STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Tariff filing of Green Mountain Power Corporation requesting a change in rates, effective October 1, 2026	)))	Case No. 26-____-TF
Petition of Green Mountain Power for approval of its new multi-year regulation plan pursuant to 30 V.S.A. §§ 209, 218, and 218d.	)))	Case No. 25-1955-PET

PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF MARIA FISCHER ON BEHALF OF GREEN MOUNTAIN POWER

January 16, 2026

Summary of Testimony

Ms. Fischer presents GMP's power supply costs during the Rate Year, Fiscal Year 2027, and describes GMP's power supply portfolio and the primary drivers of recent changes in power supply and transmission costs. Ms. Fischer also explains how GMP developed power supply cost forecasts for the following three years of the Proposed Plan.

Exhibit List

Exhibit GMP-MF-1	Power Supply Cost Summary - Test Year
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PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF MARIA FISCHER ON BEHALF OF GREEN MOUNTAIN POWER

I. Introduction

Q1. Please state your name and occupation.

A1. My name is Maria Fischer. I am the Lead Power Supply Analyst for Green Mountain Power ("GMP").

Q2. Please summarize your educational background and pertinent professional experience.

A2. I have worked for over 16 years in the electric industry, focusing on power supply portfolio planning, wholesale and retail power transactions, and Renewable Energy Credit ("REC") trading. I hold a Bachelor of Arts degree with majors in Mathematics and Economics from Lafayette College.

Starting in 2008 I worked in the power supply departments at Green Mountain Power for seven years and then at Vermont Public Power Supply Authority ("VPPSA") for three years as an Analyst and Trader for energy, capacity, and RECs. In 2018, I joined the Vermont Department of Public Service (the "Department" or "DPS") as a Utilities Economic Analyst. Working within the Department's Planning and Energy Resources Division, I supported the development of state energy policy and implementation of the Renewable Energy Standard ("RES"), reviewed rate cases, and evaluated utility integrated resource planning for electric and natural gas utilities, among other responsibilities.

I rejoined GMP in May 2021, and my current role is Leader of Power Supply Operations. In this capacity, I am responsible for forecasting, tracking, and reporting GMP's power costs. I also helped develop GMP's 2024 Integrated Resource Plan ("IRP").

Q3. Have you previously testified before the Public Utility Commission ("Commission" or "PUC")?

A3. Yes, I have testified before the Public Utility Commission on numerous occasions, on topics that include resource planning, rate case review, and energy efficiency utility efficiency screening. Most relevant to this proceeding, I provided testimony on behalf of GMP in Case No. 22-0175-TF, GMP's Fiscal Year 2023 Rate Case; in Case No. 23-0141-PET, where I presented modifications to GMP's 2023 Multi-Year Regulation Plan's (the "Current Plan") power supply and storm adjuster mechanisms, and in Case No. 25-1955-PET, which is the concurrent petition for approval of a new Multi-Year Regulation Plan (the "Proposed Plan").

Q4. What is the purpose of your testimony?

A4. My testimony explains GMP's power supply, including the significant external cost pressures from regional transmission and energy prices, the impact of inflation, and our overall strategy to provide carbon-free power to customers at a low and stable cost. Specifically, sections II–IV provide the details of GMP's power supply costs in the context of the traditional rate case filing, with summaries for the upcoming Rate Year

(Fiscal Year 2027, or "FY27," beginning in October 2026) and explaining how these costs were developed in response to many upward cost drivers.

I also present in Section V, GMP's forecasts for power supply and revenue expected for the fiscal years of 2028–2030 ("FY28–30"), as supplemental testimony in GMP's concurrent proceeding to review the Proposed Plan (Case No. 25-1955-PET).

II. Overview of This Rate Filing and GMP's Power Portfolio

Q5. Can you please quantify GMP's Rate Year power costs relative to the Test Year at a high level?

A5. For the Rate Year, total power supply-related costs, which include purchased transmission, are \$519.1M, an increase of about \$11.9M from the Test Year (FY25), and \$10.9M higher than the Interim Year, FY26.

Q6. What are the key changes in GMP's net power costs for the Rate Year, relative to the Test Year?

A6. My prefiled direct testimony submitted in the Proposed Plan proceeding summarized the overall trends driving power supply costs leading into, and during the Proposed Plan period. Many of these power cost changes reflect regional and national pressures and fall outside of GMP's direct control. The key changes in GMP's net power costs between the Test Year and the Rate Year include:

- Transmission expenses associated with the regional grid represent the largest cost driver and are expected to continue to increase. The two components with the largest projected increases are Vermont Electric Power Company ("VELCO")[1] Vermont Transmission Agreement ("'91VTA") charges and Regional Network Service ("RNS") charges under the ISO-NE OATT. As explained in the testimony of Ms. Nelson, VELCO recovers most of its costs through ISO-NE OATT, with the remaining costs recovered from Vermont distribution utilities through '91VTA, of which GMP pays a share. The '91VTA cost increase reflected in power supply costs is somewhat offset by an increase in equity in earnings. RNS costs, charged by ISO-NE, are also expected to increase, though to a lesser extent, reflecting higher RNS rates in the Rate Year despite lower forecasted peak loads.

- The implementation of ISO-New England's ("ISO-NE") Day-Ahead Ancillary Services Initiative ("DASI"), replaced the ISO-NE forward reserves market and has resulted in far higher costs than under the prior market design, with costs to date significantly exceeding ISO-NE's original expectations. As part of the original market design, ISO-NE is required to conduct a comprehensive market review at the one-year mark, which will be in spring of 2026. Based on feedback received by ISO-NE from regional stakeholders, GMP anticipates some market adjustments or other program revisions to address these adverse outcomes. Given the uncertainty at this time regarding whether, when, and to what extent ISO-NE may modify DASI, GMP has conservatively included $6M of forecasted DASI costs in the FY27 case.

[1] References to VELCO costs in this testimony also include costs associated with VELCO's affiliate Vermont Transco, LLC which holds most bulk transmission assets in Vermont.

- Higher forward prices for electricity in New England, largely driven by elevated natural gas prices, sharply reduced imports from Quebec (and often exports to Quebec), and policy and supply upheaval related to the stoppage of offshore wind, among other factors. As a result, there are higher expected costs for projected ISO-NE spot market purchases, as well as increased power purchase agreement ("PPA") prices for contracts with indexed pricing features tied to New England energy prices, such as the Hydro-Quebec U.S. ("HQUS") PPA. Higher ancillary service costs, system losses, and congestion charges—each closely tied to ISO-NE Locational Marginal Prices ("LMPs") are also going up, as they are impacted by the higher forward prices.
- Decreased REC revenues are expected due to increased retirement of credits to comply with updates to Vermont's Renewable Energy Standard ("RES"). Additionally, small distributed generation ("DG") projects that came online between January 1, 2010 and June 30, 2015, including many Standard Offer projects that had previously been sold into the Massachusetts Class I REC markets, now qualify for Vermont Tier II and therefore will no longer be sold. This change benefits our customers by helping us meet our Tier II RES requirements, while creating a reduction to REC sale revenues.
- Weather-related impacts, including changing precipitation and runoff patterns have impacted hydroelectric generation. In Summer 2025, Vermont experienced one of the worst droughts in history; August was the driest month in Vermont since records started in 1895. These historic conditions were present during much

of the Test Year resulting in lower-than-average generation. Consistent with prior practice, FY27 forecasted generation is based on a 20-year average with adjustments made for upgrades as well as applicable regulatory requirements that may reduce output.

