EXHIBIT
#38
DE 16-576

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DE 16-576

DEVELOPMENT OF NEW ALTERNATIVE NET METERING TARIFFS and/or OTHER REGULATORY MECHANISM and TARIFFS FOR CUSTOMER GENERATORS

PREFILED DIRECT TESTIMONY OF

JAMES BRIDE

ON BEHALF OF
NEW HAMPSHIRE SUSTAINABLE ENERGY ASSOCIATION

October 24, 2016

Q1. Please state your name, employer, and business address.

A1. My name is James D. Bride and I am the principle of Energy Tariff Experts, LLC. Energy Tariff Experts is located at 1 Broadway, 14^{th} FL, Cambridge, MA 02142.

Q2. Please describe your job duties at Energy Tariff Experts, LLC.

A2. I provide consulting and analytical services to large energy consumers, energy related firms, and trade organizations pertaining to retail utility rates and end use consumer costs.

Q3. Please describe your educational background

A3. I graduated from Boston College with a Bachelor of Science degree in Geophysics in 2002. I received a Masters in Business Administration from the Johnson School at Cornell University with a concentration in Operations Management in 2008.

Q4. Please describe your professional background

A4. In December 2012, I started Energy Tariff Experts. From 2007 through December 2012, I was employed by EnerNOC and held a variety of positions ranging from sales, operations, and portfolio manager. As a portfolio manager, I was responsible for advising large end use energy consumers on wholesale electric and natural gas market issues and devising hedging and utility cost management programs. Prior to EnerNOC, I was employed as a Geologist at Tetra Tech where I focused on brownfield remediation and environmental investigations.

Q5. Have you previously testified before the New Hampshire Public Utilities Commission?

A5. I have not previously testified before the New Hampshire Public Utilities Commission (NH PUC). At EnerNOC and presently at Energy Tariff Experts, I have worked on behalf of parties to public utility proceedings in Maine, Massachusetts, Connecticut, and Pennsylvania.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: provide an overview of consumer investment in solar resources and distributed generation in New Hampshire; explain the differences in residential versus commercial utility rate designs and the resulting effect of rate design on net metered facilities and utility revenues; examine the segmentation of net metered facilities; describe the benefits of solar photovoltaic (PV) systems in the electricity distribution network; propose alternative rate structures to create better alignment between customer cost causation and net metering compensation.

Q7. Please summarize trends related to consumer investment in solar PV in New Hampshire

A7. Through mid-2016, New Hampshire consumers have invested approximately ninety seven million dollars in solar energy technologies. According to the 2016 Renewable Energy Fund Report, residential consumers have invested $75.9M and commercial customers have invested $21.78M installing solar technologies with the overwhelming majority consisting of solar PV. Between 2011 and 2016, the average Renewable Energy Fund rebate paid to residential solar customers installing new systems has fallen from $5,659 to $3,294. New Hampshire solar firms have aggressively wrung efficiencies out of the solar installation process and New Hampshire consumers are benefitting from this consumer led investment in clean energy generation. As New Hampshire is a state with no fossil fuel resources, these consumers are using their own capital to help reduce the flight of money out of New Hampshire associated with energy imports.

Q8. **Are consumers who invest in solar energy technologies engaging in "rent seeking" behavior?**

A8. No, New Hampshire consumers who deploy their own capital to construct solar PV facilities are doing so to exercise their consumer preference for local zero emission generation. Presently, the economics of solar PV in New Hampshire are marginal and consumers are motivated to make solar investments by other factors than simple economic returns. Current payback periods for residential and commercial solar PV installations range from approximately seven to eleven years. Contrary to assertions of "rent seeking", New Hampshire consumers deserve to be compensated for net metered generation commensurate with the value of that generation to the electric grid. As captive customers of the monopoly Distribution Utilities, they are reliant on the NH PUC to establish an equitable net metering compensation regime that fairly values the output of their investment in solar PV.

Q9. Does net metering only pertain to solar PV?

A9. No. Although solar PV is the most prevalent net metered resource, it is important that the net metering regime remain accessible to other small scale renewable/alternative energy technologies. There are presently 8.475 MW of net metered small hydro and de-minimus amounts of other net metered renewable technologies in New Hampshire. An open access net metering regime provides opportunities for development and innovation of new clean energy generation technologies and revitalization as well as continued maintenance of small dams.

Q10. Explain the current rate designs of the Distribution Utilities in New Hampshire for common customer groups

A10. For all residential customers, the rate design includes fixed charges and usage based charges. Until and Liberty have tiers where usage over 250 kWh is billed at a higher rate.

Residential customers served by Eversource have a flat rate for all kWh. Residential Distribution charges, as they existed in August 2016 exclusive of supply charges, are summarized in Table 1 below.

Table 1: Residential Rates

	Liberty	Unitil	EverSource	
Customer Charge	$12.12	$10.27	$12.89	$/mo
Distribution Charge				
1st 250 kWh	$0.03278	$0.03603	$0.04207	$/kWh
>250 kWh	$0.04924	$0.04103	$0.04207	$/kWh
Other*	$0.00078			$/kWh
Transmision Service	$0.01361	$0.02144	$0.0239	$/kWh
Stranded Cost	$0.00040	($0.00018)	$0.0094	$/kWh
Storm Recovery Adj Factor	$0.00000	$0.00221		$/kWh
Electricity Consumption Tax	$0.00055	$0.00055	$0.0006	$/kWh
System Benefits Charge	$0.00330	$0.00330	$0.0030	$/kWh
Total T&D Charges				
1st 250 kWh	$0.05142	$0.06335	$0.07892	$/kWh
>250 kWh	$0.06788	$0.06835	$0.07892	$/kWh

* Other includes Business Profits Tax, Reliability/Vegetation Mgmt, Energy Service Reclassification

As Table 1 shows, a customer with solar PV can offset all charges except the fixed customer charge with the output from a solar PV system.

