EXHIBIT
#60
DE 16-576

THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISISON
DE 16-576

ELECTRIC DISTRIBUTION UTILITIES

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

City of Lebanon, NH

<u>Rebuttal Testimony of Clifton C. Below</u>

December 21, 2016

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Attachments

Attachment CoL R-1, Lin, Jeremy. "Potential impact of solar energy penetration on PJM electricity market." IEEE Systems Journal 6.2 (2012): 205-212.

Attachment CoL R-2 Affidavit from Jameson Brouser, CTO of EKM Metering, Inc

I. Introduction and Summary

Q. Are you the same Clifton C. Below who filed direct testimony on behalf of the City of Lebanon, NH in this docket on October 24, 2016?

A. Yes, and I am filing this Rebuttal Testimony on behalf of the City of Lebanon as well.

Q. Would you briefly summarize your rebuttal testimony?

A. Yes. I respond to a number of elements for future net metering tariffs proposed by other parties in this proceeding, by component: generation, transmission, distribution, and miscellaneous charges, metering and other regulatory issues, such as cost recovery, in that general order. While my focus is on the proposals put forth by the three distribution utilities in this docket I do touch on elements of the Office of Consumer Advocate's (OCA's) testimony and that of the New England Ratepayers Association.

Unfortunately I have not had time to respond to other testimony and did not have time to investigate and comment on the Consumer Energy Alliance (CEA) cost/benefit model of Net Energy Metering (NEM). I did do a quick superficial review and it appears that they did not take into account any avoided costs for ancillary services that are billed with LMPs to wholesale load and as are recognized by Puc 903.02 as avoided costs of surplus net metered generation. Nor does the CEA analysis seem to account for avoided transmission charges that result from NEM generation during monthly (LNS) system peaks on which such charges are imposed, nor any reduction in LMPs and FCM capacity costs that are likely to result from reductions in wholesale demand from price-taking load reducing NEM generation.

Liberty Utilities is the only electric distribution utility serving the City of Lebanon, so only their proposed tariffs are of direct interest to the City. However, I do provide a response to some of the proposals of Eversource and Unitil Energy Systems, for two reasons in particular. First is their potential precedential impact on alternative net metering tariffs that might be applied to Liberty customers in the future. Second is the fact that Eversource serves some customers in all three of the New Hampshire towns that share common boundary lines with the City: Hanover, Enfield and Plainfield. Town of Hanover officials have already expressed interest in the possibility of collaborating with the City in our proposed Real Time Pricing (RTP) NM pilot described in my direct testimony using municipal electric aggregation authority pursuant to RSA 53-E. Enfield and Plainfield are also possible participants in a cooperative municipal electric aggregation pursuant to RSA 53-E. RSA 53-E:6, II specifically requires municipal electric aggregation plans to "provide universal access" among other things. RSA 53-E:7, II provides that "[i]f the plan is adopted, the municipality or county shall mail written notification to each retail electric customer within the municipality or county." Together these two provisions seem to indicate that if our proposed pilot is implemented pursuant to RSA 53-E, we need to make it open to all retail electric customers within the community. RSA 53-E:3, II(b) and RSA 53-E:6, I expressly allows groups of municipalities to undertake municipal electric aggregation jointly through a cooperative agreement pursuant to RSA 53-A. I also note that the City's Master Plan (13.3.SD) and 2017-2020 "Outcomes & Work Plan" at p. 20 calls for the City to "explore opportunities to collaborate with local and regional partners, including the Lebanon School District and neighboring communities, to develop regional energy initiatives including aggregated power purchasing, expanded commuter engagement, and other opportunities to reduce energy use and costs." Therefore the City of Lebanon has an interest in proposed future net metering tariffs in areas of New Hampshire beyond our immediate boundaries.

II. Generation (Electricity Supply)

Q. What problem do you see with the distribution utilities' conception of net metered generation as essentially PURPA QFs (Qualitied Facilities) that are only entitled to compensation for excess generation at wholesale RT-LMPs?

A. Although Unitil, in their supplemental filing, and Liberty Utilities have volunteered to provide on-bill credit for surplus NM generation at the default service rate, at least for the time being, they, along with Eversource have argued in their direct testimony that FERC and PURPA only require credit for surplus or exported net metered generation at avoided wholesale costs based primarily on real time locational marginal prices. I think this argument continues to ignore two realities. First, PURPA itself, through Energy Policy Act of 2005 amendments, established a federal standard for net metering without reference to such facilities as QFs and called upon states to consider the adoption and implementation of such policies. 16 U.S. Code § 2621 (d) (11) regarding net metering states:

> Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

The phrase "eligible on-site generating facility" was used instead of "qualifying facility" in this amendment to PURPA. The determination of what might be an eligible facility and the applicable billing period have been left for states to determine and New Hampshire has done so through legislation implemented by the PUC. The question of how and to what extent the offset occurs was also left for the states to decide. If the New Hampshire legislature had wanted to reduce net metering to compensation only that which is available to QFs, independent of net metering, they could have just repealed the statute or otherwise said so, but instead they called for the development of alternative net metering tariffs.