- Various expirations and starts of new contracts, including for example, deliveries of energy from our long-term PPA from Great River Hydro's Connecticut River and Deerfield River plants will continue to ramp up during the Rate Year. We also have several new renewable PPAs that are expected to begin delivering energy and RECs during the Rate Year, including Twin Wind and some Vermont solar projects selected through our Summer 2025 renewable Request for Proposals ("RFP").
- The GlobalFoundries ("GF") transition period ends at the start of the new Rate Year, at which time GF will no longer be served by GMP. During the Test Year, GF was its own transmission customer but remained a GMP retail customer for energy, capacity, and other services. Beginning in the Rate Year, GMP's load will no longer include GF, resulting in a reduction in our overall load obligation, and accordingly, our allocations of Standard Offer and Ryegate resources, which are based on shares of retail sales, will decline. GMP's Capacity Load Obligation ("CLO") in the ISO New England Forward Capacity Market ("FCM") will also decrease, as will other ISO New England charges assessed on a load basis.
- Three joint-venture solar and battery projects—Milton, Ferrisburgh, and Essex—that have been treated as PPAs to date will now transition to wholly-owned

projects at the start of the Rate Year. This change creates benefits, reducing purchased power costs.

Q7. Please introduce your exhibits.

A7. I sponsor the following exhibits, organized by the categories below:

Test Year Power Supply Cost Information

- **Exh. GMP-MF-1** contains an annual summary of all costs and credits, for FY25.
- **Exh. GMP-MF-3** contains a higher-level monthly summary, for FY25.
- **Exh. GMP-MF-4** through **Exh. GMP-MF-9** contain monthly detailed information for all power supply-related categories, for FY25.

Rate Year Power Supply Cost Information

- **Exh. GMP-MF-2** contains the annual summary of all power-supply-related cost information, for FY27.
- **Exh. GMP-MF-10** contains monthly Rate Year sales and related loads, for FY27.
- **Exh. GMP-MF-11** contains forward energy market prices, for FY27.
- **Exh. GMP-MF-12** through **Exh. GMP-MF-19** contain monthly detailed projections of costs and volumes for all power supply-related categories, for FY27.

Rate Year and Test Year Power Cost Comparisons

- **Exh.GMP-MF-21** compares Rate Year and Test Year energy volumes and costs.
- **Exh. GMP-MF-22** compares Rate Year and Test Year purchased transmission costs.

<u>FY28–FY30 Power Cost Forecast</u>

- **Exh. GMP-MF-23** contains forecasted power costs for FY28–30.

Q8. Please provide an overview of GMP's power supply portfolio.

A8. GMP serves an annual retail load, including distribution system losses, of approximately 4 million MWh/year. Providing that power to customers safely, reliably, and cost effectively is our priority. We procure this energy, and other required products including capacity, RECs, and ancillary services from a variety of sources including owned and purchased physical energy from specific generating plants, system energy market purchases, and other purchase agreements ranging from short-term agreements of a few months to long-term contracts of up to 30 years.

Q9. Please describe GMP's owned resources.

A9. GMP owns, either solely or jointly with others, approximately 371 MW of generating capacity that is expected to provide approximately 835,000 MWh, or just over 20% of GMP's needs in the Rate Year. This is primarily intermittent renewable energy from several dozen hydro facilities, GMP's two wind projects, Kingdom Community Wind and Searsburg, and several solar projects. GMP also owns a share of about 20 MW in the Millstone 3 nuclear plant that is expected to produce about 145,000 MWh of baseload generation. GMP anticipates that the dispatchable wood-fired JC McNeil biomass plant in Burlington, operating at roughly a 44% capacity factor, will provide GMP with about 62,000 MWh of energy, capacity, and Maine Class IA RECs. Finally, GMP owns several combustion turbine and diesel units, along with joint ownership shares in the Wyman 4 oil-fired steam unit in Yarmouth, Maine, and the three Stony Brook intermediate dual fuel combined cycle units in Massachusetts. These units account for about 150 MW of peaking capacity, which provides value in the capacity, DASI and other markets, and provide a minimal amount of energy. They are projected to generate about 9,000 MWh of energy in the Rate Year.

Q10. What are GMP's most significant power supply purchases?

A10. GMP purchases power from a variety of sources and generation types in-state and regionally. GMP's HQUS energy contract will provide about 1.05 million MWh of energy in the Rate Year along with renewable attributes associated with the Hydro-Quebec generation system. The energy from HQUS makes up about a quarter of GMP's energy need for the Rate Year. At least 99%[2] of this energy is from hydroelectric sources and will contribute to meeting our RES Tier I requirement.

The other major resources that GMP purchases power from on a long-term basis include Great River Hydro's fleet of 13 hydroelectric facilities along the Connecticut and Deerfield Rivers, NextEra's Seabrook nuclear plant, the Granite Reliable Wind project, the Deerfield wind project,[3] the Ryegate wood-fired plant, Twin Wind and the Sheldon Springs hydro facility. Each of these sources feature zero air emissions or are relatively low-emitting generators. Great River, Granite, Deerfield, Ryegate, and Twin Wind all

[2] Environmental Attributes delivered have historically been more than 99% renewable, exceeding the contractual requirement that the generation mix be comprised of no less than 90% hydroelectricity.

[3] As described in Mr. Castonguay's prefiled direct testimony supporting the Proposed Plan filing, GMP's receives 100% of the offtake of the Deerfield wind project under a 10-year PPA. That PPA contains an option for GMP to purchase the project during 2027. We are currently analyzing whether a purchase or renewed PPA is in the best interest of customers.

provide RECs that help us meet our RES requirements or be sold as premium RECs in one or more neighboring states, with the REC revenues all going to reduce costs for our customers. In total, these renewable and nuclear PPA sources are projected to supply almost 1.2 million MWhs of energy in the Rate Year, or about 30% of GMP's needs to serve customers.

During the Rate Year, GMP will also purchase over 405,000 MWh under short term, market-based forward energy contracts that GMP has executed in recent years, as well as 58,000 MWh through a short-term off-peak hydro purchase from First Light. These fixed price bilateral purchases provide stability as they are shaped on a monthly basis and by on- and off-peak periods to match GMP's forecasted net short position, helping limit the potential year-to-year and intra-year variances in power costs and retail rates driven by energy market price changes.

