STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2016-00222

March 1, 2017

PUBLIC UTILITIES COMMISSION
Amendments to Net Energy Billing Rule
(Chapter 313)

ORDER ADOPTING RULE
AND STATEMENT OF FACTUAL
AND POLICY BASIS

VANNOY, Chairman; McLEAN and WILLIAMSON, Commissioners

I. SUMMARY

Through this Order, the Commission adopts amendments to the net energy billing rule (Chapter 313). Specifically, the Commission amends the rule to reduce over time the amount of a generation facility's output that can offset, or be netted against, the transmission and distribution (T&D) utility portion of a customer's bill. Netting regarding the supply portion of the customer bill remains unchanged. Under the amended rule, the phase down will apply to facility installations on or after January 1, 2018, and existing net energy billing customers will be grandfathered for a fifteen year period.

II. BACKGROUND

A. Net Energy Billing Rules

Chapter 313 of the Commission's rules governs net energy billing (NEB) in Maine. NEB is a metering and billing mechanism that is generally used to promote the development and operation of small renewable generation facilities. Under Chapter 313, customers that own or have an interest in an eligible generation facility are billed for electricity on the basis of "net energy" over a billing period. Net energy is defined in the existing rule as the difference between the kilowatt-hours (kWhs) a customer consumes and the kWhs produced by that customer's generating facility over a billing period. Excess generation from a customer's generating facility in a given billing period may be used as a kWh credit to offset that customer's electricity usage in a future billing period when the customer's facility did not generate enough to offset the customer's electricity usage. Excess kWh credits can be used to offset customer usage over a twelve month period.[1] The Commission first adopted a net energy billing rule in the early 1980s and significantly modified it in 1998 to adapt the rule to industry

[1] For a more detailed description of net energy billing *see Maine Public Utilities Commission*, *Commission Initiated Inquiry Into Market-Based Solar Policy Design Stakeholder Process*, Docket No. 2015-00218, Report to the Legislature Regarding Market-Based Solar Policy Design Stakeholder Process (Feb. 3, 2016).

restructuring. *Order Adopting Rule and Statement of Factual and Policy Basis*, Docket No. 2004-396 (Sept. 8, 2004).

As the Commission has consistently recognized, NEB supports State energy policies in favor of the promotion and development of renewable, diverse and indigenous electricity supply resources that do not rely on fossil fuels and do not contribute to greenhouse gas emissions.[2] Additionally, the 126th Maine Legislature found "that it is in the public interest to develop renewable resources, including solar energy, in a manner that protects and improves the health and well-being of the citizens and natural environment of the State while also providing economic benefits to communities, ratepayers and the overall economy of the State."[3]

The Commission has also consistently recognized that the NEB mechanism results in a shift of T&D utility revenue responsibility from NEB customers to non-NEB customers with corresponding impacts on the rates of non-NEB customers.[4] For this reason, to ensure costs are examined, Chapter 313 contains a provision for the review of the NEB rules.[5] Section 3 (J) of Chapter 313 specifies:

> **Commission Review**. A transmission and distribution utility shall notify the Commission if the cumulative capacity of generating facilities subject to the provisions of this Chapter reaches 1.0 percent of its peak demand. Upon notification, the Commission will review this Chapter to determine whether net energy billing pursuant to this Chapter should continue or be modified.

[2] For a full discussion of the history and operation of NEB in Maine, including costs and benefits, *see* Maine Public Utilities Commission, Report on Net Energy Billing, submitted to the Legislature on January 15, 2009.

[3] 35-A M.R.S. § 3472(1).

[4] Several commenters argue that there is no cost shift, that the Commission has not conducted an analysis of the amount of any cost-shift, and that any cost-shift is outweighed by the benefit of solar installations. These matters are discussed in section III(B)(1), below.

[5] As stated in the Commission Orders that initially adopted and modified the review trigger provision, the purpose of the provision is to assure that reexamination occurs as NEB costs increase over time. *Public Utilities Commission, Customer Net Energy Billing (Chapter 313)*, Docket No. 98-621, Order Adopting Rule and Statement of Factual and Policy Analysis at 11 (Dec. 10, 1998); *Public Utilities Commission, Amendments to Net Energy Billing Rule to Allow Shared Ownership (Chapter 313)*, Docket No. 2008-410, Order Adopting Provisional Rule and Statement of Factual and Policy Basis at 13 (Jan. 8, 2009).

B. Commission Inquiry

On January 14, 2016, Central Maine Power Company (CMP) filed a letter stating that, at the end of calendar year 2015, the cumulative capacity of the generating facilities for which CMP has net energy billing agreements under Chapter 313 is approximately 1.04% of CMP's annual peak demand.[6] At that time and related to the 1.04%, CMP identified forgone T&D revenue of over $1.2 million. Consequently, CMP requested that the Commission undertake the review of net energy billing required by Section 3(J) of Chapter 313.

In response to the CMP letter, the Commission, on June 14, 2016, issued a Notice of Inquiry to obtain comment and information from interested persons regarding Maine's NEB rules and whether the rules should be modified in light of changes in small renewable markets, technology developments and costs. *Maine Public Utilities Commission*, *Commission Initiated Inquiry into Net Energy Billing Rules (Chapter 313)*, Docket No. 2016-00120, Notice of Inquiry (June 14, 2016). The Commission received written comments from the following interested persons: David Russell, Maine Association of Building Efficiency Professionals, Conservation Law Foundation, Acadia Center, Governor's Energy Office (GEO), Revision Energy, LLC, The Nature Conservancy, Central Maine Power Company, Emera Maine, Clean Energy Collective, LLC, Energy Freedom Coalition of America, Natural Resources Council of Maine, Sunrun, Inc., Office of the Public Advocate (OPA), Municipal Street Lighting Group, Ethan Strimling, Mayor of Portland and Jon Hinck, City Councilor, legislators and several joint respondents. The Commission also received a large number of public comments. The OPA and GEO recommended fundamental changes to the NEB rules and several interested persons suggested more moderate changes to improve the current rules. Many of the commenters urged the Commission not to initiate a rulemaking proceeding or make any changes to NEB.

C. Rulemaking Process

On September 14, 2016, the Commission issued a Notice of Rulemaking (NOR) and a proposed rule that contained several proposed amendments to the net energy billing rule (Chapter 313).[7] The proposed amended rule would reduce over time the amount of the output of a generation facility that could be netted against the T&D portion of a customer's bill (referred to as "nettable" energy). No change was proposed for the supply portion of the bill. The proposed amended rule grandfathered existing

[6] CMP stated that the 1.04% is based upon the ratio of 16.261/1,565.300, where the numerator is the megawatts of nameplate capacity of contracted net energy billing facilities and the denominator represents the Company's 2015 annual hourly peak demand.

[7] Hereinafter, proposed amended rule refers to the rule included in the September 14, 2016 NOR and amended rule refers to the rule as approved by this Order.

NEB customers for a fifteen year period. In addition, the proposed amended rule increased the maximum size for an eligible generating facility from 660 kilowatts to one megawatt and added specific provisions that would allow and provide consumer protections for community net energy billing and net energy billing leases.

