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# Analysis of 2025 Net Benefits of Net Energy Billing Program

Prepared for:  
Maine Public Utilities Commission



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March 31, 2026







STATE OF MAINE  
PUBLIC UTILITIES COMMISSION

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March 31, 2026

Honorable Mark Lawrence, Senate Chair  
Honorable Melanie Sachs, House Chair  
Members, Joint Standing Committee on Energy, Utilities and Technology  
100 State House Station  
Augusta, Maine 04333

RE: 2025 NEB Cost-Benefit Analysis Report

Dear Senator Lawrence, Representative Sachs and Members of the Joint Standing Committee on Energy, Utilities and Technology:

35-A M.R.S. § 3209-C(3) directs the Maine Public Utilities Commission (Commission) to annually determine the costs and benefits of distributed generation under net energy billing (NEB) and provide the results for the prior year in a report to the Legislature by March 31. The report must include a determination of which costs and benefits are monetized and to whom the monetized value accrues. The Commission engaged Sustainable Energy Advantage (SEA) to provide the Report.

The Commission has completed the Report, and it is attached. The Report is accompanied by comments as filed in Docket No. 2026-00053.<sup>1</sup> The background, findings of the report, and recent changes to the process are described below.

In Docket No. 2024-00149, the Commission conducted an investigation into the costs and benefits of NEB.<sup>2</sup> The Net Energy Billing Report as prepared by SEA for calendar year 2023 was used as the basis for the investigation. In the stipulation approved by the Commission at the conclusion of the investigation, the Stipulating Parties concluded that there were no additional benefits monetized by the utilities that could be used to adjust stranded costs.<sup>3</sup> The stipulation also concluded that while there were aspects of the reports that could be improved, there was no

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<sup>1</sup> *Maine Public Utilities Commission, Commission Initiated Summary Investigation Seeking Comment on the 2025 Net Energy Billing Report,*

<sup>2</sup> *Maine Public Utilities Commission, Commission Initiated Investigation into Allocation of Benefits of Distributed Generation Under Net Energy Billing*

<sup>3</sup> Docket No. 2024-00149, Stipulation at 4 (Oct. 15, 2025)

need for further adjudication of the 2023 and 2024 reports with respect to the Commission's reporting requirements under 35-A M.R.S. § 3209-C(3).<sup>4</sup>

The Stipulating Parties also filed a cover letter urging the Commission to revise its process for issuing future reports. In particular, the Stipulating Parties suggested that “the Commission issue a draft of the report and convene a non-adjudicatory proceeding affording interested parties a reasonable opportunity to review the draft report and provide input thereon for the Commission's consideration.” For the 2025 report, the Commission opened Docket No. 2026-00053 to provide this opportunity for comment.

For calendar year 2025, SEA concluded that the costs of the NEB program were \$313 million and the benefits were \$257 to \$391 million. The range of benefits depends on whether greenhouse gas benefits claimed regionally (i.e. through the selling of renewable energy certificates into the regional market) are considered as benefits to Maine in the analysis. SEA included several changes to the Report in response to stakeholder feedback in Docket No. 2024-00149; these changes are summarized in Section 2.5 and noted throughout the Report.

The Commission has carefully reviewed the public comments collected in Docket No. 2026-00053 and concludes that no further changes are warranted to the Report for calendar year 2025. The Commission will take the comments under advisement when developing reports in future years.

Sincerely,

A handwritten signature in black ink, appearing to read 'P. Bartlett II', is enclosed within a rectangular box.

Philip L. Bartlett II

cc: Lindsay Laxon, Legislative Analyst, Office of Policy and Legal Analysis

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<sup>4</sup> Id.



## Table of Contents

|        |                                                                      |    |
|--------|----------------------------------------------------------------------|----|
| 1      | Executive Summary .....                                              | 1  |
| 2      | Introduction.....                                                    | 3  |
| 2.1    | LD 1986 Reporting Requirements .....                                 | 3  |
| 2.2    | General Approach & Data Sources.....                                 | 4  |
| 2.3    | Components Included in the Cost / Benefit Analysis .....             | 5  |
| 2.4    | Choosing a Perspective for the Net Benefits Analysis .....           | 6  |
| 2.5    | Summary of Revisions to Prior Methods.....                           | 7  |
| 3      | Detailed Approach to Modeling .....                                  | 7  |
| 3.1    | General Issues and Approach.....                                     | 7  |
| 3.2    | AESC Inputs .....                                                    | 9  |
| 3.3    | Quantification of Program MW and MWh .....                           | 9  |
| 3.4    | Revenue from Energy Resale .....                                     | 10 |
| 3.5    | Capacity Buyout Revenue .....                                        | 10 |
| 3.6    | Uncleared Capacity .....                                             | 11 |
| 3.7    | Reduced Share of Capacity Costs .....                                | 12 |
| 3.8    | Transmission and Distribution Benefits .....                         | 13 |
| 3.8.1  | Avoided Transmission and Distribution Investments .....              | 13 |
| 3.8.2  | Avoided Maine Regional Network Service Share.....                    | 14 |
| 3.8.3  | Avoided Transmission and Distribution Line Losses .....              | 15 |
| 3.8.4  | Transmission And Distribution Upgrades Funded by NEB Customers ..... | 16 |
| 3.9    | Demand Reduction Induced Price Effects (DRIPE) .....                 | 16 |
| 3.10   | Renewable Energy Certificate (REC) Price Suppression .....           | 17 |
| 3.11   | REC Revenue .....                                                    | 18 |
| 3.12   | Reduced RPS Requirements.....                                        | 18 |
| 3.13   | Societal Benefits from Greenhouse Gas Reduction .....                | 19 |
| 3.14   | Improved Generation Reliability .....                                | 20 |
| 3.15   | Modeling Cost Components.....                                        | 21 |
| 3.16   | Impacts of kWh Credit Program on Retail Generation Supply Costs..... | 22 |
| 3.16.1 | Quantifying Fixed Costs: Capacity.....                               | 25 |
| 3.16.2 | Quantifying Fixed Costs: Direct.....                                 | 25 |



|        |                                                                         |      |
|--------|-------------------------------------------------------------------------|------|
| 3.16.3 | Quantifying Cost of Added Volumetric Risk.....                          | 26   |
| 3.16.4 | Banking of kWh Credits .....                                            | 29   |
| 3.16.5 | Change in Load Shape Settled .....                                      | 31   |
| 3.16.6 | Avoided Energy as a kWh Credit Program Benefit.....                     | 33   |
| 4      | Results and Findings .....                                              | 34   |
| 4.1    | General Societal Perspective.....                                       | 34   |
| 4.2    | Monetization of Benefits and Costs .....                                | 39   |
| 4.3    | Sensitivity Analysis of Maine Societal and Ratepayer Perspectives ..... | 41   |
| A      | Appendix A – Component-level Results.....                               | A-1  |
| A.1    | Tariff Rate Program (2025) – Societal Perspective.....                  | A-1  |
| A.2    | kWh Credit Program (2025) – Societal Perspective .....                  | A-3  |
| A.3    | Tariff Rate Program (2025) – Maine Perspective .....                    | A-5  |
| A.4    | kWh Credit Program (2025) – Maine Perspective.....                      | A-7  |
| A.5    | Tariff Rate Program (2025) – Ratepayer Perspective .....                | A-9  |
| A.6    | kWh Credit Program (2025) – Ratepayer Perspective.....                  | A-11 |



# 1 Executive Summary

In the 2023 Legislative session, LD 1986 “An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems” was enacted (the Act).<sup>1</sup> The Act directs the Maine Public Utilities Commission (Commission) to annually determine the net energy billing (NEB) costs and benefits of distributed generation (DG) under NEB and provide the results for the prior year in annual reports to the legislature by March 31<sup>st</sup>. The Act also requires designation of which benefits and costs are monetized and who such benefits accrue to.

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive evaluation to determine the net benefits of DG under Maine’s two NEB program variants (the kilowatt hour credit program and the tariff rate program).<sup>2</sup> This document describes SEA’s methodology and quantification of the calendar year 2025 net benefits of NEB for projects within three electric distribution companies (EDCs) service territories.

- Central Maine Power (CMP);
- Versant Power - Bangor Hydro District (Versant-BHD); and,
- Versant Power - Maine Public District (Versant-MPD).

Leveraging both public, soon to be public and confidential data sources, including the most recent relevant publicly available, New England regional avoided energy supply cost study, SEA quantified the benefits and costs of the NEB program for calendar year 2025. A graphical summary of the analysis is provided in Figure 1 and a tabular summary in Table 1.

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<sup>1</sup> See <http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131>

<sup>2</sup> Legislation describing these programs can be found at <https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html> and <https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html>



**Figure 1 –  
Calendar Year 2025 NEB Program Summary Cost and Benefit**

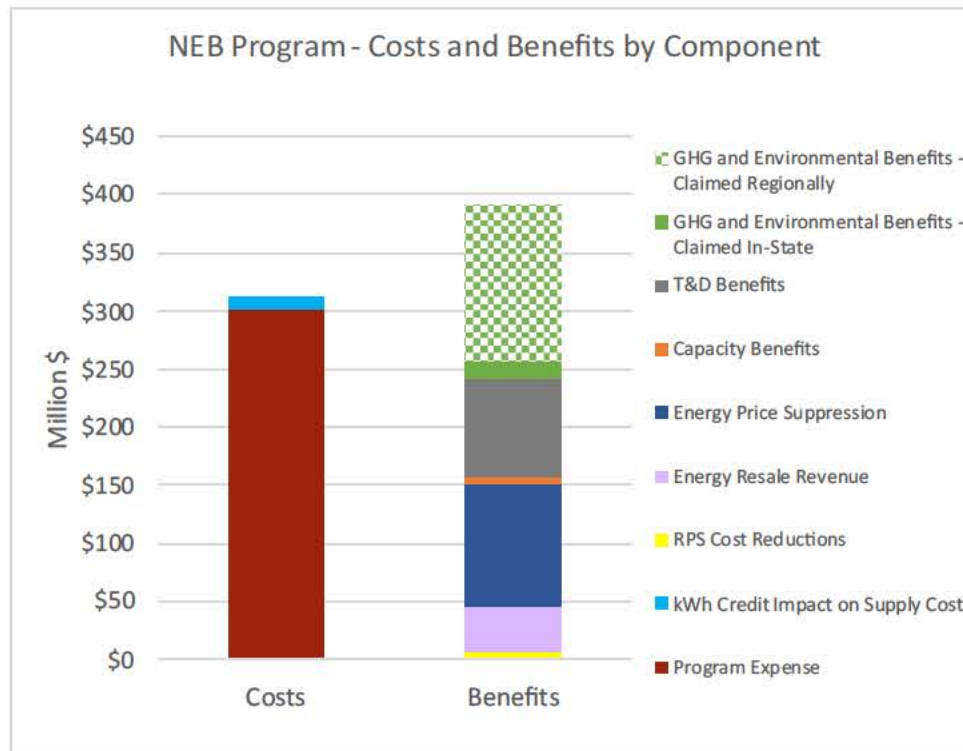


**Table 1 -  
2025 NEB Program Summary Cost and Benefit in Millions of Dollars**

| Benefit / Cost Category                             | Costs    | Benefits |
|-----------------------------------------------------|----------|----------|
| Program Expense                                     | \$302.45 | N/A      |
| kWh Credit Impact on Supply Cost                    | \$10.44  | N/A      |
| RPS Cost Reductions                                 | N/A      | \$6.39   |
| Energy Resale Revenue                               | N/A      | \$39.60  |
| Energy Price Suppression                            | N/A      | \$105.77 |
| Capacity Benefits                                   | N/A      | \$5.24   |
| Transmission and Distribution (T&D) Benefits        | N/A      | \$84.56  |
| GHG and Environmental Benefits - Claimed In-State   | N/A      | \$14.95  |
| GHG and Environmental Benefits – Claimed Regionally | N/A      | \$134.90 |
| Totals – Including GHG Benefits Claimed Regionally  | \$312.89 | \$391.40 |
| Totals – Excluding GHG Benefits Claimed Regionally  | \$312.89 | \$256.51 |



SEA calculates that the NEB 2025 calendar year program expenses were \$313 million, and the program benefits were between \$257 and \$391 million, depending on if greenhouse gas (GHG) benefits claimed regionally are considered in the analysis.<sup>3</sup> Note that the cost and expenses are for all NEB projects operating in 2025. Thus, the impact of projects as old as 1994 are included in the analysis.

Importantly, these results are not reflective of possible future marginal costs and benefits of additional capacity coming online in the future. Given that certain benefits, namely benefits associated with avoided transmission and distribution costs, are subject to declining marginal benefits, additional projects reaching commercial operation under the program in the future are expected to have a reduced benefit/cost ratio relative to the program-wide totals reported here.

In addition, as discussed further in Section 3.13, SEA has broken out the benefits associated with GHG reduction that are assumed to be claimed by other states buying and retiring RECs to meet their renewable portfolio standards. Such benefits are flagged with green hatching in Figure 1, to better differentiate from the benefits assumed to be claimed in-state.

These results were based on recent large increases in the growth of the NEB program which ended calendar year 2025 with an installed capacity of 1,271 MW<sub>AC</sub>. Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a substantial addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

## 2 Introduction

In the 2023 Legislative session, LD 1986 “An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems” was enacted (the Act).<sup>4</sup> The Maine Public Utilities Commission (Commission) is tasked per LD 1986 with providing annual reports on the net benefits of the Net Energy Billing (NEB) to the legislature by March 31<sup>st</sup> of the following calendar year. The Act also requires designation of which benefits and costs are monetized and who such benefits accrue to.

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive evaluation to determine the net benefits of distributed generation under the Maine’s two NEB program variants (the kilowatt hour program and the tariff rate program).<sup>5</sup> Working hand-in-hand with the Commission, this document describes SEA’s methodology and quantification of the calendar year 2025 net benefits of the NEB program for projects within three electric distribution companies (EDCs) service territories.

- Central Maine Power (CMP);
- Versant Power - Bangor Hydro District (Versant-BHD); and,
- Versant Power - Maine Public District (Versant-MPD).

### 2.1 LD 1986 Reporting Requirements

The Act requires the Commission to monitor the level of solar energy development in Maine in relation to the goals set forth in 35-A M.R.S. § 3474<sup>6</sup>, as well as the basic trends in solar energy markets, and the relative costs and benefits from solar energy development, including but not limited to:

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<sup>3</sup> For a majority of the NEB program, the GHG benefits associated with RECs produced may be claimed by other states purchasing and retiring RECs sold into the regional marketplace.

<sup>4</sup> See <http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131>

<sup>5</sup> Legislation describing these programs can be found at <https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html>

<sup>6</sup> See <https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html>



- A. Revenue from the sale of renewable energy credits;
- B. Societal benefits through avoided greenhouse gas emissions;
- C. Reduced electricity prices; and
- D. Avoided or reduced costs associated with:
  - (1) Electricity capacity requirements;
  - (2) Environmental compliance requirements;
  - (3) Portfolio requirements established in section 3210;
  - (4) Renewable energy credit price suppression; and
  - (5) Electricity transmission and distribution costs.

We observe that the statutory reporting requirements listed above in this subsection notably do not include project sponsor costs (i.e., the costs to develop, install and maintain a solar project). As such we infer that the requested cost / benefit analysis was from a programmatic basis perspective (versus a project sponsor basis). More detail on analysis perspective is provided in Section 2.4.

## 2.2 General Approach & Data Sources

The Act defines benefits of distributed generation under NEB and, requires the Commission to provide analysis regarding such benefits, as follows:<sup>7</sup>

1. Avoided energy and capacity costs. In determining avoided energy and capacity costs, the Commission must use reasonable estimates of energy and capacity market prices and account for transmission and distribution line losses. The Commission may determine different avoided costs for different time periods, including, but not limited to, peak and off-peak periods and summer and winter periods;
2. Avoided transmission and distribution costs. In determining avoided transmission and distribution costs, the Commission must use estimates of the marginal transmission and distribution costs and may determine different avoided costs for different time periods;
3. Avoided fossil fuel costs. The Commission must determine avoided fossil fuel costs based on estimated reductions in oil, gas or other fossil fuel use and estimated market prices for these fuels;
4. Avoided transmission and distribution line losses;
5. Demand reduction induced price effects (DRIPE);
6. Transmission and distribution plant extensions or upgrades funded by net energy billing customers; and
7. Any other benefits identified by the Commission.

The Act states that when determining the benefits of distributed generation under Net Energy Billing, the Commission must use any available regional avoided energy supply cost study that the Commission finds to be applicable to the determination and has been developed through a transparent process, with input from state agencies, public advocates and utilities or energy efficiency administrators from at least three other states in New England. When relevant information specific to a state is not provided in the regional study, the Commission may use the regional information in the regional study or information from other sources supported by evidence developed in the record. Given this, a majority of modeling inputs, if not available through historic data, were taken from the 2024 [Avoided Energy Supply Costs in New England](https://www.aesc.org/2024-avoided-energy-supply-costs-in-new-england/) (AESC) study. Much of the non-AESC sourced data to support this analysis is collected by the two EDCs and then reported to the

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<sup>7</sup> See Section 5 of LD 1986, here <https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131>



Commission in both publicly available and confidential formats. SEA, via the Commission, requested and worked collaboratively with the EDCs to access data to support the analysis herein.

The Act further defines NEB costs as all legitimate and verifiable costs incurred by a transmission and distribution utility directly attributable to net energy billing. NEB costs do not include any costs incurred by a project sponsor as defined in section 3209-A, subsection 1, paragraph D, a net energy billing customer or any other entity, as determined by the commission by rule.<sup>8</sup>

The Act also requires an annual report to be submitted by March 31 of each year to the Energy, Utilities and Technology (EUT) Committee of the Maine Legislature. The report must include, but is not limited to, costs authorized to be collected by transmission and distribution utilities in rates and benefits directly received by ratepayers. The Act specifies that the Commission must distinguish costs and benefits that are monetized from costs and benefits that are not monetized, and for those costs or benefits that are monetized, the Commission must specify the entities to which the monetized value accrues, which may include, but are not limited to, electricity customers, electricity supply providers and transmission and distribution utilities.

## 2.3 Components Included in the Cost / Benefit Analysis

In Table 2 we detail our approach to quantifying the costs and benefits for each of the following components organized by the legislatively mandated net benefit categories presented in Section 2.1.

**Table 2 –  
Adopted Benefits by Legislatively Mandated Benefit Category**

| Legislatively Mandated Benefit Category           | SEA Adopted Benefit Category                                                                                                                                                                                                                                                                 |
|---------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Avoided energy and capacity costs                 | SEA quantified the following benefits associated with avoided energy and capacity costs: <ul style="list-style-type: none"><li>• Energy resale revenue</li><li>• Capacity Buyout Revenue</li><li>• Uncleared Capacity Value</li><li>• Reduced Share of Capacity Costs</li></ul>              |
| Avoided transmission and distribution costs       | SEA quantified avoided transmission upgrades and avoided distribution upgrades                                                                                                                                                                                                               |
| Avoided fossil fuel costs                         | SEA assumes that avoided costs pertain to the utilization of fossil fuels at electricity generators supplying Maine retail customers. As such, our view is that these costs are fully embedded into wholesale energy prices, and in part embedded in energy capacity prices, captured above. |
| Avoided transmission and distribution line losses | SEA quantified avoided transmission and distribution line losses                                                                                                                                                                                                                             |
| Demand reduction induced price effects (DRIPE)    | SEA quantified the following DRIPE Benefits: <ul style="list-style-type: none"><li>• Energy DRIPE</li><li>• Capacity DRIPE</li><li>• Cross-Fuel DRIPE</li><li>• Renewable Energy Certificate (REC) price suppression</li></ul>                                                               |

<sup>8</sup> See Section 5 of LD 1986, here <https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131>



| Legislatively Mandated Benefit Category                                                           | SEA Adopted Benefit Category                                                                                                                                                                                                                                                                                                                                |
|---------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Transmission and distribution plant extensions or upgrades funded by net energy billing customers | SEA quantified assumed benefits associated with transmission and distribution plant extensions or upgrades funded by net energy billing customers                                                                                                                                                                                                           |
| Any other benefits identified by the Commission                                                   | SEA, in coordination with the Commission, identified the following additional benefits: <ul style="list-style-type: none"><li>• Avoided/Reduced Costs Associated with RPS Requirements</li><li>• Societal Benefits from Greenhouse Gas (GHG) Reduction</li><li>• Avoided Environmental Compliance Costs</li><li>• Improved generation reliability</li></ul> |

## 2.4 Choosing a Perspective for the Net Benefits Analysis

While the Act prescribed many aspects of the required annual report (as summarized in Section 2.1), it did not prescribe the perspective of the net benefit analysis. Examples of perspectives that have been applied to related energy efficiency evaluation analyses can be found [here](#), but importantly for this analysis the question is whether to take:

- A ratepayer impact perspective,
- A general societal impact perspective; or
- A Maine-only societal impact perspective

Given that the Act requires, at minimum, the consideration of “costs authorized to be collected by T&D utilities in rates and benefits directly received by ratepayers,” a ratepayer impact perspective could be justified. However, the Act also provides the PUC with discretion to consider additional benefits which could include costs and benefits from a societal perspective.

Given this, SEA determined that a general societal impact perspective is also justified in that the impetus for many of Maine’s policies promoting renewable energy (including NEB) is the reduction of GHG emissions. As the benefits GHG emission reductions are tied to global (vs. local Maine or even regional New England) GHG emission reductions, a general societal perspective, which incorporates a global perspective is justified.

Lastly, a Maine-only societal impact perspective could be justified, in that some benefits (e.g., NEB projects that lower Maine’s ISO-NE coincident peak demand and thus lower its share of ISO-NE Regional Network Service transmission costs allocated to Maine ratepayers) would be included in such a perspective. Importantly, the general societal impact perspective of NEB program net benefits analysis does not include benefits from the reduction of Maine’s ISO-NE coincident peak demand costs, as such a perspective views such reductions as a cost shift from Maine ratepayers to ratepayers of other New England states and so are netted out to zero. Conversely, a Maine-only societal impact perspective does not include energy price suppression impacts experienced by other states in ISO-NE.

Given the above considerations, for this report we have decided to primarily take a general societal impact perspective. As such, all our base analysis is conducted from this perspective. Nonetheless, in Section 4.3 we provide a sensitivity analysis of the Maine-only societal impact perspective in addition to the ratepayer impact perspective as compared to the general societal impact perspective.



