MAINE PUBLIC UTILITIES COMMISSION

Report to the Legislature Regarding Market-Based Solar Policy Design Stakeholder Process Pursuant to Resolves 2015, ch. 37

January 30, 2016

I. OVERVIEW

As directed by legislative Resolve, the Maine Public Utilities Commission (Commission) convened a stakeholder group to examine options for market-based distributed solar promotion policy and alternatives to the current net energy billing (NEB) program. The Resolve sought stakeholder group recommendations that, to the maximum extent possible, reflect a consensus among the stakeholders.

As discussed in detail in this Report, the Commission convened a diverse group of stakeholders that exchanged a variety of views through numerous rounds of written comments and seven in-person work sessions. The process was productive and resulted in substantial agreement on many aspects of a solar promotional program. However, there was significant disagreement on several fundamental issues primarily with respect to the program that would replace NEB. Accordingly, the process did not produce consensus recommendations as contemplated by the Resolve.

This Report contains a description of the stakeholder process and a discussion of areas in which, in the Commission's view, there was substantial agreement and areas in which there was disagreement. For the most part, the Commission, in this Report, does not attempt to identify the positions of each individual stakeholder or describe their arguments in favor or opposed to particular issues. The Commission anticipates that all stakeholders will have the opportunity to present their specific viewpoints on these matters through the legislative process.

II. LEGISLATIVE RESOLVE

During its 2015 session, the Maine Legislature enacted L.D. 1263, *Resolve, To Create Sustainable Growth in Maine's Distributed Energy Sector That Uses Market Forces To Fairly Compensate Energy Producers* (Resolve). Resolves 2015, ch. 37.[1] The Resolve states that the Legislature finds that net energy billing is a simple mechanism that has supported the development of distributed generation in Maine, but may not provide a suitable long-term foundation for distributed generation. The Resolve directed the Commission to convene a stakeholder group to examine options for distributed solar policy in Maine going forward. Specifically, the Legislature sought to develop an alternative to NEB that fairly and transparently allocates the costs and benefits of distributed generation to all customers, allows participation by all customers and creates a sustainable platform for future growth of distributed generation to the benefit of all ratepayers.

The Resolve required that the Commission convene a stakeholder group to develop an alternative to net energy billing. The Resolve specified that, to the

[1] A copy of the Resolve is attached as Attachment A.

maximum extent possible, the recommendations from the stakeholder group must reflect a consensus among the stakeholders. The Resolve also stated that development of the alternative solar policy be guided by a white paper prepared for the Office of the Public Advocate (OPA) by Strategen Consulting entitled, "A Ratepayer Focused Strategy for Distributed Solar in Maine" (OPA White Paper). The complete white paper is available at:
http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf

Section 1 of the Resolve provided that in developing the alternative, the Commission shall:

1. Ensure the policy proposal includes fixed, long-term compensation mechanisms for distributed generation that, when feasible, obtain the best price for ratepayers using market-based competition or capacity-based step downs, as described in the OPA White Paper and ensures the maximum level of compensation for a given technology does not exceed the ratepayer benefits as determined by a Commission evaluation of the specific benefits of that technology;

2. Develop at least three aggregate market size scenarios representing low, medium and high estimates of the total installed capacity that would be developed under existing rate structures if net energy billing were to continue through 2021;

3. Ensure the alternative provides opportunities for meaningful participation by all market segments identified in the OPA White Paper, including residential, commercial, industrial, community and wholesale or grid-scale solar distributed generation;

4. Include a method to aggregate, capture and monetize for ratepayers the benefits of distributed generation assets, including, but not limited to, benefits related to energy supply, capacity and renewable energy credits, in order to maximize revenues for aggregation to all ratepayers and identify the appropriate entity to initially serve as an aggregator, while providing for the opportunity for third-party aggregation at a future date; and

5. Develop a process and timeline for transition from current net energy billing policies to the alternative solar policy that address the following:

    a. The continued availability of net energy billing pending an assessment of the alternative, or until such date as the Commission may recommend;

b. Options for participation by existing net energy billing customers in the alternative; and

c. Continuing opportunities for self-consumption by distributed generation customers once the alternative is fully implemented.

