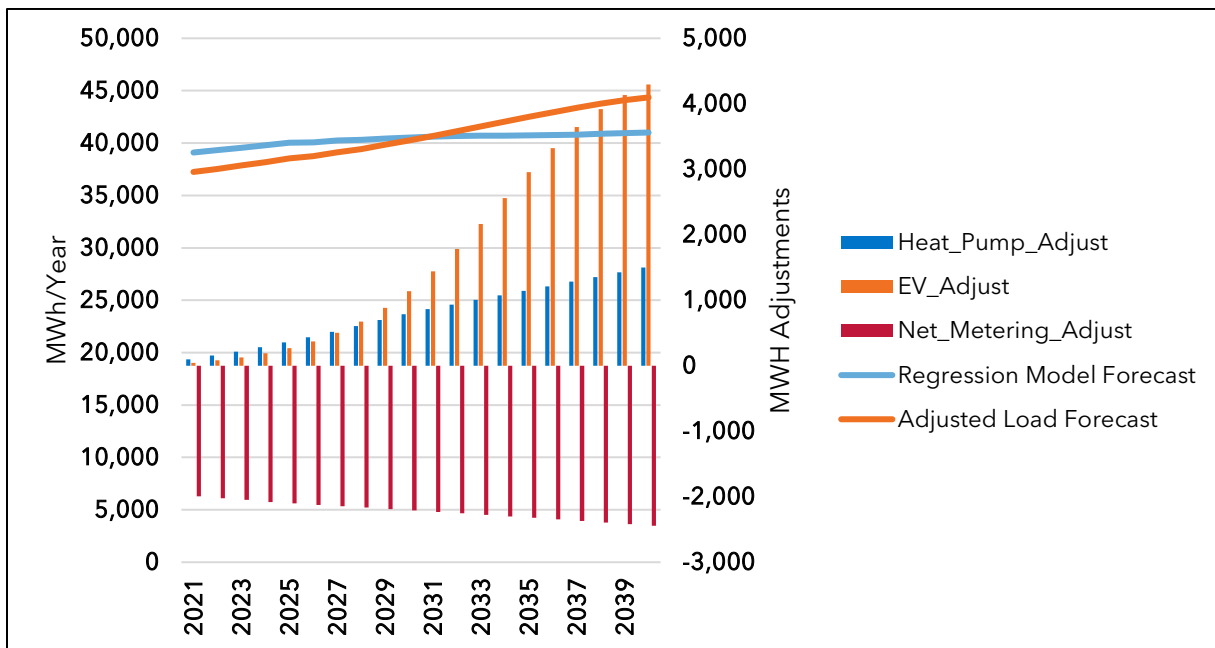
Table 6 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is increasing by 0.2% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast increases by 0.9% per year.

Table 6: Adjusted Energy Forecast (MWh/Year)

Year	Year #	Regression Forecast (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Forecast (MWh)
2021	1	39,099	98	46	-1,996	37,247
2025	5	40,026	356	268	-2,103	38,548
2030	10	40,533	786	1,138	-2,210	40,246
2035	15	40,735	1,143	2,954	-2,323	42,508
2040	20	41,007	1,499	4,293	-2,441	44,357
CAGR		0.2%	14.6%	25.4%	1.0%	0.9%

The Adjusted Forecast is the result of high CAGRs for CCHPs (14.6%) and EVs (25.4%). During the first ten years of the forecast, these two trends are more than offset by the net metering program, which grows by the historical three-year average of 1.0% per year. By 2031, the impact of CCHPs and EVs is on par with the impact of net metering, and the load growth accelerates from that year forward.

Figure 3: Adjusted Energy Forecast (MWh/Year)



Energy Forecast - High & Low Cases

To form a high case, we assumed that the CAGR for CCHPs and EV's rise to the high case levels in the 2021 Long Range Transmission Plan (LRTP) forecast. Simultaneously, we assume that net metering penetration stops at today's levels. At these growth rates, 2040 energy demand rises by over 26% compared to 2020 electricity use, a result that is driven by the 27% CAGR for EVs. Because of the nature of compound growth, the increase in energy demand does not start to accelerate until 2030. As a result, there is ample opportunity to monitor these trends during the annual budget 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)
2021	1	39,099	98	46	-1,996	37,247
2025	5	40,026	414	508	-1,996	38,953
2030	10	40,533	1,008	2,526	-1,996	42,071
2035	15	40,735	1,648	4,873	-1,996	45,260
2040	20	41,007	2,308	5,629	-1,996	46,948
CAGR		0.2%	17.1%	27.2%	0.0%	1.2%

To form a low case, we assumed that the CAGRs for CCHPs and EVs decreases to the low case levels in the 2021 LRTP. 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 *increases* by 0.6% 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	39,099	98	46	-1,996	37,247
2025	5	40,026	322	225	-2,161	38,413
2030	10	40,533	654	757	-2,385	39,558
2035	15	40,735	793	1,781	-2,634	40,674
2040	20	41,007	854	2,897	-2,908	41,849
CAGR		0.2%	11.4%	23.0%	1.9%	0.6%

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 accepted³ 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 Adjusted R-squared of 84.5%, and a MAPE of 2.34%.

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

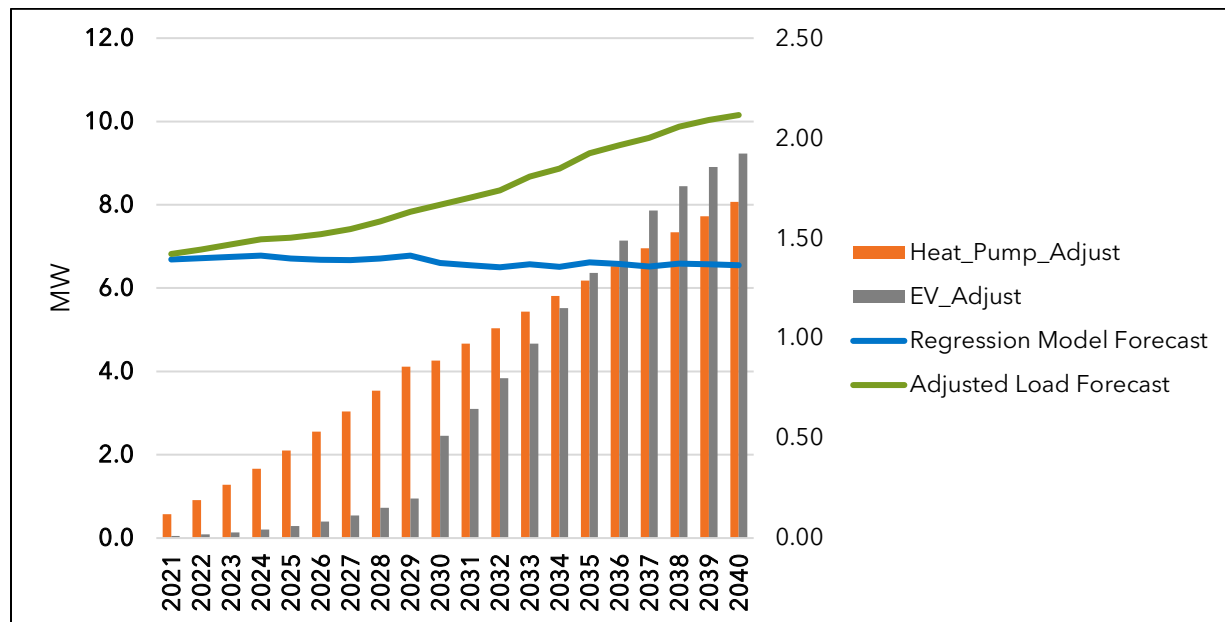
Table 9 shows the results of the Regression Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is flat. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 2.0% per year. Finally, the table shows that the timing of HED's peak load is forecast to stay in January at hour ending 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	6.69	0.01	0.12	0.00	6.82
Jan-25	1900	6.71	0.06	0.44	0.00	7.21
Jan-30	1900	6.60	0.51	0.89	0.00	8.00
Jan-35	1900	6.62	1.33	1.29	0.00	9.23
Jan-40	1900	6.55	1.92	1.68	0.00	10.15
CAGR		-0.1%	30.1%	14.1%	0.0%	2.0%

The peak load forecast starts at 6.82 MW and ends at 10.15 MW. The Adjusted Forecast exceeds the Regression Forecast immediately due to high CAGRs for CCHPs and EVs. By 2035, EV's are forecast to be responsible for as much peak load growth as CCHP's, and can be seen in Figure 4.

Figure 4: Adjusted Peak Forecast (MW)



Peak Forecast - High & Low Cases

To form a high-case, we assumed 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 after 2030. Absent a step change in consumer adoption of CCHPs and EVs, electrification is not likely to produce any appreciable peak load growth for the next ten years. However, we will continue to monitor these trends annually.

Table 10: Peak Forecast - High Case

MMM-YY	Peak Hour	Regression Forecast	CCHP Adjustment (MW)	EV Adjustment (MW)	Net Metering Adj. (MW)	Adjusted Fcst. (MW)
Jan-20	1800	6.69	0.1	0.0	0.00	6.8
Jan-25	1800	6.71	0.5	0.1	0.00	7.3
Jan-30	1800	6.60	1.1	1.1	0.00	8.9
Jan-35	1800	6.62	1.8	2.2	0.00	10.7
Jan-39	1800	6.55	2.6	2.5	0.00	11.7
CAGR		-0.1%	16.6%	31.9%	0.0%	2.7%

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

Forecast Uncertainties & Considerations

The uncertainties facing HED 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

Hardwick presently has 178 residential scale (< 15 kW) net metered customers with a total installed capacity of about 1,170 kW. In addition, there are twelve customers who have arrays greater than 15 kW, and they total 1,194 kW. All in, HED has about 2.36 MW of net-metered capacity, which is 35% of HED's 2020 peak load (6.8 MW).

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, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail revenues for the utility.

Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for HED to monitor, especially if larger net metered projects are proposed.

Electricity Supply

II. Electricity Supply

Hardwick's power supply is made up of owned generation, long-term contracts, and short-term contracts. The resources in HED's portfolio represent a range of fuel types and technologies. In addition, they are located throughout Vermont and New England, and many of their expiration dates have been chosen not to overlap. As a result, they act as a diversified portfolio that effectively hedges HED's power supply costs against the cost of serving load in ISO New England's energy, capacity and ancillary markets. The following sections describe each of HED's power supply resources, both in bulleted and in table formats.

1. Billings Road Solar

- Size: 1.65 MW AC
- Fuel: Solar
- Location: Hardwick, VT
- Entitlement: 100%, PPA
- Products: Energy, capacity, RECs
- End Date: 2045
- Notes: The project is expected to be online in 2021, and will function as a load reducing generator.

2. Chester Solar

- Size: 4.8 MW
- Fuel: Solar
- Location: Chester, MA
- Entitlement: 15.1% (0.725 MW), PPA
- Products: Energy, capacity
- End Date: 6/30/39
- Notes: The contract does not include the environmental attributes.

3. Fitchburg Landfill

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 11.25% (0.506 MW), PPA
- Products: Energy, capacity, renewable energy credits (MA I)
- End Date: 12/31/31

4. Market Contracts

- Size: Varies
- Fuel: New England System Mix
- Location: New England
- Entitlement: Varies (PPA)
- Products: Energy, renewable energy credits
- End Date: Varies, less than 5 years.
- Notes: The Electric Department purchases system power from various Other entities under short-term (5 year or less) agreements.

5. McNeil

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 1.474% (0.796 MW), joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit
- Notes: As the joint-owner, VPPSA has agreements with the Electric Department to pay for and purchase 1.474% of the unit's output.

6. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 0.335 MW (Niagara PPA), 0.022 MW (St. Lawrence PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 9/1/25 (Niagara), 4/30/32 (St. Lawrence)
- Notes: NYPA provides hydro power to the Electric Department under two contracts, which will be extended at the end of their term. The peaking power that NYPA has recently offered the State has not been included in this IRP because the negotiation is not yet complete.

7. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 9.7% (3.88 MW) MW, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with the Electric Department to pay for and purchase 9.7% of the unit's output.

8. PUC Rule 4.100 (VEPPI Program)

- Size: Small hydro < 80 MW
- Fuel: Hydro
- Location: Vermont
- Entitlement: 0.608% (Statutory)
- Products: Energy, capacity
- End Date: 10/31/2020
- Notes: The Electric Department is required to purchase hydro power from small power producers through Vermont Electric Power Producers, Inc. ("VEPPI"), in accordance with PUC Rule #4.100. The entitlement percentage fluctuates slightly each year with the Electric Department's pro rata share of Vermont's retail energy sales, and does not include the renewable energy credits.

9. PUC Rule 4.300 (Standard Offer Program)

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas and micro-hydro
- Location: Vermont
- Entitlement: 0.656% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies
- Notes: HED is required to purchase power from small power producers through the Vermont Standard Offer Program in 2019, in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with the Electric Department's pro rata share of Vermont's retail energy sales.

10. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.647% (PPA)
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2021

11. Seabrook 2018-22

- Size: 1,250 MW
- Fuel: Nuclear
- Location: East Ryegate, VT
- Entitlement: 1.853 MW On-Peak, 1.212 MW Off-Peak (PPA)
- Products: Energy, capacity, environmental attributes (Carbon-free nuclear)
- End Date: 12/31/2022

12. Stony Brook Station

- Size: 352 MW
- Fuel: Natural Gas, Oil
- Location: Ludlow, MA
- Entitlement: 0.528% (PPA)
- Products: Energy, capacity, reserves
- End Date: Life of unit

13. Wolcott Hydro

- Size: 0.815 MW
- Fuel: Hydro
- Location: Wolcott, VT
- Entitlement: 100%, Owned
- Products: Energy, capacity, environmental attributes (VT I)
- End Date: Life of Unit

14. Brookfield Contract

- Size: On-Peak: 8 MW 2023-2024, 10 MW 2025-2027
Off-Peak: 7 MW 2023-2024, 8.5 MW 2025-2027
- Fuel: Hydro
- Location: New England
- Entitlement: 12.5%-17.6% of VPPSA Total Volume, PPA
1 MW 2023-2024, 1.5 MW 2025-2027
- Products: 7x24 energy plus VT Tier I environmental attributes
- End Date: 1/1/23 - 12/31/27
- Notes: This PPA will not show up as an existing power supply resource in the following section because its start date is in 2023.

Existing Power Supply Resources

Table 11 summarizes HED's resources based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits⁴ (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 2040.

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

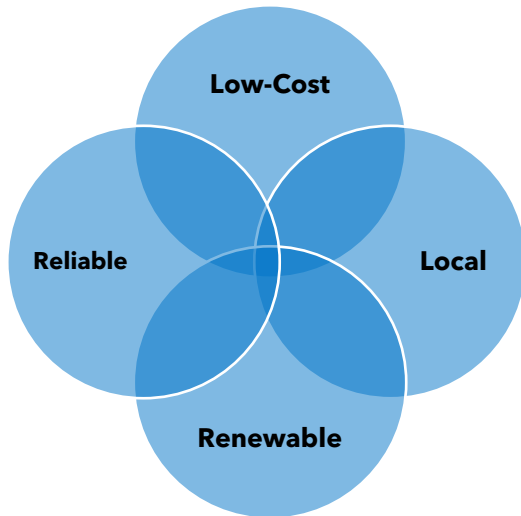
Table 11: Existing Power Supply Resources

Resource	2021 MWH	% of MWH	2021 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2040
1. Billings Road Solar	1,617	4.5%	0.000	Intermittent	Fixed	✓	2045	No
2. Chester Solar	1,052	2.9%	0.096	Intermittent	Fixed		6/30/2040	No
3. Fitchburg Landfill	2,081	5.8%	0.377	Firm	Fixed	✓	12/31/2031	No
4. Market Contracts	4,893	13.5%	0.000	Firm, Shaped	Fixed		6/30/2024	No
5. McNeil	3,094	8.6%	0.737	Dispatchable	Variable	✓	Life of unit.	Yes
6. NextEra 2018-22	13,232	36.6%	0.000	Firm, Shaped	Fixed	✓	12/31/2022	No
7. NYPA Niagara	4,200	11.6%	0.598	Baseload	Fixed	✓	04/30/2032	Yes
7.1 NYPA St. Lawrence	116	0.3%	0.017	Firm	Fixed	✓	12/31/2022	Yes
8. Project 10	102	0.3%	3.749	Dispatchable	Variable		Life of unit.	Yes
9. PUC Rule 4.100	0	0.0%	0.025	Intermittent	Fixed		2020	No
10. PUC Rule 4.300	1,051	2.9%	0.008	Intermittent	Fixed	✓	Varies	No
11. Ryegate	976	2.7%	0.135	Baseload	Fixed	✓	10/31/2024	No
12. Stonybrook	663	1.8%	1.870	Dispatchable	Variable		Life of unit.	Yes
13. Wolcott Hydro	3,043	8.4%	0.000	Intermittent	Fixed	✓	Life of unit.	Yes
Total MWH	36,120	100.0%	7.612					

Future Resources

HED 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 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 HED to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that HED 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 HED'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, HED 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 HED'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.

Vermont [Public Power](#) Supply Authority

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, HED will continue to welcome the work of the Efficiency Vermont (EVT) in its service territory. HED 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 HED 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, HED 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, HED 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, HED 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 HED 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, HED 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 pressure⁵. 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

VPPSA issued a Request for Proposals (RFP) for Electricity Storage in October 2020⁶. Like VPPSA's 2017 Solar RFP, the purpose of the Storage RFP is to identify a potential development partner who would develop storage projects in its Member's service territories.

Nine proposals were received in December. While VPPSA and its members remain open to a variety of proposals, the present proposals are for MW scale, peak-shaving storage systems. The purpose of these systems would be to reduce monthly and annual peak loads that are coincident with ISO New England, thereby reducing ISO-NE transmission and capacity costs.

At the writing of this IRP, VPPSA has chosen four companies to participate in the second round. The second-round process is now on a slower timeline than was anticipated in the RFP, but it is expected to conclude in the summer of 2021.

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 Please refer to Appendix G for a copy of the VPPSA Storage RFP.

Regional Energy Planning (Act 174)

As part of the Northern Vermont Development Association (NVDA), HED is part of a Regional Energy Plan⁷ 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 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."⁸

The full plan is included in the appendix, and all future resource decisions will be made with this plan in mind. Specifically, HED 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

Resource Acquisition Strategy

HED evaluates resource acquisitions on three different time scales.

Short-Term (< 1 year)

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

At least seasonally (four times a year), VPPSA uses a 7x24 energy product to refine the energy hedge ratio for HED. The following three-step process is used to balance supply and demand on a monthly basis within the current budget (calendar) year.

1. Update Budget Forecast

- a. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply including unit availability, fuel supply, and hydrological conditions.

2. Hydroelectric Adjustment

- a. Supply is reduced by one standard deviation from the long-term average in order to avoid making sales that could end up being unhedged by supply in the event of a dryer-than-normal month.

3. Execute Purchases or Sales

- a. **Internal Transactions:** VPPSA seeks first to make internal transactions between its members to balance supply and demand. The transactions are designed to result in a hedge ratio that falls within the +/-5% range that is required by VPPSA's Power Supply Authorities Policy.
- b. **External Transactions:** In the event that internal transactions cannot bring HED into the +/-5% range, external transactions are placed with power marketers, either directly or through a broker.
- c. **Price:** For Internal Transactions, the price of the transaction is set by an average of the bid-ask spread as reported by brokers on the date of the transaction. For External Transactions, the price is set through a negotiation with the counterparty.

Medium Term (1-5 years)

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

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

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

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

Long Term (> 5 years)

Hardwick evaluates long-term Purchased Power Agreements (PPAs) for bundled energy, capacity, renewable energy credits, and/or ancillary products on an ongoing basis. Recently, HED has evaluated a solar PPA in partnership with VPPSA and Encore Renewables, and in 2021, HED anticipates that it may evaluate two other resource acquisitions.

1. A PPA for energy and/or Tier I RECs for the 2023-2027 period, and/or
2. An Energy Storage Service Agreement (ESSA) with a battery storage developer.

Because long-term PPAs are subject to PUC approval, the acquisition strategy is to identify the optimal size and shape of the desired products (energy, capacity, RECs, ancillary services), and then negotiate the best possible terms with creditworthy counterparties. Once the rate impact of these terms is determined and the requirements of Act 248 are met, then HED would file for PUC approval. In all circumstances, the resource acquisition would be made contingent on PUC approval.

Major Decisions

As the following sections will explain, HED has a two resource needs, energy and Tier I RECs.

Hardwick needs energy starting in 2023, and the volume is consistent through 2027. This is the first resource decision.

During this 2023-2027 time frame, HED also needs Tier I RECs. Although another bundled energy and Tier I REC transaction could be modeled in this IRP, we are choosing to keep the decisions separate. This is the second resource decision, and it enables the analysis to more clearly show the benefits of hedging each resource need separately.

At the end of 2027, the Brookfield contract expires and HED needs increased volumes of both energy and RECs. Energy needs increase once again after the expiration of the Fitchburg contract in 2032. Rather than model a series of five-year decisions to replace these expiring PPAs, we are choosing to model the impact of HED becoming 100% renewable in 2028 and contracting for those volumes through 2040. This is the third resource decision.

1. 2023-2027 Energy
2. 2023-2027 Tier I RECs
3. 2028-2040 Energy plus Tier I RECs

The rationale for this third resource decision has two parts. First, other Vermont utilities⁹ have recently made commitments to develop and maintain a 100% carbon-free and/or renewable power supply. Furthermore, three of Vermont's utilities¹⁰ are already 100% renewable. In this context, it seems likely that the current Tier I RES requirement will eventually be increased to 100%.

Second, modeling this as a decision enables the IRP to measure how much it would cost for HED to become 100% renewable, and to measure what the benefits might be in terms of REC price risk. This decision will be modeled like the Brookfield contract, a PPA that is shaped to match HED's future energy and Tier I REC needs.

