2021

Integrated Resource Plan

GREEN MOUNTAIN POWER

Generating Possibilities Together

Message from Our CEO

December 10, 2021

To the Vermont Public Utility Commission:

We are pleased to file our 2021 Integrated Resource Plan (IRP). This plan represents our roadmap to proactively address climate change, increase reliability and resiliency through innovation, and provide our customers with cost effective carbon-free, renewable power.

As you will see outlined in the IRP, we are transforming the greater grid to one that is a two-way energy sharing system, generating more renewable power closer to where we all use it, all connected to what we will use it for – powering our homes and businesses, keeping our buildings warm, and providing electricity for our vehicles. The programs you will see outlined in this IRP empower our customers and cut carbon and costs for all, ensuring everyone is part of this transformation.

Never before has the team at GMP been more motivated to serve Vermonters - our customers - with a much more resilient and equitable energy delivery system, enabling decarbonization in all aspects of their lives. This work is imperative and requires that we evolve quicker than we ever have before. The climate challenges and catastrophes experienced across the country are heartbreaking and motivate us to move even faster as we radically transform the greater grid here in Vermont and deliver something much more resilient and dynamic. Together with our customers, Vermont energy companies, policymakers, and regulators, we continue to be at the forefront of energy transformation nationally, and that's because we have the best minds and hearts right here in this little brave state to get this done.

Thank you for your thoughtful consideration. We look forward to your feedback and suggestions on this IRP, and how we can best serve our customers now and into the future.

Sincerely,

Mari McClure, President & CEO
Green Mountain Power

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Executive Summary

The Energy Future We Embrace with Customers

Our focus on customers guides all our decisions, so that every action we take benefits 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 by creating a closer and connected energy system that empowers customers and strengthens the greater grid. All of these changes ensure we meet the challenge of climate change in an equitable way.

For decades, IRPs had one central theme: how will we meet growing demand with the least cost supply. Beginning with our 2018 IRP – and even more so in this IRP – you will see the lines between supply and demand blurring. The transition to this closer and connected clean energy system requires new thinking, new tools, new customer programs and much more. Throughout this IRP you will see the focus on new grid technology, mapping tools, and control platforms that are bringing this all together.

We are investing in a two-way energy delivery system that is transformational in the following ways:

- **Closer**: Generate energy close to where it's used. That means more local and regional clean energy like wind, solar, and hydro. GMP's power supply is 100% carbon free and 68% renewable now and will be 100% renewable by 2030.

- **Connected**: Everything is integrated and coordinated to drive down costs and carbon. This includes supporting innovative programs for customers such as managed storage and electric vehicle charging, strengthening the greater grid through innovative protection schemes and undergrounding, and establishing microgrids and community resiliency zones.

- **Empowered**: Providing customer options with the latest in innovations to promote equity while also cutting carbon and costs. This means making it easy for customers to choose from a diverse portfolio of innovative products and services, supporting their use and goals around renewable energy, and helping customers meet their own energy needs and their community's needs, while keeping costs lower for everyone.

Our 2021 IRP demonstrates our commitment and plan to provide reliable, cost-effective, equitable — and increasingly distributed — 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-damaging carbon pollution 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. Ensuring this transition happens rapidly and smoothly, and in a way Vermonters can afford, is paramount. And as we make this important transition away from fossil fuels, the strength and resiliency of the electric delivery system becomes even more important.

About Green Mountain Power

We are accelerating the transformation in energy by strengthening the greater grid which is the backbone servicing all our customers, as we empower them to cut carbon and costs, and improve their lives. Our strategy is to work with our customers to save money by managing the grid with a network of renewable generation, controlled devices, deployed storage technologies, and customer-focused market solutions that help accelerate adoption and thereby facilitate other energy market players. We are building a resilient two-way power grid — moving electricity and data to dynamically 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 affordability, a significant focus and concern that we proactively address by managing costs within our control to helping mitigate these risks for our customers. We focus on how to deploy technologies to manage renewable resources and load, while accelerating market solutions that can do the same thing around us so that, over time, we help control and lower our customers' share of cost for the broader regional grid.

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 transforming to a closer and connected energy system that empowers customers.

We have a strong culture that puts the customer and the center of all our work. 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. We were recertified in 2017 and 2021.

Service Territory and Resources

Our service territory spans 7,500 square miles, serves almost 269,000 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 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 42 hydroelectric units, two wind plants, six oil-fired peaking plants (with one actively being retired), and 13 solar power facilities (5 of which are paired with storage), in addition to plants we co-own as described in Chapter 6.

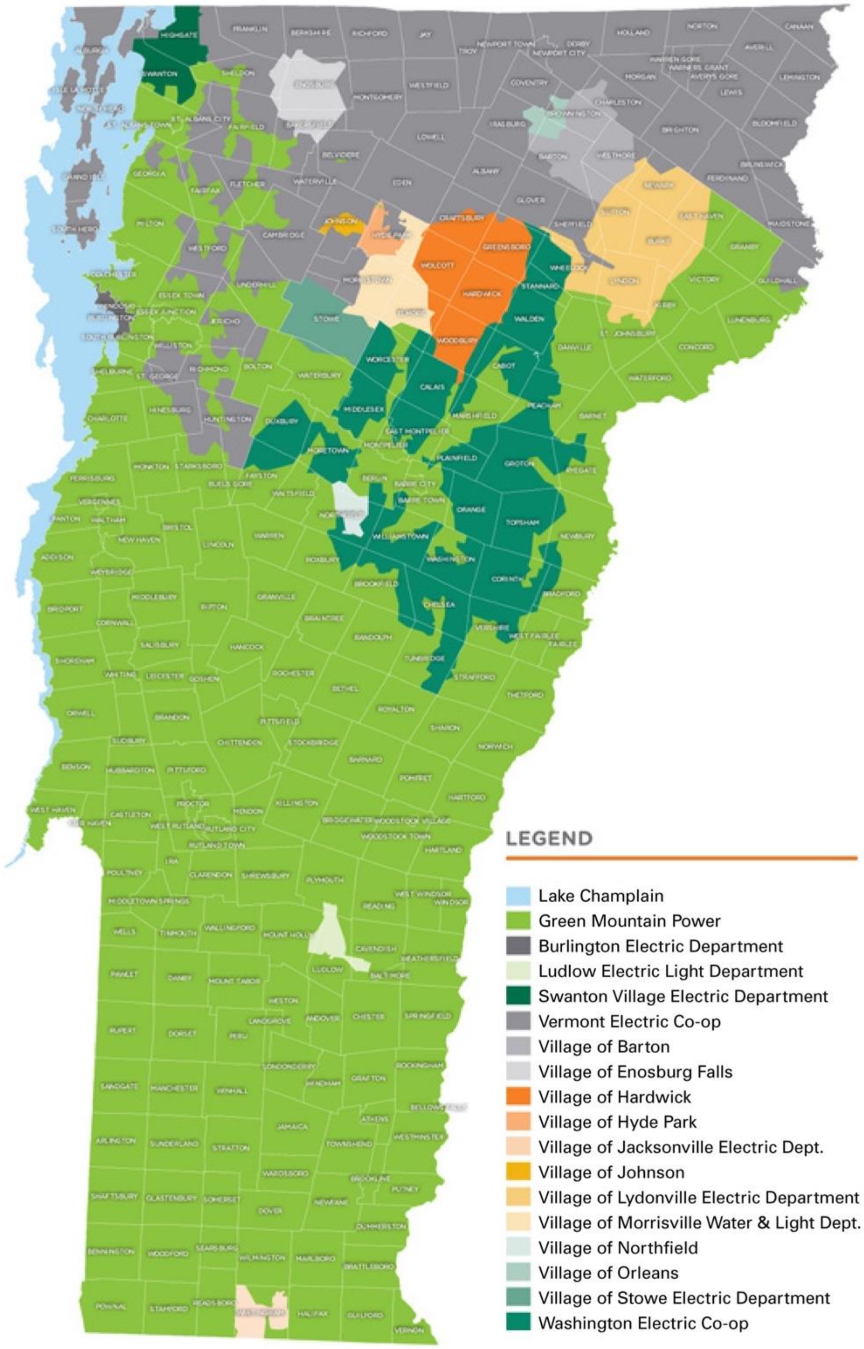
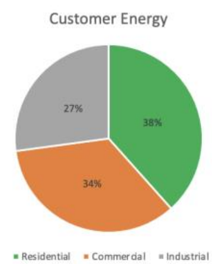


Figure 1-1. Service Territories of Vermont Electric Utilities

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.



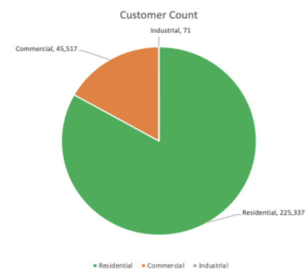


Figure 1-2. Customer Count and Energy Comparison

We are proud to have rates that are low when compared to investor-owned utilities in New England.

Figure 1-3 compares the 2020 retail rates of Green Mountain Power with the independently owned electric utilities in the five other New England states. Maine Public Service and Bangor Hydro-Electric are both part of Versant but report as two territories. Note that this rate comparison does not account for rate structure differences for power costs, and the volatility of power costs experienced by customers in some other utility territories in New England where a standard or default power supply offering is in effect, such as the more than 80% increase in that portion of rates filed in Fall 2021 for Maine utilities. GMP power costs are included in rates, subject to quarterly adjustments.

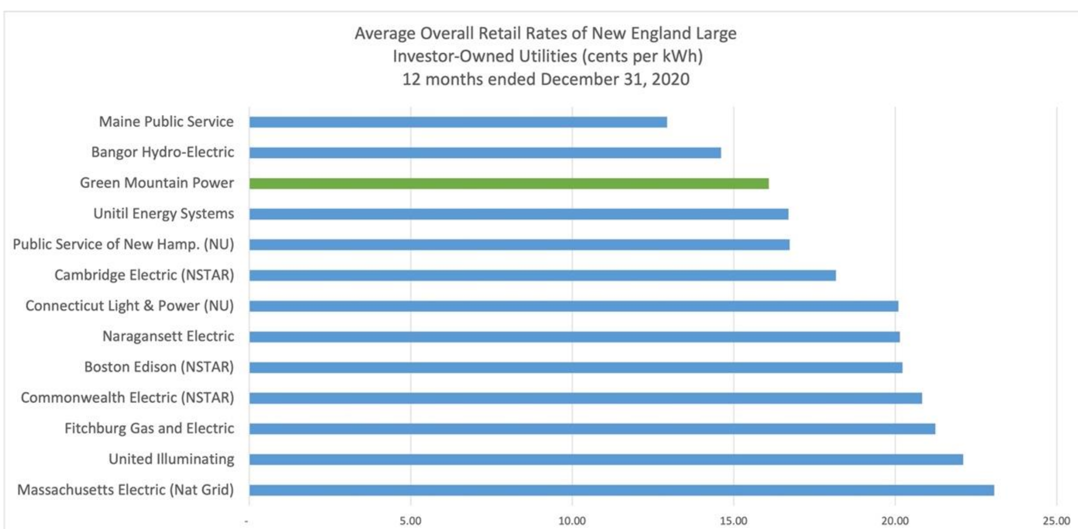


Figure 1-3. Retail Rates of Investor Electric Utilities In New England: 2020

Load and Transmission & Distribution System Summary

Load Forecast

After years of declining load, we now project to see load growth through electrification to cut carbon in Vermont. As described in Chapter 2, our 20-year projection shows meaningful growth, with the acceleration of electrification, in all but the low sales scenario.

	Annual Retail Sales (MWh)		
Fiscal Year	**Low**	**Base**	**High**
2022	4,066,066	4,077,087	4,077,087
2023	4,092,797	4,113,820	4,113,820
2024	4,109,758	4,148,307	4,148,307
2025	4,125,415	4,196,441	4,196,441
2026	4,145,376	4,262,844	4,262,844
2027	3,779,495	3,953,244	3,953,244
2028	3,813,777	4,045,603	4,048,498
2029	3,857,904	4,154,851	4,172,188
2030	3,907,456	4,269,185	4,308,134
2031	3,962,649	4,386,047	4,450,690
2032	4,025,674	4,505,954	4,600,597
2033	4,093,313	4,621,770	4,743,481
2034	4,164,489	4,737,862	4,883,858
2035	4,237,047	4,842,459	5,012,273
2036	4,308,998	4,930,276	5,124,695
2037	4,373,994	4,999,715	5,220,266
2038	4,430,872	5,055,189	5,303,887
2039	4,478,583	5,100,074	5,379,321
2040	4,516,117	5,136,128	5,448,663
2041	4,546,847	5,168,708	5,517,602

Table 1-1. Forecasted Retail Sales

T&D System Summary

GMP transports and delivers energy through a backbone of 1,011 miles of subtransmission lines. The predominant voltages for the subtransmission system are 34.5 kV, 46 kV, and 69 kV. The subtransmission system connects to both generation and distribution substations. The 140 distribution substations supply close to 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.

We are constantly monitoring and evaluating how the T&D system delivers reliable service to our customers and are continuously interconnecting new resources, be it new load such as a commercial building, or new generation such as a solar facility to this system. As of the end of 2021, we have interconnected over 15,480 generation resources to the GMP T&D system and have done so without causing reliability or stability issues to customers served by that system, which is a testament to the interconnection policies and procedures in place. Through our operations technology we can monitor real time telemetry of larger generation systems along with most all our circuits and substations.

This system is being used more than ever and is no longer delivering energy through the traditional one-way flow. Energy can flow in all directions and can fluctuate greatly depending on the weather with the intermittent production of solar energy being a key factor on these rapid changes in how energy is flowing. It is because of this that we have had to develop new programs utilizing new energy resources such as distributed storage, electric vehicles and more to manage this fluctuating system. You will see throughout this IRP that we are able leverage significant amounts of data to provide us with a resolution into our circuits that we have never had in the past. Chapter 3 of this IRP discusses in greater detail how we are leveraging data to optimize the T&D system.

2021 Integrated Resource Planning Requirements and Framework

This distributed energy future requires an 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 2021 IRP meets not only the statutory requirements, but also the needs of our customers now and in the future. This IRP, like all prior efforts, will be reviewed for approval by the Vermont Public Utility Commission (Commission), working with the Department of Public Service (Department).

The larger purpose of our 2021 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 created our 2021 IRP to meet Vermont's IRP statutory requirements along with Vermont's carbon reduction mandates and energy goals and have also developed this IRP to fulfill all commitments made in the 2018 IRP review. The following sections detail these goals and requirements.

Greenhouse Gas Reduction Requirements and the Global Warming Solutions Act (GWSA)

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. GWSA Requirements. The recently enacted Global Warming Solutions Act (GWSA), 10 V.S.A. § 592 recognizes the serious threat climate change poses to our environment, economy, and way of life, and requires Vermont to achieve the following reductions in Greenhouse Gases (GHGs):

- 26% reduction from 2005 levels by 2025
- 40% reduction from 1990 levels by 2030

1 30 V.S.A. § 202a.

2 30 V.S.A. § 218c.

- 80% reduction from 1990 levels by 2050

The GWSA established the Vermont Climate Council and required the Council to issue an initial Climate Action Plan by December 1, 2021.[3] That Plan sets forth pathways, strategies, and actions to reduce emissions to achieve the GWSA's requirements, as well as to build community resiliency and strengthen adaptation to the changed environment we are already experiencing. The initial Climate Action Plan recognizes that more than 75% of Vermont's GHG emissions come from transportation and how we heat our buildings, with less than 6% of Vermont's GHG emissions coming from the electricity sector. The initial Climate Action Plan broadly supports using clean electricity to help reduce Vermont's emissions through increased EVs and heat pumps, as well as steps to strengthen the electric grid and upgrade service and efficiency measures for individual customer's homes and businesses to support greater electrification. The initial Climate Action Plan supports moving Vermont to a 100% carbon-free or renewable electricity portfolio in the years ahead.[4]

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.[5] Meeting RES requirements will not only increase renewable generation in the state, but also reduce GHG emissions by approximately 15 million tons by 2032, supporting the state's emissions reduction goals, even while some distribution utilities, including Green Mountain Power, have established plans to go beyond these requirements. The initial Climate Action Plan and the Comprehensive Energy Plan (described further below) both recommend moving toward a 100% renewable or carbon free framework for the RES in the years ahead.

Here are the current RES 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 sub transmission 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.

[3] https://climatechange.vermont.gov/wherearewegoing

[4] https://climatechange.vermont.gov/sites/climatecouncilsandbox/files/2021-12/Initial%20Climate%20Action%20Plan%20-%20Final%20-%2012-1-21.pdf, Page 103.

[5] 30 V.S.A. § 8002–8005.

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 are equivalent to 1 MWh renewable generation required to be actually delivered within the New England region. Both utilities and generators can buy and sell RECs on an open market in the region.

Table 1-2 lists the Tier I, Tier II, and Tier III retail sales requirements over the course of the RES timeframe through 2032.

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 1-2. 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.

Standard Offer and Net Metering Programs

The Standard Offer program, 30 V.S.A. § 8005a, originally established in 2009, continues to promote an 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; after the next auction in 2022, that amount will likely have been awarded though further work may be needed to ensure that level of renewable energy is deployed. 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. Net Metering up to 500 kW, both directly connected to customer load and through virtual groups, is also supported by Vermont's renewable energy statutory provisions in 30 V.S.A. § 8010; the Commission has conducted ongoing proceedings to review the overall costs, interconnection rules, and other requirements of the program. As described in Chapters 6 and 7 below, ensuring that we use well-designed procurement programs to enable more local renewables, more cost-effectively, for more Vermonters will be a significant focus in the years ahead.

Vermont's Comprehensive Energy Plan

The Department has just published an updated Draft 2022 CEP[6] and is seeking comments at the time of this IRP submission. The Draft 2022 CEP re-establishes and furthers Vermont's high-level goal to meet 25% of energy needs statewide from renewable sources by 2025, 45% by 2035, and 90% by 2050. The Draft 2022 CEP aligns with the GWSA requirements and endorses the Department's detailed guidance for state electric utilities to develop their individual IRPs.

Draft 2022 CEP Consistency with the GWSA

The Draft 2022 CEP integrates with the GWSA and calls for meeting 100% of the electricity sector needs from carbon-free resources by 2032, with at least 75% from renewable energy, consistent with Vermont's RES. The Draft 2022 CEP centers equity in its recommendations, organized around two key themes: equitable solutions to meet Vermonters' energy needs and grid evolution. The Draft 2022 CEP recognizes that "Vermont's electric sector will play a critical role in decarbonizing the transportation and thermal sectors, increasing the importance of affordable electric rates and an electric system that is reliable and resilient for all Vermonters."[7]

Department IRP Development Guidance

The Draft 2022 CEP maintains and endorses the Department's prior guidance published in 2016 for utility IRPs, recommending 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.[8] The Draft 2022 CEP specifically calls out the need to focus IRPs on grid modernization, as set forth in Section 4.6 of the guidance.[9] Utilities are asked to organize IRPs around load growth forecasts, providing an assessment of resources to meet that demand, transmission and distribution needs, future electric portfolio planning, financial assessment, and short-term and longer-term action steps arising out of the insights gained by the IRP.

How the 2021 IRP Reflects Commitments Made in the 2018 IRP Proceeding

In addition to the methodological and process improvements adopted in the GMP 2018 IRP based upon agreement with the Department,[10] all of which continue in this 2021 IRP, GMP committed to addressing additional issues and new or emerging practices in this IRP, including:

Portfolio Analysis. GMP engaged with the Department with respect to the appropriate quantitative methods to evaluate multiple competing electricity supply portfolios, and our identification of our preferred resource supply portfolio.

Grid modernization/distribution system planning. GMP engaged with the Department and other stakeholders on the topic of distribution system planning and grid modernization, including through our

6 https://publicservice.vermont.gov/content/2022-plan

7 Draft 2022 CEP, Page ES-10.

8 https://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/State_Plans/Comp_Energy_Plan/2015/Appendix%20B.pdf

9 Draft 2022 CEP, Page 4-14.

10 See 2018 GMP IRP, Page 1-11, https://greenmountainpower.com/wp-content/uploads/2019/12/2018-Integrated-Resource-Plan.pdf and Docket 8397 March 11, 2015 MOU paragraph 14.

Resiliency Zone work discussed in Chapter 3 and our Climate Plan, reviewed and approved by the Commission in 2019-20. GMP also collaborated further with the Department and other distribution utilities on how to value locational impacts of distributed energy resources, in for example the Sheffield-Highgate Interface Exchange proceedings at the Commission, discussed in Chapter 3 and Appendix D. GMP also incorporated into this IRP its continuing work on specific analyses such as the impacts of electric vehicle penetration and electrification of heating on the distribution system.[11]

Rate design. GMP participated in the Department's Rate Design Initiative[12] and reports on and analyzes how rate design may continue to evolve to support customers, innovation, and electrification in this IRP.

Market-based mechanisms. GMP consulted and collaborated with the Department on our innovative offerings, our Resiliency Zone work, and our tariff work for energy storage systems, including how to inform our system needs and to collect data and set up programs to work with energy services companies to aid the selection of preferred least-cost solutions that allow for a fuller consideration of wires and non-wires solutions at the distribution-system level.

Manufacturing and commercial customers. As required by the Commission's 2018 IRP Order approving the Memorandum of Understanding entered into between GMP and GlobalFoundries, this IRP includes in both Chapter 2 regarding customer programs and in a separate appendix discussion that gives due consideration to how the strategies in the IRP are designed to provide electric service while meeting the State energy policy articulated in 30 V.S.A. § 218e.

When planning and drafting this IRP, GMP met several times with the Department on individual subjects and chapters of the IRP, as both GMP and the Department promised to do during the 2018 IRP proceeding. We provided the Department with a draft of our IRP one month prior to filing it with the Commission and held a meeting to discuss the Department's feedback which we then incorporated where possible into our submission.

Maximizing Public Information and Input for the 2021 IRP

Throughout 2021, we held 3 public meetings for customers and others with interest, conducting the meetings through Facebook Live and publicizing them through press releases, regarding the IRP process and ongoing work, as required by the Commission's Order approving the 2018 IRP.[13]

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11 Specifically, the 2018 IRP Order requires GMP to provide "[a]n analysis of distribution-level impacts of electrification of transportation and heating (based on observed spatial patterns of such deployment and/or a proxy such as the historical deployment distribution of net-metering, batteries, etc.) and an assessment of strategies to manage these new loads to minimize integration challenges and costs. GMP may utilize a sample set of circuits that represent a cross section of the system to inform its assumptions regarding future distribution of EVs and electric heating." Case 18-4166-PET Order of Sept. 9, 2019, page 11, paragraph 17b.

12 https://publicservice.vermont.gov/content/rate-design-initiative

13 Case 18-4166-PET Order of Sept. 9, 2019 at page 16.

Summary of Findings

We describe in the individual chapters of the 2021 IRP the plans we have for innovative services, the transmission & distribution system, distributed energy resource management, and power resource acquisitions to support our goals of a clean, distributed energy system.

Customer Program Innovations and Electrification

Customers are always at the front of every decision made at GMP. This IRP discusses how we engage with customers across many platforms and in many ways to make the work we do accessible. From social media to energy statements, to mobile apps, to in person meetings, we meet people where they are and how they want to access information. Strategic electrification through addressing the top sources of climate pollution in Vermont – transportation and heating – is a big focus to help customers cut carbon and costs.

The Future T&D System and Our Climate Plan System Hardening

This IRP integrates our Climate Plan, approved by the Commission in 2020, and the theme throughout the IRP is a focus on strengthening the greater grid as we create an energy system that is more resilient to the challenges of extreme weather brought about by climate change. Continued use of operations technology and grid hardening techniques, plus greater use of undergrounding innovations can deliver enhanced reliability and resiliency. Meanwhile, we need a flexible, responsive, two-way grid that supports strategically electrifying transportation and heating to address the top sources of carbon pollution in Vermont. Integration and connection are key; with cost-effective renewable energy, energy storage and other managed resources, we have ways to choreograph the distributed grid.

Portfolio Evaluation

A key component of any IRP is an analysis of a "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 7, we analyze these 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, recognizing that costs, the pace of deployment, technology and other changes in the years ahead will guide our decisions.

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 2021 IRP.

Functional Area	Activity
System Resiliency and Grid Transformation	Develop and deploy an integrated suite of customer offerings that drive carbon out of our total energy consumption, reduce costs for all customer, and improve the greater grid. ♦ Develop and deploy the overarching DERMS platform that acts as the choreographing tool for all DER's across the grid. This can also be done in partnership with all VT DU's, VELCO, etc. ♦ Extend and expand Tariffed offerings for battery storage in homes and businesses improving both customer reliability as well as greater system resiliency and distributed management ♦ Develop a minimum of 6 resiliency zones utilizing a combination of technology, DER's, storage and other resources to drastically improve reliability and prepare areas for greater electrification, such as transportation ♦ Deploy significant EV fast charging supply equipment in more challenging to reach areas not covered by various State programs
Generation (Distributed and Larger)	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. ♦ Relicensing in process or will be withing next three years on nine GMP hydro plants as well as two non-FERC sites currently in the 401 Water Quality Certification process ♦ Explore/Develop the next phase of Searsburg including potential repowering of the existing site ♦ Continue updating tools, maps and interconnection guidelines for distributed generation and storage resources to assure least cost, efficient interconnection processes exist while assuring system stability, reliability and safety. ♦ Plan for the retirement of the remaining GMP fossil-fuel peaking sites and evaluate the suitability of these locations for new peaking storage resources. Evaluate pairing energy storage with existing renewable facilities or construct new storage-paired systems directly or through other procurement methods.
Transmission & Distribution Innovation	Plan the energy delivery system to create a closer, connected, and empowered system that prepares for harsher storm conditions. ♦ Underground 40 miles of exposed distribution line ♦ Install 300 miles of covered wire replacing bare wire ♦ Deploy 4 additional automatic fault recovery transfer systems on the distribution system
Information Technology	♦ Continue strong focus on cybersecurity and evolving best practices including use of cloud platforms where appropriate and enhanced testing and monitoring of IT/OT systems. ♦ Consider seeking approval for enhanced investments through a cybersecurity resiliency plan, consistent with our pending regulation plan petition.
Regional Market Participation	Actively engage in regional stakeholder forums to advance ideas and programs to accelerate regional action to reduce fossil fuel dependence. ♦ Closely monitoring the methods and framework being discussed in our region to implement FERC Order 2222. ♦ Participate and follow regional efforts to adapt the capacity and energy markets to more directly support a transition to zero and low, carbon resources.

Functional Area	Activity
Power Supply	Maintain a cost-effective, zero-emission annually supply portfolio that incorporates a large share of long-term distributed renewable resources, a growing share of local renewable resources, and the flexibility needed to address changes in the evolving regional energy market. ♦ Explore regional wind purchase opportunities including participation in upcoming offshore wind developments ♦ Work with Vermont stakeholders to explore potential refinements to RES and net metering that would support an electricity supply that is increasingly renewable and financially sustainable for all customers ♦ Work on methods to support the procurement of increasing renewable supplies, including ways to geographically guide Vermont supplies (to limit grid upgrade costs) ♦ Continue to modify short-term procurement programs to further reduce dependence on fossil-fuel resources and better align customer usage with renewable supply. ♦ Innovate new procurement plans for local renewable generation outside of the net metering program to improve opportunities for direct, equitable, cost-effective customer participation.
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

IRP Chapters

Following this Executive Summary, we break down the information and planning covered by the 2021 IRP in the following chapters:

Chapter 1. Innovating for Customers demonstrates how we continue to empower our customers with several innovative energy programs, the multiple ways we communicate with our customers and meet them where they are, and our commitment to delivering excellent service. The chapter also covers how we use rate offerings to help deliver innovation programs to customers and how rate design can support electrification.

Chapter 2. Demand and Distributed Energy Forecast evaluates the way customer usage is expected to evolve in the coming years, with both increasing demand from heat pumps, EV charging, and other electrification strategies, as well as continued focus on energy efficiency. We evaluate the level of electrification that is needed to meet Vermont's GHG emissions reduction goals.

Chapter 3. System Resiliency and Grid Transformation evaluates our T&D system, discusses our innovative system management practices, discusses the role of managed energy storage in our portfolio now and the future, and outlines our grid modernization strategies.

Chapter 4. Technology and Security reviews our information technology and operations technology (IT/OT) systems and describes the strategies we rely upon to maintain safety and security in all we do.

We also describe the importance of regulatory and financial support for IT/OT investments as our energy services for customers evolve and sour systems become even more integrated, complex, and connected to our customers.

Chapter 5. Regional Market discusses regional supply, demand, and transmission developments; regional environmental policies and energy markets; regional energy and capacity resources; and how the regional system and market affect customer cost and our resource portfolio.

Chapter 6 Our Increasing Renewable Power Supply presents specifics on our generation assets and our increasingly carbon-free, renewable portfolio.

Chapter 7. Portfolio Evaluation describes the methods we used to model and analyze options to develop a preferred supply portfolio, the results and conclusions of our analysis, along with our expected portfolio preferences in the planning period.

Chapter 8 Financial Overview provides information on our overall costs, our financial forecasts, and how we diligently maintain strong finances to support customers.

Chapter 9 Action Plan describes the specific short-term and longer-term action steps for implementing our IRP that considers demand, supply, T&D maintenance and modernization, and innovative energy services for customers.

IRP Appendices

Included are several appendices that support our 2021 IRP:

Appendix A is the complete FY2022 budget forecast from Itron. The forecast includes monthly customer, sales, and revenue projections through 2041.

Appendix B reflects the S&P Global statement raising the issuer credit rating on GMP to 'A' from 'A-.'

Appendix C includes GMP's capital planning framework, last updated in September 2021. The planning framework is divided up to show the following discreet areas: information technology; property and structures/facilities; transportation and fleet; innovation pilots and new initiatives; generation; and transmission and distribution lines/substations.

Appendix D includes a summary of the recent planning studies done to determine the feasibility, necessity, costs, and benefits of certain transmission and distribution projects.

Appendix E provides an overview of the comprehensive vegetation management plans for the long-term maintenance, reliability, and safety of our entire system.

Appendix F is a copy of the current Integrated Vegetation Management Plan for the distribution system, last updated in 2018.

Appendix G is a copy of the current Transmission Right-Of Way Vegetation Management Plan, last revised in 2018.

Appendix H provides a review of how our programs support manufacturing and other businesses in Vermont, consistent with the provisions outlined in 30 V.S.A. § 218e.

Appendix I includes information about the substations managed and operated by GMP, including a table of those in FEMA-designated floodplains.

Appendix J is a complete list of the GMP-owned hydroelectric facilities.

Appendix K is the glossary of terms and acronyms used throughout the IRP.

1. Innovating for Customers

We deliver for our customers

We are partnering with customers to transform the energy system to one that has more renewable generation closer to where power is used, one that keeps communities connected through the severe effects of storms due to climate change, and one that empowers customers to reduce costs and carbon emissions through innovation. Our focus is on customers as we create a more flexible, reliable, renewable, resilient, and cost-effective grid while accelerating rapid strategic electrification to fight climate change.

We connect with customers through many pathways, so they can access information in the way that works best for them, whether by using our website or mobile app, text alerts, chat, social media, public meetings, or speaking to one of our knowledgeable customer service representatives.

We continue to be recognized for our customer-focused approach and cutting-edge innovative initiatives. In 2021, the Smart Electric Power Alliance (SEPA) named GMP Grid Integration Power Player of the Year, which recognizes organizations that "have demonstrated unique innovation and leadership in efforts to integrate clean energy and distributed energy resources (DERs) into the grid to help achieve carbon reduction and clean energy goals and meet the needs of their electricity consumers."

We were also named to SEPA's top 10 utility transformation leaderboard alongside utilities like Austin Energy and Seattle City Light. SEPA CEO Julia Hamm said, "Green Mountain Power stands out due to its comprehensive efforts to transition to a carbon-free energy future, and most importantly its results […] We applaud GMP for its progress and recognize that much work remains."

We were named to Fast Company Magazine's top 10 list of most innovative energy companies in 2019 and 2020. The award highlighted GMP's pioneering work in deploying battery storage in customer homes to better manage the grid and provide backup power. In 2021 GMP was featured in TIME Magazine as a leader in the country for how we are getting ahead of climate change and leveraging innovations to provide more resiliency for our customers.

Approach to Innovation Development

Our approach to innovation is an extension of our focus on customers and is at the core of our culture and organization. Our innovative programs empower customers to reduce carbon emissions by switching away from fossil fuel and this is vital as Vermont experiences the impacts of climate change in greater severity every year. We are very excited to have exceeded our goal of providing 100% carbon-free electricity by 2025, four years early. And we're rapidly moving to reach our goal of having a 100% renewable electricity supply by 2030. Electricity accounts for less than 2% of total statewide emissions, whereas transportation and heating account for 74%. Switching from fossil fuels to electricity in these sectors is widely acknowledged to be the most effective way to help Vermont reach clean energy goals and fight climate change. Our programs ensure that this electrification happens as quickly as possible through our Tier III incentives, strategically through our load management and rate design programs, equitably through partnerships and enhanced rebates for certain customer groups, and through education such as our public EV events. We leverage smart technology and innovative compensation models to manage load, reduce costs for customers, and encourage the deployment of more renewable generating resources by aligning load with renewable generation.

We are fortunate to partner with so many likeminded energy leaders in Vermont, from local energy committees to state policymakers to clean energy developers to startups on the cutting edge of innovation. Together we can achieve Vermont's aggressive climate goals. There is no other option.

In this chapter, we first outline our core customer service ethic, including customer satisfaction and service quality reporting. We then cover existing innovative programs with a focus on strategic electrification and battery storage, followed by Tier III offerings and partnerships with other distribution and energy efficiency utilities. Finally, we discuss how we communicate with our customers and upcoming developments in continuing to expand access to GMP services.

We Are Here to Serve Customers

At Green Mountain Power, customers are the focus of all we do, and we are always working to enhance customer service. From answering calls to innovative technologies and services, from reliability to incentives to reduce greenhouse gases, we are consumed with thinking about what's best for our customers. At our core is the belief that success – indeed, Vermont's success – is predicated on delivering an uncommon level of service quality and innovative services to our customers.

GMP has been providing exemplary levels of customer service for years and will continue to use a wide array of performance measures to challenge ourselves to maintain and improve those results for our customers. Each interaction with a customer provides a new opportunity to do so. And the empathy we bring to our customer interactions became even more critically important as our customers and state faced the health and financial impacts of the COVID-19 pandemic.

GMP is no longer a traditional utility and is an energy transformation company, with customer service as a cornerstone. As part of that, GMP was the first utility in the world to receive B Corp certification, meeting rigorous social, environmental, accountability and transparency standards, and committing to use business as a force for good.

Service Quality and Reliability Performance

Since 2014, when we developed new performance standards in the Service Quality and Reliability Performance, Monitoring, and Reporting Plan (SQRP), in collaboration with the DPS and approved by the Public Utilities Commission, we have used these benchmarks to consistently seek improvements.

The SQRP incorporates state standards for key service measures, from call answering and meter reading to billing, reliability, safety, on-time performance, and customer satisfaction. Each category is tracked through specific performance metrics, with results reported quarterly and annually to the DPS and PUC. GMP's focus on customers' needs and continuous improvement has ensured exceptional results under the SQRP.

Exceeding Customer Service Standards

The SQRP standards are base levels approved by the PUC, but to challenge ourselves, we strive to surpass them to the greatest extent feasible. We set internal customer service targets that in many cases are more difficult to reach than the SQRP measures, and we review them regularly.

Since the start of 2015, for example, when we began a data-driven effort to improve front-line customer service, GMP has beaten the SQRP standards for call answering within 20 seconds and abandonment every single month – a string now approaching 84 straight months.

The SQRP standards are to answer 75 percent of business calls between 7 a.m. and 7 p.m., Monday through Friday excluding holidays, within 20 seconds, with abandonment of 3 percent or less. Our internal stretch goal is to answer at least 83 percent of calls within 20 seconds, with abandonment of 2 percent or less. We have consistently met or exceeded these goals since implementing tighter internal goals. In late 2021, the implementation of the VCAAP and VERAP programs to help customers affected financially by the pandemic created a significant call volume, and that coupled with the loss of our in-State overflow call center caused our abandoned rate to minimally exceed 3% for the month of October. This was back on track for the month of November.

Similarly, the state standard for answering outage calls is 85 percent, a goal designed to ensure we provide adequate service levels even when there are extremely high call volumes during major storm events. A decade or more ago, we sometimes struggled to reach such levels, but today we surpass these goals with ease thanks to constant focus and adjustment of resources. Our internal stretch goal is 94 percent, a level we have routinely achieved in recent years. From January 1, 2015, to Dec. 31, 2020, we received nearly a million outage calls, and answered 96.8 percent, beating the state target by more than 11 percentage points, and the stretch goal by 2.8 percentage points.

High Customer Satisfaction

GMP continuously surveys customers about everything from how quickly we answer the phone to problem resolution, environmental protection to reliability and trust. Quarterly surveys focused on transactional satisfaction help us find trends, weaknesses, and individual customer service agent coaching opportunities. They also help feed our customer-service obsession by showing us where we are getting it right. Annual surveys help us understand what's most important to customers, from the environment to rates to reliability, priorities than can evolve over time.

In recent years, GMP has routinely received transactional satisfaction scores ranging from 92 to 98 percent in various categories. In our most recent year-end survey, in 2020, our focus on customers' needs led to 94.8 percent customer satisfaction, as reported to the PUC at that time.

Throughout the years this IRP is in place, our goal will be to continue to earn quarterly satisfaction of at least 92 percent every quarter, and year-end satisfaction in the 92-95 percent range, levels our surveyor says are among the highest they have ever seen.

Customer-Centric Projects

As we will talk about throughout this IRP, all our projects and programs are aimed at improving service to our customers. This is done through lowering costs, lowering carbon emissions, and increasing resiliency and reliability. This can include everything from our distribution system capital projects to relocating vulnerable distribution lines from the woods to the roadside, to projects that include improving our customer access on the Green Mountain Power website.

Over the next three years we will improve customer access through improvements to our website, continued improvements to our smart device app, including expanded chat capabilities in real time on greenmountainpower.com and outage reporting and tracking.

Reliable, Innovative, Cost-Effectively Priced Service

We have delivered on our promise to provide reliable, clean, and cost-effective service for our customers. While consistently reducing carbon in our energy supply and increasing local and regional renewables, we've maintained base rates that have tracked below inflation for two decades. 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've made meaningful investments in our state's critical energy infrastructure whenever needed through VELCO, and our electric rates are third lowest overall in New England.

Empowering customers to accelerate to the new energy future

GMP continues to lead the country in innovation that empowers customers to reduce carbon while lowering costs for all. Our commitment to developing programs and services that directly partner with and benefit all our customers is the foundation of how we continuously shift towards a new energy future that is smarter, cleaner, and more resilient. Our aim is simple – to transform the grid to one that is clean, more reliable, and resilient, while keeping communities connected in the face of severe weather. This work is incredibly critical as climate change continues to intensify.

We continue to develop programs that create a much more distributed grid, using resources like battery storage, electric vehicles and water heaters that enable the choreography of our power supply rather than rely on fewer and much larger generation resources that require heavy amounts of infrastructure. Distributed resources are fast-acting, flexible resources that can be used for several purposes, creating efficiency as well as opportunity. Many of these resources are managed through a distributed energy resource management system (DERMS), which communicates with devices over a secure cloud infrastructure.

Our pilot programs provide real-world experience that informs potential permanent programs, as it has with GMP's first-in-the-nation Energy Storage System (ESS) and Bring Your Own Device (BYOD) tariffs. Rather than spending years researching and studying what the impacts of a particular program may be, the best way to learn is by doing, especially as climate change demands we act quickly with real-world solutions. There is no replacement for the information and real experience gained by implementing pilot programs that seek out partnership with and for customers.

Our innovation team also regularly participates as mentors in the Delta Clime accelerator program, sponsored by the Vermont Sustainable Jobs Fund. This program has been a fantastic way to meet startups committed to tackling Vermont's climate challenges. We have partnered with several of these companies to deploy and test new technologies, including for multifamily electric vehicle charging, load flexibility in commercial refrigeration, and dynamic power switching on our distribution system.

Pilot/Innovative Program Framework for Decision-Making

GMP's regulatory framework includes the ability to offer customers pilots in key areas, all with the overarching goal of generating value back to all GMP customers. In most cases, this means designing and implementing programs that will, over time, generate a quantifiable return on any investment made to benefit customers, or create value in the form of reduced operating costs or even new revenue streams for customers. On rare occasions, the value to GMP customers may be in the experience of certain technologies that could potentially create serious quantifiable benefits in the future. Ultimately, GMP's guiding principle for Innovative Services and Pilots is to ensure that we are creating value for our customers.

In addition to creating benefits for all customers, our pilots also help participating customers leverage the use of free or reduced-cost technologies that provide a direct and tangible benefit to them, such as backup power or faster electric vehicle charging.

Each pilot also follows a framework for design that includes stakeholder engagement, its impact on Vermont's Comprehensive Energy Plan, and GMP's aggressive carbon goals. As we design pilots, we form strategic partnerships both with technology manufacturers and local organizations that will help to encourage economic growth in Vermont. Each pilot advances Vermont's State Energy Goals, in most cases by increasing distributed energy resources that can be dynamically managed and seeking to improve the grid's overall performance. And GMP constantly works towards providing a method by which customers can reduce reliance on fossil fuels, in favor of a clean energy future. Each pilot strives to include each one of these elements in its design and rollout and will be leveraged as a tool to discover what can be offered on a permanent, tariffed basis into the future.

In developing new programs, we first ask the following questions:

- How does the program help accelerate grid transformation and the transition to a clean energy future?
- Does the program include a strategy for managing new load in a way that reduces costs for all customers and fairly compensates participants?
- Is the program simple enough for all customers to understand, avoiding overly complicated rate structures that only technical experts would understand?
- How can we deliver an experience for customers that exceeds their expectations for what a utility can do?
- Is the program accessible to all customers, including low-to-moderate income Vermonters and members of the BIPOC community, who have historically been underrepresented?
- How can the program leverage partnerships with other Vermont companies and organizations that are working towards climate solutions?

While we cannot predict exactly which technologies will be available 5, 10, and 20 years from now, we can rely on this framework to ensure that any initiative we undertake keeps customers at the center and aligns with Vermont's decarbonization goals.

Criteria for Advancing Pilots to Tariffs

Equally important to our innovation approach is the framework we use to advance pilots to tariffed programs. The 18-month pilot period provides an invaluable window to determine if initial hypotheses are correct and if the original goals are being met. Several factors, including device availability, forecast accuracy, and installation cost contribute to the overall cost/benefit, which we track and report in 6-, 12-, and 18-month pilot reports.

These reports serve as the main avenue for reporting the results of our pilots; however, we also regularly issue press releases and publish blog posts to convey the impact of our pilots to a broader, non-specialist audience. One such example is [https://greenmountainpower.com/network-of-powerwall-batteries-delivers-first-in-new-england-benefit-for-customers/]. We are only able to innovate because our customers support this work and know about this work.

Customer experience is an important determinant in moving programs forward. We survey participants in all pilots we offer. A broad negative experience might outweigh successful financial performance for customers. On the other hand, if participants indicated a positive experience but the program did not return the value we anticipated, it likely indicates that a revamped pilot is warranted.

Several pilots have not moved forward to tariff but resulted in a second pilot shortly after the conclusion of the first. In these cases, we felt it was necessary to change one or more elements of the original pilot and obtain additional performance data prior to launching a more permanent program open to all customers. Examples include our Flexible Load Management and C&I Bring Your Own Device Pilots.

Finally, in some cases the pilot may be a success, but it is not necessary to expand in its current form and can be built on in that form. One such example is our Charge Fast pilot. We set out to encourage the expansion of the fast-charger network in Vermont. With 20 successful applications, based upon leveraging a specific State Volkswagen settlement grant opportunity, we learned that we can in fact deliver. Through this pilot, Vermont EV drivers will enjoy ample fast charging coverage in the near future with the help of our program, and we have gained tremendous insight to help with further plans to push out the fast-charger network Vermonters will need to make the transition to drive electric.

We ask the following questions in evaluating a pilot’s success or failure

- Did the pilot return value to all customers? (Measured by financial performance.)
- How was the overall customer experience? (Measured by customer survey.)
- Did the pilot result in a meaningful reduction in fossil fuel consumption? (Measured by Tier III value associated with pilot.)
- Is the pilot still necessary or were the original goals met? (Measured by comparing goals to results of pilots)
- Does the pilot engage third parties in a meaningful and successful way? (Measured through surveys with participating installers, vendors etc.)

Promoting Equity in Program Design

We work closely with community action agencies, state agencies, lawmakers, and members of the public to ensure all our customers can access support and programs. Our Energy Assistance Program provides arrearage assistance and an ongoing bill discount to low-income customers. GMP was among the first utilities to voluntarily suspend disconnections at the start of the COVID-19 pandemic. During the pandemic, we have aggressively promoted state and federal arrearage assistance programs using every possible channel of communication. These efforts have resulted in over $13.3 million of direct relief to our customers this year.

Many of our Tier III incentives include adders for income-eligible customers to reduce barriers to carbon-reducing technologies like heat pumps and EVs, which are also cheaper on a total cost of ownership basis.

Several of our pilots, including the Span pilot, include a carveout for low- and moderate-income customers to ensure they can participate.

We recognize that low- and moderate-income Vermonters and members of the BIPOC community have largely been omitted from the energy transition historically, yet these groups are the most impacted by climate change. We continue to do more to expand access to our programs and ensure that every Vermonter is part of this necessary energy transformation work. We have been a part of the conversations with state leaders, including members of the Climate Council, to ensure that equity is a cornerstone of our innovation work. One example is our involvement in the multifamily EV charging pilot supported by VTrans. This pilot will deploy charging solutions at multifamily properties, creating greater opportunity for residents to consider EVs for their transportation needs. In the multi-year regulation plan we have proposed to the PUC, we have added accountability through annual reports on how our renewable and innovation programs reach Vermonters with low or moderate incomes.

GMP's Role in a Fast-Changing World for DERs

The last three years have seen many exciting developments in DER aggregation and a growing acceptance that DERs can provide many of the key functions that centralized generators have historically served.

The Federal Energy Regulatory Commission's recent orders for battery storage and DER aggregation (841 and 2222, respectively) have created new opportunities for these resources to participate in wholesale markets. While much is still unknown and hinges on regional grid operators' tariff implementations, we are ready to both participate directly and partner with third-party aggregators who seek to deliver value to our customers in a way that is compatible with our own load management strategies. Our foray into frequency regulation described below is one example of how we can layer value on top of existing programs to deliver more savings to our customers.

We will continue to closely follow ISO-New England's rulemaking to enable DER aggregations to participate in wholesale markets. This is a key step in unlocking the full potential of DERs to accelerate energy transformation for customers.

Valuing Flexibility and Evaluating Program Design

Many of our innovative programs derive their value from avoided power supply costs, primarily those related to peak demand. Our power supply team forecasts these costs 20 years into the future. In some programs, such as the Flexible Load Management pilot, we pass through a portion of value realized to participating customers. This "pay-for-performance" approach works well for large customers who can leverage existing assets to shift load. Non-participating customers are mostly shielded from risk because the credits paid to participants change based on market values.

However, for technologies like residential battery storage that do not yet have well-defined financing mechanisms, upfront incentives that reduce out-of-pocket costs are warranted and essential to encourage adoption. These incentives are based on our current forecast of power supply costs. If these costs change, we cannot take back a portion of the incentive. In modeling the value of innovative programs, we incorporate potential forecast variances and performance issues. This results in a fair incentive to participants and helps ensure that non-participants are not negatively impacted and instead derive a benefit.

Simplicity is a core guiding principle for all our innovative programs -- we want the easy decision to also be the smart one in facilitating demand management. One example is our providing a free Level 2 charger to electric vehicle drivers. It is simpler for customers to check a box indicating their interest in this offer while at the dealership than to research and order a charger for themselves. And in providing a charger directly, we ensure that customers are using a charger that can communicate with us and we can manage.

The phrase “value stacking” is often mentioned when discussing the benefits of DERs. We share in the industry-wide excitement for targeting multiple value streams and markets with the same piece of equipment. However, when valuing flexibility, we are careful to rely on values we can capture today. This ensures that the financial viability of our programs – including the benefits to all customers -- is not contingent on future developments, either regulatory or technical. This philosophy does not mean we exclusively obtain value from peak shaving; the programs described below include frequency regulation, wholesale energy arbitrage, and avoided distribution upgrade costs.

Finally, we are closely tracking developments at ISO-New England that might impact how capacity and transmission costs are allocated among utilities in the region. While at present it does not look like this will impact the value of battery storage or demand flexibility, we have built our programs to be flexible enough to adapt to changes in market rules. For example, our Energy Storage System (ESS) tariff does not specify exactly when or how often batteries are dispatched; rather, it grants GMP the flexibility to discharge systems in a way that reduces costs for all customers. Regardless of how power supply costs are allocated, we are confident there will be ample opportunities for flexible DERs to save money for all customers. Adaptability is core to our approach in designing pilots; moving away from rigid rate structures allows us to stay nimble in a fast-changing energy landscape.

Load Management and DER Dispatch Strategy

GMP now has over 60 MW of flexible capacity to dispatch for peak reduction and load shaping. This represents roughly 10% of our average peaks. This fleet is comprised of various resource types, including battery storage, water heaters, and electric vehicle chargers. These technologies are supplemented by a range of rate-based approaches to load management, including our large C&I tariff riders (Curtailable Load, Critical Peak, and Load Response), and residential time-of-use rates.

We do not follow a one-size-fits-all approach to load management; rather, a diversity of approaches is necessary to orchestrate an evolving mix of technologies and customers. In certain instances, customers prefer that GMP manage devices directly. In others, a less active approach is offered – for example through dynamic rates that customers can respond to, potentially with the aid of technology.

As our fleet continues to grow, we acknowledge that dispatching DERs via a day-ahead schedule based on our load forecast will not always be sufficient to capturing the full value of these resources. We have spent much time learning about sophisticated tools that “optimize” DER dispatch, some of which can adjust behavior in real time based on changing load conditions. While until now the cost of this type of platform has outweighed the benefits, we continue to closely monitor fleet performance to determine if and when such an investment is warranted to deliver more value to customers.

Current innovative offerings

Energy Storage System ("ESS") Tariff

Building upon the successful Grid Transformation Pilot that launched in 2017, we have moved this highly sought-after program from a pilot program to the first-of-its-kind utility-managed energy storage tariffed program. The program continues to leverage the Tesla Powerwall 2.0, which has 27kWh per installed system -- a two-battery, whole-home backup solution, at an affordable monthly cost to participating customers. Each installed system provides GMP with an additional 10kW of capacity to be used for demand response, energy arbitrage, and even frequency regulation as discussed further below. GMP plans to seek renewal of this important program for customers.

For $55 per month, or a one-time upfront payment of $5,500, customers can have this system installed and providing seamless backup energy to their homes during periods of grid outage, often substituting for a fossil-fueled generator. The systems work in tandem with GMP, allowing us to significantly reduce overall operating costs by using the batteries a handful of times per month through an automated dispatch algorithm. Participating customers have the backup power and peace of mind they seek, while non-participating customers also benefit from the reduced power supply costs created by the energy storage. In 2020 alone, GMP's stored energy network, largely made up of residential batteries, reduced more than $3 million in costs for customers.

There are over 3,500 Tesla Powerwalls installed through the various previous pilots and this program. This represents approximately 15MW worth of capacity that is being used for peak reduction, which continues to grow each month. This aggregation of Powerwalls has provided GMP customers with almost $4.7 million in operational cost savings since 2017, which highlights the extreme value this program holds for our customers. Of equal importance, the Powerwalls have provided over 50,000 hours of backup in aggregate. We view this and other battery offerings as an extension of our commitment to provide reliable service, regardless of whether that service comes from our transmission or distribution infrastructure or a battery system.

Beyond peak shaving, we have recently begun using a subset of installed systems in ISO-NE's Frequency Regulation Market to generate additional revenue for our customers. Two-hundred customers signed up to participate, and while still early in overall testing, we are seeing great levels of success that warrant increasing the scope of the program. As the first such rollout to use a utility's aggregated group of distributed resources in the frequency regulation market, GMP is leading in finding new ways electric utilities can provide value back to their customers using innovative technology.

Bring Your Own Device ("BYOD") Tariff

In parallel with the ESS Tariff, GMP also advanced our BYOD pilot to a permanently tariffed program, to provide another choice for customers who wish to own, rather than lease, their home energy storage. Throughout the pilot phase of this program, GMP learned a tremendous amount about how to encourage energy storage adoption. In partnership with the local solar and storage installer community, we shifted the incentive structure from a monthly bill credit to a one-time, upfront payment for access to an energy storage system for a 10-year period. Our incentive program provides the largest battery incentive from a utility in the country, helping to reduce the up-front cost barrier to innovative technology adoption.

Customers self-enroll their self-purchased energy storage system into the program and have full control over how much access to their battery they are willing to provide to GMP. We offer a minimum of 2kW and a maximum of 10kW, which equates to an incentive of up to $10,500. We provide $850 per kilowatt of enrolled battery capacity, with an additional $100 per kilowatt for systems that are sited within solar-saturated areas of the GMP grid. By adding this additional incentive, GMP is leveraging energy storage technology to absorb excess solar energy that is adding strain to the existing infrastructure on these circuits. This may help avoid otherwise costly upgrades and again save our customers money.

In exchange for the upfront incentive, customers agree to allow GMP to access the batteries at the amount they selected for the purpose of peak shaving. In partnership with these participating customers, GMP brings value to all GMP customers by reducing operating costs, like our ESS program. For a period of 10 years, GMP will have access to the enrolled systems, using them as a demand response resource a handful of times per month, while the remainder of the month, the batteries are ready and available to provide backup power should the need arise.

The BYOD program currently supports Tesla, Sonnen, Generac, and energy storage systems compatible with the SolarEdge StorEdge inverters. Our BYOD platform is flexible enough to allow for any viable storage solution to become part of the list of systems that are compatible with the program. Due to GMP being known as innovative and the appealing program design, we have spoken with many additional vendors and continue to encourage them to integrate with our software provider to become available as an additional option for installers and customers.

Flexible Load Management ("FLM") 2.0 Pilot

The FLM 2.0 pilot leverages previously untapped flexibility among commercial and industrial customers. GMP signals customers to reduce load during peak events several times per month. In some cases, this is achieved through direct integration with a "building management system," which can seamlessly shift load without any negative impact to occupants, for example cycling compressors or pre-heating/cooling the building before a peak event. In other cases, customers receive a notification and schedule a batch process to run before or after the event window. Customers earn credit for their average load reduction during peak events (relative to a statistical baseline), reflective of the value delivered to all GMP customers by reducing demand during peak hours. Participants include commercial office buildings, manufacturers, wastewater treatment facilities, and ice rinks.

In addition to load reduction, FLM 2.0 is testing several experimental use cases:

- "Solar soaking" involves requesting an increase in load during hours in which distributed solar production is abundant.
- "Load rolling" involves shaping the participant cohort's aggregate load to match a predefined shape, for instance smoothing an evening ramp rate or flattening a peak over a period of several hours.

While customers are not compensated for these experimental use cases, they can always opt out. The ability to experiment beyond core demand response will provide invaluable experience as we evaluate future value streams for aggregated distributed energy resources. We have also partnered on several Department of Energy grant applications to further test these use cases.

FLM 2.0 is the successor to a previous pilot (FLM 1.0) in which customers earned a credit for their load reduction during the actual Vermont system peak hour each month. Results from the pilot and customer surveys indicated a change was necessary; in a few instances the peak hour shifted because of GMP's load reduction strategies and customers were not compensated despite performing when signaled. FLM 2.0 takes a slightly different approach, compensating based on the average performance during events regardless of when the actual peak hour occurs. This shifts some risk to GMP and ensures a more positive customer experience. This is but one example when piloting proved invaluable; we were able to incorporate feedback, iterate quickly, and revise the initial program to better serve the needs of our customers.

Both versions of FLM involve a close collaboration with Efficiency Vermont. The program would not be possible without their involvement and expertise, both in technical development and participant recruitment. EVT leveraged existing customer relationships to find assets well suited for FLM 2.0 event signals, and developed advanced statistical baselines, which is essential for accurate compensation.

Electric Vehicle Charging Rates

Strategic electrification is increasingly important as technology continues to shift towards using cleaner forms of energy. More Vermonters driving electric vehicles (EVs) is essential for meeting Vermont's climate goals as transportation is the top source of carbon pollution in Vermont. EVs could increase demands on the grid at times when it is more costly to supply the energy and GMP is addressing that by offering a free Level 2 Charger to EV drivers. It is also extremely simple to enroll in one of our two new EV Charging rates that are aimed at managing charging patterns by sharing peak savings with enrolled customers. Over the past 2 years, among customers who have taken advantage of our EV rebate, 75% have claimed the free charger and enrolled on one of our EV rates. Among those who opted out, many bought plug-in hybrids for which "Level 1" charging (between 1-2 kW) is sufficient given the small battery sizes. This adoption level is unheard of among utility charging programs, indicating the importance of providing equipment that can communicate with GMP for both billing and active management and making rate selection easy. Given the overwhelming role of home charging in overall EV consumption (83% according to the Tier III TAG), our EV rates will continue to be an effective tool for managing new demand created by the electrification of light-duty transportation.

We offer two different approaches for customers to select from, and the connected electric vehicle supply equipment (EVSE) makes it possible for both customer and GMP to successfully accomplish smart charging. Both rates are premised upon taking the savings created by load control and sharing it with the enrolled customer to lower the EV charging rate compared to their standard rate, without creating subsidies paid for by all other customers that would eliminate the benefit from the additional usage created by EV charging.

The first rate we offer is the Managed Charging rate, which is an iteration on the former eCharger pilot. The pilot was so successful that rolling the program design into the rate was a natural progression for GMP. On this rate, customers enroll their EVSE into GMP's DERMS and opt to allow GMP to curtail charging during peak times. For a few hours at a time, several times per month, GMP effectively prevents the EVSE from charging an EV, seamlessly turning back on when the peak event is over. In exchange for this arrangement, customers pay $0.13969 per kilowatt hour at all times outside peak events for their EV charging activity. GMP always wants to make sure customers have the flexibility they need to charge their vehicle at all times, so a notification of the peak event is sent via email and/or text message and provides a simple opt-out link. If opting out results in energy consumption during the peak event, customers are charged $0.71822/kWh. We have learned through the pilot and this rate that opt-outs are extremely uncommon – fewer than 1% across all peak events over one year of operation. Almost all peak events occur in the evening and customers are able to get a full charge by morning and are not troubled by the temporary pause in charging during high-demand hours.

GMP's philosophy of making it simple and seamless for customers by managing energy use on their behalf, in a way that accomplishes load management goals and does not interrupt the customer's lifestyle, is extremely successful and worth repeating in other programs. The incredibly low opt-out rate supports this philosophy. With over 300 customers enrolled in this rate in just one year, GMP is encouraged that we have developed a rate that meets the needs of our customers.

Our second EV Charging rate option is a time-of-use rate that provides customers with a low off-peak rate of $0.13433 per kilowatt hour for most of the hours in a day, and an on-peak rate of $0.17650 per kilowatt hours during the defined hours of Monday through Friday 1 p.m. to 9 p.m. The free EVSEs that we give to customers allow for simple scheduling of their charging times through a mobile app, making it easy to ensure all charging is done off peak. Since the rate became available in September 2020, participants have done over 90% of their charging during off-peak hours, a testament to the effectiveness of smart technology and rate design working in tandem. Five-hundred customers have enrolled in this rate, and with a resource like an electric vehicle that can easily charge in the overnight hours with a level 2 EVSE, customers find the ease of scheduling an appealing feature of the EV Rates.

With both rates, GMP has taken a major step forward in how we bill customers for their EV charging activity. In partnership with our DERMS provider, Virtual Peaker, we eliminated the need for a separate AMI meter to capture the EVSE charging data, by integrating our billing system with Virtual Peaker to capture all the data directly from the chargers themselves. We then developed a method to charge customers the appropriate energy costs based on the rate they selected, while backing out that same amount of energy from the customer's total household consumption to not double bill for the energy. By accomplishing this, we have cut down on the costs that customers would otherwise incur for installation that would have required additional hardware and labor to accomplish. Instead, customers need to have a 240V circuit run to the location of the charger and internet access, and our innovative billing can pick it up from there. This type of progress is critical as we look to a future with a more diverse set of devices within the home that can communicate energy consumption without the need for a traditional utility meter. It also points to the importance of universal broadband access, which in this case allows customers to save money through a lower off-peak kWh charge, reducing the total cost of ownership of electric vehicles even further compared to internal combustion vehicles.

Span Smart Panel Pilot

To expand our understanding of energy monitoring without a traditional utility meter, GMP launched the nation's first utility program to use the Span Smart Panel to determine if this device can be used as a full replacement for an AMI meter. GMP has been watching the smart electric panel space for years including conversations with various incumbent and startup companies. Span is the first one to have developed and certified through UL a fully integrated panel with controls, monitoring, metering, and the ability to expand to include other devices such as storage and solar. With full UL listing for a 200-amp electrical panel, a service entrance and an energy management device, Span has created a full replacement of the traditional electrical panel that allows for the combination of both circuit-level data and the ability to manage each individual load, while up until now, other devices have done either management or monitoring – not both.

With growing deployments of rooftop solar, energy storage, and EVSEs at the residential level, GMP wants to continue to explore how this system can improve upon the installation process, as well as the user experience, of these resources. With the Span App, customers can interact with, monitor, and control their home energy usage all with their smartphone. It provides customers greater visibility into the home's energy consumption, from anywhere, at any time. It provides the capability of scheduling, control, and alerts so that customers know exactly what is always going on in their homes at the individual circuit level.

This same intelligence through the smart panel allows for more DER interaction directly with GMP, which benefits all customers. It provides a central point of communication that will allow for management of multiple devices within a home, without needing a separate communication channel with each distributed asset. This helps keep connection especially for assets located far from internet routers. With this type of intelligent load panel, GMP can work with customers to make any electrical load in the home a smart DER, driving down cost and carbon in a simple, effective way.

Traditionally, the meter is the line between a utility and customers. We follow that model today: GMP owns the meter at our customer's home, and equipment beyond the meter is typically owned by our customer. This Pilot will help us explore whether, in this new era of electrification to combat climate change and distributed devices that are capable of load management, a Span panel should set a new line, where GMP provides the electrical panel as the main entrance point for electricity into the home to unlock a variety of potential opportunities in billing and load management that help cut costs and carbon and improve reliability. This review will also include any necessary regulatory or statutory changes that may need to occur to make this shift if it turns out to be the best approach for customers.

Workplace and Fast Charging

Our workplace charging pilot provides a turnkey package for businesses to install Level 2 charging for employees and members of the public. In partnership with charging network operators AmpUp and Xeal and local installers E&S Electric and Norwich Technologies, this pilot tackles one barrier to EV adoption – reliable access to charging at work – and grows daytime load to align with periods of high solar generation. To date, 12 chargers have been deployed, with more in progress. Customers can finance equipment and installation costs through a Vermont Economic Development Authority (VEDA) loan and pay for maintenance and networking services on the GMP bill. While cost remains the biggest barrier for workplaces to install EV charging, complexity ranks close behind, considering a bevy of hardware options, software packages, and installation configurations. The workplace charging pilot removes this complexity by presenting a curated list of hardware and software options and installation by reliable and local partners who have extensive experience in deploying EV infrastructure.

We recently concluded our Charge Fast pilot, which contributed up to $40,000 in make-ready costs to support deployment of fast EV charging stations. The pilot resulted in a doubling of fast charging locations in GMP territory, including six sites supported by the Agency of Commerce and Community Development's EVSE Grant Program. We also recently filed a tariff amendment that allows public fast charging stations to take service on a small commercial rate. In conversations with EVSE developers, poor load factor and high demand charges came up frequently as a major barrier to expansion. Our analysis of usage patterns at GMP-owned fast charging sites gave us the confidence to create the exemption, which makes Vermont one of the most attractive states in the U.S. now for fast charging deployment.

Innovation During the Planning Period

Expanding ESS Options

GMP will continue to pioneer customer programs at the leading edge of innovation. Technology moves fast, so it is imperative that we keep up to bring value to all our customers. To that end, GMP is constantly seeking strategic partnerships that can leverage technology innovations in the utility space, and opening access to third parties to aggregate resources. Similarly, as we pilot and test various systems and services, we are learning a great deal about how to best iterate, expand, shift, and redevelop past programs.

Over the past several years, GMP has shown that deploying residential batteries using a utility-managed model produces strong outcomes for participating and non-participating customers alike. Our current Powerwall customers are benefiting from the peace of mind that comes with knowing that they will have reliable cleaner backup energy in case of outages, and the rest of GMP customers are benefitting from the successful use of the batteries for peak shaving and frequency regulation to drive down costs. As the ESS Tariff continues to see tremendous customer interest and enrollment, GMP recognizes it will be good to continue diversifying the types of systems that are being deployed. GMP is looking to gain experience with the Enphase Encharge 10 systems, by deploying a limited number of systems in a pilot similarly structured to the ESS Tariff. The end goal for this pilot will be to determine if the systems perform at a sufficiently reliable level to include as an option in the tariff.

Expanding the type of resources GMP has access to for extending our work towards a more dynamic and distributed grid is important as markets grow and we offer more options. We have employed this diversification strategy with other device types like EVSEs and water heater retrofit controls by making use of multiple vendors. This has afforded GMP the ability to determine which systems work best and fit the needs of our customers, while also determining what components of a product or vendor need to be improved upon or avoided.

Smart Water Heating

Building off a valuable eWater pilot in 2017, GMP is developing a new program to dynamically manage water heaters, enabled by a smart access control device or smart tank. As noted in the draft Climate Action Plan of December 2021, water heaters are among the most flexible DERs because of the high thermal inertia of hot water tanks.[1] The water can be pre-heated during times of low demand and avoid consumption when demand and prices are high without any adverse impact on the customer. Given the opportunities and benefits for utilities to actively manage another grid resource, customers will be compensated for allowing GMP to manage their water heater in this way. This program is in partnership with local Vermont startup company Packetized Energy, which participated in the Delta Clime program and is on the leading edge of DER optimization. We have designed the program to also be compatible with other smart control devices and smart water heaters in which internet-connectivity is a built-in component of the tank. In addition to Packetized, we are currently integrated

[1] https://climatechange.vermont.gov/sites/climatecouncilsandbox/files/2021-12/Initial%20Climate%20Action%20Plan%20-%20Final%20-%2012-1-21.pdf#page=108

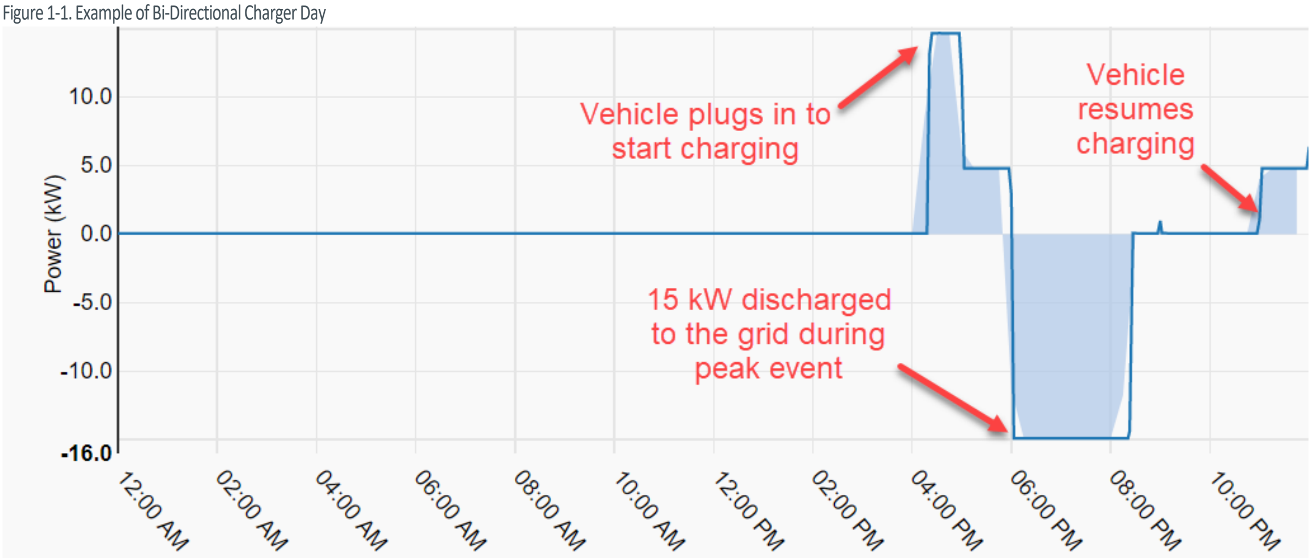
with Aquanta and Rheem's EcoNet models. Smart circuit breakers are another promising option for managing water heaters and are discussed in further detail below.

Vehicle-to-Grid Charging

We are testing vehicle-to-grid technology, through which energy is exported from an electric vehicle through a charger and back to a building or the grid. We see enormous potential in this technology in two major ways: 1) "V2G" may unlock a new revenue stream for EV owners, which could reduce overall vehicle ownership costs to a fraction of those associated with internal combustion engine vehicles and accelerate EV adoption; 2) "V2G" can provide backup power to homes and businesses, transforming a vehicle into a resiliency resource during outages.

At our Colchester office, we successfully installed a Fermata FE-15 bi-directional charger that allows us to use a fleet Nissan Leaf vehicle to reduce system-wide demand during peak times much like our residential battery fleet. Testing thus far has shown promising results; the vehicle's typical duty cycle in our fleet is 7am - 3pm, providing ample time to recharge before a peak event. Figure 1-1 shows an example of one such event.

Figure 1-1. Example of Bi-Directional Charger Day



We will use our own experience operating a bidirectional fleet vehicle to develop programs for other commercial fleets in Vermont. While dispatching a bidirectional electric vehicle is more complicated than a stationary storage asset (e.g., it may not be available when called upon due to its use for transportation), we view all electric vehicles essentially as "batteries on wheels," capable of providing grid services and reducing total ownership costs for EV owners.

We have also recently acquired and installed an additional bi-directional station known as the Wallbox Quasar EVSE unit, which is designed for residential use, and would allow GMP to make use of electric vehicles already being purchased as additional resources for managing our diverse grid.

GMP is working closely with the South Burlington School District to enable the vehicle-to-grid dispatch of four new electric school buses – supported by an Agency of Natural Resources grant – at times when they are not used for student transportation. This project is especially exciting because school buses have a natural duty cycle that fits perfectly with the timing of peak events. Typically, school buses follow a morning loop to pick students up, park during the middle of the day, and then an afternoon loop to drop students off, returning to the bus depot in the late afternoon. Not only is this duty cycle conducive for peak-related dispatch, it is also ideal for aligning charging with periods of high solar generation.

Finally, GMP is working with Ossiaco, which developed a dual DC solar inverter and EV Charger to reduce the amount of hardware needed at a home to install a solar array and own an EV. This technology could provide increased efficiency for the customer, while again, enabling an electric vehicle as an additional resource on the grid to lower costs for customers. This unit also provides the added benefit of backup power to the customer. In situations of grid outage, this system can use an electric vehicle's battery as a source of backup power. The shift to electric vehicles is happening and must accelerate, and having the ability to utilize a car in this way adds an entirely new value proposition to customers when they are purchasing electric vehicles. GMP is working with these companies to find solutions for our customers that will drive smart electrification and reduce the top source of greenhouse gases in Vermont, transportation.

Commercial Batteries and Aggregation

GMP recently concluded the C&I BYOD program that paid our commercial and industrial customers for the performance of an installed energy storage system during our monthly and annual peaks. When not dispatched for peaks, customers could use their battery assets for backup power or demand management. The program was the impetus for yet another first-in-the-nation type of installation. In the fall of 2020, Vermont's State House became the first to have clean backup power stored in batteries – using a GMP program to help lower costs for all Vermonters. Vermont State officials, and leaders from Northern Reliability, Dynapower, Virtual Peaker and GMP were joined by state officials and legislative leaders to make the announcement during a virtual news conference. This coalition of Vermont businesses, state officials, and GMP is demonstrating that storage is a clean alternative for backup power over fossil fuel. The statehouse battery project is expected to save Vermont taxpayers $44,000 and GMP customers an additional $18,000 over 10 years while also supplying clean backup power. The batteries are projected to reduce carbon emissions by 6,388 pounds per year, the equivalent of not using 326 gallons of gasoline.

The Samsung Mega E2 batteries were installed in the basement of the State House where a failing fossil fueled generator from the 1960s once was. The system is 250kWh of battery power, and now backs up more critical systems for the historic building, including the elevator. Energy storage is an important way to provide resiliency and manage the grid cost effectively. The flexibility of batteries means the potential for even more benefits for customers in the future. Not only has the battery system at the State House functioned during a grid outage, doing exactly what it was designed to do, it has also served GMP for peak reduction for several months. It is precisely these types of applications that GMP wants to continue to encourage and promote.

We plan to launch a revamped C&I BYOD pilot that mirrors the changes implemented in FLM 2.0. Specifically, customers will be compensated based on battery dispatch during events rather than during the actual peak hour. Participants can choose whether to let GMP dispatch the systems directly (with advance notice) or receive a notification and schedule dispatch themselves. The new pilot will also be open to aggregators of residential and small commercial installations, creating an opportunity for third parties to earn value.

We learned through the pilot that the compensation structure designed to incentivize customers to install battery storage still left some customers reluctant to commit to the program. As we found with our flexible load management pilot program, the response from the batteries, along with all GMP's additional distributed resources, may knock down the peak from one day only to promote another. In these instances, the program participant may miss out on compensation set to pay strictly on the peak hour. To properly incentivize customers in this program and encourage more participation, we must compensate based on the performance of the systems during all peak events. GMP is planning to relaunch the C&I BYOD pilot with a slightly different design to provide value to customers installing batteries, as well as all GMP customers.

Other Areas of Exploration

To anticipate customer needs, to address climate change, and to boost resiliency, we are constantly testing new technologies and approaches, which can create opportunities for the coming years.

Integrated Heat Pump Controls: In partnership with Efficiency Vermont, we are helping support a limited number of integrated controls installations. This technology allows a cold climate heat pump and backup fossil fuel heating system to be controlled by a single thermostat, seamlessly switching between the two when certain conditions are met (e.g., the temperature falls below a specified threshold). We are providing a Tier III incentive to help offset the high upfront cost of an integrated thermostat. One model is already compatible with our DERMS, and we plan to offer an additional incentive to customers who allow GMP to modify the thermostat setpoint during peak events, like our Sensibo program described below. We are hopeful that integrated controls will help increase heat pump utilization and efficiency, while providing more flexibility for demand management.

Heat Pumps with Energy Storage: We are testing the Stash M1 unit at a GMP facility. This heat pump has an integrated energy storage medium in the form of phase-changing material (PCM). The PCM can be "charged" during times when net demand is low (e.g., overnight and during the middle of the day), allowing a virtual zeroing out of demand during peak times without sacrificing occupant comfort. The PCM is extremely durable, capable of over 3,600 cycles throughout its lifetime. While the upfront cost of these systems remains high, the technology shows strong potential to enable the electrification of our heating sector with minimal impact to coincident peak demand.

Emission-optimized Dispatch: We are in contact with several companies including WattTime, ElectricityMap and WattCarbon that calculate the real-time emission intensity of regional grids. For flexible devices like water heaters and electric vehicle chargers, there is potential to coordinate consumption to align with periods of low grid emissions. While the emission intensity signals do not presently account for GMP's overwhelmingly clean power supply, the Tier III TAG has developed a characterization for shifting load away from emission-intensive regional peaks. Using this characterization, we are exploring how to compensate customers for allowing GMP to dispatch according to a carbon signal like Massachusetts' Clean Peak Standard.

Smart Circuit Breakers: Like the Span Pilot described above, smart circuit breakers would allow monitoring and load management at the individual circuit level. We are currently testing Eaton's Energy Management Circuit Breaker (EMCB) for the purposes of water heater management. It is still early in the testing phase, but the technology appears to be an effective option when it is not feasible to add connectivity to an end device, for example a refrigerator or non-connected electric vehicle charger. A smart circuit breaker could also be useful when the panel is within reliable Wi-Fi range, but the device is not (e.g., a water heater located in the basement).

Dynamic Rates and Solar Self Consumption: The concept of dynamic electricity rates is not new; several utilities offer tariffs that fluctuate with wholesale prices, most often for large industrial customers capable of ramping up or down production quickly, for whom electricity is a major operating expense. We are considering testing this concept at the residential level, especially to encourage increased consumption during times when solar generation is abundant, showing different values of solar at different times. We recognize that customers are unlikely to constantly check the price for electricity, but the combination of day-ahead forecasts and connected devices that can respond seamlessly to price signals is appealing. This approach could also be used to incentivize residential solar customers to consume more energy behind their own meter, thereby reducing exports to the distribution grid.

Direct to Vehicle Management: While we have successfully managed residential charging load through a smart Level 2 charger, some manufacturers allow direct communication with the vehicle telematics system for purposes of charging management. This approach would afford greater flexibility as we would have access to the battery's state of charge and could schedule charging to guarantee a specified state of charge by a certain time. Some manufacturers provide a free portable charger with the purchase of an EV, but these are not able to communicate with GMP's DERMS; communicating directly with the vehicle would allow these EV owners to get access to GMP's off-peak rates using the charger they get for free from the dealership, avoiding the need for a GMP-provided charger and therefore saving money for all customers. There are several factors we must consider before moving forward with this approach, including metering accuracy, data security, and ensuring that only residential charging is credited at the discounted rate.

Rate Design to Support the Electrification of Transportation and Heating

As we look to strategic electrification of the transportation and heating sectors and greater use of DERs, finding the right rate design to encourage adoption, cover fixed costs to support the greater grid, and ensure increased load benefits all customers, will be key. Core, traditional principles of rate design – such as overall fairness, avoiding undue discrimination between types of customers (residential, commercial etc.), avoiding cross-subsidization, and encouraging efficient adoption of technology and use of grid resources – all apply well to the acceleration of electrification we expect to see in the coming decade. While rate design can be a dry and seemingly inaccessible subject to customers, rate design for electrification done right can and will promote equity for customers by helping lower rate pressure for all.

Rate design for load-managed electrification

While some have advocated for straight marginal cost or even subsidized "Electrification Rates" to hasten the conversion of transportation and heating fuel sources from fossil fuels to electricity, our experience with EV charging rates and in other programs tells us that we instead must strongly focus on shared savings from load control in rate design, to create benefits for all customers. This is especially true as these rates do not address the top barriers of adoption for Vermonters, which is up-front cost.

Technology that allows for load management creates opportunities to marginal power cost savings for all customers. That allows for rates to be established that are lower than the general residential service rate, and also helps optimize the grid for all customers. To the extent that load management of the end-use creates marginal power cost savings, those savings can be passed on to the customer creating those savings. An example is what we have done with our EV rate that was recently approved by the Commission.

Electrification holds the promise of lowering rate pressure for all customers, important to keeping electric rates cost-effective and to supporting equity. Lowering the end-use rate **more than** the power cost savings such that it reduces the “margin” creates a **cost shift** paid for by other existing customers not utilizing the end-use and lessens the rate-reducing effect due to electrification. In fact, lowering it all the way to the actual marginal cost produces no fixed cost contribution from these sales and has no rate-reducing benefit at all to customers in general. Also, rate design done right can deliver not only great value for customers but also the benefit of load management; GMP does not favor lower cost “electrification rates” that are not tied to load management either by the customer or GMP directly.

