BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET **DE 22-060**

IN THE MATTER OF: Electric Distribution Utilities
Consideration of Changes to the Current Net Metering Tariff Structure, Including Compensation of Customer-Generators

DIRECT TESTIMONY

OF

Elizabeth R. Nixon, Mark P. Toscano, Deandra M. Perruccio

New Hampshire Department of Energy

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Table of Contents

<u>Introduction</u>

Q. Please state your full names?

A. Elizabeth R. Nixon, Mark P. Toscano, Deandra M. Perruccio

Q. By whom are you employed and what is your business address?

A. We are employed by the New Hampshire Department of Energy (DOE or the Department). Our business address is 21 S. Fruit Street, Suite 10, Concord, NH 03301.

Q. Ms. Nixon, please summarize your education and professional work experience.

A. I joined the Public Utilities Commission (PUC or Commission) in August 2012 in the Sustainable Energy Division working on renewable energy issues. I completed electric utility rate training at New Mexico State University's Center for Public Utilities. In August 2016, I became a Utility Analyst in the Electric Division at the PUC, which is now DOE. In January 2022, I became the Electric Director in the Regulatory Support Division of the DOE. Prior to the PUC, I was employed at the NH Department of Environmental Services, Air Resources Division, from 1999 until 2012, in various positions. Prior to the joining the State, I worked as a consultant at ICF and AER*X, Inc. Throughout my career, I have focused on energy, environmental, and economic issues and analysis. I earned a B.S. in Mathematics from the University of Vermont. I have testified in various dockets – energy efficiency (DE 17-136, DE 20-092, DE 23-068), Liberty Utilities battery storage docket (DE 17-189), and Unitil's distribution rate case (DE 21-030). I have also provided recommendations or testimony in several other dockets, including grid modernization docket (IR 15-296) and electric vehicle rate design (IR 20-004, DE 20-170, DE 21-078).

Q. Mr. Toscano, please summarize your education and professional work experience.

A. I am a licensed Professional Engineer (PE) in the State of New York and New Hampshire and a Certified Energy Manager (CEM) through the Association of Energy Engineers (AEE). I earned a Bachelor of Science degree in Mechanical Engineering Technology from the New York Institute of Technology and an Associate's degree in Air Conditioning and Heating Technology from Farmingdale University. I was employed for approximately three years by the Long Island Lighting Company (LILCO), an investor-owned utility, where I worked as a Project Engineer for the implementation of energy efficiency and demand-side management programs. My primary activities included advising large commercial and industrial customers on demand reduction methods and the coordination of advanced metering installations. I was employed for approximately thirty-three years at the Brookhaven National Laboratory (BNL) in various roles including as a Project Engineer, Project Manager, Energy Manager, and the Manager of Energy Management and Utilities Engineering. BNL is a U.S. Department of Energy research facility in New York on a 5,200-acre campus with approximately 350 buildings and over 4 million square feet. I have significant experience with DER, solar PV systems, energy procurement, energy efficiency, and specifying, installing, and operating advanced metering and building automation systems. I joined the DOE's Regulatory Support Division in March 2022.

Q. Ms. Perruccio, please summarize your education and professional work experience.

A. I hold a BA in Global Studies from Assumption College, Massachusetts, and an MSc. in Community Development and Applied Economics from the University of Vermont. I have worked in research positions for universities as well as state agencies. I joined the PUC, which is now the Department, in 2017 as a Utility Analyst III (UA III) in the Sustainable Energy division. I completed electric utility rate training at New Mexico State University's

Center for Public Utilities. I was promoted to UA IV in 2020 and Administrator in 2022. As an Administrator in the Sustainable Energy Division, I oversee compliance and implementation of the state Renewable Portfolio Standard (RPS) as well as administration of state net metering policies. I worked as lead analyst in conjunction with the (then Public Utilities Commission) Legal Division on Puc 900 rules changes to incorporate changes to net metering following PUC Order, as well as changes to net metering due to legislation, and I regularly handle inquiries related to these rules and net metering/group net metering programs. I have worked as part of the facilitation team for studies directed through Order 26,029 in Docket No. DE 16-576 including the New Hampshire Locational Value of Distributed Generation (LVDG) Study as well as the Value of Distributed Generation (VDER) Study. I have previously presented live testimony before the Commission as a member of Commission Staff. See Docket No. DG 20-136, *Eversource Energy, Recovery Mechanism and Rate Treatment for Net Metering and Group Host Costs*. I have previously submitted pre-filed testimony before the Commission. See DE 21-036 *Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Petition for Approval of a Renewable Natural Gas Supply and Transportation Agreement.*

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to propose any changes to the current alternative net metering tariff given that the Value of Distributed Energy Resources (VDER) study and Locational Value Study of Distributed Generation (LVDG) study have been completed. In addition, recent statutory changes allow for municipal hosts to be customer-generators with total peak generating capacity of greater than 1 megawatt (MW) and less than 5 MW. Our testimony makes recommendations regarding the net metering tariff for these customer-generators greater than 1 MW.

