Analysis of 2023 Net Benefits of Net Energy Billing Program

Prepared for:

Maine Public Utilities Commission

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1 Executive Summary

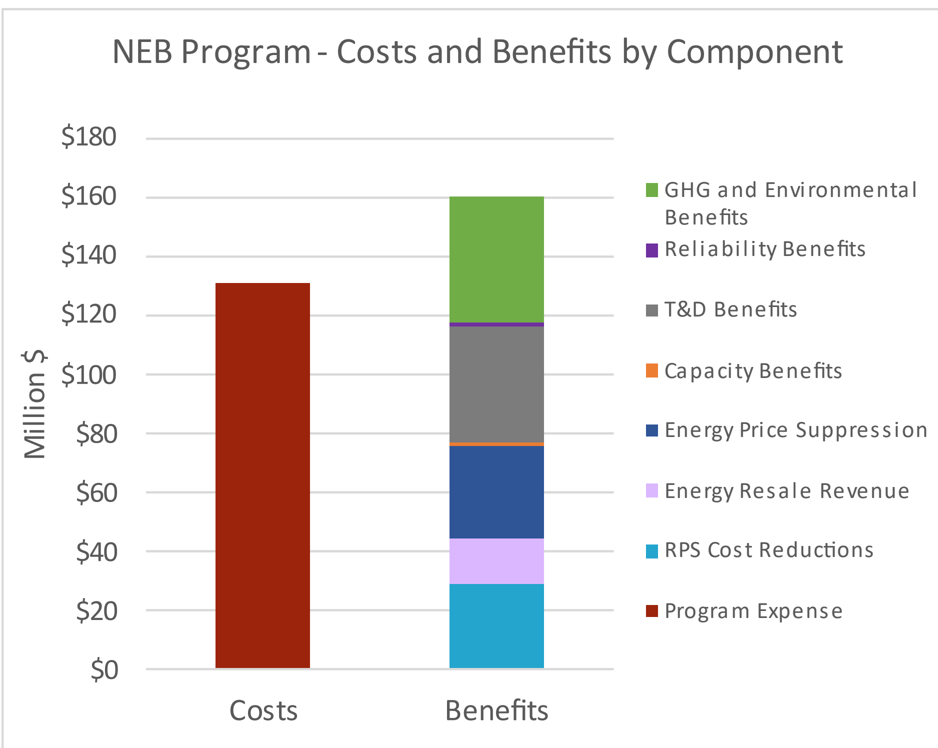
In 2023, LD 1986 "An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems" was enacted (the Act).[1] The Act directs the Maine Public Utilities Commission (Commission) to annually determine the net energy billing (NEB) costs and benefits of distributed generation (DG) under NEB and provide the results for the prior year in annual reports to the Committee on Energy, Utilities and Technology (Committee) by March 31st. 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).[2] This document describes SEA's methodology and quantification of the calendar year 2023 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 2023. A graphical summary of the analysis provided in Figure 1 and a tabular summary in Table 1.

Figure 1 – Calendar Year 2023 NEB Program Summary Cost and Benefit



[1] See Public Law 2023, ch. 411 http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131
[2] 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

Table 1 -
2023 NEB Program Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	$130.76	N/A
Renewable Portfolio Standard (RPS) Cost Reductions	N/A	$29.00
Energy Resale Revenue	N/A	$15.44
Energy Price Suppression	N/A	$31.27
Capacity Benefits	N/A	$1.23
Transmission & Distribution system (T&D) Benefits	N/A	$39.10
Reliability Benefits	N/A	$1.70
Greenhouse gas (GHG) and Environmental Benefits	N/A	$42.57
Totals	**$130.76**	**$160.33**

SEA calculates that the NEB 2023 calendar year program expenses were $130.76 million, and the program benefits were $160.33 million. Note that the cost and expenses are for all NEB projects operating in 2023. Thus, the impact of projects as old as 1994 are included in the analysis.

2 Introduction

In 2023, LD 1986 "An Act Relating to Net Energy Billing and Distributed Solar and Energy Storage Systems" was enacted (the Act).[3] The Maine Public Utilities Commission (Commission) is tasked, per the Act, with providing annual reports on the net energy billing (NEB) costs and benefits of distributed generation (DG) under NEB to the Committee on Energy, Utilities and Technology (Committee) by March 31st 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).[4] Working hand-in-hand with the Commission, this document describes SEA's methodology and quantification of the calendar year 2023 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 LD1986 Reporting Requirements

The Act defines benefits of distributed generation under NEB and, requires the Commission to provide analysis regarding such benefits, as follows:[5]

[3] See Public Law 2023, ch. 411 http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131
[4] Legislation describing these programs can be found at https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-A.html
[5] See Section 5 of LD 1986, here https://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0815&item=3&snum=131

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.

We note the Avoided Energy Supply Costs in New England (AESC) is the only comprehensive, publicly available, regional avoided energy supply cost study. We further note, while the latest AESC study (AESC 2024) was published in February 2024, it is a forward-looking study. As this report covers the net benefits for calendar year 2023 only, the analysis for this report, as applicable, will leverage the most recent previous AESC study, the AESC 2021 study. However, given that the AESC represents a forecast and the analysis contained in this report is retrospective, we have relied on actual data whenever available.

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 does 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.[6]

The Act also requires an annual report to be submitted by March 31 of each year to the Committee. 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

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

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.

2.2 General Approach & Data Sources

SEA has endeavored to conduct a detailed, bottom-up analysis practicable within the legislatively mandated schedule and data constraints. As such, in coordination with the Commission, SEA conducted a comprehensive review of publicly available data to support the legislatively mandated NEB net benefit analysis. Much of the non-AESC sourced data to support this analysis is collected by the two EDCs, and then reported to the 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. We note the following data was incorporated into this analysis.

- Some data leveraged are currently publicly available. For example, data from the
  - AESC 2021 study;
  - CMP and Versant monthly NEB reports (see Docket 2020-00199);
  - January and February 2023 monthly data from the EDC's stranded cost filings (e.g., Docket 2023-00039, Filing #2 of March 31, 2023, and Docket 2023-00076, Filing #2 of March 31, 2023).
- Some data leveraged will become publicly available. For example, March through December 2023 monthly data that will be submitted as a component of the spring 2024 EDC stranded cost filings, expected to be submitted on or about April 1, 2024.[7]
- Some data are confidential and will remain so per SEA's non-disclosure agreement with the EDCs. For example, hourly production data for individual projects. As applicable, SEA aggregates data reported to respect confidentiality.