The Distribution Utilities exhibit a wide range of diversity in their rate designs for commercial customers. Liberty Utilities has three rates that apply to commercial customers shown in Table 2. Rate G-3 applies to customers with demands up to 20 kW and is similar to the residential rates in that it consists of a customer charge and volumetric charges. Rates G-2 and G-3 have fixed customer charges, demand charges, and volumetric charges with G-1 having a Time of Use (TOU) component to the volumetric Distribution charge.

Table 2

Liberty Utilites Commercial Rates				
Customer Group	Small	Small - Med	Large	
Rate	G-3	G-2	G-1	
Demand Thresholds	< 20 kW	20-200 kW	> 200 kW	Units
Customer Charge	$12.03	$55.64	$333.68	$/mo
Demand Charges				
Distribution	--	$7.15	$7.11	$/kW
Usage Based Charges				
Distribution	$0.04075	$0.00118	Peak - $0.00398 Off-peak - $0.00078	$/kWh
Other*	$0.00078	$0.00095	$0.00095	$/kWh
Transmission Serv Cost Adj	$0.00918	$0.01188	$0.0087	$/kWh
Stranded Cost	$0.00040	$0.00040	$0.0004	$/kWh
Storm Recovery	$0.00000	$0.00000	$0.0000	$/kWh
System Benefits Charge	$0.00330	$0.00330	$0.0033	$/kWh
Electricity Consumption Tax	$0.00055	$0.00055	$0.00055	$/kWh
Total Usage Based Charges**	$0.05496	$0.01826	$0.01789	$/kWh

* Other includes Business Profits Tax, Reliability/Vegetation Mgmt, Energy Service Reclassification

** Total usage based charge for G-1 rate uses Peak Distribution rate

As Table 2 illustrates, rates G-2 and G-1 distribution base rates are largely based on fixed customer charges and demand charges.

Table 3 below shows Unitil's commercial rates. Similar to Rates G-1 and G-2 at Liberty Utilities, the distribution base rates for Unitil are largely derived from fixed customer charges and demand charges.

Table 3

Unitil Commercial Rates			
Customer Group	Small-Med	Large	
Rate	G-2	G-1	
Demand Thresholds	< 200 kW	>200	Units
Customer Charge	$18.41	$97.16	$/mo
Demand Charges			
Distribution	$10.31	$6.95	$/kW / kVA for G-1
Stranded Cost	--	($0.05)	$/kVA
Usage Based Charges			
Distribution	$0.00199	$0.00199	$/kWh
External Delivery (Trans)	$0.02144	$0.02144	$/kWh
Stranded Cost	($0.00004)	($0.00005)	$/kWh
Storm Recovery	$0.00221	$0.00221	$/kWh
System Benefits Charge	$0.00330	$0.00330	$/kWh
Electricity Consumption Tax	$0.00055	$0.00055	$/kWh
Total Usage Based Charges	$0.02945	$0.02944	$/kWh

Eversource commercial rates are shown in Table 4. Rates G and GV have distribution base rates that consist of a mix of fixed customer charges, demand charges, and tiered volumetric charges.

Table 4

Eversource Commercial Rates			
Customer Group	Small - Med	Med - Large	
Rate	G	GV	
	< 100 kW	> 100 kW	Units
Customer Charge	$30.23	$197.09	$/mo
Demand Charges			
Distribution[1]	$8.86	$5.67	$/kW
Distribution > 100 kW	N/A	$5.43	$/kW
Stranded Cost[1]	$0.12	$0.12	$/kW
Transmission[1]	$6.17	$8.26	$/kW
Usage Based Charges			
Distribution Charges			
Tier 1[x]	$0.07097	$0.00616	$/kWh
Tier 2[x]	$0.01758	$0.00517	$/kWh
Tier 3[x]	$0.00622	--	$/kWh
Transmission Charges			
Tier 1[x]	$0.02227	--	$/kWh
Tier 2[x]	$0.00838	--	$/kWh
Tier 3[x]	$0.00449	--	$/kWh
Stranded Costs	$0.00056	$0.00049	$/kWh
System Benefits Charge	$0.00330	$0.00330	$/kWh
Electricity Consumption Tax	$0.00055	$0.00055	$/kWh
Total (last tier)	$0.01512	$0.00951	$/kWh

[1] - Applies to demand > 5 kW for Rate G only

[x] - Rate G Tiers are 1 - 1st 500 kWh; 2 - next 1,000 kWh; 3 - additional kWh

[x] - Rate GV Tiers are 1 - 1st 200,000 kWh; 2 - additional kWh

In summary, with the exception of Liberty Utilities' small commercial rate, all the commercial rates for the Distribution Utilities derive all or the majority of their distribution base rates from fixed customer charges and demand charges.

