2018 Integrated Resource Plan

Our 2018 Integrated Resource Plan complies with 30 V.S.A., Chapter 005: State Policy, Plans, Jurisdiction, and Regulatory Authority of Commission and Department, most notably 30 V.S.A. § 202a and 30 V.S.A. § 218c.

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Message from Our CEO

Green Mountain Power is pleased to file with the Public Utilities Commission its 2018 Integrated Resource Plan. This plan represents our roadmap in a time of unprecedented change and opportunity. Throughout the plan, you will see we have one focus—customers: how to best serve them cost effectively and reliably in this time of climate change, and to offer them the latest in available technologies to dramatically reduce carbon and drive down costs. And we remain focused on how to provide clean, cost-effective, and reliable power, the backbone of everything we do, as more and more customers choose self-supply and strategic electrification.

Climate change requires us all in Vermont to innovate and lead. We must develop strategies that cut carbon and insulate customers from the high costs and increased challenges of managing increasingly complex, bi-directional connections on the traditional electric grid. This work includes the use of local, distributed, renewable energy, paired with battery storage, controlled devices like heat pumps, electric vehicles with smart charging solutions, and more.

The goal of it all is to offer our customers a home-, business-, and community- based clean energy system. This IRP represents our unwavering commitment to this path. Together with our customers, Vermont energy companies, policymakers, and regulators, we are at the forefront of energy transformation nationally. Every day more are following Vermont's lead.

Thank you for your careful consideration of the work we do every day for customers. We look forward to your feedback and suggestions on this IRP, and how we can best serve customers into the future.

Mary Powell | President and Chief Executive Officer

1. Executive Summary

INNOVATIVE PLANNING FOR CUSTOMER-BASED ENERGY DELIVERY

The story throughout our 2018 Integrated Resource Plan is one of innovation and change:

- Change from the old energy system of centralized, fossil fuel-based generation transmitted through traditional poles and wires to customers far away, toward lower carbon, renewable, distributed generation with new, complex local and regional grid management opportunities.
- Change from one-way electricity flowing from a central plant to a customer toward two-way energy information, storage, and delivery between customers and us to benefit all.
- Change from steady and increasing loads toward flat and declining loads, as customers choose self-generation and utilize beneficial energy efficiency programs.
- Change from separate fuels for and treatment of thermal, lighting, and transportation energy toward convergence through the strategic electrification of resources.

And our pace, while already rapid and dynamic with a bias toward action and innovation, absolutely must increase if we are to meet the threat of climate change. Given these changes, we must also change the way we think about traditional planning to meet the energy needs of our customers and help them cut carbon. We are in the midst of transforming integrated resource planning into meaningful innovation planning, covering the details of distribution, procurement, asset management, and financial planning within the context of the shift toward customer-centered distributed energy resources (DERs).

The Energy Future We Embrace With Customers

We are guided by one central principle:
We are obsessed with serving our customers—our customers are our North Star.

Our focus on customers facilitates and guides our decisions—some that are unique in our industry—so that every action we take distinctly benefits our customers. We are adopting new, clean, distributed-energy technologies on both sides of the meter and, together with our customers, changing the way energy is delivered.

We are investing in energy delivery models that seek transformation in the following ways:

- Reducing the distance between generation and consumption, to lower losses and reliance upon the bulk electrical delivery system. This will ultimately result in a lower cost and a dramatically more reliable local energy system that is greener and more resilient in the face of significant climate change impacts.
- Establishing communities of distributed energy resources that are communications-enabled to optimize the operating cost of the electrical system and the use of renewable and non-emitting generating sources.
- Offering a diverse portfolio of innovative energy programs that promote measures consistent with Vermont energy policy and appeal to the personal goals of each customer.

Our 2018 IRP demonstrates our deep commitment to providing reliable, cost-effective—and increasingly distributed and carbon free—energy solutions for our customers. This includes helping customers transition away from higher cost, carbon-laden resources for heating and transportation, the largest contributors to climate carbon pollution and climate change in Vermont. We are striving to maintain stable and cost-effective rates despite rapid changes and profound challenges in the energy landscape. Looking to the future, we see a continued transition to an even more localized energy economy, one that is home-, business-, and community based. Ensuring this transition happens rapidly and smoothly, and in a way Vermonters can afford, is important.

ABOUT GREEN MOUNTAIN POWER

Our mission statement reflects directly our deep commitment to our customers:

> We have a vision to use energy as a force for good that improves lives and transforms communities. We're focused on a new way of doing business to meet the needs of customers with integrated energy services that help people use less energy and save money, while continuing to generate clean, cost-effective, and reliable power in Vermont.

We seek to accelerate the transformation in energy by providing energy as a service to allow Vermonters to cut carbon and improve their lives. Our strategy is to work with our customers to save money by flattening the peaks with a network of controlled devices, deployed storage technologies, and customer-focused market solutions that help accelerate adoption and facilitate other energy market players. We are focused on building a resilient two-way power grid—moving electricity and data to dynamically and efficiently balance load and demand. On a broader scale, our work aligns with, and has often been a precursor of, statewide policies and statutes.

Regional and other cost pressures out of our control impact overall costs, so we proactively address issues within our control to help mitigate these risks for our customers. We focus on how to deploy technologies to control load, while accelerating a market platform that does the same thing around us so that, over time, we lower our share of cost for the broader regional grid.

Meanwhile, energy efficiency measures and net metering installations mean flat and declining demand for electricity. No part of our service area is experiencing growth in demand, even with the significant trend toward the increased electrification of heating and transportation. Instead, improvements and repair to our distribution grid will be a necessity to maintain reliability and enhance resiliency as we focus on delivering controllable, low carbon energy locally.

Background and History

Green Mountain Power was founded on August 29, 1928 following a series of consolidations that included our predecessor, the Vergennes Electric Company, an early pioneer in electricity delivery founded 35 years earlier in 1893. To give this some perspective, distributed electricity first became available to parts of urban Manhattan in 1882. By the mid-1920s, approximately 85% of urban America was electrified as compared to only about 3% of farms and rural areas.

The Rural Electrification Act of 1935 began to change all that, bringing electricity throughout Vermont and putting in place the bulk delivery model that we are now seeking to transform.

Throughout our recent history, we have created a culture of working solely for the benefit of our customers. In 2008, we introduced the solar incentive, which helped jumpstart the solar industry and customer energy independence in Vermont. In 2014, we become a B Corporation—the first utility in the world to do so—by meeting rigorous standards of performance, accountability, and transparency, and seeking to use the power of business to alleviate poverty, address climate change, and build strong local communities, while being a great place to work.

Service Territory and Resources

Our service territory spans 7,500 square miles, serves almost 264,000 customers in 202 municipalities, and delivers power to about 77% of Vermont. Table 1-1 alphabetically lists all 202 municipalities we serve.

Addison	Chittenden	Highgate	Northfield Town	Saxtons River	Waitsfield
Andover	Clarendon	Hinesburg	Northfield Village	Searsburg	Wallingford
Arlington	Colchester	Hubbardton	Norwich	Shaftsbury	Waltham
Athens	Concord	Huntington	Orange	Sharon	Wardsboro
Bakersfield	Corinth	Ira	Orwell	Shelburne	Warren
Baltimore	Cornwall	Jamaica	Panton	Sheldon	Washington
Barnard	Danby	Jeffersonville	Pawlet	Shoreham	Waterbury
Barnet	Danville	Jericho	Peacham	Shrewsbury	Waterford
Barre City	Dorset	Killington	Peru	South Burlington	Weathersfield
Barre Town	Dover	Kirby	Pittsfield	Springfield	Wells
Belvidere	Dummerston	Landgrove	Pittsford	St. Albans City	West Fairlee
Bennington	Duxbury	Leicester	Plainfield	St. Albans Town	West Haven
Benson	East Montpelier	Lincoln	Plymouth	St. Johnsbury	West Rutland
Berlin	Essex	Londonderry	Pomfret	Stamford	West Windsor
Bethel	Fair Haven	Ludlow	Poultney	Starksboro	Westford
Bolton	Fairfax	Lunenburg	Pownal	Stockbridge	Westminster
Bradford	Fairfield	Lyndon	Proctor	Stowe	Weston
Braintree	Fairlee	Manchester	Putney	Strafford	Weybridge
Brandon	Fayston	Marlboro	Quechee	Stratton	Wheelock
Brattleboro	Ferrisburgh	Marshield	Randolph	Sudbury	Whiting
Bridgewater	Fletcher	Mendon	Reading	Sunderland	Whitingham
Bridport	Georgia	Middlebury	Readsboro	Swanton	Wilder
Bristol	Glastenbury	Middlesex	Richmond	Thetford	Williamstown
Brookfield	Goshen	Middletown Springs	Ripton	Tinmouth	Williston
Brookline	Grafton	Milton	Rochester	Topsham	Wilmington
Buels Gore	Granby	Monkton	Rockingham	Townshend	Windam
Cabot	Granville	Montpelier	Roxbury	Tunbridge	Windsor
Calais	Groton	Moretown	Royalton	Underhill	Winhall
Cambridge	Guildhall	Mount Holly	Rupert	Vergennes	Winooski
Castleton	Guilford	Mount Tabor	Rutland City	Vernon	Woodford
Cavendish	Halifax	New Haven	Rutland Town	Vershire	Woodstock Town
Charlotte	Hancock	Newbury	Ryegate	Victory	Woodstock Village
Chelsea	Hartford	Newfane	Salisbury	Walden	Worcester
Chester	Hartland	North Hartland	Sandgate		

Table 1-1. Vermont Municipalities Served (Alphabetic)

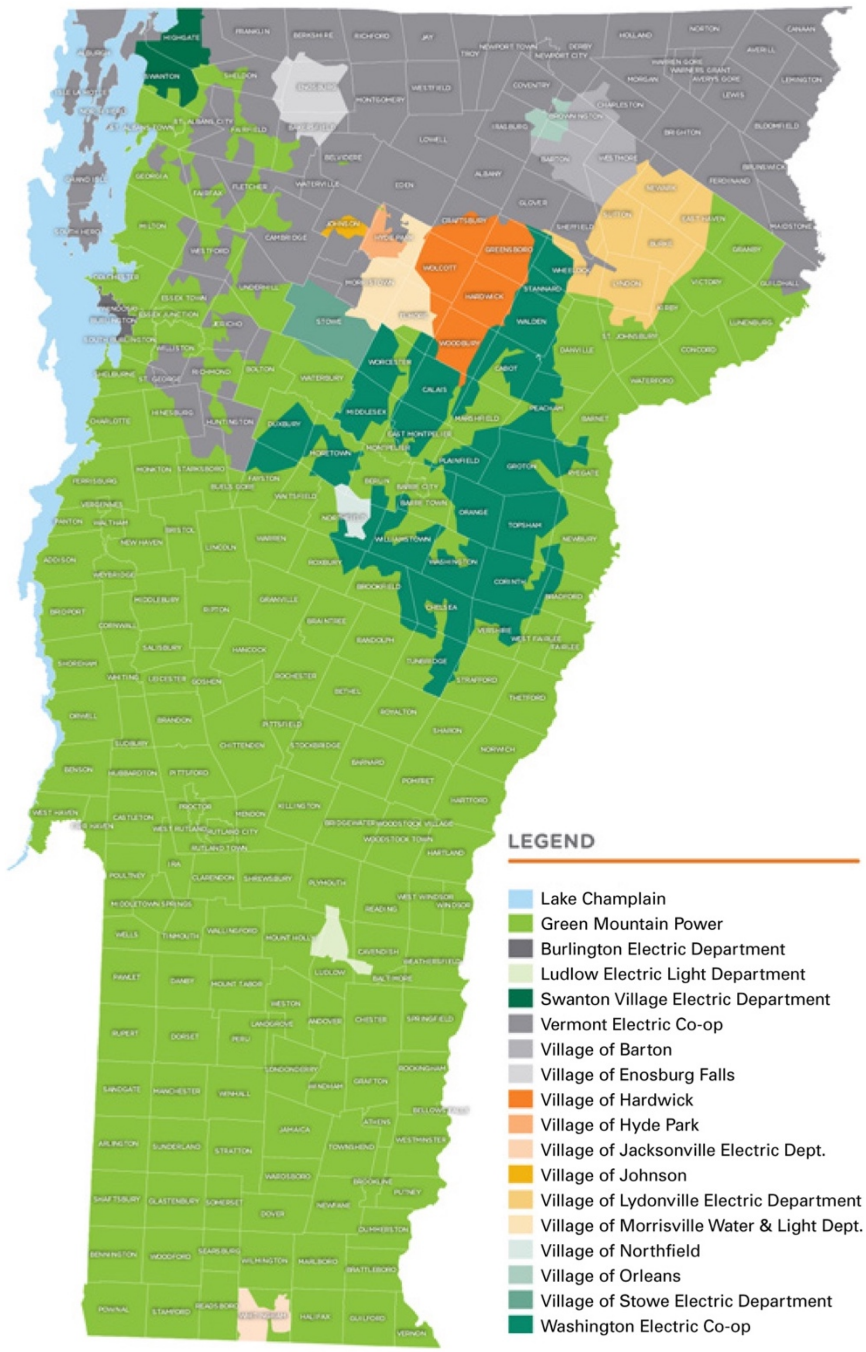

Figure 1-1. Service Territories of Vermont Electric Utilities

Figure 1-1 depicts a color-coded map of the service territories of all Vermont electric utilities. Our services area focuses mainly on the 200-plus cities and towns in the central and southern parts of the state, and includes Montpelier, Rutland, Bennington, and Brattleboro.

We own a portfolio of cost-effective generation resources, including 46 hydroelectric units, two wind plants, six oil-fired peaking plants, and 10 solar power facilities. We also co-own a wood-fired plant, a portion of a nuclear unit in Connecticut, a combined-cycle unit, and an oil-fired unit. Over time, we have significantly limited the use of carbon-intensive resources. (For a complete breakdown of this generation, our independent power purchase agreements (PPAs), and our statutory PPAs, see “Appendix C: Current Power Supply”.)

Customers and Costs

Figure 1-2 illustrates the number of commercial, industrial, and residential customers we serve, and the amount of energy each group consumes.

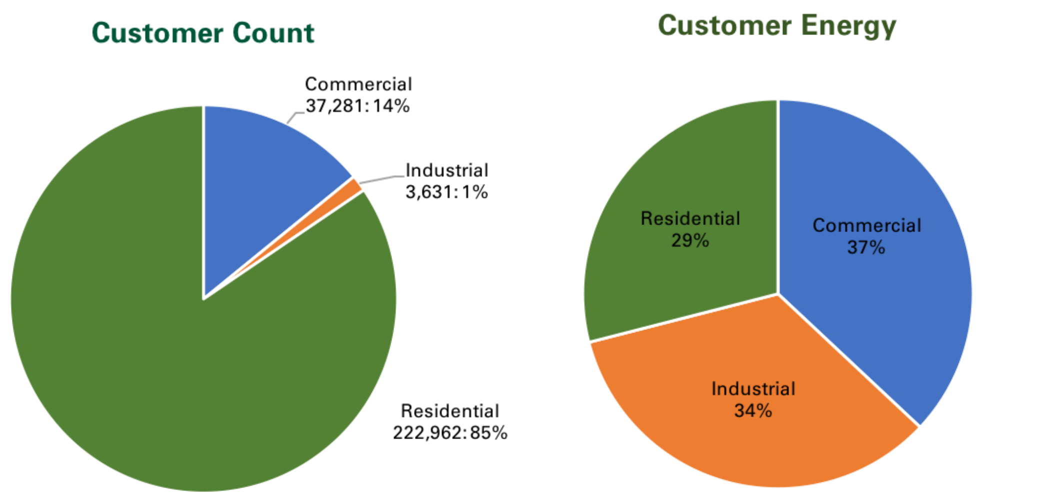

Figure 1-2. Customer Count and Energy Comparison

We are proud to have rates that are low when compared to investor-owned utilities in New England and are lower than compared with many other utilities serving Vermonters.

Figure 1-3 compares the 2017 retail rates of Green Mountain Power with the independently owned electric utilities in the five other New England states.

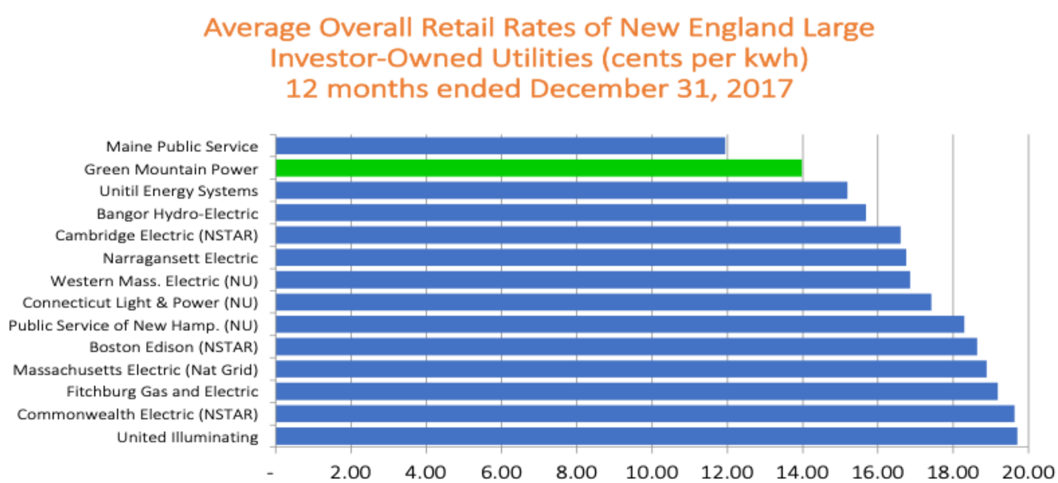

Figure 1-3. Retail Rates of Investor Electric Utilities In New England: 2017

LOAD AND T&D SYSTEM SUMMARY

Load Forecast

We are facing declining load as our customers look to personal energy systems as well as take advantage of continued improvements in efficiency, such as improved appliance standards. Table 1-2 provides a summary of our load forecast view provided in our last IRP compared to our current load forecast. In fact we are using less energy now than we have since the end of 2003. Regional cost pressures, however, continue to rise and with fewer kilowatts to spread these costs over, will lead to further rate cost pressures on customers. It is our focus to counter these cost pressures through transformative customer offerings, strategic partnerships with third-party providers, and development of a power supply resource mix that is incredibly low carbon and low cost.

Year	2015 Forecasted Retail Sales (MWh)	2019 Forecasted Retail Sales (MWh)	Annual Change (%)
2017	4,283,851	4,157,098	–3.1%
2018	4,287,010	4,166,119	–2.9%
2019	4,287,332	4,146,271	–3.4%
2020	4,280,655	4,132,091	–3.6%
2021	4,265,783	4,113,442	–3.7%
2022	4,272,630	4,102,733	–4.1%
2023	4,283,191	4,091,212	–4.7%
2024	4,300,610	4,083,897	–5.3%
2025	4,305,751	4,073,410	–5.7%
2026	4,319,724	4,065,796	–6.3%
2027	4,336,678	4,062,941	–6.7%
2028	4,363,099	4,065,519	–7.3%

Table 1-2. Forecasted Retail Sales: 2015 versus 2019

The Future T&D System

The theme throughout the IRP will be a focus on transitioning the energy delivery system to a highly distributed system, while continuing to strategically electrify transportation, heating and other fossil fuel processes. With the introduction of cost effective energy storage, we now have a new tool along with a software platform and distributed energy resources, to manage and choreograph the distributed grid. Our focus will be on how we seamlessly integrate intermittent distributed generation onto the grid. Chapter 7: Financial Assessments show how data has become an integral part of our planning and visibility into the distribution system.

2018 INTEGRATED RESOURCE PLANNING GOALS

As distributed energy resources have increasingly proliferated on the power grid, so has the challenge of integrated resource planning. The transition from last century's power grid where electricity flowed in one direction from a few central generating plants to customers, is accelerating. Net-metered solar installations together with small wind and solar plants distributed abundantly and randomly through the power grid, necessitated a bi-directional flow of power; the promise of storage now demands it.

This distributed energy future requires a new approach to integrated resource planning that is more nimble, flexible, and incorporates distribution planning down to the circuit level. We have carefully cultivated the integration of resource and distribution planning to ensure our 2018 IRP meets not only the statutory requirements, but also the needs of our customers now and in the future.

The larger purpose of our 2018 IRP is to meet Vermont's energy policy:

> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.
>
> (2) To identify and evaluate, on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least-cost integrated planning; including efficiency, conservation, and load management alternatives, wise use of renewable resources, and environmentally sound energy supply.[1]

Vermont statute requires us to develop a "least-cost integrated plan" for a safe, reliable, lowest-cost, environmentally friendly power grid that meets the energy service needs of our customers. The plan must combine prudent investments and expenditures in energy supply, transmission and distribution capacity and efficiency, and comprehensive energy efficiency programs.[2]

We have not only endeavored to create our 2018 IRP to meet these two overarching statutes, but have also developed this IRP to fulfill three additional commitments and statutory goals:

- Conditions we agreed to meet in a memorandum of understanding (MOU) jointly filed with the Vermont Department of Public Service and Vermont Energy Investment Corporation following the submission of our 2014 IRP.
- Statutory goals for greenhouse gas emission reductions, a broad-based renewable energy obligation, and Renewable Energy Standard (RES) requirements.
- Expanded goals and guidance described in detail in the 2016 Vermont Comprehensive Energy Plan (CEP).

The following sections detail these goals and requirements.

[1] 30 V.S.A. § 202a.

[2] 30 V.S.A. § 218c.

Our Memorandum of Understanding Commitments

On July 29, 2015, the Vermont Public Utility Commission (PUC) approved the Memorandum of Understanding (MOU) that we presented together with the Vermont Department of Public Service (DPS) and Vermont Energy Investment Corporation (VEIC) regarding our 2014 IRP reviewed in Docket No. 8397.

In that MOU, we agreed to several methodological improvements to incorporate into the development of our 2018 IRP. All parties in the MOU agreed that the energy landscape in Vermont is complex and shifting, as evidenced by this paragraph:

> The Parties agree that there are many forces at work on the Vermont energy system including, but not limited to, winter peak pricing spikes; escalating regional transmission costs; the Vermont Comprehensive Energy Plan; the Total Energy Study; proposed legislation that would significantly change requirements for utilities to own renewable energy as a part of their portfolio, and potentially to deliver innovative energy resources; and significant opportunities for strategic electrification in the thermal energy and transportation energy sectors. The dynamics of these discussions and related potential regulatory obligations require ongoing assessment and strategic planning to meet Vermont's energy service needs in a manner that is consistent with State Energy Policy. GMP, the PSD, and VEIC agree that they will work collaboratively to develop innovative responses to these emerging challenges in a way that maximizes the unique resources and capabilities of the individual Parties.[3]

More specifically, we agreed to incorporate new efforts in six areas:

Collaboration. The MOU underscores the importance of continuing to collaborate with the DPS and VEIC in planning the delivery of energy services. This includes incorporating common assumptions and scenarios from the Demand Resource Plan and other relevant proceedings, adopting and quantifying common assumptions and scenarios for our Innovation Pilots, and collectively seeking opportunities to deliver least-cost energy services for our customers. We also agreed to quantify and integrate plans to incorporate DERs at the lowest cost, develop improved metrics (especially to measure financial impacts), and refine our load forecasting methodology.[4]

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3 *Memorandum of Understanding between Green Mountain Power Corporation, the Vermont Department of Public Service, and Vermont Energy Investment Corporation*, filed in Docket No. 8397 on March 11, 2015; #16, page 5–6.

4 *Ibid.*; #14a, page 3.

Distributed Energy Resources (DERs). Broadly defined, DERs are connected to the distribution system and can either generate electricity or reduce the demand for electricity. For this MOU, DERs include (but are not limited to): conservation, demand response, load management, energy efficiency, fuel switching, energy storage, distributed generation that is generally less than 5 MW, and any combination of resources intended to provide energy services at least cost. Thus, we agreed to consult with the DPS and VEIC to:

- Identify opportunities where DERs can be quantified and integrated into the IRP, emphasizing responsive demand resources and our innovation pilots and programs.
- Develop and implement DERs at the lowest cost, consistent with statutory and regulatory requirements. For our 2018 IRP, we also agreed to complete and report on our efforts to make web-based, location-specific technical grid information available to DER developers before they decided on the location, size, and electrical details of a project.
- Integrate the expected volume and cost of our innovation pilots that make a meaningful impact on the load or operation of the power grid.[5]

Integration. Because of the complex nature of integrated resource planning, we agreed to continue to involve several internal departments in the development of our IRP, including Power Supply, T&D Planning, Engineering, Rates and Finance, and Innovation. In addition, we agreed to collaborate with DPS and VEIC to develop common metrics for measuring our current and future energy planning processes, and to use the same tools, methods, metrics, and report formats employed in developing our annual cost of service filings to estimate the expected revenue requirement impacts of the expected and preferred outcomes by year.[6]

Load Forecast. Accurate load forecasting is fundamental to developing an impactful IRP. As such, we agreed to continue collaborating with Vermont Electric Power Company, Vermont Transco (VELCO), the Vermont System Planning Committee (VSPC), and VEIC to adopt multiple common assumptions into our load forecasts, including the major elements of the Demand Resource Plan and the expected penetration of DER. In addition, we agreed to depict the IRP load forecast before and after incorporating energy efficiency measures, consider using heating and cooling degree-day trends instead of flat multi-year averages, and consider and quantify the magnitude and timing of DER on our peak and total energy requirements.[7]

Public Notification. Once filed, we agreed to post our 2018 IRP on a separate, dedicated website page, and notify customers of our IRP through both a bill stuffer and a press

[5] *Ibid.;* #14b, page 3–4.

[6] *Ibid.;* #14c, page 4–5.

[7] *Ibid.;* #14d, page 5.

release.[8] While our IRPs were publicly available previously, these steps help ensure higher customer engagement around these important issues.

Our Ongoing Commitments. Finally, after the IRP is filed, we agreed to continue to monitor key uncertainties and the continued accuracy of input assumptions and data; to reevaluate the merits of our decision-making processes and analytic methods; and to adapt them to new techniques or information.[9]

Greenhouse Gas Reduction Goals

Vermont is dedicated to reducing greenhouse gas (GHG) emissions, both within state boundaries and from outside the state caused by energy use in Vermont, so that we can make an appropriate contribution to achieving regional emission reduction goals. Vermont targets to reduce GHG emission from the 1990 baseline by:

- 25% by January 1, 2012;
- 50% by January 1, 2028; and
- 75% by January 1, 2050 if practicable using reasonable efforts.[10]

The 2016 Vermont CEP expanded on these goals. See "2016 Comprehensive Energy Plan Guidance" on page 1-16 for details.

We embrace these GHG emission reduction goals and have factored those reductions into our resource planning efforts. We are partnering with customers to cut carbon in this era of climate change impacts.

Renewable Energy Goals

On a broader scale, Vermont is committed to producing 25% of the energy consumed within the state through renewable energy sources, particularly from Vermont's farms and forests.[11]

The 2016 Vermont CEP expanded on these goals by broadly seeking to move the state to 90% renewable energy by 2050 across all energy sectors, including heating and transportation. See "2016 Comprehensive Energy Plan Guidance" on page 1-16 for further details.

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8 *Ibid.;* #13, page 3.

9 *Ibid.;* #17, page 6.

10 10 V.S.A. § 578.

11 10 V.S.A. § 580a.

Act 56: Renewable Energy Standard Requirements

Act 56, enacted on June 11, 2015, established Renewable Energy Standard (RES) requirements for Vermont electric distribution utilities to procure specific percentages of their total retail electric sales from renewable energy as defined under three categories, or Tiers.[12] Meeting RES requirements will not only increase renewable generation in the state, but also reduce GHG emissions by approximately 15 million tons by 2032, thus attaining one-quarter of the state's emission reduction goal by 2050.

Here are the requirements for each of the three Tiers (as itemized in Table 1-3).

Tier I requires a defined percentage of retail electric sales from any renewable energy source.

Tier II requires a defined percentage of retail electric sales from new DER generation. For RES, DERs must be either (1) electric generation facilities of 5 MW or less capacity directly connected to a subtransmission or distribution system, (2) identified plants that defer transmission upgrades, or (3) net-metered systems whose environmental attributes are owned by the distribution utility; and (4) must have started operations after June 30, 2015.

Tier III requirements can be met either through additional new DERs (as specified in Tier II) or through energy transformation projects with a net reduction in fossil fuel consumption. Examples include building weatherization; air source or geothermal heat pumps and high-efficiency heating systems; industrial-process fuel efficiency improvements; increased biofuels use; biomass heating systems; electric vehicles or related infrastructure; and renewable energy storage infrastructure on the electric grid.

Tier I and Tier II require utilities to hold Renewable Energy Certificates (RECs) to satisfy their requirements (like the five other New England states). RECs (equivalent to 1 MWh renewable generation) are created when a renewable unit generates electricity and can be sold separately from the electricity generated by the unit. Both utilities and generators can buy and sell RECs on an open market in the region. For example, a solar facility could sell electricity to one utility and RECs to another utility or to a private party.

[12] 30 V.S.A. § 8002–8005.

Table 1-3 lists the RES Tier I, Tier II, and Tier III retail sales requirements over the subsequent 14 years.

Year	Tier I	Tier II	Tier III
2017	55%	1.0%	2.00%
2018	–	1.6%	2.67%
2019	–	2.2%	3.33%
2020	59%	2.8%	4.00%
2021	–	3.4%	4.67%
2022	–	4.0%	5.33%
2023	63%	4.6%	6.00%
2024	–	5.2%	6.67%
2025	–	5.8%	7.33%
2026	67%	6.4%	8.00%
2027	–	7.0%	8.67%
2028	–	7.6%	9.33%
2029	71%	8.2%	10.00%
2030	–	8.8%	10.67%
2031	–	9.4%	11.33%
2032	75%	10.0%	12.00%

Table 1-3. Renewable Energy Standard Tier I, Tier II, and Tier III Requirements

Note: Tier I requirements encompass those of Tier II; in other words, the total Tier I and Tier II requirement for 2032 is 75% of retail sales.

Act 56: Standard Offer Program

Act 56 also repealed the Sustainably Priced Energy Enterprise Development (SPEED) program, except for its Standard Offer component with a goal is to promote a rapid increase in renewable generation facilities contracted with Vermont with a nameplate capacity of 2.2 MW or less. The Standard Offer program has a statutory cap of 127.5 MW.

The RECs and energy from Standard Offer projects, as well as their associated costs, are allotted to the Vermont utilities based on their pro-rata share of load. As of 2015, our share of the Standard Offer program is 76.67%. Thus, through Standard Offer projects we would have up to approximately 97.5 MW to use as RECs to satisfy either RES Tier I and Tier II requirements, depending on the date the project started operations.

2016 Comprehensive Energy Plan Guidance

The Vermont Department of Public Service published an updated CEP in 2016, which expanded and altered two key statutory goals, and provided detailed guidance for state electric utilities to develop their individual IRPs.

Expanded and Altered Statutory Goals

The 2016 CEP expanded on the statutory goal (10 V.S.A. § 580a) of attaining 25% renewable energy from farms and forests by establishing 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.
- Three end-use sector goals for 2025: 10% renewable transportation, 30% renewable buildings, and 67% renewable electric power.[13]

In addition, the 2016 CEP altered the statutory goal (10 V.S.A. § 578) for reducing GHG emissions from the 1990 baseline by softening the short-term goal and strengthening the long-term goal. Targets now in the CEP:

- 40% reduction by 2030.
- 80% to 95% reduction by 2050.[14]

[13] *2016 Vermont Comprehensive Energy Plan; page 2*

[14] *Ibid.*; page 4.

IRP Development Guidance

The 2016 CEP suggests utilities use the IRP process to develop methods to evaluate competing investment and purchase decisions to meet customer demand, and to develop a set of specific tools for evaluating options of balancing supply and demand at the lowest present value life cycle cost.[15]

The 2016 CEP presented guidance in six main areas. That guidance is summarized here:

1. **Forecasts and Scenarios.** Analyze load forecasts against several future scenarios, considering several demand forecasting factors, then analyze alternative sensitivities to these scenarios employing historical data as appropriate.
2. **Assessment of Resources.** Assess existing resources and available supply options, including PPAs and REC purchases, for several generation-specific factors as well as a number of financial factors including rate structures for various customer classes.
3. **Financial Assessment.** Present a strategic direction based on a "simple five-year financial projection" that includes numerous cost and risk considerations as well as 20-year metrics and ratios for testing the financial projection.
4. **T&D System Assessment.** Develop a thorough transmission and distribution plan for improving efficiency (employing 14 T&D measures), including a detailed plan for modernization, together with an implementation plan that minimizes faults and outages and maximizes safety and reliability.
5. **Environmental Impact Assessment.** Demonstrate an understanding of GHG and other toxic emissions, and assess costs related to meeting relevant environmental statutes.
6. **Integrated Analysis and Action Plan.** Through an analysis of cost, generation, environmental impact, and finances that are documented, develop an optimal portfolio of supply and distribution options and a preferred least-cost plan together with a complete implementation and action plan for the short-term (three years) and long-term (starting three years out).

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15 *Op. cit.*; *Appendix B: Guidance for Integrated Resource Plans and 202(f) Determination Requests*; page 5.

SUMMARY OF FINDINGS

We describe in the individual chapters of the 2018 IRP the plans we have for innovative services, transmission & distribution maintenance, and power resource acquisitions to support our goals of a cleaner, more distributed energy system. A key component of any IRP is the "preferred portfolio" to meet future needs at the lowest present value life cycle costs, taking both economic and environmental costs into account as required by 30 V.S.A. § 218c. In Chapter 8, we analyze portfolio choices to arrive at an illustrative future portfolio based upon what we judge to be the most appropriate choices for our customers with the information we have available today.

The notable incremental resource components of this portfolio are:

Acquisition of additional distributed renewables over time, as needed to meet Tier II requirements including appropriate allowance for uncertainty of forecasted supply growth.

A limited mix of hydro (plant-contingent, or firmed) and offshore wind during the 2020s. The hydro resources could lock in a portion of our forecasted Tier I needs; the offshore wind could offer an attractive seasonal output profile and diversity from our other renewable resources. All three resources would have the potential to provide long-term portfolio cost stability after the expiration of major PPAs in the mid-2030s.

Acquisition of additional storage and flexible load resources. This IRP assumes that 50 MW to 100 MW of these resources will be deployed in our territory over the next decade, to address a mix of the potential use cases discussed in Chapter 5: Our Increasingly Renewable Energy Supply and Chapter 8: Portfolio Evaluation.

Ongoing operation of GMP's existing generation plants. We operate a fleet of both peaking and mid-base load generation facilities. Ongoing optimization of these facilities is key to keeping the overall portfolio costs low. Specifically, for peaking plants we recognize the fairly advanced age of our fleet and are assuming retirements of about 30 MW of our peaking capacity during the planning horizon in the mid-2020s and early 2030s.

Manage short-term market price volatility through layered forward purchases. Consistent with the approach discussed in Chapter 5: Our Increasingly Renewable Energy Supply, we plan to continue managing our forecasted open positions through a series of layered short-term purchases of energy and capacity, typically for terms of less than five years.

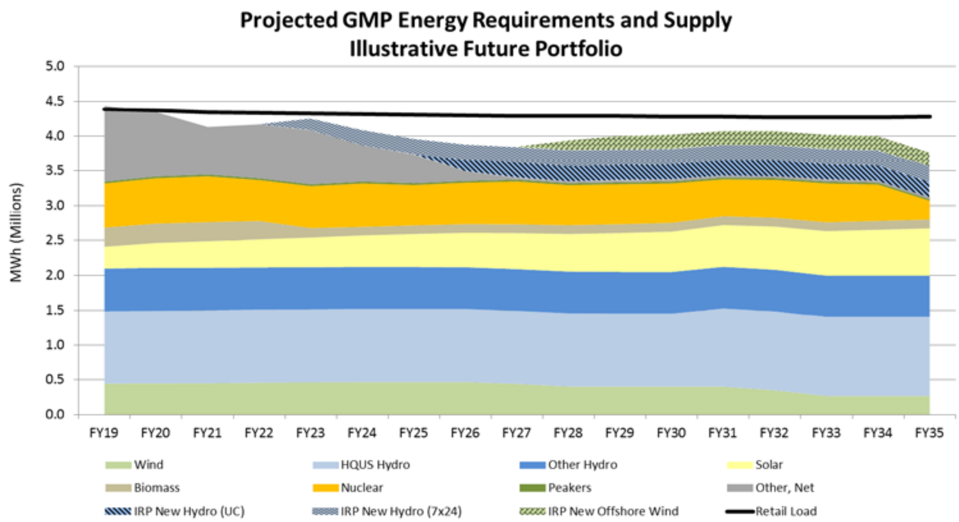

Figure 1-4. Projected Energy Requirements and Supply: Illustrative Future Portfolio

We discuss in Chapter 8: Portfolio Evaluation our preferred choices for capacity resources, as well as how we expect to meet Vermont RES requirements during the planning period. We also analyze the cost sensitivities of these choices, finding that under base case assumptions, our estimated power and transmission costs through 2035 are on the order of $4.86 Billion, with limited opportunity for significant change given our hedged position in the first few years, and substantial long-term and stable-priced resources that protect against potential movements in energy and capacity market prices in later years.

Implementation and Action Plan

Table 1-4 summarizes the action steps we expect will be needed within the planning period to achieve the outcomes we seek for customers through the 2018 IRP.

Functional Area	Activity
Energy Transformation	Develop and deploy an integrated suite of customer offerings that drive carbon out of our total energy consumption, reduce costs for all customers, and improve comfort and reliability: ♦ Expand the Bring Your Own Device program to include more devices and more options for third parties and aggregators. ♦ Deploy energy storage into customer homes and businesses to improve resiliency and reduce cost and carbon for the entire system. Focus on customer options that include third-party integration of resources and additional value for locational benefits. ♦ Transition commercial customers from fossil-fuel-based processes to electricity where feasible and cost-effective to cut carbon. ♦ Develop innovative pricing and rate strategies to encourage and accurately price resources transitioning from fossil fuel to electricity, in a seamless way to benefit customers.
Generation	Invest and maintain our existing fleet of generation while looking for opportunities for acquisition and construction of new facilities to produce long-term value to customers: ♦ Explore acquisition of hydro facilities with a focus on peaking and wintertime capability. ♦ Pair energy storage with existing renewable facilities, or construct new storage-paired systems directly or through other procurement methods.
Power Supply	Maintain a cost-effective, very low-emission supply portfolio that incorporates a large share of long-term distributed renewable resources while retaining the flexibility to address changes in the evolving regional energy market: ♦ Adapt the short-term energy plan to hedge GMP-forecasted energy positions by season using layered, competitive supply solicitations. ♦ Explore the addition of diverse long-term renewable resources to achieve future RES program targets, while reducing reliance on REC-only purchases. ♦ Seek competitive short-term capacity purchases to hedge forecasted capacity requirements in advance of the delivery period. ♦ Evaluate the addition of long-term peak reduction and storage resources to address growing capacity shortfalls and in response to increasing energy volatility.
Transmission & Distribution	Plan the energy delivery system to allow the transition to a distributed, home-, business-, and community-based energy model while preparing the grid for harsher storm conditions: ♦ Leverage the vast data produced by our AMI and distributed energy resources to evaluate our circuits for highest locational value. ♦ Prepare system for the influx of strategic electrification, such as electric vehicles and heat pumps. ♦ Continue to invest in vegetation management programs and innovative solutions to address reliability.
Financial Strength	♦ Maintain strong financial measures and results to ensure strong operational support for customers. ♦ Maintain capital planning focus and discipline in each core area of spending to provide reliable power in this time of climate change.

Table 1-4. Implementation and Action Plan

ORGANIZATION OF THIS IRP

Our 2018 IRP is designed to be accessible and readable to a wide audience, even though its subject can be technical.

IRP Chapters

Chapter 1. Executive Summary describes our company, the statutory and self-imposed goals of our IRP, and our energy mix at a high level, especially from DERs and net-metered generation. It highlights the summary findings of our IRP. It also includes an overview description of our power grid together with specific details regarding our customers, our load, and transmission and distribution system. We wrote the Executive Summary to be a stand-alone document.

Chapter 2. Innovative Customer Programs demonstrates how we continue to empower our customers with a number of innovative energy programs, the multiple ways we communicate with our customers and meet them where they are, and the commitment we have to delivering excellent service.

Chapter 3. Regional and Environmental Evolution discusses regional supply, demand, and transmission developments; environmental impacts, and regional energy markets, prices, and constraints; and how they affect our resource portfolio.

Chapter 4. Declining Electricity Demand forecasts how energy demand will slowly decline in the next decade, despite electrification in heating and transportation, because of the cumulative effect of DERs, net-metered generation, energy efficiencies, and demand response measures.

Chapter 5. Our Increasingly Renewable Energy Supply presents specifics on the evolution of our resource mix away from thermal generation toward a renewable portfolio that meets statutory requirements.

Chapter 6. Transmission and Distribution evaluates our T&D system, discusses our innovative management practices, and outlines our grid modernization and vegetation management strategies.

Chapter 7. Financial Assessments provides information on our overall costs and electricity rates, our financial forecasts, and how we diligently maintain reasonable prices.

Chapter 8. Portfolio Evaluation describes the methods we employed to model and analyze our options to develop a preferred generation portfolio, and the results and conclusions of our analysis, along with our portfolio preferences in the planning period.

Chapter 9. Integration and Action Plan describes the specific action steps for implementing our IRP that considers demand, supply, finances, and transmission and distribution.

IRP Appendices

Included are a number of appendices that support our 2018 IRP:

Appendix A. Glossary and Acronyms defines and describes terms used throughout the IRP.

Appendix B. 2019 Budget Forecast Report presents the actual budget and demand forecast report created by Itron for our use in developing this IRP.

Appendix C. Transmission and Distribution Projects describes all of the completed and in-progress T&D projects that upgrade our system, deliver energy reliably, reduce the potential for faults and outages, and plan for the future.

Appendix D. Vegetation Management includes our *Transmission Right-Of-Way Management Plan*, our *Distribution Integrated Vegetation Management Plan*, and the emerging planning regarding the Emerald Ash Borer infestation.

Appendix E. Substations lists the 13 (out of 185) substations that lie in FEMA-designated 100-year or 500-year floodplains.

2.Innovative Customer Programs

WE DELIVER FOR OUR CUSTOMERS

We are partnering with customers on the energy changes they want to make, while we remain focused on delivering reliable power, excellent service, and innovations that cut carbon and drive down costs.

All of our deliberations and all of our decisions consider what is best for our customers. The innovative programs described in this chapter all are designed to meet the grid modernization opportunities discussed earlier, the imperatives of climate change, and the desires of our customers. These programs help:

- Stabilize and lower customer bills—to participating customers as well as non-participating customers.
- Reduce and time-shift peak demand, helping to keep our thermal, environmentally unfriendly peakers offline and reducing high-cost energy.
- Empowering our customers to take control of their energy usage, enhance their in-home comfort, and reduce their carbon footprint.
- Engaging customers in new ways, providing more transparency and participation in their own energy consumption.
- Enabling customers to have a meaningful impact on reducing Vermont's overall carbon footprint.

We also work to reduce wholesale market costs (particularly at peak demand) to create downward pressure on rates. We open the door to allow customers to go off-grid, and make available opportunities for customers to generate their own power.

Beyond 2018, in continued partnership with our customers, we will work to lower costs through innovation, synergy savings, and efficient operations to attain the new energy future we all seek.

Leading this important transformation through innovation is critical to discovering and delivering ways to lower the cost of maintaining the power grid, while continuing to provide superior customer service. Our culture of innovation, paired with a lean and effective operating approach, gives us confidence during this time of challenging transition.

Partnering with the strong team of Vermont energy leaders, we will continue to navigate and accelerate the transformation to a home-, business-, and community-based energy system that creates broad socio-economic prosperity and positive climate outcomes for the customers we serve.

We are greatly concerned with climate change and the impact fossil fuel use is having on our planet. That is why our energy supply is 60% renewable and 90% carbon free. We are also offering energy transformation opportunities to help customers cut carbon at home, at work, and on the road.

OUR OBSESSIVE APPROACH TO CUSTOMER SERVICE

At Green Mountain Power, we embrace a culture of customer obsession—customers are the focus and North Star of everything we do. We are always thinking of ways to improve the customer experience, from delivering on energy transformation options to leveraging technology. Our overall goal is to be able to communicate with customers in the manner they choose, and to continually exceed their expectations during our interactions.

Our philosophy of customer obsession means we constantly assess our performance and identify ways we can improve—despite routinely exceeding service quality standards. As such, we track our performance and communicate it with our employees. Through that effort, we have maintained our focus on customers over the past several years and continue to yield extremely high satisfaction levels.

We do not pursue awards or recognitions—we simply conduct business with focus and integrity. Nonetheless, we have been recognized for excellence in customer service, innovation in partnership with customers, and leadership in this critical energy transformation.

Fast Company #1 in Energy Innovation

Earlier this year, *Fast Company* Media named Green Mountain Power #1 on its list of the Top 10 Most Innovative Companies in Energy.

MOST INNOVATIVE COMPANIES

Green Mountain Power

FAST COMPANY THE WORLD'S MOST INNOVATIVE COMPANIES 2018

If you want to go fully off the grid in Vermont, the local utility--Green Mountain Power--will help. In a first-of-its kind service, the utility offers an energy-efficiency audit, suggests solar and battery technology, and then charges a flat monthly fee. Those who want solar and battery storage but want to stay connected to the grid can also work with the utility, which offers products like the Tesla Powerwall 2 in monthly billing rather than an upfront fee. By adding batteries to individual homes, the grid gets stronger--in times of peak demand, rather than turning on an extra power plant, the utility can draw from the network of batteries and avoid emissions. Green Mountain Power was also the first utility to be certified as a B Corporation, meaning it meets rigorous standards for social responsibility.

Figure 2-1. Fast Company's Green Mountain Power Article

The list honors leading enterprises and rising newcomers that exemplify the best in business and innovation. As part of its rankings, Fast Company releases the "Top Ten Most Innovative Companies" in the world in 36 separate categories from artificial intelligence to wellness. This year, we ranked #1 in Energy, up from #8 last year.

While we are proud to be among the distinguished innovators recognized by Fast Company, we are prouder of the fact that our innovations come directly from our love of our customers and our obsession with their values and their desires for a low-cost, low-carbon and highly reliable future. We are also inspired by how many companies are embracing innovation and are working to make meaningful change in the energy space.

Our mission focuses on a new way of doing business—helping people use less energy, save money, and dramatically cut carbon emissions, essentially improving lives and transforming communities. The other companies Fast Company selected—including Apple, Netflix, and Square—pursue goals similar to ours. They explore ideas and projects that excite people and enhance the way they live. That's what drives most innovation at GMP along with a nice healthy dose of respect for the Vermonters we serve.

JD Power's #2 in Customer Satisfaction

In J.D. Power's 2018 electric utility residential customer satisfaction study, customers ranked us second highest for mid-sized utilities in the East Region of the country. We have achieved a high ranking three years in a row, demonstrating a strong record of continued excellence. Our results have risen every year over the past six years. In 2012, before merging with CVPS, the J.D. Power satisfaction score was 602. Our score has grown ever since: from 619 in 2013, to 626 in 2014, 656 in 2015, 681 in 2016, 707 in

2017, and 722 in July 2018, the most recent survey date. This is an increase of 19.93% since 2012.

The J.D. Power report results come directly from customers. Companies in the midsize utility segment serve between 100,000 and 499,999 residential customers. The study measures customer satisfaction with electric utilities by examining power quality and reliability, customer service, cost, billing, corporate citizenship, and communication.

Service Quality and Reliability Performance

In 2014, together with the Department of Public Service, we developed performance standards in the Service Quality and Reliability Performance, Monitoring, and Reporting Plan (SQRP), approved by the Public Utilities Commission.

The SQRP incorporates minimum standards for key service measures linked to customer satisfaction. Our standards cover a wide variety of important performance categories, from call answering and meter reading to billing, reliability, safety, on-time performance, and customer satisfaction. Each category is tracked through specific performance measurement metrics.

We regularly report on our performance under the SQRP. Without exception, we have met every SQRP standard for each quarter since the beginning of 2015. In many cases, we exceed the SQRP standards by significant margins.

High Customer Satisfaction

We also set internal goals and standards that are higher than those included in the SQRP. Research America, an independent survey service provider, quarterly and annually surveys our customers to evaluate our overall performance and customer satisfaction. We find these are invaluable tools to help us find patterns or problems, tweak training when necessary, and address any customer concerns.

Customers continue to be extremely satisfied with our service. Research America surveys find customer satisfaction routinely over 90% quarter after quarter, and year-end satisfaction in 2017 at an astounding 95.6%. Satisfaction has remained steady and high over the past four years.

And we have earned our customers' trust. Last year, when asked about their recent contact with us, 98% of customers said they were satisfied with employee courtesy and 97% felt our employees were very knowledgeable.

Measuring Customer Service Standards

Though the SQRP standards are generally measured quarterly and monthly, we seek to meet our higher internal customer care standards on a weekly, daily, and even hourly basis.

Our internal standards are high because we are committed to exceeding customer and regulator expectations and maintaining a performance level well above industry standards. To better remain vigilant and focused on improving customer experiences, every year, we set higher and higher standards—and each year, we attain them.

Every week, we measure and review these standards during a companywide conference call, as well as reviewing Research America's quarterly results. We email these SQRP measurements, the Research America results, and our higher internal goals to every employee weekly—highlighting our customer-oriented obsession. It's through this constant measurement, dissemination, and discussion that we are able to continue to drive progress and incredible outcomes for customers.

Customer-Centric Projects

We continue to develop and implement capital projects that improve customer access and communication. Here are three that will be implemented in the next planning period:

The Commercial and Industrial customer data access portal project will enhance our website to enable commercial and industrial customers to access their accounts and create customized reports to track their usage and costs. Currently, this is a time-consuming manual process that also involves our staff. When the project is completed, C&I customers will be better able to track their energy costs, which can help them achieve their efficiency objectives and control costs.

The customer alerts and communications project will expand text and email alerts to include bill reminders and usage alerts. This will encourage more customers to enroll in text and email alerts, and be more empowered to manage their energy use and costs.

The GMP website project will upgrade and enhance aspects of our website to improve the user interface and general functionality, adding more payment capabilities as well as outage and safety information.

We have a robust process for documenting our rationale for implementing capital projects, incorporating lessons learned, to ensure a strong, secure, resilient power grid that supports the two-way flow of energy and data. (For details on this process, see "Capital Investments Across Six Core Operating Areas" on page 7-4.)

Reliable, Innovative, Cost-Effectively Priced Service

We have delivered on our promise to provide innovative, safe, and reliable services for our customers. While some other states have seen the effects of slow utility storm recovery, our outage duration and frequency numbers are consistently among the lowest in the region.

We strive to maintain stable and affordable rates despite rapid changes and profound challenges in the energy landscape. We have assiduously invested in our state's critical energy infrastructure whenever needed through VELCO, and our electric rates are third lowest overall in New England.

Merger Commitments

We continue to meet our merger commitments.

We merged with the largest utility in the state in 2012, determined to invest in reliability and system improvements that had been deferred by them and create important savings for all of our customers. We promised higher service quality and $144 million in customer savings over 10 years, and we are on track to deliver significantly more.

In addition, we committed to reduce outage durations by at least 10%. Since 2012, the duration of our Customer Average Interruption Duration Index (CAIDI) measuring outages has already been reduced by 6.2% excluding major storms and 13.5% including our highest impact, major storm events. We are very proud of these results.

EMPOWERING CUSTOMERS TO ACCELERATE THE NEW ENERGY FUTURE

As you read through this IRP, it is important to understand the overarching vision that we are pursuing on behalf of not just our customers, but all Vermonters and beyond. We refuse to sit idly by while the planet continues to heat up to the point of no return. Vermont may be small, but we can be a leader and example of how to transform the energy delivery system to consumers—be it transportation, home heating, or even business processes, in a way that significantly reduced carbon emissions in each area.

With this in mind, we have embarked on a vision of transforming the traditional energy delivery system to one that is highly distributed and ultimately one that relies on the choreography of millions of discrete points, instead of the original path of large generation supply resources and thousands of miles of transmission connected to customers.

Vermont has made amazing strides toward a distributed energy model with the deployment of solar PV systems throughout the state. On a given spring day, we could actually be meeting a sizeable portion of our total customer demand from local, distributed, solar energy. As we push further into a distributed energy model, the level of intermittency—or 'wobble' as it is described in Chapter 8: Portfolio Evaluation—will continue to increase, which ultimately requires the need for flexible, fast-action resources that can be manipulated in a way to counter this intermittency and create an efficiently utilized and high-quality local energy system.

In addition to the intermittency management, strategic electrification of fossil fuel laden processes (such as transportation or home heating) could create new increased peak energy demands if not managed. For this reason, we have jump-started our expertise in managing a fleet of flexible demand resources in connection with various tools, such as the software platforms that are utilized to manage these resources. It has been extremely valuable for us to build up this expertise and library of resources in the early stages so that we can begin to expand and encourage the marketplace to provide these values in innovative ways. Our Bring Your Own Device program (described on 2-16) is intended to spur this opportunity by sharing the value that these flexible devices deliver with both the participating customer as well as all non-participating customers to achieve our vision of reducing carbon while also reducing cost for all customers.

To deliver on this vision, we are partnering with customers to transform their homes and businesses by participating in several energy innovation pilots that help us conserve energy, reduce costs, balance load, increase reliability, and drive down future grid costs.

In the past, the peak energy demand times would occur when air conditioning load was at its peak in the middle of the day, but increasing amounts of solar PV has shifted daily peak to later in the day. Because solar produces its greatest output in the middle of the day, it directly offsets these higher consumption times, thus reducing the daytime peak demand. Vermont now typically sees its peak energy demand occurring well after 5:00 PM, with our highest peak energy consumption occurring in the winter after dark.

Here are the innovative programs that we currently offer, and that are highlighted on our website:

- Tesla Powerwall 2.0 Battery Pilot
- Remote Water Heater Access Innovative eWater Pilot
- Cold Climate Ductless Heat Pump Pilot
- Electric Vehicle e-Charger Pilot
- Bring Your Own Device

We also offer a number of programs that enable our customers to conserve and better manage energy, including: Nissan LEAF purchase discounts, Chevrolet Bolt purchase discounts, eControl remote heat pump control, low-income EV rebate, and heat pump and heat pump water heater financing. All of these are in addition to our smart and dynamic rate offerings, including Time of Use and Critical Peak Pricing riders, that allow customers to save money by directly managing their usage.

Tesla Powerwall 2.0 Battery Pilot

Tesla's Powerwall 2.0, a 13.5 kWh lithium-ion battery with an integrated inverter, is the industry's premier small energy storage system. Our Tesla Powerwall Grid Transformation Innovative Pilot—a first-of-its kind program—benefits participating customers by increasing their personal energy reliability as well as non-participating customers through lower reduced system-wide energy costs.

Figure 2-2. Satisfied Powerwall Battery Owners

In this Pilot (which started mid-summer 2017), we offer 2,000 Powerwall 2.0 batteries to any residential customer, 100 of which are available to eligible low-income customers at no cost through a grant. While customers who own Powerwall batteries experience direct benefits, all of our customers (those participating and those not) benefit from the program's many realized advantages. This program is now fully subscribed.

Tesla Powerwall 2.0 batteries provide eight to twelve hours of backup power like a standard generator, turn on seamlessly, are cleaner than fossil fuel driven generators, produce zero on-site emissions, are quiet, and require no maintenance whatsoever. They can be charged from power off the grid, or with a customer's own home solar array.

Customers participate in the Pilot for $15 a month for ten years or a $1,500 one-time fee. They then receive backup power to their home for at least the next decade, which eliminates the need for traditional, fossil-fuel-fired backup generators. These monthly and one-time fees are only a limited fraction of the all-in cost of purchasing and operating the Powerwall 2.0 batteries. We are able to offer these prices to participating customers because, under the terms of the program, the Powerwall batteries can be dispatched to reduce wholesale costs (particularly peak-driven costs). Those estimated savings are shared between participating customers (through a monthly price) and all of our other customers (through lower power and transmission expenses).

Customers who install the Powerwall 2.0 batteries can store their own energy to power their homes during an outage. Those customers with solar installations can create their own energy island, and power their homes even longer during an outage. In addition to this Powerwall Pilot, customers could, under one of our multiple time-of-use plans, purchase a battery directly and use stored energy during higher priced times and use grid-supplied energy during off-peak times.

A $150,000 grant from the Vermont Low Income Trust for Electricity (VLITE) pays for the cutting-edge technology and its installation in the homes of low-income customers with significant need for backup power reliability because of health and mobility issues. We offer this opportunity to 100 qualifying customers.

This Pilot is unique in the industry. Using Tesla's software platform, we can aggregate the 2,000 Powerwall 2.0 batteries to reduce system-wide peak load by 10 MW—the equivalent of removing about 7,500 homes from the grid. This directly lowers costs for all customers. We use the aggregated Powerwall 2.0 batteries to:

- Store energy when it is abundant and dispatch it at peak times when it is most expensive. This results in significant transmission (regional network service) and capacity (capacity supply obligation) savings and other ancillary market revenues that will be split between participating and non-participating customers (like any classic demand response resource). Even this relatively small capacity of peak control has the potential to save customers over $2 million over the life of the program.
- Deliver dynamic capacity (energy reserves that can be dispatched when they are needed most) to provide additional grid stability for all customers, especially in areas with significant distributed generation penetration.
- Potentially avoid or reduce the scope of future transmission and distribution-related upgrades and mitigate impacts of high-penetration intermittent resources.
- Increase resiliency, and create strategic storm response plans that will account for the distribution of these resources, potentially decreasing storm restoration costs.
- Reduce the carbon content of the regional grid during the most carbon-intensive peak events.
- Provide a dynamic reactive power resource that can manage voltage or reduce the flow of reactive power across the delivery system.
- Gain operational experience building, operating, and maintaining a control platform that enables aggregated dispatch of thousands of distributed energy resources, preparing us for third-party involvement in energy platforms.

The software enables us to operate the battery units individually, as an entire fleet, or in specific groupings as needed for a local benefit. In addition, services offered through the software platform can generate new revenue streams through participation in ISO-New England's energy market, operating reserve market, and frequency regulation market.

This Pilot is a core part of our proactive approach to respond to the cost pressures of declining sales, increasing regional transmission and capacity costs, and increasing net metering cost pressures that are impacting the entire New England region. Our strategy is to directly confront these external pressures that are out of our direct control. We are working to reduce our share of transmission and capacity costs via radical peak management that includes, among other things, shared access to devices like the Powerwall batteries. Dispatching them during peak times in a way that is imperceptible to participants helps lower costs for all customers.

In addition, we use Tesla's software platform to better manage distribution system voltages and power quality. We must continually develop new solutions to better manage a power grid that continues to transition to highly distributed, variable energy sources. To achieve this, we must rely more and more on DERs that can provide very fast response to fluctuations on the distribution system. This requires a control platform that can choreograph all the resources and provide the optimal value depending on the location. As the amount of DERs continues to grow, the challenge becomes one of scaling up and automating the management of these energy resources to assure the highest and most efficient use at any given time. This Pilot, with the support of the team at Tesla, includes the development of algorithms to automatically operate the energy resources to the maximum benefit for customers to drive down costs.

In total, the Powerwall batteries in this Pilot become both grid and customer assets. They decrease regional transmission and capacity costs, generate other revenues through participation in ancillary services markets, bring in new revenue for non-participating customers, and increase reliability.

In the future, (and as repeated through this plan), we envision battery energy storage and flexible demand resources as a key tool for managing the future distributed energy system. We provide more detail on our forward-looking storage strategy in Chapter 8: Portfolio Evaluation, however, some of the highlights are that we will continue to offer storage directly to customers while also creating a market-based platform through the Bring Your Own Device approach, where third parties or aggregators can plug storage, or other flexible demand devices, into our platform creating value for the host customer as well as all customers on our system. Chapter 8 provides further detail on the specific use cases that we see for battery storage, and the relative scale and pace of deployment that we believe makes sense for our customers.

Remote Water Heater Access Innovative eWater Pilot

This Pilot enables shared access to a customer's electric resistance water heater.

To participate in this Pilot, customers receive a small, easy-to-install retrofit kit manufactured by Aquanta. That kit enables us to share access to their water heaters. Through this access, we can turn customer water heaters on and off (with opt out capability), or adjust the temperature up or down, in response to system needs. This Pilot enhances our previous water heater access program (which is less flexible, only enabling load reductions) in which 16,000 customers are enrolled.

Figure 2-3. Remote Water Heater Access eWater Pilot

The device itself is an electrical component that installs directly onto an electric resistance water heater, and communicates with both the customer and us via the customer's Wi-Fi internet connection. The device ensures customers remain comfortable by establishing high and low temperature settings; if the water heater's temperature falls below the low setting, it automatically turns back on. Customers can also turn their water heaters down when leaving for vacation, then turn the water heater's temperature back up remotely before they arrive home. Participating customers also receive a Nest smart thermostat as a way to increase their energy savings. As part of this Pilot, Nest offers voluntary enrollment in their Seasonal Savings program. This program adjusts the thermostat's temperature within a pre-defined limit of degrees, further reducing energy costs. Customers can also control the thermostat remotely.

We expect to enroll 400 customers in this Pilot by the end of 2018. There is no cost for participating customers. As an incentive for participation, customers can choose to receive a Nest smart thermostat, six smart LED light bulbs, or a donation in their name of equal value into the state's Warmth program.

The Pilot enables us to better manage a power grid that is inexorably transitioning to variable renewable generation and DERs. Through the Pilot, we can turn off or turn down water heaters during peak demand, thus reducing the cost of energy to all our customers. We also anticipate that this two-directional capability will enable additional cost savings by increasing water heating during periods when energy market prices are unusually low, and decreasing water heating when energy market prices are temporarily very high, essentially using the water heater as a thermal battery. The Pilot also provides the means to store solar energy in the form of hot water from peak solar generation times to be dispatched later, essentially utilizing a water heater like a large thermal battery.

Smart thermostats reduce carbon emissions by making heating (and in some cases, cooling systems) more efficient to operate. This benefit not only helps meet Vermont's goal of reduced greenhouse gas emissions, but also provides another resource for meeting RES Tier III requirements.

Electric water heaters are an excellent form of energy storage that already exist in tens of thousands of homes in our territory. We plan to transition this pilot into a tariff offering, for customers, terms which will be based on the results of the data collected and analyzed from the pilot period. As with all of our offerings, we believe that customers should have a choice in how to procure their equipment; therefore, we will offer water heater controls both directly and through the BYOD platform where customers can procure their own systems through a third-party provider and integrate it with us.

Through our traditional water heater control program, we know that 16,000 controlled water heaters yield roughly 3 MWs of peak reducing value. With this number in mind, we believe that there is an additional opportunity of about 3 MWs of controllable water heater value in the residential and small commercial installations. As with any customer-side flexible resource, we must balance the value that the resource provides against the share of that value provided to the participating customer. The higher the incentive, the higher the uptake—but the lower the benefit to non-participating customers. The pilots allow us to find that sweet spot and get the greatest amount of resource possible. Because this new water heater control platform allows for greater flexibility than the traditional on-off only water heater control, for customers that are currently on our Rate 03, we will look to explore the opportunity to transition those existing Rate 03 customers to this new platform over the next year.

Cold Climate Air Source Heat Pump and Heat Pump Water Heater Pilot

A cold climate heat pump is much cleaner and more efficient compared to oil or propane systems, and doubles as a cooling system in the summer. Ductless models excel in cold climates like Vermont's. Heat pump water heaters reduce your energy costs as well when replacing a fossil fuel or electrical resistance water heater.

Figure 2-4. A Customer with Their Ductless Heat Pump

Our Cold Climate Air Source Heat Pump Pilot and Heat Pump Water Heater are also a resource toward meeting our carbon reductions for RES Tier III. We partnered with VSECU to offer customers attractive financing options for purchasing heat pumps and heat pump water heaters. Customers can finance their heat pump and heat pump water heaters along with installation through VSECU's affordable VGreen loan program, which offers flexible down payment, monthly payment, and loan term options. Customers also have the option of purchasing the equipment outright through a private company. Either way, customers receive a Sensibo Sky control device free of charge with their heat pump. This device gives the customer the ability to remotely control their heat pump over their smart phone as well as provides us the ability to access the heat pump.

Figure 2-5. Sensibo Heat Pump Control Device

After installing the Sensibo app onto a smartphone, a customer can program their heat pump to pre-cool or pre-heat their home based on the time of day. Customers can also put their heat pump on a schedule, which has the potential to save even more money.

This eControl program is another way we partner with our customers to reduce peak energy demand–such as on hot summer days when energy is expensive. By enrolling, customers agree to allow us to adjust their heat pump (or air conditioner) up or down a few degrees when demand is high and energy the most expensive. We make this adjustment for, at most, one to three hours, six to eight times a month. During these times, we alert customers via their smartphone that we need to adjust their heat pump or air conditioner. Customers can opt out if they wish. Changing the temperature of all devices enrolled in the eControl program, even by a few degrees, helps reduce peak energy demand, which creates savings for all customers and lessens the impact to the grid.

We work closely with customers to ensure they receive the most benefit from participating in the Pilot. Through an onsite visit with a qualified assessor, we help customers determine how best to participate in the program, educate customers about heat pumps, help decide where best to install the unit, walk them through the financing process, and then schedule an installation with one of our trusted installers.

Once installed, we consult with customers on how to use the control device to gain maximum benefit. Then, annually for the first seven years, we service their heat pump to ensure the unit is operating at maximum efficiency.

Along the way, we will be assessing this Pilot to determine how the new financing affected participation levels; how annual servicing affected a heat pump's operation; how working with third-party partners could be employed in other pilots; how effective were heat pumps as distributed energy resources; and how controlling these grid assets through our DERM platform lowered energy costs and reduced peak demand periods.

Water heaters consume a lot of energy; traditional electric resistance usually cost about $400 annually to operate. A heat pump water heater operates more efficiently, costing about half as much to operate, saving more than $1,400 over the unit's lifetime. Heat pump water heaters operate at 550 watts, while standard water heaters operate at 4,500 watts. Besides saving money every month on an energy bill, they also reduce carbon emissions.

Figure 2-6. Heat Pump Water Heater and Dehumidifier

Heat pump water heaters absorb naturally occurring heat from the surrounding air and transfer that captured heat to the water. Through this water heating process, they also remove moisture in the air—essentially acting as a dehumidifier—that helps your basement stay nice and dry. This results in lower electricity use and energy cost savings.

Our customers can obtain affordable financing through our partnership with VSECU. This financing features low fixed-rate interest and flexible payment options, and covers the cost of the unit and its installation. In addition, customers can receive a rebate of up to $500 off the purchase price through Efficiency Vermont.

We will continue to directly offer cold climate air source heat pumps and heat pump water heaters to customers through a variety of offerings. This includes a proposed tariff currently being reviewed by the DPS to offer the Heat Pump and Heat Pump Water heater directly to customers, as well as a continuation of the VSECU program.

Electric Vehicle e-Charger Pilot

This Pilot offers up to 300 customers a free Level 2 electric vehicle charger as an incentive to purchase a new all-electric or plug-in hybrid electric vehicle. Customers who already own a qualifying EV can also participate in the Pilot for a low monthly fee. Customers are responsible for installing and commissioning their EV charger.

Customers participating in this Pilot as well as all other customers who already own an EV charger can enroll in our EV Unlimited plan. This plan encourages unlimited off-peak charging for up to two EVs for a flat monthly price for each EV. We notify customers between 8 and 24 hours before a peak demand event. Customers who elect to opt out and charge during a peak demand event are

Figure 2-7. Level 2 Electric Vehicle e-Charger

billed a higher per-kWh fee.

In exchange for participating in this Pilot, customers agree to allow us access to their EV charger so that we can manage and reduce demand during peak energy usage, saving money for all our customers. In addition, we project that 90% of all Pilot participants will purchase a new EV, thus contributing toward our annual RES Tier III goal.

This pilot not only provides valuable data on how EV charging functions on the delivery system, but also sets us up very early on to manage what could be a substantial additional peak demand if left unmanaged. By providing smart charging equipment and integrating into the energy management platform, we are able to not only mitigate the demand impacts, but also potentially extract further value through energy arbitrage or other similar benefits for customers. In Chapter 4: Declining Electricity Demand, we provide greater detail on sensitivities that we reviewed about the deployment pace of EVs.

The e-Charger Pilot will come to an end at the beginning of 2019. We are planning to transition to an EV Tariff that will allow customers who prefer it to pay a flat fee rate for 100% renewable energy charging. We will also continue our Tier III charger program and look for ways to enable greater electrification through altering demand charges or time-of-use rates to encourage deployment of EV infrastructure. The range of potential outcomes in the EV space is quite wide which is why we ran a low, base, and high case sensitivity analyses for EV deployment trajectories and how each will impact energy and demand on the system. All signs point to the importance of a strong control and shared access management program.

Bring Your Own Device

A goal in all of our piloting has been to learn fast and expand in a way that helps the marketplace provide solutions to customers, together with us. This led us to develop the Bring Your Own Device program.

This program allows customers to connect their energy storage devices to the grid and receive credits on their energy bill in exchange for allowing us to dispatch their system. By enrolling in the Bring Your Own Device program, customers allow us to use their connected device to reduce the amount of energy that their home or business is consuming at that moment, or shift the time that the energy is used. Both help us better manage the grid transformation toward distributed renewable generation and minimize energy peaks, reducing the highest-costing energy, which reduces costs for all customers.

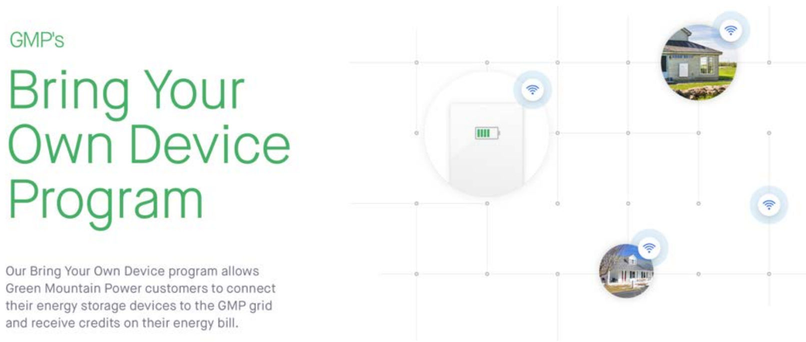

Figure 2-8. Bring Your Own Device Energy Storage Program

The program allows our customers to independently purchase their own battery energy storage solution from one of Vermont's energy solution providers. Currently, the eligible energy storage devices are the Tesla Powerwall 2.0 battery, SolarEdge StorEdge compatible storage systems, Sonnen battery storage system, and Sunverge battery energy storage system. We will evaluate the commercial options available to customers throughout the Pilot period.

Monthly bill credits depend on the amount of stored energy we use to moderate peak demand. The amount of energy we apply ranges from 2 kW to 5.9 kW, to which customers receive a monthly credit ranging from $14.50 to $36.00.

We plan to expand our Bring Your Own Device platform beyond just batteries and wrap in other flexible demand devices that we have proven add value through our other pilots. This will include flexible resources such as water heater controls, level 2 EV chargers, and thermostats. Opening the platform to these devices increases a customer's option for obtaining compatible devices, while helping us take advantage of additional distributed resources that are increasingly important to dynamically managing the grid and reducing costs for all customers. And most importantly, it provides a very simple way for the customer or provider to integrate the device with our system.

In addition to the standard value sharing provided for peak reduction, we will be piloting an expanded Bring Your Own Device platform that includes additional value based on the locational needs on the distribution system (such as in a heavily solar-saturated area). While it is not yet clear how upgrades to solar-saturated distribution circuits should be handled, we do believe it is worthwhile to pilot the Bring Your Own Device program with an added incentive when a system is sited in one of these areas and can be used to absorb excess solar generation during the middle of the day, to determine the overall effect on this problem.

Enabling Customer Energy Conservation and Management

We currently offer several programs that enable customer to conserve and better manage energy: Nissan LEAF purchase discount, Chevrolet Bolt purchase discount, low-income EV rebate, eControl remote heat pump control, and heat pump water heater financing.

Here are descriptions of our current offerings. We plan to evaluate and add similar programs throughout the next planning period.

Nissan LEAF Purchase Discount

The 2019 Nissan LEAF's driving range is about 150 miles on a single charge, making it an attractive option for local driving as well as a way to reduce automobile emissions.

Figure 2-9. Nissan LEAF All-Electric Vehicle

Through a partnership with Freedom Nissan (South Burlington) and Nissan of Keene, New Hampshire, our customers and employees can choose from two incentives to purchase a 2019 Nissan LEAF electric vehicle: receive $5,000 off the manufacturer's suggested retail price or 0% annual percentage rate financing for up to 72 months. To sweeten the deal, federal tax incentives of up to $7,500 could result in an overall saving of up to $12,000. Customers or employees who choose the $5,000 price reduction are also eligible to apply for a Green Vehicle Loan from VSECU (a statewide credit union). This loan offers lower fixed interest rates, flexible terms, and online and mobile payment options.

Chevrolet Bolt Purchase Discount

With a 238 mile driving range on a single charge, the Chevrolet Bolt makes an option for people wanting to save money on gas while having a positive effect on our environment.

Figure 2-10. Chevrolet Bolt All-Electric Vehicle

Through our partnership with Alderman's Chevrolet in Rutland, our customers and employees can receive General Motors employee discount pricing on the all-electric Bolt and the plug-in electric hybrid Volt. Customers and employees can also take advantage of other Alderman incentives, as well as federal tax incentives of up to $7,500.

As with the LEAF, customers or employees are also eligible for a Green Vehicle Loan from VSECU.

Low-Income EV Rebate

This program is yet another way we are creating incentives for customers to reduce their carbon footprint. Qualifying low-to-moderate income customers can receive a $600 rebate when purchasing any new electric vehicle with a price tag of less than $50,000. Customers simply complete a rebate form and send it to us. If they qualify, we send them a $600 check.

Innovation During the Planning Period

To reiterate, the overarching purpose of these pilots has been to build up a library of resources that will be critical in allowing us to transition the energy delivery system to one that is heavily distributed, significantly less carbon intensive, highly reliable, and lower cost. As Tier III of the RES statute lays out, strategic electrification will be a major contributor toward achieving our carbon targets. At the same time, we will need to employ the appropriate level of technology to mitigate any adverse impacts such as exacerbating peak demand in the winter. Our pilots have built up the toolset to allow this, whether through direct control of the resource or by offsetting the impact of peak through other resources like batteries.

Over the IRP planning period, we will be offering battery storage directly to customers either bundled with other goods and services or standalone. We will also offer control devices for various resources along with the smart EV charging equipment. Equally as important will be the expansion of the Bring Your Own Device program where any third party can integrate certain flexible assets into our platform and tap into the various market values that are available through us, while providing a value to all customers. We plan to further expand Bring Your Own Device by testing out locational incremental value in areas such as high solar PV penetration locations on the distribution system. While it is not yet clear what ability we have to manage the increase of solar saturation through solar hosting capacity, we do believe it is an appropriate test of the Bring Your Own Device pilot to see what types of solutions come forward and what their ultimate costs are. Success in these programs would look like the addition of 10 MWs of flexible demand resources over the next three years with at least 3 MWs able to provide multiple benefits such as adding locational value.

COMMUNICATING WITH OUR CUSTOMERS

Part of partnering with our customers and delivering the best service means we have an ongoing conversation with them to share as much information as we can about what we are doing and why we are doing it. From safety tips and weather information leading up to storms, to outage restoration work updates, to exploring new innovations to help customers cut carbon and costs, we regularly use multiple media platforms to reach all of those we serve.

As a reliable energy partner, we communicate with our customer in myriad ways, which allows them to connect with us in the way they like best. Customers can choose to access our integrated voice response phone system (which employs interactive voice response (IVR) technology to automate most transactions) or to speak directly with a customer care representative. We operate walk-in service centers at our Colchester headquarters, at our Rutland operations headquarters, and at dozens of retail locations across the state.

We offer self-service functions on multiple platforms, including text, our mobile app, and our website. In addition, we routinely communicate with customers, including individually, through email and social media, including Facebook and Twitter. Before storms hit, we communicate through text alerts, social media, press releases, and website updates to ensure customers are well informed. During major storm events, we make outbound calls and employ door-to-door outreach in many cases. Almost 37,000 customers have enrolled in text alerts; that number grows by about 200 per week.

Our new web-based self-service functions allow customers to change billing addresses, set up payment arrangements, stop service at their convenience 24 hours a day, as well as many other tasks. Over 45,000 accounts are enrolled in automatic recurring payments (increasing by 50 to 75 weekly), and over 50,000 have downloaded our mobile app (increasing by about 300 weekly).

We continue to encourage the use of paperless billing, online accounts, and automated recurring payments, for ease of use to customers and to cut back on costs. We currently have approximately 54,000 accounts enrolled in electronic billing; this amount grows by 100 per week. Mailing paper bills costs about 51.5¢ per month per mailing; thus each account receiving an electronic bill saves $6.18 annually, for a cumulative total of well over $309,000 a year.

Any enrolled customer can view detailed information online about their own energy usage and load profiles, to help educate themselves about their costs and ways to manage it.

These technological investments enable us to better interact and communicate with our customers, improve efficiency, and play a critical role in our success with customer satisfaction. We are constantly looking for new ways to reach our customers and facilitate improved communications.

Social Media and Local Area Electronic Information Boards

Social media plays a critical role in reaching customers, especially during severe weather. We can broadcast key info, which customers share, plus we can answer customer questions in real time.

Facebook

We have about 22,000 followers on Facebook. They are an active community, making it a great way for us to share news about storms and answer questions as the situation develops. For example, Figure 2-11 shows our Facebook post about a storm update; Figure 2-12 shows the ensuing dialog of our Facebook community.

Figure 2-11. Storm Update on Facebook

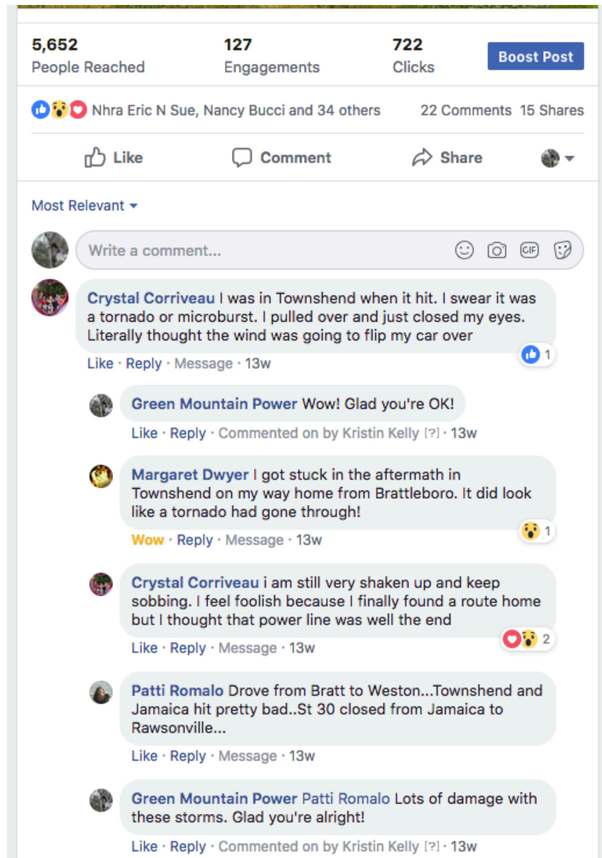

Figure 2-12. Facebook Community Storm Comment Stream

We also engage with customers about our innovative programs, using static posts and Facebook live. For example, Figure 2-13 shows our Facebook post to promote the federal tax credit on the purchase of a 2018 Chevy Bolt 100% electric vehicle. We have also used Facebook to promote our other innovation programs, such as the free in-home Level 2 charger.

Figure 2-14 depicts our Facebook post promoting a 30-minute "Ask An Expert" segment on electric vehicles with questions from followers and answers from the experts, which can be viewed through this link:

https://www.facebook.com/GreenMountainPower/videos/316496345780742/

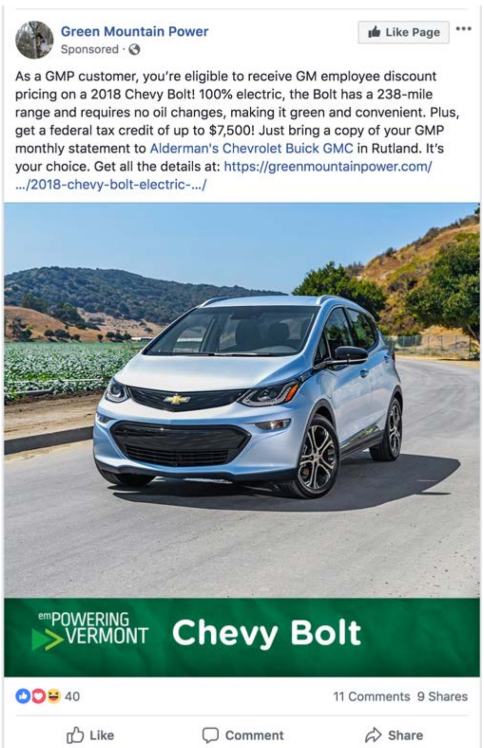

Figure 2-13. Chevy Volt Facebook Promotion

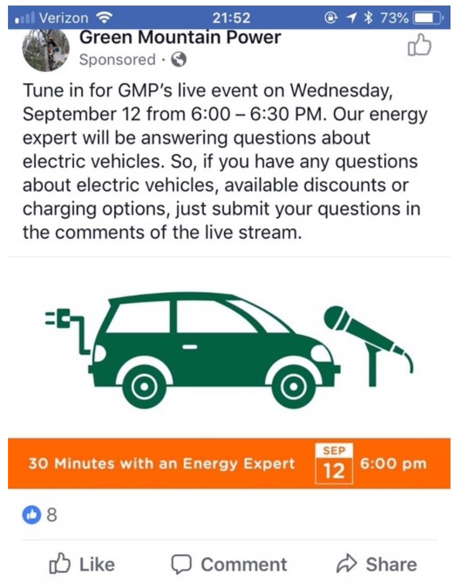

Figure 2-14. Facebook Post Promoting an "Ask An Expert" Segment

Twitter

We amplify our Facebook messages by posting the same or slightly abbreviated information on Twitter. Our Twitter following is smaller than Facebook, however we reach a different group of customers.

Front Porch Forum

We post monthly on Front Porch Forum in communities around the state—an extremely localized bulletin board. The information we share usually has tips to save money, cut carbon emissions, or increase safety or convenience. We also provide updates about impending or ongoing major storm events. Figure 2-15 depicts a post about helping customers save money by enrolling in our program to reduce peak demand.

Want to Help Crush the Energy Peak and Save Money?

GREEN MOUNTAIN POWER, CALLCENTER@GREENMOUNTAINPOWER.COM, ACORN LN, COLCHESETER

ANNOUNCEMENT

The time is now!

Forecasters and energy experts predict the weather will drive up power demand on the New England grid Tuesday August 28th and Wednesday August 29th, and GMP is pushing to save customers money by partnering with them on crushing the peak between 4 and 7 p.m. on both days. This partnership can also radically reduce carbon output, an objective important to Vermonters, and the globe.

ISO-New England, the grid operator, uses the annual peak hour of energy to calculate what each utility in the region pays for the coming year, so strategically reducing demand during that key time can create big savings for customers.

GMP expects its network of stored energy – more than 660 Powerwall batteries in customers' homes and community solar installations with battery storage – can offset more than $600,000 in costs and about 21,120 pounds of carbon, the equivalent of not burning about 1,078 gallons of gasoline. Customers can help generate even more savings and cut more carbon, by simply being aware and reducing their power use during those key hours of 4 p.m. to 7 p.m. on Tuesday August 28th and Wednesday August 29th, while remaining safe and comfortable. With GMP and customers working together, GMP estimates savings could reach more than $1 million for everyone GMP serves.

GMP has partnerships with customers to tap into stored energy in their water heaters or reduce flow through their electric vehicle chargers during peak demand times, seamlessly maintaining their comfort and convenience while increasing savings for all GMP customers.

To sign up and learn more about GMP's eWater and home charging programs go to: https://greenmountainpower.com or call 888-835-4672.

EMAIL AUTHOR | REPLY TO FORUM

Figure 2-15. Front Porch Forum Post on Helping Customers Save Money

Communication Platforms

We have multiple platforms of our own that we use to communicate with customers—our website, a mobile app, even messages on monthly bills help us to explain customers' energy usage, offer tips and discounts, and share critical information during storms.

Text Alerts

Over 36,000 customers have enrolled to receive our text alerts. We send information about impending storms so customers can prepare. Once a storm hits, we text updates and estimated power restoration times for their location.

GMP Electric Smartphone App

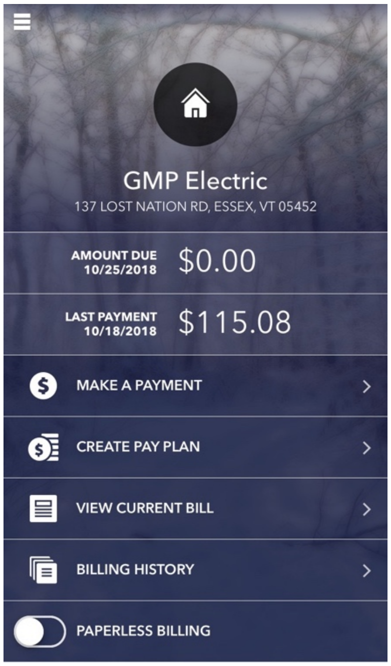

Figure 2-16. GMP Electric App Interface

Nearly 48,000 customers have downloaded the GMP Electric smartphone app. After registering, customers can perform a myriad of tasks to help them manage their account: make a payment, create a pay plan, view their current bill, and review their billing history. In addition, they can view a graph of their energy consumption, report and check on outages, review payment locations, and contact us directly.

The GMP Electric app is a great way to keep connected with our customers, especially if there is a power outage.

Our Outage Center and Map

This is another way we continue the ongoing partnership with our customers and increase transparency. They can report outages in our online outage center, and they can use the interactive map to see, in real time, where outages are, zoom in on a location, get details about the cause of an outage (a tree on line, a vehicle crash, or other reasons), and see estimated restoration times. Our IT team developed this map so it can load easily on mobile phones—because that's mainly what customers use when the power is out.

GreenMountainPower.com

Our website is robust and shares a lot of information with customers. Residential and commercial customers can manage their accounts, learn about where their power comes from, look at regulatory and legal filings, or browse products we offer to help them cut carbon, cut costs, and increase comfort. We have blog posts on new initiatives and other big announcements, and an archive of news releases, too.

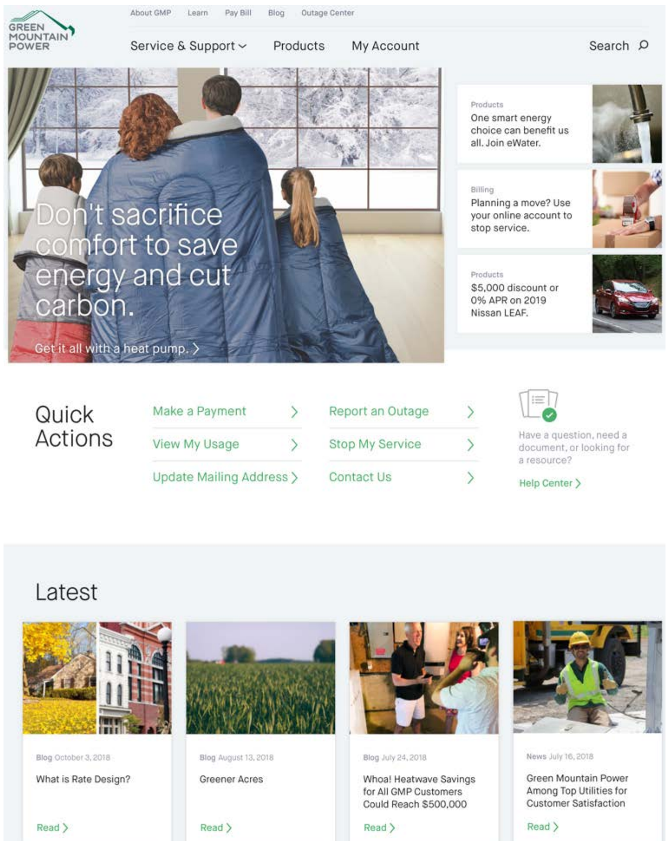

Figure 2-17. GreenMountainPower.com Home Page

In early December, we will have information about this 2018 IRP on the web site. Customers will be able to read about our IRP and how it impacts them, as well as download the Executive Summary and the entire report.

Our Call Center

We have 15 service centers scattered throughout the state. Our customer service representatives are right here in Vermont and take about 340,000 routine customer service calls every year. Every day they work with customers to answer billing or service questions, set up new accounts, or even help them get help paying their bills.

During storms, our customer service representatives are a key piece of the company-wide effort to get the power back on. They are trained to handle the flood of calls that severe weather can create, providing critical information to customers when they need it most.

Energy Statement

Customers receive bills from us once a month. In that mailing, we include helpful messages about safety, or ways to save energy and increase convenience along with billing information. When appropriate, we also include news about regulatory filings and public hearings, such as when this IRP has been filed and how to access it through our website. The bill's actual layout was redesigned recently to help customers clearly navigate the information they're receiving about their accounts.

Talk Directly with an Energy Advisor

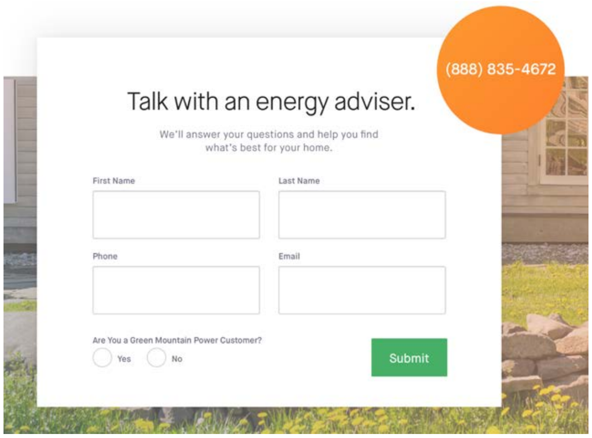

Figure 2-18. Energy Advisor Online Request Form

Our Energy Advisors work with customers on the phone and do home visits to help customers learn about the products and services we offer. From heat pump installations to Level 2 electric vehicle car chargers to smart thermostats for water heaters, Energy Advisors work with customers so they know how the product or service will impact the energy they use, the carbon they cut, and ultimately what it means for their energy bill so customers can make smart choices.

Customers can schedule a conversation simply by completing the online request form.

COMMUNICATION INNOVATIONS DURING THE PLANNING PERIOD

We are considering ways to deepen customer engagement even further. Feedback from both the DPS and the Commission has us seeking more opportunities to explain our work and the way the regulatory process supports and oversees it.

We are developing plans to conduct biannual open houses for customers and the broader public. One would be in the southern part of the state and the other farther north, rotating around all our district offices over time. We would bring company leaders and field team members to these meetings. The meetings would provide us the opportunity to review our rate-related filings and Multi-Year Regulation Plan, along with operations, safety, reliability, and customer programs.

The meetings would be scheduled for at least an hour, but go as long as the public attending warrant it should go, with plenty of time for questions and answers. We would also live-stream the meetings through our Facebook pages to broaden opportunities for customers and the public to participate or watch live, posting videos for later viewing. We would publicize these events in many ways, including local newspapers, bill messages, and on our website and Facebook page.

We are also planning to seek engagement in a new way with local public access channels across the state to further educate customers and the public about energy innovation and GMP in new and different ways.

3.Regional and Environmental Evolution

REGIONAL ELECTRICITY MARKET

The New England states operate as a single electricity system managed by the New England Independent System Operator (ISO-New England). In this role, ISO-New England is responsible for both operating a wholesale power market and overseeing a long-term planning process to ensure that adequate generating capacity and transmission infrastructure is constructed for the future.

In the ISO-New England wholesale electric energy market, the price of energy is set by the marginal, most-expensive generating units supplying power at any given time. These marginal energy costs (prices) vary by location within New England taking into consideration local differences in losses and congestion on the transmission system. Because natural gas generation is the most prevalent supply source in the region, wholesale locational marginal prices (LMPs) track the price of natural gas delivered to New England fairly closely during most of the year with some notable exceptions, for instance when energy demand is very high in the winter season or when energy demand is low in the spring and fall season.

To supplement the wholesale energy market, ISO-New England also operates a wholesale capacity market. The Forward Capacity Market (FCM) is designed to provide an additional financial incentive (beyond revenues from the short-term energy market) to ensure that sufficient resources (power plants, demand side resources, or imports) are in place to meet peak energy demands. In the FCM, prices are established through an annual auction process for a period three years in advance. Subsequent to these annual auctions, additional reconfiguration auctions are conducted closer to the delivery period to address changes in supply and demand expectations (for example, updates to the regional demand forecast) that may occur in the intervening years.

In addition to the two primary short-term markets, ISO-New England also operates ancillary service markets (such as spinning reserve, frequency regulation, and black start) that maintain grid reliability through adjustments to supply and demand on time frames from a few seconds to a few hours. Figure 3-1 represents the scale in dollars of all of these markets in New England.[16]

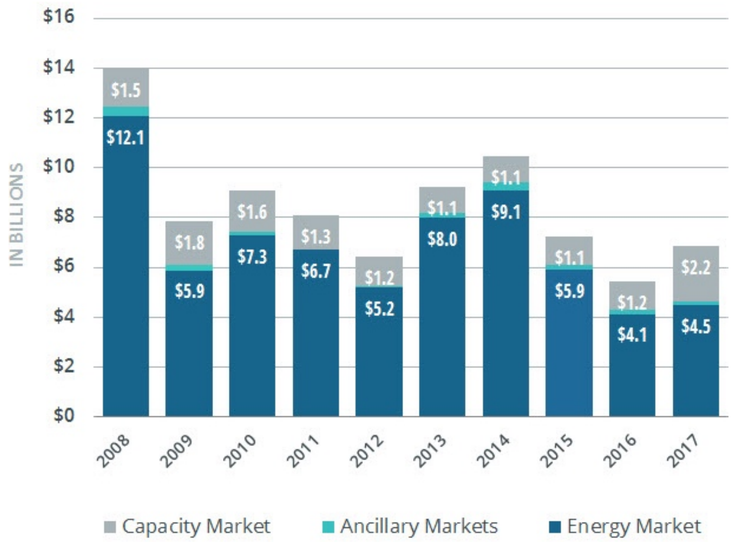

Figure 3-1. Annual Value of Wholesale Electricity Markets[17]

As Figure 3-1 demonstrates, energy is the dominate cost for load serving entities like GMP, showing significant year-to-year fluctuations based primarily on fluctuations in natural gas prices and weather (for example, polar vortex conditions during the 2013 and 2014 winters). However, capacity costs have represented a significant proportion of total wholesale costs in some periods. In 2017 in particular the capacity market price more than doubled, as retirements of significant existing generating capacity triggered the need for new generating capacity to be built in the region. Ancillary service costs are relatively small by comparison, but they do provide revenue opportunities for some resources (for example, battery storage, responsive load, quick-start generators) that are capable of responding quickly to changes in system conditions.

Regional wholesale market prices and trends like these are significant to us because the dominant share of our supply resources and energy needs all pass through and participate in the market. In addition, the conditions in the market and its prevailing

[16] For illustrative purposes, all energy, capacity, and ancillary services are supplied at spot market clearing prices.

[17] Source: ISO-New England.

prices influence the cost at which we can purchase additional supplies, irrespective of the fuel used to generate those supplies.

REGIONAL SUPPLY—EVOLVING RAPIDLY

In New England, the current generation fleet is composed of a variety of grid-connected resources, with the largest single type being natural gas-fired power plants. All together, these power plants represent approximately 30,000 MW of regionally installed generating capability. This amount is further supplemented by over 4,000 MW of import transmission connections to the neighboring New York, Québec, and New Brunswick control areas.

How the Energy Market Operates in New England

New England's wholesale electricity marketplace includes two electric energy markets that work together in what's called a multi-settlement system.

Day-Ahead Energy Market. Allows market participants to commit to buy or sell wholesale electricity one day before the operating day, which helps limit price volatility. This market produces one financial settlement.

Real-Time Energy Market. Allows market participants to buy and sell wholesale electricity during the course of the operating day. The Real-Time Energy Market balances the differences between day-ahead commitments and the actual real-time demand for the production of electricity. The Real-Time Energy Market produces a separate, second financial settlement. It establishes the real-time LMP that is either paid or charged to participants in the Day-Ahead Energy Market for demand or generation that deviates from the day-ahead commitments.[18]

In the last decade, the type and quantity of New England's generating supply has continued to change significantly with the addition of more new, efficient combined-cycle natural gas generators that helped drive a decrease in the amount of oil and coal generation that historically made up larger portion of the regions supply (see Figure 3-4).

In more recent years and over this IRP's planning horizon, the region's supply is expected to continue to evolve rapidly. In this next transition, however, renewable generating supplies (both grid-connected and distributed) are expected to represent the largest category of new supply. Since our 2014 IRP, there have been significant new wind resources and over 2,000 MW of new solar resources (mostly operating as behind-the-meter and not participating directly in the ISO-New England market) added to the region's energy supply. With continued support from state policies (such as Renewable Portfolio Standards (RPS), Vermont's Renewable Energy Standard (RES), and net metering laws),

[18] For example, if we purchase 500 MWh of energy in the Day Ahead Energy Market to meet the estimated needs of our customers in a given hour, but 510 MWh was needed in that hour, we would purchase the 10 MWh difference in the Real Time Energy Market.

the supply contribution from these two categories is expected to more than double from current levels by the mid-2020s.

Beyond these new supplies of wind and solar, one of the most significant changes to the regional energy supply in the next few years could result from surrounding states' return to long-term supply procurements (requests for proposals) for substantial renewable and carbon-free energy in support of ambitious greenhouse gas reduction and renewable power goals.

For us, the implication of this return of the surrounding states to long-term planning and procurement—as opposed to procuring power overwhelmingly on a short-term basis from the wholesale market—could represent new opportunities for our energy portfolio as new supply proposals and resource developments are brought into focus for these large regional solicitations. Specifically, the potential transmission import projects (TDI, Vermont Green Line, and Granite State Power Link) that would deliver power to Vermont or through Vermont, and which have been proposed in response to RFPs in neighboring states, could present opportunities to Vermont through power purchase opportunities or other mechanisms (such as economic activity and financial payments to Vermont entities). At the same time, we will seek to understand the extent to which such large projects could pose reliability risks or economic risks for customers (in the form of congestion on the VELCO transmission system) and to ensure that such risks are effectively mitigated.

Current and Historical Generation Supply

Lower emitting sources fuel most of the region's generation. In 2017, natural gas-fired generation, nuclear, other low- or no-emission sources, and imported electricity (mostly hydroelectricity) provided roughly 99% of the region's electricity. New England's dependency on natural gas for electricity generation has grown significantly in recent years, and is expected to be continue well into the future. Figure 3-2 shows the share of electricity generated by natural gas increased from about 13% in 2000 to over 40% in 2017. The remainder of the region's energy supply comes from a combination of oil-fired, wind, hydroelectric, and nuclear power sources, with nuclear the second-largest source at over 20%, despite recent and announced retirements.

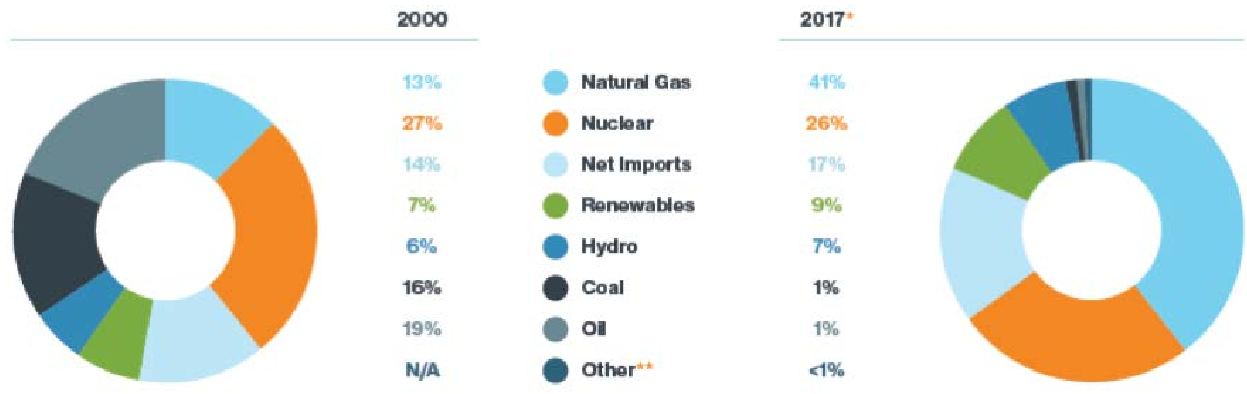

Figure 3-2. Annual New England Net Energy by Source[19]

* Total does not equal 100% because of rounding.

** "Other" represents resources using a fuel type that does not fall into any of the existing categories and may include new technologies or fuel types without sufficient quantity to have their own category.

While natural-gas-fired generation's proportion of the system capacity mix is expected to grow somewhat from 44.5% in 2017 to approximately 50.9% by 2020 (as new, efficient gas-fired capacity is scheduled to enter the market), the current situation where natural gas fuel prices typically set the marginal price for wholesale electricity is projected to continue over the planning horizon.

Two of the biggest changes in the region's resource mix since our 2014 IRP have been the announcement of the retirement of the Pilgrim nuclear energy plant in 2019 and the tremendous growth in regional solar photovoltaic (PV) capacity (mostly behind-the meter). Many of the potential retirements of older resources (mostly oil and coal) noted in our 2014 IRP have occurred (see our 2014 IRP, page 6-13) although since these plants did not operate frequently, their retirement has had little impact on the disposition of the region's energy supply.

[19] Source: ISO-New England *Net Energy and Peak Load by Source Report*.

Figure 3-3 represents the scale of developments in New England's transforming supply mix.

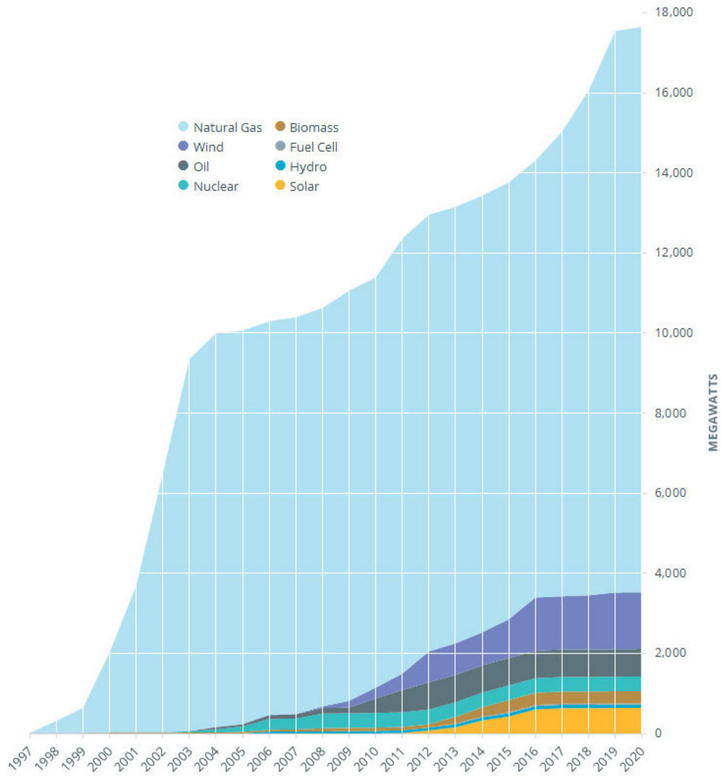

Figure 3-3. Cumulative New Generating Capacity in New England[20]

Note: New generating capacity for years 2016–2020 includes resources clearing in the recent Forward Capacity Auctions.

New Grid Scale Renewable Resources

Largely as a result of increasing state RPS goals and solicitations of large, long-term purchases—along with supportive rules for the development of distributed solar capacity at the state level—*the amount of renewable generation in the region is expected to increase substantially in the next decade*. This magnitude of growth in the renewable generation rate can have many implications for the operation of the energy market. Solar PV in particular is expected to have impacts ranging from the suppression of LMPs during sunny days and hours by reducing peak demands to greater price volatility driven by the fluctuations between sunny and cloudy periods. For wind resources, there is the potential that the large proposed offshore projects could supplant the need for costly oil-fired generation during the challenging winter months, meaningfully lowering prices while improving the region's emissions profile. Figure 3-4 and Figure 3-5 illustrate the potential growth in renewables and other resource types, although it is important to keep

[20] ISO-New England.

in mind that not all of the proposed volumes of various resources will necessarily be developed.

Many of these state-supported renewable policies are expanding over the planning horizon of this IRP, driving continued expansion of grid-scale renewables. One potential issue that could determine the pace and scale of this renewable development is the suitability and availability of transmission facilities to carry these resources from more remote locations (where they are proposed to be built) to where the energy is consumed.

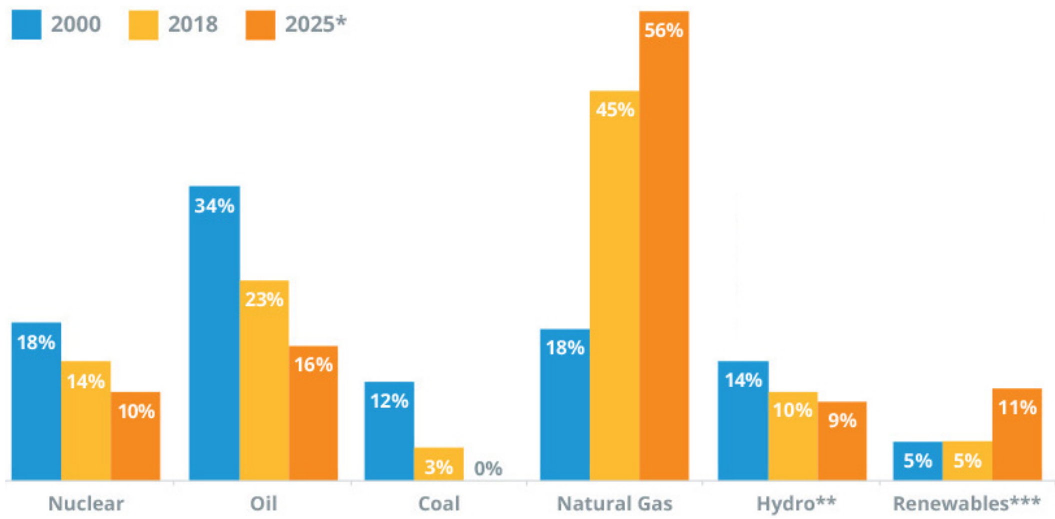

Figure 3-4. Percent of Total New England System Capacity by Fuel Type[21]

* 2025 values are hypothetical and assume new resources proposed in the ISO interconnection queue and non-price retirement requests for coal, oil, and nuclear resources as of early 2018. Values for coal, oil, and nuclear also reflect the possible loss of over 5,000 MW of generation at risk because of plant age and infrequent operation.