In Table 2 we detail our approach to quantifying the net benefits of the NEB program for calendar year 2023, 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: • Energy resale revenue • Capacity Buyout Revenue • Uncleared Capacity Value • Reduced Share of Capacity Costs
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.

[7] We note that these data will be subject to an adjudicatory proceeding at the Commission, which has yet to occur at the time of writing.

Legislatively Mandated Benefit Category	SEA Adopted Benefit Category
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: • Energy DRIPE • Capacity DRIPE • Cross-Fuel DRIPE • Renewable Energy Certificate (REC) price suppression
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: • Avoided/Reduced Costs Associated with RPS Requirements • Societal Benefits from Greenhouse Gas (GHG) Reduction • Avoided Environmental Compliance Costs • Improved generation reliability

2.3 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 Commission 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 of 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.

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)[8] 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. At times we adapt ISO-NE analysis to apply to the Versant-MPD service territory.
- The NEB program is comprised of two program variants:
    - 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 program.
    - Tariff Rate program, which provides monetary credits. SEA's analysis considered all operational Tariff Rate projects, including non-solar projects. The Tariff Rate program variant itself has two variants.
        - 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.[9]
        - 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. The alternative Tariff Rate is applicable to projects failing to meet certain milestone requirements and represents 42 MW of operational capacity as of end-of-year 2023.[10]
- 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

[8] 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.
[9] See 35-A MRSA §3209-B(5)(A), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html
[10] See 35-A MRSA §3209-B(5)(A-1), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html

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 approach differs 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).

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 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 (see final report) determined that economic development benefits should not be quantified in the benefit stack, but should instead be considered separately as a supplemental consideration.

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

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

3.2 AESC Inputs

As discussed above, most inputs informing benefit quantification not provided directly by the EDCs was derived from the AESC 2021 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 DG programs.

We note that, although an updated AESC 2024 study is currently available, AESC 2021 was utilized given the AESC study is strictly forward looking and SEA's analysis presented here is strictly retrospective. As such, a quantification of 2023 benefits and costs would not be possible using AESC 2024 inputs.

For the purposes of this analysis, SEA utilized the "All-in Climate Policy" sensitivity, as it most closely approximates a future in which states pursue the development of DG. According to the AESC 2021, the sensitivity "models a future with ambitious levels of energy efficiency, building electrification, and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. As a result, it can be interpreted not as an avoided cost, but as a projection of expected energy prices, capacity prices, and other price series in a future with ambitious climate policies."

AESC 2021 inputs used in this analysis were translated to nominal dollars assuming a discount rate of 2% (the default assumption in AESC 2021).

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 utility, 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.
  - **Tariff Rate:** SEA received actual hourly production data for all CMP projects enrolled in the Tariff Rate program. Versant provided actual monthly production data by project for the Tariff Rate Program.
  - **kWh Credit Program:** SEA received actual monthly production data for kWh exports from both utilities, disaggregated by rate class. 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 an 18% AC capacity factor, an annual production degradation rate of 1%, and a de-rate to year-one production of 60% to reflect that projects typically achieve commercial operation in the second half of the year.
- **Capacity Data:** SEA collected data on project capacities by utility, technology, and commercial operation dates from the EDC's monthly NEB reports in Docket 2020-00199, as of December 31, 2024. The reports do not designate the metering arrangement for each project. As such, SEA imputed the capacity of FTM facilities in the kWh Credit program based on the exported kWh reported by both utilities. The remainder net capacity (FTM minus total kWh Credit program capacity) was assumed to be BTM.

3.4 Revenue from Energy Resale

<u>Overview</u>

Energy re-sale revenue gained by the EDCs from production provided by operational 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 whole for out channel export NEB production.

<u>Data Source</u>

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

<u>Discussion</u>

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 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. For projects in the kWh Credit program variant, the costs of avoided energy are not considered in this analysis (see discussion in Section 3.15). As such, any potential avoided energy benefits are not quantified to provide consistent accounting of both costs and benefits.

3.5 Capacity Buyout Revenue

Overview

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

Data Source

Revenue collected in 2023 from capacity buyouts was provided to SEA by the EDCs.

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, instead projects are treated as "load reducers". As such, SEA only focused on revenues from capacity buyout.

The monetization of 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 EDCs in the region 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 2023. As such, revenues from projects electing to pay an up-front fee for capacity buyout prior to 2023 was 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) for projects enrolled in the NEB program, the capacity of projects in the program 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.[11] 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.

Data Source:

SEA utilized AESC 2021 (All-in Climate Policy case) assumptions for the value of uncleared capacity.

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[11] See page 125 of 2021 AESC for detailed discussion of such benefits, here: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

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 2021 AESC assumes that benefits from uncleared capacity do not start until 5 years after their installation date. As such, SEA's analysis assumes no uncleared capacity benefits in 2023 for Tariff Rate projects, which have their earliest commercial operation date in 2019. Given the limited capacity of NEB project online pre-2019, uncleared capacity benefits are modest relative to other benefit components.

3.7 Reduced Share of Capacity Costs

Overview

BTM, distribution-connected resources 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).

Data Source:

AESC 2021 inputs were utilized.

Discussion:

To calculate the estimated load reductions during peak periods resulting from NEB project production, SEA calculated the average 12-month coincident MW (expressed as a percent of nameplate capacity), as described above. The coincident factor was then used to calculate the reductions in capacity costs assigned to Maine, per MW, for each technology assessed.

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.

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

Transmission benefits are only applicable to projects connected to the distribution system, as transmission-connected facilities do not reduce transmission-level load. For distribution benefits, this benefit is only applicable to projects connected to the distribution system that are BTM, as FTM facilities do not reduce distribution-level load.

Data Source:

For transmission benefits, SEA utilized AESC 2021 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 2021 assumptions specific to Maine for the value per MW-year of avoided distribution capacity. The studies referenced by the AESC 2021 provide a range of possible values. Consistent with the AESC 2021, SEA adopted mid-point estimates. Both values were provided in 2020 dollars and were translated to 2023 dollars assuming an inflation rate of 2% (consistent with the inflation rate assumed in AESC 2021).

Discussion:

To calculate the estimated load reductions on the transmission system during peak periods resulting from DG projects, SEA calculated the average 12-month coincident peak MW (expressed as a % of nameplate capacity) by comparing peak Maine ISO-NE load in each month (as provided by AESC 2021) to a representative production curve for each technology assessed. The representative production curve was taken from PVWatts, assuming a facility located in Southern Maine.[12] The resulting factor was used to de-rate the full value per MW-year of avoided transmission capacity to a technology-specific value, based on each technology's production coincidence with peak periods.