Q11. **How do the present rate designs impact the potential for interclass cost shifting through net metering?**

A11. With the exception of Liberty's rate G-3 for customers under 20 kW, all commercial rates in New Hampshire derive all or the majority of their revenue requirement through fixed customer charges and demand charges. In Docket 15-147, Unitil's expert testimony presumed that the monthly billed demand for commercial customers is not impacted by intermittent generation. As a result, it is a logical assumption that Distribution Utilities fully recover their distribution revenue requirements from commercial customers with distributed generation and there is no adverse cost shifting from rate payers to net metered commercial customers.

Residential rates are comprised of fixed customer charges and usage based charges. As a result, a determination as to the existence of the potential for adverse cost shifting is more complicated. The cost of service for a unique residential customer will vary based on usage, load pattern, and if applicable, the size of any installed distributed generation. Later in the testimony, we will further examine the potential for an adverse cost shift within the residential customer group.

Q12. Do the utility rates and rate designs align with the net metering classes?

A12. No, they do not. As Table 5 illustrates, only Eversource has a rate breakpoint at 100 kW and with the exception of Liberty's G-3 rate, all of the commercial rates derive all or the majority of their distribution base rate revenue from fixed customer charges and demand charges.

Table 5

Net Metering Classes	Small			Large	
Customer Class	Residential	Commercial			
Demand Threshold (kW)		< 20	20 - 100	100 - 200	> 200
Unitil	D	G-2			G-1
Liberty	D	G-3	G-2		G-1
EverSource	D	G		GV	

Shading indicates rates w/ demand charges

Q13. Should the current classifications of small vs. large net metered facilities be maintained?

A13. No, the treatment for net metering should be driven by the rate structure for the host meter and the impact of solar on the cost drivers for the rate design elements. The current breakpoint of 100 kW facility size is arbitrary as a facility of 101 kW does not generate measurably less value than a system of 99 kW.

Q14. How should the classifications for net metering be determined?

A14. Residential customers should be a distinct group. Commercial customers with behind the meter load and generation sizes up to 1 MW should be another distinct group. Free standing distributed generation with generation up to 1 MW may comprise a third net metering class. Each of these installation types exhibit markedly different characteristics which should be recognized by the net metering compensation regime.

Q15. Should there be a distinction in the treatment of net usage in the present billing month and banked usage carried forward into future months?

A15. Yes, all net metered output for behind the meter installations should be credited at full retail avoided cost during the current billing month. Avoided consumption and excess output during the current billing month are akin to an energy efficiency measure and constitute an avoided unit of kWh consumed. kWh consumption is avoided at the host meter or adjacent meters during intervals of export to the distribution system.

Excess kWh that are banked and carried forward to future months should be treated differently in that the value of the banked kWh should be calculated based on the rate elements that are truly avoided or beneficially influenced by net metered solar PV generation.

Q16. Which cost components should be included in calculating the value of banked kWh?

A16. The inclusion or exclusion of cost components in calculating the value of banked kWh should be informed by the principle of cost causation. For a billing line item to be included in the value of banked kWh, net metered generation must serve to avoid or reduce the costs associated with the billing item for all ratepayers. As Table 6 illustrates, there are some cost components such as stranded costs where inclusion in the calculation of banked kWh would be illogical. Conversely, distribution, transmission, and electricity supply charges are avoided due to solar PV generation and therefore should be included in the value of each banked kWh.

Table 6

Billing Component	Include in Value of Banked kWh: Residential	Commercial	Rationale for Inclusion/Exclusion
Distribution Charges	Yes	Partial	Solar PV is often coincident with peak summer demands and often helps reduce distribution circuit peaks. All ratepayers benefit when peak load is reduced and utilites are able to avoid or defer system upgrades and expansions.
Transmission Charges	Yes	Yes	The ISO-NE bulk transmission system is sized to meet peak demands that occur during the summer months. Solar PV reduces these demands thereby avoiding the need for new transmission infrastructure and reducing ratepayer transmission costs
Default Energy Service	Yes	Yes	Solar PV results in avoided wholesale energy consumption and solar PV production is reduces the ISO-NE system peak. In doing so, behind the meter solar reduces the cumulative capacity tag of the default service load and saves all customers money.
Stranded Cost	No	No	Stranded costs are not avoided due to excess net metered generation
Storm Recovery	No	No	Costs associated with storm recovery are unrelated to excess net metered generation
System Benefits Charge	No	No	Compensation for System Benefits charges is illogical since excess net metered generation does not influence these charges
Electricity Consumption Tax	No	No	Excess net metered generation does not avoid the electricity consumption tax and therefore should not be included

Q17. Explain why Transmission charges should be included in the compensation for banked kWh for all net metered customers.

A17. The ISO-NE transmission system is built to accommodate peak summer loads. Solar PV generation serves to reduce peak load and as a result, helps avoid the need for new transmission infrastructure. Since peak summer load events are a cost causing activity, the impact of solar on reducing peak summer demand is beneficial to all customers on the system and therefore customers who have invested in solar PV generation assets should be compensated through inclusion of transmission charges in the calculated value of a banked kWh.

