EXHIBIT
#65
DE 16-576

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

REBUTTAL TESTIMONY OF STAN FARYNIARZ ON BEHALF OF COMMISSION STAFF

Docket No. DE 16-576
Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators

December 21, 2016

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I. INTRODUCTION

Q. Please identify yourself for the record.

A. My name is Stan Faryniarz. I am a Principal Consultant with Daymark Energy Advisors ("Daymark"). My business address is One Washington Mall, 9th Floor, Boston, Massachusetts.

Q Please describe your education and employment background.

A. I am an energy economist and power supply planning and management specialist with 30 years of experience in areas including electric utility cost of service and rates, power supply procurement and management, wholesale and retail power transactions, power project financial analysis and due diligence, asset and utility valuations, and integrated resource planning and analysis. My experience and qualifications are described in more detail in my resume, which is attached as Appendix SF-1.

I have advised managers concerning the electric power supplies of public and investor-owned electric utilities, and have advised large industrial customers, regulators, consumer advocates, and power plant developers and owners regarding specific power projects and transactions, portfolio risk management strategies, and power markets.

I have prepared numerous valuation analyses of power projects and assets, combined portfolios of assets, and electric utilities. This work has involved power production assets in the northeastern U.S., North Carolina, Ohio, Arkansas, Wisconsin, and Canada. I have evaluated the economics, contract structure, ratepayer security, development prospects or going-forward value of dozens of renewable, non-renewable merchant, and

Qualifying Facility ("QF") power projects in the northeastern U.S. and Canada. I have conducted this work for regulators and for providers of private capital and quasi-public capital.

I have prepared, or have overseen the preparation of all or portions of integrated resource plans for several Vermont utilities and for other public utilities, and I am a load forecasting specialist.

My experience includes the preparation of well over a dozen electric and water utility allocated cost of service and rate design studies, rate unbundling studies, and rate path projection studies, for or involving utilities in the northeastern U.S., North Carolina, and Utah.

Q. Have you previously testified before the Commission?

A. This is my first opportunity to appear before the Commission.

Q. Please summarize Daymark and its business.

A. Daymark provides integrated policy, planning and strategic decision support services to the North American electricity and natural gas industries.[1] We serve a diverse clientele from our offices in Boston, Massachusetts and Portland, Maine by providing consulting services to organizations involved with energy markets, including renewable energy producers, private and public utilities, transmission owners, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include cost allocation, rates and

[1] Daymark Energy Advisors is the new name of the firm formerly known as La Capra Associates. The name change occurred on November 9, 2015.

pricing, power market forecasting models and methods, economics, management, planning, energy procurement, contracting and portfolio management, and reliability assessments. Our experience includes detailed analyses of energy and environmental performance of electric systems, economic planning for transmission and distribution, and market analytics.

Q. On whose behalf are you testifying in this proceeding?

A. I am providing testimony on behalf of the New Hampshire Public Utilities Commission Staff ("Staff") in support of the development of new alternative net metering tariffs and/or other regulatory mechanisms and tariffs for customer-generators under RSA 362-A:9, as amended by New Hampshire House Bill 1116 ("HB 1116"), which contains the net energy metering ("NEM") provisions of the Limited Electrical Energy Producers Act, RSA 362-A ("Net Metering Statute").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and comment on the positions taken by the numerous parties in this proceeding addressing the development of net metering tariffs and associated proposals. I also provide certain conclusions and recommendations of Staff regarding same, in light of the statutory standards set forth in the Net Metering Statute.

Q. How is your testimony structured?

A discussion of the statute and the various issues under consideration in this proceeding is followed by a brief recap of the procedural events that have taken place since the order of notice from the Commission initiating this proceeding. Then my testimony reviews the various positions of the parties on the myriad of issues presented in this docket and evaluates and critiques those positions. Finally, my testimony provides some conclusions and recommendations.

Q. What is your understanding of the purpose of this proceeding?

A. The purpose of this proceeding is to develop new alternative net metering tariffs and/or other regulatory mechanisms and tariffs for customer-generators, as directed by the legislature and in accordance with the standards and criteria specified in the Net Metering Statute, as amended by HB 1116. Specifically, the Commission initiated this proceeding in compliance with new paragraph XVI of RSA 362-A:9, which requires the Commission, within 10-months of May 2, 2016, to commence a proceeding to develop new alternative net metering tariffs and/or other regulatory mechanisms and tariffs for customer-generators. In addition, the HB 1116 amendments direct the Commission to consider the availability and limitations of any new tariffs in the service areas of each of the utilities. In particular, the text of the amended section of the Net Metering Statute reads as follows[2]:

> No later than 3 weeks after the effective date of this paragraph, the commission shall initiate a proceeding to develop new alternative net metering tariffs, which may include other regulatory mechanisms and tariffs for customer-generators, and determine whether and to what extent such tariffs should be limited in their availability within each electric distribution utility's service territory. In developing such alternative tariffs and any limitations in their availability, the commission shall consider: the costs and benefits of customer-generator facilities; an avoidance of unjust and unreasonable cost shifting; rate effects on all customers;

[2] See RSA 362-A:9, XVI.

> alternative rate structures, including time based tariffs pursuant to paragraph VIII; whether there should be a limitation on the amount of generating capacity eligible for such tariffs; the size of facilities eligible to receive net metering tariffs: timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms. The commission may waive or modify specific size limits and terms and conditions of service for net metering specified in paragraphs I, III, IV, V, and VI that it finds to be just and reasonable in the adoption of alternative tariffs for customer-generators. The commission may approve time and/or size limited pilots of alternative tariffs.

The statutory provisions identify several aspects of NEM that must be considered by the Commission in its development of alternative NEM tariffs or other regulatory mechanisms. Although I am not an attorney, and will leave any debate on legal meaning to counsel, I provide my business-level understanding of these statutory requirements.

Q. Can you briefly explain electric metering and net energy metering?

A. Yes. In its basic terms, the process of metering a customer on an electric system involves a device designed to measure the electric energy delivered along a service line to the customer premises, typically in kilowatt hours ("kWh"). While a basic concept, it is important to understand these aspects of electric metering, because measuring consumption becomes more complicated if a customer has a source of generation serving electric load at the premises. If the generation is able to supply some, but not all, of the electricity needed by the customer, then less energy will flow through the meter, and the customer's kWh usage will be reduced. On the other hand, if the on-site generation produces more energy than needed by the customer, and that energy flows along the service line back into the electric distribution system, then the meter reverses direction (or "spins backwards"), reducing the amount of energy recorded by the meter up to that point. That process of offsetting the customer's electricity usage with on-site power production is commonly referred to as "net metering," because energy flows back and forth across the meter according to the needs of the customer and the output of the generator, all of which may vary throughout the day. Production may vary significantly for on-site renewable generation like wind, solar, or hydroelectric, which all produce power on an intermittent basis. Sometimes this netting process produces a negative usage, or surplus, meaning more energy was produced over a billing period and exported to the distribution system than was used by the customer during that period. The ability to measure inflows and outflows of power separately, along with the time of those occurrences, varies with the level of sophistication of the technology in the meter itself. More advanced "bidirectional" meters have the capability to measure separately the customer's electricity imports from and exports to the utility electric distribution system.

Q. What are the issues the Commission is required to consider in developing new alternative NEM tariffs or other regulatory mechanisms under the amended Net Metering Statute?

A. There are eight main issues under consideration in this proceeding, all based on the criteria for consideration specified in the Net Metering Statute:[3]

1. The costs and benefits of customer-generator facilities;
2. Avoidance of unjust and unreasonable cost shifting;
3. Rate effects on all customers;

[3] See RSA 362-A:9, XVI and DE 16-576 Order of Notice issued on May 19, 2016.

4. Alternative rate structures, including time based tariffs;
5. Whether there should be a limitation on the amount of generating capacity eligible for such tariffs;
6. The size of facilities eligible to receive net metering tariffs;
7. Timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; and
8. Electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms.

The Commission is also authorized to waive or modify specific net metering size limits and terms and conditions of service that are found to be just and reasonable.[4] Finally, the Commission is authorized to and may approve time and/or size limited pilots of alternative tariffs.[5]

Q. Did the Legislature provide any guiding principles to take into consideration when evaluating these issues?

A. Yes. The HB 1116 amendments to the Net Metering Statute are prefaced by a legislative purpose statement that the Legislature has found: [6]

> [I]t 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 while ensuring costs and benefits are fairly and transparently allocated among all customers. The general court continues to promote a balanced energy policy that supports economic growth and energy diversity, independence,

[4] Id.
[5] Id.
[6] See HB 1116, http://gencourt.state.nh.us/bill_status/billText.aspx?sy=2016&id=293&txtFormat=html

> reliability, efficiency, regulatory predictability, environmental benefits, a fair allocation of costs and benefits, and a modern and flexible electric grid that provides benefits for all ratepayers.

Q. What stakeholders were required to participate in this proceeding?

A. The mandatory parties to this proceeding are the three Commission-regulated electric distribution utilities, Public Service Company of New Hampshire, d/b/a Eversource Energy ("Eversource"), Liberty Utilities (Granite State Electric) Corp., d/b/a Liberty Utilities ("Liberty"), and Unitil Energy Systems, Inc. ("Unitil"). In addition, permission to intervene was sought by a number of other interested parties. As discussed further below, the proceeding has attracted a considerable number of active interveners. [7]

Q. Please briefly describe the activities that have taken place to date in this proceeding.

A. During a period of months from June through September, several technical sessions were held during which parties addressed relevant topics and directed data requests and related discovery inquiries primarily to the three electric distribution utilities. In response to these requests and inquiries, the utilities provided a significant amount of data regarding their distribution systems, billing practices, planning procedures, aggregate customer load profiles, and distributed generation ("DG") customer interconnections and interactions. Certain other parties were asked to provide data regarding solar and hydroelectric DG resources. All parties were required to submit their initial filings, supporting pre-filed testimony, and related exhibits, on or before October 24, 2016. Extensive discovery was conducted with respect to these initial filings during November. December 21st was

[7] Id., p. 2.

ultimately set as the deadline for filing of rebuttal testimony, with further opportunity for discovery thereafter. Adjudicatory hearings currently are scheduled for March 7 through March 10 and March 27 through March 31, 2017. A Final Order from the Commission is anticipated by June 2, 2017.

Q. Who are the intervening parties in this proceeding?

A. In addition to the three regulated electric distribution utilities, and the Office of Consumer Advocate ("OCA"), there are more than twenty-five additional intervening parties in this proceeding, including renewable industry trade associations, ratepayer representative organizations, solar energy system installers, environmental advocacy groups, individual utility ratepayers, a municipality, and the state Office of Energy and Planning ("OEP"). Eleven of these parties submitted pre-filed testimony and one filed written comments. Testimony was sponsored by Unitil, Eversource, Liberty, OCA, Conservation Law Foundation ("CLF"), Energy Freedom Coalition of America ("EFCA"), New Hampshire Sustainable Energy Association ("NHSEA"), The Alliance for Solar Choice ("TASC"), Consumer Energy Alliance ("CEA"), New England Ratepayers Association ("NERA"), and the City of Lebanon ("COL"). Written comments were submitted by OEP.

Q. Please provide a brief summary overview of each party's initial filing.

A. Below is a brief description of the filings and some key points made by each of the parties regarding the issues relevant to alternative NEM tariff development. A number of specific party positions are addressed in further detail, where relevant, in the Issues and Analysis section of my testimony.

1) Unitil

Unitil believes there are no distribution benefits from solar DG, and consequently there are no avoided costs to the distribution system.[8] While Unitil supports net metering and renewable energy development, it claims that benefits are related to the power supply, and not to distribution or transmission system cost avoidance. Unitil witness Meissner states that "[t]o the extent clean energy technologies confer non-wires benefits to other customers, those benefits should be recognized in the appropriate rate components from which such value is derived or associated and should not be monetized through the utility's distribution cost of service."[9] Unitil uses embedded cost of service studies ("COS") for fixed and variable energy costs to show the level of revenue requirement subsidy resulting from net metering and related energy credit banking.[10] Unitil witness Overcast asserts that marginal COS studies are not useful in determining avoided costs or levels of intra-class subsidies.[11] Unitil claims that cost-shifting from DG customers to other customers occurs for the recovery of delivery system costs, and effectively also default energy system costs "through fuel arbitrage by delivering power during lower marginal cost hours and using banked energy volumes in higher marginal cost hours".[12] As a result of this cost shift, Unitil believes the Commission should consider eliminating the banking

[8] Unitil Direct Testimony of H. Edwin Overcast, p. 10, lines 1-4; Unitil Direct Testimony of Thomas P. Meissner, Jr., p. 22, lines 12-16.
[9] Id., p. 3, lines 18-22.
[10] Unitil Direct Testimony of H. Edwin Overcast, p. 5, lines 11-15.
[11] Unitil Direct Testimony of H. Edwin Overcast, Appendix B.
[12] Id., p. 10, lines 9-13.

of cumulative net-metered energy credits by DG customers. Unitil proposes a new tariff based on a separate DG rate class and a three-part rate structure for the DG rate class, including “a kW demand charge (the rate would be based on a 15-minute maximum integrated demand reading as captured by the Company’s AMI system each billing cycle), a customer charge and the energy charge billed per kWh (including TOU based energy charges in the future)”.[13] The proposed demand charge would be $5.32 per kW per month.[14] According to Unitil, the proposed three-part rate structure for the new DG customer class will enable it to properly charge DG customers for their use of the distribution system and will provide it with the revenue needed to invest in modernization of the grid.[15]

2) Eversource

Eversource agrees that customers should be provided with opportunities to invest in DG. Eversource focuses on eliminating cost-shifting that occurs from net-metered customers to non-net metered customers under the current NEM tariff design due to DG customers avoiding payment for all of the costs related to the services they receive as provided by the utility. The Eversource witnesses argue that its future costs will increase to integrate a higher penetration of DG, but it is possible, based on certain limitations, that some of these DG resources could in the aggregate delay or eliminate the need for circuit upgrades.[16] A new tariff design for customers installing DG is proposed in the joint

[13] Id., p. 22, lines 1-3. Unitil’s Advanced Metering Infrastructure (“AMI”) system is capable of capturing interval demand data at a 15-minute level and therefore is proposing a kilowatt (“kW”) demand charge based on the maximum integrated demand during the 15-minute interval meter readings as part of its three-part rate.
[14] Unitil Supplemental Testimony of H. Edwin Overcast, p. 3, line 5 and Supplemental -1, Schedule DDER, p. 1.
[15] Unitil Direct Testimony of Thomas P. Meissner, Jr., p. 48, lines 24-33.
[16] Eversource Joint Testimony Richard C. Labrecque and Russel D. Johnson, p. 23, lines 12-14.

testimony of Eversource witnesses Labrecque and Johnson, as well as in the testimony of fellow witness Davis. The proposed NEM tariff design requires the installation of "bi-directional meters" to measure both grid power consumption and exports, as well as customer peak demand. Eversource's witnesses state it has been installing these new net meters to allow measurement through two separate channels (i.e., a purchase and a sales channel).[17] Eversource claims that the proposed rate design for customers installing DG addresses cost-shifting in two ways. The first is by assessing all distribution and transmission service charges for residential DG customers based on demand charges of $5.82 per kW (distribution) and $3.31 per kW (transmission) and for small commercial DG customers based on demand charges of $10.53 per kW (distribution) and $6.05 per kW (transmission), thus creating a class average or revenue neutral rate design.[18] Secondly, the Company would require DG customers to pay for delivery services for all purchases from the grid, which would also prevent the DG customers from not covering their share of non-bypassable charges that currently occurs under the volumetric charges.[19] These charges would be assessed on the quantities purchased by DG customers with no crediting back based on the quantities of sales from their DG system to the grid.[20] Effectively, within each monthly billing cycle, DG customers would be credited for electricity exports only at the Eversource energy service rate rather than at the full retail rate.[21] Under the Company's proposal, any excess energy credits unused at the end of the monthly billing cycle would be compensated at Eversource's avoided cost rate, which is

[17] Id., p. 4, lines 9-25.
[18] Eversource Direct Testimony of Edward A. Davis, pp. 4-5, lines 21-28 and 1-10, and Attachment 1.
[19] The charges the DG customers would have to pay include distribution, transmission, stranded cost recovery, system benefits, and electricity consumption tax charges.
[20] Eversource Direct Testimony of Edward A. Davis, p. 5, lines 16-17.
[21] Eversource Direct Testimony of Edward A. Davis, pp. 5-6, lines 23-24 and 1.

based primarily on real-time locational marginal prices ("LMPs") in the ISO New England ("ISO-NE") regional wholesale electric markets.[22]

3) Liberty

Liberty's witness testifies that it is supportive of the expansion of DG resources and has found there can be long-term distribution system level benefits.[23] In the short-term, however, these benefits are not identifiable because of the lack of monitoring on customer-sited generating systems and the relatively short length of time a significant amount of these customer systems have been interconnected.[24] In order to identify any such distribution system benefits of DG, Liberty would require a long-term study that evaluated individual circuits with and without DG systems, as well as information on facility sizes installed in different areas, time periods when the systems were installed, an analysis of what caused load to decrease in the areas, impact of energy efficiency, and customer changes.[25] Liberty claims that unjust and unreasonable cost-shifting under the current NEM tariff is occurring because DG customers have the ability to bank excess energy credits at the full retail rate to offset future monthly bills.[26] The Company proposes to reduce (but not eliminate) cost-shifting by ending the ability to bank energy and by lowering the NEM credit to the Liberty energy service rate, instead of the full retail rate.[27] In addition to changing the NEM credit rate, the Company is planning to install bi-directional meters to record both the kWh imported and exported over each

[22] Id., p. 6, lines 1-4. The avoided cost rate is determined under PURPA and is set forth in Puc 903.02.
[23] Liberty Direct Testimony of Heather M. Tebbetts, p. 6, lines 2-4.
[24] Id., pp. 6-7, lines 9-11 and 16-18.
[25] Id., p. 7, lines 7-13.
[26] Id., p. 18, lines 18-19.
[27] Id., pp. 18-19, lines 20-21 and 1-3.

monthly period,[28] so all imported energy can be charged the full retail rate components regardless of grid exports during the month.[29] Effectively, this proposal would cause all new NEM customers to be treated like those with installations of 100 kW or greater. Liberty also proposes to install production meters for all DG customers, in order to accurately measure utility lost revenues resulting from DG customer consumption of electricity produced behind the utility revenue meter.[30]

4) TASC

TASC supports continuing to allow the investment and deployment of DG installations behind the meter for electric customers. TASC maintains that customers who install DG should be fairly compensated for any excess power produced, while the benefits and costs from DG facilities should be allocated among all ratepayers in a fair and transparent way.[31] Most of the testimony offered by TASC witness Beach is a discussion of a proposed benefit-cost methodology that considers the costs and benefits from the perspectives of various stakeholders and the general public interest. The key attributes of the methodology he describes include:[32]

1. Examine and balance the benefits and costs from multiple perspectives of the key stakeholders.
2. Consider a comprehensive list of benefits and costs.
3. Use a long-term life-cycle analysis (i.e., a 25-year study period).

[28] The word "monthly" or "month" when used in this testimony should be understood to reference a customer's applicable monthly billing cycle, where the context requires that interpretation.
[29] Id., p. 4, lines 4-11.
[30] Id., p. 21, lines 17-22.
[31] TASC Direct Testimony of R. Thomas Beach, p. i, paragraph 1.
[32] Id., p. i, paragraph 3.

4. Focus on NEM exports.

TASC advocates for wider consideration of NEM benefits than purely a distribution-level COS model approach. These benefits include a list of the following: Avoided Energy, Avoided Generation Capacity, Avoided Line Losses, Avoided Ancillary Services, Avoided Transmission and Distribution ("T&D") Capacity, Avoided Environmental Costs, Avoided Carbon Emissions, Avoided Fuel Hedging / Fuel Price Uncertainty, Market Price Mitigation, Avoided Renewables, and Societal Benefits.[33] TASC recognizes that the utility distribution system incurs capital and operating and maintenance ("O&M") costs from DG, costs to integrate DG in the form of system regulation and operating reserves, program administrative costs, interconnection costs, and lost revenues due to DG customers receiving bill credits.[34]

Besides using benefit-cost study methodologies like the ones proposed in testimony,[35] TASC explains that the Commission should not assign a zero value to any cost or benefit where it is uncertain about the magnitude, but instead should create a range of reasonable values.[36] TASC used Rate Impact Measure and Total Resource Cost tests to determine there is currently no significant cost-shift occurring to non-DG customers, and claims that *in the long-run* (emphasis added), non-DG customers will realize net benefits from DG investment and deployment.[37]

[33] Id., pp. 22-23, Table 2.
[34] Id., p. 23, Table 3.
[35] These include the Total Resource Cost ("TRC"), Rate Impact Measure ("RIM"), Participant Test or Participant Cost Test ("PCT"), and Societal Cost Test ("SCT").
[36] Id., p. ii, paragraph 2.
[37] Id., p. iii, paragraph 1.

TASC does not propose a new rate structure, due to the benefit-cost study results showing that changes are not currently needed and may not be needed until solar DG penetration levels increase. According to Mr. Beach, for now, the Commission should be working to align rates with costs incurred by the utilities through time-of-use ("TOU") rates or through a minimum bill provision, as long as the rates allow customers to have a choice to adopt DG.[38] In addition, the Commission should consider the removal of non-bypassable charges such as the system benefits charge and electricity consumption tax from the credit rate applicable to NEM exports.[39] TASC argues that the Commission should not consider implementing fixed charges, demand charges, and DG-specific rate designs.[40]

5) EFCA

EFCA is supportive of continued development of DG systems and believes NEM is working in its current state, providing benefits to all electric customers.[41] EFCA claims that the current NEM tariff does not cause unjust or unreasonable cost-shifting, since "the State's utilities have not provided sufficient evidence that a cost-shift exists, or if one does, that it is unjust and unreasonable."[42] Instead of conducting its own cost-benefit analysis, EFCA relies on and supports TASC witness Beach's analysis.[43] Even though EFCA agrees with Mr. Beach's analysis, it discusses the need for further data collection, information sharing, and transparency so that evaluation of the following can occur:

[38] Id., p. iv, paragraph 2.
[39] Id., p. iv, paragraph 2.
[40] Id., p. iv, paragraph 3.
[41] EFCA Direct Testimony of Patrick Bean, p. 4, lines 19-24.
[42] Id., p. 3, lines 10-11.
[43] Id., pp. 2-3, lines 20-27 and 1-10.