Avoided intrastate transmission investments were only applied to BTM projects, as such, FTM projects are not assumed to reduce the load of transmission assets within Maine. FTM projects were assumed to contribute to avoided PTF investments. Intrastate and rest-of-pool values for avoided investments were calculated separately, based on Maine's share of the transmission costs as provided by ISO-NE.[13]

To calculate the estimated load reductions on the distribution system during peak periods resulting from DGs 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 2021) as compared to a representative production curve for each technology assessed. The resulting factor was used to calculate a technology-specific per MWh value capturing avoided distribution capacity, based on each technology's production coincidence with peak periods.

For both transmission and distribution benefits, SEA considered the use of actual system peaks, as reported by ISO-NE, in 2023 as compared to actual project production (for Tariff rate projects for which hourly production data was supplied). However, given that this benefit is intended to capture the impact of load reducing resources on system planning, using weather-neutral values are more likely to approximate the assumptions in forming system planning. In practice, system planning occurs on longer time horizons than the single year focused on in this analysis. As such, it is unlikely that a single year's production would influence system planning and yield such benefits. However, when viewed in the context of the broader NEB program, which has had multiple years of projects come online (and thereby influencing system planning over longer time horizons), it is likely that such benefits would be realized. As such, the benefits contained in this report represent the share of total program benefits that could be attributed to production occurring in 2023.

3.8.2 Avoided Maine Regional Network Service Share

Overview

BTM, distribution-connected resources 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).

[12] PVWatts is a tool developed by the National Renewable Energy Laboratory (NREL) which estimates hourly PV production based on specific locations, found here: https://pvwatts.nrel.gov/

[13] See ISO-NE 2023 peak demand by state here: https://www.iso-ne.com/static-assets/documents/2023/02/2023_smd_monthly.xlsx

Data Source:

SEA utilized the 2023 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 (expressed as a percent of nameplate capacity), as described above. The coincident factor was then used to calculate the reductions in RNS expenses, per MW, for each technology assessed.

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.

3.8.3 Avoided Transmission and Distribution Line Losses

Overview

Generation from distribution-connected distributed generation reduces the load on the transmission system and, for BTM generators, reduces the load on the 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:

AESC 2021 recommended transmission and distribution line losses were adopted.[14] These values were informed by assumptions adopted by ISO-NE.

Discussion:

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. Half the value of line loss benefits were applied to FTM facilities since they do not avoid distribution losses (assuming distribution losses are roughly half of total distribution and transmission line losses reported by the AESC).

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 NEB projects interconnecting in 2023, and the associated costs, if any, paid to fund upgrades to the transmission and distribution system.

[14] See Table 147 of AESC 2021, here: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

Discussion:

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 statue. 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. As such, SEA assumed that 25% of total interconnection costs paid to fund system upgrades were shared benefits based on SEA's professional judgment.[15] Given that the actual share of costs delivering shared benefit may be different, SEA conducted a sensitivity analysis assuming either 50% or 0% share of costs delivered shared benefits. A table providing the range of benefits, program wide, by assumption is provided below in Table 3:

Table 3 –
T&D upgrade benefits – Sensitivity Results

Share of costs assumed to deliver shared benefits	Program-Wide Benefits (Million $)
0%	0
25%	8.89
50%	17.79

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 2021 (All-in Climate Policy Case) DRIPE values specific to Maine were utilized.

Discussion:

For Energy DRIPE, which varies based on peak/off-peak period and season, hourly 2023 production data from all CMP Tariff Rate projects was utilized to calculate the share of annual production occurring in each period. These shares were applied to production from Versant or 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 applied an adjustment to such prices equal to the delta between the average load-weighted annual LMP in Maine reported by ISO-NE and the average load-weighted annual LMP assumed in AESC 2021. This adjustment resulted in a reduction of 1% to Energy DRIPE and Cross-Fuel DRIPE values.

[15] 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 3.8.4.

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 2023 (i.e., were calculated separately for each cohort year).

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 2023-3 REMO briefing.[16] 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 2023 Class I prices in each state market were then calculated. Results demonstrated a reduction of $1.75 in the price of regional Class I markets (including Massachusetts, Rhode Island, New Hampshire, Maine, and Connecticut). This price delta was then translated to total dollar savings by multiplying the delta by the 2023 compliance obligation for each Class I market. Results were then categorized by intrastate (Maine Class I) and regional (all other markets) benefits.

3.11 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). BTM production acts as a load reducer, thereby decreasing the total load from which the compliance obligation for any given year is calculated. Thus, BTM projects provide benefits in the form of reductions in total RPS costs.

To address this, in its orders granting new RPS certification, the Commission 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

[16] For details on the New England REMO service, see here: https://www.seadvantage.com/new-england-remo/

change because of BTM load reductions, but the party responsible for fulfilling RPS requirements with such load does change. Thus, 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, this component is considered a cost shift, and thus does not yield any net benefits.

Data Source:

Price quotes in March of 2024 for 2023 Maine Class I and II REC prices were taken from multiple REC brokers and averaged to derive a price for use in modeling.

Discussion:

SEA considered the benefits of avoided Class I and II RPS costs. Assumed 2023 REC prices by class were de-rated by the applicable 2023 RPS minimum standard for each class (17.3% for Maine Class I, 30% for Maine Class II), to reflect that one MWh of load reduction results in the avoided purchase of only a partial REC.

3.12 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.

Data Source:

AESC 2021 values (from Counterfactual #1) 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:

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 inclusion 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.

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. Inputs from Counterfactual #1 were utilized because the All-in Climate Policy sensitivity models GHG benefits using incremental regional clean energy policy compliance cost (IRCEP) rather than the SCC. The IRCEP approach does not produce GHG benefits prior to 2025.
>
> **SCC:** Quantification of a SCC is complex and well-studied. Given that the costs of carbon emissions (namely, climate change) occur over long time spans including impacts distant in the future, the specific year under which carbon is assumed to be emitted is less relevant to SCC quantification than assumptions like the discount rate used to put

future costs in present dollar terms. Unlike other inputs in the 2021 AESC, which reflect the specific resource mix and grid conditions in ISO-NE during the study period, the adopted SCC in AESC 2021 primarily reflects SCC values adopted in regional and national agencies at the time of study release which have since been updated.

