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 REBUTTAL TESTIMONY OF

JAMES D. BRIDE

ON BEHALF OF

NEW HAMPSHIRE SUSTAINABLE ENERGY ASSOCIATION

DECEMBER 16, 2016

I. INTRODUCTION

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, 14th FL, Cambridge, MA 02142.

Q2. Have you previously testified before the New Hampshire Public Utilities Commission?

A2. Yes. I submitted pre-filed testimony in the instant proceeding on behalf of the New Hampshire Sustainable Energy Association ("NH SEA").

Q3. What materials were reviewed in the preparation of this testimony?

A3. I reviewed the direct testimonies and related discovery documents of Mr. Edward Davis on behalf of Eversource Energy, Messrs. Lebreque and Johnson on behalf of Eversource Energy, and Mr. Lon Huber on behalf of the NH Office of the Consumer Advocate ("OCA"). I also reviewed literature and tariffs related to residential demand charges.

Q4. What is the purpose of this testimony?

A4. The purpose of my testimony is to rebut some of the assertions and assumptions in the testimonies of Messrs. Labreque and Johnson and Mr. Davis submitted on behalf of Eversource Energy. My testimony also addresses certain aspects of the testimony provided by Mr. Huber on behalf of the OCA and evaluates the appropriateness of demand charges for residential customers.

Q5. Please summarize the main points of your testimony?

A5. My testimony can be summarized in the following bullet points:

- There is evidence that residential customer consumption is dynamic before and after the installation of solar PV systems. Present utility approaches to rate design and alleged cost shifting presume static load conditions. This presumption is erroneous and leads to understatement of revenues from proposed alternate rate designs and overstatements of alleged cost shifting attributable to Distributed Generation ("DG").
- The Commission must require the study and consideration of dynamic customer loads before and after installation of solar PV prior to approving any successor Net Energy Metering ("NEM") rate designs.
- A cost shift attributable to solar PV customers has not been documented and calculations regarding potential theoretical cost shifts are highly sensitive to input assumptions regarding electricity exported to the distribution system and the wholesale market price of electricity.
- Successor rate designs must be simple and understandable.
- A charge for usage exported to the distribution system is unsupported by the case record and should be rejected.
- Residential demand charges are totally inappropriate for residential customers and should be rejected.
- Time of Use ("TOU") usage rates are a more appropriate way to charge residential customers for cost causing activities.

II. REVIEW OF THE TESTIMONY OF MR. EDWARD DAVIS ON BEHALF OF EVERSOURCE ENERGY

Q6. Does the Davis testimony presume that residential customer load is static before and after the installation of solar PV systems?

A6. It does. In Figure 1 of the Davis testimony (p. 8) and Attachment 2, the calculations provided to illustrate Eversource's proposed rate design presume that customer consumption does not change before and after the installation of solar PV.

Q7. Is this assumption regarding static residential customer load reasonable and supported by load research data?

A7. This assumption is unreasonable and appears to be unsupported by load research data detailing how residential customer consumption patterns in its service territory change after the installation of solar PV.

Q8. Is there any evidence that residential consumption changes after the installation of solar PV?

A8. Yes. The New Hampshire Electric Cooperative ("NHEC") conducted a study on residential customers who have adopted solar PV. They conducted this study approximately two years ago as part of the process to devise a successor NEM tariff. NHEC found that residential customer electricity usage increased an average of 52% after the installation of a solar PV system.[1] The dataset included 217 customers and therefore is large enough to indicate a clear trend in residential consumer behavior in New Hampshire.

Q9. Why might residential customer usage increase after the installation of solar PV?

