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STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 20-0097-INV

In re: Biennial update of the net-metering program	

COMMENTS OF THE DEPARTMENT OF PUBLIC SERVICE RE: NOTICE OF PROCEEDING AND SCHEDULING ORDER

The Department of Public Service ("Department") provides the following comments to the Public Utility Commission ("Commission") regarding proposed updates to the net-metering program's (1) REC adjustors; (2) siting adjustors; (3) statewide blended residential rate; and (4) eligibility criteria applicable to categories I, II, III, and IV. It is the Department's intention to file any responses it may have to any March 16, 2020 reply comments by April 1, 2020.

In this filing, the Department recommends a downward adjustment to the Renewable Energy Credit ("REC") adjustor.[1] This adjustor is currently set at negative $0.03/kWh for projects that retain the RECs, and positive $0.01/kWh for projects that transfer the RECs to the utility.[2] The Department proposes to maintain the $0.04/kWh differential between a project's election to retain or transfer RECs, and also to reduce the adjustors for both REC retaining projects and REC transferring projects by $0.01/kWh in each of the next two years. This reduction would be partially offset by proposed upward revisions to the blended residential rate, which is the base amount for determining the excess generation credit for net-metered customers. The primary reason for recommending a reduction in the total compensation rate is that the deployment of net-metering systems in 2018 and 2019 continues to exceed the requirements of the Renewable Energy Standard ("RES") at a cost greater than other Tier II alternatives.

[1] Commission Rule 5.127(B)(3)

[2] The positive $0.01/kWh REC adjustor currently available for projects that transfer the RECs to the utility is the result of an annual $0.01/kWh reduction in the REC adjustor as provided by the Commission during the last biennial update. *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018 at 50.

I. BACKGROUND OF NET-METERING

Act 99 of 2014 prompted a process during which the Commission revised Rule 5.100, which governs the net-metering program. The current version of Rule 5.100 became effective on July 1, 2017 ("net-metering 2.0" or "NM 2.0").[3] The net-metering statute, under 30 V.S.A § 8010(c)(1), requires the Commission to promulgate rules that establish and maintain a net-metering program that:

> (A) advances the goals and total renewables targets of [30 V.S.A. Chapter 89] and the goals of 10 V.S.A. § 578 (greenhouse gas reduction) and is consistent with the criteria of subsection 248(b) of [Title 30];
> (B) achieves a level of deployment that is consistent with the recommendations of the Electrical Energy and Comprehensive Energy Plans under sections 202 and 202b of [Title 30] . . . ;
> (C) to the extent feasible, ensures that net-metering does not shift costs included in each retail electricity provider's revenue requirement between net-metering customers and other customers;
> (D) accounts for all costs and benefits of net-metering, including the potential for net-metering to contribute toward relieving supply constraints in the transmission and distribution systems and to reduce consumption of fossil fuels for heating and transportation;
> (E) ensures that all customers who want to participate in net-metering have the opportunity to do so;
> (F) balances, over time, the pace of deployment and cost of the program with the program's impact on rates; and
> (G) accounts for changes over time in the cost of technology. . . .

Many of the Act 99 provisions relate to ratepayer costs and the pacing of deployment to meet Vermont' renewable energy goals. As such, the Commission has controlled the pacing of net-metering development through changing the adjustors which impact the level of

[3] NM 2.0 refers to the revised net-metering program. It first took effect as an interim rule starting on January 1, 2017 through June 30, 2018. NM 2.0 was then put in effect by an approved final rule on July 1, 2017. The adjustors were the same for the interim rule and the approved final rule which is still in effect. NM 2.1 and NM 2.2 refer to the annual revisions made to the NM 2.0 adjustors as provided by, *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018.

compensation for the generation of electricity and renewable energy attributes of various net-metered resources (this compensation varies depending on project size and siting). In the first biennial update of net-metering,[4] revisions were made to "REC adjustors," "siting adjustors," and the statewide blended residential rate (the baseline for adding or subtracting adjustors for excess generation). The eligibility criteria applicable to the various categories of net-metering system size/site type were also reviewed, but no updates were made. These components of Rule 5.100 are also subject to review during this biennial update proceeding.

To date, each of the net-metering programs and applicable adjustors are summarized below with naming conventions that will be used throughout these comments:[5]

			RECs		**CATEGORY**				
Program	CPG Application Date	Statewide Blended Rate	Transfer to Utility	Retain Ownership	I	II	III	IV	Hydro
NM 1.0[6]	before 1/1/2017	$0.149	n/a		n/a				
NM 2.0	1/1/2017 - 6/30/2018	$0.149	$0.03	-$0.03	$0.01	$0.01	-$0.01	-$0.03	$0.00
NM 2.1	7/1/2018 - 6/30/2019	$0.154	$0.02	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00
NM 2.2	7/1/2019 -	$0.154	$0.01	-$0.03	$0.01	$0.01	-$0.02	-$0.03	$0.00

[4] *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018.
[5] NM 2.0 refers to the revised net-metering program. It first took effect as an interim rule effect starting January 1, 2017 through June 30, 2018. NM 2.0 was then put in effect by an approved final rule on July 1, 2017. The adjustors were the same for the interim rule and the approved final rule which is still in effect. NM 2.1 and NM 2.2 refer to the annual revisions made to the NM 2.0 adjustors as provided by, *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018.
[6] After 2011, and before NM 2.0 (beginning January 1, 2017), systems received overall compensation of $0.19/kWh - $0.20/kWh and retained the RECs. Additionally, other up-front capacity-based incentives were also available.

II. NET-METERING IN THE CONTEXT OF VERMONT'S RENEWABLE ENERGY GOALS

A detailed background of the net-metering program was presented in, *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, order of 05/01/2018. In that order, the Commission identified the REC adjustors and siting adjustors as the primary mechanism for balancing the interests of ratepayers, net-metering customers, and solar developers.

