STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 18-1633-PET

Petition of Green Mountain Power for approval of	)
a multi-year regulation plan pursuant to 30 V.S.A.	)
§§ 209, 218, and 218d	)

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

February 4, 2019

Summary of Testimony

Douglas Smith testifies about the aspects of the Multi-Year Regulation Plan ("MYRP" or the "Plan") that concern power supply costs and revenue. Mr. Smith notes the areas of agreement between Green Mountain Power ("GMP") and the Department of Public Service ("DPS" or the "Department"). He also responds to the Department's proposal to remove power costs from base rates, and its proposal to revise the Power Supply Adjustor ("PSA") to remove certain categories of costs and change the dead band range in the PSA. Mr. Smith concludes that the dead band range should remain symmetrical. Mr. Smith explains that the Department's proposal to remove some items from the PSA is not compelling, and identifies some costs that clearly should remain in the PSA. Mr. Smith also responds to comments by Renewable Energy Vermont ("REV") with respect to how changes in net-metering volumes affect GMP power costs.

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I. INTRODUCTION

Q1. Please state your name, address and occupation.

A1. My name is Douglas C. Smith. 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 June 4, 2018.

Q3. What is the purpose of your testimony today?

A3. The purpose of my testimony is to respond to the power supply and power supply adjustor related items raised by the Department of Public Service witnesses in their testimony on GMP's proposed Multi-Year Regulation Plan. I first note the areas of agreement between GMP and the Department. I then address specific recommendations in the joint testimony of Maria Fischer and Edward McNamara. I start by responding to their proposed changes to the components of GMP's proposed power supply adjustor—in particular, the recommendations to remove certain categories of costs from the current adjustor and instead treat those items as base rate costs. I next address Ms. Fischer's and Mr. McNamara's recommendations regarding the PSA's dead band range. Finally, I provide an update on GMP's efforts to develop a more detailed regional market simulation model, and respond to comments by Renewable Energy Vermont witnesses with respect to how changes in net-metering volumes affect GMP's net power costs.

II. GENERAL TREATMENT OF POWER SUPPLY COSTS UNDER MYRP

Q4. To start, can you please summarize your understanding of the Department's position with respect to how power supply costs should be treated within the context of a multi-year plan?

A4. Yes, the Department's testimony indicates general support for GMP's basic recommendations for annual forecasting of power supply costs under the MYRP, and more timely recovery/return of variances in GMP's actual power costs. In particular, the Department supports the use of an annual update of power supply costs, including transmission costs, and revenue from retail electric sales, based on a third-party forecast. The Department also supports GMP's proposed new Retail Revenue Adjustor which will serve to decouple GMP's profitability from electricity sales. DPS also supports the continuation of a Power Supply Adjustor mechanism, with the improvements to its design that we have proposed. The Department agrees with GMP's proposal to return or collect variances through the PSA on a quarterly basis. The Department also supports GMP's ongoing efforts to develop a more detailed regional market model to inform the forecasting of power supply costs during the term of the Plan.

The Department proposes some refinements to GMP's proposal for the development and recovery of power supply costs. First, the Department proposes that some categories of power costs which traditionally have been included in the PSA be shifted out of the adjustor and into base rates. The Department also proposes an asymmetrical dead band range in the PSA, instead of continuing a symmetrical dead band range like the one included in GMP's current PSA. I address each of these recommendations below.

III. PROPOSED CHANGES TO POWER SUPPLY ADJUSTOR DESIGN

Q5. Can you please start by addressing the Department's recommendation to remove certain categories of costs from the existing power supply adjustor? How does GMP respond to this proposal?

A5. We appreciate the Department's perspective, and agree conceptually with the criteria they present for determining if certain costs should be included in the PSA, but do not see a compelling reason to remove most of the individual categories of power costs and revenues they have identified, with some limited exceptions noted below. Many of the costs the Department recommends excluding do not appear to truly fit their criteria or rationale for removing those costs. Removing some of the Department's recommended items would also present some practical challenges which, in my opinion, would likely outweigh the potential benefits.

Q6. Can you please summarize the Department's rationale for excluding certain power costs and identify the specific categories of costs they would exclude?