⁹ <https://vermontelectric.coop/latest-news/vec-commits-to-carbon-free>

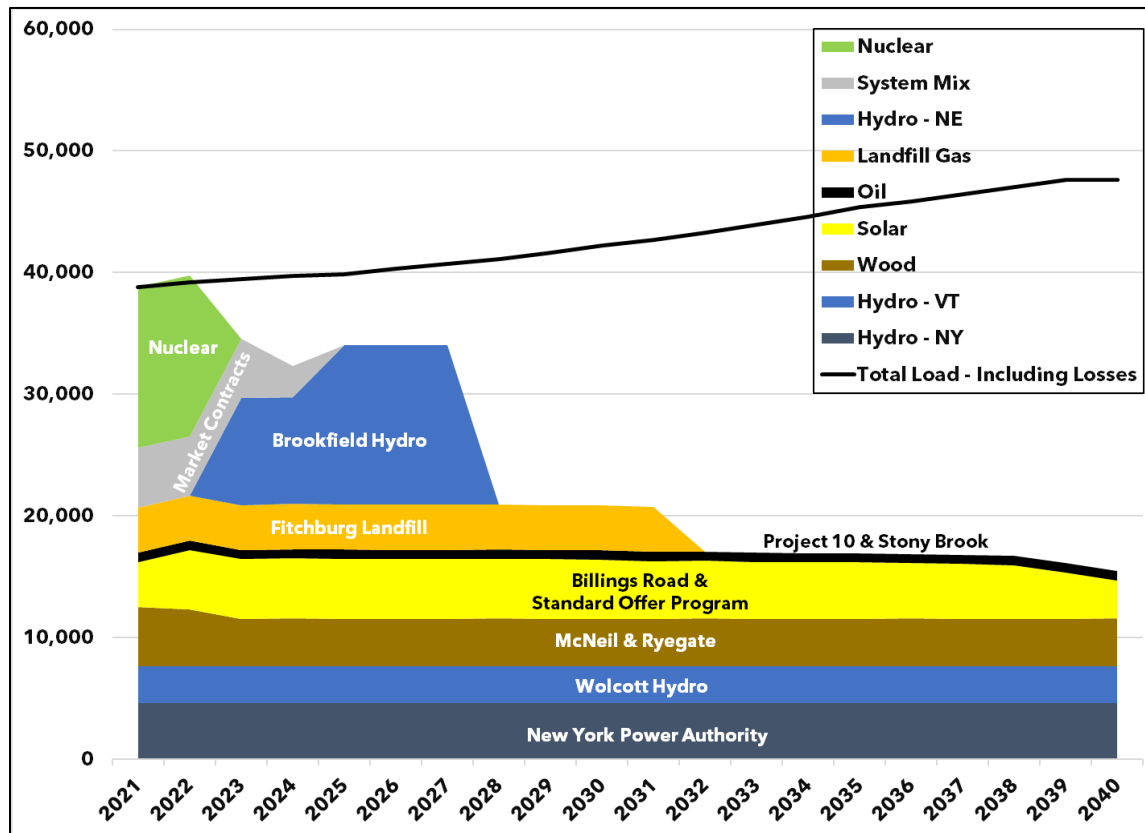
<https://greenmountainpower.com/gmp-launches-vision-to-have-100-renewable-energy-by-2030/>

¹⁰ These utilities include Burlington Electric Department, Swanton Electric Department, and Washington Electric Cooperative.

Energy Resource Plan

Figure 6 compares HED's energy supplies to its adjusted load. There are three resource decisions that, in total, will affect about 50% of HED's energy supply between 2021 and 2032. A series of market contracts will begin to expire between 2023 and 2024, and then the Brookfield contract expires in 2027. Finally in 2031, the Fitchburg Landfill PPA expires.

Figure 6: Energy Supply & Demand by Fuel Type



The impact of these resource expirations on the portfolio is summarized in Table 12. The prices of these resources are near or slightly above the market price forecast. As a result, their expiration could potentially produce some rate pressure, but the impact is presently nearly neutral. When the Brookfield PPA expires, additional Tier I RECs will be needed for RES compliance. The impact of the Fitchburg PPA expiration is expected to be neutral.

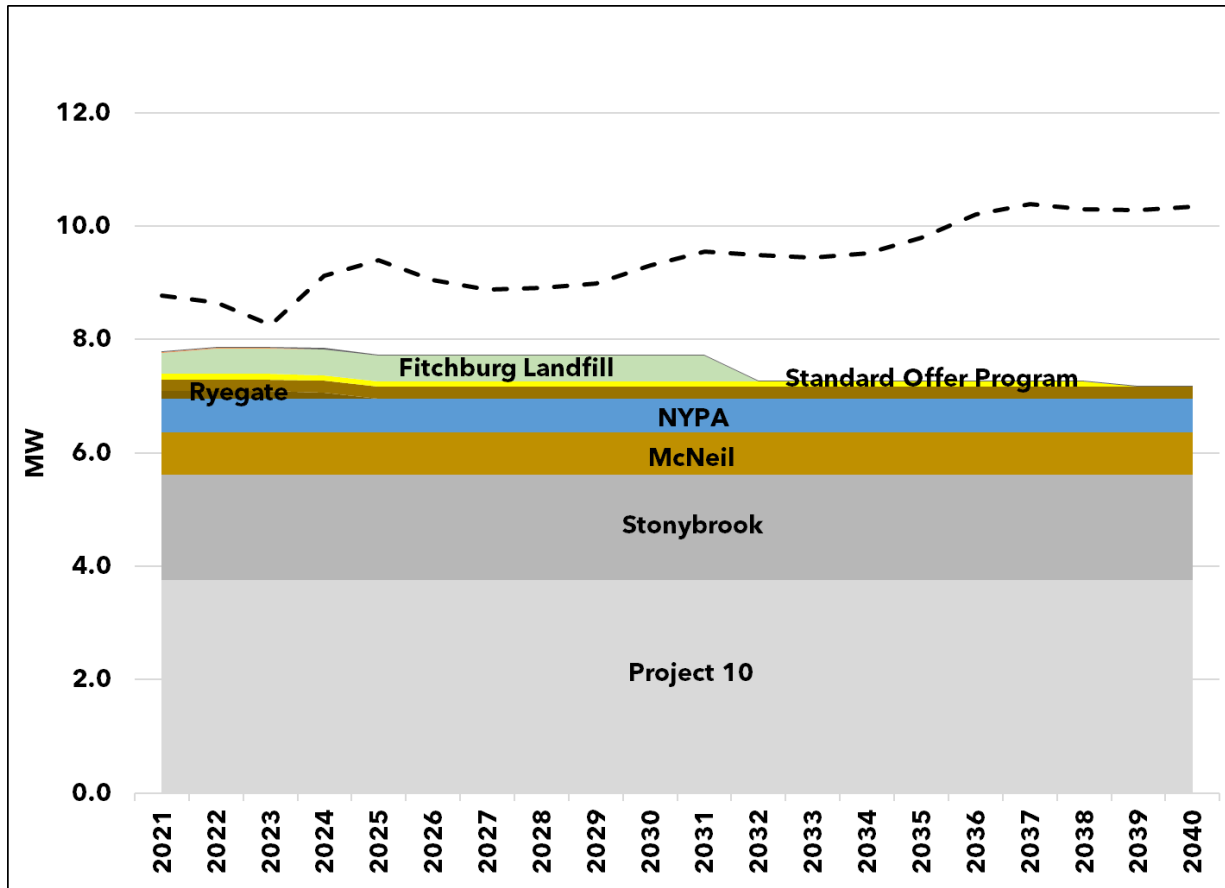
Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
1. Market Contracts	2023+	13%	Rate Reducing	None
2. Brookfield Contract	2028+	34%	Neutral	Tier I
3. Fitchburg Contract	2032+	6%	Neutral	None

Capacity Resource Plan

Figure 7 compares HED's capacity supply to its demand. Project 10 and Stonybrook provide about 70% of all of HED's capacity. The remaining supplies are primarily from McNeil, NYPA and the Fitchburg Landfill.

Figure 7: Capacity Supply & Demand (Summer MW)



In 2021, the gap between supply and demand is about 1 MW or a 10% deficit. This deficit is contingent on HED's annual coincident peak with ISO-NE, which has varied by as much as 25% in a single year. Furthermore, the generation of Wolcott Hydro (load reducing hydro generation) at the coincident peak hour will contribute to this variance. Note that Wolcott Hydro's capacity rating is almost 1 MW.

Having a deficit of this size is compatible with an investment in battery storage at some point in the future, and HED is an active participant in VPPSA's storage RFP as a result. In the meantime, imbalances will be settled through the Forward Capacity Market. At this point in time, the supply of capacity is expected to comfortably exceed the demand, and the outlook for unit retirements is modest and not increasing. As a result, the outlook for capacity prices is for them to remain low. Finally, given the uncertainty surrounding the structure of future capacity markets, buying a long-term capacity resource would be speculative, and it seems more prudent to settle HED's modest deficit position in the FCM.

As the largest part of the capacity supply, the reliability of Project 10 is the primary concern for HED. As a result, maintaining the reliability of Project 10 will be the key to minimizing HED's capacity costs, as explained in the next section.

ISO New England's Pay for Performance Program

Because HED is part of ISO New England, its capacity requirements are pooled with all of the other utilities in the region. As a result, if Project 10 is not available, HED will be provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance¹¹ (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 HED's 9.7% (3.75 MW) 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, HED could receive up to a \$8,800 payment or pay up to a \$9,900 penalty during a one-hour scarcity event. This represents a range of plus or minus 15% of HED'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 Operation¹²

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	\$3,500/MWH	-\$4,300	\$2,200	\$8,800
15,000	\$3,500/MWH	-\$6,200	\$400	\$6,900
20,000	\$3,500/MWH	-\$8,100	-\$1,500	\$5,100
25,000	\$3,500/MWH	-\$9,900	-\$3,400	\$3,200

¹¹ For an overview of the PFP program, please visit <https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project>.

¹² 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

HED's obligations under the Renewable Energy Standard¹³ (RES) are shown in Table 14. Under RES, HED 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 Energy¹⁴ (Tier II) requirement rises from 2.8% in 2020 to 10% in 2032. Note that this IRP assumes that these 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%
2033-2040	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 year¹⁵...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.

¹³ For more information on the RES program, please visit <https://vppsa.com/energy/renewable-energy-standard/>.

¹⁴ 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.

¹⁵ 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 Payment¹⁶ (\$/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).

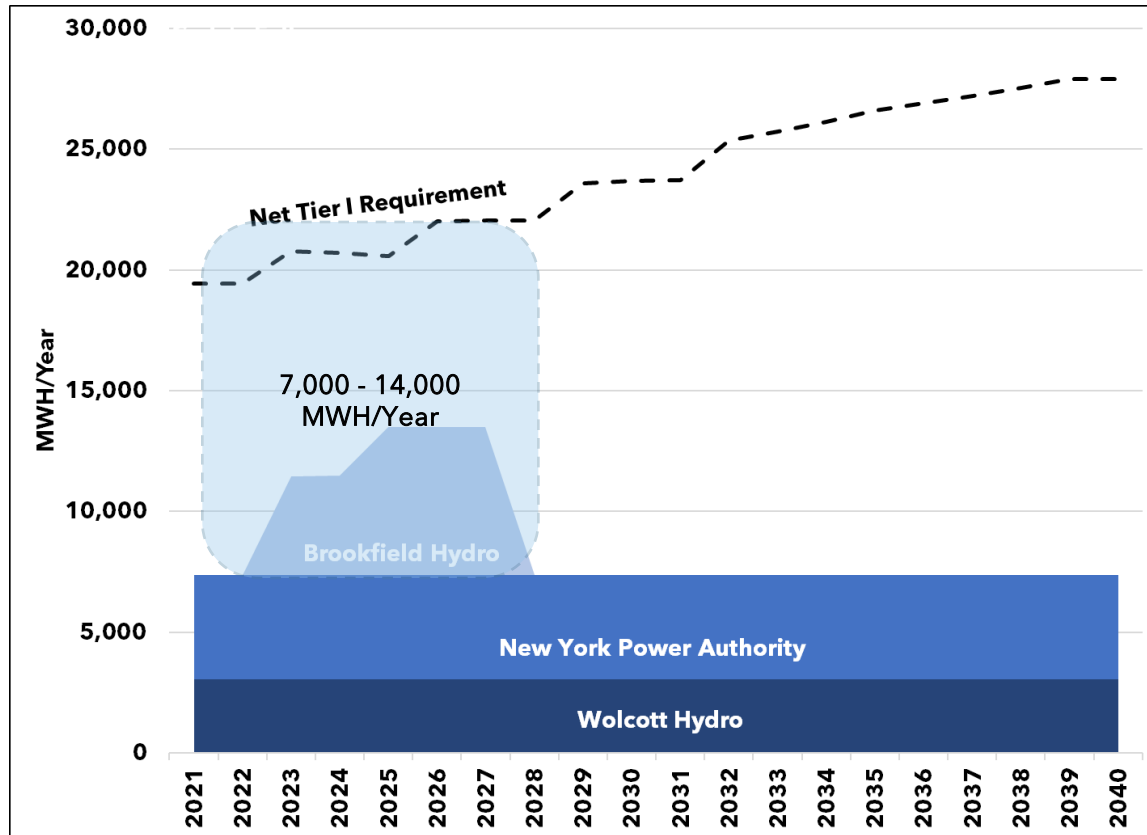
Finally, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP. Alternatively, utilities may petition PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

¹⁶ Please note that these are estimates and grow at inflation.

Tier I - Total Renewable Energy Plan

Between 2020 and 2024, HED's Net Tier I requirement is about 20,000 MWH per year. The resources that contribute to meeting it are shown in Figure 8, and they represent about 7,500 MWH per year or 37% of HED's Net Tier I requirement.

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



In the early 2020s, HED 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 \$1.5/MWH, the cost of complying with Net Tier I in the 2020 to 2024 period would be about \$20,000 per year.

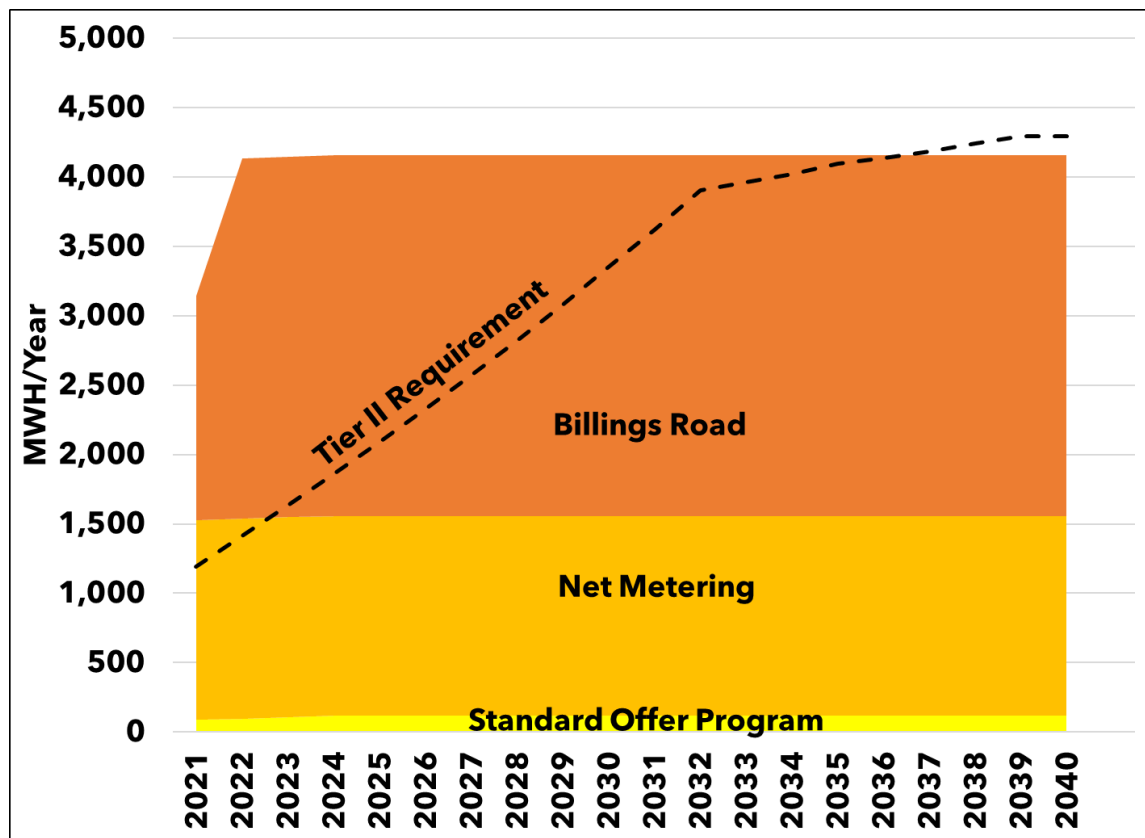
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 and Market PPAs creates an opportunity to purchase a resource that provides both energy and RECs. The 12,000 MWH per year deficit is equivalent to the size of the NextEra contract, and a 3.4 MW hydro facility¹⁷ would provide about the same amount of MWH. A hydro resource of this size (including RECs) could erase the Net Tier I deficit between 2020 and 2024. As a result, this resource choice is one of the major resource decisions that is analyzed in this IRP.

¹⁷ We have assumed a 40% capacity factor, which results in roughly 23,000 MWH per year.

Tier II - Distributed Renewable Energy Plan

The dashed line in Figure 9 shows HED's Distributed Renewable Energy¹⁸ (Tier II) requirement, which rises steadily from 1,200 MWH in 2021 to 4,000 MWH in 2032. HED's supply exceeds the demand throughout the forecast period due to high levels of net-metering and the Billings Road solar project. The surplus will be applied to HED's Tier III requirements as shown in the next section and will be sold to other VPPSA members or regional utilities at prevailing REC market prices.

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

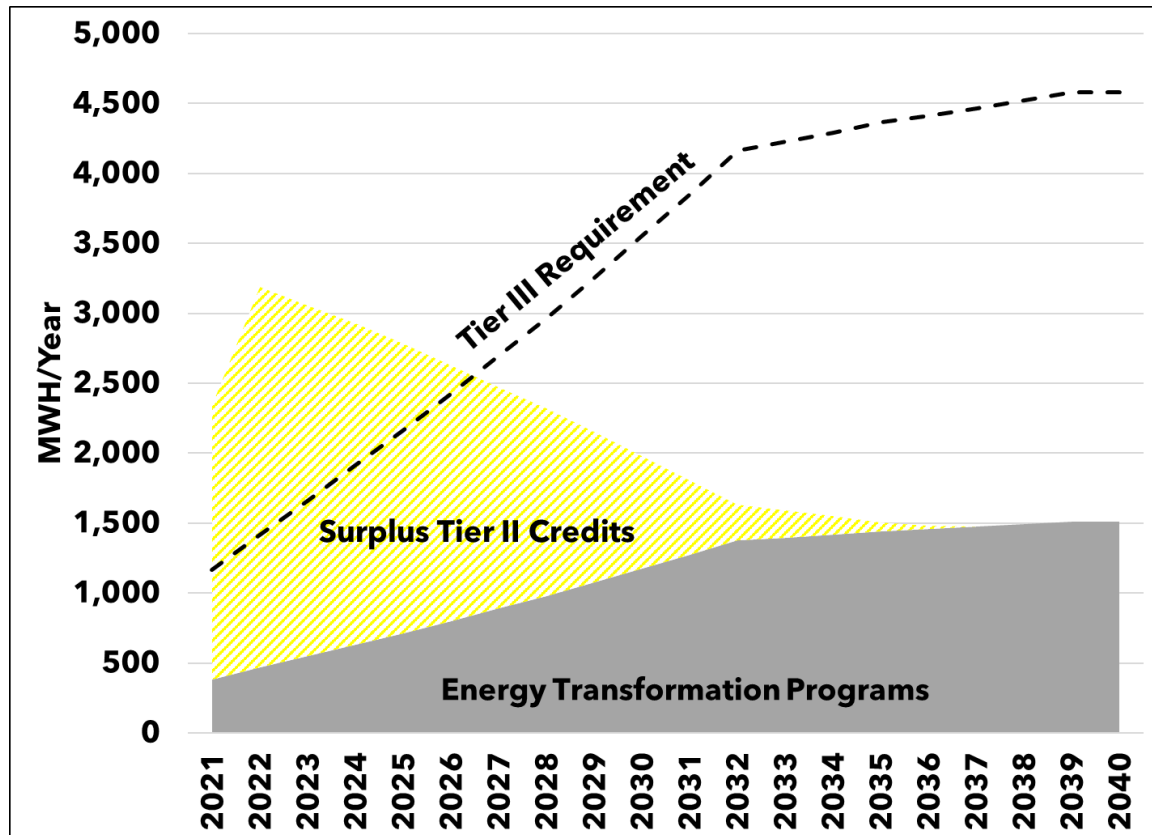


¹⁸ The TIER II requirement is also known as "Tier 2".

Tier III - Energy Transformation Plan

The dashed line in Figure 10 shows HED's Tier III requirements, which rise from about 1,200 MWH in 2021 to about 4,200 MWH in 2032. Energy Transformation programs are presently budgeted to fulfill about a third of the requirement in the early 2020s, and are shown in the gray-shaded area of Figure 10. These programs¹⁹ cover a range of qualifying technologies including EVs, CCHPs, and HPWHs.

