STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Tariff filing of Green Mountain Power requesting a 5.45% increase in its base rates effective with bills rendered January 1, 2019, to be fully offset by bill credits through Sept. 30, 2019	))))	Case No. 18-0974-TF

PREFILED REBUTTAL TESTIMONY OF

DOUGLAS C. SMITH

ON BEHALF OF GREEN MOUNTAIN POWER

September 12, 2018

Summary of Testimony

Mr. Smith responds to Department of Public Service (the "Department" or "DPS") witnesses Edward McNamara and Christopher Dawson. He explains Green Mountain Power's ("GMP" or the "Company") position regarding the Department's proposed adjustment for Regional Network Service charges. He also addresses Mr. Winn's and Dawson's comments on the need for GMP's Joint Venture ("JV") Solar-Battery projects, and the modeling of customer benefits associated with those projects. Mr. Smith also provides GMP's response to Mr. Dawson's recommendations for documentation of GMP's policies for power supply management on behalf of its customers. Finally, Mr. Smith addresses the Public Utility Commission ("PUC" or the "Commission") Information Requests.

Exhibit List

GMP-DCS-23	GMP Capacity Gap Chart
GMP-DCS-24	GMP Energy Supply Gap Chart
GMP-DCS-25	GMP Trading History for Class 1 2018 Vintage RECs

Q1. Please state your name and position.

A1. My name is Douglas C. Smith, and I am Chief Power Supply Executive for Green Mountain Power.

Q2. Have you previously submitted testimony in this proceeding?

A2. Yes, I previously provided prefiled direct testimony in this proceeding dated April 13, 2018.

Q3. What is the purpose of your testimony today?

A3. I respond to the power supply related items raised by Department of Public Service witnesses. I first respond to the Department's proposed adjustments for Regional Network System ("RNS") charge, outlined in Edward McNamara's testimony. I then address comments by Brian Winn and Christopher Dawson regarding the need for the proposed Joint Venture ("JV") Solar/Storage Projects and the Tesla Powerwall Program, as well as Mr. Dawson's comments on the methods and reasonableness of the modeling we conducted of the benefits those projects will provide our customers. Next, I respond to Mr. Dawson's testimony on GMP's energy, capacity and Renewable Energy Certificate ("REC") hedging strategies and explain why our approach is in customers' best interests. I also discuss our interest in providing the Department additional information on our methods for implementing these power supply management activities and explain GMP's commitment to provide more detailed hourly power modeling in the future. Finally, I respond to several PUC questions related to the Itron forecast and our analysis of capacity and line loss factors related to several projects proposed in the case.

I. RNS Adjustment

Q4. Can you please start by addressing Mr. McNamara's recommended adjustment to GMP's power supply costs to account for updated information on the RNS rates for the January 2019-May 2019 period? How do you respond to this proposed adjustment?

A4. I agree that the proposed adjustment is reasonable. Because the actual RNS rates for the period were not yet established and available when GMP developed its 2019 rate filing, GMP based the calculation of transmission expenses on its best estimate projection for the anticipated RNS rates. As Mr. McNamara notes, the actual RNS rates for the year June 2018 through May 2019 (covering most of the rate period) have since been established. His proposed adjustment (a reduction of about $398,000) reflects the difference between the actual established rate and the rate assumed in GMP's filing (before that information was available), as applied to GMP's monthly coincident peak billing demands. We have therefore adopted Mr. McNamara's adjustment in our revised Cost of Service, as reflected in Mr. Ryan's rebuttal testimony.

II. Need For JV Solar/Storage Projects

Q5. Mr. Winn and Mr. Dawson raise questions regarding the need for the JV Solar-Battery Projects. Can you please explain the need for these projects?

A5. Yes. As I discuss in more detail below, the JV projects are needed to help meet demand for service for GMP's customers, including energy, capacity, regional transmission service needs and our renewable energy obligations, in a way that is economic for our customers. As a load serving entity in the ISO-NE electricity market, GMP is responsible for providing or purchasing sufficient energy to meet its customers' needs (on an hourly and real-time basis), along with its share of regional capacity requirements (through the ISO-NE Forward Capacity market), along with regional transmission service and ancillary services. As a Vermont distribution utility, GMP is also responsible for complying with Vermont's Renewable Energy Standard ("RES"), including its requirements for renewable energy (Tiers I and II) and transformation (Tier III). GMP is pursuing these combined battery/solar projects because they help meet each of these needs, at a stable and reasonable price that is economic for our customers. I will address each of these issues below. In his testimony, Mr. Dawson focuses his comments with respect to valuation of battery storage and solar power on the proposed Milton project. I respond to his comments explaining why the Milton JV Solar-Storage project is important for GMP customers; my comments on this project apply equally to the other two JV solar projects that GMP has proposed.

Q6. Could you please summarize GMP's capacity and energy needs, and how the Milton project will help to meet them?

A6. Yes. Energy and capacity are the two largest components of power supply costs for GMP, and uncertainty in future energy and capacity market prices (which are not within GMP's direct control) are among the top sources of uncertainty and risk in those power costs. ***Exhibit GMP-DCS-23*** shows the estimated gap in terms of capacity (i.e., MWs of qualified capacity in the Forward Capacity Market); the amount of GMP's obligations in the FCM is determined primarily by GMP's share of ISO-NE's maximum hourly load each year. The cost of meeting these future capacity obligations will depend on the clearing prices for capacity in the FCM, which have shown substantial volatility from year to year and have put upward pressure on GMP retail rates in recent years. We actively manage this capacity obligation to mitigate cost impacts for GMP customers, through development of our own generation projects, and bilateral capacity agreements, but nevertheless overall regional capacity costs have increased in recent years. For example, as explained in my direct testimony, our capacity costs increased from about \$24 million to \$30 million in the rate period, an increase of approximately \$6.2 million. Development of these JV Solar-Storage projects is one component of our portfolio approach to addressing this capacity need. The output of the project (from the solar component, and by targeted discharges of the battery storage component) will serve to lower GMP's share of the annual peak load, and therefore of GMP's share of regional capacity obligations (including a significant capacity reserve margin).

The outlook for energy (see ***Exhibit GMP-DCS-24***) is similar. GMP has sufficient projected energy supplies (including owned plants and purchased power contracts) for the next couple of years, but by the mid-2020s GMP's projected annual load requirements exceed its committed supplies by roughly 500,000 MWh. The projected gap approaches 900,000 MWh later in the decade and increases again in the 2030s, as some of GMP's committed long-term supplies expire[1]. The project will help meet these needs by operating as a "load reducer" generator, with its output injected into

[1] I should note that the indicated energy and capacity needs shown here are largely by design. GMP has made a conscious decision to purchase its projected needs gradually over time, and to fill a portion of the portfolio with short- to mid-term purchases (reflecting then-current market prices), while acquiring new renewable supply sources on an opportunistic basis.

GMP's distribution system, thereby reducing GMP's load requirements in the ISO-NE market. For a sense of scale, the Project's estimated first-year output of about 25,000 MWh represents about 0.6 percent of GMP's current annual energy requirements.

As Mr. Shields explained in his opening testimony in this proceeding, and as Mr. Quint explains further in his rebuttal testimony in the Milton case, the estimated effective levelized cost to our customers for the solar component of the project is 8.0 cents/kWh when taking into account the benefits of the joint venture structure, as well as the potential benefits of owning and operating the project beyond 25 years. Mr. Shields notes in his testimony that we are not aware of any other operating solar facility in Vermont that has a lower per-unit cost for solar. In his rebuttal testimony Mr. Shields also outlines how the battery component of the project provides greater net benefit for customers compared to other available battery storage solutions GMP has evaluated.

Q7. Will the Milton project help to limit GMP's regional transmission expenses, and if so, how?

A7. Yes, the Milton project, and the other JV Solar Storage projects are designed and will be operated to help reduced transmission costs for our customers. As the Commission knows, Regional Network Service charges are a substantial component of GMP's Cost of Service that are not in our direct control. GMP's RNS charges are determined on a monthly basis, based on GMP's load during the hour of maximum load on the VELCO transmission system. The RNS rate is presently on the order of $9/kW-month. Increasing RNS rates have contributed to upward pressure on GMP's net power costs and retail rates. Again, for context, in the 2019 rate period, RNS costs are increasing by approximately $4.2 million, from $49.6 million to $53.8 million, more than an 8.0% increase compared to the test period, which represents a significant rate pressure for our customers in this period.[2] Emerging technologies like battery storage are a way to drive down the RNS charges. Here's how it works: to the extent that the Project (operating as a load reducer) generates energy during the monthly VELCO peak, GMP's share of that peak (and therefore its monthly RNS charges) will be reduced, thereby reducing costs for customers. GMP therefore plans to schedule the battery component of the Project to discharge during forecasted VELCO system peak hours. This is one of the benefit streams that Mr. Quint presents in the Milton case. As both Mr. Castonguay and Mr. Shields explain further in their testimony, these projects are just one of the many options GMP is pursuing in a coordinated portfolio of peak reduction measures to drive down costs in a new way for customers, including demand response resources, and other innovative solutions, such as our Tesla Powerwall program. The JV projects are part of a suite of measures that are designed to hedge against increasing capacity and transmission costs that are not in our direct control and drive down these costs for our customers.

Q8. How will the Milton project help GMP to meet its RES requirements?

A8. As the Commission knows, the RES establishes a set of mandatory requirements for Vermont distribution utilities including GMP to obtain portions of their power requirements from two broad classes of renewable sources, and to engage in energy transformation projects that lower costs and fossil fuel consumption. The following RES provisions are particularly relevant to the Project:

[2]See Smith Prefiled Direct Testimony at p.46 (as noted above, I have adjusted the $4.6 million RNS increase noted in my original testimony to reflect the $398,000 adjustment in RNS costs discussed in Question #5 above).

