STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. _________

Tariff filing of Green Mountain Power requesting an	)
increase in its base rates starting January 1, 2019, to be	)
fully offset by bill credits through September 30, 2019	)

PREFILED TESTIMONY OF
DOUGLAS C. SMITH
ON BEHALF OF GREEN MOUNTAIN POWER

April 13, 2018

Summary of Testimony

Mr. Smith describes the principal changes in GMP's power supply-related costs, which are the primary drivers of GMP's proposed rate change. The bulk of these changes from the test period to the rate period are largely out of GMP's control and include transmission expenses (due to regional bulk system and VELCO cost pressures); net-metering expense (due to a substantial increase in the volume of net-metered generation in GMP's service territory between 2017 and 2019, and a decline in the value of additional net-metered power); and regional capacity costs (due primarily to New England capacity market prices more than doubling). Mr. Smith provides an overview of GMP's power supply portfolio (estimated at 60% renewable and almost 90% carbon free) and power supply strategy.

EXHIBIT LIST

Exhibit GMP-DCS-1	Power Supply Cost Summary - Test period
Exhibit GMP-DCS-2	Power Supply Cost Summary - Rate period
Exhibit GMP-DCS-3	Test period Power Supply Costs and Revenues – Monthly Summary
Exhibit GMP-DCS-4	Test period Power Supply Costs – Purchased Power Energy
Exhibit GMP-DCS-5	Test period Power Supply Costs – Purchased Power Capacity
Exhibit GMP-DCS-6	Test period Power Supply Costs – Owned Generation O&M
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Exhibit GMP-DCS-10	Retail Sales and Load at System Boundary
Exhibit GMP-DCS-11	Ancillary Product Costs and Credits
Exhibit GMP-DCS-12	Forward Energy Prices Used in Model s
Exhibit GMP-DCS-13	Congestion & Losses Expense and Credits
Exhibit GMP-DCS-14	Generation Entitlements
Exhibit GMP-DCS-15	Power Supply Reconciliation
Exhibit GMP-DCS-16	Generation O&M and Fuel
Exhibit GMP-DCS-17	Power Contracts
Exhibit GMP-DCS-18	Net REC Revenue and RES Expense
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PREFILED TESTIMONY OF DOUGLAS C. SMITH ON BEHALF OF GREEN MOUNTAIN POWER

I. INTRODUCTION

Q1. Please state your name, occupation and business address.

A1. My name is Douglas C. Smith. I am Chief Power Supply Executive for Green Mountain Power ("GMP").

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

A2. I have worked for over 25 years in the electric industry, focusing on topics that include electric system and portfolio planning, wholesale and retail power transactions, and market price forecasting. I hold a Bachelor of Science degree in Mechanical Engineering from Brown University.

I began my career as an analyst at the Vermont Department of Public Service and was subsequently promoted to the position of Electrical Planning Engineer. From 1991 to 2007, I worked at La Capra Associates ("La Capra"), a consulting firm[1] that specializes in planning and regulatory issues in the electric industry. I ultimately became La Capra's Technical Director. While at La Capra, I advised several Vermont utilities regarding their power transactions, risk management strategies, and Integrated Resource Plans. On behalf of state agencies and large electricity customers, while at La Capra I reviewed the procurement strategies of numerous large utilities in the eastern, central, and

[1] La Capra is now known as Daymark Energy Advisors.

western U.S. I also led the firm's forecasting of New England wholesale electricity market prices and assisted in the siting applications of several proposed electric generating plants. I joined GMP in 2007. I currently play a primary role in the development of GMP's power supply strategy. The power supply team conducts the bidding of GMP's load and generation sources into the ISO-New England, Inc. ("ISO-NE") energy and capacity markets, sells Renewable Energy Certificates ("RECs") produced by GMP's resources, and leads the evaluation of potential power supply resources and the implementation of power purchase transactions. I also played a primary role in the development of GMP's 2014 Integrated Resource Plan ("IRP").

Q3. Have you previously testified before the Public Utility Commission?

A3. Yes, I have testified before the Public Utility Commission on numerous occasions, on topics that include resource planning, proposed power purchase contracts and generation projects, electric utility revenue requirements, and the development of Standard Offer rates and PURPA avoided cost rates.

Q4. What is the purpose of your testimony?

A4. I describe the underlying changes in GMP's power supply costs that are driving GMP's proposed rate change. Many of the cost drivers for the rate period - including increases in net-metering, transmission, and regional capacity - are ones that were also contributors to GMP's rate needs in 2018. These costs, largely out of GMP's control, are significant in the context of GMP's declining retail electric sales because in that environment there are fewer kilowatt hours over which to spread cost increases. I also provide the details of GMP's power supply costs and strategy, and summarize our transmission costs.

Q5. Can you please quantify GMP's rate period power costs relative to the test period at a high level?

A5. For the rate period (which is the first nine months of 2019), total power supply-related costs (which include purchased transmission) are $322.9 million, an increase of about $34.4 million from the test period (the first nine months of 2017).

Q6. What are the key changes in GMP's net power costs for the rate period, relative to the test period?

A6. The key drivers of changes in GMP's net power costs include:

- An increase in transmission expense due to costs associated with the regional bulk grid. These are primarily regional network service ("RNS") charges for use of the regional grid and significant cost increases from Vermont Electric Power Company ("VELCO")[2].
- Increased regional capacity costs due to a transition of the ISO-NE capacity market from a significant surplus to a tighter supply/demand balance, resulting in significant increases of the New England Forward Capacity Market ("FCM") price. GMP has substantially mitigated this increase by relying on long-term

[2] 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.

contracts, GMP owned generation, and bilateral forward capacity purchases at prices that stabilized GMP's capacity costs and also turned out to be below market. I expect that the cost impact from increasing regional capacity market prices will also affect customers across New England, including other distribution utilities here in Vermont.

- Increased net-metering expense, because the volume of net-metering in GMP's service territory will increase substantially between January 2017 (the start of the test period) and September 2019 (the end of the rate period). In fact, the level of net-metering - when combined with Standard Offer and other sources - places GMP's service territory second in the country after Hawaii in the amount of distributed solar capacity as a percentage of peak system load. At the same time, market prices for energy and regional RECs have remained moderate, while the value of additional net-metered solar generation to GMP customers in the form of transmission and distribution cost savings has significantly declined due to the shifting of Vermont peak loads toward evening hours. As a result, additional volumes of net-metered solar generation tend to put upward pressure on GMP's net power costs and the retail rates that our customers pay to a much greater extent than in earlier years of the net-metering program.
- GMP's net power costs include the estimated cost of compliance with Tiers 1, 2 and 3 of Vermont's Renewable Energy Standard ("RES"). These expenses are expected to increase by over $3 million, driven primarily by annual increases in the RES requirements. We project that in 2019 GMP will modestly exceed the RES requirements and achieve what our customers tell us they want - a cost-

effective, low-carbon, reliable power supply. Specifically, GMP's energy supply for 2019 is projected to be 60% renewable and almost 90% carbon free.

- Net revenues from the sale of RECs are expected to decline. This is due in part to a GMP accounting change, explained below, along with a decline in market prices for regional Class 1 RPS-eligible RECs and an offsetting increase in GMP's REC supply. We project a larger total volume of RECs to be sold in the rate period, due to increasing purchases under renewable PPAs. Our customers will continue to benefit from the value realized as a result of our forward REC sale strategy, which helped to lock in REC sale prices in advance of the current market decline.
- The implementation of some new purchases from renewable power sources (Standard Offer, Deerfield Wind, solar PPAs) will increase GMP's net energy costs somewhat; this is largely offset by savings from the expiration of legacy above-market Rule 4.100 (PURPA) PPAs from VEPPI – primarily for the output of the Sheldon Springs hydro plant.
- Energy costs will also decline due to the expiration of some shorter-term market purchases with prices higher than current market; these benefits are partially offset by an increase in the average price of the remaining short-term purchases.
- Some of GMP's long-term PPAs from renewable and zero-emission sources (HQUS, NextEra Seabrook, Granite Reliable Wind) feature contractually prescribed price escalators – for example, inflation-based indexing - that gradually increase the prices for these sources over time, while also providing stability to GMP's portfolio as intended.