A6. As explained by Department witnesses Fischer and McNamara, the Department generally believes the PSA should only include costs that are largely outside the utility's control, are material in magnitude, and are volatile to a degree that would place undue risks on the utility. Based on these criteria, the Department proposes to exclude a subset of power costs over which they assert GMP has some control, such as the operation and maintenance ("O&M") expenses associated with GMP's wholly and jointly owned generating units, as well as a subset of costs they view as immaterial in scale and/or difficult to verify. The specific items that the Department proposes to exclude from the PSA are shown on the bottom half of Exhibit PSD-MRF-EM-2; based on recent power cost benchmark data they would amount to roughly $5 million per quarter or about $21 million per year.

Q7. How do you respond to the Department's proposal to exclude O&M costs related to its share of jointly owned generation facilities?

A7. Non-fuel O&M expenses associated with GMP's share of jointly owned generating plants are the second-largest item that the Department recommends removing from the PSA, amounting to several million dollars per year. These expenses are presently in Component A of GMP's current regulation plan, with positive and negative variances relative to each quarter's benchmark passed through to customers. I recommend strongly that this expense category remain in the PSA, primarily because GMP owns a small share of each plant.[1] We therefore tend to have only a very limited ability, if any, to influence decisions that determine the magnitude and timing of O&M expenses for these plants, and the lead owner's staff tends to have the primary expertise that should inform operating decisions. Also, in actual practice significant quarterly variances sometimes

[1] GMP's ownership shares of the affected plants are approximately 1.7% of Millstone Unit 3; 2.9% of Wyman Unit 4; 8.8% of Stony Brook combined cycle; and 31% for McNeil.

occur due to shifts in project dates (e.g., a shift of a month or two in the actual project date could shift costs between quarters or even Plan years), and arcane factors such as expense true-ups or refunds associated with past periods might be difficult to capture in the budgeting/forecasting process. For these reasons, it seems clear to me that it is appropriate for non-fuel O&M at jointly owned plants to remain in the PSA.

Q8. How do you respond to the Department's proposal to exclude O&M costs related to GMP's wholly owned generation facilities?

A8. The current placement of O&M expenses associated with its wholly owned generating plants in Component B of the PSA makes sense because it aligns company incentives with favorable outcomes for customers. Plant O&M costs are spent to support the production of power, primarily energy, for our customers. The inclusion of both the O&M expenses for GMP's plants and the value of their energy output in Component B is logical and encourages continued O&M expenditures that benefit customers compared to the value of energy that would be lost if those expenditures were not pursued.

Removing GMP's plant O&M expenses from the PSA and having GMP absorb all positive and negative variances within the rate year could possibly lead to minimizing O&M expenses in the short term, but it would not necessarily lead to minimizing net power costs—including the value of output from GMP's plants—which would seem to be the higher goal for customers. As I noted in my direct testimony, removing plant O&M expenses from the PSA would in the short term leave GMP absorbing all incremental expenses to maximize plant availability, while the benefits of those expenditures would flow primarily to customers. This would be an odd incentive outcome because it would seem to discourage some types of appropriate incremental O&M activities like time-sensitive maintenance, or deployment of personnel during weekend/overtime periods to make repairs if needed to keep the generation online or restore it to operation in the event of an unplanned outage. GMP is always focused on providing the best service to customers, and I am not saying GMP would broadly forego appropriate O&M expenditures in actual practice, but the current placement of O&M in Component B seems more clearly aligned with making the best decisions for customers based on the total costs and benefits.

Q9. With respect to the category of costs that DPS believes are too small to include in the PSA, how do you respond?

A9. The rationale of excluding some power cost items due to their small size makes some sense at an intuitive level, but I do not believe there is a significant benefit to excluding the costs the Department has identified. And as noted below, there are some challenges to this approach which make implementation difficult and likely less efficient compared to simply leaving the costs in the PSA. I agree that many of the items identified by the Department in this category are typically relatively small. From that perspective, absent any other issues, either removing or including these items in the PSA likely would not have a material impact either way. Similarly, while I share the Department's goal for improving the efficiency and transparency of PSA review, excluding small items like these does not appear to materially advance these goals. For example, it seems credible for GMP and the Department to generally devote more limited attention to the estimation and after-the-fact review of small categories in the PSA with variances not substantially within GMP's control, and to conduct a "deeper dive" if and when material variances are observed in these categories.