The reduction over time in nettable energy would reduce, and ultimately eliminate, the shifting of T&D costs from NEB customers onto non-NEB customers. In addition, the proposed reduction in nettable energy tracked the continuing declining costs of renewable technologies, in particular solar photovoltaic (PV) technology.

Consistent with rulemaking procedures, the Commission held a public hearing on October 17, 2016 and received written comments on the proposed amended rule. The Commission received comments from the following: Office of Public Advocate (OPA); Governor's Energy Office (GEO); Central Maine Power Company (CMP); Emera Maine, Industrial Energy Consumer Group (IECG); Natural Resources Council of Maine (NRCM); Conservation Law Foundation (CLF); Maine Audubon; the Nature Conservancy, A Climate to Thrive (ACTT); American Lung Association; Revision Energy, LLC; Maine Association of Building Efficiency Professionals (MABEP); Clean Energy Collective, LLC (CEC); Sunrun, Inc.; Maine Community Solar Farm Association (MCSFA); Solar Energy Association of Maine (SEAM); Arrowsic Conservation Commission (ACC); Islesboro Energy Team (IET); Ashley Brown, Harvard Electricity Policy Group; Barbara R Alexander, Consumer Affairs consultant; Ahmad Faruqui, The Brattle Group.

The Commission also received a large number of public comments from individuals and groups (including customers both with and without solar facilities) which primarily supported solar incentives to address climate change and promote jobs in the solar industry. These comments were in opposition to changes to the NEB rules.[8] Other individual commenters supported changes to the NEB rules to minimize impact on non-NEB customers.[9]

[8] Many individual commenters make the erroneous assumption that proposed changes are to the benefit of the utilities. Under traditional utility ratemaking, utility rates are based on actual costs and are established to provide utilities with an opportunity to earn a reasonable return on their investments. Therefore, although lost revenue may be borne temporarily by a utility between rate cases, the revenue requirement is ultimately shifted to other customers. Moreover, under certain ratemaking mechanisms, such as the revenue decoupling mechanism currently in place for CMP, lost revenues are automatically recovered from customers through an annual adjustment to rates.

[9] The Commission also received comments regarding CMP's recent decision to require that each NEB account be assigned a specific percentage of the output of generating facilities. CMP also requested that, to the extent that NEB customers are allowed to hold multiple accounts, the NEB customers be prohibited from shifting banked credits between those accounts. These matters were not raised in the NOR or the proposed amended rule and will not be addressed in this proceeding.

The Commission addresses the comments it received in this rulemaking process relative to each issue in the following sections.

III THRESHOLD MATTERS

Several threshold matters were raised in the rulemaking process. These are discussed below.

A. Consideration of NEB Rule Changes

Several commenters, including NRCM and Sunrun, commented, as they did in the Inquiry, that the Commission should not pursue changes to its NEB rules because it is the Legislature's role to determine State energy policy and the Legislature is expected to consider solar policies. Other commenters supported the consideration of NEB rule changes, including the OPA, GEO, CMP, Mr. Brown and Ms. Alexander. Comments in support of rule changes included providing an appropriate subsidy for small solar installations, while minimizing the rate impact on other customers, including low income customers.

Fundamentally, it is the role of the Legislature to establish energy policy.[10] However, it is the Commission's responsibility to continually monitor and review rules it has promulgated and to update or modify them in light of changed circumstances. This is especially the case when a rule implements a program that raises costs to ratepayers in general; and here, the rule explicitly directs review. In this case, a failure to change the NEB rules would result in an ever increasing incentive going to NEB customers (funded by non-NEB customers) as retail rates increase and the cost of the technology decreases. Such an approach would be inefficient and would provide little or no market-based incentive to drive down the installed cost of facilities, nor for solar installers to flow through any cost reductions that are realized to customers. Solar installers, like most for-profit businesses, set their prices based on what the local market will bear, which is not necessarily in line with actual costs. The predominant NEB technology in Maine is solar PV. Because PV costs have been declining and are projected to continue to decline substantially, economic efficiency dictates that NEB should be structured so that any incentive reflects these cost trends.[11]

[10] In its January 8, 2009 Order Adopting Rule, the Commission recognized that fundamental decisions regarding the structure of NEB is ultimately a question of State energy policy to be determined by the Legislature and that the consideration of rule changes by the Commission can be helpful to the Legislature in this regard. *Public Utilities Commission, Amendments to Net Energy Billing Rule to Allow Shared Ownership (Chapter 313)*, Docket No. 2008-410, Order Adopting Provisional Rule and Statement of Factual and Policy Basis at 3-4 (Jan. 8, 2009).

[11] The declining cost trends of solar PV installation are discussed in section III(B)(3) below.

This situation is not unique to Maine. For example, according to the NC Clean Energy Technology Center, which publishes a comprehensive quarterly update on state solar policies across the country, "At the state level, the general trends are that solar rebate incentives are decreasing, solar tax incentives are expiring, renewable portfolio standards are nearing their targets, net metering caps are being reached, and net metering and rate design are undergoing regulatory and legislative review." *The 50 States of Solar*, NC Clean Energy, 5 (Q3 2015).

Thus, in light of the undisputed substantial cost reductions for small renewable generation (particularly solar PV) and the growing cost shift to non-NEB customers as the number of NEB facilities increase, the Commission concludes that it is now appropriate to consider and adopt amendments to its NEB rules to over time reduce the incentives for new NEB customers, and to reduce the corresponding impact on the rates of non-NEB customers. The reductions will be phased in over a ten year period.

B. Costs and Benefits of NEB

Many commenters, including the NRCM, MABEP, MCSFA, Sunrun, SEAM, ACTT, Revision, Nature Conservancy, ACC and IET strongly oppose any change to the NEB rules that would reduce the monetary benefits to NEB customers. These commenters generally state that the Commission failed to conduct an analysis of the benefits and costs of solar installations and has no factual record to support changes to the NEB rules or the conclusion there is any harm to ratepayers (such as cross-subsidization). Commenters also stated that NEB customers are not receiving the value their installations provide to the system, including climate change benefits, and that the Commission did not consider its own value of solar study. The IECG suggested that Commission conduct an investigation to consider whether the benefits outweigh costs and to determine if a cost shift occurs. Others commented that the rule should be modified to lessen the rate impact to customers that do not have their own generating facilities.

There are three basic categories of cost and benefit issues related to NEB. These are: 1) current and ongoing cost shifts from NEB to non-NEB customers and the resulting rate impacts; 2) longer-term system value provided by NEB facilities; and 3) declining technology costs. These are discussed below.

