Department of Public Service Report on Public Utility Commission Net-Metering Information Requests (19-0855-RULE)

I. Overview

The Department of Public Service ("Department") provides the following report in response to the Public Utility Commission's ("Commission") request for additional information, relating to the Rule 5.100 rulemaking in Case No. 19-0855-RULE, issued on August 22, 2019. This report begins with an overview of the Department's position.

Section II of this report discusses the 2016 Vermont Comprehensive Energy Plan and net-metering; whereas Section III further discusses the value of net-metering. Section IV describes the Department's straw proposal for net-metering compensation structure and suggests that the Commission conduct a stakeholder process to develop a compensation structure that minimizes cost shifts. The avoided cost of solar generation, the renewable technology used by most net-metering facilities, is discussed in Section V. The Department's comments regarding preferred siting and the joint letter provision are addressed below, in sections VI and VIII – Response to Commission Questions. The Department makes recommendations regarding interconnection applications for net-metered systems in section VII and in its mark up of "Attachment B." Answers to the Commission's enumerated questions are provided in section VIII.

To date, Vermont's net-metering program has proven to be a success in spurring the development of renewable distributed generation in Vermont. The amount of installed capacity through net-metering in Vermont has increased by 344% since 2014, and thousands of Vermonters now participate in the net-metering program. As a percentage of load, Vermont has the highest amount of installed distributed solar in the region, with distributed solar generation in the State now accounting for roughly 325 MW relative to a 2019 summer peak of just over 900 MW. The renewable sector represents almost half of clean energy jobs in the State and contributes significantly to the economy of Vermont. In addition, the siting adjusters have contributed to the placement of solar and net-metered systems on sites that generally enjoy community support.

Renewable generation in Vermont has seen significant strides in recent years. The introduction of the Renewable Energy Standard in 2017 results in retirement of renewable energy credits for 63% of Vermont's load, a considerable improvement over the 42% of Vermont's load that was met with renewable resources in 2016.[1] This puts the renewable sector on a clear path to meeting renewable and climate goals in the electric sector, and puts the electric sector far in advance of the transportation and thermal sectors in terms of achieving necessary carbon reductions.

The successful deployment of distributed solar, along with other regional changes both in Vermont and across New England, has fundamentally changed the value of solar. Vermont peaks typically occur after dark in every month of the year, and the regional peak is moving to later in the day. Wholesale energy prices are generally higher during the winter months. From a distribution perspective, higher rates of solar are raising new challenges, with distributed solar more likely to aggravate transmission and distribution constraints than help to minimize them.

The success of net-metering was driven by many factors, including the declining costs of solar modules and inverters in the US, declining installation costs, and more innovative financing structures such as solar leases. However, the most significant factor in the rapid deployment of net-metering systems has been the compensation that has been paid to net-metering systems.

Based upon the current ratepayer costs of net-metered solar relative to its value, the Department recommends that the Commission pursue a process that changes the net-metering compensation structure to minimize cost shifts between participating and non-participating customers. From a societal perspective, the same carbon reduction benefits as net-metered solar are currently being achieved at significantly lower cost through development of larger-scale solar and it is important that the compensation structure for net-metering reflect the system value being provided.

[1]The renewable portion of Vermont's 2016 load was primarily imported from Hydro-Quebec and existing hydroelectric power.

Of particular concern, the compensation for the portion of net-metering that is exported to the grid, rather than used on-site, has resulted in a significant cost shift to non-participating customers. The Department's straw compensation proposal is primarily focused on this export-based cost shifting component.

The Department's straw proposal would move to a compensation structure where excess generation, beyond what is used by the customer on premises during that month, is compensated based on the value of that energy to the system. However, recognizing that there is value in market stability, the Department recommends further process to discuss phasing in changes to compensation over time. The Department is not currently suggesting locational adjustments, which would send the appropriate price signals to convey where additional distributed generation would be beneficial or detrimental to the system. However, this issue should be discussed further in any subsequent process regarding compensation.

As the amount of renewable generation increases in Vermont, it is vital to ensure that there continues to be community support for the siting process. The increased focus on regional and municipal comprehensive energy planning has led to the identification of areas most suitable, from a community perspective, for siting renewable generation. The Department supports the ability of municipalities to express preferences for siting location. The Department's comments regarding siting are addressed below, in sections VI and VIII – Response to Commission Questions.

The interconnection of distributed generation has become an increasingly important issue. The Department makes recommendations regarding interconnection applications for net-metered systems in section VII and in its mark up of "Attachment B." This issue should also be considered in the Rule 5.500 rulemaking, Case No. 19-0856-RULE. The Department maintains that the most sustainable and efficient path is to separate interconnection review from the permitting review. It may be entirely appropriate to allow permitting of a rooftop 500 kW project through a one-page application form, but an interconnection review process could be significantly more complicated. For example, having one form for permitting review of any renewable project over 15 kW and a separate form for interconnection review would not significantly add to the application process for developers but would greatly streamline the interconnection and permitting review process for the Commission, distribution utilities, and the Department.

Reducing carbon is a necessity, and the Department's move to lower net-metering costs will assist with meeting this need. Over time, rates of net-metering may decline under the Department's proposed changes to the net-metering compensation structure. However, the State's renewable energy requirements will still be met, and at lower cost. This reduction in electricity cost trends, in turn, will help Vermont achieve overall greater carbon reductions by enabling a more cost-effective transition to electric vehicles and heat pumps.

II. Comprehensive Energy Plan and Net-Metering

The Vermont 2016 Comprehensive Energy Plan ("CEP") sets a total energy goal of 90% renewable by 2050 and a reduction in greenhouse gas emissions from energy use to 80-95% below 1990 levels by 2050. To be clear, the 90% by 2050 goal is not limited to the electric sector. As explained in the Department's 2019 Annual Energy Report,[2] the most difficult sectors to decarbonize will be the thermal and transportation sectors. These sectors represented 67% of Vermont's greenhouse gas emissions in 2015, compared to 10% for the electric sector.[3] A pie chart depicting individual sector's contribution to Vermont's greenhouse gas emissions is provided below.

[2] VERMONT DEPARTMENT OF PUBLIC SERVICE ANNUAL ENERGY REPORT (Jan. 15, 2019), *available at*: https://legislature.vermont.gov/assets/Legislative-Reports/Annual-202be-report-final.pdf.

[3] VERMONT GREENHOUSE GAS INVENTORY UPDATE: BRIEF 1990-2015 (June, 2018) at 6, *available at*: https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2015.pdf. Additionally, the 10% value for Vermont's emissions from the electric sector does not account for the 2017 introduction of the Renewable Energy Standard, which will result in decreased greenhouse gas emissions from this sector.

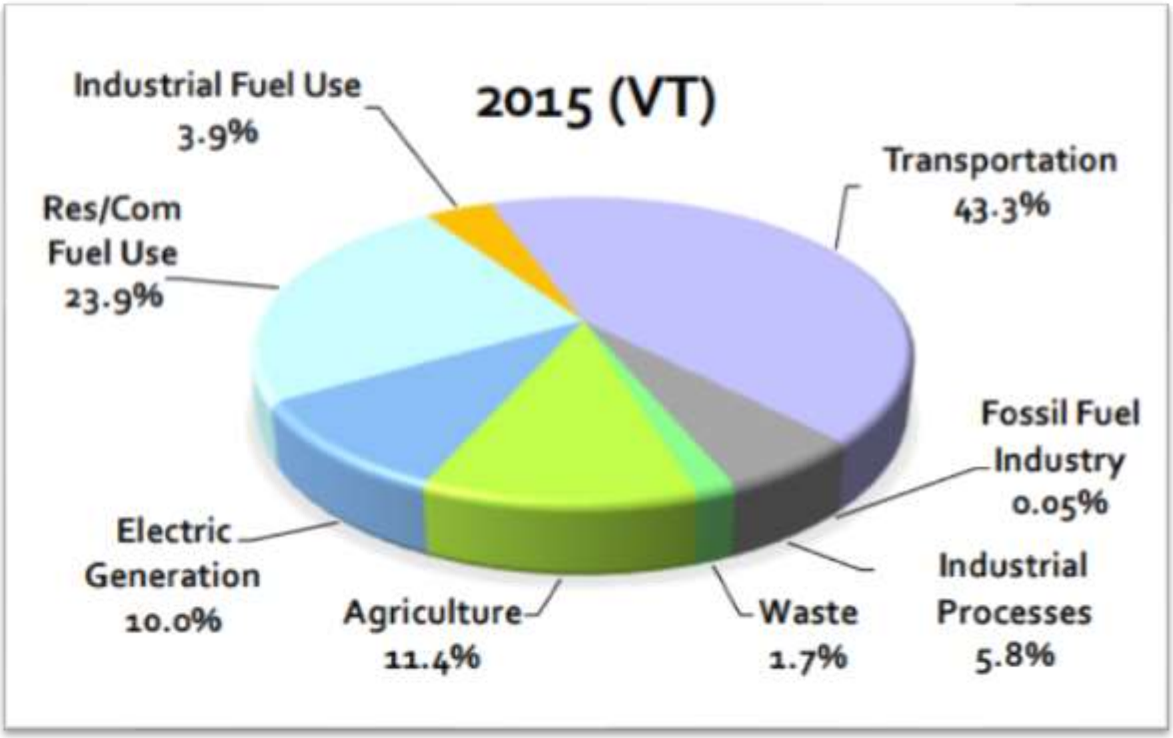

Figure 5. Sector Emissions Contribution Percentages. From, VERMONT GREENHOUSE GAS INVENTORY UPDATE: BRIEF 1990-2015 (June, 2018) at 6, *available at*: https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2015.pdf.

