Stowe Electric Department
PO Box 190
435 Moscow Rd
Stowe, VT 05672
802-253-7215
www.stoweelectric.com

November 1, 2019

Ms. Judith Whitney, Clerk
Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701

Re: Case No. 19-0855-Rule – Proposed Revisions to Vermont Public Utility Commission Rule 5.100

Dear Ms. Whitney,

The Town of Stowe Electric Department ("Stowe" or "the Utility") submits the following informational filing in response to the Public Utility Commission's ("PUC" or "Commission") informational request dated August 22, 2019.

The Commission requested that the distribution utilities ("DU") provide detailed information about the current costs and benefits of Vermont's net-metering program, whether the program as currently designed is creating a cost shift, and the effect that the program has on retail rates in order for the Commission t decide whether to amend the net-metering rule's compensation structure.

In short, Stowe's analysis clearly shows that the net-metering program does result in a cost shift between participating and non-participating ratepayers and has a negative impact on Stowe's electric rates. The following comments will speak to the magnitude of those effects.

Evaluating the Net-Metering Cost Shift

Quantifying the effects of net-metering in Stowe's service territory is inherently complicated as the program has gone through several revisions since it was first implemented. The first system was installed in Stowe in 2011. Today, 2.6% of Stowe's customers participate in the program through one or a mix of the 93 net-metering systems our service territory, not including the additional 11 systems that are in some phase of permitting or development. These systems are entitled to credits which are calculated using differing rates, adders, or methodologies that will sunset on various timelines. So, in an effort to provide meaningful information for the Commission's consideration, Stowe modeled what it refers to as a "block" of assumed new net-metering capacity and calculated the costs and benefits it represents to the utility using today's values. This is meant to be a proxy that would measure what a typical annual expansion of net-metering capacity would mean to Stowe and its ratepayers.

Stowe calculated the costs and benefits of the block using data from existing solar generation in its territory and the rates that are available to net-metering systems installed today. Power supply costs such as transmission, capacity, ancillary charges, energy, and RECs were then used to calculate the benefits that these systems provide through reduced charges. This value was then compared to the costs borne by the utility in the form of compensation to these participating net-metering customers and the cost to administer the program.

The block was given a total capacity of 288 kW by evaluating interconnection data which shows that this is the average capacity of net-metering that Stowe interconnects in an average year. Of that total, 81 kW is derived from systems designed such that the energy generated is netted against the energy consumed as registered by the consumption meter ("behind the meter" or "BTM"). The remaining 206 kW comes in the form of larger group net-metering projects that inject the energy directly into Stowe's distribution system ("direct interconnection" or "DI"). The energy generated by these systems is monetized before it is netted against the monthly bills of the group members. Stowe evaluated these two groups separately to account for the differing methods that each is compensated according to Rule 5.100.

Using commissioned solar generation data, we then calculated the average annual output of BTM and DI systems in Stowe's service territory to estimate the total generation of the

287 kW block and an average kWh per kW-installed. We assumed that each of the new systems would allocate their RECs to the utility and would qualify for Category 1 siting. We also used the metered data to estimate how much these systems' generation may reduce Stowe's charges related to RNS, the forward capacity market, ISO transmission, ancillary services, and energy purchases.[1] As shown below, Stowe calculated a total avoided cost value of $0.079/kWh generated by net-metering.

Avoided Costs per kWh	
Energy	$ 0.0419
Ancillary	$ 0.0018
Capacity	$ 0.0037
RECs	$ 0.0300
Tx 91	$ 0.0009
Tx RNS	$ 0.0004
TOTAL	$ 0.079

Stowe then applied the metered kWh/kW-installed to the two net-metering compensation methodologies to calculate the total cost of the block to the utility in a given year.