A9. There are many possibilities and I don't have sufficient load research data to fully explain all of the drivers behind observed increases in residential electric consumption after the installation of a solar PV system. It appears that many customers may decide to electrify more household appliances. Many solar PV adopters are environmentally conscious and may opt to supplement an oil or propane furnace with a heat pump. They may replace a gas stove with an electric stove. Some may decide to purchase an electric vehicle. While the individual residential consumer decisions aren't fully understood, NHEC's dataset

[1] http://www.nhec.com/filerepository/nhec_above_the_cap_net_metering_recommendationsstaff_analysis_3.pdf

clearly indicates that, on average, consumers do increase their electricity consumption after the installation of a solar PV system.

Q10. What do NHEC's findings regarding residential consumer usage after installation of a solar PV system imply regarding the accuracy of Attachment 2 to the testimony of Mr. Davis?

A10. NHEC's findings regarding a 52% increase in electricity consumption after the installation of a residential solar PV system imply that the revenue assumptions for Eversource's proposed alternate rate design are understated. Attachment 2 presumes that a model customer with an annual consumption of 6,619 kWh, a solar PV system of 5 kW, and 50% of solar PV output delivered to the grid would pay $775.18 annually under the proposed alternate rate design. This revenue calculation is highly sensitive to customer usage patterns. Table 1 below illustrates the resulting revenues from various increases in this model customer's usage post installation of a 5 kW solar array. These values were calculated using Eversource's Attachment 2 (Excel version) and presume increases in usage and demand are uniform (e.g., 10% increase in usage equates to a 10% increase in demand).

Table 1

Sensitivity to Changes in Residential Customer Usage Post Installation of Solar PV to Eversource's Current and Proposed Alternative Rates						
Change in Usage After Installation of Solar PV	0%	10%	20%	30%	40%	50%
Customer Consumption (kWh)	6,619	7,281	7,943	8,605	9,266	9,928
Solar PV Output (kWh)	6,293					
Annual Billing Demand (Billing kW)	57	63	69	74	80	86
Pre-Solar Electric Spend	$1,344					
Eversource Proposed Alt NM Rate	$775	$884	$995	$1,117	$1,239	$1,366
Eversource Current Rate w/ NM	$262	$396	$532	$680	$829	$983

presumes 5kW solar PV system

As Table 1 indicates, increases in customer usage post installation of a solar PV system result in significant increases in utility revenues under both the current and proposed alternate net metering rate design. While it's unclear if all customers adopting solar PV in NH will experience increases in usage approaching 52%, more modest increases would still result in annual utility revenues exceeding Eversource's estimate of $775.18 under its proposed alternative rate design.

Q11. Should the Commission consider the dynamic nature of residential customer load patterns and behavior pre and post installation of solar PV in setting successor NEM rates?

A11. The Commission is obligated to do this. HB 1116 requires the Commission to consider *"an avoidance of unjust and unreasonable cost shifting."* As Table 1 illustrates, a modest increase in residential customer consumption after installation of a solar PV system results in higher revenues to the utility than one would assume if the load was presumed to be static.

Using an assumption of static load overstates any claimed cost shift or under recovery of utility distribution revenue. In addition, it also results in the revenue requirements for a standalone residential DG ratemaking class being overstated.

The Commission cannot allow a standalone DG customer class to be created, especially at the residential level without a clear understanding of the dynamic nature of customer load behavior before and after installation of solar PV.

Q12. Is the proposed rate design for customers on Rate G with DG reasonable?

A12. No, it is not. The Davis testimony states *"First, in two of the Company's rate classes, Residential Rate R and General Service Rate G, distribution and transmission service rates are assessed on a volumetric kWh basis"*[2]. This is not quite right for Rate G, as Attachment 1, page 2 of the Davis testimony shows Rate G having a Distribution Demand charge of $8.86/kW and a Transmission Demand charge of $6.17/kW. There are tiered volumetric charges that recover a portion of the Distribution and Transmission revenues, but they are small. The tail blocks (> 1,500 kWh) of the Rate G volumetric charges for Distribution and Transmission are $0.00622/kWh and $0.00449/kWh, respectively.