These cost pressures highlight the value of GMP's energy transformation work to drive down costs as described by Mr. Castonguay. The benefits of battery storage and responsive load, for example, can help us continue to realize peak-shaving transmission and capacity benefits for our customers as they are not limited by shifting peaks, while they may also produce other wholesale market value streams. There is also the opportunity for new revenues from innovative products and services to help cost-effectively replace retail sales lost as a result of net-metering and other factors, to help offset rising cost pressures to customers.

Q7. Please describe your exhibits.

A7. **Exhibit GMP-DCS-1** and **Exhibit GMP-DCS-3** through **Exhibit GMP-DCS-9** contain test period power-supply-related cost information. **Exhibit GMP-DCS-1** contains an annual summary of all costs and credits, **Exhibit GMP-DCS-3** contains a higher level monthly summary, and **Exhibit GMP-DCS-4** through **Exhibit GMP-DCS-9** contain monthly detailed information for all power-supply-related categories.

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

Exhibit GMP-DCS-20 compares rate period and test period power costs, **Exhibit GMP-DCS-21** compares rate period and test period energy volumes and costs, and **Exhibit GMP-DCS-22** compares rate period and test period purchased transmission costs.

II. OVERVIEW OF POWER SUPPLY PORTFOLIO AND COSTS

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

A8. GMP serves an annual retail load, including distribution system losses, of approximately 4.4 million MWh/year[3]. Providing that power safely, reliably and cost-effectively is what guides our work. We procure this energy (and other required products like capacity, RECs and ancillary service) from a variety of sources – including owned and purchased; physical energy from specific generating plants and system energy that is not tied to specific plants; short-term sources of up to 5 years and long-term sources of up to 25 years. With the exception of market purchases of system energy that are not associated with a specific generating plant, the large majority of energy in our portfolio features low greenhouse gas emissions. GMP's largest single long-term source is the Hydro-Quebec U.S. ("HQUS") energy contract, which will provide about 779,000 MWh of rate period energy along with renewable attributes associated with the Hydro-Quebec generation system, in 178 MW blocks daily from 8 AM to 11 PM ("7x16" delivery). Approximately 95% of this energy is expected to be supplied from hydroelectric sources, and to contribute to meeting our RES Tier 1 requirement. GMP is also purchasing almost

[3] For the 9-month rate period in this case, the corresponding retail load is about 3.3 million MWh.

731,000 MWh under market-based energy contracts, which are weighted roughly 60 percent toward off-peak hours to match the approximate shape of GMP's projected open positions (i.e., the needs that are not met with longer-term committed power sources). The volumes of these bilateral purchases - which have been entered into during the past several years - are also sometimes shaped monthly in accordance with GMP's forecasted net short position. This monthly and peak/off-peak shaping allows GMP to meaningfully reduce the potential year-to-year variance in power costs and retail rates, as well as potential intra-year power cost fluctuations, due to changes in energy market prices. The energy supplied through the HQUS long-term purchase and bilateral energy purchases represents about 45% (1,510 GWh) of GMP's rate period load requirement.

GMP owns, either solely or jointly with others, approximately 360 MW of generating capacity that is expected to provide approximately 630,000 MWh, or almost 20% of GMP's needs in the rate period. This is primarily intermittent renewable energy from several dozen hydro facilities, GMP's two wind projects (Kingdom Community Wind and Searsburg), and a number of small solar installations. GMP also owns a share of about 20 MW in the Millstone 3 nuclear plant that is expected to produce about 119,000 MWh and operates as baseload generation. GMP anticipates that the dispatchable wood-fired JC McNeil plant in Burlington, operating at roughly a 60% capacity factor, will provide GMP with about 64,000 MWh of energy (and regional Class 1 RECs). Finally, GMP owns a share of 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 combined cycle units in Massachusetts, which burn natural gas or oil. These units account for about 150 MW of peaking capacity, which provides substantial value in the capacity and other markets but are only projected to generate about 17,000 MWh of energy in the rate period.

The major physical resources that GMP purchases power from on a long-term basis include NextEra's Seabrook nuclear plant, the Granite Reliable Wind project in New Hampshire, the Deerfield wind project, and the Ryegate wood-fired plant. Most of these sources feature zero air emissions or are relatively low-emission generators; the Granite, Deerfield, and Ryegate sources provide RECs that are presently eligible to meet Class 1 RPS requirements in one or more neighboring states. At present, GMP and the other Vermont buyers and Ryegate's owner are contracted to share the RECs produced by that plant. In total, these renewable and nuclear PPA sources are projected to supply almost 700,000 rate period MWhs for GMP, or about 21% of the Company's needs.

The majority of GMP's remaining retail load need is served through three Vermont programs: VEPP (under the prior Rule 4.100), Standard Offer (also administered by VEPP), and Net-Metering, all of which produce energy from renewable sources. Many of the Standard Offer sources and new Net-Metered ("Net-Meter 2.0" or "NM 2.0") projects also provide high-value RECs[4] that benefit our customers. Total rate period energy supply through these programs for GMP is projected to be 260,000 MWh, about 8% of the retail load.

A number of other smaller renewable energy projects also produce power and RECs for GMP, with GMP being a partner in five solar projects (GMPSolar) totaling

[4] By high value RECs, I mean RECs that can be used for compliance with Tier 2 of Vermont's RES program or compliance with Class 1 RPS requirements in a neighboring state.

about 22 MW. GMP also makes bilateral purchases (providing power, RECs or both) for most or all of the output of a number of other small renewable projects that are mostly hydro and solar.

Finally, GMP purchases and sells energy on an hourly basis through the ISO-NE day-ahead and real-time markets (together, "spot market") as needed. Generally, GMP plans its energy supplies (including the long-term and short-term sources discussed above) to be approximately in balance with forecasted load requirements during peak and off-peak periods each month. In actual practice, within a given month, our customers' power needs (along with the output of intermittent generating sources) can fluctuate significantly around the averages upon which our forecasts are based. As a result, we often buy or sell significant amounts of spot market energy in particular hours and days depending on variations in customer consumption and generation output. For the rate period as a whole, GMP's loads and resources are projected to be closely balanced, with GMP projected to be a net seller of about 20,000 MWh (or roughly 0.6 percent of GMP's rate period requirements) in the spot market.

Q9. Do RECs play a significant role in GMP's power supply?

A9. Yes. As explained below, GMP is both a buyer and a seller of RECs. This is a logical consequence of the Vermont renewable policy framework under which GMP operates today, and the framework that was in place when many of GMP's current power sources were developed.

First, GMP retires RECs to demonstrate compliance with the Tier 1 (total renewable) and Tier 2 (distributed renewable) requirements of the Vermont RES, in the same way that RECs are used to demonstrate compliance with Renewable Portfolio Standard (RPS) requirements in neighboring states. Expenses associated with these retired RECs are represented as a power supply expense.

Most REC sales involve the sale of RECs produced by renewable power sources that were developed during the past decade and are eligible for compliance with Class 1 RPS requirements in neighboring states - but are not eligible for Tier 2 of Vermont's RES because they are larger than 5 MW or they were completed before July, 2015. Many of these sources were developed to support the rapid development of renewables under the framework of Vermont's former SPEED program; they play a significant role in GMP's energy supply by providing relatively stable-priced power that reduces the amount of energy and capacity that must be purchased from the ISO-NE market or other sources. When GMP sells RECs from these sources the revenue is used to reduce GMP's net power costs and retail rates, and GMP does not count the associated renewable output toward the content of the power that its customers consume.

Q10. Please summarize how GMP approached the development of power supply costs for the rate period.

