

STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION



Development of New Alternative Net Metering)
Tariffs and/or Other Regulatory Mechanisms)
and Tariffs for Customer-Generators)

Docket No. DE 16-576

JOINT SUPPLEMENTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF CONSERVATION LAW FOUNDATION

AND

ELLEN HAWES

ON BEHALF OF ACADIA CENTER

MARCH 10, 2017

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

4 A: Yes.

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

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

14 **Q: Please describe the Joint Settlement.**

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

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

6 **Q: Please summarize the content of the Joint Settlement.**

7 A: The Joint Settlement is described in more detail in the Joint Supplemental Testimony
8 of Thomas Beach, Patrick Bean, Kate Epsen, Fortunat Mueller, Nathan Phelps, and
9 Karl Rabago. In short, it provides for two phases of modification to the existing net
10 metering rate structure. The Joint Settlement proposes that all projects placed into the
11 interconnection queue beginning on September 1, 2017 will be subject to the Phase 1
12 program design. Phase I would include a transition to a new tariff on September 1,
13 2017, with customers taking service under the old program until the utilities have
14 updated their billing systems to make billing under the new tariff possible. This
15 transition would include a number of changes to the method and levels of
16 compensating distributed-generation customers for excess generation. For projects
17 under 100 kW, these changes include:

- 18 • Banking of excess (or exported) kWh would be eliminated as of September 1,
19 2017 and replaced with monetary credits that would not expire until they are
20 used by the customer.
- 21 • As of September 1, 2017, the export credit for gross exports would exclude non-
22 bypassable charges for the state electricity consumption tax and to support low-
23 income programs, energy-efficiency programs, and utility recovery of stranded
24 costs.
- 25 • The distribution credit for projects entering the interconnection queue after
26 August 31, 2017 would be 75% of the volumetric distribution charge for their
27 rate class for monthly net exports.

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

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

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

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

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

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

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

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

24 Over time, the time pattern of the value of energy provided or consumed will
25 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.

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

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

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

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

18
19 **Q: The Joint Settlement contains significant decreases in the distribution portion of**
20 **the credits that customers with distributed generation receive. Please state your**
21 **position on the distribution portion of the credit.**

22 A: Dramatic cuts to distribution credits are not supported by the data in the record, and
23 are unlikely to fully compensate solar for its value to the system. While we are able
24 to support the proposed reductions in distribution credits as a short-term component
25 of the settlement, it is important that the Commission recognize that the proposed
26 reductions are arbitrary and presented as part of a proposed compromise package. The

1 proper level of compensation for reducing loads on the distribution system can be
2 addressed by more complete data collection and analysis, consistent with the process
3 proposed in the Joint Settlement. Without the data collection and pilot initiatives
4 reflected in Phase I, together with a commitment to transition to a more accurate and
5 less arbitrary Phase II credits, the near-term reduction in the distribution credits would
6 be inappropriate. We understand that many of the settling parties (including our
7 clients) would be unlikely to support the Joint Settlement without the transition to
8 value-based credits in Phase II.

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

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

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

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

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

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

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

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

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

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

25 A: Low-income customers as a specific subset of electric customers are benefited in two
26 particular ways. First, the settlement proposes to create a range of “non-bypassable

1 charges” that must be paid by all customer-generators. These non-bypassable charges
2 include the System Benefits Charge, the funds from which are directed to low-income
3 programming specifically as well as energy efficiency programs that include a carve-
4 out benefiting the state’s low-income residents. Second, the Settlement Agreement
5 adopts a pilot, consistent with a proposal advanced earlier in this proceeding by the
6 Office of the Consumer Advocate, which will test the benefits of an adder for power
7 delivered by distributed resource projects of low- and moderate-income residents, to
8 support increased participation by this customer segment.

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

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

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

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

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

² Emphasis added.

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

16 Regarding its purpose, HB 1116 explained that:

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

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

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

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

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

13 **Q: Please summarize your recommendations.**

14 A: CLF and Acadia Center both support the transition to a clean, smart energy future that
15 empowers customers and enables the integration of distributed energy resources in a
16 manner that protects both utility and consumer interests. We believe this settlement
17 agreement will benefit New Hampshire ratepayers by facilitating the transition to
18 value-based tariffs for distributed energy resources, while avoiding excessive,
19 arbitrary, abrupt and confusing jumps in compensation rates. While the Joint
20 Settlement reflects many areas of compromise, we believe that it is a reasonable
21 overall approach to satisfy HB 1116 and the Commission's May 19, 2016 Order, while
22 advancing multiple important state policy interests, including reducing ratepayer
23 bills, enhancing consumer protections, ensuring accurate and complete cost recovery,
24 and promoting sound infrastructure investments on both sides of the meter. We further
25 believe that the multi-step nature of this settlement will provide a gradual transition
26 that aligns with pending efforts to modernize New Hampshire's electric grid and rate

1 offerings, including the opportunity to provide time-variant price signals, while
2 providing a pathway to long-term solutions that can support cost-reducing
3 competition and innovation, including technologies not yet developed.

4 **Q: Does this conclude your supplemental testimony?**

5 A: Yes.