Ratepayer Value Analysis of Maine's Net Energy Billing (NEB) Resources: Load Reducers vs. Generator Assets

Prepared for:

Maine Public Utilities Commission

Sustainable Energy Advantage, LLC

161 Worcester Rd, Suite 503

Framingham, MA 01701

www.seadvantage.com

508.665.5850

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Philip L. Bartlett II
CHAIR

Patrick J. Scully
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COMMISSIONERS

Amy Dumeny
ADMINISTRATIVE DIRECTOR

September 3, 2024

Senator Mark Lawrence, Chair
Representative S. Paige Zeigler, Chair
Members of the Joint Standing Committee on Energy, Utilities and Technology
100 State House Station
Augusta, ME 04333

RE: Report required pursuant to section 7 of Public Law 2023, chapter 307 on the "Ratepayer Value Analysis of Maine's Net Energy Billing (NEB) Resources: Load Reducers vs. Generator Assets"

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

During the First Special Session of the 131st Legislature, Public Law 2023, chapter 307[1] (Act) was enacted and went into effect on October 26, 2023. Section 7, subsection 3 of the Act required the Maine Public Utilities Commission (Commission) to contract with an expert, by April 26, 2024, to evaluate whether treating distributed generation resources that use the tariff rate program under 35-A M.R.S. § 3209-B as load-reducing resources would provide greater value to all ratepayers than the treatment of those resources as wholesale generation resources. The Commission, through a competitive procurement process, contracted with Sustainable Energy Advantage, LLC (SEA) to conduct this evaluation. The Act further requires by September 1, 2024, the Commission to provide to the Committee a copy of expert's report and a description of any actions the Commission recommends based on the findings in the report. The Committee is authorized to report out a bill to the 132nd Legislature in 2025 related to the report.

Based on the attached evaluation by SEA, the Commission has the following recommendations.

First, NEB tariff rate program resources should continue to be treated as generator assets and NEB kWh credit program resources should continue to be treated as load reducers. In short, the Commission does not recommend changing the wholesale market disposition of NEB program resources at this time.

Second, the treatment of NEB tariff rate program resources should be studied again in the future. In particular, the report concluded that NEB tariff rate program resources may have higher theoretical value if instead treated as load reducers. However, this change may increase the risk that Maine ratepayers do not benefit from the higher theoretical value, since this value would accrue through supply rather than delivery rates. The impacts on supply rates are difficult to predict and the Commission has limited authority over supply rates. In future years, as the amount and characteristics of NEB tariff rate program resource generation begin to stabilize, the effects of changing the wholesale market disposition of these resources may become clearer, the risks to Maine ratepayers may be reduced, and the potential benefits

[1] LD 327

may become more predictable. For this reason, we recommend further study of NEB tariff rate program resources again in several years.

Please feel free to contact the Commission if you have any questions related to this report.

Sincerely,

Philip L. Bartlett II, Chairman
Maine Public Utilities Commission

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1 Executive Summary

In response to the legislative directive outlined in P.L. 2023, c. 307, Sec. 7(3), this report provides an analysis of the ratepayer implications of treating distributed generation resources within Maine's Net Energy Billing (NEB) programs[1] as either "wholesale generation resources" (Generator Assets) or "load-reducing resources" (Load Reducers). This analysis, conducted by Sustainable Energy Advantage, LLC (SEA) for the Maine Public Utilities Commission (Commission), evaluates the potential impact on Maine ratepayers and provides actionable recommendations to maximize the value of NEB resources.

Key Program Differences

The NEB programs under review consist of the Tariff Rate Program and the kWh Credit Program, each with distinct structures and implications for how value is generated and distributed among electricity customers:

1. **Tariff Rate Program:** Provides monetary credits to customers based on the production of subscribed resources, with the value of the financial credits tied to retail rates or fixed annual inflators. The program currently operates with resources registered as Settlement-Only Generators in the ISO-NE energy market (thus, Generator Assets), with the associated revenue used to offset program costs.
2. **kWh Credit Program:** Provides kWh credits on participants' electric bills, reducing billed kWh and, consequently, utility and energy supplier revenue. The reduction in utility revenue is offset by charges included in delivery rates. These resources are currently treated as Load Reducers.

Methodology and Data Sources

SEA employed a bottom-up analytical approach, leveraging data from the Avoided Energy Supply Costs (AESC) studies, data from Maine's investor-owned electric distribution companies (EDCs), Central Maine Power and Versant, and other publicly available sources. The analysis characterizes and quantifies values associated with both Generator Asset and Load Reducer treatments across various value streams, including energy, capacity, and transmission impacts. The analysis is informed by discussions with Central Maine Power regarding how NEB resources affect an EDC's load settlement processes.

The analysis reflects key distinctions between front-of-the-meter (FTM) and behind-the-meter (BTM) configurations as well as careful consideration of how value accrues (e.g., through delivery or supply rates) might affect the likelihood that Maine ratepayers realize the full potential value.

Findings and Implications

The analysis reveals that the choice between treating NEB resources as Generator Assets or Load Reducers has significant implications for ratepayer value. Key findings are as follows:

1. **Higher Potential Value from Load Reducers.** The results show that resources, whether in the kWh Credit or Tariff Rate program, generate more potential value when treated as Load Reducers.
2. **Tariff Rate Value Accrual Dynamics Create Risks if Treated as Load Reducers.** Values accrue differently for Tariff Rate resources depending on whether they are treated as Load Reducers (most of the value flows through suppliers) versus Generator Assets (most of the value flows through delivery rates). Furthermore, the specific means by which energy value would be realized should Tariff Rate resources be treated as Load Reducers yields an elevated risk that a portion of benefits may not be immediately passed through to customers.

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[1] The Legislature directed the Commission to conduct the analysis for the NEB Tariff Rate program. The Commission determined that it would be useful and cost-effective for SEA to conduct the analysis for both NEB programs (i.e., including the NEB kWh Credit program).

3. **kWh Credit Value Accrual Similar Across Dispositions.** Unlike the Tariff Rate program, how energy value is realized in the kWh Credit program (i.e., primarily through supply rates) is comparable whether the resource is treated as a Load Reducer or a Generator Asset.
4. **BTM Resources Provide More Value if Resources are Treated as Generator Assets.** While FTM resources can only provide certain values (such as Reduced Share of Transmission Costs) if treated as Load Reducers, energy from BTM resources consumed on-site can provide these benefits regardless even if the resources are treated as Generator Assets.
5. **Interactive Effects Complicate the Analysis.** For the Reduced Share of Transmission Costs value component, the analysis demonstrates that there is a declining marginal benefit of treating more solar resources as Load Reducers. As a result, treating either kWh Credit or Tariff Rate resources as Load Reducers would capture most of this potential benefit. However, treating both kWh Credit and Tariff Rate resources as Load Reducers would provide only a minimal marginal benefit.

<u>Recommendations:</u>

Based on our findings, SEA makes the following recommendations:

1. **Continue to Treat Tariff Rate Resources as Generator Assets.** While our analysis suggests that there may be greater potential value in treating these resources as Load Reducers, the incremental value is offset by the lower certainty that Maine electric customers will fully realize these benefits. Furthermore, because the value accrues through suppliers through the complex resettlement process, it would be challenging for the Commission to precisely assess the extent to which benefits (especially energy benefits, which have the highest value) accrue to customers. The current approach of registering Tariff Rate resources as Settlement-Only Generators (as opposed to a Modeled Generator) is appropriate.
2. **Continue to Treat kWh Credit Resources as Load Reducers.** Because the same tradeoffs in value accrual for Tariff Rate resources do not apply to kWh Credit resources, we recommend selecting the market disposition to maximize potential value. Therefore, we recommend that kWh Credit resources continue to be treated as Load Reducers. We note that the difference in design of the kWh Credit and Tariff Rate programs leads to the different recommendations for the two programs.
3. **Monitor FCM Deliverability Constraints.** The current inability to enroll NEB resource north of the Surowiec – South interface in the FCM limits the volume of NEB resources that could participate in the FCM. However, should the interface have sufficient capacity to accommodate NEB resources in the future, enrollment of Tariff Rate resources in the FCM should be considered. Our examination of the relevant value components indicates that, for resources that are already participating in wholesale energy markets, no values are diminished or lost by also taking on a capacity supply obligation (CSO). Of course, any future evaluation of FCM participation should also consider expectations for solar PV capacity accreditation values (and trends in ISO-NE capacity scarcity conditions and their implications for potential Pay-for-Performance penalties) before making a final determination with respect to FCM participation. Because we find that kWh Resources should remain Load Reducers, any future FCM consideration should be specific to Tariff Rate resources.
4. **Consider Re-Evaluating Market Disposition in Three Years.** We expect the risk for some values to be captured by suppliers and not passed on to customers to decrease over time (due to competitive pressures and additional NEB resources no longer coming online). Furthermore, the implementation of FCM reforms and additional information on transfer limits at Maine interfaces may provide greater clarity on the value of monetizing the capacity value of NEB resources. Therefore, we recommend that the wholesale disposition of NEB resources be re-evaluated in approximately three years. This analysis should focus on (i) whether Tariff Rate resources should continue to be treated as Generator Assets and (ii) if so, whether their capacity should be monetized.

2 Introduction & Background

In the 2023 legislative session, P.L. 2023, c. 307 "An Act to Provide Maine Ratepayers with Equitable Access to Interconnection of Distributed Generation Resources" was enacted (the Act). In part, the Act directed the Maine Public Utilities Commission (Commission) to contract with an expert to provide a report to the legislature by September 1, 2024, evaluating whether it is more beneficial to ratepayers to treat distributed generation (DG) resources in the Net Energy Billing (NEB) Tariff Rate Program as "wholesale generation resources" (i.e., Generator Assets), which is the current practice, or as "load-reducing resources" (i.e., Load Reducers). Throughout, we refer to the treatment of a resource as a Load Reducer or Generator Asset as its wholesale market disposition.

Accordingly, the Commission has engaged Sustainable Energy Advantage, LLC (SEA) for consulting services to conduct an analysis to evaluate the value to ratepayers for *both* the NEB Tariff Rate and kWh Credit Programs, separately[2], depending on whether the DG resources (specifically, the solar photovoltaic (PV) resources) are treated as Generator Assets or Load Reducers. This document identifies where changing the wholesale market disposition of NEB resources would lead to differences in value generated and how those values accrue, describes SEA's methodology and quantification of these differential values, and provides recommendations on how to maximize the value of NEB resources to Maine ratepayers.

Note that this analysis is not a benefit-cost analysis of the NEB program, as it focuses exclusively on the implications of NEB resources' wholesale market disposition. We therefore do not evaluate all of the benefits of NEB resources, as some benefits (e.g., avoided greenhouse gas emissions, reduced line losses, etc.) are unaffected by the participation of NEB resources in wholesale markets. Similarly, we do not quantify the total impact of the NEB program on Standard Offer Service (SOS) pricing, as we only evaluate value components where the wholesale market disposition of the NEB resource leads to different impacts on SOS.

2.1 NEB Programs: kWh Credit & Tariff Rate

While the Act specifically called for an evaluation of the wholesale market disposition of resources in the Tariff Rate program, our analysis also considers the kWh Credit program. The distinct design of these two programs yields distinctions in how we evaluate them and the resulting recommendations. An overview of each program variant and discussion of key differences is provided below.

Tariff Rate Program:

The Tariff Rate variant provides monetary credits to participating customers based on facility production of the resource to which they are subscribed. The specific rate is dependent on whether a resource 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). Because the Tariff Rate program centers on what is primarily a *financial* transaction (that is, production converted into dollar-denominated bill credits every month), some of the wholesale market disposition implications are simpler than those for the kWh Credit program. As designed, incremental costs attributable to the Tariff Rate Program are recovered exclusively through delivery rates; there is no direct impact on competitive energy providers or SOS providers (or more generally "suppliers" for this report) or the cost of SOS. Resources enrolled in the Tariff Rate program are front-of-the-meter (FTM) installations.

[2] The Commission determined that it would be useful and cost-effective for SEA to conduct the analysis for both NEB Programs, rather than only the Tariff Rate Program.

For the purposes of this analysis, SEA did not distinguish between the two Tariff Rate compensation variants as there is no difference in how value accrues to ratepayers, only the amount of compensation.

kWh Credit Program:

The kWh Credit program variant provides kWh credits on the electric distribution company (EDC) bills of NEB participants. As a result, billed kWhs offset by kWh credits reduce revenues received by the EDCs (as well as suppliers). The lost revenue represents a cost that must be recovered from ratepayers. Unlike the Tariff Rate program, the design of the kWh Credit program reduces the kWhs billed to retail customers (i.e., via the allocation of kWh credits) resulting in changes to suppliers' wholesale market obligations. Accordingly, changes in the market disposition of kWh Credit resources lead to more complex impacts.

2.2 Generator Asset vs. Load Reducer

As discussed throughout this document, the same resource can yield different values (or the same value but realized through a different means of value accrual) depending on whether it participates in wholesale markets as a Generator Asset or acts as a Load Reducer.

Generator Assets are a category of resources that offer energy, capacity, and/or ancillary services into ISO-NE wholesale markets. There are several "participation models" through which resources can offer services into ISO-NE wholesale markets. While resources with different participation models are treated differently in some respects (e.g., in ISO-NE's application of Pay-for-Performance rules), they are treated equally in other respects (e.g., in market settlement). We provide an overview of potential participation models, with a focus on those most applicable to NEB resources, in Appendix A. However, for the purposes of our quantitative modeling, we assume that all Generator Assets are participating as Non-Modeled Assets, specifically Settlement-Only Generators.

Load Reducers, in contrast, are a category of resources defined by *not* offering services into any of the ISO-NE wholesale markets. Load Reducers, which typically include small (less than 5 MW) solar PV installations, accrue value in wholesale markets by reducing a load entity's obligation to purchase energy, capacity, and/or ancillary services, rather than by selling those services.

Additionally, given the limited opportunities for standalone solar to participate in ancillary markets, this analysis focuses on energy and capacity markets. Resources that take on a CSO in the FCM are obligated to participate in energy markets, even if only as a price-taker.

Altogether, this yields three viable market participation options for NEB resources:

1. **Load Reducer** – participates in neither energy nor capacity markets. This is the current treatment of kWh Credit resources.
2. **Capacity & Energy Asset** – participates in both the energy and capacity markets.
3. **Energy-Only Asset** – participates in the energy market but not the capacity market. This is the current treatment of Tariff Rate resources.

Unless otherwise specified, any references to a Generator Asset in this report refers collectively to the second and third options listed above – that is, participating in *any* wholesale market makes a resource a Generator Asset.