A10. Most of the volumes and prices that determine GMP's projected net power supply costs in the rate period (the first nine months of 2019) are based on values from the test period (the first nine months of 2017), adjusted to reflect known and measurable changes – such as contractual changes in PPA prices or volumes, the addition and expiration of certain power sources, or changes in the market price environment for electricity or fuel. Normalizing adjustments were applied to power sources for which the production tends to fluctuate around long-term average weather values. The most prominent categories of adjustments are as follows:

- Purchased power expenses were adjusted to reflect new power purchases (e.g., Deerfield PPA, new Standard Offer projects, new hydro PPAs with Enel, and changes in bilateral energy purchases), along with a net increase in the output of GMP's hydroelectric fleet (due to retrofits, weather normalization, and relicensing of certain plants).
- Purchased power expenses were adjusted to reflect contractual changes in PPA pricing (e.g., for HQUS energy, NextEra Seabrook, Granite Reliable Wind, VEPPI); volume changes for some sources; weather normalization; and the expiration of some VEPPI legacy PPAs.
- Capacity-related expenses were adjusted to reflect changes in ISO-NE Forward Capacity Market pricing and GMP's share of regional capacity obligations.
- Energy output from intermittent renewable sources was adjusted to reflect normalized or long-term average volumes.
- Fuel prices at GMP's owned and jointly owned fossil-fired units were adjusted on a plant-specific basis based on recent futures market prices for oil and natural gas.
- Net REC revenues were adjusted to reflect increasing volumes of renewable generation from GMP's plants and PPAs using normalized plant output, where applicable; forward sales of RECs that GMP made in advance for deliveries during the rate period; updated REC market price estimates for projected REC volumes that have not been sold forward; and estimated costs associated with

compliance with RES Tiers 1, 2 and 3. Net REC revenues also reflect an accounting change that shifts some expenses from energy to RECs.

- Transmission expenses were adjusted to reflect a recent VELCO forecast and recent ISO-NE projections for regional transmission rates, as well as the estimated impact of changes to the Federal income tax code.
- O&M expenses for GMP's wholly owned generating units were adjusted to reflect the most recent forecasts of those expenses; O&M expenses for jointly owned plants reflect 5-year averages.

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

Q11. What volume of retail load is reflected in the GMP rate period power costs that you are presenting?

A11. The power costs for the rate period (the first 9 months of 2019) reflect a retail load requirement of about 3.3 million MWh. This volume reflects forecasted GMP retail sales for the period, as developed by the consulting firm Itron, along with energy losses on the distribution system. As explained by Mr. Ryan, the difference between the forecasted sales and test period sales is small, and is largely attributable to factors that would be captured in normalizing adjustments (e.g., adjustment of sales volumes to reflect normal weather conditions) or known and measurable adjustments to the test period sales to reflect discrete influences (e.g., increases in net-metering volumes, increases in end-use efficiency, additional load from electrification activities, discrete/spot customer load increases) that are expected to increase or decrease sales volumes.

Q12. What are the GMP rate period total power-supply-related costs and how are they represented in GMP's filing?

A12. Overall, projected total power-supply-related costs increase from $288.5 million in 2017 to $322.9 million in 2019, an increase of about $34.4 million. The changes are reflected in **Exhibit GMP-ER-1, Schedule 5**, as the following Cost of Service (COS) Adjustments:

- COS Adjustment 1: Net purchase power costs – which includes all purchased power costs (including those associated with net-metering) and all resales of power, including RECs - increases $19.17 million;
- COS Adjustment 2: Production fuel costs increase by $0.25 million;
- COS Adjustment 3: Joint Ownership costs decrease $0.07 million for generation O&M;
- COS Adjustment 4: Transmission by Others ("TbyO") costs increase $14.15 million;
- COS Adjustment 5: ISO New England charges increase $0.42 million;
- COS Adjustment 6: Wholly Owned Production (O&M) costs increase $0.50 million.

These changes are discussed in greater detail in the following sections of my testimony, except for Wholly Owned O&M costs, which are addressed in the testimony of GMP witness Jason Lisai.

III. RATE PERIOD POWER SUPPLY COSTS

Q13. What is the purpose of this section of your testimony?

A13. The changes described in this section explain the overwhelming majority of the change in GMP's net power costs from the test period to the rate period. Some of these changes affect several power cost components, so I will generally explain these linked changes together.

<u>Forward Capacity Market ("FCM") Costs</u>

Q14. Can you briefly explain how the Forward Capacity Market works and GMP's capacity obligation in that market?

A14. Yes. The FCM is the market-based mechanism by which ISO-NE ensures that sufficient capacity resources will be in place to meet projected resource adequacy requirements. Annual Forward Capacity Auctions ("FCAs") are conducted for the delivery of capacity about three years in advance. The auction clears at the marginal price at which sources of capacity (including supply and demand side sources, and imports from outside New England) are willing to meet ISO-NE's need for capacity. Capacity market prices are driven by the supply of and demand for capacity resources, and the prices at which they are willing to commit to supply capacity. Some auctions have yielded unique clearing prices for capacity zones that are import-constrained or export-constrained.

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.

Q15. What is the change in Capacity Costs for the rate period, and what is causing this increase?

A15. Capacity costs increase from about $24 million to $30.2 million, an increase of about $6.2 million. This change is driven by a tightening of the supply/demand balance in the New England capacity market, due primarily to the retirement of significant existing capacity sources in the region. This change resulted in more than a doubling of FCM clearing prices, starting in Forward Capacity Auction ("FCA") 8, which applies to capacity commitments for the year June 2017 through May 2018. With respect to this rate case, the first five months of the test period were affected by FCA 7 (with a clearing price for the Rest of Pool zone $3.15/kW-month) with the remainder of the test period affected by FCA 8 (with a clearing price of $7.02/kW-month). FCAs 9 and 10, which will determine GMP's rate period capacity costs, cleared at $9.55/kW-month and $7.03/kW-month, respectively.[5]

FCA clearing prices do not apply to all of GMP's capacity obligations, because a substantial portion of the obligations are covered by capacity from GMP's owned sources and long-term PPAs, which provide substantial protection against FCA price increases. Nonetheless, those capacity market price increases still represent a significant cost

[5] Invoice prices that load-serving entities like GMP pay for capacity load obligations are driven primarily by the annual auction clearing prices shown here, although other factors (e.g., multi-year capacity commitments by new generators, results of reconfiguration auctions) can cause some limited differences.

increase for GMP in the rate period; they will likely also affect many load-serving entities in the region to an even greater extent.

Q16. Has GMP taken steps that help mitigate the FCA price increases you just discussed?

A16. Yes. Before FCA8 was conducted, GMP put in place a three-year bilateral capacity purchase of 100 MW, to protect against potential high FCA price outcomes in FCAs 8 through 10. In addition, the volume of capacity that GMP will purchase under its long-term NextEra Seabrook PPA is scheduled to increase by 150 MW in June 2018, so it will be in place for the full nine months of the rate period. GMP later put in place an additional 75 MW, three-year bilateral capacity purchase for delivery in FCA10 through FCA12. The effect of these bilateral capacity purchases was to stabilize GMP's power costs by locking in a substantial fraction of GMP's projected capacity needs for these years at competitive prices, greatly reducing GMP's exposure to further FCA price increases and year-to-year market price fluctuations. The collective price of capacity under these purchases in the rate period is lower than the average clearing prices for the Rest of Pool zone for this period, so adding the purchases to GMP's power supply will lower GMP's net power costs in the rate period.

In addition to capacity purchase transactions, GMP is reducing its exposure to FCA prices through its Energy Transformation efforts – specifically deployment of distributed generation, battery storage and controllable loads. GMP witnesses Brian Otley, Kirk Shields and Josh Castonguay describe this important work in more detail. These resources - along with a weather-driven decline in GMP's share of the ISO-NE peak in Summer 2017 - reduced the expected volume of GMP's estimated capacity obligations and associated capacity purchase costs in the rate period somewhat.