The second important reality to consider is that behind the retail meter (BTM) generation that qualifies for net metering in New Hampshire does not qualify to participate in FERC regulated ISO New England administered wholesale electricity markets as a "Generator" although they may elect to register as a settlement only generator (SOG) with very limited market participation. Specifically ISO New England Operating Procedure No. 14 – concerning technical requirements for generators and other resources participating in wholesale energy supply markets at II. A.2. "Generator Defined"[1] states:

> d. A generating facility less than one (1) MW interconnected below 115 kV:
>
> o May register as a SOG or
>
> o May elect to **not** register if **not** participating in any Wholesale electric markets other than as a load reducer

I suspect that few if any net metered customer-generators in NH are registered as SOGs, and instead are considered to be load reducers because their effect on wholesale markets is essentially the same as other forms of retail load reduction that reduce the load at the wholesale

[1] p. 8, Rev. 2.4.1 Eff. 9/19/16

meter points between the FERC jurisdictional transmission system and the state jurisdictional distribution system.

All that being said I agree that accumulated surplus generation not used to offset load behind the meter or as part of a group pursuant to RSA 362-A:9, XIV is appropriately compensated at marginal RT-LMPs, plus avoided generation related ancillary services and capacity costs, all adjusted for avoided line losses between the retail meter and wholesale meter points, as provided for in Puc 903.02 (i) and recently affirmed by the Commission's approval of the Settlement Agreement in DE 16-674, dated 12/16/16.

The City of Lebanon does appreciate Liberty's proposal to allow for credit at default service rates for surplus generation that is used to offset future or group loads, as well as Eversource's proposal to at least allow for offset at full default service rate credit within each monthly billing period. However, in the absence of interval metering to allow for LMP compensation based on actual customer-generator exported generation and access to real time pricing (RTP) for load with appropriate retail mark-up (such as for administrative costs and RPS compliance), it seems that full default service credit is appropriate, at least for customers who aren't generating and selling RECs for generation that offsets their own load, as further explained in my direct testimony at lines 244-246 and 408-418.

An important consideration is how such offset credits work in conjunction with competitively procured default service. If a utility is being required to purchase surplus or any exported NM generation at wholesale for resale to others, then PURPA avoided cost rates would be all that can be required. Eversource, as a utility that has been directly providing default service is closest to that situation. However for Unitil and Liberty and eventually Eversource when they complete their transition to competitively procured default service, default service net metering acts as a condition of default service provision, not a sale to a utility. That is, the distribution utility, such as Liberty, is not purchasing power at wholesale to meet default service load and reselling it, rather the default service provider is doing that now, with metering and billing support from the utility. Surplus net metered generation acts as an offset to the load for which the default service provider has to procure power for at certain times, while increasing the amount of power that must be purchased from the wholesale market by the default service provider, not the utility, at other times, such that the whole amount of power actually purchased from wholesale markets is the amount of load net of net imports and exports of net metered generation that is part of that default service group. Conceptually the netting/offsetting events can be considered to be part of the terms of the retail transaction between the customer-generator and the default service provider, which is typically not a considered a utility that qualifies as such for the protection of PURPA avoided cost rates, especially if they voluntarily bid to provide default service, whether the net metering offsetting credits are explicitly or implicitly a condition of providing that default service.

Q How do you view Mr Harrington's testimony on behalf of NERA with regard to his contention that Demand Reduction Induced Price Effect (DRIPE) is extremely difficult to quantify and that any such benefits are likely to be marginal at best and that there should be an additional charge to distributed generation for additional load forecasting costs.

A. While I agree that the grid wide benefits (and costs) of increased levels of distributed generation are difficult to quantify, it is not impossible, and the difficulty doesn't mean that they don't exist and shouldn't be taken into consideration. An electrical engineer affiliated with the PJM Interconnection, Jeremy Lin, did just such an analysis on the potential impact of increasing distributed solar PV in the PJM market, published in the IEEE Systems Journal in June 2012[2]. Although somewhat dated and before the recent rapid increase in distributed PV it does illustrate how a simulation model of power system operation in an organized markets like PJM and ISO New England can be used to assess the impact of increased levels of distributed PV that acts price taking load reductions. For an assumed increase in solar PV in Pennsylvania the simulation found significant savings in production costs for the system ($463 million in 2015 dollars), a primary measure of economic benefit, as well as significant reductions in congestion costs, LMPs and transmission losses, concluding that "significant penetration of solar energy resources can bring about positive economic benefits for the power grid, especially in organized multilateral market areas." (p. 210). I have attached a copy of that paper as Attachment CoL R-1 with some highlighting of key points that I have added.