Per 30 V.S.A. § 8010, the Commission determines the pace of net-metering deployment necessary to be consistent with the RES, the Comprehensive Energy Plan ("CEP"), and any other relevant state programs, when updating the net-metering program's adjustors. Consideration should also be given to the broader role net-metering (and other programs that contribute toward the RES) plays in Vermont's renewable energy policy landscape, particularly in meeting the goals of 30 V.S.A. § 8001. Net-metering projects should continue to serve an important role in meeting the RES, as such projects allow many Vermonters to directly participate in meeting state renewable energy goals. Net-metering development also provides attendant benefits such as associated jobs and the general promotion of the deployment of renewable generation close to load (which can benefit the electric grid). Consistent with 30 V.S.A. §§ 202(b), 218c, 8001, 8010(c)(1)(F) and Vermont's least cost planning rubric, the Commission should place a high priority on ensuring that the State's renewable energy policies continue to deliver renewable energy at least cost. Historically, net-metering has been Vermont's highest-cost source of renewable energy generation and it continues to be so.

III. CONTEXTUAL POLICY CONSIDERATIONS FOR THE BIENNIAL UPDATE PROCEEDINGS AND OTHER CONSIDERATIONS

The Department provides the following contextual comments for the Commission to consider as it undertakes this biennial update. While the scope of review prescribed in this biennial update proceeding relates to updates to the (1) REC adjustors; (2) siting adjustors; (3) statewide blended residential rate; (4) eligibility criteria applicable to categories I, II, III, and IV, there are other issues that have emerged in the net-metering rulemaking process[7] that are summarized here.

In recent comments filed in the ongoing Rule 5.100 Rulemaking, Case No. 19-0855-RULE, the Department proposed fundamental changes to the compensation structure of net-metering to minimize cost shifts between participating and non-participating customers and to better reflect the system value being provided by net-metering systems. Specifically, the Department submitted a straw proposal under which compensation for excess generation would be based on the value of that energy to the system rather than the residential rate that is currently applied. The straw proposal would define excess generation to mean all generation not physically consumed by a customer in real-time.

Declining value of solar

The environment for renewable energy development has changed enormously in the years since the inception of net-metering in the late 1990s, the Standard Offer program in 2009, and even since the passage of Act 99 in 2014 and the previous net-metering biennial review. From 2009 until 2020, the cumulative capacity of installed distributed solar in Vermont has

[7] *See generally, Proposed revisions to Vermont Public Utility Commission Rule 5.100*, Case No. 19-0855-RULE.

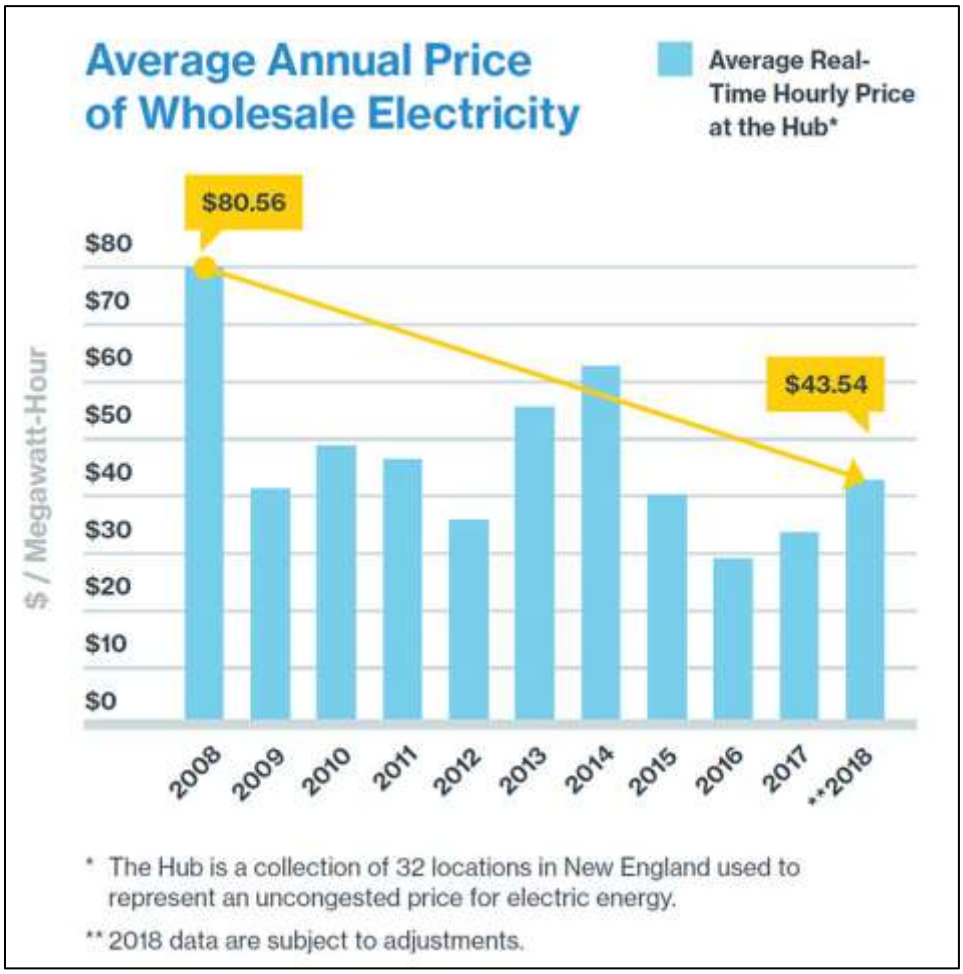
grown from roughly 5 MW to over 364 MW, with 230 MW from net-metering.[8] To date, this makes net-metering the primary mechanism for deployment of distributed generation in Vermont.[9] Although net-metering meets many of the goals laid out in 30 V.S.A. § 8001 (including economic development and distributed generation), with the current compensation rates it is the most expensive type of renewable energy available to satisfy the RES. Net-metering also results in a cost shift from participating customers to non-participating ratepayers. Moreover, the pace of net-metering deployment has been difficult to forecast, which complicates utilities' ability to plan for the RES.[10] Solar projects provide value related to several market products including energy, capacity, RES compliance, and transmission costs. Comparing the value of the products provided to the net-metering compensation rate is an important consideration.