Additionally, because we know that the upfront costs of acquisition can be a very significant barrier to customers making choices between fossil fuel equipment and vehicles and all-electric options, we are committed to continuing successful up-front incentives that address this primary market barrier. We want to drive more widespread adoption of electric vehicles and heat pumps with those incentives, and do not favor shifting those dollars to a rate design that only covers marginal energy costs. Upfront purchase incentives can be targeted and adjusted over time much more easily than overly discounted electric rates, and therefore are much more efficient in not shifting costs from other customers to customers who fuel switch.

Overall, we want to see the increased load from electrification benefit all our customers by preserving the rate-lowering effect through rate design. We believe that the transition away from fossil fuels and toward clean electricity in transportation and heating presents the dual opportunity to reduce the impacts of carbon on our climate, while also reducing the cost of that clean electricity for our customers and make it more and more accessible by all of our customers. There could also be an innovative way to approach this, wrapping in a smart panel or storage to further a new energy future for customers.

Shifting fixed cost recovery to fixed charges

One proposal that could work well with the generally accepted rate design principles mentioned above would be a modification to existing general rate classes such as Residential Service Rate 1 and General Service Rate 6 that would lower the kWh rate for electricity and increase the customer charge. This design would benefit increased usage through electrification while allowing customers to cover fixed costs of operating the grid and delivering services via the customer charge. The lower kWh rate would apply universally to all types of loads, old and new, thereby accommodating electrification goals. While reducing the kWh rate would diminish the rate-reducing effect of new sales for customers somewhat, the design would be more sustainable over the long term as customers make choices to add load or add storage, solar and other DERs in ways that will increase reliance on the increasingly interconnected greater grid. This rate design would also promote electrification across devices, while allowing the shared load control model that provides a cost-based discount for management to target specific products with that capability. To promote equity and harmonize with the Energy Assistance Program (EAP) GMP provides, this rate design also could shift customer support to the customer charge, alleviating the bill impact for low-income, low-use households. And again, we will be looking at this with an eye toward innovation, and other ways to help customers through this proposed change in the customer charge.

Current Electrification End-use Rates at GMP

EV Charging Rate 72 and Rate 74

As outlined above, we currently offer two residential electric charging end-use specific rates. Rate 72 is a rate for EV charging equipment that offers a cost-based discount to the Residential Rate 1 kWh rate consistent with the power costs savings expected by the customer allowing us to manage the availability of service and limit load at critical peak periods. Customers are provided an option to override the control of equipment at their discretion and pay a much higher rate to charge during peak events.

Similarly, customers can manage the charging period on their own and create savings via GMP's time-of-use Rate 74. Here, customers who limit charging to off-peak periods receive a similar cost-based discount from Residential Rate 1.

Both end-use rates are only possible due to the ability of the charging equipment to measure kWh use that can be accessed by GMP and those kWh are subtracted from the customers Rate 1 billing meter. Importantly, that measuring capability does not currently existing with heat pump equipment so it is likely if we pursue any cost-based incentives for allowing GMP control of space heating equipment would come in the form of fixed bill credits.

Public EV Charging and Electric Bus Charging

We have also modified the General Service Rate 6 tariff terms to accommodate public charging equipment. As modified, public EV charging equipment will be allowed to remain on Rate 6 even if usage would otherwise require the load to transition to Commercial & Industrial Rate 63/65 where the load would be subject to time-of-use pricing and demand charges that could increase the effective $/kWh cost of charging during times when the site was not experiencing significant use. Similarly, we have petitioned the Commission for the ability to provide the same waiver to electric bus accounts for an interim period while we learn more about the charging requirements of electric buses.

Tier III Programs

Tier III of Vermont's Renewable Energy Standard mandates that distribution utilities "acquire fossil fuel savings from energy transformation projects… that reduce fossil fuel consumed by DU customers." GMP has exceeded Tier III targets in each year since the RES was implemented through energy transformation projects. The Tier III program has enabled us to incent our customers to reduce their carbon footprints and save money. In many cases this involves electrifying a process that previously relied on fossil fuels, which applies downward pressure on rates, a win-win-win for participating customers, non-participating customers, and our climate.

GMP's Tier III program includes standard incentives for technologies like electric vehicles (both all-electric and plug-in hybrid), workplace EV chargers, cold climate heat pumps, heat pump water heaters, electric bicycles, electric motorcycles, and electric lawn mowers and yard care equipment. The Tier III value of each technology is determined by the Tier III Technical Advisory Committee (TAG), a working group comprised of distribution utilities, the Department of Public Service and members of the public tasked with characterizing the carbon reduction impact of a variety of measures. Table 1-1 shows a full list of Tier III incentives GMP provides based on TAG characterizations:

Measure	Rebate $
Heat Pump	$ 400.00
Heat Pump Low Income (added)	$ 600.00
Heat Pump Moderate Income (added)	$ 300.00
AEV	$ 1,500.00
PHEV	$ 1,000.00
Used AEV	$ 750.00
Used PHEV	$ 750.00
AEV/PHEV Low Income	$ 1,000.00
eMotorcycle	$ 500.00
eBike	$ 200.00
Forklift	$ 3,000.00
Residential Trimmer	$ 25.00
Residential Chainsaw	$ 25.00
Residential Leaf Blower	$ 25.00
Residential Mower	$ 50.00
Residential Garden Tractor	$ 100.00
Commercial Garden Tractor	$ 2,500.00
Level 2 Public	$ 750.00
Level 2 Workplace	$ 750.00
Level 2 Multifamily	$ 200.00
Level 3 Charger	$ 3,000.00

Table 1-1. Full list of GMP Tier III Incentives

We also provide custom Tier III incentives for unique projects that fall outside characterized TAG measures. Our business innovation team works closely with commercial and industrial customers to calculate the fossil fuel consumption of an existing process and the corresponding incentive. These custom projects are often undertaken in close partnership with Efficiency Vermont, ensuring that electrification and efficiency happen in tandem so that the customer achieves maximum operational savings. We provide examples of custom projects in Chapter 2.

To ensure that the electrification we encourage through Tier III happens strategically, our most popular Tier III incentives are paired with demand management:

- We offer a free Level 2 smart charger with the purchase of any electric vehicle, new or used, plug-in hybrid or all-electric. Customers who claim the charger are required to sign up for one of our two electric vehicle rates described above, ensuring that charging is done outside peak hours.

- We offer a free Sensibo smart thermostat with the installation of any cold climate heat pump. The Sensibo allows customer to control their heat pump with a mobile app, useful for pre-heating/cooling. GMP adjusts the thermostat setpoint several times per month during peak events to reduce demand associated with heating or cooling. Customers may opt out of these events without penalty.

Collaboration with Distribution Utilities and Other Stakeholders

Vermont is known for its collaborative spirit, and this is especially true in addressing climate change. We maintain an open and productive dialogue with all distribution utilities, sharing lessons from our pilots and learnings from their initiatives, both in informal exchanges and in dedicated forums like TAG meetings and utility meetings. We present at the same events and collaborate on statewide efforts including implementing the Agency of Transportation's electric vehicle incentive. These partnerships create a unified message for all DU customers on the importance of reducing statewide emissions by leveraging our clean electricity supply.

Efficiency Vermont is a vital partner in our Tier III work and beyond. Their dedicated team of consultants and account managers provide expertise in behind-the-meter evaluation and verification, especially in HVAC performance and industrial processes. Our business innovation team often gets project leads from EVT and vice versa, demonstrating the symbiosis between efficiency and electrification. We frequently co-promote efficiency and Tier III measures, including during Button Up presentations and the Targeted Communities program. As described above, EVT's data science team developed the statistical model to accurately baseline customers in FLM 2.0.

Our goals to cut carbon and costs continue with the passage of Act 151, which allows Efficiency Vermont to use up to $2 million per year of its existing funding for offerings that reduce greenhouse gas emissions in the thermal and transportation sectors. We view this new development as an important step to move beyond a sole focus on reducing overall kilowatt hours consumed. *Increasing* consumption significantly, through electrification, is essential for meeting Vermont's climate goals, and this necessary shift in perspective will help align EVT's efforts with state priorities. This change would parallel an unprecedented change by Sacramento Municipal Utility District to use "avoided carbon" as the key efficiency metric rather than avoided electricity consumption, which we would also like to see occur in Vermont.

We also benefit from guidance and feedback from the DPS and Renewable Energy Vermont. All innovative pilots are reviewed by these stakeholders in advance of formal submission, and we greatly appreciate their input for making the programs successful for all customers. The Department has engaged in important work in rate-design and decarbonization, which we frequently rely on for decision-making, including the cost of avoided carbon study and Rate Design Initiative (RDI).

Communicating With Our Customers

Communication is key to partnering with our customers so we can provide them with great service. We think of it as having an ongoing conversation that happens through multiple channels – phone calls, letters, the monthly energy statement, social media, online community message boards, our website, public gatherings and more. Our goal is for customers to be able to connect with us, and the information they're seeking, in whichever way is easiest for them.

This multi-path, ongoing-conversation approach to customer communication proved incredibly useful during the pandemic. Our established relationship with customers as a trusted source for clear, easily accessible information was key to sharing updates about continuing service, field operations, safety, suspension of disconnections, financial assistance available, storms and innovative programs to help customers reduce carbon and costs, as well as to help each other.

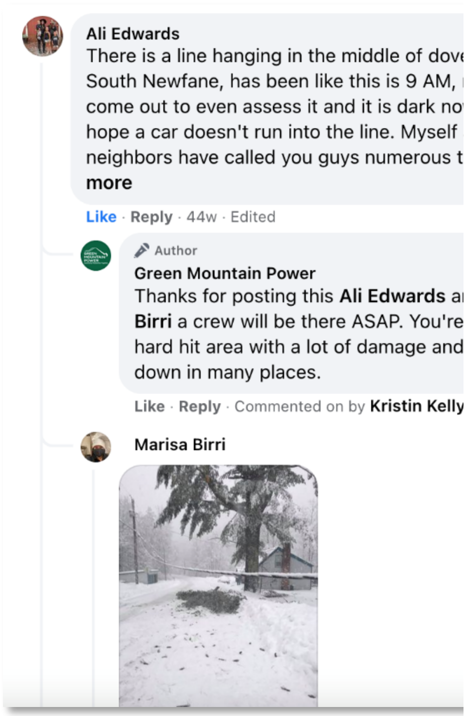
We are always looking for new ways to connect with customers to meet them where they are, and recent additions to our communication pathways include: a podcast about energy programs and information, a skill for Alexa smart speaker users, a chat option on GMP's website to answer customer questions in real time, and biannual public meetings with GMP leaders and employees.

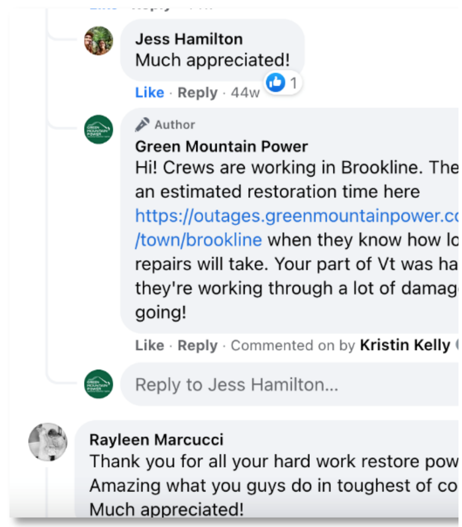
Social Media, Traditional Media, and Local Area Electronic Information Boards

Social media is a great way to talk with customers - we share news about incoming storms, new innovations, ways to reduce carbon and costs, and customers reach out with questions about our posts and sometimes just tag us on their own.

Facebook

We have more than 24,000 followers on Facebook, and it is an engaged community, especially during storm outages. We respond to customers in real time with the latest information and safety tips.





We also share photos and information about upcoming events, public meetings, and new programs, including financial assistance programs, which has been especially helpful with arrearage relief.

We used the Facebook Live broadcast feature prior to the pandemic, and it has been invaluable during this time of COVID as a way to hold open houses and public meetings with customers safely – including about the IRP as it was being prepared.

Twitter

We connect with a different group of customers through Twitter. Some customers prefer this shorter-form medium for communication, and it is a great platform to amplify our Facebook posts.

Front Porch Forum

Monthly postings on Front Porch Forum reach local community message boards throughout our service area, and several posts this year have been dedicated to information about resources available to help customers get caught up on their overdue balances. Others focus on safety and customer programs, like electric vehicle rebates and discount charging rates.

Traditional Media

We share news releases to a wide range of traditional media outlets about multiple news items including public safety information, education around new technology to help customers save money and reduce carbon, plus resources available to assist customers who are struggling during the pandemic. The news coverage generated is a powerful way to connect with customers.

Communication Platforms

We have several platforms at GMP to make it easy to share information with customers about their accounts, ways to save money, storm safety tips and opportunities to get involved in the regulatory process.

Call center (CSRs, IVR, Robo calls)

On average, GMP's call center team takes nearly 300,000 calls each year from customers, providing information on a growing range of topics. This team is an especially important link to customers during storm outages and played a key role during the pandemic. Our call center supports real-time translation services in over 300 different languages.

IVR offers customers the option to direct their calls and manage services without having to talk with a customer service representative.

Robocalls are deployed to notify customers about planned outages for system repairs and have also been a useful way during the pandemic to alert customers who are in arrears to make sure they know about state grants available.

Energy Services and Business Innovation Teams

This targeted team of employees work directly with customers to assist with programs that help them cut carbon and costs – whether it is at an EVenture Ride and Drive event in Danville (and several other community events around electric vehicles), answering a question about heat pump rebates, or ways a business can leverage GMP incentives to decarbonize and streamline their operations to save.

Email

Through email we reach customer segments with updates, important account information and programs. More than 50,000 customers get a weekly energy usage summary email from us.

Monthly Energy Statement

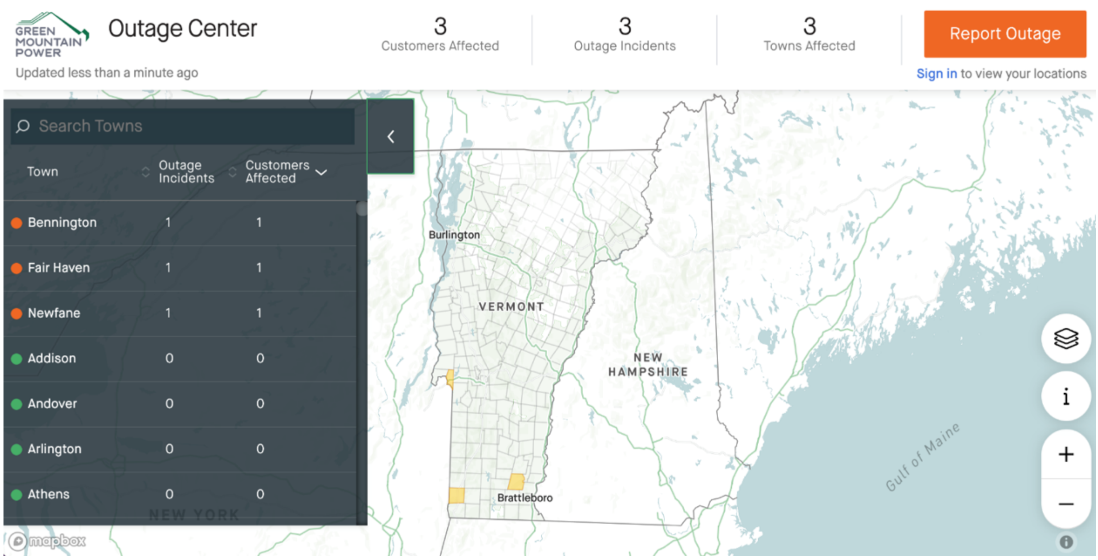
Our monthly energy statement not only provides customers with energy usage information and a breakdown of their monthly charges and fees, it also shares messages about the benefits of switching to electronic billing, public meeting invitations, ways to share input in regulatory cases, plus safety tips and rebate news.

Greenmountainpower.com

Our website has a growing number of visits – 1.6 million last year, which is up 19 percent over 2019. It is a place where customers can learn about our latest programs and news, plus check their energy usage, and manage their accounts. We are always making tweaks to improve functionality for customers, including adding a chat function, which offers customers the option to type questions and get answers from a GMP customer service representative in real time when visiting our programs pages

Our Online Outage Center and Map

The online Outage Center loads easily on smartphones and is an interactive resource where customers can report outages, plus see data about outage numbers and locations, and estimated restoration times.



Text alerts

More than 26,000 customers are signed up for text notifications about outages and storms.

GMP Smartphone App

Features of the app have been periodically upgraded to improve customer-friendly functionality for account management and outage reporting, and more than 9,000 customers have downloaded it to their smartphone.

Alexa smart speaker skill

For customers who love talking to their smart speaker, GMP created a skill so they can chat about GMP now. “Alexa, how much energy did I use last month?” and “Alexa, how much is the GMP heat pump rebate?” are the types of questions customers can get answers to, just by asking Alexa, and hundreds have done that this year.

Good Energy Now Podcast

Launched in late fall 2021, this podcast offers brief conversations that cover a variety of energy topics that are focused on customers – for example, explaining batteries and how they are helping to transform the grid, or a quick chat about heat pumps and how they work. The idea is to provide another way to answer customer questions and share interesting information that can help them as they make choices about how they use energy at home and at work.

Biannual Open House

We hold two 'GMP Open House' events per year to connect customers with leaders in the company. Pre-pandemic, we invited customers to join us at our offices – one in the southern half of the state, one in the northern half. During the pandemic we've conducted these meetings via Facebook live and it worked very well, with company leaders responding directly to customer questions in real time, covering an array of topics – from storm restoration and weather impacts to leveraging innovation to rates. We also report on metrics across the company, and we are looking forward to being able to invite customers to join us at our offices again.

EVenture Ride and Drive events

We've also held several in person EVenture Ride and Drive events, which are outdoors. The goal – share information about how simple it is to switch to driving electric. Customers who are EV drivers join GMP experts to showcase EVs, and curious customers can ask questions and test drive a variety of different EVs in a no-pressure environment. In 2021, we held popular events in Bethel, Bristol, Danville, Essex, and Middlebury, with more planned next year.

Communication Innovations During the Planning Period

We love connecting with our customers and will continue to look for ways to reach them effectively to engage in conversations, to hear their views and ideas.

Some of the ways we expect to enhance our ongoing conversations with customers will be through:

- Expanding chat on website
- Integrating more customer-friendly features on the website
- Hosting more educational public events
- Sharing more detailed outage and field work information for customers
- Creating videos to explain energy systems, storms, and more

2. Demand and Distributed Energy Forecast

Decarbonizing to Benefit all Customers

There is broad consensus that to decarbonize at the scale and speed required to limit planetary warming to 1.5 or 2°C, we must "electrify everything," especially our heating and transportation systems. Those two sectors account for over 70% of Vermont emissions as of 2018,[1] and we have the technology to rapidly transition towards lower-emission alternatives in the form of heat pumps and electric vehicles. For the first time in over two decades, the long-term expected trend in overall electricity consumption is significantly positive, which directly helps lower costs for all customers, due largely to these two core decarbonizing technologies.

In the near term we will continue to drive electrification to cut carbon and costs for customers through incentives, outreach, and education. At the same time, we will ensure new load is strategically managed, through smart technology and rate design to help customers and the grid.

In this chapter, we first discuss the context and history for GMP's base retail sales forecast, including key inputs and methodology. We explore several factors that affect the long-term forecast, including efficiency measures, solar net metering, economic and household growth, and electrification. Vermont has had robust efficiency and net metering programs, which have made a significant impact on overall electricity demand.

As more customers invest in behind-the-meter solar, there is an opportunity to pair local generation with new load and storage. Shifting the timing of electricity consumption is key not only to reduce costs associated with demand peaks, but to enable the distribution grid to support more generation and lower costs for all customers. We look forward to partnering with Vermont's extensive network of clean energy organizations to ensure that any customer who installs solar also considers backup battery storage for resiliency, cold climate heat pumps, and electric vehicles. These pairings are critical to controlling costs for all and creating a new energy future.

This chapter includes sensitivity analyses for the most prominent electrification measures to date: cold climate heat pumps, light-duty electric vehicles, and custom measure electrification projects. Less prominent measures, including ground-sourced heat pumps, heat pump hot water heaters, and heavy-duty electric transportation are instead included either in the base forecast or as part of the broader custom measure category. We will continue to evaluate new technologies to determine if they warrant scenario-based forecasting in the future.

These scenarios combine to produce three 20-year load forecasts used in subsequent chapters. We discuss demand implications and strategies for managing demand, including time-of-use rates and battery storage. The chapter concludes with customer, utility, and societal cost tests for the most prominent electrification measures.

Sales and Demand in the Planning Process

Sales and demand form a foundational standard for integrated resource planning. Traditionally, not much volatility occurs in the time between when Itron Inc., GMP's third-party retail sales forecaster, provides a sales projection for a particular year and when GMP's ensuing actual retail sales occur. 2020 and 2021 have been different.

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[1] https://www.eanvt.org/wp-content/uploads/2021/06/EAN-APR2020-21_finalJune2.pdf

COVID-19 has had a tremendous impact on so many areas including GMP's normally steady pattern of sales. We saw upheaval beginning in March 2020 when large sectors of the economy shutdown or slowed dramatically due to COVID-19 emergency measures. Itron has been tracking how GMP's weather-normalized sales have fared in comparison with a baseline pre-COVID forecast that is used by State of Vermont economists to determine when the impacts of the pandemic have finally passed. The chart below reflects that ongoing comparison.

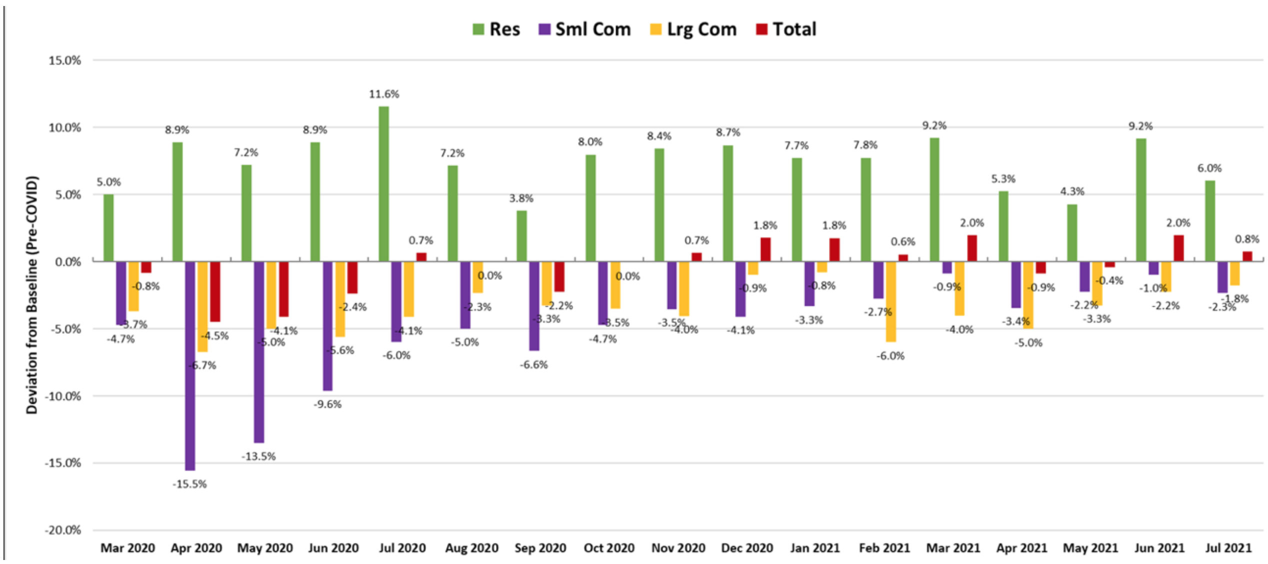


Figure 2-1. Pre-COVID Forecast vs. Actuals

The difference between the weather-normalized actual and pre-COVID forecasted sales is compelling, reflecting the upheaval felt by so many. Commercial-Small sales fell almost 16% in the month of April 2020. Commercial-Large sales in the month were off by 7%, which seems modest in comparison. Meanwhile, Residential sales in April 2020 were up 9% as people stayed home and worked from home in the early stages of the pandemic. The increases due to Residential sales and favorable weather being offset by the drop in Commercial Sales has meant that the total variance in sales versus the filed Cost of Service retail sales forecasts has been unfavorable by about 0.1% since March 2020.

Variance from the forecast for Commercial sales has dampened as the economy slowly returns to normal, so that as of July 2021 Commercial sales were about 2% below the pre-COVID forecast. As noted in Appendix A, Itron expects sales to approach pre-COVID levels by the end of Calendar Year 2022, with "small, but permanent structural change with some people continuing to work at home and correspondingly fewer people in the office; some businesses are likely permanently closed."

While the scale of the pandemic impacts is broad, unique, and continuing, this is not the first time GMP has experienced significant deviations from forecasted sales. In FY2009, total retail sales fell almost 4% below forecast due mostly to the economic downturn that began in 2007 and 2008. In FY2012, the impacts of Hurricane Irene and the accompanying warmer winter resulted in total sales ending the year almost 3% below forecast. While GMP has not seen surprise growth within a year that led to a meaningful increase in sales, it is typical to see some weather-related variance that can lead to either higher or lower sales. Still, nothing in recent history matches the volatility that GMP and its different customer segments endured during the pandemic, even if the final revenue in dollars was essentially on budget.

Other changes could be coming to GMP's base case retail sales forecast. In March 2021, GMP's largest customer, Global Foundries (GF), filed a petition with the Vermont Public Utilities Commission (PUC) to become a Self-Managed Utility (SMU). This proposal is under PUC review now. If GF does become an SMU, GF would not be a GMP retail customer as of October 1, 2026. GF will continue receiving energy and capacity from GMP through a Purchased Power Agreement (PPA) during a transitional period between FY2023 and FY2026 to provide stability and predictability for customers. GF will separately pay for its transmission costs. GF represents approximately 10% of GMP's existing sales, making the comparison between the 2018 and 2021 IRP forecasts more challenging.

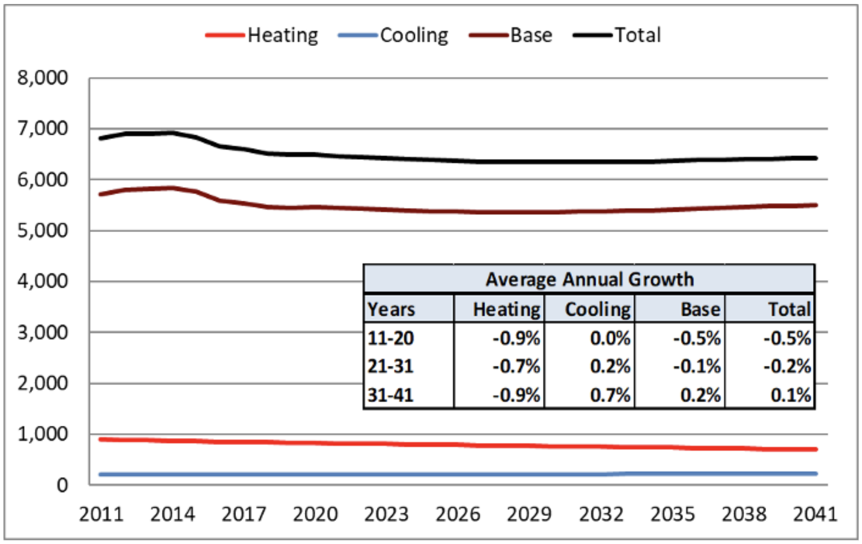
Factors Affecting Consumption

Four main factors affect retail sales forecasts: two reduce sales and two increase sales. Sales reducers include energy efficiency & appliance standards, and solar net metering. Sales increasers include economic & household growth, and strategic electrification.

Energy Efficiency and Appliance Standards

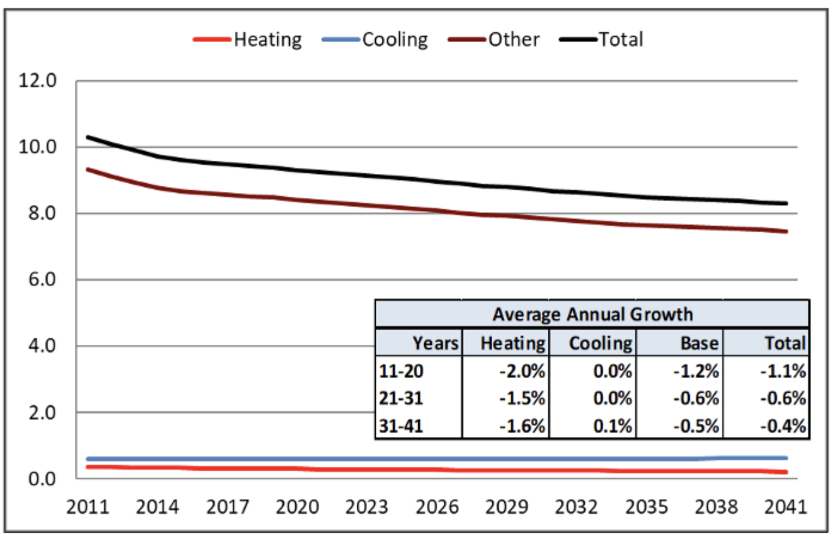
Efficiency gains continue to counter sales growth from customer and economic growth as noted in Appendix A. Itron captures efficiency gains through end-use energy intensity projections and expected state-sponsored energy efficiency savings.

End-use intensities reflect both increases in appliance ownership (saturation) and changes in stock efficiency. End-use intensities are based on the Energy Information Administration (EIA) 2020 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available. For most end-uses, increasing efficiency outweighs increasing saturation; this results in declining end-use intensities. The exception is residential cooling, where saturations continue to trend positive at a rate slightly faster than air conditioning stock efficiency. While cooling intensity is increasing, aggregate cooling consumption is still relatively small given the temperate summer weather conditions. The figures below show end-use intensities for both the Residential and C&I Small customer segments.



Average Annual Growth				
Years	Heating	Cooling	Base	Total
11-20	-0.9%	0.0%	-0.5%	-0.5%
21-31	-0.7%	0.2%	-0.1%	-0.2%
31-41	-0.9%	0.7%	0.2%	0.1%

Figure 2-2A: Residential End-Use Indices (kWh per Household)



Average Annual Growth				
Years	Heating	Cooling	Base	Total
11-20	-2.0%	0.0%	-1.2%	-1.1%
21-31	-1.5%	0.0%	-0.6%	-0.6%
31-41	-1.6%	0.1%	-0.5%	-0.4%

Figure 2-2B Small C&I End-Use Intesity (kWh/sqft)

Additional savings from Vermont energy efficiency program activity are captured by incorporating historical and projected demand-side management savings. Historical program savings are derived from Efficiency Vermont's *Savings Claim Summary* reports, and future savings provided by Efficiency Vermont reflect the state's most recently approved efficiency program budget. Historical and forecasted savings are scaled down to reflect GMP's share of state electric sales.

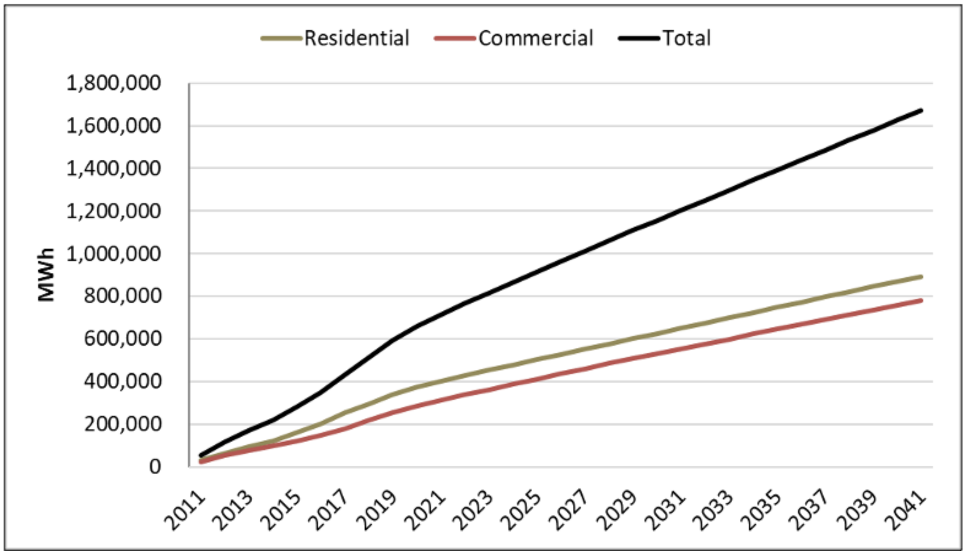


Figure 2-3: Cumulative Energy Efficiency Savings

Solar Net Metering

Unlike other power supply sources, solar net metering affects GMP's retail sales forecast. Any solar generated and consumed on the same premises within a billing month results in a reduction to retail sales known as "own use". If more kilowatt-hours are generated than are consumed onsite within a billing month, excess credits referred to as "excess" are created as a power supply expense, which may then be applied to reduce the customer's future bill. Thus, solar net metering directly impacts GMP customers by either reducing retail sales or increasing power supply expense.

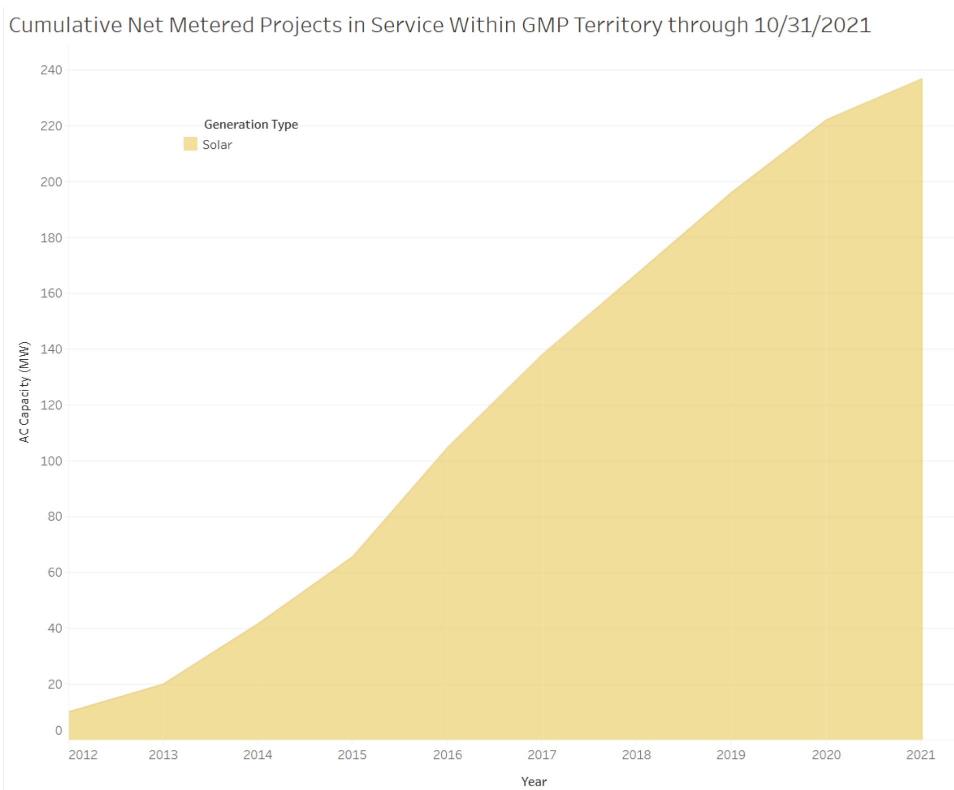


Figure 2-4. Net Metered Solar Installation Growth: 2012-2021

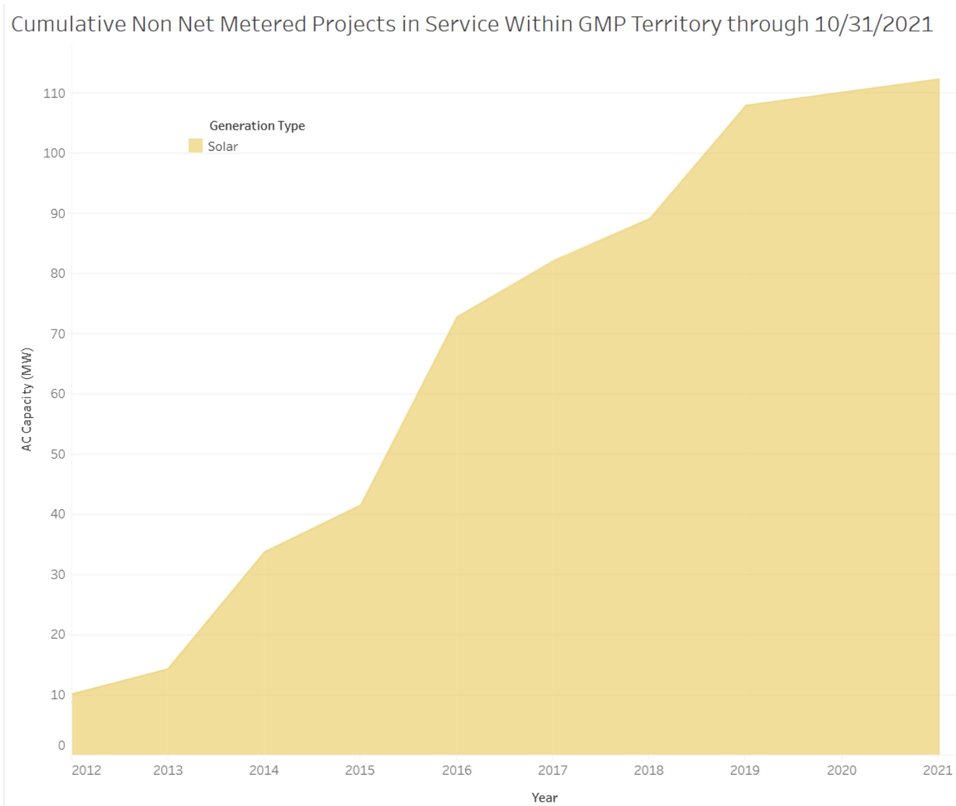


Figure 2-5. Non-Net-Metered Solar Installation Growth: 2012-2021

In Fiscal Year 2021, solar net metering projects produced about 280,000 MWh of energy. Of that total, 56,000 MWh ("own use") offset retail sales that otherwise would have occurred, and the remaining 223,000 MWh ("excess") increased GMP's power supply expenses for all customers, while appearing as a bill credit for the producers and their group members, if any (producers may either be individuals or have formed a group that shares in the generation). For context, GMP sold a total of 4,064,000 MWh in Fiscal Year 2021. Solar net metering production magnitude therefore approximates 5% of GMP's total retail sales.

The amount of solar net metering production has grown rapidly over the past few years. The 280,000 MWh of solar net metering production noted above reflects an increase of 20,000 MWh over Fiscal Year 2020, which itself was 46,000 MWh higher than Fiscal Year 2019.

Solar Net Metering in Installed Capacity and MWh of Generation by Fiscal Year

	MW		Total in MWh		
	Installed in FY	Cumulative	Generation	Own Use	Excess
FY2018	29.9	154.7	180,594	37,444	143,151
FY2019	27.8	182.5	214,005	41,591	172,414
FY2020	28.5	211.0	259,598	52,686	206,912
FY2021	24.4	235.4	279,762	56,406	223,356

Figure 2-6. Solar Net Metering in Capacity and MWh by Fiscal Year

While solar net metering has grown, GMP does not control the pace and the amount of installed net metering capacity within the company's service territory. GMP's review of net metering applications prior to issuing a permit focuses exclusively on confirming the project will not have detrimental impacts upon the distribution system. By comparison, for other sources of power, GMP uses its own generation resources or negotiates with counterparties in bilateral agreements the volume, price, and timing of megawatt deliveries

The pace of net metering installations is instead driven by other factors. This can include federal and state financial incentives, total installation cost, contractor availability, the state of the economy, and the evolution of market saturation.

Given that the pace of net metering installations is outside of GMP's control, this IRP evaluates recent trends of net metering applications and installations and assumes that those patterns will largely continue going forward for the next 10 years. As noted in Chapter 7, GMP supports more solar, more cost-effectively, for more Vermonters, and a continuing evolution of the net metering program to enable that.

GMP had approximately 211 MW of solar net metering in its service territory as of the end of Calendar Year 2020. Additionally, due to both developers wanting to qualify for existing state programs before they expire and construction time, there was another 50 MW of approved solar net metering applications queued. GMP forecasted the deployment of this queue based upon experience with timing and attrition. GMP also forecasted new applications coming in and new arrays going online. Thus, in the near-term, the forecasted solar net metering installations included both the deployment of the existing queue and the expected steady state of new applications being received and then going online. The result is that GMP included in this forecast a deployment of almost 370 MW between the end of Calendar Year 2020 and the end of Fiscal Year 2040. This translates into a pace of roughly 28 MW per year until the current queue is online followed by a steady state pace of roughly 24 MW per year through 2030. For modeling purposes, GMP assumed that solar installations would continue at approximately 50% steady state, or 12 MW per year between 2031 and 2040. For purposes of net load forecasting, we use these net metering projections. Subsequent chapters discuss scenarios for overall solar generation in GMP territory.

Economic and Household Growth

The Fiscal Year 2022 (FY22) forecast is based on Moody's January 2021 state economic projections. The primary economic drivers include number of state households, state real personal income, employment, and real state economic output (GDP). Long-term, the number of state households is expected to increase 0.4% per year; number of households drives the residential customer forecast, which historically and through the forecast period increases at a slightly lower rate. By 2023 post-COVID-19 GDP trends back to a long-term average annual growth of 1.8% per year.

Cold-Climate Heat Pumps

Cold Climate Heat Pumps (CCHPs) are continuing to become a mainstream technology to help Vermonters cut carbon and costs. In the past three years, over 12,000 customers have adopted the technology, which provides a fossil fuel-free method of space heating in the winter months and efficient cooling and dehumidification during the summer. GMP has partnered with Efficiency Vermont and other distribution utilities to promote the technology, primarily through direct rebates, outreach, and education. As of November 1, 2021, through a partnership with Efficiency Vermont, GMP customers who buy heat pumps will save per condenser, with some of the savings applied up front without the need to submit a rebate form after the purchase. And customers who are low and moderate income will get bonus savings through a single streamlined post-purchase rebate application. Previously, customers had to fill out separate forms, with different criteria, for GMP rebates and Efficiency Vermont rebates.

Between 2018 and 2021, Vermont saw a big uptick in the adoption of CCHPs, enabled in part by GMP's Tier III incentives. By way of illustration, the high scenario from GMP's 2018 IRP forecasted a total of 8,364 units would be sold in our service territory between 2019 - 2021. In fact, 14,270 were sold over the same time and received GMP Tier III incentives. Figure 2-7 shows the IRP scenarios and actual adoption curves, with a dramatic increase in 2020 that we address below. This was due in part to GMP increasing the heat pump incentive during a period of the pandemic to help customers, installers, and the economy.

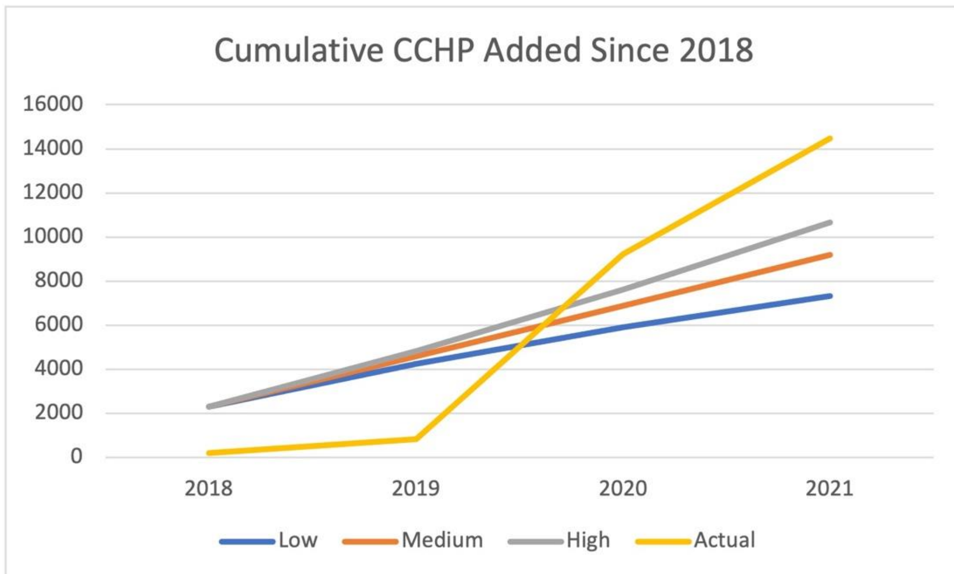


Figure 2-7. Cumulative Cold Climate Heat Pumps Added Since 2018

Continuing to support CCHP adoption is a key strategy for meeting our Tier III goals as well as reducing emissions from the residential and commercial sectors.

To model increased consumption and demand from heat pumps, we conducted a sensitivity analysis based on Efficiency Vermont's scenarios for heat pump unit adoption. These scenarios, which are updated periodically, also informed VELCO's Long Range Transmission Plan (LRTP). GMP unit volumes were calculated by scaling Efficiency Vermont's forecast by the historical percentage of CCHPs installed in GMP's service territory relative to statewide totals.

We obtained energy consumption and coincident peak demand from the 2018 Cadmus study on CCHP performance in northern New England. This study calculated that an average cold-climate heat pump system uses 2,085 kWh for heating and 140 kWh for cooling annually. We conducted an independent verification among GMP customers from Fall 2020 to Fall 2021 to calculate coincident peak demand, described in more detail below.

Our sensitivity analysis includes the quantity of Tier III MWh*e* (Megawatt-hour *equivalents*, a unit that measures fossil fuel savings from Tier III measures) under RES that would be achieved by added CCHPs for each year in the forecast. The presumed Tier III MWh*e* contribution of a heat pump was computed using a weighted average of compressor sizes sold in our service territory and their corresponding prescribed Tier III values. These values are characterized by the Tier III Technical Advisory Group's 2022 Planning Tool, using the percentage of GMP's non-fossil-fuel generation mix.

Figure 2-8 shows the major assumptions in our CCHP sensitivity analysis. Figure 2-9 shows total CCHP systems in operation under each scenario. In 2025, adoption ranges from 23,374 (low) to 34,752 (high). The spread becomes more pronounced in the later years, with 78% more CCHPs in operation in 2030 in the high scenario compared to the low scenario. Unless otherwise notes, all graphs and forecast values are presented on a fiscal year basis.

Variable	Value	Source
Annual consumption	2,225 kWh	2018 Cadmus study
Unit adoption	See adoption curves in Figure 2-9	VEIC
Coincident peak demand	0.35 kW (winter) 0.15 kW (summer)	2018 Cadmus study

Figure 2-8. Assumptions for Cold-Climate Heat Pumps Sensitivity Analysis

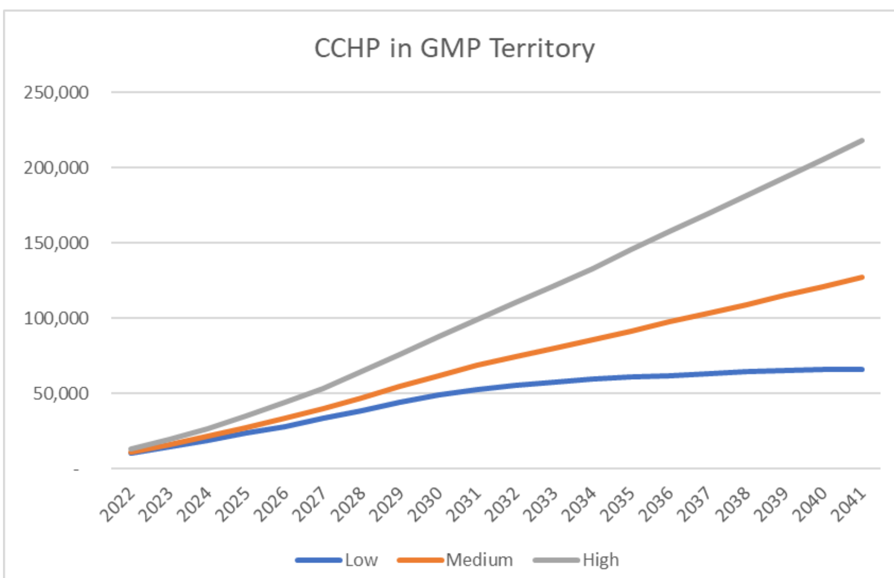


Figure 2-9. Number of Cold Climate Heat Pumps in Forecasted Scenarios

Historically, CCHP adoption has tracked most closely with the high forecast, but it remains to be seen if this trend will continue. As noted above, one contributing factor to high adoption in 2020 was a temporary doubling of our Tier III incentive. The increased incentive, coupled with a rise in home improvement projects, led to a boom in heat pump installations – over 6,500 in the months of July, August, and September 2020 alone. Installations in 2021 were lower than 2020 but still follow the high scenario more closely than any other scenario in our 2018 IRP.

Figure 2-10 shows the annual aggregate consumption from CCHPs in operation. Over 90% of annual CCHP energy consumption is due to heating, so much of this consumption takes place between October and April. CCHP systems are a significant electrical load (helping lower costs for all); in the high scenario, CCHP consumption alone represents almost 10% of total energy demand by the end of the forecast period.

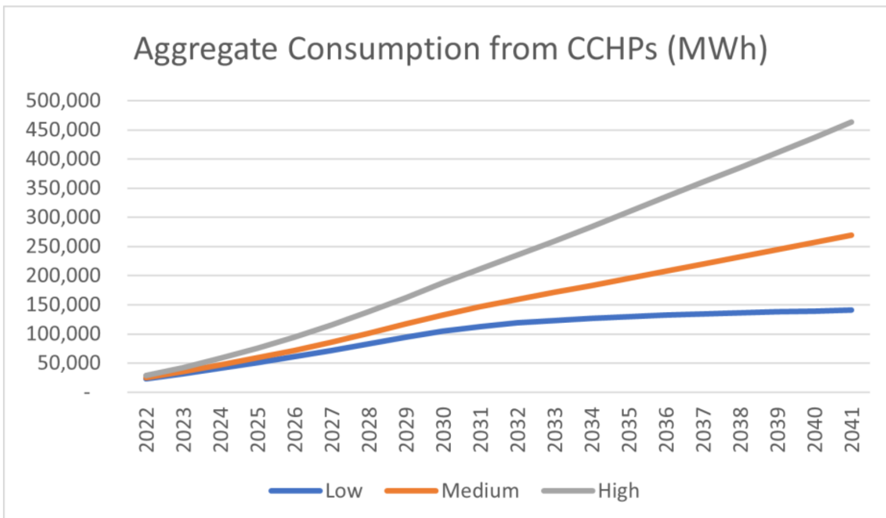


Figure 2-10. Annual Aggregate consumption from Cold Climate Heat Pumps, As Forecasted

Coincident peak demand from CCHPs is significantly larger in heating months compared to cooling months. Based on data from the 2018 Cadmus study and substantiated by a year-long validation test with GMP customers who installed load-monitoring equipment, we assume an average CCHP system's coincident peak load is 0.35 kW during heating months and 0.15 kW during cooling months. Historically, GMP has managed approximately 20% of new CCHP load through our Sensibo program, in which we provide a free Sensibo smart thermostat, and customers allow GMP to slightly modify the thermostat setpoint to reduce demand during system peaks. These data are used to project the 20-year coincident peak demand forecast from CCHPs in Figures 2-11 (heating) and 2-12 (cooling). We anticipate that improvements in CCHP technology will allow us to manage more than 20% of demand in the future as manufacturers embed internet connectivity within their products, which will facilitate enrollment in our device management platform. In partnership with Efficiency Vermont, we are also piloting "integrated controls," by which a single thermostat system can control both the CCHP and backup heating system, seamlessly switching between the two. However, because these technologies are not prevalent today, we used the historical Sensibo adoption rate of 20% as a conservative estimate of heat pump load under management in forecast years.

Even in the high-growth scenario and under the conservative assumption for the share of CCHPs that are managed, the added demand does not represent a significant burden to the overall transmission and distribution systems.

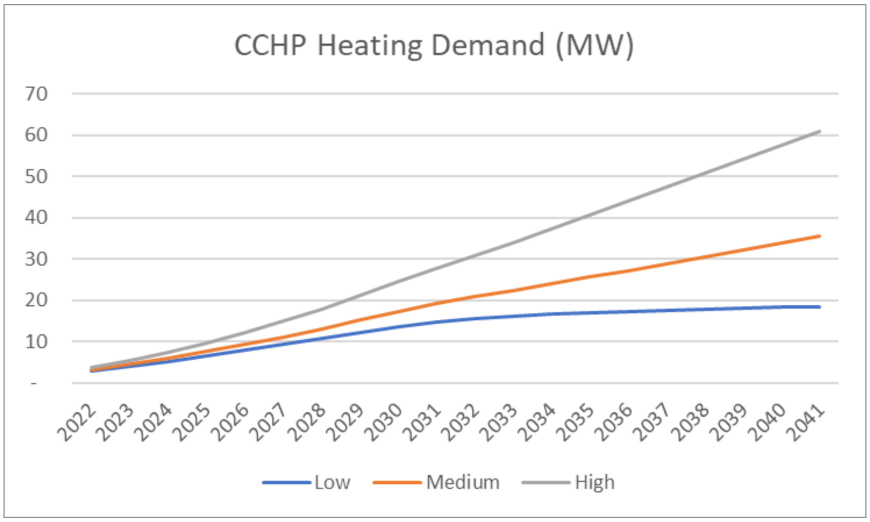


Figure 2-11. Cold Climate Heat Pumps Peak Demand Forecast – Heating

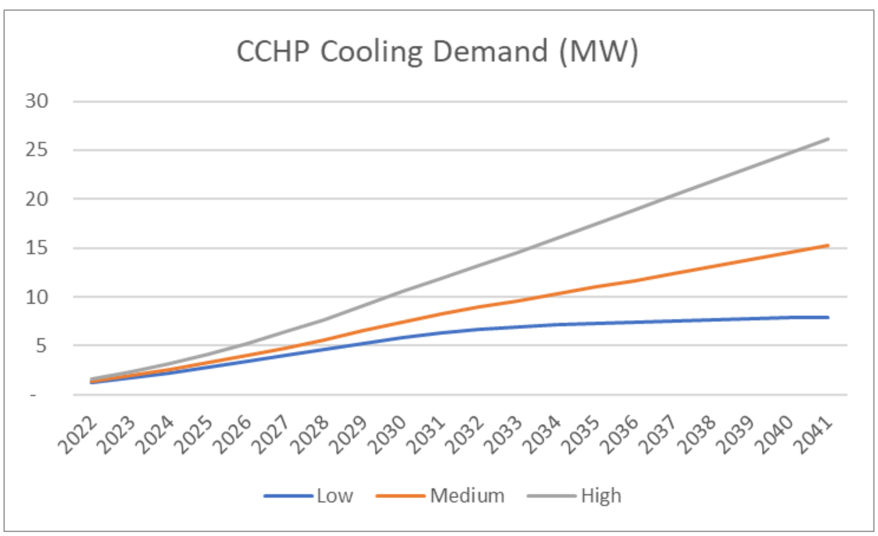


Figure 2-12. Cold Climate Heat Pumps Peak Demand Forecast – Cooling

Figure 2-13 shows the Tier III MWh*e* expected from CCHP under each scenario. Tier III value is calculated in the year the measure is installed, based on the lifetime fossil fuel reduction. The reduction of Tier III value visible in the graph is due to a decrease in *new* CCHP installed after 2028, as we move into the later adoption phases and growth could taper as modeled. Even though Tier III reports are filed on a calendar year basis, we present Tier III MWh*e* on a fiscal year basis to align with other forecasted metrics.

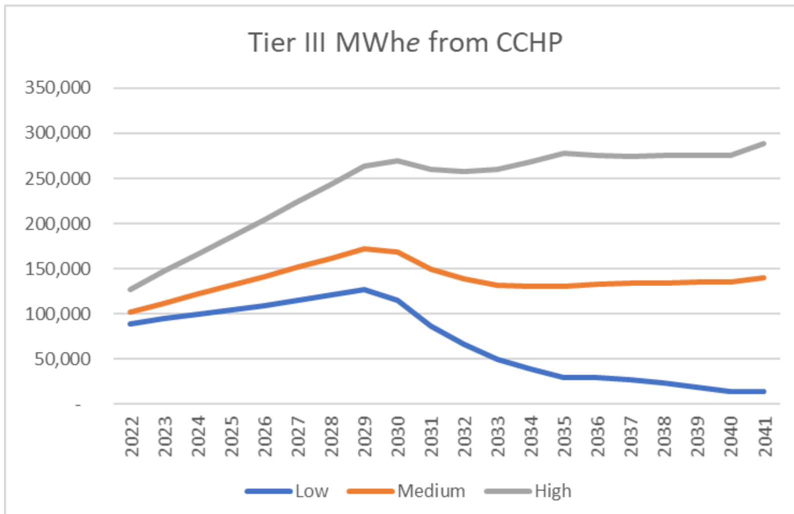


Figure 2-13. Tier III MWh*e* from Cold Climate Heat Pumps

The high CCHP adoption scenario aligns closely with Energy Action Network's (EAN) Emission Reductions Pathways Model to achieve the Global Warming Solutions Act (GWSA) requirements.[2] In that model, CCHP installations account for between 29% and 46% (depending on the year) of the required annual emissions reduction from the thermal sector; other measures include weatherization, wood and biofuels, and renewable natural gas.

Finally, Figure 2-14 shows the average daily load profile of a CCHP during the heating season on non-event days for a representative customer in our test cohort. While the magnitude of demand varies considerably depending on compressor size and home characteristics, the shape of demand is fairly regular. There is a large increase in demand in the morning that is typical of heating systems as building occupants wake up, followed by a midday trough and evening ramp as occupants return home and evening temperatures decrease. One goal of the Sensibo program is to level load throughout the day by pre-heating and pre-cooling, reducing "peakiness" and avoiding consumption during the early morning and late-evening hours.

[2] https://www.eanvt.org/wp-content/uploads/2021/08/EAN-Emissions-Reductions-Pathways-Whitepaper-Final.pdf

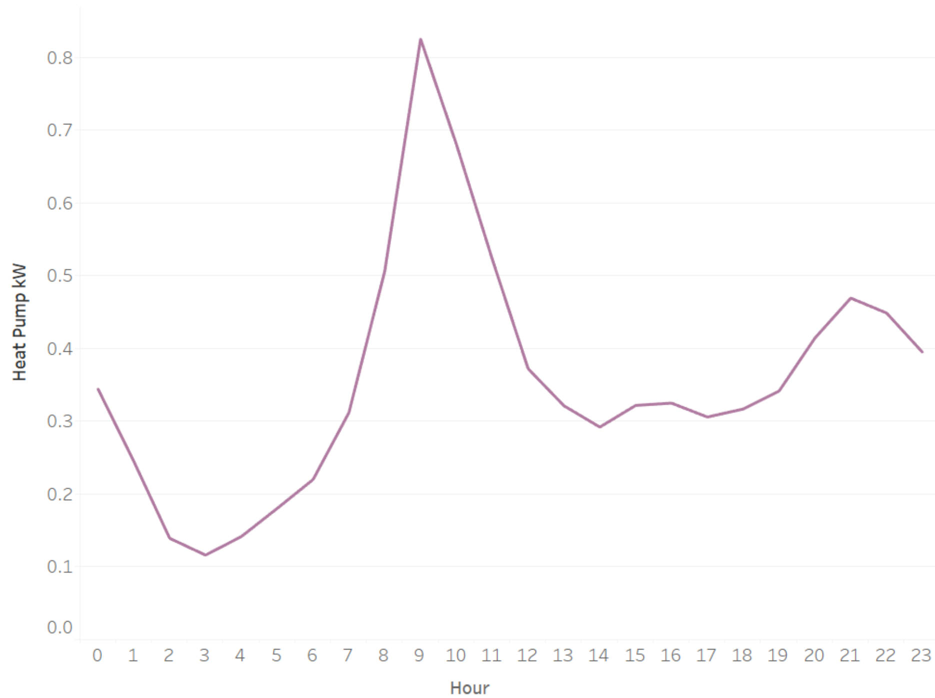


Figure 2-14. Average Daily Load Profile of a Cold Climate Heat Pump for a representative customer

Electric Vehicles

Since our last IRP, transportation emissions have grown in absolute terms and as a share of statewide emissions and remain the top source of carbon emissions in Vermont.[3] Electric vehicles (EVs) continue to be among the most effective means to reduce these emissions, due to our clean energy supply and the superior efficiency of an electric powertrain compared to a conventional internal combustion engine. Due to our 100% carbon-free supply, an EV charging in our service territory has zero operating emissions, compared to 4 metric tons of CO2 annually for an average gasoline vehicle. Even when including emissions from battery manufacturing, EVs come out far ahead.[4] One of the top way Vermonters can take action and cut carbon pollution is to change their driving, and recent EV adoption figures are encouraging, with 2018-2021 in close alignment with our medium scenario in the 2018 IRP, shown in Figure 2-15.

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[3] https://www.eanvt.org/wp-content/uploads/2021/06/EAN-APR2020-21_finalJune2.pdf

[4] https://www.carboncounter.com/

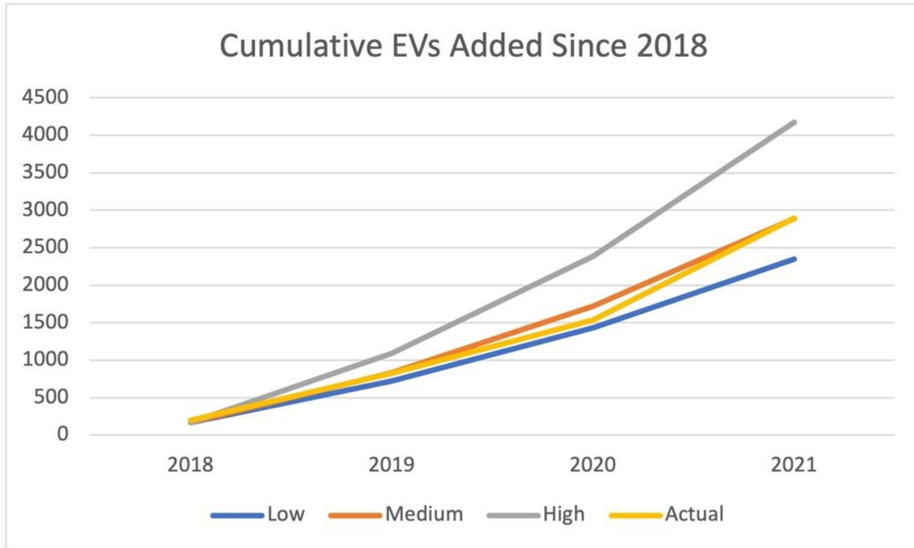

Figure 2-15. Cumulative EVs Added Since 2018

Expanded model availability and state incentives on top of existing GMP and federal incentives have put EVs in reach for even more Vermonters, who can save thousands of dollars on fuel and maintenance by driving electric. The customer cost test at the end of this chapter expands on these projected total cost-of-ownership benefits.

We offer a variety of programs to encourage EV adoption. For drivers, we provide a point-of-sale purchase rebate for all types of EVs including new, used, plug-in hybrid and all-electric, a free smart charger, and discounted off-peak rates for at-home charging. For workplaces and charging station developers, we have a workplace charging pilot and just concluded a successful make-ready pilot to help offset the cost of infrastructure upgrades to support fast-charging stations.

Home charging continues to dominate overall EV charging activity, representing over 80% according to the Tier III Technical Reference Manual (TRM) and corroborated by data from chargers enrolled on our EV rates. We believe this trend will continue even as more chargers are deployed at workplaces and points of interest across Vermont and as solutions emerge for condo and multifamily dwelling charging. Also, public fast charging deployment is a necessary step to give more EV owners the options they need to drive electric.

We now have two active residential EV charging rates and over 1,000 chargers under some form of management. These rates are described in detail in Chapter 1. Data indicate that the rates are extremely effective at shifting charging activity away from peak periods. On Rate 74, over 90% of charging has occurred outside of peak hours (1:00 p.m. to 9:00 p.m. during weekdays), shown in Figure 2-16. And on Rate 72, we have consistently seen a peak event opt-out rate of less than 1%. Figure 2-17 shows one such peak event. Customers enjoy the simplicity of letting technology manage charging for them, shifting consumption away from peak periods. In exchange, participants receive the benefit of lower rates.

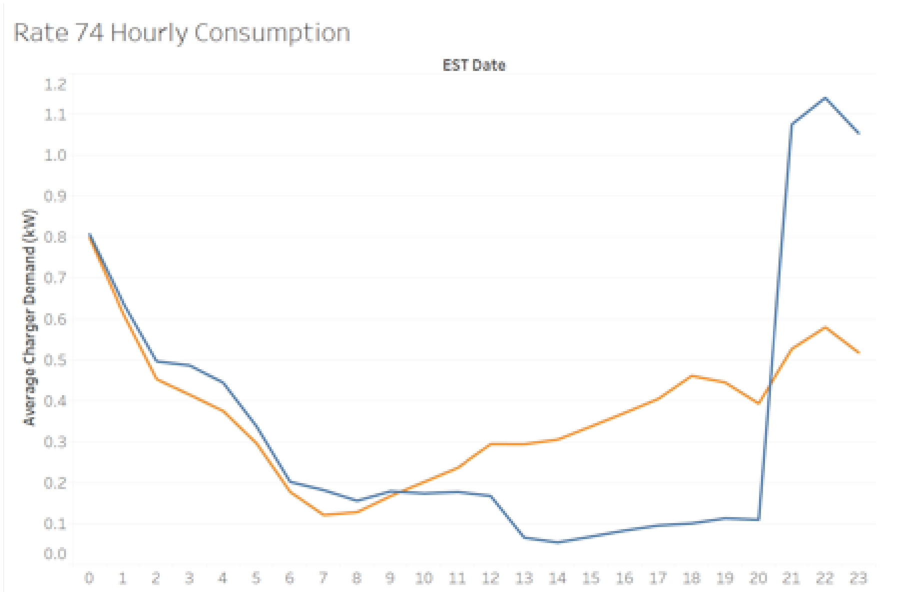

Figure 2-16. Hourly Consumption on Rate 74; Blue curve indicates weekday consumption, orange curve is weekend consumption (entirely off-peak)

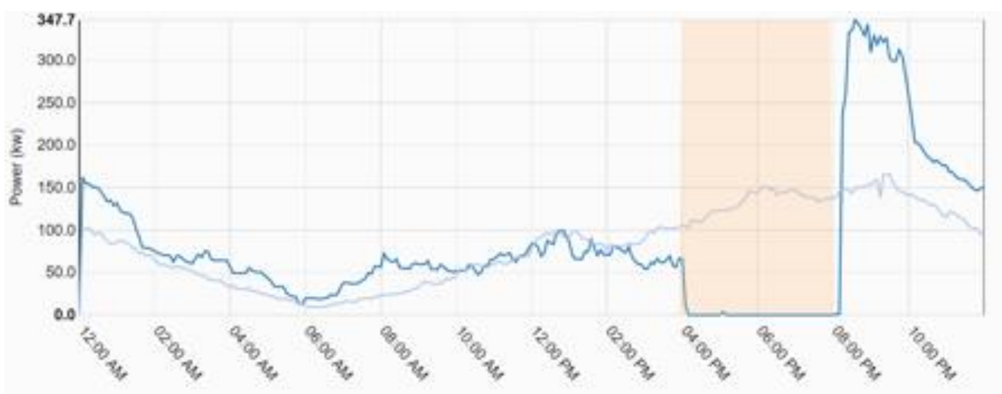

Figure 2-17. Illustration of Peak Event for Rate 72 Customers. Dark blue curve is actual demand, light blue curve is the baseline

Over the last two years, among customers who claim our point-of-sale EV rebate, approximately 75% opt for the free Level 2 charger and sign up for one of the two EV rates. Among those who do not choose the free charger, the majority are plug-in hybrid drivers for whom “Level 1” charging (i.e., a standard 110 V outlet charging at between 1-2 kW) is sufficient based on the vehicle’s low electric driving range. Given the importance of managing EV load, we will continue to provide a free charger and our EV rates, and we are actively investigating “direct-to-vehicle” technology as one alternative to charger-based management and billing. The promising results thus far, combined with the large share of charging occurring at home, have led us to believe that we can continue to manage over 60% all EV charging load. While we are working towards managed charging solutions in public and workplace settings, customer acceptance is less well-understood; as a result, we assume no EV demand management for non-residential charging.

Like for CCHPs, we modeled three growth scenarios based on Drive Electric Vermont's forecasts for EV adoption (scaled to reflect GMP's share of the statewide total) and annual use. For coincident peak demand, we used actual data from GMP-connected chargers on non-event days to calculate a per-vehicle baseline (0.65 kW), then scaled the aggregate demand by both the share of charging occurring at home and conducive to management (83% according to the Tier III TRM) and the share of new EV drivers in our territory who enroll in one of our EV rates (75%). The table below shows the major assumptions used for our EV sensitivity analysis.

Variable	Value	Source
Annual consumption	Weighted average of all-electric and plug-in hybrid	Drive Electric Vermont
Unit adoption	See adoption curves in Figure 2-19	Drive Electric Vermont
Coincident peak demand	0.65 kW	GMP residential charging data, see Figure 2-18
% of charging occurring at home	83%	Tier III Technical Reverence Manual
% of EVs under management	75%	Historical adoption since Tier III incentives introduced

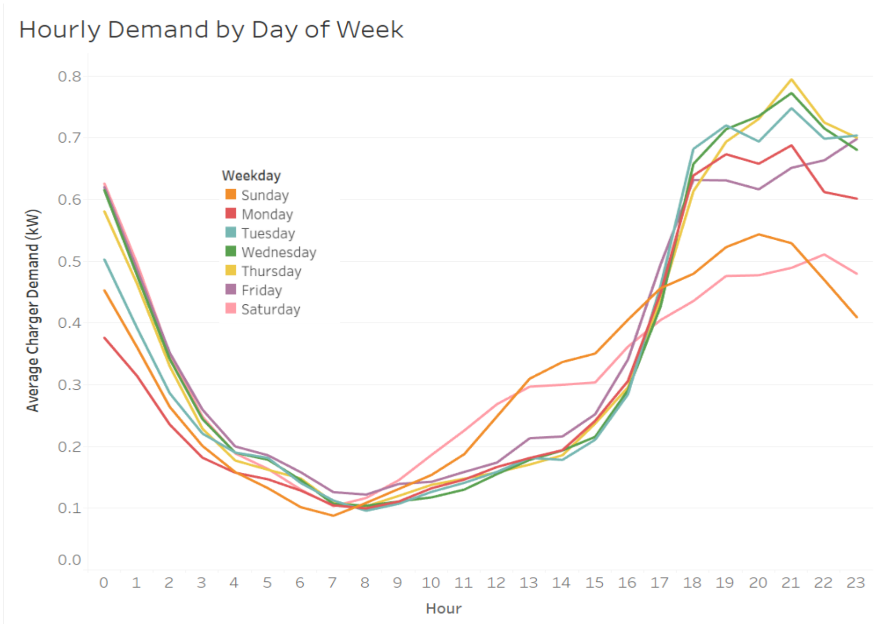

Figure 2-18. Average Charging Demand Among all EVs (with a GMP-compatible charger, segmented by weekday, on non-event days)

Figure 2-19 shows total passenger EVs registered in GMP territory under each scenario. In 2025, the low scenario projects approximately 10,000 EVs and the high scenario projects approximately 29,000. By 2030, the high scenario has over five times the number of EVs as the low scenario: 137,000 compared to 26,000. The wide gap between the low and high forecasts reflects the wide range of possible technological and policy developments that influence EV adoption, especially purchase incentives and battery cost.

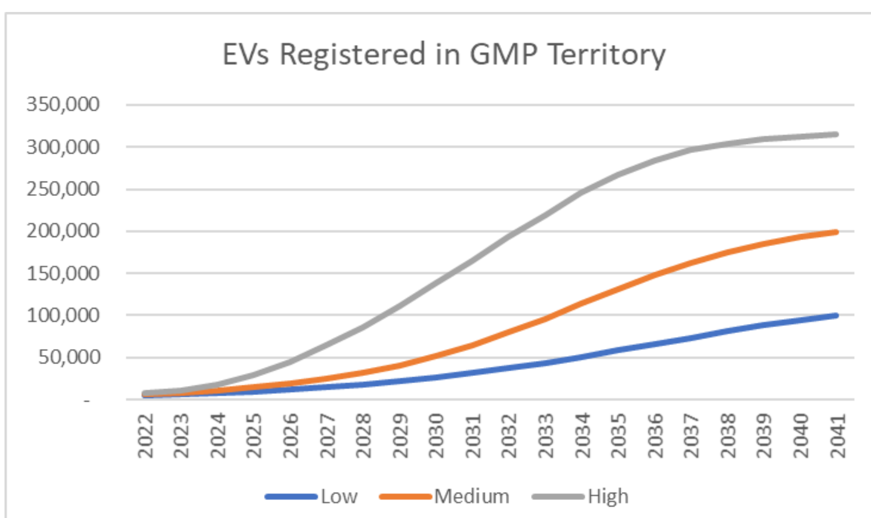

Figure 2-19. EVs Registered in GMP Territory in Forecasted Scenarios

EVs are a significant source of new load, therefore helping to reduce cost for customers. An average all-electric vehicle (AEV) that drives 10,000 miles annually consumes over 3,100 kWh, which is approximately 40% of total household electricity consumption on average in GMP territory. Consumption is higher in the winter months due to reduced battery efficiency in cold temperatures and higher energy requirements for cabin climate control. Many EVs now come equipped with heat pumps to reduce draw on the battery, as well as heated seats and steering wheels. Figure 2-20 shows the aggregate annual consumption due to EVs in each scenario. Note that aggregate consumption includes all forms of charging, including residential, public, and workplace. We recognize that some charging for vehicles registered to GMP customers will occur outside of our service territory. However, this should be more than compensated for by public charging by out-of-state visitors.

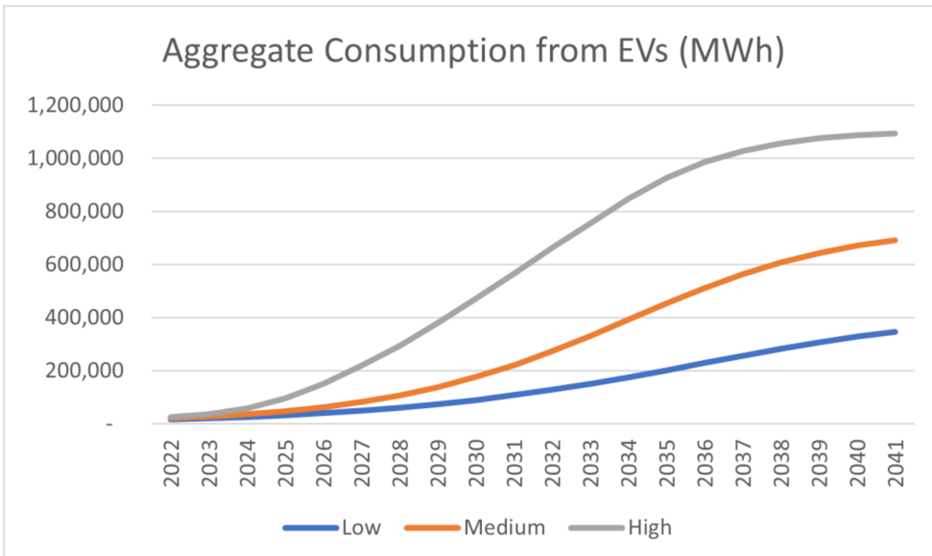

Figure 2-20. Annual Aggregate Consumption due to EVs in Forecasted Scenarios

Unlike CCHPs, where embedded internet-connectivity is not yet prevalent, all the technology required to manage EV charging load is in place today. Our two residential charging rates have been effective at shifting load away from peak times. The advent of technologies like telematics-based control (whereby a signal is sent directly to the vehicle rather than the charger) will expand opportunities for intelligent charging management, but they are not essential to reducing coincident peak load. Figure 2-21 shows the projected coincident peak demand due to EV charging under each scenario, which includes the assumptions that 75% of new EV drivers enroll in one of our EV rates and 83% of charging activity occurs at home (from the Tier III TRM).

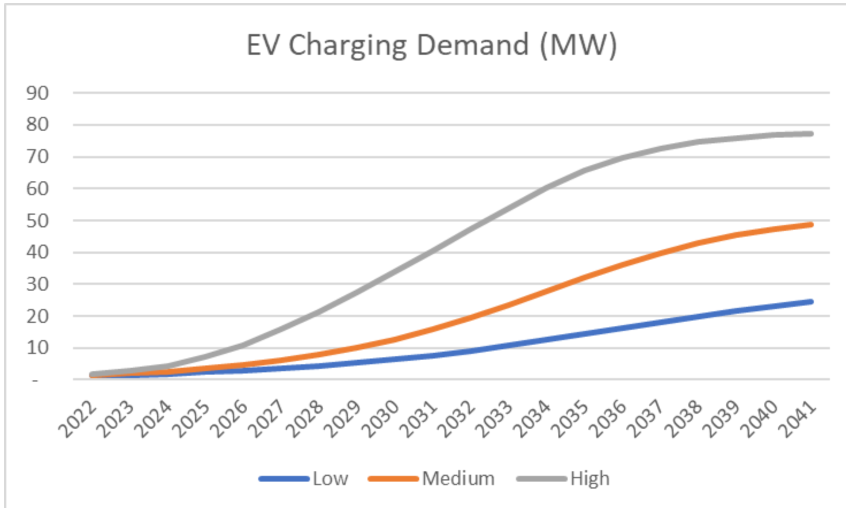

Figure 2-21. Projected Coincident Peak Demand Due to EVs, Forecasted

It is illustrative to compare our forecasts to those calculated in the LSAM model developed by the Department of Public Service (DPS) with its partner NewGen Strategies. In that model, unmitigated EV demand from weekday home charging reaches 179 MW in 2030, which is important to note is never contemplated to happen as GMP currently has managed programs. While the NewGen figure is a statewide total, it illustrates the potential for adverse impact of transportation electrification *if it is not paired with enabling technology and rate design*, which we agree is important and are doing in partnership with customers. In workshops convened by the DPS as part of its Rate Design Initiative, this topic was also covered in detail, highlighting the necessity of these programs.

Figure 2-22 shows the Tier III MWh*e* achieved for each EV scenario. The Tier III MWh*e* value for an all-electric vehicle is higher than a plug-in hybrid; a weighted average is used in our Tier III projections. Drive Electric Vermont's forecast features an increase in the share of all-electric vehicles. In recent years, however, the actual share of all-electric vehicles as a percentage of total electric vehicle sales has outpaced projections, due in part to rapid improvement in battery range and a strategic decision by some automakers to phase out plug-in hybrid production in favor of all-electric vehicles. Like for CCHP, Tier III MWh*e* decreases in the late 2030s as we approach a nearly all-electric light duty vehicle fleet and new net sales (EV replacing non-EV) could slow down.