Having co-chaired an ISO-NE Scenario Analysis Steering Committee on behalf of NECPUC back in 2007, I believe that ISO New England is capable of doing such an analysis of

[2] Lin, Jeremy. "Potential impact of solar energy penetration on PJM electricity market." IEEE Systems Journal 6.2 (2012): 205-212.

the economic impact of various levels and types of DG and NESCOE may want to consider requesting such an economic study at some point. I realize that it isn't possible to undertake such a quantification within the time frame of this docket, but the likelihood of such significant economic benefits does support Liberty Utilities' contention that compensation of NM generation at energy service (default service) rates is reasonable and includes a recognition of some of long-term value of customer-owned generation that has not been quantified.[3]

With regard to NERA's proposed adder for additional load forecasting costs, that seems altogether unnecessary and impractical. The default service bidders are responsible for making such forecasts for default service energy supply purposes. ISO New England has had active working groups to better forecast solar and other DERs and as Jeremy Lin points out in his paper at p. 207, as many distributed solar systems are aggregated over larger areas, instead of local minute to minute output fluctuations (like many small loads fluctuate) the variability of solar is attenuated "leaving regional solar fluctuations in the hour-to-day time frame as the dominant system-wide effect." An internet search of solar insolation forecasts yields many such service providers including NOAA, whose Local Analysis and Prediction System (LAPS) "is being used to produce rapid update, high resolution analyses and forecasts of solar radiation."[4] Solar insolation and other weather variables also have large impacts on loads, independent of PV, such as for air conditioning which drives much of New England's peak demand.

Q Can you account for the differences between your analysis that NM solar produces at higher than average value hours and that of Eversource witnesses Labrecque and Johnson that found that NM solar produces at lower than average value hours over similar time periods.

A. Yes, to a large extent. To recap, Eversource found that the average output from 16 solar systems that NHSEA provided hourly production data for produced energy with a production weighted average NH RT-LMP value of $35.70/MWH, an average capacity value $6.24/MWH based on total annual production, resulting in a total energy and capacity valuation of $44.61/MWH. The load weighted average wholesale energy cost for total NH load based on NH RT-LMP that they reported was $43.77/MWH, $8.07/MWH, or about 8/10 of one cent/kWh

[3] Direct Testimony of Heather M. Tebbetts in this Docket at p. 16, lines 17-22.
[4] http://laps.noaa.gov/solar/

more than for the PV systems. They did not report a load weighted average capacity cost or the sum of energy and capacity costs for total NH load.

In contrast, a similar analysis that I did found a PV production weighted average NH RT-LMP value of $35.06/MWH, an average capacity value $11.80/MWH based on total annual production, for a total energy and capacity valuation of $46.87/MWH. The load weighted average wholesale energy cost for total NH load based on NH RT-LMP that I found was $36.02/MWH, slightly less than for the PV systems. I also found an average capacity cost of NH total load of $7.45/MWH, nearly half a cent less per kWh than for the PV systems, and a total energy and capacity cost for NH load of $42.47, also nearly half a cent less per kWh than for PV systems. Both analyses found significant diversity in value of avoided energy and capacity for different PV systems. Here are the factors that I believe account for most, if not all of the difference in the two analyses:

- I used the avoided cost methodology for surplus net metered generation recently approved by the Commission in DE 16-693. Eversource did not include avoided generation related ancillary service charges in their analysis, a relatively minor difference in the analyses. Instead of using avoided capacity charges to reduced wholesale load, Eversource treated the solar PV as if it was a Generator participating in the wholesale FCM and was paid the auction clearing price based on ISO-NE capacity market rules for intermittent power resources, which don't, in fact, apply to BTM net metered generation in NH. I believe that both analyses used capacity values for the same commitment period, which in both cases doesn't actually fully match the 12 month period analyzed. This difference in approaches to valuing capacity accounts for much of the difference and I believe that the approach I used, following Puc 902.08 rules more accurately represents the avoided cost of a price taking wholesale load reducing retail located resource.
- The two analyses used 25% different time periods. Eversource used CY 2015 and I used the 12 months ending 3/31/16. This is probably the other major difference in the analyses as it appears that NH-LMPs for the winter of 2015 were much higher than for this immediate past winter. For example the total wholesale cost to NH load for March 2016 (all hours) was just $24.29 compared with $67.71 for March 2015. This is probably the cause of most of the difference in the LMP calculations for both load and PV generation. In addition to the price

difference, February 2015 had much more snow and simultaneously had temperatures that remained below freezing so that snow did not shed from PV systems as much on their own in February 2015 as occurred in February 2016. For example my PV system only produced 35 kWh in all of February 2016 but produced 430 kWh in February of this year.

- My analysis included the 16 systems analyzed by Eversource, plus 4 others from the NHSEA data set, which seemed to be substantially complete for the period analyzed and 5 others that I collected data for. Among those 5 others were two small dual axis tracking systems and my own very western oriented fixed rooftop PV system, all 3 of which produced higher energy and capacity values than the average for other fixed orientation systems. These somewhat different data sets would account for some difference.
- Both analyses adjusted for avoided costs for line losses, although Eversource used a 7.5% assumed line loss adjustment which is somewhat more generous than the 6.9% line loss assumed in my analysis.
- Finally I adjusted a few systems in the NESEA data set to account for what looked to me to be fairly obvious incorrect time stamps, mainly apparently due to not adjusting for transitions between daylight savings time and standard time that resulted in some systems showing significant production for more than a full hour after sunset starting abruptly at one point in time compared with systems for which I was much more confident of correct time stamps. This likely had a beneficial effect on Eversource's analysis for PV production for a few systems compared with my adjustments to fit sunrise and sunset reality, as LMPs seem to be a bit higher in the hour immediately after sunset than the hour immediately before. I would have liked to have done more spreadsheet analysis with these data sets, as well as data available for other time periods but I simply haven't had the time due to other obligations.

