ENERGY FREEDOM COALITION OF AMERICA

DIRECT TESTIMONY OF

Patrick Bean

New Hampshire Public Utilities Commission

Docket No. DE 16-576

I. Introduction and Purpose of Testimony

Please state your name, business address, position and for whom you are filing testimony.

My name is Patrick Bean. I am a Deputy Director of Policy and Electricity Markets at SolarCity. My business address is 601 13th Street NW, Suite 900, Washington, DC 20005. I am filing testimony on behalf of the Energy Freedom Coalition of America (EFCA). SolarCity is a member of EFCA.

Please describe your position, experience and qualifications.

As Deputy Director at SolarCity, my responsibilities include providing quantitative analysis of electricity markets, rate designs and distributed energy resource (DER) policies across the nation, with a primary focus on States east of the Mississippi. I engage in utility regulatory proceedings including rate cases, grid modernization and distributed generation programs.

Prior to joining SolarCity, I was a Senior Research Associate at the King Abdullah Petroleum Studies and Research Center (KAPSARC) which is a multi-disciplinary international energy think tank in Riyadh, Saudi Arabia. My research included statistical and economic analysis of energy productivity and renewable energy policies. I also led the development KAPSARC's "Utilities of the Future" research program which seeks to create tools to simulate electricity systems with high levels of DERs, and to provide insights about new business and regulatory models given the rise of DERs.

I previously worked at Southern Company as a Strategic Generation Planner for three years. I developed a new generation planning method to manage market uncertainty and minimize regrets and led the company's quantitative environmental policy analysis. My work was used to determine which power plants to build, retire or upgrade, and the analysis was used in regulatory filings, including the integrated resource plan, rate cases, and generation certification filings.

I hold a Bachelor of Science degree in Environmental Science and Policy from Marist College, and a Master of Environmental Management in Energy and Environmental Resources from Duke University. My resume is attached as Exhibit EFCA-PB-1.

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

No I have not.

What is the purpose of your testimony?

EFCA's goal is to create a healthy and sustainable regulatory environment in New Hampshire whereby DERs can flourish and provide benefits to customers, utilities and the grid. This proceeding should lay the groundwork for creating such an environment and provide customers, regulators, utilities, DER providers and other stakeholders with a long-term vision for net metering, DERs and the electricity system. This can be accomplished by developing pilot studies for alternative net metering tariffs, creating programs to collect and disseminate data, reforming distribution system planning, adopting an automatic rate adjustment mechanism, and encouraging utility investments that integrate more DER.

My testimony addresses several topics that are relevant to the objectives set forth by New Hampshire House Bill 1116, including the consideration of new alternative tariffs and other regulatory mechanisms that can help ensure continued opportunities for customer-generators.

The topics include:

1. Recommendations for data collection and sharing requirements to enable more refined analysis of costs and benefits of DERs, and identification of DER opportunities.
2. Reforms to the distribution system planning process to evaluate non-wires alternatives.
3. Alternative rate and regulatory mechanisms for consideration.
4. Possible Pilot Projects

SolarCity published a white paper in February 2016, called "A Pathway to the Distributed Grid", relevant to the data sharing, cost-benefit analysis, and distribution planning topics discussed in this testimony. I have attached the white paper as Exhibit EFCA-PB-2.

In preparing your testimony, did you have the opportunity to review the testimony of The Alliance for Solar Choice's (TASC) witness, Thomas Beach?

Yes, I did.

Why was reviewing Mr. Beach's testimony important to your testimony?

Mr. Beach has extensive experience calculating the costs and benefits of distributed generation, and the findings of his analysis provide insights into whether changes to New Hampshire's net metering program are warranted.

Does Mr. Beach provide a reasonable analysis?

Yes. Mr. Beach calculates the costs and benefits of net metering in a manner that follows the developing consensus for best practices of such analysis. He evaluates NEM from a variety of perspectives using accepted methodologies including the participant cost test, rate impact measure, total resource cost test, and societal cost test. Further, he includes a comprehensive list of cost and benefit categories and provides reasonable analysis given the data available.