Figure 10: Energy Transformation Supplies



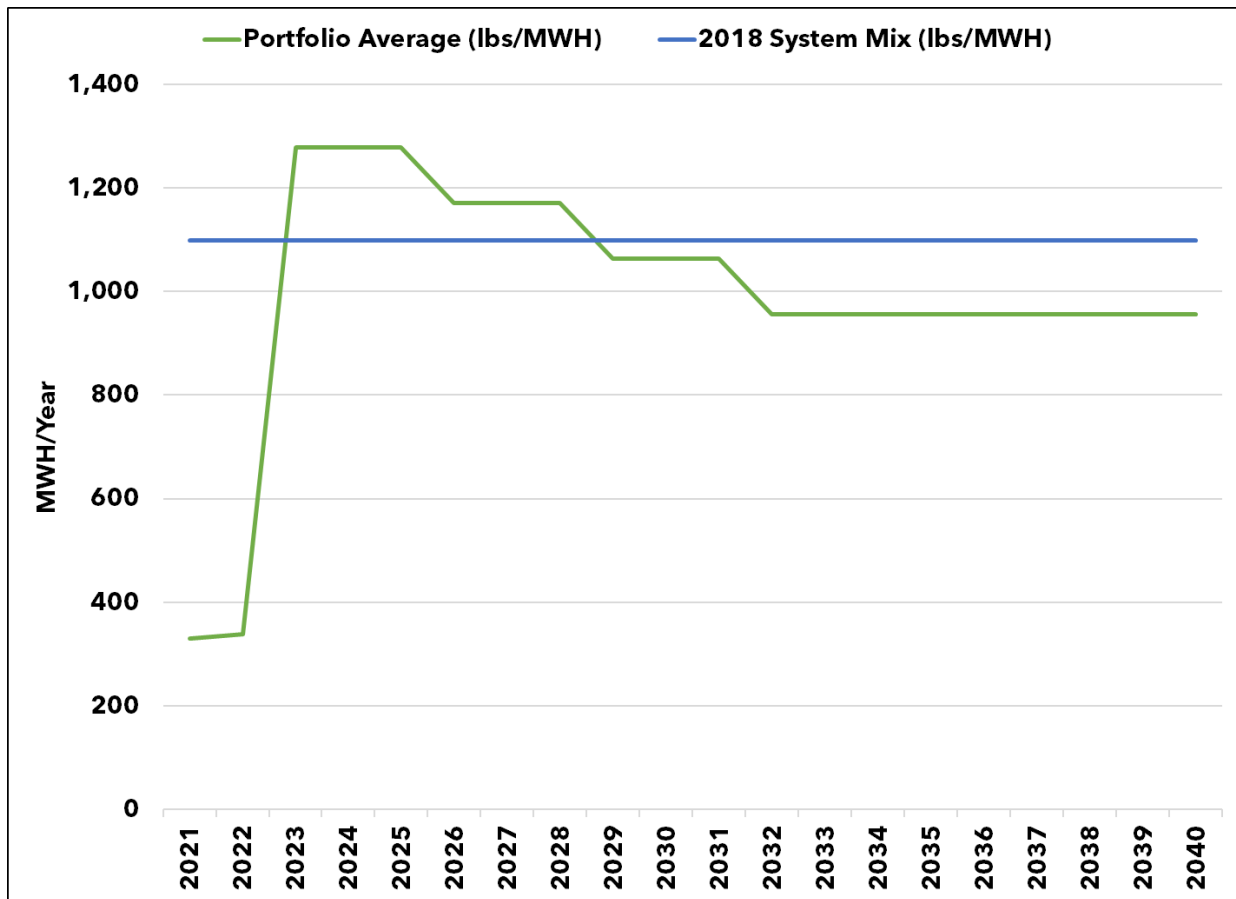
HED is expected to have a substantial surplus which is illustrated in Figure 10. In the first half of the 2020s, this surplus is likely to be sold to other VPPSA members or to utilities in the New England region at prevailing REC market prices. In the second half of the 2020's, the surplus may be banked to fulfill the Tier III obligation in the early 2030s. Whatever the deficit or surplus position, HED will continue to invest in both prescriptive and custom Tier III projects that support electrification.

¹⁹ More detail on these programs can be found in Appendix B (VPPSA's 2019 Tier 3 Annual Plan) and on VPPSA's website.

Carbon Emissions and Costs

Figure 11 shows an estimate of HED's carbon emissions rate compared to the 2018 system average emissions rate in the New England region²⁰. The emissions rate between 2020 and 2022 is about 375 lbs/MWH due to the portfolio's nuclear power. However, the emissions level rises to about 1,300 lbs/MWH in 2023, which is a level that is slightly above the 2018 system mix. This is due to the expiration of the NextEra 2018-2022 contract, whose MWHs are being replaced by fossil fuels²¹. Thereafter, the carbon emissions rate declines until 2032 as the RES requirements increase.

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



²⁰ The source of this data is the NEPOOL GIS. <https://www1.nepoolgis.com/>

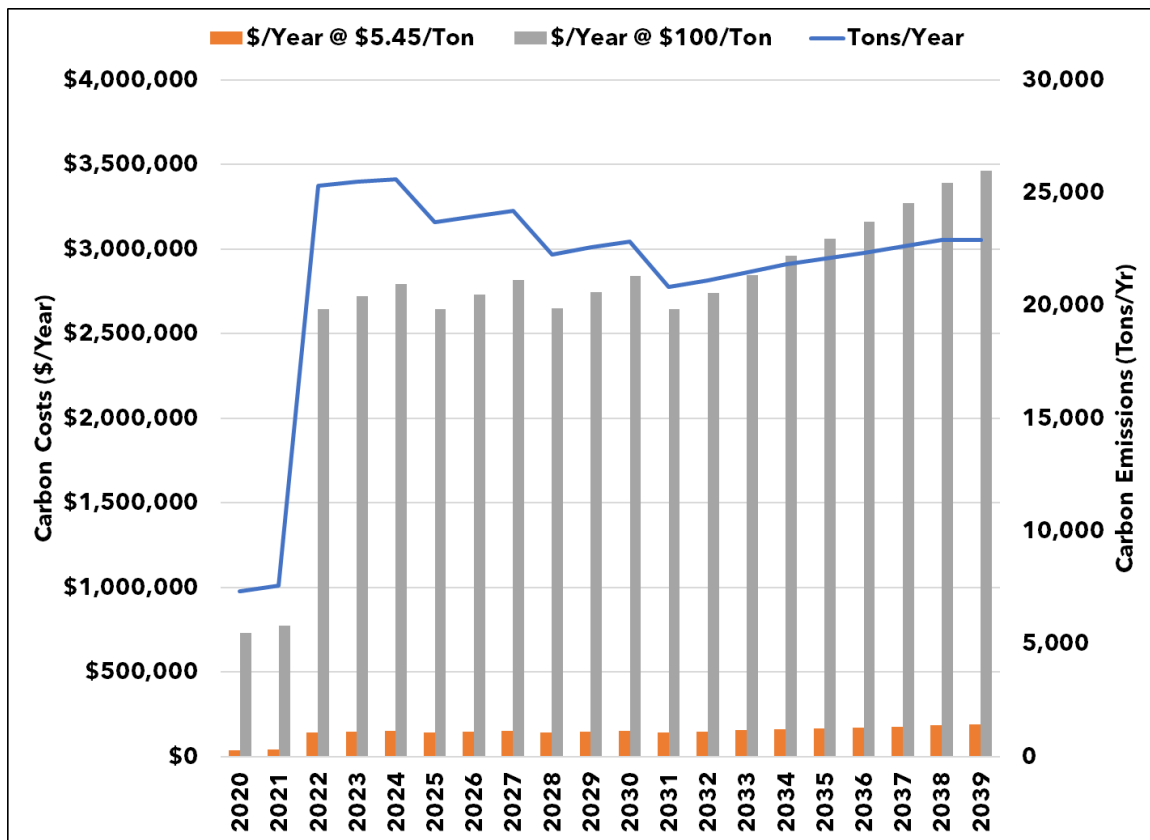
²¹ We assume that the carbon emissions rate of these MWH will be equal to the 2018 NEPOOL Residual Mix, which is a proxy for the fossil fuel emissions rate in the region. For the current value of the NEPOOL Residual Mix, please visit <https://www.nepoolgis.com/public-reports/>.

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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 7,000 tons per year in 2020 up to 24,000 tons/year in 2023, and then decline as the RES requirement increase through 2032.

The costs of these emissions were calculated using two sources, the 2019 Regional Greenhouse Initiative Auction²² (RGGI) results (\$5.45/ton) and the 2018 Avoided Cost of Energy Supply²³ (AESC) study (\$100/ton). Using RGGI prices (plus inflation), the cost of carbon emissions ranges from about \$33,000/year in 2023 to \$136,000 in 2032. Using AESC prices, the cost is \$613,000 per year in 2020 and about \$2.7 million per year in 2032.

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



²² <https://www.rggi.org/auctions/auction-results/prices-volumes>

²³ <https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf>

Conclusions

HED will quantify the impact of three different resource decisions.

1. 2023 - 2027 Energy

Q1: What are the pros and cons of buying a 5-year energy only PPA?

2. 2023 - 2027 Tier I RECs

Q2: What are the pros and cons of buying a 5-year Tier I REC contract?

3. 2028 - 2040 Energy + Tier I RECs

Q3: What are the pros and cons of becoming 100% renewable by 2028?

In addition, we quantify one load-related and one storage related question.

4. 1% CAGR

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

5. Storage

Q5: What is the potential value of storage based on Round 2 of VPPSA's storage RFP?

Transmission & Distribution

IV. Electricity Transmission & Distribution

Transmission and Distribution System Description:

Detail regarding HED transmission supply, transmission and distribution facilities is provided below.

Transmission System Description:

In addition to its hydro generating station, HED owns roughly five miles of the 34.5 kV transmission facilities serving its distribution system. This line segment is from MW&L's Green River switch running easterly to HED's Wolcott Substation. GMP's 3319 line continues from this point to HED's Hardwick Substation, and from there to the GMP Marshfield Substation.

HED's sub-transmission provider presently is GMP, but HED is working on purchasing the portion of GMP's 3319 line between Wolcott/Hardwick Substations. This ownership would result in HED obtaining a direct tie to VELCO at the VELCO Stowe Substation, after becoming a joint owner with Morrisville Water and Light (MW&L) in their 34.5 kV transmission system. Procuring ownership of this line segment offers HED potential annual savings of approximately \$160k of expenses presently paid to GMP. Those savings would first be utilized to fund the purchase agreements with GMP/MW&L, but over the following years those same savings will be utilized to pay for rebuilding this line section which is presently coming to the end of its useful life.

Distribution System Description:

The distribution system includes approximately 325 miles of line all operating on a 12.47 kV distribution system. In HED's previous IRP, one of HED's focused projects was to upgrade multiple areas within the system to accomplish this status.

The most recent comprehensive system planning study was completed in 1997 by PLM, Electric Power Engineers. This study looked forward to 2016, and projected that HED's peak system would increase to a level of 9 MW. This is roughly 30% more than what has transpired, and roughly 30% greater than the most recent VPPSA projected peak load of 6.9 MW in 2022. Overall load growth since the PLM study has been flat and the long-term goals and perspectives in the study remain accurate and/or pertinent today. One item the PLM Study included as a possible action item was conversion of the distribution system to operation at 35 kV. This did not pass the societal test and is not at all in consideration due to the operational, safety, and other significant issues that doing so would create. All action items with breakeven years of 15 or less have been completed and/or implemented.

HED's primary distribution system efforts in the last five years have been:

- Safety improvements for the public and for staff - which is always a primary concern in HED's operational projects and activities.
- Converting/upgrading all remaining 4,160/2,400 volt, and 2,400 volt delta areas of the distribution system to operate at 12,470/7,200 volts grounded wye. **NOTE - This project was completed as of November 2020.
- Improving system power factor - HED's distribution system now operates above 95% and is in fact rarely below 97%. System power factor during recent system peak hours have all been above 99%.
- System load balancing - HED balanced all main line circuits within the last seven years. Improvements were made, and a project was also identified - detail provided below in planned projects.
- Upgrades and improvements at the Wolcott Substation are complete. Work is continuing on HED's initiative to have a fully redundant distribution system between substations - where either one can serve the entire system by itself - in the event of major substation equipment failure, or outages necessary for maintenance, repairs, etc., or for any other event. The presently targeted next steps in this initiative are the purchase of GMP's 3319 between our substations - followed by the construction of a new underbuilt distribution circuit on that line. Both are in process as of the writing of this IRP, and both are presently planned to be complete by 12/31/23. Presently the Hardwick Substation can serve all HED loads - including the 2.7 MW of peak loading nominally served out of Wolcott Substation. The Wolcott Substation is also capable of

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serving all HED's loads - including the 4.3 MW nominally served out of Hardwick Substation - but the conductor between the substations limits the amount of Hardwick Substation loads that can be transferred to Wolcott Substation in a contingency to approximately 3.0 MVA. The new underbuilt circuit will be the final component needed to provide full redundancy between HED's substations.

Over the term of this IRP, in addition to the projects above, HED is planning to:

- Re-construct the old stepdown yard (adjacent to the Hardwick Sub) into a 12.47 kV distribution bus as the first step in upgrading the Hardwick Substation. The existing steel structure will be reused, new switches will be installed, and the existing pole mounted reclosers will be moved to substation rack positions in the revamped yard.
- Execute a feasibility study on adding a minimum flow generator at the Wolcott Hydro facility. During much of the year there is more water than can be utilized, and during the driest times of the year - when the main turbine cannot run - it spills about 75 kW worth of water over the dam. A minimum flow unit could offer over 220,000 kWh of inexpensive green hydroelectric energy annually to add to HED's energy resources and would contribute to HED's RES requirements.
- Finish constructing a 1.65 MW AC solar generating facility in Hardwick - which is presently well under way. All civil preparation work is complete, and racking materials are scheduled for delivery in the second quarter of 2021. The project is contracted to be online and operational in 2021, and it will provide HED customers with over 6% of their annual energy needs from a locally generated renewable source - at a price that is half of what developer net metering projects cost our ratepayers.
- Build and implement a GIS mapping system of our power network. HED is presently working with and in process with VELCO on a LIDAR project as the first step. LIDAR stands for Light Detection and Ranging which is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances) to the Earth. This system is capable of locating 80% of our poles/wires/etc. with great accuracy - at a cost much less than conventional field data gathering methods.
- Convert the south circuit from a V-phase to a full three phase feeder. Summer loading in the Woodbury Lakes area creates a sizeable circuit imbalance as well as an imbalance on the Hardwick Substation transformer for several months of the year. Adding the third phase will eliminate the imbalance, improve system losses, and improve system quality. The project includes adding a three-phase circuit recloser for protection which will eliminate the existing main line fusing and improve system reliability.
- The concrete surge tower foundation and concrete penstock supports (each side of the surge tower) at Wolcott Hydro will be repaired. The foundations have been in service for 71 years and have significant spalling damage that will be repaired.

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- The sluice gate at Wolcott Hydro will be replaced. This project will happen in several stages because there are no drawings of the existing timber gate, and it is presently under 50' of silt, sand, and debris on the upstream side of the dam. This project has gone through significant planning with state agencies as well as HED's consulting engineers. The first stage is scheduled for August of 2021.
- Expand the use of VELCO fiber which is now in service at both HED substations, as well as our warehouse and business office. Utilization for phone services, internet access at the Wolcott powerhouse, camera/security systems, and moving toward implementing some SCADA capabilities are all targets.

HED-Owned Internal Generation:

HED owns and operates the Wolcott Hydro generating station. Originally constructed in 1912, this generation station presently has one hydroelectric turbine generator. The plant is located on the Lamoille River just off VT RT 15 between Hardwick and Wolcott. Generated energy is delivered directly onto the Wolcott Substation 12.47 kV distribution bus which is also served by the 3319, 34.5 kV transmission line. The rated capacity of the unit is 948 kW and the unit can generate over 3,000 MWh per year into HED's power portfolio - and provides approximately 10% of the energy needs for HED customers annually.

The following chart summarizes the actual total generation output for the past several years.

Table 16: HED's Annual Hydroelectric Generation (kWh)

<i>Year</i>	<i>kWh</i>
2012	3,225,239
2013	3,606,310
2014	1,354,016
2015	3,122,377
2016	2,729,679
2017	4,339,108
2018	2,958,369

HED Substations:

HED currently operates two substations. Each substation is briefly described below.

Hardwick Substation:

The Hardwick Substation transformation consists of a three-phase 34.5 to 12.47 kV transformer with a base nameplate rating of 5.0 MVA at 55° C winding temperature rise. It can serve up to 5.6 MVA at 65° C and has a maximum rating of 7.0 MVA FA at 65° C.

The substation has three 250 kVA voltage regulators located on the 12.47 kV bus, which connects to three 12.47 kV distribution feeders. Feeder fault protection is via pole mounted circuit reclosers. Lastly, the substation contains a 34.5 kV, 3.6 MVAR capacitor bank for reactive flow support on the 3319 line.

Figure 13: Hardwick Substation



Wolcott Substation:

The Wolcott Substation power transformer is a three-phase 34.5 kV to 12.47 kV unit with a base rating of 5.0 MVA at 55° rise, and 5.6 MVA at 65° rise. The transformer has two stages of fans providing top end load ratings up to 8.333 MVA at 55° rise, and 9.333 at 65° rise.

The substation has bus voltage regulators, and two distribution feeder circuits. In HED's nominal configuration, one of these supplies the Craftsbury circuit, and the other supplies HED's North Wolcott circuit. 12.47 kV distribution feeder fault protection is accomplished through two three phase substation circuit reclosers.

The Wolcott Substation was recently upgraded, including the replacement of the station power transformer mentioned above.

The Wolcott Substation yard was reconstructed in accordance with HED's 248J Permit. The improvements were completed to make the yard accessible for hot line trucks and equipment, to meet modern National Electrical Safety Code (NESC) requirements, to alleviate environmental concerns for an oil spill from the power transformer, and to continue moving the HED distribution system to be fully redundant between our two substations. Prior to the improvements HED could not access more than half of the substation structure, there were also known NESC deficiencies, and an oil spill would have easily ended up in the Lamoille River (which is a short distance away down a very

Vermont [Public Power](#) Supply Authority

steep hillside). The NESC deficiencies included fencing fabric that was only 5' high, as well as inadequate clearance from a few sections of the old fence to energized parts being less than 10'. Other improvements included a new foundation for the bus regulators, as well as the power transformer (including a new imbibitor oil containment system), a new station ground grid (with new gravel and stone layers), an entirely new yard fence (with 7' of fabric plus three strands of barbed wire), a new primary underground substation by-pass circuit (for contingency configurations as well as improved flexibility for maintenance activities), reconfiguring of the overhead circuits (for generation into - as well as distribution out of the station), and all new underground conduits for station service, control, and metering systems. Upgrades also included all new structural members, arresters, and by-pass switches for the exit circuit reclosers and regulators.

Figure 14: Wolcott Substation



Circuit Description:*Table 17: HED Circuit Description*

Circuit Name	Description	Length²⁴(Feet)	# of Customers by Circuit	Outages by Circuit 2018
Greensboro	Main line leaving Hardwick Sub is 266.8 Hendrix feeding into 477 ACSR - protected by a three-phase oil recloser	57,800' to end of three phase main line and 21,000' more to end of line	2,240	80
Hardwick	Main line leaving Hardwick Sub is #1 copper feeding into 1/0 aluminum protected by a three-phase oil recloser	14,000' to end of three phase main line and 17,000' to end of line	567	17
Craftsbury	Main line leaving Wolcott Sub is 1/0 copper protected by a three-phase oil recloser	76,500' to end of three phase main line and another 8,000' to end of line	843	46
Wolcott	Main line leaving Wolcott Sub is 1/0 copper protected by a three-phase oil recloser	40,000' to end of three phase main line and another 21,000' to end of line	744	59
Woodbury	V-phase line of #4 copper tapped off and fused from the Hardwick Main line - 500' from substation	25,500' to end of V-phase and another 30,000' to end of line	738	50

There are presently four main line recloser protected circuits, plus a V-phase feeder tapped off the Hardwick circuit feeding all customers south to Woodbury/East Calais. Main line voltages are regulated at the respective substation bus, and the Craftsbury, Greensboro, and Woodbury Circuits each have a set of line regulators as well.

²⁴ Estimated from circuit maps

T&D System Evaluation:

HED evaluates T&D circuits anytime a significant change (large customer/load added) occurs within the distribution system. The main distribution circuits serving HED's customers are long radial feeders. This fact obviously limits system reconfiguration options, but it also creates a strong focus regarding the primary contributing factors. These include safety, conductor size, voltage drop, load balance, age/condition of plant, required ROW maintenance, etc. HED also reviews the Rule 4.900 Outage Reports, as well as data collected from VAR recorders, load loggers, and voltage recording data collected from throughout the system. In addition, data from microprocessor-based controls on substation bus equipment, and online voltage regulators are utilized in these evaluations. It is worth noting that over 80% of HED's customers are residential homes - so the significant changes to system loading by a single project are infrequent.

During the term of this IRP (as stated previously above) HED will be undertaking a GIS project to map its power system. This will provide a multitude of benefits, but one of the most significant will be having a full system database to utilize in performing more accurate and detailed system studies. These will greatly improve HED's abilities for system planning, and they will help improve system quality, reliability, and efficiency. They will also identify opportunities for improving the safety of the system with coordination improvements etc.

HED's Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years (2014-2018) in their entirety, can be found at the end of this document.

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

HED has committed to achieve performance levels for its distribution system below an index of 3.5 for SAIFI and 2.4 for CAIDI. HED 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 several specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

The following table summarizes HED's SAIFI and CAIDI values for the years 2014 - 2018.

Outage Statistics

Table 18: HED Outage Statistics

	Goals	2014 ²⁵	2015	2016	2017	2018
SAIFI²⁶	3.5	3.5	3.5	2.9	3.2	2.8
CAIDI²⁷	2.4	2.4	1.6	1.0	1.4	1.5

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

Animal Guards

HED has many animal events a year and has implemented a policy for installing animal guards, and insulated transformer tap conductors on all new construction and line rebuilds. History has shown, and the industry has proven that animal guards are a cost-effective means of reducing the service interruptions caused by animals.

Fault Indicators

HED continues to utilize fault locators on long main lines. These help to expedite locating faults and reduce outage times for customers. HED's standard locator continues to be the Power Delivery Products Navigator and is utilized by several Vermont utilities.

Automatic reclosers/Fusing

The two remaining McGraw Edison Form 3A main line recloser controls are in process of being replaced with microprocessor-based controls. The new controls allow for load information to be tracked on each circuit, they track fault events (for current levels as well as for fault locating), they eliminate the need for other components (for tripping and timing etc.)