Q Do you have any other concerns about Eversource's proposed calculation of avoided costs?

A. Yes. Their testimony was ambiguous as to how they would calculate avoided energy and capacity costs for surplus NM generation at the end of each billing period. Mr Davis, in his direct testimony at p. 43, lines 1-3 stated that under their proposal "excess energy produced after such netting is compensated that month at the Company's avoided cost rate under PURPA as set forth in Puc 903.02 and reaffirmed by the Commission for the Company in Order No. 25,920 Docket No. DE 14-238." Those two referenced methods have material differences. The later concerns IPPs or QFs that apparently are registered as Generators with ISO New England and provides for simple compensation at NH RT-LMP based on actual metered interval data for those generators. Puc 903.02 does an annual calculation that is different for PV systems and all other NM technologies and includes avoided generation related ancillary charges and load based avoided capacity charges, to be based on certain actual interval data if available or PV Watts modeled data if not. As I explained in my direct testimony at lines 348-374, use of the PV Watts data tends to systemically undervalue actual PV generation.

As we move from the rough justice of current net metering tariffs to more exact and granular justness of new alternative net metering tariffs, I think it is important to at least collect interval data from actual NM systems to more appropriately value the contribution of specific systems considering the considerable diversity in value produced from a relatively small sample set of actual NM PV generation, even before considering the differences in generating technologies that may be net metered, such as wind, hydro and landfill gas and for which we don't have any interval data in this proceeding. That is, in part, why the City of Lebanon has proposed a geographically limited RTP NM tariff that would collect and use interval data and RT-LMPs as the basis for valuing both exports and imports of energy over retail meters. This is also important for providing appropriate price signals for cost-effective storage and demand response that can help reduce the cost of integrating renewable resources, such as by reducing ramping rates (and LMPs) from what they would otherwise be without such DERs.

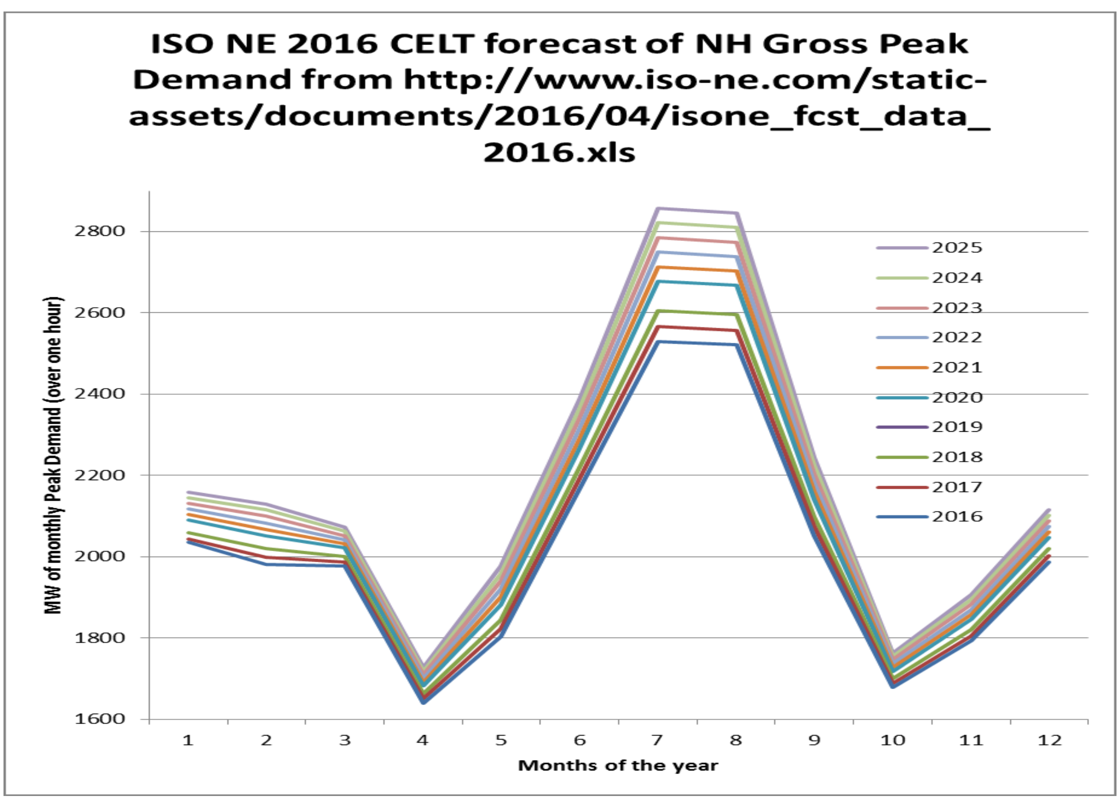
III. Transmission

Q What are your concerns about the transmission component of proposed tariffs by the distribution utilities and NERA?