Each of these options yields a different value and means of value accrual for NEB resources, as demonstrated in Table 1. Additional details on each of the value components are included in Section 3.5. At a high level, resources treated as Load Reducers can provide the greatest number of value components.

Table 1 - Market Disposition Impact Summary

	Load Reducer	Capacity & Energy Asset	Energy-Only Asset
Energy Value	Yes – accrual different kWh Credit vs. Tariff Rate	Yes – accrual different kWh Credit vs. Tariff Rate	Yes – accrual different kWh Credit vs. Tariff Rate
Reduced Share of Capacity Costs	Yes – accrues to all ME and ROP suppliers	No value (except for BTM generation offsetting on-site load during ISO-NE's annual peak hour)	No value
Reduced Share of Transmission Costs	Yes – accrues to delivery customers	No value (except for BTM generation offsetting on-site load during ME's monthly peak hour)	No value
Capacity Price Suppression	Yes – accrues to all ME and ROP suppliers	Yes – accrues to all ME and ROP suppliers	No value
Capacity Value	Yes – benefit from reduced installed capacity requirement accrues to all ME and ROP[3] suppliers[4]	Yes – monetized value accrues to delivery customers	No value
Socialization of PV Load Shape	Only applies to kWh Credit – shift from suppliers of non-large competitive supply customers to SOS suppliers	No shift	No shift

3 Detailed Approach to Modeling

3.1 General Issues and Approach

SEA, in coordination with Commission Staff, conducted a detailed, bottom-up analysis designed to determine which wholesale market disposition for NEB resources would result in the greatest ratepayer value, for both the NEB Tariff Rate and kWh Credit programs, separately. Our approach was driven by available data and determinations as to the level of necessary level of granularity. Many of the assumptions related to modeled values are derived from the AESC study, which

[3] ROP, or "Rest of Pool," refers to all ISO-NE load customers outside of Maine.

[4] In this report, when referring to values that affect the cost of power supply (as opposed to delivery charges), we refer to the value flowing to suppliers (as opposed to flowing directly to supply customers or through supply rates). This distinction reflects the possibility that a portion of value realized by suppliers may not be passed on to customers, as discussed in Section 3.2.

is jointly commissioned and overseen by utilities, energy efficiency program administrators, regulators, and state energy offices representing each of the six New England States. Much of the non-AESC sourced data to support this analysis is collected by Maine's two investor-owned EDCs, Central Maine Power Company (CMP) and Versant Power (Versant), and then reported to the Commission in publicly available formats. Discussions with CMP informed SEA's understanding of how NEB resources affect an EDC's load settlement processes, which we discuss in Appendix C.

The analysis is bottom-up in the sense that it evaluates the value components relevant to each combination of the following variables: NEB program variant, metering type (behind-the-meter (BTM) vs. FTM), energy usage (on-site vs. exported), EDC, asset type, and vintage year. Results for each permutation are then rolled up on a statewide basis to present aggregate results for the options explored in this analysis. The analysis only considers components that might differ based on wholesale market disposition, as certain benefits (e.g., avoided greenhouse gas emissions) would not vary across the options assessed. As such, this analysis does not attempt to quantity the aggregate benefits and costs of the NEB program, but rather the relative benefits and costs of different program options.

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

- The NEB program is largely dominated by solar PV resources (approximately 793 MW) but contains a small amount (approximately 44 MW) of non-solar resources. 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 this analysis.
- NEB resources 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., BTM) and thus physically offset some or all the electricity that would have been consumed from the EDC's distribution grid without the program generator. Alternatively, NEB resources can be connected separate from an EDC customer's load, with the only electrical load being the requirements of the resource itself (e.g., lighting, inverters, communications); this load is called parasitic load. If an NEB resource only has parasitic load, it is electrically connected (from the EDC's perspective) in front of the meter (FTM). Certain benefit components have differential treatment of energy consumed on-site (only applicable to a portion of BTM resources' production) or energy exported (applicable to both BTM and FTM resources). As a result, our analysis and quantification approach differ for FTM versus BTM NEB resources, as described in greater detail in Section 3.3.
- Our analysis presents results on a statewide basis, not by EDC. While different impacts might have different relative impacts for different EDCs, we expect that these differences would be small. Our analysis excludes consideration of NMISA dynamics, instead of focusing on the portion of the state within ISO-NE.

3.1.1 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:** As this analysis is forward looking, SEA relied on historical production data to estimate future production for both the Tariff Rate and kWh Credit program variants. Actual production data from 2023 for Tariff Rate resources was used to benchmark production estimates with respect to the capacity factor assumed in projections of future production. Production estimates assumed an 18% alternating current (AC) capacity factor, an annual production degradation rate of 1%, and a de-rate to year-one production of 60% to reflect that resources typically achieve commercial operation in the second half of the year. SEA received actual 2023 production data for kWh Credit program exports from both utilities which was used to inform the assumed ratio of kWh exported versus the kWh utilized on-site under the kWh Credit program variant.

- **Capacity Data:** SEA collected data on resource capacities by utility, technology, and commercial operation dates from the EDC's monthly NEB reports in Docket 2020-00199, as of December 31, 2023. The reports do not designate the metering arrangement for each resource. As such, SEA imputed the capacity of FTM facilities in the kWh Credit program based on the exported kWh reported by both utilities, after accounting for assumed exports from BTM facilities. The remaining net capacity was assumed to be BTM. For installations in 2024 through 2026, SEA relied on capacity forecasts developed through SEA's proprietary Renewable Energy Market Outlook (REMO) service. Total capacity forecasted was disaggregated by utility, program variant, and metering configuration based on historic ratios.

3.1.2 AESC Inputs

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

For the purposes of this analysis, SEA utilized the "All-in [Distributed Energy Resources]" (i.e., Counterfactual #5) sensitivity, as it most closely approximates a future the expected trajectory for energy efficiency, distributed energy resources, and electrification. According to the AESC 2024, the sensitivity models a "future in which program administrators continue to install new energy efficiency, active demand management, and building electrification resources."

AESC 2024 inputs used in this analysis were translated to nominal dollars assuming a discount rate of 2.25% (the default assumption in AESC 2024). The measure life, defined as the duration of the resource life during which unmonetized capacity and capacity price suppression benefits accrue, was set at 20 years. This duration aligns with the NEB program life of 20 years. SEA also utilized data from AESC 2021 to derive the price suppression benefits for resources with a commercial operation date prior to 2024.

3.2 Value Realization

The means through which value is realized, and who realizes it, is a crucial factor in our analysis. This analysis focuses solely on value components with a financial impact, rather than societal impacts. Some values are directly monetized, such as when EDCs receive payments for energy produced by Tariff Rate resources. Other components have indirect financial impacts, meaning they result in dollar value benefits but only as a secondary effect. For example, the reduction in the FCM installed capacity requirement (ICR) associated with Load Reducers results in a real financial benefit to ratepayers (i.e., reduced capacity costs as a component of supply charges) but is not associated with a specific exchange of money. Consequently, for many of these indirect impacts, it is not possible to identify the exact value created, even *ex post*. While this does not diminish the validity of the benefits, it does make it challenging to verify the exact value.

3.2.1 Recipient Categories

Value components included in this analysis flow either through delivery rates or through suppliers. This, in turn, may affect whether all of the value created by NEB resources is realized by customers or not. While the Commission directly reviews and approves delivery rates, it does not have jurisdiction over the rates charged by suppliers. The Commission's role in conducting solicitations for standard offer providers (SOPs) gives the Commission some insight and influence into SOS rates, but it lacks direct control over SOS rates. It has effectively no influence on competitive supply rates. Given the above, we assume that all values that flow through delivery rates are fully realized by customers. Any value that flows through supply, however, may be at risk of suppliers capturing some portion of that value and not passing it on to customers.

This creates a potential disconnect between the values modeled in our analysis that represent total potential benefit and the corresponding benefits that may be realized by customers. The risk of these values not being passed through to customers, or being delayed, varies depending on the specific value component, though we emphasize that a given value component is at greater risk of capture in the nearer term than the longer term. For example, Load Reducers can lower the ICAP tags of customers and, in turn, their suppliers. When suppliers set competitive supply rates or develop SOS bids, they rely on ICAP tag data from the EDC to inform their pricing. As a result, the impact of NEB resources in reducing ICAP tags does not require changes in their price-setting process, making it more likely that these benefits will be passed on to customers.

However, in other cases, suppliers may retain more value. For instance, if Tariff Rate resources were treated as Load Reducers, suppliers would benefit from a reduction in their wholesale load obligation, even though the kWh recorded on customer meters and reflected on bills remain unchanged (this situation is further explained in Section 4.4). This dynamic, though similar to that of the existing kWh Program, would require suppliers to update their pricing models to better account for the difference between metered kWh and wholesale load obligation caused by Load Reducers. While competitive forces would likely eventually lead to these benefits being passed on to customers, there could be a significant delay, and the full value might never be realized by customers. Additionally, it would be challenging for the Commission or other parties to verify whether the full savings were passed on to consumers.

Accordingly, we define and rank four value recipient categories from most to least likely to immediately and fully realize potential benefits, as follows:

- **Delivery (or T&D) Customers.** This category represents all Maine ratepayers. [5] The Commission has wide latitude to request relevant data, review, and approve rates. For example, the Commission reviews EDC filings detailing how NEB costs are recovered, including consideration of how energy revenues are netted out of amounts to be recovered. We therefore assume any value that flows through delivery rates will be fully realized by customers.
- **Suppliers Serving Standard Offer Service (SOS) Customers.** This category is mutually exclusive of the competitive supply customer categories. Because the Commission structures the contracts, designs the solicitation, and ultimately selects suppliers, it may have some ability to increase the probability that savings are realized by customers. Still, because individual suppliers are ultimately responsible for developing their bids, the Commission cannot directly enforce how values do or do not accrue to customers. We also assume that all customers that either have an NEB resource behind their meter or receive kWh credits are SOS customers due to the costs to suppliers

[5] Several of the components modeled have financial impacts that accrue to other New England ratepayers. We model these benefits that accrue to ratepayers outside of Maine, but only present results that include these out of state benefits in Appendix F. Providing some consideration of these benefits is worthwhile: other New England states have programs and policies that provide similar benefits to Maine's ratepayers. Were each New England state to ignore benefits that accrue to other New England states, the region might underinvest in clean energy policies, leading to the region being worse off.

associated with serving these customers.[6] This assumption means that any value components that would affect a supplier serving NEB customers is applied specifically to SOS customers.

- **Suppliers Serving Large Competitive Supply Customers.** This category, which includes all customers taking service under an industrial delivery service rate,[7] is mutually exclusive of the SOS and non-large competitive supply customer categories. While the Commission plays effectively no role in setting these rates, large competitive supply customers may have energy managers or other resources that allow them to negotiate with suppliers, which might include incorporating provisions in their contracts that automatically pass through certain charges (and, as a result, savings, e.g., associated with reductions to the customer's ICAP tag). We assume that all large customers are served by competitive suppliers.[8]
- **Suppliers Serving Non-Large Competitive Supply Customers.** This category, which includes all competitive supply customers *not* taking service under an industrial delivery service rate, is mutually exclusive of the SOS and large competitive supply customer categories. The Commission has effectively no role in setting supply rates for these customers, and these customers are unlikely to be sufficiently sophisticated or to have the scale needed to negotiate with suppliers.

The analysis uses Maine's Migration Statistics to establish the relative portions of load associated with the three types of supply customers listed above.

We further consider the potential for value to be captured in our discussion of results and recommendations.

3.3 Front-of-the-Meter vs. Behind-the-Meter

There are several value streams where our modeling must consider distinctions between BTM and FTM resources. These are specific to the kWh Credit program analysis, as the Tariff Rate program has no BTM systems.

In our review, the primary BTM versus FTM distinction is based on energy generated by BTM resources that is consumed on site versus energy that is exported to the grid on a real time basis (as opposed to netted over the course of a month). This differentiation is applicable to Capacity Value, Capacity Price Suppression, and Reduced Share of Capacity Costs. For Reduced Share of Capacity costs, energy produced by BTM resources consumed on-site during the annual system coincident peak accrues differently than BTM energy exported, or energy produced by FTM resources. For Capacity Value, resources that do not take on a CSO, but do participate in wholesale energy markets cannot influence (reduce) the ICR. An exception to this is energy from BTM resources consumed on-site, which, even if the resource is participating in energy markets, can contribute to a lower ICR. A similar dynamic applies to Capacity Price Suppression and Reduced Share of Transmission Costs.

More information on the value streams described above is provided in the relevant portions of Section 3.5.

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6 See, for example, the report "Reducing the Cost of Solar in Maine" prepared by London Economics International for the Maine Office of Public Advocate. Note that the costs are primarily associated with serving kWh Credit customers, not Tariff Rate. Most of the value components where we differentiate between different classes of supply customer, however, are associated with modeling of the kWh Credit program, not the Tariff Rate program.

7 Differentiating competitive supply customers based on their delivery service rate classes is necessary because, as described in Appendix C, the load settlement process treats large and non-large customers differently.

8 According to the most recent Migration Statistics, 96% of large customer load is served by competitive suppliers. Assuming all large-customer load is served by competitive suppliers simplifies the presentation of results without noticeably impacting results or conclusions.

Data on how much energy from BTM resources is consumed on-site during specific periods (e.g., annual system peak hour) is not directly available. To produce estimates of how much energy was consumed on-site on an hourly basis, SEA used solar PV production profiles generated in PVWatts and blended load profiles derived from CMP load profiles.

3.4 Alternative NEB Program Designs

To model the Tariff Rate and kWh Credit programs with resources with market dispositions different from how they are currently implemented requires describing how the programs would function under a different design. These alternative designs are laid out below.

3.4.1 Tariff Rate - Current and Alternative Approaches

As currently implemented, EDCs enroll Tariff Rate resources as Settlement-Only Generators in the ISO-NE energy market. While the EDCs own the rights to capacity value, there is an option for resources to purchase these rights from the EDCs, although our understanding is that no resource has exercised this right and has successfully cleared in the FCM. The EDCs do not monetize the capacity value of any NEB resource. The revenue from the sale of energy generated by Tariff Rate resources is used to offset a portion of the cost of the Tariff Rate program recovered from ratepayers. Thus, the program's direct costs and the benefits of the energy revenue are both realized through delivery rates.

Analysis for this report requires understanding how these flows would change were Tariff Rate resources treated as Load Reducers (participating in neither capacity nor energy markets) as well as if resources were treated as full Generator Assets (participating in both capacity and energy markets). To that end, next we describe how the program would function and how energy (as opposed to capacity) values would flow if Tariff Rate resources were treated as Load Reducers, that is, if their energy not sold into the wholesale market.