Q11. What are the other components of GMP's power supply portfolio?

A11. The rest of GMP's retail load is served through smaller bilateral purchases, spot market purchases, and Vermont programs for net-metering, Standard Offer, and other small renewables.

Standard Offer contracts and net-metering projects are forecasted to provide approximately 480,000 MWh of energy, about 12% of the retail load in the Rate Year. Many of the Standard Offer sources and new net-metered ("NM 2.0+") projects also provide high-value Vermont Tier II RECs that can be used for Tier II compliance to benefit our customers. As new net-metering and Standard Offer projects continue to come online, these sources will contribute an increasing share of our power supply portfolio in the Rate Year.

GMP makes bilateral purchases for energy and/or RECs from several other small renewable projects, mostly hydro and solar. We currently have PPAs with numerous small solar projects throughout Vermont, with over 50 MWs of installed capacity. During the Rate Year, we anticipate that an additional 10 MWs of projects will achieve commercial operation, including projects resulting from our Summer 2025 RFP for renewable energy to support our Tier II obligations.

Energy storage continues to be a growing and important part of GMP's portfolio, with 110 MWs of installed capacity expected by the end of the Rate Year in both residential and grid-scale energy storage systems. These storage projects provide customer value beyond resiliency through outages and other grid events, helping GMP manage monthly peak loads and reduce ISO-NE transmission charges that are allocated based on monthly peak loads.

GMP purchases and sells energy on an hourly basis through the ISO-NE day-ahead and real-time markets (together, the "spot market") as needed to balance load and resources. While GMP plans its long- and short-term energy supplies to align with forecasted load requirements during peak and off-peak periods each month, actual customer demand and the output of intermittent generating sources can fluctuate meaningfully within a given month, resulting in spot market transactions that can be significant. Energy market volatility is generally highest in the winter months, due to weather-driven customer demand for both electricity and natural gas, and intermittent generation. For the Rate Year as a whole, GMP's loads and resources are projected to be closely balanced, with GMP projected to be a net seller of about 120,000 MWh (about 3% of GMP's Rate Year requirements) in the spot market, primarily in the on-peak hours of spring months.

Q12. Please summarize how GMP approached the development of power supply costs for the Rate Year.

A12. Most of the volumes and prices that determine GMP's Rate Year projected net power supply costs are based on values from the Test Year, adjusted to reflect known and measurable changes. These changes include market price conditions for electricity, fuel, and RECs, contractual changes in PPA prices or volumes, and the addition and expiration of certain power sources. As discussed below and in the direct testimony of Laura Doane and Rob Bingel, Rate Year load and sales are based on third-party forecasts for that period. Normalizing adjustments were applied to intermittent power sources for which production tends to fluctuate around long-term average weather values. The most prominent categories of adjustments are as follows:

- Market purchases and sales were adjusted to reflect changes in GMP's forecasted load requirements and the forecasted output of power sources that supply GMP, along with changes in the wholesale market price outlook for energy, capacity, fuel, and RECs.
- Purchased power expenses were adjusted to reflect the expiration of existing PPAs and the addition of new sources (e.g., new Standard Offer projects, Twin

Wind, Vermont solar PPAs, system purchases and sales, and GMP Microgrid Solar projects transferring to wholly owned facilities during the Rate Year).

- Purchased power expenses were adjusted to reflect contractual price changes in existing PPAs (e.g., for HQUS energy, NextEra Seabrook, Granite Reliable Wind, Great River Hydro), volume changes for some sources, and weather normalization for intermittent sources.
- Transmission expenses were adjusted to reflect VELCO and ISO-NE projections for regional transmission rates, along with the estimated monthly peak loads upon which these expenses are allocated.
- Capacity-related expenses were adjusted to reflect known changes in ISO-NE FCM pricing, changes to contracted capacity supply volumes, and updates to GMP's projected share of regional capacity obligations. These updates incorporate the transition of GF to covering its own capacity obligation beginning at the start of the Rate Year.
- Forward reserve expenses were adjusted to account for ISO-NE's implementation of the DASI Market based on actual incurred costs, which have been much higher than originally forecasted by ISO-NE (for GMP and other market purchasers) and potential market changes. As described further below, GMP has reflected $6M of DASI costs in the Rate Year.
- Energy output from intermittent renewable sources was adjusted to reflect normalized or long-term average volumes and planned outages for maintenance and upgrades.

- Fuel prices at GMP's owned and jointly owned fossil-fired units were adjusted on a plant-specific basis based on recent future market prices for oil and natural gas.
- REC quantities were revised to reflect long-term average generation from GMP-owned resources and PPAs. Net REC revenues were updated to incorporate forward sales executed for delivery during the Rate Year and revised market price assumptions for projected REC volumes not yet sold. Resource eligibility classifications were also updated to align with current state criteria (e.g., Standard Offer projects reclassified from Vermont Tier I to Vermont Tier II).
- RES costs were updated to reflect the expected compliance cost of RES Tiers I, II, III, and now Tier IV during the Rate Year.
- Operating & Maintenance ("O&M") expenses for GMP's wholly owned generating units were adjusted to reflect the most recent forecasts of those expenses, as discussed in Mr. Castonguay's testimony; O&M expenses for jointly owned plants reflect five-year averages.

Many of these changes are discussed in more detail in Section III of my testimony.

Q13. What volume of retail load is reflected in the GMP Rate Year power costs that you are presenting?

A13. The power costs for the Rate Year reflect a total load requirement of about 4 million MWh. That is the forecasted GMP retail sales volume for the year, as developed by the consulting firm, Itron, plus energy losses on the distribution and sub-transmission system.

Ms. Doane and Mr. Bingel introduce and discuss the Itron forecast in their joint testimony.

Q14. How are GMP's Rate Year power supply costs represented in GMP's cost of service filing?

A14. Overall, projected total power-supply-related costs increased $11.9M from the Test Year to the Rate Year. The changes are reflected in **Exh. GMP-LD-RB-3** as the following Cost of Service ("COS") Adjustments:

COS Adjustment	**Amount**
COS Adjustment 1: Purchased Power. This adjustment includes all purchased power costs, including net-metering, and all resales of power, including REC revenues and reflects reduced GF load obligation.	$5.317M decrease
COS Adjustment 2a: Production Fuel costs	$0.496M decrease
COS Adjustment 2b: Joint Ownership costs (O&M)	$0.366M increase
COS Adjustment 2c: GMP Owned Production (O&M) costs	$1.190M increase
COS Adjustment 3: Transmission by Others ("TbyO")	$19.205M increase
COS Adjustment 4: Other Transmission-related costs	$1.398M increase

Additionally, the Test Year COS for power supply included the MYRP smoothing deferral of $4.5M, which is not applicable in the Rate Year. These changes are discussed in greater detail in the following sections of my testimony, except for wholly- and joint-owned O&M costs, which are addressed by Mr. Castonguay.

