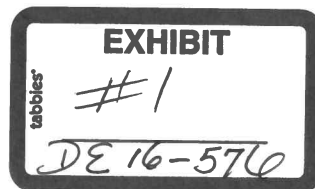


STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION



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

Docket No. DE 16-576

ENERGY FUTURE COALITION SUPPLEMENTAL SETTLEMENT TESTIMONY OF

R. THOMAS BEACH

AND

PATRICK BEAN

AND

KATE BASHFORD EPSEN

AND

FORTUNATE MUELLER

AND

NATHAN PHELPS

AND

KARL R. RABAGO

1 **I. INTRODUCTION**

2 **Q. Mr. Beach, please state your name, position and business address.**

3 A. My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy.
4 My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

5 **Q. Mr. Bean, please state your name, position and business address.**

6 A. My name is Patrick Bean. I am a Deputy Director of Policy and Electricity Markets at SolarCity, a
7 wholly owned subsidiary of Tesla, Inc. My business address is 601 13th Street NW, Suite 900,
8 Washington, DC 20005.

9 **Q. Ms. Epsen, please state your name, position and business address.**

10 A. My name is Kate Bashford Epsen and I am the Executive Director of the New Hampshire Sustainable
11 Energy Association (“NHSEA”). NHSEA’s business address is 54 Portsmouth Street, Concord, NH
12 03301.

13 **Q. Mr. Mueller, please state your name, position and business address.**

14 A. My name is Fortunat Mueller. I am co-founder and managing partner of ReVision Energy. My
15 business address is 142 Presumpscot St, Portland, ME 04103.

16 **Q. Mr. Phelps, please state your name, position and business address.**

17 A. My name is Nathan Phelps. I serve as the Program Manager of Distributed Generation (“DG”)
18 Regulatory Policy for Vote Solar. My business address is 745 Atlantic Avenue, 7th floor, Boston,
19 Massachusetts 02111.

20 **Q. Mr. Rábago, please state your name, position and business address.**

21 A. My name is Karl R. Rábago. I am the Executive Director of the Pace Energy and Climate Center at
22 the Pace University School of Law. My business address is 78 North Broadway, White Plains, New
23 York.

24 **Q. On whose behalf are you filing this settlement testimony?**

25 A. We are appearing on behalf of the Energy Future Coalition (“the Coalition”) which is comprised of
26 Acadia Center (“Acadia”), the Alliance for Solar Choice (“TASC”), Borrego Solar, the Conservation

1 Law Foundation (“CLF”), the Energy Freedom Coalition of America, LLC (“EFCA”), the New
2 Hampshire Sustainable Energy Association (“NHSEA”), ReVision Energy (“ReVision”), Granite
3 State Hydropower Association, Sunraise Investments LLC, Solar Endeavors, LLC, and Revolution
4 Energy, LLC.

5 **Q. What is the Energy Future Coalition?**

6 A. The Coalition is composed of parties participating in the DE 16-576 proceeding and that share
7 common positions in regard to the future of distributed energy resources (“DER”) and the electricity
8 system in New Hampshire. In particular, the parties share an interest in creating a comprehensive
9 roadmap for New Hampshire’s Public Utility Commission (“PUC”), utilities, DER providers and
10 other stakeholders that moves the State from Net Energy Metering (“NEM”) to a value-based
11 compensation system created through a transparent and data driven process. The parties entered a
12 Joint Settlement as the Coalition in order to develop the roadmap, identify system-wide data gaps and
13 collection of necessary information, immediately begin the transition to a value based program that
14 sends stronger and more precise price signals, and ultimately leverage DER to help reduce the cost of
15 electricity for all New Hampshire ratepayers.

16 **Q. What is the purpose of your testimony?**

17 A. We will outline the comprehensive roadmap and measures required to begin the transition to a
18 smarter energy future. We describe the rationale behind the proposal, how the compromise is in the
19 public’s interest, and how the proposal meets the statutory requirements of House Bill 1116 (“HB
20 1116”).

21 **Q. Do you incorporate by reference the testimony that you previously filed in this docket?**

22 A. Yes, we incorporate by reference the testimony that we have previously filed in this docket.¹

23 **Q. Please summarize the requirements of HB 1116.**

24 A. In May 2016, the New Hampshire General Court and Governor enacted a bill that increased the cap
25 on net metering projects from 50 megawatts to 100 megawatts, and also required that the PUC initiate
26 a proceeding to develop alternative net energy metering tariffs. The General Court’s stated purpose of

¹ Testimony and Rebuttal Testimony of R. Thomas Beach, DE 16-576, October 24, 2016 and December 21, 2016; Testimony and Rebuttal Testimony of Patrick Bean, DE 16-576, October 25, 2016 and December 21, 2016; Testimony of Kate Epsen, Nathan Phelps and James Bride, DE 16-576, October 24, 2016; Rebuttal Testimony of Karl R. Rábago, Nathan Phelps and James Bride, DE 16-576, December 21, 2016.

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

9 **Q. Does the Coalition’s proposal meet the objectives of HB 1116?**

10 A. Yes. The proposal reflects a consideration of HB 1116’s many objectives. First and foremost, it
11 considers the costs and benefits of customer-generator facilities, an avoidance of unjust and
12 unreasonable cost shifting, and its rate effects on all customers. The Coalition’s proposal also seeks to
13 develop pilot programs, data collection, and an independent value of DER (“VDER”) study sponsored
14 by the PUC in order to ensure “costs and benefits are transparently allocated among all customers.”
15 The proposal promotes energy independence, a diversified and distributed energy mix, reliability, and
16 local renewable energy sources. It seeks to allow reasonable opportunities for customer-generators
17 and others to invest in and interconnect with local renewable energy projects, for which customer-
18 generators will receive fair compensation based on fair and transparently allocated costs and benefits.
19 Finally, the proposal charts a path from the present to a modern, flexible grid that benefits all
20 ratepayers and provides regulatory predictability for the PUC, utilities, DER providers and other
21 stakeholders.

