STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 16-576

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

Order Approving Scope of Locational Value of Distributed Generation Study

O R D E R N O. 26,221

February 20, 2019

In this order, the Commission approves the scope and timeline of a locational value of distributed generation study. The purpose of the study is to inform future net metering tariff development. Commission Staff is directed to issue a request for proposals to engage a consultant to perform the study and submit the results to the Commission.

I. PROCEDURAL HISTORY

In Order No. 26,029, issued in this docket on June 23, 2017 (June 2017 Order), the Commission approved the adoption of a new net metering tariff, designed to be in effect for a period of years while additional data is collected and analyzed, pilot programs are implemented, and a value of distributed energy resource study (VDER Study) is conducted. Renewable energy distributed generation (DG) systems that are installed or receive a net metering program capacity allocation during that period of years while studies and pilots are conducted and prior to tariff revisions will have their net metering rate structure grandfathered until December 31, 2040.

With respect to the VDER Study, the Commission specified certain parameters for its design and performance, stating that

> it should be a long-term avoided cost study using marginal concepts and incorporating both TRC [Total Resource Cost] and RIM [Rate Impact Measure] test criteria, and it may also include consideration of demonstrable and quantifiable net benefits associated with relevant externalities (such as

> environmental or public health benefits), provided that the potential for double-counting of such externalities is adequately mitigated. With respect to double-counting of externality benefits, if a potential DG benefit is included in wholesale electricity market price formation, either directly or indirectly, then it should not be included in the study scope.

June 2017 Order at 60. The VDER Study should focus primarily on solar photovoltaic (PV) systems and hydroelectric facilities, and should use a methodology that is "generally consistent with that used to evaluate energy efficiency resource standard program investments." *Id.* at 60-61. The Commission determined that the VDER Study period should be 10-15 years, consistent with typical system planning horizons, and should include present value analysis using appropriate discount rates. *Id.* at 61.

The June 2017 Order also required the development of non-wires alternative (NWA) pilot programs focused on DG system deployment to avoid or defer utility distribution system upgrades. *Id.* at 63-64. In Order No. 26,124 (April 30, 2018) (April 2018 Order), the Commission ordered Staff and the parties to suspend development of NWA pilot programs and instead focus on determining the locational value of DG to the utility distribution system through study and analysis of relevant data. April 2018 Order at 15.

The Commission directed Staff and the parties to evaluate alternative study designs and methodologies to address the potential locational value of DG on the distribution system. *Id.* The Commission expressly stated that stakeholders "should consider the potential merits of a distribution-level capacity valuation analysis, as in the Nexant Study, as well as other relevant studies and analyses." *Id.* at 15-16 (referencing *Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods,* performed in 2016 by Nexant, Inc., for Central Hudson Gas & Electric (Nexant Study)). The Commission also indicated that the locational value analysis might be addressed either through a separate study or within the scope of the VDER study, "depending on which approach is determined to be most effective and efficient." *Id.* at 15.

Commission Staff (Staff) conducted a series of stakeholder working group sessions to develop a study scope and timeline for the locational value study. On November 30, 2018, Staff filed its proposed Locational Value of Distributed Generation (LVDG) Study Scope and Timeline. A public comment hearing regarding the LVDG Study Scope and Timeline was held on January 2, 2019, and written comments were filed thereafter by January 9, 2019. Written comments were submitted by Vote Solar, Clean Energy NH (formerly known as New Hampshire Sustainable Energy Association), and Conservation Law Foundation (Joint Stakeholders); Acadia Center; and the Office of the Consumer Advocate (OCA).

Prior Orders, the LVDG Study Scope and Timeline, the public hearing transcript, comments from parties, and other filings and documents related to this matter, can be found on the Commission website at http://puc.nh.gov/Regulatory/Docketbk/2016/16-576.html.