## 2.5 Summary of Revisions to Prior Methods

SEA's report covering 2023 calendar year NEB benefits and costs was subject to significant stakeholder comment in PUC Docket 2024-00149, in which the PUC assessed which benefits under the NEB program could be monetized, and if any such benefits require adjustments to stranded cost calculations. Much of the feedback received through the stakeholder process and data requests was incorporated into the report covering 2024 benefits and costs and thus is also reflected in this report covering calendar year 2025. However, certain additional updates were made following the conclusion of the Docket based on a review of the Docket's record which are reflected in this report for the first time.<sup>9</sup> A high-level overview of revisions made relative to the 2024 report in response to the Docket's record is provided below, with details provided in the relevant benefit components section:

- Broke out GHG benefits to distinguish between benefits associated with RECs retired in state vs. RECs sold into the regional Class I marketplace (see Section 3.13)
- Updated methodology used to calculate benefits associated with reduced share of capacity costs to reflect the utilities' practices with respect to accounting for energy from load reducers (see Section 3.7)
- Updated the capacity factor associated with kWh Credit projects to distinguish between FTM and BTM projects (see Section 3.3)
- Updated coincidence factor used to calculate uncleared capacity benefits to reflect actual coincidence versus weather-neutral coincidence assumptions used in system planning (see Section 3.6)
- Updated annualization methodology for transmission and distribution upgrades paid for by NEB projects (see Section 3.8.4)
- Considered revisions to methodology for calculating benefits associated with peak demand reduction, but ultimately determined prior methodology was optimal given available data (Section 3.8.1)

## 3 Detailed Approach to Modeling

### 3.1 General Issues and Approach

Our analysis considered many of the idiosyncrasies of the NEB program and the Maine electricity landscape, which included:

- While most of Maine (~95% of Maine's load)<sup>10</sup> is within the Independent System Operator – New England (ISO-NE) footprint including CMP and Versant-BHD, Versant-MPD (~5% of Maine's load) is within the Northern Maine Independent System Administrator (NMISA) footprint for which there is no comprehensive, publicly available, regional avoided energy supply cost study, as AESC only covers ISO-NE.
- The NEB program is comprised of two program variants:
  - The kWh Credit program, which provides kWh credits on the EDC electric bills of program participants. The kWh Credit program existed for years prior to the expansion of the NEB program to include the Tariff Rate program variant, with generators online as early as 1994. The kWh Credit program is largely dominated by solar photovoltaic (PV) projects but contains some quantity of non-solar generators. Given the dominance of solar PV in the program, and the expectation that solar PV will constitute the vast majority of installations going forward, SEA chose to focus exclusively on the benefits and costs of solar PV in the kWh Credit

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<sup>9</sup> Docket 2024-00149 concluded with parties filing a Stipulation, which was approved by the PUC on October 15. Although the record contained significant discussion regarding appropriate methods for calculating program benefits and costs, the Stipulation did not contain consensus recommendations. Stipulation available here: <https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=131375&CaseNumber=2024-00149>

<sup>10</sup> See the "Load" tab of <https://www.maine.gov/mpuc/sites/maine.gov/mpuc/files/inline-files/Standard%20Offer%20Migration%20Stats%20through%20Nov%202023.xls> to make the calculation.



program. By default, kWh Credit projects are treated as load reducers, which impacts the application of benefits, as discussed in Section 3. However, SEA adjusted its methodology to reflect that generating resources over 500 kW in Versant's MPD territory are not considered load reducers, regardless of NEB program variant.<sup>11</sup>

- The Tariff Rate program, which provides monetary credits on the EDC electric bills of program participants. Tariff Rate projects include non-solar projects. We note that, for the purposes of calculating commercial operation date -specific benefits for non-solar projects, we assume that all hydro projects had commercial operation dates pre 2010 given SEA's understanding that hydro participating the Tariff Rate program variant were operational prior to their enrollment in the program. SEA designated the technology of each project for the purposes of categorizing project-level data by technology. For aggregated program-wide data (e.g., program costs), values were assigned by technology based on the share of production contributed by each technology for each EDCs. The Tariff Rate program variant itself has multiple variants due to statutory amendments to the program.
  - The original Tariff Rate program where the monetary credits are calculated as a function of the retail rates set at the beginning of each calendar year.<sup>12</sup> Per Chapter 430, no Tariff Rate projects will be subject to the original Tariff rate after December 31, 2025.<sup>13</sup>
  - The alternative Tariff Rate program, where the monetary credits are set as a fixed 2.25% annual inflator applied to either the 2020 or 2025 original Tariff Rate program rates, depending on project size.
- NEB Program generators either can be electrically connected with an EDC customer's load and, from a utility's perspective, behind the EDC customer's revenue meter (i.e., behind-the-meter or BTM) and thus physically offsetting some or all the electricity that would have been consumed from the EDC's distribution grid without the program generator. Alternatively, program generators can be connected not with an EDC customer's load, with the only electrical load being the requirements of the project itself (e.g., project lighting, inverters, communications); this load is called (project) parasitic load. If a NEB project only has parasitic load, it is electrically connected (from the EDC's perspective) in front-of-the-meter (FTM). This detail is relevant here because, while the EDCs meter the total project output for FTM projects (as the parasitic load is typically miniscule compared to gross project electricity production), the EDCs do not meter the production of BTM NEB projects (though they do measure the input and output channels with their metering and are able to calculate net consumption). As a result, our analysis and quantification approaches differ for FTM vs. BTM NEB projects. Specifically, we have confirmed with the EDCs that it is reasonable to assume all Tariff Rate projects are FTM and that kWh Credit projects are a mix of FTM (e.g., community solar projects) and BTM (e.g., residential household solar).
  - It is worth noting that, in SEA's analysis covering calendar year 2023, references to "BTM" in the methods section were used to refer to the portion of energy consumed on-site, rather than the full production of projects with a BTM metering arrangement. Consistent with SEA's 2024 analysis, the use of "BTM" in this report refers to projects with a BTM metering arrangement (including energy both consumed on-site and exported).

In addition to the program-specific considerations described above, SEA considered several general methodological decisions relating to cost benefit analyses of DG programs. The most significant consideration is if economic development benefits should be considered in the analysis. SEA decided not to include economic development benefits because the

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<sup>11</sup> This revision was informed by Versant's response to data request ReVI-003-006 in Docket 2024-00149.

<sup>12</sup> See 35-A MRSA §3209-B(5)(A), here: <https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html>

<sup>13</sup> See <https://legislature.maine.gov/legis/bills/getPDF.asp?paper=HP1188&item=8&snum=132>



consideration of such benefits was not required by statute and because prior cost-benefit analysis of the NEB program conducted by Synapse Energy Economics and SEA on behalf of the DG Stakeholder Group determined that economic development benefits should not be quantified in the benefit stack but should instead be considered separately as a supplemental consideration.<sup>14</sup>

Given the general issues just detailed, in the following subsections for each net benefit component, we describe the

- o data sources for the component,
- o methodology in calculating the net benefits of the component,
- o any simplifying assumptions made, and
- o additional clarifying commentary as appropriate.

## 3.2 AESC Inputs

As discussed above, most inputs informing benefit quantification, if not provided directly by the EDCs, were derived from the AESC 2024 Study. The AESC is a forward-looking study released every three years and is the product of a study process overseen by New England regulators, state energy offices, and a team of consultants (including the prime author Synapse Energy Economics and SEA as a contributor). The study is designed to assist New England States in evaluating the cost effectiveness of policies and programs. The AESC was originally developed in the context of evaluating energy efficiency programs, but most inputs are applicable to the evaluation of renewable energy programs.

For the purposes of this analysis, SEA utilized Counterfactual #5, as it most closely approximates a future in which states pursue the development of renewable energy. According to the AESC 2024, the counterfactual models “a future in which program administrators continue to install new energy efficiency, active demand management, and building electrification resources.” AESC 2024 inputs used in this analysis were translated to nominal dollars assuming a discount rate of 2% (the default assumption in AESC 2024).

## 3.3 Quantification of Program MW and MWh

All benefits considered in this analysis are either energy (MWh) or capacity (MW) denominated. As such, quantifying the applicable volumes of energy and capacity for each EDC, program variant, technology, and commercial operation date is a necessary first step to assessing the total benefits per segment. SEA utilized actual program volumes wherever possible in its analysis. Specific data sources, assumptions, and limitations are discussed below.

- **Production Data:** The approach to quantifying production varied by program variant, discussed below.
  - o **Tariff Rate:** SEA received actual hourly production data for all CMP projects enrolled in the Tariff Rate program through November 2025. Versant provided actual monthly production data by project for the Tariff Rate Program through November 2025. SEA estimated December production based on average hourly production in November, adjusted to reflect monthly averages.
  - o **kWh Credit Program:** SEA received actual monthly production data for kWh exports from both EDCs, disaggregated by rate class through November 2025. Because the EDCs do not meter production used on-site of BTM NEB projects, such production was estimated by SEA based on the assumed capacity of BTM kWh Credit program projects (discussed below). Production estimates assumed a 17% AC capacity factor

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<sup>14</sup> See final report here: [https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Final%20Report%20of%20the%20DG%20Stakeholder%20Group\\_with%20appendix.pdf](https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/Final%20Report%20of%20the%20DG%20Stakeholder%20Group_with%20appendix.pdf)



for FTM projects, a 14.8% AC capacity factor for BTM projects, an annual production degradation rate of 1%, and a de-rate to year-one production unique to each utility based on the share of capacity online in 2025 in each month.<sup>15</sup> Given that a substantial portion of the MW installed in 2025 came online late in the year, SEA made various adjustments to benefit components expressed in \$/MW terms (e.g., avoided T&D investments) to appropriately discount benefits to reflect that a portion of the projects considered in the analysis were not online during summer months in which peak load is experienced. SEA received data from utilities regarding the volume of projects assumed metered BTM. For such projects, SEA estimates energy consumed on-site separately from energy exported to the grid. Specifically, SEA assumes that 35% of energy is exported to the grid, based on the EDC data regarding actual kWh Credit program exports (which include both FTM and BTM).

- **Capacity Data:** SEA collected data on project capacities by EDC, technology, and commercial operation dates from the EDC's monthly NEB reports in [Docket 2020-00199](#), as of November 30, 2025. SEA received data from the EDCs regarding the metering arrangement and interconnection voltage for each project, which was used to inform the applicability of certain benefit components.

## 3.4 Revenue from Energy Resale

### Overview

Energy re-sale revenue gained by the EDCs from production provided by operational procured and NEB-enrolled projects was considered in this analysis. For the purposes of this analysis, this benefit is unique to the Tariff Rate program, as projects enrolled in the Tariff Rate program variant serve as generators in ISO-NE markets. This is distinguished from projects in the kWh Credit program that act as load reducers. This can take effect on the level of an individual EDC customer for BTM consumption of NEB production, or for the EDC as a whole for out channel export NEB production.

### Data Source

EDC revenue from energy re-sale from Tariff Rate program was provided by the EDCs to SEA on a monthly basis.

### Discussion

In the context of the AESC, this benefit is most similar to “avoided energy”, which represents the avoided costs of having load serving entities procure energy on the wholesale market because of the energy transferred to the EDCs through participation in DG programs. However, given that FTM projects participating in the NEB program do not physically avoid the consumption of energy, in the context of the NEB Tariff Rate program variant, the analogous benefit is energy re-sale revenue.

## 3.5 Capacity Buyout Revenue

### Overview

This benefit captures revenue received by the EDCs from NEB or procured project owners electing to buyout capacity rights from the EDC.

### Data Source

Revenue collected in 2025 from capacity buyouts was provided to SEA by the EDCs.

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<sup>15</sup> 14.8% is an average 2024 capacity factor for BTM production in Maine, according to ISO-NE. See: [https://www.isone.com/static-assets/documents/2020/07/btm\\_pv\\_data.xlsx](https://www.isone.com/static-assets/documents/2020/07/btm_pv_data.xlsx)



### **Discussion**

In the context of the AESC, this benefit is most similar to “avoided capacity”, which represents the avoided cost of building or procuring capacity to meet the peak demand of the generation system. Generally, avoided capacity benefits would be a function of capacity benefits monetized by the EDCs through successfully bidding project capacity into the Forward Capacity Market (FCM). However, both CMP and Versant stated that NEB project capacity is not currently being monetized for either the Tariff Rate or kWh Credit program. However, projects in the kWh Credit program are treated as “load reducers”. As such, SEA only focused on revenues from capacity buyout.

The monetization of NEB program capacity represents a potential source of untapped program benefits. However, the challenges associated with successfully bidding DG project capacity into the FCM, and the risk of penalties associated with failure to perform during a scarcity event, have generally dissuaded responsible parties from monetizing capacity rights associated with DG projects. Given this, it is SEA’s expectation that potential benefits associated with monetizing capacity are modest. In addition, there are benefits from having the projects treated as load reducers, and these benefits may well outweigh the modest potential benefits of monetizing capacity (see Section 3.6).

Capacity buyout agreements differ in structure depending on the buyout agreement in question (e.g., upfront payment vs revenue share agreement). For the purposes of this analysis, SEA only considered revenues collected in 2025. As such, revenues from projects electing to pay an up-front fee for capacity buyout prior to 2025 were not included in the analysis.

Versant noted that any capacity buyout revenues collected were folded into aggregate program revenues reported to SEA (which are predominantly energy related and utilized in the “Energy Resale Revenue” component). As such, SEA did not apply separate capacity buyout revenue for Versant to prevent double counting of revenues.

## **3.6 Uncleared Capacity**

### **Overview**

Despite not monetizing capacity rights (e.g., not bidding project capacity into the FCM), the capacity of projects still provides benefits to ratepayers in Maine and ISO-NE more broadly via uncleared capacity value. Uncleared capacity value reflects how uncleared project capacity impacts the development of inputs to ISO New England’s FCM.<sup>16</sup> Specifically, the impact on historical data utilized by ISO-NE of projects serving as load reducers are assumed to reduce forecasted Installed Capacity Requirement (ICR) utilized in the FCM. As such, only NEB kWh Credit projects, which serve as load reducers, accrue this benefit.

### **Data Source:**

SEA utilized AESC 2024 (Counterfactual #5) assumptions for the value of uncleared capacity.

### **Discussion:**

Uncleared capacity utilizes a “phase-in” and “phase-out” schedule that relates the value per MW in any given year to the resource’s commercial operation date. The phase in and out is applied to reflect the lag between a resource coming online and the resource’s impact influencing ISO-NE study assumptions. Specifically, the 2024 AESC assumes that benefits from

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<sup>16</sup> See page 159 of 2024 AESC for a detailed discussion of such benefits, here: <https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf>



uncleared capacity do not start until 5 years after their installation date. Given the limited capacity of NEB project online pre-2020, uncleared capacity benefits are modest relative to other benefit components.

### 3.7 Reduced Share of Capacity Costs

#### Overview

Resources acting as load reducers (e.g., NEB kWh Credit projects) that generate energy during Maine's monthly peak hours can reduce the share of capacity costs paid for by Maine (thereby resulting in a cost shift to other New England ratepayers). Resources that act as generator assets (which are assumed to include NEB Tariff Rate projects) do not accrue this benefit.

#### Data Source:

AESC 2024 inputs were utilized.

#### Discussion:

CMP segments its daily settlement process by customer class. For suppliers serving non-Large C&I and residential rate classes, their hourly load obligation is the sum of their customers' metered load grossed up by deemed, voltage-specific line loss factors, plus hourly unaccounted for energy (UFE). Crucially, the UFE for the daily settlement process includes all the generation exported to the CMP distribution system by load reducers.

For kWh Credit resources, production (i.e., kWh credits) is accounted for in the monthly resettlement process as follows:

1. CMP first aggregates, by supplier, the total kWh credits assigned to each supplier's customers for the billing month. For SOPs, because they are not assigned individual customers but an overall portion of SOS customer load, this allocation is based on the percentage of total SOS load each SOP serves.
2. Then, in an iterative fashion, CMP reduces each supplier's hourly load over the billing cycle on a pro rata basis according to their aggregated kWh credits.

In applying the reduction, the supplier's load obligation is reduced proportionally in every hour, as opposed to the specific hours in which the PV production occurred. Given this, to calculate the estimated load reductions during peak periods resulting from NEB project production, SEA calculated the annual peak coincident MW (expressed as a percent of nameplate capacity), by comparing peak ISO-NE load (as provided by AESC 2024) to the proportional reduction in load from the kWh Credit program's UFE contributions.

Given that this benefit represents a shifting of costs to other regional states, it is only included as a benefit in this analysis for the Maine-only societal impact perspective and the ratepayer impact perspective.

Lastly, this benefit accrues to standard offer providers. As such, the share of benefits realized by ratepayers is a function of how effectively competitive procurements incentivize such value to be passed to ratepayers in the form of more competitive standard offer bids. SEA did not attempt to quantify this share, but notes that it is unlikely that 100% of such benefits are passed to ratepayers, given imperfect information and market dynamics.



## 3.8 Transmission and Distribution Benefits

### 3.8.1 Avoided Transmission and Distribution Investments

#### Overview

Distribution-connected resources that generate energy during periods of high demand could reduce future needed transmission- and distribution-level grid investments. As such, the value of such avoided investments is considered in this analysis.

Transmission benefits are applicable to all NEB projects as all projects are assumed to be connected to the distribution system. For distribution benefits, this benefit is applicable to projects connected to the distribution system that are BTM, or FTM facilities that are interconnected at secondary voltage levels given that such facilities could reduce downstream distribution-level load.

#### Data Source:

For transmission benefits, SEA utilized AESC 2024 assumptions specific to Maine for the value per MW-year of avoided transmission capacity. Specifically, the AESC provides separate values per MW-year of avoided transmission for intrastate transmission upgrades and transmission upgrades serving ISO-NE (which are referred to as Pooled Transmission Facilities (PTF) upgrades). For distribution benefits, SEA utilized AESC 2024 assumptions specific to Maine for the value per MW-year of avoided distribution capacity. The studies referenced by the AESC 2024 provide a range of possible values. Consistent with the AESC 2024, SEA adopted mid-point estimates. Both values were provided in 2020 dollars and were translated to 2025 dollars assuming an inflation rate of 2% (consistent with the inflation rate assumed in AESC 2024).

#### Discussion:

First, SEA assumed that intrastate transmission investments would be a function of the magnitude of Maine's peak load, whereas interstate investments would be a function of the ISO-NE system-wide peak.

To calculate the estimated load reductions on Maine's transmission system during peak periods resulting from DG projects, SEA calculated Maine's annual peak before and after assumed NEB load reductions utilizing the AESC-provided 2025 load curve as compared to the NEB program's estimated hourly generation. Given that the AESC load curve represents "gross" load (e.g., load prior to any BTM PV adjustments), SEA determined that it was an appropriate starting point to estimate the timing and level of peaks absent the NEB program. Estimated hourly generation was a function of both actual hourly production (in the case of CMP's Tariff Rate Program) and estimates derived from PVWatts, assuming a facility located in Southern Maine.<sup>17</sup> This approach was designed to accurately capture the impact of diminishing marginal returns from solar load reductions, as sufficient solar generation is expected to shift peak hours to periods in which further solar production would not contribute to further peak reductions.

Given that the NEB program's relative contribution to ISO-NE system-wide peak reductions is smaller as compared to intrastate peak reductions, SEA took a simplified approach. Specifically, to calculate the estimated load reductions during ISO-NE's system peak, SEA calculated coincident MW (expressed as a % of nameplate capacity), by comparing peak ISO-NE

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<sup>17</sup> PVWatts is a tool developed by the National Laboratory of the Rockies formerly known as National Renewable Energy Laboratory (NREL) which estimates hourly PV production based on specific locations, found here: <https://pvwatts.nrel.gov/>



load (as provided by AESC 2024) to the representative PVWatts curve.<sup>18</sup> The resulting factor was used to de-rate the full value per MW-year of avoided transmission, based on coincidence with peak periods.

To calculate the estimated load reductions on the distribution system during peak periods resulting from DG resources, SEA calculated the share of annual production contributing to reductions in the top 100 peak hours of the year. To do this, SEA utilized a forecast of hourly load (as provided by AESC 2024) as compared to technology-specific hourly production data.<sup>19</sup> The resulting factor was used to calculate a per MWh value capturing avoided distribution capacity, based on solar production's coincidence with peak periods.

For both transmission and distribution benefits, SEA considered the use of actual system peaks, as reported by ISO-NE, in 2025 as compared to actual project production (for Tariff rate projects for which hourly production data was supplied). However, because actual load reflects the impact of NEB production, relying on it would undervalue the program's contributions, given that peak periods have shifted to periods with less solar production as a result of the program. Thus, SEA relied on AESC 2024 as it was deemed the best source providing hourly gross (e.g., pre-PV load reduction) load over calendar year 2025 at the time the analysis was conducted.

### 3.8.2 Avoided Maine Regional Network Service Share

#### Overview

Resources acting as load reducers that generate energy during Maine's monthly peak hours can reduce the share of Regional Network Service (RNS) transmission costs paid for by Maine (thereby cost shift to other New England ratepayers). Tariff Rate projects do not accrue this benefit given that they do not act as load reducers.

#### Data Source:

SEA utilized the 2025 RNS charge as provided by ISO-NE.

#### Discussion:

To calculate the estimated load reductions during peak periods resulting from DG projects, SEA calculated the average 12-month coincident MW before and after estimated load reductions from the NEB program to compute the program's total contribution to peak reductions. Load reductions were estimated as a function of total kWh Credit program production multiplied by hourly scalars as provided by PVWatts. This approach was designed to accurately capture the impact of diminishing marginal returns from solar load reductions, as sufficient solar generation is expected to shift peak hours to periods in which further solar would not contribute to further peak reductions.

Given that this benefit represents a shifting of costs to other regional states, it is only included in this analysis for the Maine-only societal impact perspective and the ratepayer impact perspective. Lastly, this benefit was not applied for any project located in Versant's MPD service territory, as MPD is outside of ISO-NE and thus MPD load reduction would not accrue ISO-NE RNS related cost reductions.

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<sup>18</sup> Given that the program is predominantly solar, and that the resulting factor was in the range expected for non-solar, SEA applied this factor to all technologies for the limited purpose of calculating interstate avoided transmission costs.

<sup>19</sup> For based on CMP hourly production data for Tariff Rate projects and PVWatts outputs for kWh Credit projects.



### 3.8.3 Avoided Transmission and Distribution Line Losses

#### Overview

Generation from distribution-connected distributed generation can reduce the load on the transmission and distribution system. This avoids the transfer of energy across distribution or transmission lines and thereby reduces any lost energy associated with such transfer. This yields both energy and capacity related benefits.

#### Data Source:

To compute energy-related benefits, SEA utilized EDC-specific line losses, provided by level of service (e.g., secondary, primary, sub-transmission).<sup>20</sup>

To compute capacity-related benefits, SEA utilized AESC 2024 recommended transmission and distribution marginal capacity line losses, as discussed below.<sup>21</sup>

#### Discussion:

CMP's reported line losses exclude losses from pooled transmission facilities (PTF). As such, SEA added 2.5% to such losses to approximate the PTF losses, based on ISO-NE's estimated line losses from transmission facilities.<sup>22</sup> Given that all EDC-reported losses were expressed as average losses, SEA multiplied such losses by 1.5 to approximate the applicable marginal loss rate, based on the ratio of average to marginal losses reported in AESC 2024.

To compute energy-related benefits for FTM projects, SEA assigned avoided line loss benefits equal to the line losses applicable to one level of voltage greater than the project's interconnection voltage. For instance, a FTM project interconnected at secondary voltage receives benefits applicable to the line losses of serving primary voltage. For BTM projects, this same treatment was applied to energy assumed to be exported, whereas energy assumed to be consumed on-site received the full avoided line loss benefits associated with serving the project's interconnection voltage.

Versant's responses to data requests in [Docket 2024-00149](#) suggested that distribution-level line losses were not avoided for a majority of NEB facilities, and that, in many cases, NEB facilities may increase line losses.<sup>23</sup> Given this, SEA excluded all distribution-level line loss benefits for projects located in Versant's service territory from the analysis, assuming that on net the potential benefits of some projects cancel out the potential costs of others.

To compute capacity-related benefits, SEA scaled the AESC's recommended marginal capacity loss factor of 16% based on the ratio of the calculated energy-related avoided losses (discussed above) to the AESC's recommended marginal energy loss factor of 9%.

To compute a total benefit related to avoided line losses, the adopted energy line losses input was multiplied by kWh-denominated benefits discussed elsewhere in this analysis, and the adopted capacity line losses input was multiplied by kW-denominated benefits discussed elsewhere in this analysis.

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<sup>20</sup> Available here for Versant: <https://www.versantpower.com/suppliers-and-partners/rates/line-loss-factors/>

Available here for CMP: <https://www.cmpco.com/w/load-profiles>

<sup>21</sup> See page 100: <https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf>

<sup>22</sup> See page 11: [https://www.iso-ne.com/static-assets/documents/2023/03/transmission\\_planning\\_technical\\_guide\\_app\\_j\\_load\\_modeling.pdf](https://www.iso-ne.com/static-assets/documents/2023/03/transmission_planning_technical_guide_app_j_load_modeling.pdf)

<sup>23</sup> See Versant's response to Data Request ReVI-003-003



### 3.8.4 Transmission And Distribution Upgrades Funded by NEB Customers

#### Overview

Distributed generation interconnecting to the distribution system is often required to fund system upgrades to the distribution or transmission system to facilitate such interconnection. These upgrades can deliver shared benefits to all ratepayers if they provide reliability benefits or accelerate upgrades that would have been required eventually in business-as-usual system planning.

#### Data Source:

The EDCs provided a list of the associated costs, if any, paid to fund upgrades to the transmission and distribution system for projects considered in this analysis.

#### Discussion:

First, SEA amortized the investments to derive the share of benefits applicable to 2025, using the revenue requirement formula provided in the testimony of Christian Bilcheck on behalf of the Coalition for Community Solar Access in Docket 2024-00149.<sup>24</sup> Next, SEA considered the share of such investments that contribute to shared benefits to all ratepayers. Assigning the share of interconnection fees that contribute to shared benefits for all ratepayers is a difficult task. Nonetheless, inclusion of such investments as a benefit component is required by statute. Shared benefits delivered will be a function of the specific location, timing, and grid conditions in question. An analysis of this depth was not possible for the purposes of this report. However, analysis conducted by the EDCs in response to data requests in [Docket 2024-00149](#) provided illustrative examples regarding the share of interconnection expenses that could deliver shared benefits for the specific sample of upgrades assessed. In general, the EDCs found that, for the upgrades assessed, a limited share of the upgrades were expected to deliver benefits to ratepayers.<sup>25</sup> However, the EDCs acknowledged that, more broadly, an accounting of program-wide shared benefits from interconnection costs would require a detailed engineering study which is not possible under the scope of this analysis. Given this uncertainty, SEA assumed that 10% of total interconnection costs paid to fund system upgrades resulted in shared benefits.<sup>26</sup> Given these assumptions and the annualization of costs over the upgrades assumed useful life, this component delivers minimal benefits relative to other benefit categories.