Summary

Q. Please summarize your testimony.

A. In our testimony, we summarize the current net metering tariffs in use, including the standard tariff (NEM 1.0) and the alternative net metering tariff (NEM 2.0). We provide a brief summary of the two studies conducted to inform future net metering tariffs: the VDER study and the LVDG study. Finally, we provide the following observations and recommendations:

- The current alternative net metering tariff seems appropriate, as demonstrated by the results of the VDER study. Therefore, we recommend that the current alternative net metering compensation rate continue for all DG systems less than 5 MW. We propose that appropriate time of use (TOU) rates be reviewed and developed and implemented as the VDER study indicated that the value of DG systems can vary hourly, daily, or seasonally.
- We propose that the renewable energy portfolio costs and prior reconciliation be included.
- As shown in the VDER study, the bill impact analysis associated with the current alternative net metering tariff, which we propose to continue for all customer-generators, shows minimal cost shifting to non-DG customers.
- We do not currently see any reason to limit the amount of generating capacity eligible for net metering.

- With revenue decoupling and a reconciling mechanism, the utilities currently have timely recovery of any lost revenue, but note that per statute, the reconciling mechanism is to include the **net** effects, and the utilities have only calculated lost revenue without consideration of any benefits.
- In terms of administrative processes, we discuss application fees to allow for additional cost recovery, as needed. The utilities will also need to detail any additional administrative processes and associated costs (e.g., to update billing systems) that would need to be addressed with the proposed tariffs.

<u>Current Net Metering Compensation Rates</u>

Q. Please explain the current net metering compensation tariffs.

A. Currently, two net metering compensation tariffs are in place – NEM 1.0 and NEM 2.0. Generally, the standard net metering tariff (NEM 1.0) is the net metering tariff that is available to systems that were installed prior to September 1, 2017, and the alternative net metering tariff (NEM 2.0) is the net metering tariff available to systems installed beginning on September 1, 2017.

Q. Please summarize the current compensation rate under the standard net metering tariff.

A. The compensation rate for standard net metering customers is outlined on the Department website[1] and as excerpted below under the NEM 1.0 column in Figure 1 for small customer generators (up to 100 kW) and under the NEM 1.0 column in Figure 2 for large customer generators (greater than 100 kW and up to 1 MW).

[1] Microsoft PowerPoint - Net Metering Tariff 2023 Overview (nh.gov)

Figure 1. Summary of Current Net Metering Tariffs for Small Customer Generators

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charge (if applicable)	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	Full Credit	25% Credit
Transmission	Full Credit	Full Credit
System Benefits	Full Credit	No Credit
Stranded Cost	Full Credit	No Credit
Storm Recovery	Full Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

Volumetric charges based on kWh

"Non-bypassable Charges"

Under NEM 2.0 Tariff, these charges are applied to **all** kWh imports.

No credit is given for exported kWh.

Figure 2. Summary of Current Net Metering Tariffs for Large Customer Generators

Bill Component	NEM 1.0 (Standard NEM)	NEM 2.0 (Alternative NEM)
Customer Charge	Yes	Yes
Demand Charges	Yes	Yes
Default Service (Energy)	Full Credit	Full Credit
Distribution	No Credit	No Credit
Transmission	No Credit	No Credit
System Benefits	No Credit	No Credit
Stranded Cost	No Credit	No Credit
Storm Recovery	No Credit	No Credit
Credit Mechanism (end of each billing cycle)	Net kWh Carried Forward	kWh converted to monetary credit. Monetary credit carried forward as a bill credit.

Volumetric charges based on kWh

The standard tariff utilizes kWh crediting for the applicable line items as outlined in the credit mechanism section, and such credits remain on a customer bill until used in subsequent billing periods or may be monetized periodically at the utility avoided cost rate as allowed under RSA 362-A:9,V(b).

