STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 19-0855-RULE

Proposed Revisions to Vermont Public Utility
Commission Rule 5.100

GREEN MOUNTAIN POWER
RESPONSE TO PUBLIC UTILITY COMMISSION
INFORMATION REQUEST

NOW COMES Green Mountain Power ("GMP") and responds to the Public Utility Commission ("Commission") Information Requests to provide information about net-metering, as follows:

Information Requests for Electric Distribution Utilities Pursuant to 30 V.S.A. §§ 8 and 209:

Q1. Is the current net-metering compensation system causing a cost shift between customers who net-meter and those who do not? Please quantify this cost shift and provide all calculations supporting your response.

A1. GMP believes a sustainable net metering program should provide compensation to participating customers in line with the value delivered to non-participating customers through wholesale power, transmission costs, or unique local economic benefits net metering may provide. GMP was an early advocate and supporter of net metering, and designed its original solar adder program in 2007 so that the value created by customers installing net metered systems would meet or exceed the costs so as not to create a cost shift to non-participating customers. Since then, Vermont has seen robust growth of local renewable energy, in particular solar. For context, in 2013 there was only 20MW of active solar in GMP territory; today, we have nearly 300MW in service, with another 100 MW of solar applications in the queue. It is important to realize that 400 MW of solar that is either active or in the queue represents 85% of GMP's average daily load of 470 MW, and 55% of its 2018 peak load of 730MW – so on a sunny day in Vermont, solar is a dominant generation source.

The compensation structure of the current net metering program now substantially exceeds the value provided by the net metered systems, in part because the value of additional net metered generation has declined significantly over time, and consequentially, a cost shift is occurring.

Attachments GMP.1.1 and GMP.1.2 detail two net metering benefit/cost analyses showing the estimated power supply benefits as well as the various costs associated with net-metering output. The first analysis detailed in Attachment GMP.1.1 focuses on the volumes of net metering currently in service (along with a limited volume of projected installations expected during the current fiscal year), based on GMP's fiscal year 2020 rate filing. As shown in Table 1.1 below, the fiscal year 2020 impact of net-metering output totaling an estimated 263,515 MWh results in an estimated cost shift of almost $33 million[1]. This reflects estimated power supply benefits of approximately $20 million versus estimated costs of about $53 million (Attachment GMP.1.1 – FY2020 Net Metering Benefit/Cost). For a sense of scale, $33 million represents roughly five percent of GMP's total annual cost of serving its customers.

Table 1.1 - Summary of Rate Year 2020 NM Impact

Net Metering Output in MWh	MWh	
Own Use	54,261	
Excess Generation	209,254	
Total Output	263,515	
	Rate Year 2020	
	$ 000s	**Average $/MWh**
Costs $000s		
Sales Offset by Own Use	9,232	$170.15
Excess Generation	33,769	$161.38
Adders/Adjustors (includes RECs)	10,189	$38.66
Total Cost	53,190	$201.85
Power Supply Benefits $000s		
Avoided Power Cost	(11,333)	($43.01)
Transferred RECs	(1,524)	($5.78)
Avoided Capacity/RNS	(7,057)	($26.78)
Total Power Supply Benefits	(19,914)	($75.57)
Net Cost/(Benefit) $000s	33,276	$126.28

The second analysis, detailed in Attachment GMP.1.2, examines the effect of an additional volume of net metered generation installed today based on the current program. Specifically, this analysis estimates the effect of a single year's growth of net metered generation assumed at 20 MW, consistent with the assumed annual growth of net metered generation in GMP's 2018 IRP which was recently approved by the Commission, over twenty-five years of operation. For computational simplicity, we assume that the incremental 20 MW of net metering capacity is all added on day one of GMP's 2020 fiscal year. Table 1.2 below shows that 20 MW of additional net metering capacity would cause an estimated net cost shift of $47.4 million over the course of twenty-five years, in current net present worth, to non-participating customers. Under this analysis, the estimated annual cost of net metering exceeds the power supply benefits by between $2.4 and $5.3 million in nominal dollars in each year over the twenty-five year period (Attachment GMP.1.2 – 25 Year Net Metering Benefit/Cost).

[1] A portion of this cost shift to non-participating customers reflects the impacts of program features from the early years of the net metering program, where generators were not incented to transfer RECs to the VDUs and there was a high initial solar adder.