## 3.9 Demand Reduction Induced Price Effects (DRIPE)

#### Overview:

DRIPE benefits relate to the impact on market prices resulting from an increase in low-cost supply or reduction in demand for a commodity. In the context of this analysis, renewable resources with low marginal costs tend to drive down prices by shifting the supply curve to the right. This dynamic applies to capacity, energy, and natural gas prices (through reduced demand for gas-generated electricity, called “Cross-Fuel DRIPE”).

#### Data Source:

AESC 2024 (Counterfactual #5) DRIPE values specific to Maine were utilized.

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<sup>24</sup> The formula assumes Annual Revenue Requirement = Depreciation Expense + (Rate Base × Equity Ratio × Return on Equity). SEA assumed a 40-year useful life for assets, 50% equity ratio, and 9.35% return on equity.

<sup>25</sup> For example, see responses to ReVI-005-005, ReVI-005-008, ReVI-004-003, ReVI-004-009

<sup>26</sup> SEA notes that, pursuant to Ch 324 of the Commission’s rules, certain T&D upgrade costs are socialized for Level 1 projects. This cost was not quantified in this analysis. Given that Level 1 projects are not expected to trigger significant system upgrade expenses, SEA does not expect this cost to be substantial relative to the benefits quantified in Section 0.

**Discussion:**

For Energy DRIPE, which varies based on peak/off-peak period and season, hourly 2025 production data from all CMP Tariff Rate projects was utilized to calculate the share of annual production occurring in each period for the NEB program. These shares were applied to production from Versant Tariff Rate projects and all kWh Credit program projects, for which hourly data was not available.

Given that Energy DRIPE and Cross-Fuel DRIPE values are partially a function of the underlying price of electricity each year, SEA substituted AESC-forecasted LMPs with actual LMPs for all of 2025.<sup>27</sup>

DRIPE values in any given year are contingent on the commercial operation date of the resource in question. As such, DRIPE values were calculated separately for each commercial operation year represented in projects operational in the NEB program in 2025 (i.e., were calculated separately for each cohort year). Capacity DRIPE values were only applied to NEB kWh Credit projects, as such projects are the only projects assumed to accrue uncleared capacity benefits by virtue of them acting as load reducers. SEA confirmed with CMP that, although NEB Tariff Rate projects are not bid into the capacity market, they do not act as load reducers from a capacity perspective given their treatment as generator assets in energy markets.

Given that Versant-MPD operates outside of ISO-NE and does not have an organized wholesale energy or capacity market, SEA did not quantify DRIPE benefits for projects in this area. Although DRIPE benefits could theoretically apply, as even bilateral contracts are negotiated with a theoretical supply curve in mine, the quantification of such benefits for the MPD would be very difficult and speculative at best.

## 3.10 Renewable Energy Certificate (REC) Price Suppression

**Overview:**

Similar to DRIPE benefits, additional supply of Class I RECs into the regional marketplace can suppress regional Class I REC prices, thus reducing the cost of meeting RPS obligations for impacted RPS markets. Given that most RECs generated from NEB-participating projects are eligible in all Class I markets, this price suppression effect is realized in more than just Maine's RPS market. Although this is not a DRIPE benefit contained in the ASEC (given the AESC's focus on energy efficiency programs, which do not involve the generation of RECs) the concept behind this benefit is largely similar.

**Data Source:**

SEA utilized production data from the EDCs to estimate Class I REC creation. REC price suppression was calculated using SEA's suite of New England Renewable Energy Market Outlook (REMO) models, discussed below.

**Discussion:**

To calculate the REC price suppression impact of the NEB program, SEA utilized modeling completed for its 2025-3 REMO briefing.<sup>28</sup> Base case assumptions were adopted. Two separate modeling runs were completed, one containing NEB program capacity, and one excluding NEB program capacity. The differences in forecasted 2025 Class I prices in each state market were then calculated. Results demonstrated no reduction in the price of regional Class I markets. As such, there was no benefit associated with this component computed.

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<sup>27</sup> For clarity, we note the calculation of DRIPE benefits is the only instance in our modeling where LMPs are directly included in calculations. Conversely, direct energy re-sale benefits for Tariff Rate projects are implicitly based on actual 2025 LMPs, but are reported directly by EDCs and thus do not require bottom-up calculations involving hourly LMPs.

<sup>28</sup> For details on the New England REMO service, see here: <https://www.seadvantage.com/new-england-remo/>



### 3.11 REC Revenue

#### **Overview:**

Projects in both NEB programs are eligible to generate Maine Class I RECs and are also eligible for most of the regional New England Class I markets (with certain exclusions for out-of-state RECs generated by BTM facilities, though even Maine BTM facilities are eligible to register as Massachusetts Class I RECs). In both the NEB program and the power purchase agreements (PPAs) from procured facilities operational in 2025, RECs are not a product transferred to the EDCs included in the cost of such contracts. As such, RECs represent an additional value stream to program revenue through the sale of such RECs to the regional market.

#### **Data Source:**

Price quotes in December of 2025 for 2025 Maine Class I were taken from multiple REC brokers and averaged to derive a price for use in modeling.

#### **Discussion:**

Given that the primary perspective of this analysis is from a societal lens, REC revenue is not accounted for in the benefit stack presented in Section 3.16.5. This is because, from the general societal perspective, REC revenue is considered a cost shift from buyers to sellers of RECs and thus cancels out to zero net benefits (putting aside small transaction costs).

### 3.12 Reduced RPS Requirements

#### **Overview:**

RPS costs are a function of the cost of RECs, the RPS requirement (expressed as a percentage of obligated load), and the size of the obligated load (in MWh). Resources acting as load reducers (e.g., NEB kWh credit projects) reduce the total load from which the compliance obligation for any given year is calculated. Thus, such projects acting as load reducers provide benefits in the form of reductions in total RPS costs.

To address this, in its orders granting new RPS certification, the PUC requires that for BTM facilities, “the facility owners must retain GIS certificates or otherwise obtain GIS certificates necessary to satisfy Maine’s RPS for that portion of the BTM load that is served by the facilities.” As such, in the context of Maine, the total volume of RECs retired should not change because of BTM load reductions, but the party responsible for fulfilling RPS requirements with such load does change.<sup>29</sup> Thus, for BTM facilities, SEA only applied this benefit for the ratepayer impact perspective to reflect that RECs retired to fulfill RPS obligations related to BTM load reductions bears a cost on the facility owner to the benefit of the general ratepayer. For all other tests, reductions associated with BTM load are considered a cost shift and thus do not yield any net benefits. However, given there is no parallel requirement for FTM facilities acting as load reducers to fulfill RPS requirements associated with such load reduction, these benefits are applied under all tests.

#### **Data Source:**

Price quotes in December of 2025 for 2025 Maine Class I and II REC prices were taken from multiple REC brokers and averaged to derive a price for use in modeling.

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<sup>29</sup> We note that kWh Credit NEB facilities are not required to certify as RPS eligible, and thus not all BTM load will be subject to such provisions.

**Discussion:**

SEA considered the benefits of avoided Class I and II RPS costs. Assumed 2025 REC prices by class were de-rated by the applicable 2025 RPS minimum standard for each class, adjusted for exemptions, to reflect that one MWh of load reduction results in the avoided purchase of only a partial REC.

### 3.13 Societal Benefits from Greenhouse Gas Reduction

**Overview:**

Renewable energy contributes zero-carbon energy to the grid, reducing the greenhouse gas (GHG) intensity of energy consumed. The benefits of these GHG emissions reductions are quantified and considered in this analysis. However, as discussed below, because the NEB program does not require the transfer of RECs to the utility, SEA's analysis considers what share of benefits could be claimed by other states purchasing RECs generated by NEB facilities.

**Data Source:**

AESC 2024 values (from Counterfactual #5) were used to compute the marginal non-embedded emissions benefits per MWh of generation. "Non-embedded" refers to the portion of benefits that are not already accounted for (or "embedded") in wholesale energy prices via fees from the Regional Greenhouse Gas Initiative (RGGI). AESC 2024 values for the social cost of carbon (SCC) were used to translate abated emission volumes into dollar values.

**Discussion:**

**Applicability by Perspective:** The impetus behind much of the focus on incenting renewable energy relates to the impacts of climate change and the GHG reduction benefits offered by renewable generators. Given this, the consideration of such benefits in a benefit-cost analysis of renewable energy programs is critical to capture the scope of costs and benefits informing the genesis of such programs. However, given that the EDCs do not obtain title to RECs under the NEB program (e.g., project owners can sell RECs independently), it is possible that the RECs are retired to fulfill another state's RPS obligations and therefore that another state would claim the environmental benefits associated with such RECs in a potential benefit-cost analysis (e.g., a benefit-cost analysis of the Massachusetts renewable portfolio standard (RPS) including greenhouse gas reductions via REC retirement to satisfy the Massachusetts RPS requirements).

This consideration poses difficult questions regarding benefit attribution. On the one hand, it is reasonable to assume that the RECs generated by NEB projects, and the underlying GHG reduction benefit, would not have been created but for the existence of the program. As such, on a societal level, the ultimate party that claims the GHG benefit does not change the fact that the program caused the net increase in GHG benefits. However, when conducting a region-wide analysis, such a perspective could lead to double-counting, as taking title to a REC is understood to represent a claim to all environmental attributes. Given this, SEA has disaggregated the GHG benefits associated with RECs assumed to be sold into the regional Class I marketplace from RECs that associated with BTM on-site consumption, for which the PUC requires that facility owners retain and retire RECs associated with such consumption. To appropriately bound the results, SEA assumes that any RECs not explicitly pinned to Maine (e.g., not associated with BTM on-site consumption) are sold into the regional Class I marketplace, and thereby potentially retired out of state. SEA's conclusions with respect to each perspective are provided below:

- For the societal perspective, SEA reports both segments of GHG benefits (RECs sold regionally and retired in-state) separately to demonstrate the impact of this judgment call and more easily allow parties utilizing this analysis to form their own view regarding the appropriateness of including GHG benefits associated with RECs sold regionally.



- For the Maine perspective, SEA only reports GHG benefits associated with RECs retired in-state. Although one could argue that Maine benefits from societal impacts of GHG reduction more broadly, and so both categories of GHG benefits could be considered, the focus of the Maine perspective is on benefits attributed to Maine. As such, it is more difficult to justify the inclusion of GHG benefits that could be claimed by other states.
- For the ratepayer perspective, no benefits associated with GHG reduction are included.

In SEA's report covering 2024 costs and benefits, SEA netted out the value of a ME Class I REC from the GHG benefit to address the issue of double-counting. Given the approach described above, we now view this approach as unnecessary. The result of this change in methodology is an increase in the GHG benefits associated with RECs assumed sold into the regional Class I marketplace relative to the prior report.

**Calculation of Benefits:** Quantifying the GHG benefits from renewable generation is a function of the estimated volume of GHG avoided multiplied by the assumed SCC. Each component is discussed below:

**Marginal GHG reduction:** The marginal reduction in GHG resulting from a MWh of renewable generation is calculated in the AESC based on the applicable peak/off-peak period and season. Similar to the approach taken for Energy DRIPE, SEA utilized hourly production data from CMP for Tariff Rate projects to inform the share of annual MWh applicable to each period.

**SCC:** SEA utilized the recommended SCC from AESC 2024, which represents the most up to date SCC adopted by the U.S. Environmental Protection Agency (EPA) as of November 2022. The SCC is then transformed by the AESC "user interface" to remove embedded costs attributed to RGGI costs, thus preventing the doubling counting of costs that are embedded in energy costs.

## 3.14 Improved Generation Reliability

### Overview:

Projects operating as load reducers shift the demand curve for capacity to the left, thereby increasing the volume of resources above the installed capacity requirement that are able to clear in capacity auctions. This increase is associated with improved reliability.

### Data Source:

AESC 2024 values (Counterfactual #5) specific to Northern New England were used to compute the reliability benefits per MW applicable to each technology assessed.

### Discussion:

For 2025, AESC computes de minimis reliability benefits for Northern New England. As such, this benefit component contributes a very small portion of overall program benefits. Given that the AESC 2024 is designed for resources with measure years starting in 2024, it is possible that the impact of older resources would have a more significant impact on 2025 reliability outcomes. However, given that the AESC does not clearly separate out the relationship between a resources COD and the magnitude of impact for reliability benefits (as is done with other benefits that include an explicit "phase-in" and "phase-out" schedule), SEA simply adopted AESC 2024-reported reliability benefits for Northern New England for the analysis as a conservative assumption.



In addition, Versant's responses to data requests in [Docket 2024-00149](#) suggested that, in many cases, NEB facilities may decrease grid reliability.<sup>30</sup> Given this, SEA excluded reliability benefits for projects located in Versant's service territory from the analysis, assuming that on net the potential benefits of some projects cancel out the potential costs of others.

## 3.15 Modeling Cost Components

### Overview:

The costs of the solar program differ substantially by program variant. A discussion of costs by program variant is provided below.

### Tariff Rate Program:

As discussed in Section 3.1, the Tariff Rate Program variant provides monetary credits to participating customers based on facility production of the project to which they are subscribed. The specific rate is dependent on if a project is enrolled in the original Tariff Rate program (where the monetary credits are calculated as a function of the retail rates set at the beginning of each calendar year) or the alternative Tariff Rate program (where the monetary credits are set as a fixed 2.25% annual inflator applied to the 2020 original Tariff Rate program rates). We note that, beginning in 2026, all Tariff Rate projects will be moved to the alternative Tariff Rate program, with projects under 3 MW receiving a rate based on the 2025 original Tariff Rate program rate, subject to the same 2.25% annual inflator, and projects 3 MW and greater receiving the 2020 original Tariff Rate program rate plus 2.25% annual inflator.

For the purposes of SEA's analysis, SEA did not distinguish between the two Tariff Rate compensation variants, as total Tariff Rate program variant costs were provided by the EDCs on a monthly basis aggregated across all Tariff Rate projects. Such costs represented the actual monetary credits applied to participating customers' bills in 2025.

### kWh Credit Program:

As discussed in Section 3.1, the kWh Credit program variant provides kWh credits on the EDC electric bills of NEB participants. As a result, billed kWh offset through the program results in a reduction in revenues received by the EDCs. The "lost revenue" represents a cost that must be recovered from ratepayers.

To quantify such costs, kWh program costs for energy exports were provided by the EDCs in the form of lost distribution revenues, consistent with filings made through regular stranded cost proceedings. These costs, however, do not represent the full costs associated with the kWh Credit Program, as other wire charges designed to cover costs associated with transmission costs, Electricity Lifeline Program (ELP) costs, and Efficiency Maine Trust (EMT) costs are impacted as well. As such, SEA utilized the kWh of energy exports under the kWh Credit program, by rate class, provided by the EDCs to compute total costs based on all volumetric (per-kWh) wire charges.

SEA computed the lost revenues associated with BTM production consumed on-site (which are not included in the kWh of energy exports provided by the EDCs) based on the estimated production from BTM facilities, as discussed in Section 3.3.

We note that the kWh Credit program variant results in a reduction in billed kWh as compared to the kWh consumed by EDC customers. As addressed below in subsection 3.16, this disconnect of billed kWh to consumed kWh impacts the cost

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<sup>30</sup> See Versant's response to ReVI-003-019



of providing retail supply by load serving entities (i.e., competitive electricity providers and Standard Offer providers) as compared to the counterfactual of the absence of the kWh Credit program.

#### **Administrative Costs:**

In addition to per-kWh program expenses, SEA collected total costs associated with the administration of the NEB program from the EDCs. NEB costs were allocated to each program variant based on the share of capacity participating in each program. Overall, administrative costs are insignificant compared to other program expenses.

### **3.16 Impacts of kWh Credit Program on Retail Generation Supply Costs**

For purposes of this report, we define the following:

- Standard Offer Providers (SOPs) provide retail electricity generation services to standard offer customers
- Competitive Energy Providers (CEPs) provide retail electricity generation services to customers not on standard offer service (i.e., those customers that chosen to contract with willing competitive retailers)
- Load Serving Entities (LSEs) are inclusive of both SOPs and CEPs

CEPs can choose which customers they are willing to serve, while SOPs are mandated to serve any customer that chooses to be on Standard Offer service. We presume because of additional carrying costs and risks that are part and parcel of providing retail electricity generation services to kWh Credit recipients (that are described in more detail below) that the vast majority of CEPs do not have interest in serving mass market customers that receive kWh Credit program credits, and that such customers are either not offered a chance to sign up with a CEP or the CEP terminates or does not renew their contract with a customer as quickly as possible. For simplicity's sake for modeling the kWh Credit program's impact, we assume that kWh Credit program recipients are taking standard offer service and served by SOPs.

The impacts on LSEs of the kWh Credit program not only include fewer kWh served by LSEs, but also timing of responsibilities (and payments), change in load shape, and increased risks. We make the following additional assertions and observations regarding the kWh Credit Program's impact on retail generation supply costs.

- Many of the impacts described herein result in cost shifts from CEPs to SOPs, that is from LSEs of retail electric shopping customers to LSEs of non-shopping retail electric customers. While this may be an important consideration for Maine's stakeholders and policymakers, in general, such a pure cost shift does not have an aggregate impact on costs to Maine ratepayers, nor have a societal aggregate cost impact. As such, while these cost shifts are described below, they are neither quantified nor included in the benefit-cost calculations for this report as they net to zero impact.
- SOPs must account for the direct impact of the kWh Credit program on retail generation supply costs as they are required to provide last resort service. Conversely, CEPs can structure contracts and offerings to exclude kWh Credit program recipients as their customers.
- The sum of the aggregate kWh wholesale obligation of all LSEs for a settlement month within an EDC footprint (i.e., the total system load for an EDC) does not change between ISO-NE initial settlement and final resettlement. That is the total system load for an EDC for a billing month is based on the sum of hourly generation and net ties and this calculation implicitly accounts for the kWh Credit program load reduction for that billing month. At the initial ISO-NE settlement the energy associated with the kWh Credit load reduction is allocated to unaccounted for energy (UFE) and spread to all LSEs on a pro-rata basis based on the sum of each LSEs' customers' metered load for the month. Conversely, at the final ISO-NE resettlement the energy associated with the kWh Credit load reduction is



not allocated to UFE but assigned to the LSEs of customers who are kWh Credit recipients.<sup>31</sup> This accounting method has the following implications.

- The share of kWh allocated to each LSE changes from initial settlement to final resettlement based on the share of kWh Credit recipients of each LSE. Specifically, during ISO-NE's initial settlement process the allocation of kWh Credits to customers of kWh Credit program recipients is not accounted for. That means at initial settlement LSEs of kWh Credit recipients are obligated for more kWh than they will ultimately be obligated to pay for at final resettlement, and further those LSEs of kWh Credit recipients must wait until final resettlement (typically five months) before their kWh obligation is appropriately decremented.
- Conversely, all other LSEs who do not have kWh Credit recipients as customers reap the time value of money benefit from a lower kWh obligation in the period between initial settlement as compared to final settlement given that sum of the aggregate kWh obligation of all LSEs for a settlement month within an EDC footprint does not change between initial and final settlement.
- The UFE decreases between initial settlement and final resettlement by the kWh Credits assigned to LSEs during the EDC accounting process (so basically the kWh Credits change from UFE to accounted for energy and that now accounted for energy at resettlement is decremented for LSEs with customers who are kWh Credit recipients).
- Assuming no banking of kWh Credits after final ISO-NE resettlement, each LSE is obliged to pay for only the kWh consumed by their customers (metered load adjusted for losses and UFE) net of the kWh Credits assigned to their customers.

Table 3 describes generally the impact of the kWh Credit program for various LSE cost/benefit drivers. From Table 3, the following drivers need to be quantified to estimate the benefit and cost impacts from a ratepayer and societal perspective. They include:

- Fixed Costs: Capacity
- Fixed Costs: Direct
- Volumetric Risk

In the following subsections, we address the modeling approach of each in turn. We then address the complications imposed by kWh Credit banking in section 3.16.4 and then conclude with a discussion of banked kWh credits and implications regarding the change in load shape settled for kWh credit recipients in section 3.16.5.

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<sup>31</sup> See CMP's presentation to the NEPOOL Meter Reading Working Group of September 13, 2024, [2024-09-13 MRWG A02 Net Energy Billing Load Reducers](#).

**Table 3 – kWh Credit Program's Impact on LSE Costs**

| LSE Cost / Benefit Driver             | Metric of Impact          | Method of Impact on LSEs w/ kWh Credit Recipients                                     | Overall Direction of Impact on LSE \$/kWh Costs                                                    | Quantified in BCA?    | Comment                                                                                                                                                                         |
|---------------------------------------|---------------------------|---------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------|-----------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Energy - Decrease in Total Sold       | kWh                       | None                                                                                  | None                                                                                               | N/A                   | Via resettlement process LSEs only pay for energy based on the kWh consumed net kWh Credit allocations                                                                          |
| Ancillary Services                    | Peak kW via share of load | None                                                                                  | None                                                                                               | N/A                   | Via resettlement process LSEs only pay for ancillary services based on the kWh share of load after netting kWh Credit allocations                                               |
| Energy - Change in Load Shape Settled | kWh                       | Weighted cost of kWh supplied                                                         | Varies by LSE, but neutral across all LSEs.                                                        | No, only a cost shift | Load reducer provides socialized benefits to some LSEs, and socialized cost to other LSEs. See section 3.16.5 for detailed discussion.                                          |
| Fixed Costs: Capacity                 | Peak kW                   | Fewer kWh sold to spread predetermined Peak Load Contribution (PLC) costs over        | Increase in <u>avg.</u> costs to LSEs of kWh Credit recipients                                     | Yes                   | While no overall change in total fixed costs recovered, consistent with impacts on T&D rates of fewer kWh sold this impact is considered a ratepayer and societal cost increase |
| Fixed Costs: Direct                   | Labor & Systems           | Fewer kWh sold to spread fixed costs of doing business over                           | Increase in <u>avg.</u> costs to LSEs of kWh Credit recipients                                     | Yes                   |                                                                                                                                                                                 |
| Volumetric Risk                       | kWh                       | Additional kWh volume volatility                                                      | Increase in total costs to LSEs of kWh Credit recipients                                           | Yes                   | LSEs need to account for changes in NEB project production on kWh load obligation (e.g., weather variations)                                                                    |
| Working Capital                       | kWh                       | Difference of kWh obligation at initial settlement vs. kWh obligation at resettlement | Varies by LSE, but neutral across all LSEs. LSEs of kWh Credit recipients experience higher costs. | No, only a cost shift | Avg. difference between initial and resettlement monetary outlay by cost of working capital over five months.                                                                   |
| ISO-NE Financial Assurance            | kWh                       | Difference of kWh obligation at initial settlement vs. kWh obligation at resettlement | Varies by LSE, but neutral across all LSEs. LSEs of kWh Credit recipients experience higher costs  | No, only a cost shift | Financial assurances based on LSE obligation at <u>initial</u> settlement                                                                                                       |
| Banking of kWh Credits                | kWh                       | Multiple                                                                              | Varies. Increased costs from added risks, all other impacts are cost shifts                        | No                    | See Section 3.16.4 for a detailed discussion                                                                                                                                    |



### 3.16.1 Quantifying Fixed Costs: Capacity

#### Overview

Each existing New England retail electric customer has an installed capacity tag (ICAP tag, denominated in kW) per their usage during the ISO-NE annual peak hour of the preceding year. The ICAP tag (or ISO-NE peak load contribution - PLC) is set annually and is assessed to the LSE of the retail customer on a monthly basis. This ICAP tag dollar assessment is fixed for a one-year period regardless of the kWh attributed to the customer (and ultimately their LSE) in a given billing month. Thus, as the kWh Credit program decreases the kWh attributed to kWh Credit recipients the annual ICAP tag dollar assessment remains fixed for those same recipients, and therefore the \$/kWh rate needed to cover the fixed ICAP tag dollar assessment increases. For SOP providers, this \$/kWh impact would be spread over all the SOP's customers in the same customer class, as SOP providers are not allowed to price discriminate within a customer class.