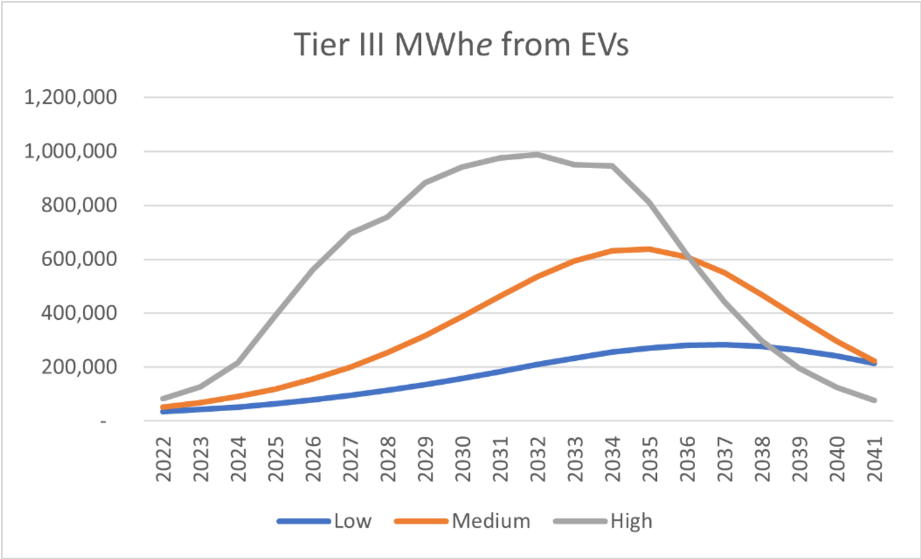

Figure 2-22. Tier III MWh*e* from EVs, as projected

The high EV adoption scenario corresponds closely to the required fossil fuel savings from light duty EVs in EAN's Pathways Model. The model also includes carpooling, public transportation, telecommuting, improved combustion engine efficiency and electrification of heavy-duty fleets for reducing transportation emissions. If those measures advance more quickly than the Pathways Model assumes, we could rely less on light duty vehicle electrification to achieve the GWSA targets. The high scenario puts us on a path to achieving a nearly 100% light-duty vehicle fleet by 2050, with approximately 315,000 registered vehicles in GMP territory in 2041.

Custom Measure Projects

In addition to prescribed measures like CCHPs and EVs (which have standard Tier III values), GMP helps encourage electrification through what are known as custom measure projects. These often involve Commercial and Industrial customers and are completed in close partnership with Efficiency Vermont to pair electrification with efficiency and reduce operating costs. In each project, GMP's business innovation team models the fossil fuel consumption based on a variety of inputs from the customer, and then calculates an incentive based on the avoided emissions, measure life, and electricity consumption of the new asset. The incentive helps reduce the up-front cost of the project, which is key for customers in all different types of industries.

The following examples are recent custom measure projects:

Glavel

Glavel Incorporated, located in the Town of Essex, specializes in manufacturing lightweight aggregate from recycled glass. The company name is descriptive of their product – Foam, Glass, Gravel. This aggregate serves as an insulating substitute for gravel, and plastic-based insulation used in building foundations. Glavel's technology enables the construction industry to more cost-effectively insulate below slabs and achieve substantial reductions in the embedded carbon of building material. GMP contributed a Tier III incentive to enable Glavel to deploy and operate an electric kiln at their new location, as opposed to one that operates using fossil fuel. Because of the amount of heat required to manufacture Glavel, this project is projected to offset over 26,000 MMBTU of fossil fuel per year, resulting in over 71,000 Tier III MWh*e* value.

Gagnon Lumber

Gagnon Lumber in Pittsford, VT has been in operation since 1958 and had always used a fossil-fuel generator to produce lumber. Despite a desire to use electricity to operate the lumber mill, the cost to convert was too high without GMP support. A custom measure Tier III incentive enabled a 3-phase line extension that eliminated the use of 7,465 MMBTU of diesel fuel, equivalent to 7,475 Tier III MWh*e*. This project also added 200 MWh of load annually.

Merck Forest and Farmland Center (MFFC)

MFFC is a nonprofit educational organization on a mission to inspire curiosity, love, and responsibility toward natural and working lands. The existing service was not adequate to supply the entire electrical load of all the buildings and operate the reverse osmosis system used for the maple sugaring operation. As such, a Generac 45KW propane generator had supplied electric power for the reverse osmosis system during sugaring season. A custom measure Tier III incentive made it possible to retire the propane generator and install a 1400-foot underground line extension from the Visitor Center to the Maple Barn. The project displaced 3,633 gallons of propane and achieved 392 Tier III MWh*e*.

Unlike the forecasts for heat pumps and EVs, which are based on unit adoption counts, modeling the impact of custom measure projects depends on a projection of the volume of projects and their presumed Tier III value. The multitude of project types makes it difficult to precisely forecast load growth, but we can use historical data from over 4 years of project experience coupled with operating data from participating customers from before and after each project was completed. We start with an evaluation of Tier III MWh*e* growth and use those projections to model consumption impacts.

An analysis of our current pipeline for custom measure projects and assessment of similar project opportunities around the state lead to three scenarios:

Low: 50,000 Tier III MWh*e* per year

Medium: 70,000 Tier III MWh*e* per year

High: 100,000 Tier III MWh*e* per year

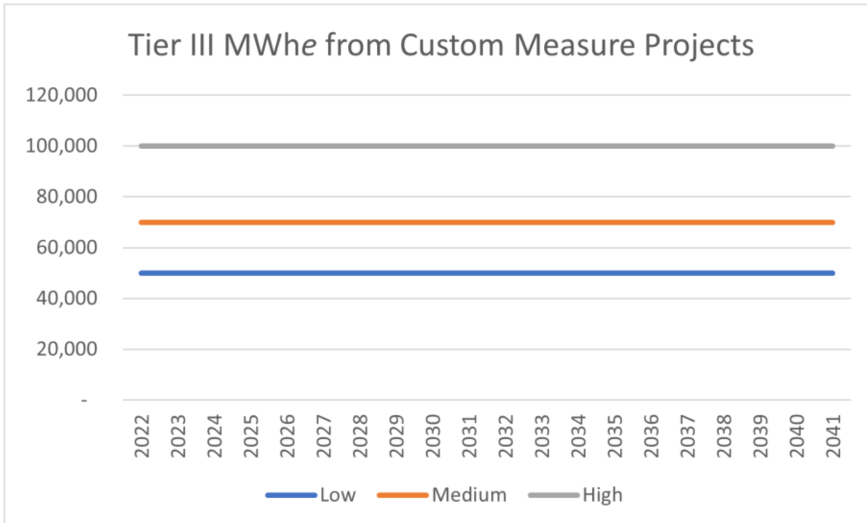

Figure 2-23. Tier III MWh*e* from Custom Measure Electrification projects

To estimate annual consumption due to custom measure projects, we use data from past projects. Historically, the ratio of electricity consumption (MWh) to Tier III MWh*e* has been 0.038. So, for a project that achieves 1000 Tier III MWh*e* (equivalent to roughly 28 all-electric vehicles), we can expect an annual load increase of 38 MWh on average.

Using this conversion factor, we can calculate the expected aggregate consumption from custom measure projects under each scenario:

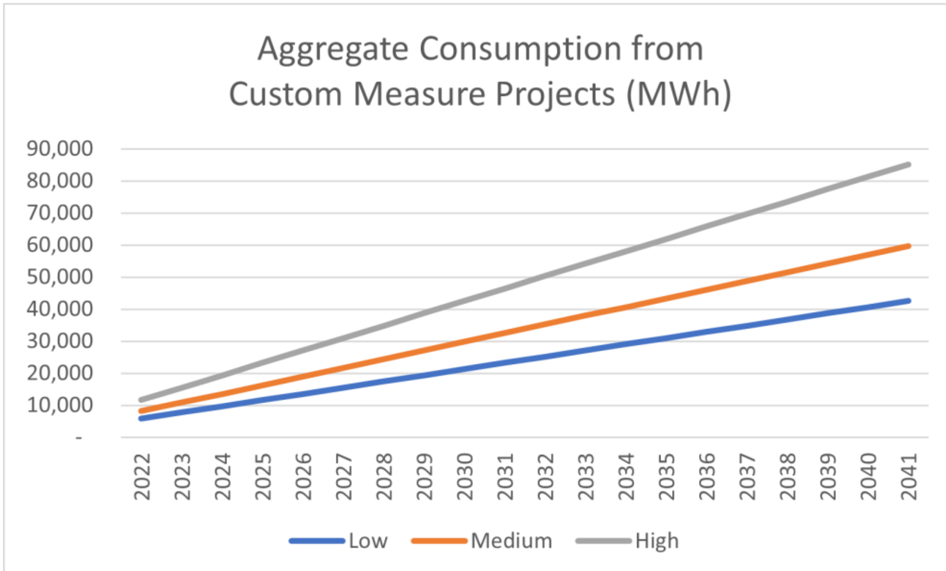

Figure 2-24. Annual Aggregate Forecasted MWh for Custom Measure Projects

The demand impacts of custom measure projects vary widely and are more contingent on the host customer's operating hours than on the measure itself. As a result, we do not separately model coincident peak demand in this category. In our demand snapshots below, we use an average C&I customer load profile for custom measure-driven electrification.

Net Impact on Retail Sales

To arrive at a set of scenarios for overall retail sales, we began with the Itron retail sales forecast, which incorporates key assumptions regarding economic and household growth, efficiency, and behind-the-meter solar growth. The Itron forecast also includes electrification based on historical adoption rates in GMP territory. This forecast is primarily intended for short-term planning purposes – informing base rate filings and power purchasing decisions – and represents the best estimate for total retail sales one to three years out. However, it does not adequately capture our long-term aspirations for an electrified future that helps cut carbon and costs in a time of climate change. In each long-term scenario, we overlay atop the Itron forecast a combination of electrification pathways from the sensitivity analyses outlined above. As adoption curves evolve, so too will the Itron retail sales forecast, which is recreated each year. The table below shows inputs for each long-term forecast (low, base, and high):

	Itron	Low	Base	High
Base load	Itron model	Itron model	Itron model	Itron model
Efficiency	Itron model	Itron model	Itron model	Itron model
Own use solar	Itron model	Itron model	Itron model	Itron model
Tier 3 - Custom measure	Itron model	GMP Medium	GMP High	EAN Measures
Tier 3 - CCHP	Itron model	GMP Medium	GMP High	GMP High
Tier 3 - EV	Itron model	GMP Medium	GMP High	GMP High
Other	Itron model	Itron model	Itron model	Itron model
Total Growth 2021-2041	4.7%	11.6%	26.7%	39.1%
Total Growth 2021-2041 if GF remains a customer	14.5%	21.3%	36.4%	48.8%

The long-term high retail sales forecast replaces the high custom measure forecast with a more specific set of unit adoption forecasts in the EAN Pathways Model, scaled to reflect GMP's share of statewide adoption. These measures include heavy duty, transit and school bus fleet electrification, ground-sourced heat pumps, and heat pump water heaters. This places the long-term high forecast in alignment with the pace of total electrification required to meet Vermont's statutory requirements for greenhouse gas reduction. In the early years, our high custom measure forecast, which includes a diversity of decarbonization projects, outpaces the EAN Pathways model, but the trend is reversed as newer technologies gain traction. Figure 2-25 shows aggregate consumption in GMP territory due to each additional electrification measure in the EAN model.

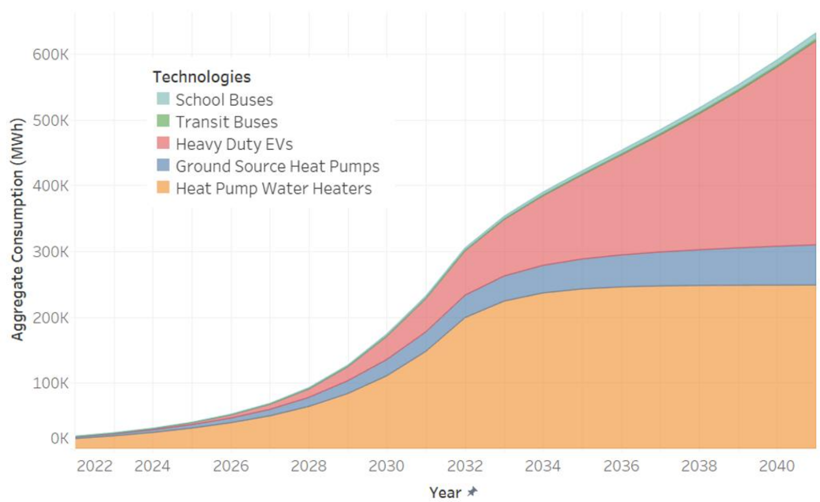

Figure 2-25. Aggregate Consumption Due to Additional Electrification from EAN Pathways Study, Scaled to GMP's Service Territory

It is worth noting that the EAN Pathways Model also includes significant emissions reductions from non-electrification measures, including efficiency, telecommuting, and biofuels. While these measures do not impact our load forecasts directly, they are important determinants for achieving statutory decarbonization requirements.

The factors discussed above combine to produce a steady annual increase in retail sales in the near term as load increases from electrification and household & economic growth outpace declines from efficiency and solar net metering. If approved, GlobalFoundries' petition to become its own utility shows up in 2027. The net result is that in 2030 we expect to serve a similar if not lower annual load to 2021. Overall, though, electrification will yield significant load additions; by 2030, the combination of CCHPs, EVs, and custom measure projects with C&I customers account for between 196,000 MWh (low) and 679,000 MWh (high) of added load relative to 2020.

Figures 2-26 and 2-27 below show total retail sales under each scenario, on a fiscal year basis:

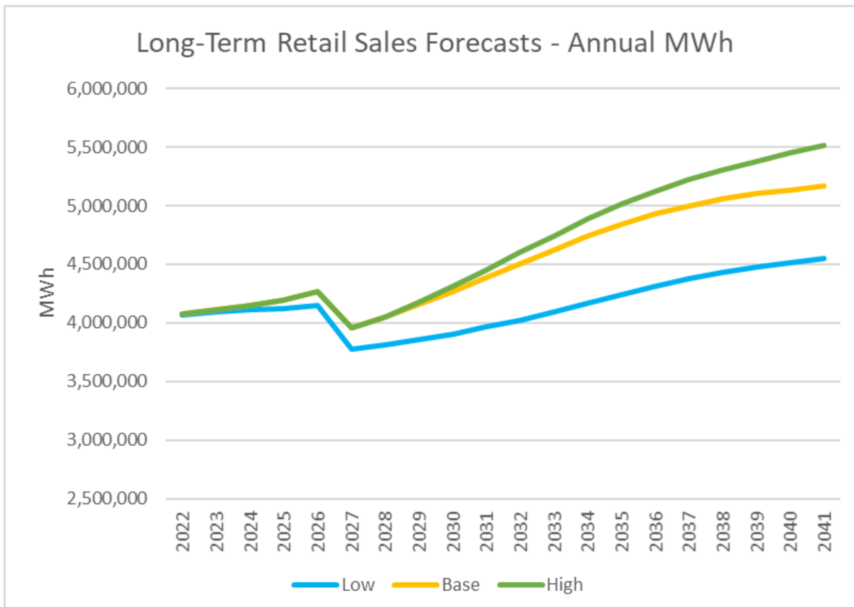

Figure 2-26. Long-term Forecasted Retail Sales, Annual MWh

Fiscal Year	Annual Retail Sales (MWh) Low	Base	High
2022	4,066,066	4,077,087	4,077,087
2023	4,092,797	4,113,820	4,113,820
2024	4,109,758	4,148,307	4,148,307
2025	4,125,415	4,196,441	4,196,441
2026	4,145,376	4,262,844	4,262,844
2027	3,779,495	3,953,244	3,953,244
2028	3,813,777	4,045,603	4,048,498
2029	3,857,904	4,154,851	4,172,188
2030	3,907,456	4,269,185	4,308,134
2031	3,962,649	4,386,047	4,450,690

Fiscal Year	Annual Retail Sales (MWh) Low	Base	High
2032	4,025,674	4,505,954	4,600,597
2033	4,093,313	4,621,770	4,743,481
2034	4,164,489	4,737,862	4,883,858
2035	4,237,047	4,842,459	5,012,273
2036	4,308,998	4,930,276	5,124,695
2037	4,373,994	4,999,715	5,220,266
2038	4,430,872	5,055,189	5,303,887
2039	4,478,583	5,100,074	5,379,321
2040	4,516,117	5,136,128	5,448,663
2041	4,546,847	5,168,708	5,517,602

Figure 2-27. Long-term Forecasted Retail Sales, Detailed Table

Hourly Load Profiles and Load Management

While annual load is an important input for our revenue projection, it does not tell a complete story. Understanding the timing of load, both hourly and seasonally, is critical to projecting peak-related costs, managing peak demand, and formulating a coherent power supply strategy.

Figures 2-28 – 2-31 show example peak weeks in the *base* forecast for two key forecast years, in both summer and winter. To better illustrate daily fluctuation in base load and electrification, these figures do not show load reducers (energy efficiency, and solar net metering), which would appear as negative numbers. The peak snapshots are not precise predictions but demonstrate at a high level how daily and seasonal patterns change with growing behind-the-meter solar and electrification. Specifically, we see:

- A widening gap between winter and summer peaks due to cold climate heat pump growth and higher EV charging consumption in cold months
- More prominent winter morning peaks driven by CCHP operation
- Increasingly pronounced midday troughs, especially in spring and summer, due to a strong pace of solar installations

In each graph, the vertical axis measures total demand (MW) in our service territory, the blue area is the base load forecast, the red area is load from CCHP and custom measure projects, and the green area is EV charging load.

2025 Winter

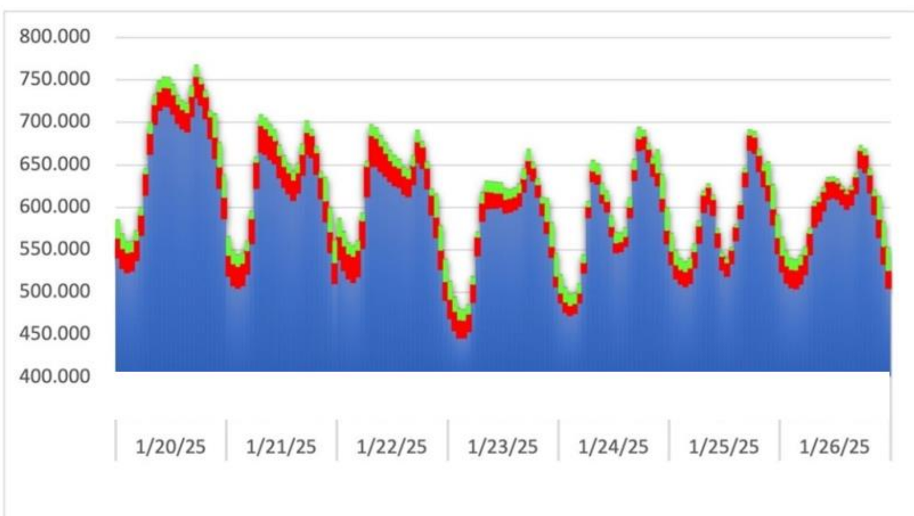

Figure 2-28. Example Peak Week in Winter 2025

2025 Summer

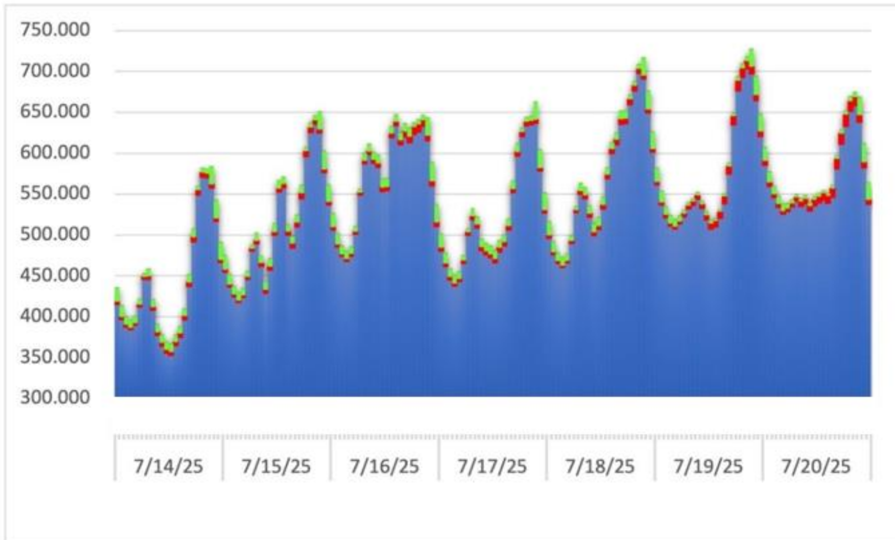

Figure 2-29. Example Peak Week in Summer 2025

2030 Winter

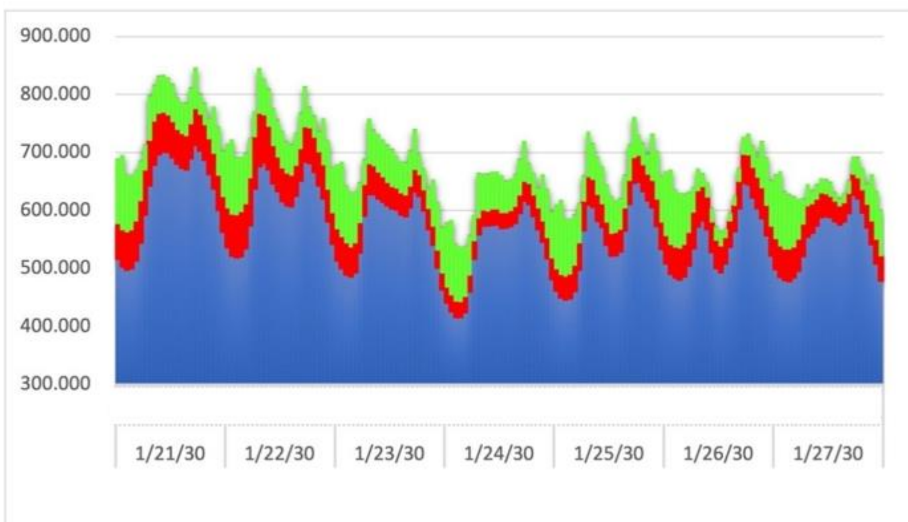

Figure 2-30. Example Peak Week in Winter 2030

2030 Summer

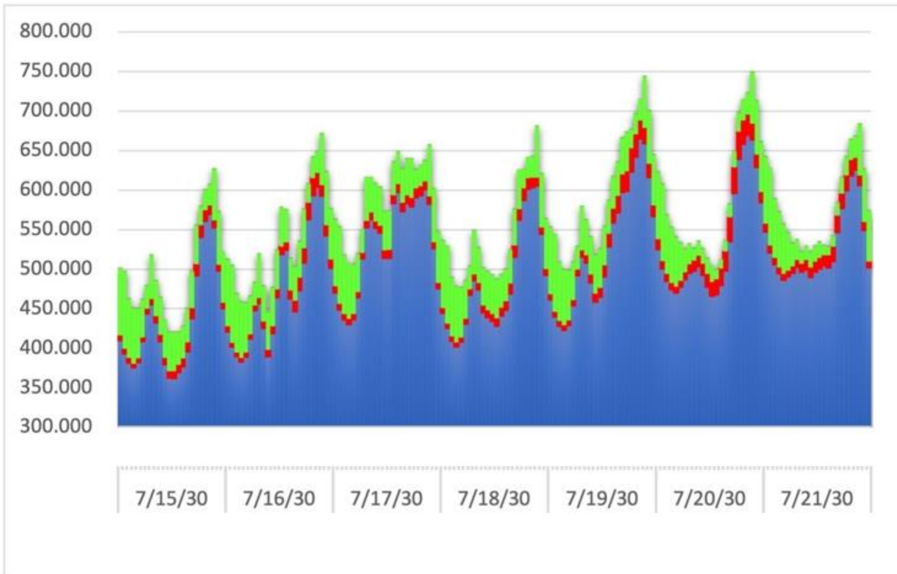

Figure 2-31. Example Peak Week in Summer 2030

These trends highlight the importance of both peak management and load-building during times when renewable generation is highest. Management of new EV and CCHP load through smart devices and rate design are incorporated into the hourly profile, but those are just two components of our broader load management portfolio.

Battery storage is a key resource for providing resilient backup and lowering costs for all customers through load management. Chapter 1 discusses our battery programs at length; in this chapter we forecast battery deployment through our residential storage tariffs. While we expect to see interest in battery storage among renewables developers and C&I customers, it is too early to make firm predictions on adoption.

All three scenarios are identical through 2022, which is the last year of the initial review period for the Energy Storage System (ESS) and Bring Your Own Device (BYOD) tariffs. The PUC approved 5 MW of new capacity in each program per year during the initial review period. After 2022, the future of these popular customer programs is contingent on additional regulatory approval. Here for modeling, we assume that a version of each program is allowed to continue; the structure and pricing will evolve as our load profile changes and peaks flatten out, and we believe customers' interest in clean backup power will only grow. Figure 2-32 shows the installed capacity for residential storage through 2041 under each scenario and Figure 2-33 shows the corresponding number of customers with battery systems installed, assuming 10 kW per system in the ESS program (the capacity of two Tesla Powerwalls) and 4.5 kW per system in the BYOD program (average enrolled capacity to date).

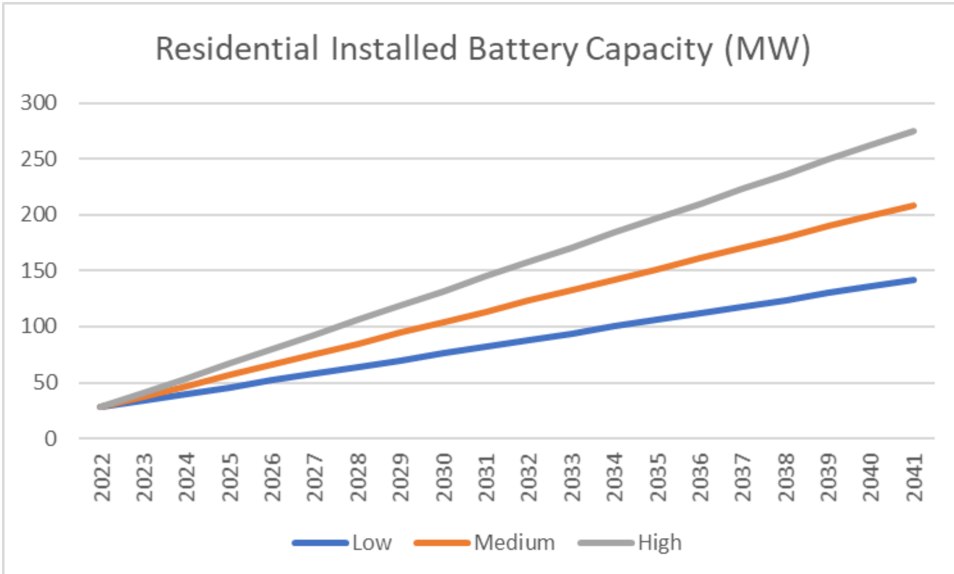

Figure 2-32. Residential Installed Battery Capacity, MW

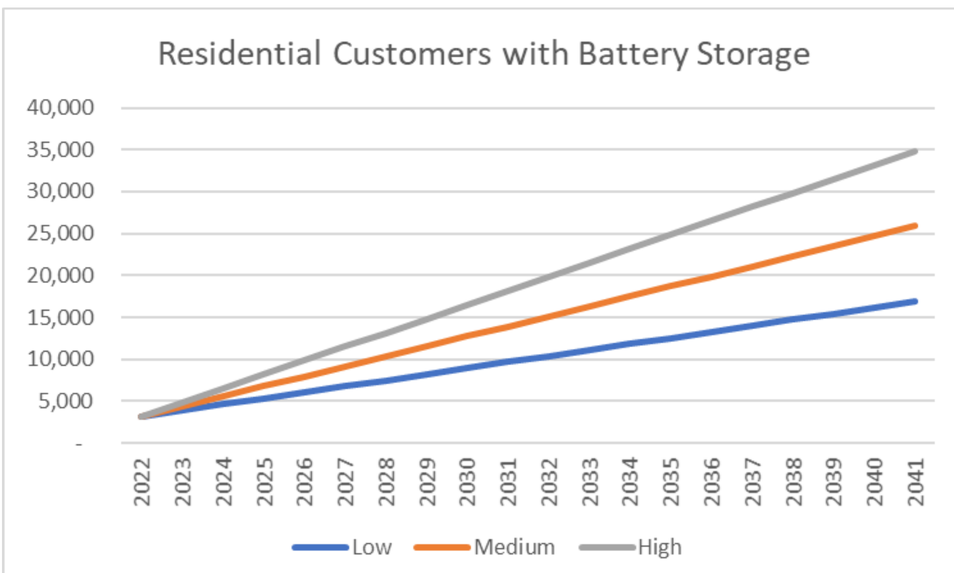

Figure 2-33. Residential Customers with Battery Storage

In the high scenario, about 8% of GMP residential customers have a battery system in the year 2030. Declining costs in battery manufacturing and evolving rules for wholesale market participation will have an influence on residential storage deployment. Our long-term goal is for every customer to have a backup solution for long-duration outages. While community-scale storage will be important, customers have also expressed a strong desire for residential backup that we anticipate will continue based on a consistent waiting list for our existing tariffed offerings.

In the ESS program, GMP manages both charging and discharging. Figure 2-34 shows the hourly charging/discharging data for all ESS-enrolled battery systems during a peak day in February 2020. This is a unique example where the systems dispatched twice in the same day. In this chart, positive values indicate charging and negative values indicate discharging. During non-peak days, the batteries sit at full state of charge ready to provide backup power in case of an unexpected outage.

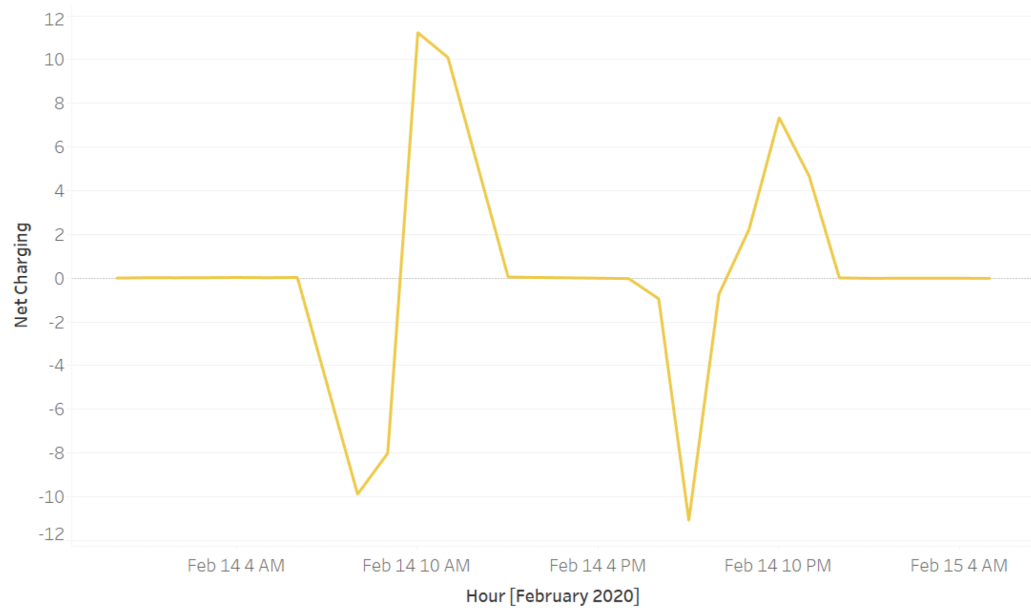

Figure 2-34. Hourly Net Charging Data (MW) for all ESS-Enrolled Battery Systems

In the BYOD program, GMP discharges systems for 3 or 4 hours (depending on the participant's enrolled preference). Outside these events, the charging and discharging behavior is controlled and managed by the customer. Figure 2-35 shows the aggregate hourly profile for batteries enrolled in the BYOD program on non-peak weekdays. A portion of customers have configured their battery systems to charge from co-located solar, which is the cause for the prominent midday charging activity.

Figure 2-36 depicts a peak event in the BYOD program. In these graphs, a positive value indicates charging and a negative value indicates discharging, similar to Figure 2-34 above. While almost all systems opted for the 3-hour enrollment, a small number of batteries were not sufficiently charged prior to the event to meet their commitment, which determines their incentive payout. That is why discharging in Figure 2-36 tapers off prior to the 3-hour mark. We notify customers when their systems do not perform as expected to give them the opportunity to work with their installer to remedy the situation.

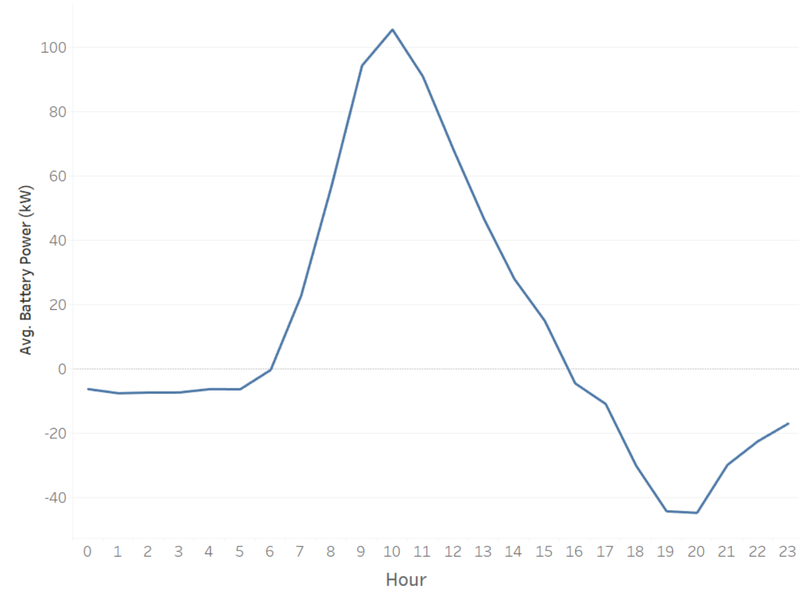

Figure 2-35. Aggregate Hourly Profile of Batteries Enrolled in BYOD Program, Non-Peak Weekdays

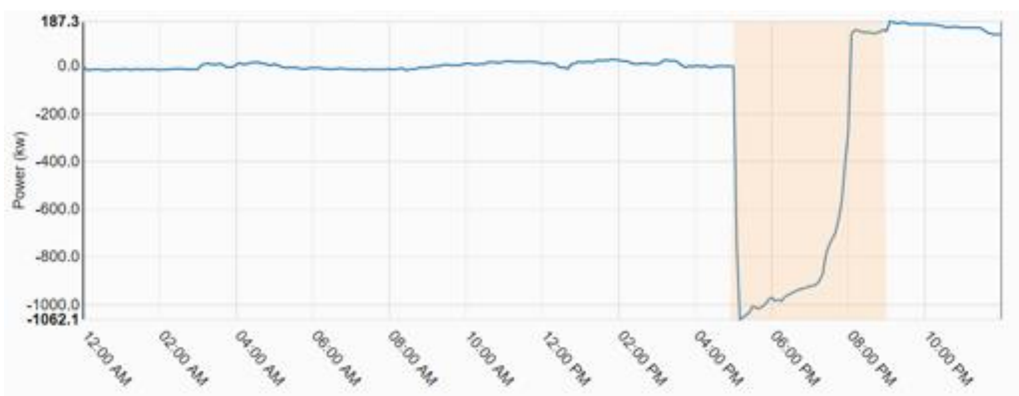

Figure 2-36. Peak Event Depiction in BYOD Program

Finally, Figure 2-37 illustrates total flexible capacity from CCHPs, EVs, and residential battery storage adoption, under the three growth scenarios. These are not the only forms of demand flexibility at our disposal, but the charts help to illustrate the positive impact of strategic electrification and resilience. In the medium scenario, we approach a total flexible capacity of over 10% of projected peak load by 2030, shown in the demand snapshots above. Our strategy for dispatching resources will evolve as adoption accelerates, including for example going beyond peak reduction to align load with either periods of low wholesale energy cost or high renewable generation.

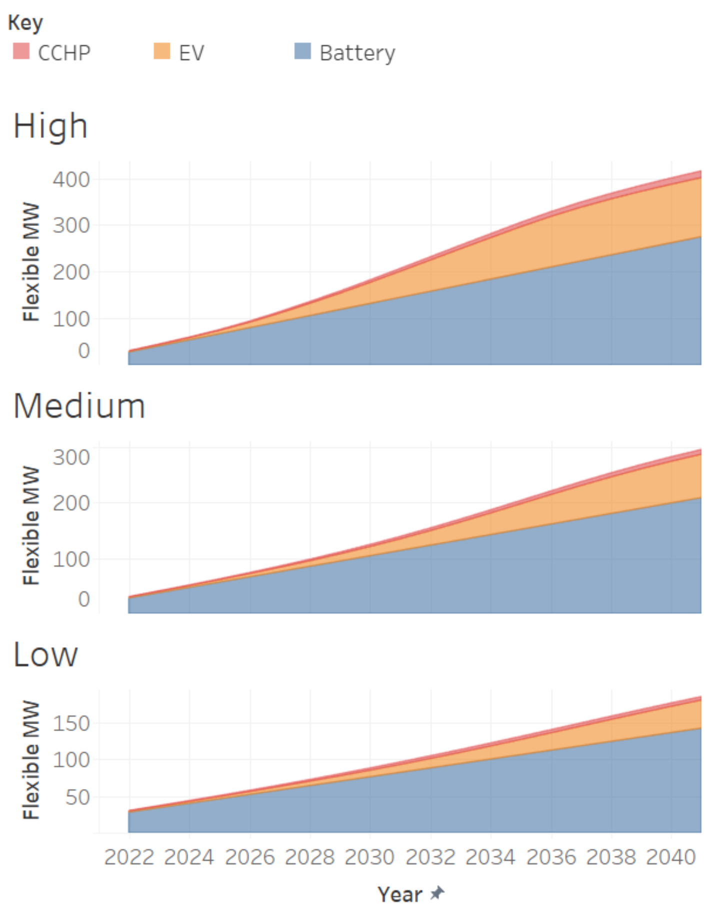

Figure 2-37. Total Flexible Capacity Due to CCHP, EV, and Residential Energy Storage

In addition to battery storage, time-of-use (TOU) rates are an important tool for shaping load. Compared to other programs where we manage end-use devices directly, TOU rates comprise a more general solution class, establishing price signals and allowing the customer to decide how to respond. Each of these rate schedules utilizes rate design to perform load management.

GMP has nearly 5,000 residential customers who utilize whole-home TOU rates. One example is Rate 11, which has an on-peak window of 1:00 p.m. to 9:00 p.m. on weekdays, during which the cost for electricity is $0.28027/kWh, about 65% higher than the energy charge on Rate 1 (a non-TOU residential rate). During off-peak hours on Rate 11, the energy charge is $0.11946/kWh, a savings of about 30% compared to Rate 1.

Customers on this rate can take advantage of smart appliances to schedule high-demand household loads during off-peak hours, such as washing machines, dishwashers, and water heaters. We also offer whole-home TOU rates with a critical peak component, including Rate 9. GMP calls peak events up to 10 times a year, typically targeted at the summer regional peak hour. Customers are notified of these events via email and/or text and can adjust their behavior accordingly. During the peak event, the energy charge is over $.71/kWh, whereas at all other times customer earn a small discount compared to Rate 1. Customers on this rate are accustomed to making significant changes to their typical consumption pattern when a peak event is signaled.

Separate from whole-house TOU rates, GMP has over 14,000 electric water heaters taking service on Rate 3, which relies on a dedicated secondary meter. On this rate plan, GMP turns off power to the meter for 5 hours per day. Due to the high thermal inertia of insulated water tanks, this does not disrupt hot water availability, and GMP is able to reduce load during high-demand hours, like Rate 74 for EV charging. While that EV rate does not require a secondary meter, customers can set a schedule in a mobile app to defer charging until the off-peak period. This way, they can plug in immediately when they get home and still take full advantage of the off-peak rate.

For commercial & industrial customers, a TOU, demand-billed rate schedule is mandatory for any customer who uses more than 7,600 kWh per month. By volume, this represents 52% of GMP sales taking TOU service.

GMP also offers several forms of load management for C&I customers through our Curtailable Load Rider, Critical Peak Rider, Load Response Rider, and Flexible Load Management Pilot. While the number of customers participating in these programs is relatively small, they included some of our largest customers. Combined, over 30 MW is available for load curtailment at various times of the year.

Prior to its next rate design, GMP will explore several topics, including verifying that current TOU periods are appropriate for both C&I and residential classes, and assessing a “bifurcated” demand charge that assesses separate charges for coincident peak and non-coincident peak demand.

Present Life Cycle Costs

We conclude this chapter with cost-effectiveness screening tests for the most common Tier III measures: electric vehicles and cold climate heat pumps. Deployment of these technologies is essential for customers to address climate change and reduce their carbon footprints, for GMP to meet requirements under Tier III of the Renewable Energy Standard, and for Vermont to meet its climate targets. Electric vehicles and cold climate heat pumps are also among the most cost-effective measures in the “cost of avoided carbon” model developed by the Vermont Department of Public Service.

For each measure, we present three tests:

The Customer Cost Test describes the customer’s perspective, inclusive of rebates and operating cost savings and is intended to demonstrate whether the measure produces a net benefit for the customer over its lifetime.

The Non-Participating Customer Cost Test (i.e., the Utility Test) describes GMP’s perspective, which is really the impact/benefit to non-participating customers when a customer purchases the measure. This includes changes to revenues and power supply costs.

The Societal Cost Test describes the perspective of society at large, including customer and utility costs, as well as "externality costs.” Burlington Electric Department’s 2020 IRP succinctly describes these externality costs as “costs that have been attributed to the provision of a service or product that is borne by society at large but is not included in the price of the service or product provided.” As advised by the DPS during the annual Tier III planning process, we have adopted a $100/ton of carbon as an avoided externality cost. It is important to note that the societal cost test does not include GMP incentives, as these are considered transfer payments from one group of customers to another, which cancel out from a societal perspective.

Electric Vehicles

Transportation is the top source of carbon emissions in Vermont and since GMP's 2018 IRP, EV adoption in the state has increased with over 4,000 EV's registered. Vehicle manufacturers are offering more all-electric and plug-in hybrid models with longer range batteries and consumers are getting signals from these manufacturers that they will continue to invest in zero emissions technologies over the next 5-10 years. Increased options will increase sales and influence competitively priced EVs for all. More vehicle options at competitive prices along with continued federal, state, and utility incentives will help continue the upward trajectory of electric vehicle adoption. When screening any Tier III measure, we assess alternatives that do not increase electricity consumption. Non-electrification alternatives for transportation are not robust. While hydrogen and some other nascent technologies are in development for vehicles, the imperative in Vermont should be to transition its transportation options as quickly as possible to EVs. In parallel, we strongly support approaches like carpooling, telecommuting, public transportation, and electric bicycles to reduce single-occupancy vehicle trips. These are not replacements for electrifying the light-duty vehicle fleet but are important components of the overall approach to decarbonizing transportation.

All Electric Vehicles

The table below shows the results of the customer, utility, and societal cost tests for an all-electric vehicle (AEV). In this table, a negative number is a cost, and a positive number is a benefit, with all values in 2021 dollars.

All-Electric Vehicle, 8-year measure life			
	Input	**Amount**	**Source**
Customer	Incremental vehicle cost	($8,334)	Drive Electric Vermont (includes federal tax rebate)
	Purchase incentives	$4,000	State & GMP incentives
	Fuel Savings	$6,219	VTRANS, GMP Rate 74 @ 90% off-peak
	Maintenance Savings	$2,077	Tier III TRM
	Net customer benefit (2021 dollars)	**$3,962**	
Utility	Tier III Costs + Administration	($1,725)	GMP Incentive
	Tier III Benefit	$974	Tier III TRM
	Net retail revenue	$2,545	See Figure 2-38
	Net utility benefit (2021 dollars)	**$1,794**	
Society	Incremental vehicle cost	($8,334)	Drive Electric Vermont (includes federal tax rebate)
	Fuel Savings	$6,219	VTRANS, GMP Rate 74 @ 90% off-peak
	Maintenance Savings	$2,077	Tier III TRM
	Net retail revenue	$2,545	See Figure 2-38
	Value of avoided emissions	$2,481	Tier III TRM, $100/ton externality cost
	Net societal benefit (2021 dollars)	**$4,989**	

The incremental cost of an AEV compared to an internal combustion engine vehicle is the same used in the DPS' Cost of Avoided Carbon model, derived from Drive Electric Vermont data and inclusive of the full federal tax credit. For additional purchase incentives, we assume the customer is eligible for the standard state purchase incentive (i.e., not the enhanced incentive), as well as GMP's Tier III incentive ($1500). Maintenance savings come from the Tier III Technical Reference Manual (TRM) and fuel savings were calculated based on the average gasoline and electric efficiencies of light-duty vehicles registered in Vermont, the average cost of gasoline from VTRANS[5] and the cost of electricity on a discounted EV rate (Rate 74), assuming 90% of charging happens during the off-peak hours. Here we have assumed that an AEV owner drives 10,000 miles annually, which is slightly higher than the Tier III Technical Reference Manual's assumption but is consistent with data from chargers in our program. This is equivalent to 3.16 MWh of added load annually based on an AEV's average efficiency. Finally, we assume an 8-year vehicle life for a new AEV in alignment with the Tier III TRM.

From the customer's perspective, an AEV reduces the total cost of vehicle ownership, producing a net benefit. This shows that the upfront cost of an AEV is offset by the savings from fuel, maintenance, and purchase incentives. On GMP's off-peak charging rate, an AEV owner can enjoy significant savings compared to the cost of gasoline.

Also important is that an AEV reduces costs for all customers through strategic electrification. Our EV rates offer customers a cost-based discount, passing on the full value of peak reduction in the form of a lower energy charge during off-peak hours. We compute a Tier III benefit using the characterized Tier III MWh*e* value of an AEV and the market value of a Tier II REC, which could be used to meet our Tier III Renewable Energy Standard requirements.

Figure 2-38 shows a more detailed view of the utility cost test, illustrating the marginal cost to serve the added charging load due to transmission ($315), capacity ($45), energy ($1,012) and RECs ($49), and gross retail revenue on Rate 74 ($3,967) over the vehicle's 8-year lifetime. Incremental cost values were calculated using the same assumptions for peak coincidence and as the demand forecast above.

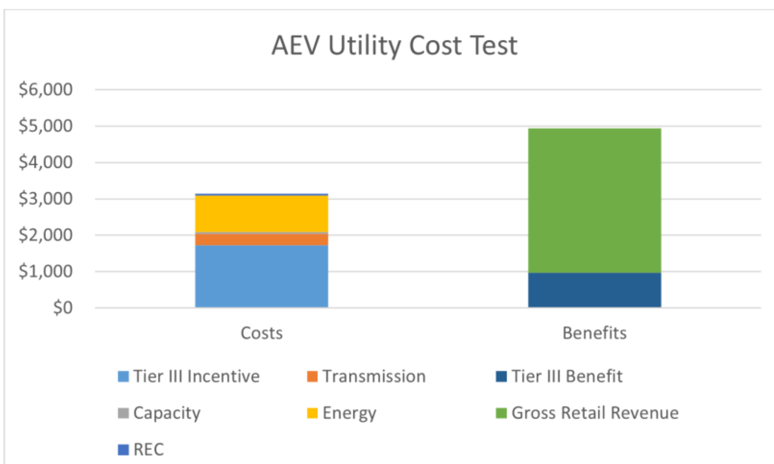

Figure 2-38. Utility Cost Test for All-Electric Vehicles

From the societal perspective, we included the tax incentive as a reduction in the incremental vehicle cost with the understanding that tax incentives are likely attributed to sales of all vehicles in some fashion, including internal combustion engine (ICE) vehicles. Every EV sold signals to automakers that customers today and in the future want to make the switch to driving electric. This has already led to commitments from automakers to

5 https://vtrans.vermont.gov/contract-admin/resources/construction-contracting/fuel-price-adjustment

introduce more electric models and in some cases cease the production of ICE vehicles entirely. As EV production ramps up, costs will come down, improving the net benefit to society. GMP will continue to provide incentives for customers to purchase electric vehicles to tackle the largest source of emissions in Vermont. Addressing climate change through switching away from fossil fuel-based transportation is a benefit to society.

Plug in Hybrid Electric Vehicles

The table below shows the results of the customer, utility, and societal cost tests for a plug-in hybrid electric vehicle (PHEV). In this table, a negative number is a cost, and a positive number is a benefit, with all values in 2021 dollars.

Plug-in Hybrid Electric Vehicle, 8-year measure life			
	Input	Amount	Source
Customer	Incremental cost	($1,732)	Drive Electric Vermont (includes federal tax rebate)
	Purchase incentives	$2,500	State & GMP incentives
	Fuel Savings	$3,296	VTRANS, GMP Rate 74 @ 90% off-peak
	Maintenance Savings	$1,034	Tier III TRM
	Net customer benefit (2021 dollars)	**$5,099**	
Utility	Tier III Costs + Administration	($1,150)	GMP Incentive
	Tier III Benefit	$727	Tier III TRM
	Net retail revenue	$1,179	See Figure 2-39
	Net utility benefit (2021 dollars)	**$756**	
Society	Incremental cost	($1,732)	Drive Electric Vermont (includes federal tax rebate)
	Fuel Savings	$3,296	VTRANS, GMP Rate 74 @ 90% off-peak
	Maintenance Savings	$1,034	Tier III TRM
	Net retail revenue	$1,179	See Figure 2-39
	Value of avoided emissions	$1,851	Tier III TRM, $100/ton externality cost
	Net societal benefit (2021 dollars)	**$5,629**	

The methodology is identical to the AEV case above. The incremental cost of a PHEV also comes from the DPS' Cost of Avoided Carbon model, inclusive of a $4,500 federal tax credit, which is based on the vehicle's electric range. We assumed the customer is eligible for the state's standard purchase incentive ($1,500) and GMP's PHEV incentive ($1,000).. We assume 10,000 miles driven annually, 53% of which are driven in electric mode based on data from Drive Electric Vermont. We calculate fuel savings using the same inputs described above for vehicle efficiencies and prices for gasoline and electricity. A PHEV represents 1.67 MWh of annual added load.

From the customer's perspective, a PHEV not only reduces costs significantly over the vehicle's lifetime, but may also have a lower net upfront cost compared to gasoline vehicles due to the purchase incentives available. Maintenance and fuel savings are significant but slightly lower than for an AEV. We have been excited to see new PHEV models introduced with extended electric range, such as the Toyota Rav4 Hybrid, which can go 42 miles on a full battery charge.

A PHEV produces a positive net benefit for all customers, albeit slightly lower than an AEV due to a smaller load addition. PHEV owners are eligible to sign up for GMP's discounted EV rates, which helps ensure that we manage power supply costs as we electrify. The Tier III benefit is derived using a PHEV's characterized Tier III MWh*e* value in the TRM. Figure 2-39 shows a more detailed view of the utility cost test, which includes the marginal cost to serve the added load due to transmission ($315), capacity ($45), energy ($536), and RECs ($26), along with gross retail revenue ($2,102).

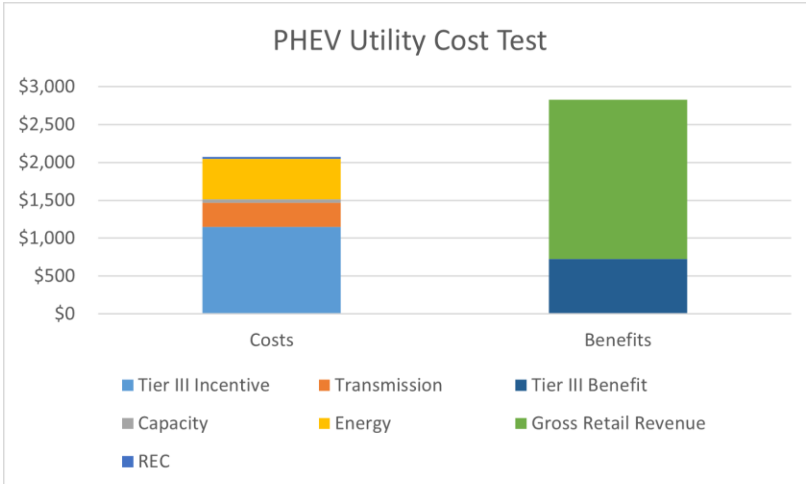

Figure 2-39. Plug-In Hybrid Electric Vehicle Utility Test

From society's perspective, a PHEV creates a net benefit. The incremental upfront cost is outweighed by the combination of fuel and maintenance savings, utility benefits, and the value of avoided emissions.

Cold Climate Heat Pumps

About 34% of Vermont's greenhouse gas emissions are related to heating. The thermal sector accounts for the second largest source of carbon in the state. GMP will continue to support the adoption of heat pump technologies including ductless and ducted systems. Similar to EVs, our assessment of CCHPs includes an analysis of measures that do not increase electricity consumption. Our heat pump incentives are administered through Efficiency Vermont's rebate programs. Alongside those incentives, Efficiency Vermont offers support to customers for a comprehensive set of non-electrification alternatives, including biomass heating and weatherization. In 2022, GMP will participate in Efficiency Vermont's EEU-DU Low-Income Fuel-Switching Pilot. This program will support the installation of cold climate heat pumps in low-income, fossil-fuel-heated homes.

The table below shows the results of the customer, utility, and societal cost tests for an 18,000- BTU single-zone CCHP system. In this table, a negative number is a cost, and a positive number is a benefit, with all values in 2021 dollars.

Single Zone Cold Climate Heat Pump, 15-year measure life			
	Input	Amount	Source
Customer	Incremental cost	($3,743)	DPS Cost of Avoided Carbon Model
	Purchase incentives	$750	GMP & Efficiency Vermont
	Fuel Savings	$3,397	DPS Cost of Avoided Carbon Model
	Net customer benefit (2021 dollars)	**$403**	
Utility	Tier III Costs + Administration	($460)	GMP Incentive
	Tier III MWh*e* Benefit	$724	Tier III TRM, GMP average
	Net retail revenue	$5,285	See Figure 2-40
	Net utility benefit (2021 dollars)	**$5,549**	
Society	Incremental cost	($3,743)	DPS Cost of Avoided Carbon Model
	Fuel Savings	$3,397	DPS Cost of Avoided Carbon Model
	Net retail revenue	$5,285	See Figure 2-40
	Value of avoided emissions	$1,812	Tier III TRM, $100/ton externality cost
	Net societal benefit (2021 dollars)	**$6,750**	

We assume a single-zone cold climate heat pump system of 18,000 BTU will add approximately 2.84 MWh of annual load. Actual consumption will depend on the Coefficient of Performance (COP) related to the heat pump model, the size of the home and space it serves, weatherization level, ambient temperatures, and fuel prices. The annual load, incremental cost, and fuel savings come from the DPS' Cost of Avoided Carbon model and GMP's general residential rate, assuming a propane-based heating system. Purchase incentives include both GMP and Efficiency Vermont contributions.

From the customer's perspective, a CCHP system produces a net benefit over its lifetime. It is important to note that this analysis does not account for the cooling benefits CCHP systems provide, which is a significant factor affecting purchase decisions. Only fuel savings related to heating are included. The incremental cost here represents the total installed cost of a CCHP system, not the incremental cost between the CCHP and a fossil fueled heating system. It is worth noting that the DPS model was created prior to the recent spikes in fuel prices. If prices remain higher than forecasted, actual customer savings will exceed those presented here. Due to the volatility of fossil fuel prices compared to electric rates over time, a customer will also experience more stability in their heating costs year-to-year by electrifying their heating.

A CCHP system delivers a significant benefit to all customers due to the rate-reducing impact of new electric load. We compute a Tier III benefit using the characterized Tier III MWh*e* value of an 18,000 single-zone CCHP, and the market value of a Tier II REC, which could be used to meet our Tier III Renewable Energy Standard requirements.

Figure 2-40 shows a more detailed view of the utility cost test, illustrating the cost to serve the added load over the system's lifetime, including transmission ($865), capacity ($106), energy ($1,753) and RECs ($83). The incremental cost to serve uses 2.84 MWh per year and the same peak coincidence factors from the forecasts above.

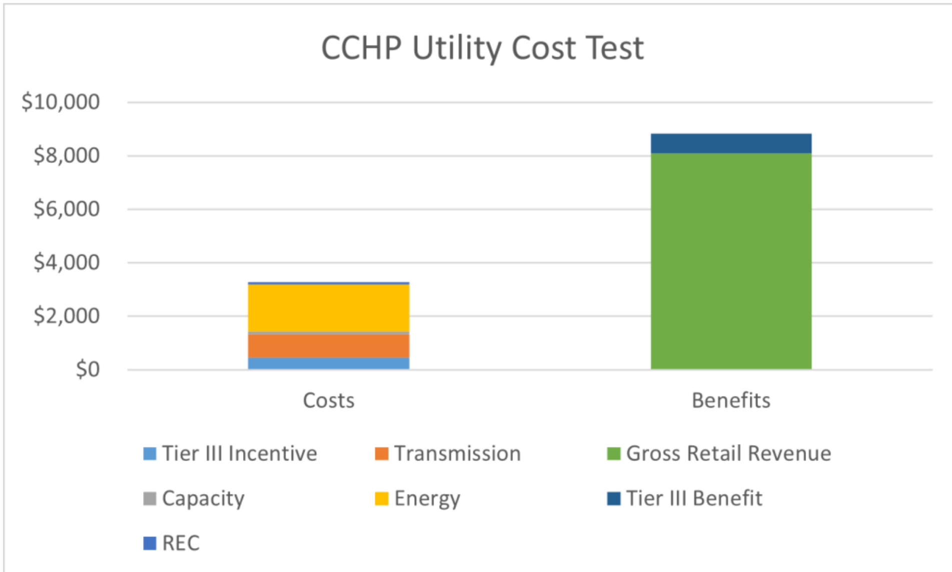

Figure 2-40. Cold Climate Heat Pump Utility Cost Test

From society's perspective, a CCHP system produces a net benefit. While the incremental system cost is not insignificant, the combination of net utility revenue, fuel savings, and avoided externality costs produce a positive savings result. GMP will continue to provide incentives to customers who install not just cold climate ductless heat pumps but also ducted systems to include Air-to Water and Geothermal systems.

3. System Resiliency and Grid Transformation

As you have read throughout this IRP, we are at a significant inflection point with respect to the traditional energy delivery system. Over the last few decades, integrated system plans have transitioned from being heavily focused on assuring that we will have the best power supply to meet the growing needs of customers, to integrating, and blurring the lines between, traditional power supply resources and other energy resources on the grid. The GMP T&D system's ability to support increasing amounts of distributed energy resources and to support the acceleration of electrification due to thermal and transportation technology decarbonization is essential to cost-effectively and reliably attack carbon emissions. Power system operations and planning is becoming more complex, requiring us to rethink traditional operating principles and planning processes. We must plan a system that quickly adapts to the electrification of the most carbon-intensive areas, while assuring our customers a reliable and resilient system in the face of greater impacts from climate change. Chosen grid investments strive not only for asset management but also for a strengthened, more flexible, and secure T&D system to provide safe, reliable, resilient, and affordable service to our customers. The great opportunity in front of us is that we can integrate all these electrified resources into a new, dynamic energy delivery system.

Transmission and Distribution System Overview

Green Mountain Power is the state's largest utility serving over 270,000 customers throughout Vermont. GMP owns and manages generating assets and the subtransmission and distribution networks that deliver power to our customers. In 2020, our transmission and distribution system delivered over 3,822,735 MWh of electricity; the peak load on the system was approximately 680 MW. We had 507,406 MWh of behind-the-meter generation, resulting in 4,330,141 MWh of load served last year.

Vermont Electric Power Company's (VELCO's) 115-kV transmission system primarily supplies the GMP 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 Eversource and National Grid in several locations at subtransmission voltages.

The backbone of our delivery system is 1,011 miles of subtransmission lines. The predominant voltages for the subtransmission system are 34.5 kV, 46 kV, and 69 kV. The subtransmission system feeds generation and distribution substations. The GMP system is connected to numerous generation sites including gas turbines, reciprocating engines, wind, hydro, methane digesters, biomass, and solar facilities. The 140 distribution substations supply close to 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.

Transmission and Distribution Planning continues to evolve and expand our planning principles. These principles assure that our T&D infrastructure assets remain safe and reliable to continue to meet our customers' electrical demands and energy requirements. These principles aspire to improve reliability through capital investments and now also include innovative programs so that customer service is maintained in the event of system outages. These principles are now expanding such that investments also focus on the ability to improve resiliency to lessen the effects of climate change on customers. Recent weather-based reliability events have highlighted the need to consider the likelihood of increasingly extreme weather events and the related reliability challenges that may result.

GMP considers emerging technologies, along with traditional infrastructure, to find the most cost-effective alternative to address our reliability and resiliency goals while also thinking through the growth of electrification needed to decarbonize our state. We consider whether storage, distributed resources, or a combination of both can replace what would otherwise be a traditional infrastructure upgrade. This provides potential for saving customers money, increasing reliability and resiliency, increased operation efficiency and flexibility and making our energy delivery system more customer centric. The increase in the level of DERs, along with the potential for load growth related to heat pump installations and electric vehicle chargers, requires continuous system monitoring and planning.

This strategy to leverage storage, distributed generation, and non-transmission alternatives for grid planning provides opportunities 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. As we discuss further, this can include new solutions such as more undergrounding of our primary distribution lines and increasing self-healing capabilities of our distribution feeders.

The evaluation of new technologies requires detailed data to properly assess whether they can effectively address a T&D system deficiency and if so, for how long. We use the data and information from our AMI and SCADA systems. 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. We have developed enhanced database and reporting tools to make data evaluations more efficient and allow for some scenario screening, such as what the impact would be for the installation of a certain size storage facility on every substation on our system.

Long-Term Planning Strategy

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 coordinate with VELCO and other parties with whom we jointly own various facilities to conduct long-term planning to ensure alignment.

As part of our long-term planning, we:

- Maintain and improve our current generation, subtransmission and distribution infrastructure for customers.
- Align planning strategies in coordination and collaboration with VELCO, other utilities, regional planning commissions and other entities as required.
- Engage in long-term energy transformation activities that enable a transition from a centralized energy delivery system to a distributed one to significantly reduce carbon emissions.
- Deliver innovative solutions and implement programs that smooth energy demand peaks and valleys, through flexible load management, strategic customer rates and battery storage.
- Prepare for load growth driven by electrification of transportation and thermal in Vermont to achieve our climate goals. This includes the modeling of significant deployments of electric vehicles, cold climate heat pumps and electrification in the commercial and industrial sector.
- Proactively respond to challenges surrounding climate change to create a more reliable and resilient system for customers that can better withstand and more quickly recover from severe storms, while also aiding in the transition to a more distributed grid.
- Continue deploying in-state renewable generation that shifts us to a distributed energy system.

System Planning Criteria

Subtransmission

Our standard subtransmission voltages are 34.5 kV, 46 kV and 69 kV. We transmit power through our subtransmission system from VELCO, Eversource and National Grid to our distribution substations and wholesale and industrial customers.

We plan the subtransmission system according to an Equal Slope Criteria. For non-bulk network planning studies (such as this one) GMP ordinarily relies on probabilistic-based and cost-based reliability criteria, to strike an appropriate balance between the infrastructure costs that are supported by our customers and the reliability that the resulting system provides to them. This is a flexible approach that best meets the needs of our customers for cost-effective yet reliable service. We evaluate using a standard N-1 criteria for the substransmission, which simply means assuring that the subtransmission can remain stable and reliable in the event that one element of the system is removed from service, such as during a fault on a subtransmission line. However, it does not always mean we strictly adhere to N-1 criteria when looking at solutions – which is what leads to the Equal Slope Criteria methodology. The goal is to achieve most of the benefit of adhering to a strict N-1 criterion but at substantially less cost. There are exceptions, depending on costs and MWs of load exposure, where GMP may require a full N-1 criteria.

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 and contingency. For specific cases for limited periods of time during first contingency operation, we allow overloading (i.e., conductor loading up to 110%), 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.

GMP has standard conductor sizes for our subtransmission and distribution systems. These include:

i. Overhead Primary: 1/0 6201 Aluminum, 4/0 6210 Aluminum, 336 ACSR, 477 ACSR, 556 ACSR and 795 ACSR
ii. Underground Primary: 1/0, 4/0, 350, 500, 750, 1000, 1250 Aluminum or Copper
iii. The largest conductor we have used on our subtransmission system is 959 ACSS Suwannee.

In 2020, GMP has developed a subtransmission bus configuration design criteria and bus configuration assessment sheet. These tools help engineers and designers choose the bus configuration design (straight bus, ring bus, breaker and a half) for a substation considering reliability, operability, maintainability, and cost.

GMP has also developed criteria for Transmission Ground Fault Overvoltage (TGFOV) that relates to the impact of higher DER penetration on the subtransmission system. The possibility of TGFOV is a concern when there is a reverse flow of power onto the transmission system that cannot be dampened during line-to-ground faults. TGFOV can also occur with no reverse flow when the minimum load-to-generation ratio (MLGR) for the section of the transmission system at issue is less than 2. GMP requires the MLGR on isolated portions of the power system containing inverter-based DER sources be greater than 2. The total generation on the isolated portion of the power system must exclude any inverter-based DER sources that have a direct transfer trip (DTT) from the upstream sectionalizing device. If the MLGR is less than 2, GMP requires a means to mitigate TGFOV. The system upgrade (3Vo or DTT scheme) will ensure that the transmission protection system will sense this flow and operate correctly. As more and more renewables are connected to the distribution system, the occurrence of this reverse flow is unavoidable and will eventually trigger a need for the system upgrade.

Distribution

Our standard distribution system voltage is 12.47 kV/7.2 kV grounded wye.[1] We also operate 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 or where there is another 34.5 kV source that can provide backup in the event of a contingency.

We are steadily converting the remaining 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. In addition to those improvements, the higher voltage allows for greater hosting capacity of distributed generation.

System Planning Information and Tools

T&D Planning is a process that requires effective communication and collaboration between teams within GMP along with other utilities and various stakeholders. System planning also requires tools to manipulate large amounts of data across the system to continuously track and monitor performance. We use several sources to effectively oversee the subtransmission and distribution system. We use this information to make decisions regarding several areas, including transferring load between circuits, removing substation transformer banks or circuits for maintenance, correcting out-of-standard voltages, determining best locations for system hardening, interconnection of distributed energy resources, and addressing load growth in potentially constrained areas. This information can dictate which areas need studying, and where non-transmission alternatives can be effective in deferring capital upgrades.

GMP uses business analytics query tools to analyze and generate reports, including reports that identify customers who have experienced a higher number of outages compared to other customers on the system. This information can direct us to areas with the worst reliability performance and aid us in targeting improvements that will increase resiliency for customers. We will talk further below about our recent work in developing resiliency zones and how that all fits in as part of our broader Climate Plan.

The information we use includes communications regarding observations by operations field personnel, review of relevant studies such as the VELCO Long-Range Transmission Plan, data from our supervisory control and data acquisition (SCADA) database, portable line device data that captures amp, voltage or power quality metering data, outage history data and geographic information system (GIS) information.

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[1] A wye is a three-phase, four-wire electrical configuration in which 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.

Accurate data is 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 outage management system, and implementing smart grid technologies to improve reliability and resiliency makes the data integrity ever-more critical.

We have a continuous process to scrub data in our Geospatial Information System (GIS) to improve its quality and accuracy. This data ultimately feeds into the various software tools and analytics that are needed to run scenarios and study system impacts.

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, management of load transfers for feeder backup, automation to support Climate Plan projects and scheduling of dispatchable resources such as Tesla Powerwall batteries and battery energy storage systems (BESS) for peak load reduction.

We continue to expand our use of AMI data since the 2018 IRP. As expected, the availability of this 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; resiliency; 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. 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. This data allows us to identify opportunities to flatten the load shape associated with circuits, finding the best opportunities for demand-side management, load control and storage applications to potentially increase the hosting capacity of substations for DER and load. We have tools that tell us the number of opt outs (i.e., no AMI meter) for each circuit. This allows us to determine if we should make assumptions regarding the load that is not being represented in the aggregated AMI data for planning and operational analysis.

AMI data has improved modeling of the distribution circuits in CYME® load flow. The CYME gateway now links to, and imports, the AMI and SCADA 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 provides insight on voltage and transformer loading to assist with power quality complaints. With better data integrity and data acquisition tools, circuit depictions will be more accurate. With additional programming in CYME, it may be possible to make the study process more efficient, by automating the load-flow runs and output reports that are now completed manually. Another future application would be to use the CYME load flow to proactively evaluate the impacts of DG penetration on the distribution system to provide insight to the most appropriate areas for DER interconnection. This proactive evaluation of DER impacts would be a complex undertaking, so accurate CYME models, detailed customer load data and generation data would be essential. Software would need to be developed to efficiently evaluate load shapes on an hourly or more frequent basis, across all circuits fed from a given substation. Assumptions would be input regarding the MWs to be added, type of DER and location/distribution of this new DER on the circuit. It would have to be recognized that this type of proactive

DER evaluation would be hypothetical and may not predict future reality due to the required assumptions. The mitigation required for a specific DG proposal is very dependent on location and size and studied based on specific circuit configurations, loads and DG saturation levels. For example, if a circuit configuration was changed such that a portion was fed from a different substation or should a large load be added or lost, the proposed study output would no longer provide any value, potentially misleading developers.

AMI data can be obtained for all DER sites with smart meters. The AMI data has been used to provide insight into individual or conglomerated solar output curves, data integrity issues, and variance in performance based on kW size. It has also allowed us to define hours of the year where solar production 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. To date, GMP has one active DER and two evaluated DERs that limit the export hours during the year due to saturation of solar on the substation they have or will be connecting to.

The AMI data in the Oracle® BI reporting and Tableau reporting, have allowed for the following capabilities:

- Development of a "Premise Count by Feeder and Customer Class," providing a report showing the number of customers on a circuit and number by rate classification; residential, small commercial and industrial and large commercial and industrial. This report also breaks the customer count per circuit by individual towns.
- Development of a "Feeder DG Data" project, which captures all the information in the DG database, rolling it up to the feeder and substation level. This project allows the user to look at DG based on status (i.e., installed, evaluate, on hold, in review, cancelled). See Figure 3-1.

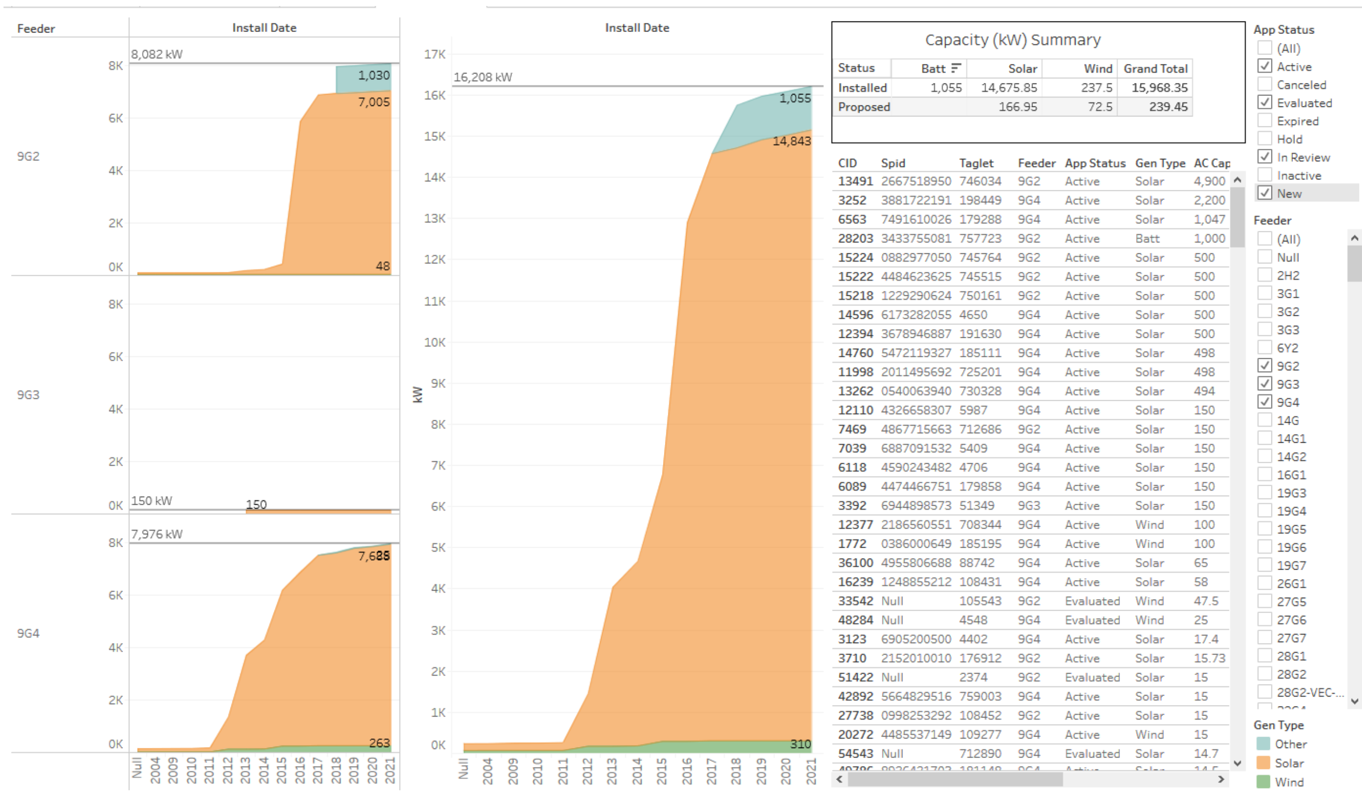


Figure 3-1. Example of Feeder DG Data

- Development of a "Feeder Rolling Data" project, which captures the peak KW demand and rolling sum (KWH) over a designated number of hours. This data can help determine the potential capability of a battery system to address a load constraint.
- In the process of completing a "Load Forecast" tool, which captures the historical peaks for each circuit for five years and aggregates these loads up to the substation level. This report also captures the transformer capacity and DER total installed. A linear trendline is applied to the historical load data and extrapolated out 20 years. This is a new tool and will likely be expanded in the future to capture substation and circuit equipment overload projections. This tool can also provide information on predicted load and provide insight for sizing substation transformers that need to be replaced.
- Developed a "Storage Impact Analysis Report," which shows the impact of charging and discharging at the substation level of adding a specific size storage facility to every substation. It looks at historical loading, transformer capacity and DER to evaluate the remaining capacity of the substation transformer for adding DERs. It also allows addition of a specified load for evaluation. See Figure 3-2.

Load Adjuster: 0
Min Load Calc % Adjuster: 30
Opt Out Customer Capacity (KW): 0
Storage Capacity (KW): 5,000
Peak Percentage Adjuster:70

Applying hypothetical storage to peak and min loads

Substation Bank	Transformer Capacity	Date of Calculated Min Load	Lowest Remaining Discharging Capacity (DR)
Airport	28000	12/11/2018 10:00:00 AM	23,594
Barker Avenue	10500	4/13/2020 11:00:00 AM	-987
Barnet	7000	9/6/2019 7:00:00 AM	1,101
Barre North End	28000	4/27/2020 11:30:00 AM	21,888
Barre South End	28000	4/27/2020 12:45:00 PM	19,529
Bay St	10500	3/23/2020 11:45:00 AM	-3,602
Bellow Falls (Bridge ..	14000	4/21/2020 12:00:00 PM	8,635
Berlin	10500	4/29/2020 11:45:00 AM	5,814
Bethel	14000	4/4/2018 9:00:00 AM	-901
Bolton	10500	5/1/2018 8:00:00 PM	5,087
Bradford	7000	4/27/2020 11:15:00 AM	28
Bromley	14000	6/14/2019 9:15:00 PM	8,549
Brownsville	7200	5/31/2018 9:45:00 PM	142
Carvers Falls	1500	10/6/2019 7:15:00 PM	-4,952
Castleton	5250	4/2/2020 11:45:00 AM	-6,217
Cavendish	3500	5/6/2021 9:45:00 PM	-1,623
Charlotte	20000	5/31/2019 10:30:00 AM	8,425
Chelsea	2500	5/31/2018 8:15:00 PM	-3,197
Chester	10500	5/30/2018 9:45:00 PM	939
Digital (Technology ..	20000	3/5/2018 1:15:00 PM	9,081
Dorset	5250	5/26/2019 9:45:00 PM	-184
Dorset Street	22400	4/9/2020 6:15:00 PM	16,647
Dover 1	22500	6/27/2020 1:15:00 PM	17,839
Dover 2	14000	6/29/2019 7:15:00 PM	8,405
East Arlington	7000	10/16/2019 7:30:00 AM	1,626
East Barnard	22400	5/28/2018 9:45:00 PM	16,757

Substation Bank	Transformer Capacity	Peak Date	Lowest Remaining Charging Capacity (LOAD)
Airport	28000	8/15/2018 12:15:00 PM	19,173
Barker Avenue	10500	7/5/2018 12:15:00 PM	-285
Barnet	7000	1/2/2018 6:00:00 PM	200
Barre North End	28000	6/28/2021 1:15:00 PM	17,144
Barre South End	28000	7/27/2020 2:15:00 PM	13,793
Bay St	10500	6/30/2021 1:00:00 PM	-1,904
Bellow Falls (Bridge	14000	6/30/2021 1:45:00 PM	2,453
Berlin	10500	7/5/2018 2:15:00 PM	-2,272
Bethel	14000	11/1/2020 1:00:00 AM	-635
Bolton	10500	1/6/2021 7:30:00 PM	2,561
Bradford	7000	7/27/2020 1:15:00 PM	-2,040
Bromley	14000	12/20/2019 11:30:00 PM	3,613
Brownsville	7200	11/1/2020 1:00:00 AM	-402
Carvers Falls	1500	7/1/2018 7:45:00 PM	-4,734
Castleton	5250	8/28/2018 8:45:00 PM	-2,794
Cavendish	3500	12/30/2020 5:45:00 PM	-3,059
Charlotte	20000	7/27/2020 1:00:00 PM	8,036
Chelsea	2500	1/2/2018 5:30:00 PM	-3,877
Chester	10500	2/8/2020 4:00:00 AM	267
Digital (Technology Park)	20000	6/7/2021 2:15:00 PM	2,736
Dorset	5250	12/29/2020 7:15:00 PM	-2,597
Dorset Street	22400	7/2/2018 6:15:00 PM	1,510
Dover 1	22500	1/14/2018 8:00:00 AM	2,038
Dover 2	14000	1/14/2018 6:15:00 PM	-294
East Arlington	7000	7/2/2018 1:00:00 PM	-3,260
East Barnard	22400	11/30/2019 8:45:00 PM	17,030

Figure 3-2. Storage Impact Analysis Report, With Option to Specify Load for Evaluation

- Developing and expanding the “AMI Feeder Data Aggregation” 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); and
E. Feeder total (kW) (approximately equal to the measured values at the feeder breaker).

Error! Reference source not found. Figure 3-3 shows a graphic representation of these output parameters (i.e., A-E listed above).

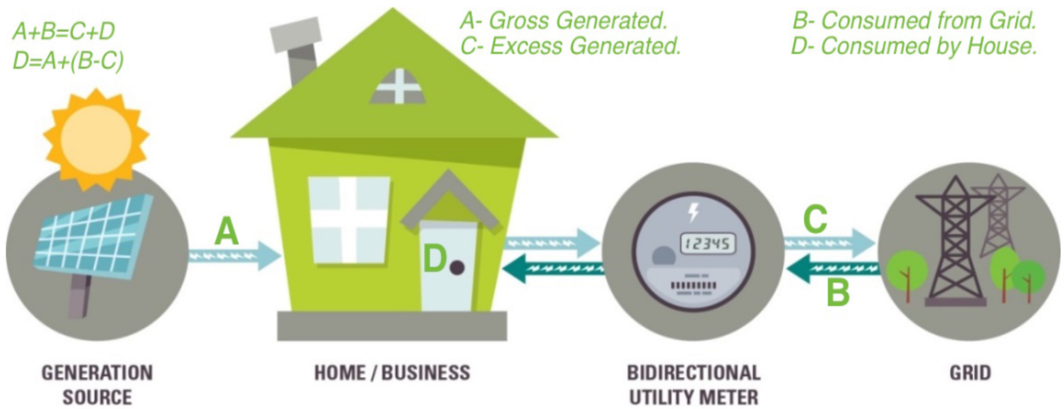


Figure 3-3. ABC by Feeder Parameters

This data provides us with clarity regarding how much load is 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. It will also show a higher demand when DERs, such as grid-scale battery energy storage systems, are charging. 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. In addition, by aggregating the load data from the end use meters, this data is immune from the effects of feeder backup. We are currently in the process of expanding the tool to include battery data, charging MW, and discharging MW. Battery data is excluded from the other data; given it has the potential to be controlled. A sample output of this data is illustrated in Figure 3-4.