1. Costs Shifts and Rate Impacts

NEB customers, as all customers, use and benefit from the T&D system but, as a result of the rule's billing mechanisms, do not pay the full costs for this use. Specifically, the only time an NEB customer is not using the T&D system is at those instantaneous points in time when their load exactly matches their generation output. At all other times

NEB customers are either importing or exporting energy from or to the electric grid.[12] In this case, the customer is using the T&D system in lieu of its own battery system. Under current NEB, rather than paying for its use of the T&D system at a given time, the customer's generation and usage would be netted against each other over the billing period and the customer would be billed only for any net kWh usage.[13] Because the costs of the T&D system to serve NEB customers are still incurred by the utility, these costs are ultimately paid for by other customers. This is what is referred to as a "cost-shift" and there can be no doubt that it exists. Moreover, the actual amount of this cost shift can be determined with reasonable accuracy and Maine utilities track this lost revenue as part of their annual NEB reports.[14]

Some have argued that the fixed minimum or customer charges cover the costs of the T&D system that is used to serve NEB customers. The Commission does not agree. The fixed or minimum charges in utility rates are established in utility rate design proceedings in which a host of factors are considered, including cost studies, rate stability, and complexity. The fixed charges in utility rates have historically accounted for only a small portion of the T&D fixed costs, most notably the customer-related costs such as metering and billing. For residential and small commercial customers, the remainder of the T&D utility's costs (which are generally fixed and do not vary with customer usage) for the investment in, and operation and maintenance of, facilities such as poles and wires, are recovered through volumetric kWh charges which are currently subject to netting. Thus, there is no validity to the argument that the existence of fixed or minimum charges eliminates the cost shift issue.[15]

2. Value Studies

A central component of the debate over "costs and benefits" of NEB is the question as to whether the costs to the general ratepayers through the cost shift is outweighed by the societal benefits or value of small solar installations.

Many of the solar advocates in this proceeding have relied upon the Maine Distributed Valuation Study (Apr. 14, 2015) (VOS study)[16] to support arguments that

[12] This is particularly the case in a scenario where solar output is about 14% of its nameplate capacity meaning that, on a daily basis, solar panels are producing energy at rated output for approximately 3.36 hours of every 24 hour period.

[13] In addition, the customer would also not pay for its use of the T&D system when it was exporting energy to the system.

[14] In its latest report, CMP determined that the lost revenue for calendar year 2016 was $1.8 million.

[15] Some commenters have argued that NEB customers should not be assessed the minimum charge. However, as described above, NEB customers use and rely on the system and should, therefore, contribute to the costs of maintaining the system.

[16] This Study was conducted pursuant to An Act to Support Solar Energy Development in Maine. P.L 2013 Chapter 562 (codified at 34-B M.R.S. §§ 3471-3473).

there are no cost shifts or subsidies involved with NEB billing. The study concluded that distributed solar facility output has a long-term levelized value that is significantly higher than the value being received by NEB customers. However, the Commission emphasizes that the Maine VOS study, as well as other "value" studies, must be viewed in the context of the methodology and purpose of such studies. Fundamentally, the methodology is an explicit application of an avoided cost methodology. The cost of solar technology is not even a component of the method. Rather, the methodology "values" solar PV by what technical and environmental matters would be avoided if current generation means were replaced by solar PV. Unique to the "what would be" approach of avoided cost, and in sharp contrast to established cost of service ratemaking, it does not matter to the calculated "value of solar" if a panel costs fifty cents per kilowatt or five thousand dollars per kilowatt. In addition, these value studies are long-term in nature, and include difficult to quantify externalities, such as environmental effects. Their results are highly dependent on assumptions about long-term energy cost and the choice of discount rates. Because energy market conditions are continually changing, such long-term studies can very quickly become outdated.

The Maine VOS study, as well as similar studies, calculates the value of attributes in two broad categories: those which are monetizable in the wholesale markets; and those that are not, generally, environmental attributes that are assigned administratively derived social costs. It is the categories that can be monetized – market-based costs identified – that can be relevant in comparisons with cost of service based utility rates. The Maine VOS study concluded that distributed solar facility output has a long-term levelized value of $0.337 per kWh over twenty-five years.[17] In terms of the first year values, for CMP's territory, the report determined there to be societal benefits of $0.092 per kWh. The monetizable benefits, including avoided energy cost, avoided capacity costs, avoided reserves, and avoided transmission, were calculated to be only $0.09 per kWh.

The Maine VOS study assumed a twenty-five year life of the technology and reflected projections over that twenty-five year period of avoided costs to analyze the value of solar. Costs and benefits over the period were levelized. In such a levelized

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This Act set forth guidance and a process by which a methodology was to be developed to value distributed solar energy generation. The Study was conducted by Clean Power Research in collaboration with a team that included Sustainable Energy Advantage, Pace Energy and Climate Center at the Pace Law School, and Dr. Richard Perez. *Commission Inquiry into the Determination of the Value of Distributed Solar Energy Generation in the State of Maine*, Docket No. 2014-00171, Final Value of Solar Study (Revised April 2015) (Apr. 15, 2015).

[17] This rulemaking record identifies at least 13 different value studies conducted in 11 different states, commissioned by utilities, public utility commissions and other organizations. The reports range in findings from as high as 33 cents per kWh to 3 cents per kWh. The widely varying range can be attributed to differing assumptions including time horizons, levelized cost approach and benefits to be counted, and whether an avoided cost or a cost of service approach was taken.

cost analysis, current and future costs and benefits are reduced to a series of cash flows, discounted to the present. Such an analysis can inform long-term investment decisions, such as technology choices. For instance, one technology may have a low capital cost but a high operation and maintenance expense, while another technology might have a low operation and maintenance cost but a high initial capital cost.[18] In the utility regulatory context, such analyses are commonly used in evaluating utility capital investments and long-term contracts for energy supply.

The results of this type of analysis, however, are of limited use in the design of a program like NEB that requires ratepayer-funded incentives. The avoided cost methodology is not helpful in cost of service ratemaking because it does not refer to the known specific costs of concern in designing rates. Ratepayer funded incentives are evaluated based on costs (similar to cost of service ratemaking), not a concept of "value."[19] For example, when an efficiency program is designed for appliance rebates, the actual dollar rebate is based on a certain portion of the cost of the appliance, not on the "value" that the installation of the appliance may have for other customers or society in general.

It is also important to emphasize that the actual costs and benefits of distributed resources, including solar PV, depends largely on the site specific, local characteristics of the electric grid and the concentration of distributed solar installations. For example, in states that have reached relatively high penetrations of distributed solar, reverse power flows actually result in net costs to the transmission and distribution system not savings.[20] Thus, the value of distributed generation is highly location dependent, a factor that was not examined in the Maine VOS.[21]

3. Technology Costs

[18] The VOS Study, in its application of levelized cost, adds an additional twist. It develops avoided costs in year one. The difficulty in avoided costs is much the same as the difficulty the Commission runs into in prudency disallowances. One has to assign a cost to a path not taken. This is further complicated by projecting these assumptions forward over a 25 year period. The output is a projection on what is avoided.

[19] The same is true in competitive markets in which prices and incentives are generally based on the cost of the product or service, not the "value" to customers.

[20] See Rich Seguin et al., *High-Penetration PV Integration Handbook for Distribution Engineers*, National Renewable Energy Laboratory (January 2016).

[21] Maine does have a mechanism in which distributed generation is considered on a location specific basis to maximize ratepayer value by paying for distributed resources where it is needed. The Commission is required to consider non - transmission alternatives whenever a T&D utility files for a certificate of public convenience and necessity to make a transmission investment. 35-A M.R.S. §§ 3132, 3132-A.