Table 1.2 - Twenty-five Year Impact of Incremental 20 MW of Net Metering

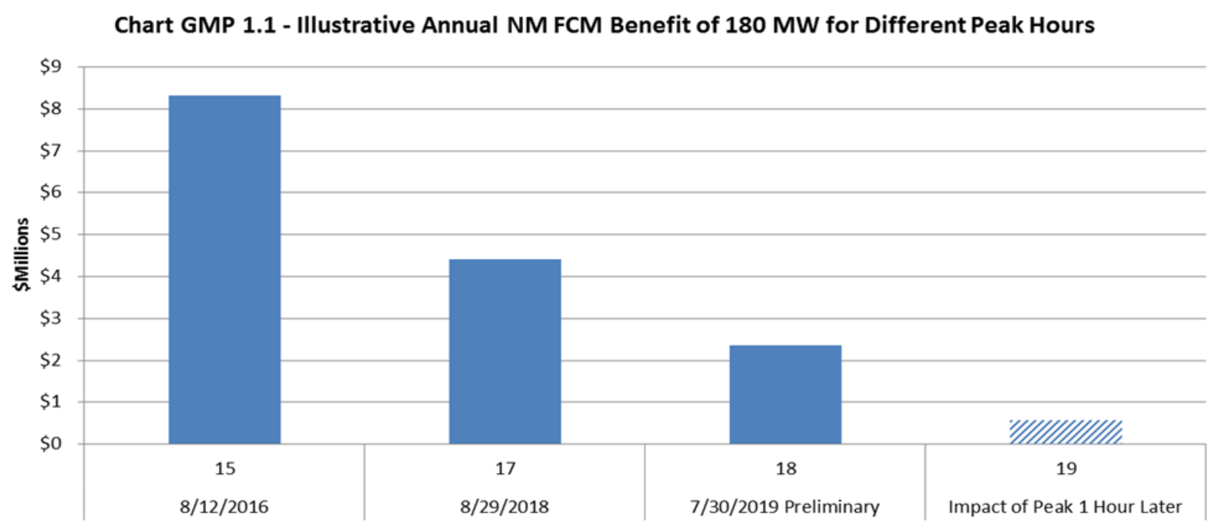
NPV of Net Metering Output in MWh	**MWh**	
Own Use	75,988	
Excess Generation	292,227	
Total Output	368,215	
NPV of Costs $000s	**$ 000s**	**Levelized $/MWh**
Sales Offset by Own Use	16,723	$220.07
Excess Generation	59,542	$203.75
Adders/Adjustors (includes RECs)	1,826	$4.96
Total Cost	78,090	$212.08
NPV of Power Supply Benefits $000s		
Avoided Power Cost	(17,375)	($47.19)
Transferred RECs	(7,131)	($19.37)
Avoided Capacity/RNS	(6,180)	($16.78)
Total Power Supply Benefits	(30,687)	($83.34)
NPV of Net Cost/(Benefit) $000s	47,403	$128.74

In both analyses, the economic costs associated with net metering, including sales offset by own use, payments for excess generation at retail rates, and Renewable Energy Credits ("REC") and siting Adjustors, markedly exceed the quantifiable power supply benefits provided by the projects, which include avoided costs for energy, capacity, transmission expenses in the form of Regional Network Service ("RNS"), and RECs. In the second analysis, which isolates the cost shift associated with current solar net metering projects, the addition of RECs to the value calculation and moderate reductions to the Adjustors are offset by diminishing peak-reducing benefits as monthly and annual peaks move to late afternoon or evening hours. As a result, the costs continue to exceed the benefits for our non-participating customers as shown in Table 1.2. This cost shift can vary to some degree based on fluctuations in the actual quantities and timing of net metered generation and changes in the wholesale market costs that this generation avoids. In addition, market effects (i.e., SIPE/DRIPE as discussed below) which are not included in the estimates above could provide some additional value. It seems clear, however, that costs associated with the current fleet of net metered generation and with new net metered generation coming online in the near term will exceed the benefits to non-participating customers by a substantial margin.

GMP notes that any analysis of the relative cost of a particular resource option is time and market dependent, and is also bounded by the availability of other resource options. At any point in time GMP's analysis of portfolio resources is based on the best currently available current information for projecting expected costs and benefits. Any particular resource's actual performance may vary over time based on changing market conditions and other factors.

Like other power sources, as net metering has evolved the benefits and costs of additional net metering should be analyzed in the context of the then-current market conditions and forecasts. Some of the major categories of benefits from net metered solar have seen significant declines over the last decade, and these have lowered the value that solar generation provides. First, wholesale energy market prices in New England have dropped, leading to annual all-hours average prices of around $40/MWh over the last four years.