Q. Are customer-generators currently under the standard net metering tariff grandfathered?

A. Yes, until December 31, 2040, but the customer-generator may opt to change to a different tariff.

Q. Please summarize the current compensation rate under the alternative net metering tariff.

A. As shown in Figure 1 above, a small customer-generator receives a monthly monetary bill credit for any surplus generation based on monthly netting at a rate of 100% of the transmission rate, 100% of the energy service (default service) rate, and 25% of the distribution rate. A large customer-generator receives a monthly monetary bill credit for any surplus generation based on instantaneous netting at a rate of 100% of the energy service (default service) rate as shown in Figure 2 above.

Q. Are customer-generators currently under the alternative net metering tariff grandfathered?

A. Yes. As stated in Order No. 26,029 issued June 23, 2017, renewable energy distributed generation (DG) systems that are installed or queued during the effective period of the alternative net metering tariff, which began on September 1, 2017, will have their net metering rate structure grandfathered until December 31, 2040, including specific provisions regarding ownership transfers and system expansions.[2]

Net Metering Compensation Rate Recommendation

Q. Do you recommend any changes to the current alternative net metering tariff?

A. No. We recommend that the compensation rates for small and large customer-generators remain the same as the current alternative net metering tariff. A small customer-generator receives a monthly monetary bill credit for any surplus generation based on monthly netting at a rate of 100% of the transmission rate, 100% of the energy service (default service) rate,

[2] See Order No. 26,047 in DE 16-576.

and 25% of the distribution rate. A large customer-generator receives a monthly monetary bill credit for any surplus generation based on instantaneous (or over the course of an hour or less) netting at a rate of 100% of the energy service (default service) rate. We also propose the exploration of compensation rate options that encourages systems that will provide more benefits to the distribution and transmission systems, possibly through time of use (TOU) compensation rates or other mechanisms.

Q. What is the basis for your recommendation for keeping the current compensation rate?

A. In Docket DE 16-576, the Commission approved additional studies to be conducted to inform future review and potential changes to the net metering tariff. The studies included the Locational Value of Distributed Generation (LVDG) study and the Value of Distributed Energy Resources (VDER) study focusing on distributed generation (DG) that is eligible for NEM and is interconnected to a New Hampshire regulated distribution utility (i.e., Eversource, Unitil, and Liberty Utilities), particularly solar photovoltaic (PV) and hydroelectric generation.

Q. Please provide a brief background of the LVDG Study.

A. A Locational Value Study of Distributed Generation[3] (LVDG study) was directed in lieu of a Non-Wires-Alternative (NWA) pilot program which was originally proposed in Order No. 26,029 in DE 16-576. Commission Order No. 26,124 (April 30,2018) in DE 16-576 modified the proposed NWA pilot program to a study, finding that a distribution-level locational DG valuation study would be more useful and cost-effective, and directed the parties to evaluate study designs and methodologies to address the potential locational value of DG on the utility distribution system resulting from capital investment avoidance or

[3] DE 16-576 docket tab 249 Staff filing Locational Value of Distributed Generation Study Scope and Timeline

deferral, and operating expense reduction or deferral, such as through equipment life extension or lower maintenance and labor costs.[4] A study scope[5] was developed through stakeholder process, and approved by the Commission through Order No. 26,221[6] (February 20, 2019). After approval, Navigant Energy Consulting (now Guidehouse) was selected to perform the study, and a final study report was filed into DE 16-576 on August 21, 2020.[7] Administrative notice of the study was taken by the Commission in this docket on September 20, 2023.[8]

The LVDG study indicates significant potential cost avoidance related to distribution system capacity upgrades in future years, with $75 million in upgrade costs estimated from just 16 of the 122 constrained locations identified. However, these values are highly locational, as well as time-dependent and would require long-term dedicated, reliable, and sustained load reduction to be realized. This suggests that development of solutions related to significant distribution system capacity deficiencies may be better suited to more highly controlled compensation structures designed with focus on reliability such as a NWA program.

Due to the significant differences in the type and level of analysis required for a distribution-level LVDG, the LVDG study was conducted as a separate analysis from the VDER study. Findings from the LVDG study were designed to be used in conjunction with the VDER study to inform future NEM tariff development and DG compensation proceedings. The

[4] Order No. 26,142, April 30, 2018, page 15.
[5] DE 16-576 docket tab 249 Staff filing Locational Value of Distributed Generation Study Scope and Timeline
[6] Order No. 26,221, February 20, 2019
[7] DE 16-576 docket tab 294 Staff Locational Value of Distributed Generation Study Final Report
[8] DE 22-060 docket tab 1 Commencement of Adjudicative Proceeding and Notice of Prehearing Conference, pg. 3

LVDG study focuses on significant distribution system capacity deficiencies to be addressed through planned or potential capital investments, such as replacements or upgrades of substations or circuits. Small capital investments such as pole top distribution transformers and capacitors are included in the system-wide VDER study and are not covered in the LVDG study. In conclusion, we recommend that the LVDG study be used to inform specific projects under a NWA, but not to be used to inform locational specific net metering tariffs at this time.