In New England, the price of energy has dropped significantly over the past decade, as shown in the chart below. Additionally, when solar is producing the most, in the spring and summer months, electric prices tend to be lowest. Over the last five years, this relationship resulted in the energy value of solar being about 8% less than the all-hours average wholesale energy price.

[8] Joseph Roberts, associate engineer ISO-NE, DECEMBER 2019 DISTRIBUTED GENERATION SURVEY RESULTS, presented at the Distributed Generation Forecast Working Group, *available at* https://www.iso-ne.com/static-assets/documents/2020/02/pv_survey_results_021420.pdf.

[9] Based on recent data submitted to ISO-NE regarding interconnected distributed generation, there are 60 MW of solar from Standard Offer projects, and 71 MW of solar either owned by utilities or purchased through a long-term PPA.

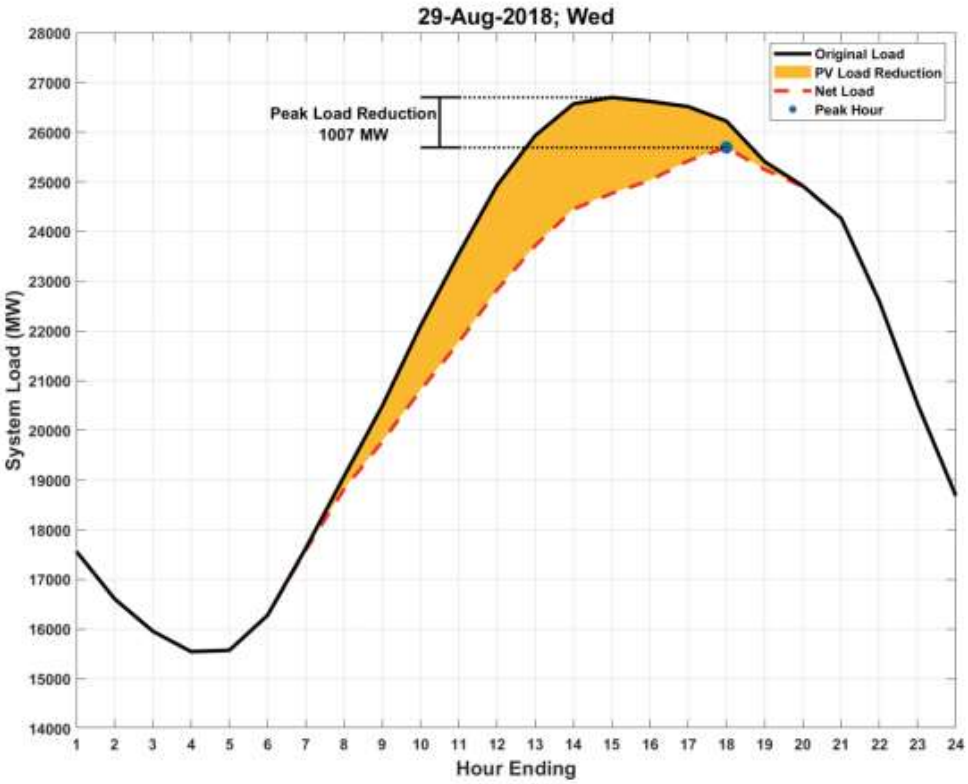
[10] Some net-metering projects elect to retain their RECs, which means they cannot be used for RES compliance; however, under the net-metering program effective in 2017, those projects are paid a much lower rate and are not as expensive for utilities, which has resulted in the vast majority of projects transferring the RECs to the utility.



Source: https://www.iso-ne.com/about/key-stats/markets/

Capacity, in this context, is the amount of resources needed to meet the New England peak hour per year (this typically occurs in the summer). Each utility is required to procure its share of resources, based on its load at the time of the annual peak, in the Forward Capacity Auction. Net-metering resources act as load-reducers and decrease the amount of capacity that a utility must procure. The region has significantly less distributed solar as a percentage of total load than Vermont does. Vermont hosts 11% of the region's distributed solar but Vermont represents 4% of the peak load. The timing of the regional annual system peak has not shifted as quickly as the timing of Vermont's peak load. However, ISO-NE estimates that the contribution

of solar resources to the New England peak will continue to decline over time as solar penetration increases across the region and the system peak shifts to later in the day. The example below of the region's load shape, with and without the impact of solar, clearly shows the peak shifting from 2-3pm to 5-6pm on this sample day.