Over the same period the rapid growth of behind-the-meter customer solar generation around the region has helped shift the ISO-NE annual coincident peak used to set Forward Capacity Market requirements to later in the day, moving from between 2 and 3 pm to occurring between 5 and 6 pm this year. This shift of the ISO-NE peak to hours with less solar generation output reduces the contribution to peak cost savings that are attributable to solar generation. For example, based on the net metering capacity currently installed in GMP's territory, about 180 MW, a regional peak occurring between 2 and 3 pm instead of 5 to 6 pm could have resulted in roughly $6 million of additional value for GMP's customers based on the higher output of solar generation during the earlier peak hour. The key driver here is that New England states other than Vermont have added major amounts of solar PV generation in recent years. ISO-New England ("ISO" or "ISO-NE") forecasts that as of the end of 2019, there will be approximately 2,050 MW[2] of behind the meter solar in New England, with significant growth projected in the next few years. Growth in behind-the-meter solar generation tends to reduce load during sunny daytime hours, so the shift toward evening peaks we have experienced is likely to persist in the future (absent a large change in consumer usage patterns), with the ISO-NE peak likely to ultimately shift to the hour from 6 to 7 pm (i.e., hour ending 19). Below in Chart GMP 1.1 is a snapshot of the value of FCM cost reduction caused by 180 MW of behind the meter solar at ISO NE peak times[3] since 2016.



Potential FCM value of solar net metering based on historical 2016 and 2018 peak hours; 2019 preliminary peak hour; and potential impact of coincident peak slipping one hour to HE 19. Analysis based on FCA#11 clearing price of $5.30/kW-month and a reserve requirement of 30% using PV Watts monthly average output by hour for slightly oversized (1.2 dc/1 ac) project located in zip code 05701 (Rutland).

Similarly, the substantial and rapid deployment of solar PV generation in Vermont has shifted monthly Vermont transmission system peaks in some months from daytime hours into the evening, so that Vermont peaks now occur overwhelmingly in evening hours that feature little or no solar PV generation. As a result, our estimate of the value of additional solar net metered generation assumes only a modest value for RNS savings.

[2] 2019 ISO-NE CELT Report https://www.iso-ne.com/system-planning/system-plans-studies/celt/

[3] To illustrate the typical decline in solar output from hours ending 15 to 19 (i.e., hours ending 3 pm to 7 pm), we show estimated average output for these hours for the months in question. Actual output during these hours on individual days can vary significantly from these averages based on actual cloud cover and other factors.

Finally, the market value of RECS (regional RPS Class 1) has also dropped from a high of over $60/MWh earlier in the decade to a low of under $5/MWh before a recent rebound to over $30/MWh.

In summary, the estimated value of additional solar generation - including solar generation that will be installed under Vermont's net metering program - has declined substantially during the past decade. The decline is due in part to shifts in peak demand in Vermont and New England that make additional solar power less valuable, along with moderate wholesale power market prices in the region. While not all of the decline was anticipated, and the future value of net metered solar generation will differ from today's estimates due to changes in market forces and other factors, most of the decline in estimated value is due to forces including peak shifts and wholesale market price drivers that appear to be relatively long lasting.

Respondent: Andrew Quint

Q2. Please quantify the effect of current net-metering compensation on your retail rates. Please provide all calculations and information supporting your response.

A2. Please see Attachment GMP.1.1 – FY2020 Net Metering Benefit/Cost, which shows about $33 million in excess of net metering costs over benefits included in GMP's current cost of service, recovered from customers through rates. As a point of reference this cost shift results from a customer participation rate of about 6 percent (15,655 net metering participants out of our total customer base of 267,170).

Respondent: Andrew Quint

3. If current net-metering compensation is having a significant effect on retail rates, please describe how compensation should be changed so that the net-metering program does not have a significant effect on retail rates.

A3. The effect on retail rates, based upon calculation of economic costs and benefits, is described in A.1 and A.2 above. Whether that cost shift is substantial and to what extent it is detrimental involves a policy judgment that the Commission may be in the best position to make.

GMP wants to have a sustainable and affordable program for all customers where the value meets or exceeds the costs; so that the program supports Vermonters using the net metering program to self-generate carbon-free energy as net metering is designed to do. It is important to point out that GMP's power supply is now over 60% renewable and 90% carbon free, while some other utilities in Vermont are already 100% renewable. In addition to increasing renewability in a sustainable and cost-effective way for the customers we serve, GMP is focused on helping address the climate crisis by focusing on the top causes of carbon pollution in Vermont, which are transportation and heating. Therefore, carefully balancing the costs and benefits of programs available to customers is important to ensure we maximize the results we are trying to achieve.

To change the effect of the current net metering program on retail rates and lessen the affordability impact on other customers, there are various combinations of changes that could be utilized. All would involve a) changing net metering compensation to align more closely with the value of the power to GMP and its non-participating customers; and/or b) lowering the overall amount of net metered generation that can be added (either directly through caps or through lower incentives that in turn lower demand). Choices could also be made to shift the use of some or all of the incentive provided for net metering by, for example, compensating excess net metered generation at estimated avoided costs unless a customer also utilizes controllable storage or an electric vehicle or other strategic, controlled electrification, in which case the customer could receive additional value for that new use. This approach would promote behaviors such as pairing solar and storage, which helps with grid resiliency, and can provide value to the utility through shared access that can lower costs for all customers.