Given this, SEA determined it was most appropriate to use an updated SCC based on inputs adopted in AESC 2024, which represents the most up to date SCC adopted by the U.S. Environmental Protection Agency (EPA) as of November 2022. Specifically, AESC 2024 recommends a 2023 SCC between $218 and $375 per short ton (representing a discount rate between 2% and 1.5%). For the purposes of this analysis, SEA adopted the low end of this range, representing a discount rate of 2%.

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.

Finally, SEA subtracts the assumed average ME Class I REC price in 2023 from the total $/MWh non-embedded GHG benefit (see Section 3.11 for a discussion of assumed REC values). This is done because RECs represent an environmental attribute whose value includes the benefits of GHG reduction from renewable generation. Given that RECs are not taken title to under the NEB program, meaning project owners can sell RECs independently, failing to subtract assumed REC value from the total non-embedded GHG benefit would result in double counting of environmental benefits, as a portion of the environmental value will be claimed outside of the program via the purchase and retiring of RECs.

SEA notes that, depending on the perspective of the benefit-cost analysis, REC revenue could under some circumstances be considered a benefit given that NEB project owners are required to be a customer of one of the Maine EDCs and are thus, by definition, a subset of Maine ratepayers. However, for the purposes of this analysis SEA has chosen to exclude the benefits of REC revenue in favor of a perspective that focuses on the broader base of all Maine ratepayers (and all New England consumers of compliance RECs) which is compatible with a general societal impact perspective used as the basis of the analysis herein (see Section 2.3). The general societal impact perspective means that 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).

3.13 Avoided Environmental Compliance Costs

Overview:

Renewable energy contributes zero-carbon energy to the grid, offsetting the dispatch of fossil generation. Fossil generation produces co-pollutants in addition to GHG, including NO_X. The benefits of these NO_X emissions reductions are quantified and considered in this analysis.

Data Source:

AESC 2021 values (All-in Climate Policy sensitivity) were used to compute the marginal NOx benefits per MWh of generation.

Discussion:

The marginal reduction in GHG resulting from a MWh of renewable generation is calculated in the AESC based on peak/off-peak period and season. Like 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.

3.14 Improved Generation Reliability

Overview:

Renewable energy can reduce peak load, thereby improving generation reliability.

Data Source:

AESC 2021 values (All-in Climate Policy sensitivity) were used to compute the reliability benefits per MW applicable to each technology assessed.

Discussion:

As discussed in AESC 2021, this benefit considers "how changing electric load levels can change reliability in several ways, which differ among generation, transmission, and distribution." This benefit component contributes a small portion of overall program benefits.

3.15 Modeling Cost Components

Overview:

The costs of the NEB 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, 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).

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 2023.

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.

Lastly, SEA computed the lost revenues associated with BTM production consumed on-site (which are, of course, 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. This disconnect of billed kWh to consumed kWh likely increases the Standard Offer pricing (as compared to the counter factual of the absence of the kWh Credit program). Regardless of the likely increase on Standard Offer pricing resulting from the structure of the kWh Credit program variant, such indirect impacts are difficult to quantify and more importantly outside the legislative mandate and the scope of this analysis.

<u>Administrative Costs:</u>
In addition to per-kWh program expenses, SEA collected total costs associated with the administration of the NEB program from the EDCs. These 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.

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 2023 is provided below, with a graphical summary of the analysis provided in Figure 2 and a tabular summary in
Table 4. 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 2023 NEB Program Summary Costs and Benefits

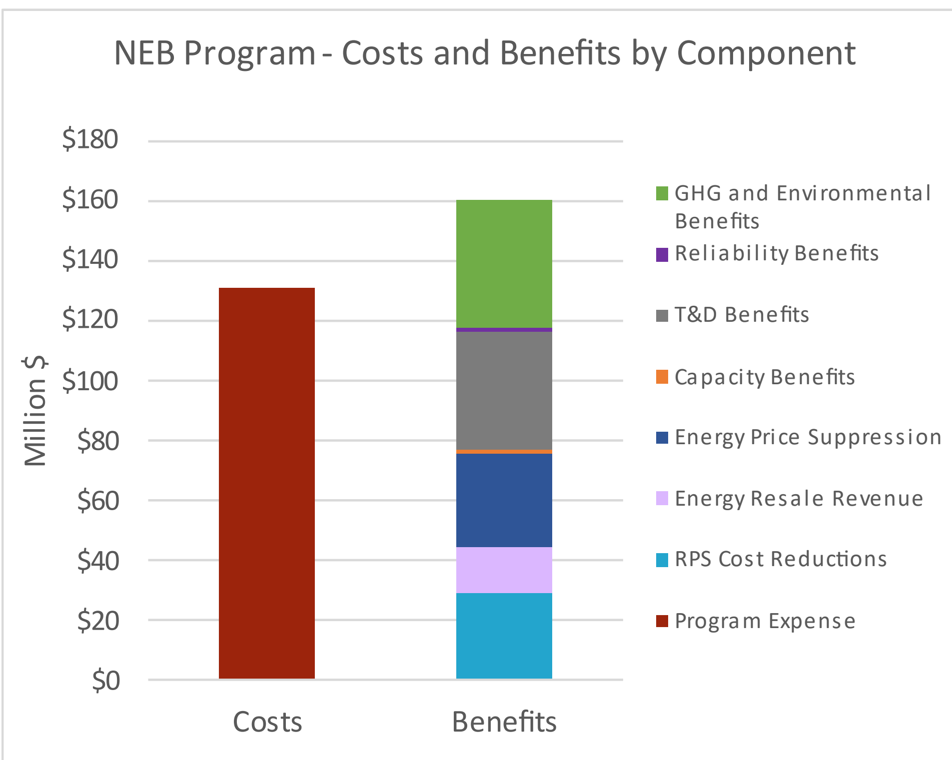


Table 4 -
2023 NEB Program Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	$130.76	N/A
Renewable Portfolio Standard (RPS) Cost Reductions	N/A	$29.00
Energy Resale Revenue	N/A	$15.44
Energy Price Suppression	N/A	$31.27
Capacity Benefits	N/A	$1.23
Transmission & Distribution system (T&D) Benefits	N/A	$39.10
Reliability Benefits	N/A	$1.70
Greenhouse gas (GHG) and Environmental Benefits	N/A	$42.57
Totals	**$130.76**	$160.33

SEA calculates that the NEB 2023 calendar year program expenses were $130.76 million, and the program benefits were $160.33 million. Note that the cost and expenses are for all NEB projects operating in 2023. Thus, the impact of projects as old as 1994 are included in the analysis.