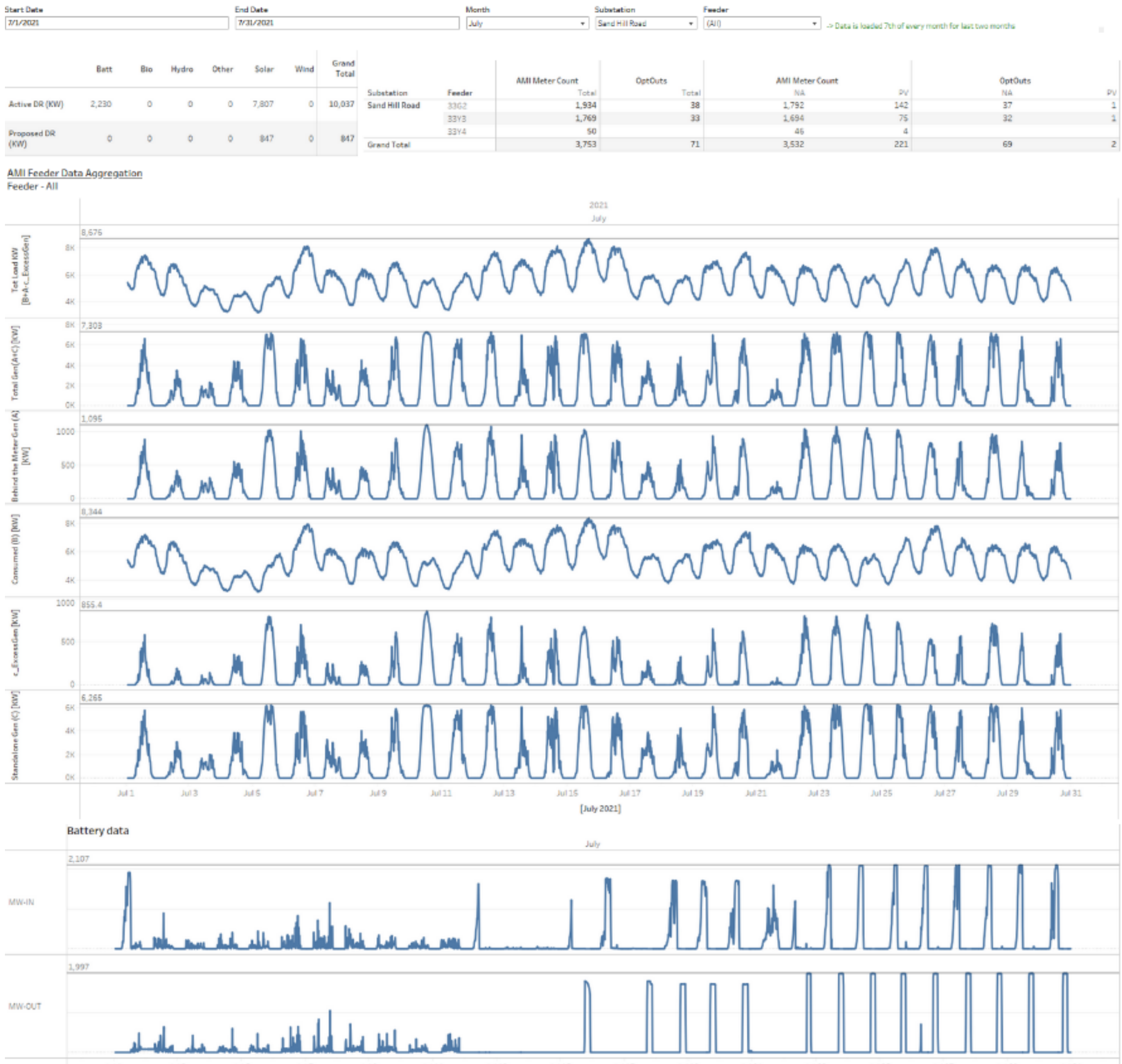


Figure 3-4. Sample Output of Battery Data

We are still working to develop tools for:

- Using AMI data to aggregate KVAR information and to track power factor by substation.
- 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.

A very important shift that has been continually evolving since the last IRP is the need to incorporate more detail, and provide more information, related to the deployment of distributed generation. As is shown on the GMP Solar Mapping tools, distributed generation continues to be very successful in Vermont and is being installed at a very good pace. Helping developers identify the best locations, typically meaning the lowest-cost interconnection locations, has been a large focus. Lower-cost locations are typically closer to the substation, in areas with existing three-phase and large conductor and near load centers. We are constantly reviewing our interconnection guidelines to assure we leverage the latest technology and work to make interconnections as efficiently as possible while assuring system stability and reliability. This has led us to update our guidelines and reduce the amount of equipment needed for distributed generation interconnection in many cases.

System Protection Practices and Philosophies

Protecting our distribution system provides multiple benefits: it minimizes hazards to the public, protects our employees, 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.

Several 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 to 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.

In addition to the traditional protection identified above, we have had to innovate around how to protect a distribution system when using only inverter-based sources to feed it, such as using solar and storage as a microgrid. Our Panton Microgrid, which we will discuss more in this section, offered us the opportunity to design and test new protection methods that assure a safe and stable system, while allowing a portion of our Vergennes 9G2 distribution circuit to be fed only from inverter-based sources. This took a tremendous engineering effort but most importantly shows that we can make this transition and create new ways to assure resiliency and reliability in more difficult to serve areas.

System Planning Process

The electric system is getting increasingly complex, and the T&D Planning process must change as needed to capture and harness the dynamics between load and DERs and leverage the changing technologies to continue to make our T&D system smarter and more resilient. Ultimately one could choose to plan the system in a way that only looks at DERs as an issue that needs to be solved on the grid, or one can expand the vision to develop an approach where we can leverage DERs to make a better distributed grid. We choose the latter.

We must plan our T&D system to ensure the safe, reliable, and resilient 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. System planning must identify a deficiency well in advance of becoming a problem to fairly evaluate and select the most cost-effective solution.

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 we explore the implementation of distributed energy resources such as energy storage as a solution.

Efficiency, reliability, and growth are the three main factors that have driven past transmission and distribution planning. Now with the goal of proactively planning for impacts from climate change, resiliency is an additional key factor that GMP employs in our planning process. Many planning exercises encompass all four of these goals. Our planning always 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 interdependent and cannot be viewed in isolation. Thus, we coordinate our planning with other T&D entities and utilities to develop the most effective solutions. This is becoming increasingly important with addition of more and more DERs to the distribution. The increase in reverse flows on the distribution can impact the subtransmission and transmission systems, potentially requiring more expansive planning studies than have been done in the past. These studies are often referred to as “Cluster Studies” and would include collaboration with VELCO and ISO-NE. It is very likely that we will be involved in these types of studies within the next year.

Performing an integrated and comprehensive study on our entire subtransmission system, 140 distribution substations and nearly 300 distribution circuits would not be cost effective. Instead, we use available system data and business analytic query tools to aid in the identification of those areas that would most benefit from a more in-depth examination for reliability, resiliency, and efficiency improvements. We focus on identifying those areas on the subtransmission or distribution systems that have potential thermal or voltage constraints, high reverse flow, inadequate power factors, poor reliability performance, 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 monitor both peak and minimum (often estimated) load for all substations and circuits; and review individual circuits that experience a significant change (such as additional load, substantial distributed generation, reconfiguration, system performance issues) as necessary. Using data, and a bulk data analysis tool such as Tableau, we can more quickly analyze the substations and circuits and determine where focus further evaluation. DER studies also may identify system areas that may need additional review.

This process enables us to find those areas that would most benefit from system improvements. All subsequent analysis to address capacity, reliability, resiliency, 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 direct our limited resources toward those circuits most in need and most likely to provide cost-effective opportunities for efficiency upgrades.

We prioritize projects that deliver multiple benefits to customers, including combinations of managing assets, improving feeder backup, relocating off-road lines, burying lines, system-hardening opportunities, increasing capacity, and avoiding 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 take less time. Long lead times needed to site, permit, and construct large projects makes it imperative to identify a problem well in advance.

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.

Planning Coordination and Collaboration

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.[2] The "least-cost transmission planning" statute requires that every three years VELCO, in coordination with Vermont's DUs, develop their Vermont Long-Range Transmission Plan. The latest plan was published in July 2021. The next one will start analysis in 2023, seek public input in early 2024 and be published in 2024.

This statute also establishes requirements for notice and public input regarding the development of the Long-Range Transmission Plan, requires distribution utilities to incorporate the most recently filed transmission plan in their least-cost integrated planning processes, and mandates that VELCO and the DUs to cooperate as necessary to develop and implement joint least-cost solutions to identified reliability deficiencies.

In 2007, the PUC developed a process to satisfy these planning requirements and established the Vermont System Planning Committee (VSPC).[3] VSPC, responsible for implementing the planning process, includes VELCO, Vermont's DUs, 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 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

2 30 V.S.A. § 218c(d).

3 Docket No. 7081.

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 Standard Offer facilitator.

The PUC 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 load 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 PUC regarding the potential for NTAs to mitigate those reliability gaps, and provide stakeholders with the opportunity to comment on the VSPC recommendations. The PUC then decides whether to issue approval for a standard offer project. Future decisions will likely also consider constraints related to generation.

GMP actively participates in VSPC processes as well as in their Coordinating, Geotargeting (GTS), Load Forecasting and Generation Constraint Subcommittees. 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 nearly 60 transmission and distribution projects to the VSPC and the GTS for consideration and review. The Generation Constraint Subcommittee (GCS) was formed in April 2019, with a goal to review least-cost policies that could be used to unlock generation-constrained areas. In early 2020, the GCS created subgroups to focus on solutions related to load management, storage, and curtailment. GMP provided an overview of its Vergennes Substation, as we have nearly 16 MW of DERs connected on a 14-MVA substation transformer. GMP demonstrated how data analytics can be applied to review load shapes to capture the net generation and its coincidence with peak loads, showing a potential margin for additional DERs. Hypothetical impacts (i.e., loss of customer load or large DER added) were applied to show the potential impact and provide a platform to discuss solution options.

Transmission and Distribution System Improvement Process

The core purpose of our system maintenance and improvement strategy is to increase reliability for customers and drive out cost and carbon. We use a sequenced planning process to identify and screen proposed projects to ensure we pursue cost-effective solutions for customers. For a project to be included in our capital plan, its proposed investment must deliver meaningful qualitative or quantitative benefits. These benefits can manifest themselves in many ways, including reduced operating costs; improved customer services; improved reliability; resiliency or safety; or advancing innovation and delivering transformative opportunities.

Project Criteria

Providing safe and reliable power to our customers is at the core of our work. To achieve improved service reliability and grid performance, GMP upgrades and improves our generation facilities and T&D infrastructure through planned projects. These reliability upgrades are important for designing, operating, and maintaining the system.

Investments are 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.

Investment 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, grid investments to improve monitoring, dispatching, and controlling DERs is becoming more essential. Increased weather-based reliability events underscore the need to focus on projects that improve the resiliency of GMP's electric system to lessen the effects of climate change on customers.

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. The main objectives of these projects are to provide a safe, reliable, resilient, efficient, and cost-effective T&D system to deliver power. We undertake T&D projects based on the following 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, such as relocating a distribution line out of the woods to the roadside.

Service Resiliency: Projects that increase resiliency by hardening grid infrastructure and improve the ability of systems to withstand and recover from severe storms, such as using cable in conduit to underground rural single-phase lines exposed to high hazards (i.e., trees, wind).

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 may result from load growth or the need for backup capability (improved reliability) for another substation or feeder. This may become an increased driver for projects than in the past few years given increased electrification associated with heating and transportation.

Customer Requested: Projects requested by a customer, such as line extensions or line relocations. These requests include distributed generation projects that require capital upgrades of T&D infrastructure to enable the customer to interconnect without adverse impacts.

Regulatory and Tariff Requirements: Projects required to achieve regulatory compliance or 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 required by our joint-use and third-party attachment agreements.

Distributed Energy Management Systems: This focus for GMP has been developing over the past five years. These resources ensure that we can truly leverage the DERs being deployed onto the distribution system, not only to monitor what these resources are doing, to use their flexibility to benefit all customers and transform the grid. For example, our software platforms that integrate with EV Level 2 chargers in homes allow us to ramp down charging during key peak times.

Climate Plan Integration

A new category of focus has been the need to strengthen the grid specifically in the face of climate change driven weather impacts. GMP filed, and the PUC approved , our Climate Plan focused specifically on this work. As part of that process, we proposed too integrate climate driven work into the IRP and into our normal capital planning process each year going forward. GMP's Climate Plan provides a framework for GMP's continuing efforts to prepare for and proactively respond to the significant impacts climate-change-driven storms are having on GMP's systems and customers. The Climate Plan supports projects that complement and accelerate GMP's ongoing system and operational hardening to maintain and evolve GMP's energy and communications systems. Climate planning is integral to the decision process in the identification and prioritization of additional T&D projects. Increasing the resiliency of the GMP grid through hardening and flexibility is a core function of this work and includes projects like strategic undergrounding which you will read more about in this IRP

Annual T&D Budgeting Process

Many teams within GMP participate in developing the T&D Capital Plan through a comprehensive planning and budgeting process. We identify possible projects by reviewing the multiyear capital priorities, seeking input from internal and external stakeholders, and using the 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 and 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, input from field personnel, specific operational needs, T&D efficiency and reliability analysis, resiliency, customer requests, cost-to-benefit ratios, capacity constraints, regulatory and tariff obligations, and resource availability and timing issues based on permitting timelines. 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.

The T&D budgeting process employs a three-step process consisting of planning, budgeting, and completion. Even with this advanced planning, projects often span different years based on permitting and easement acquisition.

Planning

Every year, each team reviews the current needs and opportunities in their areas and refreshes their list of potential projects to include those that can deliver strong operational performance. Each team evaluates the priority and necessity 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.

Budgeting

Our capital management team reviews and assesses the recommendations. 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 that makes their completion urgent or mandatory. "Recommended" indicates there are opportunities to deliver benefits to customers like lower operating costs or risks, improved service quality, better customer experience, or some other benefit. These projects are also important. "Strategic" indicates the project will advance a capability and improve service delivery but without as much urgency or financial justification as Required or Recommended projects. The team identifies each project's benefit, including improved safety, reliability, efficiency, resiliency or customer service, and regulatory compliance.

We also complete a financial analysis for individual capital projects, describing the justification, costs, benefits, and alternatives to each. 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, addresses a resiliency opportunity or is a reliability project with no reasonably available alternative. These projects also contain either a quantitative cost-benefit analysis, or an explanation of why the project meets an identified exemptions for that requirement.

For each project, we prepare a capital folder that contains six documents:

- Work order and financial analysis that explains the project, its justification, and costs;
- Capital summary of all capital expenditures;
- Quantifiable costs and benefits (such as avoided costs);
- Invoices;
- Quotes or estimates: and
- All other appropriate supporting information.

The capital management team reviews whittles the projects down to a list of capital projects for the year. Our executives and our Board reviews and approves the final list. Also, under regulation plans or as part of a rate case proceeding, the PSD and independent consultants also review our capital plan and documentation.

Completion

Throughout the rate period, we closely manage these projects. As often as necessary (at least monthly), each team and the capital management team review the status of all their capital projects and adjust 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 or have run in to obstacles (i.e., permitting, ROW) with other cost-effective, high-value capital projects that are in the interests of customers and have been identified through our budgeting process.

In 2020, we retired the existing work management system and migrated all work orders over to Varasset Work Management. This new system provides an integrated system that allows work to be managed between designers, purchasing, finance and other departments in an efficient, cost-effective manner. The new platform also provides GMP with a configurable tool that can be adapted for existing work and to help manage some of the new, innovative work that will continue to emerge as Vermont's grid continues to evolve. This single integrated system will support T&D work from start to finish in a more consistent and transparent on behalf of GMP customers.

It will provide new scheduling and resource management capabilities that do not exist in the old application. The schedule capabilities will allow operations supervisors to quickly review, prioritize, and schedule work to optimize crews and other resources. This fully integrated application will also improve communication within the different teams and help to ensure that work is completed quickly, safely, and cost-effectively. The new platform will also provide new data to better identify and understand how we can improve T&D operations.

The Varasset application will provide each GMP district with flexibility to support their work while establishing a measure of consistency that allows districts to share resources and crews more easily when this is necessary or beneficial. The inventory and asset management features within the new system will help Purchasing to optimize inventory levels and gain proactive insights into the materials that are needed for future jobs. Finance will have greater visibility that helps to ensure that T&D assets are added and retired from GMP's fixed assets system in a timely manner. In short, the new system will provide a common platform that will allow T&D to collaborate much more efficiently and cost-effectively on behalf of GMP customers.

System Reliability and Resiliency Initiatives

Climate Plan and Resiliency Zones

GMP recently received approval for our Climate Plan, as a platform for accelerating our continuing work in this area. This includes hardening our electric system, generation assets and information technology infrastructure from the worsening impacts of weather caused by climate change. Resiliency is the ability to withstand and reduce the magnitude and/or duration of disruptive events and to rapidly recover from such events. A resilient system is a reliable system that can then quickly recover from infrequent, often extreme, and unexpected outage events brought on by climate change.

The plan includes specific criteria for categorizing projects that will increase the overall resiliency of GMP's systems. For T&D projects, GMP will use several criteria to rank circuits, based on the magnitude of the impact the hardening investments will have for the customers and load being served. The criteria include:

- 20 least reliable circuits;
- Type, age, condition, and location of asset;
- The number of customers served by each circuit;
- Outage hours and expected benefits of hardening; and
- The critical facilities served by the circuit.

Prioritization will consider all these criteria along with feedback from field resources and continued assessment of achievable outage improvements.

Innovation project criteria will focus on implementation of resiliency zones to create areas that can support and sustain critical emergency response areas during extreme weather events. This assessment will include consideration of whether the area:

- Has feeder backup capability;
- Is fed by radial or networked subtransmission;
- Experiences a lot of outages or long outages;
- Has no or limited broadband; and
- Has poor or no cell service.

GMP RESILIENCY ZONE

Prioritization will consider all these criteria and project planning will be updated yearly, in accordance with the Climate Plan approved by the Commission.

In addition, we introduced the notion of Resiliency Zones in this plan. Our intention is to leverage the technological innovations that have occurred over the last few years to drastically improve the resiliency of targeted locations. Our goal in the first iteration was to work with up to four communities and take a targeted resiliency approach that was beyond traditional poles-and-wires solutions. In a sense, this is an entirely new approach to hyper local planning, with the sole focus of driving up resiliency in reliability-challenged locations.

We employed a data-driven approach to identify and select these locations using a combination of electric reliability data, communications/broadband connectivity data, and CDC social vulnerability indicators. Our initial review connected us with four communities we are now working in partnership with to develop the specific resiliency zone improvements.

Rochester: Building on our experience implementing a solar plus storage microgrid in Panton, GMP will pilot a Resiliency Zone that incorporates renewable generation and energy storage facilities with the microgrid capabilities to island downtown Rochester along Route 100.

The region included in the island will contain critical infrastructure including the town water pumps and the emergency shelter at Rochester Elementary School. Working with town officials, GMP has identified a potential site for solar generation located behind an unused former high school.

Solutions including renewable generation and storage facilities have been solicited via an RFP issued in August 2021. We expect the microgrid to be operational by December 2022. The completed Resiliency Zone will also include EV charging stations.

Grafton: Mapping outages in the town of Grafton clearly identifies a region of the town with inferior reliability (Figure 1). Our estimates indicate it would cost $456,801 for 3.5 miles of new single-phase tree wire construction and associated vegetation management to reach homes with the worst reliability and reduce their annual outage frequency to become more in line with the rest of the community. It’s important to note that because these customers rely on a fiber to the home network for telephone communications, they can lose all connectivity with the outside world once the fiber modems lose their backup. This area also has poor cellular connectivity, which creates a hazardous situation for customers during a major event.

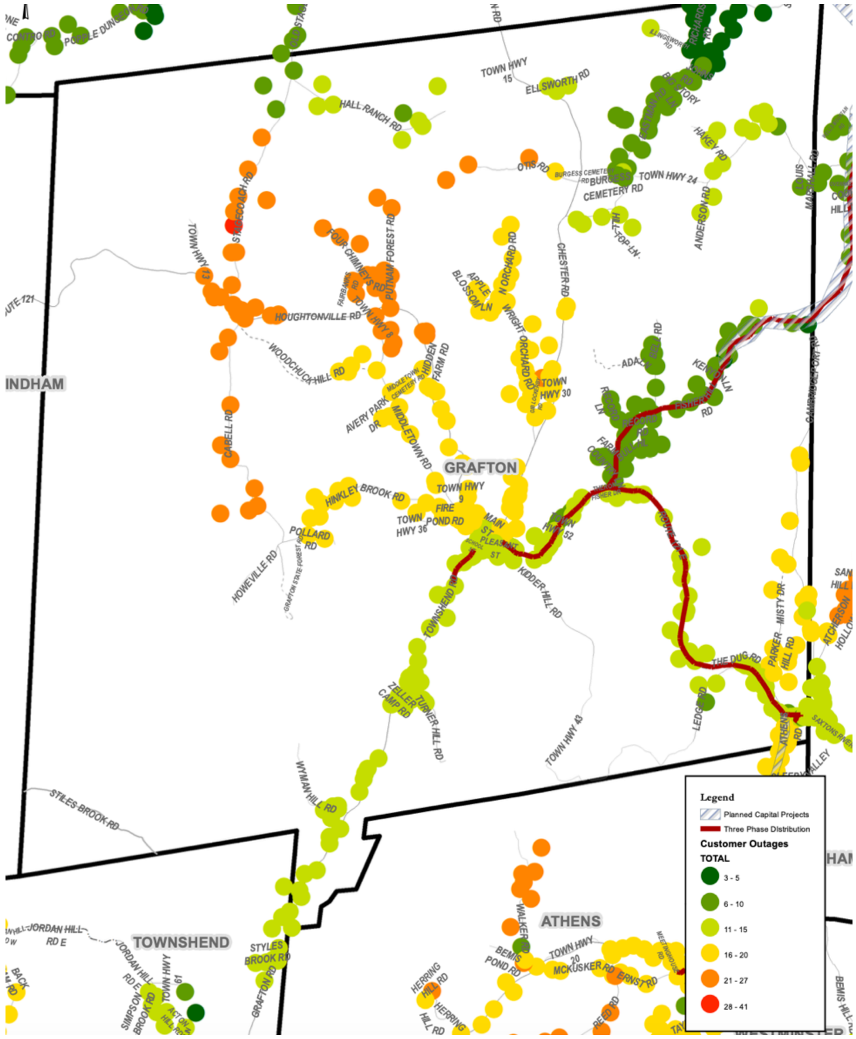


Figure 3-8. Residential Grafton Outages Between 2018 and 2020

We hope to pilot a residential intervention that offers home battery storage to customers that experienced over 20 outages between 2018 and 2020 at a reduced cost. Solutions incorporating home battery storage with an option for paired solar will be solicited using an RFP that will be issued in late 2021 or early 2022.

After pilot evaluation, GMP hopes to expand this pilot to other pockets of our service territory with poor reliability that are difficult to serve using traditional distribution upgrades.

Strafford: Our experience in Panton will also inform the development of a microgrid to serve the downtown area of Strafford including emergency shelters at the Newton School, Rosa Gym, and Barrett Hall, and the general store and post office. GMP will leverage the existing 7-MW Elizabeth Mine Solar Project on a former superfund site and a smaller solar site owned by the town to power the microgrid.

During our site visit with Strafford representatives, we also spoke with Elizabeth Mine owner/operator Greenwood Energy. GMP engineers will work with Greenwood Energy and Northern Reliability to leverage the privately owned solar and storage to be installed at this site to create a microgrid capable of islanding during grid disruption.

Brattleboro: Brattleboro's intervention will address the resiliency needs of the Tri-Park Cooperative Housing Corporation, a mobile home community in West Brattleboro that was founded in the 1950s. Prior to Tropical Storm Irene, Tri-Park was home to 333 mobile home sites and nearly 1,000 residents, almost 10% of the total population of Brattleboro. The Cooperative contains three properties: Mountain Home Park, Glen Park, and Black Mountain Park. While Brattleboro has removed home sites in the flood zone and invested over $8M to address aging and failing infrastructure, including $250,000 on electrical service upgrades, this site remains vulnerable to being isolated during flood events.

In this location, we will incorporate battery storage capable of supporting the Tri-Park load during severe weather conditions. We will also look at providing resiliency to the local water-pumping facility that is operated by the Town of Brattleboro. These batteries will provide peak savings and other grid services when not in use for resiliency.

Grid Hardening

Grid Hardening has been an effective strategy to strengthen the electric system infrastructure to improve service reliability during weather-related outages for many years. The stronger the lines, the more likely that they will remain on during a weather event. This will result in faster and less costly storm recovery. The Climate Plan work will help accelerate certain system and operational hardening efforts to provide GMP's customers reliable service even with increasing frequency of severe storms driven by climate change. These storm-hardening projects/construction techniques for our T&D system include:

- Using cable in conduit (CIC) installations to underground rural single-phase lines exposed to high hazards (i.e., trees, winds).
- Using primary underground in areas where ROW or permission for trimming for overhead lines cannot be secured.
- Using covered wire in areas where loads are small, the lines are located "cross country" or in less densely populated areas.
- Using spacer cable as part of main line feeder roadside construction where the threat of future tree growth exists.
- Increasing self-healing capabilities of distribution feeders (see Grid Innovation).
- Increasing the number of SCADA-controlled, motor-operated load break switches, which enable faster sectionalization. (See Grid Innovation).
- Relocating substations outside of flood-prone areas identified in 100-year and 500-year floodplains data.
- Continuing to recapture/widen transmission rights-of-way to reduce tree-related faults and outages. This allows GMP to remove hazard trees that have the potential of striking our lines in radial subtransmission corridors.

Grid-hardening projects have a positive impact on reliability and resiliency. First, these T&D projects improve reliability during normal conditions and smaller weather events by hardening the lines so they are better able to carry power through routine tree contacts and other incidents that might otherwise create a fault and cause a power outage. Second, during larger and more severe weather events, these projects will harden mainline feeders and sub-transmission lines against damage, so they are able to tolerate a higher threshold of weather impacts.

From 2018 through September 2021, GMP installed 27.4 miles of cable in conduit, 49.6 miles of primary underground, 87.7 miles of spacer cable and 345 miles of covered tree wire.

Grid Innovation

GMP is leveraging technology and innovation to continue to transform the electric system for customers, creating a more localized, reliable, and resilient energy delivery system. We plan our investments so smart grid and related technology will continue to improve the process of minimizing or eliminating outages. With the threats of climate change, innovation is a no longer an elective objective, it is critical to increasing customer resiliency and safety in a cost-effective way.

GMP is currently implementing an innovative pilot that will create a first-of-its-kind microgrid system using a 1MW/4MWH BESS, commissioned in July 2018, that will improve resiliency in Panton. The island will encompass 51 customers, including 45 residential customers, Panton Town Hall, town aarage, a farm and three other commercial customers. This project allows the BESS to island a portion of the town during an outage. GMP partnered with Schweitzer Engineering Laboratories (SEL) and TESLA to study and design a stable and reliable islanding system. Equipment installation began in April 2021 and the project was commissioned in October of 2021. The CP Resiliency Zone work also supports a framework to use the cutting-edge Panton microgrid design and technology at other locations. GMP is working to develop plans for Resiliency Zones where the energy and its related communications system is designed for long-duration outage resistance, to better withstand extreme weather. These zones will focus on critical infrastructure such as health facilities and emergency-operations facilities.

GMP is increasing the number of SCADA-controlled, Motor Operated Load Break (MOLB) switches on the subtransmission system, which enables us to sectionalize faster when problems occur. These MOLB switches allow our control rooms to remotely sectionalize faulted line sections, allowing the power to be restored to the unfaulted line sections within minutes. Without these switches, when faults occur on the line, the customers remain without power until a crew can be dispatched to manually operate the switches. Depending on location, weather and availability of crews, manual switching can add one to four hours to an outage. As part of the CP, GMP plans to complete 20 MOLB projects in FY2021 and FY2022.

With the use of the VELCO fiber network, GMP installed SCADA at nearly all our substations. We have also installed fault indicators at various points on our subtransmission system to provide fast and accurate information regarding the extent of an outage, allowing GMP to respond more effectively.

We have employed technology to improve the reliability and resiliency of the transmission and distribution system. GMP completed a self-healing project at Burlington International Airport in 2018. This project took a feeder backup tie that required manual switching and created an automated restoration scheme. This self-healing project was an example of a storm-hardening grid innovation to improve resiliency with innovative automation equipment coupled with high-speed communications. These self-healing capabilities are for areas with existing feeder backup capabilities and where it makes sense to isolate a particular section of customers when a fault occurs.

In 2021, GMP will complete a self-healing project for the Vermont Statehouse in Montpelier. This project will automate restoration of the Statehouse, normally fed from the Mountain View 27G6 circuit to the alternate Montpelier 3G3 circuit in the event the normal Mountain View 27G6 source is lost. A new alternate source recloser, capable of sensing voltage on both sides, will be installed on Court Street at the normally open point between the Mountain View 27G6 and the alternate source, Montpelier 3G3. When a problem results in an outage to the Mountain View 27G6, the normal source recloser will sense loss of voltage and open. At the same time, this recloser will communicate via radio to the alternate source recloser fed via the 3G3 that the State House needs to be restored. After the 3G3 recloser checks the alternate source for adequate voltages it will close, restoring the feed to the Statehouse from the alternate source Montpelier 3G3. The automation scheme can be enabled or disabled at either recloser or via SCADA. In the event a fault occurred on the underground to the Statehouse, either recloser would trip and disable the automation. This assures that the other recloser cannot close in on a fault regardless of which recloser is feeding the Statehouse, which could result in damage and safety concerns.

SCADA will be established to each recloser via cellular communications to provide system operators with remote control and status indicators, including voltage on both sides and current. The radio communications are only used for automating restoration and if the radios were lost, system operators could still control the reclosers to initiate the feeder backup scheme remotely via cellular communications. Similarly, if cellular communications were lost and the radios remained healthy, automatic restoration would still occur. GMP is actively determining where the next self-healing projects will be implemented. One area that has been identified is between Pownal and South Bennington. In 2018, we rebuilt the Pownal-to-Bennington circuit with three-phase construction to enable feeder backup. We are considering running fiber on this new line, to enable a self-healing project for improved reliability for both substations.

Batteries also offer convenient and seamless backup power to participating customers during outages. When paired with a photovoltaic system, they can also supply power for extended periods of time when the batteries are recharged each day by the sun.

In 2020, batteries in customers' homes provided a combined 17,000 hours of backup, helping customers stay up and running during outage events. In addition, these batteries help drive down peak costs, saving all customers money. As described throughout this IRP, this storage provides the ultimate resource to manage an evolving and dynamic grid.

Technology is advancing in both functionality and affordability, which will create additional opportunities for accommodating two-way flows from DERs, optimizing charging, and discharging of batteries and integrating demand-reduction schemes.

More information about various programs for home battery storage solutions can be found in Chapter 1, Innovating for Customers

Distribution Optimizations

Our planning process continues to include goals to optimize our distribution system to improve the efficiency, performance, and reliability of the power we deliver.

Conservation Voltage Regulation

Conservation voltage reduction (CVR) is implemented on several of our distribution circuits.

CVR, an energy efficiency program, involves 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 1% 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, and where the substation bus regulates voltage, and where large commercial and industrial loads provide their own voltage regulation. We have stopped CVR on some circuits to enable circuit transfers during planned or contingency situations and because of customer complaints.

Increasing amounts of distribution generation complicates the implementation of CVR, making it more challenging to maintain adequate voltage given the variability of the generation. 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 potential new tool that can be set to help stabilize voltage at feeder ends.

We are exploring how our advanced metering infrastructure (AMI) can expand CVR. AMI provides access to integrated Volt/VAR control (IVVC) of distribution circuits, which measures distribution circuit voltages along a given circuit in real time and optimizes voltage regulator settings and capacitor bank switching. We are looking into solutions with vendors to use real-time data from grid devices to coordinate device controls across the grid to provide energy savings, peak reduction, and increased hosting capacity.

Voltage Conversions

Conversion of our distribution system to our standard 12.47 kV/7.2 kV grounded wye enables us to better accommodate load growth and DER interconnection, enable feeder backup between substations, improve voltage performance, and reduce losses. However, we still have some distribution circuits fed at nonstandard voltages of 2.4 kV, 4.16 kV, and 8.3 kV distribution circuits remain.

We consider several factors before deciding to convert the voltage of a certain circuit, among them: capacity constraints, consideration of feeder backup with adjoining substations, inadequate fault currents, low voltage complaints, and voltage losses. We consider line, substation transformer, 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 to reconfigure feeders and balance voltages with adjacent area circuits, potentially creating additional loss savings.

Rather than making a specific plan, we carefully evaluate and balance the costs and benefits of any potential voltage conversion and select projects that provide the greatest value. Over the last five years, we have evaluated and selected several voltage conversions 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 rebuilt the Barre South End substation, converting its 4.16-kV and 2.4-kV circuits to 12.47 kV. In addition, we rebuilt the Websterville substation with a larger transformer to improve substation operating flexibility for feeder backup. Standardizing to 12.47 kV allowed feeder backup between the three substations and improved reliability for the Barre area.

The completion of the new Airport Substation in 2020 will allow for the conversion of the existing 4.16-kV circuits to the Vermont Air National Guard to 12.47 kV. This conversion is planned before the end of 2022. Once this load has been converted, we will retire the old Airport Substation.

We are planning and beginning construction on several other voltage conversion projects.

We filed for a certificate of public good with the PUC in April 2021 to convert the three 8.32-kV circuits at the Putney substation to 12.47 kV. This project is scheduled for completion in 2022. These conversions will reduce losses and enable improved backup between the Putney, Westminster, and Brudies Road substations. We received our Certificate of Public Good for the Putney Substation upgrade in September 2021.

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. Hydeville substation upgrade is currently scheduled for completion in 2023. Fair Haven substation conversion is in the budget for completion in 2025.

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 reduce losses. Through these placements, we maximize efficiencies by being able to use lower voltage distribution capacitors that are generally less expensive than others.

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. The ISO's 2017-2018 load power factor audit showed that GMP was compliant for all periods for the Vermont zone but showed a level of under-compensation during high load periods in the Harriman/Central zone. GMP investigated and determined that we had some failed capacitor banks, which were addressed in 2019. GMP has not received any additional notices of non-compliance.

Capacitor optimization studies are performed for circuits to help meet ISO requirements, 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. Feeder backup studies in 2021 supported the installation of capacitor banks in our Milton area. Typically, GMP will compare the performance and costs between placement of a line regulator or capacitors. DER studies also include the review regarding adequacy of capacitor placements.

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, 2021, we increased the minimum average power factor required to avoid a demand determination adjustment to 95%. This has already improved power factors.

Battery storage can also provide dynamic reactive support. Unlike capacitor 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 tested volt var curves with some of our Powerwall units. We have not implemented this on any of our circuits to date.

Circuit Reconfiguration and Load Balancing

The need to rebalance and reconfigure a circuit is driven by factors including 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.

The ability of AMI 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.

Distribution Energy Resource (DER) Interconnection

The application and installation of distributed energy resources (DER) continues to be a key factor for carbon reduction and meeting Vermont's comprehensive energy goals. The higher penetration of DER interconnection produces additional challenges for managing the transmission, subtransmission and distribution systems.

Each developer must receive a Certificate of Public Good (CPG) from the 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 and those of ISO-NE and the PUC.

We remain active within the ISO-NE Distributed Generation Forecast Working Group. This DG Working Group considers national trends, interconnection requirements, under-frequency setting concerns, and interconnection costs related to DG. We have developed several tools to help DG developers navigate the interconnection process.

These tools include:

- Information on the GMP website under Net-metering-project-requirements.[4] This interconnecting customer information provides resources to developers, including codes and standards, applicable tariffs, registration, and application forms, enabling statutes, PUC rules, and regulatory and installer contacts. Also included are service requirements, meter socket connections, battery storage requirements, and links to a map showing our three-phase distribution lines and the GMP Solar Map.
- The Green Mountain Power Distributed Energy 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. These guidelines were updated and shared with developers in April 2021. The GMP engineering team is continuously looking at the latest technology, rules, and regulations along with updated practices in system safety and protection. We collaborated with other utilities throughout New England as part of this effort. Through this work along with the continued improvement in inverter technology, we have been able to reduce the amount of interconnection protection equipment needed in many cases.
- An internal distributed energy resource database that contains information on proposed and installed DERs on our system. The database includes developers' 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. It also drives the solar map information and internal and regulatory reporting, including to ISO-NE.

[4] This information is available at: https://greenmountainpower.com/help/net-metering-project-requirements-process/

- A TGFOV database that contains information on substations needing TGFOV mitigation. This database provides minimum load-to-generation ratios, number of DER customers on hold, capacity on hold, expected mitigation start date, and status. In July 2019, GMP received approval in Case No. 19-0441-TF, for a TGFOV fee for generation projects interconnecting to substations that we have identified as requiring system upgrades to address TFGOV conditions. Twice a year, GMP provides REV and the DPS a schedule of upcoming TGFOV upgrades. Annually GMP provides REV and the DPS a report of all the TGFOV upgrades with cost data, itemized costs and total TGFOV fees collected. The accuracy of the fee will be revisited every two years, where TGFOV projections and actual costs of the TGFOV upgrades will be reviewed to consider if an increase or decrease is warranted. The TGFOV fee was reviewed in 2021 and determined to still be accurate. The next review will be in 2023. GMP has also added the circuits needing TGFOV mitigation onto our solar map.

With the successful deployment of distributed generation on our system, we are experiencing significant DG saturation on several circuits, which is bumping up against limitations, such as substation transformer limits, and the need for additional system upgrades. Unlike load-growth-related T&D system needs, under the current regulations in Vermont, generators 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 (**Error! Reference source not found.**). 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 3-5 shows a statewide perspective of our Solar Map, available on our company website. This map details where DERs are prevalent or not, and where they might be more easily interconnected.

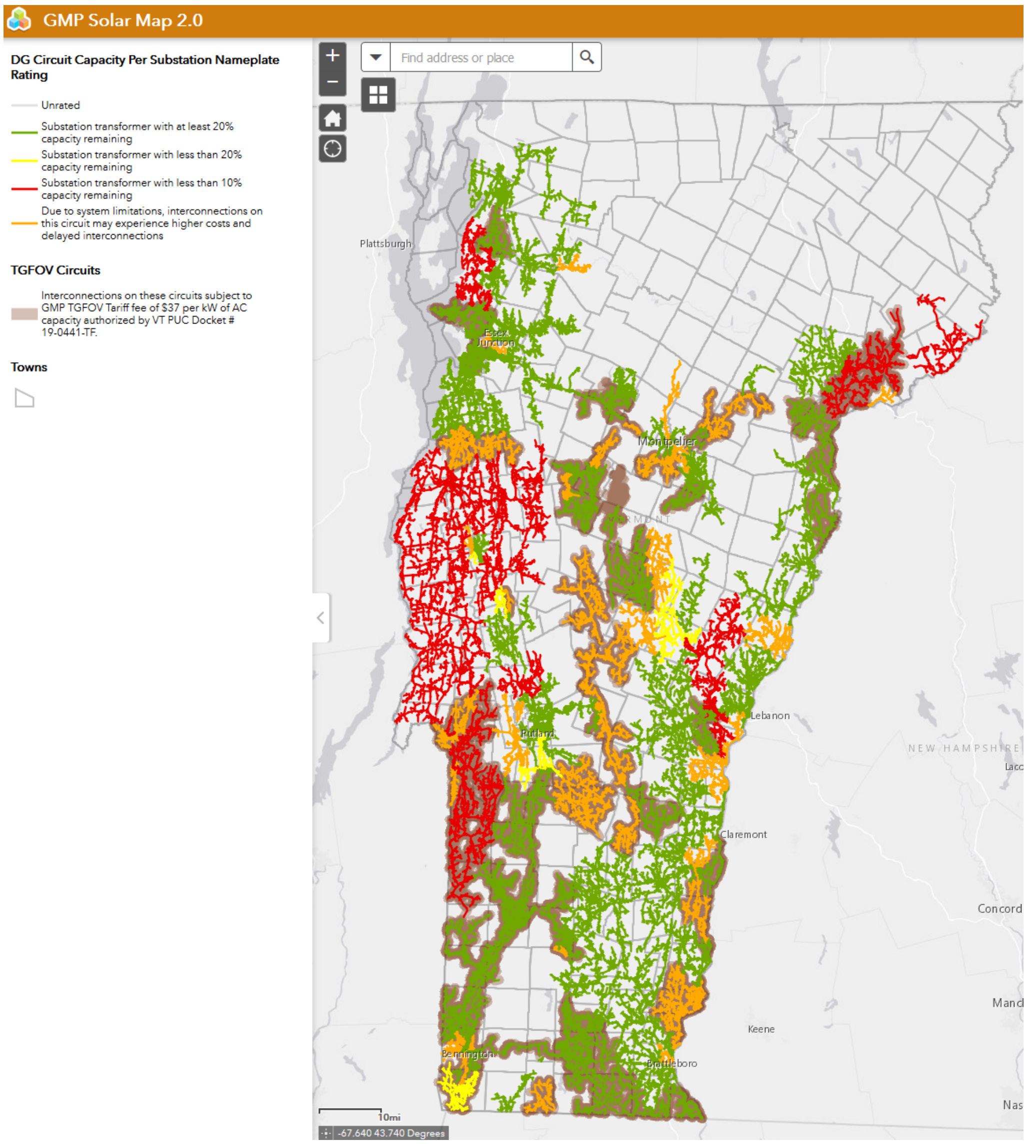


Figure 3-5. DER Solar Map

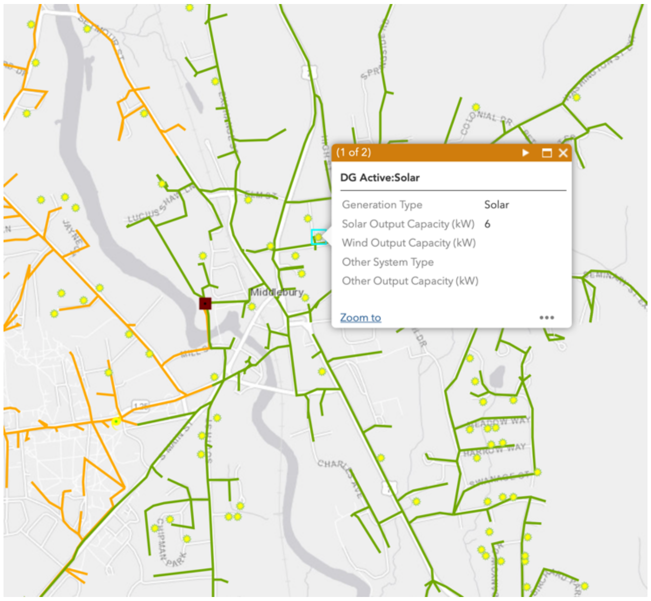


Figure 3-6. Solar Installation DER Map Details (part 1)

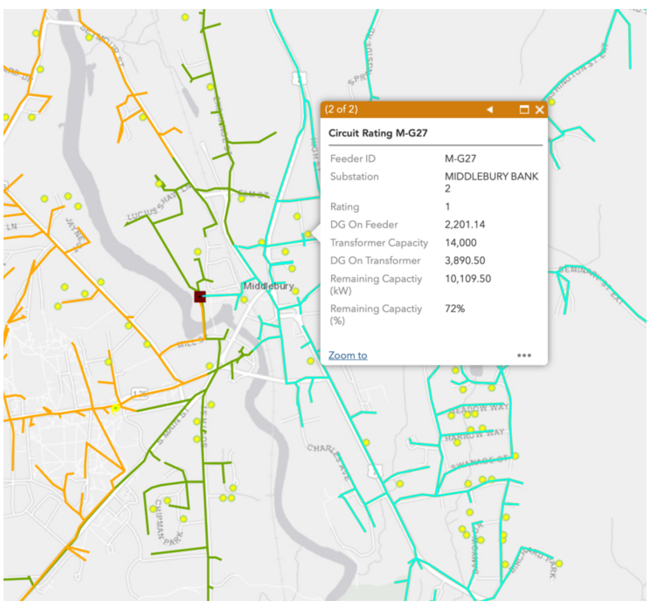


Figure 3-7. Solar Installation DER Map Details (part 2)

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 it (Figure 3-6).

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.

The second pop up box (Figure 3-7) 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, comparing this total to the top nameplate rating of the transformer. System limitations may include, but are not limited to, TGFOV constraints, and 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, circuit voltage, conductor identification, solar irradiance information, and links to Agency of Natural Resources GIS environmental data layers. If transmission constraints develop, we may be able to enhance the Solar Map to show these limitations as well. We are considering the development of a tool to help developers estimate the cost of interconnection for a proposed generator at a given location.

Opportunities for Grid Optimization

Electrification Impacts of Heat Pumps and Electric Vehicles

Electrification is a key part of the decarbonization strategy. While achieving this important goal for our customers it is important that we examine the potential impact on the grid reliability and resiliency from this increased demand, predictively related to EVs and heat pumps. The T&D planning process has always included the review and anticipation of load growth. It was only in the past decade that load growth remained relatively flat on a system basis. We will continue to monitor the growth across our system. Like DER integration, the electrification associated with EVs, fast-charging stations and heat pumps is harder to predict given the uncertainty in the timing, location, and actual KW.

GMP engineering has completed planning analysis to gain understanding of the potential system impacts that could occur with heavy EV and heat pump penetration. In 2019, we took 10 distribution circuit models representative of GMP territory. We placed an EV charger at every resident with a PV or a Powerwall, believing this represented those residents most likely to implement these lower emission upgrades. EVs were assumed to be at 6 kW per unit during peak non-solar hours.

This analysis showed about 14% of EV charger installs resulted in overloaded distribution transformers and 2% of EV charger installs resulted in overloaded fuses. All circuits experienced overloaded transformers and fuses. This analysis did not look at replacements for services and secondaries. The analysis suggested:

5 kVA transformers should be replaced when EV chargers are installed.

10 kVA transformer or less should be replaced when an EV charger and one Powerwall are installed.

15 kVA transformer or less should be replaced when an EV charger and two Powerwalls are installed.

In 2020, we performed an analysis on 10 distribution circuits representative of GMP's entire territory and analyzed the thermal impact for a 50% and 100% penetration level for EVs, with EVs modeled at 1.5 kW per unit for residential customers during peak non-solar hours. The 1.5kW value is derived from the successful EV charger management platform that GMP has been operating with customers for the last few years. The actual data shows that the average power demand from a fleet of EVs is closer to 1.5kW and during actual peak events we can take that down to near 0kW.

Like the 2019 analysis, we saw a higher number of distribution service transformers requiring changeout to larger sizes. A 6.6 kW uncontrolled charger (i.e., charger can be utilized at any time of the day or night), along with normal load, supports that service transformers less than 15 kVA will likely require replacement. For the 10 circuits this would be nearly 1,000 transformers if every 5 and 7.5 kVA unit was replaced. Including the 10 kVA units this total equates to 5,172 transformers needing replacement. This analysis did not look at replacements for services and secondaries. The 100% penetration level showed 50% of the sampled circuits had regulator overloads and 60% showed recloser overloads. The 50% and 100% penetration showed fuse overloads for every circuit. Only one circuit showed substantial amounts, near 2 miles, of overloaded conductor. In the 100% penetration case, the substation transformer loading approached >90% or exceeded top nameplate on over 50% of the circuits. This substation loading is concerning, given it will impact other load additions as well as feeder backup capability. It is very important to note, however, that this was done assuming no management of the EV charging (i.e., EV charger was able to be utilized at any time of the day or night), which as mentioned above, significantly reduces the impact that this EV charging causes to the distribution system.

Circuit	Residential Customers	5 KVA Transformers	7.5 KVA Transformers	10 KVA Transformers	15 KVA Transformers	Case	Overloaded Fuses	Overloaded Sections of Conduct	Overloaded Regulators	Overloaded Reclosers	Comments
WM-G92	1288	33	0	193	265	Base	8	0	0	2	Two circuit substation
						Add EV to 50% of residences	15	0	0	4	
						Add EV to 100% of residences	15	8	2	4	
SF-G20	1626	166	4	375	362	Base	0	0	0	0	The sub transformer is a 7 MVA top and phase balance on the sub is not great (single circuit sub)
						Add EV to 50% of residences	4	1	0	0	This case will be okay for the overall sub transformer rating (82%) but per phase is getting close to the limit (94%)
						Add EV to 100% of residences	6	3	2	4	Sub loading will be at 102 %. Two of the phases of the sub transformer will be more substantially overloaded. May need additional phases installed to better balance
WI-G31	1858	103	3	388	168	Base	1	0	0	1	The sub transformer is a 14 MVA top and serves 3 circuits (WI-G11, WI-G31 and WI-G73) with a combined peak of approximately 10.5 MVA
						Add EV to 50% of residences	2	0	0	5	WI-G11 has 1213 VT residential customers. Adding those at 50% as well pushes the sub to 91.5% loading. We would have to keep and eye on the phase balance for the sub transformer. We have limited info for residential customers on the WI-G73 as it serves Eversource in NH.
						Add EV to 100% of residences	7	1	2	9	WI-G11 has 1213 VT residential customers. Adding those at 100% also pushes the sub to 108% loading. We have limited info for residential customers on the WI-G73 as it serves Eversource in NH.
CA-G37	977	60	0	286	109	Base	1	0	0	0	Single circuit substation
						Add EV to 50% of residences	2	0	0	0	
						Add EV to 100% of residences	3	0	1	0	Substation regulators become overloaded. Sub transformer >90% top nameplate.
9G4	1542	17	0	383	241	Base	4	0	0	0	3 circuit substation
						Add EV to 50% of residences	6	0	0	0	
						Add EV to 100% of residences	13	0	0	0	
BA-G71	1441	149	5	559	228	Base	3	0	0	0	The Barker Ave sub loaded 9.4 MVA on top nameplate 10.5 MVA, reduction in feeder backup capability (both circuits modeled)
						Add EV to 50% of residences	6	0	0	7	
						Add EV to 100% of residences	10	0	0	10	Substation regulators become overloaded
BA-G72	649	6	0	67	29	Base	10	0	0	0	The Barker Ave sub loaded 9.4 MVA on top nameplate 10.5 MVA, reduction in feeder backup capability
						Add EV to 50% of residences	13	0	0	0	
						Add EV to 100% of residences	17	0	0	0	
Bay-G4	1199	161	0	674	226	Base	6	0	0	1	Showing Undervoltage conditions. Bay Street sub is 10.5MVA top nameplate rating - reduction in feeder backup capability. (4 circuit substation)
						Add EV to 50% of residences	6	0	0	1	
						Add EV to 100% of residences	8	0	0	1	
SH-G35	1180	116	3	534	220	Base	0	0	0	0	One circuit substation
						Add EV to 50% of residences	9	0	0	1	
						Add EV to 100% of residences	22	0	0	4	
PS-G43	1833	164	5	718	257	Base	2	0	0	0	3 circuit substation
						Add EV to 50% of residences	5	27	0	5	
						Add EV to 100% of residences	9	41	2	7	
						Base					
						Add EV to 50% of residences					
						Add EV to 100% of residences					
10 Ckts/9 Subs		975	20	4177	2105						

Figure 3-8. 2020 Analysis of 50% and 100% EV Penetration

In 2021, we performed the following updated analysis that included both controlled and uncontrolled EV charging:

Adding two 350 kW fast chargers plus 1 kW heat pump to residential customers at 50% penetration plus 1.5 kW EV load to residential customers at 50% penetration (100% EVs uncontrolled)

Adding two 350 kW fast chargers plus 1 kW heat pump to residential customers at 50% penetration plus 1.5 kW EV load to residential customers at 50% penetration (75% EVs controlled).

Adding two 350 kW fast chargers plus 1 kW heat pump to residential customers at 100% penetration plus 1.5 kW EV load to residential customers at 100% penetration (75% EVs controlled).

Circuit	Case	Overloaded Fuses	Overloaded Sections of Conductors and Cables	Overloaded Regulators	Overloaded Reclosers	Comments
SF-G20	Base Case 1	0	0	0	0	The sub transformer is a 7 MVA top and phase balance on the sub is not great
	Case 2	4	2	2	3	This case will overload the sub transformer rating at about 105%. Two of the phases of the sub transformer will be more substantially overloaded. May need additional phases installed to better balance
	Case 3	4	1	2	1	This case will be okay for the overall sub transformer rating at 92% but per phase on two phases is over the limit at around 105%. Some room for balance but may need additional phases run.
	Case 9	4	2	2	4	This case will overload the sub transformer rating at around 108%. Two of the phases of the sub transformer will be more substantially overloaded. May need additional phases installed to better balance
WI-G31	Base Case 1	1	0	0	1	The sub transformer is a 14 MVA top and serves 3 circuits (WI-G11, WI-G31 and WI-G73) with a combined peak of approximately 10.5 MVA
	Case 2	7	1	3	8	WI-G11 has 1213 VT residential customers. Adding those at 1.25 kW per residence and 2-350 kW chargers pushes the sub transformer 107.4% loading. We have limited info for residential customers on the WI-G73 as it serves Eversource in NH.
	Case 3	2	1	1	7	WI-G11 has 1213 VT residential customers. Adding those at .69 kW per residence and 2-350 kW chargers pushes the sub transformer 95% loading. We would have to keep an eye on and check on the phase balance for the sub transformer. We have limited info for residential customers on the WI-G73 as it serves Eversource in NH.
	Case 9	7	1	3	8	WI-G11 has 1213 VT residential customers. Adding those at 1.38 kW per residence and 2-350 kW chargers pushes the sub transformer 110% loading. We have limited info for residential customers on the WI-G73 as it serves Eversource in NH.
WM-G92	Base Case 1	8	0	0	2	
	Case 2	19	3	2	4	
	Case 3	15	0	1	4	
	Case 9	20	24	2	4	
CA-G37	Base Case 1	1	0	0	0	This analysis will assume the CA substation transformer and regs have been upgraded to 5/7MVA and 328A units, respectively.
	Case 2	3	0	0	0	The existing 219A regs in the CA substation would be overloaded for Cases 2, 3, and 9.
	Case 3	2	0	0	0	The two 350 kW chargers were installed at Castleton University (L43 P10) and Dollar General (L4 P89X)
	Case 9	3	0	0	0	In the worst case (Case 9), the maximum loading on one of the substation transformer windings is 85% of top nameplate.
9G4	Base Case 1	4	0	0	0	Vergennes substation transformer has top nameplate of 14MVA. Base Case loads the transformer 38%.
	Case 2	6	3	0	0	Overloaded conductor is 336 right outside the sub.
	Case 3	6	0	0	0	The two 350 kW chargers were installed at the Vergennes Shopping Venter / Shaws (Tag 91464) and at the Vergennes High School (Tag 88742)
	Case 9	10	3	0	0	Overloaded conductor is 336 right outside the sub.
Bay-G4	Base Case 1	6	0	0	0	2-350kW chargers installed on White Market and Maple Grove Farms. Both on Portland St.
	Case 2	9	0	0	1	OL recloser is a 70a V4L. Not sure where the previous study OL reclsoer was. Not in this model.
	Case 3	7	0	0	0	5kVA xfrms include 3kVA
	Case 9	9	0	0	1	Showing some UV conditions.
BA-G71	Base Case 1	3	0	0	1	The Barker Ave Substation Transformer has a top nameplate 10.5 MVA, reduction in feeder backup capability (both circuits modeled)
	Case 2	8	0	1	10	The Barker Ave Sub Transformer loaded 10.4 MVA
	Case 3	6	0	0	7	
	Case 9	8	0	3	10	The Barker Ave Sub Transformer loaded 10.7 MVA (OVERLOADED)
BA-G72	Base Case 1	10	0	0	0	The Barker Ave Substation Transformer has a top nameplate 10.5 MVA, reduction in feeder backup capability (both circuits modeled)
	Case 2	15	0	0	0	The Barker Ave Sub Transformer loaded 10.4 MVA
	Case 3	21	0	0	0	
	Case 9	21	0	0	0	The Barker Ave Sub Transformer loaded 10.7 MVA (OVERLOADED)
PS-G43	Base Case 1	2	0	0	0	
	Case 2	7	36	1	7	
	Case 3	5	27	0	7	
	Case 9	7	39	1	8	
SH-G35	Base Case 1	0	0	0	0	
	Case 2	13	0	0	2	
	Case 3	5	0	0	1	
	Case 9	14	0	0	2	

Figure 3-10. 2021 Analysis of 50% and 100% EV Penetration, Controlled and Uncontrolled EV Charging

The fast chargers were located at gas stations, schools, shopping plaza, community centers or hospitals. As expected from previous analysis, distribution service transformers and numerous line fuses require capacity upgrades. There was not a lot of difference between the three cases. The results were like those completed in 2020; again 50% showed need for regulator upgrades and 60% required recloser upgrades. Substation loading was also a predictable concern, however with controlled charging, we see reduced overloads on the system. For a three-phase application, a recloser upgrade historically has been between $20,000 to $80,000, depending on if the reclosers are hydraulic or electronic. A three-phase regulator upgrade has been estimated between $80,000 to $130,000. A fuse upgrade historically has been approximately $400 each. Reconductoring would be roughly $200,000/mile and this includes no trimming. These costs can vary greatly depending on the location and asset specifics.

Impact of Increasing DER Penetration

DERs can be leveraged as a grid asset, or if not deployed in an optimal way become a detriment to the grid. Certain DERs such as distributed solar generation are simple to model and understand the impacts, however, more flexible DERs such as battery storage or EVs can be leveraged in a way that actually offsets the impacts of too much solar in an area. For example, consideration must be given to a DER's size and type, the relative strength of the electric system at the proposed interconnection point, and the protection strategies in the area.

We are conducting a series of feasibility, system impact, stability, and facilities studies to identify potential problems and develop appropriate solutions with respect to distributed generation. When the studies are complete, we plan to work with generation developers to address specific interconnection issues and develop mutually beneficial solutions.

If not deployed properly or increased penetration of DERs, specifically distributed generation, can lead to system issues such as:

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 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 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.

With the continued influx of variable DERs behind the meter, our distribution system must accommodate bidirectional power flows that can be redirected to different substations and feeders across our system via feeder backup and/or impact the operation of the subtransmission and bulk transmission. In response, integrated resource planning is expanding to require additional analysis to capture multi-system level impacts. A redesign of radial subtransmission systems to looped systems, load control, generation curtailment, storage, and microgrids are some mitigation solutions.

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 distributed and renewable resources.

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 again utilize our data and bulk data analysis tools to compare circuit capabilities. 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 help direct resources and emerging technologies to the optimum locations.

Currently, the data that is considered includes:

- Circuit reliability;
- Power quality sensitivities (such as customer type, hospitals, and emergency shelters);
- Substation capacity;
- Circuit minimum and maximum kW and kWh loads; and
- Total amount of connected and proposed DERs.
- Impact of DER Penetration on Transmission
- In addition to localized issues that can arise on the distribution system from a high penetration of DER, eventually, the aggregation of these resources can roll up and create issues for the transmission system. As discussed throughout this chapter, the VELCO Long Range Plan talks more specifically about the impacts of distributed generation on the bulk transmission system. Vermont has experienced what can happen when generation in an area far exceeds the load in that same area. The first of this type of impact has occurred in the northern portion of Vermont and is known as the Sheffield Highgate Export Interface, or 'SHEI'. The SHEI is the result of area generation significantly exceeding the area load, and if the transmission system loses one element, the remaining transmission cannot support the excess generation that needs to be exported from the area. This ultimately results in a thermal overload or voltage collapse in this area, which can lead to loss of customer service.
- Until adequate transmission or system solutions are implemented, the interim solution is to curtail generation whenever it exceeds the critical limit of the transmission system. This results in lost renewable energy production leading to financial impacts to customers in Vermont. Alternatively, transmission solutions can be implemented including new transmission lines, increasing the capacity of existing transmission lines, installation of voltage-correcting devices, or adding energy storage to create load during key times. Specifically, in the case of the SHEI, GMP has worked with multiple stakeholders to implement

various solutions including the installation of a Synchronous Condenser, adding voltage control equipment to existing generators, and rebuilding subtransmission lines to allow greater export from the area in the event of a transmission contingency. We describe some of the specific study work more in Appendix D

- While the SHEI is isolated to a specific location in Vermont, it is indicative of a greater issue that can arise when high penetrations of distributed generation occur in areas without adequate electric load. The VELCO Long Range Plan goes into greater detail with respect to how much more generation can fit in various zones of Vermont before creating the next export interface limitations. As we look ahead, we must continue to deploy in-state, distributed renewable generation while also working to locate these systems as optimally as possible to avoid, or at least defer, the need for bulk transmission upgrades like the work in the SHEI area. We will continue to work closely with VELCO to optimize the deployment of these resources.

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-NE peaks reduces Forward Capacity Market and regional network service costs, providing economic value to our customers. We can attain more value when this same DER is located on a circuit (or its supplying substation) that peaks simultaneously with ISO-NE.

Under our methodology, a circuit with higher coincident kW loading would likely support more DERs than another coincident circuit having lower demand. Other ancillary T&D system metrics must also be considered (such as opportunities to improve reliability, resiliency or defer T&D upgrades).

The GMP Solar Map is an example of this data-based approach already working for ranking and organizing circuits based on their capabilities. A recent tool in development is the “Storage Impact Analysis Report”. This report allows the user to put in specified parameters, including KW load adjustments to peak (i.e., electrification) and added storage (i.e., BESS). This allows a “what if” evaluation of increased electrification and/or storage quantities and evaluates these inputs across the entire system, evaluating the remaining capacity for load and remaining capacity for DERs, for every substation. For example, an input adding a 5-MW storage facility added across the entire system would show the following:

Substation Bank	Transformer Capacity	Minimum Load	Lowest Remaining Discharging Capacity (DR)
Dover 2	14000	6/29/2019 7:15:00 PM	8,507
East Arlington	7000	10/16/2019 7:30:00 AM	1,719
East Barnard	22400	5/28/2018 9:45:00 PM	16,793
East Jamaica	7000	5/12/2019 9:30:00 AM	-2,060
East Middlebury	14000	5/2/2019 9:15:00 AM	-2,727
East Rutland	14000	4/10/2019 9:45:00 PM	663

A	B	C	D
Substation Bank	Transformer Capacity	Peak Date	Lowest Remaining Charging Capacity (LOAD)
Dover 2	14000	1/14/2018 6:15:00 PM	-294
East Arlington	7000	7/2/2018 1:00:00 PM	-3,260
East Barnard	22400	11/30/2019 8:45:00 PM	17,030
East Jamaica	7000	1/1/2018 10:15:00 AM	-2,399
East Middlebury	14000	12/16/2020 11:30:00 AM	3,542
East Rutland	14000	7/2/2018 7:45:00 PM	-1,092

Figure 3-11. Example Transformer Capacity (Discharging and Charging)

This study case shows how diverse our substation capabilities are regarding the addition of new load and DERs. The substation remaining capacities depends on the substation transformer capacity, existing loads and connected and proposed DERs on each substation. From the information in the example, we can see East Arlington has capacity for 1,719 kW of additional DERs, however a 5-MW storage facility, charging at the same time as peak load, would result in an overload of 3,260 kW. East Middlebury however has no capacity for additional DERs showing a -2,727 MW capacity should a 5-MW storage facility discharge at the same time as existing DERs. It does show the ability to carry 3,542 MW of additional load. This tool allows us to screen the substations on a high level to help us foresee expected constraints at the substation level across our system for both load and DERs. It also provides insight into the need for load control (i.e., charging of large BESS) and/or impacts of curtailment (i.e., discharging of large BESS). Charging and discharging batteries at the right time in the examples above would prevent an overload of the substation transformer.

When addressing areas with substation hosting capacity constraints, we demonstrated the importance of reviewing load shapes to capture the net generation and the coincidence with loads in our participation in the VSPC Generation Constraint Subcommittee. GMP provided analysis of its Vergennes Substation, which has nearly 16 MW of DERs connected to a transformer with a top nameplate of 14 MVA. This substation is limited to rooftop installations only <15 kW given the amount of DER saturation. The concern is the possibility of back feed greater than the top nameplate thermal rating of the substation transformer. When looking at the gross generation, the transformer capacity is exceeded on a light load day as shown:

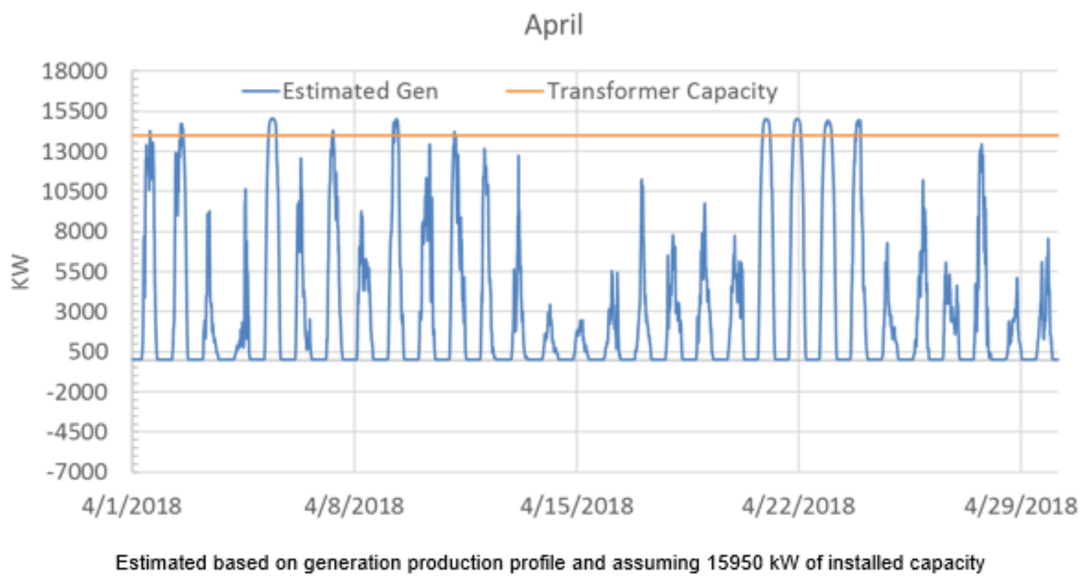


Figure 3-12. Gross Generation Exceeds Transformer Capacity

When looking at the backflow of generation net of the load, we can see that there is remaining transformer capacity:

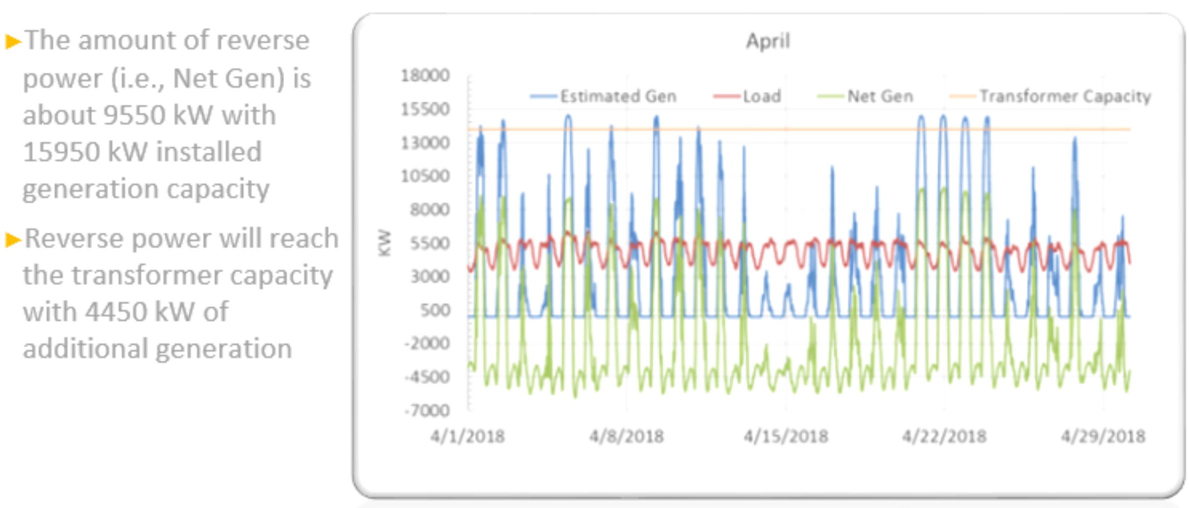
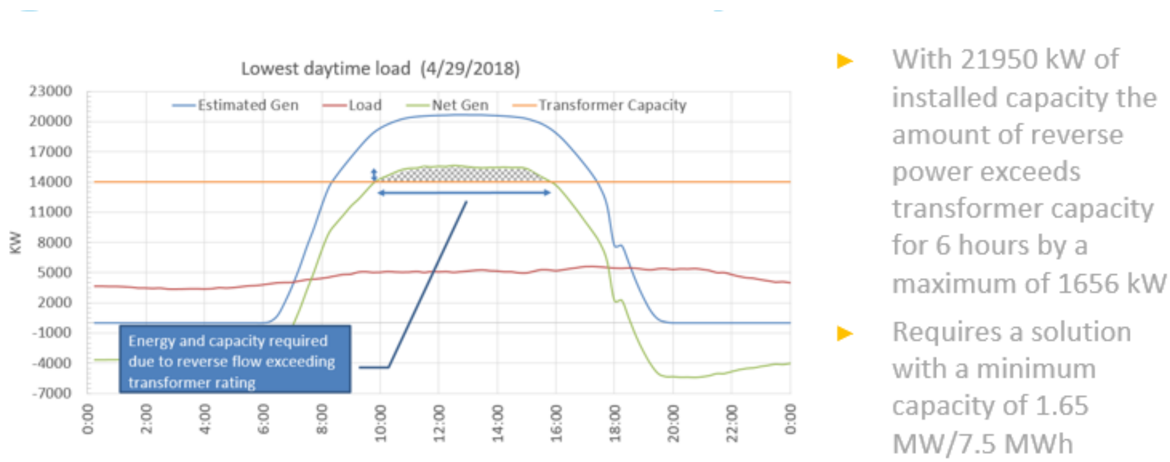


Figure 3-13. Net Generation is Lower than Transformer Capacity

Peak responsibility factors (that is, coincidence with other peaks)

As part of this analysis, we looked at several scenarios including impact on available DER hosting capacity should high generation coincide with lowest load, one of the circuit's loads is entirely lost due to an outage, a large customer permanently leaves or if a hypothetical large DER (6,000 kW generator) was connected to the system.

Figure 3-14. Hypothetical Large Generator Added to DER Constrained Area



This analysis provides a framework for a process to evaluate DER-constrained areas. The next step will be to build tools to help automate the review of actual hourly load and DER output curves to make the process more efficient as well as having the expanded ability to process these curves for any day of the year.

FERC Order 2222

FERC Order 2222, issued in September 2020, enables DERs to participate alongside traditional resources in regional wholesale markets through aggregations (i.e., distributed energy resource aggregations or DERAs). DERs have had the ability to participate in the ISO wholesale markets prior to this order being issued, but it puts a new spotlight on aggregated resources participating in the markets.

ISO-NE is in the process of establishing a set of rules and requirements for New England utilities to study and communicate these resources to ISO. A DERA may consist of one or more DERs. A DERA can comprise a wide range of DERs with different technologies and different use cases at different location. A DERA must be at least 100 kW in size. There is no minimum size for a DER. Any DER greater than or equal to 100 KW is allowed to be its own DERA. ISO will allow aggregation across a metering domain, where all constituent DERs are required to be located within the same metering domain. A metering domain generally follows a distribution utility's service territory within a single load zone. All DERs must be located with the same Demand Response Resource (DRR) Aggregation Zone. Vermont is broken in to two DRR aggregation zones, northwest Vermont, and Vermont. ISO has a total of 20 DRR aggregation zones. We expect that process will require us to be notified of any intended DERAs and have a role in the review of potential T&D system impacts. We will need to review for safety, reliability, and eligibility in accordance with ISO and GMP criteria and determine if there are any associated constraints or required upgrades. Any DER that will be part of a DERA must comply with state and utility interconnection procedures, must have an executed interconnection agreement where required and have completed all required system upgrades prior to interconnection. Revenue-quality metering and telemetry for specified intervals (i.e., 5 seconds, 5 minutes, etc.) will be required to provide data for day-ahead and real-time communications.

Operational coordination will be necessary among ISO, VELCO, the DERA and GMP. We will be required to forecast or detect reliability issues in the distribution system during real-time operation to notify the DER of any constraints, which they will be required to comply with. The requirements associated with FERC Order 2222 make operation and monitoring of the grid even more critical, fortifying grid modernization. Increased situational awareness for grid operations with time-series data, real-time analytics and geospatial information will be key to adequately mitigating and responding to potential risks associated with DERAs and any event affecting the reliability and resiliency of the grid.

It should be noted that based on GMP's current annual retail sales, we may fall within the small utility exclusion in FERC Order 2222; however, we are continuing to plan because we expect we will participate in ISO-NE's requirements for this program.

Battery Storage in the Evolving Grid

GMP continues to lead with respect to integrating battery storage into the energy system. As we have said continually, battery storage remains as one of the most flexible resources available to manage a dynamic and evolving grid. While FERC Order 2222 did not necessarily create any significant changes to the ability for storage to participate in wholesale markets, it did highlight a potential conflict that we feel is important to identify and plan through.

Battery storage has three main energy related components: The ability to charge or act like a controllable load, the ability to discharge or act like a generation source, and the ability to manipulate voltage and reactive power, providing localized grid power quality benefits.

With just these capabilities, we can leverage storage to reduce peak demands, soak up distributed generation, provide regulation service to ISO-NE and provide emergency backup power to customers to name a few. However, if this same resource is deployed in a manner that does not integrate with the needs of the local system, it can create detrimental effects to the local distribution system or new customers attempting to connect to the system. GMP is staying updated on the FERC 2222 requirements as they are developed and collaborating with VELCO, which is participating in the New England committee working on FERC 2222 issues. We are also engaging with storage developers and working to create a structure that will shift the consumption or discharging to the more beneficial times to avoid negative impacts. This can include new value streams for specific times of charging and/or discharging.

Take, for example, a 5-MW/20-MWH battery storage looking to interconnect to a GMP distribution substation. Let's assume that this substation has exactly 5MW of capacity left on the transformer and the battery system wants to be able to charge and discharge anytime they need. Meanwhile, a new customer is looking to build a commercial office building to be fed off that same transformer. However, because the battery system has used up the remaining capacity on the transformer, this customer cannot build their new office building without paying a substantial upgrade cost to increase the capacity of the substation, something that would likely halt the plans for this customer or worse, drive them to go somewhere else. This is purely illustrative but shows what can happen should storage begin to deploy for wholesale market participation with no connection to GMP to manage charging and discharging for the benefit of all customers. This is exactly the type of scenario GMP is looking to avoid when creating programs and opportunities that produce value for these types of systems.

Taking that same example, but now leveraging that same battery storage system in a more optimized way means that instead of limiting the future capacity of the substation, we could be *increasing* the capacity of that substation by timing the discharging of the battery at key times. Below is a snapshot of the electric loading over the past few years on an existing GMP substation.

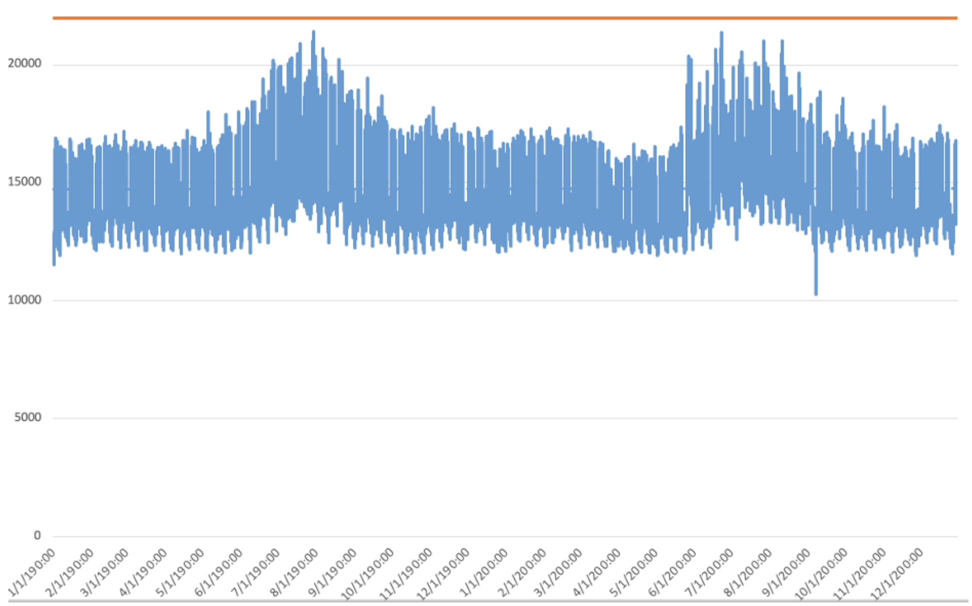


Figure 3-15. Electric Loading on an Existing GMP Substation

As you can see in the above graph, this substation reaches its peak load during the summer months, driven by the cooling load in major commercial buildings. If attempting to add battery storage to this substation and not optimizing the charging/discharging of the battery with the local needs, we would quickly reach the limit of the substation and must either increase the transformer sizing or no longer accept any new customers onto this substation. Both of which are very inefficient outcomes given how infrequently this substation is loaded to its max and the fact that the very resource that can be used to help a situation like this, is creating the issue. Now, if we flip this situation and leverage that same battery to discharge during those infrequent peak demand times, we can improve the capacity headroom, allowing for even more growth in this area before needing a major substation overhaul.

Therefore, GMP believes strongly that we must continually create local value for storage systems to assure there remains the appropriate benefit for storage developers to stay connected with the distribution utility but in a way that benefits all customers as opposed to arbitrarily creating value that leads to a customer cost not commensurate with the value being achieved.

Battery storage is mentioned in many places throughout this IRP because it touches so many aspects of the transformed grid, but the most important takeaway in all of this is that storage continues to be an incredibly valuable resource, one that when optimized is critical to the post-carbon transformation we seek.

DER Optimization – Tying it all together

GMP has successfully operated a few distributed energy resource platforms, creating the necessary software and communication tools to leverage specific DERs, such as battery storage, water heaters, EVs and even heat pumps in a way that reduces costs for customers and sets us up to leverage these resources to optimize the grid.

GMP next will look at how we choreograph the system on a day-to-day, hour-by-hour basis. As we look further down the road, and the DER population grows to the hundreds of thousands, we believe that an overarching platform will be needed to determine the optimal deployment of the entire fleet of DERs given the situation that day. For example, if the day is projecting to be a very sunny, hot, and humid day, we may want to pre-position battery storage to soak up as much solar as we can during the day, and discharge during the peak demand in the evening. On a cold winter day when the solar panels are covered in snow and the price of energy begins to rise significantly due to unexpected load in New England, we will want to ramp down EV charging, discharge storage and ramp down flexible loads. We will shift from what is now a mix of partially automated and mostly manual process to one that is prepositioned daily but has the necessary automation and flexibility to react to real-time signals that arise.