- Tier I requires that 55 percent of retail electric sales in calendar year 2017 be obtained from renewable energy sources (broadly defined, including both existing and new renewables). This requirement increases to 75 percent renewable in 2032.
- Tier II requires that 1 percent of annual retail electric sales in 2017 be obtained from new distributed renewable generation sources, increasing to 10 percent in 2032. This distributed generation requirement represents a subset of the Tier I total renewable requirement. New distributed renewable projects must have a capacity of less than 5 MW, achieve commercial operation on or after July 1, 2015, and be directly connected to the distribution or subtransmission system of a Vermont distribution utility (or an electric company required to submit a Transmission Plan—effectively VELCO).
- Tier III requires that distribution utilities implement energy transformation projects (examples of these include the implementation of electric vehicles, cold climate heat pumps, electrification of commercial/industrial processes that are presently performed using fossil fuels, and weatherization) above baseline values, in amounts equal to 2 percent of retail electric sales in 2017, increasing to 12 percent in 2032. Tier II-eligible distributed renewable generation (above that required to meet Tier II) may also be used to meet the Tier III requirements.
- Tier 1 features an Alternative Compliance Payment ("ACP") of $10/MWh, while Tiers 2 and 3 feature ACPs of $60/MWh. Each of the ACPs will escalate annually based on an inflation index.

As a new instate solar photovoltaic generator of less than 5 MW, the solar component of the Milton project will clearly be eligible as a compliance source to help meet GMP's

RES Tier I and II requirements, with Tier II expected to be the higher-value use. Because there is considerable uncertainty about the timing of Tier II-eligible supplies that GMP does not control (under the net-metering and Standard Offer programs), our Tier II compliance strategy for the early years of the program seeks to establish a pipeline which (if there were no significant delays or attrition of assumed supplies) would result in a total supply that significant exceeds the Tier II requirements. To the extent that GMP holds Tier II RECs that exceed its requirements in a given year, they can provide value to GMP and its customers in any or all of the following ways: (a) the difference could be sold to out-of-state markets, with the revenues used to reduce GMP's net power costs and retail rates; (b) excess RES compliance in the current year can be banked for use to meet RES requirements in future years; and (c) Tier II RECs could be used to help meet Tier III requirements, if needed.

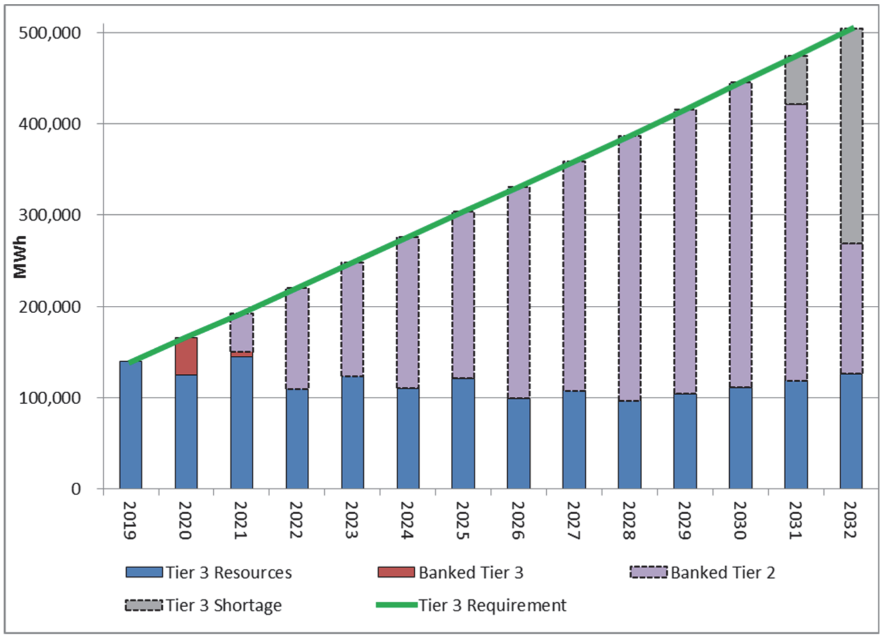
Q9. Could it be appropriate for GMP to use Tier II RECs to meet some of its Tier III requirements, at least in some years?

A9. Yes, for a few reasons. First, the Tier III Energy Transformation obligation grows at a more rapid pace than the Tier II obligation and, importantly, must essentially be met from new projects developed anew each year. That is, the value of a Tier III project claimed in one year is based on its estimated lifetime impacts, and therefore does not carry over to the following compliance year. Second, we are in the relatively early days of gaining experience with the availability and cost of Tier III compliance resources, and methods to procure them. As discussed in Mr. Shields' Supplemental Testimony in the Milton case,[3]

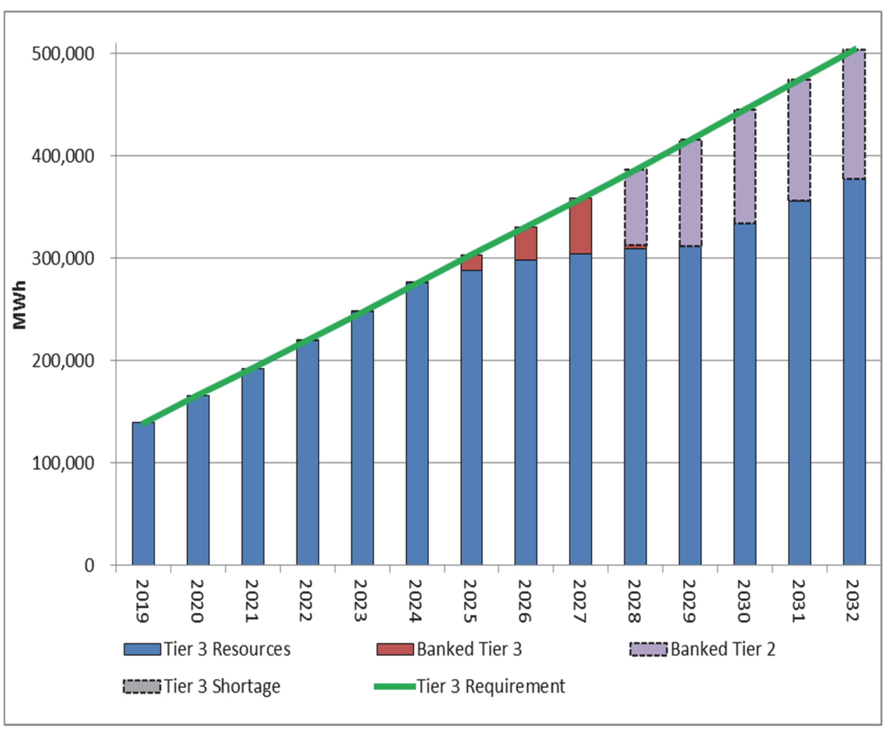
[3] Filed April 20, 2018 in Case No. 17-5003-PET, ePUC Document No. 262013/127259.

there is a good deal of uncertainty regarding the pace of Tier III supply that will be achievable, and the effective cost of stimulating sufficient Tier III projects. One of the challenges to meeting the Tier III obligation is that some of the greatest opportunities for energy transformation and reducing fossil use and greenhouse gas emissions are with commercial and industrial customer projects. GMP's experience in the past year indicates that such projects tend to have a significant lead time and are subject to business planning and budget cycles. In addition, customer payback for some electrification projects (e.g., replacing a current use of oil or propane with electricity) may be limited to some extent by current moderate oil prices. To reflect the wide range of potential outcomes, Mr. Shields developed two illustrative scenarios of how RES Tier III supply might play out over time: (1) a low case in which the supply of cost-competitive Tier III projects continues at a pace similar to the 2019 requirements (roughly 100,000 MWh of new projects per year), and (2) a high case in which growth of Tier III supply is rapid and sufficient to meet GMP's needs through the mid-2020s (at a level of roughly 300,000 MWh of new projects per year), then slows in the second half of the decade. I present these charts below for convenience.

Low Tier III Supply Case



High Tier III Supply Case



The particulars of these illustrative scenarios are not critical. In fact, if actual supply begins to follow the low scenario, I expect that GMP will respond by refining aspects of its Tier III acquisition approach (e.g., program design, incentive levels, etc.) with the goal of increasing the pace to cut carbon and costs for customers. The point here is that there is a wide range of potential outcomes for Tier III supply, and the uncertainty resides substantially on factors (e.g., customer response, future fossil fuel prices) that are not in GMP's control.

Q10. What are the implications of the uncertainty in pace and cost of Tier III supplies, as it relates to GMP's supply of Tier II RECs such as those the proposed Milton project will provide?

A10. GMP fully support the goals of Tier III and we are actively developing projects to meet them both for customers and the environment, there does however remain a reasonable likelihood that some portion of future year obligations will be met through the retirement of Tier II eligible RECs, at least during some years, due to factors such as the relative cost-effectiveness of transformation projects and the project cycles that are required to turn ideas into leads and ultimately completed projects. It is also possible that the effective cost for some eligible projects will exceed the market value of Tier II eligible RECs. If GMP is not able to meet all of its Tier III obligation through Energy Transformation projects or retirement of Tier II RECs, it will be required to pay the Alternative Compliance Price ("ACP") which started at $60/MWh in 2017 and grows each year. The ACP greatly exceeds the current market value of Tier II eligible RECs (i.e., the price that GMP could receive by selling those RECs to RPS compliance markets in neighboring states, and the opportunity cost that GMP would forego by giving up such sales), which indicates that in the event of a potential shortfall of Tier III supply, retirement of Tier II eligible RECs would be a preferable way of meeting a portion of GMP's Tier III requirements (when compared to paying the ACP). A related implication is that it may be appropriate to define the effective value of some amount of additional Tier II REC supply to GMP and its customers based on their potential use for Tier III compliance (as opposed to our current practice of approximating the REC value based on potential resales to the regional Class 1 RPS compliance market)[4]. This will be particularly true if future regional market prices for Class 1 RECs turn out lower than expected.