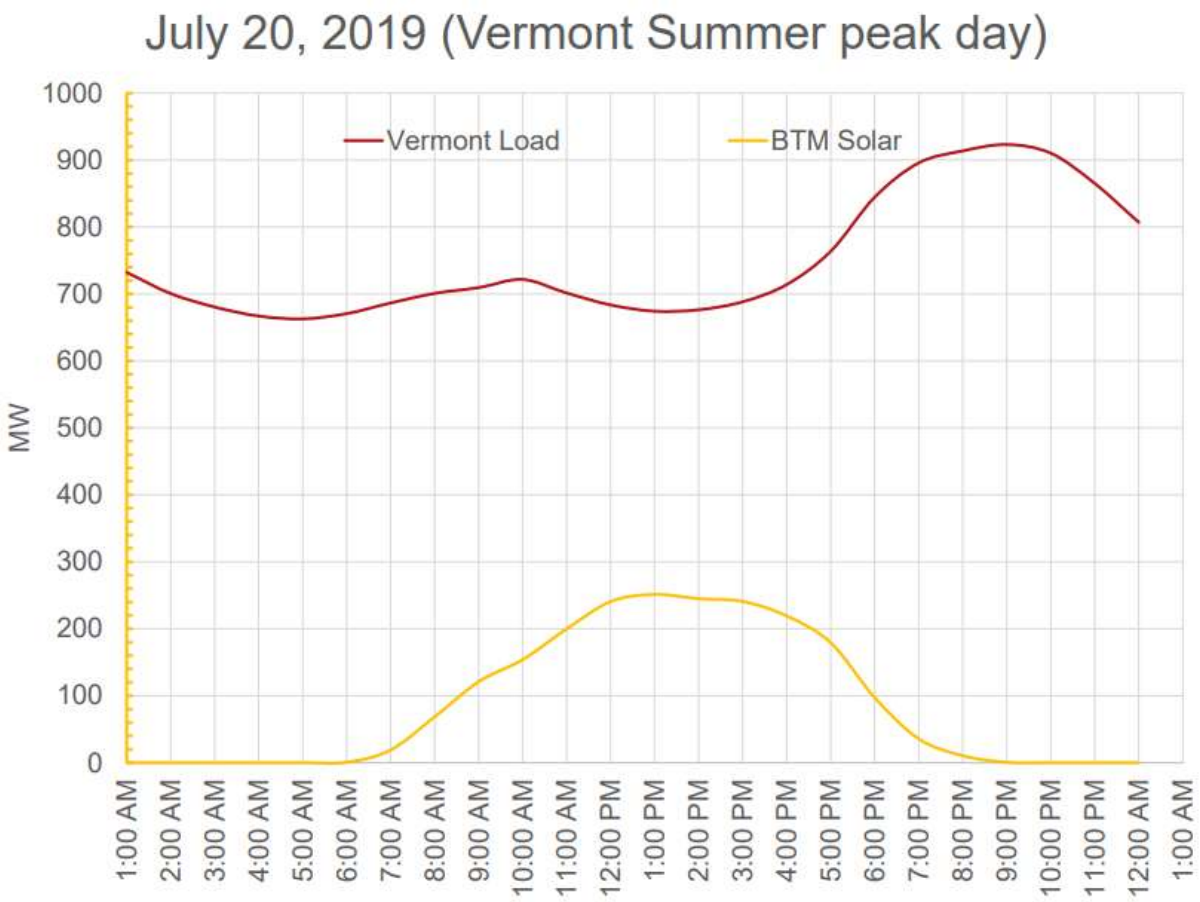
Source: ISO-NE Estimating Summer Peak Demand Impacts of BTM PV (Feb. 14, 2020), *available at*, https://www.iso-ne.com/static-assets/documents/2020/02/pv_peak_load_reduction.pdf

In addition to the declining coincidence of solar with the annual capacity peak, capacity prices are also decreasing. Historical FCA clearing prices are shown below.[11]

[11] ISO-NE – KEY GRID AND MARKET STATS: MARKETS, https://www.iso-ne.com/about/key-stats/markets/

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. With the increased solar deployment in Vermont, the hour of the monthly peak has shifted to later in the day when solar is not producing and this has diminished solar's value as a load reducer and peak shaver. In the last five years, the peak hour occurred before dark in only five of those 60 months, or 8% of the time. Thus, new incremental distributed solar now provides minimal transmission and distribution benefits. Storage could help shift the timing of solar production but does so at an additional cost. 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.[12]



The Vermont RES requires that utilities retire enough RECs to meet 55% of retail sales in 2017, increasing each year to 75% in 2032.[13] Tier II of the RES requires utilities to meet one percent of retail sales with RECs from renewable distributed generation[14] in 2017, increasing to

[12] VELCO, HISTORICAL LOAD REVIEW (Oct. 16, 2019) at slide 12, presented at the Vermont System Planning Committee Quarterly Meeting, *available at*: https://www.vermontspc.com/library/document/download/6763/Historical_load_review_Oct_2019.pdf.
[13] 30 V.S.A. § 8005(a)(1).
[14] 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. 30 V.S.A. §§ 8002(17), 8005(a)(2).

10% in 2032.[15] Given the strict eligibility requirements, and therefore the limited pool, of Tier II resources, there is not a liquid market for Tier II RECs. Utilities retire RECs from net-metering, standard offer, and any owned resources. Consequently, the Department's price forecast for Tier II RECs is based on the value these RECs have in states with liquid markets. The Department forecasts the long-term Tier II compliance costs to average around $0.025/kWh with annual fluctuations.

Although the Rule 5.100 biennial update review is not tied to the value of solar, the Commission found it to be an important consideration and concluded the value of new net-metering resources is not proportional to the current cost of obtaining such resources.[16] Consequently, the costs of net-metering are being shifted to non-participating ratepayers. Providing above-market compensation can be helpful mechanism to move forward a specific technology. However, now distributed solar is being built through other means and for substantially less money than the net-metering compensation. 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."[17] A town-level comparison of household income and the locations of residential-scale solar net-metering shows moderate correlation between high earning towns and

[15] 30 V.S.A. § 8005(a)(2).
[16] *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018 at 45.
[17] 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.

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.[18] This inequitable distribution of the benefits of net-metering makes the cost shift to non-participating customers more problematic. Expansion of net metering opportunities to low-income electric customers is best accomplished by targeted programs.[19]

Grid Penetration and Transformation

In the past, distributed generation has the potential to be beneficial to Vermont's grid by avoiding or deferring transmission and distribution upgrades that would otherwise be necessary to manage load constraints. However, these potential benefits have continued to decline in the past two years. Overall load in Vermont has been flat and is expected to have minimal growth in the medium term.[20] For at least the last four years, the Geotargeting Subcommittee of the Vermont System Planning Committee has not identified any constrained areas that could be addressed by targeted energy efficiency, or by extension, targeted distributed generation.[21]

[18] 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. Non-residential systems are excluded for all utilities except VPPSA, for which all customer types are included because VPPSA did not specify customer type.
[19] For example, Green Mountain Power Corporation is currently seeking approval of a Solar Energy Affordability Program in Case Number 19-0091-PET.
[20] 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.
[21] See, for example, letter of October 19, 2019, from Shana Louiselle to Judith Whitney, available at: https://www.vermontspc.com/library/document/download/6767/2019_VSPC_GTrecs_to_PUC_final.pdf.

One result of the rapid development of distributed generation, particularly in areas with high penetration of solar capacity, is that constraints on the Vermont grid are now often the result of *excess generation* rather than load growth. This results in "saturated" distribution circuits at risk of backward power flow through substations during certain times of the day and potentially costly upgrades to interconnect for some generators. At a macro level, export constraints on areas of the transmission system during certain times of the year (such as the Sheffield-Highgate Export Interface located in the northern portion of the state), are exacerbated by each incremental addition of renewable generation which effectively displaces other renewable generation on the system by requiring curtailments of that generation.