Q. Please provide more details regarding your review and analysis of the VDER study.

A. The VDER study was directed by the Commission in Order No. 26,029. The study scope, criteria and general methodologies were developed through stakeholder process and approved through Commission Order No. 26,316. The study assessed the relative benefits and costs of net-metered DG from the perspectives of the utility system as a whole, participating NEM customer-generators, and other electric utility ratepayers. The assessment provides a 15-year future-looking estimate of the direction and magnitude of net avoided costs as well as the direction and magnitude of rate and bill impacts of DG deployment to identify any potential cost-shifting between customers with and without DG. It does not propose to represent an exact projection of future electricity rates and utility cost recovery, nor provide proposed exact compensation rates for NEM customer-generators. Based on this analysis, the Department concludes that the current net metering tariff structure reasonably meets the purpose statement of the bill resulting in the current alternative net metering tariff, HB 1116 (2016), "[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."

Net Metering Compensation Based on TOU Rates

Q. What do you propose regarding TOU rates?

A. As mentioned above, we propose that compensation rates based on TOU rates be reviewed, explored, and implemented to encourage systems that provide more benefits to the distribution and transmission systems. The VDER study highlights that a number of system-wide avoided cost values are time-varying. As indicated in the VDER study, DG systems provide benefits in general throughout the year as indicated in the average annual values, but DG systems can also provide additional value during certain hours of the day, month, and year. As the technology neutral values show, transmission charges and capacity have the highest maximum hourly values. When the production curves of the DG systems analyzed are applied to those technology neutral values, the annual Independent System Operator – New England (ISO-NE) peak demand appears to be the hour with the highest value with daily and monthly peak hours also having high values. A compensation rate with TOU periods could provide higher compensation at the high peak periods and lower compensation during the lower value hours or off-peak periods. The peak periods could shift as more DG systems, especially solar, are interconnected. DG systems with batteries could potentially provide more benefits and flexibility by providing generation during varying, beneficial time periods.

Q. Are you proposing new TOU rates?

We are not proposing new net metering-specific TOU rates as part of our testimony, but we recommend that appropriate TOU rates be explored and implemented. Some current TOU rates may be appropriate to offer to DG customers now.

Alternatively, or where no TOU rates are available for an applicable customer class or where the TOU rate should be updated, such as tariffs that have an on-peak period extending for 10-12 hours, we propose that the utilities be required to work with stakeholders to provide TOU rate options specifically for net metered customers with energy supply, distribution, and transmission time-varying rates based on company-specific cost data as well as the latest AESC study to aid in determining potential marginal costs for specific criteria to include in the compensation rate.

Compensation for Systems Greater than 1 MW

Q. What compensation rate do you propose regarding new customer-generators with total peak generating capacity greater than one MW?

A. As mentioned above, we propose that customer-generators with capacity greater than 1 MW and less than 5 MW maintain the current net metering tariff with a compensation rate of 100% of energy supply. We propose that the netting occur on an instantaneous basis.

Q. HB 1599 (2022), effective August 30, 2022 modified RSA 362-A:9, and proposed that other factors be considered regarding the compensation rate for systems greater than 1 MW. What are those additional factors, and do you have any additional recommendations regarding them?

A. RSA 362-A:9, XXIII, as amended by HB 1599 (2022), stated that various factors should be considered for inclusion or exclusion in the compensation rate, including but not limited to, the renewable portfolio standard (RPS) compliance costs and prior period reconciliations, and other services and values, such as avoided transmission, distribution, and capacity costs and other grid services. As we discussed above, we propose compensating for 100% energy supply. This proposed compensation rate includes the RPS compliance costs and prior period reconciliations.

Q. Election of Payment Under the Standard Net Metering Tariff. In the Commission's notice opening this docket, an issue to consider relates to election of payment under the standard net metering tariff, as indicated in SB 261 (2022), which modified RSA 362-A:9, V(b). Please provide your recommendation regarding this provision.