III. Rate Year Power Supply Costs

Q15. What is the purpose of this section of your testimony?

A15. I explain in detail the changes in GMP's net power costs from the Test Year to the Rate Year. Some of these changes affect several power cost components, so I will generally explain these linked updates together.

Forward Energy Prices

Q16. Please describe the drivers of current trends in forward prices for around-the-clock energy in New England.

A16. Inflation, lack of new generation plants like once expected offshore wind, and national events continue to create volatile energy markets. Current forward prices for around-the-clock ("ATC") energy in New England reflect higher expected costs and increased risk in serving load across all hours, particularly during winter months and evening periods when solar generation is unavailable. The primary driver of LMPs in the region remains natural gas forward prices, as gas-fired generation sets the marginal price in many hours. Forward markets reflect persistent regional pipeline constraints, heightened winter fuel price volatility, and increased liquefied natural gas ("LNG") exports that have reduced the availability of domestic supply. Forward prices also incorporate greater uncertainty related to weather and load, influenced by recent cold winters, extreme heat events, and growing electric demand.

Higher forward prices are further supported by uncertainty around the timing and scale of new supply, particularly offshore wind, which has experienced project delays and cancellations. Regional imports—especially from Hydro-Québec—have also declined significantly in recent months due to extreme drought conditions, increased winter demand in Québec, and concerns about electric system adequacy. DASI market high-cost impacts and uncertainty, higher emissions compliance costs under the Regional Greenhouse Gas Initiative, together with ongoing market design and capacity reforms, add additional risk premiums. Collectively, these factors have led market participants to price higher expected costs and greater uncertainty into forward ATC energy products in New England.

Relative to the Test Year, the annual average ATC price for the Rate Year is approximately 9 percent higher. However, monthly on-peak and off-peak prices vary more significantly. The largest increases relative to Test Year prices occur in November off-peak periods when Rate Year forwards are 65 percent higher than Test Year actual prices, while February off-peak forward prices for the Rate Year are approximately 20 percent lower than actual Test Year prices.

Q17. How are forward energy prices reflected in the Rate Year power costs?

A17. As previously explained, GMP makes forward energy sales and purchases to seasonally balance supply and demand, typically buying additional supply in winter months and selling excess supply in spring and summer. GMP also purchases and sells energy on an hourly basis in the ISO-NE day-ahead and real-time markets. To estimate the expense and revenue resulting from GMP's open energy positions, we apply forward price quotations that approximate fixed prices for future monthly deliveries. For Rate Year power costs, GMP has used broker quotes from November 6, 2025. Higher forward prices, particularly during peak winter months, typically result in higher costs for spot market purchases, which are somewhat offset by higher revenues from spot market sales.

As noted previously, the HQUS PPA price also has a component tied to market prices, both historical and forward. Congestion, losses, and other ISO-required ancillary charges also tend to be closely linked to LMPs and are reflected in forecasted costs.

HQUS PPA

Q18. How is the HQUS PPA reflected in GMP's Rate Year costs?

A18. The HQUS PPA price is formula-based with components tied to inflation and historical and forward energy prices. Each year, this price is adjusted based on a weighted average of:

- The Reference Price, which is the first-year price escalated by the general level of prices in the U.S. economy as determined by a lagging measure of the GNP-IPD weighted at 60%.
- The Energy Market Price Index ("EMPI") reflecting an average of one-year historical actual Highgate node pricing for the contract profile (7x16) and one-year forward on-peak New England Hub traded energy prices, adjusted for the delivery point and 7x16 delivery profile, weighted at 40%
- Annual price changes are subject to a 15% annual upward or downward limit.

Applying current inflation, historical prices through September 2025, and on-peak forward market prices results in a price of $75.97/MWh for deliveries beginning November 1, 2026. The current contract year, which runs through October 31, 2026 and applies to one month of the Rate Year, is priced at $73.89/MWh. The average contract price during the Test Year was $67.42/MWh, and the projected average price for the Rate Year is $75.79/MWh, resulting in an approximate $8.8 million increase in HQUS PPA expense relative to the Test Year. If inflation and energy prices moderate, then the HQUS PPA price and year-over-year changes should also moderate.

Inflation

Q19. How does inflation impact power supply costs for the Rate Year, and how is this reflected in GMP's Rate Year power costs?

A19. The impact of inflation on power supply costs during the Rate Year is primarily driven by the application of inflation index values to some of GMP's largest supply contracts. Two of GMP's long-term PPAs—HQUS and NextEra Seabrook—have prices that are adjusted based on a national inflation index[4] and adjusted annually. Inflation index values have stabilized in recent years following the high inflation environment after the pandemic. For the Rate Year and the remainder of the MYRP period, GMP projects inflation rates in the low-to-mid 2 percent range.

DASI Expense

Q20. Can you describe how the DASI market works and how it differs from the Forward Reserves Market?

A20. DASI was implemented on March 1, 2025, and replaced the former Forward Reserve Market ("FRM"). It is designed to provide visibility and compensation to resources

[4] The HQUS PPA utilizes the Gross National Product-Implicit Price Deflator index ("GNP-IPD"); the NextEra PPA utilizes the Gross Domestic Product-Implicit Price Deflator index.

fulfilling contingency reserve and reliability requirements. While the FRM was a forward commitment mechanism that therefore allowed greater forecast certainty, DASI is an hourly day-ahead market that is by its nature harder to forecast, particularly in these early stages of operation. While DASI is designed to more accurately value resources capable of providing flexibility and reliability and to better align market outcomes with system needs, it remains unclear whether it is achieving these objectives in a cost-effective manner. Although there is insufficient operational data at this time to fully assess DASI's performance relative to ISO-NE's stated goals, it is clear that costs to date are significantly higher than ISO-NE originally forecast, indicating that the market is not operating as cost-effectively as anticipated.

Q21. What have been the results of DASI since the market opened in March 2025?

A21. In the December 2025 NEPOOL Participants Committee Report, it was reported that average gross credits awarded through DASI were $1.15M per day. On an annual basis, this would translate to almost $420M in credits awarded to generators in New England. The market has not yet been in operation for a full year, and actual costs may exceed this projection, particularly given that incremental DASI-related charges totaled nearly $260M regionwide for just the six-month period March 2025 through August 2025.[5] For context, prior to the implementation of DASI, ISO estimated the costs to be

[5] The Internal Market Monitor noted that from the outset of the DASI in March 2025 through August 2025, approximately $260M in incremental costs were created, nearly double the amount an earlier ISO-NE forecast had indicated. [Citation for first is Summer 2025 IMM report page 45 and second is an ISO NE model from 2021 for the DASI market]

approximately $100M per year, as reported at the May 9, 2023, NEPOOL Markets Committee meeting.