IV. DEPARTMENT RECOMMENDATIONS RE: REC ADJUSTORS

According to Rule 5.128(B), in updating the adjustors for either transferring or otherwise retaining RECs, the Commission must consider:

(1) the pace of renewable energy deployment necessary to be consistent with the Renewable Energy Standard program, the Comprehensive Energy Plan, and any other relevant state program;
(2) the total amount of renewable energy capacity commissioned in Vermont in the most recent two years;
(3) the disposition of RECs generated by net-metering systems commissioned in the past two years; and
(4) any other information deemed appropriate by the Commission.

Pace of Renewable Energy Deployment

As noted earlier in these comments, the Department estimates that 25-27 MW per year[22] of distributed generation will need to be deployed each year to meet the RES and the CEP. Given the limited eligibility criteria for Tier II, compliance is highly unlikely to come from

[22] This figure assumes ~85% of this generation is from solar PV.

retirement of RECs procured through a liquid REC market. Instead, the necessary Tier II RECs are likely to come from net-metering, standard offer, and resources owned by, or under contract to, utilities.

Of the 25-27 MW necessary to meet Tier II, the Standard Offer program will comprise an increasingly larger portion at least until the annual solicitations for new projects cease in 2021.[23] Note also that Standard Offer contracts last for up to 25 years, meaning the production from Standard Offer projects that can contribute to Tier II of the RES will increase until the full 127.5 MW of capacity comes online, but will start to decrease as contracts expire. To date, 102 MW of capacity has been awarded contracts through the Standard Offer program. Of the total contracted capacity, 47 MW was commissioned prior to 6/30/2015 and does not qualify for Tier II, 23.5 MW is online and Tier II eligible, and 32 MW has been contracted but not yet commissioned. An additional 10 MW of available capacity is to be solicited in Requests for Proposals ("RFPs") in each of the next three years.[24]

To evaluate the likely pace of net-metering participation over the next several years, the Department evaluated historical application and deployment trends in comparison to compensation rates and installation costs. In the previous biennial review, the Department undertook a complex rate-of-return analysis based on historical data going back to 2009. However, the expected deployment rates resulting from the model did not accurately capture the impacts of a reduced REC adjustor and underestimated the amount of installed net-metering. For

[23] This considers the Standard Offer capacity to be solicited by the Commission, which differs from the pace at which Standard Offer projects are permitted and/or interconnected. Projects receiving Standard Offer contracts in 2021 might not come online until 2023 or later.
[24] *See* 30 V.S.A. § 8005a.

this annual review, with more than three years of history under Rule 5.100, the Department relies on actual recent application and installation trends, as reported by utilities in this case, to inform its recommendations. [25]

The Department notes that installation costs continue to decrease, though at more modest rates than previously experienced. From 2009-2014 prices saw significant annual price declines, but installed price declines have since tapered off. The decreasing compensation rates from the REC and siting adjustors have been more than offset by the decreasing installation costs and higher retail rates, making net-metering increasingly profitable for both participating customers and developers over the years. Looking forward, solar installation costs are expected to continue to see modest installed price declines like those experienced in recent years.

Total Renewable Energy Commissioned

The Department has estimated the total amount of Tier II eligible renewable capacity commissioned in Vermont in the last two years, as depicted in the following chart:

Total Renewable Deployment

	2018	**2019**
Net-metering	33.7 MW	36.6 MW
Standard Offer	2.5 MW	5.3 MW
Utility-owned projects or PPAs	7.0 MW	14.4 MW
Total	**43.1 MW**	**56.2 MW**

The Department's estimate was derived from the utilities' filings in this case, as well as Standard Offer and ISO-NE information, with respect to renewable energy deployment of systems ≤ 5 MW in Vermont (i.e. systems eligible for Tier II of the RES) in 2018 and 2019. The

[25] The Department did not check for inconsistencies between the data provided in this case and what is available on ePUC.

summary above does not include 19.8 MW worth of solar generation that was commissioned in 2018 but does not qualify for Tier II of the RES.

The installed capacity of net-metering systems was similar in 2018 and 2019, but the composition (i.e. NM 1.0 vs. NM 2.0 vs. NM 2.2), and therefore the compensation rates, of the projects were different. In 2018, there was almost 9 MW of NM 1.0 projects installed, compared to just 1.3 MW in 2019. By 2019, most net-metering installations were part of NM 2.0 or later. The following table summarizes the projects that went into service in the last two years.

Net-Metering Deployment Summary

	NM 1.0		**NM 2.0**		**NM 2.1**		**NM 2.2**		**TOTAL**	
	kW	count	kW	count	kW	count	kW	count	**kW**	**count**
2018	8,694	55	22,093	1,513	2,852	359	n/a	n/a	**33,639**	**1,927**
2019	1,286	5	15,931	241	16,994	1,406	2,372	305	**36,582**	**1,957**
TOTAL	**9,980**	**60**	**38,024**	**1,754**	**19,846**	**1,765**	2,372	305	**70,222**	**3,884**

The pace of applications— both interconnection and Certificate of Public Good ("CPG") — is also an important consideration. Based on utility filings in this case, the Department evaluated the pace of interconnection applications.[26] The *number* of interconnection applications received under NM 2.1 exceeded those received under NM 2.0, but the *capacity* (kW) of applications under NM 2.0 and NM 2.1 was very similar. In 2019, NM 2.2 was only available for six months and received a similar number and capacity of applications as NM 2.1 received for the same time period in 2018. The capacity of applications received in 2019 associated with NM 2.2 is 11.1 MW, compared to 11.4 MW for NM 2.1 during the same time

[26] Analysis and observations are based on utility filings in this case, including a revised submission from GMP on March 9, 2020. In cases where the project has been interconnected, but no interconnection application date was provided, the interconnection application date is assumed to be the same as the CPG application date.

period in 2018. The following tables summarize the interconnection applications received in the last two years.