II. POSITIONS OF THE PARTIES AND STAFF

A. Staff

Staff recommended that the LVDG study be conducted as a separate analysis from the VDER study, due to the "significant differences in the type and level of analysis required for a distribution-level LVDG." LVDG Study Scope and Timeline at 1. The study should focus on DG that is eligible for net energy metering (NEM), including solar, hydroelectric, and solar paired with energy storage. *Id.* at 1-2. Although the LVDG study results are expected to provide "technology-neutral load reduction values organized by time and location," the study should not include analysis of load reduction approaches, such as demand response and energy efficiency (EE) as these resources are not eligible for NEM. *Id.* at 2. The study should consider the value of avoided or deferred distribution investment costs due to capacity constraint elimination at a number of distribution system locations. *Id.* Potential avoided or deferred distribution costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks, should be considered on a system-wide level through the VDER study. *Id.* Staff emphasized that the LVDG study is intended to determine a locational and not a system-wide value for DG. *Id.*

Staff recommended that the LVDG study examine avoided or deferred investment costs over a 10-year timeframe, including a review of the last five years of load and investment data to establish historical expenditures. *Id.* Due to the increased uncertainty in forecast and distribution investment beyond five years, future projections should be limited to five years. *Id.* Staff noted in its November 30 cover letter to the proposed LVDG Study Scope and Timeline that a study approach based on "current utility distribution system planning processes and load forecasting" is generally preferred by stakeholders "to one based on the Nexant Study, and that preferred approach is reflected in the proposed study scope and timeline." To the extent available and possible, the study should use a baseline analysis for each utility using load-growth projections it developed for its planning processes. LVDG Study Scope and Timeline at 2. A high load growth scenario, representing the potential impact of beneficial electrification, including electric vehicles and electric heat pumps, should also be considered for inclusion in the study. *Id.*

The LVDG study should focus on the electric distribution system, including distribution lines, substations, and circuits. *Id.* at 2. No minimum upgrade investment cost threshold should apply for consideration of a location for further study. *Id.* at 3. The level of analysis should, however, exclude small program investments that are part of a "system benefit initiative," such as pole top distribution transformers and capacitors. *Id.* Those small program investments "may be included in the separate system-wide VDER analysis currently under consideration." *Id.* Projects to be considered for detailed study should include locations:

(a) that are identified through forward-looking load growth projections and the screening method outlined below using N-0 criteria;

(b) that are identified with capacity-related investments through review of five-year historical spending and planning materials;

(c) with identified N-1 reliability investment needs due to capacity constraints in five-year historical spending plans and established investments in forward-looking five-year capital investment plans; and

(d) with non-load growth-related investment needs (e.g., asset management) that include increases to capacity may be reviewed in order to examine incremental investment costs due to equipment capacity increases.

A number of methods should be employed to identify locations with a high probability of requiring investments over the study timeframe. *Id.* The study should be conducted through a three-step process. *Id.* at 3-6.

In Staff's view, the first step would identify specific locations for detailed analysis. Utility load growth forecasts should be used as the preferred approach when available. *Id.* at 4. If forecasts beyond available utility forecasts are needed, the consultant would work to incorporate weather forecasts, econometric forecasts, DG integration forecasts, as well as known future residential, commercial, and industrial significant load impacts as incorporated in each utility forecasting process. *Id.* Appropriate component criteria thresholds should be developed through distribution planning materials and forecast review or through work with utility planning departments to develop a list of distribution lines and circuits, and distribution substation capacities and their associated peak loading on each location. *Id.* Distribution assets forecasted to exceed the N-0 design criteria for capacity should be further reviewed, and identified N-1 contingency analysis violations should be reviewed for distribution circuits and lines, and substation projected forecasts. *Id.* Five years of historical planning and expenditure information should also be reviewed to identify current or recent criteria violations and associated investments related to load growth or reliability-based capacity-constrained locations for review. *Id.*

Once relevant locations have been identified through the screening process, the consultant would work with utility planning departments and Staff to review each specific location to confirm the existence of load-related violations or the need to relieve forecasted overload conditions. *Id.* That review should determine the extent to which existing and projected capacity investments were related to load growth or reliability-based capacity constraints (as opposed to asset management replacements or other unavoidable upgrades), and therefore could be addressed by peak load reduction through DG energy production. *Id.*