If Vermont intends to meaningfully reduce its carbon emissions, the transportation and thermal sectors must be a priority.

With respect to renewable electric power, the 2016 CEP sets a goal of 67% by 2025, which is roughly the amount required by that date under the Renewable Energy Standard ("RES"). The 2016 CEP's electric power goals do not establish a percentage that must be met by in-state distributed resources. However, the CEP includes an expectation as to the percentage: "[t]he distributed projects that these programs [net-metering, standard offer, etc.] have facilitated account for 2.5% of Vermont's total electric supply – and that number is expected to rise to 12% or more by 2032 under the RES."[4] This expectation is consistent with other language that makes clear that the 2016 CEP does not supplant the RES or otherwise call for more renewable electric generation than is required by statute. Rather, "[p]ower

[4] VERMONT DEPARTMENT OF PUBLIC SERVICE COMPREHENSIVE ENERGY PLAN at 243 (2016), *available at*: https://outside.vermont.gov/sov/webservices/Shared%20Documents/2016CEP_Final.pdf.

supply questions now revolve around the most cost-effective way to meet the RES requirements, not around how much renewable energy to acquire."[5]

With respect to net-metering as an energy supply resource, the 2016 CEP states:

> Over the coming years, net metering has great potential to be a primary method for the development of small-scale renewable electric generators in Vermont. Tier 2 of the Renewable Energy Standard requires development of new distributed generation at a sustained pace, likely to exceed 20 MW per year for the next 15 years. Because net metering provides an appropriate tool to develop a significant portion of this generation, it is critical that the state implement a program that is financially sustainable over the long term and avoids boom-and-bust cycles. This requires allowing participation from a wide range of possible customers, in each utility service territory, while being financially sustainable for both participating and non-participating customers, as well as for the firms that develop and install generators.[6]

This language was written prior to the adoption of the current net-metering rule and at a time when the Department was advocating for a "value of solar" approach to compensation for net-metering. The resulting deployment has shown that the compensation under the existing structure has provided value to participating customers and installers; however, based upon the Department's analysis, the current net-metering program is not financially sustainable for non-participating customers.

In addition, the pace of net-metering over the past three years has significantly exceeded the pace required to meet Tier II of the RES. Tier II requires approximately 27 MW of solar resources, statewide, each year in order to meet the statutory requirement. However, the amount of net-metering installed in 2017 and 2018 was 42 MW and 34 MW, respectively.[7] This pace is inconsistent with the

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[5] *Id*. at 277. *See also* the statement of the PUC on this issue, in *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 5/1/18 at 29 (*quoting* "With respect to electric supply, the CEP recognizes that the consideration of future supply should be done in the context of the RES.").
[6] CEP at 257.
[7] These numbers provide a statewide overview; for some distribution utilities, the proportion of net-metering to the Tier II requirement could differ significantly.

concept, contained in the CEP, that the pace of net-metering should be consistent with the pace of the RES Tier II requirements.

The cost pressure of net-metering has undesirable implications for meeting Vermont's total climate goals. The 2016 CEP recommendations for the electric sector – which tracks the RES requirements – is being met with relative ease in contrast to the transformation of the transportation and heating sectors, which is crucial to meeting the 90% by 2050 goal. A significant portion of the transformation of these sectors will be switching from combustion vehicles to electric vehicles and from fossil-fueled boilers and furnaces to cold climate heat pumps. These technologies significantly reduce fossil fuel usage, in large part because the process of combustion is inherently inefficient.

Given that customers are much more likely to switch to electric technologies if the economics favor this decision, the cost of electricity will have a significant impact on the pace of electrification. More progressive rate designs can assist in lowering the cost of charging electric vehicles or heating with cold climate heat pumps; however, the total electric system must still be paid for by ratepayers.

Supplying these additional loads with renewable electricity will be critical to meeting the 90% by 2050 goal and the RES. However, increased costs (such as compensating net-metering resources more than necessary or building out the distribution and transmission system, to reduce curtailment in certain areas, and enable more generation to be added to the Vermont grid) must still be borne by all electric users. These increased costs hinder the transformation of the transportation and thermal sectors toward lower carbon electrification measures.

III. Considerations Regarding the Value of Net-Metering

The current net-metering program provides both benefits and costs to Vermont. The net-metering program was designed to promote an industry with the expectation that distributed generation could become cost competitive with other power supply resources. Although the Department is proposing a straw compensation structure that is designed only to minimize cost shifts between participating and non-participating customers, the Department also recognizes that a clinical review of the power supply costs of net-metering does not fully account for additional benefits that are not accounted for in that analysis, such as economic development and increased customer engagement on energy issues. There is also the statutory support for net-metering contained in 30 V.S.A. § 8010. Set forth below are general considerations regarding the value of net-metering that are relevant for determining the appropriate compensation structure.

A. Value to ratepayers

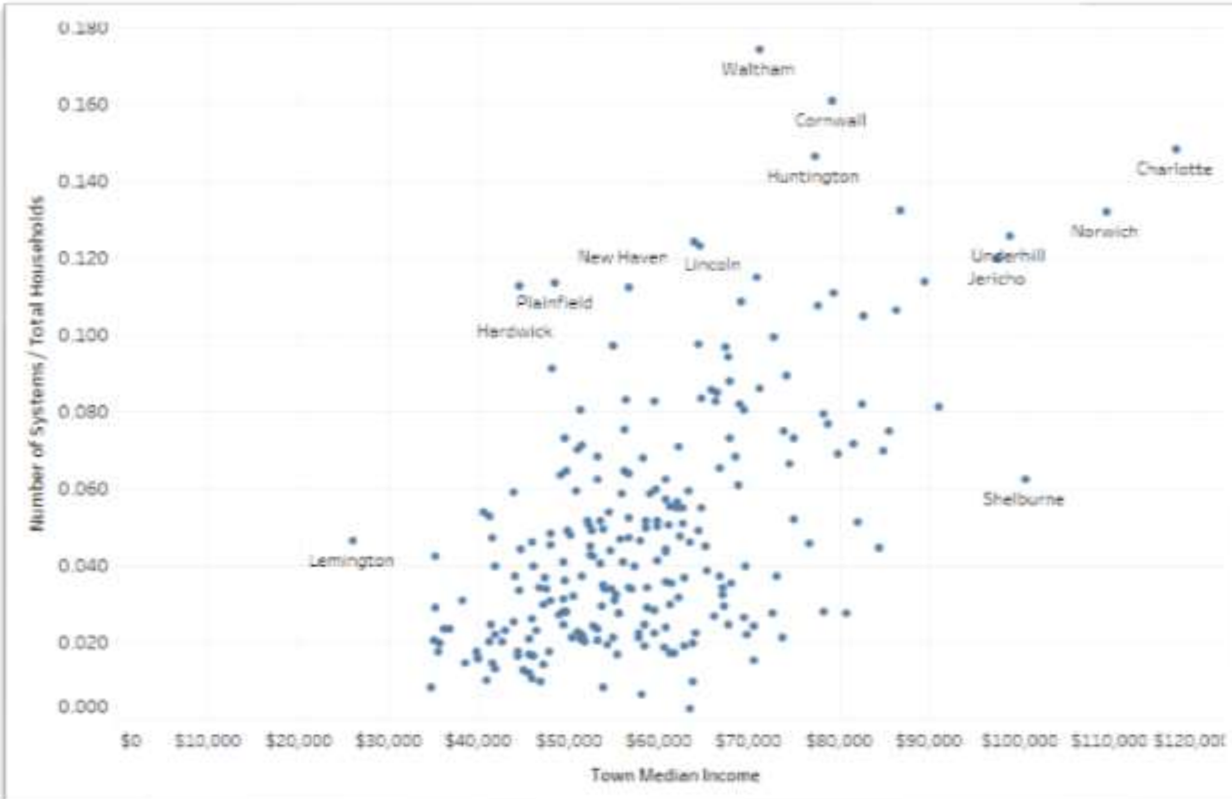
Customers that participate in net-metering can offset significant portions of their electric bill, which provides an economic benefit to participating customers. It is also reasonable to conclude that a net-metering customer will be more engaged on energy issues and therefore more likely to pursue additional measures to increase use of renewable resources.