Q18. **Provide information on summer peak load events in New Hampshire in recent years.**

A18. Table 7 shows the top five peak load days for the ISO-NE New Hampshire load zone for the past five years. As the table illustrates, peak load event days for New Hampshire as a whole exclusively occur during the summer months. Peak summer loads occur during the mid to late afternoon. ISO-NE system peak loads are indicated by bold font and italics. As the table shows, in the last five years New Hampshire peak load days have coincided with ISO-NE system peak load days

Table 7

Hourly Loads for ISO-NE NH Load Zone for Top 5 Demand Days (2012 - 2016)											
			Hour Ending (e.g., Hr Ending 13 is interval from noon - 1pm)								
Year	**Rank**	**Day**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
2016	1	8/12/2016	2,297	2,335	***2,354***	2,366	**2,367**	2,322	2,231	2,160	2,120
	2	8/11/2016	2,196	2,256	2,283	2,298	**2,309**	2,299	2,257	2,199	2,165
	3	7/22/2016	2,068	2,136	2,187	2,217	**2,230**	2,220	2,178	2,106	2,049
	4	7/28/2016	2,105	2,171	**2,192**	2,186	2,153	2,096	2,039	1,988	1,958
	5	7/27/2016	2,023	2,083	2,128	2,152	**2,172**	2,170	2,121	2,038	1,974
2015	1	7/29/2015	2,110	2,165	2,193	2,216	***2,217***	**2,219**	2,182	2,122	2,084
	2	9/9/2015	2,088	2,157	2,193	**2,218**	2,214	2,181	2,138	2,148	2,072
	3	8/18/2015	2,133	2,193	**2,209**	2,203	2,190	2,155	2,108	2,053	2,020
	4	7/30/2015	2,154	**2,206**	2,203	2,172	2,135	2,101	2,016	1,945	1,908
	5	8/19/2015	2,094	2,156	2,180	**2,191**	2,189	2,156	2,100	2,028	2,000
2014	1	7/2/2014	2,232	**2,288**	***2,269***	2,178	2,102	2,027	1,924	1,865	1,818
	2	7/23/2014	2,173	2,231	2,262	**2,276**	2,264	2,245	2,199	2,112	2,037
	3	7/1/2014	2,060	2,112	2,141	2,149	**2,156**	**2,156**	2,129	2,078	2,051
	4	7/8/2014	2,055	2,109	2,135	**2,146**	2,137	2,123	2,097	2,043	2,010
	5	7/14/2014	2,059	2,105	2,119	**2,135**	2,123	2,081	2,047	2,013	1,971
2013	1	7/19/2013	2,347	2,393	2,414	**2,421**	***2,419***	2,392	2,335	2,268	2,234
	2	7/17/2013	2,276	2,335	2,363	2,379	**2,390**	2,377	2,336	2,272	2,225
	3	7/18/2013	2,319	2,360	**2,371**	2,348	2,281	2,206	2,141	2,078	2,039
	4	7/16/2013	2,238	2,278	**2,293**	2,292	2,290	2,281	2,239	2,167	2,118
	5	7/15/2013	2,206	2,246	2,262	2,272	**2,290**	2,283	2,255	2,183	2,118
2012	1	7/17/2012	2,075	2,149	2,206	2,252	***2,290***	**2,292**	2,248	2,141	2,036
	2	6/21/2012	2,207	2,241	2,255	2,260	**2,263**	2,243	2,210	2,153	2,104
	3	6/22/2012	2,179	2,208	**2,220**	2,210	2,173	2,089	2,011	1,941	1,899
	4	7/16/2012	2,129	2,179	**2,194**	2,183	2,168	2,144	2,108	2,049	2,028
	5	8/3/2012	2,083	2,121	2,149	2,167	**2,168**	2,148	2,093	2,032	2,012

Shaded cells indicate NH Daily Peak Load Interval

Cells in bold and italics indicate annual ISO-NE System Peak Load hour for the Capacity Market

As Table 8 below illustrates, the peak load intervals on the top five load days in New Hampshire over the last five years have overwhelmingly occurred prior to 5pm when solar resources are generating electricity.

Table 8

Summary of Peak NH Demand Intervals on Top 5 Load Days (2012-2016)	
Hr Ending	Occurances
14	2
15	6
16	6
17	9
18	2

Q19. If ISO-NE Transmission charges are recovered on a 12 CP basis, why should the focus be on peak summer load events?

A19. Peak summer load events are the drivers of transmission infrastructure cost causation. The need for Transmission infrastructure is largely driven by constraints that occur during summer peaks. The carrying capacity of transmission lines is inversely related to temperature and wind speed. As a result, the capacity of the transmission system is often lowest on the days when it is under the most stress such as hot humid days in summer. Solar PV generation works to reduce summer peak load events and therefore all customers benefit year round through avoided transmission investments when summer peak load is reduced. Although the cost recovery mechanism for ISO-NE transmission charges is based on 12 CP demands, coincident peak demands in most non-summer months do not drive costs.

Q20. How should this information inform compensation rates for commercial solar customers?

A21. Commercial solar PV assets should be compensated for transmission charges for excess kWh fed back to the distribution system. Unitil and Liberty Utilities charge commercial customers for transmission on a volumetric basis. These transmission charges should be included in the compensation for excess kWh fed back to the grid.

Eversource recovers transmission costs via demand charges for rates G and GV. Rate G has a volumetric component to the transmission charge while GV exclusively uses demand charges. This structure undervalues behind the meter solar PV generation as well as excess kWh since the non-coincident peak demand charges bill customers for demands that may occur during periods of low solar PV generation, but fails to recognize the value of solar PV in reducing summer peak loads. A more equitable compensation scheme would be to periodically determine the value of avoided transmission costs associated with avoided peak summer load attributable to solar. The capacity in kW of avoided peak summer demand could be multiplied by the current ISO-NE rate for Regional Network Service to determine the value of avoided transmission capacity. This value could then be converted to a $/kWh rate and paid to all net metering customers.