Are you submitting a cost-benefit analysis of distributed solar with your testimony?

No, I am not. Having reviewed Mr. Beach's analysis, I did not see the need to repeat the analysis.

Does net metering present an unjust and unreasonable cost-shift in New Hampshire?

No. As shown in Mr. Beach's benefit-cost analysis,[1] net metering provides net benefits to all of New Hampshire's electricity consumers. Moreover, the State's utilities have not provided sufficient evidence that a cost-shift exists, or if one does, that it is unjust and unreasonable. For example, Unitil estimated displaced revenues of $15,261 due to net metering in 2013.[2] Even this is likely an overestimation since it estimates generation from all installed solar capacity and multiplies the generation by the distribution tariff rate to determine the utility's displaced revenues. It is likely an overestimation of solar generation because all solar installations are assumed by Unitil to be south-facing, which is an orientation that maximizes generation, and operating at nearly 19% capacity factor.[3] Not all roofs are south-facing and some homes can experience shading throughout the day due to the positioning of trees or other structures. Moreover, Unitil does not consider degradation of solar panels which reduces the amount of generation over time,[4] and the company appears to be relying on typical metrological year (TMY) – 2 data, rather than the most recent TMY3 dataset which estimates lower solar generation for Concord, NH than TMY2.[5] These actions will cause an overestimation of solar generation.

[1] Direct Testimony of R. Thomas Beach before the New Hampshire Public Utilities Commission. Case number: DE 16-576
[2] Unitil response to NHSEA 1-15.
[3] Unitil response to NHSEA 1-15 attachment 1.
[4] Research has shown annual degradation is likely around 0.5%/year. *See* Jordan, C.D., and Kurtz, S.R. 2012. *Photovoltaic Degradation Rates – An Analytical Review*. NREL. Available from: http://www.nrel.gov/docs/fy12osti/51664.pdf
[5] TMY2 data has 4% more solar output for Concord, NH than TMY3 as calculated from NREL's PVWatts tool. For more information about the TMY3 dataset, *see* Wilcox, S. and Marion, W. 2008. *Users Manual for TMY3 Data Sets*. NREL, available from: http://www.nrel.gov/docs/fy08osti/43156.pdf

Eversource estimates their lost distribution revenue due to net metering is some $560,000 per year.[6] Their estimate also assumes that all installations operate in the same fashion (15% capacity factor), and assumes that 50% of the solar production is consumed onsite and results in displaced sales. Again, these actions will cause an overestimation of solar generation.

Further, neither of these examples provided by utilities includes consideration of the benefits provided by net-metering. Unitil acknowledged that it has not conducted any studies or analyses addressing the actual or potential benefits of solar DG installation to the distribution system, nor does it believe that such benefits exist.[7] Without a benefit-cost analysis, it is impossible to conclude that an unjust and unreasonable cost-shift exists.

Why do benefits matter when determining whether there is an unjust and unreasonable cost-shift?

The nature of ratemaking based on the average ratepayer in a class means that intra-class cross-subsidization is inherent. For example, the residential rate class is comprised of many different types of dwellings that have different electricity patterns and different costs of service, such as different costs for urban and non-urban areas, yet all customers in the class pay the same rate. Recent research has found that utility regulatory commissions have routinely allowed cross-subsidization, particularly when it benefits the utility system.[8] If a cross-subsidy is identified and its benefits outweigh the costs, all electricity consumers are better off and the cross-subsidization is not unjust or unreasonable.

Should changes be made to net energy metering (NEM) programs in New Hampshire?

Net metering has been, and continues to be, a fair and efficient mechanism for encouraging the adoption of distributed solar in New Hampshire, and therefore should not be changed at this time. As shown by Mr. Beach,[9] NEM provides net benefits for all electricity consumers. Changes to NEM should not be considered until analysis shows the program does not provide substantial benefits. Further, the absence of relevant utility data in New Hampshire virtually eliminates the ability to make intelligent decisions about changing net metering.