However, net-metering also represents a cost shift to non-participating ratepayers because the avoided cost of solar is significantly lower than the current net-metering compensation rate. Appendix I sets out the Department's calculation of the value of solar and compares this to the current compensation structure.
In addition, the Department is concerned that there is an inequitable distribution of the costs of net-metering. As Efficiency Vermont noted in its 2019 Vermont Energy Burden Report: "[t]he most widespread adoption of clean energy technologies and efficiency appears to be in communities with the lowest energy burden. In other words, energy transformation is primarily in the purview of those who can afford the upfront cost."[8] A town-level comparison of household income and the locations of residential-scale solar net-metering shows moderate correlation between high earning towns and higher solar adoption rates. A household in a high earning town is more likely to have a solar system than a household in a low earning town. This holds true in all regions of the state, and in 13 of 14 counties.[9] This relationship can

[8] 2019 VERMONT ENERGY BURDEN REPORT at 23 (Oct. 2019), *available at*: https://www.efficiencyvermont.com/Media/Default/docs/white-papers/2019%20Vermont%20Energy%20Burden%20Report.pdf

[9] Median household income for cities and towns is based on American Community Survey five-year estimates (2013-2017) issued by the US Census Bureau. Households are individual housing units, including apartments, but exclude group quarters (such as dormitories) and their residents. The American Community Survey interviews a sample of Vermonters each year (8,100 households in 2018). The Census Bureau calculates more accurate estimates of town-level median household income by combining information reported over five years of interviewing.
Solar net-metering system count and capacity is drawn from project data reported by the distribution utilities to Energy Action Network and compiled by the Department. In order to limit the database to customer-sited systems, projects with AC capacity of 15 kW above are excluded.

be seen in the graph below. This inequitable distribution of the benefits of net-metering makes the cost shift to non-participating customers more problematic.



B. Value of economic development

According to the 2019 Vermont Clean Energy Industry Report prepared by the Clean Energy Development Fund,[10] the number of Vermont jobs associated with renewable energy in 2019 is expected to be 6,114. These are meaningful jobs that contribute to the Vermont economy.

However, it should be acknowledged that these jobs come at a net cost under the existing framework of net-metering incentives, especially compared to alternative resources designed to meet Tier II of the RES. While subsidies are ubiquitous in many job sectors, it is useful to recognize the extent of the subsidy in order to make an informed policy decision. The existing framework for net-metering provides jobs

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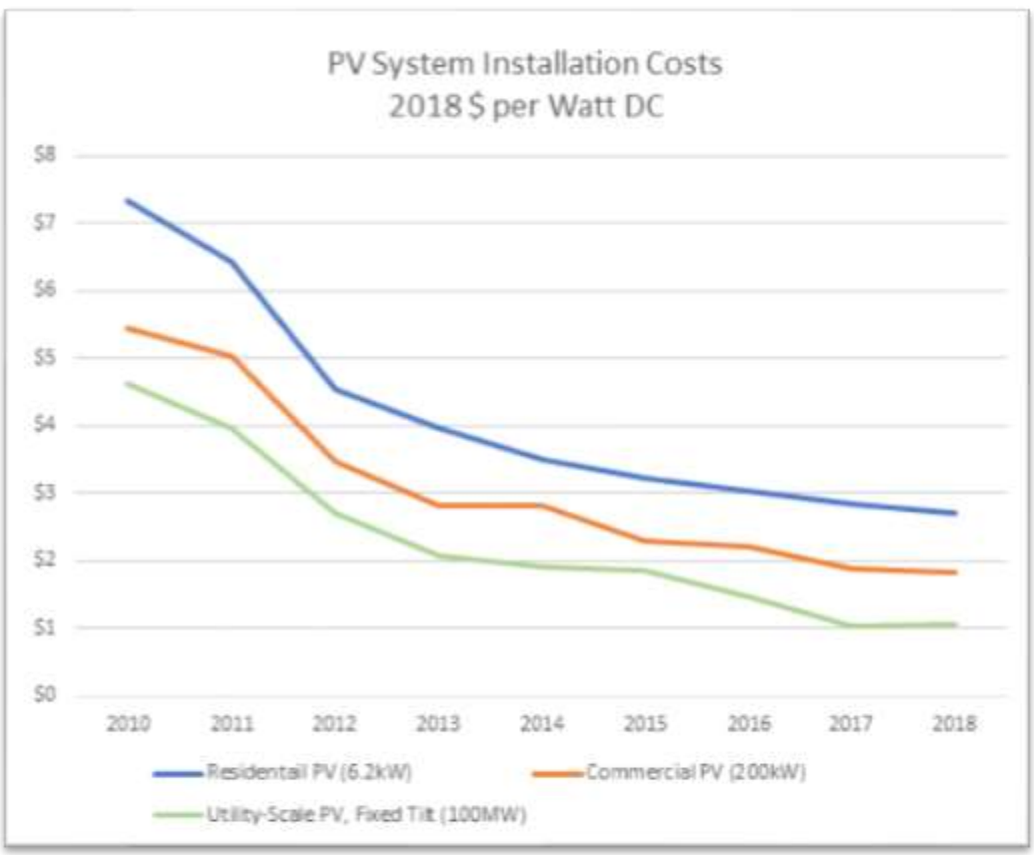
Non-residential systems are excluded for all utilities except VPPSA, for which all customer types are included because VPPSA did not specify customer type.

[10] 2019 VERMONT CLEAN ENERGY INDUSTRY REPORT, *available at*: https://publicservice.vermont.gov/sites/dps/files/documents/2019%20Vermont%20Clean%20Energy%20Industry%20Report.pdf.

but does so in a way that results in economic distortion. To the extent that electric rates are higher than they could otherwise be, there is less disposable income and therefore less economic activity across the Vermont economy.

It is also useful to review the costs associated with solar development. Although the installed costs of solar are not synonymous with the system value of solar, it provides some indication as to whether compensation is in-line with cost trends. As net-metering installers are typically private commercial enterprises, the actual installed costs are not generally available for Vermont projects. However, the National Renewable Energy Laboratory issues an annual report on the installed costs of solar. The charts below depict the declining costs of solar over the past several years. Compensation paid to net-metering resources has not seen a corresponding reduction of the same magnitude, which suggests a reassessment of the compensation structure is overdue.



Source: U.S. SOLAR PHOTOVOLTAIC SYSTEM COST BENCHMARK: Q1 2018, National Renewable Energy Laboratory, *available at* https://www.nrel.gov/docs/fy19osti/72399.pdf.

C. Value to the Grid

There are several instances in statute where distributed generation, including net-metering, is presumed to provide value to the grid when those values are not always provided in fact. For example, Section 8010 specifically requires the Commission to consider, in the costs and benefits of net-metering, "the potential for net metering to contribute toward relieving supply constraints in the transmission and distribution systems…."[11]

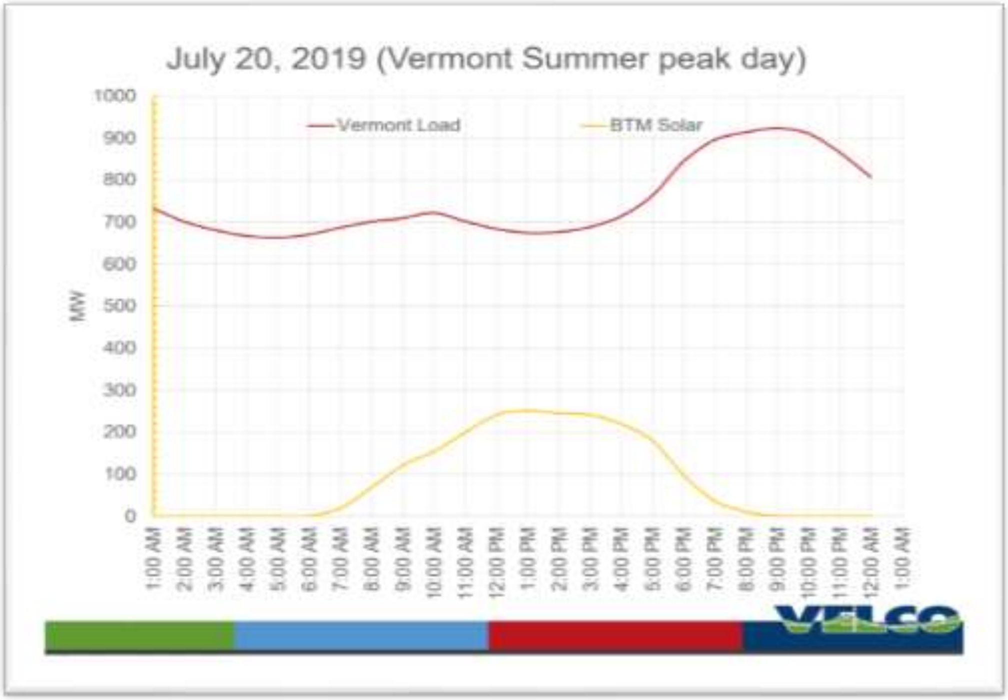
Distributed generation can provide value to the grid in cases where load growth is likely to lead to the need for infrastructure upgrades. However, overall load in Vermont has been flat, and is expected to have minimal growth in the medium term.[12] As such, distributed generation does not always relieve supply constraints.