This leads to a broader concern with the Department's proposal, which is that simply excluding these categories might actually make review of GMP power costs more complicated, not less. For example, in addition to review of the PSA components, the categories of excluded items likely would still require annual review to see if any changes are required in the treatment of those items. Some items that appear less volatile based on recent history could still from time to time be subject to changes of much greater magnitude. For example, the Department recommends excluding the "Demand Charges – Yankees" item on Exhibit PSD-MRF-EM-2 (this item is largely related to Vermont Yankee's spent fuel trust) based on an illustrative 2017 benchmark magnitude of about ($88,000) per quarter. I agree that a stable level of expenses/credits of this magnitude would make this item immaterial, but actual quarterly results for this item can sometimes fluctuate to a much larger degree based on factors such as interest rate trends or arcane events like the outcome of a DOE litigation/settlement. During the past several years, quarterly variances in this item have ranged from negative $1.4 million to positive $345,000. This is not to say that it would be impossible or financially catastrophic to remove items like this from the PSA and instead put them in base rates, but I struggle to see the benefit when doing so would expose customers and GMP to shortfalls/windfalls between GMP's actual expenses and those reflected in rates. To me, it makes sense for such items to flow through Component A as they do today so customers ultimately pay no more or less than GMP's actual expense.

Other items could change even more dramatically over the course of the Plan. For example, the Department's recommendation of items to exclude appears to be based on their relative benchmark magnitudes as of 2017. At least one item in this list, Seabrook PPA demand charges, has experienced a substantial increase in magnitude (to over $1 million) since that time, based on a large scheduled increase in capacity volumes under the PPA. As a result, this item no longer appears to meet the Department's immateriality test. It would not be reasonable to require GMP to assume all of the risk for this scale of change in a component that DPS proposes to exclude, and it is unclear how DPS would address situations where items like this change over the term of the Plan. Given these challenges, separating these costs from the rest of GMP's power supply costs does not appear to serve the goals of efficiency or transparency. In light of the small scale of these items, and potential for variation over three years, it seems to me that it would be more efficient to simply keep them in the adjustor.

Q10. Would it be reasonable to remove Unit Resales from the PSA, as the Department proposes?

A10. This item presently consists of GMP's long-term, cost-based sale of Kingdom Community Wind ("KCW") output to Vermont Electric Cooperative. The KCW cost of service is substantially within GMP's control and can likely be reasonably estimated. Therefore, while I don't see a compelling need to remove this particular resale from PSA Component B where it presently resides, I think that it could be reasonably removed.

Some caution is warranted with respect to removing Unit Resales as a category, however. While GMP does not have any immediate plans to make additional unit-contingent resales, it is possible that it would be beneficial to do so in the future—for example, to help balance GMP's energy sources and loads on a seasonal basis, or as part of a swap that would limit reliance on a particular generating plant. If the Unit Resale category were removed from the PSA then the costs and benefits of a new unit-contingent sale that is negotiated between rate years could potentially become mismatched—for example, with the revenues from a new unit resale flowing to GMP, while some of the costs (e.g., lost LMP revenues for the unit's output) are shared with customers through PSA Component B. It will probably be possible to avoid this type of potential mismatch if GMP's benchmark power costs and revenues (including those outside the PSA) are refreshed before each Plan year, but simplicity argues for leaving unit resales within the PSA.

Q11. Do you have any other observations with respect to the potential efficiencies associated with removal of items from the PSA?

A11. Yes. As noted above, part of the Department's rationale for reducing the number of PSA items is to increase efficiency of the PSA review process (e.g., after-the-fact review of quarterly variances between actual and benchmark costs). It seems to me that if many items are removed from the PSA, efficiency gains from having to review fewer items after the fact are likely to be offset substantially or entirely by increased up-front effort required from GMP and the Department in development and review of the benchmark power costs. In addition, as I noted earlier, there is the possibility that over the term of the Plan some items could "migrate" in terms of their magnitude or other characteristic that determine whether an item belongs in the PSA. It is therefore not clear that removal of these items will yield an overall improvement in administrative efficiency.