Q22. How does solar benefit the local distribution system?

A22. On distribution circuits that experience peaks coincident with the New Hampshire load zone, the peak reduction benefits of solar are clear. For distribution circuits that experience peaks later in the day, solar still has value. Solar PV helps shorten the duration of the peak load events on these circuits. By reducing the duration of peak load events, wear associated with thermal stress is lessened since the duration of the peak load event is shorter.

Q23. Do solar net metered customers result in measurable cost shifting?

A23. As described earlier in the testimony, commercial customers are billed for distribution base rates primarily through fixed customer charges and demand charges. Non-coincident peak demand charges are typically only modestly influenced by solar PV. As a result, commercial customers with solar PV can be expected to contribute to utility base rate revenue requirements in a manner that is comparable to customers without solar PV.

Residential customers are billed through fixed charges and volumetric usage charges. A demonstrated cost shift has yet to be documented in the case record or in other related NH PUC proceedings. A properly sized residential solar PV system should be viewed as akin to a customer funded energy efficiency measure. When a customer buys high efficiency appliances without any utility efficiency program rebates, the utility is not entitled to recover lost revenues attributable to the replacement of the old inefficient appliance. When a customer replaces an electric stove with a gas stove, the utility cannot claim that there is an undue cost shift among customers migrating to gas stoves. An investment in a residential PV system is not much different from the examples cited above.

Q24. Are there provisions in New Hampshire for Distribution Utilities to be compensated for lost revenues attributable to lost sales from qualified energy efficiency measures?

A24. The Settlement Agreement in NHPUC Docket 15-137 allows for the Distribution Utilities to calculate and recover lost revenues attributable to forgone sales resulting from customer energy efficiency investments that are enabled by the utility energy efficiency programs. Calculation of lost sales is determined by an independent third party per a monitoring and verification protocol. This cost recovery mechanism is not directly applicable to the instant proceeding, but it does represent a mechanism to align utility incentives with energy efficiency, distributed generation, and smart grid policy objectives.

Q25. How can cost shifting be avoided in New Hampshire's net metering regime?

A25. As described in Table 6, the potential for cost shifting can be eliminated by linking the compensation rate for banked kWh to the billing line items that are beneficially impacted by solar PV generation. Items that are unrelated to solar PV generation such as stranded costs, etc. should not be included in the compensation scheme for banked kWh. Behind the meter generation that offsets onsite host load within the current billing month should be viewed as identical to energy efficiency and credited at the full retail avoided cost.

Q26. Are there presently intra-class cost shifts among New Hampshire utilities outside of net metering?

A26. Yes, there will always be some degree of interclass cross subsidization due to the diversity of load within in a utility and rate. Examples of residential customers who may pay significantly less than the cost of service include the following:

- Summer vacation homes with high occupancy and electric usage during the summer season and minimal usage during the rest of the year
- Summer properties taking seasonal service
- All electric ski condos with low usage outside of winter and peak usage during the coldest winter days
- Properties with inefficient or oversized air conditioning systems

No utility has suggested that these types of customers receive separate ratemaking treatment. Typical residential service connections range from 100 to 400 Amps, yet regardless of the amperage of the service connection, all residential customers are placed on the same rate. Despite this, a customer with a 400 Amp service connection has the potential to impose far greater demands on the distribution system than one with 100 Amp service.

A family of five (two parents, three children) may use 1,000 kWh/mo or higher. When the children grow up and move out of the house, monthly kWh usage might drop to 400 kWh when only the parents are left. In this scenario, the utility would not call for this customer to be placed on a separate rate, but if this same customer installed a modest solar PV system, the effect on usage would be the same (1,000 kWh/mo to 400 kWh/mo). This same customer might also realize a similar usage reduction by substituting an electric stove or dryer for one fueled by natural gas or by engaging in deep energy efficiency measures. As a result, it is illogical for utilities to claim that installation of solar PV fundamentally changes the customer to the point where they require a separate rate.

Among commercial customers, the intraclass cost shifts that exist outside of net metering can be more severe. Customers with high demands, poor load factors, and rapid demand fluctuations typically contribute less to utility revenue requirements than the cost of service. There are many commercial customers with erratic and highly seasonal demand that are tolerated by utilities. Ski areas, amusement parks that operate during the summer, and customers with inefficient air conditioning are all examples of customers whose load characteristics result exhibit the potential for cost shifting. Up until recently, PSNH had a Sawmill Rider that provided a reduction in demand charges for Sawmills. Sawmills are a customer type that are known for poor load factors, low power factors, and rapid fluctuations in demands that are more expensive to serve than the commercial class average.

As described earlier in this testimony, the rate designs for commercial customers preclude material cost shifting or deficiencies in revenue requirements arising from those that have adopted solar PV relative to their peers in the rate class. This is due to the fact that distribution charges are predominantly recovered through fixed charges and non-coincident peak demand charges.

Q27. Should the value of solar output be evaluated by rate class or in aggregate?

A27. The value of solar output to the respective systems of the Distribution Utilities should be viewed in aggregate. Although each rate class exhibits very different load characteristics, solar power generation is uniform. It doesn't matter whether a solar PV facility is on a residential or commercial rooftop since the type of rooftop will not change the generation profile. The value of the solar PV resource should be determined based on its influence on the load patterns of the utilities' aggregate load profile. Not doing so could result in a cost shift from solar PV customers to non-solar PV customers.