Net-Metering

Q17. Is increasing net-metered generation a significant contributor to GMP's rate period power cost increase?

A17. Yes. Net-metering ("NM") is a significant contributor to the increase in rate period power costs because volumes of net-metered solar power in GMP's territory continue to grow rapidly. The volume of NM energy produced in GMP's territory is expected to increase by more than 60% from the test period to the rate period to about 207,000 MWh, with this growth being driven primarily by solar. This growth in NM generation is attributable primarily to projects that have been completed since the start of the test period (but were not operating during the full test period) and the anticipated completion of projects that have already applied for interconnection.

Q18. Has the anticipated value of additional net-metered power output changed over time?

A18. Yes, the estimated value of additional net-metered power to GMP and its customers has decreased significantly in recent years. This is partly because the deployment of substantial distributed solar generation from net-metering and other sources has limited the net demand on the Vermont grid (customer consumption and distribution system losses, less the output of distributed generation) during the sunniest days and hours, shifting peak demand to evening hours when additional solar power will have minimal value in terms of reducing Vermont peak demands and associated transmission charges that are allocated based on those peak demands. At the same time, energy market prices and price expectations for future years have also declined significantly since the early years of the net-metering program.

These factors lead to a significantly lower anticipated value of additional net-metered solar output to GMP and its customers than what was seen when GMP pioneered the solar adder. The estimated value of additional net-metered solar power is also significantly less than the near-term cost of that power to GMP (based on lost retail sales and net-metered excess payments). Based on the current pricing and terms of net-metering that are available to GMP customers, and the current power market outlook, additional volumes of solar net-metered power are putting noticeable upward pressure on GMP's net power costs and retail rates. These are the market trends that GMP considers as it evaluates potential new power sources (e.g., battery storage combined with solar generation), and they highlight the value for customers of battery storage and responsive load, whose capacity and transmission value should not be eroded nearly as much by a shifting system peak because the timing of their deployment can be adjusted if and when the peak shifts over time.

Q19. How do net-metering volumes and costs affect GMP's rate period power costs?

A19. Net-metered power affects GMP's rate period power costs in several ways:

- The portion of net-metered output that is not consumed at the site of generation in each billing cycle (month) is defined as "Net-metered excess" and booked as a purchased power expense, at an average price that is close to the average residential retail energy rate.[6] This Net-Metered Excess output arises for many customers with on-site systems during the months of highest solar generation when that generation exceeds the customer's usage, and for essentially all output of remotely located group net-metered projects that are not located behind a retail customer's meter (and may be located far from the participating customers' loads).

- The Net-Metered Excess line item in GMP's power costs also accounts for solar adders and adjustors associated with all solar net-metered production – whether the output reduces the participating customer's retail consumption or is excess, and includes all project vintages. These adders and adjustors are in addition to the retail energy rate and are projected to average about 4 cents/kWh for the rate period. The substantial price per kWh for these quantities, combined with rapidly increasing net-metered generation in GMP's territory, and the fact that more than half of NM generation is excess and does not offset a participating customer's retail electric consumption, has made the Net-Metered Excess item one of GMP's largest power supply expenses.
- To the extent that net-metered customers assign the environmental attributes associated with their output to GMP, the associated RECs will be used to help meet GMP's RES Tier 2 obligations. GMP did not receive a meaningful fraction of RECs associated with so-called Net-Meter 1.0 (or "NM 1.0") net-metered

[6] Specifically, an estimated average price of about $0.156/kWh for NM 1.0 energy, and $0.126/kWh ($0.156/kWh less $0.03/kWh booked as a REC expense) for NM2.0 energy.

projects (customers retained the RECs, or sold them to other parties), because customers did not have a financial incentive to assign them to GMP. Under the terms established in the revised Rule 5.100, new net-metered projects ("NM 2.0") applying in 2017 forward have a significant financial incentive to assign their RECs to GMP[7], so we assume that almost all RECs from projects that apply for interconnection from 2017 forward will do so. To the extent that GMP uses NM 2.0 RECs to meet RES obligations, the incremental cost of those RECs to GMP (i.e., 6 cents/kWh, the difference between a REC adjustor of negative 3 cents/kWh and positive 3 cents/kWh) is represented as a RES compliance expense.

- To the extent that net-metered projects are producing at the time of ISO-NE's annual peak load, GMP customers will benefit through a reduced GMP share of annual FCM requirements starting in the following June; an estimate of these savings is included in the rate period power costs.
- Because monthly peaks on the VELCO transmission system have shifted to evening hours when solar PV output tends to be small or zero, GMP does not expect that additional net-metered solar power will provide any meaningful reduction in peak-driven RNS expenses.

[7] During the past 12 months, 99 percent or more of the new net-metering capacity completed under NM2.0 has elected to assign their RECs to GMP, and receive the positive REC adjustor.

Q20. Is it likely that substantial new NM activity will continue in 2019?

A20. Yes. The pricing and terms available to future NM projects under the revised Rule 5.100 appear to yield attractive payment rates for developers of new net-metered projects.[8] While a tariff on imported panels could modestly increase the capital cost to develop net-metered projects, it appears that the continued availability of the Federal Investment Tax Credit ("ITC") and the prospect for continued declines in the solar PV capital costs will help to support project development. So far in 2018, GMP has continued to receive a strong flow of applications for new NM projects. Specifically, through March 2018 (roughly one fourth of the year), GMP had received about 9.7 MW of new NM applications from a range of project sizes, including ten 500-kW-scale projects at preferred sites.

Q21. How much net-metering capacity is reflected in GMP's rate period power costs?

A21. The volume of net-metered projects in the rate period can be considered in three major groups: projects that are already online; projects that had applied for interconnection by the end of 2016 (NM 1.0) and achieve operation before the rate period; and projects that apply for interconnection after 2016 ("Net-Metering 2.0 projects") and are completed before or during the rate period. We estimate that 193 MW of net-metered capacity will

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8 For example, a large new NM solar project that is eligible for the preferred siting adjustor and transfers its REC output to GMP will receive first-year payments approaching 17 cents/kWh, and the payment will increase over time to the extent that GMP's retail rates increase.

be online by the end of the 2019 rate period, based on the following data and assumptions:

- At the end of 2017, about 142 MW of net-metered capacity was online in GMP's territory.
- The queue of Net-Metering 1.0 projects (amounting to about 16 MW) is projected to be completed by the end of 2018. This assumption reflects the fact that little attrition has been observed in the Net-Metering 1.0 queue and that there do not appear to be strong incentives to delaying completion of these projects.
- We project that 24 MW of additional (Net-Metering 2.0) solar projects will be built in 2018, and another 24 MW in 2019. This rate of growth is consistent with the rate of applications that GMP has received during 2017 and early 2018 under the terms of NM 2.0, less a reduction for assumed attrition (to reflect that not all net-metering projects that apply for interconnection are ultimately completed). We are assuming here that the features of the revised Rule 5.100 (addressing pricing, REC ownership, and siting adjustors) will adjust the pace of net-metering development (particularly for larger projects) relative to the actual installation rates observed in recent years[9]) so the program is more sustainable and not extremely costly to our customers who do not net-meter, while still leaving a pace of development that is aggressive when compared to most other states. Of course,

[9] The amounts of net-metered capacity that were commissioned in 2016 and 2017 were about 39.5 MW and 33.9 MW, respectively.

if this slowdown does not fully materialize, then GMP's net power costs and retail rates to customers will face more upward pressure than is shown here.

Q22. What are the other key assumptions regarding net-metered solar volumes and costs in the rate period?