Figure 3 and Table 5 provide a summary of the NEB program costs and benefits by the program variants described in Section 3.1. The Tariff Rate program variant was found to have costs marginally exceeding benefits, whereas the kWh credit program variant was found to have benefits significantly exceeding costs.

Figure 3 –
2023 NEB Program Variant Summary Cost and Benefit in Millions of Dollars

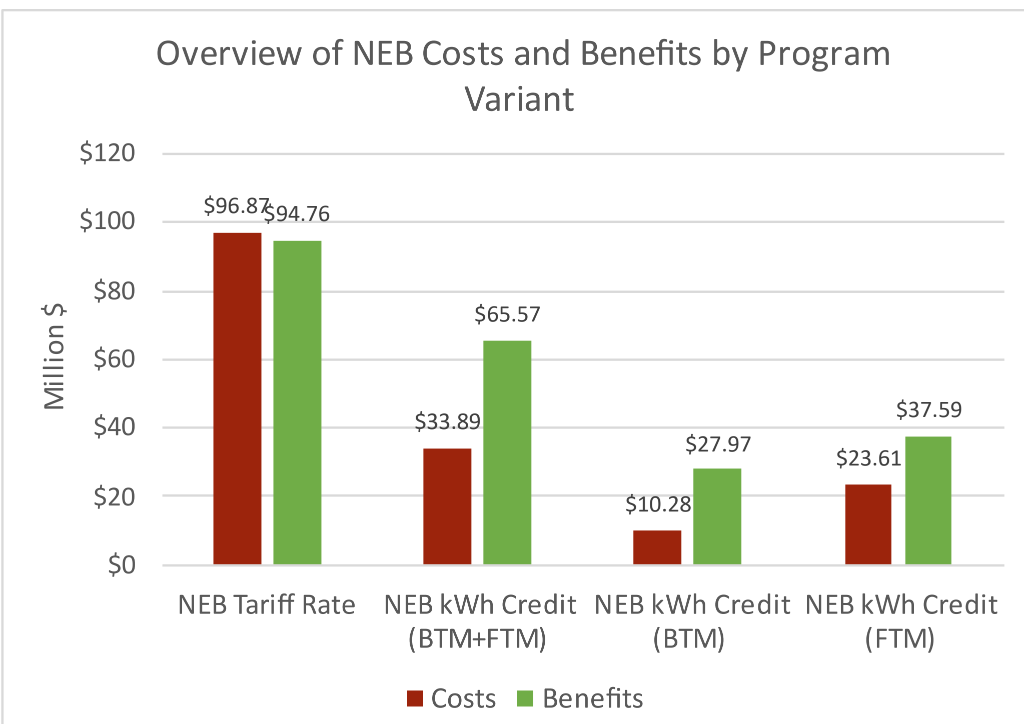
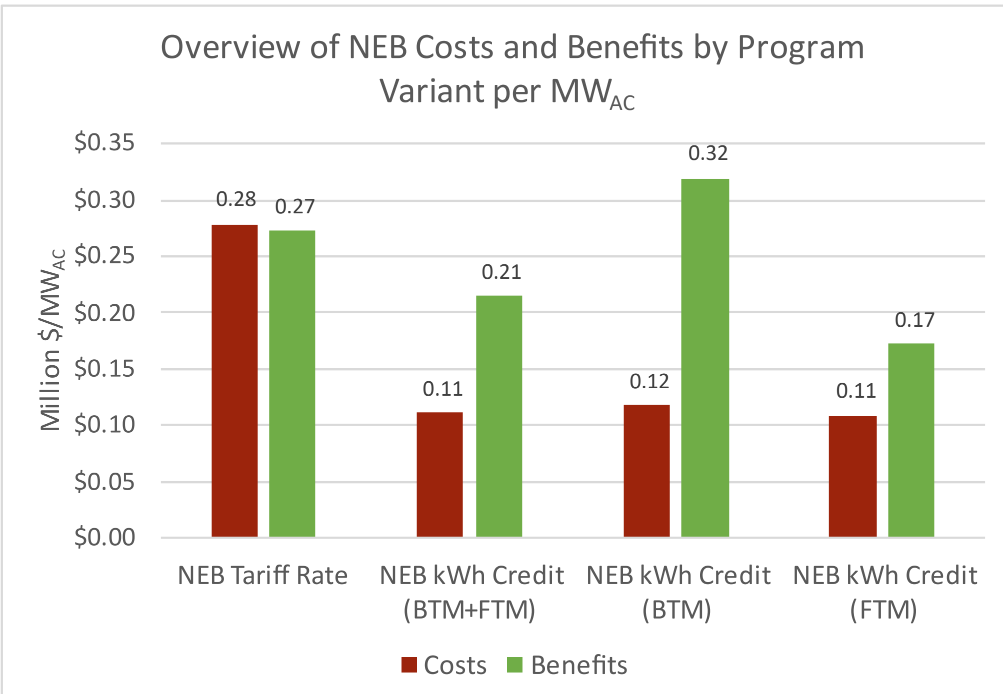


Table 5 -
2023 NEB Program Variant Summary Cost and Benefit in Millions of Dollars

Program Variant	Costs	Benefits	Benefit-Cost Ratio
NEB Tariff Rate	\$96.87	\$94.76	0.98
NEB kWh Credit	\$33.89	\$65.57	1.93
NEB kWh Credit (BTM)	\$10.28	\$27.97	2.72
NEB kWh Credit (FTM)	\$23.61	\$37.59	1.59
NEB Program Total	\$130.76	\$160.33	1.23

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 –
2023 NEB Program Variant Per MW Summary Costs and Benefits



The preceding begs the question why does the kWh Credit program variant yield greater net benefits than the Tariff Rate program variant in calendar year 2023? The answer is that, although the Tariff Rate program delivers greater total benefits per MW, the cost per MW is significantly greater, resulting in net costs per MW as compared to the kWh Credit program which delivers significant net benefits.