Also, the output of distributed solar generation does not currently coincide with the peak load on the system (this is due in part to the amount of distributed solar already on the system) and therefore has diminished value as a load reducer and peak shaver. The figure below depicts Vermont's statewide load during the peak summer day in 2019, along with the output of solar generation during that day.[13]

[11] 30 V.S.A. § 8010(c)(1)(D).

[12] VELCO, 2018 VERMONT LONG-RANGE TRANSMISSION PLAN (Apr.18, 2018) at 19, 30, *available at*: https://www.velco.com/assets/documents/2018LRTP_PublicReviewDraft_rev1.pdf. However, a significant breakthrough in electric vehicle costs, capabilities, and availability would likely result in a higher rate of load growth in the medium term.

[13] VELCO, HISTORICAL LOAD REVIEW (Oct. 16, 2019) at slide 12, Present at the Vermont System Planning Committee Quarterly Meeting, *available at*: https://www.vermontspc.com/library/document/download/6763/Historical_load_review_Oct_2019.pdf.



Even in a situation with increased load growth (for example, if electric heating and transportation became more broadly adopted), it is important that the output of distributed generation coincide with the new load coming onto the system for full benefits to be realized. For example, the California Energy Commission and National Renewable Energy Laboratory projected weekday charging load profiles for California in 2025,[14] and this projection demonstrates that, absent utility intervention, most electric vehicle ("EV") charging will occur outside the time of solar production.

[14] CALIFORNIA ENERGY COMMISSION STAFF REPORT, CALIFORNIA PLUG-IN ELECTRIC VEHICLE INFRASTRUCTURE PROJECTIONS: 2017-2025, at 27 (March 2018), *available at,* https://www.nrel.gov/docs/fy18osti/70893.pdf.

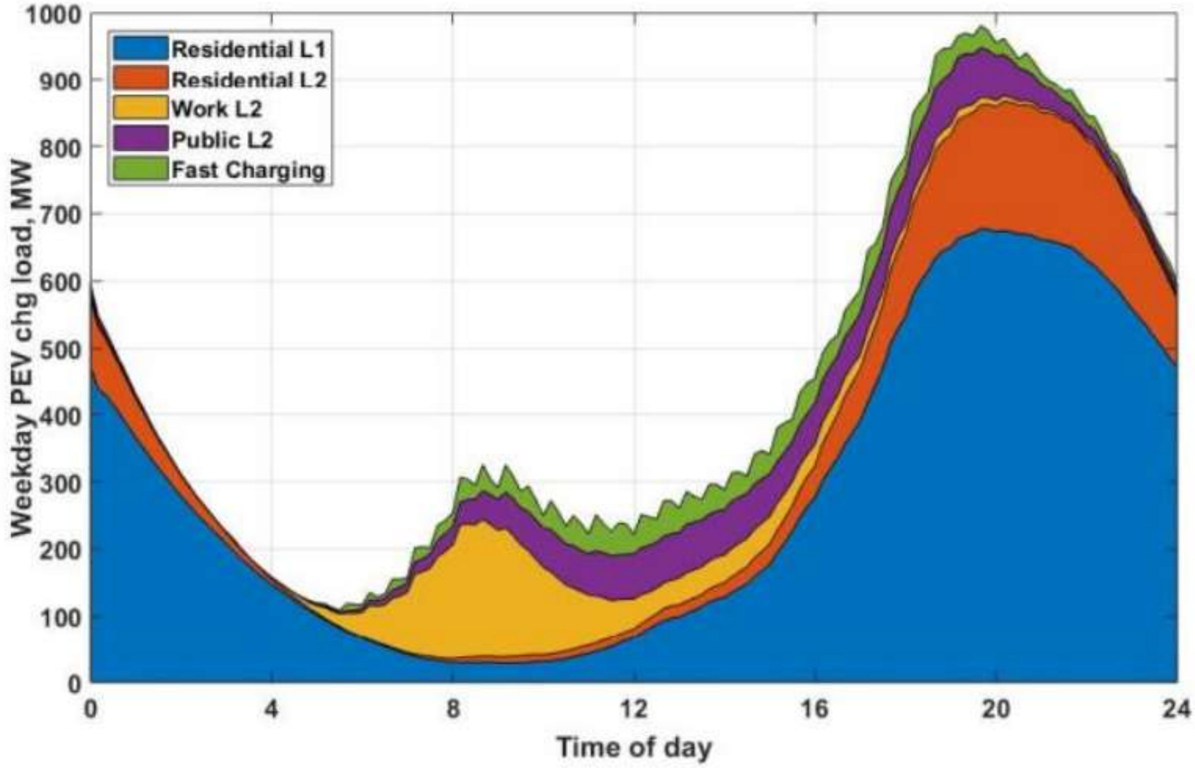


Figure 4.3: The Statewide Aggregated Electricity Load for a Typical Weekday (Source data from the National Renewable Energy Laboratory and the California Energy Commission). CALIFORNIA ENERGY COMMISSION STAFF REPORT, CALIFORNIA PLUG-IN ELECTRIC VEHICLE INFRASTRUCTURE PROJECTIONS: 2017-2025, at 27 (March 2018), *available at,* https://www.nrel.gov/docs/fy18osti/70893.pdf.

The Department has been working with utilities to determine best practices for peak load management of Tier III resources such as EVs; however, this work will require further efforts. In addition, battery storage has the potential to better coordinate intermittent generation with load. With both load management practices and storage, the distributed generation, by itself, is not providing value to the distribution system, but is only made valuable with increased infrastructure and costs from utility load control and/or battery storage.

The seasonal nature of solar resources, combined with a compensation structure that allows annual netting and therefore excess production during several months a year, results in potentially negative impacts from net-metering from a grid perspective. Residential solar PV typically has a capacity factor in the range of

14%.[15] A high penetration of solar generation means that solar energy is being put on the system during a relatively small number of hours per year.

Currently, distributed generation is becoming more likely to cause distribution and transmission issues than to resolve them, at least in some areas where loads are low relative to generation already on the circuit. These impacts can be mitigated through interconnection review, including efforts such as the implementation of IEEE 1547, ISO-NE's Source Requirements Document ("SRD") ride-through requirements,[16] and Transmission Ground Fault Over-Voltage requirements.[17]

IV. Proposed Compensation Structure

Based upon the considerations listed above, the Department submits this straw proposal for a compensation scheme that would eliminate the cost shift between net-metered and non-participating customers.

A compensation structure designed to minimize the cost shift between participating and non-participating customers would allow net-metering customers to offset usage each month (and consequently be compensated for that portion of generation at the retail rate), but would compensate excess generation from that month at the system value of that exported energy rather than at the retail rate.[18] The Department recommends that the Commission conduct further process regarding the appropriate compensation structure. However, the framework described below could be used as a straw document for discussion.

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[15] For example, a 1 kW solar project will produce, on average, 1,226 kWh per year (1 kW * 8760 hours in a year * 14%). This number can vary depending on the configuration of the facility. For example, larger projects often have oversized the panels, compared to the inverter, to produce a capacity factor closer to 20%. On the other end of the spectrum, roof-mounted systems can have lower capacity factors, as most roofs in Vermont were not oriented with solar production in mind.

[16] *See,* IMPLEMENTATION OF THE REVISED IEEE STANDARD 1547 (Apr. 25, 2018), *available at*, https://www.vermontspc.com/library/document/download/6224/ISO_IEEE_1547_Presentation_to_Vermont_Planning_Meeting_Final.pdf; INVERTER SOURCE REQUIREMENT DOCUMENT OF ISO NEW ENGLAND (ISO-NE), *available at*, https://www.vermontspc.com/library/document/download/6225/a2_implementation_of_revised_ieee_standard_1547_iso_source_document.pdf.

[17] *See, e.g.*, *Tariff filing of Green Mountain Power Corporation for net-metering transmission ground-fault overvoltage ("TGFOV") fee and new generation resource rider*, Vermont Public Utility Commission, Case No. 19-0441-TF.

[18] For an overview of different compensation structures for distributed generation, *See generally*, GRID CONNECTED DISTRIBUTED GENERATION: COMPENSATION MECHANISM BASICS, National Renewable Energy Laboratory (2017), *available at* https://www.nrel.gov/docs/fy18osti/68469.pdf.