With respect to actual technology costs, there is no dispute that the costs of solar PV installations have decreased significantly in recent years and are expected to continue to decrease in the future. According to information provided by the U.S. Department of Energy (DOE), the installed cost of residential solar PV is currently in the range of $3/WattDC.[22, 23] Over the past five-to-six years, according to the DOE, the installed cost of residential solar PV has declined from about $5/WattDC to $3/WattDC. Over the next ten years, the installed cost of residential solar PV is projected to decline by about 40% relative to the current $3/WattDC level. Relative to the cost in 2010 of about $5/WattDC, the projected installed cost of solar PV in 2026 reflects a decrease of about 60%.[24] In addition to the DOE information, a diverse set of government and industry sources of information on installed costs project further cost reductions between now and 2025.[25]

Although there is no certainty about the precise level and timing of these reductions in solar PV costs, there is no dispute that costs have and will continue to decrease. These cost trends indicate that incentives for solar PV should also decline over time, rather than increase over time as the retail cost of electricity services increases.

It should be emphasized that the discussion of these cost trends is not meant to represent a comprehensive cost analysis or suggest that NEB compensation be based on a precise calculation of eligible technology costs. Instead, these cost trends are used in this rulemaking context to inform the Commission's determination regarding amendments to the NEB rules. Finally, although these changes apply to all distributed

[22] *Photovoltaics*, U.S. Department of Energy, http://energy.gov/eere/sunshot/photovoltaics (last visited Sept. 8, 2016). These costs do not reflect an additional reduction due to the federal Investment Tax Credit, which is currently 30%.

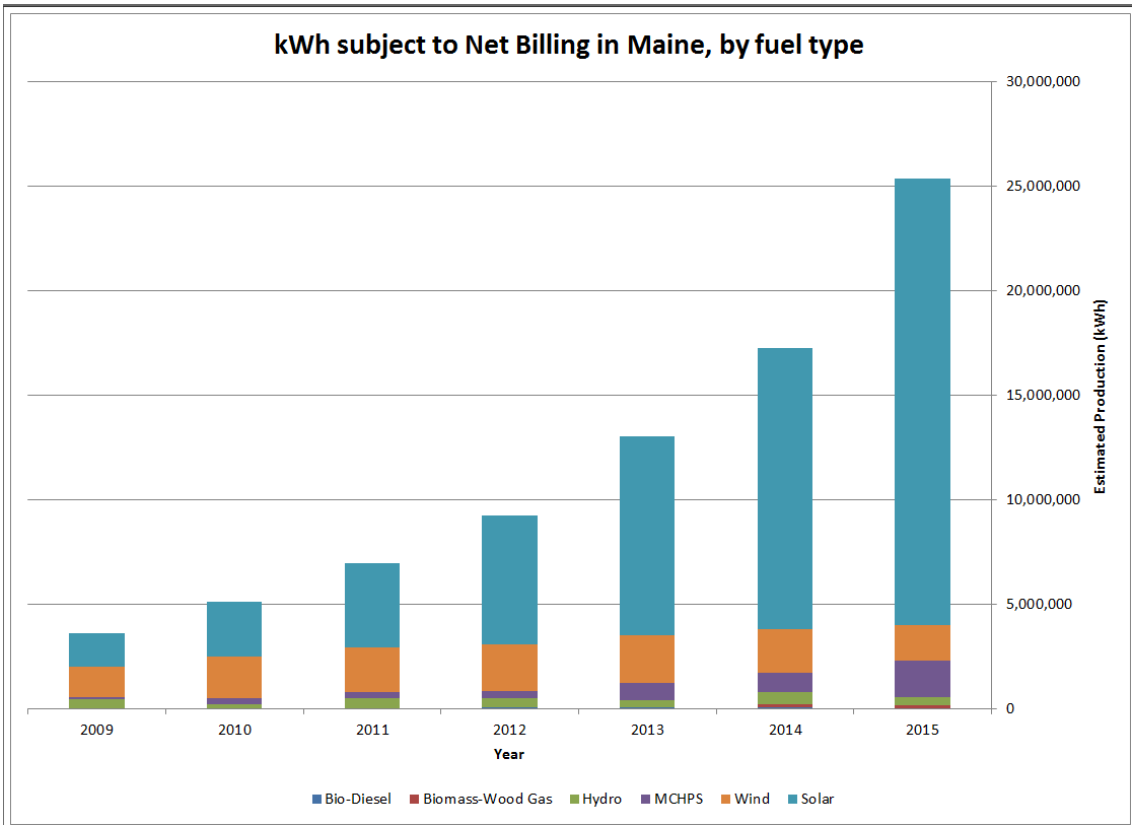
[23] Unless otherwise noted, the costs provided by DOE are in 2014 dollars.

[24] The predicted timelines for a 40% to 50% reduction from 2015 costs in the installed cost of rooftop PV range from three to ten years when looking over a diverse set of industry and government sources. For a range of predictions, *see* David Feldman et al., *Photovoltaic System Pricing Trends, Historical, Recent, and Near-Term Projections, 2015 Edition*, U.S. Department of Energy (Aug. 29, 2015); U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2015 (2015); Vishal Shah, *Solar: Grid Parity Beyond 2016?*, Deutsche Bank (Dec. 2015); International Energy Agency, *Technology Roadmap, Solar Photovoltaic Energy* (2014).

[25] *See, e.g.*, *id*.; *see also The Power to Change: Solar and Wind Cost Reduction Potential to 2025*, International Renewable Energy Agency (June 2016) available at https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf; *The Future of Solar Energy*, Massachusetts Institute of Technology (2015) available at http://energy.mit.edu/wp-content/uploads/2015/05/MITEI-The-Future-of-Solar-Energy.pdf.

technologies, solar predominates now and may continue to do so in the future. *See* Table 1 below.

TABLE 1[26]



C. Legal Authority

CLF argues that the proposed amended rule is beyond the scope of 35-A M.R.S. § 3209-A, the statutory section regarding NEB rules, and is therefore beyond the Commission's authority to implement. CLF argues that through Section 3209-A, the Legislature defined NEB to closely reflect definitions already in Commission rules and, because the structure of the proposed amended rule differs from the structure of the NEB rule at the time the statutory definition was enacted, the proposed amended rule is beyond the authority of the Commission to adopt.

CLF's interpretation of legislative intent into Section 3209-A is overly restrictive and beyond the plain meaning of that statute. Section 3209-A states:

[26] Table 1 utilizes data provided by T&D utilities pursuant to their annual reporting obligations under the former NEB rule.

> The commission may adopt or amend rules governing net energy billing. . . . "Net energy billing" means a billing and metering practice under which a customer is billed on the basis of net energy over the billing period taking into account accumulated unused kilowatt-hour credits from the previous billing period.