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[6] Eversource response to NHSEA 1-15.
[7] Unitil response to Staff-UES-10
[8] Peskoe, A. 2016. *Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar.* Texas Journal of Oil, Gas, and Energy Law. Vol. 11:2. Pg. 108-109.
[9] Direct Testimony of R. Thomas Beach, DE 16-576.

The Commission may also desire to keep in mind the purpose and context of DERs. One purpose of encouraging DERs is to reduce the future cost of the grid to all consumers by making efficient decisions at the customer level and then at the utility level. The context for New Hampshire is a regional electric grid with related energy, capacity and other markets that give New England among the highest regional electric costs in the nation.[10] This includes ISO-New England's rapidly increasing open access transmission tariff (OATT), enlarged by billions of dollars in new transmission investment.[11] This is occurring while load is generally flat. If DERs can efficiently reduce demand for distribution investment, those savings will accumulate into reduced demand for transmission investment. It also should be apparent that impairing DERs by limiting net metering when it may be one of the several solutions to high electricity costs is not prudent, especially without data to support the change.

Does your position contradict the requirements of HB 1116?

No, although NEM has been and continues to be successful in New Hampshire, developing a long-term plan provides customers and stakeholders with greater certainty about the future of DERs, and ensures a transition to alternative rates and regulatory mechanisms occurs smoothly. Collecting data, refining methodologies, and developing pilot programs in the present will assist and inform the development of future programs and alternative mechanisms.

II. Data Collection and Sharing

Why are data collection and data sharing critical to this proceeding?

There are several reasons. Data collection, sharing and transparency are critical to effectively evaluate:

1. new methodologies for quantifying benefits and costs of DERs;
2. the costs and benefits of net metering, whether changes are warranted, and the costs and benefits of potential successor programs; and
3. opportunities for non-wires alternatives in the distribution system planning process;
4. alternative or pilot rate designs and billing mechanisms.

[10] EIA, Table 5.6.B Average Price of Electricity to Ultimate Customers. *Electric Power Monthly*.
[11] One transmission provider, NextEra Energy expects New England's transmission rates to be 500% higher over a 14-year period, *see* Gibelli, S., and Gardner, M. August 16, 2016. "Delivering the benefits of competitive transmission to New England's ratepayers while balancing the need to maintain system reliability." A presentation to NEPOOL Transmission/Reliability Committee. Slide 8.

Greater data availability and transparency will enable more accurate and precise economic assessments, and ultimately lead to more informed decision making.

How is data collection and data sharing relevant to your testimony?

Later in my testimony I discuss potential changes to distribution system planning, non-wires alternatives, and potential pilots for alternative rate designs. Access to transparent data is necessary for these programs and to evaluate their value and that of other alternative proposals being considered.

What do you mean by "new methodologies for quantifying benefits and costs of DERs?"

As shown in TASC witness Tom Beach's analysis, there are a variety of cost and benefit categories that effect the net value of solar and other DERs. There is also a locational dimension to these categories that is currently often not considered due to a lack of data and quantification methodologies. For example, a DER may have a higher value on one circuit than another due to local demand profiles and capacity constraints on the distribution system. Collecting data, developing methodologies for more granular analysis and disseminating the information will help identify those opportunities and help ensure the benefits of DERs are maximized.

Do you have any suggestions for the type of data that should be collected and the sharing requirements?

Yes, a SolarCity witness in New York created a minimum set of data that would be required to develop evaluation methodologies and inform decision-making processes.[12] The recommendations are particularly useful in this proceeding. The data requirements are presented in three tables, which include the type of data request, intended use, granularity of data, and data format. The first table is related to identifying grid needs and planned investments. The second table outlines data requirements necessary to calculating hosting capacity. The final table includes data categories to calculate the locational value of DERs. The tables are attached as Exhibit EFCA-PB-3.

III. Reforming Distribution System Planning

What is a non-wire alternative?