The second step would be the determination of avoided or deferred distribution investment costs for the identified projected and existing or historical locations. *Id.* at 5. Each location with projected or historical load-growth or capacity constraint-related issues should be analyzed to determine the necessary upgrade(s) and investment costs based on modeled load growth projections. *Id.* The analysis should identify component upgrades and costs, tracking the utility planning process as closely as possible, as well as load reduction levels required to avoid or defer upgrades. *Id.* Equipment replacements should be reviewed to identify possible incremental additional costs associated with capacity increases. *Id.*

The third step would be to assign monetary values by capacity-constrained hours for the identified locations and then “map” those hours to DG generation profiles. *Id.* That analysis should ascertain the ability of specific DG technologies to achieve avoided or deferred costs through load reduction during hours of actual or projected criteria threshold violation at the identified locations. *Id.* Utility information and guidance should be used to determine representative load profiles for specific locations, with additional data collection and analysis potentially required to develop accurate load profiles. *Id.* at 6. Representative load profiles would identify hours when load exceeds threshold cutoff (e.g., equipment thermal design rating), with avoided or deferred cost values allocated across the duration of the required load reduction. *Id.* A sample of DG electricity production profiles should be developed and "mapped" against the identified hours for each identified location to provide illustrative examples of DG contributions to load reduction. *Id.* The sample production profiles investigated for the study should include DG systems eligible for net energy metering, including solar, hydroelectric, and solar plus storage. *Id.*

Staff and the consultant engaged by the Commission to conduct the LVDG study would hold periodic stakeholder working group meetings, not less frequently than every two months, to provide status updates and answer questions during the study process. *Id.* The LVDG study is expected to commence during the second quarter of 2019, following engagement of the consultant, and is to be completed by the end of 2019. *Id.*

B. Joint Stakeholders

The Joint Stakeholders recommended that the LVDG study be framed so that information generated can be used efficiently to conduct complementary analyses for additional DER technologies, including demand response, energy storage, and emerging technologies, perhaps jointly with the grid modernization docket, IR 15-296. Joint Stakeholders' Comments at 1-2. They argued that a broader range of NEM-eligible technologies, such as small-scale wind, combined heat and power (CHP), and potentially other renewable generation technologies, should be studied; and that the study should assume that future solar and solar plus storage deployment would include smart inverters. *Id.* According to the Joint Stakeholders, the parties should be provided with regular updates, at least after each step in the study process, through in-person meetings where stakeholders have an opportunity to ask questions of the consultant. *Id.* at 2-3. They maintained that an "LVDG Advisory Group," including representatives of the utilities, the OCA, and other stakeholders be organized to facilitate opportunities for Staff and the consultant to seek feedback on the LVDG study, including technical and policy recommendations, data acquisition, analyses, and review. *Id.*

The Joint Stakeholders recommended that the LVDG study use a 10-year timeframe for both historical and forward-looking projections, instead of the 5-year forward projection timeframe proposed by Staff. *Id.* at 3. The study should also include a "counter-factual" analysis of the distribution system for the term of the study, as well as illustrative analysis or qualitative review of the long-term (e.g., 30 years) locational value of net-metered DG systems. *Id.* According to the Joint Stakeholders, the high load growth assumption based on "beneficial electrification" should also consider widespread adoption of space and water heating with heat pump technology in addition to electric vehicle adoption. *Id.* at 3. The study should remove existing DG systems from the historical load used in the load growth projections. Instead, those systems should be combined with the estimate for future DG deployment. *Id.* at 3-4.

C. Acadia Center

Acadia Center asserted that the LVDG valuation model should at a minimum be easily open to incorporating additional technologies at a later point. Acadia Center Comments at 1. The full range of NEM-eligible technologies should be considered in the study, including small scale wind and CHP. *Id.* The study should also consider the possibility of cost savings due to capacity decreases when evaluating potential equipment life extension value. *Id.* According to Acadia Center, the high load growth scenario should take into account potential heating electrification as well as vehicle electrification. *Id.* at 2.