A. We recommend that the utilities may allow customers to opt for payment on a quarterly basis under the standard net metering tariff if the quarterly excess generation exceeds 600 kilowatt-hours (kWh). The customer-generator must specifically reach out to the utility when the customer believes the quarterly bank of kWh exceeds 600 kWh. The utility then verifies the total bank of kWh and calculates the quarterly payment amount and issues a check or electronic payment to the customer. Given the administrative cost to assess each customer-generator's kWh bank on a quarterly basis, to calculate the potential payment amount, and to issue payment, the Department believes that keeping the threshold the same for annual payments and/or quarterly payments is reasonable. In addition, given that many net metering systems under the standard net metering tariff, especially solar PV systems, were sized to meet annual consumption, keeping the threshold for annual and quarterly payment similar at 600 kWh seems appropriate.

RPS Costs

Q. The Commission's notice opening this docket indicated that one of the issues to consider regarding a net metering tariff is whether the cost of compliance with the electric renewable portfolio standard in RSA chapter 362-F, inclusive of prior period reconciliations, should be excluded from the monetary credit for exports to the grid. Please provide your proposal regarding RPS costs.

A. This provision, as stated in RSA 362-A:9, XXIII, regarding the cost of compliance with the renewable portfolio standard is specific to customer-generators with a total peak generating capacity of greater than 1 MW. We addressed this issue above.

Cost Shifting

Q. RSA 362-A:9, XVI(a) states that the Commission shall consider the following factors, among others, in evaluating alternative net metering tariffs: "balancing the interests of customer-generators with those of electric utility ratepayers by maximizing any net benefits while minimizing any negative cost shifts from customer-generators to other customers and from other customers to customer-generators; … an avoidance of unjust and unreasonable cost shifting; rate effects on all customers." Did you consider these factors in evaluating and reviewing your proposed net metering tariff?

A. Yes. As shown in the VDER study, the bill impact analysis associated with the current alternative net tariff, which we propose to continue for the small customer-generators, shows minimal cost shifting. For example, for an Eversource customer, the estimated average monthly bill impact is 1% or less. We believe that the net metering tariff meets the statutory directives including balancing the interests of customer-generators and all electric ratepayers because the DG systems will provide benefits for all ratepayers at minimal cost to non-DG customers. We believe that these rates avoid any unjust and unreasonable cost-shifting currently. We base this conclusion on the fact that for many of the costs incurred by the utilities for various projects and activities, such as those that are not related to net metering, customers do not all pay the same cost or receive the same benefit. The bill impacts at this time are not unreasonable. As more penetration occurs, the bill impacts and compensation rates should continue to be reviewed. In addition, with group net metering and potentially community power aggregation, participation in net metering is expected to become more accessible to more customers.

Application Fees

Q. What is your perspective regarding application fees being discussed as part of this proceeding?

A. The utilities recommend modest, standardized interconnection application fees in their testimony. Standardized interconnection application fees for customer-generator interconnection applications are utilized by electric distribution utilities in various locations across the country. The Department agrees with the joint utility testimony that standardized application fees can help increase the efficiency of processing applications and more equitably allocate costs. Further, they can assist the utilities in managing the variability of interconnection applications over time. The NH utilities cite in their testimony significant increases in applications in the last few years and the resulting increases in needed resources for processing.

Standardized application fees are considered one of the "best practices" by the Interstate Renewable Energy Council's (IREC) Model Interconnection Procedures. The IREC Model Procedures have been adopted by some states and used as references in several states' interconnection procedures.

We note that application fees are one of the subjects that was addressed as part of the Department's recent investigation, "IP 2022-01 - Investigative Proceeding Relative to Customer-Generator Interconnection."[9] The Department's report recommends the formation of working groups to address many DER interconnection issues, including application fees. However, the proposal by the joint utilities in this net metering docket is for a "modest" application fee for net-metering customer-generators that are less than 10 kW that pass the preliminary analysis screening (i.e., do not require a supplemental review or system impact study). The joint utilities state there are currently no application fees for these applications, and costs associated with processing the applications are included in the utility's rates.

Q. Do the NH utilities currently have fees for interconnection requests and processing?

A. Yes, depending on the size and complexity of the interconnection request. Interconnection requests that require a Supplemental Review and or System Impact Study incur charges/fees. The joint utilities indicate these costs are not included in the utility rates. These fees/rates for

[9] https://www.energy.nh.gov/rules-and-regulatory/investigative-proceedings

the utility Supplemental Reviews are based on the Puc 900 rules and included in the filed utility tariffs and interconnection-related documents.