Net-Metering Interconnection Applications Summary

	NM 2.0		NM 2.1		NM 2.2		TOTAL	
	kW	count	kW	count	kW	count	**kW**	**count**
2018	45,326	1,700	11,759	798	n/a	n/a	57,085	2,498
2019	n/a	n/a	36,191	1,715	11,249	674	47,440	2,389
TOTAL	45,326	1,700	47,950	2,513	11,249	674	104,525	4,887

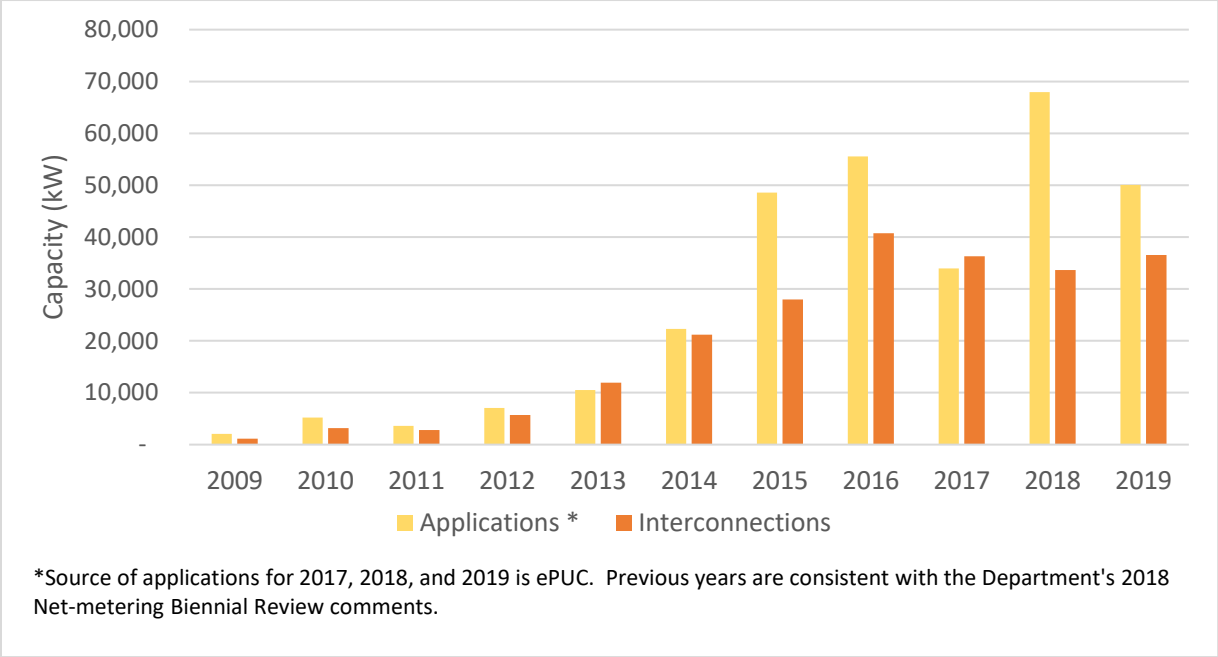
Net-Metering Interconnection Applications by Capacity (kW)
Project Size

Project Size	X <=15	15 < X <=150	150 < X <=500	TOTAL
2018	16,086	14,999	25,999	**57,085**
2019	17,014	13,546	16,880	**47,450**

Another way to look at pacing is by considering applications for CPGs or by CPGs issued. The Commission is best positioned to glean applicable information from ePUC and analyze the pace of CPG applications based on that authoritative information. Based on the utilities' filings reporting net-metering CPG applications and installations in 2018 and 2019, there are multiple projects that have applied for a CPG but have not yet been built: about 20.3 MW of NM 2.0, 23.4 MW of NM 2.1, and 4.3 MW of NM 2.2. However, the Department notes that this may not be a complete picture, as the Commission requested that utilities report on systems interconnected and those proposed for interconnection. Therefore, projects that have applied for a CPG but have not yet applied for interconnection may not be reflected here.

The chart below compares annual applications for permits with annual interconnections of solar PV systems up to 500 kW.[27]

Annual Solar Net-Metering CPG Applications versus Interconnections



*Source of applications for 2017, 2018, and 2019 is ePUC. Previous years are consistent with the Department's 2018 Net-metering Biennial Review comments.

The Department draws the following conclusions from the information presented in the chart above:

(1) More than a quarter of net-metering capacity commissioned in 2018 was from systems permitted prior to 2017. About 64% was part of NM 2.0 and 10% was NM 2.1.

(2) The number of large projects (> 150 kW to ≤ 500 kW) proposed for interconnection decreased from 57 MW in 2018 to 47 MW in 2019. This is likely due in large part

[27] 500 kW is generally the size limit for net-metering projects, though at various points in history, larger systems have been allowed under certain circumstances. Additionally, a handful of systems ≤ 500 kW are not net-metered.

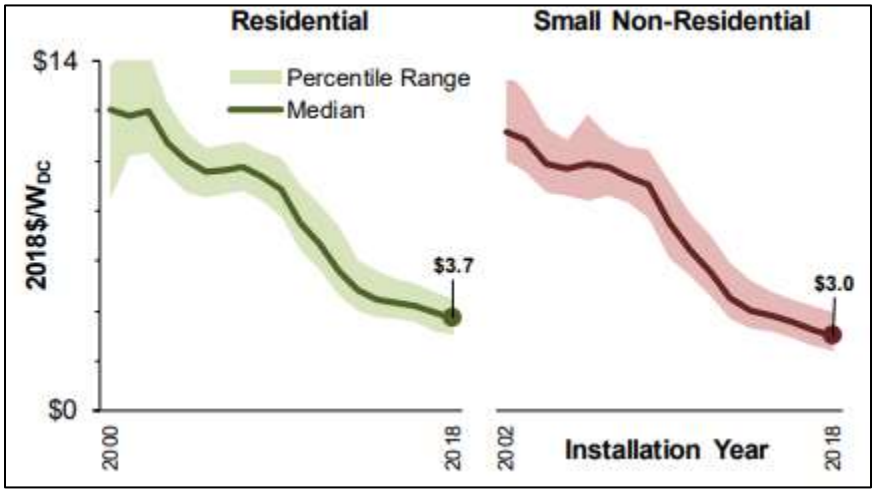
to more extensive permitting requirements, the more negative siting adjustor, and possibly the dwindling availability of easier-to-develop preferred sites.