While there would be significant changes if Tariff Rate resources were treated as Load Reducers, these changes would not be immediately apparent from the perspective of either suppliers or customers. All Tariff Rate resources are FTM, so there is (ignoring insignificant parasitic load) no on-site load to offset. Further, because the Tariff Rate program hinges on a *dollar-denominated* credit that is used to reduce the dollars charged to customers on their EDC bills, it does not impact either the supplier's wholesale obligations or the payments it receives for the load it serves; that is, treating Tariff Rate resources as Load Reducers would not directly change payments to or the obligations of suppliers. Thus, there would be no direct impact on Tariff Rate customers or suppliers.

Under the Load Reducer scenario, the energy value of the Tariff Rate resources would be realized through accounting for unaccounted for energy (UFE), as described in Appendix C. Unlike the kWh Credit program, under the Tariff Rate program there would be no rationale for an EDC to assign the kWh value of NEB Load Reducers to specific suppliers serving NEB credit recipients through the resettlement process because, for the Tariff Rate program, suppliers do not see a reduction in revenue received from customers receiving credits. Instead, all the energy generated by Tariff Rate resources would be allocated to suppliers serving non-Large customers (including both SOS and competitive supply customers) as UFE through the resettlement process (subject to the potential for supplier value capture, as discussed in Sections 3.2.1 and 4.4).

This yields two substantial changes if Tariff Rate resources were to not sell their energy into the wholesale market:

1. The value of the energy would flow through the supply component of bills, instead of delivery rates.
2. The value of the energy would benefit all non-large customers, as opposed to all customers.

Currently, the EDCs do not bid Tariff Rate resources into the FCM. If they were bid into the FCM, leading to the resources participating in both energy and capacity markets, the FCM revenue from these resources would be used in the same way as the energy revenue, that is, netted out of NEB costs recovered through delivery rates. The tradeoff would be a commensurate increase in the EDCs' aggregate capacity costs, which flow through retail supply rates. Thus, the impact would be to take a benefit currently flowing through retail suppliers, and shift this to being realized through delivery rates. We address the magnitude of the benefits resulting from these different options (reduced capacity costs vs. FCM revenue) in our Results section.

3.4.2 kWh Credit - Current and Alternative Approaches

Resources in the kWh Credit program are currently treated as Load Reducers. Through the resettlement process, the wholesale load obligation of suppliers serving kWh Credit recipients is reduced, helping to offset some of the reduction in revenue suppliers receive from customers.

If energy from a kWh Credit resource were sold into energy markets, the suppliers' wholesale obligations would not be reduced in an amount based on kWh Credits received by their customers, despite the supplier receiving reduced revenue. Given this, there are multiple potential options for how the kWh Credit program with resources selling energy into the wholesale market could be implemented, including:

1. **Energy revenue (and, if applicable, capacity revenue) could be used to reduce delivery rates, similar to the current design of the Tariff Rate program.** This approach, however, would mean that SOPs serving kWh Credit customers would receive no value to help offset a portion of their lost revenue. SOPs would have to increase rates for customers to account for the lack of any offset in their wholesale load obligation. This approach, leaving SOPs serving kWh Credit customers without any offset to their lost revenue, could create the conditions for a "death spiral": the increased onus of serving kWh Credit customers would ensure competitive suppliers would refuse to serve them, leaving all kWh Credit customers on SOS, further increasing SOS costs, potentially driving additional customers to competitive supply to seek lower rates (reducing the customer base over which to recoup costs), and driving more SOS customers to seek to cover their load with kWh Credits (again, reducing kWh over which to recoup costs). Given this, this option is not preferable.
2. **Suppliers serving kWh Credit customers could be made whole.** That is, EDCs would pay suppliers for lost revenue and recover these costs through delivery rates, offset by energy market revenue from the kWh Credit resources. From the perspective of the supplier, this would be comparable to how the Tariff Rate program works, in that suppliers would be largely indifferent to whether a customer participated in the kWh Credit Program and in that effectively all the financial impacts of the program would be recovered through delivery rates. Implementing this approach would require establishing the price at which suppliers would be reimbursed; the most obvious answer would be whatever price applied to the metered kWh reduced by kWh Credits. This option could result in moral hazard where suppliers would be incentivized to charge excessive rates to kWh Credit customers, given that this rate would govern their reimbursement from the EDCs. Normally, one would expect that competitive pressures would prevent this, as customers switch to suppliers with lower rates. Because customers offsetting most of their load with kWh credits would not have this rate apply to many kWh, however, they may accept above-market rates. While we assume elsewhere in this report that customers receiving kWh Credits are on SOS, competitive suppliers might actively seek to enroll these customers were this opportunity to charge an inflated price available. Given this moral hazard risk, this option may also not be preferable.
3. **Energy (and capacity, if applicable) revenues from kWh Credit resources could be directed to suppliers serving the associated accounts.** This would approximate the allocation of costs, benefits, and obligations stemming from the kWh Credit program as it is currently implemented, as the energy revenue would help to offset supplier costs in

the same way that reduced wholesale load obligation does under the current design.[9] Presumably, the EDCs would be responsible for selling the energy and then allocating the revenue to SOPs/CEPs serving the associated accounts. While this would pose logistical challenges for the EDCs, it would be more practical than assigning the rights to the energy to the SOPs/CEPs.[10]

While there are tradeoffs for each of the approaches contemplated above, Option 3 represents the design with the fewest concerns and is closest to the overall impact of the kWh Credit program as currently designed. Our modeling assumes Option 3 when evaluating kWh Credit resources treated as Generator Assets.

3.5 Modeled Value Components

SEA conducted a comprehensive review of value components (both costs and benefits) associated with NEB resources to determine which should be included in this analysis. Only those value components for which the market disposition of an NEB resource would significantly change the amount of value or how value is realized were included in the analysis. We provide a summary of considered value components, including those that we did not model, in Appendix D.

Table 2, below, summarizes key characteristics of the modeled value components, with additional discussion of each in subsequent sections. In particular, the table calls out the parties to which values accrue by component, NEB variant, and market disposition. Note that we do not address Energy Value for the kWh Credit program or Socialization of PV Shape for the Tariff Rate program, as we find there are no distinctions by market disposition to be drawn in these categories.

[9] "Approximate" because there is at least one important distinction. As discussed in Section 3.2, suppliers serving kWh Credit customers see their wholesale load obligation reduced proportionally in every hour in a total amount equivalent to the number of kWh credits received by customers they served. Energy revenues, however, would be calculated on the basis of the solar production profile. As discussed in Section 3.5.4, the same number of total kWh, shaped by load or production profiles and then multiplied by hourly energy prices yield different total values. More specifically, suppliers would see slightly less value from receiving energy revenues from solar PV than they would an equivalent reduction in their kWh wholesale obligation. We account for this in the "Socialization of PV Production Shape" component, as discussed in Section 3.5.4.

[10] SOPs are not assigned to specific SOS customers, but, instead, are responsible for serving a specified percentage of SOS customer load. Given this, we would expect that, under the third option, energy revenues from NEB resources associated with SOS accounts would be assigned based on the portion of SOS load served by each SOP.

Table 2 - Key Characteristics of Modeled Value Components

Value Component (NEB Variant)	Description	Impacts by Market Disposition: Load Reducer	Impacts by Market Disposition: Energy & Capacity Asset	Impacts by Market Disposition: Energy-Only Asset	BTM Distinction?	Risk of supplier value capture
Energy Value (Tariff Rate)	The value of energy is unaffected by market disposition or Tariff Rate vs. kWh Credit, but the value accrues differently depending on the specific permutation.	Value is socialized during resettlement to suppliers serving all non-large customers	Energy revenue is used to offset program costs otherwise recovered through delivery rates		Does not apply – no BTM in Tariff Rate program	Significant risk (see discussion in Section 4.4)
Reduced Share of Capacity Costs (kWh and Tariff Rate)	Each customer has a capacity tag which effectively sets the % of total ISO-NE capacity costs borne by an individual customer. This capacity tag is set based on customer load during the ISO-NE annual system peak during the preceding year. NEB resource output during coincident annual peak that can affect calculation of ICAP tag leads to lower cap tags.	Value accrues to suppliers of all non-large customers (except BTM exception)	Does not apply (except BTM exception)		Yes. Value from BTM energy consumed on-site accrues to suppliers of SOS customers only.	Some risk, though modest, as benefit is realized as lower capacity tag, which suppliers explicitly account for in developing pricing
Reduced Share of Transmission Costs (kWh and Tariff Rate)	Regional network load (RNL) is the basis of recovering PTF costs from delivery customers. It is tied to monthly coincident peak for the applicable transmission customer, though we model CMP and Versant collectively. NEB resource output that can decrease calculated RNL reduces PTF costs.	Value accrues through delivery rates	Does not apply (except BTM exception)		Yes. This value applies to BTM energy consumed on-site during coincident peaks regardless of market disposition.	No risk
Capacity Price Suppression (kWh and Tariff Rate)	*Monetized ("cleared") capacity* - increase in price-taking supply in FCM supply stack lowers FCM clearing price. *Unmonetized ("uncleared") capacity* - reduced ICR lowers FCM clearing price.	Unmonetized and monetized capacity value accrues to suppliers of all New England customers		Does not apply	No	Some risk, though modest, as benefit is realized through lower capacity price, which suppliers explicitly account for in setting prices

Value Component (NEB Variant)	Description	Impacts by Market Disposition			BTM Distinction?	Risk of supplier value capture
		Load Reducer	Energy & Capacity Asset	Energy-Only Asset		
Capacity Value (kWh and Tariff Rate)	*Monetized ("cleared") capacity* - monetized revenue from selling into capacity market. *Unmonetized ("uncleared") capacity* - NEB resource output that has the effect of reducing the ICR), thus reducing capacity costs recovered from all New England customers.	Unmonetized capacity value accrues to suppliers of all New England customers	Monetized capacity value accrues through delivery rates	Does not apply	No	*Monetized capacity* – – no risk *Unmonetized capacity* – some risk, though modest, as benefit is realized as lower capacity tag, which suppliers explicitly account for in developing pricing
Socialization of PV Production Shape (kWh Credit)	This value component captures the impact to different customer groups of the difference in value between 1 MWh of PV production and 1 MWh of load reduction caused by the misalignment of PV production and load profiles and the hourly variation in energy prices	In all future years, shift in value *from* suppliers of all non-large competitive supply customers *to* suppliers of all SOS customers	No shift – EDCs would sell energy into the wholesale markets and provide revenue to suppliers serving customers receiving NEB credits (we assume exclusively SOS) - both impacts on SOS suppliers, thus no shift between groups of customers		No	Some risk as impact as small and realized through UFE, so suppliers may not immediately and fully pass value to customers

3.5.1 Energy Value

<u>Overview</u>
The wholesale energy value of NEB resources is the same, regardless of whether the energy is monetized through energy markets or whether it serves to reduce a supplier's load obligation. A resource's market disposition, however, can affect how the energy value accrues to different parties.

<u>Data Source:</u>
SEA used AESC 2024 energy prices.

<u>Discussion:</u>
For Tariff Rate resources, when resources are treated as Generator Assets (current design), energy revenues are used to offset NEB program costs, flowing through delivery rates. As described in Section 3.4.1, when modeling Tariff Rate resources as Load Reducers, energy is realized as UFE, leading to a small reduction in the wholesale load obligation of suppliers of all non-large customers. As discussed in Section 4.4, this creates significant risk of the full value not being passed through to end-use customers.

For kWh Credit resources, when resources are treated as Load Reducers (current design), the wholesale load obligation of suppliers serving customers receiving kWh Credits is reduced. As described in Section 3.4.2, when modeling kWh Credit resources as Generator Assets, we assume that energy revenues would be monetized by the EDC and be directed to suppliers, commensurate with their lost revenues. Because the value is effectively the same (and the small difference in value we capture in the next value component – Socialization of PV Production Shape), there is no difference in total value or ultimate recipient of value between kWh Credit resources being treated as Load Reducers or Generator Assets. Still, we include this value in our presentation of results for greater consistency between the kWh Credit and Tariff Rate graphs.

3.5.2 Reduced Share of Capacity Costs

<u>Overview</u>
Distribution-connected Load Reducers within Maine that generate energy during ISO-NE's annual system peak hour can reduce the share of capacity costs paid for by Maine ratepayers (thereby resulting in a cost shift to other New England ratepayers).

<u>Data Source:</u>
SEA used AESC 2024 capacity prices and load projections.

<u>Discussion:</u>
To calculate the estimated production from NEB resources during annual system peaks, SEA calculated projected annual production from NEB resources during the ISO-NE annual peak hour (differs by year) calculated in the AESC. This output was multiplied by the applicable capacity price and an estimate of the reserve margin.

BTM output for this component would have slightly different impacts than output from FTM resources. BTM output consumed on site would lead to a reduction in the capacity tag of that individual customer (an NEB participant), which means the benefit would accrue to supplier serving that customer. Because we assume all NEB customers are on SOS, this portion of benefits would accrue only to SOS customers. Because SOS does not have a pass-through provision to individual accounts, this reduction associated with an individual account would likely be socialized across all SOS customers.

We note that there is considerable potential for volatility in the realization of this benefit, as its value for each year is tied to the output of NEB resources during a single hour.

3.5.3 Reduced Share of Transmission Costs

Overview

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 (and thereby shift costs to other New England ratepayers). The RNS rate is applied to the monthly peak load of each local network – the Regional Network Load or RNL - though, we model Maine as a whole. Importantly, monthly peak load is not based on the ISO-NE system peak, but on that of each local network.[11]

Data Source:

SEA used the actual 2025 RNS charge, with assumed escalation in line with inflation for subsequent years.

Discussion:

To estimate the load reductions during peak periods attributable to DG resources, SEA calculated the difference between the monthly peak Maine load with and without solar production associated with the NEB program variants (kWh Credit and Tariff Rate). This difference, expressed in MW of reduced RNL, is then multiplied by the RNS charge. The resulting value is distributed across the total MWs of solar for each respective program variant to determine the benefits on a per MW or solar basis. This approach, as opposed to starting with an assumed impact for each marginal MW of solar and multiplying this by the applicable MW of solar resource, is critical for accounting for the declining marginal impacts of solar on reducing RNL. Declining marginal impacts also apply to other value components, such as reduced share of capacity costs. However, because those other value components are measured based on the ISO-NE system annual peak, the impact of the NEB program is small. Because RNL is calculated based on a smaller pool of customers (in our analysis, Maine), the impact of NEB resources becomes significant.

[11] Additional discussion of RNS and RNL is available in ISO-NE's monthly Regional Network Load Cost Reports. May's report is available here: https://www.iso-ne.com/static-assets/documents/100013/2024_05_nlcr_final.pdf. We also note that in theory, there would be a slight increase in the RNS rate ($/kW) in year following a reduction in a state's actual RNL to account for the fact that the PTF costs were effectively under recovered from all ISO-NE customers in the preceding year. Given Maine's modest portion of total ISO-NE costs, this impact is not accounted for.