A. My biggest concern is that none of these proposals provide any credit for actual cost reductions to NH load that are caused by any NM generation that is exported to the distribution grid at the hours of monthly system coincident peaks thereby reducing NH load's share of regional transmission costs from what they would otherwise be. This flips the current rough justice of a one to one volumetric credit for transmission charges over to a rough injustice of a zero credit for avoided transmission charges, whereby benefits to the system and total cost to NH load provided by NM generation is transferred from customer-generators to all other customers, resulting in unjust cost shifting onto customer-generators.

At least Liberty Utilities' proposal allows for load that is offset BTM during the hours of monthly coincident systems peaks to receive some of the benefit of the transmission costs that are reduced at a result of that generation by not imposing transmission charges for that load reduced BTM. Eversource on the other hand proposes to change to a non-coincident demand charge from the current volumetric charge for residential and small NM business tariffs that would recover the same transmission costs as if there was no reduction whatsoever in total transmission charges allocated to NH load even though the evidence shows that there is likely to be such reductions as a result of NM generation, whenever there is some production during monthly coincident peak demand. This is a half measure that actually reduces incentive for energy efficiency and does nothing to improve, and in fact diminishes, appropriate price signals with regard to cost causation of transmission costs compared with the current NM tariffs, which is why I conclude that it would move us from a rough justice to a rougher injustice.

Why this should be a concern for the Commission and all NH ratepayers is illustrated by by the following graph that shows the ISO-NE current forecast for New Hampshire peak load



growth, which is substantially higher than that of the region as a whole and more than double that of any other state after accounting for projected BTM PV and PDR (passive demand response) as explained in lines 536 to 559 of my direct testimony. If this forecast or something resembling it proves to be the case, then NH will be picking up a proportionately larger share of regional transmissions costs (and FCM costs) than ratepayers any in other state, while experiencing declining load factors and resulting higher costs for distribution, transmission and FCM costs per kWh, which is economically less efficient than reducing peak load growth relative total load growth as other states in New England are forecast to do compared with New Hampshire. New Hampshire peak load growth could also become a principal regional driver for the need to increase transmission and generation capacity relative to what would otherwise be the case if we slowed or reversed peak load growth as other New England states are forecast to do by ISO New England.

In addition to significant renewable generation opportunities of up to 1 MW on various city sites, the City of Lebanon has significant opportunities for demand response and storage. Those opportunities are more likely to be cost-effective and developed sooner than later if all three rate components align to send appropriate price signals that coincident peak demand reductions are more valuable to the system and other ratepayers than non-coincident peak demand reductions (and vice versa with regard to demand increases), especially over the long term. Next to generation, transmission is the next rate component where it should be easiest to align such an appropriate price signal as all we need to do is find ways to translate the existing wholesale market price signal for transmission, which is entirely based on system coincident peak demands, into a retail rate. Understanding that the utilities may not be quite ready to do such with their metering and billing systems, that is another reason why the City is proposing a RTP NM pilot that could help pioneer such an approach to transmission rates with minimal administrative burden on the distribution utilities and some kind of simple TOU transmission rate for default service in the meantime.

Q. Are you concerned that Eversoure's proposal to selectively shift only DG NM residential customers and small business customers to non-coincident peak demand

charges could create undue discrimination against those customers compared with other residential and small business customers that remain on volumetric transmission rates.

A. Yes, very much so, as explained in more detail below under the same issue with regard to proposed selective demand charges for distribution rates. One example with regard to transmission may illustrate the point. Say a NM customer-generator had an overall load averaging 800 kWh/month before installing their DG which cuts their average consumption in half to 400 kWh/month. A neighbor, because of lifestyle and investments in energy efficiency only consumers 400 kWh/month. With current rates the NM customer would now be paying the same as the neighbor, but with revenue neutral demand charges the NM customer could end up paying twice as much for same amount of distributed electricity as their neighbor. Say further that the neighbor has average demand during monthly coincident peaks for a 400 kWh/month customer, but the NM customer zeros out their demand during half the year because of their NM generation that even exports power during those monthly coincident peak demand hours but their off peak demand remains the same as an average 800 kWh/month customer during that half of the year and during the other half their demand is like an average 400 kWh/month customer. They could end up paying twice as much for transmission for half the cost causation as their neighbor. The problem with this hypothetical and the reality is that no one in this docket seems to have the before and after interval load profile data to assess the current diversity of load profiles with regard to transmission cost causation or the diversity of load profiles after adoption of NM generation to judge whether my example is plausible or whether undue discrimination is likely or not in these new divisions and treatments of rate classes .