Over the next two years, GMP will be investigating this type of solution with specific focus on how to leverage a system that could benefit multiple stakeholders, including other utilities.

Grid of the Future

Advanced Inverters

Advanced inverters used in PV and other DER applications may be able to address some of the challenges to the integration of high levels of DER on the electric system. They may present an opportunity to improve the stability, reliability, and efficiency of the distribution system. These inverters have many capabilities including the ability to monitor performance, automatic voltage regulation, adjust ramp rate control, power output in response to a utility command, adjust real power, soft start reconnection and islanding. With the increasing penetration of distributed generation on the distribution system, advanced inverters will play a very important role to allow for continued deployment while assuring power quality and system stability.

Grid Modernization

Grid Modernization includes upgrading and redesigning grid infrastructure to facilitate adding new technologies and smart devices. Many of our proposed T&D projects increase the capability to interconnect additional DERs and allow for additional electrification without compromising system power quality or reliability. Substation projects that install larger transformers or convert voltages to our standard 12.47-kV voltage not only improve reliability and address aging assets, they strengthen the circuits. These upgrades reduce the potential adverse impacts (such as voltage flicker) when connecting DERs or constraints related to electrification. This stronger distribution system also increases flexibility and creates opportunities to implement emerging technologies including BESS solutions, improving overall system performance.

Grid Modernization is achieved with information technology investments such as installation of fiber-optic-communications networks. This technology is needed to transit, store, manage and protect immense amounts of data. This data can be leveraged to allow for system monitoring, performance evaluation, load control and system protection. It will support more automated operations and remote access, and expand options for our customers. GMP continues to invest in and expand its fiber optic networks to provide increased flexibility, reliability, resiliency, and safety for our system. GMP has agreements with VELCO and with other telecommunication carriers for fiber-optic services when those services are applicable. Many fiber-optic applications require high security and/or direct fiber connections making leased circuit services from telecommunication providers not an option. GMP continues to expand its fiber networks in areas where direct fiber services are not available.

We plan to explore implementing BESS solutions for increasing DER hosting capacity at substations nearing their hosting limit and we will continue to work with the Department and other stakeholders to propose the best solutions possible, recognizing the limitations on how to pay for projects proposed only to increase hosting capacity for DERs.

The Panton Battery project has allowed us to study, design and construct an islanding scheme. The microgrid islanding capability was successfully commissioned in October of 2021 and at the time of filing this IRP we are finishing up the remaining SCADA indication and data flow information for the control rooms. We plan to use the Panton project to explore other potential grid-related DER benefits such as reactive power support and conservation voltage reduction (which may reduce or eliminate line regulators required on the Vergennes Panton circuit in the future). This site will allow us to test and evaluate additional features of advanced inverters.

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.

Proactive Maintenance

Managing Vegetation

In 2020, trees that contacted GMP's overhead distribution and sub-transmission lines accounted for approximately 49% of all outage events, down from 63% in 2019. To reduce tree-related outages and improve operational efficiency, GMP employs an Integrated Vegetation Management (IVM) program. GMP's goal is to administer a long-term IVM program that provides for the safe and efficient operation of the subtransmission and distribution systems, reduces service interruptions and power quality disturbances, provides a high level of customer satisfaction, and is carried out in a safe and cost-effective manner with minimum impact to the environment.

We monitor the number of tree-related outages every month. We also revised our IVM program, as part of the PUC rule 3.631(J), in 2018. 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 strive to trim our entire distribution system every seven years. This cycle was developed based on the species composition within the service territory, species' growth rates, and the desired clearance from trees to energized lines. GMP's standard for clearance from energized distribution lines to most species is 20 feet above and 10 feet horizontally from the conductors. Clearances are increased where there is a danger of ice and snow loading on conifer trees, soft maples, and birch. We cannot always adequately clear in the green belt areas of most villages, towns, and cities; we are considering trimming these areas more frequently. 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).

To clear and trim, we manually cut trees, prune using various methods, mow with large equipment, and selectively apply herbicides. Appendix D: Vegetation Management Plans details these clearing techniques as well as our overall vegetation management programs.

The emerald ash borer (EAB) is in our forests and trees throughout the state. Their infestation is a source of concern for us, as well as for other state utilities and municipalities. 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.

Small trees infested by the EAB can die as soon as one to two years after infestation, while larger infested trees can survive for three to five years. Infested ash trees pose a public safety hazard as well as a reliability hazard to GMP's electric system. Over time, infested ash trees die and are prone to "ash snap," which refers to their abrupt and unpredictable failure.

GMP's proactive EAB mitigation work primarily focuses on transmission and overhead distribution lines. Phase 1 efforts have been focused on the "Confirmed" Infested areas whereas Phase 2 will consist of efforts within the "High Risk" infested areas. GMP's mitigation strategy will continue to evolve consistent with the EAB infestation, tree mortality rates, development and adoption of EAB best practices, safety, and electric system reliability.

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). Our subtransmission right-of-way management plan was updated in 2018 as part of the PUC rule 3.631(J). As part of the reclamation program in 2020, we cut vegetation on 21 transmission lines totaling 181 miles (2,239 acres). We applied herbicides to 1,214 acres.

The historical spending for line maintenance is shown in following table:

Actual $ Spent			
Type of Line Maintenance	**FY 2019**	**FY 2020**	**FY 2021**
Sub-transmission	2,569,984	2,298,827	2,026,437
Distribution	13,257,698	16,233,501	12,962,187
Emerald Ash Borer	0	1,172,381	1,151,756
Actual Total	15,827,682	19,704,709	16,140,379
Distribution Miles Trimmed	1,428	1,153	1,173
Transmission Miles Mowed	209.1	181.2	124.3

The average GMP subtransmission right-of-way width is maintained to 100 feet with 50 feet on each side of the centerline. Our subtransmission system maintenance techniques are like those used on our distribution system: flat cutting, manual and mechanical trimming, mowing with large equipment, and applying herbicides.

When managing vegetation within our distribution and sub-transmission systems, we strive to be sensitive to the concerns of property owners. We contact property owners before working in the right-of-way, and encourage them to use the land within the right-of-way to help ensure safe electricity transmission.

After we cut vegetation within the T&D right-of-way, we selectively apply herbicides to incompatible vegetation that has the potential of growing up into the energized wires. Management of the incompatible species also allows for desirable, low-growing vegetation to become established, which has the added benefit of increasing the plant biodiversity within the right-of-way. Selectively applying herbicides reaps several 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.

Herbicides help with the management of vegetation. GMP applies herbicides in three ways. Foliar application is used in areas where resprout growth has occurred, and the herbicide is applied so that it contacts only the target plants' leaf surface (this method eliminates 85% to 95% of the target plants in one year). Basal bark treatment is used to control susceptible woody plants with stems less than six inches in basal diameter. With this technique, herbicide is applied to basal parts of brush and stems including the root collar area. Cut-stump treatment is used on recently cut tree stumps to inhibit the growth of stump sprouts. The primary advantage of this method is enhanced aesthetics as there is no "brown-out" or dead stems left standing. Cut stump treatment eliminates approximately 65% to 75% of the targeted plants.

The optimum schedule for a foliar treatment is one growing season after mechanical cutting. Stump treatment is performed as soon as possible after mechanical cutting with follow-up applications as needed during the next maintenance cycle.

The application of herbicides on the GMP system is regulated by the Environmental Protection Agency and the Vermont Agency of Agriculture, Food & Markets and occurs only in areas approved for such treatments under care of licensed applicators.

Inspecting Poles

The poles on our distribution and subtransmission systems are currently inspected on a 10-year cycle by an expert pole inspection firm, Osmose, along with as-needed individual inspections when required.[5] During inspections, each pole is examined for splits, holes, damaged equipment, and abrasions. Inspectors also perform core boring and sound tests above and below the ground to detect soft spots or other internal imperfections.

They 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, and are treated with an antifungal compound, and wrapped as needed before recovering them.

The subtransmission pole inspection program employs the use of fumigants, which aim to preserve the heartwood and the inner regions of the pole from decay. Fumigants produce vapors within the pole that prevents both wood-destroying fungi and insects from compromising the structural integrity of the pole. Poles that cannot be restored or have reached the end of their useful life are scheduled for replacement.

In 2021, we engaged with our pole inspection firm to continue to review the process and determine whether some poles, particularly in seasonally wet or other potentially vulnerable locations, should be inspected more frequently based on condition assessment along with a time-based inspection. We continue to evaluate this as the first recommendation did not identify the types of poles to be looked at on a shorter duration inspection that we hoped it would. We are re-evaluating now as to whether other triggers could help identify poles that may be at a higher risk between current inspection cycles. We are doing this as a part of our response to an accident involving a pole that fell due to woodpecker damage and internal decay.

[5] GMP maintains certain distribution poles with VTel and Champlain Valley telecom. Maintenance, including pole inspections, is carried out as dictated per the Intercompany Operating Procedure obligations in each of GMP's "maintenance areas."

Preventing Underground Utility Damage

We follow regulations and procedures to ensure that we prevent damage to our subtransmission, distribution, and fiber-optic underground cables. This infrastructure is vital to system reliability, security, safety, and resiliency and will become even more critical in our pursuit of a modernized grid.

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 companies.

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 that 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. We meet monthly with our underground locator contractor to discuss any issues. Excavation within 18 inches of a marked facility must be done by hand digging.

Vermont state law 30 V.S.A. § 7001-7008 as well as Public Utility Commission 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 PUC 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 10 years. We will visually inspect our underground distribution equipment every five years, and fully inspect this equipment every 10 years.

Conducting Aerial Patrols and Infrared Inspections

We strive to conduct an aerial patrol of our entire subtransmission system every spring summer and winter, and often after major storms, to locate and assess possible system damage. During these patrols, we fly close by helicopter to locate danger trees, broken crossarms, floating phases, cracked insulators, displaced cotter pins, and other problems that might adversely affect the performance of the subtransmission lines.

GMP also completes periodic infrared inspections of its facilities. From the ground we scan our substations using hand-held infrared cameras to detect problems. From the air, the infrared camera is mounted directly to a helicopter. These scans identify hot spots on the subtransmission and substation systems that can indicate a failing conductor, corroded splice, loose connection, or other problem area where a line or substation element is stressed and vulnerable to failure. The infrared scans are done once a year during the summer patrol.

In 2020, GMP conducted aerial patrols in August and December. The April aerial patrol was not completed due to COVID-19. Year to date in 2021, we have completed aerial patrols in April and August, with one more planned for December.

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 due to associated supply transmission lines, 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 several 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 rebuilt our Barre South End substation by raising the new substation yard by approximately three feet so it is above the high-water mark of a 100-year flood. In addition, we moved several adjacent utility poles away from the floodway fringe. Fair Haven is the next identified project, which will move a substation out of an identified flood plain. This substation rebuild is scheduled for completion in 2025 and is a voltage-conversion project.

We plan to avoid locating new substations in floodplains. This is a storm-hardening strategy to improve resiliency as identified in the Climate Plan.

Implementing Power Quality Solutions

Power quality is a high priority for GMP. Poor power quality adversely affects the reliability of the computers, microprocessor-based and sensitive electronic equipment we rely on for the proper operation of the power grid. As more advanced technology and smart devices are installed on our system, the integrity of the power delivered will be critical.

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. A power quality problem can cause issues such as diming lights, automatic resets, data errors and equipment failures.

Because of this, we are developing tools using AMI data to assist or proactively address power quality issues. We have developed a Tableau report that lets us set voltage high and low thresholds and then return all meters that have continuously exceeded or fallen below the voltage threshold. This report allows the proactive approach to address areas where customers are out of acceptable voltage ranges. We have found that customers do not always know or call in for a voltage issue that is well out of range. 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 or employees. GMP likely addresses about 50 power quality issues annually. Most power quality issues result from inadequate wiring, failed connections, or poor grounding. A crew may be dispatched to test the voltage, check connections, and ensure that voltages are not excessive. In most cases, we quickly identify and solve the issue. When this isn't possible, we investigate the cause by reviewing system disturbance data and installing power quality monitoring and recording devices at the customer's premise. 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.

Storm Process

Severe weather events, increasing in frequency and intensity due to climate change, pose a significant threat to our system reliability. GMP has developed and continues to advance strategic storm response processes to help our customers. Our storm response is swift, efficient, and highly organized. We have developed an extremely efficient storm response through our Incident Command System (ICS) team; team members are well versed in their storm responsibilities and what is expected of them.

We engage our ICS team about 30 times a year. Some of these events are small and only involve a limited cross section of GMP, while others are "all-hands-on-deck" events involving virtually every employee in GMP. A survey is conducted after every large major event, and we adopt improvements based on that employee feedback.

The type and severity of weather events is indicative of the extent of outages that our customers will likely experience. The on-call storm directors closely monitor weather for conditions that may cause outages well in advance of any storm hitting. They poll many weather sources including scores of public and private weather sites and multiple contract meteorologists that are retained by the Vermont utilities. This focus helps us deploy our crews more efficiently during and after the arrival of the severe weather. All-company calls are initiated well before any major storm hits, to further ensure preparedness.

When conditions demand, the storm team convenes and a storm plan commensurate with the level of threat is developed and circulated. During certain events, the storm team will mobilize field assessors and extra field crews to districts before any outages occur. This is especially true when the forecast calls for severe weather that may impede travel.

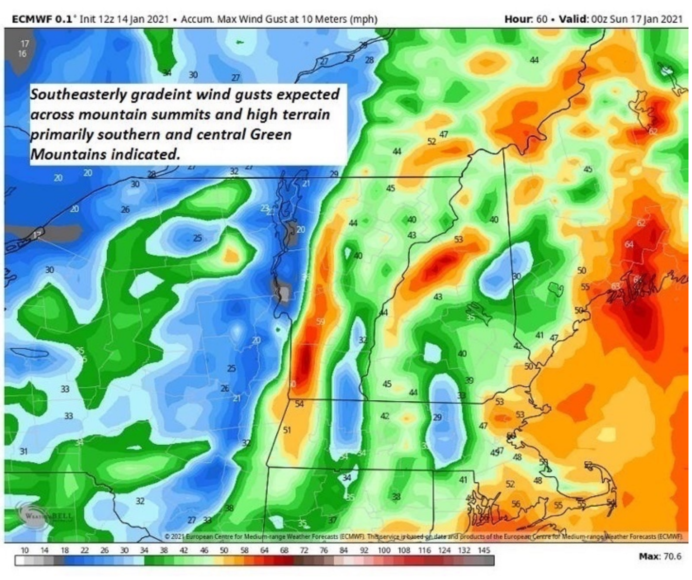
GMP is a member of the North Atlantic Mutual Assistance Group (NAMAG). As a member of NAMAG, we can request crews from around New England and beyond when Vermont is faced with a catastrophic weather event. Our proactive and disciplined approach to storm events has had a material effect in minimizing the duration of outages that our customers experience.

We use several interrelated software systems to manage restorations. This allows us to efficiently answer high volumes of customer calls, manage reported outages, and optimize the dispatching of crews.

GMP uses weather forecasts from the National Weather service, Northview Weather, Weathering Heights with Roger Hill along with publicly available weather models to make more informed decisions for storm predictions and crew mobilizations.   Roger Hill contracts with VELCO and provides weather outlooks including hazard storm warnings for Vermont Utilities. These forecasts include modeling and graphic depictions for timing and amounts of precipitation, temperature profiles, and direction/location of wind gusts. The utilization of better forecasts helps GMP have more timely information on location and severity of a weather event. This information directs our response and restoration plan allowing for reduced service interruption duration and decreased storm costs.

GMP utilizes weather data, historical storm information and forecasting tools to help predict outages. Outage prediction supports an improved proactive storm response to weather events by identifying risk areas for better crew deployment and faster restoration time. GMP uses Northview Weather LLC's forecast and outage prediction tool as well as a GMP-developed tool. The Northview Weather LLC tool provides outage predictions associated with severe weather events including ice, heavy wet snow, and wind. GMP's in-house outage prediction tool provides forecasted outage information for all types of severe weather.

Figure 3-16. Example of Weather Forecast



In addition to the outage prediction tools, GMP has utilized a visual analytics platform to develop a suite of reports that highlight the effects that historical weather events had on our system. Our storm response is improved when we can readily visualize the impacts that previous storm events had. The reports include, for each event, a profile of customers affected by the storm (i.e., number of customers affected by hour), count of events by storm (either for our entire service territory or by individual GMP Operating Districts) and maps depicting the outages by storm and outage type.

Outage Analysis and Technology

Technology plays a significant role in identifying the best capital projects for the GMP system to improve reliability and resiliency, but it also plays a very important function in the actual management of weather events as they occur. 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 managing restoration efforts. Input data comes from a variety of sources:

- Our customer service representatives and, when call 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 the customers' outage information.
- 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 can enroll in our text notification service, which allows them to report an outage as well as obtain information on the status of their power restoration. Customers can also report outages and obtain status updates from our website. GMP has implemented upgrades that send text alerts to customers who experience a power outage. These upgrades will allow GMP to add more alert types and communication channels in the future.
- Our geographic information system (GIS), which contains the locations of our customers, lines, poles, and protection 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.
- With this information, Responder predicts which protection device most likely operated for a given line fault. Operators can then dispatch line crews or outage assessors to patrol downstream of the protection device to determine the cause and extent of the outage. Once the damage causing the outage is known, the estimated restoration time is updated, as needed.

In 2020, GMP upgraded to Responder version 10.6.1. The new version of Responder included enhancements to product stability and performance.

GMP continues to leverage its Advance Metering Infrastructure (AMI) in the management of outages. This system has proven to be a valuable tool that is used by the control rooms and district personal engaged in restoration activities. The storm team uses the AMI information in several ways. First, it allows us to verify if a customer has power without needing to send personnel to the premise. The advanced meters are "pinged," or contacted, to determine those that are out and those that have voltage detected in their meter socket. This saves valuable crew time where we can avoid dispatching a crew to a premise that has power. Non-outages get introduced into the OMS when a customer experiences a momentary outage, like the operation of a breaker, but reports an outage anyway even though they have power. Customers will also call in outages when they receive an alarm from their home security system and/or when they believe they are without power while outside of their home. Second, the AMI infrastructure assists crew dispatchers in understanding the extent of outages. The OMS may not predict the full extent of an outage when only a small percentage of customers have called in. Third, we have instances, on occasion, where we identify an outage and restore the power before the customer realizes they were without power.

GMP provides two-way communications to customers to give them the best information possible when outages occur. We have made extensive efforts to take advantage of multiple communication platforms to allow customers to get the latest and most accurate information available in the manner of their choosing. These communication platforms include news releases, interviews with local media, social media posts, text alerts, Integrated Voice Response System automated reporting, a map-based web portal on the GMP website, GMP Facebook page, and direct contact with a customer service representative. GMP also has a mobile app that allows customers to access Outage Center information from their mobile device. When outages occur, crews begin to evaluate the damage and restoration estimates are produced. These estimated times of restoration (ERT) are made available, in real time, using these platforms. For long-duration events, GMP makes outbound calls to customers and does outreach to the communities that are hardest hit to provide restoration information.

4. Technology & Security

Overview

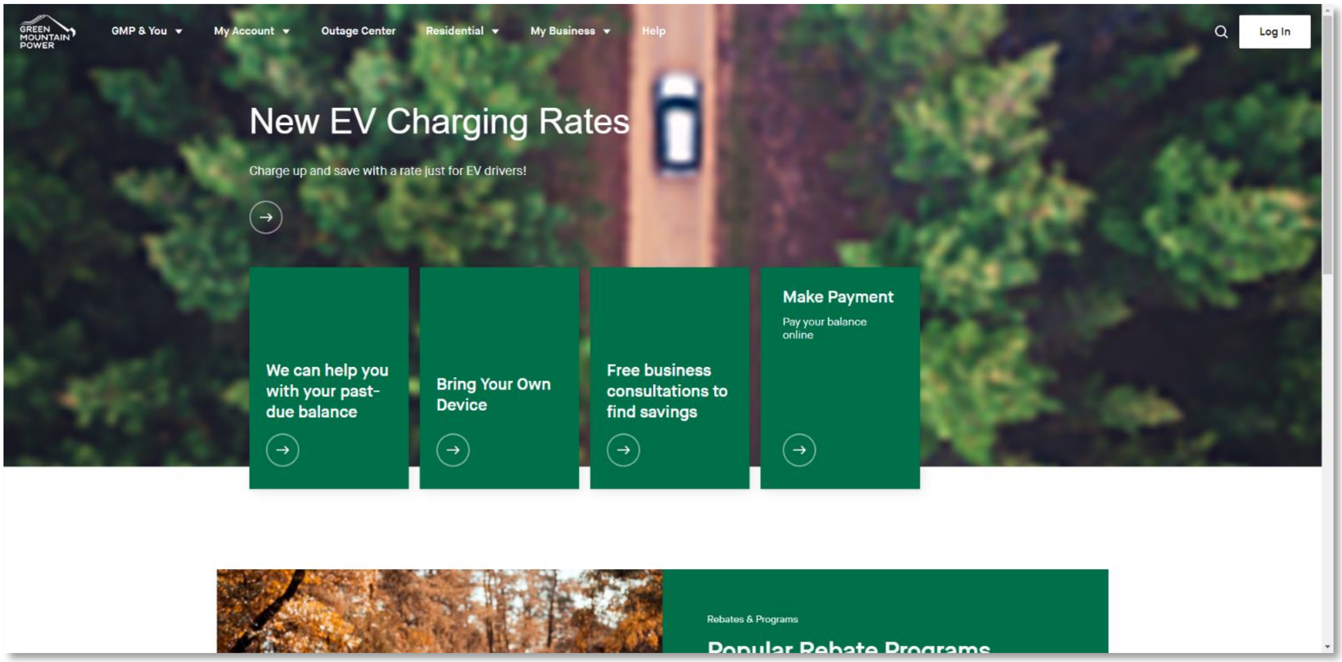
The growing use and convergence of Information Technology (IT), Operations Technology (OT), Cybersecurity, and energy services at GMP warrants a new chapter in our IRP. Collectively, these functions have emerged over several years as key pillars in supporting and driving the operational strategies, day-to-day capabilities, customer experiences, and innovation advancements in multiple areas of the business. In many ways, investments in these functional areas have created outcomes and established capabilities that have set GMP on a path towards becoming much more of a technology-centric company.

GMP is intensely focused on the interests and needs of its customers and delivering the best tools and user experiences possible. This means meeting the customer where they are, technologically, and viewing each investment we make as an opportunity to deliver real value. Innovating through digitization, automation, analytics, and resiliency is a big part of manifesting that promise and what we see as our obligation to find emerging technologies that will allow us to deliver improvements for our customers and provide efficiencies in our operations.

In doing this, we seek to harvest operational savings by leveraging flexible systems, services, and automation, while at the same time deploying technologies throughout our enterprise that lower costs, eliminate manual processes, automate, and improve the resiliency and security of our services.

While technology continues to enable more opportunity each day at GMP, it is also imperative that we acknowledge and remain focused on our role as a critical infrastructure provider, counted on by our customers and others to deliver services in a highly available and secure manner, and to weigh those responsibilities in context with a worldwide surge in cyberattacks and cybercrime. It is essential, therefore, that we fundamentally reimagine how we deploy, enhance, and protect every facet of our infrastructure, and every system utilized by our employees and customers, to ensure their integrity, availability, and utility in the face of exponentially increasing risks.

Numerous technical projects and initiatives completed over the last several years have not only leveraged GMP's unified technical abilities, they have also laid a firm foundation for future improvements.



Improving the Customer Experience

Most recently, significant focus and resources have been placed on improving and enhancing the ways in which customers interact with GMP, including:

- A full redesign of the GMP website to provide easier access to information and resources, including the integration of secure payments, usage information, and self-service account management within the customer portal.
- The creation of a real-time Outage Center that includes the ability to report and receive updates on outages as well as the ability for customers to view outage details at the town and street levels.
- Implementation of a customer notification platform for two-way texting and outage reporting.
- The release of a GMP App that provides mobile access to outage and usage information and the ability to view and report outages, make payments, enroll in paperless billing, and activate recurring payment and budget billing options.
- A full redesign and relaunch of vtoutages.com, which acts a centralized outage reporting and mapping system for Vermont DUs and is a key resource for Vermont emergency planners and managers.

Enhancing Management of The Grid

The inception of an Automated Metering Infrastructure (AMI) nearly 10 years ago has not only driven the digitization of devices at the point of metering and behind the meter, but acted as the impetus for a full-scale migration from analog to digital monitoring, control, and management within GMP's control room environments. This will position us well not only to leverage the current AMI system during its remaining useful life, but also to find and utilize the best digital tools in the coming decade, which may evolve from the traditional meter and be tied directly to customer equipment capable of load control, such as the home electrical panel, EV charger, storage, etc. While opting out from AMI technology is permitted in Vermont, GMP has a small number of customers using analog meters; most of our system benefits from the automation allowed by the AMI system. The AMI system is comprised of multiple components: the meter itself; the communications network; and the backend systems needed to manage the data and associated functionality. While portions of this system may have eight or more years of useful life remaining, GMP will begin to test and migrate to new solutions before then. We expect to use a combination of metering technologies in the future, including "meterless" applications where feasible.

Some of the advancements furthered by our digital conversion have included:

- Re-engineering and replacement of the SCADA core to improve stability, segmentation, and security.
- Enhancing the OT operational and security perimeter via the deployment of enhanced firewall and intrusion-detection infrastructures.
- Map board enhancements to GMP's control rooms, migrating from fully analog to digital displays, to provide a real-time, statewide view of the system, the ability to manage the grid from either control room, and to improve switching and tagging operations.
- Virtualization of multiple key OT and SCADA systems to facilitate improved performance, scaling, and faster recovery and resiliency.

Improving Security

GMP's management of cybersecurity relies heavily upon an overarching philosophy of isolating key systems from one another and the provisioning of alternate means of providing system operation and continuity in the event of compromise. Integral to these measures is the notion of training and using every employee as a *human firewall* of sorts, to detect, recognize, report, and mitigate unexpected or malicious activities that may manifest themselves within the enterprise and operational computing environments, or in customer-facing applications. While much work remains to be done, we have bolstered our abilities in recent years by:

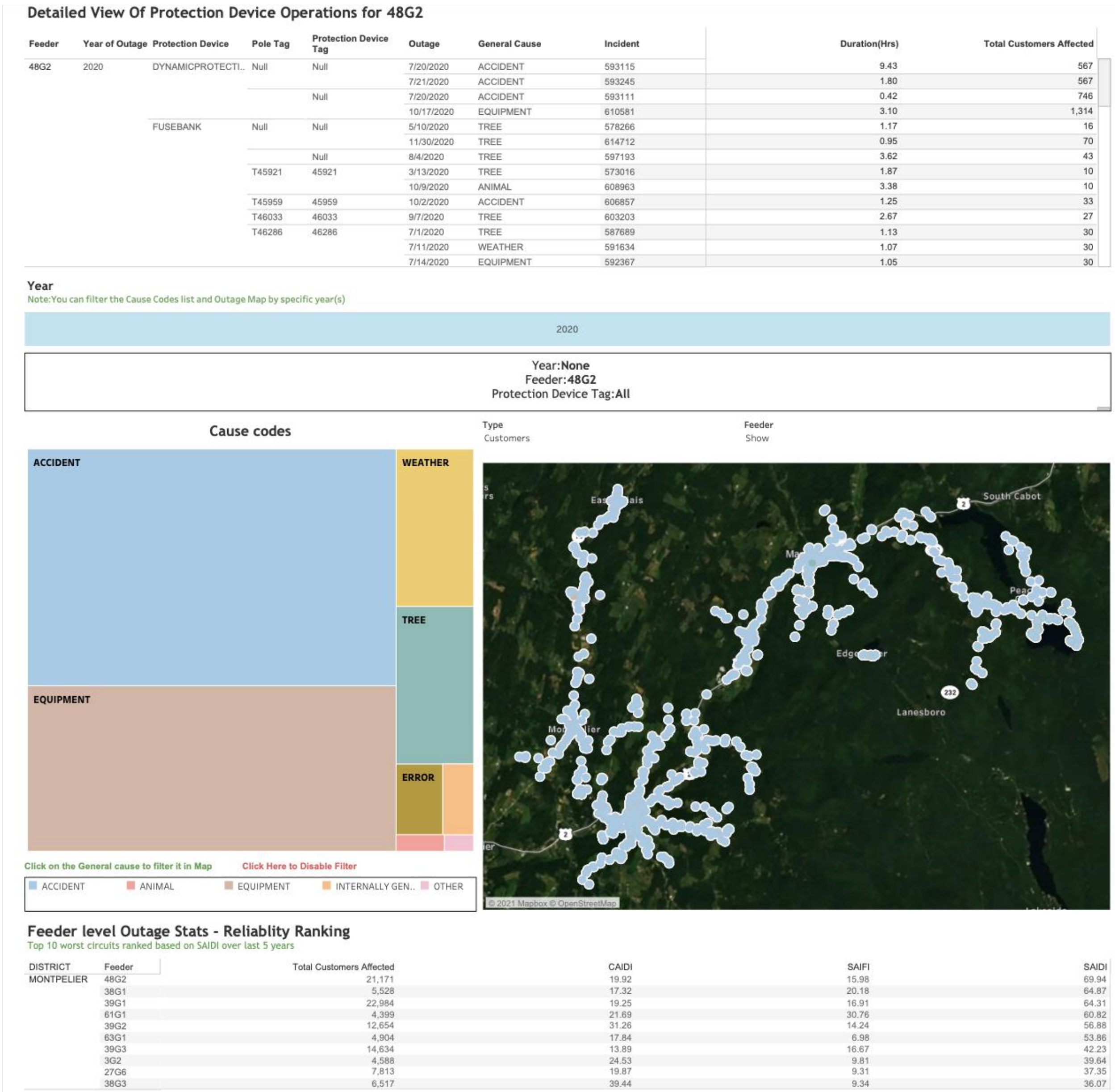
- Hardening GMP's SCADA core to isolate it from all other networks and resources.
- The implementation of endpoint and detection and response (EDR) mechanisms across all computing environments, PCs, and servers.
- The creation of a robust Incident Response Plan and team supported and augmented by top-level support from third-party security practitioners and emergency response professionals.
- Deeper engagement and relationship-building with Federal and State law enforcement resources.
- Standardization of logging and the retention of that data for forensics and incident reconstruction across all critical environments (IT, OT, PCI, etc.).
- A refresh and expansion of GMP's statewide firewall infrastructure.

- Implementing mandatory monthly computer-based security training for all employees.
- Adopting the SANS Institute's *20 Critical Security Controls* methodology as a core framework.
- Enhancing the staffing of the GMP security team to build and maintain a 24/7/365 Security Operations Center (SOC).
- Re-architecting the full GMP customer payment process to achieve PCI compliance.
- Regular auditing and penetration testing of deployed security controls.

Streamlining and Improving Operations

Utilizing its technology, GMP has been able to accelerate the streamlining of its operations in multiple ways.

- Expansion of video camera networks to remotely monitor facility operations and increase safety and security. Operators can see what is happening in real-time at substations and plants, which reduces truck rolls and provides instantaneous visual analysis capabilities.
- Enabling GMP's workforce to be fully mobile. All field personnel can communicate by multiple methods and carriers to access back-office information and resources using secure mobile devices. This proves critical during storm response.
- A newly deployed work management system enables a paperless work environment where work can be managed, assigned, and tracked digitally.
- Using data and analytics for our customers. By combining geo-spatial data, outage data, and GMP's Engineering Circuit Model, we can now quickly identify underperforming circuits and prioritize response to the worst circuits to optimize them. See Figure 4.1. This analysis of our least-reliable circuits is used as a tool to focus on those areas for possible maintenance, resiliency projects or other actions that can keep the outages from occurring in the first place and help recover more quickly when they do go out. This list, which is updated regularly and shared with distribution designers, T&D supervisors, and others, is utilized as a dynamic tool to determine ways circuit reliability can be improved and has proven instrumental in helping GMP select projects of priority for its proposed climate resiliency planning.



Detailed View Of Protection Device Operations for 48G2

Feeder	Year of Outage	Protection Device	Pole Tag	Protection Device Tag	Outage	General Cause	Incident	Duration(Hrs)	Total Customers Affected
48G2	2020	DYNAMICPROTECTI..	Null	Null	7/20/2020	ACCIDENT	593115	9.43	567
					7/21/2020	ACCIDENT	593245	1.80	567
				Null	7/20/2020	ACCIDENT	593111	0.42	746
					10/17/2020	EQUIPMENT	610581	3.10	1,314
		FUSEBANK	Null	Null	5/10/2020	TREE	578266	1.17	16
					11/30/2020	TREE	614712	0.95	70
				Null	8/4/2020	TREE	597193	3.62	43
			T45921	45921	3/13/2020	TREE	573016	1.87	10
					10/9/2020	ANIMAL	608963	3.38	10
			T45959	45959	10/2/2020	ACCIDENT	606857	1.25	33
			T46033	46033	9/7/2020	TREE	603203	2.67	27
			T46286	46286	7/1/2020	TREE	587689	1.13	30
					7/11/2020	WEATHER	591634	1.07	30
					7/14/2020	EQUIPMENT	592367	1.05	30

Feeder level Outage Stats - Reliablity Ranking

Top 10 worst circuits ranked based on SAIDI over last 5 years

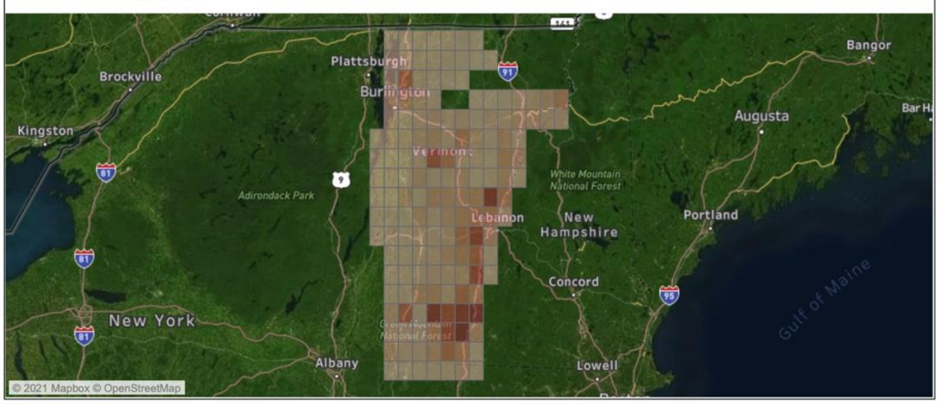
DISTRICT	Feeder	Total Customers Affected	CAIDI	SAIFI	SAIDI
MONTPELIER	48G2	21,171	19.92	15.98	69.94
	38G1	5,528	17.32	20.18	64.87
	39G1	22,984	19.25	16.91	64.31
	61G1	4,399	21.69	30.76	60.82
	39G2	12,654	31.26	14.24	56.88
	63G1	4,904	17.84	6.98	53.86
	39G3	14,634	13.89	16.67	42.23
	3G2	4,588	24.53	9.81	39.64
	27G6	7,813	19.87	9.31	37.35
	38G3	6,517	39.44	9.34	36.07

Figure 4.1. Screenshot of GMP's Engineering Circuit Model

- Outage Prediction Tool—Using neural networks in combination with geo-spatial data, NOAA weather data, vegetation data, and historical customer outage information, GMP can, with growing precision, predict which service areas will be affected by storm-related outages up to 48 hours ahead of time. This ability helps storm directors and other operational personnel proactively stage resources and plan the deployment of field crews to minimize outage durations. See Figure 4.2. This project, which is in its early stage, has not yet accumulated enough data to determine clearly whether outage durations have been improved by its use. However, the tool has helped GMP better understand the magnitude and outcomes of storms, which, in turn, has helped us be more prepared for future events.

- An example of this is the storm that occurred on Friday, November 26, 2021, the day after Thanksgiving. Although the National Weather Service and our utility forecaster were calling for only isolated outages, our outage prediction tool did show a higher number of outages events. As a result, we lined up a storm plan, had GMP internal resources on standby, and reached out to external resources who were then able to respond and help GMP and our customers recover from the heavy wet snow event that occurred in a timelier manner, during a challenging holiday weekend.

Predicted Outage using NAM forecast(Map)
Date: 20210301
hours: 06z UTC
Storm Start Time (User variable)
Date: 030121
hour: 16:00 (EST/EDT)



Model
030121_nam_20210301_06z_hour16_ensembl..

Prediction Hours
(00 is storm start hour)
- Null
- 00 to 06 hours
- 00 to 12 hours
- 00 to 18 hours
- 00 to 24 hours
- 00 to 36 hours
- 00 to 48 hours

Predicted Customer Outage
0 612

Predicted Outage using NAM forecast(By districts)
Date: 20210301
hours: 06z UTC
Storm Start Time (User variable)
Date: 030121
hour: 16:00 (EST/EDT)

Prediction Hours
00 to 24 hours

Predicted Outage
24 1,788

	00 to 06 hours	00 to 12 hours	00 to 18 hours	00 to 24 hours	00 to 36 hours	00 to 48 hours
BRATTLEBORO	352	1,112	1,625	1,788		
COLCHESTER	172	241	226	328		
JACKSONVILLE	4	28	20	33		
MIDDLEBURY	35	258	243	309		
MONTPELIER	61	1,023	585	749		
NORTHFIELD	2	27	30	51		
POULTNEY	14	23	23	24		
ROYALTON	177	998	1,111	1,697		
RUTLAND	62	205	287	381		
SPRINGFIELD	261	530	881	1,710		
ST. ALBANS	52	256	394	476		
ST. JOHNSBURY	35	570	301	629		
SUNDERLAND	168	397	602	916		
VERGENNES	11	50	43	51		
WESTMINSTER	167	442	553	896		
WHITE RIVER JCT	156	420	537	1,160		
WILMINGTON	192	498	592	455		
Grand Total	1,921	7,078	8,053	11,653		

Predicted Outages for 00 to 24 hours

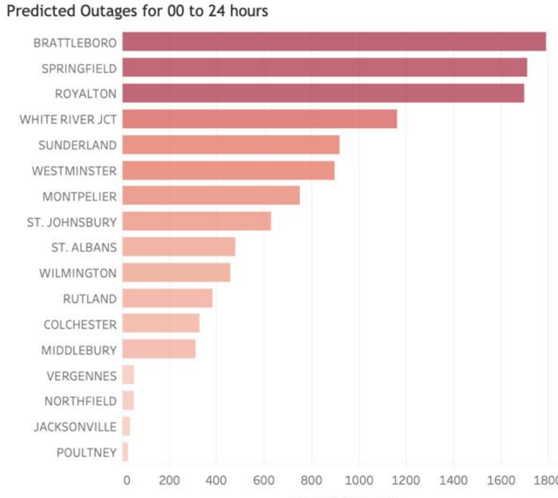


Figure 4.2. Screenshot of Outage Prediction Tool

- Electrical Circuit Analysis – Using engineering data, GMP has been able to improve operational efficiencies by creating the ability to calculate which electrical circuits in GMP's network are responsible for contributing to peak system load. This helps electrical engineers determine which circuits are suitable for introducing renewable and distributed energy resources. See Figure 4.3.

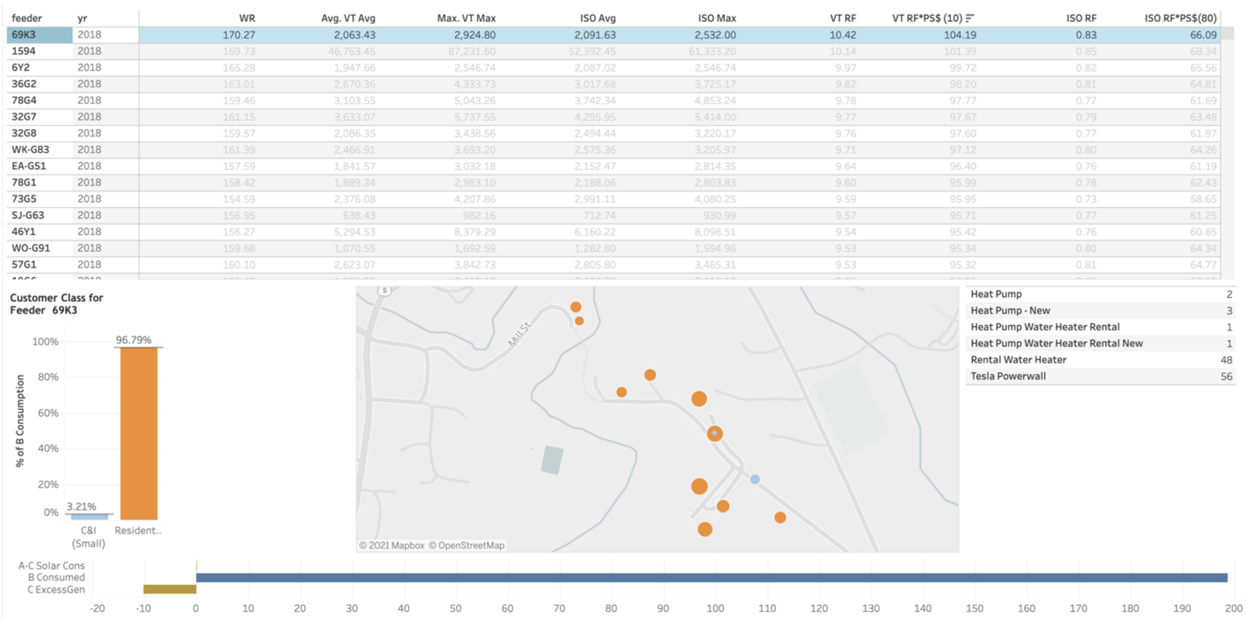


Figure 4.3. Screenshot of Electrical Circuit Analysis

- Power Supply Analysis – Using a complex electrical engineering and power supply model, GMP has developed the ability to undertake tasks like estimating power supply costs to GMP resulting from congestion in the SHEI network, revealing data formerly difficult to illustrate. See Figure 4.4.

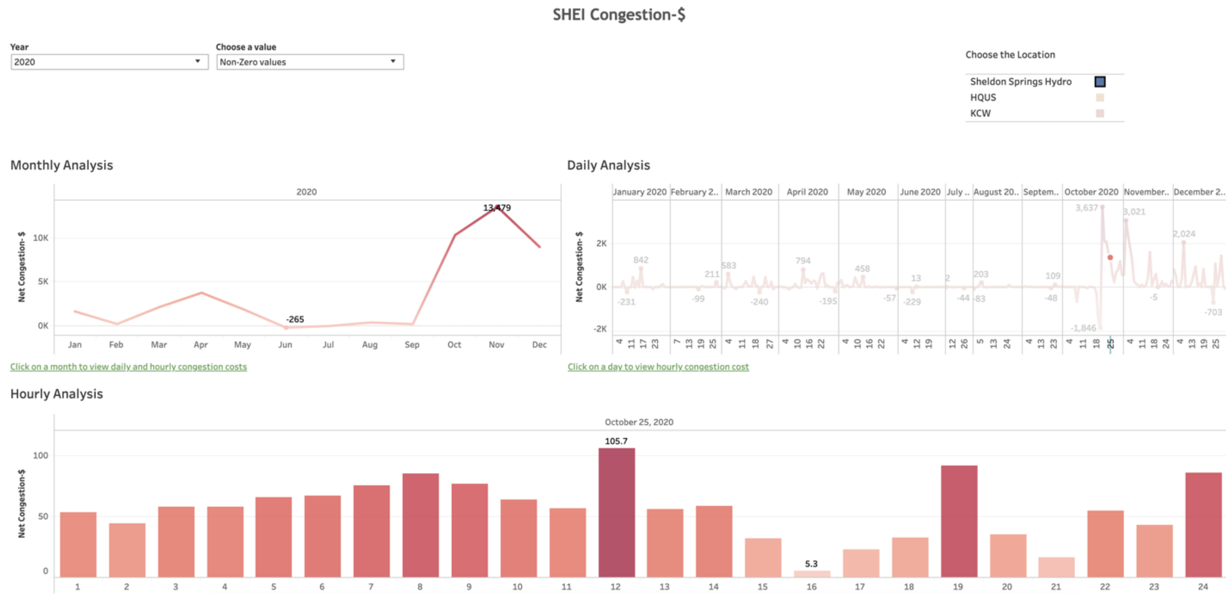


Figure 4.4. Screenshot of Power Supply Analysis

Moving Forward–Evolving Technology

As we continue to build on prior work and embrace technological advances and the ongoing adoption and integration of these new approaches into our operations, they are also creating opportunities to improve additional grid-side resources and back-office systems and services. Planning cycles have become significantly shorter and digitized solutions can be deployed more quickly, resulting in both the need and the opportunity for much faster turnaround times. At the same time, customer expectations around self-service, communications, privacy, billing, and payments, behind-the-meter energy-saving technologies, and opportunities to self-generate electricity are driving our need to provide additional technology services, use data and analytics to tune the way services are delivered and accounted for, and help enhance the overall resiliency and simplification of grid operations.

At every level, the expectation and the need are to move further away from manual and analog processes that persist and to seize the opportunities made available by the application of these technologies and the collection of data to create new outcomes for customers. Traditional ways of planning for and regulating utility IT investments also must evolve to maximize these opportunities for customers, as further described below.

Creating Resiliency

A crucial measure of GMP's success in meeting these needs is to ensure that all core operational assets – such as grid control, assessment, recovery resources, operational readiness, and information assets – are highly available and have failover systems in place in the event of natural or manmade (i.e., cyberattacks) disruptions. As such, many future projects and investments are contemplated to bolster both redundancy and resiliency, including:

- Enhancing the availability and durability of the communications infrastructures that monitor and connect the grid, provide access and information for customers, and generate telemetry for operations.
- Facilitating uninterrupted functionality for key operational applications that serve our customers including outage management, GIS, Supervisory Control and Data Acquisition (SCADA), IVR, Customer Care, and web-based services.

To meet these needs, we plan to undertake a variety of initiatives that bolster overall resiliency and allow for operations to carry on, regardless of the type of loss to any key system. Some examples include:

- Deploying cloud-based call center services (888, ACD, IVR) as a failover to the potential physical loss of services in-state.
- Developing methods to establish minimum application functionality using cloud-based services and infrastructures if local services become unavailable.
- Piloting the operation of meter data management and billing systems functions in the cloud to mitigate against data center loss.

One of the major opportunities we see to improve resiliency is to continue the movement of basic technology services from locally hosted datacenter environments to the cloud where feasible. GMP will continue to operate its systems in a hybrid fashion for the foreseeable future, investing in a mix of cloud-based and premises-based systems and software. Many businesses and utilities, including GMP, already use cloud-based services for existing production applications. The same methods of best practice applied to securing user access, production changes, system isolation, physical security, encrypted communications, and the like in our Vermont-based data centers are applied to applications developed within or hosted in the cloud. Using a cloud model, certain software systems can reside remotely at dispersed hosting centers, not only resulting in the reduction of risk by cloning systems across multiple geographic regions and leveraging additional computing power as needed, but simplifying access to many of these systems in the event of a system loss or temporary inaccessibility.

Expanding Systems Capacity

As GMP's operations and customer-facing services begin to use more technological services we must meet these expectations by continuing to focus on evolving and expanding data networks, processing capacity, storage, and security systems. Implementation of DERs, undergrounding of distribution services, and an imminent future where storage and islanding become a greater part of our service offerings and partnerships requires us to enhance and improve the redundancy of communications networks and the subsystems, software, and failover capabilities that will be necessitated by these innovative changes in grid engineering and design, including:

- Fortifying data and telecom networks to better withstand natural and manmade disasters – potentially burying some of these communications facilities alongside undergrounded distribution lines;
- Making secure use of wireless and cellular technologies (like 5G) to provide telemetry, minimum functionality, and control of remote grid and network devices in the event of the loss of a primary communications circuit;
- Enhancing improved storm response by co-locating certain functionality in the cloud, not only to prepare for potential losses or failures within the system, but to add additional application capacity, remote connectivity, and disaster recovery capabilities;
- Preserving data. GMP's AMI infrastructure, on the grid and residential sides, generates approximately 4 terabytes of detailed data per month. This enormous amount of data is critical to not only billing, but GIS, outage management, engineering studies and more recently, significant advances in data and analytics that allow GMP to, with extreme precision, understand the operation and efficiency of the grid and its infrastructure. Additional projects here to create the ability to back up and preserve this data for historical and future analytical needs will be critical.

Improving Efficiency with Data

Prior projects have allowed GMP to significantly scale its ability to acquire and store enormous amounts of data generated from its operations. As shown, this has led to greater efficiencies for customers and insights not previously available or even visible. Moving forward, improvements in tools and the ability to source, compare, and contrast data aggregated over multiple years, will play a continuing role in understanding where to apply resources and leverage opportunities, and to do so more quickly.

GMP has already developed the ability to use data science tools and analytics to replace more expensive applications to proactively gain predictive insights into its customer-focused operations. It is crucial to maintain these gains by further developing and using available artificial intelligence tools, machine learning, and the capabilities of cloud-based neural networks. In so doing, it is certain that newer and more valuable ways of understanding and improving the operation of the grid and the delivery of services to customers can continue. Some areas of likely research and investment include:

- Moving portions of our data warehouse to the cloud to leverage faster, cheaper computing power;
- Integrating Salesforce into GMP's portfolio of data tools to achieve one-stop CRM;
- Building new tools to improve outage, engineering, call center, generation, and revenue analytics;
- Leveraging SCADA data, field device location data, maintenance data, battery storage and outage information, etc., to develop AI models that can predict faulty distribution devices and DERs;
- Building an Engineering Platform to detect things like phasing problems, hi-low voltage instances, and field device health;
- Developing a nearly real-time system that will formulate a disaggregation AI model that can detect and alert customers and energy specialists to things like low generation, high consumption, energy leakage, etc.

Securing the Infrastructure

Exponential growth in global cybercrime and nation-state level involvement in the direct support and backing of these activities has placed the U.S. energy sector at significant ongoing risk with little likelihood that it will abate.

Like most business concerns, GMP finds itself defending against perpetual, daily assault, primarily by small-scale actors and criminals. Even without state-sponsored backing, many of these attacks have the potential to impair the operation of GMP and the grid itself. The threat of more serious attacks is a real and present concern we constantly assess and adjust to meet, knowing that such events occur with increasing frequency.

Vermont has already seen locally how devastating it can be to lose control of one's infrastructure, as was experienced by the University of Vermont Medical Center's ransomware attack in October of 2020. No less significantly, as a critical infrastructure provider itself, GMP is equally susceptible to the possible substantial negative outcomes of such an event and must be prepared and plan for its statistically likely inevitability.

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 North American Electric Reliability Corporation ("NERC") regulatory framework for Critical Infrastructure Protection for our bulk electric system assets.

Even as the threat landscape continues to shift and grow, GMP has made strong advances in its practice of physical and logical security measures in recent years. Perimeter protection, detection, and isolation technologies are well established and growing. GMP employees are regularly trained in cybersecurity and fraud detection methods and GMP's culture of safety has been extended to include cyber safety as a key element. The reality, however, is that this work will always be necessary, and never completed.

The work is made more complex by the increasingly connected grid. Many of our customers are connecting some form of DER to the grid, such as controllable heat pumps, EV chargers, or residential battery systems. Improving the security of this connected equipment and their connection to our systems – including logically and physically separating DER management systems from other IT/OT systems to minimize the propagation of an attack – improves the reliability and functioning of these devices, including during emergencies, and can provide protection of the customers' own systems and data, which may also be connected to the DER in some fashion. While we can provide some assistance and education to customers when they sign up for such management systems, ultimately customers must take steps to protect their own devices (both energy-related and others in their homes and businesses), and so our best defense remains separation of our key systems.

The security of our own IT systems is also critical to our customers because we store and safeguard customer information and provide e-billing and account management services via our online customer portals. We take the safety of this information and these interactions very seriously and our cyber capabilities must continue to evolve to provide protection as threats grow and change.

As a result, GMP will continue to make significant capital and human resource investments in defending its portion of the Vermont grid. Operationally, we will continue to pursue projects related to:

- OT network, generation plant, and substation physical security and monitoring;
- Privacy and the protection of customer data;
- Segmentation and isolation of critical resources;
- Endpoint detection and response;
- Resiliency of key information security resources;

- Enhancing Operational Readiness to manage potential interruptions to services and business systems.

GMP strives to pursue and invest in strong relationships with law enforcement, regulators, VELCO, and other DUs to foster a statewide "we're in it together" mentality so that challenges and problems recognized by a single utility can act as a warning and/or source of forensic information for the others. To truly protect the Vermont grid, a common and common-sense approach, especially where services overlap, will be the most prudent path.

Regulatory and Financial Considerations in Technology Deployment

The traditional regulatory environment for rate review of IT projects risks being well behind rapid developments in security practices and technology deployment. In fact, many of the regulatory treatment and accounting standards in place were developed more than 20 years ago and have been only lightly updated to consider the evolving IT landscape. These standards are based on a traditional understanding of assets vs. operating expenses. That is, for many years it was easy to see that the poles and wires in the distribution system are physical assets, and the power flowing through them or the labor to keep them maintained is an expense that is the cost of doing business. Likewise, regulating IT project deployment has traditionally attempted to fit categories of spending into capital asset vs. expense boxes – for example, treating servers, hardware, and boxed software as capital, and tech support for these devices as expense.

Now, IT investments for utility customers are quickly evolving to an increasingly interconnected, distributed system. IT is no longer simply a back-office employee support function, but instead is at the core of all critical functions provided by a modern utility. This includes not only cyber-security investments – which are critical for keeping transmission and distribution systems safe, on-line, and functioning – but also systems that integrate DER systems and provide greater customer interface and real-time communication options. These investments are the backbone that allow utilities to pursue and achieve important state policy goals (cybersecurity, DER adoption, climate resiliency, etc.) and require significant investment and attention to ensure they deliver value for customers while providing protection for customer and utility data.

Regulatory and accounting approaches have not yet fully caught up with this changing landscape. Many of these new systems operate most efficiently and securely through cloud solutions. Cloud solutions and SaaS are at base a service, but functionally they replace on-premise servers and software solutions housed on those servers that were traditionally treated as assets. The potential accounting and regulatory review frameworks for these investments make a difference for customers. This is the lens we use when reviewing any expenditure, be it capital or expense; that is, what is ultimately best for our customers. Capital treatment allows for costs to be spread out over a longer period – the useful life of the capital asset – while expenses impact rates as they are incurred. As a result, capitalization can benefit customers from a rate trajectory point of view. This is of particular importance during times of transition, where implementation and development costs may comprise a large portion of IT spending, and more intensive spending is required.

As with a traditional datacenter-centric IT infrastructure, some aspects of cloud computing should be considered capital investments while other aspects involve operating expenses. GMP believes that cloud-based subscription IT systems should be treated as capital going forward, as we proposed in our last Multi-Year Regulation Plan proceeding, Case No. 18-1633-PET, and as endorsed by the National Association of Regulatory Utility Commissioners and several jurisdictions to reflect a modern understanding of the role these systems play in replacing traditional capital assets and better serving customers. To that end, we have adopted the 2018 Financial Accounting Standards Board's ("FASB") accounting changes that treat "implementation" costs of acquiring cloud-based service agreements as a capital investment, while ongoing service fees and other operating expenses remain expensed.[1][1] This approach aligns the treatment and incentive of these cloud service agreements to reflect current technology and business practices and ensures GMP is making prudent IT investments for our customers.

To continue these improvements, an alternate approach is needed to reflect that IT investments are increasingly critical in utility planning; that cloud services are replacing traditional IT assets; and that this is a rapidly evolving sector. It is in the best interests of customers that GMP be regulated as a technology company with the flexibility and regulatory construct that supports adopting the best available solutions to improve systems and deploy solutions to better harden our systems and protect our customers. Even for this fast-evolving field, the upcoming period could be marked by particularly rapid change. Because of several recent incursions into energy company systems by cybercriminals, the U.S. Congress has held hearings on legislation relating to utility cybersecurity, and both FERC and NERC continue to evaluate applicable orders and standards. Technology will continue to develop, and new solutions or thinking may emerge. Indeed, we may find the need to innovate or develop GMP-specific solutions to address cyber risks even in the absence of regulatory guidance.

In our next regulation plan and rate case proceedings, we expect to discuss with the PUC whether consideration should be given to any potential hybrid alternatives to traditional capital and expense approaches that credit the ongoing, rapid planning cycle for today's IT investments. One model that has worked for certain utility investments – the so-called "blanket" spending approach, whereby a level of investment is allowed within a defined category, without specific project identification – could be more widely applied to technology spending than it has been in the past and adapted to support the shorter planning cycles in this area. Another model that has been used for GMP Climate Plan resiliency projects and for broadband investments, accounting for the projects in rates after deployment rather than upfront, subject to PUC approval, also may provide needed flexibility. These or other innovative regulatory models for IT project review and rate approval would help keep GMP technologically strong for customers.

[1] FASB, Accounting Standards Update 2018-15, Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40), Customer Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract (August 2018), available at https://www.fasb.org/jsp/FASB/Document_C/DocumentPage?cid=1176171138858.

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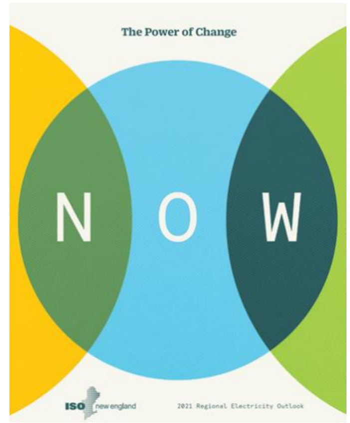
5. Regional Market Environment

ISO-NE Regional Electric Market



The New England states operate as a single electricity system and market managed by the New England Independent System Operator (ISO-NE). In this role, ISO-NE is responsible for regional transmission grid operations, the New England wholesale power market, and the region's long-term planning process to ensure that adequate generating capacity and transmission infrastructure is available into the future. The three primary categories of users with direct involvement in the ISO-NE market are generator owners, transmission providers, and load-serving entities (LSEs), like GMP.

Since the early 2000s the electric market in New England has been operated under a framework where generating plants compete on an hourly basis for the opportunity to receive revenue serving the region's electrical needs. Over the 20 years that this framework has been in place, natural gas generation has come to be the dominant resource in the region due to its relatively low installation cost and declining fuel price over much of that timeframe. Today nearly 50 percent of ISO-NE's approximately 35,000 MW of installed generating capacity is fueled by natural gas. In recent years, New England states individually have adopted goals to significantly reduce reliance on fossil fuels, including for electricity generation. A significant planning effort is now underway at ISO-NE to incorporate state climate requirements for clean energy supply to move away from this fossil-fuel dependency. Some of this work is summarized in ISO-NE's most recent Regional Energy Outlook report for 2021.[1]

One significant challenge in transforming the supply in the region will be transforming the structure of the market itself as the current design is largely built around the needs of fossil-fired units and does not consider the features of emerging renewable energy resources. Generating plants competing in the region can have three primary sources of revenue: energy sales revenue, capacity market revenue, and ancillary services market revenue. Each market product is competitive, and ISO-NE is responsible for continually ensuring that the lowest-cost combination of all three products procured on behalf of the LSEs responsible for the cost outcomes of the market. Of these costs, the energy product and capacity product make up the most significant share of the expenses incurred in the wholesale market.

Figure 5-1. Annual Value of Wholesale Electricity Markets represents the scale in dollars of all these markets in New England.[2]

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1 https://www.iso-ne.com/static-assets/documents/2021/03/2021_reo.pdf

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

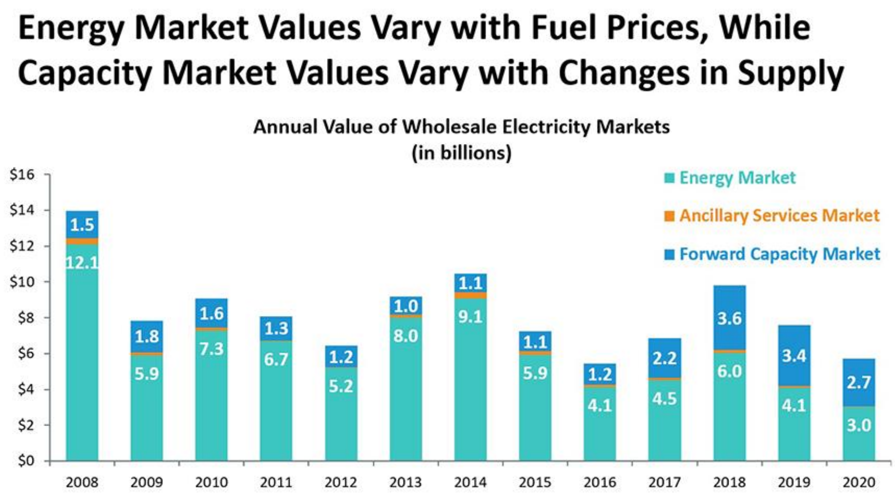


Figure 5-1. Annual Value of Wholesale Electricity Markets[3]

The cost and operation of the wholesale market is significant to GMP because the dominant share of our supply resources and energy needs pass through and participate in the ISO-NE market. Changes to the structure of the market can present different expense risks for GMP customers and affect the operation of our existing supply resources. In addition, the conditions in the market and its prevailing prices influence the cost to purchase additional supplies, irrespective of the fuel used to generate those supplies. At the same time, having a well-designed market support carbon-reduction goals of Vermont and the other New England states is important to combat climate change by continuing the efficient deployment of renewable resources while sending the right signals to existing fossil-fuel resources to maintain reliability cost-effectively during the transition. This will be a very significant regional challenge in this decade and will remain a focus of GMP's attention, along with state regulators and other utilities.

Energy Market

The largest market in terms of total share of wholesale market cost is energy. In the years since our last IRP, the general downward trend in natural gas prices and in energy market prices has continued (see Table 5.2 below). This decade-long trend has been driven by the decline in overall U.S. natural gas costs brought about by the tremendous increase in U.S. shale gas production. While most New England energy pricing outcomes are directly related to natural gas, there are periods, predominantly 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 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

3 Source: ISO-New England.

and often set the regional LMP far above typical levels. Notable periods exhibiting this price separation can be seen below in average prices in winter months in 2014, 2018, and more recently in February 2021.

As we submit this IRP heading into the 2022 winter season, another period of price uncertainty has developed based on global energy market disruptions related to the COVID-19 pandemic and supply shortages in the fossil fuel markets elsewhere. Forward energy prices are currently higher than in most of the last 10 years, and ISO-NE has indicated that Liquefied Natural Gas supplies for backup fuel purposes may be less available this winter than in prior years, due to export prices. These factors, combined with some upward inflationary pressure as the economy recovers from the pandemic, point toward some energy price pressure in the immediate term, though longer-term consultant forecasts show a return to lower prices in years ahead.

Average Monthly Day Ahead LMP - MaHub

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Jan	$86.53	$168.81	$71.14	$38.60	$40.30	$108.75	$56.76	$26.45	$42.73
Feb	$122.31	$156.02	$122.77	$29.90	$30.02	$39.58	$35.62	$23.06	$73.12
Mar	$53.09	$111.16	$64.25	$20.63	$35.75	$35.38	$38.07	$17.18	$34.88
Apr	$42.89	$44.98	$28.43	$28.36	$29.23	$45.00	$26.97	$18.36	$26.14
May	$40.31	$36.95	$24.92	$21.24	$27.31	$24.04	$24.21	$16.48	$24.98
Jun	$37.09	$37.92	$21.16	$22.61	$25.48	$26.82	$22.09	$19.84	$37.10
Jul	$52.07	$37.50	$26.44	$31.12	$27.60	$32.89	$29.78	$23.78	$37.16
Aug	$34.72	$30.35	$30.06	$35.54	$24.90	$39.16	$25.69	$23.79	$49.47
Sep	$40.43	$34.10	$30.82	$28.62	$23.57	$33.89	$21.14	$20.46	
Oct	$33.94	$32.19	$37.01	$21.98	$29.74	$38.46	$20.75	$24.78	
Nov	$45.21	$47.71	$29.42	$24.98	$33.98	$57.43	$32.29	$25.12	
Dec	$92.96	$43.00	$22.42	$53.28	$71.31	$47.31	$40.98	$40.15	
Avg.	$56.79	$65.06	$42.40	$29.74	$33.27	$44.06	$31.20	$23.29	$40.70

Table 5-2. Average Monthly Day Ahead Locational Marginal Pricing[4]

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.

Capacity Market

New England's Forward Capacity Market (FCM) is used to pay resources for being available to meet peak electricity demand. Capacity is not actual electricity, but rather the ability to produce electricity when called upon several years in the future. The capacity market payments are intended to cover some or all the fixed costs of building new units when a shortfall is anticipated, or simply maintaining generating resources when the supply is sufficient. In New England, the goal of the FCM is to identify and assign obligations to enough qualified generating resources to satisfy the region's anticipated future peak electricity needs with enough lead time to construct new capacity resources if necessary. To accomplish this, Forward Capacity Auctions (FCAs) are held

[4] Energy Market Insights Sept 2021, Enel X

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 these auctions, ISO-NE determines the necessary volume to procure and creates 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. The prices of capacity from FCA auctions since 2011 are shown in Figure 5-3 below.

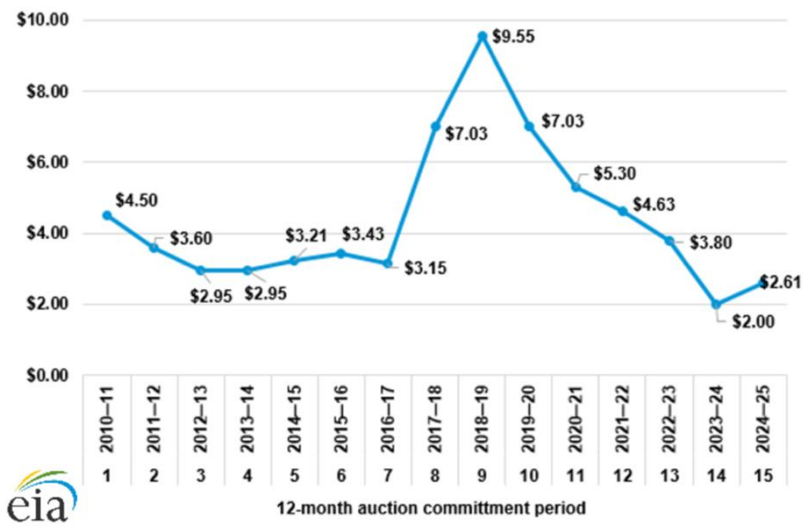


Table 5-3. Annual Forward Capacity Auction Results

Since our last IRP, ISO-NE has announced structural changes for the region's capacity market to better align the market with the state-sponsored renewable resource development that is driving new generation additions to the region. Largely these changes will remove barriers to entry (i.e., by eliminating the Minimum Offer Pricing Rule) that prevented some of these new renewable supplies from participating in the market. ISO New England has also signaled other structural changes may be necessary to adapt the capacity market to achieve its intended goal of resource adequacy once a greater share of the region's supply is sourced from intermittent wind and solar resources. Importantly, most of the efforts to reform capacity markets to address the transition away from fossil-fired resources is being undertaken across many of the ISOs at the direction of the FERC. Because of the broader scope of these changes, we expect the reforms to the capacity market structure will take considerably longer to emerge than some of the more local market changes.

Ancillary Service Market

In addition to the two primary short-term markets, ISO-NE also operates ancillary service markets (i.e., operating reserves, frequency regulation, black start, etc.) that help to maintain grid reliability. These markets, while not as financially significant as the energy and capacity markets, are becoming a focus in many planning dialogs around the greater role of intermittent renewable resources. For example, ISO-NE is currently working on a NEPOOL-requested economic study called the Future Grid Reliability Study[5] which has several phases in which varying degrees of offshore wind and other transitional resources are tested for their impact on the need for supporting ancillary service resources. We are following this and other ancillary service developments to assess how new opportunities and changes to existing programs may affect our participating resources. Already our participation is adapting through changes to our demand program offerings and implementation of battery storage resources that expand our eligibility for these regional ancillary revenues and counterbalance potential cost pressures.

Regional Transmission

The New England electric market is supported by the region's integrated transmission network. In New England, this transmission system is subject to an integrated planning process administered by ISO-NE and the cost of supporting existing investment and future upgrades is allocated to customers using the bulk transmission system. This cost is reflected in the annual rate in $ per kW-year necessary to achieve the approved revenue requirement of the region's transmission owners. In 2020, the cost of supporting regional bulk transmission using this rate approach was over $2 billion, which contributed around 30% to total wholesale market costs. According to ISO-NE External Market Monitor, Potomac Economics, this means New England has among the most expensive transmission systems in the country.[6]

Year 2020	ERCOT	MISO	PJM	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$10.8	$7.2	$12.0	$7.2	$19.2

Over just the past 10 years, the cost of using the regional transmission network has nearly doubled for GMP and all the other LSEs in the region – even at a time of relatively reduced energy prices – driven by a significant number of expensive system improvements and reliability upgrades. In 2012, an annual transmission rate of $75 per kW-year supported just over $7 billion in installed infrastructure, which has increased to $140 per kW-year supporting over $16 billion in 2021 (see Figure 5.4).

[5] https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project/

[6] See 2020 Assessment of the ISO-New England Electricity Markets (June 2021), available at https://www.iso-ne.com/static-assets/documents/2021/06/iso-ne-2020-emm-report-final-6-18-21.pdf.

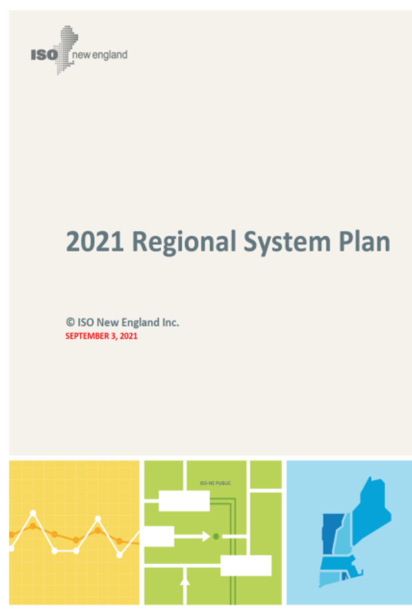
PTF Investment ($ in Millions)
RNS Rates History ($/kW-year)

	Total	CMP	CTMEEC	EVERSOURCE (CL&P, PSNH, NSTAR West)	EVERSOURCE (NSTAR East)	NGRID	NHT	UI	VTransco	Versant Power
12/31/2011	7,037.5	353.9	51.3	2,902.6	1,177.1	1,153.7	54.4	481.5	627.7	235.3
12/31/2012	8,053.8	619.0	51.3	3,324.3	1,237.9	1,239.1	57.4	553.5	659.4	311.9
12/31/2013	9,501.1	948.5	51.3	3,893.5	1,530.6	1,352.6	60.8	611.7	713.9	338.2
12/31/2014	10,412.7	1,278.0	51.3	4,201.8	1,570.5	1,466.6	62.7	634.9	802.5	344.4
12/31/2015	11,762.9	1,657.7	51.3	4,696.7	1,720.6	1,702.5	63.5	677.7	837.3	355.6
12/31/2016	12,294.9	1,673.7	51.3	5,090.8	1,981.1	1,860.4	66.1	756.6	814.9	355.7
12/31/2017	13,187.4	1,685.7	51.3	5,577.0	2,097.7	1,956.6	69.5	788.1	961.5	355.8
12/31/2018	14,321.9	1,791.5	51.3	6,232.5	2,234.1	2,018.6	74.3	884.8	1,034.8	356.0
12/31/2019	15,326.1	1,819.7	51.3	6,767.3	2,404.2	2,202.7	87.5	917.1	1,076.3	360.0
12/31/2020	16,310.9	1,881.8	51.3	7,412.7	2,479.4	2,317.1	104.8	953.9	1,109.9	362.0

	06/01/12	06/01/13	06/01/14	06/01/15	06/01/16	06/01/17	06/01/18	06/01/19	06/01/20	06/01/21
Historical RNS Rates	75.25	85.32	89.80	98.70	104.10	111.96	110.43	111.94	129.26	140.98

Figure 5.4. PTO AC Rates Working Group Presentation, NEPOOL Transmission Committee, July 14, 2021

In the IRP planning period these costs are expected to continue to grow at a rate greater than our other costs. Meanwhile, regionally, a considerable focus has turned to determining the needs and costs of the transmission system to accommodate future growth in renewable resources, which will in turn drive more transmission costs. A study commissioned by NESCOE in 2019 was specifically tasked with evaluating the transmission upgrade needs to connect 8,000 MW of offshore wind to the existing transmission system. Two additional transmission-planning efforts are ongoing in 2021 to evaluate the evolution of the power system: the Transmission Planning for the Clean Energy Transition (TPCET) study, and the New England States' 2050 Transmission Study. For the 2050 study in particular ISO-NE describes the effort with the statement that, "the 2050 Transmission Study will outline a high-level direction of transmission expansion that will help to inform the selection of solutions for nearer-term needs. [And ...] this study will provide information, including costs, for transmission upgrades needed for various hypothetical future clean-energy scenarios."[7]



[7] https://www.iso-ne.com/static-assets/documents/2021/09/iso-ne-response_to_states-vision_sept_23_2021.pdf

Additional information on the state of these planning efforts can be found in the most recent 2021 Regional System Plan published by ISO-NE.[8]

State-Driven Renewable and Clean Energy Transition

The operation of the ISO-NE market does not include any direct requirements regarding the environmental profile of the energy resources that are eligible to participate. All the environmental considerations that influence the market and the growing preference for renewable and carbon-free generating resources are currently driven by state policy. Largely because of these state policies, in 2020 new renewables made up over 12% of the energy supplied into the ISO-NE market, a marked increase from the prior decade. This share is expected to grow rapidly in this decade largely because of increasing state renewable content requirements (Regional Portfolio Standards) and state-directed solicitations of large, long-term renewable supplies. The states have also been instrumental in the development of distributed solar resources operating outside of the ISO-NE market under various retail programs and local mandates. These local solar installations added up to roughly 4,000 MW, largely behind the meter, at the end of 2020.

Many of these state-supported renewable policies are expanding over the planning horizon of this IRP. The graphic below in Figure 5.5 illustrates the current climate goals of the New England States.

Figure 5.5. Current Climate Goals of New England States

[8] https://www.iso-ne.com/system-planning/system-plans-studies/rsp

In Vermont, the legislature passed the Global Warming Solutions Act ("GWSA") in 2020 (Act 153 as enacted), which created legally binding emission-reduction targets. The Act was created "in response to concerns around Vermont's changing climate and the magnitude of what must be done to reduce greenhouse gas emissions and prepare for the impacts of climate change on Vermont's landscape."[9] The Act requires Vermont to reduce greenhouse gas pollution to 26% below 2005 levels by 2025. Emissions must be 40% below 1990 levels by 2030, and 80% below by 2050. Directed by the GWSA, the Vermont Climate Council has drafted the Vermont Climate Action Plan to describe pathways to address climate change and meet the required emissions reductions. The Climate Council has five subcommittees that developed recommendations to be included in the final Climate Action Plan to be published at the end of 2021.

The surrounding states of Connecticut, Massachusetts, Rhode Island, Maine and New Hampshire have each recently released pathway planning documents to describe the transformational needs of energy sectors. To varying degrees and with some differences in approach, each state describes need and potential methods for greater electrification of the heating/building and transportation sectors to reduce fossil fuel use and ways to add significant supplies of new, clean electricity supply to the region to support this effort.

State Renewable Portfolio Standards

All six New England states have active Renewable Portfolio Standards (RPS) or Renewable Energy Standards (RES) policies in place to support their individual climate initiatives. The resources supported by each state's RPS vary and the programs have multiple classes or tiers that group purchase obligations by technology, vintage, emissions, and other criteria. Most of the classes are focused on adding new renewable resources but others are focused on retaining existing renewables and low-carbon generation technology. More recently Massachusetts also adopted a Clean Energy Standard[10] that is aimed at carbon reduction, not just renewable resources, and includes support for existing nuclear and large hydroelectric resources[11]. Connecticut also has mandated support for nuclear along with new renewables, recognizing the need to continue these existing low-carbon baseload resources while other renewable generation is built in the region.

The New England Power Pool Generation Information System (NEPOOL GIS) is used to track compliance and resource eligibility for the state RPS programs. This tracking system issues certificates for all MWh of generation for each MWh of production. LSEs acquire the certificates they need for their respective programs and retire them to verified compliance accounts. There is also an over-the-counter forward trading market to support this activity where RECs can be purchased and sold for many of the programs out a few years into the future.

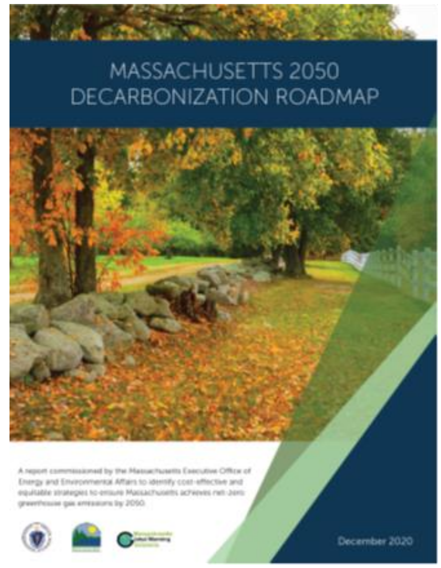
[9] See VT Climate Commission website at https://climatechange.vermont.gov/resources

[10] https://www.mass.gov/guides/clean-energy-standard-310-cmr-775

[11] See, AN ACT CREATING A NEXTGENERATION ROADMAP FOR MASSACHUSETTS CLIMATE POLICY, Mass. Bill S.9, 192nd (2021),

available at https://malegislature.gov/Bills/192/S9

Beyond these RPS-driven gradual increases in new supplies of wind and solar, the most significant driver of large changes to the regional energy supply in the next few years will result from surrounding states' return to long-term supply procurements. These state-sponsored Requests For Proposals (RFPs) in support of ambitious greenhouse gas reduction and renewable power goals have contracted to add thousands of MWs of new clean energy resources to the regions by 2025.



State Offshore Wind Procurement

Massachusetts utilities recently issued another RFP to procure up to 1,600 MW of offshore wind capacity. This would be Massachusetts' third offshore wind RFP following its 800-MW capacity award to Vineyard Wind and its prior 800-MW Mayflower Wind award. This latest RFP would keep Massachusetts on track toward its goal to have 4,000 MW of offshore wind under contract by 2027.

These renewable additions are part of Massachusetts' plan to meet the goals set out in their Global Warming Solutions Act and follow their 2050 Decarbonization Roadmap[12]. The illustration below in Figure 5.6 shows the potential magnitude of these contractual additions for Massachusetts' program over future periods.

