Status and Cost & Benefit Analysis of Maine's 2023 Solar Market

Prepared for:

Maine Public Utilities Commission

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April 1, 2024

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1 Executive Summary

In 2023, L.D. 327 "An Act to Provide Maine Ratepayers with Equitable Access to Interconnection of Distributed Generation Resources" was enacted (the Act).[1] The Act directs the Maine Public Utilities Commission (Commission) to provide annually, by January 1st, a summary report of its findings under 35-A M.R.S. § 3473(1) to the Committee on Energy, Utilities and Technology (Committee). The Committee was notified that the report for calendar year 2023 would be submitted at the same time as the report due pursuant to LD 1986 (Public Law 2023, ch. 411).

The Act requires the Commission to monitor the level of solar energy development in Maine in relation to the goals set forth in 35-A M.R.S. § 3474[2], as well as the basic trends in solar energy markets, and the relative costs and benefits from solar energy development, including but not limited to:

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

The Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an in-depth, structured, and comprehensive analysis of Maine's solar energy development for calendar year 2023. This document describes SEA's methodology and quantification of the basic trends in the solar markets in calendar year 2023 and the relative cost and benefits of Maine solar installations for projects during the 2023 calendar year 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 Maine's solar energy development for calendar year 2023. A graphical summary of the analysis provided in Figure 1 and a tabular summary in Table 1. Importantly (and with more detail provided in Section 2.4), unless otherwise stated explicitly, the analysis takes a general societal impact perspective (versus, for example, a ratepayer impact perspective).

[1] See Public Law 2023, ch. 307 http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0148&item=3&snum=131
[2] See https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

Figure 1 –
Maine's Calendar Year 2023 Solar Energy Development Summary Costs & Benefits in Millions of Dollars

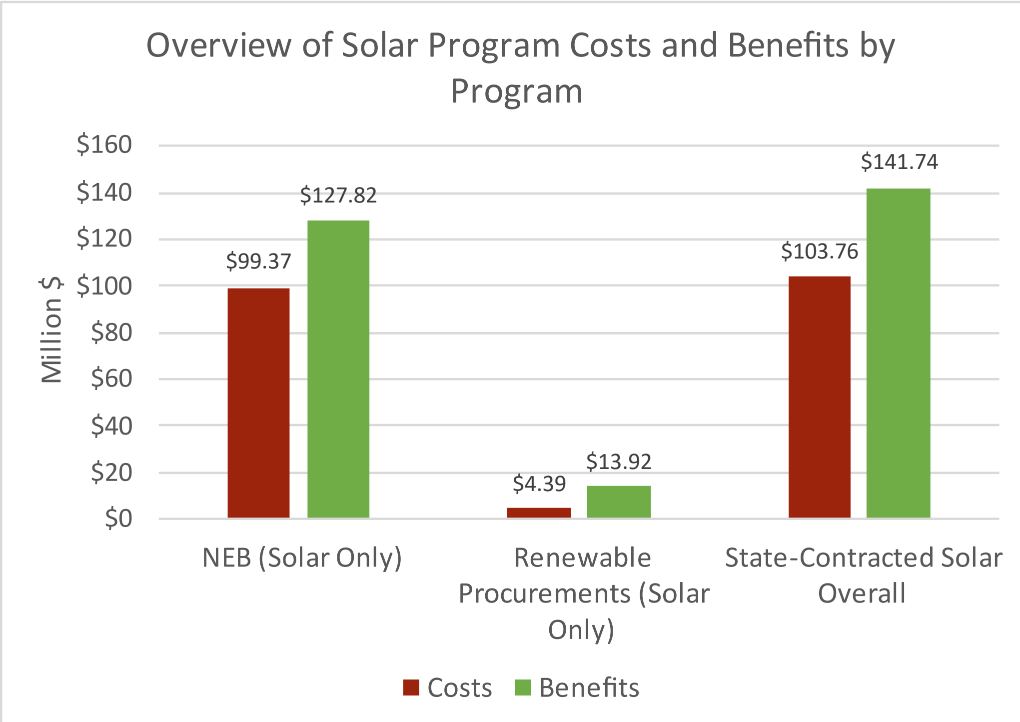


Table 1 -
Maine's Calendar Year 2023 Solar Energy Development Summary Costs & Benefits in Millions of Dollars

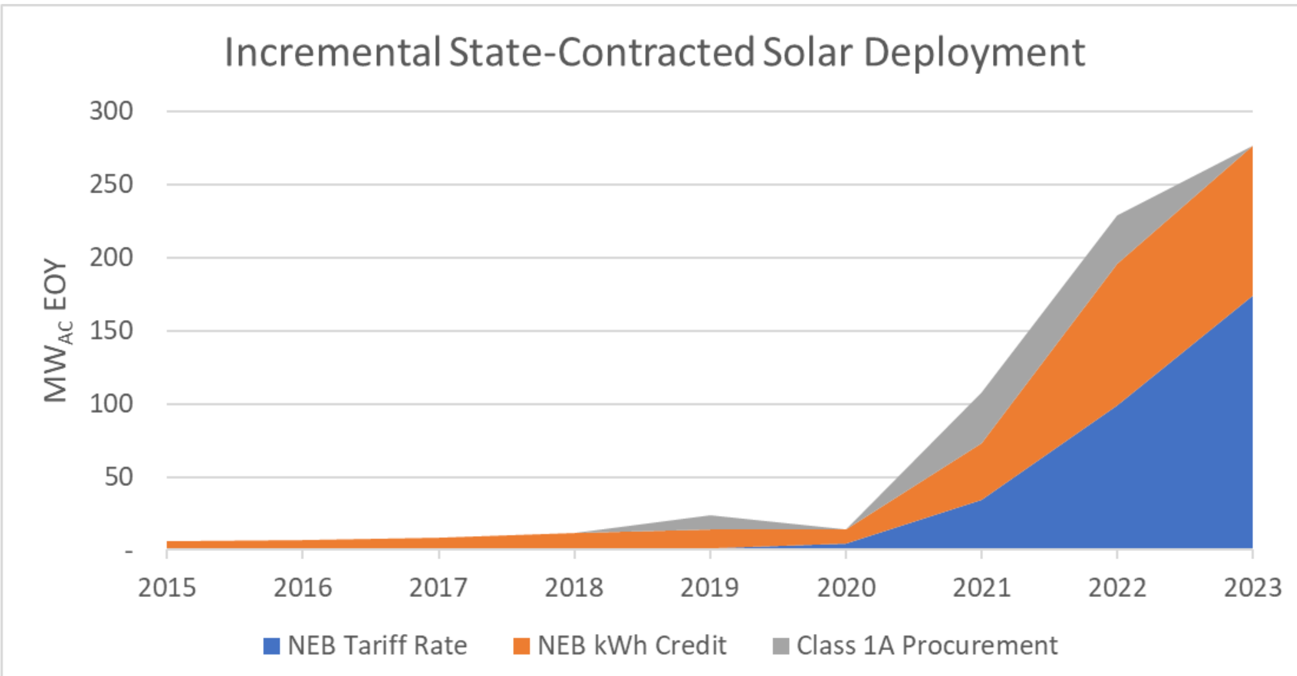
Benefit / Cost Category	Costs	Benefits
Program Expense	$103.76	N/A
RPS Cost Reductions	N/A	$26.37
Energy Resale Revenue	N/A	$13.30
Energy Price Suppression	N/A	$27.72
Capacity Benefits	N/A	$0.80
Transmission and Distribution (T&D) Benefits	N/A	$35.46
GHG and Environmental Benefits	N/A	$38.09
Totals	$103.76	$141.74