As the Commission assesses the factors that have driven the pace of solar net metering growth, we note that the recent Adjuster reductions have not greatly reduced the volume of applications. In the twelve months after the reduction implemented by the PUC for projects applying for interconnection beginning on July 1, 2018 GMP received applications for almost 40 MW of new projects – an extraordinary pace by industry standards. Over the last few months (following the Adjustor reduction effective on July 1, 2019) the pace of new interconnection applications to GMP for net metering projects of up to 500 kW has remained significant, amounting to a total of just over 5 MW as of the end of October.

While we anticipate that a full rulemaking proceeding will help determine specifics on how the net metering program should evolve, we would be in favor of continuing to support smaller systems - particularly when paired with storage or strategic, controlled electrification - while phasing out larger systems not sited at significant load or transitioning them to a different program that more closely aligns actual costs and benefits, and minimizes the cost shift to non-participating customers. Such a change could continue to encourage certain larger projects – such as solar carports – that have the ability to serve a specific load or provide other direct benefits. We may also be able to transition larger projects for some customers to the programs that most closely match their usage profile and sustainability goals with actual costs and benefits.

Respondent: Josh Castonguay, Doug Smith

Q4. Please state the amount of new net-metering capacity the utility will need to meet Vermont's Renewable Energy Standard in total and on average per year.

A4. Tier II of Vermont's Renewable Energy Standard ("RES") requires the Vermont Distribution Utilities ("VDUs") to procure a defined percentage of their retail electric sales from new, distributed renewable generation. For purposes of the RES, distributed generation is defined as 1) electric facilities with a plant capacity of 5 MW or less that are directly interconnected to the sub-transmission or distribution system and put in service after June 30, 2015, or 2) facilities that have been identified in an approved plan to defer transmission upgrades; or 3) net-metering systems. The Tier II requirement started at 1% of retail sales in

2017 and grows by three-fifths of one percent per year until it reaches ten percent in 2032. Based on this definition, the VDUs can meet their Tier II requirements by retiring a mix of Renewable Energy Certificates ("RECs"), including attributes that are transferred to the VDUs from net metering projects that requested interconnection on or after January 1, 2017.

Due to the size of GMP's Tier II requirement, we anticipate that retirement of net metering RECs will be used to meet a portion of this obligation, but that GMP will also retire RECs associated with various other distributed generation projects to help meet this obligation on an annual basis. In GMP's 2018 Integrated Resource Plan ("IRP"), we noted that an estimated net metering growth rate of 20 MW per year combined with the growth of other distributed generation (e.g., Standard Offer, renewable PPAs, and other resources) would generally be more than sufficient to meet the annual growth in GMP's Tier II requirements over the next decade. In fact, existing Tier II-eligible sources and anticipated new Standard Offer projects are projected to be sufficient to meet our Tier II requirements in the next several years. On the other hand, as discussed in the IRP, the requirements for Tier III (transformation) projects are substantial and the supply is uncertain, so it may be appropriate for GMP to use some amount of Tier II RECs to meet a portion of our Tier III requirements; those needs are uncertain and could vary greatly from year to year.

In actual practice, growth of net metered generation, almost all of which is solar, is effectively competing with and displacing alternative sources of distributed solar PV power (via PPAs or utility-sponsored projects) to meet Tier II needs. If the growth of net metered generation were to slow significantly, GMP would likely seek additional distributed renewable power from these sources, at expected prices that are significantly lower than the compensation rates that are currently available to net metering projects.

GMP notes that only a portion of the solar net metering capacity operating in its service territory provides RECs to GMP. Prior to 2017, net metered facilities (which total about 139 MW) were not required to assign RECs to the utility and, as a result very few did, meaning that the attributes associated with these projects are not part of the supplies that can be used to meet GMP's RES requirements.

Respondent: Andrew Quint

<u>Information Requests for All Stakeholders:</u>

Q5. Please identify all the benefits that net-metering provides (for example, energy, capacity, reduced regional network service charges, etc.).

A5. Net metering generation occurs "behind-the-meter" and effectively offsets a portion of the utility's metered load. Through customer net metering, a utility avoids the cost of purchasing energy and other wholesale market products that would otherwise be required to meet its customers' load requirements. These benefits include energy that is either used by the customer and therefore not purchased or excess generation that is injected into the VDU's distribution or sub-transmission system; peak shaving due to output during specific peak events such as monthly Vermont transmission peaks used for calculating RNS allocations and the annual Forward Capacity Market ("FCM") coincident peak in New England; and finally the value of the RECs that net metering customers transfer to the VDUs. This works best when systems are properly sized to serve customer load where the project is located.