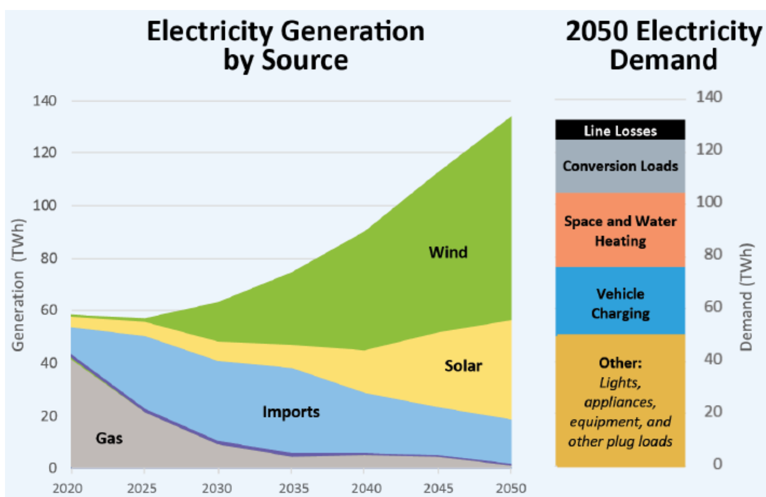


Figure 5.6. Massachusetts' Anticipated 2050 Electricity Generation by Source

12 https://www.mass.gov/info-details/ma-decarbonization-roadmap

The other Surrounding states have similarly ambitious new renewable plans and are active in state-sponsored procurement. Offshore wind is prominent in the procurement plans of Connecticut and Rhode Island, with each committing to large projects in recent years. In Connecticut's most recent IRP[13], the state noted that it is likely that they will pursue additional offshore wind in the next few years to fully subscribe the 2,000 MW of authorized offshore wind under Public Act 19-71 by 2028.

Maine is also exploring the suitability of its coastal waters to support further offshore wind development in support of the region's climate goals. To date most of the offshore projects have been in the waters off Rhode Island and lower Massachusetts. The illustration of lease areas for these resources is seen below in Figure 5.7 from the Northeast Ocean Data Portal.

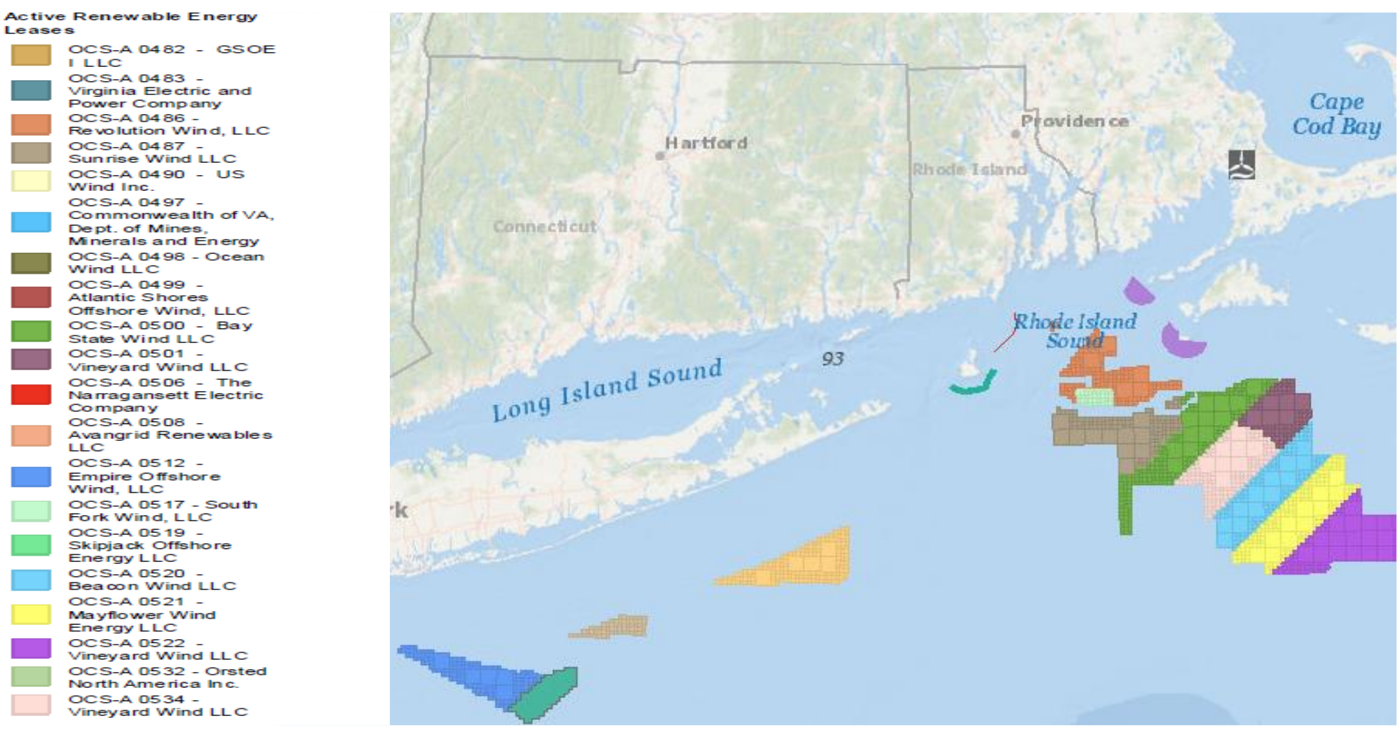


Figure 5.7. Offshore wind lease areas for proposed New England projects – Northeast Ocean Date map

For GMP, the upcoming procurements could represent new opportunities for our energy portfolio as new supply proposals and resource developments are brought into focus for these large regional solicitations.

13 https://portal.ct.gov/DEEP/Energy/Integrated-Resource-Planning/Integrated-Resource-Planning

New Distributed Solar Resources

Since our last IRP, solar PV resources continue to be added to the regional supply at a significant rate. Most of this new capacity is comprised of small-scale systems that are not connected to the regional high-voltage transmission system. This solar growth is almost entirely the result of state programs. There is also reflected in this chart the meaningful level of Behind-the-Meter solar in Vermont and in other states.[14]

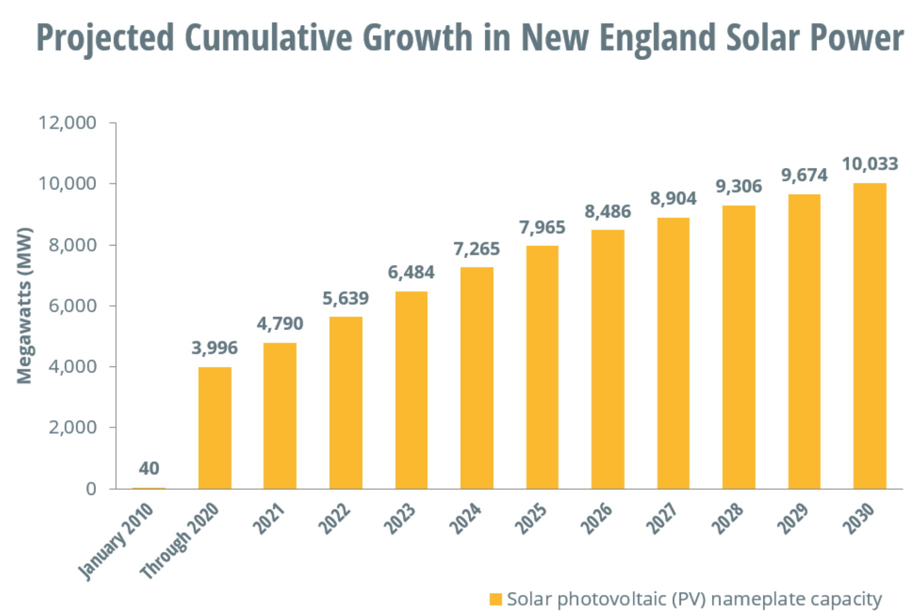


Figure 5.8. Projected Cumulative Growth in New England Solar Power: May 2021 Forecast[15][16]

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

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

[14] ISO-NE and certain New England Transmission Owners recently filed a petition at the Federal Energy Regulatory Commission to align the regional tariff treatment of Behind-the-Meter resources consistent with current practice, rather than reconstituting such load when applying the tariff. FERC Docket No. ER21-2337-000. Many other participants both for and against the filed petition have commented to FERC. GMP, VELCO and the other Vermont distribution utilities are monitoring the proceeding for its possible effect on Vermont and the other states in the region.

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

[16] The New England Transmission Owners

lowering peak demands during the summer months. By 2025, ISO-New England predicts that these solar resources will nearly double from the current amount to nearly 8,000 MW installed.

Beyond affecting the carbon emissions profile of the region, these new planned supplies are expected to meaningfully impact energy and capacity prices in the ISO-NE markets. For the energy market, these supplies could reduce the impact of natural gas shortages in the winter months, lowering prices considerably.

Carbon Pricing Market

Compliance carbon markets are marketplaces where participants need to purchase emissions permits (allowances) or offsets to meet predetermined carbon emissions reductions. In the case of cap-and-trade programs, participants are allowed to trade allowances to make a profit from unused allowances or to meet regulatory requirements. There a number of these programs in the U.S., covering carbon and other harmful air emissions and there is a considerable push to see some form of national or regional carbon pricing market implemented soon. In New England, all the states that make up the ISO-NE market have signed onto the Regional Greenhouse Gas Initiative (RGGI), which requires a steady, gradual decline in annual carbon emissions from the region's large fossil-fuel power plants.

The RGGI carbon-trading program was the first mandatory cap-and-trade program in the United States to limit carbon dioxide (CO2) from the power sector and it continues to evolve. The program expanded in 2021, adding Virginia to the previous 10-state program and enhancing its coverage to 18% of the U.S. population and 20% of the U.S. economy.

Under the current RGGI plan, annual emissions caps are applicable collectively to all participating states' fossil-fuel generators over 25 MW in size. The cap is set at 120M metric tons for 2021 and declines each year thereafter until it reaches 80M metric tons in 2030 (a 33% decline). Allowances up to the annual cap are auctioned off on a quarterly basis to producing power plants. Typical trading prices in these auctions are around $10 per ton with an expectation that the lower the cap is set each year, the higher the price will become. Because all the New England states participate, ISO-NE energy prices are affected more here than in other regions by the costs of complying with the annual limit and auction pricing. According to the report for New England's external market monitor, in 2020 compliance added as much as $6 per MWh to production costs of a gas-fired, combined-cycle generator in some locations.[17]

A comprehensive national program for CO2 emissions has not yet materialized but other program designs are advancing for other areas of the economy. For example, Connecticut, Massachusetts, and Rhode Island, along with the District of Columbia, are launching a Transportation and Climate Initiative Program (TCI-P) which would implement an allowance-trading program for the transportation sector. The Vermont Climate Council is considering recommendations related to joining the TCI-P. We expect more programs either within ISO-NE or elsewhere directed at reducing carbon emissions to emerge in the IRP planning horizon. To the extent that any future carbon pricing system is enacted to reduce carbon emissions to sustainable levels, we also expect that pricing would be much higher than what we have so far seen in the RGGI program. For example, a NY update to

[17] 2020 ASSESSMENT OF THE ISO-NEW ENGLAND ELECTRICITY MARKETS, Potomac Economics

their "Value of Carbon" reporting initiative describes a rationale for a central price level of $125 per ton for planning considerations to account for the damage associated with the greenhouse gas.[18]

Emerging National Influences on our Energy Market

FERC ORDER 2222

In 2020, the Federal Energy Regulatory Commission (FERC) issued Order No. 2222: Participation of Distributed Energy Resource Aggregations in Regional Transmission Operators (RTOs). This Order requires RTOs/ISOs to allow distributed energy resources (DERs) greater access to wholesale markets, on an equal footing with larger generation sources. Nationally, most of the electricity entering the wholesale markets is from large generation sources – wind and natural gas owned by a few larger participants that specialize in the development of these resources. Order 2222 aims to allow easier market access from distributed energy resources that may include aggregations of local, small-scale, distribution-sited assets like rooftop and community solar, energy storage, and micro-grids, among others. While in New England there are already pathways for participation for some of these alternative resources, under Order 2222 we would expect opportunities to increase, although ISO-NE is still working out some of the important details. Importantly, the FERC recognized that while small, distributed energy resources can participate in wholesale markets through many existing demand-response programs, there was a limitation to these programs that could underappreciate some types of distributed resources, like emerging battery technologies.

GMP is closely monitoring the methods and framework being discussed in our region to implement the order. A large part of this effort will clarify how these resources will straddle existing retail participation models and the wholesale market. Under currently drafted program rules a key component of the implementation will depend on metering and reporting coordination between each distributed resource wishing to participate in a wholesale aggregation and their host utility. GMP expects the implementation phase of the new market rules associated with the Order could create meaningful new administrative efforts for us and the other Vermont utilities to unlock this new opportunity. ISO-NE's compliance filing is due February 2, 2022, and GMP will be closely following this process and its ultimate full implementation timetable, which is currently targeting 2024-2026.

FERC ANOPR

The Advance Notice of Proposed Rulemaking (ANOPR)[19] is a FERC initiative to improve transmission planning processes and cost allocation mechanisms under the pro forma Open Access Transmission Tariff (OATT). This ANOPR opens a proceeding to explore reforms to current planning practices that have traditionally centered on the considerations of a fossil-fuel-based grid. Under this new initiative, FERC describes the goal for a rulemaking that will help to move U.S. electric markets "toward a new paradigm in electric system planning." It foreshadows major reforms across several interrelated transmission-planning, generator-interconnection, and

[18] https://www.dec.ny.gov/docs/administration_pdf/vocguidrev.pdf (page 4)

[19] Docket No. RM21-17-000

cost-allocation processes. Vermont utilities including GMP, and our statewide transmission company VELCO, will be following this proceeding. In a related action FERC established a Joint Federal-State Task Force on Electric Transmission to help guide the development of new transmission infrastructure and explore methods needed to plan and pay for these facilities. Because state and federal regulators each have authority over different aspects of transmission planning and at times have conflicting priorities, FERC determined that the topic requires greater federal-state coordination. The FERC appointed several state commission members to the task force, including Vermont Commissioner Riley Allen.

National clean energy programs

The recent Clean Electricity Payment Program (CEPP) proposal that emerged in Congress is an example of the potential for a national clean energy program that could impact our future market environment and planning process. This proposal would drive decarbonization toward a goal of reaching 80% clean electricity nationwide by 2030. The types of resources incented under the program could include power generated from hydroelectric, biomass, geothermal, nuclear, hydrogen, and even fossil fuels under some carbon-limiting criteria. Much like a cap-and-trade system, its design would require electric suppliers to follow a prescribed annual pace of improvement to maintain compliance. However, unlike the single price of allowances in a cap-and-trade system, this program would have a penalty-and-reward structure to motivate electricity suppliers to increase their share of clean resources each year. Whether this framework or any other emerges out of Congress, in the wake of the 26th United Nations Climate Change Conference of the Parties (COP26) in Glasgow this fall is still uncertain.

Forward clean energy market

Another candidate being evaluated regionally that could significantly change the market landscape is the idea of a Forward Clean Energy Market advanced by the Brattle Consulting Group. This change to the operating design of the markets would create a clean energy buying program within the current ISO/RTO market structure. The proposed structure would attempt to competitively procure clean energy commitments alongside the current wholesale power market products using the existing market operator (such as ISO-NE) or an interstate entity (such as RGGI). The FCEM would buy a new type of environmental attribute Brattle describes as a Clean Energy Attribute Credit (CEAC), like RECs.

The Pathways to the Future Grid study in New England[20] is exploring how this type of framework might help the region achieve clean energy goals.

[20] https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project

hydroelectric, biomass, geothermal, nuclear, hydrogen, and even fossil fuels under some carbon-limiting criteria. Much like a cap-and-trade system, its design would require electric suppliers to follow a prescribed annual pace of improvement to maintain compliance. However, unlike the single price of allowances in a cap-and-trade system, this program would have a penalty-and-reward structure to motivate electricity suppliers to increase their share of clean resources each year. Whether this framework or any other emerges out of Congress, in the wake of the 26th United Nations Climate Change Conference of the Parties (COP26) in Glasgow this fall is still uncertain.

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20 https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project

6. Our Increasingly Renewable Energy Supply

Overview

GMP's 2020 retail energy supply, as described in our Renewable Energy Standard filing with the Vermont Public Utility Commission, was 100% carbon free and more than 68% renewable. We will maintain a 100% carbon-free portfolio as we continue to ramp up our renewable supply both in state and regionally to achieve our goal of 100% renewable by 2030.

Our portfolio of resources has undergone a substantial transformation in the past decade. As we plan and work toward achieving our renewable goals, we've transitioned to a portfolio that is no longer reliant primarily on long-term contracts with just a few large resources. It is now more flexible, with contracts of differing durations, generation sources, types, and volumes.

To complement the extraordinary growth of distributed renewable generation in our service territory, we have intentionally rebuilt our portfolio with a diverse mix of resources that includes new utility-scale renewable power sources, some in combination with storage capacity; a long-term, 7x16 peak hour energy and attribute purchase from Hydro-Québec that ramps down over time; a long-term nuclear purchase backed by the Seabrook plant in New Hampshire; and most recently a long-term shaped hydro energy and attribute purchase from Great River. All of these support continued renewable deployment in Vermont and regionally, while offering reliable power in the face of the climate crisis.

As we continue to look for opportunities to deliver clean power when customers need it and diversify our own peaking resources away from fossil fuels, we prioritize projects that can deliver multiple benefits in the portfolio such as a balancing profile, stable cost, storage for peak dispatch, or locations that support local infrastructure. This type of multi-dimensional thinking is required now more than ever as we address climate change, help customers decarbonize with distributed resources, and create an energy system that is closer and more connected, relying even more than before on the greater grid.

Figure 6-1 depicts our energy supply for calendar year 2020 *before* the purchase and sale of Renewable Energy Certificates (RECs).

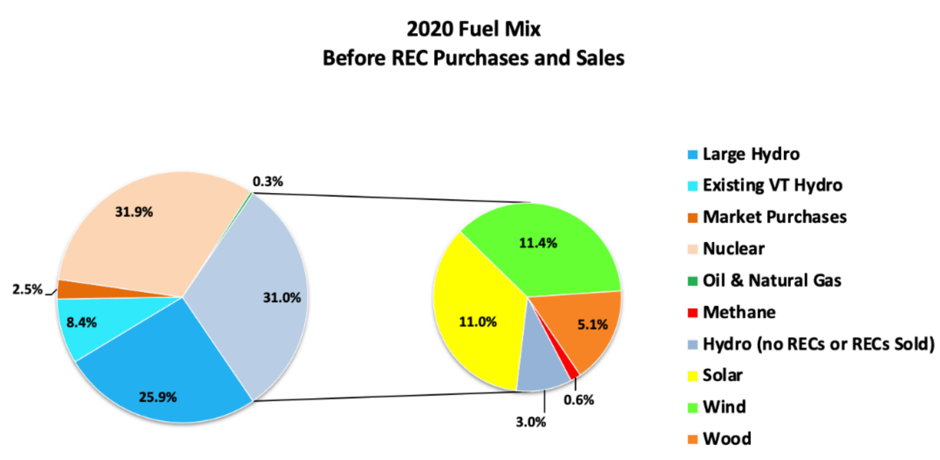

Figure 6-1. Energy Supply Mix Before Accounting for REC Transactions

Figure 6-2 depicts our energy supply for calendar year 2020 *after* purchase and sale of RECs.

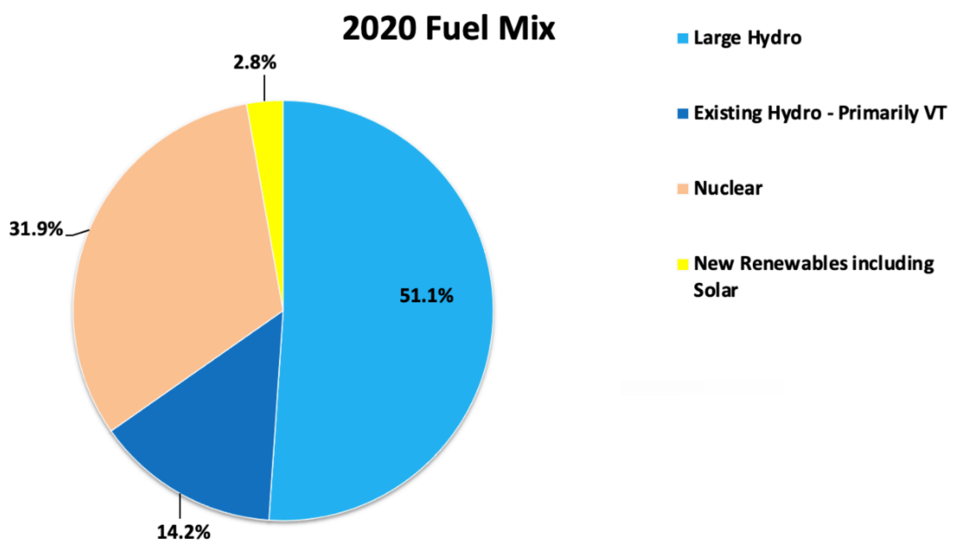

Figure 6-2. Energy Supply Mix After Accounting for REC Transactions

Current Supply Resources

Our power supply resources include output from our own facilities, longer-term PPAs from resources at various locations across Vermont, New England, and Quebec, and some market-based purchases that are generally short term, or less than five years. In the following sections, we describe each of these categories.

Owned Hydroelectric Generation

Our 42 owned hydroelectric generators have a total nameplate capacity of 117 MW of electricity and produce an average of about 360,000 MWh of energy each year. Some of these resources provide capacity amounting to approximately 65 MW of FCA-based capacity credit and additional seasonal capacity payments.

Collectively, our hydroelectric fleet generates an average of up to 10 percent of our retail energy load. The output of the plants can vary significantly on a daily, monthly, and annual basis depending on seasonal river flows, annual precipitation, and planned and unplanned outages. Although these plants require regular operation and maintenance expenses, along with periodic capital expenditures for improvements and FERC relicensing, they are the longest-lived assets in the supply category and, on average, the cost of power from our hydroelectric fleet is low 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 and qualified for premium REC markets, primarily Massachusetts Class 2, giving us the option to sell some or all the RECs from these plants and use the revenue to reduce net power costs and retail rates for customers.

In 2018, we transitioned several generating units that were historically represented in the ISO-NE market as "composite" resources to operation as load reducers.[1] We 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-NE systems, with the goal of saving customers money by limiting our share of RNS transmission charges and regional capacity market costs.

Table 6-3 below lists our hydroelectric fleet organized by total MW per waterway. Appendix J is a plant-by-plant summary of our hydroelectric fleet, including license status and major improvements that have been completed or are in progress.

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1 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 and are no longer ISO-NE composite resources. The Lower Lamoille Composite, which includes the Clark Falls, Milton, and Peterson plants, still operates as a composite resource.

Waterway	MW	Hydroelectric Resources*
Otter Creek	30.61	Beldens Falls, Center Rutland (2024), Huntington Falls, Middlebury Lower, Proctor, Vergennes (2029), Weybridge
Lamoille River	21.05	Clark's Falls, Fairfax Falls, Milton, Peterson
Winooski River	20.90	Bolton Falls (2022), Essex #19 Hydro (2025), Gorge #18, Middlesex #2
East Creek	6.00	East Pittsford, Glen, Patch
Little River	5.52	Waterbury 22
Molly's Brook	5.00	Marshfield #6
Ottauquechee River	4.94	Dewey's Mill, Ottauquechee, Taftsville (2024)
Passumpsic River	4.20	Arnold Falls, East Barnet, Gage, Passumpsic, Pierce Mills
Salmon Falls River	3.98	Rollinsford (2021), Salmon Falls, Somersworth/Lower Great Falls (2022)
Poultney River	2.55	Carver Falls
Sucker Brook	2.20	Silver Lake
Mascoma River	2.05	Mascoma (2027)
Waits River	1.50	Smith
Black River	1.44	Cavendish Hydro (2024)
Leicester River	1.30	Salisbury
Contoocook River	1.12	West Hopkinton
Joe's Pond	1.00	West Danville #1
Stevens River	0.56	Barnet
Wells River	0.42	Newbury (2023)
Piscataquog River	0.40	Kelley's Falls (2024)
TOTAL	116.74	*License renewal year in parentheses if by 2030

Table 6-3. Legacy Hydroelectric Resources

Figure 6-4. Kingdom Community Wind

Owned Wind Generation

Kingdom Community Wind is a 21-turbine, 64.5-MW generation facility in Lowell, Vt. We partnered with Vermont Electric Cooperative (VEC) to build the project with the support of the community, 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 and operate 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, except for some reductions because of a transmission system constraint that is being resolved. Transmission system constraints can add to the congestion component of local LMPs, resulting in decreased energy revenues in addition to curtailed production.

During operation in winter months, Kingdom Community Wind sometimes experiences accumulation of ice on turbine blades. When this occurs, some or all turbines may need to be shut down until the ice accumulation can be shed. Depending on weather, icing can impact generation as much or more than transmission system constraints, so to limit the duration of such events, we proactively take the plant offline (so that the blades are not rotating) when weather at the facility appears conducive to buildup. This method can limit ice buildup and associated lost generation.

Searsburg is an 11-turbine, 6-MW facility located near the southern border of Vermont. Completed in July 1997, it was the first utility-scale wind facility installed in the Northeast. After 20 years of production, Searsburg continues to operate reliably, producing energy at an average annual capacity factor of about 23%.

We expect to continue maintaining and operating Searsburg through this three-year IRP cycle, making repairs as needed. We recognize that some types of component failure make it infeasible or not cost-effective to keep one or more units in service. For example, 10 of 11 turbines are currently in operation and we expect to decommission one tower by 2022. The facility has operated well over the years and has provided GMP with valuable learning about the possibilities of wind power. GMP is evaluating the feasibility of upgrading or repowering the project to maintain renewable generation for customers from the site in future years.

GMP has a long-term contract purchasing the output from Deerfield Wind, a 30-MW project located directly adjacent to the Searsburg facility and sharing some facilities such as access roads. GMP's 2027 purchase option of Deerfield Wind will impact the timing and strategy of Searsburg repowering or potential retirement.

Solar Generation and Battery Storage

In a dynamic and two-way energy future where resources are connected between the customer and the greater grid, GMP is also supporting and helping grow utility-scale solar generation and solar combined with battery storage technology. This has become a larger component of our owned generation portfolio as its availability and cost-competitiveness continues to improve, and it also cuts costs during peak demand days, making it a critical resource. We expect solar and battery storage to continue to have a very important role in our portfolio over the IRP planning period.

In the last six years, and primarily since our last IRP in 2018, GMP has commissioned over 35 MW-AC of solar PV capacity including over 9 MW-AC of associated battery storage capacity as part of our GMP Solar and GMP Solar/Storage programs. Each battery storage project features distinct design considerations to provide flexibility and value in our portfolio for customers. We also have contracted for 17 MW of standalone storage capacity through PPAs with resources to be built within this IRP period.

Joint Venture Solar

Listed in the table below as GMP Solar, GMP commissioned five utility-scale solar projects as part of our GMP Solar Joint Venture program: 4.69 MW (AC) in Williston; 2 MW (AC) in Richmond; 4.992 MW (AC) in Hartford, 4.9 MW (AC) in Panton; and 4.99 MW (AC) in Williamstown. All the 2016 projects utilized fixed-tilt racking systems, except for Panton, which implemented single-axis trackers. The estimated lifetime cost of power from the Joint Venture Solar projects was the lowest among Vermont solar PV projects when the projects were developed.

In 2018, a 1-MW, 4-MWh battery system was commissioned on the Panton solar site and is now providing peak load reduction and frequency regulation services to the grid. Just recently, GMP completed installation of the first-of-its-kind inverter-based microgrid at this site, enhancing its capability for customers in the immediate vicinity while continuing to deliver solar/storage resources for our portfolio.

GMP Solar/ Storage

Another important part of GMP storage resources relates to their colocation with solar generation facilities. Three GMP Solar/Storage projects located in Milton (4.99 MW-AC), Essex (4.5 MW-AC), and Ferrisburgh (4.99 MW-AC) are part of an energy storage initiative that not only provides peak load reduction and frequency regulation services, but they are primarily charged from onsite solar generation. In addition to large-scale solar, each site hosts a battery consisting of a 2-MW, 8-MWH battery storage system.

These three sites, all commissioned in 2019, have been operating reliably and effectively now for over two years. GMP just completed an annual financial evaluation of the batteries' performance and issued the second annual report to the DPS with operating results, per the MOU between GMP and DPS. Operational and financial performance continues to improve, with experience in forecasting and battery discharge strategy, and GMP expects the feedback loop of forecast, perform, and evaluate to continue to add value to customers in terms of lower power costs.

Table 6-5 lists GMP owned distributed generation (DG) solar and storage resources described above.

Location	Ownership	Solar MW AC	Battery MW	Technology Type	Online Date
Berlin	GMP	0.190	-	Solar	8/11/2010
Essex	GMP-Essex Solar/Storage, LLC	4.5	2.0	Solar /Battery	8/22/2019
Ferrisburgh	GMP MicroGrid-Ferrisburgh, LLC	4.99	2.0	Solar/Battery	9/30/2019
Hartford	GMPSolar Hartford, LLC	4.992	-	Solar	12/13/2016
Milton	GMP MicroGrid-Milton, LLC	4.99	2.0	Solar/Battery	9/4/2019
Panton	GMPSolar Panton, LLC	4.9	1.0	Solar/Battery	12/9/2016 (2018)
Richmond	GMPSolar Richmond, LLC	2.0	-	Solar	9/11/2016
Rutland City	GMP	0.010	-	Solar	4/7/2014
Rutland City	GMP	0.059	-	Solar	5/20/2014
Rutland City	GMP	2.0	2.0	Solar/Battery	3/30/2015
Rutland Town	GMP	0.048	-	Solar	4/2/2019
Williston	GMPSolar Williston, LLC	4.69	-	Solar	11/8/2016
Williamstown	GMPSolar Williamstown, LLC	4.99	-	Solar	12/27/2016
		38MW+	9MW		

Table 6-5. GMP owned Distribution Generation Resources

Customer-sited and Other Storage Resources

Battery storage resources are already delivering in several ways based on the type, scale, and location of the systems. Tesla Powerwalls and residential installations of other batteries now total over 14 MW installed capacity on our system that we can coordinate charging and discharging of to manage overall load on our system, cutting costs and carbon for all customers while providing reliability and backup service at their individual locations. They also perform as an up to 2-MW aggregated regulation resource in ISO-NE markets, creating an additional revenue stream and a learning opportunity for both GMP and ISO-NE as the first aggregation of batteries used in this manner. These resources saved customers over $3 million in 2020.

For larger systems like the standalone, multi-MW-scale project located in Barre and those coming online in 2023, the role is like our peaking fossil fuel generators, but obviously cleaner. For both the smaller installations and the standalone resources, GMP directs battery operations to respond to peak demand conditions to avoid regional costs allocated based on the use of the bulk system at these critical periods. Like quick-starting generation resources, these storage facilities are also able to provide some other services to like frequency regulation when they are not being called on for peak-reduction services.

Table 6-6 lists other storage resources described above.

Location	Ownership	Solar MW AC	Battery MW	Technology Type	Online Date
Barre	PPA	4.999	4.999	Solar/Battery	12/17/2020
Georgia	PPA	-	4.99	Battery	*6/2023
N Springfield	PPA	-	4.99	Battery	*6/2023
Middlebury	PPA	-	2.00	Battery	*12/2023
Royalton	PPA	-	4.90	Battery	*12/2023
Throughout GMP service territory	Customer Powerwall and BYOD Programs	-	17+	Residential scale batteries	Various
		6.499MW	40MW+		*Estimated COD

Table 6-6. Other Storage Resources

Other Solar

We have installed solar PV equipment at several of our own properties as well as at sites owned by partners, and 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 several of our office buildings. We've also installed projects at Rutland Region Medical Center and the former 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. Most of the 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. When GMP pioneered the use of a 6-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 retail electricity rates. The magnitude of the adder made total solar compensation at the time roughly consistent with the estimated value of solar PV output to GMP and its customers - in part because of its coincidence with local and regional peak demands during daytime hours.

In the following years the expansion of net-metering eligibility to projects up to 500 kW, including remote, off-site projects, in combination with a rapid decline in the cost of solar PV project costs yielded an extraordinary phase of growth of net metering capacity in GMP's service territory.Figure 6-4 shows the growth of operating net-metering capacity from 2010 to the present. The growth has been overwhelmingly in solar PV projects, which presently make up about 97% of the net-metered generation fleet.

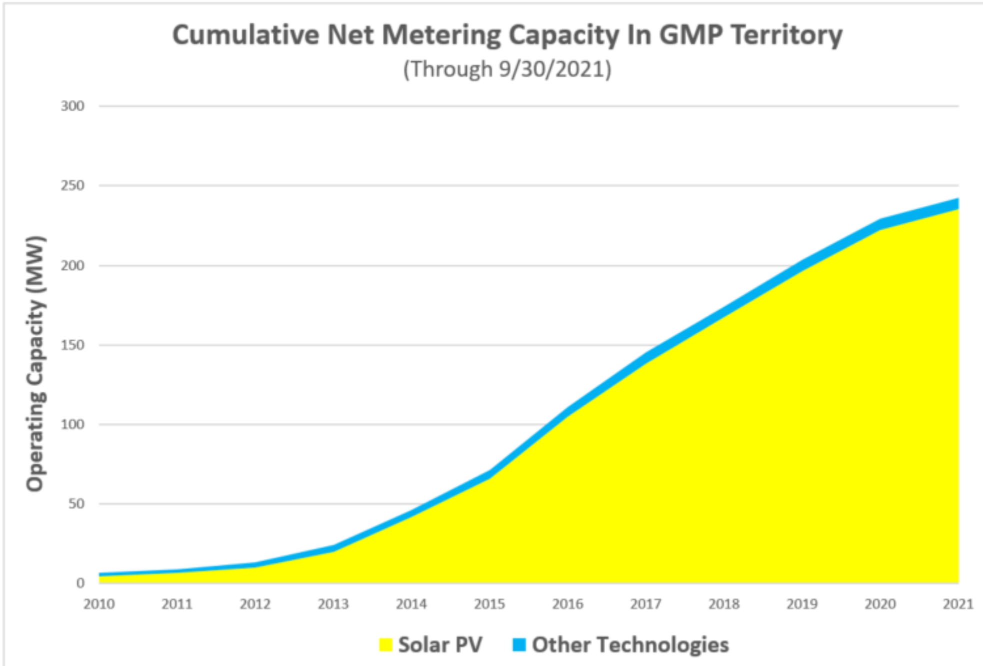

Figure 6-7. Cumulative Net Metering Capacity

Figure 6-8 illustrates the annual volumes of net-metering capacity that achieved commercial operation in GMP's service territory each year[2]. During the past seven years the amount of net-metered capacity reaching commercial operation has ranged from a low of over 20 MW in the year ending June 2015 to a maximum of almost 40 MW for the year ending June 2017. In most years the volume of capacity reaching commercial operation has fallen within a much tighter range of about 26 MW (for the pandemic-influenced year ending June 2021) to about 31 MW for the year ending June 2016. While the largest number of net-metered projects are in the small (sized up to 15 kW) category, the greatest growth and the largest share of net-metered capacity has been in the large (up to 500 kW) category.

[2] The annual totals shown here are for years ending June 30th, since in several year the compensation available to new projects changed in July.

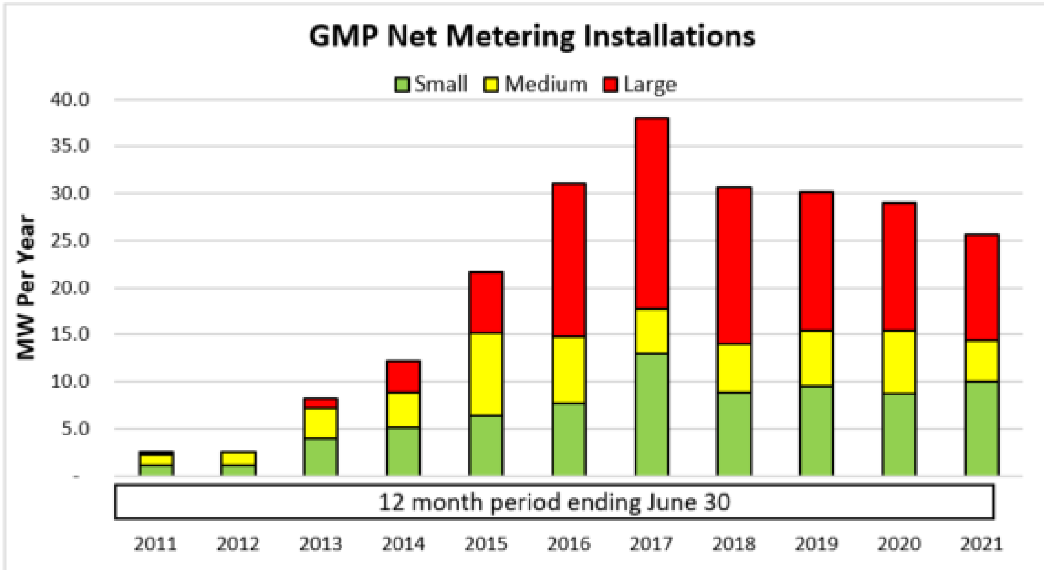

Figure 6-8. Annual Net-Metering Capacity

As a result of this extraordinary growth, there is now over 240 MW of net-metered generating capacity in GMP's service territory. 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 lower costs per kWh. This points to a particular concern for large-scale (up to 500 kW), remote net-metering projects, which do not generally offer operational advantages relative to lower-cost larger solar sources and yet contribute to greater customer cost.

This outcome in part has led the PUC to recognize the need for a more balanced mix of distributed renewables in Vermont. Under the biennial review of the net-metering program, payment rates for new net-metered generation have been lowered modestly, effective with applications received starting July 1, 2018, and in subsequent years. As Figures 6-7 and 6-8 indicate, however, the pace of growth of net metering has not slowed substantially. Interconnection applications for new net-metering projects have remained strong, resulting in an active queue of about 60 MW of proposed projects – one of the highest queue volumes in years.

Distributed generation installations that are co-located with or near the electricity load they serve should continue to be part of Vermont's path to a more renewable power supply. Smaller systems located directly on the customer premises offer greater value to the customer and greater grid, with lower individual impacts to other customers. As we consider the future of on-site and distributed generation in Vermont beyond net metering, we can evolve our traditional policies to something bigger and better that provides more solar for more Vermonters, more cost-effectively.

New and creative procurement designs outside of the current net-metering program would allow the benefits of DG to be accessible to a broader set of customers in a more inclusive way. One design could be with a focus to encourage community-scaled projects in locations that have had hurdles to participation within the traditional net-meter design. Another opportunity could be a program specifically for commercial scale non-load connected solar projects to limit the net-metering-cost shifts created from these larger projects while still recognizing the benefit that they bring in additional renewable sources to the region. We consider the value of different DG procurement for these types of projects in the Portfolio Evaluation chapter.

Jointly Owned Generation

We have joint ownerships in four generation facilities and one transmission facility. The generation facilities include one wood, one nuclear, and two fossil-fuel projects, representing baseload and peaking capacity as shown in Table 6-9 below.

Resource Name	Age (years)	GMP Share Nameplate MW	2020 MWh
McNeil Station	37	15.5	72,000
Millstone #3	35	21.4	156,000
Stony Brook 1A, 1B, 1C	40	31	12,000
Wyman #4	43	17.7	<500
HVDC Phase 2 Transmission	31	112	n/a
Total		197.6	240,000

Table 6-9. Jointly Owned Generation

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 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 for customers. The production of valuable RECs (in addition to energy) has supported the operation of McNeil at well over a 50% capacity factor. Declining value of Connecticut Class 1 RECs in combination with a proposed phase down of eligibility of biomass resources could mean that the highest and best use for McNeil RECs is to be sold in other markets or retired towards our own portfolio. Because we have current contracts to sell McNeil RECs to the Connecticut Distribution utilities through 2025, any change to current REC strategy would likely happen outside of this IRP planning horizon.

The McNeil Joint Owners, led largely by BED, are investigating how the facility could be used to support a district energy system in the City of Burlington by recovering waste heat and additional steam from the McNeil Station, and then using those sources to provide thermal energy to adjacent customers via steam pipe. A district energy system is an optimal way to reduce greenhouse gas emissions, improve the value of the existing asset and provide energy savings to all consumers.

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 #3 began commercial operations in 1986; we own a 1.7303% (21.4 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.

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 5%. The primary fuel is natural gas, although the plant can operate regularly on oil for significant periods during winter cold snaps, providing value to our customers when regional scarcity of natural gas supply makes operation on gas uneconomic. 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.

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-NE 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-NE. 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. Wyman #4 is a steam unit that requires many hours to start and therefore does not respond to shorter-term, unexpected outage events regionally.

The HVDC Phase 2 transmission and converter terminal facilities interconnect the Hydro-Québec system to the ISO-NE 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% of the facility's available transmission capacity (approximately 100 MW of firm capacity at typical availability). ISO-NE recognizes the contribution of this interconnection to regional resource adequacy, and presently provides us with roughly 70 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. In 2020, we renewed the facility-use arrangement through 2025.

We have entered a multi-year transaction with Hydro Québec that conveys generation attributes from hydroelectric sources imported into New England over the Phase 2 transmission facility.[3] During the current transaction term of 2020-2024, we purchase 1.2 million Vermont Tier 1 RECs per year, which are delivered

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3 As part of the same transaction, we are leasing the use of its Phase 2 transmission rights to Hydro-Québec through late 2024.

quarterly into the NEPOOL GIS tracking system. We anticipate banking some of these RECs to cost-effectively meet requirements for customers in subsequent years.

Owned Peaking Generation

We own a fleet of six oil-fired generators that have operated in a peaking role in Vermont to support the needs of our customers. Two of these units are pending retirement, including one that has already been taken offline, and we are exploring how to retire other units to further decrease reliance on fossil fuels. These units operate primarily during peak load days or other times when energy market prices in the ISO-NE 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 and are valid into 2023. Although these plants do not operate often (typical annual capacity factors for these units are less than 1 percent), they have at times provided significant value for our customers through their value in the Forward Capacity Market (FCM) and Forward Reserve Market (FRM). These revenue streams continue to decline in value annually due to market conditions and operational performance.

Table 6-10 below is a plant-by-plant summary of our peaking generation, including two pending retirements as noted.

Resource Name	Location	Age (years)	Nameplate MW	Description
Ascutney Gas Turbine	Ascutney, VT	57	12.5	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	Berlin, VT	46	46.5	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. Automation, control, relay protection and fire suppression were upgraded in 2019 and 2020. 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	Essex, VT	12	8.0	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	Colchester, VT	53	17.0	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 a control system upgrade in 2019.
Rutland 5 Gas Turbine	Rutland, VT	55	12.5	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. Retirement of this unit is currently planned by 2025 due to age and diversifying our peaking fleet away from fossil fuels.
Vergennes 5 & 6 Diesels	Vergennes, VT	55	(4.0)	Offline and fuel supply disconnected pending retirement as of August 2021 due to age and diversifying our peaking fleet away from fossil fuels. *(not included in MW total)*
Total			96.5MW	

Table 6-10. Owned Peaking Generation

Long-Term Renewable and Carbon-Free Power Purchases (PPAs)

A significant majority of our energy supply comes from long-term PPAs with individual suppliers. As we advance our commitment to be 100% renewable in 2030 (already 100% carbon free now) and the region continues to transition to a cleaner supply, these long-term resources will support our progress and growth of regional and in-state renewables. Through the IRP planning period we will receive a portion of our energy supply from both long-term PPAs (Great River Hydro, HQUS and NextEra) and from an increasing amount of local distributed resource purchases that continues to grow.

Table 6-11 depicts current contracts and illustrative 2020 energy volumes.

Contract Name	Contract Period	Contract MW	Typical MWh
Great River Hydro[1]	2023-2052	variable	624,000
Hydro-Québec-United States[2]	2012–2038	178	1,041,000
NextEra Seabrook[3]	Through 2034	55	450,000
Granite Reliable Wind	2012–2032	up to 82	up to 190,000
Deerfield Wind	2017–2042	30	95,000
VT Renewable PPAs-hydro	Mid 2030s	variable	up to 150,000
VT Renewable PPAs-Solar	Mid 2030s	variable	up to 95,000
		TOTAL	2,645,000

1 Great River Hydro ramps up to full volume by 2033.

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

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

Table 6-11. Long-Term Power Purchase Agreements

Great River Hydro PPA. In 2021, we added a new long-term agreement for energy and environmental attributes from Great River Hydro's fleet of 13 hydroelectric facilities located along the Connecticut and Deerfield Rivers in Vermont, New Hampshire, and Massachusetts. The first deliveries under the agreement begin in January 2023 and increase in volume in subsequent years under two distinct delivery schedules, peaking and firm. The peaking hydroelectric energy deliveries will provide a percentage of production from three units on the CT River, the Fifteen Mile Falls facilities, where deliveries begin at 20 percent their hourly output in 2023 and ramp up to 50 percent by 2029 and every year thereafter through 2052. The firm hydroelectric energy deliveries will provide a fixed quantity of energy each year with deliveries beginning at 5 MW per hour in 2028 and ramping up to 30 MW per hour in 2033 and every year thereafter through 2052.

Hydro-Québec-US PPA. In April 2011, GMP and a group of other Vermont distribution utilities received approval from the PUC (then called the Public Service Board or PSB) for a 26-year PPA with Hydro-Québec–United States (HQ-US) starting in November 2012. The HQ-US PPA provides annual energy volumes of approximately 1,000,000 MWh per year (representing around 20% 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 specific generating units or transmission facilities. In addition to the energy delivered, the PPA includes all environmental attributes of the power. The contract deliveries sharply decline in 2036 before the agreement fully expires in 2039. No capacity is included in this purchase.

NextEra Seabrook PPA. We purchase output from the Seabrook nuclear facility under two long-term PPAs. The first PPA provides 55 MW of plant-contingent energy, capacity, and generation attributes; at an illustrative 90% annual capacity factor, this would represent about 450,000 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 55 MW, declining to 50 MW. The total purchase of capacity declines over time from 235 MW to 230 MW and ultimately to 225 MW.

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.

Deerfield Wind PPA. We purchase 100% of the output from a 30-MW wind plant located in the towns of Searsburg and Readsboro VT, under a 25-year contract that also includes an option to purchase the plant for a fixed price after 10 years of operation. The plant reached commercial operation and began delivering plant-contingent energy, capacity, and RECs in December 2017. Over the past three years the facility has averaged just under 99,000 MWh of annual output.

Vermont Renewable PPAs. To help facilitate development of local small renewable projects and support the continued production from existing renewable facilities, we have entered plant-contingent PPAs for the output from several resources. About 22 MW of these are solar projects in Vermont, and 36 MW are from four hydroelectric plants (the largest of which is the Sheldon Springs plant at over 25 MW).

Standard Offer PPAs. As a result of the Vermont Energy Act of 2012 (Act 170) and preceding SPEED legislation, GMP receives a share of the long-term contracts signed under the Vermont Standard Offer Program. The program is designed to achieve approximately 127 MW of in-state, new renewable contracts over a 10-year procurement period. As we near the end of the procurement period the program has already contracted for approximately 115MW from mostly solar resources and is on track to reach the full procurement amount in the next 12 to 24 months. Under the program, GMP receives a load ratio share (presently about 85%) of the production from these resources which are each 2.2 MW or smaller and committed at fixed, levelized prices for a term of 20 or 25 years. Collectively these resources provide us with approximately 130,000 MWh today and are expected to provide around 170,000 MWh annually at program completion.

Short-Term PPAs

A portion of our energy requirements each year comes from fixed-price energy purchases from the New England wholesale energy market with durations of less than five years. These purchases are made to reduce exposure to spot market energy purchases and add stability to our near-term power supply expenses and reduce near-term fluctuation in retail rates. Generally, this short-term category of resources in GMP's supply portfolio fills for periods not covered by the longer-term committed resources in our energy portfolio and addresses periods of imbalance between the output of the long-term resources and customer usage patterns. This type of short-term contracting is also used for reliability and to support our long-term committed supplies and our load-based obligations occurring in the regional capacity market.

Currently we have short-term energy purchase contracts in the next few years that total approximately 750,000 MWh for FY2022 and FY2023 and decline to just under 400,000 by FY2024 and 2025. For capacity, we have two short-term contracts that sequentially extend out to FY2027 and provide fixed blocks of monthly capacity between 50 and 75 MW as a hedge to the annual ISO Forward Capacity Auctions (FCAs).

Table 6-12 shows total purchases by counterparty including volumes and total costs; the prices of the two agreements range between $45 and $48 per MWh over their remaining terms.

Counterparty	Contract Period	Resource Type	Description	MWh	Cost
BP	2022-2024	System Energy with Residual Attributes	Seasonally shaped, 7x24 energy block	364,000MWh per year	$45-$48 per MWh
NextEra	2022-2025	Nuclear Energy and Attributes	Seasonally shaped 7x24	386,800 MWh per year	$46-48 per Mwh
Dynegy	6/1/2020-5/31/2023	Capacity only	Monthly fixed capacity	75MW per month	$5.50 per kW-month
Dynegy	6/1/2024-5/31/2027	Capacity only	Monthly fixed capacity	50MW per month	$2.92 per kW-month
				750,000 MWh	

Table 6-12. Short-Term Purchased Energy Summary by Counterparty

Short-Term REC and Renewable Attribute Purchases

Vermont's Renewable Energy Standard (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 Renewable Energy Credits (RECs) in the NEPOOL GIS; every REC represents an actual MWh of renewable energy delivered into and used in the New England region. The RECs can be obtained from utility-owned generating plants, energy PPAs that include RECs, and REC-only purchases. Utilities also submit annual compliance filings to the PUC that show how the annual RES requirements have been achieved.

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 short-term REC purchases of less than five-year terms. For example, the REC transaction with Hydro-Quebec tied to our Phase 2 transmission rights, described above, helps us to meet the larger Tier I requirements and represents energy delivered into the New England region as registered and tracked in the NEPOOL GIS. We also purchase smaller volumes of RECs from other New England generators. Supplementing our REC volumes in this way allows us to meet and exceed Vermont's RES goals while maintaining premium REC revenue streams from owned or contracted sources to offset customer costs. As GMP works to maintain a 100% carbon-free energy mix and ramp toward 100% renewable in 2030, these plans will continue to evolve. This will depend, in part, on whether Vermont policy changes to qualify resources under Vermont's RES at a higher value, more similarly to their treatment in other states, and the performance of that market. We expect to plan to retire more RECs from our own resources in future years and utilize smaller, targeted REC transactions to balance our overall portfolio.

As we look to better align customer energy use with our renewable commitments, we will consider retiring a greater percentage of locally produced RECs that are currently sold into premium out-of-state markets. Doing so will help match our renewability to our customer's energy usage profile. Future iterations of Vermont's RES could impact resource availability, support this transition, and determine the cost-effectiveness and timing of such a decision.

Looking Ahead – Short-Term Supply Contracting

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 also 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.

Energy

Energy typically represents the 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[4] (not unit contingent) from creditworthy sellers and settle them at the ISO-NE internal hub to maximize liquidity and attract the widest seller interest. Unless the contracts also include emissions attributes associated with specified generation 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 "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 monthly. 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).

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 in either the Rest of Pool or Northern New England Zone. Because ISO-NE 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.

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

RECs

Purchasing blocks of fixed-volume, fixed-cost RECs and VT RES-qualified attributes can provide strategic flexibility to meet VT-RES obligations and our own carbon and renewable goals. Such purchases would be done in terms of calendar vintage years and delivered through the NEPOOL GIS.

VT Tier 1-eligible hydro RECs from New England or regional sources have been a cost-effective hedging strategy to meet our goals with flexibility in mind. Purchase of such RECs at times allow us to strengthen our renewable supply while selling premium RECs (beyond our RES obligations) into strong markets, offsetting customer costs. As REC markets continue to change with evolving RES requirements in other New England states, the cost difference between VT Tier 1 and Premium RECs (MAI and CTI) may be diminished such that this strategy no longer achieves the desired outcome.

At this time, it continues to make sense to proactively sell a portion of our Premium (MAI and CTI) RECs into strong markets in the short term to offset customer costs and we are currently hedging portions of our forecasted volumes with sales into 2025. We can balance the sale of local generation attributes with purchases of energy combined with RECs from other New England and regional renewable sources that while being more cost effective, can also complement current retirements to meet seasonal or daily load shapes. Significant volatility of REC markets is anticipated beyond 2025 and will continue to shape our premium REC sales and retirement strategies through this IRP period and by extension, REC purchase plans as well.

We may also purchase other classes of RECs with specific characteristics in mind such as shape, location, or resource type, that help us smooth transitional gaps between existing contracts or seasonal production of our owned resources.

Transaction Timing and Evaluation

Within the hedging program our 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 generally make energy and capacity purchases more programmatically for contracts with terms less than three to five years ahead of the delivery period.

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.

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 several 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.

Short-Term Procurement Methods

One of the most significant considerations influencing our choice of a procurement method in any 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, this is 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.

Looking Ahead – Potential New Long-Term Supply Resources

Reaching GMP's goal of 100% renewable supply in 2030 will require additional energy and REC supply from new in-state and regional sources. 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-NE wholesale power market, which can have an important role in enabling us to manage the expected cost and potential volatility in net power costs.

We plan on a significant and growing role for flexible energy storage in our portfolio, which stacks several forms of value for customer and reduce expected costs and potential market volatility. Our power supply strategy and the Vermont RES focus primarily on increasing renewable supply and limiting greenhouse gas emissions in a cost-effective way, and as part of that we are ramping down some local oil-fired peaking capacity (which operates infrequently) as noted above. The ones that remain can help meet our share of regional capacity requirements. We have started to retire our traditional oil-fired peaking generation, with at least two fuel resource retirements to be completed during this IRP period. Our current battery storage projects and continued deployment of storage is critical. A transformed and cleaner grid needs a combination of energy storage, flexible demand and bilateral contracts that will help us remove carbon from our energy supply while reducing it in our peaking capacity supply as well.

Renewable Generation

Our portfolio includes a variety of renewable resources including wind, solar, biomass, biodigesters, landfill gas, and both small and large hydroelectric resources. As GMP works to meet its 100% renewable goal our focus will be on adding a sufficient scale of new renewables that will help to fill future open positions and meet anticipated electrification growth, while also ensuring that the output shape of the procured resources cost-effectively matches our customer loads. We will explore several alternatives and potential mixes of alternatives in the Portfolio Evaluation chapter but anticipate the most likely future resources will include solar distributed generation, onshore and offshore wind, utility scale solar, and hydroelectric generation. Below, we discuss a few of these resources that we do not presently use in our portfolio but may seek in future years.

Wind Power

Several state procurement efforts have led to awards for significant offshore wind generation facilities. Over the next decade we anticipate that offshore wind on the scale of 5,000 MW will reach commercial operation. Two large projects, Vineyard Wind and Revolution Wind, are expected to come online by 2025 with a total of 1,500 MW of nameplate capacity. Over the next several years we anticipate that there will be additional procurements efforts that GMP could participate in that could lead to acquiring entitlements for portions of larger projects that will come online late this decade or early next decade.

Offshore wind is an attractive potential resource as it has strong winter and off-peak-hour output profiles that can be complimentary to solar generation. Beyond the winter and off-peak profiles, it is important to remember that there can be significant changes in output between hours and days. Based on our understanding of offshore wind we would anticipate an annual capacity factor in the range of 45%.

Onshore wind is another option that we anticipate exploring within the region. We are uncertain whether new wind facilities will be constructed in Vermont over the next decade but believe that there are opportunities to procure a share of wind projects in other New England states. While onshore wind does not typically provide the same strong winter output shape seen in offshore wind projects, it does tend to have less output during the summer months when solar PV tends to have strong potential output. This is another intermittent resource, which means that there can be meaningful variations in seasonal, monthly, daily, and hourly output. As we look forward, our entitlement to Granite Reliable Wind will decrease in 2028 and then end in 2032, which would make additional onshore wind a natural consideration.

There are several considerations as we explore additional volumes of wind in the context of managing our portfolio needs. Offshore wind is relatively new to the generation mix in New England and has seen high initial prices. This reflected significant complexity in acquiring offshore leases; a challenging permitting process; and the difficulties associated with installing turbines in the ocean. We have seen successive procurements result in lower pricing and assume that the prices will continue to decline over time. Right now, these resources qualify only for GMP's RES Tier 1 obligations due to size and anticipated locations outside of Vermont. In our Portfolio Evaluation Chapter, we will explore the potential for RES to add a new tier or sub-tier that would require the retirement of RECs from large, new renewables such as regional offshore or onshore wind to support the addition of carbon-free renewable resources in New England.

At the same time the construction of offshore and onshore generation that is located far from load will require either upgrades to the existing transmission system or, in the case of potentially unserved locations, building new transmission systems. These costs will be faced regionally as offshore wind is developed and must be considered in pricing such resources in our portfolio.

Solar Power

Additional solar generation is a strong possibility for our portfolio needs but has potential challenges as we look at metrics such as matching generation to loads on a daily and hourly basis. As of September 30, 2021, there is almost 350 MW of solar generation installed in our territory, with about 67% of the total coming from net metered solar. This installed base of solar generation means that GMP typically has large amounts of solar generation on its system during the daylight hours, while our need for energy to meet customer loads tends to be highest during the nighttime hours and winter months when solar PV has lower or no output. As we will discuss in the Portfolio Evaluation chapter, GMP is frequently a net seller of excess energy to ISO-NE during the peak solar hours, which reflects a mismatch between load and resources.

Presently, any output from new utility-scale solar generation of up to 5 MW that is interconnected in Vermont would be available for retirement toward GMP's RES Tier II obligations. Output from larger-scale solar could be used to meet potential future obligations under a new tier or sub-tier of the RES aimed at larger scale new renewables within or outside of Vermont to enhance renewable additionality in New England in furtherance of fossil fuel generation retirements.

We feel that utility scale solar, ranging from five MW and higher, will provide meaningful economies of scale that should ensure that prices remain attractive as we look at our net power costs. The 2021 Standard Offer RFP yielded prices on the order of 8.5 cents/kWh for 2.2 MW projects. We anticipate that larger future projects could yield lower prices as panel efficiency improves and bifacial panels become more prevalent.

Hydroelectricity

Hydroelectric resources represent the largest renewable resource in our portfolio and are projected to meet about one-third of our total energy requirements over the next 20 years. The new Great River Hydro PPA constitutes about 10% of portfolio when it reaches its full delivery volumes in 2033. Our PPA with Hydro-Quebec for 7x16 power will begin to ramp down in 2034 and end in late 2038. This provides an opportunity in the mid to late 2030s to explore other potential hydro resources in the context to filling an open position in our portfolio and for locking in long-term existing renewable generation that will help meet our RES Tier 1 obligations that should help provide future price stability. As with other potential resources we need to consider portfolio fit, and the challenges of integrating additional hydro shaped output that peaks during the spring runoff and would add to our generally surplus position in the months of April and May.

As we look at potential hydro resources that could provide the balanced shape and scale for our portfolio there are relatively few options in New England. These would include taking additional output from Great River Hydro, although it might be closer to a run of river shape based on the large fixed and shaped volumes GMP has contracted for through 2052; it could include resources on the Androscoggin and Kennebec Rivers in Maine that could offer some diversity of output shape; or we could explore the option of an import from New York or Canada. One of the options that we discuss in our Portfolio Evaluation Chapter is the addition of a shaped hydro product (or potentially a different shaped renewable technology paired with storage, in the future) that would help fill overnight and winter open positions. This is not currently a readily available product in New England but would provide significant value to GMP and help enable and fit with other intermittent resources as they grow in our portfolio. We will explore options for how best to sources our hydro need over but do not anticipate making any acquisitions until next decade as we get closer to the open position developing in our portfolio.

Storage

As you will read throughout this IRP, energy storage continues to be an important and rapidly emerging resource in utility markets, driven by significant technological improvements and a declining installation cost curve.[5] The flexibility of these resources to act as load or generation, provide power quality and increase system resiliency underpins much of this growing interest. In New England, where significant growth in wind and solar resources is driving a need for fast-acting, flexible resources to balance these intermittent supplies, storage applications are likely to see heightened interest. We expect that over the IRP planning horizon we will add meaningful quantities of storage resources to the power supply portfolio to address our need for capacity (peaking) resources, and to provide energy balancing to a portfolio more heavily weighted toward renewable supplies.

Balancing to better match our resources to load will be important for GMP to keep costs affordable for customers. While we have preliminary analysis of how storage may fit our portfolio in the longer term, we anticipate that future IRPs will explore opportunities to integrate large-scale storage with intermittent generation to help manage and smooth intermittent generation profiles.

Storage for Peaking Capacity

The most common type of battery storage being developed for use on the electric grid is lithium-ion batteries. This type of battery features a high level of stored energy relative to its size, offers roundtrip efficiency of between 80-90% and has the capability to respond quickly to charge/discharge instructions. The sizing of these batteries is also very flexible in both rated capacity and the available energy duration at rating. For utility applications, modular designs with battery containers each around 1MW and providing a minimum of two hours of energy duration has allowed projects to be scaled from 1 MW up to 100 MW in some recent installations.[6]

Because of these characteristics, GMP expects battery storage will replace fossil-fuel peaking generators in most short-duration reliability applications over the IRP planning horizon. The most notable application for short-duration energy storage in New England is to provide peaking capacity. In this peaking role, batteries can either directly participate in the ISO-NE Capacity Market to receive monthly payments based on established capacity ratings, or act as load reducers to reduce peak demand on the system. To be effective in this application we estimate that currently a unit should be able to run for at least four hours. In future periods, this energy duration may increase beyond 4 hours, leading to an increase in the size and cost of these peaking resources. However, unlike fossil fuel resources where retrofitting is inherently complicated and site disruptive, the modular design of battery systems can allow this additional energy duration to be added quickly with little impact on the site.

5 Current and future plans are consistent with the 2018 Memorandum of Understanding with the DPS regarding storage projects greater than 1MW.

6 For example, AES Corp.'s 100-MW/400-MWh Alamitos energy storage project in Long Beach, California, started commercial operations 1/1/2021. Source: AES Corp.

For GMP's application of this peaking-type battery, a variety of project sizes and designs will be evaluated, driven by site-specific configurations. In addition to peaking, batteries are providing multiple benefits to customers and into the ISO-NE markets, which in turn provide additional value to customers. At one end of this design spectrum would be batteries built to replace existing GMP fossil-fuel units that have reached the end of their service life. Vergennes diesel generators along with Rutland and Ascutney gas-turbine units are examples of resource locations where grid-facing peaking storage could be leveraged at scale to perform a similarly limited role. On the other end of the spectrum would be the customer-sited, behind-the-meter storage application where, in addition to peak-demand reduction and cost savings, the battery could be providing important local resilience and power-quality services. In fact, as we mention in this IRP, we are currently retiring our Vergennes Diesel generators, in part, thanks to the significant battery storage resource that has been deployed to backfill.

Storage for Energy Balancing

An emerging dynamic in our portfolio is that the growing volumes of intermittent solar, wind, and hydroelectric generation have increased the magnitude by which our energy supply fluctuates on an hourly or daily basis. The addition of battery storage is very complementary to an increasingly renewable supply, in part because of the ability of storage applications to ramp up charging or discharging quickly. In an energy-balancing role, storage shifts renewable output from hours of excess to hours of greater need and value for our customers, and show how important storage is as we continue growing renewable power. One short-duration example of this application is where excess solar output in the middle of a sunny day would be stored in the battery for discharge during high-demand periods in the evening hours later that day. In another balancing role, ISO-NE has described a growing need for resources to respond quickly and at any time of the day when New England load levels are changing rapidly or unpredictably. Today this balancing role is largely performed by natural gas plants, contributing to the region's overall carbon emissions profile. However, as product and market definitions at ISO-NE evolve to include emissions impacts, storage resources can take over this service.

Over the planning horizon, there could also be applications where long-duration storage technologies emerge beyond today's lithium-ion configurations. Commercialization of different storage chemistries at scale is presently underway, and the role of longer-duration, lower-output storage in our portfolio in the future is intriguing.

Storage for Local Grid Support

We discuss this function more thoroughly in Chapter 3 of this IRP, but highlight local grid support briefly here as another important value of local storage. While the power market considerations for battery storage can cover the costs of some battery storage systems described above, the development of smaller, distribution-connected battery systems will also be important as they can deliver 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 we can deploy a battery-storage solution with a lower total net cost than rebuilding a substation or reinforcing lines, there is a significant benefit for customers.

- 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, which is happening now, where a local circuit or portion can be supported by a battery and other local generation during an outage of the broader grid.
- Increasing the renewable generation 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.

Looking Ahead – New Partnerships and Customer Programs

With future modifications and improvements to VT RES, load growth associated with electrification, and GMP's planning for 100%, there will continue to be a strong desire and need to procure more renewables, including local renewables. GMP plans to pursue opportunities to include local grid-tied renewable projects with an eye towards cost-effectiveness and ease of administration. This effort is made particularly important as Standard Offer procurement will see its final round in 2022 and we continue to look for attractive commercial alternatives to large-scale net metering. New and creative procurement designs outside of these now-traditional programs would allow the benefits of DG to be accessible to a broader set of customers in a more inclusive way.

Planning for a 100% Renewable Future

Reaching and maintaining a 100% renewable supply by 2030 will require a combination of new procurements of the supply products described above. New solar serving local loads, regional hydro and wind, grid-tied battery storage, residential and commercial scale solar/battery, and shaped regional energy and/or REC purchases all have a role to play. Growing our portfolio with flexibility and balance in mind is necessary to meet our customers' energy load needs and supports the availability of RECs in both value and volume so that we can make the most effective renewable choices for customers.

New renewables in Vermont and the region will help us meet carbon reduction goals and continue to build the grid resiliency that comes with local distributed generation. By following Vermont Climate Council's Guiding Principles for a Just Transition[7], these outcomes can be achieved while bringing additional benefits to the communities we serve, including creating and sustaining local jobs, building trust in our working relationships through equitable engagement, and strengthening our natural environment.

With the conclusion of the Vermont Standard Offer program in 2022, net metering will be the only active statewide distributed renewable resource procurement program. GMP anticipates the need for meaningful quantities of new renewables over the IRP planning period driven by changes to the VT RES program and by growth from beneficial electrification. As a result, we are currently planning and evaluating a procurement approach to cost-effectively increase local and grid-based renewable resources in GMP's portfolio. For this

[7] Guiding Principles for a Just Transition –page 2, VCAP Summary https://climatechange.vermont.gov/sites/climatecouncilsandbox/files/2021-12/VT%20CAP%20Summary_Final.pdf

activity supporting GMP's path to a 100% renewable portfolio we expect to utilize several tools and approaches including RFPs, direct solicitation, and beneficial partnerships with customers and developers.

GMP's renewable goals are more aggressive though still consistent with Vermont RES, and GMP supports moving towards a Vermont 100% RES that will be key to decarbonizing other sectors as well. With transportation and heating being the top two sources of carbon pollution in Vermont, meaningful reductions on carbon emissions in our state will rely in part on successful electrification of transportation and heating, with a 100% carbon-free and renewable electric power supply. The preferred portfolio described in the next chapter is based upon GMP's thinking regarding how its future 100% renewable portfolio, supported by changes in Vermont's RES, could be cost-effective for customers.

7. Portfolio Evaluation

The portfolio evaluation for our 2018 IRP focused on how GMP would plan for meeting Vermont's recently implemented Renewable Energy Standard (RES). The context of the 2018 IRP differed from previous IRPs, reflecting the addition of significant long-term PPAs and rapid growth of small-scale, distributed renewable generation in Vermont; these developments reduced our forecasted open positions and yielded a more diverse and renewable portfolio. Based in part on the themes discussed in that IRP including the imperatives of climate change, GMP made a commitment to become carbon free by 2025 and 100% renewable by 2030. GMP has already exceeded the first part of those goals, and is now 100% carbon free annually, and currently 68% renewable.

Moving forward, working within the framework of Vermont's RES and GMP's commitment to continuing to provide customers with an annual carbon-free portfolio, 100% renewable by 2030, our goal is to meet these objectives cost-effectively and equitably for our customers. This portfolio evaluation explores ways to achieve our 100% renewable goal by 2030 and beyond, and discusses factors for our future decisions regarding how GMP will meet its renewable energy and transformation commitments to best serve customers. During the planning horizon GMP expects to meet its growing needs for renewable energy primarily through increasing volumes of new renewable sources from within Vermont and New England. Leading new renewable generation options include solar with primarily instate small scale projects, but also some larger projects in Vermont or New England, and wind likely as part of regional offshore projects and/or land-based projects. GMP's renewable procurement choices will depend in part on the relative pricing and effective cost of the renewable supply options – which in turn will be based on trends in the price and performance of renewable technologies, the nature and cost of potential grid upgrades that are required to integrate these sources, future federal tax policy and other factors.

GMP's portfolio design and future resource choices will also be supported by a new framework of measuring our portfolio not only on the basis of cost, carbon and renewable attributes, but also on how the various alternative new sources fit with our customer needs on an annual, monthly, daily, and hourly basis. This perspective and supporting analysis will improve the likelihood that a high fraction of our renewable electricity supply both matches our customers' electricity consumption on an annual basis and also delivers during the seasons and hours when our customers are using electricity to power their homes, vehicles, and heating and cooling. Attention to the alignment of renewable supply with electricity demand will help cut carbon emissions and save money for our customers by guiding the procurement of renewable energy toward periods when our customers need it the most, and limiting the volume of energy that needs to be resold in the ISO-NE market during times when renewable generation is high and exceeds customers' electricity consumption.

GMP is focused on delivering low-cost, low-carbon, incredibly reliable energy to our customers. We have integrated the RES framework, with its three tiers relating to new distributed renewable supply; total renewable supply; and energy transformation and decarbonization into our benchmarks as we move towards a portfolio that is 100% renewable. As part of our commitment to balancing portfolio cost and reliability, GMP continues to seek portfolio diversity and to ensure flexibility while providing stability in net power costs and rates over time for customers.

This chapter begins with a summary of the tools used to explore future portfolio options and a discussion of how these options fit into both the RES framework and GMP's own carbon and renewable goals. These building blocks provide the basis for the portfolio evaluations and conclusions that follow. The portfolio evaluation starts with assessment of a Reference Portfolio containing only committed resources and forecasted growth in net metering and Standard Offer renewable generation. We then discuss sensitivity outcomes that could affect GMP's future power requirements and costs and introduce potential resources that could be added to the portfolio. We then turn to a detailed screening analysis of the year 2036, when many of our existing supply commitments have expired, to test how a range of potential renewable resources would perform in the portfolio with respect to several metrics – particularly alignment of our renewable supply with our customers' seasonal and hourly electricity consumption, and relative cost stability under alternative future New England electricity market conditions.

We use observations from these steps to construct an Illustrative Future Portfolio that features large, appropriately balanced volumes of new solar and wind supplies, along with some regionally available hydro, to achieve and maintain an energy supply that is fully renewable on an annual basis. The Illustrative Future Portfolio also discusses potential modifications to Vermont's renewable policies and requirements that would – if implemented as a package – support portfolio and policy goals including increased reliance on new renewable sources; development of a greater volume of instate renewables than presently supported by the RES; affordability; alignment of renewable supply with electricity consumption; and stability of electricity prices. The chapter finishes with a sensitivity analysis of the Illustrative Future Portfolio, and an explanation of the assumptions supporting the portfolio analyses.

Tools and Methods

In recognition that Vermont's electric industry is evolving in important ways – including an energy supply that is becoming increasingly intermittent through the rapid increase in renewable energy resources, along with forecasted growth in electricity demand driven by electrification to address climate change – GMP determined that evaluation of our supply portfolio should evolve over time from a monthly model tool that focused on monthly on- and off-peak periods to include a more granular approach that provides a credible level of hourly detail. To this end we have partnered with Daymark Energy Advisors[1] (Daymark) to develop a representation of GMP's portfolio in PLEXOS – which is a market-simulation tool developed by Energy Exemplar. This effort also entails an accompanying spreadsheet tool to help represent GMP's full portfolio (including resources and loads that are not represented directly in the Daymark tool). This collaboration has allowed GMP to develop an hourly view of its portfolio within the context of the ISO-NE market.

While GMP will continue to use its monthly on- and off-peak model for general forecasting purposes, the modeling assisted by Daymark provides important insights into how resource procurement decisions will affect our ability to serve load while also ensuring a highly renewable power supply and managing net power costs. To that end each of GMP's resources or group of resources (e.g., solar generation broken into net metering, Standard Offer projects, and PPAs with project developers) is modeled on an hourly basis using the PPA shape for resources that are baseload or firm, and the specific, semi-normalized output profiles for intermittent resources including solar, wind, and hydro. Rather than relying on fully normalized generation output profiles that would rely strictly on long-term historical averages, GMP and Daymark have developed profiles that look at several years of actual production history but have attempted to reflect the spread of high- and low-output hours by incorporating particularly high- and low-output hours into the profiles.

The cases that were modeled, summarized below, represent one possible set of potential future outcomes; they are intended to help provide context for the interplay of the timing of customer demand and the resources in our portfolio. This perspective is particularly important as we move to an increasingly renewable and intermittent set of resources that do not match the shapes of the customer loads they are intended to supply. The model uses Daymark's current market outlook and dispatch of resources in the ISO-NE control area and tie points with other regions to simulate the region's hourly interchange. GMP represents approximately 3% of ISO-NE's annual loads, and many of its largest resources, including PPAs with NextEra Seabrook and Hydro-Quebec (HQUS), are specifically modeled as regional resources. GMP has worked with Daymark to ensure that its owned and purchased resources are reasonably reflected in the GMP-specific model.

[1] GMP chose to work with Daymark due to its long history of consulting for clients in ISO-NE, NYISO, PJM and other markets. The firm is strongly grounded in the fundamentals of the ISO-NE marketplace and brings an understanding of the region's energy infrastructure and regulations. Their recent projects have included analysis and expert testimony across the in such inititatives as the PSNH fleet valuation for the New Hampshire Public Utility Commission; the Massachusetts 83D solicitation that resulted in the New England Clean Energy Connect PPA; the Massachusetts 83C RFP for Offshore Wind; and the Maine Renewable RFPs in 2020 and 2021.

These GMP supply resources, when matched with forecasts of GMP's hourly load profile, provided a starting point for analyzing potential future needs to serve forecasted load growth and replace expiring resources over time. The base case load forecast used Itron's initial load forecast with adjustments to significantly increase the pacing and volume of electrification, and allocated hourly load volumes based on historical load profiles with adjustments to reflect anticipated gains in energy efficiency and levels of load growth driven by electrification measures that will help Vermont rapidly decarbonize as it seeks to slow climate change. Electrification measures include the important rapid growth in electric vehicles and cold climate heat pumps, along with other Vermont RES Tier III initiatives and have been modeled to increase loads based on studies of charging profiles for EVs and load associated with heat pumps. These methods and assumptions are explained further in Chapter 2.

The framework allows GMP to estimate key factors such as the degree to which a portfolio being considered fully serves customer demand across the year; what percentage of the portfolio is carbon free; what percentage of the portfolio is renewable; the net power cost associated with the selected resources; the hourly match between load and resources; and hourly, monthly, and annual long and short positions. It also enables GMP to consider how we can best meet our annual 100% renewable goal and potential changes to the Vermont RES requirements that may support the need to strongly address climate change by providing a fully renewable and carbon-free portfolio to Vermonters as they electrify transportation and heating, which are the main sources of carbon pollution.

The cases presented will start with a reference case that considers GMP's anticipated load growth; committed resources; and anticipated growth of renewables under such current programs as net metering and Standard Offer. Other cases that are presented build off this reference case and reflect open portfolio positions that begin to emerge in the middle of the decade. The Illustrative Future Portfolio reflects not only the choices that, at this time, appear to be best for GMP customers but also potential changes to Vermont's RES and procurement policies to support more local new renewables, more cost-effectively for more customers. Each case presented in this section of the IRP is based on calendar years to align with how RES compliance is measured. Financial information contained in this chapter is presented on a calendar year to match the period used for reporting under RES.

Carbon-Free and Renewable Energy Foundation

In anticipation of the need for Vermont and the country to rapidly decarbonize to address climate change, GMP set a goal to maintain an annual carbon-free portfolio by 2025 and a 100% renewable portfolio by 2030. GMP achieved its 100% carbon-free goal for the first time in 2020, as shown by the retirement of RECs and attributes under the structure of Vermont's RES.[2] While these goals exceed the current statutory framework, they are important because there is increasing urgency to fight the impending climate disaster happening around the country and world. We have also watched the increasingly strong carbon and GHG targets being set in neighboring states and the passage of the Global Warming Solutions Act (GWSA) in Vermont, and expect that Vermont's own electric supply portfolio requirements are likely to change within the next several years, consistent with recommendations set forth in the initial Climate Action Plan under the GWSA.

As currently established under 30 V.S.A. § 8002-8005, Vermont's RES sets forth mandatory requirements for Vermont's distribution utilities to obtain portions of their power needs from two broad classes of renewable sources: Tier I broadly defined to include both new and existing renewables, and Tier II for new small distributed generation under 5 MW. Compliance is demonstrated by the retirement of renewable attributes in the form of regionally registered Renewable Energy Certificates (RECs) through the NEPOOL GIS that are based on actual delivered renewable energy into the region. The program also requires Vermont's distribution utilities to engage

2 See Case No. 21-1045-INV, Order Approving 2020 Vermont Renewable Energy Standard Compliance Filing (Nov. 23, 2021).

in energy transformation projects under Tier III that lower costs and fossil fuel consumption for customers.

Portfolio Objectives and Performance Metrics

Our analysis is based on five resource planning objectives: low cost, low carbon, renewable energy, reliability, and flexibility.

Low Carbon reflects the estimated average emission rate of CO_2 (in pounds per MWh) for our power supply portfolio and also as a percentage of our portfolio resources in terms of MWh that are derived from emitting sources, based upon current GHG inventories as reported in Vermont by the Department of Environmental Conservation. In 2020 GMP achieved an average emission rate of zero pounds of CO_2 per MWh through the retirement of RECs from non-emitting resources and carbon-free attributes from nuclear resources. This compares to New England's average emission rate for the same period, which was 765 pounds of CO_2 per MWh of energy generated, as reported by NEPOOL's Generation Information System ("GIS"). We anticipate that the New England average emission rates will decline over time with the addition of significant new renewable generation that will reach commercial operation over the next decade, reflecting state efforts to decarbonize with a focus on slowing climate change.

Renewable Energy content is estimated on an annual basis in terms of retired RECs that are eligible under Tier I – total renewables – and Tier II – distributed renewables – as fractions of retail sales and total system load. Like renewable requirements in other states, Vermont's RES measures renewable energy content by comparing renewable generation and energy consumption on an annual basis.

Portfolio Fit refers to the alignment of generation in GMP's supply portfolio with the electricity consumption of its customers. The portfolio fit objective will support our consideration of renewable energy volumes at a more granular level of resolution, down to an hourly level, over time. While a complete hourly renewable portfolio fit (assuring a fully renewable energy supply across every hour of the year, irrespective of weather conditions) would be neither achievable nor cost-effective, this early stage of testing and analysis provides us with a meaningful opportunity to evaluate how GMP is meeting its renewable goals and obligations, and look at strategies to enhance renewable portfolio content as we serve customer load. The primary metric for portfolio fit is the percentage of output from GMP's supply portfolio or potential new resources that is used to serve hourly customer load across a period versus the percentage that exceeds GMP's hourly load needs and is sold in the ISO-NE marketplace. This measure is expected to be increasingly important as GMP becomes more reliant on renewable technologies that have characteristic seasonal output shapes such as high hydro flows in April; significant solar output during spring and summer midday hours; and strong winter output associated with offshore wind, along with fluctuations in output based on the availability of sun, wind, and water. Some differences between GMP's supply sources and load needs are inevitable, but large and sustained differences that require selling excess energy at some times and purchase large volumes of needed energy at other times create risk for our customers through exposure to uncertain prices as GMP attempts to balance its portfolio in the Day-Ahead and Real-Time energy markets. Understanding the implications of portfolio fit also can also help us evaluate the most cost-effective, meaningful use of generation curtailment and new storage resources over time.