SEA calculates that in calendar year 2023 program expenses for solar projects were $103.76 million and the program benefits for solar projects were $141.74 million. Note that these numbers include the cost and expenses for all NEB and renewable procurement solar projects operating in 2023. Thus, the impact of projects as old as 1994 are included in the analysis.

These results were based on recent large increases in the growth of the NEB program and to a lesser extent the renewable procurements (see Figure 2) which ended calendar year 2023 with installed capacity of 618.3 and 77.3 MW_{AC} respectively.

Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a large addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

Figure 2 –
Incremental Maine Solar Development by Calendar Year and Program Type



2 Introduction

In 2023, L.D. 327 "An Act to Provide Maine Ratepayers with Equitable Access to Interconnection of Distributed Generation Resources" was enacted (the Act).[3] The Act directs the Maine Public Utilities Commission (Commission) to provide annually, by January 1st, a summary report of its findings under 35-A M.R.S. § 3473(1) to the Committee on Energy, Utilities and Technology (Committee). The Committee was notified that the report for calendar year 2023 would be submitted at the same time as the report due pursuant to LD 1986 (Public Law 2023, ch. 411).

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

[3] See Public Law 2023, ch. 307 http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=SP0148&item=3&snum=131

- Versant Power - Maine Public District (Versant-MPD).

2.1 LD 327 Reporting Requirements

The Act requires the Commission to monitor the level of solar energy development in Maine in relation to the goals set forth in 35-A M.R.S. § 3474[4], as well as the basic trends in solar energy markets, and the relative costs and benefits from solar energy development, including but not limited to:

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

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

2.2 General Approach & Data Sources

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 analysis. A majority of modeling inputs, if not available through historic data, were taken from the 2021 Avoided Energy Supply Costs in New England (AESC) study. Much of the non-AESC sourced data to support this analysis is collected by the two EDCs and then reported to the 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 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.[5]

[4] See https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html
[5] 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.

- 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.

2.3 Components Included in the Cost / Benefit Analysis

In Table 2 we detail our approach to quantifying the costs and benefits for solar projects for calendar year 2023 for each of the following components organized by the legislatively mandated net benefit categories presented in Section 2.1.

Table 2 –
Adopted Benefits by Legislatively Mandated Benefit Category

Legislatively Mandated Benefit Category	SEA Adopted Benefit Category
Revenue from the sale of renewable energy credits	Revenue from the sale of renewable energy certificates (RECs). We note that this benefit was quantified separately from other benefits, as it is not a benefit transferred to the EDC through contracts for projects operational in 2023.
Societal benefits through avoided greenhouse gas emissions	Societal Benefits from Greenhouse Gas (GHG) Reduction
Reduced electricity prices	SEA quantified the following benefits associated with reduced electricity prices: • Energy Resale Revenue • Energy Demand reduction induced price effects (DRIPE) • Cross-Fuel DRIPE
Avoided or reduced costs associated with electricity capacity requirements	SEA quantified the following benefits associated with recued capacity costs: • Capacity Buyout Revenue • Uncleared Capacity Value • Capacity DRIPE • Reduced Share of Capacity Costs
Avoided or reduced costs associated with environmental compliance requirements	Avoided Environmental Compliance Costs
Avoided or reduced costs associated with portfolio requirements established in section 3210	Avoided/Reduced Costs Associated with RPS Requirements
Avoided or reduced costs associated with renewable energy credit price suppression	REC price suppression
Avoided or reduced costs associated with electricity transmission and distribution (T&D) costs	SEA quantified the following benefits related to reduced T&D costs: • Avoided Transmission Upgrades • Avoided Distribution Upgrades • Avoided Transmission and Distribution Line Losses • T&D plant extensions or upgrades funded by solar project sponsors

2.4 Choosing a Perspective for the Net Benefits Analysis

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

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

Given that the Act requires the consideration of GHG benefits, a general societal impact perspective is justified in that GHG benefits relate to the global impact of emissions, as opposed to impacts specific to Maine or, more specifically, Maine ratepayers.

A Maine-only societal impact perspective also 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 solar project 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 for a subset of our analysis.

3 Detailed Approach to Modeling

3.1 General Issues and Approach

The Act requires an analysis of all program-supported solar development. The two programs supporting development assessed in this analysis are:

- The Net Energy Billing (NEB) Program – The NEB program, in its current form, functions like a combination of a net metering program and a virtual net metering program open to distributed generation 5 MW_{AC} and under; and
- Renewable Procurements – SEA's analysis focused on projects in operation in 2023. A majority of such projects were selected in a 2015 procurement pursuant to 35-A M.R.S. §3210-C and Chapter 316 of the Commission's rules. A single project was selected through the community based renewable energy pilot program pursuant to 35-A M.R.S. §3602 and Chapter 325 of the Commission's rules. These procurements involve competitive bidding for distributed and utility-scale renewable energy. Notably, the procurements do not necessarily require RECs to be included as a product taken title to by the EDC via a resulting Power Purchase Agreement (PPA).

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)[6] 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.
- Several considerations are specific to the NEB program. First, 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. Tariff Rate projects include non-solar projects. To produce results for only solar projects, SEA designated the technology of each project for the purposes of categorizing project-level data by technology. For aggregated program-wide data (e.g., program costs), values were assigned by technology based on the share of production contributed by each technology for each EDCs. For context, the 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.[7]
        - 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.[8]
    - NEB Program generators either can be electrically connected with an EDC customer's load and, from a utility's perspective, behind the EDC customer's revenue meter (i.e., behind-the-meter or BTM) and thus physically offsetting some or all the electricity that would have been consumed from the EDC's distribution grid without the program generator. Alternatively, program generators can be connected not with an EDC customer's load, with the only electrical load being the requirements of the project itself (e.g., project lighting, inverters, communications); this load is called (project) parasitic load. If a NEB project only has parasitic load, it is electrically connected (from the EDC's perspective) in front-of-the-meter (FTM). This detail is relevant here because, while the EDCs meter the total project output for FTM projects (as the parasitic load is typically miniscule compared to gross project electricity production), the EDCs do not meter the production of BTM NEB projects (though they do measure the input and output channels with their metering and are able to calculate net consumption). As a result, our analysis and quantification 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).