Q22. What DASI-related costs has GMP incurred since the implementation of the market, and how has GMP mitigated those costs?

A22. DASI costs are allocated to all awarded real-time load. Through November 2025, GMP's gross DASI charges totaled more than $14 million. GMP has taken active steps to mitigate these impacts by leveraging its own resources that are eligible for compensation under DASI and by participating actively in the market as part of a broader cost-mitigation strategy. Through this participation and asset optimization, GMP has offset a portion of its gross charges, reducing net DASI costs to approximately $10.1M through November 2025. Despite these mitigation efforts, GMP's average monthly net DASI costs have exceeded $1.1M.

Q23. What is being done to account for the uncertainty and rate impact created by this new market, and how is GMP reflecting it in the FY27 case?

A23. Since DASI's launch, ISO-NE has received feedback from many market participants and consumer advocates regarding the untenable impact of these significantly higher costs than originally anticipated. Upon completion of the first year of DASI operations, ISO-NE will conduct a market review in spring 2026. GMP remains involved in the process through various committees and regional stakeholder forums and will continue to share our experience and data to help inform the review and reinforce the need for overall market adjustments. That review will likely demonstrate that DASI costs have been multiple times higher than initial projections. While no formal redesign has been proposed to date, the required reporting mechanisms allow market participants and consumer advocates to seek changes. ISO-NE has indicated that at least one year of data is required prior to making modifications or suspending the initiative, and recent DASI charges have not improved relative to pre-launch expectations.

Given this uncertainty, we have reflected $500,000 per month, or $6M annually in our Rate Year forecast.[6] It is not just and reasonable to charge customers upfront for the full net costs experienced based upon the limited data thus far, especially given how much higher those costs have been than the experts at ISO-NE had predicted. The $6M included in Rate Year costs is a material but conservative estimate and reflects a reasonable expectation of future DASI costs as the market evolves.

Net-Metering

Q24. What are the costs associated with net-metering?

A24. The power supply costs associated with net-metering for the Rate Year are $60.5M for 331,000 MWh of energy (about $183/MWh), reflecting an increase of $6.4M over the Test Year for 22,000 MWh of additional energy in the Rate Year. This increase reflects continued additions of net-metered generation combined with increasing rates due to a higher blended residential rate.

[6] The forecast applies this uniformly across the Rate Year. While DASI charges appear to increase during periods of higher LMPs, assumed flat monthly costs were applied due to the absence of winter operating experience under the program, which is expected to bring the highest costs. Consistent with Forward Reserve Market costs, DASI charges are included in Component A.

Q25. Does this represent the full impact of net-metering costs on GMP's rates?

A25. No. In addition to the power supply costs described above, net-metered generation that is consumed by customers onsite reduces GMP's retail sales (kWh), which increases GMP's rates for customers by spreading fixed costs over fewer kilowatt-hours. This effect is incorporated in GMP's retail sales and revenue forecast.

Q26. How does net-metering generally affect GMP's Rate Year power costs?

A26. Net-metering affects GMP's Rate Year power costs by increasing purchased power expenses for net-metered excess generation, reducing wholesale energy purchases during periods of high solar output, and lowering retail sales. These impacts are designed to be partially offset by the value of RECs transferred to GMP for RES compliance and by limited capacity-related savings, all of which are reflected in the Rate Year power cost forecast.

Q27. Is net-metering capacity expected to continue to grow in the Rate Year?

A27. Yes, but new additions are expected to be lower than in prior years due to the expiration of the federal Investment Tax Credit ("ITC"), reduced net-metering adjustors, and net-metering rule changes, particularly for larger group net-metering projects.

Q28. How much net-metering capacity is included in Rate Year costs?

A28. The Rate Year forecast is based on existing installed projects, projects currently in the interconnection queue, and modest new applications consistent with recent trends. Net-metering projects are categorized by program (e.g. NM 1.0, NM 2.0, NM 2.1, etc.) based on their application date and costs estimated based on the program's compensation rates and applicable adjustors. As of August 2025, there were about 312 MW[7] of solar net-metered projects online in GMP's territory, and an additional 19 MW that have submitted applications but are not yet built. The table below shows a summary of the project applications and installations by program at the end of 2025.

PROGRAM	NM 1.0	NM 2.0	NM 2.1	NM 2.2	NM 2.3	NM 2.4	NM 2.5	NM 2.6	TOTAL
Active	141	48	25	37	18	18	22	4	**312**
Proposed	0	0	0	2	2	1	11	4	**19**
Total	**141**	**48**	**25**	**38**	**19**	**19**	**33**	**8**	**331**

During the Rate Year, GMP assumes that 10 MW of net-metered capacity will be installed, resulting in 334 MW of solar net-metering to be online in our territory by the end of the Rate Year.

Other Renewable Power Sources

Q29. Do the changes in GMP's power supply mix in the Rate Year include any increases in supply from renewable sources?

A29. Yes. GMP's power supply strategy continues to focus on achieving a low-cost, low-carbon, and reliable portfolio and has included additions of renewable resources in recent years. Since 2020, GMP has maintained a carbon-free energy portfolio, and expects to continue doing so on an annual basis. Vermont's current RES requires that GMP be 100% renewable by 2030.

[7] At the end of 2025, there was 317 MW of installed net-metering capacity made up of 312 MW of solar and 5 MW of non-solar projects.

Notable changes in the Rate Year power supply include anticipated increases in production from net-metering and Standard Offer programs, increasing volumes from the Great River Hydro PPA, the start of Twin Wind PPA, and the conversion of three joint venture solar and storage projects from PPAs to wholly-owned generators. Many of the other changes in GMP's power supply mix are associated with shorter-term transactions that GMP uses to manage the size and cost of its open position, while also managing GMP's power costs and thereby the retail rates that our customers pay.

Q30. Are GMP's purchases under Standard Offer reflected in the Rate Year power costs?

A30. Yes. All projects that are currently online as part of Standard Offer are included in the Rate Year power costs at the contracted prices. Additionally, GMP has worked with the administrator VEPP Inc. to identify projects that have been awarded Standard Offer contracts and are likely to be online during the Rate Year. These projects are also reflected in GMP's Rate Year power costs. Standard Offer costs included in the Rate Year are $20.2M, compared to the $18.1M that was included in the Test Year. Contract prices continue to trend downward, with some of the most recent solar projects achieving commercial operation priced as low as $82/MWh.

Standard offer generation and associated costs are allocated to Vermont utilities based on their share of statewide retail sales, with some utilities receiving an exemption. Historically, GMP's allocation was approximately 82 percent of Standard Offer projects. Beginning at the start of the Rate Year, GF will be allocated its own share of Standard Offer projects, reducing GMP's share by approximately 6 percent, to about 76 percent.