The Distribution head and tail blocks for Rate GV are $0.00616/kWh and $0.00517/kWh, but the Davis testimony states *"Since most of the non-customer charge revenue requirements of Rate GV and LG are charged on a per kW basis in the current design, no redesign of the delivery charges for those rate classes is proposed in the DG rates."* It

[2] Page 4 of 10, Line 21

does not make sense that Rate G would be treated differently from Rate GV when the volumetric components of the Distribution usage charges are nearly identical. Furthermore, Rate G has a higher Distribution Demand charge than Rate GV, $8.86/kW vs. $5.67 (1st 100 kW). As a result, it doesn't make sense for Rate G to be treated any differently from Rates GV and LG.

III. REVIEW OF THE TESTIMONY OF MESSERS LEBRECQUE AND JOHNSON ON BEHALF OF EVERSOURCE ENERGY

Q13. Are the calculations provided in Exhibit RCL-RDJ-1 sufficient to document the existence of a cost shift from NEM customers to non-NEM customers?

A13. No, they are not. As stated in the testimony, *"The analysis is an estimate only, and incorporates a number of simplifying methods and assumptions that are explained in the exhibit."*[3] These estimates are very sensitive to input assumptions and even modest changes in input assumptions can result in significant changes to the calculated results. Page 2 of Exhibit RCL-RDJ-1, calculates the lost revenues associated with Small Net Metering Projects. It concludes that total lost revenues for this group of DG customers comprise $3,637,707 broken down by $919,097 for lost Distribution, Transmission, and Non-bypassable revenues, $869,649 in "Over-Market" payments for lost supply sales, and $1,193,902 in "Over-Market" payments related to exported energy that is banked energy.

I reviewed this model and made the following modifications to its assumptions:

[3] Page 17 of 30, Line 26

Table 2

#	Original Assumption	J. Bride Revised Assumption	J. Bride Rationale for Revision
1	Rate R and G have 50% of consumption exported	Rates R and G have 60% of their consumption consumed internally and 40% exported	50% export is a high ratio
2	Rate G lost revenues are 16% in block #1, 17% in block #2 and 67% in block #3	Rate G lost revenues are 0% in block #1, 10% in block #2 and 90% in block #3	Block 3 is the marginal block and Blocks 1 & 2 only comprise 1,500 kWh
3	Rate GV lost revenues are 100% in the first block (first 200,000 kWh)	Rate GV lost revenues are 70% in the first block (first 200,000 kWh) and 30% in the second block	Block 2 is the marginal block and many GV customers have usage in both blocks
4	Rate LG lost revenues are 100% in the On-Peak period	Rate LG lost revenues are 70% in the On-Peak period	The sun shines on weekends and holidays too
5	ISO-NE market value of electricity is \$0.05/kWh	ISO-NE market value of electricity is \$0.065/kWh	ISO-NE capacity should be valued as a behind the meter reduction in customer ICAP tags using the ISO-NE FCA 8 clearing price of \$7.02/kW adjusted for reserve margin. Using the wholesale FCM resource methodology results in too low a value.

By changing the assumptions in Table 2, the model calculates an aggregate lost sales value of \$3,132,226, which is \$505,481 less than Eversource's original calculation. My modifications to the Eversource exhibit are shown in Exhibit NHSEA-JB-Reb 1.

It also does not seem appropriate for Eversource to be including foregone electricity supply sales for solar PV output used behind the meter for self-consumption in its lost sales analysis. Page 2 of Exhibit RCL-RDJ-1 shows "'Over-Market' Payments for Energy" in the far right column. This calculation takes the presumed kWh produced by solar PV that is consumed behind the meter and multiplies it by the difference between $0.1095/kWh (Energy Service rate) and the presumed ISO-NE market value of the output of $0.05/kWh. This is problematic because the foregone supply sale associated with solar output consumed behind the meter should not be compared against market prices or counted as lost revenue. As a utility that will soon be restructured through the sale of remaining generation assets, Eversource should be agnostic as to whether future customer purchases of electricity supply come from default Energy Service, a competitive supplier, or behind the meter generation. If one were to remove this component of the lost sales analysis, then the lost revenue calculated in Page 2 of Exhibit RCL-RDJ-1 would fall to $2,679,198 and my calculation would be revised to $2,287,067.