[1] ***Energy ($/kWh): $.0419*** - Based on the average calendar year 2018 and 2019 to date (October 9, 2019) for the VT node. Used the Day Ahead Location Marginal Price for all on peak hours. ***Ancillary ($/kWh): $.0018*** **-** Based on average of the actual ancillary charges Stowe has paid for Calendar year 2019 January-September. ***Capacity ($/kWh): $.0037*** - Based on the FCM 10 for Rest of Pool of $7.071 $/kw-mo. Which equates to $.01614 $/kWh for the peak hours. The rate is multiplied by 23%. 23% is roughly the capacity factor of Nebraska Valley during the 2018 peak hour on 8/29/18. ***RECs ($/kWh): $.03*** - Based on MA Class I estimate REC price. ***VELCO 91 Transmission ($/kWh): $.0009*** - Based on the average VECLO 91 Transmission actual charges for Stowe from January through September 2019 of $.00411. Does not include any specific facility charges. The rate is multiplied by 23%. 23% is roughly the capacity factor of Nebraska Valley during the 2018 peak hour on 8/29/18. ***ISO RNS Transmission ($/kWh): $.0004*** - Based on the Transmission year (6/19-5/20) $9.328 $/kw-mo. Which equates to $.02129 $/kWh for the peak hours. The rate is then multiplied 2%. 2% is the max capacity factor of actual generation from the Nebraska Valley project for (8/18-9/19).

AVERAGE NEW BTM BLOCK		
New Capacity	82	kw
Project Generation	73,096.99	kWh annually
On-Site Consumption	20,496.94	kWh annually
Retail Rate ($/kWh)	$	0.16980
Blended Rate ($/kWh)	$	0.14931
Adder value ($/kWh)	$	0.02
Reduced Retail Sales Cost		
Reduced Retail Sales (kWh)		20,497
Lost Retail Revenue	$	3,480.38
Excess Generation and Adder Costs		
Excess Generation (kWh)		51,600
Cost of Excess Generation w/Adders	$	7,704.47
Total Adder Cost	$	1,461.94
Total Cost	$	12,646.79
Avoided Cost	$	5,758.17
Net Cost	$	6,888.62
TOTAL COST SHIFT ($/kW-installed)	**$**	**84.39**

AVERAGE NEW DIRECT INTERCONNECT BLOCK		
Project Size	206	kW
Project Generation	255044.94	kWh annually
On-Site Consumption	0	
Generation Costs		
Generation (kWh)		255045
Cost w/o Adders ($/kWh)	$	0.14931
Cost of adders ($/kWh)	$	0.02
Cost of Generation ($/kWh)	$	0.16931
Cost of Generation	$	43,181.66
Total Cost	$	43,181.66
Avoided Cost	$	20,090.99
Net Cost	$	23,090.67
TOTAL COST SHIFT($/kW-installed)	**$**	**112.32**

The total costs per kW-installed were then compared to the total avoided costs to measure the cost shift. BTM capacity accounts for a cost shift of $84.39/kW-installed while DI capacity accounts for a total cost shift of $112.32/kW. The weighted average shows that the total cost shift associated with an annual block of net metering compensated under the current net-metering rules results in a weighted average cost shift of $104.38/kW. This equates to an annual revenue deficiency of $29,979 when evaluating power supply costs and retail revenue. Stowe also measured the total administrative cost attributable to a typical net-metering system, including the marginal staff time to process billing for net-metering customers and operational time that is not recovered from the fixed meter installation charge. When applied to the block, Stowe estimated it incurs $2,776 of additional costs per year that the billing and operational costs from these new systems, bringing the total revenue deficiency to $32,755 per year.

Block Cost Shift		
Total BTM Shift	$	6,888.62
BTM Block/kW	$	84.39
Total DI Shift	$	23,090.67
DI Block/kW	$	112.32
Total	**$**	**29,979.29**
Weighted Avg/kW	**$**	**104.38**
Administrative Costs Impacts		
Block Admin Cost	$	2,775.92
TOTAL BLOCK COST SHIFT	**$**	**32,755.21**
Per kW	**$**	**114.05**

Rate Impacts for Stowe

Despite this cost shift, Stowe's rates would not be significantly affected by the annual block. A cost shift of $32,755.21 equates to a 0.27% revenue deficiency to meet Stowe's cost of service, or 1.34% over 5 years. Stowe understands that this finding may be unusually low among Vermont DUs. This difference may be explained by the rate of net-metering in Stowe. Stowe also has comparatively few DI systems which cause a more significant cost shift per kW than BTM systems. As an example, Stowe only has one 500 kW net-metering system in its territory but relatively high annual retail sales for a municipal utility of its size.

Although net-metering as currently designed does not present a significant rate impact to Stowe, the cost shift per kW-installed between those who participate in the program and those who do not raises concerns. This is a clear indication that the current compensation structure provides net-metering customers an incentive for the energy they generate that exceeds the value of that energy. This is especially true for DI systems which result in more cost shifting than BTM systems as they often aren't co-located with load or may even be located a far distance from the nearest load pocket.