[12] Testimony of Carlos Gonzalez before the State of New York Department of Public Service. Case 16- E-0060. May 27, 2016

Non-wires alternatives is a concept of deploying generation, DERs, energy efficiency or demand response to replace or defer traditional transmission and distribution investments such as new lines and substations. Integrating non-wires alternatives into the distribution planning process presents an opportunity to leverage the value of DERs and ultimately minimize system costs.

Are New Hampshire utilities required to assess non-wires alternatives in their Least Cost Integrated Resource Plans ("LCIRP")?

Yes, RSA Sections 378.38-III and 378.38-IV require utilities to assess "supply options including owned capacity, market procurements, renewable energy, and distributed energy resources" and "assess distribution and transmission requirements, including an assessment of the benefits and costs of 'smart grid' technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid…"

To what extent have New Hampshire utilities incorporated non-wires alternatives into their LCIRPs?

Liberty Utilities proposed a hypothetical non-wires alternative to illustrate its planning process in its most recent LCIRP.[13] However the company notes there are challenges to gathering data to evaluate the potential benefits and costs,[14] and that regulatory reforms and data collection are required, along with associated cost recovery, to perform non-wires alternative evaluations.[15]

In its most recent LCIRP,[16] Unitil does not outline a process for procuring and evaluating non-wires alternatives. Unitil witness Thomas Meissner, Jr. asserted in his testimony that solar is not a good alternative to traditional utility investments.[17] Mr. Meissner uses an example of an $11.75 million substation and compares it to whether $11.75 million spent on a mix of distributed and utility scale solar could meet the capacity requirements. He concludes that the solar would be 70 times more expensive than the substation since the solar could only provide 1 MW of capacity, whereas the substation provides 70 MW. This is a flawed approach for evaluating non-wires alternatives since the company assumed it would be spending $11.75 million on solar rather than a substation.[18] Instead, the utility could have evaluated incentives, including rebates, which would encourage customers to invest in a

[13] Docket No. 16-097, Appendix E.
[14] Liberty Utilities response to EFCA 2-5.
[15] Docket No. 16-097, Appendix E at page 4.
[16] Docket No. 16-463
[17] Direct Testimony of Thomas P. Meissner, Jr. at pages 35-36.
[18] Unitil response to EFCA-UES 1-21.

portfolio of DERs, including solar, demand response and storage, in the area of the distribution need. By leveraging customer investments, the cost of the incentives could be a fraction of the cost for the utility to own and operate the non-wires alternatives. Traditional utility investments, such as substations, are also typically "lumpy" in that the infrastructure is oversized to accommodate potential load growth and long-term needs. It is unclear whether the region served by the new substation requires 70 MW in the near-term, or whether non-wires alternatives could have provided a cost-effective option for deferring the substation to future years.

Eversource noted in its most recent LCIRP that its Energy Efficiency team determines whether there are targeted conservation and load management measures.[19]

Do the utilities encourage customers to make energy-related investments at specific locations on the distribution system to help meet the reliability or efficiency needs of the local distribution system?

As noted above, Liberty Utilities studied a hypothetical case study in their LCIRP about the opportunity of targeted customer investments to reduce demand on the distribution system.[20] This appears to be the extent to which the utilities are considering the encouragement of customer investments in DER at specific locations. Unitil and Eversource have no such plans for encouraging customers to invest in DERs at specific locations at this time.[21]

What can be done to encourage more non-wires alternatives in the distribution system planning process?

The Commission and utilities can incorporate a competitive procurement process in utility LCIRPs. The utility would identify a system need and "traditional wires" solution through the LCIRP process, identify potential non-wires alternative incentives, and solicit bids from third-party providers for solutions that meet the identified need. The Commission and independent evaluator then compare the proposals in a cost-benefit analysis using the Societal Cost Test, and select the solution that is expected to provide the greatest societal benefit.

