GREEN MOUNTAIN POWER
Generating Possibilities Together

2024

INTEGRATED RESOURCE PLAN

GREEN MOUNTAIN POWER
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Certified B Corporation

Serving more than 275,000 residential and business customers in Vermont with electricity that's 100% carbon free and 80% renewable on an annual basis.

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EXECUTIVE SUMMARY

Creating a More Resilient, Affordable and Clean Energy System for Customers

We are filled with purpose and optimism as we plan to deliver affordable, clean, reliable energy to power the communities and customers we serve over the next three years and beyond. We recognize the critical importance of affordability for Vermonters, and that our commitment to delivering a more affordable and more resilient place to live, work, and learn matters more than ever. The progress we make every day at GMP in transforming Vermont's energy system—lowering costs for customers and increasing rural resiliency—benefits all of our customers. In this IRP, we delve into the many ways we are partnering with customers to power communities across Vermont and increase easy, affordable access to new technologies and innovations.

We've made strides achieving this for customers. Since our last IRP, thousands of Vermonters have installed home energy storage through GMP programs for cost-effective, clean, seamless backup power at home that also lowers costs for all GMP customers through energy sharing. We've launched new rebates and programs for customers who are low income, expanded access to discount rates, and strengthened our Transmission & Distribution system to boost resiliency in rural areas. Looking ahead, we are directly taking on major challenges facing Vermont—rapidly rising costs and increasingly extreme weather—by leveraging the best of our successful work, new innovative approaches, and the latest technologies. This drive to deliver a more affordable, equitable and resilient energy system is seen through all aspects of this Integrated Resource Plan. It describes our customer-focused work, and policy-aligned strategies that we propose for the 2024–2026 planning cycle.

The accelerating and historic costly storms in Vermont since our last IRP pushed us to move even faster to transform the energy system for customers. We have done this by speeding up targeted resiliency work rooted in our 2020 Climate Plan, expanding outreach and education, and adding new innovative customer programs to increase access to energy storage and make it easier to switch away from fossil fuel to run your life. This work is industry-leading and has put Vermont in the spotlight for progress and what can be achieved when we work together.

About Green Mountain Power

As a company deploying the latest technology, our focus on affordability, resiliency, and equity is transforming the energy system for customers in the face of increasing damaging weather and regional threats that include cyber-attacks, physical attacks, and regional supply constraints. This will reduce costs and ensure all customers have the same level of affordable energy service. It is also creating a new path forward that supports increased electrification in Vermont, more distributed and local renewable power generation closer to where it is used, and at the same time it is helping to drive down costs for all customers to keep electricity affordable. Our longstanding commitment to customer service and innovation is the foundation of this reliability and resiliency work and all the work we do at GMP.

Our History

Green Mountain Power is rooted in innovation for customers with the Vergennes Electric Company which was founded in 1893 and was a pioneer in delivering hydro-generated electricity to power cable cars in Burlington, Vermont. Vergennes Electric was one of the companies that were consolidated to create Green Mountain Power on August 29, 1928. At that time, just 3% of rural America had electric service compared to 85% of urban areas. For context, distributed electricity first became available to parts of Manhattan in 1882. The Rural Electrification Act of 1935 began the expansion of electricity throughout Vermont and the U.S.

Today, we are in practice a technology company at the center of an increasingly multi-directional energy system that empowers customers and is resilient in the face of damaging weather. Our energy supply is affordable, 100% carbon free, and 83% renewable. Our workplace culture is centered on serving customers and fosters innovation to transform the energy system to benefit all customers. Everyone at GMP is motivated to do all we can to create a Vermont that is equitable, sustainable, and affordable.

In 2008, we introduced the solar incentive, which helped jumpstart the solar industry and customer energy independence in Vermont. In 2014, GMP became the first utility in the world to get a B Corp certification, meeting rigorous social, environmental, accountability and transparency standards and committing to use business as a force for good. GMP was named to Fast Company's 2024 Most Innovative Companies in the World list, the sixth time earning that honor. In 2024, 2023 and 2021 the Smart Electric Power Alliance (SEPA) honored GMP as a nationwide leader in energy transformation. And, in 2022 GMP was named to TIME's list of the 100 Most Influential Companies for its groundbreaking resiliency work to transform the grid for customers.

Service Territory

Our service territory is mostly rural and spans 7,500 square miles. We serve about 275,000 customers in 202 municipalities and deliver power to about 77% of Vermont. **Table ES-1** alphabetically lists all 202 municipalities in our service area. **Figure ES-1** below shows the service territory of each distribution utility in Vermont. Our service area focuses mainly on the cities and towns in the central and southern parts of the state.

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

Table ES-1. Table of Vermont towns and cities in GMP service area

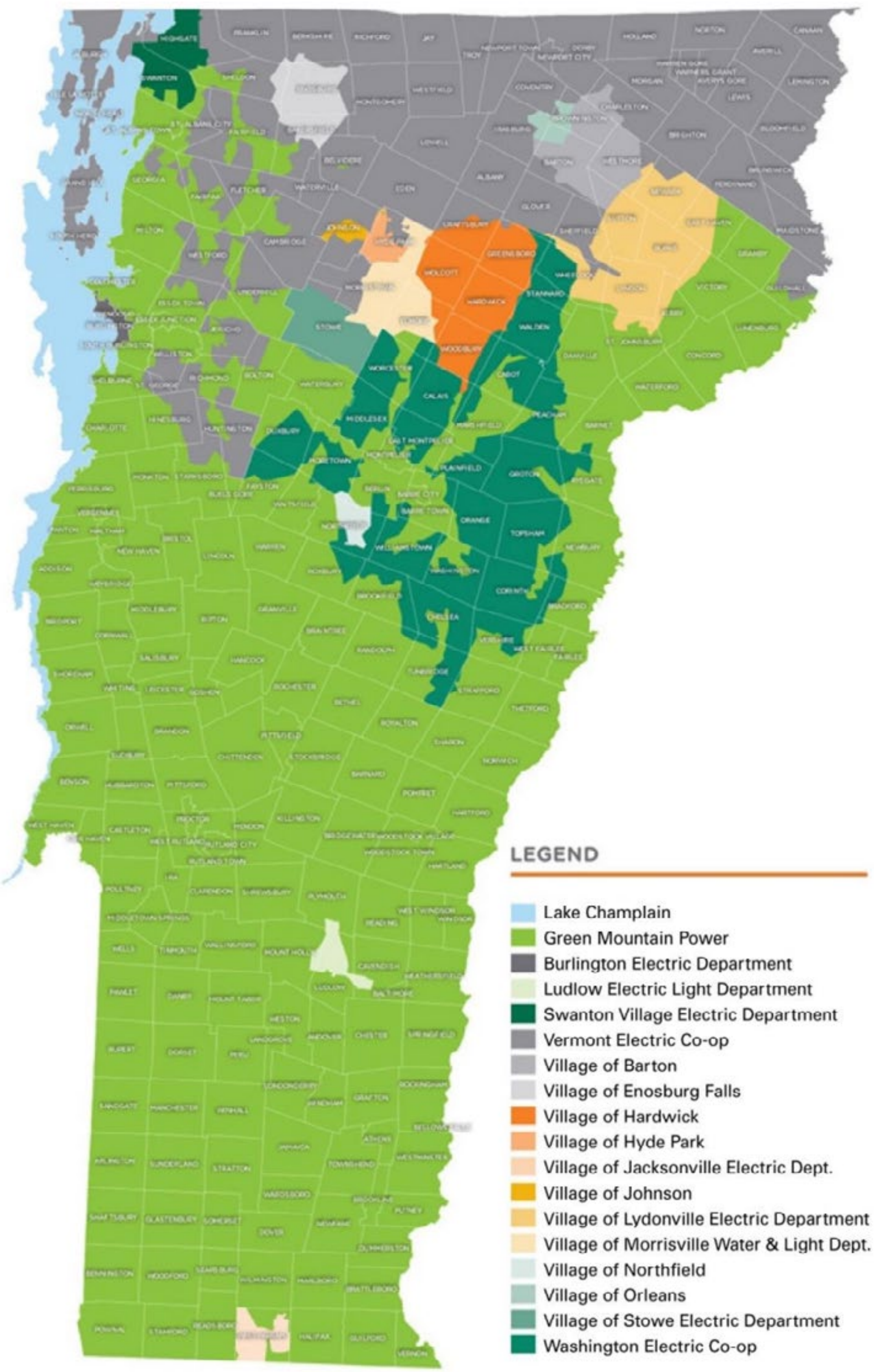


Figure ES-1. Service territories of Vermont distribution utilities

Customers' Energy Use

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

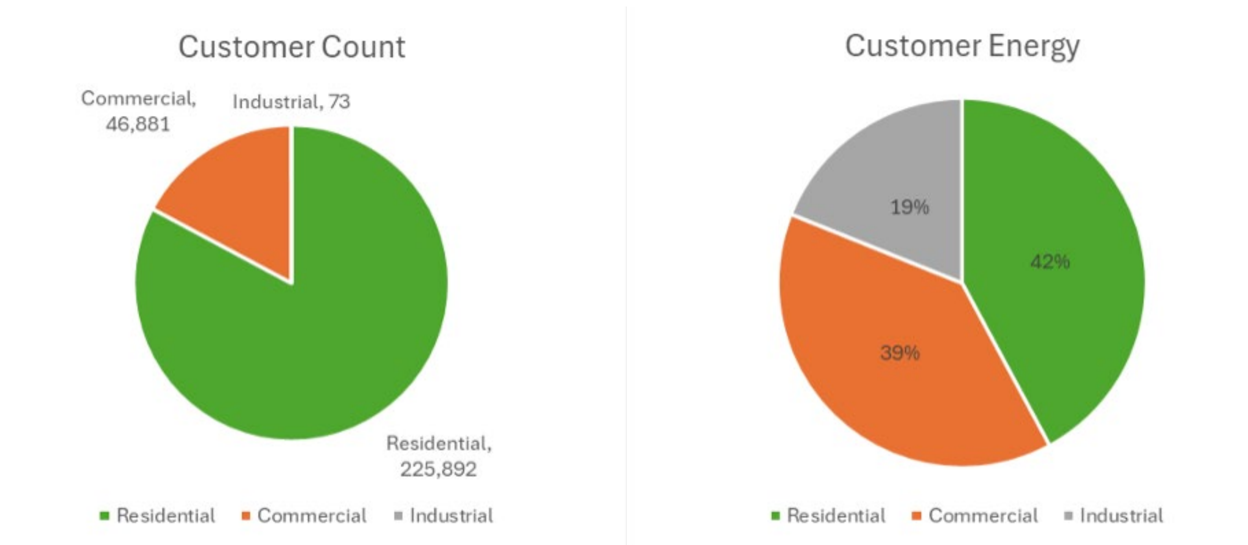


Figure ES-2. Energy consumption of commercial, industrial, and residential GMP customers

GMP Retail Rates, Relative to the Region

We are proud to have the lowest average total cost per kWh among other comparable utilities in New England. **Figure ES-3** compares the 2024 retail rates of Green Mountain Power with the independently owned electric utilities in the five other New England states. 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. GMP power costs are included in rates, subject to quarterly adjustments.

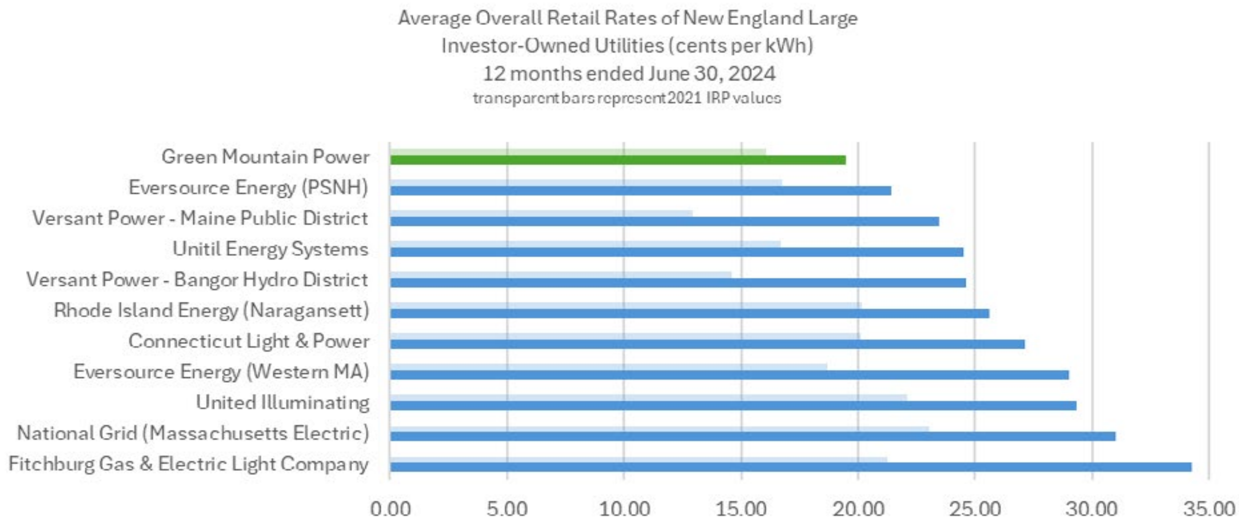


Figure ES-3. New England large investor-owned utility average overall retail rates

Figure ES-3 compares the 2024 retail rates of Green Mountain Power with the independently owned electric utilities in the five other New England states. 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. GMP power costs are included in rates, subject to quarterly adjustments.

T&D System Summary

GMP serves customers with 1,011 miles of subtransmission lines and 15,454 miles of distribution lines. This provides the framework for a multi-directional energy flow that provides Vermonters with comfort and safety at home, work and school. The system has 140 distribution substations supplying about 300 circuits. Predominant voltages for subtransmission are 34.5 kV, 46 kV, and 69 kV, while the predominant distribution voltage is 12.47 kV, with a small amount of distribution at voltages of 2.4 kV, 4.16 kV, 8.3 kV, and 34.5 kV.

More local renewable generation and more customers switching away from fossil fuel for driving and heating are key factors as we look ahead to enhancing resiliency for customers and managing peaks. In 2023, our system delivered approximately

3.7 million MWh of electricity; the peak load on the system was approximately 650 MW. There was about 630,000 MWh of behind-the-meter generation, resulting in 4.3 million MWh of load served in 2023 alone. **Chapter 3** explores how GMP's T&D system is the backbone of energy transformation.

System Resiliency for Customers

Chapter 3 also delves into how we are transforming the energy system to keep customers powered up in their homes when there are threats to the grid. This work is data driven, with targeted projects using proven techniques. Our 2020 Climate Plan launched our accelerating work as more severe, frequent, damaging weather ramped up in Vermont to keep customers connected through damaging storms or other damage to the energy system. T&D investment to boost reliability and resiliency by making the system more damage resistant will accelerate further during this IRP, following the October 2024 Zero Outages Initiative order by the PUC.

IRP Statutory and Regulatory Framework

We have drafted this IRP to meet the needs of our customers in accordance with State law and the detailed regulatory framework that applies to this work. This IRP will be reviewed for approval in a proceeding by the Vermont Public Utility Commission, with the Department of Public Service taking a lead role.

Vermont's overarching energy policy that applies to IRPs is embodied in 30 V.S.A. § 202a:

1) To ensure to the greatest extent practicable that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that ensures 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 reducing greenhouse gas emissions and least-cost integrated planning, including efficiency, conservation, and load management alternatives; wise use of renewable resources; and environmentally sound energy supply.

3) To meet Vermont's energy service needs in a manner that will achieve the greenhouse gas emissions reductions requirements pursuant to 10 V.S.A § 578 and is consistent with the Vermont Climate Action Plan adopted and updated pursuant to 10 V.S.A. § 592.

The State's greenhouse gas emissions inventory law is 10 V.S.A § 578 and the Global Warming Solutions Act (GWSA), which mandates the State's Climate Action Plan and is further described below, is set forth in 10 V.S.A. § 592. The State sets forth its requirements for meeting Vermont energy policy in a Comprehensive Energy Plan, developed by the Department and issued in accordance with 30 V.S.A. § 202b.

The Department's 2022 Comprehensive Energy Plan (2022 CEP) serves as the basis for this IRP, including the guidance in the 2022 CEP regarding integrated resource planning. The 2022 CEP centers equity in its recommendations, organized around two key themes: equitable solutions to meet Vermonters' energy needs, and grid evolution. The 2022 CEP recognizes that "Vermont's electric sector will play a critical role in decarbonizing the transportation and thermal sectors, [which] raises the importance of affordable electric rates and an electric system that is reliable and resilient for all Vermonters."[1]

30 V.S.A. § 218c requires GMP and other utilities to develop a "least-cost integrated plan" at least every three years. The plan must meet State energy policy goals as described above, along with renewable energy goals set forth in 30 V.S.A. § 8001 et. seq., and the requirements of the most recent Vermont Electric Plan which is embodied in the 2022 CEP issued by the Department under 30 V.S.A. § 202. The Department's integrated resource planning guidance, linked above, asks utilities 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.

In addition to meeting the guidance and requirements that arise from these State plans and statutes, we have created this IRP to fulfill all commitments made in the 2021 IRP review process.[2]

1 2022 CEP at 17.

2 See Case No. 21-5208-PET, Order Approving Green Mountain Power's 2021 IRP (Nov 22, 2022) (2021 IRP Order) and, incorporated into the 2021 IRP Order, Memorandum of Understanding Between the Vermont Department of Public Service and Green Mountain Power Corporation (Jun 29, 2022) (Department 2021 IRP MOU).

The GWSA and Vermont's Renewable Energy Standard

The 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
- 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, with an updated plan forthcoming in June 2025. The initial Plan recognized the significant progress in emissions reduction already achieved in the electric sector and recommended further reductions through a revised Renewable Energy Standard (RES) to move Vermont to 100% carbon-free or renewable electricity portfolio.[3]

The RES, initially implemented in 2015, was revised in 2024 in response to this recommendation, as described fully in **Chapter 6**. The RES framework, set forth in 30 V.S.A. §§ 8002–8005, now requires GMP to have by 2030 a 100% renewable electric supply on an annual basis, and to meet the tiered requirements for distributed renewable generation and new renewable energy as defined and set forth in Section 8005. The IRP describes all these requirements in detail, how they fit into the regional New England context, how prior and current State programs such as Standard Offer and Net Metering help GMP meet RES requirements, and how GMP plans to meet RES in the years ahead, in **Chapters 5–7** below.

How the 2024 IRP Reflects the Commission's 2021 IRP Order and Department MOU

In addition to a number of methodological and process improvements adopted in the 2018 IRP and continued in GMP's 2021 IRP, this IRP fulfills the requirements of the Commission's 2021 IRP Order and the Department 2021 IRP MOU.

3 2021 Vermont Climate Action Plan at 103–104.

Procedurally, GMP engaged in meetings with the Department over the past year to discuss specific sections of the IRP and incorporate Department feedback, as required by Section I of the Department 2021 IRP MOU. We provided the Department with a draft of our IRP more than one month prior to filing it with the Commission, held meetings and received detailed feedback from the Department on the draft, and incorporated that feedback where possible into our submission.

GMP also engaged with customers on the IRP, as required by the Commission in the 2021 IRP Order. **Chapter 1, Appendix A** describes this engagement further, including the attendees and questions discussed.

Substantively, this 2024 IRP incorporates refined analyses set forth in the Department 2021 IRP MOU and 2021 IRP Order. Specifically, under Section II of the Department 2021 IRP MOU, GMP has incorporated the following requirements into this IRP, in the chapters indicated:

Distributed Energy Resource (DER) forecast scenarios, Distributed Energy Management System (DERMS) planning, and Aggregation: **Chapters 2 and 3** set forth our load forecasts and engineering models incorporating distributed generation, energy storage, electric vehicles, heat pumps, and other flexible load resources. As described in those chapters, our analysis incorporates not only historical deployment and load but also State energy and emissions requirements, climate change, regional and municipal energy plans adopted pursuant to Act 174 of 2016, VELCO's Long-Range Transmission Plan forecasts, and the physical limits of distribution and transmission system infrastructure, as appropriate.[4] These chapters also discuss GMP's progress made in the evaluation, selection, development, and deployment of an overarching analyzing DERMS platform and coordination efforts with other utilities on resource dispatch.[5] A discussion GMP's efforts to enable the connection and participation of aggregations consistent with FERC Order 2222 on the GMP system, including practices surrounding dispatch instruction as they relate to the use of a DERMS, is set forth in **Chapters 3 and 5**.[6]

4 See Section II, i of the Department 2021 IRP MOU.

5 See Section II, vii of the Department 2021 IRP MOU.

6 See Section II, viii of the Department 2021 IRP MOU.

Hosting Capacity: Chapter 3 specifically analyzes the hosting capacity of distribution and subtransmission facilities throughout GMP's territory and discusses the methodologies and its limitations, including a discussion of time series analysis and peak load and export conditions.[7]

Storage: Chapters 3, 6, and 7 contain GMP's analysis of the optimal power, energy, location, and size distribution of energy storage on GMP's system in the planning horizon to increase hosting capacity, to defer a T&D upgrade and/or pursue resiliency opportunities, as well as an analysis of the costs and benefits of deploying storage versus alternatives such as flexible loads and curtailments, as required by Section II, vi of the Department 2021 IRP MOU.

Resilience and Climate Planning: Chapter 3 also contains analysis of system resilience and GMP's Zero Outages Initiative[8] and incorporates GMP's climate planning as required by the Commission's September 24, 2020, Order in Case No. 20-0276-PET.

Technology and Cybersecurity: As in the prior IRP, the 2024 IRP incorporates in **Chapter 4** an update on the use and convergence of Information Technology (IT), Operations Technology (OT), Cybersecurity, and energy services for GMP customers, consistent with Section II, v of the Department 2021 IRP MOU.

Portfolio Evaluation: After summary of all GMP portfolio resources in **Chapter 6**, GMP's portfolio evaluation in **Chapter 7** sets forth "[a]n analysis of the costs, benefits, and availability of resources on annual, seasonal, and hourly bases . . . ; an evaluation of potential climate and market risks to various resource portfolios; and an analysis of the relative achievability and cost- effectiveness of shaping load vs. procuring shaped supply resources," as required in Section II, iii of the Department 2021 IRP MOU.

7 Specifically, Section II, ii of the Department 2021 IRP MOU requires a discussion of "[h]osting capacity analysis incorporating distribution facilities and subtransmission facilities, as supported by VELCO and the Department, including: refinement of static hosting capacity methodology, as informed by discussion with stakeholders; exploration of time series analysis at the substation level for all substations; analysis of peak load and peak export conditions at the feeder level for all feeders; and investigation of time series analysis for representative feeders with consideration of potential upgrade costs. Analysis may include load flow manipulation, graphical representations and/or analytic reporting. These results, in combination with the forecasts . . . will inform a discussion of whether GMP's distribution and transmission can serve anticipated demand and DERs in the planning horizon, the strategies and tools needed to avoid system upgrades, and how reliability will be maintained as heating and transportation are increasingly electrified."

8 See Section II, iv of the Department 2021 IRP MOU, which states, "A discussion of system resilience, including any anticipated resilience-focused investments; proposed metrics for measuring the impact of those investments; and a discussion regarding the overlap in benefits and costs between reliability and resilience focused solutions. This will also include an analysis of the costs and benefits, to both participants and non-participants, of existing and proposed Resiliency Zones, as well as a discussion of any refinements made to GMP's Resiliency Zones mapping tool to incorporate the Climate Council's Municipal Vulnerability Index and the Vermont Agency of Natural Resource's Environmental Justice Mapping Tool, to the extent one or both have been developed."

Financial Analysis: Finally, consistent with the Department's integrated resource planning guidance and the Department 2021 IRP MOU, Section I, iv, **Chapter 8** provides a financial assessment of the work referenced in the IRP, using the same methodology as set forth in GMP's prior IRP.

Maximizing Public Information and Input for the 2024 IRP: Throughout 2024, in addition to the robust customer communication happening every day at GMP detailed in **Appendix A**, we did specific outreach for the IRP. All customers were invited to two open house events and one virtual open house on Facebook. We also created a specific email address, irp@greenmountainpower.com, for customers to share feedback for the IRP. The email was in a blog about the IRP planning process on our website, news release, on bill, and on social media including Front Porch Forum. Dozens and dozens of customers shared their views with us, and the three main topics customers raised were: increased compensation for net metering customers, resiliency and storms, and rates. We reached out to each customer to follow up with information which was appreciated, and we also talked with the team directly involved in drafting the IRP, which includes the topics raised by customers and they received this feedback as it arrived. All customers were alerted to our outreach events through on-bill messages, news releases and social media as required by the Commission's 2021 IRP Order. This approach to communication is typical: selecting communications channels to reach customers where they are, paying attention to what customers tell us, and sharing that feedback internally across teams in real time.

Summary of Findings: The individual chapters of the 2024 IRP explore our plans for serving customers including increasing resiliency, affordability, innovative services to empower customers, the transmission and distribution system, distributed energy resource management, and power resources.

Customer Program Innovations and Electrification: Our commitment to customer service and innovation is the foundation of all our work. This IRP covers how we're providing excellent customer service, focusing on equitable access to programs and technologies as more Vermonters electrify including Tier III programs with more options for income-qualified customers, and our approach to making rates and rate design simple for customers through direct management and flexibility of innovative products and services. Rural resiliency is tied to equitable service for customers and energy storage is a key part of that.

Load Forecast: **Chapter 2** details why we expect significant load growth through electrification, driven especially by EV and cold climate heat pump adoption. Managed EV charging is and will continue to be a significant factor in cost-effectively managing this growth for all customers.

	Annual system load (MWh)	
Fiscal Year	**Continued Adoption scenario**	**Accelerated Adoption scenario**
2025	3,988,724	4,028,942
2026	4,020,293	4,109,507
2027	4,063,720	4,241,513
2028	4,112,663	4,350,975
2029	4,160,798	4,470,117
2030	4,212,454	4,587,373
2031	4,313,812	4,747,681
2032	4,426,928	4,911,625
2033	4,548,145	5,071,084
2034	4,674,514	5,230,608
2035	4,794,646	5,363,040
2036	4,873,869	5,439,328
2037	4,930,647	5,483,207
2038	4,983,545	5,518,742
2039	5,033,943	5,551,448
2040	5,085,443	5,587,261
2041	5,120,025	5,609,034
2042	5,131,168	5,610,228
2043	5,140,247	5,611,789

Table ES-2. GMP's 20-year forecasted system load, beginning 2025, by fiscal year.

T&D System Resiliency and Grid Transformation: This IRP includes our T&D Zero Outages Initiative, as ordered by the Commission in 2024, 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 and regional threats, while increasing affordability. Continued use of storm hardening above-ground lines and undergrounding deliver enhanced reliability and resiliency for customers. This work will build 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 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 9-1** summarizes the action steps we expect will be needed within the planning period to achieve the outcomes we seek for customers through the 2024 IRP.

Organization of This IRP

IRP Chapters and Appendices

Following this Executive Summary, we break down the information and planning covered by the 2024 IRP in the following chapters:

Chapter 1: Delivering for Customers provides detailed information about how we work with customers to connect them with innovative energy programs and deliver on our commitment to excellent service. This chapter also covers how we design rates to meet customers' needs.

Chapter 2: Demand and Distributed Energy Forecast discusses our load forecast based on customer demand and provides our ongoing work to manage a more distributed grid in partnership with customers.

Chapter 3: System Resiliency and Grid Transformation does a deep dive into our overall Transmission and Distribution system and the work being done to deliver resiliency and reliability to all of our customers.

Chapter 4: Technology and Security discusses how we use technology to deliver energy services to customers.

Chapter 5: Evolving Regional Energy Markets showcases regional policy changes and how Vermont fits into the broader New England electric market.

Chapter 6: Our Renewable Energy Supply includes a discussion of our current renewable energy resources, as well as how we will comply with the Vermont Renewable Energy Standard.

Chapter 7: Portfolio Evaluation provides a review of our current and future planning for our overall resource portfolio, as we work towards 100 percent renewable by 2030 and beyond.

Chapter 8: Financial Assessments includes a base case forecast for the next five years.

Chapter 9: Integration and Action Plan, bringing together the work ahead across all sections of the IRP.

Several appendices are also included that support our 2024 IRP:

Appendix A: Communicating with Our Customers includes an overview of the many ways we communicate with customers.

Appendix B: Present Value LIfe Cycle Cost Tests

Appendix C: Budget Forecast, as prepared by Itron. This document includes methodology and review of our current sales forecast report.

Appendix D: Vegetation Budget & Actuals shows historical spending for line maintenance as required by the Department of Public Service's IRP Guidance to Utilities.

Appendix E: RLC Engineering Studies

Appendix F: Engineering Flow Charts as required by the Department of Public Service's IRP Guidance to Utilities.

Appendix G: A complete list of the GMP-owned hydroelectric facilities.

Appendix H: Portfolio Evaluation Methods

Appendix I: Sensitivity Analysis Inputs

Appendix J: S&P Global Ratings Update

Appendix K: GMP Substations

1

DELIVERING FOR CUSTOMERS

Overview

Resiliency and affordability are customer-first targets that align with Vermont's strategies for mitigating the effects of extreme weather and its danger to human life, damage to property, and costs to the state's energy infrastructure. Through Green Mountain Power's (GMP)'s focus on exceptional customer service, innovative customer programs and rates, and increasing reliability and resiliency through initiatives highlighted in **Chapter 3** GMP is strengthening the energy system and working to keep customers connected to energy resources despite increasingly damaging weather and other threats to the reliability of the traditional grid (such as cyber security, physical attacks and regional supply constraints as discussed further in **Chapter 3**). This goes to the heart of equity across the state and creates a new path forward that will drive down costs for all GMP customers to keep electricity affordable, while supporting increased electrification in Vermont and more distributed and local renewable power generation. Our longstanding commitment to customer service and innovation is the foundation of this resiliency work and all the work we do at GMP.

Serving Our Customers

Customer Service Standards

The Service Quality and Reliability Plan (SQRP) standards are target levels approved by the Public Utility Commission (PUC) for measuring and ensuring great customer service. The SQRP includes measures focused on call answering and meter reading, billing, reliability, safety, on-time performance, and customer satisfaction.

We file quarterly and annual reports to the PUC that show we consistently meet or exceed the SQRP targets. Overall, our focus on customers' needs led to a satisfaction rate of 93 percent, as reported to the PUC in our 2023 SQRP annual filing.[1]

In 2024, in collaboration with the Department of Public Service (DPS), we filed an updated SQRP with the PUC that was approved on December 9, 2024.[2] We will begin using the updated SQRP starting January 1, 2025. Extreme weather, new technologies, and growing external economic pressures on customers beyond GMP's control are all contributing to more in-depth conversations with customers, and the proposed updates maintain high response time to customers while recognizing calls might take longer. These revisions also make important modernization updates.

1 Annual filing submitted as part of 2023 Q4 and assigned Case No. 24A-0310.

2 See ePUC Case No. 24-2825-PET.

Communicating with Our Customers

Having a strong partnership with customers requires good communication over the long term, and we are always working to meet customers where they are by using multiple communication methods. We communicate clearly and approach this as an ongoing conversation with customers where we share information, hear what they say, and act on it. This ongoing relationship is at the center of successful customer service, whether we're talking about innovative pilot programs with new technologies, rates to encourage carbon reduction, or safety during extreme weather. This happens across all teams every day in various ways, from teammates in the field, to the call center, to customers stopping by the office. It will continue to be at the heart of our work doing targeted resiliency projects to help keep more customers connected as severe storms accelerate. **Appendix A** details GMP's robust communication paths to engage with customers and deliver exceptional service to achieve greater resiliency and carbon reduction.

Equity for Customers

Equity is a part of how we approach designing programs, services, and initiatives to better serve customers. This includes our work to bring proven reliability and resiliency projects to disproportionately impacted areas in rural Vermont through the Zero Outages Initiative (ZOI). This approach to serving customers is aligned with Vermont's 2022 Environmental Justice Law, Act 154.

We work to increase resiliency while keeping rates low and steady for all customers, providing optimal access to new technologies as part of the energy transition, and helping to protect the safety and well-being of customers. As noted in **Appendix A**, we are in frequent contact with community stakeholders, town officials, and customers, with various open channels of communication through direct outreach, social media, GMP's call center, and crews in the communities. This includes sharing ideas and using feedback to identify solutions and work together on customer communication and enrollment.

As noted in **Appendix A**, we are in frequent contact with community stakeholders, town officials, and customers, with various open channels of communication through direct outreach, social media, GMP's call center, and crews in the communities.

Additional information is provided in the following sections on specific programs that direct support to income-qualified customers. The new Affordable Community Renewable Energy (ACRE) pilot program launched in 2024 connects customers to local solar projects and provides an added monthly discount for income-qualified customers already enrolled in GMP's Energy Assistance Program (EAP). At the start of 2024, we doubled the heat pump rebate for low-income customers to $2,000 per condenser, and we have increased rebate adders for income-eligible customers for other Tier III programs to expand access to products that are cleaner and often less expensive to own and operate.

Everything we do for customers hinges on maintaining affordable, reliable service. Utilizing data from Edison Electric Institute (EEI) we can determine where GMP benchmarks against peer utilities in the northeast region. Currently, GMP remains the lowest in total retail average rate for electricity among comparable utilities. **Figure 1-1** below shows GMP ranks first among northeast peer utilities. Our goal in everything we do is to continue to find ways to lower costs, while providing service that is reliable.

EEI Total Retail Average Rate (Cents/kWh)	12-Months Ended 6/30/2024
Green Mountain Power	19.47
Public Service of New Hampshire DBA Eversource	21.44
Maine Public Service	23.45
Unitil	24.53
Bangor Hydro	24.59
Rhode Island Energy Co (Narragansett)	25.63
Connecticut Light & Power	27.15
Eversource	29.02
United Illumination	29.34
National Grid (Massachusetts Electric Company)	31.02
Fitchburg	34.25

Figure 1-1. EEI June 2023 – June 2024 Ranking of Northeast Utilities Total Retail Average Rate (Source: Edison Electric Institute).

Energy Assistance Program

The Energy Assistance Program (EAP) provides a 25 percent discount to income-qualified customers on the customer charge and the energy charge each month. There is also a one-time arrearage forgiveness for customers when they first enroll in the program. In 2023, we expanded the Energy Assistance Program (EAP) to 185 percent of federal poverty guidelines, so more customers now qualify for the 25 percent monthly discount. As part of this update, we also partnered with the Department for Children and Families to auto-enroll customers who qualify for other programs with the same income-level eligibility. This means easier enrollment for eligible customers.

Innovating for Customers

Innovation is at the heart of the way we deliver customer service, finding ways to make the energy transition simple and more affordable. We bring this approach to our conversations with customers and service standards, and to how we create innovative pilots that deliver industry-leading solutions with cutting edge technologies.

GMP's regulatory framework provides a path to offer customers pilot programs that deliver benefits to participants while also benefitting all other non-participating GMP customers—a focus on ensuring that one group of customers does not benefit more than another or carry unequal costs for a service that does not help them. The pilot design framework involves alignment with Vermont's Comprehensive Energy Plan, stakeholder engagement, and GMP's emissions reduction goals, and requires partnering with communities, customers, and technology manufacturers to develop customer-friendly programs that include equity to benefit all.

We consider these questions when developing new pilots:

- How does the program increase resiliency and 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?
- Are we incorporating customer feedback and takeaways from previous pilots into our approach?
- Is the program simple enough for all customers to understand, avoiding overly complicated rate structures that only technical experts can 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 connect with other Vermont companies and organizations that are working toward climate solutions?

The real-world experience gained through piloting provides valuable insights that help us deliver future customer offerings and fully tariffed programs, or to propose follow-on pilots when more information or learning is needed. Customers provide feedback through surveys, and the information they share helps us decide on next steps for that specific program, and how to improve the customer experience across multiple programs.

When deciding whether a pilot succeeded, we consider these questions:

- 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?
- Is the pilot still necessary or were the original goals met?
- Does the pilot engage third parties in a meaningful and successful way?

The success of outreach methods for pilots is measured through sign up volume and customer interest. Pilots are usually developed with a capped number of participants and if signups are lagging, we can adjust the approach throughout the pilot and document this in the pilot updates.

In seeking pilot feedback, we ask several questions about customers' experience, including about the enrollment process, why they decided to participate, how they heard about the program, and what program changes would improve their participation. We also always provide customers with the option to express additional feedback.

Innovative Customer Programs

Tier III Programs

GMP's Tier III programs help make it easy for customers who choose to switch away from fossil fuel, and last year more than 10,000 GMP customers took part in at least one program—whether it was an EV rebate for an all-electric vehicle, or a custom incentive for a business looking to transition to electricity for their manufacturing process.

In partnership with customers GMP has helped offset more than 490 million pounds of lifetime CO_2 emissions through Tier III project support since 2017. Transportation and heating are the top two sources of carbon emissions in our state and have been our primary focus when providing incentives for customers to help with fossil fuel reduction.

As in everything we do, GMP's Tier III programs consider equity in design and implementation. In 2018 we launched our first income-sensitive Tier III offering, an increased incentive for low-income and moderate-income customers' electric vehicle (EV) purchases. Since then, we have expanded the additional support we provide low-income customers into multiple income-sensitive programs. We look forward to continuing this work with customers to reduce Vermont's emissions and meet State energy goals. Of the two load and electrification forecast scenarios presented in **Chapter 2**, the higher "Accelerated Adoption" scenario leads to levels of EV and heat pump adoption sufficient to meet Vermont's current Global Warming Solutions Act (GWSA) requirements based on the pathways presented in the 2022 Vermont Pathways Analysis Report 2.0.

A goal of RES Tier III is for 31% of all residential spending to be in support of low-income customers' participation in fossil fuel reduction and electrification. The threshold for low-income qualification defined in the RES is 80% state median income (4.413(b)(2)(A)). Area median income (AMI) is also used by distribution utilities (DUs) for more granular income qualification in Tier III reporting. 80% AMI in all Vermont counties is higher than the 185% of Federal Poverty Level (FPL) used in 30 V.S.A. § 218(e) to define a "low-income electric customer" for the purposes of setting rates, and the basis for our Electric Assistance Program (EAP).

The majority of Tier III fossil fuel reduction is achieved through electrification, and there are also existing robust incentive programs for residential non-electrification measures, such as weatherization. For commercial and industrial customers engaging with GMP's Tier III program through custom projects, non-electrification measures are also considered with everything tailored to serve the customer's needs. More details on these programs are available in GMP's annual Tier III plans.[3]

Heating/Cooling, Transportation, Home/Yard Appliances, and Equipment

Heating and Cooling – GMP's largest Tier III program driven by customers, both in volume of installed measures and fossil fuel offset, is for supporting the installation of heat pump technologies for space and domestic hot water heating in homes and businesses. We currently have incentive programs for ductless (mini splits) and centrally ducted air source heat pumps, air-to-water heat pumps, ground source heat pumps, and heat pump water heaters.

GMP funds point-of-sale rebates on air source heat pump systems with Efficiency Vermont, when purchased from participating distributors. Ductless systems receive a total $350 or $450 rebate per condenser depending on the size of the condenser, $250 of which is funded by GMP regardless of equipment size. Ducted systems receive $1,000, $1,500, or $2,000 per condenser depending on size, 75% covered by GMP ($750/$1,125/$1,500). These point-of-sale rebates are passed through to the customer as a discount on their invoice from the installer/contractor.

To help more income qualified customers purchase air source heat pumps, GMP increased the heat pump rebate from the previous $600 per condenser to $2,000 per condenser for low-income customers (defined by gross household income at or below

3 GMP's 2023–2025 Tier III Plans are filed in ePUC Case Nos. 24-3273-INV, 23-3715-INV, and 22-4421-INV.

80% AMI). This change went into effect in January of 2024 and the rebate is applied for by the customer post installation. In January 2024, due to a strong heat pump market, GMP retired our midstream $400 adder rebate that could be stacked with the rebate we co-fund with Efficiency Vermont. Evolving this offering allowed us to increase the low-income adder rebate and lower the overall cost of the cold climate heat pump (CCHP) Tier III program.

GMP also contributes support to zero-cost heat pump installations for low-income customers through the Act 44 Low-Income Fuel Switch program (formerly under Act 151). Beginning in 2022, GMP contributed $2,000 per installation within our service territory, with EVT supporting the balance of the installation. The program started in 2022, and to date there have been 218 installations and we anticipate a significant uptick in Low-Income Fuel Switch heat pump installations throughout CY 2024 Q4/FY 2025 Q1. For 2024 our funding has increased to $2,500 per installation.

Air-to-water and ground source heat pump systems are eligible for similar co-funded rebates with EVT, and customers apply for these rebates post-installation. For air-to-water systems, customers can receive $1,000 per system ton, up to six tons, funded 50% by GMP. Ground source systems can receive a total of $2,100 per ton, up to 10 tons, with GMP's portion being $1,800 per ton.

Our incentive for heat pump water heaters provides customers with $300 or $600 depending on the model.

Transportation – GMP continues to help customers transition to driving electric vehicles. Beginning in 2017 with a partnership program with Nissan that delivered substantial point-of-sale discounts to customers purchasing Nissan LEAFs, GMP has maintained programs to make it easier for customers to switch to EVs. We offer a $2,200 incentive for the purchase or lease of a new all-electric vehicle (AEV), a $1,500 incentive for the purchase or lease of a used AEV, a $1,000 incentive for the purchase or lease of a new plug-in hybrid vehicle (PHEV), and a $750 incentive for the purchase or lease of a used PHEV. Additionally, for low-income customers (defined by gross household income at or below 80% State Median Income (SMI) we offer a $1,000 adder rebate for new and used AEVs. All GMP EV incentives can be applied as point-of-sale discounts when customers purchase/lease from a participating partner dealership. Customers who purchase/lease outside of this dealership network apply for the incentives post purchase. GMP also offers free Level 2 chargers for customers to install at home, when they enroll in our home charging program. These chargers connect to GMP for peak management and provide customers access to GMP's discount EV charging rates, with the charger acting as the meter (information on Rate 72 and 74 is included below). These rates are below GMP's residential rates and work out to paying about $1.20 per gallon, a significant savings over filling up with fossil fuel.

GMP is working to help expand Vermont's public EV charging network. For commercial customers, GMP offers a $750 per-port incentive for the installation of public Level 2 EV chargers, and Level 2 chargers sited at workplaces and multi-unit residences. In 2024 we increased our Level 3 DCFC incentive from $1,500 per port to $10,000 per site. GMP is also committed to installing Level 3 fast chargers in ten new locations each year, and has done this since 2022, with a focus on underserved locations. GMP also manages the State's $7 million Charge Vermont grant program in collaboration with the Vermont Agency of Commerce and Community Development, which launched in 2023 and is awarding grants to help businesses, multi-unit homes, and public attractions install Level 2 and Level 3 charging.[4]

Beyond passenger vehicles, GMP offers prescriptive transportation-based incentives for electric bicycles, motorcycles, forklifts, and snowmobiles. For customers who purchase an electric bicycle for commuting in place of an ICE vehicle, we offer a $200 incentive. Similar to EVs, this can be applied as a point-of-sale discount when the e-bike is purchased from a participating bike shop, or customers can apply for it afterwards. We offer a $500 incentive for electric motorcycles, a $3,000 incentive for new electric forklifts and a $1,500 incentive for used electric forklifts. Building on custom incentives provided to commercial customers for their purchases of electric snowmobiles, GMP will begin offering in fall 2024 a prescriptive $375 incentive for electric snowmobiles for both residential and commercial customers.

Home and Yard Appliances – GMP offers incentives for electric land care items to support customers' shift from internal combustion engine equivalents, and for induction ranges and cooktops when installed to decommission an equivalent fossil fuel-powered model. Our land care incentives are $50 for walk-behind mowers, $100 for residential yard tractors, $25 for trimmers, leaf blowers, and chainsaws, and a $50 bonus for the purchase of three items. Specific to commercial customers, we offer a $2,500 incentive for commercial-grade ride-on mowers when the mower is used for business purposes for a minimum of 475 hours per year. Introduced in fall 2022, our incentive on induction cooktops and ranges has helped retire over 400 natural gas- and propane-powered units.

Storage Programs

Energy Storage Systems Tariff

Our Energy Storage Systems (ESS) Tariff was developed out of successful pilot programs and offers the Tesla Powerwall, which has 27 kWh per installed system and is a two-battery, whole-home backup solution. Each installed system provides GMP with an

4 www.chargevermont.com

additional 10–11.5 kW of capacity for demand response, energy arbitrage, and frequency regulation that provide value to both the participating and non-participating customer.

For $55 per month, or a one-time upfront payment of $5,500, customers can install this system for seamless backup energy to their homes during grid outages and other system threats, often substituting for a fossil-fueled generator. The systems work in tandem with GMP, allowing us to significantly reduce costs by using the energy storage a few times per month through an automated dispatch algorithm. Participating customers have the backup power and peace of mind they seek, whereas non-participating customers benefit from the reduced systemwide power supply costs created by the energy storage. In 2023 alone, GMP's stored energy network, largely made up of residential energy storage, saved customers more than $3 million.

There are more than 7,000 Tesla Powerwalls installed in GMP service territory, representing approximately 35 MW of capacity that is being used for peak reduction. These numbers increase each month as customer interest remains strong and continues to grow after the cap on the storage programs was lifted in 2023. This aggregation of Powerwalls has provided GMP customers with millions of dollars in operational cost savings since 2017. Resiliency is also key, and the Powerwalls have provided approximately 225,000 hours of backup power, in aggregate. GMP continues to explore and evaluate new energy storage system technology as further described in **Chapter 3**. In 2023, GMP modified the ESS Tariff to enable customers to install energy storage systems equivalent to Tesla Powerwall through the lease program.[5] This tariff and other energy storage offerings are an extension of our commitment to provide reliable service.

Beyond peak shaving, energy storage systems participate in ISO New England's Frequency Regulation Market, which generates additional revenue for customers. Five hundred customers are currently participating, and with the conclusion of two successful pilots, GMP is increasing the scope of the program and in 2024 filed and received approval for a Frequency Regulation Rider to the ESS Tariff.[6] As the first to use utility-aggregated distributed resources in the frequency regulation market, GMP with regulatory review has found breakthrough ways utilities can provide value back to their customers using innovative technology.

In addition to the value streams identified above, we recently confirmed that the Powerwall qualified for the Domestic Content provision that allows for an additional 10% Investment Tax Credit, adding additional value for customers.

5 See ePUC Case No. 24-1071-TF.

6 See ePUC Case No. 24-3111-TF.

Bring Your Own Device Tariff

In parallel with the ESS Tariff, GMP continues to offer the Bring Your Own Device (BYOD) program. This has offered another choice for customers who want to own their home energy storage. The program's pilot informed methods for encouraging energy storage adoption among customers. With feedback from 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 one of the largest energy storage incentives from a utility, helping to reduce the up-front cost barrier to innovative technology adoption.

Customers enroll their self-purchased energy storage system and choose how much access they provide to GMP. We offer a minimum of 2 kW and a maximum of 10 kW, which equates to an incentive of up to $10,500. We provide $850 per kilowatt of enrolled storage 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 enables energy storage technology to absorb excess solar energy that could otherwise strain the existing infrastructure on these circuits. This strategy is key to 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 energy storage systems, at the amount they selected, for peak shaving. With these participating customers and similar to the ESS program, GMP brings value to all customers by reducing operating costs. For 10 years, GMP will have access to the enrolled systems, using them as a demand response resource several times per month. The energy storage systems are also prioritized to provide backup power should the need arise.

The BYOD program currently supports a number of energy storage solutions that continues to grow. Current systems compatible with the program include:

- Duracell
- Eguana
- Emporia Energy
- Enphase IQ Battery
- FranklinWH Energy Storage Inc.
- Generac PWRcell
- Tesla Powerwall 2.0
- Tesla Powerwall+
- Tesla Powerwall 3.0

Our BYOD platform is flexible to allow for any viable storage solution to be added to the list of systems compatible with the program. Given our reputation for innovation and because of the appealing program design, GMP encourages vendors to integrate with the GMP virtual power plant software provider, making themselves instantly available to installers and customers for new projects.

Energy Storage Assistance Program Rider and Home Electrical System Upgrades

GMP is developing programs for two funding opportunities that will make it possible for income qualified customers to prepare to electrify and be part of the clean energy transition.

In 2023, GMP received a $1.5 million Energy Storage Access Program (ESAP) grant award from the DPS and filed the ESAP Rider to the ESS Tariff to enable no-cost, leased whole home energy storage system installations for around 100 customers at or below 80% of area median income. Simultaneously, a $10 million award for GMP's Home Electrical System Upgrade (HESU) program will enable customers to upgrade their electric panels and services to 200 amps at no cost. Both programs are funded using American Rescue Plan Act (ARPA) grants and will work in combination with our Energy Transformation Line Extension Tariff so that income-qualified customers can ready their homes for electrification now or in the future.

In late 2024 through 2026, GMP will directly engage with income-eligible customers with medical conditions who experience frequent outages to enroll them in the ESAP and HESU programs. Customers will be connected directly with the local storage installer network that supports the ESS and BYOD programs. Through combining these two funding streams behind the scenes to make it easy for customers and contractors, GMP can leverage contractor availability and expertise to coordinate multiple electrification and resilience projects in concert and make it simple for the customer.

This will make it so that customers when they're ready to make the switch from fossil fuels to electric options, whether it is next year or further down the road have peace of mind that their electrical set up in their home is safe, reliable, and ready for heat pumps, an EV charger, a heat pump water heater, or all of the above.

Innovative Pilots and Programs

As noted above, the ability for GMP to provide our customers with pilot programs, quickly learn, iterate, and evolve them to full offerings or sunset them is incredibly beneficial to ensure the latest innovations and ideas are being used in Vermont to provide a benefit to all customers.

Every pilot filing includes a detailed description of the program and how it will benefit our customers, and also a cost benefit analysis. As mentioned under **Innovating for Customers**, we review specific criteria and questions when determining if GMP should move forward with an offering for customers. Some further examples based on recent pilots include:

- Is it something that a customer would want to engage in?
    - This can include factors such as incentives, reliability and resiliency improvements, carbon reduction, and cost reductions. Customers will have different motivations to join a program, not all of which include a financial return—the energy storage programs being examples of this (see section on **Storage Programs**).
- Does it provide value to all customers?
    - In most cases, we look for a program to provide some amount of cost reduction benefit to all non-participating customers. This can come in the form of reduced power supply costs, reduced T&D costs, reduced O&M costs, or by increasing revenue such as in ancillary markets.
- Does it provide GMP with a new flexible resource to manage a more distributed, intermittent power system?
    - This criterion does not apply to each program offering but it is something we consider when a program includes a specific product, device, or includes an incentive for any kind of flexible resource.
- Does the program directly support disadvantaged customers, which could include income based or other factors identified in various vulnerability indices?
    - Does the program have a specific focus or added support for disadvantaged customers. Examples are discussed throughout this chapter and include programs like the ACRE pilot, or incentives for income-qualified customers in a specific program.

There are some exceptions to the above as every criterion does not always have to be met. Specifically, the ACRE program does not provide GMP with a new flexible resource to manage an intermittent grid, but it does provide a way for income-qualified customers to participate in solar while reducing their costs, and it is also a Tier II resource. So, the criteria are important, and so too is examining the customer benefit as in the ACRE program example.

As discussed in **Chapter 2**, GMP provides a three-part cost test for our Tier III programs, which include the Participating Customer, Non-Participating Customer, and the Societal tests. When evaluating pilots, we typically refer to the Participating and Non-Participating Customer tests, which relate to the first two criteria above. Customers need to see a reason to participate in any given program which is why it must be appropriately appealing for customer uptake. However, if it does not generate a form of benefit—monetary or otherwise—to non-participating customers we would be unlikely to move forward. If there is a substantial non-monetized benefit such as resiliency or reliability improvements, or supporting disadvantaged customers' access to a program they otherwise may not be able to participate in, GMP may still offer such a program.

Resilient Neighborhood Pilot

GMP launched the Resilient Neighborhood pilot in May 2023 in South Burlington with 155 single-family and multi-unit homes. It is Vermont's first all-electric, fully storm resilient neighborhood and serves as a model for other neighborhoods in Vermont, where the innovative programs GMP offers are brought together in one turnkey package to keep residents connected. Each home is move-in ready with a resiliency package of Powerwalls and solar panels to recharge them, a SPAN panel to manage energy use, a Level 2 EV charger, whole home air source heat pump system, induction stove, and no fossil fuel infrastructure. The neighborhood will also serve as a microgrid, with utility scale energy storage that will be built, allowing the neighborhood to island itself and providing an extra layer of resiliency if the grid is damaged. The neighborhood serves the greater grid and all other GMP customers by sharing energy during peaks.

Flexible Load Management 3.0

This year we launched the third version of the Flexible Load Management (FLM) program, to further explore ways that incentivize commercial and industrial customers to shift their peak loads to times of the day that benefit all customers. The 3.0 program offers updated incentives and direct technical expertise to large business customers to help them move their power use to reduce peak demand, to ultimately reduce costs for all other GMP customers, while also reducing carbon emissions as ISO-NE peaks tend to have higher use of fossil generators.

FLM 3.0 offers a simplified, guaranteed way for participants to take action and save money, designed to test two new, ground-up rate designs with a goal of transitioning this final iteration into its own FLM tariff. The program offers customers the option to pay either a time-of-use rate or a flat rate per kWh based on their load profile. There are then peak events during which customers reduce power use, and their rate can be adjusted up or down depending on performance. This aligns customer and utility incentives to minimize cost for customers and grid impacts while maximizing use of variable renewables. As part of FLM 3.0 GMP is also piloting a specialized dashboard with select Vermont ski areas to explore snowmaking operations and potential grid peaks. This is intended to enhance operational flexibility for ski areas and optimize opportunities for snowmaking during peak times. GMP works with EVT and Dynamic Organics on this program.

ACRE Pilot, Shared Solar, and Future Community Renewable Offerings

As mentioned above, GMP's new Affordable Community Renewable Energy (ACRE) program expands renewable energy in Vermont while also lowering costs for income eligible customers, through a grant from the federal American Rescue Plan Act. GMP launched the ACRE program in fall 2024, to connect customers with solar, in a new community solar model which provides an additional discount for income eligible customers already enrolled in GMP's Energy Assistance Program (EAP) who live in proximity to a new 4.1 MW solar array in Pawlet, Vermont. About 1,200 customers will receive an extra discount of $0.04/kWh on top of the 25% discount they receive each month as part of EAP. The new ACRE program is set to run for five years, and is a collaboration between GMP, DPS which is managing the federal grant funding through the American Rescue Plan Act, and Bullfrog Hollow Solar which developed the array. We expect more solar arrays to launch in 2025 and beyond through Vermont's Environmental Protection Agency Solar for All award, to benefit more low-income customers through the subsidies in the ACRE program, as well as through the Shared Solar Program, described in **Chapter 6**.

Future Initiatives

Hourly Energy Matching

During this IRP, GMP plans to launch a pilot to provide commercial customers with an opportunity to match their consumption with renewable generation on an hourly basis. Vermont's current climate goals and requirements through the RES are targeted to support this on an annual basis by matching a percentage of total annual load with renewable energy generated in the same year. This has been a positive, cost-effective evolution of renewable energy policy, and setting new goals to match more electric load with renewable generation on an hourly basis will be another step to ensure a balanced and stable grid, while we rely less on fossil fuel baseload generation, as further described in **Chapter 7**. RES compliance resources in this pilot will be accounted for separately from GMP's annual RES obligations and additional renewable goals. Customer interest to begin exploring an hourly matched option for their specific energy consumption has grown and the NEPOOL Generation Information System (GIS) is also working to adopt changes to the GIS Operating Rules to accommodate tracking of generation on an hourly basis. Providing customers with a mechanism to achieve hourly targets will help further adoption of energy storage and load management technologies and incentivize development of renewable energy that more closely aligns with real time demand needs.

Expanding Customer Storage Offerings

The broader grid benefits of energy storage are discussed in **Chapters 3 and 7**, and GMP continues to seek to expand access to and provide customers with a variety of energy storage technologies, including through new initiatives like ZOI, exploring evolving thermal storage, and vehicle-to-anything (V2X) technologies. Throughout this IRP period, GMP will work to pilot new storage technologies as they become available for residential and commercial and industrial customers.

V2X

In keeping with the goals of GMP's energy storage and resiliency programs above, we are continuing to explore and test opportunities to make use of EV batteries to allow customers to stay powered up and deliver grid benefits for all through V2X. Vehicle-to-grid (V2G), and the similar but more limited vehicle-to-home (V2H) capability, allow an EV to act like a generator to power a home or send power to the grid. Through GMP's FLM 2.0 program, four South Burlington electric school buses participate in V2G through a partnership with the South Burlington School District and Highland Electric Fleets. These buses supply energy to the grid during peak summer hours while they are not in use for school transportation. Through this IRP period, GMP plans to develop a V2H or V2G offering to residential customers, likely through a partnership with an EV OEM. We are also closely following the development of brand agnostic V2H and V2G chargers. As of 2024 such chargers are only available for CHAdeMO vehicles—the Nissan Leaf. Once they become available for CCS/NACS EVs, which is expected during the term of this IRP, we plan to pilot them as part of our managed EV charging programs to give customers the option to back up their home using their car and potentially save money via enhanced charging management and grid support.

V2G equipment can provide load management and shaping similar to our stationary energy storage at both the residential and commercial scale. The current use case is peak shaving, which will continue. As market conditions and our control platforms evolve, we also see V2G EVs taking on many of the use cases we envision for stationary energy storage (see **Chapters 2 and 3**). Commercial V2G EVs will continue to make use of the FLM pilot programs and their successors, while we expect residential V2G EVs to act first as resilient backup options that also provide grid services under a program structure that may look like our ESS and/or BYOD tariff programs.

Distributed Energy Resource Management Systems

As a leader and early adopter of distributed storage, managed EV charging, flexible load management, and similar distributed energy resources (DERs), GMP has used many platforms and strategies to dispatch and coordinate these resources over time. The strategy involves OEM battery management software, a dedicated edge DER management system (DERMS) platform, a custom-built interface for commercial customers, and our grid-management SCADA system. To date most DERM has involved peak shaving and frequency regulation. GMP's peak shaving resources have grown to the point that in many cases an "all or nothing" dispatch when a peak is projected is no longer the most efficient and effective way to reduce grid stress and power supply cost. Instead, we are adopting a more nuanced approach to integrate energy storage, demand management from both commercial and residential customers, and emerging technologies like V2G. Together, we can dispatch resources either together or sequentially to smooth peaks over longer periods of time and address periods of very high or very low wholesale energy prices and grid constraints. These might include the integration of more distributed solar, EVs, and building electrification. Our plan for a comprehensive control system (**Figure 1-2**) involves communicating with each of the above systems that control discrete portions of our DER fleet.

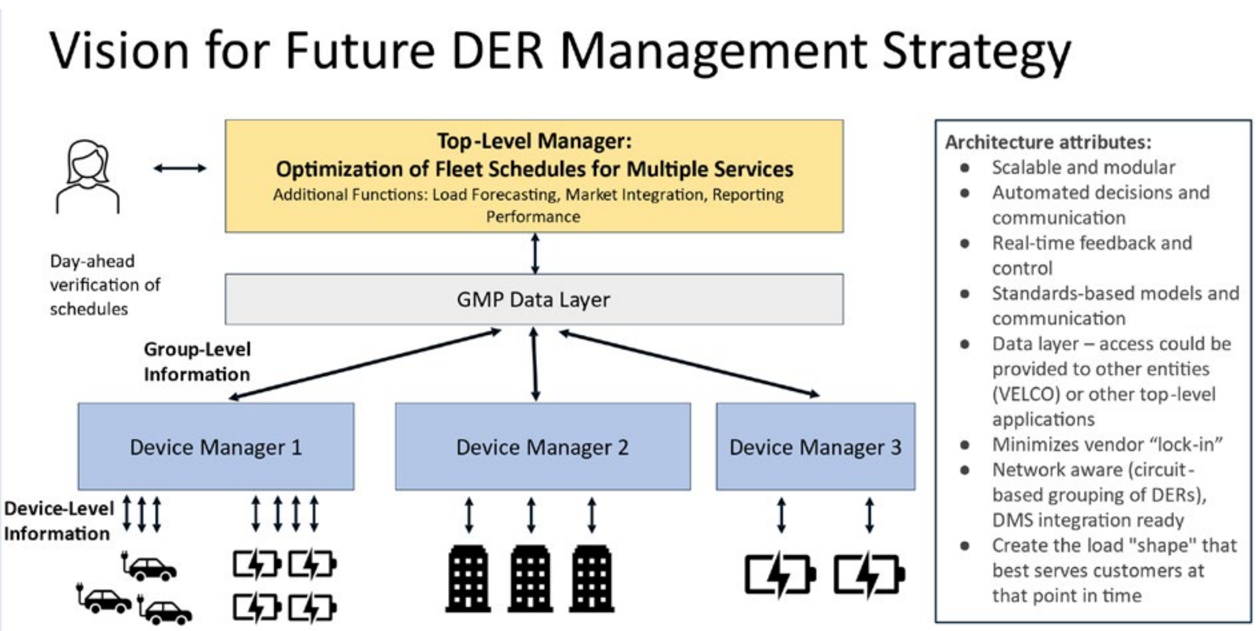


Figure 1-2. GMP's comprehensive strategy for applying DERMS to manage GMP data and relevant devices.

GMP is evaluating options for this, including through exploration of an Advanced Metering Infrastructure (AMI) update further described in **Chapter 3**, expecting to eventually take into account forecasted load, wholesale energy prices, physical grid operating constraints, and time-variable DER availability to optimize DER dispatch. With the proper data sources, such a system could also take the real-time carbon intensity of the regional grid into account to reduce regional emissions and make the most of variable renewable resources. We also can work with other utilities in Vermont to develop a framework for coordinating statewide resource dispatch.

Innovative Rates to Boost Electrification and Equity

Traditionally, the purpose of rate design is to ensure that the cost of electric service is just and reasonable for all customers, even though their usage is diverse. GMP applies that framework to our overarching goal to give customers multiple ways to use their electricity service to drive down their own GHG emissions and save costs. As described below, that includes providing customers the choice of innovative rates and programs that incorporate Time of Use (TOU) or utility load management features. Simple, easy to implement programs are more successful for customers than anything requiring frequent individual attention and decisions. Good technology fits in seamlessly and makes life easier for customers. GMP has both individually managed and automated rate offerings and programs that customers can choose. While there will continue to be options for those customers that want to manage everything themselves (such as on an individual TOU rate), we will focus on providing that same type of service to customers through programs where we help deliver the benefit rather than putting the burden on the customer to take action.

EV Rates

As noted in the **Tier III Programs** section above, the electric transportation transformation is accelerating across our territory, with more customers purchasing EVs every day as described further in **Chapter 2**. To make sure customers have options to charge these vehicles at home with less cost and hassle than their gas cars, GMP offers charging equipment programs for customers to install Electric Vehicle Supply Equipment (EVSE) and EV-specific residential rates. GMP also has TOU rates available for commercial and industrial customers. Together, GMP has options for EV charging service widely available today for residential, commercial, and industrial customers that are consistent with the requirements of Section 33(d) of Act 55 as demonstrated in Case No. 23-1364-INV. We are continuing our work to identify and remove remaining barriers to charging access for residential customers wanting to incorporate an EV into their lifestyle, and businesses working to electrify their fleets.

Residential EV Rates

GMP has offered for a few years now a TOU EV rate (Rate 74) and a peak pricing EV rate (Rate 72) for residential customers. Based upon the data from these offerings, we have learned about customer charging patterns with and without these rates, what is more convenient for customers and how much savings they achieve. All of this is reported to the Department and PUC routinely, and also serves to help GMP determine whether any changes are needed to these offerings to help enable customer adoption of EVs.

Commercial and Multifamily EV Rates and Future Expected Offerings

Outside of the residential context, GMP also supports sites that offer public fast charging for EV drivers through an exemption from demand charges that would otherwise apply to this high peak, low utilization service. With Rate 6, customers who install fast charging EVSE available to the public do not incur demand charges that would otherwise apply to their usage. This, combined with our Tier III incentive for fast charging, encourages the build-out of public fast charging infrastructure, lowering the costs of providing this service. Continued buildout of public fast charging infrastructure will help ensure all customers who drive electric can stay powered up, even if they rent or live in a housing unit where charging is not installed.

Looking ahead, we recognize the need for both additional EV charging infrastructure targeted for multifamily units, workplaces, and other locations and additional rate offerings to cover charging at those locations where a customer is otherwise unable to take advantage of the current residential and public fast-charger programs. As part of the work with the State through Charge Vermont, we are simultaneously looking at the load profiles and successful rate designs that will match. These specific use cases have charging load profiles and billing determinants different from one another and from the other EV charging rates we already offer. We are continuing to develop EV offerings specific to emerging use cases within all customer classes to further encourage implementation of EVSE infrastructure, while providing additional flexibility for GMP load control to benefit all customers. We expect to have additional offerings proposed by the end of 2025 per June 12, 2024, PUC order in Case No. 23-3612-PET.

Future of Rate Design

To support keeping electric rates and program offerings as simple for customers as possible, GMP will continue to offer direct and flexible management of distributed resources alongside rates structured to require customer actions and control. As a part of this work, we will also review and update as needed our overall allocated cost of service across all customers and rate offerings. GMP anticipates beginning work on a fully allocated class cost of service study in January 2025 to propose along with a new regulation plan in September 2025. On that timeline, the PUC would review that study and GMP could then propose any revised and additional rate designs based upon it sometime in 2026.[7] We expect to engage consultant expertise for the analysis and to apply the outcomes to support and inform new design, which encourage decarbonization through electrification. We will review ways to accomplish this, such as a lower volumetric rate coupled with a restructured customer charge. We will consider not only current innovative service offerings in this work, but also the accelerated resilience work needed to keep the GMP grid strong in the face of climate change and other disasters.

During the remainder of this MYRP period we will conduct an extensive review of all rate schedules currently offered to customers today. Future default rate designs for each class may look familiar, though with the rebalancing of costs as mentioned. Other rate schedules may use the existing design, revised to be more relevant with today's energy market and customer end uses. This could include shifting peak hours in TOU rates, adjusting use and load thresholds for demand-based rates, adding seasonality, or adding mid-peak to peak and off-peak, for example.

To date, we have been successful at targeting peak loads with TOU rates, Critical Peak Pricing, and load response programs and expect that to continue, as being an early adopter and leader put Vermont ahead in the region. We have shown an ability to be flexible and responsive and will evolve with expected changes including how ISO-NE is now assigning capacity costs differently than in prior years. As other utilities in the region increase demand response offerings, peaks are more dynamic to predict and require a stronger, more sophisticated response to manage them. At the same time, the successful deployment of solar throughout the region is shifting mid-day energy costs lower than before while shifting peak hours later. Greater electrification of heating and transportation will continue to drive higher loads in the winter that may shift GMP to winter peaking, a time when there is generally more volatility in energy pricing—particularly now that a transition to greater usage of intermittent resources is underway. This in turn is driving a restructuring of the capacity market and the use of peaking resources. The chapters addressing energy supply—**Chapters 5, 6, and 7**—examine the ways GMP can manage these circumstances through generation and purchases that will continue to benefit customers.

From a rate design and customer energy program perspective, all of this points to working to get the most out of every MW of GMP's load response resources. That will require customer load to be more flexible than ever to optimize the MW installed and duration

7 This means conducting a fully allocated cost of service study for FY27 and beyond, which aligns with when the GlobalFoundries transition approved by the Commission is complete. Such a study will inform and support an updated rate design and new rate and program offerings. The PUC has asked for GMP to provide a timeline for this study and rate design filing to be filed with FY26 base rate in June 2025.

of response. Some new programs or rates we anticipate will be broadly applicable while others may be targeted towards specific end uses (commercial fleet EV, for example) or specific cost offset (LMP versus capacity cost). These designs, in addition to helping us cut capacity costs as they have in the past, can accomplish multiple benefits for customers. For example, they can help soak up a glut of solar at low cost during the day if the time of use or program parameters are designed to encourage usage at those times. We can also use these rates and programs for customer benefit when there is volatility in LMPs, with improving coordination of variable electrification loads like EV charging to lessen grid impact and potentially prevent some of the costly transmission impacts predicted in Vermont Electric Power Company's (VELCO) Long-Range Transmission Plan (see **Chapters 2 and 7**). With all of this, to make this work for customers, we will maintain a simple and equitable approach to customer sign-up and participation. For residential customers, for example, this could look like automated TOU designs that do not require customer intervention, accomplished by implementing simple controls like SPAN panels.

To support equity GMP continues to share the benefit of any program among all customers. This helps address the lack of access some customers have, even with new rates and program designs that seek to broaden participation. For example, some customers who rent can't join certain programs because of restrictions regarding their building.

In addition to sharing benefits, GMP addresses renter equity in electrification through several existing programs (see **Energy Assistance Program**, **Energy Storage Assistance Program and Home Electrical System Upgrades**, and **ACRE Pilot, Shared Solar, and Future Community Renewable Offerings** sections). If a tenant is in an individually metered unit and has support of their landlord, a Level 2 home charger can be installed for the customer's use. For those renting units in muti-unit housing metered collectively, we offer an incentive to property owners for the installation of Level 2 chargers to be shared by residents. In both of these instances GMP often engages with tenants and property owners to review programs and incentives and provide general education regarding EV charging. The work being done through the Charge Vermont grant is helping these efforts with a focus on charger installations at multi-unit housing sites. Additionally, GMP supports custom electrification projects through Tier III at multi-unit sites where tenants are the end user of the installed electric technologies, with increased incentives available when the housing is designated for low-income tenants.

2

DEMAND & DISTRIBUTED ENERGY FORECAST

Continued Decarbonization to Benefit All Customers

An increasing number of customers are going electric, and that is expected to continue. Our innovative programs featuring successful load control techniques, such as EV charging, energy storage programs and flexible commercial load management will manage this growth smoothly and cost-effectively for customers while helping customers achieve their carbon reduction goals. This chapter explores several analyses and forecasts, all showing that electric use will grow steadily in the years ahead and the system will be more than ready to handle it because of our innovative management programs, which we conduct in partnership with customers.

Last year, 10,000 customers took part in at least one GMP Tier III program, shifting their energy use away from fossil fuel to electrification. Heat pumps in buildings, electric cars and trucks on the road, and other uses of technology cleaner than the status quo that enable load management and coordination—all of these will continue to be adopted by customers and will help lower Vermont's overall emissions.

Combined, these customer choices, as well as direct State programs and requirements mean that the long-term trend in overall electricity consumption reflects higher load.[1] This higher load lowers costs for all customers because the cost of delivery is spread across more kilowatt-hours. Thanks to GMP's already carbon free portfolio that is becoming more renewable every year, this new load will be served without emitting greenhouse gas on an annual basis.

This chapter describes the load scenarios GMP has used for planning in this IRP. We present two separate load forecasts, which are referred to throughout the IRP, to show potential outcomes for the grid (in **Chapter 3**) and our power supply decisions (in **Chapters 5 through 7**). Wherever feasible, we used assumptions for these load scenarios consistent with VELCO's Long-Range Transmission Plan and current Efficiency Vermont forecasts. Forecasting consultant Itron produced our medium-term forecast and was provided with inputs consistent with those noted here. The full Itron forecast is provided with this chapter as **Appendix C**, cited throughout this chapter. We aligned our assumptions with the State's policy requirements in the Global Warming Solutions

1 For example, Vermont has adopted California standards for vehicle emissions through the Advanced Clean Cars II rulemaking, which will have the effect of phasing out sales of new internal combustion engine passenger vehicles over time as the market shifts to electric vehicles. Changes in the thermal sector also are likely through State policy; the Vermont General Assembly passed Act 18 in 2023, requiring the Commission to engage in proposed rulemaking for a Clean Heat Standard scheduled for decision in 2025, and will consider whether that proposal or an alternative should move forward for that sector. Meanwhile, other State programs driven by available federal funds are supporting direct incentives for Vermonters to upgrade electrical equipment and support decarbonization through electrification. An example is the home electrical panel upgrades for flood victims and others seeking to improve their energy efficiency, via Efficiency Vermont's Home Energy Rebate programming.

Act that require fossil fuel savings to be met by different sources of energy. Specifically, the two load scenarios defined and discussed below are an Accelerated Adoption case, which incorporates a high forecast of adoption for all factors that influence increased load and reflects success in meeting the State's long-term climate and energy goals, and a Continued Adoption case, which is based on a somewhat lower (but continuing) pace of the customer adoption already underway. Adoption of cold climate heat pumps (CCHP) and EVs in the Accelerated Adoption case are derived from Efficiency Vermont forecasts and in line with the 2022 Vermont Pathways Analysis Report 2.0 that informs the Vermont Climate Plan to meet State goals.

Factors Affecting Retail Sales Forecasts

Four prominent factors affect retail sales forecasts: two **reduce** sales (energy efficiency including appliance standards, and solar net metering), and two **increase** sales (economic and household growth, and strategic electrification to address climate change and meet State goals).

Retail Sales Reducer 1: Energy Efficiency and Appliance Standards

With this factor, efficiency gains continue to offset sales growth from customers and economic growth. Itron, GMP's contracted retail sales forecasting service, captures efficiency gains through end-use energy intensity projections and expected State-sponsored energy efficiency savings. These take into account changes in the market and regulations that drive efficiency measures. See the full Itron forecast in **Appendix C**.

For example, in December 2023, the U.S. Department of Energy (DOE) finalized new efficiency standards for residential refrigerators and freezers. These standards will result in an estimated 11 percent reduction in energy use compared to standard products on the market. DOE will not require compliance until early 2029 or 2030, depending on the product. Compliant products, signaled by ENERGY STAR® Most Efficient labeling, have begun to enter the Vermont marketplace and are incentivized by Efficiency Vermont.

As forecasted by Itron, end-use intensities reflect both increases in appliance ownership and changes in stock efficiency from new standards such as this. End-use intensities are based on the U.S. Energy Information Administration (EIA) 2022 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific data where 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. Although cooling intensity is increasing, aggregate cooling consumption is still comparatively small, given Vermont's still-relatively temperate summer weather conditions. Further, as cooling is switched from traditional window-mount AC units to heat pumps, this will put a downward pressure on cooling load ultimately keeping it relatively flat. **Figure 2-1** shows per-household end-use indices.

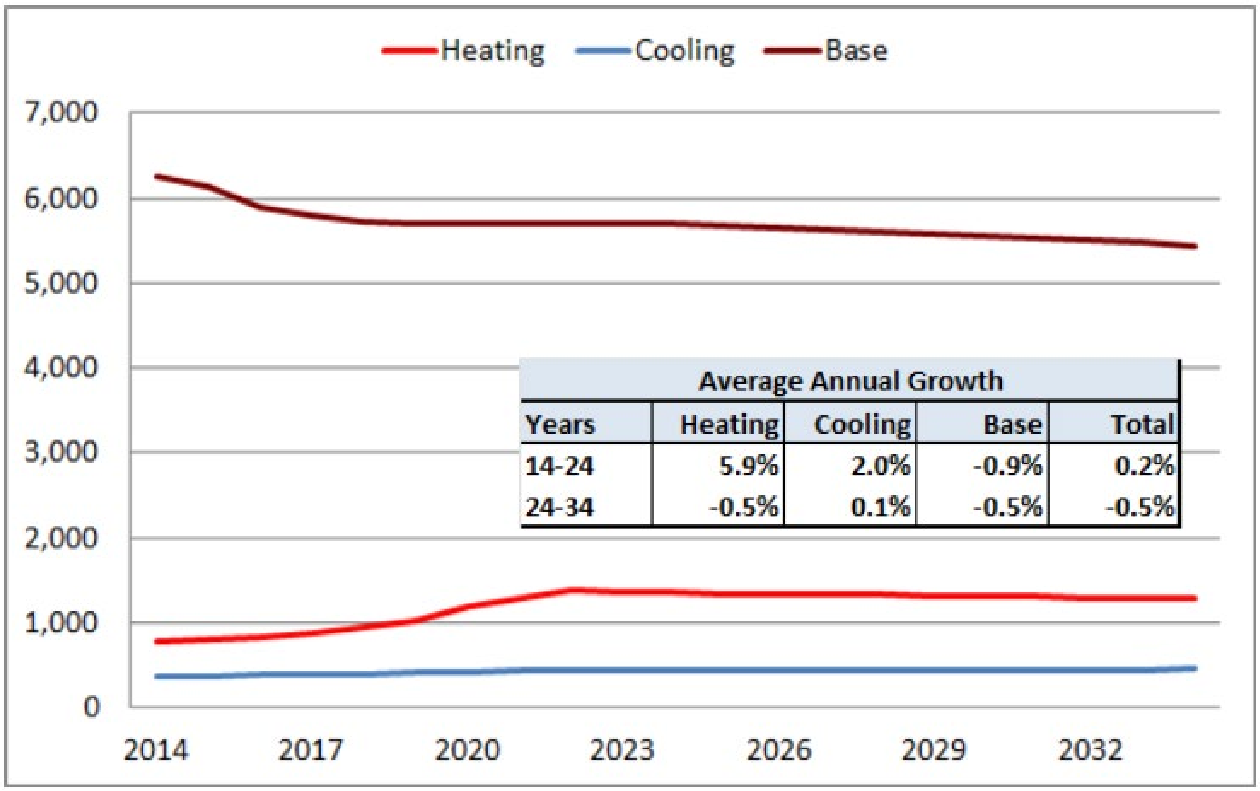


Figure 2-1. Residential end-use indices, in kWh per household (Source: Itron, see Appendix C).

GMP has captured additional savings from Vermont energy efficiency programs by incorporating historical and projected demand-side management savings. We have derived historical program savings from Efficiency Vermont's 2023 *Savings Claim Summary*. The energy efficiency utility's future savings reflect the State's most recently approved efficiency program budget. We have scaled down historical and forecasted savings proportionate to GMP's share of retail electric sales, as shown in **Figure 2-2.**

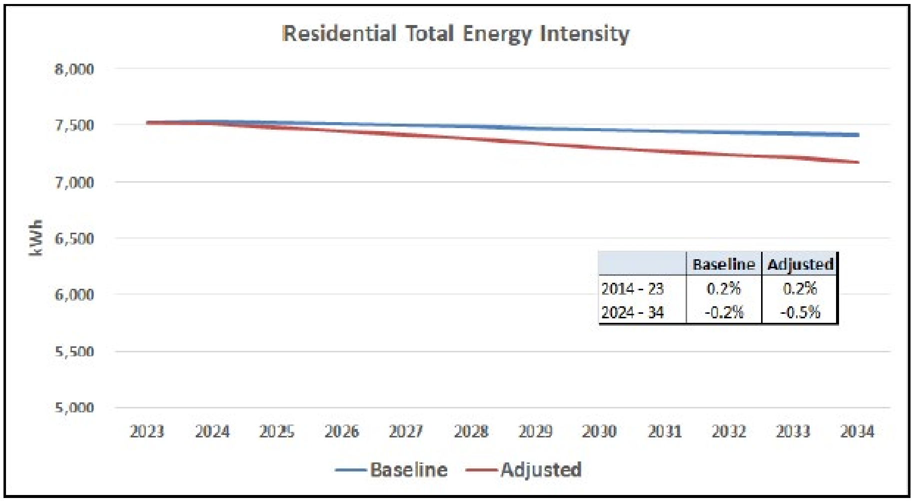


Figure 2-2. Residential energy intensity at baseline and after adjusting for energy efficiency, through 2034 (Source: Itron, see Appendix C).

Figure 2-3 shows total cumulative savings from forecasted energy efficiency measures, through 2041.

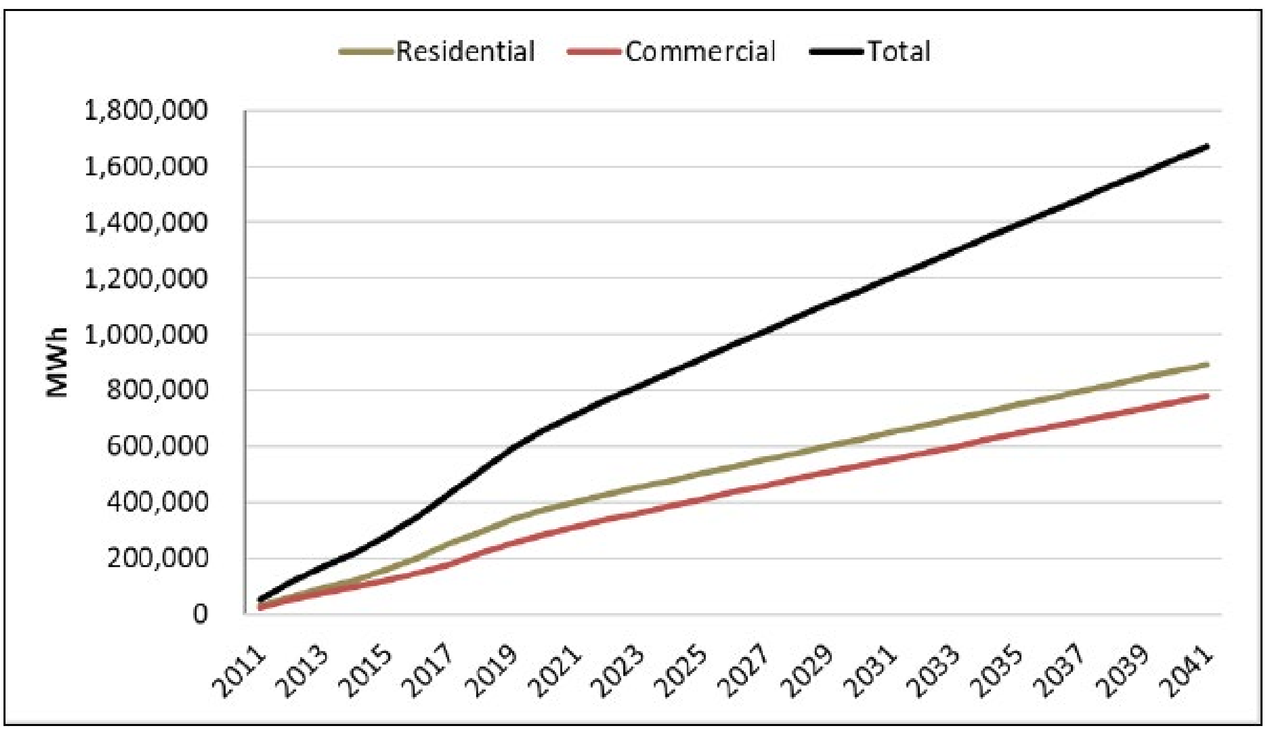


Figure 2-3. Cumulative energy efficiency savings for residential and commercial customer classes (Source: Itron, see Appendix C).

Retail Sales Reducer 2: Solar Net Metering

In this factor, solar net metering affects GMP's retail sales forecast to the extent customers self-supply a portion of their load through these systems. Any solar generated and consumed on the same premises within a billing month results in a reduction in retail sales known as *own use*. In addition, if a net-metered system generates more kilowatt-hours than are consumed onsite within a billing month, "excess" credits constitute a power supply expense, which can then be applied as credits to participating customers' future bills. Thus, solar net metering impacts GMP customers by either reducing retail sales directly through own use or by increasing power supply expenses because the excess energy is paid more than its avoided cost value for the same class of energy. In the case of a group net-metered system, 100% of the output is treated as a power supply expense. Group net-metered projects make up over 65% of the connected net metering on the GMP system.

Figure 2-4 shows the cumulative growth in net-metered projects through August 2024. Other solar generation in GMP territory that is not net-metered is discussed in **Chapter 6.**

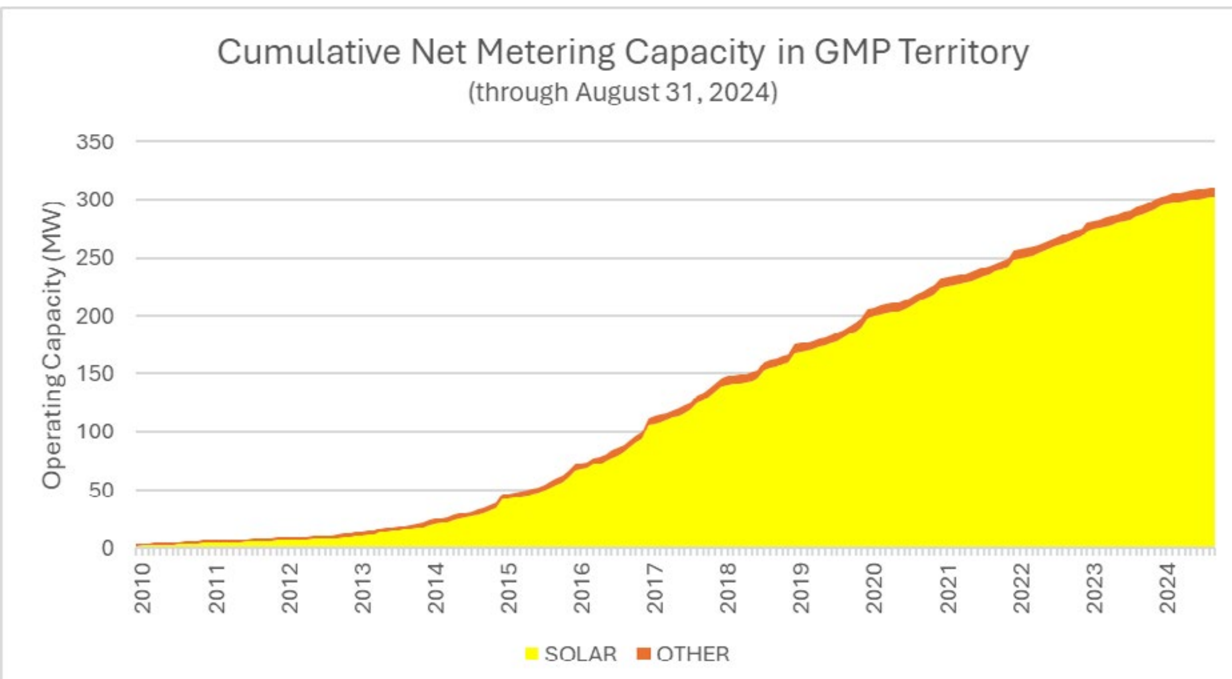


Figure 2-4. Growth in net-metered solar installations, 2012–2024.

In GMP Fiscal Year 2024, solar net-metering projects produced about 369,000 MWh of energy. Of that total, 88,000 MWh in "own use" offset retail sales that otherwise would have occurred. The remaining 281,000 MWh "excess" (credited power consumption) increased GMP's power supply expenses for all customers, while appearing as a bill credit for the producers and their group members. Producers can either be individuals or have formed a group that shares in the generation. For context, GMP sold approximately 3,753,000 MWh in Fiscal Year 2024. Solar net metering own use therefore constitutes a reduction of roughly 2.3 percent of GMP's total retail sales. Excess net-metering production supplied power equal to 7.5 percent of retail sales.

The amount of solar net-metering production has continued growing, though at a slightly moderated pace over the past few years. The 369,000 MWh of solar net-metering production reflects an increase of 21,000 MWh over Fiscal Year 2023, which was 24,000 MWh higher than Fiscal Year 2022, as shown in **Table 2-1.**

	MW		**Total in MWh**		
	Installed in FY	Cumulative	Generation	Own use	Excess
FY2021	24.3	237.6	284,000	77,000	207,000
FY2022	26.0	263.6	324,000	80,000	244,000
FY2023	23.0	286.6	348,000	88,000	260,000
FY2024	16.5	303.1	369,000	88,000	281,000

Table 2-1. Solar net metering in terms of installed capacity and MWh of generation, by GMP fiscal year.

GMP does not control the pace and the amount of installed net-metering capacity within its service territory. To the extent that adjuster fees are utilized under PUC Rule 5.136, they could have the effect of both reducing the pace of net-metered development in constrained areas and/or providing a pool of funding to mitigate those constraints, whether through grid upgrades, energy storage and control capabilities, or other innovative methods. GMP will be reviewing what an adjuster structure could look like and how it could be implemented to help steer solar, or as mentioned, provide a source of funding to support other solutions. This will occur after the filing of this IRP. The requirements for a successor program for the larger systems typically referred to as *virtual group net metering* (although they are purely an economic payment to participants and do not offset any specific customer load) are under review at the time of this IRP's filing through the process set forth in Act 179, which created sunset dates for virtual group net metering in its current form.[2] The pace of growth for those systems might abate in the years ahead and be replaced with different programs focused on community solar. At the same time, we continue to expect robust growth in smaller-scale, customer-sited net-metering arrays that offset direct customer load through initiatives such as the Solar for All federal grant awarded to the State in 2024. As noted in **Chapter 6,** GMP supports solar being available equitably and cost-effectively for more Vermonters; the evolution of the net-metering program toward individual customer-sited systems will enable that objective. Pairing solar and storage together creates resiliency for the customer, and GMP will continue to look to support and expand that, as it has through the Resilient Neighborhood pilot described in **Chapter 1**.

Considering these factors, this IRP assumes that current patterns will largely continue across the next two years, followed by a reduced rate (thereby also lessening the reduction in load from net metering) in light of new State net-metering policy.

GMP had approximately 303 MW of solar net metering in its service territory as of the end of September 2024. Another 27 MW of proposed solar net-metering applications are in the queue. Over the term of the forecast, GMP expects around 10 MW per year of new net-metered solar capacity. The Itron forecast model uses similar assumptions.

Retail Sales Increaser 1: Economic and Household Growth

Using Moody's January 2023 economic projections for Vermont, the forecast reflects the economic drivers of electricity demand: the number of households in the state; and expected statewide real personal income, employment, and real state economic output (GDP). Over the long term, the number of households served by GMP is expected to increase 0.2 percent per year. This number drives the residential customer forecast. During the forecast period, GDP trends to a long-term average annual growth rate of 1.6 percent per year.

2 See Sec. 8 of Act 179 of 2024.

Retail Sales Increaser 2: Beneficial Electrification from Cold-Climate Heat Pumps and Electric Vehicles

In this factor, load is increased by all forms of electrification of home equipment and industrial processes, and GMP is actively supporting this through Tier III incentives for heat pump water heating, electric yard care appliances, and custom electrification measures for commercial and industrial customers, among other offerings. GMP anticipates heat pumps for heating and cooling and EVs as the two most significant drivers of load growth. In this section all graphs and forecast values assume a GMP fiscal year (October through September) calculation basis, unless otherwise noted.

Cold-Climate Heat Pumps

As of the end of 2023, there were 63,000 heat pumps installed in Vermont homes and businesses. Cold-climate heat pumps (CCHP) in particular have become a growing technology for cutting carbon emissions and energy costs in Vermont. In the past three years, GMP customers added at least 22,130 heat pumps, bringing the total number in GMP territory to an estimated 47,880. The technology gives customers a way to significantly reduce or eliminate their fossil fuel-fired heating systems and drastically reduce or eliminate the emissions from heating in cold months. Meanwhile, it also provides efficient cooling and dehumidification in hotter months, which will be increasingly welcomed by customers as climate change continues to increase Vermont's summer temperatures. For many years, GMP has worked with Efficiency Vermont and other distribution utilities to promote the technology, primarily through upstream incentives, direct rebates, outreach, and education.

For example, GMP provides an additional $250 to an Efficiency Vermont buy-down program at the wholesale level so that GMP customers can pay a lower-than-retail price without having to submit a rebate form after the purchase. Customers making up to 80% of area median income also receive extra savings through a streamlined, post-purchase rebate application. This is up to $2,000 in additional incentives for qualifying customers. These improvements have helped make getting a heat pump even easier for customers by requiring only one form to access these rebates.

Between 2021 and 2023, GMP's Tier III incentives helped promote more sales of CCHPs, significantly exceeding prior forecasts. The High Growth Scenario from GMP's 2021 IRP forecasted sales of 19,402 units between 2020 and 2023. In fact, sales were more than 50 percent higher than forecasted, at 30,939 units receiving GMP Tier III incentives in that period. **Figure 2-5** shows the prior IRP scenarios and actual adoption curves, running steadily above the previous High Growth forecast.

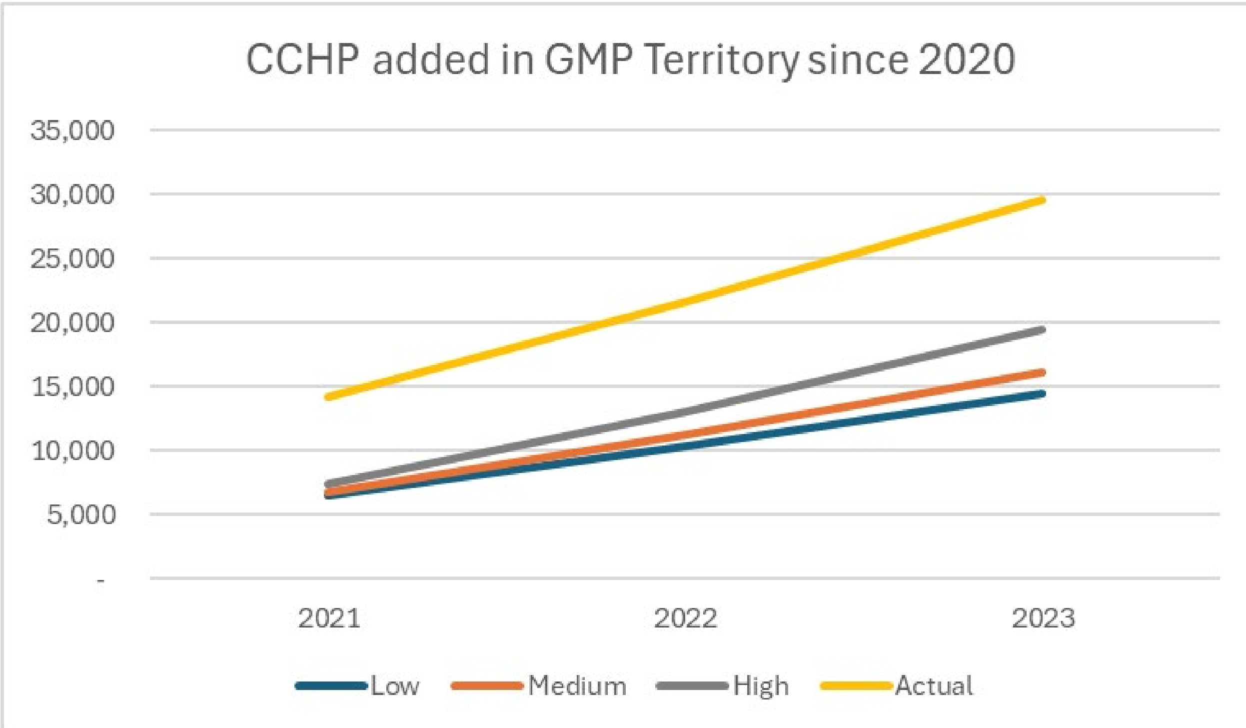


Figure 2-5. Cumulative number of new cold-climate heat pumps receiving Tier III incentives since 2020 (yellow line), compared to the Low (blue), Medium (orange), and High (gray) forecasts in GMP's 2021 IRP.

Our new forecasts, based on those by Efficiency Vermont, take these observed high adoption rates from recent years into account. GMP expects to continue to provide incentives for CCHP adoption along with strong customer interest in installing this technology, however given the maturity of the market we will be reviewing our CCHP incentives and adjusting as necessary to balance continued support of the market, GMP Tier III obligations and doing it all with the least customer cost. This is discussed further below in the Tier III section of this chapter.

GMP calculated the unit volumes by scaling Efficiency Vermont's forecast by the historical percentage of CCHP installed in GMP's service territory, relative to statewide totals, using actual per-unit consumption data and published studies, and taking into account other technical adjustments.[3]

3 We used energy consumption demand data from actual consumption by cold climate heat pumps in GMP territory, 2271 kWh per unit in 2023. We then adjusted, by EIA-projected heating seasonal performance factor (HSPF), to represent incremental efficiency improvement. We also assume 80% of energy consumption is for heating and 20% for cooling, and that 30% of cooling energy use represents new consumption that does not offset existing air conditioning load. This latter point is a professional judgment by Itron that results in per-unit consumption closely matched with the Cadmus study.

Our analysis considers the quantity of megawatt-hours of electricity (MWh) that would be consumed by added heat pumps for each year in the forecast using a weighted average of compressor sizes sold in the service territory. GMP also calculated the presumed Tier III megawatt-hour equivalent (MWhe) contribution of a heat pump, based on their corresponding prescribed Tier III values. The Tier III Technical Advisory Group's[4] 2024 Planning Tool characterizes these values, applying GMP's 100-percent non-fossil-fuel annual generation mix.

Table 2-2 summarizes the major sensitivity assumptions in our CCHP analysis, and **Figure 2-6** shows the assumed quantities of CCHP to be installed during the planning period.

Variable	Value	Source
Annual consumption	2,209 kWh in 2024, declining to 2,086 by 2043	GMP, EIA
Unit adoption	See adoption curves in **Figure 2-7**	VEIC
Coincident peak demand	0.35 kW (winter) 0.15 kW (summer)	2018 Cadmus study and GMP measurements

Table 2-2. Qualitative assumptions in sensitivity analyses for cold-climate heat pumps.

Figure 2-6 shows total CCHP systems in operation under each scenario. In 2030, adoption ranges from 105,977 (under the Continued Adoption scenario) to 133,936 (derived from the amount of accelerated adoption needed to meet State policy targets).

4 Vermont Administrative Rule 4.400 called for deploying the energy efficiency utilities' Technical Advisory Group (TAG) with representatives from all Vermont distribution utilities and other entities affected by the Renewable Energy Standard's Tier III requirements. The TAG has agreed on a common approach for estimating energy savings from measures, so that all of the utilities' reporting on savings emanate from consistently applied calculation bases and methods.

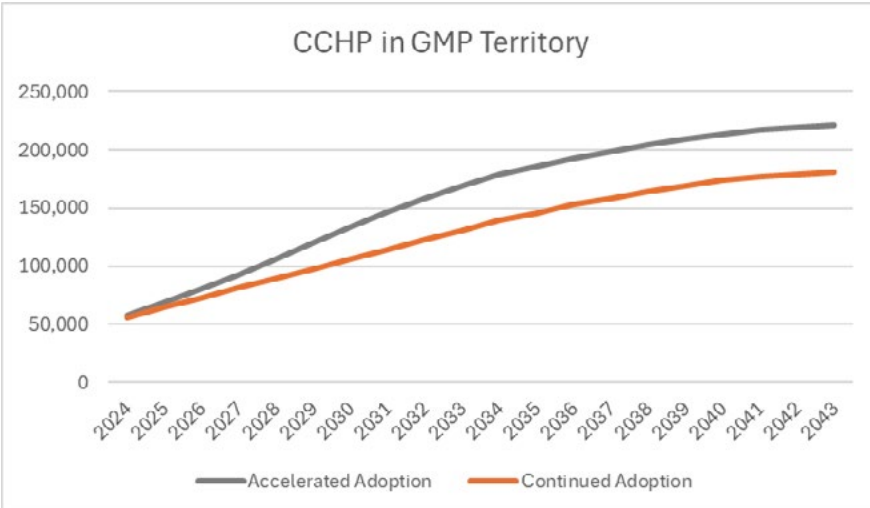


Figure 2-6. Assumed number of cold-climate heat pumps for GMP territory, derived from Efficiency Vermont's forecasted scenarios relating to meeting State policy targets and continued adoption of CCHP.

Figure 2-7 shows the annual cumulative consumption from CCHP in operation under these scenarios. Under Itron's calculations, heating accounts for approximately 80 percent of annual CCHP energy consumption. Much of this consumption takes place between October and April. CCHP constitutes a significant electrical load increase overall, which in turn increases retail sales that support system costs for the benefit of all customers. In the Accelerated Adoption scenario, CCHP consumption alone represents approximately 8.5 percent of total energy demand by the end of the forecast period.

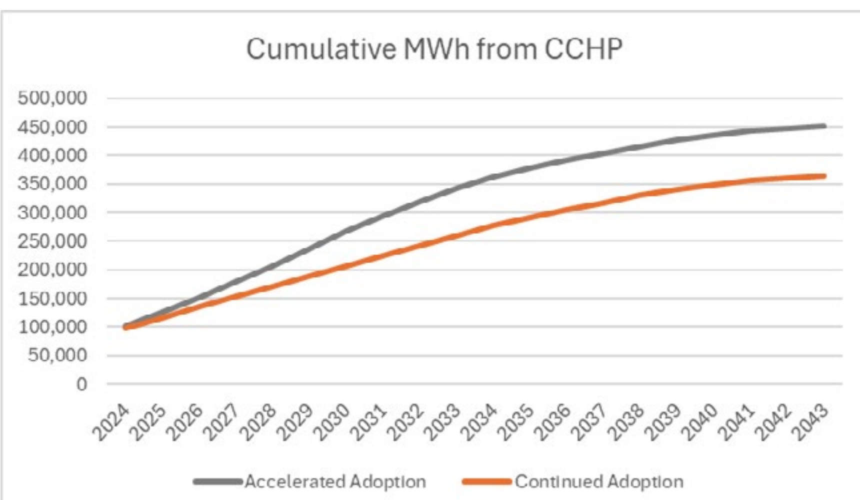


Figure 2-7. Forecasted cumulative annual energy consumption from cold-climate heat pumps, through 2043, under the Accelerated Adoption and Continued Adoption scenarios used in **Figure 2-6**, using the qualitative assumptions in **Table 2-2.**

Further, coincident peak demand from CCHP is larger in heating months. Consistent with data from the 2018 Cadmus study and VELCO's Long-Range Transmission Plan and substantiated by a year-long validation test with GMP customers who installed load-monitoring equipment, GMP has assumed an average CCHP system's coincident peak load is 0.35 kW during heating months and 0.15 kW during cooling months. GMP uses these data to project the 20-year coincident peak demand forecasts for heating and cooling from CCHP in **Figures 2-8** and **2-9**.

Even in the Accelerated Adoption case, the added demand does not represent any burden to the overall distribution system, particularly with GMP's ongoing EV charging load control that will be able to shift that load away from peak CCHP demand periods along with distributed energy storage. Overall peak load impact on the grid is assessed in **Chapter 3**.

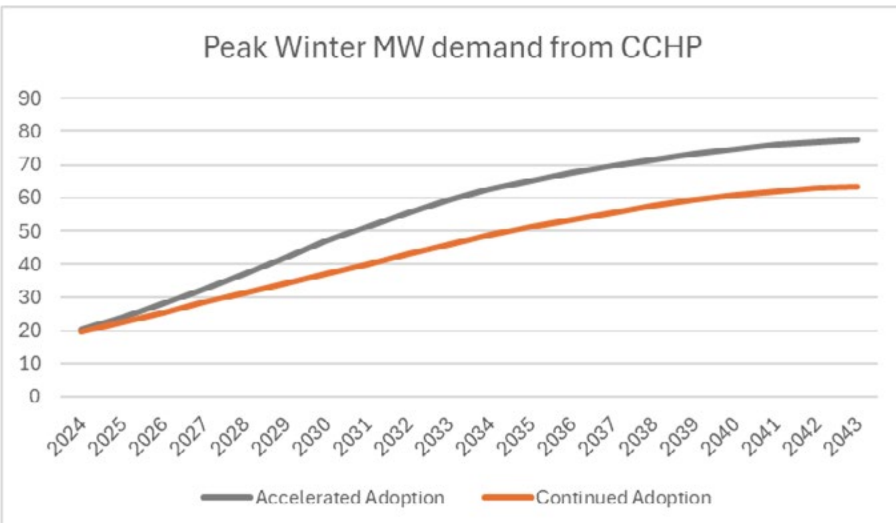


Figure 2-8. Peak demand forecast for cold-climate heat pumps, for heating only, through 2043.

Figure 2-9 shows the peak demand forecast for CCHP use in cooling buildings.

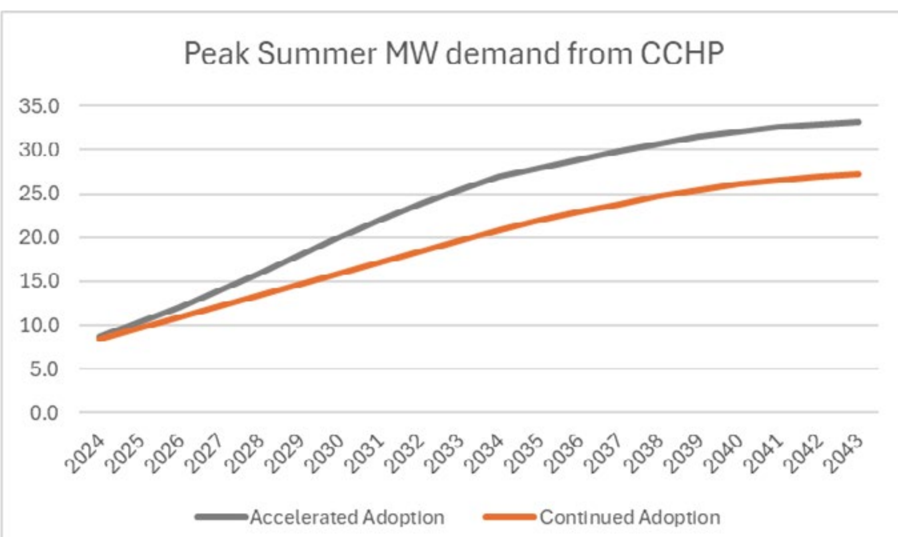


Figure 2-9. Peak demand forecast for cold-climate heat pumps, for cooling only, through 2043.

Figure 2-10 shows the Tier III MWhe expected from CCHP under each scenario. GMP has calculated the Tier III value in the year the measure is installed and assumes the measure's lifetime reduction in fossil fuel use. The reduction of the 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, where we expect growth to taper as modeled under both scenarios.

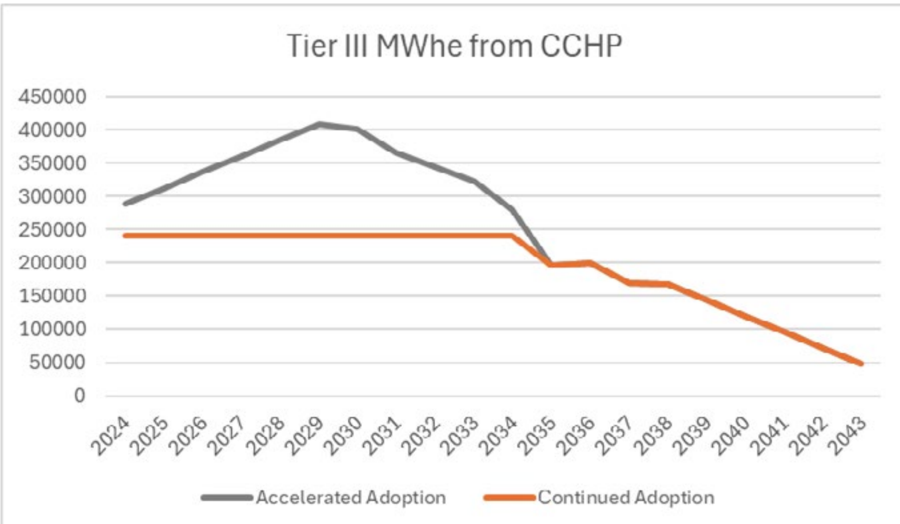


Figure 2-10. Forecasted Tier III MWhe, from cold-climate heat pumps through 2043.

Electric Vehicles

Transportation emissions continue to be a main source of climate pollution in Vermont, now ranked just behind the thermal sector. Since the 2021 IRP, federal and state policy has deepened support of transportation decarbonization, including through EVs. Specifically, the Bipartisan Infrastructure Law provides funding to build a national EV charging network. As funding from that bill flows to Vermont via the National Electric Vehicle Infrastructure (NEVI) Formula Program, EV adoption is expected to grow. This expansion of charging infrastructure will work in concert with federal, state, and Tier III incentives for some EV purchases and other policies to increase the number of EVs on Vermont's roads. For example, the State adopted amendments to its low-emission vehicle (LEV) and zero-emissions vehicle (ZEV) rules that are based on California's motor vehicle emission standard regulations known as the Advanced Clean Cars II and Advanced Clean Trucks standards. Vermont's adopted amendments will require the market to transition away from internal combustion engine passenger cars and from higher-emitting transport trucks in the years ahead.

All these programs, plus the widening model availability and lower price point for EVs as the market matures, will make EVs easier to acquire. GMP's annual clean-energy supply and the superior efficiency of EV technology make even stronger environmental cases for shifting to EVs, compared to vehicles burning fossil fuels with conventional internal combustion engines.

All-electric EV charging in GMP service territory has zero operating emissions based on the annual energy mix, compared to the annual four metric tons of CO_2 emitted for the average gasoline-powered vehicle. And taking into account emissions from battery manufacturing, research from the Massachusetts Institute of Technology has concluded that "even the dirtiest batteries emit less CO_2 than using no battery at all." Recent EV adoption figures are encouraging, with the outcome from 2021 to 2023 in close alignment with our Medium adoption scenario in the 2021 IRP, as shown in **Figure 2-11.**

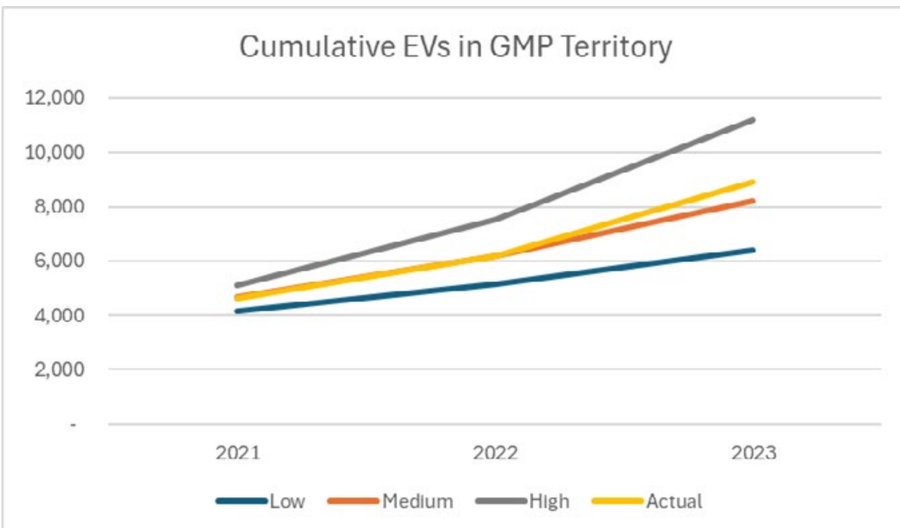


Figure 2-11. Cumulative number of EVs in GMP territory since 2021 compared to 2021 IRP load forecast scenarios (derived from Vermont Department of Environmental Conservation data).

Fortunately, expanded model availability along with available incentives have made EV costs of ownership within reach for many Vermonters. The EV customer test at the end of this chapter expands on these projected total cost-of-ownership benefits. GMP encourages EV adoption with rebates, charger programs and rates, and other incentives, all explored in **Chapter 1**.

Using data from the National Renewable Energy Laboratory (NREL), and with data from chargers under GMP management, GMP has calculated that home charging accounts for over 80 percent of customer EV charging. 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. Deploying public fast-charging equipment continues to be a necessary step in encouraging more EV adoption for Vermonters, for commerce, and for travelers, but the majority of Vermonters will most often charge their personal vehicles at home for daily use.