²⁵ SAIFI and CAIDI statistics shown are net of major storm outages.

²⁶ System Average Interruption Frequency Index

²⁷ Customer Average Interruption Duration Index

so modifications are quick and simple, and the controls are fully SCADA capable for any future needs.

Feeder back-up

As previously identified, HED is in the process of building the infrastructure for full redundant capabilities between the Hardwick and Wolcott substations. This will allow HED to easily move the system into a contingency configuration, and quickly restore services to all customers in the event of a substation event/failure. Beyond this the distribution circuits themselves serve large rural areas, via long radial circuits which are not in close proximity to each other. Hardwick Substation can presently serve all nominal loads, but the main line distribution circuit between the substations limits the amount of nominal HED load that can be served via Wolcott Sub - to about 3.0 MVA. The first pieces of constructing a new distribution circuit (with 556 ACSR Osprey conductors) will begin in the summer of 2021, and when complete will allow Wolcott Substation to serve all HED loads in a contingency well into the future.

Power Factor Measurement & Correction

All power factor correction measure identified in the PLM Study have been implemented, and the most recent power factor data/improvements are detailed in "Distribution System Description" section of this document.

Other

Vegetation management, right of way tree trimming and danger tree (outside rights of ways) removals have been critical ongoing initiatives that HED executes to meet our service quality, reliability, and safety criteria. HED recently completed a reclamation project on our 34.5 kV transmission line ROW. For the last many decades HED maintained a maximum of 70' of our 100' ROW on this critical line - which serves 100% of HED customers. As a result of this choice, trees had grown to fully mature sizes and created unacceptable risks to the line for essentially its entire length. After experiencing a few tree events on the line over the last several years, HED initiated and just completed a reclamation project which cleared the full 100' ROW. This effort was prudent and will certainly provide system reliability improvements for many years to come. HED also hired a consultant to review and advise on our overall Vegetation Management strategies which resulted in some positive changes to our goals and program philosophy.

Distribution Circuit Configuration

Voltage Upgrades

Voltage Conversion

All distribution circuits are constructed for operation via a wye configured 12,470-volt system with standard crossarm construction (three-phase), and standard pole top construction (single-phase) in accordance with HED's standards. HED utilizes a minimum size conductor of 1/0 ACSR aluminum, a minimum wood pole of 40' in length, and a strength Class of II.

HED utilizes multiple types of system recording devices in an ongoing manner for gathering data to identify any phase balancing needs and opportunities, as well as any system voltage concerns.

Also, as previously identified in this document, HED's long radial distribution lines do not presently offer or afford for prudent investment in distribution backup capabilities further out in the system.

System Protection Practices and Methodologies

Protection Philosophy

The distribution system protection involves a combination of main line reclosers, main line fusing, and extensive tap line fusing. Experience has shown with few exceptions that faults and interruptions are held to the last down line fuse. Transmission line protection is provided by breakers 3319 at GMP Marshfield, and the 619 at MW&L's yard on Garfield Road. S&C power fuses are utilized on the 34.5 kV side of the transformers at both Hardwick and Wolcott Substations.

HED considers circuit balancing, reducing VAR flows, the coordination of protective devices, and other such instances as targets for continuous ongoing improvement. HED evaluates protection schemes/philosophy for significant changes in loading, and if system changes/improvements are completed (new conductor installed etc.).

Smart Grid Initiatives

Planned Smart Grid

Beginning in 2018, HED began participating in a multi-phased, VPPSA joint-action project intended to (1) assess individual member readiness for AMI, (2) guide

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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 to determine whether the implementation of an AMI system is prudent or not.

At this time HED 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 2021, HED will decide whether to proceed to the RFP phase of the process.

HED 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 if we see continued expansion of net metering, heat pump installations, and a much wider adoption of electric vehicles.

HED 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, HED 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, HED stays abreast of these developments and the strategies needed to maintain a safe, reliable, and economically viable distribution system.

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

HED has been replacing small conductor (#8 cu, #6 cu, #6A cw, and #4 ACSR) for at least the last 15 years with 1/0 ACSR. Such replacements are triggered by the condition of conductor, by projects involving relocation of cross-country lines, and when operational improvements can be achieved. HED has approximately 325 miles of distribution that is generally considered lightly loaded, and as such there are not presently any large reconductor projects planned, other than the express circuit between substations.

Transformer Acquisition

HED purchases both new and remanufactured transformers. New transformers in larger kVA sizes are purchased for commercial or industrial services and upgrades. Most often remanufactured transformers are purchased for standard pole mounted units that will serve residential customer premises. A large majority of transformers in HED's system are 10 and 15 kVA single phase pole mounts - and the remanufactured units save HED ratepayers \$912 and \$884 respectively over the life of these units. The table below of transformer life costs shows that utilizing remanufactured transformers for these small capacity installations is clearly economically prudent.

The cost savings on remanufactured units is coupled with a "bumper to bumper 3-year warranty" under which our remanufacturers will replace a faulty/failed unit for ANY reason. Brand new units supplied by Eaton/Howard/ABB/and others only have a 12 month "limited" warranty - so there are some additional savings that do not get factored into the life cycle costs. Please note - one of our remanufacturing suppliers had a large quantity of "brand new/unused" single phase 10 kVA Howard pole mounted transformers. From 2017 through 2020, HED was able to procure many of these new units - at remanufactured prices - which were 45% less than those for the exact same transformer supplied as "new" from Howard. HED intends to continue purchasing these transformers as long as they are available.

Table 19: New & Remanufactured Distribution Transformer Price Comparison

NEW & REMANUFACTURED DISTRIBUTION TRANSFORMER PRICE COMPARISON NEW					
PRIMARY VOLTAGE	WATTS ESTIMATED NO LOAD	LOSSES FULL LOAD	TOTAL	PURCHASE COST	TOTAL COST WITH LOSSES
12470Y/7200					
10 KVA	28	167	195	\$749	\$2,938
15 KVA	38	222	260	\$807	\$3,420
25 KVA	52	348	400	\$886	\$3,737
37.5 KVA	29	513	542	\$1,472	\$5,344
*** Based on Washington Electric Coop loss formula = $Pe = 2.62P + 11.01NL + 0.40FL$ New Transformer Prices from CED Twin State 4/2021 - Remanufactured Prices from T & R Electric -4/2021					
NEW & REMANUFACTURED DISTRIBUTION TRANSFORMERS PRICE COMPARISON REMANUFACTURED					
PRIMARY VOLTAGE	WATTS ESTIMATED NO LOAD	LOSSES FULL LOAD	TOTAL	PURCHASE COST	TOTAL COST WITH LOSSES
12470Y/7200					
10 KVA	52	171	223	\$380	\$2,026
15 KVA	69	237	306	\$415	\$2,536
25 KVA	100	330	430	\$525	\$3,576
37.5 KVA	138	465	603	\$625	\$4,624
*** Based on Washington Electric Coop loss formula = $Pe = 2.62P + 11.01NL + 0.40FL$					

Conservation Voltage Regulation

HED has bus voltage regulators in our two substations, and out in the distribution system as well. Voltage regulation on all regulators is set at 123.5 volts. HED participates in voltage reduction testing, in the spring and fall, initiated by ISO-NE via VELCO.

Distribution Transformer Load Management (DTLM)

HED does not have a DTLM program. HED will likely evaluate a DTLM program in the future - after smart meters are installed and the pertinent data can be gathered.

Substations within the 100- and 500-YEAR Flood Plains

Neither of HED's two substations fall within the 100 or 500-year floodplains at their respective locations, per ANR site visit in 2015.

The Utility Underground Damage Prevention Plan (DPP)

HED's facilities and equipment are constructed almost entirely with standard overhead construction methods. The URD facilities that do exist are short taps serving a single customer, or up to a few residential homes. Nevertheless, HED participates fully as a member of Dig Safe. HED locates and identifies its facilities for others, and works through Dig Safe in all excavating activities, including drilling operations for setting poles and anchors. HED installs URD facilities in accordance with National Electrical Safety Code requirements and inspects those installed by others prior to backfilling and connecting to the system. HED follows utility best practices as standard operating procedure. These include but are not limited to participating in pre-planning and site investigation activity, utilizing and promoting the use of the Dig Safe process/system, accurately locating and marking facilities, and utilizing and promoting proper excavation processes. As of writing this document, the last contact with HED URD facilities was well over 25 years ago, per our Working Foreman who has been with HED for 47 years. HED 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

When replacing expensive transmission and distribution equipment, HED solicits three different quotes before making a purchase. HED procures and installs only the highest quality equipment from leading industry providers such as ABB, S&C, Cooper, Chance/Hubbell, Siemens, and others. Large purchases (\$10k or more) are made after a bid process from providers is executed. Appropriate evaluations are executed on equipment, as necessary.

Maintaining Optimal T&D Efficiency

System Maintenance

HED's system maintenance includes an active vegetation management plan as discussed in detail below. HED also executes many efforts common with Vermont electric utilities such as porcelain cutout replacements, aluminum distribution bell replacements, older and/or smaller pole replacements, and replacing any remaining small conductor (#8 and #6 copper) in the system.

Vermont [Public Power](#) Supply Authority

Substation Maintenance

Annual maintenance in substations include Vegetation Management, monthly inspections, dissolved gas analysis of power transformers, and annual fencing and grounding inspections. Periodically HED has Infra-Red scans of stations to identify any overheating connections and equipment before damage or failure occurs.

Pole Inspection

There are approximately 7,115 jointly-owned poles with Consolidated Communications, of which HED maintains 3,803 of them. HED also has 481 fully owned distribution poles, and 82 fully owned transmission poles. It is part of the normal duties of HED's operations staff (meter readers, utility workers, and linemen), to look for and identify poles that need replacement.

System Losses

HED is committed to providing efficient electric services to its customers and strives for continuous improvement via any efficiency opportunities that become available. A perfect example of this was the completion of a multi-year 12.47 kV distribution system wide upgrade in 2020. This upgrade reduced HED's system losses by over 3%.

Actual System Losses:

Distribution Losses

HED monitors system energy losses by tracking metered energy at its substation interconnections to the 34.5 kV transmission system and by comparing this total metered energy sales to its ratepayers. The calculation is done on a rolling 12-month basis to minimize the impact of the fact that there is unbilled energy to customers that skews the calculation because of meter reading cycles not corresponding with the interconnection meters that run from specifically the first to the last hour of each day. The 2018 calculation shows HED's distribution system losses of approximately 6.2%, which is significantly lower than the 11.8% distribution losses calculated for 2016.

Transmission Losses

Transmission system losses are calculated based on energy purchased and delivered to the HED system boundary. A significant portion of transmission and sub-

transmission losses occur when power is transmitted across intervening systems. The 2018 calculation showed transmission losses of approximately 3.2%.

Efforts to Reduce Losses:

HED's primary efforts to reduce line losses in the last several years were in upgrading the remaining lower voltage portions of the distribution system, power factor improvement (to reduce system VAR flows), balancing circuit loads (to eliminate unnecessary neutral currents and to minimize I²R losses) and running conductors of only 1/0 ACSR or larger.

Now that our upgrade projects are complete, HED has targeted the addition of the third phase to our "V-Phase" system to reduce overall system losses. This circuit runs south from the Hardwick Substation. As identified previously in this document, eliminating the inherent losses of a V-phase system as well as the imbalance the V-phase system places on the substation transformer will improve HED's system losses.

Voltage Conversion

HED completed all conversion work on our distribution network in 2020, and the entire system now operates at 12.47 kV.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

Several years ago, HED implemented the National Joint Utilities Notification System (NJUNS) online software to communicate with other utility companies (telephone & cable television) about proposed and/or completed new pole sets and pole transfers but HED found problems with the system. As a result, HED has not used the NJUNS system in many years, but we are looking into re-instating its use at this time.

Relocating cross-country lines to road-side

HED will consider relocating cross-country line segments primarily when circuit performance results in poor services for ratepayers. A large majority of the cross-country line segments in HED's system would require significant right-of-way efforts, as well as a level of tree clearing which would be unreasonable to expect property owners to support. There have been a few opportunities in the last 7 years where cross-country segments have in fact been relocated, but each of these projects resulted from property owners moving those lines to develop their respective properties. History has shown that investing in aggressive ROW maintenance, and annual visual inspections of vegetation in these areas has been the most prudent of efforts.

Distributed Generation Impact:

Hardwick presently has 178 residential scale (< 15 kW) net metered customers with a total installed capacity of about 1,170 kW. In addition, there are twelve customers who have arrays greater than 15 kW, and they total 1,194 kW. All in, HED has about 2.36 MW of net-metered capacity, which is 35% of HED's 2020 peak load (6.8 MW).

Interconnection of Distributed Generation

HED recognizes the unique challenges brought on by increasing penetration levels of distributed generation. Each project sized over 15 kW is processed by HED via the utilization of Rule 5.500. This process executes the necessary studies and other work for planning and identifying any system modifications or accommodations for interconnection of those projects to the HED system.

HED 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 HED or their representatives, typically include a review of the following issues that may arise:

- 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, HED will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow HED 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). HED 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 HED's service territory, HED 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 HED. As a reasonable compromise, HED 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, HED 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. HED 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:

HED has over 325 miles of distribution and 5 miles of transmission lines. HED estimates that roughly 85% of its lines require ROW vegetation maintenance, the remaining 15% are in fields and cleared areas. HED procures local contractors for annual ROW maintenance work and does not utilize any herbicides in pole line ROW's.

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The following table summarizes the number of trees trimmed and the cost of trimming over the past few years. HED does not inventory specific tree species, but HED's tree contractor and line crew have considerable experience and consider the species of trees while trimming. HED's line foreman oversees vegetation management efforts and utilizes a system map to track the areas completed annually as one of the tools to plan future work. HED's goal is to have the entire system trimmed every 12 years.

Table 20: HED ROW Clearing & Danger Tree Removal

Year	ROW Clearing \$	Danger Trees		Total \$
		\$	# of Trees	
2014	\$100,713	\$27,005	266	\$127,718
2015	\$96,958	\$55,178	352	\$152,135
2016	\$113,677	\$71,150	679	\$184,82
2017	\$74,622	\$74,760	748	\$149,382
2018	\$99,137	\$68,380	611	\$167,516

All distribution ROW's are cleared for a total width of 30' so that HED can maintain 15 feet of clearance between trees and vegetation along distribution power lines. HED does not use herbicides on its ROWs.

HED's "Specifications for distribution line clearance tree work and brush control" and "Right-of-way contract bidding" documents are available upon request.

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

Table 21: HED Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Transmission	5	5	7-year average cycle target
Distribution	325	Approximately 276	12-year average cycle target

Table 22: HED Distribution Vegetation Management Costs

	2016	2017	2018	2019	2020	2021	2022
Amount Budgeted	\$136,500	\$136,500	\$163,800	\$170,000	\$178,500	\$178,500	\$178,500
Amount Spent (FY)	\$184,827	\$149,382	\$167,516	\$155,155	Deliberately left blank	Deliberately left blank	Deliberately left blank

Table 23: HED Tree Related Outages

	2014	2015	2016	2017	2018
Tree Related Outages²⁸	83	86	68	97	85
Total Outages	219	213	188	246	222
Tree-related outages as % of Total outages	38%	40%	36%	39%	38%

Storm/Emergency Procedures:

Like other Vermont municipal electric utilities, HED is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows HED to coordinate not only with public power systems in Vermont, but with those throughout New England. A HED representative is also on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties.

HED uses the <https://vtoutages.org/> site during major storms, and updates data every two hours during all large or extended events. After several years of negative feedback from customers (regarding their experiences in reporting outages, and getting outage information), HED has recently partnered with the Cooperative Response Center (CRC) for call center and dispatch services. CRC is the industry leader, and satisfies the needs of smaller utilities. HED now routes all outage calls, as well as all calls received outside normal business hours through CRC for processing. They provide two fully staffed centers, either of which can handle 100% of HED calls at any given moment. One of these is normally providing services, and the second is a full back-up in an entirely different state. This further improves their services because in the event of equipment failure or other problems on their end, they can simply switch over to the backup center. HED provides a patch straight from

²⁸ statistics shown are net of major storm outages

the CRC phone system, into its radio system, so CRC has direct contact with trucks and crews. HED also provides web accessible GPS truck locations to CRC, so they always know where trucks and crews are located. Customer feedback since the implementation has been excellent. This clearly shows that the level of service, and the tools CRC provides (IVR systems, consistent phone message updates, etc.) gives HED customers what they want.

Customer notification for planned outages to accommodate field operations activities are done through newspapers (The Hardwick Gazette, and the Caledonian Record) as well as local radio stations.

Previous and Planned T&D Studies:

Fuse Coordination Study

Several of HED's main circuits have had coordination study work done. These include the Greensboro circuit, the Woodbury/Calais circuits (out of Hardwick Substation), and the North Wolcott circuit (out of Wolcott Substation) have been evaluated. Each required some slight modifications and each of these have been completed over the last 15-18 months. The Craftsbury circuit out of Wolcott substation, as well as the Hardwick Village circuit out of Hardwick Substation are planned to be evaluated in the next 12 months.

HED has become more sophisticated in its sizing and tracking of fusing. Since 2013, HED has targeted full evaluation of fusing in any problematic sections of the system. The first step of this work was to procure several sets of load loggers in order to have the ability to gather the necessary system data. HED has then worked with the much-appreciated assistance of Crockett Engineering to determine appropriate modifications/changes to those areas. HED is in an ongoing effort in this area and has begun to evaluate a full system mapping project as well. Adding reclosers and/or additional recloser programming modifications, especially at the Hardwick bus, are already intended in the next 12-24 months.

Distribution System Planning

This report, in prior sections, has discussed the purpose and results of the two distribution planning studies done in 1990 and 1997.

HED is aware of the encroaching need for a full system study, and the mapping project will be the first step in that direction. HED presently has clearly prudent system improvements and modifications planned and scheduled in the next several years. When these are complete, HED expects a full system study will be needed so that continued prudent projects/choices/efforts toward "fruit that is higher in the tree" can confidently be made on behalf of our customers.

Capital Spending:

Construction Cost (2016-2018):

Table 24: HED Historic Construction Costs

Hardwick Electric Department		Historic Construction		
Historic Construction		2016	2017	2018
Functional Summary:				
Production		37,057	-	2,263
General		131,776	227,618	-
Distribution		481,341	86,627	555,156
Transmission		257,999	2,791	-
Total Construction		908,173	317,036	557,419

Projected Construction Cost (2020-2022):

Table 25: HED Projected Construction Costs

Hardwick Electric Department		Projected Construction		
Projected Construction		2020	2021	2022
Functional Summary:				
Production		\$ 5,000	\$ 15,000	\$ 30,000
General		\$ -	\$ 35,000	\$ -
Distribution		\$ 150,000	\$ 175,000	\$ 275,000
Transmission		\$ -	\$ 75,000	\$ 25,000
Total Construction		\$ 155,000	\$ 300,000	\$ 330,000

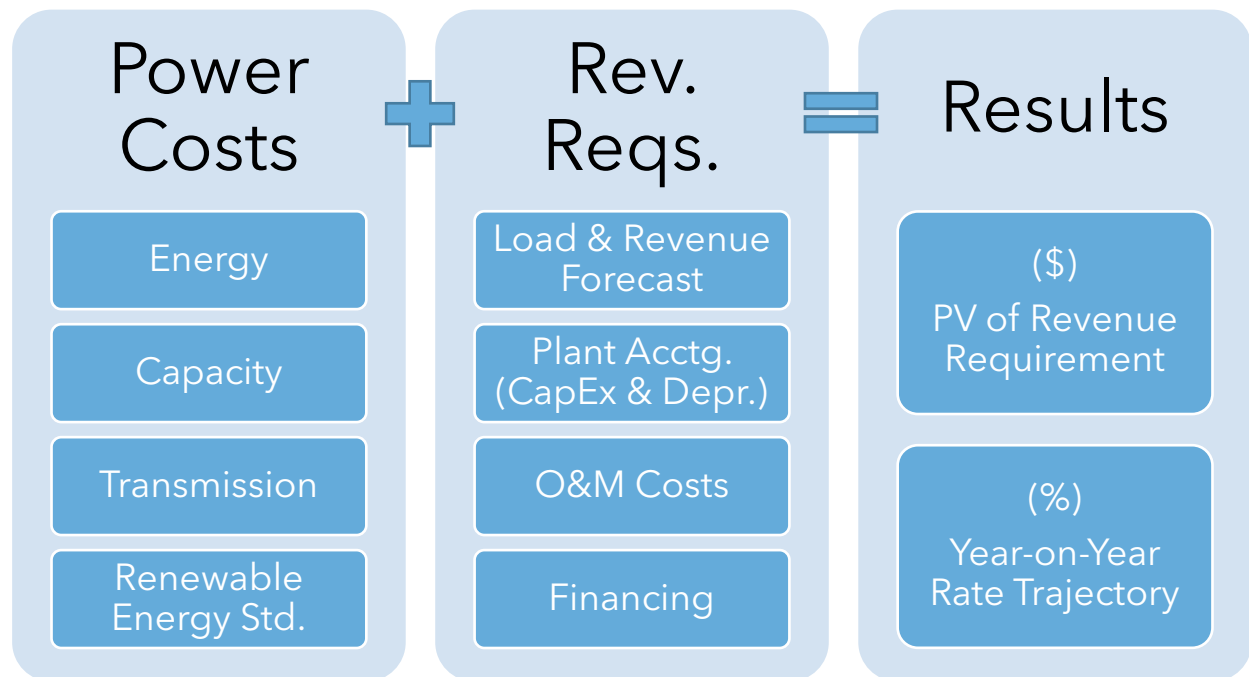
Financial Analysis

V. Financial Analysis

Components

The financial analysis represents an integrated analysis of HED's power supply costs and its revenue requirements. The results include the present value of HED'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 HED'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 HED'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 uncertainty. These include:

Decisions

There are five decisions facing HED that the financial analysis will quantify.

1. 2023 - 2027 Energy

Q1: What are the pros and cons of buying a 5-year energy only PPA?