Q11. If GMP needs additional Tier II supplies in the future, could GMP purchase Tier II RECs from existing renewable projects (as an alternative approach to GMP procuring Tier II compliance sources itself through PPAs or GMP-sponsored plants)?

A11. Perhaps, but the magnitude of any available supply is uncertain and is probably limited. This is because the scope of Tier II-eligible projects is limited by statute (i.e., Tier II projects must be smaller than 5 MW, must reach commercial operation on or after July 1, 2015, and must connect to the Vermont grid). GMP would not be able to meet Tier II needs with purchases from out-of-state renewable plants, because they are not eligible for Tier II. In addition, there are few (if any) Tier II-eligible plants in Vermont (with the

[4] For example, suppose that regional Class 1 REC market prices fell to $10/MWh in a future year, but GMP faced a shortage of Tier III supply to meet its RES obligations for that year. In this case the highest value use of an incremental volume of Tier II RECs would be to retire them to meet Tier III requirements, in lieu of paying the ACP. In this role the RECs would provide an effective value to GMP and its customers that is much higher than the regional REC price.

exception of some net-metering projects) whose output is not already committed to Vermont distribution utilities. Vermont distribution utilities other than GMP might have some amount of Tier II surplus from time to time, but considering that their collective Tier II obligations are a fraction of GMP's obligations, it seems unlikely that their surplus would be able to meet a significant fraction of GMP's needs.

III. Modeling of JV Solar-Battery & Tesla Powerwall Benefits

Q12. Mr. Dawson has commented on the methodology and assumptions GMP used to quantify the anticipated benefits (e.g., value of energy, capacity, RECs and avoided transmission expenses) associated with both the proposed JV Solar/Storage Projects, as well as the related analysis done for the Tesla Powerwall Program. Can you explain first GMP's approach to this modeling was conducted?

A12. The modeling that was done to support these projects relied on GMP's current wholesale market price outlooks. These outlooks were developed using the same approach that has been used for evaluating other potential generation projects and PPAs in the past several years. GMP also presented substantial detail on its market outlooks in the context of Docket No. 8684 (relating to PURPA avoided costs), and the same methods supported GMP's December 2016 Rule 4.100 avoided cost filing.

More specifically, GMP's avoided cost forecasts are based on an internally developed market outlook that is built on a review of regional wholesale market conditions and anticipated market price drivers for each of the key products (i.e., energy, capacity, and renewable energy certificates or RECs). Our outlooks are informed by market price forecasts and related publications from consultants who focus on the New

England markets for energy, capacity, and RECs. We also obtain additional insights by interviewing the experts who developed these forecasts, with respect to the market drivers and key assumptions that are used to develop their outlooks. Analysis is also performed with respect to transmission expenses (Regional Network Service) and—in the context of battery storage—frequency regulation service. The trends in GMP's market outlooks for these products (or expenses) over time are intended to reflect the influences of appropriate market drivers (e.g., trends in regional supply/demand, cost of entry/exit, general inflation) that affect those products.

Q13. Using the approach above, has GMP reasonably estimated the value of output from the proposed JV Solar/Storage projects?

A13. Yes, the estimates presented by my colleague Andrew Quint in Case No. 17-5003-PET are appropriate. In the context of the present GMP rate case, Mr. Dawson raises questions about GMP's valuation of some components of output from the Milton Project's output, and suggests at several points that GMP has not provided a basis for some of its assumptions (e.g., capacity prices, energy prices). Interestingly, the Department has already reviewed GMP's input assumptions and methods in the context of the Milton case, where GMP shared its benefit/cost model and reviewed its key assumptions directly with Department staff. In that case Ms. White observed on page 11 of her June 27, 2018 testimony[5], that "many of the assumptions made by GMP regarding energy, capacity, transmission savings, regulation revenues, and REC values are reasonable and have been vetted by the Department," while also observing that "there are

[5] ePUC Document No. 275935/127259

some assumptions which perhaps overstate the value of the proposed project." She also notes that the associated markets are highly variable and unpredictable. It is important to note that in the present case Mr. Dawson does not present a detailed critique of each value stream or an alternative set of recommended market views. Discovery responses confirm that Mr. Dawson's observations are thematic and general, and not based on a detailed evaluation of the New England markets or their fundamental drivers. Nonetheless, I will briefly respond to each of Mr. Dawson's comments below.

Q14. Can you please respond to Mr. Dawson's comments with respect to the future market price of energy in New England?

A14. Mr. Dawson states that, "GMP's energy price escalation can only [be] characterized as aggressive or optimistic as a base case assumption" (page 26). He goes on to state that, "[a] more gradual increase, tied to an underlying driver such as natural gas futures, would be more appropriate." GMP concurs with the importance of natural gas fuel prices (as delivered to generators in New England), and notes that ISO-NE reports that natural gas set real-time prices about 70% of the time in 2017 and that there is a strong correlation between natural gas prices and energy prices in New England. GMP has generally used natural gas prices as a starting point for projecting trends in New England electric energy prices, and I believe that GMP's current forecast is consistent with this approach and is reasonable. As shown in the table below, current NYMEX price quotes (as of 9/7/2018) for natural gas at Henry Hub increase for most of the 2020s at a rate of about 3% per year. Alternatively, if we look at the 2018 Energy Information Agency Annual Energy

Outlook the forecast natural gas prices at Henry Hub show a somewhat higher upward price trajectory.

Henry Hub $mmBTU

Year	NYMEX - HH	% Change	2018 AEO	% Change
2019	$2.6995		$3.5520	
2020	$2.5995	-3.7%	$3.9620	11.5%
2021	$2.5613	-1.5%	$4.0217	1.5%
2022	$2.5631	0.1%	$4.1613	3.5%
2023	$2.6128	1.9%	$4.4204	6.2%
2024	$2.6830	2.7%	$4.6621	5.5%
2025	$2.7636	3.0%	$4.9325	5.8%
2026	$2.8456	3.0%	$5.0985	3.4%
2027	$2.9276	2.9%	$5.2809	3.6%
2028	$3.0122	2.9%	$5.4191	2.6%
2029	$3.1036	3.0%	$5.6249	3.8%
2030	$3.1949	2.9%	$5.7514	2.2%

GMP's energy market price forecast in the Milton case assumes a long-term escalation rate of about 3.5 percent—which is moderately above the rate of general inflation and is generally consistent with these two national outlooks. The rate we applied was also informed by our view that there are reasons to expect that energy market prices in New England may increase more quickly than national prices.

Q15. Can you please explain GMP's rationale further? Are there factors that could cause electricity market prices in New England to increase more quickly than national natural gas prices?

A15. Yes. One source of upward price pressure is likely to be the influence of the Regional Greenhouse Gas Initiative ("RGGI"), a program which requires large electric generators in nine participating states (which include New England and New York) to purchase allowances sufficient to cover their actual CO^2 emissions. The allowance purchases represent a variable cost of generation (in addition to fuel and other direct O&M costs) for the major marginal generators in the region, so the price of RGGI allowances puts upward pressure on their energy offer prices and ultimately on LMPs in New England. RGGI allowance prices are moderate now (a few dollars per ton) but are expected to increase significantly over time, as a steadily declining cap on allowed emissions in the electricity sector erodes the present bank of surplus allowances, and a new "soft" price floor mechanism (associated with program revisions under the 2017 Model Rule) is implemented.

The primary rationale for our use of an energy market price escalation rate above general inflation was the perceived likelihood for tighter greenhouse gas regulation over time at the regional and/or federal level. One facet of this upward pressure has, in fact, already materialized as the 2017 RGGI program refinements are expected to cause RGGI allowance prices for electric generators in the New England market to more than double over the next decade. This change alone would put a few dollars per $/MWh (i.e., several percent) of upward pressure on New England energy market prices. Please note that if the country adopted a greenhouse gas regulation program intended to produce emission reductions consistent with estimates of those that would be required to effectively curb climate change, the upward pressure on electricity market prices could be multiples of the increases reflected in GMP's current energy market forecast or the 2017 RGGI program design.

Delivered natural gas prices to New England also appear likely to put some additional upward pressure on energy market prices. GMP has used Henry Hub pricing as an indicator of national trends in natural gas pricing, but we recognize that Algonquin

Citygates is the delivery point for natural gas into New England, and that there is typically a basis (price) differential between these two delivery points. Most notably, there are constraints to the amount of natural gas that can be delivered to New England so during very cold periods the price of gas delivered to New England typically surges to levels far above Henry Hub and most locations outside New England. In addition, during non-winter months New England has in recent years sometimes experienced negative basis differentials (i.e., delivered prices lower than Henry Hub), as natural gas produced in the Marcellus region has encountered pipeline constraints moving out of the northeast. In GMP's view, each of these seasonal basis differentials poses an upward risk for energy market prices in New England. In winter, the increasing fraction of regional generation fueled by natural gas (in absence of significant additional pipeline capacity into the region, or other resources) could increase the frequency and magnitude of natural gas pipeline constraints and natural gas price spikes in the region. In other months, the completion of pipeline projects to enable the export of additional Marcellus gas to the west and south is likely to erode the negative basis differentials that have been observed in New England.

Q16. Can you please comment on the adjustment that GMP made to reflect the energy value of the Milton project's solar component?