** Includes pondage, run-of-river, and pumped storage.

*** Resources and fuels include battery storage, landfill gas, methane, refuse, grid-connected solar, steam, wind, and wood. Hydro is not included primarily because the various sources that comprise hydroelectric generation are not universally defined as renewable in the six New England states. The nameplate capacity values of proposed grid-connected solar and wind projects were adjusted to reflect estimated actual generating capacity.

[21] ISO-New England

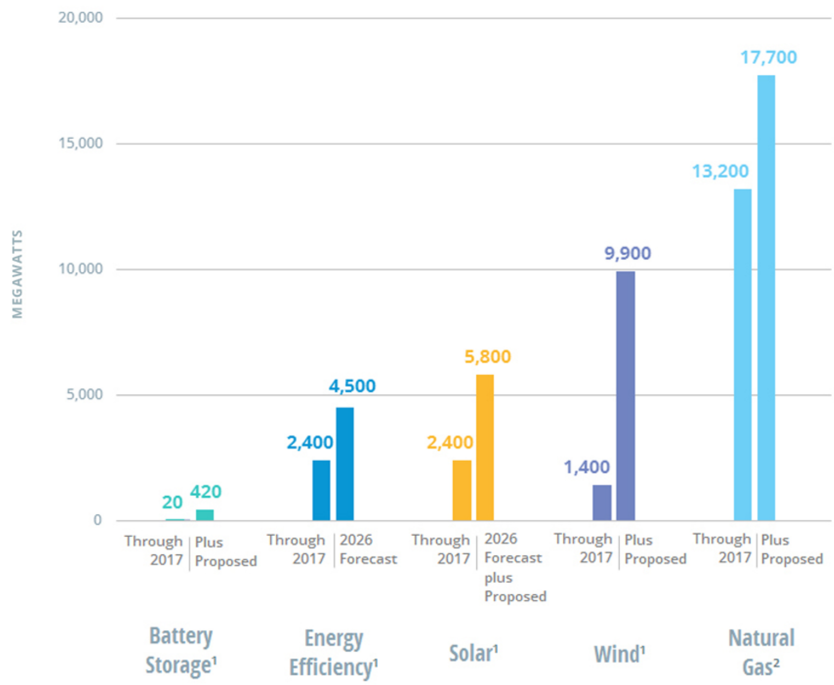

Figure 3-5. New England Efficiency and Power Resources with Significant Growth[22]

Note: Numbers are rounded. These figures include all proposed new projects; historically, however, almost 70% of proposed new megawatts in the ISO Generator Interconnection Queue are ultimately withdrawn and thus not built.

1 Nameplate capacity. Battery storage includes existing and proposed grid-connected resources. Energy efficiency includes resources participating in the capacity market, as well as forecasted future capacity. Solar includes existing and proposed grid-connected resources, as well as existing and forecasted behind-the-meter resources.

2 Nameplate capacity for proposed projects; summer season claimed capability for existing units is based on primary fuel type. This total does not include oil units that can switch to natural gas.

New Distributed Renewable Resources

For the first time, the most significant new supply of resources in the region is not coming from grid-scale developments. Instead, driven by state-specific goals and incentives at the retail customer level, solar PV resources are now being added at a significant rate as distributed, behind-the-meter resources connected to the distribution system. Already about 2,500 MW of solar is estimated to have been installed in the region (Figure 3-6), the vast majority being small-scale systems that are not connected to the regional high-voltage transmission system.

22 Sources: ISO-New England; ISO-New England generator Interconnection Queue, January 29, 2018; CELT Report: 2010, 2016, 2017; Final 2017 ISO-New England Solar PV Forecast and Final Energy Efficiency Forecast Report for 2021 to 2026; and Seasonal claimed Capability Monthly Report, January 2018.

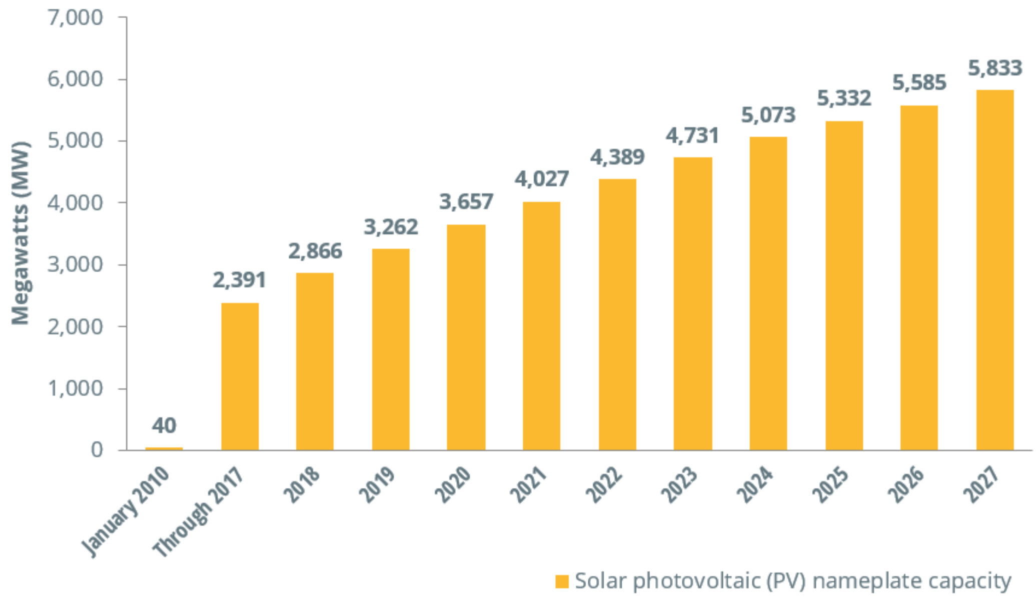

Figure 3-6. Projected Cumulative Growth in New England Solar Power: May 2018 Forecast[23]

Note: Amounts include PV connected behind-the-meter as well as PV participating in the wholesale electricity marketplace. Megawatt values are AC nameplate.

The growth in this category is expected to increase further during the planning horizon and represents one of the most significant transformational resources impacting the markets and the delivery of electricity to consumers. Unlike traditional supply, these behind-the-meter resources are tracked by the reductions they cause to the hourly energy needs on the bulk transmission system, displacing the need for grid-connected supply and lowering peak demands during the summer months. By 2025, ISO-New England predicts that these solar resources will double from the current amount to over 5,000 MW installed.

[23] Source: ISO-New England *2018 PV Forecast*, May 2018.

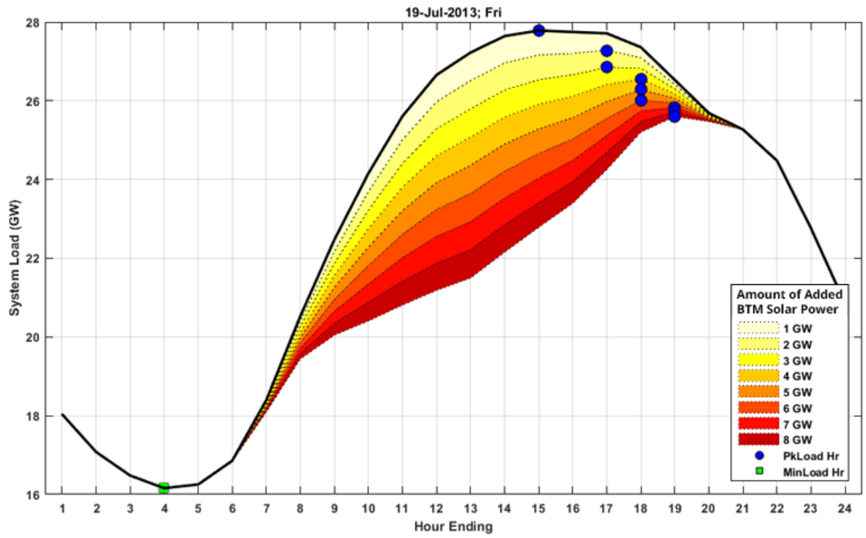

Figure 3-7. Summer Load Profile with Increasing Behind-the-Meter Solar Power[24]

Summer comprises the highest electricity use in New England, largely because of air conditioning. PV clearly helps "shave the peak" when the peak falls during the daylight hours. Greater amounts of PV will shift the timing of peak demand for grid electricity to later in the afternoon or evening (as illustrated in Figure 3-7), where increasing volumes of behind-the-meter solar would shift the ISO-New England peak hour from hour 15 to hour 17 and ultimately to hour 19. As a result, as PV penetration grows, its ability to reduce peak demand will diminish. Because regional capacity obligations are allocated to load serving entities like GMP based on their respective loads at the time of the annual ISO-New England peak, this trend is lowering the financial value of additional solar resources to our customers.

State-Sponsored Supply Procurements

Since our 2014 IRP, the surrounding states have also taken further steps into the long-term procurement of energy resources to make progress toward greenhouse gas emission reduction and renewable power goals, and to become less exposed to fluctuations in short-term ISO-New England market prices.

In the next five years, significant new generation supplies are expected to be added from this return to long-term procurement. Supplies from surrounding states include:

Massachusetts:

- Section 83C Offshore Wind Procurement: ramping from 200 MW installed in Q4 2022 to a cumulative total of 1,600 MW by 2030.

24 ISO-New England.

- Section 83D Clean Energy Procurement: 1,200 megawatts of transmission capacity to supply New England with power from reliable hydroelectric generation.
- Solar Massachusetts Renewable Target (SMART) Program: 1,600 MW no later than 2025.

Connecticut:

- Public Act 13-303 and Public Act 15-107.
- Section 8 of PA 13-303. This RFP allows for the procurement of up to 889,250 MWh per year, and it is geared toward offshore wind (capped at 825,000 MWh per year), fuel cells, and anaerobic digesters.
- Connecticut Low Emissions Renewable Energy Certificate (LREC) and Zero Emissions Renewable Energy Certificate (ZREC) Program.
- Connecticut Fuel Cell Procurement Program: 30 MW by 2021.
- Connecticut Solar Home Renewable Energy Certificate (SHREC) Program: 300 MW by 2023.

Rhode Island:

- Clean Energy RFP rolled into an assumed future procurement. Offshore wind procurement is also assumed. Rhode Island procurements are assumed separate from the Massachusetts 83D process: 80 MW of land-based renewables (25% wind, 75% solar) and 100 MW of offshore wind.
- Rhode Island Renewable Energy Growth Program: 160 MW of contracts by 2019, followed by 35 MW of contracts per year (net of contract attrition) through 2029.
- Net Metering: 100 MW in service by 2022 under virtual net metering.

Beyond impacting the carbon emissions profile of the region, these new planned supplies are expected to meaningfully impact energy and capacity prices. For the energy market, these supplies could reduce the impact of natural gas shortages in the winter months, lowering prices considerably. For capacity markets, these resources could ensure that the region has ample supply to meet peak demands, preventing FCM auctions from reaching price levels needed to create incentives for new fossil fuel peaking developments.

NEW ENGLAND MARKET PRICES

Energy Market Prices

In recent years and continuing into the planning period, the two main drivers of wholesale electricity prices in New England are the cost of fuel (mostly natural gas) used to produce electricity and the level of net consumer demand (electricity consumption plus grid losses, less output of distributed generation operation behind-the-meter) on an hour-by-hour basis.

	2012	2013	2014	2015	2016	2017	2018
Jan	$40.59	$86.53	$168.81	$71.14	$38.60	$40.30	$108.75
Feb	$30.92	$122.31	$156.02	$122.77	$29.90	$30.02	$39.58
Mar	$26.16	$53.09	$111.16	$64.25	$20.63	$35.75	$35.38
Apr	$25.88	$42.89	$44.98	$28.43	$28.36	$29.23	$45.00
May	$25.88	$40.31	$36.95	$24.92	$21.24	$27.31	$24.04
Jun	$34.75	$37.09	$37.92	$21.16	$22.61	$25.48	$26.82
Jul	$41.88	$52.07	$37.50	$26.44	$31.12	$27.60	$32.89
Aug	$38.53	$34.72	$30.35	$30.06	$35.54	$24.90	$39.16
Sep	$31.53	$40.43	$34.10	$30.82	$28.62	$23.57	
Oct	$35.27	$33.94	$32.19	$37.01	$21.98	$29.74	
Nov	$54.96	$45.21	$47.71	$29.42	$24.98	$33.98	
Dec	$46.30	$92.96	$43.00	$22.42	$53.28	$71.31	
Avg.	**$36.05**	**$56.79**	**$65.06**	**$42.40**	**$29.74**	**$33.27**	**$43.95**

Table 3-1. Average Monthly Day Ahead Locational Marginal Pricing[25]

Note: Locational Marginal Price points are color coded: green represents the lowest prices; yellow represents medium-level prices; and orange and red represent the highest prices. Thus, the table shows broad trends for prices throughout the year.

In New England, energy price is determined hourly by the marginal unit needed to satisfy the last increment of demand. In most periods, the last unit dispatched is a natural gas plant (over 50% of the generating plants are natural gas fired, and natural gas is estimated to be the region's marginal source during most hours). Thus, the price of natural gas on any given day usually is a key determinant of the hourly price of wholesale electricity. In the years since our 2014 IRP, the general downward trend in natural gas prices and in energy market prices has continued (Table 3-1, although with significant excursions). This decade-long trend has been driven largely by the national decline in United States gas costs brought about by the tremendous increase in shale gas production (see Figure 3-10). For New England, the Marcellus gas producing region has had the greatest influence with its creation of a large gas production hub in the eastern United States.

25 Source: *EnerNOC Insights*: September 2018 New England Monthly Market Commentary; page 4.

For New England, the result of this trend has been ample natural gas supply and moderate prices during non-winter months (as seen in Table 3-1). Figure 3-8 shows the history of wholesale energy prices by month as well as the relationship between the average wholesale electricity prices that prevailed and the price of natural gas available to the generating plants at that time. A notable exception to this gas-based pricing pattern occurs in the winter months where limited pipeline capacity into the region combined with very cold weather can create a condition where the flow of natural gas into New England is insufficient to fuel all of the gas plants. In these circumstances, spot market prices for natural gas in New England can soar to multiples of the prevailing prices in neighboring regions. Some natural gas plants must switch to backup oil fuel, while older, oil-fired and coal-fired generating plants are called into operation and often set the regional LMP far above typical levels. During 2014, 2015, and 2018, this situation occurred enough times to dramatically increase the prevailing price level across the winter months.

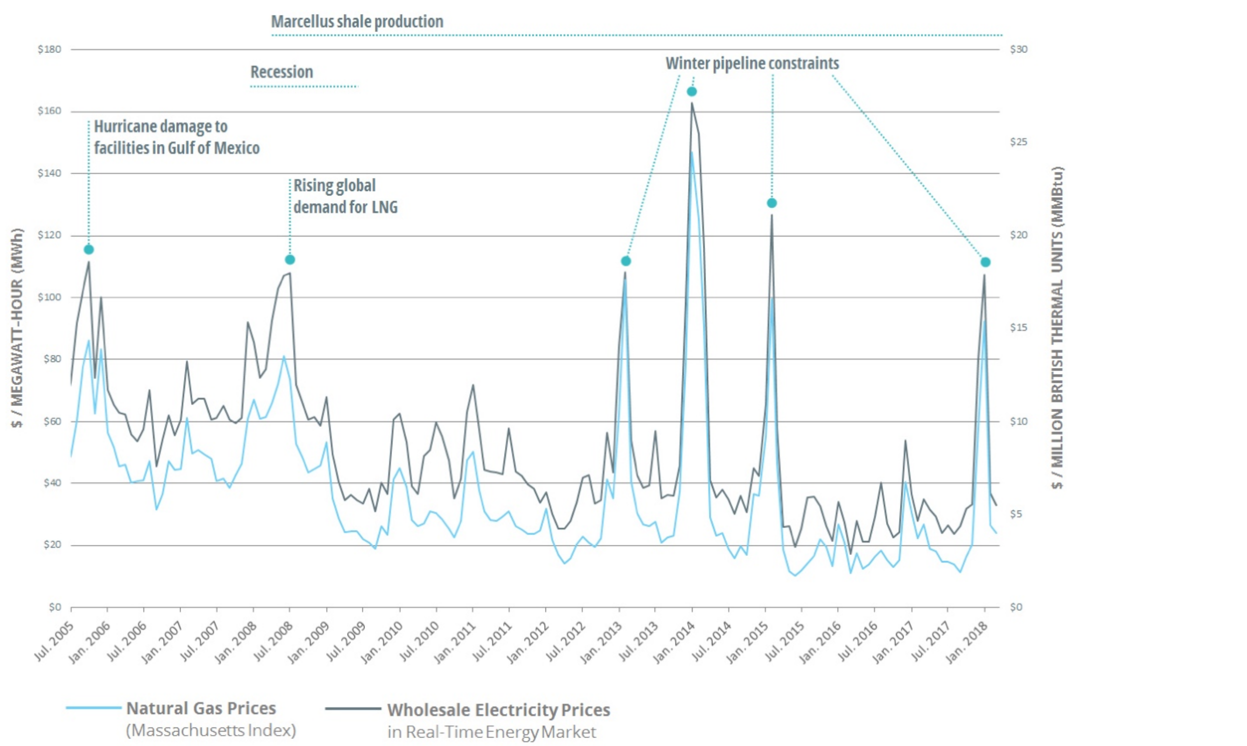

Figure 3-8. The Link Between Wholesale Electricity and Regional Natural Gas Prices[26]

Note: The Massachusetts index price is a volume-weighted average of trades at four natural gas delivery points in the state, including two Algonquin points, the Tennessee Gas Pipeline, and the Dracut Interconnect.

[26] Source: ISO-New England.

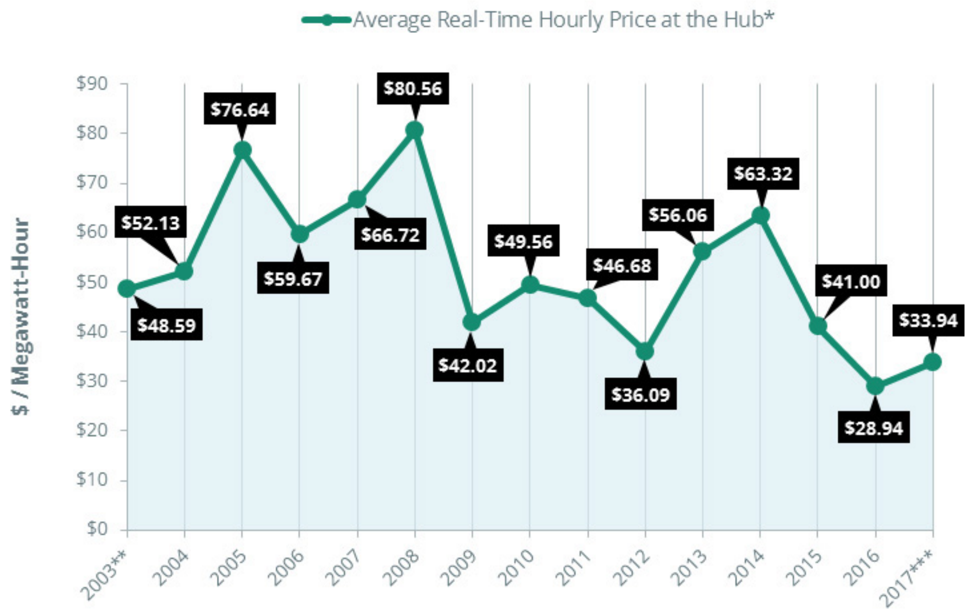

Figure 3-9. Average Annual Price of Wholesale Electricity in New England[27]

* The Hub is a collection of 32 locations in New England used to represent an uncongested price for electric energy. Starting on March 1, 2017, the value reflects the hourly average of five-minute locational marginal pricing.

** The Data start on March 1, 2003 with the launch of the redesigned wholesale electricity markets (that is, Standard Market Design).

Forward prices in the region tend to exhibit the same pattern of seasonal variation that has occurred in the spot market (Figure 3-9). This seasonal dichotomy is expected to continue and could become more pronounced to the extent that Solar PV dominates new resource additions.

Domestic Shale Gas Production

Gross production of natural gas in the United States has generally been increasing for more than a decade. This growth has been driven by production in the Appalachian Basin in the Northeast, the Permian Basin in western Texas and New Mexico, and the Haynesville Shale in Texas and Louisiana (Figure 3-10). These three regions collectively accounted for less than 15% of total U.S. natural gas production as recently as in 2007, but now they

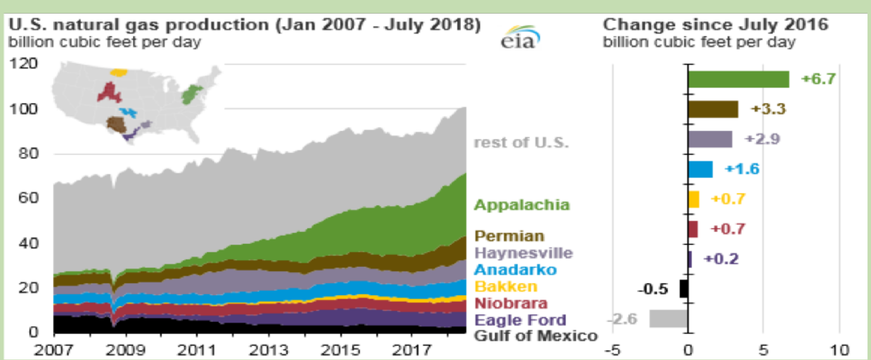

Figure 3-10. United States Natural Gas Production: January 2007–July 2018[28]

27 Source: ISO-New England.

28 U.S. Energy Information Administration (EIA).

account for nearly 50% of total production.

Regional Greenhouse Gas Initiative

Current and future prices also continue to be influenced by the Regional Greenhouse Gas Initiative (RGGI) carbon trading program. Since our 2014 IRP, the nine-state program has continued to evolve. In 2017, a redesign extended the program through 2030. In the new program, changes are implemented to ensures there will be a moderate price for GHG emissions from major electric generators in New England and much of the Northeast.

In particular, changes have been made to:

- Add an accelerated annual base cap reduction of 3% per year from 2021 to 2030.
- Adjust the number of allowances auctioned in 2021–2025 by one-fifth of the 2020-ending allowance bank.
- Introduce of a new, dynamic price floor mechanism beginning in 2021 that withholds a finite number of allowances from an auction if prices fall below threshold levels.

Previously the program approach of implementing a gradual downward trend in the RGGI cap resulted in only a mild upward influence on energy prices in New England. A comprehensive national program has not yet materialized.

These changes to the RGGI (which we anticipate will result in slightly higher compliance costs) plus the implementation of a national program with national GHG emission reduction target to levels needed to address climate change, we expect, would have a significant impact on energy prices. This prospect and the new Vermont statutory framework established under RES make carbon emission reductions one of the most important long-term considerations in the design of our energy supply portfolio.

Capacity Market Prices

The goal of the capacity market is "to purchase enough qualified resources to satisfy the region's future electricity needs and allow enough time to construct new capacity resources." To accomplish this, Forward Capacity Auctions (FCAs) are held each year approximately three years before the commitment period or delivery year where the resources have an obligation to be ready to run when called on.

Ahead of each auction, ISO-New England determines the necessary volume to procure and creates sloped demand curves designed to ensure that the region procures sufficient capacity to meet its mandatory resource adequacy planning criterion. These demand curves are designed to raise capacity prices when the region needs new power resources (for example, as aging plants retire) and lower capacity city prices when there is sufficient or excess supply and additional capacity would not materially improve reliability.

One system curve specifies a price for each capacity level for the region as a whole. Separate zonal demand curves are also used to reflect the additional congestion price to be paid on top of the system capacity price for specific constrained capacity zones—geographic sub regions of New England that may be export-constrained or import-constrained.

Since the start of this capacity market in 2008, most of the annual auction outcomes have been administratively determined where prices were not allowed to drop below the pre-established floor price. In 2014, prices moved off the floor price and remained elevated for the next two auctions, as the retirement of significant existing generating capacity in the region led to the clearing of significant new capacity (combined cycle and combustion turbine plants) in FCA #7, FCA #8 and FCA #9 (Table 3-2). This rapid doubling in the annual capacity price for these years drove significant rate pressure for us and other load serving entities in the region, but it also stimulated significant activity on the supply side.

More recently, and following this sharp increase, we have seen the capacity auctions return to very low prices as no further supply has been needed and few older plants have retired. This pattern of boom and bust can be seen in the annual prices of capacity commitment payments (CCP) for the FCAs starting in 2010 and projected through 2022.

Year-to-year volatility of regional capacity costs is a significant exposure for us, making it appropriate to consider stable-priced forward capacity purchases and to deploy resources (such as controllable loads or battery storage) that can reduce our contribution to the annual ISO-New England peak load and associated share of regional capacity obligations.

Auction Commitment Period	Total Capacity Acquired (MW)	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/kW per month)
FCA #1 in 2008 for CCP 2010–2011	34,077	1,188	626	$4.50 (floor price)
FCA #2 in 2008 for CCP 2011–2012	37,283	448	1,157	$3.60 (floor price)
FCA #3 in 2009 for CCP 2012–2013	36,996	309	1,670	$2.95 (floor price)
FCA #4 in 2010 for CCP 2013–2014	37,501	515	144	$2.95 (floor price)
FCA #5 in 2011 for CCP 2014–2015	36,918	263	42	$3.21 (floor price)
FCA #6 in 2012 for CCP 2015–2016	36,309	313	79	$3.43 (floor price)
FCA #7 in 2013 for CCP 2016–2017	36,220	245	800	$3.15 (floor price) NEMA, Boston: $14.99
FCA #8 in 2014 for CCP 2017–2018	33,712	394	30	$15.00-new and $7.025-existing
FCA #9 in 2015 for CCP 2018–2019	34,695	367	1,060	System-wide: $9.55 SEMA, Rhode Island: $17.73-new & $11.08-existing
FCA #10 in 2016 for CCP 2019–2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020–2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021–2022	34,828	514	174	$4.63

Table 3-2. Annual Forward Capacity Auction Results

KEY DEVELOPMENTS IN MARKET DESIGN

Since our 2014 IRP, and largely as a result of the introduction of new renewable supplies into the market, there have been some notable changes in the structure of the ISO-New England markets. In the energy market, the most notable of these changes are the implementation of a market-based rationing system for renewable generation called Do-Not-Exceed (DNE) dispatch together with new operating procedures to ensure fuel security in the challenging winter months. In the capacity market, there are changes to include performance incentives called Pay-for-Performance and a change to allow state sponsored, “out-of-market” resource an ability to participate in the market (for example, the CASPR rule—see “Changes to Allow State Procurement Resource (CASPR)” on page 3-21).

Energy Market Changes

Do-Not-Exceed Dispatch and Negative Prices

In May 2016, ISO-New England implemented DNE dispatch changes to the market rules to incorporate wind and hydro resources into the economic dispatch and price formation process of the energy market. Now competitive energy offer prices are used to determine the economic dispatch of generating units, including during some conditions where transmission limits prevent all generators in an export-constrained area from operating at the same time. This new DNE method for curtailment eliminates the historical practice of manually curtailing resources in congested situations. These achievements are made possible by making better use of economic dispatch signals to manage transmission system congestion and minimizing the need to use manual curtailment processes.

One result of this DNE process is that sometimes the negative offer prices of generating plants (particularly renewable resources) that have a strong incentive to operate without curtailment can result in the prevailing marginal price for the entire region to be negative for a short time.

Figure 3-11 illustrates the frequency of negative energy price events in New England during 2017 and 2018, compared to electricity markets in some other countries.

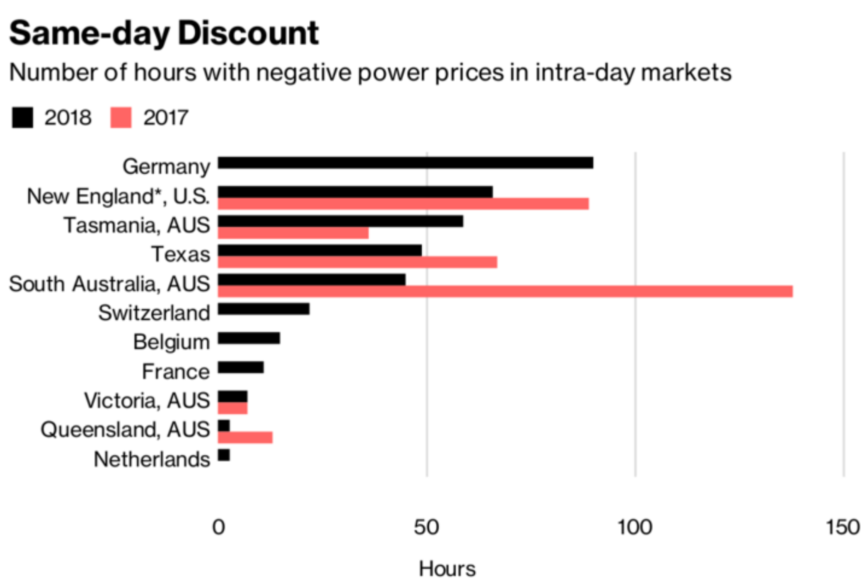

Figure 3-11. Daily Negative Power Prices Worldwide: 2018–2019[29]

* Northeast Massachusetts, Boston zone, real time.

[29] Source: Epex Spot, National electricity Market of Australia, ERCOT.

As the supply of intermittent renewable sources increases in future years, the location of many of these resources in relatively remote areas of the transmission system could lead to more frequent instances of negative pricing in these export-constrained areas. As the proportion of zero- or negative-priced energy offers from renewable supplies grows relative to the amount provided by fossil-fuel-based units in the energy market, we are also likely to see increases in the number of negative pricing periods occurring across the entire region—especially during the hours and seasons that feature relatively low energy usage.

Negative energy pricing has also occasionally occurred in two instances: during daytime hours (afternoon minimum load periods, or when actual solar generation exceeds the intra-day forecast); and during hours when large thermal generating plants in the region are being started in anticipation of higher loads later in the day. The increasing occurrence of negative spot market energy price events would tend to be favorable for quick, flexible resources (for instance, some types of battery storage and responsive loads) that can consume additional energy if and when such events occur.

Fuel Security Initiatives to Address Winter Gas Pipeline Constraints

During the winter, regional gas distribution utilities have the first priority—called firm reservations—for the available capacity on the pipelines that carry natural gas into New England (Figure 3-12). During very cold periods when heating demand is high, this leaves very little to no non-firm pipeline capacity for electric generators. In recent years, this has meant that on the coldest days, thousands of megawatts of natural-gas-fired generation are unable to operate. The region then must rely on older, more expensive oil- and coal-fired power plants with stored fuel to meet hourly energy needs.

Many of these non-gas-fired power resources are slated for retirement and are facing greater restrictions to their operation for environmental reasons. As a result, concerns have emerged that steps need to be taken to address the reliability of the energy market in the winter. (For greater detail, see the January 2018 *ISO-New England Operational Fuel-Security Analysis*.)[30]

[30] https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

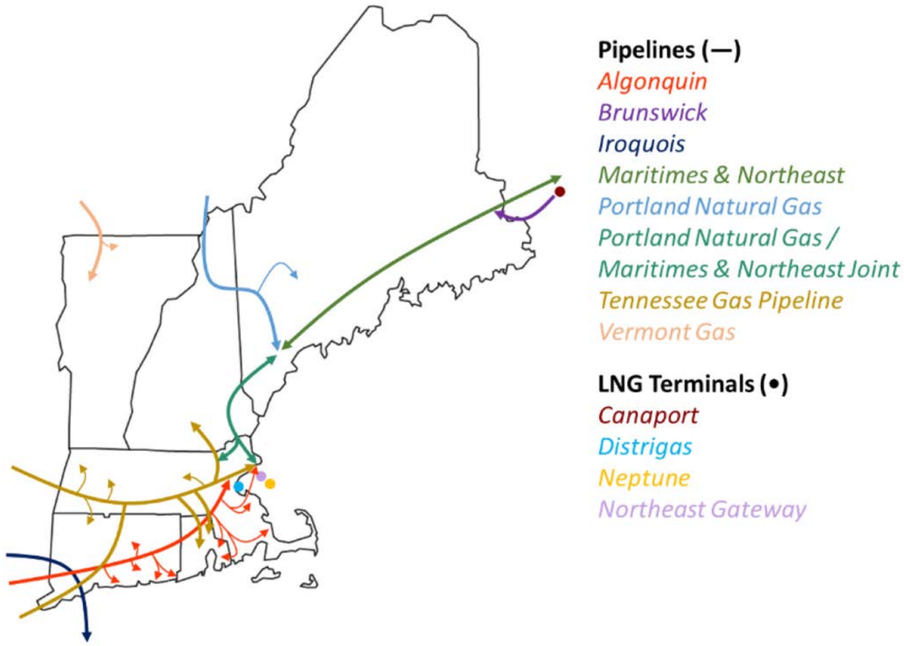

Figure 3-12. Regional Gas Distribution Patterns[31]

In 2018, ISO-New England took a significant step to seek an out-of-market cost recovery agreement for the large Mystic facility to keep it from retiring. The ISO is hoping this is only a short-term measure. In accordance with FERC's order in EL18-182-000, ISO-New England is developing improvements to the market design to better address regional fuel security for the long term.[32]

Forward Capacity Market

Pay-for-Performance

As foreshadowed in our 2014 IRP, ISO-New England has now implemented a significant modification to the FCM known as Pay-for-Performance. This approach more closely aligns the capacity payment a resource receives with its performance during critical periods. When a critical event occurs, a capacity resource that over-performs relative to its obligation will receive an additional capacity payment collected from underperforming units. These changes were approved in 2014 and first included in capacity obligations awarded through Forward Capacity Auction #9, which took effect in June 2018. This Pay-for-Performance construct is expected to reward generating units that can start quickly and reliably if a scarcity event occurs, reliable baseload units (which may already be generating during a scarcity event), and potentially intermittent renewable

[31] Source: *Avoided Energy Supply Components in New England: 2018 Report*, Synapse Energy Economics, Inc., March 30, 2018; page 34.

[32] A specific proposal is required by July 1, 2019.

generators if their typical output exceeds their seasonal FCM capacity obligation. Generators that require many hours to start up, cannot start reliably, or tend to have high unplanned outage rates will be penalized.

The first shortage event triggering a pay-for-performance settlement in 2018 occurred on the Labor Day holiday shortly after the implementation. In this event, the region was in a Capacity Scarcity Condition for about two hours and 40 minutes. Underperforming resources were penalized at a rate of $2,000 per MWh for failing to meet their capacity obligation during energy shortfalls, while resources that over-performed (including resources with no obligation) received $2,000 per MWh of additional revenue. While it remains to be seen if these types of events become associated with the fuel security concerns identified for the winter months, the frequency of these events will likely have significant bearing on the economics of continuing to operate the older, oil-fired units in the region. Our capacity resources performed well during this event. We did not incur any significant penalties or receive significant supplemental payments. Some resources (particularly our wind resources) over performed on their expected capacity obligations enough to offset the unavailability of one of our fuel units that was out for maintenance and unable to respond.

Changes to Allow State Procurement Resource (CASPR)

To accommodate resources that are being added to the regional supply through state-sponsored solicitations, ISO-New England is making changes to the rules for participating in Forward Capacity Auctions. Under the CASPR rule change, ISO-New England is now conducting each FCA in two stages. In the primary auction, ISO-New England clears the FCA (as it currently does) with limited opportunity for new units with support coming from policy arrangements outside of the ISO market to clear. In the secondary stage, ISO-New England administers a voluntary Substitution Auction immediately following the primary auction where these state-sponsored resources can purchase a capacity obligation. In the Substitution Auction, existing generation resources willing to permanently leave the markets could elect to transfer their Capacity Supply Obligations (CSOs) to state-sponsored policy resources that did not acquire CSOs in the primary stage.

The result of this change is a two-settlement system whereby new resources can clear the FCA and exiting resources can receive a retirement payment. With this change, ISO-New England hopes state-sponsored renewable energy resources can participate in the important New England capacity market (thus increasing their deployment and cost-competitiveness) without eroding the competitive dynamics of that FCM. We expect to monitor the Substitution Auction to determine whether, in the event that an existing oil-fired peaking unit is reaching the end of its economic life, sale of a capacity obligation could provide additional value to our customers.

REGIONAL MARKETS FOR RENEWABLE ENERGY

State policymakers in New England and across the country support the integration of renewable energy through a combination of supply-side and demand-side initiatives. In New England, title to the descriptive characteristics of renewable energy purchases, and compliance with RPS obligations, are demonstrated through the purchase and retirement of Renewable Energy Certificates (RECs). The supply, demand, and price dynamics and expectations in New England REC markets are distinct from the other New England markets and have grown in importance for our resource portfolio.

All six New England states have active RPS or RES policies. Each RPS program has multiple Classes—referred to as Tiers in Vermont—which are used to differentiate purchase obligations by technology, vintage, emissions, and other criteria, based on state-specific policy objectives. Regional Class I[33] requirements (as well as Class II in New Hampshire and Tier II in Vermont) are intended to create demand for new renewable energy additions. As a result, the RPS targets for these classes increase each year, either until a specified maximum obligation is reached, or indefinitely (as in Massachusetts).

RPS eligibility varies by state and Class, creating complex relationships among the New England states and between New England and adjacent control areas.[34]

[33] Referred to as "New" in Rhode Island.

[34] New York ISO (NYISO), Québec, and New Brunswick.

Figure 3-13 depicts the overlapping eligibility of RPS policies in New England. In other words, the eligibility for Tiers or Classes in the various states are sometimes the same, and sometimes unique. For instance, Vermont Tier II has the same eligibility requirements as Maine Class I, although Maine has additional eligibility requirements. While Vermont Tier I has the same eligibility requirements as Connecticut Class II, Maine Class II, and Rhode Island New class, it doesn't share any of the eligibility requirements of Class I in any other New England state. Finally, the regional market can interact because of these partially overlapping eligibility requirements.

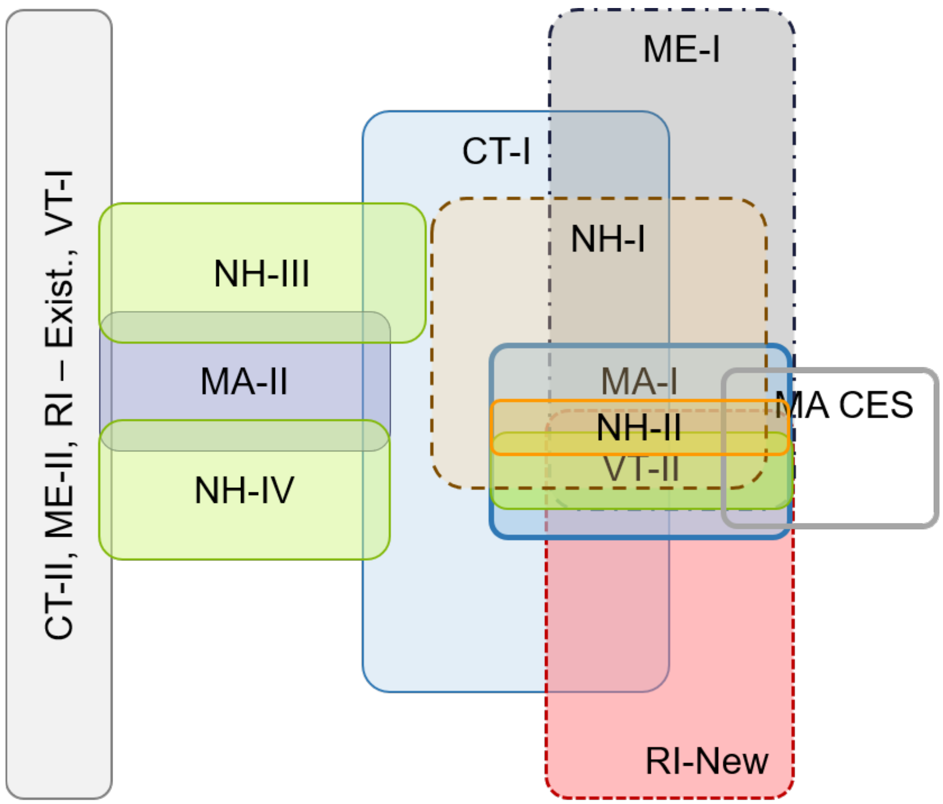

Figure 3-13. New England RPS Eligibility Map[35]

Since the Class I RPS compliance began in 2003,[36] the market has demonstrated that small differences in eligibility can cause state-by-state REC prices to either converge or diverge as supply and demand conditions vary over time. We have historically been a significant seller of RECs to the Class I markets in Massachusetts and Connecticut for customers, and to a lesser degree the Massachusetts Class II market.

[35] Source: Sustainable Energy Advisors (SEA).

[36] Maine Class 2 compliance began in 2000. The legislature defined supply eligibility to dramatically exceed demand, however, resulting in surplus conditions and permanently suppressed REC prices.

REGIONAL MARKETS FOR NEW RENEWABLES

Historic Conditions in Class I RPS and REC Markets

Early RPS markets were characterized by shortages, as Class I demand—driven by state policy—grew faster than new renewable energy supply. As a result, Class I RECs were transacted in the short-term bilateral market (which resembles a spot market) at prices just below the administratively-determined price cap—referred to as the Alternative Compliance Payment. Periodic price-variability in early RPS markets was largely driven by adjustments to legislation or regulation. Such changes often had dramatic effect because of their ability to add (or less frequently, subtract) eligible supply overnight by granting eligibility to facilities already in service.

Figure 3-14 uses historical Connecticut Class I REC prices to illustrate the impact of legislative and regulatory adjustments to existing polies. In Connecticut's case, policymakers granted eligibility to additional sources of existing supply in mid-2005, and again in mid-2008. These regulatory adjustments were the primary contributors to price declines observed in the Connecticut Class I market in those years.

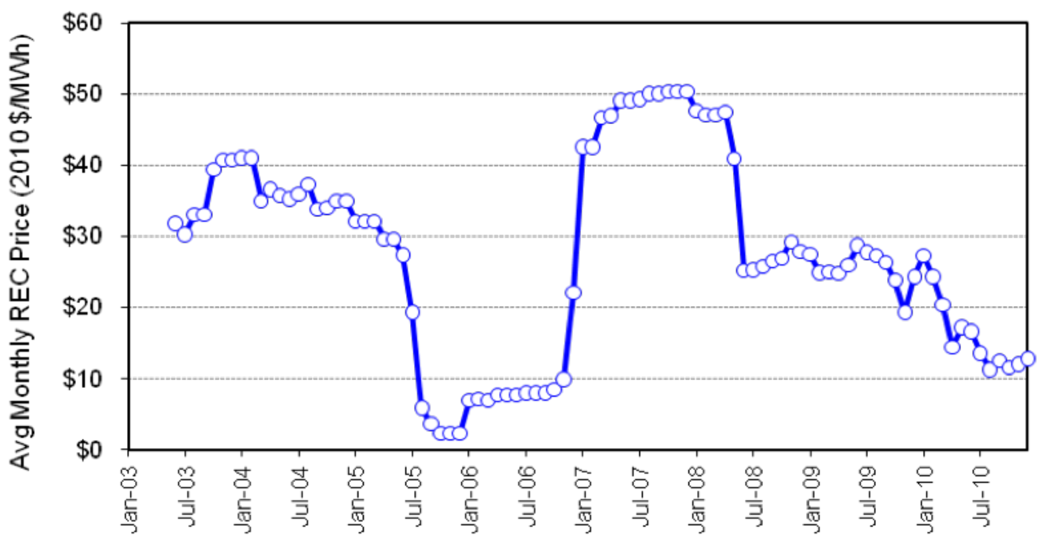

Figure 3-14. REC Price Volatility Example Resulting from Legislative or Regulatory Adjustment[37]

Note: Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices for the current or nearest compliance year.

37 Chart data source: Evolution Markets and Spectron.

Current Conditions in Class I RPS and REC Markets

By comparison, the Class I market is currently experiencing a surplus of supply over demand. Between 2015 and 2018, regional Class I supply caught up to and surpassed demand. As a result of these new surpluses across the region, Class I markets concluded the 2017 compliance year with RECs trading below $10 per MWh.

This dynamic is in dramatic contrast to historic shortages and high REC prices, and is primarily driven by three factors:

1. Long-term procurements of Class I supply quantities that exceed current and future incremental demand, based on current RPS targets. These procurements originate almost entirely from Massachusetts, Connecticut, and Rhode Island.
2. Aggressive distributed generation policies, which have been implemented effectively, and have resulted in hundreds of MWs of Class I supply, much of which is interconnected behind the retail meter and also reduces load.
3. Reductions in current and expected load. ISO-New England is producing lower region-wide load forecasts each year—a function of consumption behavior, energy efficiency penetration, and on-site generation.

Figure 3-15 summarizes the REC price declines between 2015 and 2018.

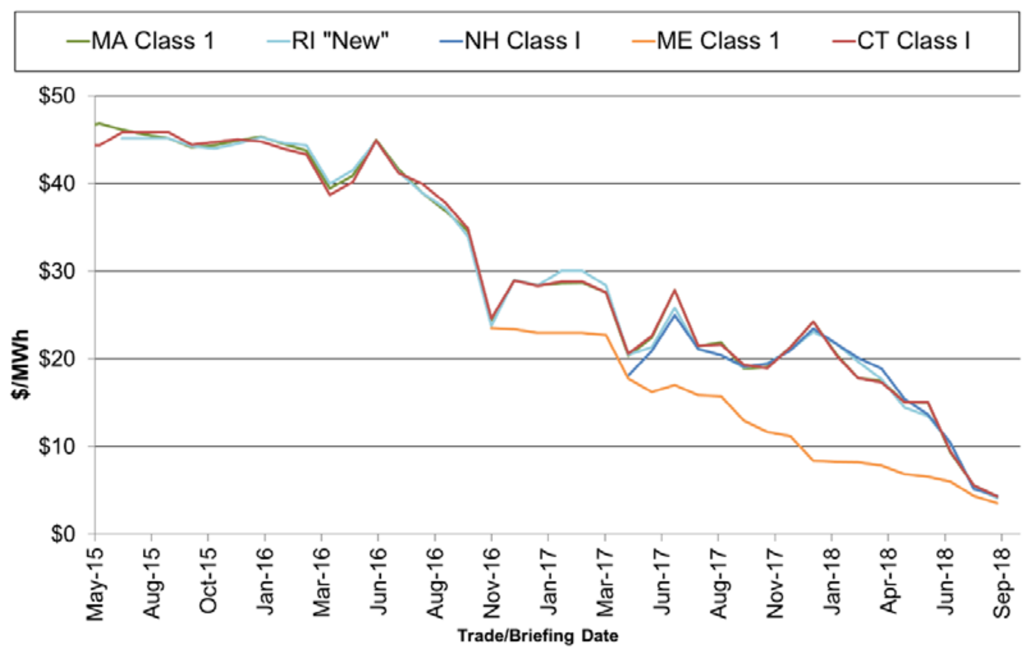

Figure 3-15. New England Class I REC Spot Market Prices: 2015–2018[38]

[38] Source: Sustainable Energy Advisors (SEA).

Current market conditions underscore that historical REC prices should not be used to set expectations for future revenues. Over the IRP planning period, we expect that the evolution of regional supply and demand dynamics will continue to create REC price uncertainty, leading to variability for GMP and our customers. The current surplus in regional Class I REC markets is expected to persist for at least the next five years.

These conditions are driven primarily by:

- Overestimating the annual load in each of the last several years, and the expectation for year-over-year reductions in actual load compared to recent ISO forecasts.
- Recent policymaker actions to support the continued operation of five existing New Hampshire biomass facilities for the next three years—and, in one case, through 2022.
- The continued success of regional distributed generation policies.

Over this period, prices for RECs produced by projects currently in operation[39] are expected to be substantially below historical levels.

Moderating this trend in surplus Class I resource, the new Massachusetts Clean Energy Standard (CES) is expected to create modest upward pressure on REC prices from approximately 2020 to 2022. The ultimate impact of Massachusetts CES demand will depend on the degree of continued load declines, energy efficiency deployment, and distributed generation penetration in the near term, and the date on which CES-eligible hydroelectric generation is ultimately delivered to New England over new transmission.

Beyond 2022 and the influence of the CES, the primary drivers of the expectation for continued regional Class I market surplus include:

- The selection of 1,400 MW of offshore wind developments.
- Massachusetts' additional authority to solicit up to 2,400 MW of additional offshore wind.
- Existing contracts with hundreds of MWs of competitively procured onshore renewable energy resources that have not yet—or only recently—come online.
- Forecasted reductions in New England load.

[39] New projects may be able to secure higher REC prices through competitive solicitations for long-term contracts aimed at projects not yet in operation.

Key Market Uncertainties

Uncertainty in regional Class I REC markets can be attributed to several primary factors, summarized in Table 3-3.

Key Uncertainty: Primary Contribution	Near-Term	Long-Term
Will Maine terminate its Class I RPS after 2022?	✓	
Will Massachusetts add capacity blocks to the SMART policy?	✓	
When will Connecticut implement the biomass REC-MWh phase-down?	✓	✓
Will New York RES Tier I demand trigger exports from New England?	✓	✓
New England project delay or attrition.	✓	✓
Energy and capacity market pricing.	✓	✓
Continued energy efficiency and consumption behavior.	✓	✓
Additional potential changes in RPS demand targets.	✓	✓
Will New York adopt a Tier II policy, causing supply to remain in that state?		✓

Table 3-3. Near-Term and Long-Term Regional Class I Rec Market Uncertainties

As of late 2018, regional renewable energy supply and demand policies are out of alignment. The supply-side policies are expected to produce substantially more RECs than are currently called for by incremental RPS demands. While Massachusetts, Connecticut, and Rhode Island have all either increased or extended their Class I RPS targets in recent years, these increases have not matched new renewable energy supply commitments. We also observe that the supply of new renewable energy in the region has become increasingly dependent on a small number of large projects (for example, offshore wind and import projects delivering energy from outside New England), as opposed to a larger number of smaller projects as was the case in past years. This raises the potential for significant, discrete movements in REC market prices in future years depending on whether or not those large projects reach completion on time.

REGIONAL MARKETS FOR EXISTING RENEWABLES

Vermont Tier I and other existing renewable supply obligations apply to facilities that were already in operation prior to the adoption of RPS and RES programs. Regionally, this type of renewable energy policy has been promoted to maintain the current fleet of renewable, carbon-free resources that tend to be cost-effective, rather than spur greater development of new generating facilities at potentially higher cost. Existing classes cover a wide range of technologies, including but not limited to: hydroelectric, biomass, landfill gas, waste-to-energy, and—in some cases—combined heat and power. Overall, the existing renewable market supply is expected to be adequate for the demand, with REC prices sufficient to keep the existing fleet in operation, but not enough to create incentives for new development.

Because of the more static supply and demand relationship in the existing renewable market, policy-based adjustments to either supply eligibility or demand targets can alter market dynamics quickly. While historical REC prices in existing markets have remained largely stable, it is possible that state-level preferences and objectives (more than market forces) could spur a policy adjustment that causes REC prices in existing RPS classes to increase in future years.

We believe it important to monitor market conditions and dynamics to determine if:

- Production variances based on resource availability may have an impact on REC prices, particularly in the short-term.
- The sum of energy, capacity, and REC prices could be insufficient to cover operating expenses for some existing plants.
- The cost and effort required to maintain RPS certification impacts participation (for example, LIHI) could limit supply.
- Changes in the role of imports and exports could impact supply, demand, and price dynamics.

In our experience, Tier I-eligible RECs tend to be available on a long-term basis only when bundled with the output of a renewable facility (that is, through a long-term PPA or asset purchases). REC-only purchases tend to only be available on a short-term basis (that is, up to a couple of years at a time).

For Vermont Tier I, during the planning period, REC prices are expected to reside within the range of approximately $1 to $9 per MWh. Prices at the low end of this range represent a market in which the majority of existing supply continues to operate, and demand for existing RECs in neighboring states remains stable. Prices at the high end of this range reflect a future with a combination of attrition among existing generators and increased demand—including both compliance and voluntary markets—in neighboring states that leads to higher REC prices. For Vermont Tier I, REC price risk is bounded by a $10 per MWh alternative compliance payment. The range between these values represents a market characterized by modest demand increases, most likely as a result of increased demand for both new and existing renewables by corporate and institutional purchasers.

4.Declining Electricity Demand

DECREASED SALES, INCREASED KILOWATT HOURS

As we transition to a new energy future, Green Mountain Power customers are buying less energy today than they were at the end of 2003. Sales of baseload energy in Vermont have declined to levels last seen fifteen years ago.

Sustained investments in energy efficiency at the local and federal levels are a part of this decline, and Vermonters also have the opportunity to buy and install their own solar energy systems on their homes and businesses or take part in group solar energy systems to satisfy all or part of their energy needs. Since 2008, Vermont's net-metering program within GMP has grown to include almost 10,000 residential customers and almost 2,700 businesses whose primary source of electricity is from either self-generation or providers other than GMP.

There is no doubt that Vermont's net-metering program has helped the state advance toward a renewable energy future and achieve environmental goals. We have been a key partner in these successes and have far exceeded our own carbon reduction goals in 2017. We are set to exceed them again in 2018.

Net metering helps attain renewable generation targets, and it also leads to reduced demand, and thus reduced sales to support the infrastructure and innovation our customers need. This situation of declining sales, spread among fewer customers, is a sign of success and also a cost issue that presents challenges for us, our customers, and state policymakers and regulators.

SALES AND DEMAND IN THE PLANNING PROCESS

Sales and demand form a foundational standard for integrated resource planning.

Historically, we could plan for consistent year-over-year sales growth. For example, Table 4-1 shows average growth in sales for the decade from 1995 through 2004. While our Vermont weather annually affects sales differently, the overall pattern of sales grow is unmistakable.

Year	Retail Sales (MWh)	Annual Change (MWh)	Annual Change (%)
1995	3,794,311	—	—
1996	3,882,150	87,839	2.3%
1997	3,934,251	52,101	1.3%
1998	3,966,877	32,626	0.8%
1999	4,074,581	107,704	2.7%
2000	4,150,626	76,045	1.9%
2001	4,117,206	–33,420	–0.8%
2002	4,129,799	12,593	0.3%
2003	4,131,891	2,092	0.1%
2004	4,211,602	79,711	1.9%
Total Change / Average Change Percentage		417,291	1.2%
Compounded Average Growth Rate (Reported to FERC)			1.2%

Table 4-1. Legacy GMP and CVPS Combined Retail Sales, 1995–2004

Recent projections, however, forecast essentially flat sales. Our 2015 IRP Load Forecast Report, which formed the basis of our 2014 IRP, indicated that we could expect 0.2% annual growth between 2017 and 2028 (Table 4-2). This represents approximately an 85% reduction in sales growth over two decades before (0.2% versus 1.2%).

Year	Retail Sales (MWh)	Annual Change (MWh)	Annual Change (%)
2017	4,283,851	—	—
2018	4,287,010	3,159	0.1%
2019	4,287,332	322	0.0%
2020	4,280,655	−6,677	−0.2%
2021	4,265,783	−14,872	−0.4%
2022	4,272,630	6,847	0.2%
2023	4,283,191	10,561	0.2%
2024	4,300,610	17,419	0.4%
2025	4,305,751	5,141	0.1%
2026	4,319,724	13,973	0.3%
2027	4,336,678	16,954	0.4%
2028	4,363,099	26,421	0.6%
Total Change / Percent		79,248	0.2%

Table 4-2. 2015 Retail Sales Forecast

The 2019 Budget Forecast Report (discussed in Appendix B), which forms the foundation of analysis for our 2018 IRP, projects sales erosion similar to those projections from our 2014 IRP. According to the forecast (Table 4-3), sales between 2017 and 2028 are expected to decline on average by 0.2% annually. In 2015, total 2017 retail sales were forecast to be approximately 4,300,000 MWh; in reality, we did not achieve that projection. Sales over the next decade are now not expected to reach that projected amount either; rather they are projected to steadily decline. Sales are expected to reach less than 4,100,000 MWh by 2028, or approximately 5% lower than the forecasted 2017 retail sales had been predicted in the 2014 IRP.

Year	Residential (MWh)	Chg	Commercial (MWh)	Chg	Industrial (MWh)	Chg	Other (MWh)	Chg	Total (MWh)	Chg
2008	1,559,231	–	1,584,987	–	1,063,320	–	10,710	–	4,218,248	–
2009	1,544,874	−0.9%	1,530,564	−3.4%	973,631	−8.4%	10,780	0.7%	4,059,848	−3.8%
2010	1,558,457	0.9%	1,534,895	0.3%	1,013,453	4.1%	10,918	1.3%	4,117,722	1.4%
2011	1,552,270	−0.4%	1,527,244	−0.5%	1,073,557	5.9%	11,414	4.5%	4,164,485	1.1%
2012	1,520,840	−2.0%	1,538,905	0.8%	1,169,331	8.9%	10,645	−6.7%	4,239,721	1.8%
2013	1,562,370	2.7%	1,550,572	0.8%	1,178,595	0.8%	8,443	−20.7%	4,299,981	1.4%
2014	1,568,689	0.4%	1,559,491	0.6%	1,177,033	−0.1%	6,887	−18.4%	4,312,099	0.3%
2015	1,539,045	−1.9%	1,531,148	−1.8%	1,168,796	−0.7%	5,274	−23.4%	4,244,263	−1.6%
2016	1,483,553	−3.6%	1,530,603	0.0%	1,188,527	1.7%	4,852	−8.0%	4,207,536	−0.9%
2017	1,465,612	−1.2%	1,516,541	−0.9%	1,170,493	−1.5%	4,453	−8.2%	4,157,098	−1.2%
2018	1,467,655	0.1%	1,518,210	0.1%	1,175,494	0.4%	4,760	6.9%	4,166,119	0.2%
2019	1,440,878	−1.8%	1,521,410	0.2%	1,179,223	0.3%	4,760	0.0%	4,146,271	−0.5%
2020	1,425,189	−1.1%	1,528,236	0.4%	1,173,906	−0.5%	4,760	0.0%	4,132,091	−0.3%
2021	1,404,761	−1.4%	1,528,060	0.0%	1,175,862	0.2%	4,760	0.0%	4,113,442	−0.5%
2022	1,390,565	−1.0%	1,529,039	0.1%	1,178,369	0.2%	4,760	0.0%	4,102,733	−0.3%
2023	1,378,673	−0.9%	1,529,121	0.0%	1,178,659	0.0%	4,760	0.0%	4,091,212	−0.3%
2024	1,370,041	−0.6%	1,530,529	0.1%	1,178,567	0.0%	4,760	0.0%	4,083,897	−0.2%
2025	1,359,059	−0.8%	1,532,087	0.1%	1,177,505	−0.1%	4,760	0.0%	4,073,410	−0.3%
2026	1,350,439	−0.6%	1,534,800	0.2%	1,175,797	−0.1%	4,760	0.0%	4,065,796	−0.2%
2027	1,345,652	−0.4%	1,538,443	0.2%	1,174,086	−0.1%	4,760	0.0%	4,062,941	−0.1%
2028	1,344,158	−0.1%	1,542,812	0.3%	1,173,789	0.0%	4,760	0.0%	4,065,519	0.1%
2008–2017		−0.7%		−0.5%		1.2%		−8.8%		−0.1%
2017–2020		−0.9%		0.3%		0.1%		2.3%		−0.2%
2020–2028		−0.8%		0.2%		0.0%		0.6%		−0.2%

Table 4-3. Customer Class Cost-of-Service Billed Sales Forecast (MWh)

Starting in 2015, the successes of solar net metering together with energy efficiency measures associated with LED lights and energy-efficient appliances, gained greater momentum, causing a decrease in electricity sales.

Table 4-4 compares projected retail sales from 2015, just four years ago, to the retail sales we are now forecasting in 2018.

Year	2015 Forecasted Retail Sales (MWh)	2019 Forecasted Retail Sales (MWh)	Annual Change (%)
2017	4,283,851	4,157,098	−3.1%
2018	4,287,010	4,166,119	−2.9%
2019	4,287,332	4,146,271	−3.4%
2020	4,280,655	4,132,091	−3.6%
2021	4,265,783	4,113,442	−3.7%
2022	4,272,630	4,102,733	−4.1%
2023	4,283,191	4,091,212	−4.7%
2024	4,300,610	4,083,897	−5.3%
2025	4,305,751	4,073,410	−5.7%
2026	4,319,724	4,065,796	−6.3%
2027	4,336,678	4,062,941	−6.7%
2028	4,363,099	4,065,519	−7.3%

Table 4-4. Sales Comparison: 2015 Retail Sales Forecast versus 2019 Retail Sales Forecast

Figure 4-1 shows how the sales forecast in 2015 projected a slight increase over the next decade, whereas the 2019 Budget Forecast Report depicts a slight decline over the same time period—a dramatic shift over the course of just four years.

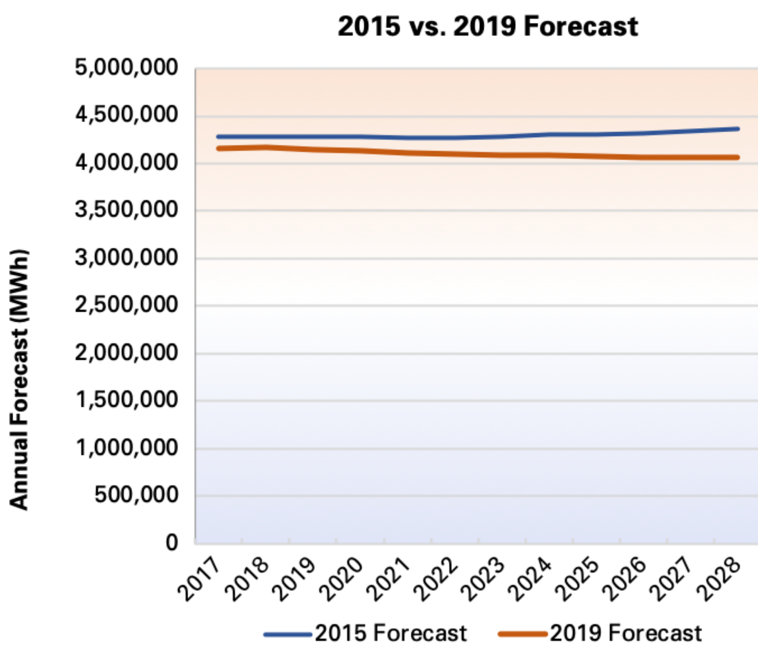

Figure 4-1. Comparison of 2015 Retail Sales Forecast versus 2019 Retail Sales Forecast Trends

Traditionally, higher customer growth led to higher retail sales, but that trend has completely changed. Table 4-5 shows that while the forecasted growth in the number of customers from 1995–2004 has slowed from a rate of approximately 1.0% to a forecasted rate of 0.4% over the next decade, the percentage increase is still positive.

Year	Number of Customers	Annual Increase	Annual % Change	Year	Number of Customers	Annual Increase	Annual % Change
1995	218,718	—	—	2018	264,482	—	—
1996	220,835	2,117	1.0%	2019	265,610	1,128	0.4%
1997	222,206	1,371	0.6%	2020	266,423	813	0.3%
1998	223,824	1,618	0.7%	2021	267,284	861	0.3%
1999	225,092	1,268	0.6%	2022	268,439	1,155	0.4%
2000	227,826	2,734	1.2%	2023	269,608	1,169	0.4%
2001	230,526	2,700	1.2%	2024	270,785	1,177	0.4%
2002	233,161	2,635	1.1%	2025	271,980	1,195	0.4%
2003	236,144	2,983	1.3%	2026	273,150	1,170	0.4%
2004	238,519	2,375	1.0%	2027	274,275	1,125	0.4%
—	—	—	—	2028	275,359	1,084	0.4%
Average Change		19,801	—	Average Change		10,877	—
Compounded Average Growth Rate (CAGR)			1.0%	Compounded Average Growth Rate (CAGR)			0.4%

Table 4-5. Historical and Forecasted Growth in Number of Customers Comparison

Year-over-year increases in the number of customers during the decade of 1995 through 2004 corresponded to an increase in sales as depicted in Table 4-1. Table 4-5 projects that, over the next decade, while the number of customers continues to grow, this growth corresponds with declining demand.

FACTORS AFFECTING CONSUMPTION

Six main factors affect retail sales forecasts: three reduce sales and three increase sales.

Sales Reducers. Energy efficiency, appliance standards, and solar net metering.

Sales Increasers. Economic and household growth, the newer technologies of heat pumps and electric vehicles, and additional strategic electrification.

Energy Efficiency and Appliance Standards

The impact of efficiency upon retail sales arises from several different sources. As stated in the 2019 Budget Forecast Report: "Factors driving change in stock efficiency include new end-use standards, state efficiency programs that either subsidize the cost of more efficient end-use options or provide new end-use measures such as lighting and weatherization as part of home and business units, and just natural turnover of existing equipment with more efficient equipment."[40]

Retail sales forecasts contained both Efficiency Vermont's (EVT's) most current energy efficiency savings projections as well as EIA's Annual Energy Outlook for 2017 end-use efficiency estimates for the New England Census Division. Table 4-6 summarizes the impact of energy efficiency and appliance standards upon our retail sales forecast. The incremental efficiencies employed between 2018 and 2028 result in our retail sales being approximately 238,000 MWh (or almost 6%) lower than they otherwise would be.

Our analysis captured 90% of residential energy efficiencies, thus applying 10% of forecasted energy efficiency to future loads (to avoid double counting). We expect that a greater portion of energy efficiency will be captured by our future analysis. Thus, energy efficiency is imbedded in load and not captured in Table 4-6.

Over the next 10 years, changes in both national and Vermont policy increasing support for efficiency measures, consistent with climate and other goals we support, could further affect these projections. That uncertainty requires monitoring throughout the planning period and beyond.

Year	Incremental (MWh)	Cumulative (MWh)
2018	−22,941	−22,941
2019	−27,508	−50,449
2020	−27,045	−77,494
2021	−30,565	−108,059
2022	−25,003	−133,062
2023	−22,928	−155,990
2024	−18,512	−174,502
2025	−20,751	−195,253
2026	−17,389	−212,642
2027	−13,354	−225,996
2028	−11,613	−237,609

Table 4-6. Energy Efficiency Impact on Retail Sales Forecast

40 *Green Mountain Power 2019 Budget Forecast Report*, prepared by Itron, Inc., April 2, 2018; pages 12–13.

Solar Net Metering

Over the last six years, we have seen a rapid increase in the installed capacity of net-metered solar installations. Table 4-7 shows installed and cumulative MW by year.

Year	Installed Net Metering (MW)	Cumulative Installed Net Metering (MW)
1999	0.002	0.002
2000	0.001	0.003
2001	0.011	0.014
2002	0.020	0.030
2003	0.030	0.060
2004	0.030	0.090
2005	0.040	0.130
2006	0.090	0.220
2007	0.050	0.260
2008	0.460	0.720
2009	1.100	1.800
2010	2.600	4.400
2011	1.900	6.300
2012	3.400	9.700
2013	9.900	19.600
2014	21.400	41.100
2015	23.600	64.700
2016	38.900	103.600
2017	33.400	137.000
2018*	20.000	157.000

* Values as of November 16, 2018

Table 4-7. Installed Solar Net Metering: 1999–2018

Net-metered solar in our service territory remained relatively dormant until the introduction of our solar adder in 2007, which stimulated activity through a net metering credit that more accurately valued solar at that time. Since then, net-metered solar, from both rooftop and group installations, has grown steadily, especially over the past five years (Figure 4-2).

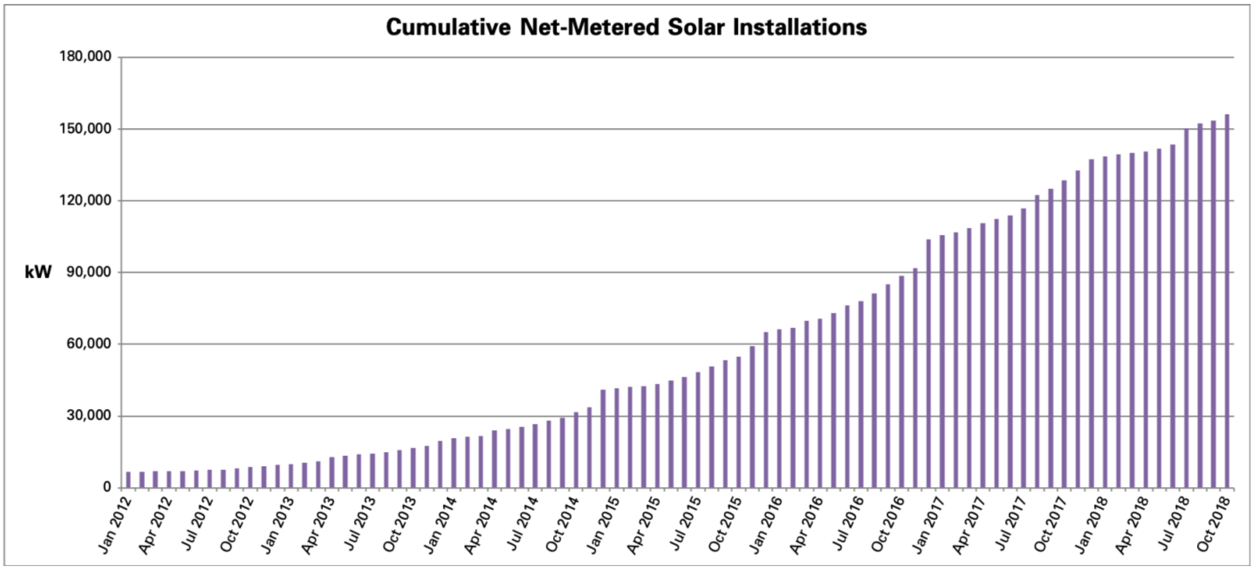

Figure 4-2. Net-Metered Solar Installation Growth: 2012–2018

We anticipate the rooftop solar net metering deployment to continue at a strong pace while the larger scale group net-metered projects (larger than 150 kW) should slow down slightly compared to the previous five years.

Solar installations that are not net-metered also continue to grow (Figure 4-3). These installations are typically larger facilities that are part of the Vermont Standard Offer program or that have PPAs with us and other Vermont utilities. Note that the cumulative kW from net-metered installations far outpaces those from non-net-metered facilities.

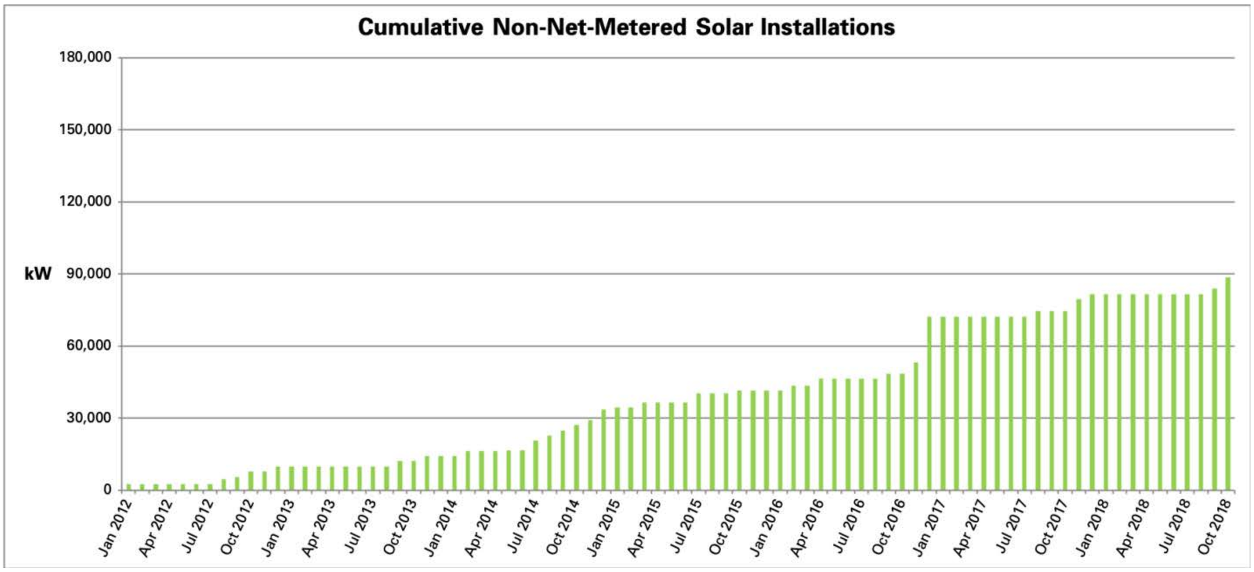

Figure 4-3. Non-Net-Metered Solar Installation Growth: 2012–2018

We developed a solar net metering installation forecast based upon both applications for a recent period (calendar year 2017) as well as historical attrition rates for those applications. After the completion of some older applications, we then used the same methodology to calculate annual installations to be approximately 24 MW per year.[41] This amount was used to forecast retail sales.

Because of both net metering rules and accounting principles, solar net metering affects both revenue and power supply expense. For customers that utilize net-metered solar, retail sales are lowered by the amount of power consumed onsite within the month that the offsetting generation was produced. Anything not consumed onsite within that month is considered 'excess' energy and creates a power supply expense in the month it was produced. This expense creates credits, which are then applied to reduce those customers' bills. In addition, the 'REC' adder that is paid to every kWh generated is treated as a power supply expense and is used to fulfill our Tier II obligation under the Vermont Renewable Energy Standard (RES) (as is discussed further in Chapter 5: Our Increasingly Renewable Energy Supply).

[41] The portfolio evaluation (in Chapter 8) reflects a modestly slower net metering growth rate of 20 MW per year (which reflects more current information, including the PUC's biennial review of net metering payment rates) as a base case. It tests the implications of alternative growth rates of 10 MW per year and 30 MW per year. While this base case portfolio analysis does not match precisely with the financial forecast presented in this chapter, many of the portfolio model's key component inputs (including volumes and prices for major power sources, which drive most of our power costs) are the same, and the bottom-line cost projections are similar.

Solar net metering generation falls into one of two general categories: interconnected or group. Interconnected solar arrays are located directly on the customer premises behind the meter. This could be either a residential or a commercial customer location, and typically the energy produced is consumed by the individual customer. These arrays tend to have larger excesses during the summer, but much lower generation during the darker months. Since the generation is co-located with the customer who consumes the power, these installations reduce retail sales on a per MW basis greater than group net metering arrays.

Group solar arrays are typically connected directly to the distribution system and generate energy that is assigned to participating customers. Since the panels are typically not co-located with the end users, this arrangement results in almost all of energy being deemed as a power supply expense. Thus, the category of solar installations is important. These historical impacts on revenue per solar net metering MW were used to determine the impact upon retail sales.

Table 4-8 shows the incremental impact of solar net metering upon the retail sales forecast.

Year	Incremental (MWh)	Cumulative (MWh)
2018	–5,802	–5,802
2019	–11,602	–17,404
2020	–8,384	–25,788
2021	–8,284	–34,072
2022	–9,355	–43,427
2023	–8,334	–51,761
2024	–8,458	–60,219
2025	–8,211	–68,430
2026	–8,334	–76,764
2027	–8,334	–85,098
2028	–8,530	–93,628

Table 4-8. Solar Net Metering's Incremental Impact of Retail Sales Forecast

The incremental impact of solar net metering added over the next 10 years results in an approximate 2.2% further reduction of retail sales in 2028 compared with a scenario in which no new arrays are added.

Economic and Household Growth

Growth marks an increase in retail sales because of household and economic activity. Growth-related sales increases are still occurring in our service territory. Historically, growth was the only variable that affected retail sales; now growth is but one of several variables.

Based on recent trends (as show in Table 4-5), we fully expect the number of customers to continue to increase, albeit at a slower pace. Thus, we are planning on the forecasted growth of 0.4% per year in the number of customers (rather than the 1.0% per year pace seen during the period 1995-2004).

We also expect economic activity to grow. Moody's Analytics projects slowing household income growth affecting slower residential retail sales. The country's projected annual growth of 1.1% in commercial gross domestic product coupled with a 0.6% annual growth in employment is expected to have a positive, although not direct, effect on our retail sales. Table 4-9 shows the expected growth in retail sales because of these economic and household growth projections.

Year	Incremental (MWh)	Cumulative (MWh)
2018	21,889	21,889
2019	8,091	29,980
2020	9,117	39,097
2021	13,694	52,791
2022	16,780	69,570
2023	12,434	82,005
2024	11,823	93,828
2025	10,021	103,850
2026	8,904	112,753
2027	8,513	121,266
2028	11,006	132,272

Table 4-9. Economic and Household Growth's Incremental Impact of Retail Sales Forecast

Note that, by 2028, the projected *increase* in retail sales from economic and household growth (132,272 MWh) is slightly more than half of the projected *decrease* in retail growth from energy efficiency measures (–237,609 MWh) as depicted in Table 4-6. This results in an overall projected *decrease* in retail sales of 105,337 MWh by 2028. While this is good news for the achievement of key energy policy goals that we support and facilitate, it creates a real gap in revenue available to support infrastructure and innovation of our customers' needs.

Cold-Climate Heat Pumps

Another area of increased sales comes from electrification of home heating. We are partnering with EVT to promote technologies that displace fossil fuel, to help our climate and our customer's costs. Cold-climate heat pumps provide customers with an alternative fossil-fuel-free method to heat their homes, as well as providing a more efficient way to cool the home in the summer.

EVT expects state households to take incentives associated with 3,000 new heat pumps per year. Based on our size, we expect that 76.6% of the heat pumps to be installed in our service area—about 2,297 heat pumps annually. These estimates were provided as part of the development of the VELCO long-term demand forecast.

A recent study conducted by Cadmus on behalf of the Vermont DPS concluded that, on average, cold-climate heat pumps use 2,085 kWh per year for heating and 140 kWh per year for cooling.

We conducted a sensitivity analysis for the added consumption and peak demand resulting from new heat pump installations. We modeled three growth scenarios, defined as follows:

Low Growth. The low growth scenario represents a 15% annual decrease in heat pump sales, starting with the EVT forecast of 2,297 in 2018. The observed trend in actual heat pump sales in Vermont between 2017 (4,161) and 2018 (3,000 as forecast by EVT) represents a decrease of 28%. We tempered the rate of decline because we do not expect this trend to continue, as we (and others) will be offering purchase incentives for heat pumps.

Baseline Growth. The baseline growth scenario uses EVT's forecast of 2,297 heat pumps per year in our service territory.

High Growth. The high growth scenario represents an increase in heat pump sales by 10% each year, starting with the EVT forecast of 2,297 for 2018.

All scenarios use the average annual values of 2,085 kWh for heating and 140 kWh for cooling.

The peak coincidence values represent the percentage of total possible heat pump load that coincides with the system-wide peak demand. We obtained these values from Efficiency Maine's 2014 Technical Reference Manual (TRM), which calculates energy and demand savings from various energy efficiency measures, including cold climate heat pumps. The TRM presents peak coincidence factors of 79.7% for winter and 10.7% for summer; peaks are defined as 1:00 PM to 5:00 PM in summer and 5:00 PM and 7:00 PM in winter. These values assume no control and include extreme examples of heat pumps running during the coldest days without a backup heating source. Although our summer peak is later in the evening, cooling load is highest during the hottest hours of the day and so we believe it reasonable to assume that the coincidence factor would not be higher for a later peak.

We obtained the average 1.0 kW heating demand and average 0.3 kW cooling demand from the aforementioned Cadmus study. Cooling only accounts for 2% of heat pump consumption so the impact on peak demand applies largely to the winter season.

To forecast Tier III performance relative to heat pumps, our sensitivity analysis includes the quantity of Tier III MWh under RES that would be met by added heat pumps alone for each year in the forecast. The presumed Tier III MWh contribution of a heat pump was computed using a weighted average of different types of heat pump units sold in our service territory and their corresponding Tier III values. These values are characterized by the Tier III Technical Advisory Group's 2018 Planning Tool, using the percentage of our non-fossil-fuel generation mix.

Table 4-10 summarizes the assumptions used in our sensitivity analysis and their corresponding sources.

Description	Value	Source
Average heating consumption	2,085 kWh per year	Vermont DPS Cadmus Study
Average cooling consumption	140 kWh per year	Vermont DPS Cadmus Study
Average heating demand	1.0 kW	Vermont DPS Cadmus Study
Average cooling demand	0.3 kW	Vermont DPS Cadmus Study
Heat pump Tier III value	27.12 MWh	Weighted average from sales

Table 4-10. Heat Pump Sensitivity Analysis Assumptions

The results of the sensitivity analysis are illustrated in Figure 4-4 through Figure 4-7.

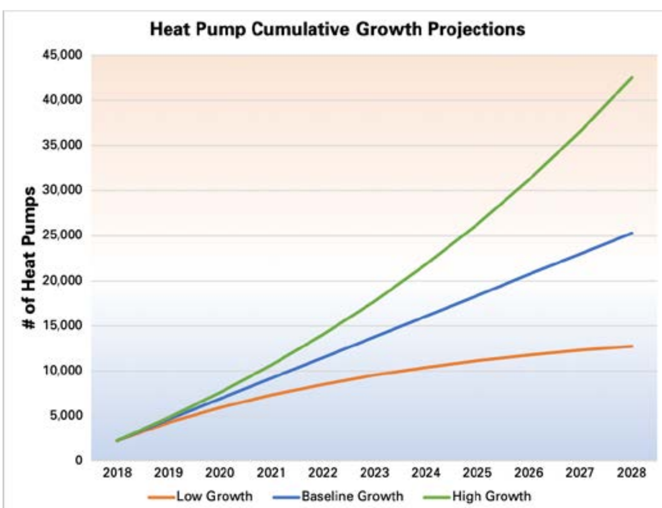

Figure 4-4. Cold-Climate Heat Pump Cumulative Growth Projections: 2018–2028

Figure 4-4 illustrates high, baseline, and low estimates for the quantity of added cold climate heat pumps in our service territory from 2018 until 2028. The cumulative values over the 10-year period are: 12,751 (low), 25,268 (medium), and 42,568 (high).

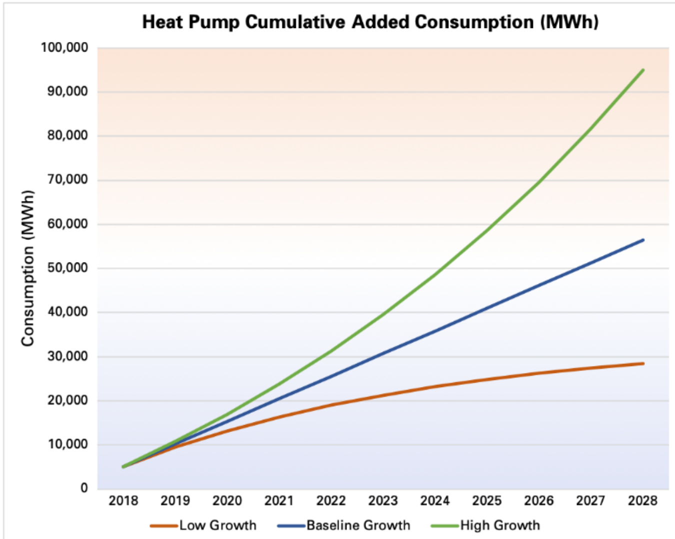

Figure 4-5. Cold-Climate Heat Pump Cumulative Added Consumption: 2018–2028

Figure 4-5 illustrates high, baseline and low projections for cumulative added MWh because of heat pump adoption through 2028. The projections are: 28,448 (low), 56,374 (baseline), and 94,970 (high).

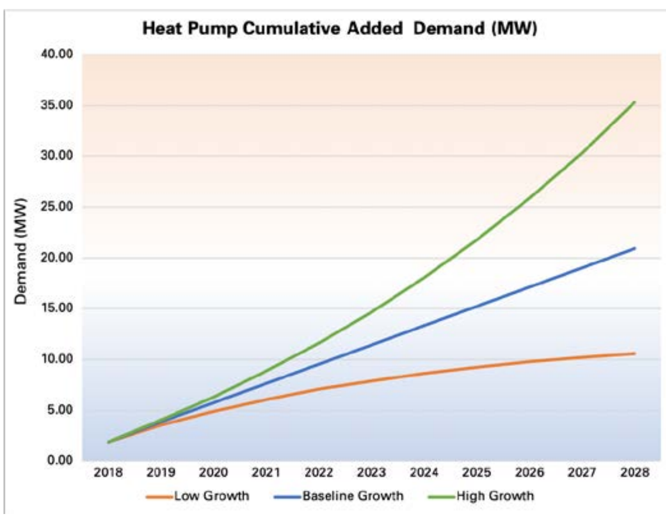

Figure 4-6. Cold-Climate Heat Pump Cumulative Added Peak Demand: 2018–2028

Figure 4-6 shows the cumulative added peak demand forecasted from the three different growth scenarios. The added demands are 10.6 MW (low growth), 20.9 (medium growth) to 35.3 MW (high growth) by 2028.

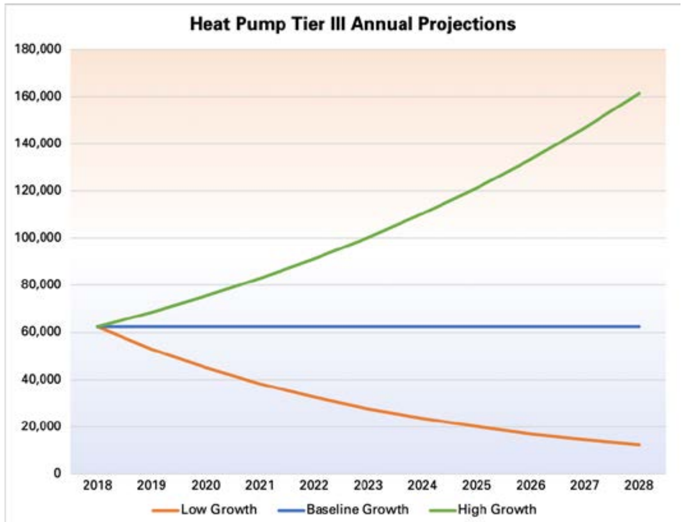

Figure 4-7. Cold-Climate Heat Pump Tier III Annual Projections: 2018–2028

Figure 4-7 illustrates high, baseline and low estimates for the annual Tier III MWh performance for added heat pumps. In the high growth scenario, heat pumps account for 56% of our total Tier III target in 2018, dropping to as low as 41% (because of a Tier III target increasing faster than the heat pump increase). In the low growth scenario, the percentage of the overall target met by Tier III ranges from 56% (2018) to 3% (2028).

Several conclusions and observations can be garnered from the analysis.

First, because of the lifetime emissions offset by cold-climate heat pumps, their adoption has a significant environmental benefit and thus supports our ability to meet Tier III targets. In the low growth scenario, heat pumps account for under 10% of our required carbon offset beginning in 2024, placing pressure on electric vehicle adoption as well as commercial and industrial (C&I) projects to make up the difference. Conversely, the high growth scenario consistently meets at least 40% of our carbon reduction targets.

Second, the analysis assumes no shared access or controls to reduce the impact of the heat pump consumption against the peak demand. We are pursuing shared access, and this control ability will improve to some extent the impact of any particular analysis outcome.

Regardless, under any analysis—even the high growth scenario—the added demand does not represent a significant peak demand addition to the overall transmission and distribution system. We have almost 300 distribution circuits; therefore, with any reasonable spread across these circuits, the individual peak contribution per circuit is still expected to be minimal even if 35 MW were added by 2028, as shown in the high growth scenario.

In any case, it will be important to effectively manage the added load through peak shaving. One challenge is that cold-climate heat pumps operate less efficiently at lower temperatures and so opportunities to shift heating load away from peak may be limited during the winter months. On the other hand, we expect many heat pump owners will have backup heating sources, as was the case for all units analyzed in the Cadmus study. This will help offset some of the added demand on very cold days when heat pumps consume most.

We observe that winter heating load dominates both the added load and consumption because of heat pump adoption. Thus, even though in the high growth scenario the cumulative added consumption equates to only 2.3% of our total projected sales, nearly all that impact occurs during the winter. That is the same time that solar generation is minimal, wholesale electricity prices are high because of a constrained natural gas supply, and the fuel mix of the grid is at its maximum CO_2 emissions. These considerations have important implications for the cost to serve each added MW, for which we are actively developing a comprehensive assessment tool.

To temper the high, and in light of our belief that the low assumption is excessively pessimistic, the baseline assumptions are used for cumulative consumption. (See "Consumption Trends" on page 4-33.)

Electric Vehicles

Transportation is the top source of carbon emission in Vermont. Transitioning from conventional combustion engines to electric vehicles will play an important role in offsetting statewide carbon emissions. This transition also will affect retail sales.

As described in Chapter 2: Innovative Customer Programs, we offer a variety of programs to encourage electric vehicle (EV) adoption. These programs include an EV charger incentive, EV charger as a service, unlimited charging, workplace contribution matches, public and workplace EV charging, and upstream rebates from manufacturers.

EV Home Charging

We believe that home charging will represent a major portion of charging activity for EV owners. Of critical importance, is the ability to manage loads during curtailments. Results from our pilot programs indicate promising responses with only a 2% opt-out rate.

Figure 4-8 shows a load curve for aggregate charging activity during a particular curtailment event that occurred between 4:00–8:00 PM. It illustrates the effectiveness of the automated control of chargers in our pilot.

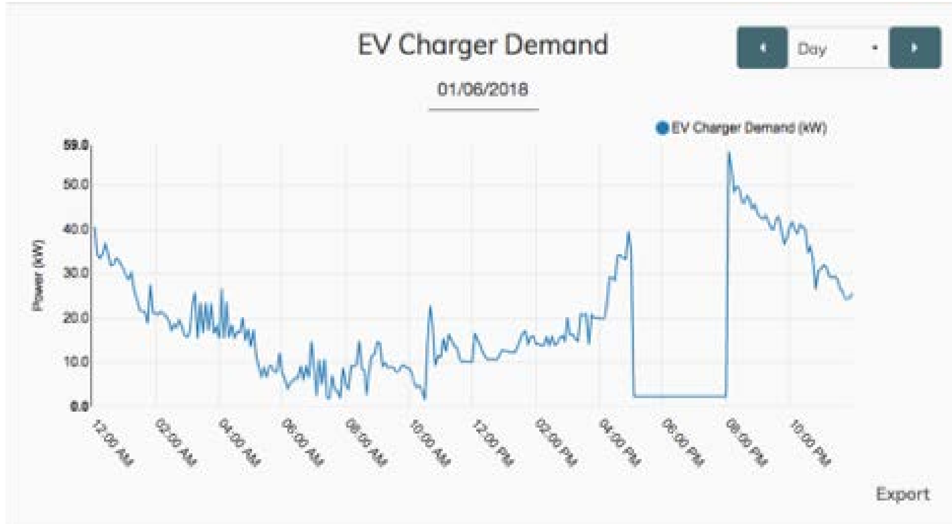

Figure 4-8. Electric Vehicle Tier III Annual Projections: 2018–2028

While these results are for a limited scale pilot, they suggest that customers are likely to cooperate with curtailments. Because the demand projection model in this report does not include an assumption that chargers will be controlled, it reflects a conservatively high demand assumption in all three projected EV volume ranges.

As an added potential value of controllable chargers, the demand associated with EV charging represents power that could be leveraged as a load-building tool in areas of high solar saturation. This would require networked chargers to be installed in businesses and other work and retail locations, allowing employees and the public to utilize these chargers during the middle of day as opposed to charging at night at home. For EV adoption to continue to grow, it must be convenient for customers; they must always have a charged EV when needed. Thus, simplicity and flexibility are critical when developing charging programs to utilize EVs as a grid resource.

Similar to heat pumps, we conducted a sensitivity analysis. For this sensitivity analysis EV sales are based on a range of projections issued in July of 2017 by VEIC. It is early in the adoption of electric vehicles, and, while there's high confidence that their proportion of the Vermont fleet will continue to grow, it is difficult to predict what trajectory the transition will take. VEIC used three ranges to identify various adoption cases. We evaluated the impacts those ranges could have, using those growth patterns, through 2028.

VEIC's forecasts cover a high range based on the level of vehicle adoption needed to reach the goals of Vermont's Comprehensive Energy Plan to achieve a 90% EV fleet. The medium range is based on a 60% EV fleet, and the low range is based on 40% EV fleet. In all scenarios, we assume that per share of Vermont total retail sales remains constant at 76.6%.

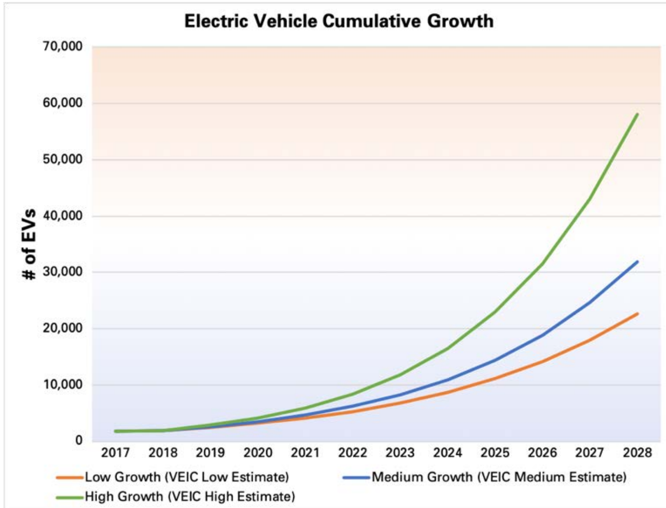

Figure 4-9. Electric Vehicle Cumulative Growth Projections: 2018–2028

Based on these models, Figure 4-9 shows a range of electric vehicle growth patterns over the study period. By 2028, the models result in a cumulative quantity of between 22,674 and 58,030 EVs in Vermont's fleet.

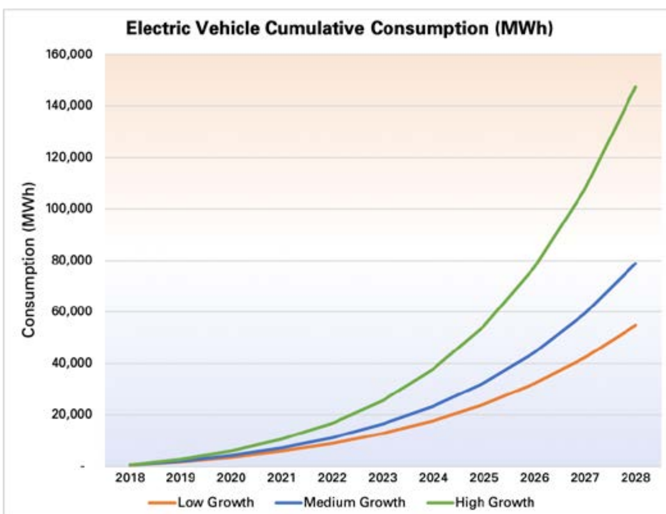

Figure 4-10. Electric Vehicle Cumulative Consumption: 2018–2028

Using Figure 4-10 shows the cumulative growth in MWh consumed by the modeled quantities of EVs over the study period. A blended averaged annual consumption of 2,470kWh is assumed for all vehicles. The forecasted effect on consumption associated with electric vehicles ranges from a low of 54,703 MWh to a high of 147,683 MWh by 2028.

Calculating consumption over time relies on a number of assumptions:

Average Electric Vehicle Miles Traveled (eVMT). In September of 2018, the Tier III Technical Advisory Group re-evaluated the characteristics of EVs, and issued an updated Technical Reference Manual (TRM). The study revealed that the average eVMT for EVs is 10,900 miles each year, and for PHEVs it is 6,908 miles each year.

Electrical Efficiency. The Technical Advisory Group TRM also reported an efficiency of 0.30 kWh per mile for all-electric vehicles (AEVs), and 0.34 kWh per mile for plug-in hybrid electric vehicles (PHEVs).

Proportion of AEVs to PHEVs. Because there is a significant difference in eVMT and electrical efficiency, the proportion between them must be factored into consumption calculations. The TRM relied on Vermont vehicle registration data to determine the proportion as of July of 2018. This proportion is roughly 33% AEV to 67% PHEV. The proportion has evolved over the past few years, with the percent of AEVs growing. The EVT model selected a growth path that would have approximately 50% AEVs by 2028. The increase from 33% to 50% over that period is depicted logarithmically in this analysis.

To estimate the average consumption of EVs each year, this model uses the quantities projected in the various volume ranges, multiplied by the weighted average of the consumption of AEVs and PHEVs as it evolves between 2018 and 2028.

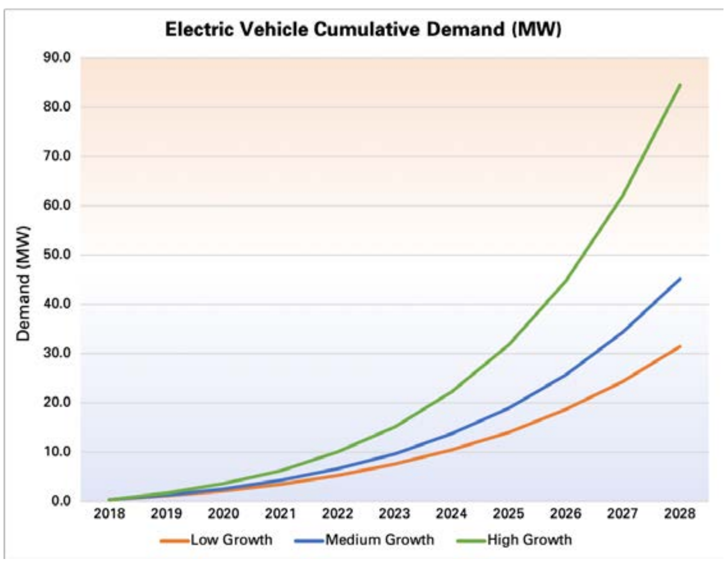

Figure 4-11. Electric Vehicle Cumulative Demand: 2018–2028

In addition to sensitivities of added retail sales we performed similar peak coincident demand sensitivities as done for the heat pumps. Figure 4-11 projects the uncontrolled, coincident peak demand for the three sensitivities performed. Assumptions include an average of 30% coincidence with peak, and an average demand of 5kW. The annual demand is calculated based on the number of EVs multiplied by the Average Demand multiplied by the Average Coincident Peak.

With over 150 network residential chargers currently operating in our Pilot platform, we were able to derive the actual peak coincidence factor. Based on aggregate load across all chargers in the program, the maximum peak coincidence factor observed in 2018 is 30%.

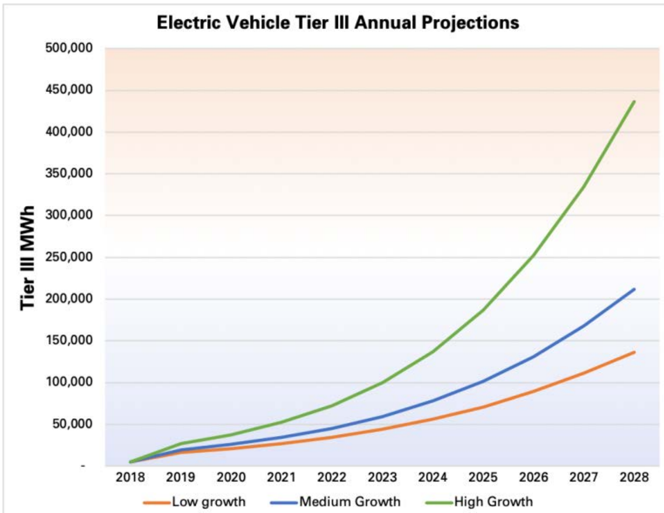

Figure 4-12. Electric Vehicle Tier III Annual Projections: 2018–2028

Figure 4-12 illustrates high, baseline and low estimates for the annual Tier III MWh performance for added EVs. The average blended MWh value of EVs changes from year to year as the proportion of AEVs to PHEVs changes starting at 66% PHEVs in 2018 and dropping to 50% by 2028. In the high growth scenario, EVs account for 436,379 MWh by 2028, 211,902 in the medium growth scenario, and 136,538 in the low growth scenario.

In terms of cumulative consumption, the high scenario shows an optimistic addition of 147,683 MWh over 10 years. This model is really illustrative to reflect what would be required to support the State's aspiration of 90% carbon free by 2050, but given what we know today, this seems like a stretch goal that would require significant acceleration beyond the planning period.

With approximately 2,300 EVs on the road today, and a manufacturing industry that has a relatively long product cycle and has not yet committed to an affordable product line that addresses the majority of driver needs, it is difficult to envision that model taking hold within the planning period.

With these factors in mind, we do believe that there will be an inflection point in the industry, and customer adoption, at some point in the near future, aided by GMP's and

Vermont's concerted efforts to encourage this transition. This led us to conclude that the low estimates are overly pessimistic. We believe the baseline scenario is the most realistic for the planning period. As such, the baseline scenario of 78,853 MWh is used in Table 4-14 (on page 4-33) that summarizes load impacts. We note that even if the high scenario were used in this planning period, the effect in these immediate years would be negligible because under any scenario adoption will accelerate in the out years.

Commercial and Industrial

In partnership with Efficiency Vermont, we have been working directly with larger commercial and industrial customers to reduce their carbon footprints while helping reduce operating costs and improve efficiency. In some instances, this involves electrification of an existing process that was formerly powered with fossil fuel.

In Tier III parlance, these projects are 'custom measures'. These measures are characterized for their fossil fuel offset, and resulting Tier III MWh value based on a set of calculations that factor in the quantity of fuel being offset, the efficiency of the legacy and new solution, the life of the measure, and our average proportion of non-fossil fuel-sourced energy in its portfolio. This is distinct from Tier III 'prescribed measures', such as heat pumps and EVs, which have pre-determined Tier III MWh values calculated by the Tier III Technical Advisory Group, and maintained in an annually updated Tier III Planning Tool.

Work with our commercial and industrial customers involving strategic electrification has included: the construction of electrical service to offset diesel generators, pumps, and compressors at quarries, maple sugar operations, ski areas, and manufacturers; air and water heating; and industrial processes.

Recent project examples have included:

- Supporting the replacement of propane-fired heating for a municipal skating rink, offsetting approximately 20,000 gallons of diesel per year.
- Extending 3-phase service to offset a generator at a manufacturer of slate roofing tiles, offsetting over 10,000 gallons of diesel per year.
- Collaborating with Efficiency Vermont to support a project that offsets propane heating in a year-round tomato greenhouse, that leverages radiated heat from high-pressure sodium lighting, combined with an insulating and light filtering curtain, offsetting over 42,000 gallons of propane per year.
- Replacing diesel compressors for snowmaking at three ski areas, offsetting a combined total of over 60,000 gallons of fossil fuel per year.

Unlike the models for heat pumps and EVs, which are based on unit quantities, modeling the impact of energy transformation projects on consumption and demand depends on a projection of the volume of projects and their presumed Tier III value. For this reason, we start with an evaluation of Tier III MWh growth, and use those projections to model consumption and demand impacts.

Figure 4-14 and Figure 4-15 show the results of a sensitivity analysis for the impact of C&I projects on consumption and demand. We modeled two scenarios: high growth and low growth.

High Growth. Assumes year-over-year increase in Tier III MWh program value starting at 150% of the previous year's performance in 2019 and decreasing 10 percentage points each year until 2024, after which the Tier III MWh performance falls below 100% of target and drops by 10% each year through 2028.

This forecast is based on several factors:

- In 2017, the first year of C&I outreach, we supported projects that achieved over 92,000 Tier III MWh. This was from just 4 projects.
- In 2018, our commercial and industrial program is expected to achieve approximately 52,000 MWh of Tier III MWh from 20 projects.
- Performance during both years was achieved with minimal external partnerships and a single full-time equivalent (FTE).
- During 2018, we crafted a collaborative partnership with EVT, an educated fleet of distribution designers looking for opportunities, and two additional full-time employees working on the program.

Low Growth. Assumes we match the 2018 projected total of 51,500 Tier III MWh in each year through 2028.

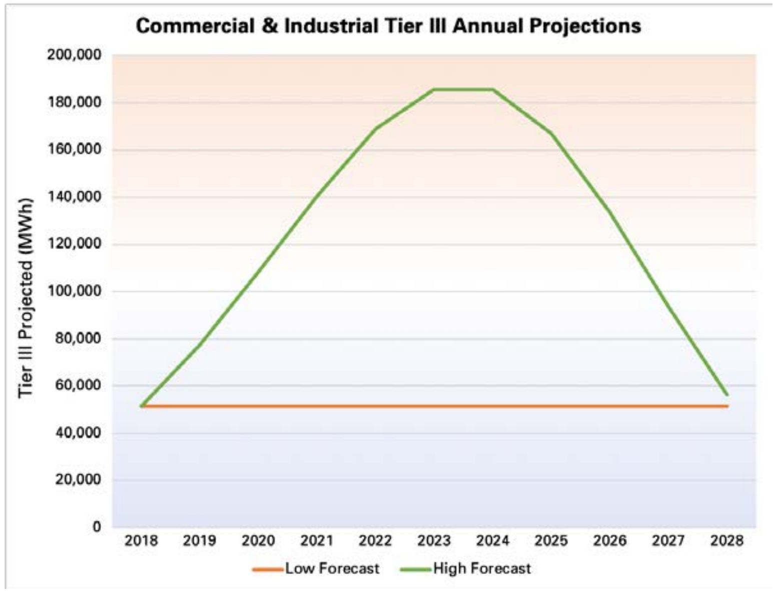

Figure 4-13. Electric Vehicle Tier III Annual Projections: 2018–2028

Figure 4-13 illustrates the trajectories of Tier III performance for these two models. The high and low estimate for Tier III MWh value each year for C&I custom projects, range from 51,500 MWh (the value in each year of the low forecast) to 185,585 MWh (maximum of the high forecast). These represent approximately 49% and 14% of our total 2028 Tier III target, respectively.

For the high and low scenarios, we calculate consumption and demand using the following assumptions based on observations from existing customers:

- Our custom Tier III projects garnered 142,281 MWh of Tier III credit between 2017 and 2018. Those projects are predicted to consume 5,398 MWh per year. This gives us a ratio of consumption added per Tier III MWh of approximately 0.038 MWh.
- The average of 1,500 hours of operations each year is arrived at based on typical operations of 2,000 hours per year, reduced by a factor to account for seasonal operations, like ski areas and gravel quarries.
- A 30% coincidence with peak. While it is early in the Tier III C&I program, this assumption takes a conservative approach to estimating peak coincidence. Some of the considerations that go into this estimate include the fact that many participants opt into the curtailable load rider program, which commits participants to curtail load specifically during peak events. In additional, many of these businesses have operating hours that end by 4:00 PM, missing typical Regional Network Service and Forward Capacity Market peak hours.