Section 2 of the Resolve directed the Commission to deliver a report to the Legislature that includes an overview of the stakeholder discussions; an overview of the new alternative solar policy developed; any areas where the stakeholders were unable to reach consensus; technical specifications, rules and policies that may be needed for implementation; a timeline for implementation; technical or legal barriers to implementation and any other recommendations. The Resolve requires that the report be submitted by January 30, 2016.

III. NET ENERGY BILLING PROGRAM

Net energy billing is a common mechanism with several variations used by many states to promote the installation and use of small renewable generation facilities. Net energy billing is a metering and billing practice that allows a customer who has his/her own generating facility (e.g., solar panel or wind turbine) to be billed on the basis of "net energy" over a billing period. Net energy is the difference between the kWhs a customer consumes and the kWhs produced by the customer's generating facility over the period. Thus, under NEB, any excess generation from a customer's own generating facility may be used as an energy credit to offset that customer's electricity usage at times when the customer's facility is not generating enough to meet the customer' electricity needs. Through this process, a NEB customer, in essence, receives the value of the full retail rate (approximately 13 cents/kWh) for any excess of generation above the customer's usage. This results in a decrease in utility revenues that is ultimately paid for by all ratepayers.

Net energy billing was not initially required or explicitly authorized by statute and is primarily a function of Commission rule.[2] The Commission initially adopted a NEB in the early 1980s as part of the rules implementing the federal Public Utility Regulatory Policies Act (PURPA) and Maine's Small Power Production and Cogeneration Act. These statutory provisions were intended to promote the development of non-utility renewable and cogeneration electric generation facilities referred to as qualifying facilities or QFs. The Commission initially adopted NEB rules as a means to reduce costs for very small generating facilities on a customer's premises by avoiding the costs of a second meter and, instead, allowing the meter to run in both directions. Under these rules, a customer's usage would be offset by generation within a billing period and any excess generation at the end of the month would be sold to the utility at its "avoided costs." Net energy billing was limited to renewable facilities with an installed capacity of 100 kW or less.

[2] In 2011, the Legislature enacted a statute that explicitly authorizes, but does not require, the Commission to adopt NEB rules, 35-A M.R.S section 3209-A.

In the late 1990s, the Legislature restructured Maine's electricity industry, requiring electric utilities to divest their generation assets and prohibited them from purchasing or selling generation related products and services. These services would instead be provided through a competitive market. As a result, the Commission amended the NEB rules to adopt an "annualized" NEB approach in which, rather than selling excess generation to utilities, customers that generate more than they use in a given month are provided "credits" that could then be used to offset usage over the following 12 months. At the end of the 12-month period, the credits expire. The Commission maintained the 100 kW capacity limit for eligible facilities.

The Commission's current net energy billing rules are a result of a major substantive rulemaking process in which the Legislature authorized changes in the rules that expanded NEB in two significant ways. First, the eligible facility limit was increased from 100 kW to 660 kW. Second, "shared ownership" NEB was authorized to allow several customers to net bill against the output of a jointly-owned generating facility.[3]

IV. OPA WHITE PAPER

The OPA White Paper contemplates the adoption of an overall program size or cap which would be broken down into the following distributed solar market segments: residential and small business; community solar; large commercial and industrial (C&I); and grid-scale. For all these segments, the OPA White Paper proposes that an aggregation entity or "Solar Standard Buyer" (SSB) would aggregate, purchase and monetize the value of all products from solar installations under the program, including energy, renewable energy credits (RECs), capacity value, and ancillary services. Centralizing procurement with the SSB would, according to the White Paper, allow for a more efficient aggregation and sale of the different attributes solar energy can provide. The underlying goal of this policy structure is to allow Maine ratepayers to capture the benefits of distributed solar energy while minimizing the costs and any inequities associated with the current program.

For residential and small business customers, the OPA White Paper proposes a firm contract price and a mechanism to lower contract prices over time based on pre-specified solar development trigger mechanisms. Under the OPA White Paper, there would also be programs for large C&I customers, community-based solar installations, and grid-scale projects. These programs would involve a competitive bid process in which the Commission would conduct reverse auctions for a specified level of installed

[3] The Commission's net energy billing rules provide that if the cumulative capacity of net energy billing facilities reaches one percent of the utility's peak demand, the Commission will review net energy billing to determine whether it should continue or be modified. Ch. 313, section 3 (J).

capacity, where only the lowest project bids would be accepted. As with residential and small commercial contracts, the output of the facilities would be purchased by the SSB.