Section 3209-A is a permissive grant of authority that, as CLF points out, codified the Commission's long-term practice of allowing for NEB by rule. It did not, either explicitly or by implication, foreclose other rate structures or mechanisms applicable to ratepayers that install grid-connected energy generation facilities. Moreover, the amended rule is consistent with the Section 3209-A definition of net energy billing and maintains the basic structure in the current rule. The amended rule changes the inputs that go into the netting calculation, maintaining a net energy calculation to compute the NEB customer's bill and to account for accumulated unused kilowatt-hour credits from the previous billing period. The statute does not specify that only imported and exported energy is netted, and to read in such language would be an overly restrictive interpretation of Section 3209-A.

D. APA Procedures

CLF argues that the Commission has violated two provisions of the Maine Administrative Procedures Act (APA). CLF's arguments are supported by NRCM, Sunrun, IECG, and MABEP. The OPA and CMP submitted comments disputing CLF's statutory arguments.

First, CLF argues that the Commission's finding that "the fiscal impact of the proposed amended rule is expected to be minimal" was insufficient to satisfy 5 M.R.S. § 8057-A, which requires a fact sheet accompanying a proposed amended rule that includes an estimate of the fiscal impact of the rule. CLF asserts that the Commission's rulemaking could "profoundly alter" the solar industry and, therefore, its fiscal impact will be more significant than indicated by the Commission.

However, contrary to CLF's argument, the fiscal impact of a proposed rule is commonly understood to refer to the monetary impact on governmental entities. For example, 5 M.R.S. § 8063 defines fiscal impact as "the estimated cost to municipalities and counties for implementing or complying with the proposed rule." The Commission has historically interpreted fiscal impact consistent with this definition and is unaware of an instance when this provision was applied to the economic impact on private industry. Accordingly, as the proposed amended rule change did not require the expenditure of public funds, the Commission's statement that its fiscal impact would be minimal is accurate.

Second, CLF also argues that the Commission has not prepared a small business economic impact statement as required by 5 M.R.S. § 8052(5-A). CLF asserts that the proposed amended rule would have "significant and severe impacts" on the solar industry, requiring an economic impact statement be prepared prior to the notice

of rulemaking, and that the notice of rulemaking should have indicated where it could have been obtained. The Commission's violation of these provisions, according to CLF, renders the rule "void and of no legal effect," in accordance with 5 M.R.S. § 8057(1).

In its supplemental comments filed on November 1, 2016, CMP responded to CLF's argument. CMP states that the small business economic impact statement is only applicable when the proposed rule actually regulates small businesses and that the Commission's practice has been consistent with this interpretation. The OPA also suggests that CLF's interpretation of subsection 8052(5-A) is not consistent with other provisions of the statute regarding reporting requirements and timelines.[27]

The Commission concludes that the language of the statute clearly indicates that it is only applicable in instances when a rule would directly regulate a small business and, therefore, the mandates regarding reporting requirements and timetables are only relevant under a direct regulation of small businesses. In this case, the rule at issue only regulates the metering and billing activities of Maine's T&D utilities, and does not regulate the solar industry. Therefore, small businesses are not subject to or regulated as part of this rulemaking and compliance with this rule requires no projected reporting, record-keeping, and other administrative costs from small businesses.

IV. AMENDED RULE PROVISIONS

A. Overview

The amended rule maintains a netting approach contained in the current rule with altered inputs, but reduces by ten percent per year over a ten year period the portion of the output of the customer's facility that is eligible to be netted (referred to in the rule as "nettable energy") against the customer's T&D bill. For instance, a customer with an effective in-service date on their installation of January 1, 2018 would receive a credit for 90% of nettable energy on the T&D portion of their bill for fifteen years; a customer with an effective in-service date on their installation of January 1, 2019 would receive a credit for 80% of nettable energy on the T&D portion of their bill; and so on. Netting regarding the supply portion of the bill remains unchanged.

Under the amended rule, the gradual reduction in nettable energy will begin for new NEB customers with facility in-service dates on January 1, 2018. In each successive year until December 31, 2026, a new customer will receive that year's designated percentage for a fifteen year period. Existing net energy billing customers will be grandfathered for a fifteen year period.

The OPA commented that the rulemaking approach appropriately recognizes that NEB is not a suitable long-term approach for promoting distributed generation and takes

[27] Despite its interpretation of 5 M.R.S. § 8052(5-A), the OPA argues an economic impact analysis may be procedurally prudent and helpful to understand the ratepayer impact of the proposed amended rule.

an important first step in separating compensation paid to distributed energy resources (DER) from the retail rate and recognizing that compensation for new resources should be reduced over time as the costs for these resources decline. However, the OPA does not support the rulemaking approach and proposes instead that DER be compensated for net exported kWhs on an hourly basis at a set per-kWh rate that is reduced over time to the wholesale rate plus any monetizable ratepayer benefits. Similarly, the GEO opposes the basic approach of the rule in favor of a market-based approach, and states that if the Commission adopts its proposed rulemaking approach, the netting ramp down should be quicker to minimize the cost shift to other customers. CMP also advocates a market-based approach in place of what it considers an arbitrary ramp down approach.[28] CMP agrees that the pace of transition should recognize rapidly declining costs, but should be faster than in the proposed amended rule. Ms. Alexander also commented that the phase down should be shorter than ten years. Emera Maine generally agrees with the rule's approach of gradually reducing T&D cross-subsidies. Mr. Brown generally agrees with the phase down as a means to reduce cross-subsidies, inefficiency and unfairness to competing resources.

The NRCM, CLF, Revision and other commenters stated that the phase down specifics are arbitrary and that the proposed amended rule is complex, unworkable and costly. Revision commented that the Commission should look more broadly at distributed generation in general through proper rate structures using smart meter technology.

As discussed in detail below, the Commission adopts the phase-down approach in the proposed amended rule. In recognition of the role of the Legislature to make broad energy policy decision, the Commission takes a narrow and tailored approach in this proceeding by maintaining the basic net billing mechanism and reducing over time the amount of generation that can be netted against the T&D bill. The Commission does not address issues that are properly in the purview of the Legislature regarding more fundamental changes to small renewable incentive programs, such as the proposal by the OPA, GEO and CMP for a utility long-term purchase and monetization approach.

The Commission leaves open for future ratemaking proceedings issues of rate design changes that may provide other approaches to the cross-subsidy and incentive level issues addressed by the amended rule. The completion of CMP's new billing system later this year will provide the necessary technology of a flexible billing software architecture coupled with the wide scale deployment of advanced metering infrastructure. This technology will enable the consideration of rate design mechanisms that lay the groundwork for equitable treatment of all customers and more granular application of cost causation principles in rate design. The Commission encourages parties to participate in a constructive manner in a future rate design case.

[28] CMP and the GEO also both recommend that advanced metering infrastructure (AMI) be utilized to measure the hourly net output of the NEB facilities and to obtain the wholesale market value for these generators.

While the GEO, OPA, and CMP advocate for some form of hourly netting with excess energy sold onto the market, this approach does not account for ongoing use of grid services by NEB customers. There would still exist a significant transfer payment due to the nature of the volumetric charge used to recover T&D costs and the fact that this approach does not account for behind the meter consumption. Existing metering data does not capture this clearly nor allow for precise modeling of its growth trajectory. Incorporating this approach in the rule at this time may result in significant transfer payments between customers going forward. The Commission also acknowledges that approaches like these espoused by the GEO, OPA, and CMP may be preferable once the AMI system has been fully deployed and more data has been gathered pursuant to this amended rule.