1) New methodologies for quantifying benefits and costs of distributed energy resources ("DERs");

2) The costs and benefits of net metering, whether changes are warranted, and the respective costs and benefits of potential successor programs;

3) Opportunities for non-wires alternatives to be considered through the utility distribution system planning process; and

4) Alternative or pilot rate designs and billing mechanisms."[44]

EFCA supports pilot programs to determine the potential benefits of DG installations in specific locations (as a non-wires alternative), and the use of TOU rates with shorter peak periods for residential customers.[45]

6) NHSEA

NHSEA supports further development of net metered distributed generation. NHSEA claims that its "experts demonstrated and concluded that the net benefits to all ratepayers are significant and that there is no demonstrable nor unreasonable cost-shifting presently attributable to net metering".[46] This conclusion was reached through the application of a Societal Cost Test to determine the net benefits of DG. NHSEA proposes a tariff that should be implemented once the levels of DG penetration reach the 100 MW cap. At that point, the current NEM tariff as it is applied to residential systems under 100 kW should only be changed so that the NEM credit provided for exported energy no longer includes

[44] Id., p. 5, lines 19-24.
[45] Id., p. 16, lines 1-14.
[46] NHSEA Direct Testimony of Kate Bashford Epsen, p. 12, lines 1-3.

the systems benefit charge, stranded cost recovery charge, and electricity consumption tax.[47] In the event of future increased DG penetration levels, NHSEA recommends that the Commission should consider re-evaluating the appropriate NEM reimbursement rate when aggregate DG penetration reaches increments of 5%. At that point NHSEA would further recommend removing the 100 kW limit on retail rate net metering in favor of a structure based on either "well-defined project sizes where economies of scale shift or on a customer-class basis" or at least an increase in the 100 kW system size limit to 250 kW.[48] NHSEA also recommended that, for residential net metered customers, the Commission consider an optional adder that would include a REC value through an aggregator purchase program offered by the utilities.[49]

For commercial customers with systems larger than 100 kW, NHSEA proposes compensation beyond the default energy supply charge that includes several potential adders.[50] These proposed adders include: a locational benefits adder for helping to relieve congestion, a directional benefits adder based on system directional orientation (e.g., west-facing PV arrays), an environmental benefits adder, a municipal or other public benefits adder, a peak demand TOU adder, an adder for encouraging development of otherwise unusable or already developed land for DG, and an adder for storage or other ancillary services such as voltage regulation.[51]

According to NHSEA, any NEM tariff that is adopted by an interconnected customer-generator should be set for 25 years with a step-down mechanism in place so that, as DG

[47] Id., p. 12, lines 8-15.
[48] Id., pp. 12-13, lines 16-22 and 1-2.
[49] Id., p. 13, lines 3-7.
[50] The rate would equal the default energy plus transmission plus distribution plus adders.
[51] NHSEA Direct Testimony of Kate Bashford Epsen, p. 14, lines 1-13.

penetration levels increase, the compensation rates decline for new customer-generators.[52] In addition, NHSEA recommends the Commission consider a TOU rate opt-in pilot program. NHSEA does not believe there should be a cap or statewide limitation of DG capacity, but if a cap is determined to be appropriate, it should be set based upon robust technical data and similar to policy practices in other states in the region.[53] Regarding the individual project size cap of 1 MW, NHSEA believes that cap should be increased, although it does not specify by how much it should be increased.[54]

7) CLF

CLF supports the expansion of DG installation and discourages adoption of policies that tend to deter additional deployments, since "experience in other states suggests that there is no obvious rationale for major changes in the near term".[55] According to CLF, there is no unjust and unreasonable cost-shifting occurring, and, if anything, the energy flowing back to the grid affects utility costs in a similar manner as other types of load reduction, and therefore the DG customer should be compensated for providing renewable energy to the system.[56] CLF claims that all customers benefit from "the avoided T&D upgrades, reduced wear and tear, the reduction in percentage line losses, reduced market prices, reduced environmental effects, and reduced cost of environmental compliance".[57] Regarding system costs, at the current low penetration levels, very little cost is incurred

[52] Id., p. 15, lines 2-5.
[53] Id., p. 11, lines 8-11.
[54] Id., p. 11, lines 15-18.
[55] CLF Direct Testimony of Paul Chernick, p. 7, lines 6-7.
[56] Id., pp. 3-4, lines 23-24 and 1-3.
[57] Id., p. 9, lines 17-20.

on the system, according to the CLF witness.[58] System costs are likely to rise as DG penetration levels increase, however, due to protective devices becoming confused by DG power flow and requiring replacement or reconfiguration, as one example.[59] On the other hand, CLF acknowledges that the net effect of NEM is not yet clear, and it is possible that it does not reduce costs for other customers.[60] Instead of putting forward a new tariff, CLF advises the Commission to review ratemaking options by recognizing all of the system costs and benefits, ensuring there is simplicity and consumer understanding, and making sure that any rate design is effective in encouraging efficient consumer choices.[61] According to CLF, the Commission should focus on a simple and straightforward NEM tariff that can change as DG penetration levels increase, and the Commission should monitor DG installed capacity as a percentage of utility peak and set threshold triggers that would initiate further review, at something like 5% and 10% thresholds.[62] CLF recommends a pilot like the City of Lebanon's proposed real-time energy pricing pilot or a locational pilot where targeted DG could be used to defer or avoid specific major system or localized distribution projects.

8) OCA

The OCA claims that DG can provide net benefits to all ratepayers if the right program structures are in place, and since implementation of these may take some time, the OCA is proposing a framework that will lead to a positive outcome for all parties within a five-

[58] Id., p. 21, lines 21-22.
[59] Id., p. 22, lines 3-5.
[60] Id., p. 4, lines 6-7.
[61] Id., p. 8, lines 1-5.
[62] Id., pp. 33-34, lines 11-18 and 1-2.

year period.[63] Its preliminary analysis conducted into the benefits of solar DG indicates potential benefits ranging from 13-15 cents per kWh, which does not include different types of societal benefits that are hard to quantify.[64] OCA witness Huber acknowledges that cost-shifting or cross-subsidization is likely in rate making, and should be minimized to the extent possible. Therefore, in its filing, the OCA proposed an optional DG TOU rate program for residential customers and a Fixed Solar Credit Rate program which would be open to all customers, including non-residential and community solar subscribers. The TOU rate would be based on volumetric usage that would send more accurate price signals to DG customers and would have an on-peak period aligned with actual system peak load hours (2pm-8pm in order to capture utility peak hours) in order to better align solar customer's sales back to the grid with real-time market pricing.[65] The DG TOU option would include the following rate components: Customer Charge, Energy Supply Charge, TOU Delivery Charge, Export Charge, Partial Non-Bypassable Transmission Charge, and other Non-Bypassable Charges.[66] The Fixed Solar Credit Rate option is designed to compensate DG customers for excess energy produced by their systems and allow for continued DG growth in New Hampshire, "by providing increased certainty and sufficient compensation to DG customers and installers, while also capturing value and cost savings for non-participating utility customers over time".[67] In order to control growth of the program, the OCA proposes that this option be initially

[63] OCA Direct Testimony of Lon Huber, p. 8, lines 11-17.
[64] Id., p. 8, lines 17-19.
[65] Id., p. 17, lines 17-23.
[66] Id., p. 18, lines 1-10.
[67] Id., p. 33, lines 7-21.

limited to 200 MW.[68] The NEM credit rate for smaller scale DG systems would be determined through a capacity-based tranche step-down mechanism that would be prescribed in advance, while the credit rate for larger scale DG systems would be determined through an auction mechanism.[69] Community solar projects would be eligible for the NEM Fixed Solar Credit Rate option and would have rates similar to residential and commercial customers, depending on system size, with potential NEM credit rate adders including an environmental benefits adder and a low and moderate income adder.[70] The OCA asserts that cost-shifting would no longer occur if DG customers were able to exchange their renewable energy certificates ("RECs") with their interconnecting utilities.[71]

9) COL

COL witness Below focused the majority of his testimony on a recommendation for an alternative NEM rate structure based on real-time energy pricing. First, Mr. Below discusses a real-time pricing NEM tariff offered on an opt-in basis. Under this tariff, Mr. Below proposes that during each real-time interval, exported power to the grid would be credited to participating DG customers at the New Hampshire load zone real-time LMPs, together with generation related ancillary services, as adjusted for avoided line losses.[72] During times when a DG customer imports power, it would be charged at the same real-

[68] The 200 MW would consist of 75 MW for Small Scale DG systems (<= 100 kW) and 125 MW for Large Scale systems (>100 kW). Id., pp. 35-36, lines 12-13 and 1-2.
[69] Id., pp. 36-37, lines 14-16 and 1.
[70] Id., p. 45, lines 6-8.
[71] Id., p. 9, lines 20-21, 31.
[72] City of Lebanon Direct Testimony of Clifton C. Below, p. 7, lines 188-193.

time LMPs, as well as a billing and overhead mark-up cost.[73] Regarding capacity charges, Forward Capacity Market ("FCM") prices would be charged or credited as avoided.[74] Transmission charges would be charged or credited depending on a DG customer's load during the monthly coincident peak ("CP").[75] Mr. Below also proposes that distribution rates be modified on a revenue-neutral basis with demand charges based on the customer's share of CP, that volumetric distribution rates be modified on a revenue-neutral basis so costs are recovered during the hours when system peaks are likely to occur, and that the distribution revenue requirement be decoupled from a net changed volumetric load compared to forecasted load.[76]

Since the ideal solution proposed by Mr. Below cannot easily be implemented within a short-time period, COL proposes a long-term (i.e., through 2040) real-time pricing net metering pilot program that would be a "work-around" to current utility metering and billing limitations. According to Mr. Below, the proposed alternative NEM rate structure is a more in-depth dynamic option as compared to a simple TOU rate structure, since it incorporates nearly all levels of a utility's cost structure. COL concludes that a volumetric credit should continue to be allowed to be carried forward for default service and transmission charges, but not for distribution services.[77]

10) NERA

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[73] Id., p. 7, lines 193-195.
[74] The FCM charges would be based on net load or production during the hour of the system-wide coincident peak for each year. Id., p. 7, lines 195-197.
[75] Id., p. 7, lines 198-201.
[76] Id., p. 7, lines 201-209.
[77] Id., p. 9, lines 241-244.

NERA witness Harrington argues that the current NEM system is flawed in its approach to deploying DG because of cost-shifting to other customers. He states that the Commission should adopt an NEM tariff that "reflects the value of the electricity generated, when it is generated and where it is generated."[78] NERA explains that the new alternative NEM tariff needs to consider a net cost of solar because solar does not provide any capacity benefits like traditional generation due to its intermittency.[79] In addition, DG also imposes costs for ISO-NE grid management and grid destabilization costs, due to potential bi-directional power flow, according to Mr. Harrington. Regarding the benefits of DG, NERA claims that Demand Reduction Induced Price Effects[80] ("DRIPE") are hard to quantify due to DG not being peak-coincident, and also that NEM tends to distort energy efficiency actions as a result of full rate energy credit banking that dampens financial incentives to implement energy efficiency measures.[81] NERA claims that grid reliability is not a benefit of DG nor is it a reason to support retail NEM policies, since DG systems are prevented from exporting energy in the event of a power outage in order to protect utility line workers.[82] NERA argues that any potential DG benefits at the transmission or distribution level should be quantified by DG advocates.[83] The externalities claimed to represent DG benefits by solar advocates, such as carbon dioxide reduction and economic impacts in the state, are already compensated to DG owners through federal income tax credits and local property tax exemptions and through sales of

[78] NERA Direct Testimony of Michael Harrington, pp. 2-3.
[79] Id., pp. 4-5.
[80] A potential savings to customers due to a reduction in electricity demand, such as results from increased energy efficiency investments.
[81] NERA Direct Testimony of Michael Harrington, p. 8.
[82] Id., p. 6.
[83] Id., p. 24.

RECs through the RPS program.[84] In terms of unjust and unreasonable cost-shifting, NERA claims that the decline in wholesale energy pricing is causing traditional generation facilities like Vermont Yankee to close, which results in price distortions in the regional wholesale energy and capacity markets and ultimately burdens ratepayers.[85] NERA claims that, in order to avoid cost-shifting, net-metered DG customers should have generation and demand measured as close to real time as possible, with recognition of associated costs and other limitations.[86]

11) CEA

CEA is supportive of continued solar development in the region, due to the potential for solar to provide clean, affordable, and reliable energy.[87] In considering DG costs and benefits, CEA witness Voyles explains that solar DG produces clean and renewable energy, is a zero carbon emission energy source, can provide health benefits, and supports grid resiliency due to generation diversity.[88] However, DG also causes system costs because DG customers need to be supported by the grid when their systems are not generating, utilities may incur integration and upgraded infrastructure costs to increase the flexibility of the distribution system, utilities may incur costs to implement new metering methods and billing systems, and utilities may incur future costs due to their inability to predict the needs of DG customers.[89] CEA claims that cost-shifting under NEM is occurring in the form of "fixed costs of grid maintenance, distribution costs, and

[84] Id., pp. 14-15.
[85] Id., p. 5.
[86] Id., p. 18.
[87] CEA Direct Testimony of James Voyles, pp. 1-2.
[88] Id., pp. 2-3.
[89] Id., p. 3.

certain administrative costs required to run the program".[90] CEA does not propose or endorse any specific NEM rate structures, but instead explains that it supports a rate structure that: (1) allows for continued solar penetration, (2) ensures the efficacy of a robust electrical grid, and (3) treats traditional and solar customers equally.[91] CEA notes that any new NEM program will require time and costs related to new utility administrative processes, and CEA maintains that the related costs should be included in new rates.[92]

II. ISSUES AND ANALYSIS

Q. Please describe the next section of your testimony.

A. In this section, I examine closely the various arguments made by the parties with respect to the features of DG in the context of the standards and criteria specified in the Net Metering Statute, as amended by HB 1116. While every claim or assertion made by every party is not addressed, most of the key subjects are.

Importantly, silence in this rebuttal testimony on any particular witness or party claim or assertion should not necessarily be construed as agreement, either by myself or Commission Staff.

A. Costs and Benefits of Distributed Generation

[90] Id., p. 5.
[91] Id., p. 6.
[92] Id., p. 8.

Q. Can you provide some background regarding Benefit-Cost testing?

A. Yes. Benefit-cost analysis is a recognized tool for economic decision-making with a goal of providing a common netting metric for the evaluation of the merits of undertaking a particular action compared to an alternative. The tests can grow in complexity to match the complexity of the economic decision under consideration. As used in the electric utility industry beginning in the 1990s when demand-side management ("DSM") and energy efficiency ("EE") options began to be considered by utilities, regulators and other stakeholders, benefit-cost analysis provided parties with an evenhanded method for comparing the life-cycle costs of non-generation projects as compared to generation alternatives. At the time, such an analysis was instrumental in helping utilities evaluate the merits of DSM and EE programs as compared to more conventional plans to invest in generation. The benefit-cost analyses conducted by TASC in the instant proceeding were used initially to evaluate such DSM and EE programs. These types of programs can reduce consumption, which benefits customers by reducing the energy portion of a bill; however, they also come with administration and incentive costs and lost revenue impacts, as well as the forgone traditional capital investment in generation and ratebasing, with attendant returns, for the utility to consider.

While the industry has changed from a vertically-integrated model in many parts of the country with restructuring and the accompanying divesture of generation resources, benefit-cost analysis is still valued for its multiple perspective approach and continues to be used for EE and DSM program analysis in utility resource planning, for example. I understand that the TRC test generally has been used in connection with the EE programs approved by the Commission and administered by the New Hampshire utilities.

1. *Limitations of Benefit-cost Analyses*

Q. Do you see any limitations with benefit-cost analysis studies being used to set DG policy?

A. Yes. Benefit-cost analyses have several significant limitations. First, they typically do not compare multiple resource options against each other as would a typical resource planning analysis. This leaves open the possibility that other resources could provide similar benefits with lower overall system costs. As an example, in some circumstances, a utility grid-scale solar project might have certain advantages over solar DG projects due to economies of scale. Second, typical resource planning studies attempt to optimize a build out of new resources over time given a number of resource options. Benefit-cost analyses generally do not provide any insight into what volume of new resources would be economic or how new resources impact retirements and other additions in the marketplace. Third, long-term benefit-cost analyses tend to have large amounts of uncertainty in several key inputs.

Q. What are the most important sources of uncertainty in a long-term analysis?

A. Many assumptions go into every long-term benefit-cost analysis of DG systems. Depending on the assumptions used, the results could change significantly. Here are some important sources of uncertainty to consider:

- Electric energy and fuel prices, notably natural gas fuel prices, may vary considerably over time.
- Capacity prices and avoided capacity costs will depend on regional load growth or decline, and retirements of existing generation resources, as well as technological changes in and the capital costs accompanying new generation resources.
- Avoided costs of DG resources vary by the level of DG resource market penetration, which could increase significantly over the long-term. Some examples include:
    - Ancillary services costs may increase if solar penetration is high enough to create additional system contingencies when sunlight levels change rapidly or unexpectedly.
    - Distribution system investment may be needed to safely and reliably transmit or store energy from DG systems; for example, in some jurisdictions (e.g., Hawaii), grid-scale and behind-the-meter battery storage is being added to accommodate very high penetrations of both grid-scale utility solar generation and behind the meter rooftop solar DG.
    - The cost of emissions and local economic benefits are very difficult to estimate and are subject to considerable debate and potential double-counting.

- Perhaps the most important uncertainty concerning DG benefit-cost studies is technological change, both the rate of adoption and the effects it has on pricing of DG systems.

2. Relevant Benefit-cost Tests

Q. What are the relevant benefit-cost tests discussed in this proceeding?

A. The benefit-cost tests that were presented by various parties included an embedded COS study from Unitil witness Overcast[93], and a solar long-term avoided cost study (based on estimates of marginal costs) performed by TASC witness Beach.

Dr. Overcast's study analyzed the impact of residential solar DG on the allocation of embedded distribution costs to all customer classes. In connection with this analysis, he separated residential DG customers into a separate rate class.

Mr. Beach's analysis included four tests: [94] a Participant Cost Test ("PCT"), a Total Resource Cost ("TRC") test, a Rate Impact Measure ("RIM") test, and a Societal Cost Test ("SCT"). Each test provides a different perspective:

- The PCT compares costs of solar DG installations and the resulting bill reductions from the perspective of a DG owner. If bill reductions are larger than the cost of the solar DG system, then there is a net benefit to customers who install such systems.

[93] Utilities typically file either an embedded cost-of-service or a marginal cost-of-service study in support of a general rate case, a rate redesign, or both.
[94] TASC Response to Staff Request 1-1 (California Standard Practice Manual Test Results for each utility).

- The TRC test compares costs of solar DG installations and utility avoided costs. If reductions in utility avoided costs are larger than the cost of the solar DG system, then there is a reduction in the total cost to produce and deliver electric power for the system as a whole.
- The RIM test compares bill reductions from solar DG installations and utility avoided costs, where bill reductions represent utility revenue losses. If such losses are equal to or less than utility avoided costs attributable to solar DG, then there is a net benefit to the utility from such installations from which all ratepayers can benefit.
- The SCT compares costs of solar DG installations and societal benefits from solar DG. The benefits include utility avoided costs, but also the avoided cost of a number of externalities.[95] These might include avoided emissions, other environmental impacts, health benefits, and/or benefits to the regional economy from DG development. As long as the societal benefits outweigh system-wide costs of the DG installations, then society stands to benefit from DG development and operation.

Q. Please provide a summary of the key arguments regarding which benefit-cost test is the right approach.

A. TASC witness Beach was the only party to actually model, run, analyze, and provide results for all of the foregoing avoided cost-based benefit-cost tests, and his studies were supported by a number of other parties. Of those tests, some parties express a preference

[95] Though there are many subsets under the term "externality", an externality generally refers to situations when the production or consumption of goods and services imposes costs or benefits on others which are not reflected in the prices charged for those goods and services. Externalities can either be positive or negative.

for using the SCT, since it is described as including a broader range of benefits to society and therefore being all-inclusive.[96] By contrast, Unitil witness Overcast argued strongly in favor of embedded COS studies and he asserted that marginal cost studies - such as the avoided cost study presented by Mr. Beach - cannot assess the following relevant issues:[97]

- The costs and benefits of customer- sited DG facilities;
- Avoidance of unjust and unreasonable cost-shifting; and
- Rate effects on all customers.

Q. Do you agree with Dr. Overcast's assessment?

A. No, I disagree with Unitil witness Overcast regarding the use of marginal cost studies to evaluate the effects of net metering programs as well as DSM and EE programs. A well-designed and properly conducted study using marginal concepts and incorporating other relevant test criteria would be useful in informing net metering program design by utilities and their regulators.

Q. What should be considered when selecting a benefit-cost study methodology?

A. All methods have limitations. The most important consideration when using any analysis to support policy decisions, or ratemaking, is to understand those limitations. Some general limitations that apply to any analysis are discussed in the previous section. Here I present some further critiques of the specific analyses presented in this proceeding.

[96] NHSEA Direct Testimony of Nathan Phelps, pp. 7-9, lines 8-11 through 1-4.
[97] Testimony of H. Edwin Overcast, Exhibit HEO-1, p. 29, lines 8-11.