(3) The capacity of installed net-metering over the previous three years has been relatively constant, with between 33 MW and 37 MW commissioned each year. These installation rates exceed the incremental Tier II RES requirements.

With more than three years of history under Net-Metering 2.0, 2.1, and 2.2, the Department can start to identify trends and make recommendations for REC adjustor levels. It is also important, when considering future deployment levels, to consider, the costs associated with solar generator development in addition to compensation rates and the value of solar. Steep declines in the installed cost of solar (since around 2008) are beginning to flatten out.[28] Because 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. The compensation paid to net-metering resources has not seen a corresponding reduction in magnitude, which suggests a reassessment of the compensation structure is overdue. While the solar import tariff and declining Investment Tax Credit ("ITC") have put upward cost pressure on module costs, based on publicly available data, overall costs have continued to decrease. Historical installed price trends can be seen below:

[28] Galen Barbose and Naïm Darghouth, Lawrence Berkeley National Lab, TRACKING THE SUN 10: THE INSTALLED PRICE OF RESIDENTIAL AND NON-RESIDENTIAL PHOTOVOLTAIC SYSTEMS IN THE UNITED STATES, September 2017: https://emp.lbl.gov/sites/default/files/tracking_the_sun_10_report.pdf.

Installed Cost of Solar



Source: Lawrence Berkley Nation Laboratory. Tracking the Sun, October 2019

REC Disposition

Regarding the disposition of net-metering RECs in the past two years, the Department offers the following statewide summary derived from the utility filings in this case:

Net-Metering Deployment Capacity (kW) REC Disposition

	REC disposition	NM 1.0	NM 2.0	NM 2.1	NM 2.2	TOTAL
2018	Retain	8,679	79	17	0	**8,775**
	Transfer	15	22,014	2,835	0	**24,864**
2019	Retain	1,153	62	97	10	**1,322**
	Transfer	133	15,868	16,897	2,362	**35,260**
TOTAL	Retain	9,831	141	114	10	**10,097**
	Transfer	148	37,882	19,731	2,362	**60,124**

Net-metering 1.0 did not differentiate compensation based on REC disposition. As a result, most NM 1.0 projects retained the ownership of RECs. NM 2.0 and beyond have a -$0.03/kWh adjustor for projects that elect to retain the RECs, with a respective $0.03/kWh, $0.02/kWh, or $0.01/kWh REC adjustors for NM 2.0, NM 2.1, and NM 2.2 projects that elect to

transfer the RECs to the utility. The compensation differential between a system owner retaining (and potentially selling RECs in the regional REC market) versus transferring them to the utility was $0.06/kWh for NM 2.0 and shrank to $0.05/kWh for NM 2.1 and to $0.04/kWh for NM 2.2. The current $0.04/kWh differential appears to decisively encourage REC transfers and remains greater than the projected value of Tier II RECs.

Department REC Adjustor Recommendation

Relying on the REC adjustor as the primary pacing mechanism for net-metering deployment, and given the importance of providing an incentive for customers to transfer their RECs to the utility, the Department proposes maintaining a $0.04/kWh price differential between projects that retain RECs and those that transfer RECs. However, the current pace of deployment and applications, both interconnection and CPG, exceeds the requirements of RES Tier II, and leaves utilities over-procured when also including new Standard Offer projects. Additionally, the difference between the value of the solar energy and the rate at which it is compensated creates a cost shift that should be minimized. Therefore, the Department recommends that the REC adjustors for both projects that retain and transfer their RECs be reduced by $0.01/kWh over each of the next two years.

Program	**Transfer RECs**	**Retain RECs**
NM 2.3	$0.00/ kWh	-$0.04/ kWh
NM 2.4	-$0.01/ kWh	-$0.05/ kWh

This gradual step-down in compensation is consistent with the Commission's previous decision to incrementally decrease the REC adjustor for projects that transfer their RECs.[29] These adjustments will be partially offset by the increase in the statewide blended residential retail rate (discussed below in section VI), resulting in little practical change to compensation between NM 2.2 projects and NM 2.3 projects.

Given the current compensation structure, as the statewide blended rate increases, the compensation paid to all net-metered resources automatically increases as well. The retail rate is not connected to the value of the net-metering resource but instead reflects the ability of the utility to recover prudently incurred necessary costs. These costs are rising as a result of several factors, including increased storms and administrative costs. The retail rate does not reflect the power supply costs of the utility, which is the more appropriate metric for the value of a net-metering resource. The only adjustments available to the compensation paid to net-metering resources are the siting adjustor and the REC adjustor.

The costs of net-metering exceed the benefits to non-participating customers, including the costs of Tier 2 RES compliance. So long as the utilities are overcompensating net-metering customers, the REC adjustor should not be considered the price paid by the utilities to procure RECs from net-metering project owners. Instead, the REC adjustor acts as a means of distinguishing between customers who keep their RECs and those who provide the RECs to the utility. Because customers who keep their RECs can resell them without benefit to the utilities or ratepayers generally, it is appropriate to compensate such customers at a reduced rate.

[29] *In re: biennial update of the net-metering program*, Case No. 18-0086-INV, Order of 05/01/2018 at 50.

V. DEPARTMENT RECOMMENDATION RE: SITING ADJUSTORS

According to Rule 5.128(C), in updating the adjustors for siting (based on system size as well as preferred siting), the Commission must consider:

(1) the number and capacity of net-metering systems receiving CPGs in the most recent two years;
(2) the extent to which the current siting adjustors are affecting siting decisions;
(3) whether changes to the qualifying criteria of the categories are necessary;
(4) the overall pace of net-metering deployment; and
(5) any other information deemed appropriate by the Commission.

Department Siting Adjustor Recommendation

The Department has not undertaken a detailed analysis of the extent to which siting adjustors are affecting siting decisions, nor does it have the data required for such an analysis. Based on the filings provided by the utilities, the Department provides the following summary of information that is relevant to factors (1) and (4), above.