We now have two active residential EV charging rates and more than 3,400 chargers under some form of management. Growth in enrollment in these rates is shown in **Table 2-3**. These rates are described in detail in **Chapter 1.** Data indicates that the rates are extremely effective at shifting charging activity away from peak periods. Rate 72 offers off-peak charging rates at all times other than grid peaks that occur 4–6 times per month. During peaks, a higher on-peak rate is charged for customers that opt out of the automatic curtailment. Rate 74 offers off-peak charging rates outside the hours of 1:00 to 9:00 PM on weekdays. On Rate 74, over 90 percent of charging has occurred outside weekday peak hours (1:00 to 9:00 PM), as shown in **Figure 2-12**. And on Rate 72, we have consistently seen a peak event opt-out rate of less than one percent. **Figure 2-13** 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.

	Rate 72	Rate 74	Total
9/30/2024	981	2,447	3,428
12/31/2023	832	1,809	2,641
12/31/2022	596	1,078	1,674
12/31/2021	373	536	909
12/31/2020	90	116	206

Table 2-3: Enrollment in Rate 72 and Rate 74 over time. (Source: GMP Response to Information Requests in ePUC Case No. 24-3023-INV – *Public Utility Commission 2024 Investigation into Rates Related to Electric Vehicles*).

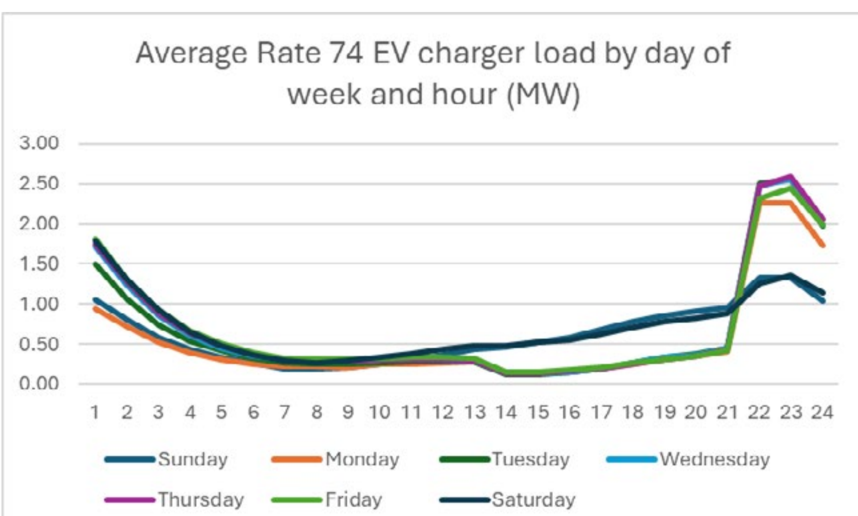


Figure 2-12. Average charging demand among EVs on Rate 74, by day of the week. Peak rates apply from 1:00 to 9:00 PM (hours ending at 14 to 21) on weekdays only.

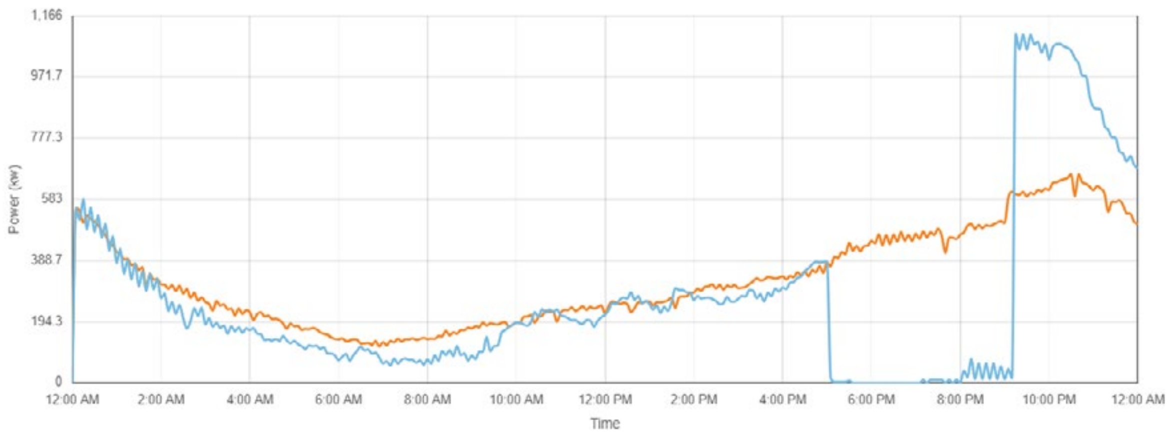


Figure 2-13. Peak event for Rate 72 customers. Blue line is actual demand and orange line is the baseline.

	EVs incentivized in households without a GMP provided charger	**EVs incentivized in households with a GMP provided charger**	**Percent of new incentivized EVs in households with a GMP provided charger**
2021	415	963	70%
2022	327	950	74%
2023	377	1386	79%
2024 (Jan-Nov)	617	1634	73%

Table 2-4. Percentage of incentivized EVs that went to households that have a GMP provided charger. Includes PHEVs while they were eligible for chargers from GMP through end of 2022; beginning in 2023 only fully electric vehicles are counted.

Over the last two years, at least 70 percent of customers claiming our point-of-sale EV rebate for an all-electric vehicle live in a household that has, at some point, received a Level 2 charger from GMP.[5] We assume 65 percent of home charging will be controlled in the future. When blended with public and other uncontrolled charging, this leads us to a forecasted 50 percent coincident peak reduction. **Table 2-4** accounts for some newly registered EVs that are adding a second EV to a household or replacing an older one. In both situations the household may already have a charger and not need to install a new one. We will continue providing a free charger for customers who purchase an EV and enroll in our home charging program, which provides access to our discount EV rates, and

5 Plug-in hybrid vehicles are also no longer eligible for a free charger, and in GMP's experience most plug-in hybrid owners find Level 1 charging (a standard 110 V outlet charging at between 1 and 1.5 kW) sufficient, based on the vehicle's relatively low electric driving range.

allows for load management from charging. We will also continue to engage with OEMs to add chargers provided under their incentive programs to our management platform. Given the percentage of EV charging that occurs at home (an estimated 80 percent), we expect that we can continue to manage over 50 percent of all EV charging load. We are also evolving our managed charging solutions in public and workplace settings in accordance with the requirements of Section 33(b) of Act 55 to offer EV charging rates to each customer class. We see commercial and workplace charging as a value to the grid in adding load during prime solar hours in the years ahead. For this IRP, we have conservatively **not** included this additional EV demand management from non-residential charging, since these offerings are still under development. Such programs, however, do provide a buffer to maintain the 50 percent coincident peak reduction from EV charging that GMP forecasts across all charging (public and home) in this IRP even if residential charging management were to decline slightly. And lastly, we are reviewing a change to our Tier III incentive for EVs that would shift more of the incentive towards the installation of the home charger, simplifying the charger installation process and increasing the adoption of GMP's discounted charging rates to benefit all customers.

Like CCHPs, we have modeled both an Accelerated Adoption case and a Continued Adoption case for EV growth, based on forecasts provided to GMP by VEIC and annual use data. 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) and scaled the aggregate demand by both the share of charging occurring at home (80 percent) and the share of new EV drivers in GMP territory who enroll in one of our EV rates (65 percent). **Table 2-5** shows the major assumptions used for our EV sensitivity analysis. Referring back to **Figure 2-12,** note that the average charging demand from EVs shows a load shape that is heavily influenced by the EV Rate 74 off-peak period that begins at 9:00 PM on weekdays. As the EV fleet grows, we will need to update the structure of our rates and control program to avoid the "bounce back" peak that occurs when the charging begins after the off-peak period, which is further discussed in **Chapter 1**.

Variable	Value	Source
Annual consumption	Weighted average of all-electric and plug-in hybrid	Drive Electric Vermont
Unit adoption	See adoption curves in **Figure 2-14**	VEIC
Coincident peak demand (unmanaged)	0.65 kW	GMP residential charging data, see **Figure 2-16**
% of charging occurring at home	80%	NREL
% of EVs under management	65%	Historical GMP customer adoption

Table 2-5. Major assumptions used for EV sensitivity analysis, by source of information.

Figure 2-14 shows total passenger EVs registered in GMP territory under each of the two scenarios.

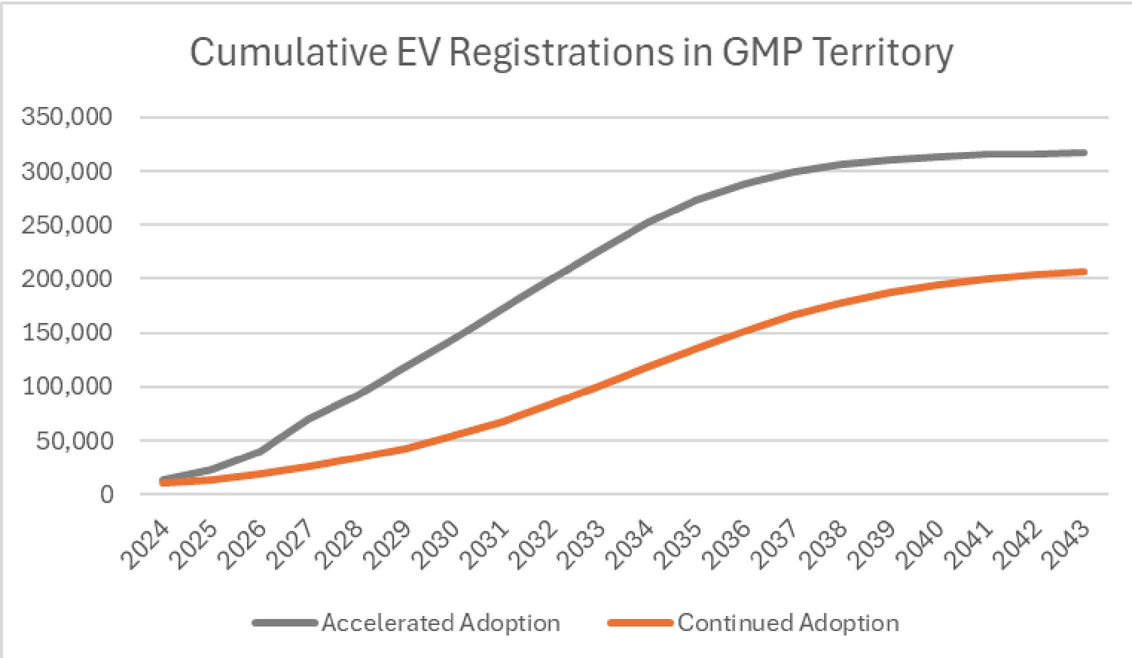


Figure 2-14. Expected number of EVs registered in GMP territory, by forecasted scenario.

As further described below, EVs offer a smart economic choice for individual purchasers in terms of vehicle lifetime cost, compared to an internal combustion engine (ICE) vehicle's fuel and maintenance costs. EVs are also a significant source of new load and therefore increase retail sales that in turn spread system costs for the benefit of all customers. An average all-electric vehicle (AEV) that drives 10,000 miles annually consumes over 3,100 kWh, which is approximately 40 percent of total household electricity consumption on average in GMP territory. EV performance in winter produces higher rates of consumption and higher energy requirements for cabin climate control. Many EVs now come equipped with heat pumps to reduce the draw on the battery, as well as heated seats and steering wheels. In addition to lowering cost and carbon and being a very flexible and responsive load, EVs also can act like storage on wheels, allowing customers to stay powered up in their homes. Called V2H, or V2X, this will be explored throughout the coming years, with GMP testing and evaluating all new options to benefit customers.

Figure 2-15 shows the cumulative annual consumption expected from EVs in each scenario. Note that aggregate consumption involves all forms of charging: residential, public, and workplace. We recognize that some charging for vehicles registered to GMP customers will occur outside the service territory. However, this should be more than offset by public charging by out-of-state visitors.

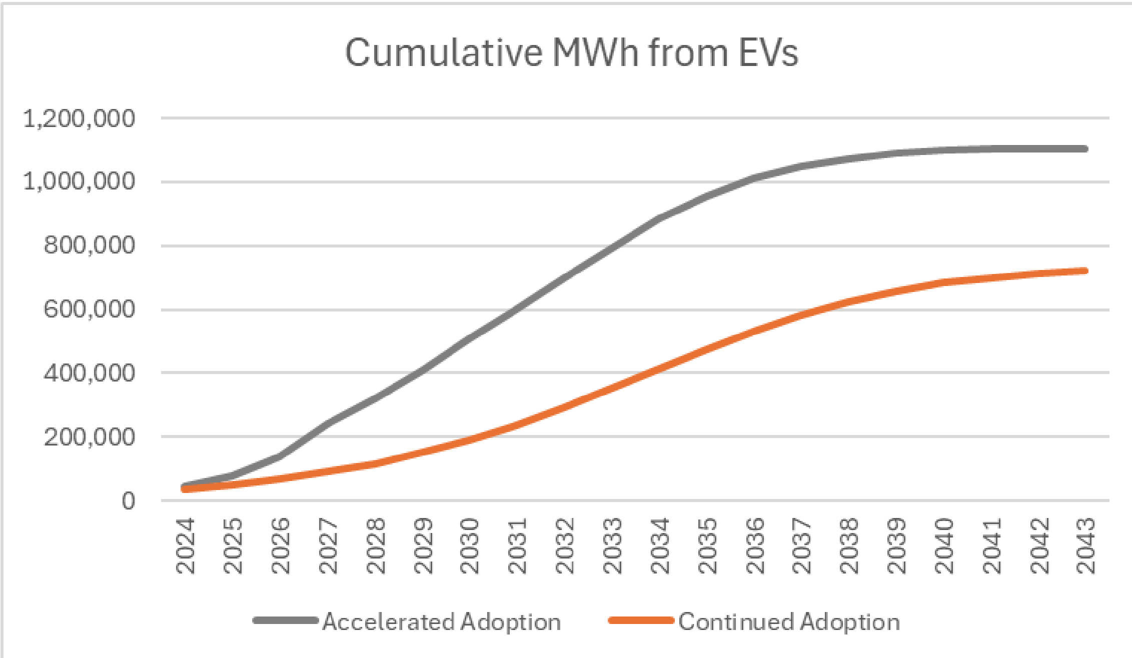


Figure 2-15. Annual expected cumulative electricity consumption in MWh, due to EV use, by forecasted scenario.

Unlike CCHPs, where embedded internet connectivity is still evolving, the technology required to manage EV charging load is in place today. GMP's two residential charging rates have been effective at shifting load away from peak times and providing customers with access to charging when they need it. We provide customers with internet connected chargers that sub-meter EV consumption to allow time-of-use (TOU) and event-based charging management. The advent of technologies like telematics-based control (a signal that is sent directly to the vehicle rather than the charger) could expand opportunities for intelligent charging management, but such technologies are not essential to reducing coincident peak load already capably managed with today's solutions.

Figure 2-16 shows projected coincident peak demand from EV charging, without managed charging.

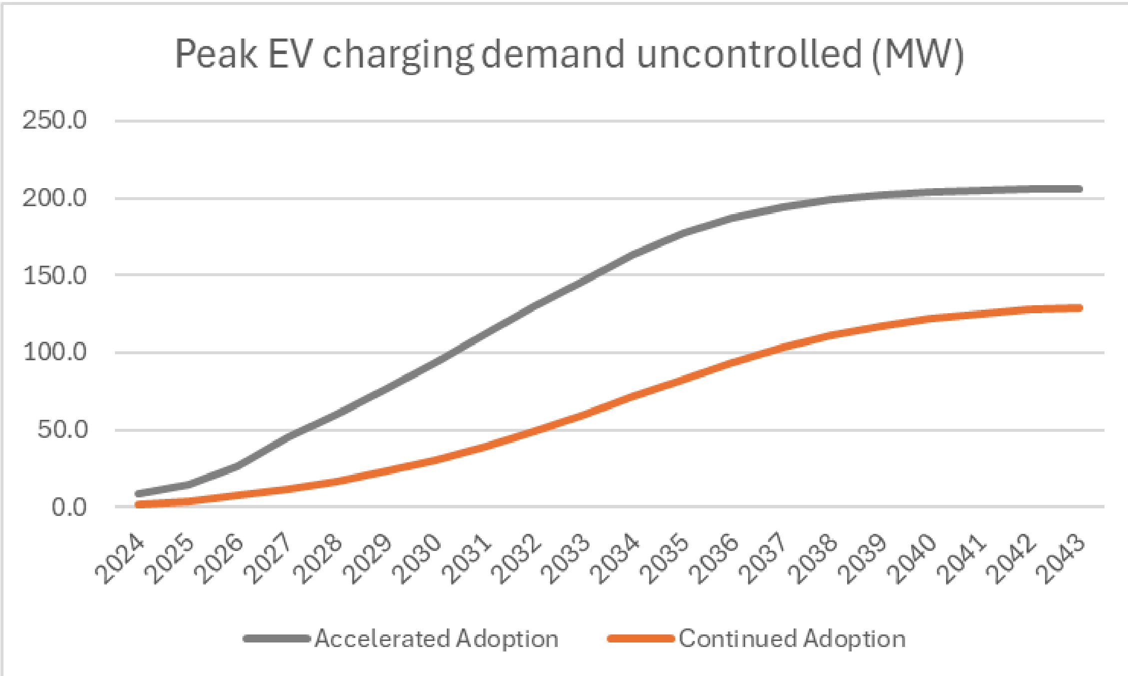


Figure 2-16. Projected coincident peak demand without managed charging (GMP is already managing charging), in MW, due to EV use.

Figure 2-17 shows the projected coincident peak demand due to EV charging with management. For each calculation, we assume that 65 percent of new EV drivers enroll in one of our EV rates (Rate 72 or Rate 74) and that such rates move 90 percent of charging under management off the peak.

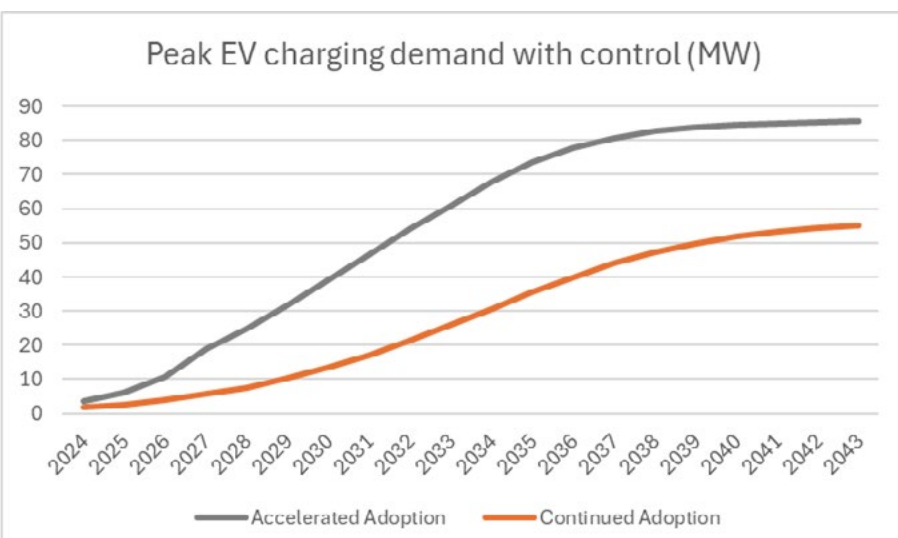


Figure 2-17. Projected coincident peak demand with continued growth of managed charging, in MW, due to EV use.

This is an opportunity to compare our forecasts to those calculated in the 2024 VELCO Long-Range Transmission Plan. VELCO's analysis shows that **without** EV charging management, EV charging peak demand could reach 400 MW in winter by 2043. Accommodating this demand would require significant upgrades to Vermont's T&D system. However, GMP has been using managed charging for years, and will continue to, showing that upgrades are not required for additional EV adoption.

Figure 2-18 shows the Tier III MWhe achieved for each EV scenario. The Tier III MWhe value for an all-electric vehicle is higher than that for a plug-in hybrid; we have used a weighted average in our Tier III projections. Drive Electric Vermont's forecast features an increase in the share of all-electric vehicles. The actual share of all-electric vehicles as a percentage of total electric vehicle sales has outpaced projections, due in part to financial incentives, rapid improvement in model availability, battery range, and fast charging. Like CCHP, Tier III MWhe decreases in the late 2030s as we approach a nearly all-electric light-duty vehicle fleet; and the possibility that new net sales (EVs replacing non-EVs) could slow down. Note that the Accelerated Adoption case spikes in 2027 because it is based on the VEIC forecast which shifts from a calibrated model from 2024 through 2026, to an uncalibrated one beginning in 2027, causing an apparent increase in one-year deployment.

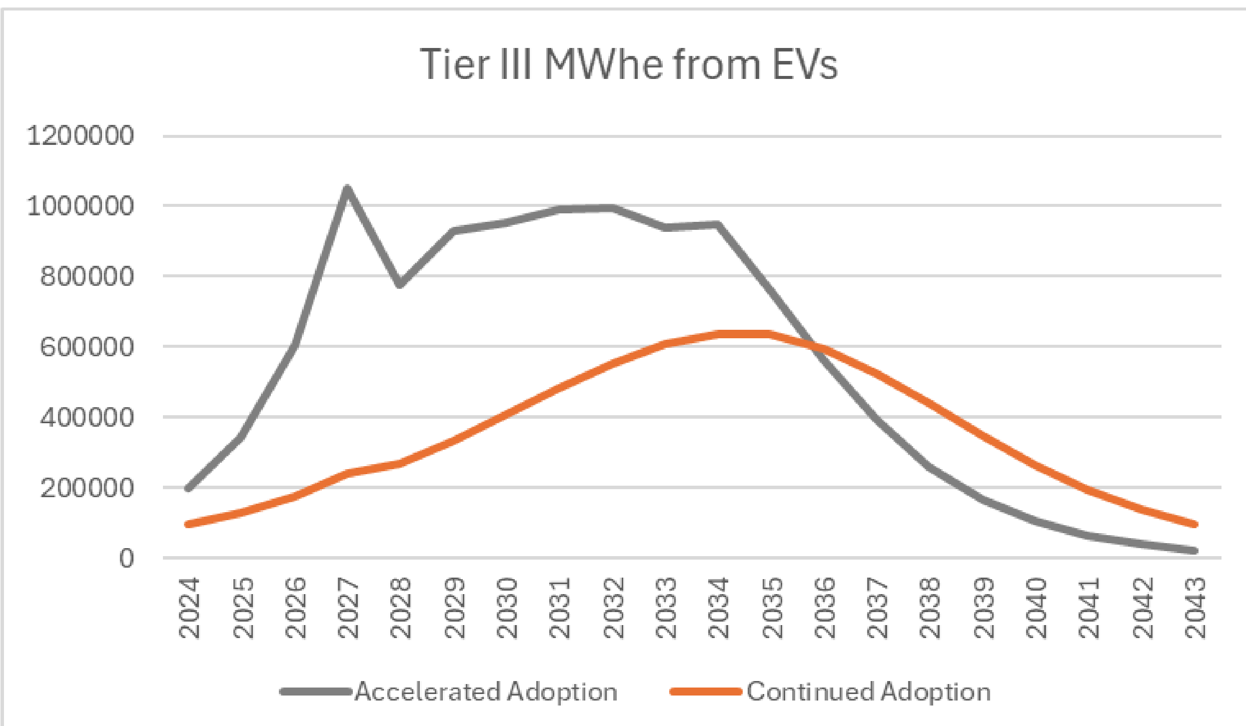


Figure 2-18. Projected Tier III MWhe from EVs, by growth scenario.

Other Sources of Load Growth: Custom Measure Projects

In addition to specific incentive programs like those for CCHPs and EVs (to which Tier III has assigned standard values), electrification also occurs through custom measure projects. These often involve commercial and industrial (C&I) customers and are often completed with Efficiency Vermont in pairing electrification with efficiency to reduce operating costs. In each project, GMP's Energy Innovation Team models fossil fuel consumption from customer inputs, and then bases an incentive on the avoided emissions, measure life, and electricity consumption of the new asset. The incentive helps reduce the upfront cost of the project, a key desire for customers in all different types of industries. The following examples are recent custom measure projects:

47 Flat Street, Brattleboro
47 Flat Street in downtown Brattleboro was a vacant historic building that was rehabilitated into 15 apartments (including eight affordable units) and office and community space. The Tier III incentives facilitated the installation of a variable refrigerant flow (VRF) heating and cooling system using air-source heat pumps. This system was installed in 2023 and reduces annual heating oil consumption by over 22,000 gallons per year.

Ben and Jerry's
In 2023, Ben & Jerry's installed an electric dehumidification system for a cold storage facility in St. Albans. This system prevents icing on the floor of the space kept at -22°F. The low temperature poses a safety hazard to employees and reduces the efficiency of the refrigeration system. The dehumidification system uses a desiccant wheel to absorb moisture from the air, then uses heat to dry it, with moist air exhausted outside. This was the first large-scale, commercial-grade electric dehumidification system GMP incentivized under the Tier III program. The system would otherwise have run on natural gas; the choice of electricity offsets over 4,300 MMBtu of natural gas annually.

Omya
In 2022, GMP extended three-phase electric power to a quarry in Middlebury operated by Omya, plus a corresponding 1,000 kilovolt-ampere (kVA) transformer. The quarry was previously powered by two diesel generators that ran from 6:00 AM to 6:00 PM every weekday, burning over 46,000 gallons of fuel per year. Those generators have now been retired. The quarry operates electric quarrying machinery using grid power directly, tapping into GMP's 100 percent carbon-free energy mix and reducing both pollution and operating costs.

Unlike the forecasts for heat pumps and EVs, which are based on unit adoption counts, modeling custom measure projects depends on a projection of the volume of projects and their presumed Tier III values. We use historical data from four-plus years of project experience, coupled with operating data from participating customers from before and after each project was completed to forecast these projects. We start with an evaluation of Tier III MWhe 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 led to two adoption scenarios, listed here and shown in **Figure 2-19**:

- **Accelerated Adoption:** 100,000 Tier III MWhe per year
- **Continued Adoption:** 50,000 Tier III MWhe per year

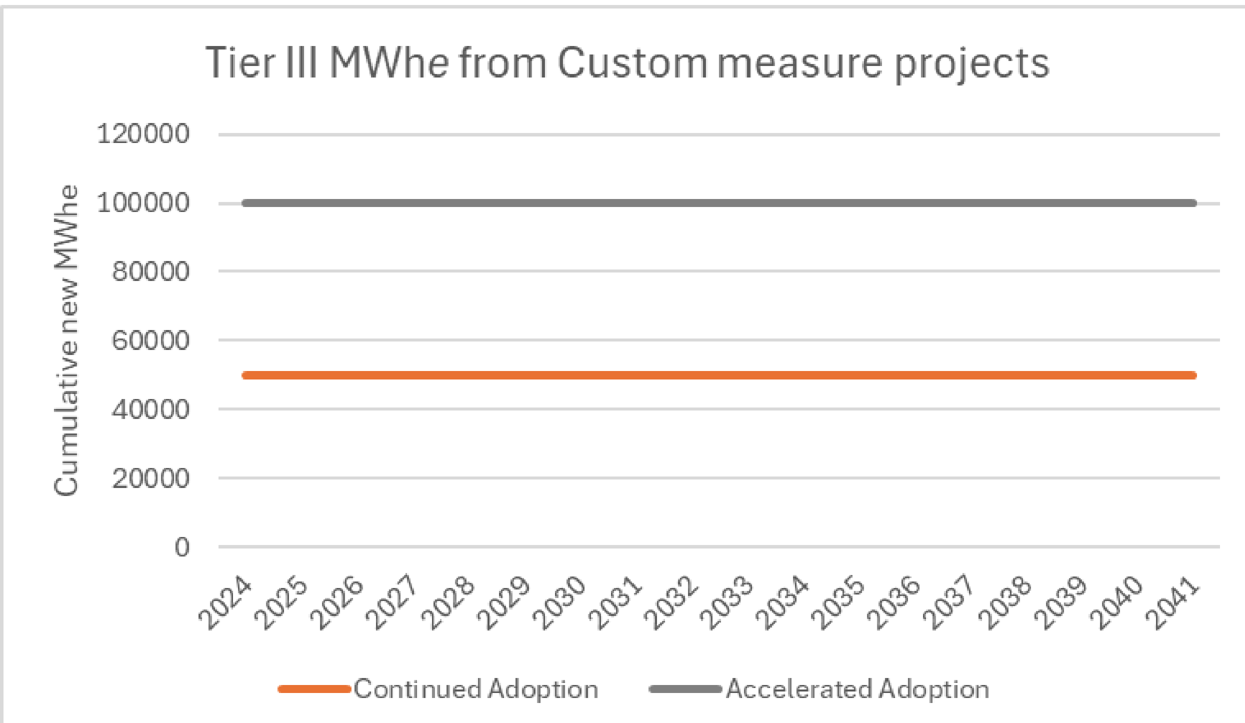


Figure 2-19. Tier III MWhe from custom measure electrification projects, under each modeled scenario.

To estimate annual electricity consumption from custom measure projects, we use data from past projects. Over the past several years, the ratio of electricity consumption (MWh) to Tier III MWhe has been 0.05:1 for custom Tier III projects. So, for a project that achieves

1,000 Tier III MWhe (equivalent to roughly 28 all-electric vehicles), we can expect an annual load increase of 50 MWh on average.

Using the 0.05 conversion factor, we can calculate the expected cumulative consumption for post-2020 custom measure projects under each scenario, as shown in **Figure 2-20.**

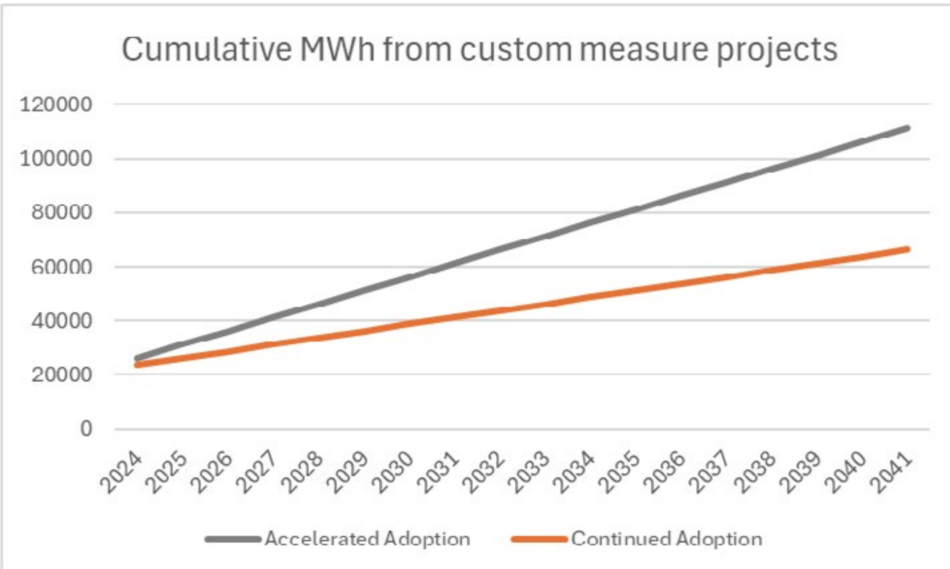


Figure 2-20. Forecasted annual cumulative electricity use, in MWh, from custom measure projects.

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, we use an average C&I customer load profile for custom measure-driven electrification.

Net Impact on System Load

To arrive at scenarios for overall retail sales (and ultimately total system load) based on these potential load increases and decreases, we begin with the Itron retail sales forecast adjusted to account for system losses. The forecast incorporates assumptions for economic and household growth, efficiency, and behind-the-meter solar growth through 2034. Beginning in 2035, we use the VELCO Long-Range Transmission Plan, adjusted to GMP's expected share of Vermont statewide load. Bridging the gap between these forecasts requires small adjustments to the Itron forecast, beginning in 2031.

In each long-term Itron scenario, the base forecast is overlaid with the electrification pathways presented above. As adoption curves evolve, so too will the Itron retail sales projection, which is re-forecasted annually. See **Appendix C**. **Table 2-6** shows inputs for each long-term forecast (Continued Adoption and Accelerated Adoption). The Accelerated Adoption case is intended to be indicative of electrification in line with Vermont's GWSA targets, as shown by the 2022 Vermont Pathways Analysis Report 2.0 that informs the Vermont Climate Plan. The Continued Adoption case uses VEIC's mid-case forecasts for electrification at similar rates, as have been occurring over the past few years, without the increase in deployment needed to meet the Accelerated Adoption case.[6] This IRP is oriented to prepare GMP for the Accelerated Adoption scenario to ensure our planning is aligned with State policy. Many factors will influence the actual trajectory of electrification and demand in Vermont, and GMP does not take a position on which scenario is "expected;" rather, we are making sure that should the accelerated adoption scenario arise, we are prepared and can execute on actions needed to assure both power supply needs and continued reliability and stability of the grid. GMP will base investment decisions on observed load growth and consider the "option value" of solutions, including energy storage, that allow upgrades to be made incrementally.

	Accelerated Adoption scenario	**Continued Adoption scenario**
Base load 2024–2034	Itron model	Itron model
Efficiency 2024–2034	Itron model	Itron model
Own use solar 2024–2034	Itron model	Itron model
Tier 3 – Custom measure	GMP forecast	GMP forecast
Tier 3 – CCHP	VEIC High/Policy case	VEIC Medium/expected case
Tier 3 – EV	VEIC High/Policy case	VEIC Medium/expected case
Total growth 2035–2043	VELCO forecast pro-rated to GMP share	VELCO forecast pro-rated to GMP share

Table 2-6. Inputs for each long-term forecasted scenario, by source.[7]

6 Itron forecasts initially included the VEIC Medium/Expected case for EV adoption and the VEIC High/Policy case for CCHP adoption. For the purposes of the two scenarios presented in this IRP, GMP backed out the EV and CCHP load and re-added it such that the Accelerated Adoption scenario includes VEIC's High/Policy case for both EVs and CCHP, while the Continued Adoption scenario contains the VEIC Medium/Expected case for both technologies. See Itron forecast in Appendix C.

7 2030–2034 Itron forecasts adjusted upward to smooth transition to VELCO forecast starting in 2035.

Figure 2-21 shows system load under each Fiscal Year scenario. **Table 2-7** presents year-by-year MWh values for the system load.[8]

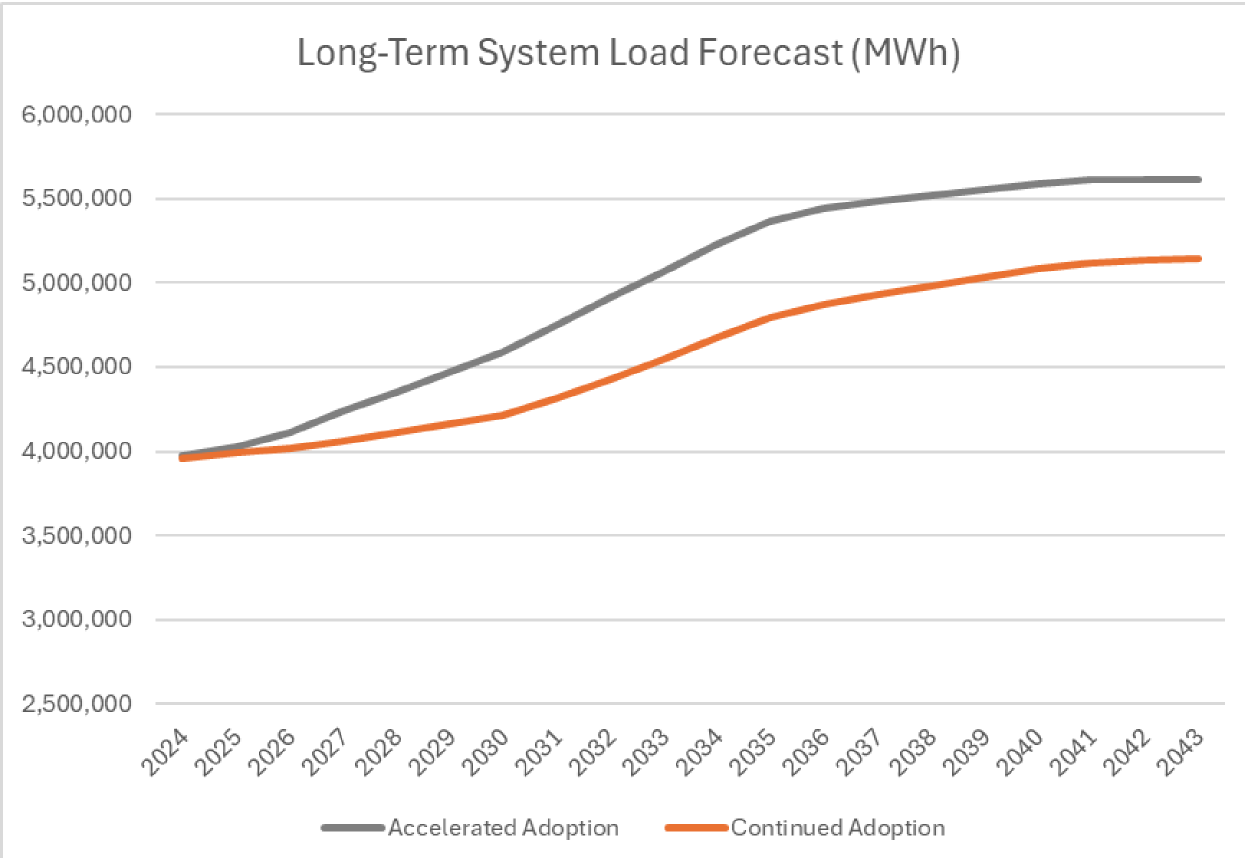


Figure 2-21. Long-term forecasted system load, in annual MWh under each scenario, through 2043, excluding GlobalFoundries.

8 Since GMP's 2021 IRP, GlobalFoundries' (GF) petition to form its own Self-Managed Utility has been approved and a transition process is underway. As of October 1, 2026, GF will no longer be a GMP customer. GF continues to receive energy and capacity from GMP through a PPA during the transitional period between FY2023 and FY2026 to provide stability and predictability for other GMP customers. GF separately pays for its transmission costs. GF has represented approximately 10 percent of GMP's existing sales, and given the impending reduction in those sales, we have excluded GF from the long-term forecasts in this chapter.

	Annual system load (MWh)	
Fiscal Year	**Continued Adoption scenario**	**Accelerated Adoption scenario**
2024	3,958,818	3,972,482
2025	3,988,724	4,028,942
2026	4,020,293	4,109,507
2027	4,063,720	4,241,513
2028	4,112,663	4,350,975
2029	4,160,798	4,470,117
2030	4,212,454	4,587,373
2031	4,313,812	4,747,681
2032	4,426,928	4,911,625
2033	4,548,145	5,071,084
2034	4,674,514	5,230,608
2035	4,794,646	5,363,040
2036	4,873,869	5,439,328
2037	4,930,647	5,483,207
2038	4,983,545	5,518,742
2039	5,033,943	5,551,448
2040	5,085,443	5,587,261
2041	5,120,025	5,609,034
2042	5,131,168	5,610,228
2043	5,140,247	5,611,789

Table 2-7. Data supporting Figure 2-21, showing annual system load through 2043.

Tier III Obligations

Annual load growth increases GMP's obligation under Tier III of the RES. Each year, GMP must retire credits for MWhe equivalent to an increasing percentage of gross load.[9] GMP's incentives for electrification (EVs, CCHPs, custom projects, and other programs) are anticipated to be more than sufficient to meet our Tier III obligations into the future. If GMP exceeds its obligations by the amounts projected, we will make programmatic changes to reduce Tier III spending. Annual expected Tier III obligations for each scenario (based on fiscal year) can be found in **Table 2-8** and **Table 2-9** and visualized in **Figure 2-22** and **Figure 2-23**. Please note that future obligations referenced in these tables are presented as approximations based on fiscal year load. Actual obligations are based on calendar year load, but the three-month shift between the fiscal and calendar year does not change the conclusion that GMP anticipates generating sufficient MWhe to satisfy its Tier III obligation over the forecast period.

After the approval of our updated Line Extension tariff in August 2023, GMP began providing customers with credits to offset the cost of transformer and service upgrades to support the installation of controllable electric technologies like Level 2 EV chargers. The associated costs are treated as administrative expenses under the Tier III program. Credits are capped and applied only up to the point where a customer's out-of-pocket cost is eliminated.

9 A Tier III obligation based on gross load begins in 2025, per changes to RES contained in H.289 passed in June 2024. In 2024 Tier III obligation is a percentage of retail sales.

Year	GMP Tier III Requirement	Approximate Tier III Obligation (MWhe)	MWhe from EVs	MWhe from CCHP	MWhe from custom projects
2024	6.67%	264,832	197,840	288,826	100,000
2025	7.33%	295,456	345,414	312,894	100,000
2026	8.00%	328,761	603,059	336,963	100,000
2027	8.67%	367,598	1,052,871	361,032	100,000
2028	9.33%	406,091	774,896	385,101	100,000
2029	10.00%	447,012	930,308	409,170	100,000
2030	10.67%	489,320	954,581	401,636	100,000
2031	11.33%	538,070	989,725	366,424	100,000
2032	12.00%	589,395	994,409	344,762	100,000
2033	12.00%	608,530	938,471	322,402	100,000
2034	12.00%	627,673	948,681	280,546	100,000
2035	12.00%	643,565	760,560	196,763	100,000
2036	12.00%	652,719	564,493	200,806	100,000
2037	12.00%	657,985	393,014	169,420	100,000
2038	12.00%	662,249	260,606	168,482	100,000
2039	12.00%	666,174	166,930	144,413	100,000
2040	12.00%	670,471	104,471	120,344	100,000
2041	12.00%	673,084	64,410	96,275	100,000
2042	12.00%	673,227	39,338	72,206	100,000

Table 2-8. Accelerated Adoption scenario Tier III obligation and major sources of MWhe assuming continued Tier III credits from these programs. Note that other GMP programs also contribute to the total pool of MWhe.

Year	GMP Tier III Requirement	Approximate Tier III Obligation (MWhe)	MWhe from EVs	MWhe from CCHP	MWhe from custom projects
2024	6.67%	263,921	95,815	240,688	50,000
2025	7.33%	292,506	130,585	240,688	50,000
2026	8.00%	321,623	177,972	240,688	50,000
2027	8.67%	352,189	242,552	240,688	50,000
2028	9.33%	383,849	270,228	240,688	50,000
2029	10.00%	416,080	336,208	240,688	50,000
2030	10.67%	449,328	409,242	240,688	50,000
2031	11.33%	488,899	484,635	240,688	50,000
2032	12.00%	531,231	554,797	240,688	50,000
2033	12.00%	545,777	609,745	240,688	50,000
2034	12.00%	560,942	638,992	240,688	50,000
2035	12.00%	575,358	634,752	196,763	50,000
2036	12.00%	584,864	595,297	200,806	50,000
2037	12.00%	591,678	526,471	169,420	50,000
2038	12.00%	598,025	440,015	168,482	50,000
2039	12.00%	604,073	349,386	144,413	50,000
2040	12.00%	610,253	265,545	120,344	50,000
2041	12.00%	614,403	194,811	96,275	50,000
2042	12.00%	615,740	139,078	72,206	50,000

Table 2-9. Continued Adoption scenario Tier III obligation and major sources of MWhe assuming continued Tier III credits from the programs mentioned. Note that other GMP programs also contribute to the total pool of MWhe.

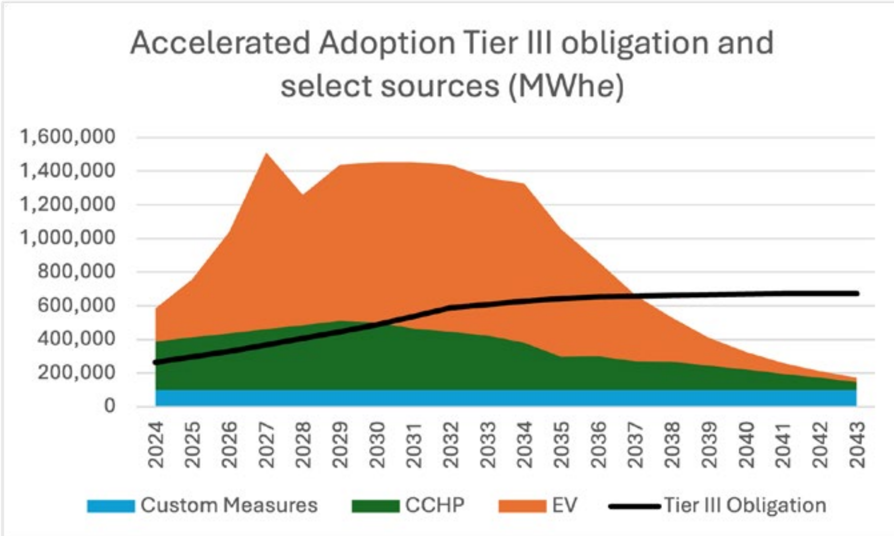


Figure 2-22. Accelerated Adoption scenario Tier III obligation and major sources of MWhe assuming continued Tier III credits from these programs.

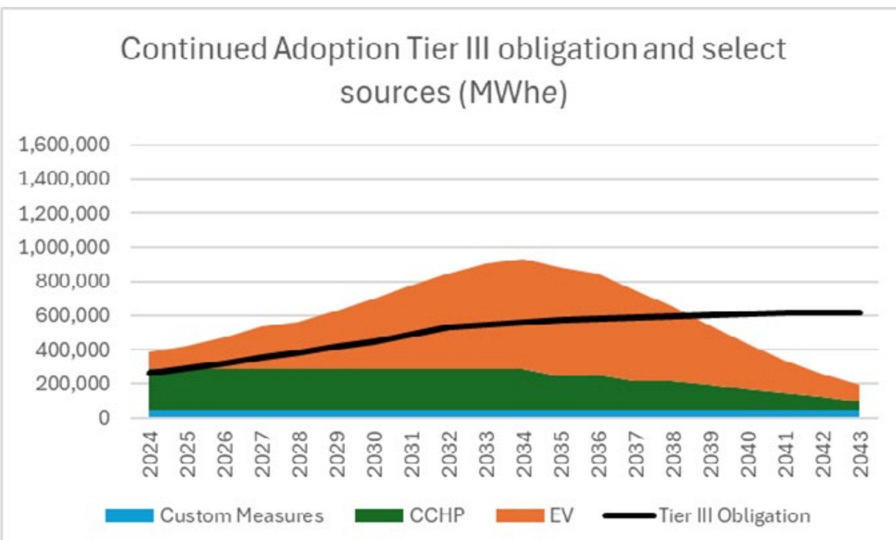


Figure 2-23. Continued Adoption scenario Tier III obligation and major sources of MWhe assuming continued Tier III credits from these programs.

GMP considers factors including market maturity, equitable participation in electrification, projected spending relative to the alternative compliance payment (ACP), and overall forecasted program spending and obligation requirements when planning adjustments to our Tier III incentive offerings. For example, as discussed in **Chapter 1**, the heat pump market has matured significantly, allowing us to reduce the incentive for non-income qualified customers, reducing our spending per MWhe while maintaining incentive programs as a mechanism for quantifying fossil fuel offset associated with customers' investment into these measures. Additionally, we will continue to focus on engaging low-income customers in Tier III offerings.

If the level of adoption of Tier III eligible technologies forecast here comes to pass, GMP will make changes to incentive programs to reduce the amount of Tier III credits being required or reduce the cost to acquire those credits. The charts above show scenarios where no change is made to the procurement of Tier III credit volumes, however, the underlying costs to obtain credits will adjust as GMP changes our incentives, similar to recent adjustments for the non-income qualified heat pump incentive. We will continually evaluate the obligation, our current MWhe accumulated at the time, total cost of the program, and forecast of open position in the future and adjust the Tier III program. The current RES law requires us to reach 12 percent of total load by 2032 and then remain there into the future. Without any changes, GMP will likely rely on credits accumulated to fulfill our obligation beyond this timeframe.

Hourly Load Profiles and Load Management

Annual load is an important input for our revenue projection, but it does not shed light on the timing of load, both hourly and seasonally. This information is critical to projecting peak-related costs, managing peak demand, and formulating an effective power supply strategy.

Figures 2-24 through 2-29 show sample weeks in the VELCO statewide forecast, adapted to GMP's share of statewide load 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 the load reducers (energy efficiency and solar net-metering own use), whose contributions would appear as negative numbers. The snapshots do not predict precisely, but they demonstrate 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 from CCHP growth and higher EV charging in cold months
- The significant impact that managed EV charging has on load shape
- More prominent winter morning peaks from CCHP operation
- Increasingly pronounced midday troughs, especially in spring and summer, due to ongoing installation of solar treated as behind the meter, including net metering

In each graph, the vertical axis measures total MW in GMP service territory. The blue area is the base load forecast; the yellow area is load from CCHP; and the green area is EV charging load.

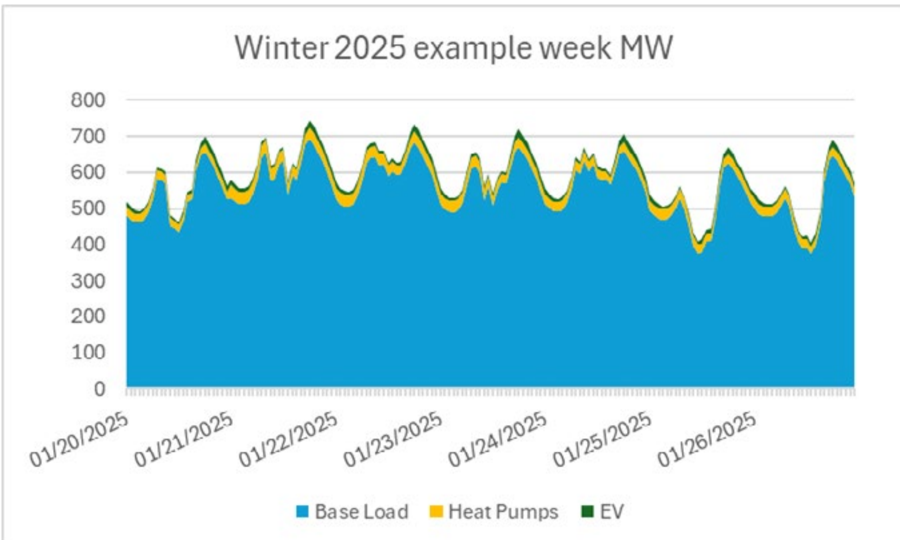


Figure 2-24. Sample week in winter 2025, showing base load, with effects from heat pumps and EVs.

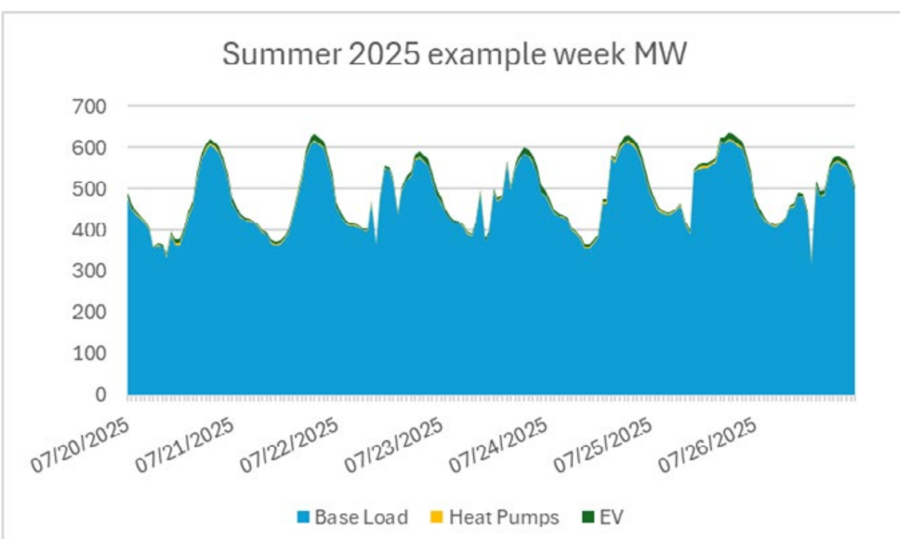


Figure 2-25. Sample week in summer 2025, showing base load, with effects from heat pumps and EVs.

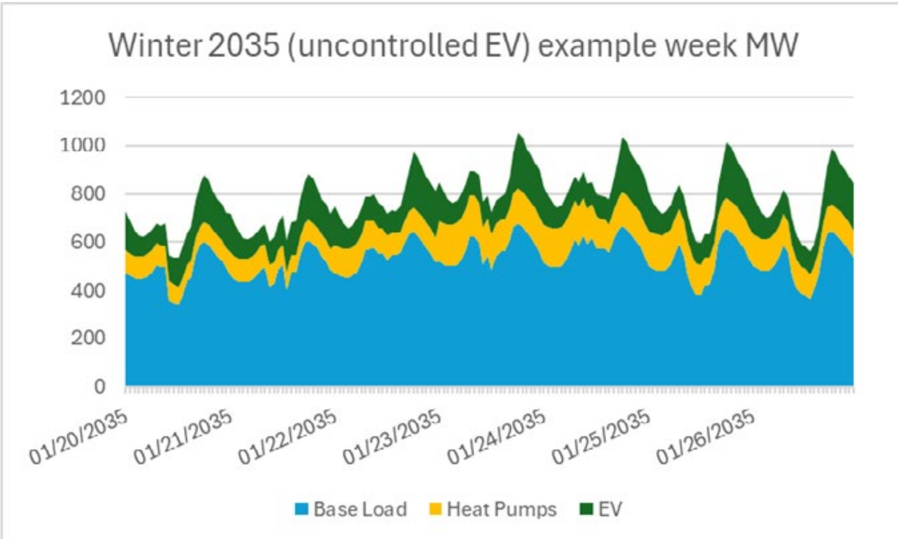


Figure 2-26. Sample week in winter 2035, without managed EV charging.

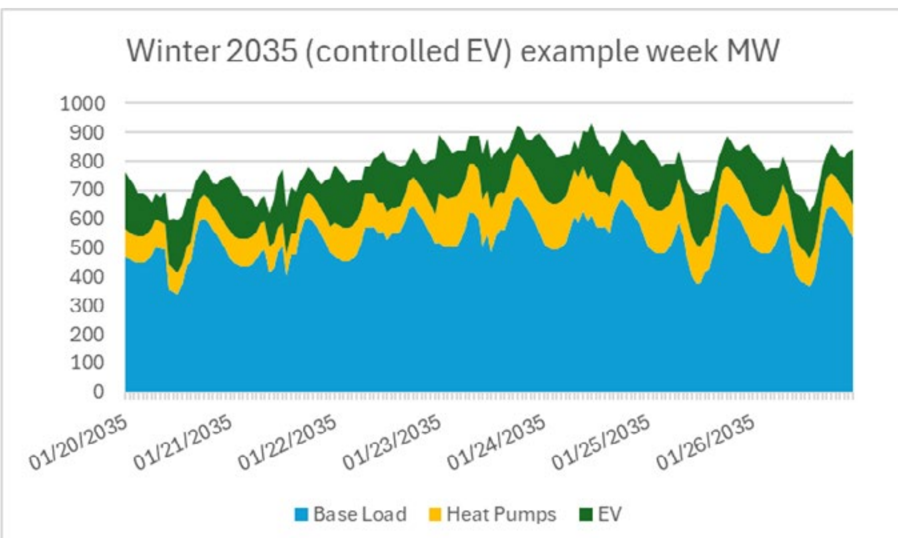


Figure 2-27. Sample week in winter 2035 assuming GMP is able to shape 50 percent of EV charging load.

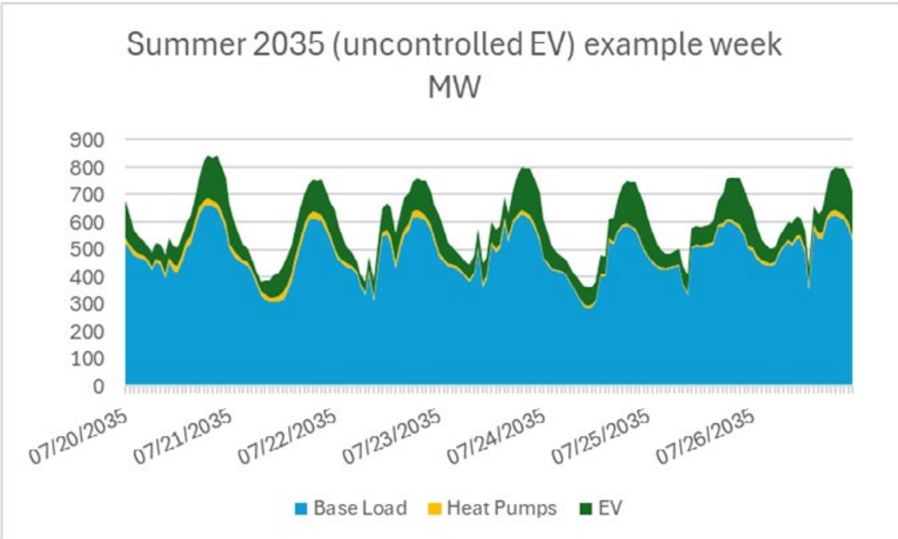


Figure 2-28. Sample week in summer 2035 without managed EV charging.

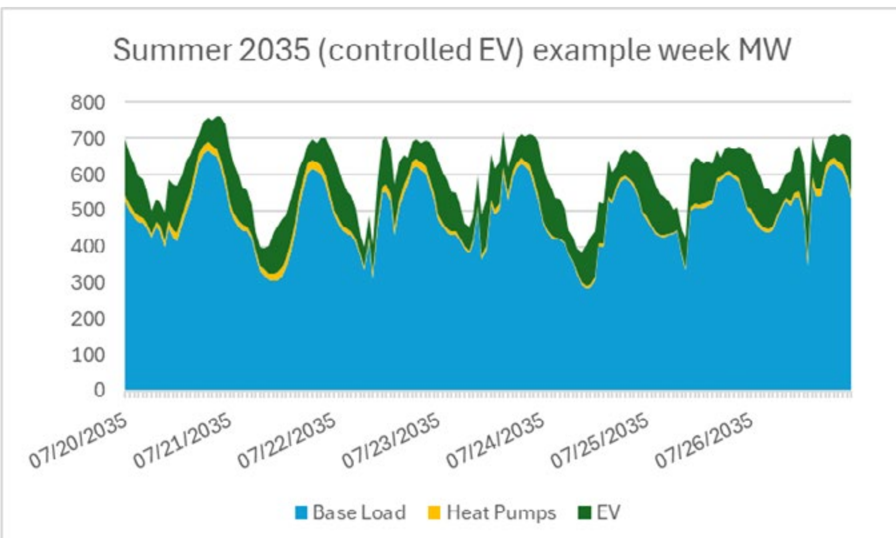


Figure 2-29. Sample week in summer 2035 assuming GMP is able to shape 50 percent of EV charging load.

These trends highlight the importance of both peak management and load-building during times when renewable generation is highest. We have incorporated management of new EVs through smart devices and rate design into these hourly profiles; but those are just two components of our total load management portfolio that we expect to utilize in the years ahead.

Energy Storage and Load Forecasting

Energy storage is a popular technology for our customers seeking clean, seamless backup power at times of damaging extreme weather. Further, stored energy is a key element of matching load with resources and how we will effectively manage the grid into the future. As part of our reliability, resiliency, and affordability work (see primarily **Chapter 3**) and our existing residential storage program, batteries provide resilient backup and lower costs for all customers through load management. **Chapter 1** discusses our energy storage programs, and in this chapter, we forecast storage deployment through our residential storage tariffs. We expect to see continued interest in energy storage among renewables developers and C&I customers, but it is too early to make firm predictions on adoption.

We model an Accelerated Adoption case in addition to Continued Adoption for future adoption of residential storage. Until August 2023, there was a cap and only 500 GMP customers could sign up for leased residential storage through GMP's Energy Storage System (ESS) tariff each year (equivalent to 5 MW). Increased demand led to a waitlist of more than 1,500 customers. The PUC approved GMP's request to lift that cap in Case No. 23-1335-TF in August 2023 and the change went into effect June 2023. Since then, customer sign-ups and installations have surged, with more than 7,000 batteries enrolled. GMP projects demand will remain strong for the foreseeable future given climate change is creating more severe and frequent storms. Over time, the structure and pricing will evolve as our load profile changes. **Figure 2-30** shows the installed capacity for residential storage through 2043 under each scenario. The Accelerated Adoption scenario for storage assumes increased deployment of residential storage under the ZOI. **Figure 2-31** shows the corresponding number of customers with energy storage systems installed, assuming 10 kW per system in the Energy Storage System program (the capacity of two Tesla Powerwalls) and 4.5 kW per system in the Bring Your Own Device (BYOD) program's average enrolled capacity to date.

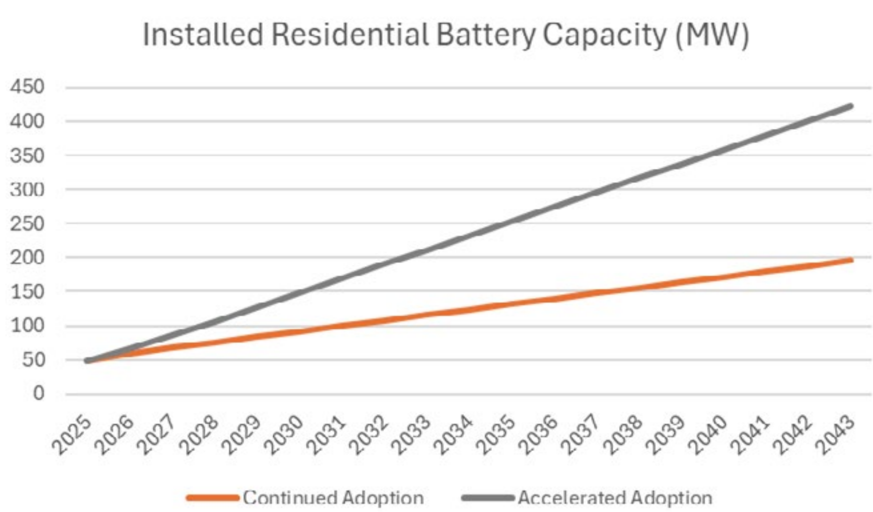


Figure 2-30. Residential installed battery capacity, in MW, through 2043.

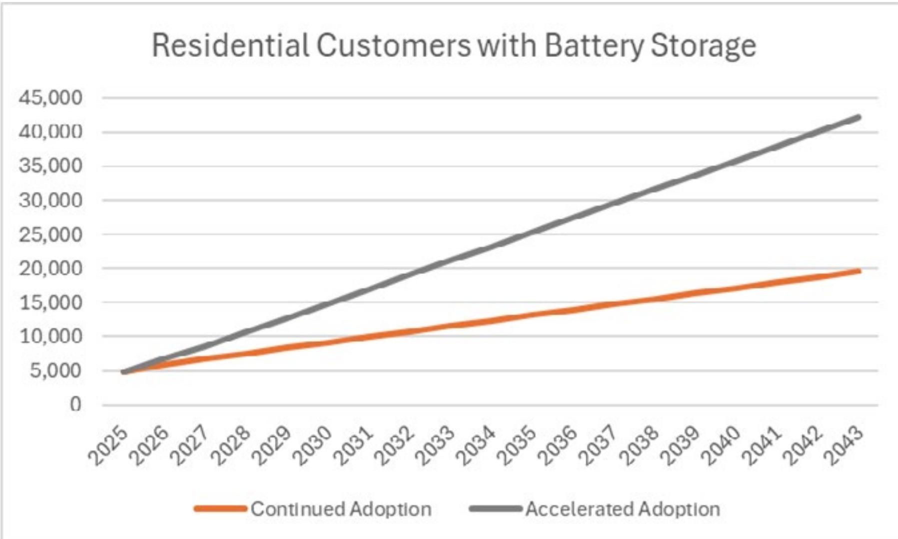


Figure 2-31. Projected number of residential customers with battery storage, through 2043, by growth scenario.

In the Accelerated Adoption scenario, about 15 percent of GMP residential customers have an energy storage system in the year 2040, including a large majority of those living in the most rural areas through our upcoming energy storage tariff filing. We expect this adoption to continue increasing sharply and will be updating this in our next IRP, taking into account other storage options that will likely be available at home to keep customers connected. This could lead to significantly higher adoption on some circuits (see **Chapter 3**). These areas generally fit Vermont's definitions of *underserved communities* that GMP strives to prioritize in its application of energy justice principles (see **Chapters 1 and 3**).

Declining costs in energy storage manufacturing and evolving rules for wholesale market participation will benefit residential storage deployment. Our long-term goal is for every customer to have a backup solution through energy storage offered to customers to not experience an outage, even when one occurs on the system. Community-scale storage and emerging V2X technology will be important, and customers have also shown a strong desire for their own residential backup.

In the ESS program, GMP manages both charging and discharging through a peak prediction algorithm supplied by Tesla. **Figure 2-32** shows the hourly charging/discharging data for all ESS-enrolled battery systems during what would have been a peak day in July 2024 if not for GMP's dispatch of energy storage and other peak shaving resources. In this chart, positive values indicate discharging, and negative values indicate charging. GMP has also piloted using ESS to participate in the ISO New England Frequency Regulation Market to further lower costs for customers (see **Chapter 1**). During non-peak days, and when not participating in frequency regulation, the batteries sit at a full state of charge, ready to provide backup power in case of an outage.

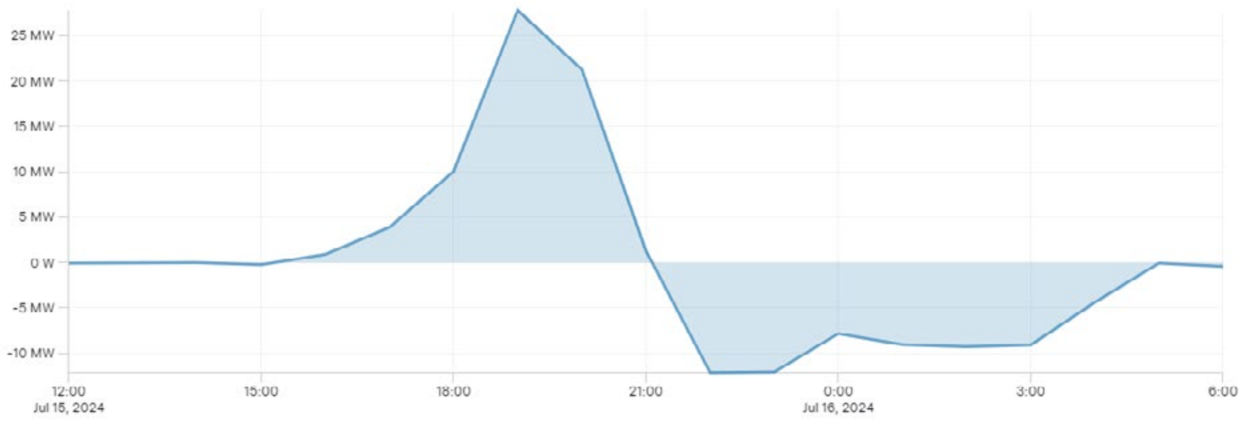


Figure 2-32. Hourly net charging data for all ESS-enrolled systems during a grid peak event in July 2024. Positive values represent discharging and negative values represent charging.

In the BYOD program, GMP discharges systems for three or four hours (depending on the participant's enrolled preference). Outside these events, the customer manages charging and discharging.

Figure 2-33 depicts a peak event in the BYOD program. In these graphs, a positive value indicates charging, and a negative value indicates discharging. Almost all systems have opted for the three-hour enrollment, but a small number of storage systems were not sufficiently charged prior to the event to meet their commitment, which determines their incentive payout. That is why discharging in **Figure 2-33** tapers off prior to the three-hour mark. We notify customers when their systems do not perform as expected, so they can remedy the situation.

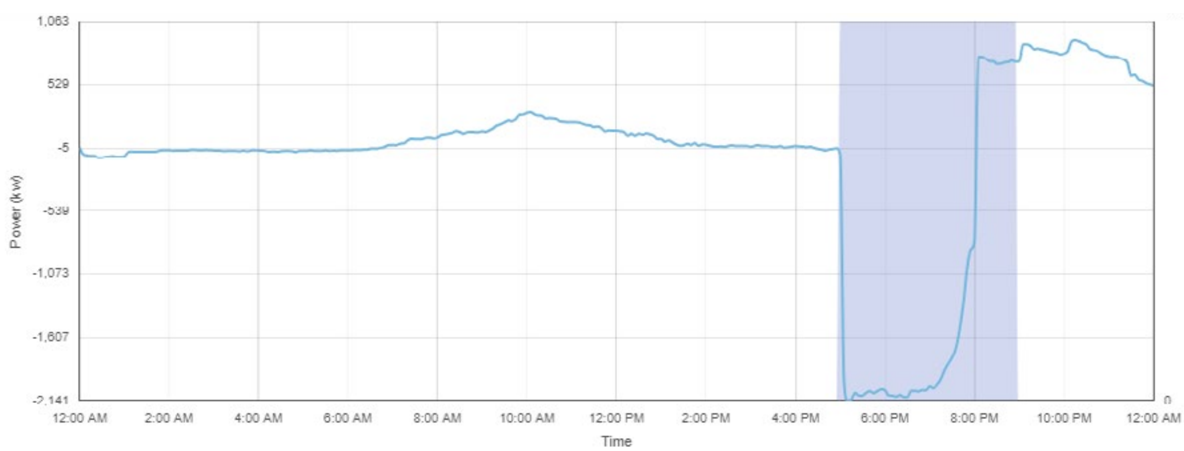
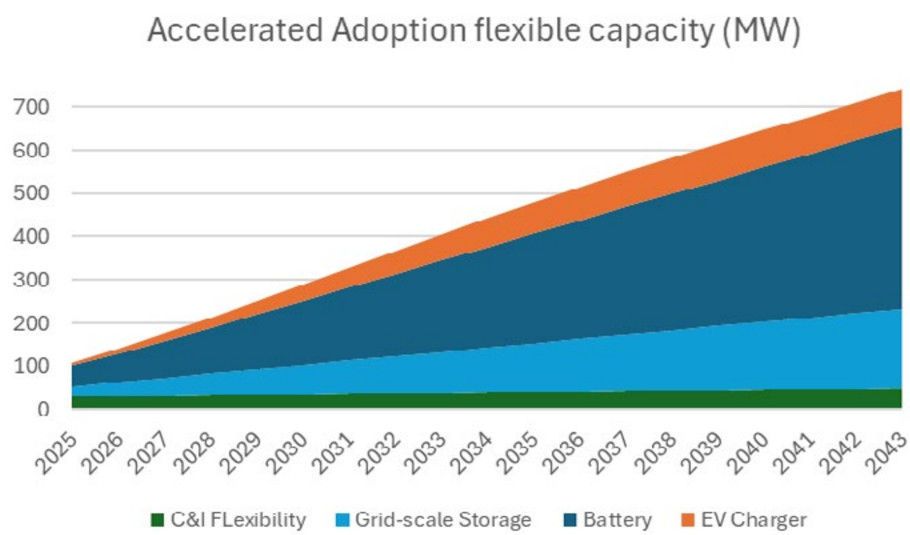


Figure 2-33. Peak event depiction in BYOD program. Negative values represent discharging and positive values represent charging.

Figure 2-34 demonstrates total flexible capacity from GMP's major sources of flexibility—EV chargers, residential energy storage, grid-scale storage, and commercial flexible loads. These are not the only forms of demand flexibility at our disposal but are what we expect to make up the bulk of capacity moving forward. The charts help show the positive impact of strategic electrification and resilience. In the Accelerated Adoption growth scenario, we approach a total flexible capacity of over 30 percent of the projected peak load by 2030, shown in the demand snapshots above. Our strategy for dispatching resources will evolve as adoption accelerates. Dispatch strategy might, for example, go beyond peak reduction to (1) align load with periods of either low wholesale energy cost or high renewable generation, (2) minimize load during price spikes, (3) alleviate grid constraints, and (4) provide other ancillary services in addition to frequency regulation.



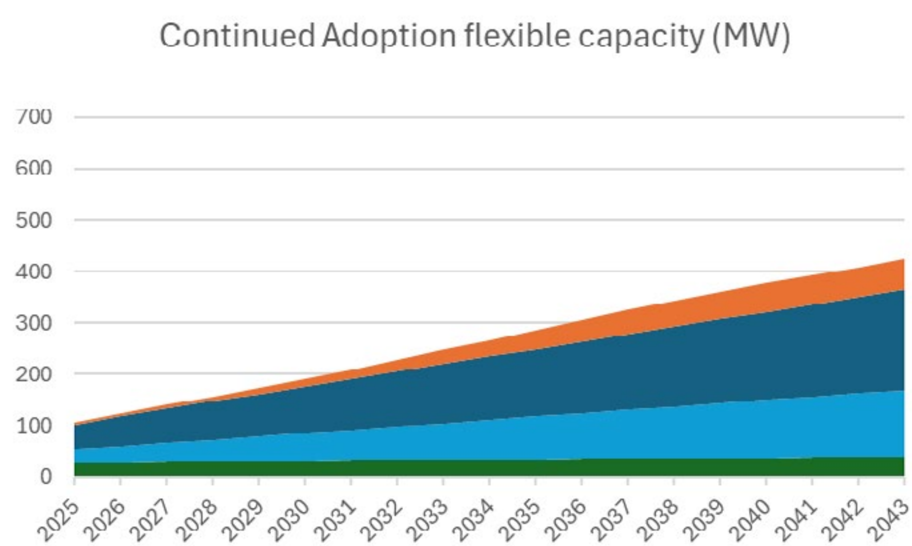


Figure 2-34. Total projected flexible capacity due to EVs and residential energy storage, through 2043.

Other Load-Shifting Techniques

In addition to energy storage, easy to use TOU rates like our EV rates are a tool for shaping load (see **Chapter 1**). Compared to other programs where we directly manage end-use devices, TOU rates are less targeted, establishing price signals and allowing the customer to decide how to respond. Each of these rate schedules uses rate design to perform load management.

GMP has more than 4,000 residential customers using whole-home TOU rates. By far the largest of these is Rate 11, which has an on-peak window of 1:00 PM to 9:00 PM on weekdays, during which the cost for electricity is $0.31739 per kWh. This price is 59 percent higher than the energy charge on Rate 1 (the default non-TOU residential rate). During off-peak hours on Rate 11, the energy charge is $0.13528 per kWh, a savings of about 32 percent, compared to Rate 1. Customers on this rate can take advantage of smart appliances to schedule high-demand household loads during off-peak hours. These might be washing machines, dishwashers, and water heaters, as well as EV chargers (only customers on Rate 1 are eligible for EV charging rates 72 and 74). Further analysis of whole-home TOU rates will be part of the next rate design, as described in **Chapter 1.**

Separate from whole-house TOU rates, GMP has more than 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 five hours per day. Due to the high thermal inertia of insulated water tanks, this does not typically disrupt hot water availability, and GMP can reduce load during high-demand hours—similar to Rate 74 for EV charging. GMP is exploring options for different technology to promote the same load shifting without requiring a second meter for water heater customers to simplify the program and potentially reduce costs. For C&I customers, a TOU demand-billed rate schedule is mandatory for any customer who uses more than 7,600 kWh per month, making up almost all TOU sales by volume. Overall, approximately 53 percent of GMP sales volume is under TOU rates, including a less than two percent contribution from residential TOU rates.

GMP also offers several forms of load management for C&I customers through the Curtailable Load Rider, Critical Peak Rider, and Load Response Rider, as well as the Flexible Load Management (FLM) 3.0 pilot which optimizes load management at customer sites during peak events. The customers participating in these programs, while relatively small in number, represent some of our largest customers. Combined, over 40 MW is available for load curtailment several times of the year.

Prior to its next rate design, GMP will explore the extent to which it can verify that current TOU periods are appropriate for both C&I and residential customer classes and consider adjusting them to account for the impact of additional behind-the-meter solar.

GMP is also assessing a bifurcated demand charge that assesses separate charges for coincident peak and non-coincident peak demand, or even removing demand charges altogether, as piloted in the FLM 3.0 program, replacing them with tiered volumetric rates based on load factor and actual coincident demand.

Present Value Life Cycle Costs

Cost-effectiveness screening tests are important for customers and to meet requirements under RES Tier III. Electric vehicles and cold-climate heat pumps contribute meaningfully to GMP's carbon reduction through Tier III programs and to future load growth as demonstrated throughout this chapter. All tests showed net benefits of these technologies and programs for at least some subsets of customers. Summaries of this test are presented below. Further explanation can be found in **Appendix B.**

For each measure, we have applied three tests:

1) **Participating Customer Test.** This 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.
2) **Non-Participating Customer (Utility) Test**. This describes GMP's perspective on impacts for all other customers, by assessing the impact/benefit to non-participating customers when a customer purchases an electric vehicle, for example. It captures changes to revenues, power supply costs, and Tier III incentives but not outside incentives or operating cost savings.
3) **Societal Test**. This is a test that attempts to describe the perspective of society at large, including customer and utility costs, and externality costs. The 2022 Vermont Comprehensive Energy Plan describes the test as answering the question "what are the net costs to society?" and that it includes the costs and benefits of that policy or program to all members of society including the program administrator, customer, impacted participants, and anyone else.

   In line with the Vermont Climate Council's decision in September 2024 to adopt the US EPA Social Cost of Greenhouse Gases (SC-GHG) at the central two percent discount rate, we use a $190/ton of carbon as an avoided externality cost. The Societal Test does not consider rebates or incentives, because they are transfer payments from one group of customers to another, but does consider the administrative cost of incentives as a net cost.

GMP focuses primarily on the Customer and Non-Participating Customer cost tests to inform programs. The Non-Participating Customer test is particularly relevant because GMP does not want non-participating customers to pay more as a result of our innovative programs. While the direct economic savings or cost to the participating customer is important, it may not be the only factor customers consider when opting in to a program. For example, the popular ESS tariff provides additional value in the form of resilience in exchange for a monthly payment from participating customers, while there is a net economic benefit to non-participating customers.

Electric vehicles (both fully electric and PHEV) are cost effective for customers after accounting for rebates, fuel, and maintenance savings. They also benefit other GMP customers by contributing to GMP's Tier III obligation and increasing net retail revenue. Net retail revenue is calculated specific to the load shape and applicable rate for each measure tested. For example, EV rates, as cost-based rates, are lower than the general residential rate because of the EV charging management—they avoid consumption and associated costs at peak times. Applying the social cost of carbon also leads to a net benefit to society for both vehicle types. Benefits tests for all-electric vehicles and PHEVs are shown in **Table 2-10** and **Table 2-11**.

All-Electric Vehicle (AEV), 8-year measure life			
	Input	Amount	Source
Customer	Incremental vehicle cost	($8,500)	US DOE
	Purchase incentives	$4,700	State, GMP
	Fuel savings	$6,487	VT average, Rate 74
	Maintenance savings	$2,077	Tier III TRM
	Net customer benefit (2024 dollars)	**$4,764**	
Utility	Tier III costs + administration	($2,245)	GMP incentive
	Tier III benefit	$1,835	Tier III TRM
	Net retail revenue	$1,311	GMP Calculation
	Net utility benefit (2024 dollars)	**$901**	
Society	Incremental vehicle cost	($8,500)	US DOE
	Tier III administration	($45)	GMP incentive
	Fuel savings	$6,487	VT average, Rate 74
	Maintenance savings	$2,077	Tier III TRM
	Value of avoided emissions	$5,538	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$5,557**	

Table 2-10. Benefits tests for all-electric vehicles.

Plug-In Hybrid Electric Vehicle (PHEV), 8-year measure life			
	Input	Amount	Source
Customer	Incremental vehicle cost	($8,000)	US DOE
	Purchase incentives	$2,500	State, GMP
	Fuel savings	$2,861	VT average, Rate 74
	Maintenance savings	$1,266	Tier III TRM
	Net customer benefit (2024 dollars)	**($1,373)**	
Utility	Tier III costs + administration	($1,034)	GMP incentive
	Tier III benefit	$1,369	Tier III TRM
	Net retail revenue	$1,300	GMP Calculation
	Net utility benefit (2024 dollars)	**$1,635**	
Society	Incremental vehicle cost	($8,000)	US DOE
	Tier III administration	($34)	GMP incentive
	Fuel savings	$2,234	VT average, Rate 74
	Maintenance savings	$1,266	Tier III TRM
	Value of avoided emissions	$2,603	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**($1,931)**	

Table 2-11. Tests for plug-in hybrid electric vehicles.

Table 2-12 and **Table 2-13** summarize the CCHP tests. From the customer's perspective, with and without the low-income rebate. Without the additional rebate provided to low-income customers, a CCHP system produces a net cost over its lifetime—but only in terms of fuel savings related to heating; the analysis does not account for CCHP cooling benefits, which are a significant factor affecting purchase decisions. As demonstrated by customer adoption well above 2021 projections (see **Cold Climate Heat Pumps** earlier this chapter) customers are finding heat pumps to provide enough value for them to choose to install in their homes. The purchase cost modeled represents the total installed cost of a CCHP system, not the incremental cost between the CCHP and a fossil fueled heating system so could be less for a customer who would otherwise need to replace the fossil fuel system anyway. This analysis does not mean that fuel expenses are higher with a heat pump than heating oil or propane, only that the energy savings from heating alone are not sufficient to fully cover the installed cost of a unit without the additional low-income rebate. A customer who installs a heat pump, even if primarily for cooling benefits, would experience lower cost by also making full use of it for heating compared to leaving it off during the winter and relying on oil or propane. For low-income customers there is a net savings from heating alone. Due to the volatility of unregulated oil and propane prices, the customer will also experience more stability in their heating costs, year to year. A CCHP system delivers a significant benefit to all customers from the rate-reducing impact of new electric load. This test provides a strong incentive for GMP to continue supporting heat pump adoption as it reduces both rate pressure and greenhouse gas emissions. From society's perspective, a CCHP system produces a net benefit. Although the incremental system cost outweighs fuel savings the avoided externality costs produce a positive social benefit result.

Single Zone Cold Climate Heat Pump, 15-year measure life - Low Income			
	Input	Amount	Source
Customer	Purchase cost	($3,206)	Tier III TRM
	Purchase incentives	$2,350	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Net customer benefit (2024 dollars)	**$1,117**	
Utility	Tier III costs + administration	($2,283)	GMP incentives
	Tier III benefit	$1,351	GMP Tier III reporting
	Net retail revenue	$3,267	GMP calculation
	Net utility benefit (2024 dollars)	**$2,335**	
Society	Incremental cost	($3,206)	Tier III TRM
	Tier III administration	($33)	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Value of avoided emissions	$4,153	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$2,886**	

Table 2-12. Tests for cold-climate heat pumps for low-income customers.

Single Zone Cold Climate Heat Pump, 15-year measure life			
	Input	Amount	Source
Customer	Purchase cost	($3,206)	Tier III TRM
	Purchase incentives	$350	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Net customer benefit (2024 dollars)	**($883)**	
Utility	Tier III costs + administration	($283)	GMP incentives
	Tier III benefit	$1,351	GMP Tier III reporting
	Net retail revenue	$3,267	GMP calculation
	Net utility benefit (2024 dollars)	**$4,335**	
Society	Incremental cost	($3,206)	Tier III TRM
	Tier III administration	($33)	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Value of avoided emissions	$4,153	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$2,886**	

Table 2-13. Tests for cold-climate heat pumps for moderate-income and above customers.

Custom Measure Tier III Projects

Table 2-14 represents an example of a custom Tier III measure that involves a customer replacing propane powered rooftop units (RTU) with hybrid heat pump models that will operate in all-electric mode when cost effective and switch to propane below a set temperature. This customer also enrolled in the FLM 3.0 pilot program (switching to propane during peaks), reducing their energy cost per kWh and GMP's transmission and capacity costs related to the new load. Custom measure Tier III projects typically generate MWhe credits for GMP at significantly lower cost than prescriptive measures. That lower cost shows up as a large Non-Participating Customer test benefit in the form of Tier III value. A lower cost to reduce carbon emissions also creates high social value after accounting for the value of avoided emissions. GMP considers both custom and prescriptive Tier III measures important to enable customers to shift away from fossil fuel use in line with Vermont's emission goals.

Example Tier III Custom RTU Project, 15-year measure life			
	Input	Amount	Source
Customer	Incremental cost	($34,900)	Custom calc, GMP estimate
	Tier III incentives	$42,614	GMP incentives
	Fuel savings	$294,967	Custom calc
	Net customer benefit (2024 dollars)	**$302,681**	
Utility	Tier III costs + administration	($44,792)	GMP incentives
	Tier III benefit	$88,033	GMP Tier III reporting
	Net retail revenue	$149,919	GMP Calculation
	Net utility benefit (2024 dollars)	**$193,160**	
Society	Project cost	($34,900)	Custom calc, GMP estimate
	Tier III administration	($2,178)	GMP incentives
	Fuel savings	$294,967	Custom calc
	Value of avoided emissions	$219,490	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$477,379**	

Table 2-14. Tests for an example custom measure Tier III project replacing propane rooftop units (RTU) with hybrid heat pump units.

3

SYSTEM RESILIENCY AND GRID TRANSFORMATION

Throughout this IRP you'll see evidence of the energy system going through transformation. This has only accelerated since our last IRP in 2021. GMP, regulators, communities, customers, and state leaders, have set a path that is supporting the necessary evolution to a two-way dynamic energy system that leads to cleaner energy, lower costs, and greater resiliency.

GMP's Transmission & Distribution (T&D) system is the backbone for grid transformation. In this chapter we will talk about how we are addressing climate change and doing it in a way that benefits everyone and will lead to greater electrification, safety, and affordability. Grid projects we plan will lead to a strengthened, more flexible, and secure system (see **Chapter 4**). In addition, we discuss managing and serving new loads from heat pumps and EVs, and how storage is helping balance the grid.

Transmission & Distribution System Overview

GMP is the state's largest utility, serving about 275,000 customers. We also own and manage generating assets and subtransmission and distribution networks. In 2023, our transmission and distribution (T&D) system delivered approximately 3.7 million MWh of electricity; the peak load on the system was approximately 650 MW. We had about 630,000 MWh of behind-the-meter generation, resulting in 4.3 million MWh of load served in 2023 alone.

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

The delivery system includes 1,011 miles of subtransmission line feeding generation and distribution substations. The predominant voltages for the subtransmission system are 34.5 kV, 46 kV, and 69 kV. 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 small amount of distribution at voltages of 2.4 kV, 4.16 kV, 8.3 kV, and 34.5 kV.

System Resiliency

Our dedication to our transmission and distribution planning criteria, described below, ensures that our T&D infrastructure assets remain safe and reliable so we can best serve customers. We apply the criteria to improve reliability through investments and innovative programs that reduce disruptions to service from system outages. Projects we prioritize target improvements in system resilience to lessen the effects of climate change on customers.

The DPS's 2022 Comprehensive Energy Plan, Section 4.5.5, discusses the definitions and intersections between reliability, traditionally measured through objective criteria on outages, and resilience, which refers to the ability to avoid or lessen damage and recover quickly when it occurs. With the increase in frequency of severe weather, improving resiliency is key to maintaining and improving reliability for customers as the two are connected with outages occurring more frequently.

Storms are increasing in frequency and severity, hitting at a historic pace, causing unsustainable cost pressures and putting customers and employees at risk. That is why GMP across all areas is delivering innovative solutions for customers in the face of this extreme weather. Through systemically and strategically improving our system with solutions that keep customers with power in their homes while our teams repair the damage to the system, we can ensure that no matter people's ability to pay for reliability improvements at their own home, or where they live, they have access to reliable and safe power. GMP has sought innovative ways to address reliability and resiliency for customers while also thinking through the growth of electrification needed to decarbonize Vermont.

As part of this work, we evaluate how storage and/or distributed resources can replace what would otherwise be a traditional infrastructure upgrade. Improvements in infrastructure can:

- Save customers money
- Increase reliability and system resilience
- Increase operational efficiency and flexibility
- Make the energy delivery system more customer centric

Data from our advanced metering infrastructure (AMI) and supervisory control and data acquisition (SCADA) systems offer a reliable picture of each circuit. The information shows the extent to which 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. Our database and reporting tools make data evaluations more efficient and allow for some scenario testing of the impact from installing certain sizes of storage facilities on each substation.

Long-Term Planning

In **Chapter 2** load and other growth factors are forecasted out 20 years. That information is then used to model our T&D planning for the next 10 years discussed further in this chapter, or up to 20 years in the case of certain power supply analysis. We also coordinate with VELCO and other entities that jointly own facilities GMP operates to conduct long-term planning to ensure alignment. For further discussion about why GMP chose to focus on the 10-year horizon for our engineering studies this IRP, see section, **Forecast Periods: 5 Years and 10 Years**.

In the coming IRP period, GMP will continue to participate in Vermont System Planning Committee (VSPC) processes. GMP also will continue its participation in the VSPC Coordinating, Geotargeting (GTS), Load Forecasting, and Generation Constraint subcommittees. GMP annually shares its planned T&D capital projects with the GTS to determine whether any reliability plans might be required. Reliability plans determine the least-cost solution for identified T&D constraints—and possible resolutions for those constraints through non-transmission alternatives (NTAs). In the past three years, GMP has presented roughly 15 T&D projects to the VSPC and the GTS for consideration and review.

VELCO's most recent Long-Range Transmission Plan (LRTP) identified the potential need for bulk transmission upgrades if certain peak loads materialize. GMP is working with VELCO through the 2005 Investigation into Least-Cost Integrated Resource Planning Docket 7081 process. VELCO is currently updating the initial non-transmission alternative results along with the identification for the specific load deficiency in each case, which GMP will then use to determine the appropriate next steps in the NTA process. VELCO's LRTP did not assume any EV charging control, which is one of the greatest peak contributors in the forecasting. This alone will alleviate a significant number of system issues in the early years as GMP has managed EV charging as part of its Virtual Power Plant.

System Planning and Protection Criteria

GMP's 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 following equal slope criteria. For non-bulk network planning studies, GMP ordinarily relies on probabilistic and cost-based reliability criteria. This helps strike an appropriate balance between infrastructure costs supported by customers and the reliability that the resulting system provides for them. We use a standard "normal minus one" (N-1) criterion for evaluating subtransmission, to assure the subtransmission remains stable and reliable if, for example, a fault occurs on a subtransmission line and removes it from service. We do not always adhere to N-1 criteria when looking at solutions, which is why we also use equal slope criteria. This approach achieves the benefit of adhering to an 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 criterion.

Our operating criteria require system voltages to be between 95 and 105 percent of nominal, on the subtransmission system during all-lines-in operation (N-0); and between 90 and 110 percent of nominal (N-1), 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 percent maximum load limit on all elements during normal operation and contingency. For specific cases involving short periods during first-contingency operation, we allow overloading (that is, conductor loading up to 110 percent), but only with the understanding that operators will take quick action to remedy the overload, including by shedding load.

GMP adheres to all applicable standards and criteria from the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and ISO New England when planning and designing the subtransmission system.

GMP has standard conductor sizes for its subtransmission and distribution systems:

1) **Overhead primary**: 1/0 6201 aluminum, 4/0 6210 aluminum, 336 ACSR, 477 ACSR, 556 ACSR and 795 ACSR
2) **Underground primary**: 1/0, 4/0, 350, 500, 750, 1000, 1250 aluminum or copper
3) The largest conductor we have used on our subtransmission system is 959 ACSS Suwannee.

To help customers in the face of escalating costs due to climate change driven storms, we are using more cable-in-conduit underground conductor because it can efficiently and safely be buried at a lower lifecycle operating cost than the equivalent overhead construction. Once installed, fewer repairs are needed, saving money and keeping customers and employees safer. GMP also uses spacer cable for the majority of our three-phase overhead construction, which positions all of the current-carrying conductors in a bundle underneath a reinforced messenger cable used as the neutral conductor. This wire is insulated and can withstand tree contact without causing outages. This means that even if there is damage to the system, the customers in their homes do not experience a disruption.

Also, GMP proactively upgrades substations through our Transmission Ground Fault Over Voltage (TGFOV) tariff so developers can continue to interconnect distributed energy resources (DERs). TGFOV mitigation is required when the minimum-load-to-generation ratio (MLGR) is below 2:1. Once the MLGR reaches this threshold a customer's interconnections is placed on hold until the TGFOV is mitigated. GMP's upgrades will ensure that the system protection can prevent a damaging overvoltage condition when a transmission ground fault occurs. The generation customer funds these upgrades through the TGFOV tariff based on a price-per-kW, according to their project size. This allows the cost to be spread across many customers and therefore does not place the full cost of a TGFOV mitigation project on one generation customer.

Distribution

Our standard distribution system voltage is 12.47 kV/7.2 kV grounded wye. We also operate a small amount of 34.5 kV/19.9 kV distribution system facilities. GMP is in the process of converting old 2.4 kV and 4.8 kV distribution circuits to our standard 12.47 kV voltage class. This upgrade increases the capacity for distributed generation hosting capacity and provides more opportunity for feeder backup. The voltage delivered to customers adheres to American National Standards Institute (ANSI) Standard C84.1.

To protect our distribution system, we design strategies that:

- Set circuit loads and distributed resources not to exceed 66 percent of relay pickup settings. We make exceptions 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 150 percent 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 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, although 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.

Distributed Generation

Inverters connecting to the GMP system must adhere to the IEEE 1547-2018 and UL 1741 standards. GMP may require system upgrades such as a live line reclose block protection scheme to avoid the reclosing of a distribution feeder onto an unintentionally islanded system due to high DG penetration.

Evolving Advanced Metering for Customers

GMP successfully deployed Advanced Metering Infrastructure (AMI) more than a decade ago and has spent time since the 2021 IRP investigating potential upgrades and successor technologies that can be used for customers, including DERs. AMI enables granular insights into load that helps GMP, and customers manage usage in ways that support the reliability of the overall grid, allow customers to sign up for innovative programs and rates, and save carbon and costs for all. During this IRP period GMP will evaluate and decide what is next for our AMI system. This can include an upgrade of the existing system, an overhaul of the front and back-end systems, or something in between. As described below GMP will weigh a number of factors to ultimately select the best system for customers with innovation, ease, and affordability in mind.

While that is happening, and over this IRP period, GMP will improve the functionality of the AMI gatekeepers, which is field equipment that acts as an interface between customers' meters and GMP's head-end system. That will involve technical work to streamline the number of gatekeepers interfacing with customer meters and ensuring the number of "hops," or data gaps, that can occur is minimized. These upgrades will also involve testing and deploying new generation gatekeepers and exploring alternative gatekeeper locations such as at sockets. Finally, GMP also will look for opportunities to enhance the communications connections and infrastructure that supports GMP's AMI. GMP will plan for and implement where feasible communications re-routing in the event of outages to help diversify the paths of service. All of this will involve close coordination between GMP's metering team, other field team leaders, and the IT and technology security teams, to ensure both cybersecurity and energy security, as described in **Chapter 4**.

As GMP explores the next evolution of GMP's AMI for customers, it is not only reviewing and testing successor AMI technologies but also scanning the horizon for new technologies that can serve as a reliable, multi-function customer meter. GMP's current vendor has developed next-generation technology that is flexible and data-driven, designed from the outset to work with radio frequency mesh, Synergy-net, and cellular networks. Meanwhile, programs such as GMP's SPAN Panel and Resilient Neighborhood pilots are providing the opportunity to test the accuracy and efficacy of using certain DERs directly as metering for customers in the future. And outside of direct customer metering, GMP also continues to evolve how it meters and manages other resources and the grid generally. GMP is reviewing and testing Supervisory Control and Data Acquisition (SCADA) metering technology designed to provide real-time information to system operators for all aspects of the grid.

The **GMP 2024 IRP Action Plan** reflects these important next steps in AMI deployment for customers, which will likely lead to planning and proposals for rolling out successor technologies during the next IRP.

Resiliency and Affordability: GMP's Zero Outages Initiative

GMP filed our Zero Outages Initiative (ZOI) in October 2023, which builds on our 2020 Climate Plan with proven techniques that are already working to reduce outages and keep customers connected. The plan was filed and reviewed after Vermont experienced years of unprecedented damaging storms. Storm repair costs for GMP customers topped nearly $100 million in one two-year timeframe. This plan was also filed as a proactive approach to address challenges on an evolving grid—one with increased demand from decarbonizing other industries such as transportation and heating.

ZOI uses data and a comprehensive approach to invest in rural resilience and solutions that focus first on areas disproportionately impacted by these historic and costly storms. But it isn't just about storms. The grid faces four challenges with respect to reliability: 1) extreme weather, 2) cyberattacks, 3) physical attacks, and 4) regional supply constraints. In other parts of the country, customers currently face rolling blackouts due to regional supply or system protection measures such as planned outages (these are known as Public Safety Power Shutoffs in other parts of the country).

ISO-NE has issued warnings that winter supply in the region could impact reliability during prolonged periods of very cold weather. Cyber and physical attacks of the electrical grid are also increasing across the country. ZOI is designed with all this in mind. Using energy storage across our system, coupled with reliability measures like undergrounding and overhead storm hardening, we not only improve traditional reliability, we can also keep customers connected to energy when the grid is offline with the use of storage. These storage assets are in turn grid assets that we aggregate together to shave peak and stabilize the grid. This lowers overall costs. Stated differently, ZOI creates a distributed energy model that can withstand many challenges while lowering costs by aggregating resources together and deploying them like a virtual power plant.

To be clear and for the avoidance of any doubt, there will still be interruptions on the electrical grid with events such as extreme weather, tree damage, car/pole accidents, equipment faults, potential cyber or physical issues, and potential regional supply constraints. We live in a time when the traditional grid model of centralized generation and poles and wires in the air is at increasing risk for the reasons stated above. ZOI is a proactive solution to many of those challenges and a real-time solution to extreme weather. ZOI gives customers, starting in rural Vermont, the opportunity to stay connected to an energy source while the grid is restored. And this energy source (batteries) is in turn connected to the grid allowing it to be used to lower costs by shaving peaks, regulating frequency, and other system benefits.

ZOI includes three components that work together:

- **Spacer Cable and Tree Wire for Overhead Lines**. Three-phase or primary overhead lines that leave substations and feed the power into Vermont communities are storm hardened with insulated, strong lines that can withstand much more damage from trees, wind and other acts of nature.
- **Undergrounding Lines**. Rapid, proactive deployment of undergrounding primary distribution lines. In rural areas particularly, this has become a cost-effective solution when compared to the cost of overhead construction thanks to new installation technology and the use of cable-in-conduit, eliminating maintenance costs and expensive and dangerous storm repairs, and results in a much more reliable energy system.
- **Energy Storage as Grid Assets**. In the first phase of ZOI, as proposed but not yet approved in the filing, customers who are located at the ends of our distribution system and enroll in the initiative would be backed up by grid connected energy storage. A form of resiliency, these customers have access to the stored energy while the grid is being restored. And, importantly, these energy storage systems, and others throughout GMP's territory, are aggregated together and in turn are used for numerous other benefits which reduce the overall cost of the system when the grid is up.

On October 18, 2024, the Public Utility Commission (PUC) issued an order approving $150M of the T&D work in ZOI (storm hardening overhead lines and undergrounding). For the storage component of ZOI in rural areas, the Order requests a tariff filing, to be reviewed separately under a new proceeding. GMP expects to file that tariff in early 2025.

Zone-Based Approach to Reliability and Resiliency

Full circuit-level data analysis determines the appropriate techniques for delivering system reliability and resilience on each circuit. Undergrounding lines and storm hardening above-ground lines increase grid reliability. As mentioned above, for customers in the most rural, remote areas, GMP will propose to install energy storage as a part of their service under the upcoming tariff filing. As such, we have analyzed our T&D system circuit by circuit into four broad zones. These run from main line distribution feeders that tie substations together (Zone 1) all the way out to the most rural, isolated areas of our system serving only a few customers (Zone 4).

- **Zone 1**: Main line three-phase distribution feeders that tie substations together and travel out to the first protective device on a circuit. In general, Zone 1 areas are the backbone, and typically tend to be closer to population centers. The majority of the construction in Zone 1 will be large conductor spacer cable projects.
- **Zone 2**: Three-phase radial tap lines, that generally have a higher customer count and larger loads. The majority of projects in Zone 2 will be three-phase spacer cable but also will include three-phase underground cable in conduit.
- **Zone 3**: Long, single-phase distribution lines that serve dozens of customers or more. These are most likely to be found in residential settings. The majority of projects in Zone 3 will be single-phase underground cable in conduit. Zone 3 will also include single-phase overhead insulated tree wire projects.
- **Zone 4**: : Single-phase lines that serve smaller groups of customers, typically one to 10. As part of our upcoming tariff filing, the majority of projects in Zone 4 would involve energy storage.

Project Selection

As ordered by the PUC, GMP will begin T&D work on the twenty worst circuits throughout our service territory. This order directs GMP to focus investments in resiliency and reliability work on the “20 worst” circuits and two circuits where we will comprehensively deploy ZOI strategies (East Jamaica EJ-G7 and Wilmington 56G1). The “20 worst” circuits are those defined by GMP’s work in the 2024 4.900 Annual Report[1] that captures customer experience of outages in the preceding calendar year. Further, the Order concludes that, “the broader ZOI program should be developed iteratively over the next several years and be grounded in baseline data that are gathered through actual, on-the-ground experience.”

1 GMP’s community-level outreach to customers will increase with collaborations involving regional planning commissions, local officials, community-based organizations, local energy committees, schools, and other points of contact throughout our service territory. GMP’s community outreach will also incorporate in-person and virtual meetings, along with participation in public events (described further in Chapter 1)

In its Order, the PUC also includedrequirements for data gathering and reporting, to help with an evaluation of the costs and benefits of further future work.[2] The PUC recognized that based upon the results achieved with completed ZOI projects, GMP will be in a position to show the benefits of these projects as they are deployed, allowing for better assessment of the data requirements. In addition, the PUC also requested that GMP report on five specific metrics proposed by the DPS.[3]

There is overlap between the priority areas as defined by the PUC Order with the State of Vermont's Municipal Vulnerability Index (MVI) data, especially when looking at the percent of population in towns that are below two times the federal poverty level.

The timeline in the Order for investment lines up with our current regulation plan. Under the Order, we will include future proposals for ZOI investments during our next regulation plan, and further detail will be included in the 2027 IRP.

Accounting for ZOI Work

GMP has proposed a regulatory accounting process for ZOI process and outcomes approved by the PUC ZOI Order. This process is consistent with the methods approved by the Commission in GMP's Climate Plan. ZOI capital projects will not appear in GMP's rate base until those projects are in operation and are reviewed and approved by the Commission. GMP will also not include ZOI-related incremental operations and maintenance expenses in its rate filing until those costs have been incurred, reviewed, and approved by the Commission.

Benefits for Communities Served and Vermont

Increasing reliability across entire circuits enhances equity. Currently, customers in the most remote parts of Vermont experience greater reliability issues, with more and longer outages than customers in suburban and urban areas (where system reliability is greater), despite paying the same for electric services.

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2 Case No. 23-3501-PET. Public Utility Commission Order Granting in Part the Petition of Green Mountain Power Corporation for Approval of the Zero Outages Initiative (October 18, 2024) at 4 ("However, with respect to the remaining term of the current MYRP, GMP's ZOI investments should be more narrowly directed at gathering meaningful experience and data to inform the development of a more robust ZOI proposal in the near-term future.") See also Order at 24 ("The broader ZOI program should be developed iteratively over the next several years and be grounded in baseline data that are gathered through actual, on-the-ground experience.")

3 Those five metrics are: (1) 33% improvement in System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) for rural feeders over 2023 SAIDI/SAIFI; (2) Forced Outage Rate per Hundred miles of Zone 1 Spacer Cable ≤ 3.0; (3) Storm costs, downward trend in rolling five-year average costs—less than $13 million by 2030; (4) Battery Failure to Start Index ≤ 1%; and (5) Report CEMI-8 for all residential customers.

GMP's community-level outreach to customers will increase with collaborations involving regional planning commissions, local officials, community-based organizations, local energy committees, schools, and other points of contact throughout our service territory. GMP's community outreach will also incorporate in-person and virtual meetings, along with participation in public events (described further in **Chapter 1**).

Community Engagement

GMP's ongoing community-level outreach to customers will continue with collaborations involving regional planning commissions, local officials and community-based organizations, local energy committees, schools, and other points of contact throughout its service territory. GMP's regular community outreach also incorporates in-person and virtual meetings, along with participation in public events (described further in **Chapter 1**).

Resiliency Zones

The 2021 IRP focused on the important preliminary work of deploying Resiliency Zones (RZ) in specific communities. Since then, we have built on that work to develop our current approach to resiliency through the ZOI projects. This approach will help more Vermonters more quickly, as storm damage continues to accelerate and the need to deliver resiliency is a system-wide requirement, not just in certain discrete areas like downtowns or mobile home parks or a neighborhood which was done with RZ.

ZOI builds on the learnings of the resiliency work completed to date. Our goal in the first iteration was to work with communities and take a targeted resiliency approach that was beyond traditional poles-and-wires solutions. This was 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.

These RZ projects below will be completed and provide important resiliency benefits for those communities and customers and will serve as important building blocks for our resiliency work to reach all customers. We are transitioning this work to the comprehensive ZOI framework that was developed in part from what we learned through the RZ work.

- **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 with the microgrid capabilities to island downtown Rochester along Route 100.
- **Grafton**: In Grafton we deployed energy storage into customers' homes where customers had experienced greater than 20 outages in a three-year period. It's important to note that because these customers rely on 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. This pilot ended September 15, 2024, with energy storage deployed in more than 40 customer homes. More details about the pilot are available in the final report filed November 14, 2024 in Case No. 22A-3112.
- **Brattleboro**: Our work in Brattleboro 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 energy 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. This energy storage will provide peak savings and other grid services when not in use for resiliency.

Vegetation

Vegetation management today is much different than it was in years past. Our vegetation management program is built to maintain safe rights of way and using data and technology to improve maintenance. But our climate is warmer and wetter with longer, more aggressive growing seasons. Additionally, extreme weather is causing tree and vegetation damage to electrical infrastructure from far outside GMP's rights of way. Modern challenges are simply not being met with traditional vegetation management approaches.

New solutions are needed. Undergrounding our system and hardening overhead lines will bring down vegetation management costs. For example, every mile of distribution that is underground is one less mile that needs vegetation management in the future. This will mean fewer trim miles per year which results in lower costs.

Currently, GMP's long-term Integrated Vegetation Management (IVM) program seeks to:

- Provide for the safe and efficient operation of the sub-transmission and distribution systems
- Reduce service interruptions and power quality disturbances due to tree contacts
- Be safe for the public and the GMP team
- Cost-effective with minimum impact to the environment providing a high level of customer satisfaction

We revised our IVM program, as submitted in early 2024 as part of the PUC rule 3.631(J).[4] The IVM plan details the relative composition of tree species near our T&D system, provides growth rates for dominant species, and lists low-growing compatible species. We work to trim vegetation across our entire distribution system every seven years, basing schedules on species composition and growth rates, and the desired clearance from trees to power lines (20 feet above and 10 feet horizontally from the conductors, in most cases). Clearances are increased where there is a danger of ice and snow loading on conifer trees, soft maples, and birch. Every year, we determine areas most in need of trimming. To clear and trim, we manually cut trees, prune, mow with large equipment, and selectively apply herbicides.

The emerald ash borer (EAB) statewide infestation causes premature tree death and poses a public safety hazard as well as a reliability hazard to GMP's electric system. Over time, infested ash trees' health declines and makes them prone to "ash snap." GMP's EAB mitigation involves transmission and overhead distribution lines in confirmed and high-risk infested areas. The strategy evolves according to rates of infestation, tree mortality rates, development and adoption of EAB best practices, safety, and electric system reliability.

Subtransmission corridors are on a five-year trimming cycle. GMP updated its subtransmission right-of-way management plan in 2024, and in Fiscal Year 2024, GMP completed vegetation management on 32 transmission lines totaling 209.13 miles (2,462 acres). We applied herbicide to 994 acres.

4 The Transmission and Distribution IVM Plans are available to download via ePUC in Case No. 24A-1131.

Even with trimming in accordance with these plans, tree contact on GMP's overhead distribution and subtransmission lines accounts for more than half of all outage events, with a five-year average of 54%. As noted already, the trend will not improve with the warmer, wetter climate, requiring other solutions beyond maintenance trimming to reduce outages.

The historical spending for line maintenance is shown **Table 3-1.**

Maintenance Type	Total Miles	Total Acres	Miles Needing Trimming	Maintenance Cycle (Years)
Sub-Transmission	970.2	11721.1	194	5
Distribution				
Five (5) Year Cycle	1,321.4	n/a		5
Seven (7) Year Cycle	8,637.7	n/a		7
Total Distribution	9,959.1		1,498.3	

Budget

Type of Line Maintenance	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027
Sub-transmission	3,160,845	4,004,863	4,004,863	4,473,240	4,570,898	4,662,316
Distribution	14,841,672	15,145,808	15,240,023	16,955,129	15,674,760	15,988,255
Emeral Ash Borer	1,200,000	0	0	0	0	0
Budget Total	19,202,517	19,150,671	19,244,886	21,428,369	20,245,658	20,650,571

Actual

Type of Line Maintenance	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027
Sub-transmission	3,061,860	2,871,363	3,335,909	n/a	n/a	n/a
Distribution	14,978,511	17,621,107	16,388,093	n/a	n/a	n/a
Emeral Ash Borer	1,314,849	-5,078		n/a	n/a	n/a
Actual Total	19,355,220	20,487,391	19,724,002	n/a	n/a	n/a
Distribution Miles Trimmed	1,199	1,121	1,176	1,498	1,498	1,498
Transmission Miles Trimmed	194	244	209	177	189	194

Table 3-1. FY2022–FY2027 vegetation line maintenance spending.

Table 3-1 is also provided as Appendix D. The average GMP subtransmission right-of-way width is 100 feet with 50 feet on each side of the centerline. Our subtransmission system maintenance techniques involve flat cutting, manual and mechanical trimming, mowing with large equipment, and applying targeted herbicides. GMP is responsive to questions and feedback from property owners, encouraging them to use the land within the right-of-way to help ensure safe electricity transmission.

After we manage vegetation within the T&D right-of-way, we apply targeted herbicides to vegetation that can grow up into the energized wires. Management of these incompatible species also allows for desirable, low-growing vegetation to become established, which increases plant biodiversity. Selectively applying herbicide reduces overall impact, lowers costs, reduces incompatible stem densities (thus decreasing the amount of herbicides applied in future maintenance cycles), and improves safety and reliability of the system.

GMP applies herbicides in three ways: (1) foliar application where resprout growth has occurred; (2) basal bark treatment on susceptible woody plants with stems less than six inches in basal diameter; and (3) cut-stump treatment to inhibit sprout growth.

The optimum schedule for a foliar treatment is one growing season after mechanical cutting. Stump treatment occurs 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 the care of licensed applicators. GMP also adheres to the International Society of Arboriculture's vegetation management practices which promote species health and diversity.