#### Data Source:

- Capacity prices are sourced from the results of the ISO-NE forward capacity auctions.
- Monthly ICAP Tag data for EDCs for all standard offer customers in a specific rate class valued at true-up (resettlement) or, if not available, at initial settlement, is sourced from the EDC's standard offer auction bidder's information page.
- Monthly billed load data for EDCs for all standard offer customers in a specific rate class is also sourced from the EDC's standard offer auction bidder's information page.
- Monthly applied NEB kWh Credits data is sourced from the EDC's standard offer auction bidder's information page.

#### Discussion:

To calculate the estimated impact of the kWh Credit program on "uncovered" capacity costs caused by the decrease in kWh billed via the application of kWh Credits requires the following components which were broken out by EDC and customer class on a monthly basis:

- ICAP cost in dollars. Such costs represent the EDC/customer class cost obligation of PLC, which is equivalent to the EDC/customer class kW of the ICAP tag multiplied by the \$/kW-Month ISO-NE capacity price.
- Percentage difference in billed load caused by the kWh Credit program. This is calculated by estimating the EDC/customer class change in gross billed load in kWh (without the kWh Credit program) vs. the kWh net billed load in practice (with the kWh Credit program) to determine the percentage difference in billed load.

To calculate total costs, we multiply that percentage difference of billed load caused by kWh Credit program (e.g., 5%) by the relevant ICAP costs in dollars, which results in the kWh Credit program impact in dollars.

### 3.16.2 Quantifying Fixed Costs: Direct

#### Overview

There are fixed costs to serve as a Maine SOP (i.e., costs that do not vary with the size of the load served). These include costs related to:

- Preparing and submitting bids
- Data systems and personnel to process and manage SOP obligations
- Accounting systems
- Legal counsel



A decrease in billed kWh, all else equal, will require higher per-kWh charges to cover such fixed costs.

#### Data Source:

- Consumer Price Index (CPI-U) data, used to adjust the estimated fixed costs to account for inflation, is sourced from the U.S. Bureau of Labor Statistics.

#### Discussion:

We do not have access to what the typical fixed costs for a Maine SOP are, as we have no data sources to reference. Nonetheless, in the next section (Section 3.16.3) on Volumetric Risk we describe a metric “Risk Premium+” which is inclusive of SOP fixed costs, and thus we are able to estimate the combination of additional volumetric risk and uncovered fixed costs that are imposed by the kWh Credit Program. Please refer to Section 3.16.3 for further discussion.

### 3.16.3 Quantifying Cost of Added Volumetric Risk

#### Overview

Volumetric risk imposed on LSEs of kWh Credit recipients is likely hedged with some combination of:

- Electricity put options (right to sell at a strike price)
- Electricity call options (right to purchase at a strike price)
- Weather-related “dirty hedges” that imperfectly hedge for risk that include puts and calls

All other things being equal, as MW volume of NEB kWh Credit projects increases, the variance of MWh ultimately supplied on ISO-NE resettlement increases, therefore requiring additional hedging per MWh ultimately supplied.

#### Data Sources:

- Monthly billed load data for EDCs for all standard offer customers in a specific rate class is sourced from the EDC’s standard offer auction bidder’s information page.
- SOP rates by EDC by rate class are sourced from the EDC’s standard offer auction bidder’s information page.
- Estimates of risk premium and fixed costs for SOPs are derived from analysis contained in the [Joint Petition Of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs](#) (Brattle Testimony). This analysis is specific to FirstEnergy Pennsylvania electric utilities. Specific references are as follows:
  - Pages 479-511 of the PDF for Discussion / Testimony. More specifically
    - A discussion of what is in Table 2, where “Risk Premium” would be more appropriately labeled “Risk Premium & Other Costs” or “Risk Premium+”
    - Table 2 from the testimony where “Risk Premium” (more appropriately labeled “Risk Premium & Other Costs” or “Risk Premium+”) encompasses everything above the passthrough of wholesale costs.
  - Pages 536-539 of the PDF for tables which provide the estimated cost components that comprise the default service rates for the four FirstEnergy Pennsylvania electric utilities.
- Annual load data for FirstEnergy Pennsylvania electric utilities is sourced from the U.S. Energy Information Administration (EIA).

#### Discussion:

Unsurprisingly, a review of literature resulted in a general lack of real-world examples of the risk premium imposed on LSEs in electricity markets akin to Maine’s load-following retail market. It is unsurprising, given that this is a niche topic, and that LSEs in competitive retail markets are understandably reticent regarding how they manage risk (it is proprietary).



Nonetheless, SEA identified one relevant study that provides an estimate of the costs of managing such risk for the default service electricity rates for FirstEnergy's Pennsylvania utilities. Pennsylvania's default service is similar to Maine's standard offer service. Both are load-following provider of last resort of retail generation service offering in a competitive retail electricity market where the investor-owned utilities have divested their generation assets. Given the similarities and lack of alternatives, we have leveraged and adapted the findings from the FirstEnergy study as an important input to estimate costs associated with risk (including fixed costs) assuming they are likely comparable to the risks (and fixed costs) of Maine's standard offer.

Table 4 displays an adaptation and extension of the FirstEnergy average estimated risk premium in default service full-requirements auctions (October 2016-April 2021). The labeling "Risk Premium+" is used because as the Brattle Testimony states on page 502 of the PDF.

*Therefore, the "risk premium"... may be larger than the "true risk-premium" to the extent that any material costs have been omitted.*

We presume that a material cost omitted by the Brattle Testimony is the fixed cost to bid for and serve the First Energy default service customers. Table 4 provides a computation of what the *Risk Premium+* is as a percentage of the average default service price and results in an unweighted average of 4.4% (see column F)

**Table 4 –  
Adaptation of the FirstEnergy (FE) Average Estimated Risk Premium in Default Service (DS)  
Full-Requirements Auctions (October 2016-April 2021)**

| (A)<br>FE DS Results Oct<br>2016 through Apr<br>2021 | (B)<br>Risk Premium+<br>(\$/MWh) | (C)<br>Risk Premium+<br>(% of No Risk<br>Premium+ Price) | (D = B/C)<br>No Risk<br>Premium+ Price | (E=B+D)<br>Avg. DS Full-<br>Requirements<br>Auction Results | (F=E/B)<br>Risk Premium+<br>(% of DS Full-<br>Requirements<br>Auction Results) |
|------------------------------------------------------|----------------------------------|----------------------------------------------------------|----------------------------------------|-------------------------------------------------------------|--------------------------------------------------------------------------------|
| Met-Ed                                               | \$2.95                           | 5.96%                                                    | \$49.50                                | \$52.45                                                     | 5.6%                                                                           |
| Penelec                                              | \$2.15                           | 4.63%                                                    | \$46.44                                | \$48.59                                                     | 4.4%                                                                           |
| Penn Power                                           | \$2.24                           | 4.10%                                                    | \$54.63                                | \$56.87                                                     | 3.9%                                                                           |
| West Penn Power                                      | \$1.54                           | 3.54%                                                    | \$43.50                                | \$45.04                                                     | 3.4%                                                                           |
| Unweighted Avg.                                      | \$2.22                           | 4.6%                                                     | \$48.52                                | \$50.74                                                     | 4.4%                                                                           |

### 3.16.3.1 Separating the FE DS Risk Premium+ Metric into Costs Associated with Volumetric Risk from Fixed Costs

The Risk Premium+ is the estimated percentage of the default service \$/MWh price above and beyond the wholesale full requirements costs and includes the costs of both the volumetric risk and the fixed costs. To appropriately estimate the cost impact of Maine's kWh Credit program on Maine's LSEs, we need to disaggregate the FE example Risk Premium+ costs associated with volumetric risk from fixed costs.

To do so, we next calculate the total average annual costs for bidding and serving the fixed price auction as a FE default service supplier as displayed in Table 5; the total average FE LSE DS revenue is \$721,313,110.



**Table 5 –  
Computation of Annual Avg. Costs for Bidding and Serving FE Fixed Price Auction by Default  
Service Suppliers (October 2016-April 2021)**

| (A)<br>FE DS Results Oct 2016<br>through Apr 2021 | (B)<br>Avg. DS Full-Requirements<br>Auction Results | (C)<br>Avg. Annual Fixed Price<br>Default Service MWh<br>Served | (D = B*C)<br>Annual Avg. Revenue for<br>Bidding and Serving FE<br>Fixed Price Auction |
|---------------------------------------------------|-----------------------------------------------------|-----------------------------------------------------------------|---------------------------------------------------------------------------------------|
| Met-Ed                                            | \$52.45                                             | 4,490,383                                                       | \$235,505,497                                                                         |
| Penelec                                           | \$48.59                                             | 3,899,721                                                       | \$189,472,969                                                                         |
| Penn Power                                        | \$56.87                                             | 2,190,547                                                       | \$124,585,489                                                                         |
| West Penn Power                                   | \$45.04                                             | 3,813,019                                                       | \$171,749,155                                                                         |
| Unweighted Avg. / Total                           | \$50.74                                             | 14,393,670                                                      | \$721,313,110                                                                         |

Assuming the fixed costs are \$1,000,000 then the fixed costs of serving FE DS load are 0.14% of the average annual revenue to serve FE DS load ( $\$1,000,000 / \$721,313,110 = 0.14\%$ , or  $\$1,000,000 / 14,393,670 = \$0.069/\text{MWh}$ ).

We then use the “Risk Premium+” metrics from Table 4 and an estimate of what the fixed costs to bid and serve are (e.g., \$1,000,000) to net out fixed costs which results in an estimate of the “True Risk Premium %”.

**Table 6 –  
Disaggregating True Risk Premium and Fixed Costs from the Risk Premium+ Metric**

| FE DS Metric                                                                                             | FE DS Metric Value | Comment                                                                                  |
|----------------------------------------------------------------------------------------------------------|--------------------|------------------------------------------------------------------------------------------|
| (A) Risk Premium+ \$/MWh                                                                                 | \$2.22             | See Table 4, Column B                                                                    |
| (B) Fixed Costs Avg. \$/MWh                                                                              | \$0.069            | As computed above. Fixed Costs do not scale with MWh served but do scale w/ inflation.   |
| (C) Risk Costs                                                                                           | \$2.151            | $C = A - B$ ; Risk and ancillary service costs scale with the size of the auction prices |
| (D) True Risk Premium as % of "Risk Premium+"                                                            | 96.9%              | $D = C/A$                                                                                |
| (E) Risk Premium+ as % of DS Full-Requirements Auction Results                                           | 4.4%               | See Table 4, Column F                                                                    |
| (F) True Risk Premium %<br>(Disaggregated from Fixed Costs as % of DS Full-Requirements Auction Results) | 4.2%               | $F = D * E$                                                                              |
| (G) Cumulative Inflation (2019-2025)                                                                     | 26.01%             | Consumer Price Index Data                                                                |
| (H) Fixed Costs in 2019 Dollars                                                                          | \$1,000,000        | As assumed                                                                               |
| (I) Fixed Costs in 2025 Dollars                                                                          | \$1,260,134        | $I = (1+G)*H$                                                                            |



With an estimate of the “True Risk Premium %” net fixed costs, we then can calculate the impact of additional base hedging costs (by EDC by customer class) attributable to Maine’s kWh Credit program. We do so for the small and medium customer classes<sup>32</sup> for each of the EDCs by

- Multiplying the average Standard Offer pricing in \$/MWh by the True Risk Premium %, which results in the Base Risk Costs in \$/MWh (i.e., without added risk costs for kWh Credit Program Variability and net fixed cost premium). This results in Base Risk Costs in \$/MWh that vary between \$4.00 and \$5.50/MWh depending on EDC and customer class.
- Multiplying the Base Risk Costs in \$/MWh by kWh Credit Production / Billed Load (%) for each EDC and customer class (e.g., 1% to 13% depending on EDC and customer class) to result in the Additional Hedging Costs Attributable to kWh Credit Program (\$/MWh).

Finally, we multiply the Additional Hedging Costs Attributable to kWh Credit Program (\$/MWh) by the Annual MWh of Standard Offer load to result in the Additional Hedging Costs Attributable to kWh Credit Program in dollars for each EDC and customer class.

In parallel, we calculate the “additional” (uncovered) fixed costs that are imposed by the kWh Credit program by leveraging the same estimate of fixed costs to bid and serve FirstEnergy default service load (e.g., \$1,000,000) discounted by the kWh Credit Production as a percent of billed load and then adjusted for inflation so it applies to the Maine SOP.

Finally, we note, if we estimated a higher or lower fixed costs to bid and serve load, then that will result in a respectively lower or higher “True Risk Premium %” to apply to the Maine SOP case. Thus, the joint accounting for the impacts of risk-premium and fixed costs are bounded by the leveraged results of the Brattle Testimony.

### 3.16.4 Banking of kWh Credits

#### Overview

Another feature of the kWh Credit program is the ability of customers to bank kWh Credits for up to 12 months from the month in which the credits were generated. While banking kWh Credits affects the retail load billed to customers (that is, the kWh for which a customer must pay in each month and therefore the retail revenue an LSE receives), it does not impact the wholesale load obligation of LSEs. That is, banking kWh credits, or using banked kWh credits, does not affect the LSE’s load obligation in a given month.<sup>33</sup>

We demonstrate this in Table 7, below. This table illustrates the impact of banking on an LSE serving a single customer receiving kWh credits. The table illustrates how, when kWh credits (column b) received exceed customer consumption (column a) in a given month, credits can be banked (column d). Critically, however, the LSE’s wholesale load obligation (after resettlement, column e) is always equal to the difference between customer consumption (a) and credits received (b), *regardless of whether any banking occurs*. In this example in which there is a single customer, this means that a LSE’s load obligation would be negative in months in which credits received exceed customer consumption (in practice, this does not

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<sup>32</sup> We exclude the large customer class as SOP costs for the large customer class are primarily a straight monthly variable pass-through of ISO-NE wholesale costs and thus any risk premium associated with the large customer class is structurally different than the risk premium for the small and medium customer classes where the standard offer pricing is set the year prior. Thus, the True Risk Premium % for the large customer class standard offer class is likely minimal and certainly much smaller than the True Risk Premium % of the small and medium customer classes. Finally, the percentage of customer class load being served by SOPs for the large customer class is much smaller than that of the small and medium customer classes, making the relative impact of kWh Credit banking even smaller for the large customer class and probably *de minimis*.

<sup>33</sup> This does not mean that the ability of customers to bank kWh Credits does not affect the cost of suppliers to serve customers these customers. The narrow conclusion here (that banking or drawing down on banked kWh credits) does not affect a supplier’s wholesale load obligation.



happen, as credits received never exceed customer consumption when aggregated over a supplier's full set of customers). Still, the example illustrates how banking *does not* change the wholesale load obligation of an LSE.

**Table 7 –  
NEB Credit Banking Simple Example**

|              | (a)                     | (b)                        | (c)                    | (d)                             | (e)                                         |
|--------------|-------------------------|----------------------------|------------------------|---------------------------------|---------------------------------------------|
|              | Customer<br>Consumption | kWh<br>Credits<br>Received | Customer<br>Billed kWh | Cumulative<br>Banked<br>Credits | RES Wholesale Load<br>Obligation<br>(a - b) |
| Jan          | 500                     | 100                        | 400                    | 0                               | 400                                         |
| Feb          | 500                     | 200                        | 300                    | 0                               | 300                                         |
| Mar          | 500                     | 600                        | 0                      | 100                             | -100                                        |
| Apr          | 500                     | 700                        | 0                      | 300                             | -200                                        |
| May          | 500                     | 400                        | 0                      | 200                             | 100                                         |
| Jun          | 500                     | 100                        | 200                    | 0                               | 400                                         |
| <b>Total</b> | <b>3000</b>             | <b>2100</b>                | <b>900</b>             | <b>600</b>                      | <b>900</b>                                  |

Those kWh credits are assigned to customers and ultimately to their LSEs in the specific billing month, regardless of whether the kWh Credits will be credited to the customer's bill in the billing month or banked for later use (or if not used, the credits expire). Thus, occurrence or not of banking of kWh Credits does not impact the initial settled nor the final re-settled wholesale load obligation of an LSE.

Put a different way, it is the assignment of credits to a customer of a LSE that impacts the wholesale load obligation of an LSE, while the banking of kWh Credits has no impact on the wholesale load obligation of an LSE. Conversely, the banking of kWh Credits does impact LSEs retail revenue collections by postponing the date when full diminution of kWh that can be billed by an LSE caused by kWh Credits occurs.

Thus, the subtlety of the impact of kWh Credit banking on LSEs that must be emphasized is the difference of impacts between wholesale load obligation of an LSE (no impact) vs. retail revenue collections for an LSE (impacts as described next).

Given the above, we next discuss the implications of banked kWh Credits for LSEs. To pay for wholesale energy purchased from ISO-NE, LSEs must finance the carrying cost of the difference between initial wholesale settlement and final wholesale resettlement. This occurs regardless of banking behavior, and thus banking kWh Credits has no additional impact on wholesale cost to serve retail load.

Nonetheless as also discussed above, there are impacts of banked credits on retail revenue collections for LSEs that have yet to be accounted for. First, we note that the LSE serving customers changes over time. This means that the LSE serving the customer when the kWh Credit was banked, may not be the LSE serving the customer when kWh Credit banked generation is used to decrease the customer's bill. We further note that some kWh Credits are never used as they expire on a 12-month rolling basis (old credits are used first).

Regardless of these specific idiosyncrasies, we note the following impacts of banked kWh Credits on LSE's billing of their customers and ultimately on the LSE's retail revenue collections:



- For banked credits that are ultimately used by customers to offset their retail consumption there are two impacts:
  - First, there is a delay of the decrement of revenue caused by the delay when the kWh Credits are applied (as compared to the no banking of kWh Credit case). This delay in the decrement of retail revenue improves the cashflow of an LSE as compared to the kWh Credits being utilized by the customer recipient in the billing month they were assigned. This, probably modest, delay helps to moderate the working capital costs of LSEs serving kWh Credit recipients and thus moderates the ratepayer and societal costs.
  - Second, there is a mismatch between the LSEs decrement of the wholesale cost of energy procured by a LSE, and the LSE's retail revenue received for providing retail generation services. That is, if kWh Credits received by a customer in June are banked and not used by the customer until October, then the decrement of retail revenue will be based on the \$/kWh retail rate applicable in October (and not June).
    - The mismatch described just above could be a swing either way as its impact could conceivably be a marginal benefit or cost to an LSE. Further because there is close to a fixed SOP rate for residential and small commercial customers for the entire calendar year, it would make little difference on nominal retail rate collection if the kWh Credit was applied in June vs. October for this customer class. Regardless, and generally, as it is unclear whether the impact would be positive or negative to a LSE, we assume there is no overall impact to model from this effect.
    - Regardless of whether the impact is positive or negative to an LSE's retail revenue collection, the chance of such a swing is a risk the LSE needs to account for, and thus an added cost to LSEs that would not occur in the absence of the kWh Credit program. Managing this risk is a cost impact to ratepayers and a societal cost increase as well.
- For unused kWh credits that are lost to customers (i.e., expired credits), an LSE (as described above) has its wholesale load obligation decremented upon wholesale resettlement, but we assume never has its retail revenue decremented for the equivalent kWh.<sup>34</sup>
  - As compared to recipients that don't bank kWh Credits, this impact is a marginal benefit to LSEs (as it decreases their net cost to serve), and overall, a marginal benefit shift back to ratepayers (at the expense of program participants).

In summary, except for the added risks, the impact of kWh Credit banking on LSEs is either a wash or a marginal decrease in the overall costs in serving kWh Credit recipients. Unfortunately, we have no basis to estimate the impact of kWh Credit banking as we do not have information on the scale of kWh Credits banked nor how long the credits are banked for. We presume such impacts will be a secondary or tertiary order impacts, and for this analysis assume that such impacts are zero. Future analysis should request from the EDCs as much information on banked kWh Credits to facilitate a possible quantification of this impact.

### 3.16.5 Change in Load Shape Settled

This impact represents the difference in the shape of customer load and solar production, which, because of how the energy resettlement process adjusts the load obligation of suppliers serving kWh Credit customers, is socialized across a set of customers.

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<sup>34</sup> It is possible that the EDCs decrement the LSEs kWh billed for the expired banked credits, but the realization that this was an issue to be confirmed by SEA with the EDCs came up too late in the report writing process to be incorporated into this analysis. Regardless, any impacts are probably small and would not significantly impact the overall conclusions of this analysis.

**Discussion:**

To illustrate this impact, consider the simple example provided in Table 8 in which five hours are considered (but one can imagine this representing a month). In this example, PV production (column (a)) generates kWh Credits which are assigned to the customer with load represented in column (b). Because the total PV production is equal to the load over the period, the supplier's wholesale load obligation associated with the customer is reduced to zero in every hour. As discussed in Appendix C.1 to SEA's report titled "Ratepayer Value Analysis of Maine's Net Energy Billing (NEB) Resources:

Load Reducers vs. Generator Assets", this load obligation is applied as a proportional reduction of the entire load shape, as opposed to simply adding PV production and load by hour.<sup>35</sup> Therefore, the supplier's wholesale cost (column (g)) is zero. Column (d) tracks the system load on an hour-by-hour basis. Multiplying this column by the hourly price in column (e) yields the actual market cost/revenue in column (f). Despite the sum of the PV production and load being the same over the full period, their different shapes yield a market cost that does not equal zero. In the example, the total market obligation (not the supplier's post-resettlement obligation) is \$410. As already established, the wholesale cost for the supplier is zero, so the \$410 must be recovered from some set of customers.

**Table 8 –  
Illustration of PV Production Shape Socialization**

|              | (a)           | (b)         | (c)                                   | (d)            | (e)   | (f)                      | (g)              | (h)                   |
|--------------|---------------|-------------|---------------------------------------|----------------|-------|--------------------------|------------------|-----------------------|
| Hour         | PV Production | Load        | Adjusted load (supplier's obligation) | Net load (a-b) | Price | Actual market cost (d*e) | Paid by supplier | Needs to be recovered |
| 1            | 100           | 0           | 0                                     | 100            | \$10  | \$1,000                  | \$0              | (\$1,000)             |
| 2            | 50            | -20         | 0                                     | 30             | \$50  | \$1,500                  | \$0              | (\$1,500)             |
| 3            | 20            | -50         | 0                                     | -30            | \$3   | (\$90)                   | \$0              | \$90                  |
| 4            | 70            | -70         | 0                                     | 0              | \$1   | \$0                      | \$0              | \$0                   |
| 5            | 0             | -100        | 0                                     | -100           | \$20  | (\$2,000)                | \$0              | \$2,000               |
| <b>Total</b> | <b>240</b>    | <b>-240</b> | <b>0</b>                              | <b>0</b>       |       | <b>\$410</b>             | <b>\$0</b>       | <b>(\$410)</b>        |

As noted above, this impact is specific to the kWh Credit program, and, more specifically, only applies when resources are treated as Load Reducers. In recent years, the market value of the solar generally has been lower than the market cost of the load, which is consistent with the example provided above. Given the assumption that kWh Credit program recipients are served by SOPs, the shift in value occurs between SOPs and suppliers of non-large competitive supply customers, as the benefit is realized only by SOPs, and then recovered from suppliers of all non-large competitive supply customers. Suppliers of large customers are unaffected by this impact, as their loads are not adjusted for Unaccounted for Energy (UFE).

However, given that this impact represents a cost shift, it is not considered in the benefit-cost calculation.

<sup>35</sup> Report available at: <https://www.maine.gov/mpuc/sites/maine.gov/mpuc/files/inline-files/ME%20PUC%20Value%20of%20DG%20-%20LD%20327-Final%20Report.pdf>



### 3.16.6 Avoided Energy as a kWh Credit Program Benefit

SEA did not compute an avoided energy benefit applicable to the kWh Credit program. Although it is true that the kWh Credit program reduces the total kWh that must be procured by load serving entities, there is no avoided energy benefit associated with such reductions to ratepayers in general as such reductions are paid for by and benefits accrue to program participants. More specifically, the benefits associated with avoided energy accrue, for example, to the kWh Credit project subscriber (in the form of a reduction to billed kWh usage) and the project owner (in the form of the kWh Credits to sell to subscribers).

Benefits applicable to such participants were not considered given that the inclusion of such benefits would require a shift in perspective to that of the program participant. Given the legislative mandate to consider “costs authorized to be collected by T&D utilities in rates and benefits directly received by ratepayers,” SEA determined that such a perspective was not appropriate for this analysis. Also importantly, for this analysis SEA interpreted “benefits directly received by ratepayers” as those benefits which any ratepayer would receive outside participation in the NEB program (i.e., NEB program nonparticipants).