Table 6 provides a breakdown of total value by component category, whereas

Table 7 provides such figures on a million-dollar per MW_{AC} 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:** First note the kWh Credit program variant is 88.0% of the size (in MW_{AC} terms) of the Tariff Rate program variant while incurring only 34.9% of the Program Expenses. On a per-MW basis, the kWh Credit program variant is roughly 40% of the costs of the Tariff Rate. 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.
- **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 avoided transmission benefits only.
- **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.
- **RPS Obligation Reductions:** Because the kWh Credit program variant includes BTM projects, it is the only program variant in which benefits associated with reducing the Maine RPS Compliance Obligation accrue. However, the most significant component driving RPS cost reductions is REC price suppression, which, as discussed above, is a function of production. As such, the higher average capacity factor of Tariff Rate projects yields greater price suppression benefits per MW, resulting in higher RPS-related benefits overall per MW as compared to the kWh Credit Program.
- **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 a total of $15.44 million for energy resale benefits in 2023. 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 6 -
Summary Comparison of Tariff Rate vs. kWh Credit 2023 NEB Program Variants (Total $)

Benefit / Cost Category	Tariff Rate (Millions $ or MW_{AC})	kWh Credit (Millions $ or MW_{AC})	kWh Credit as % of Tariff Rate
MW_{AC}	347.47	305.80	88.0%
Program Expense	$96.87	$33.89	35.0%
T&D Benefits	$17.29	$21.81	126.1%
GHG and Environmental Benefits	$25.02	$17.56	70.2%
Energy Price Suppression	$18.67	$12.59	67.4%
RPS Cost Reductions	$16.84	$12.16	72.2%
Energy Resale Revenue	$15.44	$0.00	0.0%
Reliability Benefits	$1.06	$0.65	61.3%

Benefit / Cost Category	Tariff Rate (Millions $ or MW_{AC})	kWh Credit (Millions $ or MW_{AC})	kWh Credit as % of Tariff Rate
Capacity Benefits	$0.44	$0.80	183.2%
Total Benefits	$94.76	$65.57	69.2%

Table 7 -
Summary Comparison of Tariff Rate vs. kWh Credit 2023 NEB Program Variants ($/MW)

Benefit / Cost Category	Tariff Rate (Millions $/MW$_{AC}$)	kWh Credit (Millions $/MW$_{AC}$)	kWh Credit as % of Tariff Rate
Program Expense	$0.28	$0.11	39.7%
T&D Benefits	$0.05	$0.07	143.3%
GHG and Environmental Benefits	$0.07	$0.06	79.7%
Energy Price Suppression	$0.05	$0.04	76.6%
RPS Cost Reductions	$0.05	$0.04	82.1%
Energy Resale Revenue	$0.04	$0.00	0.0%
Reliability Benefits	$0.003	$0.002	69.6%
Capacity Benefits	$0.001	$0.003	208.2%
Total Benefits	$0.27	$0.21	78.6%

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 benefits 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, is provided in

Table 8 (we note that "ROP" stands for "Rest of Pool", and designates benefits accruing to neighboring states within ISO-NE):

Table 8 -
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
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
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
NOx 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

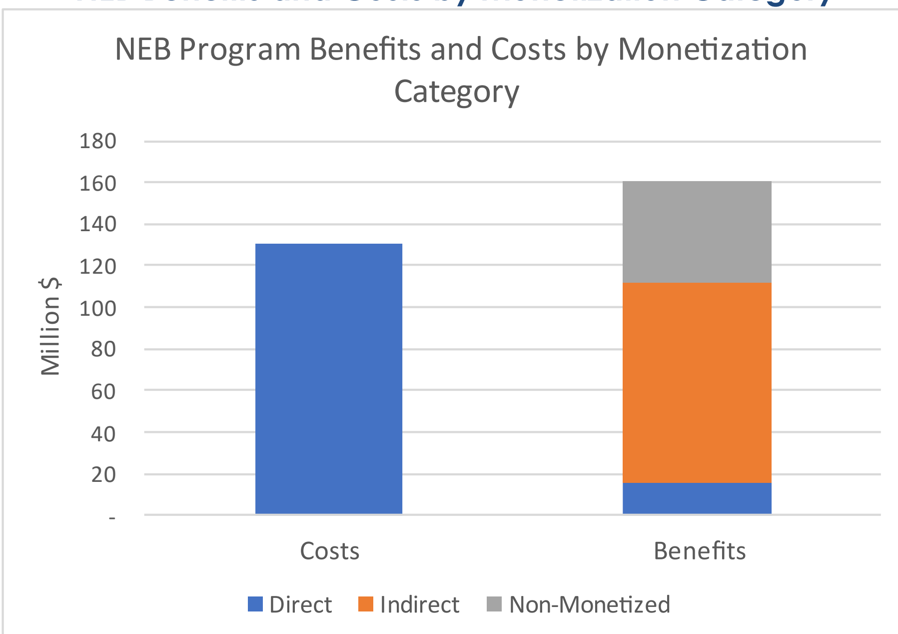
Benefits that relate to reducing the share of transmission or capacity expenses paid for by Maine ratepayers do not offer net benefits on a societal level because they are essentially a cost shift from Maine ratepayers to ratepayers in other ISO-NE states. As such, these components could be considered a benefit or a cost depending on the perspective.

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 and NO_X benefits.

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.

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.

Figure 5 –
NEB Benefits and Costs by Monetization Category



4.3 Sensitivity Analysis of Maine Societal and Ratepayer Perspectives

Per the discussion in Section 2.3, 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 9, 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 3.11, reduced RPS requirements 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 include Non-embedded GHG emissions benefits in the Maine Perspective. This is because the recognition of the importance of reducing GHG emissions is a primary motivator for the establishment of programs such as the NEB program. Such goals have been legally recognized by Maine, as the legislature has formalized GHG reduction requirements in P.L. 2019 Chapter 476, which requires the State to reduce carbon emissions by 45% relative to 1990 levels by 2030 and 80% by 2050. Given this, although such benefits are global in scale, omission of them would be antithetical to the motivations informing the establishment of the NEB program.

This determination is in line with best practices and prior analysis. First, the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources notes that societal impacts should be accounted for to the extent that they contribute to a jurisdiction's energy policy goals.[17] In contrast, ROP energy suppression benefits are not an express goal of Maine, but rather are a side effect of the NEB program (and are thus not included in the Maine Perspective). Lastly, prior benefit-cost analysis of the NEB program conducted by Synapse Energy Economics and Sustainable Energy Advantage on behalf of the DG Stakeholder Group (see final report) adopted a Maine Perspective and included GHG benefits. GHG benefits are excluded from the Ratepayer Perspective.

NOx emission benefits are also included in the Maine Perspective, as such benefits are a more local pollutant (e.g., ground-source ozone) as compared to GHG emissions. However, such benefits are minuscule compared to other benefit components, and thus do not materially impact results. These benefits are excluded from the Ratepayer Perspective.