In addition to these direct power supply benefits, there is also a generalized price effect where the growth in distributed generation across New England, including net metering, can be expected to work to suppress wholesale capacity and energy prices (Locational Marginal Prices or LMPs). This effect is commonly referred to as either Supply Induced Price Effect ("SIPE") or Demand Reduction Induced Price Effect ("DRIPE") and has been discussed extensively in Synapse's periodic Avoided Energy Supply Costs in New England ("AESC") studies.[4] It is important to understand that the AESC studies have focused on DRIPE in the context of the cumulative impact of energy efficiency programs across New England, which have the ability to provide load and peak suppression which generally matches load.

For energy, the concept behind DRIPE is that reductions in demand lead to the market price for energy being set by relatively more efficient and cheaper units in the bid stack of generation sources in New England. The AESC study does not consider net metering or solar shaped generation specifically, but all things being equal, the same type of market effects should be realized through net metered generation. However, it is possible that net metering value is somewhat lower because net metering output is not as closely correlated to demand as energy efficiency measures tend to be. For capacity, a similar dynamic can apply. GMP believes that the large fleet of behind-the-meter solar generation in New England has been applying some level of downward pressure on FCA clearing prices.

SIPE or DRIPE benefits from net metered generation would tend to decrease the cost associated with serving VDU customer demand but would, at the same time, also tend to decrease the value of the output associated with other generation resources whether owned by the VDU or subject to a Power Purchase Agreement. This means that suppression of market prices as a result of net metered generation would tend to benefit VDUs and their customers in hours when a VDU has a short position and needs to buy energy from ISO-NE, but there may be a negative impact on costs to customers from net metering generation during hours or months when solar output is highest and VDUs sell excess energy to ISO-NE. With respect to capacity, GMP tends to be a significant net purchaser so all else being equal, lower clearing prices in the FCM tend to benefit our customers. It important to recognize, however, that (as discussed in the AESC) DRIPE/SIPE benefits for energy and capacity should be expected to have limited persistence over time as

[4] https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf

market participants (sellers and buyers) make changes in response to the changing prices[5]. Overall, GMP expects that the net SIPE or DRIPE benefit is positive (favorable to our customers) though limited in scale relative to the estimated total costs and benefits of net metering as discussed in Response 1.

Distributed generation including net metering also has the potential to affect energy losses on the distribution system, and to affect required capital investments in the distribution system. The specific effects depend on factors that include the project's location on the distribution system and the relative balance of local load and generation. For example, additional net metered generation located at or near significant customer loads is more likely to reduce distribution losses, while net metered generation that is located remotely (for example, a group net metered project on a radial line without significant load) can increase system losses. Similarly, deferral of distribution investments is possible in certain situations (e.g., when an investment to accommodate increasing daytime peak loads in an area would otherwise be needed). In GMP's experience such ideal situations are relatively rare, with very few of our distribution capital projects driven by projects to meet increasing customer demands in an area.

In addition to the power supply benefits there are also other benefits like job creation and economic development. In the case where solar is paired with a battery system directly on a customer's premises, the system can also provide increased reliability and resiliency for the customer by providing emergency power during outage events.

Finally, even though the peak-reducing benefits of solar have declined as more solar has been added to the system and the peak hour has shifted, adding solar (whether net metered or otherwise) does have the opportunity to displace marginal electricity generation in New England, which will typically displace output from fossil-fired generation and reduce the overall carbon footprint of the New England energy system. For a rough sense of magnitude, GMP estimates the carbon benefit generally through the addition of solar on the regional grid to be a reduction of approximately 1100 lbs. of CO2 per kW annually based upon the marginal emissions of the system mix in New England. This specific benefit is not separately priced except to the extent that it is captured in RECs and GMP has not attempted to rigorously quantify the relative benefit of additional solar, whether net metered or otherwise, displacing carbon compared to other choices a customer could be incentivized to make to displace carbon. Cutting carbon is critical to address the climate crisis, where transportation and heating are Vermont's two top sources of pollution, and for a sense of scale, switching to an electric vehicle is estimated to save approximately 9,000 lbs of CO2 annually on average and using an electric heat pump instead of fuel oil saves 8,000 lbs of CO2 annually, both significantly higher than additional solar generation. It is also useful to keep in mind that potential emission benefits associated with net metered generation (like the SIPE/DRIPE effects discussed above) can also be obtained through other lower-cost sources of distributed solar generation.

Respondent: Andrew Quint, Josh Castonguay

[5] For example, increasing distributed generation and other factors have contributed to a number of significant, less efficient plants retiring or submitting capacity delist bids in recent years. Actions like these tend to reduce or reverse the suppressive effect on market prices.