Q. What are the limitations of Unitil witness Overcast's embedded COS approach?

A. Dr. Overcast's analysis is not a true benefit-cost analysis. It only analyzes the impact that solar DG may have on the allocation of distribution costs within an embedded COS model framework and whether DG customers, as a whole, pay for their full embedded cost of delivery service under a given rate structure. Since cost allocation is a zero sum game, if DG customers do not pay for their full share of embedded delivery costs, then other ratepayers will have to make up the difference. Such an embedded COS analysis therefore can provide some insight into the level of cost-shifting and its justness and reasonableness, but it does not provide guidance as to whether DG provides net benefits to any party now or in the future. And it does not consider changes over time, as it focuses only on a single test year.

The results will also depend on the assumptions one makes about cost causation and DG customers' load shape, which I discuss in greater detail later on in this testimony.

Q. What further critiques do you have of TASC witness Beach's avoided cost-based analyses?

A. The analyses performed by TASC witness Beach are limited in a number of respects:

- Accounting for benefits and costs over a very long-term horizon may ignore inter-temporal mismatches between when costs are incurred and when benefits are received by various ratepayers and other stakeholders;
- They do not consider potential inter-class effects, which would require consideration of cost allocations in ratemaking;

- They calculate customer bill reductions based on an assumed rate and rate structure, but do not provide information as to whether that rate realistically represents embedded costs or as to what rate structure is most appropriate for DG customers;
- The focus on avoided costs is forward-looking and does not specifically account for the collection of costs for past prudent utility investments, which are investments that cannot be avoided; and
- They present only a snapshot, long-term analysis subject to significant forecast uncertainty, and they assume all other system costs, technology, generation resource mix, T&D investment, and customer consumption trends, among other relevant factors, do not change over the long-term.

I also provide further details about these limitations in future sections of my testimony.

Q. Mr. Beach analyzed four different tests. What do you recommend about using any of those tests over the others?

A. Selection of an appropriate test depends on the goals of the DG net metering program and the regulatory focus:

- If a primary goal is to provide incentives for the expansion of DG, then the focus would include the Participant Cost Test;
- If the goal is to facilitate DG development while avoiding any significant cost-shifting, then the focus would be on the Rate Impact Measure test;

- If the goal is to reduce overall net costs of production and delivery of power, then the focus would be on the Total Resource Cost test, although the lowest-cost or optimal resource build-out typically is not analyzed as part of this test;
- If the goal is to evaluate externalities, then the focus would be on the Societal Cost Test; and
- If the goals include all of the above, then all of the benefit-cost tests could be considered in connection with DG net metering program design. However, the weight to be afforded each benefit-cost test in implementing DG net metering program policy must also be considered.

Q. **Does Staff have any suggestions or recommendations about the selection of an appropriate analytical methodology?**

A. Staff's primary focus is on making sure the conclusions derived from any analyses performed are well-supported by the analyses and relevant data and assumptions, with due consideration for their respective limitations. Staff notes that the TRC test generally has been used in connection with the EE programs approved by the Commission and administered by the New Hampshire utilities, while the RIM test provides the most useful information regarding the extent of any potential cost-shifting. Staff suggests that a well-designed and properly conducted long-term avoided cost study using marginal concepts and incorporating both TRC benefit-cost test and RIM test criteria should prove useful in informing DG net metering program designs to be considered and approved by the Commission. The use of this suggested approach should not preclude consideration of any demonstrable and quantifiable net benefits associated with relevant externalities, provided that the potential for double-counting is adequately mitigated.

3. Time Period for Benefit-cost Studies

Q. Please summarize the key arguments of the parties in regard to the time period that should be considered for analyzing costs and benefits.

A. Among the parties that performed or proffered benefit-cost tests, there were two extremes that emerged: a short-term embedded COS study model based on a single year and the long-term, 25-year avoided cost study approach advocated by TASC witness Beach. Parties supporting the short-term COS study approach argue that their results indicate there are no net benefits of DG, and they posit that DG might actually add costs to the system, while also resulting in lost utility revenue and unjust and unreasonable cost-shifting.[98] Parties supporting the long-term benefit-cost studies advocate review of 25 years of levelized DG costs and benefits, although they primarily focus on benefits as many benefits are fully realized only over the lifetime of the DG resources.[99]

Q. What are the potential issues with using a short-term cost-of-service study?

A. Any short-term COS analysis only evaluates current conditions and will indicate only whether and to what extent a party should be allocated system costs. Such studies do not focus on the benefits of specific resource options, whether they are generation,

[98] Unitil Direct Testimony of H. Edwin Overcast, p. 29, lines 7-14; NERA Direct Testimony of Michael Harrington, pp. 21-22.
[99] See, e.g.,TASC Direct Testimony of R. Thomas Beach, p. 5, lines 25-26.

transmission, distribution, or customer-related. Even if expanded to include a focus on net benefits associated with the costs to serve customers, because these analyses are short-term in nature, there is no guarantee the results would remain valid beyond the test year used for cost allocation. In fact, benefits and costs associated with system changes such as the addition of DG are likely to change over time as DG penetration levels increase. This is especially true of any costs and benefits of DG to the utility distribution system.

Utility COS studies are based on a single test year, and all three utilities only budget capital projects five years into the future.[100] Thus, the ability to do any full COS analysis over a long-term horizon is limited, although a longer-term marginal cost study would be more useful in this context than an embedded COS study. Nevertheless, all decision-making over whether to invest in a generation resource, whether DG or not, should consider a longer-term horizon, and similar analytical considerations are relevant in the context of DG net metering program design.

Q. What are the potential issues with using a long-term benefit-cost study based on a 25-year life cycle of DG resources?

A. A benefit-cost analysis done using a 25-year life cycle evaluates whether there will be net benefits over the nominal life cycle of the DG resource. This type of study does not focus on whether net benefits will be realized in every year, and it overlooks the potential that, on a cumulative basis, a considerable amount of time may be required before benefits

[100] Unitil Response to Staff Request-UES 3-06, part (a). Eversource Response to Staff Request 2-024, part (a). Liberty Response to Staff Request 1-4, part (a).

exceed costs,[101] which raises potential intergenerational ratepayer equity concerns. The DG lifecycle analysis also does not attempt to optimize timing of DG investments. For instance, if fuel prices are assumed to rise in the future, and DG is only net beneficial if such a rise actually occurs, then, based on strict economics, the solar investment should begin only at the time of the price increase.[102] Of course, such timing will never be perfectly optimal, but some consideration for the timing of costs and benefits is reasonable in consideration of any benefit-cost analysis.

Moreover, arguing that the Commission should recognize a life cycle accumulation of benefits now may be seen as internally inconsistent with arguing that some issues, like costs associated with reverse power flows or cost shifting, are not material and can be ignored at the current low DG penetration levels.

Q. Does Staff have any suggestions or recommendations about the right timeframe for costs and benefits to be considered?

A. Staff suggests that it is important to evaluate all relevant costs and benefits and to do so over a time frame that is reasonable. Staff recommends that an appropriate long-term time horizon be used for avoided cost studies using marginal concepts and incorporating relevant test criteria, while recognizing that both long-term and short-term analyses may provide useful information for DG net metering program design. As such, Staff recommends that the Commission not adopt or endorse a specific list of covered costs and benefits, leaving open the possibility that a range of DG benefits, including certain

[101] TASC Response to Staff Request 1-3, attached as Appendix SF-2 (workpapers omitted from appendix). In the response, TASC provides figures for each utility that shows benefits do not exceed costs until 2028 for Eversource, 2027 for Unitil, and 2026 for Liberty.
[102] In traditional resource planning focusing on large resource investments, new construction begins ahead of need because of long lead times for large assets. Small DG projects do not have such long lead times.

externalities and other societal benefits to the extent they are demonstrable and quantifiable and not subject to double-counting, may be included in future well-designed and data-supported benefit-cost studies. Furthermore, as stated earlier in my testimony, Staff believes that a well-designed and properly conducted long-term avoided cost study using marginal concepts and incorporating both TRC benefit-cost test and RIM test criteria should prove useful in considering prospective DG net metering program designs.

4. *Avoided Distribution Benefit-costs*

Q. Please summarize the key arguments of the parties in regard to avoided distribution benefits from DG resources.

A. Parties arguing that DG resources avoid utility distribution system costs argue that these resources reduce the need to replace, upgrade, and/or expand distribution system capacity. These avoided cost benefits of DG resources are measured based on their contribution to the peak reduction of loads on different elements of the distribution system, although the effects on the distribution system as a whole are harder to analyze because certain equipment and components such as substations and feeders peak at different times.[103]

Other parties disagree that there are avoided distribution system costs associated with DG resources, and maintain that any possible benefits would be hard to quantify and would

[103] TASC Direct Testimony of R. Thomas Beach, p. 22, Table 2.

depend on several factors, including in particular location.[104] A seemingly extreme position is that there are no avoided cost benefits of DG on the distribution system, only costs from additional wear and tear on equipment due to reverse power flows.[105] For instance, Unitil witness Overcast attempts to quantify the additional cost responsibility for reverse power flow in his solar class COS analysis.[106] His study uses a non-coincident peak ("NCP") allocator for a hypothetical solar DG class based on the maximum of net demand or net exports to the grid, whichever is greater. This essentially assumes that, with higher exports than load, upgrades to the distribution system will be necessary to the extent the system was planned on the basis of consumption. The basis for this assumption does not seem to be fully supported.

In addition, these parties argue, many distribution system costs are fixed costs that are not avoidable.[107]

Q. What are the potential issues with the parties' arguments regarding avoided distribution costs?

A. Avoided distribution costs will vary by location,[108] which is revealed by TASC witness Beach's modelling analysis for Liberty and Eversource. Mr. Beach estimates distribution avoided costs based on average distribution system costs and how much load reduction the photovoltaic ("PV") systems can achieve in hours of peak distribution loads.[109] This

[104] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, pp. 23-25.
[105] Unitil Direct Testimony of Thomas P. Meissner, Jr., p. 38, lines 7-9.
[106] Unitil Direct Testimony of H. Edwin Overcast, p. 35, lines 6-10 and p. 36 lines 4-7.
[107] Unitil Direct Testimony of H. Edwin Overcast, p. 17, lines 14-17.
[108] OCA Direct Testimony of Lon Huber, p. 47, lines 6-7.
[109] The original analysis presented in Mr. Beach's testimony equally weighted the top 100 peak load hours. He provided revised numbers using a peak cost allocation factor (PCAF) methodology that looks at hours within 10% of the maximum load and weights hours with higher loads more than other hours. The results are very similar.

approach is intended to average out the geographic variability in the peak loads on the distribution system. Based on the workpapers for Mr. Beach's analysis, the solar load match factors for each station location vary from 0.4% to 62.8% for Liberty[110] and from 0% to 79% for Eversource.[111] This is based on only one year of data, which may not be representative of all system conditions that must be considered by distribution system planners. To be sure, the potential for avoided distribution costs may also vary based on the type and vintage of distribution system infrastructure at different locations.

It is important to remember that only future fixed cost investment (including carrying costs) and potentially some operating and maintenance costs can be avoided, but not the fixed costs of existing plant. DG investment may shift the allocation of such costs to different customers or customer classes, but that shifting is not the same as cost avoidance.

The purpose for which the benefit-cost analysis is used is also important. If the focus is on an appropriate payment for grid exports, for example, then consideration should also be given to the timing of such exports. If DG energy exports do not coincide with peak loads on the distribution feeder during peak hours, then inclusion of avoided distribution costs into rates paid for exports may not be justified. There is a risk of double counting the benefits from reduced distribution loads both through reduced cost allocation in a

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According to the response to UES 1-55, the PCAF methodology is preferred and the results here come from revised workpapers with PCAF calculations.

[110] TASC Response to Staff Request 1-1 (TASC-Distribution Loads - Liberty w PCAF method.xlsx, tab "Top Load Hours").

[111] TASC Response to Staff Request 1-1 (TASC-Distribution Loads - Eversource w PCAF method.xlsx, tab "Top Load Hours").

COS study when distribution costs are allocated based on NCP and through avoided cost payments for grid exports.

On the other hand, Unitil witness Overcast's calculation of the NCP allocator for embedded costs also ignores some important characteristics of the distribution system. Reverse power flow may exceed normal power flow on certain lines or line transformers with *very high DG penetration*. But that would not be true everywhere. There could be very little bidirectional flows if DG systems under current penetration levels are spread more evenly throughout the utility service territory. Moreover, the model he uses applies this NCP allocator to all allocated distribution costs, including primary lines and substations that typically feed large amounts of customers. While there may be some chance of a small cluster of DG systems creating reverse power flow over a line transformer, there is no evidence that the current DG penetration level is high enough to warrant concerns about bidirectional power flows over primary lines and substations. Thus, DG energy exports may not cause costs to be incurred solely on the basis of hourly grid exports exceeding maximum hourly grid imports on an annual basis.

In any case, the position that DG resources provide no actual or potential benefits to the distribution system, except for incremental costs, is not fully supported, since given the current level of DG penetration in New Hampshire there has not been sufficient information provided in this proceeding to quantify all incremental costs and benefits. More specific locational data needs to be collected on distribution equipment at different levels in order to properly analyze the costs and benefits of DG resources to the distribution system.

levels in order to properly analyze the costs and benefits of DG resources to the distribution system.

Q. Does Staff have any suggestions or recommendations regarding the costs and benefits of avoided distribution costs?

A. This is a complex engineering issue that cannot be addressed through simplistic analysis of timing of loads and generation. Staff suggests that it is important to collect more data on distribution equipment for all utilities in order to model and analyze wear and tear on distribution system equipment and components caused by DG resource reverse power flows, but also with respect to the ability of DG resources to reduce the utilities' needs to replace and/or upgrade distribution equipment and system capacity. Data and results from current capital asset evaluation methods used by the utilities, or distribution system asset management modeling, including the use of asset health indices ("AHI"), would provide greater insight into the longevity of distribution equipment as DG penetration levels increases on a distribution circuit. Such information would provide the Commission with a better understanding of DG costs and benefits when considering net metering tariff revisions or alternatives, and provide a basis for coordinating capital replacement plans with DG deployments, as appropriate.

5. *Avoided Transmission System Costs*

Q. Please summarize the key arguments of the parties in regard to avoided transmission system costs from DG resources.

A. Parties suggesting there are avoided transmission system costs from DG resources argue that these resources reduce the need to replace, upgrade, and/or expand transmission system capacity.[112] In attempting to calculate this benefit, the parties explain that the contribution of DG resources towards reduction of monthly zonal peaks should be measured. Some parties claim that the summer peak should be the basis for the calculation, even though ISO-NE charges for transmission on a 12-month coincident peak basis, due to the system being planned and built for a summer peak demand.[113] Other parties disagree that there are avoided transmission costs of DG resources, and any possible benefits would depend on several factors, including the specific location and quantity of DG.[114] Even if there are benefits, these parties assert that, under the current NEM tariffs, the DG resources are already compensated for avoided transmission system costs through the applicable credit rate provided for excess DG generation.[115]

Q. What are the potential issues with the parties' arguments regarding avoided transmission system costs?

A. The potential for avoided transmission system costs can be limited in the following ways:

- As with distribution costs, only future capital investment and potentially some operation and maintenance costs can be avoided, not the fixed costs of existing plant. TASC witness Beach's transmission avoided cost analysis is based on a projection of ISO-NE Regional Network Service ("RNS") rates, and this analysis is subject to significant flaws and important limitations as noted below in this section.[116] These rates are set to recover existing as well as projected future plant,

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[112] TASC Direct Testimony of R. Thomas Beach, p. 22, Table 2.
[113] NHSEA Direct Testimony of James Bride, p. 16, lines 6-15.
[114] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, pp. 23-25. NERA Direct Testimony of Michael Harrington, pp. 24-25.
[115] Unitil Direct Testimony of Thomas P. Meissner, Jr., p. 27, lines 3-5.
[116] TASC Response to Staff Request 1-1 (TASC-NH Avoided Cost Calculations.xlsx, tab "Transmission AC").

hence the analysis may overstate avoided costs. DG investment may shift the allocation of such costs to different customers, including to customers of other utilities, but that shifting is not the same as cost avoidance.

- The present value of avoided transmission investment costs that may be far off in the future is considerably lower than the value that may be ascribed to current or near-term avoided transmission costs. This is an important consideration, given the approximately $12 billion in transmission investment made over the last decade or so in the ISO-NE control area or proposed by 2020, and the fact that current transmission rates reflect most of this sunk investment.
- Because RNS cost responsibility is based on contribution to system monthly peaks, DG will only contribute to transmission cost avoidance if it generates during those limited peak hours. Setting compensation rates based on actual generation during those peaks may be considered more appropriate than setting rates for total energy produced.
- As with distribution system costs, if the focus is on an appropriate payment for DG energy exports, consideration should also be given to the timing of such grid exports. There is a risk of double counting the benefit from reduced transmission loads both through reduced cost allocations per the terms of the ISO-NE Open Access Transmission Tariff ("OATT"), and through avoided cost credits or payments to DG grid exports.
- For solar DG resources that are only able to reduce load during daylight hours, at high-enough solar DG penetration levels, transmission system monthly peaks will

likely move to times after sunset, which could reduce the ability for solar DG to avoid future transmission system costs.

Similar to avoided distribution system costs, the position that there are no benefits to the transmission system from DG resources, and if there are they would depend on location and amount of interconnected DG resources, is not fully supported. At the current level of DG penetration in New Hampshire, there has not been sufficient information provided in this proceeding to quantify all of the incremental costs and benefits. More specific locational data needs to be collected on the transmission system and equipment in order to comprehensively analyze the costs and benefits of DG resources.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided transmission costs?

A. Staff believes there may well be avoided transmission costs associated with DG resources installed and operating in New Hampshire. Since under the ISO-NE OATT, utilities are assigned a share of RNS charges based on their relative monthly coincident peaks, DG resources in New Hampshire may serve to lower those peaks for Eversource, Liberty, and Unitil, and as a result decrease their share of ISO-NE charges that are based on regional network load.

However, Staff also suggests that it may be important to collect more data on the timing of DG resource energy exports relative to annual and monthly transmission system peaks, in order to gauge the potential for DG resources to reduce the utilities' peaks, the extent, if any, to which those peak reductions may actually reduce embedded and future system costs, and the effects of such coincident peak reductions on ISO-NE charges assessed to utilities based on regional network load. Staff further suggests that the Commission consider implementing a TOU rate structure for the net metering tariff in the future that recognizes a transmission system component for relevant periods, after instituting a pilot to collect data on the effects of TOU rates on customers' behavior to shift load to lower cost time periods and optimize the timing of DG grid exports.

6. *Avoided Line Losses*

Q. Please define line losses.

A. As power flows over power lines and is stepped down in voltage in transformers, energy is lost to heat. Thus, one kWh generated from a DG system can replace more than one kWh of generation on the transmission and distribution grids due to losses from transporting generation from its source to load.

Notably, marginal loss values for transmission losses over the regional bulk power grid are included in regional wholesale market energy prices (i.e., LMPs).

Q. Please summarize the key arguments of the parties in regard to avoided line losses from DG resources.

A. Only a few parties directly addressed the benefits of avoided line losses, which includes line losses on both the transmission and distribution systems. The parties explaining the benefits of avoided line losses group them with their discussions around the transmission and distribution systems when describing how the need for energy from further points of generation is reduced due to the output of DG resources meeting local system needs and thereby reducing line losses associated with energy from distant generation resources.[117] For example, COL witness Below suggests that credits or payments to DG customers should account for line losses avoided between wholesale and retail metering points, as well as for ISO-NE generation-related ancillary service charges assessed to utilities based on their real-time load obligations.[118] No party directly argued that avoided line losses would provide no possible benefits. However, it stands to reason that, as some parties believe that wholesale energy and capacity market mechanisms[119] should be used to compensate DG resources for any benefits related to energy and capacity, these same compensatory measures should also include avoided line losses according to those parties.

Q. What are the potential issues with the parties' arguments regarding avoided line losses?

A. None of the parties appear to argue that avoided line losses are not a benefit, but the question of if and how that benefit may already be captured in avoided energy costs, as well as the potential avoided line loss benefits of generation both produced and consumed within a local distribution circuit, should be further examined. For instance, some argue that LMPs already include bulk transmission marginal losses, but not line losses applicable within the local transmission and distribution systems or the avoidance of charges that would otherwise be assessed if energy were imported from the regional bulk power system.

[117] TASC Direct Testimony of R. Thomas Beach, p. 22, line 1.
[118] City of Lebanon Direct Testimony of Clifton C. Below, p. 7, lines 189-193.
[119] Unitil Direct Testimony of Thomas P. Meissner, Jr., p. 27, lines 1-3.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided line losses?

A. Staff suggests that it is important to collect more data and perform further analysis regarding avoided line losses and the extent to which they should be appropriately recognized in net metering program design, while excluding any such losses that are effectively already included in the current compensation rate for excess generation from DG resources exported to the grid.

7. *Avoided Energy Market Costs*

Q. Please define energy market costs.

A. ISO-NE administers a complex, two-part regional wholesale market for electric energy. Generators that clear in the energy market are compensated based on LMPs. LMPs typically reflect short-run marginal costs, especially the cost of natural gas generation. DG could avoid energy market costs by displacing other generation at the margin and its associated costs. Such costs presumably would include fuel, variable O&M, line losses, and emissions costs included under cap and trade regimes such as the Regional Greenhouse Gas Initiative ("RGGI").

Q. Please summarize the key arguments of the parties in regard to avoided energy market costs from DG resources.

A. Most of the parties address potential benefits of avoided energy market costs, albeit, most of the discussion focused on using the current default service rate for each utility to compensate DG for excess generation. Parties that advocated for avoided energy market costs as a benefit did so because DG energy production displaces energy from other marginal resources that have higher variable costs, including the cost of fuel inputs.[120] Parties opposed to including avoided energy market costs as a benefit argue that there may be benefits, but any benefits should not be considered in a rate to compensate DG resources for excess generation.[121] Rather, they argue, DG resources should be compensated at the hourly spot market energy prices (i.e., LMPs) in the same manner as other generators participating in the ISO-NE markets.