It is reasonable to evaluate the potential impact of solar PV on lost sales for Distribution, Transmission, Non-Bypassable charges, and banking for behind the meter solar PV customers, but foregone electric supply sales associated with consumption of behind the meter generation should not be considered.

Q14. Are you conceding a cost shift on behalf of NH SEA based on your review of Exhibit RCL-RDJ-1?

A14. Absolutely not. The point is to illustrate how sensitive these calculations are to input assumptions and the inclusion or exclusion of various rate elements.

Q15. Should there be a distinction between Group Net Metered Customers and Behind the Meter Solar Customers in the analysis and review of impacts related to banking?

A15. Yes. Group Net Metering is fundamentally different from behind the meter solar PV which is the primary focus of this Docket. Any changes to the banking regime predicated around utility cost of service and solar PV output considerations should not have the consequence of eliminating the viability of Group Net Metering as a means to support community scale renewable projects.

Group Net Metering in NH presently includes several small hydro facilities which exhibit fundamentally different output characteristics than solar PV. Recognizing the diversity of Group Net Metered facilities is important to ensure that small hydro projects don't wind up with a compensation scheme designed for behind the meter solar PV. Furthermore, elimination of Group Net Metering does not appear to be contemplated in the language of HB 1116 as its purpose statement specifically states that "*it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation for such locally produced power*." It is important to recognize that not all customers are suitable candidates for behind the meter solar PV and Group Net Metering is an equitable way of providing customers an avenue to invest in and benefit from local renewable energy.

Q16. **Are the payback values calculated in Exhibit RCL-RDJ-2 accurate?**

A16. As discussed in my initial testimony in the instant proceeding, many residential customers with solar PV do not realize the value of their RECs due to barriers to registration and monetization. Without changes to the way in which RECs are handled for small customers, it is not reasonable to assume that every residential customer will receive payment for RECs.

Q17. **Is a review fee of $125 appropriate for small DG systems?**

A17. It could be, but the true cost to Eversource is not known. Eversource should document the activities associated with a typical small DG interconnection request and assign a cost value to each activity and step in the process. If it costs Eversource more than $125 to process an application, it should charge whatever the true cost is.

IV. REVIEW OF THE TESTIMONY OF MR. LON HUBER ON BEHALF OF THE NEW HAMPSHIRE OFFICE OF THE CONSUMER ADVOCATE (OCA)

Q18. Please describe your understanding of the OCA's proposed rate for residential DG customers?

A18. The Huber testimony has proposed a rate with the following characteristics[4]:

- Continue with the existing customer charges
- Energy Supply charges to continue as they are presently
- A Time of Use (TOU) differentiated rate with a peak period from 2pm – 8pm and charges for imported energy and credits for exported energy
- An export charge
- Partial Non-bypassable Transmission charge
- Other Non-bypassable charges

Q19. What elements of this rate proposal should be adopted in a successor residential DG tariff?

[4] Page 18, Line 1

A19. The Huber testimony's recommendation for a TOU rate design is a good one and is aligned with the plain language of HB 1116 which requires the consideration of time based tariffs. TOU distribution and transmission charges are a more appropriate price signal for residential customers than demand charges and encourage customers to adopt consistent behavioral changes.

The Huber testimony states that the proposed rate be open to customers taking competitive supply and indicates an openness to participation in the rate by non-DG customers. The rate should be available on an opt-in basis to non-DG customers to provide customers with non-typical loads the ability to benefit from a time differentiated rate. Customers with home automation and electric vehicle charging may also benefit from the rates created by this proceeding.