The residential load class tends to peak later in the day relative to the commercial load classes. It is a good thing that different types of customer groups peak at different times since this diversity of load helps maintain system utilization. Residential PV arrays produce their maximum output when the commercial customer class is near its load peak. When the residential customer class peaks later in the day, solar PV output is typically declining. Later in the day, the system load is typically reduced as well. If one were to value solar PV generation assets against the residential class load in isolation, it would greatly undervalue the contribution of solar PV in reducing the aggregate utility system peak load. While a utility may argue that a solar PV resource has no value to the residential customer class on a day when the residential customer group peaks at 7pm, this line of analysis ignores the value of the peak load reduction in the middle of the day attributable to solar PV generation.

Q28. How should this inform the analysis regarding the presence or absence of a cost shift?

A28. In solar proceedings such as this, embedded costs and marginal costs are often conflated by intervening parties. It is important for the embedded costs of service to be determined as usual by customer class. A separate step is to calculate the value of solar PV generation for the utility system in aggregate to determine the marginal value of avoided costs attributable to solar PV generation. If a customer is contributing greater than or equal to the cost of service minus the marginal avoided costs attributable to their solar PV generation assets, then they are not creating a cost shift to other customers.

Q29. Is a demand charge appropriate for residential customers?

A29. A crucial Bonbright principle of rate design is that utility rates be understandable to the customer. While a distribution circuit level coincident peak demand charge would accurately reflect usage patterns that drive cost causation, residential customers are unlikely to embrace, much less understand, a demand charge of any sort (coincident or non-coincident peak). Presently, there are only a handful of utilities in North America that have implemented residential demand charges and they have been controversial and unpopular. Non-coincident demand charges will be very difficult for most residential customers to avoid over a given month and most customers won't even try to manage them. As a result, consumers will treat the demand charge as a fixed charge and once a customer believes their demand charge has been set for the month, they will have no further incentive to modify their usage to avoid setting subsequent peaks of equal magnitude.

The consumer behavior that a demand charge will induce contravenes New Hampshire statutory and policy goals relating to energy efficiency, smart grid, and cost reduction. Volumetric kWh billing is understandable to residential customers and each kWh is at least theoretically actionable to them. Demand charges are not actionable and if a customer believes they've set a demand peak on the first day of a billing cycle, they will have no incentive to reduce peak load for the remainder of the billing cycle. This of course presumes that the residential customer understands what a demand charge is, how it is measured, and how it is billed. For the residential customer class, time based differentiation of energy charges is more understandable, easier for the utility to communicate, and provides a better link between usage and cost causation while maintaining the actio ability of each kWh.

Q30. Are fixed charges a better way for a utility to recover their distribution revenue requirement from residential customers?

A30. Fixed charges should be used to recover items that are inherently fixed in nature such as costs for meters, meter data management systems, billing costs, etc. Fixed costs should not be used to recover charges that are tied to distribution infrastructure. When fixed charges are increased at the expense of volumetric charges, customers have less of an incentive to engage in energy efficiency or behavioral change. Fixed charges are not actionable and disproportionally impact low use and low income customers. Increasing fixed charges contravenes New Hampshire energy efficiency policy goals for the reasons described in the previous section. Consumers must be motivated to engage in energy efficiency and load management. Raising fixed charges beyond the level associated with utility costs that are truly fixed (e.g., meters, billing system, etc.) discourages customers from investments in load management and behavior change that benefits the system.

Q31. Are Time of Use (TOU) rates a better way to guard against the theoretical potential for cost shifting by some solar PV customers within the residential customer class?

A31. If there were a hypothetical residential customer with sufficient excess generation that they paid only the monthly customer charge and had a load pattern that strongly peaked coincident with the distribution circuit, they could be underpaying relative to the cost of service. This type of customer behavior could be addressed through a time differentiated rate. A TOU rate design to influence customers to shift usage outside of peak periods should have the following characteristics: a peak period that reflects the times when the distribution system peaks, by season if appropriate; and a peak period duration short enough to influence customer behavior.

If the peak period were to be defined as a four hour window running from the mid afternoon to early evening, , residential customers could make realistic choices about running appliances such as dishwashers, washers and dryers, and programing smart thermostats. A peak period that is aligned with peak load hours, but short enough that customers can work around it would accomplish several objectives. First, it would encourage customers to modify their behavior in a way that reduces distribution system costs. Second, it would help to better align residential rate design with cost causing customer behavior by charging customers with high usage during the peak hours more commensurately with the demands and costs that they impose on the system. Third, it would reinforce NH energy policy regarding energy efficiency and smart grid as it would incent customers to utilize smart thermostats, smart appliances, install more west facing solar panels, and potentially induce some early adopting customers to purchase battery storage systems.

A TOU rate design is preferable to increased fixed charges and demand charges because it is more understandable to end use customers and ensures that the majority of the customer's bill remains actionable. Whereas once a demand charge is set, the customer has no recourse, with a TOU rate design the customer has a daily opportunity (M-F) to engage in conservation or load shifting to manage their monthly bill.

Q32. How should residential TOU rates be implemented?

A32. Residential TOU rates should be implemented on a pilot basis to a limited number of customers. This pilot rate should be open to enough customers to provide a sufficient data set to support load research activities into the effectiveness of TOU rates in altering customer behavior and providing revenue adequacy to the utilities. The data obtained in this pilot could inform TOU rate designs for the broader residential customer class.