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[6] 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.
[7] See 35-A MRSA §3209-B(5)(A), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html
[8] See 35-A MRSA §3209-B(5)(A-1), here: https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3209-B.html

- Renewable procurements generally select larger resources as compared to the NEB program. As such, SEA assumed that such facilities are transmission-connected (as opposed to NEB projects which are assumed to be distribution-connected). This assumption has implications for the calculation of T&D benefits, as discussed in various sections below. In addition, projects may or may not include the sale of RECs to the EDC under PPAs. However, it is SEA's understanding that none of the selected solar projects operational in 2023 included the sale of RECs to the utility. As such, REC revenue was not included in the benefit stack for such projects (but is discussed separately, see Section Quantification of REC Revenue4.2).

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, if not provided directly by the EDCs, were 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 renewable energy 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 renewable energy. 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 EDC, program variant, technology, and commercial operation date is a necessary first step to assessing the total benefits per segment. SEA utilized actual program volumes wherever possible in its analysis. Specific data sources, assumptions, and limitations are discussed below.

- **Production Data:** The approach to quantifying production varied by program variant, discussed below.
  - **Renewable Procurement:** The EDCs provided hourly production data for all solar facilities procured through renewable procurements.
  - **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 EDCs, 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 EDC, 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 EDCs. The remainder net capacity (FTM minus total kWh Credit program capacity) was assumed to be BTM. Renewable Procurement solar project capacities were provided to SEA by the EDCs and verified with public data.

3.4 Revenue from Energy Resale

<u>Overview</u>

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

<u>Data Source</u>

EDC revenue from energy re-sale from Tariff Rate program and renewable procurement 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 procured and in the NEB program do not physically avoid the consumption of energy, in the context of renewable procurement and 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 or procured 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". For Renewable Procurement projects, the EDCs reported that, after commercially reasonable efforts, all projects failed to obtain capacity supply obligations. As such, SEA only focused on revenues from capacity buyout.

The monetization of NEB program capacity represents a potential source of untapped program benefits. However, the challenges associated with successfully bidding DG project capacity into the FCM, and the risk of penalties associated with failure to perform during a scarcity event, have generally dissuaded 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), the capacity of projects still provides benefits to ratepayers in Maine and ISO-NE more broadly via uncleared capacity value. Uncleared capacity value reflects how uncleared project capacity impacts the development of inputs to ISO New England's FCM.[9] 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. Given that this benefit relies on load reductions from the perspective of the transmission system, transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

Data Source:

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

Discussion:

Uncleared capacity utilizes a "phase-in" and "phase-out" schedule that relates the value per MW in any given year to the resource's commercial operation date. The phase in and out is applied to reflect the lag between a resource coming online and the resource's impact influencing ISO-NE study assumptions. Specifically, the 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). Transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

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 of solar.

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.

[9] 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

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. As such, transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

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 solar in Maine. The representative production curve was taken from PVWatts, assuming a facility located in Southern Maine.[10] 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.[11]

To calculate the estimated load reductions on the distribution system during peak periods resulting from DG resources, SEA calculated the share of annual production contributing to reductions in the top 100 peak hours of the year. To do this, SEA utilized a forecast of hourly load (as provided by AESC 2021) as compared to a representative production curve for solar in

[10] 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/

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

Maine. The resulting factor was used to calculate a per MWh value capturing avoided distribution capacity, based on solar production’s coincidence with peak periods.

For both transmission and distribution benefits, SEA considered the use of actual system peaks, as reported by ISO-NE, in 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

<u>Overview</u>

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). Transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

<u>Data Source:</u>

SEA utilized the 2023 RNS charge as provided by ISO-NE.

<u>Discussion:</u>

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

<u>Overview</u>

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. Transmission-connected facilities (which are assumed to include renewable procurement facilities) do not accrue this benefit.

Data Source:

AESC 2021 recommended transmission and distribution line losses were adopted.[12] 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. No renewable procurement projects came online in 2023, so no such costs were provided for these facilities.

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.[13] 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

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

[13] 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.

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 for the NEB program. These shares were applied to production from Versant or kWh Credit program projects, for which hourly data was not available. For renewable procurement projects, actual hourly production data was used for each EDC.

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.

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.[14] 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 REC revenue

Overview:

Projects in both the NEB program and participating through procurements are eligible to generate Maine Class I RECs and are also eligible for most of the regional New England Class I markets (with certain exclusions for out-of-state RECs generated by BTM facilities, though even Maine BTM facilities are eligible to register as Massachusetts Class I RECs). In both the NEB program and the power purchase agreements (PPAs) from procured facilities operational in 2023, RECs are not a product transferred to the EDCs included in the cost of such contracts. As such, RECs represent an additional value stream to program revenue through the sale of such RECs to the regional market.

Data Source:

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

Discussion:

Given that the primary perspective of this analysis is from a societal lens, REC revenue is not accounted for in the benefit stack presented in Section 4. This is because, from the general societal perspective, REC revenue is considered a cost shift from buyers to sellers of RECs, and thus cancels out to zero net benefits (putting aside small transaction costs). Nonetheless, LD 327 requires a quantification of such benefits. To address this requirement, SEA describes estimated revenues in Section 4.3.

3.12 Reduced RPS Requirements

Overview:

RPS costs are a function of the cost of RECs, the RPS requirement (expressed as a percentage of obligated load), and the size of the obligated load (in MWh). 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 change because of BTM load reductions, but the party responsible for fulfilling RPS requirements with such load does

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

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.

3.13 Societal Benefits from Greenhouse Gas Reduction

Overview:

Renewable energy contributes zero-carbon energy to the grid, reducing the greenhouse gas (GHG) intensity of energy consumed. The benefits of these GHG emissions reductions are quantified and considered in this analysis.

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 3.12 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.

3.14 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 and renewable procurement projects to inform the share of annual MWh applicable to each period.

3.15 Modeling Cost Components

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

Renewable Procurements: The cost of procured facilities was provided by the EDCs on an aggregate basis and is a function of each facility's production multiplied by the facility's applicable PPA rate. Given that procured projects are expected to be transmission-connected, SEA added costs associated with the integration of transmission-connected facilities applicable to such projects. Costs per MWh of transmission-connected solar was derived from National Renewable Energy Laboratory (NREL) analysis and was broken out by intrastate and "Rest of Pool" (ROP) impacts.[15]

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.