Figure 1 - Illustration of NEB Impacts on RNL

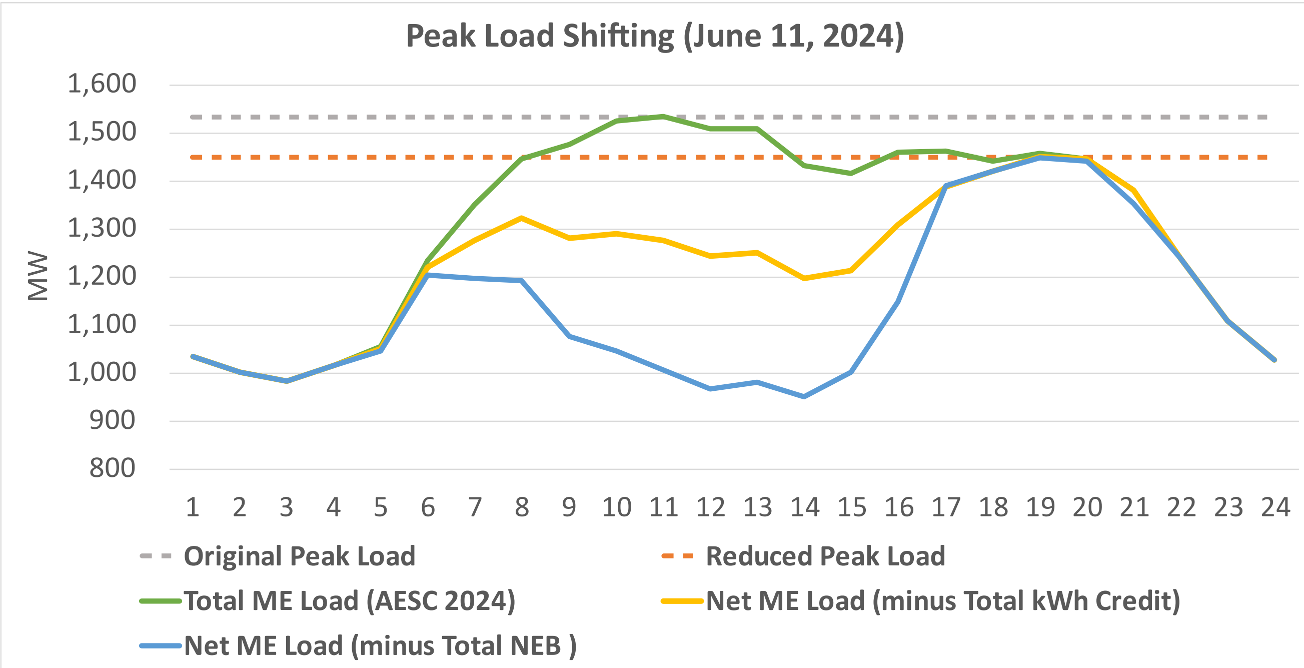


Figure 1 illustrates this impact by showing a 24-hour period on a single day (June 11, 2024), demonstrating how additional solar production beyond the point where the peak load is shifted to non-daylight hours provides no additional reductions in transmission system costs. Specifically, the figure shows Maine's load (green line) being offset by the generation from kWh Credit resources (resulting in the yellow line) or from both kWh Credit and Tariff Rate resources (resulting in the blue line). When the production from kWh Credit resources is netted out, the day's peak load decreases (from the top dashed line to the bottom dashed line) and shifts to the evening (7:00 PM) when solar PV systems produce less energy. Adding more solar production (shifting from the yellow to the blue line) significantly alters the load shape, but does not further reduce the peak load, which still occurs at 7:00 PM because there is no solar PV production at that hour. Simply, once solar capacity is sufficient to shift peak hours to times when solar is no longer generating, adding more solar does not further reduce the peak load. Our modeling reflects this dynamic in estimating the impact of NEB resources on RNL.

The sequence with which solar was netted out of load in this illustration is immaterial. That is, as long as Tariff Rate resources were Load Reducers, they could yield a similar initial benefit were they, in this example, netted out of load first. Instead, the salient point is that, while we calculate the potential benefits of Maine bearing a reduced share of transmission costs for each NEB variant separately, *these benefits cannot be summed*, as doing so would not account for the declining benefits illustrated in the example above. We account for this in our discussion of results and our recommendations.

Similar to Reduced Share of Capacity Costs, there is considerable potential for volatility in the realization of this benefit, as its value is based on the output of the evaluated resources during one hour each month. Because Reduced Share of Transmission Costs is based on the average reduction of twelve-monthly peaks, versus the annual peak hour considered in the Reduced Share of Capacity Costs, however, the volatility of this benefit is lower relative to the Reduced Share of Capacity Costs.

3.5.4 Capacity Value

Overview

There are two ways in which the capacity value of NEB resources can benefit Maine ratepayers. The first would be by monetizing the capacity by participating in the FCM (referred to as "monetized" or "cleared" capacity value). This would yield a direct financial benefit that could be used to defray the costs of the NEB program. The second would be by Load Reducers (participating in neither energy nor capacity markets) providing unmonetized (also referred to as "uncleared") capacity value. Unmonetized capacity value results from how resources not participating in the FCM impact the development of inputs to ISO-NE's ICR.[12] Specifically, the impact on historical data utilized by ISO-NE of resources serving as Load Reducers are assumed to reduce forecasted ICR utilized in the FCM. The reduction in the ICR, in turn, leads to lower capacity costs for all ISO-NE customers, realized by suppliers.

Data Source:

SEA used AESC 2024 assumptions for projected capacity (monetized and unmonetized) values. Actual capacity prices were used for years in which these prices were available.

Discussion:

For monetized capacity, SEA applies its estimate of capacity accreditation factors applicable to solar PV in the given year. Under the proposed ISO-NE accreditation reform,[13] this factor is calculated as the Marginal Reliability Impact (MRI). For unmonetized capacity, we use projected coincidence of solar with ISO-NE annual peak hours to appropriately adjust the nameplate capacity before applying the $/kW-year unmonetized capacity values included in the AESC.

In the AESC, unmonetized capacity utilizes a "phase-in" and "phase-out" schedule that reflects how a resource's impact on the calculation of the ICR changes over time, following the resource's commencement of commercial operations. Specifically, the 2024 AESC assumes that benefits from unmonetized capacity do not start until 5 years after their installation date. As such, SEA's analysis assumes no unmonetized capacity benefits between 2024-2029 if DG resources are treated as Load Reducers.

Monetized capacity, on the other hand, produces capacity value starting in the capacity commitment period in which it is enrolled. As discussed in Appendix B, deliverability constraints associated with resources north of the Surowiec-South interface present a substantial constraint to which resources could participate in the FCM. While we expect that future transmission system upgrades may provide sufficient capacity for NEB resources to hypothetically participate in the FCM, by the time that sufficient transfer capacity becomes available, ISO-NE may be a winter peaking system. In a winter peaking system, the capacity value of solar declines precipitously. Thus, the potential window to derive FCM revenue from NEB resources may be very limited.

This analysis does not explicitly account for capacity buy-out revenue, instead assuming that, if NEB resources participated in the FCM, the EDCs would monetize the capacity. However, even if resource owners did exercise their capacity buy-out rights, this revenue would approximate revenue received through the FCM, resulting in the same value to ratepayers. Thus, the value and how it flowed would be similar, regardless of whether resource owners or EDCs monetized the capacity value.

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

[13] See relevant materials here: https://www.iso-ne.com/committees/key-resources/capacity-auction-reforms-key-resource

3.5.5 Capacity Price Suppression

Overview:

Capacity price suppression[14] benefits relate to the reduction in capacity prices resulting from price takers (in this case, solar PV) shifting the supply curve to the right, resulting in the selection of a less expensive capacity resource on the margin. Because the capacity market functions on an as-cleared basis (that is, all resources that clear are paid the clearing price, not their bid price), even small reductions in the marginal price have a large impact, as they affect prices paid to all capacity resources. In the context of this analysis, we calculated capacity price suppression both for monetized capacity and unmonetized capacity.

Data Source:

AESC 2024 (Counterfactual 5) price suppression values specific to Maine were utilized.

Discussion:

Similar to capacity value, AESC modeling yields higher capacity price suppression values for unmonetized capacity than monetized capacity. As with capacity values, the impacts from monetized capacity price suppression begin in the year the resource comes online. However, the effects of these benefits phase out over time, which is reflected in the decay schedule used in the AESC. The AESC 2024 decay schedule is consistent with previous studies, with effects falling to zero by the seventh-year post-installation. Conversely, unmonetized capacity price suppression benefits take several years to materialize—five years if impacts are assessed before 2028, and three years if assessed in 2028 or later. This delay is because unmonetized resources gradually influence the load forecast, leading to sustained benefits in the mid to long term, unlike the immediate but shorter-lived effects of monetized resources. Unmonetized capacity price suppression benefits also factor in avoided reserve margins; that is, the ICR is set based on expected system needs in MW, plus a safety margin (reserve margin). So, while monetized capacity resources are valued at their accredited capacity, unmonetized resources have the incremental benefit of avoided reserve margin. Overall, unmonetized price suppression benefits are higher than monetized price suppression benefits due to higher forecasted capacity prices, associated price shifts, inclusion of avoided reserve margins, and different decay schedules, and the broader market impact of unmonetized capacity resources.

Importantly, unlike capacity value in which the value from monetized benefits accrues directly to the entity selling the capacity, the benefits of both monetized and unmonetized capacity accrue to all suppliers of ISO-NE customers.

Price suppression values in any given year are contingent on the commercial operation date of the resource in question. As such, price suppression values were calculated separately for each commercial operation year represented in our modeling (i.e., were calculated separately for each cohort year).

3.5.6 Socialization of PV Production Shape

Overview:

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

[14] Note that the AESC refers to price suppression as Demand Reduction Induced Price Effects (DRIPE). In this report, we use the term price suppression as an acknowledgement that considering the addition of generation resources can yield impacts labeled demand reductions. However, the effects are the same, and our inputs are based on the AESC DRIPE values.

<u>Data Source:</u>
SEA used AESC 2024 energy prices.

<u>Discussion:</u>
To illustrate this impact, consider the simple example provided in Table 3 in which five hours are considered (but one can imagine this representing a month). In this example, PV production (column (a)) generates kWh Credits which are assigned to the customer with load represented in column (b). Because the total PV production is equal to the load over the period, the supplier's wholesale load obligation associated with the customer is reduced to zero in every hour (proportional reduction of the load shape, as opposed to simply adding PV production and load by hour, as described in Appendix C.1). Therefore, the supplier's wholesale cost (column (g)) is zero. Column (d) tracks the system load on an hour-by-hour basis. Multiplying this column by the hourly price in column (e) yields the actual market cost/revenue in column (f). Despite the sum of the PV production and load being the same over the full period, their different shapes yield a market cost that does not equal zero. In the example, the total market obligation (not the supplier's post-resettlement obligation) is $410. As already established, the wholesale cost for the supplier is zero, so the $410 must be recovered from some set of customers.

Table 3 - Illustration of PV Production Shape Socialization

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

As noted above, this impact is specific to the kWh Credit program, and, more specifically, only applies when resources are treated as Load Reducers. Of the years evaluated (2010 through 2050), in all years following 2016 the market value of the solar is lower than the market cost of the load, which is consistent with the example provided above. The shift in value occurs between SOS suppliers and suppliers of non-large competitive supply customers, as the benefit is realized only by SOS suppliers, and then recovered from both suppliers of all non-large customers. Suppliers of large customers are unaffected by this impact, as their loads are not adjusted for UFE.

4 Results and Findings

Results and associated findings from modeling efforts are presented below. Please note that, unless otherwise specified:

- All results are presented on a statewide (CMP and Verant), present value (i.e., real dollar) basis, discounted to 2024 using a 6.74% discount rate, based on CMP's weighted average cost of capital (WACC). The values cover the NEB tariff term (20 years) of all NEB resources, including those already operating and those projected to come online.

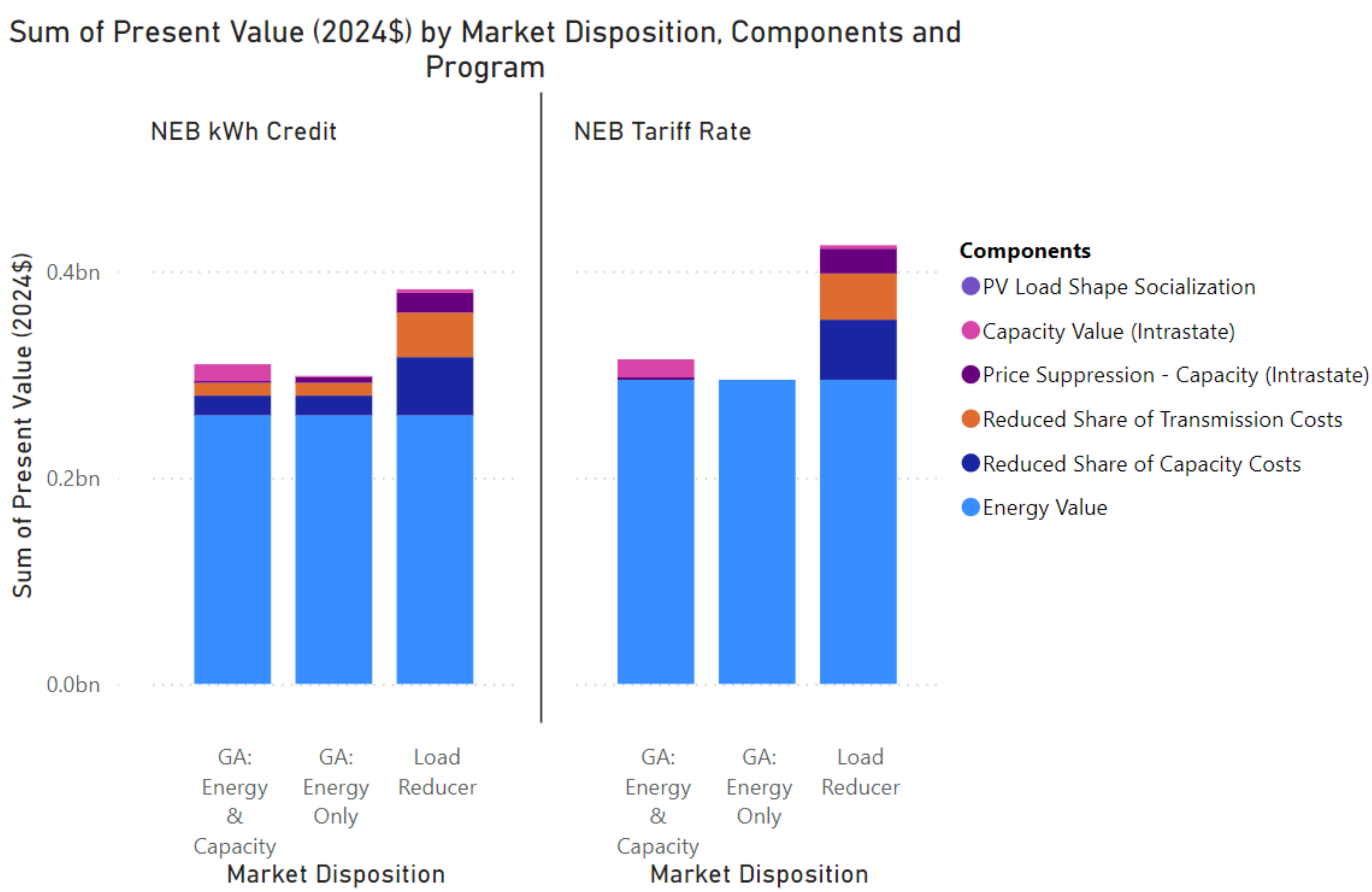
- The values included in graphs below do not represent the full value of NEB resources. The analysis only includes value components where the total value or how the value accrues is affected by wholesale market disposition.
- Only values that accrue to Maine ratepayers are included. Unless otherwise noted, values that accrue to other ISO-NE customers are not included in provided results.