Under the existing net-metering structure, a participating customer is able to net out the entire kWh component of their bill over the course of a year. This necessarily requires over-generation during those portions of the year with sufficient solar production (late spring through early fall) and the usage of bill credits during the remainder of the year. While the credits generated in high-solar months help the net-metering customer offset his or her bill in the low-solar months, the utility and its ratepayers must still bear the costs of supplying energy in the low-solar months (not to mention the costs of handling generation in excess of customer needs in the high-solar months).

Under the Department's straw proposal, a customer would be able to net out on-site consumption and generation in real time. The customer would not receive any bill credit for this netted generation but also would not pay the retail rate for the offset consumption. The Department's straw proposal would not require the utility pay for the REC value for this netted portion, as the avoided cost of the net-metered generation, including the REC value, will be lower than the retail rate.[19]

Any excess generation, beyond what is netted out through the customer's consumption, would be compensated on a monthly basis through a bill credit. The compensation of monthly excess generation would be set, upon the issuance of a certificate of public good ("CPG"), at a ten-year levelized price based on projected value of the output;[20] a customer would receive that set price for excess generation for a ten-year period. The projected value would consist of projected energy, capacity, and REC prices during that ten-year period, and this excess compensation value would be adjusted on an annual basis for new projects. In addition, the customer would be able to decide whether to retain the REC and receive lower compensation for excess generation. As calculated by the Department, a levelized, ten-year forecasted value of solar (including energy, capacity, and RECs) is approximately $0.092/kWh. The difference between the current bill credit and this

[19] In addition, it is worth considering whether the netted generation should be eligible for RES compliance, and therefore have some REC value, or whether the netted generation should only be considered as a reduction in load (and therefore a reduction in RES requirements).
[20] Because these values would vary significantly depending on the generation type, different excess compensation values would be determined for different resources – in this filing, the Department focuses exclusively on solar as this represents most net-metered installations.

forecasted value represents the cost shift between participating and non-participating customers.

Under this straw model, where excess generation exported to the grid is compensated at the utility's avoided cost, the primary incentive for the net-metering customer would be to maximize the ability of on-site generation to offset load.

With the availability of smart devices and increased customer engagement, customers have more ability to control load and therefore better align consumption and net-metering production. Increased availability of residential-scale battery storage could also provide an opportunity for customers to align consumption and output.

In addition, the adoption of time-of-use ("TOU") rates could further enhance the system value of net-metering by sending the appropriate signal as to the system value of the net-metering resource. For example, a retail rate that is higher after dark in the winter than the retail rate in the middle of the day during summer would better reflect the wholesale price of energy and could provide an incentive to net-metering customers to reduce consumption during the high price hours.

One of the benefits attributed to net-metering is increased customer engagement with renewable energy. To the extent that customers do have greater engagement, it is useful to craft a compensation structure that reflects the value of the resource. The current net-metering structure indicates to customers that installing a solar resource has year-round value, as the compensation structure allows customers to net out the power supply component of the bill on an annual basis. In actuality, there is significant difference in the monthly output of solar and the value of the production on an hourly and seasonal basis.

The proposed straw compensation structure would better correlate the value of the generation with the timing of production. By allowing annual netting, the current compensation structure encourages significant overgeneration, compared to load, during several months of the year. These customers then draw down these seasonally acquired credits during the remainder of the year. The concern with this approach is that this results in overgeneration during a period where wholesale electricity prices are relatively low (due in part to significant amounts of solar generation on the New England system) and emissions are also relatively low. In many areas, the excess generation being exported onto the distribution system is causing constraints on the distribution or transmission system.

The negative aspect of a monthly compensation structure is that a customer with a rooftop capable of 10 kW might decide to install only 5 kW as the increased generation does not provide as much economic return. Consequently, there is reduced incentive to build on existing structures.

With respect to virtual net-metering, this resource provides an opportunity for electric customers that either do not own their own residences or that have residences without good solar potential to participate in net-metering. A significant difference between on-site net-metering virtual net-metering is the fact that virtual net-metering does not directly reduce on-site load but is rather a purely financial transaction where electric customers are able to reduce their electric bills and developers are able to finance generation facilities.

Currently, customers who participate in virtual net-metering receive a set dollar per kWh that is based on retail rate, plus REC and siting adjustors, for their share of the total production. This fails to reflect the fact that virtual net-metering does not provide any reduction in consumption and these resources are identical, from a system perspective, to merchant generation. Accordingly, the more appropriate compensation for virtual net-metering projects would be the avoided cost of the utility. Consequently, the Department's straw mechanism proposes to compensate any excess generation exported to the grid at the same ten-year levelized rate, regardless of whether the net-metering system is designed to be customer-sited or virtual.

There is a statutory 500 kW cap on the size of any net-metered project.[21] This prevents the economies of scale that allow for lower cost projects. Under the straw compensation structure set forth by the Department for virtual net-metering, the generation is valued at the forecasted system benefit and therefore there is not a need for a size cap, beyond the 5 MW limit set in Tier 2 of the RES.

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[21] 30 V.S.A. § 8002(16)(A).

In summary, the Department's proposed straw compensation structure would allow customers to use onsite generation to offset consumption each month, and any generation exported to the grid – whether virtual net-metering generation or monthly excess from onsite generation – would be compensated at the avoided cost of the resource. This straw compensation structure needs additional stakeholder input and discussion before the Commission.

V. Value of Solar

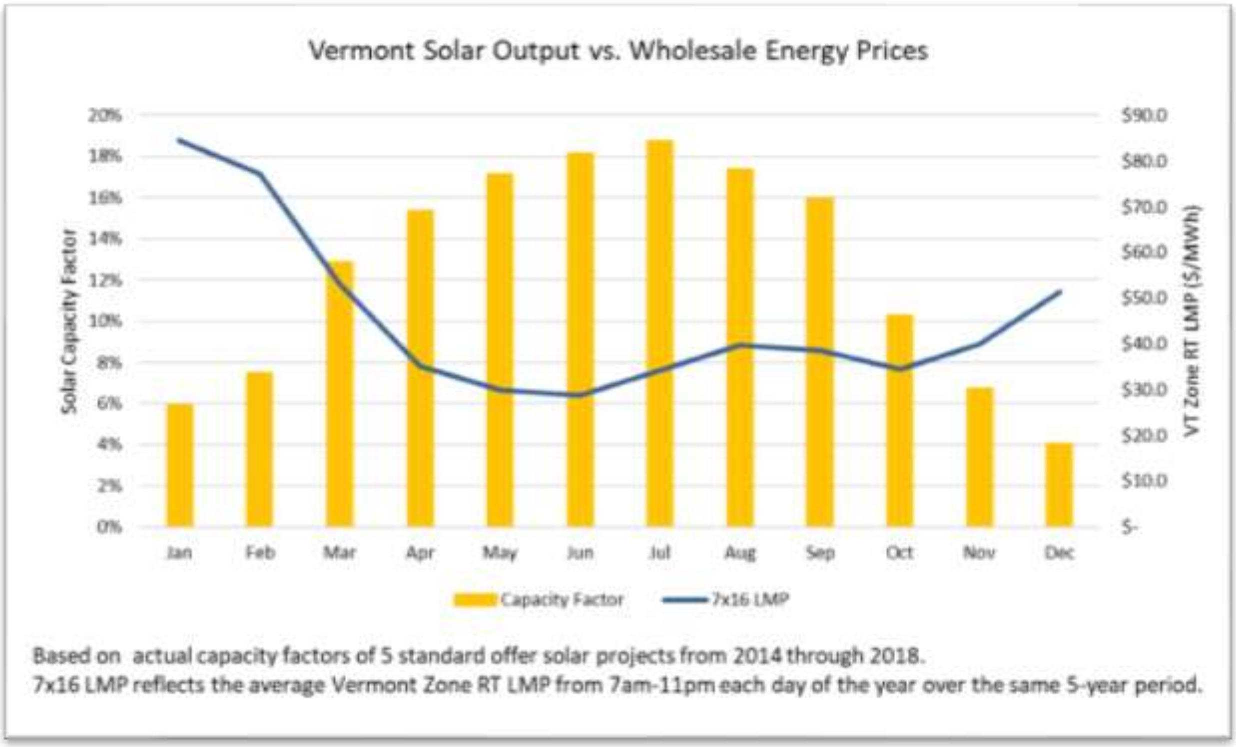
In order to determine whether the current net-metering structure results in cost shifts between participating and non-participating customers (which the Department has concluded it does), it is important to understand the value of the underlying resource. The vast majority of net-metered projects are solar. Consequently, the Department has analyzed the value of solar and compared this value to the current net-metering compensation. The Department's analysis uses an avoided cost approach – that is, if not for the output of a net-metering project, Vermont utilities would need to purchase energy, capacity, and renewable energy credits elsewhere. The avoided cost approach simply involves calculating the cost to the utility of purchasing those products through other means.