In response to comments regarding the specific phase down of T&D netting, the approach contained in the amended rule is not arbitrary, as some commenters have asserted. As discussed above, the phase down approach reflected in the amended rule is intended to maintain a return on investment by reducing over time the incentives to NEB customers in recognition of expected ongoing technology cost declines for small renewable installations. Moreover, the fifteen year grandfathering period for existing NEB customers would likely extend current net billing past the breakeven point of capital investment that has been made prior to the rule amendments.[29]

In particular, with the installed cost of solar facilities in 2012 at approximately $5.25 per Watt for an average installation size and with the inclusion of the federal tax credit of 30%, under the current rule the simple payback period would be about 21.5 years. For year 2014, with installed costs dropping to about $4.27 for the same average customer, all other assumptions being equal, and the federal tax credit remaining in place, the payback under the current rule would be about 17.4 years. For year 2028 when the T&D phase down is complete, with installation costs having fallen to $2 per Watt for the same average customer and with no federal tax credit, the payback period is approximately twenty-three years. If the tax credit remains at 30%, the payback period is sixteen years, with a range between sixteen and twenty-three years depending on how the federal tax incentive was modified**.**

B. Nettable Energy (section 3(E) and (F))

i. Netting Mechanism

The gradual phase-down of the incentive to NEB customers is accomplished in the amended rule (section 3(E) and (F)) through gradual reductions to “nettable energy.” Nettable Energy is defined in the amended rule (section 2(L)) as:

[29] As discussed in section IV(D) below, the amended rule contains a new provision that will allow for “REC aggregation.” This provision will allow future NEB customers to participate in the REC market.

> the energy in kilowatt-hours generated by an eligible facility that may be netted against a customer's kilowatt-hour consumption . . . .

As reflected in the amended rule, the inputs to nettable energy have changed from the existing rule. Nettable energy is now the entire amount of energy generated by the facility, including the amount consumed by a customer "behind-the-meter". Hence, the amended rule nets on a gross basis rather than a net basis.

In recognition of the cost declines described above, under the amended rule the nettable energy applicable to the T&D portion of a customer's bill is reduced over time, while the nettable energy for the supply portion of the bill is unchanged. The amended rule specifies that, for customers that become NEB customers over the next ten years, the "nettable" kWh applicable to the T&D bill would decline for newly installed facilities by ten percentage points each year such that for customers that become new NEB customers after the year 2026, there would be no netting on the T&D portion of the bill. Specifically, for customers that become NEB customers in 2018, 90% of the kWhs would be nettable against the T&D bill, for customers that become NEB customer in 2022, 50% of the kWhs would be nettable, and so on until, for new customers after the year 2026, the T&D component of the bill is no longer netted. Assuming a T&D component that is approximately one-half of the customer's total electricity bill, for new customers after the year 2026, the approach in the amended rule would result in a reduction in the value of NEB credits equal to about half of that that would be provided under the current rule. As noted above, this end-state would be achieved gradually over the next ten years and NEB customers would receive the nettable energy percentage applicable in the year in which they first became NEB customers for a period of fifteen years.[30] Section 3(H) of the amended rule specifies that the facility's in-service date determines the applicable year for netting purposes.

This approach phases out the shifting of T&D costs from NEB customers to non-NEB customers that is inherent in the current rule. With respect to the supply bill, under the current market settlement rules, any netted kWhs are treated as a reduction to the supplier's load obligations such that little or no cost is shifted to other customers as a result of the netting. For this reason, the amended rule achieves all of the reductions to "nettable" kWh on the T&D bill.

Under the amended rule, the value to NEB customers on their supply bill tracks retail supply costs, such as for standard offer service, rather than a value based on wholesale market prices. From an economic standpoint, the use of a wholesale rate would be the preferable approach in that NEB customers are providing a wholesale energy product. However, netting of the retail standard offer rate (or a CEP retail rate if customer is taking competitive service), which is a bundled product at an annual fixed

[30] As specified in section 3(G) of the amended rule, a customer continues netting on the specified percentage until December 31st of the fifteenth year.

rate,[31] provides price certainty. Netting of the retail standard offer rate also provides a reference to competitive electricity markets in that standard offer rates are established annually though a competitive bid process.

As noted above, the amended rule uses a "gross" approach to determine nettable energy. This approach requires the total energy produced and the total energy consumed during a billing period be determined. This is in contrast to the approach in the current rule in which both energy produced and energy used are measured on a "net" basis (e.g., generated energy offsets simultaneous load) and any excess is "netted" against current and future bills.

Thus, the approach in the amended rule accomplishes the goals of: (1) reducing the NEB incentive to track reductions in technology costs in a manner that maintains comparable payback periods for NEB customers; and (2) reducing, and ultimately eliminating, the shifting of T&D costs from NEB to non-NEB customers.

ii. Treatment of Self-Generation

Several parties opposed the gross netting approach in the proposed amended rule as a violation of a customer's ability or right to self-generate (i.e., use generation behind a customer's meter to serve its own load). The IECG strongly supports customers' "right" to self-generate and views the gross netting approach as a violation of this principle. NRCM, MABEP, MCSFA, Sunrun, Maine Audubon, ACTT, the Nature Conservancy and Mr. Grassi commented that NEB customers should not be charged when self-generating and, by assertion, not using the system, and generally argued that gross netting is unfair, unworkable, and violates the exit fee statute or is otherwise illegal. The OPA points out that NEB is optional and the GEO argues that self-generation is allowed and the superior approach is to net on an hourly basis.

The GEO's position of hourly netting does not address the so called "lost T&D revenue" issue. Such an approach will result in a reduction of volumetric T&D rates due to the behind the meter aspect of the generation. This perpetuates the shift of T&D utility revenue responsibility from NEB customers to non-NEB customers with corresponding impacts on the rates of non-NEB customers. The Commission's gross approach as reflected in the amended rule addresses this issue.

NEB is a program offered under Commission rules as permitted by statute. It is not a required program, but an option provided for customers. The Commission concludes that the gross approach in the amended rule is not a violation of the exit fee

[31] The standard offer rate is the price for a *bundled product* that includes not just energy but also ancillary services, voltage control, frequency control, reserves, capacity, bad debt, and likely some type of risk premium incorporated by the supplier to cover its forward load obligation. This approach may need to be revisited if the components of standard offer shift in such a way that capacity services become a more significant component of the bundled price.

statute or otherwise unlawful and does not impinge in any way on a customer's "right" or ability to self-generate.

First, the exit fee statute (35A M.R.S. § 3209(3)) prohibits utility charges or fees for exit or reentry for the reduction or elimination of consumption or reestablishment of service with a T&D utility. The establishment of or change to the NEB rules is in no sense an "exit" fee in that the customer is not being charged a fee to compensate the utility for lost consumption.