Table 9-
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
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

[17] See page 16, here: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Component	Societal Impact Perspective	Maine-only Societal Impact Perspective	Ratepayer Impact Perspective
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	Include	Include	Exclude
NOx emissions	Include	Include	Exclude
Reduced RPS Obligation	Exclude	Exclude	Include
REC Price Suppression (Intrastate)	Include	Include	Include
REC Price Suppression (ROP)	Include	Exclude	Exclude

Table 10 provides a summary comparison of the cost and benefits by modeling perspective. The Program Expense, Energy Resale and GHG & Environmental Benefits benefit / cost categories do not vary from the Societal Perspective to the Maine Perspective. The Ratepayer Perspective is identical to the Societal Perspective apart from marginally higher RPS cost reductions (see Section 3.11) and the exclusion of benefits relating to GHG or NOx emissions reductions. The Maine Perspective and Ratepayer Perspective have significantly lower benefits for the RPS Cost Reductions, Energy Price Suppression, and Reliability Benefits component categories 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). Conversely, the Capacity Benefits and T&D Benefits 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).

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 10 -
2023 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	$130.76	N/A	N/A	N/A	N/A	N/A
RPS Cost Reductions	N/A	$29.00	$3.32	$4.03	11.5%	13.9%
Energy Resale Revenue	N/A	$15.44	$15.44	$15.44	100.0%	100.0%
Energy Price Suppression	N/A	$31.27	$4.19	$4.19	13.4%	13.4%

Benefit / Cost Category	Costs	Societal Perspective Benefits	Maine Perspective Benefits	Ratepayer Perspective Benefits	Maine Perspective Benefits (% of Societal)	Ratepayer Perspective Benefits (% of Societal)
Capacity Benefits	N/A	$1.23	$0.94	$0.94	76.1%	76.1%
T&D Benefits	N/A	$39.10	$25.03	$25.03	64.0%	64.0%
Reliability Benefits	N/A	$1.70	$0.17	$0.00	9.8%	0.0%
GHG and Environmental Benefits	N/A	$42.57	$42.57	$0.00	100.0%	0.0%
Totals	$130.76	$160.33	$91.67	$49.63	57.2%	31.0%

As shown above, the Maine Perspective benefits are less than the NEB program expenses. It is also worth noting that, although overall costs exceed benefits under this perspective, benefits continue to exceed costs for the kWh Credit program variant specifically (for both BTM and FTM projects, though net benefits are significantly higher for BTM projects). Ratepayer Perspective benefits are lower than both the Societal and Maine Perspective. Still, benefits for BTM kWh Credit program projects are higher than costs under the Ratepayer Perspective due to the significant T&D benefits assumed for such projects.

A Appendix A – Component-level Results

A.1 Tariff Rate Program (2023) – 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	$54,379,441	$1,935,925	$19,092,653	$7,223,105	$0	$10,323,998	$3,543,866	$0	$0
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$219,989	$3,897	$21,193	$70,975	$0	$13,756	$46,200	$0	$0
Energy Resale Revenue	Energy Resale Revenue	$8,593,935	$305,947	$3,017,336	$1,240,664	$0	$1,773,283	$511,400	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$435,078	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$4,084,466	$0	$77,981	$836,470	$0	$162,115	$0	$0	$0
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)	$881,053	$27,861	$436,763	$123,970	$0	$246,335	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$5,767,736	$159,626	$2,758,139	$812,104	$0	$1,546,831	$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)	$3,521	$100	$1,660	$495	$0	$936	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$53,297	$1,520	$25,132	$7,490	$0	$14,174	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$410,648	$9,656	$183,349	$58,038	$0	$102,304	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$2,723,173	$57,752	$1,205,378	$385,070	$0	$669,112	$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)	$441,531	$24,111	$145,807	$53,759	$0	$35,715	$47,814	$0	$0
T&D Benefits	Reduced transmission costs (ROP)	$4,367,745	$238,509	$1,442,362	$531,795	$0	$353,298	$472,988	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$533,246	$29,119	$176,094	$64,925	$0	$43,133	$57,746	$0	$0
T&D Benefits	Reduced T&D losses - capacity (ROP)	$196,549	$10,733	$64,906	$23,931	$0	$15,898	$21,284	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$676,026	$12,578	$133,732	$95,490	$0	$76,670	$45,695	$0	$0
T&D Benefits	Reduced T&D losses - energy (ROP)	$910,838	$31,043	$362,190	$128,605	$0	$206,385	$60,289	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$58,516	$2,127	$23,736	$7,125	$0	$5,814	$6,337	$0	$0
Reliability Benefits	Improved generation reliability (ROP)	$538,088	$19,564	$218,264	$65,515	$0	$53,463	$58,270	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$13,315,537	$513,562	$5,102,310	$1,881,121	$0	$2,934,387	$904,937	$0	$0
GHG and Environmental Benefits	NOx emissions	$207,148	$7,018	$69,873	$29,264	$0	$40,184	$14,078	$0	$0
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$1,073,226	$38,207	$376,810	$151,618	$0	$216,707	$72,938	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$8,294,373	$295,282	$2,912,159	$1,171,768	$0	$1,674,810	$563,694	$0	$0

A.2 kWh Credit Program (2023) – 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	$7,241,419	$2,603,511	$272,229	$20,084,092	$3,090,715	$270,037
Program Expense	Program Admin	$113,489	$45,714	$3,208	$113,489	$45,714	$3,208
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	$2,578,861	$1,152,873	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (Intrastate)	$2,495	$561	$142	$7,098	$706	$172
Capacity Benefits	Uncleared capacity value (ROP)	$32,043	$7,208	$1,826	$91,161	$9,069	$2,215
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$274,734	$60,475	$0	$781,386	$76,086	$0
Energy Price Suppression	Price suppression - energy (ROP)	$1,738,269	$379,986	$0	$4,943,846	$478,070	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$12,201	$2,720	$0	$34,710	$3,422	$0
Capacity Benefits	Price suppression - capacity (ROP)	$135,555	$30,216	$0	$385,648	$38,015	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,147	$253	$0	$3,263	$319	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$17,370	$3,834	$0	$49,402	$4,823	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$115,790	$25,379	$0	$329,314	$31,930	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$756,036	$164,710	$0	$2,150,200	$207,225	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$899,658	$232,794	$22,775	$337,043	$38,583	$3,640
T&D Benefits	Reduced transmission costs (ROP)	$1,172,399	$303,367	$29,680	$3,334,121	$381,675	$36,009
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$5,885,169	$1,405,236	$173,193	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$287,593	$74,370	$7,332	$408,935	$46,783	$4,448