Q6. For each benefit identified, please state whether the value of the benefit accrues to the net-metering customer, ratepayers, the utility, or society in general.

A6. Any direct power supply value associated with GMP's net metering projects would accrue to the benefit of our customers, as these would reduce net power costs associated with meeting customer demand. The benefits associated with SIPE or DRIPE would accrue to all New England utility customers, including customers in Vermont, to the extent that the cost of serving loads is reduced on an annual basis. It is important to note that generation owners would tend to experience lower revenues associated with their output in hours where demand is reduced. This will, over time, tend to push more expensive and less efficient units to retire - which would have a net societal benefit as these plants tend to have higher greenhouse gas emission levels but also (as noted above) offset or eliminate the SIPE/DRIPE effect.

Non-power supply benefits would accrue to either society in general or the direct customer participating in the program. In the case of jobs and economic development within Vermont and carbon savings, the benefits would accrue to society in general, while increased resiliency when paired with battery storage would accrue directly to the customer hosting the system, and with shared access would accrue to all customers served by the utility.

Respondent: Andrew Quint, Josh Castonguay

Q7. For each benefit, please describe how the Commission should estimate the value of that benefit. Please identify what data sources the Commission should use to make such estimates. If you have an estimate of the value of a particular benefit, please provide the estimate, along with supporting documentation showing how the estimate was derived.

A7. GMP has calculated the value of the direct power supply benefits that are typically associated with net metering; we have not attempted to calculate the net value of SIPE/DRIPE because it is a regional calculation and beyond the scope of our typical analysis. First, the value of energy can be calculated by looking at the actual output profile of the resource multiplied by the hourly Vermont Zonal LMPs, reflecting that net metered generation reduces the loads that VDUs settle with ISO-NE at the Vermont Load Zone. Depending on the resource's location it may also be appropriate to add a loss benefit as appropriate. In general, there are distribution line losses associated with serving customer demand, and to the extent that distributed generation is located in reasonable proximity to customer demand, it should help to offset line losses which average about 4.5%. Based on a recent analysis, the relative value of solar shaped generation is about 5% less than the all hours average LMP because LMPs have tended to be highest during winter months when there is less solar output and lowest during the summer hours when solar output tends to be greater. We anticipate that the differential will grow somewhat over time as more solar generation enters service across the grid in New England. For calendar year 2020 GMP's analysis assumes the value of solar energy output (including avoided line losses) to be worth approximately $43.01/MWh, or about 4.3 cents per kWh.

Next, monthly peaks that are used to calculate allocations of RNS have been a declining component of net metering value as these peaks have been moving to later hours when net metering output is near zero. To the extent that there is output during these peak hours, it would be multiplied by the monthly per kW-month price of RNS, and, dependent on the location of the resource relative to customer demand, there could also be a line loss adjustment. As described above, recent coincidence factors of solar shaped output with RNS peaks has been quite low over the last few years (at about 3% or less of nameplate capacity over the course of a year). The annual value of RNS for 2020 is estimated to be about $2.10/MWh, or about 0.2 cents per kWh.

Generation during the annual coincident peak hour used for calculating a VDU's Capacity Requirement as a participant in the FCM helps the utility avoid twelve months of capacity expense for the following capacity period that runs from June through May of the year after the peak is measured. This avoided volume is adjusted upward to reflect the region's effective capacity reserve margin, which varies annually based on each year's Forward Capacity Auction results relative to the ISO-NE Installed Capacity Requirement ("ICR") and, depending on the resource's location relative to customer demand may also be adjusted upward to reflect the marginal losses during the peak hour. For net metering generators that have output during the coincident peak hour in 2019 that will be used to measure capacity requirements starting in June 2020, we anticipate that the twelve month capacity value will be approximately $24.68/MWh of output, or 2.5 cents/kWh[6].

Finally, the value of RECs received from net metering projects will depend on the market value associated with RECs that could otherwise be retired to meet the VDU's Tier II obligations. Tier II eligible RECs from sources other than net metering are typically also eligible for Massachusetts or Connecticut Class I markets where they can be sold to help decrease net power costs for customers. Accordingly, GMP uses the value of RECs in these markets to provide a benchmark for determining the value of Tier II eligible RECs, which is well below the current ACP for Tier II. Current Class I REC prices have been trending higher over the last several months and there are broker quotes for 2020 Massachusetts and Connecticut Class I RECs of about $37.00/MWh, or 3.7 cents/kWh. We note that there has been significant price volatility for these RECs over the last several years which has partially been driven by changing Renewable Portfolio Standards in Connecticut and Massachusetts as well as by anticipated delays in COD dates for several large offshore wind projects and several other projects that have won awards in various renewable RFPs. In the last twelve months Class I RECs have ranged in price from just a few dollars per MWh up to $37/MWh. Our Rate Year 2020 filing assumed a REC value of approximately $25/MWh or 2.5 cents/kWh, although this value is only applicable to a portion of the net meter solar output and equates to $5.78/MWh for all net metered generation, or about 0.6 cent/kWh. If we were to take a longer term view we would suggest using current market quotes of about $30/MWh through 2023 and then revert to GMP's 2018 IRP analysis reflecting regional

[6] Forward Capacity Market auctions conducted for deliveries in the following three years cleared at prices significantly below the 2020 value, so we expect that the capacity value of net metered generation will decline in the near term.