D. Office of the Consumer Advocate

The OCA recommended that the Commission clarify that any inputs provided to the consultant by the utilities should also be circulated to the broader stakeholder working group. OCA Comments at 6. The consultant should submit a work plan based on the existing scope of work and any initial discovery responses, solicit comment on that work plan from working group members, and respond in the format of a brief memo to the working group explaining why any suggested revisions were either adopted or not adopted by the consultant. *Id.* Any work product relating to the first two steps of the LVDG study should be included within the overall study in a manner which is separate and apart from the $/kilowatt-year conclusions relating to locational value, "preferably in the form of an interim report." *Id.* at 10.

According to the OCA, a ten-year forward-looking forecast should be developed for the purposes of system planning, NWA identification, and locational value compensation, and that forward-looking analysis period should begin in 2020 rather than in 2019. *Id.* at 7. In order to accurately determine locational value, "sub-regional or even substation specific forecasts are preferred over a system-wide forecast." *Id.* at 7-8. The high load growth scenario to be studied should also include increased economic growth and electrification of other end uses that are projected to accelerate above their historical deployment, such as heat pumps. *Id.* at 9. The study should also include a low growth scenario based on decreased economic growth or increased investments in energy efficiency. *Id.*

The OCA recommended that, as the Commission considers the relevance and purpose of the third step of the LVDG study, it monitor trends in California, Rhode Island, and New York regarding "solicitation-based and tariff-based compensation for the locational value of DERs on the distribution system." *Id.* at 11-14. In particular, the Commission should review New York's *ex post facto* compensation structure as it considers "future [compensation] mechanisms for the mass-market DG customers on circuits which are projected to be capacity-constrained." *Id.* at 3, 13-14.

The OCA asked that the Commission deny the request of Public Service Company of New Hampshire, d/b/a Eversource Energy (Eversource) to limit discovery on its marginal cost of service study (MCOS Study). *Id.* at 4-6. Instead, the Commission should clarify that the parties will have the opportunity to serve discovery on each of the regulated electric utilities for a rolling period of one month following the order approving the LVDG study scope, and then again once the study consultant is engaged. *Id.* at 6.

E. Eversource

Eversource stated that the LVDG Study Scope and Timeline "fairly captures [its] understanding of the proposed study." *See* Transcript of Hearing on January 2, 2019, at 18. The remainder of Eversource's comments addressed the OCA's interest in conducting discovery on Eversource's MCOS Study. *Id.* at 18-22. Eversource represented that it is in the process of updating its MCOS Study in connection with the distribution rate case it plans to file this year. *Id.* at 19. Eversource proposed that any discovery on the MCOS Study be conducted as part of the rate case filing itself, instead of "having one round of discovery now on a soon-to-be-updated document that may or may not give the consultant what it seeks, and then a second round later on once the case has been filed." *Id.* at 20. In the alternative, if discovery on the MCOS Study will be conducted prior to the rate case filing, Eversource recommended that the Commission establish an appropriate scope and timeframe for that discovery. *Id.* at 20-21. The scope should be limited to matters relevant to the LVDG study, and the discovery timeframe should be restricted to ensure its completion before the consultant begins work and to avoid overlap with the rate case filing, because "discovery on two different studies at the same time would lead to confusion." *Id.*

F. Pentti J. Aalto

Pentti Aalto proposed an alternative pricing structure that would identify locational prices in real time, based on the assumption that it costs different amounts to deliver power at different locations and with different loads. *Id.* at 5. He proposed that the pricing of existing distribution system investment be structured as if it were a market, while at the same time providing sufficient revenue to meet utility revenue requirements. *Id.* at 6-7. Under his proposal, the costs of major components of the distribution system would be identified and revenue requirements determined for those components across the system as a whole. *Id.* at 8-9. The capacity and real-time usage of each such component would then be reviewed, generating ratios that would be multiplied by relevant loads and then divided by the applicable revenue requirement, to produce the number to be applied "per kilowatt-hour in real time to the price that [the] component adds to the system." *Id.* at 9. That calculation would be done automatically, and would require metering and communication at each of the major nodes. *Id.* at 9-10.