22 **II. Summary of the Coalition Proposal**

23 **Q. Please provide an overview of the Coalition settlement proposal.**

24 A. At the core of the Coalition’s proposal is a gradual transition from net energy metering to value-based
25 tariffs that includes step downs in the distribution credit for net exports until an independent, PUC
26 sponsored study of VDER is conducted and will serve as the basis for valuing and crediting exports
27 from DER in the future. The Coalition refers to the transition period as Phase 1, while Phase 2 refers
28 to the program in which a customer’s exports are credited at the VDER and when other optional rates,
29 such as time-of-use (“TOU”) and or “Smart Home Rates” are made available to all ratepayers.

1 The Coalition proposal also seeks to begin the collection of non-bypassable charges from customer
2 generators based on their delivered loads, the move to monetary crediting from volumetric (kilowatt-
3 hours or “kWh”) crediting, and the initiation of data collection and pilot programs that will inform the
4 ultimate design of the Phase 2 program.

5 Exhibit 1 appended to our testimony outlines the proposal by topic and applicability to small and
6 large projects. Much of our testimony relates to projects that are 100 kilowatts (kW) in capacity or
7 less.

8 **Q. Are you making any changes to the program applicable to large projects (greater than 100**
9 **kW)?**

10 A. The proposal makes minor changes to the program for larger projects in the near term. These include
11 clarifying commodity billing for group hosts, and creating an optional program to receive a
12 transmission credit for demonstrated load reduction during the hour of coincident peak.

13 **Q. Please describe the design of the Coalition’s Phase 1 program.**

14 A. The Coalition’s proposes that all projects placed into the interconnection queue beginning on
15 September 1, 2017 will be subject to the Phase 1 program design. Customers would be billed non-
16 bypassable charges on all imported kWh and would not receive credit for non-bypassable charges for
17 any exported kWh, thus ensuring that all customers pay non-bypassable charges on their delivered
18 volumes from the utility. The non-bypassable charges includes the Stranded Cost Charge; System
19 Benefit Charge; Storm Recovery Adjustment; Electricity Consumption Tax. In order to charge for
20 non-bypassable charges, new projects placed in the interconnection cue beginning September 1, 2017
21 would require two-channel meters that measure imports from the utility and exports to the utility.

22 For other billing components, customers with DER would pay the full generation, transmission and
23 distribution rates for all net imports during the course of a month. For net monthly exports, the
24 customers would be credited at the retail supply rate for generation, the full transmission charge for
25 their rate class, and a portion of the distribution rate component as further described below.

26 For the distribution component of the credit for exported power, projects placed in the interconnection
27 queue beginning on September 1, 2017 would be credited at 75% of the volumetric distribution
28 charge for their rate class for monthly net exports. Projects placed in the interconnection queue
29 beginning on January 1, 2019 would be credited at 50% of the prevailing volumetric distribution rate.

1 The Coalition proposes that projects placed in the interconnection queue beginning on January 1,
2 2021 be subject to the Phase 2 requirements.

3 **Q. Why do you believe that your crediting proposal is fair to all stakeholders, including non-**
4 **participating ratepayers, and does not result in undue cost shifts?**

5 A. The Coalition continues to stand by its testimony in this case, which, as required by HB 1116,
6 presented a comprehensive benefit-cost methodology for valuing customer-sited DG resources. This
7 methodology examined the benefits and costs from the multiple perspectives of the key stakeholders
8 and analyzed a comprehensive list of benefits and costs using a long-term, life-cycle analysis. These
9 analyses concluded that solar DG is a cost-effective resource for all of the utilities, as the benefits
10 equal or exceed the costs in the Total Resource Cost and Societal tests. The benefits and costs for
11 non-participating ratepayers are also reasonably balanced, as shown by the Rate Impact Measure
12 (RIM) test results. The RIM results indicate that there is no significant cost shift to non-participating
13 ratepayers. In fact, in the long-run these other customers will also realize net benefits, both direct and
14 societal, from DG development under net metering. Given these results, the Coalition's compromise
15 proposal with lower distribution credits than assumed in our benefit-cost analyses, plus monetary
16 crediting and possible additional cost-based fees on DG customers, will provide additional benefits to
17 non-participating ratepayers flowing from customer generators.

18 **Q. Why are you proposing monthly netting for other billing components but not for non-**
19 **bypassable charges?**

20 A. Currently, net metering customers receive the non-bypassable charge in net metering credit
21 calculations. The Coalition recognizes that evidence was not provided in this proceeding that
22 demonstrates that DG provides benefits to all distribution company customers relative to the non-
23 bypassable charge components. Accordingly, the Coalition believes that VDER for these components
24 is zero for the purposes of this proceeding. As a result, we propose that Phase 1 customers be subject
25 to non-bypassable charges on an instantaneous netting basis, while netting on a monthly basis for all
26 other charges.

27 Unlike the non-bypassable charge elements, DG does provide benefits to all distribution company
28 customers, and thus at least a portion of the distribution rate should be included in the export credit.
29 As such, the current net metering framework of monthly netting is maintained until such time as the
30 VDER dictates otherwise.