4.1 General Findings

4.1.1 Load Reducer vs. Generator Asset Findings

For both the kWh Credit and Tariff Rate programs, the results demonstrate that Load Reducers have the potential to create more value for Maine ratepayers than Generator Assets, whether or not they monetize capacity value. This is demonstrated in Figure 2. Several value components, including Reduced Share of Capacity Costs and Reduced Share of Transmission Costs can only be produced by Load Reducers (with the exception of energy from BTM resources consumed onsite during peak hours). For Capacity Value and Capacity Price Suppression Value, both Generator Assets and Load Reducers can produce these values, but these values are higher for Load Reducers than for Generator Assets (again, regardless of FCM participation). Thus, the higher potential value from Load Reducers is unsurprising.

Figure 2 - Value Summary, Maine Only



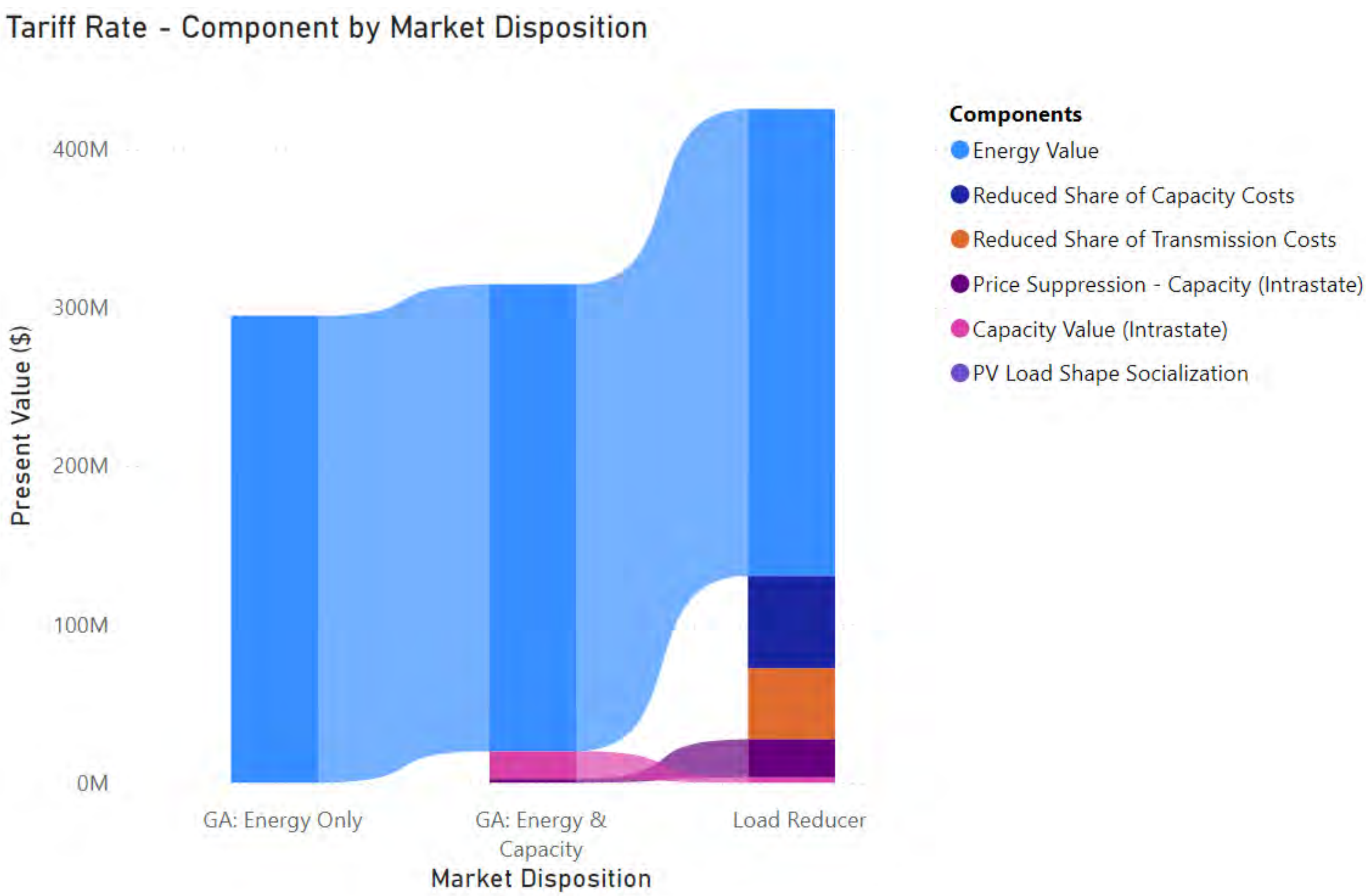
The results also reflect how BTM resources (which are only in the kWh Credit program) can produce certain value streams, including Reduced Share of Capacity Costs and Reduced Share of Transmission Costs, even when they participate in wholesale markets. This is why these value components are present in the bar for kWh Credit program (which includes BTM resources that create these values) with resources acting as Generator Assets, but not in the Tariff Rate program with resources treated as Generator Assets (as the Tariff Rate program as no FTM resources). These values are more specifically tied to energy produced by the BTM resources consumed onsite during monthly and annual peak hours.

The graphics above do not illustrate the recipients to whom the values accrue, which has implications for how likely end-use customers are to receive the full value. We address this consideration in the sections specific to the Tariff Rate and kWh Credit programs below.

4.1.2 Capacity Market Participation Findings

Section 2.2 describes how different market dispositions impact the modeled value components. Figure 3 shows how total values differ for different market dispositions of Tariff Rate resources, highlighting how Generator Assets participating in the FCM, in theory, produce more value than those only participating in energy markets.

Figure 3 – Impact of Market Disposition on Value – Tariff Rate



There are also costs (e.g., administration), risks (e.g., Pay-for-Performance penalties), and uncertainties (e.g., future capacity accreditation values for solar) associated with participation in the FCM, especially as the FCM is undergoing significant market reforms. While FCM Pay-for-Performance (PFP) penalties could erode FCM revenues, the relative infrequency of capacity scarcity events (even assuming significant increases in frequency in the future) would likely mean FCM revenues net of Pay-for-Performance would still return value to ratepayers.[15]

This value is largely hypothetical, however, given the deliverability constraints, discussed in Appendix B. The analysis indicates, however, that should deliverability constraints be resolved, it may be worthwhile to consider enrolling solar in the capacity market. On the other hand, as New England moves towards a winter-peaking system, the capacity accreditation value of solar at that point may be too small to justify the administrative burden.

4.1.3 Reduced Share of Transmission Costs

Section 3.5.3 describes how there are decreasing marginal benefits from solar for Reduced Share of Transmission Costs. The modeling bears this out. Figure 4 shows the impact of NEB resources (assuming they were all Load Reducers) on Maine's Regional Network Load (RNL), which is a MW value by which the Regional Network Service charge is multiplied to assign Pool Transmission Facility costs. The blue line shows the reduction (which equates to savings for Maine ratepayers) from just kWh Credit resources. The orange line indicates the reduction in RNL that would result from all NEB resources (which, again, would require that Tariff Rate resources be treated as Load Reducers). Our model includes roughly the same amount of MW capacity in the Tariff Rate and kWh Credit programs – thus, were there no diminishing returns, we would expect the orange line to be double the height of the blue line, as it represents twice the volume of solar. However, in the majority of years modeled, the reduction in RNL associated with having all NEB resources treated as Load Reducers is substantially less than double the RNL reduction associated with just kWh Credit resources being treated as Load Reducers. While the difference between the two lines on a percent basis becomes more pronounced in the 2040s, the overall RNL reduction from NEB resources by that time is small regardless of whether only kWh Credit resources or both kWh Credit and Tariff Rate resources are treated as Load Reducers.

Because we recommend that kWh Credit resources continue to be treated as Load Reducers, the diminishing marginal benefits discussed above imply that the potential Reduced Share of Transmission Costs benefits from Tariff Rate resources being treated as Load Reducers should be substantially discounted. In presenting results, Reduced Share of Transmission Costs are shown *specific to each NEB variant*; because of the declining marginal benefits, these values cannot be summed across programs.

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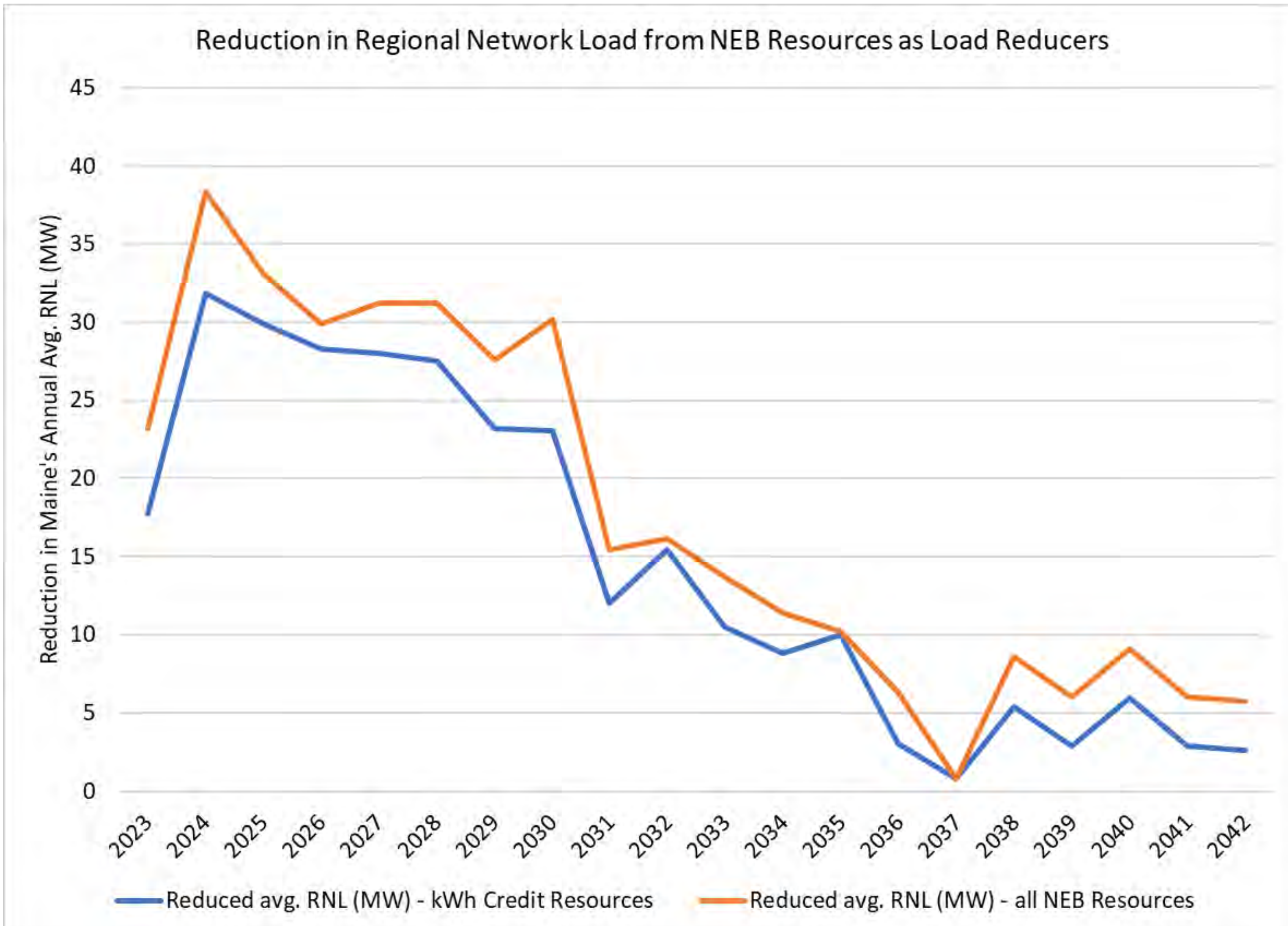
[15] Since implementing PFP penalties in 2018, ISO-NE has called five Capacity Scarcity Conditions (CSCs, the trigger for PFP penalties)—once each in 2018, 2022, and 2023, and twice (to date) in 2024. Based on ISO-NE's Historical CSC Summaries (which does not yet include data on the August 2024 CSC), SEA estimated the average "worst case" PFP penalty per CSC to be approximately $10 per kW of accredited capacity. This "worst case" scenario assumes that no solar PV resources perform during the CSC and uses the penalty rate effective beginning June 1, 2025. Notably, this penalty is significantly lower than the average FCM clearing price of approximately $32 per kW-year over the last five Forward Capacity Auctions (FCAs 14-18), covering commitment periods beginning in 2023 and ending in 2028.