This process is similar to the generation planning approach taken in vertically-integrated states, such as Georgia, in which the utility identifies a capacity need in its integrated planning process. The utilities

[19] Docket No. 15-248
[20] Liberty Utilities response to EFCA 2-9. See also Docket No. 16-097, Appendix E.
[21] See Unitil response to EFCA 2-9, and Eversource response to EFCA 2-9.

then propose a utility-owned option and other parties bid alternative projects that meet the capacity need. The Commission and independent evaluator conduct an analysis to determine which project has the lowest system cost. If the utility's project is selected, the utility is authorized to construct the project and add it to its rate base. If an alternative is selected, the utility enters into a power-purchase agreement with the alternative supplier.

Are there other ways to encourage location-specific investments in DERs?

Utilities should also be encouraged to create and disseminate hosting capacity maps to encourage deployment. Hosting capacity maps that identify available capacity for DERs on feeders can send customers and DER providers signals about areas on the distribution system where deployment should be targeted or avoided due to scarce capacity. Unitil does not currently develop or publish hosting capacity maps.[22]

Should utilities be able to own non-wires alternatives?

No. Utility ownership of non-wires alternatives such as distributed generation and energy storage should be prohibited due to the potential conflicts of interest. DER providers would be at a competitive disadvantage because utilities have customer data, information about system needs, and could use the interconnection process to favor their projects over those proposed by third-parties. Moreover, DER providers operate in a competitive industry and could be disadvantaged if utilities are allowed to use regulated assets, such as trucks and billing software, for competitive purposes. The New York Public Service Commission decided early in the Reforming the Energy Vision process to prohibit utility ownership of DERs, unless it is a demonstration project or if a market for services does not exist, due to similar concerns.[23]

Should utilities be able to recover costs associated with non-wires alternative procurement?

Yes. As noted by Liberty Utilities in their recent LCIRP, utilities need to gather the necessary data to perform these evaluations and cost recovery is necessary to accomplish that. A valuable outcome from this proceeding would be to identify data requirements, a budget to collect the data, an implementation

[22] Eversource response to NHSEA 1-12
[23] New York: Case No. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Adopting Regulatory Policy Framework and Implementation Plan (pg. 67-68). February 26, 2015.

plan, and timelines for utilities to make this data available. Utilities should be able to recover prudently incurred costs associated with these programs.

Introducing earnings incentive mechanisms tied to procurement and success of non-wires alternatives can also encourage utilities to adopt the processes discussed herein.

Have these processes and mechanisms been used in other jurisdictions?

Yes, New York provides a good example of competitive procurement of DERs for grid needs, earnings opportunities for utilities, and the creation of hosting capacity maps.

The most prominent example of competitive procurement of DERs to defer distribution upgrades is Con Edison's Brooklyn/Queens Demand Management (BQMD) Program. Con Edison identified a potential 69 MW overload on subtransmission feeders which could be mitigated a $1 billion investment in a new substation, switching stations and subtransmission feeders.[24] As an alternative, Con Edison proposed procuring 52 MW of non-wires alternatives and 17 MW of traditional investments for $200 million, which would defer the need for a substation by several years. The non-wires alternative was approved, and Con Edison was authorized to amortize the costs of the program for 10 years.[25] Con Edison released guidelines for participating in the BQDM, which are attached as Exhibit EFCA-PB-4.

New York utilities have begun sharing locational maps on their websites to assist distributed generation providers identify areas for deployment or areas to potentially avoid. Although not yet a hosting map, Orange and Rockland Utilities provide a map to identify areas that will have higher interconnection costs.[26]

Does your recommendation align with the objectives of HB 1116 and the Commission?

Yes, HB 1116 states that the Commission "may include other regulatory mechanisms and tariffs for customer-generators." The reformed distribution system process described above can lead to the development of new programs and mechanisms to incentivize DER investment in areas with the greatest need.