As I discussed in my direct testimony, inclusion of items in the PSA has limited the magnitude of financial shortfalls or windfalls that GMP and customers can experience based on quarterly variances between actual and benchmark power costs. I believe that the knowledge that most power cost items will flow through Component A or B of the PSA has enabled the Department and GMP to limit the expenditure of time and resources related to PSA administration by expending reasonable levels of effort in the estimation of benchmark power cost items, by efficiently resolving differences about benchmark power cost assumptions, and by agreeing on some simplifying assumptions (e.g., using a multi-year average for jointly owned units O&M). Conversely, to the extent that many power cost items are removed from the PSA, increasing the amounts of money that will be at stake through variances that will not ultimately be returned to/collected from customers, the parties will likely have to expend additional time and resources developing and critiquing the benchmark cost assumptions.

Q12. Can you please summarize why GMP proposed a symmetrical Efficiency Band range of plus or minus $150,000 per quarter?

A12. Yes, as explained in my opening testimony, GMP proposes to reduce the Efficiency Band range from $307,000 to $150,000 per quarter as part of the package of Plan changes, including the new Retail Sales Adjustor, that we developed to simplify the design of the PSA and make more transparent the connection (or lack thereof) between GMP's benchmark power costs and its actual results. The $150,000 per quarter figure was developed based on a review of actual power cost variances and PSA results over the past five years, which indicated that this range would have produced very similar net results, in terms of total PSA collections and returns, for GMP and our customers, compared to the prior PSA design. A larger Efficiency Band range would have increased the extent to which GMP under-collected its actual power costs over the five-year period, given the improvements to the PSA we have proposed that place more direct emphasis than the current design on meeting benchmarked costs. For example, the historical $307,000 quarterly range, if applied as part of the new PSA design that GMP is proposing, would have reduced GMP's net income by an estimated $1.8 million, or an average of about $84,000 per quarter, compared to the prior design.

GMP concluded that the improvements to the PSA design are warranted for the reasons set forth in my direct testimony, and it appears that the Department agrees. At the same time, the dead band for this new design should be set at a level that will not unduly shift to GMP risk of under-recovery. The historical results over a significant sample period suggest that a larger Efficiency Band range—and particularly the Department's proposed asymmetrical range in which GMP would be more exposed to additional costs than savings—would not provide GMP a reasonable opportunity to recover its net power supply costs. The recent federal tax reform is also supportive of a narrower Efficiency Band range because under the new lower federal marginal tax rates, a given amount of variance in net power costs that flows to GMP will tend to have a greater effect on after-tax income, providing a greater incentive for effective management of power costs.

Q13. What changes has the Department's recommended to the Efficiency Band range included in the PSA?

A13. GMP proposed a symmetrical Efficiency Band, also known as a dead band range, under which GMP would absorb the first $150,000 of increase or decrease in Component B costs each quarter, relative to Component B benchmark costs. In the joint testimony of witnesses McNamara and Fischer, the Department proposes an asymmetrical Efficiency Band for Component B expenses. Under the Department's proposal, if actual quarterly Component B costs per kWh turn out higher than the benchmark costs reflected in retail rates, GMP would absorb the first $307,000 of that increase in cost per kWh and 10 percent of any increase above that level. If actual quarterly Component B costs per kWh turn out lower than the benchmark, GMP would retain the first $150,000 of reduction in cost per kWh and 10 percent of any decrease beyond that level.

The Department's goal for proposing an asymmetrical Efficiency Band is to hold GMP more financially accountable for adverse outcomes that result from GMP's forecasting or management of power costs, while allowing customers to share more in positive outcomes.[2] The Department's primary rationale appears to be that since GMP has some control over Component B costs and customers do not, GMP should bear more of the downside risk by absorbing more of any cost increases that may occur.

I do not believe this position recognizes that the asymmetrical Efficiency Band would expose GMP to systematic under-recovery of its actual Component B power costs based largely on factors outside of its control. I therefore disagree with the Department's

[2] See DPS joint testimony at page 14, starting at line 18.

recommendation to change the dead band range, which has been symmetrical over the life of the PSA, to an asymmetrical one. Based on the structure of GMP's power supply, we have less ability to manage short-term power cost variances (the type that are typically collected/returned through the PSA) than may be apparent. In addition, as I explain in Response 16 below, GMP is likely to somewhat undercollect its actual power costs based on current forecasting methods and a symmetrical dead band range, and would undercollect even more systematically under the asymmetrical range the Department has proposed. As a result, I do not think the Department's asymmetrical dead band range is appropriate or justified.