Q. What are your thought on the OCA's proposed 50% transmission rate credit for export NM generation?

A. I think it is reasonable based on the limited available data and is a step in the right direction in finding a more just and refined approach to transmission rates that tries to strike a balance that minimizes cost shifting in either direction, albeit based on just a limited analysis of PV generation. The City's proposed pilot could provide a much richer database for refining future such analyses.

IV. Distribution

Q. What is your view on the distribution utilities' treatment of distribution rates in their proposed alternative NM tariffs?

A. I think Liberty Utilities' proposal to charge existing distribution rates whenever power is imported from the grid through a bidirectional meter and not give a credit when power is exported is reasonable and essentially the same as what the City has proposed for its pilot. Although I believe that there is some benefit to the distribution grid from adding DG, such benefits are likely to be highly locational and temporally specific and as such there may be better ways to incentivize such specific installations than a small generic aggregate credit, although I don't believe such would be unreasonable as a place holder until better methods are worked out.

I am quite concerned that Eversource's and Unitil's proposed selective substitution of non-coincident demand charges for existing volumetric distribution charges for only NM small customers could create undue discrimination contrary to law and have an unintended consequence of discouraging energy efficiency investments and making the decision to invest in NM self-generation more complex and difficult than is appropriate. I see it as a half measure that provides for cost recovery but does little or worse as an appropriate price signal as to cost causation for marginal costs on the distribution system that are, in part, driven by increasing coincident peak demands on various elements of the distribution system and the consequent need to invest in increased capacity to maintain reliability. I think the utilities recognize that growth in coincident peak demand, when the system is most heavily loaded, has greater cost causation consequences than the same amount of growth in demand when the system is most lightly loaded. Yet because the metering, data collection, and billing systems for a monthly non-coincident demand reading is relatively easy to implement and provides better cost recovery than the current NM terms, they are proposing this half measure that is limited as an appropriate cost causation price signal.

They argue that individual customer demand is the primary cost causation for distribution system capacity and O&M. Yet beyond the elements that serve an individual customer such as the service drop and a dedicated transformer, as one moves up through the distribution system to more aggregated load sharing system elements, such as circuits, feeders and substations, the capacity and some of the reliability and O&M expenses are driven by aggregate or coincident peak demand on those elements. While the utilities point out that residential class coincident peak demand is different from and later than overall system peak demand, usually when the sun isn't shining, it turns out from discovery that very few if any of their major distribution system components, such as substations and feeders, are exclusively residential, while a few are exclusively C&I. Thus most of these elements have their peak load at times that reflect some diversity of rate classes.

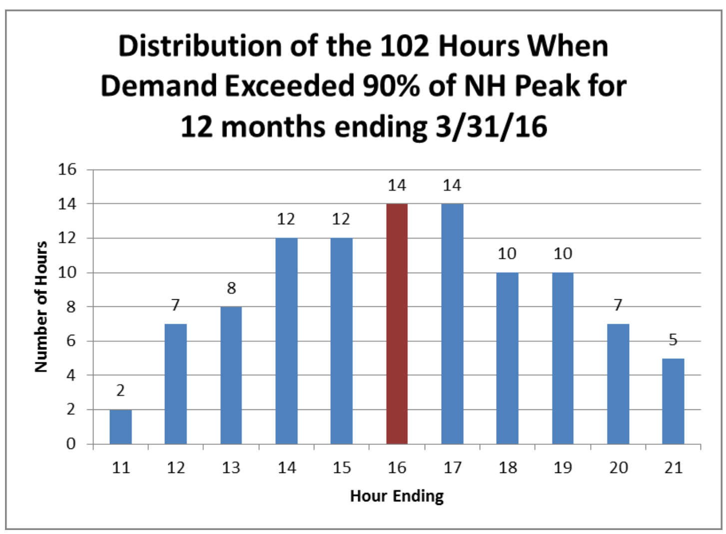
Another big problem with placement of only NM residential (and small business) customers on a distribution demand rate is the possibility of undue discrimination because we don't know the existing diversity of load profiles for such customer classes compared with the load profiles of customers from those classes after they adopt NM DG because of very limited or non-existent interval data. If a new NM customer drops their average net consumption from 600 kWh/month to 300 kWh/month, but still imports an average of 400 kWh/month, so they would pay based on 400 kWh/month under Liberty's proposal and that still might be more than their neighbor who only averages 300 kWh/month for the same size service drop and use of a shared transformer, which seems fair. But with a demand charge, the new NM customer could end up paying twice as much as the neighbor for little difference in their cost causation.

Perhaps more significantly we have many seasonal residences in New Hampshire, both winter (think ski chalet) and summer (think waterfront camp) as well as some seasonal businesses (such as an ice cream stand that is only open a few months per year). The seasonal residences may have very little annual electricity consumption because they are only used for a small part of the year, but that ski chalet might be occupied during February vacation which turns out to have the coldest night of the year and thus the winter peak and the chalet has electric resistance heat so they contribute greatly to winter peak but contribute only a fraction of the distribution revenue that a year around NM residence that has a pellet boiler and so contributes little to the winter peak, but pays more due to monthly non-coincident demand charges. Likewise that summer (only) camp may get up upgraded to a centrally air conditioned cottage, which along with the ice cream stand have their peak demand coincident with the hottest and one of the sunniest days of the year, paying only a fraction of the distribution cost that a NM customer pays due to demand charges even though the NM customer has little to negative impact on the summer distribution peak. Again, the problem is we don't know the extent of this potential undue discrimination due to the lack of data and analysis.