Administrative Costs:

In addition to per-kWh program expenses, SEA collected total costs associated with the administration of the solar program from the EDCs. CMP provided costs associated with the NEB program only, while Versant provided costs for both renewable procurement and the NEB program. NEB costs were allocated to each program variant based on the share of capacity participating in each program. Overall, administrative costs are insignificant compared to other program expenses.

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[15] See Gorman et al. 2019, here: https://eta-publications.lbl.gov/sites/default/files/td_costs_formatted_final.pdf

4 Results and Findings

4.1 General Societal Perspective

The results of SEA's analysis quantifying the benefits and costs of the Maine solar programs for calendar year 2023 is provided below, with a graphical summary of the analysis provided in Figure 3 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 3 –
Calendar Year 2023 Maine Solar Programs Summary Costs and Benefits

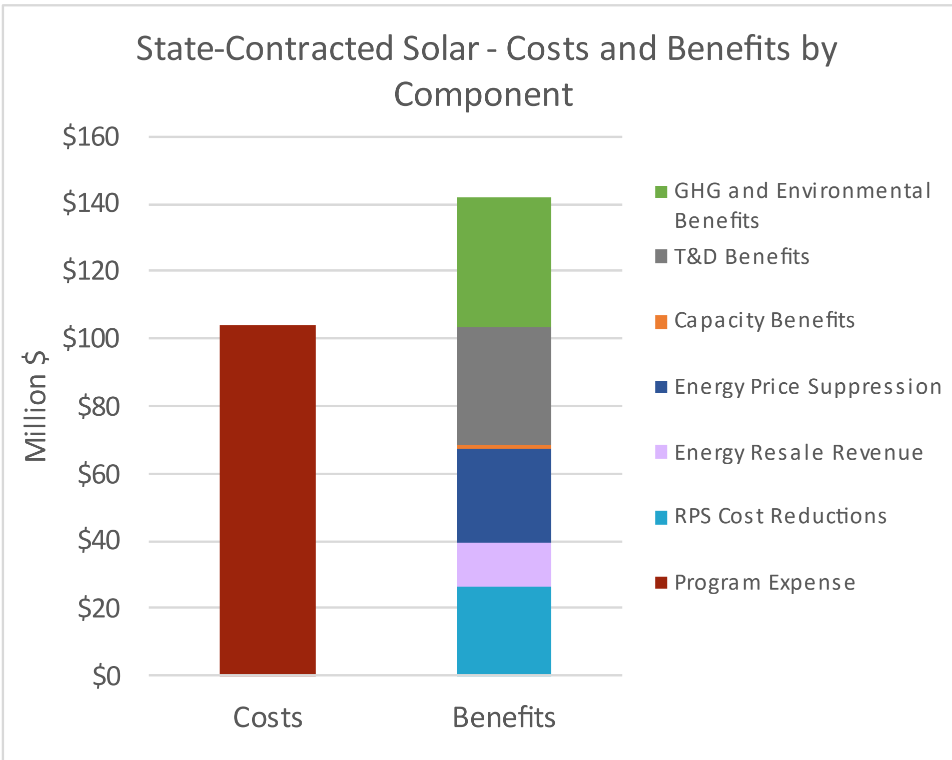


Table 4 -
Calendar Year 2023 Maine Solar Programs Summary Cost and Benefit in Millions of Dollars

Benefit / Cost Category	Costs	Benefits
Program Expense	$103.76	N/A
Renewable Portfolio Standard (RPS) Cost Reductions	N/A	$26.37
Energy Resale Revenue	N/A	$13.30
Energy Price Suppression	N/A	$27.72
Capacity Benefits	N/A	$0.80
T&D Benefits	N/A	$35.46
GHG and Environmental Benefits	N/A	$38.09
Totals	$103.76	$141.74

SEA calculates that the Maine solar programs 2023 calendar year program expenses were $103.76 million, and the program benefits were $141.74 million. Note that the cost and expenses are for all solar projects operating in 2023. Thus, the impact of projects as old as 1994 are included in the analysis.

Figure 4 and Table 5 provide a summary of the Maine solar program costs and benefits by the program described in Section 3.1. Solar projects from both the NEB program and renewable procurements are found to have benefits exceeding costs.

Figure 4 –
2023 Maine Solar Programs Summary Costs and Benefits in Millions of Dollars

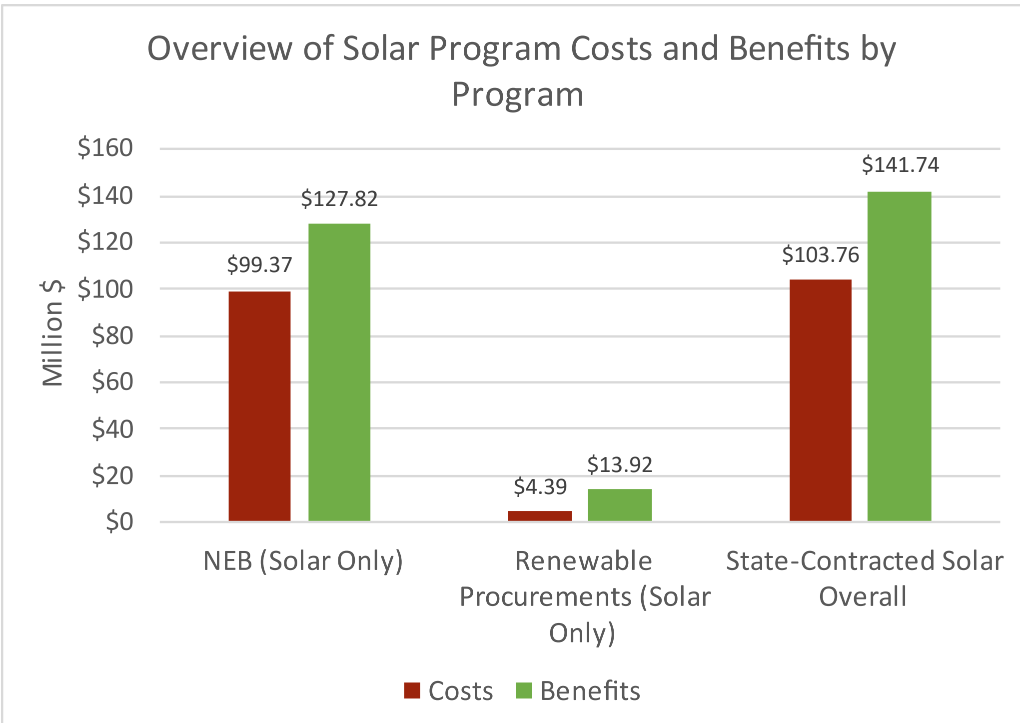


Table 5 -
2023 Maine Solar Programs Summary Costs and Benefits in Millions of Dollars

Program Variant	Costs	Benefits	Benefit-Cost Ratio
NEB Program for Solar Projects	$99.37	$127.82	1.29
Renewable Procurement Solar Projects	$4.39	$13.92	3.17
Total – Solar Projects	$103.76	$141.74	1.37

Next, Figure 5 provides a summary of the Maine solar programs costs and benefits on a million dollar per MW_{AC} basis. The solar only projects for the NEB program have benefits exceeding costs by about a 30% margin, while the solar only renewable procurement projects have benefits exceeding costs by more than a 3:1 margin.