Q. What are the potential issues with the parties' arguments regarding avoided energy market costs?

A. Avoided energy represents a large portion of anticipated benefits in TASC witness Beach's benefit-cost analyses, but are also subject to considerable uncertainty because of volatility in fuel prices, especially future natural gas prices. For example, the extraction of shale gas over the last 8 or so years has increased natural gas supply, causing a concomitant decrease in natural gas prices. In addition, pipeline constraints have caused high natural gas prices during cold weather in New England, but those constraints could be alleviated through future pipeline construction, which at this time is uncertain. Some resource types will be able to help mitigate these cold weather price spikes better than others, including hydroelectric and wind resources, whether or not they are also DG. Solar DG would not likely be the best mitigation resource due to more limited sunlight hours during cold winter days.

[120] TASC Direct Testimony of R. Thomas Beach, p. 22, line 1.
[121] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 16, lines 5-16.

Energy costs can change with the time of day and season as load levels vary, and tend to be higher during times of extreme weather. As a consequence, TOU or other time-differentiated rates for consumption and grid exports would help communicate this variation to DG customers. For example, in order to maximize production during peak hours with higher prices, solar DG customers may choose to install panels facing west instead of south, as south-facing panels are typically installed to maximize total energy production but with peak output earlier in the day, while west-facing systems provide more output later in the day often with greater system peak coincidence.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided energy market costs?

A. Staff notes that all parties recognize at least some avoided energy costs as a benefit provided by DG resources through their energy exports to the grid. However, as some parties correctly note, care must be taken to properly compensate DG generation for such benefits through a generation export credit or through some other rate. Using a TOU or other time-differentiated rate based on or developed with reference to actual LMPs for both consumption and to compensate DG resources for grid exports might be considered, but should be studied more and considered in a future proceeding before implementing any revised DG-related mandatory net metering tariffs. One way to study these potential pricing structures would be through a TOU rate pilot program or some other real-time rate pilot program that is based on or reflects variation in hourly LMPs. Of course, any potential benefits of TOU or other time-differentiated rates must be weighed against the costs of the necessary metering and billing infrastructure to capture the hourly prices, loads, and generation and the need for customer education and acceptance.

8. *Avoided Capacity Market Costs*

Q. Please briefly describe the regional capacity markets.

A. ISO-NE administers the FCM to compensate generation for supplying capacity to meet peak load and system reserve margin requirements. Generation that clears in the FCM forward capacity auction is compensated based on the clearing price for qualified generation. Prices depend on market rules, and supply and demand, both of which change over time. Prices paid to new generation resources generally reflect the fixed costs of constructing new natural gas-fired peaking generation. Resources receiving capacity payments are held accountable to deliver their capacity by bidding in the day-ahead energy market and are subject to penalties for failures to generate when called upon during a situation where the system is short of generation and emergency procedures have been activated by ISO-NE.[122] DG resources can participate in this market directly, but these resources need to have a nameplate capacity of at least 250 kW.[123]

DG resources that do not participate directly in the capacity market can avoid capacity market costs by lowering peak loads, and hence utility-specific capacity obligation requirements.

[122] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 16, lines 23-27.
[123] ISO-NE Market Rule 1, Section III.13.1., Forward Capacity Auction Qualification. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

Q. Please summarize the key arguments of the parties in regard to avoided capacity market costs from DG resources.

A. Most parties address the potential benefits of avoided capacity market costs, and for the most part there is agreement that DG resources can reduce or avoid costs of building and maintaining new gas-fired units, and that these avoided costs are quantifiable.[124] One main reason for such agreement is that a utility's capacity obligation and related FCM charges are determined based on its coincident peak with ISO-NE's annual system peak, which the parties explain typically occurs at the same time (mid-afternoon) that solar DG is generating.[125] Parties that oppose the inclusion of this benefit in net metering compensation rates, do so mainly because any benefits related to avoided capacity market costs are not part of distribution service.[126] Those parties argue that DG generation is like other wholesale market resources, and these generators should be treated similarly, which means they should be compensated through the FCM auction prices, if they clear.[127] In addition, those parties maintain that DG facilities are not producing at their peak when the rest of the system is peaking.[128]

Q. What are the potential issues with the parties' arguments regarding avoided capacity market costs?

A. Avoided capacity market costs, like avoided energy market costs, are subject to uncertainty. Any number of material changes to market dynamics may occur over time, including resource additions, retirements, load growth, technology and cost changes, and

[124] See, e.g.,TASC Direct Testimony of R. Thomas Beach, p. 22, line 1.
[125] CLF Direct Testimony of Paul Chernick, pp. 9-10, lines 23-25 and 1-3.
[126] Eversource, the only utility that still currently owns generation assets, is in the process of selling them off.
[127] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 16, lines 5-16.
[128] NERA Direct Testimony of Michael Harrington, p. 3.

market rules. In addition, for solar DG resources, since they can only reduce load peaks during daylight hours, as DG penetration levels increase over time, the system annual peak may begin moving closer to the evening hours, all else being equal, which could reduce the potential for solar DG to avoid capacity market costs in the future. For example, the ISO-NE Distributed Forecast Generation Working Group provided a graph of solar DG resources that shows that, even though these resources have the potential to reduce summer peak loads in the future by about 40% of each DG resource's capacities, as increased DG penetration continues in the ISO-NE control area, the potential to reduce peak loads will begin to decline (beginning with penetration levels exceeding about 1,400 MW) until it is closer to about 20% of each DG resource's capacity, which is predicted to occur at about 8,000 MW of regional DG penetration. This reduction effect is due to the system peak load moving to later in the day.[129]

Because only those DG resources that generate during system peak hours will avoid capacity market costs, setting compensation rates based on actual generation during these peaks would be a more appropriate approach than setting rates for total energy produced. It should be noted also that ISO-NE takes into account forecasted DG resource deployment levels in developing the capacity obligation requirements that are used in the FCM auctions.[130]

[129] ISO-NE Distributed Generation Forecast Working Group, Draft 2016 PV Forecast, revised March 7, 2016, slide 56, attached as Appendix SF-3, viewable online at: https://www.iso-ne.com/static-assets/documents/2016/03/2016_draftpvforecast_20160224revised.pdf.

[130] ISO-NE Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period, January 2016, p. 27: https://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf.

As with transmission system avoided costs, if the focus is on an appropriate payment for DG resource grid exports, then consideration should be given to the timing of such exports and the extent to which they avoid system peak loads.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided capacity market costs?

A. Staff notes that all parties recognize at least some avoided capacity cost benefit provided by DG resources that generate during system peak hours. The optimal compensation of DG generation for such benefits may be through a generation export credit or other similar approach. If the FCM does not provide reasonable opportunities for all DG resources to be properly compensated, then any change from the current rate should provide a way to properly compensate DG resources for this benefit, depending upon the timing of DG resource output and coincidence with system peak conditions.

9. *Avoided Ancillary Service Costs*

Q. Please define ancillary services.

A. Ancillary services are provided to ensure grid reliability. They include regulation resources that follow changes in load on time scales of seconds and minutes, black start service for generation that can re-energize the grid in outage conditions, and operating reserves, which are resources that can quickly respond to system contingencies such as a generator forced offline. ISO-NE administers the wholesale markets for ancillary services. DG resources could participate in these markets if they meet ISO-NE requirements. DG resources could also avoid ancillary services costs by reducing costs related to load.

Q. Please summarize the key arguments of the parties in regard to avoided ancillary service costs from DG resources.

A. Among the parties that addressed avoided ancillary service costs there was general agreement that DG will benefit the grid if the cost of reserves and other ancillary services is based on the reduced loads attributable to DG resources.[131] COL witness Below discusses the calculation of ancillary service costs under the annual avoided energy cost calculations performed pursuant to Puc 903.02(i), which provides optional compensation for annual net surplus generation from net-metered resources.[132] In addition, when paired with storage[133] or combined with other technologies such as smart inverters, DG resources themselves may actually provide ancillary services such as voltage support. There was no specific disagreement that avoided ancillary services costs represent a potential benefit provided by DG resources, although it was argued that excess generation is currently being compensated for ancillary services due to the inclusion of these charges in the full retail service rate.[134]

Q. What are the potential issues with the parties' arguments regarding avoided ancillary service costs?

A. Solar DG, like all non-dispatchable resources, has no regulation, ramping, quick start, frequency, voltage support, or black start capability, unless batteries or other storage are paired with it. It is important to note though that distribution level generation avoids wholesale market charges that are assessed based on real-time load obligation. So there is

[131] TASC Direct Testimony of R. Thomas Beach, p. 22, Table 2.
[132] City of Lebanon Direct Testimony of Clifton C. Below, p. 13, lines 341-348.
[133] NHSEA Direct Testimony of James Bride, p. 27, lines 6-16.
[134] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 14, lines 14-19.

potential for solar DG to offset the need for ancillary services to the extent the ancillary service charges are based on load levels.

On the other hand, operating reserve targets depend on the likelihood of system contingencies, especially generation outages, and at high levels of penetration, DG may create new assimilation problems. For example, large amounts of solar DG may create a contingent reserve requirement as a result of a sudden increase in cloud cover and also create demand for more ramping capability at sunset. But current penetration levels in New Hampshire are still low enough that this is not yet a serious concern, and likely will not be for some time to come.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided ancillary service costs?

A. Staff notes that, based on the current information about ancillary service costs and benefits from DG resources that is available in this proceeding, and taking notice of the settlement recently approved in Docket DE 16-674, there is a basis for calculation of avoided generation-related ancillary service charges pursuant to the avoided energy cost payment calculation under Puc 903.02(i). Even so, Staff suggests that more data collection and analysis are needed to better understand and quantify ancillary service costs and benefits.

10. *Market Price Mitigation*

Q. Please describe market price mitigation and DRIPE.

A. Market price mitigation, also known as DRIPE, refers to wholesale energy price decreases occasioned by new renewable generation, other new efficient generation (including conventional natural gas-fired units), or load reduction. The addition of these lower-cost resources may displace less-efficient and costlier generation at the margin in the energy market. This change in the marginal generation resource mix lowers market clearing prices, i.e., LMPs. Capacity market prices may be similarly depressed to the extent that DG resources provide generation during hours of system peak demand.

Q. Please summarize the key arguments of the parties in regard to market price mitigation benefits from DG resources.

A. Among the parties that addressed market price mitigation as a possible benefit of DG, there is mostly a consensus that this is a measurable benefit[135] resulting from the reduction of wholesale market energy and capacity prices caused by demand-side resources impacting the market.[136] Several examples[137] were provided to explain how New England benefits from market price mitigation caused by DG, a price-taker, replacing current and future generation that is more expensive at the wholesale level. TASC witness Beach attempted to quantify and model the effects of DRIPE, relying on the assumptions and methods from the 2013 and 2015 Avoided Energy Supply Costs in New England reports.[138]

[135] See 2013 and 2015 Avoided Energy Supply Costs in New England Reports provided by TASC. TASC Direct Testimony of R. Thomas Beach, Appendix D, p. D-5.
[136] TASC Direct Testimony of R. Thomas Beach, p. 23, line 1. Testimony of Nathan Phelps, pp. 11-12, lines 13-18 and 1-2.
[137] City of Lebanon Direct Testimony of Clifton C. Below, pp. 15-17, lines 420-457.
[138] TASC Direct Testimony of R. Thomas Beach, Appendix D, p. D-5. The latest Avoided Energy Supply Costs in New England reports and related updates are available online at:
http://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/Synapse%20AESC%20Report%20-

Other parties, while acknowledging that savings from reduced demand for electricity occur, argue these benefits are difficult to quantify. In addition, those parties assert that the benefits of solar DG should be discounted due to it not necessarily being coincidental with peak load, and note that current market compensation mechanisms are already in place for demand-side resources.[139]

Q. What are the potential issues with the parties' arguments regarding market price mitigation benefits?

A. There is potential for DG to reduce market prices through displacement of costlier generation at the margin. However, because natural gas-fired combined cycle generation is almost always on the margin in the ISO-NE markets, a high level of DG penetration would be necessary before any significant price reductions are realized, and such a level of penetration is not likely until far into the future. The TASC analysis largely supports this view, as the magnitude of the forecasted levelized DRIPE benefit is quite small, ranging from \$2.82/MWh to \$2.96/MWh, depending on the utility.[140]

At high levels of DG market penetration, market price reductions could become significant. Since renewable resources are price takers in the market, this could actually harm the economics of renewable energy investment. In such a renewable-heavy future, DG resources might potentially displace more economic utility-scale renewable resources rather than fossil fuel generation, and thus not result in any avoided fuel cost or market

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%20With%20Appendices%20Attached%20FINAL%20REPORT%20071213.pdf (2013); http://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/AESC_2015_%20w%20App_rev%202016_03_25.pdf (2015); and http://www.puc.nh.gov/Electric/Monitoring%20and%20Evaluation%20Reports/AESC%202015%20Addendum%202016_03_07.pdf (Addendum to 2015 report).

[139] NERA Direct Testimony of Michael Harrington, p. 8.

[140] TASC Response to Staff Request 1-1 (TASC-NH Avoided Cost Calculations.xlsx, tab "Summary").

price benefits. This effect has already been observed in jurisdictions with high DG penetration levels.

Q. Does Staff have any suggestions or recommendations regarding the benefits of market price mitigation?

A. Staff accepts the potential for DG resources to reduce wholesale market energy and capacity prices, but at current DG penetration levels, any such benefit is likely to be minimal. Staff suggests that more data collection and analysis would be useful to better understand the level of DG penetration at which market price reductions may be realized and quantify market price mitigation costs and benefits.

11. Fuel Price Hedging / Market Uncertainty Avoidance

Q. Please define fuel price hedging.

A. The term "fuel price hedging" may refer to a number of different fuel procurement practices. When estimating DG avoided costs, the focus is on procurement practices of generators and utilities. When generation owners and operators procure fuel for a future period, the price often includes a "risk premium" to make the transaction attractive to the party bearing the change in market price risk. The same "risk premium" also applies to utilities procuring electric power for full requirements service contracts. DG resources such as wind and solar may avoid the risk premium because they are not exposed to fuel market price uncertainty.

Q. Please summarize the key arguments of the parties in regard to fuel price hedging / market uncertainty avoidance benefits from DG resources.

A. Potential benefits from fuel price hedging/market uncertainty avoidance have not been widely discussed in this proceeding. TASC's benefit-cost analyses included a forecast of avoided fuel hedging costs using the difference between discounted energy prices based on forward natural gas prices and an assumed market heat rate as a proxy.[141] This avoided cost is included in the benefit-cost tests described above, i.e., the TRC and SCT tests.

Q. What are the potential issues with the parties' arguments regarding fuel price hedging/market uncertainty avoidance benefits?

A. Admittedly, there are benefits to avoiding fuel price risk, but it remains difficult to estimate the value of such risk avoidance, since it depends on risk tolerance of different parties in a competitive marketplace.

Some experts also argue that prices from futures markets, such as the New York Mercantile Exchange ("NYMEX"), already include risk premiums because future fuel or electricity purchases are transactable at those prices. TASC witness Beach relies on NYMEX market prices for forecasting natural gas prices in the near-term.[142] Adding a fuel price hedging/market price risk avoidance benefit in addition to an avoided energy cost benefit based on these prices may result in double-counting the avoided costs of market price risk avoidance.

Q. Does Staff have any suggestions or recommendations regarding the benefits of fuel

[141] TASC Direct Testimony of R. Thomas Beach, pp. 22-23, Table 2. The risk-free discount rate was based on projected treasury yields and compared to the utility discount rates.
[142] TASC Response to Staff Request 1-1 (TASC-NH Avoided Cost Calculations.xlsx, tab "Fuel Price Uncertainty").

price hedging / market uncertainty avoidance?

A. Staff suggests that, as this benefit is difficult to calculate at best and is subject to a large degree of uncertainty, it not be given significant weight in any benefit-cost analysis of DG at this time. Staff believes that more data collection and analysis may be warranted in order to better understand and quantify fuel price hedging/market uncertainty avoidance costs and benefits.

12. Environmental Benefits

Q. Please summarize the key arguments of the parties in regard to environmental benefits from DG resources.

A. There is a general consensus among parties that DG provides environmental benefits that include, but are not limited to, reduced criteria pollutants and carbon emissions reductions. From this general consensus, there is disagreement among the parties on whether and how to compensate for these benefits. The utilities and some other parties believe these benefits should be accounted for outside of net metering rate design, through mechanisms that are currently provided at the federal level, such as the renewable investment tax credit, and at the state level, such as via RECs and New Hampshire Renewable Energy Fund incentive programs.[143] Other parties argue that, if a benefit-cost analysis showed net positive environmental benefits, then those benefits should be incorporated into the net metering credit rate for excess generation produced by DG resources. TASC witness Beach included environmental benefits of DG resource

[143] Unitil Direct Testimony of Thomas P. Meissner, Jr., pp. 24 and 26, lines 9-11 and 3-19.

production in his SCT, reflecting avoided carbon dioxide (“CO_2”), sulfur dioxide (“SO_2”), and nitrogen oxide (“NO_x”) emissions. His avoided cost assumptions were based on the social costs of those pollutants as estimated by the Environmental Protection Agency (“EPA”).[144]

Q. What are the potential issues with the parties’ arguments regarding environmental benefits?

A. It is hard to argue against the idea that there are environmental benefits of DG resources, because they replace the need for generation from plants that emit pollutants such as CO_2, SO_2, NO_x, and particulates.[145] However, as noted earlier in my testimony, these tests are dependent upon several future assumptions regarding continued reliance on fossil fuels, and the social costs of pollutants are difficult to measure and subject to considerable debate. I take no particular issue with Mr. Beach’s use of EPA’s estimates, but there are other estimates that would produce different results.

Care should also be taken to avoid double-counting such environmental benefits. For example, some of the value of environmental benefits is already being captured through RECs sold for compliance with state Renewable Portfolio Standards (“RPS”). Although “renewable” does not necessarily mean “emission-free,” wind and solar resources that are often used to meet RPS standards are usually considered to be emission-free. The theory behind REC markets is that the price should reflect the difference between the cost of traditional fossil-fuel generation and the presumably higher cost of the most economic

[144] TASC Response to Staff Request 1-1 (TASC-Avoided Pollution and Social Costs.xlsx, tabs “Social_Cost_CO2”, “Social_Cost_SO2”, and “Social_Cost_NOx”). EPA report at https://www3.epa.gov/ttnecas1/docs/ria/utilities_ria_final-clean-power-plan-existing-units_2015-08.pdf.
[145] However, SO_2 and particulate pollution is more of a concern with coal-fired generation which is rarely on the margin in New England, although that could change.

renewable resource available. Thus, if a DG resource receives compensation for its avoided costs of fossil-fuel power and RECs, it should already be compensated for its environmental benefits. Put another way, under an RPS standard, additional renewable DG resources may only be avoiding other renewable generation (possibly grid-scale), and thus may not create additional environmental benefits.

Currently, DG resources are also receiving financial support through federal tax credits and state incentive programs. Those credits and incentives are also targeted, at least in part, to increase the supply of clean energy, and thus also provide some compensation for the potential environmental benefits of DG resources.

Q. Does Staff have any suggestions or recommendations regarding environmental benefits?

A. Based on the current policies in place to provide financial incentives for DG resources at the federal and state levels, Staff suggests that more data collection and analysis may be warranted in order to better understand the environmental impacts of DG resources and any resulting benefits to society as a whole. Such data could be used in the performance of a well-designed and properly conducted avoided cost study using marginal concepts and incorporating TRC benefit-cost test criteria, as well as RIM test criteria, as recommended by Staff.

13. Avoided Renewables Costs

Q. Please summarize the key arguments of the parties in regard to the benefits of

avoided renewable costs from DG resources.

A. Among the parties that addressed avoided renewables costs as a possible benefit of DG resources, there is consensus that, when DG resources can be used to contribute to renewable procurement goals of a utility, the DG resources will have effectively reduced the costs the utilities would have had to spend to acquire other potentially more expensive renewable resources to meet those procurement goals.[146] The procurement goals the utilities must meet are based on the state RPS, with set percentages of renewable attributes required to be obtained based on specific types of renewable energy resources. The parties that disagreed with the inclusion of this benefit did so because the benefit is already compensated for by the DG customer's ability to own, sell or transfer, and retire RECs under the RPS program.[147] Conversely, some other parties assert that compensation through RECs is only feasible for DG customers if the process of acquiring RECs is more centralized[148] and if the DG customer can transfer RECs directly to a utility in return for a benefit.[149]

Q. What are the potential issues with the parties' arguments regarding avoided renewable costs from DG resources?

A. The parties that claim avoided renewable costs are a possible benefit of DG resources do not provide any analysis showing that the renewable generation the utilities currently procure is more expensive than the renewable generation the utility could obtain through RECs from DG resources. In addition, this benefit does not seem to be directly

[146] TASC Direct Testimony of R. Thomas Beach, p. 23, line 1.
[147] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 28, lines 14-23.
[148] NHSEA Direct Testimony of James Bride, pp. 32-33, lines 10-20 and 1-7.
[149] OCA Direct Testimony of Lon Huber, p. 31, lines 4-22. In this case, Mr. Huber suggests the benefit should be compensation rates certainty for some period of time (20 years was suggested).

incorporated into any benefit-cost model, unless it is part of the avoided generation energy or capacity costs, which if so, is not well-defined.[150]

The OCA's proposed solution is to provide rate certainty to DG customers in exchange for RECs produced by DG resources.[151] But no benefit-cost analysis has been provided to support the proposed 20-year rate certainty compensation mechanism and how that proposed mechanism would affect utility revenue and other ratepayers.

Q. Does Staff have any suggestions or recommendations regarding the benefits of avoided renewable costs?

A. Staff recommends that whatever alternative net metering tariff or other mechanism is adopted should clearly state whether the transfer of REC ownership is included under or accounted for in any export rate credit or payment provided to DG resources.