A22. The 2019 net-metering buildout is assumed to occur in a mostly linear fashion across the year but features higher completion rates during summer months and near the end of the calendar year, reflecting historical trends. The overall capacity factor for net-metered solar projects collectively is estimated at about 14.5% based on a 13-month average[10] of installed capacity. Based on these parameters regarding net-metered capacity and output, total net-metered production (the vast majority of which is solar PV) is projected to increase from about 125,000 MWh in the test period to about 207,000 MWh[11] in the rate period.

Almost all Net-Metering 2.0 vintage solar projects are assumed to assign their RECs to GMP and to receive a REC adjustor of 3 cents/kWh on all of their output. Siting adjustors were also applied to all project output: +1 cent /kWh for small projects, an average of 0 cents for medium projects[12], and -1 cent for large projects (preferred siting required).

10 To the extent that the increase in net-metered capacity during this period is driven by larger projects (which can often be more optimally oriented to maximize production), actual net-metered production may turn out higher.

11 The portions of net-metered generation that are booked as excess, and therefore represented as power sources in my exhibits, are about 97,000 and 155,000 for the test period and rate period, respectively.

12 We assume that 75 percent of projects sized above 15 kW and up to 150 kW will qualify for the preferred siting adjustor of 1 cent/kWh, with the remainder receiving the non-preferred siting adjustor of negative 3 cents/kWh.

Finally, GMP estimated the monthly fraction of net-metered power that would serve to reduce the participating customers' retail electricity consumption and the remaining fraction, if any, that would be booked as Net-Meter Excess and included in GMP's power costs. For the rate period, about 75% of all net-metered generation is projected to be excess (consistent with experience to date, along with a trend towards group projects), with the remainder utilized by the customer on the site of the installation during the month in which the power is generated (thereby reducing GMP retail sales).

Q23. Based on the volumes and prices above, what is the estimated impact of the increased net-metered generation volumes on GMP's rate period power costs?

A23. The Net-Metered Excess item - which includes monthly excess net-metered generation, the solar adder payments on all Net-Metering 1.0 solar generation, and siting adjustors for Net-Metering 2.0 generation - increases from $19.8 million in the test period to about $29.8 million in the rate period. This makes Net-Metered Excess one of GMP's largest power supply expenses.

GMP's rate period capacity requirements also reflect benefits of net-metered generation through reduced capacity requirements[13]. GMP's rate period power costs also include the estimated expenses associated with the transfer of RECs from new net-metering customers under Net-Metering 2.0. These RECs are assumed to help meet

[13] In accordance with FCM rules, capacity benefits of load reducing generation (including net-metering) flow to GMP on a lagged basis. Benefits for January to May 2019 reflect GMP's contribution to the annual ISO-NE peak that occurred in Summer 2017, while the June to September 2019 benefits will reflect GMP's contribution to the annual ISO-NE peak that occurs in Summer 2018.

GMP's RES Tier 2 requirements, enabling more resales of RECs from other distributed renewable sources. While the net impact of increasing net-metering volumes on GMP's costs depends on several uncertain factors and can vary from year to year, I estimate that the net of these costs and savings represents an increase of about $7.0 million in GMP's net power costs for the rate period.

Q24. Does this represent the full impact that net-metered growth will have on GMP's retail rates?

A24. No. Net-metered generation also reduces GMP's retail kWh sales, to the extent that it is consumed onsite during the current billing cycle. Reduced retail sales are not reflected in the power cost estimates above, but they also increase GMP's retail rate needs by reducing the volume of sales over which GMP's cost of service can be spread.

<u>Other Renewable Power Sources</u>

Q25. Do the changes in GMP's power supply mix in the rate period include any increases in supply from renewable sources?

A25. Yes. GMP's power supply strategy has focused on meeting the goal of a low-cost, low-carbon, and reliable portfolio and has seen additions of significant renewable resources in recent years. Notable changes in the rate period power supply include anticipated increases in production from the net-metering and the Standard Offer programs; new hydro PPAs from two plants (Sheldon Springs and LaChute) that are owned by Enel as well as the addition of out-of-state hydros purchased from Enel; the addition of the Deerfield Wind PPA in late December 2017; and the planned addition of three new JV

Solar/Battery Storage projects (which entail a combination of solar and battery storage capacity). 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 trying to manage the potential volatility of GMP's power costs and thereby the retail rates that our customers pay.

Q26. Are the costs and value streams associated with the new JV Solar/Battery Storage projects reflected in the rate period power costs?

A26. Yes. The three GMP JV Solar/Battery Storage projects include solar generation, battery storage, and advanced controls (in the towns of Milton, Ferrisburgh, and Essex) with a total solar capacity of about 15 MW (AC), are planned to be completed on June 1, 2019. The rate period power costs reflect the PPA costs (approximately 9.9 cents /kWh for solar output and a flat annual fee for battery storage totaling 6 MW with capacity of four hours for a total of 24 MWh) associated with these projects, along with the projected value of their output. Because the collective output of these projects is limited (less than one percent of GMP's annual energy supply), and because the value of their output covers most of the cost of the power, these projects do not cause a meaningful change in GMP's net power costs in the rate period, but are projected to produce more benefits in subsequent years.

The projects are, however, going to provide other meaningful benefits to customers in the rate period through GMP's receipt of a developer fee that will flow directly to customers and lower costs by 2.2% for customers (through a regulatory asset adjustment, as explained by Mr. Ryan). As described in Mr. Shields' testimony, GMP anticipates completing these projects in a joint venture tax-equity investor structure in order to maximize the value of available investment tax credit benefits for our customers.

Q27. How is the Deerfield Wind project reflected in the rate period power costs?

A27. GMP has contracted to purchase the full output of this project under a long-term PPA, which entered commercial operation in late December 2017. GMP's rate period analysis reflects the project as operational during the rate period, providing energy output of approximately 68,000 MWh for the 9-month rate period. The wholesale market value of the project's output (energy, RECs, capacity) to GMP is projected to cover most of the PPA cost, so the estimated net impact of this source on GMP's rate period power costs is a limited increase.

Q28. How are GMP's purchases under the Standard Offer program reflected in the rate period power costs?

A28. The Standard Offer program is administered by VEPPI; GMP purchases the power output (and associated RECs, except for farm methane projects) in proportion to its load ratio share of required utility purchasers. This load share ratio has been adjusted to reflect exemptions granted to the Burlington and Swanton Electric Departments, which represents approximately $1 million of net power costs flowing to GMP customers. Total Standard Offer purchases are growing moderately over time, as projects that are awarded PPAs through VEPPI's annual solicitations are completed.

GMP purchases from units in the Standard Offer program are projected to reach 90,100 MWh in the rate period, compared to about 70,800 MWh in the test period. Of the projected rate period volume, about 75,500 MWh (84 percent) is from projects in service at the end of the test period; the remainder is from projects expected to come online in 2018 and 2019. The projected average price for the Standard Offer purchases in the rate period is about 17.3 cents per kWh, a decrease relative to the test period. This is due primarily to an accounting change that I will explain below, along with the completion of new, lower-cost projects. Based on these projected volumes and contract prices, the rate period cost for GMP's share of the standard offer purchases is projected at $15.6 million, up from $14.9 million during the test period. The benefits associated with the Standard Offer volumes are also reflected in the rate period power costs, through their energy output (reducing the amount of GMP's retail load that must be procured from other sources), and associated RECs (which can be sold or used for RES compliance), along with smaller projected reductions in expenses for the ISO-NE Forward Capacity Market. The estimated net impact of increased Standard Offer purchases on GMP's rate period power costs is an increase of several hundred thousand dollars.

Q29. Are GMP's planned PPA transactions with Enel reflected in the rate period power costs?

A29. Yes. GMP has contracted to purchase the output of two existing hydro plants owned by Enel (the Sheldon Springs plant in Vermont, and the LaChute plant in eastern New York) under long-term PPAs. The Sheldon Springs PPA began deliveries in April, 2018, and we expect that the LaChute PPA will also be in effect for the full rate period.