V. STAKEHOLDER PROCESS AND DISCUSSIONS

On August 11, 2015, the Commission issued a Notice of Inquiry (NOI), Docket No. 2015-00218, initiating the stakeholder process and providing a preliminary schedule for stakeholder work sessions. The initial process proposal was modelled after the structures proposed in the OPA White Paper and designed to investigate different program elements and questions raised therein; however, the design was sufficiently fluid to accommodate stakeholder input and any refinements of the various program options identified by stakeholders. The NOI invited interested stakeholders to comment on the proposed schedule and expected discussion topics or any others that parties thought would be helpful or relevant to the Commission's efforts. The Commission also advised interested persons that if they wished to submit comments but not otherwise participate in the stakeholder process they could do so at any time throughout the proceeding. The NOI was sent to interested persons including members of the Energy, Utilities and Technology Committee and all individuals or entities that testified on LD 1263, the bill that resulted in the Resolve creating the stakeholder process. A large number of stakeholders participated throughout the process.

Work Session I was held on September 10, 2015 and focused on a discussion of the process, a presentation on the OPA White Paper, developing the NEB penetration scenarios required by the Resolve and related questions. Work Session II was held on September 23, 2015. Stakeholders discussed NEB penetrations and market segmentation. Work Session III was held on October 7, 2015 and focused on overall program size and market segment subdivisions as well as discussion of the grid-scale and large commercial and industrial market segment procurement mechanisms. During Work Session IV, held on October 22, 2015, there was further discussion of the grid-scale and large commercial and industrial procurement mechanisms as well as the community and residential and small commercial market procurement mechanisms. Upon the completion of Work Session IV, stakeholders generally agreed that an additional work session would be helpful. Commission Staff developed a revised schedule to reflect the progress of discussions at that time and to incorporate sufficient additional discussion time of relevant issues.

During Work Session V, held on November 16, 2015, there was further discussion of the program design for the community solar and residential/small commercial market segments and also of possible transitions away from NEB and the treatment of RECs. During Work Session VI, held on December 9, 2015, there were additional discussions of the residential and small commercial market segment and market-based step downs, transitioning from NEB, treatment of RECs and the financial model used by the OPA to estimate payments and revenues of the alternative. This meeting also included a public comment period. As stakeholders had not been able to discuss all issues in the six meetings, an additional stakeholder meeting was scheduled. During Work Session VII, held on January 6, 2016, there was more discussion of the residential and small commercial market procurement mechanism including the stepdown mechanism and price levels, the transition from NEB, the structure, operations and responsibilities of the Standard Solar Buyer, a revised community solar market segment program, revisions to the OPA's financial model, what aspects of the alternative should be in statute and what should be left to a Commission rulemaking proceeding and remaining outstanding issues.

All sessions were hosted by the Commission at its offices at 101 Second Street in Hallowell. Detailed agendas were prepared and posted in the Docket the week before each stakeholder meeting. The agendas are attached as Attachment B. Commission Staff filed meeting summary memos after each stakeholder work session summarizing areas of apparent consensus, discussion topics and issues to be discussed at later meetings. These meeting summaries are attached as Attachment C. Stakeholders also had the opportunity to file comments after each stakeholder meeting and on Commission Staff summaries of areas of consensus and non-consensus with respect to the overall program size and market segment caps, grid-scale market segment procurement mechanisms, large C&I market segment procurement mechanism and the NEB scenarios through 2021. All comments are available in the Docket on the Commission's website at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2015-00218

A list of stakeholders who participated in these meetings is attached as Attachment D.

VI. SOLAR PROCURMENT MECHANISMS - ALTERNATIVE TO NET ENERGY BILLING

1. <u>OVERVIEW</u>

The stakeholders reached substantial agreement on a large number of important aspects of a market-based solar development policy and on some aspects of an alternative to NEB. As discussed above, the stakeholder group discussed a program for four distinct market segments: 1) grid-scale, 2) large C&I, 3) community solar and 4) residential and small commercial. There was substantial agreement about the structure of programs in the first three segments, but significant disagreement on major aspects of the residential and small commercial program. Thus, there was no stakeholder consensus on an overall solar program. It should be emphasized that NEB is primarily a residential and small commercial program, and that most of the substantial stakeholder disagreement involves the residential and small commercial procurement program which would serve as the alternative to NEB.