Figure 5 –
2023 Maine Solar Program Summary of Costs and Benefits per MW

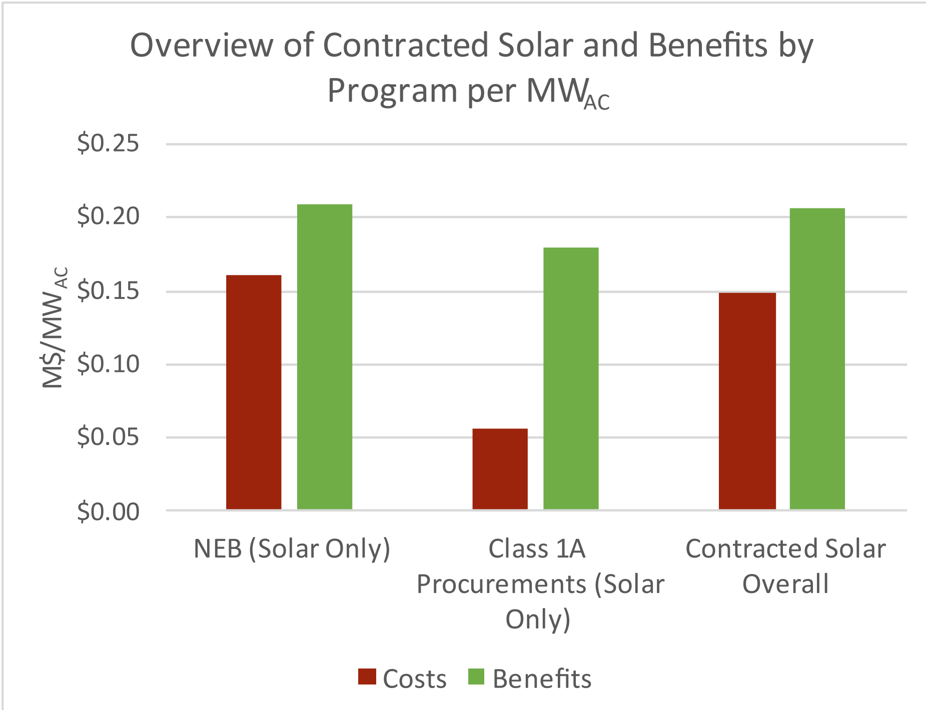


Table 6 provides a breakdown of component categories by total value, whereas Table 7 provides such figures on a million dollar per MW_{AC} basis for apples-to-apples comparisons across program. A discussion of the relative benefits and costs of each program is provided below in approximate order of significance:

- **Program Costs:** The costs for the solar components of the NEB and renewable procurements are (as noted above) a fraction of the total benefits.
- **T&D Benefits**: While T&D benefits are a significant fraction of NEB program benefits (27.6%), the renewable procurements have no T&D benefits. This occurs because we assume the renewable procurement projects are interconnected at the transmission system level, while all the NEB projects are interconnected at the distribution level.
- **GHG and Environmental Benefits / Energy Price Suppression / RPS Cost Reductions**: Benefits that are a function of project production (e.g., GHG benefits, energy price suppression, REC price suppression) are roughly equal per-MW for the renewable procurements vs the NEB program. This is because, although the capacity factor of procured projects is generally higher as compared to NEB projects (which includes smaller BTM projects), multiple procured projects were offline in 2023, which resulted in roughly equal production per MW with solar in the NEB program. Procured solar had a greater share of production during winter peak periods, resulting in marginally higher energy price suppression benefits.
- **Energy Resale Revenue**: The energy resale benefits for the NEB program are much smaller than renewable procurement benefits on a relative basis (to total benefits for each program) because there are no energy resale benefits for the solar production under the NEB kWh Credit program variant.
- **Capacity Benefits:** Capacity Benefits are negligible for the NEB program. Rarely do NEB projects try to qualify for capacity benefits and even fewer successfully qualify. This contrasts to the procured solar projects that typically attempt to qualify for ISO-NE capacity benefits. However, given that the projects assessed in this analysis were

unable to obtain competitive capacity supply obligations (CSOs), benefits are negligible for procured projects as well.

Table 6 -
Summary Comparison of NEB Solar vs. Renewable Procurements (Total $)

Benefit / Cost Category	NEB Solar Program (Millions $ or MW_{AC} w/ % of Total Benefits)	Renewable Procurements (Millions $ or MW_{AC} w/ % of Total Benefits)	Renewable Procurements as % of NEB
MW_{AC}	618.30	77.27	12.5%
Program Expense	$99.37	$4.39	4.4%
T&D Benefits	$35.46	$0.00	0.0%
GHG and Environmental Benefits	$33.91	$4.19	12.3%
Energy Price Suppression	$23.82	$3.90	16.4%
RPS Cost Reductions	$23.49	$2.88	12.3%
Energy Resale Revenue	$10.35	$2.95	28.5%
Capacity Benefits	$0.80	$0.00	0.0%
Total Benefits	$127.82	$13.92	10.9%

Table 7 -
Summary Comparison of NEB Solar vs. Renewable Procurements ($/MW)

Benefit / Cost Category	NEB Solar Program (Millions $/$MW_{AC}$)	Renewable Procurements (Millions $/$MW_{AC}$)	Renewable as % of NEB
Program Expense	$0.161	$0.057	35.4%
T&D Benefits	$0.057	$0.000	0.00%
GHG and Environmental Benefits	$0.055	$0.054	98.8%
Energy Price Suppression	$0.039	$0.050	131.0%
RPS Cost Reductions	$0.038	$0.037	98.2%
Energy Resale Revenue	$0.017	$0.038	228.1%
Capacity Benefits	$0.001	$0.000	0.0%
Total Benefits	$0.207	$0.180	87.1%

4.2 Quantification of REC Revenue

As discussed in Section 3.11, REC revenue is not accounted for in the benefit stack presented in Section 4. This is because, from the general societal perspective, REC revenue is considered a cost shift from buyers to sellers of RECs, and thus cancels out to zero net benefits (putting aside small transaction costs). Nonetheless, the Act requires a quantification of such benefits which is provided below in Table 8.