14. Other Societal Benefits

Q. Please summarize the key arguments of the parties in regard to other societal benefits from DG resources.

A. There is a general consensus among parties that DG resources provide additional societal benefits that may include, but are not limited to, economic development, siting, and public health. From this general consensus, there is disagreement among the parties on how to quantify such societal benefits and, even if quantified, whether and how such benefits should be compensated through net metering rate design. The SCT presented by

[150] TASC Response to Staff Request 1-1 provides model workpapers.
[151] OCA Direct Testimony of Lon Huber, p. 31, lines 7-10.

TASC's witness Beach incorporates such additional societal benefits.[152] Other parties argue that there is no way to quantify the value of such benefits, and therefore, even if there are such benefits, they should not be counted in any benefit-cost analysis, also noting that separate mechanisms may exist to compensate for these benefits.[153]

The parties that consider societal benefits hard to quantify mostly believe that any benefits derived should be compensated for outside of net metering rate design, through other policy mechanisms or incentive programs at the federal and/or state levels.[154]

Q. What are the potential issues with the parties' arguments regarding other societal benefits from DG resources?

A. The quantification of general societal benefits, like that of environmental externalities, is difficult and subject to considerable debate and potential double-counting. Estimating the economic impacts of any DG resource compensation program typically requires sophisticated modeling with many assumptions, results may vary by level of DG penetration, and estimates are in part dependent on other public policies such as tax incentives for DG development. Any potential cost or benefit impacts to the New Hampshire economy would be difficult to properly account for, especially at the low penetration levels of DG resources currently seen on each utility's system.

Direct compensation for any general societal benefits provided by DG resources should also be carefully considered. For instance, if DG resources are provided direct compensation for such societal benefits in ways not available to similar generation

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152 NHSEA Direct Testimony of Nathan Phelps, pp. 6-7, lines 23-26 and Chart 1, and pp.7-9, lines 8-11 through 1-4.
153 Unitil Direct Testimony of Thomas P. Meissner, Jr., pp. 23-24, lines 18-20 and 1-3.
154 Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 28, lines 4-26.

resources that are not installed behind-the-meter, this could bias the marketplace in favor of DG when utility-scale resources may be less costly or provide other potential system benefits.

Q. Does Staff have any suggestions or recommendations regarding other societal benefits?

A. Staff recommends that the Commission remain open to consideration of any demonstrable and quantifiable net benefits associated with relevant externalities, such as the general societal benefits of DG resources, provided that the potential for double-counting is adequately mitigated. In this regard, Staff suggests that additional data collection and analysis may be warranted to better understand the potential general societal benefits of DG resources.

B. Cost-Shifting Between Customers and Customer Classes

1. Definition of Cost-Shifting

Q. Please define the concept of cost-shifting.

A. Utilities are typically allowed recovery of all prudently-incurred costs of their used and useful resource investments. In New Hampshire, customers have a choice whether to receive power supply through default service from their local utility or through a competitive electric power supplier operating in the retail electricity market. These rates depend on wholesale forward market prices and charges determined through ISO-NE administered markets.

Delivery rates are state-regulated and informed by COS models that allocate distribution system and customer-related costs to rate classes in accordance with cost causation principles.

One principle of rate design is that rates should reflect the costs of serving the customer. If DG customers pay less than their full allocated cost-of-service, some other party must pay the difference for the utility to recoup all of its relevant costs included in its approved revenue requirement. As a result, costs are said to be "shifted" to another party, either to the utility (and its shareholders) if it is unable to collect all of its costs or to other non-DG ratepayers.

For a DG customer, the cost of serving much of its load using a DG system is simply the carrying and maintenance costs of the DG system. The challenge is in accounting for net grid imports to and exports from the DG customer. Utilities still have a cost of supplying service to DG customers for that portion of their load requirements not met by their DG resources.

Cost-shifting is easily conflated with problems such as added costs or lost revenue recovery, but is a separate issue that must be considered. For example, DG may add to system costs through required distribution system upgrades to accommodate high DG penetration, and DG resources, similar to EE programs, may result in utility revenue erosion. If DG customers nonetheless bear an appropriate and reasonable share of any such additional costs or lost revenue recovery, then it should not be said that unjust and unreasonable cost-shifting has occurred.

At relatively low levels of DG penetration, any such cost-shifting should not be of great concern at this time. However, at higher DG penetration levels cost-shifting may become of greater concern. Debates about how to allocate relevant costs in accordance with cost causation principles are inevitable. But much of the debate is over the application of the cost causation principles themselves to a proper rate and revenue recovery framework, not that utilities should not fully recover their approved revenue requirements with DG customers bearing a fair share of their costs of service.

2. *Determining Current and Projected Extent of Cost-Shifting*

Q. Please summarize the key arguments of the parties in regard to how to determine current and projected cost-shifting.

A. Eversource argues that above- or over-market payments to excess generation exports cause cost-shifting due to DG resources receiving compensation at the full retail or default service rate, which is higher than the avoided market costs, or what the utilities deem the "true value" of that energy.[155] Such cost-shifting is further exacerbated by banking of excess generation, according to the utilities.[156] Unitil focuses more on the cost-shift that occurs from DG customers to non-DG customers for avoided T&D costs and through "fuel arbitrage" resulting from their delivery of power "during lower marginal cost hours and using the banked energy volumes in higher marginal cost

[155] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 18, lines 19-24.
[156] Unitil Direct Testimony of H. Edwin Overcast, p. 16, lines 1-2. Liberty Direct Testimony of Heather M. Tebbetts, p. 9, lines 6-17.

hours."[157] Unitil quantifies the supposed delivery cost shift between residential DG and non-DG customers in its COS analysis.

Some parties assess costs and benefits of DG resources and argue that, as long as DG has net benefits, no cost-shifting occurs. However, these parties potentially ignore the timing mismatch between when system benefits accrue to all ratepayers and when a subset of ratepayers must contribute to cost recovery.

One of the parties argues that cost-shifting occurs from non-DG customers to DG customers because DG resources not fully compensated for the net benefits they provide to all ratepayers and non-DG customers not paying for all of the net benefits they receive from DG resources.[158]

Q. What are the potential issues with the parties' arguments about how to estimate cost-shifting?

A. Estimating cost shifting is not a trivial exercise. There are many important considerations, including the following:

- Cost-shifting estimates will depend on the analytical time frame. This is complicated by the fact that DG resources are long-term investments, but traditional regulatory rates are set on the basis of a single test year.
- Focusing on long-term analysis may result in inter-temporal cost-shifting of costs to non-DG customers in the short-term, even if in exchange for benefits that future ratepayers may realize over the longer term.

[157] Unitil Direct Testimony of H. Edwin Overcast, p. 10, lines 9-13.
[158] NHSEA Direct Testimony of Nathan Phelps, p. 26, lines 11-18.

- Careful consideration must be given to whether and how much DG resources should be compensated differently than if they were market participants in wholesale markets:
  - Most would agree that differences in compensation may be warranted to reflect differences in the services provided (e.g., a DG resource incurs lower line losses due to its proximity to customer load).
  - Compensation for any supposed market shortfalls, such as environmental externalities, is far more complicated, as such effects are difficult to quantify and may be best addressed through other mechanisms such as tax incentives, REC markets, emissions credit markets, or state incentive programs.
- The extent of cost-shifting may be different between customers within a class, between classes, and between DG customers utilizing different DG technologies.
- Analysis of costs and benefits based on future avoided costs alone cannot determine whether any rate structure results in cost-shifting for embedded delivery costs. That requires a separate COS study.
- Benefit-cost analysis shows whether benefits outweigh costs under a certain methodology, using a certain set of assumptions, and over a specified time horizon. Such studies may illuminate the issue of cost-shifting, but a projection of net benefits does not definitively mean there is no cost-shifting occurring, at least in the short-term.

In regard to the effects of net metering credits amounts and credit banking, these issues are more thoroughly discussed in Section C, *Tariff Rate and Design Issues*.

Q. Please summarize the key arguments of the parties in regard to the extent of current and projected cost-shifting.

A. Most parties agree that, in consideration of the current low penetration levels of DG resources, there is minimal to no cost-shifting occurring between customers within and between customer classes.[159] Some parties, however, argue that, even at the current levels of DG penetration, cost-shifting is a significant issue because DG customers are not paying for their fair share of system costs for services provided by the utilities.

All parties agree that, as DG resource penetration levels increase, cost-shifting will increase from current levels, all else remaining equal.

Q. What are the potential issues with the parties' arguments regarding the extent of current and projected cost-shifting?

A. Parties such as TASC, EFCA, NHSEA, and CLF assert that no cost-shift or only a deminimis one, relying primarily on a robust, but incomplete and inexact, assessment of DG resource benefits net of relevant costs. These assessments are based on long-term, life cycle analyses, where some benefits are delayed and do not fully coincide with system costs, and would be difficult to or cannot be recognized under any short-term benefit-cost analysis or utility COS study. This approach also presents issues of inter-generational inequities, and could result in locking in DG resource incentives based on assumptions that may not hold over the future planning horizon associated with the long-term life cycles of DG resources.

[159] See, e.g,, NHSEA Direct Testimony of Kate Bashford Epsen, p. 12, lines 1-4; NHSEA Direct Testimony of James Bride, p. 18, lines 10-12; EFCA Direct Testimony of Patrick Bean, p. 3, lines 9-11; TASC Direct Testimony of R. Thomas Beach, p. iii.

The parties that argue cost-shifting is currently unjust and unreasonable provide little support for this conclusion, other than before- and after-DG installation hypothetical bill examples.[160] These examples indicate that DG customers appear to be avoiding paying for embedded fixed cost recovery over a given month. One issue with these examples is that they may not be indicative of a significant number of DG customers and likely do not represent all months of the year. In addition, not every utility has the same metering capabilities[161] and therefore the ability to properly measure and quantify potential cost-shift impacts. This fact renders any analysis dependent on assumptions regarding DG customer load profiles which may or may not be representative of all affected customers.[162]

Q. Does Staff have any suggestions or recommendations about how to estimate cost-shifting and its current and projected extent?

A. Staff recognizes that cost-shifting is an important concern. Consider, for example, an extreme scenario in which all customers have DG systems sized to their load requirements; in that hypothetical scenario, the current net metering program would leave no one to pay for the embedded fixed costs of the utility system.

However, the current levels of DG penetration in New Hampshire is nowhere near the level where that scenario might be realized, and the current and near-term extent of any cost-shifting has not been fully supported in this proceeding. Once again, a well-designed and properly conducted long-term avoided cost study using marginal concepts

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[160] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 11, line 1.
[161] Eversource Direct Testimony of Edward A. Davis, pp. 6-7, lines 25-26 and 1-2. Liberty Direct Testimony of Heather Tebbetts, p. 21, lines 18-20.
[162] See the section below on the need for a separate DG rate class for more details.

and incorporating RIM test criteria as well as TRC benefit-cost test criteria, could prove useful in informing future DG net metering program designs, including aspects of such designs intended to mitigate cost-shifting.

Staff also recommends that the Commission consider the issue of potential inter-generational inequities that may shift costs to non-DG participating customers in the short-term in exchange for benefits that future ratepayers may realize only over the longer term, and appropriate mechanisms to mitigate these potential effects.

3. Whether Cost-Shifting is Unjust and Unreasonable

Q. Please summarize the key arguments of the parties in regard to whether cost-shifting is unjust and unreasonable.

A. Some parties argue that currently no unjust or unreasonable cost-shifting from DG customers to non-DG customers is occurring. Some stated that there is no unjust and unreasonable cost-shifting to the extent that DG confers net benefits on all ratepayers.[163] It is also argued that cost-shifting is not a concern because current DG resource penetration levels are low, and the utilities have not provided enough support that they are currently losing revenue as a result of DG.[164]

Among the parties that argue there is unjust and unreasonable cost-shifting, there is general agreement that this is due to utilities not being fully compensated by DG customers for their fair share of fixed system costs, which are then reallocated to all

[163] EFCA Direct Testimony of Patrick Bean, p. 3, lines 10-21.
[164] EFCA Direct Testimony of Patrick Bean, pp. 3-4, lines 10-21 and 1-17.

ratepayers or basically shifted to non-DG customers through rate increases.[165] These parties mainly focus on the fixed costs of T&D systems that are not paid for by DG customers with systems equal to or less than 100 kW through the current met metering program. However, there are also other non-bypassable charges, such as stranded cost recovery charges, system benefits charge, storm recovery surcharges, and the state electricity consumption tax, that are also not fully recovered from DG customers with smaller systems under the current net metering program.

Q. What are the potential issues with the parties' arguments regarding cost-shifting that is unjust and unreasonable?

A. A certain level of cost-shifting is part and parcel of ratemaking based on grouped classes of customers. It is common in ratemaking to set revenue targets for grouped customer classes at their estimated COS based on output from a COS study, even though consumption profiles and related costs to serve may differ significantly between customers within the class. This inevitably leads to some amount of cost-shifting, but that does not necessarily mean the resulting rates are unjust or unreasonable. Recognizing that even within classes, customers use electricity in different ways and at different times, and in view of the current low levels of DG penetration, an unjust and unreasonable level of cost-shifting for power supply costs and utility delivery service is not likely to occur within the near-term.

Cost-shifting of charges such as customer charges and non-bypassable charges for stranded costs and system benefits is a legitimate concern. Consider that customer

[165] CEA Direct Testimony of James Voyles, pp. 3-4.

charges are based on the cost to serve a customer regardless of the amount or pattern of the customer's energy consumption. The installation of DG does not avoid these costs.

As to non-bypassable charges that collect revenue to cover items such as stranded costs, traditional cost causation principles are difficult to apply in assigning responsibility for these costs, in part because stranded costs do not result in cost recovery of currently used and useful plant and equipment. However, these costs are still deemed recoverable because they were considered prudent at the time of investment. In any case, selection of the proper mechanism to recover such costs is largely based on application of core ratemaking principles.

Q. Does Staff have any suggestions or recommendations about the level of cost-shifting that would be unjust and unreasonable?

A. Staff recommends that the Commission consider whether the current and near-term levels of cost-shifting are significant enough to address at this time or rather, given the current relatively low levels of DG resource penetration, whether an approach based on the net metering compensation mechanism currently in place should be sustained for the nearer term until DG resource penetration levels increase to a threshold (e.g., 10% of utility peak load) that might result in more substantial cost-shifting. To be sure, some reforms in the net metering compensation mechanism could be applied at this time, for instance, ensuring that regardless of DG production, a minimum bill containing the customer charge and certain non-bypassable charges and assessments, would apply to all customers, including those customers with DG resources.

In addition, as stated earlier, the Commission should consider the issue of inter-generational inequities that may arise when costs are shifted to non-DG participating customers in the short-term in exchange for benefits that future ratepayers may realize only over the longer term, and appropriate mechanisms to mitigate potential these effects.

C. Tariff and Rate Design Issues

1. Separate Rate Class for DG Customers

Q. Please summarize the key arguments of the parties with regard to the necessity for a separate rate class for DG customers.

A. A few parties argued that a separate rate class for residential DG customers be established to properly account for cost causation in COS modeling,[166] and because these parties maintain that DG customers have materially different net consumption characteristics than the average residential customer.[167] Other parties disagree that there should be a separate rate class for DG customers, unless there are specific consumption and cost data that support the establishment of such a separate customer class.[168]

Q. What are the potential issues with the parties' arguments regarding a separate rate class for DG customers?

A. Load shape is the key differentiating factor to justify different rate classes. Customers with high coincident peak consumption relative to their total usage, and therefore lower load factors, have a higher cost of service on a per kWh basis. As an example, consider two customers with the same peak loads but different amounts of energy consumption.

[166] Unitil Direct Testimony of H. Edwin Overcast, p. 6, lines 5-6.
[167] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 8, lines 17-19.
[168] TASC Direct Testimony of R. Thomas Beach, pp. 33-34, lines 24-30 and 1-10.

The demand-related cost to serve these two customers will be the same. If those costs are collected through an energy charge, as is often the case for smaller customers, then a strict application of cost causation principles would support the view that the COS-based energy rate for each customer should be different. Under this approach, the customer with lower energy consumption, and hence a lower load factor, should have a higher energy charge because the demand-related costs are being spread over a lower amount of kWh consumption and kWh usage is the applicable the billing determinant.

On the other hand, rate design principles can be used to mitigate the need for separate classes. The use of TOU rates or other time-differentiated energy and demand charges could lead to different average per kWh rates for customers with different load shapes, but utility revenue recovery might be equivalent. For example, if a coincident peak demand charge were to be implemented, customers with the same peak demand would pay the same amount on their bills, even though the lower load factor customer would have a higher average rate per kWh.

Moreover, if metering were in place to measure gross consumption by both DG and non-DG customers alike, it is not clear there would be material load shape differences on the *consumption* side that are not already recognized to some extent as part of any class cost allocation exercise. It is the addition of DG generation that leads to *net* consumption load shape differences. Therefore, the focus should be on the generation side of the ledger and appropriate compensation for DG energy exports, because consumption met with DG generation is not considerably different than consumption that is affected by EE measures or energy conservation.

Q. Do you have any additional concerns with the COS analysis from Unitil witness Overcast?

A. Yes. Unitil witness Overcast assumes that the load shape of residential solar DG customers was the same load shape as the residential class as a whole prior to the installation of DG.[169] While this is possible in some cases, it will not likely be the case for some number of DG customers. Some DG customers may have had higher energy consumption and higher load factors to begin with. A customer may also choose to install a DG system at the same time the customer invests in a new appliance with a large power draw, such as an electric vehicle or heat pump. Dr. Overcast's analysis does not consider or account for these vagaries. Metering data that measures power consumption and generation output profiles for DG customers would be needed to better illuminate this issue.

In addition, Dr. Overcast treated all DG customers the same in the hypothetical DG rate class in his analysis. In reality, DG systems and customers may be very different. For instance, some customers may not generate any material amount of excess energy for grid export that can lead to bidirectional power flows, yet under Dr. Overcast's methodology, these customers would be grouped together in a class of DG customers all being allocated costs based on assumed maximum grid exports.

Q. Does Staff have any suggestions or recommendations about having a separate rate class for DG customers?

[169] Unitil Direct Testimony of H. Edwin Overcast, p. 33, lines 4-11.

A. Staff believes that, even if it could be justified on the basis of net customer load shape differences, it is neither necessary nor appropriate at this juncture to create a separate DG customer class, in the absence of some other rate design imperative. As discussed in the next section, because Staff is recommending against the imposition of demand charges on residential customers at this time, and adoption of a mandatory TOU or other time-differentiated rate structure seems premature, separate classes for DG and non-DG customers are not required at this time.

2. Demand Charges to Address Revenue Loss / Cost-Shifting

Q. Please summarize the key arguments of the parties in regard to the use of demand charges to address revenue loss and cost-shifting.

A. Two of the utilities argue for the use of demand charges to address issues regarding lost revenue and what they claim is unjust and unreasonable cost-shifting. These parties suggest that the instantaneous kW demand placed on the system by a customer at peak times is what should be used to determine recovery of the demand-related costs of delivering energy to the customer, since the distribution system is built to meet customers' non-coincident peak demand, not to meet the overall kWh delivered.[170] The demand charge, which under their proposal would be based on the maximum demand whenever it occurs regardless of system or class peak coincidence, would allow the utilities to match charges to cost causation for customers because their distribution

[170] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 8, lines 20-22.

demand costs are based on non-coincident peak demand.[171] These parties claim that DG customers impose similar peak demands on the system as non-DG customers. Further, due to their energy exports, these customers potentially impose greater demands on delivery capacity, which can translate into more fixed, distribution-related system costs.[172]

Other parties argue that demand charges based on maximum demand whenever it occurs are less manageable and avoidable by customers, which makes them similar to fixed charges. Additionally, such demand charges do not necessarily target coincident peak demand reduction which renders these charges a poor price signal. These parties also suggest that maximum demand-based charges do not provide customers incentives to conserve energy or manage peaks after a new, higher monthly peak demand has been set, which may lead to increased overall consumption and cause cost increases due to load-shifting, as well as making it hard for customers to monitor, understand, and project monthly bills and savings potential.[173]

Q. What are the potential issues with the parties' arguments regarding the use of demand charges to address revenue loss / cost-shifting?

A. Using demand charges to recover T&D costs can be justified under cost causation principles, as T&D systems are designed to meet aggregate peak demand and are mostly fixed cost in nature. But demand charges based on maximum monthly demand regardless of peak coincidence or other relevant time-differentiation send a poor price signal to

[171] Unitil Direct Testimony of H. Edwin Overcast, p. 24, lines 2-12.
[172] Unitil Direct Testimony of H. Edwin Overcast, p. 14, lines 9-12.
[173] CLF Direct Testimony of Paul Chernick, p. 25, lines 7-23.

customers, other than those whose maximum monthly demand happens to be relatively coincident with T&D system peaks. In addition, Eversource's proposed *maximum* demand charge may result in over-recovery of its T&D revenue requirement, since the charge is calculated using the residential portion of *coincident* peak demand.[174] Using this value to calculate the demand rate, which is then applied to DG customers' NCP demand will likely lead to over-collection of the revenue requirement because the sum of all maximum demands will almost certainly be greater than coincident peak demand.

Coincident or TOU demand charges could send a better price signal and better reflect the cost causation principles of ratemaking. This may be largely academic, however, since metering currently in place with the New Hampshire utilities does not allow for measurement of coincident or TOU demands.

It would also be difficult to implement demand charges for residential customers at this point for several reasons, including higher costs for new metering that would be necessary for implementing such charges, as well as a lack of customer outreach and education, and anticipated issues with general customer acceptance.[175] Because demand charges, with or without ratchets, can affect customer bills significantly, there is also the potential for significant rate shock and dislocation, which would violate another key ratemaking principle of rate stability.[176]

Q. Does Staff have any suggestions or recommendations about using demand charges

[174] Eversource Direct Testimony of Edward A. Davis, Attachment 1, p. 1.
[175] See additional discussion of these topics in *Distributed Energy Resources Rate Design and Compensation*: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design (November 2016), pp. 98-108, attached as Appendix SF-4.
[176] Bonbright, James C., *Principles of Public Utility Rates*, pp. 383-384 (1988) (rate structure characteristics), attached as Appendix SF-5.

to address revenue loss/cost-shifting?