The stakeholder group discussions and a variety of the group's agreements involve very detailed matters that would not normally be included in legislation. The stakeholder group contemplates such issues would finally be determined through subsequent Commission rulemakings.

2. <u>OVERALL PROGRAM SIZE</u>

There was substantial agreement that the overall program size should be set at 255 MW, with the following breakdown of the various market segments:

Segment	% of Market	Total MWs
Residential & Small Business	49%	125
Community	17%	45
Large Commercial / Industrial	10%	25
Grid-scale	24%	60
Total		255

However, there were stakeholders that disagreed with the overall program size and with the allocations among market segments.

3. <u>GRID-SCALE AUCTION MECHANISM</u>

Under this market segment, the Commission would procure an average of 15 MW of solar capacity a year (up to a total of 60 MW) through biannual requests for proposals for solar projects of up to 5 MW in size. The mechanism would be similar to the Commission's existing long term contracting authority, with 20-year contracts for the entire output of a solar facility.

a. <u>Procurement Process</u>

There was substantial agreement among the stakeholders on the following aspects of the procurement process:

- In each auction, a specified amount of capacity is available for developers to bid on;

- Bidders would specify a fixed 20 year price in a standardized, must take contract. The details of the standard contract would be worked out in a subsequent Commission rulemaking proceeding;

- To be eligible for a contract, bidders must demonstrate minimum viability requirements (*e.g.*, site control, development experience, interconnection application), and pay an application fee;[4]

- Projects may interconnect at either the distribution or transmission level;

- The Commission selects projects in order of least-cost/highest value up to the allocation level and enters into contracts with winning bidders;

- No bid exceeding the per kWh price of the residential/small commercial segment step-down procurement price active at the time of the auction would be awarded a contract, even if it was the lowest bid;

- Any remaining unallocated capacity available would be rolled forward into the total capacity procurement in the next auction; and

- Regular auctions would be held every six months.

There was also substantial agreement that the program would procure the grid-scale capacity allocation (60 MW) over four program years (*e.g.,* 2017-2020). The table below provides parameters for the first two program years, with the goal of procuring approximately half of the capacity allocation.

Total Allocation	60 MW
Auction Frequency	Every 6 months
Auction 1 – Q1 2017	6 MW
Auction 2 – Q3 2017	7 MW
Auction 3 – Q1 2018	8 MW
Auction 4 – Q3 2018	9 MW
Cumulative Total After Program Year 2	30 MW (50%)

[4] The application fee would be set at an amount sufficient to ensure credible proposals, and to defray administrative costs associated with the procurement. As an initial starting point, the group discussed $0.50 per kW.

The balance of the allocation would be determined in the remaining two years (*i.e.,* 2019 and 2020), subject to any modification to the auction mechanism based on experience in the first two years of the program.

b. Ensuring Competitive Proposals

The following mechanisms are intended to ensure that bids are competitive:

- Capping maximum project size at the lesser of 5 MW or half of the total auction cap. For example, if the total capacity available for auction were 6 MW, the maximum project size would be 3 MW. This would ensure at least two winning bidders, spreading programmatic risk.

- Requiring that each auction receive credible project bids from unaffiliated entities totaling at least three times the available capacity in order for contracts to be awarded. If an auction is deemed uncompetitive, no contracts would be awarded and the capacity allocation would be deferred to the next round with the threshold only pertaining to the original amount of MWs. A non-competitive auction would also trigger Commission review to identify potential changes to the auction process that would increase competition.