Q33. Should there be any additional compensation for net metered export for larger systems?

A33. Yes, larger systems are presently under-compensated relative to the value they provide to the electric grid. They are paid the default Energy Service rate which lacks any compensation for avoided transmission and distribution losses. Some distributed generation systems have higher value than others and special locational adders should be made available to systems that exhibit the following characteristics:

- Location in constrained circuit as part of a non-wires alternative to a capital intensive upgrade
- Location on a brownfield, landfill, or otherwise unusable property
- West facing solar panels that help provide peak load reduction later in the day
- Solar PV or other distributed generation paired with energy storage that is optimized to provide peak load reduction or ancillary services to the electric grid

Q34. What are the Requirements for a Solar PV facility to create and mint Class II RECs in NH?

A34. In NH, Solar PV facilities up to 100 kW must submit a completed application that meets the requirements of NH PUC 2505.02(b). On the application, the customer must list the technical specifications of the PV system as well as designate an Independent Monitor and REC Aggregator if the customer does not plan to retain the RECs or sell them on their own. The completed application must then be reviewed and approved by the NH PUC.

Q35. Are customers able to register their sites to generate RECs on their own?

A35. A customer could submit their own application if they were able to contract with an independent monitor. As the REC applications to the NH PUC demonstrate, virtually all of the REC applications are completed on behalf of customers by third parties.

Q36. Do any utilities in NH handle the REC registration process on behalf of customers?

A36. Yes, if provided customer authorization the New Hampshire Electric Cooperative (NHEC) submits the REC registration documentation to the NH PUC on behalf of customers who install solar PV. NHEC performs all tasks related to independent monitoring, verification, and REC minting and monetization with the NEPOOL GIS. The customer pays NHEC a monitoring fee in exchange for this service. NHEC remits proceeds from REC monetization back to its PV customers periodically.

Q37. Is the REC registration process unduly burdensome to small customers served by the Distribution Utilities?

A37. As of early 2016, there were 18,855 kW of Class II eligible PV facilities that were net metered but not certified to produce Class II RECs. Presuming that facilities that forgo registration to generate Class II RECs are typically small behind the meter installations, this represents a significant percentage of the installed capacity of the small customer group. The fact that over 18 MW of Class II eligible PV capacity has failed to register with NH PUC to generate RECs suggests that the current process is discouraging many small system owners.

Q38. What happens to the RECs from Class II eligible facilities that never register with NH PUC?

A38. Per NH PUC 2503.04, the Distribution Utilities are allowed to claim credit against their Class II REC compliance obligation by estimating the output of non-registered Class II eligible PV facilities using a formula. The Distribution Utilities are then able to claim this output against their Class II REC compliance obligation.

Q39. Does it benefit customers when utilities obtain Class II RECs at no cost and use them to offset their RPS compliance obligation?

A39. Although customers taking Default Energy Service do benefit through lower RPS compliance charges included in the Energy Service rate, this practice causes inequities among customer groups. In 2015 the supply of Class II RECs was short of the obligation and many entities had to use Alternative Compliance Payments (ACPs) to meet their RPS obligations. As the NH Renewable Energy Fund Report for 2015 documents, 60% of the ACPs were purchased by Competitive Energy Suppliers. 40% of the ACPs were purchased by EverSource. NHEC, Unitil, and Liberty did not purchase any ACPs. Recent migration data show that approximately 50% of the load for each of the Distribution Utilities is served by Competitive Energy Suppliers. As Unitil's migration data demonstrates, customer migration to Competitive Electric Suppliers varies widely by customer type with larger commercial customers overwhelmingly selecting competitive service while over 80% of residential customers receive Default Energy Service from their respective utilities.

As a result, while Competitive Energy Suppliers are responsible for 60% of the ACPs, these costs are largely borne by larger commercial customers. The utility practice of claiming Class II RECs from unregistered Class II eligible facilities and retiring them at no cost has the consequence of putting commercial and industrial customers served by Competitive Energy Suppliers at a disadvantage in that they end up paying more for Class II REC compliance than residential customers on Default Energy Service.

A regime like this that benefits some customers at the expense of another group of is inequitable and should be avoided. Furthermore, NH is a restructured state and this regime places Competitive Energy Suppliers at a distinct disadvantage to the Distribution Utilities with regard to the cost of RPS compliance.

Lastly, the customers whose Class II RECs are being claimed by the Distribution Utilities and retired at no cost are being deprived of the revenue associated with the environmental attributes of their PV system. Many of these facilities are unregistered due to the complex registration process that in practice requires a third party to complete.

Q40. Are Class II RECs from small PV systems efficiently monetized in practice?

A40. A 5 kW residential solar PV system will generate approximately 8.75 Class II RECs in a calendar year. As of Sept. 2016, 2016 vintage Class II RECs are worth approximately $50/REC. In total, the Class II RECs generated by such a system are worth approximately $437.50. This REC value has to support payments to the Independent Monitor to verify production, the REC broker to coordinate upload of REC data with NEPOOL GIS, REC marketing, transaction execution, and remittance of payment to the residential PV system owner. Even if the Independent Monitor and REC Broker are highly efficient, a significant portion of the Class II REC value stream is expended in administrative activities related to monetization.