Q31. What are the changes to Great River Hydro in the Rate Year?

A31. The Great River Hydro PPA continues to ramp up as contracted in both delivered volumes and price during the Rate Year. GMP expects to receive approximately 279,000 MWh of peaking energy under the contract in the Rate Year, compared to 183,000 MWh delivered in the Test Year. As a result of the increased volumes and pricing structure, Rate Year costs for the Great River Hydro PPA are forecast to be approximately $4.9 million more than Test Year costs with a corresponding reduction in our ISO purchase need.

Q32. Please describe the Twin Wind PPA and the expected generation.

A32. Twin Wind is an 18 MW proposed wind project in Rumford, Maine from which GMP has a PPA to purchase the unit-contingent energy and RECs. GMP expects to begin receiving energy and the associated RECs, which will qualify for Vermont Tier IV at the start of calendar year 2027. The project is forecast to generate approximately 42,000 MWh of energy in the Rate Year.

Q33. How are GMP Joint Venture Solar and Storage entities included in the Rate Year power costs?

A33. As detailed in Ms. Doane and Mr. Bingel's testimony, on October 1, 2027, the three GMP joint venture solar and storage projects—Milton, Ferrisburgh, and Essex— will become wholly owned by GMP. The Test Year included $3.2M in PPA costs as well as $30/MWh REC expenses from these projects. With the transition to GMP ownership, there will be no PPA costs or REC expenses associated with the 24,000 MWhs of expected annual generation from these projects beginning in the Rate Year. Additional costs are included elsewhere in the Cost of Service.

REC Revenues and RES Compliance Costs

Q34. Please describe how GMP participates in REC markets.

A34. GMP's supply portfolio produces significant volumes of RECs from wind, solar, hydroelectric, and biomass sources, many of which qualify as Class I or Class II resources for RPSs in neighboring states. These RECs are tracked in the NEPOOL Generation Information System ("GIS," or "NEPOOL GIS"), the platform used to track environmental attributes for each MWh of generation delivered in ISO-NE. Each environmental attribute describes the fuel type, emission rate, renewable program eligibility, and other attributes.

GMP participates in REC markets as both a buyer and as a seller. GMP acquires and retires RECs to comply with Vermont's RES, including with the Tier I, Tier II, and Tier IV, as updated by Act 179 of 2024. GMP retires RECs from both owned and purchased resources for compliance. The costs of retired RECs are represented as a power supply expense in RES compliance costs.

GMP also sells RECs that are not needed for Vermont RES compliance. Most REC sales are associated with renewable generators whose RECs are not used for our RES compliance because they have greater value in other markets. These mostly include projects that were developed during the past decade and are eligible as Class 1 RECs in neighboring states but were only eligible for Tier I in Vermont.

Updates to Vermont's RES shifted the online eligibility date from July 1, 2015, to January 1, 2010, for Tier II eligibility, and introduced Tier IV, requiring the retirement of RECs from regional new renewables in 2027. As a result, several projects that were historically sold as premium RECs in neighboring states will instead be retired for Tier II or Tier IV RES compliance, reducing REC revenues. When GMP sells RECs, the resulting revenue is used to reduce GMP's net power costs and retail rates which directly benefits customers, and the associated generation is not counted as renewable energy delivered to our customers.

Q35. What are the Vermont RES requirements that apply during the Rate Year and how does GMP retire RECs to meet these requirements?

A35. Vermont's RES was changed by Act 179 of 2024, effective for the calendar year 2025 (nine months of the Test Year). Under the updates, RES compliance requirements for calendar year 2027 are 63%, 9.8%, 8.66%, and 4% of annual load for Tiers I through IV, respectively. GMP works to meet the RES requirements in the most cost-effective way for customers by continuing to procure renewable power and achieve Tier III savings at the lowest cost. The net power costs for the Rate Year include the cost of RES compliance for 2026 and 2027.

As mentioned, beginning at the start of the Rate Year, GF will no longer be included in GMP's load, thereby reducing the total load for which GMP must demonstrate RES compliance. While overall load decreases from the Test Year to the Rate Year, the increasing RES compliance percentages result in a net increase in compliance-related costs.

During the Test Year, GMP sold most high-value RECs, except for those required to meet GMP's obligations under Tier II of Vermont's RES program, and those needed to cover volumes subscribed to under GMP's voluntary retail green power programs. GMP also retired Tier I–eligible RECs to comply with Tier I requirements. In the Rate Year, GMP anticipates retiring a greater volume of RECs to meet the increased RES requirements taking effect, while continuing to pursue a similar strategy of monetizing RECs not required for compliance in order to minimize overall power costs for customers. Rate Year REC revenues and RES compliance costs have been adjusted to reflect the updated load forecast excluding GF, as well as the increased level of REC retirements required for compliance.

Q36. Can you summarize how and when GMP conducts its REC sales?

A36. GMP has sold a portion of the projected Rate Year supply of high-value RECs on a forward basis, under contracts that were negotiated from a few months to several years in advance of delivery. These transactions are mostly fixed-volume, fixed-price contracts that reflect the regional market for Class 1 RPS supply at the time they are negotiated. This strategy stabilizes net power costs and mitigates customer exposure to potential declines in regional REC market prices. We have assumed that the remainder of the REC supply will ultimately be sold at prices that reflect recent broker quotes. In total, we project that GMP's Rate Year premium REC sales will amount to approximately 815,000 RECs, at an average sale price around $35/REC, for gross revenue of almost $32M to reduce overall rates.

Q37. Please explain how REC sales are accounted for.

A37. GMP first recognizes REC revenues net of the portion of PPA prices that GMP accrues for the cost of RECs produced by most renewable PPA sources (e.g., Granite Reliable Wind, Deerfield Wind, etc.) and any associated REC sale transaction costs such as broker fees. Second, the creation and delivery of RECs in the NEPOOL GIS, and the revenue that GMP receives from REC sales in that quarter, are conducted on a quarterly basis that lags production of the associated energy by approximately six months. Consistent with this lag, estimated REC revenues for the Rate Year are based on renewable energy production from the applicable sources during the 12-month period from April 2026 through March 2027.

Q38. What are the estimated net REC revenues for the Rate Year?

A38. **Exh. GMP-MF-18** presents the Rate Year figures by month, broken out by major components. After incorporating the REC purchase portion of PPA expenses that are noted above, the resulting net REC revenue is about $14.2M for the Rate Year, a decrease of $0.8M over the Test Year. While GMP continues to increase its renewable energy procurements, REC sales have declined because a greater share of RECs are retired to meet the current state RES compliance obligations and to support progress toward the 100 percent renewable requirement by 2030. This reduction is partially offset by hydro upgrades that have resulted in additional GMP-owned facilities receiving Low-Impact Hydro Institute ("LIHI") certification, allowing those RECs to qualify in higher value markets. Many of the RECs to be delivered during the Rate Year are subject to prices established through prior forward sales, providing cost stability and corresponding benefits to customers.