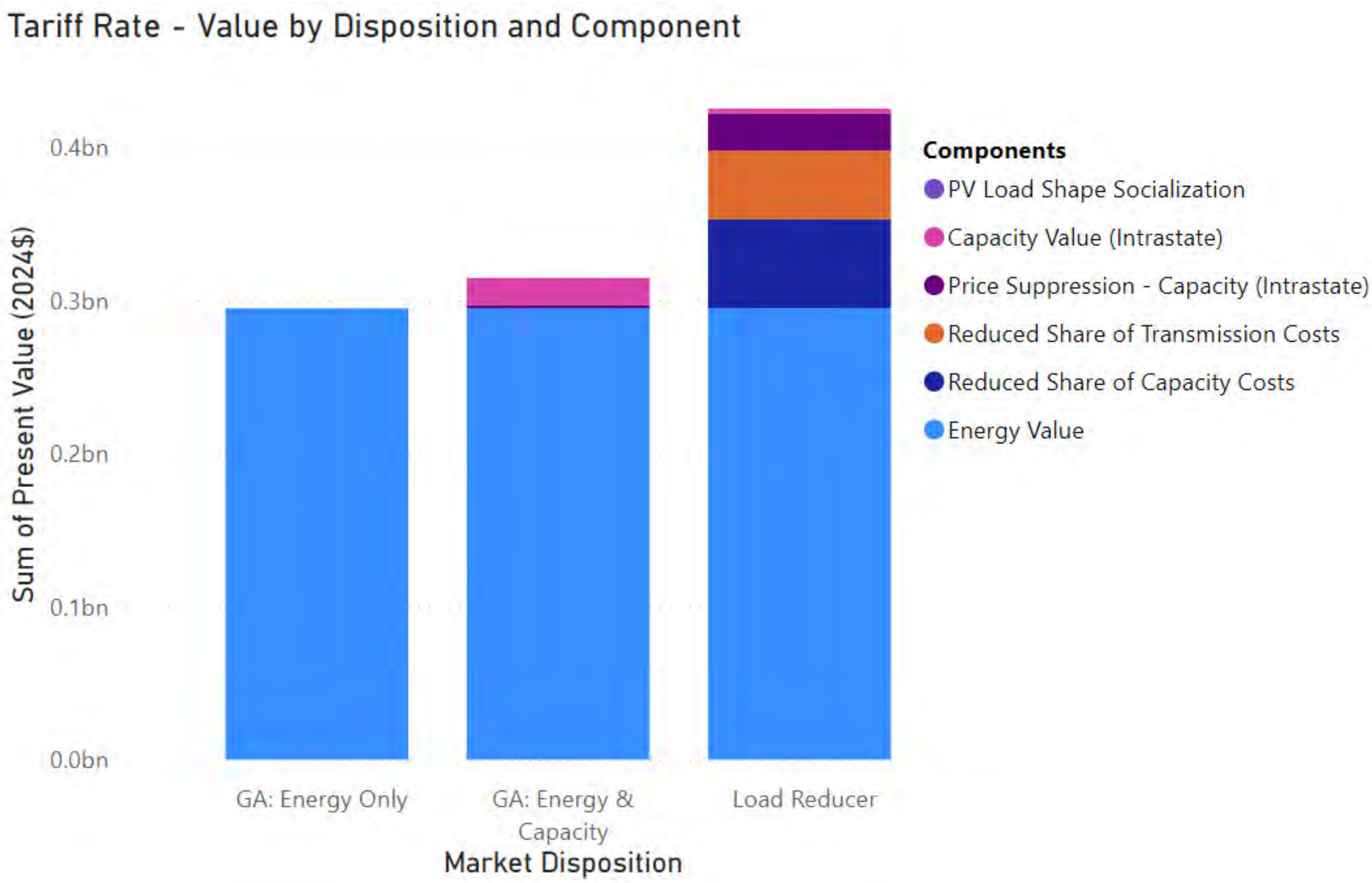
Figure 4 – Reduced Share of Transmission Costs from NEB Resources as Load Reducers



4.2 Tariff Rate Program Results

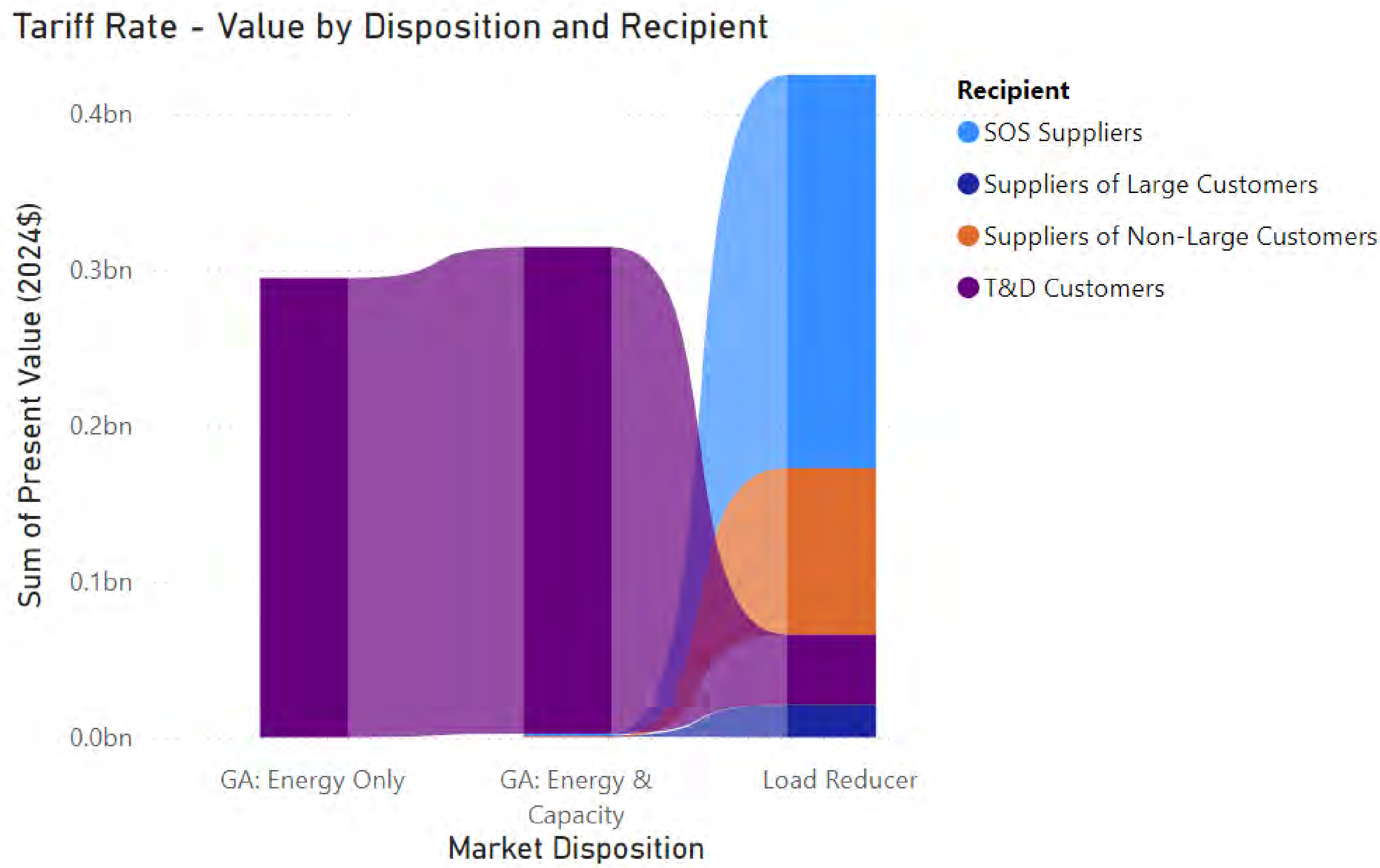
The results show that the Tariff Rate program has the greatest potential benefit when resources are treated as Load Reducers. Participation in the FCM, in theory, provides some incremental value over energy-only participation, but, at present, most Tariff Rate resources would be unable to secure a CSO because of deliverability constraints. While the total value of energy remains the same across market dispositions, Load Reducers yield Reduced Share of Capacity Costs and Reduced Share of Transmission Costs benefits, in addition to a larger volume of Capacity Price Suppression. These results are shown in Figure 5.

Figure 5 - Tariff Rate Value by Market Disposition and Value Component



Viewing values by value recipient, however, demonstrates more dramatic differences between Generator Asset and Load Reducer options, as shown in Figure 6. For Generator Assets, with or without a CSO, all value flows through delivery rates. When Tariff Rate resources are modeled as Load Reducers, however, most of the modeled values flow through supply, with a third of total value accruing to competitive suppliers serving non-large customers. As described in Section 3.2.1, having values flow through delivery rates provides the greatest certainty that customers will receive the full benefits of NEB value; competitive suppliers serving non-large customers provides the least certainty. Therefore, while treating Tariff Rate resources may produce the greatest *theoretical value*, it may not yield the greatest value to Maine electricity customers. Furthermore, as discussed in Section 4.4, the specific dynamics of how Tariff Rate energy value would be realized for Load Reducers is particularly susceptible to supplier value capture.

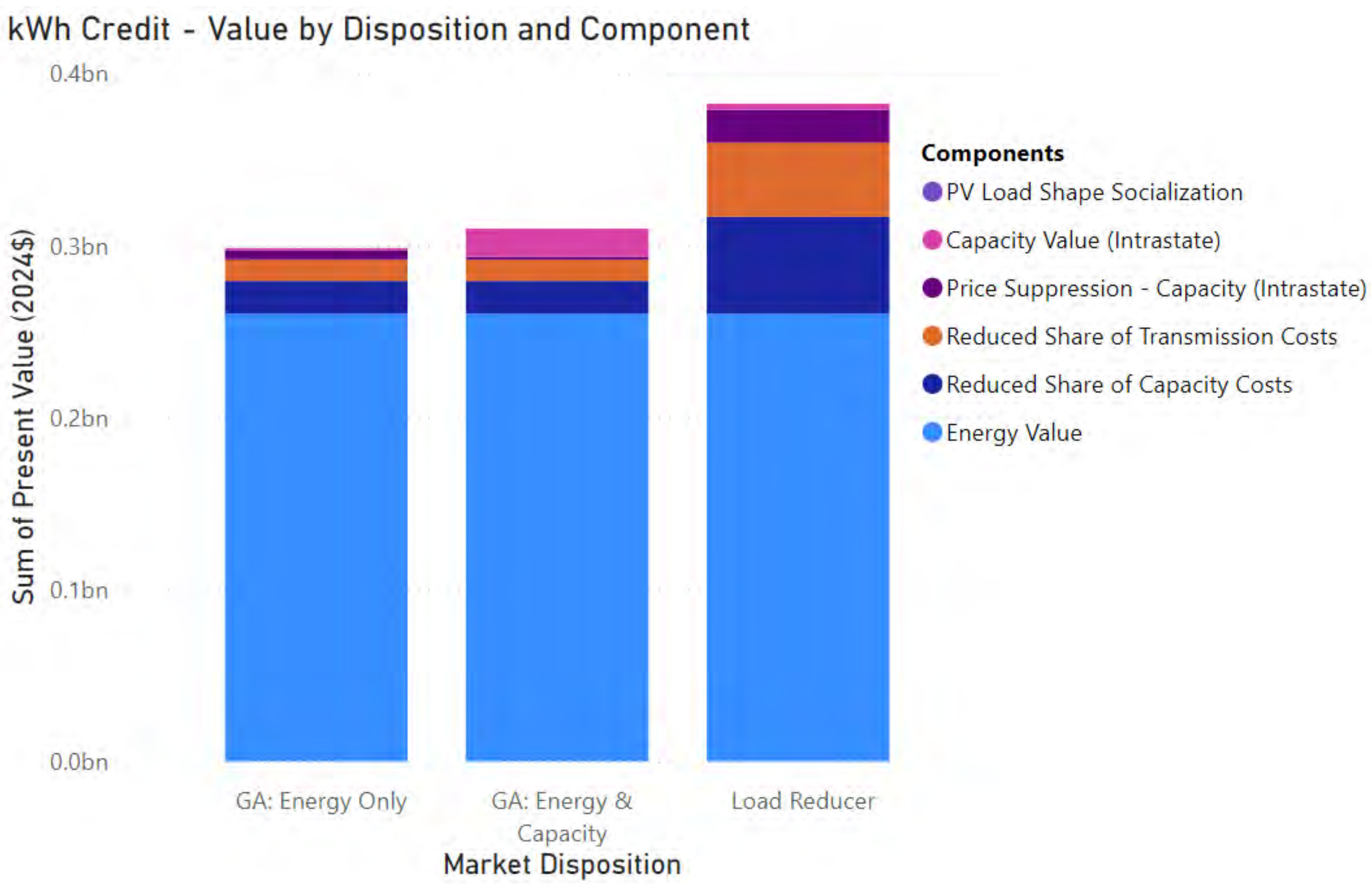
Figure 6 - Tariff Rate Value by Market Disposition and Recipient



4.3 kWh Credit Program Results

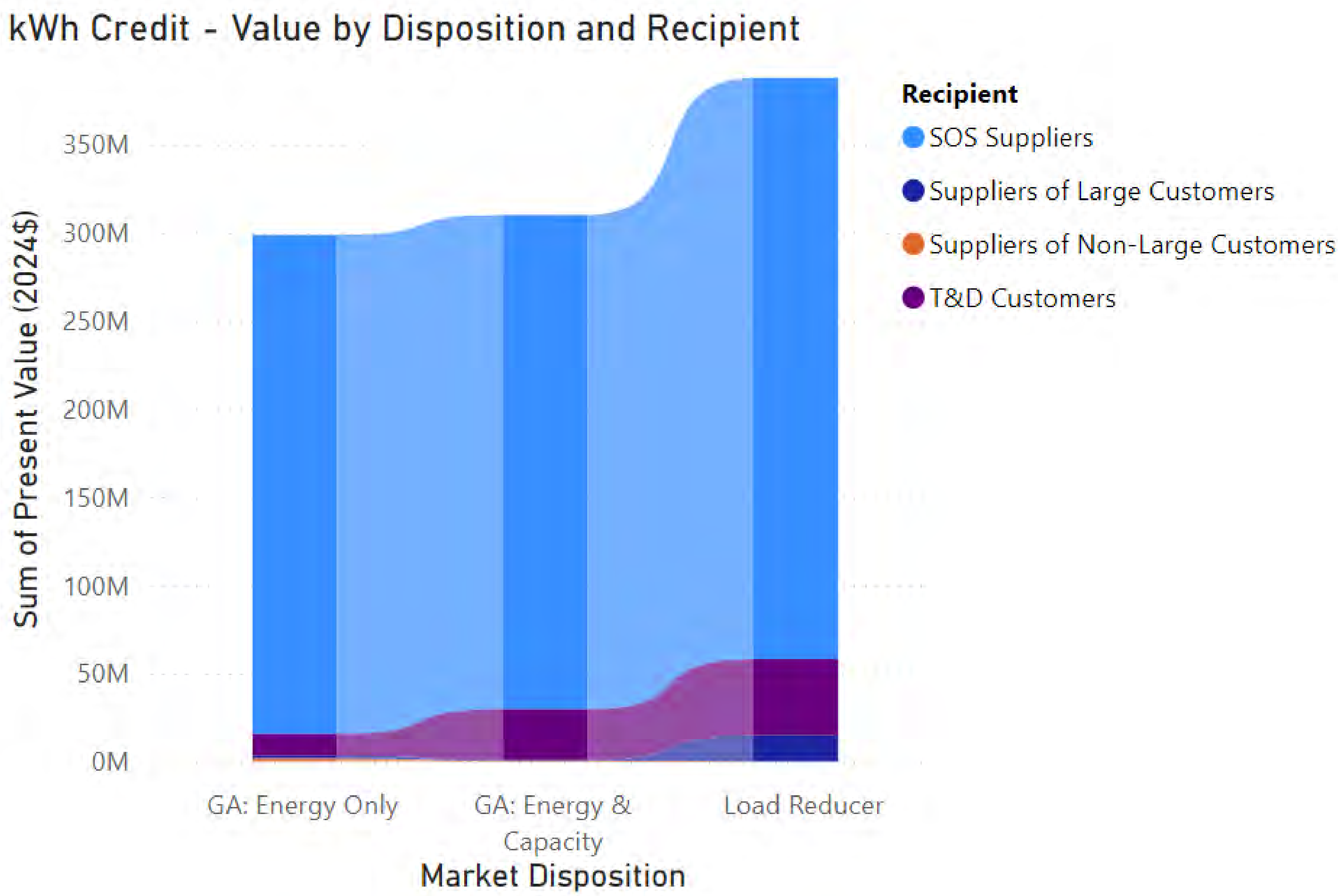
The results for the kWh Credit program also show treating resources as Load Reducers would provide the most value to ratepayers, as illustrated in Figure 7. Unlike in the Tariff Rate program, Generator Assets in the kWh Credit program still produce some Reduced Share of Capacity Costs and Reduced Share of Transmission Costs values. This is because the kWh Credit program includes BTM resources; when BTM resources offset on-site load during peak periods, they can yield these values, even if they are Generator Assets. These results are included in Figure 7.