Low Cost is a core objective, especially so that electricity remains competitive for customers to decarbonize transportation and heating, the top sources of carbon pollution in Vermont. 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 in the portfolio choices, and maintain stability with an overall average rate of increase lower than the rate of general inflation. We also seek to remain competitive relative to average market rates for power and transmission that other utilities and retail electricity suppliers in New England would face.

Reliability. 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.[3]

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 more stable the resulting portfolio costs tend to be. Long-term commitments are typically needed to support the development of new renewable electricity in Vermont and New England. It is not clear what volume of renewable energy supply will be available on a short-term basis in the future, especially with increasing competition for existing renewable resources in the region. The tradeoff for using a greater volume of long-term commitments is that the portfolio can become less flexible and would therefore not respond as much or as quickly to changes in the wholesale markets.

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 such as PPAs expire in different years and different amounts expire at different times. The largest discrete sources in our committed portfolio, PPAs with HQUS and NextEra Seabrook, while meaningful, are much smaller than similar long-term hydroelectric and nuclear commitments we held in the past. Both long-term purchases are set to expire in the mid- to late-2030s; there is ample time to manage these transitions through acquisitions of new PPAs from multiple sources.

Table 7-1 summarizes the six resource planning objectives and their performance metrics.

Objective	Attribute	Metric
Low Carbon	Metric 1	Non-emitting supply compared to load requirements (annual)
	Target	Maintain a 100% carbon free supply
Renewable Energy	Metric 1	Renewable energy supply compared to load requirements (annual)
	Target 1	Achieve 100% Renewable by 2030
	Target 2	Achieve annual RES Tier I, II and III requirements
	Target 3	Achieve each RES requirement in a cost-effective way, at average costs substantially lower than ACP
Portfolio Fit	Metric 1	Percentage of hourly renewable and carbon free energy used to serve load
	Target 1	Greater than 60%
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 a regional benchmark
Reliability	Metric 1	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 if 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 7-1 Resource Planning Objectives and their Performance Metrics

These objectives are frequently complementary and interrelated, which means they should ideally be kept in balance with each other. Overreliance on any of the objectives may create tradeoffs with undesirable implications for the portfolio, and may have negative consequences for our customers

3 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 HQUS long-term PPA is treated as partially hedged because a portion of its PPA pricing is determined based on an electricity market price index.

over the long planning horizon covered in this IRP. 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 follows the same approach as previous IRPs and 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 potential market conditions.

Budget Estimation

The resource planning process begins with GMP's portfolio of committed resources, and reasonably anticipated resource changes as reflected in GMP's current five-year financial forecast. These changes include the scheduled ramp down and expiration of existing PPAs, the inclusion of committed new PPAs, and the addition of reasonably anticipated new resources supported by Vermont's renewable policies and programs, including net metering and the Standard Offer program. The resulting resources are projected past the five-year horizon using approximations of their price and their volume on an hourly basis and then balanced against our estimated load requirements (see Chapter 2).

Reference Portfolio

The starting point for the evaluation framework is the Reference Portfolio that illustrates the anticipated portfolio loads and resources that 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 portfolio differences between energy requirements and committed resources are assumed to be settled – either purchased or sold – on a short-term basis at our current base case forecast of future wholesale energy market prices. Similarly, projected capacity requirements greater than GMP's committed sources are assumed to be met using short-term layered forward purchases or purchases from ISO-NE directly, at prices consistent with our current Base case FCM price forecast.
- Net metering in our territory under current policies is assumed to grow at a pace of over 20 MW/year through 2029 before dropping to about 17 MW in 2030 and then approximately 12 MW/year through the end of the study period. This pace is a reasonable reference point based on current policies. Moreover, this pace of new distributed solar, whether from net metering or a mix of net metering and other sources, would be more than sufficient to meet the annual growth needed for current Tier II requirements over the current decade under current load forecasts. As discussed in Chapter 6, GMP and other Vermont utilities (as well as the PUC and the Department) have recognized that the faster pace of net metering growth under current policies in recent years has put upward pressure on power costs and electricity rates for customers, and that lower-cost distributed renewables are available. With this context, the base-case assumption related to net metering could change as policy changes, and to the extent this occurs, it will present an opportunity for GMP to procure more distributed renewable generation

at overall lower cost. Similarly, higher load growth will allow greater volumes of renewable energy, including distributed renewable resources, to be acquired.

- Vermont's Standard Offer program is assumed to continue until new distributed renewables amounting to 127.5 MW achieve commercial operation. In the base case, the program is not assumed to be renewed or replaced, as the RES framework itself and GMP's own 100% renewable goal will support the future development of substantial new renewables, including cost-effective local renewables at the scale of the Standard Offer projects.
- Charts evaluating our supplies of Tier I, Tier II, and Tier III resources are presented based on the structure discussed above to illustrate potential resource volumes that would need to be procured to meet our obligations under RES and GMP's carbon and renewable goals. 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.

Sensitivity Analysis

The use of a sensitivity analysis framework allows us to gain insight into how much future portfolio uncertainty is driven by specific external factors and portfolio attributes. The sources of uncertainty that were analyzed include: wholesale market prices for energy and RECs; changes to RES and the pace of future net metering in our territory; the pace of decarbonization in the regional power supply; and future electricity demand. These alternative outcomes were formed using input from external sources and our own assessment of market prices and risks and are aligned with the outcomes described in Chapter 2 regarding electricity demand.

Some of these sensitivities lead to illustrations of potentially different outcomes or decisions. For example, regional REC prices for Class 1 renewables and existing renewables could affect the volume of RECs that it is cost-effective for us to sell, versus retiring to meet RES Tier I requirements or GMP's commitment to be 100% renewable by 2030. 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 2041; these results are shown in "Portfolio Cost Sensitivity Analysis."

IRP Alignment with Our Financial Forecasting

The first five years of the resource planning model are largely consistent with GMP's latest five-year financial forecast, although our portfolio evaluation is based on calendar years and not fiscal years, as discussed above. For example, the energy, capacity, and REC market prices in the resource plan were updated to reflect our most current base case outlooks (which are explained in detail in "Wholesale Energy Market Inputs"). While the base forecast in the IRP will not precisely match our upcoming rate case multi-year financial forecasts, most of the models' key components, such as the volumes and prices for major supply sources, which drive most power costs, 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 most of our cost of service and 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, to isolate power supply cost choices. As a result, the resource plan appropriately reflects tradeoffs in power supply costs and related metrics but is not intended to be a forecast of total retail electric rates that our customers would pay under different scenarios.

The resource-planning model is based on *nominal* dollars, meaning that all costs and prices in the analysis are expressed in dollars that include the effects of general inflation in the economy over time. The analysis reflects prices and costs that are projected to occur each year of the analysis period and no additional translation or escalation is needed to incorporate the effects of inflation.

Trends and Issues Requiring Future Study

There are several topics that we have considered but not yet fully developed in this IRP. These are complex issues requiring additional analysis and research, which will benefit as our knowledge base expands through further study of the analyses used in this IRP; a review of emerging industry trends and analysis; and anticipated future technological and market design advancements. One such topic would be the sizing and duration of storage paired with generation. Chapter 3 discusses the development of storage resources and how we have fit them into our system operations to date.

Figure 7-1 below shows hourly average ISO-NE settlement net position by month for the period of April 1 through September 30, 2021. These values reflect the net of GMP's hourly resources, including owned resources and PPAs, less customer demand, which in this case includes the impact of all behind-the-meter generation. A positive value reflects periods where resources exceed demand, leading to a sale to ISO-NE market, while a negative number means that GMP was a net purchaser from the market to meet its demand. These monthly values reflect the current potential volume that could be considered as part of any storage analysis but will change over time with the addition of new resources and the expiration of existing PPAs. During this period GMP sold about 126,000 MWh of resources that exceeded its customer demand.

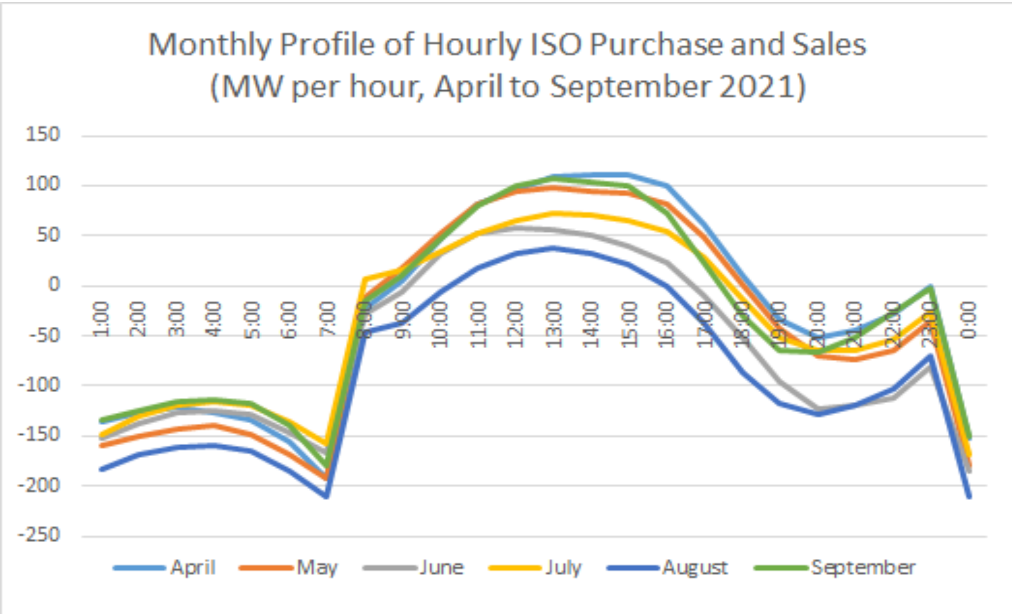

Figure 7-1. Monthly Profile of Average Hourly ISO-New England Purchase and Sales (April – September 2021

A starting point for our evaluation of battery storage was to explore the potential value of a 100 MW nameplate battery storage system with four hours of discharge, or 400 MWh. Working with Daymark we studied the potential value of charging and discharging the battery storage device to maximize the spread of hourly energy prices, charging at low market prices, and discharging at high market prices. To simplify the analysis, we assumed that the battery would cycle once per day, which is slightly above the 300 annual battery cycles anticipated by manufacturers. We also assumed that a battery of this scale, or several batteries spread throughout GMP's territory to reach this scale, would be ISO-NE registered assets and could participate in the forward capacity market and in ancillary markets such as Frequency Regulation and Operating Reserves.

Based on assumed dispatch for maximizing energy market value and the hourly energy prices developed by the PLEXOS simulation model, we derived annual energy values for the battery system that average about $1/kW-month for the next decade. The energy values reflected in our model use a forecast of Day-Ahead market prices. In practice, the battery storage system would also be dispatched following price signals in the Real-Time market and would be expected to have some incremental value *above* what has been modeled here due to greater price volatility in the Real-Time energy market not captured in our simulation.

Adding in the value of the battery storage participating in the Forward Capacity Market, the simulation shows total monthly value of under $5/kW-month through the end of this decade, reflecting relatively moderate capacity prices paired with limited growth in energy prices. This does not add revenues associated with participation in the Frequency Regulation Market, because 100 MW of nameplate capacity would exceed the total potential regulation market in New England for many hours based on the current market needs. Operating reserves have not been included in this analysis due to uncertainty around the ability of the storage to participate when called by ISO-NE, while attempting to maximize energy market value. Figure 7-2 below shows the relative nominal value of energy and capacity through 2034 using these modest assumptions, with blue representing energy value and green showing capacity value.

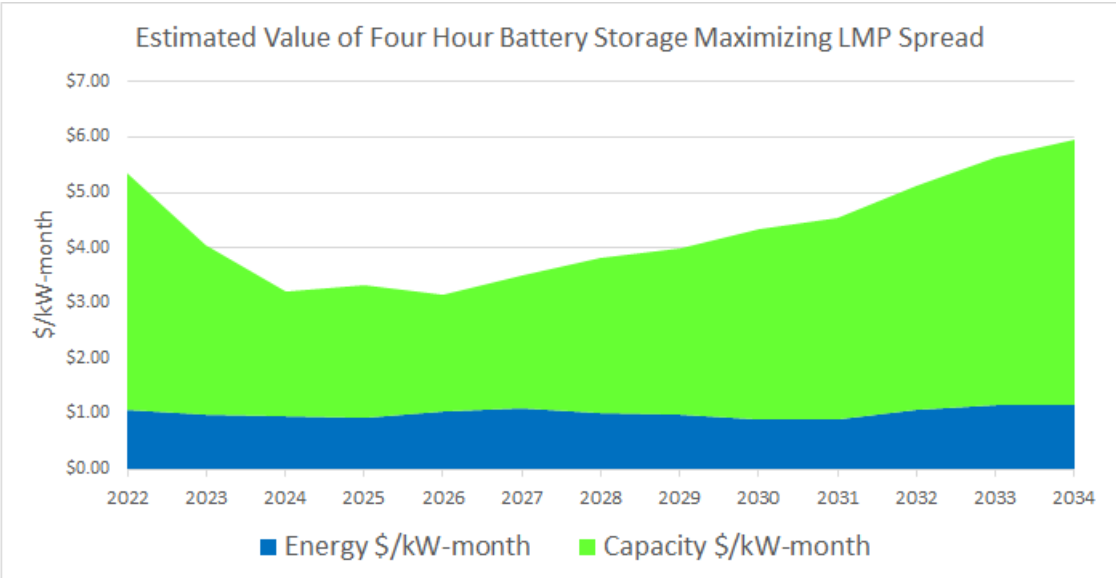

Figure 7-2 Estimated value of 4-hour duration battery storage in the modeled Energy and Capacity environment

While these two values streams alone are not sufficient to support deploying battery storage based on current prices for such systems, we recognize that this deployment could become more economically positive in the future as technology costs come down and other factors modeled above (such as energy and capacity prices) change.

We also explored how operating a significant battery storage system to optimize energy value would affect portfolio fit. As we will discuss below in the Modeled Portfolio Outcomes section, GMP has used our anticipated portfolio in 2036, when several of our larger current PPAs have expired or ramped down and we anticipate having a fully renewable portfolio, as a test year for understanding how portfolio design decisions will affect our future portfolio. We anticipate that a storage system of this size would require about 157,000 MWh to charge, including roundtrip efficiency losses, and would provide about 145,000 MWh of discharged energy. In the cases that we will discuss below an average of about 70% of the energy used to charge the battery would come from generation that exceeds customer demand and would otherwise be resold to ISO-NE (or in some locations and conditions be at risk of curtailment). Meanwhile, on average, only about 30% of the energy discharged by the storage system would be resold to ISO-NE, as exceeding customer demand. This shows that battery storage can help improve portfolio fit, a positive outcome for customers. We intend to continue studying the issue to determine when and in what configuration larger volumes of storage provides an economic tool for better matching our anticipated generation with our customer demand. This is separate from our successful small scale storage programs in customer homes and community projects which is discussed in more detail elsewhere in this IRP.

We anticipate that our next IRP will include a more detailed analysis of how battery storage can further be integrated into our portfolio. Factors considered will likely include the optimal sizing of storage in terms of nameplate capacity and duration; the value of shifting excess renewable generation from hours when GMP is a net seller to ISO-NE to hours where intermittent generation is low and GMP is a net purchaser from ISO-NE, which will enhance the hourly percentage of renewable energy meeting load on an annual basis; the ability of larger storage devices primarily used to shift energy between hours with excess renewables to hours with more demand than resources; the ability to participate in ISO-NE ancillary markets or provide other value to our customers such as enhance power quality or reliability; and an understanding of how changing economics will affect future opportunities for deploying large scale storage

Signposts

As discussed in our last IRP, we continue to use "signposts" as metrics from a local, regional, or national perspective that could serve as indicators of trends that will inform future transitions or resource choices. Because of the dynamic nature of our energy system and portfolio we believe defining the signposts and possible future adjustments in response is more realistic than claiming perfect foresight in developing an optimal portfolio and resource mix for the next 10 years or more. These signposts are set forth in detail later in this chapter.

Evaluation of the Reference Portfolio

This section presents our evaluation across a range of metrics of the Reference Portfolio, defined in the previous section as anticipated portfolio loads and resources that result from current commitments and policies, without any substantial new long-term resource commitments.

Attribute: Open Energy Position

Figure 7-3 presents our forecasted long-term energy "gap chart" that compares our projected supply sources on an annual basis to the energy requirements to serve forecasted retail sales and associated system losses.

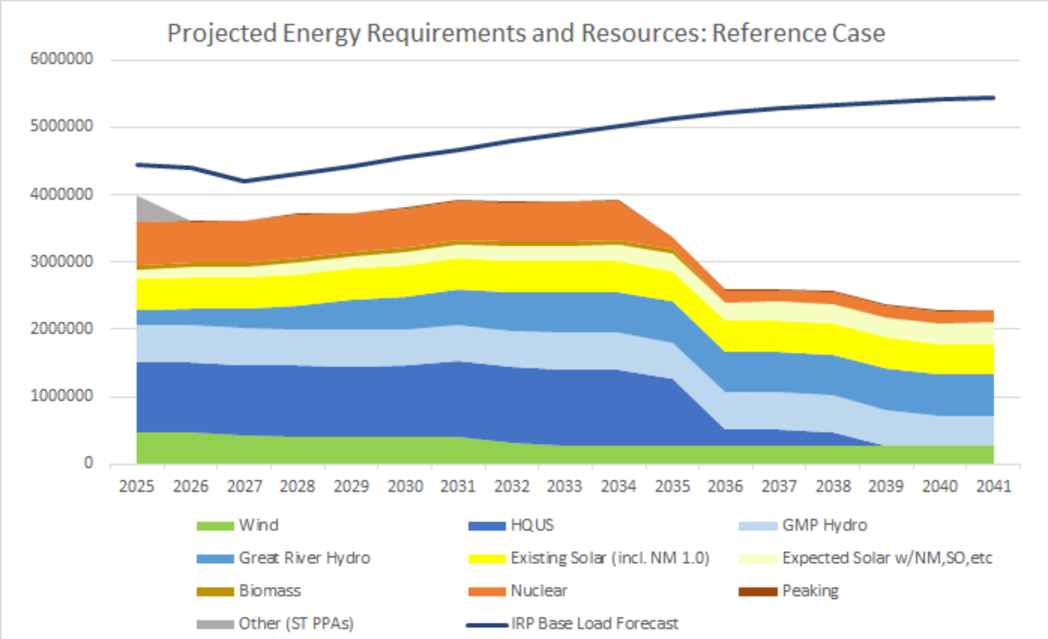

Figure 7-3 Projected Energy Requirements and Supply for the Reference Portfolio

Our projected open energy position on an annual basis is by design are significant in the long-term to limit the degree that our portfolio costs and electric rates could diverge from those in neighboring states; to maintain some flexibility to acquire resources to meet strategic objectives for carbon and renewable goals at competitive prices; or to accommodate unanticipated changes in customer-driven electricity requirements. After our current set of layered short-term energy purchases expire, the magnitude of that open position is roughly fifteen percent for the remainder of the 2020s under current load projections. Some other notable observations that emerge from this view:

- Today our portfolio is purposefully designed so long-term committed sources are somewhat less than our projected load requirements. Layered short-term forward energy purchases, the declining gray source on the upper left, bridge the gap between long-term committed sources and load requirements. As GMP moves to a fully renewable portfolio on an annual basis we expect to use short-term system purchases, which are typically for non-renewable system power, more for periods within the year when renewable resources may not fit our shorter-term load requirements.
- Long-term growth is projected for solar PV from all sources, but in this case based upon current policies is largely assumed to be from net metering. Energy from net metered solar generation that is more than the participating customers' needs is depicted as a power source, rather than as 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 or longer.

This chart extends about 20 years, through December 31, 2041. GMP's new PPA with Great River Hydro begins deliveries in 2023 and has been added as a new resource to GMP's portfolio. This PPA locks in significant volumes of renewable energy through the study period and provides a bit more than 10% of GMP's annual energy supply in 2033, when it reaches its full contractual volume. At around that time, the HQUS and NextEra Seabrook PPAs, amounting to roughly a third of our annual energy supply, will expire. We anticipate that these expirations will become a more significant consideration in our portfolio design later in the decade. Some potential resources, such as offshore wind, may have a longer lead time between negotiation of a PPA and the commencement of commercial operation due to factors that include the permitting process and significant scale of these projects. Based on the renewable and carbon-free electricity goals here and in the region, it may be appropriate to acquire some volume of additional long-term resources later in the 2020s to limit the fraction of our supply that needs to be replaced at one time in the next decade. Figure 7-3 depicts the energy sources that we use to offset our energy purchase obligations in the ISO-NE market but does not depict our purchases and sales of RECs without the associated energy. This chart therefore does not depict the ultimate energy mix after accounting for annual REC sales and purchases that ultimately serve our customers and meet RES obligations and GMP's renewable and carbon-free goals, which will be addressed in detail later in this section.

Figure 7-4 illustrates how our net energy position tends to vary on a daily and monthly basis using calendar year 2023 as an example. Our open (short) energy position tends to be weighted toward winter and off-peak hours, while supply tends to be more in balance with load during other seasons and exceeds load during peak periods in spring and peak summer solar hours. To effectively hedge these forecasted open energy positions, we generally seek to match the expected output of supply resources to the period of need. On this chart, the blue area represents projected daily output of our committed sources, with intermittent renewable sources represented at their semi-normalized (as discussed above) values. The gray volumes represent net market purchases that are needed to supplement our committed supply to serve our total energy requirements. The orange area represents estimated daily net energy resales, during periods when our committed sources are projected to exceed load requirements.

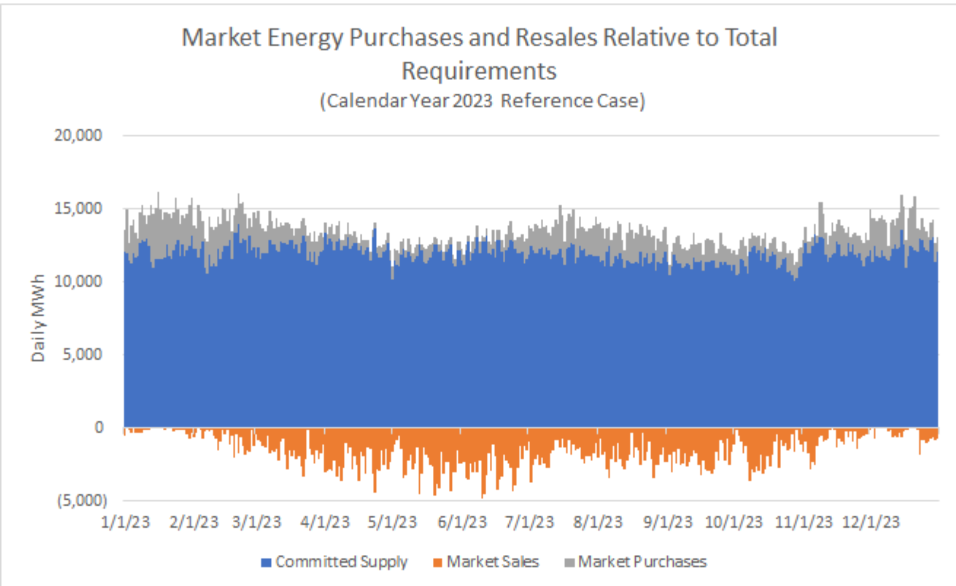

Figure 7-4 Market Energy Purchases and Resales Relative to Total Requirements

Figure 7-4 shows three distinct patterns that have implications for our short- and long-term planning process.

- Our total energy requirements shown by the top of the gray area follow a seasonal pattern with highest loads in the winter months, that begin to moderate in March before dropping in April and May, and then increasing in the summer months as cooling load increases, before moderating again during the fall months.

- Historically, periods when requirements exceed supply, tend to be concentrated in the winter sesaon, as shown by the relative size of the gray purchase volumes in the winter months on the right- and left-hand sides of the chart. 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 5: Regional and Environmental Evolution) than the other months.
- Figure 7-4 shows that we are projected to be in a consistant surplus positon during peak hours in the spring season as illustrated by the orange area. This reflects lower seasonal energy requirements during spring, along with higher seasonal hydro generation and the growth of distributed solar generation, which tends to produce at relatively high rates in these months. Finally, the summer months shows consistent purchases and sales, as significant solar output tends to exceed demand during the midday hours and solar production drops off as demand remains high during the late afternoon and evening hours, requiring market purchases to balance demand.

Attribute: Price Stability

Figure 7-5 presents our forecast open energy position from the perspective of price stability. It begins with the fraction of hedged forecasted load requirements, those that are matched with fixed or stable priced supply sources. The black line 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 under 50% in 2041. This is an extremely long planning horizon, which features the expiration of the Granite Reliable Wind, NextEra Seabrook, and HQUS PPAs that are anticipated to collectively account for about 40% of loads in 2022.

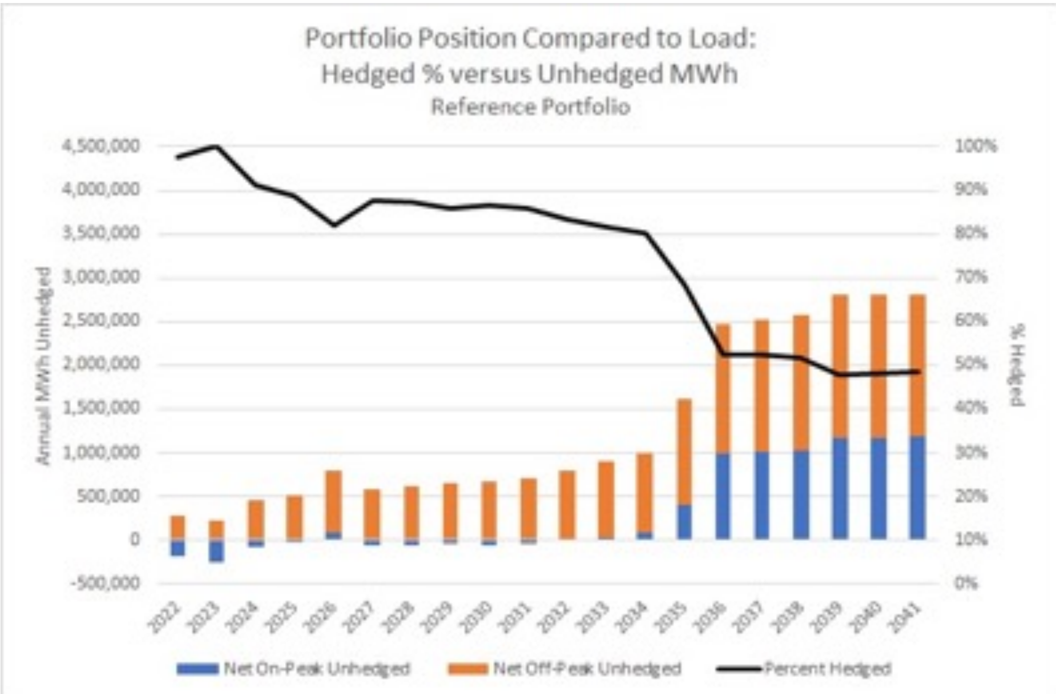

Figure 7-5 Portfolio Position Compared to Load: Hedged Percent and Unhedged MWh

Viewed in combination with Figure 7-4, this level of long-term stability indicates that for the purpose of stabilizing energy costs for our customers, 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 decarbonization.

The stacked orange and blue bars depicted in Figure 7-5 indicate whether the forecasted energy needs and surplus are during on- or off-peak hours, where on-peak is defined as non-holiday weekday hours from 7 a.m. to 11 p..m and off-peak is all holday, weekend, and overnight hours beginning at 11 p.m. and ending at 7 a.m.

- Our primary estimated net-short positions are during off-peak hours (indicated by the orange area), in volumes of about 200,000 MWh to 300,000 MWh for the next few years, increasing to about 750,000 MWh to 700,000 MWh in the late 2020s, before increasing to over 1,000,000 MWh in the mid 2030s.
- The GMP energy portfolio is projected to be long, on average, during peak hours through 2030. This is due in part to rapid growth of solar resources, which produce primarily during peak daytime hours. In the mid 2030s this trend reverses itself as sources such as Hydro-Quebec and NextEra Seabrook wind down, and create annual on-peak open positions that climb into the 1,000,000 MWh range by 2036.

Attribute: Open Capacity Position

GMP’s capacity portfolio is, by design, structured to be full for the near-term, with a mix of self-supplied generation, long-term capacity PPAs, layered short-term purchases, and the remaining open position, which has certainty about cost exposure through the results of the annual forward-capacity auctions that set the prices about three years in advance of each capacity year. GMP’s ability to use layered short-term purchases to meet future capacity obligations has helped reduce the potential risks associated with our capacity portfolio; we plan to continue using such purchases to lock in the price for blocks of capacity when they are reasonably priced relative to current market expectations. Peak-reducing resources like battery storage and controllable loads have shown meaningful potential to act as a capacity hedge by cost-competitively reducing our capacity market exposure, which is calculated based on GMP’s loads during the ISO-NE coincident peak hour used to determine each load serving entity’s Capacity Load Obligation.

Moderating capacity market prices in the last three annual FCM auctions – along with a significant fleet of capacity sources including de-listed capacity, imports, demand-side resources and new generation that could enter the market to support a sufficient supply through the rest of this decade – reduces the near-term market risks associated with capacity. As such, this chapter does not provide additional analysis of our capacity position; GMP expects to revisit this in future IRPs to the extent that we perceive significant additional future risk associated with our portfolio choices.

Attribute: RES Tier I Supply

As previously described, GMP’s 2020 annual portfolio was 68% renewable annually, and 100% carbon-fre based upon all purchases including REC retirements. We are exceeding RES Tier 1 goals and expect to continue to do so, unless the Vermont RES is modified to increase requirements.

Figure 7-6 presents our projected long-term Tier I "gap chart" under the current Vermont RES that compares our committed Tier I-eligible supply to projected Tier I requirements on an annual basis.

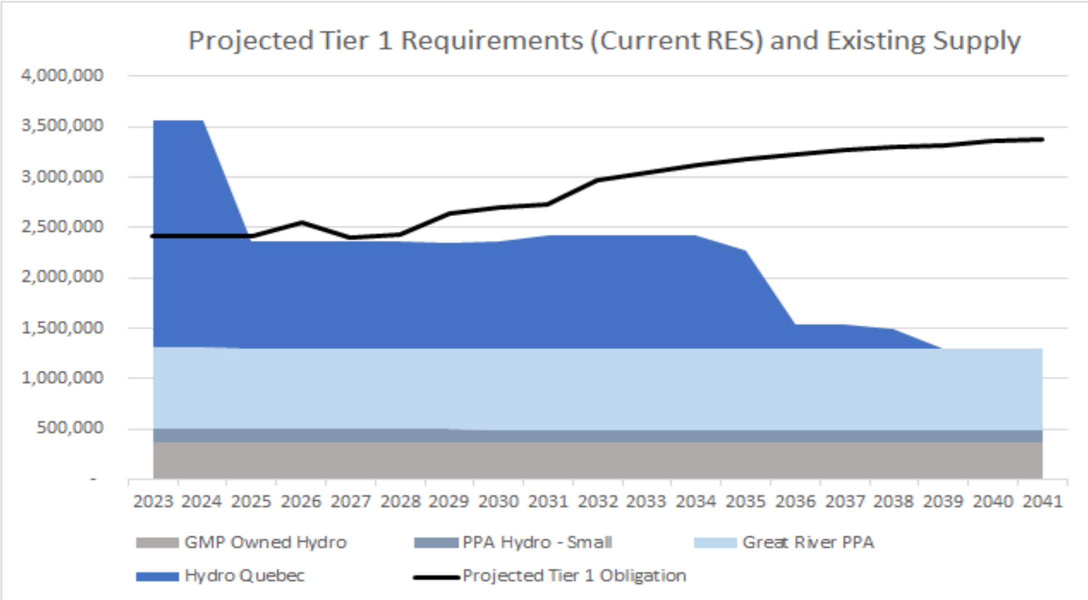

Figure 7-6 Projected Tier I Requirement and Supply

The following are notable features of this illustration:

- In the near term, to the extent that RECs eligible for Class 1 markets in other states feature meaningfully higher prices than Vermont Tier I RECs, we will continue to sell the RECs to help reduce net power costs and rates directly for customers. When the RECs associated with these sources are sold, they are, by definition, no longer available for GMP to use for RES compliance or to contribute toward our 100% renewable goal.
- We anticipate that GMP will have sufficient supply of Tier I-eligible sources in the near term, largely because of the long-term hydroelectric sources in our portfolio together with significant existing purchases of hydroelectric RECs. In the long-term, even with the recent addition of our long-term PPA with Great River Hydro, our committed Tier I supply is projected to be well short of the Tier I requirements, reflecting our transition to a 100% renewable goal at the end of the decade and the ramp down and eventual expiration of the Granite Reliable Wind and HQUS PPAs in the next decade. We will explore potential long-term renewable resource additions to fill a portion of this gap later in this chapter. The Sensitivity Analysis section explores the implications of reducing sales of regional Class 1 RECs from current levels, and instead using those RECs to meet its Tier I obligations.

Attribute: RES Tier II Supply

Figure 7-7 presents our projected long-term Tier II “gap chart” under current Vermont RES requirements —comparing our Tier II-eligible supply to projected Tier II requirements on an annual basis.

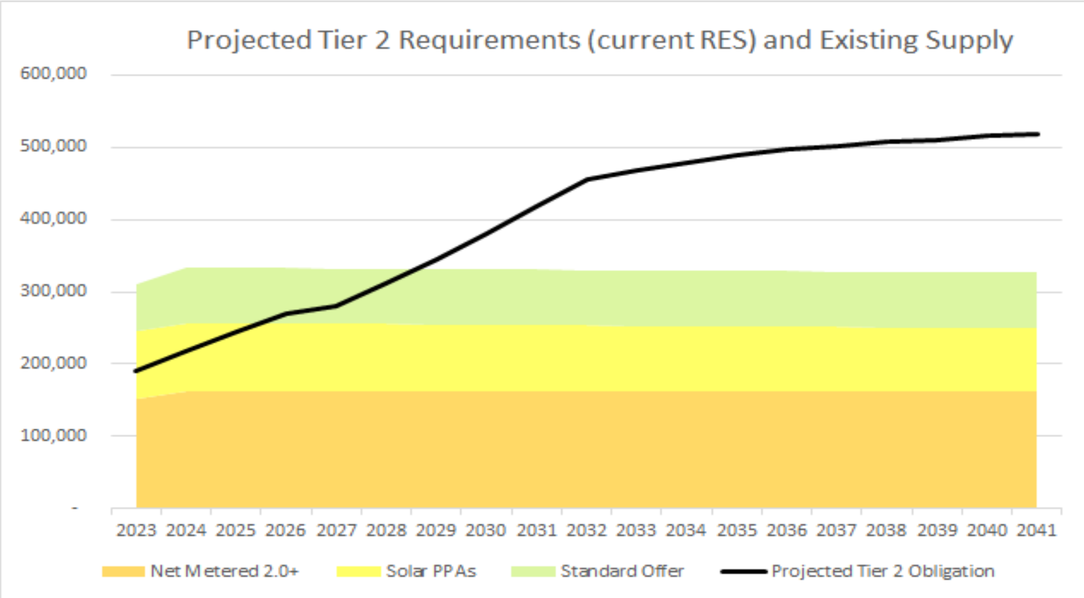

Figure 7-7 Projected Tier II Requirement and Existing Supply

Based on these assumptions – along with expected continued growth of net metering and Standard Offer supply – we are projected to be well-supplied with Tier II RECs through much of the planning horizon based on the current RES Tier II requirements. The sensitivity analysis section below explores the implications of net-metering growth turning out higher or lower than the rates assumed in our base case. Our Illustrative Future Portfolio describes how a higher RES Tier II requirement combined with new procurement strategies may deliver a more cost-effective fully renewable annual portfolio for customers in the future.

Attribute: Low Carbon

A key touchstone for our portfolio design is low carbon content for our electricity supply. For the calendar year ended December 31, 2020, GMP retired RECs and attributes for totally carbon-free annual portfolio, which exceeded our stated goal of being carbon free by 2025. As we transition to meeting our 100% renewable goal by 2030, we anticipate that we will remain 100% carbon free through the use of non-emitting renewable resources to meet our load requirements. In our 2018 IRP, we focused on low carbon as an attribute that we reviewed and tested in the various porfolios that were considered. Unless noted otherwise, the potential future portfolios tested in this IRP are designed to be 100% carbon free and renewable on an annual basis.

Attribute: Reliance on Intermittent Supply Sources

Intermittency increases somewhat in the near term with the addition of the peaking product from Great River Hydro in 2023 through 2028, along with increasing net metered and Standard Offer volumes. Intermittent supply decreases somewhat thereafter with a scheduled volume reduction under our PPA with Granite Reliable Wind in 2028 and its expiration in 2032, and as electricity consumption by our customers is projected to increase over time.

Figure 7-8 illustrates potential day-to-day variations in output for Vermont solar projects, using actual output from GMP's solar fleet (including solar net metering, Standard Offer solar, and solar PPAs) on two days in April 2021. A very sunny day is depicted by the blue dashed line, with maximum midday output exceeding 250 MW; a very cloudy day is depicted by the red dashed line, with maximum midday output of only about 50 MW. The sunny day provided an average of roughly 50 MW more generation than an average day in that month, while the cloudy day provided an average of roughly 80 MW less than the daily average.

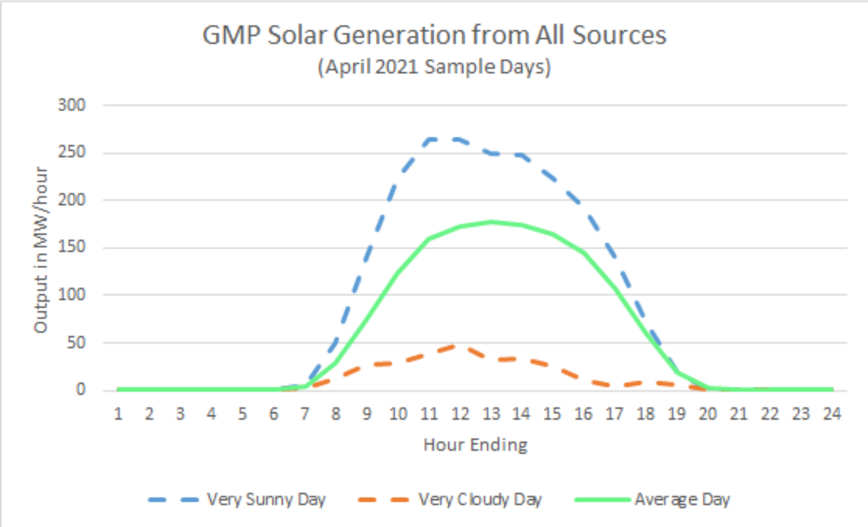

Figure 7-8 GMP Solar Generation from All-Sources

As GMP's current solar fleet exclusively features load reducers, these two days provide markedly different hourly load profiles as the high volume of solar on the sunny day significantly decreases loads during daylight hours. The figure below (7-9) is an example of the "Duck Curve", showing how daytime loads can be significantly reduced by solar generation before snapping back to normal levels once solar generation declines in the late afternoon and evening hours.

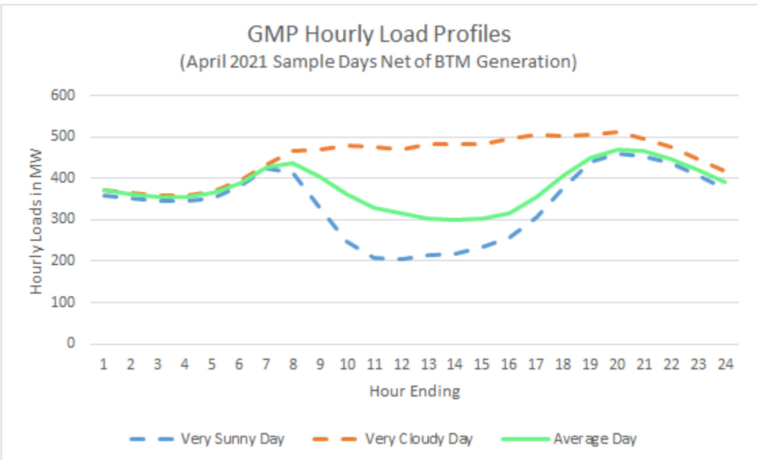

Figure 7-9 GMP Hourly Load Profiles

This trend is mirrored in the figure below where GMP had an excess of resources over demand shown as negative values during hours ending 9 through 17 on the sunny day and was a net seller to ISO-NE. In contrast, on the cloudy day GMP remained a substantial net buyer from ISO-NE as demand exceeded resources on an hourly basis. April 2021 tended to be a sunny month with significant hydro production, resulting in GMP generally being a net seller to ISO-NE during the daylight hours as shown by the solid green line.

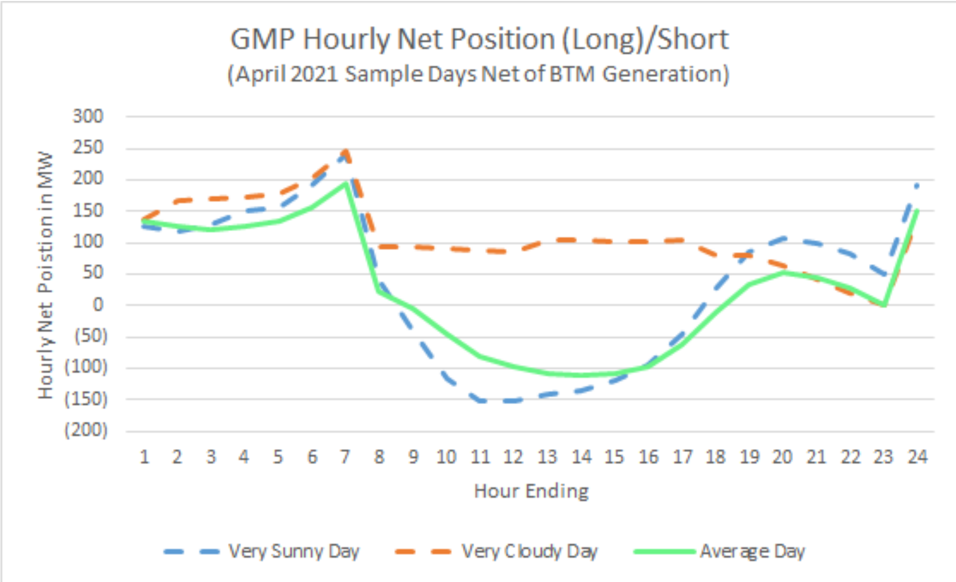

Figure 7-10 GMP Hourly Net Position

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 typically varies with the wind speed cubed. Vermont hydro generation is seasonal with high output during the spring runoff and with more limited output during summer months, that tend to feature limited rainfall resulting in diminished river flows. Hydro availability and output can vary greatly depending on the mode of operation. Run-of-river generators provide output that is totally dependent on water flow while dispatchable units have ponding capability that provides some ability to shape and time their output.

We generally seek to balance our energy sources and load requirements within each month; however, as our portfolio continues to become more intermittent with more renewables we anticipate increasing imbalances in our portfolio on an hourly and daily basis. Balancing our portfolio on a monthly forecasted basis can be accomplished by taking into account the characteristic seasonal shapes of our intermittent supply sources. The implication of relying on intermittent sources is that day-to-day production fluctuations yield corresponding fluctuations in the volume of energy that we need to purchase from or sell in the ISO-NE spot market. When combined with strong fluctuations in hourly LMPs, changes in intermittent generation volumes can yield noticeable short-term variations in net power costs, while periods of stable hourly LMPs tends to mute this type of variation. These outcomes will tend to offset over the long-term, but sustained variances in intermittent output can affect collections from or returns to customers under our power supply adjustor.

The continued growth and development of flexible energy resources like battery storage or controllable load tends to be complementary to an increasingly renewable and intermittent portfolio. Strategies for planned and managed curtailment to manage customer cost and fit also may be helpful as more resources enter our portfolio. While there are still significant issues such as price, size, and duration that need to be resolved, storage resources have the potential to mitigate some of our exposure to short-term variances associated with fluctuations of renewable output by helping smooth out renewable generation and managing charging or discharging based on market conditions such as changes in hourly LMPs.

Potential Renewable Resource Additions in Portfolio Analysis

To explore the tradeoffs between potential portfolios that could address the needs for renewable energy identified in the Reference Portfolio and achieve a 100% renewable supply, we tested portfolio combinations that include the following illustrative potential renewable supply additions, using a year in the mid-2030s when GMP supply needs are likely to be large, under any load scenario. Each of these resources could 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.

Plant-contingent existing hydro. This resource reflects a long-term PPA to purchase the output of one or more existing hydro plants in New England, or a purchase of existing hydro capacity in the region. Existing plant-contingent hydro has the potential to provide renewable energy to meet GMP's renewable energy needs, along with some amount of capacity, on a long-term basis. A long-term PPA would most likely feature stable or fixed pricing over time, although we would be open to exploring other pricing arrangements. 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 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. For this analysis, we assume that plant-contingent hydro would be priced consistent with our base case outlook for energy market prices (weighted to reflect the seasonal profile of hydro generation) plus some value as a Tier 1-eligible renewable resource, with capacity priced separately.

Historically an advantage of existing hydro purchases has been the potential for a low price per kWh of renewable supply. As neighboring states are increasingly focusing on how to reduce the carbon intensity of their electricity supplies and their economies more broadly, we are seeing increasing competition for the finite supply of existing hydro and nuclear generation. This trend seems likely to limit the availability and/or increase the price of the existing hydro supply. We also know that GMP's supply portfolio already includes hydro generation through PPAs and owned plants, and that we have limited projected need for additional supply during the spring months when hydro generation in New England tends to be at its highest. For these reasons, our IRP portfolio analysis caps the cumulative addition of new hydro resources at a maximum of 500,000 MWh.

Firmed or shaped renewable purchases refer to purchases in which the buyer receives renewable energy on a schedule that does not fluctuate, at least to a substantial degree, based on fluctuations in streamflow from one or more supplying hydro plants. Examples of this type of purchase include the long-term hydro purchase that Massachusetts is seeking to obtain via the proposed NECEC transmission line in Maine, and a long-term power purchase and transmission project that New York recently selected to help supply renewable energy to the New York City area; in the future such purchases could also include other renewables paired with storage. It is also possible that future shaped renewable imports could be arranged to deliver energy in profiles that are more closely aligned with New England's emerging seasonal and hourly needs, and therefore complementary to existing and future solar and wind supplies. It is also possible that existing renewable suppliers in New England could offer a firmed renewable product (as Great River Hydro did under GMP's recently approved long-term PPA), although a substantial scale of renewable fleet and/or energy storage resources would likely be required to support this type of transaction.

The IRP portfolio analysis tests how one version of a shaped renewable purchase could fit into GMP's portfolio in the mid-2030s when our existing HQUS purchase begins to ramp down. Specifically, we test a shaped purchase featuring a fixed delivery schedule that is weighted heavily toward GMP's projected seasonal and hourly energy needs (greatest volumes in peak winter months, least volumes in spring months; greatest volumes during overnight hours and morning/evening hours of peak consumption, no deliveries during peak solar generation hours); the annual capacity factor is approximately 50 percent. A shaped purchase of this nature – particularly if it can be dispatched to some degree to follow the buyer's needs – could, if available, play a useful portfolio role that complements our increasing reliance on instate solar and other intermittent renewable supplies.

Because the availability and pricing for this type of custom product is uncertain, the IRP analysis does not test multiple potential designs of a firm renewable transaction or test such purchases prior to the mid 2030s. Pricing for a shaped renewable energy purchase is assumed to start at $60/MWh, reflecting a significant premium to forecasted regional spot market energy prices in the base market outlook. We note that depending on the details of this resource it is possible that additional costs – for example, associated with transmission upgrades to accommodate imports, or long-duration storage to supplement in-region resources – could be required. Since this representative purchase is primarily included as a resource for future consideration and it is not depicted in the Illustrative Future Portfolio until the last few years of our study horizon, we have not attempted to estimate the range of such additional costs or the associated benefits (e.g., greater dispatchability) that they might support.

Offshore wind (OSW). This resource would likely be pursued for its output profile - which is projected to be relatively high during winter months and steadier than land-based wind, with fluctuations not highly correlated with our existing northern New England wind sources – along with long-term price stability. While there is only modest OSW capacity operating in New England today, some New England states along with New York have entered into substantial (400 MW or more) long-term PPAs for the output of proposed OSW projects – amounting to several thousand MW in total – which would be completed in the 2020s. Considering these commitments along with plans for additional OSW procurements, OSW has emerged as the largest tool that New England states expect to rely on to decarbonize the New England grid over the next decade. While GMP's needs alone would probably not be sufficient to support the development of a major new OSW project, we could potentially participate in OSW as part of solicitations conducted by a neighboring state or aggregation of buyers, or through other paths such as purchasing potential output that is not already committed to such solicitations.

Pricing for wind power is assumed to start at about $77/MWh constant over the PPA term – comparable to the lower end of reported pricing for New England offshore projects to date. Pricing for projects that achieve operation in future years is assumed to decline at an average of 0.3% per year, on the prospect that increasing industry experience and scale (particularly for the nascent industry in the United States) could lead to savings in initial capital costs and long-term operating costs. Potential output from offshore wind plants would not be supported well by Vermont's current RES, since the only requirement for new renewables in the current design is in RES Tier II and new OSW would not be eligible for RES Tier II as presently defined. As a result, the use of OSW RECs (i.e., the extent to which they would be retired versus sold to reduce net power costs for our customers) could depend on future RES design changes, market conditions, and the availability and pricing of other renewable electricity sources.

Distributed scale solar. Development of solar PV capacity in Vermont to date has been almost exclusively via projects sized 5 MW or less – primarily through net metering (maximum project size 500 kW) and Vermont's Standard Offer program (maximum project size 2.2 MW). Some distributed solar projects have also been supported by bilateral PPAs or utility ownership; GMP views these latter paths as relatively low-cost ways to increase Vermont's use of distributed renewable energy, particularly if the pace of larger net metering projects, which presently feature much higher effective pricing than PPA or utility options, can be limited to focus on projects that are co-located with the customers who will use their output. Pricing for new distributed solar PPAs is assumed to start at about $85/MWh, representative of the pricing of leading Standard Offer and other PPA opportunities in recent years. Pricing for projects in future years is assumed to increase at 0.4% per year – well below the rate of general price inflation in the economy – except for a temporary increase in the late 2020s when the magnitude of the federal investment tax credit is assumed to decline.

Larger-scale solar. Development activity for Vermont solar PV projects sized larger than 5 MW has been limited to a small number of much larger projects (one 20 MW project has achieved commercial operations; multiple projects sized up to 50 MW have requested interconnection) focused on projects intending to sell output to neighboring states. The limited instate focus on larger solar projects is in part a reflection of Vermont's RES structure, and the availability of moderately priced existing renewables to help meet Tier 1 requirements. GMP expects that in the future it may be appropriate to consider larger solar projects in Vermont or a neighboring state as a cost-competitive option to increase our renewable supply. Pricing for larger solar projects is assumed to start at about $65/MWh – significantly less than for distributed scale projects – on the expectation that some well-located larger projects will be able to achieve lower prices through economies of scale without incurring excessive grid upgrade costs.

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 amounts of each of these sources in the Illustrative Future Portfolio, with assumed acquisition dates ranging from the mid to late 2020s or later. 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 the design of Vermont's RES; 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.

Value of Output from Renewable Sources

A significant focus of this IRP is how various potential future resources fit with GMP's existing resources and our customers' anticipated consumption on a seasonal and hourly basis. An extension of the fit analysis is understanding how the value of potential renewable generation sources will affect GMP's net power costs for customers. In short, the attractiveness of a potential resource depends not only on the price to purchase or own the resource as discussed in the previous section, but on the value of the energy and other products that the resource provides. This value equation becomes important as it helps to inform what prices we should be willing to pay for future resource additions, with a focus on trying to balance the value of all benefits received such as energy, capacity, renewable attributes, and any ancillary benefits with the price being paid for those benefits. Combining fit and value provides an important tool for understanding our future portfolio decisions.

Exploring the value proposition of the various technologies being considered allows us to plan for meeting our requirements to serve load; provide capacity to ISO-NE; meet our obligations under RES; and anticipate how future changes to RES could impact our future portfolio design decisions. The table below shows the various benefits that any purchasing utility would anticipate recognizing from the various technologies.

Technology	Energy type	Capacity method	REC eligibility	Location
Small-scale PV	Load Reducer (BTM)	Limited to peak coincidence	VT Tier II eligible	In State
Grid-scale PV	Grid Connected	Limited - Summer Season	Class 1, New NE Regional Tier	Regional/In-state
Offshore Wind	Grid Connected	Average monthly rating	Class 1, New NE Regional Tier	Regional
Onshore wind	Grid Connected	Average monthly rating	Class 1, New NE Regional Tier	Regional
Regional Hydro	Grid Connected	Average monthly rating	VT Tier I	Regional

Table 7-2 Selected Characteristics of available renewable resources

Using a market-simulation model allows us to explore potential trends in the projected value of energy from intermittent generation sources on an hourly basis by combining the output shape of the resource with the hourly energy prices developed by Daymark in the PLEXOS model. The graph below shows the projected average value of energy output for several of the technologies along with the average all-hours energy price for the Day-Ahead market, for the GMP base case energy market case.

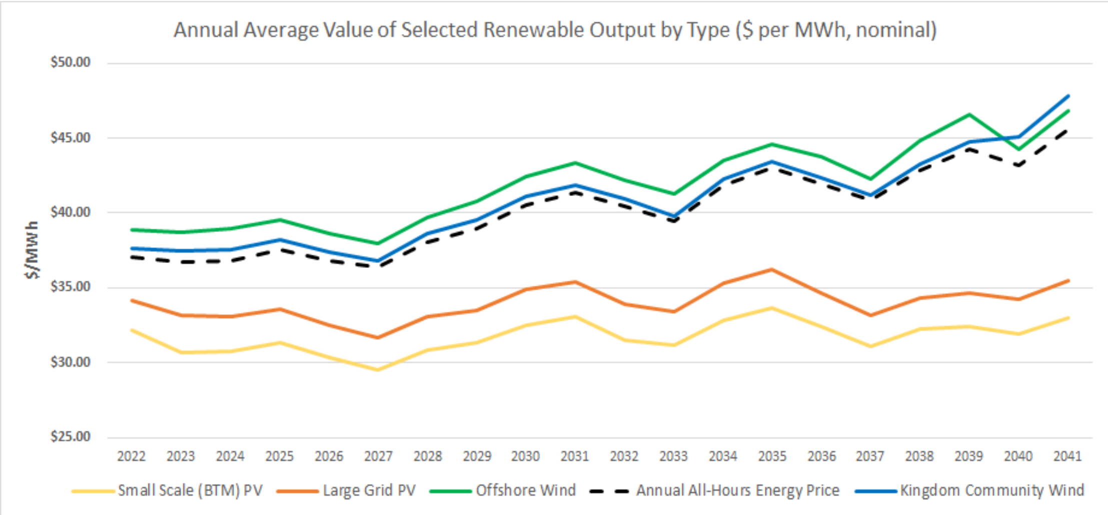

Figure 7-11 Average Annual Value of Solar and Wind Resources relative to All hours $LMP prices

The projected average value of small-scale PV – which would be behind the meter and have relatively lower capacity factors reflective of smaller net metering projects – averages about 80% of the all-hours average energy value in the near term and declines to 72% of the all-hours average by 2041. Grid-scale PV fares somewhat better, with a long-term average of about 85% of the all-hours average and a 2041 average of about 78% of the all-hours average. This reflects the output profile for solar, which tends to be highest during spring and summer, which have started to show lower energy prices during the daylight hours due to significant volumes of intermittent generation that tend to depress loads and, consequently, the ISO-NE bid stack that is used to dispatch generation and sets the hourly Day-Ahead energy prices. This is exacerbated by lower output during the winter months that tend to feature higher energy prices to meet higher demand. Other technologies such as onshore and offshore wind slightly exceed the all-hours average energy prices over the full period, with offshore wind reflecting high average winter capacity factors and consistent generation during hours when solar generation is not producing.

These considerations of the value of renewable energy resources does not include values not presently embedded in the market or pricing directly for our customers, such as the social cost of carbon discussed in Chapter 5.

Peaking and Flexible Load Resources

Flexibility of resources is an important factor when evaluating specific assets on a distributed grid. Battery storage systems have proven to be one of the most flexible resources currently available. This section explores the value streams, or 'use cases', that a battery system can provide and how we currently use 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. We will also explore Flexible Load Management ("FLM"), now in its second pilot phase, which is engaging our customers in load and peak management. 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.

Batteries are nimble and flexible and can be considered very similar to a peaking generator such as a diesel generation set. When system peaks occur, these resources can be dispatched, and in the case of batteries, lower the net load that we are pulling from the bulk system in real-time, thereby lowering the cost that our customers 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 customers for GMP battery projects to date, as described in Chapter 6: Our Increasingly Renewable Energy Supply.

While different from batteries, load management encourages commercial and industrial customers to manage their loads during peak events. This is accomplished by sending signals indicating expected monthly and annual peak events, with the customers receiving a credit for their load reductions during actual peak events. In some cases, this is achieved through direct integration with a "building-management system," which can seamlessly shift load without any negative impact to occupants, for example cycling compressors or pre-heating/cooling the building before a peak event. In other cases, customers receive a notification and schedule a batch process to run before or after the event window. Rather than providing generation, these customers shed load during the peak events.

In addition to the value derived from reducing system peaks, the following values are either being captured or could be captured with existing battery storage and some benefits could also be realized through FLM.

Energy Arbitrage. Battery storage can act as a load and a supply source at different times, making it an ideal energy arbitrage resource as 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. Some 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. These arbitrage opportunities have been limited over the past couple of years due to moderate energy prices with relatively limited spreads between daily high and low prices. In general, as we see meaningful spreads begin to develop, we will strive to refine the program's design and operation to achieve greater energy arbitrage.

The current FLM design will not directly help to participate in energy arbitrage, but "load rolling" could shape the participant cohort's aggregate load to match a predefined shape, for instance smoothing an evening ramp rate or flattening a peak over a period of several hours and attempting to shift load from high- to low-energy-price hours.

Operating Reserves. FERC Order 888 requires all ISOs to allow battery storage to participate in all energy and ancillary markets. This means battery storage can become an operating reserve resource in the ISO market. However, participation in a market like this may require giving up other peaking benefits, which requires weighing this value stream against the value of the lost peak management opportunities.

Intermittent Generation Output. The difference in solar generation on sunny days and cloudy days can amount to hundreds of MW of spot market energy exposure for GMP and customers. These fluctuations can be exacerbated by other intermittent resources such as hydro and wind generation and can lead to significant daily mismatches between resources and demand. 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 can be useful from a portfolio perspective. Storage and flexible load management at a sufficient scale can fit that role nicely. These resources provide us with the ability to either soak up or fill in gaps that are created when significant swings in PV output occur. As noted above we have included, as a topic for future IRPs, the exploration of using battery storage to capture and move intermittent generation as we seek to determine the volume and duration of storage that could be cost effectively deployed.

Frequency Regulation. ISO-NE 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 had traditionally been provided by large natural gas and hydroelectric power plants but is now part of the supply of frequency regulation is being 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, and we are also the first to utilize our small-scale residential storage fleet in this market to benefit customers.

In addition to power supply benefits, battery storage provides a very useful tool to manage the local T&D system and create a resiliency resource for use cases that include customer backup power; system resilience; distribution system voltage and VAR management; and distributed generation hosting capacity. These use cases are discussed in Chapter 3.

Locational Considerations

The New England electricity market is largely 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 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. These operating limits include some 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 could 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 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-NE market at the Vermont Load Zone and sells the output our generating sources and PPAs to the market at the pricing nodes where energy is delivered. The net effects of transmission congestion 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 such as a potential PPA to purchase output from a generating plant can depend not only on the resource's total price, but also the extent to which the value of its output in the ISO-NE market is reduced or enhanced by effects of transmission congestion and losses.

Transmission Project Proposals

In the past several years new import transmission projects (including TDI's New England Clean Power Link, already permitted, and Vermont Green Line, which was withdrawn from ISO-NE and is on hold) have been proposed to deliver substantial volumes of power into Vermont, in support of decarbonization efforts by New England states. To date these projects have not been awarded contracts as preferred resources, but it is possible that development interest will increase as the states firm up their decarbonization plans and/or if other resources, such as the proposed New England Clean Energy Connect ("NECEC") project in Maine, cannot be developed as planned. We expect that sponsors of bulk transmission projects delivering power into Vermont will need to clearly demonstrate that their projects will be beneficial to Vermont electricity customers while considering and mitigating potential grid impacts. This would include consideration of the extent to which the project would deliver power on positive terms to benefit Vermont customers, along with detailed transmission system analysis to identify reasonably anticipated impacts on the bulk transmission and subtransmission systems, and appropriate measures to mitigate them.

Sensitivity Analysis

In keeping with our last IRP, the Reference Portfolio using base case assumptions shows reasonable balance in the short term and does not show insufficiency of supply or extreme market price exposure with respect to needs for energy, capacity, or RECs for either Tier I or Tier II. However, the Reference Portfolio evaluation shows that several uncertainties could alter this conclusion and affect the timing and magnitude of our future portfolio needs. These uncertainties include:

- The design of Vermont's RES in the event it is amended in ways that align with or differ from our 100% renewable goal.
- The pace of load growth, particularly at this time of increasing electrification and policy support through sources such as the GWSA. This signals the potential for more meaningful growth than we have seen over the past several years. Load growth drives the need to determine the best resources to continue cost-effectively meeting changing customer demand. More growth could also have implications for required grid upgrades in Vermont to strengthen the greater grid, and for the alignment of renewable supply with demand on a seasonal and hourly basis.
- Local generation. As previously discussed, the way local small-scale resources are acquired and the pace at which they are built will have a meaningful impact on our net power costs. Changes to Vermont's procurement strategies, including in particular net metering, could permit overall more cost-effective local renewables to be deployed for more of our customers, through for example, community solar strategies, emphasis on customer load-centered projects, and site selection that integrates best with the grid and customer need.
- Tier III. To the extent that the pace of Tier III electrification varies from GMP's base case outlook, it could have a meaningful impact on annual retail electric sales and energy requirements and relative size of our open position. In addition, although we believe that our Tier III decarbonization customer programs will continue to meet or exceed our annual RES obligations, any major lag in achieving Tier III savings could potentially produce a need to retire additional Tier II RECs toward Tier III compliance.

Each of these themes is explored in the following sections via sensitivity cases. These cases assume that, over the long term, one of the portfolio components or market price outcomes turns out differently from the base case.

Sensitivity: Changes to Vermont's RES

GMP will be 100% renewable annually by 2030 and anticipates there is a reasonable likelihood that there will be changes to Vermont's RES based on the requirements of the GWSA and the resulting initial Vermont Climate Action Plan delivered on December 1, 2021. Changes to the RES could include, among other changes: increasing the total renewable requirements from a maximum of 75% to a maximum of 100%; increasing Tier II or Vermont-based requirements; expanding resource eligibility and qualifying dates and creating new tiers or sub-tiers to encourage regional new renewables (often referred to as enhancing "additionality"); considering carbon in addition to or instead of only renewability; and changing how the obligation is calculated by using loads instead of retail sales. Changes to the RES likely would follow trends seen in other states in the region, which have significantly expanded their renewable and carbon-free goals and obligations over the last few years.

Changes to the RES could cause GMP to make different portfolio decisions than we currently anticipate. Meanwhile, New England's drive to decarbonize will likely lead to changes in the balance of supply and demand for renewable and non-emitting resources and the associated RECs. We anticipate that it will also spur a meaningful increase in new renewables that may provide opportunities for GMP to participate in procurements for resources such as offshore wind. We have considered changes to Vermont's RES in the design of an Illustrative Future Portfolio, discussed below.

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 electrification growth that we anticipate will fully meet the 2021 Energy Action Network Pathways Model's anticipated level for compliance with the GWSA's requirements. The low case assumes that significant progress will be made in electrification, but that growth will be limited to what has previously been labeled as GMP's medium case for cold climate heat pumps and electric vehicles. In both cases GMP would fully comply with its obligations under RES Tier III.

Each of the sales scenarios begins with Itron's load forecast but changes the electrification assumptions to reflect more recent assumptions and goals. These cases all reflect the same levels of economic growth, efficiency savings, own-use net-metered solar, and assume that Global Foundries will become a standalone utility in 2026 given its petition pending at the time of the IRP filing (this is the near-term 2020s dip in our load forecast). The key differentiator in the cases is the pace and volume of electrification. The large spread between the high and low cases in Figure 7-12 below illustrates the scale of electrification that will likely be needed for Vermont to decarbonize its economy.

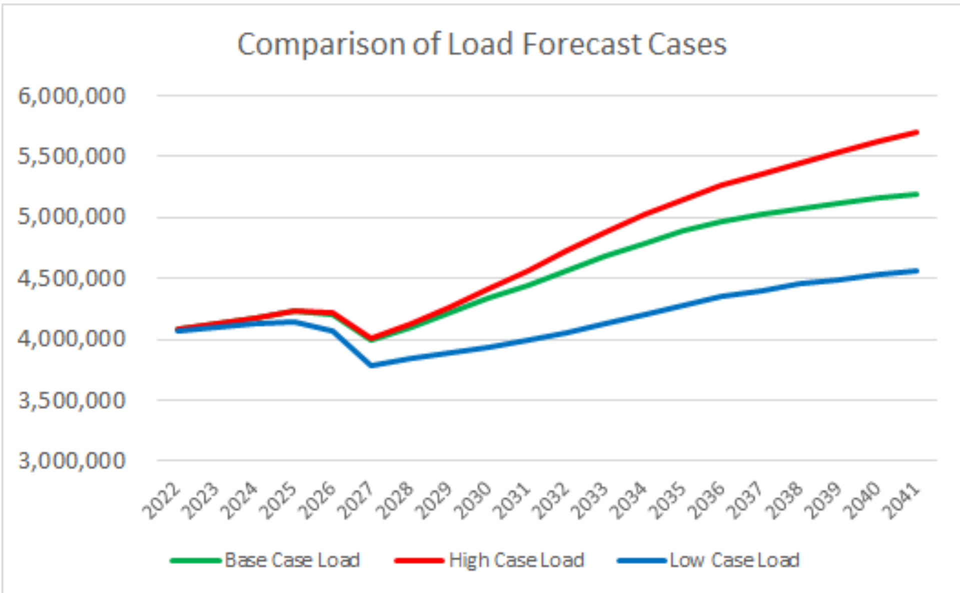

Figure 7-12 Load forecast cases used in portfolio evaluation

Sensitivity: Cost of New Renewable Sources

Mid-case assumptions for the direct cost of new solar and wind sources were introduced earlier in this chapter. This section explains the alternative paths for future solar and wind sources that we tested in the portfolio cost sensitivity analysis, driven by two factors: grid upgrade costs required to integrate these sources, and potential trends in their inherent equipment costs and performance.

Distributed and Larger Scale Solar

Our mid-case assumption features solar PPA costs increasing about 0.4% per year – that is, declining modestly over time relative to general inflation – with the exception of an assumed decline in the federal Investment Tax Credit in the late 2020s. In the cost-sensitivity analysis we tested two alternative paths:

In the low case, the price of new solar PPAs starts a few percent lower, and declines substantially over time at an average rate of about 1.9% per year. This reflects a future in which technology improvements in capital costs and operating costs put downward pressure on solar costs on a sustained basis.

In the high case, the price of new solar PPAs starts a few percent higher and increases at 0.7% per year. This is intended to approximate a future in which technology improvements and industry scale continue to put some downard pressure on costs, but other factors (e.g., materials costs, land scarcity, etc.) also bring upward pressure.

Neither of these price trends consider the potential for additional grid upgrade costs to accommodate higher levels of instate generation; this factor is discussed below.

Increasing volumes of local generation appear likely to require greater levels of transmission grid upgrades and associated costs than the first few hundred MW did. Experience in other states – such as cluster studies in Massachusetts and Maine – suggest this, and VELCO's 2021 Long Range Transmission Plan (LRTP) explores this topic directly. In particular, the LRTP specifically tested the upgrades that would be required to accommodate up to 1,000 MW of local generation; this roughly approximates the level of solar generation that would be needed to support a doubling of the RES Tier II requirement to 20% of annual electricity sales. A few observations from this work – along with GMP's experience – stand out:

Based on electrical system modeling VELCO identifies specific transmission upgrades, including the bulk and subtransmission systems, that could be required to accommodate this level of local generation, assuming that the additional generation is distributed around the state in the same geographic patterns where distributed solar has been built to date. VELCO also provides illustrative estimated costs for the upgrade projects, which in total amount to roughly $500 million. These are preliminary estimates of project scope and costs that would occur over the next decade or more, so they could turn out meaningfully different from today's estimates; VELCO reports that they include significant contingency allowances.

The need for upgrades for this type of buildout would be triggered at various levels of local distributed generation ranging from 450 MW up to 1,000 MW. If grid upgrades of this magnitude were required, they will represent a meaningful part of the capital costs to develop local solar generation. If Vermont electric customers were ultimately responsible for those upgrade costs, the costs would significantly increase the effective cost of the local resource.

Importantly, VELCO's analysis also indicates that almost all the indicated upgrades could potentially be avoided, if the geographic distribution of future solar deployment is shifted toward areas of the state where the grid has substantial additional hosting capacity, and away from areas with little hosting capacity. GMP expects that it will be increasingly important to geographically deploy local solar development with this goal in mind.

It is also possible that if transmission upgrade projects are identified as needed as the deployment of solar capacity in Vermont grows, some of them could be deferred or even avoided using alternative non-transmission resources. Examples include the use of energy storage to absorb energy during periods of high solar generation; or flexible load programs to direct local energy consumption toward times when solar generation is abundant. Curtailment of local solar generation could also be a credible option, particularly if it is only needed occasionally. Non-transmission tools like these will have their own costs and will require careful design and implementation, but in some instances, they could turn out to be cost-effective alternatives to making some grid upgrades, helping control the overall cost of the renewable transition for Vermont customers.

With this context in mind, our analysis assumes that a combination of geographic targeting and the other tools above will enable Vermont to reduce the pace of potential grid upgrades and substantially limit potential costs, as we strengthen the greater grid. Specifically, we assume that Vermont solar sources will incur a modest level of additional grid upgrade costs starting in the late 2020s, growing gradually to an effective range of about $5 per MWh of solar generation in the low case to $20/MWh in the high case.

Putting together the ranges of potential long-term cost trends and transmission upgrade costs, Figures 7-13 and 7-14 below illustrate the assumed costs for distributed and larger scale solar sources deployed in Vermont over time in our Low case and High case. In each chart the solid lines represent the trend of direct project costs, while the dashed lines illustrate the potential additional costs associated with transmission upgrades.

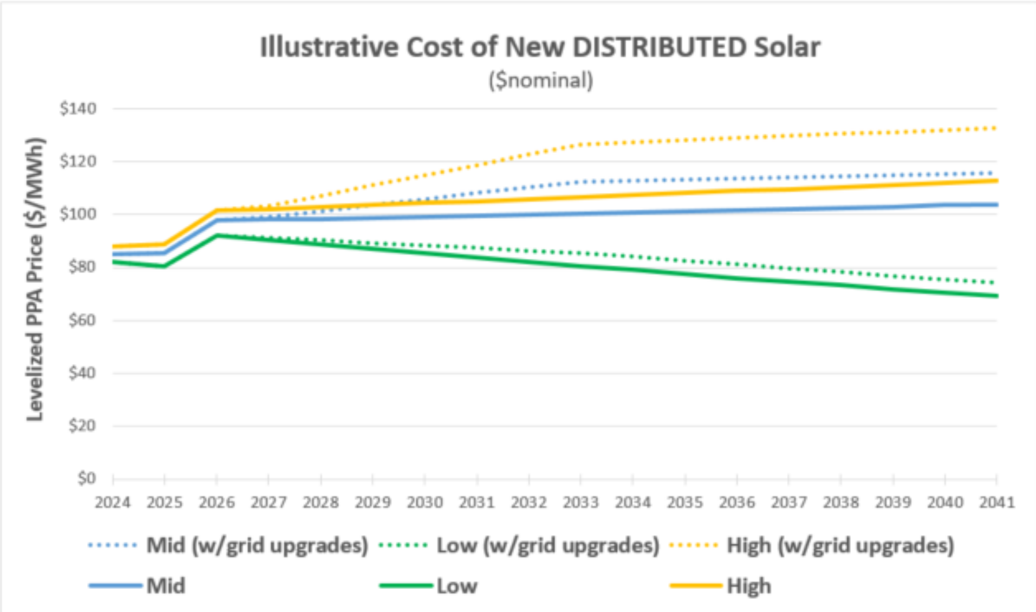

Figure 7-13 Cost of Distributed Solar

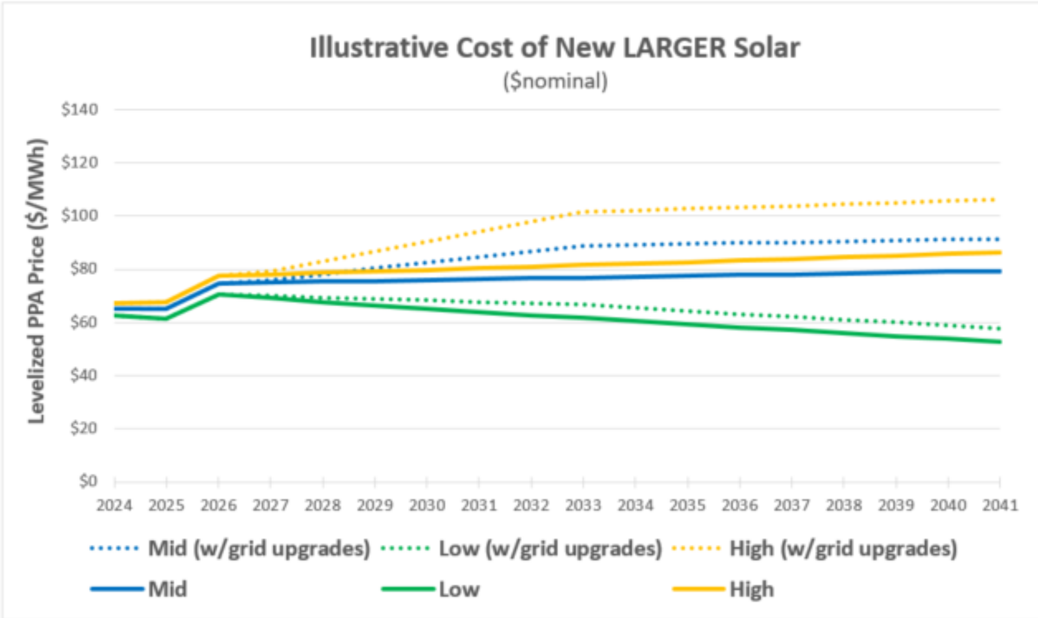

Figure 7-14 Cost of Larger Solar

Wind

Our mid case features wind power being priced similarly to the lower end of offshore wind pricing obtained by New England state solicitations – although we recognize that if current transmission bottlenecks can be addressed some wind supply could be obtained from land-based projects. In the portfolio cost sensitivity analysis we tested two alternative price paths, based on alternative outcomes with respect to industry cost trends and the transmission costs required to deliver offshore wind output. With respect to transmission costs, the primary assumption is that several thousand MW of offshore wind capacity appears to be deliverable to southern New England coastal locations with limited increases in the distance and complexity of required offshore transmission, whereas early indications are that much more substantial transmission costs (offshore and/or on the New England grid) will be needed to accommodate capacity above a cumulative total of 6,500 to 7,000 MW. With this in mind, the three price paths for offshore wind cost trends are:

In the mid case, the price of power from new projects in this growing industry is assumed to decline over time by about 0.8% per year – that is, to decline significantly over time relative to general inflation – with the exception of an assumed expiration of availability of the federal Investment Tax Credit in the mid-2030s. Grid costs are assumed to gradually put upward pressure on pricing, ramping up to about $7/MWh in 2036 and $12/MWh thereafter.

In the low case, the price of new wind PPAs starts a few percent lower, and declines more rapidly over time at an average rate of about 1.9% per year. This reflects a future in which technology improvements and industry scale put more downward pressure on wind capital and operating costs on a sustained basis. Increasing transmission costs are assumed to put about $4/MWh of upward pressure on PPA pricing by the mid-2030s, and $9/MWh by 2041.

In the high case, the price of new wind PPAs starts a few percent higher and declines more gradually – at a rate of 0.3% per year. This is intended to approximate a future in which technology improvements and industry scale continue to put some downard pressure on costs, but other factors (e.g., materials costs, challenges in the growing New England industry, potential for limited competition among offshore develpers) also bring upward pressure. In the high case transmission costs are assumed to put more upward pressure on PPA pricing, ramping up to $10/MWh by the mid-2030s.

Figure 7-15 below illustrates the three paths for offshore wind pricing. Note that the significant bump up in price in the mid- to late-2030s is based on not only grid upgrade costs but also the presently-assumed expiration of the wind ITC, which may not actually occur. We plan to continue to monitor related developments closely.

Figure 7-15 Three Paths for Offshore Wind Pricing

Sensitivity: Future Growth in Local Small-Scale Solar Generation

Our Reference Portfolio evaluation reflects current net metering policy. The assumed growth rate continues to be high by regional and national standards. Currently, net metering is one of the most expensive resources in our portfolio and to the extent that net metering capacity at current compensation levels grows at a faster or slower rate than anticipated, there could be a meaningful increase or decrease in our net power costs which directly impacts all customers. Net metering is, however, only one of several sources for solar in Vermont and to the extent that net metering changes, any potential shortfall in Tier II eligible RECs from net metering could be made up by acquiring additional distributed solar generation cost-effectively through PPAs or other purchase methods, or through already-deployed solar projects here or regionally not currently used in our portfolio.

This sensitivity examines the percentage of local solar capacity that is acquired through net metering versus other solar sources that feature lower prices than the net metering compensation rate. Our Reference Portfolio assumes the current RES structure with 10% of customer loads being served by Tier II eligible resource by 2032. As the percentage of small-scale solar acquired through net metering increases there is a corresponding increase in GMP's annual net power costs. We see a continued important place for small net metering generation collocated with load but know that larger projects (or alternative distributed solar supplies) can be acquired more cost competitively through other programs. As discussed in the Illustrative Future Portfolio we hope to have procurement programs complement the cost-effective growth of local renewable generation requirements.

Sensitivity: RES Tier III Supply

Based on GMP's recent performance relative to RES Tier III goals and the aggressive electrification growth assumptions in GMP's base demand forecast that are targeted to significantly reduce carbon-based heating and transportation, there appears to be a strong probability that GMP will continue to meet or exceed its annual obligations under Tier III for several years. Our base case assessment of RES compliance needs therefore assumes that GMP will not need to retire a substantial volume of Tier II-eligible RECs toward Tier III compliance, and we have not developed a quantitative illustration of potential alternative future outcomes with respect to future Tier III supply quantities.

The actual volume of Tier III supply will depend on several factors including the volume of commercial and industrial (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. We plan to pursue Tier III progress 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 Alternative Compliance Payment (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 review our program offerings including incentive levels to have greater customer participation. Under the RES framework, another option available would be to meet some of the Tier III shortfall by retiring additional Tier II RECs (quantities more than GMP's annual Tier II requirements). In the event that a forecasted shortfall of Tier III emerges, GMP would expect to evaluate the use of Tier II RECs to address the shortfall. Depending on the composition of GMP's renewable energy supply and pipeline, along with prevailing renewable market conditions, GMP's options to address a projected Tier III gap could include banking some Tier II RECs in anticipation of the shortfall, selling fewer RECs to the regional Class 1 market, or procuring additional Tier II supply.