A. Demand charges have the potential to better reflect cost causation on the distribution system, especially if they are based on coincident peak or are time-differentiated. However, implementation of residential customer demand charges at this time is not recommended, based on issues regarding the installation and cost of required metering capable of recording demands over all hours of the billing cycle, customer acceptance and understanding, ability to monitor and control electricity bills, and the potential for rate shock and dislocation. Further data collection, including on DG and non-DG customer load shapes, and the impacts on residential customers where such charges have been implemented in other jurisdictions, is warranted in order to better understand the effects of demand charges on gross and net consumption and how these charges would impact DG resource development on a forward-looking basis.

3. Alternatives to Demand / Fixed Charges

Q. Please summarize the key arguments of the parties in regard to the use of alternatives to demand/fixed charges.

A. Many parties express support for adoption of some type of time-varying energy rate (e.g., TOU pricing, variable peak pricing, critical peak pricing, or real-time pricing) that would better incentivize customers to shift load to lower cost periods than does a uniform energy rate that is not time-differentiated.[177] There is some debate about the appropriate

[177] CLF Direct Testimony of Paul Chernick, pp. 29-30, lines 1-21 and 1-7.

length of an appropriate TOU peak period, but some parties maintain that Liberty and Eversource's current TOU peak period rates are too long.[178] One party stresses that any TOU rates need to incorporate a shorter peak rate period based on the hours of distribution system peaks, in order to incent beneficial customer behavior, and that it may be best to have this peak rate period shift seasonally.[179] All of the utility parties plan on retaining a customer charge, although none of them explicitly states that charge would increase.[180] Other parties agree with the premise of a customer charge or a minimum bill, as long as that charge would not increase.[181]

Unitil witness Overcast argues in favor of a $38 residential monthly customer cost based on results derived from his COS models,[182] and he also strongly advocates for implementation of residential DG customer demand charges.[183]

Q. What are the potential issues with the parties' arguments regarding alternatives to demand/fixed charges?

A. Demand charges that are time-based or based on coincident peak demand can be effective at signaling the times of highest long-term cost on the aggregate utility system, including the distribution system. On the other hand, a TOU or other time-differentiated rate with higher charges during hours of the day when the residential class typically peaks (i.e., early evening) would also reflect cost causation and send an appropriate price signal, but

[178] EFCA Direct Testimony of Patrick Bean, pp. 12-13, lines 13-19 and 1-21.
[179] NHSEA Direct Testimony of James Bride, p. 25, lines 10-19.
[180] Eversource Direct Testimony of Edward A. Davis, p. 4, lines 24-25.
[181] CLF Direct Testimony of Paul Chernick, p. 23, lines 4-25. TASC Direct Testimony of R. Thomas Beach, p. 36, lines 1-3.
[182] Unitil Direct Testimony of H. Edwin Overcast, p. 37, lines 4-5.
[183] Unitil Direct Testimony of H. Edwin Overcast, p. 37, lines 15-18.

would be difficult to avoid with solar DG for peak hours after sunset. Therefore, the argument that demand charges or high customer charges are absolutely necessary to create a fair rate structure for DG customers is unpersuasive.

TOU pricing is generally viewed as favorable and would be preferable to the proposed NCP demand charges or other fixed charges. Properly-designed TOU or other time-differentiated energy rates can reflect changes in hourly energy prices throughout the daytime and seasons and therefore serve as an appropriate determinant for recovery of many fixed costs associated with T&D service as well as better reflecting market prices for energy. Under TOU or other time-differentiated energy rates, regardless of when a customer sets a peak demand, the customer still has an incentive to adjust energy consumption, add DG, or both, in order to respond to and benefit from lower bills if the customer is able to shift usage to lower TOU rate periods going forward. In addition, the use of super peak TOU periods during times of peak demand on the overall system and/or the utility distribution system could also help ensure recovery of T&D costs without introducing demand charges. As noted earlier, the current issue with TOU rates is the infeasibility of their implementation due to the need for installation of metering capable of capturing hourly interval demand data.

Q. Does Staff have any suggestions or recommendations about alternatives to demand/fixed charges?

A. TOU or other time-differentiated energy charges would be preferable to demand charges as a means to more closely align DG rate design with cost causation principles, provided that metering can be implemented to measure customer imports and exports separately over all hours of the billing cycle, in order to reflect hourly and seasonal differences in wholesale power supply costs and the peak demand periods which T&D systems are built to meet. The design of TOU or other time-differentiated rates would be informed by additional data collection and analysis in order to better understand the impact of such rates on sending price signals to DG customer so they shift their loads out of the peak, higher cost times. Data collection through the different pilot programs discussed in Section D, *Potential Pilot Programs*, would enable the Commission to have better information about different time-based rate structures.

As noted earlier, a minimum bill set at the level of the customer charge and including certain non-bypassable charges assessed on a kWh basis would also be an option in the meantime, and this approach would not require metering changes or harder-to-understand and control demand-based charges.

Staff believes that, in the longer term, time-differentiated rate designs for DG customer net metering tariffs should be considered by the Commission, as Staff has concluded that these rate structures send better price signals to DG customers than demand charges based on NCP maximum customer demands. However, there is a current lack of interval metering needed to implement TOU charges in any form. Further, the complexity of implementing these new rate designs for residential customers, as well as lack of relevant data regarding DG costs and benefits and flaws and limitations as noted in the available benefit-cost studies, all suggest that TOU or other time-differentiated rates be rolled into DG customer net metering tariff rates prospectively when these issues have been resolved, and potentially first through opt-in pilots in order to gain better understanding, acceptance, and critical data on their impacts.

4. Intra-Monthly NEM Credit Amount

Q. Please summarize the key arguments of the parties in regard to using different Intra-monthly NEM credit amounts.

A. Multiple claims and proposals exist as to how to treat the excess generation credit to be applied within the monthly billing period for net-metered DG customers. The utilities generally take the view that the credit rate should be market-based avoided energy costs, such as real-time LMPs, although they propose that the default service rate be used primarily due to current metering limitations.[184] The utilities support the view that DG generation should no longer be credited at the full retail rate, because the retail rate includes charges for T&D cost recovery and non-bypassable charges. They note also that the default service rate effectively includes adders for procurement costs, capacity, ancillary services, RPS compliance, risk, overhead, and other cost components, therefore being priced different than standalone generation or DG generation which does not bear these associated costs.[185]

Among non-utility parties, different views are expressed on how to credit excess generation from DG customers. Several parties advocate maintaining the current status quo net metering credits, with DG resources sized 100 kW or less credited at the full retail rate, with the possible exception of certain non-bypassable charges and

[184] Unitil Direct Testimony of H. Edwin Overcast, p. 15, lines 17-20; Eversource Direct Testimony of Edward A. Davis, p. 6, lines 1-6. Liberty Direct Testimony of Heather M. Tebbetts, p. 19, lines 1-8.
[185] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 14, lines 14-19.

assessments.[186] One party argued that the default service rate is appropriate, as the cost of purchasing RECs would be greater than cost savings from RPS costs being subtracted from DG crediting.[187]

Another party expressed the concern that, without real-time metering and tracking, it is impossible to estimate the true value of generation.[188] Yet another argues that the excess generation credit should be based on a benefit-cost analysis, which would be run at predetermined capacity or time intervals.[189]

Other proposed mechanisms to determine the applicable amount for intra-monthly excess generation net metering credits include the OCA's proposal to adopt a Fixed Solar Credit Rate, which will be discussed later in my testimony.[190]

Q. What are the potential issues with the parties' arguments regarding the amount of the intra-monthly NEM credit?

A. DG customers with systems equal to or less than 100 kW currently receive the utility's full retail service rate as a credit for excess generation from their DG resources. This rate includes all of the costs the utility pays for the procurement and delivery of electricity to its customers. The full retail rate therefore might be considered over-compensatory for grid exports to the extent it exceeds the costs avoided by DG as well as any relevant net benefits of DG. This is the main argument made by the utilities because they only focus

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[186] TASC Direct Testimony of R. Thomas Beach, pp. 35-36, lines 16-27 and lines 1-8; EFCA Direct Testimony of Patrick Bean, p. 4, lines 19-24; NHSEA Direct Testimony of James Bride, p. 12, lines 1-2 and pp. 35-36, lines 18-20 and lines 1-2.
[187] City of Lebanon Direct Testimony of Clifton C. Below, p. 15, lines 416-418.
[188] NERA Direct Testimony of Michael Harrington, p. 17.
[189] NHSEA Direct Testimony of Nathan Phelps, p. 28, lines 9-22.
[190] OCA Direct Testimony of Lon Huber, p.33 lines 9-13.

on the avoided cost value of DG and do not consider other net benefits from DG. Another issue with the full retail rate is that it does not vary with the wholesale hourly prices of energy and ancillary services, nor directly with the changing costs of generating, transmission and distribution capacity over time. As a result, it may send an inefficient price signal regarding the value of hourly exports, and an inappropriate one to the extent that DG is not avoiding some utility costs to serve customers. For example, as already noted, the full retail rate includes T&D charges designed to recover the embedded costs of utility delivery infrastructure which is built to meet peak customer demand regardless of reductions in individual or total customer energy usage.

In the long run, the full retail rate probably should be discontinued as the appropriate compensation for excess generation exported to the grid from DG resources. In the near-term, at a minimum it seems reasonable, as many parties have conceded, that the net metering credit amount should not include non-bypassable charges and assessments such as the system benefits charge, stranded recovery costs charge, and state electricity consumption tax, as these are items that should be recovered from all customers, including those with DG.

Alternatively, the default service energy rate could be used as the basis for the net metering credit for excess generation from DG resources, since this rate provides an approximation of utility avoided costs with some basis in market pricing and it would not require additional metering capability. This credit rate would ensure DG resources receive the benefit of avoided power supply costs at a minimum for exported energy within the current billing cycle. However, use of this methodology could potentially undervalue excess generation to the extent DG confers other non-energy net benefits as described earlier in my testimony. For example, a credit amount based on the default service rate would not compensate DG for any avoided transmission or distribution costs, nor any environmental or other societal benefits, to the extent these are deemed appropriate for inclusion in the determination of excess generation net metering credits.

Two other possible solutions, which could likely be implemented only in the longer term, are crediting the exported energy through hourly real-time LMPs or at a TOU or other time-differentiated rate. Crediting excess generation at a rate based primarily on real-time hourly LMPs in the hours when the excess generation is exported to the grid might be seen as the most accurate way of compensating DG for avoided energy costs; however, that structure would require more sophisticated metering and billing systems.

A TOU or other time-differentiated credit rate is another possibility, as such a rate could send an appropriate price signal regarding the value of DG exported energy, especially during the peak hours of the day. As with an LMP-based credit, a TOU or other time-differentiated rate could be set based on consideration of both the costs and net benefits of DG as determined through an appropriate benefit-cost analysis. Such a rate would be more complex and difficult to implement than the current compensation mechanisms, and it may take some time to collect and analyze relevant data in order to better understand how different TOU periods and rates may impact DG system sizing and the amount and timing of DG exported energy.

Regardless, as already noted, these compensation reforms are only able to be implemented once meters are installed to allow hourly accounting for grid exports.

Q. Does Staff have any suggestions or recommendations regarding the intra-monthly NEM credit amount?

A. Staff believes that, in the longer term, time-differentiated rate designs for net metering tariffs applicable to DG customers, such as TOU rates or real-time pricing models, may hold great promise and should be considered by the Commission. In particular, Staff has concluded that such time-differentiated rate structures would send better price signals to DG customers than demand charges based on NCP maximum customer demand. However, in view of the current general lack of interval metering for residential and small commercial customers and the complexity of implementing such a different rate design, and in view of the current unavailability of significant relevant data regarding DG costs and benefits and flaws and limitations in the available benefit-cost studies as noted in this testimony, Staff recommends that in the near-term the current net metering structure be continued for a period with certain modifications made to the credit amount and the credit banking applicable to energy exported to the grid from DG customers. Staff recommends that any net metering tariff re-design that would cause applicable rates to be based on peak time periods or hourly intervals, such as hourly real-time prices, be deferred until more comprehensive data and improved metering and billing capabilities are available to support such changes to net metering tariffs and applicable rates. Staff notes that these issues are currently being addressed in the Commission's investigation into grid modernization, Docket IR 15-296 (Grid Mod Docket).

During the near-term period, Staff therefore recommends that, for DG systems with capacity equal to or less than 100 kW, the applicable credit for exported energy be the utility's full retail rate with the exception of non-bypassable charges and assessments such as the systems benefits charge, stranded cost recovery charge, storm recovery surcharges, and state electricity consumption tax. For larger size systems with capacity greater than 100 kW up to 1 MW, the applicable credit for exported energy should be the utility's default service rate only.

5. NEM Credit Banking Continued or Monthly Excess Cash-Out

Q. Please summarize the key arguments of the parties in regard to continuing NEM credit banking or changing to a monthly excess cash-out.

A. There is a consensus among the utility parties that address banking, that the current practice of NEM credit banking beyond the monthly billing period is not representative of the value of DG energy to the system at the time the credits are applied, resulting in unjust and unreasonable cost shifting.[191] They also express concern that such credit banking leads to oversized systems, due to lack of economic consequences, because DG customers are compensated at the full retail rate for excess generation produced during months with generally lower wholesale prices of energy such as in the summer and certain shoulder months. Those customers can bank such credits, which can then be applied to reduce their charges in winter and other times with higher wholesale energy prices and where their gross consumption is greater than their DG resource production.[192] The utilities argue for elimination of banking of excess generation credits altogether, in

[191] Liberty Direct Testimony of Heather M. Tebbetts p. 9, lines 14-21. Unitil Direct Testimony of H. Edwin Overcast, p. 16, lines 1-2.
[192] Unitil Direct Testimony of Thomas P. Meissner, Jr., pp. 43-44, lines 17-20 and 1-4.

order to avoid kWh credits generated during one month being applied to another where the prices of wholesale energy and even default service may be significantly higher. They argue that this reform would reduce cost-shifting.[193]

The utilities propose that customers be "cashed out" for the value of excess energy credits unused at the end of each monthly billing cycle, at the default service rate at least initially and perhaps at a rate based on real-time LMPs if interval metering is implemented.[194] Other parties argue that credit banking should continue without limit in recognition of the overall net benefits provided by DG resources, and because banking effectively represents simply an accounting transaction and does not impact the utility's cost to "store" the energy for later use.[195] As a potential alternative, a seasonal TOU rate to value credits in dollar terms might be seen to more accurately reflect the value of banked energy from season to season, as is done in California with high DG penetration levels.[196]

Q. What are the potential issues with the parties' arguments for and against continuing NEM credit banking or changing to a monthly excess cash-out?

A. Currently, NEM credit banking allows DG customers to bank excess generation credits at the end of each month to reduce bills in a future month. Of course, the generation is not physically banked, since once it is exported it is used within the grid to serve other utility customers. Banking is rather a means of accounting for excess generation that allows DG customers who generate more energy than they use in a month to roll that generated

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[193] Liberty Direct Testimony of Heather M. Tebbetts, p. 18, lines 18-21 and p. 19, lines 1-5.
[194] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, p. 29, lines 10-11; Liberty Direct Testimony of Heather M. Tebbetts, p. 4, lines 6-12, pp.12-13, lines 19-20 and 1-7, p. 16, lines 21-22, and p. 18, lines 12-13; Unitil Supplemental Testimony of H. Edwin Overcast, p. 5, lines 5-14.
[195] TASC Direct Testimony of R. Thomas Beach, p. 18, lines 7-19.
[196] TASC Response to Staff Request 1-20, attached as Appendix SF-6.

energy into a future month as a credit against later consumption. This crediting mechanism is especially beneficial to DG customers who size their DG resource installation on the basis of annual expected consumption, since solar DG, for example, can only generate during daylight hours with minimal cloud cover. The banked energy can then be used for times and periods after the month of excess production when there is less solar production (e.g., the winter months with shorter daylight hours).

However, the issue with banking such excess energy credits for use in later months is that the value of energy differs both diurnally and seasonally. Reviewing LMPs from the wholesale market over the course of any year, it is obvious that there are average price changes associated with on-peak and off-peak hours and during different months and seasons. In some years, these price differences can be quite stark, for example, the cold winter of 2014-2015 that led to very high winter electricity prices. The price differences change the value of the banked energy credits and can therefore lead to cross-subsidies associated with DG systems based on how variable price differences may be throughout a given year. Such market price variation is also reflected in utility default service rates, which are typically set twice each year and tend to reflect current and forecasted wholesale pricing trends at the time determined.

It is clear from the analysis above that current banking practices have the potential to mis-align the value of banked credits when generated with the costs to serve when these credits are used. Currently the utilities lack the necessary metering to credit hourly excess generation based on real-time LMPs, even if that might be seen to represent the optimal means of fully aligning credit values. A seasonal TOU compensation rate could be used to value excess generation in the short-term, but this type of temporary variable rate would need to be developed consistent with an appropriate avoided cost and net benefits analysis.

Some other approaches to consider, at least in the short-term, are either to limit banking to at most one-year with a cash-out at the end of the year or to use a different rate to credit banking used in future periods to help address the seasonal price differences issue and the potential arbitrage between such time periods. This rate could be something like the default service rate, which changes twice a year. Additional details regarding implementation of such a rate would need to be considered, including when would the rate changes be determined and become effective each year.

One last point to address is that persuasive evidence has not been presented that DG customers are building oversized systems in order to bank production to offset usage during higher cost periods, although it is theoretically possible. It could be imagined that if banking were allowed to continue indefinitely and without limit, or if the cash-out compensation were a high enough economic incentive, then this could lead to DG system overbuilds, but without sufficient evidence indicating this is occurring, there seems to be no need to adjust banking solely to address overbuilds.

Q. Does Staff have any suggestions or recommendations about continuing NEM credit banking or changing to a monthly excess cash-out?

A. In the short-term, Staff recommends that the Commission consider limitations on NEM credit banking such that any excess net metering credits then outstanding would be cashed out on an annual basis at a calculated avoided cost rate similar to that currently used under Puc 903.02. This approach would preclude the unlimited and indefinite banking of NEM credits with greater administrative cost efficiencies as compared to more frequent credit liquidations.

Staff also suggests that collection and analysis of additional data would serve to improve understanding of seasonal or any other cost-shifting issues related to NEM credit banking. Such data could be collected during a pilot program where the utilities are using better metering to capture hourly interval data, i.e., customer consumption and exported energy. After meters capable of collecting hourly interval data are in place and seasonal credit value variation and other cost-shifting issues can be more thoroughly studied, then the Commission would have a better foundation for implementing additional changes to the banking of credits as well as the crediting of exported energy.

6. Group Net Metering Impacts

Q. Please summarize the key arguments of the parties in regard to group net metering impacts.

A. Group net metering ("GNM") impacts are only addressed by a few parties. Some of the parties do not support GNM under the current net metering tariffs, claiming that GNM customers and members cannot avoid delivery costs because they all require the distribution system, and because the size of the host customer's facility needs to be large enough to serve multiple customers, thereby exacerbating cost avoidance issues.[197] Liberty claims that its current billing system cannot adequately support group net

[197] Unitil Supplemental Testimony of H. Edwin Overcast, p. 4, lines 10-17.

metering so it has to bill these customers through manual processes.[198] In addition, the argument is made that customers should only receive the default energy service rate for excess generation.[199]

Other parties support GNM and argue for more options to enable participation, which could include higher size limits, credit adders, and targeting of low income households and other groups that could not otherwise participate in net metering.[200] The OCA proposes a community solar tariff with a rate determined similarly to its Fixed Solar Credit Rate tariff as described later in my testimony. In addition, the OCA includes the possibility of two adders to the community solar credit rate: an environmental adder so that all participants can receive credit for RECs,[201] and a Low to Moderate Income ("LMI") adder that can increase the credit rate depending on the kW percentage of LMI customers participating in a community solar project.[202]

The main difference between a customer selling RECs to the utility versus bundling is that bundling provides the environmental benefits to society, while selling RECs simply allows the purchasing load-serving entity to comply with RPS mandates, keeping the "benefits" in New Hampshire.[203] The environmental adder proposed by OCA is $0.03/kWh for a ten-year fixed period, based on the claimed lower end of market REC prices that have ranged from $30 to $60 per MWh. The adder would receive biennial review, but would not change the rate of the REC adder for current customers, which

[198] Liberty Direct Testimony of Heather M. Tebbetts, p. 23, lines 11-14.
[199] Unitil Supplemental Testimony of H. Edwin Overcast, p. 5, lines 1-3.
[200] CLF Direct Testimony of Paul Chernick, p. 15, lines 19-22.
[201] The customers will get an environmental adder per kWh if they elect to bundle the RECs with electricity; this benefits New Hampshire by reducing its carbon footprint through keeping the RECs in state.
[202] OCA Direct Testimony of Elizabeth Doherty, pp. 69, lines 7-8, 70 and 73-74, lines 4-13, 33, and 7-10.
[203] OCA Direct Testimony of Elizabeth Doherty, p. 71, lines 5-19.

would be constant for ten years.[204] These adders would be in addition to the Fixed Solar Credit Rate.[205]

Q. What are the potential issues with the parties' arguments regarding impacts on group net metering?

A. The position that GNM avoids delivery costs is not fully supported based on evidence provided in this proceeding, as discussed earlier in my testimony with regard to DG as a whole. More specific locational data needs to be collected regarding the impacts of GNM and the avoidance of distribution plant investment in order to properly analyze the specific costs and benefits associated with this category of DG resources.

GNM allows customers with unsuitable roofs, renters and others such as low income customers to participate in DG resource development as group members. Any incentives to increase LMI participation in GNM or other community solar initiatives, such as an LMI adder, should be carefully evaluated regarding the extent to which it is necessary and also to ensure that participation in the program is only by LMI customers who would not otherwise be able to participate.