1 **Q. Do you have concerns about instantaneous netting?**

2 A. Yes. Instantaneous netting does not send good price signals and can be complicated for customers to
3 understand. First, instantaneous netting results in a distorted price signal to customers and encourages
4 behavior that is suboptimal for the electric system. Instantaneous netting only makes sense when an
5 entity wants to charge a customer a different price for using electricity from the utility than for
6 exporting electricity to the utility. If a customer is charged more for electricity deliveries from the
7 utility than they receive for electricity exports, then the customer is financially motivated to use as
8 much electricity on-site regardless of the impacts on the electric system. For instance, under
9 instantaneous netting a customer with a solar system would be financially motivated to program their
10 dishwasher to run during hours when their solar system would produce electricity, rather than
11 program their dishwasher to run in the middle of the night in order for optimal usage of the electricity
12 system. Although flat monthly rates do not send very good price signals in general, flat monthly rates
13 combined with monthly netting motivate customers to maximize production and minimize
14 consumption through energy conservation, energy efficiency, and DER implementation as a whole.
15 The Coalition is strongly supportive of rate structures that will further send price signals to customers
16 to maximize production during periods of electric system constraints and minimize consumption
17 during periods of electric system constraints, such as TOU rates with netting during each time period.

18 Furthermore customers currently only receive a limited amount of data from utilities about their
19 consumption. Most often this is the customer's monthly consumption, and sometimes hourly
20 consumption. Instantaneous customer demand data is not currently available – and likely will not be
21 available in the near future² -- which therefore makes it difficult for DER providers to confidently
22 forecast potential energy savings to prospective customers, and for customers to understand the value
23 of investing in DER. Experience in other states has shown that there can be a significant difference in
24 exported volumes depending on whether netting occurs on a monthly, hourly, or instantaneous basis.
25 These differences are also customer-specific, depending on the details of the customer's load profile
26 and solar system. Data to assess and understand these differences in the New Hampshire market do
27 not exist at present. Accordingly, the lack of real-time information to customers combined with
28 instantaneous netting creates, at best, an obfuscated price signal to customers to operate in a manner
29 that is beneficial to the electric system.

² See Eversource's response to TASC 3-11 and Unital's response to TASC 3-7.

1 Secondly, customers understand monthly netting, and they may not respond well to the idea of
2 instantaneous netting. Currently, many customers – especially residential customers – are sheltered
3 from price fluctuations in electricity markets. While we are strongly supportive of sending better price
4 signals to customers in order to optimize the use of the electricity system, instantaneous netting
5 layered on top of other price signals may confuse customers and, as discussed above, result in
6 suboptimal customer behavior. Monthly netting is easy to understand for customers and preserves the
7 current motivation to use less electricity through conservation and energy efficiency, and therefore
8 advances NH state policy.

9 **Q. Please describe the Coalition’s monetary crediting proposal.**

10 A. The current net energy metering program for customer-generators credits customers on a volumetric
11 (kWh) basis. For example, if a customer exports energy in the summer months such that they have a
12 balance of 500 kWh credits at the end of September, those kWhs can be credited towards the
13 customer’s consumption in the winter months when their DERs are producing less. With monetary
14 crediting, each excess kWh is assigned a monetary value. In the example above, the summer credits
15 would have a value of 12 cents/kWh, thereby equating to a credit of \$60 that the customer can apply
16 to their winter bills. If electricity prices are the same in every month, then kWh crediting and
17 monetary crediting have the same value. However, electricity prices in New Hampshire often exhibit
18 seasonal differences due to underlying generation supply costs. Therefore, moving to monetary
19 crediting is a compromise by the Coalition that would reduce the value of DER for the customer due
20 to the seasonal electricity price and DER production differentials between summer and winter
21 months. Moving to monetary crediting also supports the transition to greater dependence on time-
22 dependent rates. States such as Arizona and California that have large solar markets and widespread
23 use of TOU rates employ monetary crediting. The Coalition proposes that all customers placed in the
24 interconnection queue beginning on September 1, 2017 be subject to monetary crediting.

25 **Q. Have you performed any calculations with regards to the potential impacts of the Coalition**
26 **proposal?**

27 A. Yes. We created a bill impact model to demonstrate the impacts of solar systems up to 100 kW. The
28 model compares the bills of customers with solar under the current regime (a.k.a. the status quo) to
29 the bills of customers with solar under the Coalition’s Phase 1 proposal. The model evaluates the
30 proposal for the periods of 2014 to the present as a counterfactual in order to capture the changes in

1 rates over time (including changes to default service), rather than use steady-state assumptions for
2 rates.

3 **Q. What are the results of the modeling?**

4 A. The modeling shows that on September 1, 2017, an average residential solar customer that consumes
5 600 kWh a month and has a 6 kW array would see an average monthly increase to their electric bill of
6 between 9.73% and 22.65% compared to the status quo. On January 1, 2019, the increase rises to
7 between 12.34% and 25.39%. Table 1, below, is a summary of the percentage increase from the status
8 quo for all customer classes.