Q14. Can you further explain factors that limit GMP's ability to manage some significant short-term fluctuations in Component B costs?

A14. GMP's power supply relies substantially on power sources, including several types of renewable sources, that are stable-priced in the long-term. Our power supply strategy combines these sources with layered forward purchases of energy and layered forward sales of RECs to produce a relatively smooth path of expected net power costs over time. Nonetheless, GMP's net power costs are still subject to meaningful variance within any quarter or year that can be largely outside GMP's control. For example, consistent with Vermont energy policy, GMP's energy portfolio relies on very substantial volumes of plant-contingent wind (167 MW), solar (over 200 MW, and growing), and hydroelectric (over 100 MW) capacity. These sources deliver energy on a variable basis, reflecting the actual availability of wind, sun, and streamflow. My direct testimony in this case explains how weather-driven variations in output from our substantial fleet of renewables, particularly in combination with changes in energy market prices, can easily produce annual net power cost variances of millions of dollars per year relative to benchmark levels. Similarly, weather-driven variations in our customers' electricity consumption—along with outcomes for other factors such as the actual pace of new capacity installations for net-metering and Standard Offer generation projects—can noticeably increase or decrease GMP's Component B power costs, and the average cost per kWh that will be used in combination with the Efficiency Band to determine collections/returns under Component B.

I expect that the Department would agree that quarterly variances arising from these factors, like weather-driven increases/decreases in renewable output and electricity consumption and fluctuations in net-metering deployment, are largely outside of GMP's control. GMP can and does take some steps (e.g., efforts to maximize availability of GMP generating plants, accurate short-term forecasting, adjustments to generation offers, and load bids) to manage Component B costs in the short term, but volume-driven changes such as those mentioned above—and that are driven by weather fluctuations and uncertainty in the pace of completion for non-GMP generating plants—can sometimes overwhelm GMP's short-term influence.

Q15. Could GMP potentially manage or eliminate these uncertainties contractually?

A15. Yes, some of them could potentially be managed. For example, load following energy supply, in which the seller commits to provide a specified fraction of the buyer's actual energy requirements at a fixed price per kWh irrespective of actual weather conditions, could be purchased in lieu of the fixed-volume, fixed-price energy block purchases that

GMP often uses to balance its supply on a monthly basis. It is also possible that GMP could purchase insurance or enter into swap transactions to reduce the financial impact of fluctuations in the output of some renewable plants. The challenge with products like these that transfer financial risk from GMP to another party generally come at a price. GMP presently chooses not to enter into transactions of this type because while they would reduce the exposure of GMP and its customers to short-term variances in net energy costs, they would also increase the expected cost of power for our customers.[3] We believe that our current approach to addressing weather-driven variability through purchasing low-cost energy blocks to approximately balance loads and resources based on normal weather conditions, with hourly/daily differences generally settled in the ISO-NE spot market, is in our customers' best interests because it limits overall costs over time. The consequence of this management choice is that GMP is likely to regularly experience short-term variances in Component B costs due to weather-driven outcomes discussed above, and is more likely to under collect actual Component B costs on balance under the Department's proposed asymmetrical Efficiency Band. Please note that while variances of this type are typically small in the context of GMP's overall power supply costs, they can be substantial relative to the dead band range for a particular quarter or relative to the impact of other activities that GMP can take to manage Component B costs within the quarter.

[3] For example, while fixed-price load following supply would likely deliver a lower cost/kWh for GMP's load purchases in a quarter when cold winter weather drives load and energy market prices well above normal, on average it would be expected to cost more than GMP's current strategy over a sustained period that includes a mix of weather outcomes.

Q16. Why do you say earlier that GMP is likely to undercollect its Component B costs on average under a symmetrical Efficiency Band range?