Starting in 2024, GMP began piloting the use of AI in conjunction with satellite imagery to better target trimming needs in the most efficient and highest risk locations. We will be testing this product on various circuits over the next few trimming cycles and will be able to report results in our next IRP.

Beneficial Electrification and Distributed Generation

The Renewable Energy Standard (RES) described in **Chapter 6** increases the required amount for GMP of small-scale, less than 5 MW distributed generation, from 10% to 20% by 2032. Since our system is already having to accommodate constraints such as substation capacities, ISO/ASO cluster studies,[5] and transmission export challenges, GMP will continue to provide tools that guide solar developers toward regions that will likely result in lower cost interconnections and fewer upgrades needed.

5 ISO/ASO: Independent System Operator and Affected System Operator; the studies address the extent to which a distributed generation project affects the transmission system or the electric power systems of neighboring electric distribution utilities. ISO New England and Eversource have undertaken these ASO studies

Identifying hosting capacity on the GMP system while taking into account all of the constraints is essential as we continue procuring renewable sources to meet the 20 percent Tier II RES requirements. Working with power supply planning, we will target procurements that meet Tier II by siting projects in locations that are best for the grid and do not drive up costs further for customers, however, as will be discussed further below, there remains considerable headroom across the system to achieve the distributed generation targets set in the RES if we can optimize the geographic location of the distributed generation. If not optimized, some form of control like storage or flexible loads will be needed and is discussed later in this chapter.

New Loads and Distributed Generation on the System to Benefit Customers

As Vermont continues to electrify the top two sources of carbon pollution, transportation and heating, we anticipate a higher pace of electrification and load growth in the late 2020s and beyond from heat pumps and EV adoption, described further in **Chapter 2**.

To accurately capture where we are today and to look ahead at where we are heading, GMP used 2030 and 2035 as the main study years for our engineering studies and also used a base case of 2024 as a starting point. We first assumed that 100 percent of electric vehicle (EV) charging was not controlled, so that we can stress-test the system in a worst-case scenario. The 2024 VELCO Long-Range Transmission Plan reflects this assumption, following input from stakeholders at the VSPC. Most GMP customers with EVs enroll in either Rate 72 or 74 Time of Use (TOU) tariffs, which charge at off-peak hours or allow GMP to call for the temporary curtailment of charging during high load events. This saves all customers money, avoiding expensive and often dirty power and just as importantly significantly reduces the need for future infrastructure growth due to peak demands. See **Innovation for Customers: Powerwalls and EV Management** later in this chapter for a discussion of how GMP currently manages EV charging loads during peak hours. GMP's actual planning basis, however, will include the controlled charging for the future and any transmission or distribution needs that are driven from this demand growth will be based off the net impact of electric vehicles on the system.

Table 3-2 summarizes regional peak loads that we studied as a part of this IRP. Although these peaks occur after dark when distributed solar cannot help to reduce the peaks, distributed storage and EV charging management can affect these peak loads. The loads in Table 3-3 are representative of total uncontrolled loads on the system. The potential for flexible load management increases over time as more customers enroll in GMP's EV and storage programs (**Table 3-3**).

Peak Uncontrolled Regional Loads (MW)				
Region	**2030 Summer**	**2030 Winter**	**2035 Summer**	**2035 Winter**
Ascutney	79.9	83.6	90.4	96.6
BED	77.1	78.3	68.1	98.3
Burlington	201.0	216.1	252.3	281.4
Central	67.2	88.1	74.6	99.5
Florence	21.9	24.0	21.9	24.0
GF	54.6	42.8	54.6	42.8
Highgate	47.9	46.3	51.9	51.5
Johnson	14.1	19.4	15.8	22.0
Middlebury	40.1	42.6	43.6	47.3
Montpelier	111.5	146.5	132.2	174.6
Morrisville	38.0	43.0	41.6	48.3
Newport	46.1	54.4	50.6	61.0
Rutland	106.0	131.6	115.7	145.9
Southern	125.9	174.8	143.5	199.1
St. Albans	85.7	82.0	94.2	92.7
St. Johnsbury	26.3	37.3	27.7	41.0
Total	**1145.8**	**1310.2**	**1281.4**	**1526.0**

Table 3-2. Peak regional load estimates for 2030 and 2035.

Vermont systemwide load components (MW)				
End Use	**2030 Summer**	**2030 Winter**	**2035 Summer**	**2035 Winter**
Base load	1035.1	1013.6	1040.5	1000.6
Heat pump	23.7	133.9	39.2	204.4
EVs	87.0	163.3	201.7	321.0
Total	**1145.8**	**1310.2**	**1281.4**	**1526**

Table 3-3. The effects of heat pumps and EVs on Vermont's system, during 2030 and 2035 peaks.

Base loads remain relatively stable over the course of our forecasts, even decreasing at peak winter hours from 2030 to 2035. EV charging and winter heat pumps become an increasingly large portion of the statewide peak load. EV charging also requires more energy in the winter months because electric vehicles get fewer miles per kWh than in the summer.

These peak load cases are the same forecasts VELCO used in its 2024 Long-Range Transmission Plan, using a 90/10 severe weather case (that is, 90 percent chance of actual load being less than the shown amounts, and a 10 percent chance of being greater). These forecasts are extremely conservative as they do not include any amount of management of EV charging load and show a very high rate of EV adoption in Vermont. With that in mind, it is important to align our forecasts with VELCO's forecasts so that we can draw conclusions from the same data source.

To test the GMP system at light load, high DG conditions, GMP used the same base load forecast as VELCO did in its LRTP. This involved a total load of around 450 MW on the GMP system. This case is used in tandem with DG forecasts to determine how the distribution and subtransmission can obtain high penetrations of solar.

Using the regional load forecasts, GMP distributed the total zonal loads across each substation, so that feeder loads in the future are assumed to share the same proportion as they do today. GMP modeled heat pumps and electric vehicle loads as separate loads at each bus. This allows modeling the impact of different levels of management of EVs. We expect different regions of Vermont to experience load growth at different rates and to different extents. **Figure 3-1** shows the expected effects of CCHP and unmanaged EVs on the Burlington area (Chittenden County, minus BED) load between now and 2043. **Figure 3-2** shows expected effects of those technologies on GMP's southern region.

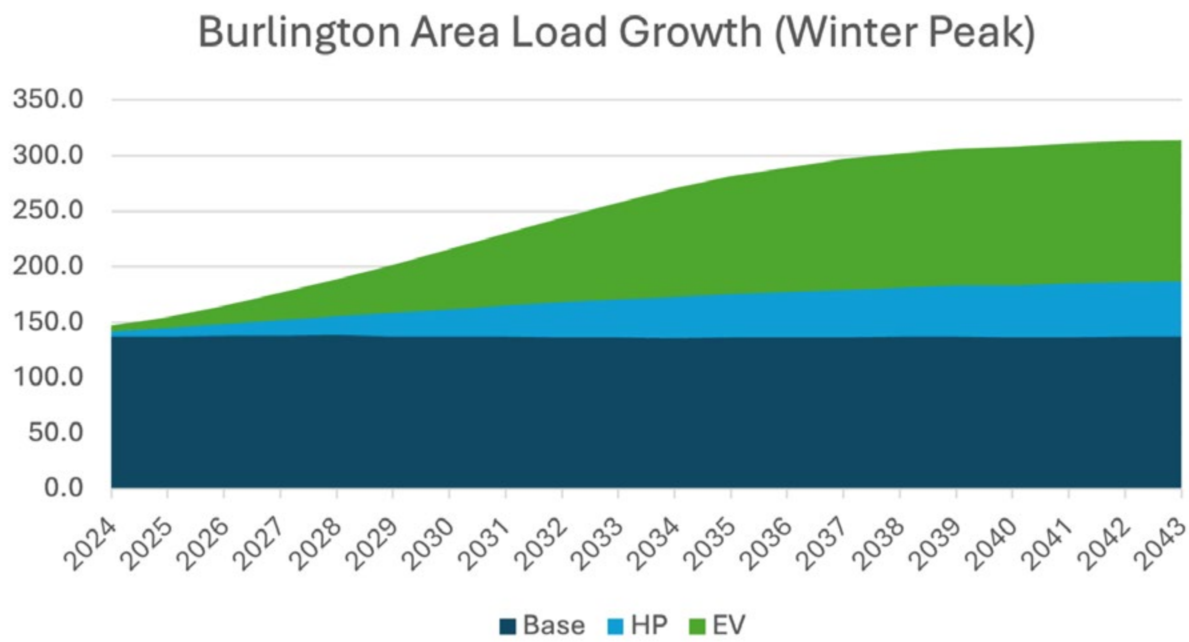


Figure 3-1. Burlington's expected load growth, taking into account increases in CCHP and EVs, through 2043.

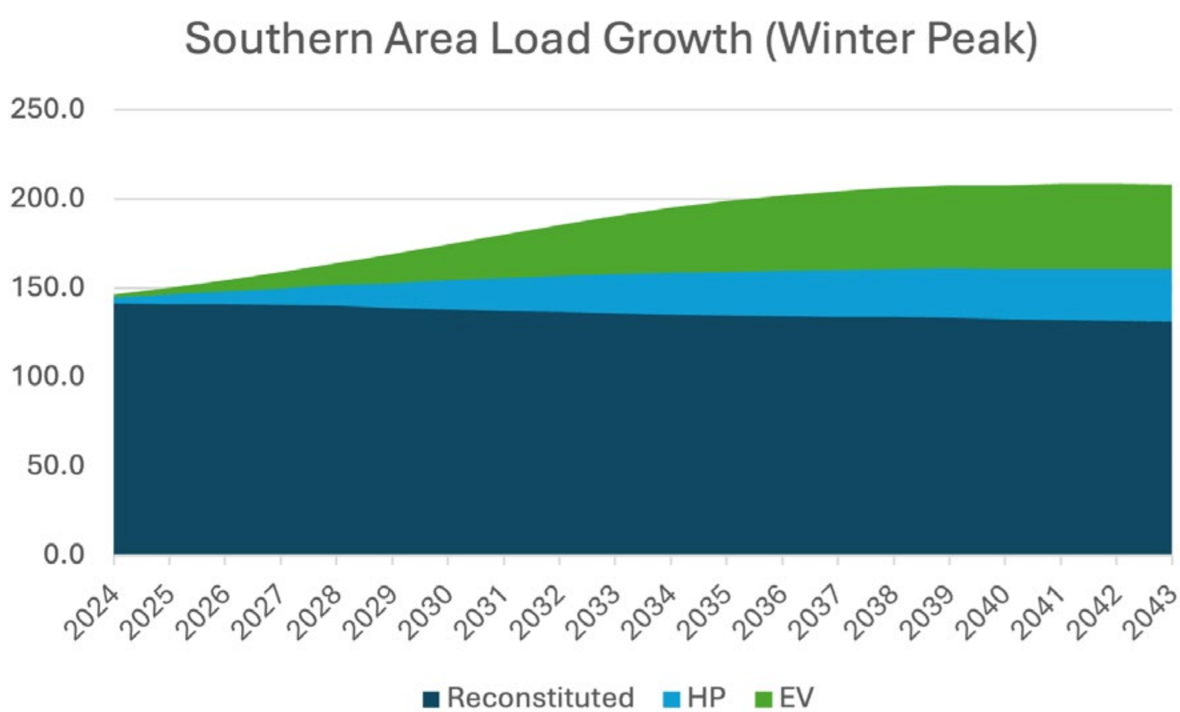


Figure 3-2. Expected effects of CCHP and EV growth on load in the southern service area, through 2043.

A key difference across load zones is the portion of net load that EV charging will make up in the future. In denser population zones like greater Burlington and Rutland, EV charging can contribute closer to 30 percent of peak load if left uncontrolled, whereas in rural areas this contribution can drop to 15 percent. In regions where EV load is a larger portion of net load, GMP has more opportunity to reduce net load by shifting EV charging later into the night or during daytime solar production hours.

A Note on Time Series Analysis

GMP developed spatially granular time series from Itron hourly forecasts and the ISO New England 2023 Capacity, Energy, Loads, and Transmission (CELT) Report to guide time series analyses on the subtransmission levels. On the distribution system, GMP built individual customer and feeder level load forecasts up from hourly load profiles of EV charging, heat pumps, and base loads. Time series analysis remains a challenge for three reasons:

1) It is difficult to develop hourly forecasts at a geographic granularity that is required to accurately capture expected upgrade costs on the distribution system. When developing forecasts at the feeder level, we are getting closer to forecasting an individual customer's electric consumption for every hour of the year. This is a level of precision that is extremely difficult to achieve and can result in over- or underestimating local distribution system upgrades if we forecast usage incorrectly. At the subtransmission and bulk transmission levels, the aggregation of thousands of individual customers with varying usage profiles leads to a more diverse load profile that is easier to forecast from state and regional electrification goals.

2) Similarly, the distribution system is constantly evolving and does not look the same year-to-year. Circuits topologies frequently change to support feeder backup, balance load, and provide better service quality. Loads come and go offline, and components are upgraded for a whole host of reasons, including upgrades added by DG developers required for their projects. We cannot therefore accurately predict what each circuit will look like in 10 years, let alone 20 years. Simply moving an open point in our models could alleviate potential overloads for example.
3) There is a lack of power flow tools at the transmission level that allow for time series analysis in a manner that is useful for analyzing the effects of loading on the system. GMP, with our consultants, use a simulation tool, PROBE, and threat and risk analysis (TARA) software for time series analysis to model the ISO Day-Ahead and Real-Time markets and dispatch generators according to these markets. This method ensures a reliable transmission system while doing this. PROBE lacks the functionality to look at the potential for load reduction. PSS®E 36 (high-performance transmission planning and analysis software) has a new time series analysis package that could prove useful in the future. However, the industry has not yet sufficiently adopted this tool to inform the extent to which it would be useful for this particular challenge.

GMP looked at critical contingencies on the subtransmission system and projected systemwide hourly loads, down to the substation level, to determine which load reductions might be needed, and how deep, long, and frequent they should be to avoid overloads if these contingencies were to occur.

We used CYME (a distribution modeling software) to explore time series analysis on our distribution system. This is a tool we are experienced with and use daily to evaluate the distribution system.

Feeder Level Forecasting

In our study of ten representative distribution feeders across the GMP system, we modeled a scenario in which every customer has a Level 2 EV charger and heat pump, and in which 25 percent of customers on any circuit have Tesla Powerwalls that GMP can dispatch when called upon. **Chapter 2** forecasts customer-sited storage at around15% percent of houses, with potentially some circuits having more than this if these regions require more storage for resiliency reasons.

We used systemwide data from EV chargers enrolled in Rate 72 and 74, an hourly heat pump load forecast from Itron (which corresponds to the forecast used for peak loading), and historical dispatch data from our Powerwalls. From these data, we derived per-customer average load profiles and distributed these across each of the representative feeders. We also deployed DG on each feeder at the levels specified in the systemwide DG forecast.

Figure 3-3 shows the per-customer hourly heat pump demand, projected out to 2035. **Figure 3-4** shows the hourly demand from EV charging, across one year; and **Figure 3-5** presents the per-customer hourly new electrification curves. All values are in kW.

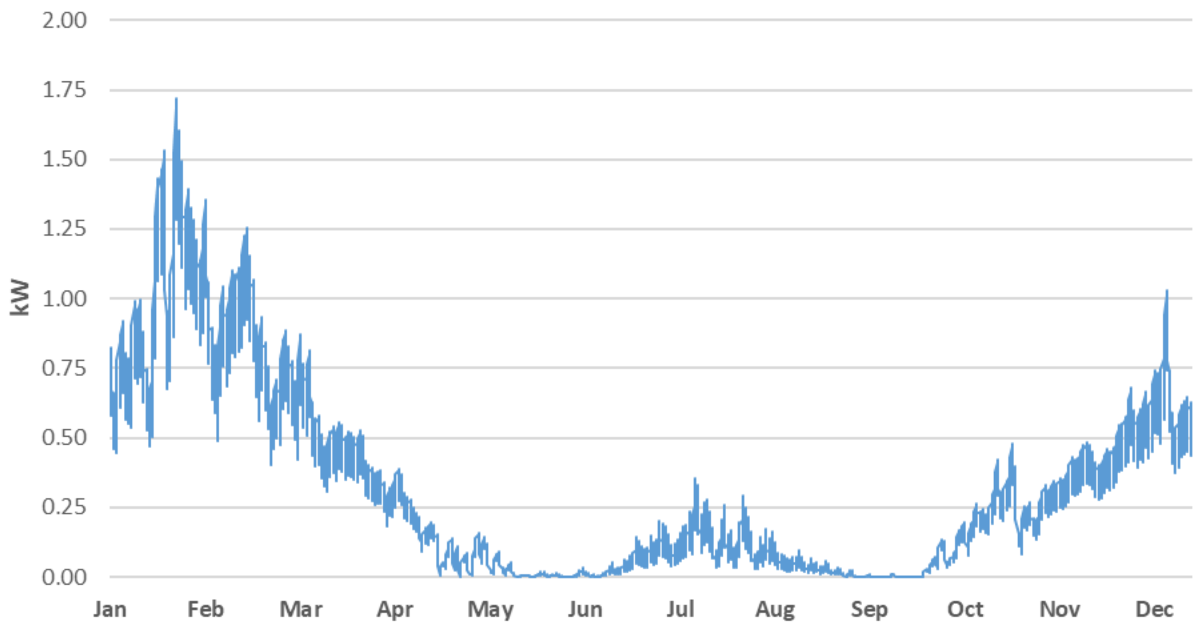


Figure 3-3. GMP's per-customer projected hourly heat pump demand, in kW, for 2035.

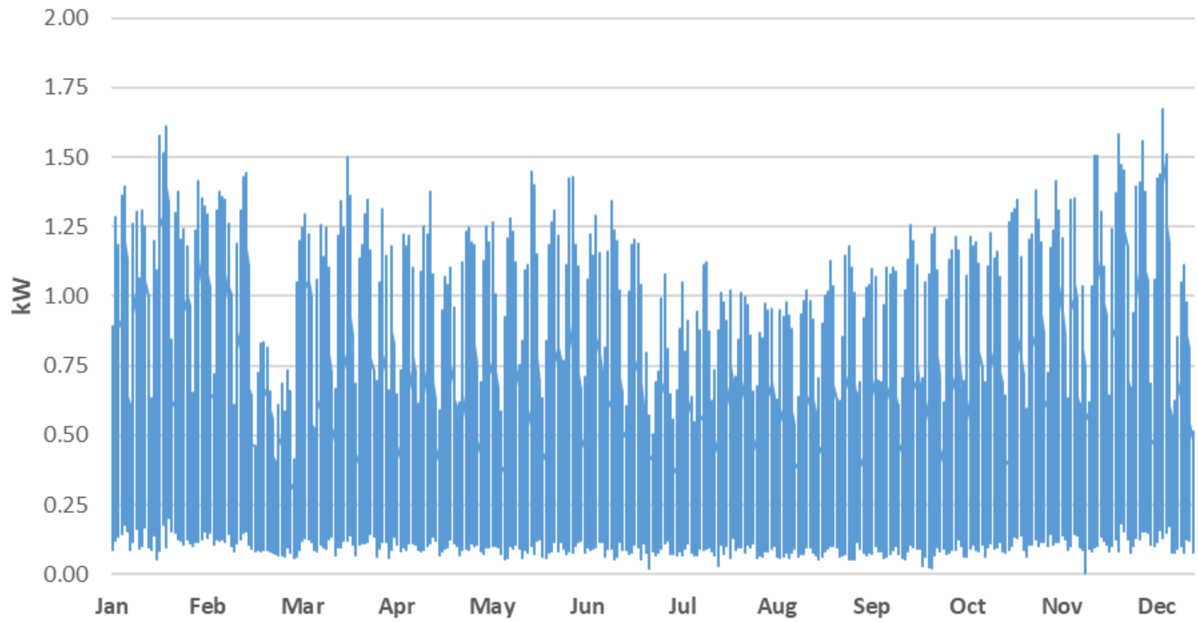


Figure 3-4. The per-customer hourly charging demand from EVs, across 2035.

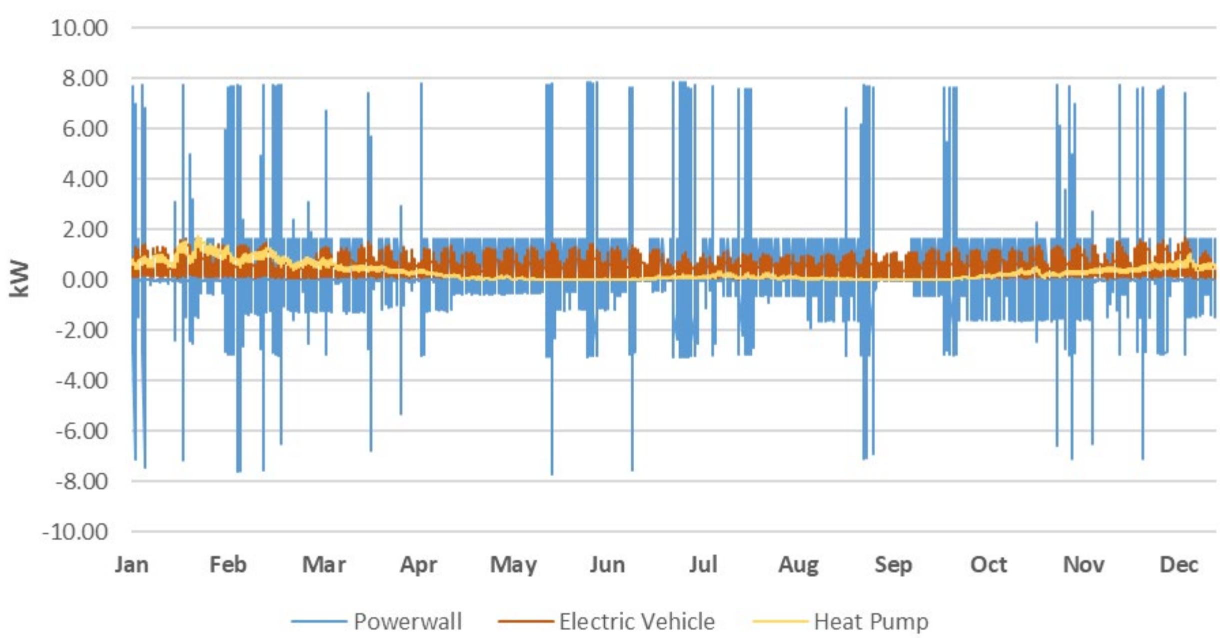


Figure 3-5. The estimated per-customer hourly new electrification curves, in kW, combining Powerwall, electric vehicle, and heat pump loads.

Both heat pumps and EV chargers have a high level of load diversity, even at peak hours when most people would be charging their vehicles and heating their homes. Although a Level 2 charger might have a demand of 7 kW or more, the average demand per customer at peak hours ranges between 0.5 to 1.5 kW.

Our historical EV charging data show that the per customer demand for charging is higher in winter than in the summer. As EVs get lower miles per kWh in cold weather, these cars charge for longer periods. With more customers needing to remain plugged in for longer, some of the load diversity is lost during the winter months, leading to this higher load. This seasonal phenomenon is reflected in our system-wide load forecasts as well.

Customer sited energy storage require special attention since they export to the grid as a virtual power plant, harnessing their collective power to reduce systemwide peaks. By functioning at the same time, there is not load diversity. This can be detrimental if the dispatch is not choreographed in a way that supports this system. GMP's current dispatch strategy is to reduce both the Vermont transmission peaks as well as the annual ISO Capacity peak. Additionally, GMP dispatches customer storage to provide ISO New England with frequency regulation services producing further benefit to all customers. In the future, energy storage on individual circuits could be dispatched as solar soakers, to reduce local peaks, and to regulate voltage at far ends of lines. Beyond this use case, distributed battery energy storage systems (BESS) is a powerful tool to curb local overloads on distribution and subtransmission, if appropriately coordinated systemwide. GMP will be including some of these additional value streams in upcoming storage program reviews such as the upcoming ZOI storage tariff filing.

Using historical data is helpful in that we can see current trends in the load patterns of EVs, heat pumps, and energy storage. Having a strong understanding of how weather and customer usage affects loads is essential to planning a reliable system in the future. That being said, EV and heat pump loads are very dependent on external factors such as weather and individual driver patterns. Our historical deployment of energy storage aims to minimize peaks that are occurring in real time, and the peaks from 2023 likely do not line up with peaks in 2035. Therefore, feeder-level, hourly forecasts should be considered as a worst-case, uncoordinated picture of what loads could look like in the future. GMP occasionally has fielded initial requests from large loads like data centers seeking interconnection, although we have yet to see any of these requests move beyond the exploratory phase and do not expect any to materialize with any significant size during the three-year window of this IRP cycle.

Today GMP runs a distribution system where TOU rates, energy storage, and flexible load programs all coordinate to limit peaks and improve the efficient utilization of the energy system through local load reduction leading to lower losses on the T&D system. GMP expects the level of coordination to increase as more DERs come online and our controls become more advanced and thorough.

Load Cases

Forecast Periods: 5 Years and 10 Years

For the 2024 IRP, GMP studied scenarios based in the years 2030 and 2035. Past 2035, load growth is forecasted to be minimal when compared to the growth that is expected to occur from electrification in the late 2020s and early 2030s. Due to the nature of the load growth, we capture most of the thermal and voltage violations that are likely to occur by studying 2035.

Since we are modeling loads and DG down to the substation and feeder levels, we require spatially and temporally granular forecasting which is difficult to develop with confidence. While it is relatively straightforward to conduct a bulk transmission study for confidently capturing load growth patterns across a 20-year horizon, a study of the distribution system is challenging, because it cannot accurately predict when and where load growth might occur on a feeder.

Our studies of hosting capacity, peak load, and storage optimization have offered insights about the regions we must examine as load growth materializes. As load growth ramps up, we will have better information to extend our assumptions to longer time horizons. **Figure 3-6** shows the expected statewide peak load growth and trajectory through 2043.

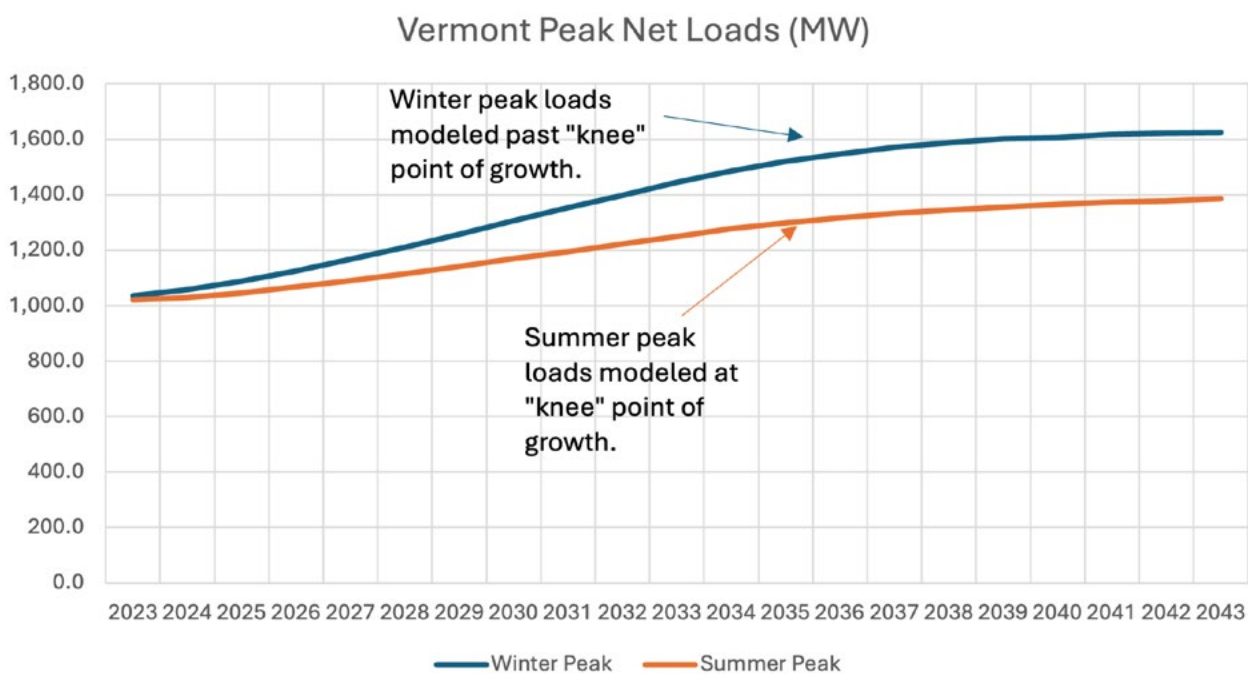


Figure 3-6. Vermont statewide peak net loads, forecasted to 2043.

Distributed Generation Forecasts

GMP's distributed generation resources involve rooftop solar, utility scale solar, biomass generators, wind, and hydro. As of the 2030s, solar development will likely be the main contributor to meeting our portion of the 20 percent Tier II RES goals. Solar development over the past 10 years has been relatively unconstrained. Some of the larger projects will require line reconductoring and substation upgrades, whereas small, rooftop projects typically will need only a transformer and/or a service upgrade. This in turn informs the procurement strategies specific to electric system location as we meet RES goals.

GMP forecasted the "natural" growth of net-metered solar smaller than 25 kW, based on each substation's current share of these small projects. Historically, this has accounted for about 10 MW of small projects per year. GMP has made some conservative assumptions about being able to capture the unconstrained growth of these projects from homeowners in the future. We also included larger projects that are currently in our interconnection queue; we expect these projects to interconnect in the next few years.

Altogether, we project in 2035 there will be approximately 580 MW of interconnected solar due to natural growth of small-scale projects and existing projects in the queue. **Table 3-4** shows the locations of such projects.

Zone	Total existing solar	Forecasted solar (net-metered and utility-scale)
Ascutney	25.1	6.0
Burlington	82.7	25.7
Central	51.7	20.2
Florence	0.4	0.2
Johnson	0.6	0.4
Middlebury	41.5	5.9
Montpelier	35.2	24.3
Morrisville	5.0	2.9
Rutland	64.6	28.5
Southern	55.2	25.8
St. Albans	38.4	24.9
St. Johnsbury	15.2	3.4
Total	**415.5**	**168.1**

Table 3-4. GMP expectations for future contributions from solar projects in the next 20 years, in MW.

GMP estimates a need for an additional 250 MW beyond this forecasted amount to meet Tier II goals. The following hosting capacity analysis (see section below, **The Long View on Changing Loadshapes, Systemwide**) determined an optimized distribution of solar to exceed the Tier II goals, and an unoptimized (but more realistic) distribution that would have us reaching State goals, while minimizing transmission impacts and continuing to allow some development in constrained regions.

The Role of FERC Orders on GMP's Forecasting

An additional constraint that could delay Vermont's procurement of solar for the RES is FERC Order 2023. This order streamlines the interconnection of generation by implementing cluster studies, rather than one-time studies for each individual project. It also requires developers to have land control before their projects are studied, to reduce the drop-out rate of interconnection queues. This was mainly meant to streamline studies in regions where many DG projects apply in the same period, such as in Massachusetts and Maine. Vermont has not so far seen the amount of interconnection requests that make cluster studies more efficient compared to individual system impact studies.

ISO New England revised its Planning Procedure No. 5-6 (PP5-6), which will comply with FERC Order 2023. It outlines a procedure for studying solar projects between one and five megawatts in clusters, once a region meets a 20-MW threshold. These studies require PSCAD simulations, which model each inverter to see if there would be loss of generation in the event of a transmission fault. **Figure 3-7** shows ISO New England's project timeline for compliance with FERC Order 2023 and the coordination of ASO and FERC Cluster Studies.

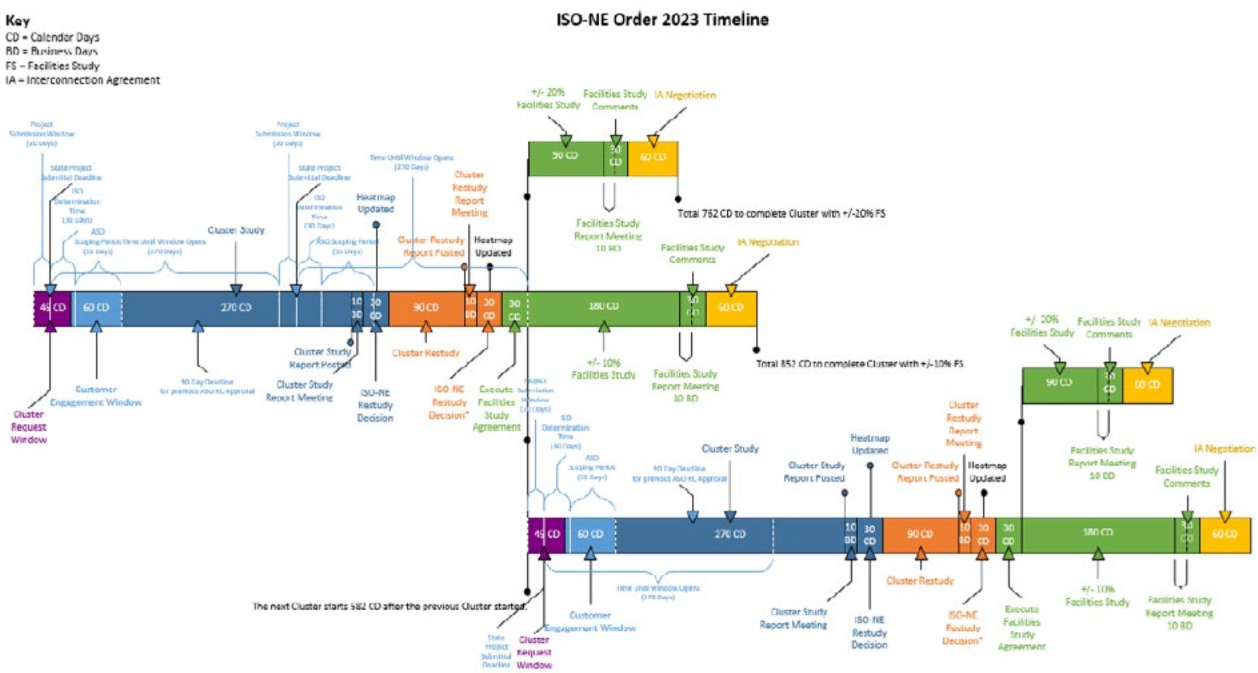


Figure 3-7. ISO New England's timeline for studies, decisions, agreements, and negotiations sufficient to meet FERC Order 2023.

Level 3 ASO transmission cluster studies are expensive and could make some solar projects infeasible. It could also lead to interconnection delays and complicate the timing for reaching Tier II goals, however, most projects will remain with just the Vermont interconnection process under PUC Rule 5.500 with no additional delays due to this process.

GMP is beginning its first Level 3 ASO Cluster Study at the time of filing this IRP and will be working closely with VELCO to define the way these new studies are performed. We anticipate finding efficiencies during this first iteration that will streamline future cluster studies and reduce costs. The zones in which the 20 MW aggregation limit is applied are still being determined by VELCO and ISO as their definitions of these zones are refined. We expect to learn more about the criteria that trigger cluster studies and how they are scoped in the coming months.

The Long View on Changing Load Shapes, Systemwide

The loads that GMP expects, and hopes, to see in the next 10 years will change in ways not seen for decades. We are planning for unprecedented load growth, but the largest contributor to this load growth, EV charging, is also one of the most flexible. Likewise, Vermont will need solar amounts in addition to what we have interconnected today to meet State requirements for renewable generation. However, we are increasingly able to shift generation to different hours of the day through distributed storage. Understanding what we face without conventional management is necessary as we continue to design programs to manage load and generation.

Hosting Capacity Analysis

GMP analyzed hosting capacity across several rounds, with each subsequent round introducing a new constraint to the system. We began by looking only at substation power transformer capacity, then redistributing solar to determine each region's export limit, and finally by considering all N-1 contingencies on the bulk and subtransmission to find a systemwide hosting capacity. This study was performed using the same planning criteria as VELCO's hosting capacity analysis in the 2024 LRP and includes all of the same bulk transmission limitations identified in the 2024 LRP. Our hosting capacity study left us with an optimized, total hosting capacity for solar on the GMP system without requiring subtransmission or bulk transmission upgrades.

During the process of optimizing hosting capacity, the reliability dispatch algorithm initially closed the Burlington and Middlebury zones to further solar development beyond our net-meter forecasts. The total hosting capacity with this most-optimized approach was 962 MW. However, we do not think that this is an accurate representation of how solar will be developed in the future due to historical development of larger projects in these areas, so we reserved some capacity in these zones and reran the dispatch algorithm to hold the Burlington and Middlebury zones constant with additional headroom. We found a new optimized total hosting capacity of 957.3 MW, or 4.4 MW below the truly optimized capacity. The results are shown in **Table 3-5.**

Zone	Total existing solar	Total forecasted solar (net-metered and utility-scale)	Additional hosting capacity	Total optimized solar hosting capacity (interconnected + forecasted + optimized)
Ascutney	25.1	6.0	55.2	**86.2**
Burlington	82.7	25.7	8.8	**117.2**
Central	51.7	20.2	21.2	**93.1**
Florence	0.4	0.2	0	**0.6**
Johnson	0.6	0.4	0	**0.9**
Middlebury	41.5	5.9	11	**58.5**
Montpelier	35.2	24.3	4.2	**63.6**
Morrisville	5.0	2.9	0	**7.9**
Rutland	64.6	28.5	80.5	**173.7**
Southern	55.2	25.8	192.8	**273.7**
St. Albans	38.4	24.9	0	**63.3**
St. Johnsbury	15.2	3.4	0	**18.7**
Total	**415.5**	**168.1**	**373.7**	**957.3**

Table 3-5. GMP results of its optimized solar hosting capacity analysis, in MW, by zone.

This table show the following:

- We can support approximately 950 MW of interconnected solar without requiring transmission or substation power transformer upgrades if care is taken to site solar in optimized locations, while taking T&D constraints into account. Based on our power supply planning, we need a total of about 835 MW to achieve our Tier II requirements. This is roughly an additional 350 MW of DG above where we are as of the end of 2024.

- Based on sensitivity analysis of the impact of other resources, such as SHEI and the flows on the Granite Phase-Angle-Regulators (PARs), we note that reducing flow on SHEI and adjusting the Granite PARs to reduce west to east transfer will restore some additional capacity in these four zones.
- There are sub-areas supplied by 34.5 kV or 46 kV lines. The loss of one end of these lines forces all of the generation to export from the other end of the loop, which can limit the amount of generation added in these sub-areas.

Additional distributed or utility scale storage can be used to reduce exports that distribution substation transformers and the transmission system see, increasing hosting capacity on the GMP system. All storage on the GMP system has multiple use cases, and depending on location and amount of installed storage, GMP could use customer sited distributed storage to reduce exports or partner with utility scale “solar soaking” energy storage whose operational philosophy would be to charge during solar hours and discharge in the evenings.

Figures 3-8 and 3-9 visualize how solar in Vermont could be distributed, to minimize upgrade costs.

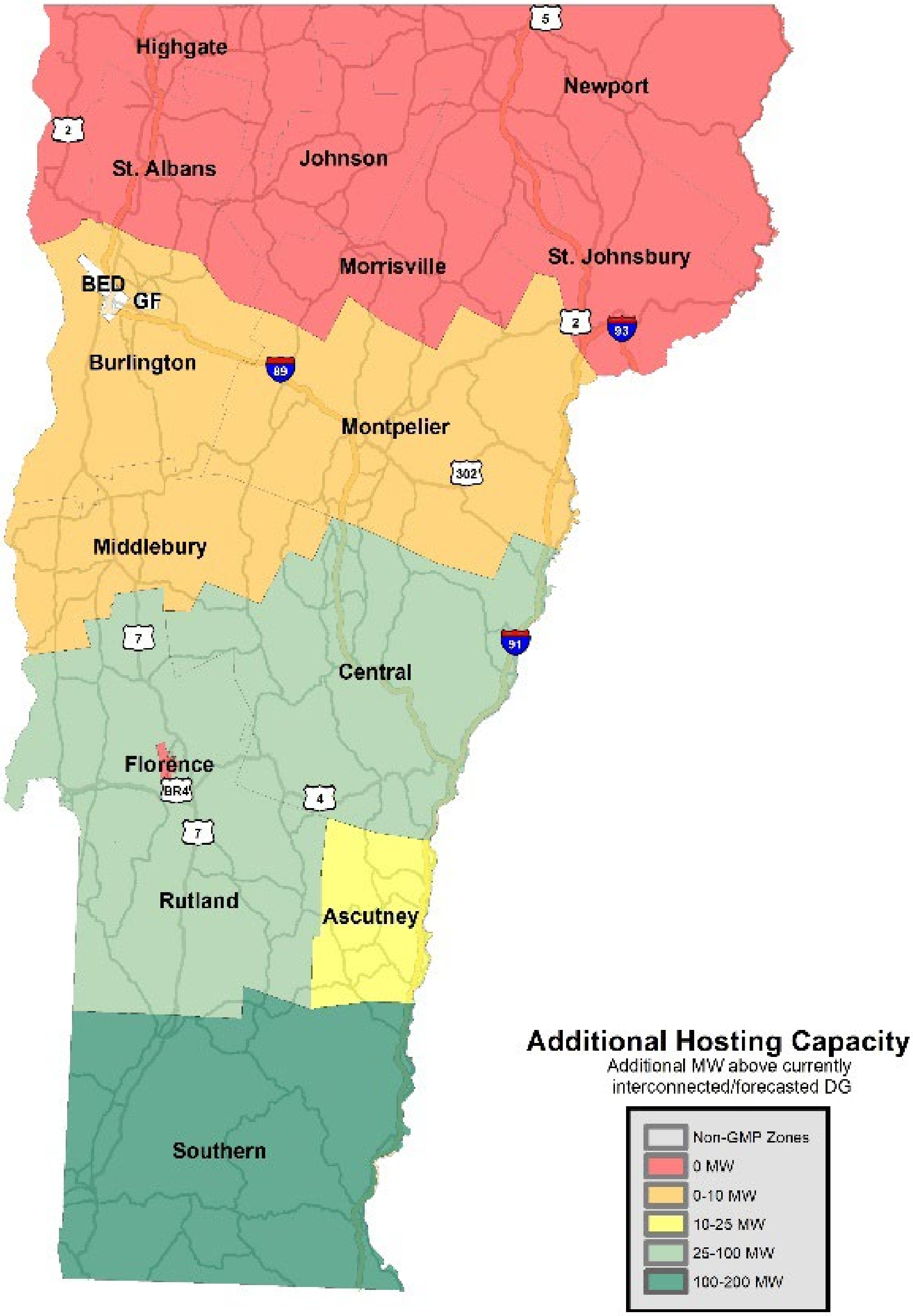


Figure 3-8. Additional hosting capacity beyond forecasted and projected solar growth, according to GMP's hosting capacity analyses.

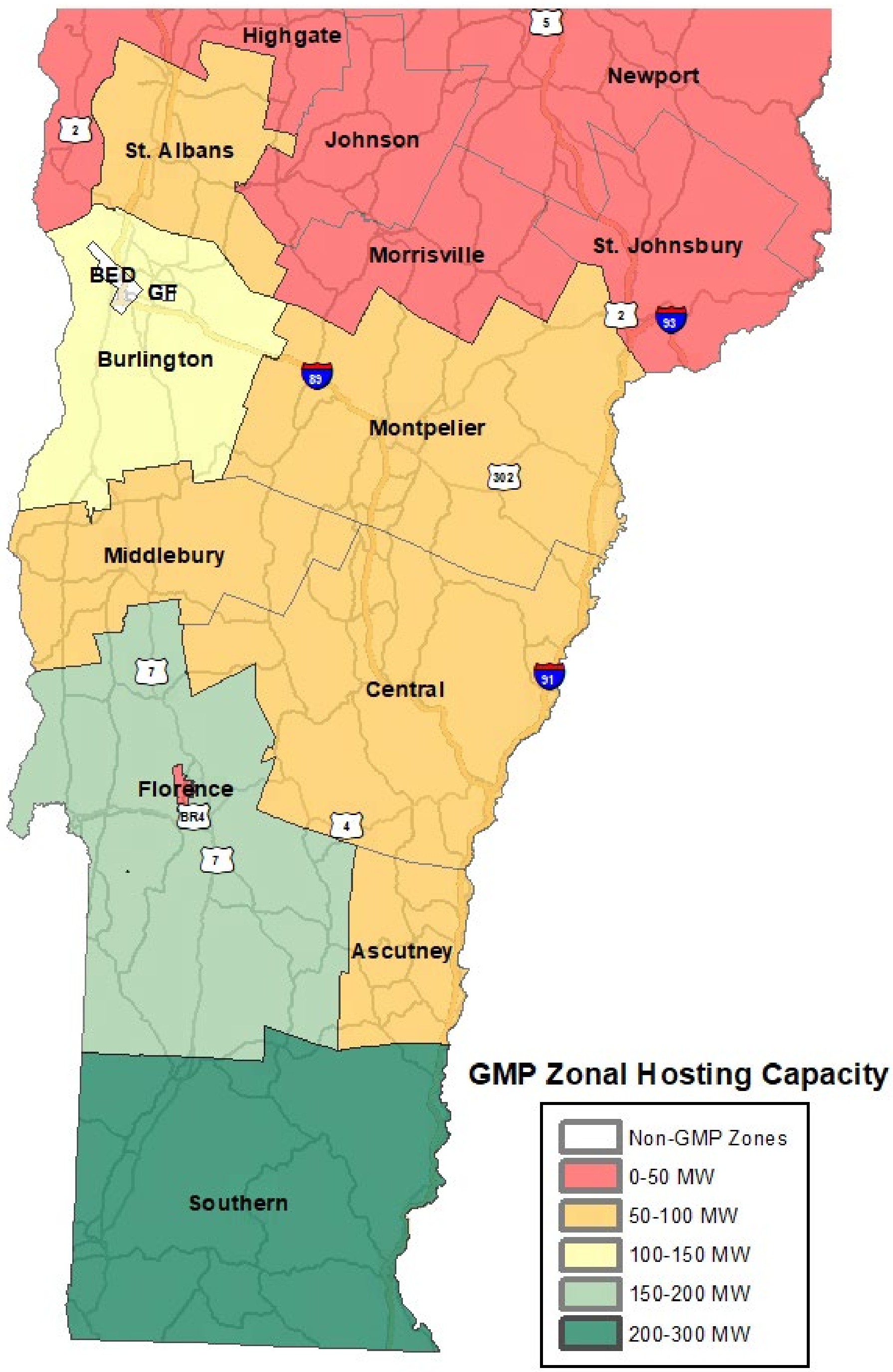


Figure 3-9. Zonal distribution results for solar, from GMP's hosting capacity analyses.

The results of our subtransmission hosting capacity analysis show that if solar development were guided toward the Rutland, Southern, and Central regions of Vermont shown in the maps above, it would minimize subtransmission and transmission upgrade costs. GMP is considering several tools such as RFPs, the GMP solar map, PPAs, the 5.500 interconnection process, locational pricing adjustors and associated studies to help guide solar into unconstrained areas while also meeting Tier II obligations.

The revised ISO PP5-6, which complies with FERC Order 2023, will also require additional studies in areas that are saturated with one megawatt or larger solar projects. As of September 2024, one ASO cluster study has been triggered in the Essex area, including some proposed projects in the Bristol area. Although GMP has not facilitated Level 3 transmission studies in the past, we understand these in-depth stability studies required by FERC will have added cost paid for by the generation developers. It is possible that the requirement of costly transmission studies will naturally guide developers toward regions where they are not close to the regional threshold—such as in the southern parts of the state.

When GMP provides a forward curve on the anticipated PPA pricing for larger scale solar projects, this includes the cost of interconnection. If an increase in interconnection costs beyond those assumptions occurs through the study process, it does not necessarily translate one for one to an increased PPA price, and in fact solar developers may need to absorb some or all the increased costs depending on the negotiated terms of the PPA price. Storage can also help alleviate these costs, as storage paired with solar could both reduce the total cost of interconnection and increase the hosting capacity of a circuit while still providing a host of other values discussed throughout this chapter. This could be looked at as an alternative to a portion of the cost to interconnect the project, and could provide many more benefits to the local system.

Other regional developments, such as decreases in Hydro-Québec (HQ) imports and changes to our interfaces with New York ISO and the rest of ISO New England, could affect how much and where solar can be developed. A scenario in which HQ reduces imports through Highgate could increase hosting capacity in northern Vermont, although this could provide some challenges for our broader power supply portfolio. Through the VSPC and relationships with neighboring entities, GMP is closely monitoring any changes in grid topology and imports that could change the landscape of solar hosting capacity.

For instance, the VELCO and Grid United *Alliance Transmission Exchange*, presented at the July 2024 VSPC meeting, could create new opportunities for larger renewable projects to come online in the northern Vermont region and address some of the SHEI. Changes in the output of large generators like McNeil could also increase hosting capacity in the northern region of Vermont.

Our takeaway from the solar hosting capacity study is that GMP can reach its Tier II goals without large transmission upgrades if we are strategic about where new generators interconnect on our system and also focus on storage. We will continue to monitor where solar gets interconnected as well as regional developments that could unlock hosting capacity or further constrain renewable development.

Peak Load Studies

GMP performed a full N-1 contingency analysis on its subtransmission using standard contingencies on both the bulk and subtransmission to assess the subtransmission system's ability to operate reliably at peak loads in the next 10 years. When looking at solutions for issues on our subtransmission, we applied a probability and reliability equal slope criterion. This criterion aims to gain most of the benefits of full N-1 reliability while reducing the costs by considering the probability of an event at a critical load level. We evaluated a 2024 operating case as our base case, and 2030 and 2035 summer/winter peaks and light-load/high-DG cases.

Our 2024 base case is a conservative case, placing the total Vermont summer peak load at roughly 1,028 MW. The last time that Vermont saw this level of loading was in the summer of 2013. The load growth that Vermont is expecting in the future due to electrification needs to be considered in the context of our actual loads lagging behind conservative forecasts for growth.

Figure 3-10 shows **actual** winter and summer peak loads in Vermont, from 1980 to 2024.

N-1 Results

GMP found thermal and low/high-voltage violations in peak import/export scenarios. Many of the worst overloads were existing constraints on our subtransmission system and were impacted by electrification or high amounts of DG on the system. GMP did not find any thermal violations for all-lines-in conditions in the next 10 years. **Table 3-6** lists contingency violations that could be potential reliability issues in the next 10 years without load management. With EV charging management we can eliminate a couple of these violations and reduce the depth of others.

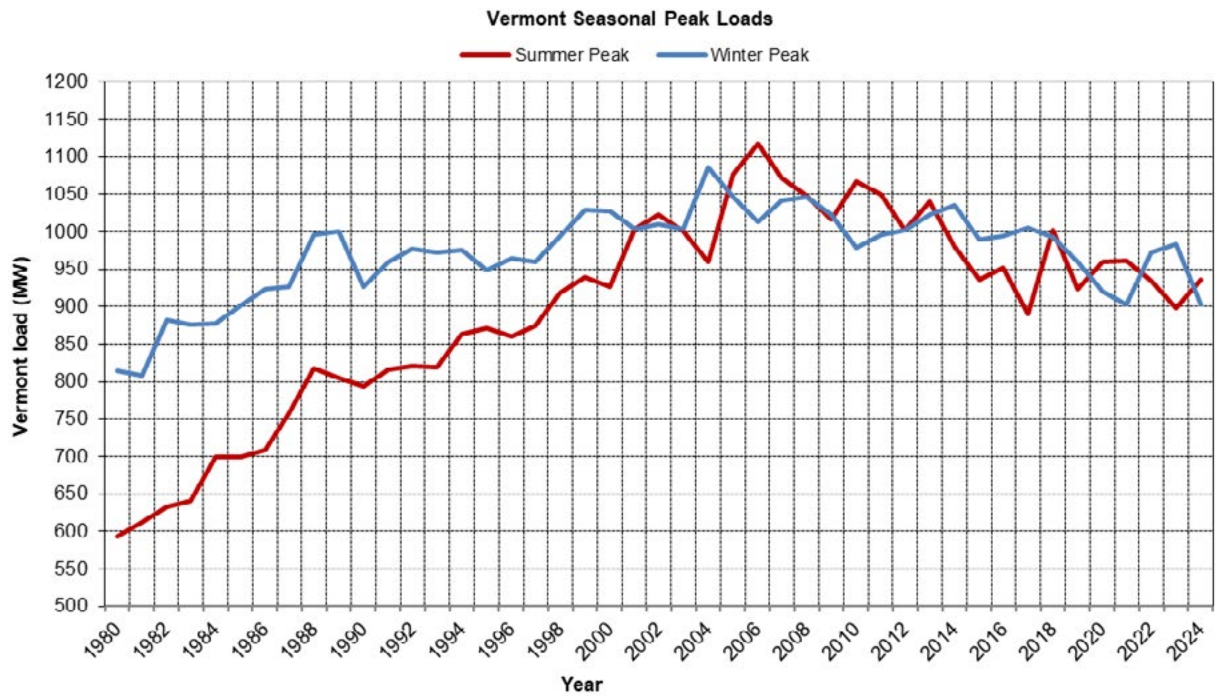


Figure 3-10. Historical metered peak loads for all of Vermont, from 1980 to 2024.

Transmission Element	Worst Contingency
Windsor Area	Transformer
Highbridge-Ascutney	Subtransmission Open End
Middlesex-Bolton	Subtransmission Open End
Blissville Area	Transformer
Marshfield- Danville	Subtransmission Open End
Barre – South End	Subtransmission Open End
Montpelier - West Berlin	Subtransmission Open End
Middlesex – Moretown	Subtransmission Open End

Table 3-6. Contingency violations exacerbated by electrification or additional DG during their most critical single contingencies, in no particular order.

We expect certain regions of GMP's subtransmission system to become more heavily loaded as demand changes in the next 10 years. The contingencies that carry the greatest impacts are when a normally networked area opens on a single end, causing all this region's load to be fed radially. These contingencies are rare. However, regions where this possibility exists are along the Interstate 89 corridor, in the Montpelier area, and in Southern Vermont.

When looking for solutions for these potential violations, GMP estimates that without any load control or energy storage dispatch in 2035, over 120 miles of subtransmission lines would have to be reconductored to achieve full N-1 reliability on the subtransmission system. Reconductoring would likely resolve some voltage violations under N-1 criteria, but additional reactive support and substation upgrades would likely be needed in some areas to provide complete solutions. Therefore, GMP expects that the traditional wires solution to N-1 overloads due to load growth to exceed $120M for thermal violations alone, with additional costs needed for some voltage violations. The cost of these solutions would require specific study, likely greatly inflating this $120M figure by tens of millions of dollars.

Since the nature of these new overloads is due to load growth of highly manageable loads, there are promising non-wires alternatives to help resolve any thermal and voltage violations at peak hours. Using flexible rates like the ones GMP offers customers to shift EV charging away from peak hours would immediately reduce the demand we have modeled in this study. For additional relief beyond load management, the dispatch of distributed storage such as Powerwalls and customer-owned devices, and utility scale storage, would provide enough time for the load cycle to complete and demand to drop. We explore this use of storage in **Optimizing Storage,** below.

Representative Feeder Studies

In addition to studying our subtransmission system, we also modeled and studied 10 representative distribution feeders over the course of a year in 2035:

1) Bay Street G4 (Bay-G4)
2) Castleton G37 (CA-G37)
3) Pleasant Street G43 (PS-G43)
4) Queen City 32G8 (32G8)
5) Sand Hill Road 33G2 (33G2)
6) Sharon G35 (SH-G35)
7) South Shaftsbury G20 (SF-G20)
8) Vergennes 9G4 (9G4)
9) West Milton G92 (WM-G92)
10) Windsor G31 (WI-G31)

These feeders offer a snapshot of the GMP system: from the suburban and commercial areas in South Burlington and Williston, rural areas in St. Johnsbury and Windsor, and regions with high amounts of DG, like Vergennes.

We checked for overloads on main three-phase lines and substation equipment to understand how much and for how long these items will be affected in the future. **Table 3-7** shows the results.

Feeder	**2024**			**2035**
	Maximum %	**Maximum % date and time**	**% time over**	**% time over**
Bay-G4	67.7%	5/14 13:45	0.0%	2.5%
CA-G37	53.6%	5/14 15:00	0.0%	0.1%
PS-G43	33.1%	1/15 17:30	0.0%	0.2%
32G8	49.9%	9/7 13:30	0.0%	0.0%
33G2	39.0%	9/6 20:00	0.0%	0.1%
SH-G35	87.8%	5/13 12:15	0.0%	1.8%
SF-G20	68.7%	7/27 12:00	0.0%	5.6%
9G4	74.9%	10/9 12:30	0.0%	0.4%
WM-G92	80.1%	7/6 20:15	0.0%	3.5%
WI-G31	87.2%	9/7 19:30	0.0%	15.8%

Table 3-7. GMP's 10 studied feeders and their estimated overloads.

Although we saw some overloads on high-cost items, these results are generally quite promising. We assumed that each house would have an uncontrolled Level 2 EV charger and a heat pump, and that 25 percent of houses on any circuit would have a Powerwall. These assumptions are more conservative than the loads we used for our subtransmission study, to try to stress-test individual feeders and discover any patterns that might emerge as electrification increases.

Even with these conservative assumptions, most substations saw overloads for less than one percent of the year. Substations that overload more than one percent tended to have smaller transformers and voltage regulators and are more heavily loaded today. Since overloads are minimal in most cases, flexible load management at peak hours is a reasonable option that would help both the distribution and subtransmission systems.

Although we did not examine service conductor loading and individual distribution transformers, we expect these would have to be upgraded for some customers who are fed off smaller transformers. GMP reviews transformer capacity and service conductor loading before customers interconnect new equipment such as Powerwalls and/or solar and monitor this today through AMI tools.

Innovation for Customers: Powerwalls and EV Management

Distributed Storage

As detailed in GMP's last several IRPs, in addition to EVs, energy storage is the ultimate, flexible tool for the energy system. And the values generated from storage for customers are only growing. This became even more clear in recent ISO and VELCO studies. ISO New England performed a transmission study that looked at system growth through 2050. A key takeaway was that reducing peak demand by 10 percent by 2050 could result in $10 billion in lower costs. VELCO's LRTP shows that with 80 MW of flexible load and storage in northwest Vermont alone, we could defer or even eliminate the need for $381 million of transmission buildout. Looking at the whole system, roughly 250 MW of storage in 2035 across the state could eliminate the need for over $600 million of transmission upgrades.

GMP has deployed distributed storage in a way that produces net benefits for all GMP customers, while using only the value derived from capacity and transmission peak demand reduction as well as harvesting the Investment Tax Credit for customers. We will begin incorporating these additional deferral benefits into the valuation of deployed storage as well as flexible loads. Since T&D deferral costs differ between locations and the nature of the grid limitation, the value of storage as a deferral will depend on the cost of the traditional T&D solution storage would defer. This is all before the addition of the derived value of resilience when these systems are located at the customer premises or as part of a microgrid. GMP will be evaluating an approach similar to the T&D deferral benefit that is attributed to electric efficiency whereby every kW of efficiency reduction includes some portion of value assumption for reduced future T&D needs.

GMP's Virtual Power Plant and innovative use of customer-sited energy storage and distributed grid storage has transformed power flow on the grid. In addition to resiliency during storms, storage acts as a load when solar is generating, helping voltage and thermal issues on the distribution. It also is a generator and load reducer when customer load is high.

As seen in this sample Powerwall dispatch event in September 2024, GMP's virtual power plant of energy storage systems functions as a block load of over 30 MW to help reduce system peaks and save customers money for RNS peak rates. With a fleet of storage on each circuit, GMP can reduce local peaks affecting substation transformer and equipment while also reducing power flow on the subtransmission system; it can also reduce the risk of an overload, should a critical contingency occur. **Figure 3-11** shows the load effects of energy storage, grid, and solar real power across a three-day span in September.

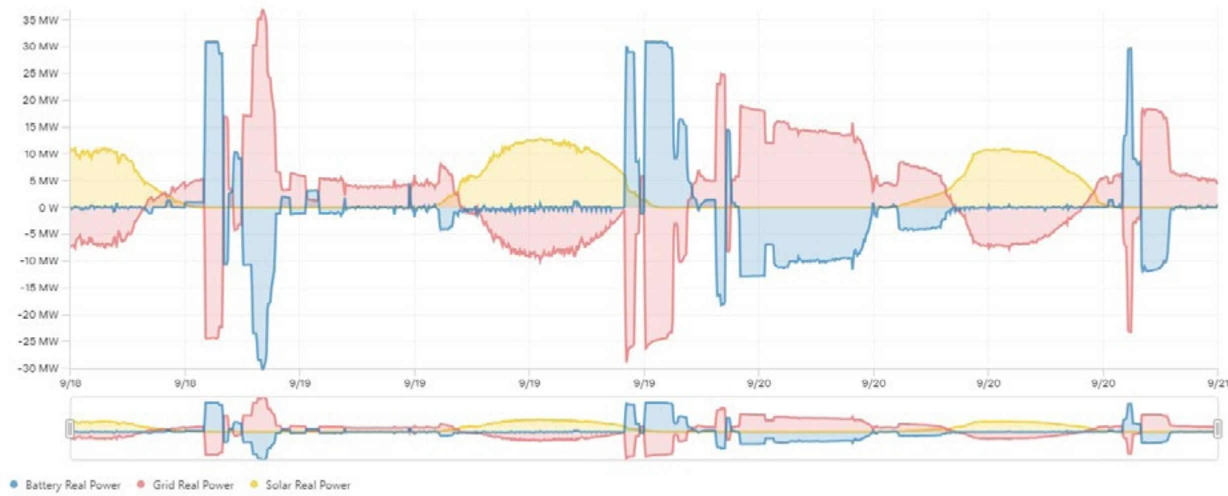


Figure 3-11. Load effects from battery real power (in blue), grid real power (in pink), and solar real power (in yellow), across a three-day span in Vermont, in MW.

VELCO's LRTP posits that without controls in place, the grid in Vermont will face two challenges per day: (1) too much solar production during the day and (2) too much load in the morning/evening. However, with smart storage, flexible loads and the right programs, GMP can shift some load to the daytime to offset solar production and to reduce peak load burdens in the evenings, work that GMP is already doing.

Also, GMP is forecasting that there will be anywhere from 100–250 MW of customer-sited storage interconnected on our system by 2035. **Chapter 2** discusses our forecasts for distributed storage for the next 20 years. This amount of storage, if located in the correct areas, would be a tremendous tool to strengthen the grid.

EV Charging Management

Innovative and easy to use customer friendly time-of-use rates are helping to reduce peak loads on the system. As we covered in **Chapter 2**, GMP estimates that 65% of new EV drivers in GMP territory are enrolled in either Rate 72 or Rate 74. Load curtailment events for chargers in these programs have opt-in rates above 90%. When considering public chargers, GMP forecasts we will be able to reduce EV loads at peak hours on our system by 50%.

We further explore the impact that a 50% EV load reduction at peak hours could have on reliability questions on our subtransmission system in **Managing Overloads from Added Beneficial Electrification** below. Ensuring the continued adoption of managed EV charging programs, as well as refining dispatch events, rebound peaks, and coordination with storage and other FLM programs will be an important focus of GMP's planning efforts in this IRP period.

Innovations Ahead: BESS, DERMS, Other Strategies to Manage the Sequence and Types of Needed Upgrades

As the grid becomes more flexible and intermittent as more DERs interconnect, GMP wwill continue to look for new ways to manage and coordinate these assets. We are currently exploring the Schweitzer Engineering Labs (SEL) Blueframe product, a Fault, Location, Isolation, and Service Restoration (FLISR) platform for automating resources at the feeder level. This is in addition to the DER control platforms we currently have in place and where we envision adding in a top-level platform that can optimize all resources together and communicate out to the DER dispatch tools that we currently operate, as discussed in **Chapter 1**.

Through expansion of existing successful programs GMP can mitigate many traditional system upgrades expected from electrification and widespread DG.

Optimizing Storage

How Storage Can Increase Hosting Capacity and Meet RES Goals

GMP conducted an 8760 Analysis using PowerGem's TARA PROBE production cost modeling tool to evaluate the energy performance and curtailment of solar projects at each bus, to increase hosting capacity. We studied our system with 832 MW of solar interconnected. This is a level slightly below the maximum optimized hosting capacity of our system, but the level achieves the 20 percent Tier II RES goal. We chose to test the system at this level, because it is the system's likely level in 2032 when Tier II requirements need to be met.

This analysis is similar to the optimized hosting capacity study as we are ensuring reliability of the bulk and subtransmission systems under N-1 contingencies. However, this 8760 analysis also simulates ISO New England's market rules and processes and uses a proprietary load curve based off the 2024 CELT Report. Since this simulates the Day-Ahead and Real-Time Markets and effects of transmission congestion, assumptions such as load levels, generator dispatches, and inter-area flows might be different from the assumptions that we made in the hosting capacity study. These differences lead to an opportunity to study and use storage in saturated areas to reduce the possibility of curtailment of solar projects.

The amount of curtailed solar generation from this study is shown in **Table 3-8.**

Zone	Dispatch (MWh)	Total Curtailment (MWh)	Max. Curtailment (MW)
Burlington	18,037.66	-	-
Montpelier	6,706.56	1,902.32	4.20
Middlebury	22,187.49	359.59	6.86
Rutland	83,908.50	18,578.19	48.01
Ascutney	70,091.67	9.23	5.36
Southern	216,646.36	28,091.87	66.78

Table 3-8. The estimated role of solar projects in curtailment events, assuming 832 MW of interconnected solar, by zone.

With this distribution of 832 MW of solar, we found that the Rutland and Southern Zones needed more curtailment than other regions, to ensure a secure system for customers.

Taking a closer look at the buses that require the most curtailment, we can see that a 5 MW/25 MWh battery at these substations would be enough to reduce curtailment and possibly make solar projects in constrained locations more attractive to developers, as shown in **Table 3-9**. This size is very reasonable to build and more valuable than shorter-duration energy storage. With a 5-hour battery, we get closer to being able to store and shift an entire load cycle which creates the most benefit for customers.

Bus	**Maximum curtailment (MW)**	**Maximum daily curtailment (MWh)**
Dorset	2.2	23.4
Poultney	0.7	7.4
Lalor Avenue	8.1	77.7
West Rutland	3.5	35.0
Londonderry	3.6	22.1
Rawsonville	3.7	28.0

Table 3-9. Modeled number of hours of curtailed energy demand and consumption, by bus.

GMP has storage projects in the interconnection queue that would use a solar soaker operational philosophy—whereby the developer uses the power its solar equipment produces—to charge during solar hours and discharge in the evening. This makes it possible for the customer to act as a peak reducer for exports in the day and load during the evening. This essentially turns a solar plant into a fixed, dispatchable resource similar to a fossil-fired peaker facility.

When the need arises to solve a problem, the solutions will be reviewed in their actual context to determine which is appropriate and most cost-effective for customers for the given circumstance.

Managing Overloads from Added Beneficial Electrification

As noted above, GMP estimates that traditional upgrades (reconductoring, etc.) would cost over $120M to ensure full N-1 reliability of our subtransmission in 2035 without

any load control or storage. Fortunately, our system today has thousands of customers enrolled in FLM programs and tens of MWs of distributed storage that we can dispatch to manage peak loads. We currently use and will continue to use a combination of EV management, storage, and other flexible loads to help mitigate the need for expensive traditional transmission upgrades. Using storage as a load reducer at peak hours is a great non-wires alternative to traditional upgrades like reconductoring or building new lines. The decision to defer line equipment upgrades with storage depends on an alternatives analysis and factors like location, load growth, type of customer in the region, asset condition, etc. Each T&D upgrade requires specific understanding of the context of the challenge at hand and study to ensure the best solution is implemented.

GMP also recognizes that managing EV charging loads is important for managing a changing grid. To capture this, we ran the same contingency analysis at an assumed 50 percent EV charging load. This is still a conservative assumption, since our Rate 72 program can effectively reduce charging loads to 0 kW across customers enrolled in this rate. Rate 74 has a similar effect during peak hours.

Using the results from our peak load contingency analysis, we looked at the single worst contingency for each section of overloaded lines and determined how much load reduction would be needed to resolve thermal overloads.

The following capacities **(Table 3-10)** would be needed in each region to alleviate overloads on the subtransmission during critical N-1 constraints.

Zone	MVA reduction before EV curtailment	MVA reduction after 50% EV curtailment
Ascutney	9.9	6.7
Burlington	21.2	7.11
Florence	6.3	6.0
Middlebury	10.9	9.1
Montpelier	81.4	48.6
Rutland	9.5	5.3
St. Albans	9.6	7.1
Total	**148.8**	**99.9**

Table 3-10. Megavolt-amp (MVA) reduction capacities, with and without a 50% curtailment from EV charging, by zone

In the column showing MVA reduction after a 50 percent EV curtailment, we see that we would need nearly 100 MW of installed storage capacity ready to discharge, to avoid all possible N-1 overloads. For each contingency, this equates to 1 MW to 16 MW of storage across the length of a line. For one potential violation in the Burlington area, for example, this would mean a 4.2 MW reduction across four substations—a very reasonable amount of storage for that area. And in many cases, the natural deployment of customer-sited energy storage could produce the needed amounts discussed here.

The Montpelier area could require higher amounts of storage in this analysis due to the topology of the subtransmission in this region and the existence of a few contingencies that make it hard to secure full N-1 reliability. We found that we would need nearly 50 MW of load reduction across this area to achieve full N-1 reliability, however today the system is not designed to this criterion and to maintain the same degree of reliability in the future would likely require far less than 50 MW of load reduction. GMP also has substation projects in the next five years lined up to reduce the impact and likelihood of certain contingencies by adding transmission circuit breakers in the middle of long transmission lines.

If GMP were to curtail EV charging at peak hours by more than 50 percent, the amount of required storage would drop even further at peak hours. Today, GMP can dispatch about 70 MWs of energy storage and flexible resources to reduce peaks. In the next 10 years, the size of this virtual power plant will increase and grow to around 250 MW potentially in which the combination of EV curtailment and energy storage dispatch can reduce the need for transmission upgrades. As Vermont engages in more non-transmission alternatives (NTA) analyses, the real value of avoiding large-scale transmission upgrades should be considered when assessing the role of storage on the grid.

As load growth increases beyond 2035 levels, more flexible resources will be needed to effectively manage peak demand. With increasing peak demands, system loads will spend more time near the operating limits of transmission lines. This means solutions like longer-term storage (6+ hours) and daytime EV charging will become important over time. This all has the added benefit of making the overall energy delivery system more efficiently utilized, meaning we fill in the low load times and clip off the peak load times.

Costs and Benefits of Storage Compared to Traditional Upgrades, FLM, and Curtailment

When considering whether storage is a preferred solution to load growth related reliability violations over traditional wires solutions, GMP will conduct an alternatives analysis that considers factors such as the cost of each solution; the robustness of storage as a solution (in other words, how long can storage defer upgrades for); condition of existing assets; additional revenue streams for storage; and ability for storage to increase hosting capacity in the area. Each situation is unique and requires individual review.

Through our storage optimization study, GMP has begun to identify what potential curtailment profiles could look like in congested regions of our subtransmission system. As more of our system becomes loaded with solar PV, we will assess whether overloads on substation or subtransmission elements are likely and how often (is it expected a few times a year, or every day where solar production is high). Like load growth, the choice of using storage to increase hosting capacity will depend on where in the system the overloads are, existing and proposed DG, cost of traditional upgrades, duration/length of curtailment, potential load growth issues, and how/where solar is actually developed in the future. GMP will consider all of these factors when weighing curtailment compared to deploying storage.

4

TECHNOLOGY & SECURITY

Overview

GMP is committed to providing innovative energy services to customers and increasingly this is enabled and supported by information technology (IT) and operations technology (OT), transforming our work to that of a technology company. That work is constantly evolving to meet the ever-changing threat environment, both for cybersecurity and for energy security in the operation of GMP facilities, systems, and customer programs. GMP has a deep-rooted safety culture that includes both physical safety for customers and employees and cybersecurity safety. Technology is and will remain at the core of serving customers, especially as we manage a growing number of distributed energy resources (DERs) on a bidirectional distribution grid.

As shown throughout this IRP, GMP serves customers by making resiliency and the energy transition affordable, simple, and accessible. We also serve customers by making energy technology work for them in a seamless, straightforward way. Innovations in customer programs that incorporate load management technologies enhance individual customer and community resilience while bolstering GMP's ability to operate the grid for the benefit of all customers. **Chapter 1** describes innovations in customer programs and service technologies.

In its role as a critical infrastructure provider in Vermont, GMP drives technology and security work toward reducing the risk of cyberattack and cybercrime threats, at the same time, it reduces the consequences of any incursion. Energy security in the day-to-day operations of GMP's facilities and the interconnected distribution grid relies on this work to mitigate risks from those cyberattacks, increasingly harmful weather, potential regional grid supply constraints, physical attacks, and other threats. That is why GMP prioritizes system integrity, availability, and usefulness, assuming an increasing-risk environment across all of these areas.

There is great importance in flexibility and for GMP to rapidly deploy technology and security initiatives to respond quickly to uncertain and evolving risks for customers. The regulatory framework supports the goals for these critical investments in energy infrastructure.

Cybersecurity

As the threat landscape expands and becomes ever more complex, GMP continues to advance its physical and logical security measures, expanding perimeter protection, detection, and isolation technologies.

Global cybercrime has put all utilities, including GMP, on defensive alert against ongoing, daily threats. Even without state sponsors, such attacks could impair the operation of

GMP and the grid itself. The threat of serious attacks is real and ongoing, and in response, GMP continuously monitors and meets them head on.

Like any critical infrastructure provider, GMP is a target of attempted cyberattacks. Potential incursions are ubiquitous and require GMP to be ready to respond at all times. To mitigate security risks, we continue to use controls recommended by three risk mitigation and management frameworks:

- The National Institute of Standards and Technology (NIST) Cybersecurity Framework
- The CIS Controls v8 Framework
- The North American Electric Reliability Corporation (NERC) Regulatory Framework (created by the Reliability and Security Technical Committee for our bulk electric system assets)

We also track and comply with specific regulatory standards applicable to our infrastructure, such as through FERC's Division of Dam Safety and Inspections.

GMP's cybersecurity work isolates key systems and deploys alternative system operating methods and continuity, in the event of a compromise. Every GMP employee is trained to detect, recognize, report, and mitigate unexpected or malicious activities. Some of the ways used to continue to protect GMP and its customers are:

- Hardening GMP's SCADA core to isolate it from all other networks and resources
- Using endpoint detection and response (EDR) mechanisms across all computing environments and servers
- Performing ongoing assessment and updates to GMP's operations-wide firewall infrastructure
- Maintaining the Incident Response Plan and team, which involves top-level support from third-party security practitioners and emergency response professionals
- Performing occasional table-top and other exercises to educate teammates and test planning, including with partners, as appropriate
- Communicating and engaging frequently with federal and state law enforcement
- Logging and retaining data for forensics and incident reconstruction across IT and OT environments
- Conducting mandatory monthly security training for all employees designed to hone their "human firewall" skills
- Adopting industry standards as warranted, such as the SANS Institute's CIS 18 Security Framework

- Enhancing GMP security team staffing to build and maintain a 24/7/365 Security Operations Center (SOC)
- Maintaining GMP customer payment process architecture to ensure PCI compliance and keeping appropriate segregated systems and access in place to protect customer data
- Regular auditing and penetration testing of deployed security controls

The increasingly connected grid heightens the importance of cybersecurity. More and more customers are connecting some form of DER to the grid, such as controllable heat pumps, EV chargers, or residential energy storage systems in their homes. Continuing to strengthen the security of our systems that interact with this connected equipment is a high priority; separation of GMP systems remains the best defense since customers ultimately must protect their own devices. Such work involves logically and physically separating DERs and their management systems from other GMP IT/OT systems, to minimize the chances or effects of an attack. This improves the reliability and functioning of these devices, including during emergencies.

Throughout the planning period, GMP will continue to invest in defending its portion of the Vermont grid. This work will involve projects related to privacy and protection of customer data, segmentation and isolation of mission-critical resources, continual endpoint detection and response, multiple pathways and failovers for systems when possible, and team operational readiness to manage disruptions to services and systems.

GMP values relationships with law enforcement, regulators, the Vermont Electric Power Company (VELCO), and other utilities. Together, we foster a statewide “we’re in it together” mentality on technology security. In this way, a single entity that recognizes challenges and problems can warn others and become a source of important forensic information for them. GMP regularly works with other utilities, state and federal agencies, and law enforcement on evolving issues and practices. GMP offers information and expertise, when requested, at the Vermont General Assembly and elsewhere on data privacy and security issues. The Department of Public Service also holds meetings annually with all utilities to discuss technology security issues. Protecting the Vermont grid continues to require a united and common-sense approach, especially where services overlap.

Operational Security

GMP’s operations and customer-facing services require constant management of their expanding data networks, processing capacity, storage, and security systems. Implementation of DERs, undergrounding of distribution services, and increased storage and islanding capacity also require us to improve the redundancy of communications. This involves networks and the subsystems, software, and failover capabilities that help these operations serve customers. To support that work, the technology team at GMP works with field teams across operations to implement OT security enhancements such as:

- Fortifying data and telecom networks to withstand natural and human-caused disasters, including burying some communications facilities alongside undergrounded distribution lines
- Making use of secure 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 physically or in the cloud, to prepare for system losses or failures and add application capacity, remote connectivity, and disaster recovery capabilities
- Ensuring all field personnel have connected, secure, remote devices essential to effective storm response
- Supporting a work management system that effectively and efficiently assigns and tracks projects and field work
- Routinely assessing GMP’s OT network, generation plant, and substation physical security and monitoring capabilities, through onsite and remote means

Over the last several years, GMP has expanded its capacity to preserve and analyze data. For example, GMP's AMI residential customers generate approximately four terabytes of data each month, necessary for billing, GIS, outage management, engineering studies, and analytics. The need for data preservation and analysis will grow and become even more sophisticated in the coming years. For example, GMP's next-generation metering systems will be deployed as current AMI systems are retired, as discussed in the **Evolving Advanced Metering for Customers** section in **Chapter 3**. This data analysis will also help support continued innovation in rate designs and programs that share value between all customers driving down cost and carbon (see **Chapter 1**). GMP's outage management and response will also evolve with resiliency work discussed in **Chapter 3** and throughout this IRP.

Technological and Operational Security: Delivering Resilience for Customers

As we make clear in all this work and in the examples of interrelated data needs, our security work is designed to counteract disruptions, no matter their source. Whether primarily related to cybersecurity or operational readiness, *all* security initiatives at GMP strengthen redundancy and make systems more resilient for customers.

For example, when we facilitate uninterrupted functionality for operations applications such as outage management, GIS, SCADA, interactive voice response (IVR), customer care, and web services, we not only make our systems more resistant to cyberattack, but also enhance storm response to help keep customers powered up during increasingly severe weather.

GMP will continue to bolster overall resilience for customers, regardless of the type of system and loss it could face, by:

- Deploying cloud-based systems that avoid the potential physical loss of services and diversify the paths to provide them;
- Requiring use of best practices by software-as-a-service (SaaS) vendors, cloud providers, and other technology partners for securing user access, verifying the efficacy of production changes, using system isolation and physical security to reduce risk, and requiring encryption; and
- Establishing what is known as minimum application functionality standards within such services so that core systems operate, even when some aspects are unavailable.

GMP's investments in technology solutions are integral to our core operations for customers, to keep them secure against cybersecurity attacks and all other risks that could threaten resilience for customers and communities.

Regulatory Treatment in Support of Technology Deployment

Working with the Department of Public Service and through review and approval by the Vermont Public Utility Commission (PUC), GMP has a regulatory framework in place that supports flexible, effective technology improvements. Recognizing the rapid pace of technology projects and cycles of obsolescence, the Vermont PUC approved a "blanket" approach to IT investments. This allows GMP to continuously identify, design, and deploy projects within an investment limit as a part of the multi-year regulatory process, similar to how GMP plans for and invests in smaller distribution projects that have shorter time horizons and must be responsive to customer, town, and development needs. Technology investments similarly evolve with technological advancements, changes in customer programs and usage, and changes in the threat environment.

This is an effective approach for this type of investment that improves upon the previous, prospective project-by-project rate review. GMP has also moved toward capital treatment of certain multi-year IT software and cloud-based systems to more closely follow the rate trajectory for customers such projects would have received through technology hardware acquisitions in earlier years. To that end, GMP adopted the 2024 Financial Accounting Standards Board's (FASB) updates that treat "implementation" costs of acquiring cloud-based service agreements as a capital investment, while ongoing service and operating costs are booked in a single year. This approach aligns the treatment and incentive of these cloud service agreements to reflect current technology and business practices while also ensuring prudent IT investments for customers. This is also consistent with Vermont's longstanding support for lower, steady, predictable rates for customers.

Finally, GMP's Multi-Year Regulation Plan (MYRP) explicitly recognizes that technology security is an area that will require different levels of investment in the future. This is particularly true, given the ability of federal regulators to strengthen standards quickly in response to emerging threats or deployed attacks. The MYRP notes that GMP could seek additional authority above the investment limits set forth in the MYRP through a Cybersecurity Resilience Plan filing (described on page 12 of the MYRP). To date, GMP has managed technology spending both within the IT department budget reflected in the last MYRP filing and through the budgets of other departments (such as Generation and Fleet & Facilities) that are the subject of particular technology projects.

Given evolving regulatory requirements, increased threats, and the need to maintain a 24/7/365 SOC to manage risks, GMP expects enhanced technology project investment in the years ahead. The traditional rate case approach of setting rates based upon a retrospective review of the past three to five years might not meet the quickly evolving challenges of safely serving customers today. Technology investment is and should be a growing area for all utilities and will be for GMP. GMP plans to review these critical investment requirements with the Department of Public Service and Vermont PUC as a part of the FY27 Rate Case and next MYRP proposal.

Emerging Technology

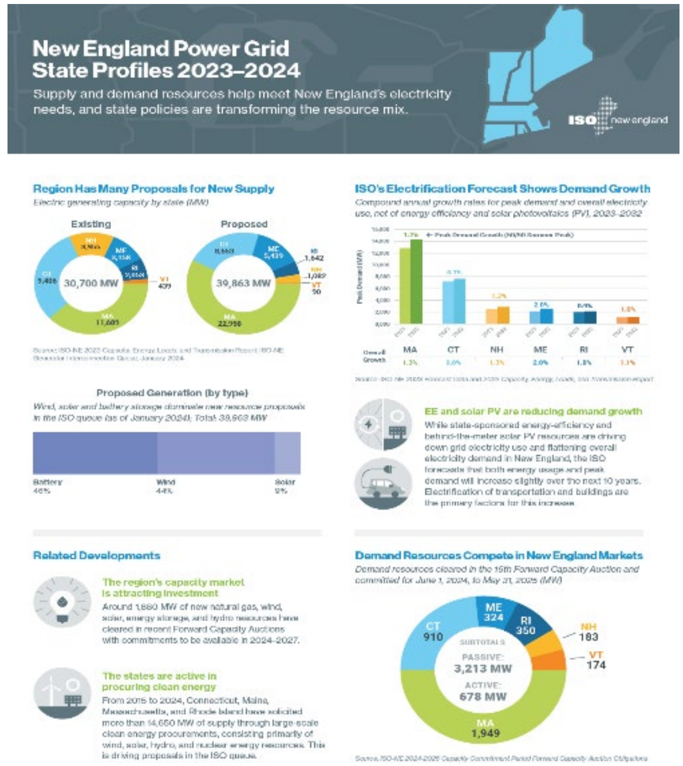
GMP continuously reviews and researches emerging technology to understand its capabilities and limitations, and to deploy it wherever appropriate. Since GMP's 2021 IRP, there have been significant improvements in DER management systems and grid management tools, many of which could benefit from the promise of generative artificial intelligence (AI). Whether in vegetation management (such as the satellite surveillance of vegetation growth and hazards, zone by zone, via the Ai-Dash discussed in **Chapter 3**) or in load matching renewable, carbon-free generation for customers (such as through the **Hourly Energy Matching** pilot discussed in **Chapter 1**), GMP has tested AI-based systems for their efficacy and potential wider deployment to customers. GMP's data science tools and analytics offer predictive insights into its operations. As AI tools improve, GMP may be able to use machine learning and cloud-based neural networks to improve grid operations, load to clean energy generation matching, storage utilization, and other program delivery for customers. Like when choosing other technology tools, GMP will thoroughly review the compatibility, use, and safety of AI tools when considering whether to incorporate them into operations. In doing so, GMP will maintain its nimble, innovative, technology-centric culture open to the possibilities and benefits while vigilant to the risks.

GMP also recently completed an overall upgrade to its analytic and customer resource management platform that will allow greater use of AI tools, as vendors incorporate them in the future. Ensuring the integrity and utility of these systems for customers will be a central part of GMP's technology team in the coming years. GMP also will look for ways such systems can save resources and time while continuing to support the delivery of clean, cost-effective and reliable power for customers.

5

EVOLVING REGIONAL ENERGY MARKETS

A Changing Regional Energy Supply



GMP regularly reviews planning assumptions and analysis to align with customers' changing power needs—and how the increasing supply of renewable energy, both locally and across the region, can best help deliver cost-effective, reliable service for customers. Since the New England states are connected through the regional electric grid and all participate in a single electricity market, changes in regional supply brought about by the increasing effects of climate change, customer electrification initiatives, and states' own climate policies will affect the resources available for GMP's customers.

With substantial amounts of new, renewable generating resources coming online across New England,[1] including increasing amounts of distributed generating resources and storage resources, we will have many new opportunities in and around the region to evaluate in our planning. To deepen the forecasting and modeling described in **Chapter 2** and **Chapter 7**, this chapter highlights key elements in the changing character of the regional energy supply and changes to the regional electricity market design and infrastructure needed to support the New England states' accelerating transition to cleaner resources.

Since our last IRP, the regional grid operator ISO New England has initiated several new long-term planning efforts to ensure adequate generating capacity and transmission infrastructure for successfully transitioning away from fossil fuels. ISO New England's most recent Regional System Plan (RSP) provides a snapshot of the expected renewable resource additions (shown in **Figure 5-1**) by 2050 to achieve the New England states' policy goals.

1 https://www.iso-ne.com/static-assets/documents/100010/new-england-power-grid-regional-profile.pdf

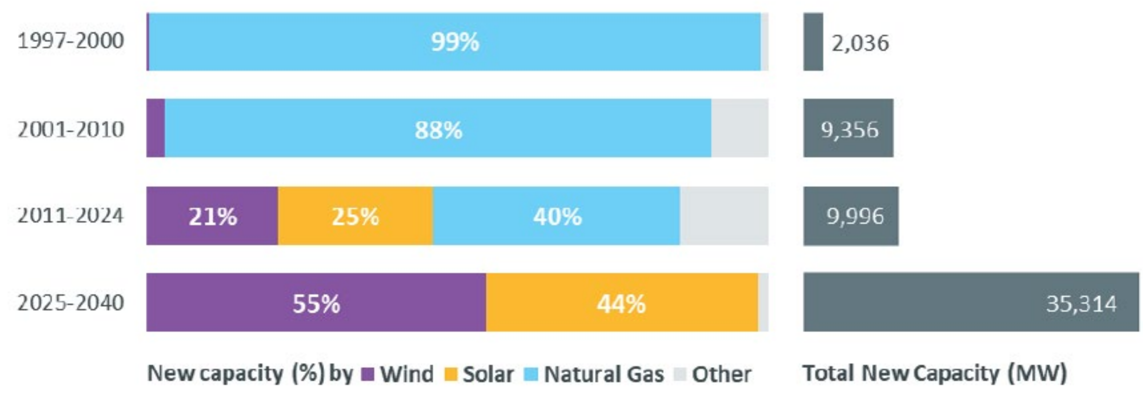


Figure 5-1. ISO New England's assessment of historical and anticipated resource additions, by fuel type, for 2040 (Source: ISO RSP 2023).

Regional planning activity like the RSP is increasingly examining the evolving state and national energy policy, since initiatives implemented via these policies are significant drivers influencing the regional energy market and the growing availability of renewable and carbon-free generating resources. GMP's planning draws significantly from these regional planning materials and reflects the expectation that the share of the energy in the ISO New England market met by renewable resources will grow rapidly through the early 2030s.

Table 5-1 shows a snapshot of current New England climate policy targets that was presented in ISO New England's 2024 Economic Study. Each state government approaches its goals differently. Some of the differences can be seen in their renewable portfolio standards to define future, required percentages of renewable energy relative to total retail loads. Many State-supported renewable policies, including the Vermont Renewable Energy Standard (RES), require increasing percentages of renewable energy delivered to customers across long-term planning horizons. These programs involve specific timelines and resource eligibility requirements and collectively represent a regional roadmap for decarbonizing the grid over the next 20 to 30 years. Most of the states require annual compliance reporting. As the requirements grow to account for most of the annual energy production in the region, achieving successful coordination of the eligible sources (wind, solar, hydro), and their intermittency characteristics, will call for careful planning by GMP and all other regional distribution utilities.

Goal	Participating states
≥ 80% by 2050	Five states mandate greenhouse gas reductions, economy-wide: Massachusetts, Connecticut, Maine, Rhode Island, and Vermont (mostly below 1990 levels)
Net zero by 2050 80% by 2050	Massachusetts emissions requirement Massachusetts clean energy standard
100% by 2035	Vermont renewable energy requirement, with distinct and earlier targets for some utilities including GMP
100% by 2050 Carbon-neutral by 2045	Maine renewable energy goal Maine emissions requirement
100% by 2040	Connecticut zero-carbon electricity requirement
100% by 2033	Rhode Island renewable energy requirement

Table 5-1. New England climate policy targets (Source: https://www.iso-ne.com/static-assets/documents/100010/new-england-power-grid-state-profiles.pdf).

GMP has incorporated the requirements of the Vermont RES, as passed in Act 179 of the 2024 legislative session, in planning cases presented in this IRP. We have also adopted several assumptions in the ISO New England 2024 Economic Study and VELCO's Long-Range Transmission Plan to maintain consistency on major findings and meaningful economic considerations.

State Renewable Resource Procurements

New England states are increasingly pairing policy guiding future renewable resource requirements with legislation directing the procurement of supply by state agencies and jurisdictional utilities. These state-issued requests for proposals (RFPs) support greenhouse gas reduction and renewable power goals that are expected to result in the addition of many thousands of MWs of new clean energy in the region by 2030, as shown in **Table 5-2**. Vermont does not require this framework for policy procurement of renewable energy because we remain a vertically integrated, fully regulated state and the Vermont PUC reviews and approves significant power purchase agreements to ensure they are in the public good and consistent with state policy.

Discretional procurement	Enabling legislation	Total authority
Massachusetts	Diversity Act: Sec. 83C Rd 1 + 2 (OSW) Diversity Act: Sec. 83D Section 83C Rd 3 (OSW) + Climate Act: Section 83C (additional OSW)	1,600 MW, nameplate (1,600 selected to date; 800 terminated) 9,450 GWh (100% hydro selected) 4,000 MW, nameplate (1,600 selected to date; 1,600 terminated)
Connecticut	PA 17-3: An Act Concerning Zero Carbon Solicitation and Procurement PA 19-71: An Act Concerning the Procurement of Energy Derived from Offshore Wind	Up to 12 TWh / year total (11.7 TWh selected to date) 2,000 MW, nameplate (804 selected to date; 804 terminated)
Maine	Public Law Chapter 380 (N. ME Tx + Gen) Public Law Chapter 371 of 2023 (additional N. ME gen) Public Law Chapter 321 (additional Class IA)	≥ 345 kV, implicitly up to 1,200 MW (1,200 Tx + 1,000 Gen. selected and terminated) Unused space over 1,200 MW N. ME Tx 5% of 2021 load + Tranche 1 and 2 RFP attrition
Rhode Island	State Budget Bill, 2022 Session + Governor 2023 announcement	1,200 MW, nameplate
New Hampshire	SB 52 of 2023 (additional post-September 1, 2023 energy resources)	2,000 GWh

Table 5-2. Legislative renewable procurement initiatives in states near Vermont (Source: Data from Sustainable Energy Analytics, *Renewable Energy Market Outlook*).

Procurements in the past several years under these and similar predecessor laws resulted in the awards of primarily offshore wind (OSW) contracts designed to build a significant share of the region's future energy production capacity in the waters of coastal New England. Although projects have advanced to various stages and some commercial operation is under way, some of them have stalled because of inflationary pressures and supply chain challenges, requiring refreshed RFP processes. Vermont policymakers and utilities, including GMP, have kept up to date on this process with interest in understanding the pacing and cost of these important resources and how they align with Vermont interests.

Distributed Solar Resources

The other key renewable energy source central to New England's climate policy transformation is solar photovoltaic (PV) resources. These generating facilities continue to be added to the regional supply at a significant rate. However, unlike large offshore wind, most of this new capacity comprises distributed and other small-scale systems that are not connected to the regional high-voltage transmission system. This solar growth is largely the result of state renewable incentive programs like net metering and community solar programs. **Table 5-3** shows the increasing level of behind-the-meter solar in Vermont and in other states.

State	Annual total MW (AC nameplate rating)							
	Thru 2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Connecticut	1,090.5	150.8	160.6	164.9	164.7	158.5	160.4	162.4
Massachusetts	3,712.0	326.5	320.9	313.6	309.7	300.1	288.0	279.2
Maine	588.0	223.6	123.0	119.6	118.9	113.0	111.0	107.6
New Hampshire	244.0	27.3	26.5	25.6	24.0	22.7	22.0	22.8
Rhode Island	400.0	46.4	49.0	49.0	49.3	48.2	48.7	49.2
Vermont	507.0	29.3	29.2	29.0	29.8	25.4	27.3	28.9
Regional – Cumulative MW	**6,541.5**	**7,345.4**	**8,054.5**	**8,756.2**	**9,452.6**	**10,120.5**	**10,778.0**	**11,428.2**

Table 5-3. Current and projected cumulative growth in New England behind-the-meter solar power, though 2030 (Source: Data from ISO New England *Final 2024 PV Nameplate Capacity Forecast*).

Unlike traditional supply, these behind-the-meter resources are tracked by the reductions they cause to the hourly energy needs on the bulk transmission system, displacing the need for grid-connected supply and lowering peak demands during the summer months.

Taken together, the changes to the ISO New England grid from nearly doubling the amount of currently installed generation with new solar and wind development will require significant regional transmission planning and new wholesale energy marketplace reforms.

Regional Transmission Planning and Forecasted Costs

ISO New England released its 2050 Transmission Study in February 2024, offering information about the amount, type, and high-level cost estimates of transmission infrastructure that would be needed to serve peak loads growing from the region's plans for electrified transportation and heating. It also considers the rapid growth in regional offshore wind and solar associated with the state policy and procurement plans described above. The study estimates that these growth combinations could require between $16 and $25 billion in new grid investment by 2050.

The 2050 Transmission Study is the first longer-term such study conducted for New England. The authors noted that the results are not comprehensive plans but offer information for decision-making. ISO New England also responded to the NESCOE Vision document by revising Attachment K to its Open Access Transmission Tariff, establishing rules as a first phase in extending the transmission planning horizon beyond 10 years. A second phase will explore a process for moving "policy-related transmission projects forward, with an associated cost allocation" (2050 Transmission Study, pages 8–9). That work began in early 2024. For this second phase, ISO New England will identify needs for future years and will likely solicit transmission projects through an RFP, recommending a project to NESCOE for review and approval.

For more near-term planning and grid information, ISO New England's 2023 Regional System Plan offers a full consideration of the challenges for the future grid, taking into account the ability of renewable sources to replace conventional thermal generation. It also discusses the factors affecting the study's key results.

Ultimately, customers using the bulk transmission system take on the cost of supporting existing grid transmission investment and future upgrades. The evolution in the ongoing grid support costs can be seen in the annual revenue requirement rate in dollars per kW-year paid to the region's transmission owners. These RNS transmission costs accounted for 28 percent of total wholesale energy related costs in 2023. In the most recent market assessment provided by ISO New England's External Market Monitor, Potomac Economics, New England continues to be highlighted as one of the most expensive transmission systems in the country, as shown in **Table 5-4.**

Year 2023	**Electric Reliability Council of Texas (ERCOT)**	**Midcontinent Independent System Operator (MISO; serving the Midwest)**	**PJM (grid operator for 13 states and DC)**	**New York ISO**	**ISO New England**
Transmission costs ($ / MWh of load)	$9.90	$7.60	$16.50	$5.70	$22.00

Table 5-4. Comparison of 2023 transmission costs, across regional transmission organizations (Source: Extract from Potomac Energy, *2023 Assessment of the ISO New England Electricity Markets*, page 4)

In the past decade, the cost of using the regional transmission network has roughly doubled for GMP customers and all the region's other load-serving entities from an annual transmission rate of $75 per kW-year in 2012 to over $185 per kW-year in 2025. Over the next five years this transmission supporting rate is expected to grow by another 17 percent, with many regional additions focused on adapting to the changing electric marketplace (summaries are in **Table 5-5** and **Table 5-6**).

GMP is paying close attention to these regional costs and the impact on our customers that we do not control. That is why investments in our distribution system through energy storage are key, as that is in Vermont's control, and will help lower what our customers pay to the region.

Table 1		January 1, 2025	January 1, 2026	January 1, 2027	January 1, 2028	January 1, 2029
1	Estimated RNS impact ($ / kW-year)	$31	$12	$12	$8	$12
2	Estimated RNS rate forecast ($ / kW-year)	$185	$184	$197	$205	$217
3	Estimated RNS rate forecast ($ / kW-year) (Assumes a 54.7% load factor)	$0.029	$0.029	$0.031	$0.032	$0.034
4	Estimated incremental additions and CWIP ($ in millions)	$1,635	$1,396	$1,449	$988	$1,441
5	Forecasted revenue requirement ($ in millions; Line 4 carry charge factor)	$239	$212	$220	$150	$223

Table 5-5. Forecast of RNS transmission rates (Source: Data from NEPOOL Transmission Committee, *NEPOOL RC / TC Summer Meeting*)

Table 2		Regional system plan projects	Asset condition listing project	Other projects	Total
1	Forecasted 2024 regional investments	$622	$814	$237	$1,673
2	Forecasted 2025 regional investments	$254	$965	$175	$1,394

Table 5-6. Forecasted regional investments (Source: Data from NEPOOL Transmission Committee, *NEPOOL RC / TC Summer Meeting*)

ISO New England Wholesale Electric Market

The cost and operation of the regional wholesale electricity markets heavily influence GMP's current and future supply resources. Today the dominant share of our supply resources and energy needs pass through and participate in the ISO New England market. Changes to the structure of this market can present risk and opportunity for GMP customers and affect the operation of our purchases and owned supply resources. The character and scale of this diverse GMP supply mix is discussed in greater detail in the following chapter (**Chapter 6).** In addition, the conditions and prevailing price levels in the marketplace over the near term are an important influence on the cost to purchase and the expected benefits of new supply for future periods.

Since the early 2000s, the New England electricity market has operated under a framework where generating plants compete hourly for the opportunity to obtain revenue that serves the region's electrical needs. In the 20 years that this framework has been in place, natural gas generation has been the dominant resource. Even today, nearly 48% of ISO New England's market-facing energy production comes from natural gas generation, as shown in **Figure 5-2.**

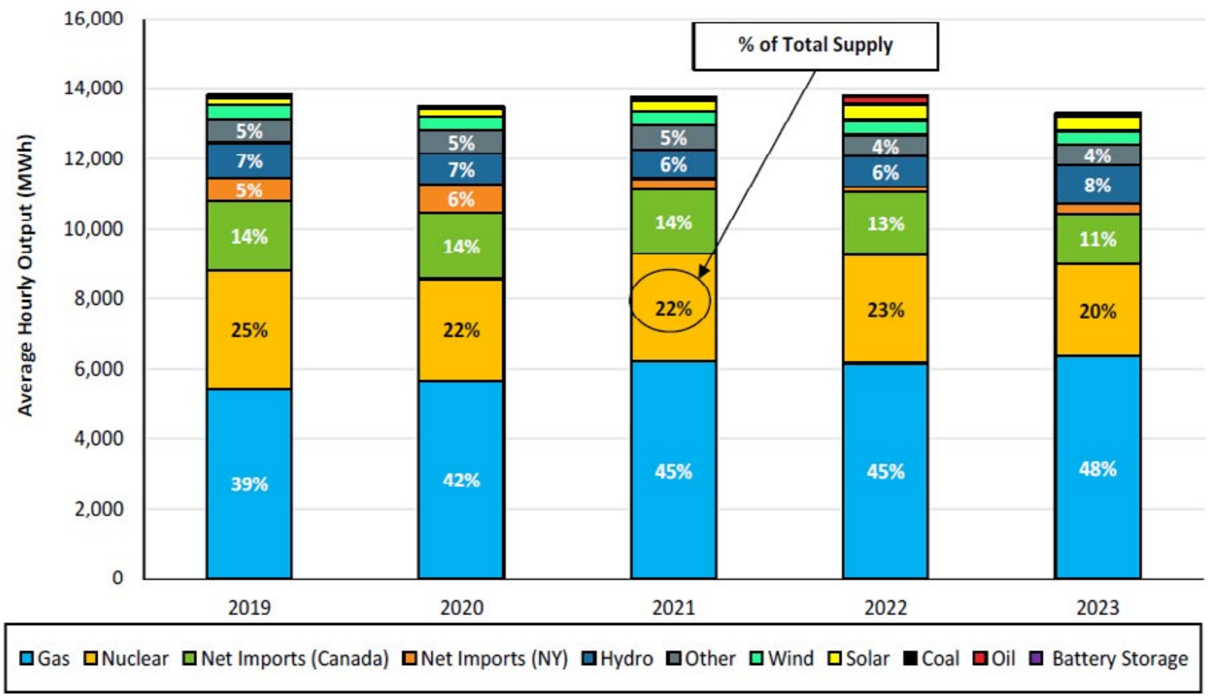


Figure 5-2. The share of fuels comprising average hourly electricity generation in New England, 2019 to 2023 (Source: ISO New England Internal Market Monitor, *2023 Annual Markets Report*, page 37).

The design of the electricity market has also been largely built around the needs and characteristics of these fossil-fired units. 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 New England administers them financially independently from companies doing business in the marketplace. The relative scale of these markets in annual dollars is shown in **Figure 5-3.**

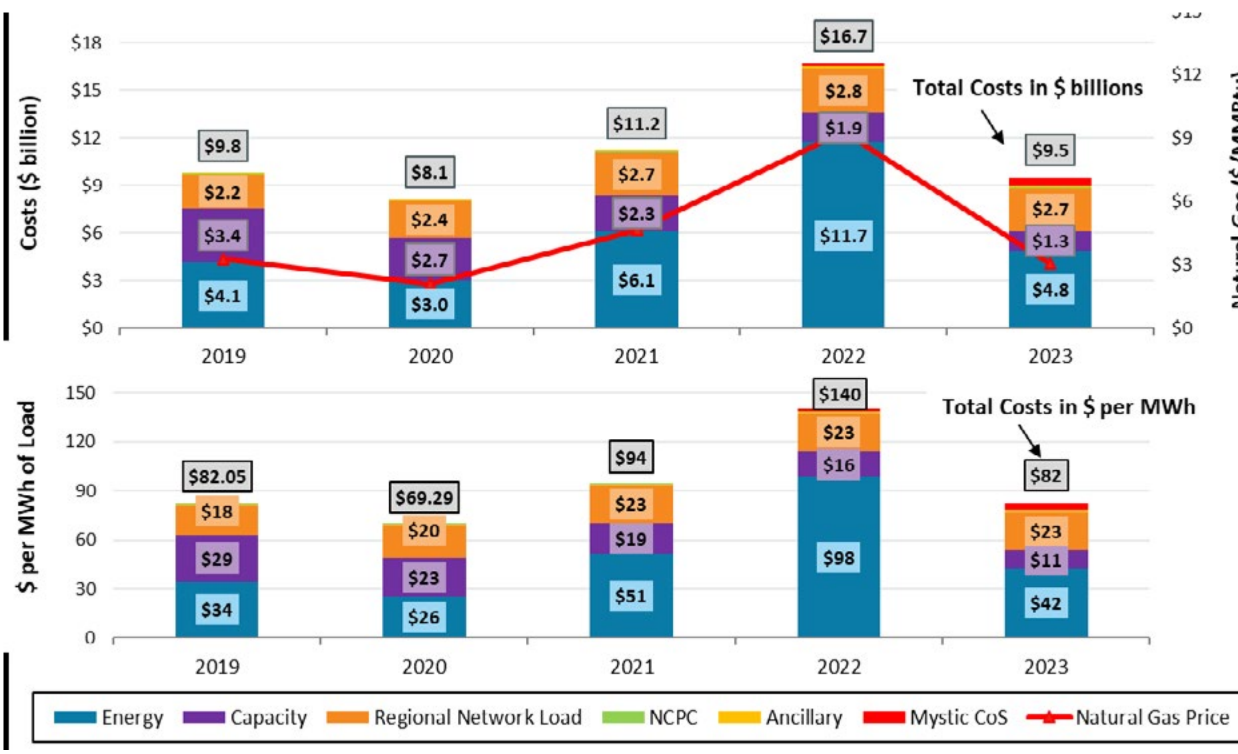


Figure 5-3. Annual value of wholesale electricity markets (Source: ISO New England, *IMM Annual Markets Performance Report*, Slide 3).

Achieving a clean grid, balancing resources, ensuring the adequacy of energy supply, and keeping transmission strong when an increasing amount of supply is intermittent renewable resources are a regional opportunity now and in the years ahead. GMP keeps all of these considerations in mind when selecting supply options, as further described in **Chapter 7** in keeping with the comprehensive interests of State regulators and other utilities as we plan ahead to best serve customers with affordable clean power.

Energy Market

The energy market is New England's largest in terms of total share of wholesale market cost. Most New England energy pricing is directly related to natural gas; however, especially in the winter months, limited regional pipeline capacity can combine with very cold weather, creating a condition where the flow of natural gas into New England is insufficient to fuel all the region's natural gas power plants. To address this situation the ISO has implemented a series of winter-focused reliability enhancements to improve fuel-security in the region for the next few years—and until additional resources are brought online to improve reliability. Specifically, the ISO used a generator retention mechanism in the Forward Capacity Market from the June 2022 through May 2025 commitment periods to keep key resources from retiring from the market.

They also entered into a very costly Cost of Service Agreement with the Mystic generating units 8 and 9 through May of 2024 to ensure the continued availability of this facility. This had a direct impact on our customers with higher prices, and was beyond our control. More recently in 2023 they began the two-year Inventoried Energy Program to compensate generating resources that hold reserves for cold days. **Figure 5-4** shows the share of wholesale electricity and natural gas prices from 2003 through 2023.

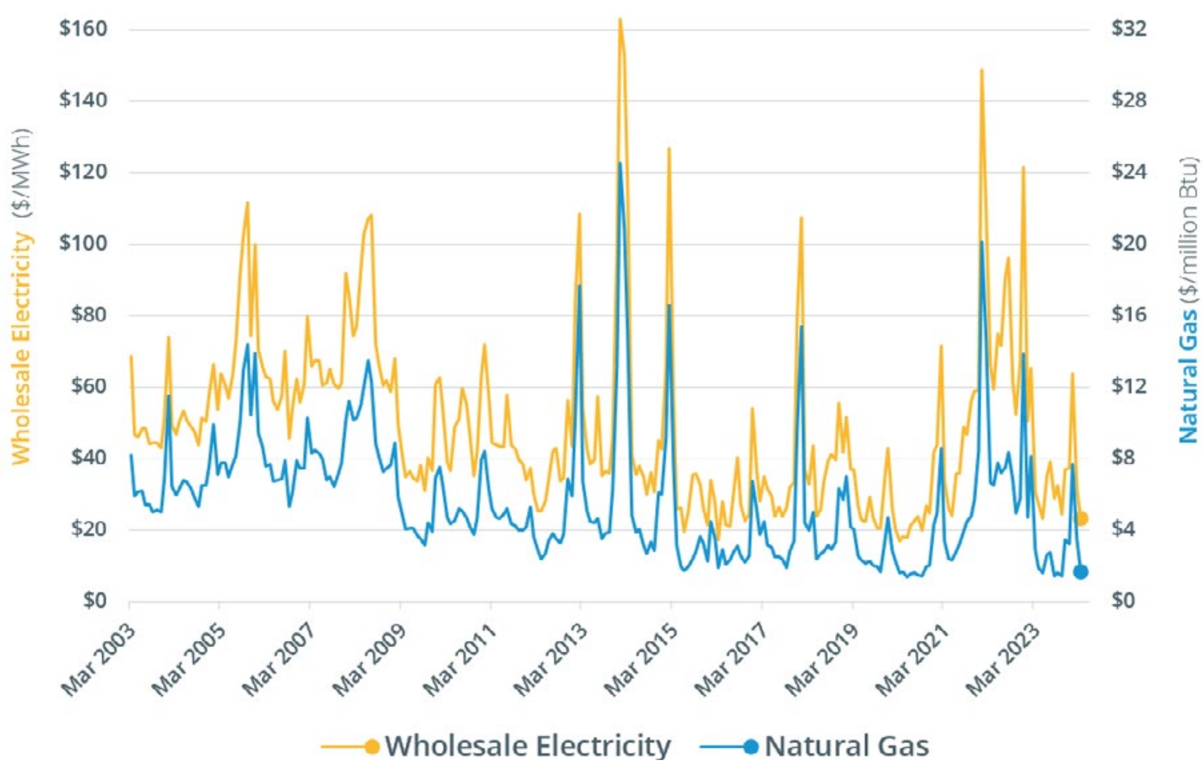


Figure 5-4. Average annual energy prices in the ISO New England market (Source: ISO New England, *Monthly Wholesale Electricity Prices and Demand in New England, March 2024*).

The energy market in New England has seen several large pricing swings because of this close relationship with natural gas, the most recent occurring following the Russian invasion of Ukraine in 2022. More recently prices for energy have returned to pre-2022 levels due largely to back-to-back warm winter seasons that did not feature any meaningful constraints on the local natural gas system. The change was also driven by the overall price of gas which fell by 67% in 2023 allowing natural gas fired generators to set the price for 84 percent of load in the real-time energy market.

Capacity Market

New England's Forward Capacity Market (FCM) pays for resource availability in meeting three-years-ahead peak electricity demand. As with other capacity markets, FCM payments to providers cover some or all the fixed costs of building new units when a shortfall is anticipated, or of simply maintaining generating resources when the supply is sufficient.