Although these are rough estimates only given the uncertainties created in this type of program, we expect that there will be enough natural variation among C&I customers to achieve a balanced demand curve.

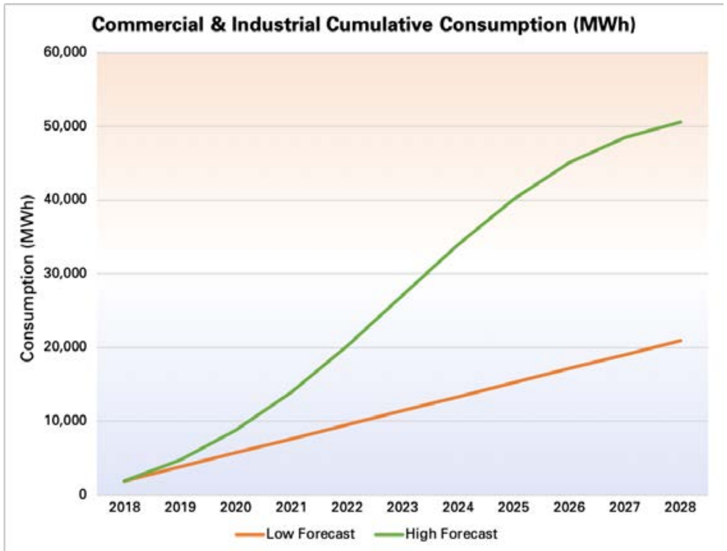

Figure 4-14. Commercial and Industrial Cumulative Consumption: 2018–2028

Figure 4-14 illustrates the resulting estimates for aggregate C&I consumption that would result from the high and low forecasts. Consumption tops out at 21,961 MWh for the low scenario, and 50,604 MWh for the high scenario, by 2028.

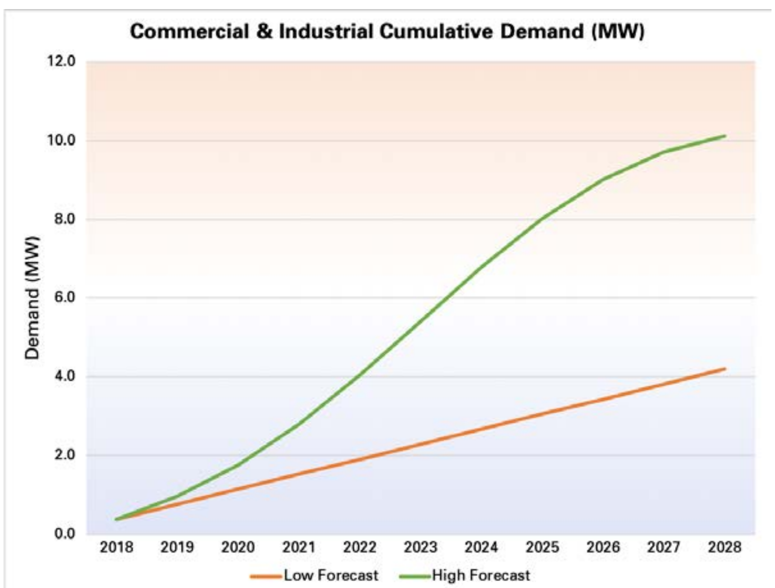

Figure 4-15. Commercial and Industrial Cumulative Demand: 2018–2028

Based on calculated consumption, and the assumed 30% coincident peak, Figure 4-15 illustrates the aggregate impact of C&I projects on demand for the two performance ranges. The aggregate demand for the high performance range is 10 MW, while the low range is projected to demand 4 MW by 2028.

While the widely varying results for C&I between 2017 and 2018 suggest divergent forecasts, there is reason to believe that the program will experience a period of growing performance for at least the next few years. The scenario carried forward to Table 4-14 (on page 4-33) assumes a baseline level of performance that is the average of high and low scenarios, which results in a forecast of 35,782 cumulative MWh over the next 10 years.

Tier III Implications

Overall Tier III performance is illustrated by combining the performance assumptions for the heat pump, EV, and C&I models. Our Tier III performance has financial, operational, and environmental implications. Tier III performance will also impact aggregate consumption and demand of our operations.

The Tier III program drives financial costs because of the manpower, promotional activities, and incentives that have to be funded to support the program. These costs are offset by revenue from the increased MWh sales that result from strategic electrification. Anther financial dynamic is the Alternate Compliance Payment, which is the regulatory penalty assessed for missed Tier III targets. ACP started at $60 per MWh in 2017, and escalates based on inflation.

The environmental implications get to the heart of why the RES exists. Each Tier III project completed will reduce Vermont's carbon footprint for the long term, by replacing a process that consumes fossil fuel with an alternative that eliminates carbon emissions.

Finally, Act 56 establishes a relationship between Tier II and Tier III by allowing Tier II MWh to satisfy shortfalls in Tier III performance.

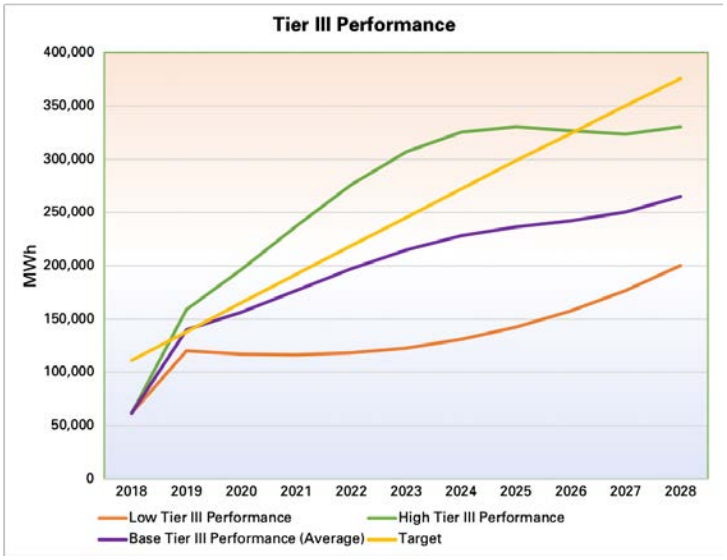

Figure 4-16. Tier III Performance: 2018–2028

Figure 4-16 illustrates a variety of trajectories for overall Tier III performance through 2028. The low model combines the low performance ranges from each of the Tier III programs: heat pumps, EVs, and C&I. The high model uses the high C&I estimate, combined with the medium performance ranges for heat pumps and EVs. This reduces the risk of magnifying the highs of multiple models. The Base model illustrates the average of the high and low Tier III performance ranges. Figure 4-16 includes the Tier III Target to show how each performance model relates to the regulatory mandate.

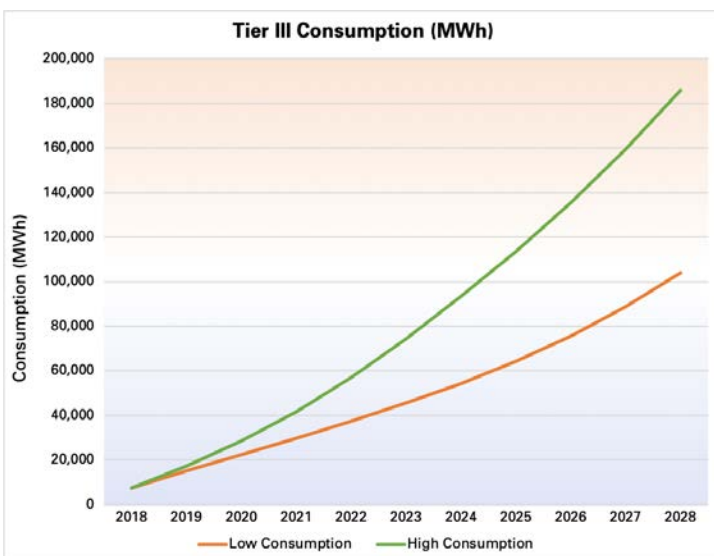

Figure 4-17. Tier III Consumption: 2018–2028

Figure 4-17 illustrates the cumulative aggregate consumption associated with the low and high models. The high model tops out at 185,831 MWh, while the low model tops out at 104,112 MWh.

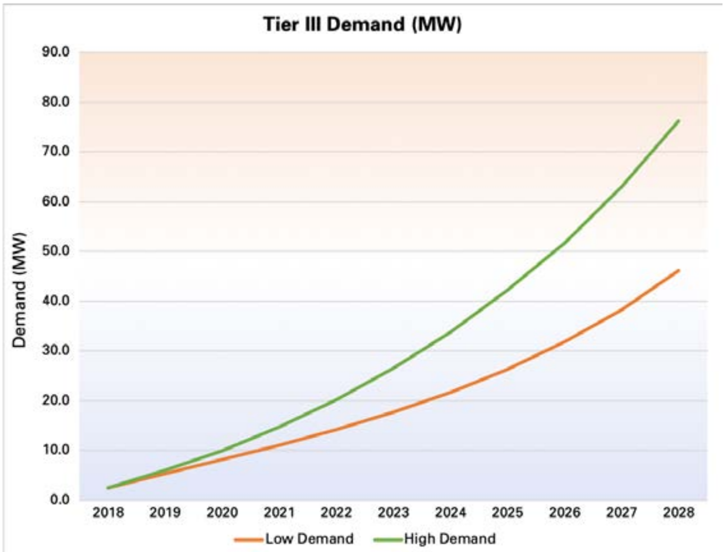

Figure 4-18. Tier III Demand: 2018–2028

Figure 4-18 illustrates the high and low estimates for overall our Tier III cumulative demand. The high model tops out at 76 MW, while the low model tops out at 46 MW.

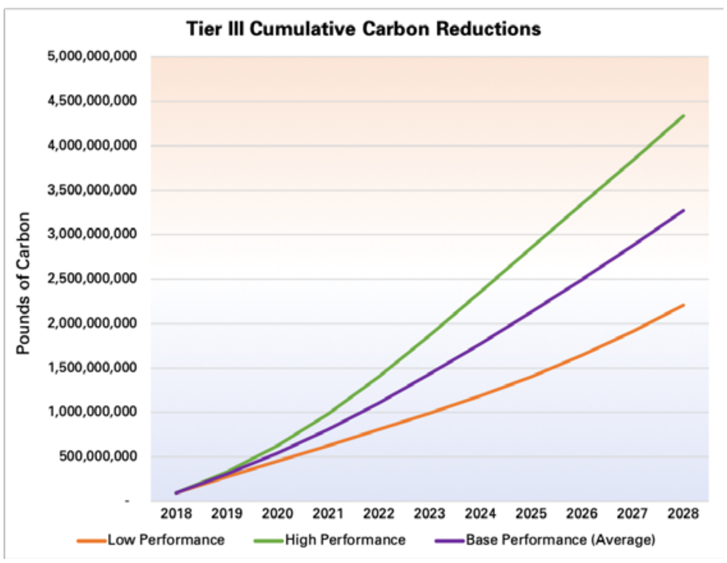

Figure 4-19. Tier III Cumulative Carbon Reductions: 2018–2028

Figure 4-19 illustrates the cumulative carbon Reductions. The high model achieves nearly 4.5 billion pounds of CO_2 reductions by 2028, while the low model approaches 2.5 billion pounds of CO_2 reductions in that timeframe.

Tier III Program Costs

The achievement of Tier III targets comes with associated costs. These costs are generated from a combination of the operations and maintenance costs associated with program administration, program promotion, the incentives that we will provide to customers to drive adoption of these energy transformation initiatives, and the cost of Tier II RECs, which can be retired to substitute for Tier III MWh.

Operations and Maintenance Costs. Labor costs represent the largest portion of program costs for Tier III. Costs reported for the 2017 Tier III program were based on 50% of the staff that supports our Energy Innovation Center. Fifty percent of average productive hours were multiplied by the fully loaded hourly rate to come up with cost. For the sensitivity analysis, all cases assume an annual one-FTE reduction of EIC headcount beginning in 2020. The fully loaded rate is escalated by 2% per year to account for inflation.

Promotion Costs. Costs in 2017 were $160,000, and 2018 promotional costs are expected to by $280,000. The budget for 2019 is $220,000. The sensitivity analysis for all ranges starts with the 2019 budget, and escalates annually by 5%.

Incentive Costs. we have a short history of how incentives depict the valuation of Tier III MWh. 2018 cost per Tier III MWh was $13.59. For purposes of the sensitivity analysis, we assumed that this would escalate by 5% per year.

Tier II RECs. Because Tier II RECs can be retired to offset MWh shortfalls in Tier III, they can represent a cost of Tier III MWhs missed in any year. The value of Tier II RECs is projected using Regional Class I RECs as a proxy. Table 4-11 shows the annual cost projections for these RECs.

Year	Cost
2019	$9.00
2020	$13.50
2021	$17.00
2022	$17.50
2023	$16.50
2024	$16.00
2025	$15.50
2026	$15.00
2027	$15.00
2028	$15.00

Table 4-11. Annual Regional Class I REC Costs

Three ranges are used for the sensitivity analysis, based on Tier III performance.

Low Tier III Performance. This range uses the Tier III rollup model that reflects low performance. It is based on the low range being achieved each year in each of the three programs—cold climate heat pumps, EVs, and C&I. This range assumes the Tier III target is missed each year, and the shortfall is assumed to be covered by Tier II RECs.

Baseline. This range models costs if Tier III targets are achieved each year.

High Tier III Performance. This range uses the high range from the Tier III rollup. It shows Tier III targets being met through 2026. In 2027 and 2028, Tier II RECs are used to cover the shortfall.

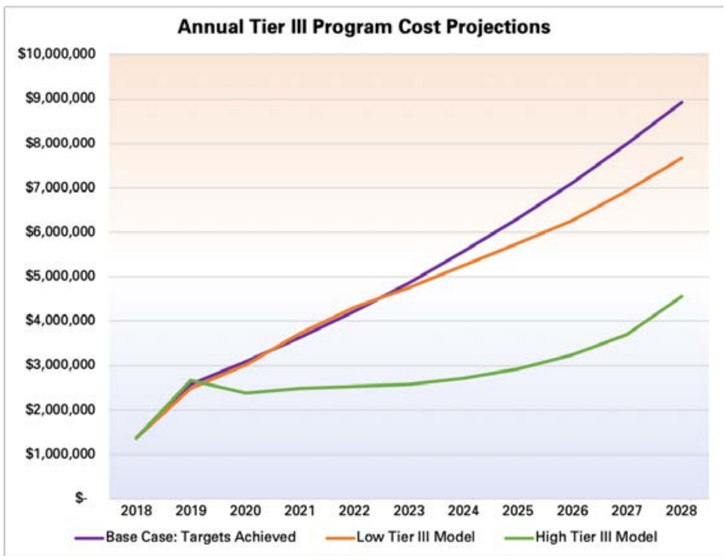

Figure 4-20. Tier III Annual Cost Projections: 2018–2028

Figure 4-20 shows the projected program costs under the three separate scenarios.

Given the divergent cost paths in this analysis, and the complex relationship between heat pump, EV, and C&I forecasts, the averaging of these models into a baseline scenario is likely to provide the most reasonable prediction of future performance of the overall Tier III program and associated costs. Table 4-12 illustrates annual costs under this scenario for the period from 2018 until 2028.

Year	Total Cost
2018	$1,369,862
2019	$2,583,401
2020	$3,086,712
2021	$3,629,185
2022	$4,221,756
2023	$4,864,612
2024	$5,563,637
2025	$6,316,706
2026	$7,116,219
2027	$7,986,585
2028	$8,923,977

Table 4-12. Tier III Cost By Year Baseline Scenario

Cooling and Heating Degree Days

Retail sales can also be forecasted against weather normalization. To do this, weather trends are analyzed over various periods of time. When this analysis was conducted on our service area, it was observed that the number of heating degree days has decreased over time, resulting in warmer winters. Concurrently, the number of cooling degree days has increased over that same time period, meaning that the summers are becoming warmer.

Figure 4-21 shows this trend over the past 30 years.

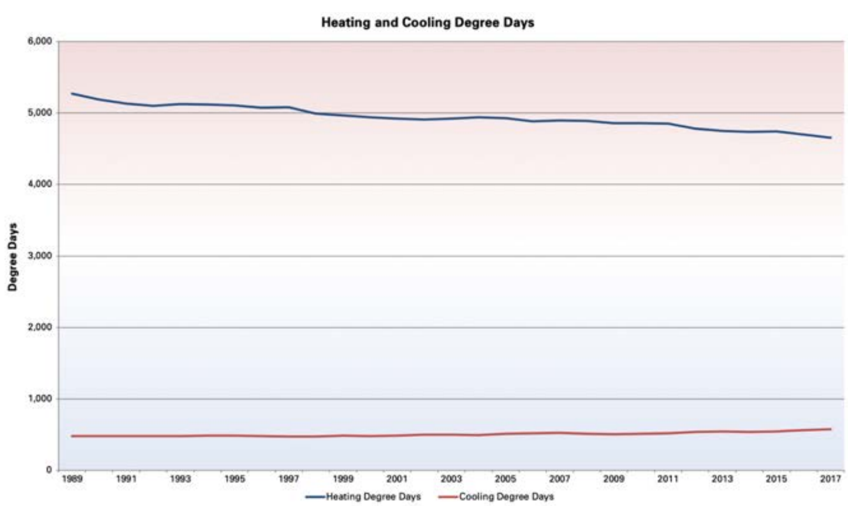

Figure 4-21. Trends in Heating and Cooling Degree Days

Heating degree days are trending down by about 0.4% annually, while cooling degree days are trending up by 1.0% annually. These trends are similar to the EIA's data for all of New England.

Table 4-13 shows the impact of these warming trends upon our forecast.

Year	Incremental (MWh)	Cumulative (MWh)
2018	1,097	1,097
2019	2,214	3,311
2020	549	3,860
2021	619	4,479
2022	671	5,150
2023	736	5,886
2024	805	6,691
2025	860	7,551
2026	930	8,481
2027	1,014	9,495
2028	1,089	10,584

Table 4-13. Incremental Impact of HDD and CDD Trends on Retail Sales Forecast

Note that the effect of heating and cooling degree days is incorporated in the growth found in Table 4-9.

CONSUMPTION TRENDS

All of the factors impacting load have a cumulative effect over the next ten years that shows downward pressure. Energy efficiency, appliance standards, and solar net metering all reduce load; economic and household growth, cold-climate heat pumps, and electric vehicles all increase load but not at a projected pace to offset reductions. Projected over ten years, the cumulative totals of these factors have a significant effect on load, and show how load is projected to decrease over the subsequent decade.

Load Affecting Factor	Cumulative Effect (MWh)
Cold-Climate Heat Pumps	56,374
Economic & Household Growth	132,272
Electric Vehicles	78,853
Electrification	35,782
Energy Efficiency	–237,609
Solar Net Metering	–93,628
Total	-27,956

Table 4-14. Cumulative Effect of Load Reducers and Increasers: 2018–2028

Table 4-14 details the ten-year cumulative total of each of these load increasing and decreasing factors, then their overall total effect on load. For those factors for which we conducted sensitivity analyses (EV, heat pumps, and C&I electrification), we used the baseline average result.

5. Our Increasingly Renewable Energy Supply

Our electricity load obligation (retail electricity consumption minus distribution and transmission grid losses) is met almost fully from energy from power purchase agreements (PPAs) and output from units that we wholly or partially own.

This portfolio of resources has undergone a substantial transformation in the past decade, as the two largest sources that supplied the bulk of our power needs—long-term PPAs from Hydro-Québec and the Vermont Yankee nuclear plant—ended and have been replaced with a more diverse mix of resources that includes more utility scale renewable power sources; a somewhat smaller long-term purchase from Hydro-Québec; a smaller long-term nuclear purchase backed by the Seabrook plant in New Hampshire; and extraordinary growth of distributed renewable generation in our service territory.

Our present portfolio is more flexible because not all of our supply is committed to long-term sources. By design, a portion of the portfolio is presently obtained through layered energy and capacity market purchases of up to five years in duration.

CURRENT SUPPLY RESOURCES

Our power supply resources include output from facilities at various locations across Vermont and New England, along with market-based purchases that are generally short term (five years or less). Most of our supply comes from PPAs; roughly 20% is obtained from GMP-owned sources.

Table 5-1 summarizes our resource mix.

Ownership	Subtype	Generator
Owned Generation	Jointly Owned	McNeil, Millstone 3, Stony Brook, and Wyman
	Wholly Owned	Our hydroelectric, oil-fired, solar and wind generators
Power Purchase Agreements	Long-Term Units	NextEra Seabrook; Granite Reliable Wind; Deerfield Wind; Moretown Landfill; Ryegate biomass; Stony Brook combined cycle; Joint Venture solar (Hartford, Panton, Williston, Williamstown, and Richmond); Sheldon Springs hydro; North Hartland Hydro; Ampersand Gilman hydro; Lower Village hydro; and nine small solar projects (ranging from 1 MW to 5 MW)
	Long-Term System	HQ-US long-term PPA
	Short-Term Unit	Boltonville hydro
	Short-Term Market	Macquarie, Shell, Citigroup, BP, and NextEra energy contracts
	Standard Offer	Primarily solar PV; also biomass, farm and landfill methane, hydro and wind—all from projects up to 2.2 MW
	Vermont Electric Power Producers Inc.	Vermont's Qualified Facilities (Hydro) under Vermont's PURPA implementation also known as Rule 4.100
Net-Metered Generation	Under PUC Rule 5.100	Overwhelmingly solar PV; projects are generally sized from a few kW up to 500 kW.[42] They serve to reduce our retail sales and reduce requirements from other wholesale power sources.

Table 5-1. Total General Supply

Major owned generation resources include 44 hydroelectric, 12 solar, six oil-fired, and two wind projects. PPAs currently include twenty-four long-term contracts, six short-term contracts, and several renewable sources that are credited to our supply portfolio by statute.

[42] By statute, a small number of larger projects (for example, solar PV located at closed landfills or military facilities) are also eligible for net metering.

Figure 5-1 depicts our energy supply for calendar year 2017 *before* the purchase and sale of renewable energy certificates.

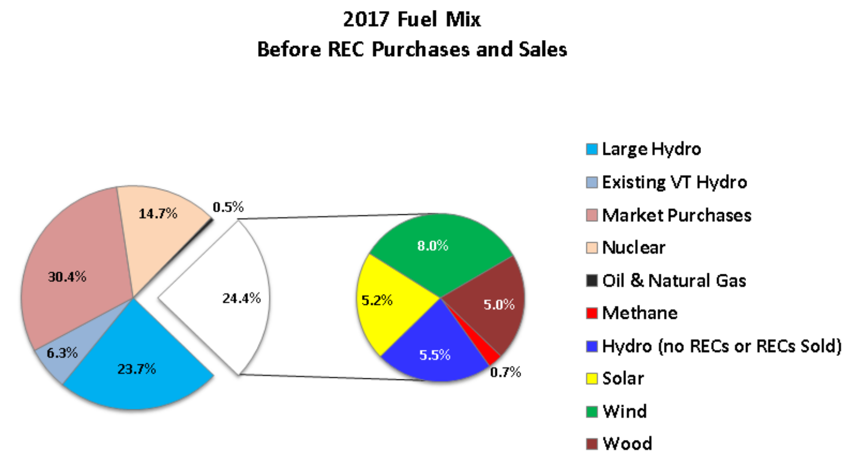

Figure 5-1. Fuel Mix Before Accounting for REC Transactions

Figure 5-2 depicts our energy supply for calendar year 2017 *after* the purchase and sale of renewable energy certificates.

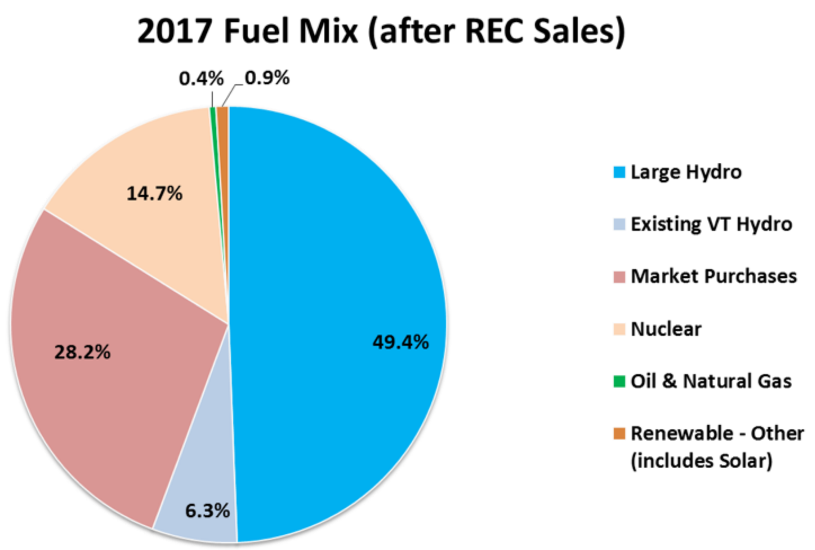

Figure 5-2. Fuel Mix After Accounting for REC Transactions

Owned Hydroelectric Generation

We currently operate 44 hydroelectric generators: 32 are legacy systems and 12 were recently acquired from Enel. Table 5-2 summarizes our legacy hydroelectric plants.

Unit	Age (years)	Type	MW	Unit	Age (years)	Type	MW
Arnold Falls	90	Run-of-River	0.35	Middlebury Lower	98	Run-of-River	2.25
Beldens Falls	105	Run-of-River	5.85	Middlesex #2	90	Run-of-River	3.20
Bolton Falls	32	Run-of-River	7.50	Milton	89	Dispatchable	7.50
Carver Falls	124	Run-of-River	2.55	Passumpsic	90	Run-of-River	0.70
Cavendish	110	Run-of-River	1.44	Patch	97	Run-of-River	0.40
Center Rutland	120	Run-of-River	0.28	Peterson	70	Dispatchable	6.35
Clarks Falls	81	Dispatchable	3.00	Pierce Mills	90	Run-of-River	0.25
East Barnet	35	Run-of-River	2.20	Proctor	113	Dispatchable	10.23
East Pittsford	104	Dispatchable	3.60	Salisbury	101	Dispatchable	1.30
Essex #19	101	Run-of-River	7.20	Silver Lake	102	Dispatchable	2.20
Fairfax Falls	98	Run-of-River	4.20	Smith	34	Run-of-River	1.50
Gage	99	Run-of-River	0.70	Taftsville	76	Run-of-River	0.50
Glen	98	Dispatchable	2.00	Vergennes A&B	106	Run-of-River	2.40
Gorge #18	90	Run-of-River	3.00	Waterbury #22	65	Run-of-River	5.52
Huntington Falls	107	Run-of-River	5.50	West Danville #1	101	Run-of-River	1.00
Marshfield #6	91	Dispatchable	5.00	Weybridge	67	Dispatchable	3.00
					Total	102.67	

Table 5-2. Legacy Hydroelectric Resources

Table 5-3 summarizes the hydros we have recently acquired from Enel.

Unit	Age (years)	Type	MW	Unit	Age (years)	Type	MW
Barnet	32	Run-of-River	0.56	Ottauquechee	94	Run-of-River	1.69
Deweys Mill	33	Run-of-River	2.75	Rollinsford	35	Run-of-River	1.50
Kelley's Falls	29	Run-of-River	0.40	Salmon Falls	95	Run-of-River	1.20
Lower Valley	111	Run-of-River	0.92	Somersworth	34	Run-of-River	1.28
Mascoma	30	Run-of-River	2.05	West Hopkinton	35	Run-of-River	1.12
Newbury	14	Run-of-River	0.42	Woodsville	94	Run-of-River	0.36
					Total	14.25	

Table 5-3. Hydroelectric Resources Acquired from Enel

Our 44 hydroelectric generators are capable of generating almost 117 MW of electricity and produce an average of about 390,000 MWh of energy each year. These resources provide approximately 63 MW of FCA-based capacity credit and additional seasonal capacity payments.

Collectively, our fleet of owned hydroelectric plants generates an average of roughly nine percent of our annual energy requirements. The output of the hydroelectric plants can vary significantly on a daily, monthly, and annual basis depending on the actual flow of the rivers where the plants are located. Although these plants require regular operation and maintenance expenses, along with periodic capital expenditures for major improvements (and periodic FERC relicensing), they are the longest-lived assets in the supply category and, on average, the cost of power from our hydroelectric fleet is moderate and relatively stable. The hydroelectric plants incur no fuel expenses so the output helps to stabilize our power supply costs and retail rates, and they do not emit greenhouse gases. All hydroelectric plants are eligible to help us meet our RES Tier I renewable requirements. Some plants are also eligible to comply RPS markets in neighboring states (primarily Massachusetts Class 2); we therefore have the option to sell some or all of the RECs from these plants (with the revenues used to reduce net power costs and retail rates).

Legacy Hydroelectric Fleet

Here is a plant-by-plant summary of our legacy hydroelectric fleet, including license status and major improvements that have been completed or are in progress. Seven hydro plants (with a collective capacity of about 17.3 MW) are scheduled for FERC license renewals by 2024.

Arnold Falls. A run-of river facility located on the Passumpsic River in Saint Johnsbury.
Operational License: FERC 40-year license No. 2396 that expires June 16, 2034.
Recent Improvements: In 2008, we modernized the facility's switchgear, relay protection, and controls; in 2009, we constructed a new concrete gravity dam to replace the dam's deteriorated timber cribs.

Beldens Falls. Run-of-river facility located on Otter Creek in New Haven. Central Vermont Public Service (CVPS) acquired this former Vermont Marble Power Division (VMPD) facility in 2011.
Operational License: FERC 40-year license No. 2558 that expires in 2054.
Recent Improvements: In 2008, we modernized the station's electrical switchgear, protection relays, and control devices; refurbished turbine-generator Unit 2; and completed FERC-required recreational improvements and runner upgrades for Unit 3.

Bolton Falls. Run-of-river facility located in Duxbury.
Operational License: FERC 40-year license that expires January 31, 2022.
Recent Improvements: Originally built in 1899, we rebuilt it in 1985 and again in 2005. We also modernized the station's electrical switchgear, protection relays, automation, and control devices.

Carver Falls. Run-of-river facility located on the Poultney River in East Hampton, New York and West Haven, Vermont.
Operational License: FERC 30-year license No. 11475 that expires in 2039.
Recent Improvements: In 2011, we replaced and uprated turbine-generator Unit 1.

Cavendish. Run-of-river facility located in Cavendish.
Operational License: FERC license No. 2489.
Recent Improvements: Since the unit was commissioned, we installed an automated spillway crest control at the dam.

Center Rutland. Run-of-river former VMPD facility (acquired by CVPS in 2011) located in Rutland on Otter Creek.
Operational License: FERC 30-year license No. 2445 that expires in 2024.
Recent Improvements: Recently, we added relay protection and SCADA controls to improve remote operation, and refurbished major mechanical components to enable the hydro to be brought back online.

Figure 5-3. Clarks Falls Hydro, Milton

Clarks Falls. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.
Operational License: FERC 30-year license No. 2205 that expires in 2035.
Recent Improvements: In 2001, we installed a new generator step-up transformer; in 2004, we replaced the turbine runner.

East Barnet. Run-of river facility on the Passumpsic River in Barnet.
Operational License: FERC Exempt No. 3051.
Planned Improvements: We plan to improve the communication network.

East Pittsford. Dispatchable facility located on East Creek in Pittsford; one of two facilities that comprise the North Rutland Composite. Because of the size and hazard classification of the Chittenden Dam, which forms the station's impoundment, this facility falls under the Vermont Public Service Board's (PSB's) dam safety regulation.
Operational License: Non-FERC jurisdiction.
Recent Improvements: In 2010, we modernized the station's switchgear, protection relays, and control devices; replaced the penstock in the powerhouse; automated critical equipment, including the head gate; and refurbished the major penstock.

Figure 5-4. Essex #19 Hydro Station

Essex #19. Run-of-river facility constructed in 1917 located on the Winooski River in Williston and Essex Junction.
Operational License: FERC 30-year license that expires on March 30, 2025.
Recent Improvements: In 1990, we significantly repaired the dam. More recently, we continued to resurface the concrete dam, replaced the GUS Transformer, upgraded the exciters, and replaced two of the three rubber bladders.

Figure 5-5. Fairfax Falls Hydro Turbine Generators

Fairfax Falls. Run-of-river facility located in Fairfax, on the Lamoille River.
Operational License: FERC 30-year license No. 2205 that expires in 2035.
Recent Improvements: In 2004, we modernized the station's electrical switchgear, protection relays, and control devices; and refurbished and uprated turbine-generator Unit 1; refurbished the Unit 2 generator and stator; and replaced the waste gate.

Gage. Run-of-river facility located on the Passumpsic River in St. Johnsbury.
Operational License: FERC 40-year license No. 2397 that expires 2034.
Recent Improvements: We replaced the original head gates and actuators with new steel gates and automated actuators, made safety improvements, and resurfaced the concrete on the intake canal.

Glen. Dispatchable facility located in Rutland, on East Creek; one of two facilities that comprise the North Rutland Composite.
Operational License: Non-FERC jurisdiction.
Recent Improvements: We modernized the station's electrical switchgear, protection relays, and control devices; installed a new generator step-up transformer; replaced sections of the penstock; rewound Unit 1; performed environmental abatement in the powerhouse; replaced over 2,000 linear feet of penstock; replaced the trash racks and head gate actuator; modernized the station's switchgear, relay protection, and controls; installed a new generator step-up transformer; and replaced penstock sections.

Figure 5-6. Gorge #18 Hydro Facility

Gorge #18. Run-of-river facility located in Colchester and South Burlington.
Operational License: Non-FERC jurisdiction.
Recent Improvements: Gorge's two dams were built in 1914 and 1928. Recently, we installed a new runner to capture lower flows and an automated crest control rubber dam system. These improvements are expected to significantly increase the station's capacity of approximately 9,500 to 11,500 MWh per year.

Huntington Falls. This former VMPD run-of-river facility is located on Otter Creek in Weybridge.
Operational License: 40-year FERC license No. 2558 expires in 2054.
Recent Improvements: In 2015, we refurbished and uprated the turbine-generator on Unit 1 and Unit 2 (the turbine-generator on Unit 3 operates well and is in good repair), modernized the electrical system, and automated the plant.

Marshfield #6. Dispatchable facility located in Cabot. The dam is a rolled earth-fill construction built in 1927 with an additional spillway added in 1991. Because of the size and hazard classification of the Marshfield Dam, this facility falls under the PSB's dam safety regulation.
Operational License: Non-FERC jurisdiction.
Recent Improvements: We replaced the wood-stave penstock over a six-year timeframe, modernized the electric system, rebuilt the substation, resurfaced the concrete, and replaced the head gate. We plan to improve the dam infrastructure and make safety improvements; we are currently involved in Chapter 43 proceedings to gain approval for these upgrades.

Middlebury Lower. Run-of-river facility located on Otter Creek in Middlebury.
Operational License: FERC 30-year license No. 2737 that expires in 2031.
Recent Improvements: In 2004, we modernized the electrical relay protection relays and control devices; in 2010, we installed a new generator step-up transformer. More recently, we made building improvements, and rewound the generator. We plan to resurface the concrete and potentially rebuild Unit 1 and Unit 2, both recommended by FERC.

Middlesex #2. Run-of-river with minimal ponding facility located in Middlesex was originally built in 1928.

Operational License: Non-FERC jurisdiction.
Recent Improvements: We reconstructed the intake canal and headworks, and replaced the original turbine runners.

Figure 5-7. Milton Hydro Plant

Milton. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.
Operational License: FERC 30-year license No. 2205 that expires 2035.
Recent Improvements: In 2002, we modernized the station's electrical system; in 2005, we installed an automated spillway crest control; and in 2007, we reconstructed the intake and headworks. More recently, we upgraded the governor controls and resound the generator.

Passumpsic. Run-of-river facility located on the Passumpsic River in St. Johnsbury.
Operational License: FERC 40-year license No. 2400 that expires in 2034.
Recent Improvements: We improved the fish passage and resurfaced the concrete.

Patch. A run-of-river facility located on East Creek in Rutland.
Operational License: Non-FERC jurisdiction.
Recent Improvements: In 2011, Hurricane Irene significantly damaged the Patch station and flooded the plant. We thoroughly cleaned and replaced many electrical components, including a full rewind of the generator, and brought the unit back online in 2013.

Peterson. Dispatchable facility located on the Lamoille River in Milton; one of three facilities that comprise the Lower Lamoille Composite.
Operational License: FERC 30-year license No. 2205 that expires in 2035.
Planned Improvements: In 2019, we plan to start a major mechanical and electrical modernization project to improve safety, operations, and reliability.

Pierce Mills. Run-of-river facility located on the Passumpsic River in St. Johnsbury.
Operational License: FERC 40-year license No. 2396 that expires in 2034.

Proctor. Dispatchable former VMPD facility (acquired by CVPS in 2011) located on Otter Creek in Proctor.
Operational License: FERC 40-year license issued in October 2014.
Recent Improvements: We have fully restored this facility. In 2012, we built a vehicular

bridge that spans Otter Creek at the station; in 2013, we extensively modified the intake headworks. After receiving authorization from FERC in 2014, we began modernizing the mechanical and electrical systems, and adding a new turbine-generator for increasing capacity. After FERC issued a new operating license in October 2014, we completed the work started earlier in the year: we replaced three turbine-generator sets and completely overhauled and rebuilt another turbine-generator unit. The facility became fully operational in the second quarter of 2015. In 2016, we completed FERC-required recreational improvements.

Salisbury. Dispatchable facility located on the Leicester River in Salisbury; one of three facilities that comprise the Middlebury Composite.
Operational License: Non-FERC jurisdiction.
Recent Improvements: In 2011, we modernized the station's electrical switchgear, protection relays, and control devices; installed a new generator step-up transformer; and recoated sections of the penstock pipeline.

Silver Lake. Dispatchable facility located on the Sucker Brook in Leicester; one of three facilities that comprise the Middlebury Composite.
Operational License: FERC 30-year license No. 11478 that expires in 2039.
Recent Improvements: In 2008, we improved the stability of the Goshen and Silver Lake dams to meet FERC dam safety guidelines. In 2011, we automated the station components. We are currently underway with a large capital project to complete final dam safety improvements at the Goshen Spillway, which we expect to complete by 2020.

Smith. Run-of-river facility located on the Waits River in Bradford.
Operational License: FERC Exempt No. 3051.
Recent Improvements: In 2006, we replaced the Unit 1 turbine runner. More recently, we replaced the taintor gate control and a gearbox for Unit 2.

Taftsville. Run-of-river facility located on the Ottauquechee River in Woodstock.
Operational License: FERC 30-year license No. 2490 that expires in 2024.
Recent Improvements: In 2011, the Taftsville facility flooded extensively during Hurricane Irene. Since then, we cleaned up the site, modified the powerhouse, modernized the electrical equipment, and replaced the station's electrical switchgear, protection relays, and control devices, and its generator rewind.

Figure 5-8. Vergennes Hydro Facility

Vergennes. Run-of-river facility with limited storage capacity located on Otter Creek in Vergennes.
Operational License: FERC 30-year license that expires on May 31, 2029.
Recent Improvements: In 2010, we completely rebuilt the intake system, associated penstocks, and turbines of Units 1 and 2. Currently, we are replacing the penstock to Unit 9b. In 2019, we plan to modernize the station's electrical system with new switchgear, relay protection, and controls.

Waterbury #22. The dam was constructed in 1938 and received significant repairs in 2006. Although we operate the facility, the dam itself is owned by the State of Vermont, and operates under a recently renewed 40-year FERC license that expires in 2056. 2018 is the first year of operations under the new license regime as improvements were completed in June of 2018. The generation output has been reduced and the facility is no longer in the dispatchable market as the site transitions to a run-of-river operation.
Operational License: FERC 40-year license that expires in 2056.
Recent Improvements: To best meet the FERC and 401 requirements while maximizing generation, we replaced the turbine runner with a runner that produces more efficiently at lower flows earlier this year. In 2019, we will complete the FERC-required recreational projects. For the facility to move to true run-of-river, the State must repair gates on the dam. This is likely to occur in the next five to 10 years.

West Danville #1. Run-of-river facility with limited storage capacity located on Joe's Pond in West Danville.
Operational License: Non-FERC jurisdiction.
Recent Improvements: We resurfaced the dam in 1996. In 2011, Hurricane Irene significantly damaged the facility, which we repaired in 2014. In 2014, we upgraded the penstock from the surge tank to the powerhouse; last year, we upgraded the dam control system; this year, we overhauled the unit because of mechanical failures.

Weybridge. Dispatchable facility located on Otter Creek in Weybridge; one of three facilities that comprise the Middlebury Composite.
Operational License: FERC 30-year license No. 2731 that expires in 2031.
Planned Improvements: In 2020, we plan to mechanically refurbish the runner.

Expanded Hydro Fleet Acquired from Enel

We expanded our renewable portfolio in 2016 with the acquisition from Enel of 12 small hydro plants located in Vermont, New Hampshire, and Maine. The plants can be generally described as small, run-of-river power stations that are similar to our existing hydro portfolio. Seven of the plants were incorporated into existing or expanded operating districts: Woodsville, Barnett, and Newbury into the St Johnsbury district; Dewey's Mills, Ottauquechee, Mascoma, and Lower Valley into the Cavendish-White River district, and West Hopkinton, Kellys Falls, Somersworth, Rollingsford, and Salmon Falls into a newly created New Hampshire-Maine district.

During 2018, we transitioned several generating units that were historically represented in the ISO-New England market as "composite" resources to operation as load reducers.[43] This change avoided some operational challenges associated with offering output from a composite system into the market and responding quickly to ISO-New England instructions reflecting changing market conditions at five minute intervals. We plan to dispatch the limited storage capability of these units (along with distributed storage and controllable load resources) to maximize energy output during peak load conditions on the VELCO and ISO-New England systems, with the goal of limiting our share of RNS transmission charges and regional capacity market costs. The Lower Lamoille Composite, which includes the Clark Falls, Milton, and Peterson plants, still operates as a composite resource.

Owned Peaking Generation

We own a fleet of six oil-fired generators that operate in a peaking role. These units operate primarily during peak load days (or other times when energy market prices in the ISO-New England market are unusually high); they also are sometimes operated to support the Vermont transmission system and to provide ancillary products (for example, quick-start operating reserves) required for operation of the NEPOOL system. All units' air permits were renewed in 2018. Although these plants do not operate often (typical annual capacity factors for these units are less than one percent), they provide significant value for our customers—primarily through their value in the Forward Capacity Market (FCM) and Forward Reserve Market (FRM). These revenues depend on the ability of the plants to respond quickly and reliably during the occasional periods when they are called upon to operate. Reliable operation is becoming even more important, as the ISO-New England Pay-For-Performance Program penalizes capacity sources that fail to produce during regional shortage events and rewards those that do

[43] The Glen and East Pittsford plants made up the former North Rutland composite resource; the Salisbury, Silver Lake, and Weybridge plants made up the former Middlebury composite.

(as explained in Chapter 3: Regional and Environmental Evolution). We have reviewed our operation and maintenance regimes for these units with the goal of maximizing availability. We expect that ongoing activities will include performing monthly test starts—targeting worst-case periods, such as extreme temperatures when possible—and continuing internal inspections of the turbines each spring.

Resource Name	Age (years)	Nameplate MW
Ascutney Gas Turbine	57	12.5
Berlin 1 Gas Turbine	46	46.5
Essex Diesels	12	8.0
Gorge Gas Turbine	53	17.0
Rutland 5 Gas Turbine	55	12.5
Vergennes 5 & 6 Diesels	55	4.0
	Total	**100.5**

Table 5-4. Owned Peaking Generation

Ascutney Gas Turbine. The Ascutney Gas Turbine is a two-stage turbine, internal combustion unit located in Ascutney. The unit operates under an air pollution control permit issued by the VANR's Air Quality and Climate Division. Significant recent improvements include the replacement of the fuel control system, voltage regulator and auto synchronizer, and unit automation upgrades in 2018. Replacement of the engine section as part of a hot gas path and overhaul project was completed in 2011.

Berlin 1 Gas Turbine. The Berlin Gas Turbine facility is the largest peaking plant in Vermont, and consists of a Pratt & Whitney Twin Pack gas turbine generator and two Pratt & Whitney Simple Cycle FT4 engines. The unit has an approximate capacity of 50 MW at full output in winter, and about 40 MW in summer. Low-sulfur kerosene fuels the engines from two on-site fuel tanks.

In 2008, the Berlin Gas Turbine facility was upgraded; both engines were overhauled and rebuilt, together with a complete rewind of the generator. An additional air-assisted start pack was installed, enabling both engines to start simultaneously. Additional improvements, upgrades and replacements were made in 2012 and 2013. As a result of the upgrades, the plant can more fully participate in the ISO Reserve market, the life expectancy of the plant was extended, and reliability improved.

Essex Diesels. This diesel generation facility consists of four 2 MW Caterpillar diesel reciprocating engines that operate on ultra-low sulfur diesel. In 2007, we upgraded the facility, replacing 60-year-old, 1 MW Electro-Motive Division (EMD) diesel engines and upgrading all associated switchgear and controls.

Gorge Gas Turbine. The Gorge Gas Turbine is a two-stage turbine, internal combustion unit located in Colchester. The unit operates under an air pollution control permit issued by the VANR's Air Quality and Climate Division. The Gorge Gas Turbine underwent a major overhaul in 2014 and is slated for a control system upgrade in 2019.

Rutland 5 Gas Turbine. The Rutland Gas Turbine is a two-stage turbine, internal combustion unit located in Rutland. The unit operates under an air pollution control permit issued by the ANR's Air Quality and Climate Division. Significant improvements include the replacement of the fuel control system in 2006, and refurbishment of the unit's engine components as part of a hot gas path inspection and overhaul project in 2009. We are currently evaluating the costs and benefits of this gas turbine based on recent experience featuring poor reliability and significant unplanned outages.

Vergennes 5 & 6 Diesels. The Vergennes peaking facility consists of two 16-cylinder reciprocating engines, originally installed in 1964, with a total nameplate capacity of 4 MW. The engines are fueled using ultra-low sulfur, blended #2 diesel oil. Both engines have been overhauled in the last decade. In 2013, we installed a DOC catalyst to the emissions control system and, in 2014, upgraded the unit's control systems. In 2018, the generator for Unit 5 failed and was rewound; we are planning to rewind Unit 6 in 2019.

Owned Wind Generation

We own two utility-scale wind plants. The first, Searsburg Wind, is a 6 MW facility located near the Massachusetts border. The second is Kingdom Community Wind (KCW). With a nameplate rating of 64.5 MW, KCW entered commercial operation in 2012, and is located in the town of Lowell in northeastern Vermont.

Kingdom Community Wind

Kingdom Community Wind is a 21-turbine wind generation facility. We partnered with Vermont Electric Cooperative (VEC) to build the project, which began generating electricity at the end of 2012. The wind turbines at Kingdom Community Wind were manufactured by VESTAS, and are rated at just over 3 MW each. We own 100% of the project, and retain 87% (55 MW) of the output for our customers. The remaining output serves VEC customers, via a long-term power sale agreement. The plant is expected to operate at a 33% annual capacity factor, which yields approximately 186,000 MWh of energy annually. Since the Jay synchronous condenser facility was installed and fully operational in spring of 2014, the project has produced at approximately this level, with the exception of some reductions because of a transmission system constraint.

Figure 5-9. Kingdom Community Wind

During operation in winter months, Kingdom Community Wind sometimes experiences accumulation of ice on turbine blades. This tends to occur with the arrival of freezing rain, and can also occur through accumulation of heavy wet snow on leading edges of blades. In such instances, some or all of the turbines may need to be shut down until the ice accumulation can be shed (after a few hours to a few days). In recent years, we have sought to limit the duration of such events by proactively taking the plant offline (so that the blades are not rotating) when weather at the facility appears conducive to turbine blade leading edge buildup. This method appears to have limited ice buildup (and associated lost generation) in recent years. We plan to continue seeking a technology that is in production (and approved by the turbine manufacturer Vestas) that will assist in ice shedding once ice has accumulated on blades; at this time, no technology is available for installation on Vestas V112 model turbines that are already in operation.

KCW has also been susceptible to lightning strikes that have damaged blades on average of about once per year. During initial years of operation at KCW, the process of repairing lightning damage to the spar of a turbine blade meant craning a blade to the ground, making the carbon repair, and then reinstalling the blade on the turbine. This method of repair has historically been costly, and would require the affected turbine to remain out of service for approximately 30 days depending on the time of year and relative ease of site access. In recent years, we have worked with Vestas to complete the fiberglass and carbon fiber repairs without removing the blade from the tower. Technicians can utilize a man lift, or a blade access platform basket to complete the needed repairs. This method of repairing blades has significantly reduced the cost associated with blade repairs, as well as reducing lost generation associated with the turbine being off line for extended periods of time.

Searsburg Wind

Searsburg is an eleven-turbine facility completed in July 1997, the first utility scale facility installed in the Northeast. After twenty years of production, Searsburg continues to be fully operational, producing energy at an average annual capacity factor between 20 and 25%. In fact, the plant has produced some historical monthly high generation totals within the past two years.

Searsburg remains powered by the same Zond turbines that were installed in 1997. Zond has been out of business as a turbine manufacturer for many years, and turbine parts at times have been difficult to locate. We have been able to find vendors that were able to remanufacture parts needed to keep turbines operational. We have also been successful in locating some turbine parts (for use as spares) from other plants in the western U.S. that were repowered with newer turbines, and have taken Zond units out of service. The turbine operating system (SCADA) was upgraded in 2016. We proactively have one gearbox rebuilt yearly, to minimize the chance that gearbox failures will require extended outages. Generators are also long lead time items; we store one spare generator locally as a backup, and rebuild failed generators as needed. Parts including controller circuit cards and other electronic components can be difficult to locate.

We expect to continue maintaining and operating Searsburg for the foreseeable future, using the methods specified here and making repairs as needed. We recognize that, in the future, some types of component failure could conceivably make it infeasible (or not cost effective) to return one or more units to service. In the long-term, the Searsburg site could potentially be repowered—by replacement in kind (for example, same or similar number of units, sized equivalent to the current units) or by installing a smaller number of larger turbines. We expect to evaluate these options in the future based on the trend in Searsburg performance and other factors.

It is important to note that the Deerfield Wind project was recently constructed directly adjacent to the Searsburg facility and shares some facilities such as access roads. This provides a more cost-effective opportunity to re-power Searsburg in the future.

Owned Solar Generation

We have embraced solar PV technology, particularly as its cost-competitiveness improved over time. The 2 MW (AC) Stafford Hill solar and battery storage project, constructed on a closed Rutland landfill in 2014, was our initial launch into utility-scale solar and battery storage. In 2016, we commissioned five additional solar projects; in 2018, we added a 1 MW-4 MWh of utility-scale battery storage in Panton. In total, including several smaller solar generation projects installed at GMP-owned properties and partner sites, we own about 25 MW of solar capacity. In addition, we have proposed installing a total of approximately 14 MW of solar PV capacity, along with 6 MW-24 MWh of battery storage capacity, in 2019 as part of the Joint Venture Solar and Storage program.

Here are additional details about components of our solar PV generation fleet.

Figure 5-10. Stafford Hill Solar Facility

Stafford Hill. The Stafford Hill project was an innovative, first-of-its-kind project using solar, two types of battery storage and a common inverter to tie it all together on top of a previously capped landfill. Under normal operating conditions, this project will supply energy to the grid while the battery system continues to smooth, regulate and support the grid throughout the day. We are able to achieve significant capacity-related savings by maximizing the plant's output (through a combination of solar generation and battery discharge) during the ISO-New England annual peak load, and discharging the battery system during monthly peak loads on the VELCO system. The battery storage system has also achieved revenue as a supplier of Regulation Service in the ISO-New England market. Finally, the project can electrically island the nearby Rutland High School emergency shelter during times of grid emergency utilizing the battery and solar to power the facility. We are presently exploring an upgrade to the lithium-ion batteries at the Stafford Hill site to allow greater participating and therefore additional revenue in the ISO regulation market but will be weighing this against the cost of this upgrade.

Joint Venture Solar. Five utility-scale solar projects were commissioned in 2016: 4.7 MW (AC) in Williston; 2 MW (AC) in Richmond; 4.9 MW (AC) in Hartford, 4.9 MW (AC) in Panton; and 4.9 MW (AC) in Williamstown. All of the projects utilized fixed-tilt racking systems, with the exception of Panton, which was designed for single-axis trackers. Hartford was notable because its re-use of the site of a former gravel extraction operation. Williston included a creative partnership with Global Foundries to provide that customer with a portion of the project's output in return for hosting the site. The estimated lifetime cost of power from the Joint Venture Solar projects was the lowest among Vermont solar PV projects at the time the projects were developed. In 2018, a 1 MW-4 MWh battery system was commissioned on the Panton solar site, which is now providing peak load reduction and frequency regulation services to the grid.

Joint Venture Solar and Storage. We are in the final stages of permitting three additional solar and battery storage projects which, if approved, will be commissioned in 2019. At each project site (Milton, Ferrisburgh, and Essex), there will be between 4.5 MW (AC) and 4.9 MW (AC) of solar generating capacity and 2 MW-8 MWh of battery storage. The batteries will primarily be charged by the solar generation and the batteries will in turn, be used to achieve peak load reductions and frequency regulation services to lower power costs for customers. Like Panton, Ferrisburgh will feature single-axis trackers while Milton and Essex will use fixed-tilt racks because of their topology. Each of these projects will take advantage of significant cost declines for solar PV and battery projects in recent years, and will enable us to lower the cost to our customers by taking advantage of the federal investment tax credit that is presently available on both the solar and storage components of combined projects. As a result, we expect that the lifetime cost of power to customers from the solar components of these projects will be the lowest of any Vermont solar PV projects developed to date.

Other Owned Solar. We have installed solar PV equipment at a number of our sites as well at sites owned by partners, and also on streetlights. For example, we have installed projects at the site of the Berlin Gas Turbine, at a site on Cleveland Ave (Creek Path Solar) in Rutland, and at a number of our office buildings. We've also installed projects at Rutland Region Medical Center and the College of Saint Joseph's in Rutland.

GMP-owned plants represent a small fraction of the number of projects and total capacity of solar PV development in Vermont. The vast majority of solar development has occurred through the net metering program and the Standard Offer program, along with bilateral PPAs under which we purchase the output of specific projects.

Net-Metered Solar Generation

Vermont's net metering program has existed for almost 20 years, with the primary purpose of enabling customers to offset their electricity usage with their own on-site generation. In Vermont, net metering is administered under PUC Rule 5.100. When we pioneered the use of a six-cent per kWh solar "adder" for net-metered solar projects in 2008, solar PV generation in Vermont was generally not cost-competitive relative to wholesale power alternatives or with retail electricity rates. We implemented this adder to support the development of customer-sponsored local generation, and its significant magnitude reflected that fact at the time. The estimated value of solar PV output to us could (in part because of its coincidence with local and regional peak demands) significantly exceed the retail electric rates that net metering customers could avoid through their generation.

The *Vermont Energy Act of 2011* required (among other things) that GMP and other Vermont utilities offer solar adders that would result in total payment rates for net-metered solar generation at 20 cents per kWh, while guaranteeing the associated incentive for 10 years. The Act also increased the size of generators eligible for net metering to 500 kW, an order of magnitude larger than the early residential scale projects in our territory. This change, combined with the fact that Vermont allows virtual net metering (that is, a net-metered project located remotely from the customer receiving credit for the output) set the stage for much more rapid growth. Act 99 of 2014 greatly increased prior caps on the total volume of net-metered generation projects in a utility's territory, and allowed solar facilities up to 5 MW (if located on a closed landfill) to be treated as net metered. Act 99 also charged the PUC to create a new framework for net metering, beginning in 2017, and to balance the setting of payment rates to stimulate development with potential shifting of electric system costs to non-participating customers.

Because of a rapid decline in the cost of solar PV project costs (including panels and other components, along with installation) and the expansion of eligibility to projects up to 500 kW, the quantity of net-metered generation capacity in our territory has increased at an extraordinary pace in the past four years—from total operating capacity of about 40 MW in mid-2014 to about 163 MW as of mid-November 2018. This scale of net-metered capacity (relative to electricity demand) places us as an industry leader; it also has implications for the value of additional solar power.

Figure 5-11 illustrates the cumulative volumes of net-metered capacity that have applied for interconnection since 2014 (the green line), while the red line depicts the capacity that has achieved commercial operation or is still under development. The difference between the two lines reflects attrition—that is, capacity from projects that applied for interconnection but ultimately withdrew because of permitting challenges, financial feasibility, or other reasons. As evidenced from Figure 5-11, net metering applications have increased steadily since 2014, with the pace punctuated by a large surge in late 2015 (as a temporary 15% cap in program capacity was approached).

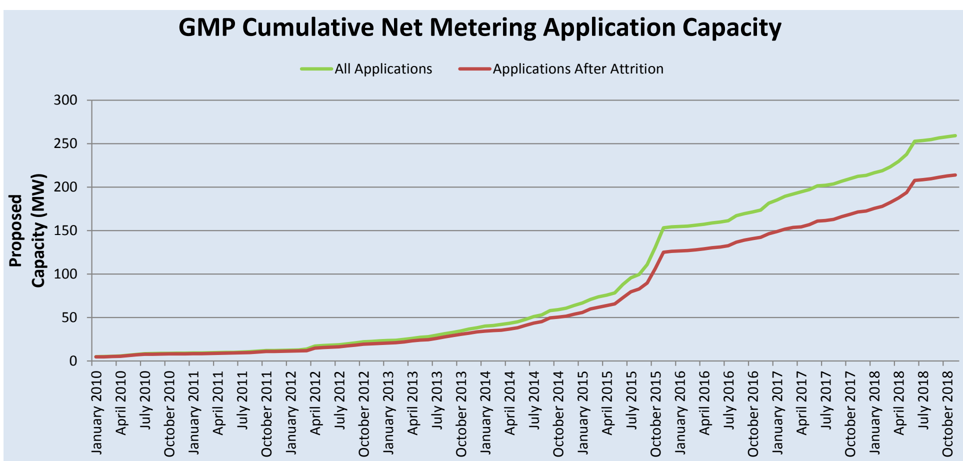

Figure 5-11. Cumulative Net Metering Interconnection Applications to GMP

The applications shown in Figure 5-11 have translated into large increases in operating net-metered generation capacity. The growth has been overwhelmingly in solar PV projects, which presently make up about 96% of the net-metered generation fleet.

Figure 5-12 tracks the growth of operating net metering capacity in our territory from 2010 to the present. While the vast majority of net-metered projects are residential scale (up to 15 kW), the most explosive growth of net-metered capacity has been in the large (up to 500 kW) category.

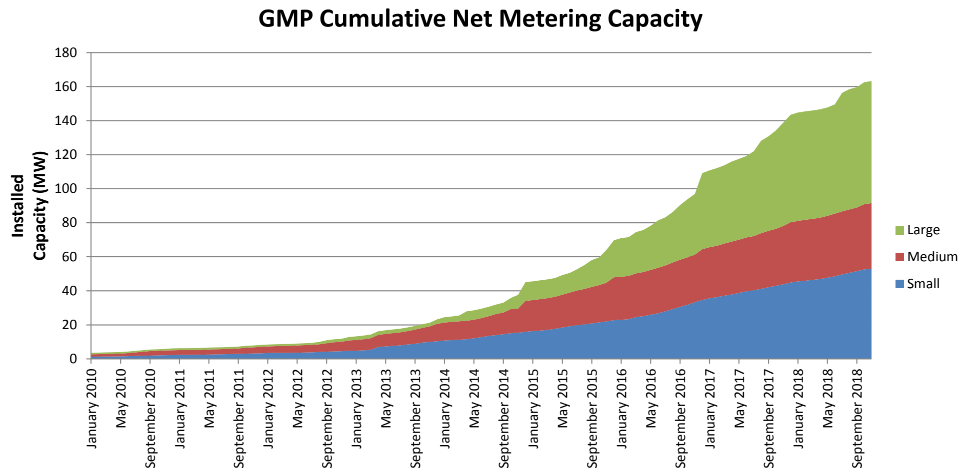

Figure 5-12. Cumulative Net Metering Capacity

Figure 5-13 presents an alternative view of this net metering information, showing the total net-metered generating capacity that achieved commercial operation in each calendar year. Since 2014, the amount of net-metered capacity reaching commercial operation has ranged from a low of over 20 MW in 2014 to a maximum of almost 40 MW in 2016.

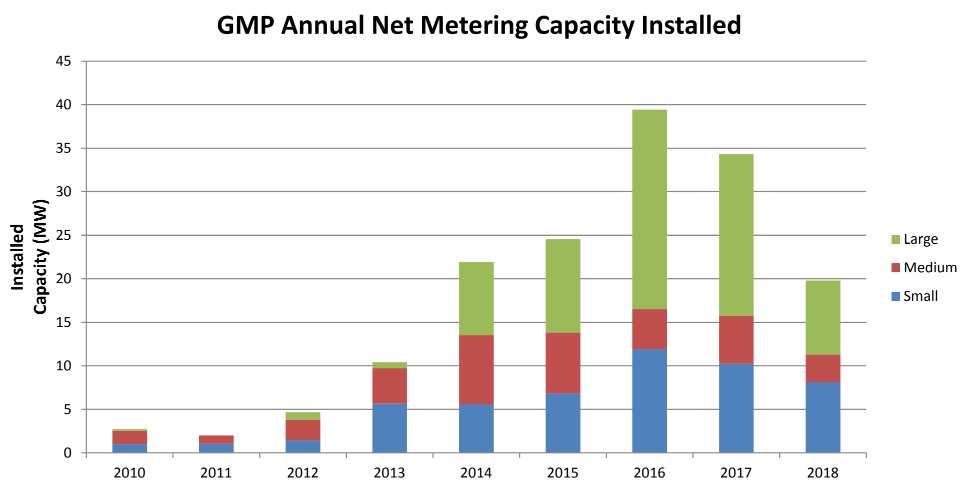

Figure 5-13. Annual Net Metering Installed Capacity

The extraordinary growth of net metering in our territory (relative to electricity demand) has been more rapid than for the industry as a whole, including other leading solar states. Net metering has become by far the largest source of solar PV in our territory, with much greater capacity than solar PV from larger sources (MW-scale PPAs, or utility-owned project) which can be obtained at substantially lower cost per kWh. This is a particular concern for large-scale (up to 500 kW) projects, which are often located remotely from customer load and don't offer operational advantages relative to lower-cost larger solar sources. During the same period that net metering and other initiatives have been very successful at supporting the development of new solar capacity, the value of additional solar power (above that already in place) has declined significantly. As a result, additional net-metered generation at current payment rates tends to put upward pressure on our net power costs and retail electric rates.

There are two primary reasons for this. First, the success of solar PV deployment in Vermont has lowered peak loads during daytime hours, shifting the remaining peak loads primarily to evening hours when solar power is not generating. While initial installations of solar PV in Vermont were estimated to provide several cents per kWh of value in the form of reduced regional transmission charges and potential deferral of peak-driven transmission and distribution capital projects, it is likely that additional solar PV will provide only minimal benefits of this type.[44]

Second, near-term wholesale market prices for energy, capacity, and regional Class 1 RECs in New England, along with expectations for those prices in the future, have each stabilized or declined over time. For example, "7x24" (round-the-clock) energy for delivery in the next several years (2019 through 2022) is presently available for a fixed price of about 4 cents per kWh; a few years ago, broker indications for similar forward purchases were priced at more than 6 cents per kWh. These market price declines affect the value of additional solar PV power, as well as the value of other potential power resources.

Starting with net-metered generation projects applying for interconnection in 2017, the PUC established that payment rates should be differentiated in two ways. First, net-metered customers who elect to transfer the renewable attributes associated with their projects to the host utility to help meet RES requirements receive a positive REC Adjustor (presently 2 cents per kWh). Net-metered customers who elect to retain the renewable attributes (for example, in anticipation of selling them, or to be able to claim that their home or business is fully powered from the net-metered project) receive a negative REC Adjustor. Second, each project receives a Siting Adjustor, which may be positive, zero, or negative depending on the size of the project and whether the project is located on a "preferred" site. In general, larger projects that are typically able to achieve greater scale economies receive lower Siting Adjustors—and therefore somewhat lower total payment rates for their output.

[44] The shift in Vermont peaks into evening hours does not mean that peak load reductions that were caused in part by past deployment of solar PV (including net metering) are lost, but it does mean that additional volumes of solar PV will provide much less value per kW to GMP customers than the initial volumes did.

As a result of the PUC's biennial review of the net metering program, payment rates for new net-metered generation were lowered somewhat, effective with applications received starting July 1, 2018. Specifically, the REC Adjustor available to all projects was reduced from 3 cents per kWh to 2 cents per kWh; this Adjustor will be reduced to 1 cent per kWh for projects proposed from July 1, 2019 onward. In addition, the Siting Adder available to large projects (those with the greatest potential scale economies) was lowered by 1 cent per kWh.

Table 5-5 illustrates the current (as of mid-November 2018) status of our net metering queue: active and proposed projects for the small, medium, and large size ranges. The header "NM 1.0" refers to projects that applied to interconnect in 2016 or earlier; "NM 2.0" refers to projects that applied from January 1, 2017 to June 30, 2018; while "NM 2.1" refers to projects that applied July 1, 2018 or later.

Size	Status	Solar NM 1.0		Solar NM 2.0		Solar NM 2.1		Non-Solar NM		NM Totals	
		#	Capacity (MW)	#	Capacity (MW)	#	Capacity (MW)	#	Capacity (MW)	#	Capacity (MW)
Small	Active	6,379	38.9	1,923	12.5	139	0.9	82	0.5	8,523	52.8
	Proposed	1	0.0	373	3.1	234	1.7	3	0.0	611	4.8
Medium	Active	416	32.2	76	4.7	2	0.0	17	1.6	511	38.5
	Proposed	3	0.3	113	10.9	20	0.7	1	0.1	137	12.0
Large	Active	120	66.0	4	1.8	0	0.0	12	4.0	136	71.8
	Proposed	6	2.9	59	28.6	6	2.5	0	0.0	71	34.0
Total Active		6,915	137.1	2,003	19.0	141	0.9	111	6.1	9,170	163.1
Total Proposed		10	3.2	545	42.6	260	4.9	4	0.1	819	50.8
Combined Total		**6,925**	**140.3**	**2,548**	**6261**	**401**	**5.8**	**115**	**6.2**	**9,989**	**213.9**

Table 5-5. Net Metering Resources: November 16, 2018

There is about 163 MW of active net-metered generating capacity on our distribution system, and a queue of about another 51 MW of proposed projects that have applied for interconnection.

A few other observations about the net metering fleet:

- About 96% (all but 6 MW) of operational net metering capacity is from solar PV projects.
- Almost 93% of net metering systems (over 8,500) are in the small category; they make up only about 53 MW (or about 32%) of installed capacity.
- Large systems make up 72 MW (or about 45%) of operating capacity, and about two-thirds of proposed projects.

- The bulk of project capacity that has been proposed (but not yet completed) is from "Net Metering 2.0" projects that applied for interconnection before July 1, 2018, particularly during a surge of applications submitted between February and June 2018. The pace of new applications since July 2018 has been slower, particularly for large projects.

Jointly Owned Generation

We have joint ownerships in four generation facilities and one transmission facility. The generation facilities include one nuclear, one wood, and two fossil-fuel projects, representing baseload and peaking capacity.

Resource Name	Age (years)	GMP Share Nameplate MW	2017 MWh
McNeil Station	34	15.5	83,382
Millstone #3	32	21.3	168,147
Stony Brook 1A, 1B, 1C	37	31	8,472
Wyman #4	40	17.7	2,653
HVDC Phase 2 Transmission	28	112	n/a
	Total	**270.5**	**266,461**

Table 5-6. Jointly Owned Generation

McNeil Station. McNeil Station is a 50 MW wood-fired generation facility located in Burlington; the plant began operation in 1984. Our ownership share is 31% (about 15.5 MW); we therefore receive that fraction of output and pay for that share of the plant's operating costs. McNeil can also operate using natural gas (either alone or in combination with woodchips), although this only rarely occurs in actual practice. Burlington Electric Department (BED) owns 50% of the facility and the Vermont Public Power Supply Authority owns the remaining 19%. BED operates the facility on behalf of the joint owners.

In 2008, a selective catalytic reduction system was installed on the plant to reduce its nitrogen oxides (NOx) emissions. This emission reduction enabled the plant's output to qualify as eligible for compliance with Connecticut Class 1 RPS. As a result, in recent years, we (often in collaboration with other McNeil joint owners) have sold most or all of our share of McNeil RECs to load-serving entities in Connecticut for RPS compliance, with the associated revenues used to reduce our net power supply costs and retail electric rates. The production of valuable RECs (in addition to energy) has supported the operation of McNeil at well over a 50% capacity factor. Although the market value of McNeil's output is expected to decline significantly in the near-term because of declines in market prices for energy (in non-winter months) and Connecticut

Class 1 RECs, we assume that McNeil will continue to operate during this IRP planning horizon.

Millstone #3. Millstone Unit #3 is a 1,235 MW pressurized-water base-load nuclear reactor situated in Waterford, Connecticut, on Long Island Sound. It is part of the three-unit Millstone Station. Millstone #1 is being decommissioned, while Millstone #2 is actively generating. Millstone #3 began commercial operations in 1986; we own a 1.7303% (21.5 MW) share of the unit. Dominion Nuclear Connecticut owns 93.470% of the unit with the Massachusetts Municipal Wholesale Electric Company (MMWEC) owning the remaining 4.799%. Dominion Nuclear Connecticut operates the facility on behalf of its joint owners.

The Millstone #3 operating license from the NRC runs through November of 2045. The future decommissioning of Millstone #3 is supported by dedicated Decommissioning Trust Funds for each joint owner.

Stony Brook 1A, 1B, 1C. The Stony Brook Station, located near Springfield, Massachusetts, hosts a combined-cycle gas- and oil-fired generation facility with both peaking and intermediate units. The intermediate units (1A, 1B, and 1C) have a combined capacity of 353 MW and typically operate as peaking generation with an annual capacity factor of under five percent. The primary fuel is natural gas, although the plant has operated regularly on oil (and provided value to our customers) for significant periods during cold snaps in recent winters, when regional scarcity of natural gas supply made operation on gas uneconomic. This dual-fuel capability provides important protection against the physical unavailability and financial costs associated with potential interruptions of natural gas supply. The combined-cycle plant can be started relatively quickly in response to regional market contingencies, and can be operated over a wide range of output levels. Stony Brook began commercial operations in 1981. We own an 8.8029% (31 MW) share of the combined intermediate units, along with a smaller share of output through a long-term PPA. MMWEC operates the facility on behalf of its joint owners, which are mostly Massachusetts municipal utilities.

Wyman #4. The Wyman Station facilities, located on Cousins Island near Yarmouth, Maine, comprise four generating units. Unit 4, the largest at 606 MW, is a steam unit that burns residual oil as the primary fuel, and functions as a peaking generator in the ISO-New England dispatch; it can be dispatched over a wide range of output levels. Unit 4 began commercial operations in 1978 and was originally intended to function as an intermediate dispatch unit. Wyman #4 earns FCM and other ancillary product revenue from ISO-New England. We own a 2.9207% (17.7 MW) share of Wyman #4; NextEra owns 84.346% of the plant and operates the facility on our behalf and the unit's other joint owners. The plant has been economically dispatched at low annual capacity factors in recent years, but it tends to be dispatched more heavily (and provide savings to our customers) during winter cold snaps, when regional natural gas prices and energy market prices are high. As a steam unit that requires many hours to start, Wyman #4 is not expected to be able to respond to shortage events that are triggered by unexpected regional contingencies (for example, trips of major generating units or transmission elements) that arise quickly.

HVDC Phase 2 Transmission. The Phase 2 transmission and converter terminal facilities interconnect the Hydro-Québec system to the ISO-New England system with a nominal transfer capability of 2,000 MW. We have both an equity ownership share and a leased share of the facility providing use rights to approximately 8% the facility's available transmission capacity (approximately 112 MW of firm capacity at typical availability). ISO-New England recognizes the contribution of this interconnection to regional resource adequacy, and presently provides us with roughly 80 MW per month of FCM Hydro-Québec Interconnection Capability Credits (HQICC). We currently resell the energy-use rights of the facility short-term to other entities wishing to import energy across the facility, with the revenue used to reduce our net power costs. We expect to renew the current facility-use arrangement when the lease expires in 2020.

Highgate Converter. The Highgate Converter is a back-to-back AC-DC-AC facility located near Highgate Springs, with transmission capability as high as 225 MW connecting with Hydro-Québec to the north and the VELCO system to the south. It began commercial operations in 1985; its annual capacity factor for energy deliveries has typically been about 75%. The facility has primarily been used to import Hydro-Québec Vermont Joint Owner (HQ-VJO) power, but exports are also possible. We sold our 82.29% (185 MW) share of the facility to VELCO in 2017, with the goal of lowering net cost to our customers. VELCO is now the primary owner of Highgate and operates the facility on behalf of the joint owners.

Long-Term Power Purchase Agreements (PPAs)

The majority of our energy supply comes from long-term PPAs with individual suppliers. Until the Vermont Yankee (VY) contract expired, the VY and HQ-VJO PPAs supplied the vast majority of the energy requirements of the legacy companies. We have transitioned away from a few large PPAs toward smaller and more diverse resources, including new nuclear and hydro-based PPAs, an 82 MW wind PPA, and other purchased and owned resources. Through the IRP planning period, we receive a significant portion of our energy from a few large, long-term PPAs (HQ-US and NextEra), but significantly less than earlier in the decade.

Table 5-7 depicts current contracts and illustrative 2017 energy volumes.

Generator Name	Contract Period	Contract MW	2017 MWh
Hydro Québec-United States[1]	2012–2038	178	1,041,727
Moretown Landfill	2009–2023	3	11,798
Granite Reliable Wind	2012–2032	82	170,994
Small Renewable PPAs—Solar	Various	43	46,808
Small Renewable PPAs—Other	Various	36	93,159
NextEra Seabrook (unit output)[2]	Through 2034	60	476,658
NextEra Seabrook (capacity only)[3]	Through 2034	175	none
Stony Brook 1a, b, and c	1981-Life of Unit	15	3,807
Deerfield Wind[4]	2017–2042	30	–
Total		**622**	**1,844,951**

1 The HQ-US contract delivers firm energy without capacity.

2 We purchase energy and capacity from NextEra Seabrook under two long-term PPAs; for simplicity, we have presented their energy and capacity components separately in this table.

3 Our purchase of plant-contingent energy, capacity, and generation attributes from NextEra Seabrook is presently 60 MW; it will decline to 55 MW in 2021 and to 50 MW in 2029.

4 Began commercial operation on December 27, 2017.

Table 5-7. Long-Term Power Purchase Agreements

Hydro-Québec–United States. In April 2011, GMP and a group of other Vermont distribution utilities received approval from the PSB for a 26-year PPA with Hydro-Québec–United States (HQ-US) starting in November 2012. Our current share of the purchase increased to about 170 MW at the end of 2016 as the HQ-VJO contract expires. The HQ-US PPA will provide annual energy volumes of approximately 1,000,000 MWh per year (representing about 22% of our current annual energy requirements) during much of the delivery term, in a flat schedule during the peak 16 hours of every day. These deliveries are financially firm and not contingent on the operation of particular generating units or transmission facilities. In addition to the energy delivered, the PPA includes all environmental attributes of the power, at least 90% of which will be based on hydroelectric resources, helping us maintain our low-emission energy profile at a relatively stable price that reflects a blend of general inflation and regional energy market prices. No capacity is included in this purchase.

Figure 5-14. Granite Reliable Wind Facility

Granite Reliable Wind. We purchase about 82% of the output from this 99 MW wind plant located in northern New Hampshire under a 20-year contract. This is projected to supply about 5% of our annual energy requirements at a fixed schedule of contract prices. The output of the project includes plant-contingent energy, capacity, and RECs; the size of our purchase declines to about 55 MW in 2027.

Moretown Landfill Gas. In December 2008, we began receiving energy from Moretown Landfill Gas through a 15-year PPA. We receive 100% of the plant output, which includes energy, capacity, and RECs. This plant operates in a baseload mode; its output was originally about 3 MW. Declining methane production at the landfill has (as anticipated) gradually reduced the typical available output to roughly 1.5 MW.

Figure 5-15. Williston Solar Facility

Small Renewable PPAs. To help facilitate development of local small renewable projects across a range of technologies, we have entered into plant-contingent PPAs for the output from a number of these facilities. About 43 MW of these are solar projects in Vermont, including Rutland, Williston, Panton, Strafford, Williamstown, and Ryegate. The remainder are long-term PPAs for the output of four hydroelectric plants totaling approximately 36 MW (the largest of which is the Sheldon Springs plant at over 25 MW). These purchases represent a small portion of our total power and REC needs today, although such bilateral purchases from local renewables could be increased over time to help meet our RES Tier II requirements.

Stony Brook 1a, b, and c. As described earlier, we own a small interest in these units. In addition to the ownership allocation, there is a PPA for 4.4% of the output from the facility that runs for the life of the units at a price that follows the cost of operating the facility.

NextEra Seabrook. We purchase output from the Seabrook nuclear facility under two long-term PPAs. The first PPA provides 60 MW of plant-contingent energy, capacity, and generation attributes; at an illustrative 90% annual capacity factor, this would represent about 473,000 MWh or roughly 11% of our annual energy requirements. Over time, deliveries of these products under the contract are scheduled to decline by 10 MW (about 80,000 MWh per year) starting June 2021 and by another 10 MW starting in June 2029, with the PPA ending in 2034. We also purchased an additional 25 MW of capacity (without associated energy or attributes, and constant over time) under this long-term purchase.

The second PPA provides an additional 150 MW of plant-contingent capacity on a long-term basis, along with 5 MW of additional plant-contingent energy and attributes starting in June 2021, increasing to 10 MW in June 2029 before the PPA ends in 2034.

Overall, the purchase provides low-emission baseload energy and capacity at relatively stable prices, with increases driven primarily by an index of general inflation. Based on the two transactions together, our purchase of plant-contingent energy and attributes is presently 60 MW, declining to 55 MW, and ultimately to 50 MW. The total purchase of capacity declines over time from 235 MW to 230 MW and ultimately to 225 MW. Although this PPA is one of our largest single sources, the total long-term purchase commitment from NextEra Seabrook is only a small fraction of our former reliance on the Vermont Yankee plant. If the plant were to retire early, there would be a notable adverse impact on the emission profile of our portfolio. The impact on our net power costs would depend on prevailing market prices at the time, relative to the PPA prices for energy and capacity.

Deerfield Wind. We purchase 100% of the output from a 30 MW wind plant located in the towns of Searsburg and Readsboro, under a 25-year contract that also includes an option to purchase the plant for a fixed price after ten years of operation. The plant reached commercial operation and began delivering plant-contingent energy, capacity, and RECs in December 2017. This is projected to supply about 2% of our annual energy requirements at a fixed price.

Long-Term Vermont Policy Resources

NYPA. We receive approximately 0.5 MW of NYPA power, most of which comes from the Niagara Power Plant on the U.S.-Canada border. Although the current NYPA contract expires in 2025, it is projected to remain available through the IRP planning period. Delivery of NYPA energy can be shaped to correspond with the higher load periods of the day, and is expected to amount to about 6,000 MWh per year.

Ryegate. Ryegate is a 21 MW woodchip-fired generator. The plant presently operates under a 10-year contract between Ryegate Associates and VEPPI, mandated by

Vermont's Baseload Renewable Energy Standard. The expected annual plant output is roughly 172,000 MWh; our portion is approximately 82%, or 141,000 MWh per year. The PPA has an estimated levelized price of roughly 10 cents per kWh, with a portion of fuel price risk passed through the PPA price. This price is significantly higher than our current base case outlook for the value of the plant output (energy, capacity, and RECs) that we receive; the PPA expires in late 2022. The portfolio analysis (in Chapter 8: Portfolio Evaluation) assumes that our purchase obligation from Ryegate will expire at that time. The volume of output from this plant is significant enough that if the Ryegate PPA were extended or replaced at pricing similar to the current PPA, the resulting increase in our net power costs starting in 2023 would likely put upward pressure of at least one percent on average electric rates for our customers.

Standard Offer. Under the Standard Offer program, we purchase our load ratio share (presently about 82%)[45] of output from up to 127.5 MW of participating renewable projects, which must each be sized 2.2 MW or smaller. The PUC appointed VEPPI as the facilitator to administer these resources, which presently include more than 56 solar, hydro, biomass, and methane generators with an aggregate capacity of about 65 MW.[46] Standard Offer resources generally carry a fixed, levelized price for a term of 20 or 25 years. We estimate these resources will supply about 109,000 MWh to our portfolio in FY 2019 and project that this amount will grow to about 170,000 MWh per year when the program is fully subscribed.

The actual volumes and cost of new Standard Offer power depends on the specific mix of renewable technologies that supply the program, and the actual capacity factors of those plants. The PSB implements the SPEED program as described in Rule 4.300, with the goal to "achieve the goals of 30 V.S.A. §8001 related to the promotion of renewable energy and long-term stably priced contracts for such energy that are anticipated to be below the market price."[47] In actual practice, the average price of Standard Offer PPAs has turned out to be far above market, owing primarily to very high PPA prices from projects in the early years of the program, along with declining wholesale market price expectations over time. After a transition to procurement via annual RFPs in 2013, the pace of project completion slowed significantly, as some projects receiving Standard Offer PPAs struggled with a range of challenges (for example, difficulties or delays in obtaining required permits, or delivering on the prices they had offered). The pace of project completion has picked up significantly in the past year; VEPPI anticipates that several more projects will be completed in 2019.

45 Program exemptions granted to several Vermont municipal utilities have increased our share of Standard Offer power by several percent in recent years, increasing our net power costs by an estimated $1 million or more per year.

46 For more information, please refer to www.vermontspeed.com.

47 Vermont Public Service Board, 4.300 Sustainably Priced Energy Enterprise Development Program, 4.301 Purpose.

VEPPI and PURPA Contracts. We purchase approximately 77% of the output from Vermont's legacy Qualified Facilities under the federal Public Utility Regulatory Policies Act (PURPA). The PSB appointed VEPPI as the agent to administer these resources, which were contracted in the 1980s and 1990s. A share of the output of these Qualified Facilities is assigned to our power supply portfolio under PUC Rule 4.100, which states that "The purpose of this rule is to encourage development of electricity through use of biomass, other renewable resources, waste and cogeneration, while giving due consideration to the duties and responsibilities of utilities. The rule implements the provisions of 30 V.S.A. Section 209(a)(8) and 16 U.S.C. Section 824a-3."[48] Most of these legacy PPAs have expired in the past decade; the remaining fleet includes four hydroelectric generating stations, with two contracts ending by January 31, 2019 and the final two expiring in 2020.

Short-Term Energy PPAs

We source a portion of our energy requirements each year through fixed-price energy purchases from the New England wholesale energy market. These purchases avoid us being substantially exposed to spot market energy purchases at volatile prices, thereby stabilizing our near-term power supply costs and retail rates. We have approached these purchases with the goal of staggering the effective dates and costs to mitigate risk and lower overall cost exposure for customers. For that reason, we have and expect to continue to approach these purchases on layered basis with terms up to five years; this limits the occurrence of large "step" changes in costs when new purchases are implemented or existing purchases expire. Limiting the purchase term to five years or less ensures that the company's power supply costs maintain some significant linkage to the New England wholesale energy market, and limits the degree to which our power costs can become disconnected from those of utilities in neighboring states that buy a greater portion of their needs in the short-term markets.

Generally, we make these purchases for firm energy (as opposed to unit contingent) from creditworthy sellers, and settle them at the ISO-New England internal hub. We seek to shape the volume of our energy purchases on a monthly basis (and between peak and off-peak hours), to match the shape of our forecasted net open position.[49] Unless the contracts also include generation attributes from particular sources, they are considered for purposes of describing the fuel mix and air emission profile of our power supply to carry an emissions profile of the New England "system residual" mix.

[48] Vermont Public Service Board, 4.100 Small Power Production and Cogeneration, 4.101 Purpose.

[49] As discussed in Chapter 9, our energy needs (that is, load requirements less committed generation sources) tend to be larger in winter and during off-peak hours. We tend to need less energy during spring months and in daytime hours when solar generation is high; sometimes we are a net seller of energy during those hours.

Currently contracted short-term purchases total approximately 1 million MWh for each of FY2019 and FY2020, 700,000 MWh for FY2021 to 2023, and about 400,000 MWh for FY2024 and 2025. Table 5-8 shows total purchases by counterparty including volumes and total costs; the average price of these committed forward purchases over the next five years is about $47 per MWh. The total costs reflect a number of factors, including the forward energy market outlook at the time that each purchase was contracted, and the period(s) and monthly volumes for each purchase. By design the average price we pay for these forward-market purchases collectively in any given year is therefore not an indication of the current market value of energy in that single period, but rather reflects a weighted average value of multiple contracts that cover multiple delivery periods, negotiated at different points in time, and featuring different market conditions.

Counterparty	Contract Period	Description	MWh	Cost
Macquarie	FY2019	Winter months 7x24	99,405	$4,612,392
Shell	FY2019-21	Baseload 7x24	512,250	$20,657,415
BP	FY2019-FY2024	Seasonally shaped 7x24 block	1,973,100	$100,947,174
Citigroup	FY2019-21	Peak seasons in FY19, baseload remainder	365,425	$18,196,614
NextEra	FY2019-FY2025	Seasonally shaped 7x24	2,068,430	$93,804,649
		Total	**5,018,610**	**$238,218,244**

Table 5-8. Short-Term Purchased Energy Summary by Counterparty

Short-Term Renewable Attribute Purchases (RECs)

Vermont's RES, which took effect in 2017, requires utilities to meet specific fractions of their retail sales volume with renewable energy. Compliance is demonstrated based on the retirement of RECs in the NEPOOL GIS; the RECs can be obtained from utility-owned generating plants, bundled PPAs (under which the power output and associated RECs from a generating facility are sold together), or unbundled (REC-only) purchases. Utilities also submit annual compliance filings to the PUC that show how the annual RES requirements have been achieved (and address Vermont-specific features like banking of RES compliance across years).

While there are a significant number of supply resources within our supply portfolio that meet the eligibility requirements for RES Tier I and Tier II, we also buy a portion of the required renewable energy through unbundled REC purchases. For example, to help meet the larger Tier I requirements, we have entered into a multi-year transaction with Hydro-Québec that convey generation attributes from hydroelectric sources imported into New England over the Phase 2 transmission facility.[50] Under this transaction which began in 2018, we purchase between 1.5 million to 1.7 million RECs per year, which are delivered quarterly into the NEPOOL GIS tracking system. The purchase continues until late in 2020. We anticipate banking some of these RECs (in excess of its annual Tier I requirements) to meet requirements in subsequent years. We have also purchased smaller volumes of RECs from other New England generators.

POTENTIAL NEW SUPPLY RESOURCES

The available supply resources include multiple types of renewable power sources, which vary in terms of their scale, location, relative cost, output profiles, and other features. Some of these sources are options that we could potentially explore and implement directly, while others are policy resources whose volumes and timing are not under our control. We are also able to purchase from (and sell to) the ISO-New England wholesale power market, which can play an important role in enabling us to manage the expected cost and potential volatility in net power costs. We also anticipate a significant role for flexible energy storage—which has the potential to "stack" several forms of value and reduce expected costs and potential volatility. While our power supply strategy and the Vermont RES focus primarily on increasing renewable supply and limiting greenhouse gas emissions in a cost-effective way, local oil-fired peaking capacity (which operates infrequently) can complement this transition by helping to meet our share of regional capacity requirements and by supporting the Vermont transmission and distribution grid. That being said, we envision a time in the not too distant future where we can actually retire our traditional oil-fired peaking generation and replace with a combination of energy storage, flexible demand and bilateral contracts with a focus on not just reducing carbon from our energy supply but our capacity supply as well.

Renewable Generation

Our portfolio includes a variety of renewable resources including wind, solar, biomass, bio-digesters, landfill gas, and both small and large hydroelectric resources.

Net Metering

As previously discussed, the pace of growth of net metering in our territory in recent years has been extraordinary. The future growth of net-metered generation will affect our ability to make other resource choices (such as small-scale solar PPAs). The precise

50 As part of the same transaction, we are leasing the use of its Phase 2 transmission rights to Hydro-Québec through late 2020.

pace will depend on a range of factors, including the pace at which solar capital costs continue to decline; the trend of customer interest in net metering; the relative availability of "preferred" sites for larger projects; and future changes in net metering payment rates or other program features. As a result, the volume of future net metering growth represents a significant planning uncertainty for us.

As shown in Figure 5-11, Figure 5-12, and Figure 5-13, annual installations of new net metering capacity in our territory since 2014 have ranged from roughly 20 MW per year to almost 40 MW per year. For this IRP's portfolio evaluation, we assume as a base case that net metering capacity in our territory will continue to grow at a pace of about 20 MW per year. This pace of net metering growth, combined with other committed sources, would be sufficient to meet essentially all of our estimated RES Tier II requirements over the next decade. Our portfolio evaluation (in Chapter 8: Portfolio Evaluation) also tests the implications of sustained net-metered growth rates as high as 30 MW a year and as low as 10 MW a year.

Wind Power

On-shore wind has represented one of the most cost-competitive sources of new utility-scale renewable power in New England, but it is not clear that additional long-term commitments to onshore wind will be a good fit for our portfolio, at least in the near future. Our primary needs for RES compliance appear to be in the areas of new Tier II (distributed) renewables in Vermont, and lower-cost existing renewables (from Vermont or the region) to meet Tier I requirements. In addition, our power portfolio presently includes a total of 173 MW of wind capacity, from four plants located in Vermont and New Hampshire; on an "average year" basis their production is sufficient to meet an estimated ten percent of our current annual energy requirements. This volume of intermittent wind power also carries a degree of variability in output (over time frames from an hour to a year). In addition, proposed wind plants in Vermont are often sited on mountains where a combination of difficult terrain and/or distant transmission access can increase project capital costs, and we recognize that proposed wind plants have encountered significant resistance in the permitting process.

Recently proposed pricing for off-shore wind projects in New England suggests that this resource could (if the indicated pricing gains are realized, and particularly if further declines materialize over time because of industry experience and scale) potentially become an attractive option for us in the future. The attractive features of offshore wind include relatively high capacity factors (with output weighted toward high-value winter months); the potential for relatively high capacity ratings; and diversity of output relative to our significant existing fleet of onshore wind resources. Because our renewable power needs are small in comparison to potential offshore wind projects, the most likely way for us to participate would be to seek a long-term PPA as part of a much larger solicitation conducted by a neighboring state or aggregation of states or utilities. As part of the portfolio evaluation (see Chapter 8: Portfolio Evaluation), we address the implications of adding offshore wind in the late 2020s, at assumed pricing (for example, roughly $75 per MWh, escalating over time) that is consistent with reported pricing offered to Massachusetts in its 2018 solicitation.

Standard Offer

As previous discussed, the Standard Offer program supports the development of new renewable sources sized up to 2.2 MW. In recent years the price competitive block has been filled primarily with solar PV projects, although technology diversity provisions have supported more limited volumes of other types of projects. Our portfolio analysis assumes that the program will continue until the total capacity of operating Standard Offer projects reaches the statutory goal of 127.5 MW in 2024. We do not assume that the program will be renewed after that time, as a central procurement program no longer appears to be necessary in light of the extraordinary growth of renewable power in Vermont. Should the Standard Offer program be discontinued prior to reaching the statutory goal, we believe that the RES framework nevertheless establishes clear expectations that distributed renewable generation should continue over time, and we expect that GMP and other Vermont utilities will be able to effectively solicit additional supplies at competitive prices as needed.

Solar Power

As previously discussed, in recent years net metering has been the primary source of distributed renewables, while some GMP-sponsored projects (up to 5 MW in size) and PPAs have been completed at significantly lower effective prices. The amount of additional distributed renewables that we will need to meet our RES Tier II requirements will depend on the pace of growth for net-metered generation and Standard Offer renewable generation. To the extent that additional distributed renewables are needed, we expect to solicit PPA proposals from qualified generation firms, and to compare those options to additional GMP-owned generation. For the purpose of portfolio evaluation in this IRP, we assume that the primary Tier II resource that it would call upon will be solar PV on the scale of 1 MW to 5 MW, priced in the near-term at about $85 per MWh levelized. The price of additional solar PV is expected to continue its long-term decline, although the solar ITC will begin to decline in 2020, and will step down to 10% in 2022, which may temporarily interrupt this trend.

Several larger scale solar PV project proposals (up to 20 MW or more) have also been proposed in Vermont, primarily for the purpose of selling their output under long-term contract to neighboring states. We have not yet purchased output from any of these larger projects, primarily because their size makes them ineligible for RES Tier II and there appear to be other renewable options (primarily existing sources) available at lower cost to meet our Tier I needs. Larger scale solar PV could potentially be an option in the future, however, considering that larger projects may be able to achieve greater scale economies (and lower effective cost per kWh) than smaller projects; solar PV costs are anticipated to decline further over time; and solar PV in some locations could potentially (in combination with energy storage) be used to support local grid resiliency. On the other hand, larger proposed projects warrant careful review with respect to their potential impact on the VELCO bulk transmission system and our subtransmission system.

Hydroelectricity

Hydroelectric resources continue to represent the largest portion of renewable power in our resource mix, and are projected to meet about one-third of our total energy requirements over the next 20 years. The largest single source is the HQ-US contract, which provides firm deliveries in accordance with a fixed schedule. Because hydroelectricity is a resource that can play multiple roles within the portfolio (renewable, zero-air emissions, stable price, stronger winter supply), we will continue to explore adding cost-effective hydroelectric resources to the portfolio as those opportunities arise. In particular, we will continue to seek additional opportunities to increase output from our existing hydro plants and to develop new projects, although we expect that the scale of new projects that are feasible and cost-competitive will be limited. We also expect to explore acquisitions of existing hydroelectric power, through PPAs and/or purchases of specific plants. Our analysis (in Chapter 8: Portfolio Evaluation) tests the potential implications of acquiring additional hydroelectric power on a long-term basis through plant-contingent sources (that is, long-term PPA, or acquiring ownership in existing hydroelectric plants) or a firm PPA basis (as Massachusetts is pursuing through the proposed NECEC project in Maine). Although very limited, we will also look to develop new hydro in Vermont should the opportunity present itself in a way that can be done cost effectively and in conjunction with the community it is located in. This would provide the opportunity for a Tier II resource aside from solar, with better supply in the winter months and higher capacity factor for production.

Biomass Power

As a joint-owner of McNeil and the majority off-taker of Ryegate, we presently receive about 5% of our energy requirements from woody biomass. Biomass plants have some advantages (not intermittent, able to produce power in a baseload duty cycle) relative to other new renewables, and they also have the potential to support significant local economic activity. Newly constructed biomass plants appear to be much less cost-competitive than both wind and solar, however, and existing biomass plants in the region are under financial pressure from moderating market prices for energy and regional Class 1 RECs. Low market prices are particularly challenging for biomass plants because in addition to a significant capital cost ($/kW), they also face a significant fuel expense ($/MWh) and non-fuel operating costs, in fact, two biomass plants in New Hampshire (the Pinetree Power plants in Bethlehem and Tamworth) have recently announced plans to operate under reserve shut-down status with the option of restarting if economic conditions improve or if they are called by ISO-New England. In contrast to wind and (particularly) solar, we are not aware of any technological changes that are expected to lower the cost of biomass energy in a major way in the near future. We have therefore not modeled utility scale biomass as a new resource for evaluation in this IRP, and have not continued Ryegate in the modeling past our current contract obligation.

Bio-Digesters

Methane-producing farm digester systems have been a part of our mix for a number of years, and continue to be added under the Cow Power program. As previously mentioned, these facilities are owned by the farmers, with the revenue from the electricity and renewable credits flowing back to them. As we explore the next generation of these facilities, we believe that a GMP-owned model that incorporates both farm manure as well as pre- and post-consumer food waste could provide substantial benefit for Vermonters. The current technology for digesters, their generation sets, pumps, and other equipment require substantial capital investment that provides a real hurdle to the economics of this type of project when they are evaluated solely on the basis of their power supply benefits. One possible strategy for supporting bio-digester projects is to value other benefits such as phosphorous and nitrogen capture that can help to decrease farm runoff into streams, rivers, and Lake Champlain, and to determine if there is way to monetize these benefits to help rationalize the economics of bio-digesters. Given the challenges, we conservatively have not modeled increased bio-digester production in this planning period.

The Vermont Legislature has recently taken a step forward with the passing of Act 148, which requires a phased-in approach to ultimately keep all food waste out of landfills. This creates an opportunity to capture this abundant waste stream and turn it into energy, as well as heat and other products, such as compost. This can further be combined with wastewater treatment facilities to produce additional methane, which can also be used to generate clean electricity.

Geothermal Power

We are not aware of any commercial-quality sources of geothermal energy for electricity production at present, so geothermal resources are not specifically considered in the resource plan.

Battery Storage

Battery storage is a rapidly emerging tool for utilities in New England that has been driven by significant technological improvements and a rapidly declining cost curve in the past decade. In addition, as peak-driven charges (based on monthly or annual peaks) have grown significantly in the past decade, there has been an increased focus on minimizing peaks that are used to allocate transmission (Regional Network Service or RNS) and capacity charges.[51] A number of tools such as demand response (programs through which customers reduce consumption during key peak conditions) and devices (such as our car chargers and water heater controls) that enable responsive load have begun to feature prominently in utilities' strategies for managing peak loads. Battery storage, with its rapid response and ability to accurately discharge, is a new tool that we have begun to use for peak management. This includes the small battery storage devices for home use (for example, Tesla Powerwall batteries) and larger MW-scale devices such as the batteries deployed at our Stafford Hill and Panton PV solar sites.

When evaluating battery storage as a resource, we sum it up with one word: flexible. Battery storage has the amazing ability to act as multiple types of resources, all packaged into on system. These systems can act as loads, generation, a power quality management tool, and a system resiliency tool to name a few. While not every one of these values is easily monetized, they can all play a very important role when it comes to operating a highly distributed and growingly more intermittent energy delivery system. As you have read throughout this IRP, we continue to shift to an energy delivery system that utilizes more and more distributed generation and will require more distributed, managed, energy resources like controllable loads. Battery storage is not purely a peak-shaving resource. At present, cost-effective deployment generally relies on combining or "stacking" several types of benefits, but we will discuss battery storage among peaking resource options because peak management presently provides the majority of estimated power and transmission benefits. Our current use case for battery storage (whether located at customer premises or on the distribution grid) deploys the storage "behind the meter" as load reducers to maximize the benefits that ultimately flow to our customers. The batteries are primarily focused on peak shaving, whereby batteries are discharged for

51 For example, for each MW decrease in loads during monthly Vermont system peaks, GMP is able to reduce its RNS transmission charges by approximately $10,000. Reducing one MW of load during the regional peak load hour that is used for allocating Forward Capacity Market requirements can reduce our power costs by about $100,000.

periods of up to four hours when we forecast the potential for monthly or annual peak loads to occur. By discharging these batteries, we are able to effectively decrease load requirements from the ISO-New England market during these periods by the total output of all of the batteries connected to our system, which is currently several MW.

In addition to peak shaving, we are currently using our utility scale batteries (those over 1 MW), which as of the time of this IRP filing is our Stafford Hill solar/storage facility and our Panton storage facility, to participate in the ISO-New England Frequency Regulation Market, where the battery receives instructions from ISO-New England every four seconds and reacts almost instantaneously to increase or decrease its consumption or discharge rate to help balance the regional electric system in response to fluctuations in loads and generator output. Historically, natural gas-fired units that were generating at less than full output levels have been used to meet frequency regulation needs, but ISO-New England indicates that battery storage devices are able to react more quickly and accurately than these generators. Our expectation is that battery storage could grow to provide the majority of frequency regulation in New England within the next several years. As more storage devices are offered into the market, our expectation is that the prices paid for participation will probably decline substantially by the early 2020s and we have modeled this assumption into our battery financial analyses. If it turns out that the regulation market remains high, or increases because of the higher penetration of intermittent renewables in the region, the increased value will flow directly to customers.

An additional revenue stream for storage devices is energy arbitrage, whereby batteries are charged during hours with low or negative LMPs and then discharged during hours with higher LMPs. Some level of "natural" energy arbitrage is likely through the peak shaving duty cycle. We have seen limited additional energy arbitrage value to date, but we are working with Tesla (the provider of Powerwall home battery systems and the PowerPack battery storage system at our Panton site) to automate battery responses to changes in LMP for the purpose of energy arbitrage. We are also collaborating with the firm Virtual Peaker toward this goal for battery storage and other responsive loads. Over time, it appears that increasing penetration of intermittent renewable generation in New England will lead to more significant fluctuations in LMPs (for example, more highs and lows) that will increase the opportunity for arbitrage over time.

This points to the fact that while we can identify and model the value that these various markets show us today, the upside value for energy storage is much greater in our opinion than the downside risk. We anticipate the growing need for fast-acting, flexible resources, not just for economic value, but also as the next level distribution resource, an emergency resiliency tool and beyond. As we put the finishing touches on this IRP, we are reminded of the devastation that the impact of climate change is having and how severe our storms are becoming. Our customers just experienced one of our five worst storms in history during the last week of November. Although outages lasted as long as five days for some, a number of customers with Powerwall batteries were able to maintain backup power in their homes until power was restored. Now imagine if every single customer had a system like this. You cannot even begin to put a dollar value on customer satisfaction and security when it comes to having a backup resource during a major weather event like the one we just had. Not to mention the benefit of not having to fuel up a generator system, listen to the noise or run the risk of creating a carbon monoxide health hazard for your family. And equally important, when the storm is over and we are in the clear, we can go back to leverage the battery as a power supply and grid resource—again the ultimate in flexibility. The only question we ask now is how do we deploy, or cause to deploy, these systems much faster and to more customers.

An emerging issue for our portfolio is that the introduction of increasing volumes of intermittent solar, wind, and hydroelectric generation have increased the magnitude by which our energy supply (and therefore the open position that is exposed to spot market prices) fluctuates on an hourly or daily basis. We expect that the addition of battery storage will be complementary to an increasingly renewable supply, in part because of the inherent flexibility (for example, ability to ramp up charging or discharging quickly) of many battery systems. Storage could, for example, help us to begin to shift renewable output to hours of greater need (for example, solar output stored in a battery can be discharged during overnight hours to meet demand) as the scale of battery storage begins to increase.

Benefits and ISO-New England market opportunities will change over time and the flexibility of battery storage will enable them to play a part of our future strategy of minimizing net power costs for our customers. For example, over the next couple of years, changes to the ISO-New England operating reserve market will likely allow batteries to provide Ten Minute Non-Spinning Reserve; to the extent that the value from this market exceeds the value of any current battery uses, we may shift the operational duty cycles to participate in the Reserve Market, or possibly change the stack of benefits to include this market. ISO-New England has also begun to describe the need for a 'ramping' market, which would compensate resources that can respond quickly during key hours of the day where the New England load levels are somewhere in between the current level of resources and the need to turn on the next plant.

Battery storage systems can also benefit from the same federal Investment Tax Credit (ITC), that solar PV can receive, which is a further boost to the economics for Vermonters. Currently, to qualify for the ITC, a battery storage device must be collocated with a solar PV array and, for the first five years, at least 75% of charging energy must come from the solar unit. The taxpaying owner receives the equivalent amount of the 30% ITC based on the charging percentage, so for example, if the plant just hits the 75% threshold for charging off of the solar, the owner will get 75% of the 30% ITC benefit, and up from there. It is important to note that the 30% ITC is scheduled to step down beginning in 2020 and will drop to 10% in 2022, making it significantly less valuable for projects. At the same time, market studies indicate that increasing industry scale—particularly driven by a shift in the automotive industry toward partially electric and all-electric vehicles—is likely to drive down the cost of battery storage options significantly over the next five years, which should more than offset the drop in the ITC.

In the long-term, battery storage will play a role in displacing a portion of fossil fired peaking units, especially those units that are inefficient and have high emission profiles (for example, CO_2 and Nitrogen oxides). These batteries can directly participate in the ISO-New England Capacity Market and will receive monthly payments based on seasonal capacity ratings or continue to act as a load reducers. Currently, the key obstacle to participation in the peaking capacity market is that any unit must, at a minimum, be able to run for at least four hours, and in many instances peaking units have been required to run for significantly longer periods. Currently, adding hours of discharge requires the addition of cells, with each incremental hour of capacity coming at a slight discount to the initial hours of capacity. If the declining cost trends—or potentially breakthrough technological developments—lower the cost of longer-duration storage, several of the potential use cases would be enhanced.

While the power market and transmission benefits of battery storage can cover most or all of the costs of some battery storage systems today, the appropriate pace and locations for deployment of battery systems is likely to depend strongly on the extent to which they can provide local grid benefits.

Categories of potential benefits include:

- Deferral or displacement of transmission or distribution infrastructure that would otherwise be needed to provide reliable service. To the extent that we are able to deploy a battery storage solution with a lower total net cost than rebuilding a substation or reinforcing lines to manage demand on a circuit or potential demand growth, there is a significant benefit for customers (for example, a less expensive solution creates less potential rate pressure).
- Management of voltage on the distribution system. If a battery system is well located, its inverters may also be available to provide voltage support that is needed—especially as the saturation of distributed generation resources increases.
- Grid resilience, whereby a local circuit (or portion) can be supported by a battery (potentially in combination with other local generation) during an outage of the

broader grid. We have engaged with consultants to fully analyze the relay and protection schemes required for safe and stable islanding. We have reached an agreement with Vermont Department of Public Service that we will file for a Certificate of Public Good (CPG) before it undertakes islanding capability projects, whether through an initial CPG filing for a project including battery storage or a secondary filing specifically for islanding.

- Increasing the hosting capacity of a distribution circuit (or increasing the feasible generation in an export-constrained transmission area), by charging during times of excess local generation. As Vermont charges toward not only meeting our comprehensive energy goals, but exceeding them, energy storage plays a critical role in managing the new demands that may exist from the strategic electrification of fossil-fuel-based energy systems.
- As a customer-sited resiliency and power quality tool. Many customers in the C&I space are susceptible to business losses caused by voltage fluctuations that occur when faults happen on the system. Even if the fault is 50 miles away on the transmission system, sensitive operations can still be affected, costing the customer significant downtime or lost product. The addition of storage can not only smooth out those fluctuations but also act as a complete emergency power source if a complete outage occurs. This creates a new resource for the customer and revenue source for all our customers. And as with all storage options, the systems can be utilized at the right times for other grid and power supply benefits.

Battery storage is an important component of our future strategy for meeting customer demand and managing net power costs that will largely be driven by advances in technology and declining prices as manufacturers continue to scale up to meet growing global demand. In the near-term, we will focus on stacking peak-shaving benefits and Frequency Regulation to support the development of our battery fleet. In the longer term, other uses will begin to supersede these stacked benefits, through such use cases as firming renewable generation and replacing fossil-fired peaking units. At the same time, we will also be working to identify opportunities to minimize costs for customers through deferring T&D upgrades and enhancing grid reliability through voltage support and islanding.