Table 8 - Estimated REC Revenue by Solar Program

Program	REC Revenue (M$)
NEB (Solar only)	26.66
Renewable Procurements	3.27
Total	29.93

4.3 Sensitivity Analysis of Maine Societal and Ratepayer Impact Perspectives

Per the discussion in Section 2.4, we have conducted the above net benefit analysis from a societal impact perspective (Societal Perspective). In this subsection we provide a sensitivity analysis from the Maine-only societal impact perspective (Maine Perspective) in addition to a ratepayer impact perspective (Ratepayer Perspective). Before doing so it is instructive to compare what net benefit analysis components are included in each perspective as is provided in Table 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 3.12, 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.

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 establishing programs like 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 solar incentive programs.

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.[16] 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.

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

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. The 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
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
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. Overall, the Maine Perspective benefits are slightly less than the solar project program expenses. This is primarily because the Maine Perspective has significantly lower benefits for the RPS Cost Reductions and Energy Price Suppression categories than the Societal Perspective because the Maine Perspective does not include the benefits of the Maine NEB and procurement programs 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). 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 3.12) and the exclusion of benefits relating to GHG or NOx emissions reductions.

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 Solar 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	$103.76	N/A	N/A	N/A	N/A	N/A
RPS Cost Reductions	N/A	$26.37	$3.02	$3.73	11.5%	14.1%
Energy Resale Revenue	N/A	$13.30	$13.30	$13.30	100.0%	100.0%
Energy Price Suppression	N/A	$27.72	$3.70	$3.70	13.3%	13.3%
Capacity Benefits	N/A	$0.80	$0.50	$0.50	63.0%	63.0%
T&D Benefits	N/A	$35.46	$24.12	$24.12	68.0%	68.0%
GHG and Environmental Benefits	N/A	$38.09	$38.09	$0.00	100.0%	0.0%
Totals	$103.76	$141.74	$82.73	$45.34	58.4%	32.0%

5 Maine Solar Energy Development and Basic Solar Energy Market Trends

LD 327 requires the Commission to monitor the level of solar energy development in Maine in relation to the goals set forth in 35-A M.R.S. § 3474,[17] as well as the basic trends in solar energy markets, which state in part the following:

2. State solar energy generation goals. *When encouraging the development of solar energy generation, the State shall pursue cost-effective developments, policies and programs that advance the following goals:*

> *A. Ensuring that solar electricity generation, along with electricity generation from other renewable energy technologies, meaningfully contributes to the generation capacity of the State through increasing private investment in solar capacity in the State;*
>
> *B. Ensuring that the production of thermal energy from solar technologies meaningfully contributes to reducing the State's dependence on imported energy sources;*

[17] https://www.mainelegislature.org/legis/statutes/35-a/title35-Asec3474.html

C. Ensuring that the production of electricity from solar energy meaningfully contributes to mitigating more costly transmission and distribution investments otherwise needed for system reliability;

D. Ensuring that solar energy provides energy that benefits all ratepayers regardless of income level;

E. Increasing the number of businesses and residences using solar technology as an energy resource; and

F. Increasing the State's workforce engaged in the manufacturing and installation of solar technology.

The incremental growth in installed state-contracted / incented solar is provided in provided in Table 11 which ended calendar year 2023 with installed capacity of 618.3 and 77.3 MW_{AC} respectively. Graphically, the recent large incremental increases in the growth of the NEB program and to a lesser extent the renewable procurements are shown in Figure 6 and cumulatively in Figure 7.

Table 11 -
Incremental Growth in Maine Solar MW_{AC} Installed by Year & Program Type

End of Calendar Year	NEB Tariff Rate	NEB kWh Credit	Renewable Procurement
2010	0.0	2.8	0.0
2011	0.0	1.2	0.0
2012	0.0	1.7	0.0
2013	0.0	2.6	0.0
2014	0.0	3.2	0.0
2015	0.0	5.9	0.0
2016	0.0	7.1	0.0
2017	0.0	8.5	0.0
2018	0.0	11.4	0.0
2019	1.1	12.9	9.9
2020	4.1	10.3	0.0
2021	34.6	38.5	34.2
2022	99.1	96.9	33.2
2023	173.5	102.7	0.0
Total	312.5	305.8	77.3