The proposal that all DG customers have a production meter installed is also a good one. As discussed in my initial testimony in the instant proceeding, many small DG customers forego registration as a REC eligible facility and therefore are unable to monetize their RECs. The installation of a production meter would remove this barrier to REC minting and monetization for small DG customers.

Q20. What elements of the OCA's proposal for a residential DG tariff are problematic and should be avoided?

A20. There are several problematic elements that will be discussed in detail below.

The first problematic element is the proposal for an export charge. An export charge is completely unsupported by data in the case record. Rates should be aligned with cost causing activities and to date, the case record only documents de-minimis costs that are attributable to customer export of DG output. The distribution system must be sized to accommodate coincident peak demands that occur during the summer months and if anything, DG export helps ameliorate these peak demands. The Huber testimony appears to propose using the export charge as a "make whole payment" to the utility so that residential DG customers yield the Embedded Cost of Service[5], but designing a charge that is completely divorced from cost causation activities is not a sound way to recover the utility's revenue requirement. The DG export charge should be rejected in any residential rate design adopted by the Commission.

The methodology and logic used to apportion the non-bypassable Transmission charge neglects to account for the contributions of solar PV to reducing the ISO-NE transmission peak[6]. Although ISO-NE Transmission charges are assessed on a 12CP basis, the cost causing activity that drives these charges is peak summer load since transmission line carrying capacity is inversely related to temperature and wind speed. This proposed charge severely undervalues the capacity of solar PV to reduce peak summer loads.

The proposed peak period of 2pm-8pm is too long. A more appropriate peak period would run from approximately 2pm to 6pm because summer peak load intervals occur predominantly within this timeframe.[7] As the case record demonstrates, summer peak load events are a cost causing activity while winter events are generally not. The carrying capacity of the distribution system is higher in winter due to lower temperatures that

[5] Page 26, Line 17
[6] Pages 23-25
[7] Pages 20-21

facilitate dissipation of heat from distribution infrastructure. In addition, peak winter loads are lower than summer peak loads. As a result, the hours of 7pm and 8pm should not be included in the peak period. The peak period should also be seasonally differentiated to account for the impact of summer peak loads on cost causation. Although left unstated in the Huber testimony, the peak period is presumed to only apply Monday through Friday as weekend and holiday loads are typically less than those on weekdays.

Q21. Why should the problematic elements of the residential DG rate design proposed by the OCA in the Huber testimony be rejected?

A21. A crucial Bonbright principle of rate design is that rates be simple and understandable to end use consumers. The rate design currently proposed is very complex and is likely to be misunderstood by residential customers. The complexity proposed, especially through the export charge, is needless and unsupported by the case record. The objectives of HB 1116 could be accomplished through a simpler rate design that includes charges for consumption and credits for export.

V. OTHER OPTIONS TO ADDRESS POTENTIAL COST SHIFTING OR CROSS SUBSIDIZATION IF DEMONSTRATED IN THE CASE RECORD

Q22. **Should documented or potential cross subsidies within the distribution system be singled out or addressed on a global basis?**

A22. As the Huber testimony on behalf of the NH OCA states, *"At the same time we must not be overly zealous in focusing on just one cross-subsidy when there may be larger* *subsidies elsewhere that should also be addressed."*[8] If the distribution utilities are concerned about revenue adequacy from their current rate designs, singling out residential DG customers is not a reasonable solution.

Q23. Are there better approaches to reduce potential cross subsidization and revenue adequacy concerns of the Distribution Utilities?