Furthermore, REC markets are illiquid and facilitated by Over-the-Counter (OTC) brokers. Broker commissions for small lot sizes are typically in the lower double digit percentage range due to the administrative burden of aggregating many small sites or conducting small transactions. Due to the periodic illiquidity in REC markets, bid ask spreads can be over $1/REC.

Q41. Who is harmed by inefficient Class II REC monetization?

A41. Both consumers and solar PV system owners are harmed by inefficiencies in the REC monetization process. Consumers are harmed because the administrative overhead, market inefficiencies, and elevated broker commissions for small transactions all drive up the costs of Class II RECs. Solar PV system owners are harmed because the value of the environmental attributes of their system is diverted towards administrative tasks associated with REC minting and monetization.

Q42. How should Class II REC registration, minting, and monetization be handled for smaller systems?

A42. NHEC provides an example of an efficient model for REC registration, certification, and monetization. By centralizing the administrative tasks, economies of scale are realized and less value is lost. Solar PV system owners are compensated for the value of their RECs on their utility invoices and NHEC recovers the cost of providing this service through their Monitoring Fee.

A model where the Distribution Utilities centralize the process for REC registration, verification, and monetization for small customers would result in greater efficiencies for consumers and solar PV system owners. The Distribution Utilities could perform this function themselves or outsource it to a third party contractor.

NH PUC 2505.09 allows distribution utilities to serve as Independent Monitors and the utilities already have revenue grade meters and high quality information technology systems. As a result, the cost of a joint utility administered or supervised Independent Monitor function should be more efficient than the status quo. Periodic joint utility administered or supervised auctions of Class II RECs would help improve market liquidity as buyers would know that a large lot size is coming to market and transaction costs would be reduced.

Q43. How should solar PV system owners be compensated for their Class II RECs by a centralized REC management function?

A43. An on-bill crediting mechanism where utilities credit solar customers for the value of RECs realized would be a lower cost mechanism to pay solar PV customers compared with the status quo. Since REC prices can fluctuate, a formulaic method for determining REC compensation would be beneficial to provide visibility and predictability into the REC revenue stream for solar PV customers.

Q44. How should the Distribution Utilities be compensated for providing this service if managed internally or outsourced to a third party?

A44. The REC value stream is currently claimed by several intermediaries in the value chain. The Distribution Utilities could claim a percentage of the REC revenue realized through monetization to offset the costs of administering a centralized REC management function. Utility investments eligible for recovery should include all investments related to information technology resources, billing system changes required to facilitate crediting, and labor costs associated with staff to manage the program.

Q45. What are some other advantages to a centrally managed REC administration function?

A45. Connecticut, Massachusetts, and Rhode Island consider out of state solar PV to be a Class I RPS resource. Depending on REC market conditions, it may be advantageous to market some NH Class II RECs into compliance markets in other states if prices are higher. All NH customers could benefit from such a scenario through an earnings sharing mechanism. The only way to efficiently cross register smaller PV assets in other states is through a centralized bulk registration that could be executed by the proposed structure.

Q46. Why is the proposed REC administration program more equitable than the status quo?

A46. As described above, the current system for registering, verifying, and monetizing Class II RECs is inefficient and inequitable. A significant number of smaller systems have foregone REC registration and the resulting process by which Distribution Utilities claim and retire these RECs causes inequities among customers served by Competitive Energy

Suppliers and those on Default Service. The cost of Class II REC compliance for all customers would be reduced and administrative inefficiencies could be realized through a centralized REC management function. In addition, enhanced REC revenue paid to solar PV system owners could potentially offset a reduction in net metering compensation.

My testimony can be summarized as follows:

- New Hampshire consumers who have installed solar PV are not engaging in "rent seeking" behavior. To the contrary, they have expended thousands of dollars of their own capital to install emissions free distributed generation despite paybacks of approximately seven to eleven years or more.
- Commercial rate designs that are based on fixed customer charges and distribution demand charges preclude material cost shifting among commercial customers. If anything, commercial customers with solar PV are being undercompensated relative to the value provided by their solar PV resources
- Net metering size distinctions do not align with commercial rate class breakpoints and are arbitrary. Better alignment of net metering size classes and utility rate structures would be beneficial.
- The inclusion or exclusion of utility line item charges in the computation of the value of banked excess generation should be informed by the degree to which distributed generation avoids or beneficially influences those costs. Items such as

stranded costs, system benefits charges, etc. should not be included in the value of banked excess generation.

- The State of New Hampshire is summer peaking and New Hampshire peak load days tend to coincide with ISO-NE system peak load days. New Hampshire peak load events occur when solar resources are generating electricity. Solar PV helps reduce the need for peak generation capacity and reduces the need for new transmission capacity due to its ability to reduce peak summer load.
- There are significant cost shifts within existing rate classes and customer groups that are unrelated to distributed generation and are tolerated by utilities. There is no documented cost shift for distributed generation and special rate treatments that extract greater revenues out of distributed generation customers while ignoring other cost shifting behavior would be discriminatory.
- The value of solar PV resources should be evaluated in aggregate, not on a class specific basis.
- Alternative rate designs that rely on fixed charges or demand charges contravene energy efficiency policy goals and should be avoided
- A pilot TOU program for residential customers with solar PV should be implemented along with a centralized REC management function.
- Commercial customers should be compensated with adders for excess generation based on the value of their distributed generation output to the transmission and distribution system with additional compensation for selected societally beneficial attributes such as being located on brownfields, etc.

Q47. Does this conclude your testimony?

A47. Yes.