Table 1: Bill Impact Summary of the Percentage Difference From Status Quo	Coalition Proposal Phase 1, 9/1/17	Coalition Proposal Phase 1, 1/1/19
Eversource Residential	22.65%	25.39%
Liberty Residential	16.27%	18.56%
Unitil Residential	9.73%	12.34%
Eversource Small C&I	1.87%	1.92%
Liberty Small C&I	3.69%	3.75%
Unitil Small C&I	1.63%	1.63%
Eversource Medium C&I	0.12%	0.12%
Liberty Medium C&I	0.12%	0.12%
Unitil Medium C&I	0.27%	0.27%
Eversource Large C&I	0.01%	0.01%
Liberty Large C&I	0.01%	0.01%
Unitil Large C&I	0.01%	0.01%

9 Exhibit 2, appended to our testimony, presents the model.

10 **Q. What are the bill impacts on a monetary basis?**

11 A. The modeling shows that on September 1, 2017, an average residential solar customer that consumes
12 600 kWh a month and has a 6 kW array would see an average monthly increase to their electric bill of
13 between \$1.63 and \$4.38 compared to the status quo. On January 1, 2019, the increase rises to
14 between \$2.07 and \$4.91. Table 2, below, is a summary of the monetary increase from the status quo
15 for all customer classes.

Table 2: Bill Impact Summary of the Average Monetary Monthly Difference From Status Quo	Coalition Proposal Phase 1, 9/1/17	Coalition Proposal Phase 1, 1/1/19
Eversource Residential	\$4.38	\$4.91
Liberty Residential	\$2.95	\$3.36
Unitil Residential	\$1.63	\$2.07
Eversource Small C&I	\$2.02	\$2.08
Liberty Small C&I	\$2.05	\$2.08
Unitil Small C&I	\$2.16	\$2.16
Eversource Medium C&I	\$17.38	\$17.38
Liberty Medium C&I	\$16.21	\$16.21
Unitil Medium C&I	\$29.26	\$29.26
Eversource Large C&I	\$9.54	\$9.54
Liberty Large C&I	\$10.02	\$10.02
Unitil Large C&I	\$11.52	\$11.52

1

2 **Q. Why are you proposing a September 1, 2017 start date to Phase 1 rather than at the time of the**
3 **Commission order in this proceeding?**

4 A. DER systems represent major investments and the timeline from initial contracting through financing
5 to the operation date can take several months or more. If a Commission Order were to be filed in the
6 next few months that includes a dramatic departure from the current NEM program, DER providers
7 could be left scrambling to upgrade systems, retrain sales staff, and educate prospective customers
8 about DER opportunities. Beginning September 1, 2017 gives the companies some time to make
9 changes and adapt to the new program. Potential net metering customers should also be afforded the
10 opportunity to account for policy changes that will impact their potential investment. An abrupt
11 change in policy would harm potential net metering customers that are in the decision-making process
12 and future net metering customers that are in the process of installing DG. Moreover, based on the
13 most recent available utility data, Eversource, Liberty Utilities, and Unitil have 16.3 megawatts
14 (“MW”),³ 3.65 MW,⁴ and 3.2 MW⁵ of capacity allocations available, respectively, for small projects
15 up to 100 kW under the existing Net Metering program. Although significant capacity is available
16 under the current program, the Coalition is willing to begin transitioning small projects (below 100

³ Eversource Net Metering Program Capacity Cap as of February 6, 2017.

<https://www.eversource.com/Content/nh/about/doing-business-with-us/builders-contractors/interconnections/new-hampshire-net-metering/new-hampshire-net-metering-program-capacity-cap>

⁴ Liberty Utilities Net Metering Status as of February 17, 2017. <https://new-hampshire.libertyutilities.com/uploads/Rates%20and%20Tariffs/Net%20Metering/NetMeteringWeeklyStatusReportFeb17.pdf>

⁵ Unitil Energy Systems Net Metering Cap Allocation Status as of February 16, 2017. <http://unitil.com/energy-for-residents/electric-information/distributed-energy-resources/net-metering>

1 kW) to the new rules in the coming months in order to create a program that is value based and sends
2 customers more precise price signals.

3 **Q. What if utilities are unable to update their billing and metering systems for Phase 1 customers**
4 **by September 1, 2017?**

5 A. If utilities are unable to administer the Phase 1 program by September 1, 2017, customers can be
6 billed under the current program until the utilities' systems are capable of billing Phase 1. Under such
7 a scenario, utilities should provide customers with thirty days' notice of when their billing will
8 convert to the Phase 1 program and reduced crediting value. Customers would not be subject to any
9 retroactive adjustments back to September 1, 2017.

10 **Q. Does the Coalition's proposal include a separate rate class for customer-generators or DER**
11 **customers?**

12 A. No. The Coalition is not proposing to create a separate rate class for DER customers. In accordance to
13 Section I of HB 1116, the Coalition recommends that DER customers take service under "standard
14 tariffs" which "shall be identical, with respect to rates, rate structure, and charges, to the tariff under
15 which a customer-generator would otherwise take default generation supply service from the
16 distribution utility."

17 **Q. Please describe the design of the Coalition's Phase 2 program.**

18 A. The Coalition's proposes that DER customers placed in the interconnection queue beginning on
19 January 1, 2021 be credited for their monthly exports at the Value of DER as determined by an
20 independent, Commission sponsored VDER study.

21 **Q. Why are a gradual transition and a long-term roadmap important in this proceeding?**

22 A. Providing measured, gradual steps along with a roadmap gives utilities and New Hampshire's DER
23 providers greater certainty in order to plan and adapt their businesses. It also provides greater
24 certainty to customers. A sudden and drastic change from the net energy metering framework can
25 have severe economic consequences for the State, its DER industry and their customers. Such a
26 change occurred in Nevada in late 2015, when rate changes were announced on December 22, 2015
27 and implemented effective January 1, 2016. Bill savings for typical net metered customer fell by 42%

1 or more.⁶ As a comparison, Eversource's and Unitil's proposals in this case would reduce customer
2 bill savings by 47% - 51%, and 60% - 63%, respectively.⁷ In Nevada, the sudden rate change led to a
3 99% decline in solar applications—down to just 287 solar applications statewide in 2016.⁸ A recent
4 report found the state lost 2,687 rooftop solar jobs in 2016,⁹ and the Governor of Nevada's Chief
5 Strategy Officer testified that the decision “damaged” Nevada's international reputation.¹⁰

6 Subsequently, the Governor of Nevada asked for a “new direction” for the Public Utilities
7 Commission and replaced two of the three Commissioners. The new Commission ruled that the 2015
8 order was “incongruous with the policy of the State of Nevada...and the public interest.”