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 (ROP)	$120,600	$30,671	$3,639	$171,492	$19,294	$2,208
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$395,403	$93,968	$11,527	$562,285	$59,112	$6,993
T&D Benefits	Reduced T&D losses - energy (ROP)	$532,726	$124,130	$14,698	$757,564	$78,086	$8,916
Reliability Benefits	Improved generation reliability (Intrastate)	$14,159	$3,717	$309	$40,265	$4,677	$374
Reliability Benefits	Improved generation reliability (ROP)	$130,202	$34,184	$2,837	$370,258	$43,007	$3,442
GHG and Environmental Benefits	Non-embedded GHG emissions	$3,886,004	$927,884	$114,360	$11,052,220	$1,167,395	$138,746
GHG and Environmental Benefits	NOx emissions	$60,454	$14,435	$1,779	$171,938	$18,161	$2,158
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$313,210	$74,787	$9,217	$890,804	$94,092	$11,183
RPS Cost Reductions	REC Price Suppression (ROP)	$2,420,629	$577,987	$71,236	$6,884,532	$727,181	$86,426

A.3 Tariff Rate Program (2023) – Maine 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	$54,379,441	$1,935,925	$19,092,653	$7,223,105	$0	$10,323,998	$3,543,866	$0	$0
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$219,989	$3,897	$21,193	$70,975	$0	$13,756	$46,200	$0	$0
Energy Resale Revenue	Energy Resale Revenue	$8,593,935	$305,947	$3,017,336	$1,240,664	$0	$1,773,283	$511,400	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$435,078	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$4,084,466	$0	$77,981	$836,470	$0	$162,115	$0	$0	$0
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)	$881,053	$27,861	$436,763	$123,970	$0	$246,335	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$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)	$3,521	$100	$1,660	$495	$0	$936	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$410,648	$9,656	$183,349	$58,038	$0	$102,304	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$441,531	$24,111	$145,807	$53,759	$0	$35,715	$47,814	$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 (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$533,246	$29,119	$176,094	$64,925	$0	$43,133	$57,746	$0	$0
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$676,026	$12,578	$133,732	$95,490	$0	$76,670	$45,695	$0	$0
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$58,516	$2,127	$23,736	$7,125	$0	$5,814	$6,337	$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	$13,315,537	$513,562	$5,102,310	$1,881,121	$0	$2,934,387	$904,937	$0	$0
GHG and Environmental Benefits	NOx emissions	$207,148	$7,018	$69,873	$29,264	$0	$40,184	$14,078	$0	$0
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$1,073,226	$38,207	$376,810	$151,618	$0	$216,707	$72,938	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

A.4 kWh Credit Program (2023) – 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	$7,241,419	$2,603,511	$272,229	$20,084,092	$3,090,715	$270,037
Program Expense	Program Admin	$113,489	$45,714	$3,208	$113,489	$45,714	$3,208
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	$2,578,861	$1,152,873	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (Intrastate)	$2,495	$561	$142	$7,098	$706	$172
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$341,246	$88,300	$8,639	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$274,734	$60,475	$0	$781,386	$76,086	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$12,201	$2,720	$0	$34,710	$3,422	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,147	$253	$0	$3,263	$319	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$115,790	$25,379	$0	$329,314	$31,930	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$899,658	$232,794	$22,775	$337,043	$38,583	$3,640
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$1,939,873	$501,957	$49,109	$0	$0	$0
T&D Benefits	Reduced distribution costs	$5,885,169	$1,405,236	$173,193	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$287,593	$74,370	$7,332	$408,935	$46,783	$4,448

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 (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$395,403	$93,968	$11,527	$562,285	$59,112	$6,993
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0
Reliability Benefits	Improved generation reliability (Intrastate)	$14,159	$3,717	$309	$40,265	$4,677	$374
Reliability Benefits	Improved generation reliability (ROP)	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$3,886,004	$927,884	$114,360	$11,052,220	$1,167,395	$138,746
GHG and Environmental Benefits	NOx emissions	$60,454	$14,435	$1,779	$171,938	$18,161	$2,158
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$313,210	$74,787	$9,217	$890,804	$94,092	$11,183
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0

A.5 Tariff Rate Program (2023) – Ratepayer 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	$54,379,441	$1,935,925	$19,092,653	$7,223,105	$0	$10,323,998	$3,543,866	$0	$0
Program Expense	Lost Utility Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
Program Expense	Program Admin	$219,989	$3,897	$21,193	$70,975	$0	$13,756	$46,200	$0	$0
Energy Resale Revenue	Energy Resale Revenue	$8,593,935	$305,947	$3,017,336	$1,240,664	$0	$1,773,283	$511,400	$0	$0
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$435,078	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$4,084,466	$0	$77,981	$836,470	$0	$162,115	$0	$0	$0
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)	$881,053	$27,861	$436,763	$123,970	$0	$246,335	$0	$0	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$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)	$3,521	$100	$1,660	$495	$0	$936	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$410,648	$9,656	$183,349	$58,038	$0	$102,304	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$441,531	$24,111	$145,807	$53,759	$0	$35,715	$47,814	$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 (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$533,246	$29,119	$176,094	$64,925	$0	$43,133	$57,746	$0	$0
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$676,026	$12,578	$133,732	$95,490	$0	$76,670	$45,695	$0	$0
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0	$0	$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	$0	$0	$0	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	NOx emissions	$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)	$1,073,226	$38,207	$376,810	$151,618	$0	$216,707	$72,938	$0	$0
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0	$0	$0	$0

A.6 kWh Credit Program (2023) – 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	$7,241,419	$2,603,511	$272,229	$20,084,092	$3,090,715	$270,037
Program Expense	Program Admin	$113,489	$45,714	$3,208	$113,489	$45,714	$3,208
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	$2,578,861	$1,152,873	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (Intrastate)	$2,495	$561	$142	$7,098	$706	$172
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$341,246	$88,300	$8,639	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$274,734	$60,475	$0	$781,386	$76,086	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$12,201	$2,720	$0	$34,710	$3,422	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$1,147	$253	$0	$3,263	$319	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$115,790	$25,379	$0	$329,314	$31,930	$0
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$899,658	$232,794	$22,775	$337,043	$38,583	$3,640
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$1,939,873	$501,957	$49,109	$0	$0	$0
T&D Benefits	Reduced distribution costs	$5,885,169	$1,405,236	$173,193	$0	$0	$0
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$287,593	$74,370	$7,332	$408,935	$46,783	$4,448

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 (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$395,403	$93,968	$11,527	$562,285	$59,112	$6,993
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	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	NOx emissions	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	Reduced RPS Obligation	$555,815	$132,715	$16,357	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$313,210	$74,787	$9,217	$890,804	$94,092	$11,183
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0