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 are not eligible for Vermont's RES Tier II because of the size, location, or age of the plants. These RECs can be used for Tier I compliance or sold into Class I RPS markets in neighboring states. Regional Class I REC price expectations have stabilized over the past year as various states in the region have increased their renewable and clean energy obligations to be better balanced with the various procurements that have taken place in recent years. This has resulted in a roughly balanced regional supply and demand of Class I eligible RECs, setting up the possibility that market prices could remain strong for the next decade. As such the Reference Portfolio evaluation assumes that GMP continues the current practice of selling those RECs and using the revenues to reduce our net power costs for customers, rather than retiring them for Tier I compliance.

As we will discuss late in this chapter, our preferred portfolio design assumes that through our own 100% path supported by market changes or future refinements to RES, GMP and other Vermont utilities will retire many of the Class I eligible RECs that are now being sold in other states to help manage net power costs. This is a meaningful change that would help to better match GMP's renewable energy sources with our customer loads. Typically, RECs purchased without the associated energy do not carry the underlying output shape of their source that can be used to match our customer hourly needs. We believe that retiring most of our RECs toward RES compliance makes sense as we work to ensure that our portfolio is carbon free and 100% renewable. The RECs that we would anticipate continuing to sell in the event the RES were updated to accommodate it would be from our committed renewables not located here in Vermont or with emissions at the "stack" such as biomass or landfill gas.

This sensitivity explores the potential portfolio implications of regional Class 1 REC prices turning out significantly higher or lower on a sustained basis as we begin the process of retiring rather than selling these RECs. Figure 7-16 illustrates the resulting base-, high-, and low-price outlooks for regional RPS Class 1 RECs. The base case assumes that regional supply of Class 1-eligible sources will remain roughly in balance with the considerable growth in state RPS requirements over time. The high case is intended to reflect a future in which the regional supply of new renewables is more challenged – for example, due to challenges in the permitting or construction of major projects. The low case is more consistent with a future in which the pace of renewable development in New England generally keeps up with the states' ambitious renewable and clean energy goals or RPS volume requirements do not fully keep up with the pace of renewable energy procured in the New England states.

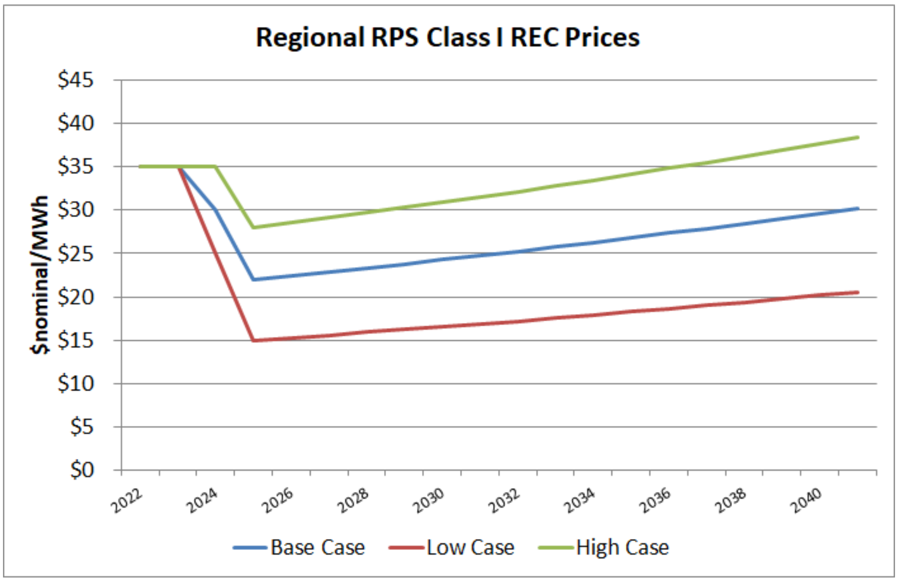

Figure 7-16 Regional RPS Class I REC Prices

Higher or lower regional Class 1 REC market prices would result in different REC revenue for GMP's projected inventory of salable Class 1 RECs and could affect the timing and extent to which GMP sells the RECs to reduce net power costs or retires the RECs for its own 100% renewable goals or RES Tier I compliance.

Sensitivity: Vermont Tier 1 REC Market 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. Increasing regional renewable and clean energy obligations in neighboring states are anticipated to place pressure on the price of Tier I eligible existing renewables. Voluntary demand for existing renewables on the part of businesses and institutions could also contribute to increasing demand in this market.

Figure 7-17 illustrates the base-, high-, and low-price outlooks for Vermont Tier I RECs that are used in the sensitivity analysis later in this chapter. The common theme is that some noticeable tightening of the supply/demand balance for existing renewables seems likely during the 2020s, but the pace and ultimate magnitude of the increase is uncertain.

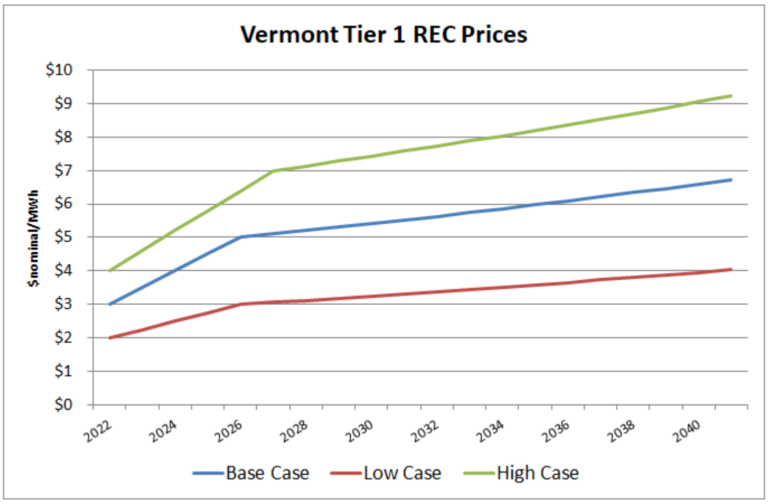

Figure 7-17 Vermont Tier I REC Market Prices

Modeled Portfolio Outcomes

Using a simulation model that depicts supply and demand at an hourly level of resolution has provided opportunities to better understand tradeoffs between potential portfolio designs containing different mixes of resource types. To inform the long-term design of GMP's portfolio, we conducted a screening analysis of potential portfolio designs focused on calendar year 2036 – a year when the current Granite Reliable Wind and NextEra Seabrook PPAs will have expired, and volumes under the current HQUS PPA will have largely wound down. GMP's new Great River Hydro PPA will also have reached its full volumes by that time. This analysis compared the energy supply from a range of potential portfolios to forecasted electricity demand, at an hourly level of resolution. The hourly portfolio level outputs that we tracked and summarized for the study include the fraction of electricity consumption met with renewable supply on an hourly basis, hourly energy purchases from and sales to the ISO-NE energy market; and the fraction of each portfolio's assumed renewable energy additions that is projected to meet the hourly needs of GMP's customers versus being resold to the regional market. We also estimated the net energy costs and revenues associated with those purchases and sales, based on Daymark's simulation of regional wholesale energy market prices under a base case outlook and three alternative paths.

The hypothetical portfolios tested generally feature mixes of future resources that could collectively meet GMP's 100% renewable goal on an annual basis. A few cases test the implications of procuring renewable supply more than our customers' consumption, while one case focuses instead on being largely renewable and 100% carbon free to test fit and cost. The following table summarizes the hypothetical future portfolios that were tested.

Portfolio Name	Summary
1. Initial portfolio	Mix of plant-contingent renewable sources – mostly solar and wind – fill the projected open energy position. About 2.4 million MWh of renewable supply added to the portfolio by 2036.
2. 100 MW Battery	Add 100MW of 4-hour duration battery storage, dispatched on regional energy market prices.
3. Extra Wind +10%	Increase the renewable energy supply to 110% of annual energy requirements, using only wind additions.
4. Extra Solar +10%	Increase the renewable energy supply to 110% of annual energy requirements, using only solar additions.
5. Extra Wind +20%	Increase the renewable energy supply to 120% of annual energy requirements, using only wind additions.
6. Extra Solar + 20%	Increase the renewable energy supply to 120% of annual energy requirements, using only solar additions.
7. Shaped Renewable	GMP procures a shaped renewable purchase in the mid-2030s, in lieu of additional plant-contingent wind & solar purchases. Fixed delivery profile, weighted heavily toward times when GMP is projected to need energy (winter months, overnight and peak load hours) and away from times when GMP is projected to have surplus energy (peak solar hours, spring months).
8. Shaped Renewable + High Solar	Increase the fraction of solar energy in the portfolio by 10%.
9. Shaped Renewable + High Wind	Increase the fraction of wind energy in the portfolio by 10%.
10. Carbon-Free Focus	Portfolio goal is 100% carbon free and highly renewable. Includes the shaped hydro purchase above and replaces 400,000 MWh of potential solar and wind additions by extending the NextEra Seabrook PPA at a similar volume.

Table7-3 2036 Summary of Hypothetical Future Profiles Tested

The table below summarizes key results of this single-year analysis for these cases.

The first column shows the total volume of energy associated with the assumed future resource additions in each hypothetical portfolio. These quantities are equivalent across the portfolios except for those that are specifically designed to illustrate the acquisition of renewable supply more than our customers' annual consumption, and one portfolio design that explores the implications of a zero-carbon portfolio objective rather than 100% renewable.

The next column shows the estimated fraction of hourly electricity demand in 2036 that would be met with renewable sources, based on each portfolio's unique supply mix. A higher percentage indicates that the portfolio of supply sources would be better aligned with our customers' electricity consumption on a seasonal and hourly basis.

The last two columns show the estimated volume of energy that would be more than GMP's load requirements – and therefore would be resold to the ISO-NE market on an hourly basis – and the volume of hourly resales as a fraction of the future resource additions.

Portfolio Name	Total MWh Acquired	Hourly Renewable MWh %	Energy Resales to ISO-NE	Percentage Resold
1. Initial portfolio	2,438,000	73%	(1,149,350)	47%
2. 100 MW Battery	2,454,333	72%	(1,035,373)	42%
3. Extra Wind +10%	2,931,740	79%	(1,396,217)	48%
4. Extra Solar +10%	2,954,297	75%	(1,601,462)	54%
5. Extra Wind +20%	3,434,503	82%	(1,726,073)	50%
6. Extra Solar + 20%	3,457,060	76%	(2,081,912)	60%
7. Shaped Renewable	2,495,896	81%	(728,824)	29%
8. Shaped Renewable + High Solar	2,495,896	80%	(818,639)	33%
9. Shaped Renewable + High Wind	2,498,286	82%	(677,162)	27%
10. Carbon Free Focus	2,499,675	77%	(654,249)	26%

Table7-4 2036 Summary of Energy additions by Portfolio and resulting hourly renewable and resale metrics

The following observations emerge from these results:

The fit of the portfolio is enhanced when GMP retires RECs associated with its Class 1 and 2 eligible resources, allowing us to count that generation as renewable supply serving Vermont electricity consumption.

The cases with shaped hydro and additional wind energy show the highest percentages of hourly load served with renewable resources, as well as the lowest volumes of required hourly resales to and purchases from ISO-NE. These results tend to limit our customers' financial exposure to future transactions (i.e., purchases at times when demand exceeds supply, or sales when GMP supply exceeds demand) at uncertain future market prices.

The portfolio designs that feature procurement of renewable supplies well more than our customers' needs tend to show somewhat higher fractions of customer loads being served by renewable energy on an hourly basis. If the additional wind and solar supplies in these portfolios were procured on a long-term basis (e.g., through long-term PPAs or other procurement methods) the important tradeoff would be that these portfolios also feature much larger volumes of required resales of surplus energy. This would likely leave GMP's net power costs more financially exposed to a downturn in regional market prices (generally, or during periods when solar and/or wind generation are high, and the largest volumes of resales occur).

The portfolio designs featuring more wind energy tend to produce somewhat greater supply/demand alignment and lower required energy resales than those featuring more solar energy. For example, the portfolio featuring 10% additional wind energy increases the estimated hourly renewable supply fraction from about 73% to 79% (a gain of 6 percentage points), and less than half of the additional renewable energy assumed to be acquired in this portfolio would be resold to the regional market. In contrast, the corresponding portfolio featuring the same volume of 10% additional solar energy produces only about a 2% gain in hourly renewable supply, with most of the additional solar energy being resold to the regional market.

Taken together, the cases above support the conclusion that although most Vermont policy support and local procurement activity in recent years has focused on solar energy developed here, significant additional regional wind supplies would likely be an appropriate component of a balanced long-term portfolio to serve customers.

The final portfolio design that is focused on carbon-free energy and leverages the steady output profile of some ongoing nuclear purchases, shows the most favorable results from the perspective of supply/demand alignment: an estimated 85% of hourly load is met with carbon-free energy, with the lowest volume of required resales among the portfolio designs tested in this analysis. If Vermont moves toward requirements that are not just annually but instead seasonally (or even more granularly based), it will likely be important to utilize carbon free, rather than renewable, as a touchstone for portfolio balance and customer costs.

Figure 7-18 below is a multi-attribute chart illustrates the relative alignment of supply with electricity consumption for each of the hypothetical portfolios above. Specifically, each portfolio is represented by a dot on the chart, with the volume of additional energy sources acquired in each portfolio depicted on the X-axis, and the fraction of that acquired energy that is estimated to be resold to the ISO-NE spot market (because it exceeds the hourly needs of GMP customers) depicted on the Y-axis. In general, lower percentages of energy resold indicate that the acquisitions are a closer fit with GMP's open energy position on an hourly basis; thus, the better-fit portfolios with the least exposure to market price changes are in the lower, left areas of the chart, whereas portfolios with greater resale and purchase volumes and more exposure to market price changes are in the upper right areas.

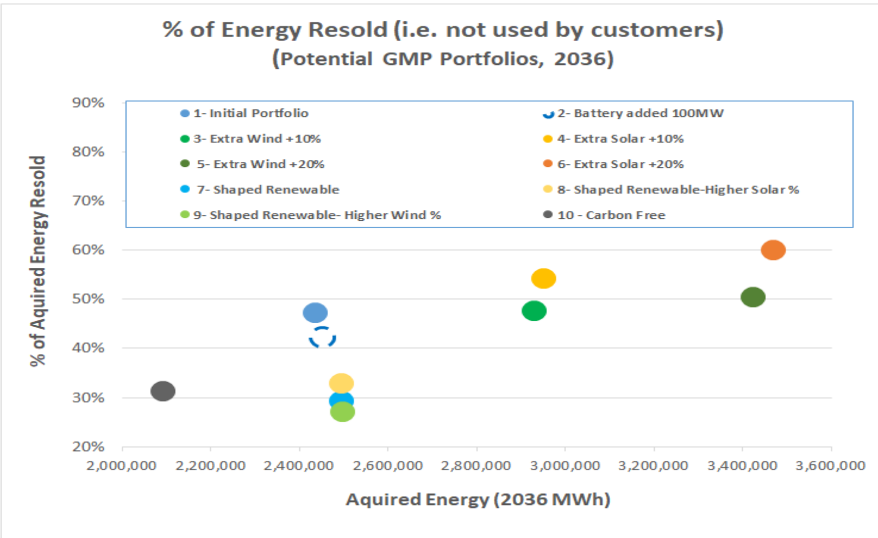

Figure 7-18 Percent of Energy Resold Under Potential Portfolios

Lower percentages of energy resold tend to indicate that the energy acquisitions in a given portfolio fit more closely with GMP's open positions on a seasonal and hourly basis than the additions in portfolios with higher resale percentages. The portfolios to the right side of the chart contain increasing volumes of renewable supply designed to exceed customers' forecasted annual energy needs; these portfolios show fractions of resold energy that approach (or in the case of solar-heavy portfolios) exceed 50 percent, which suggest a relatively poor fit. The hollow blue dot indicates that addition of energy storage to the initial portfolio could somewhat reduce the fraction of energy resold – specifically by charging primarily during hours when market prices are low and GMP has surplus renewable energy and discharging primarily during hours when market prices are higher and GMP's energy requirements exceed its renewable supplies. Addition of energy storage to other portfolio designs could also increase their hourly alignment to varying degrees, although we did not test this directly.

It is reasonable to expect that a portfolio of energy sources with output relatively closely aligned with customers' energy requirements on a seasonal and hourly basis – and is not strongly affected by location-specific congestion or losses – will also tend to be relatively effective at stabilizing net power costs to serve those requirements. We tested that proposition for the set of potential GMP portfolio designs summarized above, by using Daymark's hourly regional simulation model to estimate how net energy costs for each portfolio would be affected by three alternative regional market price outcomes in 2036. These alternative market cases – driven by assumptions regarding higher CO_2 prices for generators in the New England electric market, delays in some regional renewable energy projects, and a reduction in the volume of offshore wind that is ultimately developed in New England, are explained further below ("Wholesale Energy Market Inputs"); the results are summarized in Figure 7-19 below.

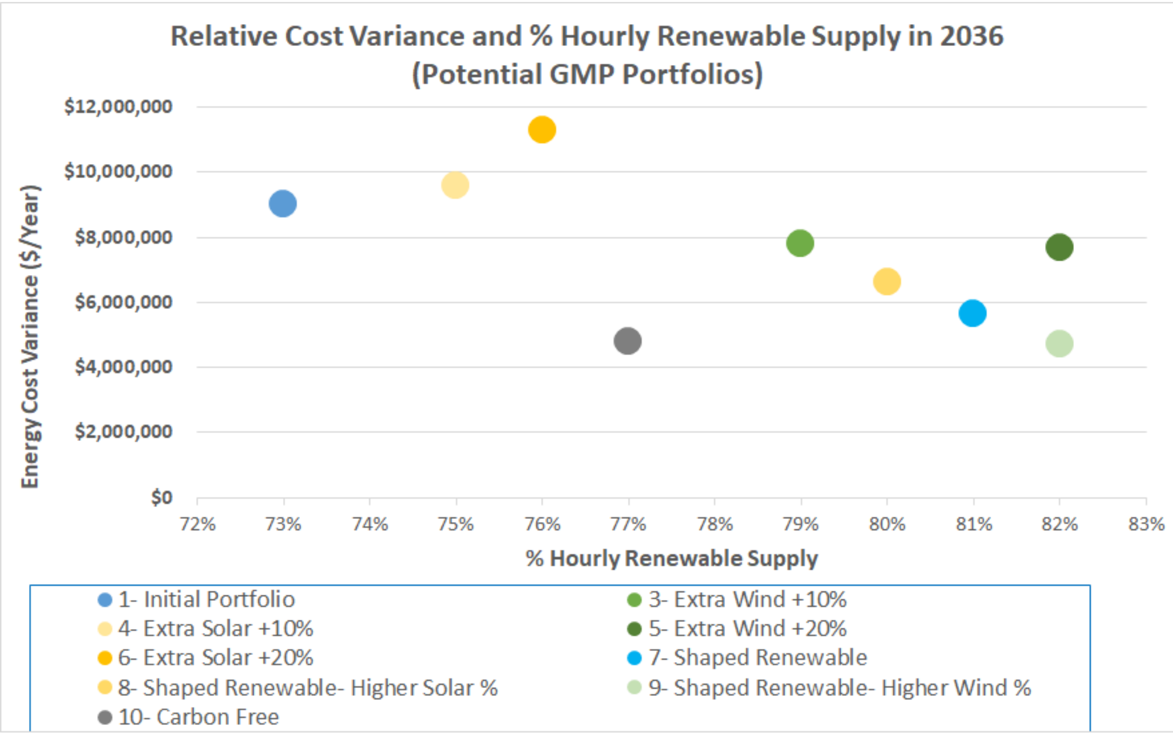

Figure 7-19 Relative Cost Variance and % Hourly Renewable Supply

The X-axis on this chart indicates the relative fit of supply and demand for each portfolio as approximated by the fraction of demand that is supplied with renewable or carbon-free sources on an hourly basis. The Y-axis illustrates the range of simulated net energy costs in 2036 for each portfolio under the four regional market cases outlined above. Simulated net energy costs for the portfolios with relatively high hourly alignment – those on the right side of the chart – tended to be least affected by changes in the energy market. Portfolios featuring lower degrees of hourly alignment – those on the left side – were more significantly affected by market changes. For example, net energy costs for the least aligned of the hypothetical portfolios – the Initial Portfolio based only on plant-contingent additions, and the portfolio featuring 10% of extra solar supply – varied two to three times as much as net energy costs for the most aligned portfolio, which includes a hypothetical, shaped renewable purchase and a relatively high fraction of wind energy.

As discussed above, portfolio fit – which ideally reflects a balance of supply and demand on both a seasonal and hourly basis – is an important metric for understanding the potential impact of the various options explored above. What can be seen by studying the various cases is that the overall fit is better for some than others. For example, the strategy of continuing REC sales on a substantial scale creates a meaningful mismatch between renewable energy supply and customer loads on an hourly basis. This is largely driven by a portion of GMP's renewable supply being met with REC-only purchases that are not associated with generation during specific hours. As we seek to improve the alignment of renewable energy output and demand this strategy comes up short against all the other options tested.

The strategy of procuring renewable sources significantly more than GMP's annual needs increases the volumes of renewable supply available to serve customer load on an hourly basis, but also noticeably increases the projected volumes of required energy resales into the regional market, particularly in the spring and summer months (unless the use of other purchase or operational structures alters that outcome). The increase in resales creates potential risk of a mismatch between prices paid for the renewable energy and the value received for the resale of the volumes that are not used to meet customer demand.

The portfolio option that includes some shaped renewable purchases consistently has the highest energy volumes used to meet customer demand, while this portfolio design features the lowest required resales of energy above our customers' needs. This indicates that adding custom-shaped renewable purchases to the portfolio – if such purchases are available at reasonable prices – would allow GMP to significantly decrease the price risk associated with resales and purchases, compared to portfolios in which all future renewable additions deliver energy on a plant-contingent basis.

On average, about 73% of the additional renewable energy supplies procured in the shaped resource strategy are used to meet hourly customer demand; this significantly exceeds the other two options, which show about half of the additional renewable purchases being used to meet hourly customer demand. This means that GMP would anticipate reselling an average of about 56,000 MWh per month with the shaped resource option, versus double that volume in the other options.

Insights for Portfolio Design

As discussed in this chapter, the need for additional renewable energy sources will be substantial in the long term based on anticipated demand growth driven primarily by electrification, which helps lower cost and carbon for all, and the expiration of some current long-term supply sources. Using a simulation model provides context for understanding the interplay between future demand and the output of resources that could be added to our portfolio to help meet load growth and fill open positions driven by PPA expirations and ramp downs. Based on our attempt to balance portfolio fit, cost, and renewability we believe that the addition of resources featuring different technologies and output profiles will help meet our portfolio needs while maximizing the amount of purchased renewable energy that is used to meet customer demand and minimizing the risk created by balancing hourly portfolio needs through sales to or purchases from ISO-NE.

The following section presents an Illustrative Future Portfolio that features a mix of generation technologies and takes advantage of the complementary output profiles to improve the fit of energy resources with anticipated customer demand. Specifically, the primary new renewable technologies being developed in New England are solar and wind. Expected pricing for these resources is roughly similar, and they are assumed to help meet GMP's additional renewable energy needs. Consistent with the 2036 screening analysis – which indicates that a balance of these resources will be most effective at aligning GMP's renewable supply with electricity consumption and stabilizing portfolio energy costs for customers – in the long term, solar energy and wind energy are added to the portfolio in similar energy quantities. The portfolio is designed to provide sufficient renewable generation to match our customers' consumption on an annual basis, under average weather conditions. Procurement of additional renewable supply could increase the fraction of hourly demand that can be served with renewable sources but as noted in the 2036 screening analysis, this strategy would also entail greater financial risk for our customers depending on future market prices and/or different procurement and operational strategies.

Illustrative Future Portfolio

This section presents an Illustrative Future Portfolio of supply resources, incorporating observations and insights presented in this chapter. The primary challenge and opportunity before us will be to develop a portfolio of resources to achieve and maintain a fully clean and renewable power supply annually in an affordable way. We recognize that the context for this transition has changed since our last IRP – most notably that over the planning horizon electricity consumption by our customers could increase substantially as Vermont strives to decarbonize its economy, while the regional wholesale market environment in which we operate is also likely to evolve significantly. The IFP is "preferred" in that it outlines the types of resources that we expect to explore or maintain in the next decade, based on our current understanding of wholesale markets, customer preferences, and resource options. The portfolio is illustrative in that the resources identified here are not firm commitments; the types and amounts of resources that ultimately make sense to implement could evolve significantly over time based on the factors and signposts outlined in this chapter.

The key resource components of the IFP are as follows.

Additional distributed renewables. The IFP features large growth in distributed renewables, presumed in Vermont to be largely solar generation, with the total solar supply serving GMP customers growing in volume to over 1.1 million MWh/year by 2032, and additional volumes thereafter. For a sense of scale, this would entail solar capacity supplying GMP reaching a total of over 750 MW by 2032, with additional volumes thereafter. The bulk of additional solar generation is assumed to be obtained from Vermont projects sized 5 MW or less.

As discussed in Chapter 6, a large fraction of distributed renewable development in Vermont in recent years has been through the net metering program. Most of the net metering capacity is being developed in projects sized between 15 kW and 500 kW, including many not co-located with load of the customers who financially benefit and take their output. Net metering is presently a relatively high-cost program for all other customers, as the compensation rates are significantly higher than the price at which alternative distributed renewable projects (particularly solar) have been available through other means like PPAs, Standard Offer program, and utility-owned projects. GMP believes net metering can and should continue in Vermont, with the primary focus on smaller systems co-located with customer load. The IFP therefore assumes that the portion of distributed solar growth supplied from net metering at current pricing levels will decrease to about 10 MW/year (a level consistent with the pace of residential net metering in recent years), and that GMP will obtain increasing volumes of distributed solar projects through competitive solicitations or other means producing lower per-kWh cost. This ultimately will result in more solar, more cost-effectively, and more equitably for more Vermonters.

Regardless of the commercial paths that support the development of additional distributed renewables, our customers will likely stand to benefit the most if that generation is located near electricity demand where it can be consumed; this maximizes the potential for distributed generation to reduce electrical losses on the grid and enhances the potential for that generation to support resiliency for customers in the face of climate change. As discussed in VELCO's Long Range Transmission Plan, and in the sensitivity section of this chapter, the geographic distribution of that development should also generally be weighted toward areas of the state where there is ample hosting capacity on the transmission and distribution systems to accommodate that capacity, and away from areas where hosting capacity is more limited and costly grid upgrades would be required to accommodate their output safely and reliably. Smart placement benefits customers and the greater grid.

Larger-scale solar. GMP expects that in the future it will be appropriate to consider larger solar projects as a cost-competitive option to provide a limited portion of our increasingly renewable energy supply, particularly to the extent that they can achieve meaningful economies of scale and offer significantly lower price per kWh than smaller distributed projects. In the IFP, roughly 10% of long-term solar additions are assumed to be from projects larger than 5 MW; these could be in Vermont or elsewhere in New England.

Utility-Scale Wind. The 2036 screening analysis above showed that additions of plant-contingent wind energy would be well aligned with the seasonal and hourly needs for additional renewable energy to supply electricity consumption of our customers and complement the growing fleet of solar generation. Wind energy could be particularly helpful to address current winter needs, along with future electrification loads that are expected to be weighted somewhat toward winter. The IFP therefore contains additions of utility-scale wind projects starting in the late 2020s, increasing significantly into the 2030s as forecasted electricity demand increases and the current Granite Reliable PPA expires. For simplicity, our portfolio analysis depicts the wind resource as offshore projects because wind development activities and state-supported renewable procurement activities in New England are presently focused primarily on offshore projects, and our understanding is that substantial bulk transmission upgrades will be needed to unlock potential low-cost wind resources in northern Maine. In actual practice, however, a meaningful fraction of this supply could potentially be obtained cost-competitively from land-based wind (presumably located largely in other states given the reception of additional wind development here in Vermont) – particularly if current challenges associated with required bulk transmission upgrades are resolved.

New England Hydro. Purchases of existing hydro have historically been a low-cost source of renewable energy available for purchase, particularly for short contract terms up to a few years. As discussed earlier in this chapter, the availability and pricing of hydro energy for purchase in the longer term as other states increase their goals is uncertain; we also recognize that significant portions of output from hydro plants occurs during spring months when GMP's needs for additional renewable energy are typically the least. For these reasons, we have limited the role of in-region hydro purchases in this analysis to a cumulative total of no more than 500,000 MWh per year of additional supply, above the volume from GMP's committed fleet of owned and purchased hydro resources such as HQUS and Great River Hydro. For a sense of scale, this means that in the mid-2030s, additional hydro resources would be limited to about 10 percent of GMP's projected energy requirements.

Reduce REC Sales. The IFP reflects the assumption that by 2030, GMP will retire most RECs that are presently sold to RPS Class 1 and 2 markets in neighboring states, with the revenues all used to reduce net power costs for our customers. This transition would reduce the corresponding volume of REC-only purchases needed from other renewable sources in the region and would reduce the exposure of GMP's net power costs to changing market conditions or RPS program designs in neighboring states. As shown in the 2036 screening analysis above, this step would also noticeably increase the alignment of renewable supply with electricity consumption on a seasonal and hourly basis. Importantly, retirement of RECs associated with renewable generation that GMP purchase or owns would also be positive in terms of clarity of the renewable supply in the eyes of our customers and other stakeholders – making it clear that those sources are serving the electricity needs of our Vermont customers.

Shaped Renewable Purchase. Shaped renewable purchases – if available at a reasonable price – could complement our growing supply of intermittent renewable-energy sources by delivering more energy during seasons and hours when production of those intermittent sources is relatively low and GMP's needs for additional energy are relatively high. The 2036 portfolio screening analysis illustrated that purchases with a seasonal and hourly profile that are complementary to instate solar generation and the rest of GMP's renewable generation supply – and which is sized no larger than our current HQUS contract – have the potential to significantly increase the seasonal and hourly alignment between GMP's increasingly renewable and intermittent energy supplies and our customers' electricity consumption. The IFP includes a volume of shaped renewable purchase starting in 2036, as volumes under the current HQUS contract are scheduled to decline and then end in the late 2030s.

Additional storage and flexible load resources. We expect that tens and potentially hundreds of MW of these resources will be deployed in our territory over the next decade, to address a mix of potential use cases. Because the actual mix of resources, and the appropriate pace of deployment, is substantially uncertain and will depend on several factors (including battery cost, customer needs for resiliency solutions, and wholesale market price trends, among others) that will affect the cost fit and scale of the market for them, we have not explicitly depicted deployment of substantial new storage or flexible load resources in the Illustrative Future Portfolio. To the extent that the range of commercially available longer-duration storage options (from alternative battery chemistries to Highview Power's liquid air storage to other forms) increases over time, the number of feasible use cases is likely to also increase.

We note that the quantity of commercially feasible flexible load is not known with certainty today. This will depend to some extent on the magnitude of value that can ultimately be tapped through emerging use cases – such as shifting energy consumption away from times when renewable energy supply is relatively low and/or market prices are high toward times when the supply of renewable energy is ample and spot market energy prices are lower. GMP will continue to pursue initiatives like the Flexible Load Management 2.0 pilot to help characterize the flexible load resource potential, and help develop processes and skills that GMP and its customers will need to effectively deploy flexible loads in this and other potential new use cases to drive down carbon and costs.

Manage short-term market price volatility through layered forward purchases – and sales. We plan to continue managing forecasted net short energy and capacity positions through a series of layered short-term forward purchases at fixed or stable prices, typically for terms of less than five years. The most prominent examples of these transactions today are forward purchases of energy for delivery during winter months, and forward purchases of capacity. Similarly, we plan to make forward energy sales at fixed/stable prices during periods (e.g., during spring months) that feature forecasted long energy positions. This strategy adds significant near-term price stability to our net power costs and retail rates, compared to leaving these positions to be purchased/sold primarily in the spot market.

Reduced operation and retirements of our existing peaking plants. GMP's existing combustion turbine and diesel plants rarely operate but do provide value as a significant capacity market hedge and at times for local grid support. We recognize the fairly advanced age of our peaking fleet and expect to evaluate the economics of these units in the coming years, considering whether deployment of multi-MW battery storage would be an appropriate use of these sites. For the IRP portfolio analysis, we assume the retirement and replacement path explained in Chapter 6. Actual retirement decisions would, of course, be assessed on a plant-specific basis based on a range of factors so actual retirement dates could differ significantly from the illustrative path presented here.

Potential Refinements to Vermont's RES Requirements. Some components of the IFP make sense when viewed through the lens of GMP's portfolio analysis and goals but would not be fully aligned with the current design of Vermont's RES requirements. GMP expects that RES will evolve in the coming years and has designed the IFP with possible RES improvements in mind. In particular:

Importance of additionality – adding new renewables – for the region's overall carbon goals and limiting the extent to which more existing renewables are added to the portfolio to meet increasing electricity demand over the planning horizon.

New renewable sources from projects sized greater than 5 MW (particularly wind) are likely to play a critical role in achieving a highly renewable and affordable energy supply that also increases the regional supply of renewable energy. The current RES program does not feature a clear path for new renewables in or out of state sized greater than 5 MW, as these sources are only eligible for Tier 1 and are implicitly in competition with existing renewables to supply RES Tier 1.

Phasing out most REC sales, particularly of GMP-owned instate resources, would be a logical and beneficial choice as described previously but is not currently supported by Vermont's RES, making the more prudent choice currently to engage in cost-effective REC sales. Should RES be redesigned to qualify these resources – perhaps under a new renewable tier that would count any new resource, in- or out-of-state, built after a year chosen to better align with other state's Class 1 programs – the phaseout of REC sales would be better supported for customers.

The pace of local renewable generation, if procurement policies can be modified to support more local renewables, more cost-effectively, for more customers. GMP's IFP assumes that this will occur in combination with increasing Tier II above 10% to help increase local renewables while also lowering overall costs.

These observations suggest that in the context of current conditions and planning considerations, it could make sense to revisit some components of the RES requirements and renewable program changes to best serve customers. Our IFP depicts the following combination of potential changes, which are intended to support an increasingly renewable electricity supply that is affordable and informed by the portfolio observations discussed above:

Increase the RES total renewable (Tier 1) requirement from 75% to 100%. GMP has adopted a 100% renewable goal, which is complementary to Vermont's electrification efforts and enjoys substantial stakeholder support. While the exact year for achievement of such an increase under RES would depend upon the overall policy designs, we have modeled 100% Tier 1 by the mid 2030s for the IFP.

Introduce a new RES tier for regional new renewable energy ("New RE Regional Tier") similar in design to RPS Class I in neighboring states - in which output from eligible renewable projects anywhere in New England, including Vermont, that reached commercial operation after a threshold date can qualify for compliance. A tier of this type would support the development of new renewables with project sizes greater than 5 MW, including local projects if competitively priced. This tier would ensure that an increasing portion of future renewable needs are met with new or recently constructed projects and would limit reliance on existing renewables that are eligible for Tier 1. For illustration we depict a New RE Regional Tier requirement that begins in 2025 at 5% and ramps up to 20% by 2035 – when some of GMP's largest existing power purchase contracts expire. Our illustration assumes that projects achieving commercial operation on July 1, 2012, or later (the last legislative check-in date for the prior Sustainably Priced Energy Enterprise Development program) will be eligible to supply this new renewable requirement. For context, this eligibility date is significantly later – and therefore much more restrictive – than those for many RPS Class 1 programs in neighboring states. It would, however, support the retirement of RECs from some GMP sources that are now only eligible for RES Tier I and are therefore sold out of state to Class I RPS markets.

Increase RES Tier II requirements to 20%. This illustration depicts the Tier II requirement ramping up to 20% by 2032, while simultaneously appropriately evolving Vermont's net metering program to focus on small-scale co-located projects, while stepping up the pace of procurement of other solar resources at a lower cost than present pricing for remote group net metered projects. These changes must be viewed as a pair; they would ensure that local distributed renewable energy continues to increase in a more sustainable, equitable, and affordable way. In short, this would provide more local renewables at a similar or lower net cost.

Make instate small-scale hydroelectric plants that qualify under Low Impact Hydro Institute standards eligible for compliance with RES Tier II. While Vermont energy policy is generally supportive of instate hydroelectric generation, existing hydro projects larger than 500 kW are presently only eligible for RES Tier 1. This essentially places them in competition with much larger renewables including existing projects and makes it challenging for owners to justify significant capital investments and for utilities to enter PPAs priced much higher than regional wholesale power prices. Tier II eligibility for low-impact hydro plants would provide a path to support the improvement of the existing hydro fleet for the long term; the IFP reflects an assumption that only low-impact hydro projects sized up to 5 MW would be eligible.

While the preferred Illustrative Future Portfolio is modeled on retail sales like the current Vermont RES, it is possible that Vermont should explore setting renewable requirements as fractions of total electric energy requirements (including electrical losses on the distribution system), as opposed to retail sales. This refinement could enhance clarity about the fraction of Vermont's electricity supply that is being served with renewable energy.

In summary, this package of steps appears to support a Vermont electricity portfolio path that features more new renewable supply – including more Vermont distributed renewables – in an affordable way. The RES refinements would increase the range of renewable technologies and sizes that could be used to supply Vermonters, enhancing our ability to shop among potential renewable options here and regionally, and develop a portfolio in which renewable supplies are relatively aligned with our customers' consumption. The RES refinements would also enhance the ability of GMP to increasingly use Vermont-supported renewable sources to serve Vermont customers and limit our future reliance on REC sales.

Figure 7-20 below compares the fractions of supply from new renewable resources that would be required under the hypothetical RES changes discussed above (including increased Tier II requirements, and a new Regional New Tier) to the volumes presently required under RES Tier II.

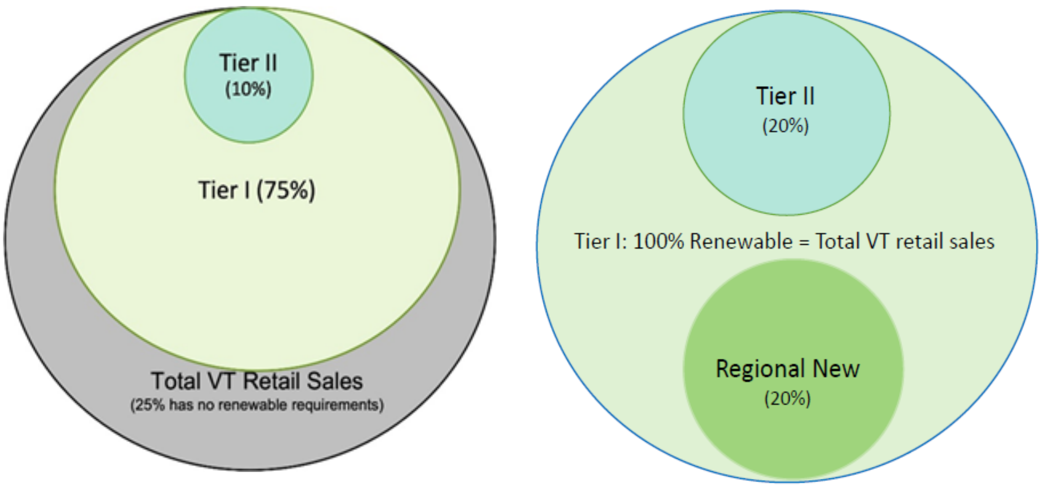

Figure 7-20 Comparison of Existing RES Total Renewable Supply Requirement and Hypothetical 100% design

The combination of an increased RES Tier II and an additional New RE Regional Tier would increase the required role of new or recently constructed renewables rapidly in the 2020s, reaching a total of 40% which is four times the current requirement, by the mid-2030s. If RES requirements like these were implemented, the effect would be to substantially increase the focus on new renewable supply, and to correspondingly limit the fraction of the portfolio that would be committed from existing renewables.

Critically, all these changes would need to be made together with one another to support an affordable transition for customers. The implications of potential RES design modifications like these would, of course, depend strongly on the details – and their effectiveness at achieving policy goals including affordability will need to be evaluated as a package. GMP's primary point here is that evaluation of potential future portfolios sheds light on some RES design features that could enhance the program's effectiveness at supporting the decarbonization of Vermont's economy in an affordable way. We also recognize that the portfolio discussion and evaluation presented in this chapter is based on GMP's supply portfolio and forecasted electricity needs. Changes in RES requirements along the lines of those raised above could affect other Vermont utilities differently; proper review of such changes would need to consider such differences.

Portfolio Cost

Figure 7-21 below presents a projection of annual net power and transmission costs associated with the Illustrative Future Portfolio. The largest component of projected cost is energy, reflecting this chapter's discussion of an increasingly renewable supply portfolio; the other major components are transmission by others and net capacity costs. A line depicting projected retail sales growth (right axis) is also included for context as – in contrast to recent IRPs – projected power costs are driven in part by significant increases in electricity consumption over the planning horizon.

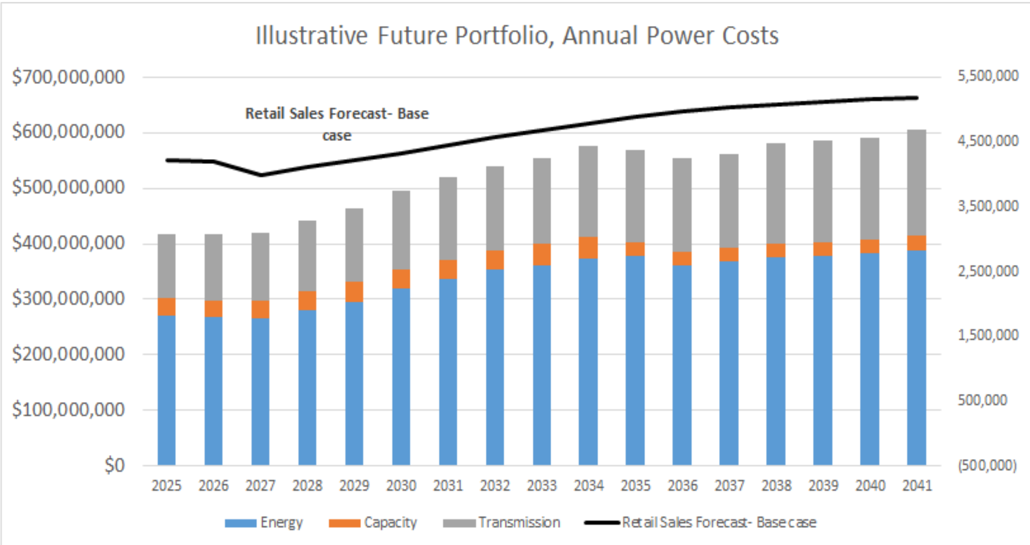

Figure 7-21 Annual power costs for key components of the Illustrative Future Portfolio.

The trend in projected portfolio costs is fairly flat in the near term, as GMP's portfolio is relatively hedged with stable-priced resources. (The near term difference in load is due to modeling Global Foundries as its utility in late 2026, consistent with its petition under review.) We also note that the upward trend in power costs per MWh is tempered somewhat by the expiration of some relatively high-priced existing resources over the planning horizon.

Portfolio Cost Sensitivity Analysis

The goal of this sensitivity analysis is to test the extent to which the costs associated with the IFP could vary based on potential alternative future outcomes for several uncertain factors – primarily alternative outcomes for regional market prices and the cost of new renewable energy sources. The outcomes tested are summarized in the following table; for further details on some factors see discussion in the section "Wholesale Energy Market Inputs" below.

Uncertainty	Sensitivity Case(s) Tested
Cost of Future Renewable Additions	Low and High paths for the effective cost of Solar and Wind sources. The range is driven by potential industry trends and required grid upgrade costs.
Energy Market: Higher CO_2 Prices	CO2 prices for generators in the ISO-NE turn out similar to the RGGI program's Cost Containment Reserve path.
Energy Market: Regional Renewables Delayed	NECEC transmission project delayed to 2026. New England offshore wind projects are completed on a smoother, moderately delayed path.
Energy Market: Offshore Wind Capped	New England offshore wind projects are moderately delayed, and reach a maximum of ~2,000 MW less than in GMP base case. New England solar PV replaces most of the lost energy.
REC Market Prices (RPS Class 1)	Low and High market price paths, driven by the pace of new renewable supply growth in New England compared to RPS requirements.
REC Market Prices (Vermont Tier 1)	Low and High market price paths, driven by regional supply and demand for existing renewable and low-carbon generation sources.
Net Metering Growth at Current Pricing	Net metering grows consistent with Reference Case. By 2032, about XXX MW of additional net metering displaces lower-priced solar PPAs.

Table7-5 Inputs to Sensitivity Analysis

The results of the portfolio cost-sensitivity analysis – expressed for each uncertainty as the estimated increase or decrease in GMP's net portfolio costs over the period 2022 through 2041 – are summarized in Figure 7-22 below.

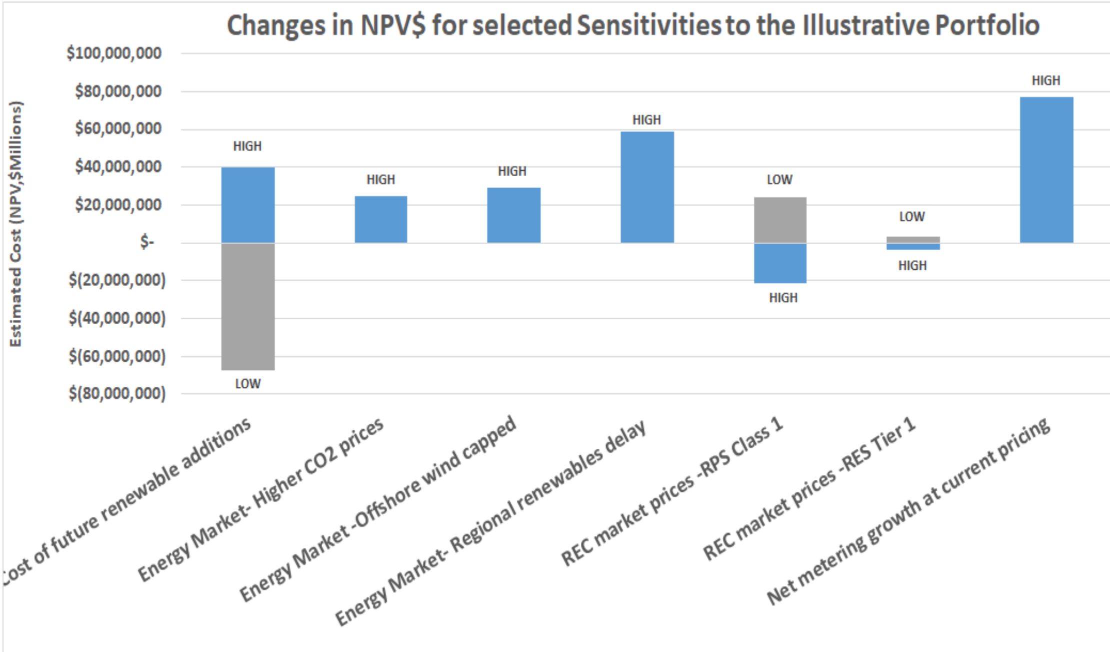

Figure 7-22 Changes in NPV$ for selected Sensitivities to the Illustrative Future Portfolio.

Not surprisingly for a portfolio strategy that strives to become fully renewable on an annual basis, the largest indicated cost uncertainties indicated for GMP's illustrative portfolio are associated with the effective cost at which future renewable supplies can be obtained. A low-price path for future solar and wind sources provides the largest opportunity for lower costs for this portfolio, while the net metering uncertainty (i.e., continuation of recent growth trends over the long term, at current net metering compensation rates) is indicated as the largest single exposure to higher costs for customers. The regional energy market sensitivities show direct cost impacts due in part to the supply/demand alignment effects discussed earlier in this chapter; part of the indicated increases arise from our assumption that negotiated pricing for the regional hydro and shaped renewable energy purchases would also increase in the context of higher spot market energy prices.

Other Portfolio Metrics

We have not calculated flexibility metrics – the ratio of fixed or stable-priced MWh to total energy requirements, fraction of the portfolio hedged five-plus years in the future – for the IFP, primarily because the exercise of analyzing a preferred portfolio entails commitment to procure specific resources and volumes of renewable energy at specific points in time. In actual practice, consideration of these metrics tends to come to the fore when specific resource opportunities with discrete resource sizes and terms are sought or become available. For example, in the context of the Great River Hydro PPA opportunity in 2020, GMP's negotiation of contract volumes that ramp up over time was directly informed by consideration of our then-current projections of open renewable energy positions and the prospect of substantial volumes of existing supply expiring within several years in the mid-2030s.

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 identify additional factors expected to help guide resource decisions in the coming years. This approach introduces new threshold events to help inform and potentially narrow the list of resources that will be considered for addition to the portfolio in future years.

Table 7-6 below presents a list of potential factors that we expect to monitor in the course of evaluating future resource additions and identifies the type of resources they inform.

Indicator	Context	How This Indicator Could Inform Our Choices and Actions
GHG emission regulations	National or Regional	Leading indicator of trends in electricity market prices, and relative price of electricity versus fossil fuels.
Frequency of extreme weather events	National, Regional, & Local	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 the changing relative energy 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-NE annual, Vermont monthly)	Local & Regional	Benefit and cost evaluation of potential battery storage and flexible load resources, for managing peak.
Potential changes to rules around peak shaving such as load reconstitution for RNS	Local & Regional	Impact on value of peak-shaving resources such as storage.
MW and MWh of battery storage deployed in the region	Regional	Leading indicator of potential trends in ISO-NE peak load profile, and anticipated supply saturation for the ISO-NE Frequency Regulation market.
Pace of net metering applications and installations in our territory	Local	Leading indicator of how much Tier II-eligible supply we will acquire and impact on our net power cost relative to other forms of solar generation.
"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; and changes to scoring of Tier III projects	Local	Leading indicator of GMP's ability to meet Tier III obligations. Potential requirement to retire Tier II RECs if different forms of transformation are excluded from scoring.
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 7-6 Potential Signpost Indicators

National Indicators

For this category, we will evaluate the larger transformative energy trends that have the broadest 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 regional 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.

Wholesale Energy Market Inputs

The regional energy market outlook depicted in this chapter as GMP's base-case outlook was derived using Daymark's Northeast Market Model, which uses Plexos, a detailed fundamentals-based market simulation software. This is an hourly simulation model that analyzes dispatch based on anticipated loads and available resources across the region and along with electrical interconnections to other regions. The energy prices are based on assumptions of future natural gas prices, basis differential at the Algonquin City gates location; anticipated generation additions and retirements; implied heat rates that reflect the changing regional generation fleet; anticipated future carbon pricing based on RGGI and other sources; and general assumptions about future levels of inflation. In general, we relied on Daymark's fundamental analysis and reviewed the underlying assumptions for reasonableness. The following are notable assumptions reflected in the GMP base case:

Large additions of wind and solar generation are assumed to enter the market, consistent with the New England states' collective goals to substantially decarbonize the electricity generation sector. This entry of renewables significantly changes the generation supply stack, displacing most of the current natural gas generation volumes in New England by the mid-2030s. This dynamic puts significant downward pressure on energy market prices over time, and affects the seasonal and hourly patterns of energy market prices.

The price of CO_2 allowances for electric generators in New England is between the RGGI program's Cost Containment Reserve and Emissions Containment Reserve prices. These prices put increasing upward pressure on energy market prices over time but are well below estimates of the societal cost of carbon as regional policymakers have so far emphasized other policies (e.g., renewable and clean energy requirements; long-term stable-priced PPAs; energy efficiency investments) to pursue decarbonization of the electric sector.

Winter natural gas price basis differentials (at Algonquin Citygate) are assumed to decrease modestly relative to historical multi-year averages, consistent with the modeled decline in regional natural gas generation volumes over time.

A general inflation rate of 2% per year. While inflation over the past 12 months has been much higher, this appears to be a temporary distortion that will dissipate over the next few years as inflation returns to historical levels. Observing inflationary trends throughout the next few years and into our next IRP period will of course be important to test this assumption.

Since the bulk of this case was prepared, there has been a substantial increase in near-term fossil fuel prices – particularly for deliveries in 2022 and to a lesser extent the following few years. This development – which appears to be having a much more muted effect on longer-term market expectations – is not captured in our analysis.

In addition to the base case, GMP and Daymark tested how the energy market price outcomes might be affected by three alternative assumptions about the region's electricity supply and market conditions:

Higher CO_2. Emission prices in the electricity market are assumed to follow a path consistent with the RGGI Cost Containment Reserve path. This represents significantly higher pricing – reaching about $32/ton by 2035, or roughly double the price in the base case – although still well below estimates of the societal cost of carbon.

Delayed Regional Renewables. In this case the large, assumed buildout of renewable generation ultimately occurs, but on a more gradual pace in which several offshore wind projects are delayed for a few years. An outcome like this could result from challenges in project permitting and/or construction logistics. This change has the effect of reducing the volume of zero-cost renewable energy in the New England electricity supply stack in most years, most prominently during months (including winter) when offshore generation is relatively high.

OSW Delayed & Capped. In this case the buildout of offshore wind projects is delayed as in the prior case and achieves a cumulative total of roughly 3,000 fewer MW than in the base case. By the mid-2030s most of the unrealized wind energy is replaced with about 4,500 MW of additional solar PV generation across New England.

Figure 7-23 illustrates the range of simulated energy market prices used in the portfolio analysis for energy delivered at the Vermont Load Zone. The prices shown here are round-the-clock ("7x24") averages; coincidentally the average impacts for the sensitivity cases are similar in the long-term. Due to their different generation mixes and emission pricing the cases also feature some differences in seasonal and hourly energy market price profiles which are not shown here; the sensitivity analyses summarized earlier in this chapter tested net portfolio costs impacts using the simulated hourly market prices.

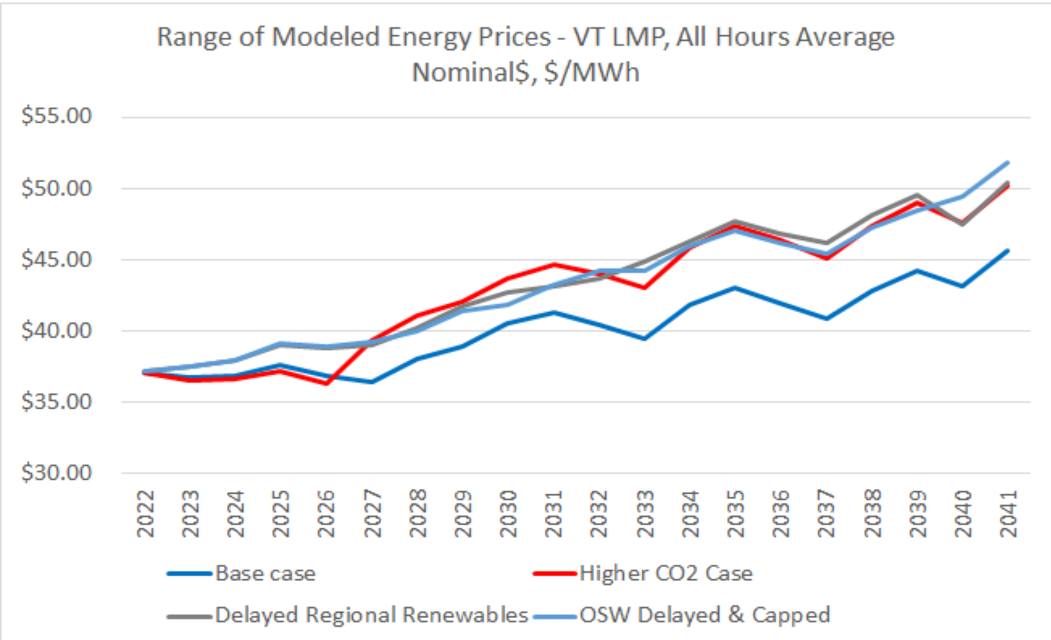

Figure 7-23 Energy Pricing from Regional Market Simulations

8. Financial Assessments

Overview

Financial forecasts serve an essential role in providing an assurance that GMP is functioning properly today and has a blueprint to continue to serve our customers and maintain sound footing in the future. Financial-forecasting data serves different stakeholders. Regulators want to know that GMP is financially stable and therefore remains strong for customers. Rating agencies like Standard & Poor's (S&P) use forecasts to issue credit ratings that inform lending institutions as they offer short- and long-term costs of debt to fund GMP's liquidity needs, which in turn affects the amount customers pay. Finally, forecasts are used to plan what equity investments will or will not be required in the future so we have the capital available to operate.

The base case 2021 IRP financial forecast was put together in Summer 2021 and was anchored by the revenue and load forecasts used to set rates beginning in October 2021 (GMP's fiscal year (FY) 2022). GMP will be providing the PUC an updated forecast in January 2022 for the next four fiscal years as part of our 2023 rate case. The due dates and preparation need for both the IRP and the FY23 rate case required that we use two different forecasts for these two activities – one for the IRP and one for the upcoming rate case. While these forecasts will be prepared within a few months of each other and cover overlapping years, they will not be the same. Nevertheless, the IRP forecast used here provides an appropriate foundation for the planning purposes of this document and will be directionally like the updated forecast provided in the upcoming rate case.

The base case 2021 IRP projected five years of financial results. Like all forecasts, the earlier years are likelier to be more accurate than those more distant in the future. In this forecast, we are projecting the impact of known variables in the current environment over a going-concern basis. Contrary to scenario-based modeling, where all variables are assigned a probability, a base-case scenario reflects the most probable case based on widely accepted assumptions. Variables like weather, interest, ROE changes, and tax rates are kept constant to avoid presenting a financial profile of the company impacted by elements over which we have no control. Annual updated forecasting for rate setting will ensure that these items are captured, understood, and adjusted appropriately to reflect costs. Similarly, strategic investment opportunities may arise over the next five years that are not included in the forecast here. Like our purchase of the fleet of hydro dams in 2017 or our Broadband Deployment Rider approved early in 2021, these opportunities are relatively rare and arise relatively suddenly. Rather than speculate, this base case forecast does not include spending for any such potential opportunity but rather assumes that the overall spending profile is similar to how resources are currently allocated.

Rating Agency Perspective

Appendix B contains the latest S&P review of GMP. Because the rating agency now considers the company to be a core investment of a larger enterprise, which means it is a stable investment important to the group's long-term strategy, S&P increased GMP's issuer credit rating from "A-" to "A." The stand-alone credit profile remains unchanged at "BBB+" based on an excellent business risk profile. This highlights the value of the long-term nature of GMP's business.

Capital Spending

Capital spending is an important component of GMP's financial considerations. We spend capital dollars to both maintain the current infrastructure and adapt to the changing environment of the electric utility industry.

A portion of capital must be spent to support existing operations, like pole and vehicle replacements, and other equipment and components needed for generation, transmission, and distribution projects. Some of these cannot be anticipated at the outset of any year. For example, GMP has seen an increase in car vs. pole incidents arising from distracted driving and cannot predict year to year exactly how much expense will be created by such hard-to-predict repairs. Work to support municipal and state road projects, or to perform make-ready work for communications carriers, or line extensions for new customers all are other examples of capital spending that vary year to year based upon the schedule and needs of others, rather than GMP's own planning processes.

Many parts of the company need sustained investments. Generation units wear with time and need upkeep. Laptops and other IT equipment degrade with time or become obsolete. The company's fleet vehicles, which travel approximately 4 million miles each year, have limited useful lives and need to be replaced. As we look towards a decarbonized future, our next regulation plan will focus on replacing fleet vehicles with electric equivalents as much as possible.

In addition to maintaining infrastructure, we also make investments to adapt to the changing conditions in the electric industry. We have placed a strong emphasis on spending capital on projects that improve both the grid and the company's resiliency. For example, through our Climate Plan, we have undertaken more projects to harden the grid in the face of growing climate change challenges than we had previously done. Additionally, the rise of distributed energy resources (DERs) throughout the service territory has led to the need to make investments so that the grid continues to operate smoothly.

We also continue to make investments in innovative technologies that transform both how we operate and interact with customers. As an example, GMP leases batteries to customers that give them backup support in case of a storm-related outage. In exchange, all customers receive the benefit of both monthly payments and the ability to deploy the batteries during peak usage times, thereby reducing both transmission and market capacity costs.

Appendix C explains the capital planning philosophy by each major area within the company.

The chart in Figure 8.1 below shows our current view of base-case capital spending by major area for the 10-year period of 2022 – 2031. It is important to note that these figures for both FY22 already underway and the next few years are preliminary as we complete our capital project review for the FY23 case, and work to incorporate certain investments such as Climate Plan spending into our base capital projections.

Forecasted Capital Spending

(in $000s)

	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030	FY2031
IT/Cyber Security	$9,227	$9,611	$9,036	$9,036	$9,036	$9,036	$9,036	$9,036	$9,036	$9,036
Transmission and Distribution	$58,314	$70,206	$66,001	$66,001	$66,001	$66,001	$66,001	$66,001	$66,001	$66,001
Transportation and Facilities	$3,418	$12,547	$11,796	$11,796	$11,796	$11,796	$11,796	$11,796	$11,796	$11,796
Production	$12,928	$29,000	$27,263	$27,263	$27,263	$27,263	$27,263	$27,263	$27,263	$27,263
New Initiatives	$10,750	$11,600	$10,905	$10,905	$10,905	$10,905	$10,905	$10,905	$10,905	$10,905
Total	**$94,636**	**$132,965**	**$125,000**	**$125,000**	**$125,000**	**$125,000**	**$125,000**	**$125,000**	**$125,000**	**$125,000**

Figure 8.1. Forecasted Capital Spending

The amounts included in the long-term forecast are based on the overarching goal of providing low-cost, clean, reliable energy to our customers.

We continue to invest in our transmission and distribution infrastructure to minimize the effects of climate change on our system and increase overall system resiliency. We are focused on relocating our lines roadside as well as going underground using cable in conduit to advance reliability. Installing automated technology on the lines such as motor-operated breakers and reconfiguration of circuits allows the system to clear faults and sectionalize circuits so the duration of customer outages will be shorter. Substation reconstruction and relocation is also critical to system reliability. Substations will be rebuilt to address exposure to failure of aged equipment and address safety concerns within each substation. We are also identifying specific substations that will require relocations to reduce the risk of failure due to flooding.

The generation fleet investment focuses on safety and reliability. Much of the production fleet is original vintage and continued investment is required to ensure nameplate ratings are achieved, and automation upgrades are made to minimize extended down time due to equipment failure. Ensuring that the wind and hydro units are reliable and running ensures that we are 100% carbon free. Battery storage is also a key part of our generation plan, allowing us to capture this energy to offset peak loads and help customers keep the lights on during restoration events. Providing these innovative alternatives for customers on an ongoing basis gives each individual control over their energy usage, which in turn helps change the overall framework of the delivery of electric utility services.

Along with system hardening, improving our technology across all aspects of our operations is critical to keep up with the evolving threat landscape. Investments in our core technology operating systems will continue to be made to help limit any interruptions in day-to-day operations and keep up with enhancements or additional functionality to improve security and service to customers.

Meanwhile, reduction in carbon emissions and improvements in reliability and safety are drivers for our buildings and fleet capital investments over the next 10-year period. As electric vehicles become more available with longer battery life viable for GMP's operations, we are committed to transition to an all-EV fleet for small vehicles by 2025, and for the remainder of the fleet as larger units enter the market. Investments in our buildings and properties include not only the replacement of aged plant like roofs but also the replacements of less-efficient heating and control units to help reduce carbon and overall cost of operations.

Financial Statements

The table below shows the major assumptions used in our five-year forecast:

Variable	Assumption
Retail Sales Forecast	Itron forecast from FY22 Base Rate filing.
Power Supply Forecast	Summer '21 vintage
Capital Spending	Level noted in charts above
Allowed ROE	8.57%
Debt to Equity	50 / 50
LT Interest Rate	4.5% across the period
ST Interest Rate	<1% in FY22 rising to 2.25% in FY30
Payroll Increase	2.5%
Overheads	3%
General Inflation	2%
Major Acquisition	None Included

Figure 8-2. Assumptions Used in 5-Year Forecast

The Tables below show the output from our five-year financial forecast.

INCOME STATEMENT	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**
Operating Revenues:					
Retail Revenues	$ 680,762	$ 684,726	$ 712,479	$ 737,937	$ 762,212
Electricity Sales (Billing Adj's)	9,830	-	-	-	-
Business Development - Net	280	258	250	250	250
Other Operating Revenues	20,833	25,818	24,532	21,523	18,826
REC Revenue	14,860	16,754	15,848	12,236	5,210
Total Operating Revenues	***726,565***	***727,557***	***753,109***	***771,946***	***786,498***
Operating Expenses:					
Power Supply Total Energy, net of resales	252,556	269,602	279,152	279,768	280,321
Power Supply Total Capacity	54,654	44,552	41,049	44,945	47,060
Subtotal Power Supply	*307,210*	*314,155*	*320,201*	*324,713*	*327,381*
Transmission by Others/Transmission Rents	123,046	117,189	122,447	125,532	126,307
Depreciation/Amortization	87,607	80,377	84,845	88,968	92,651
Regulatory Deferrals	4,145	-	-	-	-
Cost Center O&M (incl. Payroll and Overheads)	108,299	111,758	114,293	116,904	119,461
Taxes other than Income	45,193	47,458	49,544	51,678	53,660
Total Operating Expenses	***$ 675,501***	***$ 670,936***	***$ 691,330***	***$ 707,793***	***$ 719,460***
Operating Income	***$ 51,064***	***$ 56,621***	***$ 61,779***	***$ 64,153***	***$ 67,038***
Other Income (Loss):					
Other Income, includes Equity-in-Earnings	69,724	74,961	74,731	74,639	74,343
Interest Expense	37,037	37,604	38,999	39,528	40,870
KCW Accretion Expense (ARO)	370	385	401	584	436
Pre-tax Income	*83,381*	*93,593*	*97,109*	*98,679*	*100,076*
Income Taxes	13,560	22,391	24,486	25,039	25,467
Net Income before Non-Controlling Interest in Income	**$ 69,821**	**$ 71,202**	**$ 72,624**	**$ 73,640**	**$ 74,609**
Non-Controlling Interest in Income - Income/(loss)	(764)	(602)	(543)	(117)	0
Net Income	**$ 69,057**	**$ 70,601**	**$ 72,081**	**$ 73,524**	**$ 74,609**
Pre-Tax Income + Non-Controlling Interest	*82,617*	*92,991*	*96,567*	*98,562*	*100,076*
Effective Tax Rate	16.41%	24.08%	25.36%	25.40%	25.45%

Table 8-2. Income Statement

BALANCE SHEET - ASSETS	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Utility Plant:					
Utility Plant in Service	2,266,466	2,395,565	2,506,401	2,616,062	2,726,708
Less: Accumulated Depreciation and Amortization	(835,511)	(911,291)	(985,410)	(1,064,083)	(1,146,017)
Net Plant in Service	1,430,956	1,484,274	1,520,991	1,551,979	1,580,692
CWIP	58,386	58,964	62,829	67,799	70,435
Nuclear Fuel	1,747	1,841	1,857	1,975	2,078
Net Utility Plant	*1,491,089*	*1,545,078*	*1,585,677*	*1,621,753*	*1,653,204*
Current Assets:					
Cash and Cash Equivalents	8,623	7,638	7,735	7,832	7,951
Special Fund Millstone Decomm	16,392	16,392	16,392	16,392	16,392
Accounts Receivable, Net of Allowance	92,628	92,856	94,727	96,441	98,055
Inventories	28,167	29,153	30,100	31,047	31,993
Derivative Financial - Current	3,118	3,118	3,118	3,118	3,118
Prepaid Expenses and Other Current Assets	30,584	31,949	32,243	32,536	32,829
Total Current Assets	179,513	181,106	184,315	187,366	190,339
Other Utility Assets:					
Pine Street, Asset	6,547	6,263	5,979	5,696	5,412
Derivative	14,385	14,385	14,385	14,385	14,385
Pension Fund	93,449	95,122	96,690	98,254	100,157
Total Regulatory Assets	114,381	115,771	117,054	118,335	119,954
Other Deferred Charges:					
Preliminary Survey	4,292	4,292	4,292	4,292	4,292
Deferred Assets - Other	41,716	37,631	35,240	32,849	30,591
Deferred Assets - Efficiency Fund Payments	6,314	4,182	2,655	1,389	725
VYNPC Special Trust Funds	2,857	2,891	2,926	2,960	2,994
Total Other Deferred Charges	55,179	48,996	45,113	41,490	38,602
Other Assets:					
Accumulated Deferred Income Tax	150,941	150,941	150,941	150,941	150,941
Associated Companies	691,441	696,941	698,933	699,727	697,731
Cash Surrender Value of Officers' Life Insurance	20,214	20,210	20,207	20,203	20,199
Other Assets and Investments	16,124	15,555	14,978	14,399	13,802
Total Other Assets	878,721	883,648	885,058	885,271	882,674
Other Assets - Non-Utility Property	7,172	7,172	7,172	7,172	7,172
Total Assets	**$ 2,726,054**	**$ 2,781,770**	**$ 2,824,388**	**$ 2,861,387**	**$ 2,891,945**

Figure 8-3. Balance Sheet – Assets

BALANCE SHEET - CAPITALIZATION AND LIABILITIES	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Capitalization:					
Additional Paid-In Capital	587,636	549,394	539,394	529,394	516,894
Distributions to Non-Controlling Member	(1,101)	(1,101)	(1,101)	(1,101)	(1,101)
Equity Interest of Non-Controlling Member	(14,589)	4,254	4,797	4,914	4,914
Retained Earnings	359,890	384,077	408,782	431,944	455,194
Total Stockholder's Equity	931,836	936,625	951,872	965,152	975,902
Long-Term Debt	782,585	805,085	855,085	855,085	877,085
Total Capitalization	1,714,421	1,741,710	1,806,957	1,820,237	1,852,987
Current Liabilities:					
Short-Term Debt	147,023	139,341	113,050	117,272	93,068
Current Portion of Long-Term Debt	915	17,500	0	0	18,000
Accounts Payable	44,954	46,785	47,773	48,759	49,746
Derivative Financial Instruments - Current Portion	3,118	3,118	3,118	3,118	3,118
Other Accounts Payable and Accruals:					
Accounts Payable - Associated Companies	3,605	3,699	3,787	3,875	3,964
Accrued Interest Payable	11,872	11,981	12,293	12,257	12,857
Other Misc.	41,358	42,138	42,872	43,105	43,838
Total Other Accounts Payable and Accruals	56,834	57,818	58,952	59,237	60,659
Total Current Liabilities	252,845	264,561	222,893	228,387	224,591
Regulatory Liabilities:					
Pine Street, Liability	2,601	2,601	2,601	2,601	2,601
Reg Liability - Def Future Income Taxes	135,883	133,223	130,564	127,904	125,244
Cost of Removal - Reg Liability	25,100	25,694	26,253	26,811	27,369
Other Requlatory Liabilities	16,792	16,792	16,792	16,792	16,792
Total Regulatory Liabilities	180,376	178,310	176,209	174,107	172,005
Derivative Regulatory Liability	14,385	14,385	14,385	14,385	14,385
Asset Retirement Obligations	12,374	12,759	13,161	13,744	14,180
Deferred Taxes	454,011	474,143	496,195	517,431	521,582
Minimum Pension Funding Liability	89,102	88,578	88,077	87,576	87,413
Other Liabilities	8,540	7,324	6,512	5,520	4,801
Total Liabilities	1,011,633	1,040,059	1,017,431	1,041,150	1,038,958
Total Liabilities & Capitalization	**$ 2,726,054**	**$ 2,781,770**	**$ 2,824,388**	**$ 2,861,387**	**$ 2,891,945**

Figure 8-4. Capitalization and Liabilities

CASH FLOW	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Operating Activities:					
Net Income	69,057	70,601	72,081	73,524	74,609
Net Income Attributable to Non-Controlling Interest	(764)	(602)	(543)	(117)	-
Net Income Before Non-Controlling Interest	$ 69,821	$ 71,202	$ 72,624	$ 73,640	$ 74,609
Adjustments to Reconcile Net Income to Net Cash Provided by					
Depreciation and Amortization	79,493	80,118	85,440	90,067	94,698
Amortization of Regulatory and Other Deferred Amounts	13,396	4,312	2,011	1,751	1,149
Amortization and Deferral of Purchased Power Costs, Net	1,290	1,406	1,284	1,282	1,397
Dividends and Distributions From Associated Companies	68,750	73,486	75,090	76,538	78,672
Equity in Undistributed Earnings of Associated Companies	(72,995)	(77,426)	(77,082)	(76,949)	(76,676)
AFUDC	(1,187)	(1,200)	(1,200)	(1,200)	(1,200)
Deferred Income Tax Expense, Net of Investment Tax Credit Amortization	11,480	17,472	19,392	18,576	1,492
Environmental and Conservation Deferrals, Net	(141)	(170)	(170)	(170)	(170)
Working Capital Changes in:					
Accounts Receivable	(1,889)	(227)	(1,871)	(1,714)	(1,614)
Other Current Assets & Deferred Tax Adjustment	(4,219)	(3,882)	(2,572)	(2,671)	(2,771)
Accounts Payable and Other Current Liabilities	442	1,692	1,960	1,044	2,133
Other Assets	3,406	307	436	439	306
Other Liabilities	(685)	(523)	(282)	(217)	(47)
Net Cash Provided by Operating Activities	***$ 166,963***	***$ 166,566***	***$ 175,061***	***$ 180,416***	***$ 171,978***
Investing activities:					
Utility Plant Expenditures	(93,742)	(131,761)	(123,796)	(123,796)	(123,796)
Investment in Associated Companies	(33,126)	(780)	-	(384)	-
Net Cash Used in Investing Activities	***$ (126,869)***	***$ (132,541)***	***$ (123,796)***	***$ (124,180)***	***$ (123,796)***
Financing activities:					
Issuance of Long-term Debt	(400)	40,000	50,000	-	40,000
Repayment of Long-term Debt	(8,000)	(915)	(17,500)	-	-
Additional Paid-In Capital	-	(20,000)	(10,000)	(10,000)	(12,500)
Net Borrowings on Short-Term Debt	16,949	(7,682)	(26,291)	4,222	(24,204)
Cash Dividends	(49,085)	(46,413)	(47,377)	(50,361)	(51,359)
Net Cash Provided by Financing Activities	***$ (40,536)***	***$ (35,010)***	***$ (51,168)***	***$ (56,139)***	***$ (48,063)***
Net Increase in Cash and Cash Equivalents	**$ (442)**	**$ (986)**	**$ 97**	**$ 97**	**$ 119**

Figure 8-5 Cash Flow

The resulting key outcomes or statistics of the above financial projections are summarized in the chart below, though it should be noted again that these are only directional, using several assumptions, and not reflective of what GMP anticipates filing in the FY23 rate case after updating and review is completed:

FINANCIAL STATISTICS - RATIOS $ millions	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**
Total MWh	4,063,498	4,092,586	4,111,661	4,129,134	4,150,498
Capital Spending	$ 94.6	$ 133.0	$ 125.0	$ 125.0	$ 125.0
Investment / (Return of Capital) in Transco	$ 33.1	$ 0.8	$ -	$ (0.8)	$ -
Investment in JV Solar-Battery	$ -	$ -	$ -	$ 1.2	$ -
Base Rate Impact - with flat ROE	**4.7%**	**2.5%**	**3.7%**	**3.1%**	**2.9%**
Allowed ROE	**8.6%**	**8.6%**	**8.6%**	**8.6%**	**8.6%**
Projected Earned ROE	**7.5%**	**7.5%**	**7.6%**	**7.6%**	**7.7%**
13 month Average Equity Ratio	**49.8%**	**50.0%**	**50.0%**	**49.9%**	**50.0%**
Key Credit Statistics					
FFO to Total Debt	17.1%	16.8%	17.8%	18.4%	18.8%
Debt / EBITDA X	4.8	4.9	4.7	4.6	4.5
Debt / Book Capitalization	52.8%	53.4%	53.2%	52.9%	53.0%
Collateral Coverage Ratio	1.6	1.6	1.6	1.7	1.7
Liquidity Sources / Uses Ratio	1.7	1.6	1.8	2.0	2.2

Figure 8-6. Financial Statistics

9. Implemention and Action Plan

As you have read throughout this IRP, we are focused on transitioning our energy system to one that is closer, more connected and where customers are more empowered. This means a continued shift to more distributed renewable energy, more cost effectively for more Vermonters all while transitioning our traditional fossil fueled systems to electric such as transportation and heating. In order to assure that GMP remains not only prepared for this, but is actually driving this change we will implement, or continue to implement the following actions as described in more detail through this IRP.

Functional Area	Activity
System Resiliency and Grid Transformation	Develop and deploy an integrated suite of customer offerings that drive carbon out of our total energy consumption, reduce costs for all customer, and improve the greater grid. ♦ Develop and deploy the overarching DERMS platform that acts as the choreographing tool for all DER's across the grid. This can also be done in partnership with all VT DU's, VELCO, etc. ♦ Extend and expand Tariffed offerings for battery storage in homes and businesses improving both customer reliability as well as greater system resiliency and distributed management ♦ Develop a minimum of 6 resiliency zones utilizing a combination of technology, DER's, storage and other resources to drastically improve reliability and prepare areas for greater electrification, such as transportation ♦ Deploy significant EV fast charging supply equipment in more challenging to reach areas not covered by various State programs
Generation (Distributed and Larger)	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. ♦ Relicensing in process or will be withing next three years on nine GMP hydro plants as well as two non-FERC sites currently in the 401 Water Quality Certification process ♦ Explore/Develop the next phase of Searsburg including potential repowering of the existing site ♦ Continue updating tools, maps and interconnection guidelines for distributed generation and storage resources to assure least cost, efficient interconnection processes exist while assuring system stability, reliability and safety. ♦ Plan for the retirement of the remaining GMP fossil-fuel peaking sites and evaluate the suitability of these locations for new peaking storage resources. ♦ Evaluate pairing energy storage with existing renewable facilities or construct new storage-paired systems directly or through other procurement methods.
Transmission & Distribution Innovation	Plan the energy delivery system to create a closer, connected, and empowered system that prepares for harsher storm conditions. ♦ Underground 40 miles of exposed distribution line ♦ Install 300 miles of covered wire replacing bare wire ♦ Deploy 4 additional automatic fault recovery transfer systems on the distribution system
Information Technology	♦ Continue strong focus on cybersecurity and evolving best practices including use of cloud platforms where appropriate and enhanced testing and monitoring of IT/OT systems. ♦ Consider seeking approval for enhanced investments through a cybersecurity resiliency plan, consistent with our pending regulation plan petition.
Regional Market Participation	Actively engage in regional stakeholder forums to advance ideas and programs to accelerate regional action to reduce fossil fuel dependence. ♦ Closely monitoring the methods and framework being discussed in our region to implement FERC Order 2222. ♦ Participate and follow regional efforts to adapt the capacity and energy markets to more directly support a transition to zero and low, carbon resources.
Power Supply	Maintain a cost-effective, zero-emission annually supply portfolio that incorporates a large share of long-term distributed renewable resources, a growing share of local renewable resources, and the flexibility needed to address changes in the evolving regional energy market. ♦ Explore regional wind purchase opportunities including participation in upcoming offshore wind developments ♦ Work with Vermont stakeholders to explore potential refinements to RES and net metering that would support an electricity supply that is increasingly renewable and financially sustainable for all customers ♦ Work on methods to support the procurement of increasing renewable supplies, including ways to geographically guide Vermont supplies (to limit grid upgrade costs) ♦ Continue to modify short-term procurement programs to further reduce dependence on fossil-fuel resources and better align customer usage with renewable supply. ♦ Innovate new procurement plans for local renewable generation outside of the net metering program to improve opportunities for direct, equitable, cost-effective customer participation.
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.