The expenses associated with the two hydro PPAs, along with the associated value of the power and RECs that GMP will receive, are reflected in GMP's rate period power costs. Because the value of the output from these sources largely offsets the associated costs, the addition of these renewable power sources is not expected to meaningfully change GMP's rate period cost of service.

REC Revenues and RES Compliance Costs

Q30. Please explain how REC revenues affect GMP's net power supply costs, and how net REC revenues for the rate period were developed.

A30. GMP's supply portfolio produces substantial volumes of RECs – particularly from wind, solar, hydroelectric, and biomass sources – that typically qualify as eligible supply sources for compliance with Renewable Portfolio Standard ("RPS") programs in neighboring states in either "Class 1" or "Class 2" tiers. These RECs are tracked in a database known as the NEPOOL Generation Information System (GIS, or NEPOOL GIS), that describes the fuel type, emission rate, renewable program eligibility, and other attributes associated with specific MWh of generation. During the test period, GMP sold almost all of these high-value RECs, with the exception of those needed to cover volumes subscribed under GMP's voluntary retail green power programs and those required for meeting GMP's obligations under Tier 2 of Vermont's RES program. Additionally, GMP retired significant volumes of Tier 1 qualified RECs to comply with Tier 1 of the RES program. We anticipate using the same approach to REC sales and retirements in the rate period and have estimated GMP's net power supply costs accordingly.

REC sales and retirements are fairly straightforward in concept, but there are several unique features of REC markets and the associated accounting for REC revenues and expenses. First, GMP 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, GMP JVSolar projects, 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 period are based on renewable energy production from the applicable sources during the 9-month period from July 2018 through March 2019.

Q31. Can you please summarize how and when GMP conducts its REC sales?

A31. GMP has sold most of the projected rate period supply of high-value RECs on a forward basis – that is, under contracts that were negotiated from a few months to several years in advance of delivery. These are mostly fixed-volume, fixed-price contracts that reflect the regional market for Class 1 RPS supply on the dates they are negotiated. This forward sale approach helps to stabilize our net power costs and to mitigate the risk of potential declines in regional REC market prices. Because regional market prices have, in fact, fallen significantly in the past several years, the forward REC sales that GMP made in the past few years (for vintage 2018 and 2019 RECs) will provide several million dollars of additional value compared to the revenue that GMP could achieve by selling the same volumes at today's market prices; this value is reflected in the rate period power costs. We have assumed that the remainder of the REC supply will ultimately be sold at prices that reflect a blend of recent broker price indications and consultant projections of REC market prices. In total, we project that GMP's rate period REC sales will amount to about 653,000 MWh, at an average price of about $31/MWh, for gross revenue of about $20.3 million. For a sense of scale, this gross revenue amounts to over 3 percent of GMP's annual revenue requirement.

Q32. What are the estimated net REC revenues for the rate period?

A32. **Exhibit GMP-DCS-18** presents the rate period figures by month, in terms of their major components. After incorporating the REC purchase portion of PPA expenses that I noted above, the resulting REC revenue is about $11.6 million for the rate period, a decrease of about $0.9 million relative to the test period. This limited change in net REC revenues is attributable to the offsetting effects of three factors: an increase in REC sale volumes, lower market prices for regional RPS-eligible RECs, and an accounting change.

Q33. Could you please explain the accounting change that contributes to the decrease in net REC revenue for the rate period?

A33. Yes, about $1.9 million of the decrease in net REC revenue is the result of an accounting change that GMP implemented since the test period. Specifically, in the test period GMP imputed a REC price component in major bundled renewable PPAs (e.g., Granite Reliable Wind) under which GMP purchases power and RECs together and there is not an explicit REC price component. This approach is intended to reflect the relative prices of the products that GMP purchases under bundled PPAs, with the imputed REC price component designed to reflect REC market price expectations at the time the PPA was developed. Since the test period, GMP has imputed a REC price in a few additional renewable PPA sources (e.g., Standard Offer purchases) for which a REC price component was not imputed in the test period. This change does not alter the total cost that GMP pays for bundled renewable PPAs; it shifts a portion of the expense in the rate period from energy to RECs – thereby lowering net REC revenues in the rate period and also lowering energy expense.

Q34. Do the net rate period power costs that you are presenting also include costs associated with compliance with Vermont's RES requirements?

A34. Yes. In addition to the net revenues associated with REC sales as described above, the power costs include about $4.4 million in estimated costs associated with RES compliance for 2019.

Q35. Please summarize GMP's overall approach to RES compliance.

A35. GMP seeks to meet the RES requirements in a cost-competitive way by continuing to procure renewable power. GMP will also explore opportunities to bank excess RES compliance in some years if it will lead to lower expected compliance costs and risks, particularly for Tier 1 in the early years of the program.

For the first three years of the RES program, we plan to retire sufficient Tier 1-eligible RECs to achieve a total renewable supply fraction of 60% of retail sales for per year, or 5% more than the statutory minimum. When combined with GMP's estimated production and associated generation attributes from nuclear sources, this will make GMP's projected power supply almost 90 % non-carbon-emitting for the next several years – effectively lowering GMP's portfolio emission profile and enhancing the compliance value of GMP's Energy Transformation projects by minimizing fossil fuel-fired power.

Q36. Please summarize the components of GMP's RES compliance costs.

A36. The form of compliance costs varies across the tiers of the RES program, as follows:

- For Tiers 1 and 2, compliance will be demonstrated by retiring sufficient quantities of eligible RECs through the NEPOOL GIS. In general, RECs associated with generation from each year may be claimed to meet the RES requirements in that year or banked for use in compliance with requirements in one of the next several years.
- For Tier 2 covering new, distributed renewables, the 2019 requirement is 2.2% of retail sales. GMP anticipates having sufficient eligible RECs to meet the requirement through a mix of sources: PPAs including those under the Standard Offer Program, the GMPSolar projects, and net-metering projects that assign their attributes to GMP under the terms of revised Rule 5.100. The total cost of Tier 2 compliance for the rate period is projected to be about $3.2 million, including about $2.5 million of net-metering project RECs[14] that we assume will be assigned to GMP. In addition, to the extent that GMP retires RECs from new distributed renewable projects to meet its Tier 2 requirements, GMP will not be able to obtain revenue by selling those same RECs into other markets.

[14] The cost of using NM RECs to meet RES requirements is booked as 6 cents/kWh, based on the increase in REC adjustor that new net-metered solar customers will receive under the Commission's draft Rule 5.100 for assigning the RECs from their projects to GMP, versus retaining the RECs for their own use).

- For Tier 1 (total renewables), the 2019 requirement is 55% of retail sales, which we expect to meet using the attributes of renewable sources (mostly GMP Hydro units and the HQUS PPA) that do not qualify for higher-value REC resales, and through short-term transactions that provide additional hydro-based RECs to GMP. The projected rate period compliance cost for Tier 1 is about $0.5 million.
- For Tier 3 (Energy Transformation), the 2019 requirement is 3.34% of retail sales, which translates to about 103,700 MWh for the rate period. The projected 2019 compliance expense through electrification measures (such as cold climate heat pumps, or custom commercial/industrial measures)[15] is $825,000, as explained by Mr. Otley.

Q37. Are there any notable features associated with the estimation of RES compliance expenses that you would like to mention?

A37. Yes. Under the RES program GMP has the ability to retire RECs exceeding the RES requirement for a calendar year in the NEPOOL Generation Information System and may bank some or all of those excess RECs to be used for compliance with RES Tier 1 or 2 in one of the following three years. In the event that GMP banks RECs in excess of compliance requirements in a year, we plan to defer the costs associated with the excess RES compliance, and to recognize them as expenses in the year that the RECs are actually needed to meet RES requirements.

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[15] This expense does not include the additional electric sales that these measures will provide.

Energy Market Purchases

Q38. Have you made any rate period adjustments to GMP's net energy market purchases? If so, why?