2. 2023 - 2027 Tier I RECs

Q2: What are the pros and cons of buying a 5-year Tier I REC contract?

3. 2028 - 2040 Energy + Tier I RECs

Q3: What are the pros and cons of becoming 100% renewable by 2028?

In addition, we quantify one load-related and one storage-related question.

4. 1% CAGR

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

5. Storage RFP

Q5: What is the potential value of storage based on Round 2 of VPPSA's storage RFP?

There are eight relevant “pathways”, as shown in Table 26.

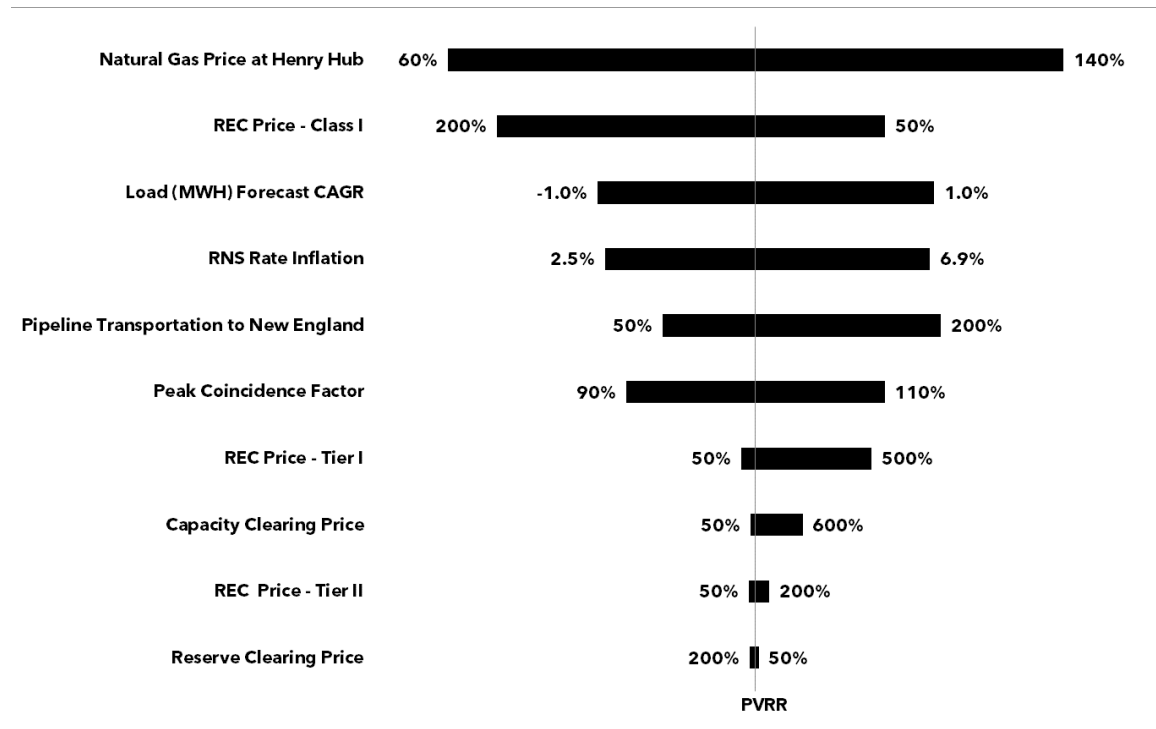
- Pathway 1 is the reference case.
- Pathway 2 shows the costs and benefits of hedging energy from 2023 - 2027.
- Pathway 3 shows the cost and benefits of hedging Tier I RECs from 2023 - 2027.
- Pathway 4 shows the costs and benefits of becoming 100% renewable by 2028.
- Pathways 5-8 are combinations of pathways 2 - 4.

Table 26: Event / Decision Pathways

Pathway	Name	Energy	Tier I RECs	Bundled Energy + RECs
1	Reference Case			
2	2023-2027 Energy PPA	✓		
3	2023-2027 Tier I RECs		✓	
4	2028-2040 Energy + RECs			✓
5	2 + 3	✓	✓	
6	2 + 4	✓		✓
7	3 + 4		✓	✓
8	2 + 3 + 4	✓	✓	✓

The financial analysis estimates the cost of each of these pathways, and then runs sensitivity analysis on ten different variables that are known to have a material impact on HED’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)



The number one risk facing HED is the price of natural gas. Number two is the price of Class I Renewable Energy Credits (RECs). These outcomes are intuitive because price of natural gas and RECs are known to change quickly and competing alternatives (supplies) are limited in the short-term. Notice, however, that HED's cost decrease as REC prices increase. This is because HED sells Class I RECs from both the Fitchburg Landfill and McNeil.²⁹

One percent load growth is the third most important variable to HED's cost of service (COS), but as we will discuss later, the increased costs that are associated with load growth are also associated with decreased electric rates.

The fourth most important variable is the rate of inflation in Regional Transmission Service (RNS). Also known as ISO Transmission, these costs have been rising at multiples of inflation for decades and are expected to continue rising at double the rate of inflation. As a result, minimizing coincident peak loads with ISO each month is a key strategy for HED.

The fifth most important variable is pipeline transportation to New England. When winter temperatures drop for sustained periods, New England's natural gas infrastructure cannot deliver enough gas to power all of the gas-fired generators. This causes price spike that are expected to remain a risk for years to come. There is some relief on the horizon, however. If the offshore wind projects that are contracted by Massachusetts and Connecticut are built, the natural gas deliverability constraint will be eased considerably.

²⁹ As of this writing, HED has locked in several forward sales of Class I RECs through 2024 to mitigate this risk while taking advantage of high REC market prices.

HED's peak coincidence with ISO-NE each month is the sixth most important variable. Any time that HED's loads increase relative to the other utilities around New England, it bears increased costs. As a result, managing and minimizing peak loads is an important strategy to follow as opportunities arise.

Tier I REC prices are the seventh most important variable to HEDs COS. Prices are presently in the \$2.00/MWH range, but could increase to about \$10. This possibility is what creates the risk from this variable.

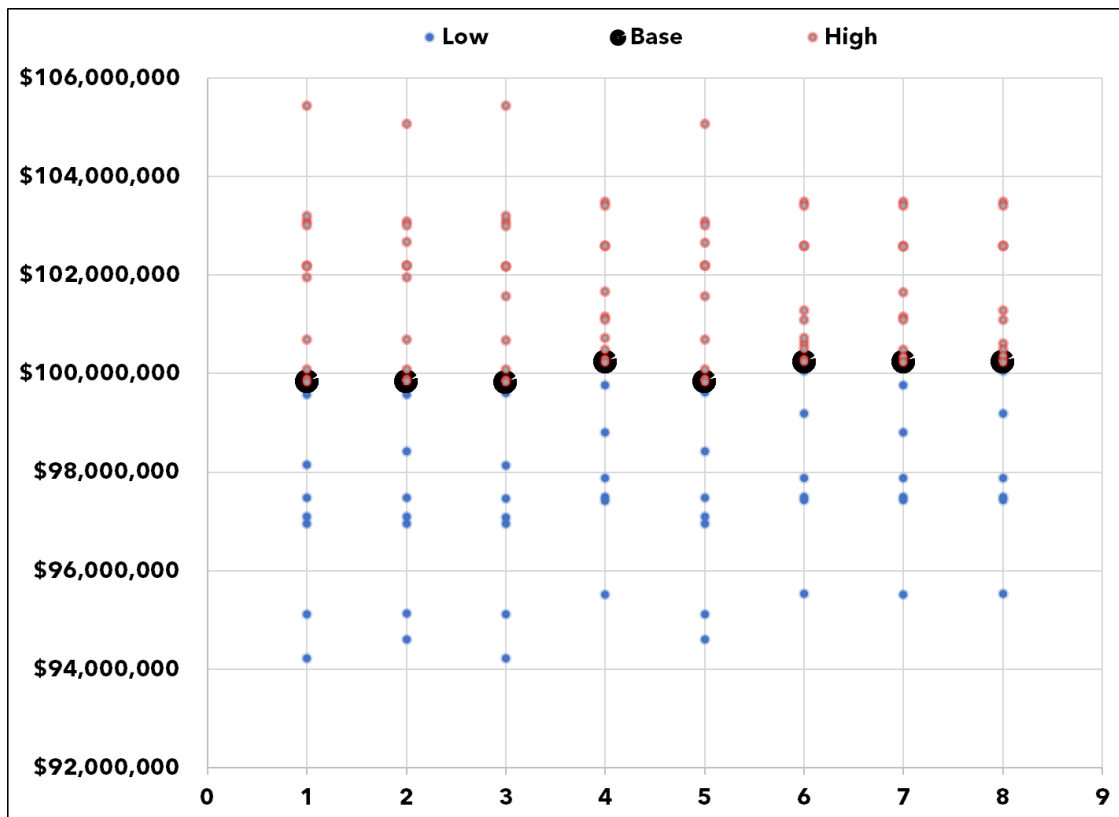
Finally, capacity, Tier II REC, and reserve market risks are quite small. HED's capacity entitlements already hedge most of its risk in the Forward Capacity Market, its entitlement in the Billings Road solar project effectively hedges its Tier II REC risks, and its entitlement in Project 10 effectively hedges its reserve market risks.

Revenue Requirement Results

The high-level results of the financial analysis appear in Figure 17.

- **Pathway 1:** This range of outcomes is the reference case and it shows how much variability HED can expect from changes in market conditions over time.
- **Pathway 2, 3 & 5:** These slightly narrower range of outcomes are the result of hedging energy only between 2023 and 2027, RECs only between 2023 and 2027, and both energy and RECs between 2023 and 2027.
- **Pathways 4 & 6-8:** These pathways show the benefits of becoming 100% renewable in 2028 and maintaining that level through 2040. The range of outcomes is the narrowest because both energy and Tier I RECs are hedged, but the costs are higher, on average, because of the resource decision to become 100% Tier I renewable in 2028.

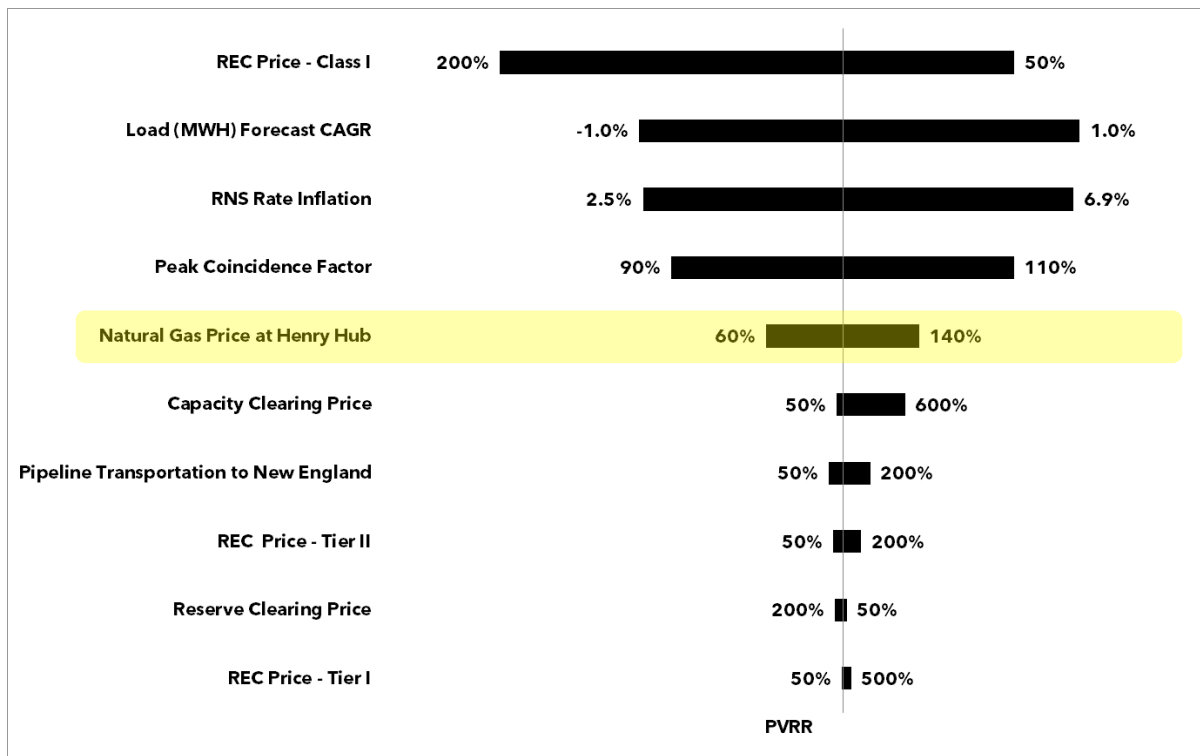
Figure 17: Scatter Plot of Financial Analysis Results (PV of Revenue Requirement)



The costs of the first three pathways are nearly identical, and this is by design. There is a reason to believe that hedging resource needs in advance will reduce costs compared to market prices. The costs of the last four pathways are higher due to the nearly identical for the same reason. However, hedging has a marked impact on the price risk that HED faces as shown in Figure 18.

Figure 18: Sensitivity Analysis of Key Variables - Pathway 8

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Notice that natural gas prices have dropped from the #1 risk in the Reference Case to the #5 risk after energy supplies have been procured to hedge against market price changes. Similarly, Tier I REC prices drop three places in the ranking and place last in the list of variables. This is one key conclusion of this analysis.

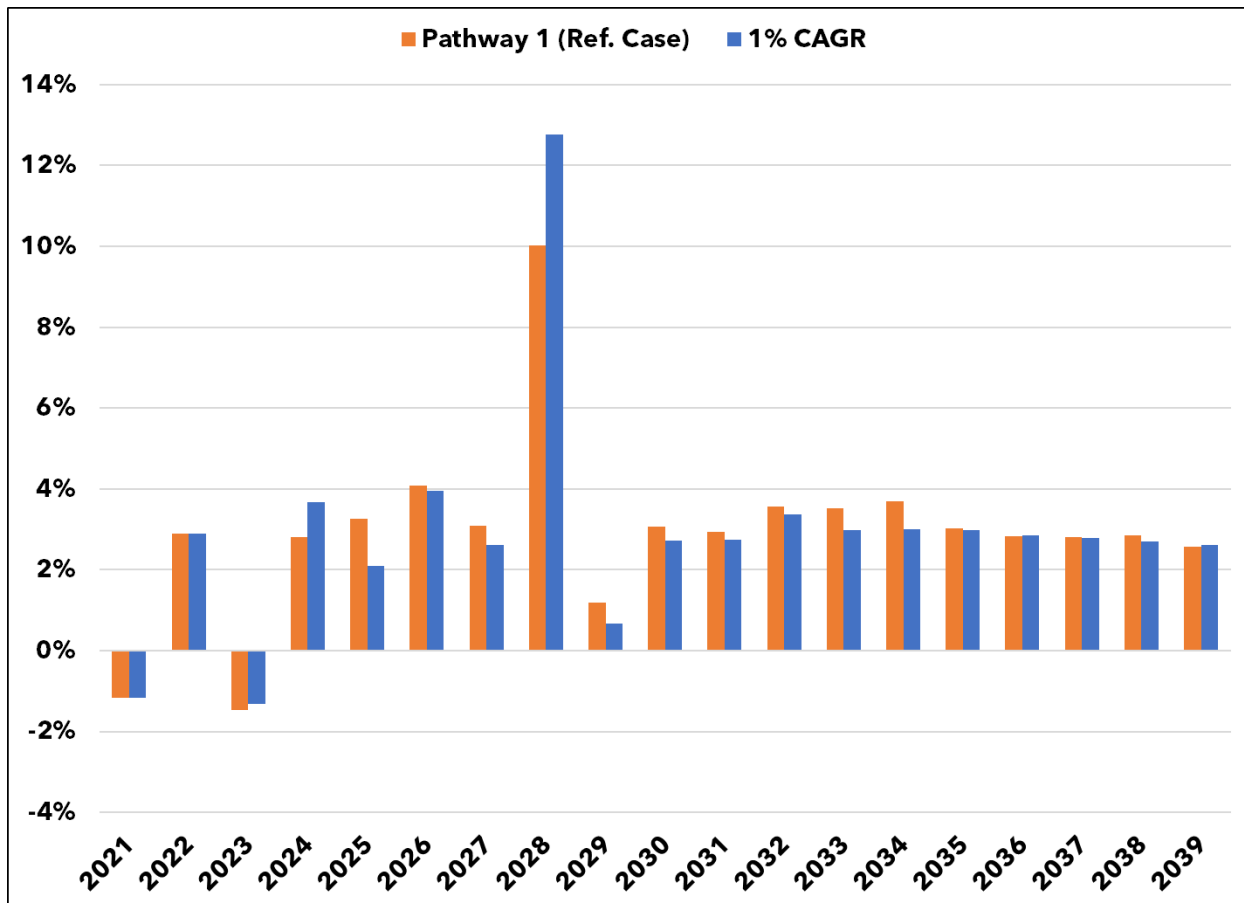
1. Hedging reduces price risk and enables the utility to focus on managing the other, remaining risks.
2. The other key conclusion of this analysis is that the cost of becoming 100% renewable is inflationary and manageable.

Specifically, rate pressure would be approximately 2.5% in 2028 if HED committed to a 100% power supply. However, rate pressure drops to 1.2% within five years (2032) because the cost of RECs is fixed while inflation continues to increase the cost of Tier I RECs. This range of rate pressure is inflationary and is not cause for a rate case in many instances, especially when the impact decreases over time as this one does. As a result, this is a manageable cost, especially when it is considered in the context of rate reducing opportunities like 1% annual load growth and battery storage.

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 19 shows, the impact is to lower rates in most years. This is intuitive but is an important outcome to quantify. If this level of load growth were to occur between 2021 and 2032, for example, 1% compound annual load growth could reduce rates by about 7% in 2032 as compared to the reference case.

Figure 19: Rate Impact of 1% CAGR Load Growth



Impact of Battery Storage

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

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

If HED were to sign a Battery Energy Storage Service Agreement (BESS) at these prices and size ranges, the cost to HED would be within the ranges shown in Figure 20.

Figure 20: Annual Cost Ranges for Hypothetical Peak Shaving Batteries (\$/Year)

Battery Cost (\$/kW-mo)	MW AC of Peak Shaving				
	1 MW	2 MW	3 MW	4 MW	5 MW
\$8.00	\$96,000	\$192,000	\$288,000	\$384,000	\$480,000
\$10.00	\$120,000	\$240,000	\$360,000	\$480,000	\$600,000
\$12.00	\$144,000	\$288,000	\$432,000	\$576,000	\$720,000

To determine the value of a peak shaving battery, VPPSA modeled the avoided cost of capacity and ISO transmission that could be achieved under different peak shaving success rates. We assumed a 50% success rate for shaving the annual peak, and a 75% success rate at shaving the monthly peaks. Based on a Monte Carlo analysis of 1,000 different randomly generated results, the value of a peak shaving battery averaged \$12/kW-month (levelized) between 2023 and 2032.

Based on this avoided cost estimate, how much money could this save each year, and what might the impact be on electric rates? The answers appear in Figure 21 and Figure 22. For example, a 3 MW battery priced at \$8/kW-month could reduce HED's electric rates in 2023 by about \$144,000 or 2.4%.

Figure 21: Annual Avoided Costs Ranges for Hypothetical Peak Shaving Batteries (\$/Year)

Battery Cost (\$/kW-mo)	MW AC of Peak Shaving				
	1 MW	2 MW	3 MW	4 MW	5 MW
\$8.00	-\$48,000	-\$96,000	-\$144,000	-\$192,000	-\$240,000
\$10.00	-\$24,000	-\$48,000	-\$72,000	-\$96,000	-\$120,000
\$12.00	\$0	\$0	\$0	\$0	\$0

Figure 22: Estimated 2023 Rate Impact (% of Revenue Requirement)

Battery Cost (\$/kW-mo)	MW AC of Peak Shaving				
	1 MW	2 MW	3 MW	4 MW	5 MW
\$8.00	-0.8%	-1.6%	-2.4%	-3.2%	-4.1%
\$10.00	-0.4%	-0.8%	-1.2%	-1.6%	-2.0%
\$12.00	0.0%	0.0%	0.0%	0.0%	0.0%

Based on this analysis, it appears that a BESS agreement can reduce costs. This would be almost certain if the proposed 30% federal Investment Tax Credit become law. As a result, HED will continue to seek a development partner through VPPSA's storage RFP in 2021, and to identify appropriate sites for storage in its service territory.

Impact of Supply - Demand Imbalances

The impacts of supply-demand imbalances are summarized in Figure 23. Any time the supply of energy is less than the demand, lower market prices also lower HED's cost of service. Conversely, any time the supply is greater than the demand, higher market prices lower HED's cost of service. As a result, the financial impact of supply-demand imbalances are indeterminant, and depend on the market price of energy. Said differently, we cannot say with certainty that an imbalance (surplus or deficit of energy) is cost minimizing.

However, as we just learned in the previous section, the *size* of the imbalance has a direct impact on the price risk that HED faces. As a result, minimizing supply-demand imbalances is definitely *risk* minimizing.

Figure 23: Quadrant Analysis of Market Price & Energy Length Outcomes

	Long MWH	Short MWH
Market Energy Prices HIGHER than Contract Price	Cost of Service DECREASES	Cost of Service INCREASES
Market Energy Prices LOWER than Contract Price	Cost of Service INCREASES	Cost of Service DECREASES

Summary and Conclusions

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

Decisions

1. **2023 - 2027 Energy Only PPA**

Q1: What are the pros and cons of buying a 5-year energy only PPA?

A1: The advantage of hedging energy is that it reduces price risk, especially during winter months when New England's power plants lack sufficient natural gas supply during cold weather events. The cost of hedging is dependent on the timing of the purchase and is likely to match market prices over time. As a result, no cost savings is expected over time, but more cost stability is.

2. **2023 - 2027 Tier I REC Only PPA**

Q2: What are the pros and cons of buying a 5-year Tier I REC only PPA?