Q. Are the OCA's proposal for a Time of Use (TOU) volumetric distribution rate for residential distribution charges and a distribution export charge reasonable ?

A. The proposed simple TOU distribution rate is reasonable and would be a good step in the right direction for sending a more appropriate price signal regarding distribution costs to customers. I would quibble with the proposed peak period of 2 pm to 8 pm, especially if that means the hour beginning at 2 pm versus the hour ending at 2 pm. The reason is simple, as illustrated in my direct testimony at lines 594-602 and as shown in the graph below. For a recent 12 month period the hours that exceeded 90% of the NH Peak demand extended from the hour ending 11 am to the hour ending at 9 pm. All of these hours were in the summer season, which is more critical than the winter peak, which is lower than the summer peak, and the system can handle somewhat larger winter peaks in most cases because lower ambient temperatures dissipate much of the heat generated by high loads which is a key cause of reliability issues from heavily loaded wires, transformers and other equipment.

I would suggest that a more appropriate peak time frame would begin at noon and extend through the hour ending at 8 pm, lopping off 9 hours in the morning and 5 later in the evening from this group of highest probability peak hours. This would still encompass most winter evening hours when peak is most likely to occur.



I do not believe that the proposed distribution export rate is reasonable however. It certainly would be without precedent as far as I can tell. Generation only exists to serve load. Except for additional costs to interconnect a generator to the distribution or transmission grid, which are already charged to the generator under current policies, generation does not pay to access the grid. Load pays for distribution, transmission, and generation, because they all serve load. This proposal could go well beyond recovering revenue from lost sales due to BTM self supply in cases where a resident sizes their PV system to produce more power than they presently consume, which should not be discouraged. It would also penalize increases in energy efficiency investments made after NM generation is put in place.

V. Miscellaneous Charges

Q. What do you think of utility proposals to recover miscellaneous charges such as the Systems Benefit Charge (SBC), stranded cost recovery charges, and the electricity consumption tax on any power imported from the grid, such as measured from a bidirectional meter with separate import and export channels?

A. I agree that would be reasonable, although I don't agree that it is required because some of these are called "nonbypassable" in RSA 374-F. The original net metering law was enacted soon after the adoption of RSA 374-F and was sponsored and developed in the same committees by many of the same legislators who worked on RSA 374-F. Since the enactment of both statutes, including various amendments over the years, the offset that occurs under net metering has never been considered to be illegal or contrary to statute. There is nothing in the most recent amendment s to these laws to indicate otherwise, although I think it is still reasonable to do so and well within authority of the Commission to direct such.

Q. Is the OCA's proposal to extend these charges to gross consumption of electricity, to include BTM production/consumption reasonable?

A. No, it is not. With regard to the electricity consumption tax the OCA proposal would be contrary to New Hampshire law. The relevant NH Department of Revenue Administration administrative rule, Rev 2602.05 states the following: "Generation by a Residential Customer. The generation of electricity by a person who is a residential customer under the tariff of the distribution center serving the geographic area where that person is located shall not make: (a) A person a producer; or (b) The consumption of such generation subject to the tax under RSA 83-E." Administrative rules have the force and effect of law in New Hampshire, so the OCA proposal in this regard would be unlawful. With regard to the System Benefits Charge, RSA

374-F:3, VI states that such should be "applied to the use of the distribution system." BTM self-generation does not directly involve the use of the distribution system. Other miscellaneous charges should likewise be applied in the same way that volumetric distribution charges will or would apply under alternative net metering tariffs. Otherwise it could be quite administratively burdensome to the utilities.

VI. Metering and Other Regulatory Issues

Q. Can you address any other metering and regulatory issues?

A. I agree with NERA's recommendation that we should move to as granular interval metering for net metering to enable RTP as quickly and technically and financially feasible and it would be a missed opportunity to install new bidirectional meters for new NM customers that don't collect interval data. I agree with the utilities and other parties that there is no need for a cap on net metering if we get the tariffs right and minimize unreasonable cost shifting.