9 Articulating the general direction in which New Hampshire intends to move towards such as value
10 based or dynamic pricing programs, gives utilities and DER providers some certainty about how to
11 upgrade their billing systems (along with the required flexibility to accommodate incremental
12 changes rather than complete system overhauls), adapt their business models, make additional
13 investments (such as in metering infrastructure), and retrain their sales teams. It also provides greater
14 certainty and information to prospective DER customers. One of the general court's stated objectives
15 for HB 1116 was to promote “regulatory predictability” and for the Commission to consider
16 “administrative processes required to implement such tariffs and related regulatory mechanisms.” The
17 Coalition believes its proposal provides that to utilities, DER providers, customers and other
18 stakeholders.

19 **Q. Are there examples of programs in other States that are similar to the Coalition's phased-in**
20 **proposal?**

21 A. Yes. In New York, electricity distribution utilities and DER providers came to agreement in 2016 that
22 new on-site (i.e., not virtual or remote net metering systems) DER installations should continue under
23 the existing net energy metering program. The agreement proposed that new on-site DER projects

⁶ Direct testimony of R. Thomas Beach, Application of Nevada Power Company d/b// NV Energy and Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of Cost of Service Study and Net Metering Tariffs. Dockets Nos. 15-07041 and 15-07042. February 1, 2016. Pg. 15.

⁷ Rebuttal Testimony of R. Thomas Beach, Docket No. DE 16-576, December 21, 2016, at pg. 44.

⁸ Rothberg, D. February 20, 2017. “Energy updates: Coal is out, NV Energy asks to boost rooftop solar incentives.” The Las Vegas Sun. Available from <https://lasvegassun.com/news/2017/feb/20/energy-updates-no-gas-plant-for-nv-energy-the-sola/>

⁹ Whaley, S. February 7, 2017. “Nevada loses 400 solar jobs, but still ranks 4th nationally.” The Review-Journal. Available from <http://www.reviewjournal.com/business/energy/nevada-loses-400-solar-jobs-still-ranks-4th-nationally>

¹⁰ Whaley, S. March 22, 2016. “Official: Fallout from PUC ruling tarnished Nevada's clean energy image.” The Review-Journal. Available from <http://www.reviewjournal.com/business/energy/official-fallout-puc-ruling-tarnished-nevada-s-clean-energy-image>

1 beginning in January 1, 2020 would transition to a value-based program.¹¹ On March 9, 2017, the
2 New York Public Service Commission issued an order in which net energy metering would continue
3 for new on-site DER projects, and DER projects placed into service after January 1, 2020 would take
4 service under a value-based tariff in which the customer would receive monetary credits for net
5 hourly injections at the calculated VDER.¹²

6 **Q. Is the Coalition proposing application fees?**

7 A. The Coalition is not recommending any changes to interconnection application fees at this time.
8 However, we are open to utilities filing for an application fee based on demonstrated administrative
9 processing costs, and according to case DE 15-271.

10 **Q. Are you proposing any changes to the customer charge?**

11 A. No changes to the customer charge are recommended by the Coalition at this time due to a lack of
12 data showing incremental customer costs specific costs. The Coalition is open to utilities filing
13 supplemental customer charges for DER customers only if total customer-related costs for DER
14 customers are higher than for non-DER customers in the same rate class. The supplemental customer
15 charges would cover demonstrated incremental customer-related costs (i.e., for metering, billing, or
16 interconnection) that are specific to DER customers and adequately demonstrated with competent,
17 objective evidence. These incremental costs should be tracked in separate utility accounts in order to
18 more easily audit the charges and ensure that one-off costs are not being charged as recurring in
19 perpetuity.

20 **Q. What does the Coalition recommend in regard to grandfathering projects?**

21 A. HB 1116 grandfathers existing eligible customer-generators through December 31, 2040. The
22 Coalition recommends that any customers placed in an interconnection queue between September 1,
23 2017 and December 31, 2020 (i.e., Phase 1 customers) also be grandfathered in their existing
24 programs through December 31, 2040. For Phase 2 customers, the Coalition recommends a twenty-
25 year grandfathering provision. The Coalition also recommends that customers have the option to
26 voluntarily request a transition to alternative programs in the future (which would cancel their
27 existing grandfathering provision).

¹¹ New York Case 15-E-0751 “In the Matter of the Value of Distributed Energy Resources.” Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering. April 18, 2016.

¹² New York Case 15-E-0751 “In the Matter of the Value of Distributed Energy Resources.” Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. March 9, 2017.

1 **Q. Why does the Coalition recommend 20-year grandfathering for Phase 2 projects?**

2 A. Customers often finance or lease their solar or DER technologies, which have useful lives in excess of
3 30 years. The decision to lease, purchase, or finance a DER system is an investment-backed decision
4 based on an expectation of a reasonable opportunity to recover that investment through credit for
5 energy production over the life of the investment. In order to provide financing, underwriters will
6 look for assurances that the customers will not be subject to program changes that could impede their
7 ability to pay for the loans or leases.