A16. The conceptual reason to expect this outcome is that weather-driven variances in GMP's load requirements and the output from some of its power sources tend to be adversely correlated with the spot market energy prices, or LMPs, that GMP pays for its load requirements and receives for its generation output, because the rest of the New England market tends to experience the same effects, at least directionally. For example, when GMP needs to purchase additional energy from the ISO-NE market because its customers are consuming more electricity during a sustained cold spell in January, it is likely that some or all of the rest of New England will also be experiencing cold weather and above-average electricity demand and natural gas spot market prices. This leads to above-average electricity demand, the commitment and dispatch of higher-cost power plants, and higher regional energy market prices during the cold spell. Conversely, if a sustained mild spell in January leads GMP's customers to consume less electricity than normal, it is likely that some or all of the region will also be experiencing mild weather and below-normal power demand, leading to lower energy market prices during the mild spell. Weather-driven variances in GMP's generation supply will also likely be subject to a similar effect, because the conditions that produce high solar/wind/hydro output for GMP's sources like a sunny/windy/rainy month, are likely to also apply to some degree across the region.

The implication of this dynamic is that over time when GMP needs to purchase more energy from the regional market, the market price it must pay for that energy will tend to be higher than average, and when GMP has more generation to sell to the market the prevailing price that it receives for that output will tend to be lower than average. Higher costs to purchase load and lower revenue for GMP's generation sources each tend to increase GMP's net power costs. As a result, either type of weather-driven variance, increasing or decreasing GMP's load requirements, or its generation supply, has the potential to increase GMP's average Component B cost per kWh, and GMP's average costs over time reflecting a range of weather conditions and associated load requirements will likely turn out higher than indicated by a single "base case" analysis predicated on normal weather.

Q17. Isn't the balancing adjustment in GMP's benchmark power costs intended to capture the effect of adverse correlation between GMP's energy demand/supply volumes and market prices?

A17. Yes, but not entirely. The balancing adjustment that GMP presently includes in its estimate of net energy costs is designed to capture the implications of "highs and lows" of actual hourly electricity market prices and GMP load and generation volumes over the course of each month, compared to the simple average of actual peak and off-peak market prices and actual load and generation volumes for the month. The balancing adjustment does not, however, capture the additional effect on GMP's net power costs that can result from weather-driven changes in supply and demand on a sustained basis like a cold/mild winter month, or a wet/dry summer month, that produce electricity consumption and generation volumes much different from normal levels. Sustained volume variances like these will also tend to be associated with average energy market prices that differ from those in the benchmark power cost estimate, and higher net energy costs for GMP. As an example, in the relatively cold month of January 2014, GMP had to purchase more energy than expected in an LMP environment that was much higher than normal, averaging over $150/MWh. In contrast, in the relatively mild month of January 2016, GMP had more surplus energy to sell in a market price environment that was much lower than normal (averaging only about $34/MWh). Each of these outcomes—purchasing more energy from the market than expected at relatively high prices, and purchasing less energy from the market at relatively low prices—has the potential to increase GMPs average Component B costs per kWh. The point here is that while it is reasonable to expect that weather-driven variances in the volume of energy that GMP's customers consume will average out over the long-term, along with the output from GMP's intermittent generation sources, the impact of those fluctuating volumes on GMP's net energy costs likely will not fully average out. Because GMP's energy requirements and generation supply volumes are adversely correlated with regional energy market prices, GMP's actual Component B cost/kWh over time (based on a range of weather conditions) are likely to average somewhat higher than indicated by a single base case featuring normalized load and generation volumes.

Q18. Do historical PSA results support your expectation that on average and over time, GMP tends to undercollect its Component B costs?

A18. Yes. In recent years, GMP has undercollected its actual Component B costs (that is, actual costs exceeded the benchmark costs) during the clear majority of quarters. It is important to recognize that the weather-driven volume changes in GMP's load requirements and generation supply that I discussed above are far from the only drivers of Component B variances; such variances can be driven by multiple other factors. Nonetheless, the historical PSA results are consistent with the expectation that under a symmetrical Efficiency Band range and current power cost forecasting methods, GMP would over time tend to undercollect its Component B expenses by some amount.

Q19. Isn't part of the role of the Efficiency Band to provide an incentive for GMP to effectively manage its net power costs?