There are several components of this avoided cost analysis, which are broken down and described, below. The Department has developed 25-year price forecasts for four market products associated with solar generation but recommends only using the first 10-years in calculating the appropriate compensation. As with any forecast, the later years are more difficult to predict and have a greater degree of uncertainty. The forecast in the near-term should have greater accuracy and precision.

a) <u>Energy</u>

Every MWh produced by a net-metering project is a MWh not purchased through the ISO New England ("ISO-NE") wholesale electricity market. The ISO-NE market prices energy on a five-minute basis, with the prices fluctuating considerably over the course of the year. In order to understand the value of a resource such as solar, which is highly seasonal in output, it is useful to understand the wholesale price at the time of solar production, rather than relying on an annual average price which would mask seasonal variations in prices and production.

The chart below shows the average monthly wholesale energy prices over the past five years[22] and overlays the average monthly capacity factor of five representative standard offer solar projects.[23] As can be seen from the chart, the lowest energy prices tend to be in spring and fall, while the highest prices tend to be in winter. In other words, during the times when solar production is highest, wholesale prices tend to be low.



In addition, the Department analyzed the wholesale Vermont zonal price during the hours when solar is being produced to understand the relative value of solar production compared to the wholesale energy price. Over the last five years, the energy value of the solar output was worth approximately 8% less than the average wholesale energy price.

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[22] Monthly average prices were calculated based on hourly real-time Vermont zone clearing prices. This information can be downloaded here: ISO NEW ENGLAND, INC, PRICING REPORTS: SELECTABLE FINAL REAL-TIME HOURLY LMPS, *available at,* https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/final-lmp-by-node (Last visited Oct. 25, 2019).

[23] Monthly average capacity factors were calculated based on the actual hourly generation from 2014 through 2018 for Ferrisburg Solar Farm, South Burlington Solar Farm, SunGen1 Solar, White River Junction Solar Farm and Williamstown Solar Project. Each of these projects was commissioned before 2014 and has a contract through the Standard Offer Program.

The Department's wholesale energy price forecast is based on current New York Mercantile Exchange ("NYMEX") futures for ISO-NE day-ahead energy delivered to Mass Hub and natural gas ("NG") at Henry Hub. Current futures quotes are available through CME group.[24] ISO-NE energy futures are available through 2024, and NG futures are available through 2031. For the first 5 years, ISO-NE futures are used, then the price increases at the same escalation rate as NG futures because ISO-NE electric prices tend to be closely correlated to NG prices. Forecasting past 2031, prices increase at the escalation rate of Energy Information Administration's ("EIA") 2019 Annual Energy Outlook ("AEO") reference case natural gas forecast.[25]

The Department's forecasted wholesale energy price, including the adjustment for value at time of production, is listed in column B of Appendix I.

b) Capacity

Capacity, in this context, is the amount of resources needed to meet the New England peak hour per year. This value is based on a percentage of nameplate and is based upon an assessment of the likelihood that a resource will be providing energy during the peak hour. ISO-NE conducts an annual Forward Capacity Auction ("FCA") that procures resources three years in advance of delivery, so the wholesale price for capacity is known through 2022. For intermittent resources such as solar, ISO-NE estimates that a certain percentage of a facility's output will be generating during the peak hour. However, net-metering resources act as load-

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[24] CME Group provides publicly available information regarding energy futures, among other market products. This information is *available at*, https://www.cmegroup.com/trading/products/#pageNumber=1&sortAsc=false&sortField=oi (accessed October 10, 2019).

[25] EIA's *Annual Energy Outlook 2019 Reference Case* is a projection of domestic energy markets through 2050 that can be interpreted as a reasonable baseline case. It includes assumptions about macroeconomic growth, world oil prices, and technological progress. For instance, the Reference Case projection assumes improvement in known energy production, delivery, and consumption technology trends. The economic and demographic trends reflected in the Reference case reflect current views of leading economic forecasters and demographers. It generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period.

reducers and decrease the amount of capacity that the utility must procure in the FCA. Due to the structure of the FCA, utilities ultimately purchase capacity in excess of their actual load; this "reserve margin" is an additional benefit of net-metered generation and assumed to be 35% for all years for the forecast.

In addition, ISO-NE estimates that a solar resource's contribution during the New England peak will decline over time as the amount of solar PV in the region increases and the system peak moves to later in the day, when solar production diminishes.[26]

The Department's capacity forecast is based on actual cleared ISO-NE FCA prices through 2021, then escalates at the rate of the forecast in the Avoided Energy Supply Cost ("AESC") 2018 study.[27] The AESC forecast states that "the forecast capacity prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules." However, this forecast assumes a future with no new energy efficiency, resulting in higher prices than a future that includes efficiency measures. Additionally, since the AESC prices were developed, ISO-NE has updated its methodology for determining its load forecast and generator availability, which both reduce the Installed Capacity Requirement ("ICR") in the FCA. The lower ICR translates to lower demand in the capacity auction, and thus lower prices. The Department's capacity forecast is about 25% lower than the AESC forecast in the long-term.

The Department's forecasted wholesale capacity values, with the adjustments noted above, are included as column C of Appendix I.

c) RES Compliance

The Vermont Renewable Energy Standard ("RES") requires that utilities retire sufficient Renewable Energy Credits ("RECs") to meet 55% of retail sales in 2017,

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[26] ISO-NE FINAL 2019 PV FORECAST at 61 (Apr. 29, 2019), *available at*, https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf.

[27] AVOIDED ENERGY SUPPLY COSTS IN NEW ENGLAND, *available at,* https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england, (The full study with supporting materials can be found via the links on this webpage). The case, *Petition of Vermont Department of Public Service to open a proceeding to update EEU screening values including avoided costs, externality adjustments, and other EEU screening components*, Vermont Public Utility Commission Case No. 19-0397-PET, regarding those values is ongoing.

increasing each year to 75% in 2032. Tier 2 of the RES requires utilities to meet one percent of retail sales with RECs from renewable distributed generation[28] in 2017, increasing to 10% in 2032. Pursuant to 30 V.S.A. § 8010(c)(1)(H)(ii), utilities must retire the RECs associated with net-metering facilities, which are counted toward Tier 2 compliance.[29]

RECs are not traded on a single platform like wholesale energy and capacity. The Department analyzed broker sheets and discussed long-term REC price projections with brokers. New net-metering resources are currently compensated at $0.04/kWh for RECs (this represents the difference between the rate that a customer receives if they transfer RECs to the host utility or not). The Department forecasts Tier 2 RECs at $26 on a levelized 25-year basis (or $0.0260/kWh).

The Department's REC forecast is based on recent (9/3/2019) Class I broker quotes through 2025, then assumes a flat price of $25/REC in the long-term. Vermont Tier II RECs generally qualify as Class I RECs in neighboring states, and therefore Tier II and Class I REC prices are often similar, making Class I broker quotes a good proxy for Tier II prices. In the near-term, broker quotes reflect a generally balanced market, with some oversupply being banked for future years. There are many factors that can affect both the supply (new build generation, imports, biomass phase down, etc.) and demand (Regional Portfolio Standard ("RPS") requirement changes, additional programs, etc.) in either direction. Historically, REC markets have been very volatile and tend to close the trading year very high ($64/REC in 2013) or very low ($2/REC in 2017) as the actual supply and demand positions become known. The long-term price of $25/REC reflects a generally balanced market, but prices often settle closer to zero, or the Alternative Compliance Payment, by the end of a vintage's trading year. The delay of offshore wind has caused prices to rebound from recent lows, and the market is expected to remain relatively balanced in the long-term.

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[28] Eligible Tier 2 resources must be facilities with a nameplate capacity of less than 5 MW, commissioned after June 30, 2015, and interconnected to a Vermont distribution or subtransmission line.

[29] *Investigation re: establishment of the Renewable Energy Standard Program*, Docket No. 8550, Order implementing the Renewable Energy Standard at 19 (06/28/2016). *See also* 30 V.S.A. § 8005(a)(2)(B)(ii).

The Tier II criteria are narrower than Class I criteria, resulting in the potential for price separation between the two products, with Vermont Tier II RECs realizing a higher price. If there are not enough resources to meet Tier II demand, Tier II prices will increase. If the entire region is in a shortage, both Tier II and Class I REC prices will increase, likely in tandem. However, if there are sufficient resources to satisfy Class I obligations, but a shortage of Tier II resources, then there will price separation. For example, if large offshore wind resources are built and the supply of Class I RECs exceeds the demand, Class I prices will decrease. Offshore wind would not impact the supply of Tier II resources, and if Tier II obligations could not be met with small in-state generation, then Vermont Tier II prices would rise, while Class I prices fall.

The Department's REC price forecast is included in column G of Appendix I.

d) <u>Line losses</u>

As power is transmitted across the grid, line (and transformer) losses are incurred, typically on the transmission system and the distribution system. The Commission is exploring the appropriate value of line losses in, *Petition of Vermont Department of Public Service to open a proceeding to update EEU screening values including avoided costs, externality adjustments, and other EEU screening components*, Public Utility Commission Case No. 19-0397-PET, and the final determination in that case will be useful here.