Storage Procurement Strategy (Memorandum of Understanding with DPS)

As part of the recent petitions before the PUC for CPGs for three Joint Venture Solar and Storage Projects (JV Projects) that feature battery storage, GMP and the DPS have agreed on a process and criteria for the selection of future storage projects greater than 1 MW. The agreement is captured in a Memorandum of Understanding filed in each permitting proceeding (the Storage MOU). This was done to address the DPS's concern that the estimates regarding performance of these emerging battery strategies are more subject to risk than traditional resources. In the Storage MOU, a number of specific steps and actions for future storage procurements are outlined, including conducting system-wide analysis in consultation with the DPS, individual project analysis methods, and a least-cost evaluation process.

Among other details for these future procurements, the Storage MOU defines that this process will strive to utilize competitive procurements and will include evaluations of and details on:

- Economic benefits
- Distribution system benefits
- How the project facilitates integration of distributed energy resources
- The potential for third-party cost and benefit sharing
- Estimates for all expected costs to achieve the project's expected value streams
- Least-cost, best-fit alternatives analysis

Beyond this specific approach to evaluating and procuring storage established in our MOU, we also describe how other elements of portfolio design may impact or include storage as a supply resource for the portfolio and describe some of the key metrics that may guide the approach to adding resources from this supply category across the long-term planning horizon.

With this in mind, our strategy is simple: to continue driving the implementation of battery storage on the system in the right locations and through a mix of customer and third-party-owned resources, as well as direct GMP-deployed systems. When it comes to battery solutions, in the next planning period, we believe the strategy truly should be "all of the above" as we work to respond to the cost pressures, reduce carbon further, and deploy the most flexible resources possible. We look at energy storage as the new version of poles and wires and other traditional utility assets when it comes to managing the distribution system. This procurement will take many forms such as RFPs, the Bring Your Own Device program with a fixed offer pricing, and through other solicitations that stimulate the market.

Fossil-Fueled Generation

The oil- and gas-fired generators that we own or purchase from under long-term contracts provide only small amounts of energy—in recent years, less than one percent of our energy supply. Fossil-fueled energy can enter our energy mix indirectly, however, through the portions of energy that are purchased from the ISO-New England spot market, PPAs that are not associated with specific generating units, or the sale of RECs we control. These portions of our energy supply are generally assigned attributes from the New England "system residual mix", meaning the mix of generation attributes that is not retired by market participants to meet Renewable Portfolio Standards or other goals. As discussed throughout, we are intensely focused on lowering the carbon profile of our overall supply so we will continue to explore ways to mitigate any fossil-fuel-generated energy that is in our portfolio.

Natural Gas Generation

According to ISO-New England, natural-gas-fired generators set the energy clearing price in New England during most hours of the year, meaning that natural gas is typically the marginal fuel resource in New England. The price of natural gas-fired generation has moderated in recent years, with the exception of cold winter periods when pipeline capacity in New England is constrained. This has benefited our customers by putting significant downward pressure on energy spot market prices and expectations for prices in future years, putting downward pressure on the market price for forward energy purchases as well as the price at which existing generating plants may be available for sale. The substantial supply of efficient natural gas-fired generation also limits price volatility in the energy market during many hours of the year; this tends to be helpful to us because it limits the risk associated with reliance on intermittent renewable resources.

The fixed costs to construct, own and operate natural gas-fired generation also affect the FCM, since the estimated net cost of new entry (Net CONE) for new natural gas-fired capacity is used as a reference point to establish the FCM's administrative demand curve. The profitability of existing natural gas-fired plants can also affect the supply of capacity in the FCM (through delisting decisions), and therefore FCM clearing prices.

Existing natural gas-fired capacity (through PPAs or purchases of ownership) could in theory be a viable source of stable-priced capacity and peaking energy for us. Because we already own a significant amount of existing peaking capacity, and there is a relatively ample supply of gas-fired energy in New England, we are not presently pursuing acquisition of any existing gas-fired capacity and we have not modeled it as an option to explore.

Peaking Resources

Conventional fossil-fuel-fired peaking facilities will continue to play a significant role in the region's electricity market, providing both capacity and peaking energy for the foreseeable future. Because these resources tend to be fast starting and flexible, they can also provide operating reserves to the ISO markets, and can be supportive of greater levels of intermittent generation in the region. In the context of the recent changes in the Forward Capacity Market (FCM) and the Pay-for-Performance program (PFP), existing peaking resources (like our oil-fired combustion turbine and diesel units) can also be a cost-competitive hedge against both capacity and energy prices. As a result, the Resource Plan considers the role of conventional peaking resources continuing in our future portfolio.

Oil and Coal Generation

Oil- and coal-fired generation has been declining in New England for years, displaced largely by a combination of natural gas-fired generation and renewables. Coal-fired generation is not considered as a potential resource. New oil-fired generation is only considered as a potential local peaking resource, which would likely generate only occasionally and would not provide a meaningful portion of our energy supply.

Nuclear Generation

Our ownership share in Millstone Unit 3, along with our long-term PPA from NextEra Seabrook, provide roughly 14% of our annual energy requirements from nuclear power. These sources feature relatively stable costs, and they help keep our emissions profile well below the New England average. This fraction of nuclear energy is far below our historical level of nuclear reliance, which exceeded 40% during the past decade, when we relied on the Vermont Yankee plant for a third or more of our energy.

To our knowledge, no new nuclear development is taking place in New England, and in fact a number of nuclear resources in New England and the rest of the Northeast are expected to retire in the next several years (for example, Pilgrim in Massachusetts and Indian Point 2 & 3 in New York). Under the RES framework, it is expected that most new long-term sources entering our portfolio will be renewables, and our portfolio already features a substantial degree of long-term price stability. As a result, we are not presently seeking to add more long-term nuclear power purchases to the portfolio (and such purchases are not evaluated as potential resources in Chapter 8: Portfolio Evaluation). We have purchased nuclear attributes on a short-term basis in combination with forward energy market purchases, to stabilize near-term energy costs without absorbing the relatively high emission profile of the New England system residual energy mix.

SHORT-TERM CONTRACTING STRATEGY

Many elements that make up the total cost of power are subject to changes in market prices that can result in significant cost variability over annual, monthly, or even hourly durations. Since our long-term supplies typically feature operating profiles that are not intended to perfectly match short-term energy requirements, there are often periods where we (for some fraction of our power needs) are exposed to short-term market or spot market outcomes. To address the cost uncertainty presented by these exposures, we use fixed price short-term transactions (that is, "forward" sales or purchases) in the wholesale energy, capacity and renewable markets to achieve more stable outcomes for the near-term cost of purchased power. This stability derives from locking in fixed pricing for specified volumes in advance of delivery, as well as from matching the size of the transactions reasonably closely to our forecasted needs. Short-term forward transactions therefore protect us and our customers from having to buy or sell large volumes at volatile spot market prices, while limiting the terms of these transactions (and regularly replacing them over time at then-current market prices) allows this component of our portfolio to follow long-term market trends and will continue to be an important strategy in our power supply hedging portfolio.

Open Positions Managed with Short-Term Transactions

Open positions are volumes within the major supply categories (energy, capacity, RECs) that are associated with an exposure to variable pricing outcomes, because our committed supply and requirements are not matched for a period of time. Broadly, these three products make up a great deal of the costs that any load serving entity incurs to serve customers. In each of these three product categories where we have open positions, there are different actions and time frames over which their potential variability in cost or revenue is managed.

For energy, by design, our committed long-term resources several years prior to delivery are typically significantly less than customer requirements on an annual basis, with the intent to fill the open positions through short-term purchases in advance of delivery. We strive not to fill all of our forecasted needs with long-term commitments (that is, we choose to leave a sustained open position, to be filled closer to delivery) for a few reasons:

- Limit the extent to which our power costs may become disconnected in the long term from those of utilities in neighboring states that generally buy a greater portion of their needs in the short-term markets;

- Leave flexibility to procure new longer-term supply sources (particularly ones that support other strategic goals such as RES compliance) that may not be specifically anticipated today; and
- Limit the extent to which the portfolio could become substantially imbalanced in the event that retail load requirements decline relative to current projections.

We approach the capacity component of the portfolio in the same way, with the goal of meeting most (but not all) of our forecasted needs through stable-priced long-term sources. In the next several years, we therefore have a forecasted open (short) capacity position (typically 200 to 300 MW) that is available to be purchased through short-term bilateral purchases or through monthly FCM transactions. Although the Vermont RES does not apply directly to capacity, we are looking at the opportunities to procure more capacity from local, distributed resources such as energy storage or even third-party aggregators that provide this as a service, much as we would approach Tier II under the RES. When coupled with the benefits of adding storage in certain locations, this could be a powerful tool. We expect to carve out some fixed portion of our open capacity position and utilize it as an in-state resource procurement mechanism to further this possibility.

We receive (through long-term PPA sources and owned sources) a substantial inventory of RECs that are eligible for Class 1 RPS compliance in neighboring states. Unless Class 1 REC prices fall to unusually low levels (see Chapter 8: Portfolio Evaluation for further discussion), it will likely be cost-effective to continue sell those RECs (and use the revenues to reduce our net power costs and electric rates). In our experience, there are few buyers in New England who are interested in purchasing Class 1 RECs for terms longer than 4 years, largely because the ultimate buyers for RPS compliance in neighboring states have only limited long-term retail load commitments from retail customers. The vast majority of our Class 1 REC holdings have not been sold on a long-term basis, and are therefore available to be sold through shorter-term forward sale transactions.

Design of the Short-Term Trading Program

Short-term transactions to address market exposures from the open positions are made with the fundamental goal of limiting our customers' exposure to short-term market energy prices (or spot market prices) providing greater stability in near term power supply costs and retail rates. Other goals include:

- Low net cost for customers. We presently seek to do this by typically using low-cost transaction types for each product—this tends to mean transactions that are actively traded in the market (not requiring a substantial illiquidity premium); transactions for which natural hedgers (for example, power plant owners selling energy and capacity, competitive retail suppliers buying RECs) may logically match our needs; and transactions that do not require the counterparty to provide optionality or insurance features that would require a significant price premium (above reasonable current expectations for spot market outcomes).

- For large open positions, avoid purchasing and selling all of the open position at one time, based on a single set of market conditions. We typically accomplish this by buying and selling our forecasted open position through several transactions over time. It may also be possible to accomplish the same effect through bilateral transactions that lock in prices at multiple pricing dates.

By combining these goals, we maintain a program for each product category to best address the unique characteristics and limitations in each product category and market. The key elements in these programs revolve around tracking the available hedging tools and market conditions surrounding each product, and then establishing the appropriate transaction timing, duration, and frequency to achieve the best outcomes for customers (that is, limiting price uncertainty at lowest practical cost).

Products for Short-Term Hedging

In the short-term hedging program, our primary focus is addressing market exposures using physical supplies that settle within the established markets. The products that make up this program center on energy, capacity and renewable attributes because they represent our largest short-term uncertainty and because theses marketplaces tend to be the most mature and feature meaningful numbers of participants (for example, they allow for more competitive and transparent outcomes).

Energy

We will discuss energy first because it typically represents the single largest cost exposure for any load serving entity in the region. If we do not purchase our open energy position in advance, those volumes will ultimately be purchased in the spot market (DA and RT energy markets) on an hourly basis. Our current strategy focuses primarily on purchasing (or less often, selling) fixed blocks of energy at fixed prices; this is a prime example of a low-cost product. In the energy short-term program, we generally purchase firm energy[52] (not unit contingent) from creditworthy sellers, and settle them at the ISO-New England internal hub to maximize liquidity and attract the widest seller interest. Unless the contracts also include emissions attributes associated with particular generation sources,

[52] GMP would also consider plant-contingent purchases, depending on factors including the transaction size, source unit(s), and pricing.

they are considered for purposes of describing the fuel mix and air emission profile of our power supply to carry an emissions profile of the "system residual" mix.

In planning short-term transaction volumes, we focus first on achieving balance between energy needs and supply for each year as a whole; we also use specific transaction volumes to balance forecasted supply and requirements on a monthly basis. To determine the profile of the energy to purchase (for example, annual or monthly on-peak or off-peak blocks, or all-hours baseload) and the duration of these purchases, we monitor and update projections of future energy requirements for periods ranging from one month to five years in advance of a delivery period. We also check for any recent or expected changes in our committed supply sources (for example, expirations of existing resources, additions of new supply sources, or pace of growth in net metering volumes).

The resulting pattern of committed energy supply sources and forecasted demand removes the vast majority of our potential exposure to sustained market price changes. This forward purchasing approach yields a large degree of short-term stability in our net energy costs, but it does not fix them entirely. Variations in electricity demand and generation (particularly intermittent renewable sources) over shorter time frames from an hour to a month sometimes present significant short-term cost variations for the power portfolio. These short-term fluctuations tend to substantially offset each other over time, however, and it is generally not practical to eliminate them without using more costly products that would increase our expected power costs.

Capacity

Fixed-volume forward purchases of capacity share the low-cost characteristics for energy, and are our primary short-term hedging tool for stabilizing the cost of capacity. Such transactions typically take the form of an exchange of capacity from a specific generating unit, a transfer of a portion of our capacity obligation quantity to the seller, or a self-supply transaction to meet a specified volume of our capacity needs. Capacity is settled on a zonal basis in the FCM, with our load being located in either the Rest of Pool or Northern New England Zone. Because ISO-New England reviews the definition of capacity zones from auction to auction, the appropriate zone(s) upon which to base short-term capacity purchases can change over time.

RECs

State-administered RPS compliance markets are the overwhelming source of demand for Class 1 RECs. The primary transaction structure in this market is fixed volume, fixed price blocks for calendar year vintages (the period of obligation for most state RPS programs), with quarterly delivery of RECs through the NEPOOL GIS.

Aside from the direct, physical supply hedges, there are also indirect or financial hedging products that reside outside of the ISO-New England market or the NEPOOL GIS (renewable attribute exchange). Often this type of financial hedging involves an exchange of financial value instead of the actual physical delivery of a product[53] and can require special, derivative accounting treatment. In this financial hedging category there are also products available that resemble insurance policies, where in exchange for a premium payment a specific exposure to some element of supplier risk can be limited.

Transaction Timing and Durations

Within the hedging program our general goal is to lock in fixed prices for short-term transactions over several years in advance of delivery. The general goal is to diversify the timing of these purchases (so as not to "put all of our eggs in one basket" by purchasing an entire open position at one time, under one set of market conditions). As a result, we make energy and capacity purchases regularly on a layered basis with terms up to five years ahead of the delivery period; we use a similar approach for REC sales. The timing of transactions for different products tends to vary somewhat based on structural differences in the markets for those products.

For REC sales, the regional Class 1 RPS market is not as large or as liquid as the energy market; in our experience, typical transaction sizes range from a few thousand MWh up to 50,000 MWh. Our REC inventory for a given vintage year has been at least 600,000 MWh in recent years, so it is not practical to sell this inventory all at once. Further, if we attempted to aggressively sell a large fraction of inventory over a short period (for example, a month or two), we believe that we would put meaningful downward pressure on the regional market price. We therefore seek to implement forward REC sales regularly over approximately a four-year period. Buyer interest in REC purchases for three or more years in advance tends to be modest, so the timing of forward sales sometimes depends on market availability. Short-term variations in the production of our sources (mostly wind, solar, and hydroelectric) causes some variation in the supply of RECs that we have to sell for any given vintage year; these variances are typically managed in the final few quarters of each vintage year.

53 For example, in a capacity contract for differences the buyer and seller might exchange no capacity, each settling their positions in the annual FCA. The seller would pay the buyer to the extent that the FCA clearing price turned out higher than a negotiated notional price for capacity; the buyer would pay the seller to the extent the FCA clearing price turned out lower.

For capacity, the FCM does not have a typical "spot market" (as the energy market does) where prices are variable up to the time of delivery. Instead, the final pricing event that we seek to hedge against is the annual capacity auction (conducted in winter), which largely determines the price of capacity to load three years into the future. Since that period we are hedging against is already three years into the future we tend to transact less frequently for any individual capacity year. In our experience capacity sellers are most interested in trading during the few months leading up to the next annual auction, so we tend to solicit forward capacity proposals in the November to December time frame.

We start with a benchmark expectation of implementing forward purchases and sales over a roughly even pace over several years; the particulars of transaction timing very by product, along with the magnitude of our expected open position.[54] Notably, we consider accelerating the pace of transactions for each product during times when available prices are perceived to be relatively attractive, with the goal of reducing the expected cost of energy and capacity (and maximizing the expected revenue from REC sales) to benefit our customers. Conversely, we may slow our transaction pace if we perceive available market prices as less favorable,[55] or if conditions within our resource portfolio have become more uncertain.

To support the choice of transaction durations and pace for short-term transactions, we regularly collect and review market price indications (for example, broker indications for standardized energy forward contracts, and for REC pricing). We also review information (for example, trade press, consultant reports and forecasts obtained via subscription, interviews of consultant experts) that address in detail regional supply, demand, and other factors that affect price formation. We use these sources to form our view of the relative attractiveness of current markets, and how forward market pricing may move over time.

[54] For example, if our forecasted short energy position for a given month is small relative to our load requirements and relative to liquid transaction sizes in the regional market, it makes sense for us to purchase the entire (small) need in a single transaction. Spreading out the purchase over many (very) small transactions would incur additional administrative costs, and likely a higher price because of an "odd lot" or illiquidity premium.

[55] For example, in 2016, we accelerated its forward REC sales for the 2018 and 2019 vintages, when prevailing forward prices were $30 per MWh or more, and our market intelligence indicated the potential for an emerging regional surplus and potentially substantial price declines. Since forward REC prices have fallen substantially during 2018, we have slowed its pace of forward REC sales for the next few years.

Available Short-Term Procurement Methods

One of the most significant considerations influencing our choice of a procurement method in any particular hedging activity is ensuring a competitive and low-cost result (or greatest value result in the case of sales). There are four primary methods for procuring short-term hedges.

Broker Services. In both the energy and renewable attribute markets there are firms that specialize in matching buyers and sellers for commissions. Some brokers publish regular trading quotes to help inform clients of market conditions. Brokers charge a small fee for this service; advantages of brokered transactions include regular market monitoring on our behalf, access to multiple potential buyers, and anonymity for us (until the buyer and seller are matched for a transaction).

GMP-Initiated Request for Proposals (RFP). Typically a targeted request from GMP directly to active participants in the market. In this low-cost method, we typically provide a product term sheet specifying criteria for offers and a date for offers and awards.

Auction Events. Firms offer fee-based online platforms where a live event can be scheduled to allow potential suppliers an opportunity to compete with some visibility on resulting awards and prices at the conclusion of the event.

Counterparty-Initiated Request for Proposals. From time to time a supplier or purchaser (most often of RECs) will include us on their direct request for offers and provide specific criterial for their needs and a schedule for participation and award.

Within these formats, there is no single preferred method, and the detail and formality of each method used can vary considerably depending on the nature and significance of the transaction. Requests with shorter, more standardized terms will tend to have less administrative burden and resolve quickly (for example, within hours) whereas longer-term and larger procurements can potentially resolve over weeks from the date of the solicitation, to allow time for thorough evaluations.

Proposal Evaluation and Selection

In deciding outcomes of a solicitation to implement an element of the short-term portfolio hedging programs, we seek to ensure that a selection of an offered product meets the standards and goals established for each solicitation. The evaluation steps can vary considerably depending upon the type of solicitation and the overall significance of the procurement.

In the broadest terms this variability in evaluation and selection tends to fall along a continuum where the shortest-duration, lowest-impact transactions are assessed rapidly using a limited set of benchmarks (market quotations) to longer-duration, more economically significant proposals that may be evaluated against a number of screening criteria and involve the use of outside consultants with uniquely specialized knowledge of the product.

Aside from evaluation factors that test competitiveness and the lowest cost (or highest value) features of a new short-term proposal, we also take into consideration certain risk factors to reduce the likelihood of negative outcomes during the delivery period of the hedge. The most common example of this is the application of creditworthiness requirements and volume concentration limits.

Ultimately in each solicitation awards are made to the extent that offers achieve the goals of the solicitation and the leading suppliers meet our contracting requirements.

6.Transmission and Distribution

As energy delivery becomes more distributed and more renewable, our transmission, subtransmission, and distribution grid network, which supports and enables that transformation, becomes more important and more complex to operate. Combined with enhanced cyber security requirements, this transformation exerts pressure on the performance of our network grid. Keeping up means we must make critical grid investments, not only to ensure the bulk system is safe and reliable for basic energy delivery to customers, but also to reliably orchestrate delivery of energy from literally thousands of ever-growing distributed sources around the clock.

TRANSMISSION AND DISTRIBUTION SYSTEM OVERVIEW

Green Mountain Power is a vertically integrated electric distribution utility. We own and manage, for our customers' benefit, both generating assets and the subtransmission and distribution network that delivers power to our customers. We are the state's largest electric utility, serving over 265,000 customers in 202 towns in Vermont.

We currently own over 60 power generation facilities in Vermont and more than 22,000 miles of transmission and distribution lines. In 2017, our transmission and distribution system delivered over 4,633,475 MWh of electricity; the peak load on the system was approximately 700 MW.

The backbone of our delivery system is 1,005 miles of subtransmission lines. The predominant voltages for the subtransmission system are 34.5 kV, 46 kV, and 69 kV. The interface between the subtransmission system and the distribution system is comprised of 185 distribution substations. These substations supply approximately 300 circuits and 15,454 miles of distribution lines. Our predominant distribution voltage is

12.47 kV. We also have a limited amount of distribution at voltages of 2.4 kV, 4.16 kV, 8.3 kV, and 34.5 kV.

Vermont Electric Power Company's (VELCO's) 115-kV transmission system primarily supplies our subtransmission system. The VELCO system, in turn, interconnects to the bulk transmission systems administered by ISO-New England, New York ISO, and Hydro-Québec at voltages of 115 kV, 230 kV, and 345 kV. Our system also interconnects with National Grid in several locations at subtransmission voltages.

TRANSMISSION AND DISTRIBUTION PLANNING

We are evolving our traditional transmission and distribution planning principles. Instead of limiting our thinking to traditional infrastructure that continues our reliance on century-old infrastructure models, we now consider how to use emerging technologies to better provide reliable service at a lower cost.

This means that we now consider whether storage, distributed resources, or a combination of both can replace what would otherwise be a traditional infrastructure upgrade, saving customers money, increasing reliability and resiliency, and making our energy delivery system more customer-based. While we no longer expect projects to be driven by load growth like years past, we are seeing a distribution system being used more than ever as the level of distributed generation grows significantly.

This is part of our larger strategy to leverage storage, distributed generation, and non-transmission alternatives for grid planning and to harness multiple benefit streams for customers, including reduced power and transmission expenses, reduced transmission and distribution projects, reduced power supply risk, and enhanced resiliency. At the same time, we are upgrading and modernizing the existing T&D system to ensure we continue to deliver on our commitment to cost-effective, reliable, safe, and efficient service for our customers.

We have a greater depth of data and information related to the operation of our distribution system than we did a decade ago, thanks to the AMI system that has been in service as well as the thousands of integrated points on the system that communicate back to GMP via our SCADA system or other means. This data is analyzed in a way that provides us with a better picture of each circuit, such as how it contributes to the overall peak, how it contributes to the local peak, its level of distributed generation and the classes of customers on the circuit, to name a few.

T&D Capital Investment Goals

To support the reliability and transformation of our grid, we plan and implement our capital investments in generation facilities and related T&D systems for one purpose only—to meet our customers' needs through the delivery of energy and energy services. To meet these needs, ongoing capital investment is required to repair and maintain our existing generation assets to produce as much low-cost, low-carbon electricity as possible, while meeting the important environmental and regulatory obligations associated with the operation of these facilities.

Capital is also required to maintain, and where necessary upgrade, our transmission and distribution infrastructure to ensure the safe and reliable delivery of power to each customer. As the grid becomes more decentralized and more complex, maintaining the resiliency needed to withstand the effects of climate change becomes more challenging.

Meeting our customers' needs also requires an investment in the technology and tools that are essential to the quick and efficient management of outages when they occur, while also protecting grid operations from cyber events and other threats of operational disruption. It also requires us to identify and pursue, with our customers' assistance, innovative investments that accelerate the transition to a home-, business-, and community-based energy delivery system that our customers tell us they want.

Infrastructure Investment Objectives

The main objectives of capital investments are to assure that our T&D system can deliver power to our customers safely, efficiently, reliably, and cost-effectively. We undertake T&D projects based on several categories of improvement criteria.

Safety. Projects to replace obsolete or deteriorated plant that may not comply with current standards and codes, that may have reduced functionality or will improve safe access for our field crews.

Service Reliability. Projects that increase reliability by reducing the number of outages, the duration of outages, or the number of customers affected by outages. An example of this type is relocating a distribution line out of the woods to the roadside making storm damage less likely and access safer and quicker.

Efficiency. Projects for the cost-effective reduction of system losses. These projects include capacitor placements, line reconductoring, load balancing, circuit reconfiguration, and voltage conversions.

Capacity Requirements. Projects to upgrade facilities to address thermal, voltage, or stability constraints. These projects can be the result of load growth or the need for backup capability (improved reliability) for another substation or feeder.

Customer Requested. Projects requested by a customer, such as line extensions or line relocations. These customer requests include distributed generation projects that require capital upgrades of T&D infrastructure to enable the customer to interconnect with no adverse impacts.

Regulatory and Tariff Requirements. Projects required to achieve regulatory compliance or to meet a contractual or tariff obligation. These projects can be the result of a stipulation with the DPS, the Agency of Natural Resources, or the Agency of Transportation (for state and municipal road jobs), or be required by our joint-use and third-party attachment agreements.

The Transmission and Distribution Capital Plan

Many teams within the company participated in developing the T&D Capital Plan through a comprehensive planning and budgeting process. We identify possible projects by reviewing the multi-year capital priorities, seeking input from internal and external stakeholders and using the aforementioned criteria. From this list, we select a subset of potential projects that we determine to be the most important. We then gather information and develop an initial scope that describes the purpose of each project and its design requirements. From this initial scope, we develop a preliminary budget estimate for each project; the Engineering, Operations, and Operation Technology teams review the projects to identify those with the highest priority.

Priority is based on a variety of factors: safety considerations, input from field personnel, specific operational needs, T&D efficiency and reliability analysis, customer requests, cost-to-benefit ratios, capacity constraints, regulatory and tariff obligations, and resource availability and timing issues. From this analysis, we establish a list of preliminary projects for that year's T&D capital budget. Our Capital Management team examines this list to determine the final T&D capital budget for the year.

Subtransmission and Distribution Criteria

Subtransmission

Our standard subtransmission voltages are 34.5 kV, 46 kV and 69 kV. We transmit power through our subtransmission system from VELCO and National Grid to our distribution substations as well as to our wholesale and large industrial customers.

We plan the subtransmission system according to an Equal Slope Criteria. The Equal Slope Criteria is a modified N-1 criterion in which a reasonable balance is sought between the total costs of a given solution and the total benefits achieved. The goal is to achieve most of the benefit of adhering to a strict N-1 criterion but at substantially less cost.

Our operating criteria require system voltages to be between 95% and 105% of nominal on the subtransmission system during all-lines-in operation and between 90% and 110% of nominal following a first contingency. Each element in the power delivery system has a thermal design load limit reflecting the load at which an element begins to overheat and fail. We apply a 100% maximum load limit on all elements during normal operation. For specific cases for limited periods of time during first contingency operation, we allow overloading, but only with the understanding that operators will take quick action to remedy the overload by any means necessary, including the use of load shedding.

Distribution

Our standard distribution system voltage is 12.47 kV/7.2 kV grounded wye.[56] We also employ a limited amount of 34.5 kV/19.9 kV distribution system facilities. Because of operating challenges with 34.5-kV equipment, we only expand this voltage to areas where 34.5-kV distribution has already been established.

We are steadily converting the remaining of 2.4-kV, 4.16-kV, and 8.3-kV distribution voltages to the standard 12.47 kV to improve voltage performance, reduce losses, and permit feeder backup between substations. The voltage delivered to customers adheres to the standards prescribed by the American National Standards Institute (ANSI) Standard C84.1.

Subtransmission and Distribution System Monitoring

We assess a number of data sources to effectively monitor the subtransmission and distribution system. We use this information to make decisions regarding a number of areas, including transferring load between circuits, removing substation banks for maintenance, correcting out-of-standard voltages, interconnection of distributed generation, and addressing load growth in potentially constrained areas. This information can dictate which areas need studying, and which areas where non-transmission alternatives can be effective in deferring capital upgrades.

56 A wye is a three phase, four-wire electrical configuration where each of the individual phases is connected to a common point, the “center” of the Y. This common point normally is connected to an electrical ground.

The monitoring information includes:

- Observations by line workers and substation technicians.
- The VELCO Long-Range Transmission Plan. Updated every three years, this plan identifies portions of our subtransmission system that could violate subtransmission planning criteria considering forecasted load growth over the next 20 years.
- Line and equipment loading obtained from our supervisory control and data acquisition (SCADA) database. This database contains real power, reactive power, the status of capacitor banks, and phase unbalance data for the majority of our subtransmission lines as well as a number of our distribution feeders. SCADA data is essential in calibrating transmission and subtransmission load flow models that are used in planning studies.
- Substation and circuit MV90 data, which includes real and reactive load and voltage data for substations and individual circuits. Selected substations have per-phase metering to further enhance the understanding of critical circuit loading.
- Additional monitoring equipment, including thermal demand ammeters and revenue meters, for those distribution feeders that are not monitored by SCADA or MV90.
- Customer interval load data, which is available from most of our customers. Through AMI, we accumulate interval load data from all customers. Customer interval load data can be combined with load data from other sources to help determine spatial loading of a circuit at a given point in time.
- New relays, such as the Schweitzer SEL-351, which collects and stores data including per-phase current, voltage, real power, reactive power, and neutral currents. These relays have been installed at a number of substations and their data can be retrieved as needed.
- Load loggers, which are portable devices that attach to an individual phase wire and record current flow in one-, five-, or fifteen-minute intervals. These devices are useful for analyzing phase balancing and determining spatial load distribution across a given circuit.
- Tong tests, which are instantaneous readings taken with a recording ammeter. Tong testing is useful for balancing loads and verifying load estimates, and is often used to analyze planned outages.
- Ability-to-Serve requests from developers who are planning new load additions greater than 100 kW (as per Act 250). These requests are reviewed to ensure that the T&D system can accommodate the proposed new load. All requests are stored in a database; a review of these proposed load additions and their respective analyses can provide an indication of system adequacy and the potential for future constraints.

- Outage history and outage analyses, including identifying distribution feeders with the poorest reliability performance to determine system problems. Customer complaints (such as those involving reliability concerns, low voltage, and voltage flicker) also help identify system weaknesses.
- Our geographic information system, which is used to locate aging infrastructure and equipment that may need replacing.
- AMI data. For details, see "AMI Data" on page 7-6-52.

The Transmission and Distribution Planning Process

We plan our T&D system to ensure safe and reliable power delivery while achieving a reasonable balance between costs and benefits. There are three main steps in the overall planning process:

Orientation. Identify a system problem or potential problem; gather information; coordinate with likely stakeholders; identify a study scope and timeline.

Study Development and Analysis. Identify the necessary methods, tools and data requirements to solve the problem; analyze load-flow simulation to better understand system deficiencies; study and devise alternative solutions using the load-flow analysis, engineering calculations, and economic analysis as appropriate.

Decision-Making and Action. Review results; draw conclusions; make and support recommendations (typically a project proposal). Secure regulatory approval if necessary; implement the project. Note that in this phase, unlike the past, we are now able to explore the implementation of distributed energy resources such as energy storage as a solution.

Efficiency, reliability and growth (both traditional growth as well as DER growth) are the three main factors that drive transmission and distribution planning although over the last number of years, growth has not been a factor driving the system needs. Many planning exercises encompass all three. Our planning also considers non-transmission alternatives (NTAs), which we discuss through a public process directed by the Vermont System Planning Committee (VSPC). The performance of the transmission, subtransmission, and distribution systems are highly interdependent and cannot be viewed in isolation. Thus, we coordinate our planning with other T&D entities and utilities to develop effective, least-cost plans.

Performing an integrated and comprehensive study on each of our 185 distribution substations and 299 distribution circuits would not be cost effective. Instead, we use available system data and screening methodologies to identify those areas that would most benefit from an in-depth examination of adequacy and efficiency improvements. These screenings identify circuits that have potential thermal or voltage constraints, inadequate power factors, phase imbalances, relay pickup overloads, or do not meet our planning criteria. Much of this analysis requires that we manually review the system data and create numerous reports. Because of this, we measure our planning for maximum benefit: we annually review peak load for all substations and circuits; and review individual circuits that experience a significant change (such as additional load, substantial distributed generation, reconfiguration, power performance issues, or phase imbalance) as necessary. Through the use of data, and a bulk data analysis tool such as Tableau, we are able to more quickly analyze the characteristics of circuits and rank them based on factors that we are concerned with.

This process enables us to find those areas that would most benefit from efficiency improvements. All subsequent analysis to address capacity, reliability, and asset management inadequacies also incorporates a review of loss-avoidance opportunities (including capacitor placement, reconductoring, voltage conversion, feeder balancing, and circuit reconfiguration). This strategy helps us direct our limited resources toward those circuits most in need and most likely to provide cost-effective opportunities for efficiency upgrades.

VELCO and the Vermont System Planning Committee

Together with VELCO and other Vermont distribution utilities, we plan the Vermont transmission system. In 2005, the Vermont legislature amended the laws governing electric utility transmission planning.[57] The "least-cost transmission planning" statute requires that every three years VELCO, in coordination with Vermont's distribution utilities, develop their Vermont Long-Range Transmission Plan that:

- Identifies existing and potential transmission system reliability deficiencies by location within Vermont.
- Estimates the date, and identifies the local or regional load levels and other system conditions where these reliability deficiencies would likely occur without intervening action.
- Describes the manner of resolving the identified deficiencies through transmission system improvements.
- Estimates the cost of these improvements.
- Identifies potential obstacles to realizing these improvements.

57 30 V.S.A. § 218c(d).

- Identifies the demand or supply parameters that generation, demand response, energy efficiency, or other non-transmission strategies would need to resolve the identified reliability deficiencies.

This statute also (1) establishes requirements for notice and public input regarding the development of the Long-Range Transmission Plan, (2) requires that distribution utilities incorporate the most recently filed transmission plan in their individual least-cost integrated planning processes, and (3) mandates that VELCO and the distribution utilities cooperate as necessary to develop and implement joint least-cost solutions to reliability deficiencies identified in the Long-Range Transmission Plan.

In 2007, the PSB developed a process for satisfying these planning requirements and established the Vermont System Planning Committee (VSPC).[58] VSPC, responsible for implementing the planning process, comprises VELCO, Vermont's electric distribution utilities, public members, and members representing supply and demand resources. The goal of the planning process is to ensure the full, fair, and timely consideration of all options to solve grid reliability in a way that is transparent and public. Ultimately, VSPC allows Vermont's electric utilities to fulfill the public policy goal behind the "least-cost transmission planning" statute, namely that the most cost-effective solution is chosen, whether a traditional transmission upgrade, energy efficiency, demand response, generation, or a hybrid solution. As part of this process, VSPC coordinates with stakeholders at the local, state, and regional levels. These stakeholders include ISO-New England, which has the primary responsibility for transmission planning in the region; regional planning commissions; local energy committees; Vermont's energy efficiency utility (EEU); and Vermont's Sustainably Priced Energy Development (SPEED) facilitator.

[58] Docket No. 7081.

The PSB approved a transmission planning process; VSPC implements it. The process comprises the following steps:

Step 1. VELCO coordinates with ISO-New England to analyze the transmission system, consider a twenty-year horizon, and identify reliability deficiencies with subtransmission systems owned and operated by the distribution utilities; then create a draft plan.

Step 2A. VSPC reviews the draft plan and makes a preliminary determination of the utilities impacted by the identified reliability deficiencies.

Step 2B. Distribution utilities and VELCO determine the applicable reliability criteria for each reliability deficiency, identify transmission solutions, and determine equivalent non-transmission alternatives (NTAs).

Step 3A. VELCO conducts a preliminary NTA analysis for bulk transmission system reliability deficiencies where appropriate.

Step 3B. Distribution utilities together with VELCO conduct preliminary NTA analyses for subtransmission system deficiencies where appropriate.

Step 4. VELCO releases a draft Long-Range Transmission Plan.

Step 5. The draft Long-Range Transmission Plan is subject to a statewide public involvement process, where comments are solicited.

Step 6. VELCO and VSPC incorporate relevant comments, and publish the revised Long-Range Transmission Plan.

Step 7. VSPC reviews each reliability deficiency or group of deficiencies, and refines the impacted utilities determinations.

Step 8. For each reliability deficiency or group of deficiencies, the affected utilities, VELCO, and VSPC engage in a public involvement process and perform the required detailed NTA analysis.

Step 9. For each reliability deficiency or deficiencies, the affected utilities, VELCO, and VSPC select a solution and determine cost allocation among the parties based on the results of the public involvement process.

Step 10. VELCO updates and finalizes the Long-Range Transmission Plan.

Figure 6-1 summarizes this ten-step process. Depending on relevancy, VELCO and VSPC can choose to follow the 2A-3A path, or the 2B-3B path.

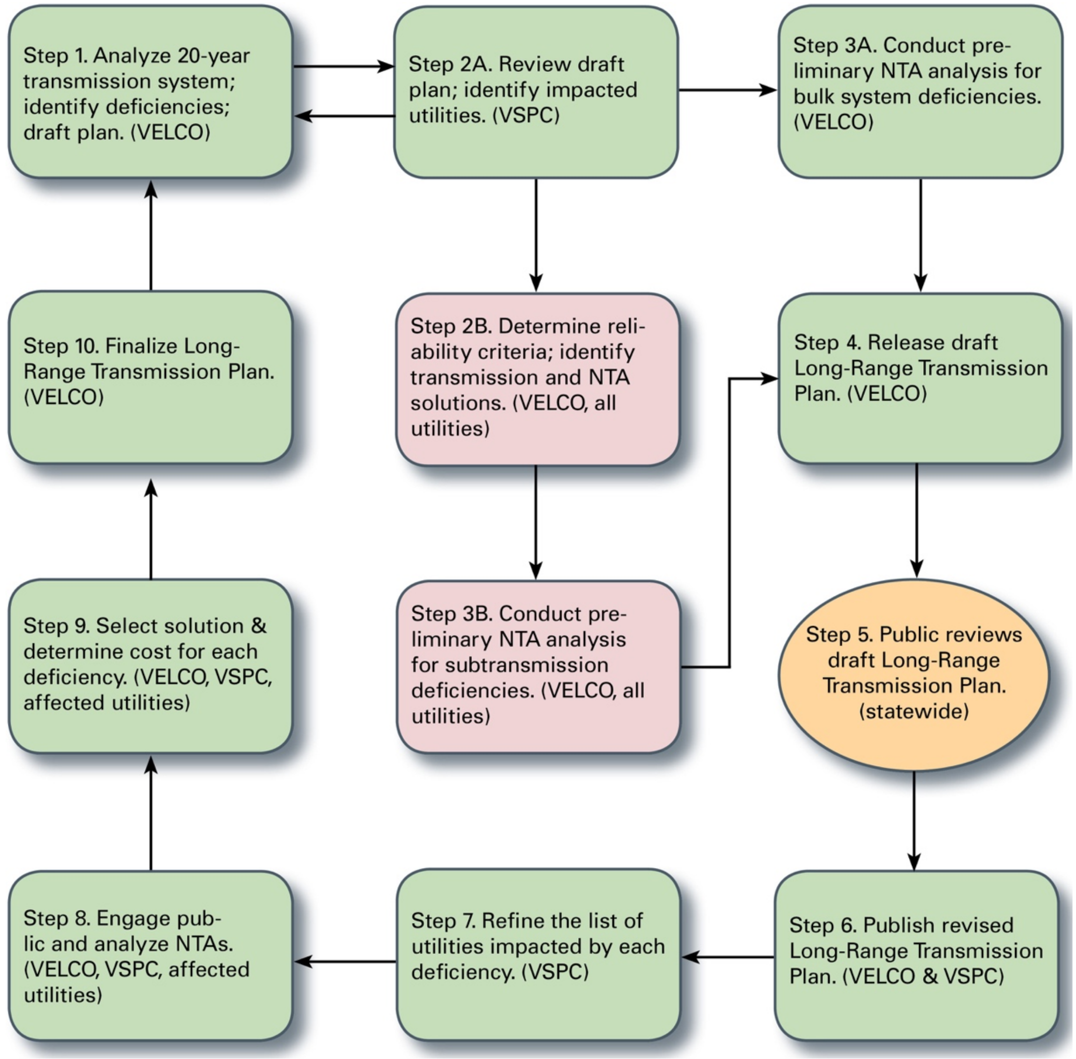

Figure 6-1. VELCO and VSPC Planning Coordination Flowchart (8.0)

Standard Offer Projects to Address Reliability Constraints

In 2012, the Vermont General Assembly passed Act 170, mandating certain changes to the Sustainably Priced Energy Enterprise Development (SPEED) standard offer program. One of these changes is to exclude new standard offer plants that provide sufficient benefits to the operation and management of the electric grid from cumulative plant capacity.

The PSB adopted a screening framework and guidelines that provide potential standard offer project developers with information on transmission and distribution constrained areas where renewable generation might resolve the constraints. This framework and guidelines use VSPC processes, reporting mechanisms, and subcommittees to identify and resolve T&D constraints via NTAs, including standard offer projects. These processes analyze the electric grid for reliability gaps, make recommendations to the PSB regarding the potential for NTAs to mitigate those reliability gaps, and provide stakeholders with the opportunity to comment on the VSPC recommendations. The PSB then decides whether or not to issue an RFP for new standard-offer plants.

We actively participate in this VSPC processes as well as in their Geotargeting Subcommittee (GTS). Annually, we share our planned T&D capital projects with the GTS to determine whether any reliability plans may be required. Reliability plans determine the least-cost solution for identified T&D constraints and potential resolution through NTAs. We have presented over 50 transmission and distribution projects to the VSPC and the GTS for consideration and review.

In April 2014, we developed a reliability plan for the St. Albans area, and provided it to the PUC and interested parties. Our analysis showed that the need date, even under a very aggressive growth scenario, was not until 2021. We continue to monitor this area for increases in peak demand and include our new toolset of DERs when reviewing future solutions.

In 2015, we filed the Rutland Area Reliability Plan, which proposed upgrades to improve reliability. These upgrades included eliminating a radial transmission line and recommended NTA options to address area load growth. With these measures, a large transmission build-out would not be needed for 10 to 20 years. We continue to monitor this area.

In 2016, we filed the Hinesburg Area Reliability Plan. This study supported deferring a proposed new Hinesburg substation with a battery energy storage system (BESS) to address load growth when it occurs. The BESS is currently budgeted for 2023.

In 2017 and 2018, GMP and the VSPC have not found any new areas where geographically targeted energy efficiency or DERs would have the potential to cost-effectively avoid or defer a transmission or distribution project. As such, no new reliability plans have been required or are currently under review.

Projects with Other Utilities

The electric grid is interconnected, and so are we with other area electric utilities. We continually interact with these utilities to exchange information and upgrade the grid for our shared benefit, but especially for the benefit of our customers. Our interactions with other utilities have increased since the adoption of Rule 5.500, which governs the interconnection of DERs.

Hinesburg Distribution Feeder. As a short-term solution to relieve potential load constraints in the Hinesburg area, we collaborated with Vermont Electric Cooperative (VEC) to install a new 12.47-kV distribution feeder originating from the VEC Rhode Island Corners substation. We completed this project in 2015. For information on the planned long-term solution, see "Hinesburg Substation Rebuild" on page C-19.

Supply for Sheldon Substation. Early in 2015, VEC temporarily supplied our Sheldon substation from the VEC Sheldon Springs substation to relieve the reliability exposure on our 34.5-kV subtransmission system until we upgraded the supply into this system later that same year.

Subtransmission Line Ownership Transfer. In 2017, we transferred ownership of a recently disconnected subtransmission line to the Burlington Electric Department (BED) to our mutual benefit. As a result, we avoided the expense of retiring and removing the line; BED developed a low-cost express feeder from its Queen City substation into the downtown Burlington area.

Collaboration with Vermont Municipal Electric Companies. We are committed to being an advocate for all electric service customers in Vermont. Toward that end, we provide bulk power, operational services, and engineering services to two of Vermont's municipal electric companies:

- Jacksonville Electric Department, serving 716 residential, commercial, and industrial customers in Jacksonville and Whitingham with about 5,400 MWh of energy per year.
- Northfield Electric Department, serving 1,850 residential, commercial, and industrial customers in Northfield with about 25,500 MWh of energy per year.

For example, we collaborated with Jacksonville to study the feasibility of a proposed installation of 150 kW solar generation. We also collaborated with Northfield Electric regarding solar installations and to address load increases that required upgraded protection settings.

National Grid Collaboration. National Grid provides service to its New York customers adjacent the western portion of our service area, and to its Massachusetts customers adjacent the southern portion of our service area in Vermont. Because of this geographic positioning, National Grid's subtransmission system supplies our lines at several interconnection points. In reciprocity, we annually develop load forecasts and summarize power factor data that helps National Grid meet certain planning and reporting requirements for ISO-New England.

Some recent collaborations included:

- Updating the G33 contract, in relation to the 69-kV line feeding from Putney to Brattleboro in August 2018.

- In August 2018, together we updated the G33 contract, in relation to the 69-kV line feeding from Putney to Brattleboro.
- Discussions regarding the National Grid Vernon (GMP#57) substation and its capacity about serving load for the decommissioning of the Vermont Yankee nuclear power plant.
- Discussions regarding the ownership of the 6,900-volt delta line served from Harriman station in Readsboro, Vermont. The line is old and in bad shape, and only serves our customers.
- Our supplying a small section of single-phase National Grid load from our North Bennington #72 circuit (via single-phase primary metering) at the state line on Route 67A in Shaftsbury, Vermont. As part of the project, National Grid must remove an existing railroad crossing.

Our collaboration with National Grid is ongoing.

Village of Ludlow Electric Primary-Metered Delivery Point. In 2015, after collaboration with the Village of Ludlow Electric Department, we constructed a primary-metered delivery point originating on the Ludlow distribution system to supply an expanding load in our service territory (specifically for a local ski area expansion) through 2020. This short-term project allows three-phase load to be fed to the area, avoids our upgrading several miles of single-phase distribution lines, helps the ski area meet short-term deadlines, and lowers the overall cost to our customers. We plan to feed this load from our Smithville 62G circuit starting in 2020.

In addition, we are working with Ludlow to configure their system to supply their expanding loads, lowering both our services costs and making the best use of existing distribution facilities.

Hinesburg Substation. We are continuing to collaborate with VEC on a jointly-owned 34.5/12.47 kV substation in Hinesburg (as discussed in see "Hinesburg Substation Rebuild" on page C-19). This substation is part of a longer-term solution to relieve potential constraints surrounding load growth, solar penetration, and the proposed BESS performance. We will be reviewing the need for this substation more closely within the next two years and determine how the need could be resolved utilizing DERs and other demand side resources.

Cambridge Substation. We are working with VEC to construct a new, jointly owned 34.5/12.47 kV substation in Cambridge. Together, we designed the concept of us retaining sole ownership of the in and out transmission line breakers. This substation is under construction.

CAPITAL INVESTMENT PLANNING, REVIEW, AND APPROVAL PROCESS

The core purpose of our capital investments is to improve outcomes for customers. Thus, we use a sequenced planning process to identify and screen proposed capital projects to ensure that the ones we pursue are cost-effective and valuable for customers. For a project to be included in our capital plan, its proposed investment must deliver meaningful qualitative or quantitative benefits to our customers. These benefits can manifest themselves in many ways, including: reduced operating costs, improved customer services, improved reliability or safety, or advancing innovation and delivering transformative opportunities. To achieve these outcomes, we employ a four-part process consisting of: (1) long-term strategic alignment; (2) annual capital project planning; (3) annual capital project budget preparation; and (4) capital project tracking and monitoring.

Long Term Strategic Alignment

We plan in three to twenty-year horizons through our IRP, our Long-Range T&D Plan, and our 10-Year Generation Capital Plan. We also work with VELCO and other parties with whom we jointly own various facilities to conduct long-term planning to ensure a group alignment.

As part of our long-term planning, we:

- Maintain and improve our current infrastructure for customers.
- Engage in long-term energy transformation activities that enable a transition from a centralized energy delivery system to a distributed one and allows for the elimination of carbon as much as possible.
- Explore new generation opportunities for customers that will save them money over the long term.

Annual Capital Project Planning

Every year, each team reviews the current needs and opportunities in their respective areas, and refreshes their list of potential projects to include those that can deliver strong operational performance. Each team evaluates the priority and exigency of each one, then develops scope and design considerations for those that make the cut. All budgeting information and documentation is then assessed as part of our capital project budgeting process.

Annual Capital Project Budget Preparation

Our capital management team reviews and assesses project recommendations made by each team. The team then evaluates each project and assigns a ranking—Required, Recommended, or Strategic—to determine if the project will be included in our capital plan. "Required" indicates there is a regulatory, safety, certification, or other element to them that makes their completion urgent, if not mandatory. These projects are deemed the most important. "Recommended" indicates there are operating improvement opportunities that will deliver benefits to customers in the form of lower operating costs or risks, improved service quality, better customer experience, or some other benefit. These projects are deemed to be of lesser importance. "Strategic" indicates the project will advance a capability for us and our customers that improves service delivery but without as much urgency or financial justification as Required or Recommended. The team identifies each project's benefit, including improved safety, improved reliability, regulatory compliance, improved operational efficiency, and improved customer service.

The capital management team reviews and filters each project, and whittles the projects down to a list of capital projects for the year. Our executives and our Board reviews and approves the final list. For the last ten years, the PSD and its independent consultant, either under our prior regulation plan or as part of a traditional rate case, has also reviewed our capital plan and documentation.

Capital Project Tracking and Monitoring

Throughout the rate period, we track and monitor the status of these capital projects. As often as necessary (at least monthly), each team and the capital management team review the status of all their capital projects, and make adjustments as necessary. We do not want customer rates to include costs for capital projects that we are not able to deliver. We replace planned projects that are no longer feasible with other cost-effective, high-value capital projects that are in the interests of customers and have passed mettle when examined by our rigorous selection process.

Capital Project Planning and Documentation Process

As part of our project implementation process, we complete a financial analysis for individual capital projects describing the justification, costs, benefits, and alternatives to each capital project. All projects above $2 million are subject to a full cost-benefit analysis or clearly address an immediate safety hazard, replace in-kind equipment that is damaged or no longer usable, address a regulatory requirement, or is a reliability project with no reasonably available alternative. These projects also contain either a full, quantitative cost-benefit analysis evaluating the net present value of each project, or an explanation for why the project meets one of the identified exemptions for this cost-benefit requirement.

For each project in our capital plan, we prepare a capital folder that contains six documents:

- Work order and financial analysis that explains the project, its justification, and its costs.
- Capital summary of all capital expenditures for each project.
- Quantifiable costs and benefits (such as avoided costs).
- Copies of invoices.
- Quotes or estimates.
- All other appropriate supporting information unique to each project.

DISTRIBUTION SYSTEM OPTIMIZATIONS

Optimizing our distribution system improves the efficiency, performance, and reliability of energy deliver.

Conservation Voltage Regulation

We continue to implement conservation voltage reduction (CVR) on a number of our distribution circuits.

CVR, an energy efficiency program, involving measures and operating strategies designed to provide service at the lowest practicable voltage level while meeting all applicable voltage standards. It is applied to distribution systems. Studies revealed that, in general, reducing voltage by one percent results in energy consumption also being reduced by one percent. The predominant strategy for implementing CVR is the use of line drop compensation (LDC), a control device connected to tap-changing transformers and voltage regulators that measures feeder load current and computes the resultant voltage drop. The value of the voltage drop is then used by the tap changer or regulator to raise or lower the feeder voltage.

We supply service voltage to our residential customers at 120 volts nominal with a range of +5% to –5% (as required by ANSI Standard C84.1-2011). By changing the central mean voltage (CMV) settings on distribution substation and line regulators from 122 volts to 120 volts, we reduce the maximum service voltage on these circuits by 2%, which results in a compressed service voltage range of +3% to –5% with 120 volts nominal.

Implementing CVR is not appropriate for certain circuits. These include long circuits, circuits where the substation bus regulates voltage, and circuits where large commercial and industrial loads provide their own voltage regulation. We have stopped CVR on some circuits to enable circuits transfers during planned or contingency situations and because of customer complaints.

Increasing amounts of distribution generation complicates the implementation of CVR. A large penetration of DG on a distribution feeder reduces the amount of current that LDC controls can detect; this reduces the apparent voltage drop across the feeder length, resulting in low voltages at the ends of feeders. However, the addition of distributed energy storage is providing us with a new tool that can be set to help stabilize voltage out on the ends of the feeder.

We have begun to capitalize on our advanced metering infrastructure (AMI) to widen the implementation of CVR. AMI gives us access to integrated Volt/VAR control (IVVC) of distribution circuits, which measures distribution circuit voltages along a given circuit in real time then, using these measurements, optimizes voltage regulator settings and capacitor bank switching.

Voltage Conversion

We are continually converting our distribution system to our standard 12.47 kV/7.2 kV grounded wye to better accommodate load growth, enable feeder back up between substations, improve voltage performance, and reduce losses. Still, some 2.4 kV, 4.16 kV, and 8.3 kV distribution circuits remain.

We consider a number of factors before deciding to convert the voltage of a certain circuit, among them: capacity constraints, consideration of feeder backup with adjoining substations, in adequate fault currents, low voltage complaints, and voltage losses. We consider line losses, substation transformer losses, and distribution transformer losses when analyzing the potential for voltage loss savings. The most significant loss savings can be gained by converting highly loaded circuits. In addition, voltage conversions can provide opportunities for reconfiguring feeders and balancing voltages with adjacent area circuits, enabling further opportunities for loss savings.

Rather than making a specific plan, we carefully evaluate and balance the costs and benefits of any potential voltage conversion, and select those projects that provide the greatest value to our customers. Over the last four years, we have evaluated and selected a number of voltage conversion to make progress toward our goal.

When the Graniteville substation was rebuilt, we converted our circuits from 4.16 kV to 12.47 kV. By rebuilding this substation, we were able to retire the Wetmore Morse #58 substation that fed the 58H1 circuit at 2.4 kV, improve motor starting at area quarries, and enable feeder backup with the Websterville #61 substation.

We rebuilt the Barre North End substation, converting its 2.4-kV circuits to 12.47 kV as a first step in standardizing all area substations. We are currently in the process of rebuilding the Barre South End substation, converting its 4.16-kV and 2.4-kV circuits to 12.47 kV. In addition, we filed for a Certificate of Public Good to rebuild the Websterville substation and convert its circuits to 12.47 kV. When completed, service to the Barre area will significantly improve.

After being flooded during Tropical Storm Irene in 2011, we relocated and rebuilt the Waterbury substation. As part of that rebuild, we converted all of its circuits from 4.16 kV to 12.47 kV to better accommodate future load growth and to permit feeder backup with circuits from the Waterbury Center Substation.

In addition to these completed conversions, we are planning and beginning construction on a number of other voltage conversion projects.

Over the next several years, we plan to convert the Fair Haven and Hydeville substations from 4.16-kV to 12.47-kV circuits. These conversions will reduce losses and enable backup among the Fair Haven, Hydeville, and Castleton substations to be improved.

Our rebuild of the Airport substation, planned for 2019, includes converting its existing 4.16-kV circuits to the Vermont Air National Guard to 12.47 kV.

We plan to convert the three 8.32-kV circuits at the Putney substation to 12.47 kV over the next several years. These conversions will reduce losses and enable improved backup between the Putney, Westminster, and Brudies Road substations.

Power Factor Correction

Placing capacitors enables reactive power (VAR) compensation, delivering power more efficiently. We place most of these capacitors on our distribution system, close to load to correct reactive power flow and to reduces losses. Through these placements, we maximize efficiencies by being able to use lower voltage distribution capacitors that are generally less expensive than higher voltage subtransmission capacitor banks.

ISO-New England strictly limits reactive power flow between reliability regions, and requires VELCO to hold its transmission system power factor to 0.98 at a minimum. In turn, VELCO limits the power factor at our delivery points to no less than 0.95. We calculate power factor using real and reactive power obtained from our SCADA database and from substation and circuit MV90 data.

We perform capacitor optimization studies for the majority of our circuits to help meet these limitations, enhance circuit performance, and decrease losses. Optimal capacitor placement involves several factors including voltage drop, regulator placement, loss reduction, and capacitor costs. We plan to continue these studies when our engineering judgment or our monitoring suggests that loading, DSM efforts, growth, and circuit configuration indicate that we re-evaluate the placement of capacitors.

We set the minimum power factor required for customers to avoid a demand determination adjustment under its commercial and industrial tariffs to 90% as an incentive for them to correct their power factors adjacent to their loads. On April 1, 2020, we will increase the minimum power factor required to avoid a demand determination adjustment to 95%.

Battery storage can also provide dynamic reactive support. Unlike capacity banks that provide fixed amounts of reactive power, storage systems can provide a continuous dynamic range of reactive power up to their limits. We have begun testing these capabilities with our Powerwall program.

Circuit Reconfiguration and Phase Balancing

Many factors drive the need to rebalance and reconfigure a circuit: inadequate capacity, unstable reliability, voltage performance issues, low fault currents, inadequate protection issues, feeder backup opportunities, the addition of large single-phase loads, insufficient DER interconnection, and opportunities for loss savings. Reconfiguring and balancing circuits most often occurs in dense urban areas and not so much in rural areas where distribution feeder backup is not as crucial.

AMI's ability to collect relevant data helps better quantify the distribution circuit loads by phase. This information identifies potential imbalances at substations, as well as at key locations on a circuit, including protective devices, tie points, and distributed generation sites. This helps us identify circuits that can be balanced by swapping their loads to reduce losses and improve voltage performance.

AMI data also helps us evaluate the relative loading of adjacent circuits and, when necessary, optimize the normally open points between these circuits to lower losses, improve voltage performance, enhance circuit protection, and extend the load capabilities of substation transformers.

Completed Reconfiguration and Balancing Projects

We have reconfigured and balanced a number of circuits over the previous four years.

Barre City Circuits. We converted most of the remaining 2.4-kV and 4.16-kV circuits in the Barre area to 12.47 kV mainly to maximize their feeder backup capabilities.

Barre Town Circuits. We balanced the load and upgraded the circuit ties on the Websterville 61G1 circuit as part of the voltage conversion of the Graniteville substation and its circuits to 12.47 kV.

Brandon to Salisbury Circuit. We rebuilt portions of the Brandon BR-G71 and Salisbury SA-G23 distribution circuits and tied them together to allow for enhanced circuit balancing and feeder backup.

Leicester Circuit. We added phases to the end of the LJ-G12 and LJ-G13 circuits (supplied by the Leicester Junction substation) to allow for load growth and to unload overloaded circuit reclosers.

Pownal to Bennington Circuit. We rebuilt the Pownal to Bennington circuit with three-phase construction to enable feeder backup between the circuit's terminal Pownal and South Bennington substations.

South Brattleboro Substation. We rebuilt the South Brattleboro substation, reducing its transformers from two to one, and its distribution circuits from four to three. By reconfiguring these circuits, we eliminated some cross-country lines and enhanced feeder backup.

Waterbury Substation. We relocated the Waterbury substation and converted the associated feeders from 4.16 kV to 12.47 kV. In addition, we reconfigured the area's circuits to address load growth and to allow for feeder backup with the Waterbury Center substation's 12.47 kV circuits.

White River Junction to Wilder Circuits. We rebuilt the White River Junction substation, expanding its circuits from one to three. In addition, we reconfigured these circuits with the adjoining three circuits from the Wilder substation to reduce losses and enhance feeder backup.

Planned Reconfiguration and Balancing Projects

We constantly assess our transmission and distribution system. As such, we anticipate completing a number of circuit reconfiguration and phase-balancing projects over the next several years.

Dover to Wilmington Circuit. We plan to build a second Dover substation to supply expanding loads at the Mount Snow ski area. In addition, we plan to reconfigure the circuits between this new substation, the existing Dover substation, and the Wilmington substation to better balance loads, improve reliability, and enhance feeder backup.

Milton Circuit. We plan to extend a circuit south from the Milton substation to provide feeder backup to the Catamount Industrial Park. We are also analyzing the benefits of extending a circuit north from the Mallets Bay substation into this area. Together, these projects promise to improve the balance among existing feeders and enhance feeder backup.

Sharon Circuit. To ease interconnecting a large solar facility, we plan to balance the SH-G35 circuit phase that is supplied by the Sharon substation.

Sheldon Substation. The 12.47 kV circuit that originates at the Sheldon substation is long, carries high loads, and experiences low fault current. We plan to balance this circuit to reduce losses, and improve its voltage profile.

South Burlington Area. We plan to rebuild and relocate the Airport substation, in part, to upgrade the existing 4.16-kV circuits to 12.47 kV. In addition, we plan to reconfigure the circuits among this new substation and the adjacent Essex, Gorge, and Dorset Street substations.

Winooski Area. We are currently upgrading a three-conductor, two-phase step-down area to a three-phase step-down area. This upgrade will relieve step-down transformer overloading, improve the balance on the phases, improve voltage profile, and lower losses.

Winooski Feeder. In 2015, we built a new 34.5-kV distribution feeder from the Gorge substation into Winooski. To complete the project, we plan to reconfigure, the 34.5-kV feeders from the Winooski and Ethan Allen substations to better balance the loads among these three feeders and enhance reliability.

Distribution Transformer Load Management

We are developing a distribution transformer load management (DTLM) program as part of our AMI structure. A DTLM program matches individual distribution transformers to their respective loads to:

- Optimally size new transformers while considering existing loads, motor starting requirements, and the projected capacity and energy losses over the lifetime of the installation.
- Replace highly loaded transformers that are sources of failures and high load losses.

- Replace under-loaded transformers that are sources of excessive capital investment and no-load losses.

Our AMI could establish a link between meter accounts and the individual transformer supplying these meters. This would allow the AMI to:

- Calculate the coincident demand imposed on a given transformer.
- Calculate the energy supplied by the transformer.
- Calculate load losses and no-load losses on the transformer.
- Identify overloaded units.
- Identify potentially under-loaded units.
- Evaluate the effects of anticipated load growth on the losses and remaining capacity of a given transformer.

A DTLM program could efficiently manage transformer loading, postpone unnecessary transformer replacements, and identify overloaded and inefficient units. The program could be especially useful in areas where distribution voltage will be converted and a large number of transformers will be replaced.

We started a DTLM project using DataRaker analytics, but it was too complex. Instead, we can bring AMI data for a specific date and time directly into our CYME models, enabling us to identify overloaded transformers during the one interval snapshot. We continue to develop a systematic program for reviewing the distribution transformer loading for all transformers.

Interconnecting Distributed Generation

The application and installation of renewable distributed generation (DG) continues robustly, creating new opportunities for carbon reduction and load balancing along with new challenges for managing the distribution system. We methodically interconnect these DG systems onto our transmission and distribution system. DG developers generally follow one of three paths: net metering, purchase power contracts through the Sustainably Priced Energy Enterprise Development (SPEED) programs, or direct purchase power agreements (PPAs).

Each developer must receive a Certificate of Public Good (CPG) from the Public Utilities Commission (PUC) for their DG facility before interconnecting with our T&D system. As part of this process, we ensure a safe and reliable interconnection, consistent with our procedures and requirements as well as those of ISO-New England and the Public Service Board.

We remain active within the ISO-New England Distributed Generation Forecast Working Group. This DG Working Group considers national trends, interconnection requirements, under-frequency setting concerns, and interconnection costs related to DG. In addition, we have developed a number of tools to help DG developers navigate the interconnection process.

These tools include:

- *A Guide to Customer-Owned Generation & Distributed Resources.*[59] This guide provides resources to the developer including applicable tariffs, registration and application forms, enabling statutes, PUC rules, trade association information, and regulatory contacts. The guide also provides service requirements, meter socket connections, and a map showing the location of our three-phase distribution lines.
- The *Green Mountain Power Distributed Resource Interconnection Guidelines (Interconnection Guidelines)*. These detailed technical interconnection guidelines provide developers with information on the interconnection process, equipment requirements, application instructions, screening criteria, and service extensions.
- An internal distributed resources database that contains information on proposed and installed distributed resources on our system. The database includes the developer's contact information, type of generator, the primary energy source, generator technical parameters (including capacity), generator location, interconnection voltage, ancillary equipment, and site information. This database, linked to our CYME distribution system planning software, automatically updates our planning models and streamlines needed interconnection studies or future system analyses.

We are running into significant DG saturation on a number of circuits, which is bumping up against limitations and the need for additional system upgrades. Unlike load growth-related T&D system needs, under the current PUC rules, generation must pay for the upgrades necessary for them to interconnect. However, because it would not be feasible or realistic to perform a detailed system impact study on every single small-scale rooftop solar installation (not to mention it would add considerable time to the process for the solar customer), these smaller systems typically go through the expedited net metering process and are able to interconnect in a matter of weeks, regardless of whether any particular new system might "tip" the circuit toward needing an upgrade. Ultimately, these smaller systems add up and push distribution circuits toward their limit. To begin to address this issue, we are now able to show which circuits on our system have either reached these limits or are approaching them through our Solar Map (Figure 6-2).

59 This guide is available at: http://www.greenmountainpower.com/customers/distributed-resources/a-guide-to-customer-owned-generation-and-distributed-resourc.

Distributed Energy Resource Map

On our website, we publish and constantly update a comprehensive DER map—the GMP Solar Map—detailing all distributed generation installations on our distribution system. This publicly displayed distribution grid data helps customers, developers, and other state and local organizations better understand DER integration issues to reduce delays from competing queue positions or needed system upgrades.

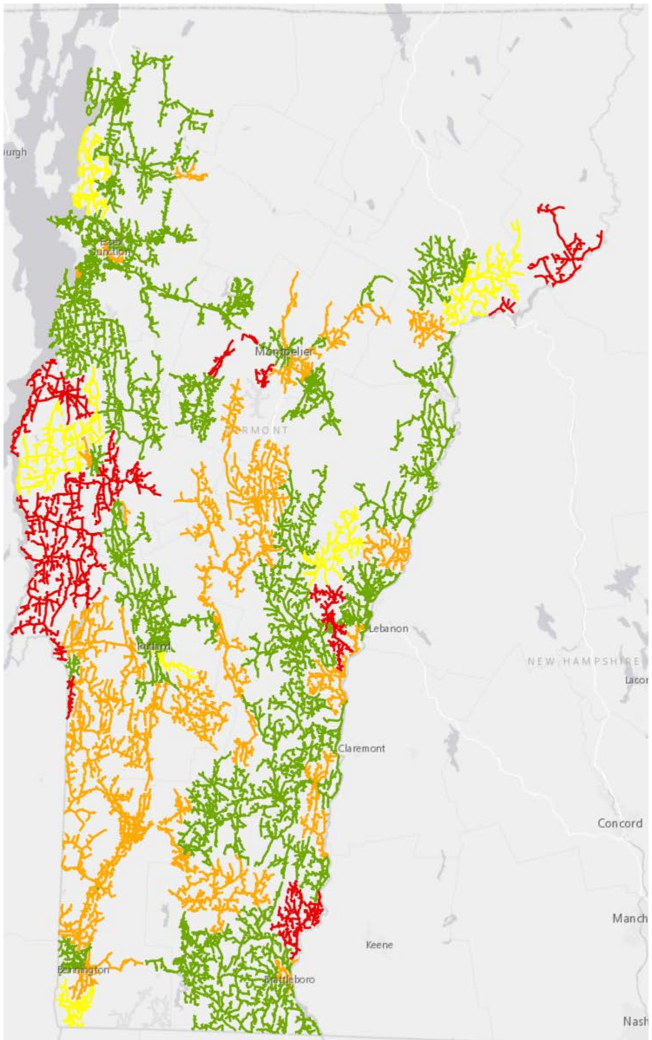

Figure 6-2. Our Distributed Energy Resource (Solar) Map

Figure 6-2 shows a statewide perspective of our Solar Map, available on our company website.[60] This map currently details where DERs are prevalent, where they are not, and where DERs might be more easily interconnected.

Our DER map allows customers and developers to see how their installation would fit into the overall picture of DERs across our service area. This map gives a great deal of useful, color-coded information. Icons viewable on the website represent substations, solar installations, wind installation, and other types of generation. The Solar Map displays circuits in different colors:

- **Green.** Substation transformer rating with at least 20% capacity remaining.
- **Yellow.** Substation transformer rating with between 10% and 20% capacity remaining.
- **Red.** Substation transformer rating with less than 10% capacity remaining.
- **Orange.** Constrained circuits that, because of system limitations, might result in higher costs and delayed interconnections.

[60] http://gmp.maps.arcgis.com/apps/webappviewer/index.html?id=4eaec2b58c4c4820b24c408a95ee8956

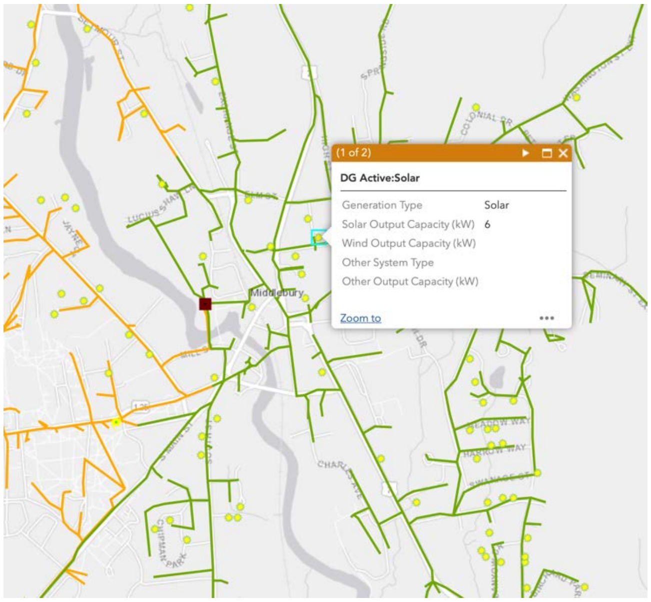

Figure 6-3. Solar Installation DER Map Details (part 1)

Zooming in produces a clear map of all the icons that represent DER installations. Clicking on an icon places a light blue box around the installation's icon, and reveals detailed information about that installation (Figure 6-3). There are two pop-up boxes that describe each installation.

The first pop-up box describes the type of installation, whether solar or wind (this example is 'DG Active: Solar') and its output capacity (6 kW).

Clicking on the triangle icon on the pop-up box's heading bar displays the information on the second pop-up box.

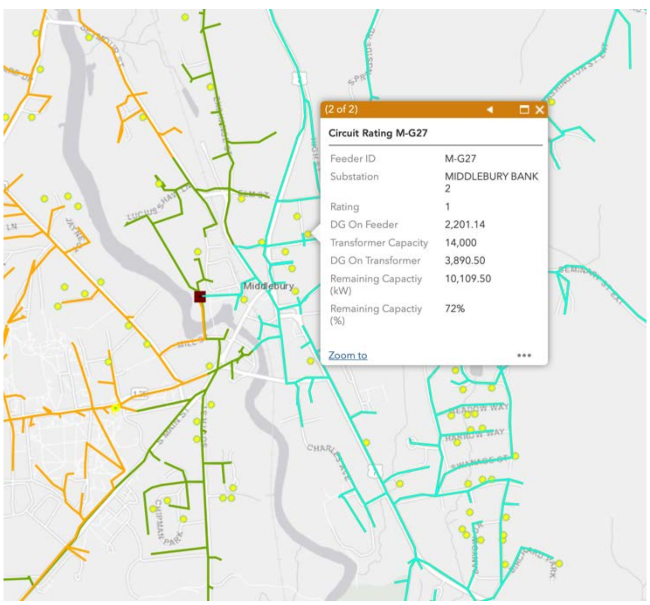

Figure 6-4. Solar Installation DER Map Details (part 2)

The second pop-up box (Figure 6-4) describes the:

- Circuit rating
- Circuit feeder ID
- Substation
- Location rating
- Total DG on the feed
- Transformer capacity
- Total DG on the substation transformer
- Remaining capacity in kW
- Remaining capacity in percent

Notice also that the circuit fed by this substation turns a light blue color.

Substation loading is calculated by adding the connected and proposed generation, and comparing this total to the top nameplate rating of the transformer. System limitations may include, but are not limited to, transmission ground fault over voltage (TGFOV) constraints, as well as areas where the primary operating voltage of the distribution circuit is less than 12.47 kV.

We plan to continue to enhance the Solar Map to include additional information as it becomes available. Potential enhancements include the distance from a proposed site to the nearest circuit and substation, the number of phases available, the circuit voltage, conductor identification, solar irradiance information, and links to Agency of Natural Resources GIS environmental data layers. We are considering the development of a cost estimation tool to help developers estimate the cost of interconnection for a proposed generator at a given location.

Conductor Selection

We have standard conductor sizes for our subtransmission and distribution systems. These include:

- Overhead Primary: 1/0 6201 Aluminum, 4/0 6210 Aluminum, 336 ACSR, 477 ACSR, and 556 ACSR
- Underground Primary: 1/0, 4/0, 350, 500, 750, 1000, 1250 Aluminum or Copper

Our conductor methodology can evaluate a least-cost conductor size based on the conductor's first cost together with the conductor's present value of the demand and energy losses calculated over a twenty-year period. This makes it possible to evaluate the least-cost conductor to install for new line construction and reconstruction.

System planners can also employ this methodology to select the appropriate conductor using the expected (non-contingency) conductor loading. Planners must consider other factors (including expected voltage drops, fault currents, post-contingency current levels, geographic constraints, and expected system changes) before ultimately choosing a conductor. For example, we installed a 795 ACSR conductor when reconductoring on the 34.5 kV subtransmission system. We chose the 795 ACSR conductor because it experiences very low loss under normal loads, can carry the post-contingency thermal loadings of this system, and be supported with single pole and cross-arm construction without the expense of excessively robust structures or short spans. This is a common conductor used in Vermont and New England, making it readily available in emergency situations.

With few exceptions, reconductoring solely for loss savings is not cost effective. The cost of new conductors together with new, larger pole plants will generally exceed the value of any expected loss savings. Nonetheless, we always analyze the benefits of reconductoring whenever a subtransmission and distribution plant needs to be rebuilt. The need to rebuild a plant arises for many reasons—to support road improvement projects, address age, improve degraded plant condition, relocate lines from cross-country to roadside and from overhead to underground, or establish feeder backup between substations—and sometimes reconductoring can be cost-effective.

TRANSMISSION AND DISTRIBUTION RELIABILITY INITIATIVES

Hinesburg Substation and Energy Storage Solution

Reliability deficiencies in the Hinesburg area needed to be addressed. We considered numerous options, ruling out a new substation because that would have created two substations in the area: ours and VEC's. In addition, VEC would have been forced to rebuild its substation to address asset condition.

Our analysis also determined that DG would not address post-sundown peaks and could actually exacerbate system voltage fluctuations. VEIC's energy efficiency study showed very limited potential for load reduction with geographic targeting. These potential load reductions were not substantial enough to ward off additional upgrade requirements.

A jointly owned GMP-VEC substation emerged as the least-cost solution. It provides the lowest cost "T&D only" option for both utilities, effectively addressing all Hinesburg reliability and system protection deficiencies as well as removing any requirement for distance relaying. Installing a battery energy storage system (BESS) with a two-circuit substation (rather than a four-circuit substation) appears to be a more flexible solution. In addition, it can potentially provide the lowest cost solution under some outcomes (such as limited load growth in the Hinesburg area and robust market revenues from battery operation).

A BESS can potentially defer certain GMP upgrades, including delaying construction of two GMP circuit positions at the substation as well as the distribution line infrastructure needed to interconnect the substation to the GMP Hinesburg distribution system. Depending on the input assumptions, comparing a BESS with the two-circuit substation with a fully constructed four-circuit GMP/VEC jointly-owned substation resulted in a wide disparity between resulting higher or lower net costs.

As outlined in our 2014 IRP and discussed in the Vermont Comprehensive Electric Plan 2016,[61] building a BESS is a shared goal for us and the state. We are committed to building additional storage facilities on our electric system to obtain project-specific benefits (such as reduced power and transmission expenses, deferred distribution and transmission projects, reduced power supply risk, and additional resiliency).

The Hinesburg area provides an opportunity for us to gain insight into the costs and effectiveness of a BESS to address an actual reliability deficiency. The Hinesburg area

[61] The 2016 Vermont Comprehensive Energy Plan, page 232, states: "The fact that energy storage blurs (the) line between load and supply, and offers other values to consumers, utilities, and grid operators, poses challenges that regulators, utilities, and industry will need to address sooner rather than later… As the industry matures, and states including Vermont learn from the pilot projects we are undertaking, solutions to these growing pains will emerge—but it's clearly time to get started."

reliability deficiencies include multiple facets of interest, including high solar penetration and a weak radial distribution system with limited capacity for future growth. Unlike most traditional T&D solutions, battery solutions have the advantage of modularity, allowing for relatively easy expansion as system needs dictate.

In the Hinesburg area, the flexibility of a battery system could be particularly useful to help us respond to a substantial degree of uncertainty in the key planning assumptions (such as the amount, type, and timing of future load in the area). Markets, such as the Forward Reserve Market (FRM),[62] can potentially provide even further benefits from storage. Our recent offering of Tesla Powerwall batteries as behind-the-meter energy storage may, in the future, offer even more options for implementing battery storage to defer T&D upgrades in the Hinesburg area.

If a BESS fails to address the reliability deficiencies or system growth expands beyond the BESS's capacity, we could then complete the capital upgrades associated with the jointly owned GMP-VEC substation. If that occurs, the BESS could fully participate as a merchant project. Together, we plan to build the substation with enough space to allow for two future GMP circuit positions.[63]

Given the uncertainties in this area surrounding load growth, solar penetration, and the BESS performance, we believe it appropriate for us to pursue the BESS together with a new substation with VEC.

Relocating Cross Country Distribution Lines

A number of our distribution lines do not run along roadsides, but rather traverse open fields, forests, and other rural areas. Most of these lines were built over twenty years ago when rural loads were low and the need to interconnect DERs was virtually nonexistent.

There are a number of challenges with these cross-country lines. Rather than using our bucket trucks, our crews must access them on foot or with all-terrain vehicles. As a result, trimming trees, maintaining lines, upgrading equipment, restoring outages, and a plethora of other tasks are more time-consuming and costlier. Climbing these older, smaller, and often failing poles also presents safety issues.

The obvious solutions of undergrounding or relocating these lines along roadsides, however, presents a number of problems. Relocation is costly; roadside areas are limited, easements are difficult to obtain, construction often requires substantial effort to create a

[62] In winter and summer, the Forward Reserve Market acquires commitments ahead of time from resources to provide reserve capacity (that is, to start or ramp-up output quickly) in real time.

[63] The actual cost allocation between GMP and VEC for this project has not yet been determined.

viable, safe path, Act 250[64] permits take time and are difficult to obtain, and the even greater expense and effort for burying lines underground is mostly unjustified.

When these cross-country lines must be rebuilt in place, we improve the line's safety and reliability by spending a little more in their reconstruction to save a lot more in the long term: we use stronger poles, install poly-coated tree wire for primary conductors and transformer taps, trim trees with wider clearances, and install animal guards.

Whenever possible, we combine other necessary safety and reliability upgrades when relocating a line to maximize our investment.

Implementing System Improvements

We seek opportunities for implementing efficiencies in our T&D studies and capital expenditures. These efficiencies can be realized through sizing wires, correcting power factors, purchasing transformers, balancing circuits, converting voltage, and reconfiguring circuits.

We prioritize projects that reap multiple benefits, including combinations of managing assets, improving feeder backup, relocating off-road lines, increasing capacity, and avoid line loss. Larger projects often involve upgrading a substation, reconductoring subtransmission lines, and upgrading larger three-phase distribution lines. Smaller projects generally involve working on individual distribution circuits, and include placing capacitors, balancing phases, and balancing load among feeders. Larger projects require three to five years to complete, while smaller projects because of their smaller scope and reduced preconstruction requirements take less time.

Implementation schedules are project specific. For example, installing a distribution transformer (identified through our least-cost transformer acquisition tool) to quickly capture loss-avoidance opportunities generally are completed with a year of being evaluated. We would select the least-cost conductor when the project is designed; completion time would depend on the upgrade's scope and its priority compared to other ongoing projects.

Replacing Streetlights with LEDs

We have taken the initiative to change all non-LED street lights to LED streetlight technology. Through August 31, 2018, we have installed 4,186 LEDs for a system-wide total of 18,812 LED streetlights.

[64] Act 250, Vermont's Land Use and Development Act, enables a public review for construction projects to mitigate their environmental, social, and fiscal impact while complimenting Vermont's unique landscape, economy, and community needs.

Our collaborative initiative with Efficiency Vermont helps all customers improve the lighting efficiency on streets, public spaces, and in private locations by re-examining their lighting needs and replacing less efficient streetlights with new LEDs.

LED streetlight benefits include:

- Significantly reduced energy use.
- Longer lasting lamps—at least four times that of mercury vapor fixtures, thus lowering maintenance costs.
- Improved nighttime environment. LED fixtures fully shut off; no light escapes from the top, reducing light pollution into the night sky and neighboring properties and decreasing glare to motorists and pedestrians.

Together with Efficiency Vermont, we have developed tariffs that offer financial savings to municipal customers for converting to LEDs. To obtain the savings, customers simply determine where to install the LED and its size.

Since 2014, we have collaborated with the cities of South Burlington, St. Albans, Worcester, and Montpelier to install high-efficiency LED streetlights with intelligent controls together with solar panels mounted on utility poles. The panels should produce enough energy to offset the use of the LEDs. These LEDs can notify the installing company when they fail, which reduces down time with more continuous lighting, and improves customer service.

Table 6-1 listed the solar panels mounted on LED streetlights in these four cities.

City	Solar Panels Mounted	Nameplate Capacity (kW)
Montpelier	43	8.6
South Burlington	31	6.2
St Albans	33	6.6
Worcester	7	1.4

Table 6-1. Solar Panels Mounted on LED Streetlights

TRANSMISSION AND DISTRIBUTION SYSTEM PLANNING CHALLENGES

The Impacts of Electric Vehicles and Heat Pumps on Load Growth

Chapter 5: Our Increasingly Renewable Energy Supply provides a much deeper dive into the different potential system loading outcomes from electric vehicles and heat pumps. For example, in the high EV deployment case, we would see an estimated 85 MW of coincident peak demand addition to the system, if we did not implement any control of the charging infrastructure. We have already implemented a control platform and specifically integrated with residential Level 2 charging, which we believe will provide the bulk of customer charging during the peak hours of early evening. This means that if this high case outcome were to materialize, it is highly likely that we will be able to manage a majority of the charging infrastructure and avoid complications to the distribution system. For the EVs charged through uncontrolled charging infrastructure, it will depend on the location and disbursement of the vehicles as to whether or not local issues could arise. We hope to continue to have a high uptake rate through our charging program and the Bring Your Own Device charging program to keep track of the location for these resources, as well as have the ability to control for peak reductions whether that be regional peak value or local peak management.

The same is true for heat pumps, except a lower anticipated coincident peak demand in the high deployment case. As laid out in Chapter 5, our view of a high deployment case would hit approximately 35MW of coincident peak demand if no control is implemented. As with our EV program, we have developed a control methodology for heat pumps as well. However, a peak demand of 35MW spread out over 300 distribution circuits does not pose major concerns for operation of the distribution system. There will be the possibility for very localized distribution transformer loading issues that may arise, we hope to catch those through our AMI data and transformer monitoring program.

In addition to controlling these resources to manage their peak impacts to the distribution system, they will be leveraged as power supply resources and capture additional value for customers such as energy arbitrage. (This is further discussed in Chapter 8: Portfolio Evaluation.) They can also be used as tools to improve DG hosting ability by, whenever possible, creating more demand during the peak solar hours. For example, through charging controls we can ramp up charging during the peak solar hours and ramp it down during the evening peak demand hours.

Securing Our System from Cyber Attacks

Technology and innovation continue to transform the distribution system from a largely conventional analog electrical grid to a smart grid built on a platform of software-centric services. This evolution both standardizes the technologies shared between conventional transmission, distribution, and corporate systems, and also harnesses a variety of new data sources for improving the efficiency and overall operation of the grid.

These technologies continue to proliferate and mature. Coincidently, so does the complexity of cyberattack sources and mechanisms, dramatically increasing the risk to the security of our operations and grid infrastructure. To mitigate these security risks, we subscribe to and implement many of the controls recommended by three key risk mitigation and management frameworks:

- The National Institute of Standards and Technology (NIST) Cyber Security Framework.
- The Center For Internet Security (CIS) 20 Critical Controls Framework.
- The ISO/IEC 27001 Security Standards.

With these frameworks as a guide, our cybersecurity program has evolved significantly. We now employ a number of key practices and technologies to detect, defend, and respond to a wide variety of technical attack methods. We have also incorporated numerous social-engineering practices. We augment this approach by consulting and engaging with several independent cybersecurity partners as well as the Department of Homeland Security's Industrial Control Systems Cyber Emergency Response Team (ICS-CERT).

The Vermont Department of Public Service and Public Utility Commission have been actively engaged in monitoring utility cyber security protocols and responses through meetings that may lead to a statewide response program.

ISSUES SURROUNDING DISTRIBUTED ENERGY RESOURCES

The Numerous Challenges of Increasing DER Penetration

The increasing penetration of DERs onto radial distribution circuits presents numerous planning, operational, and interconnection challenges. Consideration must be given to a DER's size and generation type, the relative strength of the electric system at the proposed interconnection point, and the protection strategies in the area. Regarding protection strategies, GMP is requiring that all inverter-based resources be compliant with IEEE 1547 SA and also meet the requirements of the ISO New England Source Requirement Document, February 6, 2018, which is available at: Inverter Source Requirement Document of ISO New England (ISO-NE).

We are conducting a series of feasibility, system impact, stability, and facilities studies to identify potential problems and develop appropriate solutions. When the studies are complete, we plan to work with generation developers to address specific interconnection issues and develop mutually beneficial solutions.

The increased penetration of DERs gives rise to a number of issues.

Thermal Loading. Conductors, transformers, voltage regulators, and other equipment along the electrical path to the interconnection point can potentially exceed their thermal ratings because of the current contributions from these resources.

Operational Loading. Fuses, reclosers, and other protective devices can exceed their thermal rating (above nameplate, but below trip level) and operational rating (above trip level).

Reverse Power Flow. Large interconnections can reverse the power flow through voltage regulators and protective devices, precipitating the need to replace devices that cannot properly operate with reverse power flow.

Voltage Fluctuations. Power entering the grid from DERs can affect voltage levels, usually raising the voltage at the interconnection point. Induction generators, when first starting, can create a large reactive power surge that causes voltage sags. Gradually integrating larger facilities online might be necessary to allow distribution voltage regulation equipment to keep pace with changing voltage levels.

Unintentional Islanding. Protective devices can sometimes cause DER-supplied load to disconnect from the grid, resulting in a phenomenon called islanding. Without an adequately stronger and larger grid, islanding can cause voltage and frequency to fluctuate, damaging equipment and degrading both safety and reliability.

Fault Current Contributions. DERs connected on radial feeders can cause line protection problems. Radial feeder protection schemes s handle current that flows into a fault through the upstream protective devices. DG can provide fault current from alternate directions, which causes the existing protection to fail.

Ground Fault Over-Voltages. DERs that are not effectively grounded can cause high voltage levels during ground faults when there is a relatively large generation-to-load ratio in the area. This is one of the most common limitations that we run into with saturation because of distributed generation.

Distribution Grid of the Future

Many of our proposed T&D capital additions increase the capability to interconnect additional DERs without compromising system power quality or reliability. This is one of the reasons we rebuilt the Barre North End substation and are rebuilding the Barre South End substation (the primary drivers were to improve reliability and better manage assets). The previous infrastructure had very limited capability for interconnection of DERs. Converting these substations from 4.16 kV to 12.47 kV and adding a larger substation transformer strengthened all of the Barre-area distribution circuits and reduced the potential adverse impacts (such as voltage flicker) when connecting DERs.

This stronger distribution system also increases flexibility and creates opportunities to implement emerging technologies, improving overall system performance.

We plan to explore implementing BESS solutions for increasing DG hosting capacity at substations nearing their hosting limit and while we do not yet have the ability to propose capital improvements to increase hosting capacity we will continue to test and work with the Department and other stakeholders to propose the best solutions possible. During the Panton Battery project, we proposed limited testing of implementing a BESS to increase DG hosting capability to gain experience, and learn requirements and tradeoffs. In addition, we used this project to explore other potential grid-related DER benefits such as reactive power support, conservation voltage reduction (which may reduce or eliminate line regulators required on the Panton circuit in the future) and distribution islanding.

Battery storage also provides potential benefits of reducing the regional network service charge and of participating as a merchant plant in the Forward Capacity Market, energy arbitrage, and frequency regulation market.

Distribution Planning and Design Considerations

With the continued influx of variable DERs behind the meter, our distribution system must accommodate bi-directional power flows that can be redirected to different substations and feeders across our system. In response, integrated resource planning is expanding to include other areas of system and grid planning, especially distribution planning. A redesign of radial distribution system to looped systems, self-healing networks, and microgrids might prove necessary.

More and more, as our circuits become constrained with DERs, passive and reactive system management is transitioning to active management with real time processing of large amounts of information and proactive system operation. We constantly plan for cost-effective system upgrades that create and maintain a secure, flexible distribution system, improves grid resiliency and reliability, and enhances system efficiency—all while facilitating the integration of more and more distributed and renewable resources.

Circuit Ranking for Future DER Installations

Determining how to effectively and efficiently increase DER capacity on our circuits would require a capability study performed on every circuit. With almost 300 distribution circuits, it would not be cost effective to perform this type of detailed analysis for every location on our system, especially given the unknowns regarding potential DER sizes and locations. A more reasonable path would be to determine which circuits have greater potential to host more DERs. In addition, it would be valuable to identify circuits where limited resources could be added that maximizes cost-effective DER integration.

To solve this issue, we are developing a "circuit-ranking matrix" screening process across our service territory. This process strategically employs available system data to determine areas that warrant an in-depth examination of possible DER integration. The goal is to use data metrics and analytics to direct resources and emerging technologies to the optimum locations.

Currently, the circuit-ranking matrix considers:

- Circuit reliability
- Power quality sensitivities (such as customer type, hospitals, and emergency shelters)
- Substation capacity
- Circuit minimum and maximum kW and kWh loads
- Total amount of connected and proposed DERs
- Peak responsibility factors (that is, coincidence with other peaks)

One of our strategic goals is to reduce our system peak when it coincides with the ISO-New England peak. Employing DERs when ISO-New England peaks reduces Forward Capacity Market and regional network service costs, thereby providing economic value to our customers. We can attain further value when this same DER is located on a circuit (or its supplying substation) peaks simultaneously with the ISO-New England peak. Locating DERs in this manner extends substation transformer life and reduces losses.

Under our methodology, a circuit with higher coincident kW loading would likely screen higher than another coincident circuit having lower demand. Other ancillary T&D system metrics must also be considered (such as opportunities to improve reliability or defer T&D upgrades).

This methodology bridges the engineering particulars of system operation with the economic opportunities of market operation, and may act as good indicators for the placement of DERs. Each matrix component is weighted to identify a "DER opportunity" numeric ranking of a circuit. We then review this ranking together with other pertinent information (such as planned capital projects) to prioritize DER placement.

The GMP Solar Map is an example of this data-based approach already working for ranking and organizing circuits based on their capabilities.

PRESERVING RELIABILITY

Reliability Improvements

Our method for identifying areas to improve reliability continues to evolve. Every month, we compile and analyze reliability data (such as the average number of interruptions and their average length from SAIFI and CAIDI indices, as well as other sources) to better track performance and establish reliability goals. From this information, we choose projects—tree trimming, fuse coordination, sectionalizing, new infrastructure and reconstruction—to improve reliability.

While this method has proved successful, we nonetheless continue to develop and implement programs, pilots, and recommendations to improve reliability. We separated these recommendations by area: transmission, distribution, and substation.

Transmission Reliability Recommendations

We have identified several reliability recommendations for our transmission system.

- Continue to recapture transmission rights-of-way to reduce tree-related faults and outages.
- Increase the number of SCADA-controlled, motor-operated load break switches, which enables us to sectionalize faster when problems occur.
- Control and monitor SCADA-controlled switches by using the VELCO fiber build-out.
- Quicken our pace for replacing aging poles.
- Reconductor lines and develop operating practices to address identified thermal constraints during critical outages.
- Reduce the length of voltage sags during a fault by installing high-speed communications-assisted tripping (HSCAT) schemes. These schemes allow sensitive electronic loads to ride through temporary system disturbances that otherwise would have caused the electronic loads to shut off or malfunction.

Distribution Reliability Recommendations

Here are several reliability recommendations we've identified for our distribution system.

- Continue to rely on outage statistics to prioritize circuits for tree trimming and capital reconstruction projects.
- Increase our pace for replacing the miles of aging distribution line.
- Continue to implement our method for coordinating fuses to restrict circuit outages.
- Implement the updated transformer standard that foregoes completely self-protected (CSP) transformers in favor of conventional transformers.
- Install animal deterrents, guards, and fences on our line equipment.
- Expand the use of spacer cable.
- Develop distribution pilots including AMSC Dynamic-VAR volt/VAR (to stabilize and regulate voltage and power factors), GridEdge Networks (transfer trip protection systems that better enable DER integration), and microgrids (to mitigate and isolate power quality issues).

Substation Reliability Recommendations

We have identified several areas for improving reliability at our substations.

- Quicken our pace for replacing aging substation infrastructure.
- Continue to use portable substations to minimize planned outages.
- Install more animal deterrents, guards, and fences on our substations.
- Install substation fence security systems.
- Enhance feeder backup capability between substation circuits whenever a substation is upgraded.

Substation Reliability Improvements

In "Reliability Improvements" (page 7-6-37), we discuss a number of programs, pilots, and recommendations for improving reliability. This section elaborates on some of those recommendations.

Figure 6-5. Animal Deterrent System

Animal Fences. Most of our substations and switches are located in out-of-way and rural places, where the chance for animals to "investigate" increases. Outages caused by animal contact have affected the reliability and power quality to our equipment as well as thousands of residential customers and hundreds of commercial and industrial customers. Animal fences protect substations and their assets, virtually eliminating outages caused by wandering animals—as our experience with animal fence installations at several substations has clearly demonstrated.

Animal Mitigation. Not all animals amble into the grounds of our substations. Some climb security fences; other simply fly in. To protect against these "invasions", we have installed a product called Green Jacket to subtransmission buses, disconnect switches, breakers, and substation transformers to enhance reliability. The animal protection is form fitted for its exact location and placed either on live parts or the ground plane to eliminate the different potential locations where animal contact is most likely to occur

Substation Security System. Animals aren't the only "invaders" we have to deal with; some people also find "visiting" a substation irresistible. To counteract these unauthorized entries, we are installing security systems at our substations, which include surrounding fences with barbed wire tops and video cameras. These security fences reduce the risk of injury or death to the intruder. The remote cameras enable us to record events at the substation, helping identify intruders, identify potential fault causes, and improve overall safety.

High-Speed Communications-Aided Tripping Scheme. An HSCAT improves power quality by reducing the length of voltage sags during a fault. This time reduction allows sensitive electronic loads to ride through temporary system disturbances, maintaining power. Without an HSCAT, these voltage sags would cause the electronic load to shut off or malfunction.

Motor-Operated Air Breaks. Motorizing switches significantly improves the reliability, operations, and safety of our subtransmission system. A MOAB helps to isolate and sectionalize remote faults and disturbances, enabling us to restore service quicker to substations supplied by those line sections, therefore minimizing outage times for customers. Motorizing switches increases safety because line workers will no longer have to access the switch and manually operate it.

We are upgrading all of our older, manual gang-operated air brake (GOAB) switches with modern, remote MOAB switches. These upgrades improve worker safety and efficiency and decrease outage times. MOAB switches integrate with our SCADA systems, which helps us more quickly address outages from our centralized control system. This integration reduces the time customers are without service during each outage event. Installing MOABs further automates our SCADA master system, which operates over a high-speed fiber communication network, to better reduce outages and increase safety.

Managing Vegetation

In 2017, faults from trees contacting our overhead subtransmission and distribution lines accounted for 50% of all outages, and we have seen a similar pattern this year. To combat this, we have created, and constantly update, an integrated, long-term vegetation management (IVM) program. We implement our IVM program safely and cost-effectively with minimum environmental impact. Our goal is to create safe and efficient operation of the subtransmission and distribution system by reducing service interruptions and power quality disturbances.

Trimming Around Distribution Lines

We monitor the number of tree-related outages every month. We also revised our distribution vegetation management plan as part of the PSB rule 3.631(J). The IVM plan details the relative composition of tree species near our T&D system, provides growth rates for the dominant species, and lists low-growing compatible species. We trim our entire distribution system every seven years. We developed this periodicity based on a 2015 study of the composition of the trees in our service territory, their growth rates, and clearance distances from energized lines. Every year, we determine areas most in need of trimming based on the last year the area was trimmed, the frequency of service interruptions, customer density, and the number of sensitive customers (such as hospitals).

We clear at least 20 feet vertically and 10 feet horizontally for 2.4-kV to 34.5-kV distribution lines, whenever possible. These clearances increase for conifers (with their tendency toward ice and snow loading) and tree species whose regrowth rates exceed the seven-year standards. We cannot always adequately clear in the green belt areas of most villages, towns, and cities; we are considering trimming these areas more frequently.

To clear and trim, we manually cut trees, prune using various methods, mow with large equipment, and selectively apply herbicides. Appendix E: Vegetation Management Plans details these clearing techniques as well as our overall vegetation management programs.

State officials recently detected the emerald ash borer (EAB) in our forests and trees. There are hot spots in certain areas of our service territory and the infestation is expected to spread. Their infestation is a source of concern for us, as well as for other state utilities and municipalities across the state. The EAB larvae feed on the inner bark of the ash trees, disrupting the tree's ability to transport water and nutrients, which ultimately leads to the tree's death.

Because EABs feed under an ash trees bark, it is extremely difficult to identify infected trees until the tree is on the verge of dying. Because of this, we have devised an EAB mitigation strategy that proactively removes healthy ash trees along utility corridors within confirmed infested areas and are working with the Department now, as we release this IRP, to review and implement this plan. Getting ahead of this problem, rather than letting ash trees become infested, weaken, and fall, is the right way to approach this in the planning period.

Maintaining Our Subtransmission System

Our subtransmission right-of-way management plan was updated in 2018 as part of the PSB rule 3.631(J).

As part of the reclamation program in 2018, we cut vegetation in 115 acres of our subtransmission system, and removed 967 hazard trees and 4,701 danger trees. We applied herbicides on 967 of the total 1,350 acres on the subtransmission system.

Our subtransmission system supplies power to cities, towns, villages, and other large areas. Losing a single subtransmission line negatively impacts large numbers of customers. Because of this, we maintain our subtransmission corridor on a five-year cycle (rather than a seven-year cycle).

On average, we maintain 50 feet to 100 feet wide on each side of the centerline of our subtransmission right-of-way. Our subtransmission system maintenance techniques are similar to those of our distribution system: flat cutting, manual and mechanical trimming, mowing with large equipment, and applying herbicides.

When managing vegetation within our distribution and subtransmission system, we strive to be sensitive to the concerns of property owners. We contact property owners before working in the right-of-way, and also encourage them to use the land within the right-of-way to help ensure safe electricity transmission.

Using Herbicides

After we cut vegetation within the T&D right-of-way, we selectively apply herbicides on vegetation troublesome to electricity transmission, and to promote low-growing vegetation as a way to increase plant bio-diversity. Selectively applying herbicides reaps a number of benefits: reduced overall environmental impact, lower costs, reduced incompatible stem densities (thus decreasing the amount of herbicides applied in future maintenance cycles), and improved safety and reliability of the system.

We apply herbicides in three ways:

1. **Foliar Application Treatment.** Typically used where sprout growth is dense. We apply herbicide directly onto the incompatible plant's leaf surfaces, a method of up to 95% effective in treating target plants in one year.
2. **Basal Bark Treatment.** Used to control susceptible woody stemmed plants less than six inches in basal diameter. We apply herbicide to basal parts of brush and stems, including the root collar area.
3. **Cut Stump Treatment.** Used on recently cut tree stumps to inhibit the regrowth of stump sprouts. This technique is primarily aesthetic, as no brown-out or dead stems remain standing. It's our least effective treatment, however, because of the difficulty of finding tree or brush stumps after they have been cut.

The Foliar treatment is best applied one growing season after cutting. This allows the sprouts to grow long enough to be easily located and at a size where the herbicide is most effective. We treat stumps right after they are cut, applying additional herbicide during our next maintenance cycle.

The Vermont Agency of Agriculture, Food & Markets regulates the herbicide application on our system; we comply with their regulations.

Inspecting Poles

Every ten years, we inspect every pole on our distribution and subtransmission system. During our inspection, we examine each pole for splits, holes, and abrasions. We also perform core boring and sound tests above and below the ground to detect soft spots or other internal imperfections.

We excavate distribution poles to eight inches below grade on two sides of the pole. Subtransmission poles are excavated 360 degrees, removing soil to 18 inches below grade. We then treat those portions below grade with an antifungal compound, and wrap them before covering them up again.

We chemically treat a partially decayed subtransmission pole when its life can reasonably be extended. If extending its life is not an option, we replace the pole. We generally replace distribution poles that fail inspection or are decayed because, after ten years, they most likely do not meet current height and class specifications.

Preventing Underground Utility Damage

It's important to us to prevent any damage to our subtransmission, distribution, and fiber optic underground cables. Their integrity is vital to system reliability.

We routinely excavate (such as when we set utility poles), as do other outside parties. Damaging our underground infrastructure can create serious safety hazards, compromise reliability, and result in costly repairs. Therefore, we must be diligent when we excavate to prevent damage not only to our own infrastructure, but that of water, natural gas, telephone, and cable television.

To remain diligent and avoid damaging equipment, we participate in and adhere to the procedures of Dig Safe® for the states of Maine, Massachusetts, New Hampshire, Vermont and Rhode Island. Dig Safe is a not-for-profit clearinghouse, providing a free service to its member utilities. Dig Safe notifies participating utilities of plans to excavate in areas where underground facilities may be present. In turn, these utilities mark the location of their underground facilities. Excavation within 18 inches of a marked facility must be non-mechanical—in other words, hand digging.

Vermont state law 30 V.S.A. § 7001-7008 as well as Public Service Board Rule 3.800 requires our participation in Dig Safe. Specifically, these regulations require us to:

- Be a member of Dig Safe.
- Notify Dig Safe at least 48 hours (but not more than 30 days) before excavation.
- Mark our facilities within 48 hours of being notified by Dig Safe.
- Forward an Underground Facility Damage Prevention Report to the Vermont PSB and DPS when we discover damage to underground facilities.
- Build our facilities to conform to the National Electric Safety Code.
- Install subsurface markers above all underground facilities.

We have formalized our practices for inspecting overhead and underground distribution equipment. For our overhead distribution equipment, we will inspect regulators, air break switches, load break switches, and hydraulic reclosers every five years; we will inspect capacitors, poles (Osmose inspection), framing structures (Osmose inspection), and solid dielectric reclosers every ten years. We will visually inspect our underground distribution equipment every five years, and fully inspect this equipment every ten years.

Conducting Aerial Patrols and Infrared Inspections

We conduct an aerial patrol of our entire subtransmission system every spring and fall, and after major storms, to locate and assess possible damage. During these patrols, we fly our helicopter close to locate danger trees, broken cross arms, floating phases, cracked insulators, displaced cotter pins, and other problems that might adversely affect the performance of the transmission lines.

In August during peak load, we conduct an additional aerial patrol to perform an infrared scan of both transmission lines and substations. These scans employ an infrared camera mounted directly to the helicopter. The scan identifies hot spots that can indicate a failing conductor, corroded splice, loose connection, or other problem area where a line or substation is stressed and vulnerable to failure.

From the ground, we also periodically scan our substations using hand-held infrared cameras to detect problems.

Securing Substations in Floodplains

Thirteen of our substations are located within Federal Emergency Management Agency (FEMA) floodplains: 11 are in a FEMA-designated 100-year floodplain, and two are in a FEMA-designated 500-year floodplain. Under extreme weather conditions, these substations may be vulnerable to damage from flooding.

To identify substations in FEMA, we cross referenced their locations with the available FEMA geographic information systems (GIS) floodplain maps. FEMA has developed GIS layer maps showing 100-year and 500-year floodplains for Chittenden, Washington, Rutland, Windsor, and Windham counties. These five counties contain 110, or 54% of our 202 distribution, hydro, and switching substations.

The most effective method to protect a substation from flooding damage is to relocate it out of the floodplain. Relocating substations solely to mitigate against flood risks is costly. For example, our reconstruction and relocation of the Waterbury substation cost over $2.4 million. The costs associated with relocating a substation can include supply transmission line additions, distribution line upgrades required to relocate main feeders, and the environmental impacts of disturbing and developing a new site.

We evaluate the costs and benefits of relocating a substation in a floodplain when it is scheduled for a major upgrade. Upgrades can be triggered by a number of issues including obsolescence, structure or equipment deterioration, load growth, or the desire for enhanced feeder backup with adjacent substations. We consider relocating these substations when the overall benefits exceed the total current and projected costs.

For example, we are rebuilding our Barre South End substation (currently located within the floodplain of the Jail Branch river) by raising the new substation yard by approximately three feet to that it is above the high-water mark of a 100-year flood. In addition, we are moving several adjacent utility poles away from the floodway fringe.

We plan to avoid locating new substations in floodplains.

Implementing Power Quality Solutions

Poor power quality adversely affects the reliability of the now ubiquitous computers and microprocessor-based equipment integral to the operation of the power grid.

Power quality is the relative frequency and severity of deviations in the incoming power supplied to electrical equipment from the customary, steady, 60 Hertz sinusoidal voltage waveform. Examples of poor power quality include voltage impulses, high frequency noise, harmonic distortion, unbalanced phases, voltage swells and sags, and total power loss. Because the sensitivity to such deviations varies among equipment, poor power quality to one device might be acceptable on another.

Because of this, we are developing tools using AMI data to assist or proactively address power quality issues. We have used AMI data to show areas where customers are out of acceptable voltage ranges. We are also exploring using AMI data to identify momentary outages to assist with power quality complaints associated with blinking lights or temporary outages.