A19. Yes. The $150,000 Efficiency Band range would leave a significant amount at stake for GMP – that is, a potential range of $1.2 million per year from the top to the bottom of the Efficiency Bands each quarter, plus 10 percent of all quarterly variances outside of the dead band; such variances have been significant in the past. This provides a significant incentive to manage power costs effectively in the short-term.

In addition, the more transparent design of the PSA as proposed in this Plan—which eliminates the Volume Variance Adjustment and bases Component B collections and returns to customers directly on how our actual quarterly power costs per kWh compare to the benchmark—also will help add a greater level of discipline to GMP's efforts. I say this because it will be much clearer whether we hit our benchmark costs, and this result will affect directly the outcome for GMP under the Component B dead band application.

IV. UPDATE ON REGIONAL MARKET SIMULATION MODEL

Q20. Ms. Fischer and Mr. McNamara express support for GMP's plan to use a regional market simulation model to project energy costs during the term of the Plan. Can you provide an update on GMP's efforts to develop this regional market simulation tool?

A20. Yes. Briefly, this activity entails the use of a simulation model to approximate the functioning of the ISO-NE energy market, including the commitment and dispatch of generating sources to meet the region's load requirements, producing estimates of generation output and energy market prices on an hourly basis. This hourly level of resolution has the potential to enhance the estimation of the net energy costs associated with GMP's loads and generation portfolio, compared to our current model which balances loads and resources across monthly peak and off-peak periods (i.e., 24 periods/year). During 2018, GMP interviewed representatives from EPIS, which offers the Aurora modeling suite, and several consulting firms that focus substantially on the New England electricity market.

Based on that dialogue and further discussion with the Department, we concluded that the most effective and affordable way for GMP to gain access to regional market simulation capability would be to contract with a consulting firm that already maintains a regional model to support other client activities, and work with that firm to incorporate GMP's portfolio of energy resources and loads into that model. In the fourth quarter GMP received detailed proposals from three firms to provide this outsourced modeling service. We selected Daymark Energy Advisors based on several factors including price.

We have begun the process of sharing detailed information about GMP's generation portfolio and load requirements with Daymark, and exploring potential methods to represent some of the more unique resources in the model. Our current goal is that the collaboration with Daymark will yield a portfolio modeling process that will inform GMPs forecast of net power costs starting with our filing in or around June 2019 of forecasted costs for the fiscal year 2020. We have kept the Department apprised of our progress.

Q21. Do you have any observations regarding what to expect from this regional market simulation exercise?

A21. Yes. The hourly level of modeling resolution for GMP's generation supply, load requirements, and regional energy market prices, has the potential to improve our estimates of net energy costs. It also could improve our evaluation of potential future supply resources, and provide forward-looking context about trends in the New England market that are not readily available elsewhere.

I would like to emphasize, however, that expectations from this exercise should be kept in check to some extent. Simulation modeling is a helpful tool, particularly to capture the volume and costs/revenues associated with GMP's open position on an hourly basis, which we hope will reduce the magnitude of the "balancing adjustment" that is presently needed to refine our estimates of net power costs. It is not, however, a universal tool that will effectively address all relevant aspects of how the regional market affects GMP's portfolio. For example, GMP's review of vendors and platforms confirmed that regional simulation models are generally designed to approximate the market from a day-ahead perspective, not capturing the ultra-short-term fluctuations in regional supply and demand that can produce different and wider outcomes for generation dispatch and LMPs in the real time market. Similarly, many firms find a zonal level of granularity sufficient to support most of their clients' needs—as opposed to a much more detailed nodal structure that can capture additional locational details, but is much more costly to set up and maintain, and more time consuming to run. As a result, GMP expects that while representation of our portfolio in a regional model will provide significant insights, and will probably reduce the need for some off-line spreadsheet adjustments to accurately represent net portfolio costs, it will not entirely displace the need for such tools.

V. RESPONSE TO REV CLAIMS REGARDING GMP POWER SUPPLY COSTS AND SELF-GENERATION

Q22. REV asserts that increasing volumes of net-metering are not driving up GMP's rates. Is that accurate?