The line losses calculated in that proceeding were specific to energy efficiency. The Department expects that transmission losses would be similar for net-metering resources as they are considered behind-the-meter resources from a regional perspective.

It is doubtful that a positive value for distribution losses would be appropriate for net-metered resources, however. For energy efficiency, there is no excess generation exported to the grid, as there is under the net-metering structure. Distributed generation can result in higher losses, particularly in constrained areas with significant amounts of generation on the distribution system. Consequently, there would need to be further thought as to whether line losses should appropriately be considered a positive or negative value with respect to net-metering.

Appendix I assumes transmission line losses of 8%, as seen in cell B5.

e) Avoided Transmission Costs

To the extent that solar reduces load during Vermont's monthly peak, Vermont utilities can avoid Regional Network Service ("RNS") charges, which are used to fund the region's bulk transmission grid. In the last five years, the peak hour occurred before dark in only five of those 60 months, or 8% of the time. Looking forward, solar production has a limited and generally declining value in reducing RNS charges.

The Department's forecast of RNS rates is based on the forecast through 2023 presented by the Participating Transmission Owners Administrative Committee at the July NEPOOL Reliability Committee meeting, then escalates at 2%.[30] Rates in the past 10-years have doubled as a result of the significant necessary investments in transmission upgrades, but going forward, those additional needs are expected to diminish. Additionally, the transmission system in the region has been overbuilt and significant transmission headroom exists, which makes load-driven transmission investments unlikely. However, investments will still be needed for ongoing asset condition maintenance and security improvements, contributing to slightly higher per kw-year rates.

Vermont Electric Power Company's ("VELCO") most recent Long-Range Transmission Plan ("LRTP") was completed in 2018 and presents a 20-year load forecast. The forecast is flat in the first 10 years but begins increasing in 2029 as the electrification of transportation and heating is more widely adopted.[31] While electrification is expected to contribute to increased energy consumption, in the near-term much of that load will be offset by net-metering, and the new load is expected to be managed, resulting in minimal peak load impacts. Based on these factors, the Department is escalating rates 2% in the long term.

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[30] July 16 & 17, 2019 NEPOOL Reliability Committee /Transmission Committee – Summer Meeting. RNS RATES: 2019-2023 PTF FORECAST, *available at* https://www.iso-ne.com/static-assets/documents/2019/07/a03_rc_tc_2019_07_16_17_five_year_forecast.pptx.

[31] 2017 LONG-TERM ELECTRIC ENERGY AND DEMAND FORECAST REPORT (Nov. 9, 2017), *available at*, https://www.vermontspc.com/library/document/download/5996/VELCO_FinalLoadForecast_2017.pdf. This reported informed VELCO's 2018 LRTP.

The Department's forecasted RNS reduction values in included in column F of Appendix I.

VI. Preferred Sites

The preferred sites construct generally directs net-metering development to areas that, in theory, are less likely to raise issues under the relevant criteria. It accomplishes this by providing a compensation differential for projects in preferred vs. not preferred areas. It also limits the ability of larger (> 150 kW, non-hydro) net-metering projects to proceed unless they are located on preferred sites. Most of the preferred site types direct projects to locations that have already been impacted by some type of development (e.g., rooftops, capped landfills, gravel pits, brownfields, etc.). Even the "on the same parcel or adjacent to the primary off-taker" preferred site category generally serves to direct development to (or adjacent to) previously developed areas.

The town-plan (or town-supported, in the case of the joint letter) preferred site type seeks a somewhat different objective – directing development to areas that are supported by local communities, as expressly provided in their land use plans or via a letter of support from the local and regional planning bodies and the local legislative body (on a case-by-case basis). Sites favored by local communities may encompass the other categories of preferred sites, but may also include some greenfields that, based on local planning and knowledge, are more suitable for development than others.

Act 174 of 2016 created a process by which regions and towns could undertake an analysis of their current and future total energy use, with the outcomes being used to create policies and detailed maps expressing potential and unsuitable areas for siting energy resources within their jurisdictions. The resulting plans that the Department has certified as Act 174 complaint, or in the case of municipalities, are so certified by qualified regional planning commissions, receive substantial deference – or greater say – in generation siting reviews before the Public Utility Commission.

The Commission's questions on preferred sites relate to what required standards or criteria should be applied by regional and local bodies when determining whether a site is preferred, and if towns and regions should follow certain procedures in the designation of preferred sites to ensure adequate notice and opportunity for input from the public.

The Department offers proposed options to address the Commission's questions regarding preferred sites below, in section VIII, but in general defers to the recommendations of regions and municipalities on matters relating to how they select locally preferred sites. The Department will review these recommendations for consideration.

VII. Administrative Issues

Included as Appendix II is the Department's marked-up copy of "Attachment B," the Commission's worksheet on net-metering registrations. The Department supports improving and streamlining the net-metering registration and application process where practicable. However, as stated in its May 17, 2019 comments, the Department maintains the net-metering registration contains grossly insufficient information to effectively serve as an interconnection application and enable full review, especially in the instance of larger[32] roof mounted projects. The Rule 5.500 application form requests more technical information, with which a study may be conducted, than "Attachment B."[33]

The ideal solution would be to separate out the interconnection and siting review processes and require any eligible projects to file applications under both Rule 5.100 and Rule 5.500. A roof-mounted 500 kW project could have no significant siting issues, but the interconnection review could be significant. Under the Department's proposal, the interconnection issues would be sorted out through the Rule 5.500 process and the function of Rule 5.100 would be adjusted to accommodate the Rule 5.500 interconnection review process (e.g. Rule 5.500 could be a prefiling requirement, Rule 5.100 applications could be stayed, timelines made to coincide, etc.).

[32] The Department recognizes that the level of interconnection study and review may vary by size of generator and the circumstances of the distribution utility circuit. As such, the Department requests utility comment on the necessary information as well as how storage technologies should be assessed in both this case and Case No. 19-0856-RULE.

[33] *See* VERMONT PUBLIC UTILITY COMMISSION ATTACHMENT 1 TO RULE 5.500, *available at* https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application_0.pdf.

To the extent that the Commission chooses to continue interconnection and siting review simultaneously, additional information would need to be included in the registration if it is to serve a dual purpose. If canopies are added to net-metering registrations, additional electrical safety information is also needed. The Department recommends that this issue be addressed in a workshop, after receipt of comments by stakeholders, as well as in case number 19-0856-RULE. The Department also wishes to engage in discussion about the role of storage technology in interconnection applications in both cases.

VIII. Responses to Commission Questions

Net-metering Compensation Structure

1. *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.*

The current net-metering compensation structure is causing a cost shift from customers that are not participating in net metering to customers who are participating in net metering. As noted in section IV, above, excess generation that is exported to the grid from a roof-mounted 15 kW system giving its RECs to the utility receives approximately $0.174/kWh (depending on the host utility's retail rate), whereas the system value of that excess generation is approximately $0.092/kWh.

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

The Department looks forward to reviewing the filings of the electric utilities regarding the impact of net-metering on retail rates.

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.

See Section IV, above, for the Department's straw proposal compensation structure that minimizes cost shifts between participating and non-participating customers.

4. 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.

The Renewable Energy Standard could be met with no net-metering. Tier 2 of the RES requires utilities to retire RECs from projects that are smaller than 5 MW, commissioned after June 30, 2015, and interconnected to a Vermont distribution or subtransmission circuit. There is no requirement that any portion of a utility's Tier 2 obligation be met through net-metering. Under the current net-metering compensation, the RES would be met at a much lower cost without net-metering. That said, appropriately compensated net-metered projects should be available to meet the Tier II requirement.

The following values are based on data that the Vermont utilities provide to ISO-NE on a quarterly (or in some cases monthly) basis. Currently, there is approximately 345 MW of distributed solar in Vermont, with about 216 MW of that in the net-metering program, 58 MW in the Standard Offer Program, and the remaining 71 MW either purchased by the utility through a Power Purchase Agreement ("PPA") or owned by the utility. Of the total distributed solar at least 209 MW cannot be used for RES compliance, with at least 161 MW of that unusable total from net-metering 1.0 and another 48 MW in Standard Offer, PPAs or utility owned that came online before July 2015. The remaining 135 MW of solar that is currently online can be used for RES compliance and meets roughly 3% of the state's load.

If Tier II were to be met entirely with solar (the projected total capacity needed to meet the 10% requirement in 2032 is 480 MW) an additional 345 MW would be needed. Under this scenario, the resulting total amount of distributed generation solar would be 689 MW in 2032 (209 MW non-RES + 135 MW RES on-line + 345 MW new RES).

Each year, the Tier II requirement increases by 0.6%. Assuming flat loads, that translates to about 27 MW of solar each year. Based on current installations, to satisfy Tier 2 of RES, Vermont would need an additional 18 MW of solar in 2021, and an additional 27 MW each year thereafter to meet the increasing Tier II requirement.