## 4 Results and Findings

### 4.1 General Societal Perspective

The results of SEA's analysis quantifying the benefits and costs of the NEB program for calendar year 2025 are provided below, with a graphical summary of the analysis provided in Figure 2 and a tabular summary in Table 9. Benefit components displayed below are an aggregation of more granular components, organized by component category. For a more detailed breakdown of individual benefit components, please see Appendix A.

**Figure 2 –  
Calendar Year 2025 NEB Summary Costs and Benefits**

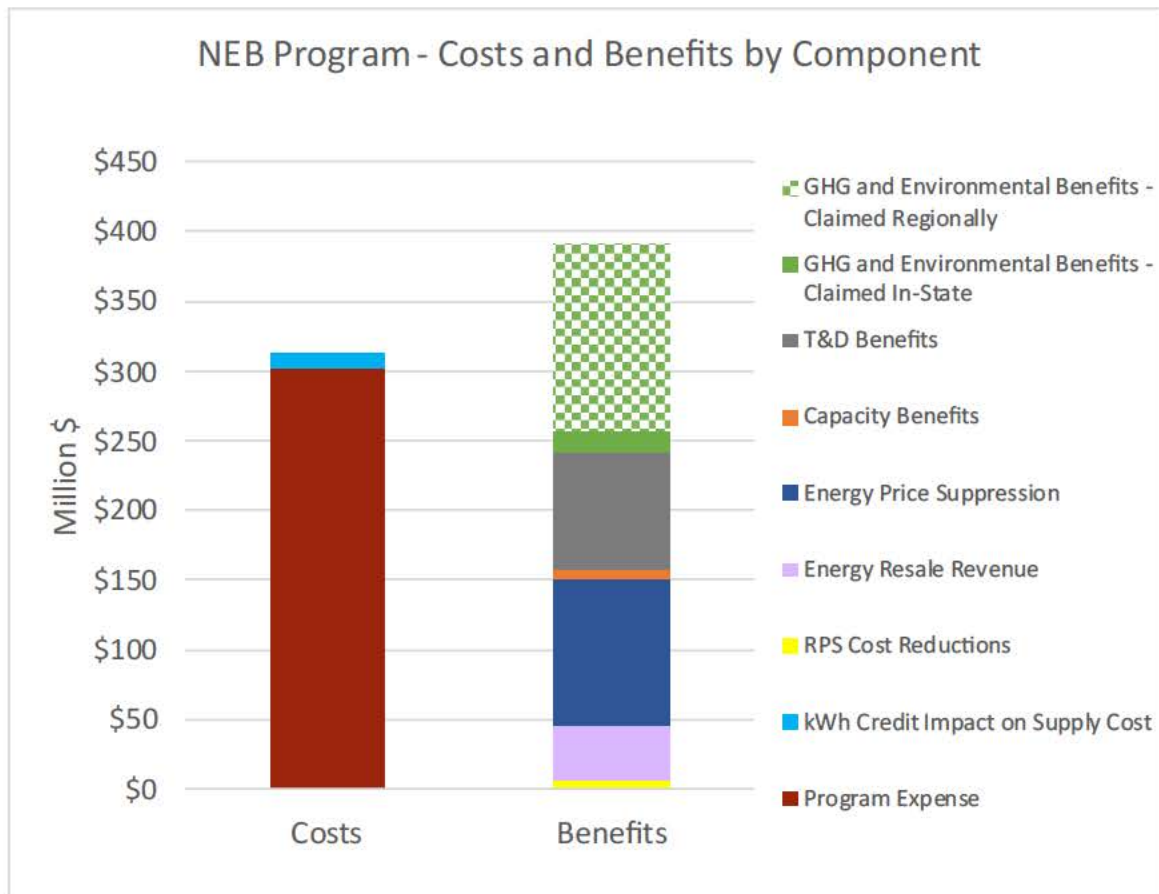




**Table 9 -**  
**Calendar Year 2025 NEB Summary Cost and Benefit in Millions of Dollars**

| Benefit / Cost Category                             | Costs    | Benefits |
|-----------------------------------------------------|----------|----------|
| Program Expense                                     | \$302.45 | N/A      |
| kWh Credit Impact on Supply Cost                    | \$10.44  | N/A      |
| RPS Cost Reductions                                 | N/A      | \$6.39   |
| Energy Resale Revenue                               | N/A      | \$39.60  |
| Energy Price Suppression                            | N/A      | \$105.77 |
| Capacity Benefits                                   | N/A      | \$5.24   |
| Transmission and Distribution (T&D) Benefits        | N/A      | \$84.56  |
| GHG and Environmental Benefits - Claimed In-State   | N/A      | \$14.95  |
| GHG and Environmental Benefits – Claimed Regionally | N/A      | \$134.90 |
| Totals – Including GHG Benefits Claimed Regionally  | \$312.89 | \$391.40 |
| Totals – Excluding GHG Benefits Claimed Regionally  | \$312.89 | \$256.51 |

SEA calculates that the NEB program’s 2025 calendar year program expenses were \$313 million, and the program benefits were between \$257 and \$391 million, depending on if GHG benefits claimed regionally are considered in the analysis.<sup>36</sup> Note that the cost and expenses are for all solar projects operating in 2025. Thus, the impact of projects as old as 1994 are included in the analysis. This report includes costs and benefits significantly greater than the 2024 report, a product of the high volume of projects coming online late in 2024, which have their first full year of production reflected in 2025.

As discussed in Section 3.13, the most significant revision to the results presented is SEA’s decision to differentiate GHG benefits associated with RECs retained in state versus sold into the regional Class I marketplace (and thereby potentially claimed out of state). As such, the results demonstrate that the program’s net benefits are highly contingent on if such benefits are included in the analysis. Given varying perspectives and complexity regarding the appropriateness of applying such benefits in a BCA, SEA is presenting both sets of results for increased transparency. Figure 3 and Table 10 provides a summary of the Maine NEB program costs and benefits by the program variants described in Section 3.1.

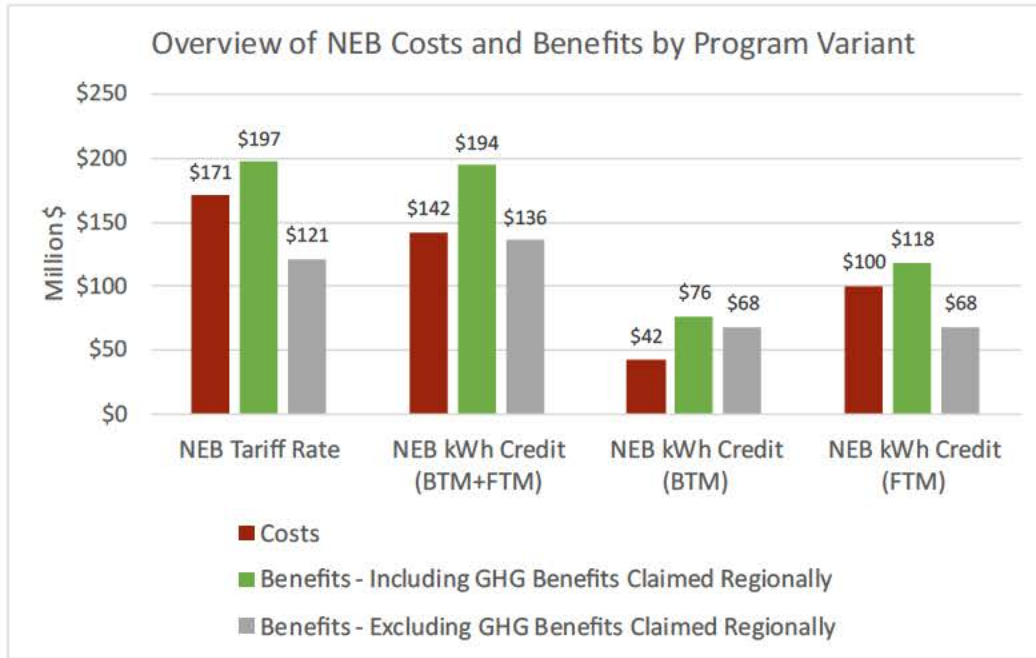
**Table 10 -**  
**2025 NEB Program Variant Summary Cost and Benefit in Millions of Dollars**

| Program Variant          | Benefit-Cost Ratio - Including GHG Benefits Claimed Regionally | Benefit-Cost Ratio - Excluding GHG Benefits Claimed Regionally |
|--------------------------|----------------------------------------------------------------|----------------------------------------------------------------|
| NEB Tariff Rate          | 1.16                                                           | 0.71                                                           |
| NEB kWh Credit           | 1.36                                                           | 0.95                                                           |
| NEB kWh Credit (BTM)     | 1.79                                                           | 1.60                                                           |
| NEB kWh Credit (FTM)     | 1.18                                                           | 0.68                                                           |
| <b>NEB Program Total</b> | <b>1.25</b>                                                    | <b>0.82</b>                                                    |

<sup>36</sup> For a majority of the NEB program, the GHG benefits associated with RECs produced may be claimed by other states purchasing and retiring RECs sold into the regional marketplace.



**Figure 3 –  
2025 NEB Program Variant Summary Costs and Benefits in Millions of Dollars**



Next, Figure 4 provides a summary of the NEB program costs and benefits by the program variants on a million-dollar per  $MW_{AC}$  basis.

**Figure 4 –  
2025 NEB Program Variant Per MW Summary Costs and Benefits**

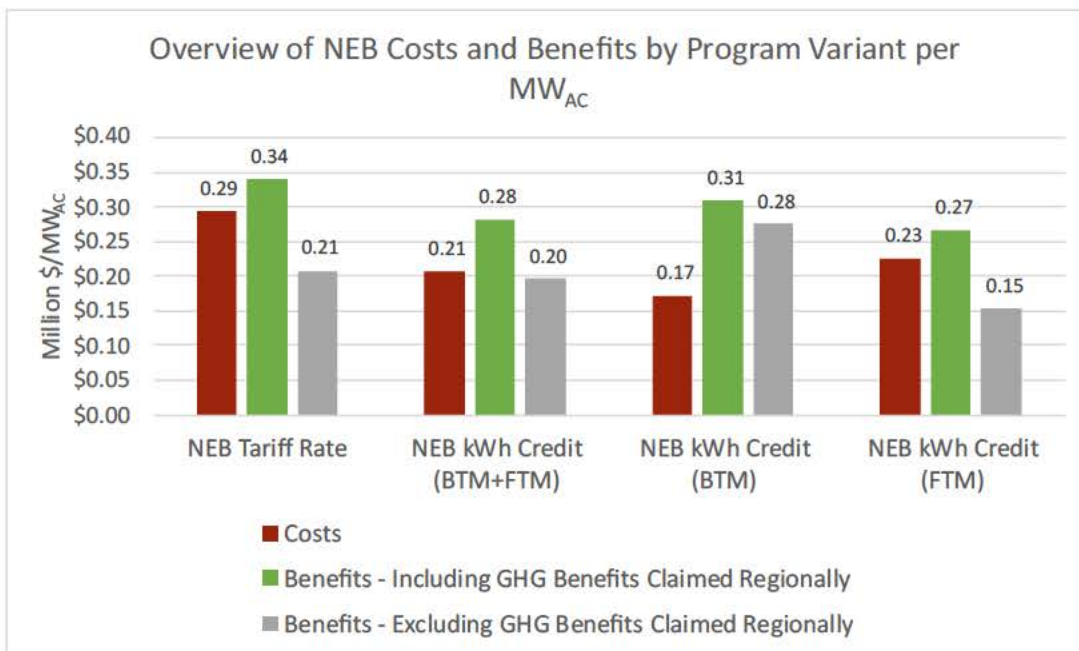




Table 11 provides a breakdown of total value by component category, whereas Table 12 provides such figures on a million-dollar per MW<sub>AC</sub> basis for apples-to-apples comparisons across program variants.

A discussion of the relative benefits and costs of each program variant is provided below in approximate order of significance:

- **Program Costs:** Although the Tariff Rate program delivers greater total benefits per MW, the cost per MW is significantly greater, resulting in a worse benefit-cost ratio as compared to the kWh Credit program. This is because, for kWh Credit projects, program expenses do *not* include the full avoided \$/kWh charges. Instead, because the production from kWh Credit projects is treated as a load reducer, program costs are a function of lost transmission and distribution revenue, and do not include the generation component of the retail rate. Conversely, for the original Tariff Rate program participants, the full cost of the Tariff Rate (which is a derivative of the full \$/kWh retail rate) is being provided as a dollar-denominated credit and shows up in the Program Expense category. These findings are partially offset by the inclusion of costs related to the kWh Credit program variant's impact on Standard Offer rates. However, such costs are relatively small compared to direct program expenses quantified and do not change the conclusion that the kWh Credit program variant includes lower costs on an absolute and relative basis.
- **T&D Benefits:** The kWh Credit Program variant accrues a lot more of these benefits, because BTM projects (which are only kWh Credit program variant projects) accrue both avoided distribution and transmission benefits, while FTM projects (which are both kWh Credit program variant and Tariff Rate program variant projects) accrue primarily avoided transmission benefits.
- **kWh-denominated Benefits:** Benefits that are a function of project production (e.g., GHG benefits, energy price suppression, REC price suppression) are higher per-MW for the Tariff Rate program variant because the capacity factor of small BTM projects is typically lower than capacity factor of large FTM projects for the same location. In addition, the Tariff Rate program portfolio includes non-solar projects which have a significantly higher capacity factor, contributing to greater production per MW on a program-variant-wide basis.
- **Load Reducer Benefits:** Because projects participating in the kWh Credit program variant act as load reducers, they are the only projects for which benefits associated with reducing the Maine RPS Compliance Obligation, uncleared capacity value, and capacity DRIPE benefits accrue. In addition, for the Maine Test (discussed in Section 4.3), these are the only projects for which benefits associated with reduced share of capacity and transmission costs accrue.
- **Energy Resale Revenue:** kWh Credit program variant projects do not receive energy resale benefits. Conversely, projects enrolled in the Tariff Rate program serve as generators in ISO-NE markets and received \$39.6 million in energy resale benefits in 2025. This occurs because, as discussed above in Section 3.1, the kWh Credit program variant projects act as load reducers and thus they are not directly monetized by selling the energy on the wholesale market, while the energy output from the Tariff Rate projects are monetized by the EDCs.



**Table 11 -  
Summary Comparison of Tariff Rate vs. kWh Credit 2025 NEB Program Variants (Total \$)**

| Benefit / Cost Category                                           | Tariff Rate (Millions \$ or MW <sub>AC</sub> ) | kWh Credit (Millions \$ or MW <sub>AC</sub> ) | kWh Credit as % of Tariff Rate |
|-------------------------------------------------------------------|------------------------------------------------|-----------------------------------------------|--------------------------------|
| MW <sub>AC</sub>                                                  | 581.25                                         | 689.69                                        | 118.7%                         |
| Program Expense                                                   | \$170.59                                       | \$131.86                                      | 77.3%                          |
| kWh Credit Impact on Supply Cost                                  | \$0.00                                         | \$10.44                                       | N/A                            |
| T&D Benefits                                                      | \$29.10                                        | \$55.45                                       | 190.6%                         |
| GHG and Environmental Benefits - Claimed Regionally               | \$76.39                                        | \$58.50                                       | 76.6%                          |
| GHG and Environmental Benefits - Claimed In-State                 | \$0.00                                         | \$14.95                                       | N/A                            |
| Energy Price Suppression                                          | \$51.92                                        | \$53.85                                       | 103.7%                         |
| RPS Cost Reductions                                               | \$0.00                                         | \$6.39                                        | 425232.8%                      |
| Energy Resale Revenue                                             | \$39.60                                        | \$0.00                                        | 0.0%                           |
| Capacity Benefits                                                 | \$0.23                                         | \$5.01                                        | 2154.2%                        |
| <b>Total Benefits - Including GHG Benefits Claimed Regionally</b> | <b>\$197.25</b>                                | <b>\$194.15</b>                               | <b>98.4%</b>                   |
| <b>Total Benefits - Excluding GHG Benefits Claimed Regionally</b> | <b>\$120.86</b>                                | <b>\$135.65</b>                               | <b>112.2%</b>                  |

**12 Table -  
Summary Comparison of Tariff Rate vs. kWh Credit 2025 NEB Program Variants (\$/MW)**

| Benefit / Cost Category                                           | Tariff Rate (Millions \$/MW <sub>AC</sub> ) | kWh Credit (Millions \$/MW <sub>AC</sub> ) | kWh Credit as % of Tariff Rate |
|-------------------------------------------------------------------|---------------------------------------------|--------------------------------------------|--------------------------------|
| Program Expense                                                   | \$0.29                                      | \$0.19                                     | 65.1%                          |
| kWh Credit Impact on Supply Cost                                  | \$0.00                                      | \$0.02                                     | N/A                            |
| T&D Benefits                                                      | \$0.05                                      | \$0.08                                     | 160.6%                         |
| GHG and Environmental Benefits - Claimed Regionally               | \$0.13                                      | \$0.08                                     | 64.5%                          |
| GHG and Environmental Benefits - Claimed In-State                 | \$0.00                                      | \$0.02                                     | N/A                            |
| Energy Price Suppression                                          | \$0.09                                      | \$0.08                                     | 87.4%                          |
| RPS Cost Reductions                                               | \$0.00                                      | \$0.01                                     | N/A                            |
| Energy Resale Revenue                                             | \$0.07                                      | \$0.00                                     | 0.0%                           |
| Capacity Benefits                                                 | \$0.000                                     | \$0.007                                    | 1815.5%                        |
| <b>Total Benefits - Including GHG Benefits Claimed Regionally</b> | <b>\$0.34</b>                               | <b>\$0.28</b>                              | <b>83.0%</b>                   |
| <b>Total Benefits - Excluding GHG Benefits Claimed Regionally</b> | <b>\$0.21</b>                               | <b>\$0.20</b>                              | <b>94.6%</b>                   |



## 4.2 Monetization of Benefits and Costs

The Act specifies that the Commission must distinguish costs and benefits that are monetized from costs and benefits that are not monetized, and for those costs or benefits that are monetized, the Commission must specify the entities to which the monetized value accrues, which may include, but are not limited to, electricity customers, electricity supply providers and transmission and distribution utilities. A discussion of which benefit and cost components are monetized, and to which parties those values accrue, is provided below.

While all benefits and costs assessed in this analysis are quantified in dollar terms (as is necessary in a benefit-cost analysis to provide apples-to-apples comparisons across components), not all benefits will have their impact realized in dollar terms (e.g., environmental benefits are not provided in dollar terms). Still, defining what constitutes monetization is difficult, as many benefit components are expected to result in dollar value impacts, but through mechanisms that do not involve the direct transfer of funds through the NEB program. On the other hand, certain components are clearly monetized (e.g., PPA payments to projects). To address this nuance, SEA has classified benefit component monetization into the following categories:

- Direct – Components which involved the direct transfer of funds between parties, facilitated by the NEB program.
- Indirect – Components for which impacts are experienced in dollar value terms, but for which the mechanism driving the impact is an indirect effect of the NEB program.
- Not Monetized – Components for which impacts are not exclusively experienced in dollar terms. The use of the word “exclusively” is meant to reflect that for certain non-monetized benefits (such as GHG benefits), the quantification of impacts does include consideration of economic damages which will eventually be experienced in dollar terms. However, such benefits are broader in scope and include more difficult-to-quantify impacts such as impacts on human health.

Components with monetization designations, including the party to which value accrues, are provided in Table 13 (we note that “ROP” stands for “Rest of Pool”, and designates benefits accruing to neighboring states within ISO-NE):

**Table 13 -  
Benefit & Cost Components Included by Monetization Designation**

| Component                                 | Monetization | Category | Impacted Party                                        |
|-------------------------------------------|--------------|----------|-------------------------------------------------------|
| Project PPA Expenses                      | Direct       | Cost     | ME Ratepayers                                         |
| Lost Utility Revenues                     | Direct       | Cost     | ME Ratepayers                                         |
| kWh Credit Impact on Supply Cost          | Direct       | Cost     | ME Ratepayers (Standard Offer Customers Only)         |
| Program Admin                             | Direct       | Cost     | ME Ratepayers                                         |
| Energy Resale                             | Direct       | Benefit  | ME Ratepayers                                         |
| Capacity Buyout Revenue                   | Direct       | Benefit  | ME Ratepayers                                         |
| Interconnection upgrade benefits          | Indirect     | Benefit  | ME Ratepayers                                         |
| Uncleared capacity value (Intrastate)     | Indirect     | Benefit  | ME Ratepayers                                         |
| Uncleared capacity value (ROP)            | Indirect     | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Reduced Share of Capacity Costs           | Indirect     | Benefit  | ME Ratepayers                                         |
| Price suppression - energy (Intrastate)   | Indirect     | Benefit  | ME Ratepayers, at expense of Non-ME ISO-NE Ratepayers |
| Price suppression - energy (ROP)          | Indirect     | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Price suppression - capacity (Intrastate) | Indirect     | Benefit  | ME Ratepayers                                         |



| Component                                              | Monetization  | Category | Impacted Party                                        |
|--------------------------------------------------------|---------------|----------|-------------------------------------------------------|
| Price suppression - capacity (ROP)                     | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Price suppression - electric-gas (Intrastate)          | Indirect      | Benefit  | ME Ratepayers                                         |
| Price suppression - electric-gas (ROP)                 | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Price suppression - electric-gas-electric (Intrastate) | Indirect      | Benefit  | ME Ratepayers                                         |
| Price suppression - electric-gas-electric (ROP)        | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Reduced transmission costs (Intrastate)                | Indirect      | Benefit  | ME Ratepayers                                         |
| Reduced transmission costs (ROP)                       | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Reduced Share of Transmission Costs                    | Indirect      | Benefit  | ME Ratepayers, at expense of Non-ME ISO-NE Ratepayers |
| Reduced distribution costs                             | Indirect      | Benefit  | ME Ratepayers                                         |
| Reduced T&D losses - capacity (Intrastate)             | Indirect      | Benefit  | ME Ratepayers                                         |
| Reduced T&D losses - capacity (ROP)                    | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Reduced T&D losses - energy (Intrastate)               | Mixed         | Benefit  | ME Ratepayers                                         |
| Reduced T&D losses - energy (ROP)                      | Mixed         | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Improved generation reliability (Intrastate)           | Indirect      | Benefit  | ME Ratepayers                                         |
| Improved generation reliability (ROP)                  | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |
| Non-embedded GHG emissions                             | Non-Monetized | Benefit  | Society                                               |
| Reduced RPS Obligation                                 | Indirect      | Benefit  | ME Ratepayers                                         |
| REC Price Suppression (Intrastate)                     | Indirect      | Benefit  | ME Ratepayers                                         |
| REC Price Suppression (ROP)                            | Indirect      | Benefit  | Non-ME ISO-NE Ratepayers                              |

Benefits that relate to reducing the share of transmission or capacity expenses paid for by Maine ratepayers do not offer net benefits on a societal level because they are essentially a cost shift from Maine ratepayers to ratepayers in other ISO-NE states. As such, these components could be considered a benefit or a cost depending on the perspective. Next, reduced T&D losses for energy are denoted as both Indirect and Non-Monetized given that they are a function of all kWh denominated benefits, which include Non-Monetized GHG benefits. Lastly, REC revenue was not considered as a benefit in this analysis, as RECs are not a product that is purchased by the EDCs through the NEB program. However, it is worth noting that the monetization of REC benefits would be considered a “Direct” monetization, with benefit accruing to the project owner.