A2: The advantage of hedging Tier I RECs is that it reduces price risk. Based on historical data, Tier I REC prices can range from 20% to 500% of the long-term average in any given year. Prices today are at the low end of this range, making it a good time to hedge Tier I RECs for multi-year terms.

3. **2028 - 2040 Energy + Tier I REC PPA**

Q3: What are the pros and cons of becoming 100% renewable by 2028?

A3: Becoming 100% renewable in 2028 would presently cost about \$178,000 in 2028, which represents about 2.5% of rate pressure in that year. However, by fixing the cost of Tier I RECs, the rate impact decreases over five years to about 1.2% in 2032. As a result, this strategy adds rate pressure that is within the range of inflation. The advantage is that both energy and Tier I REC price risks are hedged, both from market price changes and from changes in state renewable policy. This decision would also enable HED to focus on managing remaining risks such as coincident peak loads and their associated capacity and transmission costs.

4. **1% CAGR**

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

A4: 1% compound annual growth in load could reduce rates in 2032 by 7% compared to the reference case.

5. **Storage RFP**

Q5: What is the potential value of storage based on Round 2 of VPPSA's storage RFP?

A5: The value of storage appears to be about \$12/kW-month, and a 3 MW battery priced at \$10/kW-month could reduce HED's rates in 2023 by about 1.2%.

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)

- HED 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, HED will have the information needed to examine the business case and make a decision to commit to implementation of an AMI system, or not. HED 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. HED 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. HED also notes that unanticipated initiatives may emerge over time that positively impact the perceived value of having an AMI system in place. HED 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.
- Negotiate a five-year, energy-only or energy plus Tier I RECs PPA to reduce both energy and Tier I costs and risks for the 2023- 2027 period.
- Consider early compliance with the RES standard (75-100% renewable) in 2028 by purchasing a 2028 - 2040 energy + Tier I REC PPA.

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.
- Reduce annual coincident peaks with ISO-NE to reduce capacity requirements.
- Participate in Round 2 of the VPPSA storage RFP, and work with VPPSA's development partner to site peak shaving battery storage near one of HED's substations.

4. Tier I Requirements

- Make forward purchases of qualifying RECs on the regional market to manage REC price and ACP risk.
- Negotiate a five-year, energy-only or energy plus Tier I RECs PPA to reduce both energy and Tier I costs and risks for the 2023-2027 period.
- Consider early compliance with the RES standard (75-100% renewable) in 2028 by purchasing a 2028 - 2040 energy + Tier I REC PPA.

5. Tier II Requirements

- Commission the Billings Road (H11) Solar project, bank surplus RECs for future compliance years to the extent allowed.
- Make forward purchases and sales of qualifying RECs on the Vermont market to manage REC price and ACP risk.

6. Tier III Requirements

- Identify and deliver prescriptive and/or custom Energy Transformation programs, and/or
- Commission the Billings Road (H11) solar project and retire surplus RECs to fulfill Tier III to the extent allowable.
- 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

- Participate in Round 2 of the VPPSA storage RFP, and work with VPPSA's development partner to site peak shaving battery storage near one of HED's substations.

Appendix

Appendix A: NVDA Regional Plan

This appendix is provided separately in a file named:

Appendix A - NVDA Regional Plan.pdf

Appendix B: 2020 Tier 3 Annual Plan

This appendix is provided separately in a file named:

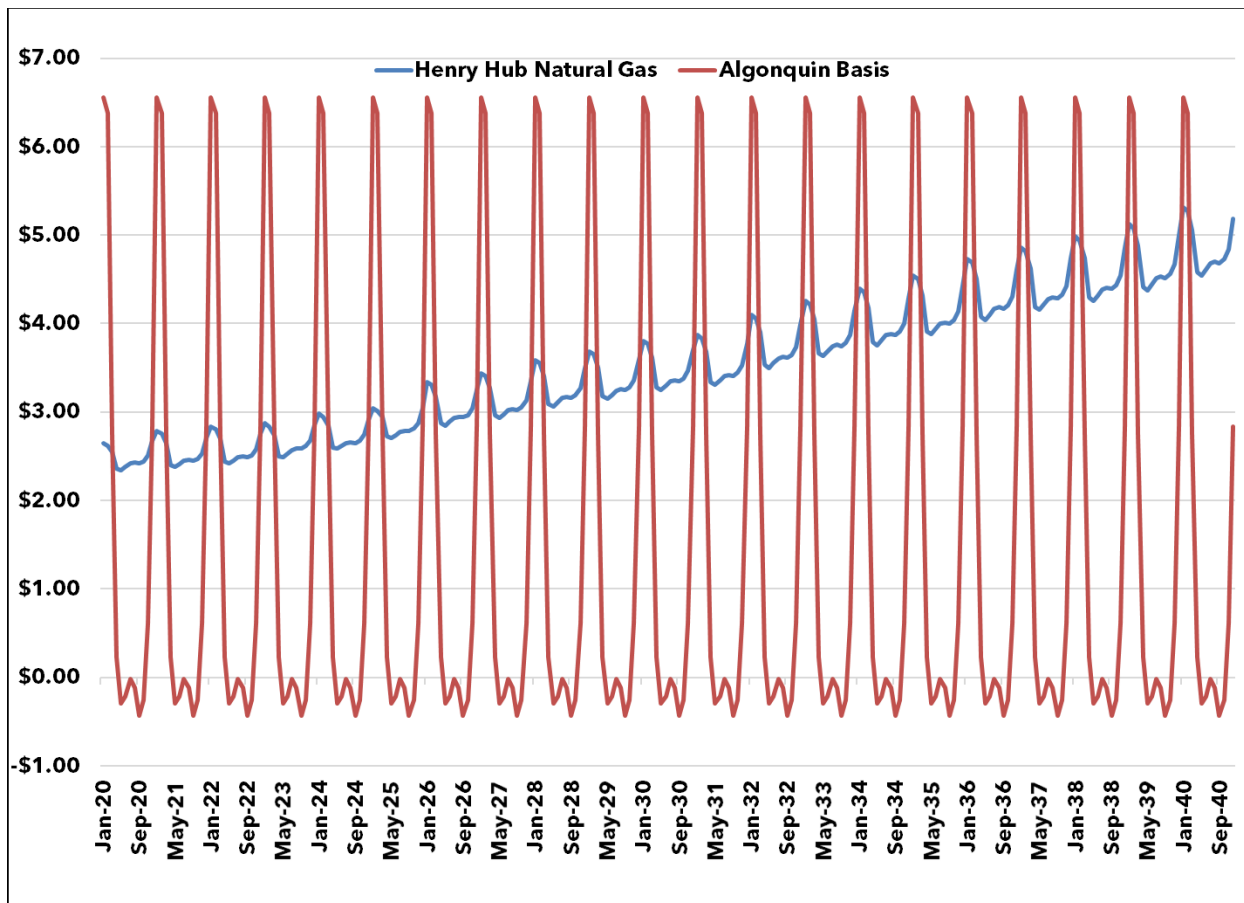
Appendix B - VPPSA Revised 2020 Tier 3 Annual Plan.pdf

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 2040. The forecast of Henry Hub Natural Gas prices can be seen in Figure 24.

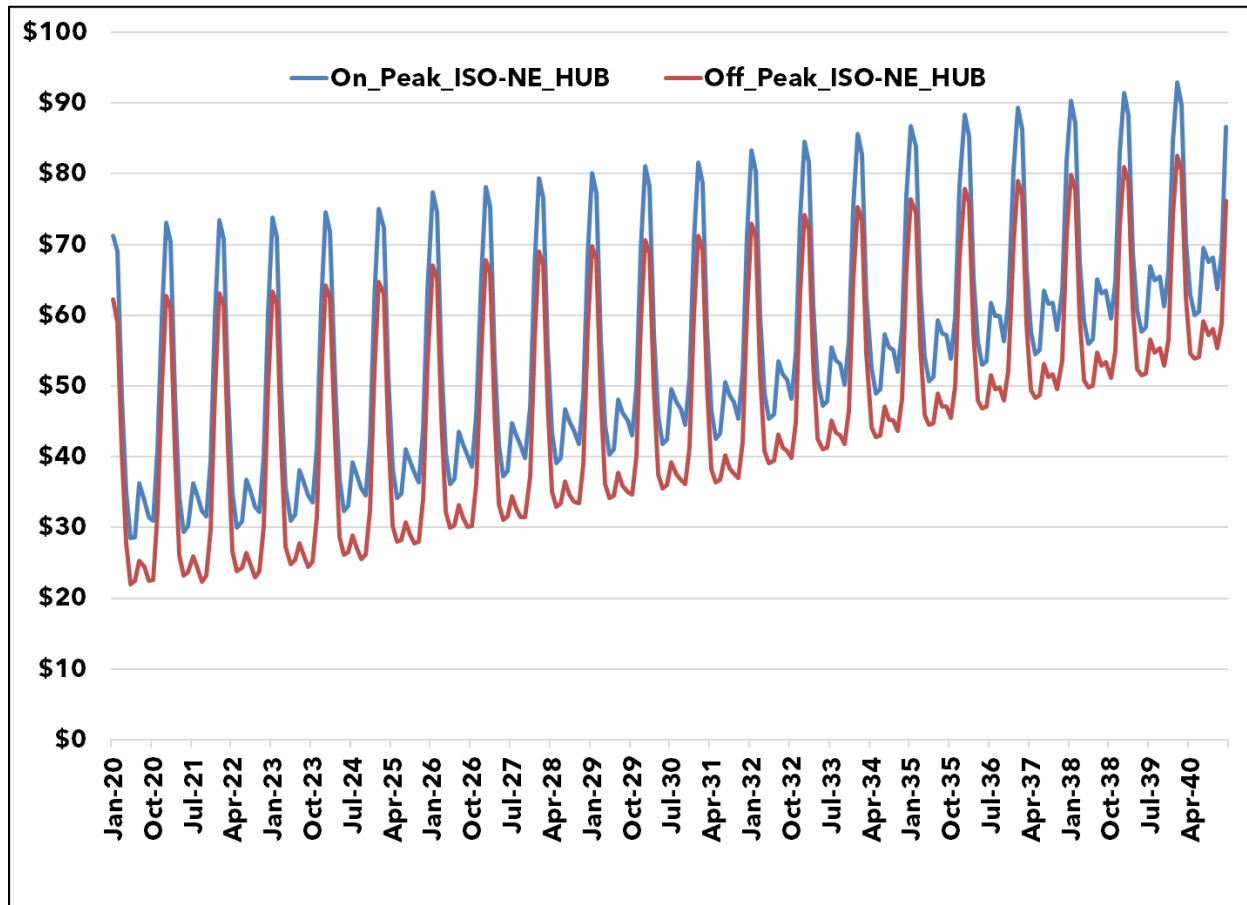
Figure 24: Henry Hub Natural Gas Price Forecast (Nominal \$/MMBtu)



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 25.

Figure 25: Electricity Price Forecast (Nominal \$/MWH)

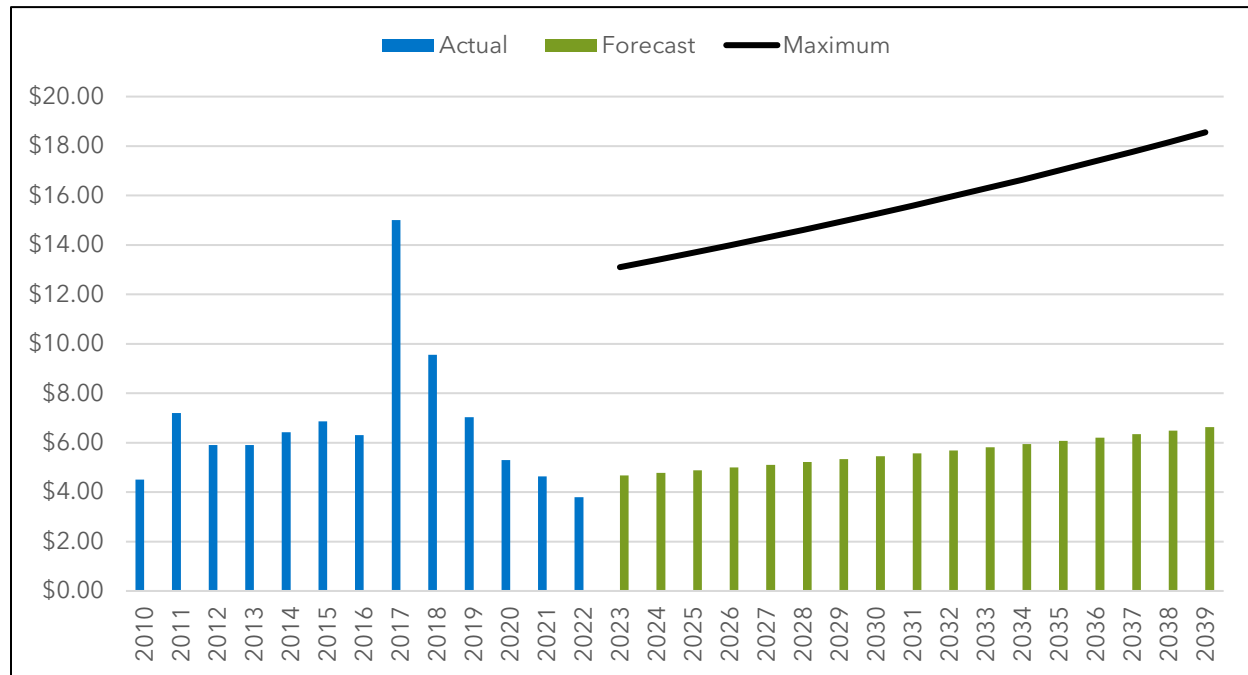


Finally, and in keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between LMP nodes to adjust the price forecast at the MA Hub to the location of HED's load and resources.

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 2040. Significant upside price risk does exist, as shown by the Maximum line in Figure 26. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 26: Capacity Price Forecast (Nominal \$/kW-Month)



Appendix D: PUC Rule 4.900 Outage Reports

Hardwick Electric Department

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	Hardwick Electric Department
Calendar year report covers	2014
Contact person	Mike Sullivan
Phone number	(802) 472-5201
Number of customers	4,343

System average interruption frequency index (SAIFI) =	3.5
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	2.4
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	83	6,307	
2	Weather	24	8,030	
3	Company initiated outage	10	1,998	
4	Equipment failure	58	1,860	
5	Operator error	0	0	
6	Accidents	12	1,545	
7	Animals	20	52	
8	Power supplier	1	16,286	
9	Non-utility power supplier	0	0	
10	Other	10	11	
11	Unknown	1	6	
	Total	219	36,096	

Hardwick Electric Department**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	Hardwick Electric Department
Calendar year report covers	2015
Contact person	Mike Sullivan
Phone number	(802) 472-5201
Number of customers	4,343

System average interruption frequency index (SAIFI) =	3.5
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	1.6
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	86	9,638	
2	Weather	30	2,733	
3	Company initiated outage	13	3,471	
4	Equipment failure	40	2,053	
5	Operator error	0	0	
6	Accidents	8	24	
7	Animals	25	829	
8	Power supplier	1	4,777	
9	Non-utility power supplier	0	0	
10	Other	5	762	
11	Unknown	5	108	
	Total	213	24,396	

Hardwick Electric Department**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	Hardwick Electric Department
Calendar year report covers	2016
Contact person	MIKE SULLIVAN
Phone number	(802) 472-5201
Number of customers	4,350

System average interruption frequency index (SAIFI) =	2.9
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	1.0
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	68	7,479	
2	Weather	19	2,624	
3	Company initiated outage	0	0	
4	Equipment failure	49	538	
5	Operator error	0	0	
6	Accidents	5	390	
7	Animals	25	163	
8	Power supplier	2	1,508	
9	Non-utility power supplier	0	0	
10	Other	0	0	
11	Unknown	20	301	
	Total	188	13,003	

Hardwick Electric Department**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	Hardwick Electric Department
Calendar year report covers	2017
Contact person	MIKE SULLIVAN
Phone number	(802) 472-5201
Number of customers	4,350

System average interruption frequency index (SAIFI) =	3.2
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	1.4
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	97	4,847	
2	Weather	39	5,465	
3	Company initiated outage	5	176	
4	Equipment failure	35	5,471	
5	Operator error	0	0	
6	Accidents	15	2,755	
7	Animals	29	405	
8	Power supplier	0	0	
9	Non-utility power supplier	0	0	
10	Other	4	3	
11	Unknown	22	600	
	Total	246	19,722	

Town of Hardwick Electric Department - 2019 Integrated Resource Plan

Hardwick Electric Department

2018

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

Electricity Outage Report -- PSB Rule 4.900

Name of company Hardwick Electric Department
 Calendar year report covers 2018
 Contact person MIKE SULLIVAN
 Phone number (802) 472-5201
 Number of customers 4,423

System average interruption frequency index (SAIFI) =	2.8
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	1.5
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out	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	76	5,720	
2	Weather	7	950	
3	Company initiated outage	2	32	
4	Equipment failure	37	8,379	
5	Operator error	0	0	
6	Accidents	13	1,584	
7	Animals	42	762	
8	Power supplier	0	0	
9	Non-utility power supplier	0	0	
10	Other	5	11	
11	Unknown	26	1,199	
	Total	208	18,638	

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 detail 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.

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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
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A	Identical
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A	Identical
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A	Identical
$0.88 \leq V \leq 1.10$	Continuous Operation	infinite	N/A	Identical
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T = 3 \text{ s} + 8.7 \text{ s} (V - 0.65)$	N/A	Identical
$0.45 \leq V < 0.65$	Permissive Operation ^{a,b}	0.32	N/A	See footnotes a & b
$0.30 \leq V < 0.45$	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:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- 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
$61.2 < f \leq 61.8$	Mandatory Operation	299	Identical
$58.8 \leq f \leq 61.2$	Continuous Operation	Infinite	Identical
$57.0 \leq f < 58.8$	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	OFF²
Q(V), Volt-Var Function with Watt	OFF
SS, Soft-Start Ramp Rate	ON
FW, Freq-Watt Function OFF	Default value: 2% of maximum current
	OFF

2

with unity PF.

Appendix G: RFP For Electric Storage Facilities

This appendix is provided separately in a file named:

Appendix A - VPPSA_2020_Storage_RFP.pdf

Glossary

Glossary

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
APPA	American Public Power Association
BESS	Battery Energy Storage Service Agreement
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
CEDF	Clean Energy Development Fund
CEP	Comprehensive Energy Plan
CRC	Cooperative Response Center
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
EIA	U.S. Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GMP	Green Mountain Power
HED	Town of Hardwick Electric Department
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
LIDAR	Light Detection and Ranging
LIHI	Low Impact Hydro Institute
L RTP	Long Range Transmission Plan
MAPE	Mean Absolute Percent Error
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
MW&L	Morrisville Water & Light Department
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NJUNS	National Joint Utilities Notification System
NYP&A	New York Power Authority
NVDA	Northeastern Vermont Development Association
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
PVRR	Present Value of Revenue Requirement

Vermont [Public Power](#) Supply Authority

Town of Hardwick Electric Department - 2019 Integrated Resource Plan

R ²	R-squared
RES	Renewable Energy Standard
ROW	Right-of-way
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
VTrans	Vermont Agency of Transportation
WQC	Water Quality Certificate

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.

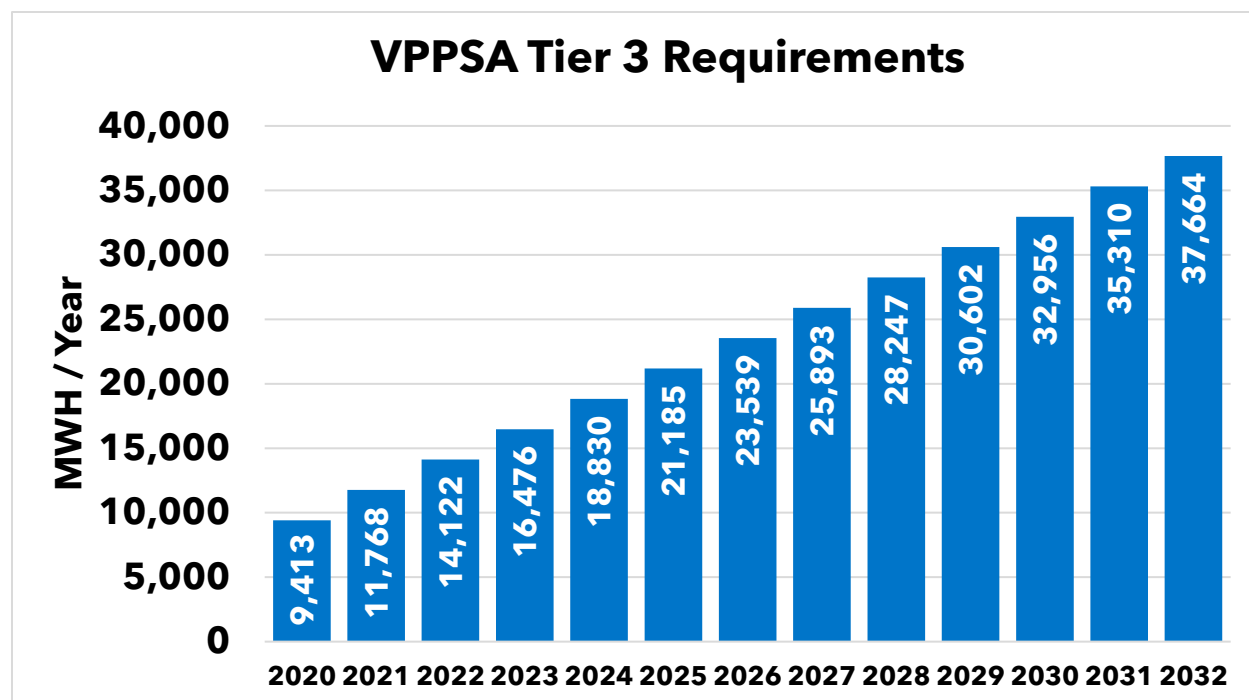


VPPSA Members:

- 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, VPPSA's post-purchase incentives were provided in conjunction with Efficiency Vermont's ("EVT") upstream rebates, which are paid to the equipment distributor. Because EVT and VPPSA were both claiming fossil fuel savings in 2019 for HPWH that replaced fossil-fuel water heaters, it was necessary to split savings and costs between the two entities. VPPSA continues to urge EVT to avoid using Thermal Energy and Process Fuels ("TEPF") funds for incentives on electrification measures. For 2020, VPPSA and EVT have agreed that VPPSA will fund 100% of the upstream rebate for HPWH that replace fossil fuel systems and thus will claim 100% of the fossil fuel savings in the form of Tier 3 credits. Efficiency Vermont will fund the upstream rebate and claim the associated savings for HPWH that are installed to replace *electric* water heaters.