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[24] New York Case No. 14-E-0302. Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program. Order Establishing Brooklyn/Queens Demand Management Program (December 12, 2014). Pages 2-3.
[25] Ibid at pages 26-27.
[26] Orange and Rockland Utilities interconnection map. Available from http://coned.maps.arcgis.com/apps/webappviewer/index.html?id=566397d6a395447f9ab80dc9941f0d31

The recommendation also directly aligns the New Hampshire's Public Utilities Statutes, including the aforementioned RSA Section 378.38. Section 378:37 states that meeting New Hampshire's energy needs shall be "at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources…" In the event that the Commission determines options in a LCIRP have "equivalent reliability, and equivalent environmental, economic, and health-related impacts", Section 378.39 provides the Commission with an order of energy policy priorities that should guide the Commission's evaluation. The order of priorities include: 1. Energy efficiency and other demand-side management resources; 2. Renewable energy sources; and 3, all other energy sources.

IV. Alternative Rate and Regulatory Mechanisms

What are some appropriate alternative rate and regulatory mechanisms for the Commission to consider in this proceeding?

Improving price signals in rates can benefit customers by changing consumption behavior or incentivizing the adoption of DERs, both of which can reduce system costs. Location-based incentives and time-of-use (TOU) rates are two potential alternatives to consider.

Please describe location-based incentives.

As previously discussed in the non-wires alternatives and distribution system planning sections, distributed energy resources potentially have higher net benefits in some locations than others. The Commission can consider a pilot that identifies high value areas and provides locational incentives, such as rebates or bill credits, for deploying DERs in those areas.

How can TOU rates send signals about system costs and opportunities for DERs?

TOU rates can be designed to send signals about the relative marginal cost, both fixed and variable, of electricity. Peak periods of high demand have higher marginal costs due to higher energy prices in the short-run and demand driving the need for additional fixed assets in the long-run. Off-peak periods coincide with lower demand and thus have lower marginal costs due to lower energy prices and the availability of excess fixed capacity. Therefore, the TOU rate is designed to charge customers a higher rate for kWh consumed during peak periods, and lower rate for consumption during off-peak periods. This signals to customers that they should shift their consumption to off-peak hours when possible.

With regard to DERs, TOU rates provide more granular, time-specific signals about the value that such resources provide to the system.

Do the New Hampshire utilities currently have TOU rates for residential customers and are there any NEM customers subscribing to those rates?

Liberty Utilities and Eversource both have optional TOU rates for residential customers, while Unitil does not. None of Eversource's NEM customers are on the utility's TOU rate,[27] and only one of Liberty Utilities' nearly 300 NEM customers is on the TOU rate.[28]

Please describe Liberty Utilities' existing TOU rate.

The optional TOU rate provided by Liberty Utilities includes a $12.28/month fixed customer charge, $0.1999/kWh on-peak charges and $0.10796/kWh off-peak charges.[29] The on-peak period is between 8am and 9pm on non-holiday weekdays, and all other hours are off-peak.

Is Liberty Utilities' existing TOU rate a viable alternative rate for the purposes of this proceeding?

While the rate does send a general signal about marginal costs, I do believe the rate should be improved. My primary concern with the rate is the length of the peak period. At thirteen hours long, it creates a challenge for customers to shift their consumption to off-peak hours. Based on the utility's hourly data since 2013, I suggest the Commission consider a TOU rate with a shorter peak period that better reflects the length of the utility's peak. The utility's hourly data[30] shows that demand within 5% of peak occurred between 11am and 6pm, and demand within 10% of peak occurred between 10am and 9pm.

Please describe Eversource's existing TOU rate.

Eversource's TOU rate includes a $29.90/month fixed customer charge, a $0.24752/kWh on-peak charge and $0.10967/kWh off-peak charges.[31] The on-peak period is between 7am and 8pm on non-holiday weekdays, and all other hours are off-peak.

Is Eversource's existing TOU rate a viable alternative rate for the purposes of this proceeding?

[27] Eversource response to TASC 2-1
[28] Liberty Utilities response to Staff 2-13
[29] Liberty Utilities response to NERA 1-3 attachment, pg. 16.
[30] Liberty Utilities response to OCA 1-3
[31] Eversource response to NERA 1-3 attachment, pg. 12.

