STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

Development of New Alternative Net Metering	**)**	
Tariffs and/or Other Regulatory Mechanisms	**)**	**Docket No. DE 16-576**
and Tariffs for Customer-Generators	**)**	

JOINT SUPPLEMENTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF CONSERVATION LAW FOUNDATION

AND

ELLEN HAWES

ON BEHALF OF ACADIA CENTER

MARCH 10, 2017

Q: Are you the same Paul Chernick and Ellen Hawes who previously filed testimony in this proceeding, on behalf of Conservation Law Foundation and Acadia Center, respectively?

A: Yes.

Q: What is the scope of your joint supplemental testimony?

A: This joint supplemental testimony explains and supports the settlement filed on this day by a group of parties jointly referred to as the Energy Future Coalition, which is comprised of Acadia Center, the Alliance for Solar Choice, Borrego Solar, Conservation Law Foundation ("CLF"), the Energy Freedom Coalition of America, Granite State Hydropower Association, the New Hampshire Sustainable Energy Association, Sunraise Investments, Solar Endeavors, ReVision Energy, and Revolution Energy. For convenience, we refer to that settlement herein as the Joint Settlement.

Q: Please describe the Joint Settlement.

A: The Joint Settlement represents the current consensus among participating parties as to the appropriate ratemaking treatment of distributed generation and net metering in New Hampshire. It reflects the efforts of the participating parties to reach agreement and compromise, as well as recent work in the net-metering docket to come to a shared understanding among all of the parties. These efforts have been guided by the statutory directives reflected in HB 1116, which prompted this proceeding, and by the Commission's Order of May 19, 2016 opening this docket. While this settlement may differ in certain important respects from the positions of the utilities, the conversations in this docket have increased mutual understanding. As a result, we anticipate that there will also be numerous commonalities among the positions of the parties participating in this settlement agreement and the utilities' current positions.

From our perspective, one of the most important aspects of the Joint Settlement is the agreement to move in phased but rapid steps toward a value-based rate structure, which we recommend include time-varying rates and netting by time of use period, following the completion of key studies, information-gathering, and pilots designed to support and advance this transition.

Q: Please summarize the content of the Joint Settlement.

A: The Joint Settlement is described in more detail in the Joint Supplemental Testimony of Thomas Beach, Patrick Bean, Kate Epsen, Fortunat Mueller, Nathan Phelps, and Karl Rabago. In short, it provides for two phases of modification to the existing net metering rate structure. The Joint Settlement proposes that all projects placed into the interconnection queue beginning on September 1, 2017 will be subject to the Phase 1 program design. Phase I would include a transition to a new tariff on September 1, 2017, with customers taking service under the old program until the utilities have updated their billing systems to make billing under the new tariff possible. This transition would include a number of changes to the method and levels of compensating distributed-generation customers for excess generation. For projects under 100 kW, these changes include:

- Banking of excess (or exported) kWh would be eliminated as of September 1, 2017 and replaced with monetary credits that would not expire until they are used by the customer.
- As of September 1, 2017, the export credit for gross exports would exclude non-bypassable charges for the state electricity consumption tax and to support low-income programs, energy-efficiency programs, and utility recovery of stranded costs.
- The distribution credit for projects entering the interconnection queue after August 31, 2017 would be 75% of the volumetric distribution charge for their rate class for monthly net exports.

- The distribution credit for projects entering the interconnection queue after December 31, 2018 would be 50% of the current volumetric distribution rate.
- The export credit for generation and transmission would remain at the retail rate.

Phase I would also include a number of pilots consistent with HB 1116 and the Commission's May 19, 2016 Order, and other studies and information collection to support the transition to value-based rates for distributed energy resources in Phase II, which would begin January 1, 2021.

The Phase II value of distributed energy resources (VDER) rates would be firmly supported by actual data, avoiding the arbitrary tariff structures in some of the proposals in this docket and reflecting the actual value of different forms and aspects of distributed generation. We anticipate and recommend that the VDER tariff would incorporate pricing and compensation based on time of consumption and production.

Q: What is the benefit of a transition to value-based compensation?

A: Traditional net metering is generally considered to represent a rough approximation of the benefit of distributed generation. In contrast, cost-based valuation of the benefits and costs of distributed resources (e.g., generation, energy storage, and demand response) to the utilities and their customers should better encourage consumers, the utilities and third parties to pursue the types of distributed resources that are beneficial to ratepayers and the state as a whole, eliminating potential cross subsidies to or by distributed-generation customers. It expands consumer choice, maintains the ability of ratepayers to understand and control their bills, increases transparency, facilitates lower-cost and higher-benefit investments, and has the greatest potential to help reduce the high generation, distribution and transmission costs that New Hampshire ratepayers currently face.

Q: What is the benefit of a transition to time-of-use (TOU) rates for distributed energy resources?