8 **Q. Please summarize the optional transmission program proposed for large projects.**

9 A. The proposal is to create an opt-in program that enables large projects to receive a credit for
10 demonstrated avoidance of transmission charges. Participants in this program would be required to
11 have a utility-owned revenue-grade production meter in order to demonstrate the production, and
12 therefore system load reduction, at the hour of coincident peak.

13 **Q: How does this settlement propose addressing Renewable Energy Certificates that are associated**
14 **with net-metered DER production?**

15 A. The Coalition proposes that REC ownership remain with the customer-generator, but that utilities will
16 work with both customers, aggregators, and other relevant third parties to better facilitate the creation
17 of RECs by the customer-generator, and that utilities may choose to purchase RECs directly from a
18 customer for a fixed fee. REC creation, aggregation, and sales have been historically difficult and
19 cost-ineffective for small residential customer-generators. Utility-led facilitation and assistance with
20 RECs may better enable residential and lower-income customer-generators to participate in
21 reasonable opportunities to invest in DER.

22 **III. Data Collection, Pilot Studies and Analysis**

23 **Q. Do you have any recommendations about measures that can help get New Hampshire to Phase**
24 **2?**

25 A. Yes, we recommend that, following the Commission's order in this proceeding, stakeholder working
26 groups convene to formulate pilot studies, establish data collection requirements, and develop a
27 VDER study methodology, all of which would run in parallel to the Phase 1 program. These measures
28 would require approval of the Commission and ultimately would be used to inform the crediting value
29 in Phase 2, optional tariffs, and more transparent distribution planning procedures that can leverage
30 the value of DER.

1 **Q. Do you believe there are currently data gaps in the utilities' case regarding the costs and**
2 **benefits of customer-generator facilities?**

3 A. Yes. A fair and transparent calculation of the costs and benefits of customer-generator or DER
4 technologies adequate to support rate making requires New Hampshire-specific data and empirical
5 evidence. The utilities did not quantify the full range of relevant costs and benefits of DER. For
6 example, in Eversource's initial testimony it claimed "that the future costs to integrate a higher
7 penetration of DG will be considerable."¹³ Yet, when asked whether they quantified those costs, their
8 response was "no."¹⁴ Moreover, when asked whether Eversource quantified the benefits of distributed
9 generation, the company responded that it discussed the benefits "in a qualitative manner."¹⁵ Until
10 applied subjective assumptions to cost of service data derived from customers without installed
11 DER.¹⁶ The determination of costs and benefits of DER and new crediting mechanisms cannot rely on
12 qualitative observations or assumptions unsupported by empirical data. In order to develop more
13 precise price signals, more granular spatial and temporal data is required, such as circuit level hourly
14 customer demand and forecasted demand, reliability events driven by DER, and marginal cost of
15 service studies. This data must, in turn, be incorporated into an objective analysis of both costs and
16 benefits (avoided costs) resulting from the operation of distributed generation.

17 **Q. Do you have data collection recommendations?**

18 A. Several parties provided recommendations for data collection in written testimony and discovery. The
19 Coalition suggests that a collaborative working group build off the recommendations in the current
20 record and the ongoing Grid Modernization proceeding in order to develop a data collection proposal
21 for the PUC's consideration.

22 **Q. Why is the Coalition proposing an independent, Commission sponsored VDER study?**

23 A. The Coalition is seeking a constructive approach to a value-based crediting system. Utilities are
24 currently skeptical of the value that DER provide to all ratepayers, and are skeptical of the results of
25 studies sponsored by DER providers. Therefore, we propose that an objective and independent party

¹³ Joint testimony of Richard C. Labrecque and Russel D. Johnson. DE 16-576. October 24, 2016. Pg. 23, lines 8-9.

¹⁴ Eversource response to EFCA 3-003.

¹⁵ Eversource response to EFCA 3-011.

¹⁶ Prefiled Rebuttal Testimony of Karl R. Rábago, Docket No. DE 16-576, December 16, 2016, at pp. 21-25, p. 27, lines 12-18.

1 sponsored by the PUC conduct the analysis and be subject to cross examination and review by all
2 interested parties.

3 **Q. Please describe the timeline for such a study.**

4 A. In order to implement Phase 2 by January 1, 2021 and give parties sufficient time to retrain staff and
5 upgrade systems, the independent VDER study must be completed by early 2020. We recommend
6 that following the Order in this case, a collaborative working group develop the data requirements
7 and methodologies for approval by the PUC. The 2020 study would then utilize the best available
8 data and methodologies to arrive at a VDER.

9 **Q. Are you envisioning a single study or would there be additional VDER studies in the future?**

10 A. We suggest that, once developed and approved by the PUC, the VDER study be updated every three
11 years and utilize the best available data and methodologies at the time of the update in order to
12 continually improve the precision of price signals and promote innovation as a way to reduce system
13 costs.

14 **Q. What pilot programs are you proposing in your Settlement Agreement?**

15 A. The Coalition is proposing four pilot studies. These include an incentive mechanism that helps enable
16 DER adoption by low to moderate income customers, a TOU pilot, a “Smart Energy Home” pilot, and
17 a non-wires alternative pilot.

18 **Q. Please describe the low to moderate income pilot program.**

19 A. Adoption of DER by low to moderate income customers is currently lagging, and the intention of this
20 program is to provide more DER opportunities for low to moderate income customers. We
21 recommend a collaborative working group develop a pilot program that builds off the
22 recommendation by the Office of Consumer Advocate¹⁷ and that helps overcome barriers to DER
23 adoption by low to moderate income customers. The Coalition recommends that the pilot include a
24 minimum of 100 customers for each utility.