Energy Market Purchases

Q39. Have you made any Rate Year adjustments to GMP's net energy market purchases and sales? If so, why?

A39. Yes. Net bilateral energy market purchases of fixed-price purchases for terms of less than five years decline by about 362,000 MWh from the Test Year to the Rate Year, as some existing purchases expired. A primary reason for the trend of declining bilateral market purchases is that increasing amounts of GMP's energy needs are being met with renewable sources. The nominal decrease in costs resulting from changes in these purchases is about $23.4M; the average price of the purchases remains relatively flat, increasing from about $65.87/MWh in the Test Year to about $66.89/MWh in the Rate Year.

Forward Capacity Market Costs

Q40. Please explain how the FCM works and GMP's capacity obligation in that market.

A40. The FCM is the market-based mechanism by which ISO-NE ensures that sufficient capacity resources are in place to meet the future demand for electricity. Under the current market structure, annual Forward Capacity Auctions ("FCAs") are conducted for the delivery of capacity three years in advance of the capacity period, which runs for the 12-month period from June through May. Resources participate in the auction to acquire a commitment to supply capacity and are compensated at a market-priced payment rate.

Capacity market prices are driven by the supply of and demand for capacity resources, and the prices at which participants are willing to commit to supply capacity.

Load-serving entities, like GMP, are responsible for a share of the capacity that ISO-NE purchases each year; these capacity requirements are allocated to load-serving entities based on their respective contribution to the ISO-NE annual peak load. GMP may meet that obligation using its owned or purchased capacity resources, or through payments to ISO-NE. Beginning at the start of the Rate Year, GF will be responsible for meeting its own capacity load obligation, thereby reducing GMP's overall capacity requirement.

Q41. What are the capacity costs for the Rate Year?

A41. Capacity costs in the Rate Year are expected to be $34.2M, a $3.8M decrease from the Test Year. This reduction is primarily driven by a lower capacity load obligation resulting from the exclusion of GF from GMP's load and a lower system coincident peak in summer 2025. That coincident peak establishes GMP's capacity obligation beginning in June 2026, which applies to the first eight months of the Rate Year. In addition, GMP's battery initiatives are expected to continue reducing capacity costs by lowering GMP's contribution to the ISO-NE coincident peak load.

FCA 17, which applies to the Capacity Period from June 2026 through May 2027, had a clearing price of $2.59/kW-mo and applies to eight months of the Rate Year. The remaining four months of the Rate Year fall within Capacity Period 18, which cleared at $3.58/kW-mo. During the Test Year, applicable Capacity Periods 15 and 16 had clearing prices of $2.477/kW-mo and $2.531/kW-mo, respectively. The Test Year also included bilateral capacity purchases that are replaced by ISO-NE purchases in the Rate Year, at a lower cost in the first 8 months and at a higher cost in the final 4 months.

Ancillary Services, Congestion, and Losses

Q42. Have you made any adjustments for ancillary service charges, congestion and losses in the Rate Year?

A42. Yes. The Rate Year forecast includes approximately $12.4 million for ISO-NE ancillary services, congestion, and losses, compared to about $14.6 million in the Test Year. This category includes the high net DASI costs, as discussed previously, as well as marginal loss and congestion components associated with ISO-NE energy purchases and sales and other ancillary services such as operating reserves, net commitment period compensation, and regulation.

Net ancillary costs reflect ISO-NE charges net of revenues earned by GMP resources. The Rate Year forecast includes $6 million of DASI-related costs, while the Test Year reflects only a partial year of DASI activity and includes $2.2 million of costs associated with the winter Inventoried Energy Program, which will not recur in the Rate Year. Marginal losses and congestion are projected to increase modestly from approximately $5.3 million in the Test Year to $5.5 million in the Rate Year, primarily due to higher projected energy prices. Other ancillary service costs are based on Test Year actuals and adjusted for projected Rate Year market conditions.

Q43. Are there any other significant changes in energy costs you wish to highlight?

A43. Yes. In the Rate Year, projected generation from GMP-owned hydro units is projected to be 138,000 MWh higher than the Test Year. During summer into the fall of 2025, New England experienced historic drought conditions, resulting in some of the lowest hydro generation experienced in years, affecting Test Year generation. Rate Year generation is based on a historical 20-year average, adjusted for known changes such as plant upgrades or river flow requirements and planned outages.

IV. Transmission Costs

Q44. Please provide an overview of GMP's purchased transmission and related costs.

A44. GMP's purchased transmission costs consist of Regional Network Service ("RNS") charges that are part of the NEPOOL Open Access Transmission Tariff ("NOATT"), VELCO 1991 Vermont Transmission Agreement ("'91 VTA Common") charges, Hydro-Quebec Phase 1 and 2 support charges, various ISO-NE and NEPOOL tariff charges, and a number of smaller charges from other utilities whose transmission facilities GMP uses. Transmission costs have grown significantly in recent years, primarily for RNS due to the region's high-voltage Pool Transmission Facilities ("PTF") transmission network. RNS costs represent approximately 63% of all purchased transmission costs for the Rate Year and are not within GMP's direct control.

VELCO '91 VTA Common charge costs are the second-largest component of transmission costs and vary significantly from year to year. Under the '91 VTA Common, net VELCO monthly costs are assigned to Vermont electric distribution companies based on each utility's share of trailing 12-month coincident and noncoincident loads, reduced by the Purchaser's Internal Generation Adjustment ("IGAP") credits. '91 VTA Common charges are a limited fraction of total VELCO costs due primarily to reimbursements through ISO-NE for VELCO's PTF assets, which typically represent 80% or more of VELCO's revenues. Please see VELCO Chief Financial Officer Michele Nelson's testimony for more information on VELCO's actual Test Year and projected Rate Year costs and revenues, and the resulting increase to the '91 VTA Common charge.[8]

Q45. What is the projected change in purchased transmission costs between the Test Year and Rate Year, and what are the drivers of the increase?

A45. Purchased transmission costs (which include certain ISO-NE tariff charges) for GMP are projected to increase from $137.8M in the Test Year to $158.4M in the Rate Year, an increase of $20.6M. The primary drivers of the difference between Test Year and Rate Year is a projected $16.1M increase in the VELCO '91 VTA Common charge (which is based on Ms. Nelson's forecast regarding VT Transco costs and revenues), and an increase of $4.8M in RNS charges.

From the Test Year to the Rate Year, GMP's VELCO VTA Common charge expense is projected to increase from $28.5M to $44.6M, an increase of about $16.1M. Ms. Nelson explains the primary reasons for the increase. In summary, VELCO's revenue requirement is projected to increase by about $36.5M from the Test Year to the

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[8] Ms. Nelson's testimony presents statewide figures. GMP's share for the Rate Year is expected to be 76 percent of VELCO's total, which does not include GF in GMP's load.