A38. Yes. Net bilateral energy market purchases (these are the fixed-price purchases for terms of less than 5 years that I discussed above) declines about 367,000 MWh from the test period to the rate period, as some existing purchases expired and were replaced by new purchases with smaller total volumes. 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 $16.8 million; the average price of the remaining purchases increases from about $51/MWh in the test period to about $54/MWh in the rate period. The estimated impact of the changes (in volume and price) on GMP's net power costs for the rate period is a decrease of about $2.1 million.

Ancillary Services, Congestion and Losses

Q39. Have you made any adjustments for ancillary service charges or congestion in the rate period?

A39. Yes. ISO-NE Ancillary charges of $7.4 million (compared to about $6.8 million in the test period) are included in Net Power Costs. This category includes the net marginal loss and congestion components of energy costs for all purchases and sales of energy with ISO-NE, as well as the net cost (i.e., costs that GMP pays, less revenues that GMP sources provide) for products including reserves, net commitment period compensation, and regulation. Marginal losses and congestion are the largest components of this category. Generation that is not located near load centers (such as HQUS or NextEra), or in areas with less robust transmission, tend to experience higher marginal losses, and sometimes negative congestion (when limits on the transmission system prevent power from flowing freely across the region). As a result, the LMP revenues available to these sources are typically somewhat less than would be the case if the same generation were produced at a more central location. Net losses plus congestion cost is projected to increase from $4.9 million in the test period to $5.9 million in the rate period (a modest change in the context of GMP's several hundred million dollars of annual energy transactions), in part because LMPs in the rate period are projected to be somewhat higher than in the test period. Other ISO-NE (Net) Ancillary charges are projected to decrease by about $0.3 million, due primarily to anticipated expiration of ISO-NE's winter reliability program.

Q40. Are there any specific issues with respect to congestion costs that are noteworthy?

A40. ISO-NE implemented its DNE (do not exceed) dispatch framework at the end of May 2016, requiring renewable large-scale power sources to offer their output economically (e.g., specific volumes of output at specific prices) even if they are subject to fuel availability. This has sometimes led to renewable resources being dispatched downward when generation in the region exceeds ISO-NE's real-time requirements, or in local areas when generation must be limited because potential flows over an interface exceed the interface's limit. If and when renewable sources are the marginal energy sources for New England or for a constrained area, their offers can now set the energy market price in the same way that other generators do.

Some energy sources (including non-renewables) offer part or all of their energy output at very low or even negative prices (indicating a willingness to pay to generate energy, if needed), which reflects such factors as operational constraints, fuel commitments, or non-energy values such as RECs or the Production Tax Credit that are obtained when a renewable generator produces energy[16]. In the context of the DNE regime, this offering behavior has led to an increasing frequency for locational marginal prices in the ISO-NE market to settle at zero or negative prices for minutes or hours at a time. While these outcomes are occurring during a relatively small fraction of hours across a year, they are putting some downward pressure on spot market energy prices. This tends to reduce the market revenue that GMP receives for the output of its generating sources (increasing GMP's net power costs), and can reduce the cost that GMP pays to purchase its load requirements in the ISO-NE market (lower net cost to GMP)[17].

At the same time the Sheffield-Highgate Export Interface ("SHEI"), a transmission interface in northern Vermont, has become constrained on a fairly frequent basis when generation in the area is high and/or when load in the area is low. This has led to generators in northern Vermont competing based on price when the interface is constrained, which has consequently led to LMPs in this area sometimes dropping noticeably lower than LMPs in the rest of New England. These lower LMPs tend to

[16] A plant owner whose PPA revenues are based directly on energy production, and who does not receive the plant's LMP revenues, would also be incented to offer energy output at very low prices.

[17] In the most pronounced instance of transmission congestion affecting GMP, the export-constrained SHEI area, the load benefits to GMP from negative congestion have been quite small relative to the cost of reduced revenue from generation sources in the area.

adversely affect GMP's net power costs, because they decrease the value that GMP receives for the energy output of sources that are located in that area such as the HQUS PPA, Kingdom Community Wind, and other smaller renewable sources. Over the past year, congestion has also periodically suppressed the value of energy output from other sources such as the Granite Reliable and NextEra Seabrook PPAs in New Hampshire. Implementation of the DNE framework drove an increase in net congestion costs in the test period relative to past years, putting upward pressure on GMP's net power costs.

Q41. Has GMP assumed any changes with respect to transmission congestion that will reduce GMP's net power costs for the rate period?

A41. Yes, the rate case power costs reflect two adjustments that lower congestion costs. First, we have assumed that a major transmission outage that lowered SHEI limits and increased congestion during the test period will not recur in the rate period. We have therefore made a normalizing adjustment to reduce the test period congestion factors for sources located in the SHEI area by half during this portion of the rate period – effectively increasing the average LMP revenue that these sources receive during the months of March to May.

Second, GMP and others are exploring potential solutions. GMP is presently in discussions with Enel (the owner of the Sheldon Springs plant) to install an AVR (automatic voltage regulation) system at this plant. Transmission system analysis by VELCO and its consultant EIG indicates that installation of AVR at Sheldon Springs would noticeably increase the SHEI limit during some conditions. This potential solution appears to be relatively low-cost and cost-effective and could potentially be installed before the end of this year (much more quickly than most other potential solutions). GMP's projected rate period power costs reflect the assumption that the Sheldon Springs AVR project can be implemented before the rate period begins. Sheldon Springs AVR is only a partial solution (VELCO indicates that it is most effective during "all lines in" conditions, and this hydro-based solution will not be effective when streamflow is very low), but GMP estimates that it will provide some reduction in SHEI congestion (i.e., a known and measurable cost reduction) relative to test period conditions.

Q42. Please explain what volume of KCW output is assumed in the rate period, and how that volume was developed.

A42. The rate period power costs assume KCW output of about 124,000 MWh (total plant); this corresponds to full-year output of about 171,000 MWh. This volume was developed on a monthly basis by normalizing the test period output to reflect long-term average wind conditions, as well as removal of the estimated impact of the Essex Statcom transmission outage I discussed above, and a known and measurable adjustment to reflect partial relief of congestion of the SHEI interface based on the assumed implementation of the Sheldon Springs AVR project. Specifically, monthly KCW output was developed in the following steps:

- The starting point is a long-term forecast of about 185,600 MWh per year of plant output (this is for the full year and includes the roughly 13% of plant output that GMP sells to VEC under a long-term PPA). This is the same output that GMP presented as a base case forecast in the plant's certificate of public good proceeding.

- The underlying monthly profile of output was adjusted to shift 5,000 MWh of output from winter months to Spring and Fall months. This reflects that the plant has historically lost some potential winter output due to icing conditions but has tended to overproduce in other months.
- Output was reduced on a monthly basis to reflect the estimated[18] volume of KCW output that was lost in each month of the test period (totaling about 27,000 MWh over 2017 as a whole) due to congestion of the SHEI.
- Finally, KCW output was increased to reflect the two factors I discussed above: an increase of about 8,000 MWh to replace generation that was lost during March to May of the test period during the Essex Statcom outage; and an increase of about 4,000 MWh to reflect estimated benefits from the Sheldon Springs AVR project.

Based on these adjustments, GMP's power costs for the 9-month rate period reflect about 124,000 MWh of KCW output (total plant). GMP's corresponding share of KCW output (after the sale of output to VEC) is about 108,000 MWh, an increase of about 10,600 MWh from the test period. As explained above, this reflects an operating environment in which KCW output is sometimes limited due to congestion of the SHEI, but not as much as in the test period.

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

A43. Yes. Other notable changes affecting GMP's net energy costs are as follows:

[18] This estimate is based on a review of historical KCW output, KCW dispatch instructions (DNE limits), and LMP data.