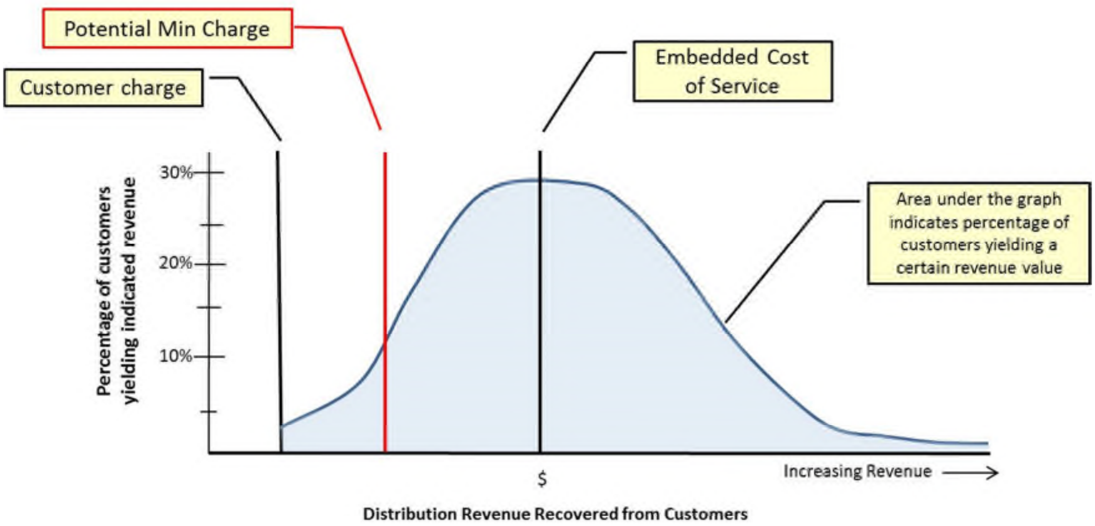
A23. Yes, there are. One such approach is a minimum bill. Presently, the customer charge represents a floor on revenues to the Distribution Utilities. There is no ceiling on potential utility revenues per the current rate designs. If the customer charge is less than the embedded cost of service, then certain customers may pay less than the utility's embedded costs.

In a minimum bill rate design, the Distribution Utilities could determine a minimum charge that is greater than the customer charge. This minimum charge could be determined based on a percentage of the embedded cost of service that falls within a reasonable range so as not to disproportionally impact low usage and low income customers, but addresses potential revenue deficiencies associated with certain customers that may fall below a certain threshold relative to the embedded cost of service. A standard deviation multiple would be one way to set this value. Figure 1 below provides a visual illustration of how this minimum charge could be set.

[8] Huber Testimony, Page 9, line 9

Figure 1

Simplified Illustration of a Minimum Charge for Residential Customers



* Graphic is illustrative and not based on an actual Embedded Cost of Service Study

VI. PROPRIETY OF DEMAND CHARGES FOR RESIDENTIAL CUSTOMERS

Q24. Are demand charges appropriate for residential customers?

A24. No, they are not. Residential rates must be simple and understandable for the residential consumer. In a residential household, consumers can leverage technology (e.g., smart thermostats) and behavior change to respond to price signals such as TOU price differentiation in their utility rates.

A residential household may consistently shift load, but many households have multiple members who may not be in constant active communication with each other regarding utility rate optimization. If a household member in the basement turns on an electric clothes dryer while another household member turns on an electric stove, that household would be punished with an elevated demand charge for a 15 to 30 minute lapse in appliance optimization. Such a lapse need only occur once during a billing cycle to negate the cost savings associated with any load shifting activity during the month.

Q25. Are residential customers presently capable of understanding their household electric demand?

A25. No, they are not. While conservation could help reduce the impact of a residential demand charge, consumers have been trained to think of conservation as related to reducing the volume of consumption, not the instantaneous rate of consumption. In addition, appliance Energy Star ratings are related to overall annual energy use, not maximum demand. Few residential consumers are sophisticated enough to obtain appliance nameplate data to determine the total maximum potential demand.

Q26. Is there evidence that residential customers can successfully manage their demand to limit demand charges?