Like Liberty Utilities' optional TOU, I believe Eversource's rate does send a general signal about marginal costs but think the rate must be improved. The 13 hour length of the peak period is a concern because of the challenges it poses for customers to shift their consumption to off-peak hours. Based on the utility's hourly data since 2013, I suggest the Commission consider a TOU rate with a shorter peak period that better reflects the length of the utility's peak. The utility's hourly data[32] shows that demand within 5% of peak occurred between 12pm and 7pm, and demand within 10% of peak occurred between 10am and 9pm. An additional concern is the high fixed customer charge.

Why are fixed charges a concern?

With regard to DERs and energy efficiency, high fixed charges reduce the incentive for customers to invest in these technologies because fixed charges reduce potential bill savings. Increasing fixed charges also harms customers that have already invested in DERs and energy efficiency because the charges reduce the value of their investments.

There are other ways that fixed charges harm customers as noted in a recent report by *Synapse Energy Economics*.[33] Fixed charges limit a customer's ability to control their energy bills, harm low-use customers the most, disproportionally impacts low-income customers, and can ultimately lead to increased system costs, since lower the volumetric charges (c/kWh) associated with fixed charges can lead to greater total electricity consumption.

If Unitil had an optional TOU rate, what would be an appropriate peak period?

Data from Unitil's peak days shows that hours with demand within 5% of the peak occurred between 12pm and 6pm, and hours with demand within 10% of the peak occurred between 10am and 8pm.[34] A TOU rate with peak periods within these ranges is appropriate.

Is Unitil's demand charge proposal an appropriate alternative?

Unitil proposes that DG customers be moved to a separate class of service and to three part rates that includes demand charges based on the customer's peak demand over a 15-minute period.[35] Mandatory demand charges are problematic for DG customers, or any residential customer, for that matter.

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[32] Eversource response to OCA 1-3

[33] Whited, M., Woolf, T., Daniel, J. 2016. *Caught in a Fix: The Problem with Fixed Charges for Electricity*. Synapse Energy Economics. Available from: http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf

[34] Unitil response to OCA 1-3.

A residential customer's demand is a function of many factors, including the weather, R-value of their home, types and efficiency of appliances, and the customer's consumption behavior. Their demand can vary widely from hour to hour and day to day, making it burdensome for customers to monitor their demand in 15-minute increments. It can also reduce investment in energy efficiency and DER because customers cannot realize bill savings.

For example, Figure 1 below shows a hypothetical example of how a move to demand charges can change a customer's bill.[36] Customers with lower load factors would likely see substantial increases in their bills, while customers with higher load factors would realize bill savings. For lower load factor customers, demand charges can wipe out any potential savings from energy efficiency and DER investments. If a customer that consumes 600 kWh in one month invests in energy efficiency, and the next month consumes 500 kWh, they would save $11 under the volumetric rate design. A shift to demand rates after that investment would increase the customer's monthly bill by $20, thus wiping out their bill savings and then some.

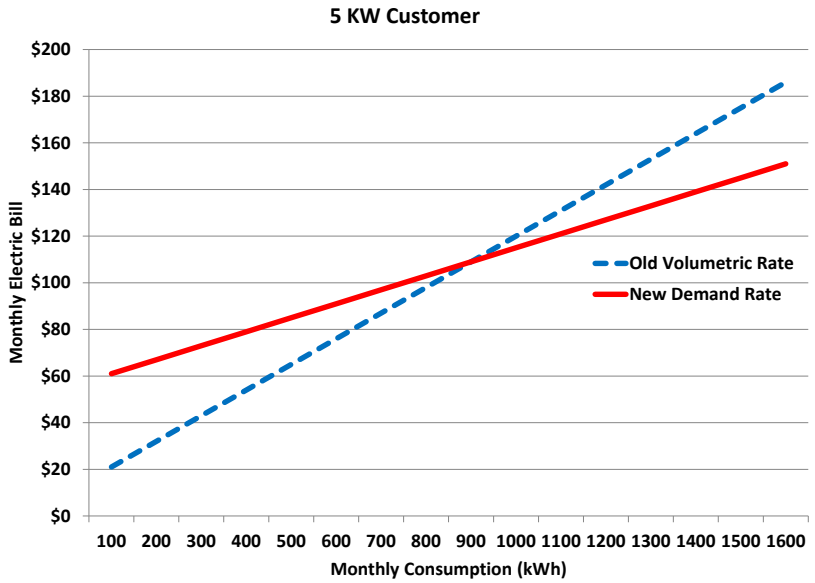

Figure 1 – A comparison of a customer's monthly electricity bill under a two-part rate ("Old Volumetric Rate") and a three-part rate ("New Demand Rate"). The figure shows the bill for a 5 kW of demand and varying levels of kWh consumption.