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 customers² 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 \$3000.

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 or e-bike conversion kit.

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	31.88	\$1,000	\$403	\$1,403	16	\$44.00	510	\$22,443
PHEV	24.55	\$500	\$310	\$810	18	\$33.00	442	\$14,582
EV (Low Income)	31.88	\$1,400	\$403	\$1,803	5	\$56.55	159	\$9,013
PHEV (Low Income)	24.55	\$900	\$310	\$1,210	5	\$49.29	123	\$6,050
EV (Used)	15.94	\$500	\$201	\$701	4	\$44.00	64	\$2,805
PHEV (Used)	12.27	\$250	\$155	\$405	4	\$33.01	49	\$1,620
CCHP	21.74	\$400	\$275	\$675	42	\$ 31.03	913	\$28,333
CCHP (Weatherized)	26.84	\$500	\$339	\$ 839	8	\$31.26	215	\$6,712
HPWH	14.23	\$650	\$180	\$830	10	\$58.31	142	\$8,297
Level 2 Charger	16.75	\$500	\$212	\$ 712	4	\$42.48	67	\$2,805
Forklift	89.64	\$3,000	\$1,132	\$4,132	3	\$46.10	269	\$12,397
Golf Cart	3.24	\$50	\$41	\$91	25	\$28.06	81	\$2,273
Lawn Mower (Residential)	1.51	\$25	\$19	\$44	20	\$29.19	30	\$881
Lawn Mower (Commercial)	52.35	\$1,000	\$814	\$1,814	2	\$28.15	129	\$3,628
E-Bike	5.3	\$100	\$67	\$167	10	\$31.57	53	\$1,667
TOTAL					176	\$38.06	3,246	\$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

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 Vermont¹. 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 chooses 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

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

What is a BTU?

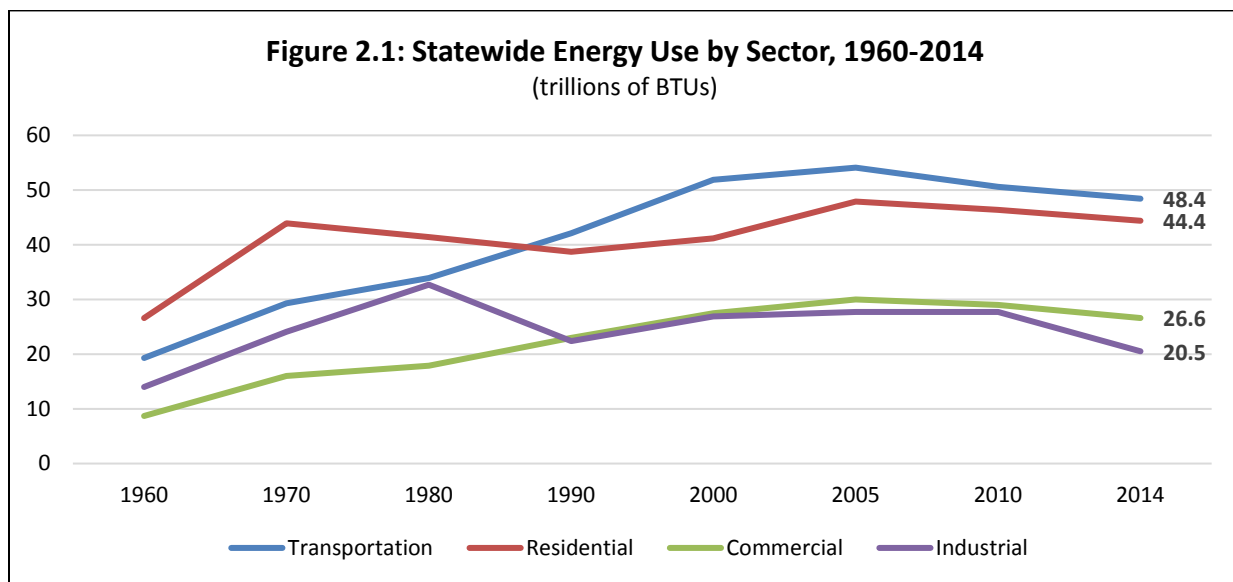
BTU stands for **British Thermal Unit**, and it is defined by US Energy Information Administration as the measurement of the quantity of heat required to raise the temperature of one pound of liquid water by 1° F at the temperature that water has its greatest density (approximately 39 °F).

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.

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.



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%. Transportation⁴ 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)

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)

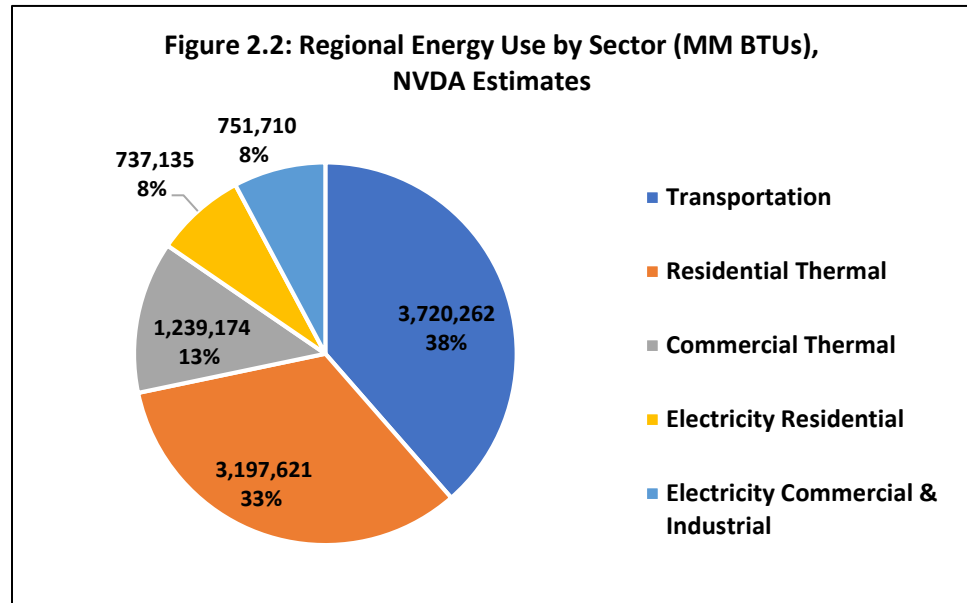


Table 2.2: Residential Heating Fuels Used in the Northeast Kingdom

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

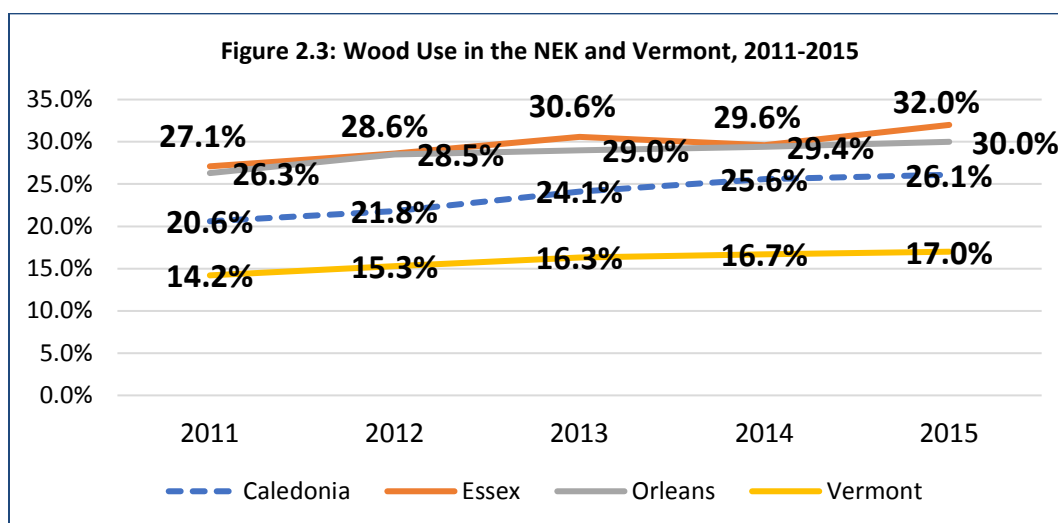
⁶ The American Community Survey (ACS) data differs from Census data in that it utilizes annual survey figures, from a smaller cross-section of the population, across a rolling 5-year timeframe to provide data estimates for a given year. The estimates used for this update were from 2011-2015.

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.



Source: American Community Survey

Table 2.3: Cost of Fuels, 2011-2016									
Types of Energy	BTU/Unit	November 2011			November 2016				
		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 annually⁷ 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 cap-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)

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

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				

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.

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

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.	

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. VTTrans 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 consumption⁸:

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.

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 2.8: 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			

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				

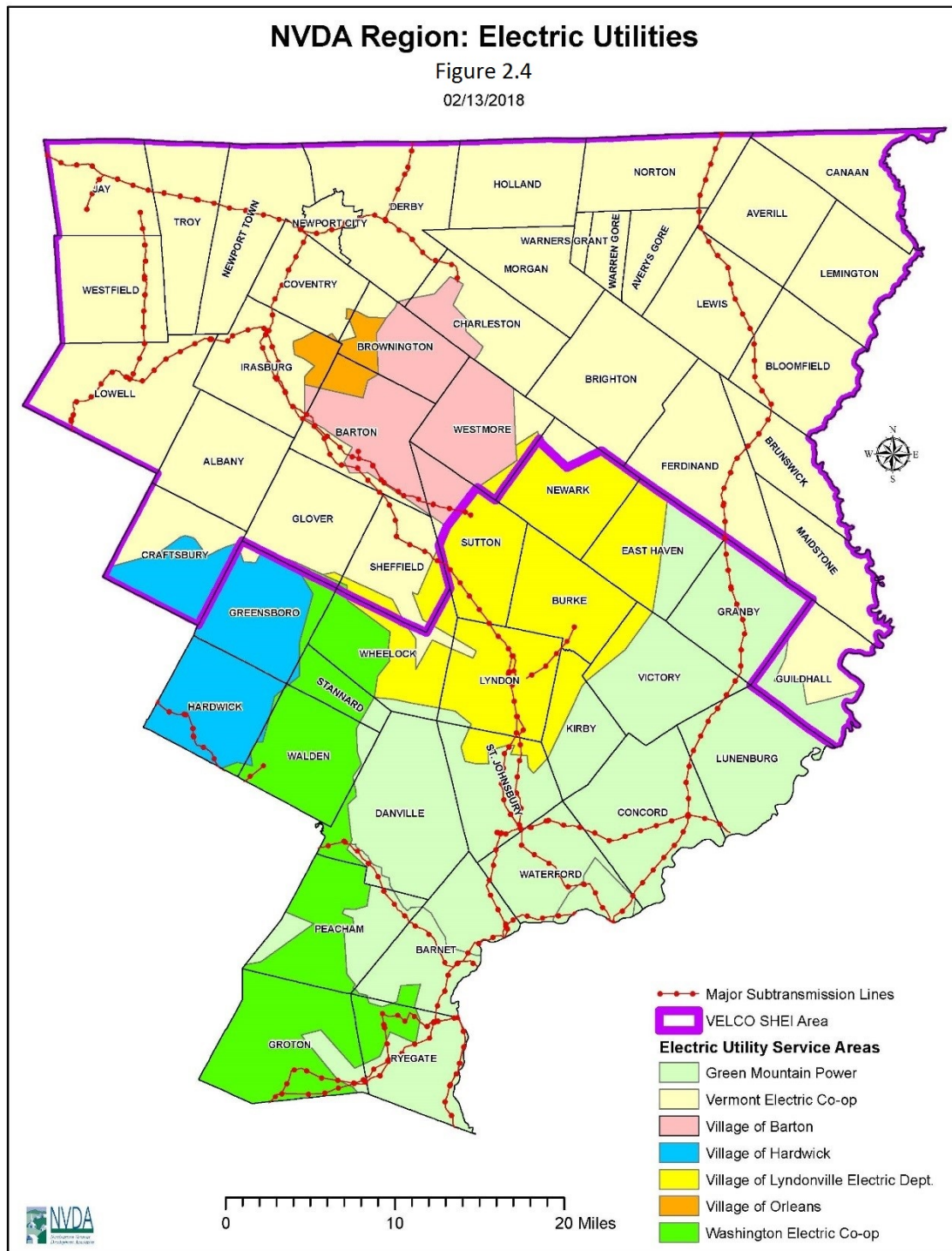
III. GENERATION AND DISTRIBUTION

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

- 1 municipal electric utilities include Barton Electric, Orleans Electric, Lyndonville Electric, and
- 2 Hardwick Electric. Together the municipal utilities provide service to 19 different towns and villages
- 3 (Figure 2.4⁹).



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) (Standard 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
Solalect 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 2.12 presents 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.

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,

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				

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:

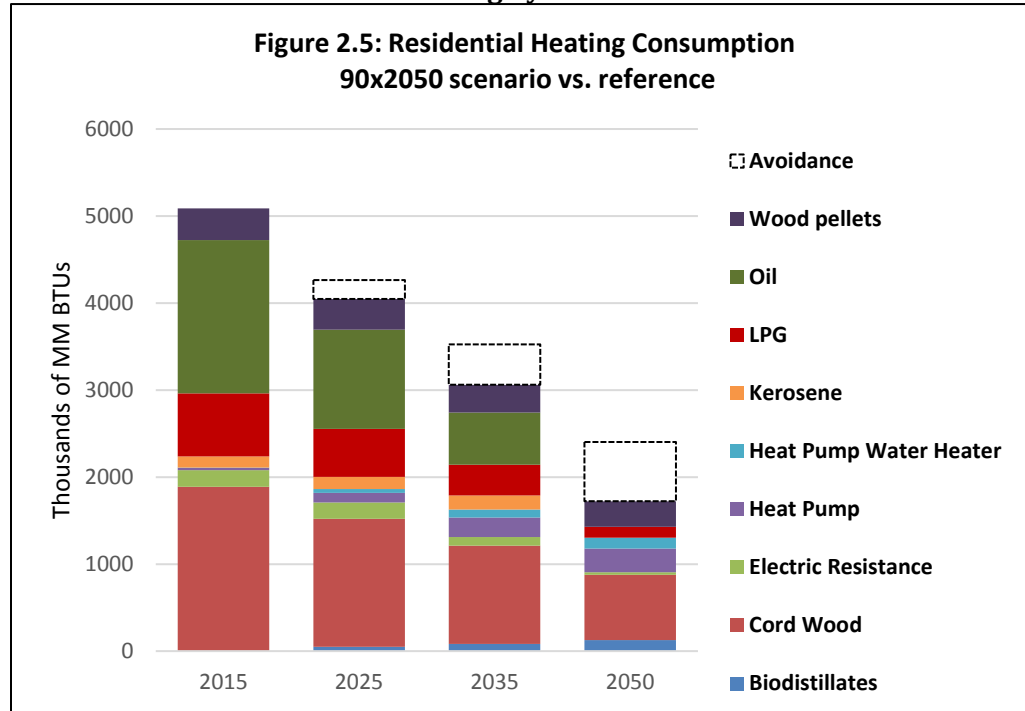
1. The "**reference**" scenario assumes a business-as-usual continuation of today's energy use patterns but does not reflect the Vermont's renewable portfolio standard or renewable energy or greenhouse gas emissions goals. The main changes over time in the reference scenario are more fuel-efficient cars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

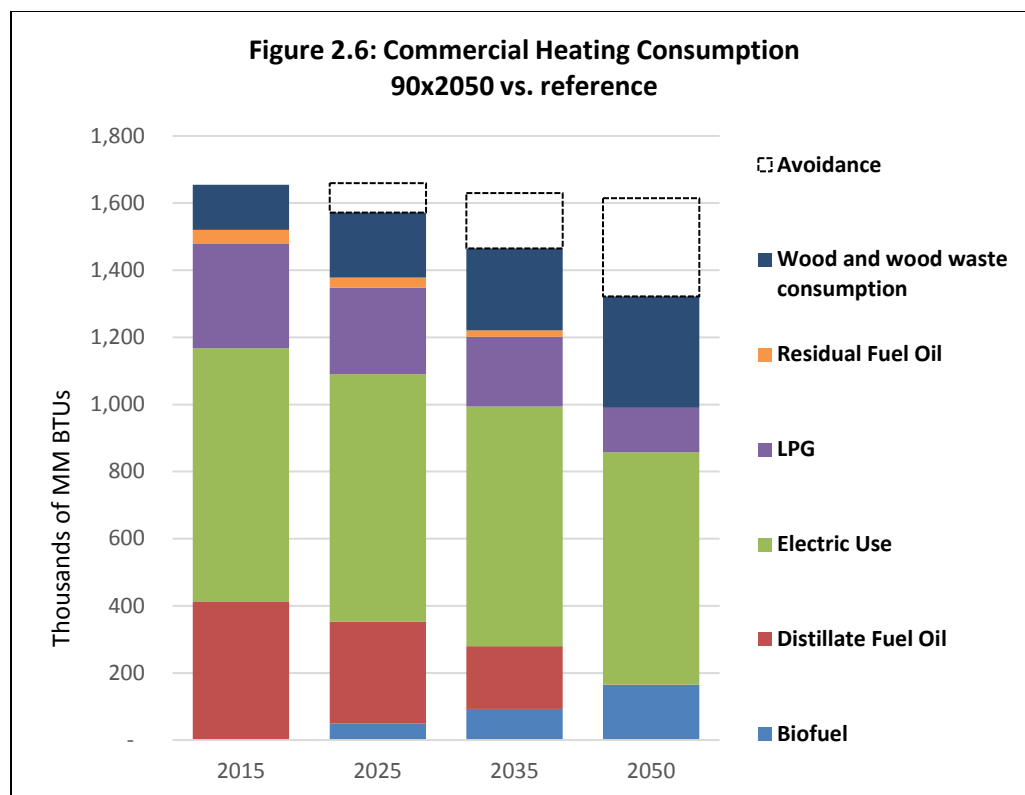
¹⁴ Vermont Energy Investment Corporation: NVDA Modeling, Summary Results and Methodology

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





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%

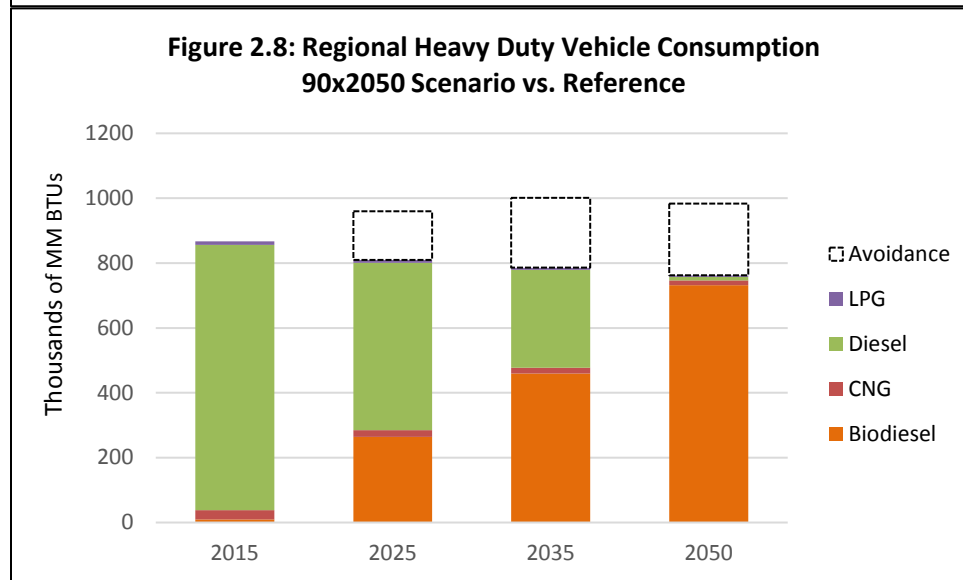
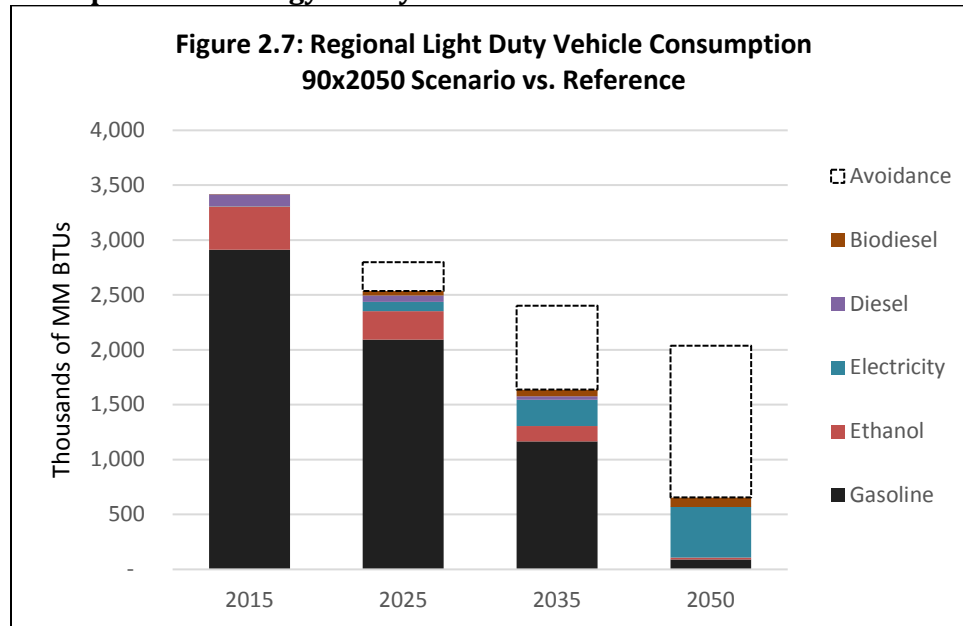
This estimate assumes an average savings of 400 kWh per project and assumes a projected number of customers by multiplying the number of housing units by 1.5 (to account for multi-units and non-residential customers).