A26. No. There is very limited load research in the public domain regarding this topic. Salt River Project[9] in Arizona recently implemented a mandatory residential demand charge for customers installing DG and their management has publicly stated that only 14% of customers have been able to successfully manage this charge. See Exhibit NHSEA-JB-Reb 2 for the article with this statement.

Q27. Is it accurate to state that residential demand charges will eliminate or reduce potential cross subsidization issues?

[9] Salt River Project is a self-regulated entity that does not fall under the jurisdiction of the Arizona Corporation Commission.

A27. No it is not. A non-coincident peak residential demand charge may exacerbate cross subsidization. Residential load is very diverse. A non-coincident peak demand charge has the potential to result in significant cost increases to low use customers and those with irregular load patterns. For customers with peak usage outside of the distribution system's peak load hours, the result would be elevated charges that are divorced from cost causing activities. Consider the example of an early riser with electric water heating. Should this early rising customer pay the same demand charge for a peak occurring at 5:30 am as the large house with air conditioning that peaks in the late afternoon?

For residential customers, the most effective price signal that is consistently aligned with charging for cost causing activities, ensuring revenue adequacy, and minimizing cross subsidization and inequities is a volumetric TOU rate design with peak charges set at a level sufficient to reflect utility costs.

Q28. Do regulators and policy makers increasingly accept demand charges as an effective rate design?

A28. No. In Illinois, ComEd was recently forced to drop its request for a legislative mandate for residential demand charge due to consumer opposition. ComEd was able to convince the Illinois legislature to pass a significant energy bill, but without the proposal for residential demand charges. See Exhibit NHSEA-JB-Reb 3 for a ComEd statement on this issue and an article from Greentech Media on this topic.

In Oklahoma, Oklahoma Gas & Electric filed a rate case in 2015 (Case PUD 201500273) requesting a residential demand charge and a separate rate class for residential DG customers that included a demand charge. In the Report of the Administrative Law Judge

("ALJ") issued on Dec 8, 2016, the ALJ affirmed the Joint Stipulation reached by certain parties to the proceeding that DG customers do not warrant treatment as a distinct class for ratemaking purposes.[10] The stipulating parties also agreed that no demand charges would be imposed on residential customers without a pilot.

In Arizona, a state with a relatively high penetration of residential demand rates, the Arizona Corporation Commission ("ACC") recently denied a request by UniSource Energy to implement mandatory residential demand charges. The ACC approved an optional demand rate open to all customers, but resisted a mandatory residential demand rate over concerns regarding customer education and acceptance of such a rate structure. This finding of the ACC is contained in Decision 75697 of Docket E-04204A-15-0142.

Q29. Do the demand charge proposals proffered by Eversource or Unitil comply with the plain language of HB 1116?

A29. No, they do not. Per my review of their proposals, they are non-coincident peak demand charges that do not appear to have a defined peak period associated with them. HB 1116 requires the consideration of time based rates and the lack of a peak time period for proposed non-coincident peak demand charges is contrary to this requirement of the legislation.

Q30. Are residential demand charges presently in common use?

A30. No, they are not. Table 3 below provides an overview of residential demand based rates that have been implemented by major Investor Owned Utilities (IOUs) in the United

[10] Oklahoma Corporation Commission – Public Utility Division, Case PUD 201500273 "Report of the Administrative Law Judge on the Full Evidentiary Hearing" page 79 of 238

States. As the table shows, they are all optional rates. None are mandatory for residential DG customers. If the Commission were to authorize the rates as proposed by the Distribution Utilities, New Hampshire would be an outlier relative to present day utility ratemaking practice.