A16. Yes, the estimates presented by my colleague Andrew Quint in Case No. 17-5003-PET included an energy price adjustment for solar generation component of the JV Solar-Storage Project, reflecting the fact that the value of solar output (basically the weighted average of LMPs when solar PV is producing) has fallen in recent years, and has recently been lower than the simple average of LMPs across all hours of the year. This discount is fairly small but it appears to be based in part on the growth of solar PV generation in the region (especially during daylight hours in the summer), along with a moderation of summer energy prices relative to winter (consistent with my earlier discussion of natural gas prices). On page 31 Mr. Dawson discusses GMP's use of an adjustment factor to account for the timing of solar production. While he concludes that the overall concept of such an adjustment is appropriate he suggests that the growth of solar generation will cause further degradation of the energy value achieved by solar generation over time.

While GMP has not yet included a further degradation factor in our solar model, Mr. Dawson's suggestion here is a reasonable refinement that we will consider making in future solar modeling after reviewing a number of factors—such as the current MWs of solar across New England; the expected pace of solar growth over the next decade; the historical marginal units especially during summer months; forecasted trends in seasonal on- and off-peak energy prices; and the distribution of high and low LMP hours driven by shortage and other events. The hourly regional dispatch modeling that GMP is presently exploring to implement, discussed further below in Question 36, could also provide additional insight on this point.

Q17. Please respond to Mr. Dawson's critique of GMP's capacity market price outlook.

A17. Mr. Dawson discusses GMP's capacity market outlook on pages 26-27 of his testimony and states, "a forecast that more closely resembles the growth and expectations from recent capacity auctions and market forecasts is more conservative than an aggressive increase to Net CONE." Interestingly, the chart that Mr. Dawson presents as Figure 6 begins with 2019 and does not include the current capacity year of June 2018 to May 2019 that featured an annual clearing price of $9.55/kW-month, the highest in recent memory.

Our evaluation of the capacity market (based in part on review of material from our regional consultants) indicates that the most likely case appears to be moderate prices (with a gradual increase) over the next several auctions, reflecting a rough balance between supply and demand (i.e., no additional retirements of major capacity sources, or major net entry of new sources). Over a longer horizon, capacity prices in the $4 to $5/kW-month range are unlikely to be sufficient to attract substantial new market entry (e.g., from combustion turbine or combined cycle plants, which required prices of $7.03/kW-month to $9.55/kW-month in recent auctions). It is also possible that these price levels will not be sufficient to support some relatively high-cost existing units (e.g., aging fossil fueled intermediate units) to continue to operate in an energy market where they can earn only limited net energy revenues. There is also concern that significant baseload plants such as Millstone face continued uncertainty without some additional value stream such as the Connecticut Zero Carbon market.

I should also note that the results of FCA#12 may be somewhat misleading as two units, Mystic 8 and Mystic 7 (which combined total well over 1,000 MW) had submitted delist bids at $5.499/kW-month and $5.00/kW-month, respectively, and were not allowed to delist because of fuel security concerns. If both units had been allowed to delist the auction, which cleared with 1,100 MWs of surplus capacity, the clearing price would likely have ended up somewhere between the delist bids for the two units. The final result was that the auction cleared at $4.63/kW-month, while the two units that were not allowed to delist are being paid their (higher) delist bids for the capacity year ending May 2022. It is not yet clear if this treatment will continue in the future. If the Mystic units are ultimately allowed to exit the capacity market that change would (all else equal) put upward pressure on capacity market prices.

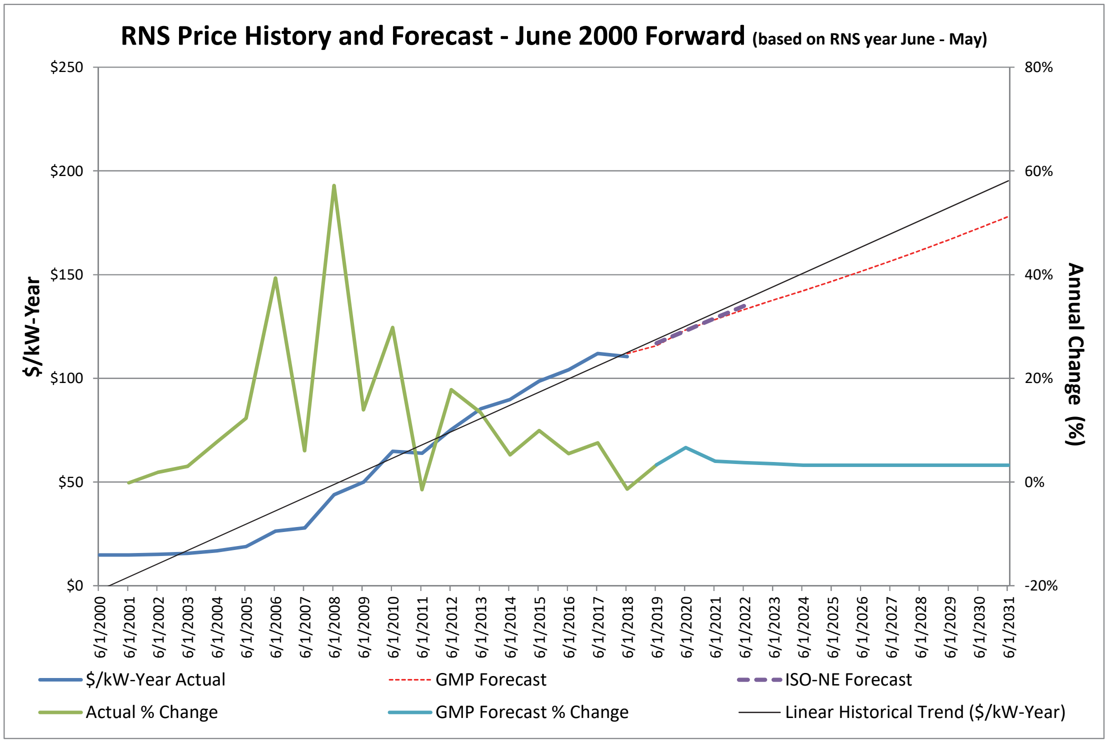
Over the next few years it appears that expected retirements and other changes to the New York ISO capacity market could limit the volume of capacity that elects to export capacity from NYISO to ISO-NE. When considered in the context of possible retirements and changing conditions in NYISO, it is reasonable to expect that ISO-NE capacity prices will increase gradually toward Net CONE by the end of the 2020s, as GMP has assumed. In actual practice, capacity prices will likely move up and down over time somewhat in a non-linear fashion, due in part to the steep slope of the administrative demand curve that is used to clear the market. For modeling purposes we do not try to guess when rapid, short-term price swings will occur, but rather we try to develop a curve that produces a credible trend over time that is consistent with the anticipated market drivers—in this case, a gradual increase over the next decade toward estimated Net CONE. Finally, I should note that our assessment of the reasonableness of our forecast includes the fact that Net CONE itself can evolve over time, and that some factors (e.g., moderate energy and ancillary service margins, increasing interest rates over time) have the potential to increase Net CONE relative to current values. Our method of analysis for capacity prices in this case uses the same approach we have used for evaluating other capacity transactions, and we believe the approach is well-informed and reasonable. I do not see a basis to adjust our base case capacity assumptions in this analysis.

Q18. Please respond to Mr. Dawson's discussion of future RNS rate trends.

A18. On pages 28-29 Mr. Dawson discusses GMP's outlook for transmission rates and notes that much of GMP's outlook is based on an escalation rate of 3.25% per year, which is higher than the expected general inflation rate. In fact, Mr. Dawson suggests that a transmission rate forecast which assumes inflation-rate growth is more reasonable. For a few reasons, I believe that GMP's base case forecast (which reflects a recent ISO-NE projection for the first five years, followed by an escalation rate of 3.25% per year) is completely appropriate as a base case forecast.

First, our assumed 3.25%/year trend line is slower than the historical growth trend for RNS rates since 2000 (over 10% CAGR) and also slower than the growth rate over the past five years (about 5% CAGR)—in spite of the fact that the 2018-19 rate declined slightly due largely to a one-time reduction to the federal corporate income tax rate that provided about $9.50/kW-year in benefit according to ISO-NE[6]; reductions of this type and magnitude seem very unlikely to recur in the future. The historical track of annual RNS prices (along with the historical trend line) is shown in the chart below, along with GMP's current forecast.

[6] https://www.iso-ne.com/static-assets/documents/2018/08/a2.0_2018_08_07_08_rc_tc_ptoac_rates.pptx page 4.



Second, in spite of modest peak demand growth expectations, it is reasonable to expect that regional investment in bulk transmission plant will continue to grow—driven by asset condition projects (i.e., replacement of transmission equipment facilities nearing the end of their useful lives); investments in grid security; and potentially grid reinforcements to manage increasing amounts of intermittent generation or to manage existing transmission constraints. In addition, bulk grid investments for these purposes have historically faced cost escalation more rapid than the rate of general inflation. This trend has been a contributor to upward pressure on RNS rates and seems likely to continue to be in the future.

Finally, RNS rates also depend on the volume of usage (i.e., monthly peak kW) over which the bulk transmission revenue requirements are spread. Peak demand growth in New England has been modest due to the influence of energy efficiency, distributed generation, and moderate economic growth, so that increasing bulk transmission costs have not been offset by an increasing denominator over which to spread them. The flat regional load trend is anticipated to continue in the next decade[7], contributing to upward pressure on RNS rates. In summary, based on historical observations and forward-looking trends, I continue to believe that GMP's base case outlook for the RNS price trend is reasonable and appropriate.