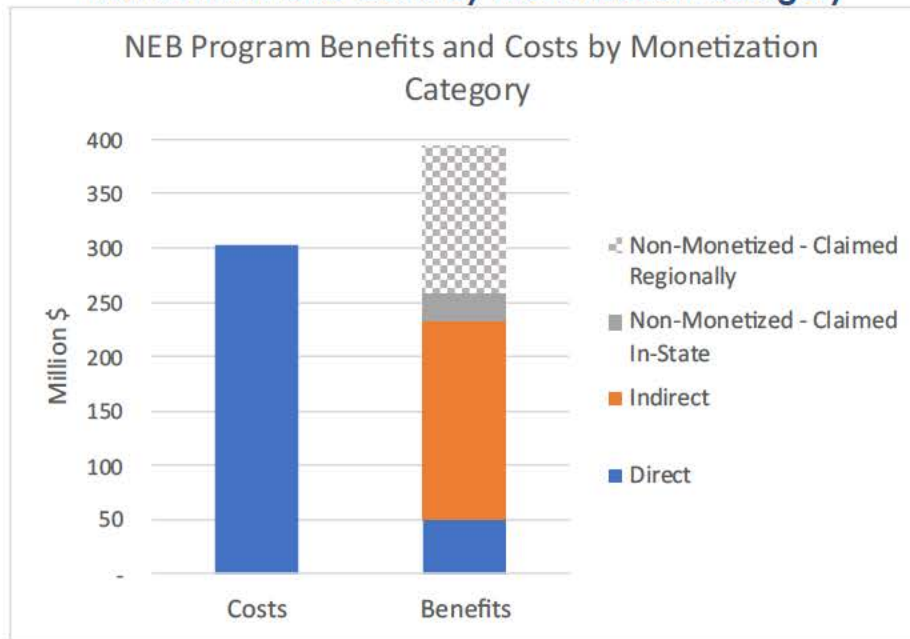
Notably, in Docket 2024-00149, the Maine PUC investigated which benefits from the NEB program may be monetized, to whom those benefits accrue, and how to appropriately apply such benefits in stranded cost proceedings. In the Stipulation filed by parties and approved by the PUC on October 15, parties agreed that there are no additional NEB benefits monetized by the utilities that could be used to adjust stranded costs.<sup>37</sup> As such, SEA’s benefit monetization categories described above have not been adjusted as a result of the proceeding.

Figure 5 shows a breakdown of the total program benefits and cost by each category. We note that reduced T&D energy losses were included in the non-monetized category, given a large portion of these benefits relate to GHG benefits.

<sup>37</sup> See October 2 Stipulation, filed here: <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2024-00149>



**Figure 5 –  
NEB Benefits and Costs by Monetization Category**



### 4.3 Sensitivity Analysis of Maine Societal and Ratepayer Perspectives

Per the discussion in Section 2.4, we have conducted the above net benefit analysis from a societal impact perspective (Societal Perspective). In this subsection we provide a sensitivity analysis from the Maine-only societal impact perspective (Maine Perspective) in addition to a ratepayer impact perspective (Ratepayer Perspective). Before doing so it is instructive to compare what net benefit analysis components are included in each perspective as is provided in Table 14, where ROP stands for “Rest of Pool”, or the rest of the ISO-NE power pool outside of Maine.

As should be expected, any components that only impact the ROP (i.e., New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island) are excluded from the Maine Perspective and the Ratepayer Perspective but are included in the Societal Perspective. In addition, “Reduced Share of Capacity Costs” and “Reduced Share of Transmission Costs” to Maine ratepayers are included in the Maine Perspective and the Ratepayer Perspective but excluded from the Societal Perspective because the overall ISO-NE (more or less) fixed capacity and transmission costs are allocated to each state based on each state’s impact on the regional T&D system. Thus, from the Societal Perspective, a reduction in Maine’s share of such costs just represents a cost transfer to other New England state ratepayers, and not a true benefit.

As discussed in Section 3.12, reduced RPS requirements applicable to BTM projects are only considered a benefit for the Ratepayer Perspective as this benefit represents a cost shift from general ratepayers to facility owners. Lastly, reliability benefits are not included in the Ratepayer Perspective, as such benefits are based on the “Value of Lost Load” (VoLL) which is a measure of willingness to pay for improved reliability, but not a monetizable benefit for ratepayers.

Notably, SEA has chosen to exclude non-embedded GHG emissions benefits that are claimed regionally in the Maine Perspective. In reports covering prior years, SEA included such benefits, reasoning that the importance of reducing GHG emissions is a primary motivator for establishing programs like the NEB program and that societal benefits reflected in



policy goals are often included in state-level perspectives. Although SEA still maintains that one could reasonably take this perspective and justify the inclusion of such benefits, upon reflection of the commentary provided to our 2024 analyses we have been persuaded that the inclusion of such benefits for the Maine perspective poses clearer concerns with respect to double-counting as compared to the societal perspective. As such, SEA has decided to exclude such benefits as the default for reporting sensitivity results below. Lastly, GHG benefits of all types are excluded from the Ratepayer Perspective.

**Table 14-  
Benefit & Cost Components Included by Analysis Perspective**

| Component                                              | Societal Impact Perspective | Maine-only Societal Impact Perspective | Ratepayer Impact Perspective |
|--------------------------------------------------------|-----------------------------|----------------------------------------|------------------------------|
| Project PPA Expenses                                   | Include                     | Include                                | Include                      |
| Lost Utility Revenues                                  | Include                     | Include                                | Include                      |
| kWh Credit Impact on Supply Cost                       | Include                     | Include                                | Include                      |
| Program Admin                                          | Include                     | Include                                | Include                      |
| Energy Resale Revenue                                  | Include                     | Include                                | Include                      |
| Capacity Buyout Revenue                                | Include                     | Include                                | Include                      |
| Interconnection upgrade benefits                       | Include                     | Include                                | Include                      |
| Uncleared capacity value (Intrastate)                  | Include                     | Include                                | Include                      |
| Uncleared capacity value (ROP)                         | Include                     | Exclude                                | Exclude                      |
| Reduced Share of Capacity Costs                        | Exclude                     | Include                                | Include                      |
| Price suppression - energy (Intrastate)                | Include                     | Include                                | Include                      |
| Price suppression - energy (ROP)                       | Include                     | Exclude                                | Exclude                      |
| Price suppression - capacity (Intrastate)              | Include                     | Include                                | Include                      |
| Price suppression - capacity (ROP)                     | Include                     | Exclude                                | Exclude                      |
| Price suppression - electric-gas (Intrastate)          | Include                     | Include                                | Include                      |
| Price suppression - electric-gas (ROP)                 | Include                     | Exclude                                | Exclude                      |
| Price suppression - electric-gas-electric (Intrastate) | Include                     | Include                                | Include                      |
| Price suppression - electric-gas-electric (ROP)        | Include                     | Exclude                                | Exclude                      |
| Reduced transmission costs (Intrastate)                | Include                     | Include                                | Include                      |
| Reduced transmission costs (ROP)                       | Include                     | Exclude                                | Exclude                      |
| Reduced Share of Transmission Costs                    | Exclude                     | Include                                | Include                      |
| Reduced distribution costs                             | Include                     | Include                                | Include                      |
| Reduced T&D losses - capacity (Intrastate)             | Include                     | Include                                | Include                      |
| Reduced T&D losses - capacity (ROP)                    | Include                     | Exclude                                | Exclude                      |
| Reduced T&D losses - energy (Intrastate)               | Include                     | Include                                | Include                      |
| Reduced T&D losses - energy (ROP)                      | Include                     | Exclude                                | Exclude                      |
| Improved generation reliability (Intrastate)           | Include                     | Include                                | Include                      |
| Improved generation reliability (ROP)                  | Include                     | Exclude                                | Exclude                      |
| Non-embedded GHG emissions – Claimed in state          | Include                     | Include                                | Exclude                      |
| Non-embedded GHG emissions – Claimed regionally        | Include                     | Exclude                                | Exclude                      |
| Reduced RPS Obligation                                 | Exclude for BTM             | Exclude for BTM                        | Include                      |
| REC Price Suppression (Intrastate)                     | Include                     | Include                                | Include                      |
| REC Price Suppression (ROP)                            | Include                     | Exclude                                | Exclude                      |

Table 15 provides a summary comparison of the cost and benefits by modeling perspective. The Program Expense, kWh Credit Impact on Supply Cost, and Energy Resale benefit/cost categories do not vary from the Societal Perspective to the



Maine Perspective. The most significant difference between perspectives is that the Maine Perspective does not include GHG benefits claimed regionally, and the Ratepayer Perspective includes no GHG benefits at all. In addition, the Maine Perspective and Ratepayer Perspective have significantly lower benefits for the energy and capacity price suppression benefit component than the Societal Perspective because the Maine Perspective and Ratepayer Perspective do not include the benefits of the Maine NEB program that are reaped by other New England states (e.g., does not include the benefits associated with ROP). This is partially offset by certain T&D benefits that are greater for the Maine Perspective and the Ratepayer Perspective, because some of those benefits accrue to Maine ratepayers only while increasing rates by the same aggregate amount for ratepayers in other New England states (and are thus considered cost shifts from the Societal Perspective). The Ratepayer Perspective is identical to the Maine Perspective apart from marginally higher RPS cost reductions (see Section 3.12) and the exclusion of GHG benefits claimed in-state.

Details on the individual component level results that make up the results of each component category by benefit-cost analysis perspective, program type, EDC and technology are provided in Appendix A.

**Table 15 -  
2025 NEB Program Summary Cost and Benefit in Millions of Dollars by Analysis Perspective**

| Benefit / Cost Category           | Costs    | Societal Perspective Benefits | Maine Perspective Benefits | Ratepayer Perspective Benefits | Maine Perspective Benefits (% of Societal) | Ratepayer Perspective Benefits (% of Societal) |
|-----------------------------------|----------|-------------------------------|----------------------------|--------------------------------|--------------------------------------------|------------------------------------------------|
| Program Expense                   | \$302.45 | N/A                           | N/A                        | N/A                            | 100%                                       | 100%                                           |
| kWh Credit Impact on Supply Cost  | \$10.44  | N/A                           | N/A                        | N/A                            | 100%                                       | 100%                                           |
| RPS Cost Reductions               | N/A      | \$6.39                        | \$6.39                     | \$10.02                        | 100.0%                                     | 156.8%                                         |
| Energy Resale Revenue             | N/A      | \$39.60                       | \$39.60                    | \$39.60                        | 100.0%                                     | 100.0%                                         |
| Energy Price Suppression          | N/A      | \$105.77                      | \$14.62                    | \$14.62                        | 13.8%                                      | 13.8%                                          |
| Capacity Benefits                 | N/A      | \$5.24                        | \$5.15                     | \$5.15                         | 98.3%                                      | 98.3%                                          |
| T&D Benefits                      | N/A      | \$84.56                       | \$51.44                    | \$50.59                        | 60.8%                                      | 59.8%                                          |
| GHG Benefits - Claimed In-State   | N/A      | \$14.95                       | \$14.95                    | \$0.00                         | 100.0%                                     | 0.0%                                           |
| GHG Benefits - Claimed Regionally | N/A      | \$134.90                      | \$0.00                     | \$0.00                         | 0.0%                                       | 0.0%                                           |
| Totals                            | \$312.89 | \$391.40                      | \$132.14                   | \$119.98                       | 33.8%                                      | 30.7%                                          |

As shown above, the Maine Perspective and Ratepayer Perspective benefits are less than the NEB program expenses. It is also worth noting that, although overall costs exceed benefits under these perspectives, benefits continue to exceed costs for BTM projects in the kWh Credit program variant specifically. This is primarily because BTM projects are assumed to have greater benefits associated with avoided distribution system investments, and because such projects are forced to retire RECs in-state for the portion of energy consumed on-site.



## A Appendix A – Component-level Results

### A.1 Tariff Rate Program (2025) – Societal Perspective

| Component Category               | Components                                             | CMP - Solar   | CMP - Wind  | CMP - Hydro  | Versant - BHD - Solar | Versant - BHD - Wind | Versant - BHD - Hydro | Versant - MPD - Solar | Versant - MPD - Wind | Versant - MPD - Hydro |
|----------------------------------|--------------------------------------------------------|---------------|-------------|--------------|-----------------------|----------------------|-----------------------|-----------------------|----------------------|-----------------------|
| Program Expense                  | Project PPA Expenses                                   | \$107,687,290 | \$1,913,677 | \$11,840,891 | \$23,727,995          | \$0                  | \$7,777,447           | \$16,974,624          | \$0                  | \$0                   |
| Program Expense                  | Lost Utility Revenues                                  | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| kWh Credit Impact on Supply Cost | kWh Credit Impact on Supply Cost                       | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Program Expense                  | Program Admin                                          | \$475,653     | \$5,569     | \$35,736     | \$95,662              | \$0                  | \$7,136               | \$42,658              | \$0                  | \$859                 |
| Energy Resale Revenue            | Energy Resale Revenue                                  | \$24,555,403  | \$558,623   | \$3,393,377  | \$5,151,170           | \$0                  | \$1,688,426           | \$4,250,882           | \$0                  | \$0                   |
| Capacity Benefits                | Capacity Buyout Revenue                                | \$0           | \$0         | \$232,674    | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| T&D Benefits                     | Interconnection upgrade benefits                       | \$332,862     | \$3,897     | \$25,008     | \$199,226             | \$0                  | \$14,861              | \$177,536             | \$0                  | \$3,574               |
| Capacity Benefits                | Uncleared capacity value (Intrastate)                  | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Capacity Benefits                | Uncleared capacity value (ROP)                         | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Capacity Benefits                | Reduced Share of Capacity Costs                        | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - energy (Intrastate)                | \$3,671,888   | \$23,156    | \$0          | \$791,527             | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - energy (ROP)                       | \$22,703,909  | \$163,471   | \$0          | \$4,912,173           | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Capacity Benefits                | Price suppression - capacity (Intrastate)              | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Capacity Benefits                | Price suppression - capacity (ROP)                     | \$0           | \$0         | \$0          | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - electric-gas (Intrastate)          | \$8,897       | \$94        | \$95         | \$1,693               | \$0                  | \$59                  | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - electric-gas (ROP)                 | \$134,467     | \$1,420     | \$1,433      | \$25,593              | \$0                  | \$897                 | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - electric-gas-electric (Intrastate) | \$2,224,944   | \$13,537    | \$0          | \$434,099             | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Energy Price Suppression         | Price suppression - electric-gas-electric (ROP)        | \$13,985,854  | \$88,955    | \$0          | \$2,735,205           | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |



| Component Category             | Components                                      | CMP - Solar  | CMP - Wind | CMP - Hydro | Versant - BHD - Solar | Versant - BHD - Wind | Versant - BHD - Hydro | Versant - MPD - Solar | Versant - MPD - Wind | Versant - MPD - Hydro |
|--------------------------------|-------------------------------------------------|--------------|------------|-------------|-----------------------|----------------------|-----------------------|-----------------------|----------------------|-----------------------|
| T&D Benefits                   | Reduced transmission costs (Intrastate)         | \$1,148,187  | \$13,444   | \$86,264    | \$257,492             | \$0                  | \$19,207              | \$207,769             | \$0                  | \$4,183               |
| T&D Benefits                   | Reduced transmission costs (ROP)                | \$8,058,448  | \$95,451   | \$612,459   | \$1,828,161           | \$0                  | \$136,368             | \$1,410,625           | \$0                  | \$29,696              |
| T&D Benefits                   | Reduced Share of Transmission Costs             | \$0          | \$0        | \$0         | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| T&D Benefits                   | Reduced distribution costs                      | \$2,564,371  | \$9,437    | \$40,473    | \$1,077,418           | \$0                  | \$50,690              | \$770,993             | \$0                  | \$0                   |
| T&D Benefits                   | Reduced T&D losses - capacity (Intrastate)      | \$73,182     | \$857      | \$5,498     | \$9,952               | \$0                  | \$742                 | \$8,313               | \$0                  | \$167                 |
| T&D Benefits                   | Reduced T&D losses - capacity (ROP)             | \$1,007,097  | \$11,929   | \$76,541    | \$138,550             | \$0                  | \$10,335              | \$110,668             | \$0                  | \$2,330               |
| T&D Benefits                   | Reduced T&D losses - energy (Intrastate)        | \$4,018,472  | \$65,586   | \$403,110   | \$534,447             | \$0                  | \$154,206             | \$357,146             | \$0                  | \$0                   |
| T&D Benefits                   | Reduced T&D losses - energy (ROP)               | \$2,588,704  | \$17,846   | \$105       | \$327,104             | \$0                  | \$40                  | \$4                   | \$0                  | \$0                   |
| Reliability Benefits           | Improved generation reliability (Intrastate)    | \$0          | \$0        | \$0         | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| Reliability Benefits           | Improved generation reliability (ROP)           | \$0          | \$0        | \$0         | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed Regionally | \$48,692,942 | \$886,736  | \$5,693,695 | \$10,232,057          | \$0                  | \$3,566,541           | \$7,321,989           | \$0                  | \$0                   |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed In-State   | \$0          | \$0        | \$0         | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| RPS Cost Reductions            | Reduced RPS Obligation                          | \$0          | \$0        | \$0         | \$0                   | \$0                  | \$0                   | \$0                   | \$0                  | \$0                   |
| RPS Cost Reductions            | REC Price Suppression (Intrastate)              | \$427        | \$8        | \$47        | \$90                  | \$0                  | \$29                  | \$64                  | \$0                  | \$0                   |
| RPS Cost Reductions            | REC Price Suppression (ROP)                     | \$537        | \$10       | \$59        | \$113                 | \$0                  | \$37                  | \$81                  | \$0                  | \$0                   |



## A.2 kWh Credit Program (2025) – Societal Perspective

| Component Category               | Components                                             | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|----------------------------------|--------------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| Program Expense                  | Project PPA Expenses                                   | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Program Expense                  | Lost Utility Revenues                                  | \$22,540,402    | \$11,104,806              | \$5,530,796               | \$67,687,999    | \$19,011,215              | \$5,179,371               |
| kWh Credit Impact on Supply Cost | kWh Credit Impact on Supply Cost                       | \$2,208,474     | \$670,904                 | \$358,200                 | \$5,867,030     | \$1,085,365               | \$248,916                 |
| Program Expense                  | Program Admin                                          | \$0             | \$0                       | \$0                       | \$628,195       | \$152,982                 | \$27,169                  |
| Energy Resale Revenue            | Energy Resale Revenue                                  | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Capacity Buyout Revenue                                | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Interconnection upgrade benefits                       | \$0             | \$0                       | \$0                       | \$302,832       | \$186,165                 | \$2,524                   |
| Capacity Benefits                | Uncleared capacity value (Intrastate)                  | \$88,213        | \$8,438                   | \$881                     | \$3,004         | \$2,568                   | \$1,923                   |
| Capacity Benefits                | Uncleared capacity value (ROP)                         | \$811,178       | \$77,592                  | \$8,101                   | \$27,621        | \$23,618                  | \$17,687                  |
| Capacity Benefits                | Reduced Share of Capacity Costs                        | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Energy Price Suppression         | Price suppression - energy (Intrastate)                | \$734,116       | \$354,157                 | \$0                       | \$3,034,217     | \$680,222                 | \$0                       |
| Energy Price Suppression         | Price suppression - energy (ROP)                       | \$4,616,668     | \$2,217,929               | \$0                       | \$18,617,916    | \$4,181,665               | \$0                       |
| Capacity Benefits                | Price suppression - capacity (Intrastate)              | \$282,470       | \$28,863                  | \$0                       | \$12,348        | \$9,448                   | \$0                       |
| Capacity Benefits                | Price suppression - capacity (ROP)                     | \$3,059,622     | \$312,634                 | \$0                       | \$133,750       | \$102,338                 | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (Intrastate)          | \$1,804         | \$698                     | \$0                       | \$6,805         | \$1,360                   | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (ROP)                 | \$27,269        | \$10,550                  | \$0                       | \$102,857       | \$20,557                  | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (Intrastate) | \$406,057       | \$175,338                 | \$0                       | \$1,707,973     | \$347,852                 | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (ROP)        | \$2,568,115     | \$1,109,907               | \$0                       | \$10,731,958    | \$2,193,445               | \$0                       |
| T&D Benefits                     | Reduced transmission costs (Intrastate)                | \$964,558       | \$342,823                 | \$163,369                 | \$1,034,133     | \$240,370                 | \$50,643                  |
| T&D Benefits                     | Reduced transmission costs (ROP)                       | \$3,496,984     | \$1,177,826               | \$607,903                 | \$7,063,540     | \$1,555,868               | \$355,032                 |
| T&D Benefits                     | Reduced Share of Transmission Costs                    | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Reduced distribution costs                             | \$12,532,216    | \$4,643,169               | \$2,352,879               | \$1,569,000     | \$707,482                 | \$154,063                 |



| Component Category             | Components                                      | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|--------------------------------|-------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| T&D Benefits                   | Reduced T&D losses - capacity (Intrastate)      | \$849,307       | \$85,551                  | \$17,396                  | \$439,373       | \$59,913                  | \$5,839                   |
| T&D Benefits                   | Reduced T&D losses - capacity (ROP)             | \$2,509,421     | \$148,411                 | \$48,963                  | \$902,927       | \$127,460                 | \$29,241                  |
| T&D Benefits                   | Reduced T&D losses - energy (Intrastate)        | \$2,621,325     | \$333,304                 | \$164,009                 | \$3,608,344     | \$503,537                 | \$105,267                 |
| T&D Benefits                   | Reduced T&D losses - energy (ROP)               | \$905,843       | \$142,318                 | \$1                       | \$2,070,495     | \$272,651                 | \$1                       |
| Reliability Benefits           | Improved generation reliability (Intrastate)    | \$7             | \$0                       | \$0                       | \$19            | \$0                       | \$0                       |
| Reliability Benefits           | Improved generation reliability (ROP)           | \$64            | \$0                       | \$0                       | \$175           | \$0                       | \$0                       |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed Regionally | \$5,168,249     | \$1,899,745               | \$979,637                 | \$39,623,136    | \$8,868,976               | \$1,964,493               |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed In-State   | \$9,598,177     | \$3,528,098               | \$1,819,326               | \$0             | \$0                       | \$0                       |
| RPS Cost Reductions            | Reduced RPS Obligation                          | \$1,292,698     | \$475,096                 | \$244,734                 | \$3,434,182     | \$768,594                 | \$170,068                 |
| RPS Cost Reductions            | REC Price Suppression (Intrastate)              | \$127           | \$47                      | \$24                      | \$338           | \$76                      | \$17                      |
| RPS Cost Reductions            | REC Price Suppression (ROP)                     | \$160           | \$59                      | \$30                      | \$425           | \$95                      | \$21                      |

[illegible]

[illegible]



## A.4 kWh Credit Program (2025) – Maine Perspective

| Component Category               | Components                                             | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|----------------------------------|--------------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| Program Expense                  | Project PPA Expenses                                   | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Program Expense                  | Lost Utility Revenues                                  | \$22,540,402    | \$11,104,806              | \$5,530,796               | \$67,687,999    | \$19,011,215              | \$5,179,371               |
| kWh Credit Impact on Supply Cost | kWh Credit Impact on Supply Cost                       | \$2,208,474     | \$670,904                 | \$358,200                 | \$5,867,030     | \$1,085,365               | \$248,916                 |
| Program Expense                  | Program Admin                                          | \$0             | \$0                       | \$0                       | \$628,195       | \$152,982                 | \$27,169                  |
| Energy Resale Revenue            | Energy Resale Revenue                                  | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Capacity Buyout Revenue                                | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Interconnection upgrade benefits                       | \$0             | \$0                       | \$0                       | \$302,832       | \$186,165                 | \$2,524                   |
| Capacity Benefits                | Uncleared capacity value (Intrastate)                  | \$88,213        | \$8,438                   | \$881                     | \$3,004         | \$2,568                   | \$1,923                   |
| Capacity Benefits                | Uncleared capacity value (ROP)                         | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Reduced Share of Capacity Costs                        | \$1,062,242     | \$332,019                 | \$134,821                 | \$2,340,018     | \$520,124                 | \$93,378                  |
| Energy Price Suppression         | Price suppression - energy (Intrastate)                | \$734,116       | \$354,157                 | \$0                       | \$3,034,217     | \$680,222                 | \$0                       |
| Energy Price Suppression         | Price suppression - energy (ROP)                       | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Price suppression - capacity (Intrastate)              | \$282,470       | \$28,863                  | \$0                       | \$12,348        | \$9,448                   | \$0                       |
| Capacity Benefits                | Price suppression - capacity (ROP)                     | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (Intrastate)          | \$1,804         | \$698                     | \$0                       | \$6,805         | \$1,360                   | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (ROP)                 | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (Intrastate) | \$406,057       | \$175,338                 | \$0                       | \$1,707,973     | \$347,852                 | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (ROP)        | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Reduced transmission costs (Intrastate)                | \$964,558       | \$342,823                 | \$163,369                 | \$1,034,133     | \$240,370                 | \$50,643                  |
| T&D Benefits                     | Reduced transmission costs (ROP)                       | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Reduced Share of Transmission Costs                    | \$1,813,881     | \$565,971                 | \$0                       | \$3,504,057     | \$777,596                 | \$0                       |
| T&D Benefits                     | Reduced distribution costs                             | \$12,532,216    | \$4,643,169               | \$2,352,879               | \$1,569,000     | \$707,482                 | \$154,063                 |



| Component Category             | Components                                      | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|--------------------------------|-------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| T&D Benefits                   | Reduced T&D losses - capacity (Intrastate)      | \$1,665,307     | \$167,747                 | \$34,109                  | \$861,516       | \$117,477                 | \$11,450                  |
| T&D Benefits                   | Reduced T&D losses - capacity (ROP)             | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                   | Reduced T&D losses - energy (Intrastate)        | \$1,929,296     | \$245,312                 | \$120,711                 | \$2,655,741     | \$370,604                 | \$77,477                  |
| T&D Benefits                   | Reduced T&D losses - energy (ROP)               | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Reliability Benefits           | Improved generation reliability (Intrastate)    | \$7             | \$0                       | \$0                       | \$19            | \$0                       | \$0                       |
| Reliability Benefits           | Improved generation reliability (ROP)           | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed Regionally | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed In-State   | \$9,598,177     | \$3,528,098               | \$1,819,326               | \$0             | \$0                       | \$0                       |
| RPS Cost Reductions            | Reduced RPS Obligation                          | \$1,292,698     | \$475,096                 | \$244,734                 | \$3,434,182     | \$768,594                 | \$170,068                 |
| RPS Cost Reductions            | REC Price Suppression (Intrastate)              | \$127           | \$47                      | \$24                      | \$338           | \$76                      | \$17                      |
| RPS Cost Reductions            | REC Price Suppression (ROP)                     | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |

[illegible]

[illegible]



## A.6 kWh Credit Program (2025) – Ratepayer Perspective

| Component Category               | Components                                             | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|----------------------------------|--------------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| Program Expense                  | Project PPA Expenses                                   | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Program Expense                  | Lost Utility Revenues                                  | \$22,540,402    | \$11,104,806              | \$5,530,796               | \$67,687,999    | \$19,011,215              | \$5,179,371               |
| kWh Credit Impact on Supply Cost | kWh Credit Impact on Supply Cost                       | \$2,208,474     | \$670,904                 | \$358,200                 | \$5,867,030     | \$1,085,365               | \$248,916                 |
| Program Expense                  | Program Admin                                          | \$0             | \$0                       | \$0                       | \$628,195       | \$152,982                 | \$27,169                  |
| Energy Resale Revenue            | Energy Resale Revenue                                  | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Capacity Buyout Revenue                                | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Interconnection upgrade benefits                       | \$0             | \$0                       | \$0                       | \$302,832       | \$186,165                 | \$2,524                   |
| Capacity Benefits                | Uncleared capacity value (Intrastate)                  | \$88,213        | \$8,438                   | \$881                     | \$3,004         | \$2,568                   | \$1,923                   |
| Capacity Benefits                | Uncleared capacity value (ROP)                         | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Reduced Share of Capacity Costs                        | \$1,062,242     | \$332,019                 | \$134,821                 | \$2,340,018     | \$520,124                 | \$93,378                  |
| Energy Price Suppression         | Price suppression - energy (Intrastate)                | \$734,116       | \$354,157                 | \$0                       | \$3,034,217     | \$680,222                 | \$0                       |
| Energy Price Suppression         | Price suppression - energy (ROP)                       | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Capacity Benefits                | Price suppression - capacity (Intrastate)              | \$282,470       | \$28,863                  | \$0                       | \$12,348        | \$9,448                   | \$0                       |
| Capacity Benefits                | Price suppression - capacity (ROP)                     | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (Intrastate)          | \$1,804         | \$698                     | \$0                       | \$6,805         | \$1,360                   | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas (ROP)                 | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (Intrastate) | \$406,057       | \$175,338                 | \$0                       | \$1,707,973     | \$347,852                 | \$0                       |
| Energy Price Suppression         | Price suppression - electric-gas-electric (ROP)        | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Reduced transmission costs (Intrastate)                | \$964,558       | \$342,823                 | \$163,369                 | \$1,034,133     | \$240,370                 | \$50,643                  |
| T&D Benefits                     | Reduced transmission costs (ROP)                       | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                     | Reduced Share of Transmission Costs                    | \$1,813,881     | \$565,971                 | \$0                       | \$3,504,057     | \$777,596                 | \$0                       |
| T&D Benefits                     | Reduced distribution costs                             | \$12,532,216    | \$4,643,169               | \$2,352,879               | \$1,569,000     | \$707,482                 | \$154,063                 |



| Component Category             | Components                                      | CMP - BTM Solar | Versant - BHD - BTM Solar | Versant - MPD - BTM Solar | CMP - FTM Solar | Versant - BHD - FTM Solar | Versant - MPD - FTM Solar |
|--------------------------------|-------------------------------------------------|-----------------|---------------------------|---------------------------|-----------------|---------------------------|---------------------------|
| T&D Benefits                   | Reduced T&D losses - capacity (Intrastate)      | \$1,665,307     | \$167,747                 | \$34,109                  | \$861,516       | \$117,477                 | \$11,450                  |
| T&D Benefits                   | Reduced T&D losses - capacity (ROP)             | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| T&D Benefits                   | Reduced T&D losses - energy (Intrastate)        | \$1,756,288     | \$223,314                 | \$109,886                 | \$2,417,591     | \$337,370                 | \$70,529                  |
| T&D Benefits                   | Reduced T&D losses - energy (ROP)               | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Reliability Benefits           | Improved generation reliability (Intrastate)    | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| Reliability Benefits           | Improved generation reliability (ROP)           | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed Regionally | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| GHG and Environmental Benefits | Non-embedded GHG emissions - Claimed In-State   | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |
| RPS Cost Reductions            | Reduced RPS Obligation                          | \$2,028,103     | \$745,374                 | \$383,962                 | \$5,387,858     | \$1,205,841               | \$266,818                 |
| RPS Cost Reductions            | REC Price Suppression (Intrastate)              | \$127           | \$47                      | \$24                      | \$338           | \$76                      | \$17                      |
| RPS Cost Reductions            | REC Price Suppression (ROP)                     | \$0             | \$0                       | \$0                       | \$0             | \$0                       | \$0                       |

**STATE OF MAINE  
PUBLIC UTILITIES COMMISSION**

**MAINE PUBLIC UTILITIES COMMISSION**

**SUMMARY INVESTIGATION SEEKING  
COMMENT ON 2025 NET ENERGY BILLING  
COST BENEFIT REPORT**

**DOCKET NO. 2026-00053**

**COMMENTS**

**EFFICIENCY MAINE TRUST**

**MARCH 25, 2026**

Efficiency Maine Trust (hereinafter “the Trust”) offers these comments in response to the March 13, 2026 Notice of Investigation requesting comments on the 2025 Net Energy Billing Report, (hereinafter the “2025 SEA Report”).

As part of these comments, the Trust will address 1) how various perspectives are weighted, 2) how GHG benefits are accounted for, 3) how the diminishing value of solar peak shaving is represented, and 4) how benefits accrued in real time and in system planning are calculated remain. Finally, the Trust finds that it is unclear whether the utilization of the 2024 AESC outputs are appropriate for evaluating a renewable generation program.

**Part 1: Findings from the 2025 SEA Report**

The Trust generally agrees with the finding that Maine’s Net Energy Billing (NEB) Program was not cost-effective from a Maine-only societal impact perspective and even less so from a Maine ratepayer perspective in 2025. SEA estimates the NEB program benefits totaled \$132m for Maine society and \$120m for Maine ratepayers. The program cost \$302m, of which \$171m was accrued to the tariff rate program and \$142m was accrued to the kWh Credit program. Behind-the-meter (BTM) projects in the kWh Credit program variant remained cost-effective because of their greater in-state REC retirement and grid benefits provided.

**Part 2: The Trust appreciates the methodological improvements made to capacity factor assumptions and capacity cost calculations in response to its testimony.**

In Docket 2024-00149, the Trust filed testimony recommending the use of capacity factors unique to each program variant to calculate MWh-based benefits. The Trust specifically recommended the use of a capacity factor from ISO-NE System Planning<sup>1</sup> for Maine Behind-the-Meter (BTM) projects in the kWh Credit program. This iteration of the report updated the kWh Credit FTM and BTM capacity factors accordingly.

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<sup>1</sup> See “Normalized BTM PV” for Maine. See the Excel spreadsheet here: [https://www.iso-ne.com/static-assets/documents/2020/07/btm\\_pv\\_data.xlsx](https://www.iso-ne.com/static-assets/documents/2020/07/btm_pv_data.xlsx)

Additionally, the Trust's testimony recommended incorporating the load resettlement process in calculating reductions in Maine's share of capacity costs resulting from kWh credit projects. CMP segments its daily settlement process by customer class. In the load resettlement process, unaccounted for energy (UFE) which includes all generation exported to the distribution system is assigned to a supplier's hourly load proportionally every hour, as opposed to the specific hour in which the PV production occurred. This iteration of the report calculates benefits using a load reduction shape after resettlement accordingly.

**Part 3: The SEA Report should track the Maine ratepayer and Maine-only societal impact perspective throughout the report.**

In Docket 2024-00149, the Trust filed testimony recommending the report track the Maine-only societal impact perspective throughout the report. The 2025 SEA Report primarily tracks the "general societal impact perspective." In section 2.4, SEA describes its decision to utilize a general societal impact perspective, stating it is "justified in that the impetus for many of Maine's policies promoting renewable energy (including NEB) is the reduction of GHG emissions. As the benefits GHG emission reductions are tied to global (vs. local Maine or even regional New England) GHG emission reductions, a general societal perspective, which incorporates a global perspective is justified."<sup>2</sup>

As the Trust articulated in testimony filed in Docket 2024-00149 and rearticulates here,

While 35-A M.R.S. § 3209-C does not explicitly prescribe a perspective, the purpose of the law is to "ensure that benefits of distributed generation under net energy billing are reported and net energy billing costs are allocated in accordance with this section." It would only be reasonable to assume that the Maine Legislature would ask the Commission to primarily focus on the benefits and costs of the Maine NEB program on Maine ratepayers.<sup>3</sup>

The Trust believes that, at minimum, the Maine ratepayer and Maine-only societal impact perspective should have the same emphasis and weight as the general societal impact perspective. If for some reason this is not possible, the Maine ratepayer and Maine-only societal impact perspective should include a data visualization alongside or included in Figure

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<sup>2</sup> Sustainable Energy Advantage, LLC, Analysis of 2025 Net Benefits of Net Energy Billing Program, March 31, 2026 (hereinafter cited as the "2025 SEA Report") at Page 6.

<sup>3</sup> Efficiency Maine Trust, Direct Testimony, Maine Public Utilities Commission Investigation into the Allocation of Benefits of Distributed Generation under Net Energy Billing, Docket No. 2024-00149, April 7, 2025, at Page 4.

1.<sup>4</sup> It is unfortunate that despite discussion in Docket 2024-00149, which revealed the SEA interpretation of the law was not held by significant stakeholders in that proceeding, that the reader still has to wait until page 41 and Table 15 to see the Maine ratepayer and Maine-only societal impact perspective.

**Part 4: The SEA Report’s accounting of GHG emissions and RECs is flawed and should be addressed to eliminate potential double counting of GHG savings.**

The Trust appreciates that the current draft attempts to update the accounting of GHG benefits from projects that sell their RECs, but the current approach does not go far enough to address the concerns the Trust explained in its testimony. The Trust is concerned by potential double counting of GHG benefits sold for compliance purposes. Whether or not a REC is sold in Maine, elsewhere in New England, or to a private party, the sale of that REC represents the renewable attribute of the energy. As a result, the purchaser has the right to the full benefit of the GHG benefit. Counting the sold REC as a benefit here would likely represent double counting of that benefit. The NEB program should only take credit for RECs that are retained and retired for non-compliance purposes.

The SEA report states that “the ultimate party that claims the GHG benefit does not change the fact that the program caused the net increase in GHG benefits.”<sup>5</sup> This is an untested assertion that deserves more discussion. Does this mean that renewable portfolio programs of New England do not cause a net increase in GHG benefits? This would appear to be too strong a finding to make without further discussion. It would be more appropriate to state that the NEB program is a system of financial credits, that RECs are not taken title to under the NEB program, and therefore the program cannot take credit for RECs that are sold.

**Part 5: The SEA Report continues to overstate peak load reduction benefits of the NEB program in 2025 by ignoring peak shifting impacts of solar.**

In its testimony in Docket 2024-00149, the Trust offered several suggestions on how the 2023 SEA Report could more accurately reflect the fact that solar has successfully shifted the peak into the later afternoon, where it has an increasingly smaller contribution to peak load reduction. The current report acknowledges this point in the executive summary:

Importantly, these results are not reflective of possible future marginal costs and benefits of additional capacity coming online in the future. Given that certain

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<sup>4</sup> 2025 SEA Report, at Page 2.

<sup>5</sup> 2025 SEA Report, at Page 19.

benefits, namely benefits associated with avoided transmission and distribution costs, are subject to declining marginal benefits, additional projects reaching commercial operation under the program in the future are expected to have a reduced benefit/cost ratio relative to the program-wide totals reported here.<sup>6</sup>

This point should be emphasized in the presentation of this report to the Legislature where any change to the law would generally affect future projects. The Trust also believes that more could be done within the report methodology to more accurately reflect the effect NEB projects have on peak load reduction.

The Trust's testimony recommended the use of net load curves rather than gross load curves as provided by the AESC to calculate MW-based benefits to reflect actual or expected grid conditions. This change would reflect the diminishing value of solar benefits associated with peak shaving as peak load hours shift later into the day when solar generation is typically lower. The Trust recognizes that peak *shaving* during midday peaks by solar in the NEB program has resulted in peaks *shifting* to early evening hours. The Trust also recognizes the challenge of reflecting the diminishing value of solar peak shaving in a backwards-looking study. The Trust appreciates SEA's attempt to address this challenge by determining the differential between Maine's annual peak with and without the NEB program (e.g., net and gross load peak). The MW differential (e.g., peak load reduction) was used to calculate MW-based benefits such as Maine-specific avoided transmission investments and reductions in Maine's Regional Network Service cost share. This "net vs. gross differential methodology" is an improvement over the original methodology in the 2023 report in which coincident load reduction during the gross peak(s) was used to calculate all MW-based benefits. Nonetheless, the Trust would argue that the diminishing value of solar peak shaving in a backwards looking study could be observed with a year-over-year decline of MW-based benefits calculated using net load.

The "net vs. gross differential methodology" was not utilized to calculate Maine-specific avoided distribution investments. Instead, SEA used a Maine-specific gross hourly load forecast as provided by the AESC to identify the top 100 gross peaks and found coincident load reduction from relevant NEB projects. Applying the "net vs. gross differential methodology" would be an improvement to the continued use of coincident load reduction during gross peaks, but the Trust would go further and recommend the use of coincident load reduction during net peaks. Given that distribution investments are also driven by peak load rather than the top 100 hours, the Trust would again recommend evaluating load reductions during an annual peak rather than the top 100 hours.

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<sup>6</sup> SEA Report at Page 3.

The “net vs. gross peak differential methodology” was also not utilized to calculate system-wide avoided transmission benefits or reduced capacity costs. Instead, SEA used a system-wide gross peak as provided by the AESC and found coincident load reduction from relevant NEB projects. By using a system-wide gross peak, SEA ignores all peak shaving and shifting resulting from other New England states’ distributed solar programs and assigns the “first share” of peak shaving value to Maine’s NEB program. A “net vs. gross peak differential methodology” for system-wide benefits would compare a net system-wide load shape to a net system-wide load shape with NEB program generation added back in. Again, the Trust would go further and recommend the use of coincident load reductions during net peak load.

**Part 6: The SEA Report does not accurately capture benefits accrued in real time vs. in system planning.**

The Trust’s testimony recommended using real time net load and a solar production curve specific to the year being evaluated for benefits accrued in real time<sup>7</sup> and a historical net load forecast load and weather neutral solar production curve for benefits accrued in system planning<sup>8</sup>. SEA continued to use a forecasted weather neutral gross load shape as provided by the AESC but did implement the use of a 2025-specific and a weather neutral solar production curve for benefits accrued in real time and system planning, respectively. The Trust would argue that without implementing the corresponding real time and weather neutral load shapes, this introduces unnecessary complexity without improved accuracy. The coincidence of actual solar production with weather neutral forecasted peak load is not an improvement over coincidence of weather neutral solar production with weather neutral forecasted peak load.

**Part 7: There are concerns regarding the applicability of the AESC for this study.**

The Trust recognizes that 35-A M.R.S. § 3209-C(3) directs the commission to “use any available regional avoided energy supply cost study that the commission finds to be applicable to the determination and has been developed through a transparent process, with input from state agencies, public advocates and utilities or energy efficiency administrators from at least 3 other states in New England.”<sup>9</sup> The corresponding study would be the AESC.

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<sup>7</sup> These are Reduced Share of Capacity Costs (3.7), Avoided Maine RNS Share (3.8.2), and Capacity DRIPE (both intrastate and Rest of Pool) (3.9).

<sup>8</sup> These are Uncleared Capacity Value (both intrastate and Rest of Pool) (3.6), Avoided Transmission Investments (both intrastate and Rest of Pool) (3.8.1), and Avoided Distribution Investments (3.8.1).

<sup>9</sup> 35-A M.R.S. § 3209-C(3).

The AESC is a forward-looking study that forecasts energy supply costs that can be avoided with demand-side energy efficiency, demand reduction, and/or electrification programs in New England. SEA asserts that “most inputs are applicable to the evaluation of renewable energy programs.” However, the AESC does not comment on the applicability of its avoided costs for the evaluation of renewable energy programs. In the AESC, distributed solar is modeled as a supply-side resource rather than a demand-side resource and a gross load shape based on 2022 data is utilized<sup>10</sup>. Using AESC outputs to evaluate distributed solar as a demand-side resource when it is modeled as a supply-side resource in the AESC may lead to inaccuracies or double-counting. Other states such as Massachusetts<sup>11</sup> and Connecticut<sup>12</sup> have developed separate avoided costs to quantify benefits of solar and other distributed energy resources (DERs) by creating counterfactuals that *exclude* DERs. Note these evaluations were also forward-looking. All counterfactuals in the AESC *include* distributed generation. The Trust will work with the study group to potentially clarify the applicability of the AESC for use in value of solar studies with the 2027 iteration of the study. That clarification may be that it is inappropriate for value of solar studies. If the Commission shares these concerns, it might consider suggesting to the legislature that they revisit the requirements of this study to align with best practices.

## Conclusion

The SEA Report indicates that Maine’s Net Energy Billing (NEB) Program was not cost-effective from a Maine-only societal impact perspective and even less so from a Maine ratepayer perspective in 2025. The Trust appreciates SEA’s efforts to address recommendations made by the Trust and other parties in Docket 2024-00149. Nonetheless, concerns raised by the Trust regarding 1) how various perspectives are weighted, 2) how GHG benefits are accounted for, 3) how the diminishing value of solar peak shaving is represented, and 4) how benefits accrued in real time and in system planning are calculated remain. Finally, the Trust finds that it is unclear whether the utilization of the 2024 AESC outputs are appropriate for evaluating a renewable generation program.

Respectfully submitted,

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<sup>10</sup> See page 97 regarding modeling of distributed solar. See page 76 regarding the use of the 2002 gross load shape. <https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024.pdf>

<sup>11</sup> See SEIA, “The stakes are clear. Massachusetts needs solar and storage.” January 23, 2026 <https://seia.org/research-resources/powered-up-evaluating-the-year-round-benefits-of-solar-and-storage-in-massachusetts/>

<sup>12</sup> See Connecticut Department of Energy and Environmental Protection and Connecticut Public Utilities Regulatory Authority, “Distributed Energy Resources in Connecticut (Draft)” July 2020, <https://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/acfa7be554497d1785258db70047ce29?OpenDocument>

/s/IGB

Ian Burnes  
Director of Strategic Initiatives  
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March 25, 2026

Re: Comments on 2025 Net Energy Billing Report, Docket 2026-00053

Dear Ms. Dumeny:

On behalf of the Maine Renewable Energy Association (“MREA”) and Coalition for Community Solar Access (“CCSA”), thank you for the opportunity to file written comments on the *Analysis of 2025 Net Benefits of Net Energy Billing Program* report (“Report”) prepared for the Maine Public Utilities Commission (“Commission”) by Sustainable Energy Advantage (SEA) pursuant to 35-A M.R.S. § 3209-C(3). MREA and CCSA offer these comments for consideration by the Commission, as well as by the Maine Legislature’s Energy, Utilities and Technology Committee (“Committee”), to whom the Report and associated comments must be provided on or before March 31, 2026.

**MREA and CCSA are pleased to see that 2025 net energy billing (NEB) program benefits, including greenhouse gas benefits claimed regionally, were \$391.40 million and program expenses were \$312.89 million - a benefit-cost ratio of 1.25.<sup>1</sup>** Indeed, the totality of NEB program benefits including but not limited to avoided fossil fuel costs, avoided transmission and distribution costs, and demand reduction induced price effects are substantial and are an important component of an overall energy affordability strategy.

Notably, as part of *Maine Public Utilities Commission Investigation Into Allocation of Benefits of Distributed Generation Under Net Energy Billing*, Docket 2024-00149, parties (including MREA and CCSA) disputed the methodology of determining the NEB program’s benefits and costs. The investigation’s settlement did not result in the adoption of a comprehensive methodology. As such, the 2025 Report is not the product of an agreed-upon methodology. Many of the following of MREA’s and CCSA’s comments critique SEA’s self-selected methodology.

- **General societal greenhouse gas (GHG) emission avoidance must not be discounted.** LD 1986, “An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems,” requires the Commission to report on the relative costs and benefits from solar energy development, including “Societal benefits through avoided

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<sup>1</sup> See *Analysis of 2025 Net Benefits of Net Energy Billing Program*, Sustainable Energy Advantage, March 31, 2026 at 35.

greenhouse gas emissions”.<sup>2</sup> MREA and CCSA agree with SEA that “the impetus for many of Maine’s policies promoting renewable energy (including NEB) is the reduction of GHG emissions. As the benefits [sic] GHG emission reductions are tied to global (vs. local Maine or even regional New England) GHG emission reductions, a general societal perspective, which incorporates a global perspective is justified.”<sup>3</sup> Emission reduction benefits do not recognize state borders; to assume that a REC retired in a neighboring state has no benefits to the people of Maine is grossly inaccurate.

MREA and CCSA take issue with the notion that it is appropriate to dramatically reduce the greenhouse gas benefits of the NEB program out of unfounded fears that those benefits are being counted by another state renewable portfolio standard (RPS), and therefore do not exist under the NEB program. The existence of a state RPS is insufficient to drive distributed renewable energy development, as evidenced by the lack of 1 - 5 MW solar projects in states with an RPS but without any other community solar or distributed generation program. Given the complex nature of energy development, multiple policies are typically needed or instrumental to support the development, financing, and contracting of renewable energy projects. It is absurd to assume that the over 1 GW of renewable energy in the Maine NEB program can be attributed exclusively to the RPS’ of neighboring states.

Even if one were to assume the double counting concern is valid, the assumptions in SEA’s report are overly broad and inappropriately over-estimate the amount of RECs that may be retired for state RPS compliance. The approach in the Report confuses RECs retired within the state of Maine and RECs retired for RPS compliance; two entirely different concepts that do *not* represent the same set of attributes: “To appropriately bound the results, SEA assumes that any RECs not explicitly pinned to Maine (e.g., not associated with behind the meter on-site consumption) are sold into the regional Class I marketplace, and thereby potentially retired out of state.”<sup>4</sup> First, RECs sold into the Class I market may still be retired within Maine. Second, RECs that are sold - whether inside or outside of Maine - may also be sold for voluntary purposes, including entities wishing to “do their part” to support renewable energy. In those cases, there is no other state policy that may be claiming these benefits. Though we do not have a quantification of how many RECs are sold on the voluntary market versus the RPS compliance market, based on our membership feedback, we estimate a significant amount are sold for voluntary purposes, perhaps even the majority.

Finally, though we hold that REC retirements are a poor stand in for emission reduction benefits, it is important to clarify that separating a REC from the renewable generation does not change the physical nature of that generation. For purposes of emissions accounting, that energy is now assumed to have the equivalent emissions profile of the

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<sup>2</sup> See 35-A M.R.S. 3473 (2023).

<sup>3</sup> See Analysis of 2025 Net Benefits of Net Energy Billing Program, Sustainable Energy Advantage, March 31, 2026 at 6.

<sup>4</sup> *Id.* at 19.

“grid mix.” Renewable energy under NEB displaces fossil fuels, and thereby inherently reduces the emissions profile of the “grid mix.” Counting only RECs from NEB associated with behind-the-meter generation in Maine completely discounts this attribute of the NEB program.