Figure 6 –
Cumulative Maine Solar Development by Calendar Year and Program Type

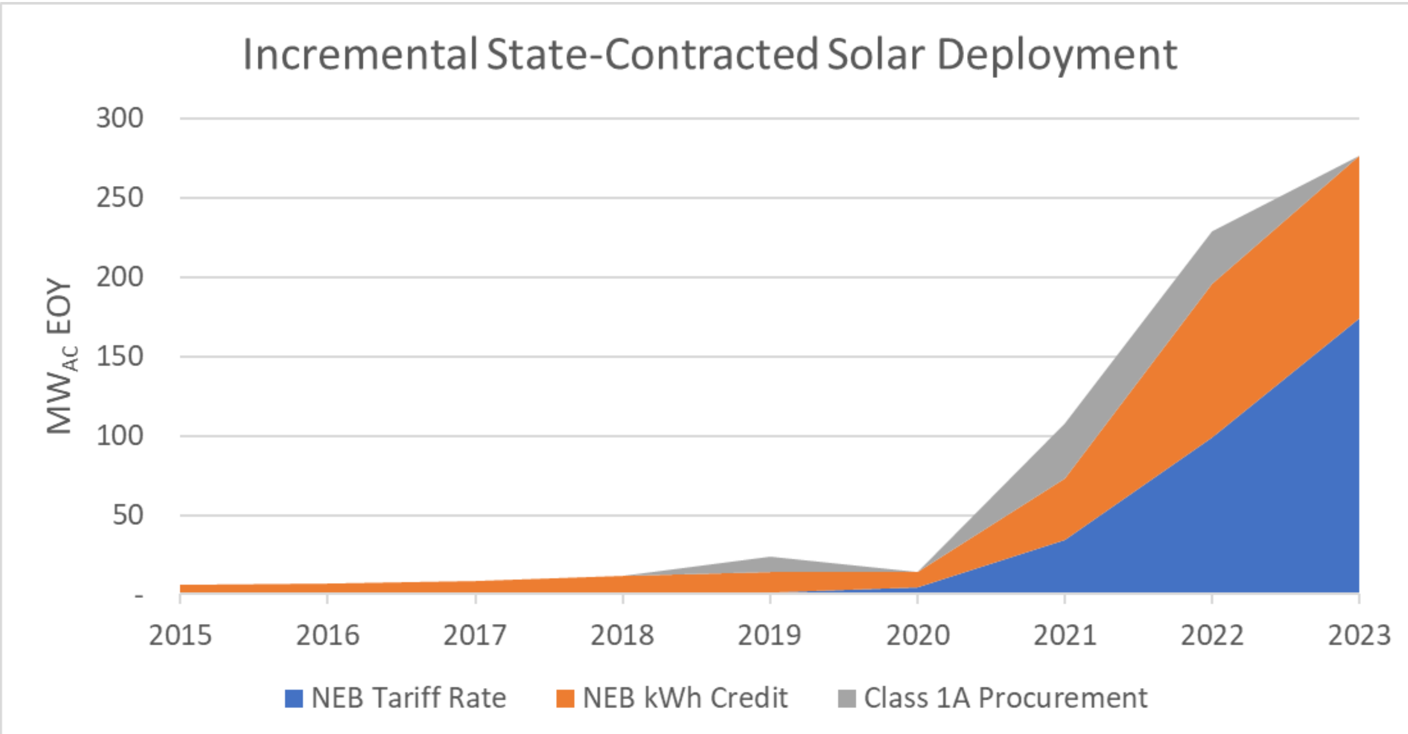
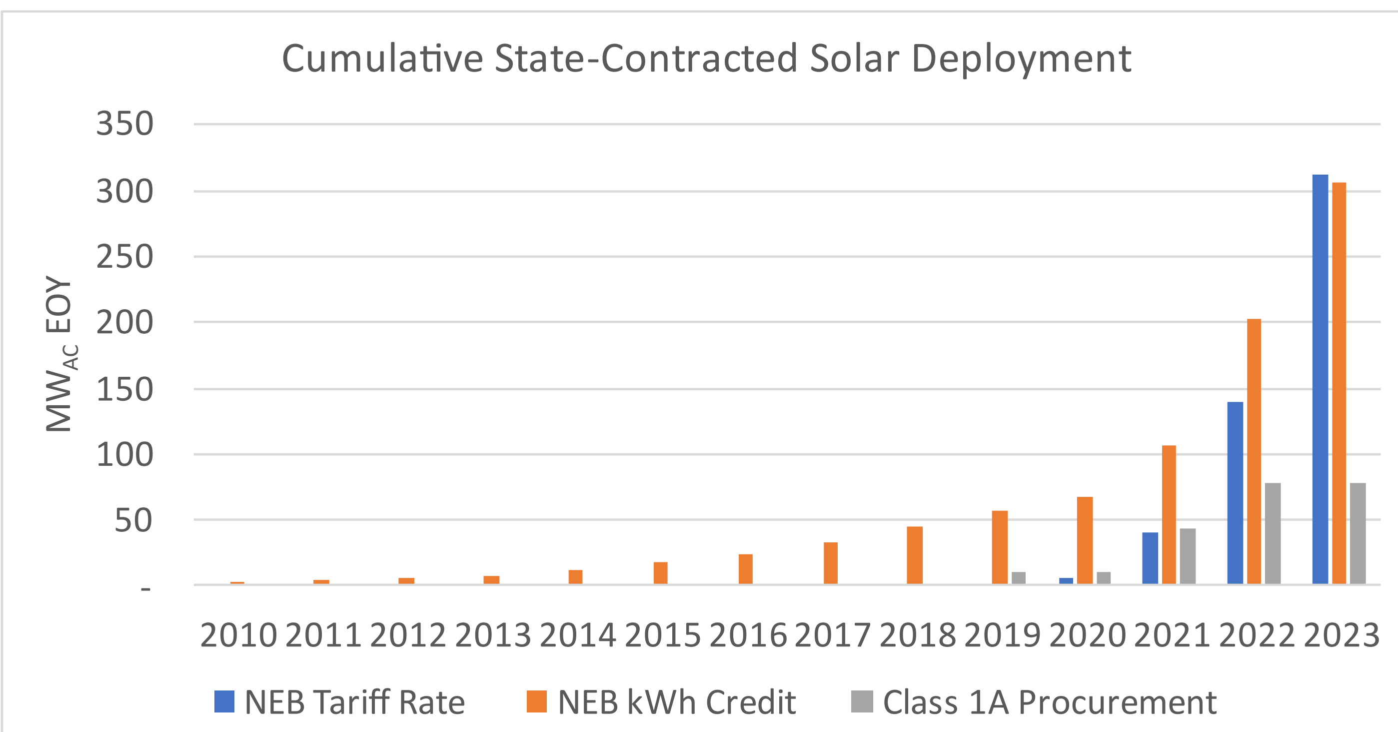


Figure 7 –
Cumulative Maine Solar Development by Calendar Year and Program Type



Likely drivers of the growth included the open-ended structure of the NEB program (i.e., no MW cap) with a large addressable market and favorable economics; this occurred even with the headwinds of a difficult interconnection environment.

As for adherence to Maine's solar energy generation goals, goals A, E and F have been met by the large amount of in-state solar development. Goal D (*Ensuring that solar energy provides energy that benefits all ratepayers regardless of income level*) was more the focus of the Maine analysis, and it appears that the costs slightly outweigh the benefits from that perspective. At this time, it is unclear whether goals B (*Ensuring that the production of thermal energy from solar technologies meaningfully contributes to reducing the State's dependence on imported energy sources*) and C (*Ensuring that the production of electricity from solar energy meaningfully contributes to mitigating more costly transmission and distribution investments otherwise needed for system reliability*) have been met.

A Appendix A – Component-level Results

A.1 Solar Programs (2023) – Societal Perspective

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$2,857,236	$1,018,934	$0	$54,379,441	$7,223,105	$3,543,866
Program Expense	Lost Utility Revenues	$0	$0	$0	$27,325,510	$5,694,226	$542,266
Program Expense	Program Admin	$0	$7,189	$0	$446,968	$162,403	$52,616
Energy Resale Revenue	Energy Resale Revenue	$1,648,637	$1,300,618	$0	$8,593,935	$1,240,664	$511,400
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$6,663,326	$1,989,344	$0
Program Expense	Transmission integration costs (Intrastate)	$31,523	$15,215	$0	$9,593	$1,267	$315
Program Expense	Transmission integration costs (ROP)	$311,835	$150,515	$0	$123,204	$16,277	$4,041
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$9,593	$1,267	$315
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$123,204	$16,277	$4,041
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - energy (Intrastate)	$232,798	$130,319	$0	$1,937,173	$260,531	$0
Energy Price Suppression	Price suppression - energy (ROP)	$1,474,944	$852,272	$0	$12,449,851	$1,670,161	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$46,911	$6,141	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$521,203	$68,230	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$901	$522	$0	$7,931	$1,067	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$13,638	$7,902	$0	$120,069	$16,147	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$98,457	$58,710	$0	$855,751	$115,347	$0