Q19. How do you respond to Mr. Dawson's critique of GMP's REC market price outlook?

A19. As with the energy and capacity market price outlooks, our REC market outlook is developed based on monitoring of the regional market (in this case, Class 1 RPS compliance markets in New England states) and is informed by review of appropriate consulting resources focused on that market.

As 2018 has unfolded, we have seen REC market prices for near-term vintages drop to levels not seen in many years, as new renewable supply (including large scale renewable plants and distributed solar PV generation) has caught up to (and essentially passed) the current requirements. On the other hand, there are forces (e.g., the MA CES program) in place that will increase demand and market prices for the next couple of years, along with developments (e.g., significant increases in state RPS volume requirements, potential withdrawal of discretionary existing supply sources such as biomass plants and imports from neighboring regions) that will tend to rebalance supply and demand (and support higher price levels) on a longer-term basis. GMP's base case

[7] To the extent that significant battery storage projects are deployed in the region as load reducers, they can be expected to reduce regional peaks by some additional amount.

outlook for regional Class 1 REC prices trends to about $25/MWh in nominal terms (which means a gently declining price relative to inflation) over the next decade. I believe that this is reasonable because it is well within the range of historical REC market prices in New England, as well as the range of current consultant outlooks for various supply/demand scenarios. This price level is close to the approximate "cost of entry" (i.e., theoretical price level required to support the development or import of new supplies) for some types of new renewables in New England.

GMP recognizes that REC markets are very much subject to changes in regional supply/demand (which, in turn, are driven partly by the design and evolution of renewable policies in neighboring states). There is significant potential for short-term price volatility and trend variance in the 2020s, depending in part on whether some planned "mega" projects (e.g., planned offshore wind projects that have been selected as RFP winners by Massachusetts) achieve commercial operation, and (if so) when. Nonetheless, our base case outlook is based on consideration of appropriate resources and factors and is therefore reasonable.

Q20. Mr. Dawson notes (page 33) that since GMP's price forecasts appear generally aggressive and the projects rely on uncertain capacity and energy prices, consideration of a range of prices for the key variables would be beneficial. Has GMP performed a sensitivity analysis of alternative outcomes that would affect the project's net benefits?

A20. Yes. While my testimony above makes clear that I disagree with a characterization of GMP's market outlooks as aggressive, I should note that in his rebuttal testimony in the

Milton case[8], Mr. Quint presented a sensitivity analysis that tested potential alternative outcomes for several factors that affect the project's anticipated value streams. The following table presents the potential impacts of those factors:

Change	Impact	25 Year NPV Impact
Increased Regulation prices through 2021 (reflects slow drop in market prices)	+	97,916
Increased loss benefit for battery storage from 5% to 15%	+	428,764
Incremental change for 1 month of RNS peak capture for battery	+/-	312,943
10% Decrease in FCM benefit (from 95% to 85%) for battery	-	(234,051)
5% Change in forecast Capacity prices (for solar and battery)	+/-	164,469
0.75% Change in growth rate for RNS Prices	+/-	174,123
Exclude loss benefit for PV output (currently 8%)	-	(324,509)
5% change in scalar used for PV FCM coincidence (e.g. 95% to 90%)	-	(468,655)

These changes are not statistically derived or tuned to represent a consistent likelihood of occurrence, but they are illustrative of credible variances for each of several relevant factors, and they provide an indication of how strongly each variable could affect the project's net benefits. Note that the sensitivities reflect both positive and negative potential outcomes, meaning that there are some instances with a reasonable possibility of producing more favorable results than reflected in GMP's base case assumptions. For a sense of scale, none of these uncertainties individually would come close to negating the roughly $2 million of present worth benefit that GMP currently estimates over the project's lifetime.

When considering the robustness of the project's benefit streams and how the various uncertainties could interact, it is also important to keep in mind that many of the factors that Mr. Quint tests will depend on outcomes for different drivers that are not related. For example, a future outcome in which FCM market prices turn out higher/lower than expected may be driven by supply/demand conditions (e.g., attrition of

[8] August 20, 2018, ePUC Document No. 297900/127259.

aging capacity, higher or lower levels of demand growth or imports to the region) that are not the same as those that would drive changes in other factors (e.g., higher or lower RNS rates) in the same direction. In fact, unfavorable outcomes for some factors could be offset by favorable outcomes in others. Finally, it is important to note that the project is not a stand-alone investment—rather, it is part of an investment in GMP's portfolio of resources to meet its customers' needs. The project will essentially lock in a small portion of GMP's various costs (including FCM, RNS, energy, and RECs) at a reasonable cost (in this case, the cost is somewhat less than the base case estimates of value streams the project would provide). Some potential future outcomes that appear unfavorable in terms of market revenue or avoided cost for this investment (particularly those that reflect low future market price outcomes for Energy, RNS, or Capacity) would not be adverse for GMP customers. In such an outcome, the lower market prices would cause project revenues or avoided costs to turn out lower than modeled today, but a significant portion of GMP's portfolio (i.e., the open position that has not yet been purchased today) would also benefit from those same lower prices resulting in lower overall net cost to customers. Thus, when considering the value of these projects, it is important to keep in mind the role they play as a hedge against increasing costs in these areas. They should be considered in the context of our overall portfolio-wide strategy to protect customers from cost impacts associated with uncertain future conditions.

Q21. Can the battery component of the Milton project be dispatched flexibly?

A21. Yes, this lithium ion battery storage system does not have any appreciable ramping or minimum runtime constraints, so if needed the system can respond very quickly (to discharge or charge) in response to changing market conditions or information. This means that the battery can be discharged for one or more hours (or fractions of an hour) at a time, and the hours of discharge do not need to be contiguous. It also means that, GMP will be able to schedule discharges of the battery system to reduce peak loads whenever they occur, based on the best current information. It is therefore reasonable to expect that the battery system will be effective in the peak-reducing roles I discussed earlier, even if the specific timing of the key peak loads in Vermont and New England shift over time.

Q22. Are there other facets of flexibility that bear on the robustness of the Project's estimated benefits?

A22. Yes. As discussed above (and in Mr. Quint's prefiled testimony in the Milton proceeding[9]), GMP has stacked the benefits of the battery system to maximize its value to customers, and GMP's evaluation of the project reflects our current understanding of the value streams that the system would provide. The battery's flexibility will also allow GMP to be proactive at limiting costs and nimbly reacting to changing short-term market conditions (e.g., to discharge when LMPs are particularly high, or to charge from the grid when LMPs drop below $0/MWh). This instantaneous controllability should allow GMP to maximize the device's value to customers by operating in the most beneficial mode, sometimes with limited advanced notice. Over time, benefit stacking and operational flexibility should also allow GMP to refine its operation of the battery system if and when there are significant market changes—for example, if the relative market values of

[9] November 22, 2017, ePUC Document No. 238483/128259

certain products change over time[10], or through the addition of new markets such as reserves. This flexibility, and the fact that the estimated benefits of the project derive from several value streams (as opposed to a single product receiving a single market price) enhances the probability that the project will be able to provide value to customers under a range of future conditions.

Q23. Does the proposed project have value to customers as part of GMP's portfolio of power resources?

A23. Yes, it does. At times the testimony of Department witnesses Dawson and Winn appear inclined to view the proposed project's prospective value to customers based solely on a comparison of its costs and actual future market revenues, as a stand-alone investment. A project's costs and revenues are obviously critical, and GMP strives to find resources to meet its customers' needs at the lowest possible cost, but a stand-alone evaluation perspective (for example, requiring that GMP provide assurance that project revenues will exceed project costs) does not make sense to me. As I discussed in detail above, the project's output will be used to provide (or reduce requirements for) each of several products that are needed to serve the load requirements of GMP's customers[11]. In short, the project is expected to act as a hedge—to stabilize GMP's net power costs—at a price that is less than a reasonable current estimate of the project's combined value streams. This is a favorable profile for our customers.

[10] For example, if real time LMPs feature more extreme intra-day highs and lows in the future, or if/when Regulation prices decline, GMP could refine the system's operating strategy away from Regulation service and toward energy arbitrage.

[11] The addition of flexible battery storage will also be complementary to a GMP power portfolio that contains substantial volumes of intermittent generation (and load requirements that are offset by substantial volumes of distributed intermittent generation). GMP has not assigned any value to this complementary role.

Moreover, the type of market outcome (say, for example, that both capacity market prices and energy market prices turn out much lower than expected on a sustained basis) that would make the project look the worst if viewed from a stand-alone perspective would be quite favorable for our customers when viewed from the portfolio perspective, because GMP would be able to lower its net power costs to a much greater degree by filling its larger remaining open positions at those lower market prices. Considering GMP's substantial exposure to future costs for capacity, energy, RECs and transmission, I believe that the project is a reasonable portfolio investment, and it will not be appropriate to value the project's future success based solely on a stand-alone comparison of project costs and actual market revenues.

IV. Estimation of Powerwall Benefits

Q24. Does your discussion above regarding GMP's approach to market price outlooks, and the reasonableness of those used to evaluate the proposed Milton project, also apply to GMP's evaluation of output from Powerwall battery storage units under GMP's pilot program?

A24. Yes, it does. GMP evaluates the output of Powerwalls (and other potential resources), using the same approach and market outlooks that reflect the period when the project is reviewed, applied to the market products or avoided costs that are provided by each resource. In the case of Powerwalls, those value streams are capacity and RNS savings (by discharging during ISO-NE's annual peak and VELCO monthly peaks, respectively), along with some assumed value for energy arbitrage (i.e., discharging the battery systems during periods when LMPs are higher than when charging occurs). We have also modeled the value of payments received from customers participating in the program. While there may be opportunities for participation of the Powerwalls in other ISO-NE ancillary services, we have not assumed any revenues from providing frequency regulation service or other types of ancillary services. I address the PUC's Information Requests related to the Powerwall model values in Section VI below.