I have problems with Liberty's proposal to require a generation meter that could be redundant to revenue grade metering for REC production. In discovery they indicated that they would expect that additional meter to be installed in a round meter socket in proximity to the existing service point utility meters, typically outdoors and that the meter would not be available for REC production. They also asserted that revenue grade meters aren't capable of metering more than one circuit so all NM generator output would need to be combined into one circuit. I have attached an affidavit from Jameson Brouser, CTO of EKM Metering, Inc. (Attachment CoL RP-2) that contradicts that assertion. Liberty's proposed requirements for an additional generation meter could add significant cost to some NM DG installations and would preclude the customer from installed their BTM DG electrical system in a number of ways permitted by the National Electric Code that governs such installations, including using multiple circuits to bring DG power directly into the bottom of circuit breaker panels or subpanels. That happens to be what my personal PV system does and it's output is being measured by a revenue grade meter installed next to my subpanel in my basement. If the customer-generator provides their own revenue grade meter as they would need to do for REC production and can provide an annual report of the amount of power generated, which is all Liberty is looking for, then that should be an acceptable alternative to avoid economically inefficient redundancy and unnecessary additional costs imposed on the customer-generator to modify their internal wiring and other distribution system customers (for the redundant meter, including utility installation).

There is an additional material problem with how Liberty and the OCA have proposed the metering of generation output be used to calculate lost distribution system revenue, which is that they don't account for the possibility that customers who install NM DG may increase their gross electricity consumption as a result of their decision to install renewable self-generation. As I noted in my direct testimony, the NH Electric Cooperative, which had before and after granular data to analyze for both NM and other customers, because of their smart interval meters and widespread deployment of generation meters for REC production, which is a service they offer, and "found that, on average, we could attribute an increase in usage of about 52% to PV accounts. . . . As the number, size, and utilization of PV systems continue to change, we will need to monitor the amount of increased usage that should be credited against net sale losses and cost recoveries."[5]

I can also offer my own anecdotal evidence in this regard. During the year prior to installation of our PV system we averaged about 300 kWh/month[6] Over the course of 2015 our gross consumption averaged 277 kWh/month.[7] This may have dropped from the prior year due at least in part to continued implementation of energy efficiency measures such as conversion to LED lighting. By the end of 2015, realizing how much surplus generation we had accumulated we began to increase our electric consumption, first by purchasing and installing an electric clothes dryer for the first time in our lives early this year. In the spring we bought a used Chevy Volt that my wife uses for a nearly 20 mile roundtrip commute to work, which the electric charge covers. We replaced our gas powered lawn mower and chain saw with a 56 volt battery electric models and added an electric weed whacker, which we never had before. Finally this summer, instead of using our pellet boiler to heat domestic hot water through its buffer tank, we turned back on our old electric resistance hot water heater that we had discontinued the use of prior to

[5] www.nhec.com/filerepository/nhec_above_the_cap_net_metering_recommendationsstaff_analysis_2.pdf at p. 3. There is more on this point in my direct testimony starting at line 259.
[6] I've misplaced the papers with the exact numbers.
[7] Calculated by adding our gross production from our microinverter monitoring system, from the day beginning the 12 months meter reading period reported by Liberty to the day of the last Liberty meter read, to the net load reported by Liberty for the same 12 month period.

installing our PV system. These combined actions, none of which we would have taken during this time frame if we weren't generating our own renewable electricity, increased our average monthly gross electric consumption to 433 kWh/month for the 12 monthly billing periods ending just last week, a 57% increase from the prior 12 month period. On Monday I sat next to a Hanover resident who participated in the Solarize Hanover program and told me that he has done something similar, that is purchase a plug-in electric vehicle because he and his wife are now generating their own renewable electricity and wanted to reduce their fossil fuel consumption. They are planning to replace their second car with another plug-in vehicle, as we are, at some point in the not too distant future. The City of Lebanon could experience some of this phenomenon too as our Master Plan calls for consideration of reduction of fossil fuel usage for building heating and transportation, especially as energy efficiency is increased and renewable generation is increased such as by increased use of electric heat pumps and possibly purchase of electric vehicles.

This available evidence, as meager as it may be, suggests that metering BTM generation and adding it to net load at the utility meter to figure gross consumption could well go beyond recovery of lost revenues from NM and create an undue windfall for the distribution utility at the expense of all ratepayers. It may be more appropriate to use the customer load for the 12 months prior to installation of NM DG to figure a baseline from which to estimate under recoveries of distribution revenue caused by new NM installations as an interim method to provide for timely recovery of lost revenue. In the longer run lost distribution revenue from NM DG might be better calculated in conjunction with a revenue decoupling mechanism as has been contemplated to be proposed pursuant to the settlement approved in DE 15-137, where both positive and negative deviations from load forecasted for determining rates to meet revenue requirement, from whatever source, including both decreases of distribution sales from NM and increases in load from more electrification of thermal and transportation loads, are taken into account.

VII. Conclusion

Q. Do you have any concluding thoughts?

A. Yes, in order to improve NH's load factor from what it is likely to otherwise be we should use this opportunity in developing alternative NM tariffs to begin to better align all three major rate components to yield more appropriate price signals as to cost causation and marginal costs. Not only will this result in more just and sustainable net metering tariffs it will also improve the integration of net metered distributed generation into the grid and enhance the development of cost effective storage and demand response. Perhaps even more importantly this will result in greater economic efficiency, innovation, and cost savings for all ratepayers, which is the goal of electric utility industry regulation in New Hampshire under RSA 374-F.

Q. Does this conclude your rebuttal testimony?

A. Yes.