We immediately respond to power quality issues identified by our customers. The majority of power quality issues result from inadequate wiring, failed connections, or poor grounding. In most cases, we quickly identify and solve the issue. When this isn't possible, we investigate the cause by using power quality recording devices installed at the customer's premises. When the problem lies with the customer's equipment, we inform them of the source and help them in finding appropriate consultants and vendors to solve the problem. If the problem originates with our transmission or distribution system, we immediately develop and implement a solution to the customer's satisfaction.

Protecting Our Distribution System

Protecting our distribution system provides multiple benefits; it minimizes hazards to the public, protects utility workers, prevents equipment damage, maximizes reliability, and enables prompt service restoration. Overcurrent devices on our distribution circuits remove temporary faults and limit the number of customers impacted by permanent faults.

A number of specific design strategies protect our distribution system. We:

- Set circuit loads and distributed resources to not exceed 66% of relay pickup settings. Exceptions are made for circuits that feed only one customer (such as a ski area or a solar facility) or when a feeder is being backed up. This strategy provides for 150% cold-load pickup capability.
- Size and set overcurrent protection (including circuit breakers, reclosers, and fuses) to allow for maximum load or generation current, cold load pickup, feeder backup, and load growth, while maintaining the sensitivity required to detect bolted faults at that end of each device protection zones.
- Set temporary protection operating sequences for "fuse saving" under normal circumstances. Fuse saving enables circuit breakers and reclosers initially operate with a "fast" timing characteristic, allowing temporary faults to clear before downstream fuses operate. Fuse saving, while avoiding permanent fuse outages downstream, subjects upstream customers to momentary interruptions. As such, fuse saving is not set for circuits that supply customers that are especially sensitive to momentary interruptions.
- Install three-phase or single-phase electronic reclosers where justified to provide additional capability and flexibility for present and future loads, and for distributed resources.

Planning for and Responding to Weather Events

Severe weather events, which can occur almost without warning, pose a significant threat to our system reliability. Our response, however, is swift. We have developed a sharply honed planned response through our Incident Command System (ICS) team; these employees are well versed in their storm responsibilities and what is expected of them.

We engage our ICS team about thirty times a year. Some of these events are small and only involve a limited cross section of company; others are "all-hands-on-deck" events involving virtually every employee in the company. We continually adopt improvements based on feedback after each event.

The type and severity of weather events predicate power outages. The on-call Storm Directors closely monitor weather for conditions that may cause outages. They poll many weather sources and scores of public and private weather sites, and contact a meteorologist retained by the Vermont utilities as well.

When conditions demand, the storm team convenes, then develops and implements a storm plan commensurate with the weather event. The storm team mobilizes field assessors and field crews before an outage occurs.

We are also a member of the North Atlantic Mutual Assistance Group (NAMAG). As a member of NAMAG, we can request crews from around New England and beyond when Vermont is faced with a catastrophic weather event. Our proactive and disciplined approach to storm events has had a material effect in minimizing the duration of outages that our customers experience.

Besides eight Storm Directors, we use ICS Chiefs to prepare for and manage our restoration efforts. The following teams have been established, each with an upper management Chief and executive sponsor:

Incident Commander. Oversees the overall restoration effort and works directly with the ICS Chiefs to ensure a safe, fast, and effective restoration.

Operations Chief. Oversees several functions related to our restoration efforts, including both internal and contract line crews, tree crews, and the teams responsible for dispatching resources locally when operations are decentralized to the District office.

Assessment Chief. Assembles assessor crews that inventory the storm damage and, when necessary, escort contract line crews to trouble locations.

Logistics Chief. Oversees the logistics team and is responsible for securing rooms and meals for the overall storm team.

Information Technology Chief. Ensures the functioning of all computer hardware, software, and communications equipment during storm restoration.

Communications Chiefs. Ensure coverage for the call center, public relations, press, and social media.

Safety Chief. Provides safety briefings to all contract crews and performs safety visits to crews during storm restoration.

We use several interrelated software systems to manage restorations. This allows us to efficiently answer high volumes of customer calls, manage reported outages, and maximize available resources.

Our advanced metering infrastructure (AMI) allows storm organizers to contact or "ping" meters to determine which are out and which have had their power restored. This saves valuable crew time. The AMI infrastructure also assists crew dispatchers in understanding the extent of outages.

Our main focus at the start is to restore power to priority areas first. These areas include critical roadways are blocked with downed wires, outages affecting large number of customers, and outages affecting key customer sites, including hospitals and patient care facilities.

MANAGING OUTAGES

Every year, we make concerted efforts to reduce the number of outages and their duration, as well as implement upgrades and improvements to our distribution system to reduce outages.

Outage Analysis and Technology

Technology also plays a significant role in managing weather events. We employ a software package called Responder, a device-driven, highly integrated outage management system (OMS). Responder accepts a variety of customer and system information inputs and outputs information useful for analyzing and responding to outages.

Input data comes from a variety of sources:

- Our customer service representatives and, when volume is high, our overflow call center inputs information received from outage phone calls into our outage portal. The portal then automatically populates Responder with this data.
- Our integrated voice response (IVR) system uses pre-recorded voice messages and customer responses to automatically log customers' outage information into Responder and, if available, provide the customers with an anticipated restoration time for their outage.
- Customers who enroll receive text notification can report an outage as well as obtain the status of power restoration. Customers can also report outages and obtain status updates from our website.
- Our geographic information system (GIS), which contains the locations of customer data, line types, and the interrupting devices, is also integrated into Responder.
- Finally, our fleet truck tracking system is integrated with Responder which allows operators to track the locations of line crews and tree crews.

Armed with this information, Responder predicts the discrete interrupting device that most likely operated for a given fault and locates the failing device. Operators can then dispatch line crews or outage assessors to patrol downstream of the device to determine the cause of the outage. Once the extent of the outage is known, the estimated restoration time is updated, as needed.

Outage History

We track outage history to assess year-to-year impacts. Table 6-2 compiles the history for major storm-related outages in 2017.

Outage Cause	Customers Affected	Customer Hours Out
Trees	433,578	2,757,486
Weather	16,157	67,813
Company Initiated	61,888	103,881
Equipment	54,834	142,746
Operator	772	255
Accident	41,243	85,546
Animal	15,941	19,704
Supplier	2,797	1,894
Unknown	37,406	54,828
Total	664,616	3,234,152

Table 6-2. 2017 Outages with Major Storms

Table 6-3 compiles the history for storm-related outages in 2017 outside of major storms.

Outage Cause	Customers Affected	Customer Hours Out
Trees	287,350	718,066
Weather	14,684	46,184
Company Initiated	59,483	100,925
Equipment	50,430	102,748
Operator	772	255
Accident	41,237	85,323
Animal	15,940	19,703
Supplier	2,792	1,809
Unknown	35,858	51,203
Total	508,546	1,126,216

Table 6-3. 2017 Outages without Major Storms

Every year, we review and analyze outage data to discover overall trends, identify our worst-performing circuits, develop a priority list, and implement plans to improve the reliability of these circuits. We create a priority list by ranking each circuit by the number of customers affected by outage events and by total customer hours out. This priority list allows us to focus our available resources on the least reliable areas of the power system—a cost-effective method for improving overall performance. Coupled with a system-wide focus on preparedness, technology, and a proactive vegetation management plan, this initiative creates a comprehensive approach to advancing the reliability of our power system.

We target improvements on the 20 worst circuits, considering a number of factors before considering capital improvements, especially the main reason why a particular circuit failed. Changing the operation or maintenance of a given circuit sometimes is the best way to address an issue, thus avoiding a capital expenditure. For the 20 worst circuits identified in 2017, we implemented improvements including road-side rebuild projects, installation of covered tree-resistant wire, installation of the animal guard, and various reconstruction projects.

Figure 6-6. Line Crew Restoring a Storm-Related Outage

We use business analytics query tools to analyze and generate reports, including monthly reports that identify customers who have experienced a high number of outages over a short period of time. These reports help us decide where improvement dollars may best be invested.

We continue to make significant investments in the reliability of our electric system. We invest millions each year in capital upgrades to the transmission and distribution system (as illustrated in Chapter 7: Financial Assessments). We have rebuilt substations (including installing conductors large enough to provide feeder back-up where necessary), moved cross-country lines roadside, installed new protection devices, upgraded SCADA controls, and replaced end-of-life plants. These capital investments are in addition to the operation and maintenance expenses associated with vegetative management, pole inspections, aerial patrols, and infrared scanning.

Smart Grid Technologies

We employ Smart Grid technologies to improve the functionality and reliability of the transmission and distribution system. The Airport Self-Healing Project that will minimize outage durations is an example of a Smart Grid project. This project, put into service in spring 2018, provides an automatic restoration scheme for the Burlington International Airport.

The airport BTV is normally supplied by the Town Line 44G2 feeder. Existing circuit ties allow for feeder backup between the Town Line 44G2 and the Dorset Street 78G1 circuit. These feeder backup ties have required manual switching in the past. The airport restoration scheme automates this load transfer in the surrounding area.

The auto restoration scheme required the installation of two new line reclosers which have voltage sensing on both sides of the line recloser. We installed one recloser at the 44G2/78G1 tie point on White Street and the other on Patrick Street, connecting a fiber optic cable between both devices to allow them to communicate. This project has already addressed an outage; the restoration scheme worked as designed, quickly restoring power to the airport.

We expect to implement an additional automatic restoration scheme on a recently constructed a tie line between the Pownal and South Bennington substations. This tie line establishes a permanent feeder backup for both of these substations to improve reliability. This project not only replaced the aged and deteriorating Bennington tie line, but also greatly improved reliability for our Pownal customers, who had experienced numerous outages. The Pownal substation was supplied from a radial 46 kV transmission line and had no feeder backup. The entire village of Pownal was being supplied from a single-source radial transmission line. The Pownal tie line provides backup for the Pownal substation from the South Bennington substation and vice versa. Adding an automatic restoration scheme will further improve reliability.

We have been working with Schweitzer Engineering Laboratories to implement a microgrid in Vergennes in 2019. The use of the Smart Grid technologies will continue to evolve and expand to improve the reliability of the electric system.

Smart Grid Data

Accurate data are imperative in operations, decision making, and planning. We are making a concerted effort across numerous areas to improve our data quality. Interconnecting high quantities of DERs, using the Responder OMS, and implementing Smart Grid technologies makes the data integrity ever more critical.

We are making progress in correcting items that are in our customer care and billing system but are incorrectly modeled in GIS. These include conductor sizes, connectivity errors, missing stepdown transformers, missing primary metering points, and missing meters. We are working on getting all of the induction and synchronous machines in the proper equipment files, working to improve phasing, and properly training designers to ensure that the corrections are maintained into the future.

Better data will lead to better results, which in turn, means more effective service for our customers. Data quality has a direct impact on our planning circuit models, outage management reporting, and storm response. Improved data mean more accurate analysis to support the interconnection of DERs and new load (including Tier III loads), management of load transfers for feeder backup, and scheduling of dispatchable resources such as Tesla Powerwall batteries and BESS for peak load reduction.

AMI Data

We have greatly expanded our use of AMI data since the 2014 IRP. As expected, the availability of these data has allowed us to develop additional tools to aid in the planning and operation of the T&D system. AMI technology is allowing us to improve reliability; enhance operational outage management; proactively address power quality issues; and enhance monitoring, data quality, and planning of the T&D system. AMI technology also supports the interconnection of DERs and facilitates peak load reductions.

The AMI data in the Oracle® BI reporting and DataRaker analytics, have allowed for the following capabilities:

- Improved modeling of the distribution circuits in CYME® load flow. The CYME gateway now links to, and imports, the AMI, SCADA, and MV90 data, and can create data models for a specific date and time. The AMI data provide engineers with a more accurate distribution of loads and allows for more efficient and accurate model calibration. The result is a calibrated circuit based on actual data from every smart meter.

  The AMI data help with model troubleshooting if a large customer load, primary metering point or generator, has not been modeled correctly. The AMI voltage readings also provide validity of the CYME load flow results and help identify overloaded transformers from the load flow results.

- AMI data can be pulled for every service point identifier where a smart meter has been installed. This provides insight on voltage and transformer loading to assist with power quality complaints.
- We have plotted all of voltages outside of the ANSI Range A for four consecutive intervals for the entire company. This allows us to proactively address steady state power quality issues.

AMI data can be obtained for all DER sites with smart meters. This has been used to provide insight into individual or conglomerated solar output curves, data integrity issues, and variance in performance on the basis of kW size. It has also allowed us to define hours of the year where solar production actually occurs. This knowledge allows for further penetration of DERs in highly saturated areas by allowing generation to interconnect if it follows a "non-solar hour" generation schedule. We had a wind and a solar project wanting to interconnect in highly saturated areas with the requirement that they cannot export power onto the grid during specified solar hours throughout the year.

Figure 6-7 shows the results of an effort to use AMI data to show how solar output compares for different size categories of solar. This diagram shows categories of solar interconnections for 150 kW, 500 kW, less than 15 kW, and greater than 500 kW interconnections.

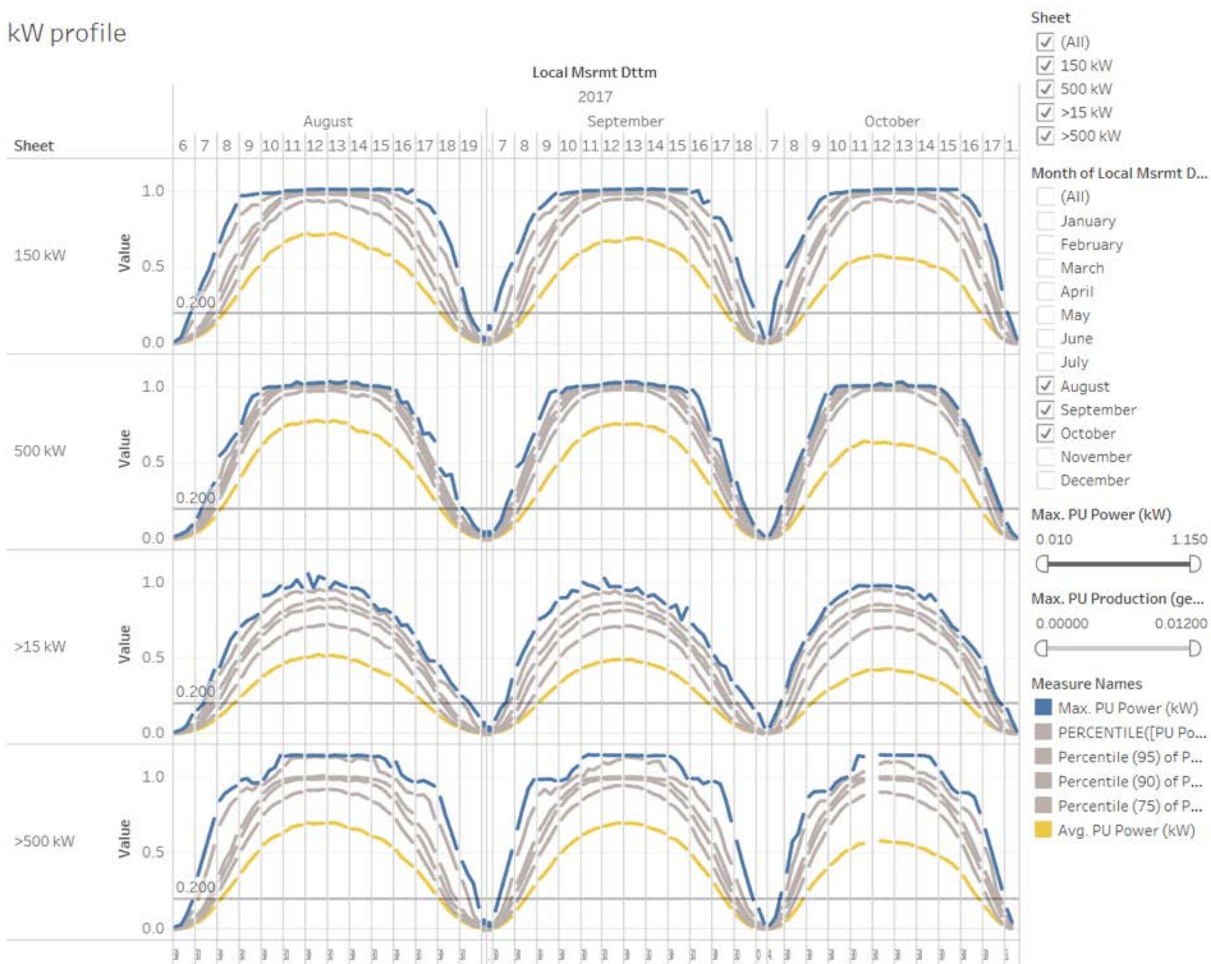

Figure 6-7. Comparison of Solar Output to Different Size Categories

We are developing additional tools, including:

- Using AMI data to identify momentary outages to assist with power quality complaints associated with blinking lights or temporary outages.
- Validating system phasing by using AMI voltage data for all the meters on a circuit. Identifying incorrect phasing and correction in GIS will improve data quality which help system planning and storm response.

- Developing the "ABC by Feeder" project, which uses service meter AMI data, rolling it up to the feeder and substation level. This project outputs the following aggregate feeder and substation data:

A. Gross generation.

B. Grid consumption.

C. Excess generation from customer meter (that is, net metering). We also consider generation directly interconnected to the feeder.

D. Real load (system load without generation).

E. Feeder total (kW) (approximately equal to the measured values at the feeder breaker).

Figure 6-8 shows a graphic representation of these parameters.

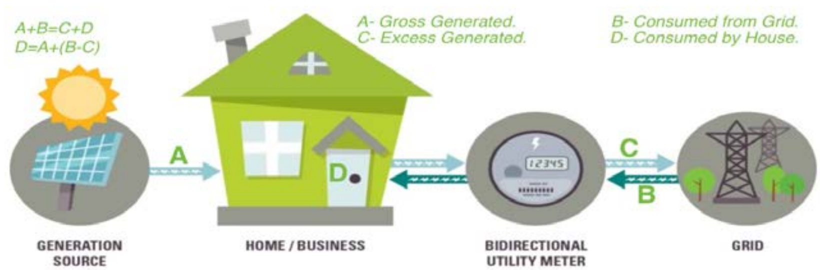

Figure 6-8. ABC by Feeder Parameters

This data provides us with clarity regarding how much load is actually on a circuit as large amounts of DERs can mask circuit load. This masking effect results in the feeder meter showing low demand or possibly reverse flow when, in fact, feeder load is present. These enhanced data allow us to understand the risks associated with the sudden loss of generation and plan the system accordingly. Identifying real load also helps us identify a circuit's minimum load more accurately, which adds efficiency and improves the analytics for interconnection studies. Also, by aggregating the load data from the end use meters, this data is immune from the effects of feeder backup. A few more examples of how we can leverage the data to review a snapshot of the overall system can be seen in Figure 6-9.

This is a direct snapshot from our data toolset and shows three color-coded views of the system. The first map is showing the conductor sizing across the system; the darker the color, the larger the conductor sizing, which means the greater loading it can handle before reaching its limit. The middle map provides a color-coded view of each circuit segment's distance from the substation. Generally speaking, the closer you are to a substation, the less likely for certain power quality issues when interconnecting load or distributed generation. And the last map is showing the likelihood of voltage flicker which is a function of both the wire sizing as well as the distance from the substation. In this map, the darker the coloring, the lower the probability of flicker when interconnecting generation. These types of screening tools provide us, and ultimately all stakeholders with a way to focus their siting where it is the least likely to create new issues, or require costly interconnection.

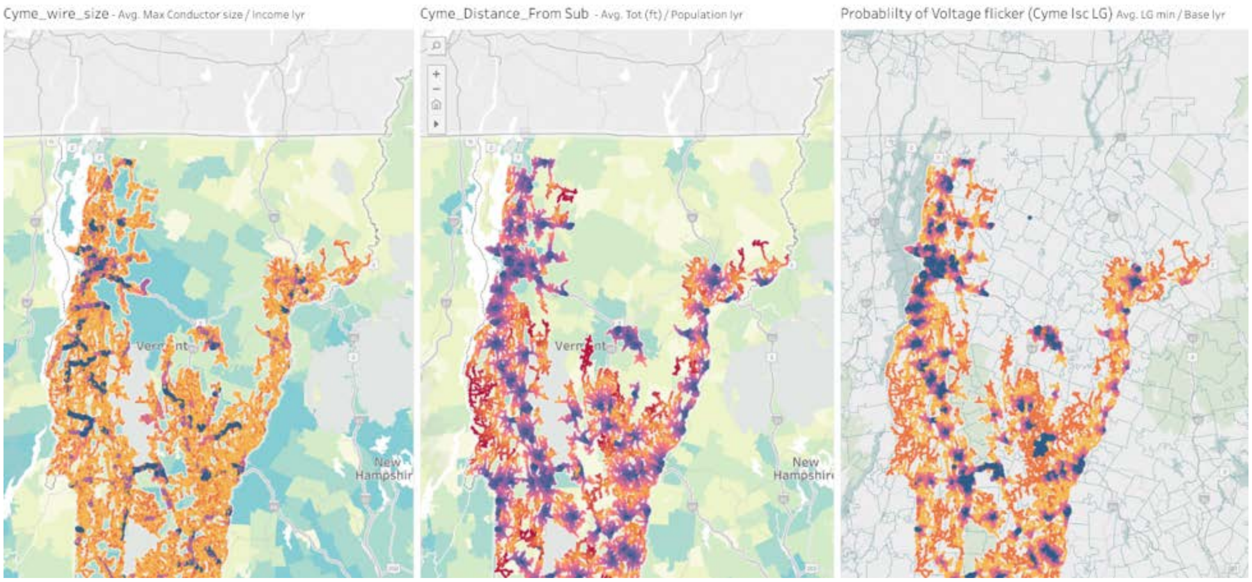

Figure 6-9. Transmission and Distribution System Mapping

With better data integrity and data acquisition tools, circuit depictions will be more accurate. Possible future application would be to use the CYME load flow to proactively evaluate the impacts of DG penetration and indicate the most appropriate areas for DER interconnection.

TRANSMISSION AND DISTRIBUTION STUDIES

Through the year, we conduct studies to determine the feasibility, necessity, costs, and benefits of certain transmission and distribution projects. Here is a summary of recent studies and their outcomes.

Barre Area Study

The Study. Our Barre area study had a number of performance, reliability, and safety goals. One performance goal was to rebuild the area's substations, upgrading all existing 2.4-kV, 4.16-kV, and 12.47-kV circuit voltages to 12.47 kV, enabling several benefits: loading flexibility among the circuits, lowering line losses, enhancing feeder voltage profiles, permitting feeder backup throughout the area, enabling more load growth, allowing increased penetration of DERs, and lowering maintenance and equipment stocking costs. Rebuilding each substation to enable feeder backup throughout the area ensures that any one substation can be out of service while allowing all of that substation's load to be served by the other substations, thus substantially increasing reliability.

Outcomes. As a result, we rebuilt the Barre North End substation, are currently rebuilding the Barre South End substation, and have plans to rebuild the Websterville substation. When completed, all three substations will include a new 15/28-MVA transformer and three 12.47-kV feeders. In addition, the Barre North End substation now permits full feeder backup to the Barre South End substation and partial feeder backup to the Berlin substation; the Barre South End substation will permit full feeder backup to the Barre North End substation and partial feeder backup to the Graniteville and Websterville substations; and the Websterville substation will permit full feeder backup to the Graniteville substation and partial feeder backup to the Barre South End substation.

For more details on the construction of all three substations, see Appendix D: Transmission and Distribution Projects.

Rutland Area Study

The Configuration. The greater Rutland area includes the 46-kV subtransmission system with associated distribution systems. VELCO's North Rutland, Cold River, and Blissville substations' three 115-kV-to-46-kV transformers are the area's primary supply points. In addition, the recently acquired VMPD 46-kV subtransmission system, distribution system and loads, primarily supplied by the VELCO Florence 115-kV-to-46-kV transformer, is effectively islanded from the Rutland area 46-kV system.

The Study. Three years ago, we completed our Rutland Area Study (required by Docket Nos. 7873 and 7874 Attachment II Screening Framework and Guidelines), which identified solutions to potential transformer overloads accompanied by line overloads and system under-voltages.

Outcomes. The study presented several solutions that are being addressed. As a result, we:

- Reconductored the 46-kV line from West Rutland to Florence in August 2018.
- Are permanently closing the 46-kV West Rutland B7 tie to the former VMPD system. This is under construction and scheduled to be completed in December 2018.

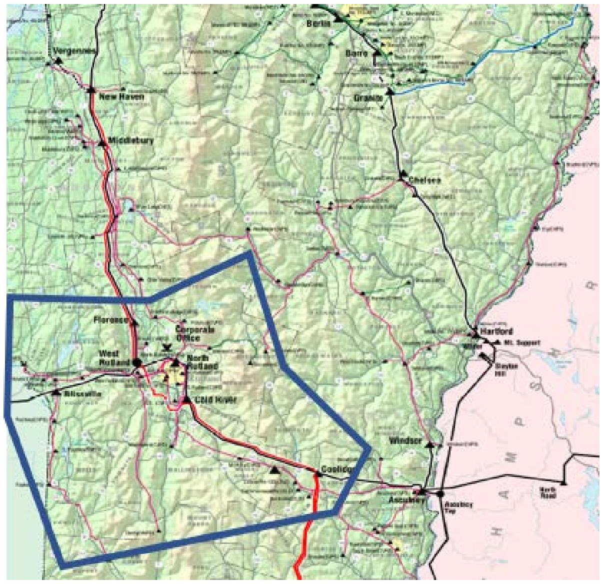

Figure 6-10. Rutland Area Study Map

- Are permanently closing the presently normally open second 46-kV line between Rutland and West Rutland and reconductoring this line to enhance reliability. This closing requires two new 46-kV breakers at West Rutland, transfer-trip protection to the Glen and Patch generators, and approximately one mile of reconductoring on the 46-kV Rutland to West Rutland tap line. These elements are under construction and scheduled for to be completed in spring 2019.

The study also recommended the following be implemented on a recurring basis:

- Monitor area load growth to determine when the available reliability margin is within three to four years of being exhausted.
- Monitor the shapes of the daily peak load curve and annual load duration curve.
- Evaluate the impact of new company initiatives on Rutland area reliability margins.
- When the reliability margin is within three to four years of being exhausted, begin implementing the necessary resource options to reestablish adequate reliability margins.

Results from the Rutland Study listed seven resource options to close this three-to-four-year reliability gap. This hierarchical list of options is based on a cost-benefit analysis; in other words, the option with the lowest cost and most benefit is first. Also, these options are the ones recommended to be implemented today. As such, these options might change as technology advances and new opportunities arise. Nonetheless, here are the seven recommended resource options.

1. **Dispatch the new Stafford Hill energy storage facility following a contingency.** The facility already exists and its operating cost to regulate frequency is minimal. Because of its location, its effectiveness on a per MW basis would be high.

2. **Use smart meters to control hot water heating.** The cost of this option is minimal, since all capital costs have already been expended and operating costs are minimal. Targeted implementation of this water control program would have a profound effect on reducing load, especially in the North Rutland area.

3. **Island our operations headquarters following a contingency.** The cost of this option is minimal as capital costs have been expended, and its implementation would be the

cost of fuel minus the wholesale cost of the avoided energy purchase. Since this option entails a backup diesel classified as "emergency use", its implementation might include penalties. Its effectiveness on a per MW basis, however, would be high.

4. **Implement broad-based energy efficiency measures.** The cost of this option rises in conjunction with its use. As such, the cost-to-benefit ratio of its implementation would be higher than the first three options. The first three options, however, are shorter-term solutions (essentially constituting kilowatts of efficacy) whereas this option would have a greater effect (in MWs). This option, then, would keep the reliability gap from re-emerging for a longer period of time than would the combined impact of the first three options.

5. **Implement future initiatives (including E-Co).** This option's cost cannot be determined, while its impact would be similar to that of the first four options.

6. **Dispatch other new energy storage facilities following a contingency.** The cost for this option is substantial, while its impact would be similar to that of the first four options.

7. **Employ other renewable sources (such as biomass and bio-gasification).** This option's cost would be substantial (higher than option 6), while its impact would be similar to that of the first four options.

Windsor Area Study

The Configuration. Our Windsor substation, which includes a 14-MVA, 46-kV-to-12.47-kV transformer supplying three 12.47-kV distribution circuits, is the only source to the Windsor area.

The Problem. In July 2013, the substation reached its top nameplate rating, prompting the need to address thermal issues, especially since there are no opportunities for feeder backup in the area.

The Study. Our study, completed in 2015, examined the feasibility, costs, and benefits of constructing a new North Windsor substation. This potential substation could consist of a 14 MVA, 46-kV-to-12.47-kV transformer with oil containment that supplies two 12.47-kV distribution circuits, distribution circuit breakers, feeder voltage regulators, steel structures, foundations, and a 46-kV high-side circuit breaker. It could be supplied via a 46-kV subtransmission tap line from the existing 46-kV VELCO Windsor-to-GMP Taftsville line. This substation could supply part of the load presently supplied by the Windsor substation, increase available capacity to the area to serve new load and host distributed generation, and provide feeder backup for Windsor area loads.

Outcomes. Since 2013, peak loads at the Windsor substation have dropped to 10 MVA and the project has become a lower priority. As such, we have postponed any possible upgrades for at least five years.

Legacy VMPD Subtransmission Lines Study

The Configuration. A 14-mile, 46-kV subtransmission line from the Huntington Falls hydro to our Salisbury switching station (formerly owned and operated by the Vermont Marble Power Division (VMPD) of Omya) connects both this hydro and the Beldens hydro (about 1.5 miles apart on Otter Creek in Addison County) to our distribution system.

The Problem. The proximity of this line to other 46 kV subtransmission lines uncovers the possibility of multiple system improvements: reduced reliability exposure, reduced maintenance expenses, enhanced aesthetics, improved system connectivity, and lower system losses.

The Study. We first studied these configurations in 2004, and then again in 2016 to consider the feasibility, costs, and benefits of certain projects to improve system performance. One possibility connects the Huntington and Beldens hydro units directly to the VELCO Middlebury substation by constructing a 0.7-mile, 46-kV subtransmission line. The line would begin where the Huntington to Salisbury line crosses our Middlebury Lower to VELCO Middlebury 46-kV line, and end at VELCO Middlebury substation. This new line would allow us to decommission a nine-mile section of the 46-kV Huntington to Salisbury line.

Another possibility would be to build a four-mile, 46-kV subtransmission line to connect Huntington directly to the VELCO New Haven substation. This would transform the radial line connecting the Huntington and Beldens hydro units to a networked line and allow us to return the 46-kV, 5.4-MVAR capacitor at the Hewitt Road substation to inventory.

Outcomes. Continuing the study and implementing a solution, while valuable, has been postponed to at least 2022 while we pursue other higher-priority projects.

Berlin to Mountain View Subtransmission Line Analysis

The Configuration. A three-mile, 34.5-kV subtransmission line, the 3325 line, extends from our Berlin #5 substation to our Montpelier substation. At the Dog River switch (a half-mile east of the Berlin #5 substation), a 0.7-mile radial tap line extends to the Mountain View substation. This substation not only supplies 12.47 kV loads to the Montpelier area, but also provides feeder backup to Montpelier substation distribution circuits and Berlin #40 substation distribution circuits.

The Problem. Preliminary analysis indicates that the one-half-mile line section between the Berlin #5 substation and the Dog River switch may thermally overload following the loss of the 115-kV-to-34.5-kV source at the VELCO Barre substation. In addition, the 0.7-mile radial tap line may thermally overload under certain feeder backup configurations.

The Study. Our study, completed in 2015, examined the thermal and voltage parameters of the 3325 line and the 0.7-mile radial tap line to the Mountain View substation. The study considered normal peak loads, post-contingency scenarios, the impact of increased distributed generation, and various feeder backup configurations. Three potential solutions emerged: reconductoring both the 3325 line and the 0.7-mile radial tap line; retiring the Dog River switch and upgrading the radial tap with a two-line, in-and-out configuration; and upgrading the Mountain View substation with a high-side circuit breaker and 34.5-kV switching capability.

Outcomes. Continuing the study and implementing a solution, while valuable, has been postponed to at least 2022 while we pursue other higher-priority projects.

Sheffield Highgate Export Interface (SHEI) Initiative

The Configuration. SHEI is a region in northern Vermont, bounded by the 115-kV loop spanning from the Sheffield to Lyndonville line (K39 line) to the Highgate to St. Albans line (K42 line). The 34.5 kV Johnson to Lowell line (B20 line) is a critical subtransmission asset within the interface because it creates a parallel path back to the 115kV system creating a closed loop system.

The Problem. Power generated in northern Vermont exceeds local demand. Excess power is then transmitted to points south in the state. Under certain contingencies, this north to south transfer puts a tremendous strain on the existing aging electrical infrastructure, which could lead to voltage collapse or overloading of the transmission system. To handle these contingencies, ISO-New England created the SHEI to control power flow in the region by calculating a set of power export limits for different system configurations. When the system is in a specific configuration, ISO-New England institutes a limit of power that can be transferred across the interface. In many cases this results in the issuance of do-not-exceed (DNE) orders to generators in the region to mitigate contingencies before they happen. These DNE orders, however, lead to lost revenue for these generators—an untenable situation.

A Partial Solution. We are currently implementing an automatic voltage regulator (AVR) upgrade at Sheldon Springs Hydro which we expect to have in service by late 2018. This upgrade will help enhance the 46-kV voltage in the Highgate area, thus having a positive impact on the transmission SHEI voltage-based limit.

The Study. GMP and other Vermont utilities have formed a working group to address the current problem in this region which adversely affects the generator stakeholders in the SHEI. Collectively, with the assistance of VELCO, we are currently evaluating several options to increase the SHEI limits, many of which were identified and studied in VELCO's Northern Vermont Export Study. The group is evaluating and researching a wide array of options, including traditional transmission projects, battery storage, and demand-side options. The group is focused on cost effectively mitigating current SHEI congestion and providing relief for all affected customers as quickly as possible. We expect to have recommendations to resolve the current SHEI constraints in the first quarter of 2019. This work also has the potential to help inform the evaluation of future generation in the area.

New Planning Studies

As noted earlier, we are constantly conducting studies to evaluate and improve our transmission and distribution system. Here are four we are conducting or planning to conduct.

Danby Area. A recent study showed that we need to construct a 28-MVA, 46-kV-to-12.47-kV substation in Danby, which is planned for 2022. In addition, we also plan to construct a new 46-kV line networked between Dorset to Danby to West Rutland, eliminating two weak radial subtransmission lines. We will update our study to support a future filing.

Killington Area. We plan to conduct a study to determine the available capacity in the Killington area should additional load start being added in that area. The study will determine the best method for serving this additional load.

Ryegate Area. We currently have plans to upgrade the East Ryegate transmission substation to address asset management concerns. Before upgrading, however, we plan evaluate the potential for permanently closing the 46-kV subtransmission line at Bradford and creating a network from the VELCO Hartford substation instead.

In 2015, we improved the subtransmission system by installing a 46-kV breaker at the Bradford Switch station, providing protection from the Bradford Switch station to the Ryegate bus. This protection allows for the Newbury and Wells River substations to be supplied in the event the Ryegate B-37 breaker trips because of a fault on the 3324 line or loss of the TransCanada source. It also allows the Ryegate Wood Plant and Dodge Falls Hydro to come back on line, but at a curtailed amount.

Vergennes, Ferrisburgh, Weybridge and Hewitt Road Area. An influx of DER projects has saturated the 12.47-kV distribution systems in this area. These substations have virtually no feeder backup capability. We plan to study this area for how best to provide feeder backup at least-cost with the potential ancillary benefit of allowing for additional DER interconnections.

7. Financial Assessments

DEVELOPING OUR COST OF SERVICE

Utility rates are set based upon the cost of service, meaning the amount of revenue needed to cover a utility's costs to provide service and an opportunity to earn a reasonable return. The revenue requirement for a particular rate period is measured against sales and other revenue expected for that same period; if expected sales revenue is lower than the revenue requirement, rates will increase to cover the difference. The percentage increase is based upon the difference between current rates and the rates that are shown to be required in the rate period.

For the 2018 IRP financial analysis, we use data from our most recent rate case consistent with the analysis we perform for our ratings agency. We developed the rate period cost of service by taking the actual level of these costs incurred during a test period—January 1, 2017 to September 30, 2017. We then made known and measurable changes to these costs so that the net costs reflect, as closely as possible, the projected level of net costs that will occur in the rate period— January 1, 2019 through September 30, 2019.[65]

It is important to note a few points about our financial summary.

First, given the data used for this financial analysis, there is necessarily some disconnect between the specific inputs used here and the resource modeling and scenario analysis performed elsewhere in the 2018 IRP. That is because we use the most up-to-date individual resource figures we have available, and test scenarios accordingly, while we take a more conservative, accounting approach to our multi-year financial analysis.

[65] The test period and rate period reflect the 2019 traditional cost of service rate case we filed in April 2018. It included a nine-month rate period to align our base rate changes with our fiscal year.

Nevertheless, the differences are minimal over the planning period. As described in Chapter 8: Portfolio Evaluation and elsewhere, the first five years of the resource planning model are largely consistent with our current five-year financial forecast (see "Financial Forecast" on page 7-15). While the base forecast in the IRP does not match precisely to our internal financial forecast, for many of the models' key components (including the volumes and prices for major supply sources, which drive most of our power costs), the inputs are directionally the same, and the bottom-line cost projections are similar.

Second, the financial forecasts and base rate assumptions do not reflect extraordinary, compounding costs from major storm restoration during this time of climate change. While we already have approved major storm costs awaiting customer collection under our regulation plan and projections for these costs in coming years (shown as "Deferred Assets–Storm" in Table 7-7 on page 7-18), major storm costs exceeding expectations continue to accrue this year for reporting and collection in coming years. This is a significant challenge for us and our customers, and is one that we strongly believe requires careful attention in the planning period. Major storm costs add millions of dollars to what customers pay, and therefore create real pressure even though not part of routine storm clean up and related maintenance reflected in base rates. In our pending regulation plan, we have proposed a fixed annual collection to help cover costs over time. At the time the regulation plan was filed, the $8 million annual collection we proposed appeared reasonable to test whether this new methodology would help alleviate stacked cost pressure. Given the major storm costs we have experienced in the remainder of 2018, that amount will likely not be adequate. We expect to address this issue with the Department and Commission as the regulation plan proceeding continues.

The fundamental part of establishing rates is determining the appropriate cost of providing service during the rate period. This is determined by evaluating the costs incurred by GMP in the test period and then making appropriate adjustments for changes that are anticipated to occur within the rate period. Utilities include costs in the rate period's revenue requirement that are just and reasonable, prudently incurred, and known and measurable.

The cost of service has two overarching components: costs directly related to providing service to customers (sometimes referred to as "operating costs") and costs related to our capital investments for customers that are made or will be made within the rate period to provide service, along with the associated depreciation expenses, taxes, and capital cost recovery—this is commonly referred to as "rate base" when taken together.

Our cost of service for any particular rate period is based on a number of factors. Among them are:

- Load and revenue forecast
- Growth-related plant additions
- Return on equity
- Gains and losses from the sale of utility property

CAPITAL INVESTMENTS

Navigating the significant transition in the energy sector requires continued thoughtful and strategic capital investments to ensure the delivery of safe and reliable service, while pursuing the types of energy projects and programs necessary to transform our energy delivery model and keep the overall cost of service manageable in years to come, despite the rapid and significant changes in the energy industry.

Over the course of the IRP planning period, we will invest in several key areas to meet our customer commitments:

- Maintain and develop as appropriate low-cost, renewable energy generation resources within Vermont.
- Harden and make more resilient the subtransmission and distribution system that is the backbone of the energy transformation.
- Equip our workforce with the tools and technologies to safely and effectively perform their work every day, while simultaneously keeping our customers safe.
- Continue to automate and digitize our operations to reduce costs and improve the quality of our services.
- Identify and pilot emerging energy technologies that can be integrated within our operations and customer programs to deliver better results and lower costs year-over-year.

Capital investments must benefit customers and our workforce, thus enabling us to deliver service to our customers in a safe and reliable way. We evaluate all of our potential capital investments against these benefits.

Capital investments are broken out into capital additions and capital retirements. Capital additions represent the capital projects that will be completed and added to our overall rate base in the rate period; retirements represent capital assets that will be removed from our overall rate base. These two amounts are netted out to determine the overall "net capital additions," or the overall change in our rate base for any particular period.

CAPITAL INVESTMENTS ACROSS SIX CORE OPERATING AREAS

Providing strong performance for customers throughout our entire energy delivery system requires coordinated capital investment across our six core teams, which include:

- Transmission and Distribution.
- Information Technology (including communications, computer software, and computer hardware).
- Facilities (also called Property and Structures).
- Transportation.
- New Initiatives (also called Energy Transformation).
- Generation (also called Production).

The investment needed from each of these teams can vary from year to year. Each year, we identify and properly manage these investments to maximize the potential benefits while controlling the overall costs for our customers.

Guiding Principles for Selecting Capital Projects

Each capital team has an individual set of guiding principles that are used as a framework to identify, assess, and evaluate capital project candidates for recommendation into a given capital plan.

Each team constantly assesses the operational performance of their selected capital investments and opportunities for improvement. Out of this continuous assessment, new capital project candidates are identified and developed within the team, then submitted to be assessed as a group with the other teams.

Transmission and Distribution Projects

Over the recent planning period, our T&D team successfully completed several important reliability projects. For example, in 2017, we rebuilt the Line 7 circuit in Lincoln. Originally set in the 1950s and 1960s, this line had a poor history of reliability because of the age of the infrastructure, the physical terrain the circuit was constructed on, and the evolving weather patterns in that part of the service territory. We replaced

109 poles, a 3.25-mile length of conductor, brought about half of that length roadside from its original off-road, cross-country location, and replaced the original conductor with hardened 336-tree wire to provide additional resiliency. Customers served by Line 7 have seen dramatic improvement to their power reliability as a result of this project.

Many of the proposed capital additions in the next planning period allow for more capability to interconnect additional distributed energy resources without compromising system power quality or reliability. Good examples of this are the strengthening of the Barre North End and the Barre South End substations. This increased system strength will reduce the potential for voltage flicker from connected DERs, and will allow for increased flexibility and opportunities for integrating emerging technologies.

We are also planning to explore the potential to increase distributed generation (DG) hosting capacity through battery storage systems to possibly implement at substations nearing their DG hosting capacity limits. An example of this is the Panton Battery project. We proposed a limited testing of this capability to gain experience and learn about the requirements and potential tradeoffs related to increasing DG hosting capacity through battery storage systems. The Panton Battery project also enables us to explore other potential grid-related benefits of DERs (such as reactive power support, conservation voltage reduction, and distribution islanding.) The battery storage also provides potential benefits of reducing the regional network service charge and of participating as a merchant plant in the forward capacity market, energy arbitrage, and frequency regulation market.

Distribution Substations. The primary purpose of distribution substation capital projects is to improve reliability and safety. In addition, many of our substation transformers, breakers, reclosers, and protection systems are 30 years old or older, and have reached the end of their service life or become obsolete. The probability of failure starts increasing after 30 years of service and continues to increase as the age profile for equipment increases. Although proper maintenance and diagnostic testing can extend the life of substation transformers and other equipment, eventually it must be replaced because of failure risk, obsolescence, or the unavailability of spare parts.

Some projects are upgrades to vintage equipment, such as replacing specific types of circuit breakers because of bearings sticking, close latches malfunctioning, dash pots malfunctioning, spare parts becoming obsolete, and technology that is no longer supported (such as remote terminal units). Other projects replace transformers and equipment to provide feeder backup. These transformers must be capable of serving their normal load while being able to pick up the additional load of another feeder or substation at the same time. Increased transformer capacity allows for increased operating flexibility for feeder backup during planned and emergency outages, which improves reliability to serve present load.

Transmission Lines. Transmission line projects include reconductoring, structure replacements, and grid automation to address reliability, safety, and the potential overloading of lines. A good example is the reconductoring of transmission Line 43 between the Evergreen Tap and West Rutland, which will enhance the connectivity and consequent reliability of the 46-kV subtransmission system in Central Vermont.

Transmission Substations. Transmission substation projects are focused on reliability and safety, which involves replacing equipment that has reached the end of its service life or become obsolete and implementing power quality improvements. As with the distribution substations, many of our transmission substation transformers, breakers, reclosers, and protection systems are 30 years old or older.

Distribution Equipment Purchases. These capital purchases are for acquiring transformers, meters, and regulators, and capacitors. They permit the installation of new or replacement of deteriorated, obsolete, or failed equipment on the system.

Distribution Lines. Distribution line projects can be broken out into four primary categories.

1. *Reconstruction and rebuild* projects that improve the safety, efficiency, and reliability of the distribution system. These projects include: voltage conversions, fuse coordination, relocation of lines to the road to improve reliability, and replacement of old and deteriorated plant at the end of its service life. This category includes investments in distribution line equipment needed to facilitate distribution automation projects, as well as small capital improvements.
2. *Customer-requested* projects, such as line extensions, relocations, and upgrades. These requests include distributed generation projects that require capital upgrades of our infrastructure to enable the customer to interconnect.
3. *Road relocation* projects that involve relocating T&D facilities where the present location interferes with state or municipality road or bridge construction.
4. *Third-party reconstruction* projects in which a telephone or cable company requests to upgrade and relocate joint facilities to accommodate their service requirements.

Information Technology Projects

Our Information Technology (IT) team manages a host of responsibilities, including communications, computer software, and computer hardware. IT projects are essential to supporting our transformation from a traditional electric utility to an energy services provider. IT projects are also critical for maintaining the safety and security of our grid network and ensuring the efficiency of our workforce.

In the last planning period, our IT group completed a range of key projects that improved the safety and security of our networks, the efficiency of our employees, and the overall customer service experience for our customers. For example, IT refreshed our Outage Center as part of the 2017 website redesign project. The overhaul consolidated all outage and incident reporting into one location and provided several improvements to the customers' experience. This project also improved our internal operations performance, as well as delivered a better experience for our customers when they interact with our outage center. The outage center is a key information hub for customers and other stakeholders during severe weather events.

IT continues to be focused on a number of safety enhancements to our facilities and networks. For example, Project 159554 in 2019 will implement a centralized, server-based digital key and lock management system that will significantly improve the auditability and security of plant and substation assets. This project will incrementally replace existing substation and plant lock and key systems with a digital padlock infrastructure. Project 158850 will license Oracle's Advanced Security software, an add-on option to our existing Oracle database, that will address privacy and regulatory requirements. Advanced Security provides data encryption and strong authentication services to the Oracle database, safeguarding sensitive data against unauthorized access from the network and the operating system. It also protects against theft, loss, and improper decommissioning of storage media and database backups to ensure the highest level of security available in the industry for Oracle databases.

IT priorities also include improving operational efficiency through new and upgraded software. For instance, Project 159555 will improve our meter-to-billing process to ensure accurate meter reading and billing by building a Meter-to-Revenue management tool (MET2REV) that will continuously look for patterns that indicate defective or improperly configured meters. This project will not only increase screening and monitoring to protect against lost or inaccurate data, but also reduce meter operations costs while improving billing accuracy for customers.

Facilities Projects

Facilities projects essentially manage company property and structures. We recently completed several Facilities projects to improve the safety of our staff. For example, the Facilities team replaced a number of gas heater exchangers that were over 20 years old and had begun to fail. A failing heat exchanger creates an unsafe level of carbon monoxide, putting our employees at risk. Facilities replaced the gas heater exchangers with infrared tube heaters, a much safer alternative.

Facilities also constructed an outdoor storage building at our St. Johnsbury district office to store and secure a variety of vehicles, trailers, construction equipment, and other material. This equipment is essential for completing routine work, and for restoring service mostly during inclement weather. Our line crews work not only during busy daytime operations, but also at all hours of the night during emergency situations and service restoration events, working in conditions from pleasant weather to raging storms. Keeping this equipment under cover and out of the inclement Vermont weather allows our crews to work safely, quickly and efficiently during both daily operations and emergency storm restoration. Storing the equipment under cover also ensures that it will be ready when necessary, enabling us to get the most out of this equipment and limiting downtime and maintenance.

Over the past several years, we have redesigned many of the office locations throughout our service territory. One of the keys to our culture of clear communication, informal collaboration and configurable workspaces is our open office workspace. Thus, after merging with CVPS, we redesigned all former CVPS district offices to comply with this foundational work environment of clean, bright workspaces with minimal walls and no enclosed or private offices.

Because of these recently completed renovations, we do not foresee any major new facility investments during the period of this IRP. Instead, we expect only the normal level of maintenance and upkeep projects related to HVAC systems, backup power systems, security systems and other routine facility maintenance projects.

Transportation Projects

In the recent planning period, the Transportation team replaced a variety of vehicles that had reached the end of their productive lives, including eight buckets trucks, two digger trucks, and 25 light vehicles. These replacements better ensure safe and reliable transportation and equipment to complete repairs for our customers in a timely and efficient manner.

Our Transportation team manages and maintains our fleet of vehicles and related transportation equipment. Transportation's priorities in this planning period are to continue to ensure vehicle reliability and safety. We are committed to maintaining a fleet so that when a storm hits, our line crews have safe, reliable vehicles to respond and restore service as quickly as possible. For example, Transportation is replacing four bucket trucks in 2019 that are in poor condition. Bucket trucks are the primary vehicles our line crews use to respond to trouble calls and outages during storms.

New Initiatives Projects

Our New Initiatives team adopts new energy technologies and resources as they emerge in the market. Once adopted, the team evaluates them, and incorporates them into programs based on their ability to deliver cost-effective, cleaner, more reliable energy solutions to our customers.

In our transition to the new energy delivery model, we embrace technological innovation and energy transformation tools that enable an increasingly distributed energy network and a system of developing new value streams for customers. Our goal is to lower customer costs as much as possible while creating a dramatically more localized, reliable, and resilient energy delivery system.

Several New Initiatives projects have helped us advance this vision. These projects focus on new, low-carbon, distributed energy technologies that support Vermont's energy policy, reduce power costs, introduce new revenue streams, and provide customers with options to transition off of traditional fossil-fuel systems for heating or transportation.

New Initiatives projects are selected to comply with four goals:

1. Deliver increased resiliency in new ways to all customers, especially by managing and balancing the power grid.
2. Create new value revenue streams, especially from new non-traditional sources that flow back to all customers and reduce rates.
3. Deliver services and a platform that enable customers to reduce their carbon footprints while increasing their comfort and saving money on total energy consumption.
4. Strategically partner with customers and third parties to deliver more innovative program offerings to achieve our goals, as well as Vermont's energy goals.

Ongoing New Initiatives projects include these programs:

- Tesla Powerwall 2.0 Battery Pilot
- Remote Water Heater Access Innovative eWater Pilot
- Cold Climate Ductless Heat Pump Pilot
- Electric Vehicle e-Charger Pilot
- Bring Your Own Device

(All of these programs are discussed in detail in Chapter 2: Innovative Customer Programs.)

Each program is based upon a customer device. Our Virtual Peaker management software enables customers (through a mobile app) and our staff shared access to manage these customer devices individually or in aggregate. We use Virtual Peaker to aggregate devices from participating customers and use them during peak events and other grid conditions to lower grid costs and carbon impacts. Another benefit of our Virtual Peaker platform is the economic development it supported in Vermont through our Inspire Space "co-laboratory" at our Colchester office. Virtual Peaker is an energy sector start-up attracted to Vermont through our launch of that co-working space and program. Virtual Peaker has secured its first round of growth funding, including participation by a Vermont early stage fund.

Our New Initiatives team will use these same goals to continually develop innovative programs that help us save money for customers and to continue our transformation into an energy services company that responds to the new, dynamic energy landscape.

Generation Projects

The primary goal of our Generation team is to manage and operate our fleet of generation assets in a safe and responsible manner that provides our customers the greatest benefit possible. We are focused on providing power that is low-cost, low-carbon, highly reliable, and meets our important regulatory and environmental obligations. To achieve these customer-focused objectives, we generate energy from a range of different sources.

The Generation team is responsible for maintaining and operating more than 60 solely owned facilities, including 44 hydro facilities, two wind facilities, twelve solar projects, and six thermal peaking facilities. We also have interests in four jointly owned facilities, including five joint venture solar projects.

We are working to develop innovative and transformational energy projects (such as grid-scale battery storage facilities) that will provide important new benefits to customers while reducing costs for all. We currently have one grid-scale battery storage project installed at an existing solar facility (Stafford Hill), one grid-scale battery project installed and pending commissioning at another solar facility (Panton), and three joint venture solar and battery storage projects under development.

CAPITAL INVESTMENTS FOR THE PLANNING PERIOD

Our proposed capital additions are broken out by functional area (Transmission and Distribution, Information Technology, Facilities, Transportation, New Initiatives, and Generation,), the interim period (the time between the test year and the rate year), and the rate year. All amounts in Table 7-1 through Table 7-4 are as of April 2018.

Table 7-1 summarizes the capital investments for all six functional areas.

Functional Area	Interim Period ($000) 10/1/2017–12/31/2018)	Rate Period ($000) 1/1/2019–9/30/2019	Totals ($000)
Transmission & Distribution	$63,672	$33,612	$97,284
Generation	$30,065	$6,025	$36,090
Information Technology	$9,008	$4,549	$13,557
Facilities	$1,287	$0	$1,287
Transportation	$4,524	$2,214	$6,738
New Initiatives	$11,364	$6,087	$17,451
Total Capital Additions	$119,920	$52,487	$172,407
Retirements	$24,186	$15,602	$39,788
Net Capital Additions	**$95,734**	**$36,885**	**$132,619**

Table 7-1. Capital Investments by Functional Area

Table 7-2 breaks out the capital investments for the Transmission and Distribution functional area into five categories: Distribution Substations, Transmission Lines, Transmission Substations, Distribution Equipment Purchases, and Distribution Lines.

Transmission and Distribution Category	Interim Period ($000) 10/1/2017–12/31/2018)	Rate Period ($000) 1/1/2019–9/30/2019	Totals ($000)
Distribution Substations	$8,471	$5,753	$14,224
Transmission Lines	$8,009	$3,228	$11,327
Transmission Substations	$5,566	$348	$5,915
Distribution Equipment Purchases	$6,977	$4,115	$11,092
Distribution Lines	$34,558	$20,168	$54,726
T&D Total	**$63,672**	**$33,612**	**$97,284**

Table 7-2. Transmission and Distribution Capital Investments

Table 7-3 breaks out the capital investments for the Generation functional area into three categories: Owned Generation, Joint Ownership, and Other Generation.

Generation Category	Interim Period ($000) 10/1/2017–12/31/2018)	Rate Period ($000) 1/1/2019–9/30/2019	Totals ($000)
Owned Generation	$28,210	$4,146	$32,356
Joint Ownership	$1,855	$1,879	$3,734
Generation Total	**$30,065**	**$6,025**	**$36,090**

Table 7-3. Generation Capital Investments

Table 7-4 breaks out the capital investments for the New Initiatives functional area into the several main programs and pilots that we are currently offering.

Program	Interim Period ($000) 10/1/2017–12/31/2018)	Rate Period ($000) 1/1/2019–9/30/2019	Totals ($000)
Tesla Powerwall 2.0 Battery	$9,671	$5,558	$15,229
Residential Battery Storage	$12	$0	$12
Cold Climate Heat Pumps	$1,173	$189	$1,362
Heat Pump Water Heaters	$278	$256	$534
Level 2 EV Home Chargers	$0	$84	$84
BTM Controls	$75	$0	$75
ePark	$155	$0	$155
New Initiatives Total	**$11,364**	**$6,087**	**$17,451**

Table 7-4. New Initiatives Capital Investments

The total capital additions across all functional areas in the nine-month 2019 rate period used in this IRP is $52.5 million; total capital retirements in the rate period equal $15.6 million. This represents a net increase to our rate base of $36.9 million during this period.

Figure 7-1 summarizes our planned capital investments from 2018–2022 in our six functional areas. (The Other category combines the Facilities and Transportation functional areas.)

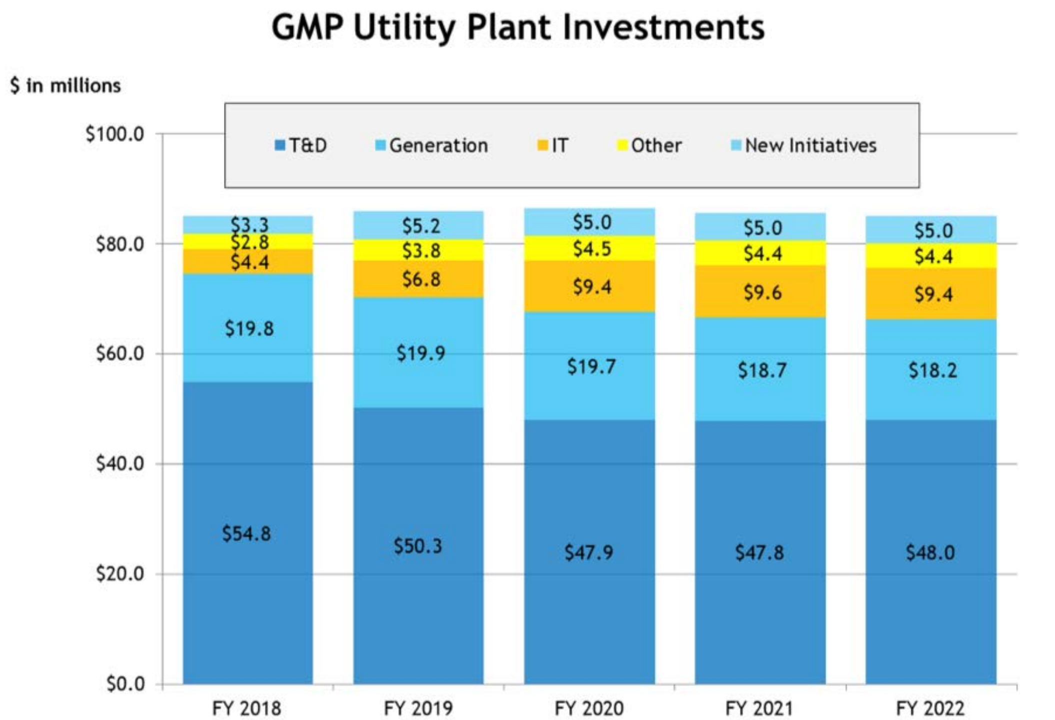

Figure 7-1. Capital Expenditures and Investments: 2018–2022

The amounts for transmission and distribution initially declines then remains steady, even though we anticipate a greater need in this area as the grid evolves.

The amounts for New Initiatives and IT initially grow, then remain flat. We expect to offer additional energy-related transformative projects for our customers and develop the communications infrastructure to better manage the grid and the growth of intermittent distributed renewable generation and distributed energy resources. These transformative programs will typically create new revenues from participating customers that offset program costs while delivering a net benefit to all customers. These projected capital investments, based on spending in recent previous years, represent our best estimate as to the amount of capital required to continue our progress in these important areas.

In prior years, our capital spending increased for several reasons, including:

- The implementation of Our Smart Grid program under Vermont's ARRA Smart Grid Incentive Grant.
- The expansion of our communications and mobile computing capabilities throughout our field organization.

- The construction and commissioning of Our Kingdom Community Wind facility.
- The integration of GMP and CVPS operational systems and processes to create a unified workforce and deliver substantial cost savings for our customers.

Each of these investments, as well as the normal capital investment in our operating infrastructure, was important to deliver services to our customers in a high-quality and contemporary manner. We have successfully implemented many necessary systematic improvements and investments in major operational areas, including capital investments associated with the successful merger with CVPS. While the merger required strategic capital investment to address outdated systems and infrastructure in certain areas, the merger also resulted in significant cost savings to customers, returning millions of dollars in operational synergy savings.

The overall flat trajectory of our total investment amount starting in 2018 represents a reduction from prior years, and reflects our desire to meet DPS's request to ramp down our capital investments after significant projects were undertaken in recent years. We believe this total amount also balances customer safety, system reliability, and our other core operating needs. We do anticipate, however, that we may need to increase our capital investments after this rate period to ensure continued system reliability and to meet the needs and expectations of our customers, especially as the grid continues to evolve.

We remain committed to disciplined spending on behalf of our customers. We aim for a measured level of investment—neither too high nor too low. Given the age and condition of the grid infrastructure in Vermont, the impacts from climate change beyond major storms, and our need to maintain a disciplined course of investment to avoid a backlog of deferred projects, it is likely that additional capital investment may be required to fulfill our responsibilities to our customers.

The pace of change in the energy sector continues to accelerate and the needs of our customers evolve in response. As such, we continue to closely monitor this evolution, keeping an eye on the proper level of capital investment to meet the needs of our distribution grid and those of our customers.

FINANCIAL FORECAST

The overriding principle we employ with our finances is rigor on behalf of our customers. We keep a careful eye on our current financial standing, and constantly assess the financial implications against the evolving nature of the energy landscape. Because of our rigor, we can present a current financial picture that is sound, and a forecast that shows we expect it to remain strong over the next five years.

Table 7-5 summarizes key financial areas over a five-year forecast.

Financial Area	Fiscal Year 2018 ($000)	Fiscal Years 2019–2022 ($000)
Capital Investments	$85,000	$343,000
Transco and Joint-Venture Solar & Storage Investments	$39,000 (Transco)	$50,000
Generating Funds from Operations	$124,000	$589,000
Generating Net Income	$74,000	$318,000
Total Base Rate Increases	5.37% (CY 2018)	2019: ≥5.00% before 6% ADIT credit 2020–2022: Base rate increases expected in range≥ average inflation

Table 7-5. Financial Five-Year Forecast Highlights: 2018–2022

Financial Liquidity

Financial liquidity measures our ability to convert liquid assets (such as cash on hand, as well as current assets and other short-term investments that can be quickly converted to cash) to pay for ongoing operations and other debts when they become due. As such, we hold a number of options to maintain financial liquidity.

Income generated from our daily energy-related activities fund our ongoing operations and maintenance. In September 2018, we renewed a long-term (three-year minimum) revolving credit line, raising our credit line from $110 million plus a $15 million accordion to $140 million with a $10 million accordion. In addition, we maintain liquidity from an available $9 million loan from insurance policies. Finally, Northern New England Energy Corporation (a wholly owned subsidiary of Energir) continues its equity investment in our company.

Forecasts show us maintaining our 50% debt to 50% capital ratio over the planning horizon.

Financial Forecasts

Table 7-6 through Table 7-9 present four essential projections regarding our operational financial statements. To create these projections, we assumed that:

- Retail MWh sales continued to decline because of greater efficiency measures and a sustained increased in net-metered installations, not fully offset by new load from certain areas of strategic electrification (such as transportation and heating) within the planning period.
- Power supply costs would remain stable and that we will continue to hedge on most short-term positions.
- Savings that satisfy the merger requirements would continue to be achieved.
- Key aspects of our Regulation Plan will be renewed through 2022 (major storm cost adjustor, power supply adjustor, innovative program pilot, among others).
- Special dividends would be issued as needed to maintain our capital structure.
- Dividend payouts would be made on approximately 55% of our net income.

The forecast also shows a return-on-equity of 9.3% with a modest inflation provision from 2019 through 2022, as requested in our pending Regulation Plan proceeding.

Income Statement

Starting in 2021, customers will receive 100% of the synergy benefits associated with the GMP-CVPS merger. As a result, our income will begin to decline starting in 2021. Table 7-6 details our consolidated income statement.

Income Statement Category	FY 2018 ($000)	FY 2019 ($000)	FY 2020 ($000)	FY 2021 ($000)	FY 2022 ($000)
Operating Revenues					
Retail Revenues	$618,000	$613,818	$681,492	$687,430	$707,493
Electricity Sales (Billing Adjustments)	7,047	6,047	3,776	2,316	2,316
Business Development–Net	319	343	337	327	327
Provision for Rate Refund/Collections	(9,899)	(7,276)	(3,191)	(2,316)	(2,316)
Other Operating Revenues	19,601	19,273	19,588	18,751	18,660
REC Revenue	21,735	15,711	11,306	7,052	7,016
Rate w/Revenues and/or VY Payment to Sponsor	28,805	4,077	4,055	4,033	4,011
Total Operating Revenues	685,608	651,993	717,364	717,593	737,506
Operating Expenses					
Power Supply Total Energy, Net of Resales	271,686	259,269	260,796	263,234	263,199
Power Supply Total Capacity	61,373	52,532	59,460	58,442	57,616
Subtotal Power Supply	333,060	311,801	320,257	321,676	320,815
Transmission by Others/Transmission Rents	96,422	114,406	112,399	113,607	122,120
Depreciation/Amortization	53,160	42,374	63,844	73,020	78,429
Investment Gain Deferral	(2,029)	8,191	1,185	–	–
Regulatory Deferrals	(885)	–	–	–	–
Cost Center O&M (including Payroll and Overheads)	106,033	100,041	103,253	105,699	108,250
Taxes Other than Income	36,652	39,022	40,376	41,839	43,807
Total Operating Expenses	622,412	615,835	641,314	655,841	673,421
Operating Income	63,196	36,157	76,049	61,753	64,085
Other Income (Loss)					
Equity-in-Earnings	78,713	80,131	79,561	75,852	75,095
Other Income	2,146	(1,015)	(1,254)	(1,243)	(718)
Interest Expense	43,254	40,701	42,377	41,735	41,504
KCW Accretion Expense (ARO)	256	294	307	320	335
Pre-tax Income	100,544	74,279	111,672	94,307	96,624
Income Taxes	24,967	21,582	23,511	18,617	18,265
Net Income before Non-Controlling Interest in Income	75,577	79,697	88,161	75,690	78,358
Non-Controlling Interest in Income–Income/(loss)	(1,228)	(671)	(568)	(527)	(2,301)
Net Income	$74,349	$79,026	$87,593	$75,163	$76,057
Effective Tax Rate	25.14%	(7.36%)	21.16%	19.85%	19.36%

Table 7-6. Consolidated Income Statement: 2018–2022

Balance Sheet: Assets

Over the planning period of 2018 through 2022, we forecast our total assets to grow by 1.55% annually (6.19% in total). Table 7-7 details our entire asset-related balance sheet.

Balance Sheet: Asset Category	FY 2018 ($000)	FY 2019 ($000)	FY 2020 ($000)	FY 2021 ($000)	FY 2022 ($000)
Utility Plant					
Utility Plant in Service	$1,883,380	$1,938,442	$2,008,489	$2,075,253	$2,144,803
Less: Accumulated Depreciation and Amortization	(632,482)	(667,124)	(712,517)	(762,436)	(821,228)
Net Plant in Service	1,250,899	1,271,319	1,295,973	1,312,817	1,323,575
CWIP	51,248	61,374	62,064	62,064	62,064
Nuclear Fuel	1,979	1,979	1,979	1,979	1,979
Net Utility Plant	1,304,126	1,334,672	1,360,016	1,376,861	1,387,619
Current Assets					
Cash and Cash Equivalents	8,762	8,326	11,741	14,683	18,490
Special Fund Millstone Decommission	12,940	12,940	12,940	12,940	12,940
VYNPC Spent Fuel Trust	146,041	143,936	141,831	139,725	137,620
Accounts Receivable, Net of Allowance	81,629	81,189	86,123	86,672	88,117
Inventories	24,504	25,185	25,992	26,825	27,672
Derivative Financial Instruments	11,101	11,101	11,101	11,101	11,101
Derivative Financial–Current	8,433	8,433	8,433	8,433	8,433
Prepaid Expenses and Other Current Assets	14,454	13,736	13,064	13,231	13,401
Total Current Assets	307,866	304,846	311,225	313,611	317,774
Regulatory Assets–Long Term: Pine Street	9,059	8,448	7,837	7,225	6,605
Other Deferred Charges					
Preliminary Survey	5,057	5,057	3,251	3,251	3,251
Deferred Assets–Other	21,394	12,613	9,775	7,837	5,926
Deferred Assets–Storm	13,664	12,563	9,671	7,364	5,058
Deferred Assets–Efficiency Fund Payments	16,470	13,624	10,957	8,457	6,148
VYNPC Special Trust Funds	2,878	2,670	2,461	2,252	2,044
Total Other Deferred Charges	59,462	46,526	36,115	29,162	22,427
Other Assets					
Associated Companies	597,890	657,596	678,765	683,072	690,798
Cash Surrender Value of Officers' Life Insurance	17,020	16,317	15,614	14,910	14,716
Other Investments	1,811	1,811	1,811	1,811	1,811
Other Assets	100,292	100,994	103,308	103,992	104,730
Total Other Assets	717,014	776,719	799,498	803,785	812,054
Other Assets–Non-Utility Property	6,600	7,300	8,001	8,715	9,444
Total Assets	$2,404,126	$2,478,511	$2,522,691	$2,539,359	$2,555,923

Table 7-7. Consolidated Balance Sheet–Assets: 2018–2022

Balance Sheet: Liabilities and Capitalization

Table 7-8 details our entire capitalization and liabilities-related balance sheet, projected over the planning period.

Balance Sheet: Capitalization and Liabilities Category	FY 2018 ($000)	FY 2019 ($000)	FY 2020 ($000)	FY 2021 ($000)	FY 2022 ($000)
Capitalization					
Additional Paid-In Capital	$559,394	$569,394	$545,394	$520,394	$493,394
Distributions to Non-Controlling Member	(406)	(3,187)	(5,946)	(9,156)	(11,476)
Equity Interest of Non-Controlling Member GMP VT Solar	721	1,391	1,959	2,486	4,787
Retained Earnings	244,586	280,078	319,425	353,178	387,334
Total Stockholder's Equity	804,295	847,677	860,833	866,902	874,039
Long Term Debt	639,830	739,500	749,145	726,235	720,730
Total Capitalization	1,444,126	1,587,177	1,609,978	1,593,137	1,594,769
Current Liabilities					
Short-Term Debt	73,511	99,571	76,122	107,499	117,225
Current Portion of Long-Term Debt	86,300	10,330	40,355	30,910	27,530
Accounts Payable	48,782	49,609	51,898	54,242	56,613
Power Supply Adjustor	5	(0)	(0)	(0)	(0)
Derivative Financial Instruments–Current Portion	17,624	17,624	17,624	17,624	17,624
Other Accounts Payable and Accruals					
Accrued Officers Compensation	1,266	1,287	1,316	1,345	1,376
Accounts Payable–Associated Companies	(509)	(439)	(347)	(251)	(152)
Customer Deposits & Unearned Revenue	1,372	1,395	1,426	1,458	1,491
Accrued Interest Payable	10,963	11,979	13,561	13,022	12,928
Other Miscellaneous	16,584	16,285	16,145	16,024	15,911
Total Other Accounts Payable and Accruals	29,677	30,508	32,101	31,599	31,554
Total Current Liabilities	255,899	207,642	218,099	241,874	250,546
Regulatory Liabilities					
Reg Liability–Deferred Future Income Taxes	177,544	148,192	144,501	140,767	136,847
Cost of Removal–Regulatory Liability	24,244	24,657	25,199	25,769	26,352
Other Regulatory Liabilities	41,048	31,262	30,047	30,047	30,047
Total Regulatory Liabilities	242,836	204,111	199,747	196,583	193,246
Derivative Regulatory Liability	16,308	16,308	16,308	16,308	16,308
Customer Advances for Construction	204	204	204	204	204
Spent Fuel Obligation–VY	109,252	109,758	110,263	110,768	111,274
Asset Retirement Obligations	9,798	10,091	10,398	10,718	11,053
Deferred Taxes	216,774	238,370	253,204	265,917	275,266
Minimum Pension Funding Liability	58,153	57,967	57,780	57,646	57,530
Other	50,777	46,884	46,709	46,202	45,726
Total Liabilities	960,000	891,334	912,713	946,221	961,153

Total Liabilities & Capitalization	$2,404,126	$2,478,511	$2,522,691	$2,539,359	$2,555,923

Table 7-8. Consolidated Balance Sheet–Liabilities and Capitalization: 2018–2022

Cash Flow

Fiscal year 2019 reflects the return of $27 million to our customers as a result of the 2018 Tax Reform Act. Table 7-9 details our entire cash flow statement over the planning period.

Balance Sheet: Capitalization and Liabilities Category	FY 2018 ($000)	FY 2019 ($000)	FY 2020 ($000)	FY 2021 ($000)	FY 2022 ($000)
Operating Activities					
Net Income	74,349	79,026	87,593	75,163	76,057
Net Income attributable to Non-Controlling Interest	(1,228)	(671)	(568)	(527)	(2,301)
Net Income before Non-Controlling Interest	75,577	79,697	88,161	75,690	78,358
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	58,024	58,861	62,131	69,603	75,199
Amortization of regulatory & other deferred amounts	(4,864)	(8,755)	4,836	5,609	5,418
Amortization & deferral of purchased power costs, net	5,738	–	–	–	–
Dividends & distributions from assoc. companies	60,993	62,878	66,033	67,285	68,148
Equity in undistributed earnings of assoc. companies	(78,713)	(80,131)	(79,561)	(75,852)	(75,095)
AFUDC	(1,794)	(1,271)	(1,000)	(1,000)	(1,000)
Accretion–KCW	256	–	–	–	–
Deferred income tax expense, net of investment tax credit amortization	25,047	(7,756)	11,143	8,980	5,428
Environmental and conservation deferrals, net	(31)	(145)	(145)	(145)	(136)
Working Capital Changes in:					
Accounts Receivable	(6,122)	441	(4,934)	(550)	(1,445)
Other current assets & Deferred Tax Adjustment	(9,214)	37	(135)	(1,000)	(1,017)
Accounts Payable and other current liabilities	(7,646)	(650)	3,632	1,308	1,922
Accrued income taxes	22	(0)	0	(0)	0
Other assets	46,108	1,354	3,533	3,440	3,382
Other liabilities	(39,412)	11,608	2,044	822	737
Net cash provided by operating activities	$123,969	$116,167	$155,737	$154,191	$159,900
Investing Activities					
Utility plant expenditures	(90,033)	(87,197)	(85,500)	(84,500)	(84,000)
Investment in associated companies	(71,322)	(42,453)	(7,640)	4,260	(780)
Proceeds from sale of assets and other items, Investment in Non-Utility and Other	(2,844)	3	3	(11)	(534)
Net cash used in investing activities	$(164,199)	$(129,647)	$(93,137)	$(80,251)	$(85,313)
Financing Activities					
Issuance of long-term debt	25,000	108,800	48,770	(1,255)	(1,285)
Repayment of long-term debt	(7,280)	(85,500)	(9,500)	(31,500)	(8,000)
Additional paid in capital	–	10,000	(24,000)	(25,000)	(27,000)
Capital Contributions from Non-Controlling Partners	(406)	–	–	–	–
Other	149	–	–	–	–

Net borrowings on short-term debt	43,511	26,060	(23,450)	31,377	9,726
Cash dividends	(40,984)	(46,316)	(51,005)	(44,621)	(44,221)
Net cash provided by financing activities	$19,991	$13,044	$(59,185)	$(70,998)	$(70,780)
Net increase in cash and cash equivalents	(20,239)	(436)	3,415	2,942	3,807

Table 7-9. Consolidated Cash Flow Statement: 2018–2022

Financial Metrics and Ratios

Financial metrics and ratios identify prudent balances between revenue and expenses, between assets and liabilities, and between other opposing financial indicators. Table 7-10 shows a number of these ratios as projected over the planning period. Our calculated ratios include estimated adjustments consistent with generally accepted Standard & Poor's methodology.

Financial Statistics: Ratios	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Capital Spending	$85,105	$85,965	$86,500	$85,500	$85,000
Investment in Transco	71,322	15,040	7,756	(4,145)	895
Investment in Joint-Venture Solar & Storage Project	–	27,729	–	–	–
Short and Long-Term Debt	799,641	849,401	865,622	864,644	865,485
Base Rate Impact–with Indexed ROE	5.37%	5.43%	5.53%	1.64%	3.63%
Allowed ROE	9.10%	9.30%	9.65%	9.70%	9.72%
Effective Allowed ROE for Fiscal Year	9.08%	9.25%	9.65%	9.70%	9.72%
Earned ROE	9.4%	9.5%	10.3%	8.7%	8.7%
13-Month Average Equity Ratio	49.9%	50.2%	49.6%	49.8%	50.0%
Key Credit Statistics					
FFO to Total Debt	15.6%	11.3%	17.6%	17.4%	18.3%
Debt / EBITDA x	4.90	6.42	4.56	4.62	4.42
Debt / Book Capitalization	54.20%	55.30%	54.70%	53.90%	54.60%
Liquidity (Sources/Uses) Ratio	1.5	1.2	1.6	1.3	1.5
Other					
Net Income	74,349	79,026	87,593	75,163	76,057
Interest	43,254	40,701	42,377	41,735	41,504
Income Taxes	24,967	(5,418)	23,511	18,617	18,265
Depreciation and Amortization	53,160	42,374	63,844	73,020	78,429
EBIT	$142,571	$114,309	$153,482	$135,514	$135,826
EBITDA	195,731	156,683	217,326	208,535	214,255

Table 7-10. Financial Statistics and Ratios: 2018–2022

Based on our evaluation of necessary investments, we have forecast the overall capital spending across all departments at approximately $85 million annually over the planning period. We have requested this overall level of investment in our pending Regulation Plan proceeding.

Category	FY 2019 Forecast ($000)	FY 2020 Forecast ($000)	FY 2021 Forecast ($000)	FY 2022 Forecast ($000)
Information Technology	$6,845	$9,375	$9,551	$9,423
Distribution Lines Large Cap	$7,861	$9,500	$9,500	$9,500
Distribution Line Extensions	$4,481	$4,500	$4,500	$4,500
Distribution Lines Small Cap	$14,846	$10,100	$10,100	$10,100
Distribution Substation	$6,068	$4,900	$4,775	$4,425
General Plant	$402	*	*	*
Joint Ownership	$1,466	$2,000	$2,000	$2,000
Kingdom Community Wind	$963	*	*	*
Meters	$913	$650	$650	$650
New Initiatives	$5,170	$5,000	$5,000	$5,000
Production	$17,207	$17,700	$16,700	$16,200
Property & Structures	$329	$1,500	$1,400	$1,400
Regulators and Capacitors	$1,085	$1,100	$1,100	$1,100
Transformers	$3,608	$4,500	$4,550	$4,600
Transmission Lines	$4,462	$7,100	$8,524	$8,852
Transmission Substations	$6,971	$5,575	$4,150	$4,250
Transportation	$3,042	$3,000	$3,000	$3,000
Wind Generation	$246	*	*	*
Total	$85,965	$86,500	$85,500	$85,000

* = These costs are included in the Production line item for each fiscal year.

Table 7-11. Capital Spending Breakout: 2019–2022

8.Portfolio Evaluation

Portfolio evaluations in our most recent IRPs have focused considerable attention on how best to fill substantial open positions in energy and capacity that were anticipated based on the expiration of major long-term PPAs (from Vermont Yankee and Hydro-Québec) that historically provided the majority of our needs. Vermont's renewable energy framework at the time (centered on the SPEED program) was primarily focused on the short-term, and lacked the type of specific guidance that many states had established through Renewable Portfolio Standards or other frameworks. As a result, our IRP portfolio evaluations have also explored the tradeoffs between a fairly wide range of potential strategies and renewable energy policies that GMP and Vermont could potentially pursue.

The context for this 2018 IRP is much different. Significant new long-term PPAs (along with much smaller new GMP-sponsored generation sources) have been added to our portfolio in recent years, reducing our forecasted open positions and yielding a portfolio of sources that is more diverse and more renewable. In addition, Vermont's Renewable Energy Standard (RES), which took effect in 2017, established specific guidance for the types of renewable resources and energy transformation that Vermont utilities should pursue, and at what pace. Since our 2014 IRP, Vermont renewable policy resources (particularly net-metered generation, along with Standard Offer) have assumed a prominent role in the state's energy supply, and now represent a signficant cost driver and planning uncertainty for our portfolio.

With these important developments in mind, the 2018 portfolio evaluation focuses largely on how to achieve these policy goals and RES requirements most cost-effectively for our customers, and explores the factors that could change the type and timing of our future decisions regarding renewable energy and transformation. We strive to deliver low-cost, low-carbon, incredibly reliable energy services to our customers. The RES framework provides three metrics (relating to distributed renewable suppy, total renewable supply, and energy transformation and decarbonization) that are critical to our portfolio's performance. In the context of resource planning, we seek to manage two additional objectives: portfolio diversity and a balance between flexibility and stability.

This chapter summarizes the RES framework and describes these portfolio attributes in more detail; portfolio evaluations and conclusions follow. The chapter concludes with an explanation of the wholesale market price outlooks used in some of the portfolio analyses.

VERMONT'S RENEWABLE ENERGY STANDARD

Vermont's RES was established by 30 V.S.A. §8002-8005. It establishes a set of mandatory requirements for Vermont's distribution utilities to obtain portions of their power requirements from two broad classes of renewable sources. Compliance is demonstrated by the retirement of renewable attributes in the form of Renewable Energy Certificates (RECs). The program also requires that Vermont's distribution utilities engage in energy transformation projects that lower costs and fossil fuel consumption.

The RES requirements are broken into three tiers. Tier I requires that 55% of 2017 retail electric sales be obtained from renewable energy sources, which, broadly defined, include both new and existing renewables. This requirement increases by four percent every three years until reaching 75% renewable in 2032.

Tier II requires that one percent of retail electric sales in 2017 be obtained from new distributed renewable generation sources, increasing by 0.6% per year to a total obligation of 10% in 2032. This distributed generation requirement (which represents a subset of the Tier I total renewable obligation) requires new distributed renewable projects located in and connected to the grid in Vermont, with a maximum project size of less than 5 MW and have achieved commercial operation on or after July 1, 2015.

Finally, Tier III requires that distribution utilities implement energy transformation projects such as electric vehicles, cold climate heat pumps, and weatherization above baseline values. The obligation begins at 2% of retail electric sales in 2017 and increases by 0.667% per year to a maximum of 12% in 2032.

Each RES tier features an Alternative Compliance Payment (ACP), with Tier I's ACP starting at $10 per MWh while Tier II and Tier III have a beginning ACP of $60 per MWh. After the first year, these ACPs escalate annually based on an inflation index.

PORTFOLIO OBJECTIVES AND PERFORMANCE METRICS

Our analysis is based on five resource planning objectives: low cost, low carbon, renewable energy, reliability, and flexibility.

Low Cost is an important objective. We use the average portfolio cost (including power costs and transmission by others) in $/MWh as the relevant performance metric. We seek to avoid substantial annual increases, and to maintain an average rate of increase lower than the rate of general inflation. We also seek to remain competitive relative to average market rates ($/MWh) for power and transmission that other utilities and retail electricity suppliers in New England would face.

Low Carbon reflects the estimated average emission rate of CO_2 (in pounds per MWh) for our power supply portfolio. We compare our portfolio average emission rate to estimates of the New England average emission rate, which we represent at about 600 pounds per MWh,[66] declining over time to reflect state efforts to lower their emission profiles. We also depict an estimate of the system residual emission rate for New England. This represents average emissions for generation certificates that are not retired by market pariticpants (for example, to meet state RPS requirements or other reasons.

Renewable Energy content is estimated on an annual basis in terms of retired RECs that are eligible with Tier I—total renewables—and Tier II—distributed renewables—as fractions of retail sales. We also track the implications of potential paths of complying with Tier III—energy transformation (as discussed in Chapter 4: Declining Electricity Demand).

Reliability means lack of interruption of electric service to customers. Reliability is measured using the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI). From a resource planning perspective, reliability reflects a goal to stabilize (or "hedge") power costs to provide a measure of price stability to our customers (particularly in the near term), while leaving some flexibility and exposure to market in the long term. This metric is measured by the fraction of our energy load requirements that is met with fixed or stable-priced sources.[67]

Flexibility. Finally, the balance between portfolio flexibility and stability is primarily measured by the size of our long-term, fixed-priced resource commitments compared to the total energy requirements. The higher the percentage of resource commitments, the

[66] The average emissions in the NEPOOL Generation Information System (GIS) of roughly 900 pounds per MWh appears to be significantly affected by relatively small fractions of power from non-fossil fuel plants (such as biomass, trash to energy), suggesting that those rates might be overstated. We have therefore depicted regional average emissions at a lower rate of 600 pounds per MWh.

[67] In this metric, the most notable treatment of our sources is that energy from oil- and natural gas-fired plants is not treated as "hedged" in the long term, and the HQ-US long-term PPA is treated as partially hedged because a portion of its PPA pricing is determined based on an electricity market price index.

more stable the resulting portfolio costs tend to be. The tradeoff is that the portfolio also becomes less flexible, as it does not respond as much or as quickly to changes in the wholesale markets.

Table 3-1 summarizes the five resource planning objectives and their performance metrics.

Objective	Attribute	Metric
Low Cost	Metric 1	Average portfolio cost ($/MWh)
	Target 1	Limit increases to less than general inflation
	Target 2	Average portfolio cost is less than the regional benchmark
Low Carbon	Metric 1	Our annual average portfolio emission rate (CO_2 pounds per MWh)
	Target	Our average emission rate is well below the regional average
Renewable Energy	Target 1	Achieve annual Tier I requirements
	Target 2	Achieve annual Tier II requirements
	Target 3	Achieve annual Tier III requirements
	Target 4	Achieve each RES requirement in a cost-effective way, at average costs substantially lower than ACP
Reliability	Metric 1	SAIFI and CAIDI
	Metric 2	Percentage of resource commitments compared to loads
	Target 1	Estimated open positions 100% hedged by start of operating year
	Target 2	Five-plus years in the future, portfolio is less than fully hedged
Flexibility	Metric 1	Long-term ratio of fixed (or stable) priced MWh to total energy requirements
	Target 1	Five-plus years in the future, portfolio is significantly less than fully hedged. Percentage may float as long as the portfolio remains below regional rate benchmarks
	Metric 2	Resource expiration sequence and duration
	Target 2	Resource expirations are layered, and do not expire all at once

Table 8-1. Resource Planning Objectives and their Performance Metrics

The final measure of portfolio flexibility and stability is the sequencing or layering of expiration dates of resources over time. Flexibility can be balanced with stability when long-term resources (PPAs primarily) expire in different years and different amounts expire at different times. The largest sources in our committed portfolio (PPAs from HQ-US and NextEra Seabrook) are much smaller than corresponding long-term hydroelectric and nuclear commitments we held in the past, but it is notable that both of these purchases expire in the mid-2030s.

Because these objectives are frequently interrelated, they should ideally be kept in balance with each other. The pursuit of any one objective to the detriment of another can create a tradeoff that is not desirable under different circumstances. Ideally, resource plans seek to balance the objectives; as markets, policy and technology change, the portfolio may need to be managed to maintain a state of dynamic equilibrium between them.

PORTFOLIO EVALUATION METHODOLOGY

The portfolio evaluation process combines three common analytical methods (budget estimation, portfolio-based multi-attribute analysis; and sensitivity analysis) to gain insights into how different portfolios perform under a range of future market conditions.

Budget Estimation

The resource planning process begins with our current portfolio of committed resources, and reasonably anticipated resource changes that are contained its current five-year financial forecast. These resource changes include scheduled expirations of existing PPAs, inclusion of new PPAs that are presently committed, and the addition of reasonably anticipated new resources such as those that are supported by Vermont renewable policies or programs (such as net metering and the Standard Offer program). With these changes, the resulting resources are projected past the five-year horizon using estimates of their price and volume on a monthly on-peak and off-peak basis, and balanced against our estimated load requirements (see Chapter 4: Declining Electricity Demand).

Reference Portfolio

The foundation for the portfolio evaluation is the Reference Portfolio, which is intended to illustrate the portfolio of loads and resources that would result from current commitments and policies, without any substantial new long-term resource commitments.

The Reference Portfolio is based on the projected sources and load requirements with the following assumptions being among the most notable:

- Projected gaps between energy requirements and committed resources are assumed to be purchased (or, as appropriate, sold) on a short-term basis at our current base case forecast of future wholesale energy market prices. Similarly, projected capacity requirements in excess of Our committed sources are assumed to be met using short-term layered forward purchases (or from ISO-New England directly) at prices consistent with our current Base case FCM price forecast.

- Net metering in our territory is assumed to grow at a pace of 20 MW/year. The 20 MW/year pace seems to be a good reference point because it is consistent with the lowest growth of net-metered capacity observed in any year since 2014, yet this pace of new distributed solar (from all sources, not only net metering) would also be sufficient to meet the annual growth of Tier II requirements over the next decade. The PUC has recognized that the faster pace of net metering growth in recent years has put upward pressure on utility power costs and electricity rates for customers, and that lower-cost distributed renewables are available. The PUC therefore lowered net metering payment rates by limited amounts in 2018 to seek an appropriate balance between supporting the net metering industry and limiting rate impacts to non-participants.
- Vermont's Standard Offer program is assumed to run its current course (ultimately supporting about 127.5 MW of distributed renewables). The program is not assumed to be renewed or replaced, because the distributed renewable sector in Vermont has matured greatly since the Standard Offer program was initiated, and the RES framework is now in place to support the future development of substantial new distributed renewables.
- Three solar and storage projects we proposed (with total solar capacity of about 15 MW, and battery storage capacity of about 6 MW and 24 MWh) are assumed to receive CPGs and reach commercial operation (and start contributing to our supply of Tier II RECs) in 2019.
- Charts evaluating our supplies of Tier I, Tier II, and Tier III are presented assuming that we do not make any future purchases to meet projected shortfalls (to illustrate potentially required volumes that are yet to be procured), while estimated portfolio power costs are developed assuming that we will purchase any projected Tier I or Tier II shortfalls at current Base case price outlooks.

Portfolio-Based Multi-Attribute Scenario Analysis

This chapter evaluates our portfolio (first the Reference portfolio, and ultimately for an illustrative future portfolio) across the several metrics[68] listed in Table 3-1. Consistent with our past IRP analysis, most attributes are estimated annually, and presented in their natural units (such as renewable percentage or CO_2 pounds per MWh)—that is, they are not weighted or otherwise translated for comparison with other metrics. Portfolio costs are first estimated using base assumptions for market prices for energy, capacity, and two types of RECs, and later tested under alternative future outcomes for these markets.

68 This chapter does not evaluate our portfolio with respect to SAIFI and CAIDI, although we discuss how some distributed resources have the potential to help improve these metrics.

Similarly, multi-attribute evaluation of the Illustrative Future Portfolio is discussed in "Illustrative Future Portfolio" (page 8-45).

Sensitivity Analysis

The use of sensitivity analysis allows us to gain insight into how sensitive a portfolio's attributes are to sources of uncertainty. The sources of uncertainty that were analyzed using alternative assumptions (differing from the base case) include wholesale market prices for energy, capacity and RECs; the pace of future net metering in our territory; the pace of future Tier III supply; and future electricity demand. These alternative outcomes were formed using input from external experts and our own assessment of market prices and risks. (Chapter 4: Declining Electricity Demand discusses a potential range of alternative outcomes for Tier III supply.)

Some of these sensitivities lead to illustrations of potentially different outcomes or decisions. For example, a higher or lower pace of net metering growth in our territory could change the timing of our need for additional Tier II (distributed renewable) resources; higher or lower paces of acquisition for Tier III supply could potentially change the amount of Tier II RECs that we retire toward RES requirements (and therefore the amount available for resale); and regional REC prices for Class 1 renewables and existing renewables could affect the amount of RECs that it is cost-effective for us to sell versus retiring them to meet Tier I requirements. The relative sensitivity of our portfolio costs to several of these variables are visualized using a "tornado chart" format that ranks relative impacts on the net present value (NPV) of the portfolio's costs through 2035; these results are shown in "Illustrative Future Portfolio" (page 8-45).

IRP Alignment with Our Financial Forecasting

The first five years of the resource planning model are largely consistent with our then-current five-year financial forecast. The primary difference is that the energy, capacity, and REC market prices in the resource plan were updated to reflect our updated base case outlooks (which are explained in detail in "Market Price Inputs to the Portfolio Analysis" on page 8-58"). In addition, the IRP portfolio analysis reflects a base case rate of growth of 20 MW per year for net metering in our territory, compared to about 24 MW in the financial forecast. As a result, the base forecast in the IRP does not match up precisely to our internal financial forecast, but for many of the models' key components (including the volumes and prices for major supply sources, which drive most power costs) the inputs are the same, and the bottom-line cost projections are similar.

The resource plan estimates and analyzes net power supply and purchased transmission costs. These costs represent the majority of our cost of service, and they tend to change directly under the alternative strategies and scenarios discussed in this chapter. Capital-related costs of all existing and future T&D assets, administrative and general expenses, and non-power operations and maintenance costs are not modeled. As a result, the resource plan appropriately reflects tradeoffs in power supply costs and related metrics, but is not a forecast of total retail electric rates that our customers would pay under the different scenarios.

Nominal Analysis

The resource-planning model is an entirely *nominal* analysis. All of the costs and prices in the analysis are expressed in nominal dollars (which include the effects of general inflation in the economy over time), and therefore reflect prices and costs that are projected to occur in each year in question. No additional translation or escalation is needed to incorporate the effects of inflation.

Peaking Resources

Our fleet of peaking combustion turbine and diesel generating units—along with flexible load and storage resources—can also provide significant value to customers. These resources do not typically produce large quantities of energy. Rather, their value and operations tend to be determined by relatively specialized aspects of the power market and grid (for example, periods of very high electricity demand and market prices; ISO-New England ancillary service markets, support of the local transmission and distribution grid). The benefits and considerations associated with these resources are discussed in a separate section, rather than the broader multi-attribute analysis of portfolio characteristics and needs.

Signposts

The "Signposts" section (page 8-55) discusses "signposts" as a concept. These are metrics (from a local, regional, or national perspective) that could serve as indicators of developments or trends that will inform future transitions or resource choices. Because of the more dynamic nature of our energy system and portfolio, unlike previous IRPs, we believe defining the signposts and how we will adjust as a result of what they tell us is more realistic than claiming an optimal portfolio and resource mix for the next 10 years that will become stale.

EVALUATION OF THE REFERENCE PORTFOLIO

This section presents our evaluation of the Reference Portfolio (which is defined in the previous section) across a range of metrics.

Attribute: Open Energy Position

Figure 8-1 presents our forecasted long-term energy "gap chart"—comparing our projected supply sources to the energy requirements to serve forecasted retail sales.

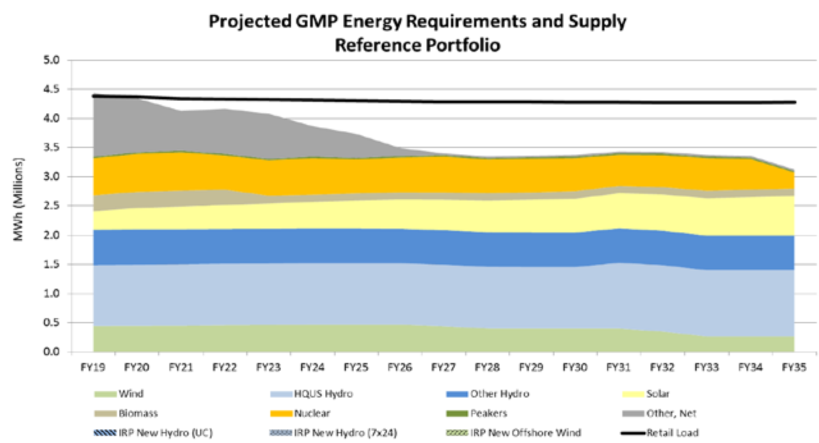

Figure 8-1. Projected Energy Requirements and Supply

Some notable observations that emerge from this view:

- By design, long-term committed sources are somewhat less than our projected load requirements. Layered short-term forward energy purchases (which are most of the declining grey source on the upper left) bridge the gap between long-term committed sources and load requirements, declining gradually over the next five years and leaving a minimal average open position for the next three years.
- Solar PV is projected to continue as a growing long-term source. For net metering, which represents most of the solar PV growth, this chart depicts net metered excess energy as a power source (as opposed to a reduction in retail sales).
- Aside from layered short-term purchases, our portfolio consists largely of long-term sources that will remain in place over the next decade.
- This chart extends about 15 years, through our fiscal year 2035. Two major PPAs (HQ-US and NextEra Seabrook), amounting to roughly a third of our annual energy supply, are slated to expire shortly thereafter. During the 2020s as these expirations grow closer, they will probably become a more significant consideration in our portfolio design. For example, it could become appropriate to acquire some volume of additional long-term resources (and accept some loss in open position and

portfolio flexibility) to limit the fraction of our supply that needs to be replaced at one time.

Figure 8-1 depicts the energy sources that we use to offset our energy purchase obligations in the ISO-New England market; it does not depict our sales of RECs to other parties (or our purchases of RECs that do not provide energy). This chart therefore does not depict the ultimate fuel mix (after accounting for REC sales and purchases) that may ultimately serve our customers and meet RES requirements; this ultimate mix will be addressed in detail later in this section.

Finally, it is significant that Figure 8-1 compares sources and requirements on an annual basis. While this provides a useful first-order indication of portfolio length, our energy positions also feature some significant seasonal and temporal differences within each year that are not evident from this annual view. Based on the characteristic shapes of customer loads and committed sources (for example, substantial fractions of solar PV and hydroelectric sources, and a large HQ-US PPA that delivers in a "7x16" pattern), our open energy position tends to be weighted toward winter and toward off-peak hours, while supply tends to be more in balance with load during other seasons and exceeds load during peak periods in spring.

Figure 8-2 illustrates how our net energy position tends to vary on a monthly basis, using the fiscal years 2025 through 2027 as an example. To effectively hedge its forecasted open energy positions, we need to generally match the expected output of supply resouces (including short-term purchases and sales, as needed) to the period of need. On this chart, the blue area represents projected output of our committed sources, with intermittent renewable sources represented at their normalized (that is, long-term average) values. The red area represents estimated volumes of net market purchases (on a monthly basis) that would be needed to supplement our committed supply to serve our total energy requirements. The green area reprsents estimated net energy resales, during periods when our committed sources are projected to exceed load requirements.

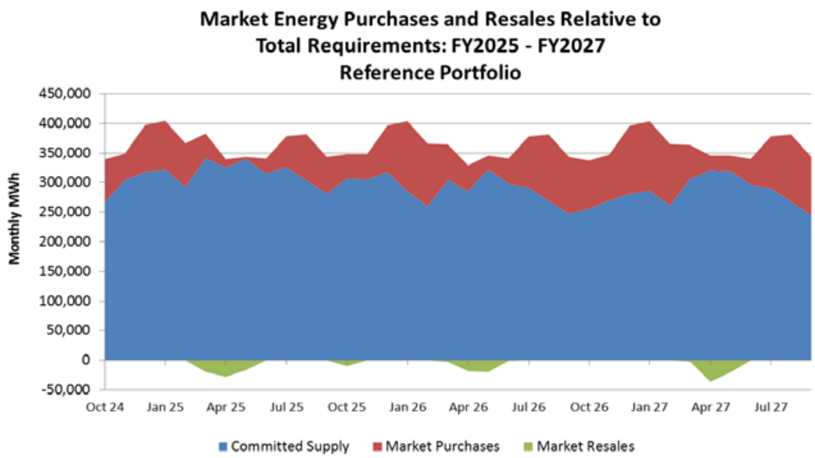

Figure 8-2. Market Energy Purchases and Resales Relative to Total Requirements: 2025–2027

Figure 8-2 shows three distinct patterns that have implications for our short- and long-term planning process.

- Our total energy requirements (the top of the red area) consistently follow a seasonal pattern that is highest in the peak winter months. Energy requirements are also relatively high in the mid summer months, and noticeably lower in spring and fall.
- Our open positions (when requirements exceed supply, requiring additional purchases) tend to be concentrated in the winter sesaons. This can be seen by the relative size of the red purchase areas in the winter months of each year. As a result, our forward energy purchase descisons in the coming years will focus more on this period, which features different market price drivers and risks (described in Chapter 3: Regional and Environmental Evolution) than the other months.
- Lastly, Figure 8-2 shows a notable new feature in our energy positions where we are projected to be in a consistant surplus positon during peak hours in the spring season (as illustrated by the green area). This feature reflects the lower seasonal energy requirements during spring, along with higher seasonal hycro generation and the

extraordinary growth of distributed solar generation, which tends to produce at relatively high rates in these months.

Attribute: Price Stability

Figure 8-1 illustrated our projected energy open position on an annual basis. By design, our portfolio features significant long-term open energy positions to limit the degree that our portfolio costs and electric rates could diverge from those in neighboring states, and to maintain some flexibility to acquire resources to meet strategic objectives (that is, acquire competitively priced renewables to meet RES requirements) or to accommodate unanticipated declines in the electricity requirements of our customers. After our current set of layered short-term energy purchases expire, the magnitude of that open position is roughly 20% for the remainder of the 2020s. This is somewhat less than in previous long-term analyses, primarily because of declining retail energy sales and forecasts, along with the large increase in net-metered solar generation that has occurred in our territory (and is anticipated to continue).

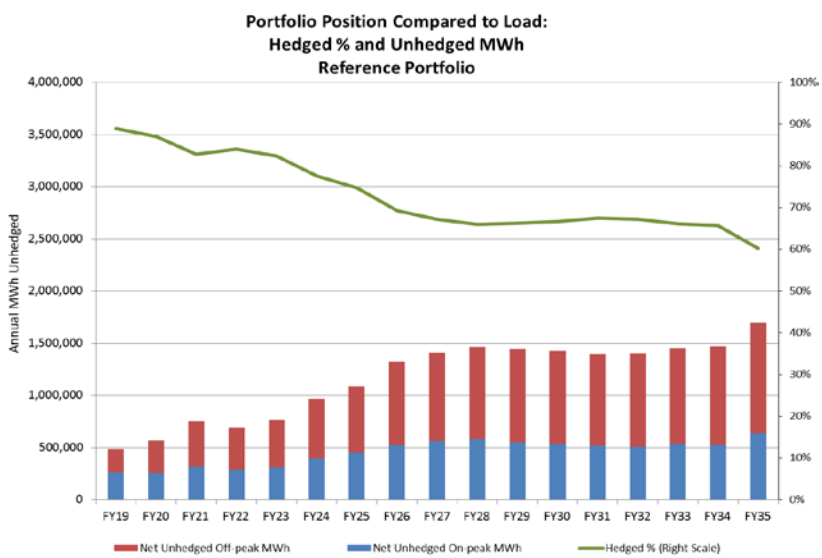

Figure 8-3. Portfolio Position Compared to Load: Hedged Percent and Unhedged MWh

Figure 8-3 views our estimated energy open position from the perspective of price stability, first from the perspective of the fraction of forecasted load requirements that are hedged—that is, matched with supply sources that feature fixed or stable pricing. The green line in Figure 8-3 depicts the estimated fraction of forecasted requirements that are hedged, on an annual basis. This fraction declines by design from about 100% in the first year to roughly 70% through the early 2030s. A decline of the hedged fraction in the final year of the chart foreshadows the expiration of our HQ-US and NextEra Seabrook contracts in 2038 and 2034, respectively.

When viewed in combination with Figure 8-1, this level of long-term stability indicates that we do not have a strong need for additional new long-term resources for the purpose of stabilizing energy costs for our customers. By simply replacing its layered short-term energy purchases as they expire over time, we could likely achieve a reasonable portfolio balance between energy cost stability and flexibility over the next decade. Our primary long-term portfolio needs during this period appear likely to be associated with other strategic goals: meeting renewable energy requirements in a cost-competitive way; managing peak-driven capacity and transmission costs; and achieving cost-effective electrification and decarbonizing projects.

The stacked red and blue bars on Figure 8-3 provide an indication of when during the year, peak or off-peak hours, our forecasted energy needs and surplus are likely to occur.

- Our primary estimated net short positions are during off-peak hours (indicated by the red area), in volumes of about 200,000 MWh to 300,000 MWh during the early 2020s, increasing to about 700,000 MWh to 800,000 MWh in the late 2020s.
- We are projected to be long, on average, during peak hours for the next several years. This is, in part, because of rapid growth of net-metered solar generation along with other solar sources, which produce primarily during peak daytime hours (while in evening hours, we are often a net purchaser). In the 2020s, a modest net short position during peak hours (depicted by the blue area) on the order of 100,000 MWh to 200,000 MWh develops.

Attribute: Open Capacity Position

Figure 8-4 presents our projected long-term capacity "gap chart"—comparing our projected capacity sources to our projected share of regional capacity requirements[69] to serve our customers' needs.

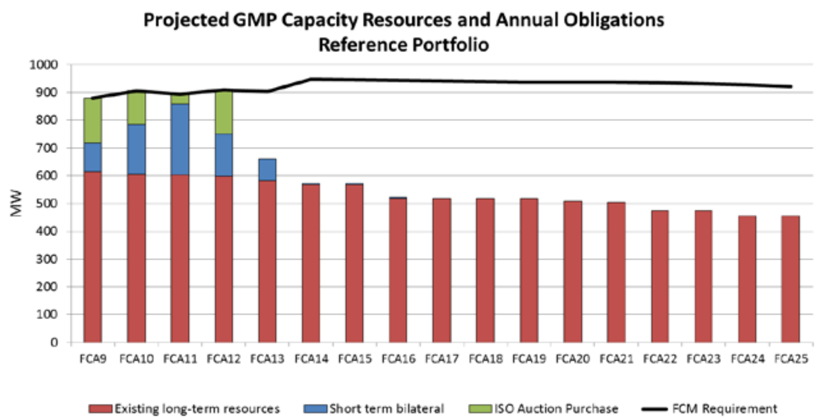

Figure 8-4. Projected Capacity Resources and Annual Obligations: Reference Portfolio

The red bars represent capacity from existing long-term sources (such as long-term PPAs and GMP-owned generating plants), while the blue area represents layered short-term purchases consistent with the strategy. The green area represents estimated our capacity requirements that were not matched by either of these sources, but for which the price of ISO-New England purchases is largely known at this time because the annual capacity auction for the relevant year has already been conducted.

The primary observations that emerge from this view are similar to those for energy. By design, long-term committed sources are somewhat less than our projected capacity requirements. Layered short-term forward capacity purchases bridge the gap between long-term committed sources and load requirements; these expire gradually over the next several years. To replace these expirations and protect against short-term FCM price fluctuations, we are presently seeking an additional short-term capacity purchase (for delivery starting in FCA #13) at a price reflective of our current market view which is moderate by historical standards.

Aside from these layered short-term capacity purchases, our portfolio consists largely of long-term sources that will remain in place over the next decade. The scale of long-term capacity gap is, by design, somewhat larger in percentage terms than for energy—partly because annual Forward Capacity Auctions are conducted about three years in advance. These auctions are the primary driver of the price that GMP and other load serving entities pay to purchase capacity in the FCM. Peak-reducing resources like battery

69 Figure 8-4 shows capacity volumes for Forward Capacity Auction #19 through FCA #25. This covers the period May 2018 through June 2035.

storage and controllable loads have the potential to act as a capacity hedge by cost-competitively reducing our capacity market exposure.

Attribute: RES Tier I Supply

Figure 8-5 presents our projected long-term Tier I "gap chart"—comparing our committed Tier I-eligible supply to projected Tier I requirements on an annual basis.