A: The value of each type of distributed resource is determined with the time pattern of the energy it delivers to the system directly (as exported energy) or indirectly (as reduction in the host customer's load). The daily and seasonal patterns of energy production are very different for photovoltaic systems with different orientations, with more east-facing systems producing more energy in the morning, south-facing systems producing more in the middle of the day, and west-facing system producing more in the afternoon. Orientation and tilt of the panels also affects the seasonal production patterns. Other distributed generation (small wind, biogas, combined heat and power) will have even more varied patterns. Energy storage will enable a user to consume energy in low-cost periods, and return it in high-cost hours, whatever those are over time. Technology-neutral time-of-use charges and credits will automatically price these complex patterns in a more fair and accurate manner.

Many parts of the electric system have costs that are driven by the timing of consumption of generation. The costs of energy consumption and the benefits of distributed energy production vary over the day, in response to changes in the marginal price of energy, contribution to the summer daytime peaks that drive generation capacity and cost, contribution to the monthly peak hours that drive transmission cost allocation, and contribution to peaks and other high loads on various parts of the distribution system. The value of the average kWh provided by the various types of distributed resources will similarly vary widely. Any ratemaking scheme with constant energy prices will fail to capture these differences, particularly as applied to a range of different investments and actions, and hence will give misleading price signals regarding the economics of the alternatives.[1]

Over time, the time pattern of the value of energy provided or consumed will change. As renewables and efficiency reduce New England's natural-gas

[1] Pricing structures with charges for the customer's maximum demand would be even worse.

consumption, the current winter premium for gas (and hence electric energy) will decline. If photovoltaics become a large share of New England capacity, the current mid-day summer peaks are likely to move later in the day. Other changes in supply (e.g., Canadian imports, off-shore wind) and demand (e.g., electric vehicles, efficient electric heating) may shift cost patterns in other ways. A pricing system based on cost by time of use can be updated easily to reflect these changes.

To be clear, however, we recommend adopting time-of-use rates for other New Hampshire customers as well, not solely customers with DER. Acadia Center and CLF have made this clear in the ongoing grid modernization docket, IR 15-296.

Q. How should TOU rates be integrated into net metering?

A. When TOU rates become available, netting should be done on a TOU basis. The simplest version of TOU netting uses two numbers at the end of the billing period – (1) net imports or exports off-peak (netted over the course of the month) and (2) net imports or exports on-peak (netted over the course of the month). Unlike two-channel instantaneous netting, time-of-use rates and netting by time-of-use period provides good temporal incentives for customers to manage their load and use dispatchable DER like energy storage.

Q: The Joint Settlement contains significant decreases in the distribution portion of the credits that customers with distributed generation receive. Please state your position on the distribution portion of the credit.

A: Dramatic cuts to distribution credits are not supported by the data in the record, and are unlikely to fully compensate solar for its value to the system. While we are able to support the proposed reductions in distribution credits as a short-term component of the settlement, it is important that the Commission recognize that the proposed reductions are arbitrary and presented as part of a proposed compromise package. The proper level of compensation for reducing loads on the distribution system can be addressed by more complete data collection and analysis, consistent with the process proposed in the Joint Settlement. Without the data collection and pilot initiatives reflected in Phase I, together with a commitment to transition to a more accurate and less arbitrary Phase II credits, the near-term reduction in the distribution credits would be inappropriate. We understand that many of the settling parties (including our clients) would be unlikely to support the Joint Settlement without the transition to value-based credits in Phase II.

Q: How does the prevalence of distributed energy resources in New Hampshire compare to other states?

A: As indicated in Mr. Chernick's initial testimony, New Hampshire has relatively little distributed generation compared to a number of other states in the region, and much less than national leaders in distributed generation. In part as a result of the relatively nascent presence of distributed energy resources in the state, it is unlikely that significant cost under-recovery or cost-shifting is taking place. The low penetration of distributed resources in New Hampshire will not require expensive grid modifications and upgrades. Certainly as compared to the benefits of distributed generation, any costs or other adverse effects can be expected to be de minimis. Indeed, the utilities have largely conceded as much in their testimony.

Given New Hampshire's low penetration of distributed energy resources, modest changes to the existing net metering would be sufficient, but the greater effort to implement a more sophisticated tariff structure reflecting cost variation by time of use is warranted to support transparent, accurate pricing in the medium- and long-term, reflecting the benefits of a range of distributed resources. Refined price signals will increase the value of distributed energy resources (generation, storage, and demand response), while maintaining equity among customers.

Q: Do additional considerations argue for additional data collection and analysis prior to the transition to fully cost-based net-metering rates in 2021?

A: Yes. Over the course of this proceeding, the utilities have demonstrated a scarcity of information about their own systems, which has the potential to adversely affect costs and reliability. The limited information of the New Hampshire utilities on the pattern of loads on their feeders and substations also prevents optimal planning for DER integration and needs to be addressed sooner rather than later for all of these reasons.

A Non-Wires Alternative pilot, as described in the joint testimony filed by Beach, Bean, Epsen, Mueller, Phelps, and Rabago, would refine estimates of the ability of targeted distributed generation to avoid costly upgrades to the transmission grid. As described in Ms. Hawes's initial testimony and discovery responses, pilots in other states have shown this to be possible, but New Hampshire utilities need to develop the supporting planning tools and a demonstrate of local application of this approach.

If New Hampshire continues to fall behind other regional states in both energy efficiency and distributed-generation investment, its distribution costs and its share of regional transmission and generation costs will increase.