Q. Does the Department have concerns regarding potential over-recovery or "double counting" of interconnection application fees?

A. Yes. To date, the proposal and material provided by the joint utilities is mainly illustrative and lacks details and cost history. However, the Department feels that with sufficient transparency regarding how costs are currently accounted for, and a detailed proposal by the joint utilities, this concern can be addressed.

Q. Does the Department believe addressing standardized net metering interconnection application fees as part of this proceeding is appropriate?

A. The Department observes there are aspects of addressing standardized net metering application fees that appear relevant as part of this proceeding. However, as mentioned above, the information provided by the joint utilities is illustrative and not fully developed. Several issues must be properly evaluated, including, but not limited to the following:

- How each utility currently accounts for interconnection-related costs.
- What costs the application fees will offset (e.g., support for interconnection application portals such as PowerClerk®).
- Historical costs.
- Current recovery methods.
- Whether the joint utilities believe service levels will be improved regarding processing time, reduction of errors and omissions, etc.
- If utilities and non-utility organizations are willing to commit to enforceable timelines for interconnections.

The Department notes that during the Department's recent IP 2022-001 investigation regarding customer-generator interconnection virtually all stakeholders expressed a desire to make near-term improvements to customer-generator interconnection processes that will not require statutory changes. Standardized application fees for small customer-generators less than 10 kW is one of the IP 2022-001 investigation topics that may be able to be addressed as part of this proceeding, or through the modification of Puc 900 rules.

Given the numerous issues that need to be addressed regarding application fees, the Department believes the recommended working groups from the IP 2022-001 investigation are the most appropriate place to develop standardized customer-generator net metering application fees.

<u>Other Considerations for the Net Metering Tariffs</u>

Q. RSA 362-A:9, XVI(a) lists several factors in addition to what has already been addressed above to consider when reviewing and developing alternative net metering tariffs. These factors include whether there should be any limitations in the tariff availability within each electric distribution utility's service territory; whether there should be a limitation on the amount of generating capacity eligible for such 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. Please comment on these additional factors.

A. At this time, we do not see any reason to limit the amount of generating capacity eligible for net metering. Currently, two of the distribution utilities have a revenue decoupling mechanism, and the third utility (which currently has a lost revenue recovery mechanism) must propose a revenue decoupling mechanism during its next distribution rate case. Pursuant to RSA 362-A:9 VII and Puc 903.02 (v), a distribution utility may perform an annual calculation to determine the **net** effect of the net metering tariff on its default service and distribution revenues and expenses in the prior calendar year. The **net** impact can then be collected or credited in a reconciliation mechanism after approval. Therefore, per the statute and rules, the utilities presently, have timely recovery of lost revenues either through revenue decoupling or a reconciling mechanism. Note, however, that in any reconciling mechanism approved to recover the lost revenues, the utilities have not proposed any benefits to consider in determining the **net** effects, and therefore, should be required to provide the **net** effects in any future filings. In terms of administrative processes, we have discussed application fees above to allow for additional cost recovery as needed. The utilities will need to detail any additional administrative processes that would need to be addressed, such as implementation of possible TOU rates for customer-generators. If certain costs required to implement additional administrative processes are excessive, such as the costs to update billing systems, then possibly a less expensive workaround could be used until more appropriate updated systems are in place that allow for the flexibility to accommodate any necessary changes.

Conclusion

Q. Please summarize your recommendations regarding the net metering tariff compensation rate and related considerations.

A. We recommend the following regarding future net metering tariffs:

- We recommend that the current alternative net metering compensation rate continue for all DG systems less than 5 MW.
- We propose that customer-generators can be placed on appropriate TOU rate, if available, but if the utilities do not currently have an appropriate TOU rate for a customer class, then stakeholders and the utilities should work to develop an appropriate rate.
- We propose that the renewable energy portfolio costs and prior period reconciliation be included.
- We believe that the net metering tariff balances the interests of customer-generators and all electric ratepayers because the DG systems will provide benefits for all ratepayers at minimal cost to non-DG customers. We believe that these rates avoid unjust and unreasonable cost-shifting.
- We do not propose any limitations on the amount of generating capacity eligible for net metering.
- We recommend that the development of standardized application fees be addressed in the working groups to be established as part of the Department's interconnection investigation in IP 2022-001.

Q. Does this conclude your testimony?

A. Yes.