A22. No. While a detailed discussion of net-metering generally or its specific impacts on retail electric rates is beyond the focus of this proceeding, I need to point out that REV's testimony on this topic (Cadwell & Anderson Testimony, starting at page 18) is mistaken, or at least very misleading. The incremental cost of net-metered power to GMP and our customers, including reduced retail sales, applicable adjustors, and net-metered excess, exceeds the estimated value of the power that GMP receives—including reduced wholesale energy, capacity, and transmission charges, along with RECs that can be used for compliance with Vermont RES Tier II—by a significant margin. As a result, additional volumes of net-metered solar generation tend to put upward pressure on GMP's net power costs and retail electric rates. The Commission has confirmed this conclusion numerous times, including in GMP's 2018 rate case, where it affirmed GMP's accounting of the power costs associated with net-metering, rejecting REV's characterization of these costs.[4]

Annual installations of new net-metered capacity in GMP's service territory during the past five years have ranged from about 20 MW to almost 40 MW, and total operating net-metered generating capacity exceeds 170 MW. Even though that is a relatively small slice of our overall power supply portfolio, it is our second largest power supply expense. GMP is and has been a supporter of net-metering; we are proud that our solar adder helped spur the market and legislative change. But the spread between the cost of net-metered power and its value to GMP and other Vermont utilities has developed and grown over time, in part because the value of additional net-metered output has declined. In particular, wholesale market prices for energy and regional Class 1 RECs have remained moderate or declined in recent years, while the potential value of additional distributed solar generation to Vermont utilities and their customers, through avoidance of transmission expenses, and deferral or displacement of transmission and distribution costs, has significantly declined due to the shifting of Vermont peak loads into evening hours. The combination of substantial net-metering growth and a decline in value of output are the primary reasons that the Commission recognized that increasing net-metering volumes can bring upward rate pressure, and made adjustments to the net-

[4] *See* Case No. 17-3112-INV, Order of 12/21/2017 at 9-10. ePUC Document No. 242618/86567.

metering program in 2018 to ensure that the program remains financially sustainable and to balance other statutory goals.[5]

Q23. Does REV's discussion of GMP's overall power costs refute the notion that increasing net-metering volumes tend to put upward pressure on GMP's net costs and retail rates?

A23. No. Starting on page 18 of Ms. Cadwell & Ms. Andersen's joint testimony, REV compares GMP's power costs from 2013 and 2018, concluding that overall power costs have decreased significantly during this period. REV appears to be arguing that because GMP's power costs in total did not increase during this period, net-metering is not "driving up" electric rates. This is not accurate for a few reasons.

First, if REV is arguing here that upward rate pressure from increasing net-metering volumes should not be a concern if it does not increase GMP's power costs and retail electric rates (i.e., if it only reduces the magnitude of rate reductions that could otherwise have been achieved), then I don't follow the argument. The affordability of electricity is a significant concern for Vermont electricity customers. It is reasonable to expect that incremental upward pressure on electric rates, whether it is driven by increasing net-metering volumes or other factors, would be a concern for customers regardless of the current trend in power costs and retail rates.

More importantly, REV's observation that GMP's power costs declined greatly during the 2013 to 2018 period is mistaken. In fact, almost all of the apparent decline

[5] *See* Case No. 18-0086-INV, Order of 5/4/2018. ePUC Document No. 264653/128318.

that REV points to was due to a change in the grouping and presentation of GMP's power costs rather than an actual decline in the net power costs. Specifically, REV's information here, including the table on page 19 of REV's joint testimony, was obtained from August 2018 Public Service Department testimony in GMP's most recent rate case (Case No. 18-0974-TF). As GMP explained via discovery responses in that case, which were provided to REV at that time, a very large portion—approximately $29 million—of the indicated $33 million change in the Department's Purchased Power and Production line from 2013 to 2018 was due to a change in how resale revenues were reported, not to a decline in GMP's net power costs. That is, substantial resale revenues were included in the Purchased Power and Production figure in 2018, significantly reducing it, but were not included in the 2013 figure. Thus, REV's representation that GMP's power costs have declined $33M between 2013 and 2018 is not correct and the table upon which it relies is not accurate. GMP provided a detailed discovery response to REV and to the Department in the 2019 rate case outlining why this $33 million figure is not correct, which REV does not acknowledge or address in its testimony in this proceeding.

Q24. Does that conclude your testimony today?

A24. Yes, it does.