The New England FCM assigns obligations to ensure qualified generating resources can satisfy the region's anticipated future peak electricity needs with enough lead time to construct new capacity resources, as needed. Annual Forward Capacity Auctions (FCAs) obtain three-years-ahead commitments; the resources must be ready to run when called on. The prices of capacity from FCA auctions since 2011 are shown in **Figure 5-5.**

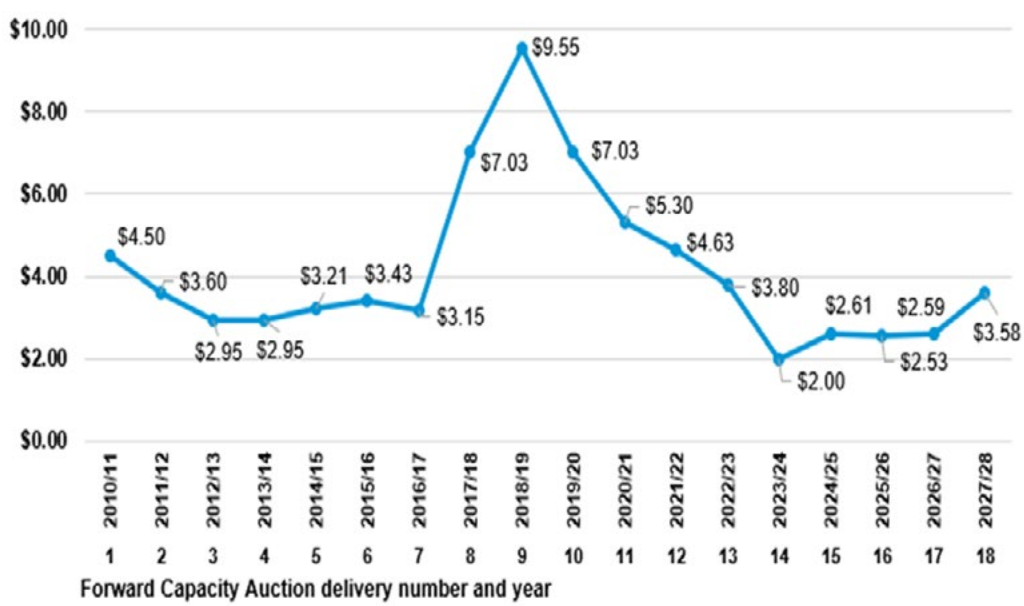


Figure 5-5. Annual Forward Capacity Auction floor price results, for bids made from 2008 through 2024 as commitments for 2011 through 2028 (Source: U.S. Energy Information Administration, *ISO-New England New England Dashboard Commentary February 28, 2024*).

Capacity Market Reforms

Since GMP's 2021 IRP, ISO New England has announced major structural changes for the region's capacity market to align it more closely with the region's State-mandated renewable resource development. The Capacity Auction Reforms Key Project (CAR) proposes to transition the capacity market from a "forward/annual market to a prompt/seasonal market with [resource] accreditation reforms."

ISO New England believes the existing FCM design does not adequately reflect the needs of the current or future system. Specifically, they have observed that the forward nature of the market is inefficient for smaller distributed resources that can be deployed quickly, and the annual cycle does not capture the seasonal needs and the various energy constraints on the system.

The Resource Adequacy Assessment (RAA) is a proposed process for resource accreditation under ISO New England's Resource Capacity Accreditation project. The proposed new requirements adapt the method for allocating capability to supply resources to better align these amounts to what is provided by the units during peak periods and reliability events. The method assumes a future where a greater share of the region's supply is sourced from intermittent wind and solar resources.

Ancillary Services Markets and Resource Adequacy

ISO New England's Ancillary Services Markets (operating reserves, regulation services, voltage support service, and black start services) help maintain grid reliability. Ancillary Services, although not as financially significant as the energy and capacity markets, are becoming prominent in planning for increasing amounts of intermittent renewable resources. In addition to the increasing need for these products in the renewable transition, the advances in storage technology and the lower cost of implementing energy storage are also driving a reassessment in many of these reliability services. Recently the ISO noted that battery storage projects made up about 46% of the proposed generating capacity in the Interconnection Request Queue as of January 2024, compared to 10% in July 2020—and less than 1% in May 2017, highlighting this rapid evolution.

Day-Ahead Ancillary Services Initiative

In 2025 ISO will be implementing a significant change to the region's operating reserves framework. The Day-Ahead Ancillary Services Initiative (DASI) replaces the current forward reserve markets and establishes an improved method to procure the critical ancillary services in harmony with the Day-Ahead energy market. Starting in March 2025, ISO New England will procure and transparently price reserves in the day-ahead market. In addition, sellers will now be subject to more meaningful financial consequences if they fail to deliver on these reserve commitments.

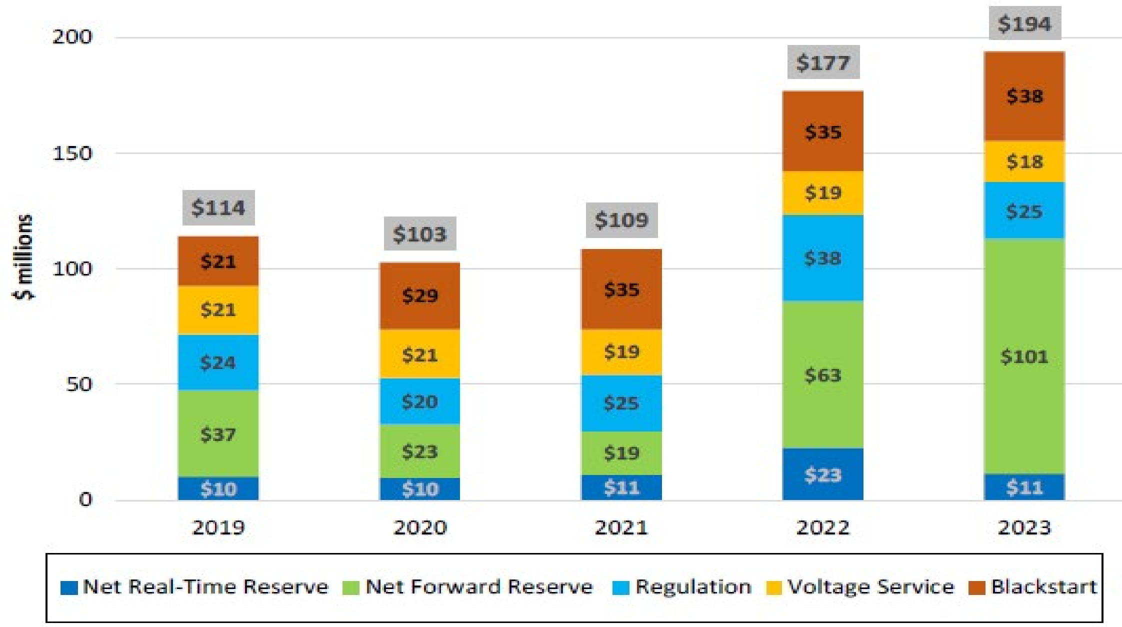


Figure 5-6. Scale of the ISO New England Ancillary Services (Source: ISO New England, *2023 Annual Markets Report*, page 154.)

The new Day-Ahead Ancillary Services Market (DAASM) includes four products: Day-Ahead Ten-Minute Spinning Reserves, Day-Ahead Ten-Minute Non-Spinning Reserves, Day-Ahead Thirty-Minute Operating Reserves, and Day-Ahead Energy Imbalance Reserves (DA EIR). Each of the four products will have its own clearing price and credits to suppliers will be based on a novel two-component call option structure that relies on the clearing price and a "close-out" charge based on a strike price set by ISO-NE. Additionally, the ISO has highlighted the value of adding compensation strategies for flexible resources that may only dispatch to support reliability in its recent Economic Planning for the Clean Energy Transition (EPCET) report (page 5), making an expansion of these grid supportive products and opportunities likely in the years ahead.

Regulation Market

The Regulation Market selects and compensates market participants that can provide regulation—the capability to increase or decrease energy output or consumption every four seconds. In addition to its importance to individual distribution networks as discussed elsewhere in the IRP, since our last IRP, storage now provides the majority of capacity supplying the regional frequency regulation market. GMP, with our energy storage customers, participates in frequency regulation services under the alternative technology regulation resources (ATRR) category, and it provides a supplementary revenue stream for many of GMP's distribution connected storage facilities. The overall market demand for this service is small at just under 100 MW on average, but it has demonstrated the important capability distributed storage resources can provide in supporting grid reliability.

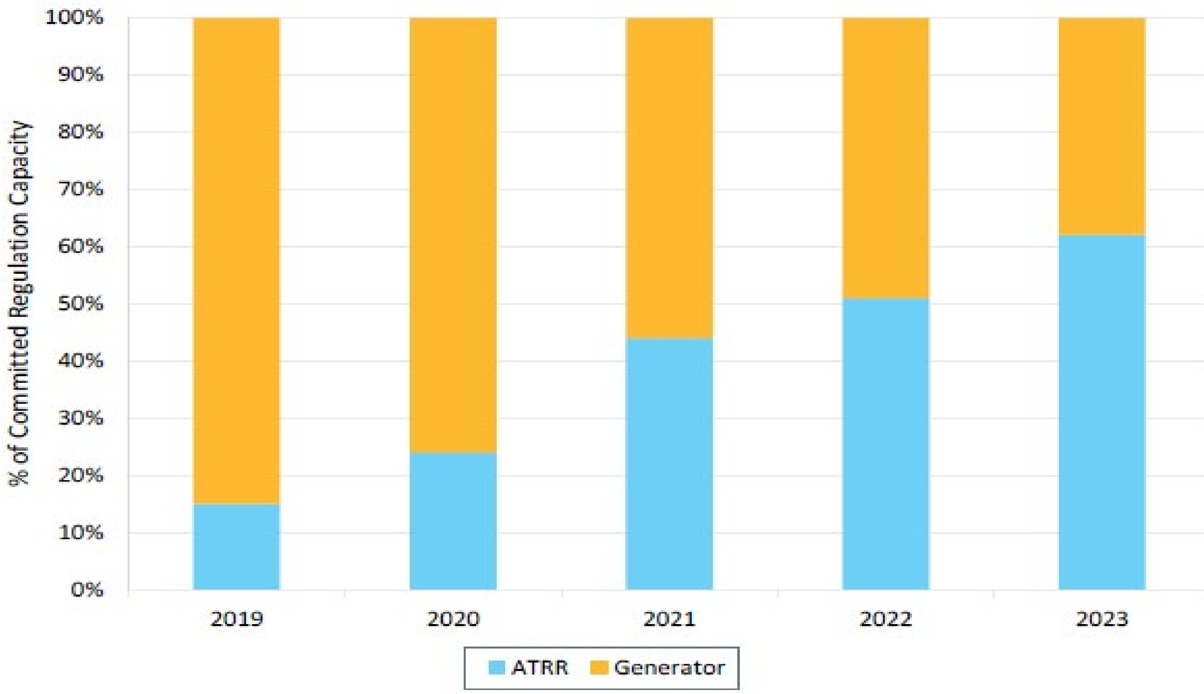


Figure 5-7. Share of regulation market by technology (Source: ISO New England, *2023 Annual Markets Report*, page 168).

Carbon Cap and Trade Programs

New England has two carbon-reducing programs that affect production costs and electricity prices: (1) the Regional Greenhouse Gas Initiative (RGGI), covering generators in all New England states, and (2) the Massachusetts Electricity Generator Emissions Limits (EGEL) under that commonwealth's Global Warming Solutions Act, covering only Massachusetts generators. In these compliance carbon markets, participants can purchase emissions permits (allowances) or offsets to meet predetermined carbon emissions reductions, and trade carbon allowances.

Regional Greenhouse Gas Initiative

The RGGI carbon-offsetting program was the first mandatory cap-and-invest program in the United States to limit carbon dioxide (CO_2) 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 producing more than 25 MW of nameplate capacity. The cap is set at 120 million metric tons for 2021 and declines each year thereafter until it reaches 80 million metric tons in 2030 (a 33 percent decline across 10 years). Each quarter, RGGI auctions off allowances up to the annual cap, to producing power plants. In 2023, CO_2 emission costs comprised about 20 to 30 percent of energy production costs for a typical combined-cycle generator, depending on its location. Since natural gas generation makes up most supply and the vast majority of price-setting supply (84 percent in the real-time market in 2023), CO_2 costs were a key driver of wholesale energy costs.

According to the ISO New England External Market Monitor report, compliance in 2023 added $6 per MWh to the production costs of gas-fired, combined-cycle generators in some locations. As emission prices rose and fuel prices dropped in 2023, emissions contributed to a higher proportion of overall energy production costs.

Massachusetts EGEL

The Massachusetts EGEL program covers only Massachusetts electricity generators. The average estimated costs of the Massachusetts EGEL program increased 23 percent in 2023 to $4.12/MWh for the average natural gas combined-cycle generator, bringing the total emissions costs to $10.31/MWh or about 30 percent of production costs for a typical combined cycle in Massachusetts.

National Influences on New England's Energy Market

While GMP's day-to-day planning and market participation focus is directed throughout our territory and regionally, there are also national policies that affect wholesale market function through the Federal Energy Regulatory Commission (FERC), interstate energy planning, and federal funding decisions.

Inflation Reduction Act and Bipartisan Infrastructure Law

The Inflation Reduction Act of 2022 (IRA) and the Bipartisan Infrastructure Law of 2021 (BIL) constitute a historic investment of more than $430 billion for modernizing the American energy system. The provisions in these two laws have begun to enhance the nation's energy security, lower energy costs for American households and businesses, drive clean energy innovation, improve human health, and mitigate climate change.

As posted on the U.S. Department of the Treasury website:

> The Inflation Reduction Act enhanced or created more than 20 tax incentives for clean energy and manufacturing. For many of these incentives, it created additional bonuses to enhance investments in communities and workers as well as mechanisms that will increase private sector investment and—for the first time—open access to certain clean energy tax incentives to tax-exempt entities, like state, local, and Tribal governments, rural electric cooperatives, and many more.

U.S. Department of the Treasury Inflation Reduction Act Informational Resources. The Bipartisan Infrastructure Law contained significant appropriations for the energy sector under four major areas: (1) delivering clean power (~$21.3 billion), (2) clean energy demonstrations (~$21.5 billion), (3) energy efficiency and weatherization retrofits for homes, buildings, and communities ($6.5 billion), and (4) funding for clean energy manufacturing and workforce development ($8.6 billion).

Where relevant, Vermont and GMP have been applicants for competitive grants authorized by both the IRA and BIL. When the applications have been successful, like we have seen with the IRA Low Income Communities Program and the Solar For All funding, the resulting local projects can reduce costs for customers while also improving system resilience and expanding renewable energy. GMP programs like the ACRE pilot and the Shared Solar tariff are actively applying these federal funding streams for our Low- and Moderate-income focused Energy Assistance Program populations. GMP will work with the State as it deploys significant Solar for All funding, and continue to partner with others, such as through NOMAD's federally funded mobile storage grant and Efficiency Vermont's administration of grant funds for electric panel upgrades for low-income customers. While implementing these targeted programs, GMP is focused on the principles drawn from Vermont's Environmental Justice framework in Act 154 and advancing strategies to reduce greenhouse gas emissions and to build resilience to the effects of climate change that benefit and support all residents of the State of Vermont fairly and equitably.

During this period of our IRP, it is possible for these federal funding opportunities to change dramatically pending decisions and changes at the federal level. We would expect grants that have already been awarded to have minimal risk of a clawback, but future opportunities could be limited or eliminated. We will continue to monitor alongside state partners and regulators to determine what changes may occur and any impacts to Vermont and our customers.

Major FERC Orders (2222, 2023, and 1920)

Interested in ensuring a timely, robust transition to a clean, lower emission power grid that can reliably serve customers nationwide, FERC has embarked on a number of important rulemakings in the past several years designed to coordinate transmission buildout and enhance wholesale markets for distributed energy resources and other clean energy market participants. Key orders GMP is actively tracking are summarized below.

FERC Order No. 2222

FERC's Order No. 2222, Participation of Distributed Energy Resource Aggregations in Regional Transmission Operators (RTOs) requires RTOs/ISOs to allow distributed energy resources (DERs) greater access to wholesale markets. Order 2222 allows easier market access from DERs, including aggregations of local, small-scale, distribution-sited assets like rooftop and community solar, energy storage, and microgrids.

New England already has pathways for participation for some of these alternative resources; however, under Order 2222, GMP expects opportunities to increase. ISO New England has made several compliance filings to adapt the market tariffs in New England to provide for this increased access to markets. Many of the filings and delays in implementation have been related to the metering data and settlement supporting information that will be required from distributed resource aggregations. The final compliance filings were made in June 2024, and ISO has set a date at the end of 2026 to start the program. GMP has monitored the methods and framework for implementing Order 2222. Under program rules a key component of implementation will require metering and reporting coordination between each distributed resource owner wishing to participate in a wholesale aggregation and their host utility. In a key program clarification, ISO added tariff language that these aggregations will be subject to all obligations applicable in the ISO's Tariff, Metering and Telemetry Criteria, Market Rule 1 Accounting. The final market participation language also contains provisions for notifications for affected utilities as follows:

1) ... a Distributed Energy Resource Aggregator shall make an initial notification to both the ISO and the Host Utility (or the Host Utility's Agent) of its intent to register a Distributed Energy Resource Aggregation. Such notification shall include the information required by applicable ISO New England Manuals, including, but not limited to: the retail billing account(s) of the individual Distributed Energy Resource(s) participating in the aggregation, information regarding the location, anticipated size, technologies to be included...
2) The Host Utility (or its agent) shall review each Distributed Energy Resource's eligibility to participate in a Distributed Energy Resource Aggregation and confirm the Aggregator's eligibility to register the proposed Distributed Energy Resource Aggregation in the manner established in this subsection. The time period for such review shall begin when the Host Utility or its agent receives the initial notification from the Distributed Energy Resource Aggregator and shall not exceed 60 calendar days.

GMP will continue to follow the implementation of Order 2222 and how it may apply to GMP as it rolls out in the next couple of years. As of this IRP, no aggregators have identified issues associated with administration of Order 2222, including ISO-NE's metering requirements on aggregators. It's important to note that regardless of Order 2222, aggregators are able to participate in various ISO wholesale markets today. GMP's own aggregation of residential energy storage systems in the frequency regulation market is an example of this. Most importantly, GMP must assure safe and reliable interconnection of any resources that could be dispatched or flexed while interconnected to the distribution system—regardless of their participation through Order 2222 or any other market mechanism.

FERC Order No. 2023

On July 28, 2023, FERC issued Order 2023, its final rule on proposed reforms to generator interconnection procedures and agreements. Order 2023 adopts reforms to:

i) Implement a first-ready, first-served cluster study process
ii) Increase the speed of interconnection queue processing
iii) Incorporate technological advancements into the interconnection process.

Of these reforms, the most consequential requirement is that transmission providers eliminate the long-standing first-come, first-served interconnection study process and instead implement a first-ready, first-served cluster study process under which Interconnection Requests included in each cluster are considered equally queued.

In May 2024, ISO New England, the New England Power Pool (NEPOOL) and the New England Participating Transmission Owners Administrative Committee (PTO AC) filed proposed tariff revisions in response to the requirements of Orders 2023 and 2023-A (Order 2023 Revisions). The Order 2023 Revisions adopt most of the required *pro forma* Open Access Transmission Tariff (OATT) changes, with some regional variations to recognize certain existing features of the ISO New England interconnection process. **Chapter 3** includes some additional context for how Order 2023 may impact interconnection of renewable generation in Vermont.

FERC Order No. 1920

On May 13, 2024, FERC issued Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*. Order 1920 adopts specific requirements addressing how transmission providers must conduct long-term planning for regional transmission facilities and determine how to pay for them to ensure the identification of more efficient or cost-effective regional transmission solutions. Many elements of Order 1920 align with New England's innovative Longer-Term Transmission Planning (LTTP) framework accepted by FERC in July 2024, which also addresses future regional transmission planning to help meet clean energy goals, but with some differences. Order 1920 requires all transmission providers to:

- Conduct long-term regional transmission planning to identify, evaluate, and select long-term regional transmission facilities to address long-term transmission needs
    - Evaluate for selection regional transmission facilities that will address identified interconnection-related transmission needs through the existing Order No. 1000 processes
- Include in their compliance filings one or more default *ex ante* long-term regional transmission cost allocation methods to allocate costs for long-term regional transmission facilities (or a portfolio of such facilities) that are selected for regional cost allocation
- Revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms adopted in Order 1920

On July 8, 2024, FERC accepted proposed revisions to Section 16 of Attachment K of the OATT to establish, as part of the optional longer-term transmission planning process, the mechanisms that enable the New England states to develop policy-based transmission facilities in connection with longer-term transmission studies (LTTS) and the associated cost allocation methods for these upgrades (known as LTTP Phase 2 Tariff Changes).

6

OUR RENEWABLE ENERGY SUPPLY

Overview

GMP's electricity portfolio for customers is 100 percent carbon free on an annual basis and is also 82 percent renewable.[1] Over the next three years, GMP will continue to make progress toward the requirement of serving customers with an annual portfolio of 100 percent renewable energy by 2030. This chapter describes Vermont's Renewable Energy

Standard, GMP's current supply portfolio, and the ways GMP procures and uses these resources for customers. The chapter concludes with a section that describes future supply options. This sets the background necessary for **Chapter 7,** which analyzes supply portfolios for the years ahead that will meet customer needs and fulfill Vermont's clean energy requirements.

Vermont Renewable Energy Standard

Since its passage in 2017, Vermont's Renewable Energy Standard, 30 V.S.A. § 8002–8005 (RES), has guided GMP's power supply portfolio decisions. Updates to the RES in 2024 modify and increase renewable requirements, mandating all utilities be 100 percent renewable by 2035, with GMP required to meet this target by 2030, in line with the goal that GMP has had in place. The revisions also increase RES Tier II distributed generation (DG) requirements, doubling it to 20 percent of annual load by 2032 and established a new Tier IV that sets targets for procuring new renewable resources capable of being delivered into New England. Tier IV requirements for GMP begin in 2027, with a target of four percent of its annual load being met by Tier IV new renewable generation in that year, escalating through 2035 to 20%. At the same time, the percentage of existing renewables (renewables built prior to a specific date set in statute) that are a part of a utility's supply mix decreases somewhat over time, as other requirements ramp up based upon the build out of new renewables here and regionally.[2] **Table 6-1** summarizes the original and revised RES requirements as RES applies to GMP.

1 See Calendar Year 2023 GMP RES compliance filing, dated August 30, 2024, in PUC Case No. 24-0775-INV.

2 Tier IV, the new category in the RES, "encourages the use of new renewable generation to support the reliability of the regional ISO-NE [ISO New England] electric system. To satisfy this requirement, a provider shall use new renewable energy with environmental attributes attached or any class of tradeable renewable energy credits generated by any renewable energy plant coming into service after January 1, 2010, whose energy is capable of delivery in New England." (page 13)

	Original RES		2024 Revised RES		
Category	**2024 Requirement**	**End**	**2024 Requirement**	**End**	**Description**
Tier I	63%	75% by 2032	63%	100% by 2030 ramping down to 60% by 2035	Faster transition to renewables that reaches 100% by 2030. Includes new and existing renewable generators.
Tier II	5.20%	10% by 2032	5.20%	20% by 2032	Vermont DG < 5 MW achieving commercial operation in 2010 or later, and output from existing hydro certified by Low-Impact Hydro Institute and < 5 MW. Final requirement is doubled from original RES, but existing supply has increased with the earlier COD and LIHI resources
Tier IV	N/A	N/A	None	20% by 2035	New tier added for regional renewables built in 2010 or later to include utility scale wind and solar. For hydro, generators must be < 200 MW.

Table 6-1. Comparison of Vermont's original RES (2017) and the 2024 revisions to requirements for renewable energy supply.

RES compliance is demonstrated through the retirement of RECs in the NEPOOL Generation Information System (GIS). Each REC represents 1 MWh of renewable energy actually delivered into and used in the New England region. RECs can be sourced from utility-generating plants, energy PPAs that include RECs, and REC-only purchases. The updated RES did not change how RECs are counted for compliance. Utilities submit annual compliance filings to the PUC, demonstrating that annual RES requirements have been met. As discussed further in **Chapter 5**, this system of accounting is transparent and uniform across the New England states, helping make our region a leader in the clean energy transition.

The 2024 RES revisions call for future studies and check-backs to ensure the structure is working well for Vermonters. The first of these is a report required by January 2025 from the Department of Public Service proposing a replacement program for group net metering to reduce operating costs and encourage electrification and decarbonization of buildings, with a focus on affordable housing and community solar programs. And in 2028, the PUC will open a docket to evaluate the status of the RES including costs and availability of resources, making recommendations for adjustments as needed.

The RES requirements will become the guideposts as GMP seeks paths for achieving a cost-effective, all-renewable portfolio that is compliant with Tiers I, II, and IV in the years ahead. **Chapter 7** describes this work.

GMP Current Supply Portfolio

Our current portfolio of resources uses diverse, carbon-free, and increasingly renewable resources, fulfilling current RES requirements, and setting the path for more rigorous requirements in the years ahead. Our current portfolio includes contracts of differing durations, generation sources, types, and volumes, along with a significant amount of distributed renewable generation. All these resources support continued renewable generation in Vermont and regionally, while supplying reliable energy sources that offer resilience as climate-driven extreme weather accelerates in Vermont.

Figure 6-1 depicts our energy supply for Calendar Year 2023 *before* the purchase and sale of renewable energy certificates (RECs). **Figure 6-2** shows energy supply for the same period *after* the purchase and sale of RECs, as filed in our 2023 RES compliance annual report.

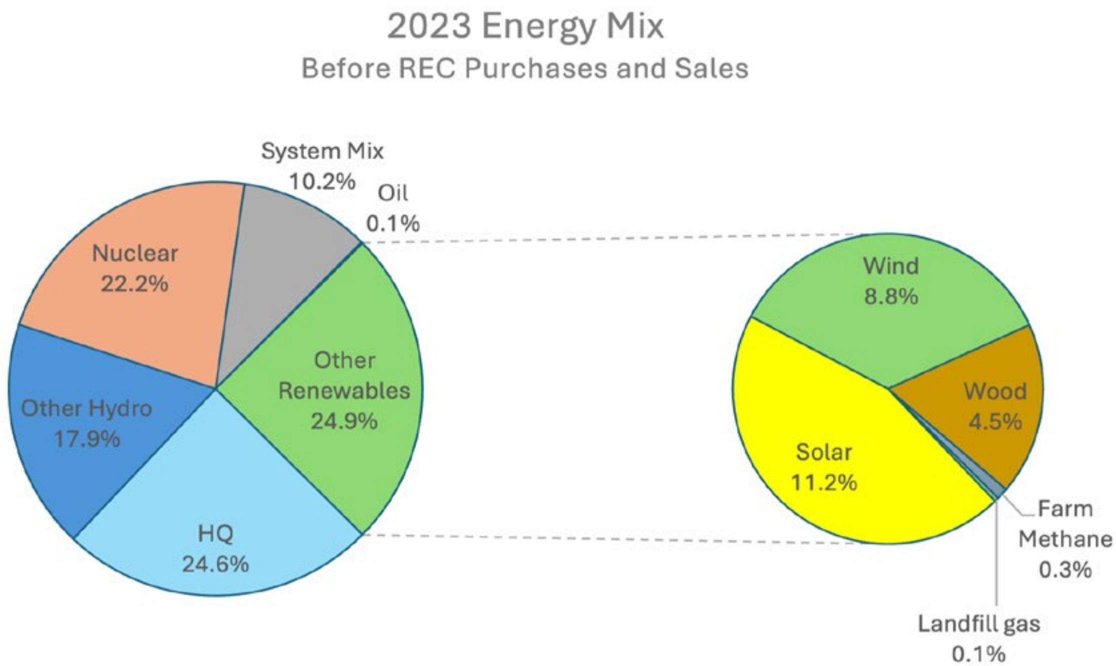


Figure 6-1. Energy supply mix, before accounting for REC transactions.

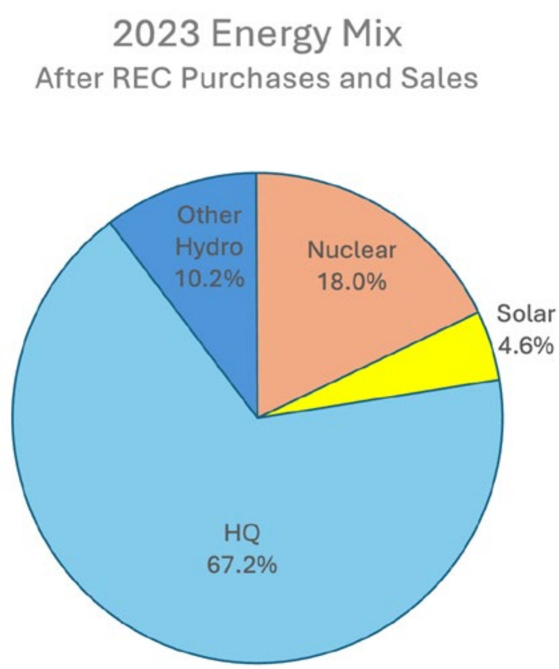


Figure 6-2. Energy supply mix, after accounting for REC transactions.

In 2023, as in previous years, we sold all premium wind and solar RECs that were not used for Vermont RES compliance, which helped lower costs for all customers. As RES Tier II amounts increase and the new Tier IV takes effect in 2027, we will begin to retire more wind and solar RECs from our portfolio to fulfill Vermont RES requirements.

Our power supply resources involve output from:

- GMP's own facilities
- Distributed generation renewable and storage resources that are customer-sited (net-metered) or under power purchase agreements (PPAs)
- Long-term power purchase agreements (PPAs) with resources across Vermont, the Northeast, and Quebec
- Shorter-term market-based purchases with durations typically less than five years

Below each category is described in detail.

Owned Hydroelectric Generation

GMP's 41 owned hydroelectric generators have a total nameplate capacity of 117 MW of electricity and produce an average of 410,000 MWh of energy each year. These resources provide capacity amounting to approximately 65 MW through either the ISO New England Forward Capacity Market (FCM) or as load reducers, and additional seasonal capacity payments (see discussion of GMP's market participation in the **Forward Capacity Market** in **Chapter 5**).

Collectively, GMP's hydroelectric fleet typically generates around 10 percent of energy need annually. The output of the plants can vary each day, month, or year, depending on seasonal river flows, compliance requirements, annual precipitation, and planned and unplanned outages.

As our hydroelectric fleet ages and rivers face increasing challenges from extreme rainfall events, we continually assess capital investments in our generating plants based on safety, regulatory obligations, and operational efficiency. These evaluations first prioritize public and team safety, followed by requirements for regulatory compliance and plant efficiency improvements, which can include increased production or better peaking capability. Although these plants have regular operation and maintenance expenses and require periodic project improvements (and FERC re-licensing), they are the longest-lived assets in the supply category. On average, the cost of power from our hydroelectric fleet is low and stable for customers.

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. Our hydroelectric plants all qualify as Tier I resources and can be used to meet the RES Tier I requirements of 100 percent renewable energy supply by 2030. Currently, 19 of our plants, totaling almost 65 MW of capacity, are certified by the Low Impact Hydro Institute (LIHI), with an additional six plants with 11 MW of capacity expected to become certified during this planning period. In addition to being eligible and qualified for premium Massachusetts Class II RECs, the new RES includes LIHI-certified hydro projects with a nameplate capacity of 5 MW or less as Tier II eligible resources. Qualification in multiple markets gives us the option to use these RECs for future RES compliance, and / or to sell the RECs to reduce net power costs and retail rates for customers.

In 2018 and again in 2023, we transitioned several generating units that were historically represented in the ISO New England market to operation as load reducers.[3] 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 New England systems. This saved customers money by limiting our share of Regional Network Service (RNS) transmission charges and regional capacity market costs (see also the discussion of **Ancillary Services Markets** in **Chapter 5**).

Table 6-2 lists our hydroelectric fleet, organized by total MW per waterway. This IRP's **Appendix G** contains a plant-by-plant summary of our hydroelectric fleet, including license status and major improvements that have been completed or are in progress.

3 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 New England composite resources as of June 1, 2018. The Lower Lamoille Composite—the Clark Falls, Milton, and Peterson plants—still operates as a composite resource. As of June 1, 2023, the following GMP-owned and -operated plants are no longer ISO New England resources: Arnold Falls, Barnet, Beldens Falls, Carver Falls, Cavendish, Center Rutland, Dewey Mills, East Barnet, Gage, Gorge, Middlebury Lower, Middlesex 2, Newbury, Ottauquechee, Passumpsic, Patch, Pierce Mills, Smith, Taftsville, and Vergennes.

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, Essex #19 Hydro, Gorge #18 (2025), Middlesex #2
East Creek	6.00	East Pittsford, Glen, Patch
Little River	5.52	Waterbury 22
Molly's Brook	5.00	Marshfield #6 (2025)
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, Salmon Falls, Somersworth/Lower Great Falls
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 (2024)
Total	**116.34**	***License renewal year in parentheses if by 2030**

Table 6-2. GMP hydroelectric resources, by waterway.

Owned Wind Generation

Kingdom Community Wind

Kingdom Community Wind in Lowell, Vermont, is a 21-turbine wind facility with a nameplate capacity of 64.5 MW. Each turbine is rated at just over 3 MW. We own and operate the entire facility and retain 87 percent (55 MW) of the output for our customers. The remaining output serves Vermont Electric Cooperative customers, via a long-term power sale agreement. On average, the plant is expected to operate at a 33 percent annual capacity factor, which yields approximately 186,000 MWh of energy annually.

The plant became operational at the end of 2012, qualifying it as a contribution toward the "new regional renewable" generation requirements in the RES Tier IV. With a projected life of 25 years, the end of the plant's useful life will be reached during this IRP's 20-year planning period, in 2037. We expect to maintain the plant and generate energy past 2037 and will consider next steps for the facility to continue to benefit customers as that date approaches. KCW produces RECs that were previously more valuable to GMP customers to sell out of state. Under the RES, KCW now qualifies as a Tier IV resource, meaning that in the years ahead GMP will be able to bring these RECs home to Vermont to satisfy RES requirements and keep KCW's renewable energy with Vermonters.

During winter months, KCW occasionally experiences ice accumulation on its turbine blades, which per the PUC approved winter operating protocol, requires some or all turbines to be shut down until the ice melts or falls off. To minimize icing, we preemptively take the plant offline during weather conditions that are likely to cause ice buildup. This prevents the blades from rotating and reduces ice formation and the potential loss of generation. However, as Vermont sees warmer, wetter weather systems, recent winter patterns have increasingly favored conditions that promote icing, which has had a growing effect on the plant's generation.

KCW's output has periodically been curtailed by ISO New England to manage constraints on the transmission system. Such congestion tends to occur during times when electric load in northern Vermont is low or when one or more elements of the transmission system in northern Vermont is temporarily out of service. During 2023 and 2024, congestion of the Sheffield Highgate Export Interface (SHEI) and associated curtailment declined substantially, in part because of declines in the volume of energy flowing southbound from Quebec into the SHEI area via the Highgate Converter. Because energy demand in Quebec is forecast to increase significantly in the future and Hydro-Quebec will be exporting substantial volumes of energy to Maine, New York, and elsewhere under new long-term contracts, it is not clear if higher levels will recur. In addition, GMP has completed the Lowell-to-Morrisville transmission upgrade project. Upon completion of ISO New England transmission studies, GMP projects a noticeable increase in the export limits for the SHEI. It therefore appears likely that SHEI-driven congestion costs and curtailment of KCW output will remain improved and at moderate levels for the next several years. Lastly, VELCO is rebuilding a 115 kV Transmission line, known as the K42 line, which connects Highgate into Chittenden County. This will also have positive impacts for the SHEI region, further reducing congestion.

Searsburg

Searsburg is an 11-turbine, 6-MW facility, and was the first utility-scale wind facility installed in the Northeast (1997). After 27 years of production, Searsburg continues to operate, producing energy at an average annual capacity factor of about 22 percent.

GMP expects to seek approval within the next two years to re-power the Searsburg Wind site with larger, more efficient turbines. DNV, an independent expert in wind analysis, led the evaluation through comprehensive wind studies and turbine selection processes. Since turbine models vary in characteristics, DNV's modeling has enabled GMP to forecast the annual energy output of potential turbine options. As part of the process, GMP hosted a site visit with the Department of Environmental Conservation (DEC) and provided a high-level project overview. Additionally, a local acoustics expert developed acoustic models for the site, and our environmental consultants have also conducted on-site studies to support the re-powering evaluation.

The evaluation concluded with a decision to move forward with re-powering the site. Advances in turbine technology over the last few decades mean replacing the older turbines with three to four modern turbines would more than double the site's nameplate capacity—from 6 MW to between 12 and 16 MW, depending on the turbine model. GMP is collaborating with several turbine vendors to identify suitable models that accommodate the site's environmental requirements, operational needs, and anticipated availability of turbines in 2027. Any repowering would allow this site to qualify as a Tier IV resource for RES, another reason to maximize the ability to use this already-built infrastructure to advance Vermont's renewable goals. A full cost-benefit analysis was performed based on known information at the time and has shown it is beneficial for customers to continue evaluating. As with any generation-based Section 248 permit, a full need and cost benefit analysis will be conducted and filed to receive approval for this repowering if we move ahead.

Jointly Owned Generation

GMP jointly owns four generation facilities and one transmission facility, with characteristics shown in **Table 6-3.** The generation facilities are one wood chip plant, one nuclear plant, and two fossil-fuel projects.

Resource name	Age (years)	GMP share nameplate MW	2023 MWh
McNeil Station	40	15.5	57,000
Millstone #3	38	21.4	142,300
Stony Brook 1A, 1B, 1C	43	31	1,300
Wyman #4	46	17.7	1,200
HVDC Phase 2 Transmission	34	112	n/a
Total		**197.6**	**240,000**

Table 6-3. GMP's jointly owned generation resources.

McNeil Station (Wood Chip)

This station is a 50-MW wood-fired generation facility in Burlington. GMP currently owns 31 percent of the plant, equating to about 15.5 MW of the plant's output, and pays for its proportional share of operating costs. In 2023, GMP's share of the plant's output was approximately 57,000 MWh, a small resource within the overall portfolio, equaling about one percent. Although the McNeil facility can also operate on natural gas, either alone or in combination with woodchips, it rarely does. The Burlington Electric Department (BED) owns 50 percent of the facility, and Vermont Public Power Supply Authority (VPPSA) the remaining 19 percent. BED operates the facility on behalf of the joint owners.

Consistent with GMP's planning approach in prior years, GMP does not include McNeil as a part of its portfolio for GHG and RES purposes given the emissions profile of the facility, which is not a carbon-free resource, and GMP's practice of selling the RECs into the Connecticut REC market. In 2008, the McNeil Station installed a selective catalytic reduction system to reduce its nitrogen oxides (NO_x) emissions. This emission reduction enabled the plant's output to qualify as a Connecticut Class 1 Renewable Portfolio Standard (RPS) resource. GMP typically sells McNeil RECs to load-serving entities in Connecticut for RPS compliance, and we currently have contracts to sell a portion of them to Connecticut distribution utilities through 2025.

In October 2024, BED announced it would seek to acquire sole ownership of the plant from GMP and VPPSA. GMP is engaged in a review and negotiation with the joint owners now, recognizing both BED's desire to control this resource for its possible use for district energy in support of Burlington's Net Zero goals and the overall minor role it plays in GMP's supply resources for customers. GMP will make a determination as to what is the best outcome for our customers. As mentioned, this facility has not been used to meet any portion of the RES or climate goals for GMP.

Millstone Unit #3 (Nuclear)

Millstone is a 1,235 MW pressurized-water baseload nuclear reactor, part of the three-unit Millstone Station in Waterford, Connecticut, on Long Island Sound. Millstone #3 began commercial operations in 1986; GMP owns a 1.7303 percent (21.4 MW) share of the unit, which generated 142,000 MWh for GMP in 2023. Dominion Nuclear Connecticut owns 93.470 percent of the unit, and Massachusetts Municipal Wholesale Electric Company (MMWEC) owns the remaining 4.799 percent. Dominion Nuclear Connecticut operates the facility on behalf of its joint owners. In addition to baseload energy and capacity, Millstone also provides carbon-free nuclear attributes. As we move toward our 100% renewable requirement in 2030, we will face key decisions on these attributes—whether we retire them in our portfolio or sell them. These attributes help bridge gaps in our supply and demand alignment. Our evaluation, as further described in **Chapter 7**, will weigh the benefits of retaining attributes to enhance alignment against the potential revenue from selling these carbon-free attributes.

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

Stony Brook Station (Fossil Fuels)

The Stony Brook Station, near Springfield, Massachusetts, is a combined-cycle generation facility powered by both natural gas and oil. It features peaking and intermediate units. The intermediate units (1A, 1B, and 1C) have a combined capacity of 353 MW and primarily function as peaking generation, with an annual capacity factor of less than five percent. Although natural gas is the primary fuel, the plant can operate on oil for extended periods during winter cold snaps, offering support to customers when regional natural gas supplies are constrained. The combined-cycle plant can start up quickly in response to regional market needs and can operate across many output levels.

Stony Brook has been in commercial operation since 1981. We own an 8.8 percent (31 MW) stake in the intermediate units, along with an additional share of the output through a long-term PPA. MMWEC operates the facility on behalf of its joint owners, primarily Massachusetts municipal utilities.

Wyman Station (Fossil Fuel)

Wyman Station facilities are on Cousins Island near Yarmouth, Maine, and comprise four generating units. Unit 4, the largest at 606 MW, is a steam unit that burns residual oil as the primary fuel, and functions as a peaking generator in the ISO New England dispatch. It can be dispatched over a wide range of output levels. Unit 4 began commercial operations in 1978 and was intended to function as an intermediate dispatch unit. GMP owns a 2.9 percent (17.7 MW) share; NextEra owns 84.3 percent of the plant and operates the facility on our behalf and the unit's other joint owners.

Wyman #4 earns FCM and other ancillary product revenue from ISO New England. The plant has been economically dispatched at low annual capacity factors in recent years, but it tends to be dispatched more heavily and provides customer savings in 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 short-term, unexpected outage events regionally.

HVDC Phase 2

The High-Voltage Direct Current (HVDC) Phase 2 transmission and converter terminal facilities interconnect the Hydro-Quebec system to the ISO New England system with a nominal transfer capability of 2,000 MW. We have both an equity ownership share and a leased share of the facility, providing use rights to approximately eight percent of the facility's available transmission capacity (approximately 100 MW of firm capacity at typical availability).

ISO New England recognizes the contribution of this interconnection to regional resource adequacy, and presently provides us with approximately 70 MW per month of FCM credits via Hydro-Quebec Interconnection Capability Credits. We currently resell the energy-use rights of the facility, in the short term, to other entities wishing to import energy across the facility. Revenue from this participation reduces our net power costs for customers.

Owned Peaking Generation

GMP owns four fossil-fired generation plants currently in service and operated in a peaking role in Vermont with one additional fossil-fired plant that is actively going through decommissioning. As our network of dispatchable stored energy grows, we are beginning to retire these plants. Evaluating these units involves assessing their ability to meet current and future emissions standards, the cost of upgrades to comply with evolving environmental requirements, and the age and condition of equipment, including fuel storage tanks and the associated risk with those components, as many components are at or near end of life. The Vergennes units were retired and physically removed from the site in 2023. The Rutland gas generator was taken offline in April 2024 and scheduled for demolition and recycling in 2025. As energy storage grows, additional fossil retirements will happen, particularly for sites with redevelopment potential as Battery Energy Storage Systems (BESS). Gorge and Ascutney, both about 60 years old, are the next likely candidates for retirement in the next five to eight years. GMP will review the costs to maintain and operate these, the risks of continued operation weighed against the benefits received in the power markets to determine the appropriate timing of retirement.

The remaining peaking units operate in limited and narrow ways during peak load days or other times when energy market prices in the ISO New England market are unusually high. Occasionally, their operation also supports the Vermont transmission system and provides ancillary products (for example, quick-start operating reserves or ISO-NE's Inventoried Energy Program) required for operation of the NEPOOL system.

All of these units' air permits were renewed in 2023, valid into 2028. Although these plants do not operate often (typical annual capacity factors are less than one percent), they have at times provided significant value for customers through participation in the FCM and ISO New England's Forward Reserve Market (FRM). Each year, however, these revenue streams continue to decline in value because of changing market conditions and operational performance while the risk of continued operations increases. **Table 6-4** is a plant-by-plant summary of our peaking generation, including one pending retirement as noted.

Resource name	Location	Age (years)	Nameplate MW	Description
Ascutney Gas Turbine	Ascutney	57	12.5	A 2-stage turbine, internal combustion unit, operating under an air pollution control permit issued by the Vermont Agency of Natural Resources' (VANR's) Air Quality and Climate Division. Significant recent improvements are 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	46	46.5	The largest peaking plant in Vermont, consisting 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 2 on-site fuel tanks. In 2008, 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. Other improvements, upgrades, and replacements were made in 2012 and 2013. Automation, control, relay protection and fire suppression were upgraded in 2019 and 2020. The plant now participates in the ISO FRM and Inventoried Energy Program.
Essex Diesels	Essex	12	8.0	A facility with 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 diesel engines and upgrading all associated switchgear and controls.
Gorge Gas Turbine	Colchester	53	17.0	A 2-stage turbine, internal combustion unit in Colchester. The unit operates under an air pollution control permit issued by 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	55	12.5	Taken offline and removed from service in April 2024. The physical removal and demolition are scheduled to be completed in 2025.
Total			**84 MW currently online**	

Table 6-4. GMP-owned peaking generation portfolio.

Solar Generation and Energy Storage—GMP-Owned, Customer-Sited, and Under PPA

As noted throughout our IRP, a resilient, reliable energy system requires dynamic, two-way energy flow and solar and energy storage will continue to have an important role in our portfolio over the IRP planning period, particularly with load control. GMP has commissioned over 39 MW of alternating current (AC) of solar PV capacity, with 7 MW/34 MWh-AC of associated battery storage capacity as part of the GMP solar and GMP solar plus storage programs. Each energy storage project features distinct design considerations to provide portfolio-level flexibility and value for customers. In addition, customer-sited solar and storage both are meaningful resources in GMP's portfolio that will grow in the years ahead. The section below describes all of the solar and storage resources GMP maintains in its current portfolio.

GMP-Owned Solar

Listed in **Table 6-5** as *GMP Solar*, GMP commissioned five utility-scale solar projects in 2016 as part of the original GMP Solar Joint Venture program—now, wholly-owned GMP facilities:

- 4.69 MW (AC) in Williston
- 2 MW (AC) in Richmond
- 4.992 MW (AC) in Hartford
- 4.9 MW (AC) in Panton
- 4.99 MW (AC) in Williamstown

All the 2016 projects used fixed-tilt racking systems, except for Panton, which installed sun-responsive single-axis trackers. The estimated lifetime cost of power from these projects was the lowest among Vermont solar PV projects, when the projects were developed.

The Panton solar site also has a 1 MW/4 MWh battery system, commissioned in 2018, that provides peak load reduction and frequency regulation services to the grid. In 2021, GMP installed the first-of-its-kind inverter-based microgrid at this site, designed to keep a portion of Panton connected, with energy still flowing, even if the greater grid in the area is damaged. This all-renewable microgrid can island 51 residential and commercial customers, including the Panton Town Hall, a town garage, and a farm. Under normal conditions, the project continues to deliver a flexible solar + storage resource for our portfolio (see **GMP Solar + Storage,** below). The Panton microgrid was successfully tested and physically islanded a portion of Panton after commissioning of the facility. Further, GMP in partnership with the Addison Country Regional Planning Commission and a grant from the EPA is studying the potential to expand the island further out on the circuit in order to incorporate more customers in the islanded area. As with all microgrids, you must balance the tradeoff of a larger island with the greater risk of a fault occurring inside of the island area.

Solar PV equipment has been installed at several GMP properties, as well as at partner-owned sites and on streetlights. For example, solar has been installed at a site on Cleveland Avenue (Creek Path Solar) in Rutland, on several hydro facilities' rooftops, and at several of our office buildings. We have also installed a project at Rutland Regional Medical Center.

GMP-owned solar plants account for only a small portion of the total solar PV capacity in Vermont. Most solar development has been driven by net metering, the Standard Offer program, and bilateral PPAs, where we purchase the output from specific projects.

GMP Solar + Storage

An important feature of GMP storage resources is their co-location with solar generation facilities. In addition to the Panton project, GMP Solar + Storage projects in Milton (4.99 MW-AC), Essex (4.5 MW-AC), and Ferrisburgh (4.99 MW-AC) are integral to the energy storage initiative aimed at reducing peak load and providing frequency regulation services. Onsite solar generation primarily charges the projects, and each site hosts a 2 MW/8 MWh battery storage system.

Commissioned in 2019, the three solar + storage sites in Milton, Essex, and Ferrisburgh have operated reliably and effectively for more than five years. Developed in a joint venture, these projects will transition to being wholly owned GMP subsidiaries in late 2024 and will become directly owned power supply assets by October 2026. These facilities generate power and RECs while delivering added value to customers by reducing costs through peak shaving and participating in the ISO New England frequency regulation market when peak demand is not forecasted. The full list of GMP-owned DG solar + storage resources is in **Table 6-5**. All of these resources are eligible Vermont Tier II resources.

Location	Ownership	Solar MW (AC)	Battery MW	Technology Type	Date resource came online
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	GMP Solar	4.992	-	Solar	12/13/2016
Milton	GMP MicroGrid-Milton, LLC	4.99	2.0	Solar/Battery	9/4/2019
Panton	GMP Solar	4.9	1.0	Solar/Battery	12/9/2016 (2018)
Richmond	GMP Solar	2.0	-	Solar	9/11/2016
Rutland City	GMP	0.010	-	Solar	4/7/2014
Rutland City	GMP	0.059	-	Solar	5/20/2014
Stafford Hill	GMP	2.0		Solar	3/30/2015
Rutland Town	GMP	0.048	-	Solar	4/2/2019
Williston	GMP Solar	4.69	-	Solar	11/8/2016
Williamstown	GMP Solar	4.99	-	Solar	12/27/2016
		38 MW+	**7 MW**		

Table 6-5. GMP-owned distributed generation resources.

Customer-Sited Net-Metered Solar

Vermont's net-metering program has been in place for over 20 years, with the primary purpose of enabling customers to offset their electricity use with their own onsite generation. Before GMP implemented a six-cent-per-kWh solar "adder" benefit to its rate structure 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, because of its coincidence with local and regional peak demands during daytime hours. The adjustors' benefits resulted in significant adoption of net-metering projects throughout Vermont. Historically, GMP has satisfied the majority of its RES Tier

II obligations with RECs from net-metering projects. Net metering has been the largest source of solar PV in our territory, with a much greater installed capacity than solar PV from larger-scale projects, which come at lower costs per kWh.

Figure 6-3 shows the growth of operating net-metering capacity from 2010 to the present. Solar PV projects have driven the growth and presently account for 97+ percent of the net-metered generation fleet.

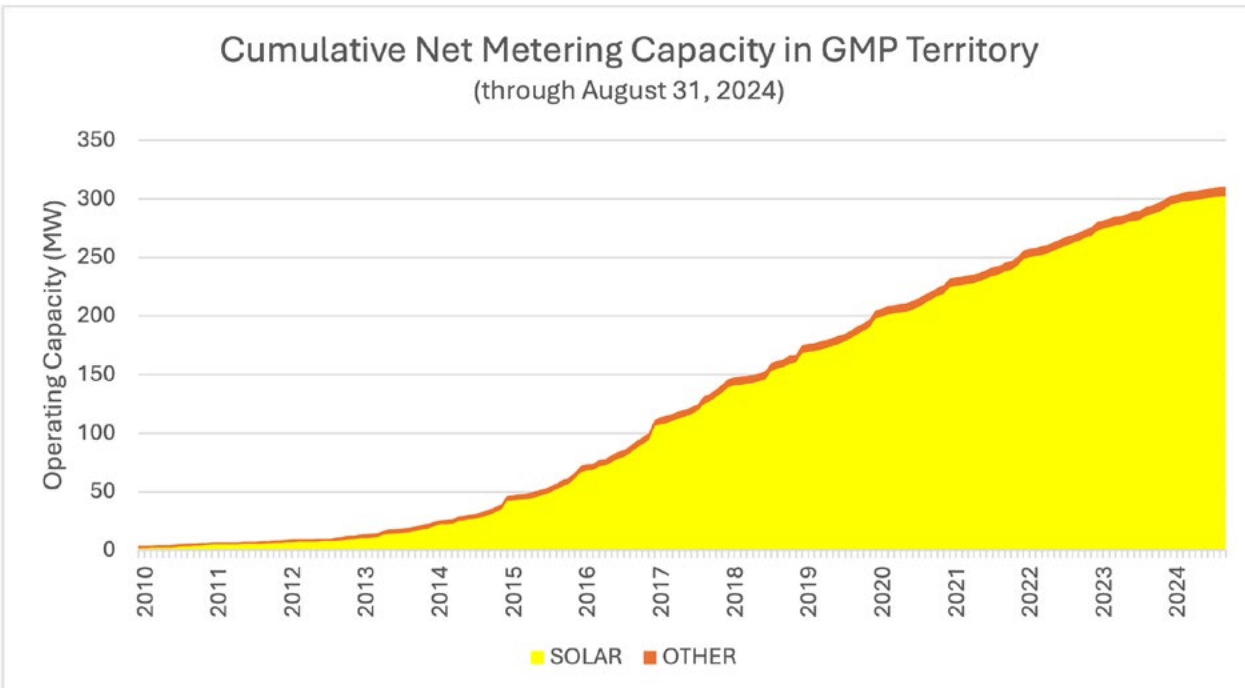


Figure 6-3. GMP's cumulative net-metering capacity, from 2010 to the present.

Figure 6-4 shows annual volumes of net-metering capacity that achieved commercial operation in GMP's service territory each year. In the past 10 years, the amount of net-metered capacity reaching commercial operation ranged from 22 MW in 2014 to nearly 40 MW in 2016. In recent years, annual installations have stabilized to around 24 MW each year, with essentially an even split between small projects (up to 15 kW) and large projects (150 kW to 500 kW) projects, making up about 85 percent of all installed capacity. Installations to date in 2024 are lower than previous years, particularly for large projects, with 10 MW of installed capacity in the first 10 months of the year.

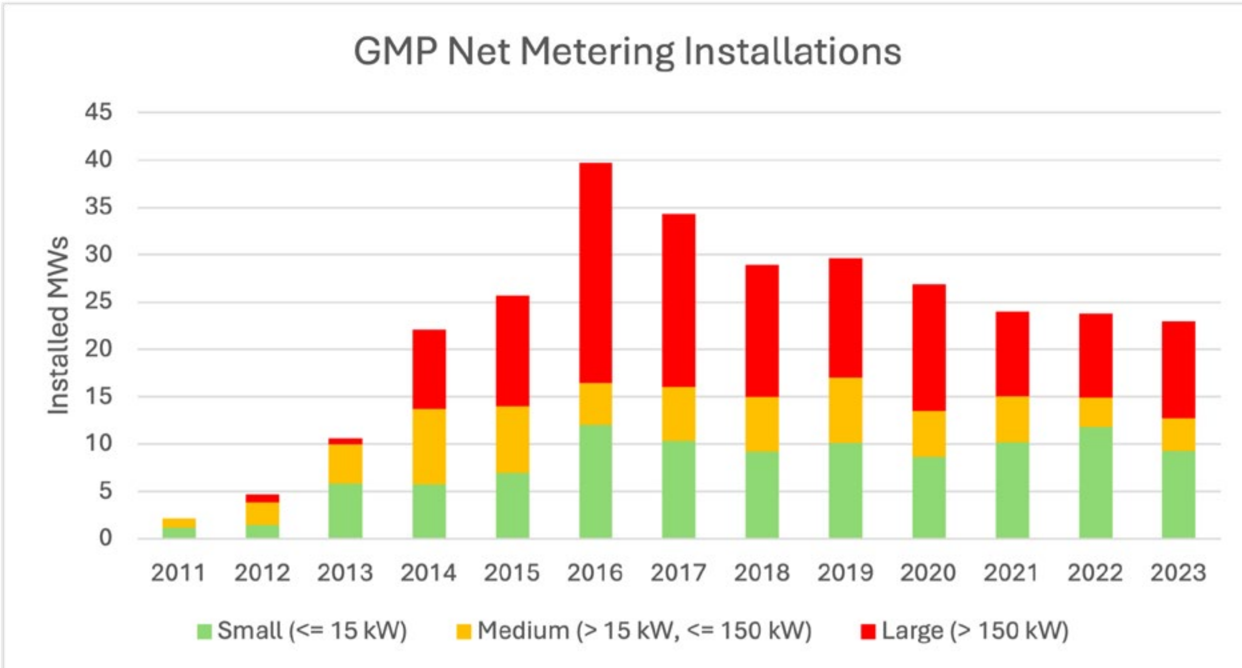


Figure 6-4. Annual net-metering capacity, from 2011 through 2023, shows the proportion of small, medium, and large installations for each year.

GMP's service territory now hosts nearly 310 MW of net-metered generating capacity. The expansion of net-metering eligibility to projects up to 500 kW and a rapid decline in the cost of solar PV project costs have driven this growth. However, as more net-metering projects have come online, the value of the output has steadily declined because of shifts in the timing of monthly peak demand—which now occurs later in the day.

In response to this growing mismatch between benefits and costs and impact on non-participating customers, the PUC has gradually reduced payment rates for new net-metered generation through its biennial program reviews to bring the compensation better in line with the benefits. Further, the 2024 RES revisions have defined future group net-metering projects to those located physically adjacent to where the energy is consumed. This effectively will return net metering to customer-sited installations, not "virtual," and will shift the emphasis to larger, lower-cost renewable resources and community scale programs like the GMP Shared Solar tariff.

This shift will be particularly helpful in meeting the new RES requirements, which double Tier II requirements for in-state DG to account for 20 percent of annual load by 2032. This will require GMP to procure additional resources to satisfy the higher Tier II requirements.

Solar PPAs

As set forth in Table 6-6 below, GMP has a number of longer-term PPAs for solar resources located in Vermont, in addition to its share of Standard Offer projects described elsewhere. GMP has also initiated a few programs that will begin to address the increased Tier II requirement and will lead to future procurement designs. Specifically, the Shared Solar Program is designed to connect customers with the benefits of solar outside the current net-metering program through direct GMP PPAs for solar projects. This program takes advantage of the Low-Income Communities Bonus Credit portion of the Inflation Reduction Act to deliver the benefits of distributed solar to customers in an inclusive way. Soon GMP expects to expand the Shared Solar design to support elements of Solar for All Vermont funding to similarly launch community-scaled solar projects for underserved populations that have had barriers to participation within the traditional net-meter design. The ACRE program, as described further in **Chapter 1**, supported by State ARPA funding, similarly will match low-income customers with new solar projects under GMP PPA, using the grant funding to provide direct bill credits for participating customers.

Larger community-scale solar projects will be an integral part of GMP's procurement path under the new RES Tier II requirements with their lower overall production costs, and the ability to connect these projects directly to customers taking the State's Environmental Justice provisions into consideration, when possible.[4] We consider the value of different DG procurement for these types of projects in **Chapter 7**.

Customer-Sited and Other Storage Resources

There had been remarkable growth in customer adoption of home energy storage for resiliency through GMP's programs, especially since receiving regulatory approval to lift the enrollment cap starting in August 2023. **Chapter 2** describes in more detail this important fleet of customer-sited resources and their effect on our load forecast and load management. Energy storage resources are already delivering expected benefits in terms of type, scale, and location. In partnership with customers, Tesla Powerwalls and other residential energy storage installations now contribute over 35 MW of installed capacity to our system. This network allows us to coordinate charging and discharging to manage overall system load, reducing capacity and transmission costs and carbon emissions for all customers while providing reliability and backup power at individual locations. The installed capacity also serves as a 5 MW aggregation resource in ISO New England's Frequency Regulation Market, providing additional revenue. This successful deployment has offered valuable learning experiences for both GMP and ISO New England, marking

4 Although the literature contains many recent interpretations of energy justice principles, GMP is guided by the Initiative for Energy Justice's essential objective: "The goal of energy justice or energy equity is to achieve equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system." *Initiative for Energy Justice: The Energy Justice Workbook*, page 60.

the first aggregation of batteries used in this manner. This aggregation is projected to grow to 30 MW within two years.

Larger, multi-MW projects like those in Barre, Springfield, Georgia, and Bristol contribute an additional 19 MW of capacity, offering a clean alternative to traditional peaking fossil fuel generators. For both residential and standalone installations, GMP seamlessly manages energy storage system operations to respond to peak demand conditions, avoiding regional costs associated with bulk system use during critical periods, saving customers money. Similar to quick-start generation resources, these storage facilities can provide frequency regulation and other ancillary services when not actively used for peak reduction.

Another example of a larger-scale energy storage installation is the North Troy Battery, commissioned in July 2024 and co-owned with Vermont Electric Cooperative (VEC). The 3-MW system received a grant from the U.S. Department of Energy (DOE), and the project will help Sandia National Laboratories and the DOE study how batteries can expand renewable energy production and integrate more renewables into the New England Grid. GMP and VEC each own a 50 percent share of the project, located in VEC's service territory. GMP has the lead operational control of the system; approaches with respect to use cases will be determined in consultation with VEC. In addition to storing renewable energy during times of strong production and low demand in the area, the battery helps reduce peak demand on the regional grid with these benefits directly benefiting our customers.

Table 6-6 lists other storage resources in GMP's portfolio, as of August 31, 2024.

Location	**Ownership**	**Battery MW**	**Technology type**	**Date resource came online**
Barre	PPA	4.999 total (3.0 GMP share)	Solar / battery	February 5, 2021
Georgia	PPA	4.99	Battery	March 10, 2023
North Springfield	PPA	4.99	Battery	March 25, 2023
Waterbury	PPA	1.00	Transportable battery	January 3, 2024
Bristol	PPA	2.95	Battery	June 27, 2024
North Troy	Joint Owned	3.0 total (1.5 GMP share)	Battery	August 2024
Middlebury	PPA	2.00	Battery	*December 2025
Royalton	PPA	4.90	Battery	*December 2025
Throughout GMP service territory	Customer Powerwall and BYOD Programs	36+	Residential scale batteries	Various
		Total: 64 MW+		* Estimated commercial operation date

Table 6-6. Other storage resources, their ownership, and battery capacity.

Long-Term Renewable and Carbon-Free Power Purchases

A significant portion of our energy supply is secured through long-term PPAs with individual suppliers. As we advance toward 100 percent renewable by 2030—having already reached 100 percent carbon-free for our annual supply portfolio—and as the region shifts toward a cleaner energy mix, these long-term resources will play an important role in supporting our progress and the growth of both regional and in-state renewable energy. Throughout the IRP period, our energy supply will be sourced from long-term PPAs, including agreements with Great River Hydro, the U.S. subsidiary of Hydro-Québec, and NextEra, along with an increasing share of local distributed resource purchases. **Table 6-7** presents current contracts and 2023 energy volumes.

Contract name	Contract period	Contract MW	2023 MWh
Great River Hydro1	2023–2052	variable	161,000
HQ Energy Service (U.S.) (HQUS)2	2012–2038	178	1,053,000
NextEra Seabrook3	Through 2034	55	418,000
Granite Reliable Wind	2012–2032	up to 82	140,000
Deerfield Wind	2017–2042	30	91,000
Vermont Renewable PPAs - hydro	Mid-2030s	variable	134,000
Vermont Renewable PPAs - solar	Mid-2030s	variable	29,000
Standard Offer	Late 2030s into 2040s	variable	98,000
		Total	**2,124,000**

Table 6-7. Current long-term PPAs. Notes: (1) Great River Hydro ramps up to full volume by 2033; (2) The HQUS contract delivers firm energy without capacity; (3) Our purchase of plant-contingent energy, capacity, and generation attributes from NextEra Seabrook involves 55 MW in 2024 and declines to 50 MW in 2029.

Great River Hydro PPA In 2021, we entered into a long-term agreement for energy and environmental attributes from Great River Hydro's portfolio of 13 hydroelectric facilities along the Connecticut and Deerfield Rivers in Vermont, New Hampshire, and Massachusetts. The first deliveries under this agreement began in January 2023, with volumes increasing each year under two distinct delivery schedules: peaking and firm. Peaking hydroelectric energy will come from three units at the Fifteen Mile Falls facilities on the Connecticut River, with deliveries starting at 20 percent of their hourly output in 2023 and gradually increasing to 50 percent by 2029, continuing annually through 2052.

Firm hydroelectric energy deliveries will provide a fixed amount of energy each year, starting at 5 MW per hour in 2028 and ramping up to 30 MW per hour by 2033, continuing at that level each year through 2052.

HQUS PPA In April 2011, GMP and other Vermont distribution utilities received approval from the PUC for a 26-year PPA with HQUS, starting in November 2012. The HQUS PPA provides approximately 1 million MWh of energy annually—about 20 percent of our current annual energy needs—delivered on a flat schedule during the peak 16 hours of each day for much of the contract term. These deliveries are financially firm and are not dependent 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. This purchase does not include capacity delivery.

NextEra Seabrook PPA GMP purchases 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 a 90 percent annual capacity factor, this equates to approximately 450,000 MWh or about 11 percent of our annual energy needs. Deliveries under this contract are scheduled to decrease by 5 MW (around 80,000 MWh per year) in June 2029, with the PPA ending in 2034. In addition, we have secured an extra 25 MW of capacity (without associated energy or attributes), which remains constant over time.

The second PPA provides an additional 150 MW of long-term, plant-contingent capacity, along with 5 MW of additional plant-contingent energy and attributes that will increase to 10 MW in June 2029; 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. The two transactions together account for our purchase of plant-contingent energy and attributes of 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.

As GMP transitions the rest of its portfolio to 100% renewable annually, this carbon-free resource will continue to be important as a source of year-round supply of energy and capacity. This PPA will also provide an opportunity to explore the benefits of selling the carbon-free nuclear attributes in the market. During the next few years, we will be reviewing ways to use the final years of this PPA to create customer value as we meet the new RES requirements.

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

Deerfield Wind PPA GMP purchases 100 percent of the output from a 30-MW wind plant in Searsburg and Readsboro, under a 25-year contract that contains an option to purchase the plant for a fixed price in 2027, after 10 years of operation. The plant began commercial operations and started delivering plant-contingent energy, capacity, and RECs in December 2017. Over the past five years, the facility has averaged just under 100,000 MWh of annual output. As described further GMP will be evaluating this purchase option in the same timeframe as our Searsburg repower project.

Vermont Renewable PPAs To help facilitate development of local small renewable projects and to 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. Another 40 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 Sustainably Priced Energy for Economic Development (SPEED) legislation, GMP receives a share of the long-term contracts signed under the Vermont Standard Offer program. The program was designed to achieve approximately 127 MW of in-state, new renewable contracts over a 10-year procurement period. The program has already contracted for the full procurement of 127 MW, with over 87 MW of installed capacity online as of September 2024.

Under this program, GMP receives a load ratio share (presently about 83 percent) of the production from these resources, each 2.2 MW or smaller and committed at fixed, levelized prices for 20 or 25 years. Today, these resources provide us with about 100,000 MWh per year of renewable energy. **Chapter 7** contains assumptions that the Standard Offer program will ultimately support sufficient new renewable projects—those already contracted, with additional projects solicited as needed to replace those that do not reach commercial operation—to achieve the statutory goal of approximately 127 MW. The resulting fleet of Standard Offer projects is expected to provide around 170,000 MWh annually at program completion.

The Standard Offer program fulfilled the need to have a standard method for encouraging cost-effective renewable energy development over time. The program showed the benefits and drawbacks of an annual statewide procurement. While successful bid prices dropped over time as anticipated, the location of projects were not always well-matched to grid needs and the pace of actual build-out has also lagged. GMP's direct PPA procurements have the advantage of meeting specific needs at the right price and quantity over time to fulfill the clear requirements of the RES.

Short-Term PPAs and Short-Term Procurement Methods

Some of our annual energy requirements are met through fixed-price energy purchases from the New England wholesale energy market, with contract durations of under five years. These purchases can act as a hedge to help minimize the need for spot market energy and add stability to our near-term power supply costs, reducing fluctuations in retail rates. This short-term resource category in GMP's supply portfolio fills gaps not covered by our long-term committed resources and addresses imbalances between the output of these resources and customer energy use patterns. Short-term contracts also enhance reliability and support our long-term supplies and load-based obligations in the regional FCM.

When selecting a procurement method for short-term purchases, we seek to achieve competitive, low-cost results or maximize sales value. The four main methods for procuring short-term positions are:

1) **Broker Services**: Energy and renewable attribute market firms 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 are regular market monitoring on our behalf, access to several buyers, and anonymity for us (until the buyer and seller are matched for a transaction).
2) **GMP-Initiated RFPs**: Typically, GMP targets active market participants. In this low-cost method, we provide a product term sheet specifying criteria for offers and a date for offers and awards.
3) **Auction Events**: Firms offer fee-based online platforms where a live event can allow potential suppliers to compete with some visibility on resulting awards and prices at the conclusion of the event.
4) **Counterparty-Initiated RFPs**: A supplier or purchaser (of RECs, typically) will occasionally include us on their direct request for offers and provide specific criteria for their needs and a schedule for participation and award.

Within these formats, there is no single preferred method for all circumstances, and the detail and formality of each method depend on the nature and significance of the transaction.

Short-Term Transaction Timing and Evaluation

GMP layers its short-term purchases to lock in fixed prices for short-term transactions across several years prior to delivery, with the goal of diversifying the timing of these purchases to avoid concentrating all transactions under a single market condition. This approach involves making energy and capacity purchases systematically for unmet needs through contracts with terms typically between 3 to 5 years before delivery.

We support our decisions about transaction durations and pace for short-term transactions by continuously collecting and reviewing 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, and interviews of consultant experts) that detail regional supply, demand, and other factors affecting price formation. This information helps us assess the current market landscape and anticipate future price movements to stay nimble for customers.

In addition to evaluating competitiveness and cost-effectiveness, we consider risk factors—such as the creditworthiness of counterparties and volume concentration limits—to minimize potential negative impacts during the contract delivery period. The short-term purchases can be for energy, for capacity, or for a mix of products and attributes.

Energy

Energy is the largest cost exposure with open energy volumes ultimately bought in the ISO New England spot market (Day-Ahead and Real-Time energy markets). We manage this by purchasing and selling fixed energy blocks from creditworthy sellers. We also settle at the ISO New England internal hub to maximize liquidity and attract the widest seller interest. This approach balances energy needs annually and monthly, considering forecast changes, supply expirations, new sources, and net-metering growth. However, variations in electric demand and generation (particularly intermittent renewable sources), across 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. 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 involve an exchange of capacity from a specific generating unit, a transfer of some of our capacity obligation quantity to the seller, or a self-supply transaction to meet a specified volume of our capacity needs. The FCM settles capacity zonally, with our load in the Northern New England and Rest of Pool zones.

Current Short-Term Contracts

Currently we have short-term energy purchase contracts in the next few years that total approximately 900,000 MWh for FY 2025; 350,000 MWh for FY 2026; 225,000 MWh for FY 2027; 105,000 MWh in FY 2028; and 47,000 MWh in FY29. We also have a short-term capacity contract through FY 2027 to provide 50 MW of monthly capacity as a hedge against annual FCAs.

Table 6-8 shows total counterparty purchases, with volumes and total costs; the prices of the agreements range between $45 and $71 per MWh over their remaining terms.

Counterparty	Contract Period	Resource Type	Description	Quantity	Cost
BP	2023–2027	System energy purchases and sales	Seasonally shaped, 7 × 24 energy block	107,000–220,000 MWh per year	$45–$71 per MWh
NextEra	2022–2025	Nuclear energy and attributes	50 MW seasonally shaped	400,000 MWh per year	$46–$48 per MWh
First Light	2025-2029	Energy and RECs	Off-peak unit contingent hydro and RECs	47,000 – 58,000 MWh per year	$66.25 per MWh
Dynegy	June 1, 2024–May 31, 2027	Capacity only	Monthly fixed capacity	50 MW per month	$2.92 per kW-month

Table 6-8. GMP's short-term purchased energy, by counterparty.

Planning for a 100 Percent Renewable Future

Planning for 100 percent renewable energy supply and load growth driven by electrification, GMP will accelerate the demand for additional in-state and regional renewable resources. GMP will pursue cost-effective, local grid-tied renewable projects, as well as new utility-scale renewable developments and construction. Meeting RES requirements in the years ahead will necessitate the procurement of significant resources involving:

- New solar supply serving local loads
- Regional hydro
- Land and offshore wind
- Grid-tied energy storage
- Residential and commercial scale solar + energy storage
- Shaped regional energy and/or REC purchases
- Load management, such as daytime EV charging incentives

New renewables in the form of local distributed generation in Vermont and the region support carbon reduction goals and complement grid resilience strategies. GMP's adherence to the Vermont Climate Council's Guiding Principles for a Just Transition will drive climate-favorable outcomes. Such outcomes in turn drive community benefits, including local workforce development in clean-energy careers and local economic development for a wide variety of businesses, and support continued partnerships with contractors and communities.

GMP will directly procure new renewable energy sources—both DG and utility-scale projects—through several ways. These involve direct solicitations, partnerships with other utilities and developers, RFPs, and potential future State-administered programs, supported in the short term by federally funded Solar for All projects.

The broader objective of GMP, aligned with Vermont policy, is to enable the electrification of transportation and heating systems, cleanly and sustainably, with a 100 percent carbon-free and renewable electric power supply portfolio for our customers. We have based our **Illustrative Future Portfolio**, described in **Chapter 7,** on objectives for achieving a 100 percent renewable portfolio by 2030 that aligns hourly renewable generation with demand, ensuring that the energy delivered to customers is clean, reliable, and accessible.

As set forth above, GMP's supply portfolio contains many resources that meet the eligibility requirements for RES Tiers I, II, and the new Tier IV. To manage RES compliance, we also purchase some of the required renewable energy through short-term REC transactions with terms of under five years. For example, our REC agreement with HQ, linked to our HVDC Phase 2 transmission rights, helps us meet the broader Tier I requirements, representing energy delivered into the New England region, as registered and tracked in the NEPOOL GIS. Additionally, we 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 now, while maintaining a REC revenue stream for customers from owned or contracted sources that are not needed to meet those requirements to offset customer costs. As GMP maintains a 100 percent carbon-free annual energy mix and ramps toward 100 percent renewable energy supply by 2030 to fulfill the RES requirements, these plans will continue to evolve. For example, as Tier IV ramps up, we expect to retire more RECs from our own qualifying resources (such as the wind resources described above, and some renewable PPAs including Standard Offer projects) and use smaller, targeted REC transactions to balance our overall portfolio.

Future Supply Resources

Achieving Vermont's RES requirements of 100 percent renewable supply in 2030 will require additional energy and REC supply from new in-state and regional sources. There are many types of renewable power sources varying in scale, location, relative cost, output profiles, and other features. Some of these can be directly implemented, whereas others are policy-driven resources with volumes and timing outside our control. We can also use the ISO New England wholesale power market to manage costs and mitigate volatility in net power expenses. All these resources can and should be complemented by storage resources, which will continue to be an important and growing part of our portfolio, delivering many benefits for customers and reducing both costs and market volatility. Our power supply strategy, aligned with Vermont's RES, seeks to increase renewable energy while cost-effectively limiting greenhouse gas emissions. As described earlier, we are starting to retire our rarely operated oil-fired peaking plants, with two already permanently offline with future retirements considered in this IRP period. Those that remain in service will continue to help us meet our mandated regional capacity requirements. Our existing energy storage projects and continued deployment of storage are critical to enabling these retirements. Storage resources are critical to achieving a transformed and cleaner grid that combines energy storage, flexible demand, local renewable generation and bilateral contracts that will help us maintain a carbon-free energy supply.

Renewable Generation

GMP will add new renewable generation to its portfolio. These additions will meet future energy needs and accommodate anticipated electrification growth. The expansion will ensure that the new resources align cost-effectively with customer demand patterns. In **Chapter 7**, we explore likely future resource alternatives such as distributed solar generation, onshore and offshore wind, utility-scale solar, and hydroelectric power. Below, we highlight some of the key resources we plan to explore in the coming years.

New Regional Wind

Offshore wind is the largest new renewable source that New England states are pursuing to support the decarbonization of their economies over the next two decades. Offshore wind (OSW) could be a useful addition to GMP's portfolio, because its output profile is projected to be relatively high during winter months when GMP's projected needs for additional energy supply are largest. Output from OSW plants is also expected to be steadier than land-based wind, making annual capacity factors on the order of 45 percent possible. OSW output is also expected to fluctuate in patterns that differ from those of GMP's existing wind sources located in northern New England.

Commercial prospects for OSW in New England look promising in the long term, but uncertain in the near term. State RFPs have led to awards for significant OSW wind generation facilities (discussed in **Chapter 5**). But project cost increases from inflation, supply chain constraints, grid integration, and environmental considerations have led to the termination of PPAs and suspension of development from some proposed projects, pending re-bidding of output several years later. New England states awarded just over 2,800 MW of new offshore wind contracts in 2024, and State-supported solicitations for several thousand additional MW of new OSW projects are anticipated in the next few years. In the near term, newly contracted projects are most likely to be those using leased areas off the southern coast of New England, with target commercial operation dates in the early 2030s. It appears possible that OSW projects located in the Gulf of Maine could become realistic options for Vermont by the mid-2030s. These projects would likely be located in deeper water and would use floating platform technology, with possible higher capital and operating costs. Projects in some Gulf of Maine lease areas could, however, be delivered to interconnection points relatively close to load centers in Massachusetts or New Hampshire. These would likely come with associated advantages with respect to the magnitude of required transmission upgrades, and the extent to which the market value of project energy is eroded by transmission congestion and losses.

From the perspective of regional wind suppliers, GMP could be an attractive buyer for a long-term contract, due in part to our status as a regulated utility with statutory and regulatory frameworks that are supportive of long-term renewable energy purchases. GMP has experience in obtaining regulatory approval for long-term purchase contracts. We also have contracts with other renewable energy suppliers and NextEra Seabrook. It is clear, however, that GMP alone could not support the development of a major OSW project. One path for GMP to purchase output from large regional wind projects therefore appears to be to combine purchases with neighboring states and perhaps with other Vermont utilities. This might involve GMP's participation as a buyer in future State-supported renewable solicitations. GMP also expects to directly explore opportunities for complementary purchases with regional wind suppliers.

GMP recognizes that pricing for OSW PPAs has increased greatly in the past few years due to several factors—and that there is presently considerable uncertainty about the availability and pricing of output from OSW projects that could achieve commercial operation in the early to mid-2030s. GMP therefore expects that its procurement of regional wind sources will focus on seeking opportunities to purchase from OSW projects or land-based projects. Land-based wind PPA opportunities could potentially be supported by existing projects still in operation, by the repowering of existing projects, or by newly constructed projects.

For a base outlook in the portfolio evaluation, we have assumed pricing for regional wind power that achieves operation in the early 2030s at $130 per MWh, constant over a 20-

year PPA term.[5] Pricing for projects that achieve operation in later years is assumed to decline gradually during the 2030s, on the prospect that increasing experience and scale for the nascent industry in the United States could lead to savings in project capital costs and long-term operating costs. As discussed in **Appendix I** this price path for regional wind—along with high and low cases tested in the cost sensitivity analysis—reflects a blend of potential price outcomes for OSW and land-based wind during the 2030s. The more challenging the OSW outlook turns out to be with respect to pricing and availability, the more heavily GMP expects to seek land-based wind options, as we continue to provide affordable power to our customers. There have been recent developments in DOE grant opportunities that could reduce the cost of necessary transmission development to interconnect more OSW which GMP will be following closely.

Land-Based Wind

The majority of recent wind development activity in New England has related to OSW procurements and construction, but GMP is also open to purchasing output from land-based wind projects—particularly if the net cost of such power is less than that of offshore wind.

The largest, recent land-based effort appears to have been Maine's RFP for wind power in northern Maine and associated transmission service, which did not ultimately yield any successful projects. GMP expects that large-scale wind in northern Maine would be significantly less costly per kWh at the busbar than offshore wind, so it remains an appropriate resource to consider. The net cost of power from this resource could involve the costs of a substantial new transmission path to southern Maine, however. It is possible that the market value of Maine wind energy to GMP and other buyers could be eroded by negative congestion and loss components of locational marginal energy prices at the delivery point. GMP understands that Maine is preparing to conduct a new solicitation for renewables in northern Maine that will include an opportunity for non-Maine buyers. We plan to monitor this opportunity and participate, if appropriate.

Land-based wind opportunities in New England will likely also include full or partial repowering of some existing projects, as projects built in the 2010s reach an age range when repowering them could become cost effective. Although repowering projects would lack the scale of offshore projects, they could benefit from continuing to use existing project sites and transmission infrastructure. The timing and cost of repowering projects are likely to be quite plant-specific, depending on factors like the vendor and model of existing turbines, and the size and condition of existing towers. GMP expects to explore

5 Pricing for potential new wind and solar projects is generally discussed here in terms of levelized prices that are constant over the PPA term. Levelized pricing is often a preferred structure for capital-intensive new renewable projects, as reflected in many projects in Vermont (e.g., standard offer, some bilateral PPAs) and neighboring states. Alternative pricing structures—for example, featuring a lower initial price with gradual escalation to higher pricing in the later years—may also be possible.

repowering opportunities with wind plant owners who seek PPA buyers, particularly if offshore wind pricing in the future turns out relatively high. Due to plant-specific availability and costs of PPA opportunities from existing land-based wind projects, we address them in the portfolio evaluation as part of the regional wind resource rather than modeling them as a unique resource option.

Finally, GMP notes that the construction of offshore and onshore generation located far from load will require either upgrades to the existing transmission system or, in the case of unserved locations, building new transmission systems. The region will have to face these costs as large wind resources are developed, and GMP will need to consider whether and to what extent the effective cost of such resources in the portfolio will include the cost of transmission upgrades or new systems.

Distributed Solar Power

Additional distributed solar capacity in Vermont is and will be the primary source to meet RES Tier II requirements, and several hundred MW of additional capacity will likely be needed by the mid-2030s. While the majority of solar PV capacity developed in GMP's territory to date has been via net-metering projects at 500 kW or less, the upcoming update of group net metering presents an opportunity to procure an increasing fraction of new distributed solar via projects sized more flexibly to match available sites, up to a maximum of 5 MW. To fulfill the Tier II requirements over the next decade, GMP expects to regularly solicit significant volumes of long-term PPAs to purchase output from new distributed solar projects in Vermont, in similar quantities to the Shared Solar solicitation conducted in 2023 and in concert with system planning to maximize the benefits of such projects on the grid. Utility ownership of projects could also be appropriate for customers' benefit in some cases, particularly for projects that include energy storage.

For the portfolio evaluation, pricing for new distributed solar PPAs under a base outlook is assumed to start at about $90 per MWh (with no escalation over the contract term).[6] Pricing for projects in future years is assumed to decline gradually over time based on expectations of increasing industry scale and technology improvements.

Large-Scale Solar Power

Output from any new solar project sized up to 5 MW that is interconnected in Vermont would be available for retirement toward GMP's RES Tier II obligations. Output from all new solar projects, including those larger than 5 MW, can be used to meet the requirements

6 The general solar pricing assumptions presented here do not reflect possible, project-specific savings (which GMP expects to seek) from enhanced federal tax credits or other forms of support to benefit low-income customers or distributed renewable generation.

of the new RES Tier IV. Although the overwhelming majority of Vermont solar projects to date have been sized less than 5 MW,[7] larger projects can provide meaningful economies of scale in terms of project design, procurement, and financing. Thus, they can also lower PPA prices more efficiently than can small-scale projects. It therefore could be appropriate to consider larger solar projects in Vermont or nearby states as a cost-competitive renewable supply option to supply a portion of RES Tier IV needs.

The portfolio analysis assumes that under a base outlook, some volume of larger solar projects will be available at PPA prices starting at about $85 per MWh—that is, $5 per MWh less than for distributed scale projects. This would be consistent with some well-located larger projects achieving lower prices through economies of scale, without incurring excessive grid upgrade costs. **Chapter 7** also demonstrates some of the implications of using additional solar power (above the substantial volumes needed to fulfill Tier II requirements) to meet Tier IV. It particularly discusses the tradeoff between wind power and solar power in terms of alignment of renewable supply when our customers use electricity.

Similar to existing wind projects, repowering of existing solar is an interesting opportunity that has the potential to generate more MWhs from the same footprint of existing solar. For example, when GMP built our first larger scale solar project in 2009 (the 200 kW Berlin Solar plant), it utilized solar panels rated at 185 watts each. Today, panels are over 400 watts each and are more efficient at converting sunlight into electric energy.

Plant-Contingent Hydroelectricity

This resource refers primarily to purchasing the output of one or more existing hydro plants in New England when that energy is actually produced, subject to seasonal and daily streamflow variations and plant availability and outages. The degree of correlation with the output of GMP's committed hydro fleet would depend to some degree on the river system on which the supplying plant(s) are located, and on any ponding capacity that they possess. From the perspective of portfolio design, it is helpful that New England hydro plants tend to generate at least moderate fractions of output during peak winter months, when GMP's projected need for additional energy is the greatest. However, such plants also tend to produce the most during April and May, when GMP's need for additional energy tends to be the least, and when we will have surplus energy during many daytime hours during sunny days.

A long-term PPA with stable or fixed pricing would be the most likely mechanism for GMP to acquire these resources, although GMP would be open to exploring shorter contract

7 Several Vermont solar projects sized up to 50 MW have requested interconnection, with the expectation of selling output to neighboring states under long-term contracts.

terms and other pricing arrangements. GMP also expects to explore purchases of existing regional hydro plants, if and when such opportunities become available.

Historically an advantage of purchasing existing hydro output has been the prospect of a relatively low price per kWh of renewable supply. As neighboring states have stepped up their programs to limit the carbon intensity of their electricity supplies, we expect to see increasing competition for the finite supply of energy from existing hydro and nuclear plants. As a result, the scale of existing hydro supplies in New England that will be available for long-term purchase is not clear, and that volume will probably be price sensitive. GMP's portfolio evaluation assumes that market pricing for RECs that are eligible for RES Tier I—but not eligible for higher-priced RPS/Clean Energy Standard (CES) tiers—will increase over time. Our portfolio evaluation also considers the possibility that the available existing hydro supply will be more limited, yielding higher prices and potentially different choices such as using more short-term PPAs.

For the portfolio evaluation, we assume that available plant-contingent hydro PPAs would deliver energy and RECs and would be priced consistently with the Base Case outlook for energy market prices and Tier 1 REC market prices. The output profile approximates the New England hydro fleet (not including pumped storage). Outright purchases of hydro plants by GMP for adding to the existing fleet would have similar portfolio implications as a long-term PPA.

Shaped Renewable Purchases

Purchases of this type enable the buyer to receive renewable energy on a schedule that is partly or entirely fixed. Such purchases are generally backed by a substantial fleet of generators.

GMP's largest existing shaped renewable purchase is our long-term purchase from HQUS, which features deliveries during 16 peak hours each day. Depending on the blend of resources, it is possible that future shaped renewable import transactions could deliver energy in profiles that are more closely aligned with New England's emerging hourly and seasonal needs than would be plant-contingent purchases. This then complements existing and future solar and wind supplies. At this time, it is uncertain whether a shaped renewable purchase from Quebec will be available as a cost-competitive replacement for some or all the existing HQUS PPA when it ramps down in the mid-2030s. To the extent that a long-term renewable transaction with Quebec is viable, potential transmission paths could involve GMP's roughly 100 MW long-term entitlement in Phase II of the Quebec/New England Interconnection, or a portion of a new Vermont interconnection such as the Alliance Transmission Exchange project that VELCO is presently exploring.

Future shaped renewable purchases from within or outside New England could be supported by renewables in combination, for example, plant-contingent wind, solar, and hydro, or paired with energy storage. Some existing renewable suppliers in New England could also offer a shaped renewable product, as Great River Hydro did under GMP's long-term PPA, from part of the output of a plant or portfolio. The available scale of this type of purchase for GMP is uncertain, since it would likely need to be supported by renewable generating plants, along with new or existing energy storage resources such as battery storage and pumped-storage hydro.

The hourly screening analysis in **Chapter 7** tests two possible versions of a shaped renewable purchase that could fit into GMP's portfolio in the mid-2030s when the existing HQUS purchase ramps down. One version features round-the-clock deliveries over the course of the year, and one features round-the-clock deliveries during all months other than peak winter months, December through February.

The primary purpose of testing these shaped renewable purchases is to get a sense of the extent to which they could improve the alignment of GMP's renewable energy supply with electricity consumption on an hourly basis, compared to relying primarily on plant-contingent renewable power options. The availability and pricing for a custom product of this type are presently very uncertain. However, the portfolio evaluation assumes, as an illustration, that a shaped purchase of hydroelectric energy would be available to meet a portion of GMP's Tier 1 renewable needs and that it would deliver energy and RECs. This option is priced consistently with the Base Case outlook for energy market prices and Tier 1 REC market prices, plus a significant price premium to reflect the fact that a steady output profile that is not plant-contingent would be more valuable to buyers like GMP, and that sellers would likely incur incremental costs to provide it.

Storage

Energy storage continues to be an important and rapidly emerging resource in utility markets. The flexibility of these resources to act as load or generation, provide power quality, and increase system resilience underpins much of this growing interest. VELCO's 2024 Long-Range Transmission Plan (LRTP) finds that transmission capacity will be exceeded if DG continues to be deployed in the same manner as today. It also identifies storage as an important tool to mitigate some of those transmission concerns. See **Chapter 3** for in-depth analysis of where solar and storage should be sited in the future and how GMP currently operates and plans to operate these assets in the future. It's important to note that the location of storage, or any flexible load, is important to alleviate a system constraint such as those identified in the LRTP. Often, certain power supply benefits are achieved regardless of the location, but T&D system benefits or local peak management benefits require storage or flexible dispatch be located at optimal locations on the electric system.

In the coming years, we will be adding meaningful quantities of storage resources, which will continue to benefit the power supply portfolio. The benefits of storage are extensive, including addressing our capacity (peaking) needs, providing energy balancing to a portfolio more reliant on renewable supplies, providing local grid support, and improving the alignment between resources and load, all while increasing resiliency and driving down power supply costs for customers.

Storage for Resource Adequacy and Capacity

Lithium-ion batteries are currently the most common type of energy storage used on the grid. These systems offer a high energy density, with roundtrip efficiency between 80 and 90 percent, and can quickly respond to charge and discharge commands. They are also highly flexible in terms of size, both in rated capacity and energy duration. For utility applications, modular designs featuring batteries contain around 1 MW, providing at least 2 hours of energy, and allow for project scaling from 1 MW to over 100 MW.

Given these advantages, as noted above, GMP is using energy storage to replace fossil-fuel peaking generators in most short-duration reliability applications. The primary role for short-duration energy storage in New England is to provide peaking capacity. In this role, batteries can either participate directly in ISO New England's FCM, earning monthly payments based on their capacity ratings, or reduce load on the grid. To be effective in this application, we expect a unit should be able to run for at least four hours. Over time, this energy duration may increase beyond four hours, which would raise the size and cost of these peaking resources. However, unlike fossil fuel resources, where retrofitting is complex and disruptive, the modular design of battery systems allows for relatively quick and low-impact expansion to increase energy duration.

GMP will assess the use of these peaking-type batteries by project size and design, tailored to specific site configurations. In addition to replacing fossil fuel peaking units, energy storage offers benefits to both customers and the ISO New England markets, creating additional value for customers. At one end of the design spectrum are large batteries intended to replace existing GMP peaking fossil fuel units nearing the end of their service lives. Examples are the Vergennes, Rutland, and Ascutney fossil fuel generation sites. These locations present opportunities for grid-facing peaking storage at scale, offering similar performance. At the other end of the spectrum are customer-sited, behind-the-meter storage applications—where, in addition to peak demand reduction and cost savings, energy storage provides crucial local resilience and power-quality services, as described in other chapters of the IRP regarding GMP's Energy Storage System tariff, BYOD tariff, Energy Storage Assistance Program, and other storage programs for customers.

Storage for Energy Balancing

The increasing volumes of intermittent solar, wind, and hydroelectric generation have amplified the variability in our hourly and daily energy supply. The integration of energy storage complements our growing renewable portfolio by offering rapid charge and discharge capabilities. In an energy-balancing role, storage shifts renewable output from periods of excess to times of greater demand and value for our customers, underscoring the critical role storage plays as we expand our renewable power resources.

One example of this short-duration application is storing excess solar energy generated during the middle of a sunny day for discharge during high-demand evening hours. Another balancing role involves responding quickly to fluctuating load levels, as ISO New England has noted a growing need for resources that can respond at any time to rapid or unpredictable load changes. Natural gas plants perform much of this balancing, contributing to the region's carbon emissions. However, as ISO New England's market definitions evolve to include emissions impacts, storage resources can increasingly take on this role, reducing reliance on fossil fuels.

Looking ahead, long-duration storage technologies might also emerge beyond lithium-ion configurations. Commercializing alternative storage chemistries at scale is already under way, and the potential role of longer-duration, lower-output storage in our portfolio presents promising future possibilities.

Chapter 3 discusses GMP's approach of shaping EV load profiles to reduce peaks before considering storage as a solution and explores how EV load management has the potential to alleviate many upgrades, especially when paired with storage.

Storage for Local Grid Support

Although this IRP addresses territory-wide and regional grid support in **Chapter 3,** the development of small, distribution-connected energy storage systems is equally important for the benefits they provide to local grids. The 2024 VELCO Long-Range Transmission Plan emphasizes the importance of collaborating on flexible loads including strategically located storage, to address both thermal and voltage concerns, unlocking the following benefits:

- **Deferral or displacement of transmission or distribution infrastructure that would otherwise be needed to provide reliable service.** Energy storage can delay or eliminate the need for costly transmission or distribution upgrades. Such upgrades might be rebuilding substations or reinforcing power lines. This offers significant savings for customers by providing a lower total net cost alternative.
- **Voltage management on the distribution system.** Batteries, particularly those equipped with advanced inverters, can offer vital voltage support, especially in areas with high DG penetration.

- **Grid resilience.** During grid-level outages, energy storage systems support local circuits or areas, providing power alongside local generation to enhance overall resilience for customers.
- **Increasing renewable generation hosting capacity.** By charging during periods of excess local generation, energy storage can increase the capacity of a distribution circuit to host more renewable energy or boost generation potential in export-constrained transmission areas.

7

PORTFOLIO EVALUATION

GMP is building a resource portfolio that continues to be cost-competitive, and increasingly renewable as we work towards the requirement to be 100 percent renewable by 2030 and beyond. We also continue to look for resources that will provide renewable energy during the seasons and times of day when our customers use electricity. We will accomplish this in part through the diverse portfolio of renewable sources that GMP has developed, by sustaining the growth of small renewable generation sources in Vermont, and by using larger new renewable generation located in or connected to the grid in New England.

The portfolio evaluation in this chapter tests possible combinations of renewable generation sources that could be used, along with energy storage and load management, to support GMP's customers. This includes consideration of the alignment of supply and electricity use during all times of the day, over all seasons and throughout the entire year, so that GMP can maximize the performance of a portfolio for customers that will rely on increasing volumes of renewable energy and energy storage over time. This GMP portfolio evaluation examines choices that GMP expects to consider when evaluating potential resource additions and adapting the design of the portfolio to changing conditions over time.

The Context for Our Portfolio Evaluation

Vermont's Renewable Energy Standard (RES), as revised effective July 1, 2024, provides guidance about the mix of renewable energy sources that GMP is required to use to serve customers, building from GMP's already carbon-free portfolio toward one that is 100 percent renewable on an annual basis by 2030. The **Overview** in **Chapter 6** explains these recent revisions to the RES and summarizes GMP's current supply, providing the starting point for our future portfolio analysis set forth in this chapter. This portfolio evaluation focuses on how best to construct a renewable energy supply for customers over time, with a mix of resources that is consistent with Vermont's revised RES requirements. We identify three objectives for this evaluation as described below.

Portfolio Evaluation Goals

Goal 1: Meet GMP Customer Needs

This portfolio evaluation describes how GMP will review options over time as they develop to ensure they meet customer needs, looking at the price, performance, portfolio alignment, and the scale and cost of grid upgrades necessary to integrate new sources. GMP's renewable procurement choices will depend on how well sources meet the overall needs of GMP customers, based upon these and other factors as described below. In addition to straightforward but important metrics like the anticipated volume of additional renewables to meet annual RES tier requirements and the relative cost of potential sources, the chapter illustrates how alternative combinations of new sources are likely to align with our customers' electricity consumption over hourly and seasonal timeframes. The greater the alignment, the more often customers' real-time use can be met with renewable energy. The degree of alignment between supply and demand—which will vary based on GMP's future resource choices—can also affect the stability of GMP's net power costs.

Goal 2: Meet RES Requirements

This portfolio evaluation discusses paths to achieving and maintaining a fully renewable annual energy supply, as required by RES. GMP's delivery of low-cost, renewable, reliable energy involves full integration with the RES's four tiers relating to total renewable energy supply, new distributed renewable supply, energy transformation and decarbonization, and new regional renewable energy. These integrated tiers align with our benchmarks for a diverse, flexible, 100 percent renewable portfolio that provides stability in net power cost and electric rates over time. This portfolio evaluation seeks to inform the composition of a portfolio containing resources that in combination can achieve these requirements. GMP expects to meet its growing needs for renewable energy primarily through increasing volumes of new renewable sources from within Vermont and New England. A significant portion of these acquisitions will be through long-term commitments, in addition to GMP's own sources.

The primary options for new renewable generation involve distributed solar projects in Vermont, large solar projects in Vermont and New England, and wind projects—whether offshore or land-based—plus energy storage, in or connected to New England. These sources will be included within a total portfolio of GMP's owned resources, contracted existing renewable sources, energy storage, and demand management, all designed to meet RES requirements by Tier as they evolve over time.

Goal 3: Recognize Uncertainty, Through Use of Evaluation Objectives and Metrics Over Time

This evaluation seeks to illustrate the performance of GMP's future portfolio, using metrics that will inform choices about appropriate types and volumes of future resource acquisitions as circumstances change over time. GMP recognizes that there is significant uncertainty in future outcomes for some factors (for example: the date projects will be commissioned; the price to purchase new wind and solar power; or the future conditions in the ISO New England wholesale energy and capacity markets) that will affect GMP's resource choices. This portfolio evaluation discusses how these uncertainties could affect GMP's resource choices and net power costs and illustrates the relative magnitude of key uncertainties as we understand them today.

GMP's Approach to the Portfolio Evaluation

The portfolio evaluation begins with an assessment of a Reference Portfolio that contains GMP's committed resources as described in the **GMP Current Supply Portfolio** section of **Chapter 6**. The Reference Portfolio includes specified volumes of other expected resources (for example, continued growth in net-metered generation, and completion of Standard Offer projects sufficient to fulfill the program's current statutory goal). We view these resources as likely to be present in nearly all futures.

Comparing the Reference Portfolio to GMP's forecasted future load requirements (as described in **Chapter 2**) provides the approximate magnitude and timing of additional resources that GMP anticipates needing to serve customers. Matching that with what is required to achieve the RES, particularly through the types of renewable energy required by Tiers I, II and IV, gives us the outline of what our future portfolio must contain.

We then perform a detailed hourly screening analysis for the year 2035, when many of our existing supply commitments have either expired or are about to. This analysis tests possible RES-compliant portfolios that contain various quantities and types of existing and new renewable energy sources (drawn from the options discussed in **Chapter 6**). This screening tool also allows us to test the extent to which GMP's energy supply under different portfolios (containing varying volumes of resources like new solar, new wind, existing hydro, and energy storage) will align with our customers' hourly electricity consumption, and summarizes the results on average by month, and over the course of the year.

The next step of the evaluation is to use observations from the Reference Portfolio evaluation and hourly screening analysis to derive an Illustrative Future Portfolio, which contains the types and volumes of new resources that GMP expects to pursue to achieve an energy supply that meets the RES while achieving other portfolio goals. By using the label *Illustrative* for this forward-looking portfolio, we mean that it builds from our assessment of current information and projections. We recognize that there is a considerable degree of uncertainty in the cost and volumes of future resources that will be available to GMP, and that we will need to adapt our procurement plans as conditions change.

The final step is a sensitivity analysis of the extent to which net power costs associated with the Illustrative Future Portfolio would change because of alternative future outcomes for factors like the cost of new renewables and market price for wholesale energy, capacity, and RECs. This step helps show the extent to which these factors have the potential to drive changes in GMP's future net power costs.

Tools and Methods to Enhance Energy Analytics

GMP routinely uses a monthly on- and off- peak energy model (that is, using 24 periods per year) for general power supply forecasting. In the 2021 IRP, GMP introduced an evaluation tool that considered electricity supply and demand at an hourly level, in recognition of the need to understand the interplay of increasing volume of intermittent renewable sources with forecasted load growth from beneficial electrification. In this 2024 IRP, GMP has again used and enhanced each of these tools. Specifically, GMP conducted hourly screening of numerous potential portfolios using a spreadsheet tool and retained Daymark Energy Advisors to develop a representation of GMP's portfolio within PLEXOS, an energy analytics and decision platform (Energy Exemplar). With that platform, Daymark simulated the operation of the New England electricity market.

Monthly On-Peak/Off-Peak Energy Model

GMP's routine monthly on- and off-peak energy model is useful because it is straightforward to use and maintain in house, and the level of resolution aligns with GMP's monthly financial forecasting. This tool quickly conveys GMP's projected average long/short energy positions for monthly periods that align with standard trading periods for forward energy in New England. This monthly level of resolution captures most of the variations in loads, supply sources, and market prices that drive GMP's net energy costs, and shows the months and times of day when GMP could have significant net long or short positions that are appropriate to manage with forward energy purchases or sales.

The limitation of the monthly model structure is that the average volumes for the 24 periods smooth over what are sometimes strong differences in generation and load within the peak and off-peak periods. For example, GMP's generation supply varies significantly between peak solar hours and other hours within the peak period, and between sunny and cloudy days. Similarly, electricity demand is consistently above the peak period average during certain evening and morning hours. Within each month, demand tends to be significantly higher on unusually cold/hot days than on mild days. The effects of these daily and hourly variations on GMP's net power costs can be reasonably estimated based upon experience with the monthly model for purposes of internal budgeting and setting benchmark power costs in GMP's Multi-Year Regulation Plan.

Hourly Screening Tool

In the context of portfolio evaluation and planning in this IRP, it is useful to take the variations that are not granularly captured in the monthly model and to analyze them using an hourly model in order to understand how their magnitude could be managed through the design of GMP's resource portfolio. The hourly screening tool is used to model each of GMP's resources or group of resources (for example, solar, wind, and hydroelectric), along with electricity demand.

For this IRP, the hourly profiles for output of existing and potential future supply sources, along with electricity demand, were each derived from the weather year 2022. In addition to tracking the percentage of the annual portfolio that is renewable or carbon free, this framework allows us to estimate the degree to which potential portfolios would align with customer demand across the year—including the average fraction of annual electricity that is matched with renewable energy on an hourly basis, and average of hourly long and short positions over monthly and annual timeframes. The advantage of this approach to hourly modeling is that it captures the interaction of supply and demand, consistent with a particular year of weather (temperature, wind speed, solar irradiance, stream flows) that actually occurred—including the highs and lows of intermittent renewable generation observed.

The results of the hourly portfolio modeling are useful—particularly when tested under conditions from a common weather year—because they indicate the extent to which the portfolio would rely on hourly balancing purchase and sale transactions with the ISO New England wholesale energy market, and in turn the relative stability of the portfolio's net energy costs under alternative energy market price outcomes. For example, a portfolio that is balanced on average but features consistent short positions during certain hours in winter months and consistent long positions during sunny hours in other months would tend to experience higher net costs if future market prices in winter months turn out higher than expected or market prices were lower than expected during the sunniest days and hours.

Applying a Regional Perspective

Daymark's regional market model simulates the hourly dispatch of generating plants and other supply sources in the ISO New England control area to meet electricity demand. This modeling takes into account the supply of generating plants, their fuel costs and other operating characteristics, and an approximation of New England's hourly interchange of energy with neighboring markets. The section **Wholesale Energy Market Analysis** summarizes the structure of the Daymark regional market model, and some of the key input assumptions that form the base case outlook. More details of the analysis are contained in **Appendix H**.

The regional model is conducted over a 20-year horizon, incorporating planning assumptions about trends in New England with respect to electricity demand growth, future generation additions and retirements, and prices that fossil fuel generators will face to purchase fuel and emission allowances. Key outputs of the simulation modeling are the projected mix of energy sources used to meet electricity demand in New England, and projected spot market energy prices associated with this future. This is significant in the context of a New England electricity market in which states are seeking to greatly increase the volume of renewable energy supply over the next decade, while electrifying substantial end uses that presently consume fossil fuels. By directly simulating these changes to supply and demand, the hourly regional market model provides an informed indication of the trend in average energy market prices, and how the seasonal and hourly profile of energy market prices could evolve over time.

The Foundation for a Carbon-Free and Renewable Energy Supply

After achieving a 100 percent carbon-free annual portfolio four years ahead of its 2025 goal,[1] GMP will maintain that carbon-free status as it moves toward a 100 percent renewable portfolio by 2030. GMP's portfolio exceeds current requirements for acquisition of renewable resources, is well-aligned with Vermont's Global Warming Solutions Act (GWSA), and positions GMP to meet the revised and enhanced RES requirements discussed previously.

As will be detailed in the portfolio evaluation, the revised RES substantially increases the required volumes of new renewable energy in GMP's portfolio. It also provides guidance as to the types of renewable energy that GMP will procure. All renewable energy eligible for RES compliance must be capable of delivery to New England. The Alternative Compliance Payment (ACP) for each tier will increase annually, according to changes in the U.S. Bureau of Labor Statistics' Consumer Price Index.[2]

What Do the *Carbon-free* and *Renewable* Metrics Mean?

Carbon-free

Electrical energy **produced** from resources that do not generate carbon emissions

Examples in GMP Portfolio:

- Solar
- Wind
- Hydro
- Carbon-free nuclear

GMP's portfolio of electricity generation is 100% carbon free

Renewable

An energy resource that can be **used** repeatedly and is naturally replenished

Examples in GMP's Portfolio:

Solar
Wind
Hydro

80%+ of the energy GMP customers use comes from renewable resources

1 GMP 2021 Tier III Savings Claim (May 9, 2022) ("GMP is pleased to report that our annual power sourcing is now 100% carbon-free and this is reflected in the 2021 results reported here.")

2 In 2025, the ACP levels are as follows: Tier I, $12.72/REC; Tier II, $76.35/REC; Tier IV, $42.16/REC

Portfolio Evaluation Objectives

This portfolio evaluation considers six resource planning objectives:

- Low cost
- Carbon free
- Renewable energy
- Alignment of supply and demand
- Cost stability
- Portfolio flexibility

Low Cost

GMP seeks to keep electricity competitively priced and affordable; this also helps customers choose transportation and heating options that rely on electricity. We use total power costs in $ per MWh as the relevant metric in presenting the average portfolio cost.[3] We seek to keep the overall average rate of increase lower than the general rate of inflation over time, and to remain competitive relative to rates for power and transmission at other utilities in the region.

Carbon Free

GMP estimates the average emission rate of CO_2 (in pounds per MWh) for its power supply portfolio and also as a percentage of portfolio resources (in MWh) derived from carbon-emitting sources. GMP bases this information on current GHG inventories reported by the Vermont Climate Action Office. In each year since 2021, GMP has achieved an average annual emission rate of zero pounds of CO_2 per MWh through the retirement of RECs from non-emitting renewable 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 the NEPOOL 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.

3 Total power costs consist of purchased power—including energy, capacity, ancillary services and related costs from ISO-NE, and RES compliance costs—along with O&M and fuel costs for generating facilities that are jointly or fully owned by GMP; revenues from resales of power and RECs; and purchased transmission costs.

Renewable Energy

Like renewable requirements in many other states, Vermont's RES measures renewable energy content by comparing annual volumes of renewable generation—generally demonstrated by retirement of RECs in the NEPOOL GIS—to annual energy use. GMP will measure renewable content each year based on the volume of retired RECS that are eligible under Tier I (total renewables), Tier II (distributed renewables), and Tier IV (new renewables) as fractions of total energy requirements.

Alignment of Supply and Demand

This objective refers to the extent to which GMP's portfolio of power resources delivers energy during times when customers consume electricity. The primary metric for this alignment is the percentage of output from GMP's supply portfolio or possible new resources to serve customer load on an hourly basis across a given period (for example, hour, month, year) versus the percentage that exceeds GMP's hourly load needs—and is typically sold into the ISO New England energy market. A high alignment fraction also indicates that the volume of required purchases from the market is limited.

While it is neither cost-effective nor practical at this time to design a portfolio that assures a fully renewable energy supply across every hour of the year and under all possible weather conditions, understanding the alignment of supply and electricity demand can help us design an efficient, cost-competitive portfolio of renewable supply, energy storage, and flexible demand resources over time. That is why we are piloting an hourly matching pilot as detailed in **Chapter 1**. Sustained gaps in alignment that require the purchase of large volumes of needed energy from the regional market during certain seasons and times of day—while selling large volumes of excess energy into the market at other times—create cost risk for our customers. A well-aligned portfolio also serves our customers efficiently by not only delivering sufficient renewable energy to offset their consumption on average but also doing so at times when they are actually using electricity.

Cost Stability

The cost stability objective aims to keep GMP's average cost of power relatively stable, to limit the magnitude of annual changes and the likelihood of large, rapid swings in cost, all in keeping with long-standing Vermont policy in favor of electric cost stability. We seek to provide price stability and predictability for our customers while leaving some flexibility in adjusting to the market in the long term. The metric for this objective is the fraction of energy load requirements met with sources that feature fixed or stable prices[4] and do not directly follow wholesale power market prices. Some portfolio choices that affect this metric are the size and timing of major supply commitments, the extent to which GMP's power needs are met with long-term purchases that feature fixed or stable prices, and the extent to which GMP's supply sources are well aligned with when our customers consume power.

Portfolio Flexibility

The final objective, portfolio flexibility, refers to the extent to which the portfolio resources and associated costs can adapt to changing future conditions (e.g., large changes in the cost of new renewable options or wholesale power market prices); this objective is to some extent in tension with the prior one. The balance between portfolio flexibility and stability is primarily measured by the collective volume of our long-term, fixed-priced resource commitments compared to total energy requirements. Developing new renewable electricity in Vermont and New England typically requires long-term commitments. It is not clear what volume of renewable energy supply will be available in the short term, especially with increasing competition for existing regional renewable resources. The tradeoff is that using a greater volume of long-term fixed price

4 Therefore, formulaic pricing in PPAs based on a general inflation index is treated as stably priced, whereas market exposed pricing is not. In this metric, any energy from oil- and natural gas-fired plants subject to market pricing 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 pricing is tied to an electricity market price index.

commitments tends to increase portfolio cost stability but can also make the portfolio less flexible and less responsive to changes in the wholesale markets. In order to manage this balance, we seek to sequence and layer expiration dates of resources over time. Flexibility can be balanced with stability when PPAs expire in different years and different amounts expire at different times. For example, the two largest discrete sources in our committed portfolio, HQUS and NextEra Seabrook PPAs, expire in stages in the mid- to late-2030s; there is sufficient time to manage these transitions through acquisitions of new PPAs from multiple sources.

More specifically, looking five years in advance of any particular year, GMP seeks to maintain projected open positions for energy of around 10 to 20 percent. In subsequent years we narrow the open position by implementing short-term forward purchases[5] at fixed prices. We seek to fill larger open positions (e.g., those in winter months) with two or three forward purchases for volumes delivered over multiple years, which limits the portion of energy that is purchased in any one set of market conditions.[6] Because of this work, projected open energy positions at the start of each operating year—based on normal weather and generation volumes - are typically very small on an annual basis and are limited to five percent or less on a monthly basis.