25 **Q. What is the TOU pilot?**

26 A. At present, Eversource and Liberty Utilities both have optional TOU rates for residential and small
27 commercial customers. However, the on-peak periods are very long, do not accurately reflect the

¹⁷ Direct testimony of Elizabeth Doherty. DE 16-576. October 24, 2016.

1 length of the system peak, and do not provide customers with reasonable opportunities to shift
2 consumption to off-peak hours. For example, Liberty Utilities' on-peak period is thirteen hours long
3 from 8 a.m. to 9 p.m., while their data shows that demand within 5% of peak occurred between 11
4 a.m. and 6 p.m. Similarly, Eversource's on-peak period is 13 hours and occurs 7 a.m.- 8 p.m. on non-
5 holiday weekdays.

6 The objective of this pilot is to create a more actionable TOU rate that is designed to recover the
7 underlying energy and delivery revenue requirements and send signals to customers about the high
8 demand times that are driving additional investments and costs in generation, transmission, and
9 primary distribution. This TOU pilot also would be developed by a collaborative working group that
10 would recommend a specific design to the PUC for approval.

11 **Q. What is the "Smart Energy Home" Pilot?**

12 A. The objective of this optional Smart Home Rate pilot is to test rate designs such as real-time pricing,
13 critical peak pricing, demand charges, or other structures that enable customers to adopt a variety of
14 technologies and behaviors to manage their electricity consumption.

15 We envision a voluntary Smart Home Rate that send customers accurate and actionable signals
16 customers to shift their consumption to times when the system is under-utilized.

17 **Q. In previous written testimony many witnesses criticized the utilities' demand charge proposals,
18 why are you proposing they potentially be included in a pilot study here?**

19 A. In their written testimony, Unitil and Eversource proposed mandatory non-coincident demand
20 charges for new distributed generation customers. To date, no State Utility Commissions have
21 approved mandatory demand charges for residential or distributed generation customers. Moreover,
22 very few studies focusing on residential demand charges have been conducted.¹⁸ Given the utilities'
23 interest in demand charges and the lack of experience or research nationwide, we are open to working
24 with utilities to develop a more accurate and actionable optional demand-based rates than the 15- or
25 30-minute non-coincident charges proposed in their testimony

26 **Q. Please describe the non-wires alternative pilot.**

¹⁸ Chtkara, A. Cross-Call, D. Li, B., Sherwood, J. 2016. "A Review of Alternative Rate Designs" Pg. 60. (Submitted into the record as an attachment to EFCA's response to UES 3-1).

1 A. The objective of this pilot is to test the concept of deploying DER to areas in order to replace or defer
2 traditional transmission and distribution investments (such as new lines and substations). The
3 program leverages DER as a cheaper alternative to traditional investments as a way to maintain
4 system reliability while minimizing system costs. We recommend the pilot be designed to test
5 incentive mechanisms that drive investments to specific areas on the grid, to collect data about the
6 positive impact DERs can have on the distribution system, and to gain experience integrating these
7 relatively new resources in utility planning processes and operations. This pilot will also encourage
8 utilities to develop a better understanding of their short- and long-term marginal distribution and
9 transmission capacity costs. An improved understanding of these values, ultimately at a feeder level,
10 will support the development of a wide variety of cost-reducing grid modernization technologies,
11 services, and rates.

12 Experience with a non-wires alternative pilot would also help inform the Phase 2 program, which
13 credits exports at the VDER, by shedding more light on the locational values of DERs, the additional
14 services DER can provide (voltage support, frequency regulation, etc.), and DERs' ability to defer
15 traditional delivery investments.

16 **Q. Would you consider other pilots?**

17 A. Yes, we are open to considering additional pilot studies and are willing to work constructively in
18 working groups to develop pilots that test various concepts and yield actionable data to inform future
19 rate design.

20 **IV. Conclusion**

21 **Q. Does the Coalition view this proposal as a significant compromise?**

22 A. Yes. This proposal makes several concessions in order to hasten the transition to a more modern and
23 flexible electricity system that leverages DER technologies to reduce system costs. While there is
24 presently significant NEM capacity allocations available for smaller projects (under 100 kW), the
25 Coalition proposes to begin Phase 1 on September 1, 2017. At that time, new customer-generators
26 would be subject to non-bypassable charges on all of their delivered loads, the value of their exports
27 would be reduced by 25% of the prevailing volumetric distribution charge, and credits for excess
28 generation would move from volumetric (kWh) to monetary. Taken together, these measures would
29 reduce the bill savings of new customer-generators as described above. The proposal further ratchets
30 down the value of exports for new customer-generators as of January 1, 2019 to 50% of the prevailing

1 distribution charge. Finally, the Coalition is seeking to resolve the debate about the value of DERs by
2 proposing an independent, Commission-sponsored Value of DER study that is informed by newly
3 collected data and pilot studies, and will ultimately set the rate for crediting exports in the future.

4 **Q. Why is the Coalition making these concessions?**

5 A. As noted above, the Coalition would like New Hampshire to transition to a more modern grid that
6 includes more transparent distribution planning and precise price signals that can help reduce system
7 costs. The Coalition recognizes that more data, analysis, and experience is required to get there, so it
8 is proposing incremental changes to the customer-generator crediting program while proposing pilot
9 studies and data collection that can help inform the design of Phase 2. The result will be a transition
10 to a modern, efficient electric system which enables a transactive energy marketplace with smarter
11 price signals for consumers, and closer integration between utilities and DER providers.