V. GMP Risk Management Strategies for Energy, Capacity & REC Purchases

Q25. Mr. Dawson comments on the structure and documentation of GMP's hedging strategy for energy, capacity and RECs. Can you please summarize your response?

A25. Yes, Mr. Dawson raises some questions regarding GMP's approach to short-term market hedging practices in the procurement of energy and capacity and sales of renewable energy certificates. Based on these observations, Mr. Dawson recommends that GMP adopt a new corporate Risk Management plan for hedging practices, new energy modeling methods, specific energy transaction routines, and a triennial audit of the hedging plan. *See* Dawson page 20.

I believe that GMP pursues its transaction strategy more systematically than may be apparent from Mr. Dawson's limited review through the discovery process, but after reviewing Mr. Dawson's testimony I also believe that GMP can improve the clarity and transparency of its transaction process in some ways that would be responsive to Mr. Dawson's comments. I recommend that GMP and the Department collaborate (presumably outside the context of this rate case), to identify appropriate refinements along these lines.

I believe strongly, however, that the resulting process(es) and routines used to impart clarity and transparency should not impart undue rigidity into the timing and structuring of transactions. I believe in order to obtain maximum value for customers (in terms of lower power costs and/or risk), it is important for GMP to maintain some significant degree of flexibility to respond to changing market conditions, including the rapid transitions occurring in the New England energy, capacity, and REC markets. If Mr. Dawson intended by his examples or his recommendations to remove substantial flexibility from GMP's hedging[12] practices (as opposed to improving their clarity and transparency), then I would not agree with this limitation because it could have harmful consequences for customers. Also, I don't believe Mr. Dawson's recommendations for refinements to GMP's risk management practice or his suggestion to add an auditing program are necessary or supported by his assessments. I discuss these issues in more detail below.

Q26. In your view, does GMP's current short-term Energy, Capacity, and REC hedging approach strike an appropriate balance between flexibility and proscribed activity?

A26. Yes. As GMP describes in discovery (Response DPS2.Q13), short-term energy purchasing is a feature of GMP's portfolio approach to addressing customer energy requirements. The role of these short-term purchases has been summarized in GMP's last Integrated Resource Plan as a tool to stabilize GMP's net power costs and retail rates, while maintaining a degree of long-term flexibility so that customers can benefit with

[12] In this context, hedging refers to transactions that lock in fixed or stable prices for future deliveries of products that GMP needs to purchase (i.e., energy, capacity) or sell (i.e., regional Class 1 RECs) in order to meet the needs of its customers.

regionally competitive retail rates even when market prices fall (see, for example, pages 1-20, 3-29, and 7-2).

More specifically, GMP presently sources a portion of its energy requirements each year through fixed-price, fixed-volume forward energy purchases from the New England wholesale energy market. These purchases reduce our customers' exposure to year-over-year volatility in power supply costs that could occur if GMP purchased substantial fractions of its retail load requirements through spot market purchases or very short-term bilateral contracts. GMP typically implements these forward market purchases on a layered basis, with terms up to five years. This approach is intended to provide the short-term price stability noted above while ensuring that beyond five years the Company's power supply costs maintain some significant linkage to the New England wholesale energy market, thereby limiting the degree to which GMP's retail rates could diverge significantly from those in neighboring states. It also leaves flexibility to procure new longer-term supply sources that may not be specifically anticipated today while limiting the extent to which the portfolio could become imbalanced in the event that retail load requirements decline relative to current projections.

Significant considerations in GMP's purchase strategy for these "rolling" short-term purchases include GMP's judgment about the relative attractiveness of forward market prices at the time, along with a goal to diversify the timing of these purchases (so as not to "put all of our eggs in one basket" by purchasing all of a very large open position at one time, under one set of market conditions). These purchases may be around-the-clock or shaped on a seasonal or peak/off peak basis to match the shape of GMP's projected net short position. Specifically, GMP makes these purchases regularly over time with the goal to hedge essentially all expected energy and capacity requirements leading into an operating year. GMP seeks to accelerate these short-term purchases during times when energy and capacity markets are perceived to be relatively attractive (or there is great risk of adverse market price movements), with the goal of reducing the expected cost of energy and capacity to our customers

Q27. Is GMP's approach to managing REC sales consistent with the approach to hedging short-term energy needs that you described above?

A27. Yes. The goals and approach of GMP's REC sales strategy is to create more stability in GMP's net power costs and retail rate outcomes by reducing the risk to rates from potential unfavorable changes in market prices for the benefit of our customers (for GMP REC sales, a decline in regional market prices would be unfavorable, resulting in increased net power costs). As Mr. Dawson observes, we rely primarily on layered forward sales for delivery up to four years in the future. In the case of the REC sales program, many of the details relative to timing, volumes, transaction duration, and vintage are affected by the unique features of these state-administered compliance markets (which are the overwhelming source of demand) and the relatively limited liquidity of those markets.

Q28. How does the actual activity in GMP's hedging program bear on Mr. Dawson's recommendation that "GMP contracts with an independent auditor to review its hedging practices and procedures on a triennial basis"?

A28. In assessing the REC hedging program Mr. Dawson's repeats claims that documentation flaws make GMP's actions in support of its stated approach nontransparent (page 19).

Mr. Dawson uses this observation and similar ones from review of short-term energy and capacity hedging materials to support a recommendation that GMP should "contract with an independent auditor to review its hedging practices…" (page 20). I strongly believe this recommendation is misplaced. Using GMP REC sale activity as an example, a simple review of GMP's actual REC trades (based on public Rule 5.200 filings, or discovery served on GMP) in recent years would show that the activity in the REC hedges is consistent with the GMP's stated goal for the program (as discussed above).

Exhibit GMP-DCS-2 from the April 13, 2018 initial filing shows GMP's actual trade activity within the REC sales program by date and volume for Class 1 RECs in the calendar 2018 vintage year. The table clearly depicts a broad distribution of forward sale activity, where:

- GMP began making forward sales for vintage 2018 RECs in January 2015. This is about 4.5 years before the final trading period for vintage 2018 RECs in the NEPOOL Generation Information System ("GIS");
- GMP achieved a benefit from spreading activity such that in total, GMP has sold forward about 721,000 MWh of 2018 vintage Class 1 RECs, or well over 90% of our forecasted supply, at an average price of about $36/REC.

Because the activity and trading results in this program are relatively transparent and are subject to regulatory review, and because GMP's activity in energy and capacity hedging can be reviewed in a similar fashion, I am not clear as to what purpose would be served by incurring the costs of a new independent auditor, and don't presently see the need for such a role. As discussed below, however, GMP is open to working with the

Department to identify improvements in the clarity and transparency of GMP's internal documents associated with its trading activities.

Q29. How does this trading pattern in GMP's REC sale program bear on recommendations by Mr. Dawson for GMP to adopt a new Risk Management plan and to submit to a new triennial hedging audit?

A29. At a number of points in his testimony Mr. Dawson observes that GMP should have more process and procedures governing the application of judgement in the Company's implementation of its short-term hedging strategy. He also cites examples of alternative procurement approaches and assigns significant value to the adherence to systematic codified procurement methods. Mr. Dawson's comments with respect to transparency and clarity appear to be well meaning and logical. I agree that such clarity can provide value within GMP's decision making process and in the course of the Department's review of GMP's activities. I should note, however, that this value is distinct from any perceived benefit from the application of more programed or restrictive hedging strategies (as discussed on pages 9, 18, 19).

In particular, Mr. Dawson appears to be saying that it is appropriate for GMP's hedging activities to feature some flexibility with respect to timing of purchases and sales (as opposed to, for example, a fixed schedule of X MWh purchased every Y months), so long as we are more clear about what that flexibility is and when/why we are using it. If that is Mr. Dawson's point here, then we are largely in agreement. Alternatively, if the purpose of recommending a new risk management plan and triennial audit is to promote strict adherence to a pattern of buying/selling similar to Mr. Dawson's example on page 9 of his testimony (e.g., where a utility addresses 10% of its hedging needs on a quarterly basis for about 3 years leading up to the delivery period) then I don't agree; this approach could easily drive up costs for customers as I explain further below.

I also believe that the example from GMP's 2018 vintage REC sale program illustrates the potential value of transaction flexibility, and serves as a caution against excessively limiting that flexibility (e.g., pursuing a strict linear sales program). The first column of the table below shows GMP's actual pace of forward sales activity for vintage 2018 Class 1 RECs (trade detail is provided in ***Exhibit GMP-DCS-25***) by calendar year; the total sale program sums to about 747,000 RECs. This column shows that GMP began by making over 200,000 MWh of forward REC sales in 2015, then accelerated the pace of forward sales in 2016 so that by the end of 2016, about 550,000 MWh of vintage 2018 RECs (representing the clear majority of projected supply) had been sold forward. The second and third columns show how two alternative hypothetical plans would reach the same quantity of forward sales, by spreading them evenly over four and three years, respectively.

Sales Timing Comparison for GMP Sales of Class 1 2018 Vintage RECs

Year	GMP Actual REC trading Volume	Illustrative 4 year linear volume plan	Illustrative 3 year linear volume plan
2015	**213,902**	186,886	
2016	**346,134**	186,886	249,181
2017	170,000	186,886	249,181
2018*	*27,708*	186,886	249,181
Totals	**747,544**	**747,544**	**747,544**

***** The 2018 transaction volumes for each sales program assume that additional sales will be made in order to match the same forward sales goal for the 2018 vintage RECs by the end of 2018.