GMP seeks to use this same general approach with respect to capacity purchases, keeping track of pricing expectations. For example, in recent years forward purchases have not consistently been available at pricing consistent with GMP's moderate outlook for clearing prices in the annual forward capacity auctions. As a result, GMP's open capacity position has been larger than for energy, with GMP settling more of its capacity needs via the ISO-NE rather than bilateral forward purchases. Looking forward, the transition of the ISO-NE capacity market to a prompt and seasonal structure (see **Chapter 5**) is expected to bring increased volatility in annual capacity clearing prices, with less advanced notice of the changes. This will likely make bilateral forward purchases more favorable in the future.

Table 7-1 summarizes the six resource planning objectives and their performance metrics.

5 For simplicity this discussion refers to forward purchases; during some periods (e.g., peak hours in spring) GMP tends to have projected long energy positions so our forward transactions will be sales.

6 GMP adjusts the pace of forward transactions if we assess that forward market prices are particularly favorable or unfavorable.

Objective	Attribute	Metric
Low Cost	Metric 1	Average portfolio cost ($/MWh)
	Target 1	Limit increases to less than general inflation
	Target 2	Average portfolio cost is less than a regional benchmark
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 (measured annually) by 2030
	Target 2	Achieve annual RES Tier I, II, and IV requirements
	Target 3	Achieve each RES requirement in a cost-effective way, at average costs substantially lower than ACP
Alignment of Supply and Demand	Metric 1	Percentage of hourly renewable and carbon-free energy used to serve load
	Target 1	Greater than 60%
Cost Stability	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
Portfolio Flexibility	Metric 1	Long-term ratio of fixed (or stable) price MWh to total energy requirements
	Target 1	Five-plus years in the future, portfolio is significantly less than fully hedged. Percentage might 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.

All of these work together and require balancing. Overreliance on any one objective could create negative results for the portfolio and could disadvantage our customers over time. Resource planning helps us see the factors that influence the balance we must achieve as markets, policy, and technology change.

Evaluation of Potential Resources

When evaluating specific potential resource additions and choosing among options, the projected net cost of the candidate resources is important. While a substantial projected cost advantage compared to potential alternatives or substitutes that address the same portfolio need (e.g., achieve one of the RES tier requirements), it is always necessary to consider how that resource fares on the other metrics before making a selection. A resource's net cost per MWh or MW depends directly on the cost of power from the resource—for example, the PPA price for a renewable energy source—as well as the projected value of the resource's output in the ISO-NE market. Other considerations in the selection of resources include operational flexibility, project viability (e.g., likelihood of completion); and locational considerations such as exposure to transmission congestion costs.

When evaluating specific potential resources or portfolio designs to get the best outcome for customers, GMP does not compare resources by distilling the metrics above into a single evaluation metric or score—for example, by using prescribed formulaic factors or weightings. Rather, GMP compares and considers the planning objectives and metrics together based upon the specific context of the purchasing need. In addition, several of the metrics (alignment of renewable supply with demand, cost stability, flexibility) are considered on a portfolio level rather than for each potential resource in isolation. This approach has the advantage of evaluating potential resources in their portfolio context. The overall appropriateness of a potential resource therefore depends on not only the cost of the resource but also its size and type, when it would be added to the portfolio, and GMP's projected portfolio needs at the time.[7]

Evaluation of specific potential renewable energy sources will also include consideration of the ACP for the respective RES tier(s) that the resource will help to supply. For short-term purchases of RECs separately without other products like energy or capacity, this entails a relatively simple comparison of the REC purchase price to the applicable ACP for the year(s) of delivery. For longer-term renewable purchases of multiple products together like energy, RECs, capacity, the methodology must be more nuanced because such PPAs can provide more potential value to GMP's customers than a short-term REC purchase or the ACP for a single compliance year. In particular, long-term renewable PPAs typically ensure access to RECs—as well as for other products that contribute to supplying Vermont customers—for many years, along with sustained price stability for those products. Therefore, while ACPs for the RES tiers provide a form of guidance with

7 For example, consider a potential new renewable resource that is reasonably priced but only available to GMP five years before it is needed to address one or more of the portfolio needs above, and only in a discrete volume that is large relative to GMP's needs. Such a resource could pose a risk to portfolio cost stability due to its size—particularly if incorporating it into GMP's portfolio would require large volumes of resales of energy or RECs. On the other hand, the same resource type would not pose the same risk if it were available in a smaller size, and on date(s) more closely aligned with GMP's needs.

respect to pricing of short-term REC purchases, the ACPs and associated language of 30 V.S.A. § 8005(6) do not directly guide evaluation of long-term PPAs.

One way to screen a potential long-term renewable power purchase would be to compare the PPA price to current base case or most likely estimates of the future value in the ISO-NE market of the energy and capacity that they will provide, with the difference treated as a rough indication of the implicit cost that is being paid to obtain renewable power under the PPA. The implied renewable cost from this simple method would likely tend to be conservative (overstated), absent some additional adjustment to recognize the stability of supply and pricing that long-term contracts provide. An implied renewable cost estimated in this way would also depend directly on the regional wholesale market price forecast being used—the higher the market forecast, the lower the implied renewable cost. This is notable because wholesale market forecasts can fluctuate over time based on new information for a range of input factors. These complexities demonstrate why further consideration of how RES ACPs should factor into analysis of new long-term renewable supplies will be warranted.

Defining the Reference Portfolio

The Reference Portfolio contains anticipated portfolio loads and resources that result from current commitments and policies, without any substantial new long-term resource commitments. GMP bases the Reference Portfolio on the projected sources and load requirements, using the following assumptions:

- Electricity demand growth consistent with substantial electrification of Vermont's transportation and heating sectors, in accordance with the Accelerated Adoption forecast presented in **Chapter 2**. From 2025 to 2035, GMP's annual electricity requirements increase from approximately 4.0 million MWh to 5.4 million MWh.
- Net metering grows at a pace of 10 MW per year of solar PV capacity on GMP's distribution system over the next decade. This pace is consistent with continuation of growth in customer sited net-metering projects, primarily via small scale (up to 15 kW) projects.[8]

8 Starting in the late 2030s, increasing fractions of net-metered projects will exceed 20 years of age, raising the potential that some original panels or other equipment will need replacement. In actual practice some original projects will presumably retire without replacement—representing a loss in net-metered generation—while others may be replaced with panels that can produce more power from the same footprint. In the portfolio evaluation GMP has assumed that the aggregate capacity from existing solar net-metering projects will remain constant—a balance between these outcomes.

- Vermont's Standard Offer program continues until new distributed renewables of 127.5 MW enter commercial operation. In the Reference Portfolio we assume the full complement of Standard Offer volume is built. The increased RES Tier II requirements will then support the future development of substantial new renewables, which utilities including GMP will procure in order to meet these new required volumes. GMP assumes that both net-metering and standard offer projects will continue beyond the end of their term through repowering.
- Residential energy storage grows by 5 MW annually (assuming four hours of storage duration) on GMP's distribution system from existing levels of approximately 35 MW. GMP-owned and PPA utility-scale energy storage remains at existing levels around 25 MW.
- Projected differences between energy requirements and committed resources are either purchased or sold, short-term, 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 New England directly, at prices consistent with our current Base Case FCM price forecast.

Evaluating the Reference Portfolio

This section presents our evaluation across metrics of the Reference Portfolio, which anticipates portfolio loads and resources that result from current commitments and policies, without any substantial new, long-term resource commitments by GMP. In each gap chart that compares GMP annual energy or renewable supplies to projected requirements, the solid line for requirements reflects the Accelerated Adoption future described in **Chapter 2,** whereas the lower dashed line reflects the Continued Adoption future.

Open Energy Position

presents our forecasted long-term energy gap chart, comparing the projected annual output of supply sources already acquired or anticipated as described above to the annual energy needed to serve forecasted retail sales and associated system losses. Note that this chart is based on energy only, without regard to REC purchases or sales that may be made separate from energy.

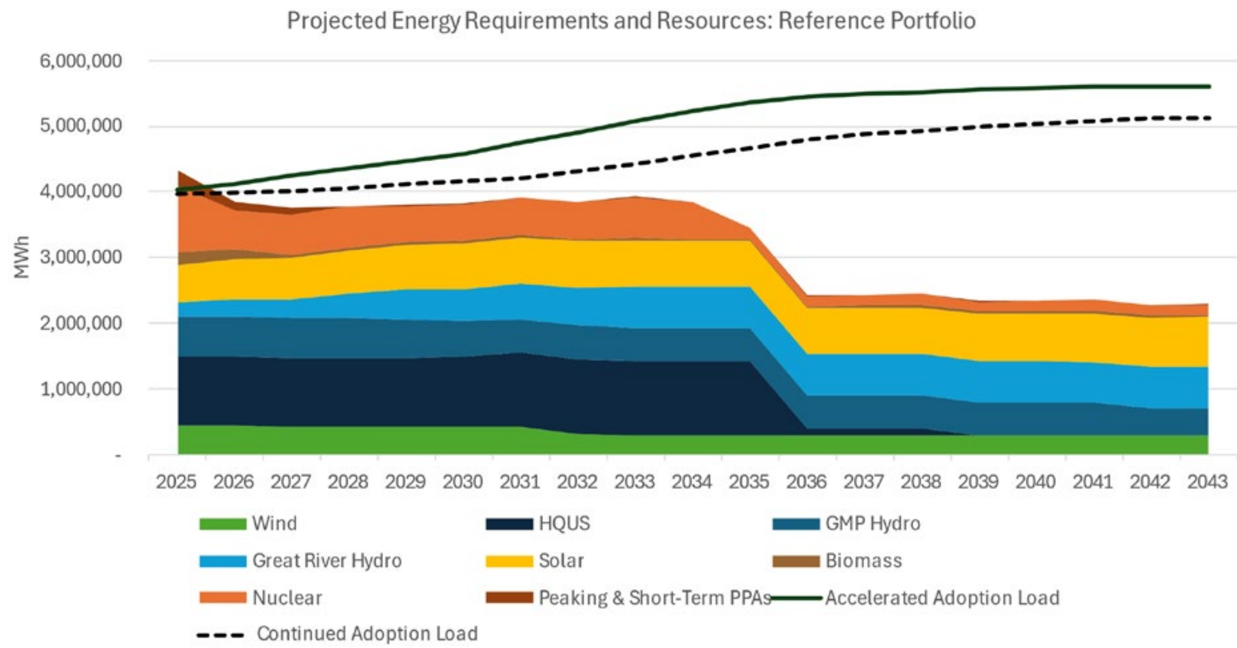


Figure 7-1. Projected annual energy requirements and supply for the Reference Portfolio.

Observations

- GMP designs its portfolio so that long-term committed sources are somewhat less than the projected load requirements. Layered, short-term, forward energy purchases (which are limited portions of the red and orange sources in the first few years) presently bridge the gap between long-term committed sources and load requirements. As GMP moves to an annual, fully renewable portfolio we expect to complement committed renewable supplies with some volumes of short-term forward market purchases during peak winter months, for example, when GMP's committed renewable supplies are less than projected energy requirements. The purpose of these purchases is to lock in a fixed or stable price for limited volumes of needed energy, rather than to rely on more volatile spot market energy prices. Such short-term purchases could be supplied by renewable sources or by non-renewable system energy along with retirement of appropriate REC volumes to ensure RES compliance. Similarly, during months when GMP's committed supplies exceed projected energy requirements, GMP will explore forward sales to lock in the price of projected energy sales. The more seasonally aligned GMP's future renewable supplies are with our customers' electricity consumption, the more limited the need for such seasonal balancing purchases and sales will tend to be.

- GMP's new PPA with Great River Hydro began deliveries in 2023 and is now a resource in GMP's portfolio. This PPA locks in significant volumes of renewable energy through the forecast period and provides 10+ percent of GMP's annual energy supply in 2033, when it reaches its full contracted volume.
- A significant portion of future distributed solar capacity in Vermont is expected to serve GMP customer needs and RES goals. For net-metered solar, GMP considers the portion of energy from net-metered solar generation that supplies more than the participating customer needs as an energy source—rather than as a reduction to GMP's retail sales and load requirements.

In the mid-2030s the HQUS and NextEra Seabrook PPAs will expire. Some potential alternative resources—such as large regional wind projects, or renewable projects that depend directly on expansion of the bulk transmission system—will likely feature long lead times between negotiation of a PPA and the commencement of commercial operation. GMP has therefore begun exploring opportunities for such renewable sources with long lead times, and we expect to continue doing so.

Open Capacity Position

7-2 presents our forecasted capacity energy gap chart, comparing projected qualified capacity volumes from GMP's committed sources to projected capacity volumes that GMP will be responsible for supplying or purchasing in the Forward Capacity Market. The chart below shows both the demand obligation curve and the current committed resources. Flexible loads, energy storage and demand response programs will show up as a reduction to the demand obligation curve.

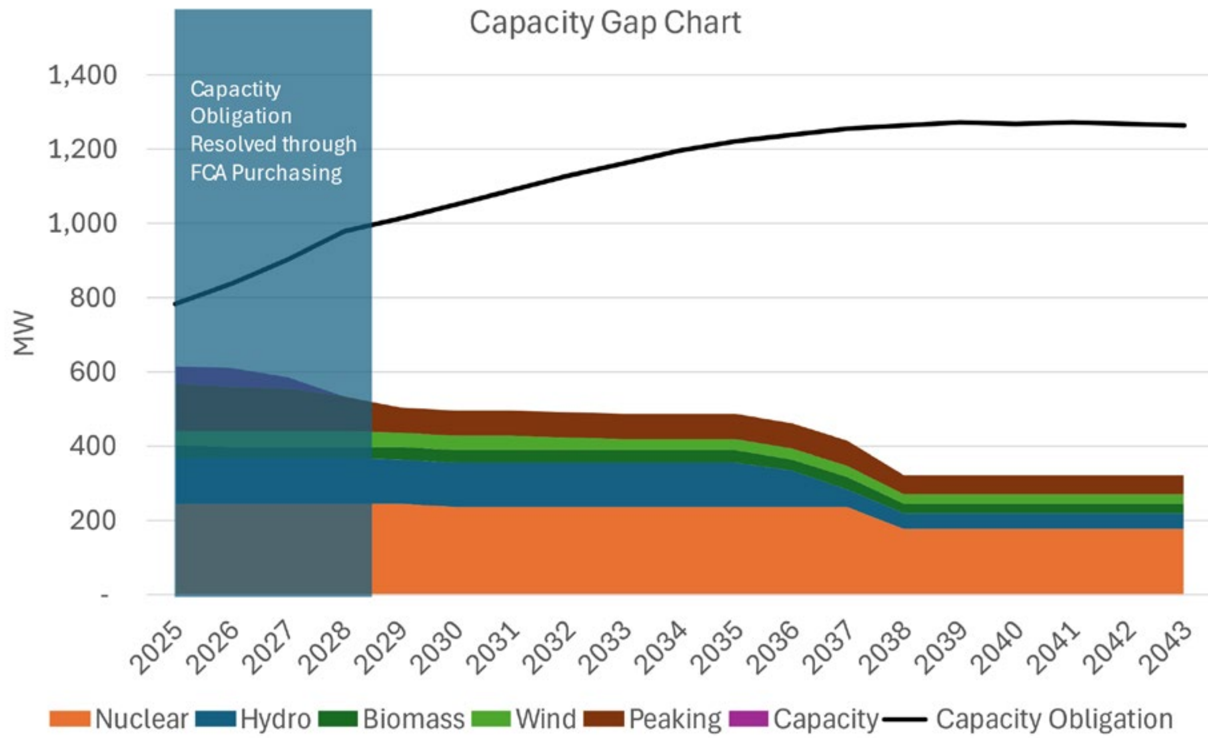


Figure 7-2. Comparison of projected qualified, committed capacity volumes and projected capacity volumes to be supplied or purchased in the FCM.

The section on **Capacity Market Reforms** in **Chapter 5,** notes that the ISO New England FCM is undergoing significant reform, with changes to the capacity accreditation that will be applied to various types of resources. Under ISO New England's Capacity Auction Reforms Key Project, the FCM will also transition from an annual forward market to a seasonal and prompt market. It seems likely that the resource accreditation changes will yield a net reduction in the volume of qualified capacity associated with the existing fleet of resources in New England. All else equal, this would likely lead to an increase in capacity clearing prices.

It also appears likely that under the seasonal market construct, clearing prices for capacity in winter months will clear at higher prices than those for summer months. This is due to forecasted growth in winter peak demands that would make ISO New England a winter peaking system by the 2030s, along with an expectation that some significant existing capacity sources (for example, natural gas plants that lack firm fuel supplies or lack significant quantities of backup fuel) could receive lower accredited capacity values in the future than they have in the past.

GMP will continue to follow these capacity market changes and expects to revisit price differentials after the details of the ISO New England capacity market redesign are finalized and seasonal auctions are under way. Directionally, however, a long-term trend toward peak loads and peak capacity pricing in winter is likely to increase the relative value of renewable energy sources like wind—which tends to produce more output in winter—by some amount relative to solar.

GMP's capacity portfolio has historically been structured to supply most of our projected capacity requirements for the near term using self-supplied generation, long-term capacity PPAs, and layered short-term purchases. The remaining open capacity position has certain cost exposure through the results of the annual FCAs that set the prices three years ahead of each annual capacity commitment. GMP's ability to layer short-term bilateral capacity purchases—typically at fixed prices, for terms of up to a few years—has helped limit the potential variance in GMP's annual net capacity costs.

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. Under the prompt market structure that will be implemented in New England in 2028, changes in auction clearing prices for capacity will no longer be lagged by more than three years, so GMP and other market participants will experience clearing price changes more quickly after each auction. GMP will therefore consider adjusting its procurement approach so that if bilateral forward capacity purchases are available at reasonable prices, we purchase more capacity through forward purchases and leave less of our capacity obligation to be priced in the annual ISO New England FCA.

Peak-reducing resources like energy storage and controllable loads are also promising as a means of reducing GMP's capacity market exposure. The amount of this exposure is based on GMP's loads during the ISO New England coincident peak hour to determine each load-serving entity's capacity load obligation. GMP discharges its distributed energy storage resources and calls on flexible load resources to limit GMP's net load during potential peak conditions in New England. Looking forward, under the new marginal capacity accreditation method in New England, the accredited capacity value of additional solar, wind, and battery storage capacity will tend to decline as the volume of these resource classes increases relative to the size of the ISO New England market. With this in mind, GMP expects to consider whether it would be cost-effective to mitigate this trend of declining capacity ratings by modifying the design of future battery storage plants to feature larger volumes of energy storage capability, relative to their maximum rated output.

Renewable Energy: RES Tier I Supply

Figure 7-3 is a projected long-term Tier I gap chart that reflects the revised RES, which requires more renewable energy supply more quickly. The chart compares our committed supply of Tier I-eligible renewable energy to projected Tier I requirements.[9] The Tier I requirements are depicted here as the minimum required annual volumes of renewable energy, minus the requirements for Tier II and Tier IV.

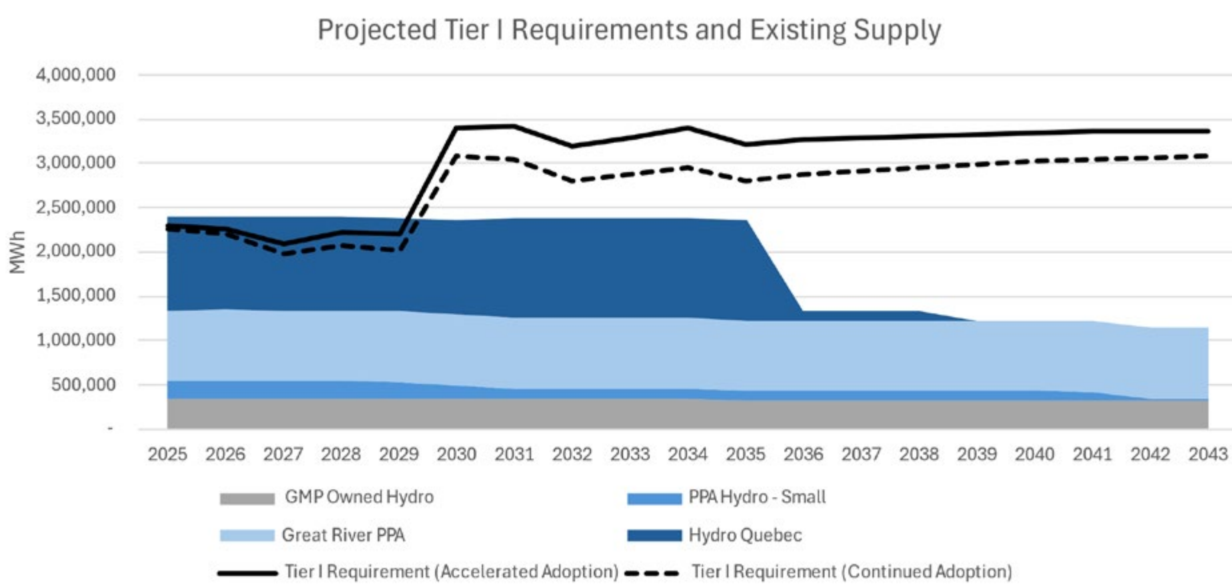


Figure 7-3. Projected Tier I requirement (dark line), compared to existing supply.

Observations

- In the near term, to the extent that RECs eligible for Class 1 markets in other states feature meaningfully higher prices than Tier I RECs, we will continue to sell those RECs to directly reduce net power costs and rates for customers, rather than using them to meet RES compliance or GMP's percent renewable calculation. This activity will decline as RES requirements increase and the gap between REC values here and elsewhere narrows.

9 See **Chapter 6, Table 6-1,** for a comparison of requirements between the 2017 RES and the 2024 RES.

- We expect to have sufficient supply of Tier I-eligible sources in the near term. In the long term, even with the recent addition of our multi-year PPA with Great River Hydro, our committed Tier I supply would be short of the 2024 revised Tier I requirements without additional sources. We discuss possible long-term renewable resource additions to fill this gap later in this chapter.
- The Tier I requirements are based on system load, so they differ noticeably between demand scenarios; by the late 2030s the required volumes are large in both scenarios.

Renewable Energy: RES Tier II Supply

Figure 7-4 compares our projected annual supply of Tier II-eligible new distributed renewable energy to requirements under the revised RES.

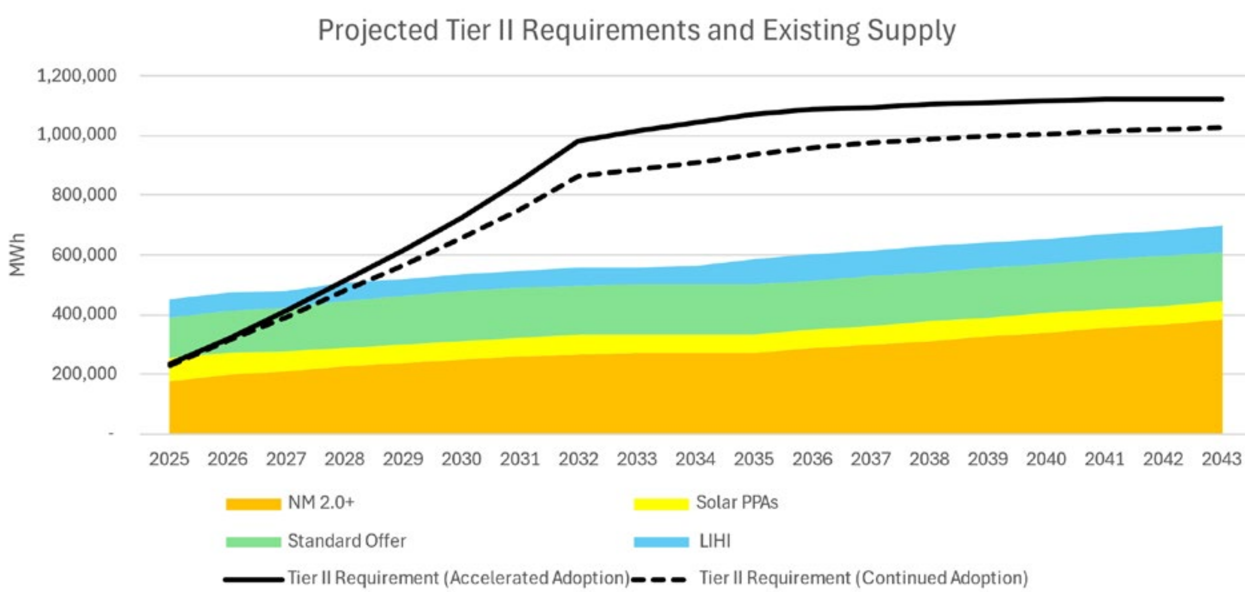


Figure 7-4. Projected RES Tier II requirement vs. GMP's Reference Portfolio supply.

This chart shows the projected RES Tier II requirement compared to GMP's Reference Portfolio supply. One type of existing resource that we plan to use to meet the Tier II requirement is LIHI certified hydroelectric plants with nameplate capacity of 5 MW or less. our LIHI certified plants can be found in **Appendix G**.

Figure 7-4 indicates that GMP is likely to be well supplied with Tier II RECs for the next few years. To meet increasing Tier II requirements across the next decade, GMP will need to procure substantial new in-state distributed renewables.

Specifically, under the Accelerated Adoption demand outlook approximately 430,000 MWh per year of additional Tier II supply beyond those already included in the Reference Portfolio will be needed by 2032. For a sense of scale, if all of the new Tier II supply were solar PV producing energy at an annual capacity factor of 17 to 20 percent, the volume of additional solar capacity needed by 2032 would be approximately 250 to 290 MW.

GMP expects to obtain most of the additional Tier II supply through long-term PPAs that are regularly solicited, starting in 2025. To meet GMP's Tier II requirements under the Accelerated Adoption Case demand forecast, an average pace of annual procurement of over 30 MW of distributed solar capacity will be needed over the next decade.

Renewable Energy: RES Tier IV Supply

Figure 7-5 compares our committed annual supply of Tier IV-eligible new regional renewable energy to requirements under the revised RES.

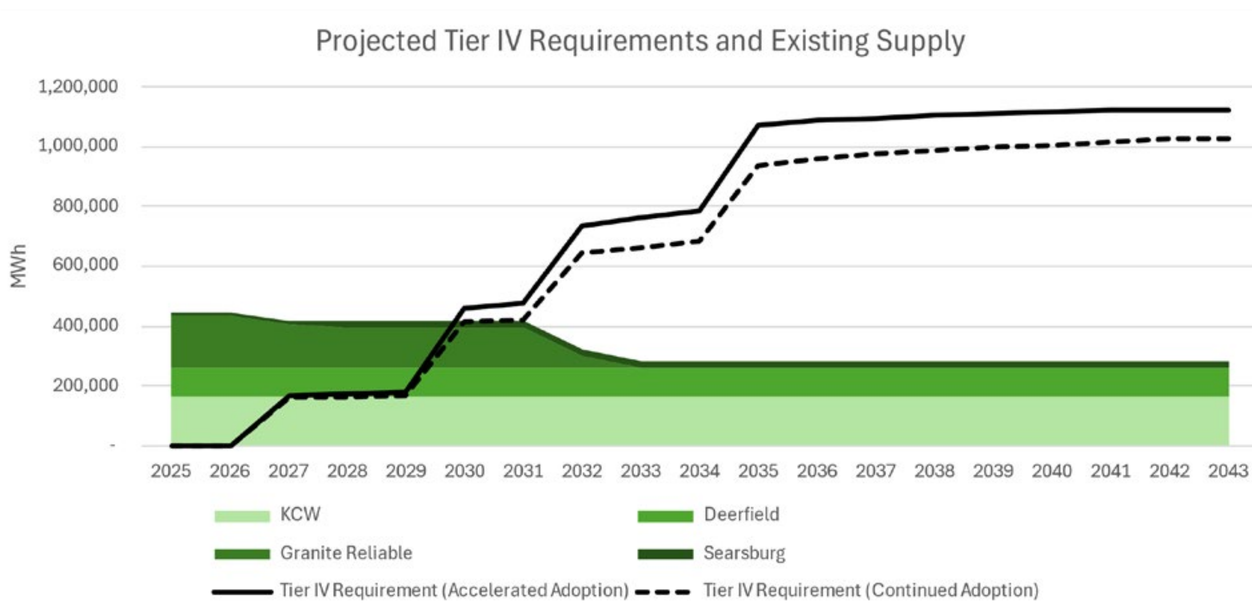


Figure 7-5. Projected RES Tier IV requirement vs. GMP's Reference Portfolio supply.

Observations

- The volume of Tier IV requirements ramps up rapidly over time, reaching approximately 1.1 million MWh per year by 2035.
- As depicted in the chart, one of GMP's first options for Tier IV compliance will be to retire RECs from sources already in our Reference Portfolio but not presently used for RES compliance. These RECs are associated primarily with generation from renewable plants such as Deerfield Wind, Kingdom Community Wind, Granite Reliable Wind, and some Standard Offer plants, now eligible for Tier IV under the revised RES. These have not historically been eligible for RES Tier II because they are too large or were not built recently enough and had more value for GMP customers through REC sales to buyers using them for compliance with other states' renewable portfolio standards. This volume of potential REC retirements associated with renewable plants already in GMP's Reference Portfolio is substantial—about 447,000 RECs per year.
- Under the Accelerated Adoption demand outlook, these REC retirements would be sufficient to meet GMP's Tier IV needs for several years, through approximately 2030. The remaining volume of projected Tier IV requirements is about 0.8 million MWh per year. This is equivalent to the annual energy production from a 200 MW slice of an offshore wind project operating at a 45 percent capacity factor; for land-based wind producing at a lower capacity factor, the required slice of output would be somewhat larger.

Carbon Free

A touchstone for our portfolio design is low carbon content for our electricity supply, on the way to meeting our 100 percent renewable requirement by 2030. As we move forward, we expect to remain 100 percent carbon free in our annual generation mix, with the fraction of renewable energy increasing each year. The Reference Portfolio provides a strong foundation for doing this, and the RES gap charts above indicate the projected volumes and timing of additional renewable energy that will be needed. Unless noted otherwise, we have designed the future portfolios tested in this IRP to be 100 percent carbon free and renewable, annually. GMP's approach to meeting RES is to maintain a steady path ramping up to 100% renewable that we can adjust as needed.

Price Stability and Portfolio Flexibility

A primary driver of portfolio cost stability over time is reliance on power sources that feature fixed or stable prices over long terms. As illustrated in **Figure 7-1**, after GMP's current layered short-term energy purchases expire, the magnitude of the projected annual open energy position is limited for the remainder of the 2020s, then increasing to about 3 million MWh per year by 2036. The extent to which GMP fills these needs with resources that are stable priced over long periods of time will therefore determine the degree to which the portfolio remains stably priced on balance; conversely shorter-term commitments tend to create less price stability but greater flexibility. To achieve the new RES requirements, GMP will need to rely on long-term commitments to support the construction of renewable plants to supply Tiers II and IV. New wind and solar plants are generally being constructed in New England with the support of long-term contracts, or in the case of some distributed renewables, within a program structure that is very likely to deliver a predictable and sufficient revenue stream once the project is built. GMP expects that it will also be appropriate to procure a significant fraction of Tier I needs via long-term contract in the years ahead. This will ensure adequate supply and limit exposure from having to buy most of that supply at elevated short-term prices in the event that the market for existing renewables becomes very tight.

Figure 7-6 presents the Reference Portfolio from the perspective of price stability, measured by the fraction of forecasted energy requirements that are matched with fixed or stable priced supply sources. The black line depicts the estimated fraction of forecasted requirements that are hedged, annually.

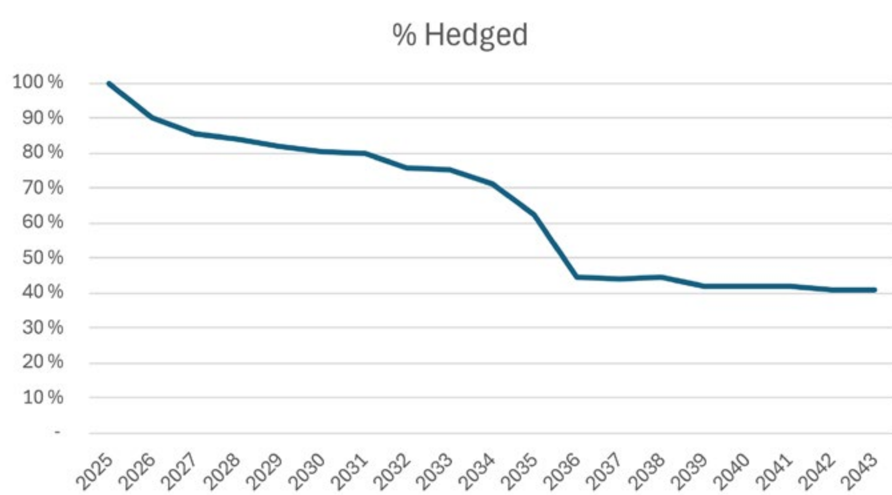


Figure 7-6. Percent of projected annual energy requirements hedged with respect to price.

The chart shows that a majority of GMP's annual energy supply is from stable-priced resources until the mid-2030s, with stable-priced source comprising over 80% of the supply through the late 2020s.[10] This fraction of stable priced sources will substantially insulate our net power costs from energy market price changes during this period, while leaving a portion to be purchased at prevailing market prices. By the late 2030s, after the current NextEra Seabrook and HQUS PPAs expire, the projected fraction of hedged energy declines to about 40 percent.

The effectiveness of stable-priced supply at steadying GMP's net power costs—which include purchases and sales in the regional energy market that are required to balance GMP's loads and sources—can also depend on the particular mix of renewable sources and the extent to which the output from those sources aligns with when our customers use electricity. And of course, one major stability benefit with most renewables, such as wind, solar and hydro, is that the fuel price will not change and is not impacted by geopolitical influences unlike more volatile fossil-fueled generation.

Renewable Generation Profiles and Alignment of Supply and Demand

The objectives of renewability, alignment between supply and demand, and cost stability are also intertwined. The extent to which energy supply is aligned with when GMP's customers use electricity on a seasonal and hourly basis depends on the characteristic seasonal generation profiles of the renewable energy sources in the portfolio, and the extent to which output fluctuates on a daily and hourly basis within each season. The degree of supply/demand alignment, in turn, can affect the stability of GMP's net power costs.

The Reference Portfolio consists primarily of plant-contingent hydroelectric, solar and wind supply, along with a large shaped renewable purchase. As GMP progresses to a fully renewable annual energy supply, the alignment of supply and demand over seasonal, daily, and hourly timeframes will depend primary on the specific renewable sources that are added to the Reference Portfolio. The long-term alignment of supply and demand for potential GMP portfolios is therefore considered in depth in **Hourly Screening Analysis of Supply/Demand Alignment** (below), by testing specific possible combinations of future renewable sources and energy storage, with consideration of the seasonal patterns and characteristics of these choices.[11] It is therefore useful to briefly consider those seasonal patterns here.

10 As illustrated in depth in the hourly screening analysis of supply/demand alignment later in this chapter, GMP's highest projected fractions of committed supply relative to energy requirements are during spring months and during daytime hours on sunny days; the lowest are in winter months and during overnight hours.

11 Actual renewable generation can also vary significantly around those characteristic patterns, because of sustained weather fluctuations (an unusually sunny or cloudy month, for example, or an unusually windy or calm month).

Average wind generation in New England tends to be significantly higher in winter months than in summer, whereas solar output is strongest in spring and summer months. **Figure 7-7** shows seasonal output profiles based on 2022 output for Vermont distributed solar generation, Vermont land-based wind generation, and regional hydropower generation.

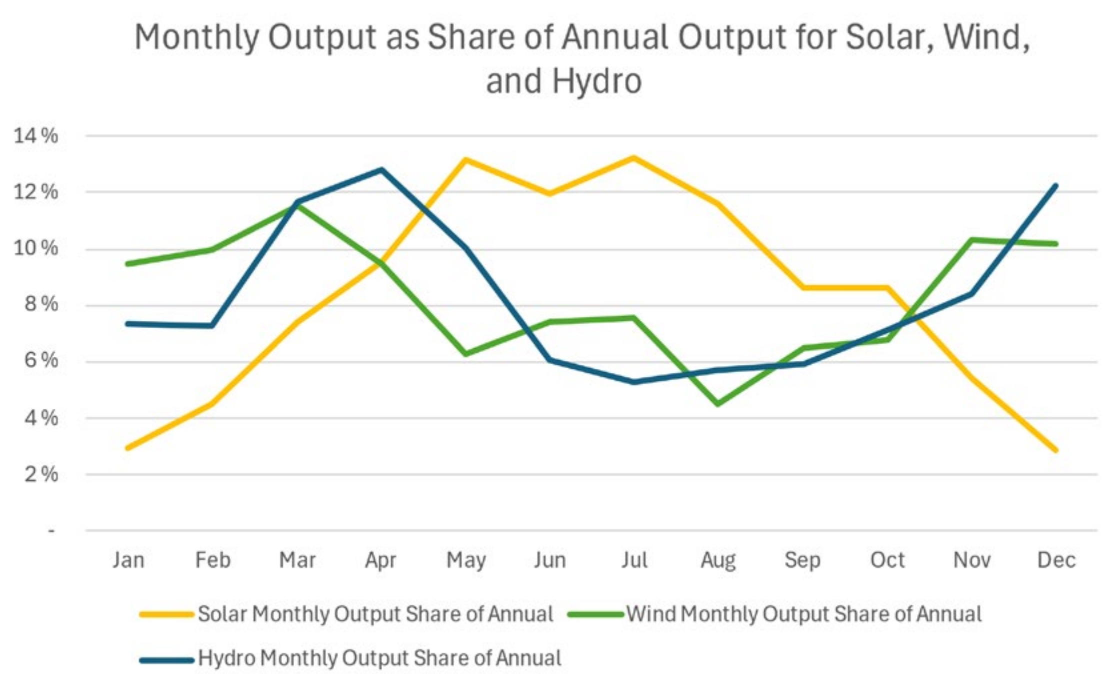


Figure 7-7. Output profiles for solar, hydropower, and wind, across 2022.

Hydro generation in New England tends to be seasonal with the highest output during the spring runoff and lower average output during summer months, when the annual runoff is complete and rainfall tends to be less frequent.

Renewable energy generation within each season can also fluctuate greatly on a daily and hourly basis based on fluctuations in actual wind speeds, stream flows, and cloud cover. **Figure 7-8** shows daily profiles for output of Vermont solar and wind sources that supply GMP. The profiles were derived using actual output from GMP's wind sources, Standard Offer solar, and solar PPAs during 2022. The profile for each technology shows the average hourly output profile over the year, along with a profile from very high output days. Each of them is normalized to illustrate a fleet of 100 MW of capacity. Days of extreme low output for each of the technologies feature generation near zero in all hours; these values are not shown here.

High-output days for each technology feature production approaching double the output in an average day. The most striking visual difference between the wind and solar curves is also an obvious one: the wind sources can deliver power across all hours of the day during windy conditions, while solar output during a high-output day is contained to daylight hours. This concentrated output profile has significant implications for GMP's portfolio, which already contains substantial volumes of solar generation. Large additions of solar power, without accompanying storage or flexible load resources, run an increasing risk of producing energy that is surplus to GMP's customer needs on the sunniest days, while not providing energy to meet open energy position at night or on very cloudy days. This dynamic affects the results in the section, **Hourly Screening Analysis of Supply/ Demand Alignment,** below.

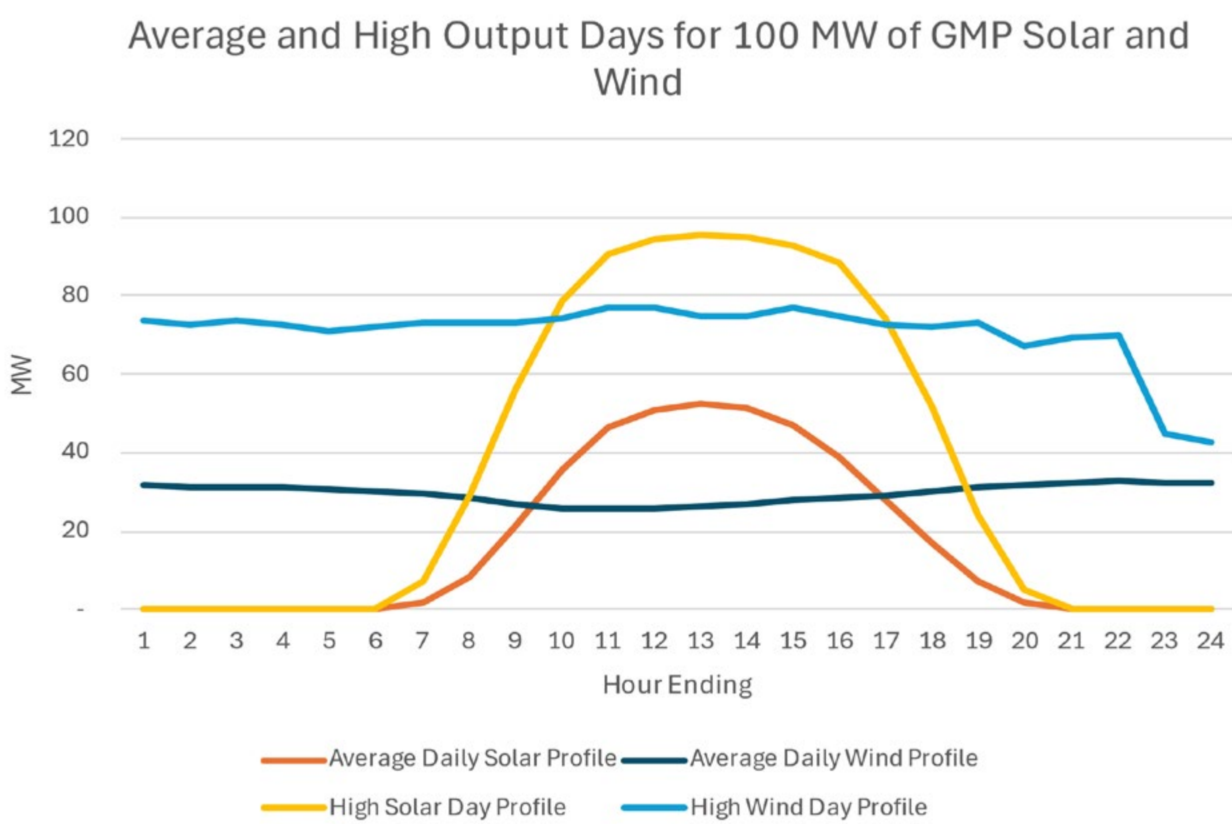


Figure 7-8. GMP solar and wind generation profiles for average and high-output days.

The **Hourly Screening Analysis of Supply/Demand Alignment** tests the alignment of supply and demand under several portfolio designs that feature different mixes of renewable energy supply and paired energy storage resources. The analysis confirms that continued additions of flexible resources like energy storage or controllable load will tend to increase the alignment of hourly supply/demand alignment in GMP's increasingly renewable and intermittent portfolio, which therefore limits the magnitude of energy market risk. The seasonal balance between supply and demand is better managed via the mix of renewable resources in the portfolio.

Portfolio Analysis

Hourly Screening Analysis of Supply/Demand Alignment

As GMP moves from its current Reference Portfolio to a future mix of sources that fulfill the goals outlined above in the context of higher customer load and an evolving regional resource mix, a screening model that depicts supply and demand at an hourly level of resolution helps GMP fully understand tradeoffs among different portfolio designs.

To inform the design of Illustrative Future Portfolio in the long term, we screened several portfolio designs to test their relative alignment between our renewable supply and our customers' electricity use. The year 2035 is useful for this purpose because GMP's electricity portfolio will have changed markedly by that time. For example, the Great River Hydro PPA will also have ramped up to its full volumes by that time, whereas the Granite Reliable Wind and NextEra Seabrook PPAs will have expired and the current HQUS PPA will be approaching expiration.[12] Vermont's revised RES requirements will also have reached their full extent for Tiers I, II, and IV by that date, and there will be substantial electricity demand in line with the forecasts described in this IRP.

This analysis compared the energy supply from several portfolios to forecasted electricity demand, at an hourly level of resolution. The hourly portfolio level outputs that we tracked and summarized for the study involve the fraction of hourly electricity consumption met with renewable supply, hourly energy balancing purchases from and sales to the ISO New England energy market, and the fraction of each portfolio's assumed renewable energy additions projected to meet the hourly needs of GMP's customers versus being resold to the regional market.

Types of Likely Additional Resources

GMP's portfolio analysis considers possible alternative resource mixes that could address the gaps in renewable energy identified in the Reference Portfolio in the years ahead. We have tested portfolio combinations that involve hypothetical volumes of various renewable supply and storage resources.

12 The primary step-down of HQUS PPA volumes is scheduled for 2036. We conducted this long-term screening analysis, starting from a portfolio without the HQUS PPA, and tested levels of potential shaped renewable PPAs, which could be obtained from HQ or other suppliers.

The specific types of resources we tested are summarized in **Table 7-2** (continued on next page).

RES Tier	Option	Potential role/rationale	Key characteristics/ observations
Tier I	Plant-contingent hydro energy & RECs from within New England	Primary source of existing renewables in New England that are not eligible for a high-prices RPS/CES tier.	Daily output profile is approximated from the New England hydro fleet.
	Shaped hydro energy with RECs	Improve alignment with GMP's seasonal/ hourly net short positions.	Fixed output profile, backed by multiple generators or energy storage.
Tier II	New Vermont DG solar (up to 5 MW)	Flexibility in project sizes; some economies expected based upon scale and location.	This refers to volumes above the pace of net metering. Procured via ongoing GMP-led RFPs/process.
Tier IV	Retire RECs from GMP sources that are newly eligible for Tier II or Tier IV.	Increases the use of committed GMP renewable sources to serve GMP customers, match with hourly load requirements.	GMP first option for Tier IV supply, in the quantities presently known to be available.
	New offshore wind	Largest potential source for new renewables to supply New England. Output profiles likely to complement GMP's existing Vermont/New Hampshire wind sources. Build out timing and price will be key considerations.	Output profile approximated as a blend of south coast and Gulf of Maine supply.
	New solar – in Vermont or neighboring states	Build out has been and is expected to be robust. Fits particularly with storage additions and if regional wind sources are not paced for operation as planned or prices are higher.	Using observed output profile without paired storage, wherein solar is not as well aligned with expected open positions in winter and evening peaks as other resources.

RES Tier	Option	Potential role/rationale	Key characteristics/ observations
Energy storage	Resilience-focused storage	Short-duration battery storage. Deployed primarily to reduce customer outages. Sited at customer premises or on GMP distribution system.	Storage capacity = 4 hours at maximum output; round trip efficiency 89%. State of charge limited to a minimum of 10%.
	Other distributed storage	Short-duration battery storage. Deployed to enhance transmission and distribution system peak capacity and/or DG hosting capacity.	Storage capacity = 4 hours at maximum output; round trip efficiency 89%.
	Longer duration storage	Longer duration designed to help bridge longer energy shortfalls (e.g., hot/cold weather, periods of low renewable generation).	A proxy for longer duration battery, or for other energy storage technologies. Storage duration of 6 hours or more could be needed for deferral of some grid upgrades identified in **Chapter 3** analysis.

Table 7-2. GMP-tested resources, by RES tier, in its screening analysis of various portfolios.

While we have not tested every possible resource type, this group reasonably reflects the types of resources known at this time to be most likely available to fulfill RES and other goals.

Portfolios Tested

We built portfolio alternatives to test performance in the hourly screening model based upon predominant themes or features. **Table 7-3** summarizes the hypothetical future portfolios GMP tested, organized by the portfolio theme or feature they were intended to explore. We started with a portfolio that builds efficiently from the Reference Portfolio to future RES requirements—for example, it uses enough in-state solar to fulfill Tier II requirement, offshore wind additions to meet Tier IV cost-effectively, and plant-contingent hydro to fulfill Tier I requirements. We then tested other ways to meet RES tier goals, based upon more solar in Tier IV, greater use of shaped hydro resources in Tier I, and storage. Finally, we tested a portfolio that uses REC-only purchases for a significant volume of Tier I.

Portfolio theme / feature	Summary
Wind vs. solar supply for Tier IV	Projected Tier IV needs filled (50% or 100% variations) with solar resources, instead of OSW
Battery storage	Use additional 300 MW increments of short-duration battery storage in conjunction with resources as described in other portfolios, to enhance fit of renewable resources to forecasted demand.[13]
Resource Mix to Supply Tier I	Test combinations of plant-contingent hydro; a shaped hydropower product; and REC purchases (without energy)

Table 7-3. Portfolio themes tested in hourly screening analysis

Portfolio Screening Results

Below we present a summary of results and observations from the hourly screening analysis, organized by portfolio themes.

Wind vs. Solar Supply for Tier IV

Figure 7-9 shows the projected average hourly fraction of load served with renewable energy for each month of the 2035 study year, for portfolios that feature three combinations of wind and solar. When combined with GMP's other renewable sources in the Reference Portfolio, they approximately meet GMP's projected annual RES Tier IV supply needs:

- 200 MW of OSW (enough to meet GMP's projected Tier IV needs), and no solar
- 100 MW of OSW, and 260 MW of solar
- No OSW and 530 MW of solar

13 Adding storage in isolation does not increase the volume of renewable supply, but depending on how storage is dispatched and the other portfolio resources, it can noticeably improve the alignment of GMP's supply with electricity demand. In this screening analysis, the battery storage was dispatched with the sole goal of maximizing the alignment of renewable supply with GMP's hourly load obligations. That is, the storage was modeled as charging during hours when available renewable supply exceeds load and discharging when load exceeds supply—all subject to the battery fleet's state of charge over time.

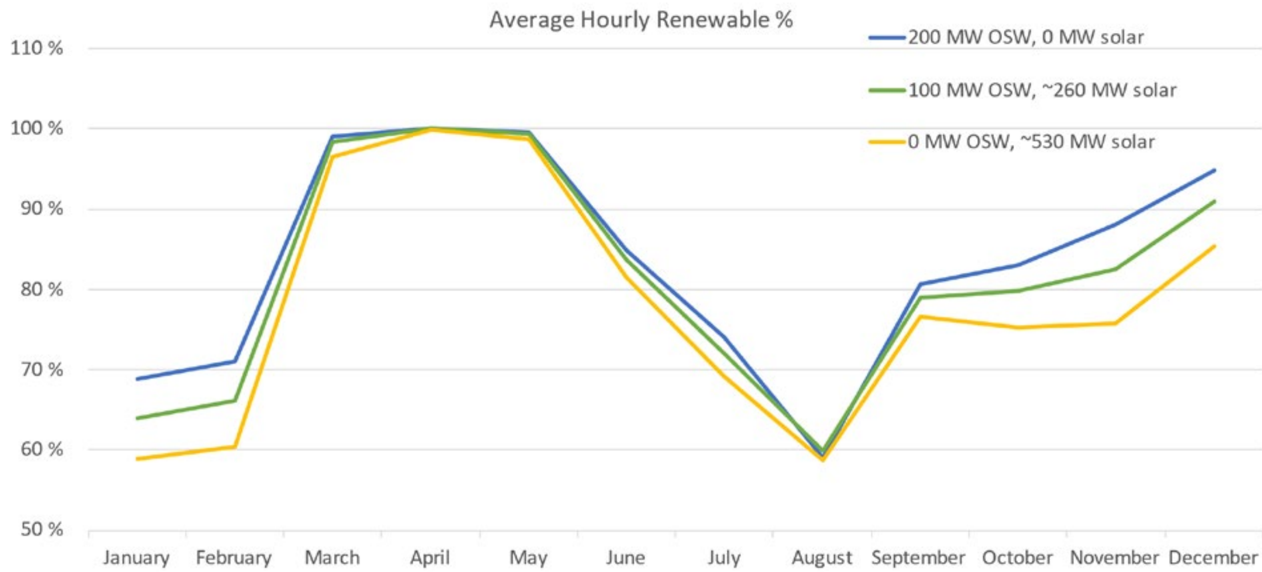


Figure 7-9. Average hourly renewable supply fractions, tradeoff between wind and solar supply.

GMP calculated the hourly renewable supply fraction for each of these portfolios in the screening model by comparing the sum of GMP's hourly renewable supplies to hourly electricity requirements, with the results aggregated over each calendar month. The average renewable fraction in each month is primarily driven by two factors: (a) how the overall volume of GMP renewable supplies compares to load requirements in the month, and (b) how the hourly profile of those renewable supplies in aggregate aligns with GMP's projected hourly load profile.

Figure 7-9 indicates that the portfolios featuring Tier IV supplies most heavily weighted toward wind (the blue line) yield the highest average renewable supply fractions. Portfolios with more solar and less wind (the green and yellow lines) yield noticeably lower hourly renewable fractions overall—with reductions observed in most months, except in the spring, which feature relatively high generation levels for hydro, solar, and wind. Each replacement of 100 MW of OSW with an equivalent volume of solar generation suggests a two to three percent decrease in the average fraction of hourly loads supplied with renewables in the same hour.

Finally, we note that all portfolios show a pronounced drop in hourly renewable supply in August. This result reflects the 2022 weather year upon which the hourly output volumes for most renewable sources is based. August 2022 was a dry month with extraordinarily low hydro production in Vermont. It essentially serves as a stress test to illustrate how the supply/demand balance can change during extreme drought conditions. We expect that hourly renewable supply fractions in a typical August will be significantly higher, but still often below average, because both hydro and wind production in Vermont tends to be only moderate during August and loads can be high during extended hot periods.

Energy Storage

Based on the same hourly screening tool, **Figure 7-10** illustrates how energy storage can improve the average hourly renewable supply fractions. Here we tested the addition of 300 MW of short-duration energy storage to portfolios that fulfill GMP's projected Tier IV needs in two very different ways: through additions of offshore wind (blue lines) or additional solar capacity above the Tier II requirements (yellow lines). The dashed lines show results for portfolios that contain 300 MW of additional short-duration storage; the solid lines do not contain additional storage.

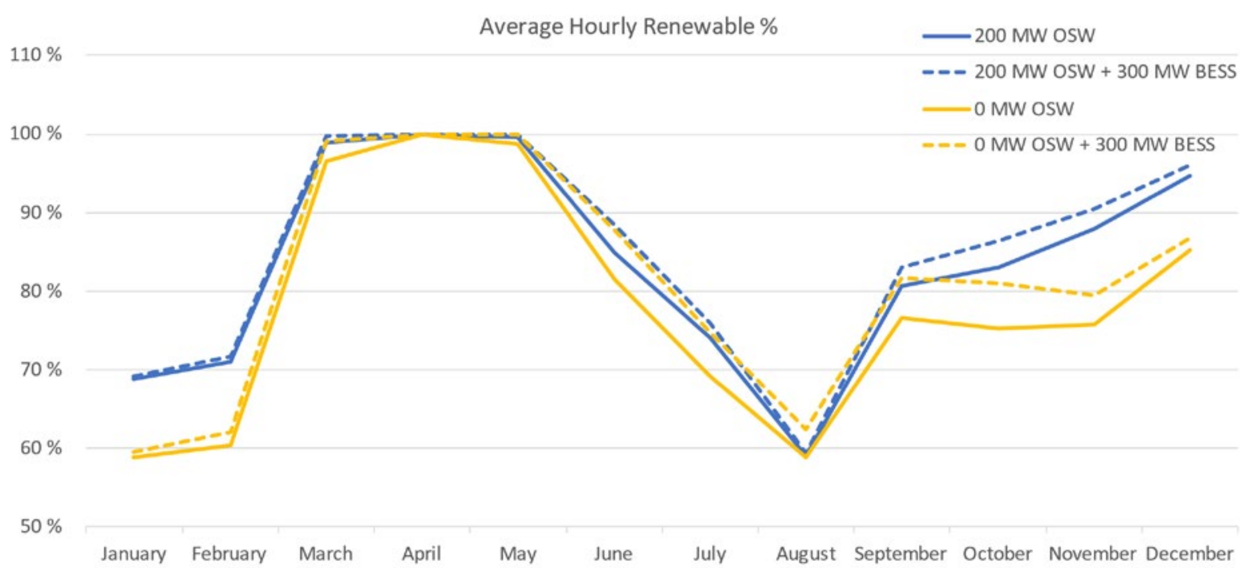


Figure 7-10. Average hourly renewable supply fractions, with potential influence of energy storage.

Here are primary observations when storage is paired in this way:

- Portfolios with more wind and energy storage achieved the highest hourly renewable supply fractions. In the fall and winter months, average hourly renewable fractions in the portfolio that supplies Tier IV needs with wind energy are 10 to 15 percent higher than for the portfolio that meets Tier IV with additional solar.
- In spring months, the projected hourly renewable supply fraction is high for all portfolios. This reflects that the leading renewable options in New England all feature substantial production in the spring months. As GMP acquires more long-term plant-contingent renewable sources, the portfolio will become highly renewable in these months first. As the portfolio becomes annually fully renewable, GMP will typically have significant, excess renewable energy during the spring months, offset by net short positions in other months.

- Addition of 300 MW of short-duration (4-hour) battery storage improves the hourly renewable fraction—reflecting the alignment of supply with electricity use—by up to 5 percent, a noticeable change.
- Energy storage tends to provide the most pronounced increases in average hourly renewable supply during times when solar production is high—that is, during spring and summer months of high solar production, and in the solar-focused portfolio. In short, abundant solar energy is available for charging during daytime hours on sunny days and can be discharged during later night hours or on cloudy days.

The latter observation confirms that to the extent GMP deploys energy storage for other purposes like resilience and managing future peak loads to limit grid upgrades, use of that energy storage during non-critical times could meaningfully enhance the alignment of GMP's renewable supply with demand. Significantly increasing volumes of short-duration storage could be appropriate for GMP as the penetration of distributed solar grows. It also means that if a significant part of the Tier IV supply needs to be met with additional solar generation—for example, if the availability or pricing of regional wind supplies are challenging—then it would be appropriate to considering pairing some portion of that additional solar supply with energy storage.

The two preceding charts, **Figure 7-9** and **Figure 7-10**, present the relative alignment of renewable supply with demand for possible portfolios using average hourly renewable supply fractions. For a sense of scale, **Figure 7-11** illustrates relative alignment in terms of the absolute scale (in MW) of hourly differences between renewable supply and electricity load.[14]

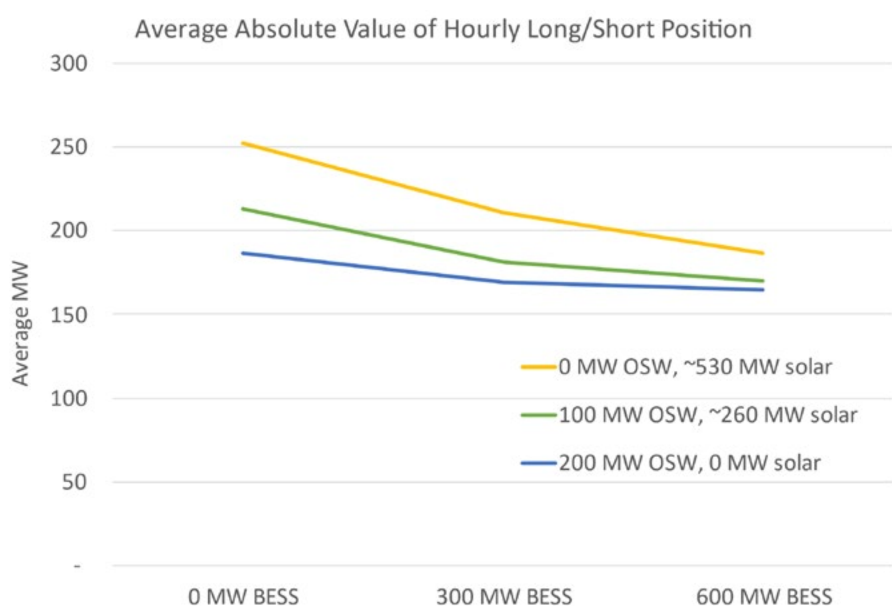


Figure 7-11. Magnitude of average hourly long and short positions, for portfolios containing varying volumes of OSW, solar, and storage.

14 For example, if GMP's renewable supply is 100 MW less than load in one hour and 100 MW greater than load in another hour, each hour would be assigned a value of 100 MW.

In this context, a higher absolute value for a portfolio indicates that, on average, instances of hourly surplus and hourly shortfall tend to be larger than for portfolios with lower absolute values. Primary observations from this presentation are:

- The results broadly indicate that for portfolios that rely primarily on intermittent renewable sources to achieve a fully renewable annual energy supply, hourly variances between supply and demand of 200 MW or more will be common. Such variances tend to offset within timeframes as short as several hours and over long time periods—and they can be managed to some degree with forward sales, but they are an indicator of relative market exposure.
- The wind-dominant portfolio (blue line) shows the lowest absolute value of average hourly long/short position, compared to portfolios that rely on more solar in lieu of wind.
- Addition of short-duration storage—moving from left to right across each portfolio—lowers the absolute value of average hourly long/short position. This is particularly evident in the solar-dominant portfolio (orange line), and less so in the wind-dominant portfolio. This makes sense because storage with a duration of a few hours of maximum output is sized to address the diurnal pattern of solar generation (charge in daytime, discharge at night). By contrast, wind-dominant portfolios are better aligned with electricity load to start (smaller shortfalls and surpluses), and fluctuations in wind output tend to occur over longer periods (many hours at a time, sometimes a full day or more). Such periods cannot be managed as effectively with short-duration storage.
- Although this illustration involves large blocks of energy storage and is not an optimization analysis, we note the first 300 MW of energy storage meaningfully lowers the average absolute value of hourly long/short positions. And an additional 300 MW of storage, absent any change to the renewable supply mix, lowers the variance to a much smaller degree.

Resource Mix to Supply Tier I

Under the Accelerated Adoption demand forecast, approximately 2.2 million MWh per year of Tier I supply will be needed by the mid-2030s. We tested the implications of meeting this large long-term need by using combinations of resources with significantly different characteristics:

- **Plant-contingent New England hydro**. If GMP's projected needs were met entirely with plant-contingent New England hydro, the output of approximately 600 MW of hydro capacity would be needed. We estimated the output profile of this resource from the data in the same 2022 weather year used to represent most other renewable sources.

- **Shaped hydro purchases**. Current examples of this are GMP's share of Vermont's long-term HQUS PPA and the firm portion of GMP's Great River Hydro PPA. To recognize uncertainty about the scale and nature of shaped purchases that will be available in the future from HQUS or other sellers, we set the size of this resource to provide half of the annual energy that we presently receive from the HQUS PPA. We assumed deliveries to be constant across the year.
- **Purchases of RECs without energy**. This resource option represents the purchase of quarterly NEPOOL Generation Information System certificates associated with hydro energy in a specific quarter, but not in specific hours; it would not allow GMP to count the associated energy as serving GMP load requirements in specific hours.[15]

Figure 7-12 shows the projected average hourly fraction of load served with renewable energy for each month, for three portfolios that feature different combinations of renewable supply. Specifically, the Plant-contingent hydro portfolio meets all projected Tier IV needs with this resource type. The Partial Shaped Hydro portfolio includes a shaped hydro purchase sized to provide half of the annual energy that GMP presently receives from the HQUS long-term contract, with the balance obtained from plant-contingent hydro. The 50% RECs portfolio meets half of projected Tier IV needs with REC purchases without energy, with the balance obtained from plant-contingent hydro.

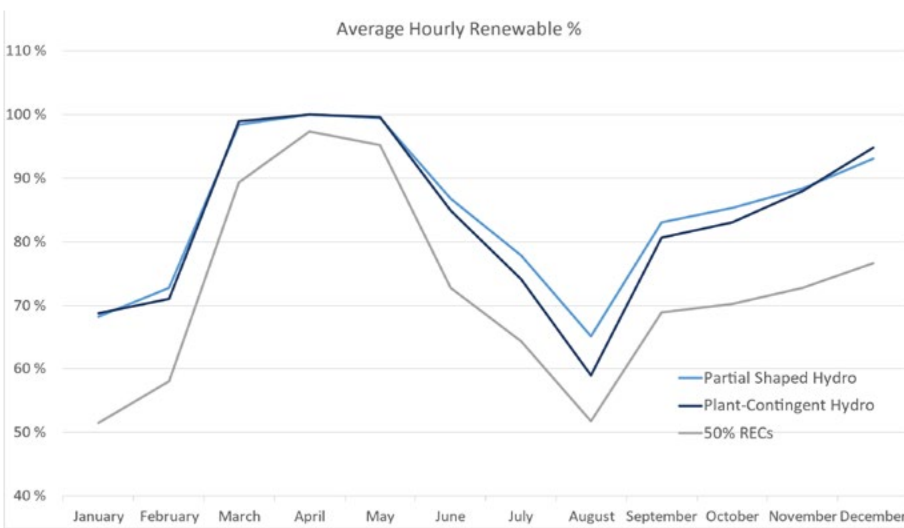


Figure 7-12. Average hourly renewable supply fractions for potential Tier 1 supply mixes.

15 Quarterly REC purchases of this type are consistent with the structure of the current NEPOOL GIS. NEPOOL is presently exploring enhancement of the GIS to allow generators to produce hourly RECs, which could become another renewable supply option for GMP. At this time, however, liquidity and pricing for a future hourly REC market are uncertain.

Primary observations arising from the contrasting Tier 1 portfolio components are:

- The shaped hydro PPA option would reduce the volume of needed plant-contingent hydro by approximately one-third, but the remaining need would still be approximately 300 MW. The shaped hydro option is projected to increase the average hourly renewable supply fraction noticeably in the summer months, and more modestly in other months. A purchase of this type would also make the portfolio less sensitive to fluctuations in hydro output.
- Meeting half of Tier I with REC purchases (without energy) would greatly reduce the needed volume of plant-contingent hydro purchases. This would meaningfully increase GMP's compliance options and the range of potential suppliers but would lower the projected average hourly renewable fraction significantly in most months, to about 72 percent on average.

Additional Considerations for Resource Evaluation

The screening analysis above examines how possible future portfolios—combinations of resource types—would align with what GMP customers' consumption is likely to be, seasonally and hourly. This section discusses three other factors—market value of output profile, locational value of energy, and grid upgrades—that are typically considered in the evaluation of specific potential resources based on their respective output profiles and where on the grid the output will be delivered.

Relative Market Value of Output Profile

The value of an energy resource to GMP depends not only on the price that GMP pays to purchase the resource's output, but also on the value that GMP receives for that energy in the ISO New England market settlement system.[16] The market value of output from a particular resource depends, in turn, on how the resource's output profile aligns with patterns of energy market prices in New England. A source that delivers energy during seasons and times of day when New England market prices tend to be relatively high (for example, winter and evenings), will provide more value to GMP than another source that delivers more energy during periods when market prices tend to be lower (for example, peak solar hours in spring). When evaluating potential additions to GMP's portfolio, we

16 The system that sets the process of calculating, billing, and invoicing charges and payments between market participants and an ISO.

consider the combination of price, alignment with the needs of our customers, and the relative market value of output.[17]

A market simulation model allows us to explore trends in the projected hourly value of energy from intermittent generation sources by combining the output shape of the resource with the hourly energy prices from Daymark's PLEXOS modeling of the New England region (see the **Wholesale Energy Market Analysis** section below). **Figure 7-13** shows the projected average value of energy output for several types of renewable energy for the Day-Ahead market, under the Daymark/GMP Base Case.

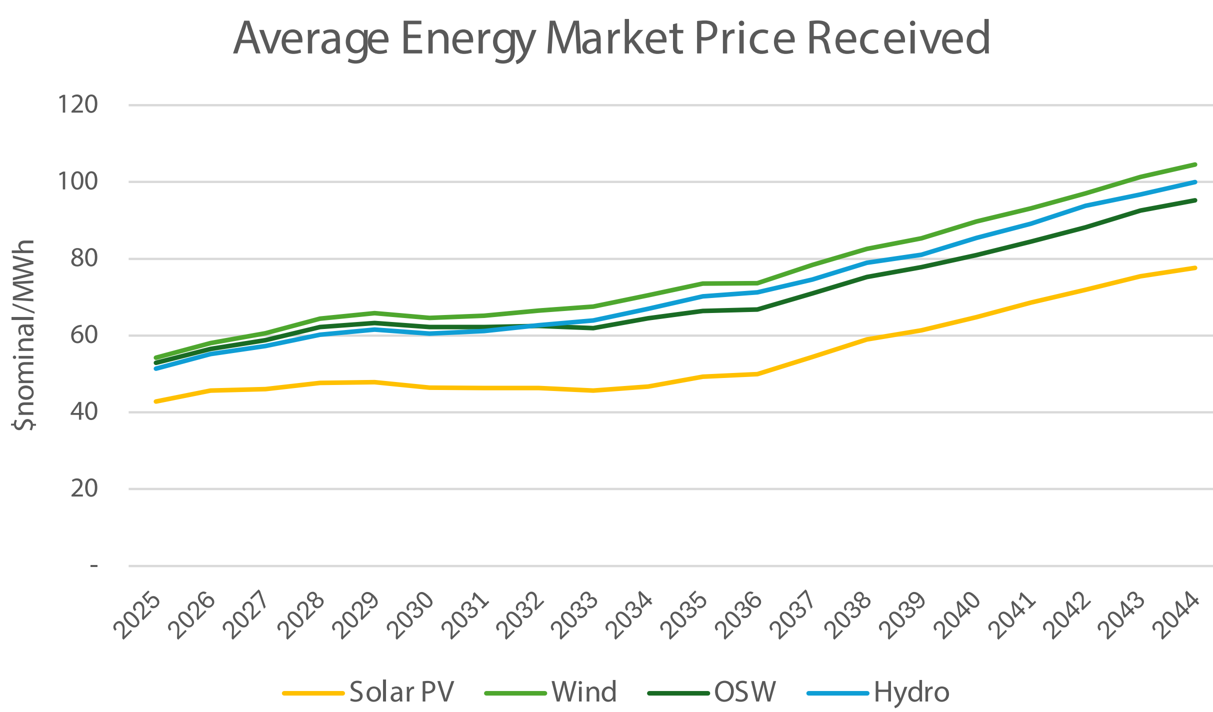


Figure 7-13. Projected average market value of solar and wind output average.

In this analysis, the projected average value of energy output from all technologies generally follows trends in average annual market prices over time, although solar output declines somewhat in relative terms because its output is weighted toward months and hours (e.g., spring, daytime hours) in which increasing renewable supply in New England is projected to put downward pressure on market prices. The projected value of wind and hydro sources is higher than solar, based primarily on their seasonal output profiles—

17 Although this portfolio evaluation addresses GMP's renewable energy supply, the same themes—purchase price, alignment of output with GMP's needs, and market value of output—are relevant to the evaluation of other resources like energy storage or flexible load that might provide other market products.

which include significant production during winter months. In the second decade of the analysis, the average value of OSW is projected to decline moderately relative to land-based wind, as the scale of projected OSW additions becomes large relative to the New England market.

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 and consistent generation during hours when solar generation is not producing. Of course, the ability of OSW to deliver at these projected values depends upon the successful build out of already slated and upcoming projects. Delays in the deployment of OSW have already been observed and will be critical to keep track of as this decade evolves.

These considerations of the value of renewable energy resources do not include values not presently embedded in the wholesale market, such as the social cost of carbon discussed in **Chapter 5**.

Locational Value of Energy

This consideration reflects the fact that the market value of energy that New England generators receive is based on locational marginal energy prices which reflect congestion and loss components. The New England electricity market is largely uncongested during much 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, locational marginal prices (LMPs) at all sites differ only in the marginal loss component.

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 involve 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 times when an interface on the transmission system is congested, the congestion component of LMPs on opposite sides of export-constrained and import-constrained interfaces can differ significantly. This difference in turn can substantially affect the payments that generators receive for their output and the payments that load-serving entities make for their load obligations.

GMP is an integrated utility that purchases load requirements from ISO New England at the Vermont Load Zone and sells the output from 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. Thus, depending on the contract terms and delivery point of potential renewable energy PPA, the effective cost of power to GMP under the PPA can depend on not only the price to purchase the resource's output but also the extent to which the financial value of its output in the ISO New England market is reduced—or enhanced—by effects of transmission congestion and losses.

Grid Upgrades

The anticipated growth of in-state renewable capacity will benefit our customers the most if it is located near electricity demand, where it can be consumed. As discussed in VELCO's LRTP and in **Chapter 3**, the magnitude and cost of required grid upgrades to accommodate new local generation will be greatly limited if the location of that generation is weighted toward areas in Vermont where there is sufficient hosting capacity on the transmission and distribution systems to accommodate it. Siting distributed generation near load also enhances the potential for local generation to reduce electrical losses on the grid and the potential for that generation to support system resilience for customers. Thoughtful placement will benefit customers and the greater grid.

As explained in **Chapter 3**, GMP performed a detailed screening analysis of hosting capacity on the distribution and subtransmission system, by testing increasing amounts of distributed generation in each of multiple geographic zones and observing potential operating violations under light load conditions. The screening analysis indicates hosting capacity for well over 500 MW of additional solar capacity, if that capacity were geographically distributed in relatively optimal way. This amount of hosting capacity is comparable to the projected volume of solar capacity that would be needed to achieve GMP's Tier II requirements through the mid-2030s under the Accelerated Adoption demand forecast, and significantly more than needed under the Continued Adoption forecast. It is reasonable to expect that hosting capacity in some areas could be supplemented by employing curtailment of some solar output during key light load conditions, or by supplementing load during such conditions (via rate design or flexible load management programs). For these reasons, when estimating the cost of required distributed renewable generation needed to meet RES Tier II GMP has not included a discrete cost adder for grid upgrades or alternatively, energy storage additions to increase hosting capacity. GMP expects to monitor the location of future distributed generation additions and to help guide the location toward areas of sufficient hosting capacity where this is practical, and then to revisit and refine the hosting capacity estimates over time based on new information.

Illustrative Future Portfolio

Based upon the outcomes of the portfolio testing described above, GMP has created the Illustrative Future Portfolio (IFP) to address the primary challenge and opportunity before us: to continue to develop a portfolio of resources that achieves and then maintains a fully renewable energy supply in an affordable way. The portfolio features complementary renewable technologies and project sizes consistent with the Vermont RES framework. It also incorporates observations from the portfolio evaluation above.

The IFP is informed by our current assessment of the costs and characteristics of renewable power and energy storage resources that will be available to GMP, and the wholesale market in which GMP will operate. We term the portfolio *illustrative* because we recognize that the types and amounts of resources that ultimately make the most sense to implement could evolve significantly as conditions change across the planning period. Below are the resource elements included in the IFP.

Additional Distributed Renewables

The IFP features continued substantial growth beyond the amounts described in the Reference Portfolio of distributed renewables to achieve Vermont's increased RES Tier II requirements; we represent these additions in the IFP as new distributed solar generation in Vermont, the resource currently expected to be most prevalent for this category. In the IFP, the total solar supply serving GMP customers grows to over 1.1 million MWh per year by 2032, with additional volumes thereafter. This amount involves the volume of installed solar capacity reaching a total of over 750 MW by 2032 for GMP; this solar capacity is assumed to be obtained from Vermont projects sized at 5 MW or smaller.

Large-Scale Solar

The hourly screening analysis showed that additional solar supply beyond that needed to fulfill Tier II would not be very well aligned with GMP's seasonal and hourly needs for additional renewables. Nonetheless, GMP expects that it will be appropriate to consider solar projects larger than 5 MW for meeting some of its RES Tier IV requirements, particularly if actual costs for regional wind opportunities turn out to be relatively high or these projects do not achieve operation on the timeframes expected. We have included in the IFP 113 MW of large-scale solar capacity—representing about 20 percent of GMP's projected Tier IV needs in 2035—to represent that possibility.

Regional Wind

The hourly screening analysis showed that additions of plant-contingent wind energy would align to a substantial degree with GMP's seasonal and hourly needs for additional renewable energy, complementing our large fleet of solar generation. The IFP therefore features additions of regional wind in sufficient volumes to supply most of GMP's projected RES Tier IV needs, above those met by current GMP renewable sources. Because wind development and State-supported renewable procurement activities in New England largely center on offshore projects, our portfolio analysis depicts the regional wind resource as plant-contingent PPAs for output from 200 MW of offshore projects achieving commercial operation in the early to mid-2030s. Such OSW contracts could potentially be obtained through participation in future state RFPs or direct negotiation with OSW developers.

GMP recognizes, however, that the pace of OSW development off the U.S. East Coast has been slow in recent years and that there is a wide range of uncertainty regarding future pricing for OSW in this region. We therefore plan to explore additional wind supplies through other paths. Land-based wind sources could involve a new large project in northern Maine or elsewhere in the region, as well as smaller new plants sized 100 MW or less. This is comparable in scale to many operating wind plants in New England. Some existing wind plants in New England could present opportunities to purchase uncommitted output over their remaining expected lives, or through longer-term PPAs that would support repowering of existing capacity.

For Tier IV, we expect at this time to make bundled purchases of energy and attributes, consistent with how procurement contracts for these long-term renewable resources have been formulated but will be watching regional developments to ascertain the availability and appropriateness of using RECs without energy in this category.

New England Hydro

Existing hydro plants in New England have historically been a moderately priced source of renewable energy available for purchase, particularly for contract terms of only a few years. They are also an attractive supply for RES Tier I. As discussed in **Chapter 6,** the future availability and pricing of existing hydro energy for purchase over the longer term are uncertain, because some neighboring states increase their renewable energy goals, which could draw on a finite supply of existing hydropower in the region. In the IFP we include some new plant-contingent hydro purchases (energy and RECs) starting in the late 2020s, increasing to 200 MW by 2036.

Shaped Renewable Purchases

Hydroelectric energy from Quebec has been an important part of Vermont's energy supply since the 1980s. GMP's largest present source of Tier 1 supply is a shaped renewable energy purchase: the long-term HQUS PPA. If shaped renewable purchases remain available from Hydro-Québec or other suppliers at reasonable prices, they would complement our intermittent renewable energy sources by delivering some of the renewable supply in a steady output profile. The IFP therefore includes shaped renewable purchases starting in 2036, when volumes under the current HQUS contract are scheduled to decline sharply. The shaped renewable purchases are sized to deliver half of the annual energy volume that GMP presently receives under the long-term HQUS PPA, with a flat round-the-clock delivery profile. While Hydro-Québec has been a longstanding contractual partner because of its large hydroelectric supply with storage capacity, such purchases could also be obtained from other suppliers that use renewable generators (perhaps including more than one technology) and energy storage. We also note that a shaped renewable purchase of this type would not have to deliver in a truly fixed delivery profile to stabilize GMP's renewable energy supply and improve its alignment with electricity demand. Some shaping of the delivery profile, or contingencies to reduce deliveries during low generation conditions, could make such a supply more feasible.

REC Purchases Without Energy

Most of GMP's current renewable energy sources—long-term PPAs and owned plants—deliver energy and RECs together. GMP expects that to continue, and in the IFP we have depicted additional solar and wind supplies for RES Tiers II and IV as being procured through purchases of energy and RECs together.

Purchases of RECs separately from energy can, however, play a constructive role in GMP's portfolio in some situations. For example, purchases of RECs without energy would enable GMP to achieve a fully renewable annual energy supply while continuing to use the limited non-renewable (mostly nuclear) portion of committed energy supplies to limit required purchases from the ISO New England market. The IFP includes GMP's existing nuclear resources of Millstone Unit #3 ownership and the long-term, NextEra Seabrook PPA, as described in **Chapter 6**. While these nuclear sources do not contribute to meeting GMP's RES requirements, they provide value to our customers as sources of year-round energy and capacity.[18] The IFP also features some Tier 1 supply—the volumes not met by the plant-contingent hydro purchases or a shaped renewable purchase—to be met

18 As noted in **Chapter 6**, GMP expects to explore the option of selling carbon-free generation attributes from the nuclear sources for the benefit of our customers.

with purchases of RECs without energy, which complements our limited supply of nuclear energy. Many REC purchases of this type would likely be made over terms of up to a few years—shorter than the long-term PPAs that will be needed to support the development of new renewables to supply Tiers II and IV.

Additional Storage and Flexible Load Resources

GMP expects that several hundred MW of distributed storage and flexible load resources will be deployed in our territory over the next decade, to support multiple use cases. For example, the grid assessment presented in **Chapter 3** discusses how distributed energy storage can be used to help GMP's distribution system meet future peak loads. It also presents illustrative magnitudes of storage—amounting to about 100 MW in total—that could address future needs in specific geographic areas. **Chapter 3** also explains how distributed storage, deployed on GMP customers' premises or on the distribution system, is the most appropriate tool to support grid resilience in certain areas of the grid, such as Zone 4. The increasing fleet of electric vehicles in Vermont provides another form of distributed energy storage that could be tapped to support these use cases in the future, or at times to support GMP's power portfolio. Meanwhile GMP initiatives such as the Flexible Load Management 3.0 program will continue to help characterize the flexible load resource potential and help develop tools and processes that will be needed to effectively tap the potential of flexible loads to drive down carbon and costs.

We include 300 MW of additional distributed storage in the IFP by the mid-2030s; this is similar to the volume depicted in **Chapter 2** for the Accelerated Adoption scenario. The hourly screening analysis presented in this chapter showed that 300 MW of additional short-duration storage resources—meaning a total storage fleet on the order of 400 MW by the mid-2030s—could improve the hourly alignment of GMP's renewable supply with electricity demand and reduce wholesale energy market exposures. These resources will serve to reduce the forecasted peak loads discussed in **Chapter 2**, and to meet some of the capacity needs indicated in **Figure 7-1** above.[19]

The actual volumes, location, and timing of deployment for distributed storage and flexible load resources will depend greatly on location-specific assessments of each of these use cases. These assessments will reflect actual trends over time with respect to the costs and performance of energy storage systems, customer needs for resiliency solutions, and

19 The actual volumes of reductions in peak loads and capacity obligations that GMP can obtain from these resources will depend on whether GMP deploys them as load reducers or enrolls them to participate directly in the ISO-NE wholesale market, and on other factors such as the evolution of ISO-NE capacity market rules and the evolution of GMP's hourly load profile as electrification in Vermont progresses.

wholesale markets. The ultimate volumes and pace of deployment for these resources will therefore depend on what volumes are determined to be cost-effective based on their potential use cases and value streams—particularly those related to resiliency, transmission deferral, and distributed generation hosting capacity as discussed in **Chapter 3**.

Managed Short-Term Market Price Volatility

GMP expects to continue managing forecasted net short energy and capacity positions through layered short-term forward purchases at fixed or stable prices. These will typically be for terms of less than five years. Prominent examples of such transactions are forward purchases of energy for delivery during winter months when GMP's committed supplies are less than projected load requirements, and forward purchases of capacity to help meet GMP's share of regional capacity requirements in the Forward Capacity Market. Similarly, we expect to make forward energy sales at fixed or stable prices 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 or sold primarily in the spot market.

Reduced Operation and Retirements of Existing Peaking Plants

For the IRP portfolio analysis, we assume the retirement and replacement path for our existing peaking plants as explained in **Chapter 6**—most notably the expectation that the Gorge and Ascutney units will reach retirement in the next five to eight years. We will make actual retirement decisions specific to each plant as they are developed over time, so actual retirement dates could vary.

Outcomes of the Illustrative Future Portfolio

Figure 7-14 shows the annual energy supply associated with the Illustrative Future Portfolio. When the additional renewable supplies summarized above are combined with largely committed renewables from the Reference Portfolio (gray area), the result is an energy supply that is fully renewable annually and contains the types of sources required by Tiers I, II, and IV.

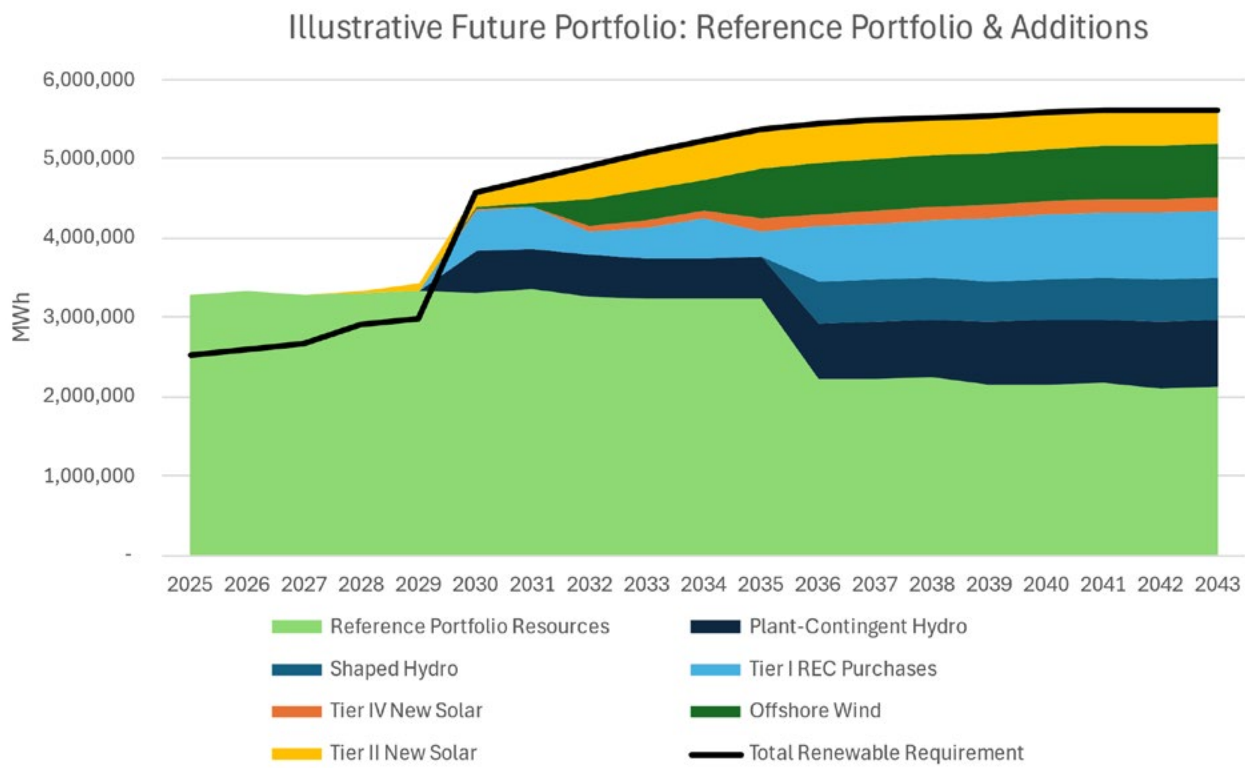


Figure 7-14. The mix of renewable supply in the Illustrative Future Portfolio.

Portfolio Cost and Sensitivity Analysis

Figure 7-15 projects annual net power and transmission costs associated with the Illustrative Future Portfolio. The largest component of projected cost is energy, reflecting this chapter's primary focus on 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) offers context, because significant increases in electricity consumption in part drive projected power costs.

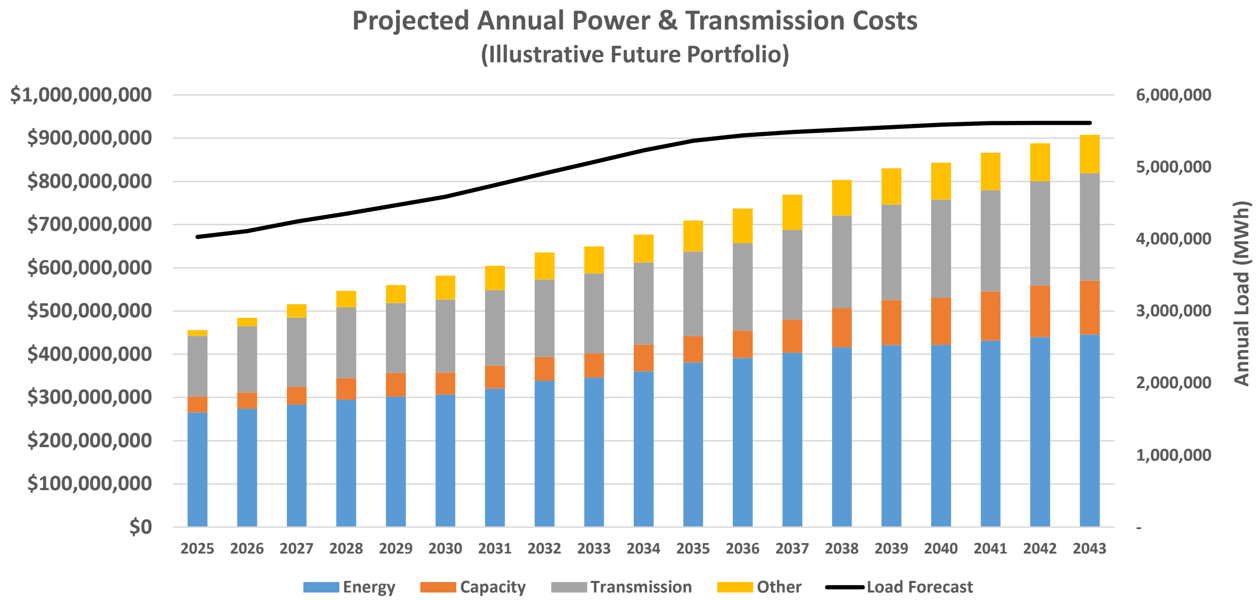


Figure 7-15. Annual power and transmission costs for the Illustrative Future Portfolio.

The projection features an upward trend in projected portfolio power and transmission costs over the next decade. Some of the increases are driven by increasing load requirements associated with the Accelerated Adoption demand outlook—which requires increasing volumes of energy, capacity, RECs, and transmission. Other drivers include increasing RES requirements as a percent of load, and gradually increasing market price outlooks for energy, RECs and capacity.

Figure 7-16 below shows the projected annual power and transmission costs in terms of average $ per MWh of load requirements.

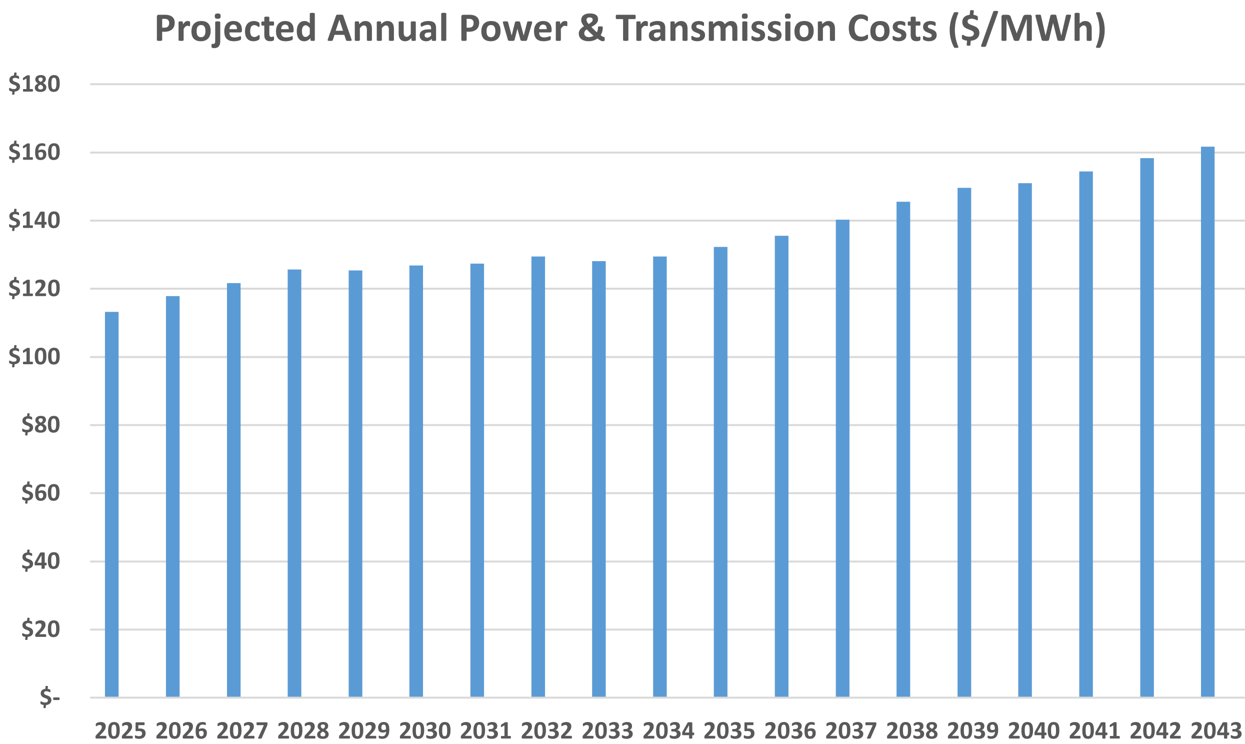


Figure 7-16. Projected annual power and transmission costs per MWh.

The projected trend in average cost per MWh is understandably more gradual than the trend in total costs, because a significant portion of the projected cost increases are driven by growing load requirements. The projected moderation of annual increases in the late 2020s and early 2030s is driven in part by a moderating forecast of regional energy market prices and expiration of some higher-priced existing resources. Rising regional market prices generally—and particularly for capacity—are leading drivers of the projected upward trend in costs per MWh in the later years of the projection.[20]

The cost sensitivity analysis tests the extent to which the costs associated with the IFP could vary, relative to potential alternative future outcomes for several uncertain factors. Such factors are primarily alternative outcomes for regional market prices and the cost of new renewable energy sources. The tested outcomes are summarized below and are illustrated in more detail in **Appendix I.**

20 The projected increase in costs in the last few years of the analysis is driven significantly by projected increases in regional energy market prices. To the extent that electricity demand growth is not as rapid as expected, or New England states refine their renewable and clean energy policies to emphasize their long-term emission reduction goals, this increase may not fully materialize.

- **Cost of new renewable energy sources.** This sensitivity tests how GMP's net power costs would be affected if actual PPA prices required to procure new distributed solar power in Vermont and new wind power in the Northeast turn out higher or lower than current expectations.
- **Natural gas prices.** This sensitivity tests how higher or lower outcomes for natural gas prices nationally, driven by factors such as increasing liquid natural gas export demand, could affect the magnitude and profile of New England power market prices.
- **Regional Greenhouse Gas Initiative emission allowance prices**. RGGI allowance purchases have become a major variable operating expense for large fossil fuel generators in the Northeast, and therefore a notable driver of energy market prices. This sensitivity tests how wholesale energy market prices would be affected if RGGI allowance prices turn out higher or lower than the prices assumed in Daymark's regional market model.
- **Reduced offshore wind buildout**. This sensitivity tests how a substantial reduction in the volume of new OSW capacity in New England would affect regional market prices.
- **REC market prices**. This sensitivity tests how GMP's net power costs could be affected by changes in market price expectations for RECs in New England. For example, market pricing to buy output from existing renewable energy plants in New England in the future will depend in part on market expectations for the value of RECs that the plants generate.
- **Capacity market prices**. This sensitivity tests how higher or lower price outcomes in the price of capacity in New England would affect GMP's net power costs. Such alternative price outcomes could be driven by changes in the regional balance of capacity supply and demand, or by factors that change the effective cost for new capacity sources to enter the market.

The sensitivity analysis illustrates how a range of potential outcomes for each of these factors could affect GMP's net power costs over 20 years. We summarize in **Figure 7-17** the results of the portfolio cost sensitivity analysis—expressed for each uncertainty as the potential for an outcome to increase or decrease in GMP's net power costs, in net present value.

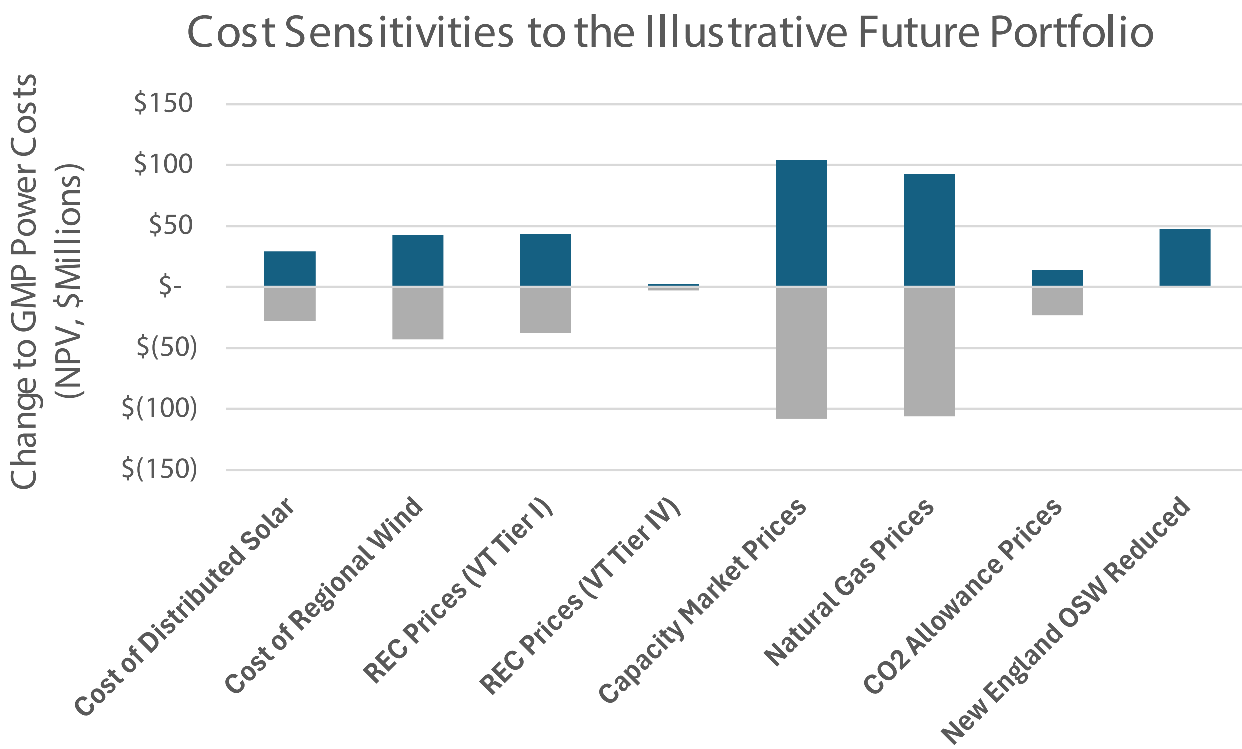


Figure 7-17. Potential increases/(decreases) in cost for the Illustrative Future Portfolio.

The following observations stand out with respect to the cost sensitivity results:

- An important driver of GMP's future power costs will be the actual cost at which GMP is able to obtain new renewables—particularly Vermont solar and regional wind. This makes sense considering that substantial new renewables will be needed to achieve the RES Tier II and IV requirements.21
- Future market prices for Tier I RECs will be an important cost driver due to the large volume of renewable supplies that will be needed to meet the Tier 1 requirement.
- Natural gas prices are one of the largest drivers of potential cost variance for GMP because we tested a very substantial range of potential gas price outcomes. Natural gas prices tend to strongly affect energy market prices in New England which in turn can affect the cost of filling GMP's open energy positions—particularly in winter—as well as the price at which GMP is able to purchase renewable energy from existing plants to help meet the Tier I requirement.

21 In the long-term, actual outcomes for costs of regional wind will probably be greater than they appear in **Figure 7-17**, because the wind additions in the IFP do not occur until the 2030s so they are substantially discounted in current present value terms.

- Capacity market prices are also shown as one of the major cost sensitivities for GMP, because GMP is a significant net buyer of capacity and we tested a significant range of capacity market price outcomes starting in the late 2020s.
- Tier IV REC market prices are shown as only modestly impacting GMP power costs, which is consistent with Tier IV needs being met overwhelmingly in the IFP with long-term PPAs for output from wind and solar plants. If GMP ultimately uses other options (e.g., short-term REC purchases, retirement of RECs from GMP sources that are Tier IV-eligible) to meet a greater portion of Tier IV needs, then Tier IV REC market prices would affect GMP power costs more than indicated here.
- We tested major reductions to the assumed volumes of offshore wind developed in New England which would affect New England energy market prices in the 2030s. The projected market effects from this major change in regional supply are large enough to make this cost sensitivity significant in present value terms.

Other Relevant Indicators

Beyond the direct market inputs and variables typically applied in the evaluation 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. These are threshold events or trends outside of GMP's control that could affect the list of potential resources that GMP should explore as portfolio additions, or the relative value of resources to GMP.

Table 7-4 lists 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**
Timing and shape of peak electricity demands (ISO-NE annual, Vermont monthly)	Local & regional	Benefit/cost evaluation of potential energy storage and flexible load resources, for managing peak.
Growth of flexible resources, status of potential interregional transmission projects.	Regional	Leading indicator of relative value of output from varying types of energy resources, and potential energy price spreads available for energy storage and flexible load.
Spread of high and low hourly energy market prices (LMPs)	Regional	Benefit/cost evaluation of potential new energy storage and flexible load resources. Also, directional guidance for operation of existing resources.
State RPS/CES requirements	Regional	Changes to State requirements can strongly affect availability and pricing of renewable power and RECs
GHG emission regulation	National or regional	Changes to RGGI program parameters or national regulations affect energy market price trends, and relative market prices across the year
Tax changes	National	Federal tax credits and related rules can significantly affect net cost of some renewables
Energy market prices in winter versus other months	Regional	Management of GMP's winter net short energy position. Relative value of wind and other resources that can provide energy during peak winter months.
General inflation in the economy	National	An indication of portfolio cost trends, since pricing for some committed sources and open positions is directly or indirectly linked to inflation.

Table 7-4. Indicators, their geographic context, and how they can inform GMP action.

Wholesale Energy Market Analysis

GMP used Daymark's Northeast Market Model to derive the Base Case regional energy market outlook. This is an hourly simulation model that analyzes dispatch from regionally anticipated loads and available resources, and along with electrical interconnections to other regions. GMP based energy prices on assumptions of:

- Future natural gas prices, basis differential at the Algonquin Citygate 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
- Interchanges between regions

In general, we relied on Daymark's fundamental analysis after we reviewed the underlying assumptions for reasonableness.

Regional market modeling informs GMP by quantifying market price trends that could affect GMP's net power costs—particularly the price to purchase output from existing renewable sources and the net cost of purchasing/selling GMP's seasonal open energy positions in the future. **Figure 7-18** below shows annual average energy market price results from the Daymark modeling, in constant 2023 dollars and nominal dollars (i.e., with effects of general inflation included).

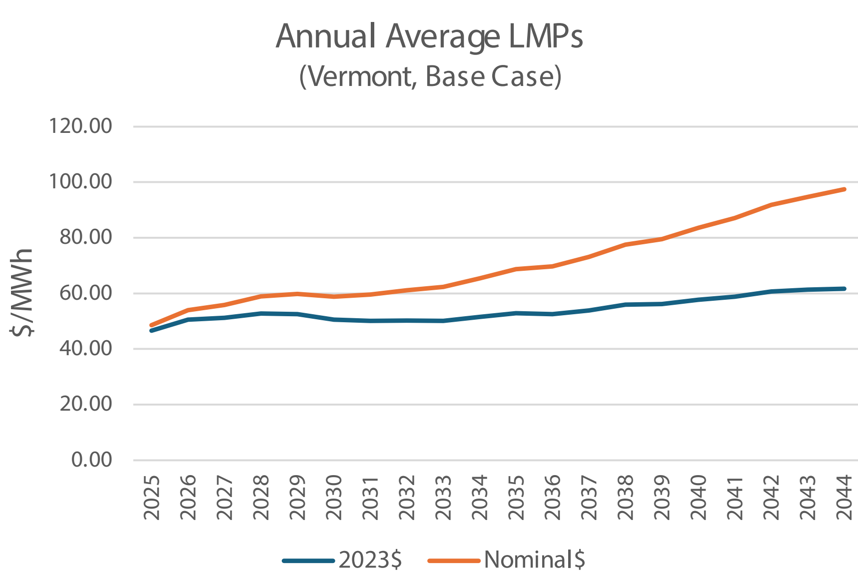


Figure 7-18. Projected Annual Average Energy Market Prices.

As discussed in more depth in **Appendix H**, the energy market price trends in the Daymark model show the influences of the driving assumptions—including increasing prices for natural gas and emission allowances, increasing electricity demand in New England, and a projected surge of new renewable generation (particularly offshore wind) that pauses the upward price trend in the early 2030s.

Figure 7-19 below compares monthly average energy market prices as projected for the first year of the Daymark regional model to those for 2035—when regional trends in electricity demand growth and major renewable supply additions including solar and offshore wind are forecasted to be well underway.

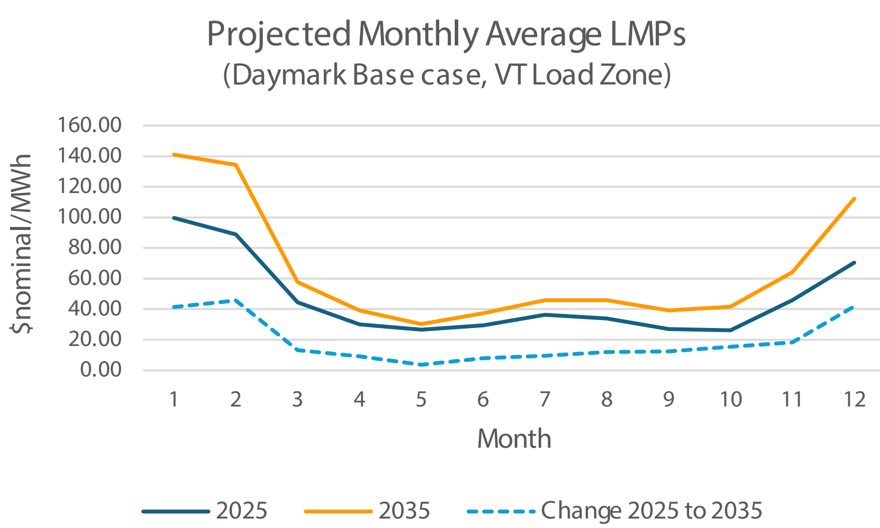


Figure 7-19. Projected monthly average energy market prices in 2025 and 2035.

The primary indication from the Daymark modeling is that projected energy market prices increase significantly over the next decade increase significantly—by as much as $40/MWh—during the peak winter months when market prices currently tend to be the highest. Higher winter prices tend to put upward pressure on GMP's net power costs because the portfolio screening analysis indicates that GMP will be a net purchaser of energy from the ISO-NE market in those months. In contrast, market prices in other months—including those when GMP is more likely to be a net seller of energy into the ISO-NE market—are projected to increase much more modestly. While actual outcomes could of course vary from this simulation for several reasons, the evolving seasonal market price profile indicated by Daymark's modeling supports GMP's continued focus on measuring the seasonal balance of its energy supply, and consideration of the market value of renewable output profiles in portfolio design and the evaluation of specific potential resources.

Appendix H includes more details on the regional energy market modeling inputs and results.

8

FINANCIAL ASSESSMENTS

Overview

GMP compiled its Base Case for the 2024 IRP financial forecast at the end of its 2024 Fiscal Year (FY). The Base Case projects five years of financial results, with the earlier years having a higher degree of certainty than the later years. In this forecast, we project the impact of known variables in the current environment, across a going-concern basis. Unlike scenario modeling, where all variables are assigned a probability, the Base Case reflects the most probable case, based on approved, expected investments through the current regulation plan period and widely accepted assumptions. GMP has kept constant variables such as weather, interest rates, and tax rates. This strategy avoids presenting a financial profile affected by factors 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 likely to arise over the next five years, like the repowering of the Searsburg Wind site as discussed in **Chapter 6**, are reflected in the forecast presented.

Rating Agency Perspective

Appendix J contains the latest Standard & Poor's (S&P) review of GMP. Its issuer credit rating remains A/Stable, supported by its low-risk, regulated utility operations. This excellent rating reflects the long-term value of GMP's business. Maintaining this strong rating leads to a lower cost of borrowing which means lower costs for customers.

Investments for Customers

GMP maintains its current infrastructure and adapts to the changing environment for customers through important capital investments. While we cannot anticipate precise projects for areas like line extensions requested by new customers, make-ready work for communications carriers, and support for municipal and state road projects, we do forecast investments to provide affordable, clean, reliable energy to our customers. We do also include assumptions for customer-driven projects.

For this IRP, in most areas we are forecasting our capital projects in line with what we have approved in our current Multi-Year Regulation Plan (MYRP). We will continue to invest in our generation fleet, grid infrastructure, cybersecurity, and innovative technologies. There are two notable areas of capital projects that differ from the current MYRP. First, as noted above, we are anticipating to seek approval for the repowering of our Searsburg wind site, and that spending may be found in the Production line in **Table 8-1** below. Second, our

Zero Outages Initiative (ZOI) order has given GMP approval to invest $150 million in grid-hardening measures over the remainder of the current MYRP, as reflected in the forecast. Because of the persistent effects upon our customers from more frequent outages from storms in recent years and the need to continue this work, we are also including in the IRP projected increased ZOI spending in the years 2027–2030. Investment in ZOI and other initiatives after the current MYRP will be subject to further regulatory review and will require regulatory approval. As noted in the ZOI Order, the rise in storm-related outages necessitates proactive approaches and the accompanying investment is included here.

Capital Expenditures by Year and by Category (in $ MM)

	2025	2026	2027	2028	2029	2030
T & D	$66	$68	$65	$65	$65	$65
Production	$37	$60	$39	$33	$33	$33
IT	$9	$9	$9	$9	$9	$9
Other	$7	$7	$5	$5	$5	$5
ZOI	$60	$69	$150	$200	$250	$300
Total	$180	$213	$268	$312	$362	$412

Home Batteries included in Production
Production also includes repowering of Searsburg in '26 and '27

Table 8-1. Forecasted capital spending, FY 2025 through FY 2030.

Financial Statements

Table 8-2 provides an overview of the assumptions GMP has made for each financial variable contained in the forecast.

Variable	Assumption
Retail Sales Forecast	Itron forecast from FY25 Base Rate filing
Power Supply Forecast	Fall 2024 Forecast
Capital Spending	Level noted in chart above
Allowed ROE	9.97% for FY25 and FY26, as filed. 9.88% thereafter, reflecting current market conditions
Debt to Equity	In FY25: 51/49 Equity. 50/50 thereafter
LT Interest Rate	5%
ST Interest Rate	5%
Payroll Increase	2.50%
Overheads	3%
General Inflation	2%
Major Acquisition	None

Table 8-2. GMP's considerations for investments, and their respective essential assumptions or sources for the 5-year forecast.

The following tables show the output from our 5-year financial forecast.