Net-Metering Applications Capacity (kW)
Category

		NM 2.0	NM 2.1	NM 2.2	TOTAL
2018	Category I	11,895	5,581	n/a	17,476
	Category II	10,473	2,146	n/a	12,619
	Category III	22,319	3,480	n/a	25,799
	Category IV	30	0	n/a	30
2019	Category I	n/a	13,289	5,065	18,354
	Category II	n/a	6,077	1,247	7,325
	Category III	n/a	12,363	4,500	16,863
	Category IV	n/a	200	0	200

Net-Metering Deployment Capacity (kW)
Category

		NM 2.0	NM 2.1	NM 2.2	TOTAL
2018	Category I	10,236	2,620	n/a	12,856
	Category II	5,283	233	n/a	5,516
	Category III	6,514	0	n/a	6,514
	Category IV	60	0	n/a	60
2019	Category I	1,812	10,742	2,330	14,884
	Category II	2,423	3,619	42	6,084
	Category III	11,556	2,360	0	13,916
	Category IV	140	200	0	340

Generally, because siting adjustors contribute to overall system compensation, the Department does not recommend increasing the siting adjustors (commensurate with the rationales for REC adjustors above). Modifications could be made to the siting adjustors to modulate the pace of net-metering if the Commission desired more, or less, deployment in certain categories, instead of using the REC adjustor for this purpose. Based on recent experience, it appears that applications for Category III projects have been greatly reduced. This could be the result of a combination of factors, including the -$0.02/kWh siting adjustor or perhaps the limited availability of preferred sites. It is possible that due to nuances in design, permitting, and construction costs, as well as in system production it would be necessary to provide differential adjustor or regulatory treatment to projects on different types of preferred sites. However, a siting adjustor should be designed to encourage well-sited projects and not be designed to make construction on a specific type of preferred site cost effective for the developer.

Lastly, the Department encourages the Commission to consider whether it would be possible to implement siting adjustors based on a project's impacts on the grid (for instance, a project located on a "saturated" distribution circuit would receive a lower adjustor unless paired

with storage or otherwise able to time-shift production to hours of higher load and lower generation on that circuit). Should the Commission consider this topic germane to the biennial adjustor review,[30] the Department would be able to provide additional comments.

VI. DEPARTMENT RECOMMENDATION RE: STATEWIDE BLENDED RESIDENTIAL RATE

The net-metering rules describe how the blended residential rate, which is used to determine the value of net-metering credits ("statewide blended residential rate"), is determined.[31] The Department has determined that the statewide blended residential rate has risen, since the previous rate was set in 2018, as a result of rate increases at several utilities in the intervening year. *The Department recommends that the Commission set the statewide blended residential rate to $0.16413/kWh, which is an increase of $0.0100/kWh.* This rate will replace the existing blended residential rate for *all*—both existing and new— net-metering customers, increasing the overall cost of the net-metering program.[32]

The Department's recommended statewide blended residential rate was calculated using the attached spreadsheet ("Attachment A") "2020 blended rates." Retail sales data for 2019 will not be available until later this year, so the utilities' share of load is calculated using 2018 retail

[30] Or perhaps the net-metering rulemaking.
[31] It is the weighted statewide average of all electric company blended residential retail rates. Rule 5.127(A)(3).
[32] *See* Revised Rule 5.124, 5.125, 5.126 (effective January 1, 2017) *available at*, https://puc.vermont.gov/sites/psbnew/files/doc_library/5100-PUC-attachment-a-on-reconsideration_0.pdf; Rule 5.125, 5.126, 5.127 (effective July 1, 2017) *available at*, https://puc.vermont.gov/sites/psbnew/files/doc_library/5100-PUC-nm-effective-07-01-2017_0.pdf.

sales. Rates for each utility were updated to their most current Commission-ordered tariffs.[33] The rate is weighted by each utility's share of retail sales.[34]

Although this attachment calculates the blended rate for each utility with an inclining block rate, the method employed here is slightly different than the one prescribed by the Commission for the purposes of setting net-metering rates under 5.127(A)(2).[35] Utilities that include inclining block rates in their general residential service tariffs are required to recalculate their blended residential retail rates by May 15 of each even-numbered year, including in 2018.[36] If the recalculation shows that the rate has changed, the utility is required to file a revised net-metered tariff with the Commission. The Department recommends that utilities conduct this exercise for themselves regardless of our calculations here.

VII. ELIGIBIILTY FOR CATEGORIES

The Department does not recommend significant changes to the eligibility criteria for the net-metering categories[37] at present, commensurate with our comments above on siting adjustors.

Category	Size/site type	Adjustor
I	≤ 15 kW, not hydro	0.01/kWh
II	> 15 to ≤ 150 kW, not hydro, on a preferred site	0.01/kWh
III	> 150 to ≤ 500 kW, not hydro, on a preferred site	-0.02/kWh
IV	> 15 to ≤ 150 kW, not hydro, NOT on a preferred site	-0.03/kWh
Hydro	Up to 500 kW	0.00/kWh

[33] Currently, Hyde Park, Vermont Electric Cooperative, and Washington Electric Cooperative have pending rate increase requests.
[34] In accordance with Rule 5.127(A)(3).
[35] The Department employed a slightly different method because it does not have access to the granular level of data required for the Commission's method. Specifically, the Department does not have revenue data for collections under the *volumetric* portion of the block rates. The Department used a proxy for this measure by inferring sales under each block and multiplying by the rate for that block. Although results for individual utilities may vary from what is shown in our attachment, the Department believes the effect on the statewide blended rate of these differences would be minimal.
[36] 5.127(A)(2).
[37] Rule 5.103 "Category" at page 6.

The Commission may wish to consider this question in Case No. 19-0855-Rule as well.

VIII. CONCLUSION

The Department looks forward to working with the Commission and other stakeholders to assess the impacts of net-metering adjustors on deployment and the role of net-metering within the context of Vermont's renewable energy goals. To that end, the Department recommends that the Commission solicit comments on additional changes that may be useful in giving shape to the biennial review process in the future, particularly in relation to data needs and considerations.

cc: ePUC Service List

Attachments list:
Attachment A – 2020 Blended Rates