Second, and most importantly, NEB is a voluntary incentive program and in no way mandates customer participation. Thus, the existence of the rule does not in any way alter a customer's ability to self-generate and use its generation to offset load in real time.[32] As discussed in Section IV(E) below, the purpose of the NEB rule is to provide for an incentive for the adoption of distributed generation that is generally matched to a consumer's consumption. Notably, customers who wish to self-generate do not have to participate in the optional NEB program. Some customers (if their generating facility is 5 MW or less), may find it more advantageous to use the provisions of Chapter 315 (Small Generator Aggregation) of the Commission rules. Under Chapter 315, customers can self-generate and export any excess generation to the grid. The rule requires the standard offer provider to purchase the excess generation and settle it in the real-time wholesale electricity market on behalf of the generator. The customer receives payment for that excess generation at the wholesale price for the hour in which the energy was generated.

C. Grandfathering (section 3(E))

Section 3(E) of the amended rule specifies that existing NEB customers will continue to net bill under the current rule's approach for a fifteen year period. As discussed above, this fifteen year grandfathering period for existing NEB customers addresses the likely breakeven point of capital investments made by existing NEB customers prior to the rule amendments. After this fifteen year period, customers would continue to net the full output of their facility against the supply portion of their bills.

The IECG recommends that the period be changed to twenty years to more closely match the likely term of financing periods. NRCM also requests that this period be extended, and argues that the term should be beyond what is necessary to reach the payback period to allow NEB customers to receive a return on their investment. NRCM also questions the fairness of a single time period that is applied to all existing NEB customers. The Maine Association of Building Efficiency Professionals also contends that fifteen years is too short, as it does not align with the twenty-five to thirty year

[32] Likewise, the amended rule does not conflict with 35-A M.R.S. § 3305(2), as suggested by the OPA. Section 3305(2) forbids the Commission from imposing approval or regulation requirements on a small power producer's or cogenerator's ability to self-generate. NEB is a voluntary incentive program and under the amended rule these individuals remain free to self-generate without participating in the NEB program.

service life of many NEB facilities and would result in a tangible loss for a number of existing NEB customers. Sunrun recommends that the grandfathering period be set at the average useful life of the NEB facilities out of basic fairness towards NEB customers who relied on the status quo in making long-term financial decisions. CMP generally supports a limited grandfathering period which considers the declining costs of NEB facilities and extends the break-even point for existing customers. CMP considers such a period to be ten to fifteen years. The GEO suggests a time period of three to ten years and notes that the Legislature limited contract lengths between T&D utilities and NEB customers to ten years through An Act to Expand Net Energy Billing, P.L. 2011, ch. 262. Further, the GEO asserts that the Legislature chose this time period as appropriate for NEB customers to recover their costs, and these costs have been in decline since that time.

Although Commission rules and utility programs can be expected to change over time, the Commission recognizes that customers may expect, or have been told to expect, certain paybacks when they make an investment. The Commission concludes that a grandfathering provision at fifteen years strikes an appropriate balance. Based on the current capital costs of installation, the payback period is approximately equal to the fifteen year period. While some customers may have made a decision based on the assumption that the current program would stay into perpetuity, the current NEB rule allows for contracts of up to ten years and NEB contracts are explicitly subject to regulatory changes. Accordingly, it is reasonable to grandfather existing customers for fifteen years.

D. REC Aggregation (Section 4)

The amended rule contains a new provision for renewable energy credits (REC) aggregation. Section 4 states that new NEB customers with an in-service date on or after January 1, 2018 may elect to have the RECs associated with their eligible NEB facility aggregated by the T&D utility and sold into the regional market with proceeds from such sales returned to the participating NEB customers. Consumer-owned utilities (COUs) may, but are not required to, offer a REC aggregation program.[33]

In the NOR, the Commission requested comments on how to aggregate and monetize RECs associated with NEB facilities. The Commission received several comments. The GEO recommends that the T&D utilities aggregate and sell RECs into the regional market, using the resulting revenue to offset lost T&D revenue. The OPA similarly suggests that the Commission retain rights to the environmental attributes of facilities participating in NEB (along with associated energy and capacity) and use the revenue from the sale of the aggregated RECs to offset any existing subsidy. If customers retain ownership of the environmental attributes, however, the OPA recommends that NEB facilities automatically receive ME Class I REC certification and that T&D utilities report on behalf of NEB customers their hourly export data to a

[33] As a general matter, COUs have not been required to implement changes or expansions to NEB. *See* Sections 3(B)(6) and 3(C) of the former Chapter 313.

designated NEPOOL-GIS account. The OPA also suggests designating a buyer to offer to purchase a customer's RECs at a default rate. CMP also recommends that RECs be aggregated and sold to a single market buyer. Emera supports efforts to monetize RECs and suggests a working group to examine REC aggregation and evaluate the benefits against the costs of administration.

The decision to include a REC aggregation provision in the amended rule is an effort to obtain on an optional basis a value stream that is not currently being monetized. Because the details of such an aggregation program require further review, the amended rule requires that the T&D utilities file proposed terms and conditions, including expected administrative costs, which would be subject to further process. For purposes of administrative ease, the amended rule provides that NEB facilities participating in the REC aggregation program will be automatically certified as a Class I resource[34] and the T&D utilities will be required to retire RECs in an amount such that the customer's usage meets Maine's new renewable resource portfolio requirement. [35]

Under the amended rule, this REC aggregation option is available to new customers on or after January 1, 2018. This will provide an optional revenue stream for new customers that could allow new customer payback period to be kept in line with the payback period for existing customers, given the scheduled reductions in the federal ITC.

E. NEB Size and Structure Expansions

The proposed amended rule included expansions to NEB in Maine in several respects. First, the proposed amended rule would have increased the size cap for an

[34] Chapter 311, section 3(B)(4) of the Commission's rules establishes a Maine Class I REC certification process that requires generators to pre-certify facilities as a new renewable resource under the requirements of the rule and provides for a Commission determination of resource eligibility on a case-by-case basis. The rule also contains the information that must be included in a petition for certification. The amended NEB rule allows RPS eligible NEB facilities to avoid this process and receive automatic certification.

[35] Although the Commission has historically permitted REC certification of behind-the-meter generation, these generators have been required to retain or obtain certificates necessary to satisfy Maine's RPS for that portion of their load that is served by the facility. *See Lincoln Paper and Tissue, LLC, Request for Certification for RPS Eligibility*, Docket No. 2008-173, Order Granting New Renewable Resource Certification at 8 (Jan. 27, 2009). Under current law, this would equate to ten percent of the NEB facility's generation that is consumed behind-the-meter for Class I RECs and thirty percent for Class II RECs. The logic for this requirement is that behind-the-meter generation is serving the load of customers that would otherwise have been served by a CEP or standard offer provider to which the RPS requirement applies. It is therefore consistent to require this behind-the-meter consumption to adhere to Maine's RPS requirements.

eligible facility from 660 kilowatts to one megawatt. Second, the proposed amended rule explicitly allowed for "community" NEB. Third, the proposed amended rule would have eliminated the number of meters limitation in the current rule. Fourth, the proposed amended rule contained specific provisions regarding "NEB leases," including customer protection provisions.