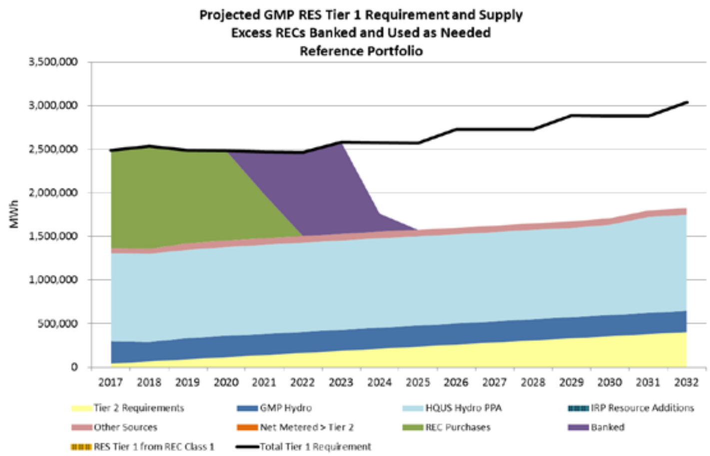

Figure 8-5. Projected Tier I Requirement and Supply Excess RECs Banked and Used Reference Portfolio

The following are notable features of this illustration:

- Tier II requirements, which we plan to meet, are depicted by the yellow area at the bottom of the chart. By statute, the total renewable requirement increases in a step function every three years.
- This illustration assumes that we will continue to sell our substantial inventory of RECs that are eligible for Class 1 or similar RPS markets in neighboring states, with the revenues used to reduce our net power costs and electric rates, and that RECs associated with these sources will therefore not be available for RES compliance.
- The "REC purchases" and "banked" sources refer to unbundled hydroelectric REC purchases (see Chapter 5: Our Increasingly Renewable Energy Supply). We expect to over-comply with our Tier I requirements in the next few years, and to bank some of our REC supply for compliance with our requirements in the early 2020s.

This summary projects that we will be well-supplied with Tier I-eligible sources in the near term, largely because of the long-term hydroelectric sources in our portfolio together with significant purchases of hydroelectric RECs. In the long-term, our Tier I supply is projected to be well short of the Tier I requirements, in part because of the substantial REC sale program that is assumed to continue during this period.

Later in this chapter, in the context of potential long-term resource additions, we explore the potential implications of procuring additional long-term renewable supply that would fill some of this gap, while in "Sensitivity Analysis" (page 8-20), we explore the implications of retiring some or all of the regional Class 1 RECs that we presently sell.

Attribute: RES Tier II Supply

Figure 8-6 presents our projected long-term Tier II "gap chart"—comparing our projected Tier II-eligible supply to projected Tier I requirements on an annual basis.

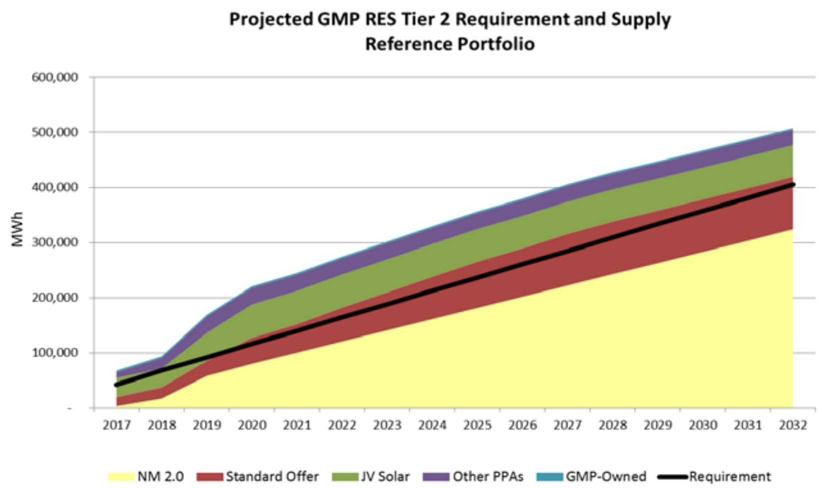

Figure 8-6. Projected Tier II Requirement and Supply and Potential Tier III Reference Portfolio

The Tier II supply reflects our base case assumption that net metering in our territory, which is almost entirely solar PV, will increase at a pace of 20 MW/year. We assume that, consistent with experience since 2017, almost all net metering customers will choose to assign the RECs associated with their projects to GMP (rather than retaining the RECs and receiving a significantly lower payment rate).

Based on these assumptions, we are projected to be well-supplied with Tier II RECs through the planning horizon. Our actual supply could vary significantly, higher or lower, based on the actual pace of net metering. In "Sensitivity Analysis" (page 8-20), we explore the implications of net metering growth turning out higher or lower.

Attribute: Greenhouse Gas Emission Profile

One of the key touchstones for our portfolio design is low carbon content for our electricity supply. Over the last five years our portfolio has had significantly lower CO_2 emissions (pounds per MWh) than New England as a whole, based on substantial reliance on hydro and nuclear sources.[70] We project that our average emission profile will continue to remain lower than the regional average in the future; this is substantially because of the increasing RES requirements reaching 75% renewable by 2032, which we assume will be met primarily with non-emitting renewable sources. The projected emissions profile of our Reference portfolio, along with an Illustrative Future Portfolio, is presented in “Illustrative Future Portfolio” (page 8-45).

Attribute: Reliance on Intermittent Supply Sources

The rapid growth of renewable generation led by solar PV and wind in Vermont, combined with a substantial base of hydroelectric plants, has led to an increasing intermittence in our portfolio. Intermittent sources are projected to assume an increasing role in the next decade, as increasing volumes of net-metered generation and Standard Offer projects are completed.

This trend can be seen in Figure 8-7.

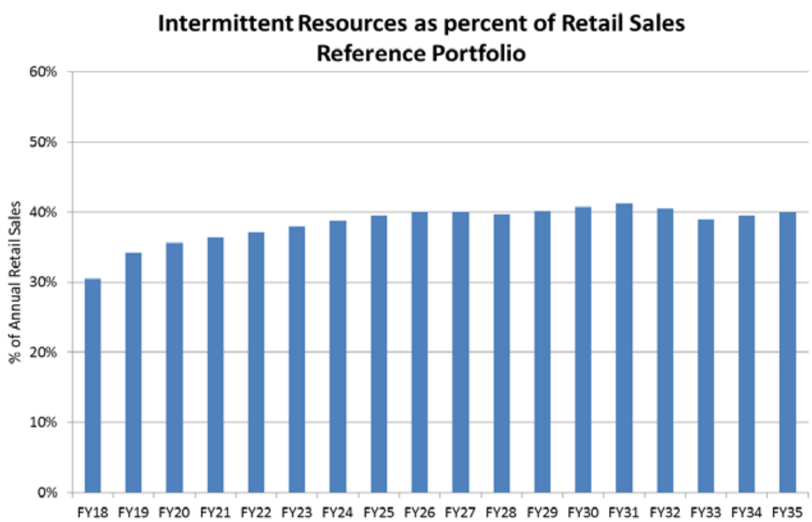

Figure 8-7. Intermittent Resources as a Percent of Retail Sales Reference Portfolio

Intermittence, in the context of an electric generation resource, means the resource does not generate on a level and consistent basis for long periods. Rather, intermittent resources are powered by renewable sources such as wind, sun, and water, which may have periods of high availability followed by periods of low or no availability. Each of these sources features a characteristic seasonal output profile, and in some cases a diurnal output profile; these can be incorporated into asset valuation and portfolio planning to a significant degree. In addition, each of these sources is subject to short-

70 We also receive substantial energy from renewable plants (such as wind and solar) from which we presently sell the associated RECs. To the extent that RECs associated with a volume of renewable energy are sold, we do not count that energy as renewable or zero-emitting when calculating greenhouse gas emissions. Rather, we assume that it takes on the characteristics of the Residual System Mix.

term influences such as cloud cover and precipitation that can create large fluctuations in daily and even hourly production volumes compared to the seasonal averages.

Figure 8-8 illustrates potential day-to-day variations in output for Vermont solar projects, using actual output from the fleet of net-metered solar projects in our territory on two consecutive days in April 2017. A very sunny day is depicted by the red dashed line, with maximum mid-day output approaching 100 MW; a very cloudy day is depicted by the blue dashed line, with maximum mid-day output of only about 20 MW. The sunny day provided an average of roughly 40 MW more generation than an average day in that month, while the cloudy day provided an average of roughly 25 MW less than the daily average.

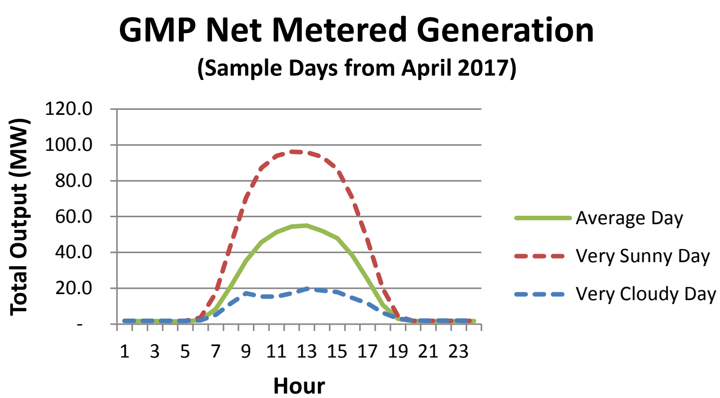

Figure 8-8. Daily Net-Metered Generation

Wind generation in New England tends to be stronger in winter months, and exhibits strong hourly and daily output variations around the long-term average since its output tends to vary with the cube of wind speed. Vermont hydro generation is seasonal with high output during the spring run-off and with more limited output during summer months when there is limited rainfall and rivers tend to dry out. The mode of operation can also affect hydro availability, with run-of-river generators providing output that is totally dependent on water flow versus dispatchable units that have ponding capability and at least some ability to shape and time their output.

We generally seek to balance our energy sources and load requirements within each month. This can be accomplished by taking into account the characteristic seasonal shapes of our intermittent supply sources. A balanced monthly supply does not, however, provide balance in all days and hours. The implication of relying on intermittent sources is that day-to-day fluctuations in intermittent production yield corresponding fluctuations in the volume of energy that we need to purchase or sell from the ISO-New England spot market. When combined with strong fluctuations in hourly LMPs, fluctuations in intermittent generation can yield noticeable short-term fluctuations in net power costs.[71] These will tend to offset over time, but sustained variances in intermittent output can drive variances of sufficient magnitude that they noticeably affect collections from or returns to customers under our power supply adjustor.

We track reliance on intermittent sources in this portfolio evaluation as a potential differentiator between sources that are similar with respect to other characteristics like price, RES eligibility, or emissions, for example. The intermittency attribute also provides a directional indication of the trend in potential short-term portfolio cost fluctuations that we may see over time. We are currently seeking to obtain consultant assistance to model our energy portfolio, along with market prices, on an hourly basis in the context of a regional market simulation model. While we recognize the limits of such models, it is possible that this type of simulation tool will be able to help us characterize the short-term cost variance associated with intermittent generation, along with load and other factors, more quantitatively in future IRP analyses.

Finally, we note that the development of flexible energy resources like battery storage or controllable load tends to be complementary to a portfolio that is increasingly renewable and intermittent. Such resources have the potential to mitigate some of our exposure to short-term variances associated with fluctuations of renewable output—for example, through battery discharge during hours when renewable output is low and LMPs are high, or conversely through battery charging during hours when renewable output is high and LMPs are low.

Attribute: Portfolio Costs

Figure 8-9 illustrates the trend in our projected annual portfolio costs.

71 On the other hand, during periods when LMPs are relatively stable, offsetting temporary fluctuations in intermittent generation output tend to cause only modest fluctuations in net power costs.

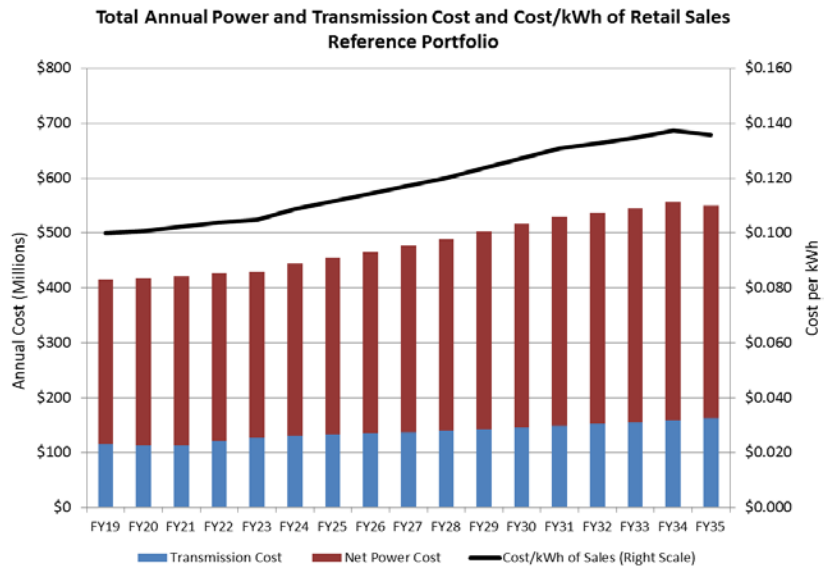

Figure 8-9. Total Annual Power and Transmission Cost and Retail Sales Cost per kWh Reference Portfolio

Power supply-related costs are the majority, but the blue portion shows that expenses for transmission by others (primarily Regional Network Service) amounts to roughly two cents per kWh of retail sales in the near term, increasing over time.

SENSITIVITY ANALYSIS

In contrast to the portfolio evaluations in our most recent IRPs, the Reference portfolio does not show any large, near-term needs to address sufficiency of supply or extreme market price exposure with respect to needs for energy, capacity, or Tier I and Tier II. If the future unfolds along the lines of the base case assumptions with respect to Vermont renewable resources and wholesale markets, there does not appear to be an urgent near-term need for new long-term resources to address these products. Continuation of our short-term programs for the purchase of energy and capacity, and for the sale of regional Class 1 RECs, is likely to yield a reasonable balance of portfolio attribute outcomes.

However, review of the Reference Portfolio evaluation suggests that several uncertainties could alter this conclusion, affecting the timing and magnitude of our portfolio needs. These uncertainties include:

- The future pace of net metering growth in our territory will affect our net power costs, as well as the volume of Tier II-eligible RECs that we hold for potential regional Class 1 REC sales, and the extent to which we have sufficient Tier II supply to address a potential shortfall of Tier III supply.

- The actual pace of Tier III supply that we experiences in the coming years could potentially produce a need to retire Tier II RECs. The pace of Tier III electrification measures will also affect our annual retail electric sales and energy requirements, although in a much more limited proportion.
- If future electricity sales to our customers turn out higher or lower than the base case forecast, the size of our open positions for several products, and relative need for long-term resources, will change.
- Since we are currently a meaningful seller of regional Class 1 RECs, future market prices for these RECs will remain a noticeable influence on our net power costs (with higher Class 1 REC prices generally resulting in lower net power costs for us). In addition, if future regional Class 1 prices remain very low (that is, well below $10 per MWh), it could make sense for us to retire for the purpose of Tier I compliance, some or all of the RECs that it presently sells to out-of-state buyers.
- In addition to these uncertainties, which are mostly or entirely outside of our control, we could choose to fill some of its forecasted future open position—for example, to lock in additional Tier I-eligible supplies, or to address resource needs focused on the long-term and the winter season.

Each of these themes is explored in the following sections via sensitivity cases. In this context, a sensitivity case means that one of the portfolio components or market price outcomes turns out differently from the base case, over the long term.

Sensitivity: Future Growth in Net-Metered Generation

Our Reference portfolio evaluation reflects future growth of net metering in our territory at a pace of 20 MW per year. This pace is high by regional and national standards, and sufficient to meet essentially all growth in our Tier II requirements during the next decade, even without help from larger, lower-cost MW-scale renewables. This pace would be consistent with a future in which residential and smaller group net metering projects continue at a substantial pace, but larger projects (over 150 kW) see more limited growth.

This sensitivity examines the portfolio implications that would be associated with actual net-metered capacity increasing faster or slower than the base case: The High Net Metering sensitivity reflects sustained growth of 30 MW/year; the Low Net Metering sensitivity reflects the growth of 10 MW/year. The most direct implication of faster or slower net metering growth would be more or less Tier II-eligible supply.

Figure 8-10 illustrates our Tier II gap chart for the High Net Metering growth sensitivity.

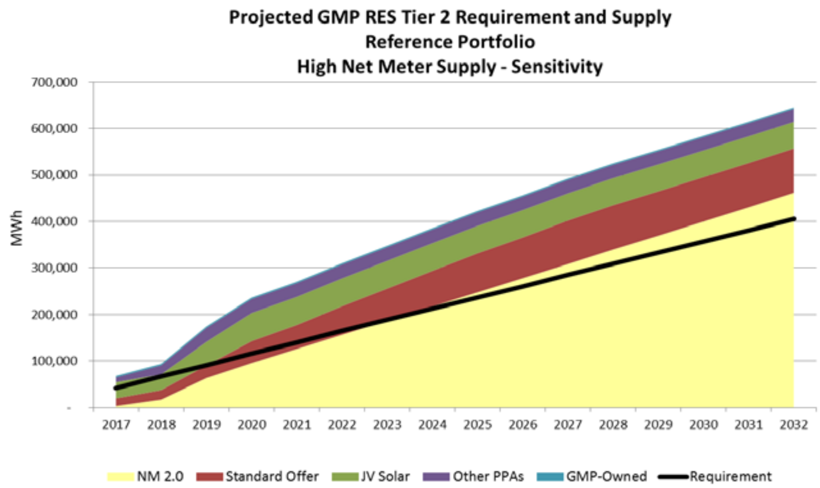

Figure 8-10. Projected Tier II Requirement and Supply Reference Portfolio: High Net Meter Supply

Figure 8-11 illustrates our Tier II gap chart for the Low Net Metering growth sensitivity.

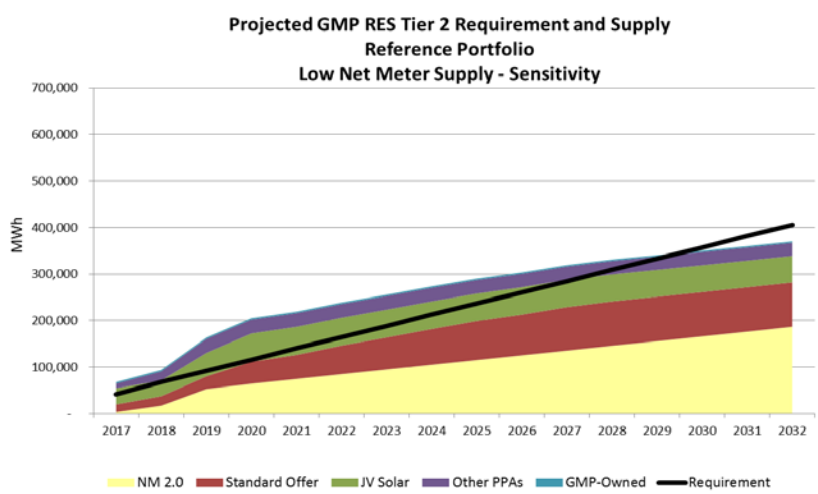

Figure 8-11. Projected Tier II Requirement and Supply Reference Portfolio: Low Net Meter Supply

Not surprisingly, the High Net Metering sensitivity (30 MW/year) shows that our supply of Tier II-eligible sources would grow more rapidly than the Tier II requirements, increasing our projected surplus of Tier II supply substantially over time. We would not need additional Tier II supplies to meet our requirements. In addition, we would have sufficient Tier II RECs to cover substantial shortfalls in Tier III supply if needed. In this future, we would expect our procurement of distributed renewables to be limited to projects that are cost-effective based on projected wholesale power prices alone, or that would provide a specific local benefit (for example, transmission and distribution deferral, pairing with storage to enhance local grid resilience). Estimated portfolio costs in this sensitivity are somewhat higher than the base case, because of the presence of additional net metering at prices higher than the wholesale power and REC value that they provide.

In the Low Net Metering sensitivity (10 MW/year), the pace of growth in net-metered generation fills a substantial fraction of the increase in our Tier II requirements, but not nearly all of it. Our projected near-term surplus of Tier II supply gradually erodes, nominally reaching zero in about 2029. Considering that there will be some degree of uncertainty in the pace of completion of new Tier II sources, as well as in the actual output of Tier II sources (for example, because of fluctuations in cloud cover), we would likely procure additional Tier II supply in the mid- to late-2020s under this future. Estimated portfolio costs in this sensitivity are somewhat lower than the base case, because of lower volumes of relatively high-priced net-metered supply.

Sensitivity: RES Tier III Supply

There is a substantial degree of uncertainty in the pace of Tier III transformation opportunities that can be found in our territory. Key uncertainties include the volume of C&I electrification opportunities, the pace of adoption of electric vehicles in Vermont, the future price of oil relative to electricity, and the pace of customer adoption of cold climate heat pumps and other devices.

Figure 8-12 presents our projected Tier III "gap chart"—comparing our projected Tier III-eligible supply to projected Tier III requirements on an annual basis for the next decade, under the base, high, and low Tier III supply scenarios presented in Chapter 4: Declining Electricity Demand.

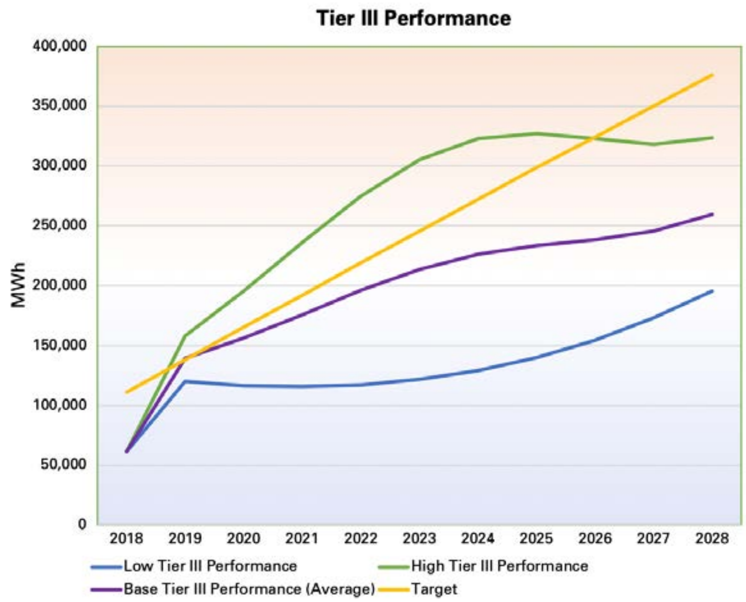

Figure 8-12. Tier III Supply Performance Scenarios

The potential Tier III supply paths shown here are quite wide; to some extent this reflects the fact that the RES program is new and we have has only limited experience with planning and acquisition of Tier III resources. The range also reflects the inherent uncertainty in some of the key drivers (for example, availability of cost-effective C&I electrification opportunities, pace of adoption of electric vehicles in Vermont). The indicated shortfalls relative to the Tier III requirement in many years are therefore illustrative. We plan to seek Tier III compliance in a cost-effective way—pursuing sufficient programs (and offering sufficient incentives) to meet the requirements without paying more than necessary, and ideally spending much less than the Tier III ACP, on average. To the extent that the pipeline of future Tier III supply appears to be insufficient to meet the annual requirements, we would expect to review our program offerings including incentive levels with an eye toward stimulating greater customer participation.

Under the RES framework, another option available would be to meet the Tier III shortfall by retiring additional Tier II RECs (quantities in excess of the annual Tier II requirements). Figure 8-13 illustrates the potential portfolio implications of pursuing this option.

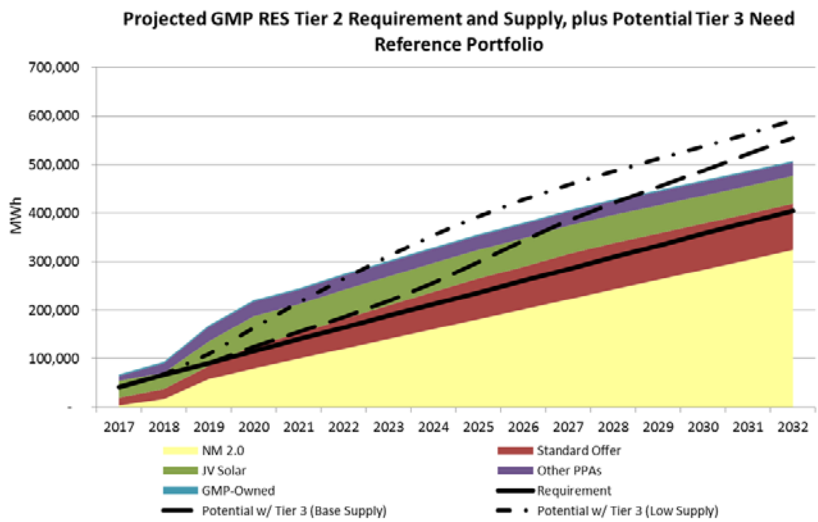

Figure 8-13. Projected Tier II Requirement and Supply Plus Potential Tier III Need Reference Portfolio

Specifically, the solid line represents our estimated annual Tier II requirements. The two new dashed lines illustrate the higher total volume of Tier II-eligible RECs that we would need to also meet the entire projected shortfall of Tier III supply under the Base and Low scenarios of Tier III supply (identified in Chapter 4: Declining Electricity Demand).

The lower dashed line indicates that our presently projected supply of Tier II-eligible RECs would, under base assumptions for electric sales and net metering growth, be sufficient to cover potential shortfalls of Tier III supply under the Base Tier III supply case for most of the next decade. In this future, we would have fewer RECs to sell to the regional Class 1 market; to address a projected gap in the late 2020s, we would presumably evaluate banking Tier II RECs in the mid-2020s, or procuring additional Tier II supply.

The higher dashed line indicates that under the Low Tier III supply scenario, in which Tier III supply falls substantially short of requirements very early in the planning horizon, almost all of our projected supply of Tier II-eligible RECs would be required to meet the Tier III shortfall. Under this future, we would likely seek to procure additional Tier II supplies in the early 2020s.

Because these sensitivities conceptually represent bounding cases, since we would explore other Tier III program options if low supply begins to materialize, they provide an indication of the significant magnitude of Tier II RECs that could potentially be needed to assist with Tier III compliance under some circumstances, at least in some years. Thematically, this indicates that the adequacy of our forecasted Tier II REC supply could depend to some degree on the actual path of Tier III supply, and that the pace of our actual Tier III supplies and pipeline of Tier III projects for future years, should be monitored as a leading indicator of Tier II needs.

One other implication of retiring additional Tier II RECs above RES requirements to cover a shortfall in Tier III supply, is that our portfolio emission profile would likely be slightly lower, as additional distributed renewables displace market power sources supplied by natural gas or the regional system residual mix.

Sensitivity: Regional Class 1 REC Market Prices

Long-term PPA sources and owned renewable plants provide a substantial inventory of RECs that are eligible for Class 1 RPS compliance in neighboring states, but not eligible for Tier II because of the size or age of the plants. Although regional REC price expectations have declined significantly, the Reference Portfolio evaluation assumes that it will continue to be cost-effective to sell those RECs and use the revenues to reduce our net power costs and electric rates, rather than retiring them for Tier I compliance.

This sensitivity explores what would be the portfolio implications if regional Class 1 REC prices turn out significantly higher or lower on a sustained basis, reflecting the High and Low REC Price scenarios (outlined in “Market Price Inputs to the Portfolio Analysis” on page 8-58).

The first-order effect of higher or lower regional Class 1 REC market prices is that we would receive less REC revenue for its projected inventory of salable Class 1 RECs (that is, those that are eligible for Tier II compliance). Based on a projected REC inventory on the order of 800,000 MWh during the mid-2020s, the High REC Price scenario would increase our REC revenues, and therefore lower net power costs and retail rates, by about $7 million/year, relative to the Base REC Price scenario. Through the year 2035, this amounts to about $57 million (present worth) of additional revenue. The Low REC Price scenario has the opposite effect, lowering projected REC revenues and increasing net power costs by about $64 million (present worth).

An additional consideration is that if regional Class 1 RECs were to fall to historically low levels, it could become increasingly cost-competitive for us to retire some or all of its REC inventory for compliance with Tier I. Retiring these RECs would forego some amount of resale revenue at then-current Class 1 market prices, while reducing the amount of RECs we would need to procure from other renewable sources. For a sense of scale, Figure 8-14 illustrates the magnitude of Tier I requirements that we could meet by retiring all of our projected Class 1 REC inventory, starting in the mid-2020s.

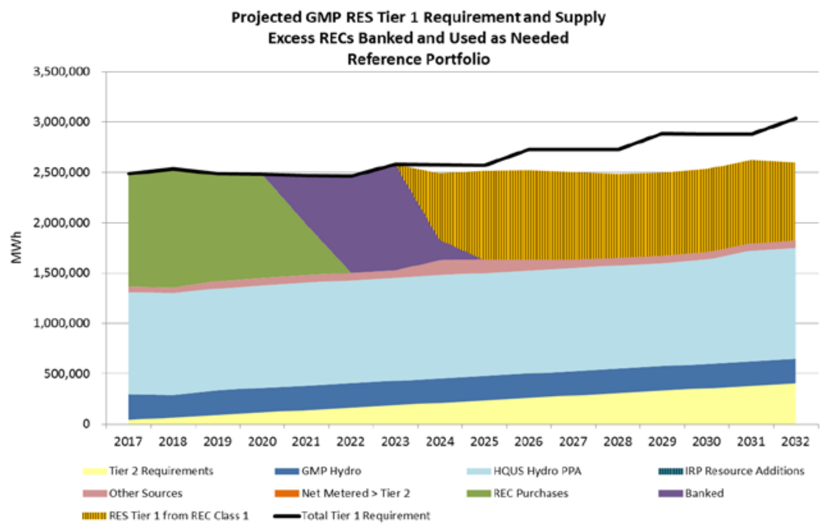

Figure 8-14. Projected Tier I Requirement and Supply Excess RECs Banked and Used Reference Portfolio

As illustrated in Figure 8-14, retirement of our full inventory of Class 1-eligible RECs could cover the vast majority of our projected Tier I needs in the 2020s.

It would likely only be cost-effective to retire our Class 1-eligible RECs in a low REC price environment. Foregoing regional Class 1 REC sales beginning in 2024 under the Base market price outlook would increase our estimated net power costs by $8 million or more per year. Under the High market price outlook, retiring the Class 1 RECs could increase our net power costs by $15 million or more per year.

Sensitivity: RES Tier I REC Prices

Our estimated Tier I open (short) position is substantial—on the order of 1 million MWh/year starting in the mid 2020s—making the purchase of additional renewable supply in the 2020s a priority. Based on the projected open position, this sensitivity explores the potential impact on our net power costs if future prices to acquire Tier I-eligible RECs turn out along the lines of the high and low price outlooks (summarized in "Market Price Inputs to the Portfolio Analysis" on page 8-58.)

Table 8-2 summarizes the results.

Tier I REC Price Outlook	REC Purchase Cost ($NPV)	Difference from Base Outlook
Base	$14.5 million	n/a
High	$24.4 million	$9.9 million
Low	$4.5 million	($10 million)

Table 8-2. Estimated Cost of Tier I REC Purchases

This sensitivity indicates that the High and Low Tier I REC price outlooks present a range of plus or minus $10 million (present worth) relative to the base price outlook. In the late 2020s, the upside cost exposure in individual years is roughly $2 million to $4 million. This range of cost uncertainty is not extraordinary in the context of our total portfolio costs, and we have some time to address it. But the exposure is meaningful, and indicates that in the coming years, we should be on the lookout for potential resources—such as low-priced REC purchases that may become available, or opportunities to affordably acquire existing renewables on a long-term basis (via PPAs or asset purchase)—that could be used to mitigate this exposure at reasonable prices.

Sensitivity: Retail Electricity Sales

This sensitivity explores the portfolio implications of electricity sales turning out higher or lower than the base case forecast. The high sales case reflects an increase of three percent over the next five years (that is, by 2024); this could credibly be driven by a combination of one or more of the following: more Tier III electrification projects than reflect in the base case; somewhat more favorable economic and demographic trends; and net metering growth slower than the base case forecast. The low sales case reflects a decrease of five percent by 2024. This would be consistent with a future in which the drivers of electrification, economic growth and net metering exert downward pressure on electricity sales; we test a larger decline because of the risk of discrete sales reductions if one of our major industrial customers were to reduce its operations.

Figure 8-15 and Figure 8-16 illustrate the scale of impact that these changes would have on our projected energy and capacity gap charts.

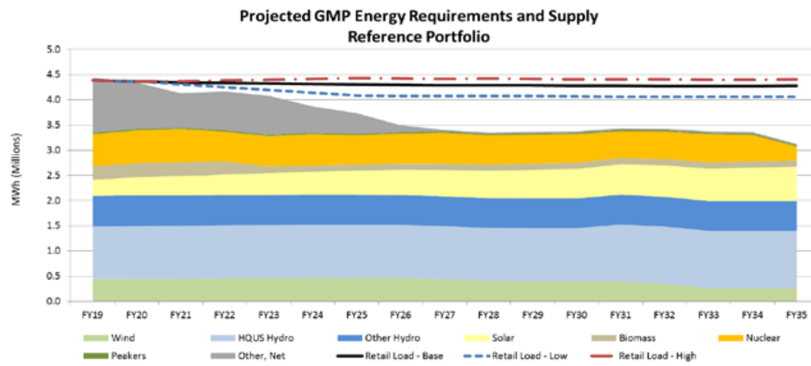

Figure 8-15. Projected Energy Requirement and Supply Reference Portfolio

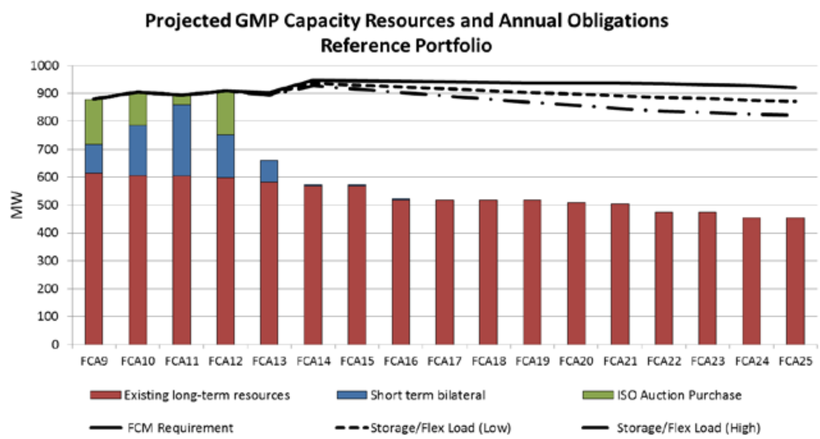

Figure 8-16. Projected Capacity Resources and Annual Obligations Reference Portfolio

The High sales sensitivity would not leave us "open" (and exposed to market prices) to a degree that is concerning. The Low sales sensitivity would, however, more noticeably reduce our estimated open energy position, and would moderately increase the fraction of our portfolio that is hedged by long-term sources. At these levels, our portfolio costs would still be moderately linked to trends in regional market prices, so this observation is not a fatal flaw that requires action at this time. It does, however, reinforce our sense that large long-term energy sources are not presently needed for the purpose of energy cost stability, and that the primary motivation for adding new long-term sources should be to address other strategic priorities—such as achieving the RES requirements; managing peak-driven costs; and enhancing grid resiliency.

POTENTIAL LONG-TERM RESOURCE ADDITIONS

The Reference portfolio does not show any large, near-term needs to address sufficiency of supply or extreme market price exposures with respect to most portfolio products. Our estimated need for additional renewable resources to meet Tier I requirements is substantial, however, at roughly 800,000 to 1 million MWh/year from the mid-2020s onward. This raises the question of whether it may be appropriate for us to seek additional long-term renewable sources in the 2020s, to reduce this gap and what types and volumes may be appropriate. While our committed sources are estimated to cover up to 80% of projected energy requirements during most of the 2020s,[72] long-term resources acquired during the 2020s could also help replace some of the substantial energy resources that are scheduled to expire by 2035.

To explore the potential merits of additional long-term renewable sources to our portfolio, we tested the following illustrative potential additions. Each of these resources would provide renewable energy on a long-term basis, and would likely offer price stability past the expiration of our major sources in the mid-2030s, but their portfolio implications would be somewhat different.

50 MW of plant-contingent existing hydro. This resource reflects a long-term PPA for the output of one or more existing hydro plants, or a purchase of existing hydro capacity in the region. Existing plant-contingent hydro has the potential to provide renewable energy to meet Tier I, along with some amount of capacity, on a long-term basis. An asset purchase or long-term PPA would most likely feature stable or fixed pricing over time, although we would be open to exploring other pricing arrangements. If this resource featured an average annual capacity factor of 50%, it would provide about 220,000 MWh/year. For this analysis, we assume that plant-contingent hydro would be priced consistent with our 2016 PPA purchase from the Sheldon Springs plant—which starts under $50/MWh for energy and RECs, with capacity priced separately. Plant-contingent hydro output would be delivered on an as-available basis, subject to some amount of intermittency based on streamflow variations; the degree of correlation with our existing hydro fleet would depend to some degree on what (if any) ponding capacity it possesses, and the river system it is located on including its geographic proximity to our plants.

25 MW of firmed hydroelectric purchases, similar to the product that Massachusetts is seeking to purchase via the proposed NECEC line in Maine. We assume that this product would be delivered on a firm "7x24" basis, thus providing hydroelectric energy without the fluctuations in output that are associated with plant-specific sources. For this analysis,

[72] Because not all committed sources feature fixed or very stable prices, the fraction of our portfolio that is hedged on a long-term basis is somewhat less.

we assume that firmed hydro would be priced consistent with publicly reported pricing for the commodity portion of the NECEC purchase (not including transmission), starting at around $53/MWh] and escalating gradually over time.

50 MW of offshore wind. This resource would likely be pursued for its long-term price stability and winter-weighted output profile. We assume pricing of about $75/MWh (escalating over time), consistent with reported pricing recently offered to Massachusetts. Relative to onshore wind, offshore wind would likely offer value through higher capacity ratings and diversity of output profile, and potentially through higher locational energy value. Because offshore wind plants would not be eligible for Tier II because of their large size and location, it appears likely that if we purchased the output under a bundled contract, we would use the energy and capacity as hedges for our open positions, and sell the RECs to the regional Class 1 market (of course, using the revenues to lower power costs and retail rates).

Our primary opportunity to participate in either of the latter two resources would likely be as part of a large solicitation conducted by a neighboring state or aggregation of buyers.

We would also consider purchasing additional solar PV, particularly if solar prices continue to decline over time. We did not test this option here because our portfolio already contains a large and increasing amount of solar PV, and the solar PV output profile is not as well-matched with our projected energy portfolio needs which are largest during winter months and off-peak hours.

The firmed hydro product is somewhat more costly under our assumptions than the plant-contingent hydro; this is only illustrative because pricing for hydro resources would be project-specific based on market conditions at the time the resources are offered. The primary attribute difference is that the plant-contingent hydro source would add 50 MW of additional intermittent supply to our portfolio.

Figure 8-17 shows our resulting reliance on intermittent sources with the plant-contingent hydro purchase—several percent higher than for the Reference Portfolio.

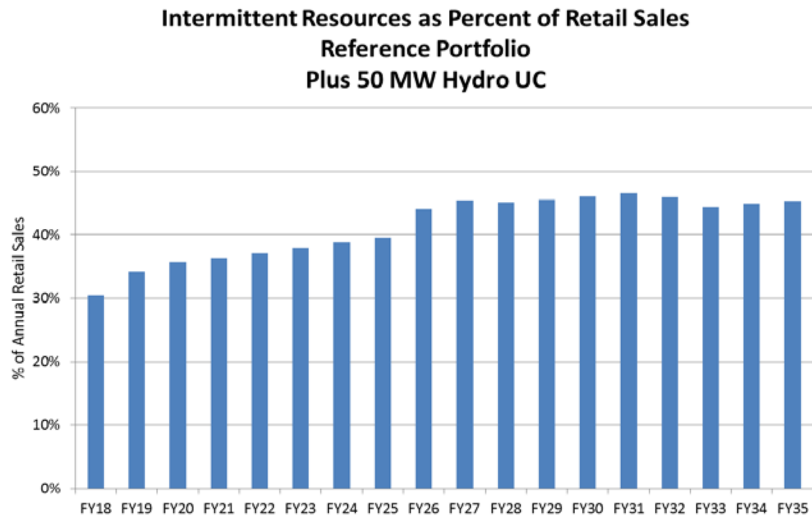

Figure 8-17. Intermittent Resources as Retails Sales Percent Reference Portfolio, plus 50 MW Hydro

The higher assumed price of offshore wind in our analysis is partly although not fully offset by higher assumed weighting] of output toward higher-value winter months. Offshore wind would increase our intermittent reliance to a similar degree as the plant-contingent hydro option, so we do not present a unique chart here. We note, however, that fluctuations of offshore wind output would probably be somewhat less correlated with our existing onshore wind portfolio than a plant-contingent hydro purchase in New England might be to our existing hydro fleet.

Based on these initial observations, it appears that each of these renewable sources could be credible long-term additions to our portfolio. We therefore include smaller amounts of each of these sources in the Illustrative Future Portfolio, with assumed acquisition dates ranging from the mid to late 2020s. We emphasize these resources are in no way committed, in part because their availability is uncertain, particularly for the firmed hydro and offshore wind options. In addition, the relative attractiveness of these resources will depend significantly on when they become available and at what price levels, along with other factors—such as expectations for regional Class 1 REC prices; relative capacity values; and correlations of output of the plant-specific sources with the output of our existing portfolio and wholesale energy market prices.

PEAKING AND FLEXIBLE LOAD RESOURCES

As is discussed in several places in this IRP, flexibility of resources is an important factor when evaluating the importance of any given asset on a distributed grid. Battery storage systems prove themselves to be one of the most flexible of the resources that are currently available. In this section, we dive a little deeper into the value streams, or 'use cases', that a battery system can provide and how we intend to utilize storage as an integral part of our portfolio. We discuss these value streams primarily with respect to battery storage resources, but many of them also apply to flexible load resources that can manage electricity use at key times. It should be noted that in this instance, the term 'portfolio' does not simply mean our power supply portfolio, but our entire operating energy space including the T&D system, resiliency, and emergency power along with direct customer power quality resources.

Currently, the greatest monetized value stream of energy storage comes from its peaking capabilities: by reducing our net system load at the time of the annual ISO-New England peak, we can limit our share of regional capacity obligations; reducing load during monthly Vermont peaks can limit our share of regional network service transmission costs. Batteries can be considered very similar to a peaking generator, such as a diesel generation set. When the peaks occur, these resources can be dispatched, and in the case of batteries, actually lower the net load that we are pulling from the bulk system in real-time, thereby lowering the cost that our customers ultimately pay into the capacity market or for transmission service. This peak management role can be viewed as one of the simpler value streams provided by battery storage. It has been the largest monetized value stream for our battery projects to date. As described in Chapter 5: Our Increasingly Renewable Energy Supply, 1 MW of peak reduction during a single hour from a battery storage system can save customers as much as $100,000 annually in reduced capacity costs.

As of December 1, 2018, we have the following storage systems deployed:

- 2 MW/1 MWh Lithium Ion System + 2 MW/2.4MWh: Stafford Hill Solar Storage facility
- 1 MW/4 MWh Lithium Ion System: Panton Storage Park
- 5 MW/13.5 MWh Lithium Ion System: Powerwall 2.0 residential batteries

The following projects are in development and permitting:

- 2 MW/8 MWh Lithium Ion System: Essex Solar-Storage Park
- 2 MW/8 MWh Lithium Ion System: Milton Solar-Storage Park
- 2 MW/8 MWh Lithium Ion System: Ferrisburgh Solar-Storage Park

In addition to the value derived from reducing system peaks, the following are values that are either being captured with existing battery storage or battery storage could be able to capture.

Energy Arbitrage. Because a battery can act as a load and a supply source at different times, it makes for an ideal energy arbitrage resource—meaning that it can store energy when spot market prices are low and discharge that energy later when marginal prices are higher, capturing the value of that spread with less cycle losses to lower net power costs. A noticeable amount of natural energy arbitrage should be achievable through use of storage resources for peak reduction purposes, because LMPs during near-peak conditions when a battery would discharge, tend to be significantly higher than during non-peak hours when the battery would recharge. As we get more skilled about optimizing the performance of battery and flexible load systems, we will strive to achieve greater energy arbitrage by taking advantage of spreads between high and low or even negative spot market energy prices that occur during non-peak days.

Operating Reserves. Under FERC Order 888, the FERC ordered all ISOs to allow battery storage to participate in any markets just as any other resource could. This means battery storage can become an operating reserve resource in the ISO market. However, when participating in a market like this, you may have to give up other peaking benefits so weighing the value of this against the loss of those other opportunities is important in deciding if you should pursue this value stream.

Intermittent Generation Output. The difference in solar generation on sunny days and cloudy days can amount to many tens of MW of spot market energy market exposure for us. Hydroelectric and wind generation can also fluctuate greatly on a daily and hourly basis. In combination, output fluctuations from renewable sources can amount to over 100 MW. While such fluctuations are not costly when spot market prices are stable, having a tool to blunt the financial exposure associated with significant swings in intermittent output is useful from a portfolio perspective; storage and flexible loads at a large enough scale can fit that role nicely. These resources provide us with a resource that can either soak up, or fill in gaps that are created when significant swings in PV output occur.

Frequency Regulation. ISO-New England runs a market that compensates fast acting resources for providing quick power response on the time scale of a few seconds, to maintain a stable frequency on the regional grid. This service has traditionally been provided by large natural gas and hydroelectric power plants, but can now be provided by fast-responding battery systems. Our Stafford Hill solar storage facility was the first battery system to participate in the commercial frequency regulation market in New England.

In addition to power supply benefits, battery storage provides a useful tool to manage the local T&D system as well as create a resiliency resource which include the following additional use cases:

Customer Resilience and Backup. Residential and Commercial customers can benefit from the emergency backup power that storage can provide. Certain C&I customers are also very sensitive to voltage fluctuations which can interrupt their business process costing the customer lost production or product.

System Resiliency. With the addition of substantial distributed solar generation across our system we have a resource that can potentially be tapped into during outages on the broader electricity grid. A key link to allow such local generation, or other forms like distributed hydro, to carry load on sections of our system is battery storage, along with sophisticated control systems that enable load generation and load to be balanced in real time. We are presently designing the protection and controls to be able to perform this function safely and reliably.

Distribution System Voltage and Var Management. In addition to the energy that can stored in the battery and released when needed, the inverter and associated power electronics provide the ability to dynamically adjust voltage and reactive power (Vars) at the point where the battery system is connected. This can be very important at sensitive C&I customer locations where voltage quality is extremely important to their process.

Distributed Generation Integration. As distributed solar PV installations increase, we are seeing more and more circuits reaching their saturation point. While current interconnection rules do not allow us to perform upgrades to the system to handle more generation, we anticipate that storage will be leveraged in some cases to manage interconnections. As an example, battery storage could be used in some instances as a load during the middle of the day, effectively absorbing excess local solar generation and then allowing that stored energy to be utilized later in the day and evening when local generation declines.

The Future of Energy Storage and Flexible Demand

Over the next decade, we will continue to develop storage capability through multiple channels. It will become increasingly important to harness value streams other than peak management, as there is essentially a finite amount of peak reduction that is practical and cost-effective. While small peak reductions may be practical using short-duration resources that are deployed only occasionally and for a few hours, reducing the Vermont or GMP peak by larger amounts (for example, many tens of MW) would require reducing load during more hours and more days.

Figure 8-18 shows an example of a near-peak December day, when achieving large peak reductions would have required us to reduce load across most of the day.

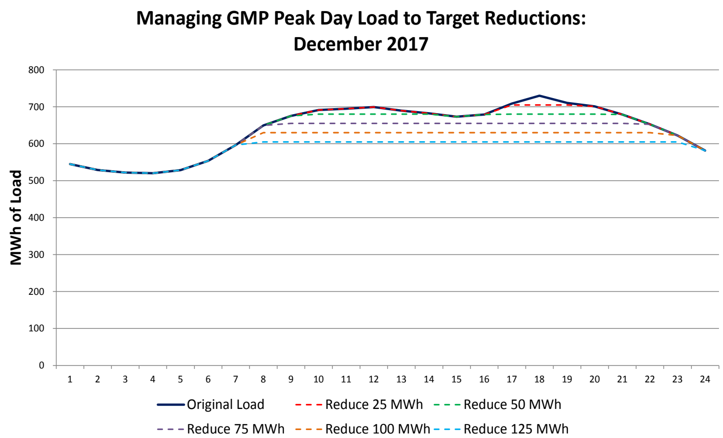

Figure 8-18. Managing Peak Day Load to Target Reductions: December 2017

The countervailing point to this, however, is that strategic electrification could provide pressure in the opposite direction, pushing peaks upward from some new loads that are not controlled as a flexible resource. The specific mix of storage and the locations will depend on a number of outcomes including some distribution analysis that is currently underway to rank circuits across the state for storage.

With that in mind, our current deployment strategy has several key parts.

Customer Resiliency and Power Quality

We expect to continue deploying storage systems behind the meter of residential and C&I customer locations to improve power quality and resiliency, and to leverage all the stacked values identified. The mechanism for deployment will be a combination of direct partnership and enhanced Bring Your Own Device (BYOD) value through other entities, for a target of about 47 MW over the next 10 years. This assumes that storage will be deployed at 25 C&I customer locations with an average installation size of 500kW per location and that 8,000 residential customers will install battery systems at an average size of 4kW per installation. This includes expansion of residential behind-the-meter programs as well as expanding the offerings into the C&I space. Additional opportunities arise when a C&I customer is exploring the need for a major capital expense replacing a traditional fossil-fuel-fired back up generation system.

T&D System Support, Renewable Integration, and Circuit Level Resiliency

The transmission and distribution system have traditionally been managed with a set of resources to maintain or improve reliability and manage power quality. These include the typical poles and wires along with voltage correction devices such as voltage regulators and capacitor banks, and sectionalizing equipment such as switches, circuit breakers and intelligent technology, including relays and automation equipment to manage it all. Battery storage systems are providing us with a new tool that can be used at the right locations on the distribution or transmission system to improve the power quality of the system or even defer the need for certain growth-driven transmission or distribution upgrades. It's important to note that at present we do not have load growth driving the need for transmission and distribution upgrades, so these opportunities do not exist today, however, over the next decade it is conceivable to think that there could be discrete pockets where growth-driven improvements are needed.

While load is not growing, distributed generation is growing and the distribution of electricity over our system is growing along with it. This is quickly resulting in multiple distribution circuits reaching their saturation points, which then require significant protection or other system upgrades. The next distributed generation project to request interconnection would be on the hook for those costs. While under the current interconnection rules for generation, we cannot unilaterally increase the generation-hosting capacity of a circuit, energy storage appears to be an excellent resource to unlock additional hosting capacity and allow smaller rooftop solar systems to continue installing, for example. With that in mind, we have put an illustrative target for these types of T&D beneficial systems over the next decade of approximately 25 MW of systems. These systems will be procured a number of different ways including RFP, GMP developed, or even through a fixed-price method like Bring Your Own Device. (Chapter 5: Our Increasingly Renewable Energy Supply further explains the circulate analysis and ranking that we performing prior to deploying any grid-scale storage systems larger than 1 MW.)

With any grid-connected battery storage system we will be looking to create local islanding capability of entire portions of the distribution system. In 2018, we engaged with an engineering consulting firm to develop the necessary protection and control systems that will allow for solar and battery systems to safely and reliably island the distribution system without the need for any rotating machines. We are starting with our Panton battery storage facility and will be replicating the design to our other solar and storage projects.

A Sense of Scale

The pace of deployment of storage and flexible loads in our territory is subject to uncertainty, and will depend on actual outcomes related to factors that include storage cost trends; adoption of battery storage for backup power and power quality by residential and C&I customers; the prevalence and timing of local distribution system use cases; and the feasibility of replacing some fossil-fired peaking capacity with grid-scale storage.

Table 8-3 presents an illustrative sense of potential scale for several different use cases; together these amount to a potential scale on the order of 100 MW. For these reasons, we do not know today how many of these use cases will materialize together, and at what pace.

Location	Type	Rationale and Value	Potential Scale	Comments
BTM	Non-Battery Resources	Leverage all available DERs to knock down peak, such as water heaters, car chargers, and heat pumps.	10 MW	Includes growth in electrification of fossil fuel processes.
BTM	Residential Resiliency	Grid transformation and customer resiliency. Assumes 8,000 homes over the next decade install some form of integrated battery storage.	32 MW	Includes Powerwall program and BYOD. Install smaller scale, residential battery systems in homes.
BTM	C&I Resiliency & Power Quality	Resiliency package offering to C&I customers in addition to peak value stacking; replacing fossil generation or providing power quality support for sensitive commercial processes. Assumes up to 25 customers over the next decade with an average installed system size of 500 kW per location.	12.5 MW	Leverage storage to optimize customer operations, reduce certain costs, and improve power quality and resiliency.
BTM and Grid	T&D System Support & Hosting Capacity	Potentially includes anything from T&D upgrade deferrals to distributed generation hosting and other location-specific improvements, including constrained areas (such as SHEI).	25 MW	As T&D constrained pockets arise over the next decade, storage and flexible demand will be evaluated as a solution.
Grid	Grid Connected Storage Systems	Strategically located storage on our distribution system to provide resiliency, T&D benefits, and all power supply benefits. Also includes fossil fuel peaker unit replacements.	25 MW	Mix of PPA, GMP-developed, and other projects connected at grid scale.

Table 8-3. Illustrative Storage and Flex Demand Portfolio Over the Next Decade

We have included in the Illustrative Future Portfolio a range of 50 to 100 MW of reduction in our capacity requirements from these storage and flexible load sources, ramping in over a ten-year period starting in 2022.

Peaker Retirement and Portfolio Storage

We own approximately 100 MW of instate peaking capacity at six plants. These are primarily oil-fired combustion turbines constructed in the 1960s that operate infrequently primarily because of their high fuel expense. They are relatively flexible and can generally operate for extended periods of time if needed. The primary value stream that these units provide to our customers is capacity (their FCM self-supply value was very helpful in recent capacity auctions when prices cleared as high as $9.55/kW-month); quick-start operating reserves can also provide significant revenues, although not as consistently. They can also provide value in the energy market during occasional times when ISO-New England energy market prices temporarily spike to unusually high levels.

Our current base case capacity market price outlook features prices ranging from $4 to $7/kW-month during most of the 2020s. This outlook is considerably below the estimated cost of entry for new combustion turbine or peaking plants, but the peaking plants still can achieve significant value under this outlook, while also limiting our exposure to market prices with the potential for significant year-to-year price volatility around the long-term trend. Under this market outlook, we expect that our peaking units will continue to be financially viable resources for our customers, with the market value of their output at least equal to their operating and capital costs.[73] On the other hand, if a major equipment failure were to occur at any of these plants, requiring a major capital investment to fix, it is possible that the plant's economic viability could be jeopardized. We would expect to review a plants estimated costs and value of output before making a large expenditure of this type.

For the Illustrative Future Portfolio, we assume that one of our peaking plants will retire in the mid-2020s, and that a second one will retire in the early 2030s. These dates are credible placeholder assumptions for these plants based on their ages but are strictly illustrative, since the actual long-term viability of the peaking units could vary greatly based on plant-specific equipment condition and performance in the coming years. In actual practice, when considering the potential retirement of an existing peaking unit, we would expect to consider several factors and questions, in addition to the costs and value of the plant's output:

- Would there be significant implications for the design and operation of the VELCO transmission system or our subtransmission system? Instate peaking plants sometimes provide operational support under some operating conditions like outages of transmission lines or equipment for example, and they are considered in design of the transmission system to handle contingency conditions. It is therefore possible that retirement of an existing peaking plant without replacement could trigger the need for some additional grid investment that would not be apparent based on wholesale power market prices.

73 The possible exception is the Rutland combustion turbine unit which has recently experienced more operating challenges than the other units; we are presently reviewing the long-term viability of this unit.

- Could repowering make sense? We have considered the replacement of existing peaking plants with equivalent or larger generation equipment. This type of repowering has the potential advantage of leveraging existing transmission and site infrastructure, to achiever lower cost than a similar plant at a "greenfield" site. Our current base case capacity price outlook features prices significantly below the estimated cost of new entry for newly constructed peaking plants, so a repowering option would likely not be cost-competitive in the next several years unless repowering could displace local grid investment that would otherwise be necessary.
- Could the site be productively used for an alternative peaking generation resource—including large scale battery storage? Our experience with battery storage to date has focused on projects sized 1 to 2 MW, but larger projects (for example, 5 MW to 15 MW) could achieve lower capital costs per kW through scale economies. It does not appear that battery storage is broadly cost-competitive with combustion turbine peaking plants at current pricing, although capital costs are anticipated to decline significantly during the next decade. In additional, when other potential value streams that storage can provide are considered, the economics of storage as a peaking resource can get a lot closer. It appears that replacement of aging peaking capacity will warrant consideration as a use case for battery storage in the 2020s, particularly if some amount of local grid investment would otherwise be necessary. We expect that a significant design consideration for this use case will be what size of storage system is required—to ensure capacity value in the FCM and to provide grid support if needed—since existing peaking plants are capable of running for many hours at a time.

LOCATIONAL CONSIDERATIONS

The New England electricity market is uncongested during substantial fractions of the year, allowing energy to flow freely across the transmission grid from power plants to serve load anywhere in the region. During uncongested conditions, LMPs at all locations differ only based on (typically modest) differences in the marginal loss component. In contrast, when there is congestion on the transmission system, the commitment and dispatch of power plants in the region must be constrained to avoid violating one or more operating limits. Examples of such operating limits include ones that are designed to avoid thermally overloading a transmission line, or to avoid conditions in which an unanticipated contingency event would have unacceptable operational impacts that would threaten reliable grid operation. During these conditions the congestion component of LMPs on opposite sides of export-constrained and import-constrained interfaces can differ significantly—which, in turn, can significantly affect the payments that generators receive for their output and the payments that load serving entities pay for their load obligations.

We are an integrated utility that purchases our load requirements from the ISO-New England market at the Vermont Load Zone, and sells the output of its generating sources and PPAs to the market at individual nodes. The net effects of transmission congestion on us can be positive or negative, depending on the location of the congested interface relative to our load and generation sources. Similarly, the value of a potential future generation resource (for example, a potential PPA to purchase output from a generating plant) to us and our customers can depend not only on the resource's total price, but also the extent to which the value of its output in the ISO-New England market is reduced (or enhanced) by effects of transmission congestion and losses.

The remainder of this section discusses congestion associated with transmission interfaces that are sometimes congested today, along with potential future congestion issues that could have implications for the operation of Vermont generation or the feasibility and cost of installing new generation.

Sheffield-Highgate Export Interface

The Sheffield-Highgate Export Interface (SHEI) area refers to a region in northern Vermont that is bounded by the 115 kV loop spanning from the Sheffield–Lyndonville (K39) line to the Highgate-St. Albans (K42) line. The amount of generation and transmission imports that delivery energy into this area far exceeds the load in the area. If certain system contingency events were to occur during some conditions, unacceptable operational consequences (such as a voltage collapse) could occur. ISO-New England established the SHEI interface to limit power flow from the area, by establishing a set of interface export limits[74] for various system conditions. During a limited fraction of the year (typically when local generation is high and local load is low, or when elements on the bulk transmission system are out of service), potential generation in the area can exceed the amount that could be accommodated by the export limit. In such times the SHEI becomes export-constrained, and a local generation source must reduce generation so that export limit is not exceeded. This adversely affects us and our customers (along with those of most other Vermont utilities) because the KCW plant is often required to reduce output, and because LMPs paid to our generating sources (such as HQ-US PPA, KCW, and Sheldon Springs hydro) during export-constrained conditions are lower than they would be if the interface were not constrained.

We are exploring potential solutions to cost-effectively mitigate SHEI congestion, as are others. VELCO's useful Northern Vermont Export study estimating the extent to which a range of potential solutions[75] would (individually, or in combination) increase the SHEI operating limits. We have collaborated with Enel (the owner of the Sheldon Springs plant) to install automatic voltage regulation (AVR) capability at the plant—a low-cost partial solution. We expect this system to be operational and to conduct ISO-New England testing in the near future, in hopes of increasing the SHEI limit in early 2019. GMP and other Vermont utilities, assisted by VELCO, are also collaborating in a working group to evaluate additional steps to cost-effectively reduce or eliminate current levels of SHEI congestion; we expect to identify one or more recommended steps in the first quarter of 2019.

Installation of additional generation in the SHEI area will tend to increase the frequency and depth of congestion on this interface, and will tend to offset the benefits of potential solutions that GMP and Vermont utilities may deploy on behalf of their customers to mitigate current levels of congestion. GMP and other Vermont utilities

[74] The SHEI limit is currently set to manage post-contingency voltage performance. VELCO indicates that if the voltage limit is substantially increased, thermal performance may also become limiting.

[75] Potential solutions include relatively discrete and limited-cost projects such as installation of reactive devices; reconductoring of existing subtransmission lines; and deployment of battery storage. Larger and more costly options include replacing existing transmission lines or constructing new lines.

have therefore intervened in Certificate of Public Good proceedings for some proposed distributed renewable projects that would be located in the SHEI area, in hopes of helping the Commission understand the costs that additional congestion could impose on Vermont customers. To the extent that future generation projects are proposed in the area (particularly large projects, and ones that would sell their output to out-of-state buyers rather than help to meet Vermont renewable requirements), we expect that petitioners will need to clearly demonstrate that their projects will not impose adverse congestion impacts on Vermont customers. This could potentially be accomplished by implementing or financially supporting one or more of the aforementioned SHEI mitigation steps.

Potential Transmission Import Projects

The most immediate potential for additional congestion on the Vermont transmission system appears to stem from major import transmission projects that proposed to deliver substantial volumes of power into Vermont. For example, in 2017, analysis of the proposed Vermont Green Line (400 MW, to deliver power for sale to southern New England buyers) showed that the project would likely create significant north and south transmission congestion, and might require significant backing down of existing Vermont renewable generation (for example, the McNeil biomass plant or existing hydro and wind plants). Bulk transmission projects that would deliver large volumes of power also have the potential to cause overloads on our subtransmission system, particularly under contingency conditions.

We expect that sponsors of bulk transmission projects delivering power into Vermont as well as proposers of significant generation projects that are proposed for the purpose of selling output to out-of-state buyers, will need to clearly demonstrate that their projects will be beneficial to Vermont electricity customers, taking into account grid impacts. This would presumably include detailed transmission system analysis to identify reasonably anticipated bulk transmission system congestion impacts, and the implementation of appropriate measures to mitigate them.

Future Vermont Generation

Other transmission system constraints could develop in Vermont over time, as additional distributed generation is deployed. In most cases, the initial limiting factor will be the distribution and subtransmission system (further discussed Chapter 6: Transmission and Distribution), however, enough distributed generation will eventually cause issues to arise on the bulk transmission system. To shed light on where and how such constraints might occur, VELCO's 2018 Long Range Transmission Plan (LRTP) explored Base and High Solar PV scenarios in which Vermont reaches a total of 500 MW to 1,000 MW of distributed solar generation, respectively, by the mid-2020s. While it appears that 1,000 MW substantially exceeds the volume of solar PV that will be deployed to meet the needs of Vermont customers by the mid 2020s, the VELCO analysis is instructive.

Under the High Solar PV case, VELCO's analysis indicated that this volume of additional distributed solar generation would overload some lines and transformers on the 115 kV system, with other areas of concern that include voltage regulation (pre- and post-contingency); overloads on subtransmission elements; and increasing system losses. Experience with the SHEI interface, along with insights from the VELCO LRTP, suggest that policies will need to be developed (or refined) to help address these considerations. For example, if the potential for transmission congestion is sufficiently understood, guidance or incentives with respect to the location of future distributed generation (and potentially load) might be developed to limit the degree to which transmission constraints are aggravated (or new ones created) by the deployment of additional distributed generation, and therefore the amount of grid investments and associated costs that must be incurred to mitigate those constraints. We are already encountering multiple instances where deployment of distributed generation is reaching export limits on the distribution system, the level at which locational guidance is needed first (as further discussed in Chapter 5: Our Increasingly Renewable Energy Supply).

The most appropriate forms of guidance are not yet certain, and will need to be developed thoughtfully. For example, VELCO notes that to limit future transmission system constraints, restrictions on growth of distributed generation in particular areas (for example, those that appear *likely* to trigger grid concerns) may not be as effective a strategy as directing generation toward areas that appear *unlikely* to aggravate such constraints. Further, VELCO analysis suggests that strategic location of distributed solar PV, the Vermont grid could accommodate over 1,000 MW of such generation. While this analysis focused only on transmission capacity, and other considerations such as siting and costs would need to be weighed, it hints at the potential to mitigate congestion on the transmission and subtransmission system through more strategic location of future distributed generation.

In addition to more strategic location of future generation, the occurrence and severity of transmission and distribution system constraints could potentially be mitigated by the deployment of battery storage in selected locations. Storage can act as a load during high distributed generation output times and the required inverter systems can also provide dynamic voltage support to mitigate adverse voltage performance on the transmission and distribution system.

Finally, in an environment of increasing renewable generation it appears appropriate to make future larger renewable generation sites dispatchable—that is, capable of turning down output automatically if and when needed—where this is practical. While it may seem counterintuitive to consider reducing output from a renewable power source with no fuel expense, this capability can be beneficial for our customers in some circumstances. For example, reduction of output during some conditions (very high local generation and low load) could conceivably help to avoid or limit anticipated distribution system overloading or transmission system congestion more cost effectively than an infrastructure investment. Similarly, the ability to temporarily reduce output from a renewable plant could be valuable during instances when LMPs are temporarily negative.[76] Pairing energy storage with these facilities can perform the same function without actually reducing the output of the facility.

ILLUSTRATIVE FUTURE PORTFOLIO

This section presents an illustrative future portfolio of supply resources, incorporating the observations and insights presented in this chapter. The illustrative future portfolio is "preferred" in the sense that it outlines the types of resources that we expect to explore or maintain in the next decade—including plausible types and amounts of resources that may be appropriate to help us meet the requirements of Vermont's RES program and manage wholesale market exposures—based on our current understanding of wholesale markets, customer preferences, and resource options. We do not appear to face any major portfolio deficiencies that require major long-term resource decisions or commitments at this time, or apparent "fork in the road" choices that would entail mutually exclusive resource options. This reflects the fact that our portfolio is more balanced and features more modest open positions than in the past, and many of the primary resource that we expect to pursue are relatively modular in scale and would be implemented over time in steps. The future portfolio is therefore illustrative in that it does not reflect any firm commitments, and the types and amounts of resources that we actually acquire could evolve over time in response to the factors and signposts outlined in this chapter.

There are several notable resource components of the Illustrative Future Portfolio.

Acquisition of additional distributed renewables over time, as needed to meet Tier II requirements including appropriate allowance for uncertainty of forecasted supply growth. Our base case assumptions do not show a need for new Tier II renewables in the near term, so we

[76] See Chapter 3: Regional and Environmental Evolution, for a discussion of the increasing occurrence of negative energy pricing under ISO-New England's Do Not Exceed dispatch framework.

have not built explicit new distributed renewable additions into the portfolio model. But it seems clear that the timing and amount of potential need for additional distributed renewables could change based on the actual pace of growth of net-metered generation as well as Tier III supply in the coming years.

A limited mix of hydro (plant-contingent, or firmed) and offshore wind during the 2020s. The hydro resources could lock in a portion of our forecasted Tier I needs; the offshore wind could offer an attractive seasonal output profile and diversity from our other renewable resources. All three resources would have the potential to provide long-term portfolio cost stability after the expiration of major PPAs in the mid-2030s.

Acquisition of additional storage and flexible load resources. We assume that 50 to 100 MW of these resources will be deployed in our territory over the next decade, to address a mix of the potential use cases (as discussed in "Peaking and Flexible Load Resources" on page 8-33; and in Chapter 5: Our Increasingly Renewable Energy Supply). We recognize that the actual mix of resources, and the appropriate pace of deployment, is substantially uncertain and will depend strongly on several factors (including battery cost trends, customer needs for resiliency solutions, wholesale market price trends, among others) that will affect the cost-effectiveness of these resources and the scale of market for them.

Ongoing operation of our existing peaking plants. These plants rarely operate but do provide value as a significant capacity market hedge and potentially for local grid support. We recognize the fairly advanced age of our peaking fleet by assuming retirements of about 30 MW of peaking capacity during the planning horizon in the mid-2020s and early 2030s. Actual retirement decisions would, of course, be assessed on a plant-specific basis based on a range of factors (discussed in "Peaking and Flexible Load Resources" on page 8-33), so actual retirement dates are likely to differ significantly from the illustrative path presented here.

Manage short-term market price volatility through layered future purchases. We plan to continue managing our forecasted open positions through a series of layered short-term purchases of energy and capacity, typically for terms of less than five years. This strategy provides significant near-term price stability to our net power costs and retail rates, while in the longer term it retains a link to regional market prices and flexibility to acquire some amount of future resources that are not specifically anticipated today.

We have evaluated the Illustrative Future Portfolio using the attributes and metrics discussed throughout this chapter. Several of the attribute charts that were presented earlier in this chapter show very similar results for the Illustrative Future Portfolio. We therefore do not present all of the attribute charts again individually. The following results with respect to the Illustrative Future Portfolio are the most notable.

Attribute: Energy Open Position

Figure 8-19 shows a moderate open energy position during the 2020s, which is reduced gradually in the late 2020s as illustrative purchases from hydroelectric and offshore wind resources are phased in. These purchases would address strategic goals of locking in renewable supply and achieving greater long-term supply stability in the 2030s after the expiration of large existing PPAs.

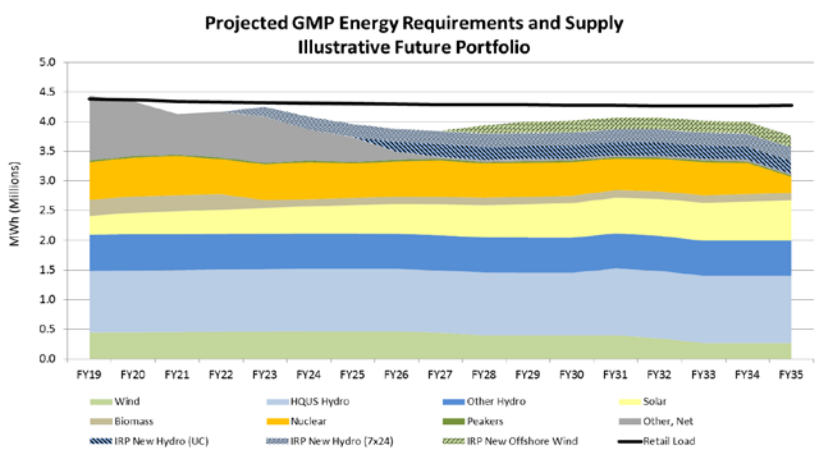

Figure 8-19. Projected Energy Requirements and Supply Preferred Portfolio

Figure 8-19 also illustrates how an increase in long-term supply in the late 2020s would further reduce our open position, and therefore the degree to which portfolio costs would follow regional market price trends. We expect that this tradeoff would be one of the factors to be considered in the evaluation of sizable additional long-term renewable sources like these.

Attribute: Capacity Open Position

Figure 8-20 shows a moderate open capacity position through the next decade, consistent with our strategy.

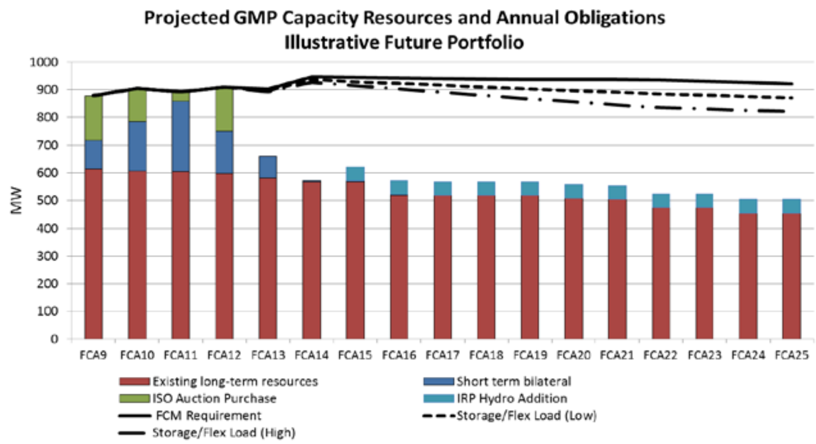

Figure 8-20. Projected Capacity Resources and Annual Obligations Preferred Portfolio

To manage exposure to year-to-year fluctuations in FCM clearing prices, we expect to continue to seek layered forward capacity purchases at stable or fixed prices. An illustrative path for deployment of storage and responsive load resources (discussed in "Peaking and Flexible Load Resources" on page 8-33) is illustrated here as a load reducer resource, with the benefit depicted by a dashed line reflecting lower capacity requirements achieved through peak reductions using these flexible resources.

Attribute: RES Tier I Gap Chart

Figure 8-21 illustrates how, as intended, the illustrative hydro purchases shown here would lock in a significant portion of our projected Tier I needs through the 2020s, while leaving a noticeable (but greatly reduced) fraction to be procured on a short-term basis.

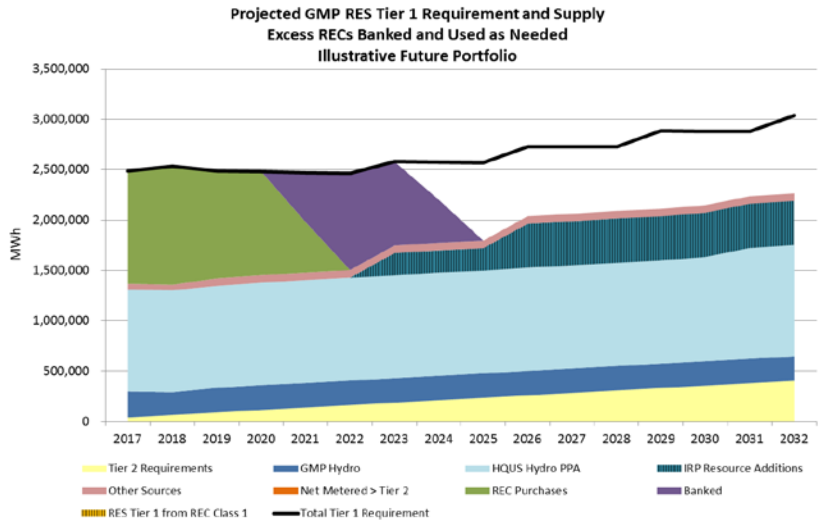

Figure 8-21. Projected Tier I Requirement and Supply Excess RECs Banked and Used Preferred Portfolio

Attribute: Portfolio Cost Sensitivity

Figure 8-22 illustrates the estimated sensitivity of our portfolio costs over the long-term to the high and low sensitivities for wholesale market prices for energy, capacity, and two types of renewable energy certificates, along with the future pace of growth of net-metered generation.

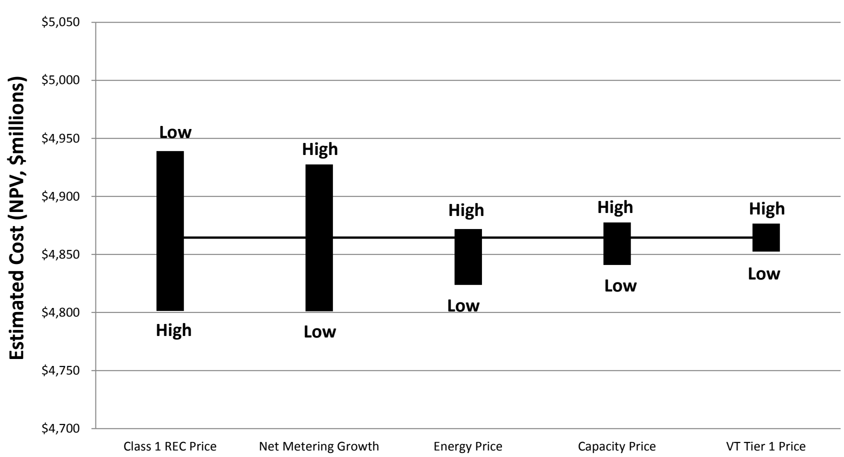

Figure 8-22. Tornado Chart for the Preferred Portfolio (Customer Costs)

Under base case assumptions, our estimated power and transmission costs through 2035 are on the order of $4.86 billion. Changes in these driving assumptions produce significant changes in the estimated costs, although those changes in the tens of millions of dollars are modest as a fraction of portfolio costs. This result is understandable as our portfolio is highly hedged in the first few years of the analysis, with limited open positions. Further, we have substantial long-term and stable-priced resources that protect against potential movements in energy and capacity market prices.

Class 1 REC prices have become a larger projected sensitivity than energy or capacity market prices. This is primarily because in New England it is not practical to hedge REC sales for delivery more than a few years into the future. As a result, most of our forward REC sales generally extend five years or less into the future, so our portfolio of salable RECs is more exposed to long-term market prices changes than are the energy and capacity components of the portfolio.

Finally, the sensitivity of portfolio costs to the future pace of net metering is considerable—comparable in impact to significant long-term changes in wholesale market prices. This is partly because the range of future net-metered growth tested here is quite large—from 10 MW to 30 MW per year, for many years. In addition, a substantial impact from net metering is not surprising because at present the effective price of net metering is substantial, and higher than the market value of net-metered output based on our current market outlooks.

Attribute: Greenhouse Gas Emission Profile

Figure 8-23 compares the projected emission profile of our portfolio to two regional benchmarks. Specifically, the dashed blue line depicts our projected average portfolio CO_2 emission rate for the Reference portfolio, while the purple dashed line depicts our projected emission rate for the Illustrative Future Portfolio.

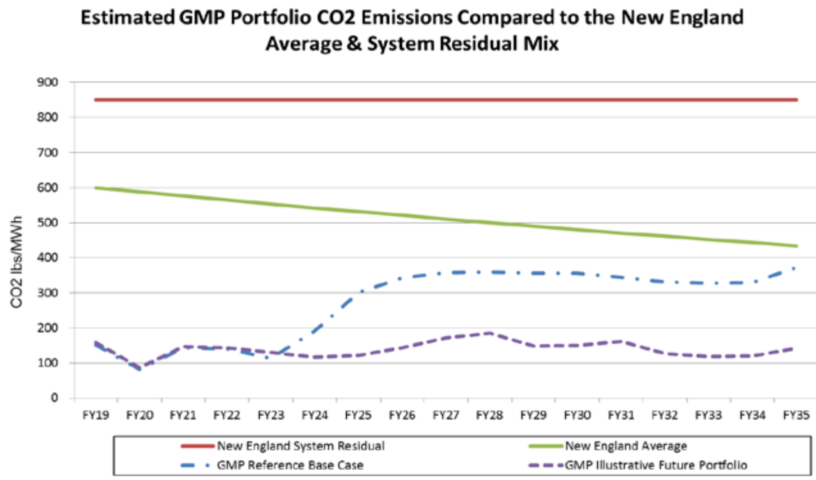

Figure 8-23. Estimated Portfolio CO_2 Emissions New England Comparison

The green line is a proxy for the ISO-New England System Mix, which includes all of the energy sources in New England, inclusive of imports from neighboring control areas.[77] We assume that the regional average emission rate will decline gradually over the planning horizon, as a result of efforts in neighboring states to lower their Greenhouse Gas (GHG) emission profiles. The red line is a proxy for the ISO-New England Residual System Mix, which includes all generation not specifically claimed and retired by market participants in the NEPOOL GIS, the region's database for tracking RECs and other generation attributes, for RPS compliance or other purposes. As a result, the Residual Mix contains the output of most of the region's fossil-fired generation fleet. In our portfolio evaluation, this is the rate assigned to the portion of our supply that is not met with generation attributes from other sources. The CO_2 emission rate shown here for the Residual Mix is higher than historically reported and we do not assume that this rate will decline over time. These assumptions reflect an expectation that increasing societal attention to greenhouse gas emissions could increasingly lead market participants to retire attributes from most non-emitting sources—leaving the residual mix increasingly reflecting the emission profile of gas- and oil-fired plants.

[77] Reported average emissions in the NEPOOL Generation Information System (GIS) of roughly 900 pounds per MWh appear to be substantially affected by relatively small fractions of power from non-fossil fuel plants (such as biomass, trash to energy), suggesting that those rates might be overstated. We have therefore depicted regional average emissions at a lower proxy rate of 600 pounds per MWh. It is possible that this rate will turn out to be understated.

Our committed renewable supplies are sufficient to meet RES requirements through the early 2020s, but not in the long-term. As a result, our projected Reference portfolio emission rate in Figure 8-23 increases somewhat in the mid-2020s as current purchases of hydroelectric and nuclear generation attributes expire, but the core of low-emission sources keeps us somewhat below the regional average. In the Illustrative Future Portfolio, the acquisition of additional renewables over time—through a mix of plant-contingent hydro, firmed hydro, and market REC purchases—enables us to achieve the Tier I total renewable requirement, and significantly lowers our emission profile to a low fraction of the regional average.

Observations About the Illustrative Future Portfolio

Based on the resource additions and attributes, the following are notable observations about the Illustrative Future Portfolio:

- Our projected GHG emission profile is presently low relative to the New England region; it is projected to stay low over time in part because of achieving the increasing renewable requirements of the Vermont RES.
- The portfolio is fairly balanced, without extraordinarily large open positions. Our Tier I open position is relatively large, although the risk is somewhat limited in dollar terms.
- Based on the limited scale of open positions, and the fact that most of our sources are stable-priced, the sensitivity of our portfolio costs to alternative market prices (energy, capacity, regional Class 1 RECs, Tier I RECs) is moderate—and likely much less than for electric utilities and customers in neighboring states.
- Under base case assumptions, we are not projected to have a significant need for additional Tier II-eligible supply for a number of years. Low Tier III supply or low net metering growth in the coming years or both, could potentially change that assessment.
- Our portfolio is becoming more reliant on intermittent renewable resources over time; this can lead to short-term fluctuations in portfolio output and net power costs. This reliance is not a critical flaw, because such fluctuations tend to largely offset over time and there are potential tools to help manage them, but we are seeking additional portfolio modeling capability that may help us better understand and quantify this risk.

Finally, we plan to monitor a number of signposts that are potential leading or lagging indicators that could change some of our observations, or otherwise inform our future resource choices.

Summary of Metrics (Illustrative Future Portfolio)

The charts and narrative presented earlier in this section highlight the most notable attribute results for the Illustrative Future Portfolio. The "Evaluation of the Reference Portfolio" and "Sensitivity Analysis" sections provide valuable context that inform the portfolio. Table 8-4 and Table 8-5 present the estimated metrics under base case market assumptions on an annual basis.

	Flexibility			Cost		
Fiscal Year	Retail Sales (MWh)	Long-Term Resource %	Intermittent %	Net PP Costs ($ M)	Net PP & Tax Costs ($ M)	Average Portfolio Costs ($/kWh)
2019	4,156,468	77%	34%	$300	$415	$0.0999
2020	4,144,656	79%	36%	$305	$417	$0.1006
2021	4,120,065	80%	36%	$308	$421	$0.1022
2022	4,108,764	79%	37%	$305	$427	$0.1039
2023	4,097,182	81%	38%	$305	$432	$0.1054
2024	4,088,937	83%	39%	$316	$447	$0.1093
2025	4,079,429	83%	40%	$324	$458	$0.1122
2026	4,071,171	88%	44%	$336	$472	$0.1158
2027	4,066,829	90%	45%	$346	$483	$0.1188
2028	4,068,136	92%	49%	$359	$498	$0.1225
2029	4,066,874	93%	50%	$370	$512	$0.1260
2030	4,059,107	94%	51%	$380	$526	$0.1296
2031	4,054,489	95%	52%	$390	$539	$0.1329
2032	4,051,461	95%	51%	$393	$545	$0.1346
2033	4,050,516	94%	49%	$397	$553	$0.1364
2034	4,050,765	93%	50%	$404	$563	$0.1390
2035	4,052,243	88%	50%	$394	$556	$0.1372
NPV 2019–2035	42,249,337			$3,494	$4,866	

Table 8-4. Illustrative Future Portfolio (part one)

	Carbon				Cost	Renewability		
Fiscal Year	Portfolio CO_2 Emissions (pounds/MWh)	Percent of Regional System Mix	Portfolio CO_2 Emissions (Short Tons)	External Cost ($ M)	Total Cost with External ($M)	Tier I	Tier II	Total
2019	158	26%	346,607	$35	$450	58.0%	2.1%	60.0%
2020	87	15%	190,611	$19	$437	57.4%	2.7%	60.0%
2021	146	25%	320,384	$33	$455	56.8%	3.3%	60.0%
2022	143	25%	310,760	$33	$460	56.2%	3.9%	60.0%
2023	130	23%	279,745	$30	$462	57.8%	4.5%	62.3%
2024	117	22%	252,512	$28	$474	58.0%	5.1%	63.0%
2025	122	23%	261,721	$29	$487	57.4%	5.7%	63.0%
2026	143	27%	308,995	$35	$506	59.8%	6.3%	66.0%
2027	172	34%	371,762	$42	$526	60.2%	6.9%	67.0%
2028	186	37%	396,579	$46	$544	59.6%	7.5%	67.0%
2029	148	30%	317,140	$37	$549	62.0%	8.1%	70.0%
2030	149	31%	318,812	$38	$564	62.4%	8.7%	71.0%
2031	162	34%	343,201	$41	$580	61.8%	9.3%	71.0%
2032	126	27%	268,987	$32	$578	64.2%	9.9%	74.0%
2033	119	26%	252,173	$31	$583	65.0%	10.0%	75.0%
2034	121	27%	256,047	$32	$594	65.0%	10.0%	75.0%
2035	142	33%	303,486	$38	$594	65.0%	10.0%	75.0%
NPV 2019–2035	–	–	–	$327	$5,193	–	–	–

Table 8-5. Illustrative Future Portfolio (part one)

Estimated total portfolio costs over the analysis horizon is roughly $4.9 Billion present value; over 70% of this is projected power supply costs, with the remainder being transmission by others, primarily Regional Network Service. Most of the key metrics shown here (such as long-term resources and emission profile) are as presented earlier in this section.

Societal costs include power and transmission costs that our customers pay, along with the estimated external costs to society that are not already reflected or "internalized" in the market price of electricity. External societal costs associated with our portfolio are estimated based on the projected CO_2 emission profile of the portfolio, and a benchmark societal cost of $100/ton.[78] Because the CO_2 emission allowance prices incorporated in our base case market price forecast are much less than the $100/ton

78 Future societal cost of greenhouse gas emissions are uncertain and difficult to quantify; estimates vary widely. The $100 per ton amount used here is the same one that we used in its most recent IRP, and is consistent with the level presently being used in Vermont EEU screening of energy efficiency measures.

benchmark, there is a substantial external cost of emissions. As a result, the projected societal cost for the portfolio is more than $300 millon (or about %) higher than the direct customer cost. The projected emissions and societal costs associated with our portfolio over time are greatly limited by the subtantial and increasing RES requirements, along with the portion of our portolio from nuclear sources.

SIGNPOSTS

Beyond the direct market inputs and variables typically applied in the evalution of new resource additions, and against the backdrop of a rapidly evolving energy market, the portfolio evaluation helped to identify some additional factors that we expect to use to help guide resource decisions in the coming years. This approach introduces new threshold events or “signposts” to help inform and potentially narrow the list of resources that will brought into consideration for addition to the portfolio. In the application of signpost evaluation, our goal is to follow metrics that could be national, regional, or local—and tend to be rooted in the key energy transformation themes (described in Chapter 3: Regional and Environmental Evolution) indicating whether certain types of resources that may be needed or cost-competitive.

Table 8-6 presents a list of potential signposts that we expect to monitor in the course of evaluating future resource additions, and identifies the type of resources that could be informed by the signposts.

Indicator	Context	How This Indicator Could Inform Our Choices and Actions
GHG enacted & proposed emission regulation	National	Leading indicator of trends in electricity market prices, and relative price of electricity versus fossil fuels.
Frequency of extreme weather events	National & Regional	The value of resilience in our supply would be expected to grow with increases in event frequency, leading to more emphasis on reserves and supply that is less variable with the weather.
Growth of solar PV capacity in New England, and observed LMP value of solar PV output profile	Regional	Leading indicator of the value of output from additional solar PV sources.
Timing and shape of peak electricity demands (ISO-New England annual, Vermont monthly)	Local & Regional	Benefit and cost evaluation of potential battery storage and flexible load resources, for managing peak.
MW and MWh of battery storage deployed in the region	Regional	Leading indicator of potential trends in ISO-New England peak load profile, and potential supply saturation for the ISO-New England Frequency Regulation market.
Will battery storage systems paired with existing renewable systems be eligible for Federal investment tax credits?	National	Indicator of net cost to install battery storage at various locations in Vermont, with or without having to also install new renewables.
Pace of net metering applications and installations in our territory	Local	Leading indicator of how much Tier II-eligible supply we will acquire in the near future.
"Spread" of high and low hourly energy market prices (LMPs)	Regional	Benefit and cost evaluation of potential responsive load or battery storage resources. Also, directional guidance for operation of existing resources.
Energy market prices in winter versus other months	Regional	Indicator of the relative incremental cost of electricity to serve heating load vs. other types of electric load. Also, management of our winter net short energy position.
Relative prices of oil versus electricity	Local	Leading indicator of the future cost-effectiveness of electrification measures and customer adoption.
Our pace of completed Tier III transformation projects; pipeline for future projects	Local	Leading indicator that we might need to retire some Tier II RECs to cover a shortfall in Tier III supply. Also, an input to our retail sales forecast.
General inflation in the economy	National	An indication of portfolio cost trends, since some committed sources and open positions are directly and indirectly linked to inflation.

Table 8-6. Potential Signpost Indicators

National Indicators

For this category, we will be evaluating the larger transformative energy trends that have the broadest geographic implications. The most notable of these signposts will be the direction taken with the regulation of GHG and the policies that could emerge to address climate change. Metrics for this indicator would include the pace and evolutions of region efforts like Regional Greenhouse Gas Initiative (RGGI) in our region, and activities at the national level that increase the likelihood of new, meaningful policies to reduce emissions. In this example, to the extent that activity and data point to a likelihood of new regulations on the electric sector, we would use this indicator and more quickly advance the evalution of zero-carbon energy resources like those described in the preferred portfolio.

Regional Indicators

For these signposts the considerations are not as geographically wide as the national markers but they represent topics and considerations that could occur on a regional level to impact our resource decisions. This category of indicators can exist without being triggered by larger, nationwide trends and often the data collected will be related to the pace of change in New England. The most notable example of this type of indicator is the pace of solar PV installations in surrounding states. This growth has been extraordinary in the last few years and there are forecasts for rapid growth to continue. The actual pace at which this forecasted development occurs could have important implications for the value of future PV in our resource portfolio, and we would expect to use this indicator before pursuing additional PV resources.

Local Indicators

A number of the potential signpost indicators in the table are more specific to conditions that might be occurring in our service territory or within Vermont. Often this category of signpost will be oriented to tracking elements or trends in customer energy use or behavior that could have a direct bearing on the type of supply that might be best suited to address the trend. While local considerations are already a staple of the resource planning process, the overarching goal in this application will be to track items that might reveal the pace of transformation locally with examples being the pace of net metering applications or the pipeline of Tier III transformation projects.

MARKET PRICE INPUTS TO THE PORTFOLIO ANALYSIS

There are three major categories of market prices that we typically forecast: energy, capacity, and RECs. Energy and capacity are typically the two largest power supply cost categories, respectively; these feature markets that are managed by ISO-New England and can be viewed in the context of regional market dynamics for supply and demand and pricing. REC markets are driven more strongly by state RPS programs so although there is significant overlap across the states, significant supply and demand changes can occur based on legislative and regulatory changes to renewable policy at the state level. In general, market price expectations for these products are somewhat lower than in our 2014 IRP, although substantial uncertainty about future prices remains.

Energy Market

We developed our energy market price outlook starting with NYMEX-quoted energy futures for 5 MW blocks delivered at the Massachusetts Hub through 2022. These quotes generally reflect price levels at which we are able to transact arms-length energy purchases and sales.

Beyond the initial four year time horizon, energy prices are developed based on a number of factors that have historically been energy price drivers including anticipated New England load levels; anticipated generation additions and retirements; and future natural gas prices. Currently ISO-New England anticipates flat to slightly lower forecast loads over the next decade as shown in ISO-New England's Capacity, Energy, Loads, and Transmission (CELT) report. This is primarily driven by slow demand growth and the growth of behind-the-meter PV solar generation as well as continued energy efficiency initiatives.

There have been a number of significant retirements over the last several years including the 1,535 MW Brayton Point coal fired unit. In addition, Pilgrim (683 MW) will retire in 2019, Bridgeport Harbor (400 MW) anticipates retiring in 2021, and it is likely that Mystic Units 8 and 9 (1,744 MW) will retire in 2024. Additions include Towantic (801 MW natural gas) in 2018, Bridgeport Harbor (509 MW natural gas), and Canal 3 (342 MW natural gas) in 2019, followed by the New England Clean Energy Connect (1,200 MW) and offshore wind totaling 1,400 MW in 2023. Besides these large named projects, there are significant renewable additions anticipated based on various state RFPs over the last several years as well as more smaller behind-the-meter distributed generation projects. The addition of new, higher efficiency gas-fired units will have the near-term impact of pushing down the implied heat rate across New England, but we anticipate that this will be short-lived and that over the longer-term there will be a gradual increase in heat rates because of a number of factors including retirements of nuclear units and the need for rapid-ramping units as the growth of intermittent generation in the region continues.

New England natural gas prices are based on deliveries to Algonquin Citygate, which is not currently an actively traded NYMEX future contract. To develop an outlook for Algonquin Citygate, we rely on the historical basis differential between spot prices for deliveries of natural gas at Algonquin Citygate and at the Henry Hub, which is a commonly quoted pricing point for natural gas in North America. We used this historical relationship, along with NYMEX futures for natural gas delivered at the Henry Hub in Louisiana (NG), to derive anticipated futures prices for Algonquin Citygate.

Over the longer term, the energy model reflects a number of adjustments to more accurately reflect anticipated market dynamics. First, futures for natural gas delivered at the Henry Hub are relatively thinly traded after the first few years; we adjusted them reflect fundamentals-based considerations underlying the Energy Information Agency's 2018 Annual Energy Outlook (AEO) report and the 2018 Synapse Avoided Energy Supply Components in New England (AESC) report. These consideration include anticipated drilling activity; higher breakeven drilling and operating costs; anticipated LNG exports; and growing domestic natural gas demand. In addition, we reduced the basis differential between Henry Hub and Algonquin Citygate in the 2020s to reflect the anticipated moderating influence during winter months of new non-gas sources like the (NECEC) transmission line from Québec and offshore wind generation, which should displace some gas-fired generation and help to decrease the number of winter hours that experience significant natural gas constraints. Finally, some additional upgrades to existing pipeline capacity and the addition of new pipeline capacity into New York and the Mid-Atlantic region should help to free up some incremental natural gas for New England during normal conditions.

The forecast also assumes that there will be some modest incremental carbon priced into New England energy prices to reflect changes to the RGGI and potential future carbon initiatives in the region. These assumptions are reflective of RGGI prices growing to about \$10/short ton by 2026 and continuing to grow slowly through 2030 based on the August 2017 RGGI model rule. If tighter new regulation of greenhouse gases were introduced on a national or regional level, significantly higher allowance price and energy market price outcomes could result.

For the Low Energy Market Price scenario, we assume that market prices are 5% lower than in the base case, and that from 2030 forward market prices turn out 15% below the Base Case. This scenario is consistent with a future in which natural gas prices turn out lower than presently anticipated (because of lower extraction costs nationally; additional pipeline capacity or LNG deliveries into New England) or the implied market heat rate[79] turns out lower (because of substantial offshore wind development displacing the need for some thermal generation; lower regional electricity demand). This scenario also assumes that there is a limited push for internalizing carbon into energy pricing, CO_2 allowance pricing following the base case growth rate until 2030, after which it would grow at a slightly slower pace ending at $7.03/short ton in 2035.

Finally, the High Energy Market Price Scenario assumes that energy market prices turn out 5% higher than in the base case, and 15% higher from 2030 forward, because of higher natural gas prices and/or an increase in the implied market heat rate. These higher price outcomes could be driven by delays in additional pipeline capacity projects into New York and the Mid-Atlantic states; delays in the proposed NECEC or offshore wind projects; or increasing demand. In addition to this higher pricing environment, the High Energy Market Price scenario assumes more rapid increases in the pricing of CO_2 in the electricity market, through coordinated state action or a new national policy. The projection assumes internalized CO_2 pricing will resemble Synapse's 2016 Low Case in real dollars per short ton, starting at around $0.65/short ton in 2023 and rising to about $18.62/short ton in 2035. As a result of higher emission pricing, the "upside" market price exposure in the High Energy Market Price scenario is somewhat lower than the "downside" price exposure in the Low Energy Market Price scenario.

Figure 8-24 illustrates the resulting Base, High, and Low energy market price outlooks for round-the-clock ("7x24") energy delivered at the Mass Hub.

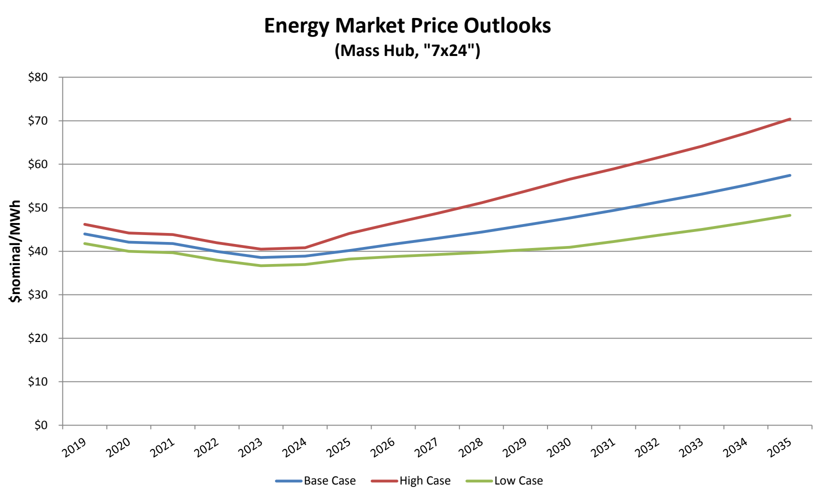

Figure 8-24. Energy Market Price Outlooks

79 An implied market heat rate reflects the ratio between electricity market prices and natural gas prices to power plants at a particular location.

Capacity Market

The FCM is the market-based mechanism used by ISO-New England to ensure that sufficient capacity resources will be in place to meet projected resource adequacy requirements. Annual FCAs are conducted for the delivery of capacity about three years in advance of each capacity year. The auction clears at the marginal price at which sources of capacity like supply, demand side sources, and imports from outside New England, are willing to meet ISO-New England's need for capacity. Capacity market prices are driven by the supply and demand of capacity resources, and the prices at which they are willing to commit to supply capacity. Some auctions have yielded unique clearing prices for capacity zones that are import or export-constrained. Load-serving entities like GMP are responsible for a share of the capacity that ISO-New England purchases each year that are allocated based on their respective contribution to the ISO-New England annual peak load. This obligation may be met using owned or purchased capacity resources, or through payments to ISO-New England.

The capacity price forecast is based on an understanding of the FCA structure, current assumed plant additions, and current assumed plant retirements. The last auction (FCA #12) cleared at $4.63/kW-month because two large natural gas plants (Mystic 8 and Mystic 9) were not allowed to delist because of ISO-New England reliability concerns. Had these two units been allowed to delist the auction would have stopped somewhere between the two units' delist bids which were both above $5.00/kW-month.

Our current assumption is that the two units, totaling over 1,700 MW of nameplate capacity, will now retire in 2024. Beginning with FCA #13 which will be held in February 2019, there are several changes to the auction that will likely affect clearing prices. These include lowering the dynamic delist threshold for $5.50/kW-month to $4.30/kW-month; the implementation of Competitive Auctions for Sponsored Policy Resources (CASPR) where ISO-New England will conduct a "substitution auction" after the primary FCA to allow new state-sponsored resources that did not clear the primary FCA to obtain the Capacity Supply Obligation (CSO) awarded to units wishing to retire but that retained a CSO in the primary FCA; and finally a sustained drop in ISO-New England's peak load forecast. These factors should, all other things being equal, tend to moderate the auction clearing prices over the next several auctions.

We are currently projecting that the next three auctions will be slightly above the $4.63/kW-month clearing price featured in FCA #12 before beginning a gradual upward slope to a point at which it will be about 20% lower than the Net Cost of New Entry (Net CONE) at the same time we have moderated our inflation assumption for Net CONE to reflect a 2% historical inflation rate, rather than the slightly higher than inflation 2.5% assumption that we had previously used.

The major forces that this forecast tries to balance are the influx of new renewable generation under various state RFPs and other programs, with the need to maintain fossil generation to help manage the intermittency of these new sources. The interplay of these two forces will likely moderate the upward slope of the price curve, but will also limit the downward price pressure as the current low energy price environment makes it difficult for relatively high priced units that are called to run infrequently to remain financially viable without some reasonable level of capacity or other ancillary revenue source. This forecast assumes that there will be a rough balance between retiring and new resources that will provide a reasonable pricing floor, but that retirements of units that are slow ramping and have long minimum runtimes will begin in the late 2020s, leading to higher prices to incent new entrants.

The Low Capacity Market Price scenario assumes that marginal units are able to continue operating into the 2030s before they delist and that higher capacity factors for renewables such as offshore wind help to minimize the need for new fossil generation. Another important assumption is that technological advances help to hold down the cost of replacement units, meaning that these generators will need lower capacity payments to be financially viable. In this scenario there is a movement to using battery storage for capacity resources, based on a four-hour or longer battery configuration that will help to displace peaking units.

The High Capacity Market Price scenario assumes that a large number of generators with undesirable attributes such as slow ramp rates, long minimum runtimes, and limited starts per day, begin to delist sooner because of the mix of low capacity prices and low energy prices. Once these marginal units have delisted, ISO-New England will need significant additional new generation to help manage intermittency, including fast ramping units to help manage output shifts from large renewable generation (for example, 1,400 MW of offshore wind). This scenario assumes that prices for battery storage drops at a slower than anticipated rate and the units remain expensive relative to other fast-ramping generation.

Figure 8-25 illustrates the resulting Base, High, and Low price outlooks for the ISO-New England FCM.

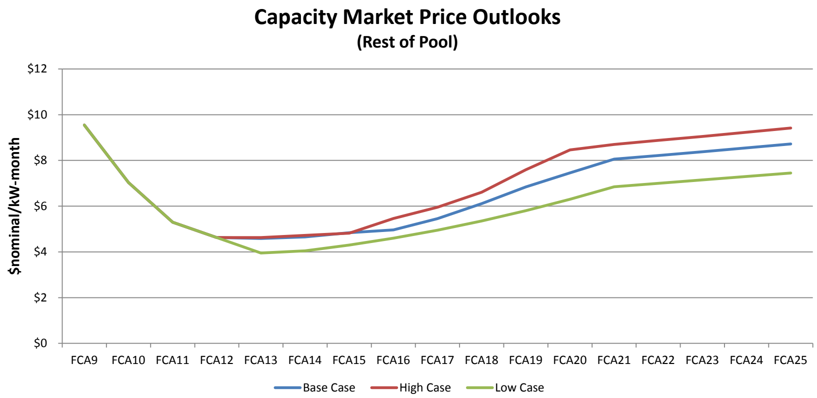

Figure 8-25. Capacity Market Price Outlooks

Renewable Attributes and RECs

Each of the New England states has either a RPS or, in Vermont's case, a RES, that mandates renewable energy purchases by type and volume. Renewable generation resources can qualify for participation in multiple state programs, but the underlying generation can only be counted once for purposes of meeting a specific utility's obligation. A REC is a claim to the attributes of one MWh of renewable generation. RECs can be bought and sold either bundled with the underlying energy or separately as a claim to the renewable attributes of the generation.

Certain RECs associated with our generation that qualify for Tier I in Vermont based on such factors as the project's size or the date that it reached commercial operation may also qualify for participation in another state's RPS—typically Class 1 in Massachusetts and Connecticut. There is substantial overlap between the Class 1 RPS eligibility requirements in the New England states, like wind and solar PV generation tend to qualify in all of them, so this outlook addresses trends for these market as a whole.

The outlook for regional Class I REC value is driven by the balance of demand that is driven by policy and the available supply. The New England market has swung toward a surplus in recent years, driven by a combination of substantial distributed renewables and state-supported solicitations for long-term renewable PPAs. This balance appears unlikely to change fundamentally any time soon, although parallel requirements of the Massachusetts Clean Energy Standard appear to provide some price support in the near-term, before anticipated low-emission imports over the proposed NECEC line in Maine arrive.

Based on this situation assessment, regional Class I REC market prices are assumed to increase modestly to about $17/MWh in 2021, before trailing off to around $15/MWh through 2030. In a Low Class 1 REC Price scenario, reflecting a more extreme and sustained regional surplus, these RECs would only increase to $10/MWh and then slow drop to $5/MWh for the long-term. In a High Class 1 REC Price scenario, which would be consistent with slower renewable development and a greater level of attrition from some renewable supplies (for example, imports from neighboring control areas, existing biomass plants), prices are assumed to increase to $25/MWh and hold steady until 2030, reflecting tight supply.

Figure 8-26 illustrates the resulting Base, High, and Low price outlooks for regional RPS Class 1 RECs.

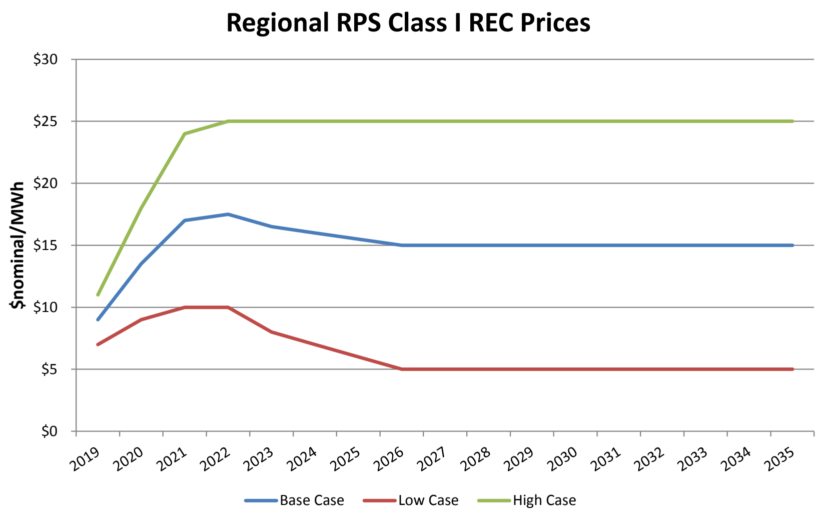

Figure 8-26. Regional RPS Class I REC Prices

Vermont RES Tier I features a much wider range of renewable resource eligibility than the regional Class 1 markets, so this is presently a relatively large volume, low-priced market. Factors that could lead to a tightening supply and demand balance and higher prices include temporary variations in renewable output; policy changes in neighboring states that increase demand; the growth of Vermont's Tier I obligation over time; and voluntary demand on the part of businesses and institutions. We also observe that ownership of existing renewables in the region is relatively concentrated, and attrition of some smaller, higher-cost existing renewable units also seems possible in light of the low energy and capacity environment.