Class I REC markets reaching a reasonable supply/demand balance.[7] This would, over the next decade, result in a levelized value of about $22/MWh or 2.2 cents/kWh.

GMP does not have a value or method for estimating the value of societal or direct customer benefits such as jobs, economic development, or individual customer resiliency.

Respondent: Andrew Quint, Josh Castonguay

Q8. When estimating the value of the benefits of net-metering, what time horizon should the Commission consider? Why?

A8. We anticipate that the typical life of a Net Metering project is between twenty and thirty years. Rule 5.100 does not limit the number of years that a customer can participate in the net metering program, and accordingly, we assume that the applicable life should be similar to a typical PPA term for a solar project, or about twenty-five years.

Respondent: Andrew Quint

Q9. Please identify all costs of net-metering. Please describe how the Commission should account for these costs so that they can be compared to the benefits of net metering.

A9. The costs associated with net metering fall into three main categories: sales offset by own use, payments for excess generation, and adjustors (e.g., RECs and siting adjustors). Sales offset by own use can be calculated as own use volumes by category (residential, commercial, and industrial) multiplied by the appropriate incremental rate for the class of offset sales. Payments for excess generation are based on the kWh of output, less any own use, multiplied by the appropriate rate paid to the net metering customer depending when it came online (e.g., $0.15417/kWh for Net Metering 2.0 customers). The final component is the adder, which is calculated under the rules applicable when the project entered service. For example, a Net Metering 2.0 customer who transfers the RECs associated with generation would receive a REC adjustor and an associated siting adjuster (e.g., first year NM 2.0 project transferring RECs and eligible for a Category I siting adjustment) would have a total adjustor of $0.04/kWh multiplied by total system output defined as own use plus excess generation for the first ten years of the project's life.

Respondent: Josh Castonguay, Andrew Quint

Q10. For each cost, please identify who pays the cost (ratepayers, the utility, society).

A10. The costs associated with purchasing excess generation and the net REC adjuster are borne by GMP's customers as part of GMP's net power cost. Any adders for the previous net metering program that are still being paid to net metering customers are also borne by GMP's customers.

[7] Most notably, the addition of major new renewable resources (e.g., Vineyard Wind, hydroelectric power via the NECEC line in Maine) in the early 2020s is likely to fundamentally increase the regional supply/demand balance for Class 1 RECs.

Sales offset by own use affect customers somewhat differently, but have a measurable impact on the rates that they pay. Net metering sales offset by own use reduce retail sales volumes and, absent a change in policy regarding how utility costs are paid, the reduced retail sales have the effect of allocating all non-variable costs across a smaller volume of kWh sales. This leads to rate pressure for all customers, and customers without net metering of course do not receive the associated net metering benefit.

Respondent: Andrew Quint, Josh Castonguay, Robert Dostis

Q11. Please compare the benefits of net-metering to the cost of net-metering under the current net-metering rule.

A11. See responses to Questions 1, 2 and 9.

Respondent: Andrew Quint, Josh Castonguay, Robert Dostis

Q12. If the current net-metering compensation system does not balance the costs and benefits of net-metering, please describe how the compensation system could be changed to better balance costs and benefits.

A12. See response to Question 3.

Respondent: Josh Castonguay, Doug Smith

Q13. Would using time-of-use retail rates to set net-metering compensation better align the costs and benefits of net-metering? Should the Commission require net-metering customers to be on time-of-use rates?

A13. Absent other policy changes, GMP does not believe that requiring time-of-use rates would better align costs and benefits and does not recommend the Commission require such a solution for net metering. Retail rates are meant to recover the total annual revenue requirement of an electric utility including many costs that are not directly related to power supply and many costs that do not change with the level of energy throughput on the system. That is, these costs are not variable or volumetric in nature. When compensating self-generation at a full retail rate that has been historically heavily weighted to a volumetric rate design (i.e., lower fixed charges and higher volumetric kWh charges) generation tends to be over-compensated and a cost shift occurs. This cost shift to customers is demonstrated in Attachments GMP.1.1 and GMP.1.2.