Rate Year. Primary drivers of this increase are higher operating costs and higher earnings before tax associated with significant recent and ongoing capital investments. Operating costs rose by approximately $24.70M, driven mainly by increased property taxes and depreciation from major transmission and substation projects placed in service, along with higher maintenance, administrative, interest, and AFUDC expenses. Earnings before tax increase by about $11.76 million, reflecting higher equity invested to fund these projects and the resulting increase in return on equity and related income taxes, partially offset by higher ISO-NE RNS reimbursements.

GMP charges for RNS were $94.2M in the Test Year and are projected to increase to $99.0M in the Rate Year. The Test Year included three months with an RNS rate of $154/kw-yr and nine months at a rate of $185/kw-yr. The first three months of the Rate Year will be at a rate of $184/kw-yr, and the remaining nine months is projected to have a modest increase to $186/kw-yr based on the most recent RNS rate forecast.[9] Despite lower overall forecasted monthly peak loads resulting from GMP's many successful peak shaving measures, including various energy storage programs, the higher rates result in higher RNS costs in the Rate Year compared to the Test Year.

Q46. Are there other projected changes in Transmission costs?

A46. Purchased transmission costs other than RNS and VELCO VTA Common are not expected to change significantly from the Test Year.

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[9] *2026 RNS Rate Overview and Forecast* materials presented at the July 15, 2025 NEPOOL Reliability Committee/ Transmission Committee meeting. (https://www.iso-ne.com/static-assets/documents/100025/a05.2a_tc_rns_rate_forecast_presentation.pdf)

V. Fiscal Year 2028–30 Power Supply and Revenue Forecasts

Q47. How has GMP developed its power supply and revenue forecasts for the remainder of the Proposed Plan?

A47. Power supply costs and revenue forecast for the remainder of the Proposed Plan, through FY30, used the same methods used for the Rate Year.

Based on Itron's retail sales forecast plus distribution losses, a forecast of the cost to serve that load is developed using assumptions and adjustments consistent with those used in traditional rate filings and described earlier in my testimony. A summary of projected power supply costs by year of the Proposed Plan is set forth in **Exh. GMP-MF-23**. Notable items for Fiscal Years 2028, 2029, and 2030 include the following:

- Changes to expected annual energy and capacity deliveries:
    - Increasing energy deliveries from Great River Hydro.
    - Twin Wind PPA is expected to have a full year of deliveries beginning in FY28.
    - Net-metering is forecast to continue experiencing annual growth, though at a more modest pace than in prior years.
    - The Standard Offer program is forecast to be fully built out by FY28, with deliveries in FY29 and FY30 remaining flat.
    - The NextEra Seabrook contract ramps down in June 2029 from 55 MW to 50 MW for energy and from 75 MW to 65 MW for capacity.

  - GMP's Granite Wind share declines by 19.8 MW in April 2027, from 81 MW to 61 MW.
  - First Light off-peak hydro purchase has declining volumes from FY27 to FY28, and the contract expires in December 2029.

- Forward energy market prices reflect broker quotations from November 6, 2025, consistent with the forwards used for the Rate Year. Average around-the-clock energy prices are projected to decline throughout the forecast period, with the FY28 annual average approximately 6% lower than the Rate Year and the FY30 annual average more than 28% lower than the Rate Year. These lower forward energy prices translate into reduced costs to procure power to cover our open energy position in future years.
- Projected PPA costs for indexed contracts such as HQUS and Seabrook reflect forecasted PPA prices. Inflation and forward market prices are expected to moderate over time, which will result in modest annual changes.
- The current Ryegate contract, which provides about 135,000 MWh of energy annually, is assumed to expire in November 2028. No further contract extension is assumed, and replacement energy to be procured at market prices is expected to be lower than the current contract rate. Annual RES compliance costs increase with increasing requirements for Tiers I, II, III and IV, and reflect current REC market prices.
- Transmission costs are forecast using VELCO's projections for '91VTA costs and ISO-NE's 5-year forecast for RNS rates. Costs from the '91VTA are projected to

decline from FY27 to FY28, followed by a resumption of annual increases in FY29, consistent with VELCO's forecast. RNS costs are expected to experience modest year-over-year increases of approximately 5 percent annually over the Plan period.

Q48. How and why will these forecasts be adjusted during the Proposed Plan?

A48. These forecasts will be updated each year in the Annual Base Rate Filing. As noted in my initial MYRP testimony, while GMP's power supply portfolio features many relatively stable contracts, total power supply costs will continue to be subject to changes over the term of the Proposed Plan due to factors that may not be foreseeable at the time of this filing. Annual updates to the retail sales and power costs will ensure that GMP's electric rates reasonably reflect expected net power supply costs and retail electric sales for the applicable year, while limiting reliance on adjustors to recover or return funds to customers. This annual adjustment framework has previously been approved by the Commission in Case No. 18-1633-PET and Case No. 21-3707-PET. Therefore, while these forecasts are important to include in consideration of our overall cost of service and rate path through the term of the Proposed Plan, GMP's actual base rates will be established based on annual reforecasts, closer in time to when power supply costs are incurred.

Q49. Please discuss GMP's current supplemental reporting on procurement and any changes you feel are warranted?

A49. While not explicitly incorporated into GMP's Current or Proposed Plan, I wish to address reports GMP has been providing following the Commission's Order in Case No. 18-0974 supplementing its Rule 5.200 reporting. In a June 21, 2019, letter in that proceeding, GMP informed the Commission that it had agreed with the DPS to provide supplemental reporting, semiannually, on procurements under its short-term hedging program in addition to Rule 5.200 reports starting in March 2020. GMP has been making those filings since that time, but requests that they no longer be required as much of the information provided is duplicative of other reports.

Q50. Do you have any additional items to discuss regarding power supply costs or planning under the Proposed Plan?

A50. Yes, through this time of extreme volatility and inflationary pressure in power markets and contracts, our work remains focused on delivering clean, reliable power at the lowest reasonable cost. We continue to build and manage a diverse portfolio that includes long-term power purchase agreements, owned generation, storage projects, and spot market transactions. This diversified approach reduces risk for customers while meeting current state energy goals and providing stability and predictability wherever possible. While much of the New England region can experience swings exceeding 20 percent from season to season, we have been able to maintain stability and predictability for customers through these volatile conditions.

Q51. Does that conclude your testimony at this time?

A51. Yes.

I, Maria Fischer, declare that the testimony and exhibits that I have sponsored are true and accurate to the best of my knowledge and belief and were prepared by me or under my direct supervision. I understand that if the above statement is false, I may be subject to sanctions by the Commission pursuant to 30 V.S.A. § 30.

Dated at Colchester, VT on the 16th day of January, 2026.

Maria Fischer

Maria Fischer