Income Statement (in 000s)	FY 2025 Final Budget	FY2026	FY2027	FY2028	FY2029	FY2030
Retail Revenues, net of adj	$ 807,308	$ 861,694	$ 889,048	$ 951,047	$ 994,956	$1,044,435
REC Revenues	16,481	16,826	9,860	8,233	9,402	10,461
Other Revenues	24,827	24,204	23,264	23,650	24,055	24,461
Total Revenue	848,616	902,725	922,172	982,930	1,028,413	1,079,357
Energy	312,771	321,500	311,901	318,870	337,884	367,435
Capacity	41,844	43,851	43,181	45,503	50,529	48,040
Transmission Costs	127,969	135,184	141,437	149,739	145,640	148,972
Total Electricity Costs	482,584	500,535	496,519	514,112	534,053	564,448
Gross Margin	366,032	402,190	425,653	468,817	494,360	514,909
Gross Margin %	43.1%	44.6%	46.2%	47.7%	48.1%	47.7%
O&M Expenses	138,424	138,369	147,927	151,757	155,343	159,038
Taxes other than Income	55,423	57,919	58,909	61,321	63,668	65,953
Depreciation & Amortization	97,338	103,904	114,418	124,632	108,370	116,753
Regulatory Deferrals (Rate Smoothing)	(4,530)	21,583	(12,240)	(3,360)	15,600	-
Interest Expense	51,308	55,300	60,362	66,757	72,098	79,284
Earnings from Affiliates	(80,603)	(84,206)	(89,171)	(90,894)	(91,955)	(92,997)
Net Income before Tax	108,672	109,321	145,449	158,605	171,236	186,879
Income Taxes	26,295	26,178	35,580	39,177	42,661	46,972
Net Income before Non-Controlling interest	82,377	83,143	109,869	119,428	128,574	139,906
Non-Controlling Interest Income / (Loss)	(117)	-	-	-	-	-
Net Income	**$ 82,260**	**$ 83,143**	**$ 109,869**	**$ 119,428**	**$ 128,574**	**$ 139,906**

Table 8-3. GMP's forecasted income statement.

Balance Sheet (in 000s)	FY 2025 Final Budget	FY2026	FY2027	FY2028	FY2029	FY2030
Assets:						
Utility Plant in Service	$2,637,123	$2,760,452	$3,035,259	$3,323,379	$3,661,443	$4,045,663
Less: (Accumulated Depreciation	(914,469)	(971,876)	(1,032,370)	(1,097,955)	(1,170,576)	(1,246,996)
CWIP	95,638	154,396	124,568	124,523	124,686	125,056
Net Utility Plant	1,818,291	1,942,972	2,127,456	2,349,947	2,615,553	2,923,724
Cash and Cash Equivalents	1,041	1,138	4,322	7,152	9,964	12,760
Accounts Receivable	83,348	86,435	88,747	92,704	96,845	99,886
Inventory	55,208	57,031	58,382	59,751	61,139	62,546
Other Current Assets	101,582	103,250	103,922	104,594	105,266	105,938
Total Current Assets	241,179	247,854	255,374	264,201	273,213	281,129
Total Regulatory Assets & Deferred Charges	432,151	415,309	424,773	425,469	407,370	404,916
Accumulated Deferred Income Tax	204,330	204,330	204,330	204,330	204,330	204,330
Associated Companies	752,232	774,357	806,625	834,190	829,750	821,155
Other Assets	96,426	72,992	49,759	21,861	21,218	20,078
Total Other Assets	1,485,139	1,466,989	1,485,487	1,485,850	1,462,668	1,450,479
Total Assets	**$3,544,609**	**$3,657,815**	**$3,868,318**	**$4,099,997**	**$4,351,435**	**$4,655,331**
Liabilities						
Total Stockholder's Equity	1,167,749	1,196,849	1,301,659	1,414,915	1,528,112	1,683,355
Long Term Debt	1,026,000	1,128,000	1,143,000	1,226,000	1,466,000	1,586,000
Capitalized Leases	8,523	7,477	6,366	5,188	3,938	2,611
Total Capitalization	2,202,272	2,332,326	2,451,025	2,646,103	2,998,050	3,271,966
Short-Term Debt	97,440	81,751	123,370	143,434	108,703	122,252
Current Portion of Long Term Debt	-	18,000	65,000	77,000	-	-
Accounts Payable	57,019	58,430	59,558	60,686	61,813	62,941
Other Current Liabilities	116,593	107,439	115,253	124,125	139,256	153,984
Total Current Liabilities	271,052	265,620	363,181	405,245	309,773	339,177
Total Regulatory Liabilities	191,051	185,927	174,978	164,020	153,063	142,106
Derivative Regulatory Liability	261,298	261,298	261,298	261,298	261,298	261,298
Deferred Taxes	555,613	550,595	556,911	563,097	566,603	576,741
Other Liabilities	63,324	62,050	60,926	60,234	62,649	64,044
Total Liabilities	1,342,337	1,325,490	1,417,293	1,453,894	1,353,385	1,383,366
Total Liabilities and Capitalization	**$3,544,609**	**$3,657,815**	**$3,868,318**	**$4,099,997**	**$4,351,435**	**$4,655,331**

Table 8-4. GMP's forecasted balance sheet.

Cash Flow Statement (in 000s)	FY 2025 Final Budget	FY2026	FY2027	FY2028	FY2029	FY2030
Operating Activities :						
Net Income before non-controlling	$ 82,377	$ 83,143	$ 109,869	$ 119,428	$ 128,574	$ 139,906
Depreciation & Amortization	82,550	85,987	92,670	100,068	108,385	117,463
Amortization of regulatory amounts	2,678	2,217	(3,984)	(4,090)	(4,120)	(4,247)
Dividends from associated companies	83,450	89,746	94,889	101,135	104,200	104,435
Equity in undistributed earnings for associated companies	(84,740)	(88,435)	(92,965)	(94,532)	(95,480)	(95,502)
AFUDC	(2,607)	(2,428)	(3,076)	(3,346)	(3,622)	(3,897)
Deferred income tax	3,251	(10,432)	1,367	1,229	(1,452)	5,181
Other deferrals	(170)	(170)	(170)	(170)	(170)	(170)
Working Capital Changes:						
Accounts Receivable	478	(3,087)	(2,312)	(3,957)	(4,141)	(3,041)
Accounts Payable and Other	10,895	3,703	8,490	9,302	15,564	15,119
Other assets/liabilities	39,591	24,253	8,392	20,589	15,324	(831)
Net cash provided by operating activities	**$ 217,753**	**$ 184,497**	**$ 213,169**	**$ 245,656**	**$ 263,062**	**$ 274,416**
Investing Activities:						
Utility plant expenditures	(181,728)	(208,322)	(274,020)	(319,414)	(370,722)	(422,029)
Investment in associated companies	(31,587)	(23,435)	(34,192)	(34,168)	(4,280)	(338)
Investment in non-utility property	800	800	800	800	800	800
Net cash used in investing activities	**$ (212,515)**	**$ (230,957)**	**$ (307,412)**	**$ (352,782)**	**$ (374,202)**	**$ (421,568)**
Financing Activities:						
Issuance of long-term debt	50,000	120,000	80,000	160,000	240,000	120,000
Repayment of long-term debt	-	-	(18,000)	(65,000)	(77,000)	-
Additional paid-in capital	0	0	61,999	68,659	65,416	103,515
Net borrowing on short-term debt	1,298	(15,689)	41,619	20,065	(34,731)	13,549
Cash dividends	(53,570)	(54,043)	(68,596)	(74,830)	(80,794)	(88,178)
Net cash provided by financing activities	**$ (2,273)**	**$ 50,268**	**$ 97,022**	**$ 108,893**	**$ 112,891**	**$ 148,885**
Net increase in cash and cash equivalents	**$ 2,966**	**$ 3,808**	**$ 2,779**	**$ 1,768**	**$ 1,751**	**$ 1,734**

Table 8-5. GMP's cash flow position through FY 2030.

9

INTEGRATION AND ACTION PLAN

Integration and Action Plan

This IRP provides the basis for an energy system with increased resiliency and distributed renewable energy resources that is more affordable for customers. GMP will take the actions described in **Table 9-1** throughout the course of this IRP period to continue to further this important work. For each action item, we refer to the corresponding section of the IRP for more detail.

Functional area	Activity
Expanding Resiliency, Reliability, and Innovative Programs for Customers **Chapters 1, 2, and 3**	• Evolve and expand access to GMP's integrated suite of customer offerings that increase electrification, with equity in mind, to reduce carbon and costs, and improve resiliency for all customers. • Continue multi-faceted, ongoing community-level engagement and communication with customers on resiliency work with collaborations involving regional planning commissions, local officials and community-based organizations, local energy committees, schools, and other points of contact throughout GMP's service territory. • Provide customers with a variety of energy storage technologies for increased resiliency, including evolving vehicle-to-anything (V2X) technologies. Pilot new storage technologies as they become available for residential and commercial and industrial customers as well as piloting new models for deploying the storage. • Extend, expand, and evolve tariffed offerings for stored energy at homes and businesses improving both customer access to storage and reliability as well as greater system resiliency. • Maintain or increase the percentage of controlled charging of EVs in GMP territory while also expanding programs for shifting of charging load. • Continue developing overarching DERMS framework or platform that accounts for forecasted load, wholesale energy prices, physical grid operating constraints, and time-variable DER availability to optimize DER dispatch. Include Vermont stakeholders with plan to implement new solution prior to next IRP (2027). • Complete analysis for fully allocated class cost of service and consider updated rate design to meet customer electrification and innovation goals. • Analyze replacement or upgrade plan for AMI system and related business case for customers prior to next IRP.

Functional area	Activity
Transmission & Distribution Innovations **Chapter 3**	• Execute undergrounding and storm hardening of distribution lines per Zero Outages Initiative PUC order. • Deploy additional automatic fault recovery transfer systems on the distribution system. • Complete two circuits using Zero Outages approach combining undergrounding, storm hardening, and energy storage, if storage tariff is approved by PUC. • Design future zero outages work.
A 100% Renewable Future **Chapters 3 and 6**	• Continue investments in our existing fleet of generation, maintaining a high level of safety and regulatory compliance, while looking for opportunities for acquisition and construction of new facilities to produce long-term value to customers. • Develop the next phase for Searsburg project, including seeking approval for repowering the existing site. • Analyze and plan for the retirement of additional GMP fossil-fuel peaking sites and evaluate the suitability of these locations for new energy storage systems. • Evaluate pairing energy storage with existing renewable facilities or construct new storage-paired systems directly or through other procurement methods. • Utilize energy storage systems to increase hosting capacity, including a new mechanism for developer share.
Information Technology & Security **Chapter 4**	• Follow AI developments and best practices and incorporate AI tools and further cybersecurity defenses as appropriate. • Continue to engage with utilities, VELCO, and the State as warranted on industry IT and physical security. • Evaluate investment in IT and security measures to keep pace with evolving threat landscape and cybersecurity needs, including cybersecurity resiliency plan if warranted.
Regional and Environmental Evolution **Chapter 5**	• Have direct engagement in the FERC Order 2222 process and assure proposed frameworks can be implemented in Vermont. • Participate directly in ISO process to update the capacity market in New England with focus on how GMP flexible resources such as storage will extract additional value from new market designs. • Follow with state and regional partners developments in renewable (offshore wind or land-based wind) procurement, construction, and interconnection.

Functional area	Activity
Power Supply and Portfolio Evaluation **Chapters 3, 6, and 7**	• Execute 100 percent renewable energy supply by 2030 and beyond through acquiring a resource portfolio that is cost-competitive and RES compliant. • Evaluate opportunities for GMP's nuclear PPA and portfolio assets to create customer value as we meet new RES requirements. • Explore regional wind purchase opportunities—including participation in upcoming offshore wind developments and land-based wind opportunities. • Develop and execute procurements that help guide development of Vermont distributed solar towards regions that are not constrained by transmission upgrades to maximize our hosting capacity, and through expansion of existing programs like solar-soaking energy storage, increase hosting capacity in constrained regions to allow more DG to interconnect. • Refine portfolio options to meet Tier I and Tier IV of RES beyond 2030. • Support community scale programs like the GMP Shared Solar tariff that meet the new RES Tier II requirements with lower cost than existing programs, including through implementing RFPs for resources.
Financial Strength **Chapter 8**	• 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, including increased resiliency projects through ZOI.

Table 9-1. Action items for the 2024–2026 period, by GMP functional area.

Appendix A

COMMUNICATING WITH OUR CUSTOMERS

Communicating with customers is something that is happening all the time—it is an ongoing conversation over the long term. Great customer service is all about meeting customers where they are, listening, asking questions, and taking action to deliver great results for customers. As noted throughout the IRP and below, we use various channels to reach customers including one-on-one calls. On-bill notices reach all our customers, and we use other methods that can be more targeted depending on the purpose of the communication. Below is a list of the many ways we are connecting with customers.

GMP Call Center (CSRs, IVR, Automated Calls)

GMP's customer service representatives have hundreds of conversations with customers every day, and about 300,000 calls on average each year. Storms and outages are taking an increasing amount of their time as more storms and outages happen in Vermont.

Customers select the general reason for their call before they reach a customer care team member—e.g., report an outage, customer service, billing question, energy products. Those responses are tracked so our Call Center team can evaluate trends and areas to improve. They also escalate trends they see daily, for example with customers reporting scam calls. This is shared with the communications team and can lead to outreach that day in real time to customers via press release, news, social media, the Department of Public Service, and the Attorney General's office. We are exploring how AI and other platforms could help customers get information quickly and provide more insight into call trends.

News Media

Sharing information through news releases and interviews with TV, radio, newspapers and online outlets allows us to reach many customers at once and is a key method of raising awareness and sharing safety information about storms and repair updates.

Social Media and Community Message Boards

Facebook and Facebook Live

We have a dedicated following of 30,000 on Facebook where we post updates and share information about customer programs. This is an important channel for communication during severe weather. We post forecast and safety information, restoration updates, and respond to customer questions. Customers help us reach more people by sharing these updates with their networks. Facebook Live helps us connect with customers and share information and context as we answer questions. Recent topics covered weather trends in Vermont, energy storage and virtual power plants, our Integrated Resource Planning work, and follow-up to our September open house for customers who could not attend in person. The videos stay in our feed and over time receive thousands of views.

X (Twitter)

We have 7,400 followers on X, and we post similar content to what we share on Facebook. X tends to be most active during severe weather.

Front Porch Forum

This online community message board is a useful tool to reach customers right in their community, and we post in every forum available in our service area. The posts provide useful information and resources on everything from storm safety to EV rebates, to a request for feedback for this IRP.

GMP Website

Our website www.greenmountainpower.com is a hub for customers to manage their GMP accounts and learn about and enroll in GMP's innovative programs, with 91,000 visitors monthly. The Outage Center makes it easy to report outages and track restoration progress. Customers can use the live chat function to get information—about 450 use this function each month.

GMP is always working to enhance the customer experience and recently expanded the energy usage tools customers can use to get more granular detail about their monthly energy usage.

GMP Mobile App

20,000 to 30,000 unique users turn to the GMP app each month to manage their accounts, report outages, and track storm restoration. It is an easy way to connect with us when it is convenient for customers. The customer experience was enhanced through a series of updates in 2022 and will be further updated to ensure strong performance for customers as more and more are using it.

GMP Energy Statement

The monthly energy statement is another place we share updates with customers. Extra pages share information about regulatory filings, feedback, meetings, and other opportunities. The statement is designed to provide a transparent picture of a customer's energy use, and the line items that are assessed in addition to usage. We offer e-billing and digital versions of monthly statements, and the number of customers enrolled in these has grown to 111,500.

Good Energy Now Podcast

This podcast provides an additional way for customers to learn more about energy programs, innovation, and GMP. Episodes include quick conversations with a subject matter expert to share information and some extra context in an easy-to-follow way. Recent episodes looked at weather trends in Vermont and virtual power plants.

Public Events and Meetings

We hold two open house meetings for customers per year, each one hosted at a different GMP district office. Customers receive an invitation on their monthly energy statement, followed by a news release and posts on social media. The turnout for these events typically a few dozen people and provide a fun, casual way for customers to get to know their local crews and GMP leaders and ask questions they have about GMP. During and immediately following the pandemic these meetings were virtual via Facebook Live but we have transitioned back to being in person. Customers ask about a variety of topics at open house meetings, from EVs to their energy statements to solar net metering. Energy storage and storms are consistent topics. The open house meetings in 2024 served as opportunities for customers to learn about the IRP and share information with us.

GMP team members attend dozens of public events and meetings each year to share information about Tier III programs directly with customers at Ride and Drive events and town energy fairs, and to talk about storm response and resiliency work at selectboard, planning commission, and emergency responder meetings. GMP staff participated in more than 100 meetings and events over the last two years.

Storm and Resiliency Communications

As extreme weather accelerates, so does our communication with customers. We do extensive outreach around storms and restoration, to share forecasts, safety, and field operations updates with customers through news releases and interviews, social media, automated calls, text alerts, and tens of thousands of conversations through the Call Center. We added specialized additional outreach to customers with health needs dependent on electric equipment and to town officials during severe weather events, with dedicated teams on that task during storm restoration. The updates by email and phone help town emergency coordinators plan their own local efforts and provide customers experiencing health challenges with as much information as possible, so they can make plans and take action to be safe. During good weather, we work collaboratively with local stakeholders and customers through public meetings and community visits to hear directly from them and share information about our storm planning, response, and resiliency work to keep customers connected. Since 2022, more than 50 of the meetings GMP team members attended focused on storm response and resiliency work. We continue to enhance how and what we are communicating in tandem with the accelerating severe storms.

Appendix B

PRESENT VALUE LIFE CYCLE COST TESTS

Electric Vehicles

Electric vehicles, as demonstrated in this chapter's section on system load (with EVs as a system load increaser), are in the transportation category of *alternative fuel vehicles*. When screening any Tier III measure, we also assess alternatives that do not increase electricity consumption. The use of non-electrification alternatives to fossil-fuel vehicles are not robust, either nationally or in Vermont. Hydrogen-fueled vehicles and other nascent technologies are in development, and right now EVs offer the fastest and most secure path to meeting decarbonization targets.

The All-Electric Vehicle

Table B-1 shows the results of the Customer, Non-Participating Customer, and Societal 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 2024 dollars.

All-Electric Vehicle (AEV), 8-year measure life			
	Input	Amount	Source
Customer	Incremental vehicle cost	($8,500)	US DOE
	Purchase incentives	$4,700	State, GMP
	Fuel savings	$6,487	VT average, Rate 74
	Maintenance savings	$2,077	Tier III TRM
	Net customer benefit (2024 dollars)	**$4,764**	
Utility	Tier III costs + administration	($2,245)	GMP incentive
	Tier III benefit	$1,835	Tier III TRM
	Net retail revenue	$1,311	GMP calculation
	Net utility benefit (2024 dollars)	**$901**	
Society	Incremental vehicle cost	($8,500)	US DOE
	Tier III administration	($45)	GMP incentive
	Fuel savings	$6,487	VT average, Rate 74
	Maintenance savings	$2,077	Tier III TRM
	Value of avoided emissions	$5,538	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$5,557**	

Table B-1. Net benefits from ownership of all-electric vehicles, assuming an 8-year measure life.

The incremental costs of purchasing and operating an AEV, compared to an internal combustion engine vehicle, is as calculated by the US Department of Energy's 2022 Incremental Purchase Cost Methodology and Results for Clean Vehicles, using results for a midsize car. For purchase incentives, we assume the customer is eligible for the full federal tax credit (included in the incremental cost) and the standard State purchase incentive (that is, not the increased income-based incentive), as well as GMP's Tier III incentive ($2,200) as available to all customers (not the enhanced income-eligible amount). Maintenance savings come from the Tier III TRM, and GMP based its fuel savings on the average gasoline and electric efficiencies of light-duty vehicles registered in Vermont, the average cost of gasoline in Vermont as of October 2024 and the cost of electricity on a discounted EV rate (Rate 74), assuming 80 percent 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 TRM's assumption but is consistent with data from chargers under management. This is equivalent to 3.16 MWh of added load annually, based on an AEV's efficiency. Finally, we assume an eight-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 upfront purchase incentives. On GMP's off-peak charging rate, an AEV owner can enjoy significant savings compared to the cost of gasoline.

An AEV reduces costs for all customers through strategic electrification. Our EV rates offer customers a cost-based discount, passing on much of the 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 MWhe value of an AEV and the market value of a Tier II renewable energy credit, which could be used to meet our Tier III Renewable Energy Standard requirements.

From the societal perspective, we included the federal tax incentive as a reduction to 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 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 introduce more electric models and, in some cases, cease the production of internal combustion engine vehicles entirely.[1] As EV production ramps up, costs will come down, improving the net benefit to society.[2] GMP anticipates ongoing incentives for customers to purchase electric vehicles, to tackle one of the top sources of emissions in Vermont.

Plug-in Hybrid Electric Vehicles

Table B-2 shows the results of the customer, non-participating customer, and societal 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 2024 dollars.

1 Ford, GM, Mercedes-Benz, Volvo, Jaguar Land Rover, and a Chinese automaker have pledged to stop global sales of new gas and diesel vehicles by 2040.

2 According to the EIA, new electric car registrations in the United States increased 40% over sales in 2022.

Plug-In Hybrid Electric Vehicle (PHEV), 8-year measure life			
	Input	Amount	Source
Customer	Incremental vehicle cost	($8,000)	US DOE
	Purchase incentives	$2,500	State, GMP
	Fuel savings	$2,861	VT average, Rate 74
	Maintenance savings	$1,266	Tier III TRM
	Net customer benefit (2024 dollars)	**($1,373)**	
Utility	Tier III costs + administration	($1,034)	GMP incentive
	Tier III benefit	$1,369	Tier III TRM
	Net retail revenue	$1,300	GMP calculation
	Net utility benefit (2024 dollars)	**$1,635**	
Society	Incremental vehicle cost	($8,000)	US DOE
	Tier III administration	($34)	GMP incentive
	Fuel savings	$2,234	VT average, Rate 74
	Maintenance savings	$1,266	Tier III TRM
	Value of avoided emissions	$2,603	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**($1,931)**	

Table B-2. Net benefits from ownership of plug-in hybrid EVs, assuming an 8-year measure life.

GMP used the same methods as those used in the AEV case (**Table B-1**). The incremental cost of a PHEV also comes from the same DOE incremental cost study. We assumed the customer is eligible for the State's standard purchase incentive ($1,500) and GMP's PHEV incentive ($1,000). We assumed the customer is eligible for the State's standard purchase incentive ($1,500) GMP's PHEV incentive ($1,000). We assume 10,000 miles driven annually, 53 percent of which are driven in electric mode based on data from Drive Electric Vermont. We also use the same inputs to calculate fuel savings for vehicle efficiencies and prices for gasoline and electricity. A PHEV represents 1.68 MWh of annual added load.

From the customer's perspective, a PHEV not only reduces costs significantly over the vehicle's lifetime. Maintenance and fuel savings are significant but slightly lower than for an AEV. Notably, the Toyota RAV4 Hybrid can go 42 miles on a full battery charge, reflecting an increase in the electric battery range for these PHEVs.

A PHEV produces a positive net benefit for all customers, albeit slightly lower than an AEV, because of a smaller load addition, with most PHEV owners using Level 1 charging that ranges from 1–1.6 kW, PHEVs are not eligible for GMP's discounted EV rates. The Tier III benefit is derived from the Tier III MWhe value in the TRM.

Cold-Climate Heat Pumps

Like EV tests, our tests of CCHPs analyze measures that do not increase electricity consumption. Our heat pump incentives are administered through Efficiency Vermont's rebate programs. Efficiency Vermont also supports non-electrification alternatives such as biomass heating and weatherization.

Table B-3 shows the results of the customer, non-participating customer, and societal 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 2024 dollars.

Single Zone Cold Climate Heat Pump, 15-year measure life - Low Income			
	Input	Amount	Source
Customer	Purchase cost	($3,206)	Tier III TRM
	Purchase incentives	$2,550	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Net customer benefit (2024 dollars)	**$1,317**	
Utility	Tier III costs + administration	($2,483)	GMP incentives
	Tier III benefit	$1,351	GMP Tier III reporting
	Net retail revenue	$3,267	GMP calculation
	Net utility benefit (2024 dollars)	**$2,135**	
Society	Incremental cost	($3,206)	Tier III TRM
	Tier III administration	($33)	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Value of avoided emissions	$4,153	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$2,886**	

Table B-3. Net benefits from ownership of cold-climate heat pumps, assuming a 15-year measure life for low-income customers.

Single Zone Cold Climate Heat Pump, 15-year measure life			
	Input	Amount	Source
Customer	Purchase cost	($3,206)	Tier III TRM
	Purchase incentives	$550	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Net customer benefit (2024 dollars)	**($683)**	
Utility	Tier III costs + administration	($483)	GMP incentives
	Tier III benefit	$1,351	GMP Tier III reporting
	Net retail revenue	$3,267	GMP calculation
	Net utility benefit (2024 dollars)	**$4,135**	
Society	Incremental cost	($3,206)	Tier III TRM
	Tier III administration	($33)	GMP incentives
	Fuel savings	$1,973	Tier III TRM, VT average
	Value of avoided emissions	$4,153	VT Climate Action Plan
	Net societal benefit (2024 dollars)	**$2,886**	

Table B-4. Net benefits from ownership of cold-climate heat pumps, assuming a 15-year measure life for moderate-income and above customers.

We assume a single-zone CCHP system of 18,000 BTU will add approximately 2.3 MWh of annual load. Actual consumption will depend on the coefficient of performance (COP)—the ratio of useful heating or cooling to the amount of energy needed to provide either function, related to the heat pump model, the size of the home and space it serves, weatherization level, ambient temperatures, and fuel prices. The incremental cost and fuel savings come from the Department's Cost of Carbon Reduction model and GMP's general residential rate, assuming an oil-based heating system. Purchase incentives comprise both GMP and Efficiency Vermont contributions (but not federal tax credits or incentives).

From the customer's perspective, a CCHP system produces a net cost over its lifetime—but only in terms of fuel savings related to heating; the analysis does not account for CCHP cooling benefits, which are a significant factor affecting purchase decisions. The incremental cost represents the total installed cost of a CCHP system, not the incremental cost between the CCHP and a fossil-fueled heating system without the additional low-income rebate. This analysis does not mean that fuel expenses are higher with a heat pump than heating oil or propane, only that the energy savings from heating alone are not sufficient to fully cover the installed cost of a unit without the additional low-income rebate. A customer who installs a heat pump, even if primarily for cooling benefits, would experience lower cost by also making full use of it for heating compared to leaving it off during the winter and relying on oil or propane. For low-income customers there is a net savings from heating alone. Due to the volatility of unregulated oil and propane prices, the customer will also experience more stability in their heating costs, year to year.

A CCHP system delivers a significant benefit to all customers from the rate-reducing impact of new electric load. We compute a Tier III benefit using the characterized Tier III MWhe value of an 18,000 BTU 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.

From society's perspective, a CCHP system produces a net benefit. Although the incremental system cost outweighs fuel savings, the combination of net revenue and avoided externality costs produces a positive savings result. GMP will continue to provide incentives to customers who install not just ductless CCHPs but also ducted systems, air-to-water and geothermal systems.

As shown in **Table B-5**, custom measure Tier III projects typically generate MWhe credits for GMP at significantly lower cost than prescriptive measures. That lower cost shows up as a large utility test benefit in the form of Tier III value. A lower cost to reduce carbon emissions also creates high social value after accounting for the value of avoided emissions. GMP considers both custom and prescriptive Tier III measures important to enable customers to shift away from fossil fuel use in line with Vermont's emission goals.

Example Tier III Custom RTU Project, 15-year measure life		
Input	Amount	Source
Incremental cost	($34,900)	Custom calc, GMP estimate
Tier III incentives	$42,614	GMP incentives
Fuel savings	$294,967	Custom calc
Net customer benefit (2024 dollars)	$302,681	
Tier III costs + administration	($44,792)	GMP incentives
Tier III benefit	$88,033	GMP Tier III reporting
Net retail revenue	$149,919	GMP calculation
Net utility benefit (2024 dollars)	$193,160	
Project cost	($34,900)	Custom calc, GMP estimate
Tier III administration	($2,178)	GMP incentives
Fuel savings	$294,967	Custom calc
Value of avoided emissions	$219,490	VT Climate Action Plan
Net societal benefit (2024 dollars)	**$477,379**	

Table B-5. Tests for an example custom measure Tier III project.

Appendix C

ITRON BUDGET FORECAST

Itron

Knowledge to Shape Your Future

Electric | Gas | Water

information collection, analysis and application

Green Mountain Power
FY 2025 Sales Forecast Report

Prepared for:

Green Mountain Power

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1 2025 FISCAL YEAR BUDGET FORECAST SUMMARY

This report presents the FY2025 Forecast. The report summarizes forecast results, discusses methodology and assumptions, and examines the technologies that are reshaping load and sales growth projections.

Separate forecasts are derived for four customer classes – Residential, Small Commercial and Industrial, Large Commercial and Industrial, and Other sales; Other is primarily street lighting. Forecasts are derived from a set of linear regression models estimated for average use and customers in the residential class, and total sales in the Small C&I, Large C&I, and other loads. Monthly models are estimated with billed sales and customer data over the period January 2011 to December 2023. While the focus is on FY 2025 (October 2024 to September 2025), the forecast includes expected sales, customers, and revenues through 2034. Revenues are generated at the tariff level using a set of rate class and billing determinant models that translate the revenue class sales and customer forecast to billing determinants that are then priced out at current rates.

Where sales have been flat to declining historically, we now expect relatively strong sales growth driven primarily by state electrification efforts (primarily through heat pump adoption), and electric vehicle market growth. Continued solar adoption mitigates some of the impact from increasing heat pump and EV adoption. There is a significant drop in 2027 industrial sales as a large industrial customer is scheduled to procure their own power requirements beginning in that year. Table 1 shows the fiscal-year sales forecast.

TABLE 1: FISCAL YEAR SALES FORECAST (MWH)

	Residential	Chg	Small C&I	Chg	Large C&I	Chg	Other	Chg	Total	Chg
2024	1,593,779		1,453,041		1,044,723		3,681		4,095,223	
2025	1,617,317	1.5%	1,458,525	0.4%	1,050,578	0.6%	3,673	-0.2%	4,130,093	0.9%
2026	1,642,563	1.6%	1,466,172	0.5%	1,053,396	0.3%	3,673	0.0%	4,165,804	0.9%
2027	1,676,667	2.1%	1,476,951	0.7%	721,724	-31.5%	3,673	0.0%	3,879,015	-6.9%
2028	1,718,117	2.5%	1,489,548	0.9%	722,999	0.2%	3,673	0.0%	3,934,337	1.4%
2029	1,766,452	2.8%	1,503,244	0.9%	723,757	0.1%	3,673	0.0%	3,997,127	1.6%
2030	1,811,792	2.6%	1,513,071	0.7%	723,897	0.0%	3,673	0.0%	4,052,433	1.4%
2031	1,866,195	3.0%	1,522,599	0.6%	722,717	-0.2%	3,673	0.0%	4,115,184	1.5%
2032	1,924,814	3.1%	1,534,772	0.8%	721,148	-0.2%	3,673	0.0%	4,184,407	1.7%
2033	1,986,621	3.2%	1,549,047	0.9%	719,810	-0.2%	3,673	0.0%	4,259,152	1.8%
2034	2,060,087	3.7%	1,566,376	1.1%	718,555	-0.2%	3,673	0.0%	4,348,692	2.1%
24-29		2.1%		0.7%		-6.1%		0.0%		-0.4%
29-34		3.1%		0.8%		-0.1%		0.0%		1.7%

Revenues are derived by "pricing out" sales at the rate schedule level. Revenue class sales and customer forecasts are allocated to rate schedules and further into billing determinants (e.g., on and off-peak sales, billing demand, demand blocks) based on a set of rate class share and determinant models generated from historical billing data. Revenues are then calculated by pricing the billing determinants at the current tariff rates (*Revenues = Billing Determinants * Rates*). Table 2 shows the revenue forecast rolled back up to revenue classes.

TABLE 2: FISCAL YEAR REVENUE FORECAST ($)

	Residential	Chg	Small C&I	Chg	Large C&I	Chg	Other	Chg	Total	Chg
2024	346,589,160		272,306,327		111,487,726		2,894,699		733,277,912	
2025	350,574,437	1.1%	273,585,184	0.5%	113,139,417	1.5%	2,886,737	-0.3%	740,185,775	0.9%
2026	354,902,579	1.2%	275,109,882	0.6%	114,170,404	0.9%	2,886,737	0.0%	747,069,602	0.9%
2027	360,719,661	1.6%	277,208,148	0.8%	96,887,099	-15.1%	2,886,737	0.0%	737,701,645	-1.3%
2028	367,853,524	2.0%	279,516,325	0.8%	96,970,280	0.1%	2,886,737	0.0%	747,226,866	1.3%
2029	375,869,593	2.2%	282,287,053	1.0%	97,159,592	0.2%	2,886,737	0.0%	758,202,975	1.5%
2030	383,205,593	2.0%	284,243,894	0.7%	97,178,192	0.0%	2,886,737	0.0%	767,514,416	1.2%
2031	391,969,375	2.3%	286,136,020	0.7%	97,019,991	-0.2%	2,886,737	0.0%	778,012,124	1.4%
2032	401,393,648	2.4%	288,353,778	0.8%	96,722,137	-0.3%	2,886,737	0.0%	789,356,300	1.5%
2033	410,918,335	2.4%	291,209,710	1.0%	96,630,157	-0.1%	2,886,737	0.0%	801,644,939	1.6%
2034	422,590,808	2.8%	294,473,350	1.1%	96,461,868	-0.2%	2,886,737	0.0%	816,412,763	1.8%
24-29		1.6%		0.7%		-2.5%		-0.1%		0.7%
29-34		2.4%		0.8%		-0.1%		0.0%		1.5%

1.1 FORECAST APPROACH

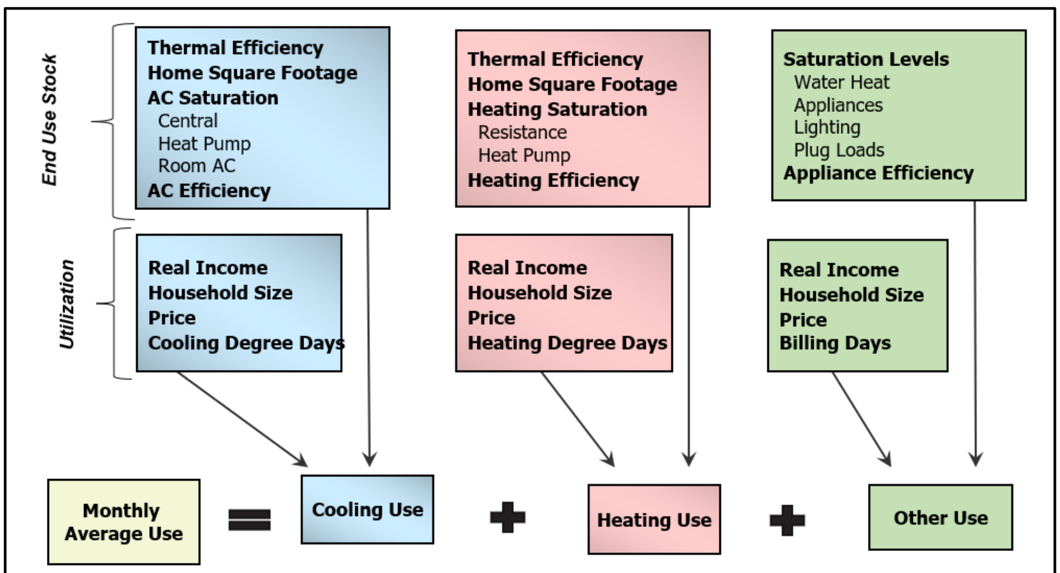
Baseline Sale Forecast. The process starts with estimating *baseline* sales and customers for each of the primary customer classes. The baseline forecast represents expected sales before adjustments for additional solar, heat pumps, and electric vehicles. Baseline models are estimated using linear regression models based on historical billed sales and customer data. The forecast is derived from a set of monthly customer class regression models that relate customer average use (residential), customers (residential) and sales (Small and Large C&I) to the economic, weather, and end-use energy intensities driving demand. Baseline forecast drivers include the number of households, employment, real income, GDP, weather, and end-use intensity trends (kWh per households in the residential sector and kWh per sqft in the commercial sector) that capture end-use ownership and efficiency trends. The end-use intensity trends also incorporate the impact of state energy efficiency programs. Models are estimated over the period January 2011 to December 2023.

Adjusted Forecast. The baseline forecast is adjusted for projected behind-the-meter (BTM) solar, heat pumps, and C&I electrification projects and in the longer-term electric vehicles. Most of the adjustments impact residential customer class. Solar has little impact on commercial billed sales and revenues as most of the commercial solar generation is treated as a power purchase cost. Heat pump and EV charging sales primarily impact the residential sector and are expected to have a significant impact on future residential sales and revenues.

1.2 RESIDENTIAL BASELINE FORECAST

Residential average use and commercial sales are modeled using a Statistically Adjusted End-Use (SAE) modeling framework. This modeling framework integrates end-use saturation and efficiency trends that capture long-term end-use energy trends with monthly weather, number of days, and economic drivers that capture expected utilization of the end-use stock. End-uses are mapped to heating (XHeat), cooling (XCool), and other uses (XOther). Figure 1 shows the residential average use model.

FIGURE 1: RESIDENTIAL AVERAGE USE MODEL



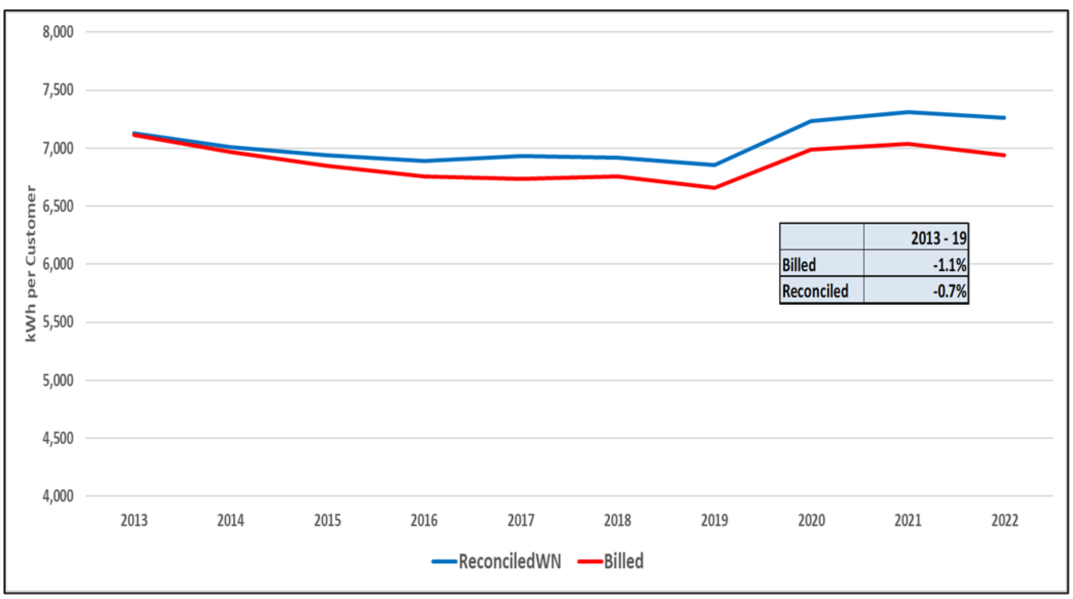
$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Linear regression is used to estimate the model coefficients – b_c, b_h, and b_0. Forecasts of cooling, heating, and base usage then drive the monthly average use forecast. The model is estimated with monthly billed average use data that is reconstituted (added back in) for BTM solar data from January 2011 to December 2023.

The initial model includes an energy efficiency variable (EE) that when combined with the estimated coefficient (b_e) measures the EE not captured in the structured model variables. The final model drops the EE variable as the end-use intensities are adjusted to account for the *missing* EE program savings.

Sales and Customer Trends. Figure 2 shows weather-normalized average use for both billed and reconstituted sales. Reconstituted sales include customer solar generation for their own use. Residential solar systems are meeting part of their own energy requirements with what is not used directly pushed back into the power grid. Own-use generation is added back to billed sales to generate a historical data series that reflects what the average household uses and not just what it purchases from GMP. Ultimately, revenues are based on billed sales which are calculated by subtracting out historical and forecasted own-use solar generation. Figure 2 shows historical billed and reconstituted average use (weather normalized).

FIGURE 2: RESIDENTIAL WEATHER NORMAL AVERAGE USE



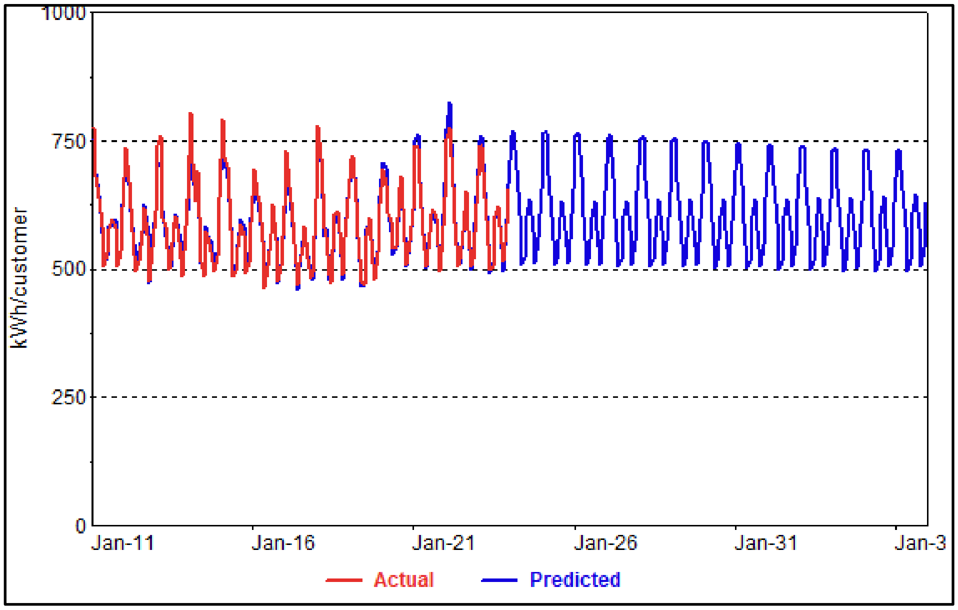
The gap between billed average use and reconstituted average use is the estimated amount of customer own generation on a per customer basis. On average residential customers are generating over five percent of their electricity use.

Between 2013 and 2019, billed average use declined 1.1% per year while reconstituted average use has declined 0.7% per year. Solar has accounted for 0.4% of the average annual decline in billed customer use. The long-term trend was upended with COVID-19 as work and school moved to the home. In 2020, average billed use jumped 5% to nearly 7,000 kWh, and reconstituted use to 7,300 kWh; reconstituted average use is higher than it was in 2013. Sales are still elevated largely as a result of people continuing to work from home. Another contributing factor is the large number of heat pumps that have been recently installed as part of the state's electrification effort.

Customer growth has been relatively consistent over the last ten years with GMP adding on average 600 new customers per year for 0.3% average annual growth. There was a jump of 1,800 in customers in 2021, but this followed a year (2020) in which GMP recorded just 7 new customers. Given state household projections, we are forecasting 0.2% average annual customer growth.

Baseline Average Use Forecast. The baseline model expresses reconstituted average use as function of cooling use (XCool), heating use (XHeat), and other non-weather sensitive use (XOther). The model is estimated using historical billed sales, customers, and own-use solar generation from January 2011 through December 2023. The same model specification has been used for nearly ten years and has proven to be extremely stable as measured by model fit statistics and out of sample performance. The model Adjusted R-Squared is 0.96 with a mean absolute error of 2.0%. Model coefficients and statistics are included in Appendix A. Figure 3 shows actual and predicted baseline average use.

FIGURE 3: RESIDENTIAL BASELINE AVERAGE USE MODEL (KWH)

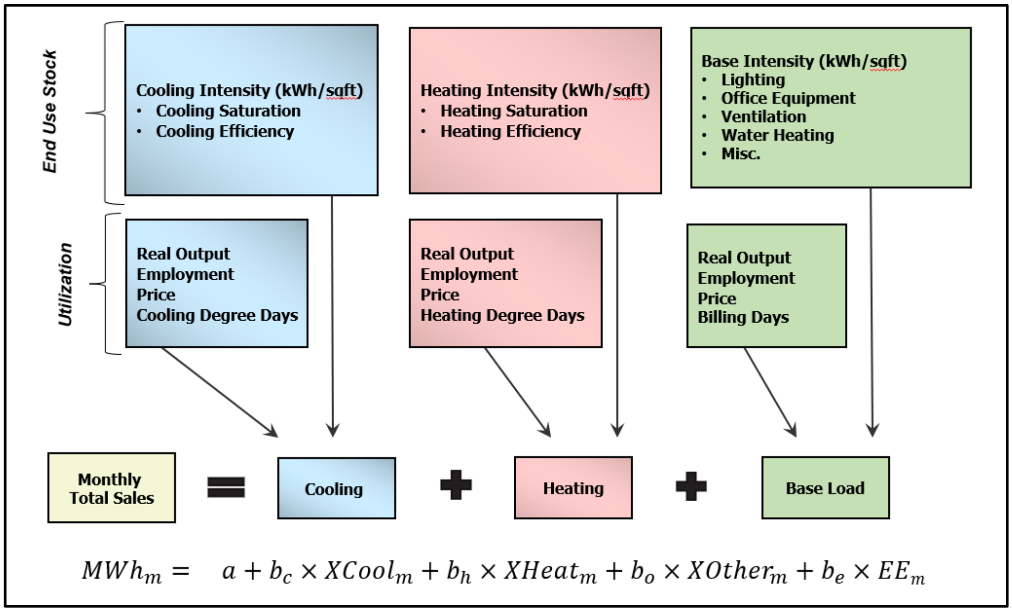


Average use jumps up in 2020 and stays elevated through 2023. We expect baseline loads to stay at this level given the new "work at home" normal and underlying sales gains due to recent heat pump adoption.

1.3 COMMERCIAL BASELINE FORECAST

Separate sales forecast models are estimated for the Small and Large commercial customer classes. Small commercial sales are also estimated using an SAE model where sales are specified as a function of commercial heating (XHeat), cooling (XCool), and base-use energy requirements (XOther). Figure 4 shows the commercial SAE model.

FIGURE 4: COMMERCIAL SALES MODEL



Linear regression is used to estimate the model coefficients – b_c, b_h, and b_0. Forecasts of cooling, heating, and base load requirements then drive the monthly sales forecast. The model is estimated with monthly billed sales data from January 2011 to December 2023. The initial model also includes an energy efficiency variable (EE) that when combined with the estimated coefficient (b_e) measures the EE not captured in the structured model variables. The final model drops the EE variable as the end-use intensities are adjusted to account for the additional EE program savings.

Large C&I includes GMP's largest commercial and industrial customers; there are 75 Large C&I customers. The Large C&I sales forecast is based on a generalized econometric model that relates monthly consumption to economic activity, weather, and seasonal use captured by monthly binary variables. The model is estimated over the period January 2015 through December 2023.

THE SAE COMMERCIAL MODEL, LIKE THE RESIDENTIAL MODEL, WORKS WELL TO EXPLAIN HISTORICAL SALES AND RESULTS IN A REASONABLE FORECAST CONSISTENT WITH THESE TRENDS. THE SMALL C&I MODEL ADJUSTED R-SQUARED IS 0.90 WITH A MEAN ABSOLUTE ERROR OF 1.9%. THE LARGE C&I MODEL FIT IS MUCH WEAKER WITH AN ADJUSTED R-SQUARED IS 0.68 WITH A MEAN ABSOLUTE ERROR OF 4.8%. THE LARGE C&I MODEL FIT IS NOT AS STRONG AS THERE IS SIGNIFICANT MORE MONTH TO MONTH VARIATION REFLECTING THE LARGE MIX OF VERY DIFFERENT TYPES OF BUSINESS ACTIVITY. THE ADJUSTED R-SQUARED AND ESTIMATED MODEL COEFFICIENT AND STATISTICS ARE INCLUDED IN APPENDIX A. FIGURE 5 AND

Figure 6 show actual and predicted sales.

FIGURE 5: ACTUAL AND PREDICTED SMALL COMMERCIAL SALES (MWH)

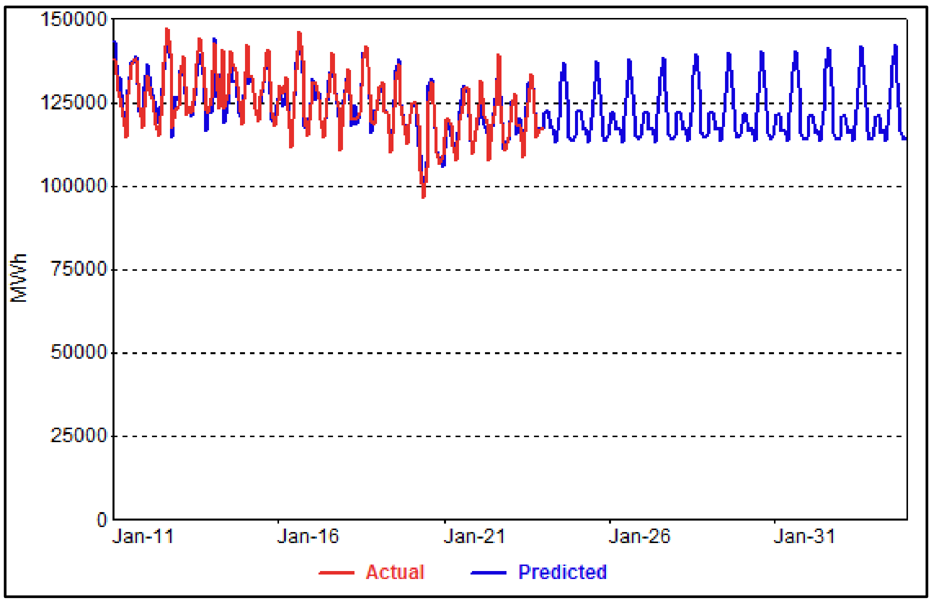
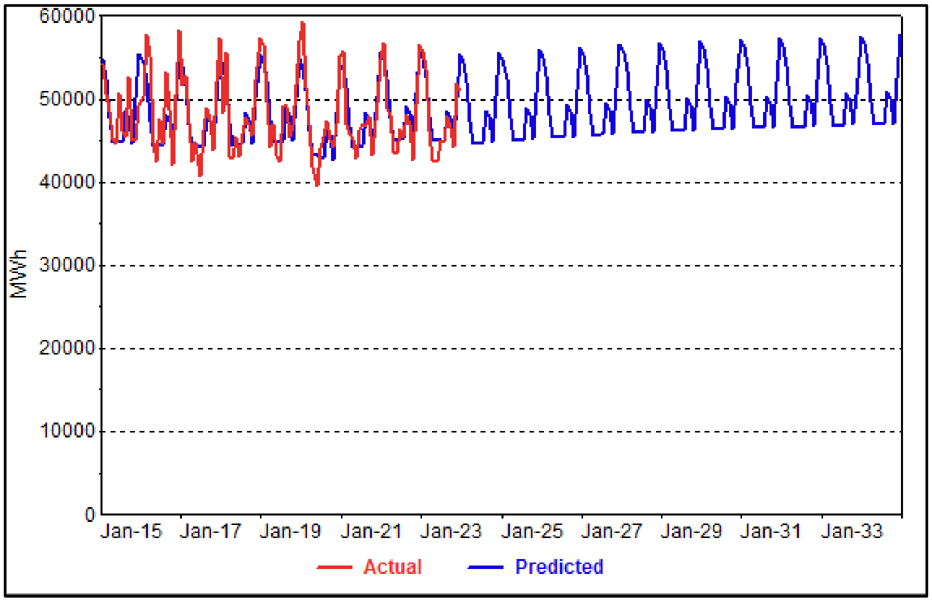


FIGURE 6: LARGE C&I ACTUAL AND PREDICTED SALES (MWH)



Large C&I forecast is adjusted for large customer load additions and losses that are not captured in the model based on historical sales. As part of the forecast process, we review customer-specific activity with GMP customer account representatives. Some customers are expected to add load through onsite expansion activity while others are closing or reducing operations. In the 2025 forecast, the net impact is a loss of 7,000 MWh per year. Also, in 2027 GMP loses a major customer, who is becoming a self-managed utility.

1.4 FORECAST DRIVERS

Several factors drive the sales and customer forecast through the estimated sales and customer models. These drivers include:

- Moody's Analytics January 2024 Vermont economic forecast.
- End-use saturation, efficiency and resulting energy intensities (kWh per end-use)
- VEIC current energy efficiency savings projections
- GMP's heat pump and EV forecast filed in their recent IRP.
- GMP's updated solar capacity forecast.

- GMP adjustments for C&I Tier 3 electrification efforts and large load adjustments that would not be reflected in the historical billing data.
- Expected HDD and CDD based on historical trends.

1.4.1 Economic Forecast

The FY25 forecast is based on Moody's January 2024 state economic projections. The primary economic drivers include the number of state households, state real personal income, employment, and real state economic output (GDP). Table 3 shows historical and projected economic outlook.

TABLE 3: STATE ECONOMIC PROJECTIONS

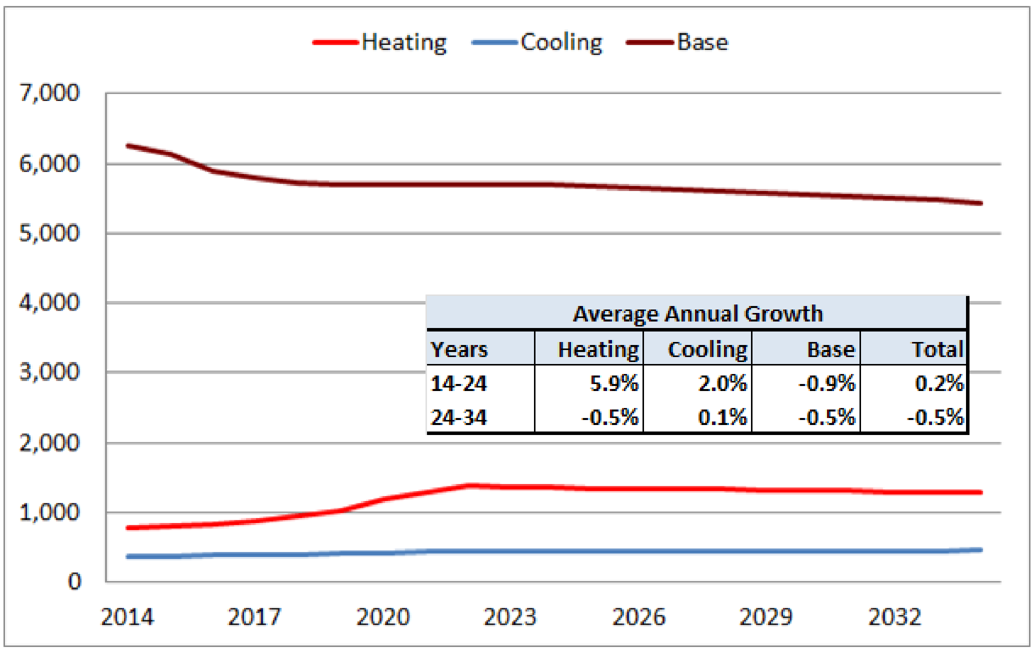
Year	Households (Thou)	Chg	RPI (Mil $)	Chg	GDP (Mil $)	Chg	Emp (Thou)	Chg
2014	270.6		30,558		31,754		309.6	
2015	272.9	0.8%	31,425	2.8%	32,117	1.1%	312.1	0.8%
2016	275.1	0.8%	31,632	0.7%	32,353	0.7%	313.3	0.4%
2017	276.6	0.5%	31,921	0.9%	32,594	0.7%	315.0	0.5%
2018	277.4	0.3%	32,513	1.9%	32,838	0.7%	316.1	0.3%
2019	276.0	-0.5%	33,619	3.4%	33,081	0.7%	315.4	-0.2%
2020	271.2	-1.8%	35,795	6.5%	32,422	-2.0%	289.2	-8.3%
2021	270.1	-0.4%	36,011	0.6%	33,821	4.3%	294.4	1.8%
2022	271.2	0.4%	35,194	-2.3%	34,568	2.2%	303.4	3.1%
2023	271.3	0.0%	35,860	1.9%	34,984	1.2%	307.0	1.2%
2024	272.1	0.3%	36,539	1.9%	35,414	1.2%	308.8	0.6%
2025	273.2	0.4%	37,144	1.7%	35,844	1.2%	309.7	0.3%
2026	274.1	0.3%	37,830	1.8%	36,413	1.6%	310.0	0.1%
2027	274.8	0.2%	38,572	2.0%	37,053	1.8%	309.9	0.0%
2028	275.4	0.2%	39,353	2.0%	37,742	1.9%	309.8	0.0%
2029	276.0	0.2%	40,102	1.9%	38,411	1.8%	309.9	0.0%
2030	276.5	0.2%	40,804	1.8%	39,030	1.6%	309.8	0.0%
2031	276.9	0.2%	41,466	1.6%	39,617	1.5%	309.7	0.0%
2032	277.3	0.1%	42,127	1.6%	40,220	1.5%	309.6	0.0%
2033	277.5	0.1%	42,801	1.6%	40,857	1.6%	309.7	0.0%
2034	277.5	0.0%	43,461	1.5%	41,507	1.6%	309.7	0.0%
14-24		0.1%		1.8%		1.1%		0.0%
24-34		0.2%		1.8%		1.6%		0.0%

The long-term outlook is for slow household and employment growth, but reasonable household income and real state output. Employment saw a steep drop in 2020 and while recovering through 2023, it never gets back to pre-COVID levels.

1.4.2 Energy Efficiency Impact

While slowing, energy efficiency improvements still have a significant impact. Efficiency gains are captured through the model heating, cooling, and other use end-use intensity projection. End-use intensities are derived for ten residential and nine small C&I end-uses. End-use intensities reflect both increase in appliance ownership (saturation) and change in stock efficiency. In the residential sector, intensities are measured on a kWh per household basis and in the small C&I sector on a kWh per square-foot basis. End-use intensities are based on EIA 2022 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available. This year the starting saturation and end-use energy was calibrated using the recent statewide residential saturation study and housing and building simulation output from the National Energy Renewable Laboratory (NREL). This is shown in Figure 7.

FIGURE 7: RESIDENTIAL END-USE INDICES (KWH PER HOUSEHOLD)

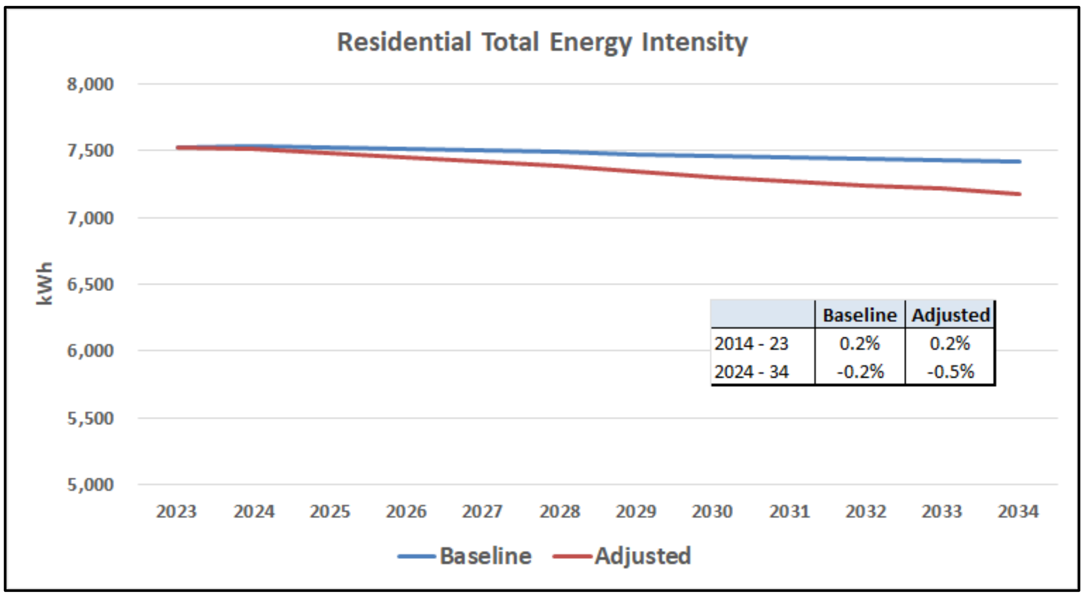


Heating intensity ramps up significantly between 2019 and 2023. For the forecast the heating intensity declines as heat pump saturation is held constant. Heat pumps are held constant as we assume that all heat pump purchases will be through the incentive program. Future heat pump saturation and associated load growth are treated separately and then added to the baseline forecast. Heating decline reflecting continued decline in resistant heat saturation and improvements in furnace fan efficiency.

Cooling intensity increases through the forecast period at 0.1% per year. Cooling intensity change is significantly slower than the prior ten years as cooling end-use saturation slows and unit efficiency continues to improve. Average intensity across the other use declines on average 0.5% per year reflecting continued end-use and housing shell efficiency improvements.

End-use intensities are also adjusted for state energy efficiency programs. Most of the savings are captured in the starting EIA end-use intensity projections as EIA builds regional (New England) efficiency savings estimates into the estimated end-use sales and resulting end-use intensities. A simple model is used to isolate the EE savings that are not captured in the initial SAE model. The model indicates that GMP is doing 30% more in efficiency savings than New England. The end-use intensity drivers are adjusted by 30% to account for state EE impacts. Figure 8 compares total intensity against the EE savings adjusted intensities.

FIGURE 8: RESIDENTIAL BASELINE AND EE ADJUSTED INTENSITY COMPARISON

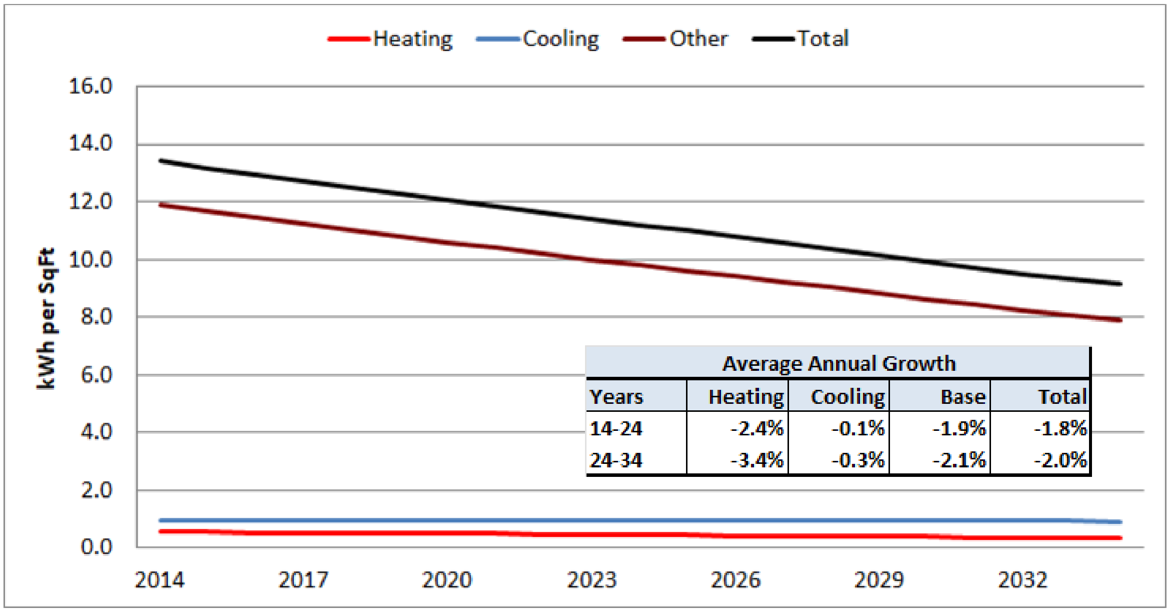


	Baseline	Adjusted
2014 - 23	0.2%	0.2%
2024 - 34	-0.2%	-0.5%

The EE program adjusted total intensity declines 0.5% per year compared with the initial EIA projection of 0.2% annual decline. The adjusted intensity is in line with the intensity trend before the recent jump in heat pump sales.

Figure 9 shows commercial heating, cooling, and other use intensity trends. Intensities are expressed on a kWh per square foot basis. Heating and cooling are relatively small in New England; most of the heating and cooling related loads show up in the ventilation end-use which is part of the base intensity. Ventilation and lighting are two of the largest commercial end-uses; EIA expects significant efficiency gains in these end-uses. Figure 9 shows historical and forecasted primary end-use intensity trends.

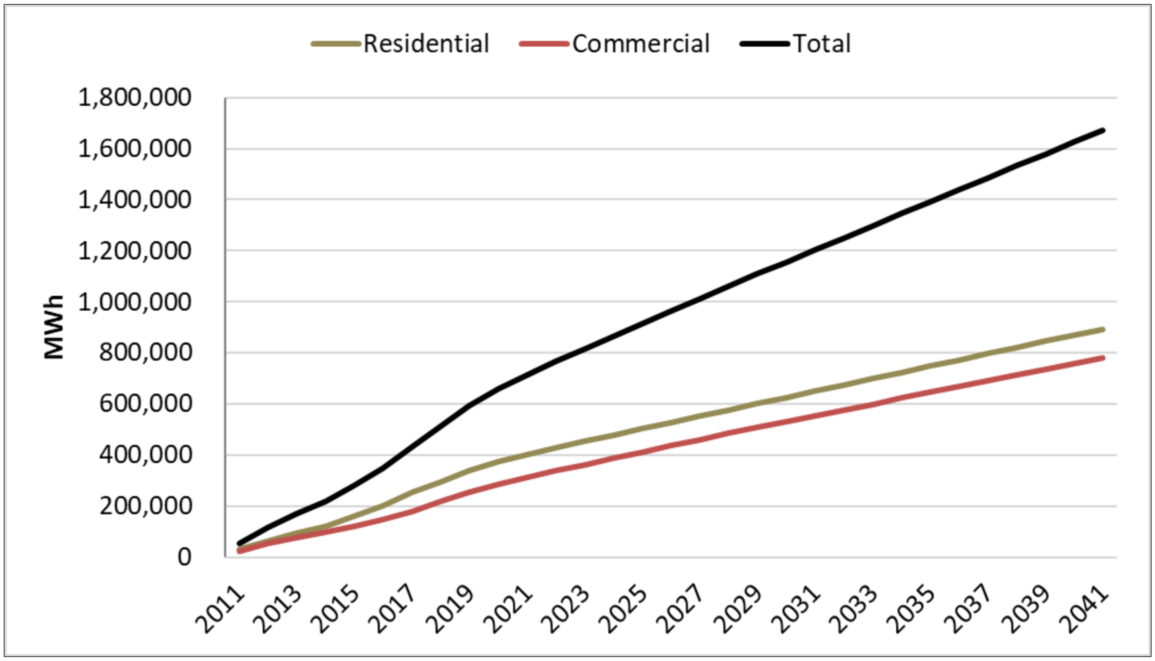
FIGURE 9: SMALL C&I END-USE INTENSITIES (KWH/SQFT)



Years	Heating	Cooling	Base	Total
14-24	-2.4%	-0.1%	-1.9%	-1.8%
24-34	-3.4%	-0.3%	-2.1%	-2.0%

The long-term decline in commercial intensity is the primary reason there has been little to no growth in commercial sales. The intensity projection also reflects the expected impact of future EE savings which contribute roughly 0.7% of the annual intensity decline. EE savings projections are based on the current Demand Resource Plan (DRP). Figure 10 shows cumulative historical savings and projected savings.

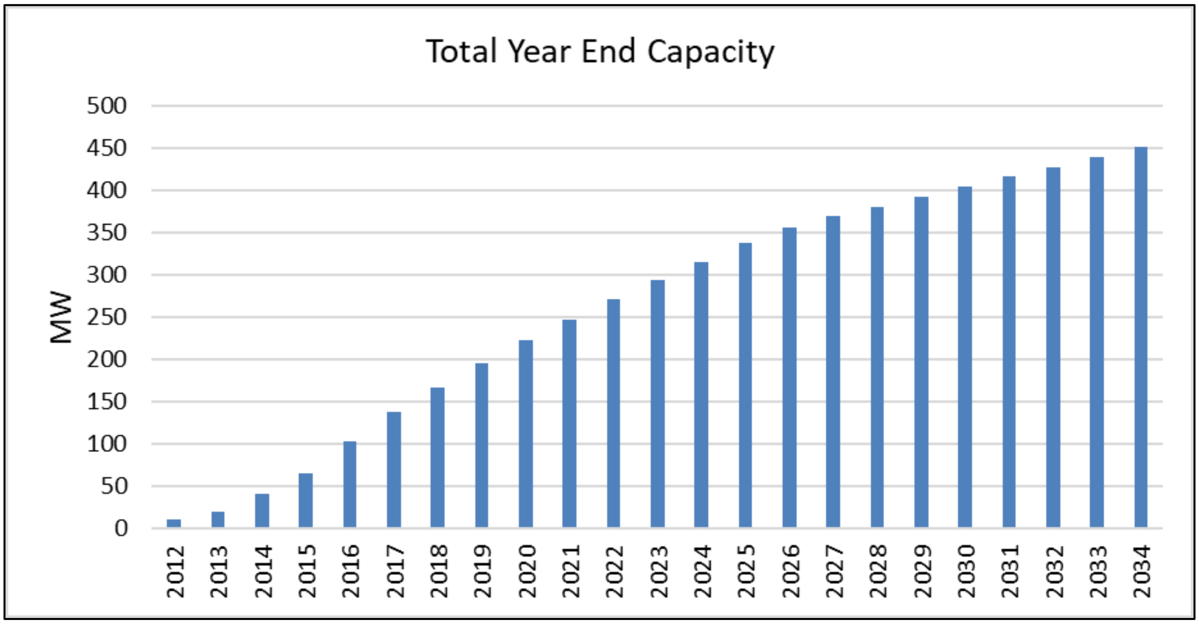
FIGURE 10: CUMULATIVE STATE EE SAVINGS



1.4.3 Behind the Meter Solar

Solar Capacity Forecast. Behind the meter (BTM) solar capacity forecast is developed by GMP based on historical trends and the interconnection application queue. As of December 2024, an estimated 294 MW of BTM solar has been installed; this includes traditional, customer owned or leased roof-top systems, and larger community/group-based systems. GMP expects BTM solar to continue to increase, adding 21 MW of capacity in 2024 and approximately 23 MW in 2025. Adoption slows to 19 MW of new capacity in 2026, followed by 13 MW of new capacity for the years 2027 through 2034. Figure 11 shows the year end capacity forecast.

FIGURE 11: YEAR-YEAR SOLAR CAPACITY FORECAST



Capacity Class Allocation. The capacity forecast is allocated to the residential, small C&I, and large C&I classes based on the previous 12 months of billed solar generation data. Table 4 shows the allocation factors.

TABLE 4: CAPACITY ALLOCATION FACTORS

Class	Previous 12 Mnth Generation (MWh)	Share of Total
Residential	122,921	34.6%
Commerical	195,911	55.1%
Industrial	36,524	10.3%
Total	355,356	

Solar Generation. Solar output is derived by applying monthly solar load factors to the capacity forecast; load factors are based on typical solar generation patterns developed by GMP. Table 5 shows the solar generation load factors.

TABLE 5: SOLAR LOAD FACTORS

Month	Load Factor
Jan	7.7%
Feb	10.8%
Mar	14.1%
Apr	18.8%
May	19.5%
Jun	20.6%
Jul	20.3%
Aug	19.5%
Sep	15.7%
Oct	12.5%
Nov	8.4%
Dec	5.7%

Solar Own-Use. Solar generation is either consumed onsite (*own-use*) or returned to the connected power-grid (*excess*); own-use reduces billed revenues, while excess is treated as power purchase cost. Solar billing data are used to determine the own-use and excess allocations. The split between own-use and excess varies by revenue class and month; own-use share is typically smaller in the summer months with a larger percentage of the generation sent to the grid. Figure 12 shows total, own use, and excess solar generation. Excess is significantly higher than own use. One reason is that most of small C&I solar generation are purchases from large offsite solar installations that do not directly impact the customer's usage.

FIGURE 12: BTM SOLAR GENERATION

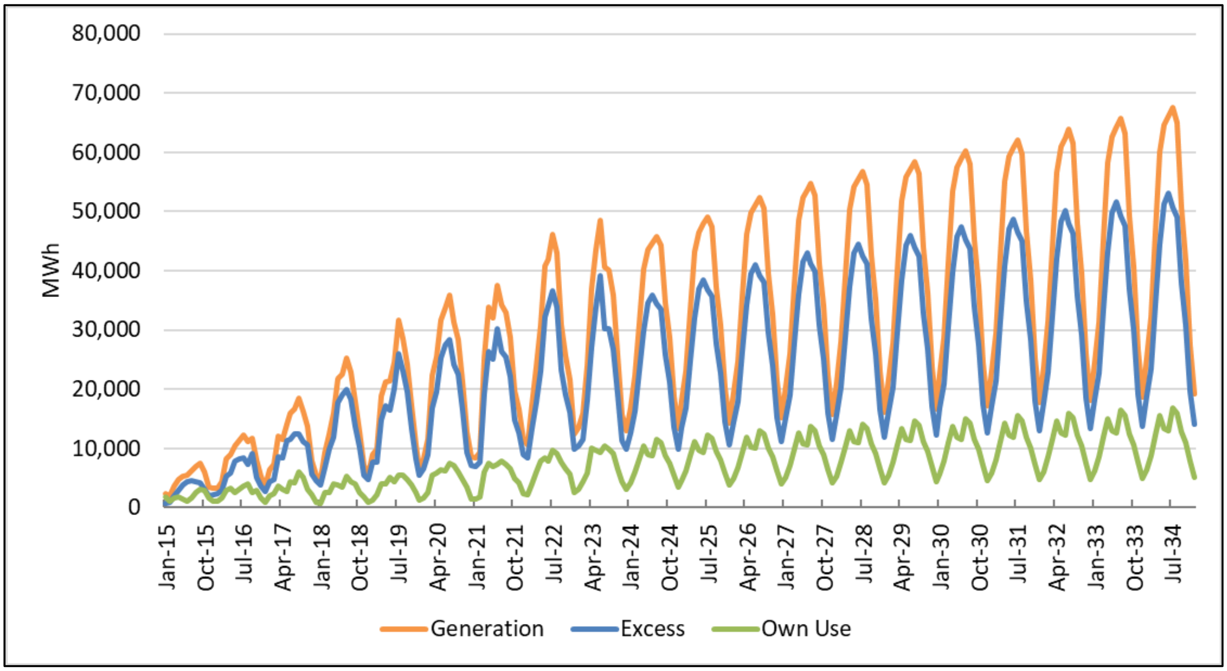


Table 6 shows the forecasted capacity and solar generation by rate case.

TABLE 6: SOLAR GENERATION (HISTORICAL & NEW CAPACITY)

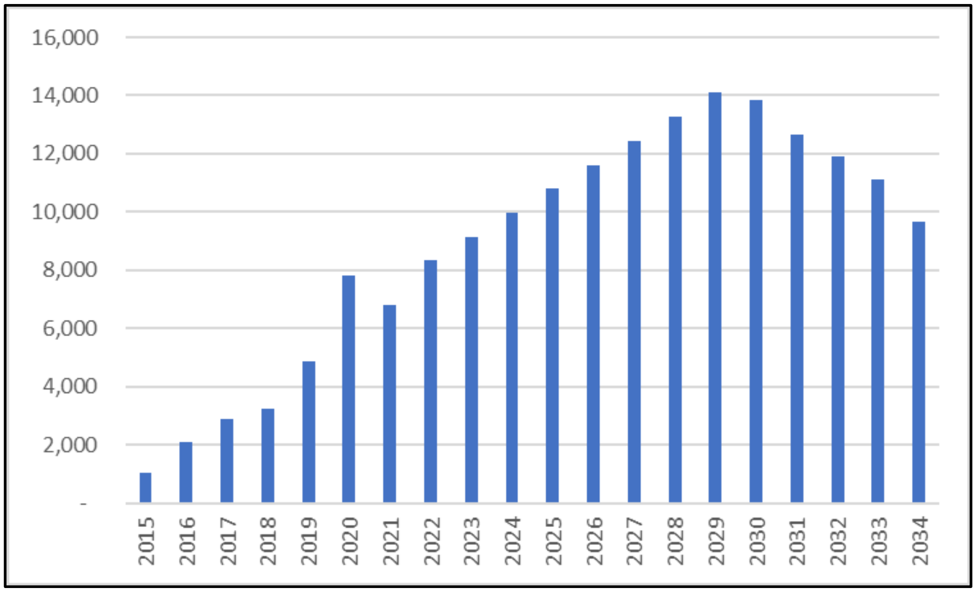
Year	Year End Capacity (MW)	Total MWh Generation	Total MWh Excess	Total MWh Own Use	Residential MWh Generation	Residential MWh Excess	Residential MWh Own Use	Commercial & Industrial MWh Generation	Commercial & Industrial MWh Excess	Commercial & Industrial MWh Own Use
2024	314.6	384,731	290,319	94,413	133,082	45,928	87,154	251,649	244,391	7,258
2025	337.7	411,184	310,303	100,882	142,232	49,121	93,112	268,952	261,182	7,770
2026	356.5	438,463	330,899	107,564	151,668	52,382	99,286	286,794	278,517	8,278
2027	369.2	459,482	346,775	112,708	158,939	54,897	104,042	300,543	291,878	8,666
2028	381.0	476,233	359,393	116,840	164,733	56,857	107,876	311,500	302,536	8,964
2029	392.9	490,261	370,007	120,254	169,586	58,575	111,011	320,675	311,432	9,244
2030	404.7	505,253	381,322	123,931	174,771	60,366	114,405	330,481	320,955	9,526
2031	416.5	520,244	392,637	127,607	179,957	62,158	117,800	340,287	330,479	9,808
2032	428.3	536,322	404,742	131,580	185,519	64,031	121,488	350,803	340,711	10,092
2033	440.1	550,227	415,267	134,960	190,329	65,740	124,589	359,899	349,527	10,372
2034	451.9	566,449	427,519	138,930	195,940	67,689	128,251	370,509	359,830	10,679

The sales forecast is adjusted for solar load impacts by subtracting cumulative new solar own-use generation from the appropriate class sales forecasts. In 2024, solar generation reduces residential sales by 94,413 MWh, which represents a reduction of 385 kWh per customer, by 2034 this increases to 555 kWh per customer. C&I solar impacts are relatively small as most of the C&I solar generation is treated as excess generation that shows up as a reduction in system energy requirements.

1.4.4 Heat Pumps

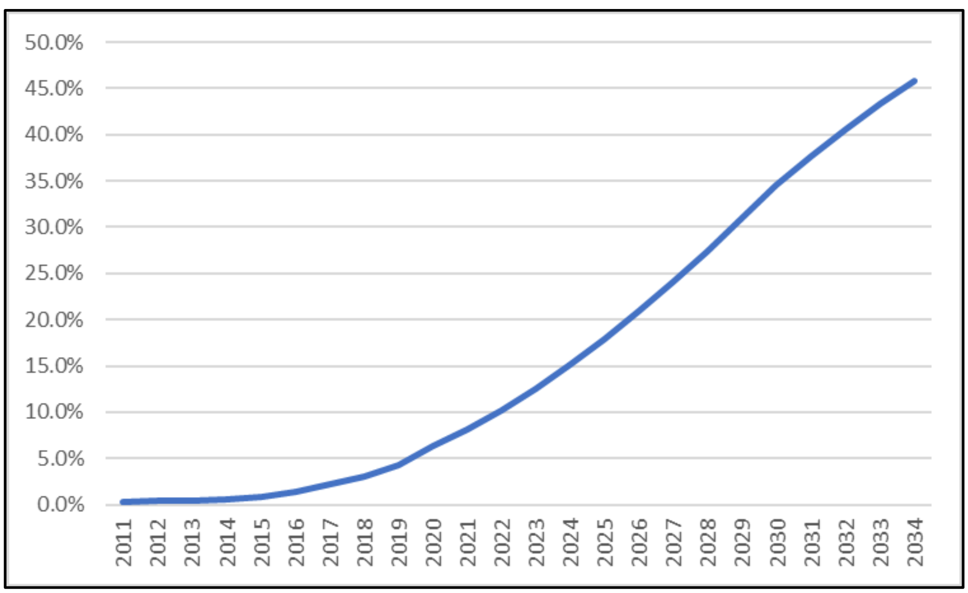
Heat pump sales drive most of the near-term residential sales growth. Heat pumps are being promoted through state heat pump incentives and are part of the state's building electrification strategy designed to reduce CO2 emissions. The recently adopted federal Inflation Reduction Act (IRA) will further contribute to heat pump adoption through federal tax credits and rebates that will flow through to VEIC. To date, the state heat pump program has been highly successful with roughly 60,000 heat pumps installed across the state over the last five years. With each home installing approximately 1.7 units, (much of the market are auxiliary mini-split units) estimated heat pump saturation has increased from approximately 1.0% in 2015 to 15% in 2023. Heat pump adoption has had a measurable impact on residential sales and partially explains (along with COVID's impact on at home work activity) why there has been no significant decline in residential usage even with increasing efficiency. The heat pump forecast was developed as part of the VELCO state IRP forecast completed last summer. It is based on VEIC and DPS expected case scenario. The forecast is relatively aggressive assuming that the number of annual heat pump units increases from roughly 10,000 units per year today to 18,000 annual units by 2029 before beginning to decline. Given GMP's share of the state customer base, we expect to see roughly 70% of heat pump sales in the GMP service area. This translates into peak heat pump sales of 14,000 units by 2029. Figure 13 shows the GMP heat pump unit forecast.

FIGURE 13: HEAT PUMP UNIT FORECAST



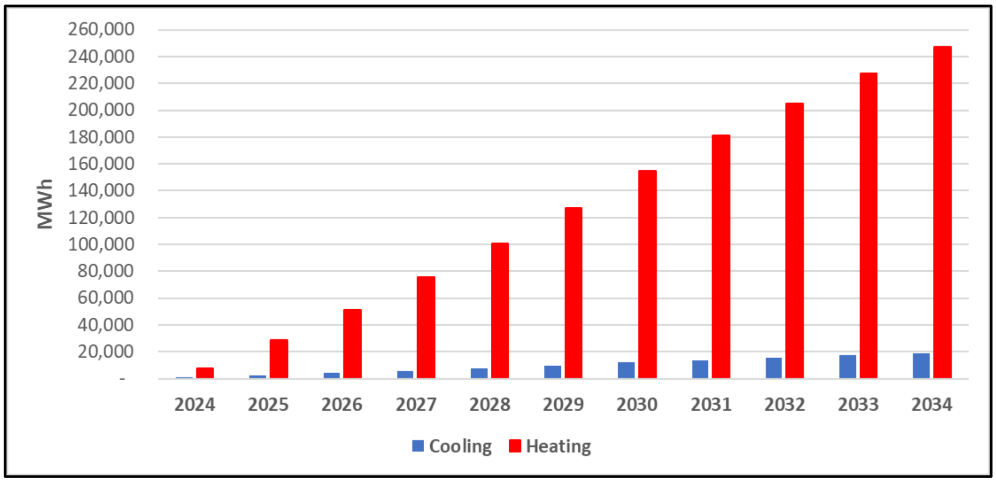
The unit forecast implies that in five years over, 25% of residential customers will have heat pumps increasing to 45% of residential customers by 2034. Figure 14 shows forecasted heat pump saturation.

FIGURE 14: HEAT PUMP SATURATION



Translation to Sales. Heat pump sales are estimated for both heating and cooling. Sales are derived by multiplying the unit forecast by annual heating and cooling average use (UEC). The starting UEC is based on a Cadmus study that metered heat pump electricity input. Average heat pump use declines over time with projected heat pump efficiency improvements. Annual heating and cooling are allocated to months based on heating and cooling estimated load profiles. Ninety percent of heat pump sales are residential, and ten percent are commercial. Projected sales starting in 2024 are shown in Figure 15.

FIGURE 15: HEAT PUMP SALES FORECAST

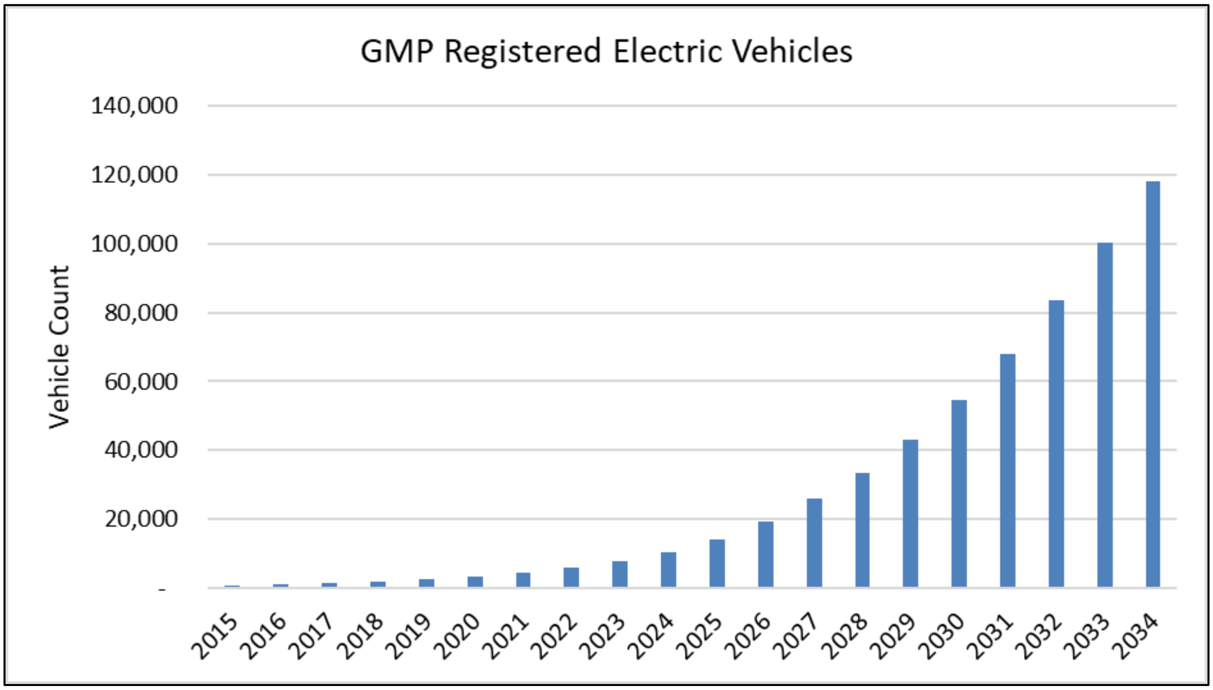


1.4.5 Electric Vehicles

As of January 2024, Vermont had approximately 12,754 registered plug-in hybrid (PHEV) and all battery electric (BEV) vehicles, this is up 44% over the past year. Electric vehicles constituted 10% of all new light duty vehicle sales in 2023, up from 6.9% in 2022. Vermont has joined 16 other states in adopting California's Advanced Clean Cars II goals. By 2035 all new passenger cars, trucks and SUVs sold in Vermont must qualify as zero or low emission vehicles, which includes battery electric, plug-in hybrid electric, and hydrogen vehicles. There are interim goals of 35% by 2026 and 68% by 2030.

The EV sales forecast is based on VELCO's 2023 high-case projections. While the mandate addresses new vehicle sales, given the current and future combustion engine vehicle stock, the increase in total EV market share will be much slower. Figure 16 shows the projected number of GMP electric vehicles.

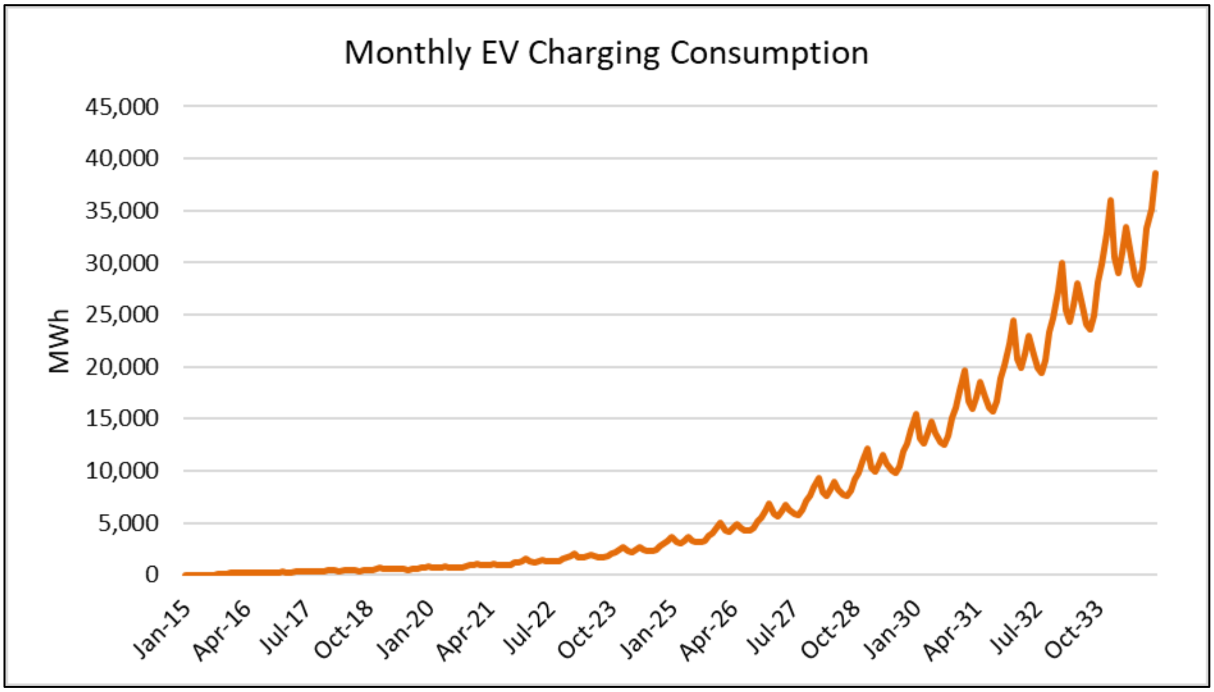
FIGURE 16: REGISTERED ELECTRIC VEHICLES



Based on studies by NREL, we assume 80% of the charging energy will be at home impacting residential sales and 20% will be away adding to commercial sales.

Figure 17Figure 17 shows the GMP electric vehicle sales forecast. Inputs include number of EVs, average annual miles driven, and miles per kWh. The monthly charging consumption is based on AMI vehicle charging data and reflects the impact of increased charging needs in colder months. Based on studies by NREL, we assume 80% of the charging energy will be at home impacting residential sales and 20% will be away adding to commercial sales.

FIGURE 17: ELECTRIC VEHICLE SALES



1.4.6 Customer Specific Load Adjustments

Forecasts are adjusted for specific customer business activity that result in large changes in load; this load change would not be captured in historical data series, and as a result not captured in the forecast models. The expected downward spot load adjustment is relatively small at 7,000 MWh.

The largest load adjustment is for the removal of GlobalFoundries from GMP's service territory as they commence operations as their own electric utility, consistent with the Vermont Public Utility Commission's Order in Case Nos. 21-1107-PET and 21-1109-PET. GMP is currently serving GlobalFoundries' load under a transitional power purchase agreement (PPA), which represents a third of the Large C&I class sales. This PPA expires in October 2026, at which time GlobalFoundries load is removed from the sales forecast.

1.4.7 Load Adjustments Summary

Table 7 summarizes load adjustments applied to the baseline forecast. Electrification programs and increasing penetration of electric vehicles outweigh efficiency and solar impacts after 2026. The large drop in 2027 sales reflects the loss of a large customer to transmission only service.

TABLE 7: ADJUSTMENTS SUMMARY

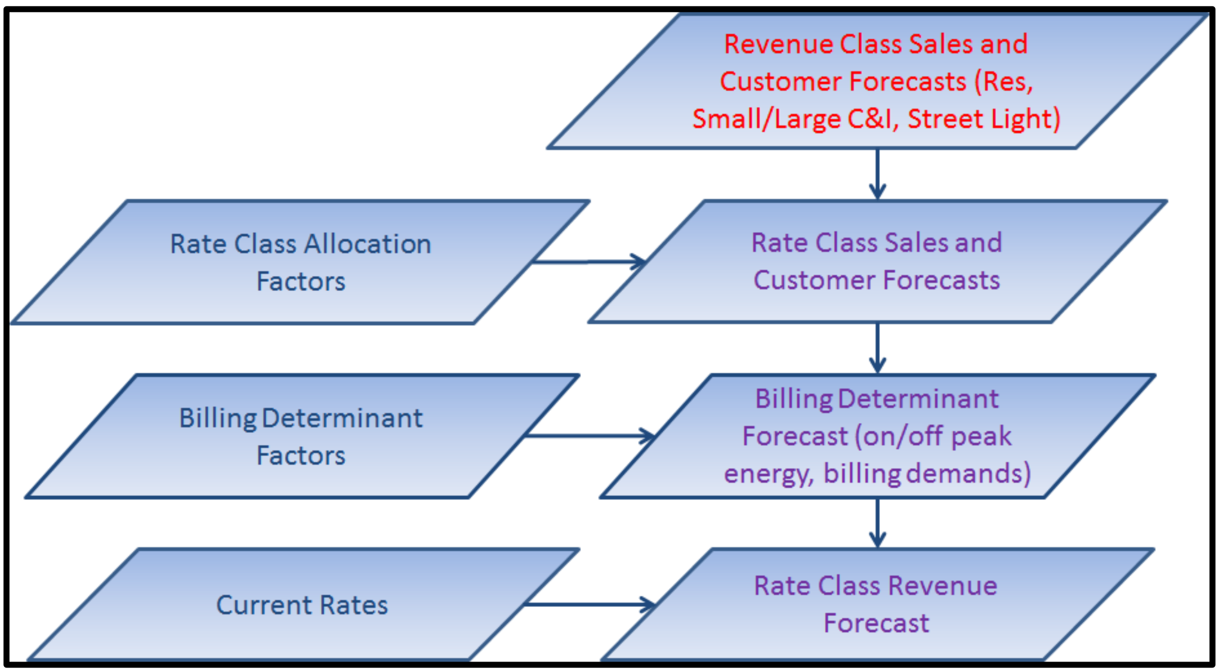
ear	NoEE(1)	EE(2)	Solar(3)	Tier3(4)	EV(5)	SpotLds(6)	TtlAdj	Forecast
2025	4,142,318	-39,226	-8,111	29,439	12,673	-7,000	-12,224	4,130,093
2026	4,171,285	-66,152	-14,812	55,772	26,712	-7,000	-5,480	4,165,804
2027	3,869,307	-92,420	-20,173	83,444	45,858	-7,000	9,709	3,879,015
2028	3,902,937	-120,307	-24,157	112,436	70,428	-7,000	31,400	3,934,337
2029	3,932,519	-148,289	-27,736	148,841	98,792	-7,000	64,608	3,997,127
2030	3,958,937	-178,217	-31,357	176,358	133,712	-7,000	93,496	4,052,433
2031	3,982,515	-206,541	-34,980	205,387	175,803	-7,000	132,668	4,115,184
2032	4,006,893	-232,687	-38,694	230,838	225,056	-7,000	177,513	4,184,407
2033	4,029,742	-256,550	-42,225	254,531	280,654	-7,000	229,410	4,259,152
2034	4,053,487	-280,811	-46,116	288,349	340,783	-7,000	295,205	4,348,692

1. No EE forecast assumes no efficiency improvements after 2023.
2. Efficiency includes impacts of new standards, naturally occurring, and EE program-based efficiency improvements.
3. Solar is derived from GMP solar capacity forecast and is allocated to classes.
4. Tier 3 heat pump forecast is derived by scaling VEIC state projections to the GMP service area and also includes sales for commercial building electrification.
5. VEIC EV forecast adjusted for GMP state share of electricity sales.
6. Customer specific spot load adjustments.

1.5 REVENUE FORECAST

The revenue forecast is derived at the rate schedule level. Class sales forecasts are allocated to rate schedules and within rate schedules to billing determinants (i.e., customer, on and off-peak use, and billing demands). Revenues are then generated by multiplying rate schedule billing determinants by the current tariff rates. Figure 18 provides an overview of the revenue model.

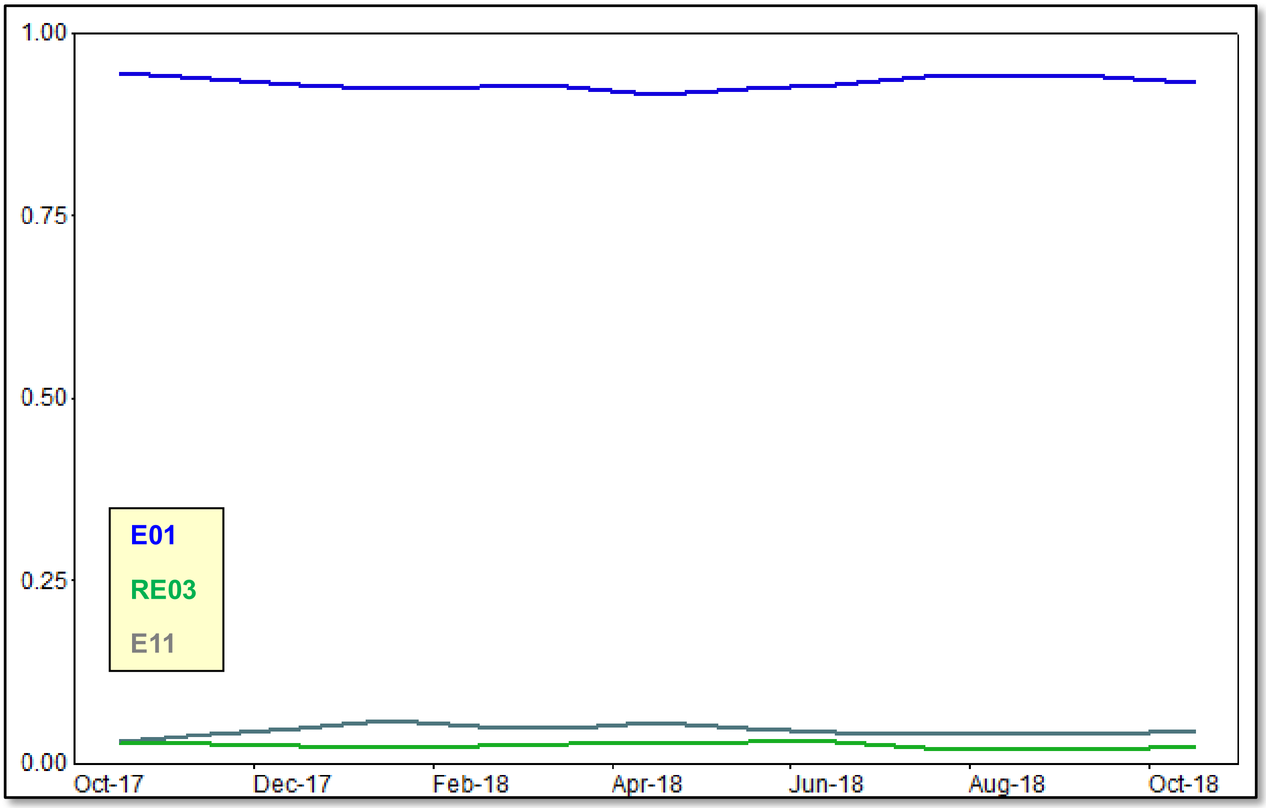
FIGURE 18: REVENUE MODEL



1.5.1 Derive Rate Class Monthly Sales Forecast

Revenue class sales and customer forecasts are allocated to the underlying rate schedules based on projected monthly allocation factors. The allocation factors are derived from historical billing data and simple regression models that capture any share trends and seasonal variation. Residential class sales, for example, are allocated to rate schedules - E01, RE03, and E11 rate classes. Figure 19 shows historical and forecasted residential rate class sales shares.

FIGURE 19: RESIDENTIAL RATE CLASS SHARE FORECAST



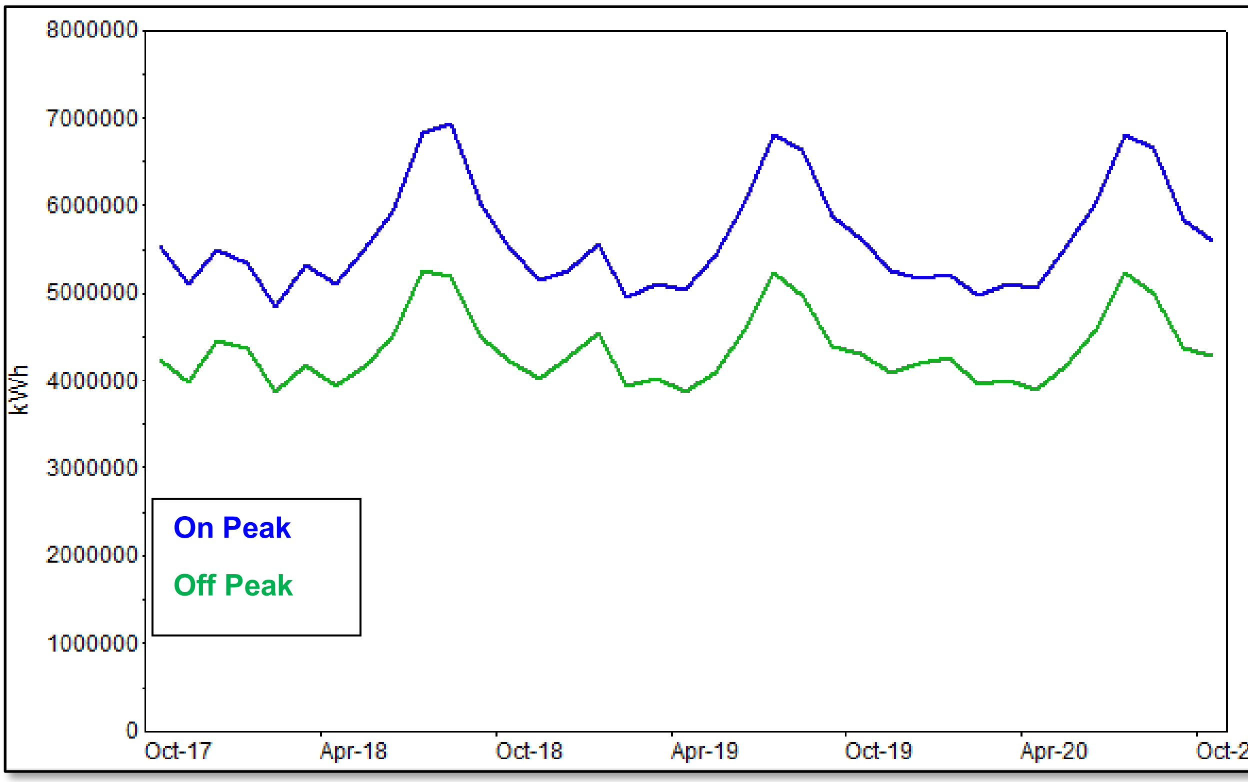
Approximately 95% of residential sales are billed under rate E01. The percentage is slightly lower in the winter months as the electric time-of-use rate (E11) is higher in these months.

1.5.2 Estimate Monthly Billing Determinants

In the next step, rate class sales (and customers counts for some rates) are allocated to billing blocks, time-of-use billing periods, and on and off-peak billing demand blocks. Billing block and demand factors are derived from historical billing data. For example, residential rate E11 has on peak and off-peak energy billing periods that are priced differently. Rate E11 monthly sales are allocated to TOU periods based on historical on-peak and off-peak sales data.

Some of the rates are complex. The small C&I rate E65, for example, includes non-demand and demand billed sales and customers, load factor kWh blocks (for demand customers), and different demand charges for demand for on/off peak, which are scheduled to replace block rates within the next two years. Figure 20 shows the resulting sales block forecasts for rate E65 Demand Customers.

FIGURE 20: RATE E65 DEMAND CUSTOMER - SALES BILLING BLOCK FORECAST



1.5.3 Calculate Rate Schedule and Revenue Class Revenues

Once the billing determinants are derived, revenues are generated by multiplying the forecasted billing determinants by the current customer, energy, and demand charges. Revenues are aggregated by rate schedule and month. Rate schedule revenues are then mapped back to the customer classes residential, small C&I, large C&I, and street lighting as reported in the Summary Table 2.