- Winning bidders, winning contract price(s), and related auction information (*e.g.* average price, number of bidders) are released to the public prior to the next auction round.

c. Developer Obligations

The stakeholders also agreed that there should be developer deposit and milestone requirements. The milestones that were discussed would include:

Months From Award	Milestone
1	• Submit non-refundable deposit
6	• Financing in place
12	• All local and state permits obtained • Utility interconnection approval obtained • Engineering Procurement and Construction (EPC) contract in place
18	• Begin Construction
24	• Commercial operation

d. Other Considerations

- Utilities may provide maps to assist developers in identifying suitable interconnection sites, though final determination of interconnection costs would be subject to existing utility interconnection processes; and

- The Commission may consider additional incentives or selection "points" for projects that provide benefits to the grid through avoided transmission or distribution investments, additional reliability/dispatchability through use of smart inverters or storage, and/or for projects built on brownfield sites. To the extent such "points" are desired, stakeholders understood a clear rubric would need to be spelled out so as not to create additional administrative burdens of individual project evaluation.

4. LARGE COMMERCIAL AND INDUSTRIAL PROCUREMENT MECHANISM

For this market segment, the general agreement was that the Commission would hold bi-annual reverse auctions for 20-year contracts for the full output of solar generation sited at the facilities of large commercial and industrial customers. The facilities could range in size from 250 kW up to 1 MW, with a total procurement of 25 MW. Upon commercial operation of the solar facility, these customers would receive a monthly bill credit equal to the delivered AC output (not the nameplate DC output) of the facility for the prior month times the contract price.

a. Procurement Mechanism

There was substantial stakeholder agreement on the following aspects of the program:

- In each auction, a specified amount of capacity is available for developers to bid on;

- Bidders specify a fixed price for a standardized must take contract of 20 years;

- Minimum facility size would be 250 kW (the cutoff for small business eligibility), maximum size would be 1 MW;

- To be eligible for a contract, bidders must demonstrate minimum viability requirements (*e.g.*, signed customer consent to bid form, development experience, system details), and pay an application fee;

- The Commission selects projects based on cost and project characteristics, up to the allocation level and the Standard Solar Buyer enters into contracts with winning bidders; and

- Auctions would be held biannually, and could be scheduled so as to be staggered with the grid-scale and/or community solar procurements. The program would procure the Large C&I capacity allocation (25 MW) over four program years (*e.g*. 2017-2020). The table below provides a proposed annual allocation for each program year.

Large Commercial & Industrial	
Total Allocation	**25 MW**
2017 Procurement	5 MW
2018 Procurement	6 MW
2019 Procurement	7 MW
2020 Procurement	7 MW

b. <u>Ensuring Competitive Proposals</u>

The following mechanisms are intended to ensure that bids are competitive:

- Capping project size at 1 MW. These allocations would result in biannual auction amounts of at least 3 MW, sufficient to support a minimum of two projects per auction;

- Requiring that each auction receive credible project bids from unaffiliated entities totally at least two times the available capacity in order for contracts to be awarded. If an auction is deemed uncompetitive, no contracts are awarded and the capacity allocation is deferred to the next round with the threshold only pertaining to the original amount of MWs. A non-competitive auction would also trigger Commission review to identify potential changes to the auction process that would increase competition; and

- Winning bidders, winning contract price(s), and related auction information (*e.g.,* average price, number of bidders) are released to the public prior to the next auction round.

c. Customer Obligations

The stakeholders also agreed that, upon selection, there should be customer deposit and milestone requirements. The milestones that were discussed would include:

Months From Award	**Milestone**
1	• Submit non-refundable deposit
6	• Financing in place
9	• All local and state permits obtained • Utility interconnection approval obtained • EPC contract in place
12	• Begin Construction
18	• Commercial operation

d. Bill Crediting

There was also substantial stakeholder agreement on the following issues related to bill credits:

- The facility will be metered separately from the customer's load. Upon commercial operation, customers will receive a monthly bill credit equal to the output of the facility for the prior month times the contract price. All customer usage will continue to be metered, and billed based on the applicable rate schedule;

- A host customer may apply excess credits to other meters, even those at remote sites, provided they are on the same customer account; and

- Any credits in excess of the customer's total monthly bill will be retained for future months (i.e., a customer's monthly bill cannot be less than zero).

The initial proposal was that all unused credits would expire at a specified date each year. However, several stakeholders took the position that the ability to roll credits forward should continue for a longer period.