So, the cost shift would continue under current time-of-use retail rate designs as long as the utilities recover non-variable costs through the variable volumetric component of the rate design. In particular for residential customers, having net metering customers on time-of-use rates that remain heavily volumetric-weighted would likely actually exacerbate the cost shift since the peak rate is higher than the non-TOU residential rate. A better solution would be to either decouple the compensation of net metering from full retail kWh rates or modify rate designs to recover a lower portion of fixed costs through volumetric charges.

Requiring utilities to modify their historic rate designs and collect non-variable cost via fixed, non-variable rates (relatively higher customer charges, traditional demand charges) while setting the variable rate component (kWh charges) equal to the utility avoided power cost would reduce this imbalance. A substantial change to utility rate design to move revenue out of volumetric charges and into fixed charges would be revenue neutral for the utility and would have the effect of narrowing the bill difference between low use customers and high use customers since all customers would pay less via volumetric charges. This design would also have the effect of aligning kWh rates closer to the avoided cost of self-generation if the PUC continued to use residential kWh rates as a compensation mechanism.

Respondent: Scott Anderson

Q14. Should the Commission allow utilities that provide their customers 100% renewable energy to propose alternative net-metering tariffs? If so, what minimum requirements should the Commission adopt for such tariffs?

A14. GMP continues to believe that overall consistency of the rule across all utilities is preferable regardless of an individual utility's power supply renewable mix.

Respondent: Josh Castonguay

Q15. Should the Commission adopt a limit on the amount of new net-metering resources? If so, how should the Commission determine the amount?

A15. GMP would prefer not to impose a specific MW cap but instead to utilize appropriate pricing and program design to provide a natural and appropriate pacing of deployment. GMP believes customer programs, including net metering, should be designed to balance costs and benefits to limit cost shifts; in fact, ideally such programs would share benefits between participating and non-participating customers so that all customers are better off with the programs in place than otherwise.

Respondent: Josh Castonguay

Q16. What standards or criteria should regional and local bodies apply to determine whether a site should be designated as "preferred"?

A16. GMP will direct its answer to the issues it knows best: grid reliability and resiliency. As solar development has increased, the amount of development has not been without challenge. In particular, the concentration of development in certain areas has put a strain on the capacity of the grid to handle it, and those areas of grid constraint have grown over time. GMP created its solar map to aid solar developers in finding areas that are less concentrated with fewer constraints. As we think about what priority to give to the siting of new solar generation, in light of the costs and inefficiencies of grid constraints, GMP suggests a significant emphasis be placed on building resiliency. Solar energy is one key to resiliency, because it can be configured with storage to enable dwellings and enterprises to self-power when an outage occurs. We have already seen and, given the realities of climate change, expect to continue to see storms with greater ferocity, bringing rain, snow and winds that can cause more significant damage and outages. That is why we believe building resiliency is critical at the home, business and community level. Siting solar where it has the greatest ability to create this resiliency should be the priority. This means locations where solar is tied directly to load, i.e. feeding homes and businesses, and critical infrastructure directly. This also would help ameliorate the grid constraints and interconnection cost issues we have seen over time. Therefore, regardless of the entity(ies) involved in determining preferred siting, GMP recommends that preferred siting focus on installations on top of and directly next to the load that they serve, and would also recommend preference be given to solar installations that are paired with storage and configured to allow immediately or at some point in the future self-sufficiency during limited duration outages.

Respondent: Josh Castonguay and Robert Dostis

Q17. Which entity should be responsible for making a determination that a preferred site meets the applicable standards and criteria? Should it be the local planning body, the regional planning body, or the local legislative body? Or all three?

A17. See response to Question 16. The PUC should continue to oversee all decisions concerning grid interconnections, stability and reliability.

Respondent: Josh Castonguay and Robert Dostis

Q18. What procedures should regional and local bodies follow before designating a site as preferred? Should notice be provided to adjoining landowners and the public before this decision is rendered?

A18. See response to Question 16 and 17.

Respondent: Josh Castonguay and Robert Dostis

Q19. What information should applicants be required to provide to regional and local bodies before a site is designated as preferred?

A19. See response to Question 16 and 17.

Respondent: Josh Castonguay and Robert Dostis

Q20. Should a local determination that a site is or is not a preferred site be subject to review by the Commission? If so, what procedures should the Commission use to review such determinations?

A20. See response to Question 16 and 17.

Respondent: Josh Castonguay and Robert Dostis

Q.21 The Commission is seeking to streamline the net-metering registration/interconnection process and to reduce the need for amendments to net-metering registrations. Attached is a worksheet (Attachment B) with questions related to the fields contained in the net metering registration form. The goal is to determine whether the form is collecting necessary information and whether any fields should be altered, added, or removed.

A.21 See Attachment GMP.1.21 – GMP Net Metering Registration Process Response

Respondent: Michael Butler

Dated this 1st day of November, 2019.

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