The locational aspect would be introduced by "adding up all of [those values] as you go down the system, from substation through the feeders and any branches." *Id.* at 10. The intent would be to provide a system that emulates a market price for a fixed asset in real-time, giving customers the opportunity to accept a real-time locational pricing structure and letting them respond through their selected technologies to shift load and make different choices about sources. *Id.* at 10-11. That voluntary pricing structure would provide "reasonable signals to customers as to how they might respond where they are," and give them flexibility and the ability to control their costs. *Id.* at 11. Ultimately, the applicable price would be a type of real-time price with potential adders for each of the phases of the distribution system. *Id.*

Mr. Aalto noted the general reluctance to provide real-time pricing to retail customers, while suggesting that a Commonwealth Edison (ComEd) program implemented in the Chicago area might serve as a useful model. *Id.* at 11-12. According to Mr. Aalto, ComEd has had residential hourly pricing for 15 years, now based on the hourly real-time price, and it also offers systems for customers to help manage their loads. *Id.* The pricing structure is based on locational marginal prices with a capacity component designed to meet customers' capacity obligations. *Id.* at 12. For customers willing to pay highly variable prices, the program provides benefits both to those customers and to the system as a whole. *Id.*

Mr. Aalto maintained that the purpose of such a voluntary pricing structure is to recover required revenues in a way that helps customers control their loads and make decisions based on the actual state of their locational prices. *Id.* Those prices may be higher in some locations and lower in others. *Id.* The pricing structure would provide the proper price signals going forward for storage and also identify values for other DERs "that would come directly out of the market, not out of the necessity to do some type of prescribed valuation." *Id.* at 13.

III. COMMISSION ANALYSIS

In the June 2017 Order, the Commission required actions be taken to collect data and develop a more comprehensive factual record to inform future net metering tariff modifications or alternative compensation mechanisms. Those actions included the performance of a VDER study and the implementation of NWA pilot programs. In the April 2018 Order, the Commission changed the focus of the locational value analysis from pilot programs to a study approach. We have now reviewed Staff's LVDG Study Scope and Timeline and the comments filed by a range of stakeholders, and find that Staff's proposed scope and timeline represent a reasonable and appropriate plan to ascertain the locational value of DG on utility distribution systems. We therefore approve that study scope and timeline, with the specific clarifications and modifications discussed below, and we direct Staff to engage a consultant to perform the LVDG study.

With respect to the parties' comments, we acknowledge that the proposed LVDG study scope does not cover the full range of NEM-eligible technologies. Instead, it focuses on solar with or without associated storage and hydroelectric plants, because those are the resources most commonly net-metered at this time. We note, however, that the third step of the study will involve mapping of DG production profiles to hourly locational values based on avoided distribution system upgrade costs. We encourage Staff to work with the consultant to develop and make available, if possible, a flexible and accessible valuation model that may be used to evaluate a number of NEM-eligible technologies other than those which are the focus of the study.

Regarding the assumption that so-called "smart inverters" will be installed in future solar PV systems, we find that assumption to be reasonable, provided it is not assumed that the inverters will be dispatched or otherwise managed in the aggregate. We note as well that the potential benefits of any such aggregation most likely will accrue on a system-wide basis, and therefore are not appropriate for inclusion in a locational value analysis such as the LVDG study.

We believe that Staff's proposal to limit the LVDG study period to 10 years, including 5 years of historical experience and 5 years of projected circumstances, is reasonable and should form the baseline for the study. That proposal recognizes the inherent uncertainty of longer-term projections of both system-wide and local load growth. We encourage Staff, however, to work with the consultant to determine whether an extended study period of a further five-year projection may be included as an additional option at a reasonable cost. It may be appropriate for the later years of such an extended study period to be subject to discounting to reflect the greater uncertainty.