5. COMMUNITY SOLAR PROCUREMENT MECHANISM

There was substantial stakeholder agreement that the procurement mechanism for larger community solar mechanism should be similar to that for grid-scale facilities with auctions would be held every 6 months. The notable differences are lower barriers of entry (*e.g.,* less stringent deposits) and the allocation of provisions and consumer protection measures associated with sharing the output of a developed solar facility among multiple customers. Smaller community solar projects (below 250 kW) would not participate in the auction process, and would receive the currently applicate contract price for residential and small commercial customers.

a. Procurement Mechanism

The general understanding of a community solar project is that the developer would undertake customer aggregation for participation in a community solar project and provide proposals for consideration through the auction mechanism. Bill credits based on the proposal would be applied directly to individual customer bills as described in greater detail below.

There was substantial agreement on the following aspects of the program:

- In each auction, a specified amount of capacity would be available for developers to bid on;

- Bidders specify a fixed price for a standardized must take contract of 20 years;

- No minimum facility size. Maximum size would be 3 MW;

- To be eligible for a contract, bidders must demonstrate minimum viability requirements (*e.g.*, site control, development experience, interconnection application, system details) and pay an application fee;

- The application fee and eligibility requirements would be relaxed for municipalities and non-profits.

- The Commission selects projects based on cost and project characteristics, up to the allocation level and the SSB would enter into contracts with winning bidders; and

- No single customer may be allocated more than 50% of a project's total installation size. There was a suggestion that each project allocate 50% of its capacity to residential customers, but it was unclear whether there was any significant agreement on this particular design element.

There was significant discussion regarding the desirability of a Commission certification/licensing process that would ensure developer viability and address consumer protection and disclosure issues. There was also discussion about how to specifically define a community solar project and a possible RFP approach where issues other than lowest cost could be considered. For example, one discussion centered on whether the benefits of brownfield development should be considered in proposal evaluations. Finally, there was discussion, but no agreement, on whether the auction approach for community solar projects (in particular, smaller projects) should be replaced by an alternative mechanism.

The mechanism would procure the community solar capacity allocation of 45 MW over four program years (e.g. 2017-2020), although it was recognized that additional time may be needed before beginning these auctions to account for additional complexities in program design (*e.g.*, subscriber details). The auctions could be either combined or staggered with the grid-scale and C&I auctions to ease administrative burden. The table below provides the discussed annual allocation for each program year, but the extent of stakeholder agreement is unclear.

Community Solar	
Total Allocation	45 MW
2017 Procurement	8 MW
2018 Procurement	10 MW
2019 Procurement	12 MW
2020 Procurement	15 MW

b. <u>Ensuring Competitive Proposals</u>

There was substantial stakeholder agreement on the following mechanisms which are intended to ensure that proposals are competitive:

- Capping project size at 3 MW. These allocations would result in semi-annual auction amounts of at least 4 MW being available;

- Requiring that each auction receive credible bids from unaffiliated entities totaling at least two times the available capacity in order for contracts to be awarded. If an auction is deemed uncompetitive, no contracts are awarded and the capacity allocation is deferred to the next round; and

- Winning bidders, winning contract price(s), and related auction information (*e.g.* average price, number of bidders) are released to the public prior to the next auction round.

The following milestones were proposed, although there was some discussion that this level of program specificity may be better addressed in a Commission rulemaking:

Months From Award	Milestone
1	• Submit non-refundable deposit per kWh
6	• Financing in place
12	• All local and state permits obtained • Utility interconnection approval obtained • Engineering Procurement Construction (EPC) contract in place
18	• Begin Construction
24	• Commercial operation

c. Bill Crediting

There was also substantial stakeholder agreement on the following issues related to bill credits:

Upon commercial operation, subscribers would receive a monthly bill credit equal to their share of the output of the facility for the prior month times the rate established. The bill credit rate for all participating customers for a given project must be the same;

- Customers should be limited to subscribing to only one project so as to avoid potential administrative problems on how to apply credits;

- Credits should remain in the same utility service territory (i.e., if the project is in CMP's service territory, only CMP customers may participate);

- All customer usage will continue to be metered, and billed based on the applicable rate schedule; and

- Any credits in excess of the customer's total monthly bill would be retained for future months (*i.e.*, a customer's monthly bill cannot be less than zero.