Q: What comments do you have on monetary crediting and bidirectional metering?

A: Monetary crediting and bidirectional metering allow the rate structure to differentiate between the embedded-cost retail rate for energy received, including non-bypassable and unavoidable costs described in the Joint Settlement, and the full marginal-cost value of energy exported.

Q: Are low-income customers as a specific customer group identified and addressed in the Joint Settlement?

A: Low-income customers as a specific subset of electric customers are benefited in two particular ways. First, the settlement proposes to create a range of "non-bypassable charges" that must be paid by all customer-generators. These non-bypassable charges include the System Benefits Charge, the funds from which are directed to low-income programming specifically as well as energy efficiency programs that include a carve-out benefiting the state's low-income residents. Second, the Settlement Agreement adopts a pilot, consistent with a proposal advanced earlier in this proceeding by the Office of the Consumer Advocate, which will test the benefits of an adder for power delivered by distributed resource projects of low- and moderate-income residents, to support increased participation by this customer segment.

Q: Are there any key distinctions between small, largely residential, customer generators and the owners of larger distributed energy systems?

A: Yes. Although both share a general need for certainty and transparency, it is more vital that smaller customer-generators have a simple rate structure. This is partly why traditional net metering was created: to provide a simple compensation mechanism for these small distributed generators that was easy for the utilities to implement and easy for customers to understand. In transitioning to any new rates or rate structures, it is essential to continue to prioritize simplicity, ease of understanding, and predictability for smaller customers.

Q: How does the Joint Settlement satisfy HB 1116 and the Commission's May 19, 2016 Order?

A: In spring 2016, the New Hampshire legislature passed HB 1116, which increased the state-wide cap on total net metered projects from 50 megawatts to 100 megawatts and required the PUC to initiate a proceeding to develop alternative net metering tariffs. Specifically, HB 1116 directed that the Commission:[2]

> *shall initiate* a proceeding to develop net alternative net metering tariffs, which *may include* other regulatory mechanisms and tariffs for customer-generators, and

[2] Emphasis added.

> *determine* whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory. In developing such alternative tariffs and any limitations in their availability, the commission *shall consider*: the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time based tariffs pursuant to paragraph VIII; whether there should be a limitation on the amount of generating capacity eligible for such tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and electric distribution utility's administrative processes required to implement such tariffs and related regulatory mechanisms. The commission *may waive or modify* specific size limits and terms and conditions of service for net metering specified in paragraphs I, III, IV, V, and VI that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators. The commission *may approve* time and/or size limited pilots of alternative tariffs.

Regarding its purpose, HB 1116 explained that:

> to promote energy independence, and local renewable energy resources, the general court finds that it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generators facilities and receive fair compensation for such locally produced power while ensuring costs and benefits are fairly and transparently allocated among all customers. The general court continues to promote a balanced energy policy that supports economic growth and promotes energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of cost and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

Consistent with HB 1116, on May 19, 2016, the Commission issued an Order initiating a proceeding to address the issues enumerated in HB 1116 in light of the purpose statement of HB 1116, and also to address, *inter alia*:

1. The performance of marginal cost of service studies by the three regulated electric distribution utilities and the anticipated completion of filing dates for such studies.
2. The timing and sequence of filing by the three regulated electric distribution utilities and other parties of proposed alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators.

3. The extent to which any such tariff or alternative filing must be supported by pre-filed written testimony and related studies and documentation.

This settlement is consistent with the purposes and directives of HB 1116, as well as the Commission's Order. It furthers each of the purposes of HB 1116, including but not limited to the development of competitive markets and customer choice, and, to the extent possible given the limits of currently available data, weighs factors such as the costs and benefits provided by distributed resources, potential cost-shifting, and prompt utility cost recovery. Through value-based tariffs, it advances the objective of lowering rates and improving price signals. The pilots, VDER study, and other information-gathering detailed in the Joint Settlement each address elements of the statute and the Commission's Order, and further policy objectives of the state that include reducing electric rates and enhancing competitive energy options.

Q: Please summarize your recommendations.

A: CLF and Acadia Center both support the transition to a clean, smart energy future that empowers customers and enables the integration of distributed energy resources in a manner that protects both utility and consumer interests. We believe this settlement agreement will benefit New Hampshire ratepayers by facilitating the transition to value-based tariffs for distributed energy resources, while avoiding excessive, arbitrary, abrupt and confusing jumps in compensation rates. While the Joint Settlement reflects many areas of compromise, we believe that it is a reasonable overall approach to satisfy HB 1116 and the Commission's May 19, 2016 Order, while advancing multiple important state policy interests, including reducing ratepayer bills, enhancing consumer protections, ensuring accurate and complete cost recovery, and promoting sound infrastructure investments on both sides of the meter. We further believe that the multi-step nature of this settlement will provide a gradual transition that aligns with pending efforts to modernize New Hampshire's electric grid and rate offerings, including the opportunity to provide time-variant price signals, while providing a pathway to long-term solutions that can support cost-reducing competition and innovation, including technologies not yet developed.

Q: Does this conclude your supplemental testimony?

A: Yes.