Figure 8-27 illustrates the resulting Base, High, and Low price outlooks for Vermont Tier I RECs.

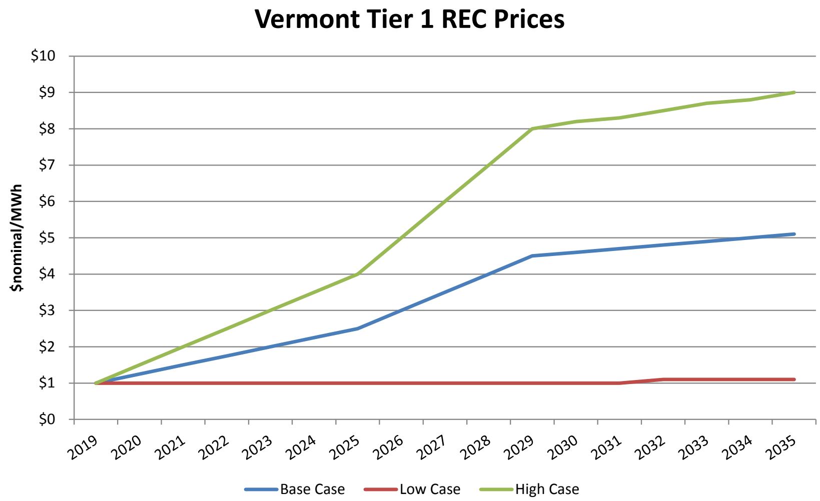

Figure 8-27. Vermont Tier I REC Prices

In light of these forces, the Base Tier I REC price outlook grows gradually from $1/MWh to around $5/MWh by 2030. For the Low Tier I REC price future we assume that the Tier I price remains at about $1/MWh through 2030, while the High Tier I REC price future has the price growing more rapidly and reaching about 60% of anticipated ACP by 2030 at about $8 per MWh.

9.Integration and Action Plan

As discussed throughout this IRP, we have an intense focus on driving carbon out of our energy system in everything we do, and helping our customers do the same. We look to do this in a way that reduces cost, strengthens reliability and improves our customers' lives. Through our development of transformation programs, pricing and rate development, and our procurement strategies for power supply, we are implementing this transformation right now, and will continue to do so during this planning period. Our times demand strong and rapid action, and we are committed to delivering on this new energy future in partnership with our customers, stakeholders and energy leaders in Vermont.

Functional Area	Activity
Energy Transformation	Develop and deploy an integrated suite of customer offerings that drive carbon out of our total energy consumption, reduce costs for all customers, and improve comfort and reliability: ♦ Expand the Bring Your Own Device program to include more devices and more options for third parties and aggregators. ♦ Deploy energy storage into customer homes and businesses to improve resiliency and reduce cost and carbon for the entire system. Focus on customer options that include third-party integration of resources and additional value for locational benefits. ♦ Transition commercial customers from fossil-fuel-based processes to electricity where feasible and cost-effective to cut carbon. ♦ Develop innovative pricing and rate strategies to encourage and accurately price resources transitioning from fossil fuel to electricity, in a seamless way to benefit customers.
Generation	Invest and maintain our existing fleet of generation while looking for opportunities for acquisition and construction of new facilities to produce long-term value to customers: ♦ Explore acquisition of hydro facilities with a focus on peaking and wintertime capability. ♦ Pair energy storage with existing renewable facilities, or construct new storage-paired systems directly or through other procurement methods.
Power Supply	Maintain a cost-effective, very low-emission supply portfolio that incorporates a large share of long-term distributed renewable resources while retaining the flexibility to address changes in the evolving regional energy market: ♦ Adapt the short-term energy plan to hedge GMP-forecasted energy positions by season using layered, competitive supply solicitations. ♦ Explore the addition of diverse long-term renewable resources to achieve future RES program targets, while reducing reliance on REC-only purchases. ♦ Seek competitive short-term capacity purchases to hedge forecasted capacity requirements in advance of the delivery period. ♦ Evaluate the addition of long-term peak reduction and storage resources to address growing capacity shortfalls and in response to increasing energy volatility.
Transmission & Distribution	Plan the energy delivery system to allow the transition to a distributed, home-, business-, and community-based energy model while preparing the grid for harsher storm conditions: ♦ Leverage the vast data produced by our AMI and distributed energy resources to evaluate our circuits for highest locational value. ♦ Prepare system for the influx of strategic electrification, such as electric vehicles and heat pumps. ♦ Continue to invest in vegetation management programs and innovative solutions to address reliability.
Financial Strength	♦ Maintain strong financial measures and results to ensure strong operational support for customers. ♦ Maintain capital planning focus and discipline in each core area of spending to provide reliable power in this time of climate change.

A. Glossary and Acronyms

These glossary and acronym entries clarify the terms and concepts used throughout this *2018 Integrated Resource Pan*, and aid in its comprehension and scope.

A

Advanced Distribution Management System (ADMS). A software platform that supports the full suite of distribution management and optimization functions that automate outage restoration and optimize the performance of the distribution grid. An ADMS is capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information, which allows operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads.

Advanced Metering Infrastructure (AMI). An integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. Functions include automatically and remotely measuring electricity use, connecting and disconnecting service, detecting tampering, identifying and isolating outages, and monitoring voltage. When combined with customer technologies (such as in-home displays and programmable communicating thermostats), AMI can be used to offer time-based rates as well as incentives to reduce peak demand and to manage energy consumption and costs.

Alternating Current (AC). An electric current whose flow of electric charge periodically reverses direction. In many developed countries, alternating current is the form in which electric power is delivered to businesses and residences. The usual waveform of an AC power circuit is a sine wave. The usual power system frequency is 60 hertz (1 hertz (Hz), which is 60 cycles per second.

Ancillary Services. Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the electric grid in accordance with good utility practice.

Automatic Generation Control (AGC). A process for adjusting demand and resources from a central location to help maintain frequency. AGC helps balance supply and demand. (See also Regulating Reserves on page A-18.)

Auxiliary Load. The load that serves the power plant itself, normally served by the power plant itself, but also served by the power grid when the power plant is offline.

Avoided Costs. The costs that utility customers would avoid by having the utility purchase capacity or energy from another source (for example, energy storage or demand response) or from a third party, compared to having the utility generate the electricity itself. Avoided costs comprise two components:

- Avoided capacity costs, which includes avoided capital costs (for example, return on investment, depreciation, and income taxes) and avoided fixed operation and maintenance costs.
- Avoided energy costs, which includes avoided fuel costs and avoided variable operation and maintenance costs.

B

Balancing Authority (BA). The eastern United States and Canada interconnected grid is divided into over 100 balancing areas. A Balancing Authority is an area's main operator who matches generation with load.

Base Scenario. In resource planning: a set of assumptions used as a reference point for comparing other sets of assumptions.

Baseload. The minimum electric or thermal load that is supplied continuously over a period of time. (See also Load on page A-12.)

Baseload Capacity. See Capacity on page A-3.

Baseload Generation. Electric generation units that produce electricity at a constant rate—almost always at full capacity—to meet the system's baseload (continuous energy need). Baseload units have the lowest incremental cost of all units on the system; thus, are operated virtually continuously and are taken offline relatively infrequently.

Battery Energy Storage System (BESS). Any battery storage system used for contingency or regulating reserves, load shifting, ancillary services, peaking, or other utility or customer functions. (See also Energy Storage on page A-7.)

Biomass. Organic non-fossil biological material constituting a renewable energy source that can be either processed into synthetic fuels or burned directly to produce steam or electricity.

Black Start Resource. A generating unit and its associated set of equipment that can be started without system support or can remain energized without connection to the remainder of the system, and that has the ability to energize a bus, thus meeting a restoration plan's needs for real and reactive power capability, frequency and voltage control, and is included in the restoration plan.

British Thermal Unit (Btu). A unit of energy equal to about 1055 joules that describes the energy (heat) content of fuels. A Btu is the amount of heat required to raise the temperature of 1 pound of water by 1°F at a constant atmospheric pressure. When measuring electricity, the proper unit would be Btu per hour (or Btu/h) although this is generally abbreviated to just Btu. The term MBtu means a thousand Btu; the term MMBtu means a million Btu. The price of fuel is typically expressed in dollars per million Btu (or $/MMBtu).

C

Cap-and-Trade. Financial incentives to control emissions reductions. A central authority (usually a government or international body) sets a limit or cap on the amount that can be emitted, then issue emission permits for a number of allowances (or credits) for emitting a specific amount that cannot exceed the cap, thus limiting total emissions. Utilities needing to increase their emissions must buy—trade—credits from utilities that emit less than their cap. This approach caps emissions at a preset amount, regardless of which utilities is emitting them.

Capacitor. A device that stores an electrical charge to correct AC voltage so that the voltage is in phase with the AC current. Capacitors are typically installed in substations and on distribution system poles, at locations where local voltage correction can reduce system current flow, reducing losses and improves efficiency.

Capacity. The rated maximum continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA), of an electric generation plant. Most generation plants are not operated at their maximum capacity rating. Types of capacity include the following:

- *Baseload Capacity.* Those generating facilities within a utility system that are operated to the greatest extent possible to maximize system mechanical and thermal efficiency and minimize system operating costs. Baseload capacity typically operates at high annual capacity factors, for example greater than 60%.
- *Firm Capacity.* Capacity that is intended to be available at all times during the period covered by a commitment, even under adverse conditions.
- *Installed Capacity (ICAP).* The total capacity of all generators able to serve load in a given power system, or the total wattage of all generation resources to serve a given service or control area.
- *Intermediate Capacity.* Flexible generators able to efficiently increase or decrease their power output across a wide band of loading conditions (referred to as load following). Also known as Cycling Capacity. Typically, annual capacity factors for intermediate duty generating units range from 20% to 60%. The incremental cost of operating these units is higher than baseload units, but less than peakers.
- *Net Capacity.* The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
- *Peaking and Emergency Capacity.* Generators typically called on for short periods of time during system peak load conditions or as replacement resources following contingencies. Annual capacity factors for peaking generation are typically less than 20%. Peakers run at the highest incremental cost of all units on the system.

Capacity Factor. The ratio of the average operating load of a generation unit for a period of time to the full nameplate capacity during that same period of time, expressed as a percentage of the unit's maximum capacity.

Capital Expenditures. Funds expended by a utility to construct, acquire, or upgrade physical assets (generating plants, energy storage devices, transmission plant, distribution plant, general plant, major software systems, or IT infrastructure). Capital expenditures for a given asset include funds expended for the acquisition and development of land related to the asset, obtaining permits and approvals related to the asset, environmental and engineering studies specifically related to construction of the asset, engineering design of the asset, procurement of materials for the asset, construction of the asset, and startup activities related to the asset. Capital expenditures may be associated with a new asset or an existing asset (that is, renovations, additions, upgrades, and replacement of major components).

Carbon Dioxide (CO_2). A greenhouse gas produced as a by-product of burning fossil fuels and biomass.

Carbon Monoxide (CO). A major air pollutant produced in large quantities in the exhaust of gasoline-powered vehicles because of the incomplete combustion of carbon-containing substances.

Clean Air Act (CAA). The federal law that regulates emissions into the atmosphere nationwide. The Environmental Protection Agency, who has prime responsibility for administering the CAA, develops and enforces regulations to protect the general public from exposure to airborne contaminants.

Combined Cycle (CC). Twin-stage natural gas-fired power plants that deliver higher fuel efficiency. A combination of combustion turbine- and steam turbine-driven electrical generators, where the combustion turbine exhaust is passed through a heat recovery waste heat boiler which, in turn, produces steam which drives the steam turbine. Using the residual heat from the combustion turbine contributes to the unit's fuel efficiency. There are a number of possible configurations for combined cycle units. Three common configurations are: a 3x1 Combined-Cycle: three combustion turbines, three heat recovery waste heat boilers, and one steam turbine; a Dual-Train Combined-Cycle (DTCC): two combustion turbines, two heat recover waste heat boilers, and one steam turbine; and a Single-Train Combined-Cycle (STCC): one combustion turbine, one heat recovery waste heat boiler, and one steam turbine.

Combined Heat and Power (CHP). The simultaneous production of electric energy and useful thermal energy for industrial or commercial heating or cooling purposes. The Energy Information Administration (EIA) has adopted this term in place of cogeneration.

Combustion Turbine (CT). Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power; also commonly referred to as a gas turbine. Combustion turbines typically use natural gas or liquid petroleum fuels to operate. Ambient air is compressed to high pressures in a compressor where a gaseous fuel source is added and combusted in the combustor. The resulting hot gases are then expanded through a turbine to drive both an electric generator and the compressor section.

Compact Fluorescent Lamp (CFL). A type of fluorescent lamp that uses less power and has a longer rated life than a comparable incandescent lamp. A CFL also gives off much less heat than an incandescent bulb, resulting in seasonal energy implications.

Comprehensive Energy Plan (CEP). As its name suggests, the CEP establishes specific, measurable goals and objectives in land use, buildings, transportation, and energy for Vermont, including a dramatic increase in renewable generation. Created by the Vermont Department of Public Service, and updated every three years. (See also Vermont Electric Plan on page A-22.)

Concentrated Solar Thermal Power (CSP). A technology that uses mirrors to concentrate solar energy to drive traditional steam turbines or engines to generate electricity. This class of solar technologies includes solar trough, power towers, parabolic dish-Stirling generator, and concentrating photovoltaics A CSP plant can store this energy until needed to meet demand.

Conductor. An object or type of material, almost always an aluminum or copper metal wire, that allows an electrical current to flow in one or more directions.

Conductor Sag. The distance between the connection point of a conductor (transmission and distribution line) and the lowest point of the line.

Connected Load. See Load on page A-12.

Contingency. An unplanned event that creates an outage of a transmission line, transformer, or generator.

Contingency Reserves. Reserves added to balancing reserves deployed to meet contingency disturbance requirements, typically based upon the largest single contingency on the grid. Contingency reserves are usually automatically initiated, and intended to bolster short-term reliability during forced outages.

Curtailment. Cutting back on variable resources to keep generation and consumption of electricity in balance.

Customer Average Interruption Duration Index (CAIDI). The average duration for customers experiencing an outage.

Cycling. The operation of generating units at varying load levels (including on-off and low load variations), in response to changes in system load requirements. Cycling causes a power plant's boiler, steam lines, turbine, and auxiliary components to go through unavoidably large thermal and pressure stresses.

D

Day-Ahead Energy Market. Energy trading that engages in forward markets covering the 24-hour period before any given day. It matches buyers and sellers in a financially binding commitment to purchase energy on the following day. (See also Real-Time Energy Market on page A-18.

Daytime Minimum Load (DML). The absolute minimum demand for electricity between 9 AM and 5 PM on one or more circuits each day.

Delivered Cost. The cost of power produced by a generating unit (or power purchase agreement) that includes the cost of delivering the electric power from the generating source to the load center.

Demand. The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is measured in kilowatts or megawatts (kW = 1 kilowatt = 1,000 watts or 1 MW), while energy use is measured in kilowatt-hours or megawatt hours (for example, kWh = kilowatts x hours of use = kilowatt-hours). Load is considered synonymous with demand. (See also Load on page A-12.)

Demand Response (DR). Mechanisms that provide incentives to customers to reduce their load in response to high electric market prices, short-term demand spikes, or electric system reliability concerns. The underlying objective of demand response is to actively engage customers in reducing their demand for electricity to address system needs, in lieu of increasing the amount of utility-scale generation to address system needs. Demand response measures could include direct load control programs (such as cycling air conditioner load or slightly reducing the watt output of large-scale lighting) or customer-initiated load reductions. Demand response programs include real-time pricing, dynamic pricing, critical peak pricing, time-of-use rates, and demand bidding or buyback programs.

Demand-Side Management (DSM). The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand—in other words, managing demand patterns. It refers only to modifying energy and load-shapes that are undertaken in response to utility or third party-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards. Demand-side management covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Demand-Side Resources. Resources on the customer side of the meter that reduce overall system load.

Direct Current (DC). An electric current whose flow of electric charge remains constant. Certain renewable power generators (such as solar photovoltaics) deliver DC electricity, which must first be converted to alternating current (AC) electricity, using an inverter, for use in the power system.

Direct Load Control (DLC). This demand-side management category represents the consumer load that can be interrupted by direct control by a utility system operator. For example, the utility may install a device (such as a radio-controlled device) on a customer's air conditioning equipment or water heater. During periods of system need, the operator sends a radio signal to device-equipped appliances to control the appliance for a set period of time.

Direct Transfer Trip (DTT). A protection mechanism that originates from station relays in response to a specific system event. Remote events, such as generator trips, can cause load shed through DTT.

Discount Rate. An interest rate used to convert future cash flows to present values.

Dispatchable Generation. A generation source controlled by a system operator or dispatcher who can increase or decrease the amount of power from that source as the system requirements change based upon economic or other considerations. Different types of generating units have varying degrees of dispatchability.

Distributed Energy Resources (DER). Decentralized small generation (such as rooftop solar panels), typically 10 megawatts or less, sited at or near load, attached to the distribution grid or a customer's electrical system. DERs serve as primary or backup energy sources, and use various technologies including combustion turbines, reciprocating engines, fuel cells, and wind generators, but mostly solar photovoltaics in the form of rooftop solar panels. Also known as Distributed Generation.

Distributed Energy Storage System (DESS). Energy storage systems on the distribution circuit, generally sited at substations and customer property.

Distributed Generation. See Distributed Energy Resources on page A-6.

Distribution Circuit. The physical elements of the grid involved in carrying electricity from the transmission system to end users.

Distribution Transformer. A transformer used to step down voltage from the distribution circuit to levels appropriate for customer use.

Disturbance Ride-Through. The capability of resources to remain connected to the grid during transient off-normal voltage and frequency conditions that occur for typical system disturbances.

Droop and Droop Response. The amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop. Droop response is the time it takes for online generators to pick up load following a contingency event. Electrical systems with faster droop response times can better withstand contingency events.

E

Economic Dispatch. The allocation of load to online dispatchable generating units based on their costs, to affect the most economical production of electricity for customers.

Efficiency Vermont (EVT). Founded in 2000 as the nation's first energy efficiency utility, Vermont's objective advisor to homeowners, businesses, and communities on saving energy through efficiency. EVT provides technical services and financial support as well as train and partner with local providers of efficient goods and services.

Electric Grid. See Grid (Electric) on page A-10.

Electric Power Research Institute (EPRI). A nonprofit research and development organization that conducts research, development, and demonstration relating to the generation, delivery, and use of electricity.

Electric Vehicle (EV). A vehicle that uses one or more electric motors or traction motors for propulsion.

Electric Vehicle Supply Equipment (EVSE). An element in an infrastructure that supplies electric energy for the recharging of electric vehicles (such as plug-in electric vehicles, electric cars, and plug-in hybrids); also called an electric vehicle (EV) charging station, electric recharging point, charging point, charge point, or electronic charging station (ECS).

Electricity. The set of physical phenomena associated with the presence and flow of electric charge.

Emissions. Polluting discharges (such as carbon dioxide and sulfur dioxide) into the atmosphere from electric power plants, commercial and industrial facilities, residential chimneys, and from vehicle (automobile, locomotive, or aircraft) exhaust during normal operation. These pollutants may be classified as primary (emitted directly from the source) or secondary (formed in the atmosphere from primary pollutants). The pollutants emitted vary based on the type of fuel.

Energy. The amount of electricity a generation resource produces, or an end user consumes, in any given period of time. Energy is computed as capacity or demand (kilowatts, megawatts, or gigawatts) multiplied by time (hours). For example, a one-megawatt power plant running at full output for one hour produces one megawatt-hour (1,000 kilowatt-hours) of electrical energy.

Energy Efficiency (EE). Actions taken by customers to reduce their overall consumption of electric energy. Reductions are generally achieved by substituting more energy efficient equipment (such as high-efficiency appliances, water heaters, and CLF or LED light bulbs), improving the thermal envelopes of structures, or changing behavior. Energy efficiency improvements can be encouraged through utility-sponsored programs, mandated by building codes or other standards, implemented by the customer, or prompted by Efficiency Vermont.

Energy Information Administration (EIA). A principal agency of the United States Federal Statistical System (within the U.S. Department of Energy) responsible for collecting, analyzing, and disseminating energy information. One of its major roles is to provide publicly available fuel price projections for the power generation industry.

Energy Management System (EMS). A centralized system of computer-aided tools used to monitor, control, and optimize the performance of the utility power system and interconnected resources.

Energy Storage. A system or a device capable of storing electrical energy for future use. Three major types of energy storage are:

- *Battery.* An energy storage device composed of one or more electrolyte cells that stores chemical energy. A large-scale battery can provide a number of ancillary services, including frequency regulation, voltage support (dynamic reactive power supply), load following, and black start capability as well as providing energy services such as peak shaving, valley filling, and potentially energy arbitrage. (See also Battery Energy Storage System on page A-2 and Distributed Energy Storage System on page A-6.)

- *Flywheel.* A cylinder that spins at very high speeds, storing rotational kinetic energy. A flywheel can be combined with a device that operates either as an electric motor that accelerates the flywheel to store energy or as a generator that produces electricity from the energy stored in the flywheel. The faster the flywheel spins, the more energy it retains. Energy can be drawn off as needed by slowing the flywheel. A large flywheel plant can provide a number of ancillary services including frequency regulation, voltage support (dynamic reactive power supply), and spinning reserve.

- *Pumped Storage Hydroelectric.* Pumped storage hydro facilities typically use off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy. When the water stored in the upper reservoir is released, it is passed through hydraulic turbines to generate electricity. The off-peak electrical energy used to pump the water uphill can be stored indefinitely as gravitational energy in the upper reservoir. Thus, two reservoirs in combination can be used to store electrical energy for a long period of time, and in large quantities. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following, and black start capability as well as energy services such as peak shaving and energy arbitrage.

- **Thermal Energy Storage.** Allows excess thermal energy to be stored and used hours, days, or months later to balance energy demand between daytime and nighttime, storing summer heat for winter heating, or winter cold for summer air conditioning; considered an important method to inexpensively balance high penetration of variable renewable electricity. Storage media include water heater tanks or ice-slush tanks. Sources of thermal energy for storage include heat or cold produced with heat pumps from off-peak, lower cost electric power; heat from combined heat and power (CHP) plants; and heat produced by renewable energy that exceeds grid demand.

Environmental Protection Agency (EPA). The federal agency established in 1970 to research, monitor, and establish standards that protect human health and the environment. The EPA also has the authority to enforce regulations when necessary, although normally the states implement them.

Expense. An outflow of cash or other consideration (for example, incurring a commercial credit obligation) from a utility to another person or company in return for products or services (such as fuel expense, operating expense, maintenance expense, sales expense, customer service expense, or interest expense). An expense might also be a non-cash accounting entry where an asset (created as a result of a capital expenditure) is used up (for example, depreciation expense) or a liability is incurred.

F

Fast Frequency Response (FFR1 and FFR2). Reduces the rate of change of frequency (RoCoF) with a response proportional to the generation contingency, and quickly restores the balance between supply and demand following a loss of load, thus reducing operational down reserves from synchronous generation. FFR1 is a proportional response that reduces the RoCoF caused by the loss of generation. FFR2 reduces the RoCoF caused by the loss of generation. FFR2 is considered fixed because, once committed, it cannot be altered; however, the amount available can be variable because the FFR2 capacity depends on customer load.

Fault. Any abnormal electric current, a deviation from the expected values of voltage, on an open electric circuit.

Federal Energy Regulatory Commission (FERC). The federal agency that regulates the interstate transmission of electricity and natural gas and their wholesales transactions; regulates the transportation of oil by pipeline; and licenses non-federal hydropower projects. FERC also reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas (LNG) terminals.

Feeder. A circuit carrying power from a major conductor to a one or more distribution circuits.

Firm Capacity. See Capacity on page A-3.

Feed-In Tariff (FIT). A policy mechanism for the rate at which exported DERs are compensated by the utility, designed to accelerate investments in renewable energy.

Flywheel. See Energy Storage on page A-7.

Forced Outage. See Outage on page A-15.

Forced Outage Rate. See Outage on page A-15.

Forward Capacity Market (FCM). A market operated by ISO-New England to ensure that their jurisdictional area will have sufficient resources to meet future needs. FCM uses an auction system for purchasing sufficient power capacity for reliable system operation for a future year at competitive prices where both new and existing resources can participate.

Fossil Fuel. Any naturally occurring fuel formed from the decomposition of buried organic matter, essentially coal, petroleum (oil), and natural gas. Fossil fuels take millions of years to form, and thus are non-renewable resources. Because of their high percentages of carbon, burning fossil fuels produces about twice as much carbon dioxide (a greenhouse gas) as can be absorbed by natural processes.

Frequency. The number of cycles per second through which an alternating current passes. Frequency has been standardized in the United States electric utility industry at 60 cycles per second (60 Hz). The balancing authority and utility operator strive to maintain the system frequency as close as possible to 60 Hz at all times by varying the output of dispatchable generators, typically through automatic means. In general, if demand exceeds supply, the frequency drops below 60 Hz; if supply exceeds demand, the frequency rises above 60 Hz. If the system frequency drops to an unacceptable level (under-frequency) or rises to an unacceptable level (over-frequency), a system failure can occur. Accordingly, system frequency is an important indicator of the power system's condition at any given point in time.

Frequency Regulation. The effort, within fractions of seconds, to keep an alternating current at a consistent 60 hertz per second (or other fixed standard).

Fuel Cell. A device that converts chemical energy into electrical energy using a fuel. Fuel cells require a constant supply of fuel and oxygen for its chemical reaction, unlike batteries where the chemicals react with each other to provide the electricity.

Full-Forced Outage. See Outage on page A-15.

G

Generating Capacity. See **Capacity** on page A-3.

Generation (Electricity). The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh). Generation output can be specified as either:

- *Nameplate Generation (Gross Generation).* The electrical output at the terminals of the generator, usually expressed in megawatts.
- *Net Generation.* Gross generation minus station service or unit service power requirements, usually expressed in megawatts. For example, the energy required for pumping at a pumped storage hydroelectric facility is regarded as plant use and must be deducted from the gross generation.

Generator (Electric). A machine that transforms mechanical, chemical, or thermal energy into electric energy, which includes wind generators, solar PV generators, and other systems that convert energy of one form into electric energy.

Geographic Information System (GIS). A computer system designed to capture, store, manipulate, analyze, manage, and present all types of geographical data.

Gigawatt (GW). A unit of power, capacity, or demand equal to one billion watts, one million kilowatts, or one thousand megawatts.

Gigawatt-Hour (GWh). A unit of electric energy equal to one billion watt-hours, one million kilowatt-hours, or one thousand megawatt-hours.

Greenhouse Gases (GHG). Any gaseous substance (mostly carbon dioxide, methane, sulfur dioxide, and nitrogen oxides) that has been shown to warm the earth's atmosphere by trapping solar radiation. Greenhouse gases also include chlorofluorocarbons, a group of chemicals used primarily in cooling systems and which are now either outlawed or severely restricted by most industrialized nations.

Grid (Electric). An interconnected network of electric transmission lines and related facilities. The United States power grid comprises the eastern interconnection (including parts of Canada), the western interconnection (including parts of Canada and Mexico), and the Texas interconnection. These networks include extra-high-voltage connections between individual utilities, which transfer electrical energy from one part of the network to another. The interconnects distribute electricity in their respective areas via a network of smaller units that enable better management of power distribution.

Grid-Scale Generation. See Utility-Scale Generation on page A-22.

Gross Generation. See Generation (Electricity) on page A-9.

H

Heat Rate. A measure of thermal energy required to produce a given amount of electric energy, usually expressed in British thermal units per net kilowatt-hour. Heat rate indicates the efficiency with which thermal energy is converted into electric energy, and thus measures the performance of power plants. Heat rate is measured by dividing the rate of fuel consumption (Btu per hour) by the resulting generated electric energy (net kilowatt-hours).

Heat Recovery Steam Generator (HRSG). An energy recovery heat exchanger that recovers heat from a hot exhaust gas stream, and produces steam that can be used in a process (cogeneration) or used to drive a steam turbine in a combined-cycle plant.

Hydrokinetic Energy. Several technologies that capture the energy from flowing water that occurs in rivers and mostly in ocean currents, including tidal range, tidal stream, ocean current energy (river in-stream energy), ocean wave energy, ocean thermal energy conversion (OTEC), and salinity gradient.

I

Impacts. The positive or negative consequences of an activity. For example, there may be negative consequences associated with the operation of power plants from the emission discharge or release of a material to the environment (for example, health effects). There may also be positive consequences resulting from the construction and siting of power plants which could affect society and culture.

Impedance. A measure of the opposition to the flow of power in an alternating current circuit.

Independent Power Producer (IPP). Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, co-generators (or combined heat and power generators) and small power producers (including net metered and feed-in tariff systems) and all other non-utility electricity producers (such as exempt wholesale generators who sell electricity or exchange electricity with the utility). IPPs are sometimes referred to as non-utility generators.

Independent System Operator (ISO). An independent, member-based, nonprofit organization that oversees the operation of a bulk electric power system, its transmission lines, and the electricity market generated and transmitted by its member utilities. The goal of an ISO is to operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, and facilitate effective markets and promote infrastructure development (similar to the goals of a regional transmission organization). ISO-New England is responsible for the transmission grid in all six New England states, including Vermont. Several ISOs operate within the electric power grid in the United States and Canada; not all areas of the electric grid, however, are covered by an ISO (or an RTO). (See also Regional Transmission Organization on page A-18.

Inertia. The response of generators from the kinetic energy in the rotating masses that remain online as frequency starts to drop following a contingency event. Inertia provides ride-through of momentary system disruptions to avoid a system contingency. Inertia reduces the rate of change of frequency (RoCoF), allowing slower governor actions to catch up and contribute to frequency stabilization. Electrical systems with high inertia are more robust and can better withstand contingency events.

Installed Capacity. See Capacity on page A-3.

Integrated Resource Plan (IRP). The plan created by electric utilities to identify the resources mix for meeting near-term and long-term energy needs. An IRP conveys the results from a planning, analysis, and decision-making process that examines and determines how a utility will meet future demands. Developed in the 1980s, the IRP process integrates efficiency and load management programs, considered on par with supply resources; broadly framed societal concerns, considered in addition to direct dollar costs to the utility and its customers; and public participation into the utility planning process. A number of factors—the massive influx of DERs and the resulting decentralization of generation, flat and declining demand, energy efficiency, renewable generation targets, two-way distribution systems and the resulting distribution planning, lower emission standards, and many others—are affecting a fundamental transformation in the IRP process, creating a more volatile planning environment and shorter planning horizons.

Interconnection Charge. A one-off charge to DER customers reflecting costs of studies and any potential upgrades (such as transformer upgrades) associated with distributed generation.

Intermediate Capacity. See Capacity on page A-3.

Internal Combustion Engines (ICE). A heat engine that combines fuel with an oxidizer (usually air) in a combustion chamber that creates pressure and mechanical force to generate electricity.

Inverter. A device that converts direct current (DC) electricity to alternating current (AC) either for stand-alone systems or to supply power to an electricity grid. An appropriately designed inverter can provide dynamic reactive power as well as real power and disturbance ride-through capability. A solar PV system uses inverters to convert DC electricity to AC electricity for use in the grid, or directly by a customer.

Investment Tax Credit (ITC). A financial vehicle that allows customers to take a dollar-for-dollar reduction in federal income taxes for qualified energy investments. Depending on the technology, certain energy property can also be considered qualified facilities for a production tax credit (PTC). Customers, however, must choose only one tax credit for facilities that qualify for both an ITC and a PTC. (See also Production Tax Credit on page A-17.

Islanding. A condition in which a circuit remains powered by non-utility generation (that is, distributed generation resources) even when the circuit has been disconnected from the wider utility power network.

ISO-New England (ISO—NE). ISO-New England is responsible for the transmission grid in all six New England states, including Vermont.

K

Kilowatt (kW). A unit of power, capacity, or demand equal to one thousand watts. The demand for an individual electric customer, or the capacity of a distributed generator, is sometimes expressed in kilowatts. The standard billing unit for electric tariffs with a demand charge component is the kilowatt. (See also Watt on page A-23.)

Kilowatt-Hour (kWh). A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour. (See also Watt-Hour on page A-23.)

L

Levelized Cost of Energy (LCOE). The price per kilowatt-hour for an energy project to break even; it does not include risk or return on investment.

Life-Cycle Costs. The total cost impact over the life of a program or the life of an asset. Life-cycle costs include capital expenditures, operation, maintenance and administrative expenses, and the costs of decommissioning.

Light-Emitting Diode (LED). A semiconductor light source used for lighting. LEDs present many advantages over incandescent light sources including lower energy consumption, improved robustness, smaller size, faster switching, greater durability and reliability, and lower generated heat.

Load. The moment-to-moment measurement of power that an end-use device or an end-use customer consumes. The total of this consumption plus planning margins and operating reserves is the entire system load. (Load is often used synonymously with demand. While related, the two concepts are fundamentally different.) Load consists of:

- *Baseload.* The constant generation of electric power load to meet demand.
- *Connected Load.* The sum of the capacities or ratings of the electric power consuming devices connected to a supplying system, or any part of the system under consideration.

Load Balancing. The efforts of the system operator to ensure that the load is equal to the generation. During normal operating conditions, the system operator utilizes load following and frequency regulation for load balancing.

Load Control Program. A program offering some form of compensation (for example, a bill credit) in return for having permission to remotely control a customer's energy use (such as an air conditioner or water heater) for defined periods of time in response to short-term increases in demand. (See also Demand Response on page A-5.)

Load Following. The ability of a generation resource to increase or decrease its power output in response to operator control to match near-simultaneous increases and decreases in load.

Load Forecast. An estimate of the level of future energy needs of customers in an electric system. Bottom-up forecasting uses utility revenue meters to develop system-wide loads; used often in projecting loads of specific customer classes. Top-down forecasting uses utility meters at generation and transmission sites to develop aggregate control area loads; useful in determining reliability planning requirements, especially where retail choice programs are not in effect.

Load Management. Electric utility or third-party marketing programs designed to encourage the utility's customers to adjust the timing of their energy consumption. By coordinating the timing of its customers' consumption, the utility can achieve a variety of goals including reducing the utility's peak system load; increasing the utility's minimum system load; and meeting unusual, transient, or critical system operating conditions.

Load Profile. Measurements of a customer's electricity usage over a period of time, which shows how much and when a customer uses electricity. Load profiles can be used by suppliers and transmission system operators to forecast electricity supply requirements and to determine the cost of serving a customer.

Load Shedding. A purposeful, immediate response to curtail electric service. Load shedding is typically used to curtail large blocks of customer load (for example, particular distribution feeders) during an under-frequency event (when frequency drops below a certain level) when demand for electricity exceeds supply (for example, during the sudden loss of a generating unit).

Load Tap Changer (LTC). A substation controller used to regulate the voltage output of a transformer.

Locational Marginal Pricing (LMP). A method to establish a wholesale electric energy price that reflects the value of the energy at a specific location; the time it is delivered; and the patterns of load, generation, and physical limitations of the system. The purpose is to balance generation throughout the electric system by raising energy prices in constrained areas and reducing energy prices in unconstrained areas.

Loss-of-Load Probability (LOLP) or Loss of Load Expectation (LOLE). The probability that a generation shortfall (loss of load) would occur over a broad period of time. This probability can be used as a consideration in generation adequacy requirements. The LOLE is usually set as one day in ten years.

Low Voltages. Voltages above 0.9 per unit that are of concern because these voltages can become an under-voltage violation in the future.

M

Maintenance Outage. See Outage on page A-15.

MBtu. A thousand Btu. (See also British Thermal Unit on page A-2.)

Megawatt (MW). A unit of power, capacity, or demand equal to one million watts or one thousand kilowatts. Generating capacities of power plants and system demand are typically expressed in megawatts. (See also Kilowatt on page A-11 and Watt on page A-23.)

Megawatt-Hour (MWh). A unit of electric energy equal to one million watt-hours or one thousand kilowatt-hours. The energy output of generators or the amount of energy purchased from independent power producers is oftentimes specified in megawatt-hours. (See also Kilowatt-Hour on page A-12 and Watt-Hour on page A-23.)

Mercury and Air Toxics Standard (MATS). A federal standard that requires coal- and oil-fired power plants to limit the emissions of toxic air pollutants: particular matter (such as arsenic), heavy metals (such as mercury) and acid gases (such as carbon dioxide).

MMBtu. One million Btu. (See also British Thermal Unit on page A-2.)

Must-Run Unit. A generation facility that must run continually because of operational constraints or system requirements to maintain system reliability; typically a large thermal or nuclear power plant.

Must-Take Generation. Electricity produced from a generation unit (whether owned by the utility, and independent power producer, or a customer) that must be taken onto the power grid when produced. Sometimes refers to qualifying facilities under the Public Utility Regulatory Policies Act (PURPA).

N

N–1 or N–1–1 Contingency. The unexpected failure or outage of one (N–1) or two (N–1–1) system components (such as a generator, transmission line, circuit breaker, switch, or other electrical element); and can include multiple electrical elements if they are linked so that failures occur simultaneously at the loss of the single component. "N" refers to the total number of components that the system relies on to operate.

Nameplate Generation. See Generation (Electricity) on page A-9.

National Ambient Air Quality Standards (NAAQS). A Federal standard, set by the Environmental Protection Agency (EPA) under authority of the Clean Air Act, to limit the emission of six "criteria" pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter, and sulfur dioxide (SO_2). These regulations apply to all fuel-fired power plants.

National Pollutant Discharge Elimination System (NPDES). As authorized by the Clean Water Act, the NPDES program permits, administers, and enforces a program that regulates pollutants discharged into water sources.

National Renewable Energy Laboratory (NREL). The Federal laboratory dedicated to researching, developing, commercializing, and using renewable energy and energy efficiency technologies. NREL creates a wealth of well-researched studies that utilities across the country rely on for planning to integrate renewable generation.

Net Capacity. See Capacity on page A-3.

Net Metering. A financial arrangement between a customer with a renewable distributed generator and the utility, where the customer only pays for the net amount of electricity taken from the grid, regardless of the time periods when the customer imported from or exported to the grid. Under a net-metered arrangement, the customer is allowed to remain connected to the power grid, so that the customer can take advantage of the grid's reliability infrastructure (such as ancillary services provided by generators, energy storage devices, and demand response programs), use the grid as a "bank" for power generated by the customer in excess of the customer's needs, and use the grid as a backup resource for times when the power generated by the customer is less than the customer's needs. Power produced under a net-metered arrangement is almost always must-take generation.

Net Generation. See Generation (Electricity) on page A-9.

Net Present Value (NPV). Method for evaluating the cost or profitability of an investment. Individual future cash amounts are discounted back to their present values and then summed.

New Source Review (NSR). A permitting process created by Congress in 1977 as an amendment to the Clean Air Act requiring pre-construction review for environmental controls for building new facilities or modifying existing facilities (not routine scheduled maintenance) that would significantly increase a regulated pollutant. NSR was designed to eventually force the modernization of existing generation assets to comply with air emission regulations.

New Source Performance Standards (NSPS). Created as part of the Clean Air Act in 1970 to establish limits for certain air pollution emissions and water pollution discharges for how much certain categories of new facilities or modified existing facilities (such as boilers) can emit.

Nitrogen Oxide (NOx). Compounds of nitrogen and oxygen formed by combusting fuels under high temperature and high pressure, creating a strong pollutant and greenhouse gas.

Nominal Dollars. At its most basic, nominal dollars are based on a measure of money over a period of time that *has not been* adjusted for inflation. Nominal value represents a cost usually in the current year. As such, nominal dollars can also be referred to as current dollars; in other words, what it costs to buy something today. Nominal dollars are often contrasted with real dollars. (See also Real Dollars on page A-18.

Non-Spinning Reserves. A generating reserve not connected to the system but capable of serving demand within a specified time, usually ten minutes.

Non-Transmission Alternative (NTA). Programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system.

North American Electric Reliability Corporation (NERC). An international non-governmental regulatory authority with a statutory responsibility to ensure the reliability of the North American electric grid by regulating bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices. (APS)

O

Ocean Thermal Energy Conversion (OTEC). A process that can produce electricity by using the temperature difference between deep cold ocean water and warm tropical surface waters.

Off-Peak Energy. Electric energy supplied during periods of relatively low system demand, or the use of electricity during that period when the overall demand for electricity is below normal.

Once-Through Steam Generator (OTSG). A specialized type of HRSG without boiler drums that enables the inlet feedwater to follow a continuous path (without segmented sections for economizers, evaporators, and superheaters) allowing it to grow or contract based on the heat load being received from the gas turbine exhaust. OTSGs can be run dry, meaning the hot exhaust gases can pass over the tubes with no water flowing inside the tubes.

On-Peak Energy. Electric energy supplied during periods of relatively high system demand.

Operating Reliability. The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components. Operating reliability is synonymous with system security. (See also System Security on page A-21.)

Operating Reserves. That portion of generation above firm system demand (called the reserve margin) required to provide regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves. Utilities generally carry a 15% reserve margin, however with the influx of DERs, reserve margins have been steadily increasing. (See also Non-Spinning Reserves on page A-14, Spinning Reserves on page A-20, and Reserve Margin on page A-19.)

Operation and Maintenance (O&M) Expense. The recurring costs of operating, supporting, and maintaining facilities (including costs for labor, fuel, materials, and supplies, and other current expenses) to ensure proper operation and to achieve optimum efficiency levels.

Outage. The period during which a generating unit, transmission line, or other facility is out of service. The following are types of outages or outage-related terms.

- *Forced Outage.* The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable because of an unanticipated failure.
- *Forced Outage Rate.* The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service plus the total number of hours the facility was connected to the electricity system; expressed as a percent.
- *Full-Forced Outage.* The net capability of main generating units that is unavailable for load for emergency reasons.
- *Maintenance Outage.* The removal of equipment from service availability to perform work on specific components that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a maintenance outage can occur anytime during

the year, have a flexible start date, and may or may not have a predetermined duration.

- *Partial Outage.* The outage of a unit or plant auxiliary equipment that reduces the capability of the unit or plant without causing a complete shutdown. It may also include the outage of boilers in common header installations.
- *Planned (or Scheduled) Outage.* The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Outage Management System (OMS). A computer system that provides the capability to efficiently identify, analyze, and resolve unplanned outages.

P

Partial Outage. See Outage on page A-15.

Particulate Matter (PM). A complex mixture of extremely small particles and liquid droplets made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles.

Peak Demand. The maximum amount of power necessary to supply customers; in other words, the greatest demand occurring in a given period (for example, an hour, a day, month, season, or year). Peak demand equals the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. From a customer's perspective, peak demand is the maximum power used during a specific period of time.

Peaker. A generation resource that can quickly ramp up and down to meet spikes in demand, usually during the late afternoon and early evening when demand is highest. Peakers are often used for supplemental reserves, generally operate less than 10% of available hours, and cost the most to operate.

Peaking Capacity. See Capacity on page A-3.

Photovoltaic (PV). Electricity from solar radiation typically produced with photovoltaic cells (also called solar cells): semiconductors that absorb photons and then emit electrons.

Planned Outage. See Outage on page A-15.

Planning Reserves. The difference between a control area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Power. The rate at which energy is supplied to a load (consumed), usually measured in watts (W), kilowatts (kW), megawatts (MW), gigawatts (GW), and terawatts (TW).

Power Factor. A dimensionless quantity that measures the extent to which the current and voltage sine waves in an AC power system are synchronized. If the voltage and current sine waves perfectly match, the power factor is 1.0. Power factors not equal to 1.0 result in dissipation (losses) of electric energy.

Power Purchase Agreement (PPA). A bilateral wholesale or retail power short-term or long-term contract to purchase energy or capacity from a commercial source (for example, an independent power producer) at a predetermined price or based on pre-determined pricing formulas and delivered to an agreed-upon point. (Also referred to as a purchased power agreement.)

Public Utility Regulatory Policies Act (PURPA). Enacted by Congress in 1978, PURPA encouraged a number of energy initiatives in response to the 1973 energy crisis that utilities above a certain threshold "must consider". In effect, though, PURPA created a market for independent power producers, increased energy efficiency, boosted hydroelectric power development, and outlined other measures that, in total, promoted renewable energy. An update to the Act in 2005 outlined new Federal standards for net metering, additional fuel sources, generation efficiency, time-based metering, and distribution interconnection. Another update in 2007 added standards for integrated resource planning, rate design to promote investments in energy efficiency, and smart grid investment.

Present Value. The value of an asset, taking into account the time value of money—a future dollar is worth less today. Present value dollars are expressed in constant year dollars (usually the current year). Future dollars are converted to present dollars using a discount rate. For example, borrowing money with a payback agreement of $1.00 in one year at a discount rate of 10% would result in an available loan amount of $0.90. Utility planners use present value as a way to directly compare the economic value of multi-year plans with different future expenditure profiles. Net present value (NPV) is the difference between the present value of all future benefits, less the present value of all future costs.

Primary Frequency Response (PFR). Primary frequency response is the reserve capacity from online synchronous generation that provides both regulating reserves and contingency reserves. PFR is available to handle the sudden loss of a generator or major transmission line with a response proportional to the changes in frequency. In general, the largest online unit tends to determine the amount of PFR available to the system following a contingency event. If this largest unit trips offline, then the generators already online (and "spinning") can quickly pick up load within a defined time period to keep the system running.

Production Tax Credit (PTC). A tax credit for the generation of qualified energy from qualified facilities. The PTC amounts, credit periods, and definitions of qualified facilities are technology-specific. Qualified energy resources include wind, closed-loop biomass, open-loop biomass, geothermal, solar, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy. Customers, however, must choose only one tax credit for facilities that qualify for both an ITC and a PTC. (See also Investment Tax Credit on page A-11.)

Pumped Storage Hydroelectric. See Energy Storage on page A-7.

Q

Qualitative. Consideration of externalities which assigns relative values or rankings to the costs and benefits. This approach allows expert assessments to be derived when actual data from conclusive scientific investigation of impacts are not available.

Quantitative. Consideration of externalities which provides value based on available information on impacts. This approach allows for the quantification of impacts without assigning a monetary value to those impacts.

R

Ramp Rate. A measure of the speed at which a generating unit can increase or decrease output, generally specified as MW per minute.

Rate Base. The value of property which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the book value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes net cost of plant in service, working cash, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Reactive Power. The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment (such as capacitors), and directly influences electric system voltage.

Real Dollars. At its most basic, real dollars are a measure of money over a period of time that *has been* adjusted for inflation. Real dollars represent the true cost of goods and services sold because the effects of inflation are stripped from the cost. Over time, real dollars are a measure of purchasing power. As such, real dollars can also be referred to as constant dollars; in other words, if the price of something goes up over time at the same rate as inflation, the cost is the same in real dollars. Real dollars are often contrasted with nominal dollars. (See also Nominal Dollars on page A-14.

Real-Time Energy Market. Energy trading that involves the current price of energy based on supply. Prices are determined by the locational marginal pricing (LMP) algorithm for balancing supply from available generating units. (See also Day-Ahead Energy Market on page A-5, and Locational Marginal Pricing on page A-13.

Reciprocating Internal Combustion Engines (RICE). An engine using the reciprocating movement of pistons to create pressure that is converted into electricity.

Regional Transmission Organization (RTO). An independent, member-based, nonprofit organization that coordinates, controls, and monitors the electric grid over multiple states while promoting economic efficiency, reliability, and non-discriminatory practices. An RTO is essentially similar to an independent system operator (ISO), albeit with greater responsibility for the transmission network. Several RTOs operate within the electric power grid in the United States and Canada; not all areas of the electric grid, however, are covered by an RTO (or an ISO). (See also Independent System Operator on page A-10.)

Regulating Reserves (RegUp & RegDown). The service used to maintain system frequency in response to supply and demand imbalances over short time frames, typically on the order of one to several seconds. RegUp and RegDown resources adjust their generation or load levels in response to automatic generation control (AGC) signals provided by the system operator. (See also Automatic Generation Control on page A-1.)

Reliability. The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system, adequacy of supply and system security. (See also System Reliability on page A-21.)

Renewable Energy Credit (REC). Intangible assets that represent the environmental attributes of a renewable generation project and are issued for each MWh of energy generated from such resources. RECs are a commodity that can be traded to comply with Renewable Portfolio Standards (RPS) or, in Vermont, with the Renewable Energy Standard (RES).

Renewable Energy Resources. Energy resources that are naturally replenished and are virtually inexhaustible, but are limited in the amount of energy that is available over a given period of time (capacity factor). The amount of some renewable resources (such as geothermal and biomass) might be limited over the short term as stocks are depleted by use, but on a time scale of decades or perhaps centuries, they can likely be replenished.

Renewable energy resources currently in widespread use include photovoltaics, biomass, hydroelectric, geothermal, solar, and wind. Other renewables resources still under development include ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Unlike fossil fuel generation plants (which can be sited where most convenient because the fuel is transported to the plant), most renewable energy generation plants must be sited where the energy is available; that is, a wind plant must be sited where a sufficient and relatively constant supply of wind is available. In other words, fossil fuels can be brought to their generation plants whereas most renewable energy generating plants must be brought to the renewable energy source. Some renewable resources are exceptions; their fuels (such as biomass and biofuels), like fossil generation, can be brought to the generation plant.

Renewable Energy Standard (RES). In Vermont, a statute that requires electric distribution utilities to obtain a defined percentage of their total retail electric sales from renewable energy (essentially similar to an RPS). RES requirements are divided into three tiers:

- Tier I requires procurement of a defined percentage of retail electric sales from any source of renewable energy.
- Tier II requires procurement a defined percentage of retail electric sales from *new distributed* renewable generation.
- Tier III requires either the procurement of additional Tier II energy or reduce the fossil-fuel consumption and the greenhouse gas emissions associated with that consumption.

Renewable Portfolio Standards (RPS). A statutory goal that requires electric utilities to acquire a minimum percentage of their electricity sales from renewable energy resources. Approximately 40 states have RPS requirements.

Replacement Reserves (RR). Offline, quick-start resources used as replacement reserves provided they can be started and synchronized to the grid within a 10-minute or 30-minute timeframe depending upon system needs. These resources may be used for restoring load, regulation, or supporting and replacing contingency reserves.

Request for Proposal (RFP). A competitive solicitation for suppliers to submit a proposal on a specific commodity or service, often through a bidding process.

Reserves. See Operating Reserves on page A-15 and Planning Reserves on page A-16.

Reserve Margin (Planning). The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability. Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins is a relative indication of adequacy of supply.

Resiliency. The ability to quickly locate faults and automatically restore service after a fault, using FLISR (Fault Location, Isolation, and Service Restoration).

Retail Rate. The rate at which specific classes of customers compensate the utility for grid electricity.

Reverse Flow. The flow of electricity from the customer site onto the distribution circuit or from the distribution circuit through the substation to higher voltage lines. Also called backfeed.

S

Scheduled Outage. See Outage on page A-15.

Service Charge. A fixed customer charge intended to allocate the cost of servicing the grid to all customers, regardless of capacity needs.

Simple-Cycle Combustion Turbine (SCCT). A generating unit in which the combustion turbine operates in a stand-alone mode, without waste heat recovery.

Single-Train Combined Cycle (STCC). See Combined Cycle on page A-4.

Smart Grid. A platform connecting grid hardware devices to smart grid applications, including Advanced Metering Infrastructure (AMI), Volt/VAR Optimization (VVO), Direct Load Control (DLC), and electric vehicle charging. A smart grid enables the communication of massive amounts of system data that better enable a utility to manage their power grid.

Solar Photovoltaic. See Photovoltaic on page A-16.

Spinning Reserves. Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system. (See also Operating Reserves on page A-15 and Primary Frequency Response on page A-17.)

Standard Offer Program. See Sustainably Priced Energy Enterprise Development (SPEED) Program on page A-20.

Steam Turbine (ST). A turbine that is powered by pressurized steam and provides rotary power for an electrical generator.

Stochastic Modeling. Modeling analysis using as input a random collection of variables that represent the uncertainties associated with those variables (as opposed to deterministic modeling that analyzes a single state). Stochastic modeling analyzes multiple states and the range of their uncertainty, then captures the probabilities of those uncertainties. Stochastic modeling can analyze how different generation portfolios perform with regard to cost and risk across a wide range of potential future input assumptions (including, but not limited to, power prices, hydro generation, wind generation, DERs, solar generation, loads, plant forced outages, and REC prices.

Sulfur Oxide (SOx). A precursor to sulfates and acidic depositions formed when fuel (oil or coal) containing sulfur is combusted. Sulfur oxide, a regulated pollutant, refers to many types of sulfur and oxygen containing compounds, such as sulfur dioxide (SO_2).

Substation. A small building or fenced in yard containing switches, transformers, and other equipment and structures for stepping up or stepping down voltage, switching and monitoring transmission and distribution circuits, and other service functions. Electricity, as gets closer to where it is to be used, goes through a substation where the voltage is lowered so it can be used by customers.

Supervisory Control and Data Acquisition (SCADA). A system used for monitoring and control of remote equipment using communications networks.

Supply-Side Management. Actions taken to ensure the generation, transmission, and distribution of energy are conducted efficiently.

Supply-Side Resources. Generating plants that supply power into the electric grid that originate on the utility side of the meter.

Sustainably Priced Energy Enterprise Development (SPEED) Program. Established by the Vermont Legislature in 2005 to encourage the development and purchase of renewable energy resources. In 2009, the Vermont Energy Act (Act 45) implemented the SPEED Standard Offer Program as one of the nation's first feed-in tariff (FIT) programs, essentially to create access to fixed-price long-term renewable contracts. In 2012, Act 170 increased the amount available through the program to 127.5 MW.

Switching Station. An electrical substation, with a single voltage level, whose only function is switching actions.

System. A generic term to describe the utility power grid: a combination of generation, transmission, and distribution components.

System Average Interruption Duration Index (SAIDI). The average annual outage duration experienced by the average customer. SAIDI is a reliability indicator.

System Average Interruption Frequency Index (SAIFI). The average number of interruptions that a utility customer would experience. SAIFI is a reliability indicator.

System Reliability. Broadly defined as the ability of the electric power grid to meet the demand of its customers while maintaining system stability. Reliability can be measured in the number of hours that system demand is met.

System Security. The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. (See also Operating Reliability on page A-15.)

T

Tariff. A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Terawatt (TW). A unit of power, capacity, or demand equal to one trillion watts, one billion kilowatts, one million megawatts, or one thousand gigawatts. The total power used by humans worldwide is commonly measured in terawatts.

Terawatt Hour (TWh). A unit of electric energy equal to one trillion watt-hours, one billion kilowatt-hours, one million megawatt-hours, or one thousand gigawatt-hours.

Time-of-Use (TOU) Rates. The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). The purpose of TOU rates is to price usage based on when it is consumed, and to encourage usage shifting as a means of lowering peak demand periods.

Total Resource Cost (TRC). A method for measuring the net costs of a conservation, load management, or fuel substitution as a resource option, based on the total costs of the participants and the utility.

Transformer. A device used to change voltage levels to facilitate the transfer of power from the generating plant to the customer. A transformer is necessary because higher voltages are best used to move power over long distances, while lower voltages are best for consumption. A step-up transformer increases voltage (power) while a step-down transformer decreases it.

Transmission and Distribution (T&D). Transmission of the bulk transfer of electric power across the power system, typically from generators to load centers, often intended to refer specifically to high-voltage (69,000 volts or higher) electricity. Distribution is the transfer of electric power from the bulk power level to end-users and from distributed generators into the bulk power system.

Two-Way Communications. The platform and capabilities required to allow bi-directional communication between the utility and elements of the grid (including customer-sited advanced inverters), and control over key functions of those elements. The platform must include monitor and control functions, be TCP/IP addressable, be compliant with IEC 61850, and provide cyber security at the transport and application layers as well as user and device authentication.

U

Under Frequency Load Shedding (UFLS). A system protection scheme used during transient adverse conditions to balance load and generation. The term essentially explains the process: when frequency drops below a certain point, this scheme sheds load to keep from completely losing the system.

Under Voltage Load Shedding (UVLS). A system protection scheme used during low voltage conditions to avoid a voltage collapse.

Unit Contingency PPA. A unit contingent sale is contingent on a particular generating unit being available to deliver power. Generally, this means that there is some allowed portion of time during which the unit is expected to be unavailable and therefore not deliver power.

United States Department of Energy (DOE). An executive department of the U.S. government that is concerned with the United States' policies regarding energy, environmental, and nuclear challenges.

United States Energy Information Administration (EIA). The principal agency responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy. The EIA conducts independent comprehensive data collection of energy sources, end uses, and energy flows; generates short- and long-term domestic and international energy projections; and performs informative energy analyses. EIA programs cover data on coal, petroleum, natural gas, electric, renewable, and nuclear energy.

United States Environmental Protection Agency (EPA). An executive department of the U.S. government whose mission is to protect human health and the environment.

Utility-Scale Generation. The designation for any small- or large-scale generation facility—usually a variable renewable resource such as solar PV or wind—either owned by the utility or owned by an independent power producer (IPP). While generally not defined by output, their generation capabilities can range from as small as 1 MW to much larger (such as 100 MW or more). Sometimes referred to as grid-scale generation.

V

Variable Renewable Energy. Generation whose output varies with the availability of its primary energy resource, such as wind, the sun, and flowing water. The primary energy source cannot be controlled in the same manner as firm, conventional, fossil-fuel generators. Specifically, while a variable generator (without storage) can be dispatched to operate below the available energy, it cannot be increased above what can be produced by the available resource energy. Variable energy can be coupled with storage, or the primary energy source can be stored for future use (such as with solar thermal storage, or when converted into electricity via storage technologies). Also referred to as intermittent and as-available renewable energy.

Vermont Comprehensive Energy Plan. See Comprehensive Energy Plan on page A-4.

Vermont Electric Plan. Published by the Vermont Public Service Department, this plan serves as a basis for state electric energy policy. It includes a 20-year outlook, an assessment of all energy resources available to the state for electricity generation or to supply electric power, estimates of electric energy demand, and specific strategies for reducing electric rates. Among other objectives, it also considers the protection of public health and safety and the preservation of environmental quality. The Vermont Electric Plan is wholly encompassed in the Vermont Comprehensive Energy Plan (CEP). (See also Comprehensive Energy Plan on page A-4.)

Vermont Electric Power Company (VELCO). Formed in 1956, VELCO manages the safe, reliable, cost-effective, interconnected transmission grid capable of sharing electrical energy throughout Vermont. VELCO manages 738 miles of transmission lines and 55 substations, switching stations, and terminal facilities.

Vermont Energy Education Program (VEEP). A not-for-profit Vermont corporation that administers two of

Vermont's renewable energy programs under contract with the Vermont Public Utility Commission (VPUC). VEEP acts as the purchasing agent for existing VPUC Rule 4.100 Projects, and as the facilitator for existing and new Standard Offer Projects.

Vermont Energy Investment Corporation (VEIC). A nonprofit organization whose goal is to reduce the economic and environmental costs of energy consumption through energy efficiency and renewable energy adoption.

Vermont Public Service Board (PSB). The former name of the Vermont Public Utility Commission. See Vermont Public Utility Commission on page A-23.

Vermont Public Service Department (PSD). Housed within the executive branch of Vermont state government, this department represents the public interest in energy, telecommunications, water, and wastewater utility matters. PSD also represents the public interest in utility cases before state and federal agencies and courts. More specifically, PSF provides long-range planning for Vermont's energy and telecommunications needs through Vermont Comprehensive Energy Plan (which also encompasses the Vermont Electric Plan) and the Vermont Telecommunications Plan. (See also Comprehensive Energy Plan on page A-4).

Vermont Public Utility Commission (VPUC). An independent, three-member, quasi-judicial commission that regulates the siting of electric and natural gas infrastructure and supervises the rates, quality of service, and overall financial management of Vermont's public utilities: electric, gas, energy efficiency, telecommunications, cable television (terms of service only, not rates), water, and large wastewater companies. Formerly known as the Vermont Public Service Board.

Volt-Ampere Reactive (VAR). A unit by which reactive power is expressed in an AC electric power system.

Voltage. Voltage is a measure of the electromotive force or electric pressure for moving electricity.

Voltage Regulation. The control of voltage to keep the value within a specified target or range.

W

Waste-to-Energy (WTE). A process of generating electricity from the primary treatment (usually burning) of waste. WTE is a form of energy recovery.

Watt. The basic unit of measure of electric power, capacity, or demand; specifically, the rate of energy transfer equivalent to one ampere flowing because of an electrical pressure of one volt at unity power factor. Named after the Scottish engineer James Watt (1736–1819).

Watt-Hour. The total amount of energy used in one hour by a device that requires one watt of power for continuous operation. Electric energy sold to retail customers is commonly measured in kilowatt-hours, or one thousand watt-hours.

Wave and Tidal Power. A process that captures the power of waves and tides and converts it into electricity. While the arrival of waves at a power facility is somewhat predictable (mainly because waves travel across the ocean), tides are extremely predictable because they are driven by the gravitational pull of the moon and sun.

B. 2019 Budget Forecast Report

For our 2018 IRP, we utilized the report developed by Itron for the 2019 Cost of Service filing—a sales and revenue forecast for 2019 and the succeeding nine years. Sales were broken out by customer class: residential, commercial, industrial, and other.

As a contrast, for our 2014 IRP, Itron produced a load forecast for twenty years. We changed tactics for two main reasons: we found that sales and revenue more accurately forecast the future, and that forecasting has become too volatile to be accurate past ten years. Case in point: our actual 2017 sales were approximately 5.0% lower than forecasted three years ago in the 2014 IRP.

We continue to contract with Itron for several reasons: they are expert in modeling and forecasting, have access to data not readily available to us; and are an independent third-party. While we seed their work with our company-specific data, they add their own revenue trends gathered from far-reaching sources mixed in with their own external inputs and expertise. Thus, they produce a forecast based on this compiled data that is essentially theirs, albeit one that applies directly to us. It is exactly this expertise, independence, and transparency we find most valuable.

This appendix contains the 2019 Budget Forecast Report Itron prepared for us. See Chapter 4: Declining Electricity Consumption for how we used this information to develop our 2018 IRP.

Highlights of the 2019 Budget Forecast Report

- The forecast shows combined customer class sales initially declining by about 0.2% annually over the next three years and remaining steady for an overall annual sales loss of 0.2% over the entire ten-year test period. Source: Table 1. Customer Class Billed Sales Forecast-MWh (on Budget Forecast Report page 2, which is the same as IRP page B-7).
- Residential sales are projected to decline about approximately 0.9% of the ten-year test period, despite a 0.3% increase in the forecasted number of customers. Source: Table 2. Residential Sales Forecast (on Budget Forecast Report page 3, which is the same as IRP page B-8).
- Sales from small commercial and industrial customers is forecast to increase by approximately 0.2% annually over the ten-year test period. Source: Table 5. Commercial Customer Usage Forecast (on Budget Forecast Report page 7, which is the same as IRP page B-12).
- Strategic electrification, more specifically electric vehicles, is projected to increase by an average of 35.3% over the ten-year study period according to the Energy Futures Group forecast for EV deployments. Source: Figure 5. Electric Vehicle Forecast (on Budget Forecast Report page 18, which is the same as IRP page B-23).
- Revenues are projected to decline by 0.2% over the ten-year study period. Source: Table 15. Fiscal Year Revenue Forecast-$ (on Budget Forecast Report page 33, which is the same as IRP page B-38).

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Green Mountain Power 2019 Budget Forecast Report

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2019 FISCAL YEAR BUDGET FORECAST: SUMMARY

Itron, Inc. recently completed the Green Mountain Power (GMP) 2019 fiscal-year sales and revenue forecast. The forecast includes sales, customers, and revenue projections through 2028. The forecast is based on billed sales and customer data through December 2017. Forecast inputs include:

- Moody Analytics January 2018 Vermont economic forecast
- AEO 2017 end-use efficiency estimates for the New England Census Division
- VEIC most current energy efficiency savings projections and Tier III cold climate heat pump forecast
- Energy Futures Group 2017 electric vehicle forecast (Project for GMP)
- GMP's updated solar capacity forecast
- GMP adjustments for commercial Tier III electrification activity, and other large load adjustments that would not be reflected in the historical billing data
- Updated normal HDD and CDD (1998 to 2017)

Sales forecasts are generated at the customer class level and include residential, commercial, industrial, and street lighting. Class level sales forecasts are then allocated to rate schedules and billing determinants for the purpose of estimating revenues.

The sales and customer forecasts are based on linear regression models that relate monthly customer-class sales (average use in the residential sector) to monthly weather conditions, population growth, economic activity, prices, and end-use efficiency improvements. The sales forecast is adjusted for factors not reflected in historical data including expected changes in energy requirements for the largest commercial and industrial customers, solar load penetration, cold climate heat pumps, and electric vehicles. Impact of future efficiency programs are incorporated into the end-use intensity projections that drive the class sales forecasts.

Over the next 10 years, total sales are expected to continue to decline at a slow rate. Residential sales will see the strongest decline averaging 0.9% through 2020 and 0.8% over the longer ten-year period. With Tier III electrification activities and adjusted for expected load additions Small Commercial & Industrial sales average 0.3% increase over the next three years and 0.2% over the next ten years. Industrial sales average 0.1% annual growth over the next three years and are flat (0.0% annual growth) over the long-term. Table 1 shows the customer class sales forecast.

Table 1: Customer Class Billed Sales Forecast (MWh)

Year	Residential	Chg	Commercial	Chg	Industrial	Chg	Other	Chg	Total	Chg
2008	1,559,231		1,584,987		1,063,320		10,710		4,218,248	
2009	1,544,874	-0.9%	1,530,564	-3.4%	973,631	-8.4%	10,780	0.7%	4,059,848	-3.8%
2010	1,558,457	0.9%	1,534,895	0.3%	1,013,453	4.1%	10,918	1.3%	4,117,722	1.4%
2011	1,552,270	-0.4%	1,527,244	-0.5%	1,073,557	5.9%	11,414	4.5%	4,164,485	1.1%
2012	1,520,840	-2.0%	1,538,905	0.8%	1,169,331	8.9%	10,645	-6.7%	4,239,721	1.8%
2013	1,562,370	2.7%	1,550,572	0.8%	1,178,595	0.8%	8,443	-20.7%	4,299,981	1.4%
2014	1,568,689	0.4%	1,559,491	0.6%	1,177,033	-0.1%	6,887	-18.4%	4,312,099	0.3%
2015	1,539,045	-1.9%	1,531,148	-1.8%	1,168,796	-0.7%	5,274	-23.4%	4,244,263	-1.6%
2016	1,483,553	-3.6%	1,530,603	0.0%	1,188,527	1.7%	4,852	-8.0%	4,207,536	-0.9%
2017	1,465,612	-1.2%	1,516,541	-0.9%	1,170,493	-1.5%	4,453	-8.2%	4,157,098	-1.2%
2018	1,467,655	0.1%	1,518,210	0.1%	1,175,494	0.4%	4,760	6.9%	4,166,119	0.2%
2019	1,440,878	-1.8%	1,521,410	0.2%	1,179,223	0.3%	4,760	0.0%	4,146,271	-0.5%
2020	1,425,189	-1.1%	1,528,236	0.4%	1,173,906	-0.5%	4,760	0.0%	4,132,091	-0.3%
2021	1,404,761	-1.4%	1,528,060	0.0%	1,175,862	0.2%	4,760	0.0%	4,113,442	-0.5%
2022	1,390,565	-1.0%	1,529,039	0.1%	1,178,369	0.2%	4,760	0.0%	4,102,733	-0.3%
2023	1,378,673	-0.9%	1,529,121	0.0%	1,178,659	0.0%	4,760	0.0%	4,091,212	-0.3%
2024	1,370,041	-0.6%	1,530,529	0.1%	1,178,567	0.0%	4,760	0.0%	4,083,897	-0.2%
2025	1,359,059	-0.8%	1,532,087	0.1%	1,177,505	-0.1%	4,760	0.0%	4,073,410	-0.3%
2026	1,350,439	-0.6%	1,534,800	0.2%	1,175,797	-0.1%	4,760	0.0%	4,065,796	-0.2%
2027	1,345,652	-0.4%	1,538,443	0.2%	1,174,086	-0.1%	4,760	0.0%	4,062,941	-0.1%
2028	1,344,158	-0.1%	1,542,812	0.3%	1,173,789	0.0%	4,760	0.0%	4,065,519	0.1%
2008 - 17		-0.7%		-0.5%		1.2%		-8.8%		-0.1%
2017 - 20		**-0.9%**		**0.3%**		**0.1%**		**2.3%**		**-0.2%**
2017 - 28		-0.8%		0.2%		0.0%		0.6%		-0.2%

1. Class Sales Forecast

Monthly customer class sales and customer forecasts are based on regression models that relate monthly sales to household projections, economic activity as measured by real GDP, employment, household income, expected weather, price, and changes in end-use energy intensities resulting from new standards, natural occurring appliance stock replacement, and state energy efficiency programs. Models are estimated with monthly billed sales and customer counts from January 2008 to December 2017.

The forecast incorporates Moody's Analytics January 2018 state economic forecast and the Energy Information Administration (EIA) 2017 end-use energy intensity projections for New England. End-use intensity projections are adjusted to reflect end-use saturations for Vermont and VEIC's energy efficiency (EE) program savings projections.

Estimated forecast models incorporating household growth, economic activity, price, efficiency, and weather trends are used to generate the *Baseline* forecast.

The baseline forecast reflects both economic and end-use efficiency impacts. The forecast is then adjusted to include:

- New solar capacity projections
- Expected Tier III electrification impacts
- Electric Vehicle sales
- Spot load adjustments for expected large load additions (and losses)

1. Residential

Since 2008, residential weather normalized sales have declined 0.7% on an annual basis. Sales decline has even been stronger over the last three years (averaging 2.2% annual decline); strong solar capacity growth and the new lighting standards have been major contributors.

Sales growth can be disaggregated into customer and average use growth. Since 2008, normalized average use has declined 1.0% per year with the number of residential customers averaging a 0.3% increase. Weather normalized average use has declined from 7,226 kWh in 1008 to 6,620 kWh in 2017.

The residential baseline forecast is derived by combining average use forecast with customer forecast. The forecast is then adjusted for expected solar load growth, Tier III electrification impacts, and electric vehicle sales. Table 2 shows the forecast results.

Table 2: Residential Sales Forecast

Year	Average Use (kWh)	Chg	Customers	Chg	Sales (MWh)	Chg
2018	6,610		222,034		1,467,655	
2019	6,472	-2.1%	222,642	0.3%	1,440,878	-1.8%
2020	6,382	-1.4%	223,316	0.3%	1,425,189	-1.1%
2021	6,273	-1.7%	223,948	0.3%	1,404,761	-1.4%
2022	6,190	-1.3%	224,633	0.3%	1,390,565	-1.0%
2023	6,116	-1.2%	225,413	0.3%	1,378,673	-0.9%
2024	6,055	-1.0%	226,263	0.4%	1,370,041	-0.6%
2025	5,983	-1.2%	227,170	0.4%	1,359,059	-0.8%
2026	5,920	-1.0%	228,098	0.4%	1,350,439	-0.6%
2027	5,876	-0.7%	228,996	0.4%	1,345,652	-0.4%
2028	5,849	-0.5%	229,822	0.4%	1,344,158	-0.1%
18-28		-1.2%		0.3%		-0.9%

Table 3 shows the forecast adjustments and isolates efficiency impacts. The efficiency embedded in the baseline forecast is disaggregated by holding the model end-use intensities constant through the forecast period. Efficiency reflects the impact of new standards, natural occurring efficiency, and state efficiency programs.

Table 3: Residential Sales Forecast Disaggregation

Year	No EE (1)	Efficiency (2)	Solar (3)	Heat Pumps (4)	Electric Vehicles (5)	Total Adj	Forecast
2018	1,484,658	-15,262	-6,143	3,356	1,047	-17,003	1,467,655
2019	1,485,966	-35,024	-19,058	6,690	2,303	-45,088	1,440,878
2020	1,494,878	-55,202	-28,318	10,021	3,811	-69,688	1,425,189
2021	1,502,098	-78,881	-37,459	13,384	5,620	-97,337	1,404,761
2022	1,510,205	-96,417	-47,785	16,771	7,791	-119,640	1,390,565
2023	1,517,144	-112,089	-56,986	20,208	10,396	-138,471	1,378,673
2024	1,523,832	-124,648	-66,335	23,670	13,522	-153,791	1,370,041
2025	1,530,359	-140,310	-75,388	27,125	17,273	-171,300	1,359,059
2026	1,536,718	-154,037	-84,589	30,573	21,775	-186,278	1,350,439
2027	1,542,833	-164,813	-93,790	34,029	27,393	-197,181	1,345,652
2028	1,549,251	-173,755	-103,225	37,481	34,405	-205,093	1,344,158

1. No EE reflects sales growth due to household and economic activty
2. Efficiency includes impacts of new standards, naturally-occuring, and program-based efficiency improvements.
3. Solar - Derived from GMP solar capacity forecast, residential 36%, commercial 52%, and industrial 12% of capacity.
4. Heat Pumps - assume 2,200 units installed per year, based on VEIC state forecast (3,000 units per year).
5. Electric vehicles - EFG's 2017 Scenario 1 forecast (approx 9.3% of vehicle sales by 2026).

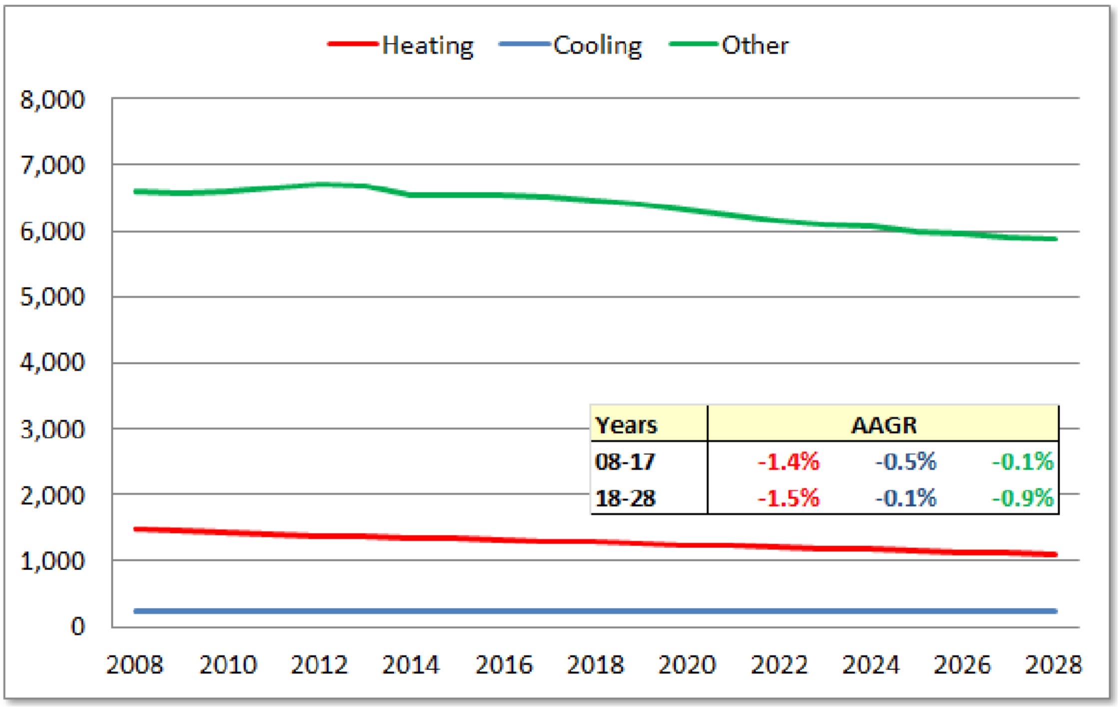
Forecast Drivers. The baseline forecast incorporates both household and income growth and the impacts of efficiency improvements through estimated end-use intensity projections. Moody Analytics' projects relatively slow household and income growth. Vermont has seen some of the slowest population growth in the U.S. This trend is expected through the forecast period; slow population growth translates into low household formation and low real income growth. Table 4 shows the residential economic drivers.

Table 4: Residential Economic Drivers

Year	Population (Thou)	Chg	Households (Thou)	Chg	RPI (Mil $)	Chg
2008	624.2		255.8		25,395	
2009	624.8	0.1%	256.2	0.2%	25,150	-1.0%
2010	625.8	0.2%	256.8	0.2%	25,249	0.4%
2011	626.2	0.1%	258.7	0.8%	26,038	3.1%
2012	625.6	-0.1%	260.2	0.6%	26,451	1.6%
2013	626.0	0.1%	262.2	0.7%	26,612	0.6%
2014	625.7	-0.1%	263.7	0.6%	27,045	1.6%
2015	624.5	-0.2%	264.2	0.2%	27,914	3.2%
2016	623.4	-0.2%	264.7	0.2%	28,202	1.0%
2017	623.7	0.0%	265.3	0.2%	28,228	0.1%
2018	623.7	0.0%	266.4	0.4%	28,499	1.0%
2019	624.5	0.1%	267.4	0.4%	28,603	0.4%
2020	625.2	0.1%	268.6	0.4%	28,558	-0.2%
2021	625.9	0.1%	269.8	0.4%	28,935	1.3%
2022	627.0	0.2%	271.0	0.5%	29,353	1.4%
2023	628.3	0.2%	272.4	0.5%	29,695	1.2%
2024	629.6	0.2%	273.9	0.6%	30,036	1.1%
2025	631.0	0.2%	275.5	0.6%	30,332	1.0%
2026	632.4	0.2%	277.1	0.6%	30,608	0.9%
2027	633.7	0.2%	278.7	0.6%	30,874	0.9%
2028	635.0	0.2%	280.2	0.5%	31,206	1.1%
08-17		0.0%		0.5%		1.1%
18-28		0.2%		0.4%		1.0%

Energy efficiency gains will continue to outweigh sales gains from customer and economic growth translating into lower residential sales. Efficiency gains are captured in end-use energy intensities. End-use intensities are derived for ten residential end-uses and are based on EIA 2017 Annual Energy Outlook for New England. End-use intensities are calibrated to Vermont and are adjusted to reflect state projected EE program savings. Figure 1 shows end-use intensities aggregated into heating, cooling, and other end-uses.

Figure 1: Residential End-Use Indices (Annual kWh per Household) Update



Years	AAGR		
08-17	-1.4%	-0.5%	-0.1%
18-28	-1.5%	-0.1%	-0.9%

Overall, total residential intensity is expected to decline 1.0% annually over the next ten years with the heating and non-weather sensitive end-uses seeing the largest improvement in efficiency, averaging respectively 1.5% and 0.9% decline through 2028. The strong decline in other use is largely the outcome of statewide EE programs promoting LED lighting, along with future end-use appliance standards.

2. Small Commercial & Industrial Sales

Sales for the Small C&I revenue class are projected to increase on average 0.2% per year. Baseline commercial sales forecast is derived using a total commercial sales model. Baseline forecast is then adjusted for solar own-use (excess generation is treated as power purchase cost), Tier III electrification projects, and large load additions (and losses) that are not reflected in the baseline forecast model. Table 5 shows the commercial sales forecast.

Table 5: Commercial Customer Usage Forecast

Year	Average Use (kWh)	Chg	Customers	Chg	Sales (MWh)	Chg
2018	35,665		42,568		1,518,210	
2019	35,422	-0.7%	42,951	0.9%	1,521,410	0.2%
2020	35,484	0.2%	43,069	0.3%	1,528,236	0.4%
2021	35,226	-0.7%	43,378	0.7%	1,528,060	0.0%
2022	34,852	-1.1%	43,872	1.1%	1,529,039	0.1%
2023	34,553	-0.9%	44,254	0.9%	1,529,121	0.0%
2024	34,323	-0.7%	44,592	0.8%	1,530,529	0.1%
2025	34,141	-0.5%	44,875	0.6%	1,532,087	0.1%
2026	34,026	-0.3%	45,107	0.5%	1,534,800	0.2%
2027	33,945	-0.2%	45,322	0.5%	1,538,443	0.2%
2028	33,854	-0.3%	45,572	0.6%	1,542,812	0.3%
18-28		-0.5%		0.7%		0.2%

Table 6 shows the forecast disaggregation. Efficiency impacts are derived by holding the model end-use energy intensity inputs constant through the forecast period; efficiency impacts reflect new standards, natural occurring efficiency gains, as well state-level efficiency program activity.

Table 6: Commercial Sales Forecast Disaggregation

Year	No EE (1)	Efficiency (2)	Solar (3)	Electrification (4)	Spot Loads (5)	Total Adj	Forecast
2018	1,520,988	-5,460	-344	1,329	1,697	-2,778	1,518,210
2019	1,520,166	-11,006	-568	6,549	6,269	1,244	1,521,410
2020	1,522,860	-15,667	-778	12,478	9,343	5,376	1,528,236
2021	1,527,686	-20,445	-1,001	12,478	9,343	374	1,528,060
2022	1,534,305	-25,835	-1,252	12,478	9,343	-5,266	1,529,039
2023	1,539,991	-31,222	-1,468	12,478	9,343	-10,870	1,529,121
2024	1,545,692	-35,313	-1,670	12,478	9,343	-15,162	1,530,529
2025	1,550,685	-38,517	-1,902	12,478	9,343	-18,598	1,532,087
2026	1,555,352	-40,254	-2,119	12,478	9,343	-20,552	1,534,800
2027	1,559,841	-40,883	-2,335	12,478	9,343	-21,398	1,538,443
2028	1,565,257	-41,738	-2,528	12,478	9,343	-22,445	1,542,812

1. No EE reflects sales growth to due to household and economic activty
2. Efficiency incorporates both impacts of end-use standards and state efficiency programs
3. Solar is based on GMP Behind the Meter Solar Capacity Forecast and Historical "Own-Use" share of system generation.
4. Electrification is based on expected gains from specific Tier 3 electrification projects
5. Spot Loads are based on expected net new loads from large customer expansion/contraction activity not captured in the model

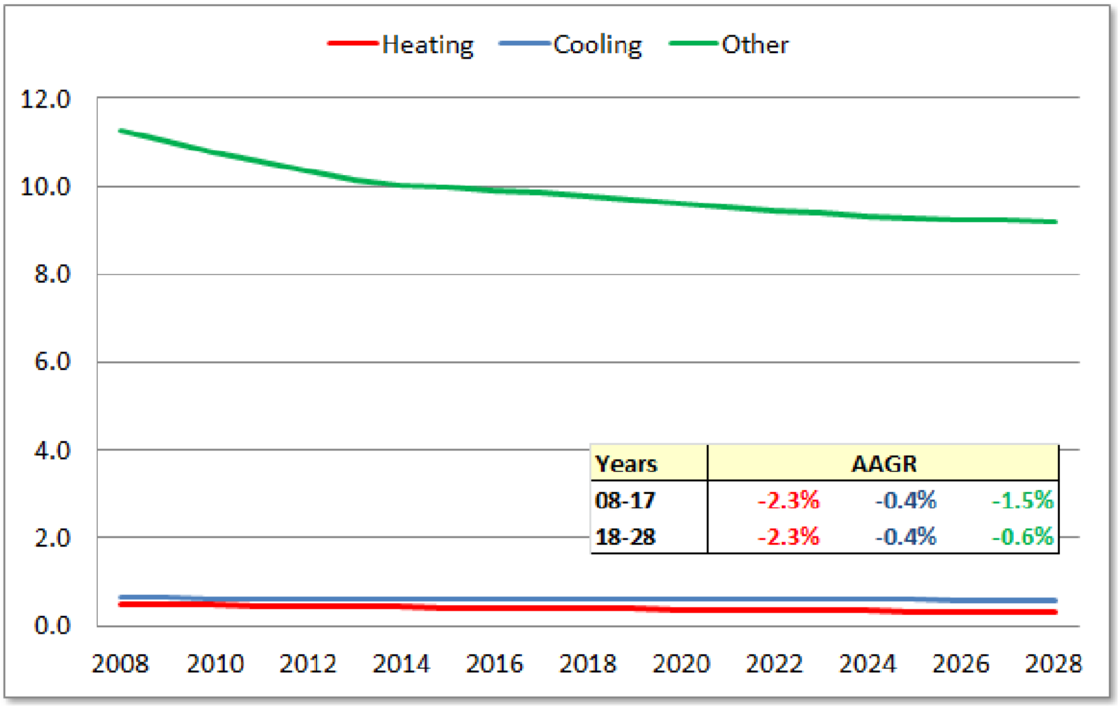
We expect to see moderate baseline commercial sales growth with increase in economic activity slightly out weighting commercial efficiency improvements. Table 7 shows Moody's January 2018 GDP and employment projections. GDP averages 1.1% annual growth over the next ten years with annual employment growth of 0.6%.

Table 7: State GDP and Employment Forecast

Year	GDP (Mil $)	Chg	Emp (Thou)	Chg	ManEmp (Thou)	Chg	NManEmp (Thou)	Chg
2008	25,980		306.8		34.9		271.8	
2009	25,595	-1.5%	298.2	-2.8%	31.5	-9.7%	266.7	-1.9%
2010	26,338	2.9%	297.8	-0.1%	30.6	-2.9%	267.2	0.2%
2011	26,968	2.4%	300.8	1.0%	31.1	1.5%	269.7	0.9%
2012	27,067	0.4%	304.3	1.2%	31.8	2.3%	272.5	1.0%
2013	26,830	-0.9%	306.5	0.7%	31.8	-0.2%	274.8	0.8%
2014	27,014	0.7%	309.5	1.0%	31.2	-1.7%	278.3	1.3%
2015	27,329	1.2%	311.9	0.8%	30.8	-1.3%	281.1	1.0%
2016	27,463	0.5%	313.2	0.4%	29.9	-3.0%	283.3	0.8%
2017	27,704	0.9%	316.0	0.9%	28.9	-3.4%	287.1	1.3%
2018	28,062	1.3%	319.6	1.1%	28.8	-0.3%	290.8	1.3%
2019	28,190	0.5%	321.6	0.6%	28.6	-0.7%	293.0	0.8%
2020	28,134	-0.2%	321.7	0.0%	28.2	-1.5%	293.5	0.2%
2021	28,598	1.6%	323.1	0.4%	27.8	-1.3%	295.3	0.6%
2022	29,115	1.8%	326.0	0.9%	27.6	-0.8%	298.4	1.0%
2023	29,539	1.5%	328.1	0.6%	27.3	-1.2%	300.8	0.8%
2024	29,962	1.4%	329.8	0.5%	26.9	-1.2%	302.9	0.7%
2025	30,332	1.2%	331.2	0.4%	26.6	-1.3%	304.7	0.6%
2026	30,677	1.1%	332.3	0.3%	26.2	-1.5%	306.1	0.5%
2027	31,011	1.1%	333.2	0.3%	25.8	-1.4%	307.4	0.4%
2028	31,427	1.3%	334.5	0.4%	25.5	-1.2%	309.0	0.5%
08-17		0.7%		0.2%		-1.8%		0.4%
18-28		1.1%		0.6%		-1.4%		0.8%

Figure 2 shows projected commercial heating, cooling, and other use intensity trends. Intensities are expressed on a kWh per square foot basis. Commercial heating and cooling intensities are relatively small in New England. Other use is composed of 8 end-uses where the largest end-uses include ventilation, lighting, refrigeration, and miscellaneous use. Indices are adjusted to reflect impact of statewide commercial EE program activity.

Figure 2: Commercial End-Use Intensities (kWh/sq ft)



3. Large Commercial & Industrial and Other Sales

The Large C&I class includes GMP's largest customers. While this class is dominated by industrial load, it also includes some of GMP's largest commercial customers.

The baseline Large C&I sales forecast excluding Global Foundries and OMYA is derived using a generalized econometric model that relates monthly billed sales to state-level GDP and manufacturing employment. The baseline forecast is effectively flat as a result of slow GDP growth and declining manufacturing employment; table shows the GDP and employment projections. The baseline forecast is adjusted for process savings as a result of VEIC energy efficiency activity and new loads from expected customer expansions. The solar adjustment is actually positive as the solar load reduction is accounted for on the other side of the ledger as a power purchase cost.

Other use primarily consists of street lighting sales, but also includes public authority sales. Total sales are expected to be flat as continued efficiency gains outweigh new street-lighting fixture growth.

Table 8 summarizes industrial and other use sales forecasts.

Table 8: Industrial Sales Forecast

Year	Industrial (MWh)	Chg	Other (MWh)	Chg
2018	1,175,494		4,760	
2019	1,179,223	0.3%	4,760	0.0%
2020	1,173,906	-0.5%	4,760	0.0%
2021	1,175,862	0.2%	4,760	0.0%
2022	1,178,369	0.2%	4,760	0.0%
2023	1,178,659	0.0%	4,760	0.0%
2024	1,178,567	0.0%	4,760	0.0%
2025	1,177,505	-0.1%	4,760	0.0%
2026	1,175,797	-0.1%	4,760	0.0%
2027	1,174,086	-0.1%	4,760	0.0%
2028	1,173,789	0.0%	4,760	0.0%
18-28		0.0%		0.0%

Table 9 shows the disaggregated industrial sales forecast

Table 9: Disaggregated Industrial Sales Forecast

Year	No EE (1)	Efficiency (2)	Solar (3)	Spot Loads (4)	Total Adj	Forecast	Adj to Baseline
2018	1,178,685	-2,219	685	-1,658	-3,192	1,175,494	-0.3%
2019	1,173,728	-4,419	2,221	7,693	5,495	1,179,223	0.5%
2020	1,168,362	-6,626	3,308	8,861	5,544	1,173,906	0.5%
2021	1,169,709	-8,733	4,388	10,497	6,152	1,175,862	0.5%
2022	1,173,073	-10,811	5,610	10,497	5,296	1,178,369	0.5%
2023	1,174,148	-12,680	6,693	10,497	4,510	1,178,659	0.4%
2024	1,174,825	-14,541	7,786	10,497	3,742	1,178,567	0.3%
2025	1,174,574	-16,426	8,860	10,497	2,931	1,177,505	0.2%
2026	1,173,707	-18,350	9,944	10,497	2,090	1,175,797	0.2%
2027	1,172,862	-20,300	11,027	10,497	1,224	1,174,086	0.1%
2028	1,173,284	-22,117	12,124	10,497	504	1,173,789	0.0%

1. No EE reflects sales growth to due to economic activty
2. VEIC industrial process EE savings
3. Solar is additive as it's treated as part of power purchase costs
4. Spot Loads are based on expected net new loads from large customer expansion/contraction activity not accounted for in the model

2. Forecast Adjustments

The forecast begins by developing baseline forecasts for each revenue class. The baseline forecast is then adjusted for expected growth in solar capacity, Tier III electrification activity, electric vehicle sales, and large C&I load additions. Table 10 shows the breakdown of total billed sales forecast.

Table 10: Forecast Breakdown

Year	No EE (1)	Efficiency (2)	Solar (3)	Electrification (4)	Electric Vehicles (5)	Spot Loads (6)	Total Adj	Forecast
2018	4,189,091	-22,941	-5,802	4,684	1,047	39	-22,972	4,166,119
2019	4,184,620	-50,449	-17,404	13,239	2,303	13,962	-38,349	4,146,271
2020	4,190,859	-77,494	-25,788	22,499	3,811	18,204	-58,768	4,132,091
2021	4,204,252	-108,059	-34,072	25,861	5,620	19,840	-90,811	4,113,442
2022	4,222,343	-133,062	-43,427	29,249	7,791	19,840	-119,610	4,102,733
2023	4,236,043	-155,990	-51,761	32,686	10,396	19,840	-144,831	4,091,212
2024	4,249,108	-174,502	-60,219	36,148	13,522	19,840	-165,211	4,083,897
2025	4,260,378	-195,253	-68,430	39,602	17,273	19,840	-186,967	4,073,410
2026	4,270,536	-212,642	-76,764	43,051	21,775	19,840	-204,740	4,065,796
2027	4,280,296	-225,996	-85,098	46,507	27,393	19,840	-217,355	4,062,941
2028	4,292,553	-237,609	-93,628	49,959	34,405	19,840	-227,033	4,065,519

1. No EE reflects sales growth to due to household and economic activty
2. Efficiency incorporates both impacts of end-use standards and state efficiency programs
3. Solar is based on GMP Behind the Meter Solar Capacity Forecast and Historical "Own-Use" share of system generation.
4. Electrification is based on expected gains from cold-climate heat pump sales and specific commercial electrification projects
5. Electric vehicle sales are based on Energy Future's Group 2017 EV forecast for GMP (low case ?)
6. Spot Loads are based on expected net new loads from large customer expansion/contraction activity that are not be captured in the baseline model

1. Energy Efficiency

Energy efficiency impacts are embedded in the baseline forecast as end-use intensities are explicitly incorporated in the residential and commercial forecast models. Energy efficiency impacts can be isolated by first executing the forecast models where end-use intensities are held constant; this is called the constant efficiency forecast. The baseline forecast is then subtracted from the constant efficiency forecast giving us efficiency impact estimates (column 2 in the table above.) Adding the efficiency savings to the baseline forecast results in column 1 the No efficiency forecast.

Efficiency impacts are captured in the end-use intensity projections. For all but miscellaneous, end-use intensities are declining or are flat as improvements in efficiency outweigh additional gains in end-use saturation. Appliance stock efficiency continues to improve as existing equipment is replaced with more efficient equipment. Factors driving change in stock efficiency include new end-use standards, state efficiency programs that either subsidize the cost of more efficient end-use options or provide new end-use measures such as lighting and weatherization as part of home and business audits, and just natural turnover of existing equipment with more efficient equipment.

Historical end-use intensities for New England are adjusted to reflect Vermont end-use saturations and calibrated into Vermont residential, and commercial customer usage. End-use intensities are further adjusted to account for expected savings from state energy efficiency (EE) program activity that is not already captured in the intensity estimates. The current set of end-use intensity estimates were developed as part of the Vermont Electric Power Company (VELCO) 2018 long-term forecast. Itron worked with *Vermont Energy Investment Corporation (VEIC)* and other members of the *Vermont System Planning Forecast Subcommittee* to develop a set of end-use intensity projections that reflect both Federal efficiency standards and the impact of future EE program savings. The end-use intensities were updated in the June 2017 forecast to reflect changes in VEIC's EE program savings projections.

As the state has been aggressively pursuing efficiency programs for the last twelve years, there is significant efficiency improvements already embedded in the baseline forecast. To avoid "double counting" future EE savings; future EE program savings are adjusted to account for EE savings already embedded in the baseline forecast.

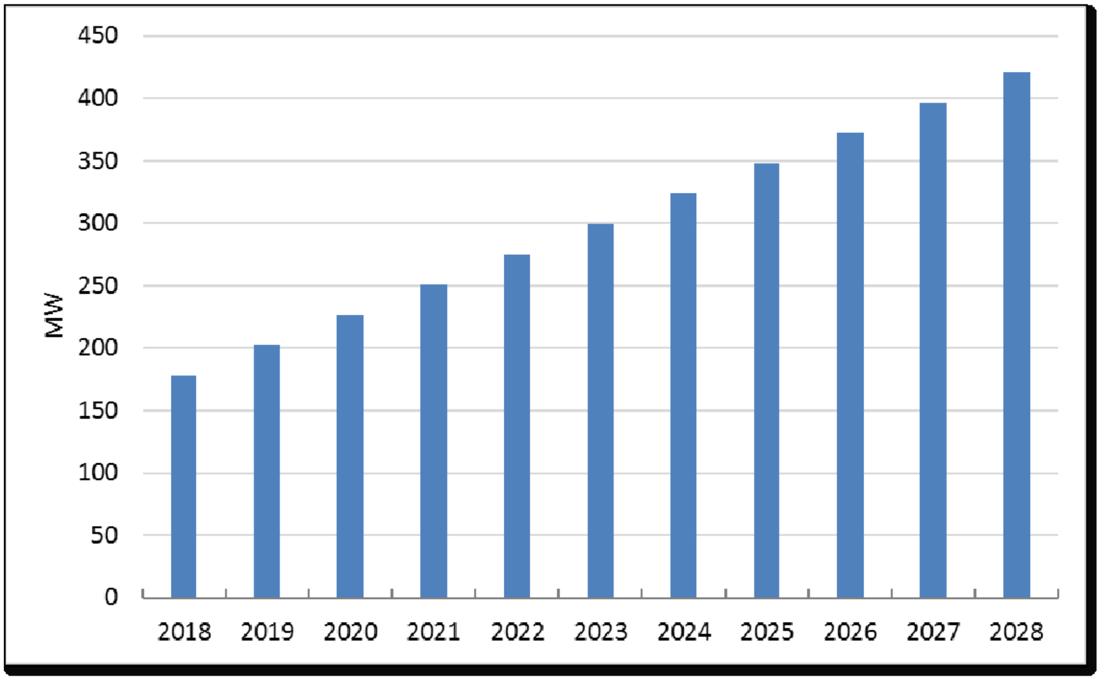
In the residential sector, end-use intensities that are adjusted for future EE program impacts include heating, water heating, cooling, refrigeration, lighting, kitchen/laundry, and miscellaneous use. In the commercial sector, program efficiency adjustments are made to heating, lighting, refrigeration, cooling, ventilation, water heating, and miscellaneous use.

2. Solar Load Forecast

Solar Capacity Forecast
As of December 2017, installed solar capacity is 137 MW. This is a combination of traditional, customer owned or leased roof-top systems, and larger community/group based systems. GMP projects 40.7 MW of solar capacity is will be installed in 2018, and 24.3 MW of additional solar capacity each subsequent year.

Figure 3 shows the year-end capacity forecast.

Figure 3: Year-End Solar Capacity Forecast



The forecast is adjusted for new solar installations beginning in January 2018; existing solar load is embedded in the historical sales data.

Allocation of Capacity to Classes

The capacity forecast is allocated to the residential, commercial, and industrial classes based on the previous 12 months of billed solar generation data. Table 11 shows the allocation factors.

Table 11: Capacity Allocation Factors

Class	Previous 12 Mnth Generation (MWh)	% of total
Residental	52,619	36%
Commercial	75,343	52%
Industrial	17,920	12%
Total	145,882	

Capacity to Generation
Monthly generation is derived by applying monthly solar load factors to the capacity forecast. Table 12 shows the solar generation load factors.

Table 12: Solar Load Factors

Month	Load Factor
Jan	7.7%
Feb	10.8%
Mar	14.1%
Apr	18.8%
May	19.5%
Jun	20.6%
Jul	20.3%
Aug	19.5%
Sep	15.7%
Oct	12.5%
Nov	8.4%
Dec	5.7%

The monthly load factors are derived from engineering-based solar hourly load profile for 1 MW solar system load. The load shape is a weighted profile, which assumes 33% of systems are roof-mounted, 57% are fixed-tilt, and 10% 2 are axis trackers. The system hourly load profile was estimated by GMP.

The solar generation forecast (MWh) is derived by applying the load factors to solar capacity projections. The following equation shows an example of how 100 MW of capacity is translated into June generation.

$$100MW_{june} \times 0.206LdFct_{june} \times 720hrs_{june} = 14{,}832\ MWh_{june}$$

Estimation of Solar "Own-Use"
Solar generation is either consumed by the solar customer (*own-use*) or returned to the connected power-grid (*excess*); own-use reduces billed revenues, while excess is treated as power purchase cost. Historical solar billing data is used to determine the month share that is own-use and excess. The split between own-use and excess varies by revenue class and month; own-use share is typically smaller in the summer months with a larger percentage of the generation sent to the grid. Table 13 shows the forecasted generation based on the incremental new capacity, by own-use and excess use.

Table 13: Solar Generation

Year	Year End Capacity (MW)	Total MWh Generation	Total MWh Excess	Total MWh Own Use	Residential MWh Generation	Residential MWh Excess	Residential MWh Own Use	Commercial MWh Generation	Commercial MWh Excess	Commercial MWh Own Use	Industrial MWh Generation	Industrial MWh Excess
2018	40.7	20,660	14,858	5,802	7,452	1,309	6,143	10,670	10,326	344	2,538	3,223
2019	65.0	63,966	46,562	17,404	23,073	4,015	19,058	33,036	32,469	568	7,857	10,079
2020	89.3	95,009	69,221	25,788	34,270	5,951	28,318	49,069	48,290	778	11,671	14,979
2021	113.6	125,703	91,630	34,072	45,341	7,881	37,459	64,921	63,920	1,001	15,441	19,829
2022	138.0	160,465	117,038	43,427	57,879	10,094	47,785	82,875	81,623	1,252	19,711	25,321
2023	162.3	191,333	139,572	51,761	69,014	12,027	56,986	98,817	97,348	1,468	23,503	30,196
2024	186.6	222,634	162,415	60,219	80,304	13,969	66,335	114,983	113,313	1,670	27,348	35,133
2025	210.9	253,069	184,640	68,430	91,282	15,894	75,388	130,701	128,800	1,902	31,086	39,947
2026	235.2	283,937	207,174	76,764	102,416	17,827	84,589	146,644	144,525	2,119	34,878	44,822
2027	259.6	314,806	229,708	85,098	113,550	19,760	93,790	162,586	160,251	2,335	38,670	49,697
2028	283.9	346,359	252,731	93,628	124,931	21,707	103,225	178,882	176,355	2,528	42,546	54,670

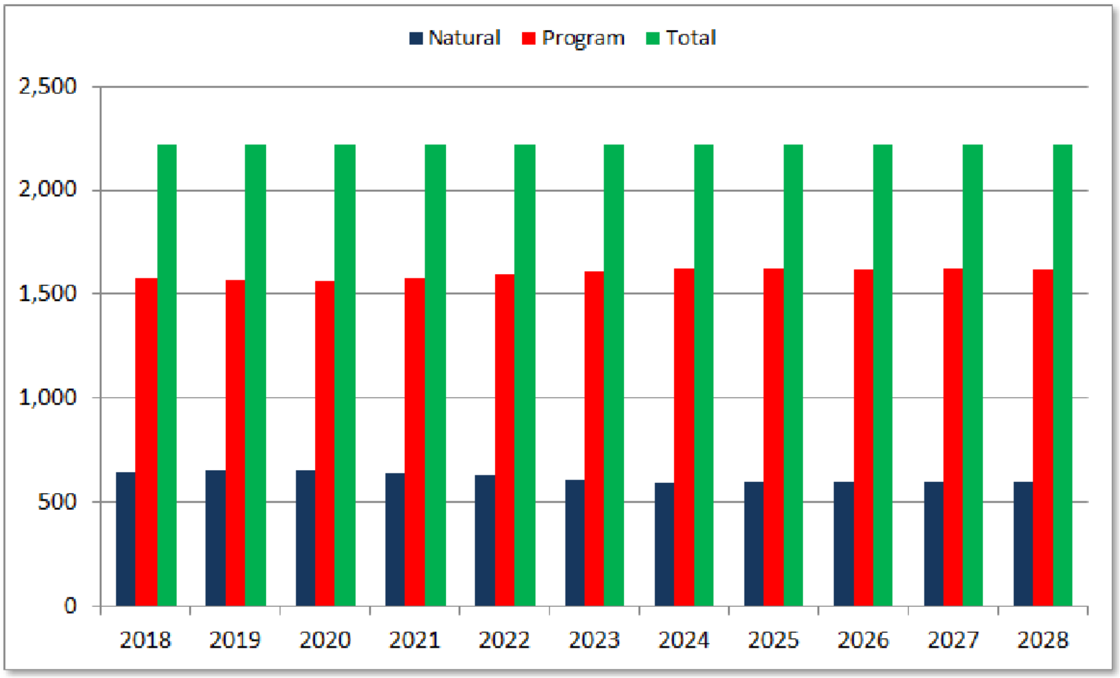
The sales forecast is adjusted for solar load impacts by subtracting cumulative new solar own-use generation from the appropriate class sales forecasts. By 2028, solar generation reduces residential sales by 93,628 MWh, which represents reduction of 340 kWh per customer. Industrial own-use is negative, meaning that solar is additive. This is due to an accounting practice within GMP's billing system in which generation from community/group systems is metered and booked under one rate class but excess can be credited to another. As such industrial excess is greater than generation, creating negative own-use.

3. Tier III Electrification Impacts

To meet Tier III obligations, VEIC and GMP are promoting technologies that displace fossil fuel. The largest program is an incentive program promoting adoption of cold-climate heat pumps. VEIC expects state households to take incentives associated with 3,000 new heat pumps per year. The estimates were provided as part of the development of the VELCO long-term demand forecast. Based on GMP's size, we expect that 74 percent of the heat pumps (2,220 heat pumps per year) will be sold in GMP service area.

Given the operating cost-effectiveness, EIA projects heat pump market penetration in New England even without incentives; we would expect some GMP households to take the incentives even if it is not influencing their purchase decision. Program related heat pump sales are reduced to reflect the "natural occurring" adoption reflected in EIA's heat pump saturation forecast. Figure 4 shows the breakdown of cold-climate heat pump adoption by market driven (*Natural*) and program induced (*Program*).

Figure 4: Cold-Climate Heat Pump Adoption (units)

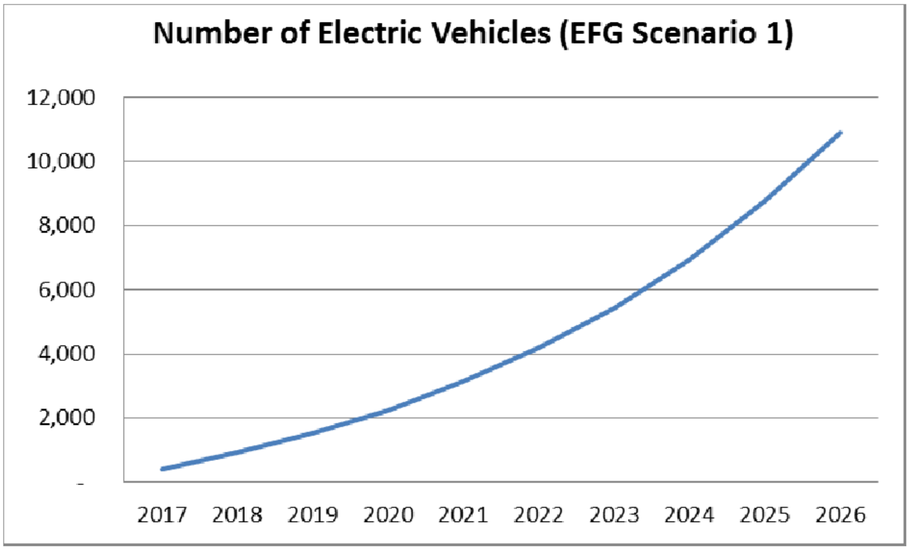


Of the 2,200 heat pumps sold through the incentive program, roughly 1,600 a year are directly attributable to the offered incentive. A recent GMP-study expects cold-climate heat pumps on average to use 2,085 kWh per year for heating and 140 kWh per year for cooling. Heat pump sales are derived by multiplying the net heat pump unit forecast with the winter and summer heat-pump annual usage.