Figure 7 - kWh Credit - Value by Market Disposition and Component



The kWh Credit program differs from the Tariff Rate program in how certain values accrue based on resources' market dispositions. As shown in Figure 8, most of the value for kWh Credit resources is realized through SOS rates, regardless of market disposition. This is a result of the basic design of the kWh Credit program and suggests a greater risk that suppliers may capture some of the value that would otherwise benefit Maine customers through supply rates, relative to value that accrues through delivery rates. Therefore, unlike for the Tariff Rate program, the value recipient may be a less critical factor in determining the preferred market disposition for kWh Credit resources, and, instead, the focus should be on maximizing total potential value. Consequently, the results indicate that treating kWh Credit resources as Load Reducers would provide the most value to Maine ratepayers.

Figure 8 - kWh Credit - Value by Market Disposition and Recipient

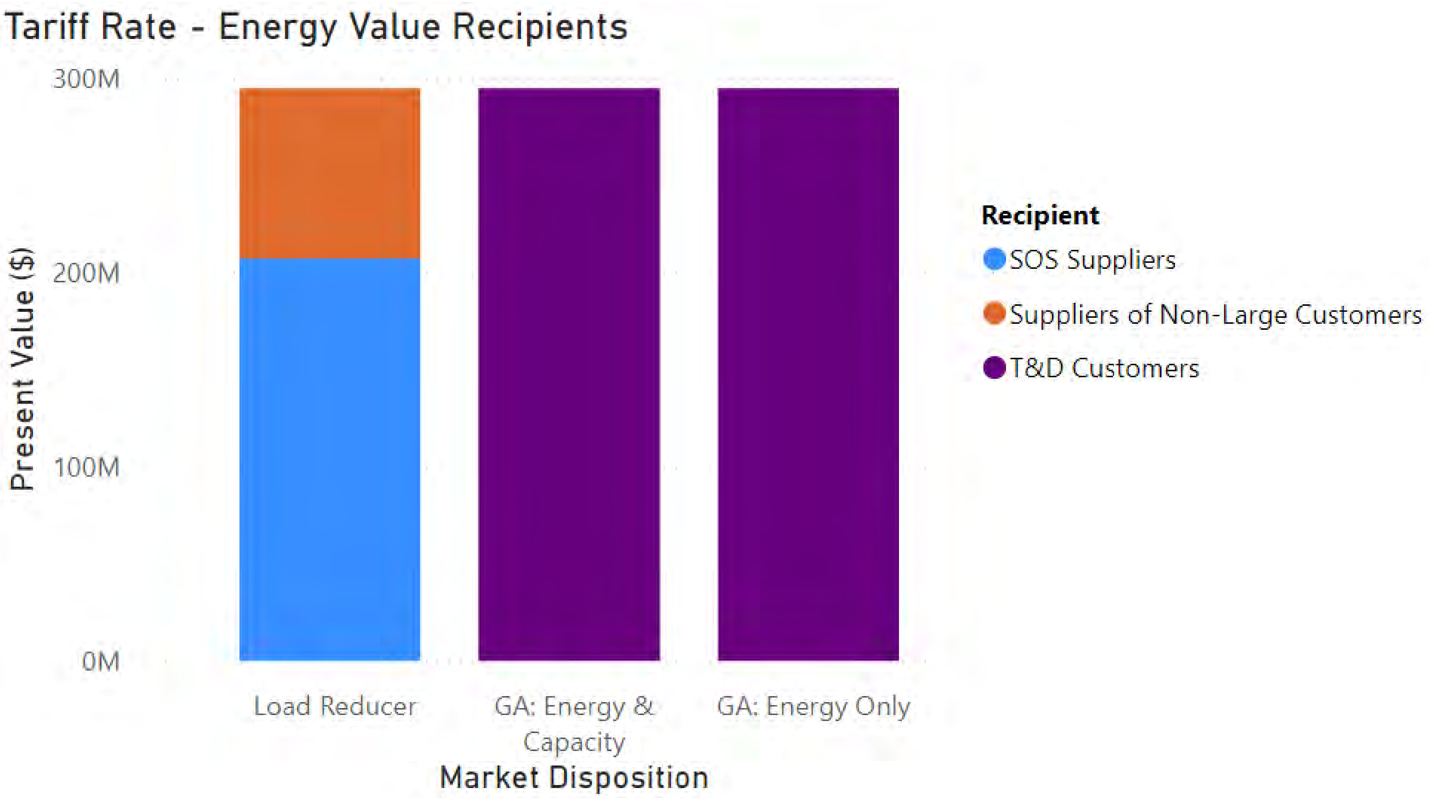


4.4 Potential for Energy Value Capture

4.4.1 Tariff Rate Program Energy Value Capture

While there are potential additional benefits to Maine customers associated with Tariff Rate resources being treated as Load Reducers instead of Generator Assets (the status quo), switching Tariff Rate resources to Load Reducers would also dramatically change how the values accrue, as discussed above. As a Generator Asset, all of the value (with the exception of ROP, which is excluded in the graphic below) accrues through delivery rates. As a Load Reducer, however, all of the energy value flows through suppliers, as demonstrated in Figure 9.

Figure 9 - Tariff Rate Energy Value Recipients



As discussed in Section 3.2.1, this makes it critical to consider how benefits that accrue directly to *suppliers* will (or will not) flow through to *customers*. Section 3.4.1 outlines the specific mechanism through which energy value resources accrues to customers when Tariff Rate resources are treated as Load Reducers. By socializing energy value to all non-large suppliers through unaccounted for energy (UFE), [16] several dynamics emerge that may reduce the likelihood of customers immediately and fully realizing the energy value. These dynamics include:

- **Separation Between Customer Metered and Billed kWh from Wholesale Load Obligation.** Unlike the kWh Credit program, the Tariff Rate program has no provision for adjusting kWhs billed to customers. Instead, value would accrue through UFE, which, after the resettlement process, reduces suppliers' wholesale load obligation. This would not, however, affect kWhs billed to customers. This disconnect creates a risk for the value to not be passed on to customers. SOS solicitations provide data on both wholesale load obligation and customer billed kWh. While this would provide an opportunity for suppliers to consider pricing the benefit of UFE from Tariff Rate Load Reducers into their bids, if this is not standard practice for price development, the SOP bidders may not sufficiently account for this impact. For CEPs, data provided for individual customers is based on metered kWh, not the associated wholesale load obligation.[17] Again, while the suppliers would have access to some data on losses/UFE, it may not be their standard business practice to account for how UFE could change over time as a result of Tariff Rate Load Reducers.
- **Challenge in Anticipating Volumes.** Even if suppliers accounted for the impact of Tariff Rate resources in their pricing, this would likely be done primarily on a retrospective basis. In other words, future pricing would be based

[16] At a high level, UFE refers to the difference between the sum of energy measured at individual customer meters and energy metered for a utility's corresponding metering domain. See Appendix C for a description of the load settlement process and unaccounted for energy.
[17] See Section 18.13(B) of CMP's Terms and Conditions for customer data that may be requested by CEPs.

on suppliers' past adjustments to their wholesale load obligations due to Tariff Rate resources, as captured through UFE, and would not reflect the value of new Tariff Rate resources expect to come online. As the pace of new NEB resources coming online after 2024 is expected to slow, this issue will become less significant over time.

- **Value Becomes Highly Diluted.** More generally, realizing energy value through UFE makes the impact highly diluted. While the aggregate market value of energy from Tariff Rate resources is significant, distributing this value across all suppliers through UFE makes the impact appear minimal from the perspective of a supplier. Such a small (and complex) impact may be considered "noise" by the supplier and is less likely to be incorporated into pricing.

Based on the above, we assume that, at a minimum, there would be a one-year lag between when resources come online, and when suppliers begin to price the impacts of the incremental Tariff Rate resources into their rates. Given that our modeling suggests resources would be online by 2026, this would make the impact of this one-year lag relatively short lived. However, we also assume that, unlike the guarantee that 100% of energy value will be passed on if realized through delivery rates in the treatment of Tariff Rate resources as Generator Assets, suppliers may never pass 100% of the benefit onto customers if Tariff Rate resources were treated as Load Reducers. Generally, we would expect that, over time, competitive pressures would cause most of the benefit to be passed on to customers. In the future, it would be possible to roughly gauge, on a retrospective basis, how much value is being retained by suppliers.

4.4.2 kWh Credit Program Energy Value Capture

Of course, the kWh Credit program currently treats resources as Load Reducers. This raises the question of whether the dynamic discussed above would also apply to the kWh Credit program. We find that there are several meaningful distinctions:

- **kWh Credit Program Design Incentivizes Suppliers to Account for Program Impacts in Pricing**. When Tariff Rate resources are treated as Load Reducers, it may not be critical for suppliers to carefully consider the potential and diluted impact of reduced wholesale load obligations through UFE. Suppliers who do not explicitly consider the impact in their pricing models would be, at worst, slightly less competitive than their competitors (although, their competitors may also not be pricing the impact in). The same is not true of the kWh Program. The kWh Program *reduces supplier revenue* through reductions in kWh billed to a customer. While the reduction in their wholesale load obligations helps mitigate the reduction in billed kWh, it does not cover other costs (e.g., capacity, fixed costs, margin, etc.). As a result, suppliers must explicitly consider the impact of the kWh Credit program as they price their products, as failing to do so could lead to losses. This explicit consideration increases the likelihood that the impacts of kWh Credit resources as Load Reducers are reflected in prices.[18]
- **Undiluted Value.** Unlike the Tariff Rate Load Reducer scenario, suppliers serving kWh Credit customers experience a one-to-one relationship between reductions in kWh revenue from customers they serve and a reduction in their wholesale load obligation. By not socializing the value across all loads, suppliers serving kWh Credit customers are more acutely impacted and thus suppliers must consider energy value associated with NEB resources that are used to reduce suppliers' wholesale load obligations when setting prices.
- **Alternative Option (kWh Credit resources as Generator Assets) Does Not Eliminate Risk of Supplier Capture.** With the Tariff Rate program, the concern over suppliers retaining energy value is eliminated if resources are treated as Generator Assets, as the energy value flows through delivery rates. With the kWh Credit program, the alternative would be for energy to be monetized and for this value to be shared with suppliers serving customers receiving kWh Credits. In either case, the value would flow through suppliers, so the opportunity for capture would be

[18] We note that the NEB program provides other benefits not addressed in this report, as these other benefits do not differ by market disposition.

effectively equivalent. That almost all value from kWh Credit resources flows through suppliers regardless of market disposition is illustrated in Figure 8.

In sum, there are good reasons to believe that the probability and magnitude of supplier capture of energy value from Load Reducers is lower through the kWh Credit program than the Tariff Rate Program. However, even if the risk of suppliers capturing energy value from Load Reducers were the same for the kWh Credit and Tariff Rate programs, the kWh Credit program would not eliminate this risk by treating resources as Generator Assets, as the value would flow through suppliers even if resources are treated as Generator Assets. Given that the energy value is the largest single source of value included in our analysis of the Tariff Rate program, the potential for supplier capture supports maintaining the current treatment of Tariff Rate resources as Generator Assets. In several years, when new NEB resources are no longer coming online and competitive pressures and changes to supplier practices have increased the likelihood of value being passed on to customers, we recommend evaluating whether suppliers are capturing energy value in the kWh Credit program and revisiting consideration of the market disposition of Tariff Rate resources.