With respect to the proposed high load growth scenario intended to account for future "beneficial electrification" through adoption of electric vehicles, we recognize that other electric equipment deployment may have similar effects. For example, electric heat pumps may increase electricity usage as customers switch from other heating fuels such as oil, propane, and natural gas. We encourage Staff to work with the consultant to determine whether heat pumps and other electric equipment, as well as the potential effects of greater than anticipated economic growth, should be included in the assumptions used for the high load growth scenario analysis. We also agree with the OCA that the study should include a low growth scenario to account for potential increases in levels of energy efficiency, conservation, and demand response, or for economic growth that is slower than expected. The inclusion of both high-load and low-load growth scenarios will serve to define sensitivity parameters around the baseline analysis.

A number of commenters asked us to require a more formal stakeholder input process than Staff has recommended, including the formation of an "LVDG Advisory Group" and the requirement that the consultant's specific work plans be proposed for stakeholder review and critique. We are concerned that such an additional stakeholder process may prove cumbersome and intrusive in connection with the performance of the study by the consultant engaged by the Commission and overseen by Staff, and may unnecessarily delay completion of the work. We believe that Staff's proposal to hold periodic stakeholder working group meetings to provide status updates and answer questions during the study process, at least once every two months, represents a reasonable approach to stakeholder participation. We will, however, address two points of clarification. First, we believe Staff should convene a stakeholder working group meeting in connection with any major step in the study process, even if that meeting would be held sooner than would otherwise occur under the bi-monthly schedule. Second, we direct Staff to provide to the stakeholder working group certain material documentation, such as any reports and analyses completed in connection with the first two steps of the study process, on an interim basis during the study period. We believe that periodic, substantive stakeholder briefings, along with the provision of material documentation as the study progresses, will balance the need for stakeholder input with the need for timely completion of the work required to complete the study.

With respect to other comments and proposed modifications suggested by parties, such as counter-factual scenarios and removal of existing DG installations from the analysis, we find that it is not appropriate to include those elements because they are overly speculative and inconsistent with the fundamental reliance on actual utility system planning processes. In addition, comments regarding the ultimate design of future tariffs, markets, or other compensation mechanisms are premature and beyond the scope of the LVDG study.

Finally, with respect to discovery regarding Eversource's MCOS Study, we agree with the OCA that it may contain information relevant to the LVDG study and related matters, both in the version filed in this docket in July 2018 and in the updated version expected to be filed with

Eversource's anticipated rate case. The most recent such studies prepared by the other two regulated electric distribution utilities[1] may also contain information relevant in this proceeding. We therefore find that the parties should have the opportunity to serve discovery on each of the three regulated electric distribution utilities for a rolling period of 30 days following the date of this order, and then again on Eversource alone for a rolling period of 30 days once Eversource's updated MCOS Study is filed later this year. We also direct Eversource to file in this docket its updated MCOS Study, and a summary of the material changes between the original and updated versions of that study, at the same time the updated MCOS Study is filed in its rate case.

Based upon the foregoing, it is hereby

ORDERED, that Staff's proposed Locational Value of Distributed Generation Study Scope and Timeline, with the modifications and clarifications specified in the body of this order, is approved and Staff is directed to engage a consultant to perform that study; and it is

FURTHER ORDERED, that the parties shall have the opportunity to engage in two rounds of discovery regarding the Eversource MCOS Study, the first round to be completed within 30 days of the date of this order and the second round to be completed within 30 days of Eversource's filing of an updated version of its MCOS Study; and it is

FURTHER ORDERED, that the parties shall have the opportunity to engage in discovery regarding the most recent marginal cost of service studies of Liberty and Unitil, to be completed within 30 days of the date of this order; and it is

FURTHER ORDERED, that Eversource shall file in this docket its updated MCOS Study, and a summary of the material changes between the original and updated versions of that study, at the same time the updated MCOS Study is filed in its anticipated rate case.

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[1] The other two regulated electric distribution utilities are Liberty Utilities (Granite State Electric) Corp., d/b/a Liberty Utilities (Liberty), and Unitil Energy Systems, Inc. (Unitil).

By order of the Public Utilities Commission of New Hampshire this twentieth day of February, 2019.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Debra A. Howland
Executive Director