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$640,330	$389,888	$0	$5,629,408	$757,005	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$1,678,231	$325,135	$74,229
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$8,874,265	$1,216,837	$538,676
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced distribution costs	$0	$0	$0	$5,885,169	$1,405,236	$173,193
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$1,229,774	$186,079	$69,526
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$488,640	$73,896	$27,131
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,633,714	$248,569	$64,215
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$2,201,128	$330,820	$83,902
GHG and Environmental Benefits	Non-embedded GHG emissions	$2,773,911	$1,348,100	$0	$28,253,762	$3,976,400	$1,158,043
GHG and Environmental Benefits	NOx emissions	$42,544	$20,670	$0	$439,539	$61,860	$18,015
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$222,811	$107,546	$0	$2,277,241	$320,496	$93,338
RPS Cost Reductions	REC Price Suppression (ROP)	$1,721,985	$831,160	$0	$17,599,534	$2,476,937	$721,356

A.2 Solar Programs (2023) – Maine Perspective

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$2,857,236	$1,018,934	$0	$54,379,441	$7,223,105	$3,543,866
Program Expense	Lost Utility Revenues	$0	$0	$0	$27,325,510	$5,694,226	$542,266
Program Expense	Program Admin	$0	$7,189	$0	$446,968	$162,403	$52,616
Energy Resale Revenue	Energy Resale Revenue	$1,648,637	$1,300,618	$0	$8,593,935	$1,240,664	$511,400
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$6,663,326	$1,989,344	$0
Program Expense	Transmission integration costs (Intrastate)	$31,523	$15,215	$0	$9,593	$1,267	$315
Program Expense	Transmission integration costs (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$9,593	$1,267	$315
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$341,246	$88,300	$8,639
Energy Price Suppression	Price suppression - energy (Intrastate)	$232,798	$130,319	$0	$1,937,173	$260,531	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$46,911	$6,141	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$901	$522	$0	$7,931	$1,067	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$98,457	$58,710	$0	$855,751	$115,347	$0

Component Category	Components	CMP – Procurements	Versant - BHD - Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$1,678,231	$325,135	$74,229
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$1,939,873	$501,957	$49,109
T&D Benefits	Reduced distribution costs	$0	$0	$0	$5,885,169	$1,405,236	$173,193
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$1,229,774	$186,079	$69,526
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,633,714	$248,569	$64,215
T&D Benefits	Reduced T&D losses - energy (ROP)	$0	$0	$0	$0	$0	$0
GHG and Environmental Benefits	Non-embedded GHG emissions	$2,773,911	$1,348,100	$0	$28,253,762	$3,976,400	$1,158,043
GHG and Environmental Benefits	NOx emissions	$42,544	$20,670	$0	$439,539	$61,860	$18,015
RPS Cost Reductions	Reduced RPS Obligation	$0	$0	$0	$0	$0	$0
RPS Cost Reductions	REC Price Suppression (Intrastate)	$222,811	$107,546	$0	$2,277,241	$320,496	$93,338
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0

A.3 Solar Programs (2023) – Ratepayer Perspective

Component Category	Components	CMP – Procurements	Versant - BHD – Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Program Expense	Project PPA Expenses	$2,857,236	$1,018,934	$0	$54,379,441	$7,223,105	$3,543,866
Program Expense	Lost Utility Revenues	$0	$0	$0	$27,325,510	$5,694,226	$542,266
Program Expense	Program Admin	$0	$7,189	$0	$446,968	$162,403	$52,616
Energy Resale Revenue	Energy Resale Revenue	$1,648,637	$1,300,618	$0	$8,593,935	$1,240,664	$511,400
Capacity Benefits	Capacity Buyout Revenue	$0	$0	$0	$0	$0	$0
T&D Benefits	Interconnection upgrade benefits	$0	$0	$0	$6,663,326	$1,989,344	$0
Program Expense	Transmission integration costs (Intrastate)	$31,523	$15,215	$0	$9,593	$1,267	$315
Program Expense	Transmission integration costs (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Uncleared capacity value (Intrastate)	$0	$0	$0	$9,593	$1,267	$315
Capacity Benefits	Uncleared capacity value (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Reduced Share of Capacity Costs	$0	$0	$0	$341,246	$88,300	$8,639
Energy Price Suppression	Price suppression - energy (Intrastate)	$232,798	$130,319	$0	$1,937,173	$260,531	$0
Energy Price Suppression	Price suppression - energy (ROP)	$0	$0	$0	$0	$0	$0
Capacity Benefits	Price suppression - capacity (Intrastate)	$0	$0	$0	$46,911	$6,141	$0
Capacity Benefits	Price suppression - capacity (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas (Intrastate)	$901	$522	$0	$7,931	$1,067	$0
Energy Price Suppression	Price suppression - electric-gas (ROP)	$0	$0	$0	$0	$0	$0
Energy Price Suppression	Price suppression - electric-gas-electric (Intrastate)	$98,457	$58,710	$0	$855,751	$115,347	$0

Component Category	Components	CMP – Procurements	Versant - BHD – Procurements	Versant - MPD - Procurements	CMP - NEB	Versant - BHD - NEB	Versant - MPD - NEB
Energy Price Suppression	Price suppression - electric-gas-electric (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced transmission costs (Intrastate)	$0	$0	$0	$1,678,231	$325,135	$74,229
T&D Benefits	Reduced transmission costs (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced Share of Transmission Costs	$0	$0	$0	$1,939,873	$501,957	$49,109
T&D Benefits	Reduced distribution costs	$0	$0	$0	$5,885,169	$1,405,236	$173,193
T&D Benefits	Reduced T&D losses - capacity (Intrastate)	$0	$0	$0	$1,229,774	$186,079	$69,526
T&D Benefits	Reduced T&D losses - capacity (ROP)	$0	$0	$0	$0	$0	$0
T&D Benefits	Reduced T&D losses - energy (Intrastate)	$0	$0	$0	$1,633,714	$248,569	$64,215
T&D Benefits	Reduced T&D losses - energy (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	$0	$0	$0	$555,815	$132,715	$16,357
RPS Cost Reductions	REC Price Suppression (Intrastate)	$222,811	$107,546	$0	$2,277,241	$320,496	$93,338
RPS Cost Reductions	REC Price Suppression (ROP)	$0	$0	$0	$0	$0	$0