The decision to sell forward actively starting in 2015 was based on GMP's view at the time that the forward REC market prices were relatively attractive, and we accelerated the pace of forward sales in 2016 because GMP and our consultants had noted emerging events that signaled a greater potential for declines in regional Class 1 REC prices over between 2016 and the end of trading for 2018 RECs (which occurs in mid-2019). As a result, we locked in the majority of 2018 REC sales during 2015 and 2016, mostly at prices between $30 and $45 per REC. If instead of taking this type of flexible action, GMP had adhered strictly to a programmed approach as illustrated in the two right hand columns in the table, up to 30% of REC hedging activity could still be outstanding for 2018 instead of the much more modest volumes that currently remain to be sold. Because prevailing REC trading prices for vintage 2018 Class 1 product have fallen from well over $40/REC in 2015 to less than $10/MWh today, the ability of the GMP hedging program to adapt to rapidly changing events and circumstances resulted in greater stability in revenue, and millions of dollars more in value for our customers than a rigid linear sale program would have.

Q30. Are there also reasons why a program trading example like the one Mr. Dawson cites may not be appropriate in GMP's short-term energy hedging program?

A30. Yes. I should note here that Mr. Dawson has not explicitly recommended any single method for trading, but he provides an example that we assume represents the type of approach he would recommend in his pre-defined trading method on page 9 of his testimony. I have concerns that the described benefits from the type of proscribed activity are overstated. In particular, it is not clear that Mr. Dawson has fully considered unique characteristics that are specific to the New England markets in which GMP operates, which favor a hedging approach that includes some flexibility and the ability to adapt to rapidly changing conditions. Any heavily codified methods or plan could run the risk of delaying appropriate actions for as long as it takes to first revise the plan document.

For example, in the energy market a considerable amount of GMPs former short-term energy needs in certain seasons is now being met by output from net-metering and other policy-supported renewables. The uneven pace of development in these supplies (along with the small size of GMP's open positions in some months) can pose a challenge to the type of programmed trading method which attempts to preordain purchase volumes and divide them evenly across future periods. I should also note that in the current energy market in New England, forward prices available for short-term energy hedging will be influenced significantly by local factors like the availability of sufficient generating resources and fuel during the coldest periods in New England's winter months. Presently new procurement practices (e.g., fuel security initiatives) are being advanced by ISO New England and the development of significant new supply is being advanced through state sponsored actions (in support state energy goals) and also to some extent address the current market conditions. Applying a procurement approach that is limited to only prescriptive, predetermined transaction activity in a market being driven by discrete and local policy actions could easily result in transactions that are poorly timed or potentially unneeded in comparison with a more attentive and flexible approach, or could miss the opportunity to hedge aggressively against potential unfavorable market outcomes that GMP would consider unacceptable.

Q31. Are you saying that GMP expects to systematically "beat the market" through decisions regarding the timing of its hedging purchase and sale transactions?

A31. No, and a layered purchase or sale program is a useful point of reference. My point here is that there are likely to be some times when adjustments to the timing of sales or purchases can be made for the benefit of our customers. For example, at some points in time GMP might observe the potential for market outcomes (e.g., potential for a rapid rise/fall in market prices) adverse enough that they would be unacceptable, so it makes sense to advance our hedging transactions. Or at some times GMP (aided by the regional market information sources I discussed earlier) might observe a market development that is likely to occur, but does not appear to be fully reflected in current market pricing.[13]

Q32. Does GMP agree with Mr. Dawson's advice that GMP limit the procurement of large quantities of capacity at one time?

A32. Yes, and our current practice reflects this. On Page 18 of testimony Mr. Dawson recommends added structure to GMP's capacity procurement strategy, including a schedule for acquiring quantities of short-term capacity and longer-term capacity blocks. GMP's practice is to review its forecasted open capacity position and to explore bilateral forward capacity purchases - typically within several months of each upcoming annual Forward Capacity Auction. We believe this is an appropriate time because both GMP and potential capacity sellers have the best available information about the regional supply/demand balance and developments in market rules that may affect pricing for the next several years. It also allows GMP to have a better understanding of its future open position than might be the case earlier in the year. We typically seek bilateral capacity purchases of less than five years in duration; the notable exception here is the long-term purchase that GMP entered into with NextEra Seabrook in 2015, at a time when the open position was substantially larger and there was a concern that much higher capacity market prices would be required to attract new suppliers (particularly newly constructed thermal power plants) into the New England market. As with the energy and REC products, GMP is open to the notion that its capacity acquisition strategy could be made clearer, and to working with the Department to achieve that goal.

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[13] This type of circumstance is more likely to occur in the relatively small and unique New England markets in which GMP operates than, for example, in larger and more heavily contested markets.

Q33. Do you have any other observations with respect to Mr. Dawson's commentary on GMP's transaction practices?

A33. While we see value in many of the outlined steps that Mr. Dawson advances for energy procurement on page 15, and we currently use or have used all of these approaches, we do not believe that every transaction must necessarily be subjected to the same program of action. *See* Dawson pages 19-20. GMP takes steps in every procurement to ensure a competitive result, but we do not apply a one-size fits all method irrespective of the product, volume, and duration involved in any particular procurement. Doing so would not necessarily produce better outcomes particularly in the case of shorter duration energy procurement, where standard products are quoted and traded on a futures exchange there is very likely limited benefit to be gained by adopting more administratively burdensome practices to replicate the price formation activity of a public trading platform. Moreover, while full service brokerage and "live auction" services are available for procuring these products, there are costs associated with the use of these methods which need to be netted against the potential benefits. There are also considerations beyond participation (e.g., creditworthiness of the participants) that bear on the successful outcome of a procurement.

Finally, while obtaining competitive pricing for purchases and sale transactions is important, I should observe that outcomes for GMP's net power costs (and ultimately the rates that our customers pay) are much more strongly influenced by the types of products that GMP transacts, and when it enters into those transactions. This is because movements in market prices across a year can amount to several dollars per MWh—or in the case of RECs, many dollars per MWh. Our primary focus is (and should continue to be) understanding the New England markets and the factors that are driving them, in order to make informed decisions about when to purchase/sell the wholesale products needed to serve our customers.

Q34. Does GMP support Mr. Dawson's request that improved documentation procedures could provide the benefit of making GMP's strategy and actions more transparent?

A34. Yes. While GMP has reservations with some of the specifics of Mr. Dawson's findings and recommendations for specific hedging plan improvements, we are generally supportive of suggestions to make our activities more transparent. As I noted above, GMP is open to exploring with the Department specific ideas for improving transparency, including in GMP internal documents that describe GMP's transaction strategy and implementation.

Q35. Do you agree with Mr. Dawson's recommendation that GMP contract with an independent auditor to review its hedging practices and procedures on a triennial basis?

A35. No. Mr. Dawson promotes a specific type of risk oversight plan that would, "at a minimum, detail the specifics of the trading strategy, procedures related to setting acceptable risk parameters and limits, policies for risk reporting and permitted transaction types…" (page 20).

GMP is not clear on what role, purpose, or scope is being advanced by incurring the cost for Mr. Dawson's recommended periodic independent audit of hedging practices and procedures, or whether Mr. Dawson has considered materiality and regional context in recommending new process solely for short-term energy, capacity, and REC transactions. As described in discovery responses, GMP has regularly repeating meetings between power supply staff and senior management, and there are corporate governance committees and financial reporting requirements that encompass risk topics related to power supply and the bounds of authority for transacting. We are focused on outcomes for customers and do not see how this will deliver better outcomes. As such, I don't see the need for an additional independent audit, particularly if GMP and the Department can work together to agree on refinements that improve the clarity and transparency of GMP's transaction strategy and activities.

Q36. One of Mr. Dawson's recommendations is that GMP should improve its analytical energy modeling tools. Is GMP making progress on this topic?

A36. Yes. GMP has agreed with the Department that it is appropriate to develop a representation of GMP's power portfolio (i.e., its power sources and loads) in a regional market simulation model, for the purposes of better informing GMP's analysis of its energy needs and its estimation of net power supply costs. In recent months we have had multiple conversations with vendors of market simulation models (particularly the firm EPIS, regarding its Aurora platform), to increase our understanding of market simulation models' capabilities, as well as what would be required to run them. Rather than attempting to build and maintain a working model internally at GMP, we have concluded that a preferred approach is to leverage the capabilities of market modeling by teaming with a regional consulting firm that already maintains a reasonably calibrated model of the ISO-NE market. With that in mind, we are presently in the process of identifying and qualifying potential firms with appropriate experience in the ISO-NE market, and we hope to seek proposals from a short list of regional vendors soon.

VI. Response to PUC Information Requests

Q37. Regarding PUC Information Request #3, the PUC notes that GMP has identified several new sources of electricity demand like heat pumps, storage batteries, and electric vehicles. Has GMP developed its own forecast of electricity demand resulting from adoption of these new technologies? Does GMP disagree with any portions of Itron's forecast of new load resulting from these technologies?

A37. GMP has developed forecasts for electricity demand resulting from adoption of new technologies for various purposes in the past, but it did not develop its own independent forecast for use in the 2019 Cost of Service. Rather, GMP relied on Itron's forecast as the basis for the 2019 Cost of Service. Itron's analysis did incorporate some aspects of GMP's prior forecasting work, but relied on more recent published data, where available, for other aspects of the forecast. For example, in 2016, GMP hired Energy Futures Group ("EFG"), a consultant based in Hinesburg, Vermont, to develop forecasts for adoption of heat pumps and electric vehicles under different market scenarios. For purposes of its forecast for heat pumps, Itron choose to rely on VEIC's more recent cold climate heat pump forecast, rather than the data prepared by EFG. However, because there was no other third-party forecast focusing on near-term deployment rates in Vermont, Itron did include the electric vehicle forecast from one of EFG's scenarios in its analysis. Table #3 in Itron's forecast (***Exhibit GMP-ER-14***) summarizes the assumptions from EFG's model scenario that were incorporated into Itron's analysis. Battery storage is not anticipated to materially affect retail sales in this time frame (because charging and discharging energy offset each other, except for moderate cycle losses), so the Itron forecast does not assume any adjustment for battery storage. GMP participated in the development of Itron's combined forecast of electricity demand, and we agree with the forecast.