A number of commenters supported these proposed provisions, while others expressed concern about increasing the facility limit to one megawatt and allowing for community solar and larger scale joint ownership projects which are not behind the meter and for which economies of scale reduce the need for a subsidy compared to residential rooftop installations. Specifically, NRCM, SEAM, Maine Audubon, the Nature Conservancy and CEC supported the community and shared ownership provisions and the removal of the limit on the number of meters. The GEO commented that new, larger projects should not be eligible for NEB because the NEB incentive is not necessary for these projects and adopting NEB expansion provisions would increase costs to other customers by expanding the number of NEB customers and NEB eligible facilities. CMP expressed concern with the proposed expansion of NEB, noting that community solar and larger scale joint ownership projects are not behind the meter and therefore use the T&D system for all customer usage.

With respect to the removal of the limit on the number of accounts or meters permissible under a single NEB billing arrangement, CMP commented that such an expansion would negatively affect its billing system performance and recommended a cap of 200 customers. Emera similarly suggested that expanding the cap on eligible customers allowed for an NEB arrangement that will increase its administrative costs. The GEO argued that the final rule should retain the ten customer cap rule until a full market compensation approach for NEB facilities is adopted.

For the following reasons, the amended rule does not include these provisions. First, as discussed in section III(B) above, the Commission focuses this rulemaking on addressing technology cost decreases and reducing cost-shifting and to do so in a manner that maintains the current NEB structure consistent with statute. Fundamental changes to NEB in Maine and promotional programs for larger renewable and community solar projects are the purview of the Legislature as a matter of State energy policy. Second, the purpose of NEB, as has consistently been articulated by the Commission,[36] is to incentivize the installation of small renewable systems used primarily to provide a customer's own electricity needs. The expansion of NEB to larger projects and community solar, which would not be behind the customers' meters, may be inconsistent with this articulated purpose. Third, it is recognized that there are economies of scale for larger projects and, accordingly, such projects do not need the same subsidy as smaller projects, such as residential roof-top installations.

[36] *See, e.g., Re Customer Net Energy Billing (Chapter 313)*, Docket No. 98-621, Order Adopting Rule and Statement of Factual and Policy Analysis at 3 (Dec. 10, 1998).

The Commission notes that the NEB rule will continue to allow for facility leasing consistent with precedent. The Commission has authorized leases consistent with the standard that the lease arrangement be "akin to ownership."[37] *See Central Maine Power Company, Request for Review of Notice of Eligibility for Net Energy Billing Arrangement*, Docket No. 2014-00114, Order (June 23, 2014); *see also Union Atlantic Electricity & Union Atlantic Hydro, LLC, Petition for Advisory Ruling Regarding Interpretation of Chapter 313*, Docket No. 2012-00466, Advisory Ruling (Jan. 31, 2013).

F. Effective Date (section 3(H))

CMP requested that the final rule clarify how utilities are to determine which calendar year applies to each system, for example, by application date, contract execution date, interconnection date, or in-service date, and how to address existing NEB customers that request additional accounts.

The amended rule contains a provision (section 3(H)) that specifies that the effective date to determine the applicable calendar year pursuant to section 3(F) is the in-service date of the facility. The timing of the other potential approaches suggested by CMP can vary to a large degree among new NEB customers. Thus, to treat potential NEB customers similarly, the more meaningful in-service date is appropriate for this purpose.

G. Billing Requirements (section 3(I))

CMP stated that, as structured, the proposed amended rule would create a number of different rates for NEB customers over time, which will have to be accounted for in the utility's billing system. CMP also suggested that the final rule allow T&D utilities to require uniform billing cycles for all types of arrangements where there are multiple accounts receiving credits from a single facility.

The amended rule may result in added complexity regarding utility billing and metering practices, but the additional administrative complexity should be manageable for the utilities. However, CMP's request regarding uniform billing cycles is a reasonable approach to mitigate the utility's incremental administrative obligations associated with NEB and has therefore been included in the amended rule.

H. Competitive Electricity Providers (section 3(J))

[37] While some ambiguity exists under current precedent, simply allowing all leases has the potential to create significant consumer protection concerns. Leases in many ways as practiced in other states are more akin to power purchase agreements than they are ownership. This raises the question of whether such arrangements would be more appropriately viewed as retail sale involving a competitive electricity provider.

CMP recommends that the language of section 5(G) of the proposed amended rule be modified to be consistent with current NEB billing practices for CEPs. Currently, CEPs are required to bill the NEB customers they enroll on a net basis, but the proposed amended rule stated that CEPs may, but are not required to, bill on a net basis. CMP asserts that if CEPs are allowed to enroll NEB customers, but do not bill those customers on a net basis, then CMP will have to make a number of system modifications to account for the resulting mismatch in the amount of usage metered by CMP and the amount of usage to be billed by the supplier.

The Commission agrees with CMP in this regard and the amended rule requires that CEPs, if they enroll NEB customers, must bill on a net basis.

I. Additional Meters and Equipment (section 3(L))

As noted above, the amended rule will require the output of the facility and the customer usage to be measured on a gross basis. To the extent this requires additional metering relative to the current rule, the additional costs may not be charged to the NEB customer unless allowed by Commission Order.

J. Consumer-Owned Utility Exemptions (sections 3(B)(6) and 4(E))

Sections 3(B)(6) and 4(E) of the amended rule contain certain exemptions for consumer-owned utilities (COUs). The existing rule explicitly exempts COUs from the shared ownership requirements of the rule. This was done in recognition of potential COU administrative difficulties and expense in providing for shared ownership NEB. For a similar reason, the amended rule explicitly exempts COUs from the REC aggregation requirements of the rule.

K. Reporting and Commission Review (section 5)

The amended rule re-sets the Commission review trigger at 3% of peak demand, rather than 4% of peak demand included in the proposed rule. In addition, the amended rule contains a biannual utility reporting requirement. This will allow the Commission to actively monitor developments, including whether installations are declining, increasing or holding steady, and consider whether rule changes may be warranted.

Accordingly, the Commission

O R D E RS

1. That the amendments to Chapter 313, Customer Net Energy Billing, are hereby adopted:

2. That the Administrative Director shall file the adopted rule and related materials with the Secretary of State;

3. That the Administrative Director shall notify the following of the adoption of the amended rules:

a. all transmission and distribution utilities in the State;

b. all person who filed comments in the inquiry, *Maine Public Utilities Commission*, *Commission Initiated Inquiry into Net Energy Billing Rules (Chapter 313)*, Docket No. 2016-00120;

c. all persons who have commented in this rulemaking proceeding, Docket No. 2016-00222; and

d. all persons who have filed with the Commission within the past year a written request for notice of rulemakings;

4. That the Administrative Director shall send copies of this Order and attached amended rule to the Executive Director of the Legislative Council, 115 State House Station, Augusta, Maine 04333-0115.

Dated at Hallowell, Maine, this 1st day of March, 2017.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear

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Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Vannoy
McLean
Williamson

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.