If an approach quantifying the “GHG and Environmental Benefits - Claimed In-State” is to be presented in the report, there must be sufficient data to actually support the quantification, which is not the case in the 2025 Report. As presented, this perspective is grossly misleading and should be removed from the Report.

- **Class 1 renewable energy certificates (REC) resulting from the NEB program suppress regional REC prices.** Most RECs generated from NEB-participating projects are eligible in all Class 1 markets and as such, the price suppression effect is realized in both Maine’s and the broader RPS markets.<sup>5</sup> This benefit must not be overlooked. The report does not sufficiently explain why SEA’s Renewable Energy Market Outlook analysis did not find any difference in REC prices with or without NEB-generated Class I RECs. It is also contradictory to assume that Maine cannot claim the vast majority of the greenhouse gas emission benefits from NEB because these benefits accrue to other state RPS’s, and yet the participation of NEB projects in New England Class I markets is so low as to not impact Class I REC prices.
- **The tariff rate program component of NEB includes non-solar projects, including hydro.**<sup>6</sup> Too often, the inclusion of this dispatchable, economically important, heritage renewable energy resource in the NEB program is overlooked. Concurrently, Section 2.1 should be revised to note that LD 1986 focused on the NEB program and not solar resources specifically.
- **The Report excludes the fact the majority of the NEB program is closed as a result of LD 1777, “An Act to Reduce Costs and Increase Customer Protections for the State’s Net Energy Billing Programs”.<sup>7</sup>** The Report states that “these results are not reflective of possible future marginal costs and benefits of additional capacity coming online in the future.”<sup>8</sup> LD 1777 closed the NEB program to front of the meter projects without an interconnection agreement in hand by December 31, 2025. Front of the meter tariff rate and kWh credit projects comprise the majority of NEB program costs and benefits. While future reports will include front of the meter projects that secured an interconnection agreement in 2025 and came online in subsequent years, as well as behind the meter kWh credit projects, MREA and CCSA are certain that the growth of the program will be gradual, particularly compared to program growth in 2025 and in previous years.

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<sup>5</sup> *Id.* at 17.

<sup>6</sup> *Id.* at 8.

<sup>7</sup> See Public Law 2025, Chapter 430.

<sup>8</sup> See Analysis of 2025 Net Benefits of Net Energy Billing Program, Sustainable Energy Advantage, March 31, 2026 at 3.

- **The share of grid upgrades that provide ratepayers benefits is understated.** MREA and CCSA were pleased to see that SEA incorporated the testimony of Christian Bilcheck, in part, to estimate the benefits of NEB-project-funded grid upgrades. However, we are puzzled and disappointed as to why SEA did not also utilize Belchick’s approach to estimate the share of upgrades that provide ratepayer benefits, rather than just amortization approach. SEA has taken the utilities at their word that these benefits do not provide any improvements to the system beyond what is minimally necessary to safely connect the project. Both the Bilcheck testimony and the testimony of Peter Evans on behalf of ReVision Energy in Docket 2024-00149 demonstrate how that is blatantly untrue.
- **The role that the NEB program plays as a “hedge” on gas prices must not be overlooked.** As another global conflict sends oil and gas prices through the roof, the importance of domestic, fuel-free energy sources increases. Quantified DRIPE and market benefits are estimated based on actual 2025 prices and do not include the “hedge” on gas prices that solar and other NEB-renewable energy sources provide. As this benefit accrues largely in the future, it cannot be quantified in the 2025 Report; however, its implications on energy policy are clear and should not be overlooked.
- **Despite our critiques of the analysis, the Report finds that on both sides of the NEB Program, benefits exceed the costs.** This is true even without the reforms included in LD 1777 to cut NEB compensation in order to lower program costs. Even if GHG benefits claimed regionally are excluded (which MREA and CCSA take issue with, as noted above), the Report finds that the kWh Credit Program benefits exceed the costs for behind the meter projects.<sup>9</sup> Stakeholders, including the Commission and the Committee, must take note of the unique benefits of behind the meter (often “rooftop”) projects, particularly because LD 1777 ended commercial behind the meter projects and as stakeholders begin to consider a successor DG program, as directed by LD 1777.

Thank you for the consideration of our comments.

Sincerely,



Eliza Donoghue  
Executive Director  
Maine Renewable Energy Association



Kate Daniel  
Northeast Regional Director  
Coalition for Community Solar Access

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<sup>9</sup> *Id.* at 36.

**STATE OF MAINE**  
**PUBLIC UTILITIES COMMISSION**

**MAINE PUBLIC UTILITIES  
COMMISSION**

**Commission Initiated Summary  
Investigation Seeking Comment  
on 2025 Net Energy Billing Cost  
Benefit Report**

**Docket No. 2026-00053**

**COMMENTS OF THE OFFICE OF  
THE PUBLIC ADVOCATE**

**March 25, 2025**

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**I. Introduction**

The Office of the Public Advocate (OPA) files these comments in accordance with the Notice of Summary Investigation and Opportunity for Comment issued on March 13, 2026 in this matter (the Notice). In general, the OPA is extremely disappointed that the Commission's request for comment does not provide a meaningful opportunity for recommendations presented by interested parties to be incorporated into the 2025 Net Energy Billing Report (the Report). The OPA is further disappointed that the Report fails to correct well-documented flaws in the 2023 Net Energy Billing Report presented by interested parties in Docket No. 2024-00149. Notably, the Report repeats the critical problem with the 2023 Report by focusing the bulk of its discussion and analysis on the so-called Societal Perspective under which \$259 million of \$391 million total benefits calculated in the Report are provided to customers residing outside of Maine. The emphasis of the Report on a perspective that is dominated by benefits to out-of-state customers masks the disastrous impact of this program on Maine citizens and Maine electricity consumers, for whom this program constitutes a massive wealth transfer from Mainers to out-of-state customers.

## **II. Discussion**

### **a. Timing**

As the Commission is aware, a majority of the parties to the Stipulation in 2024-00149 requested the opportunity to comment on future Net Energy Billing benefits reports. The cover letter to the Stipulation, dated October 2, 2025 stated:

... that, as part of the Order in this docket, the Commission revise its process for issuing future reports. Specifically, they recommend that, in advance of issuing final versions of future reports analyzing the net benefits of the Net Energy Billing Program (required by Maine Revised Statutes, Title 35-A, § 3209-C 3), the Commission issue a draft of the report and convene a non-adjudicatory proceeding affording interested parties a reasonable opportunity to review the draft report and provide input thereon for the Commission's consideration.<sup>1</sup>

However, in its Order Approving Stipulation issued on October 15, 2025, the Commission declined to adopt this recommendation, but indicated it was taking the request under advisement.

The issuance of the Notice in this matter reflects an effort by the Commission to address this recommendation. Since comments are due on March 25, and the final Report is due to the Legislature by April 1, however, the timing of the Notice eliminates the possibility of incorporating any meaningful input from interested parties in this proceeding into the Report.

Further, a sister report prepared by SEA, Status and Cost & Benefit Analysis of Maine's 2025 Solar Market, was issued by the Commission on February 10, 2026. That report incorporates a number of the same flaws as this Report, notably its misleading focus on the so-called Societal Perspective. The Societal Perspective includes in its benefits calculation a disproportionate level of benefits that flow to out-of-state

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<sup>1</sup> Cover letter to the Stipulation in Docket No. 2024-00199 (October 2, 2025).

residents. Thus, this misleading presentation of costs and benefits has already been shared with the Legislature and the public without providing opportunity for additional context through the receipt of stakeholder input.

Given the deadline for presenting the Report to the Legislature, and the lack of time for the Report to be modified before doing so, the OPA respectfully requests that the Commission include all comments filed by interested parties in this Docket with the Report in its presentation to the Legislature, for instance as an appendix. Doing so would provide at least some balance in perspectives regarding the analyses presented in the Report.

#### **b. Focus on Regional Benefits**

Since the issuance of the 2023 Report, the OPA has consistently criticized SEA's approach for its improper focus on its so-called Societal Perspective, which overemphasizes benefits provided to out-of-state residents. The OPA first did so in a memorandum to the Commissioners in April, 2023, before the Commission had even opened a proceeding to receive input on the 2023 Report. Since that time the Legislature has amended the requirements for procurements to emphasize the primacy of benefits to Maine ratepayers in determining the cost effectiveness of any new contract or program for the procurement of renewable generation.

Indeed, during the 2025 session, the Legislature enacted four statutes that require the use of a Maine ratepayer perspective test in authorizing any new renewable energy procurement. In PL 2025, Chapter 430 (LD 1777), the Legislature enacted 35-A MRSA §3209-I(2) requiring any new front of the meter distributed energy resources to “provide benefits to ratepayers in the State in excess of the costs to ratepayers.” Similar language was added in PL 2025, Chapter 476 (LD 1270), in which the Legislature

created a new energy procurement process in 35-A MRSA §10313 and amended 35-A MRSA §3210-C(6). Both provisions require the Commission to determine that the benefits to Maine ratepayers of the contract are likely to exceed the costs to Maine ratepayers as a result of the contract.” In PL 2025, Chapter 392 (LD 597), the Legislature amended 35-A MRSA §3210-J(2) to implement similar requirements in the award of renewable resource contracts in solicitations for projects that reuse contaminated lands. Finally, in PL 2025, Chapter 386 (LD 1868), the Legislature amended 35-A MRSA §3210-C(3) to authorize regional coordination in the procurement of renewable resources only “[i]f the commission determines that the likely benefits to ratepayers in the State will exceed the likely costs.”

Despite this clear direction from the Legislature, SEA has remained steadfast in its focus on the so-called Societal Perspective. As the OPA has consistently argued, this approach is extremely misleading. It is not just a difference of opinion about how to value the greenhouse gas (GHG) savings from the projects that sets the so-called Societal Perspective test apart from the other two perspectives. In addition to the GHG benefits, SEA counts **monetary benefits that flow to out-of-state consumers** as a benefit of the program. SEA calls these monetary benefits “rest of pool” benefits and fully counts them under the so-called Societal Perspective test. Perhaps one could argue that the Maine Legislature would want the Commission to weigh the global impact of the greenhouse gas savings of the program, but at the OPA we find it absurd to claim that the Maine Legislature would view a reduction in the electric bills of households in Connecticut and Massachusetts as a credible benefit of the NEB program. Without the so called “rest of pool” monetary benefits, Maine’s NEB programs, paid for by Maine consumers, are simply not cost-effective for Maine electricity customers, or for Maine

citizens, even when applying SEA's own analysis and assumptions. Indeed, SEA's Maine and ratepayer specific analyses demonstrate clearly that Maine's NEB programs are highly cost ineffective.

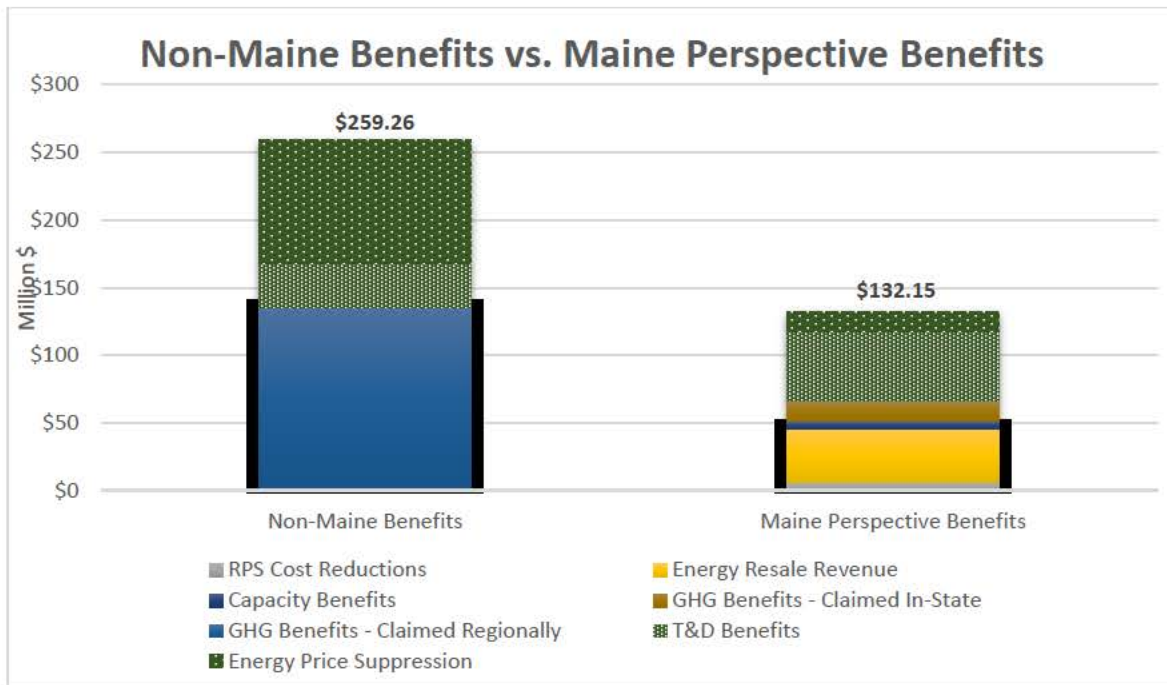
The Report does present analyses of the program from the Maine specific, and Ratepayer specific perspectives. However, it does not present these in an equivalent manner as the so-called Societal Perspective. Critically, the Report's Executive Summary addresses only the Societal Perspective, completely ignoring the more pertinent Maine and Ratepayer Perspectives. These latter perspectives are not addressed until the sections beginning on page 39 of the 43-page Report. As a result, the structure of the Report effectively "buries" these important analyses in a manner that leaves a casual reader aware only of the deeply flawed Societal Perspective.

Ignoring any other concerns the OPA has with SEA's analysis,<sup>2</sup> two of which are discussed below, the following charts prepared using SEA's own data demonstrate this concern with program cost effectiveness.

This first chart compares the value of benefits provided by the program to out-of-state residents to those provided to Maine citizens.

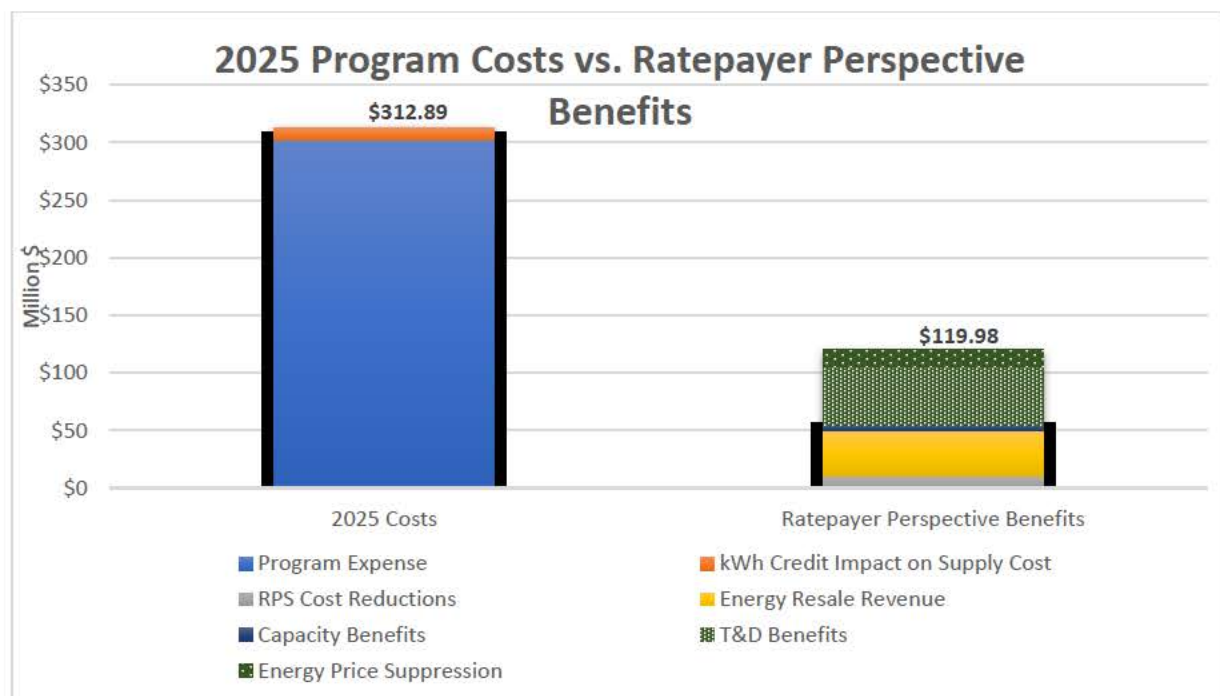
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<sup>2</sup> For a more complete discussion of the OPA's other concerns, please refer to the Direct Testimony of Marie Fagan dated April 4, 2025 and filed on behalf of the OPA in Docket No. 2024-00149, particularly Exhibit C thereto.



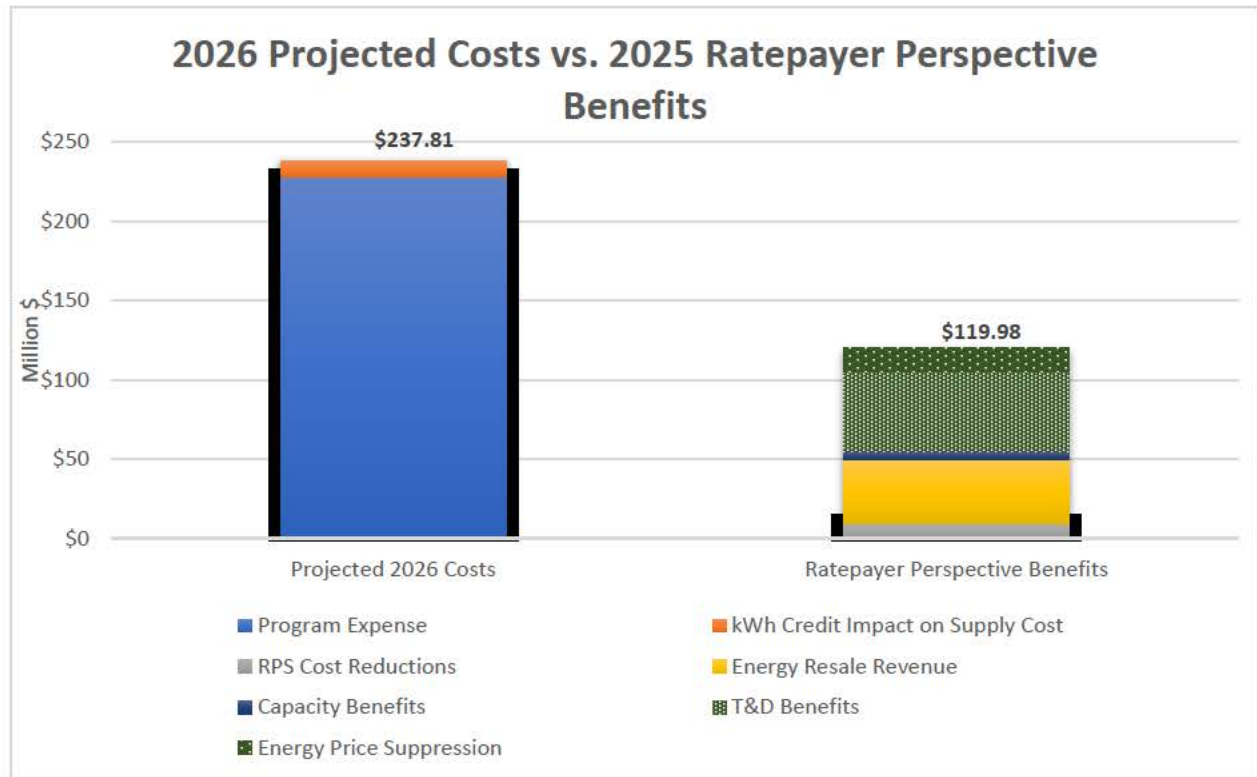
The benefits of the programs provided to out-of-state residents are essentially twice the benefits provided to Mainers.

This second chart presents the cost effectiveness of the programs under the Ratepayer Perspective analysis:



This chart demonstrates that the costs charged to Maine utility customers for Maine’s NEB programs exceeded benefits received from this program by a factor of 2.6 to 1.

Finally, this third chart is intended to demonstrate the improvement in cost effectiveness of the programs for Maine ratepayers by the revised funding scheme adopted by the Legislature in LD 1777:



While the programs remain extremely cost ineffective, the cost benefit ratio improves from the 2.6 to 1 experienced in 2025 to approximately 2 to 1.

### c. Transmission and Distribution Benefits

In estimating transmission and distribution savings derived from Maine’s NEB programs, SEA relied heavily on the 2024 Avoided Energy Supply Costs in New England (AESC) study prepared by Synapse Energy Economics. This report presents New England system average savings for the purpose of analyzing the cost effectiveness of

energy efficiency and demand response programs. However, applying the concept of avoided costs to a generation option such as NEB raises issues that do not occur when avoided costs are applied energy efficiency analysis. With respect to SEA's estimates of the avoided cost of transmission there are a number of issues.

First, it cannot be known whether NEB projects avoid the need for transmission and distribution investment unless the location of the project is known. The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy (August, 2020)(NSPM) states that “DERs can either increase or decrease utility system infrastructure costs, depending upon the loading characteristics and hosting capacity available on the distribution system.”<sup>3</sup> In addition, “[s]ome DERs will have different impacts depending upon the location of the DER on the distribution grid, and [a Benefit Cost Analysis (BCA)] should attempt to account for this locational value wherever it is likely to have a material effect on the BCA results. There may be some locations where community solar projects increase infrastructure costs and some locations where it decreases them.”<sup>4</sup>

Further, as the Commission is aware, Maine overall is a generation pocket, not a load pocket, which is evidenced by Maine's lower locational marginal prices of energy compared to other parts of New England. Adding new generation in Maine might therefore require adding more transmission, not less. SEA noted in response to data request CMP-001-014 in Docket No. 2024-00149 that it “did not consider the location of projects when determining whether resources could reduce planned transmission

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<sup>3</sup> NSPM at 151.

<sup>4</sup> *Id.*

investment.” Despite this, SEA assumed all NEB projects reduce the need to build out the transmission and distribution system.

Consideration of these factors would likely lead to a lower estimate of avoided transmission costs, because not all NEB projects reduce the need for transmission, and it is not known whether the avoided cost assumptions in the 2024 AESC would apply in Maine because it is load-constrained rather than generation-constrained.

#### **d. Benefits from Hydroelectric Facilities**

In conducting a benefit cost analysis, it is a fundamental requirement that there be a direct causal relationship between costs incurred in implementing an initiative and any benefits attributed to that initiative in order for those benefits to be claimed as resulting from that initiative. As the OPA has consistently argued since the issuance of the 2023 Report, no such causal nexus exists between the NEB programs and the benefits that the NEB report attributes to hydroelectric projects participating in the NEB programs.

A review of publicly available information confirms that all hydroelectric units participating in the NEB program preexisted the 2019 amendments to the NEB statutes. These projects represent significant investments that were undertaken with no expectation of the subsidy provided under the 2019 amendments to the NEB statutes. Indeed, many plants were re-licensed for new 20-year terms within a relatively recent period in advance of the 2019 NEB amendments. This indicates that owners were confident enough that the plants would create earnings to engage in the capital investment needed to extend the plant’s license well into the future, without the NEB subsidy.

For these reasons, the benefits of these hydropower plants should not be included in SEA's analysis, because the benefits, except for the energy resale and capacity buyout revenues, derived from the market sale of energy and capacity of the projects, exist with or without the NEB program. The costs of the plants, in contrast, do belong in SEA's analysis because the NEB program is the reason the costs are borne by ratepayers, rather than by the plant operators. Reviewing Appendix A.5 to the Report, ignoring energy and capacity resale revenues, it appears that approximately \$620,000 of benefits have been claimed from hydroelectric projects under the Ratepayer Perspective. This amount should be removed from benefits under the Ratepayer Perspective. Even larger benefits were calculated under the Societal and Maine Perspectives. These claimed benefits should be similarly removed from those analyses.

### **III. Conclusion**

The OPA appreciates the opportunity to file these comments. For the reasons described herein, we respectfully request that the Commission include these comments, together with comments received in this proceeding from other interested parties, as an appendix to the 2025 Net Energy Billing Report when submitted to the Legislature.

Respectfully submitted,

*/s/Heather Sanborn*

Heather Sanborn  
Public Advocate

*/s/ Andrew Landry*

Andrew Landry  
Deputy Public Advocate