APPENDIX A: MODEL STATISTICS AND COEFFICIENTS

FIGURE 21: RESIDENTIAL AVERAGE USE MODEL (KWH PER CUSTOMER)

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRevRes.XHeat	1.143	0.046	24.896	0.00%
mStructRevRes.XCool	1.110	0.064	17.422	0.00%
mStructRevRes.XOther	0.966	0.013	74.363	0.00%
mBin.Feb	-22.707	5.908	-3.843	0.02%
mBin.Mar	-25.933	6.948	-3.732	0.03%
mBin.Apr	-29.021	6.765	-4.290	0.00%
mBin.May	-30.150	7.191	-4.193	0.01%
mBin.Jun	-27.161	5.476	-4.960	0.00%
mBin.Oct	-10.442	5.724	-1.824	7.02%
mBin.Nov	-13.314	5.612	-2.373	1.90%
mBin.Apr14	118.737	13.726	8.650	0.00%
MA(1)	0.663	0.072	9.188	0.00%

Model Statistics	
Iterations	31
Adjusted Observations	156
Deg. of Freedom for Error	144
R-Squared	0.963
Adjusted R-Squared	0.960
AIC	5.677
BIC	5.911
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-652.15
Model Sum of Squares	1,005,651.37
Sum of Squared Errors	39,059.48
Mean Squared Error	271.25
Std. Error of Regression	16.47
Mean Abs. Dev. (MAD)	12.03
Mean Abs. % Err. (MAPE)	1.98%
Durbin-Watson Statistic	1.683

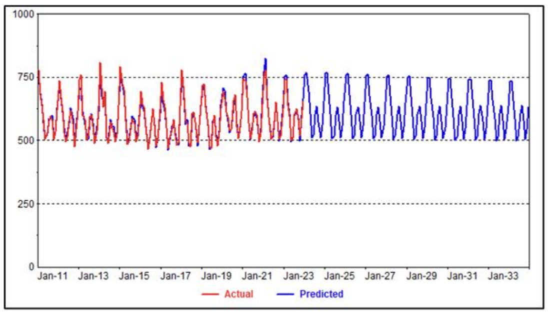


FIGURE 22: RESIDENTIAL CUSTOMER MODEL

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	44870.376	14179.484	3.164	0.19%
mEcon.GDP	0.992	0.154	6.438	0.00%
mEcon.Pop	225.573	28.262	7.981	0.00%
MA(1)	0.547	0.070	7.856	0.00%
MA(2)	0.517	0.070	7.406	0.00%

Model Statistics	
Iterations	32
Adjusted Observations	156
Deg. of Freedom for Error	151
R-Squared	0.945
Adjusted R-Squared	0.943
AIC	12.742
BIC	12.840
F-Statistic	647.470
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,210.25
Model Sum of Squares	858,011,704.75
Sum of Squared Errors	50,025,356.86
Mean Squared Error	331,293.75
Std. Error of Regression	575.58
Mean Abs. Dev. (MAD)	438.51
Mean Abs. % Err. (MAPE)	0.20%
Durbin-Watson Statistic	1.500

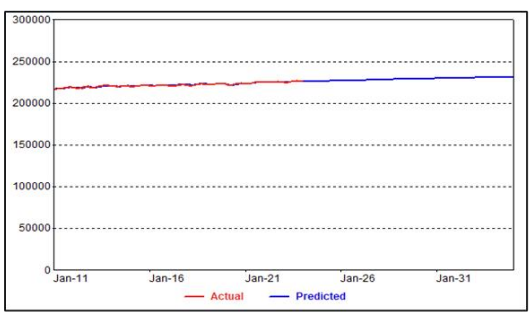
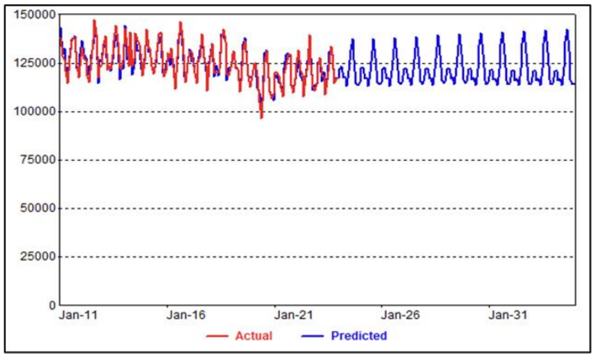


FIGURE 23: SMALL C&I SALES MODEL (MWH)

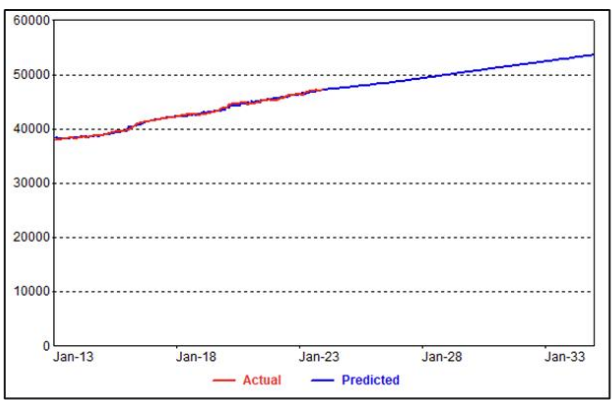
Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	921.097	111.116	8.290	0.00%
mStructRevCom.XHeat	161484.777	10574.558	15.271	0.00%
mStructRevCom.XCool	77495.980	3706.426	20.909	0.00%
mStructRevCom.XOther	9409.659	81.939	114.837	0.00%
mBin.Apr14	17406.057	2734.574	6.365	0.00%
mBin.May20	-7288.794	3080.622	-2.366	1.93%
mBin.Jun20	-10109.954	2994.350	-3.376	0.09%
Covid.NResIndex	-5704.240	1082.588	-5.269	0.00%
MA(1)	0.450	0.078	5.737	0.00%



Model Statistics	
Iterations	21
Adjusted Observations	156
Deg. of Freedom for Error	147
R-Squared	0.910
Adjusted R-Squared	0.905
AIC	16.036
BIC	16.212
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,463.14
Model Sum of Squares	12,878,399,972.43
Sum of Squared Errors	1,280,073,955.76
Mean Squared Error	8,707,986.09
Std. Error of Regression	2,950.93
Mean Abs. Dev. (MAD)	2,309.63
Mean Abs. % Err. (MAPE)	1.85%
Durbin-Watson Statistic	1.734

FIGURE 24: SMALL C&I CUSTOMER MODEL

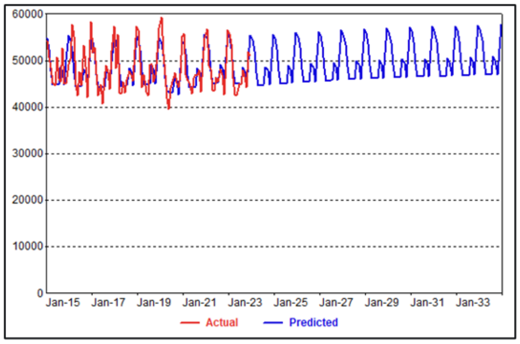
Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.ComVar	13768.471	2107.745	6.532	0.00%
mBin.Yr16Plus	862.041	128.072	6.731	0.00%
mBin.Yr19Plus	340.228	124.115	2.741	0.70%
mBin.Yr20Plus	541.702	142.630	3.798	0.02%
ComCust.LagDep(6)	0.653	0.054	12.040	0.00%
MA(1)	0.514	0.077	6.701	0.00%



Model Statistics	
Iterations	14
Adjusted Observations	132
Deg. of Freedom for Error	126
R-Squared	0.994
Adjusted R-Squared	0.993
AIC	10.953
BIC	11.084
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-904.20
Model Sum of Squares	1,067,928,115.58
Sum of Squared Errors	6,885,554.94
Mean Squared Error	54,647.26
Std. Error of Regression	233.77
Mean Abs. Dev. (MAD)	182.99
Mean Abs. % Err. (MAPE)	0.43%
Durbin-Watson Statistic	1.645

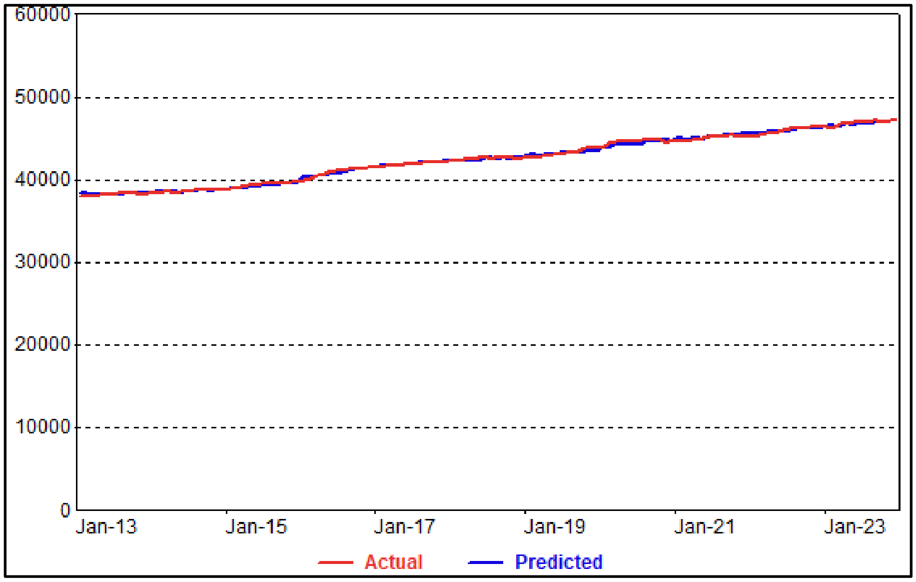
FIGURE 25: LARGE C&I SALES MODEL (MWH)

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	250.831	2.186	114.765	0.00%
mBin.Jan	9803.702	949.795	10.322	0.00%
mBin.Feb	7464.724	949.788	7.859	0.00%
mBin.Aug	3799.059	949.700	4.000	0.01%
mBin.Sep	3035.597	949.697	3.196	0.19%
mBin.Nov	5448.821	949.693	5.737	0.00%
mBin.Dec	10670.095	949.688	11.235	0.00%
mBin.Mar	2771.523	949.780	2.918	0.44%



Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	100
R-Squared	0.697
Adjusted R-Squared	0.676
AIC	15.799
BIC	15.997
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-998.36
Model Sum of Squares	1,556,285,476.89
Sum of Squared Errors	676,534,368.66
Mean Squared Error	6,765,343.69
Std. Error of Regression	2,601.03
Mean Abs. Dev. (MAD)	1,939.43
Mean Abs. % Err. (MAPE)	4.00%
Durbin-Watson Statistic	1.941

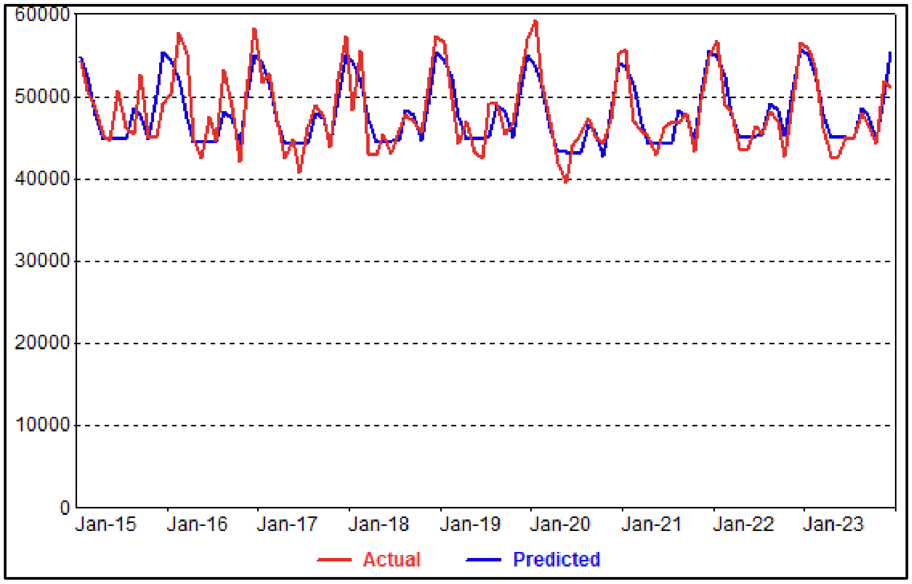
FIGURE 26: SMALL C&I CUSTOMER MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.ComVar	13768.471	2107.75	6.532	0.00%
mBin.Yr16Plus	862.041	128.072	6.731	0.00%
mBin.Yr19Plus	340.228	124.115	2.741	0.70%
mBin.Yr20Plus	541.702	142.63	3.798	0.02%
ComCust.LagDep(6)	0.653	0.054	12.04	0.00%
MA(1)	0.514	0.077	6.701	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	132
Deg. of Freedom for Error	126
R-Squared	0.994
Adjusted R-Squared	0.993
AIC	10.953
BIC	11.084
Log-Likelihood	-904.2
Model Sum of Squares	1,067,928,115.58
Sum of Squared Errors	6,885,554.94
Mean Squared Error	54,647.26
Std. Error of Regression	233.77
Mean Abs. Dev. (MAD)	182.99
Mean Abs. % Err. (MAPE)	0.43%
Durbin-Watson Statistic	1.645

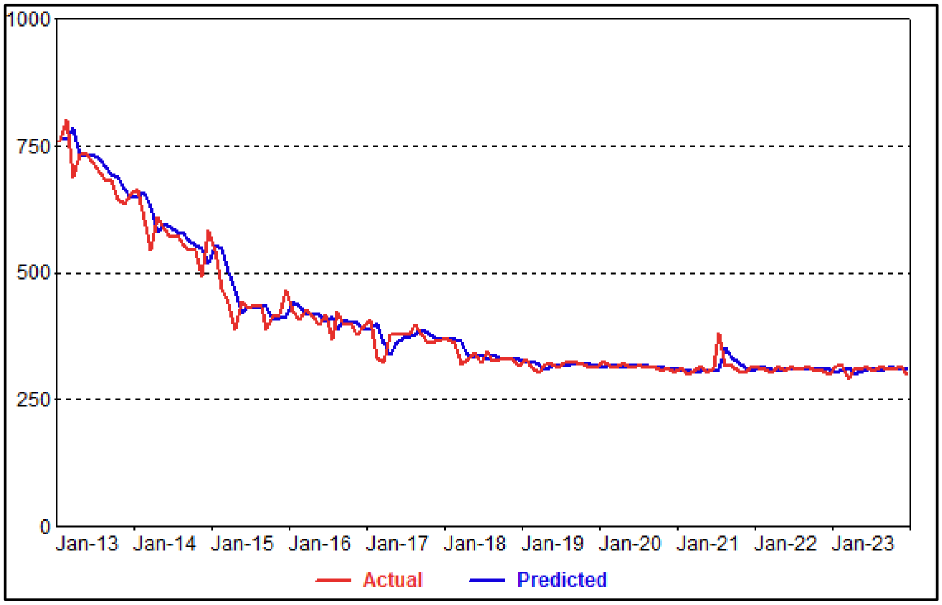
FIGURE 27: LARGE C&I SALES MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	250.831	2.186	114.765	0.00%
mBin.Jan	9803.702	949.795	10.322	0.00%
mBin.Feb	7464.724	949.788	7.859	0.00%
mBin.Aug	3799.059	949.7	4	0.01%
mBin.Sep	3035.597	949.697	3.196	0.19%
mBin.Nov	5448.821	949.693	5.737	0.00%
mBin.Dec	10670.095	949.688	11.235	0.00%
mBin.Mar	2771.523	949.78	2.918	0.44%

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	100
R-Squared	0.697
Adjusted R-Squared	0.676
AIC	15.799
BIC	15.997
Log-Likelihood	-998.36
Model Sum of Squares	1,556,285,476.89
Sum of Squared Errors	676,534,368.66
Mean Squared Error	6,765,343.69
Std. Error of Regression	2,601.03
Mean Abs. Dev. (MAD)	1,939.43
Mean Abs. % Err. (MAPE)	4.00%
Durbin-Watson Statistic	1.941

FIGURE 28: OTHER SALES MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.583	0.079	7.332	0

Model Statistics	
Iterations	11
Adjusted Observations	132
Deg. of Freedom for Error	131
R-Squared	0.959
Adjusted R-Squared	0.959
AIC	6.496
BIC	6.518
Log-Likelihood	-615.02
Model Sum of Squares	1,996,336
Sum of Squared Errors	86,115
Mean Squared Error	657.37
Std. Error of Regression	25.64
Mean Abs. Dev. (MAD)	16.36
Mean Abs. % Err. (MAPE)	3.94%
Durbin-Watson Statistic	1.997

Appendix D

VEGETATION BUDGET & ACTUALS

Maintenance Type	Total Miles	Total Acres	Miles Needing Trimming	Maintenance Cycle (Years)
Sub-Transmission	970.2	11721.1	194	5
Distribution				
Five (5) Year Cycle	1,321.4	n/a		5
Seven (7) Year Cycle	8,637.7	n/a		7
Total Distribution	9,959.1		1,498.3	

Budget

Type of Line Maintenance	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027
Sub-transmission	3,160,845	4,004,863	4,004,863	4,473,240	4,570,898	4,662,316
Distribution	14,841,672	15,145,808	15,240,023	16,955,129	15,674,760	15,988,255
Emeral Ash Borer	1,200,000	0	0	0	0	0
Budget Total	19,202,517	19,150,671	19,244,886	21,428,369	20,245,658	20,650,571

Actual

Type of Line Maintenance	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027
Sub-transmission	3,061,860	2,871,363	3,335,909	n/a	n/a	n/a
Distribution	14,978,511	17,621,107	16,388,093	n/a	n/a	n/a
Emeral Ash Borer	1,314,849	-5,078		n/a	n/a	n/a
Actual Total	19,355,220	20,487,391	19,724,002	n/a	n/a	n/a

Distribution Miles Trimmed	1,199	1,121	1,176	1,498	1,498	1,498
Transmission Miles Trimmed	194	244	209	177	189	194

Appendix E

RLC ENGINEERING STUDIES

RLC ENGINEERING

REPORT

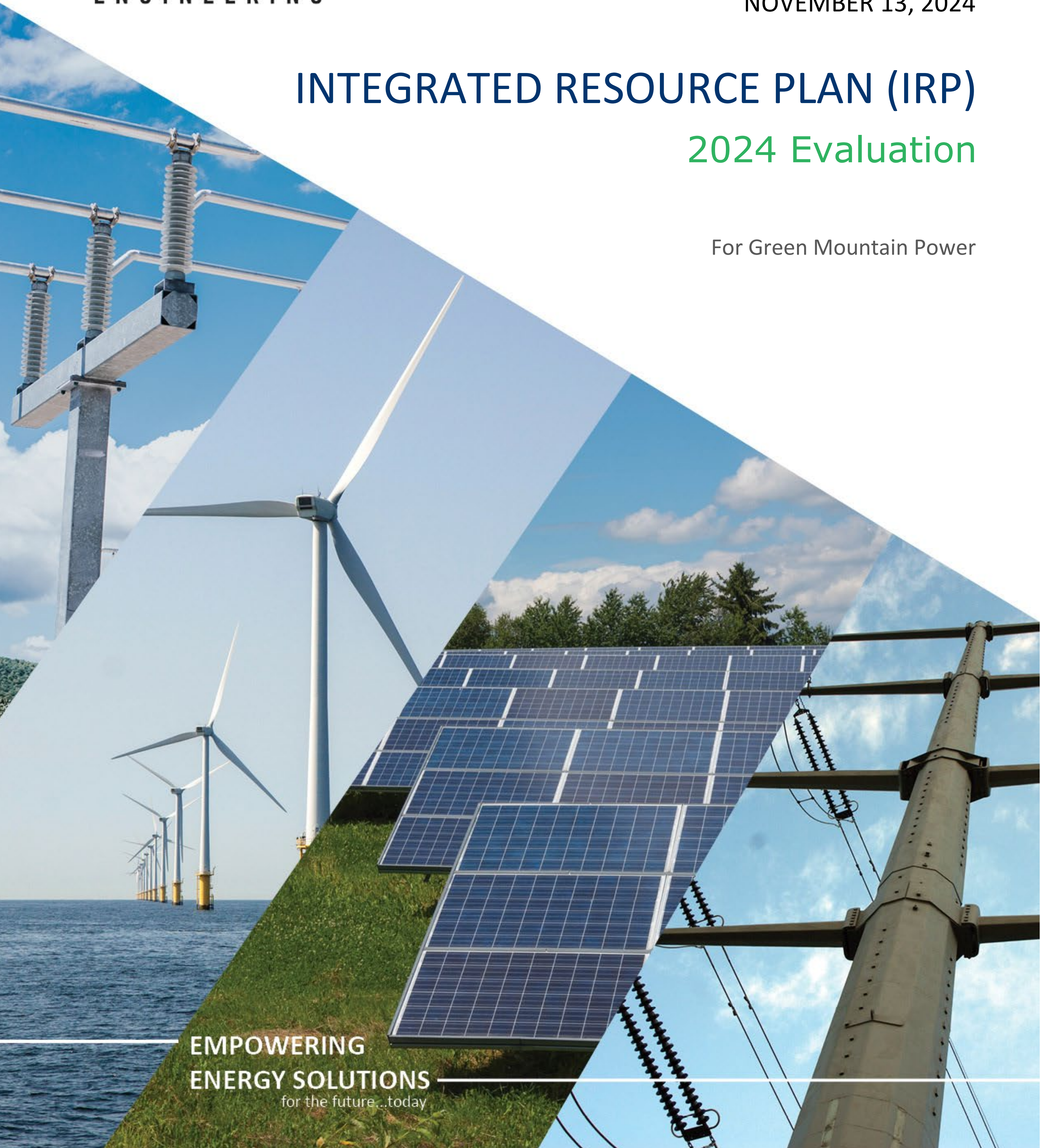
REVISION 1

NOVEMBER 13, 2024

INTEGRATED RESOURCE PLAN (IRP)

2024 Evaluation

For Green Mountain Power



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Revision History

Rev.	Date	Revised By	Reason
A	6/25/2024	DG/ALS/JTG/RCM	Original Draft Release
B	9/26/2024	ALS/DWG	Revised Draft Release
1	11/13/2024	DWG	CEII update

LEGAL NOTICE

EXECUTIVE SUMMARY

RLC Engineering, PLLC has conducted an Integrated Resource Plan (IRP) Study (the "Study") on behalf of Green Mountain Power (GMP). The Study represented the 2030 and 2035 model years and incorporated granular load forecast data as well beneficial electrification, including heat pumps and electric vehicles provided by GMP. The Study also evaluated Distributed Energy Resources (DER) forecasts including PV, Energy Storage, Hydro, and Wind.

The Study was separated into three (3) phases:

1. DER/Load Forecast Study and Sub-Transmission System Hosting Capacity Analysis
2. Distribution Time Series Analysis (10-Year)
3. Production Cost Analysis

The DER/Load Forecast Study and Sub-Transmission System Hosting Capacity Analysis included the following items:

- Power flow case development of GMP transmission system including load and DER forecasts
- Steady state voltage analysis (N-0 and N-1)
- Steady state thermal analysis (N-0 and N-1)
- Hosting capacity analysis
- Identification of energy storage siting opportunities

The Distribution Time Series Analysis (10-Year) included the following items:

- Power flow case development of ten (10) representative GMP distribution feeders including load and DER forecasts
- Time-based load and DER data processing
- Times series analysis
- Identification of solutions driven by load and/or DER growth

The Production Cost Analysis included the following items:

- Production cost modeling case development of GMP transmission system including load and DER forecasts
- Evaluation of energy performance and curtailment of DER projects for hosting capacity improvement purposes
- Identification of energy storage siting opportunities

The Study was performed in accordance with applicable Green Mountain Power, NERC, NPCC and ISO reliability standards.

1 DER/LOAD FORECAST STUDY & SUBTRANSMISSION ADDITIONAL HOSTING CAPACITY

1.1 Background

RLC conducted steady state and hosting capacity analyses on GMP's 2030 and 2035 transmission system using Siemen's PSS/E Version 34 and PowerGem TARA Version 2401.1 software packages.

The purpose of these analyses was to identify substations that have additional hosting capacity to allow GMP to meet Vermont's Tier 2 renewable energy goals of 150 MW solar photovoltaic (PV) without causing additional reliability violations on the sub-transmission system. The analyses included steady state N-0 and N-1 contingency analysis on the transmission 34.5 kV and above. The time series analysis was performed on a Bulk Electric System basis.

1.2 Study Area

1.2.1 Transmission System

The primary area of concern for this Study is Green Mountain Power service territory in Vermont. This consists of 46 kV and 34.5 kV networks, as well as the lower voltage distribution systems. Figure 1-1 provides a geographic representation of the Bulk Electric System in Vermont.

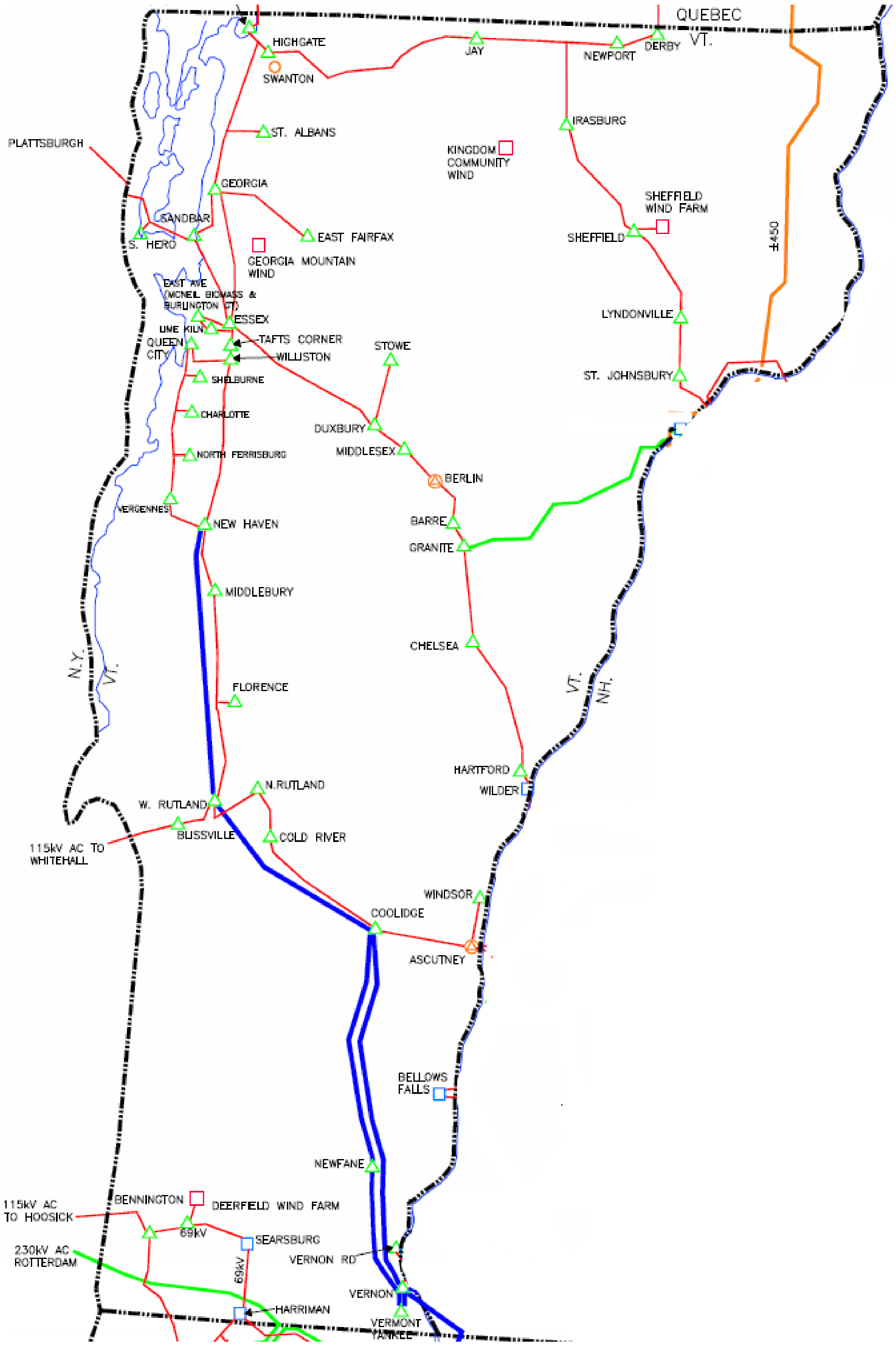


Figure 1-1: Geographic Diagram of the Vermont Area Bulk Electric System

1.3 Power Flow Base Case Development

1.3.1 Steady State Base Case Origin and Year

The summer and winter peak load PSS/E version 34 steady state cases originated from the 2024 VELCO Long-Range Transmission Plan Base Cases. The Spring Light load cases originated from 2022 VELCO Base Cases.

1.3.2 Model Years and Load Levels Studied

The Winter Peak Load, Summer Peak Load and Spring Light Load levels were evaluated for the 2030 and 2035 model years.

1.3.3 Load Forecasts

GMP provided the load forecast data, including electric vehicles and heat pumps for each station in the VELCO territory. The details of this load forecast can be found in Appendix B-1.

1.3.4 DER Forecasts

GMP provided the forecast data for distribution connected generation for each substation in the VELCO territory. An aggregation of each generation type (PV, BESS, hydro, wind) was modeled discretely for each substation. The forecast includes DER that is already connected, as well as future generation that is already in the planning or construction phases. A summary of the DER forecast used for this assessment is shown in Table 1-1. The details of this DER forecast can be found in Appendix B-2.

Table 1-1: GMP DER Forecast

Zone	2024 Existing <25 kW Solar	2024-2035 Forecasted < 25 kW Solar	2035 Total < 25kW Solar	2024 Existing >25 kW Solar	2024-23035 Forecasted > 25 kW Solar	2035 Total > 25 kW Solar	2024 Existing BESS	2024-2035 Forecasted BESS*	2035 Sum of BESS**
Ascutney	5.4	6.0	11.3	19.7	0.0	19.7	6.0	0.0	6.0
Burlington	25.2	25.7	50.8	57.6	0.0	57.6	6.5	0.0	6.5
Central	17.6	17.0	34.6	34.0	3.2	37.2	4.2	6.9	11.2
Florence	0.2	0.2	0.4	0.2	0.0	0.2	0.0	0.0	0.0
Johnson	0.3	0.4	0.7	0.2	0.0	0.2	0.0	0.0	0.0
Middlebury	9.9	5.9	15.8	31.6	0.0	31.6	0.9	5.0	5.8
Montpelier	11.3	12.4	23.7	23.9	11.9	35.7	6.7	0.0	6.7
Morrisville	2.6	2.9	5.5	2.4	0.0	2.4	2.4	0.0	2.4
Rutland	12.2	11.4	23.6	52.4	17.2	69.6	5.8	0.0	5.8
Southern	13.7	15.2	28.8	41.5	10.6	52.1	4.4	0.0	4.4
StAlbans	12.4	11.8	24.1	26.0	13.1	39.1	8.1	0.0	8.1
StJohnsbury	2.4	1.2	3.6	12.9	2.2	15.1	0.3	0.0	0.3
Total	**113.2**	**110.0**	**223.2**	**302.3**	**58.1**	**360.5**	**45.3**	**11.9**	**57.2**
*Utility-scale BESS only. Not including growth of GMP Program BTM or BYOD BESS									
**Existing GMP, BYOD, Utility-Scale, and forecasted Utility-Scale									

1.4 Power Flow Software Tools

Steady State analysis was performed using the Siemens PTI's PSS®E load flow software package, Version 34 and PowerGem TARA software, Version 2401.1.

1.5 Steady State Analysis Methodology

Steady state thermal and voltage analyses examined system performance and compared that against the performance criteria described below to determine where reliability needs exist and to identify localized areas that may already be export constrained.

1.5.1 Steady State Reliability Standards

This Study was performed in accordance with the following standards or criteria:

- NERC TPL-001-5 "Transmission System Planning Standard"
- NPCC Directory D-1 "Design and Operation of the Bulk Power Supply System"
- ISO New England Planning Procedure 3 (PP3), "Reliability Standards for the New England Area Bulk Power Supply System"

1.5.2 Steady State Solution Parameters

The steady state voltage contingency analysis was analyzed prior to and after equipment adjustments according to Table 1-2. The results of the two separate post contingency conditions was analyzed based on voltage criteria applicable to each condition.

Analysis prior to equipment adjustments ensures there are no instantaneous voltage concerns that may cause voltage collapse. Analysis after equipment adjustments ensures that load tap changer (LTC) adjustments are sufficient to maintain system voltages within applicable criteria. The steady state thermal performance assessment incorporates the solution parameters for the after equipment adjustment condition.

Table 1-2: Steady State Solution Parameters

Pre/Post Contingency	Area Interchange	LTC Taps	Discrete Switched Shunts	Continuous Control Shunts	Phase Angle Regulators	DC Taps
Pre-Contingency	Enabled	Stepping	Enabled	Enabled	Enabled	Enabled
Post-Contingency (Prior to Equipment Adjustment)	Disabled	Locked	Disabled	Enabled	Disabled	Disabled
Post-Contingency (After Equipment Adjustment)	Disabled	Stepping	Disabled	Enabled	Disabled	Disabled

1.5.3 Steady State Voltage Limits

Substation voltage levels must be maintained within a prescribed bandwidth to ensure proper operation of electrical equipment at both the transmission and customer voltage ranges. Equipment damage and widespread power outages are more likely to occur when transmission-level voltages are not maintained within pre-defined limits. Table 1-3 identifies the voltage criteria applied for the steady state voltage assessment.

Table 1-3: Steady State Voltage Criteria

<table>
<tr><th rowspan="3">Study Area</th><th rowspan="3">Voltage Level</th><th colspan="3">Bus Voltage Limits (p.u.)</th></tr>
<tr><th rowspan="2">Normal Conditions (Pre-contingency)</th><th colspan="2">Emergency Conditions (Post-contingency)</th></tr>
<tr><th>Prior to LTC Adjustment</th><th>Following LTC Adjustment</th></tr>
<tr><td rowspan="2">Vermont</td><td>345 kV and 115 kV</td><td>0.95 to 1.05</td><td>0.90 to 1.05</td><td>0.95 to 1.05</td></tr>
<tr><td>34.5 kV and 46 kV</td><td>0.95 to 1.05</td><td>0.90 to 1.05</td><td>0.90 to 1.05</td></tr>
</table>

1.5.4 Steady State Thermal Limits

New England electric utilities follow a planning philosophy whereby Normal thermal ratings shall not be violated under all-lines-in conditions, and the LTE thermal rating shall not be violated under contingency conditions. The use of LTE thermal ratings in planning studies recognizes the limited line switching, re-dispatch and system re-configuration options available to operators. Table 1-4 identifies the thermal criteria applied for the steady state thermal assessment.

Table 1-4: Steady State Thermal Criteria

System Condition	Maximum Allowable Facility Loading
Pre-contingency (All lines in)	Normal Rating
Post-Contingency	Long Time Emergency (LTE) Rating

1.5.5 Steady State Contingencies

N-1 contingency analysis examined a list of contingencies that includes contingencies from 34.5 kV to 345 kV relevant to the Vermont study area. The contingency list was provided by GMP and includes single element loss of lines, transformers, and generators for all transmission and sub-transmission voltage levels; as well as multiple element bus faults, double circuit tower, and breaker failure simulations for Bulk Electric System (BES) facilities.

1.5.6 Generation and Dispatch Assumptions

Several transmission and generation facilities are important to reliability in Vermont. The assumptions relevant to the Vermont study area are the Highgate HVDC facility and the various Phase Angle Regulating Transformers (PAR), which are shown in Table 1-5 with the generation dispatches shown in Table 1-6.

Table 1-5: Interface and Transmission Facility Transfers

Interface & Transmission Facility Transfers						
Interface/Generator	Spring Light 2030	Spring Light 2035	Summer Peak 2300	Summer Peak 2335	Winter Peak 2030	Winter Peak 2035
Interfaces						
ME-NH	1039	1039	1409	1409	1734	1754
Y138 (ME toward NH)	0	0	0	0	0	0
NORTH-SOUTH	895	933	2175	2058	3152	1956
EAST-WEST	341	344	278	413	1211	1437
WEST-EAST	-347	-351	-270	-407	-1178	-1408
NY-NE	-742	-791	614	605	-838	-853
HVDC Imports						
Sandy Pond HVDC	0	0	1500	1500	2000	2000
Highgate HVDC	225	225	225	225	225	225
Phase Angle Regulators						
PV-20 PAR	5	0	3	22	0	-1
Blissville PAR	0	0	0	0	0	0
Granite PARS	75	70	-150	-151	-189	-194

Table 1-6: Generation Dispatches

Generation Dispatch						
Generator	Spring Light 2030	Spring Light 2035	Summer Peak 2300	Summer Peak 2335	Winter Peak 2030	Winter Peak 2035
Wind						
Georgia Mountain Wind	10	10	0	0	4	4
Sheffield Wind	40	40	10	10	10	10
Kingdom Wind	54	54	16	16	15	15
Sears Wind	6	6	1	1	0	0
Deerfield Wind	30	30	8	8	10	10
Biomass/Wood						
JC McNeil Biomass	59	59	50	50	50	50
Ryegate Wood	21	21	19	19	21	21
Wind						
Coolidge PV	20	20	0	0	0	0
Larger Hydro						
Sheldon Falls Hydro	19	19	4	4	3	3
Harriman Hydro	0	0	14	14	27	27
Sears Hydro	0	0	0	0	0	0
Vernon Hydro	0	0	0	0	0	0
Bellows Falls Hydro	32	32	49	49	6	6
Wilder Hydro	0	0	39	39	6	6
Comerford	0	0	0	0	0	0
Moore	0	0	140	140	144	144
McIndoes	0	0	0	0	0	0
Smaller Hydro Totals						
S. Johnsbury Zone Hydro	3.6	3.6	0	0	0	0
Burlington Zone Hydro	12.6	12.6	1.8	1.8	0	0
Bedington Zone Hydro	7.5	7.5	0	0	2	2
Montpelier Zone Hydro	21.9	21.9	4.6	4.6	4	4
Morrisville Zone Hydro	5	5	1.3	1.3	1	1
Middlebury Zone Hydro	6.5	6.5	0	0	0	0
Rutland Zone Hydro	7	7	0	0	0	0
Ascutney Zone Hydro	1.2	1.2	0	0	0	0
St. Albans Zone Hydro	19.8	19.8	5	5	4.5	4.5
Central Zone Hydro	9.4	9.4	1.1	1.1	1	1
Florence Zone Hydro	18.8	18.8	3.7	3.7	1	1
Fast Starts (GTs & Diesels)						
GTs & Diesels	0	0	0	0	0	0

1.5.7 Incremental Hosting Capacity Determination

N-1 contingency analysis for each bus was determined using a multi-step process. The first step in the process was to determine the N-0 export capability for each bus. This was done by netting the load and generation to determine where the distribution transformer or a radial supply line was at or above capability. The second step was to determine the N-1 export capability for each bus. The objective was to determine the amount of additional capacity that could be added to each bus respecting BES level contingencies and the single element contingencies on the sub-transmission systems. The N-1 hosting capacity for each bus was determined using the TARA Transfer Limit Analysis tool (TrLim). The last two steps used TARA Security Constrained Re-Dispatch (SCRD) tool to identify hosting capacity on a zonal basis, then on an area wide basis.

- **Step 1** – Determine buses that already at or above the hosting capacity, based on distribution transformer capacity.
    - This was done by netting the load and generation at each bus and determine where the distribution transformer(s) are at or above the Normal rating.
    - This test determines which buses may be excluded from consideration for additional generation
- **Step 2** – Determine additional hosting capacity for each GMP load bus that was not excluded in Step 1.
    - The TARA Transfer Limit tool (TrLim) was used to determine the incremental capacity that could be added to each individual bus in the GMP area until N-0 or N-1 system conditions caused thermal violations on the sub-transmission system. Only Single element contingencies were evaluated.
    - The combination of Step 1 & Step 2 provide the hosting capacity for each single bus on a standalone basis.
- **Step 3** – Determine N-1 hosting capacity by zone.
    - The results from Steps 1 & 2 were used to determine hosting capacity (location and size) on a bus-by-bus basis, without regard for additional generation that may be added nearby. Step 3 modeled generators at each bus representing the bus by bus hosting capacity determined in steps 1 & 2.
    - The TARA Security Constrained Re-Dispatch (SCRD) tool re-dispatches (reduces) generation to optimize the dispatch to resolve thermal violations.
    - TARA SCRD was run with generators added to the case representing steps 1 & 2, one zone at a time. The SCRD tool reduced the output of the generation where needed to eliminate thermal violations, which equates to the zonal hosting capability.
- **Step 4** – Determine N-1 hosting capacity for the GMP system with results from step 3.
    - Step 4 modeled generators at each bus representing the zonal hosting capacities from step 3.
    - TARA SCRD was run, allowing all of the zones to optimize to resolve all of the thermal violations in the GMP area. The SCRD tool reduced the output of the generation where needed to eliminate thermal violations, which equates to the area-wide hosting capability.

1.6 Steady State Analysis Results

1.6.1 Steady State Contingency Analysis Results

Steady state thermal and voltage analyses examined system performance and compared that against the performance criteria. The contingency analysis results help show where areas are already export or import constrained. The export-constrained areas show where there is no additional hosting capacity available. At the peak load levels, the import-constrained areas show areas that would benefit by deployment of energy storage technologies.

1.6.1.1 Steady State Thermal Results

The following observations were made from the steady state thermal analysis of the sub-transmission system:

- There were thermal violations in the vicinity of the Ryegate and McNeil generating stations caused by generating levels of existing generation and increases of the forecast DER.
- The Summer Peak and Winter Peak load cases for 2030 and 2035 showed thermal violations that did not previously exist, likely caused by the addition of the Electric Vehicles, Heat Pumps, and Forecast DER.
- There were existing thermal violations that were made worse by the addition of the Electric Vehicles, Heat Pumps, and Forecast DER.

1.6.1.2 Steady State Voltage Results

The following observations were made from the steady state voltage analysis of the sub-transmission system:

- There were no low voltage violations in the light load cases
- The PV additions did not cause low voltage violations to get worse
- There were low voltage violations in the Summer and Winter Peak load cases that were made worse by the addition of the Electric Vehicles and Heat Pump loads.
- There were some high voltages in the light load case in the Poultney area that were caused by the addition of the forecast DER and made worse by the generation added from the hosting capacity analysis.

1.6.2 Steady State Incremental Hosting Capacity Results

The incremental hosting capacity analysis was performed using the methodology described in Section 1.5.7 on the light load cases. These cases started with the existing DG, forecasted DG that is < 25 kW, and Standard Offer Projects in service. The incremental hosting capacity investigated possible locations for additional future solar generation.

1.6.2.1 Step 1 – Distribution Transformers at/near Capacity

The first step in locating substations with additional hosting capacity is to determine the substations that are already at or above the distribution transformer export capacity. Table 1-7 lists the transformers that have flows above 80% of the transformer rating. The transformer flow represents the net export from the low side bus (generation minus load). These stations should be considered to have zero available hosting capacity.

Table 1-7: Transformers with Flows Above 80% Capacity

Station	From Bus	To Bus	ID	Zone	Zone Name	Normal Rating (MVA)	LTE Rating (MVA)	Base Flow (% Normal)
QUECHEE 12.5/46	109135	108246	1	842	Central	14	14	**166.4**
BAY STREET 12.5/35	109242	108555	1	712	St. Johnsbury	10.5	10.5	**131.0**
BRANDON_D1 12.5/46	109081	108410	1	802	Rutland	3.8	3.8	**113.4**
CASTLETON_D 12.5/46	109029	108477	1	802	Rutland	5.25	5.25	**101.9**
JAMAICA 12.5/46	108995	108523	1	822	Southern	7	7	98.6
WELLS RIVER 12.5/46	109129	108230	1	772	Montpelier	4.2	4.2	96.4
POWNAL_D 12.5/46	108983	108493	1	822	Southern	7	7	92.7
WEYBRIDGE_D 12.5/46	109099	108424	1	792	Middlebury	14	14	86.1
SHARON_D 12.5/35	109115	108859	1	842	Central	10.5	10.5	84.2
BRADFORD 12.5/46	109125	108216	1	842	Central	7	7	84.1

1.6.2.2 Step 2 – Determine Incremental Hosting Capacity for Each Bus on Standalone Basis

The second step in determining the system wide hosting capacity was to utilize the TARA Transfer Limit tool (TrLim) to determine the incremental capacity that could be added to each individual bus in the GMP area until N-0 or N-1 system conditions caused thermal violations on the sub-transmission system. The excluded buses from Step 1 and the transfer limit results from Step 2 provide the hosting capacity for each single bus on a standalone basis. There were locations that GMP reduced/eliminated from consideration based on knowledge of the area and/or transmission system. The total hosting capacity from steps 1 & 2 was approximately 765 MW. The transfer limit results testing results are located in Appendix D.

1.6.2.3 Step 3 – Determine Incremental Hosting Capacity for Each Zone

The third step in determining the system wide hosting capacity was to utilize the TARA SCRD tool to optimize the dispatch by zones to prevent thermal violations for N-0 and N-1 system conditions. SCRD optimizes the dispatch to resolve the sub-transmission constraints that would caused by the addition of generation from step 2 within each zone. Generators with capabilities from step 2 of the hosting capacity analysis were added to the base cases. The total hosting capacity from step 3 was 373 MW.

1.6.2.4 Step 4 – Determine Incremental Hosting Capacity for the GMP Area

The fourth step in determining the system wide hosting capacity was to utilize the TARA SCRD tool to optimize the dispatch for all GMP zones to prevent thermal violations for N-0 and N-1 system conditions. Generators with capabilities from step 3 of the hosting capacity analysis were added to the base cases. SCRD optimized the dispatch to resolve the sub-transmission constraints that would caused by the addition of generation from step 3 from all of the GMP zones simultaneously.

The remaining Tier 2 renewable goal objective is 150 MW. The total hosting capacity from step 3 was 373 MW. RLC and GMP decided to reduce the final portfolio of generation to 250 MW in order to provide some margin above the required 150 MW when siting PV, to minimize the inter-zonal impact, and reduce the number of reliability violations caused by the additional generation. This reduction was accomplished by reducing the following zones to 62% of the step 3 capacities: Rutland (Zone 802), Ascutney (Zone 812), Southern (Zone 822), and Central (Zone 842). The 250 MW was added to the cases and analyzed with SCRD to ensure that none of the proposed generation portfolio was reduced further. A summary of the incremental and total hosting capacity is shown in Table 1-8The detailed hosting capacity results are located in Appendix D.

Table 1-8: Summary of Incremental & Total Hosting Capacity

Zone	Total Existing Solar	Total Forecasted Solar (net-metered and utility-scale)	Additional Solar for Tier II from Step 4)	Optimized Forecasted Solar (from Step 3)	Total Solar Hosting Capacity (Interconnected + Forecasted, Level Tested to meet Tier II Goals from step 4)	Total Optimized Solar Hosting Capacity (Interconnected + Forecasted + Optimized from step 3)
Ascutney	25.1	6.0	34.2	55.2	65.2	86.2
Burlington	82.7	25.7	8.8	8.8	117.2	117.2
Central	51.7	20.2	21.2	21.2	93.1	93.1
Florence	0.4	0.2	0	0	0.6	0.6
Johnson	0.6	0.4	0	0	0.9	0.9
Middlebury	41.5	5.9	11	11	58.5	58.5
Montpelier	35.2	24.3	4.2	4.2	63.6	63.6
Morrisville	5.0	2.9	0	0	7.9	7.9
Rutland	64.6	28.5	49.9	80.5	143.1	173.7
Southern	55.2	25.8	119.5	192.8	200.4	273.7
StAlbans	38.4	24.9	0	0	63.3	63.3
StJohnsbury	15.2	3.4	0	0	18.7	18.7
Total	**415.5**	**168.1**	**248.8**	**373.7**	**832.4**	**957.3**

The following observations were made during the analysis:

- Although there was interaction between generation levels in the different zones, it was less than expected. Allowing SCRD to optimize the generation in all GMP zones resulted in a small reduction in total hosting capacity from step 3.
- SCRD reduced a significant amount of generation in some zones and very little in other zones. This analysis helps identify the better areas of the GMP service territory to site new PV generation to meet the Tier 2 objectives.
- There were 115 kV contingencies that removed west to east transmission paths and caused SCRD to reduce generation in the Montpelier, Burlington, Middlebury and Morrisville zones to prevent thermal violations. Sensitivity analysis was performed to check the impact of other resources, such as Highgate and the flows on the Granite PARs. Reducing flow on Highgate and adjustment of the Granite PARs to reduce west to east transfer will restore some additional capacity in these four zones.
- There were sub-areas that are supplied by a series of 34.5 kV or 46 kV lines. The loss of one end of these lines forces all of the generation to export from the other end of the loop, which can limit the amount of generation added in these sub-areas. The following contingency and limiting element pairs will limit the amount of generation that can be added in these sub-areas.
    - Loss of 34.5 kV Line 3331 between Middlesex and Bolton Falls causes thermal violations on 34.5 kV Line 3302 between Sand Road and Essex.

- Loss of 46 kV Line L-33 between Newfane and East Jamaica causes thermal violations on the 46 kV Line L-18 between Bromley and East Arlington.
    - Loss of the Stowe 115/34.5 kV Transformer causes thermal violations on the 34.5 kV Line 3312 between Little River and Middlesex.
    - Loss of Blissville 115/46 kV Transformer causes 46 kV Line L-44 between Hydeville and W. Rutland and 46 kV Line L-47A between Poultney and Hydeville.
    - Loss of the 115/34.5 kV Barre Transformer causes thermal violations on the 34.5 kV Line 3325 between Montpelier and Berlin. This contingency does not leave the 3325 line radial like the ones listed above.
- In order to allow SCRD to function properly, some contingencies and/or limiting facilities were excluded from the SCRD process. The following lines were excluded in the SCRD process:
    - There were lines that were overloaded due to generation additions near the McNeil generator. These lines were excluded from the SCRD process to prevent SCRD from reducing McNeil or other nearby generation to be conservative.
    - There were lines that were overloaded due to generation levels at Ryegate Wood, Ryegate Falls, McIndoes, and in nearby New Hampshire. These lines were excluded from the SCRD process to prevent SCRD from reducing generation to be conservative.
    - Contingencies involving 115 kV K23 and K27 were excluded. There is a Remedial Action Scheme that will open 34.5 kV lines to prevent thermal overloads following either of these contingencies. TARA does not have Remedial Action Scheme functionality while running SCRD. Excluding these contingencies from SCRD prevents SCRD from reducing generation to resolve thermal violations that would not exist due to the Remedial Action Scheme.
    - Non GMP sub-transmission lines were excluded (all, not just SCRD) to prevent SCRD from reducing the generation for violations in other areas.

The hosting capacities described from the results above were used to create a map of the total hosting capacities for the GMP Service territory, as shown in Figure 1-2.

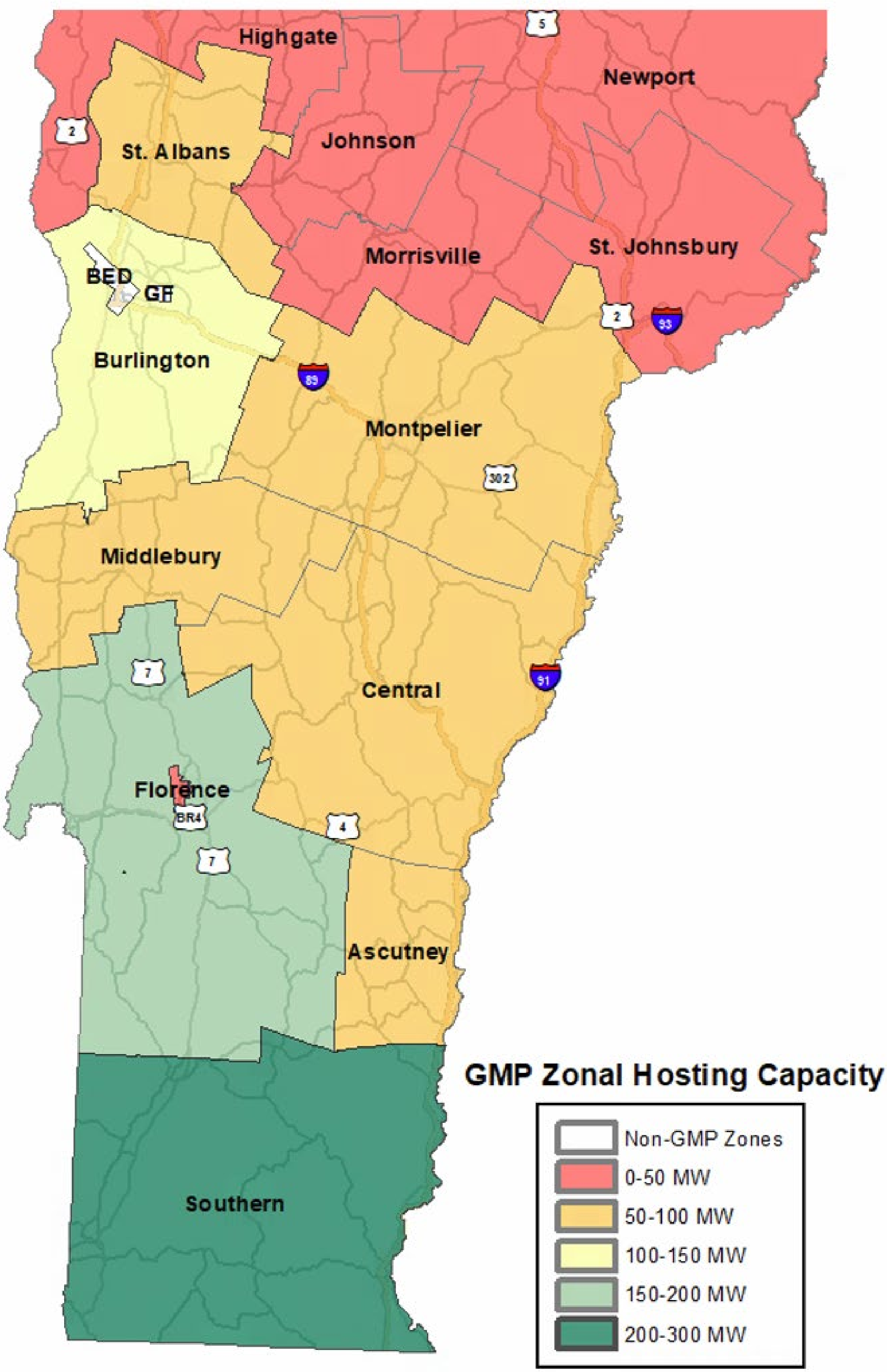


Figure 1-2: Geographic Map with Hosting Capacity

1.6.3 Deployment of Energy Storage to Increase Reliability or Defer System Upgrades

The steady state contingency analysis showed sub-areas where the load that was represented in the summer and winter peak load cases cause low voltage violations. The winter and summer peak load hours both occur well after the time of day when PV generation can be relied upon. Substations in these pockets would be ideal locations to site energy storage facilities, since they could be relied upon to offset higher loads during peak hours.

2 DISTRIBUTION TIME SERIES ANALYSIS (10-YEAR)

2.1 Background

RLC conducted a time series analysis on GMP's distribution system under existing (2024) and 10-year (2035) scenarios using Eaton's CYME distribution analysis software. Note that 2024 models were provided and scaled to 2035 scenarios based on data and assumptions provided by GMP.

The purpose of this analysis was to determine how extreme load growth due to electrification and DER growth based on GMP forecasts could impact the net load profile across various distribution feeders. From this point, issues arising from the aggregate effects were observed and solutions that could be strategically employed to mitigate these issues were explored. The end result of the analysis was a set of guidelines that could be used by GMP in future scenarios to mitigate similar issues.

2.2 Study Area

In lieu of modeling all of GMP's distribution feeders, the following ten (10) feeders were chosen by GMP to be analyzed:

1. Bay Street G4 (Bay-G4)
2. Castleton G37 (CA-G37)
3. Pleasant Street G43 (PS-G43)
4. Queen City 32G8 (32G8)
5. Sand Hill Road 33G2 (33G2)
6. Sharon G35 (SH-G35)
7. South Shaftsbury G20 (SF-G20)
8. Vergennes 9G4 (9G4)
9. West Milton G92 (WM-G92)
10. Windsor G31 (WI-G31)

Note that these feeders were intended to be representations of GMP's distribution system such that results and insights gained could be applied to other, similar feeders in future cases.

2.3 Distribution Modeling

The CYME models corresponding with the ten (10) feeders listed in Section 2.2 were provided by GMP. RLC validated and made necessary modifications to each model to optimize accuracy via QA/QC process, which covered the following topics:

- Substation (transformer ratings, voltage regulation, and fault contributions)
- Conductors (phase, neutral, and spacing properly assigned across feeders)
- Loading (peak and minimum loading values with corresponding capture dates)
- Generation (large and small generator output values, types, and operation)
- Voltage control (LTC, regulator, and/or capacitor ratings and operation)
- Protection (fuse, breaker, and/or recloser ratings and operation)

Loading and generation magnitudes for each feeder can be seen in Table 2-1.

Table 2-1: Representative Feeder Loading and Generation Magnitudes

Feeder	Peak Load (kW)	Minimum Daytime Load (kW)	Minimum 24 Hour Load (kW)	Generation (kW)
Bay-G4	4,186	1,504	1,142	4,646
CA-G37	2,822	1,130	206	7,200
PS-G43	3,170	1,386	905	1,497
32G8	3,494	1,231	817	216
33G2	2,934	1,300	963	2,243
SH-G35	1,890	764	586	9,561
SF-G20	4,183	1,036	901	4,548
9G4	4,768	1,909	1,791	8,108
WM-G92	4,694	1,462	1,258	1,906
WI-G31	4,515	2,035	1,384	8,204

For visualization purposes, these values are also displayed in Figure 2-1.

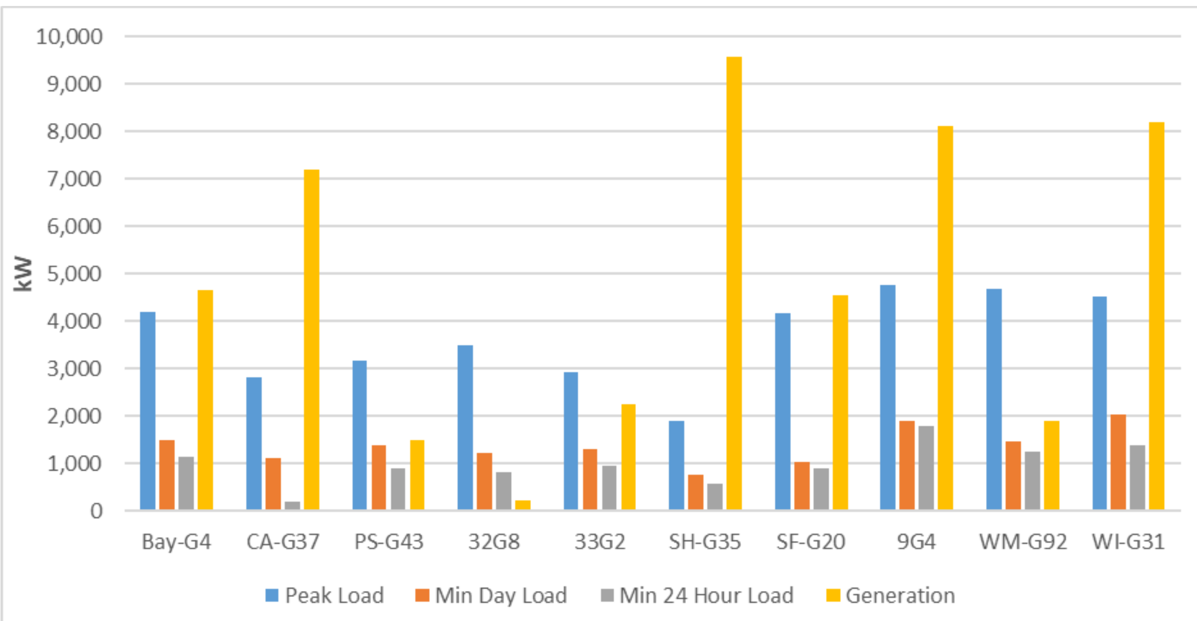


Figure 2-1: Representative Feeder Loading and Generation Chart

As shown, the representative feeders provide a varying mix of loading and generation characteristics.

Note that CYME feeder loading was allocated based on SCADA loading (MW and MVAR). Some feeders may have had incomplete data, requiring scaling adjustments based on available online DER in the Advanced Metering Infrastructure (AMI) data for proper native load extraction. SCADA scaling used data from the same time entry as the peak AMI data and feeder allocation was based on substation coincident peak AMI loading.

2.4 Time Series Analysis Modeling

The time series analysis was conducted using CYME's Long Term Dynamics module in order to evaluate time-based performance, load and generation coincidence, potential criteria violations, and corresponding mitigation solutions. The models discussed in Section 2.3 were utilized and GMP provided interval data for the following:

- Existing load
- Existing DER
- New electrification loads
    - Heat pumps
    - Electric vehicles
    - Tesla Powerwalls

Methods and assumptions used to process this data for use with Long Term Dynamics are detailed in the following subsections. It should be noted that this evaluation was intended to analyze highly conservative electrification scenarios rather than actual forecast data with the purpose of evaluating representative feeder suitability for these scenarios.

2.4.1 Data Normalization

All data were normalized around CYME intervals. This approach standardized the time series data to ensure forecasts were consistently represented.

- **Interval Definition**: Every 15-minute interval of the year was considered, resulting in 35,040 intervals.
    - Example: January 1st at 00:00 corresponds to interval 0, while December 31st at 23:45 is interval 35,039.
- **Data Alignment**: If the data did not start at the beginning of a year, the latest full year's worth of data was used.
- **Leap Year Adjustment**: As 2024 is a leap year, February 29th data was removed from both historical and GMP-provided data to ensure easier comparison with 2035.

2.4.2 Load Curve Modeling

The existing load data, which represented the current-day demand across the network, was processed and modeled such that the baseline native load profile would be consistent with 2035 forecast data.

- **Modeling Scope**: Not all feeders per substation were included in CYME. For unmodeled feeders, aggregate spot loads were added to evaluate substation flows.
- **8760 Evaluation**: This was based on the percent of peak AMI kW flows for each feeder.
    - The complete 2023 AMI dataset was used for each applicable circuit's load profile.
    - The profiles were scaled to 2024 values based on the percent of peak in 2023, with each 2023 AMI entry used for scaling.
- **2035 Forecasting Curves**: These curves were developed by adding together the following load curves:

- Base Load Curve**:** Derived from the 2024 curve and scaled according to the load forecasting "base load" increase from 2024 to 2035 determined in the Section 1 analysis.
- Heat pump, electric vehicle, and Powerwall Load Curves**:** Created as per customer kW as described in their respective sections below, then multiplied by feeder customer count and the 2035 "% of customer use" scaler.
  - The "% of customer use scaler" was applied to scale different scenarios, such as 100% of customers adopting heat pumps and electric vehicles, but only 25% adopting Powerwalls.
  - If customer count was unknown for unmodeled feeders, it was estimated based on the ratio of load to kW per customer of the feeder with known values.

2.4.3 DER Curve Modeling

DER data (primarily PV) was processed and modeled such that historic/realistic generation profiles were represented in 2035 forecast data.

- **Modeling Scope**: Similar to load data, not all feeder generation per substation was included. For unmodeled feeders, aggregate DER was added to evaluate substation flows.
- **8760 Evaluation**: This was based on the percent of peak AMI kW flows for each feeder.
  - The complete 2023 AMI dataset was used for each applicable circuit's aggregate DER profile.
  - The profiles were scaled to 2024 values based on the percent of peak in 2023, with each 2023 AMI entry used for scaling.
- **DER Modeling**: If a feeder was modeled, it was checked for consistency with peak AMI measured values. If not, a DER was added to match the peak AMI measured value.
  - Unmodeled feeder DERs were scaled to ensure that the total substation generation matched the forecasted total DER per substation.
  - In CYME, DER cannot be scaled beyond the specified inverter capacity. For scaling beyond 100% in the 2035 case, inverter capacities of all DERs were set to 10 MVA/MW using automation techniques.
  - The nominal output was not changed, so 100% of the original peak remained as the set value.
- **2035 Forecasting Curve**: The 2024 curve was used as a base, scaling it according to the ratio of 2024 to 2035 total DG per substation determined in the Section 1 analysis.
  - Planned large DER projects were manually added to the model for the 2035 scenario and their capacity was removed from the 2035 scaler.
- **Feeder DER Scaling**: Scaling each feeder's DER by feeder curves is a complex process within the Long Term Dynamics simulation parameters.
  - Each DER's specified LTD curve was aligned with its feeder curve using automation techniques.
  - Separate 2024 and 2035 DER models were added to change all DER curves simultaneously for the simulations via CYME's Advanced Project Manager interface.

2.4.4 Heat Pump Load Data Processing

Heat pumps represent a growing load on the electric grid, especially as more customers replace traditional heating and cooling sources with this technology. The analysis considered their impact on the 2035 load profile.

- **Data Coverage**: Forecast data was provided for the years 2023 through 2043, with the years 2024 and 2035 specifically evaluated. Note that 2024 data was used as a reference point and not included in the forecasting process.
- **Data Processing**:
  - The entire GMP customer heat pump aggregate load was provided in MW.
  - Separate GMP data was used to derive per-customer load in kW based on the aforementioned aggregate value.
  - Hourly load data was linearly interpolated to create 15-minute intervals for data normalization purposes.
  - In some cases, annual data represented load growth due to additional customers installing heat pumps. In order to properly normalize this data, scale factors were utilized such that load curves were accurately represented.

The per customer heat pump load curve resulting from this data processing can be seen in Figure 2-2.

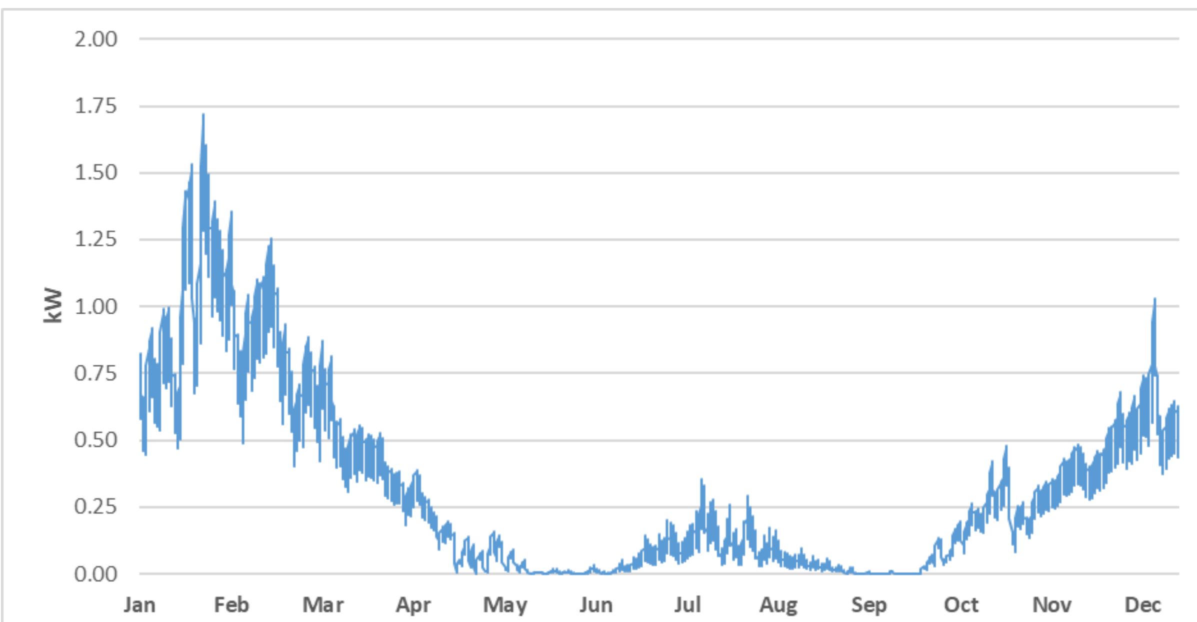


Figure 2-2: Per Customer Heat Pump Load Curve

2.4.5 Electric Vehicle Load Data Processing

The adoption of electric vehicles (EVs) introduces a significant variable in load forecasting. The analysis accounted for the additional load from EVs and projected future growth in EV adoption.

- **Data Coverage**: Forecast data was provided for July 1st, 2023 through to June 30th, 2024. Therefore, assumptions were required for 2035 forecasting and scaling.
- **Data Processing**:
    - The EV data was provided in MW for the entire customer base and was converted to kW per customer by simple division.
    - The data was provided in 5-minute intervals and was converted into 15-minute intervals by extracting the maximum value within each 15-minute block.
    - Some data gaps were present, so missing points were filled using linear interpolation between known values.
    - The customer count was only available for the latest few months of the data. A linear extrapolation was used to estimate customer growth for data normalization purposes.

The per customer EV load curve resulting from this data processing can be seen in Figure 2-3.

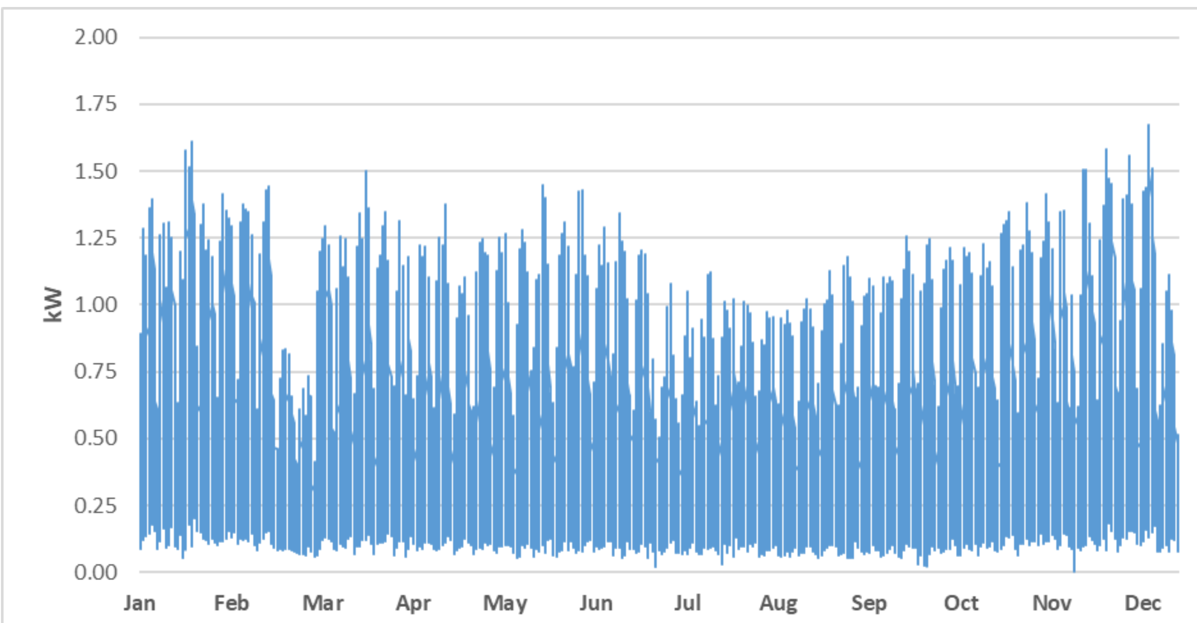


Figure 2-3: Per Customer EV Load Curve

2.4.6 Tesla Powerwall Load Data Processing

Tesla Powerwalls represent a unique load and generation resource, with the ability to store energy and provide it back to the grid. The analysis took into account the behavior of these battery systems, particularly their impact on peak loads and daily flow patterns.

- **Data Coverage**: 15-minute interval data was provided from July 18th, 2023 to July 18th, 2024. Therefore, assumptions were required for 2035 forecasting and scaling.
- **Data Processing**:
  - The Powerwall data was provided in MW for the entire customer base and was converted to kW per customer by simple division.
  - Aggregate Powerwall load growth was observed over the year, without consideration for customer count. To normalize per customer kW values, linear extrapolation was utilized per a few known data points.
  - The normalized customer kW flows resulted in more consistent peak flows, although the average daily flows appeared reduced as customer count increased. This may be due to the manufacturer limiting the average flows per unit as the total unit count increased; however, GMP does not have visibility on these control algorithms.

The per customer Powerwall load curve resulting from this data processing can be seen in Figure 2-4.

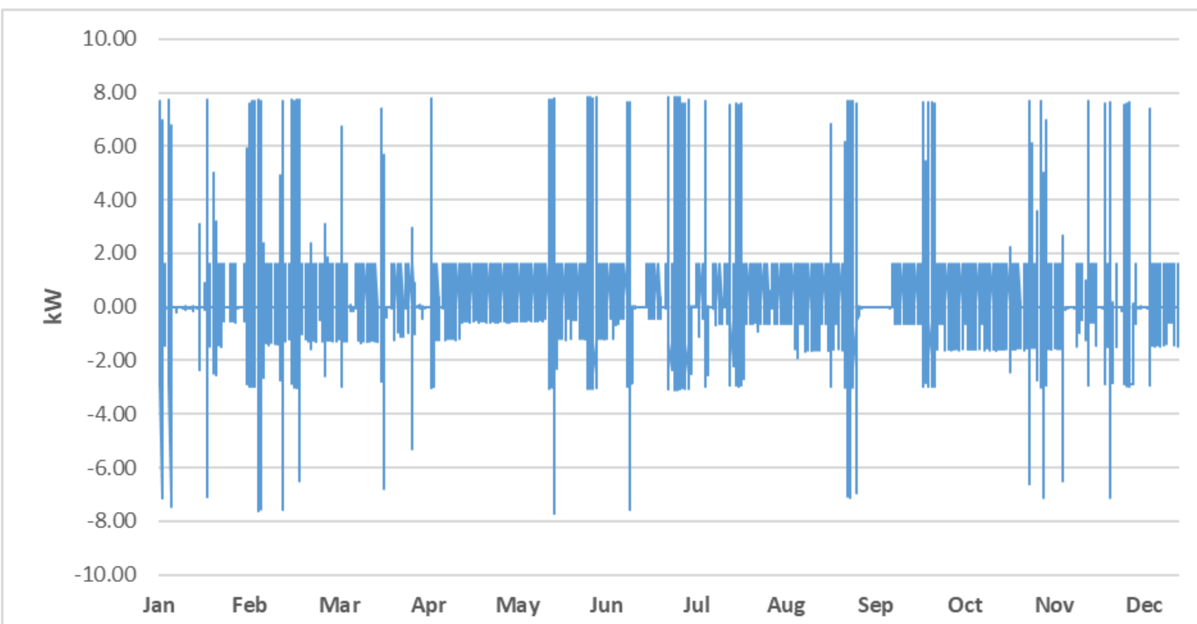


Figure 2-4: Per Customer Powerwall Load Curve

2.4.7 New Electrification Load Profiles

With the new electrification load profiles established in Sections 2.4.4, 2.4.5, and 2.4.6, a combination curve with all three (3) profiles included was created for informational purposes. This can be seen in Figure 2-5.

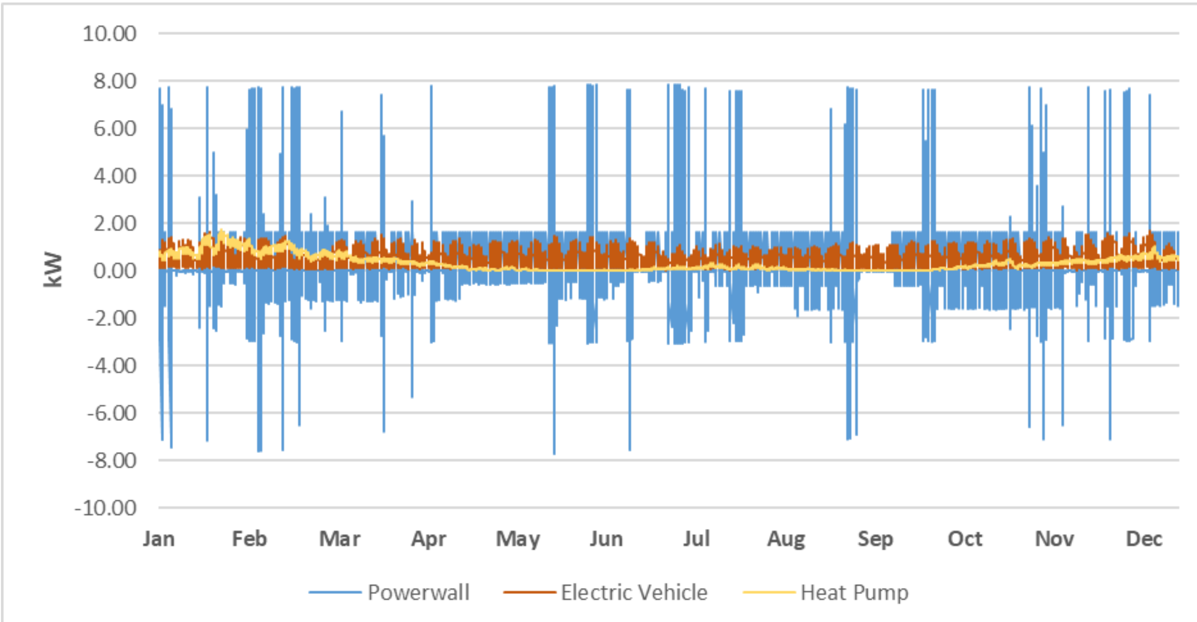


Figure 2-5: New Electrification Load Curves

As shown, the Powerwall curve exhibits load magnitudes very large relative to the EV and heat pumps curves. This behavior is explored further in Section 2.5.

It should be noted that this representation is highly conservative. Currently, Powerwalls are being used to lower transmission peak Regional Network Services (RNS) and Forward Capacity Market (FCM) charges while ensuring that there are no resulting local distribution overloads. However, GMP plans to refine dispatch strategies in the future as electrification loads increase and/or DER penetration becomes more prevalent such that overloads are prevented and load profiles are levelized rather than exacerbated.

2.4.8 Forecasted 2035 Load Curve Profile

With the components of the forecasted 2035 load curve established in Section 2.4.2, and the new electrification load profiles shown in Section 2.4.7, a total combined 2035 load curve was developed and used for the time series analysis.

Once all the 2035 curve was developed for all of the evaluated feeders, a trend emerged where the new feeder peak load was on 2/3/2035 around the time of 18:00. To better understand what factors were contributing to this new winter peak load period, a twenty-four (24) hour profile of this day on the WI-G31 feeder was created for informational purposes. This can be seen in Figure 2-6.

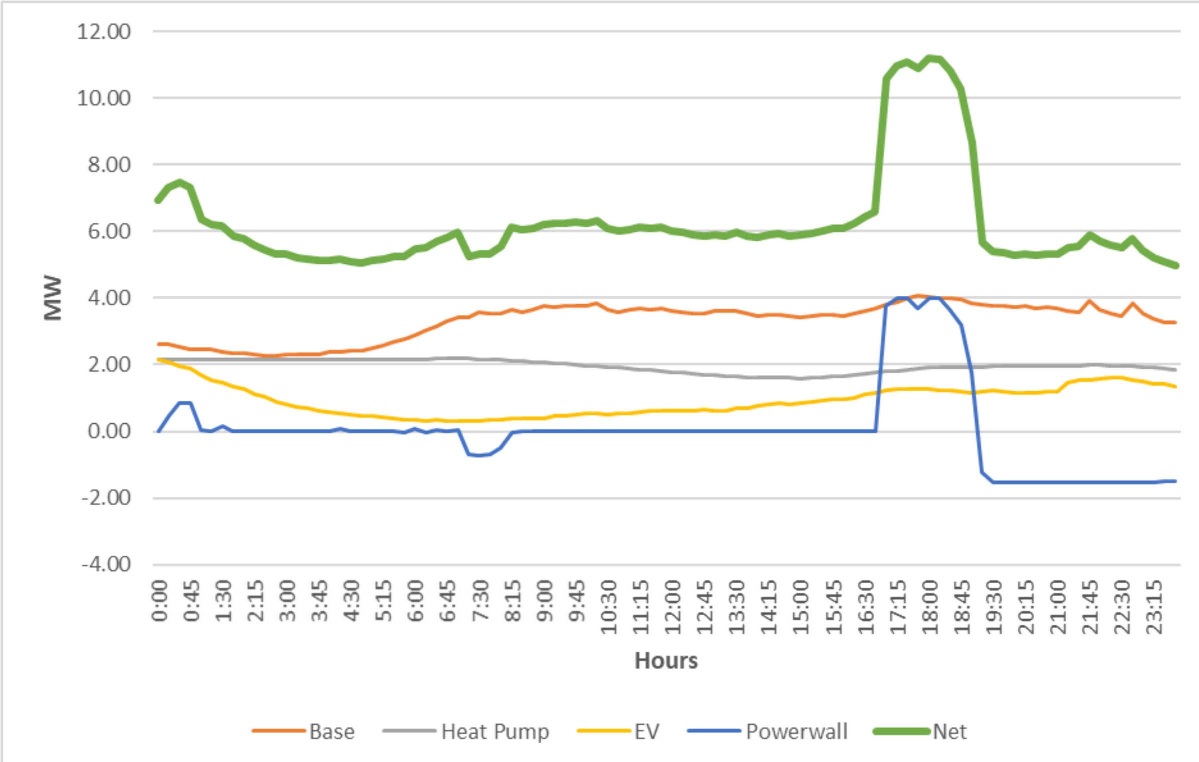


Figure 2-6: WI-G31 Forecasted 2035 Load Curve

As shown, the peak event is not sustained throughout the day and instead, is significantly influenced by the Powerwall curve. This tracks with Figure 2-5, where the Powerwall curve has a much greater magnitude in comparison to the EV and heat pump curves.

At 17:45 in Figure 2-6, the base load curve was 36.0% of the total (11.18 MW), the heat pump curve was 17.1%, the EV curve was 11.4%, and the Powerwall curve was 35.6%. Disregarding the heat pump and EV curves, the Powerwall curve alone almost doubled the total load on the feeder. Additionally, the total generation output on this feeder was 64 kW at this time, or 1.4% of the total generation capacity on G31.

In this winter peak load day example, the Powerwall curve added significant load to the grid during the evening hours when the PV contribution was negligible. As previously mentioned, the observed load coincidence and corresponding violations are counterintuitive if the Powerwall is used as a dispatchable resource. Therefore, it is imperative that these resources are dispatched intelligently. This is discussed in further detail in Section 2.5.2.

Additionally, heat pump and EV load diversification via time of use and/or intelligent control has the potential to result in less significant per customer load increases as compared to simply considering the maximum ratings of the respective units. For example, each load may result in 0.8 kW to 1.5 kW per customer when coincidence is factored in rather than 7 kW per EV charger, etc.

2.5 Time Series Analysis Results

With CYME distribution modeling established and inputs to the Long Term Dynamics module processed, time series simulations were run to evaluate circuit loading and performance in the presence of the load and DER growth discussed in Section 2.4. Both 2024 (existing system) and 2035 (10-year forecast) scenarios were evaluated in order to provide insight into how significant electrification could impact the GMP distribution system.

Full time series results from the ten (10) representative feeders can be found in Appendix E.

2.5.1 Representative Feeder Results Summary

2024 and 2035 scenarios were simulated and analyzed for the ten (10) representative feeders based on previously established modeling methodologies. Observations gained from the analysis can be seen in Table 2-2.

Table 2-2: Distribution Time Series Analysis Results Summary

Feeder	2024				2035				Limiting Device
	Max %	Max % Date	Flow Direction	% Time Over	Max %	Max % Date	Flow Direction	% Time Over	
Bay-G4	67.7%	5/14 13:45	Reverse	0.0%	174.8%	2/3 18:15	Forward	2.5%	Sub XFO (10.5 MVA)
CA-G37	53.6%	5/14 15:00	Reverse	0.0%	120.1%	2/3 18:00	Forward	0.1%	Sub Reg (328 A)
PS-G43	33.1%	1/15 17:30	Forward	0.0%	122.6%	1/18 18:00	Forward	0.2%	Feeder Reg (437 A)
32G8	49.9%	9/7 13:30	Forward	0.0%	76.9%	2/3 17:30	Forward	0.0%	Sub XFO (22.4 MVA)
33G2	39.0%	9/6 20:00	Forward	0.0%	119.4%	2/3 18:00	Forward	0.1%	Sub Reg (328 A)
SH-G35	87.8%	5/13 12:15	Reverse	0.0%	142.5%	1/23 22:00	Forward	1.8%	Sub Reg (437 A)
SF-G20	68.7%	7/27 12:00	Forward	0.0%	207.0%	2/3 18:15	Forward	5.6%	Sub XFO (6.25 MVA)
9G4	74.9%	10/9 12:30	Reverse	0.0%	124.2%	2/3 18:00	Forward	0.4%	Sub XFO (14 MVA)
WM-G92	80.1%	7/6 20:15	Forward	0.0%	161.2%	2/2 18:15	Forward	3.5%	Sub XFO (10.5 MVA)
WI-G31	87.2%	9/7 19:30	Forward	0.0%	217.2%	2/3 18:00	Forward	15.8%	Sub XFO (12.5 MVA)

As shown, load and DER growth impacted the various representative feeders in different ways. One important point to note is that in this analysis, all feeders became winter-peaking in 2035 due of the nature of the added electrification loads (heat pumps, EV's, and Powerwalls). Additionally, as noted in Section 2.4.8, the majority of feeders experienced the peak load on 2/3/2035 at around the time of 18:00 in which the Powerwall curve was a significant contributor to the total load.

An example of this shift in characteristics would be the CA-G37, which previously exhibited higher DER nameplate magnitudes than peak load magnitudes, thus leading to peak 2024 substation loading due to reverse flow (generation) during light load periods. With the conservative electrification load assumptions in place, however, this feeder and its associated thermal loading becomes driven by load under winter peak conditions.

It should be noted that even with the conservative forecasting considerations, not all substations experienced violations. Substations such as Queen City, with a large substation transformer (22.4 MVA), and feeders with large regulators (437 A) and mainline conductor (395 A) were able to host all additional forecasted load. Note that 32G8 had the largest commercial customer capacity of the evaluated feeder and the smallest amount of DER.

2.5.2 Solutions and Guidelines

Solutions to criteria violations are likely to be situational and must be determined on a case-by-case basis. However, the following general conclusions and guidelines can be extracted from the results of this analysis:

- Powerwall contributions played the largest role on the net load profiles and corresponding loading violations, which was primarily due to the conservative coincidence factor assumption of the associated loads. Should GMP experience this level of Powerwall penetration in the future, it is imperative that the loads are monitored, controlled, and managed properly across the respective distribution feeders such that the end result is load levelization rather than extreme spiking of magnitudes, as observed in this analysis. Heat pump and EV load management would also contribute to this effect.
- Spot BESS installations – often coined "Solar Soakers" – can be promising non-wires solutions in cases where overloads on equipment are infrequent and/or of low magnitude relative to the equipment. In cases where these installations are economically feasible, it is recommended that BESS controls are intelligently selected and programmed. For example, an Overload Mitigation Scheme (OMS) may be used to monitor substation equipment such that the BESS keeps the equipment within its thermal limits. However, an additional layer to this control scheme may be utilized to optimize network load profiles and ensure that proper charge levels are present when needed.
- In cases where equipment is frequently overloaded, it may be most sensible to upgrade to larger sizes. However, in scenarios where substation transformer replacements require substation yard expansions that are either cost prohibitive or spatially infeasible, alternative solutions may be considered. Circuit cutovers – either permanent or temporary – to adjacent circuits could alleviate these loading issues. Alternatively, the largest size that could fit within the yard could be selected and the remaining capacity deficit could be made up through a combination of spot BESS, circuit cutovers, and/or intelligent management of customer loads.
- High load and/or DER capacity may cause over and/or undervoltage issues as well as general voltage volatility leading to power quality issues or equipment misoperation. Traditional voltage regulation means such as additional line regulators, existing device settings changes, switched capacitors, etc. may alleviate these issues. However, smart inverter functionality of DER sites (i.e. Volt/Var, Volt/Watt, flexible interconnections) should be utilized alongside these traditional methods.
- With the growing amount of forecasted dispatchable load and DER resources, the addition of distributed energy resource management systems (DERMS) to the distribution system may be considered. For example, a DERMS may allow for the distributed Powerwalls to act as collective 'Solar Soakers' when properly coordinated with the DER and EVs on the grid.

3 PRODUCTION COST ANALYSIS

3.1 Background

RLC conducted an 8760-Analysis using PowerGem's TARA PROBE production cost modeling tool to evaluate the energy performance and curtailment of solar projects sited at specific buses within Green Mountain Power's (GMPs) electrical grid to increase hosting capacity within their distribution network. The following energy performance and curtailment characteristics were used for the evaluation:

- Capacity Factor (%)
- Maximum Curtailment (MW)
- Dispatch (MWh)
- Hours Curtailed
- Total Curtailment (MWh)

3.2 VELCO Zone Analysis

The electrical performance of the solar projects was first evaluated at the VELCO Zone-level. GMP provided the following list of zones to be used in this initial evaluation: 752, 772, 792, 802, 812, and 822. Table 3-1 summarize the results.

Table 3-1: Summary 8760 Analysis – VELCO Zones

ZONE	Capacity Factor (%)	Dispatch (MWh)	Total Curtailment (MWh)	Max. Curtailment (MW)	Hours Curtailed
752	23.59%	18,037.66	-	-	-
772	18.38%	6,706.56	1,902.32	4.20	1,573
792	23.22%	22,187.49	359.59	6.86	130
802	19.32%	83,908.50	18,578.19	48.01	13,026
812	23.59%	70,091.67	9.23	5.36	30
822	20.88%	216,646.36	28,091.87	66.78	7,433

Based on these results, it was observed that total curtailment in zones 802 and 822 was significantly higher than in the other zones.

An evaluation at the bus level for each of these zones was then conducted using the same energy performance and curtailment characteristics noted above. Table 3-2 and Table 3-3 summarize the results.

Table 3-2: Summary 8760 Analysis – VELCO Zone 802 Buses

Bus	Capacity Factor (%)	Dispatch (MWh)	Total Curtailment (MWh)	Max. Curtailment (MW)	Hours Curtailed
SNOWSHED_TL	19.99%	13,374.71	2,408.24	7.70	517
SMITHVILLE_TL	23.58%	6,351.30	2.87	1.56	5
DORSET_D_TL	3.68%	703.00	3,806.41	2.20	3,839
POULTNEY_TL	3.81%	231.49	1,203.32	0.70	3,810
LALOR_TL	18.90%	13,300.79	3,302.05	8.10	628
ALLIED_D_TL	23.18%	1,812.49	32.27	0.90	56
E_RUTLAND_TL	19.64%	6,826.49	1,372.45	4.00	531
MENDON_D_TL	20.11%	6,640.19	1,148.80	3.80	478
N_RUTLAND_TL	19.29%	335.27	74.68	0.20	575
RUT_GT_D1_TL	19.04%	5,457.52	1,306.61	3.30	587
RUTLND_GT_TL	18.98%	4,287.67	1,041.64	2.60	581
S_RUTLAND_TL	20.15%	4,376.71	747.63	2.50	480
W_RUTLAND_TL	17.20%	5,229.86	1,944.21	3.50	811
BRANDON_TL	23.40%	3,252.88	26.69	1.47	31
MT_HOLLY_TL	23.52%	5,926.42	17.81	2.58	16
WALLINGFORD_TL	23.03%	5,801.72	142.51	2.90	81

Table 3-3: Summary 8760 Analysis – VELCO Zone 822 Buses

Bus	Capacity Factor (%)	Dispatch (MWh)	Total Curtailment (MWh)	Max. Curtailment (MW)	Hours Curtailed
BRIDGE_ST_TL	23.59%	6,354.17	-	-	-
DOVER_D1_TL	23.59%	20,292.37	-	-	-
DOVER_D2_TL	23.59%	15,782.95	-	-	-
PUTNEY_TL	23.59%	11,478.51	-	-	-
WILMINGTO_TL	23.59%	14,963.06	-	-	-
LYONS_ST_TL	23.58%	15,979.14	8.78	3.80	18
MILL_ST_TL	23.59%	11,679.87	3.61	0.48	16
N_BENNING_TL	23.58%	15,571.94	6.04	1.21	18
S_BENNING_TL	23.59%	1,229.46	0.38	0.05	16
E_ARLING_TL	23.57%	5,938.01	6.22	1.41	24
LONDONDER_TL	21.76%	6,995.73	588.29	3.59	340
RAWSONVIL_TL	19.37%	6,226.78	1,357.24	3.70	703
SO_SHFTSBU_TL	23.58%	1,843.68	1.08	0.44	19
STRATTON_TL	14.35%	19,576.44	12,604.39	15.70	1,342
STRATTON_TL	15.25%	927.15	507.66	0.70	1,022
ARLINGTON_TL	23.56%	3,889.08	5.42	1.34	25
N_BRATLBRO_TL	16.85%	8,781.13	3,517.28	6.00	1,008
VERNON_RD_TL	17.59%	8,864.23	3,024.22	5.80	905
W_DUMMRS_TL	15.55%	3,377.07	1,747.26	2.50	1,183
BRUDIES_RD_TL	20.94%	9,276.82	1,176.82	5.04	391
S_BRATLBR_TL	20.91%	27,618.77	3,537.19	15.02	403

3.3 GMP Bus Analysis

GMP used the results shown in Table 3-2 and Table 3-3 to identify specific buses for further analysis and determine if the installation of a 25 MWh (5 MW / 5 Hour) battery would be sufficient to reduce curtailment and alleviate load-driven thermal violations at these locations. GMP selected the following buses for further evaluation: Dorset, Poultney, Lalor Ave., West Rutland, North Brattleboro, South Brattleboro, Londonderry and Rawsonville.

Table 3-4 and Figure 3-1 through Figure 3-8 summarize the results.

Table 3-4: Summary 8760 Analysis – Bus-Level

Bus	Total Dispatch (MWh)	Total Curtailment (MWh)	Total Hours Curtailed (Hrs.)	Max. Curtailment (MW)	Max. Daily Curtailment (MWh)	Date Max. Daily Curtailment
Dorset	703.0	3806.4	3839	2.2	23.4	May 3, 2033
Poultney	231.5	1203.3	3810	0.7	7.4	May 3, 2033
Lalor Ave.	13300.8	3302.1	628	8.1	77.7	March 31, 2033
West Rutland	5229.9	1944.2	811	3.5	35.0	April 20, 2033
North Brattleboro	8781.1	3517.3	1008	6.0	57.5	March 31, 2033
South Brattleboro	27618.8	3537.2	403	15.0	139.8	May 16, 2033
Londonderry	6995.7	588.3	340	3.6	22.1	July 3, 2033
Rawsonville	6226.8	1357.2	703	3.7	28.0	July 3, 2033

The following set of histograms illustrate the number of days the energy at each bus is curtailed for a given range of curtailment (MWh) range.

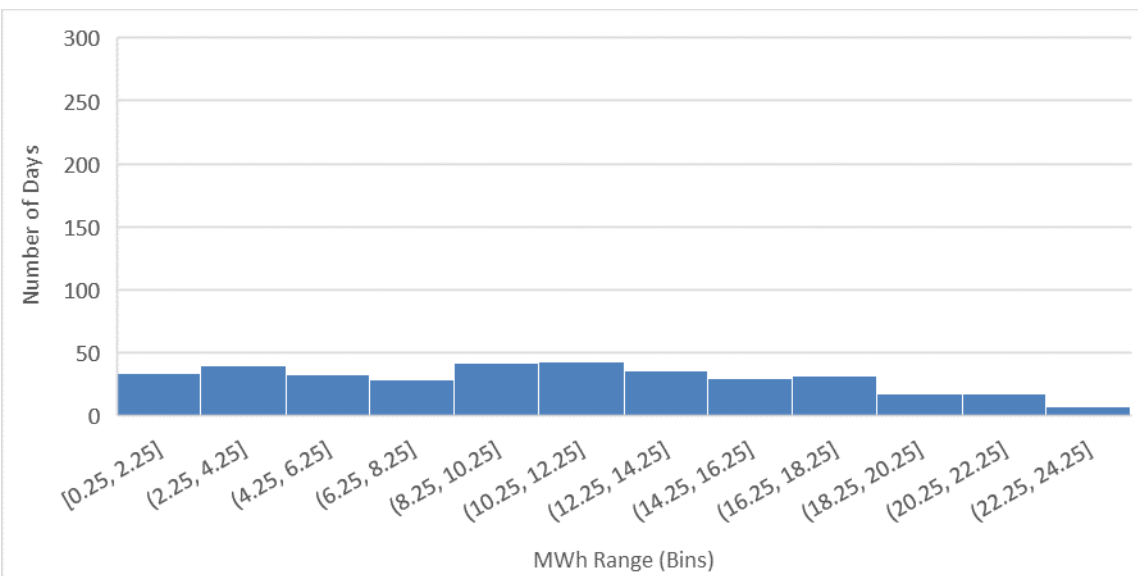


Figure 3-1: Histogram – Dorset Bus Curtailment

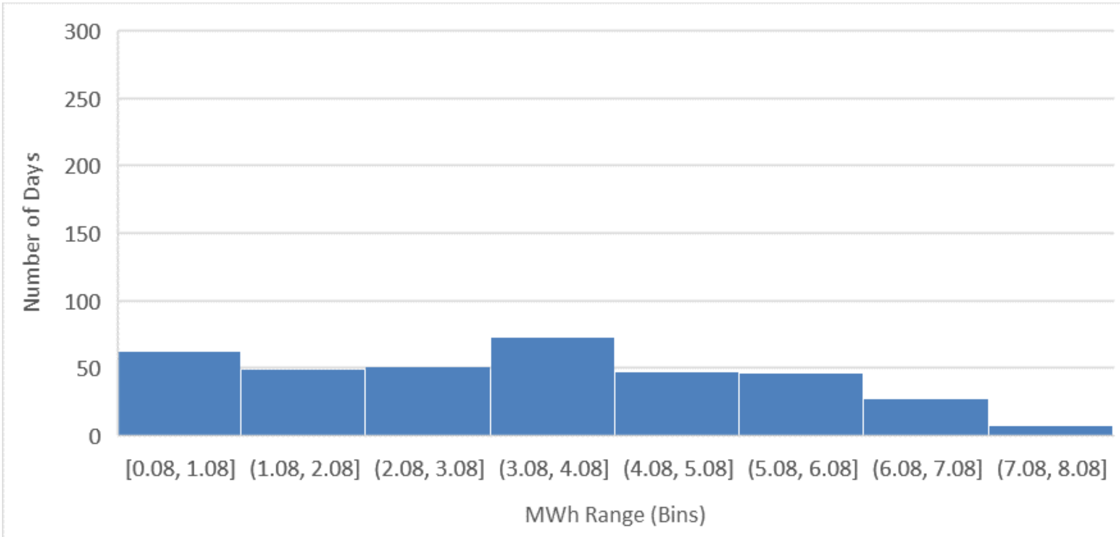


Figure 3-2: Histogram – Poultney Bus Curtailment

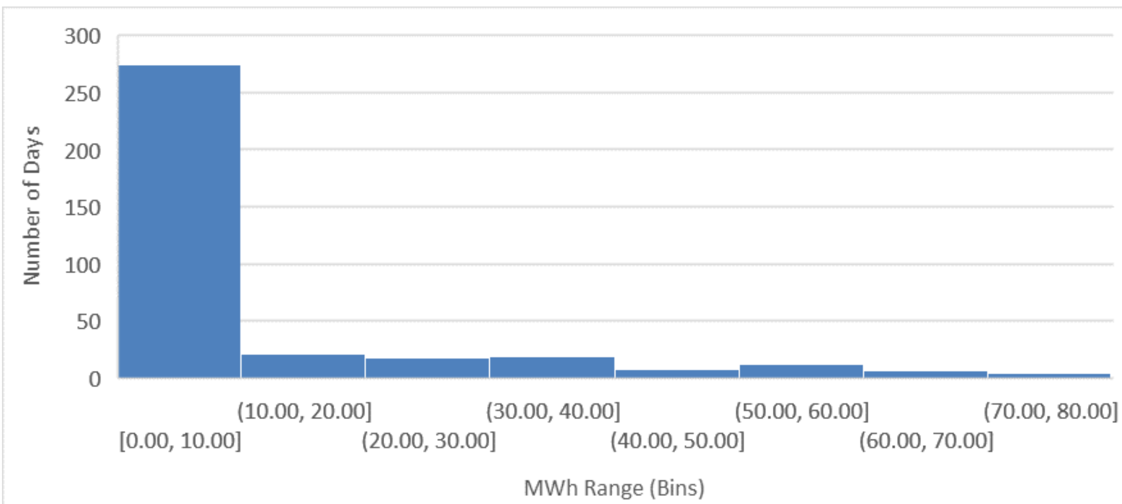


Figure 3-3: Histogram – Lalor Ave. Bus Curtailment

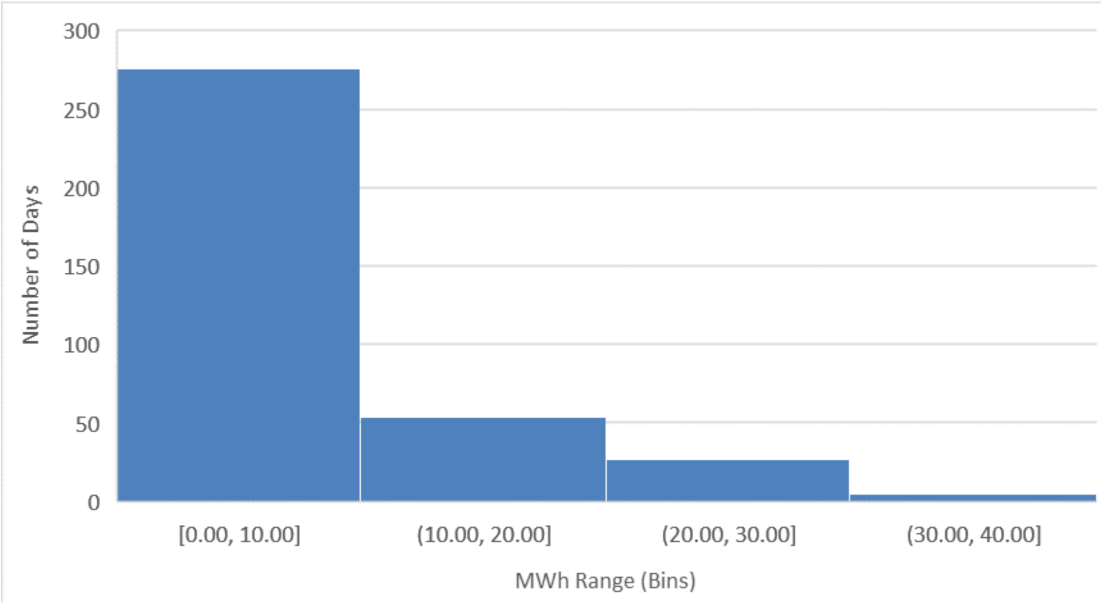


Figure 3-4: Histogram – West Rutland Bus Curtailment

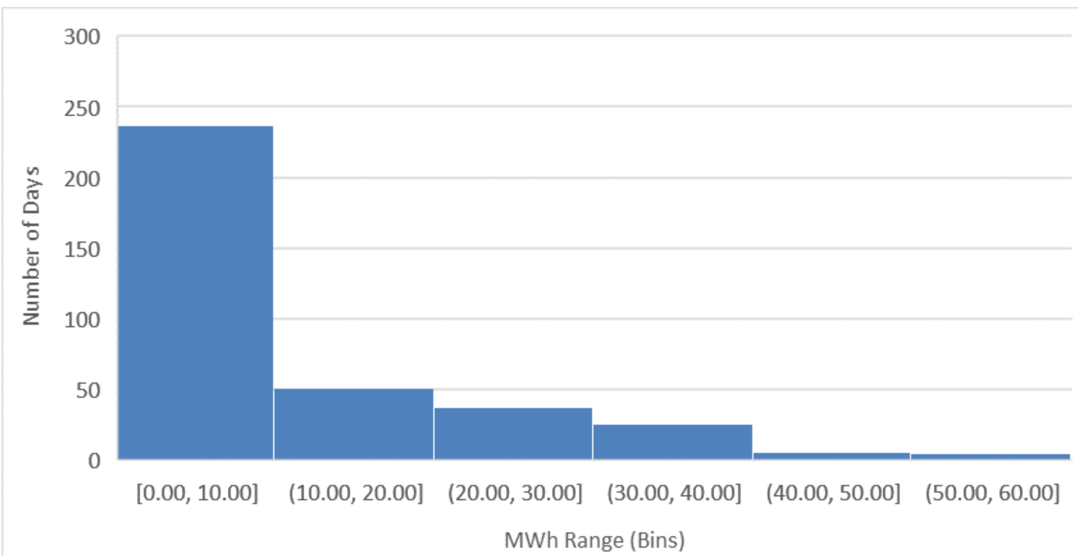


Figure 3-5: Histogram – North Brattleboro Bus Curtailment

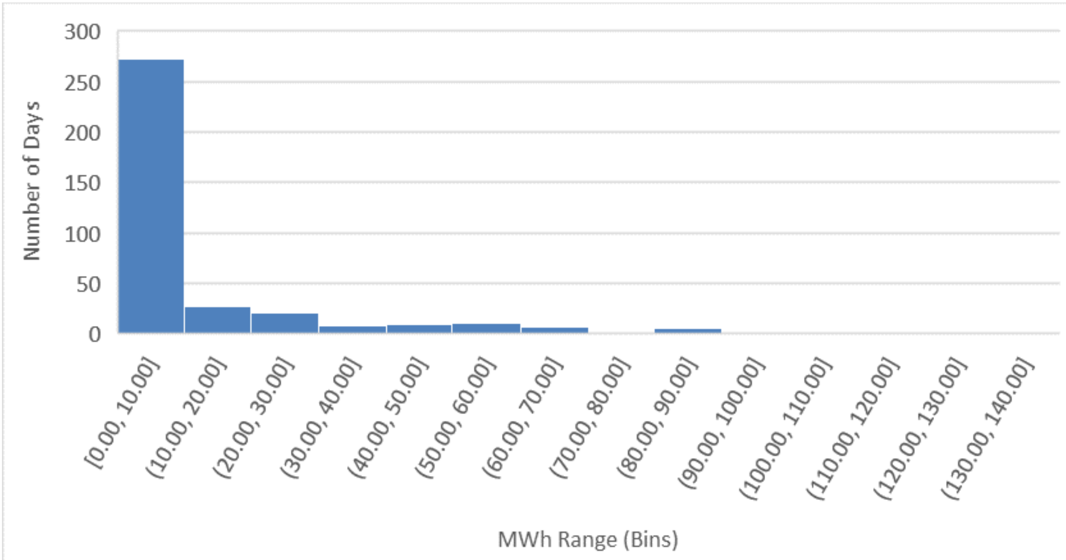


Figure 3-6: Histogram – South Brattleboro Bus Curtailment

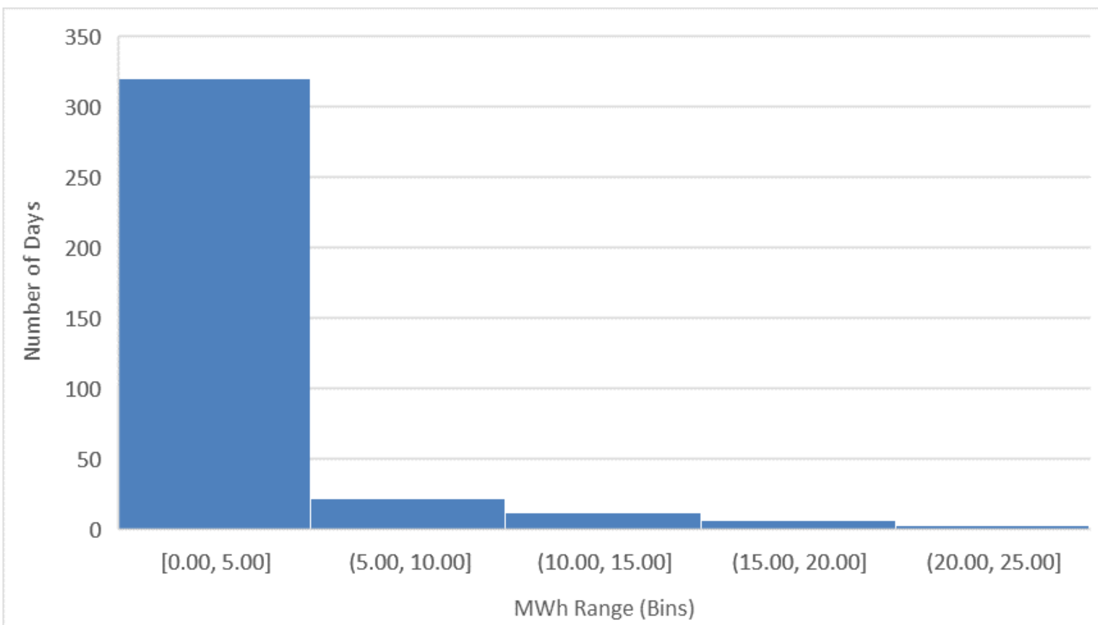


Figure 3-7: Histogram – Londonderry Bus Curtailment

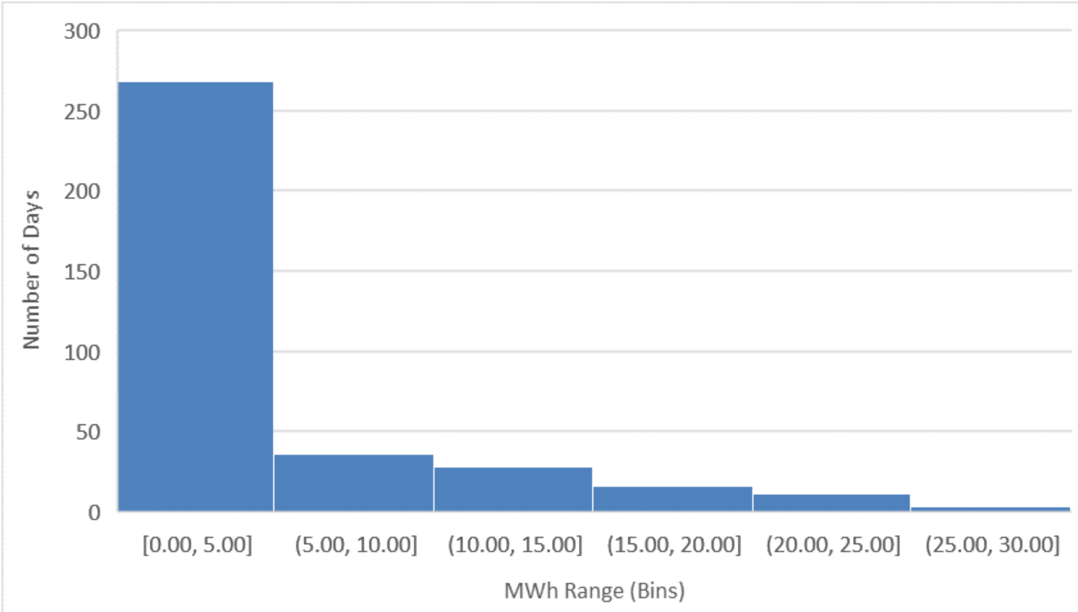


Figure 3-8: Histogram – Rawsonville Bus Curtailment

Based on these results, it was determined that the installation of a 25 MWh battery at these locations would either reduce a significant portion, if not all of the curtailment, at these buses.

Appendix A – Base Case Summaries

Intentionally Left Blank – Critical Energy Infrastructure Information (CEII)

Appendix B – Base Case Forecast Data

Included in Appendix B:

Load Forecast

Appendix B-1.1: 2030 Winter Peak Load Forecast Data

Appendix B-1.2: 2035 Winter Peak Load Forecast Data

Appendix B-2.1: 2030 Summer Peak Load Forecast Data

Appendix B-2.2: 2035 Summer Peak Load Forecast Data

Appendix B-3.1: 2030 Spring Light Load Forecast Data

Appendix B-3.2: 2035 Spring Light Load Forecast Data

DER Generation Forecast

Appendix B-4.1: 2030 Winter Peak DER Forecast Data

Appendix B-4.2: 2035 Winter Peak DER Forecast Data

Appendix B-5.1: 2030 Summer Peak DER Forecast Data

Appendix B-5.2: 2035 Summer Peak DER Forecast Data

Appendix B-6.1: 2030 Spring Light DER Forecast Data

Appendix B-6.2: 2035 Spring Light DER Forecast Data

Appendix C – Contingency Analysis Results

Intentionally Left Blank – Critical Energy Infrastructure Information (CEII)

Appendix D – Hosting Capacity Results

Included in Appendix D:

Appendix D-1: Transfer Limit Analysis Results

Appendix D-2: Hosting Capacity Results Summary

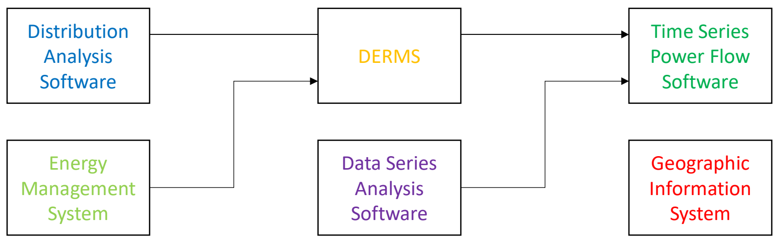
Appendix E – Distribution Time Series Analysis Results

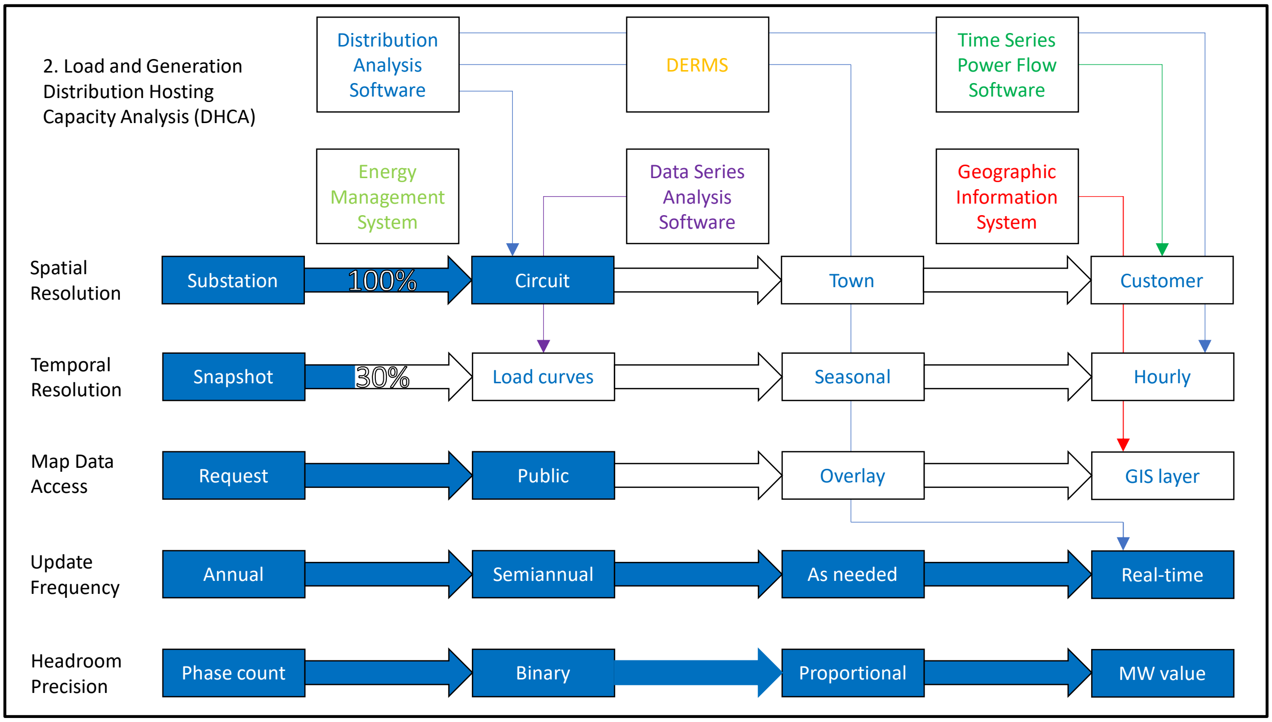
Included in Appendix E:

Appendix F

FLOW CHARTS

1. Software
Dependencies





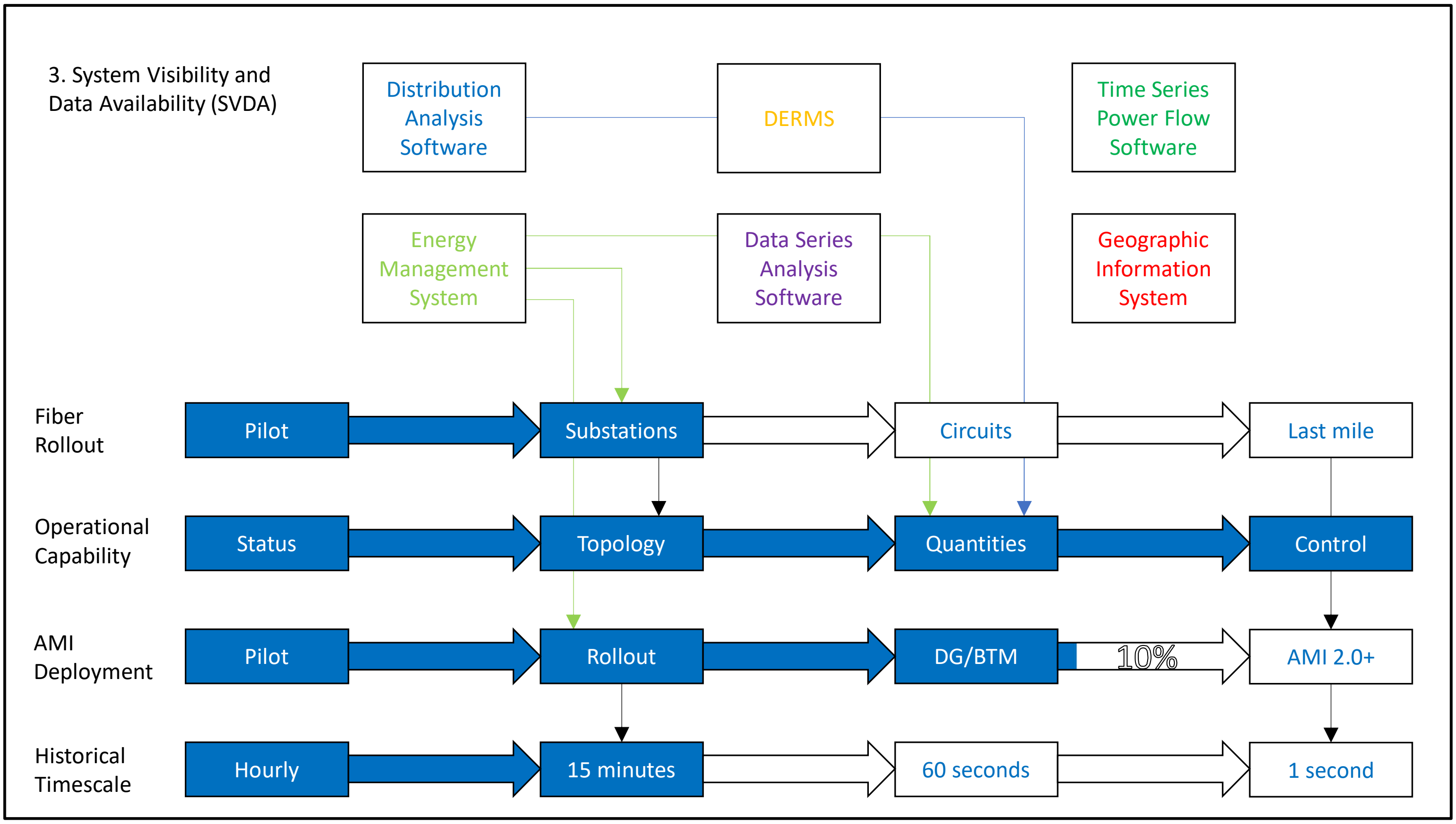
Spatial resolution: GMP continually determines hosting capacity at the substation and circuit level for all locations on the distribution system. Many towns on GMP's distribution system are served by multiple substations and circuits and many substations serve multiple towns. While GMP does not determine hosting capacity on a town-by-town basis as it does for substations and feeders, Regional Planning Commissions could use the solar map to determine how much hosting capacity is available on the distribution circuits that feed their towns. Hosting capacity on a customer-by-customer basis is not calculated until a customer applies to interconnect to the GMP system. Generally, small, net-metered projects can interconnect without many upgrades, although small upgrades like distribution transformers, service wires, etc. may need to be upgraded in order to safely and reliably interconnect to the GMP system. Refer to Section 3 of the IRP for more discussion of system hosting capacity analysis.