Net Metering and the RES

One of the benefits that most new net-metering currently provides is that the generation can qualify towards Vermont's Renewable Energy Standard ("RES") if the owners of the systems have elected to allocate the renewable energy credits ("REC") to the DU. Theoretically, all the statutory targets of three RES Tiers can be met through net-metering generation. But as a primary matter, Stowe would not pursue a resource procurement strategy that depended solely upon new net-metering capacity.

As shown above, due to the policy goals behind the current net-metering compensation structure, energy from such projects is considerably more expensive than alternatives. Stowe owns and operates a 1 MW solar facility located within its own service territory that provides all of the same power supply benefits as net-metered generation and without reducing retail rate revenue. The net-metering facilities Stowe evaluated for these comments also exhibit an average capacity factor 33% lower than Stowe's 1 MW facility, therefore requiring more installed capacity and associated cost shifting to meet the same compliance mandates. These two facts in consideration, and the reality that Stowe cannot reasonably rely on new-net metering capacity to come online with sufficient pace and timing to meet the RES mandates, it would be reasonable to question the prudence of a utility electing to employ this strategy.

That said, it is still theoretically possible. Assuming that the utility would keep its existing resource entitlements and that new net-metered generation would be commissioned at the rate necessary, Stowe would need a total of 26.73 MW of new net-metered solar capacity by 2032 to meet all three RES Tiers.[2] Meeting this target would require an average of 2.06 MW per

---

[2] This estimate does not account for any efficiency losses over the life of the systems or any vintage systems reaching the end of their useful lives and being taken offline. It also does not presume increased any future module efficiency improvements.

year, a rate of development 716% higher than what Stowe experienced in recent years. This would amount to an average cost shift of $1.7 million per year and a total of $22.5 million over the remaining 13 years of the RES program. By comparison, Stowe could instead meet its RES mandates by electing to pay the Alternative Compliance Payment for a total cost of $8.6 million over the life of the program, saving $13.8 million a year.

Net Metering and TOU Rates

Stowe currently offers a residential time-of-use ("TOU") tariff which includes rates designed to capture the capacity and transmission costs associated with energy delivered to Stowe's system during peak periods. The tariff includes separate rates for winter and summer peaks, winter and summer off-peaks, and a critical peak pricing component that is only exercised during certain summer peaks where the regional grid is experiencing the highest levels of stress. Transmission operators have shown that as more solar generation comes online each year, it has the effect of shifting peak periods to later in the day or even into the evening, thereby reducing the utility's observed value of solar with each new kW of capacity installed in the region. The TOU tariff is designed to influence customer consumption habits through price signals during periods when the grid is stressed. But solar generation is intermittent and uncontrollable so a traditional net-metering system would be unable to respond to price signals to deliver more energy during periods than they would have under a traditional rate. That could be achieved if the solar panels are paired with battery storage but only if the economics were strong enough to justify the additional expense.

The administrative cost of pairing solar net-metering with a TOU rate would also present a significant challenge. As explained earlier, net-metering requires considerable staff time beyond what is collected through Stowe's generation meter installation charge in large part because the billing is complicated. Billing a customer on a TOU rate is also complex to administer and combining these two rate categories complicates matters further. Stowe would not advocate that the Commission require net-metering customers to be on TOU rates.

100% Renewable Utilities and Net-Metering Caps

One of the motivations for the State's policy for net-metering is to encourage the development and procurement of renewable energy for Vermonters and to reduce the carbon intensity of the electricity we consume. A utility that provides its customers with 100% renewable energy has already achieved that goal. Under the current compensation structure, additional net-metering capacity would have reduced benefit for that utility and would increase the power supply costs while perpetuating the cost shifting between the customers who do and don't participate. However, precluding that utility's service territory from new-net metering would cause confusion among its customers and net-metering developers. Adjusting the net-metering rates in order to accurately reflect the costs and benefits for that utility would avoid this cost-shift. It could also eliminate the need for a cap on new net-metering development.

This question is similar to whether the Commission should reinstate caps on net-metering development. In both cases, a system that properly aligns the incentives and the values attributable to the energy net-metering systems, and a regular reassessment of those factors, would preclude the need to restrict development.

Please let me know if you have any questions.

Matthew DS Rutherford
Manager of Regulatory Compliance
Town of Stowe Electric Department