An environmental adder as proposed by the OCA adds a further complication to a customer's decision on how to treat their RECs in the GNM or community solar context. The OCA's proposed ten-year REC rate may not reflect actual REC market value over that period. While incentives are important for DG integration, it is not the responsibility of other ratepayers to bear the risk of potential fluctuations in REC market pricing.

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[204] OCA Direct Testimony of Elizabeth Doherty, p. 73, lines 4-14.
[205] OCA Direct Testimony of Elizabeth Doherty, pp. 69, lines 23-25, 70, lines 1-2.

Furthermore, proposals to compensate DG for RECs it creates could impose cost-shifting problems, since utilities are now able to use DG-created RECs in estimates to meet their RPS obligations.

Q. Does Staff have any suggestions or recommendations addressing potential impacts on group net metering?

A. The Net Metering Statute supports allowing group net metering to be open to all customers. In the near-term, Staff recommends that the Commission not require any material modifications to the current GNM-specific provisions of net metering tariffs, unless and to the extent that recommended changes to the NEM credit amount result in a necessary change.

7. Lost Revenue Adjustment Mechanism

Q. Please summarize the key arguments of the parties in regard to a lost revenue adjustment mechanism.

A. Most parties that addressed a lost revenue adjustment mechanism ("LRAM") agree that allowing utilities to recover lost revenue is "appropriate and fair".[206] Some of the parties further claim that only through full revenue decoupling can the utilities properly recover their revenue requirements,[207] which could be impacted by time-varying rates, energy efficiency, and behind-the-meter generation.[208] Some parties argue that better

[206] OCA Direct Testimony of Lon Huber, p. 11, lines 10-11.
[207] Unitil Direct Testimony of H. Edwin Overcast, p. 12, lines 10-15.
[208] CLF Direct Testimony of Paul Chernick, p. 4, lines 19-23.

metering[209] must be implemented in order to calculate and understand the impact of lost revenues. Only Liberty actually presented a structure for calculating lost revenue that differs from the lost revenue recovery process recommended in Docket DE 15-147 as a short-term measure.[210] Liberty's proposed approach would be to bill customers under a lost revenue rate component calculated by forecasting lost or reduced sales, multiplying that amount by the average distribution rates, and then dividing by the forecasted annual sales, later reconciling those estimates against actual metered data.[211] One of the parties suggested that, instead of an LRAM, which would still lead to cost-shifting, utility lost revenue recovery could be addressed through tariff rate adjustments (i.e., demand charges) and billing determinant changes such as DG customers paying for metered purchases.[212]

Q. What are the potential issues with the parties' arguments regarding a lost revenue adjustment mechanism?

A. Based on the current lack of definitive metering data available in this proceeding, and the utilities' acknowledgment that better metering would be needed in order to fully measure bidirectional power flows as well as DG resource production, current lost revenues for each utility are not easily calculated with precision. While the installation of meters capable of measuring both gross and net DG customer consumption and generation, such as proposed by Liberty, would permit lost revenue to be calculated with greater accuracy,

209 OCA Direct Testimony of Lon Huber, p. 11, lines 18-20.
210 OCA Direct Testimony of Lon Huber, p. 11, lines 15-17.
211 Liberty Direct Testimony of Heather M. Tebbetts, p. 21, lines 10-15.
212 Eversource Direct Testimony of Edward A. Davis, pp. 6-7, lines 17-26 and 1-14.

the respective costs and benefits of such metering implementation should be carefully considered in light of reasonable alternatives.

In regards to addressing lost revenues or cost-shifting from new net metering tariff rates and/or designs, as discussed earlier, even though time-based or coincident peak demand charges have potential benefits, there are also issues that render their implementation infeasible in the near-term.

Q. Does Staff have any suggestions or recommendations about a lost revenue adjustment mechanism?

A. Staff recommends that the Commission consider implementing an LRAM model in the near-term, based on reasonable estimated utility revenue losses attributable to DG resources, unless and until the utilities are able to measure and calculate the actual amount of such lost revenue, in order to avoid separate utility rate case filings solely for lost revenue recovery. Staff agrees with the OCA proposal to use the lost revenue calculation methodology proposed in the settlement filed for approval in Docket DE 15-147 in the short-term, unless and until a better alternative approach is proposed and approved.

8. Administrative Impacts on Utilities

Q. Please summarize the key arguments of the parties in regard to administrative impacts on utilities.

A. All parties recognize that the utilities likely would incur administrative costs related to the deployment of new meters and necessary upgrades to billing systems, as well as other costs related to the implementation of any pilot programs, in connection with the alternative tariff proposals under consideration in this proceeding. The utilities themselves assert that billing modifications are needed. Liberty indicates that it would cost about $314,000 to update its billing system, and would take about six to eight months to implement related changes, just to effect the NEM tariff modifications it proposes.[213]

Q. What are the potential issues with the parties' arguments regarding administrative impacts on utilities?

A. Other than Liberty, the utilities did not provide any specific details in terms of a timeframe for rolling out new administrative processes. Unitil believes its proposed rates will make the administrative process more simplified,[214] while Eversource explains only that it would just need "sufficient" time to implement changes to the billing system.[215] None of the utilities, however, appears to be explicitly considering the potential implementation or administrative costs of a new NEM tariff that has rate structures and program designs different than the ones each has proposed.

It seems clear that there will be additional metering costs depending on their capabilities. Whether they are deployed only for DG customers or all customers, and whether DG customers must pay for some or all of their costs are important questions left unanswered

[213] Liberty Direct Testimony of Heather M. Tebbetts, pp. 23-24, lines 17-21 and 1-6.
[214] Unitil Direct Testimony of H. Edwin Overcast, p. 12, lines 16-22.
[215] Eversource Direct Testimony of Edward A. Davis, p. 7, lines 15-25.

by most parties. In addition, depending on how the utility billing systems need to be redesigned and on how readily the utilities can implement any potential pilot programs, the costs may change even more significantly.

Costs related to NEM program administration that are not covered by customers during the interconnection of DG resources have been considered in the TRC benefit-cost test conducted by TASC witness Beach.[216] Even though TASC considered such administrative costs, these costs can only be considered estimates, since administrative costs will vary depending upon rate structures and designs that arise out of this proceeding, as well as pilot programs that are potentially implemented following this proceeding.

Significantly, the question of who pays for the metering and billing system upgrades, whether all customers or just DG customers assuming they are otherwise not required, will be an important one that may materially impact benefit and cost calculations under different approaches. Typically, billing system upgrades would be paid for by all rate paying customers, if such upgrades are determined to be cost-beneficial and prudent; however, that typical treatment may not be optimal in the case of net-metered DG customers.

Q. Does Staff have any suggestions or recommendations about the administrative impacts on utilities?

A. Pursuant to HB 1116, Staff recommends that the Commission should carefully

[216] TASC Direct Testimony of R. Thomas Beach, p. 23, Table 3.

consider all administrative costs utilities would incur resulting from an alternative NEM tariff and/or potential pilot programs, including any costs related to the need for utilities to update their billing systems and potentially installing new metering equipment. The record on these issues in this proceeding appears not to be complete. If so, then compliance filings requiring proposals by the utilities and other parties could be ordered to be filed for Commission evaluation.

Regardless, Staff strongly recommends that any near-term alternative NEM tariff should incorporate the same rate structure for all three regulated utilities, which would allow for common implementation processes, ease of program comparison, pilot program administration, and implementation of other potentially affected rate elements. Therefore, the aforementioned compliance filings should squarely address the question of which ratepayers (all customers or only the DG customer subset) benefit from and should pay for any required upgrades and related administrative costs.

9. Tariff Limitations and Triggers for Future Tariff Review

Q. Please summarize the key arguments of the parties in regard to tariff limitations and triggers for future tariff review.

A. In general, parties agree that if benefits equal or exceed costs and no unreasonable cost shifts pertain, then there should be no limitation on the amount of generating capacity eligible for new alternative NEM tariffs. However, some parties argue that limitations on each utility's system should be reviewed in the future,[217] as well as the potential limitation of DG resource capacity on specific distribution feeders and monitoring the capacity of NEM generation as a percentage of utility peak load.[218]

Some of the parties consider prospective triggers that would initiate further tariff review. One party suggested that a threshold percentage of net-metered generation capacity as a percentage of utility peak load should trigger an initial stakeholder process to consider if any changes are necessary (5% was suggested for this potential threshold). If the DG resource penetration threshold increases to another certain level, such as 10% of utility peak load, then another proceeding like this one would take place to consider adoption of new alternative NEM tariffs.[219]

Q. What are the potential issues with the parties' arguments regarding tariff limitations and triggers for future tariff review?

A. It will be important to monitor the growth in DG resource penetration on the distribution system for each utility down to the circuit level. Based on the data provided in this proceeding, there does not appear to be a sufficient foundation to fully understand the impact of DG resources at either the system or circuit level. Therefore, DG resource growth on the distribution system as a whole, and more particularly on each circuit, substation, and feeder, should be monitored against the utility and equipment peaks. The suggested thresholds for monitoring DG resource penetration are in line with the National Association of Regulatory Utility Commissioners ("NARUC") Manual on DER, which

[217] Eversource Direct Testimony of Edward A. Davis, p. 9, lines 15-20.
[218] CLF Direct Testimony of Paul Chernick, p. 33, lines 11-13.
[219] CLF Direct Testimony of Paul Chernick, pp. 33-34, lines 14-18 and 1-2.

considers what levels of penetration cause a more complex amount of grid infrastructure investment and more sophisticated regulatory mechanisms to be in place in order to allow further DG resource penetration.[220]

Q. Does Staff have any suggestions or recommendations about tariff limitations and triggers for future tariff review?

A. Staff agrees that monitoring DG resource penetration against the peaks of each utility, as well as their equipment loadings, is important and should be undertaken. Current DG resource penetration levels are relatively low, but as these levels increase and system impacts become more apparent and quantifiable, it will be important to know what thresholds should trigger further tariff review.

Staff does not recommend that any NEM tariff limitation be set based on installed capacity limits (i.e., a MW limit) at this time. Instead, Staff recommends that any alternative NEM tariff approved in the near-term should be in effect until a new alternative NEM tariff or tariffs is developed during a new Commission proceeding that would be triggered upon the first to occur of: (1) the availability of sufficient relevant data to complete the avoided cost study described in previous sections, including any such data collected through approved pilot programs, (2) such time as the total capacity of DG systems operating under all NEM tariffs exceeds 10% of the total aggregate peak demands of the three regulated utilities for the preceding calendar year, or (3) a specified period of time, such as three years as an example.

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[220] *Manual on Distributed Energy Resources Rate Design and Compensation*: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design (November, 2016), pp. 59-62, attached as Appendix SF-7.

10. OCA Tariff Proposals

Q. Please summarize the key arguments of the OCA's alternative NEM tariff proposals.

A. OCA witness Huber presented two alternative NEM tariffs, a DG TOU Rate and a Fixed Solar Credit Rate, that new residential DG customers could choose from, as well as the community solar tariff that was discussed earlier in my testimony. The DG TOU rate is designed to send price signals to DG customers through a volumetric TOU rate with an on-peak period from 2pm-8pm to align with the system peak hours in New Hampshire.[221] By using this volumetric rate to account for either consumed or exported kWh, the DG TOU Rate differs from how the current NEM tariffs charge for the delivery rate component, which includes distribution system costs and the part of the retail transmission costs for which the average customer is held responsible.[222] In addition, the DG customer would be responsible for all of the energy-based non-bypassable charges, including stranded cost recovery charges, system benefits charge, storm recovery surcharge, external delivery charge, and electricity consumption tax, as well as the other parts of the transmission charge (a new charge that accounts for load that is coincident with the monthly peak, but not offset by the DG production[223]).[224] The OCA's proposed alternative tariff also includes a new export charge component targeted at recovering utility grid fixed costs incurred when energy is exported by a DG facility.[225] The OCA proposes that costs of new metering required under the alternative tariff should be

[221] OCA Direct Testimony of Lon Huber, p. 17, lines 17-23.
[222] OCA Direct Testimony of Lon Huber, p. 19, lines 7-18.
[223] OCA Direct Testimony of Lon Huber, pp. 23-24, lines 23-24 and 1-3.
[224] OCA Direct Testimony of Lon Huber, p. 22, lines 16-20.
[225] OCA Direct Testimony of Lon Huber, p. 25, lines 11-13.

divided between the utility and the DG customer.[226] Other details of the proposed new DG TOU Rate include a requirement that customers be locked into the rate for at least one year to prevent gaming, and a limitation of the program to a MW-based capacity limit that would exceed the current 100 MW limit by some yet-to-be-determined amount.[227]

The other proposed new alternative tariff component, the Fixed Solar Credit Rate, is designed to compensate DG customers for excess generation exported to the grid through a compensation rate based on a delivery credit rate determined through a capacity-based, tranche step-down mechanism for residential DG, and through a market-based auction mechanism for commercial DG.[228] This compensation rate would be fixed for a 20-year period, but would decline for new customers over time as DG penetration increases.[229] Participation would be limited to 200 MW initially, in order to help manage the program and mitigate any cross-subsidies.[230] Other program features include the application of the Fixed Solar Credit Rate to all DG energy produced, the credit rate having the ability to potentially offset a fixed customer charge for larger systems, excess generation indefinite rollover or end–of-year cash-out, and program design that is flexible enough to adapt to DG technologies other than solar.[231]

Q. What are the potential issues with the OCA's alternative NEM tariff proposals?

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[226] OCA Direct Testimony of Lon Huber, pp. 31-32, lines 25-26 and 1-4.
[227] OCA Direct Testimony of Lon Huber, p. 32, lines 7-8 and 19-22.
[228] OCA Direct Testimony of Lon Huber, pp. 36-37, lines 13-16 and 1.
[229] OCA Direct Testimony of Lon Huber, p. 33, lines 9-15.
[230] OCA Direct Testimony of Lon Huber, p. 36, lines 1-6.
[231] OCA Direct Testimony of Lon Huber, p. 37, lines 4-24.

A. In determining the on-peak TOU rate, the OCA analyzed the number of hours for each utility that were within 5% of the annual peak load for the last three years for summer and winter. This is a reasonable way to arrive at an on-peak period that has the potential to incent customer load shifts.

Further, as I have discussed earlier, certain non-bypassable charges and assessments should be paid for by DG customers as well as non-DG customers because DG customers do not avoid these costs and can benefit from the programs supported by certain of the charges.

In calculating the non-bypassable portion of the transmission charge that can be attributed to DG customers, the PVWatts® software tool is used to estimate solar output.[232] Even though the use of actual New Hampshire data would lead to a more accurate identification of the average reduction in peak load over a year resulting from DG resources, the PVWatts® software tool generates a reasonable average generation profile based on its use of locational, historical weather data and system parameters that best summarize average PV installation attributes.[233]

A more controversial rate component is the proposed export rate charge. It is not clear from either the OCA or utility filings whether this charge is necessary at this time, and if so what the charge should be. The OCA assumes that an average DG customer exports 50% of generation from the DG resource.[234] In light of generally used DG "right-sizing" parameters, this percentage seems high and is in any case not well- supported in this

[232] NREL PVWatts® Calculator. http://pvwatts.nrel.gov/pvwatts.php.
[233] Attributes include array type, system losses percentage, tilt, azimuth, module type, etc.
[234] OCA Direct Testimony of Lon Huber, p. 27, lines 5-7. Eversource also estimated that DG customers export 50% of their DG resource's generation. See Exhibit RCL-RDJ-1, p. 2.

proceeding. If the Commission were to approve such a charge, it should be based on actual energy export data.

The Fixed Solar Credit Rate is proposed to be in place for a 20-year period once a new DG customer adopts the rate, even when increased DG penetration lowers the potential rate for new DG customers. The 20-year period could have been proposed in consideration of the lifespan of a solar DG facility, which is similar to utility planning initiatives such as some Power Purchase Agreements ("PPAs") between utilities and energy suppliers. However, this might be seen as a long period of time over which to lock in place any fixed credit rate without considering other potential dynamics such as DG penetration increases, DG cost and technology changes over the period, the effect of other new tariff revisions, or the effect of new or modified federal tax or state incentive policies.

The proposed initial cap limit seems sensible, since it allows for program growth control and is set up similarly to the current 100 MW cap allocated by utility.[235]

Another part of the OCA's proposed program that is not sufficiently explained is the suggestion that the rate to apply to all production from the DG resource rather than only its energy exports, although the proposal suggests the latter limitation may also be workable.

Additionally, the OCA envisions it would be possible for the credit rate of a large DG system to offset the fixed customer charge, an issue addressed earlier in this testimony with respect to grid export compensation. This concept was not explained by the OCA as

[235] OCA Direct Testimony of Lon Huber, p. 36, line 10.

to either its necessity or its intent, or whether it would be expected to exacerbate any customer-related cost-shifts to non-DG customers.

In regard to the credit rate tranche step-down mechanism, it is not clear how the credit rates by tranche were determined.

With respect to the proposed auction process to determine prices for larger scale DG projects, the general methodology and use of a reverse auction has merit; however, without more detailed information to support a maximum credit rate and size of auction round, it is difficult to evaluate potential sizes and costs.

Q. Does Staff have any suggestions or recommendations regarding the OCA's alternative NEM tariff proposals?

A. Staff recognizes and appreciates the substantial development effort that went into the OCA's proposed program designs, and some features, such as a graduated decline in fixed solar credit rates as the program grows and costs of DG technology decline, may have potential for improving the current net metering program. However, even though some of the OCA's proposals are intriguing and may have merit, they would require too much change and refinement in order to be implemented in the near-term, and in the aggregate also seem too complex for a short-term pilot program suitable for adoption in this proceeding.

11. City of Lebanon Proposal

Q. Please summarize the key arguments of the City of Lebanon's proposal.

A. City of Lebanon witness Below presents an "ideal" NEM tariff based on wholesale real-time pricing for consumption and exports. Under this real-time pricing tariff: (i) exported power would be credited at the New Hampshire Load Zone Real-Time LMPs, including generation and ancillary services billed with the LMPs, adjusted for avoided line losses; (ii) imported power would also be charged at the same Real-Time LMPs, including a markup to cover billing and overhead costs; (iii) FCM charges would be charged or credited depending on the DG customer's net load or production during the hour each year of the ISO-NE system coincident peak; (iv) transmission charges would be charged or credited depending on the DG customer's load during the monthly coincident peaks of the transmission system; and (v) distribution rates would be made revenue-neutral by customer class and collected as demand charges, which would be based on share of coincident peak or customer peak during hours in a year when the peak is likely to occur.[236] This new tariff is intended to lead to an effective decoupling of the utility distribution revenue requirement.

Q. What are the potential issues with the City of Lebanon's proposal?

A. Even though this solution comports with cost causation principles, as it is based on wholesale market costs and avoided cost benefits, the implementation would take some time and would require bi-directional metering and billing system modifications or upgrades. In addition, this tariff contemplates using a demand charge for the distribution rates, which, as was discussed earlier in my testimony, is not sufficiently supported at this time for residential DG customers.

[236] City of Lebanon Direct Testimony of Clifton C. Below, p. 7, lines 188-209.

Q. Does Staff have any suggestions or recommendations regarding the City of Lebanon's proposal?

A. Due to issues regarding implementation, in the near-term, this proposed alternative NEM tariff would be better adopted as a limited opt-in pilot program in order to allow for data collection and analysis in order to more thoroughly understand the effects on net-metered DG customers of real-time pricing and related demand charges. The potential administrative costs that may be incurred by Liberty or other participating utilities also should be taken into account in the design and implementation of any such pilot program.

D. Potential Pilot Programs

1. TOU Rate Pilot Programs

Q. Please summarize the key arguments of the parties in regard to implementation of TOU rate pilot programs.

A. Among the parties that commented on pilot programs, all agreed that a TOU pilot program would be helpful in collecting information to better understand customer behavioral changes related to time-based rate design.[237] Suggestions regarding a potential TOU pilot included shorter peak periods, allowing participation from all types of residential customers, limiting the overall participation level, and seasonal pricing considerations.

[237] NHSEA Direct Testimony of James Bride, pp. 26-27, lines 19-21 and 1-2.

The City of Lebanon proposed that the "ideal" tariff proposed by its witness could also be considered for adoption as a potential pilot program, because current metering and billing systems are not yet set up to accommodate real-time pricing for consumption and exports by DG customers. As a way around this problem, COL's suggestion is to use a competitive electric power supplier to administer the program while metering would be paid for by DG customers. Liberty would still bill all pilot program participants for T&D services, but a credit or a charge for transmission could be obtained through a transmission tariff rider based on the percentage of a customer's deviation from its class's average load shape, measured during each interval. Distribution charges would be billed based on net consumption through a coincident peak demand charge or TOU charge. Any customer that generated and sold RECs for all of its production would pay a RPS compliance adder, similar to the one in Liberty's default service rate. This pilot program is designed to last until 2040, so that long-term investments that occur during that time frame would continue to operate under the program terms for their project lifecycles.[238]

Q. What are the potential issues with the parties' arguments regarding the implementation of TOU rate pilot programs?

A. For a TOU rate pilot in general, allowing full participation from DG and non-DG residential customers would be the best way to collect relevant information about how time-based rates affect behaviors of participating residential customers. It is important, however, to limit program participation in some way, since this would only be a pilot program designed to collect data and the incremental costs to the utilities must be taken

[238] City of Lebanon Direct Testimony of Clifton C. Below, pp. 8-9, lines 210-250.

into account. An opt-in pilot program with a maximum subscription should be considered for adoption.