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



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.

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

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

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:

Known constraints 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).

Possible constraints 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

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

	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.

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:	<p>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.</p> <p>Even though no significant acreage is required for a farm- or residential scaled turbine, NVDA’s estimate</p>

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

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).

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 (sic¹⁶) 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

Existing hydro-power facilities in the Northeast Kingdom collectively produce more than 118,000 MWh annually, accounting for more than

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.

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 wildlife¹⁷. 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

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

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.

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 power¹⁸. 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).

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

4 **Siting policies for biomass:**

- 5 • Siting wood-generation and co-generation facilities can be fraught with challenges. Noise,
6 emissions, truck traffic, and unsightly smoke stacks are concerns when siting facilities near
7 residential neighborhoods. Municipalities are strongly encouraged to develop performance
8 standards for industrial uses.
- 9 • These facilities use a renewable fuel that grows at a specific rate, so overharvesting of the
10 regional woodshed is a concern. The plan strongly urges a commitment to responsible
11 stewardship of the region's forestry resources, accomplished through the use of forestry
12 overlays that minimize fragmentation (regulatory), or enrollment in Vermont's Current Use
13 Program and conservation easements (non-regulatory). A number of planning tools are
14 available to municipalities, including forestry land evaluation and site analyses (FLESAs), that
15 can help municipalities prioritize lands for protection. NVDA encourages local planning
16 commissions to seek technical assistance.

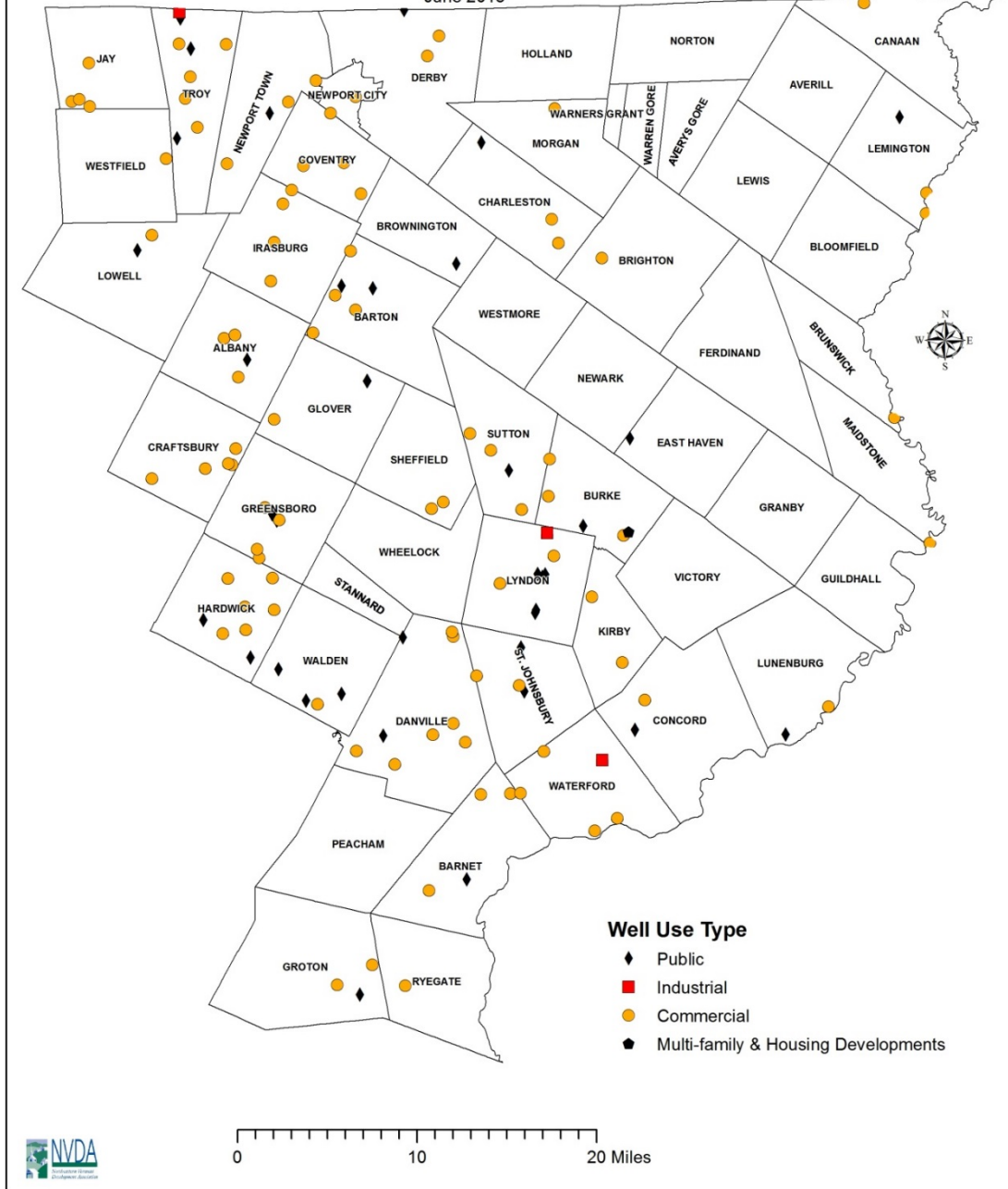
18 **Geothermal**

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

Geothermal Heating & Cooling High Potential Wells in the Northeast Kingdom

Figure 2.4

June 2015



1
2

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 than 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 tradeshow 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.

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

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

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

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

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

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

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

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

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

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

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



REQUEST FOR PROPOSALS FOR ELECTRICITY STORAGE FACILITIES

Issue Date: October 23, 2020

Response Deadline: December 4, 2020

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1. Overview & Structure

Vermont Public Power Supply Authority (VPPSA) is a joint action agency and instrumentality of the State of Vermont with broad authority to buy and sell electricity for its eleven non-profit, public power electric utilities (“Members”) in Vermont.

By this Request for Proposals (RFP), **VPPSA is seeking potential development partners for electric storage facilities in its Member service territories.**

VPPSA and its Members are open to a wide variety of proposals as described herein, and have identified potential sites in their service territories that may be suitable for locating storage facilities. These sites are discussed in Section 4.1, and **VPPSA is requesting initial proposals for the feasibility and development cost of these “Existing Sites”.**

- VPPSA is seeking potential development partners for electric storage facilities.
- VPPSA is requesting initial proposals for the feasibility and development cost of Existing Sites.

As described in Section 4.2, “New Sites” may also be identified by potential partners in response to this proposal. Such proposals are encouraged. Finally, VPPSA’s Members are open to a variety of ownership structures, including Purchase Power Agreements (PPAs), direct ownership, and other structures.

1.1 RFP Structure

This Request for Proposals (RFP) is divided into eight sections.

1. Overview & Structure
2. Operational Requirements
3. Facility and Site Requirements
4. RFP Structure and Schedule
5. Proposal Components
6. Evaluation and Selection Process
7. Proposal Submittal Requirements
8. Other Terms

2. Operational Requirements

The primary purpose of the storage facilities is to reduce coincident monthly and annual peaks with ISO New England. Reducing these peak loads reduces transmission and capacity costs in ISO New England's markets. Other applications for the storage facilities may include renewables integration, microgrid mode for emergency resilience, and other value-added modes of operation.

Table 2-1: Operational Requirements

APPLICATION	DESCRIPTION
Peak Load Reduction	<u>Required.</u> The primary purpose of the storage facility is to reduce coincident monthly and annual peaks.
Renewables Integration	<u>Desired.</u> The secondary purpose of the storage system is to manage the distribution system in the presence of increasing levels of behind-the-meter renewable generation (primarily hydro and solar).
Microgrid for Resiliency	<u>Desired.</u> This mode of operation is desired if the location of the facility is near critical facilities that can be cost-effectively incorporated into a microgrid for use during emergencies.
Other Applications	<u>Optional.</u> Other value-added applications or modes of operation will be considered.

The timing of the coincident peaks is summarized in Table 2-1, and corresponds well with the timing of the annual peaks, which have occurred in July at hour ending (HE) 18 for the past two years. With some exceptions, the storage facility would need to be fully charged by HE 17 and be discharging between HE 18 and 21.

Table 2-2: Timing of Monthly Peaks (Hour Ending)

	MONTH											
YEAR	1	2	3	4	5	6	7	8	9	10	11	12
2015	18	19	19	21	16	19	18	21	20	19	18	18
2016	18	19	19	21	21	21	19	21	20	19	18	19
2017	18	19	19	20	20	15	21	18	20	19	18	18
2018	18	19	8	12	21	21	20	20	20	19	18	18
2019	18	18	19	20	19	21	21	19	19	19	18	8

- The decision to operate the storage facility for peak load reduction may rest with either the Respondent or VPPSA, and Respondents should express their preference for holding this responsibility and the associated performance risk.

3. Facility and Site Requirements

3.1 General Requirements

1. The Facility or Facilities must be an electric energy storage facility.
2. The Facility or Facilities must be less than or equal to 4.9 MW (AC) in size at any one location, and Facilities less than 1 MW in size may be given preference.
3. The Storage Facility must interconnect with a VPPSA Member utility:
 - Barton Village Inc. Electric Department
 - Northfield Electric Department
 - Swanton Village, Inc. Electric Department
 - Town of Hardwick Electric Department
 - Village of Enosburg Falls Water & Light Department
 - Village of Jacksonville Electric Company
 - Village of Johnson Water and Light Department
 - Village of Ludlow Electric Light Department
 - Village of Lyndonville Electric Department
 - Village of Morrisville Water & Light Department
 - Village of Orleans Electric Department
4. The Delivery Point for the Facility shall be the point where the VPPSA Member distribution system connects with the Seller's Facility, specifically the load side connection of existing Member facilities, to allow Respondent's facility to operate interconnected and in parallel with the Member's electric system.

3.2 Products Requirements

Responses should assume that VPPSA or its Member utility will retain the peak-reducing benefits of the Facility, and may propose to retain any or all of the other products associated with the Facility.

3.3 Physical Requirements

The preferred location, capabilities and ISO market participation of the Facility are listed in Table 3-1. The preferred location is on the distribution system, but colocation with new or existing generation will be considered as will large customer sites. The capacity of the Facility should be less than 5 MW, and longer durations are preferred. Finally, unless greater value can be captured by participating in ISO-NE markets, the storage system is expected to operate independent of ISO-NE energy, capacity and ancillary markets.

Table 3-1: Physical Requirements

TERM	DESCRIPTION
LOCATION	1. Distribution systems of VPPSA municipal utilities, and/or 2. Renewable generators on municipal distribution systems, or 3. Large customers of VPPSA municipal utilities.
CAPACITY	100 – 4,900 kW.
DURATION	4+ hours
ENERGY	TBD based on the optimal capacity and duration of the system.
ISO-NE	Unless greater value can be captured by participating in ISO-NE markets, the storage system will operate independent of ISO-NE energy, capacity and ancillary markets.

3.4 Financial Requirements

Table 3-2 summarizes the high-level financial terms that are being sought. The preferred ownership option is a 10+ year PPA with a purchase option where O&M costs are the responsibility of the Seller. However, direct ownership by VPPSA or one of its individual Members will be considered. Respondents are encouraged to offer their preferred ownership structure. In terms of pricing, a fixed \$/kW-month charge is preferred, but other pricing structures will be considered.

Table 3-2: Financial Requirements

TERM	DESCRIPTION
BUYER	Vermont Public Power Supply Authority and/or VPPSA Member
SELLER	To be determined (TBD)
TERM	10 years. Longer terms will be considered.
OWNERSHIP	A PPA is preferred where O&M is the responsibility of the Seller. Other structures, including direct ownership, may be considered.
PRICE	A fixed \$/kW-month charge is preferred. Other price structures will be considered.

3.5 Existing Sites

Table 3-3 lists Existing Sites that have been identified as having potential for storage development. Respondents may focus their proposals on these sites or propose a New Site as described in the next section. These sites have established or can readily establish site control and are located close to the indicated substation.

Table 3-3: Existing Sites

UTILITY	SITE NAME	ADDRESS	SUBSTATION	VOLTAGE
Enosburg Falls	Waste Water Pumping Station	387 St. Albans St.	Enosburg Substation	46 kV
Enosburg Falls	Public Works Building	210 Dickenson Ave.	Enosburg Substation	46 kV
Lyndonville	National Guard Garage	Hill St., Lyndonville	VELCO's Lyndonville Substation	115 – 34.5 kV
Northfield	King St. Substation	150 King St., Northfield	King St. Substation	12.47 kV
Barton & Orleans	Heath Substation	Baird Road, Orleans	Heath Substation	46 kV
Morrisville	Trombley Hill	Trombley Hill, Morrisville	Morrisville's Substation #5	34.5 – 12.5 kV

Neither VPPSA nor any of its Members have conducted any analysis of the sites identified in Table 3-3, nor has VPPSA or any Member evaluated any interconnection constraints at these locations. Interconnection cost estimates and any feasibility analyses will need to be completed before a proposals is chosen.

In preparing responses to this RFP, respondents will not be allowed to perform detailed site visits of any identified sites. Such detailed site visits will be limited to respondents that reach the second round of screening. However, municipal sites are open to the public, and many sites can be viewed from various nearby locations, or via desktop methods. Any observed unique features of a site relevant to development should be clearly described.

3.6 New Sites

In addition to sites identified Section 3.5, Respondents are encouraged to offer New Sites for development of storage facilities. If a Respondent offers a New Site, a description of the site including physical address (and/or GPS coordinates), level of Respondent site control, unique features of the site, and any other relevant information should be included in the RFP response. To the extent that these features require additional cost, this should be clearly described in the response.

4. RFP Structure and Schedule

VPPSA intends to hold a two (2) round process.

4.1 Round One

This RFP represents the first round, and its purpose is two-fold.

- i. The primary purpose is to identify a short list of qualified development partners.
- ii. The secondary purpose is to identify a short list of potential sites, and to prioritize them by their feasibility, cost, and other characteristics.

- Round 1 requires an initial *non-binding* cost estimate and site feasibility assessment. Through these estimates and assessments, Respondents have the opportunity to make a show of interest in the RFP and to illustrate their qualifications.

4.2 Round Two

The second round will consist of a Requests for Proposals that is issued only to selected Respondents.

- i. The goal of this round is to select a partner or partners to develop site(s) in 2021.
- ii. Responses to this round will be binding, and may include site visits.

4.3 Schedule

The schedule is illustrated in the table below. VPPSA reserves the right to modify this schedule at its sole discretion.

Table 4-1: RFP Schedule

DATE	EVENT
October 23, 2020	Round One begins. VPPSA issues the RFP.
November 13, 2020	Pre-bid conference call at 2:00 PM
December 4, 2020	Round One ends. Deadline to respond to RFP.
January 15, 2021	VPPSA issues second round RFP to selected respondents.
February 26, 2021	Round Two ends. Deadline to respond to RFP.
March 26, 2021	Project awards are announced. (Tentative)

5. Proposal Components

5.1 Statement of Qualifications

Respondents shall provide a statement of qualifications containing the following elements (maximum of 5 pages):

- (a) **Experience**: Respondents must include a description of similar projects, including experience with public entities and experience in Vermont.
- (b) **Project Team/Partner Resources**: Respondents must include a proposed project team, including known financial partners. Include a brief summary of the project team's professional background and experience.
- (c) **References**: Respondents must include at least three client or partner references. Public partner references are preferred.

5.2 Site by Site Proposal(s)

Each site identified as viable for a storage facility should be developed as a standalone proposal that can be evaluated individually. For each location that is proposed for development, the Response should include the following.

- (a) **Project Proposal**: Respondents must include a detailed description of the existing sites for which the Respondent believes a storage facility is feasible and/or any New Sites. Proposals should include the type of storage technology, manufacturer, description of all anticipated equipment, and an explanation of any modifications of the property that might be required, required permitting, and any other relevant conditions.
- (b) **Operating & Dispatch Plan**: Respondents must include a detailed operating and dispatch plan that illustrates what time of day and how often each month the facility would be operating in a particular mode. In addition, the plan must address which entity holds the power to make dispatch decisions and how the operating risk(s) (peak forecasting risk, primarily) is borne by the parties.
- (c) **Finance and Ownership Structure**: Respondents must include the type of ownership structure proposed and the estimated cost associated with that structure. Multiple ownership structures for the same site may be proposed. Any financing vehicles expected to be utilized should be clearly described. The information submitted must be sufficient for VPPSA to determine the total estimated project cost. Interconnection cost estimates should be made and included in the overall cost; interconnection agreements and interconnection applications are not required for this RFP.

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- (d) **Operations and Maintenance Costs**: Respondents must include estimated operations and maintenance costs, and if the Respondent has the capability to provide O&M Services.
- (e) **Development Risk**: Respondents must identify the risks to the project's development and provide a plan for managing them.
- (f) **Estimated Timeframe**: Respondents should include an anticipated timeline for development of the project.

5.3 Required Agreements

Respondents should identify any contracts and agreements that need to be in place with VPPSA and/or its Member to facilitate project development.

6. Proposal Submittal

6.1 Submission of Responses

- (a) Name and Address of the Respondent's primary contact should be clearly identified on the first page of the proposal.
- (b) Proposals for more than one site and/or ownership structure should be included in a single package response to the RFP.
- (c) Respondents shall submit one digital, e-mailed copy of the proposal. Paper copies will not be accepted.
- (d) All proposals must be received by VPPSA no later than **December 4th, 2020, as indicated on the timestamp on the submitting e-mail**. Proposals and/or modifications received after this time will not be accepted or reviewed.
- (e) Proposals and Questions should be directed to:

Shawn Enterline
Senior Power Supply Analyst
Vermont Public Power Supply Authority
5195 Waterbury Stowe Road
Waterbury Center, VT 05677
senterline@vppsa.com

6.2 Question Submittal and Pre-Bid conference

Entities considering responding to this RFP who provide a notice of interest via email to the contact listed in Section 6.1 not later than **November 10th, 2020** will be invited to the pre-bid conference call on **November 13th at 2:00 PM**.

Such notice will enable the Respondent to receive any additional communications from VPPSA related to this RFP, including, but not limited to answers to questions raised by other potential Respondents.

Questions may be submitted in advance of any pre-bid conference call to senterline@vppsa.com. Responses to questions, to the extent provided, will be provided to all who have provided notice of interest.

7. Evaluation Process

Proposals will be opened and reviewed for completeness immediately following the submittal deadline. VPPSA will review the proposals for economic viability and intends to select multiple Respondents for each viable location for Round Two.

VPPSA reserves the right to reject proposals or eliminate sites from further consideration at its own discretion. VPPSA reserves the right, where it serves its interest, to request additional information or clarification from Respondents. VPPSA understands that the initial round of RFP is very broad in scope, and further clarity may be required as options are explored. Respondents are urged to make their proposals as detailed as possible, while identifying areas where further detail is required or risks are apparent.

The RFP process may result in multiple Respondents being chosen for one or more sites and ownership structures.

There will not be a public bid opening.

7.1 Evaluation Criteria

Proposals will be evaluated on the following criteria.

- (a) Total Project Cost,
- (b) Net cost, including risk, to VPPSA and/or Members,
- (c) Location – Member Existing Sites or desirable New Sites,
- (d) Qualifications of Respondents and Personnel assigned to project,
- (e) Ownership Structure,
- (f) Community Support.

In addition, the overall fit of the proposal will be considered, including combinations of siting, experience, ownership structure(s) and cost.

The lowest cost may not necessarily be chosen.

8. Other Terms

8.1 Conflicts of Interest

Respondents must certify that no elected official from a VPPSA Member system will benefit financially or materially from acceptance for this procurement.

Any alleged oral agreement or arrangement by a Respondent with any employee of VPPSA or VPPSA Member will be considered grounds to reject a proposal.

8.2 Confidentiality

Due regard will be given for the protection of proprietary information contained in all proposals received. However, Respondents should be aware that all materials associated with their submittals are subject to the terms of the Vermont Access to Public Records Act (1 V.S.A. Chapter 5, Subchapter 3) and all rules, regulations and interpretations resulting from, and any other applicable rules, regulations or judicial decisions regarding access to the records of government.

If confidential treatment is requested as part of the proposal, it will not be sufficient for Respondents to merely state generally that the proposal is proprietary in nature and not therefore subject to release to third parties. The pages or sections which a Respondent believes to be proprietary must be specifically identified as such and must be separated from other sections or pages of their proposal. Convincing explanation and rationale sufficient to justify each exemption from release consistent with Section 316 of Title 1 of the Vermont Statutes Annotated must accompany the proposal.

The rationale and explanation must be stated in terms of the prospective harm to the competitive position of the Respondent that would result if the material were to be released and the reasons why the materials are legally exempt from release pursuant to the above cited statute. The final administrative authority to release or exempt any or all material so identified, rests with VPPSA.

8.3 Collusion

By responding to this RFP, the Respondent implicitly states that the proposal is not made in conjunction with any competing Respondent submitting a separate response to this RFP and that it is in all respects fair and without collusion or fraud.

8.4 VPPSA's Rights

Neither VPPSA nor VPPSA Members shall be liable for any costs incurred by Respondents in the preparation of proposals or for any work performed prior to the approval of any executed contract.

All proposals upon submission become the property of VPPSA. VPPSA reserves the right to request additional information to assess and evaluate proposals.

VPPSA reserves the right to reject any or all responses to the RFP, to partner with Respondent(s) best suited to VPPSA or VPPSA Member interests, or re-issue the RFP.

This RFP in no way obligates VPPSA to contract with or otherwise partner with any Respondent.