Temporal Resolution: GMP Currently takes minimum load on a feeder and substation into account when performing feasibility studies for larger solar projects and when a substation's power transformer nameplate capacity is reached to allow additional DG to interconnect. As the system becomes more saturated with DG and reverse flow on transformers reaches nameplate values, GMP will be exploring time-of-day limited export agreements where projects limit export at peak solar production hours in order to avoid exceeding transformer ratings. This will move GMP more towards an seasonal and hourly hosting capacity for individual feeders which are export limited. See the end of Section 3 for exploration of hourly hosting capacity.

Map Data Access: GMP's solar map is a publicly available online GIS map that shows available hosting capacity and interconnected DG on the GMP system. There are currently no plans to overlay this map with other utility's maps or to turn this into a downloadable GIS layer. See Section 4 for elaboration on GMP's GIS tools.

Update Frequency: As DG projects apply to the GMP interconnection queue, the GMP Solar Map and hosting capacity calculations are recalculated. See Section 3 for information on the DG Interconnection Queue.

Headroom Precision: Through the GMP Solar Map, customers can see the transformer nameplate rating for each substation as well as the remaining headroom on the substation equipment. Phase count, ability to interconnect, and remaining hosting capacity is available at all locations on the GMP system.

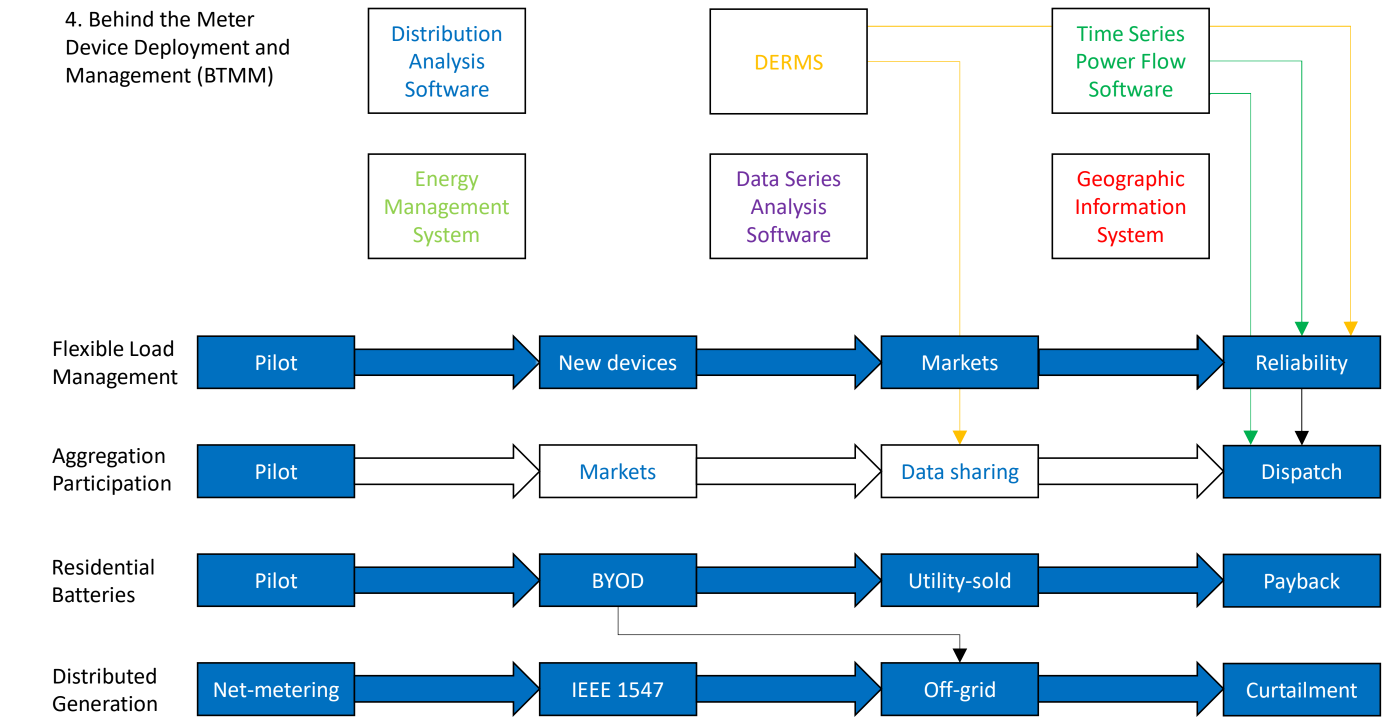


Fiber Rollout: Fiber is rolled out to nearly all substations. For DG projects over a certain size, we require a PCC recloser which the control center can remotely operate. This is sometimes done over fiber, but we also have some installations with radio and cellular communications paths. We do not currently have plans to roll out fiber to individual customers unless control of reclosers is required.

Operational Capability: Operators can see the status of 100% of systems and circuit topologies, MW/Mvar, voltages and current at system elements, and can control elements such as distribution and transmission breakers, SCADA controlled tie switches, reactive support, etc.

AMI Deployment: AMI is available/deployed at 100% of customer and DG sites. We are considering the best path forward to take for AMI 2.0 implementation on our system while continually improving our existing AMI system.

Historical Timescale: AMI and SCADA data is currently stored on a 15-minute basis. AMI 2.0 will likely store AMI data on a 60 second timescale. Storing data below this timescale becomes a big data management challenge and is of limited value. Below one-minute intervals, we would likely install a power quality meter at locations that need high resolution in order to diagnose issues with power delivery or customer equipment.



FLM:

GMP has run pilot programs for managed EV chargers, Tesla Powerwalls, and other FLM-based programs. When a GMP customer purchases an EV and claims their Level 2 charger from GMP, they enroll in discounted charging rates which are either time-of-use rates that restrict charging during peak hours or allow GMP to curtail chargers during peak events. GMP has used Powerwalls in the frequency regulation market through a pilot program. We are also using “Solar Soaker” batteries that defer substation upgrades in areas with lots of distributed generation by charging during solar hours and discharging at peak load hours.

Aggregation:

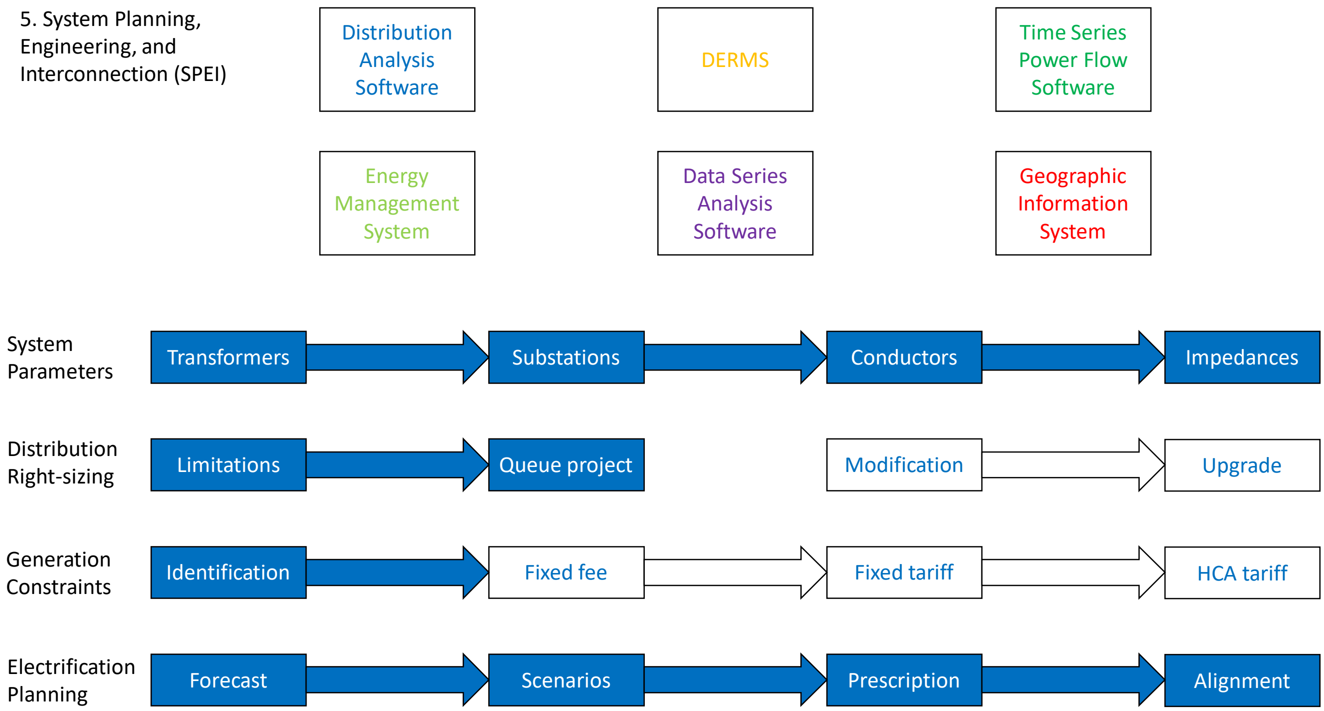
GMP has a successful frequency regulation aggregation program using customer sited storage. This is being rolled out to all customers in the GMP BESS program in the upcoming months. At this point, GMP is able to opt out of FERC Order 2222 due to our annual energy sales being below 4 million MWh. We expect that our annual sales will increase beyond the 4 million MWh threshold in the next 5 years and this would require compliance by with FERC Order 2222 by 11/1/2026. NYISO launched their DERA market in April 2024, and accounts from distribution utilities in NY state that this process took longer than expected and was challenging for a variety of reasons. GMP expects that customers are poised to gain more financially from having their DERs registered as BTM resources than by participating in wholesale energy markets.

Residential Batteries:

GMP has implemented a pilot program for customer siter storage and is now expanding this program after the cap on the number of units was lifted in 2024. BYOD is allowed and customers can opt to have their batteries be zero-export back to the GMP system. Customers can lease storage from GMP and these are economic for both the customer and for GMP. This storage program provides 30 MW of VPP capability to shave RNS and FCM peak as well as providing increased resiliency for customers with these batteries installed. We expect this program to continue to grow and to be a valuable tool for managing our system peaks and providing customers protection against outages.

DG:

Net-metering is allowed and is highly penetrated on the GMP system. All inverter-based resources must comply with IEEE 1547 and UL 1741 and for larger projects, GMP performs feasibility and system impact studies to identify any necessary upgrades in order for the DG project to operate reliably. Customers are able to separate from the grid if they would like to. GMP has the ability to curtail larger DG projects that have a PCC recloser installed. We are actively exploring the use limited-export agreements with some generators to allow for interconnection on constrained circuits.

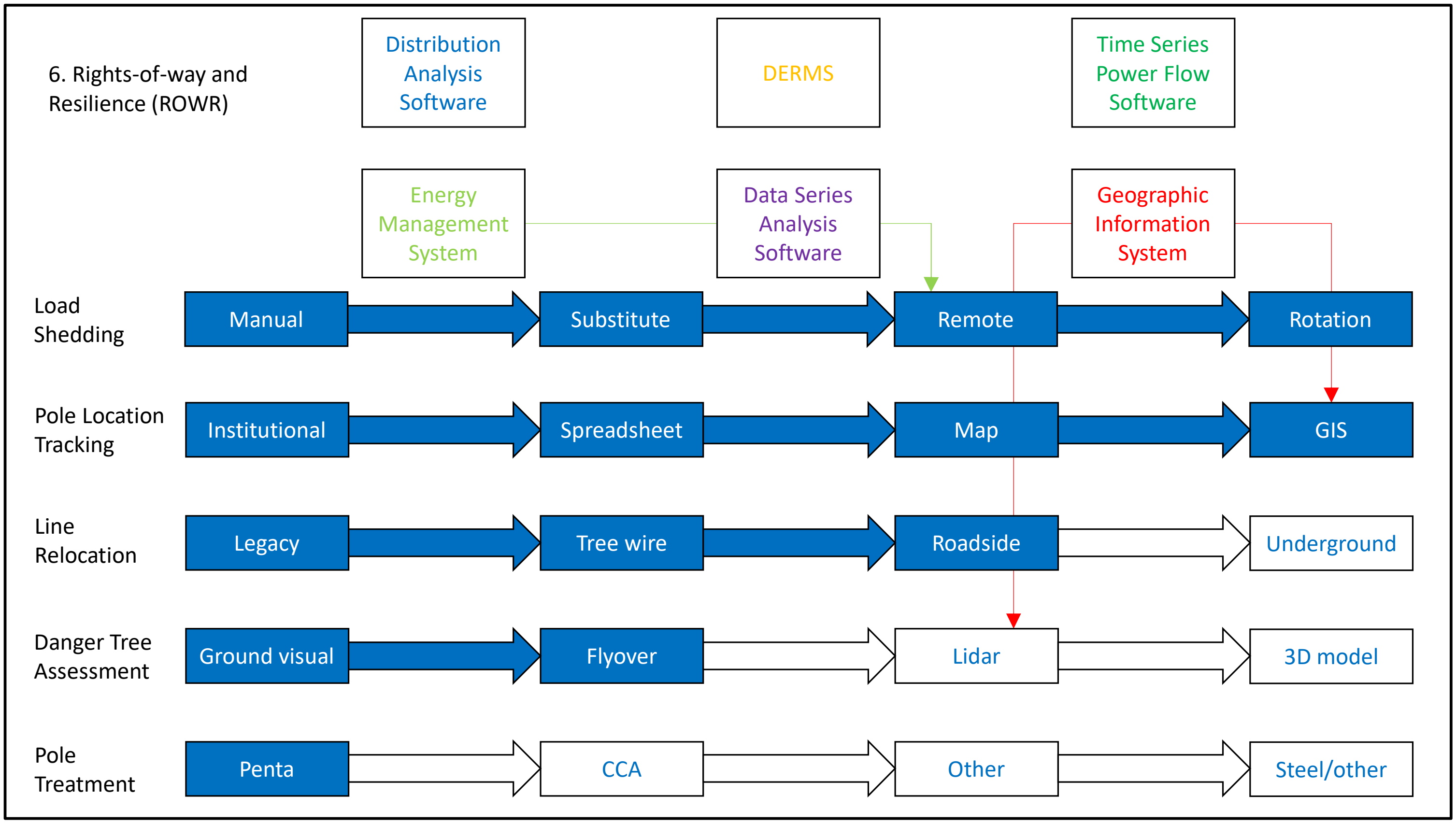


System Parameters:
GMP has ratings for 100% of transformers (substation and distribution), substation elements, conductors, and impedance data for all conductors. This information is stored in a variety of locations, including GIS, ASPEN OneLiner, CYME, and PSSE.

Distribution Right-Sizing:
We upgrade low-cost equipment such as breaker leads, etc. when completing larger projects on the system. When a DG project in the interconnection queue is studied, GMP determines the upgrades that must happen to the system to ensure the new project does not have an adverse impact. The developer pays for these upgrades which may increase line ratings on certain parts of the system. When completing some projects such as reconductoring, medium cost items like load break switches may be upgraded. There is currently not a mechanism to upgrade high cost items like conductors that limit the rating of a line while completing routine work, and these types of upgrades could require more extensive permitting and engineering work.

Generation Constraints:
GMP publishes up-to-date hosting capacity for each feeder on our Solar Map. This is updated based on transformer capacity and minimum load when applicable. Apart from fees associated with a project's individual required upgrades, there are no fees for interconnecting to our system. We have implemented a TGFOV tariff that projects pay into based on a $/kW fee. This tariff is then used to mitigate the potential for a ground fault overvoltage on the transmission system due to low load and high distributed generation. GMP does not currently have other mechanisms for cost sharing for system upgrades. ISONE recently revised their PP5-6 to comply with FERC Order 2023. This requires the use of cluster studies in areas that have over 20 MW of DG projects over 1 MW in size. The revised PP 5-6 also includes some mechanics for cost-sharing for upgrade costs on the transmission system, although whether or not this would practically result in projects sharing costs is yet to be determined.

Electrification Planning:
GMP considers long and short term electrification scenarios in our planning studies. In this IRP, we explored 5, 10, and 20 year forecasts between our engineering, innovation, and power supply teams. These forecasts include alignment with State goals and the VELCO Long Range Transmission Plan and Vermont Climate Council.



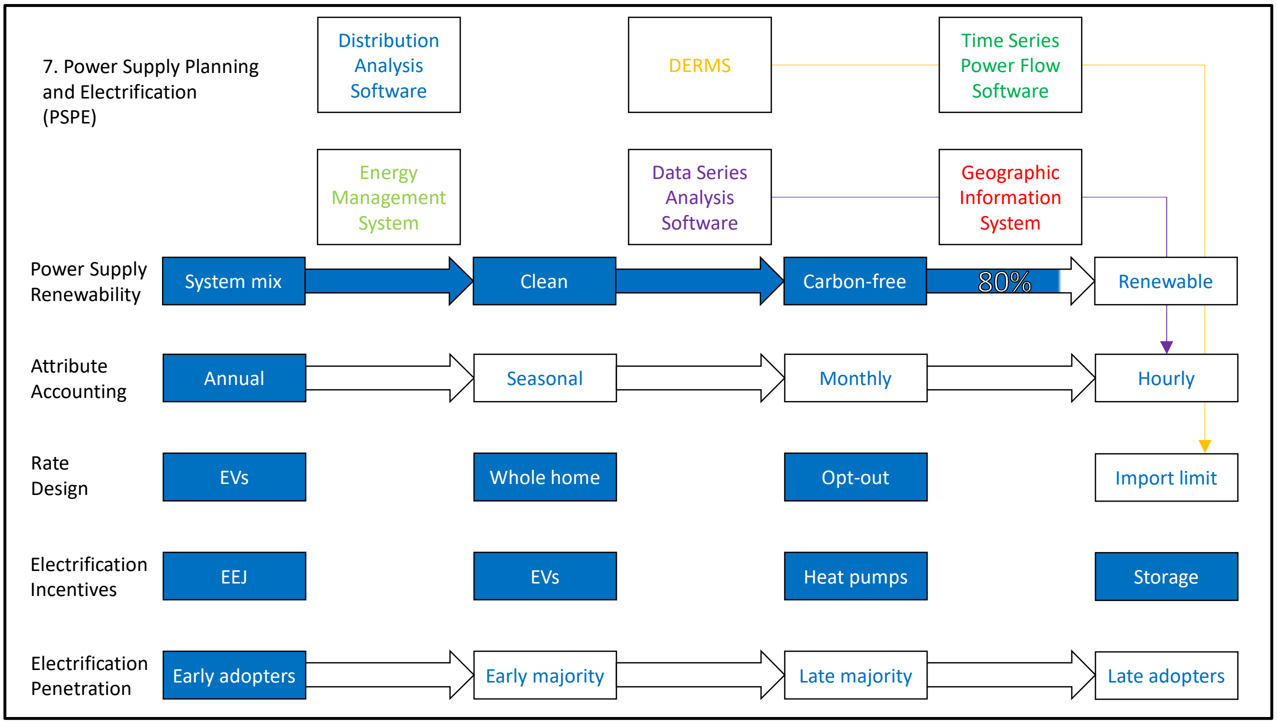
Load Shedding: GMP has an operational program set in place to reduce winter peaks during high load hours and during contingencies. GMP operators have a procedure to follow that rotates through different high load customers to help reduce peak loads. Operators also have the ability to open reclosers and manage load shedding remotely if needed.

Pole Location Tracking: GMP tracks all pole locations and attributes in GIS.

Line Relocation: GMP is working to locate all main line, three-phase lines to the road-side and to replace bare wire with tree wire. Single phase lines will be undergrounded, and those that cannot be undergrounded will be replaced with tree wire. See Chapter 3 for more information on line relocation.

Danger Tree Assessment: GMP crews perform a ground inspection of their local circuits every time that they perform maintenance on the lines. Tree crews who trim lines also look out for danger trees as part of their work. Transmission lines are checked for danger trees at least once a year from helicopters including after major storms to assess for damage. GMP is moving towards using a satellite/AI tool called AiDASH to proactively identify danger trees and increase reliability on our T&D system. See Chapter 3 for more information on danger tree assessment.

Pole Treatment: GMP is phasing out penta treated poles on our system. For certain poles on our system where extra strength is needed, we are moving towards laminated poles, and if not possible, we may consider some steel poles for added resiliency.



Power Supply Renewability: GMP's power supply is 100% clean and 80% renewable. See Chapter 7 for more information on our current power supply mix and illustrative portfolios of the future.
Attribute Accounting: GMP keeps track of our RECs through the NEPOOL Generator Information System on an annual basis. There is currently not a tool to track RECs at a timescale below 1 year. This could change in the future as the regions and GMP's goals change.
Rate Design: GMP offers time of use rates for EV charging and whole-home demand. We also offer special rates for home water heaters during off-peak hours. For customers using GMP EV chargers, they must enroll in either Rate 72 or 74 time of use rates to allow management of peak charging loads on the system.
Electrification Incentives: GMP has incentives and programs for all of the above categories. See Chapter 1 for more information on customer-facing programs.
Electrification Penetration: GMP is still in the early stage of electrification despite having many innovative programs to incentivize and manage the growth of peak loads. We haven't yet seen much increase in annual or peak loads.

Appendix G

OWNED HYDROELECTRIC FACILITIES

Table G-1. GMP-Owned Hydroelectric Fleet

Resource Name	Age (years)	Type of Operation	Location	City/Town	State	Capacity (MW)	LIHI Certification	REC Eligibility	Operational License	Operational License Expiration	Description
Arnold Falls	96	Run-of-River	Passumpsic River	St Johnsbury	VT	0.35	Yes	VT Tier II	P-2396	2034	Recent Improvements: In 2022 this site was awarded LIHI certification. In the next 3-5 years we plant to upgrade the PLC and will assess refurbishment of the turbine.
Barnet	38	Run-of-River	Stevens River	Barnet	VT	0.56	No	ME Class II	P-5702	2032	The plant was damaged during flooding in 2024 and is currently offline. We are assessing the scope and budget required to repair the plant and put it back into service.
Beldens Falls	111	Run-of-River	Otter Creek	New Haven	VT	5.85	Yes	MA Class II	P-2558	2054	Recent Improvements: In 2023 and 2024, we completed a dam safety improvement to address water migration issues and upgraded the unit 1 excitation system. In the next 3-5 years we will assess and scope electrical upgrades for remaining excitation systems, motor control cabinets, breakers and turbine controls.
Bolton Falls	38	Run-of-River	Winooski River	Duxbury	VT	7.5	Yes	MA Class II	P-2879	2062	Recent Improvements: A project is ongoing to replace both turbines and generators; this project reduces the nameplate capacity of the plant, but performance curves on the new units are expected to result in a 3% efficiency increase moving forward.
Carver Falls	130	Run-of-River	Poultney River	West Haven (and East Hampton, NY)	VT	2.55	Yes	VT Tier II	P-11475	2039	Recent Improvements: In 2023, we upgraded a retaining wall at the station and performed an electric heat upgrade. In the next 3-5 years, we plan to assess upgrades to the PLC and concrete resurfacing.
Cavendish	116	Run-of-River	Black River	Cavendish	VT	1.44	Yes	VT Tier II	P-2489	2024	FERC issued a license extension while processing the Final License Application filed October 31, 2022. Recent Improvements: In 2023, we modernized the electrical system, upgraded the GSU and refurbished the HPU. In the next 3-5 years, we will plan work at the intake and assess new
Center Rutland	126	Run-of-River	Otter Creek	Rutland	VT	0.28	No	ME Class II	P-2445	2024	FERC issued a license extension while processing the Final License Application filed December 22, 2021. In 2023, we completed ledge stabilization work in vicinity of the dam for site safety. In the next 3-5 years, we expect to upgrade the headgate operator from manual hand
Clarks Falls	87	Dispatchable	Lamoille River	Milton	VT	3	No	ME Class II	P-2205	2035	Utilized for behind the meter load reduction. Recent Improvements: In 2023, the tainter gates were recoated to add to longevity and reliability. In 2024, a downstream stone retaining wall was resurfaced with concrete to improve stability and dam safety. In the next 3-5 years, we will assess replacing the wood stanchions.
Deweys Mill	39	Run-of-River	Ottauquechee River	Quechee	VT	2.75	No	ME Class II	P-5313	2032	Recent improvements include refurbishment of unit 2 in 2024 and rock face stabilization in 2023. In the next 3-5 years, we will assess concrete resurfacing and evaluate the GSU for potential replacement.
East Barnet	41	Run-of-River	Passumpsic River	Barnet	VT	2.2	No	ME Class II	P-3051 - FERC Exempt	FERC Exempt	In the next 3-5 years, we plan to do an electrical modernization at the plant.
East Pittsford	110	Dispatchable	East Creek	Pittsford	VT	3.6	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Utilized for behind the meter load reduction. Recent Improvements: In 2022, we upgraded the notification system, installed a sand trap, and improved ventilation at the station. In the next 3-5 years, we will schedule penstock inspection, upgrade the PLC, and perform concrete resurfacing at the auxiliary spillway.
Essex #19	107	Run-of-River	Winooski River	Williston/ Essex Junction	VT	7.2	Yes	89% MA Class II, 11% ME Class II	P-2513	2025	FERC relicensing underway with expected license extension similar to other projects. Recent Improvements: In 2024, the RTU and PLC were upgraded. In 2025 we plan to upgrade the headgates, upgrade the switchgear, and epoxy coat the minflow penstocks.
Fairfax Falls	104	Run-of-River	Lamoille River	Fairfax	VT	4.2	No	ME Class II	P-2205	2035	Recent Improvements: In 2021, the draft tube was repaired and in 2022 the penstock exterior was recoated. In 2024, dam abutment concrete was repaired, an improved access platform was installed, and the excitation system was upgraded. In the next 3-5 years, we will assess upgrades to the SCADA system and the headgate actuators.
Gage	105	Run-of-River	Passumpsic River	St Johnsbury	VT	0.7	Yes	VT Tier II	P-2397	2034	Recent Improvements: We installed a new Obermeyer Spillway Gate system to replace existing hinged flashboards and upgraded the excitation system. In the next 3-5 years, we plan to refurbish both units at the site.
Glen	104	Dispatchable	East Creek	Rutland	VT	2	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Utilized for behind the meter load reduction. Recent Improvements: We replaced 500 feet of penstock as required by a 2015 inspection report. In the next 3-5 years, we plan to continue with another 500 feet of penstock and make improvements to the surge tank.

Gorge #18	96	Run-of-River	Winooski River	Colchester/ South Burlington	VT	3	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Recent Improvements: In 2024 we upgraded the headgate structure to add automatic actuators and repaired deep sluice gates to increase reliability and longevity. In the next 3-5 years, we are planning for an excitation upgrade and ledge stabilization at the station, and will assess
Huntington Falls	113	Run-of-River	Otter Creek	Weybridge	VT	6.6	Yes	MA Class II	P-2558	2054	Recent Improvements: In 2022, we qualified the site for LIHI certification. In 2023 we upgraded the cooling system for units 1 and 2. In 2025, we plan to complete an upgrade of the motor control cabinet for Unit 3. in the next 3-5 years, we plan to assess and perform concrete resurfacing on
Marshfield #6	97	Dispatchable	Molly's Brook	Cabot	VT	5	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Recent Improvements: We made significant improvements to the emergency spillway in 2022. In the next 3-5 years we plan to evaluate the section of penstock below the surge tank for lining or replacement.
Mascoma	36	Run-of-River	Mascoma River	Lebanon	NH	2.05	No	ME Class II	P-8405	2027	Recent improvements include mechanical seal upgrades on Units 1 and 3, and PLC and controls upgrade. In the next 3-5 years, we plan for an electrical modernization at the station.
Middlebury Lower	104	Run-of-River	Otter Creek	Middlebury	VT	2.25	Yes	VT Tier II	P-2737	2031	Recent Improvements: In 2024 we completed concrete repairs at the intake and tailrace as well as a remote terminal unit upgrade and station service electrical/heat upgrades. In the next 3-5 years, we are planning to upgrade the #3 unit runners and the switchgear in the station, and evaluate upgrading the runners for units 1 and 2.
Middlesex #2	96	Run-of-River	Winooski River	Middlesex	VT	3.2	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Recent Improvements: In 2022, we performed electrical and controls upgrade.
Milton	95	Dispatchable	Lamoille River	Milton	VT	7.5	No	ME Class II	P-2205	2035	Recent Improvements include refurbished HPUs and governors. In the next 3-5 years, we plan a detailed assessment of the turbines and electrical systems to include SCADA system and RTU.
Newbury	20	Run-of-River	Wells River	Wells River	VT	0.42	No	ME Class II	P-5261	2064	FERC issued subsequent license March 28, 2024. In the next 3-5 year, consistent with the license, we anticipate recreation plan enhancements for canoe portage and fishway improvements.
Ottauquechee	100	Run-of-River	Ottauquechee River	North Hartland	VT	1.69	No	ME Class II	P-2787 - FERC Exempt	FERC Exempt	Recent improvements include an upgrade of the PLC and SCADA system and safety improvements at the substation. In the next 3-5 years, we plan for a switchgear upgrade.
Passumpsic	96	Run-of-River	Passumpsic River	St Johnsbury	VT	0.7	Yes	VT Tier II	P-2400	2034	Recent Improvements include upgrades to the fish passage and concrete resurfacing, along with upgrade to PLC. In the next 3-5 years we plan for an upgrade to the governor on the unit.
Patch	103	Run-of-River	East Creek	Rutland	VT	0.4	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	The plant was refurbished after Hurricane Irene damage. In the next 3-5 years we plan to assess projects for electrical modernization, intake improvements and concrete resurfacing.
Peterson	76	Dispatchable	Lamoille River	Milton	VT	6.35	No	ME Class II	P-2205	2035	Recent Improvements: in 2024, we upgraded signage, the notification system, and station control system for increased safety of the public at the site. In the next 3-5 years, we will assess concrete repairs at the dam for
Pierce Mills	96	Run-of-River	Passumpsic River	St Johnsbury	VT	0.25	Yes	VT Tier II	P-2396	2034	This plant was affected by flooding in July 2024. It is currently offline and we are developing and evaluating the plan to make all necessary repairs to return it into operation.
Proctor	119	Dispatchable	Otter Creek	Proctor	VT	10.23	Yes	80% MA Class I, 20% MA Class II	P-2558	2054	Recent Improvements: In 2022, the station became LIHI-Certified. In 2024, an automatic rack raker was installed at the intake to improve water flow and reliability. In the next 3-5 years, we will be inspecting and lining our #5 penstock and conducting lead paint abatement in the power
Rollinsford	41	Run-of-River	Salmon Falls River	Rollinsford	NH	1.5	Yes	MA Class II	P-3777	2062	The site was issued a new FERC license in 2023. In 2025, both runners will be upgraded and downstream fish passage improvements will be made as a condition of the license.
Salisbury	107	Dispatchable	Leicester River	Salisbury	VT	1.3	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Utilized for behind the meter load reduction. Recent Improvements: Construction to improve the Dunmore outlet structure will be complete by the end of 2024. In the next 3-5 years we plan to upgrade the turbine controls and refurbish the runner.
Salmon Falls	101	Run-of-River	Salmon Falls River	Berwick	ME	1.2	Yes	MA Class II	P-11163	2037	Recent improvements include mechanical overhaul of unit 3 and a SCADA upgrade. In the next 3-5 years, we plan to scope an electrical modernization projects and spillway resurfacing.

Silver Lake	108	Dispatchable	Sucker Brook	Leicester	VT	2.2	Yes	VT Tier II	P-11478	2039	Utilized for behind the meter load reduction. Recent Improvements: We replaced the water control device at the Goshen Reservoir. This work was directed by FERC and includes moving the control of water from the downstream end to the upstream side of the earthen dam conduit by construction of a new intake tower, bridge and valve system. In the next 3-5 years, we will be upgrading the auxiliary spillway and performing concrete repair at the intake and tailrace.
Smith (Bradford)	40	Run-of-River	Waits River	Bradford	VT	1.5	No	ME Class II	P-2488 - FERC Exempt	FERC Exempt	Recent Improvements: in 2024, we recoated the tainter gates to extend useful life. In the next 3-5 years, we plan for an upgrade to the excitation, controls and protection system.
Somersworth (Lower Great Falls)	40	Run-of-River	Salmon Falls River	Somersworth	NH	1.28	Yes	MA Class II	P-4451	2062	In the next 3-5 years, we plan for upgrades to the switchgear and improved fish and eel passage.
Taftsville	82	Run-of-River	Ottauquechee River	Woodstock	VT	0.5	No	ME Class II	P-2490	2024	FERC licensing underway; we expect a license extension similar to other projects. Site improvements will be as directed in that relicensing, expected to be issued in 2025.
Vergennes A&B	112	Run-of-River	Otter Creek	Vergennes	VT	2.4	Yes	VT Tier II	P-2674	2029	Limited storage capacity facility. Recent Improvements: HVAC improvements were made to the station in 2023. In the next 3-5 years, we expect to rewind both unit 1 and unit 2 generators.
Waterbury #22	71	Run-of-River	Little River	Waterbury	VT	5.52	Yes	MA Class II	P-2090	2056	GMP operates the hydroelectric facility, but the dam is owned and operated by the State of Vermont. For the facility to move to true run-of-river, the State must repair gates on the dam, likely to occur in the next 3-5 years pending federal funding. State continutes to perform analysis.
West Danville #1	107	Run-of-River	Joe's Pond	West Danville	VT	1	No	ME Class II	Non-FERC jurisdiction	Non-FERC jurisdiction	Limited storage capacity facility. In the next 3-5 years, we plan to replace the rubber crest and upgrade the intake structure.
West Hopkinton	41	Run-of-River	Contoocook River	W Hopkinton	NH	1.12	No	ME Class II	P-4337 - FERC Exempt	FERC Exempt	Recent improvements include a new rack raker system and interior coating and structural improvement of the penstocks. In the next 3-5, years we plan for upgrades to the switchgear and at toe of the dam.
Weybridge	73	Dispatchable	Otter Creek	Weybridge	VT	3	Yes	VT Tier II	P-2731	2031	Utilized for behind the meter load reduction; Recent Improvements: in 2023, we replaced the gantry crane hoist systems with modern equipment and are completing a project to replace the rubber dam crest. In the next 3-5 years, we plan for replacement of the mechanical runner to
					TOTAL	**116.34**					

Appendix H

PORTFOLIO EVALUATION METHODS AND REGIONAL ENERGY MARKET INPUTS

This appendix provides details on analytical steps that support GMP's portfolio evaluation which is discussed in IRP **Chapter 7**. We start with a review of methods associated with GMP's short-term power supply budgeting and our approach to estimating net power costs in this IRP. The remainder of the appendix presents input assumptions and selected outputs associated with Daymark Energy Advisors' regional energy market model.

Budget Estimation

GMP's portfolio of committed resources and the expected resource changes—as described in the IRP **Chapter 6** and shown in GMP's current five-year financial forecast—comprise the starting point for GMP's resource planning. Primary changes over time reflect 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. The resulting portfolio of resources is balanced against projected needs for energy, capacity, and RECs based on GMP's forecasted load requirements (see **Chapter 2**). Specifically, portfolio supplies are compared to projected requirements with respect to energy (for monthly peak- and off-peak periods); RECs to meet each tier of Vermont RES requirements (on an annual basis); and capacity in the ISO-NE capacity market.

Differences between GMP's projected supply and needs for each product are assumed to be purchased or sold based on a current forecast of future spot market prices. GMP's energy budgeting also includes an energy balancing cost adjustment—derived from ISO-NE market settlement data—to reflect the fact that GMP's actual net costs of energy purchases and sales in the ISO-NE Day-Ahead and Real-Time markets consistently exceeds the net costs indicated by a monthly peak- and off-peak level of analysis. This is primarily because GMP tends to be a net purchaser of energy during times within the peak- and off-peak periods (e.g., evening peak hours, or a cold winter day) when market prices are typically higher than average and a net seller of energy during times (e.g., hours of maximum solar production, or a mild winter day) when market prices are typically below average.

We presently balance GMP's capacity needs on an annual basis, consistent with ISO-NE's current forward capacity market structure. As more information regarding ISO-NE's transition to a seasonal capacity market (see **Chapter 5**) becomes available we expect that this balancing step will evolve to one that reflects seasonal capacity requirements and seasonal capacity market pricing.

IRP Portfolio Cost Projections

The resource plan estimates net power supply and purchased transmission costs, which can change directly under alternative future market outcomes or alternative procurement strategies. The portfolio analysis does not model other components of GMP's revenue requirement—such as capital-related costs associated with all existing and future T&D assets, administrative and general expenses, or non-power operations and maintenance costs—so that we can isolate power supply-related trends. The resource plan therefore reflects potential paths for power supply costs and related metrics; it is not intended to be a forecast of total retail electric rates that our customers would pay under different scenarios.

The IRP portfolio evaluation is performed based on calendar years rather than on the fiscal year basis that is used for GMP's near-term budgeting. This is primarily because Vermont RES requirements are defined for calendar years; calendar year summation also allows us to utilize Daymark's standard reporting of results from its regional market model.

Evaluation and discussion of future GMP portfolio costs reflects *nominal* dollars that include the effects of general inflation over time. That is, the analysis reflects prices and costs projected for each year of the analysis period; no additional translation or escalation is needed to capture the effects of general inflation in the economy over time.

In the IRP cost analysis GMP leverages Daymark's regional market model to approximate the net cost of interchange with the ISO-NE energy market, based on projected hourly long/short positions for GMP's portfolio and hourly regional market prices. This hourly level of resolution captures estimated differences in market prices during times when GMP is selling or buying energy from the market, so it reduces the magnitude of energy balancing cost adjustment that is needed.

Regional Energy Market Inputs

The regional energy market outlook utilized in **Chapter 7** 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 model simulates the commitment and dispatch of generating plants in New England at an hourly level of resolution, based on loads and available resources along with electrical interconnections to other regions.[1] The model estimates hourly volumes of energy produced for each generating plant or

1 The regional market model can be viewed as illustrating Day Ahead energy market dynamics and pricing. The model does not attempt to simulate Real Time market interactions and pricing—which derive primarily from differences in actual electricity demand and generation supply during an operating day compared to expected volumes in the Day Ahead market.

generation group, along with hourly energy market prices for New England. Key results are summarized below and in **Chapter 7** (see for example **Figure 7-9** and **Figure 7-18**).

The energy market simulation and resulting prices are based on assumptions that include future electricity demand, natural gas prices to electric generators in New England, anticipated generation additions and retirements, and anticipated future carbon pricing applicable to electric generators. In general, we relied on Daymark's fundamental analysis and reviewed the underlying assumptions for reasonableness. The following are notable assumptions in the base case energy market outlook:

- Large additions of wind and solar generation are assumed to enter the market over the next decade, consistent with the New England states' goals to substantially decarbonize the electricity generation sector. The base case includes 8,000 MW of OSW capacity and over 14,000 MW of total solar PV capacity by 2035; this reflects Daymark's estimate of new renewables needed to achieve the collective renewable and clean energy requirements in the New England states over this period. The entry of such substantial renewable volumes significantly changes the generation supply stack—offsetting electricity demand growth and displacing a significant portion of the current natural gas generation volumes in New England. The increasing size of the renewable generation fleet puts downward pressure on energy market prices over time and affects the seasonal and hourly patterns of energy market prices.
- Consistent with ISO-NE's 2024 Capacity, Energy, Load and Transmission Report, annual electricity consumption in New England is projected to increase by 25 percent by 2035 based primarily on electrification trends—particularly increasing penetration of electric vehicles and heat pumps.
- The price of CO2 allowances for electric generators in New England in Daymark's base case is between the RGGI program's Cost Containment Reserve and Emissions Containment Reserve prices. Allowance prices represent incremental costs of operation for large fossil-fired generators in New England, so an upward trend in allowance prices puts upward pressure on energy market prices over time. The RGGI allowance price levels in the base case are well below estimates of the societal cost of carbon, however, as regional policymakers have so far emphasized other policy tools—like requirements for renewable and clean energy supply, long-term stable-priced PPAs to support development of new renewables, and energy efficiency investments—as the primary methods to pursue emission reductions in the electric sector.
- Winter natural gas price basis differentials (at Algonquin Citygate) are assumed to decrease modestly over time relative to historical multi-year averages, consistent with projected declines in regional natural gas generation volumes.

- Daymark modeled energy interchanges between New England and neighboring regions (Quebec, New York, New Brunswick) using static hourly patterns based on historical monthly flows for each major interface, with one exception. The assumed rates of imports from Quebec were reduced from historical levels based on lower flow volumes observed in the last two years, along with other indications that southbound flows are likely to be less continuous in the future. In the Daymark simulation model, the static flow patterns between New England and neighboring regions were generally treated as fixed but were allowed to increase or decrease on an hourly basis in response to extraordinarily high or low simulated hourly energy market prices in New England.

Selected Regional Energy Market Results

Figure H-1 below summarizes the projected evolution of New England's annual electricity supply, based on the Daymark assumptions discussed above.

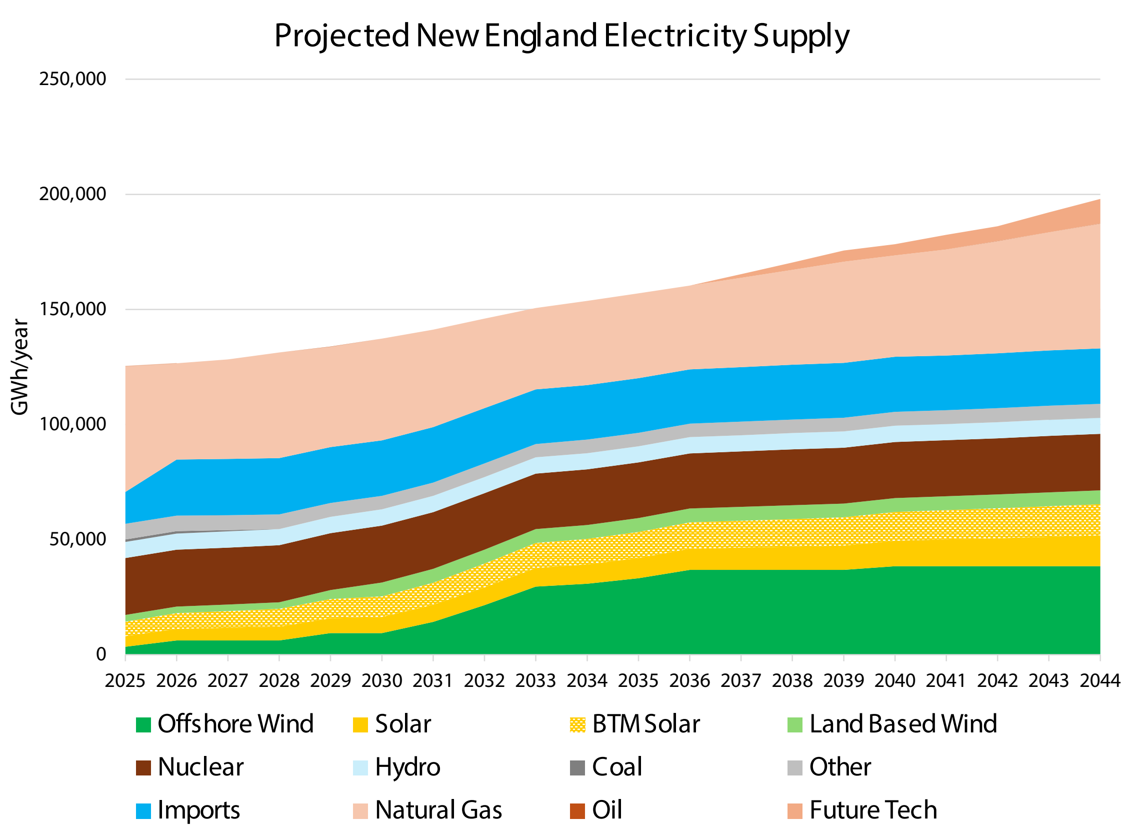


Figure H-1: Projected Annual Electricity Supply for New England

From a regional market perspective, some highlights of the New England energy mix include:

- Continued growth in solar generation (yellow), some participating directly in the ISO-NE markets and some operating as load reducers or as behind-the-meter (BTM) generation.
- Offshore wind (dark green) appears in material volumes in 2025 and is projected to take a prominent role in the regional generation mix by the mid-2030s. Land-based wind volumes (light green) increase to a lesser degree in the Daymark analysis, primarily via assumed development of large wind capacity in northern Maine.
- Projected natural gas-fired generation in New England declines in absolute terms and provides a shrinking fraction of total supply. The volume of natural gas-fired generation in the region is projected to drop noticeably in 2026 with the arrival of the New England Clean Energy Connect (NECEC) line from Quebec to Maine. The projected New England renewable generation additions above—particularly offshore wind—more than match substantial electricity demand growth over the next decade, leading to some additional reduction in gas-fired generation volumes by the mid-2030s. As noted in **Chapters 5 and 6** actual offshore wind growth in the Northeast US has been halting, due largely to major cost increases in the past few years. If the actual pace of offshore wind project completions unfolds at a slower pace, the drop in natural gas generation and emissions will be less than shown here.
- The Daymark analysis shows a rebound in the volume of natural gas generation in the early 2040s. GMP notes that to the extent the New England states refine their renewable and clean energy policies to achieve their long-term emission reduction goals, this increase may not actually materialize.

Figure H-2 below shows annual average energy market price results from the Daymark modeling, in constant 2023 dollars and nominal dollars (i.e., with effects of general inflation included).

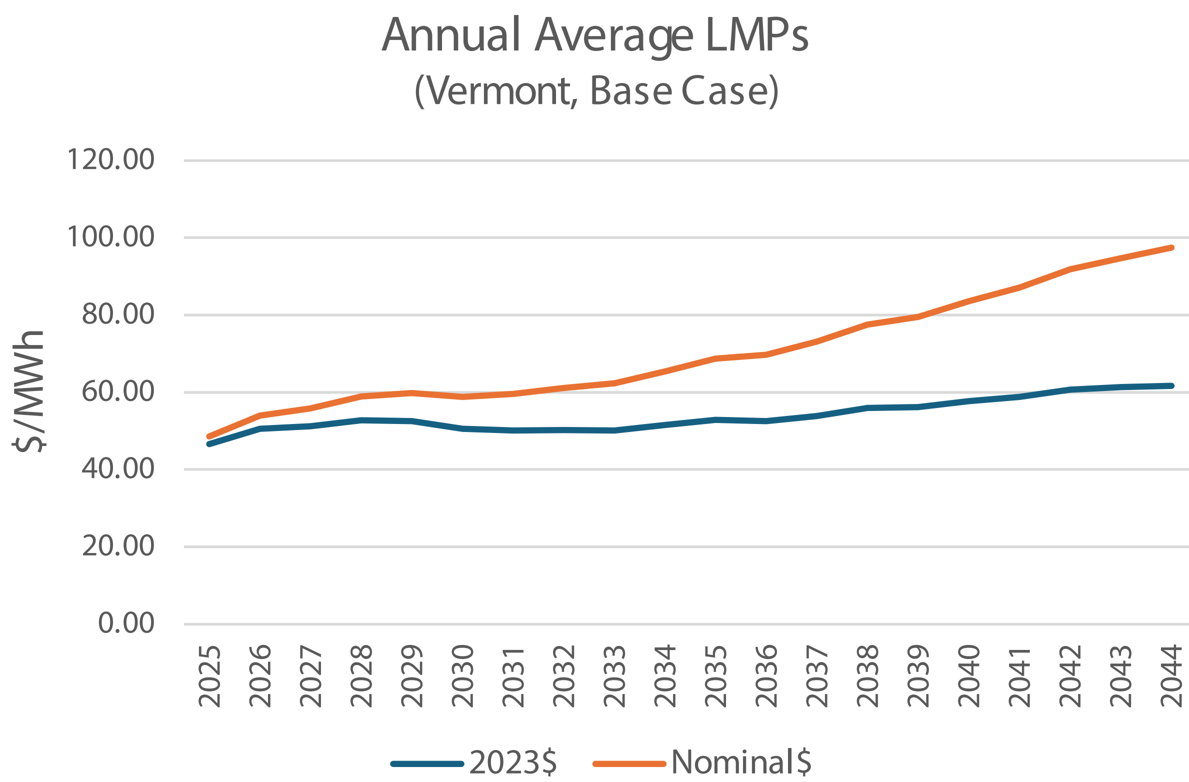


Figure H-2: Projected Annual Average Energy Market Prices

The trend of average energy market prices in the Daymark model shows the influence of the input assumptions summarized above:

- Over the long term the price trend in nominal dollars is generally higher, driven by increasing prices for natural gas prices and emission allowances, increasing electricity demand in New England, and the effects of general inflation. The price trend is much more gradual in constant dollars, with only a modest increase through the early 2030s.
- The upward price trend pauses in the early- to mid-2030s, as substantial volumes of offshore wind capacity are projected to enter the market. This new generation, combined with growing volumes of solar capacity, more than offsets electricity demand growth for several years and puts downward pressure on the New England generation supply stack.
- In the later years of the forecast the upward price trend resumes, as the volume of renewable sources increases but not as rapidly as in the early 2030s. Gradual increases in prices for natural gas and emission allowances also contribute to the increasing price trend.

Projected trends in New England energy market prices are not uniform across the year, as shown in **Figure H-3** below.

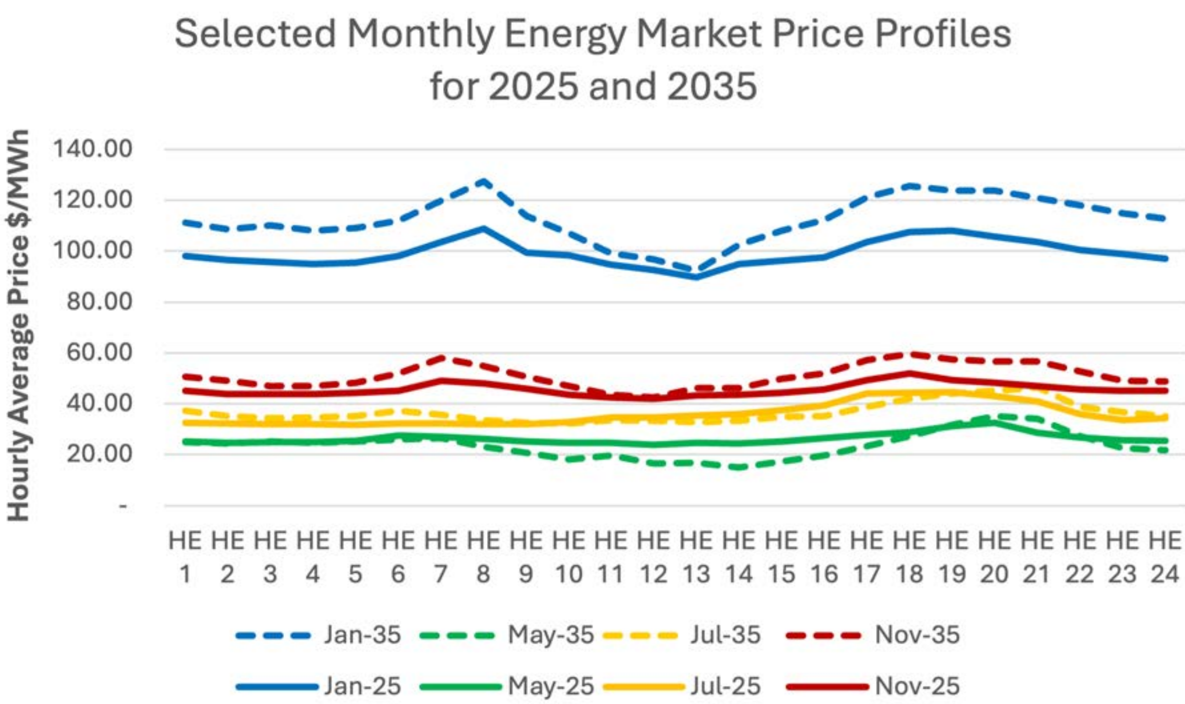


Figure H-3: Selected Monthly Energy Market Price Profiles for 2025 and 2035

Figure H-3 shows projected average energy market prices for hours ending 1 through 24, for four selected months that reflect a range of seasonal electricity market conditions in New England. The chart compares these results for 2025 (solid line) to those in 2035 (dashed line)—when large volumes of electrification demand and renewable generation additions are projected to have significantly transformed the electricity supply. The following trends in the Daymark forecast are notable:

- January market prices (blue lines) increase significantly over the next decade—consistent with forecasted electrification of heating loads in New England—indicating that winter will likely remain the season of highest energy market prices in New England.
- In contrast, market prices in May (green lines) are projected to decline somewhat over the next decade, as output from new renewable generation (particularly solar) during spring months is relatively robust and displaces fossil-fired generation. The price declines are concentrated during daytime hours when solar generation is

highest, with projected average market prices during daytime hours falling noticeably below those in overnight hours.

- Projected energy market prices in all months tend to increase the most during evening and morning peak hours, and the least during midday hours. This is consistent with projected electrification of transportation and home heating in New England, and with expectations that a substantial portion of regional renewable energy supply growth will be solar generation which produces during daylight hours.

It is important to keep in mind that the results above are based on a simulation of conditions well into the future, so actual conditions and numerical price outcomes could turn out differently. Directionally, however, the projected trends of average market prices in **Figure H-3** are noticeable and indicate that it will make sense for GMP to seek a portfolio of energy resources that is reasonably aligned with our customers' electricity use on a seasonal and hourly basis. The projected trends also indicate that resources that provide substantial energy during winter months and during evening/morning peak hours have the potential to provide more value for GMP's customers than would be suggested by market prices averaged across all hours or traditional peak/off-peak periods, while the value of solar energy (highest average production during daytime hours, lowest in winter months) will likely remain somewhat below average. Finally, the trends in hourly energy market price profiles above suggest that opportunities for load shifting and energy storage resources to provide energy arbitrage value for our customers—by shifting energy usage from times when market prices are high toward those when market prices are lower—could increase somewhat over time as price spreads across the hours increase.

Application of Daymark Results to GMP Portfolio

In addition to informing discussion above and in **Chapter 7** with respect to how regional energy market trends could affect GMP's resource procurement decisions, Daymark's regional energy market model results were used to estimate the volumes and pricing associated with GMP's purchases and sales in the ISO-NE spot market over time—reflecting the changes above in the regional market along with the changes in GMP's energy portfolio. Specifically, Daymark simulated the operation of GMP's Illustrative Future Portfolio within the regional market framework discussed above on an hourly basis, comparing the projected output of GMP's generating plants to GMP's projected hourly load requirements.[2] Hourly differences between GMP energy supply and requirements were reflected as purchases or sales from the market, priced at the projected hourly

2 The hourly profiles for New England wind and solar generation in Daymark's model, along with electricity demand, were derived to reflect a 2014 weather year. Therefore, hourly profiles for GMP's wind and solar generation and electricity demand were derived to reflect the same weather year.

energy market prices from Daymark's simulation. The resulting net costs of energy interchange are incorporated into our projection of net power costs (see **Chapter 7, Figure 7-16**).

Portfolio Sensitivity Analysis

A sensitivity analysis can provide insights into the extent to which specific portfolio attributes—we focus primarily on net power costs—can vary based on alternative outcomes for certain planning assumptions. Sources of cost uncertainty applicable to GMP's net power costs include future costs to purchase new renewable supplies, and future wholesale market prices for energy, capacity and RECs in New England.

To characterize potential alternative outcomes, we use data from external information (via subscription or public sources) and our own assessment of market prices and risks, aligned with the electricity demand outcomes described in **Chapter 2**. We visualize the relative sensitivity of GMP portfolio costs to these variables via a tornado chart that illustrates relative impacts on the net present value of the portfolio's costs through 2041. See **Figure 7-17** and associated narrative for the results; input assumptions are discussed in **Appendix I, Cost Sensitivity Analysis**.

We also illustrate the procurement implications of potential paths for electricity demand growth, using the Accelerated Adoption and Continued Adoption cases from **Chapter 2**. In each of the energy and renewable energy gap charts (see **Chapter 7, Portfolio Evaluation**) that depict the Reference Portfolio, the Accelerated Adoption demand scenario is depicted as a solid line while the Continued Adoption case is depicted as a dotted line. To the extent that actual electricity demand growth unfolds along the lines of the Continued Adoption case, GMP will be able to moderate the pace of procurement of renewable energy to meet each RES tier.

The details of the cost sensitivity analysis input assumptions are presented in **Appendix I**.

Appendix I

COST SENSITIVITY ANALYSIS

The goal of the sensitivity analysis is to test the extent to which the costs associated with the Illustrative Future Portfolio could vary based on potential alternative future outcomes for several uncertain factors related to outcomes for the costs associated with new renewable sources, and future regional market prices for energy, RECs and capacity. This appendix provides details on the range of potential future outcomes with respect to these factors, as summarized in the Sensitivity Analysis subsection of Chapter 7. The remainder of this appendix shows the specific sensitivities tested, along with a brief description of what types of conditions could cause them.

For each sensitivity tested, the intent is to capture a large fraction of the potential long-term trend outcomes, but not all potential outcomes. It is also important to recognize that outcomes for particular years can and probably will fall outside of the ranges shown here due to one or more temporary influences such as unusual weather conditions—which can affect both electricity demand and generation.

Sensitivity: Cost of Solar Power to Supply RES Tier II

Our Base Case price path assumes that long-term PPAs will be available from distributed solar projects at fixed levelized prices of about $90/MWh in the near term. This price level is higher than assumed in the 2021 IRP, reflecting more recent project experience as influenced by upward price pressures from higher equipment costs, supply chain delays and higher cost of capital for solar projects. These influences appear to be temporary to a significant degree. Over the long term the industry is projected to return to a trend of gradually declining costs based on technology improvements and increasing manufacturing scale in the solar industry. The Base outlook therefore assumes that solar PPA prices will decline gradually to around $75/MWh in 2035.

In the cost sensitivity analysis we tested two alternative paths for the price of distributed solar power.

- In the Low price path, the price of new solar PPAs is assumed to start a bit lower at $85/MWh, and to decline to about $67/MWh by 2035 (an average decline of about 2.4% per year). This is intended to reflect a future in which technology improvements in capital costs and operating costs put sustained downward pressure on solar project costs.

- In the High price path, the price of new distributed solar PPAs is assumed to start at $95/MWh and to decline more gradually to about $83/MWh by 2035. This path is intended to reflect a future in which technology improvements and increasing solar industry scale continue to put some downward pressure on costs, but other factors (e.g., development costs, land scarcity) also bring upward pressure on project costs.

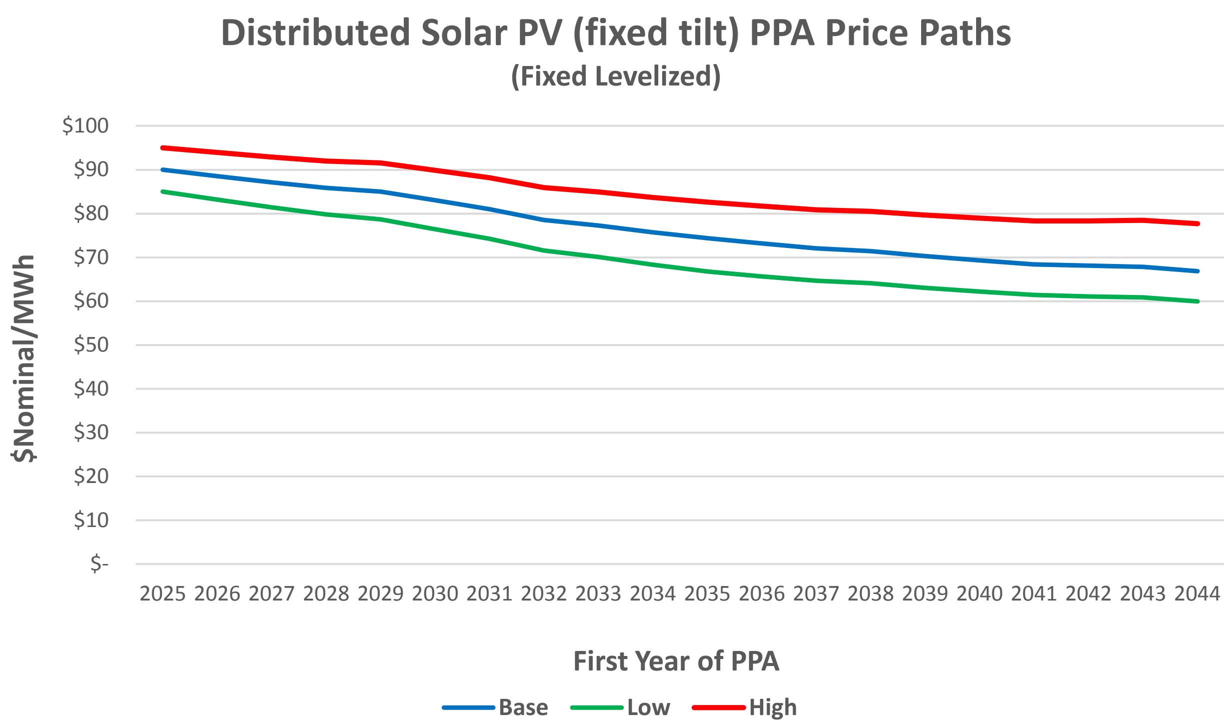


Figure I-1. Distributed Solar PV PPA Price Paths.

The price paths in Figure I-1 above for distributed solar do not include an explicit incremental cost or adder to reflect assumed additional grid upgrade costs or alternative investments like distributed battery storage to increase hosting capacity. As noted in Chapter 7 under Grid Upgrades, VELCO's 2024 Long-Range Transmission Plan and Chapter 3 indicate that the magnitude and required cost of grid upgrades to accommodate new local generation will be greatly limited if the location of that generation is weighted toward areas of Vermont where there is sufficient hosting capacity to accommodate it. It is also reasonable to expect that hosting capacity in some areas could be supplemented using tools that include curtailment of some solar output during light load conditions or by supplementing load during such conditions (e.g., via the influence of retail rate design or flexible load programs).

Sensitivity: Cost of Regional Wind to Supply RES Tier IV

Because wind in New England tends to produce the most energy during winter months, significant additions of wind supply would improve the alignment of GMP's renewable energy supply with our customers' electricity use on a seasonal basis. Offshore wind is presently the largest new renewable source that New England states are pursuing to support the decarbonization of their economies in the 2030s and beyond. Offshore wind (OSW) costs also are projected to decline significantly in the 2030s, based in part on the potential that supporting industries will develop along the East Coast of the United States to enable ongoing deployment with scale economies over time. The hourly screening analysis section of Chapter 7 includes the effects of adding offshore wind to GMP's portfolio.

We recognize, however, that pricing for OSW PPAs has increased greatly in the past few years due to several factors—and that there is presently considerable uncertainty about the availability and pricing of output from OSW projects that could achieve commercial operation in the early to mid-2030s. GMP therefore expects that its procurement of regional wind sources will focus on seeking opportunities to purchase from both OSW projects and land-based projects. Land-based wind PPA opportunities could potentially be supported by existing projects still in operation; by the repowering of existing projects; or by newly constructed projects. GMP's choices among these options—particularly in the next several years—will depend on their relative availability and pricing in the coming years. For example, if actual OSW pricing turns out toward the high end of expectations GMP will likely put greater emphasis on obtaining land-based wind alternatives—and the more likely that such alternatives could be cost-competitive additions compared to OSW.

With this context in mind, GMP's sensitivity tests a range of potential PPA pricing for regional wind—illustrated in Figure I-2 below—that that reflects a blend of these influences. The regional wind costs shown here are generally much higher than those presented in the 2021 IRP, and show a wider range of potential outcomes, informed by the recent OSW industry experience noted above.

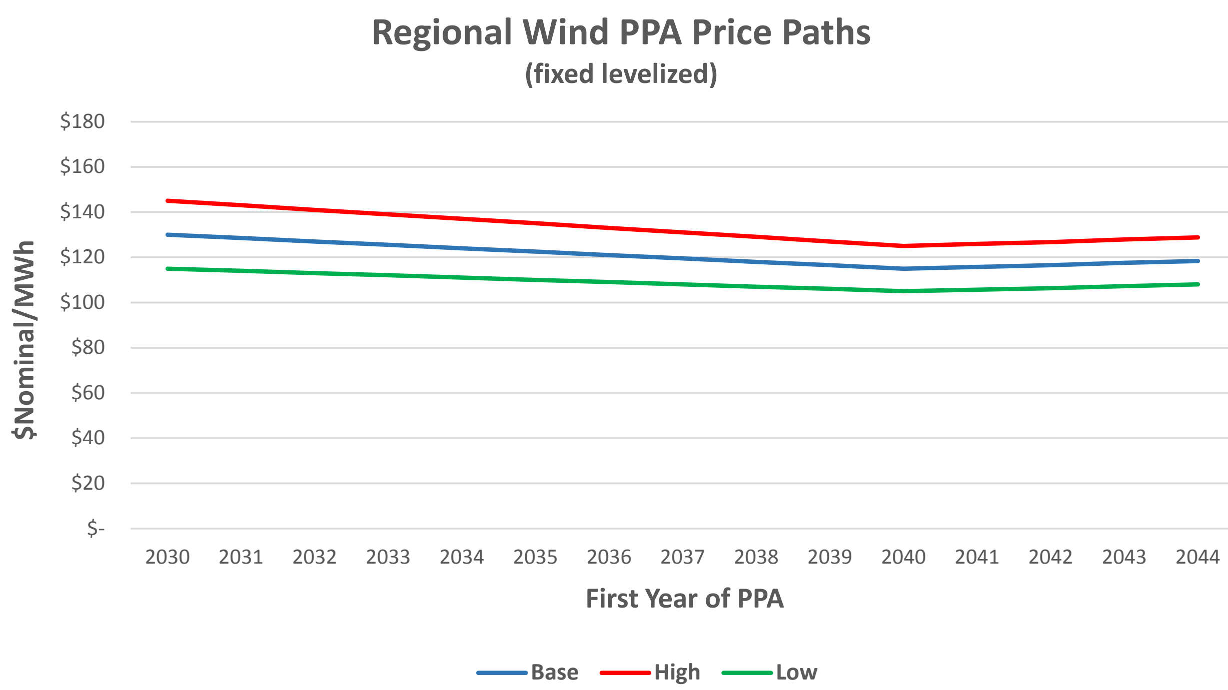


Figure I-2. Potential price paths for regional wind PPAs.

Each price path in **Figure I-2 depicts a potential PPA price**[1] (fixed levelized, no escalation) associated with the start year of the PPA. For example, the Base path represents an average price of about $130/MWh for regional wind PPAs starting deliveries in 2030, declining to about $115/MWh for PPAs starting deliveries in 2040. This path would be consistent with an outcome in which offshore wind PPAs starting deliveries in 2030 are available at a price of $140/MWh—modestly lower than reported recent PPA awards in New York and New Jersey—in combination with GMP obtaining a portion of its wind needs during the 2030s from land-based projects at somewhat lower prices. The Base price path declines significantly over time on an expectation that increasing US OSW industry scale will deliver some efficiencies and cost savings as cited above, while reducing the degree of financial risk associated with development of OSW projects. Many potential combinations of wind contract volumes and pricing are, of course, possible.

The High price path for regional wind PPAs starts significantly higher at $145/MWh in 2030, declining to about $125/MWh by 2040. This path would be consistent with an outcome in which pricing for offshore wind PPAs starting deliveries in 2030 is much higher than in the Base path—for example, on the order of $160/MWh—but GMP purchases only limited volumes of OSW initially and is able to obtain a portion of its wind needs during the 2030s from land-based projects at somewhat lower prices.

1 The regional wind prices discussed here are assumed to cover the cost of transmission upgrades needed to deliver output to a delivery point on the New England bulk transmission system (e.g., for offshore wind, a major substation along the New England coast), consistent with reported PPA pricing in New England. The prices do not include additional major upgrades that could be needed to more fully integrate wind-based supplies and mitigate congestion that arises over time from interconnection of large new wind supplies.

The Low price path for regional wind starts at $115/MWh, declining to $105/MWh in 2040. This price path would be consistent with a future in which recent increases in OSW capital costs and the cost of capital are substantially reversed, allowing OSW pricing in the early 2030s to achieve levels similar to several project proposals in the early 2020s—and well below reported OSW pricing from the past two years. Alternatively, this price path could be achievable for GMP if we are able to obtain a substantial fraction of wind needs from land-based PPAs at prices much lower than OSW options.

Sensitivity: Vermont Tier IV REC Market Prices

This sensitivity tests alternative outcomes for market pricing of RECs that are eligible to supply Tier IV requirements under Vermont's RES. These REC prices can affect GMP's net power costs through the cost of REC purchases to comply with the annual Tier IV requirements, or (primarily in the near term) through the revenue for sale of eligible RECs above those needed to meet the annual Tier IV requirements.

Renewable projects eligible to supply this tier may be sized larger than 5 MW (the maximum project size for Tier II) and are not required to be located in Vermont. The Tier IV eligibility requirements largely overlap with those for Class 1 RPS tiers in neighboring states except with respect to the threshold date for commercial operation,[2] so market prices for regional RPS Class 1 RECs are a reasonable proxy for Vermont Tier IV.

Figure I-3 below shows the Base, High, and Low price paths for Vermont Tier IV RECs that were tested in the sensitivity analysis.

2 Tier IV-eligible renewable projects must have reached commercial operation in the year 2010 or later. At present, threshold commercial operation dates for Class 1 RPS eligibility in several neighboring states are somewhat earlier (i.e., less restrictive).

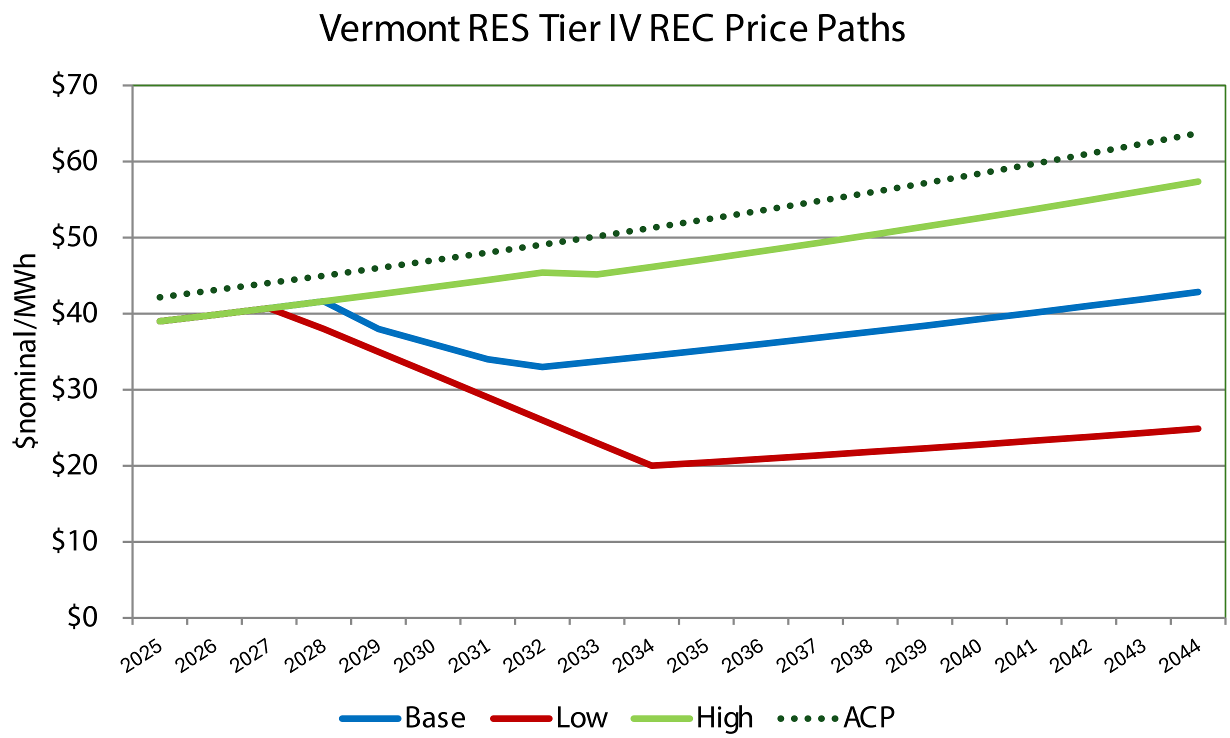


Figure I-3. Vermont RES Tier IV REC market price paths.

Market prices for Tier IV REC prices are likely to be driven primarily by regional considerations—particularly how the supply of RPS Class 1-eligible RECs compares to the collective requirements for them. The regional Class 1 market is presently tight—primarily as a result of delays to offshore wind projects and the NECEC transmission project in Maine—with forward prices for delivery in the next few years approaching $40/REC. The Base price path (blue line) assumes that prices will remain near $40/REC for the next few years, with additions of regional wind (offshore, and perhaps some land-based) bringing supply closer to balance by the early to mid-2030s. Projected REC prices decline to a still substantial level of $33/MWh in 2033 and rise with general inflation thereafter.

In the High price path (green line), Tier IV REC market prices remain fairly close to the ACP for this tier (dashed black line), as the pace of additions of new regional renewables (particularly wind) struggle to keep pace with increasing RPS requirements and growing electricity demand. In the Low price path (red line), Tier IV REC market prices start near ACP levels (consistent with current market conditions), then decline to about $25/REC by the mid-2030s. This path is more consistent with a future in which New England is able to meaningfully accelerate the pace of deployment for new renewables (particularly wind), so that supply of eligible RECs keeps up with the states' ambitious renewable and clean-energy goals. In the absence of increased renewable deployment, the only likely path to a price decline of this magnitude would appear to be one or more New England states reducing their Class 1 RPS requirements to balance them with available supply.

Sensitivity: Vermont Tier I REC Market Prices

RES Tier I features a relatively wide range of renewable resource eligibility—most notably including existing hydro plants—so the market for Tier 1 RECs has historically featured pricing under $5/REC, with temporary excursions to higher levels.

Figure I-4 below shows the Base, High, and Low price paths for Vermont Tier I RECs used in the sensitivity analysis. The common theme is that some noticeable tightening of the supply/demand balance for existing renewables seems likely during the 2020s, but there is uncertainty around the pace and ultimate magnitude of the increase.

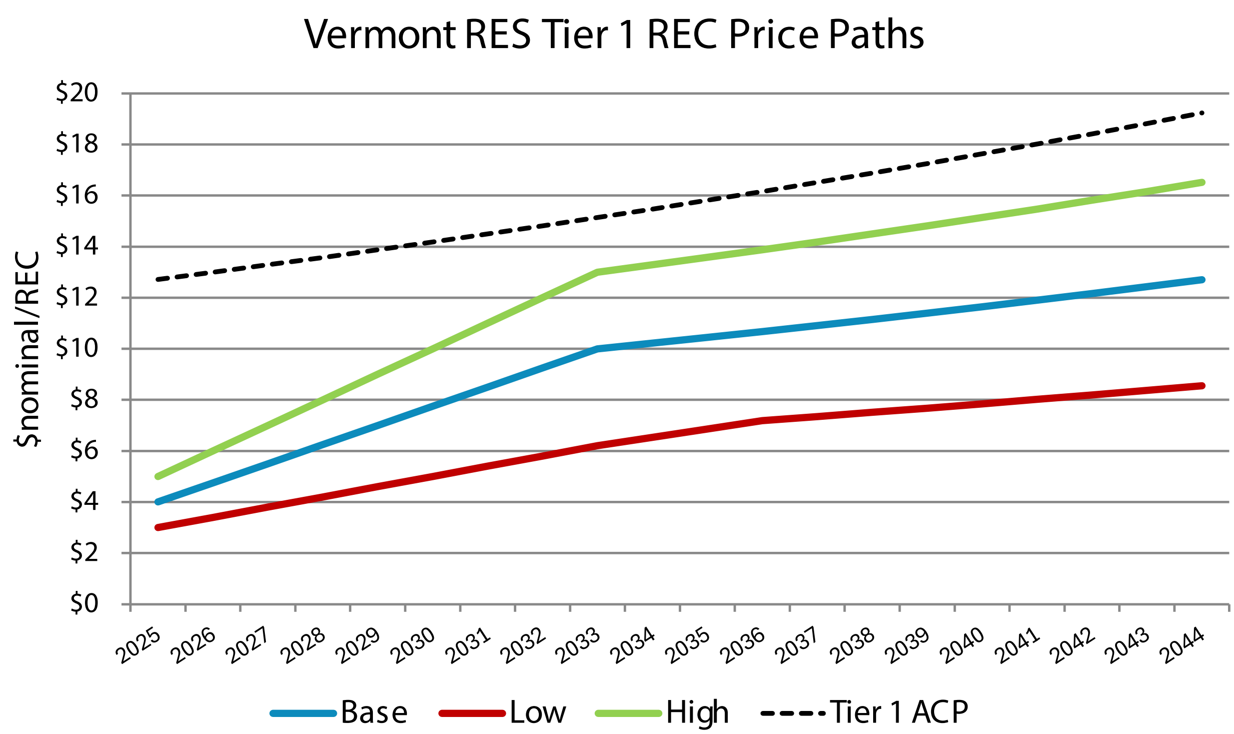


Figure I-4. Vermont Tier I REC market price paths.

GMP's understanding is that renewable and clean energy requirements of neighboring states—including those for which existing renewables are eligible to supply—are slated to grow in the coming years, while the supply of existing renewables within the region is essentially finite. Voluntary demand for existing renewables on the part of corporations and other buyers could also contribute to demand in this market. The Base outlook for Tier 1 REC prices (blue line) therefore features a gradual upward trend through the early 2030s, with the trend slowing at around $10/REC which is the current Alternative Compliance Payment (ACP) level for Massachusetts' Clean Energy Standard.

The High price path (green line) trends closer to the projected Tier 1 ACP (dashed black line), with prices settling higher than $10/REC in the long-term. A price path like this—reflecting a significantly tightening supply/demand balance for existing renewables in New England—appears possible if neighboring states increase their requirements for existing renewable supplies and/or if net supply of existing renewables from Quebec and New York decreases over time. The Low price path would be consistent with a future in which the supply of existing renewables in New England stays in approximate balance with demand—for example, if only limited volumes of existing renewables migrate to New York or if Quebec continues to deliver into New England meaningful volumes of existing renewables that can meet some of the states' requirements for clean/renewable energy.

Sensitivity: Capacity Market Prices

GMP is typically a net buyer of capacity, meaning that the volume of qualified capacity that GMP's long-term power sources can deliver in the ISO-NE capacity market is significantly less than GMP's share of New England's total capacity requirements. This sensitivity tests the effect of higher or lower capacity market prices on GMP's net power costs.

Figure I-5 below shows the three capacity market price outlooks that were tested. Annual forward capacity auctions have already been conducted for the first three capacity years; potential prices diverge thereafter. The capacity market prices depicted below approximate the current market design based on annual capacity commitment periods. As discussed in **Chapter 5**, the ISO-NE capacity market is presently transitioning to a prompt and seasonal market structure—in which capacity auctions are conducted much closer to the capacity commitment period and are conducted for both winter and summer periods. Multiple details about auction parameters and other details remain to be determined, and are expected to become clearer during 2025. Once sufficient details become available to support seasonal forecasting, GMP will likely transition to seasonal assessment of capacity needs and pricing.

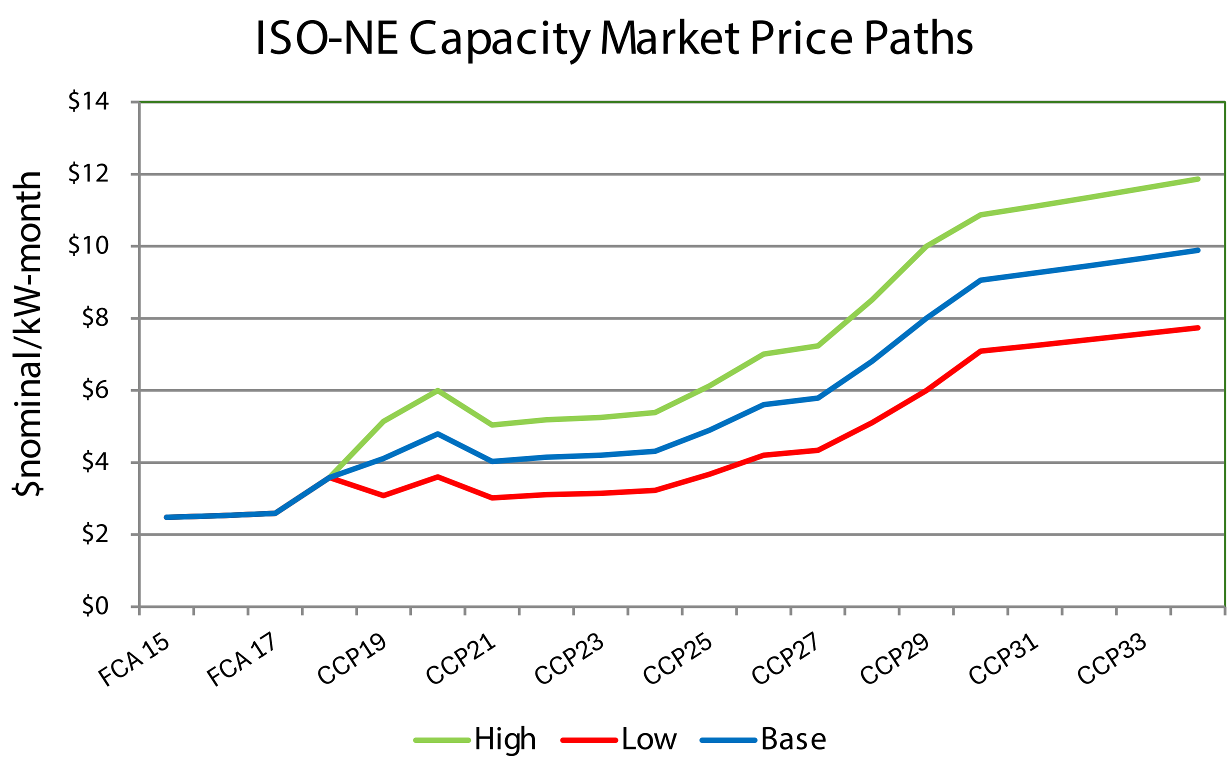


Figure I-5. ISO-NE Capacity Market Price Paths.

The Base outlook (blue line) features some near-term price increases driven primarily by updated auction parameters and an expected net reduction in the volume of qualified capacity that is associated with the existing fleet of New England generating plants under new capacity accreditation methods. This upward price pressure is partly offset by the assumed arrival of capacity from new renewable sources (e.g., NECEC line in Maine; OSW) and potential increases in cleared capacity from imports and presently delisted sources. In the long term electricity demand growth in New England is projected to more than offset capacity supply from new renewable sources, driving capacity clearing prices closer to the estimated net cost for newly constructed battery storage plants or fossil-fired peaking plants to enter the market.

The High and Low capacity price paths reflect a simple adjustment of plus or minus 25 percent of the Base price, respectively, for most of the forecast period. The steep administrative demand curve used in ISO-NE's capacity auction construct makes annual clearing prices sensitive to limited supply/demand changes, so that clearing prices for individual years could credibly fall outside of this range. On the other hand, the significant spread between these cases—which is on the order of $2/kW-month between these cases through the mid-2030s and more in the long-term—seems sufficient to attract entry or exit of capacity resources (e.g., older fossil-fired power plants, imports from neighboring control areas, demand response) that have historically been price sensitive. This limits the likelihood that clearing prices will quickly and permanently move outside the range.

Energy Market Sensitivity: Natural Gas Prices

This sensitivity tests how higher or lower outcomes for natural gas prices—which could be driven by factors that include the pace of demand growth (for direct use, exports of liquefied natural gas, and power generation) and the productivity and cost of future natural gas extraction activities—could affect regional electricity market prices. While GMP's procurement activities will continue to be overwhelmingly focused on renewable power sources, changes in regional market prices can affect GMP's net power costs through short-term balancing purchases and sales of energy, and through the price of energy from existing renewable sources whose offer prices understandably reflect their expected revenues in the New England energy market.

Figure I-6 below illustrates the natural gas price paths that were tested in the sensitivity analysis, representing the Henry Hub trading location in Louisiana for which natural gas futures contracts presently settle.

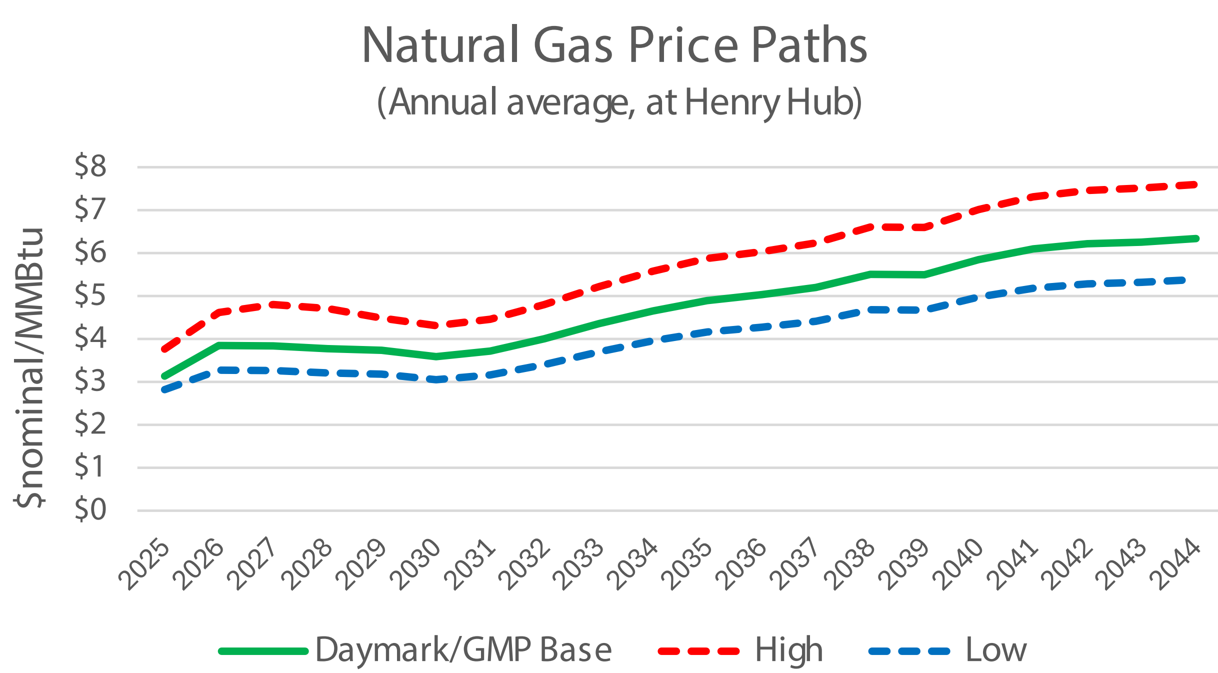


Figure I-6. Natural gas price paths.

The Base price path (blue line) was developed by Daymark based on the 2023 Annual Energy Outlook (AEO). This path features natural gas prices increasing from approximately $3/MMBtu to $4/MMBtu in constant dollars over the next 20 years; the effects of general inflation push prices to over $6/MMBtu in nominal dollars.

The Low price path is 10% below the Base path in 2025, and 15% below the Base price path thereafter. This reduction was informed by inspection of side cases from the 2023 AEO that result in lower US natural gas prices; a 15% decrease captures many of the low-price outcomes but not all of them. The High price path features a 20% increase from the Base price path. We chose a slightly larger variance than the Low price path based in part on recent consultant forecasts suggesting higher potential price outcomes—driven in part by large increases in LNG exports and gradual increases in U.S. electricity demand (which in turn reflect electrification of transportation and heating, and emerging data center load).

The price of natural gas to electric generators in New England has historically included strong seasonal differences in price relative to Henry Hub; Daymark's regional market model appropriately includes projections of these "basis differentials" although they are not shown here. The average basis differentials during peak winter months (when natural gas consumption is highest) essentially triple the price of natural gas to generators in New England, while in some spring and fall months the basis differential tends to be modestly negative (i.e., average price in New England lower than Henry Hub). When testing the implications of higher or lower natural gas prices, Daymark adjusted both Henry Hub prices and the basis differentials to New England.

Energy Market Sensitivity: RGGI Emission Allowance Prices

As noted in **Chapter 7**, purchases of CO_2 emission allowances under the Regional Greenhouse Gas Initiative (RGGI) program have become an important variable operating expense for large fossil-fueled generators in the Northeast, and a significant component of the prices at which fossil-fueled generators offer their energy into the ISO-NE market. Allowance prices can therefore be a significant driver of energy market prices.

This sensitivity tests how wholesale energy market prices would be affected if RGGI allowance prices turn out higher or lower than the prices assumed in Daymark's base regional market model. **Figure I-7** below shows the paths of RGGI allowance prices that were tested.

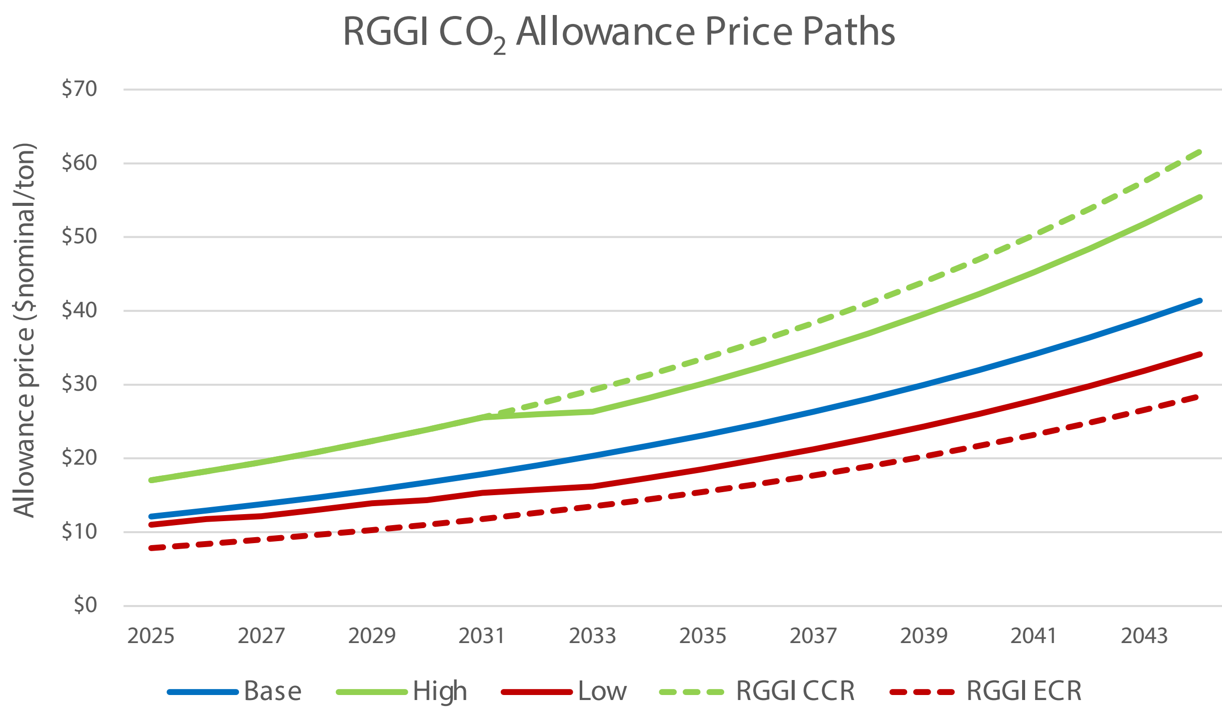


Figure I-7. RGGI emission allowance price paths.

The solid blue line shows the RGGI allowance price path featured in Daymark's base model; these prices are projected to increase significantly over time as the cap on annual CO_2 emissions for the RGGI participating states is gradually reduced.

The high price path (solid green line) is consistent with a future in which the current RGGI program design is maintained in the long-term but supply of RGGI allowances is generally tight—pushing the price of allowances in RGGI auctions to the program's Cost Containment Reserve (CCR)[3] over the next several years and toward that price level in the long term. The likelihood of this path presently appears to be increasing as electricity demand in the region is forecasted to increase over the next decade and offshore wind projects—which have the potential to displace large volumes of emitting generation—have been delayed. Allowance prices in the most recent RGGI auctions have reached levels above the CCR. In contrast, the Low price path would be consistent with a future in which the supply of RGGI allowances can more comfortably cover the volume of actual emissions in the region. This type of outcome—in which the market price for RGGI allowances declines toward the Emissions Containment Reserve (ECR)—could be driven

3 The CCR is not a hard cap for the price of RGGI allowances, but auction pricing above this level triggers the release of additional allowances—making it a point of price resistance when the supply/demand balance for allowances is tight. Similarly, the ECR mechanism entails a reduction in the volume of allowances made available for sale if market prices fall below the established trigger price.

by supply/demand factors (e.g., electricity demand growth slower than current market expectations, robust buildout of offshore wind and other renewables) or potentially by adjustments to the RGGI program design parameters.

For context, projections of the CCR and ECR price levels are included on **Figure I-7** as the dashed green and red lines, respectively.

Energy Market Sensitivity: Reduced Offshore Wind Buildout

As noted in **Appendix H**, large volumes of new wind and solar generation are assumed to enter the market over the next decade, consistent with the New England states' goals to substantially decarbonize the electricity generation sector. The base case includes 8,000 MW of OSW capacity and over 14,000 MW of total solar PV capacity by 2035. The increasing size of the renewable generation fleet—which does not incur fuel expense to operate—puts downward pressure on energy market prices over time, and can affect seasonal and hourly price patterns.

This sensitivity tests how energy market prices in New England would be affected if actual growth in OSW capacity were significantly delayed. Specifically, the projected OSW additions that were assumed in the Daymark base case to reach commercial operation in the years 2029 through 2033—amounting to about 5,800 MW in total—are removed from the analysis. This change would be expected to significantly reduce the displacement of natural gas-fired generation in New England, and to increase energy market clearing prices in many hours.

Summary of Energy Market Sensitivity Results

Figure I-8 below illustrates the projected annual average market prices that were obtained from the regional market price sensitivities above with respect to natural gas prices, RGGI emission allowance prices, and delay of regional wind additions.

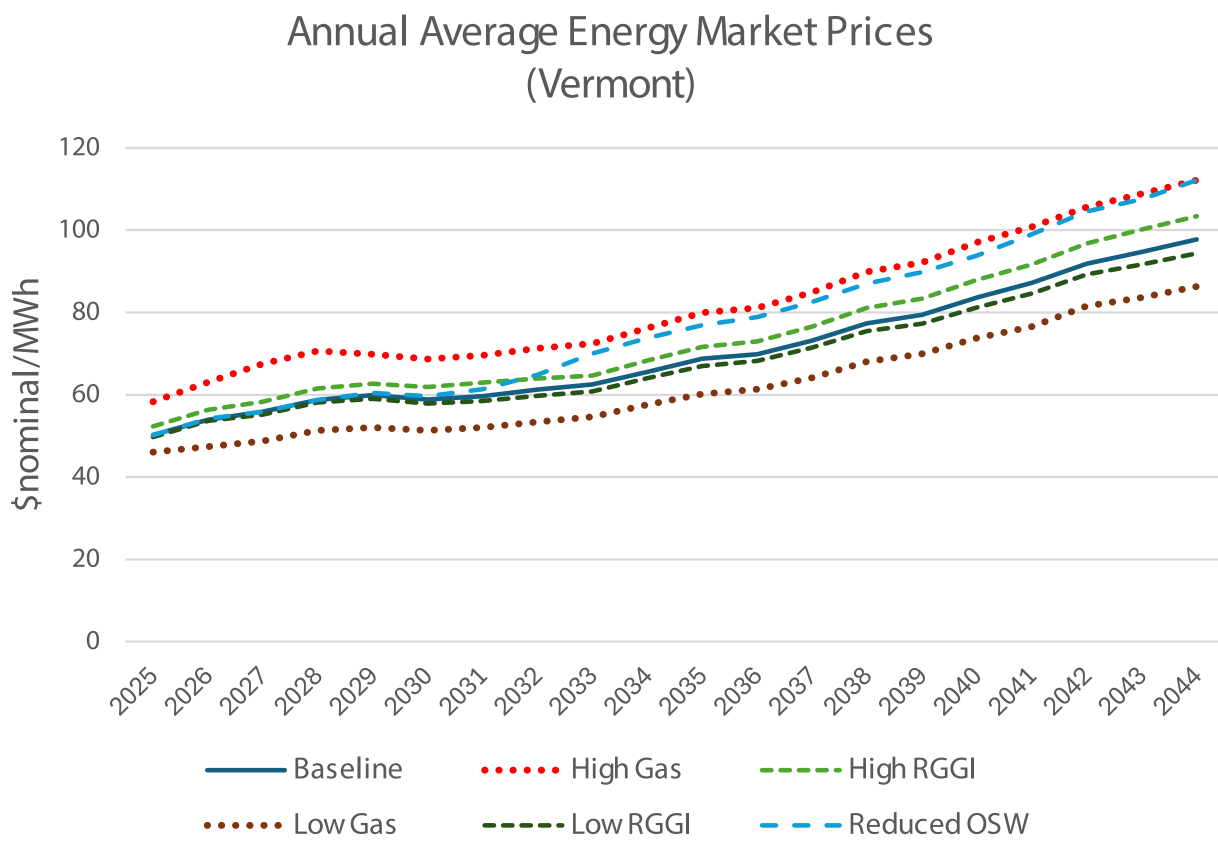


Figure I-8. Annual average energy market price outcomes for regional sensitivity cases.

The natural gas price sensitivities produced the largest differences in projected energy market prices. This is understandable considering that in Daymark's analysis natural gas-fired generating plants are projected to remain New England's marginal energy source during most hours—including in months when market prices are relatively high. Changes in RGGI emission allowance prices produce noticeable although more muted changes in projected energy market prices. The sensitivity in which the volume of offshore wind in New England is reduced yielded a significant increase in projected market prices by the mid-2030s. This sensitivity is a relatively extreme one because it features a substantial and sustained reduction in New England's wind supply—without eventual replacement from alternative wind or other renewable sources—but it reflects the important effects that additional wind power is projected to have on New England's long-term energy supply and market.

Appendix J

S&P GLOBAL RATINGS UPDATE

S&P Global
Ratings

RatingsDirect®

Green Mountain Power Corp.

July 22, 2024

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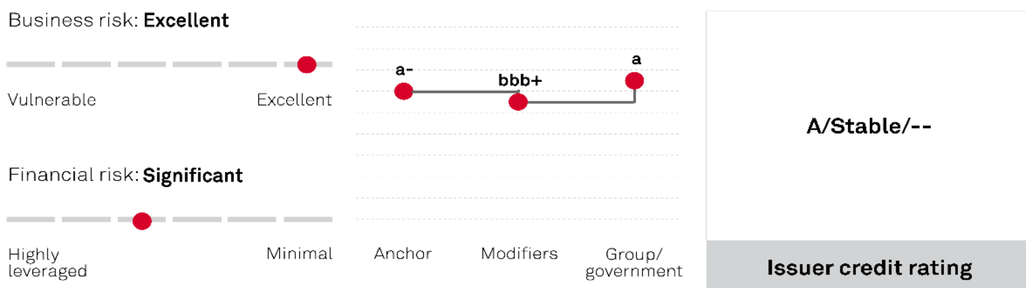
Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Mostly low-risk electric utility operations.	Relatively small customer base and limited geographic and regulatory diversity given operation solely in Vermont.
Operates in a stable and generally supportive regulatory environment that allows for multiyear rate plans (MYRPs).	Service territory exposed to extreme winter events that could damage infrastructure.
Core subsidiary of parent Energir Inc., which leads us to apply two-notches of uplift to the stand-alone credit profile (SACP).	

Green Mountain Power Corp.'s (GMP) credit quality is supported by its low-risk, regulated utility operations. GMP's operations are regulated by the Vermont Public Utilities Commission (VPUC), which we view as generally constructive. In our view, this enhanced GMP's ability to manage its regulatory risk. Rates are set through MYRPs with pre-approved capital expenditure (capex) plans. MYRPs enhance GMP's cash flow predictability and reduce the risks of regulatory lag and material disallowances. Although the company is exposed to severe winter storms and higher costs in Vermont, the company reduces this risk through a storm reserve and the ability to defer excess costs for future recovery. GMP's unconsolidated transmission electric utility investment in Vermont, Vermont Transco (about 77% ownership), is regulated by the Federal Energy Regulatory Commission, which we view as credit supportive because of forward-looking rates and annual true-ups to recover prudently incurred costs.

That said, GMP's business profile is partially constrained by its midsize base of about 266,000 customers and geographic concentration in Vermont. In addition, it has an elevated concentration of high-consumption commercial and industrial customers (greater than 50% of its revenues), which could lead to some cash flow volatility. Overall, we consider GMP's business risk as being in the lower half of our range for the excellent business risk category relative to those of its peers.

We continue to monitor GMP’s zero outage filing. In October 2023, the company filed an “unexpected or strategic capital exception” to its MYRP, requesting $280 million in capex over 2025 and 2026, to underground and storm hardening lines. GMP is proposing to defer the costs associated with the zero-outage plan, with projects in place to be included in the next base-rate proceeding. We expect a decision on the company's zero-outage plan during 2024. We also expect that GMP will seek additional resilience plans from the VPUC beyond 2026.

GMP filed for a fiscal-year 2025 rate increase under its current MYRP. The company is currently operating under an MYRP effective from Oct. 1, 2022, until Sept. 30, 2026, that governs its rates. In June 2024, GMP requested an increase about $38 million (about 5.3%) in its base rates reflecting a formulaic return on equity adjustment (9.97% for 2025 compared to 9.58% for 2024), inflationary adjustments for its operations and maintenance (O&M), and accumulated deferred taxes adjustments. The filing builds on the updated forecasts the company filed in 2023 for its cost of service in fiscal years 2025 and 2026 (ending September) that established a projected, smoothed, annual base rate for the MYRP.

We expect stable financial measures. We expect GMP’s annual rate increases and the dividends it receives from Vermont Transco will support its financial measures. We also expect that, if its zero outage plan is approved, the company capex would increase by about $550 million in 2024-2026 relative to our previous base-case assumption of about $350 million. This robust level of capex would cause GMP to generate negative discretionary cash flow. We expect that the company will use operating cash flow to fund about 40%-60% of its needs and that deficits will be funded by debt and equity contributions. Overall, we expect GMP’s financial measures will be in the middle of our expected range for the significant financial risk profile category. Specifically, we expect its funds from operations (FFO) to debt will be in the 15%-17% range through 2026.

Our rating on GMP’s rating benefits from that of parent Energir Inc. (Energir). We rate the company two notches higher than our SACP to reflect Energir's strong credit quality. We view GMP as a core subsidiary of its parent because it is highly integrated in Energir's main line of business and has a track record of receiving financial support.

Outlook

The stable outlook on GMP reflects our outlook on Energir. The stable outlook on Energir reflects our expectation that it will consistently maintain consolidated FFO to debt of greater than 14%. The outlook also reflects our expectation that Energir will continue to primarily focus on growing its regulated businesses without experiencing any material adverse regulatory decisions. Under our base case, we assume GMP’s stand-alone FFO to debt will be in the 15%-17% range through 2026.

Downside scenario

We could downgrade GMP over the next 24 months if we downgrade Energir or no longer assess GMP as a core subsidiary of its parent. We could lower our rating on Energir over the next 24 months if its consolidated FFO to debt consistently weakens below 14%. This could occur if the company experiences a material adverse regulatory decision, undertakes a material debt-financed acquisition, faces significant operating challenges, or its business risk increases substantially.

Upside scenario

We could raise our rating on GMP over the next 24 months if we upgrade Energir. This could occur if Energir's consolidated FFO to debt consistently improves above 20% absent an increase in its business risk.

Company Description

GMP operates as an electric utility that purchases, generates, transmits, distributes, and sells electricity and utility construction services in Vermont to about 266,000 customers. GMP is a subsidiary of Northern New England Power Corp., which is a subsidiary of Energir Inc.

Group Influence

We view GMP as a core subsidiary of its parent Energir. This assessment reflects our view that it is highly unlikely to be sold; is important to the group's long-term strategy of owning and operating gas and electricity distribution, electricity transmission, and renewable energy generation in Vermont; constitutes a significant proportion (about 30% EBITDA) of Energir's EBITDA; is fully integrated with the parent; and has a strong, long-term commitment of support from the group. In addition, Energir has supported GMP's financial stability since acquiring it in 2007 through equity injections and dividend limitations, contributing to maintaining its capital structure while enabling it to invest in growth opportunities.

Issue Ratings--Recovery Analysis

Key analytical factors

- GMP's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of greater than 1.5x supports a recovery rating of '1+' and an issue-level rating of 'A+', which is one notch above the issuer credit rating.

Rating Component Scores	
Foreign currency issuer credit rating	**A/Stable/--**
Local currency issuer credit rating	**A/Stable/--**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bbb+**

Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of July 22, 2024)*	
Green Mountain Power Corp.	
Issuer Credit Rating	A/Stable/--
Issuer Credit Ratings History	

Ratings Detail (as of July 22, 2024)*	
18-Aug-2021	A/Stable/--
08-Dec-2015	A-/Stable/--
02-Dec-2014	BBB+/Positive/--
Related Entities	
Energir Inc.	
Issuer Credit Rating	A/Stable/--
Energir L.P.	
Issuer Credit Rating	A/Stable/--
Commercial Paper	
Local Currency	A-1
Canada National Scale Commercial Paper	A-1(MID)
Northern New England Energy Corporation	
Issuer Credit Rating	A/Stable/--
Senior Unsecured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Appendix K

GMP SUBSTATIONS

Green Mountain Power manages and operates 185 transmission, distribution, switching, and hydro substations. Of these, 11 are in FEMA-designated 100-year floodplains, and two are in FEMA-designated 500-year floodplains. As defined by FEMA, a 100-year floodplain is a geographic area with a 1.0% chance of flooding every 100 years; in other words, the potential to flood once every 100 years. A 500-year floodplain is a geographic area with a 0.2% chance of flooding every 500 years; in other words, the potential to flood once every 500 years.

Proposed Changes to Our Substations in Floodplains

The Fair Haven substation is proposed to be removed from its location in the 100-year floodplain (Cottage Street, Fair Haven, Rutland County), and rebuilt on Airport Road, Fair Haven in a location outside of the floodplain. GMP submitted an advance notice for the approval to reconstruct and relocate this substation on April 17, 2024 and intends to submit the full petition by the end of 2024.

Substations in FEMA-Designated Floodplains

Table K-1 provides an overview of the substations in either a 100-year or 500-year FEMA designated floodplain.

Substation	Address	County	Floodplain Designation
Brownsville	Churchill Road at Route 44, West Windsor	Windsor	100-year
Dover	37 Kingswood Road, Dover	Windham	100-year
Fair Haven	33 Cottage Street, Fair Haven	Rutland	100-year
Georgia Pacific	0 Riverside Drive, Brattleboro	Windham	100-year
Glen	Route 7, Rutland Town	Rutland	100-year
Riverside	6 Chester Road, Springfield	Windsor	100-year
Riverton	2074 Route 12, Berlin	Washington	500-year
Rochester	237 Peavine Drive, Rochester	Windsor	100-year
Taftsville	Taftsville Covered Bridge Road, Woodstock	Windsor	100-year
Vernon Road	567 Vernon Street, Brattleboro	Windham	100-year
Windsor	26 River Street, Windsor	Windsor	100-year
Winooski	250 West Allen Street, Winooski	Chittenden	100-year
Woodstock	0 Maxham Meadow Way, Woodstock	Windsor	500-year

Table K-1. Substations in FEMA-Designated Floodplains

There is no history of flooding at the Dover, Fair Haven, Riverside, Riverton, Windsor, Winooski, or Woodstock substations. The Brownsville substation experienced minor flooding after the July 2023 storm that caused flooding in many towns around Vermont. The Brownsville, Glen, Rochester, and Taftsville substations all flooded during Tropical Storm Irene in 2011. Brownsville and Glen also experienced some erosion. Taftsville was subsequently repaired; Rochester was rebuilt with elevated control systems.