In addition, the length of the applicable TOU peak period is discussed only in terms of a potentially shorter time period than is currently used by the utilities, with a greater corresponding differential between the rates in that period compared to off-peak rates, in order to better incentivize customer behavior changes. The OCA is the only party that proposes a specific peak period for any TOU rates, running from 2pm to 8pm. The methodology to arrive at that time period, as discussed earlier in my testimony, appears to be reasonable based as it is on an analysis of the number of hours when system load was within 5% of each utility's annual system peak based on data provided by the utilities.[239] A seasonal TOU rate would also be appropriate in recognition of wholesale market energy price seasonality, changes in hourly coincident peaks by month, and the fact that ISO-NE system capacity requirements are set based on system peaks in the summer. A seasonal TOU rate also would provide better price signals to incentivize DG customers to shift load out of high-cost time periods. However, this type of rate is more complex for customers to understand and for utilities to implement, due to the number of rate changes throughout the year and changes to peak and off-peak periods. Before implementation of seasonal TOU rates, the price signal complexity of such a rate change should be weighed against the simplicity of a constant TOU peak rate period throughout the year. In any event, for purposes of customer understanding, and with regard to the consistency of resulting data generated statewide to be used in evaluating customer response, pilot programs implemented by the utilities should use similar TOU pricing periods.

[239] OCA Direct Testimony of Lon Huber, pp. 20-21, lines 4-10 and 1-15.

Regarding the City of Lebanon's proposed real-time pricing pilot program, it appears that even though COL would use a third party supplier due to Liberty's current metering and billing limitations, Liberty would still need to approve the proposed methods for billing of transmission[240] and distribution charges.[241]

COL witness Below contemplates that a TOU charge could be used for volumetric energy rates to create a better price signal, but he does not discuss any specific way to design the TOU rates for peak and off-peak periods.

The COL pilot program is proposed to last until 2040, which seems to be a long period of time to run a pilot, although the duration seems intended to preserve the economic value of long-term investments made while it is in effect. A TOU rate pilot program would need to be in effect long enough to collect the data necessary to better understand the effects of TOU rates on incentivizing customer behavior to shift load from high price hours to low price hours, but a considerably shorter pilot duration also could accomplish that objective.

Of course, the City of Lebanon represents just one municipality in New Hampshire. Even though the proposed pilot program would include certain surrounding communities, it may be more beneficial to have TOU pilot programs open to all residential customers

[240] Mr. Below is proposing a transmission tariff rider for participants of the pilot based on their measured interval deviation percentage from the customer class average load shape, where they would either receive a charge or credit with monthly differences being settled under Liberty's Transmission Cost Adjustment Mechanism. City of Lebanon Direct Testimony of Clifton C. Below, p. 8, lines 225-231.

[241] Mr. Below is proposing distribution charges either be billed over each month based on net load with no credit for net monthly exports, or through coincident peak demand charges and/or TOU volumetric components under a pilot tariff where hourly charges would be incurred for net consumption, with exports receiving little to no credit. City of Lebanon Direct Testimony of Clifton C. Below, p. 8, lines 231-236.

across the three utility service territories in order to cover a more representative sample of New Hampshire customers.

Q. Does Staff have any suggestions or recommendations regarding the implementation of TOU rate pilot programs?

A. Staff recommends that the Commission consider implementing a TOU or other time-differentiated rate pilot program or programs that would enable the collection of data on DG and non-DG residential customers and allow for the analysis of the effectiveness of different types of TOU rates[242] during different peak periods in signaling customers to alter their behavior by shifting usage from higher-cost to lower-cost periods. In addition, Staff recommends that the regulated utilities report to the Commission on the TOU or other time-differentiated rate pilot programs on a regular basis.

2. Localized DG Siting Pilot Program

Q. Please summarize the key arguments of the parties in regard to implementation of a localized DG siting pilot program.

A. Some parties supported a locational siting pilot program that would be focused on distribution feeders or circuits with high load levels as a way of implementing a non-wires alternative to upgrading the equipment.[243] It was also suggested that the utilities could create hosting capacity maps to increase the transparency of their systems and allow for targeted DG resource deployment. A locational siting pilot program would

[242] A well-designed TOU rate can help optimize DG systems by providing incentives to better align solar production with times of high market prices, and, in the future, even appropriately incentivize customer-owned energy storage.
[243] CLF Direct Testimony of Paul Chernick, pp. 35-36, lines 20-26 and 1-16.

encourage customers to invest in DG resources in a particular location on the utility distribution system, and information to be gained from the pilot would include "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)."[244]

Q. What are the potential issues with the parties' arguments regarding implementation of a localized DG siting pilot program?

A. Utilities would need to provide information regarding locations where DG resources could be considered as a non-wires alternative to investing in system upgrades. In addition to the need for the utilities to identify such locations, the utilities would also need to address potential non-wires alternatives as part of their system planning, especially if the capital investment plans would take time to develop and implement, which certain parties claim the utilities are not doing at a locational level.[245] The creation of hosting capacity maps could prove useful in identifying beneficial locations for potential future deployment of DG resources, but in the short-term it is not clear that the creation of complete and accurate hosting capacity maps is feasible based on the nature of the data currently collected by the three utilities.[246]

The utilities generally acknowledge that DG resources could provide a potential solution, or be incorporated as part of a solution, to address deficiencies in distribution capacity on a circuit or substation, as long as incentives or a tariff were put in place to facilitate DG

[244] EFCA Direct Testimony of Patrick Bean, p. 16, lines 1-5.
[245] EFCA Direct Testimony of Patrick Bean, p. 8, lines 12-16.
[246] Staff notes as well that a requirement for hosting capacity maps may be best considered in the context of the Grid Mod Docket.

resource deployment and the benefits provided by the DG resource were capable of measurement.[247] It does seem likely that incentives would be necessary to properly target DG resource deployment in the identified locations. No parties have currently proposed any specific ideas for how to design a locational siting pilot program, provide incentives for targeted DG resource development, or accurately measure the benefits resulting from that deployment.

Q. Does Staff have any suggestions or recommendations regarding implementation of a localized DG siting pilot program?

A. Staff recommends that the Commission consider adoption of locational siting pilot programs for DG resource development in concept, but an appropriate program design would need to be developed and implemented. A locational siting pilot program would allow all parties to gain better visibility into the utility distribution systems, better understand the ability of DG resources to positively impact the distribution system, enable the utility capital investment process to properly consider DG resources as potential non-wires alternatives, and be useful for the collection of further data on all of these matters. In addition, Staff recommends that the regulated utilities provide reports to the Commission regarding locational DG siting pilot programs on a regular basis.

3. Other Potential Pilot Programs.

Q. Please summarize the key arguments of the parties in regard to other potential pilot programs.

[247] Eversource Joint Testimony of Richard C. Labrecque and Russel D. Johnson, pp. 26-27, lines 20-22 and 6-14.

A. Among the parties that suggested potential pilot programs, none proposed any specific programs other than those already described. Some parties explained that any pilot programs implemented based on pricing or planning should be used to help the Commission make new tariff determinations and would permit the assessment of how other states, especially in New England, are implementing NEM policies and tariffs.[248]

The OCA offered its proposed alternative NEM tariffs as potential pilots, as long as customers that participated were required to stay in the program for at least one year to avoid gaming.

Q. What are the potential issues with the parties' positions regarding other potential pilot programs?

A. The primary reason to implement any pilot programs is to better understand how different rate structures and designs, as well as system planning, impact customer and utility behavior. Data collected from pilot programs should better inform the Commission on how DG customers are impacting the system through incremental costs and incremental benefits. Given the need for data collection and analysis of how different rates impact DG customers, it might also make sense to consider including optional coincident peak or other time-differentiated demand charges as part of a potential pilot program. By incorporating well-designed demand charges as part of a pilot program, data can be collected on their effectiveness and customer outreach and education may be monitored.

The OCA alternative NEM tariffs would be harder to implement as pilots based on the requirements the OCA proposes to set for how long the rates would be fixed for

[248] CLF Direct Testimony of Paul Chernick, p. 32, lines 1-8.

participants, as well as other administrative complexities. If these tariffs were implemented as pilots, new fixed rate periods would need to be set. In addition, the tranche rate-setting mechanism and MW thresholds should be altered to support a pilot program that would likely last 3-5 years or less, although it is possible it could continue longer depending on DG penetration levels.

Q. Does Staff have any suggestions or recommendations regarding other potential pilot programs?

A. Due to implementation issues, some of the possible pilot programs will not be feasible in the near-term, but versions of such programs could be considered in order to facilitate collection of data regarding DG customer behavior and system impacts that could lead to the development of different rates and structures in the future. The OCA proposals, however, seem to be currently infeasible as limited pilot programs.

Instead, the Commission might consider the potential benefits of a DG energy storage pilot program, to be developed and implemented by the regulated utilities on a limited, opt-in basis. This type of pilot could provide general system benefits such as frequency response, intermittency mitigation and peak demand reduction, as well as providing useful opportunities for additional data collection. In addition, Staff recommends that any other pilot program considered by the Commission include regular reporting by the utilities to the Commission.

E. Data Collection to Inform Future NEM Tariff Revisions and Refinements

1. *Identification of Significant Data Gaps*

Q. Please summarize the significant data gaps identified through this proceeding.

A. Most parties agree that there is a current lack of relevant interval data for DG customers that makes analysis of load shapes and impacts within each of the customer classes challenging[249] and has resulted in the use of data from other sources like PVWatts®. Some parties further contend that new meters capable of measuring DG production, in addition to bi-directional meters measuring power flows into and out of the utility system, are necessary to install for all new DG customers.[250] Unitil proposes new tariff rates and a new rate structure for residential DG customers. Eversource proposes a new rate structure as well, but focused more on new rate methodology, including the calculation and assessment of distribution charges on a per kW demand basis. Liberty proposes new rates, but it is not proposing a new three-part rate structure.

Other data that parties consider to be limited in this proceeding include load patterns on different parts of the utility distribution system, the effects of DG resources on distribution system loads including the incremental costs of maintaining system reliability, and future system technology for better metering and grid monitoring and control.[251]

Distribution system transparency is described by some as being a fundamental need to implement and assess pilot programs that would help in determining alternative rate designs.[252] Many of the data requirements involve obtaining specific system details to

[249] City of Lebanon Direct Testimony of Clifton C. Below, p. 9, lines 254-258.
[250] Liberty Direct Testimony of Heather M. Tebbetts, p. 21, lines 20-22.
[251] CLF Direct Testimony of Paul Chernick, p. 31, lines 1-12.
[252] EFCA puts forth a list, see Exhibit EFCA-PB-3, of data needed to be gathered in order to evaluate methods and inform decision-makers (originally presented by SolarCity witness Carlos Gonzalez in New York). EFCA Direct

model circuits, which includes loading and equipment details. In addition, in order to better understand how DG resources can offset investments in different locations, data is requested on the capacity projects planned by the utilities, voltage and power quality issues experienced in different locations, and data on reliability statistics to better understand circuit performance, resiliency, and other security needs that DG resources potentially may address.[253] Based on the data provided to date by the utilities in this proceeding, the utilities either have provided some of this information or would be capable of producing it. The creation of a hosting capacity map would serve to improve understanding of the utility distributions systems and the potential for DG resources to be targeted for the areas where they would have the greatest beneficial impacts.

2. Procedures and Timing to Obtain Needed Data

Q. Please outline proposed procedures and timing for data collection needed to make future NEM tariff revisions and refinements.

A. Most of the information needed is in the forms of utility distribution system data and customer data. In addressing the customer data gaps, the most important consideration is the utilities' requirement for metering that would enable recording of interval data for both grid imports and exports, i.e., a bi-directional meter, and potentially also production meters intended to measure gross DG resource production and enable calculations of total DG customer consumption. Meter implementation optimally should be completed

Testimony of Patrick Bean, p. 6, lines 17-25. Staff notes that many issues regarding distribution system planning and data transparency are currently under review in the Grid Mod Docket.

[253] EFCA Exhibit EFCA-PB-3, pp. 1-3.

concurrently with DG system interconnection, and may well be necessary to implement pilot programs to be administered in the nearer term. Collection of distribution system data by the utilities may require technology upgrades or system modifications in order to produce the detailed, location-specific circuit and substation level data necessary for creating a hosting capacity map or to enable system transparency in general, and the timing of such data collection may be extended depending on needed incremental investments that might occur during the implementation and duration of any pilots programs adopted as a result of this proceeding. Staff notes again that related issues involving system data collection and incremental technology investments are currently under review in the Grid Mod Docket.

3. Recommended Commission Action to Obtain Needed Data

Q. Please provide recommendations regarding the collection of additional data needed to inform future NEM tariff revisions and refinements.

A. The Commission should consider directing the utilities to implement bi-directional metering, and potentially DG production metering, for DG customers participating in approved pilot programs, as these actions would allow for the collection of DG customer data for both grid imports and exports and possibly DG resource gross production and total DG customer consumption. These metering installations would also allow potential TOU or other rate pilots to accurately assign cost causation, as well as study the impacts on DG customer behavior. The utilities could be directed to provide this metered data in annual or semi-annual reports to the Commission. Much of this data should also be relevant in connection with the various initiatives under review in the Grid Mod Docket.

Staff believes it would be beneficial for the utilities, other parties, and Staff to participate in working groups to develop the detailed plans and timelines for further data collection, any required metering and equipment procurement and installation, and the production and dissemination of the additional data collected.

The Commission should also consider in this proceeding and/or in the Grid Mod Docket directing the utilities to collect data on a circuit and substation level and to generate hosting capacity maps that would be available for online use or downloadable in order to identify beneficial locations for future DG development.

III. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize Staff's key conclusions and recommendations regarding the Commission's adoption of alternative NEM tariffs and related matters.

Based on the evidence provided and analyzed to date, the statutory criteria and related considerations relevant in New Hampshire, and the interim nature of the recommended path forward, the following is a summary of Staff's key conclusions and recommendations.

Staff recognizes and acknowledges that DG imposes costs and provides benefits that are demonstrable and quantifiable, and that well-designed and data-driven benefit-cost studies may prove useful in guiding the development of alternative NEM tariffs and rate structures. For the purpose of determining DG system costs and benefits in the context of New Hampshire's pending NEM tariff development, Staff believes that the embedded COS test year approach advocated by Unitil is inappropriate and that any relevant study must instead use marginal concepts. On the other hand, the benefit-cost studies performed on behalf of TASC using PCT, TRC, RIM and SCT calculations and assuming a 25-year DG system life cycle have flaws and limitations as described earlier in the testimony. Staff notes that the TRC test generally has been used in connection with the EE programs approved by the Commission and administered by the New Hampshire utilities, while the RIM test provides the most useful information regarding the extent of any potential cost-shifting. Staff suggests that a well-designed and properly conducted long-term avoided cost study using marginal concepts and incorporating both TRC benefit-cost test and RIM test criteria should prove useful in informing DG net metering program designs to be considered and approved by the Commission. The use of this suggested approach should not preclude consideration of any demonstrable and quantifiable net benefits associated with relevant externalities, provided that the potential for double-counting is adequately mitigated.

Staff believes that, in the longer term, time-differentiated rate designs for NEM tariffs applicable to DG customers, such as TOU rates or real-time pricing models, may hold promise and should be considered by the Commission. In particular, Staff has concluded that such time-differentiated rate structures would send better price signals to DG and non-DG customers than uniform energy rates or demand charges based on non-coincident peak maximum customer loads, for example. However, in view of: (a) the current general lack of interval metering for residential and small commercial customers and the complexity of implementing such a different rate design, (b) the current unavailability of significant relevant data regarding DG costs and benefits and the noted flaws and limitations in the benefit-cost studies provided in this proceeding, and (c) the current relatively low DG penetration level in New Hampshire, Staff recommends that in the near-term the current NEM structure be continued for a period of time with certain modifications made to the credit amount and the credit banking applicable to energy exported to the delivery system from DG customers. Staff recommends that any NEM tariff re-design that would cause applicable rates to be based on peak time periods or hourly intervals, such as hourly real-time prices, be deferred until more comprehensive data and improved metering and billing capabilities are available to support such changes to the NEM tariffs and applicable rates. Staff notes as well that these issues are currently being discussed in the Commission's Grid Mod Docket.

During the near-term period, Staff recommends that, for DG systems with capacity equal to or less than 100 kW, the applicable NEM credit for exported energy continue to be the utility's full retail rate with the exception of non-bypassable charges and assessments such as the systems benefits charge, stranded cost recovery charge, storm recovery surcharges, and state electricity consumption tax. For larger size systems with capacity greater than 100 kW up to 1 MW, the applicable credit for exported energy should continue to be the utility's default service rate only.

With respect to NEM credit banking beyond the end of the monthly billing cycle during which excess energy was exported, Staff recommends that the Commission consider limitation of credit banking such that any excess NEM credits then outstanding would be cashed out on an annual basis at a calculated avoided cost rate similar to that currently used under Puc 903.02.

Staff recommends that this near-term period alternative NEM tariff be in effect until the adoption of a new alternative NEM tariff or tariffs, which would be developed through a new Commission proceeding to be initiated following the first to occur of either: (1) the availability of sufficient relevant data to complete the avoided cost study described above, including any such data collected through approved pilot programs, (2) such time as the total capacity of DG systems operating under all NEM tariffs exceeds 10% of the total aggregate peak demands of the three regulated utilities for the preceding calendar year, or (3) a specified period of time, such as three years as an example. At that time, the Commission would initiate a new proceeding to develop the next version of an alternative NEM tariff or other regulatory mechanism for customers with newly installed DG systems.

Staff recommends that any NEM tariff should not separate DG customers into separate rate classes until sufficient, actual New Hampshire DG customer data has been presented to show that these customers impose significantly different costs on the system than other customers in the same rate class. Staff further recommends that the Commission not approve demand charges for residential DG customers at this time, and consider such demand charges only if and when: (a) they can be assessed on a TOU or coincident peak basis, (b) residential customers can be sufficiently educated regarding their operation and effect, and (c) metering and other technology improvements are installed to provide customers with real-time information regarding their kWh usage and kW demands and meaningful opportunities to control such usage and demand.

Staff strongly recommends that any near-term period NEM tariff should incorporate the same rate structures for all three regulated utilities, in order to allow for common implementation processes, as well as ease of program comparison, pilot program administration, and implementation of other potentially affected rate elements.

Staff recommends that the Commission consider approving tariff provisions that would maintain a particular NEM rate structure for a defined period of time (e.g., based on the useful life of DG system components such as 10, 15, or 25 years, or equivalent to a typical financing or lease period over which such systems are paid for) for those DG customers who secure a NEM capacity allocation within a specified time period before any future NEM tariff changes are implemented, all subject to monitoring and verification intended to deter impermissible later expansions or modifications or other unintended consequences. Such "grandfathering" provisions would provide rate structure certainty as a reasonable incentive for DG project investment.

Staff agrees with the majority of parties that support approval of a uniform lost revenue recovery adjustment mechanism for the utilities to recover lost revenue resulting from

NEM, based on reasonable estimated revenue losses unless and until the utilities are able to measure and calculate actual lost revenues due to NEM through improved metering capabilities. In the near-term, the lost revenue calculation methodology described in the settlement agreement filed in Docket DE 15-147 may serve as a reasonable model for a utility LRAM unless and until a better alternative approach is proposed and approved. Proposals for such a better alternative could be reviewed in the next NEM tariff development proceeding or in another more-focused proceeding.

Staff recommends that the Commission direct the regulated utilities to develop and implement two separate NEM pilot programs, each for a limited number of residential and/or small commercial customers on an opt-in basis: (1) a TOU or other time-differentiated rate pilot program, and (2) a locational DG siting pilot program targeted to segments of the utility distribution system on which DG installations would be expected to have a demonstrably positive impact. The Commission also should consider whether a DG customer energy storage pilot program may be developed and implemented by the regulated utilities. An energy storage pilot could provide general system benefits such as frequency response, intermittency mitigation and peak demand reduction. Each of these pilot programs would provide the opportunity for collection and publication of more comprehensive and detailed data regarding DG system costs and benefits, system planning, DG customer behavior, and the effects of alternative NEM rate structures. The utilities should submit the pilot plans to the Commission within 120 days of an order in this docket, and then file reports every 180 days regarding pilot implementation, data, and results.

Staff recommends that the Commission direct the regulated utilities to collect and make available specific and detailed data regarding at least a representative sample of DG customer load profiles, highlighting both consumption and DG output, and increases or decreases in DG customer energy usage and demand and energy imports and exports from DG systems to the electric grid over defined time periods. This data regarding DG customers and systems will be useful in informing future rate designs for alternative NEM tariff structures. Staff further recommends that the Commission direct the regulated utilities to collect and make available more detailed and specific data regarding operation of their distribution circuits, substations, and other system components, and the actual and potential effects of DG installations on such circuits, substations, and other components. This data regarding utility distribution systems should be useful in identifying and measuring relevant DG system costs and benefits, and also may form a basis for identifying locations where DG resources may avoid equipment replacement and other capital investments and/or locations where additional system upgrades may be required as DG penetration levels increase. The Commission might direct the utilities to provide all such data and information in annual or semi-annual reports to the Commission. Staff notes that much of the data proposed to be collected would also be relevant in the initiatives under review in the Grid Mod Docket. Staff recommends that working groups including the utilities, other parties, and Staff be convened to develop detailed plans and timelines for further data collection, any required metering and equipment procurement and installation, and the production and dissemination of the additional data collected.

Finally, Staff recommends that the Commission not require any material modifications to group net metering at this time, except as may be affected by the recommended revisions to the NEM credit amount or by the other recommended changes as are described in my testimony.

Staff believes that these recommendations are consistent with the criteria for consideration specified in RSA 362-A:9, XVI and with the legislative purpose statement in HB 1116. In particular, Staff believes the recommendations recognize that there are both costs and benefits of DG systems, but that current data unavailability and study limitations provide an imprecise quantification of such costs and benefits. Staff's recommendations also would serve to mitigate potential unjust and unreasonable cost-shifting in a measured manner, recognizing that the currently low levels of DG penetration in New Hampshire reduce the materiality of any such shifts. Staff's recommendations, including those suggesting a future proceeding(s) once better data is developed and pilot programs are undertaken, also would advance the legislative purposes stated in HB 1116 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 while ensuring costs and benefits are fairly and transparently allocated among all customers."

Q. Does that conclude your testimony?

A. At this time, yes.