12 **Q. Does your proposal include any flexibility or is it entirely prescriptive?**

13 A. The Coalition's proposal is not intended to be prescriptive. Rather, it is intended to provide the PUC
14 with flexibility to adapt the program and develop more precise valuation and pricing signals in the
15 future. The proposal seeks to foster collaborative stakeholder engagement on pilot studies and
16 alternative rate designs that will ultimately require PUC approval.

17 **Q. Should utilities receive timely recovery of costs associated with data collection, billing and
18 metering system upgrades, and pilot programs?**

19 A. Yes, the Coalition believes these measures are in the interest of all ratepayers and supports the timely
20 recovery of the costs related to enhanced data collection, upgrading billing and metering systems, and
21 pilot programs, subject to regulatory oversight and approval.

22 **Q. Why is the Coalition's proposal in the public interest?**

23 A. The Coalition's proposal seeks a gradual transition away from net energy metering to a program with
24 more precise signals about system costs in order to maximize the benefits that DER can provide to all
25 ratepayers. The Coalition believes a methodical, transparent and data-driven approach will enable the
26 New Hampshire DER industry to continue to grow and innovate, while also advancing the interests of
27 the State to the benefit of all ratepayers. The proposal reduces the value of the DER energy export
28 credits in the near term, and lays the groundwork for more precise price signals and transparent
29 distribution planning procedures to minimize system costs. The cost of energy is at a 10-year low, and

1 dropping. Yet the cost of retail electricity is rising—due primarily to soaring transmission and
2 distribution costs. As seen in Figure 1, New Hampshire’s distributed solar capacity is lagging behind
3 its New England. On a population normalized basis, New Hampshire has about 41 watts of distributed
4 solar per capita, compared to 78-, 196-, and 317 watts/capita in Connecticut, Massachusetts, and
5 Vermont, respectively.¹⁹ If DER development in New Hampshire does not keep pace with
6 neighboring states, New Hampshire’s ratepayers share of the region’s transmission costs will
7 increase. A properly designed policy to integrate distributed energy resources into the grid, as
8 contemplated in this settlement proposal, can unleash the power of the free market to help contain
9 rising infrastructure costs by incentivizing those private investments that will save ratepayers the most
10 money.

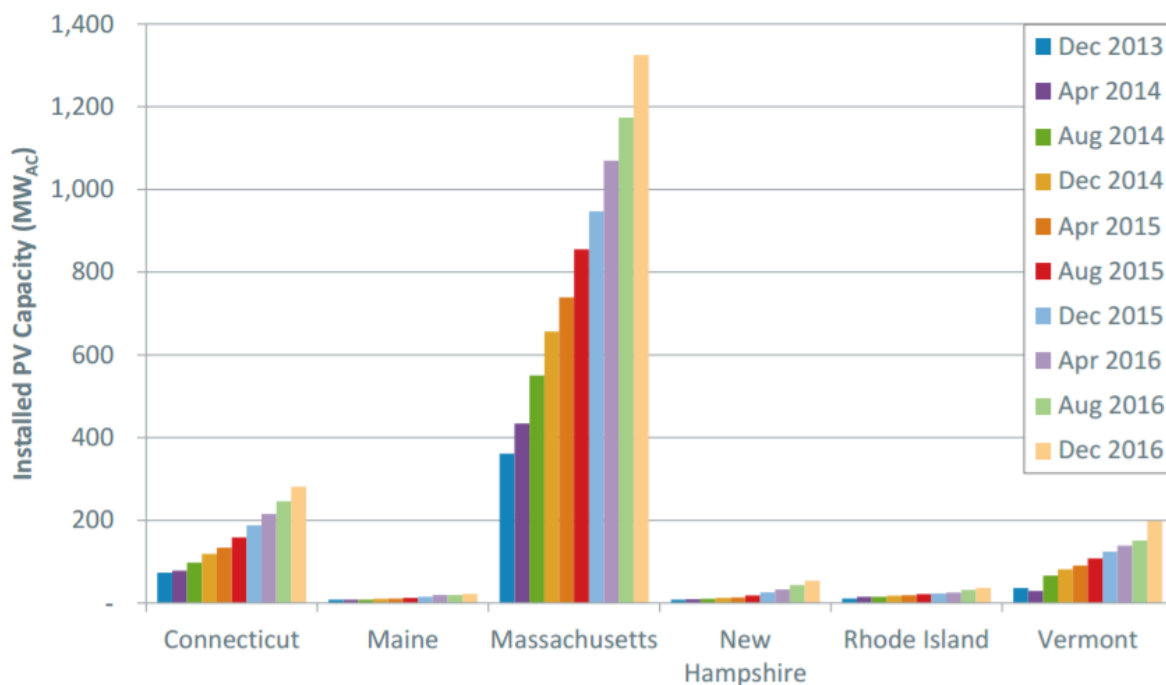
11 This proposal fairly balances the many objectives of HB 1116 and seeks to create a more modern grid
12 that minimizes total system costs while maximizing the value DER can provide to all New Hampshire
13 ratepayers.

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

15 A: Yes.

¹⁹ Victoria Rojo. February 28, 2017. “December 2016 Distributed Generation Survey Results.” ISO-NE Distributed Generation Forecast Working Group. 2014 population data to normalizing the capacity was retrieved from the U.S. Census Bureau.

Historical Installed PV Capacity Survey Results *December 2013 - December 2016 (MW_{AC})*



1

2 Figure 1 – Historical Installed Distributed Solar Capacity. Source: Victoria Rojo. February 28, 2017. “December 2016
3 Distributed Generation Survey Results.” ISO-NE Distributed Generation Forecast Working Group.