There was no agreement on the proposal that all unused credits expire at a specified date each year. Some stakeholders proposed the ability to roll credits forward for a longer period.

6. RESIDENTIAL AND SMALL COMMERCIAL PROCUREMENT – ALTERNATIVE TO NET ENERGY BILLING

a. General Program Design

The residential and small commercial procurement mechanism would serve as the alternative to NEB. Although there was substantial agreement among the stakeholders on many aspects of this program, there was significant disagreement on fundamental details of the program design and its operation, as well as the transition from NEB.

The stakeholders did reach substantial agreement on the overall design of a residential and small commercial program. Under that program, the customer would enter into a fixed price 20 year contract for the net output of a solar facility with the SSB at pre-determined price levels.[5] The payment would be based on a per kWh rate that would appear as a monthly bill credit on the customer's bill (similar to Maine's existing NEB structure). There was also discussion, but no agreement, on a fixed price approach in which the price escalates at a fixed rate over the term of the contract.

For this customer group, there would be a declining trigger mechanism based on installed solar capacity that would automatically decrease the level of compensation for new customers entering into contracts. The capacity-based stepdown approach reduces the contract price by a certain amount at each step. The number of MWs available at each step increases with each consecutive step. Once the capacity based step down mechanism is in place, preset adjustment mechanisms to the compensation rate are triggered if certain events happen (e.g., market installations are below a certain level, federal investment tax credit sunsets) to stimulate more installations.

The capacity-based stepdowns are intended to substitute for the market-based pricing mechanisms used for the other market segments in recognition that such mechanisms would be impractical for residential and small commercial customers. Like those market mechanisms, the stepdowns are intended to, over the five year period covered by the program, bring prices closer to cost and create incentives for installers to reduce installation costs.

[5] CMP disagreed with the long-term contract approach, preferring that payment be based on current market value. If there is a contracting approach, CMP's position is that the term be shorter and that prices escalate over the contract term.

b. Purchase Price and Capacity Stepdowns

The stakeholders did not reach agreement on the fundamental issue of the initial purchase price under the program and on how those purchase prices would be reduced over time through the capacity stepdowns. Stakeholder positions on the initial purchase price ranged from 18.5 cents/kWh to the prevailing market price at the time the contract is entered, which may be in the range of 10 cent/kWh.

c. Customer Self Consumption

Under the OPA's original proposal, the output of the solar facilities would have been separately metered, and the SSB would purchase the entire output and all attributes associated with the facility (e.g., renewable energy credits, capacity value, etc.) referred to as the "buy-all, sell-all" approach. A number of stakeholders advocated that customers should retain the ability to self-consume their on-site generation. After lengthy discussion, there was substantial agreement that customers should be able to self-consume and that the SSB would purchase only the net amounts of electricity exported to the system.

d. Renewable Energy Credits

Under the OPA's original proposal, the SSB would purchase and monetize all attributes from the solar facilities, including the RECs. There was substantial discussion regarding whether customers should be able to retain the environmental attributes, in the form of RECs, associated with the solar facility output. The OPA presented a proposal in which all RECs would be purchased by the SSB, but those customers wishing to claim the environmental benefits would have the option to participate in the Maine Green Power program either through the current product offering or a to-be-developed premium Maine solar offering. There was substantial stakeholder agreement on this approach, but there were stakeholders that expressed some reservations.

e. Transition from NEB to the Alternative

The stakeholders did not reach agreement on the transition from NEB to the alternative. Some stakeholders advocated that customers continue to have the option of NEB under current rules for a time period of time while the alternative is available. Most stakeholders appeared to agree that that current NEB mechanism should at least be suspended so that the alternative can be reasonably evaluated.

f. Bill Crediting

As with the other industry segments, there was substantial agreement that customers would receive a monthly bill credit equal to the exports of the facility for the prior month times the contract price and that any credits in excess of the customer's total monthly bill will be retained for future months (i.e., a customer's monthly bill cannot be less than zero). As noted in the other market segments, there was disagreement regarding when these credits would expire.