4. Electric Vehicle Forecast

Like the heat pump forecast, electric vehicle (EV) forecast is added to the baseline sales forecast. EV sales are based on Energy Futures Group's (EFG) Scenario 1 forecast that was part of an electrification forecast study conducted for GMP last year. By 2026, EFG projects there will be roughly 11,000 electric vehicles in the GMP service territory starting from 300 vehicles in 2017. Figure 5 shows the electric vehicle forecast.

Figure 5: Electric Vehicle Forecast



By 2026, EFG estimates that 9% of all new car sales or roughly 2,000 new vehicles per year. In comparison EIA projects electric vehicles will account 6% of new car sales and Efficiency Vermont expects 12% of new car will be electric by 2026 (low case scenario). The vehicle forecast is translated into electric sales by multiplying the vehicle forecast by expected average use per vehicle. EFG expects partial plug-in EVs to account for 78% of the market and all electric vehicles to represent 22% of the market. The average annual vehicle use is 2,007 kWh. Electric vehicles are expected to account for over 34,000 MWh in annual consumption by 2028.

5. Customer Specific Load Adjustments

GMP provides monthly forecasts for their two large transmission customers - Global Foundries and OMYA.

In addition, GMP provides expected load gains and losses for large commercial and industrial customers that are not reflected in the historical sales trend and thus not captured by the baseline forecast models. By 2020, GMP expects an additional 19,800 MWh of non-residential sales that are not captured in the baseline forecast model.

3. Baseline Forecast Models

Baseline sales forecasts are derived from estimated linear regression models that relate monthly historical sales to economic conditions, price, weather conditions, and long-term appliance saturation and efficiency trends. Saturation and efficiency trends are combined to construct annual energy intensity projections that are then adjusted for future EE program savings projections. Once models are estimated, assumptions about future conditions are executed through the models to generate customer and sales forecasts.

Separate forecast models are estimated for the primary revenue classes. Models are estimated for the following:

- Residential
- Commercial (Small C&I)
- Industrial (Large C&I)
- Other

Residential and commercial models are constructed using an SAE modeling framework. This approach entails constructing generalized end-use variables (Heating, Cooling, and Other Use) that incorporate expected end-use saturation and efficiency projections as well as price, economic drivers, and weather. The SAE specification allows us to directly capture the impact of improving end-use efficiency and end-use saturation trends on class sales.

1. Residential

The residential forecast is generated using separate average use and customer forecast models. The average use model is estimated using an SAE specification where monthly average use is estimated as a function of a heating variable ($XHeat$), cooling variable ($XCool$) and other use variable ($XOther$) as shown below:

$$AvgUse_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

$XHeat$ is calculated as a product of a variable that captures changes in heating end-use saturation and efficiency (HeatIndex), economic and other factors that impact stock utilization (HDD, household size, household income, and price). $XHeat$ is calculated as:

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}$$

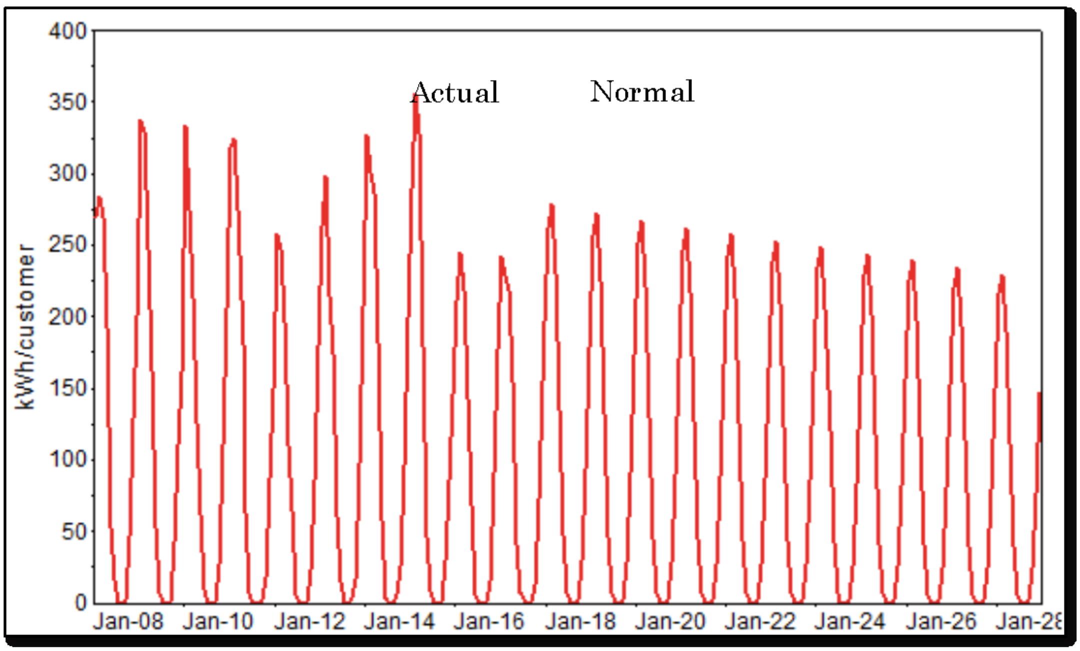
Where:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.20} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{09}}\right)^{-0.10}$$

The heat index is a variable that captures heating end-use efficiency and saturation trends, thermal shell improvement trends, and housing square footage trends. The index is constructed from the EIA's annual end-use residential forecast for the New England census division. The economic and price drivers are incorporated into the HeatUse variable. By construction, the $HeatUse_{y,m}$ variable sums close to 1.0 in the base year (2009). This index value changes through time and across months in response to changes in weather conditions, prices, household size, and household income.

The heat index ($HeatIndex$) and heat use variable ($HeatUse$) are combined to generate the monthly heating variable XHeat. Figure 6 shows the calculated XHeat variable.

Figure 6: XHeat Variable



The strong decline in the XHeat is largely driven by expected efficiency improvements and significant adoption of more efficient heat pumps. Adoption of heat pumps referenced here is organic; program-driven adoption is addressed separately.

Similar variables are constructed for cooling ($XCool$) and other end-uses ($XOther$).

Figure 7 and Figure 8 show XCool and XOther.

Figure 7: XCool Variable

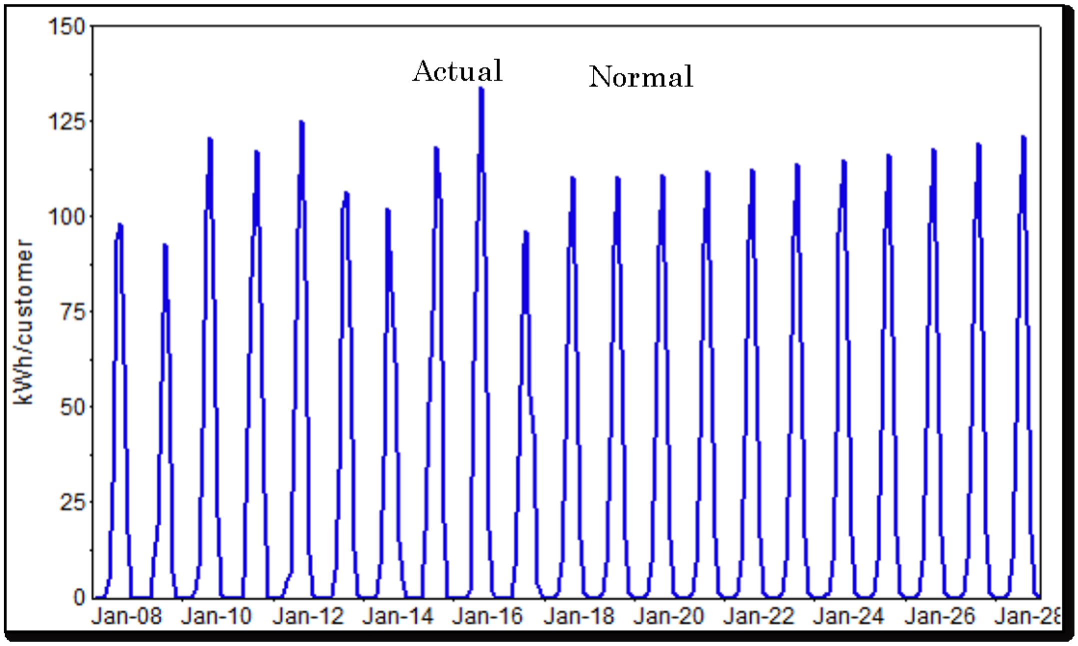
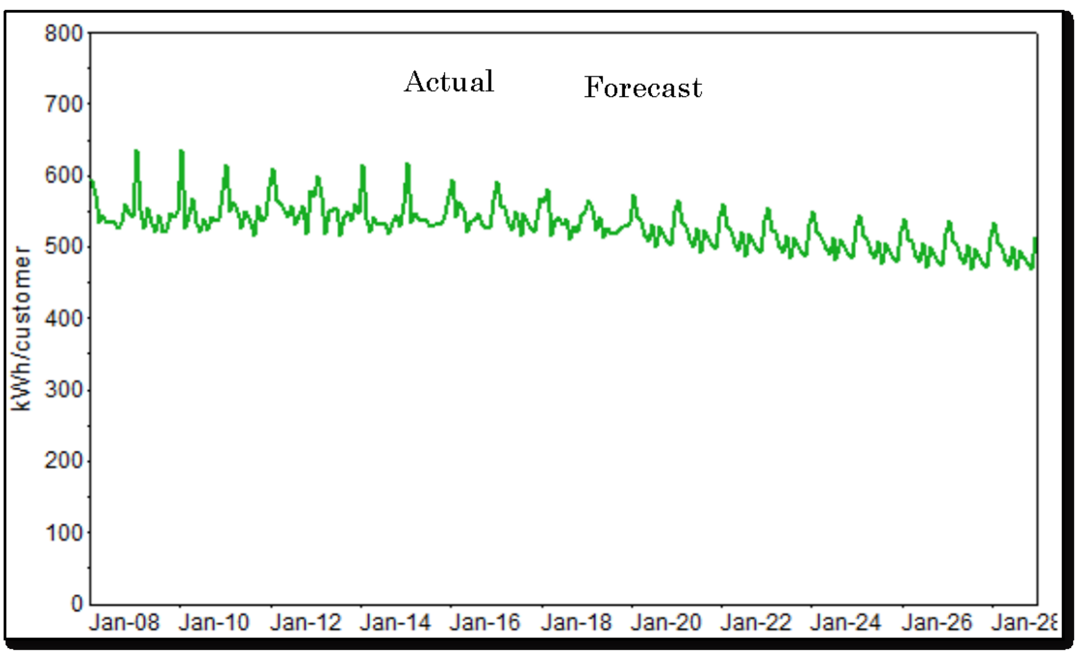


Figure 8: XOther Variable

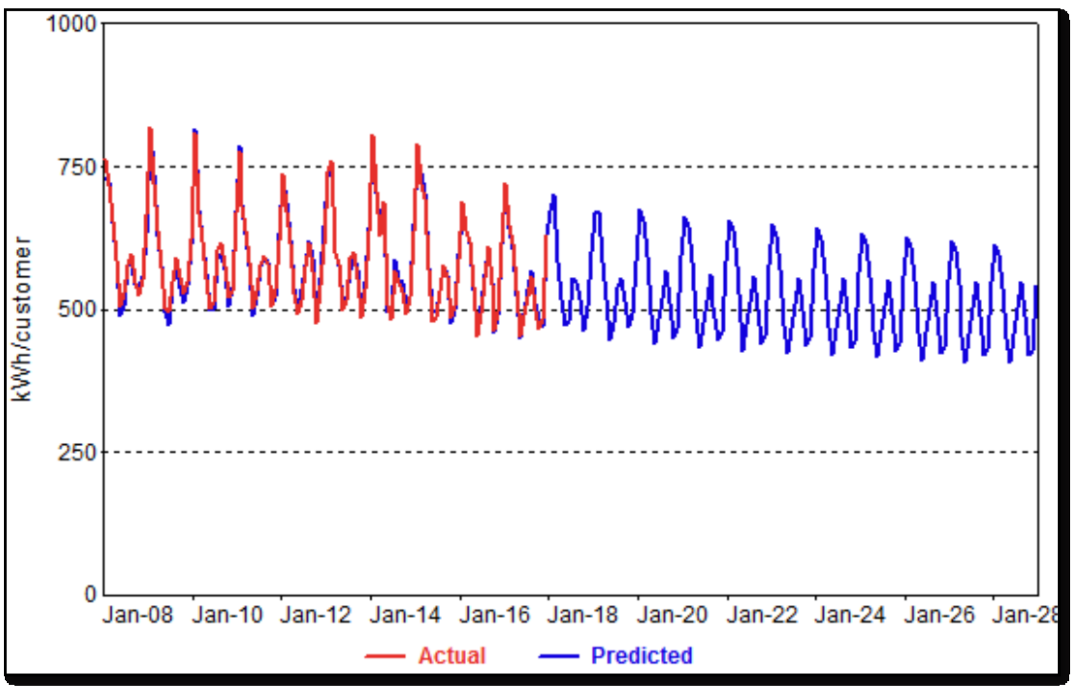


While cooling intensity is relatively small, cooling per household increases over the forecast period largely as a result of increasing heat pump saturation.

XOther (non-weather sensitive use) declines over the forecast period. The monthly variation in XOther reflects variation in the number of monthly billing days, lighting requirements, and monthly variation in water heater and refrigerator use. End-use intensities across non weather-sensitive end-uses are declining and, as a result, XOther also declines driving total average use downwards.

The end-use variables are used to estimate the residential average use model. Figure 9 shows actual and predicted residential average use.

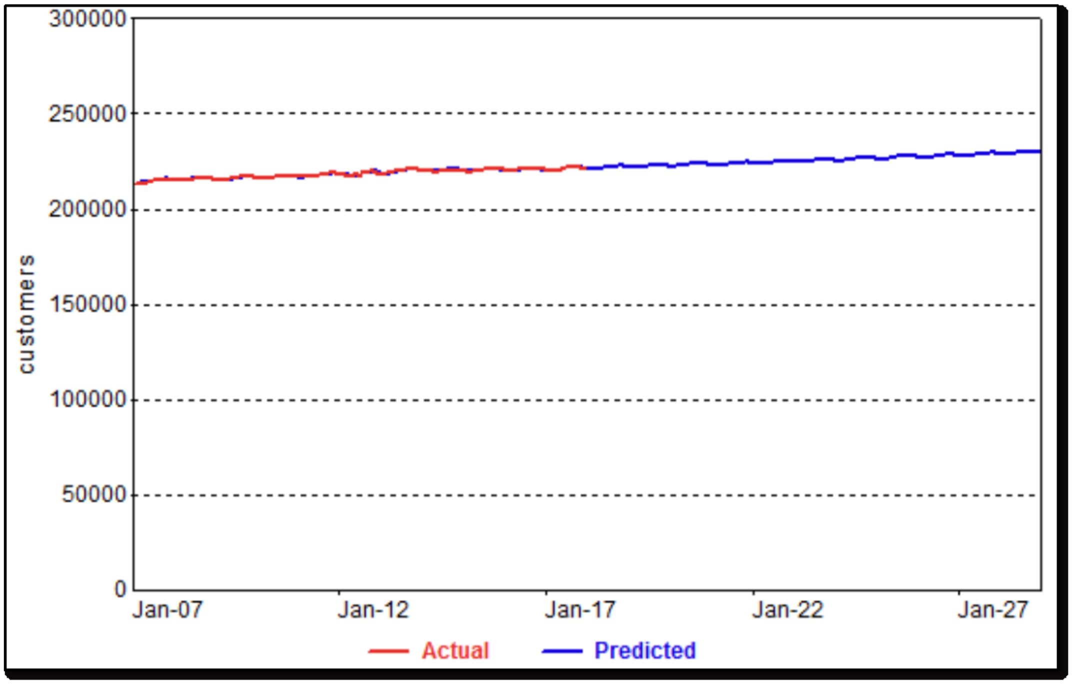
Figure 9: Residential Average Use



The model explains historical monthly sales variation well with an Adjusted R-Squared of 0.98 and a MAPE of 1.7%.

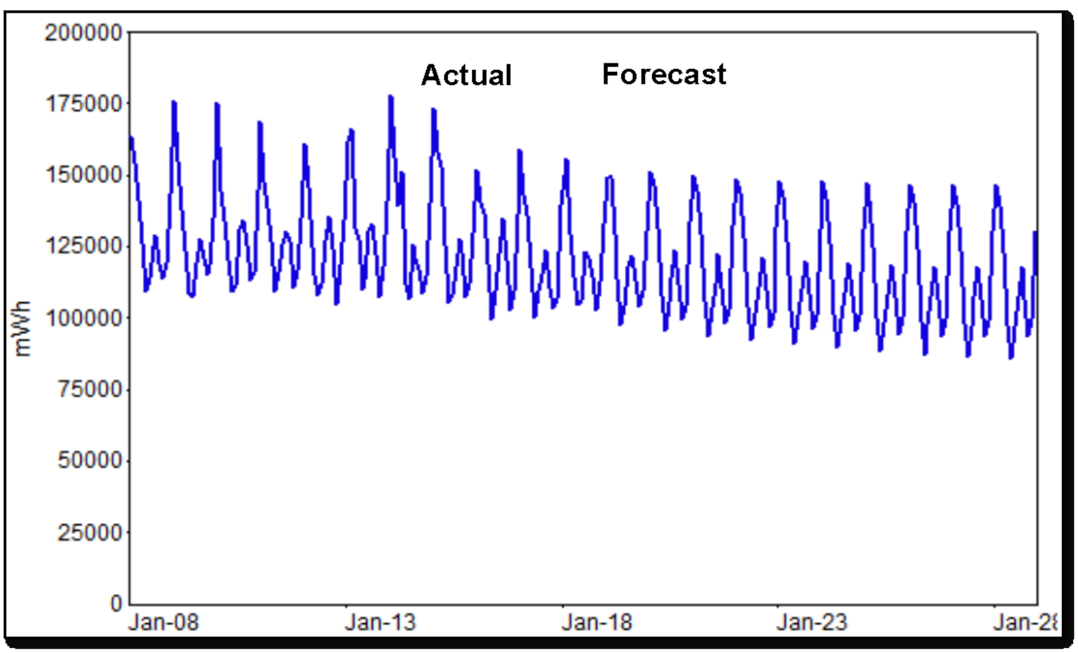
Residential customer projections are based on state household projections. The models explain historical customer growth well with an Adjusted R-Squared of 0.98 and MAPE of 0.1%. Figure 10 shows actual and predicted customers for GMP.

Figure 10: Residential Customer Forecast



Customer and average use forecasts are combined to generate monthly billed sales forecast. Figure 11 shows the monthly residential forecast for the combined GMP.

Figure 11: Residential Sales Forecast



2. Commercial

The commercial model is also based on SAE specification. Monthly commercial class sales and customers are derived adding the former North GS (general service) and TOU revenue class and the former GMP South commercial sales.

The SAE commercial model captures the impact of changing end-use intensity as well as economic conditions, price, and weather in the constructed model variables. As in the residential model, end-use variables XHeat, XCool, and XOther are constructed from end-use saturation and efficiency trends, regional output, price, and weather conditions. The commercial SAE model is defined as:

$$ComSales_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

The SAE model variables are constructed similarly to that of the residential model, the primary differences is that the end-use intensities are measured on a kWh per square foot basis (vs. kWh per household in the residential model), and output and employment are used to capture economic activity (vs. household income and population in the residential model).

The GMP commercial class is forecasted using a total sales model where XCool is defined as:

$$XCool_{y,m} = CoolEI_y \times CoolUse_{y,m}$$

Where:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{09}}\right) \times \left(\frac{ComVar_y}{ComVar_{09}}\right) \times \left(\frac{Price_{y,m}}{Price_{09}}\right)^{-0.10}$$

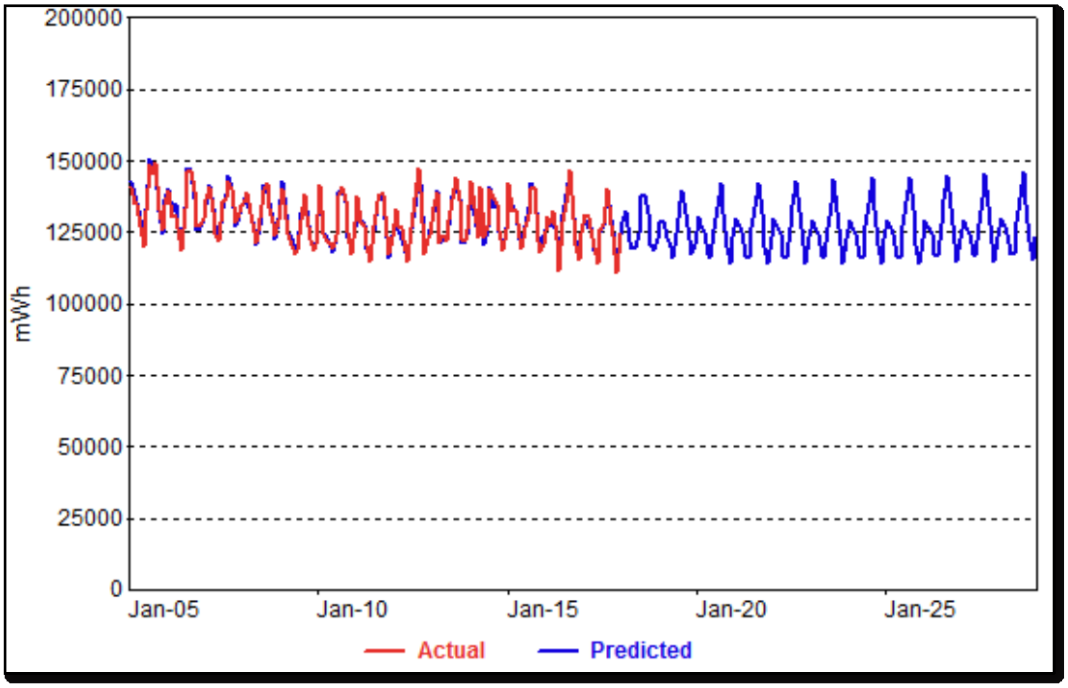
And

$$ComVar_{y,m} = \left(\frac{Emp_{y,m}}{Emp_{09}}\right)^{0.25} \times \left(\frac{GDP_{y,m}}{GDP_{09}}\right)^{0.25} \times \left(\frac{HHs_{y,m}}{HHs_{09}}\right)^{0.50}$$

In the constructed economic variable output and employment are weighted equally reflecting the relationship between economy and sales in the last five years.

A monthly variable is constructed for heating (XHeat) and other use (XOther) similar to that of XCool. The model variables are used to drive total sales through an estimated monthly regression model. Figure 12 shows the commercial sales model results.

Figure 12: Commercial Sales Forecast



This model fits commercial data well with an Adjusted R-Squared of 0.95 and model MAPE of 1.2%. Model statistics can be found in the Appendix A.

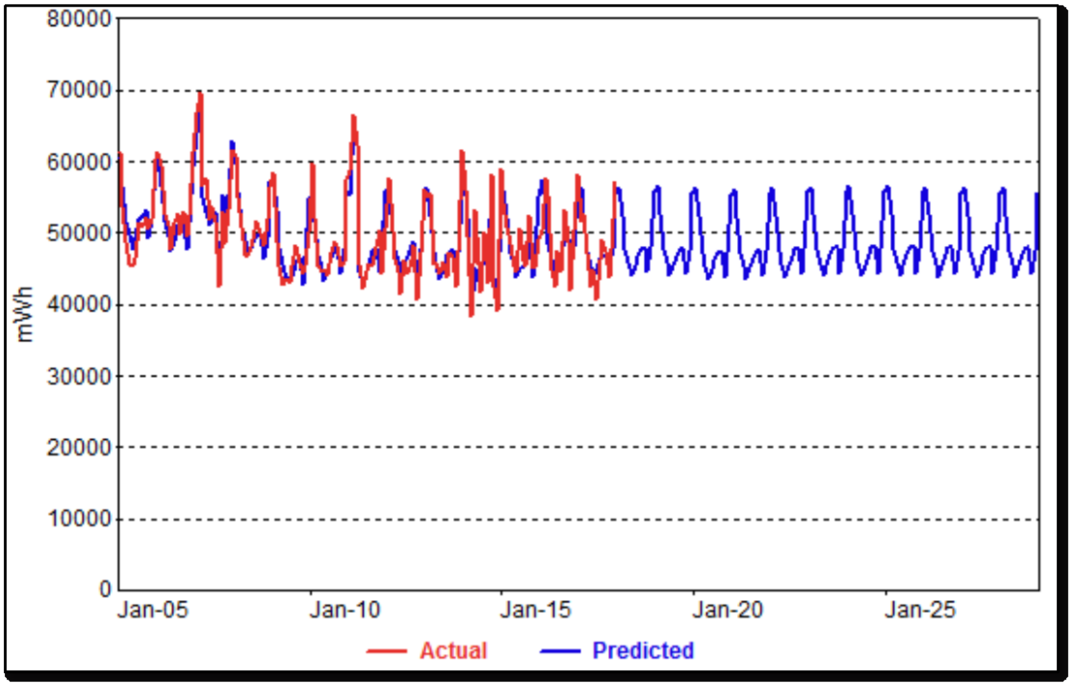
3. Industrial

Industrial sales are estimated using a generalized (vs. SAE model) model specification that is driven by economic projections. The economic variable includes both manufacturing employment projections and state GDP where half of the weight is on manufacturing employment (0.5). The constructed economic variable is summarized below:

$$IndVar_{y,m} = \left(\frac{ManEmp_{y,m}}{ManEmp_{09}}\right)^{0.50} \times \left(\frac{GDP_{y,m}}{GDP_{09}}\right)^{0.50}$$

Seasonal load variation is captured through a set of monthly binary variables. The industrial model excludes Global Foundries and OMYA sales as GMP provides an independent forecast for these customers. Figure 13 shows actual and predicted industrial sales.

Figure 13: Industrial Sales Forecast

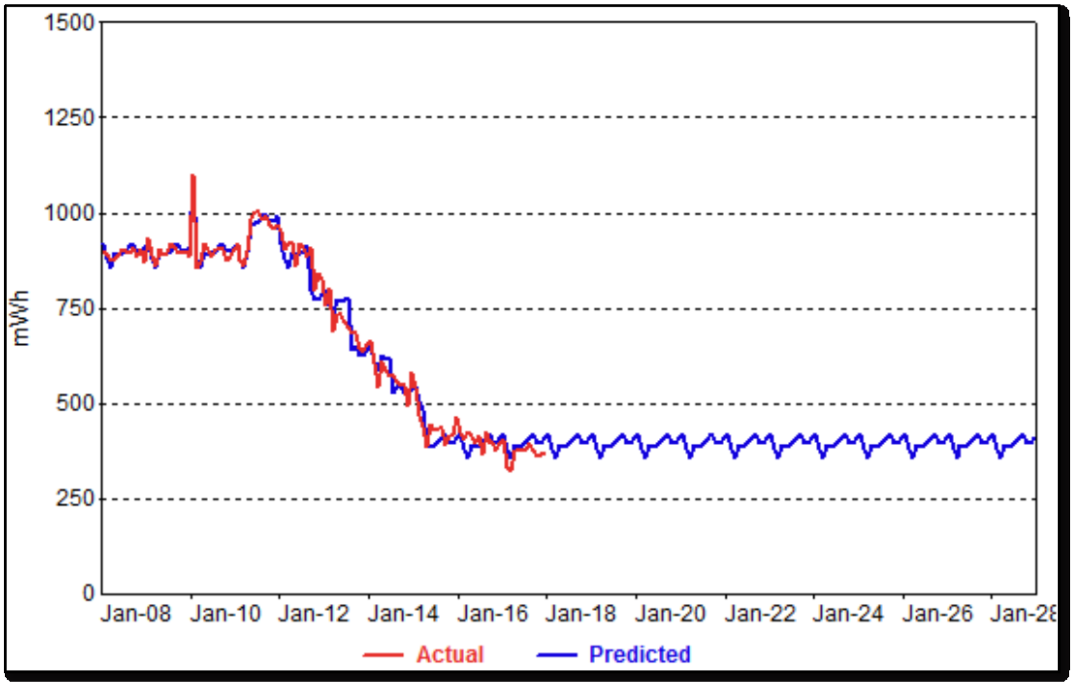


This model Adjusted R-Squared is 0.8 and the MAPE is 3.7%. The lower, relative to other models, Adjusted R-Square is due to the large variation in monthly billed sales data. There is significant month-to-month variation driven by customer-specific activity and billing adjustments that cannot be totally accounted for by economic drivers and weather conditions.

4. Other Use

Other Use sales are estimated using a simple regression model constructed to capture seasonal effects and shifts in the data. This class is dominated by street lighting, but also includes a small amount of other public authority sales. GMP has seen a significant drop in street lighting sales as existing lamps were replaced with high efficiency lamps. We assume some additional savings in the near-term and project flat sales after the savings adjustments. Figure 14 shows actual and forecasted sales for this revenue class

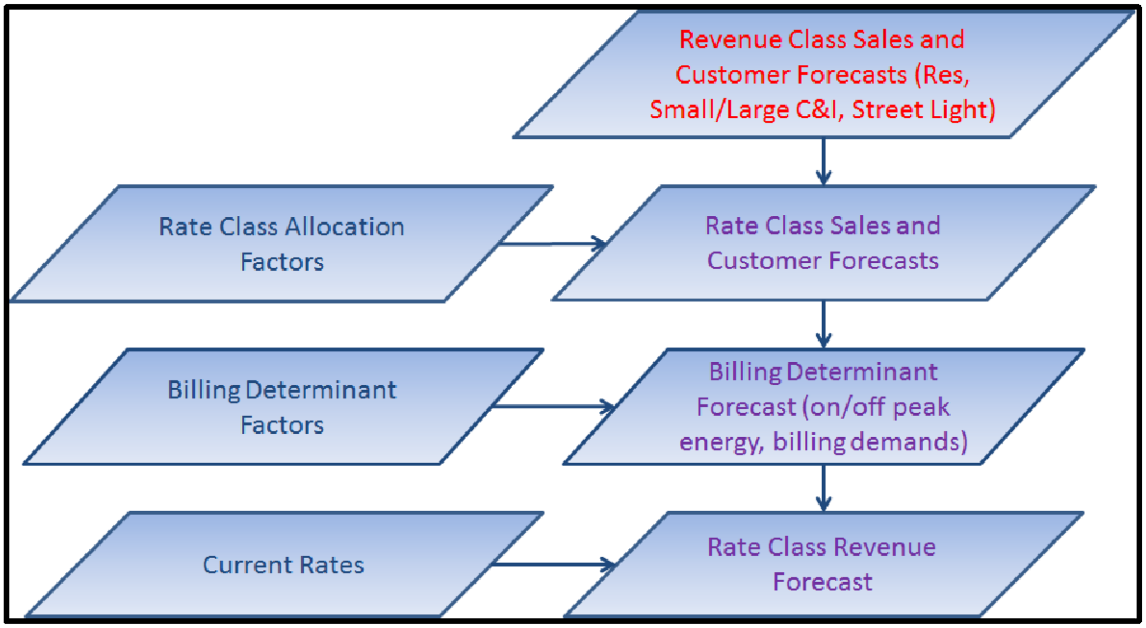
Figure 14: Other Sales Forecast (MWh)



4. Revenue Forecast

The revenue forecast is derived at the rate schedule level. Class sales forecasts are allocated to rate schedules and within rate schedules to billing determinants (i.e., customer, on and off-peak use, and billing demands). Revenues are then generated by multiplying rate schedule billing determinants by the current tariff rates. Figure 15 provides an overview of the revenue model.

Figure 15: Revenue Model



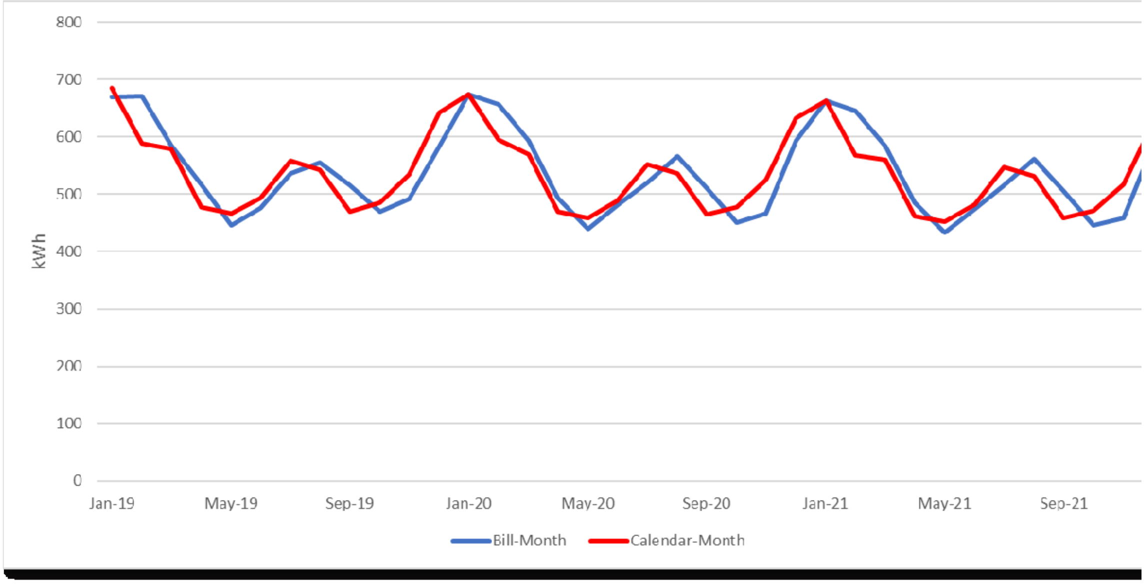
The process is described below.

1. Calendarize Class Sales Forecast

The estimated models are based on monthly billed sales data. As such the forecast is also on a billed sales basis. For financial analysis and revenue projections sales are converted to a calendar-month basis.

The billing-month spans across calendar-months. In general, the billing month includes the last two weeks of the prior month and the first two weeks of the current month. The September billing-month for example includes the last half of August and the first half of September. The billing month period is determined by the meter read schedule. We use the meter-read schedule to construct monthly HDD and CDD (cycle-weighted degree-days) and number of billing days that are consistent with the billing month period. Utilities report revenues and costs on a calendar-month basis. A MetrixND Simulation Object is used to convert billed sales to calendar sales. This is done by replacing billing-month normal HDD and CDD with calendar-month normal HDD and CDD and replacing the number of billing days with the number of calendar days. Figure 16 shows the result of this simulation for the residential sales class.

Figure 16: Comparison of Billed and Calendar-Month Average Use

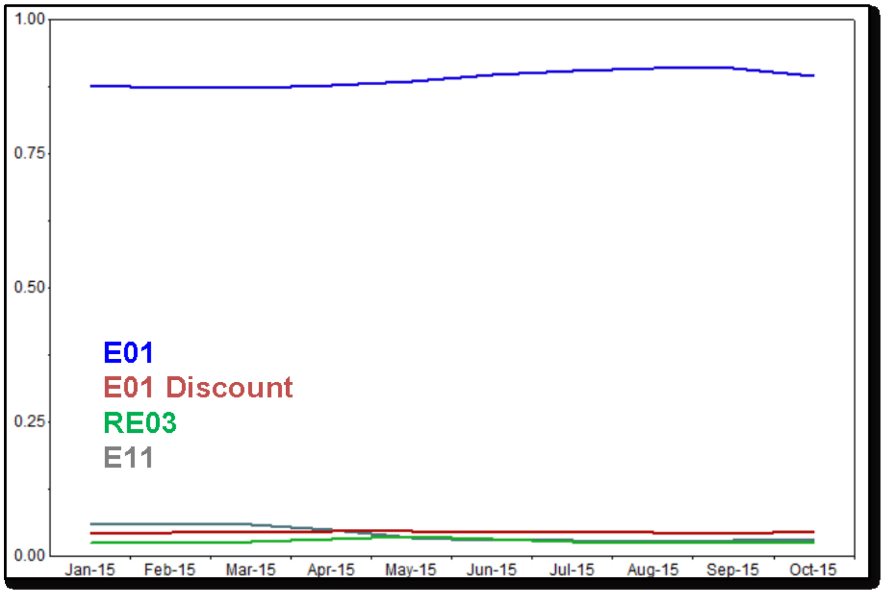


The **blue** line is the forecasted baseline average residential use on a billing month basis and the **red** line shows the forecast on a calendar-month basis.

2. Derive Rate Class Monthly Sales Forecast

Revenue class sales and customer forecasts are first allocated to the underlying rate schedules based on projected monthly allocation factors. The allocation factors are derived from historical billing data and simple regression models that allow us to capture any seasonal variation in the rate class shares. Residential class sales, for example, are allocated to rate schedules - E01, RE03, and E11 rate classes. Figure 17 shows historical and forecasted residential rate class sales shares.

Figure 17: Residential Rate Class Share Forecast (%)



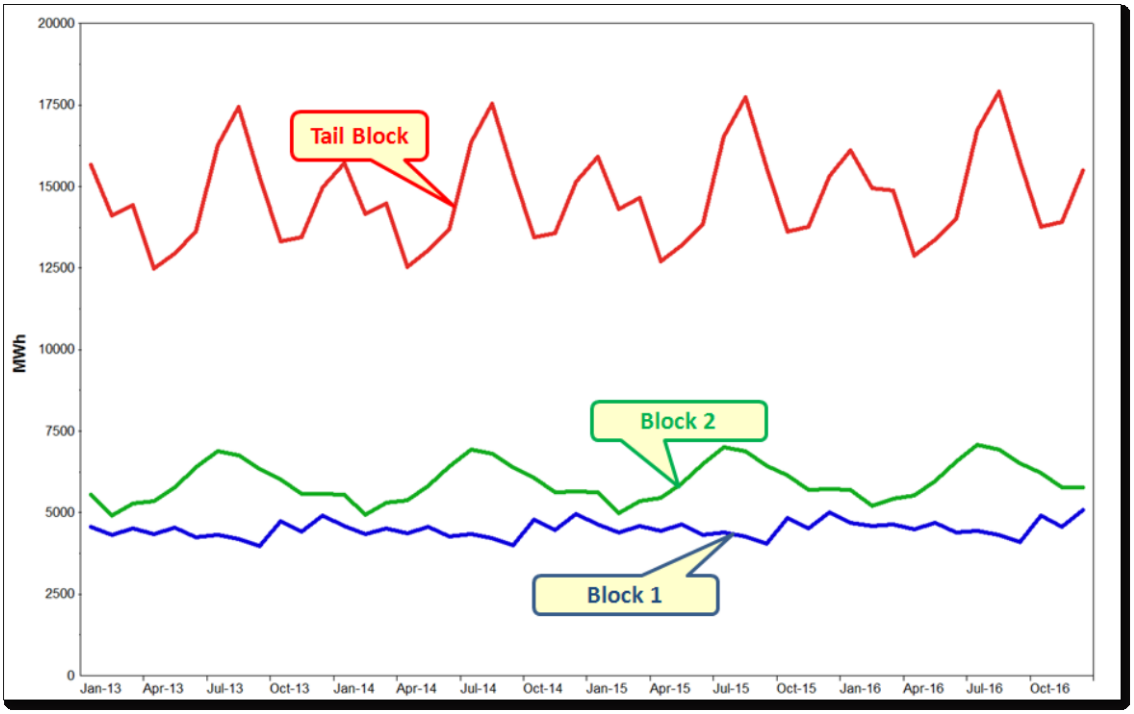
Approximately 97% of residential sales are billed under rate E01. The percentage is slightly lower in the winter months as the electric heat rate (E11) is higher in these months.

3. Estimate Monthly Billing Determinants

In the next step, rate class sales (and customers counts for some rates) are allocated to billing blocks, time-of-use billing periods, and on and off-peak billing demand blocks. Billing block and demand factors are derived from historical billing data. For example, residential rate E11 has on-peak and off-peak energy billing periods that are priced differently. Rate E11 monthly sales are allocated to TOU periods based on historical on-peak and off-peak sales data.

Some of the rates are complex. The commercial rate RE02, for example, includes non-demand and demand billed sales and customers, load factor kWh blocks (for demand customers), and different demand charges for demand below 5 kW and demand above 5 kW. Figure 18 shows the resulting sales block forecasts for rate RE02 Demand Customers.

Figure 18: Rate RE02 Demand Customer - Sales Billing Block Forecast



4. Calculate Rate Schedule and Revenue Class Revenues

Once the billing determinants are derived, revenues are generated by multiplying the forecasted billing determinants by the current customer, energy, and demand charges. Revenues are aggregated by rate schedule and month. Rate schedule revenues are then aggregated to revenue classes: residential, commercial, industrial, and street lighting.

5. Model Rate Restructuring

Starting in April 2016, GMP has begun to gradually merge most of the legacy GMP South rates into modified GMP North rates or completely new rates for the entire company. The rate restructuring occurs over the next five-years with the final rate tariffs effective April 2020. Major restructuring includes:

- Legacy South RE02 non-demand rate customers migrate to modified rate E06.
- Legacy South RE02 demand rate customers migrate to modified rates E06, E63, and new rate E08 based on the individual customer load characteristics.
- Legacy North E06 rate is split between rates E06 and E08.
- Legacy South RE10 customers will migrate to rates E06 and E63.
- Legacy South RE04, RE05, RE16 customers will join existing E63 customers in the modified company-wide rate E63.

New rates E06, E08, and E63 which are scheduled to begin in April 2016 combine parts of pre-existing rates, but have no historical billed data of their own. The new rates are estimated by allocating sales to the new rate schedules based on allocation factors provided by GMP. Revenue is then calculated by applying billing determinant factors to rate class sales.

6. Validate and Calibrate Revenue Calculation

To validate the revenue calculations, calculated revenues are compared to actual 2017 revenues on a per kWh basis. Estimated revenues are within 0.2% of actual revenues.

7. Fiscal Year Sales and Revenue Forecast

GMP uses a fiscal year for financial planning and reporting. The fiscal-year is from October to the following September. Fiscal Year 2019, for example, will run from October 2018 through September 2019. Table 14 and Table 15 show the fiscal year sales and revenue forecasts where sales and revenue are reported on a calendar-month basis.

Table 14: Fiscal Year Sales Forecast (MWh)

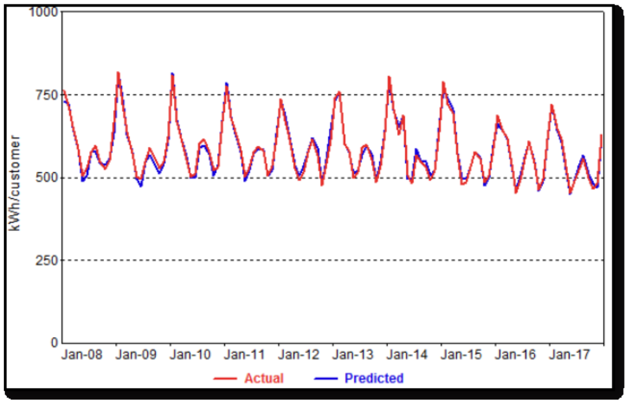
Year	Residential	Chg	Commercial	Chg	Industrial	Chg	Other	Chg	Total	Chg
2018	1,475,914		1,514,737		1,178,408		4,657		4,173,716	
2019	1,448,883	-1.8%	1,520,467	0.4%	1,182,356	0.3%	4,763	2.3%	4,156,468	-0.4%
2020	1,435,062	-1.0%	1,529,699	0.6%	1,175,132	-0.6%	4,763	0.0%	4,144,656	-0.3%
2021	1,411,987	-1.6%	1,527,704	-0.1%	1,175,612	0.0%	4,763	0.0%	4,120,065	-0.6%
2022	1,396,407	-1.1%	1,529,063	0.1%	1,178,532	0.2%	4,763	0.0%	4,108,764	-0.3%
2023	1,384,005	-0.9%	1,529,238	0.0%	1,179,177	0.1%	4,763	0.0%	4,097,182	-0.3%
2024	1,374,626	-0.7%	1,530,377	0.1%	1,179,172	0.0%	4,763	0.0%	4,088,937	-0.2%
2025	1,364,459	-0.7%	1,531,856	0.1%	1,178,351	-0.1%	4,763	0.0%	4,079,429	-0.2%
2026	1,355,285	-0.7%	1,534,325	0.2%	1,176,798	-0.1%	4,763	0.0%	4,071,171	-0.2%
2027	1,349,454	-0.4%	1,537,690	0.2%	1,174,922	-0.2%	4,763	0.0%	4,066,829	-0.1%
2028	1,347,171	-0.2%	1,541,920	0.3%	1,174,282	-0.1%	4,763	0.0%	4,068,136	0.0%
18-28		-0.9%		0.2%		0.0%		0.2%		-0.3%

Table 15: Fiscal Year Revenue Forecast ($)

Year	Residential	Chg	Commercial	Chg	Industrial	Chg	Other	Chg	Total	Chg
2018	265,977,367		228,172,138		122,075,792		2,738,422		618,963,718	
2019	261,940,833	-1.5%	229,764,614	0.7%	123,188,017	0.9%	2,800,489	2.3%	617,693,953	-0.2%
2020	259,975,368	-0.8%	231,353,300	0.7%	122,120,648	-0.9%	2,800,489	0.0%	616,249,805	-0.2%
2021	256,367,655	-1.4%	231,490,458	0.1%	121,985,659	-0.1%	2,800,489	0.0%	612,644,261	-0.6%
2022	254,024,848	-0.9%	231,824,066	0.1%	122,302,852	0.3%	2,800,489	0.0%	610,952,255	-0.3%
2023	252,187,152	-0.7%	231,963,674	0.1%	122,372,977	0.1%	2,800,489	0.0%	609,324,293	-0.3%
2024	250,934,708	-0.5%	232,090,085	0.1%	122,299,687	-0.1%	2,800,489	0.0%	608,124,969	-0.2%
2025	249,357,519	-0.6%	232,524,353	0.2%	122,283,544	0.0%	2,800,489	0.0%	606,965,905	-0.2%
2026	248,045,504	-0.5%	232,952,438	0.2%	122,115,105	-0.1%	2,800,489	0.0%	605,913,537	-0.2%
2027	247,245,569	-0.3%	233,504,291	0.2%	121,911,486	-0.2%	2,800,489	0.0%	605,461,835	-0.1%
2028	247,089,556	-0.1%	234,054,490	0.2%	121,769,894	-0.1%	2,800,489	0.0%	605,714,430	0.0%
18-28		-0.7%		0.3%		0.0%		0.2%		-0.2%

APPENDIX A: MODEL STATISTICS AND COEFFICIENTS

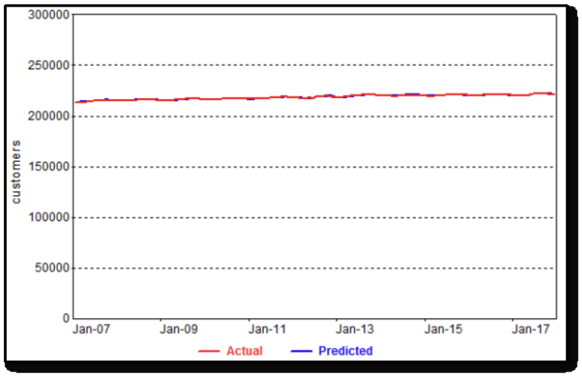
Figure 19: Residential Average Use Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeat	0.726	0.029	24.847	0.00%
mStructRev.XCool	1.034	0.075	13.868	0.00%
mStructRev.XOther	0.901	0.013	70.018	0.00%
mBin.FebMar11	-46.288	9.787	-4.73	0.00%
mBin.AftJun15	-24.612	2.822	-8.722	0.00%
mBin.Mar	-25.234	4.812	-5.244	0.00%
mBin.Apr	-42.348	5.303	-7.986	0.00%
mBin.May	-34.985	6.273	-5.577	0.00%
mBin.Jun	-22.151	5.694	-3.89	0.02%
mBin.Oct	-18.205	6.329	-2.877	0.49%
mBin.Nov	-28.228	5.942	-4.75	0.00%
mBin.Feb13	28.216	13.481	2.093	3.87%
mBin.Apr14	110.702	13.874	7.979	0.00%
mBin.Jan17	38.329	13.557	2.827	0.56%

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.979
Adjusted R-Squared	0.976
AIC	5.259
BIC	5.584
Log-Likelihood	-471.81
Model Sum of Squares	849,230.11
Sum of Squared Errors	18,272.95
Mean Squared Error	172.39
Std. Error of Regression	13.13
Mean Abs. Dev. (MAD)	9.7
Mean Abs. % Err. (MAPE)	1.69%
Durbin-Watson Statistic	1.626

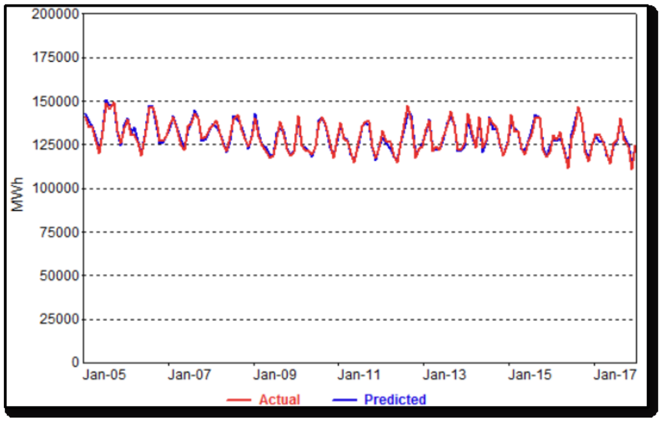
Figure 20: Residential Customer Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	72282.481	9786.52	7.386	0.00%
Economics.HHs	563.639	37.549	15.011	0.00%
mBin.Jan	-875.386	147.247	-5.945	0.00%
mBin.Feb	-871.335	158.029	-5.514	0.00%
mBin.Mar	-871.039	157.353	-5.536	0.00%
mBin.Apr	-902.552	145.082	-6.221	0.00%
mBin.May	-450.071	115.968	-3.881	0.02%
mBin.Dec	-544.161	113.719	-4.785	0.00%
mBin.Jun12	-2009.87	342.459	-5.869	0.00%
mBin.Jul12	1083.886	336.325	3.223	0.16%
AR(1)	0.767	0.058	13.325	0.00%

Model Statistics	
Iterations	13
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.977
Adjusted R-Squared	0.975
AIC	11.906
BIC	12.148
F-Statistic	500.328
Prob (F-Statistic)	0
Log-Likelihood	-954.73
Model Sum of Squares	684,194,459.87
Sum of Squared Errors	16,409,901.84
Mean Squared Error	136,749.18
Std. Error of Regression	369.8
Mean Abs. Dev. (MAD)	261.27
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	2.154

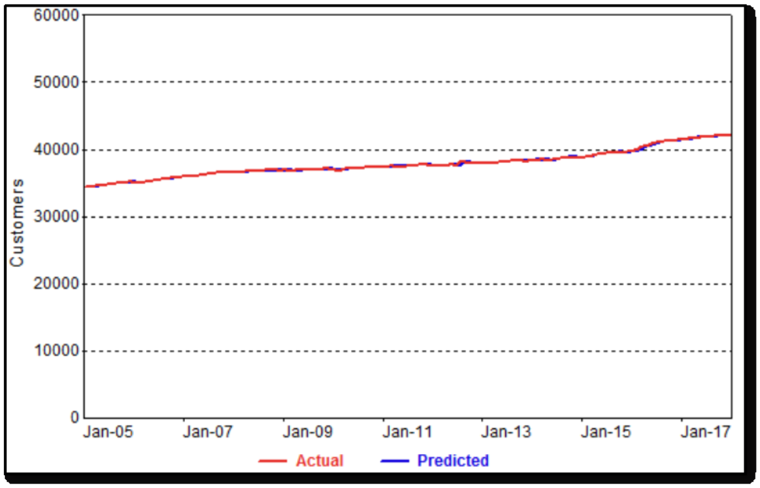
Figure 21: Commercial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	40132.587	4025.489	9.97	0.00%
mStructRev.XHeat	21092392.46	951984	22.156	0.00%
mStructRev.XCool	81005.357	2562.368	31.613	0.00%
mStructRev.XOther	7780.145	404.607	19.229	0.00%
mBin.Apr	-1646.899	533.655	-3.086	0.25%
mBin.Sep	1733.535	628.64	2.758	0.66%
mBin.Oct	3393.557	605.761	5.602	0.00%
mBin.Dec08	4707.581	1801.241	2.614	0.99%
mBin.Feb13	6536.091	1814.923	3.601	0.04%
mBin.Mar14	-5969.261	2007.456	-2.974	0.35%
mBin.Apr14	16399.991	2044.491	8.022	0.00%
mBin.May16	-4486.483	1833.82	-2.447	1.57%
mBin.Jul17	-7370.562	1834.194	-4.018	0.01%
mBin.Sep12Plus	4941.307	582.294	8.486	0.00%
mBin.Yr2017Plus	-1964	876.993	-2.239	2.67%
MA(1)	0.423	0.085	4.997	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	156
Deg. of Freedom for Error	140
R-Squared	0.952
Adjusted R-Squared	0.947
AIC	15.256
BIC	15.569
F-Statistic	186.732
Prob (F-Statistic)	0
Log-Likelihood	-1,395.33
Model Sum of Squares	10,735,865,180.55
Sum of Squared Errors	536,604,240.33
Mean Squared Error	3,832,887.43
Std. Error of Regression	1,957.78
Mean Abs. Dev. (MAD)	1,499.82
Mean Abs. % Err. (MAPE)	1.15%
Durbin-Watson Statistic	1.865

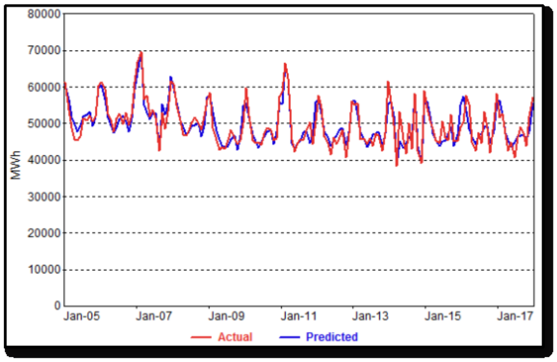
Figure 22: Commercial Customer Model



Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.NManEmp	147.863	8.057	18.35	0.00%
AR(1)	0.989	0.008	116.7	0.00%

Model Statistics	
Iterations	12
Adjusted Observations	155
Deg. of Freedom for Error	153
R-Squared	0.995
Adjusted R-Squared	0.995
AIC	9.893
BIC	9.932
Log-Likelihood	-984.61
Model Sum of Squares	575,310,529.74
Sum of Squared Errors	2,988,360.65
Mean Squared Error	19,531.77
Std. Error of Regression	139.76
Mean Abs. Dev. (MAD)	95.52
Mean Abs. % Err. (MAPE)	0.25%
Durbin-Watson Statistic	2.534

Figure 23: Industrial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	53549.428	816.168	65.611	0.00%
mWthrRev.CDD60	18.227	8.778	2.076	3.98%
mBin.Yr07	3844.68	915.435	4.2	0.01%
mBin.Jan11Plus	-1232.747	493.956	-2.496	1.38%
mBin.Yr2016Plus	1708.579	651.106	2.624	0.97%
mBin.Jan	3880.521	1086.75	3.571	0.05%
mBin.Mar	-4971.477	1132.312	-4.391	0.00%
mBin.Apr	-6896.629	1085.689	-6.352	0.00%
mBin.May	-9096.448	1095.012	-8.307	0.00%
mBin.Jun	-9324.953	1431.944	-6.512	0.00%
mBin.Jul	-10579.802	2416.049	-4.379	0.00%
mBin.Aug	-10442.82	2827.002	-3.694	0.03%
mBin.Sep	-7950.265	2050.261	-3.878	0.02%
mBin.Oct	-9004.395	1182.069	-7.617	0.00%
mBin.Nov	-4940.069	1104.302	-4.473	0.00%
mBin.Dec	3158.083	1083.327	2.915	0.42%
mBin.Feb07	9585.623	2905.183	3.299	0.13%
mBin.Aug07	-12087.037	2901.397	-4.166	0.01%
mBin.Feb11	14932.243	2782.79	5.366	0.00%
mBin.Mar11	15911.246	2791.455	5.7	0.00%
mBin.Mar14	-8770.012	2791.249	-3.142	0.21%
mBin.Sep14	10931.654	2794.157	3.912	0.02%
mBin.Nov14	-8224.982	2779.175	-2.96	0.37%

Model Statistics	
Iterations	1
Adjusted Observations	156
Deg. of Freedom for Error	133
R-Squared	0.829
Adjusted R-Squared	0.801
AIC	15.903
BIC	16.352
Log-Likelihood	-1,438.77
Model Sum of Squares	4,535,249,287.39
Sum of Squared Errors	936,571,151.87
Mean Squared Error	7,041,888.36
Std. Error of Regression	2,653.66
Mean Abs. Dev. (MAD)	1,856.78
Mean Abs. % Err. (MAPE)	3.73%
Durbin-Watson Statistic	1.832

Figure 24: Other Sales Model

C. Transmission and Distribution Projects

This appendix describes the transmission and distribution projects that have been completed since our 2014 IRP, projects that are underway, and projects that we plan to start after 2020.

PROJECTS COMPLETED SINCE THE 2014 IRP

Barre North End Substation Rebuild

After retiring the Barre substation in 2014, three substations—Barre North End, Barre South End, and Websterville—remained as the primary supplies to Barre area distribution. Each substation was supplied from the 34.5-kV subtransmission system, which in turn, supplied distribution circuits at voltages of 2.4 kV, 4.16 kV, and 12.47 kV; each also had asset management concerns impacting the equipment's reliability.

A Vermont Public Service Board Order in Docket No. 8069 required us to examine rebuilding and relocating the Barre South End substation as well as converting all area substations to 12.47 kV to improve reliability in the Barre area. We are designing the Barre South End substation with a 15/28-MVA transformer and three circuits to provide complete feeder backup to nearby substations, which will significantly improve reliability for local residents and businesses. This necessitated rebuilding the Barre North End substation as well as rebuilding the Websterville substation.

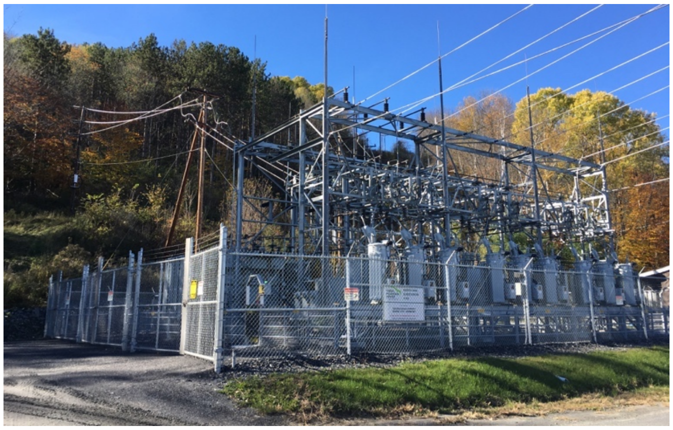


Figure C-1. Rebuilt Barre North End Substation

To rebuild the Barre North End substation, we created a new substation yard with a gravel parking area, fence, steel structures and foundations, oil containment system, ground grid, conduit system, cable trench system, yard stone, emergency fence lights and a security system. We installed a 34.5-kV circuit breaker, two 34.5-kV motor-operated load break switches, three 34.5-kV bus voltage transformers and fuses, one 15/28-MVA 34.5-kV-to-12.47-kV power transformer, one 15-kV load break switch, three 15-kV circuit breakers, three 15-kV bus voltage transformers, three 15-kV line voltage transformers, eighteen single-blade disconnects, nine 438A voltage regulators, three relay and communication equipment enclosures, one AC station service with associated AC panel, one 48V-DC battery bank, charger, and a DC panel.

The new Barre North End substation enables full feeder backup to the new Barre South End substation and partial feeder backup to the Berlin substation.

Project completion: May 2018.

East Middlebury to Smead Road Line Upgrade

A 46-kV subtransmission line runs from the East Middlebury substation for approximately one-half mile to the Smead Road substation, then for another three miles to the Silver Lake Hydro station (in Salisbury). The first half-mile section is conductored with 4/0 Aluminum Conductor Steel-Reinforced (ACSR, installed in 1954) and has aged pole plants; the three-mile section is conductored with 4/0 ACSR (installed in 1937), but with pole plants in good condition.

The VELCO Connecticut River Valley Study, which focuses on the need to upgrade the VELCO Coolidge to Ascutney 115-kV transmission line, shows that these two subtransmission lines are overloaded following certain contingencies on the VELCO transmission system. These post-contingency overloads expose the Connecticut River Valley to low voltages and possible voltage collapse.

To address these post-contingency thermal constraints and enhance reliability, we replaced the aged pole plants with new ones and installed a larger 477 ACSR conductor in the section from East Middlebury to Smead Road. We determined that the remaining three miles were adequate for current conditions and do not require reconductoring. Project completion: October 2016.

Georgia Interconnection Subtransmission Replacement

Our subtransmission system in northwest Vermont includes networked 34.5-kV lines bounded by the towns of St. Albans, Milton, Fairfax, Johnson, and Lowell. Its current summer peak of 83 MW is forecasted to be 101 MW by 2024. Three interconnections supply the system:

- VELCO 115-kV-to-34.5-kV substations at Nason Street (in St. Albans) and in East Fairfax.
- A 34.5-kV line from the Johnson, Lowell, and Stowe areas.
- Local hydro generators at Milton, Peterson, Clark Falls, and Fairfax.

The VELCO supply, however, contained a number of deficiencies:

- Loss of the Nason Street source resulted in significant voltage and thermal violations at various points in our subtransmission system.
- Loss of the East Fairfax source also resulted in thermal overloads and widespread undervoltages.
- Loss of the 34.5-kV subtransmission line between the Nason Street substation and the Ben & Jerry's substation results in undervoltage at the Ben & Jerry's substation.

To address these deficiencies, we installed a new 115-kV-to-34.5-kV supply into the subtransmission system with an interconnection at Ballard Road in the Town of Georgia. To complete this project, we:

- Installed a new 56-MVA, 115-kV-to-34.5-kV transformer at the VELCO Georgia substation together with oil containment and associated switchgear and controls.
- Built a new Ballard Road switching station, comprised of three-circuit breakers and associated foundations, relaying, disconnect switches, control building, and SCADA that interconnected the VELCO source to the our subtransmission system.
- Erected a new two-mile-long, 34.5-kV subtransmission line (located within an existing VELCO transmission line right-of-way) from the VELCO Georgia substation to the Ballard Road switching station.
- Reconductored the five-mile-long Milton to St. Albans 34.5 kV subtransmission line.
- Installed a new 5.4-MVAR, 34.5-kV capacitor bank at the VELCO East Fairfax substation.

Project completion: May 2015.

Gorge Substation Voltage Conversion

The Gorge substation is a 34.5-kV switching facility and peaking hydro facility located on the Winooski River. This substation also serves approximately 600 distribution customers in Colchester, Winooski, and South Burlington. Rapid growth in the surrounding area overloaded a 12.47-kV circuit from our Essex substation, limiting our ability to serve existing and new loads or to provide feeder backup in the area.

Figure C-2. Gorge Substation

To mitigate these constraints, we removed the 7-MVA, 34.5-kV-to-4.16-kV transformer as the supply to the distribution circuits (but kept it as a generator step-up unit) and replaced it with a 10/14-MVA, 34.5-kV-to-12.47-kV transformer together with associated voltage regulators, station service transformers, and surge arresters. We also converted two 4.16-kV distribution circuits to 12.47-kV. We also created a footprint and take-off structure to accommodate a new 16Y3 feeder to serve load in Winooski. (See “Winooski 34.5-kV Feeder Addition” on page C-10 for details.)

The conversion relieved the overloaded Essex circuit, increased capacity to serve existing and new load, corrected low voltages, increased operational flexibility, and greatly enhanced feeder backup between the Gorge, Essex, and Ethan Allen substations. In addition, the conversion enables us to defer the construction of a new 115-kV-to-12.47-kV substation in the Susie Wilson Road area of Essex.

Project completion: July 2015.

Graniteville and Wetmore Morse Substations Rebuild

The Graniteville and Wetmore Morse substations supply load to the granite quarries and surrounding area in Barre Town. The 90-year-old, 3-MVA, 34.5-kV-to-2.4-kV transformer bank at Graniteville and the 1.5-MVA, 34.5-kV-to-2.4-kV transformer bank at Wetmore Morse were both aged and near the end of their useful lives.

To address these aged facilities and improve reliability, we rebuilt the Graniteville substation with new components that included a 7.5/10.5-MVA, 34.5-kV-to-12.47-kV transformer, an oil containment system, and associated bus work and foundations together with new distribution feeder circuit breakers, voltage regulators, security system, and a control cabinet. This larger transformer enables quarry-area motors to start without voltage flicker, and allows for future backup of the Websterville substation. We also converted the 2.4-kV distribution line between the two substations to 12.47-kV to supply Wetmore Morse loads from the rebuilt Graniteville substation. Wetmore Morse substation was retired and the Wetmore load is now fed off the 61G1 (Websterville) circuit. The new Graniteville 12kV circuits was able to pick up majority of the existing 61G1 circuit heading to Williamstown.

Project completion: July 2017.

Highbridge to Lafayette (Line 92) Subtransmission Line Reconductoring

VELCO's analytical studies that supported its 2016 Long Range Plan identified the Highbridge to Lafayette 46 kV subtransmission path as potentially overloading to a very serious degree under credible first contingencies, which violates our transmission line criteria. These overloads were 139% of normal summer rating—high enough to pose both reliability and safety concerns.

As a result, we reconductored approximately 2.35 miles of the subtransmission line from 336 ACSR to 795 ACSR.

Project completion: March 2017.

Marble Street to Danby Subtransmission (Line 36) Line Reconstruction

In 2011, CVPS acquired the assets of Omya's Vermont Marble Power Division (VMPD), which we subsequently acquired from CVPS in 2012. One of those assets is a 46-kV subtransmission line from the Marble Street switching station in West Rutland to the Danby substation (which solely serves the Danby Imperial Quarry with approximately 500 kW of load).

That line contained structures installed between 1938 and 1951 together with #2 ACSR, and suffered from aging poles, crossarms, and insulators, all making the line vulnerable during storms. Terms of the acquisition required CVPS to reconstruct the line by 2016—an obligation that we inherited.

As such, we rebuilt the subtransmission line by installing new poles, crossarms, and insulators. While we reused the existing conductor, we redesigned the line to accept a larger capacity 477 ACSR conductor in the future.

Project completion: July 2016.

Marshfield Substation Rehabilitation

The aged Marshfield substation had numerous problems: clearances that do not meet modern code requirements, obsolete equipment, a transformer with limited ability to support load growth, a 4.16kV distribution voltage that could not back up the adjacent 12.47-kV feeder originating from the Plainfield substation, an inability to accept a mobile transformer, and a 34.5-kV distribution feeder that could not be adequately protected during certain system conditions and maintenance procedures.

To correct these deficiencies, we:

- Installed a new 6-MVA, 34.5-kV-to-4.16-kV generator step-up transformer, new steel structures, foundations, fence, and oil containment.
- Added a second 34.5-kV distribution circuit recloser that adequately protects the circuit under certain system conditions and maintenance procedures.
- Retired a 4.16-kV feeder, moving its load to an adjacent 12.47-kV feeder out of the Plainfield substation.

These upgrades not only improve reliability and enhance safety, but also enable growth on the distribution system.

Project completion: March 2015.

Sharon Substation Upgrade

Existing solar generation combined with a generation from new large solar project exceeded the top nameplate rating of the existing Sharon substation transformer, thus prompting the need to increase the transformer's capacity. In addition, aging infrastructure at the substation needed upgrading to improve safety and reliability.

We installed a new 7.5/10-MVA transformer, replaced the existing 35-year-old 15kV breaker with a new ABB RMAG circuit breaker; raised the existing distribution steel to increase clearances; added new yard stone, ground grid, new 7200V line voltage transformer and fuse, and alternate station service; and upgraded the existing protective relaying to include line voltage sensing and SCADA control of new voltage regulators.

Project completion: May 2018.

South Brattleboro Substation Upgrade

We upgraded the two transformers at the South Brattleboro substation to address aging infrastructure and provide feeder backup for the area. The previous 54-year-old, 3.75-MVA, 69-kV-to-12.47-kV transformer fed two circuits; the 27-year-old. 14-MVA, 69-kV-to-12.47-kV transformer also fed two circuits; both had limited capacity for feeder backup.

We upgraded both transformers by installing one new 28-MVA, 69-kV-to-12.47-kV transformer, oil containment, a 69-kV high-side circuit breaker and associated fence, ground grid, communications, and security. In addition, we installed three distribution circuits with associated circuit breakers and voltage regulators, and larger voltage regulators to allow for greater flexibility with circuit ties during planned outages and contingencies.

Project completion: February 2018.

South Poultney Substation Upgrade

Asset management combined with safety concerns prompted an upgrade to the South Poultney substation. The three single-phase transformers were almost 100 years old. As a result, we upgraded the substation to a 2,500-KVA 46-kV-to-12.47/4.16-kV power transformer with a new oil containment system, and installed a ground grid system, a perimeter fence, and a security system to prevent unauthorized entry.

Project completion: September 2018.

Wallingford Substation Transformer Upgrade

The Wallingford substation's 5/7 MVA transformer, relocated here when the substation was reconstructed in 2002, fed one circuit (#23) with three 328-amp voltage regulators. We upgraded the substation because the infrastructure was aging, and to increase its capacity, efficiency, and reliability.

We removed the existing transformer and installed a new 7.5/10.5-MVA transformer, three 46kV single-blade disconnects with a new pole, upgraded to 438-amp voltage regulators, and installed a new 15kV RMAG distribution circuit breaker, three 46-kV fuses, a new relay and control panel, a 15-kV line voltage transformer, and a security system.

Project completion: April 2016.

Waterbury Substation Relocation and Replacement

In 2011, Tropical Storm Irene caused significant flooding of our Waterbury substation, then located in a FEMA-designated 100-year floodplain at 48 Winooski Street. We realized we needed to relocate the substation, and to redesign and rebuild it for two reasons: One, significant load growth in the area from several large customers (including the State of Vermont and Vermont Coffee Roasters); and two, the need to provide feeder backup because the area's 4.16-kV feeders were approaching capacity and could not be backed up by the Waterbury Center substation because the feeder voltages are dissimilar. (The previous Waterbury substation included a 10.5-MVA, 34.5-kV-to-4.16-kV transformer, voltage regulators, and three 4.16-kV feeders; the Waterbury Center substation contains a 14-MVA, 34.5-kV-to-12.47-kV transformer, voltage regulators, and two 12.47-kV feeders.)

Figure C-3. Waterbury Substation: Relocated and Replaced

The new Waterbury substation comprises one 15/28-MVA, 34.5-kV-to-12.47-kV transformer, a high-side circuit breaker, motor-operated load break switches for transmission line sectionalizing, oil containment, three distribution circuits with associated circuit breakers, voltage regulation at each feeder, and SCADA. We also converted area feeders from 4.16 kV to 12.47 kV. The new substation is located along Vermont Route 100 (outside of the flood plain) adjacent to our Middlesex to Duxbury Switch 34.5-kV subtransmission line.

Replacing the substation and converting the area's feeders enables the two area substations to back up each other, lowers distribution line losses, accommodates new loads, and enhances the accommodation of distributed generation installations.

Project completion: December 2015.

White River Junction Substation Replacement

Our White River Junction substation and Wilder substation both feed the local area. Our recent upgrade to the White River Junction substation and its associated distribution system from 4.16 kV to 12.47 kV (for load growth and partially backing up circuits from the Wilder substation) proved inadequate. Larger load growth, limitations on the non-standard 13.8-kV transmission supply from the National Grid Wilder substation hydro generation bus, and limited feeder backup all contributed to this inadequacy.

Figure C-4. White River Junction Substation During Construction

As a result, we have replaced the White River Junction substation. The new substation, located on the existing Lantern Lane site (albeit expanded), comprises a 15/28-MVA, 46-kV-to-12.47-kV transformer, oil containment, high-side circuit breaker, 5.4-MVAR capacitor bank, three distribution circuits (with space for a fourth circuit), voltage regulators, and SCADA control.

We replaced the existing, non-standard 13.8-kV transmission line (that traverses rugged and hard-to-reach terrain) with a new 2.5-mile, 46-kV transmission line, overbuilt on distribution. Located along Old River Road in Hartford, the new line taps the Hartford to Taftsville 46-kV line to supply the substation.

Project completion: January 2016.

Wilder Subtransmission Switching Station Upgrade

Our Wilder subtransmission switching station contains a 46-kV single-circuit breaker that ties the National Grid Wilder substation to our 46-kV subtransmission system in Hartford. The substation needed upgrading because much of the equipment was either near the end of its useful life, some replacement parts were unavailable, and current codes or design standards were not met.

We replaced and installed a new outdoor relaying cabinet including new SCADA and communication equipment; a 25KVA station service transformer including steel pedestal and concrete foundation; AC & DC distribution panels; a 48VDC battery bank with charger; new insulators for all bus work, disconnects, and air breaks; and lightning arresters for B-40 line termination, and upgraded the substation ground grid. All new equipment is within the existing switching station fence. This equipment modernization enables us to properly operate the substation, and improves its safety and reliability.

Project completion: December 2015.

Winooski 34.5-kV Feeder Addition

Two 34.5-kV feeders used to serve the Winooski load: the 46Y1 feeder (originating at the Winooski substation) and the adjacent 36Y5 feeder (originating at the Ethan Allen substation in Colchester) which provided only partial backup. As such, we added a third 34.5-kV feeder to provide full-time backup originating at the recently converted Gorge substation.

To add the new feeder, we rebuilt one-half mile of the existing 3309 transmission line between the Gorge substation and the downtown Winooski redevelopment area, upgrading the 3309 transmission conductor and installing the underbuilt 16Y3 feeder. We also upgraded the Gorge substation with a circuit breaker, reactor, and voltage regulators to accommodate the new feeder.

As a result of adding this new feeder, we improved reliability, created a full-time feeder backup, enhanced the thermal performance of the 3309 transmission conductor, replaced aged equipment, reduced line losses, enhanced area voltage performance following certain contingencies, and deferred the need for another substation in the area.

Project completion: December 2015.

Woodford Road Substation Upgrade and Pickett Hill Substation New Construction

Our Woodford Road substation used to include a 46-kV switching infrastructure and one 12.5-MVA, 46-kV-to-12.47-kV transformer supplying two 12.47-kV distribution feeders. Much of this equipment, however, was near the end of its useful life (so old in most cases that replacement parts were no longer available). We upgraded some of this equipment; and we retired some and replaced it with new equipment at our new Pickett Hill substation. We built the Picket Hill substation near a new VELCO Bennington substation to more easily connect to their transmission system.

For the Pickett Hill substation, we:

- Upgraded the 46-kV switchgear to accommodate the newly located VELCO Bennington substation, which is a 115-kV-to-46-kV source for the Bennington area.
- Built several sections of new 46-kV transmission lines to tie the Pickett Hill substation to the 46-kV subtransmission system.
- Built one section of 69-kV transmission line to tie the new VELCO Bennington substation to the 69-kV subtransmission system.

For the Woodford Road substation, we:

- Added new bus work, switches, breakers, relays, SCADA equipment, larger voltage regulators, batteries, station service transformer, oil containment, and a control house.
- Added a high-side circuit breaker and transformer differential to better protect the existing transformer.

This entire project of replacing infrastructure and equipment maintains system reliability to the Bennington area, improves system operation, corrects deficiencies of current NESC standards, and improves safety and reliability.

Project completion: January 2015.

PROJECTS PLANNED AND UNDERWAY

Airport Substation Conversion and Rebuild

The Airport substation is sited on Vermont Air National Guard property in South Burlington, adjacent the Burlington International Airport. The substation includes a 59-year-old, 1.5-MVA, 34.5-kV-to-4.16-kV transformer and two 4.16-kV distribution circuits, neither of which allow for feeder backup from adjacent substations. In addition, the wood structures are aged with clearances that do not meet modern code requirements.

As such, we plan to convert and rebuild the substation on a new larger site. We plan to install a new 15/28-MVA, 34.5-kV-to-12.47-kV transformer; oil containment; three 12.47-kV distribution circuits; three 34.5-kV breakers (two for transmission and one for transformer bank); and associated circuit breakers, voltage regulators, bus work, foundations, fence, ground grid, security system, control cabinet, and switchgear.

The new substation would still be centrally located in Chittenden County, and allow for the reconfiguration of existing circuit loads among the Gorge, Ethan Allen, Dorset Street, Essex, and Tafts Corners substations. The upgrade would thus enhance feeder backup in this area, extend the useful lives of the adjacent substations, address aging infrastructure, and improve safety and reliability.

We have petitioned the Vermont Public Utilities Commission for a certificate of public good (CPG), and expect to begin construction in 2019.

Projected start date: February 2020.

Barre South End Substation Replacement

As discussed previously in "Barre North End Substation Rebuild" (page C-1), our examination under Docket No. 8069 revealed that the Barre South End substation also needed to be rebuilt and relocated. As a result, we are currently in the process of newly constructing the Barre South End substation. The rebuild includes upgrading to a 15/28-MVA 34.5-kV-to-12.47-kV power transformer and three 12.47-kV feeders.

Figure C-5. Ongoing Construction of New Barre South End Substation

In addition, we are installing a new fence, yard lighting and security cameras, ground grid, below-grade trench and conduit systems, oil containment, 34.5 kV circuit breaker, two motor-operated load break switches, transmission voltage potential transformers, and relay protection and control. Distribution equipment includes three vacuum circuit breakers, arresters, line tie switches, potential transformers, and underground feeder getaways.

Once finished, this substation will be able to provide full feeder backup to the Barre North End substation and partial feeder backup to the Graniteville and Websterville substation.

Expected completion date: December 2018.

Cambridge Transmission Substation Expansion

We have upgraded and expanded our Cambridge substation to be configured with a new tap line associated with two new breakers. This project improves reliability to Vermont Electric Cooperative (VEC) customers as well as our customers in the area.

VEC first identified this project in their most recent Integrated Resource Plan as a way to manage assets and address safety issues. The Public Utilities Commission approved the project in its order in Case No. 17-2675-PET dated September 26, 2017.

When completed, the new tap line will automatically sectionalize our B8 line. If a fault occurs on one section of that line, this upgraded configuration will still allow energy to flow to VEC's substations while shutting off the faulted line. For line faults east of our Cambridge substation, VEC's Johnson substation would lose power; for line faults west of our Cambridge substation, VEC's Pleasant Valley substation and our Jeffersonville substation would lose power. In both cases, however, VEC's Cambridge and

Jeffersonville substations would retain power. Thus, thousands of customers who previously would have lost power, will now retain power.

Expected completion date: December 2018.

East Barnard to Bethel (Line 107) Subtransmission Line Rebuild

The VELCO Connecticut River Valley Study indicated that the existing 3/0 ACSR conductor on the six-mile East Barnard to Bethel line would overload after certain contingencies, resulting in cascading line overloads and losses of up to 40 MW of load. The study also indicated the existing Bethel to East Barnard 3/0 ACSR line section was overloaded by 115.7% of its thermal rating of 24.54 MVA.

This project reconductors the Bethel to East Barnard (Line 107) to 477 ACSR conductor. This line is 6.3 miles long, however, we plan to reconductor only a small portion of it (0.22 miles of 3/0 ACSR) because most of it is already thermally adequate (4/0 ACSR). Accordingly, we plan to replace this 0.22 miles of 3/0 ACSR located at the Bethel end of the line with 477 ACSR. This line is part of a 46-kV transmission loop in the Middlebury, Windsor, and Chelsea areas.

We have obtained a CPG to rebuild this line with new structures and a larger 477 ACSR conductor. This addresses the overloading and lower line losses, and remediates the structural issues. We began construction in September, 2018.

Projected completion date: February 2019.

Rutland Reliability Project

After extensively analyzing the load flow of our recently acquired VMPD system, we found that the Florence 115/46-kV source could not "ride through" a first contingency loss unless we reinforced the system by:

- Permanently closing the normally open 46-kV B7 tie at West Rutland.
- Reconductoring the Florence-to-West Rutland 46-kV line, which includes the Marble Street to Florence segment.
- Permanently closing the normally open second Rutland-to-West Rutland 46-kV line with reconductoring.

We submitted this Rutland Reliability Plan to the Public Utility Commission in 2015.

Without reconductoring, the existing Florence to West Rutland line could not carry peak demand. In addition, the Rutland area system substantially benefits from integrating VMPD by effectively adding another 115/46-kV transformer to support the area's

46-kV network (via Florence to West Rutland). This extra source improves area voltage and reduces loading on the area's other transformers, which could otherwise exceed their ratings post-contingency. Substation upgrades are required at Marble Street and Lalor Avenue to support this project. These upgrades will improve the connectivity and reliability of the former VMPD system that serves our customers in Florence, Danby, and Proctor. The project includes several components.

Upgrading the West Rutland Transmission Substation consists of adding two 46-kV Vacuum Circuit Breakers transmission breakers (B-4 and B-5) to replace the two existing 1969-vintage OCBs (B-7 and B-56). These vintage breakers have proven troublesome, experiencing many failures. We are also replacing the bus and line instrument transformers (as they have reached their limit for useful life) and adding a new security system.

Rebuilding the West Rutland to Marble Street (Line 39) Subtransmission Line. We will rebuild approximately 0.56 miles of 46-kV transmission line from Marble Street Substation to West Rutland Substation with 477 ACSR.

Rebuilding the Marble Street to Proctor (Line 37) Subtransmission Line. We will rebuild approximately 7.22 miles of 46-kV transmission line from the Florence Substation to the Marble Street Substation with 477 ACSR.

Rebuilding the Evergreen Tap to West Rutland (L43) Subtransmission Line. We will rebuild approximately 0.94 miles of 46-kV transmission line from Evergreen Tap to West Rutland Substation (Line 43) with 477 MCM ACSR conductor. The larger conductor on Line 43 allows this radial feed to become part of the looped transmission system in the Rutland Area.

Projected completion date: November 2019.

Taftsville to Windsor (Line 105) Subtransmission Line Rebuild

The VELCO Connecticut River Valley Study indicated that the existing 477 ACSR conductor on the 10.5-mile Taftsville to Windsor line would overload by 124% of its thermal rating of 49 MVA following certain contingencies. This line is part of a 46-kV transmission loop extending across Windsor County.

In the 248 process under Docket 8605, the need to upgrade this line was identified in the VELCO Connecticut River Valley Project filing. The VELCO pre-filed testimony stated "Related to these improvements, GMP will replace conductors for three 46 kV line sections: the East Middlebury to Smead Road line (Project 143180 completed in 2016), the Bethel to East Barnard line (Project 148615 FY2019), and the Windsor to Taftsville line (Project 148614 FY2020)."

ISO-New England and VELCO studies determined that upgrading an existing 115 kV line, supplemented with other component transmission and subtransmission upgrades, would be the most cost-effective solution to mitigate the identified concerns. As such, we plan to reconductor the Taftsville to Windsor (Line 105) to 795 ACSR conductor. This line is part of a 46-kV transmission loop in the Middlebury, Windsor, and Chelsea areas.

Projected completion date: December 2020.

Websterville Substation Rebuild

We plan to rebuild the Websterville substation on its existing site as part of our complete revamp of the substations that feed the Barre area. (See "Barre North End Substation Rebuild", page C-1, and "Barre South End Substation Replacement", page C-12, for information on our rebuilding all three substations.)

The rebuilt substation would be equipped with new transmission circuit breakers, two capacitor banks, a new 15/28-MVA transformer, and three 12.47-kV feeders. The new substation will permit full feeder backup to the Graniteville substation and partial feeder backup to the Barre South End substation.

In conjunction with a Websterville substation rebuild, a 34.5-kV recloser will be added to tie the Websterville to Barre 3306 line to the Websterville to McIndoes Falls 3311 line to maintain a 34.5-kV network while the Websterville substation is being upgraded. This bypass will be permanent and allow for additional operational flexibility to reconfigure the 34.5-KV network in the future as needed to optimize system conditions.

In October 2018, we filed for a certificate of public good with the Public Utilities Commission. We intend to begin construction in spring 2019.

Projected completion date: February 2020.

Welden to North St. Albans (Line 135) Subtransmission Line Reconductoring

VELCO, conducting a study for us in the St. Albans area, identified an existing overload of the Welden St to East St Albans 3/0 ACSR line segment of Line 135. The overload exceeded 10% of the line segment's thermal rating when the Nason Street end of the B10 line was opened for planned or emergency outages. This overload could result in a hazard from a conductor sag resulting in inadequate clearance, or in a complete burndown of the conductor, resulting in loss of customer load. VELCO also identified this overload in their 2018 Long-Range Transmission Plan.

To remedy these hazards, we are reconductoring the 0.41-mile long, 34.5-kV subtransmission overhead line (Line 135) with the larger wire 477 ACSR. This segment, which runs from our Welden Street substation to the North St. Albans substation, is part of the 34.5-kV subtransmission loop that provides redundant transmission supply to the substations feeding the distribution system in the affected area. The reconductoring will increase reliability to our customers by preventing the line from failing from the aforementioned contingencies.

Expected completion date: March 2019.

PROPOSED PROJECTS STARTING AFTER 2020

Danby Substation New Construction

Building a new substation in Danby will create multiple benefits for the area. Our plan for the new Danby substation includes a 7.5/10.5-MVA, 46-kV-to-12.47-kV transformer, oil containment, a 46-kV high-side circuit breaker, two 12.47-kV distribution circuits with associated circuit breakers and voltage regulators together with a fence, ground grid, communications, and security.

We plan to initially supply the Danby substation from the 46-kV Marble Street to Danby Quarry subtransmission line, relieving capacity issues by providing a portion of the load presently supplied by the Wallingford substation. The 12.47-kV distribution installed at the Danby substation will supply the Danby Imperial Quarry, thus improving voltage regulation at the quarry.

Next, we plan to build a new 46-kV tie line from the Dorset substation, forming a three-way network that adds capacity to both the Danby and Wallingford substations (and thus the surrounding area) while providing backup for the latter. The three-way network also enhances area reliability by reconfiguring two relatively long and weak radial 46-kV subtransmission lines, the Marble Street to Danby Quarry line and the Blissville to Dorset line.

After this 46-kV tie line is built, we will be able to reconductor the Marble Street to Danby line to 477 ACSR without interrupting service to Danby substation customers, including the quarry. In addition, should it become necessary, we could build a new 46 kV tie line from the Bromley substation to either the Danby substation or the Dorset substation to further increase network reliability in the area.

Projected start date: 2022.

East Ryegate Substation Upgrade

We need to upgrade the East Ryegate substation to improve reliability. We plan to eliminate two radial transmission lines to form a 46-kV network between Hartford and Ryegate. The upgrade comprises two transformers (one 46/34.5 kV and one 34.5/12.47 kV), oil containment, circuit breakers, relay protection upgrade and associated fence, ground grid, communications, and security.

Projected start date: 2020.

East St. Albans Substation Upgrade

As part of its St. Albans study for us, VELCO looked at a proposed load increase for the area. VELCO identified low voltage in the St. Albans area with the loss of the St. Albans 115/34.5-kV source at existing loads.

To increase reliability, we plan to install two SCADA-controlled, 3.6-MVAR capacitor banks at our East St. Albans substation. These two capacitor banks will provide voltage support during emergency contingency situations as well as during planned maintenance on the St Albans area 34.5-kV network.

Projected start date: 2020.

Fair Haven and Hydeville Distribution Substation Conversions

Whenever feasible, we convert existing 2.4-kV, 4.16-kV, and 8.3-kV distribution circuits to our standard distribution system voltage of 12.47/7.2-kV grounded wye. Converting these substations is one of those projects.

We plan to convert the Fair Haven and Hydeville substations from 46/4.16 kV to 46/12.47 kV with all new components including, at minimum. a top nameplate 10.5-MVA, 46-kV-to-12.47-kV transformer, oil containment system, and associated bus work and foundations. Also included would be distribution feeder circuit breakers, voltage regulators, security system, and a control cabinet. The larger transformer will allow for feeder backup capability between these substations, for the Castleton substation, and for potential future ties to the Carvers Falls and Poultney area substations. Converting these substations to 12.47 kV will also reduce losses.

Projected start date: 2020–2021.

Haystack Substation New Construction

There is very limited capacity for the GMP Dover and Wilmington substations, and there is very limited feeder backup capability. In addition, the Hermitage Club at Haystack Mountain in Wilmington has future plans for an expansion requiring 10 MW of additional load. As such, we plan to build a new Haystack substation in Wilmington to accommodate future load growth, improve area reliability, and reduce system losses; as well as to improve the limited feeder backup capability between the Dover and Wilmington substations. This upgrade is necessary even if the Hermitage Club does not proceed with their expansion.

Our plan for the substation comprises a 28-MVA, 69-kV-to-12.47-kV transformer with oil containment, a high-side circuit breaker, three distribution circuits with circuit breakers and voltage regulation for each feeder, motor-operated load break switches, and SCADA. The transmission supply will be from the 69-kV Searsburg-to-Dover subtransmission line.

We initially intended to site the substation close to the load to reduce system losses, but the adjacent land owner would not grant us access, thus the project is on hold until we can find a suitable parcel of land.

Projected start date: Currently in 2020 budget.

Highbridge Substation Upgrade

The Highbridge substation needs to be upgraded to improve reliability. We plan to replace an existing breaker and voltage transformer, and add two new breakers, associated relaying, ground grid, fence, and control house.

Projected start date: 2021 (depending on land acquisition).

Hinesburg Substation Rebuild

An eight-mile, 12.47-kV distribution line originating at the Charlotte substation serves Hinesburg. New development in the area is likely to increase its 4.6 MW winter peak. This increasing load and distribution line length contribute to potential thermal and voltage limitations as well as challenges in protecting the line from contingencies. To temporarily mitigate this situation, we connected a portion of the load to the Vermont Electric Cooperative (VEC) Rhode Island Corners substation. Nonetheless, this short-term solution still exposes the area to a number of long-term reliability and capacity needs: the potential for continued load growth, voltage constraints, high distributed solar penetration, and motor start limitations.

Initially, we planned to build a new substation. Instead, we conducted a Reliability Plan (filed under Docket No. 7873 in October 2016) to analyze the situation and identify a robust, cost-effective, long-term solution. The Plan concluded that we could initially address these issues with a non-transmission alternative (NTA). As such, we now plan to install a battery energy storage system (BESS) solution with deferred construction of a new Hinesburg substation jointly owned with VEC together with distance relay protections, distributed energy installations with reactive inverters, and energy efficiency measures.

The new Hinesburg substation would include a new 15/28-MVA, 34.5-kV-to-12.47-kV transformer with oil containment, high-side circuit breaker, associated fence, ground grid, communications and security, and two distribution circuits with circuit breakers and voltage regulators. A new one-mile, 34.5-kV subtransmission line extension of the existing Richmond to VEC Hinesburg substation 34.5-kV transmission line would supply the substation. This substation would increase the available capacity to serve existing and new load, allow for appropriate circuit protection, reduce losses, and provide feeder backup to the Charlotte substation, as well as provide backup for VEC area circuits and back up circuits originating at the North Ferrisburgh substation.

After acquiring property for siting, the current plan is to install the NTA solution in 2023.

Irasville Substation Upgrade

The Irasville substation is tapped off from a 37-mile-long line between Middlesex and Montpelier with inadequate remote line protection. To improve reliability, we plan to upgrade the substation. The upgrade comprises oil containment, 34.5-kV circuit breakers, relay protection upgrade, yard expansion associated fence, ground grid, and communications

Projected start date: 2021.

Johnson to Lowell (Line 133) Subtransmission Line Upgrade

We plan to upgrade the Johnson to Lowell (Line 133) subtransmission line to address aging infrastructure, and improve reliability.

Projected start date: 2020.

Lowell Substation Upgrade

The Lowell substation is aged and near the end of its useful life. As such, we plan to upgrade the substation to address aging infrastructure and to improve safety and reliability.

The current transformer, a 15/20-MVA, 46-kV-to-34.5-kV bank, is 43 years old. The existing 34.5-kV B-20 breaker is 1973 vintage of a style that has proven to fail without warning. The protection and control technologies are obsolete, utilizing electromechanical relaying.

Projected start date: 2021.

Maple Avenue Substation

This project will add two SCADA-controlled 2.7-MVAR capacitor banks at the Maple Avenue substation to provide voltage support during emergency contingency situations as well as during planned maintenance of the 46-kV network extending from Lafayette Street substation to National Grid Bellows Falls substation. This project will also address asset management issues with the Joy substation located approximately 2.0 miles away from the Maple Avenue substation. We will install a 46-kV breaker at Maple Avenue and retire the Joy substation.

Projected start date: 2019.

Maple Avenue to Charlestown (Line 102) Subtransmission Line Reconductoring

VELCO 2018 Long-Range Transmission Plan identified the Maple Avenue to Charlestown 46-kV path as potentially overloading under first contingencies at existing loads (that is, the loss of Lafayette Street to Maple Avenue), which violates our transmission line criteria. As such, we plan to reconductor the Maple Avenue to Charlestown subtransmission line to conform to our line criteria and, as a result, improve reliability.

Projected start date: 2021.

McNeil to Gorge (Line 3309) Subtransmission Line Reconductoring

After certain contingencies on the VELCO 155-kV system, a bulk system deficiency results in thermal overloads and low voltages on sections of the 34.5 subtransmission line (Line 3309) between the McNeil generating station and the Gorge substation. VELCO's 2015 Long-Range Transmission Plan originally identified this condition several years ago. To remedy this condition, we plan to reconductor this line.

Projected start date: 2021.

Mill Street Substation Upgrade

The 14-MVA, 46-kV-to-12.47-kV transformer, enclosed switchgear, and 12.47-kV distribution feeders at the Mill Street substation (in Bennington) is aging. Much of the substation, constructed in 1974, is close to the end of its useful life, and many replacement parts are unavailable. In addition, the control wiring, cabling, distribution panels, and groundings are deficient in meeting current safety codes.

To address these issues, we plan to install a new 15/28-MVA, 46-kV-to-12.47-kV unit, oil containment, and a high-side circuit breaker (to better protect the transformer); replace the enclosed switchgear with open-air bus work; and install new switches, breakers, relays, SCADA equipment, circuit regulators, batteries, station service, and a control building. We also plan to upgrade the 350-MCM-Cu underground getaways with 1,000 MCM Cu to enhance feeder backup capability and support distributed generation, and to install larger voltage regulators to increase the flexibility of circuit ties to the adjacent Lyons Street, South Bennington, Woodford Road, and Silk Road substations during planned outages and contingencies.

All told, the upgrade addresses aging infrastructure, improves system operation, corrects deficiencies, and improves safety and reliability.

Deferred project start date: 2024.

Newbury Distribution Substation Upgrade

The Newbury distribution substation needs to be upgraded to improve safety and reliability. We plan to install a new foundation for the transformer, a new 12.47-kV circuit breaker, and a security system, as well as replace the old porcelain insulators.

Projected start date: 2022.

North Brattleboro Substation Upgrade

The North Brattleboro substation contains a 14-MVA, 46-kV-to-12.47-kV transformer, 328-amp voltage regulators connected to the 12.47-kV bus by 750 MCM copper underground cable getaways; and two 12.47-kV distribution circuits each with 350 MCM copper underground cable getaways.

The 750 MCM copper underground cables, summer rated at 619 amps, do not fully utilize the capacity of the 14-MVA transformer; the 350 MCM copper underground cable getaways, summer rated at 384 amps, constrain the North Brattleboro substation's ability to backup area substation feeders.

To relieve these constraints, we plan to replace the current cables with 1,000 MCM copper cables, and upgrade the existing 328-amp voltage regulators to 437-amp regulators, which will allow for greater flexibility with circuit ties during planned outages and contingencies. Overall, the upgrades will improve reliability and increase the substation's transfer capacity.

Deferred project start date: 2023.

Pleasant Street Distribution Substation Upgrade

Aging equipment on the Pleasant Street distribution substation is being replaced with similar replacement parts to improve safety and reliability.

We plan to replace the three 12.5-kV vacuum circuit breakers. with new 12.5-kV ABB RMAG circuit breakers, raise the existing steel to accommodate the new 12.5-kV circuit breakers, and install steel adapters to mount the new 12.5-kV breakers on existing foundations. In addition, we plan to install new conduit and control cables, add cameras to the security system, install a new RTU, add line voltage transmitters to each distribution circuit, and replace the existing electromechanical protection with new microprocessor-based protective relays housed in a new outdoor relay cabinet.

Projected start date: 2021.

Putney Distribution Substation Conversion

Whenever feasible, we convert existing 2.4-kV, 4.16-kV, and 8.3-kV distribution circuits to our standard distribution system voltage of 12.47/7.2-kV grounded wye. Converting the Putney distribution substation is one of those projects. We plan to convert the Putney 69/8.32-kV substation to 69/12.47-kV.

Projected start date: 2020.

Richmond Substation

The primary reason for completing this project is to improve reliability. The upgrades to the substation would be comprised of adding two breakers, replacing an existing recloser with a breaker associated relaying and control house. This will improve reliability to customers served out of Richmond and Bolton.

Projected start date: 2021.

Sand Road to Richmond (Line 3334) Subtransmission Line Rebuild

Our analysis revealed system limitations when the Sand Road end of this line is open. Thus, we plan to rebuild the existing 34.5-kV line that was constructed in the 1930s to improve reliability.

Projected start date: 2022.

Websterville to VELCO Barre (Line 3306) Subtransmission Line Reconductoring

VELCO's 2015 Long-Range Transmission Plan identified the Websterville to VELCO Barre 34.5 kV subtransmission line as potentially overloading under first contingencies at existing loads (that is, at the VELCO Barre 115/34.5 kV source), which violates our transmission line criteria. Thus, we plan to reconductor the Websterville to VELCO Barre (Line 3306) subtransmission line to improve reliability.

Projected start date: 2021.

Wilder Distribution Substation Upgrade

Capacity limitations in the area served by the White River Junction and Wilder substations could overload the White River Junction substation and leave little remaining capacity for Wilder to address contingencies. Upgrading the Wilder substation would address these capacity issues and provide robust feeder backup between the substations.

As such, we plan to replace the existing 14-MVA, 46-kV-to-12.47-kV transformer with a new 15/28-MVA, 46-kV-to-12.47-kV transformer and install a high-side circuit breaker, oil containment, distribution circuit breakers, and feeder voltage regulation.

Deferred project start date: 2021.

D. Vegetation Management

We maintain comprehensive vegetation management plans for the long-term maintenance, reliability, and safety of our entire system. Toward that end, our crews install, service, and maintain 11,034 miles of subtransmission and distribution lines.

This appendix contains our Transmission Right-Of-Way Management Plan, our Distribution Integrated Vegetation Management Plan, and a short description of our emerging plans to combat the emerald ash borer, a highly invasive species already affecting portions of our service territory.

VEGETATION MANAGEMENT PROGRAM STATISTICS

Table D- shows the total miles trimmed for our subtransmission and distribution system, and the annualized trimming cycle. Note: subtransmission totals are reported as brush acres, not miles, as noted in section 3.611(a) of the 3.600 rule Maintenance of Electric Utility Rights of Ways.

Description	Total Miles	Trimming Cycle (years)
Subtransmission	973	5
Distribution	10,061	7

Table D-1. Subtransmission and Distribution Vegetation Management Statistics

Table shows the budget versus actuals for 2016 through 2018, the budget for 2019.and estimated budgets for 2020 and 2021.

Description	2016	2017	2018	2019	2020	2021
Miles needed trim*	1289	1436	1436	1436	1436	1436
Amount Budgeted	$11,602,692	$13,932,512	$12,724,610	$16,775,385	$17,788,674	$17,789,075
Amount Spent	$12,302,693	$14,075,768	$12,921,720	TBD	TBD	TBD
Miles Trimmed	D: 1,367 T: 1,142 (acres)	D: 1,644 T: 2,890 (acres)	D: 1,359+265(FY&CY) T: 3,313 (acres)	D:1,785 (target) T: 2,567 (target)	TBD	TBD

D = Distribution; T = Transmission

Table D-2. Vegetation Management Costs and Scope

*Does not include miles to be made up by end of 2019 to bring whole system to 7 year cycle per DPS agreement.

TRANSMISSION RIGHT-OF-WAY MANAGEMENT PLAN

Our plan discusses our philosophy for regularly handling the vagaries of nature, then describes the physical attributes of our transmission system. The plan then describes in detail our plan for managing our rights-of-way and how that plan is implemented.

We updated our plan in 2018 to include updated conditions, techniques, procedures, and our overall process.

DISTRIBUTION INTEGRATED VEGETATION MANAGEMENT PLAN

Our distribution IVM plan discusses our goals and objectives, details surrounding the types of vegetation and their growth rates, costs related to managing this growth, how we manage trimming and herbicidal application needs, and the fundamentals of operating this plan.

We also updated our IVM plan in 2018 as part of our continued commitment to maintain and operate a low-cost, effective vegetation management.

EMERALD ASH BORER MANAGEMENT PLAN

The emerald ash borer (EAB) might be an exotic beetle in its native Asia, where ash trees have co-evolved and developed inborn defenses. In North America, however, the beetle has become a monumental pest, killing hundreds of millions of ash trees since its discovery in southeastern Michigan near Detroit in the summer of 2002. It has been assumed that this invasive insect was transported to North American on wood packing materials carried by cargo ships or airplanes that originated in its native Asia.

The emerald ash borer was confirmed in Vermont less than a year ago, in February 2018. As of October 2018, emerald ash borers have been discovered in 34 states and five Canadian provinces. Its range continues to grow.

Vermont state officials have confirmed that the emerald ash borer has infested two main areas of our service territory, in the middle of the state and in the south, and is at high risk to infest surrounding areas of both sites.

Without close inspection of each tree, it's impossible to determine if a healthy looking ash tree has been infected by the emerald ash borer. Certainly, not all ash trees in our ROW will become infected, and of those infected, not all will eventually strike our conductors or pose immediate risk to the general public or our line crews. Nonetheless, our evaluations have determined it safer, more efficient, and more cost effective to remove all ash trees within our ROW, even those uninfected. All ash trees are susceptible to infestation. We are choosing to be proactive rather than reactive. We have determined that waiting for signs of infestation not only poses significant safety risks, but also doubles or even triples our removal costs.

As a result of our research and evaluations, we have developed a proposed EAB Mitigation Program for removing ash trees within both already-confirmed infestation areas and those at high risk. We are reviewing that plan with the Department at the time of this writing, and expect to implement it within the IRP planning period.

E. Substations

Green Mountain Power manages and operates 185 transmission, distribution, switching, and hydro substations. Out of that total, 11 are in a FEMA-designated 100-year floodplain, and two are in a FEMA-designated 500-year floodplain. As defined by FEMA, a 100-year floodplain is a geographic area with a 1.0% chance of flooding every 100 years; in other words, the potential to flood once every 100 years. A 500-year floodplain is a geographic area with a 0.2% chance of flooding every 500 years; in other words, the potential to flood once every 500 years.

CHANGES TO OUR SUBSTATIONS IN FLOODPLAINS

Over the past four years, we have conducted topographical surveys of our substations, including those in FEMA-designated floodplains. As a result, there are a number of changes from our list of substations in floodplain from our 2014 IRP:

- The Middlesex transmission station and hydro generation step-up (located at 7510 Vermont 100B, Moretown in Washington County) were both found to be located on ground higher than both the 100-year and 500-year floodplain. There is no history of flooding at either location.
- The Waterbury distribution substation was removed from its location in the 100-year floodplain (48 Winooski Street, Waterbury in Washington County), and rebuilt it on Cloverdale Lane, Waterbury in a location outside of the floodplain.
- The Barre South End distribution substation (located at 121 South Main Street, Barre City in Washington County) has been raised three feet (from 616 feet to 619 feet) at its current location so that it resides above the 100-year floodplain. There is no history of flooding at this substation.

- The Vernon equipment (located at 152 Governor Hunt Road, Vernon in Windham County) is actually a pole-mounted recloser that, while in the 500-year floodplain, is above a potential high-water mark. There is no history of flooding of this equipment.
- The East Jamaica distribution substation (located at 2069 Route 30, Jamaica in Windham County), while in the 500-year floodplain, was found to be four feet above a potential high-water mark, so it no longer resides in the floodplain.
- Our topographic survey uncovered three additional substations in a FEMA-designated floodplain: Taftsville transmission and hydro substation, Brownsville distribution substation, and Glen hydro substation.

SUBSTATIONS IN FEMA-DESIGNATED FLOODPLAINS

Table E-1 provides an overview of the substations in either a 100-year or 500-year FEMA designated floodplain.

Substation	Address	County	Floodplain Designation
Brownsville	Churchill Road at Route 44, West Windsor	Windsor	100-year
Dover	37 Kingswood Road, Dover	Windham	100-year
Fair Haven	33 Cottage Street, Fair Haven	Rutland	100-year
Georgia Pacific	0 Riverside Drive, Brattleboro	Windham	100-year
Glen	Route 7, Rutland Town	Rutland	100-year
Riverside	6 Chester Road, Springfield	Windsor	100-year
Riverton	2074 Route 12, Berlin	Washington	500-year
Rochester	237 Peavine Drive, Rochester	Windsor	100-year
Taftsville	Taftsville Covered Bridge Road, Woodstock	Windsor	100-year
Vernon Road	567 Vernon Street, Brattleboro	Windham	100-year
Windsor	26 River Street, Windsor	Windsor	100-year
Winooski	250 West Allen Street, Winooski	Chittenden	100-year
Woodstock	0 Maxham Meadow Way, Woodstock	Windsor	500-year

Table E-1. Substations in FEMA-Designated Floodplains

There is no history of flooding at the Dover, Fair Haven, Riverside, Riverton, Windsor, Winooski, or Woodstock substations. The Brownsville (partially), Glen, Rochester, and Taftsville substations all flooded during Tropical Storm Irene in 2011. Brownsville and Glen also experienced some erosion. Taftsville was subsequently repaired; Rochester was rebuilt with elevated control systems.