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

Sections III and IV set forth the Department's analysis of the benefits and costs of net-metering. However, it is important to not limit the analysis to benefits and costs. This is because, pursuant to 30 V.S.A. § 218c, lower cost alternatives should also be factored into the analysis. For example, a 4.9 MW solar project, financed through a utility Power Purchase Agreement, would meet carbon reduction and Tier II compliance goals in a much more cost-effective manner than a net-metering system under the current compensation structure.

6. 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.

Generally, the power supply benefits associated with net-metering accrue to all ratepayers, although as the Department notes above, these power supply benefits are being procured at costs that are significantly higher than alternative sources. Customers that participate in net-metering receive an increased benefit over non-participating customers. This is because customers that install net-metering can receive higher compensation for excess generation than the actual value.

There are also jobs associated with net-metering installations, and these jobs provide value to society, as a whole, through increased employment and taxes.

7. 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.

See Appendix I for the forecasted value of the power supply components of net-metered projects.

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

The Department recommends that the Commission consider a ten-year period. Forecasts beyond that period are generally not particularly helpful and run the risk of providing significant over or under-compensation for a resource. For example, a 30-year forecast of avoided cost rates under PUC Rule 4.100 resulted in payments to the Sheldon Springs hydroelectric at over $1,000/MWh for on-peak production. *See*, *VEPP, Inc. Petition Re: Sheldon Springs Hydro Rule 4.100 Project missing rate for December 1, 2017 Power Billing*, Public Utility Commission Case No. 17-4528-PET, Order of May 2, 2018 at 4.

9. 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.

The costs of net-metering are payments to participating customers for excess generation that is exported to the grid and paid at a greater rate than the value of that energy.

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

Ratepayers pay for the excess costs of net-metering.

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

The current net-metering rule results in cost shifts among ratepayers and procurement of renewable energy at a significantly higher cost than available alternatives. This increased cost pressure in the electric sector makes it difficult to further the transition of the transportation and thermal sectors to a lower carbon future through electrification measures such as electric vehicles and cold climate heat pumps.

12. 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.

See Section IV, above. Generally, the Department's straw proposal would allow customers to use onsite generation to offset consumption each month, and any generation exported to the grid – whether monthly excess from onsite generation or all virtual net metering generation – would be compensated at the avoided cost of the resource.

13. 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?

See Section IV, above. Generally, time-of-use retail rates would better align costs and benefits by sending more appropriate price signals as to the value of production from net-metered generation and encourage kWh consumption during times that net-metered generation is producing.

14. 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?

No. The General Assembly has set the pace and amount of required renewable electricity in Vermont. Regardless of whether a utility is meeting the minimum RES requirements or has voluntarily decided to be 100% renewable, under the current compensation structure, net-metering is displacing a lower cost renewable resource that provides carbon reduction benefits. Net-metering is not providing additional renewable resources under either scenario – if a utility is 100% renewable or some other percentage. Accordingly, the percentage that a utility is renewable is irrelevant.

Additionally, to the extent that a utility is 100% renewable, the only Tier II requirement is to offer a net-metering program. Absent a net-metering requirement, there is no requirement that a utility that is 100% renewable take any measures to procure local distributed resources. This is clearly counter to the intent of Tier II of the RES.

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

If the compensation for net-metering is structured appropriately to minimize cost shifts, it is unlikely that a limit on new net-metering would be necessary. To the extent that the Commission elects to continue compensating excess generation based upon retail rate, or some other measure that does not reflect the avoided cost value of the resource, the amount of net-metering should be limited to some percentage of the annual Tier 2 requirements.

<u>Preferred sites</u>

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

The Department recommends that the two existing options (i.e. identified in a town plan or letter(s) of support) should continue to be offered, with potential modifications. The existing "Option A," for a project in a specific location designated in a duly adopted municipal plan, could potentially be modified to acknowledge and make use of the extensive energy planning work undertaken by all regions – and many towns – since the passage of Act 174. Under Act 174, preferred sites are identified pursuant to a comprehensive, transparent, and consistent set of screening criteria designed to meet the needs of a variety of stakeholders. To incorporate Act 174, a Potential Modified Option A could read:

> A specific location<u>,</u> designated in a duly adopted municipal plan under 24 V.S.A. chapter 117 <u>with an enhanced energy plan that has been granted an affirmative determination of energy compliance under 24 V.S.A. 4352,</u> for the siting of a renewable energy plant or specific type or size of renewable energy plant, provided that the plant meets the siting criteria recommended in the plan for the location.

However, not all towns have "Act 174" plans as of yet, and some enhanced energy plans stop short of identifying preferred sites at the parcel level, hence the need to retain "Option B," the letter or letters of support. Based on comments submitted in this rulemaking to date, regions and towns appear to be generally supportive of the letter option but have asked to be able to submit separate letters (reflecting their status as separate parties). This separate letter allowance would be consistent with common practice before the Commission regarding joint letters.

Towns and regions have also recommended that the letters should discuss the site in terms compliance with plan land use policies, which if required could create more transparency around the designation of preferred sites. Because regions all have Act 174 plans that have received affirmative determinations, the land use policies therein are also likely to reflect their extensive energy planning work, including identification of potential and unsuitable areas for the siting of energy resources. To incorporate the recommendations of regions and towns, a Potential Modified Option B could read:

> A specific location that is identified in either a joint, or separate, letters of consistency with planning guidelines from the municipal legislative body and municipal and regional planning commissions in the community where the net-metering system will be located.

17. 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?

The Department recommends that the existing requirement for all three entities – the local and regional planning bodies as well as the local legislative body – to be involved in vetting preferred sites requests invites the most transparent and thorough process. Above, Potential Modified Option A incorporates all three entities in the decision-making process through the statutory process requirements for preparation and adoption of plans, including enhanced energy plans. Potential Modified Option B also incorporates the three diverse sets of perspectives.[34]

[34] The Department recommends preserving the status quo of requiring input from both the town selectboard and planning commission as this allows for transparency and ensures that project proposals be considered by the appropriate entities. However, the Department also notes that the Commission has held that town "planning commissions appear to be creatures of the municipality…" that are not "distinct from that of the municipal legislative body." *Petitions of Vermont Electric Power Company, Inc. (VELCO) and Green Mountain Power Corporation (GMP) for a certificate of*

18. 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?

All options above involve extensive public process (related to plan development process but also public meeting process). Currently, Option B may have less extensive process, since it does not reference a plan that would otherwise involve public input. As stated in the Commission's information request, concerns have been expressed as to what standards and process should be considered when a region or municipality decides whether to issue a letter of support.[35] These shortcomings could be remedied by adding (as suggested in the Department's May 17, 2019 comments) a requirement that the locations identified in the letter(s) of support be in areas identified as suitable for development in the applicable regional plan. Another, similar, option is to provide that the location be consistent with (and provide reference to) land use policies in duly adopted regional and municipal plans consistent with the proposed type and scale of development. This could provide a land-use planning basis for preferred site letters that would help to mitigate against arbitrary designations. The Department also supports adding rule language that clarifies that the letter is in support of the site rather than the project per se, and that the town and the regional planning commission preserve the right to comment on the specifics of the project later in the process (as proposed in Potential Modified Option B, above).[36] Such a revision will provide reassurance to those bodies, and to the public, that issuance of a preferred site letter does not preclude further opportunities for input.

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

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public good, pursuant to 30 V.S.A. Section 248, authorizing VELCO to construct the so-called Northwest Vermont Reliability Project, Docket No. 6860, Order of 10/17/2003 at 7.

[35] The Department notes that requiring input from a town planning commission, despite previous Commission decisions holding that it is indistinct from its municipality, effectively signals that planning considerations should weigh into joint letter preferred site designations.

[36] This recommendation is consistent with comments from towns and regions in this rulemaking, and in *Workshop on Commission Rule 5.103 Preferred Site Definitions*, Public Utility Commission Case No. 17-5202-PET.

The Department recommends applicants should be required, at least, to provide local and regional bodies with a site plan identifying the parcel boundaries, project location on the parcel, and the limits of disturbance. It may also make sense for applicants to include "known constraints" (e.g., vernal pools, river corridors, floodways, endangered species habitat, wilderness areas, wetlands, etc.) when possible, as developed by stakeholders as part of the Act 174 planning standards development process. Known constraints are available from the applicable regional energy plan, Vermont Center for Geographic Information and/or Agency of Natural Resource's Natural Resources Atlas.

20. 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?

The Department recommends that the proper venue for consideration of an appeals process related to land-use planning is the Legislature. If the suggested changes in Potential Modified Option B are adopted, a developer, neighbors, and other stakeholders would have some sense of whether a specific site would be potentially eligible for preferred site designation (given a particular type and scale of project). Then the appeal question is likely narrowed to whether there is a policy basis in the town plan or bylaws for the designation, or denial of designation, of a proposed project parcel as a preferred site.