7. STANDARD SOLAR BUYER

The purpose of the Standard Solar Buyer is to aggregate the output of the solar portfolio procured in each market segment and sell the various products into the applicable market to maximize the benefits of this portfolio of resources to ratepayers. The primary means of capturing these benefits would be sale of the energy, capacity, and environmental attributes into the applicable New England markets. Revenue from these sales would offset ratepayer costs associated with the payments made to solar developers and customers under the long term contracts associated with each procurement mechanism.

There was substantial agreement among the stakeholders that, at the outset of the program, the investor-owned T&D utilities should serve as the Standard Solar Buyer in their respective service territories. However, the stakeholders agreed that there should be a process by which the Commission may transfer the obligation to serve as Standard Solar Buyer to another entity at a future date, as well consideration of opportunities for third-parties to aggregate and sell a portfolio of distributed generation resources in same manner as the Standard Solar Buyer.

VII. ESTIMATED INSTALLED SOLAR CAPACITY UNDER NET ENERGY BILLING

Section 1(2) of the Resolve states that in developing an alternative to net energy billing, the Commission shall:

> "Develop at least 3 aggregate market size scenarios representing low, medium and high estimates of the total installed capacity that would be developed under existing rate structures if net energy billing were to continue through 2021."

The Commission used various approaches, including obtaining technical support from the National Renewable Energy Laboratory (NREL), to develop these market scenarios. Guided by the Commission's initial sensitivities, stakeholders agreed that plausible medium and high estimates for 2021 would be 100 and 200 MW. Subsequently, NREL provided medium and high estimates that were 146 and 189, respectively. NREL's low estimates were based on expiration of the solar investment tax credit, which was subsequently extended by Congress in December of 2015, and are therefore no longer valid.

Although not required by the Resolve, stakeholders expressed interest in also understanding the amount of grid-scale solar that might be developed in Maine by 2021. These projects would not be net metered and were not assumed to receive any subsidy from Maine ratepayers. Based upon various sources of information, the stakeholders agreed on the following future scenarios:

Scenario	Total	NEB Eligible	Grid-scale
LOW	50	50	0
MEDIUM	140	100	40
HIGH	270	200	70

As noted above, the Commission also sought and received support from the NREL through its Solar Technical Assistance program. NREL developed four net energy billing scenarios utilizing its dSolar model following the parameters of the Resolve. Variables adjusted in the scenarios were the installed PV cost trajectory, retail electricity prices, load growth, and whether the federal investment tax credit would be extended.[6] The NREL results were as follows:

NREL Scenario	**State-wide Installed Capacity of Distributed PV under NEB(MW dc)**					
	2016	2017	2018	2019	2020	2021
High PV Adoption	25	40	54	89	124	189
Medium PV Adoption – ITC Extends	24	38	52	76	101	146
Medium PV Adoption – ITC Expires	24	32	39	56	72	97
Low PV Adoption	20	23	25	30	34	40

[6] At the time, the 30% Investment Tax Credit for residential and commercial solar systems was set to expire December 31, 2016, after which it would be eliminated for residential systems and reduced to 10% for commercial systems.

The NREL estimates are generally consistent with the scenarios considered plausible by the stakeholders. Subsequently, Congress enacted an omnibus appropriations bill which extended the 30% investment tax credit for solar through 2018, with step downs to 10% by 2022. Therefore, the scenarios that assume expiration of the Investment Tax Credit at the end of 2016 are no longer applicable.

VIII. TECHNICAL SPECIFICATIONS, RULES NEEDED TO IMPLEMENT THE ALTERNATIVE

During the stakeholder meetings, a number of complex matters were identified as more appropriately determined through a Commission rulemaking proceeding. This is due to the timeframe stakeholders had to develop a solar promotion mechanism and an alternative to NEB, the complexity of many of the issues involved, and that such issues are generally determined through agency rulemaking rather than legislation. These issues include, but are not limited to, a mid-program review of the mechanism; developing a standard contract/agreement; project development milestones; issues related to customer bill credits (e.g., administrative issues related to standardization of credits, tracking credits, accounting issues and when credits would expire); various aspects of the community solar market segment procurement mechanism (including how to define applicants, reporting, enforcement and consumer protection requirements; structural auction details; a potential carve-out for low-income customer participation; issues related to the subscription rate thresholds, relaxed application fee and eligibility requirements for non-profits and municipalities and defining restrictions on co-location of facilities.