Q38. Regarding PUC Information Request #4, what sensitivity analyses has GMP or Itron made of the assumptions in their projections of electricity growth/decline over the rate year and what factors went into those analyses? How have GMP's or Itron's previous forecasts of solar penetration compared with the actual rate of solar penetration? What lessons has GMP learned from that experience, and how are those lessons applied in the current proceeding?

A38. GMP and Itron have not performed sensitivity analysis pertaining to the assumptions of electricity growth or decline over the rate year. The rate period is relatively short (nine months), and the amount of time that elapses from forecast development to the rate period is fairly limited—not long enough for potential long-term trends to become pronounced. As a result, typically only a few factors–like weather and unforeseen circumstances, such as businesses closing—are likely to immediately impact sales in a meaningful way. GMP and Itron have learned that it is important to update the retail sales forecast annually to capture any recent trends that may impact assumptions. Longer intervals between updates usually lead to greater variance in future years. Shorter intervals are not practical or useful since power supply costs are typically established in rates once a year.

With respect to forecasts of solar penetration, the chart below shows how the final installed solar net-metering forecast for the past few years has compared to actual results.

Actual versus Forecast Installed Solar Net Metering Capacity

	Installed MW*	
	Forecast	Actual
FY15	30.1	53.1
FY16	100.7	84.9
FY17	137.3	124.8
FY18**	170.8	149.9

* as of last month of fiscal year (September)
** Both forecast and actual numbers through July

As is evident from this information, prior forecasts have both underestimated and overestimated actual megawatts installed at various times. It is not surprising to see such variances, given the fluid deployment of net-metering installations that continue at a robust pace. In addition, the current structure of Vermont's net-metering program (which features essentially fixed above-market payment rates for net-metered generation and does not include targets or limits on annual deployment volumes) is inherently subject to significant variances between forecasted and actual deployment.

The main lesson we have learned here is that it is important to reforecast estimates of solar net-metering installations annually to incorporate the most up-to-date information, in order to establish the most reasonable benchmark power costs and retail rates. Even within fairly short periods, net-metered generators sometimes interconnect to GMP's system at different paces and respond to different policies and market conditions, creating variances compared to forecast. For example, the highest month of installations recorded was not during the summer (which is associated with good solar generation and might be anticipated in a forecast), but in December 2016, when approximately 12 MW came online, in part to receive tax-related benefits before year end. Similarly, GMP saw the queue increase significantly in the second quarter of 2018—apparently in anticipation of a pending change in solar net-metering rules. Because GMP cannot control the pace of solar net-metering directly or foresee what may occur each year that differs from assumptions made in the last forecast, the best course of action is to update the forecast annually. With respect to forecasting quantities of net-metered generation deployment, a lesson learned has been to apply some amount of assumed attrition to the existing queue of net-metered projects, to allow for the likelihood that not all projects that apply for interconnection will ultimately reach completion.

Q39. Regarding PUC Information Request #5, the PUC notes that Itron validated and calibrated its model for revenue calculations. Did it conduct similar validation and calibration for its model for penetration of new sources of electricity and expected energy efficiency? If so, what were those analyses? If not, why not?

A39. It is my understanding that Itron did not conduct a similar validation or calibration of the model with respect to new sources of electricity use and expected energy efficiency because the anticipated penetration of new sources of electricity consumption cannot easily be evaluated in the same way that revenue is validated and calibrated.

Itron's revenue validation is a "backcast" exercise. For the prior twelve months, Itron runs actual sales through the revenue model and compares the resulting average rates with actual average rates. The revenue model allocates sales and customers to rate classes, calculates on-and off-peak usage blocks where there is block or TOU pricing, and billing demands for those rates that feature a billing demand component. Resulting determinants are then multiplied by actual tariffs to generate total revenue by rate class. Rate class revenues are then divided by rate class kWh sales estimates. The model-based average rate is then compared to actual average rate. In the 2018 forecast the model-based average rate estimate was very close to actual average rate and there were no adjustments made. In prior years there have been some slight differences between model rate estimate and actual average rate in specific rate classes. In these cases revenue model results have been calibrated to actual revenues by applying a small adjustment factor to rate-class revenue forecast.

In contrast, the forecast of new sources of electricity use cannot be directly calibrated in the same manner as revenue. While comparing actual and forecasted MWh and rates on a monthly basis is relatively straightforward, determining exact impacts on retail sales due to heat pumps, electric vehicles, and efficiency is not practical because GMP doesn't meter these impacts separately. Instead, the penetration of new sources of electricity and energy efficiency are embedded in the actual sales data used in the forecast models and are thus captured through the estimated linear regression models.

Because actual penetration of new technologies and efficiency are already embedded in the latest retail sales data that flows into their model, Itron focuses instead of finding the best projections for the near-term adoption of new technologies and efficiency. For this reason, Itron utilizes data sources like Efficiency Vermont and the Energy Information Agency 2017 Annual Energy Outlook for New England. This work is informed by Itron's experience working with GMP over time, along with Itron's support of VELCO's long range planning analysis. Itron does indirectly test to see if there is additional state-program efficiency that is possibly missing by incorporating an efficiency program savings variable in the forecast model. Itron reports that based on statistical estimates the 2018 model appears to be capturing most of the program savings. Itron will modify forecasted end-use intensities to reflect Vermont efficiency activity if efficiency levels are stronger than what is reflected in the model. In the 2019 forecast Itron made very little adjustment to the end-use intensity projections.

Q40. Can you please address PUC Information Request #11, with respect to the outlook for capacity market prices?

A40. Yes. Mr. Dawson observes that a capacity market price forecast that more closely resembles the growth and expectations from recent capacity auctions and market forecasts is more conservative than an aggressive increase to NET Cone. In Response 17 above, I explain that GMP's capacity market outlook is based on a review of recent auction results and market drivers, and is reasonable in my view. I provide observations on several capacity market drivers in support of that view.

Q41. Regarding PUC Information Request #12, referring to Mr. Dawson's prefiled testimony at pages 40 through 41: Why did the analyses of the Powerwall program and the JV Solar/Battery projects not use the same capacity price forecasts and loss factors?

A41. With respect to the capacity market prices, the original capacity outlooks were developed using the same approach, but at different points in time. When the Powerwall program was being developed in early 2017, GMP's estimation of Powerwall benefits reflected a FCM price outlook from early 2017, while GMP's estimates for the Milton project (presented in Mr. Quint's testimony in Case No. 17-5003-PET[14]) reflect a more recent (early 2018) vintage price outlook. The latter capacity price outlook is somewhat lower, based in part on the results of an additional annual capacity auction and updated market assessments from our regional consultants. GMP did update its Powerwall model for this more recent price outlook in March 2018 for this rate case.

With respect to the line loss forecasts, to model the solar output of the Milton project, my colleague Mr. Quint used loss factors that are reflective of those that GMP has used in recent years when evaluating similar projects. Specifically, we assumed that marginal energy losses on GMP's distribution and subtransmission system (i.e., not including the bulk system), averaged over the year, are about 8% (for context, average energy losses across all hours are approximately 5%). We assumed that marginal losses during near-peak conditions (i.e., during high-load events which set annual FCM obligations and monthly RNS charges, and when battery storage systems would likely be discharged) are about 15%. These assumptions are based on loss factors that have been used for energy efficiency screening in Vermont;[15] other past loss studies; and observations regarding relative losses during different time periods. The reason that marginal system losses during near-peak conditions tend to be higher than average losses (or marginal losses averaged over the year) is that resistive energy losses tend to vary with the square of the current and loads during near-peak conditions are much higher than average. Near-peak conditions in summer months are also consistently associated with

[14] ePUC Document No. 238483/127259

[15] For example, the order approving Energy Efficiency Utility's 2015 avoided costs (EEU-2015-04) featured somewhat higher marginal energy losses by costing period (ranging from 9.5% to 11.9%), and average losses at peak hour (excluding PTF losses) of about 9 percent.

unusually high ambient temperatures; this tends to increase average and marginal energy losses relative to cooler periods.

For the battery storage component of the project, we assumed a marginal energy loss factor of 5% (i.e., 1 MWh of project output would avoid 1.05 MWh of load requirements including losses). While a much higher marginal energy loss factor (on the order of 15%) could have been used given that two of the important value streams for the battery project are expected to be associated with discharging the system during near-peak conditions when higher marginal losses are likely, a higher value would have created a higher overall lifetime project benefit. Mr. Quint's use of the lower 5% loss assumption was intended as an element of conservatism in the analysis—to fairly reflect the value of the proposed project's output, while limiting the risk of overstating that value. Had a 15% marginal loss assumption been used for near-peak conditions, the estimated project benefits on a lifetime basis would have been several hundred thousand dollars (or about 6 percent) higher.

Finally, with respect to the Powerwall program, GMP's modeling of benefits assumes a marginal loss factor of 8.9%. For the same reasons I discussed above, this figure is also likely conservative with respect to the near-peak conditions in which the Powerwalls are expected to be deployed for their key value streams (i.e., peak shaving to limit GMP's capacity and RNS costs).

Q42. Does this conclude your testimony at this time?

A42. Yes, it does.