[35] Testimony of H. Edwin Overcast, Exhibit HEO-1, pages 7 and 22.
[36] The example is for customers with 5 kW of demand and across a range of kWh consumption, and the rates are from a *Brattle Group* example. Hledik, R., 2015. *Rolling out Demand Charges*. Presentation available from: http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444

Demand and fixed charges are, in a sense, the antithesis of revenue decoupling. With demand and higher fixed charges, a customer's electricity bill is decoupled from their total electricity consumption, while revenue decoupling decouples a utility's revenues from its electricity sales. Both mechanisms provide the utility with more revenue certainty, but only revenue decoupling ensures residential customers can confidently invest in energy efficiency and DERs.

Are there additional concerns with implementing mandatory demand charges?

Yes, implementing demand charges also present potential unintended consequences. First, total electricity consumption could increase because customers pay a lower volumetric rate with demand charges.[37] This means that every incremental kWh that doesn't contribute to the customer's peak is cheaper than on rates without demand charges (as evidenced by the relative steepness of the slopes in Figure 1). Second, demand charges can disincentivize high wattage appliances, including electric heat, hot water heaters, dryers, and stoves. Customers with the means of converting to natural gas-fired appliances would be able to realize savings, leaving customers unable to convert to natural gas on the hook for more system costs. In other words, use of demand charges creates a potential cost-shift.

Does Unitil's demand charge proposal meet the criteria set forth in HB 1116?

No it does not. Unitil or its witnesses did not provide any cost-benefit analysis showing that such a change in rate design is warranted,[38] or how the proposed rate design could affect investment in energy efficiency and DERs.[39] For these reasons and those stated above, demand charges violate the legislative purposes of HB 1116, including, among other things, "the continuance of reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities."[40]

V. Pilot Programs

In conclusion, do you have suggestions for potential pilot programs?

[37] A simulation of potential impacts by *Brattle Group* found a 0.2% increase in consumption of average residential load profile. *See* Hledik, R., 2015. *Rolling out Demand Charges*. Page 14 (slide 13). Presentation available from: http://www.brattle.com/system/publications/pdfs/000/005/170/original/Rolling_Out_Residential_Demand_Charges_Hledik_EUCI.pdf?1431628444
[38] Unitil response to Staff-UES-10
[39] Unitil response to EFCA-UES 1-27.
[40] DE 16-576, pg. 2.

Yes, I suggest that the Commission consider two pilot programs. The first is a non-wires alternative pilot in which each utility identifies an area of grid need and encourages customers to invest in DERs in that location. This program can gain insights into the process of subscribing and evaluating non-wires alternatives, how DERs can provide grid services or defer potential investments, and how customers and DER providers respond to different signals (whether they are incentives or marketing materials).

I also recommend a residential TOU pilot program. Although Eversource and Liberty Utilities both have optional TOU rates, they can be improved by creating a shorter peak period that more closely aligns with the system peak and allows customers to more easily shift consumption to off-peak periods. The pilot should be open to all customers in order to gain a better understanding about how different customers (such as apartment dwellers, single family homes, low-income, solar customers, or customers with electric vehicles, etc.) are impacted by the rates, how they respond to signals and educational materials, and ultimately how their consumption behaviors change.

Finally, while the pilot programs are ongoing, I recommend that NEM be reviewed every few years with a cost-benefit analysis that utilizes the best available data and information at the time.

Does this conclude your testimony?

Yes it does.