- The HQUS energy contract, GMP's largest single source of energy, is projected to see a (formula) price increase of about $2.50 per MWh, adding about $1.9 million in rate period costs.
- Granite Reliable energy will see contractual price increases of about $1.66/MWh. Combined with somewhat higher output in the rate period, this increases net power costs by an estimated $1.0 million.
- In the rate period, GMP projects that its hydro plants will produce almost 40,000 more MWh of energy than were produced in the test period. This is due in part to normalization of test period output to reflect long-term average production levels, as well as output from the acquired Enel plants, and upgrades made to other GMP hydro plants. This added generation is expected to reduce net energy costs in the rate period by about $1.4 million.
- The largest legacy Rule 4.100 contract administered by VEPP Inc. (Sheldon Springs) expired at the end of March 2018. Going forward, GMP will be purchasing the output from this plant under a long-term PPA at a much lower price. The net rate period savings from this change is estimated at about $3.9 million.

IV. JOINTLY OWNED SOURCES

Q44. Please summarize how GMP experiences costs associated with jointly owned units.

A44. The jointly owned facility structure is characterized by a lead participant (e.g., Burlington Electric Department, for the McNeil plant) that is responsible for leading the operation of the facility on behalf of all its owners. The lead owner tracks the expenses and revenues, along with capital expenditures, which are recovered pro-rata from the remaining joint owners. In this way, each joint owner shares in the costs and accounts for their share of O&M and capital associated with the plant on its own books. Typically, a joint ownership relationship covers the economic life of the facility (which is not known in advance), rather than a fixed term as is the usual case for PPAs.

Q45. What are the jointly owned facilities in which GMP participates?

A45. GMP participates in four jointly owned facilities. They are:

- The McNeil wood-fired plant in Burlington, Vermont. Burlington Electric Department is the lead participant with GMP's 31.0 percent share representing about 16 MW of capacity. The plant is dispatchable, but normally runs most on-peak hours and other higher-market-price times. GMP receives RECs for all its share of generation.
- The Wyman #4 oil-fired steam generating unit in Yarmouth, Maine with NextEra as the lead participant. GMP has an ownership share of 2.9207 percent or about 18 MW. The plant now runs primarily as a peaking unit and also supplies ancillary products.
- The Millstone #3 nuclear facility in Waterford, Connecticut with Dominion Nuclear Connecticut as the lead participant. GMP's ownership share is 1.7303 percent accounting for about 21 MW of capacity. Millstone is a baseload plant and typically operates at an average capacity factor over 90% when not down for

refueling and major maintenance. The next outage is scheduled for April 2019, so it will be unavailable for somewhat over a month of the rate period.

- The Stony Brook 1A, 1B, and 1C intermediate combined cycle turbine facility in Massachusetts. The Massachusetts Municipal Wholesale Electric Company is the lead participant and GMP's ownership share is 8.8029 percent (about 30 MW). GMP also has a smaller PPA share of output from the same facility. These units can operate on either natural gas or distillate oil, but primarily the former.

Q46. Please summarize the operating roles of these jointly owned facilities.

A46. Millstone #3 operates as a baseload generating plant with an eighteen-month fuel cycle; it had a refuel outage in Fall of 2017 and the next refueling outage is scheduled for Spring of 2019. Wyman #4 is a steam unit that uses residual oil as its primary fuel; it operates as a peaking unit with a capacity factor of less than 5 percent in recent years. McNeil is an intermediate unit that typically dispatches at a capacity factor between 55 percent and 70 percent, using the value of RECs as an offset to its fuel costs. Stony Brook is a gas/oil-fired combined cycle plant that has functioned in recent years in largely a peaking role, with a capacity factor less than 10 percent.

Q47. How does GMP forecast the relevant rate period O&M costs for these facilities?

A47. The rate period power costs reflect a five-year average of actual, historical non-fuel O&M costs for the months of January through September over the period 2013-2017 totaling about $5.2 million, as follows: Millstone $3.0 million, McNeil $1.4 million, Stonybrook $0.6 million, and Wyman $0.15 million. For comparison, the test period costs in 2017 for these facilities totaled about $5.3 million.

V. TRANSMISSION COSTS

Q48. Please provide an overview of GMP's purchased transmission and related costs.

A48. GMP's purchased transmission costs consist of RNS charges, which are part of the NEPOOL Open Access Transmission Tariff ("NOATT"), VELCO 1991 Vermont Transmission Agreement ("'91 VTA") 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 utilizes. Transmission costs have grown significantly over the past ten years, primarily for RNS as a result of the expansion of the region's high-voltage (Pool Transmission Facilities, or PTF) transmission network. RNS costs represent approximately 63% of all purchased transmission costs for the rate period.

VELCO '91 VTA Common charge costs normally comprise the second-largest component of transmission costs, although they can vary significantly from year to year. Under the VTA, net VELCO monthly costs are assigned to Vermont distribution companies based on each utility's share of trailing 12-month coincident and non-coincident loads, reduced by Internal Generation ("IGAP") credits. VTA Common charges are a limited fraction of total VELCO costs due primarily to reimbursements through ISO 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 2017 and projected 2019 costs and revenues, and the resulting increase to the '91 VTA charge[19].

Q49. What is the projected change in purchased transmission costs between the test period and rate period, and what are the drivers of the increase?

A49. Purchased transmission costs (which include certain ISO-NE tariff charges) for GMP are projected to increase from $71.6 million (including Highgate O&M charges) in the test period to $86.3 million in the rate period, an increase of $14.7 million. The two primary drivers of the increase are a projected $11.1 million increase in the VELCO VTA Common charge (which is based on Ms. Nelson's testimony regarding VT Transco costs and revenues) and a $4.6 million increase in RNS charges. All other purchased transmission costs are projected to decrease $1.0 million.

GMP charges for RNS were $49.6 million in the 2017 test period and are projected to be $54.2 million in the rate period, about a 9.3 percent increase. This RNS increase is largely due to ongoing increases in overall PTF costs in the region, reflecting increases in the net bulk transmission plant in service. Because New England is not experiencing significant growth in peak loads, increasing PTF costs translates to higher RNS rates on a dollar-per-kW basis.

From the test period to the rate period, GMP's VELCO VTA Common charge expense is projected to increase from $8.7 million to $19.7 million, an increase of about $11 million. Ms. Nelson explains the primary reasons for the increase. In summary,

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[19] Please note that Ms. Nelson's testimony presents statewide figures; GMP's projected share is 78.9 percent.

VELCO costs are projected to increase by about $20 million from the test period to the rate period. Primary drivers of this increase are revenue requirements associated with major transmission projects placed in service during 2017 and 2018, along with increased maintenance and administrative costs (some of this increase reflects a shift in allocation of some VELCO costs from regional transmission capital projects to operating expense). At the same time, revenues from sources other than the VTA Common charge are expected to only increase by about $5.7 million, as the share of VELCO's revenue requirements that will be recovered through RNS charges is projected to drop to about 77% in the rate period compared to about 84% in the test period. Reasons for this shift include a significant decline in large capital project activity at VELCO, and a true-up of RNS collections from 2017. It should also be noted that an increase to GMP's equity in earnings from increased VELCO/Transco investment - reflected elsewhere in GMP's revenue requirements - offsets a portion of the increase in VTA charges to GMP.

Q50. What are some of the other projected changes in Transmission costs?

A50. Purchased transmission costs excluding RNS and VELCO VTA Common are projected to decrease by $1.0 million. The largest contributor is VELCO Specific Facilities charges, projected to decrease about $900,000 due to costs currently charged to GMP being moved from the Specific Facility category at VELCO to Common, where all VT utilities share the cost[20]. Another notable (though relatively small) decrease is for

[20] GMP will now pay its load share (about 79%) of these costs, which are included in the VTA Common charge increase discussed in the answer to the prior question.

Highgate O&M due to the sale of the facility by the various (VT) owners to VELCO. The only cost increase in this group is for ISO/NEPOOL-related tariffs, due to actual 2018 and projected 2019 rate increases since the test period.

Q51. Does that conclude your testimony at this time?

A51. Yes.