Table 3

Survey of Residential Demand Charges by Major IOUs - Fall 2016

Utility	State	Rate	Demand Interval (min)	Demand Charges: Summer ($/kW)	Demand Charges: Winter ($/kW)	TOU	Mandatory / Optional	Required for DG	Eligibility Criteria
Arizona Public Service	AZ	ECT-2	60	$13.50[1]	$9.30[1]	Yes	Optional	No, DG customers can also stay on Base Rate E-12 and pay a fee per LFCR Rider	Opt In
UNS Electric Inc.	AZ	Res Demand	60	$5.10	$5.10	Yes	Optional	No	Opt In
Alabama Power	AL	RTA - Demand	15	$1.50	$1.50	Yes	Optional	No	Opt In
Xcel	CO	RD	15	$8.57	$6.59	No	Optional	No	Opt In
Duke - Progress	NC	R-TOUD-40	15	$4.97	$3.69	Yes	Optional	No	Opt In
Duke	NC	Residential TOU	30	$7.77	$3.88	Yes	Optional	No	Opt In
Duke	SC	Residential TOU	30	$8.15	$4.00	Yes	Optional	No	Opt In
Duke - Progress	SC	R-TOUD-38	15	$5.20	$3.89	Yes	Optional	No	Opt In
Dominion	VA	1S	30	$5.68	$3.95	Yes	Optional	No	Opt In
Black Hills Power	SD	Residential Demand	15	$8.10	$8.10	No	Optional	No	Opt In, > 1,000 kWh/mo
Otter Tail Power	MN	Residential Demand Control	60[2]	$6.08	$5.11	No	Optional	No	Demand Controls req.
Otter Tail Power	ND	Residential Demand Control	60[2]	$6.52	$2.63	No	Optional	No	Demand Controls req.
Otter Tail Power	SD	Residential Demand Control	60[2]	$7.05	$5.93	No	Optional	No	Demand Controls req.
SCE&G	SC	Rate 7	15	$12.04	$8.60	Yes	Optional	No	Opt In
LG&E	KY	RTOD-Demand	15	$12.38	$3.25	Yes	Optional	No	Opt In
Georgia Power	GA	TOU-RD-3	30	$6.64	$6.64	No[2]	Optional	No	Opt In

[1] - Summer peak rate for Jul/Aug. Other summer months are $14.63/kW
[2] - Energy component of Georgia Power rate TOU-RD-3 is TOU, but demand component is not

Table 3 excludes municipal utilities, cooperatives, and only includes rates that are open to new customers for residential service in single dwellings. Delmarva Power in Delaware and Ameren in Illinois have a demand component to their Transmission charges, but their Transmission charges are by-passable for customers electing competitive supply. As a result, these utilities were omitted from the table. Salt River Project implemented a mandatory demand rate for customers installing DG after December 2014, but this rate change was approved by the Salt River Project's Board of Directors, not the ACC. Salt River Project is not an IOU, but instead is a hybrid municipal/cooperative structure.

Q31. Does Table 3 list all demand charges offered by IOUs in the United States?

A31. Table 3 is comprehensive, but possibly not exhaustive. It contains the regulator approved demand rates at IOUs that I am presently aware of.

VII. SUMMARY AND RECOMMENDATIONS

My testimony can be summarized as follows:

- Residential load is dynamic and there is evidence that it increases significantly after the installation of solar PV. Any future rate design or calculation regarding cost shifts must quantify this dynamic load behavior.
- A cost shift attributable to solar PV customers has not been documented and calculations regarding potential theoretical cost shifts are highly sensitive to input assumptions regarding electricity exported to the distribution system and the wholesale market price of electricity.
- Mandatory demand charges are inappropriate for residential customers and must be rejected.
- A charge for usage exported to the distribution system is unsupported by the case record and should be rejected.
- TOU usage rates are a more appropriate way to charge residential customers for cost causing activities.

- Cross subsidies within the distribution system should be addressed on a global basis and distributed generation customers should not be singled out. A minimum bill rate design tied to a percentage of the embedded cost of service is a more reasonable way to address distribution revenue adequacy issues if supported by the case record.

Q32. Does this conclude your testimony?

A32. Yes.