5 Recommendations

Based on the above analysis and findings, SEA offers the following recommendations:

1. **Continue to Treat Tariff Rate Resources as Generator Assets.** While our analysis suggests that there may be greater potential value in treating these resources as Load Reducers, the incremental value is offset by the lower certainty that Maine electric customers will fully realize these benefits. Furthermore, because the value accrues through suppliers through the complex resettlement process, it would be challenging for the Commission to precisely assess the extent to which benefits (especially energy benefits, which have the highest value) accrue to customers. We also note that, because we recommend that kWh Credit resources continue to be treated as Load Reducers, the Avoided Share of Transmission Costs benefits illustrated in our results would not be fully realized, given the diminishing marginal benefits discussed in Section 3.5.3. The current approach of registering Tariff Rate resources as Settlement-Only Generators (as opposed to a Modeled Generator) is appropriate.
2. **Continue to Treat kWh Credit Resources as Load Reducers.** Because the same tradeoffs in value accrual for Tariff Rate resources do not apply to kWh Credit resources, we recommend selecting the market disposition to maximize potential value. Therefore, we recommend that kWh Credit resources continue to be treated as Load Reducers. We note that the difference in design of the kWh Credit and Tariff Rate programs leads to the different recommendations for the two programs.
3. **Monitor FCM Deliverability Constraints.** The current inability to enroll NEB resource north of the Surowiec – South interface in the FCM limits the volume of NEB resources that could participate in the FCM. However, should the interface have sufficient capacity to accommodate NEB resources in the future, enrollment of Tariff Rate resources in the FCM should be considered. Our examination of the relevant value components indicates that, for resources that are already participating in wholesale energy markets, no values are diminished or lost by also taking on a CSO. Of course, any future evaluation of FCM participation should also consider expectations for solar PV capacity accreditation values (and trends in ISO-NE capacity scarcity conditions and their implications for potential Pay-for-Performance penalties) before making a final determination with respect to FCM participation. Because we find that kWh Resources should remain Load Reducers, any future FCM consideration should be specific to Tariff Rate resources.
4. **Consider Re-Evaluating Market Disposition in Three Years.** We expect the risk for some values to be captured by suppliers and not passed on to customers to decrease over time (due to competitive pressures and additional NEB resources no longer coming online). Furthermore, the implementation of FCM reforms and additional information

on transfer limits at Maine interfaces may provide greater clarity on the value of monetizing the capacity value of NEB resources. Therefore, we recommend that the wholesale disposition of NEB resources be re-evaluated in approximately three years. This analysis should focus on (i) whether Tariff Rate resources should continue to be treated as Generator Assets and (ii) if so, whether their capacity should be monetized.

A Appendix A: Generator Asset Participation Models

ISO-NE's Generator Asset participation models each fall into one of three overarching Asset Types: Modeled Assets, Non-Modeled Assets, and Demand Response Assets. Resources with a net generating capacity less than 5 MW and interconnected at less than 115 kV have the option to participate as either:

- **Modeled Asset, via the Modeled Generator (MG) Participation Model**. Modeled Assets, including Modeled Generators, are visible and controllable by the ISO-NE control room and must bid into the Day-Ahead and/or Real-Time Energy Markets. Modeled Assets must be at least 1 MW.
- **Non-Modeled Asset, via the Settlement-Only Generator (SOG) Participation Model**. Non-Modeled Assets, including SOGs, are neither visible nor controllable by the ISO-NE control room and act as price takers (i.e., they receive the market clearing price and do not contribute to price formation).
- **Demand Response Asset, via the Passive Demand Resource (PDR) Participation Model**, which includes On-Peak and Seasonal-Peak Resources. Demand Response Assets, including PDRs, are visible and controllable by the ISO-NE control room. PDRs must be at least 100 kW (but can be an aggregation of individual resources) and can only participate in the FCM, not the wholesale energy or ancillary services markets.

Based on our review, there are few instances in which NEB resources would be better off registering with ISO-NE as a Modeled Generator or PDR instead of a Settlement-Only Generator. Modeled Generators have additional reporting and telemetry requirements relative to Settlement-Only Generators (and thus are the more costly participation model) despite minimal, if any, difference in revenue potential for NEB resources. Additionally, only a subset of NEB resources could be Modeled Generators (i.e., those between 1 and 5 MW). PDRs do not appear to have a significant advantage or disadvantage relative to SOGs. However, since we do not recommend that NEB resources participate in the FCM, this report does not include an exhaustive evaluation of the implications of registering resources as PDRs (e.g., any relative difference in FCM revenue potential).

B Appendix B: Forward Capacity Market (FCM) Participation

Historically, resources interconnected north of the Orrington–South interface and, to a lesser extent, the Surowiec–South interface (key boundaries in Maine's electric power transmission infrastructure) have been unable to qualify for the FCM due to concerns about whether electricity generated north of those interfaces can be reliability delivered to where it is needed in New England. These concerns are driven by stability and thermal constraints at those interfaces. Though ISO-NE recently completed a re-analysis of transfer limits at those interfaces (triggered by a change in an underlying reliability process) that resulted in a 20-25% increase in transfer limits, ISO-NE has largely evaluated the impact of the re-analysis as increasing the capacity import capability at the New Brunswick–New England interface.[19] While it remains possible that some existing resources will newly qualify to participate in the FCM due to re-analysis, we expect these to be larger existing resources, not distribution-scale solar PV resources like those in the NEB program. In addition, the New England Clean Energy Connect (NECEC), a proposed (and under construction) 1,200 MW, 145.3-mile-high voltage direct current (HVDC) transmission line being developed by Avangrid (CMP's parent company), is the only currently proposed transmission resource anticipated to affect transfer limits at those interfaces. However, NECEC is primarily intended to import Canadian hydropower, meaning that its impact on transfer limits is uncertain and may be limited.

ISO-NE is also developing several capacity market reforms that present forecasting challenges. Specifically, ISO-NE delayed its Forward Capacity Auction #19 (FCA 19), which corresponds to the 2028-2029 Capacity Commitment Period, by three years (i.e., from February 2025 to February 2028) with the intent to:

- Design and implement a resource capacity accreditation (RCA) framework, which would measure and value a resource's contribution to maintaining resource adequacy;
- Transition from a forward-annual market (the current practice in which ISO-NE procures capacity approximately 40 months in advance of a one-year commitment period) to a prompt-seasonal market (in which ISO-NE would procure capacity shortly before a seasonal commitment period); and
- Consider several other potential reforms, including a gas availability market constraint and a change from a descending clock to sealed bid auction format.[20]

Notably, an RCA framework would result in reduced capacity accreditation values for non-dispatchable resources, such as solar, and thus reduce their capacity market revenues.

There are additional reasons that effectively no NEB resources have participated in the FCM to date (through either EDC enrollment or resource owner capacity buyout). Taking on a CSO creates an obligation to perform during capacity scarcity conditions. With exceptions discussed here, non-performance during scarcity conditions can lead to substantial penalties through the Pay-for-Performance rules, which levy penalties on resources with CSOs that fail to perform during capacity scarcity conditions. PDRs and SOGs are treated differently during scarcity conditions. For Distributed Generation PDRs, Actual Capacity Provided (ACP) is equal to submitted meter data for a 24-hour calendar day during the scarcity condition. For SOGs, ACP is equal to the resource's output during the scarcity condition in addition to the resource's Reserve Quantity for Settlement. Thus, the penalty for not fulfilling a CSO may be lower for PDRs than for SOGs, lowering the risk for PDRs and providing an incentive to participate as a PDR, instead of a SOG.

[19] https://www.iso-ne.com/static-assets/documents/100013/a04_me_capacity_transfer_capability.pdf
[20] https://www.iso-ne.com/static-assets/documents/100013/a08_mc_2024_07_09-10_initial_car_scope_considerations.pdf

In practice, these limitations restrict opportunities for NEB resources to participate in the FCM. While some NEB resources are located south of the Surowiec–South interface, this is a minority of the NEB program's overall capacity.[21] Still, the results in this report include consideration of NEB resources participating in both energy and capacity markets. Including these results provides stakeholders and policymakers with an understanding of the magnitude of potential value associated with FCM participation. Furthermore, while it represents a minority of the overall NEB program capacity, resources south of the Surowiec-South interface could be enrolled in the FCM without the same deliverability constraints.

[21] Given challenges in establishing whether specific resources are north or south of specific interfaces, SEA did not quantify the volume of resources subject to deliverability constraints.

C Appendix C: Load Settlement and Installed Capacity Tags

Below, we provide a description of load settlement and the process for establishing ICAP tags, as both have implications for how NEB resource values are realized.

C.1 Load Settlement Overview

At a high level, load settlement (including the initial settlement and resettlement) is an allocation and reconciliation process in which the sum of the hourly load assigned to individual suppliers must equal the EDC's metered ISO-NE System Load (sum of all generators and tie lines) plus any unaccounted for energy (UFE) for the same hour. The initial load settlement occurs on a daily basis, with a subsequent monthly[22] load resettlement process. UFE is the difference between the EDC's ISO-NE System Load and the sum of metered consumption grossed up to account for line losses. Historically, unmetered load was the primary driver of UFE; however, today, a growing portion of UFE is due to production from Load Reducers (e.g., NEB kWh Credit resources), as they are not registered with ISO-NE and thus not accounted for in ISO-NE System Load. Conversely, Generator Assets (e.g., NEB Tariff Rate resources) are registered with ISO-NE and thus accounted for in ISO-NE System Load; Generator Assets do not directly affect UFE.

Accordingly, Tariff Rate resources, as Generator Assets, do not impact suppliers' wholesale load obligations through the load settlement process, but kWh Credit resources, as Load Reducers, do. Production from kWh Credit resources is allocated to suppliers of kWh Credit recipients through the monthly resettlement process, thereby reducing those suppliers' wholesale load obligations customers.

We note that each EDC has its own procedures to handle the allocation of UFE and installed capacity (or ICAP) tags (which are used to assign capacity costs to individual customers), based in part on the roll-out and capabilities of its metering and billing systems. We base our modeling on CMP's load settlement process because it has fully implemented advanced metering. The Versant-Bangor Hydro District load settlement process is likely to be similar to CMP's process. We do not speculate on the details of Versant-Maine Public District's (Versant-MPD's) Load Settlement given the additional idiosyncrasies of serving retail load in NMISA and Versant-MPD's small fraction of Maine served load.

C.2 **CMP's Approach to Energy Settlement**

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

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

1. CMP first aggregates, by supplier, the total kWh credits assigned to each supplier's customers for the billing month. For SOPs, because they are not assigned individual customers but an overall portion of SOS customer load, this allocation is based on the percent of total SOS load each SOP serves.

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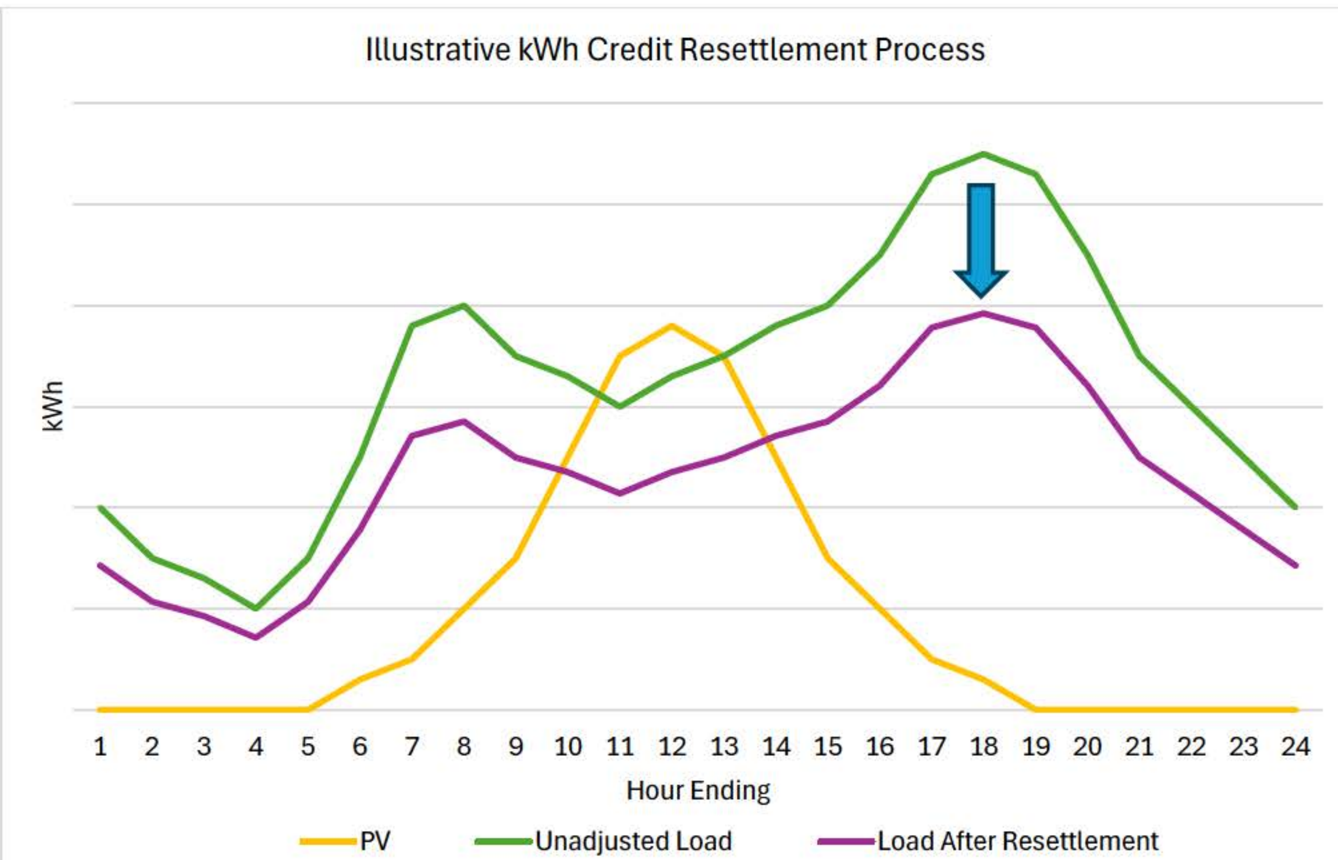
[22] The monthly resettlement aligns with the EDC's monthly billing cycle rather than calendar months.

2. Then, in an iterative fashion, CMP reduces each supplier's hourly load over the billing cycle on a pro rata basis according to their aggregated kWh credits.

Figure 10 - Illustrative kWh Credit Resettlement Process illustrates how a supplier's wholesale load obligation is adjusted to account for kWh credits during the monthly resettlement process. We emphasize that, in applying the reduction, the supplier's load obligation is reduced proportionally in every hour, as opposed to the specific hours in which the PV production occurred. This approach to adjusting the wholesale load obligations of suppliers serving customers receiving kWh credits leads to the Socialization of PV Production Shape impact discussed in Section 3.5.4. The lag between initial settlement (in which suppliers do not see their wholesale load obligation reduced to account for customers receiving kWh credits) and resettlement (when the adjustment occurs) would yield an increased need for working capital, which we discuss in Appendix E.4.

Figure 10 - Illustrative kWh Credit Resettlement Process



C.3 CMP's Approach to ICAP Tag Allocation

ICAP tags are assigned to individual customers and then rolled up by supplier. ICAP tags are used to assign the total costs of the ISO-NE FCM to customers through supply rates. CMP, like all EDCs subject to ISO-NE rules, must allocate ICAP tags for a given capacity commitment period based on that customer's consumption during ISO-NE's coincident system peak hour in the previous Capability Period. For example, in 2023, ISO-NE's coincident system peak occurred on September 7, 2023, during hour ending 1800; accordingly, each CMP customer was assigned a Customer Peak Load Calculation (CPLC) based on the customer's consumption during the hour ending 1800 on September 7, 2023, for the ISO-NE Capability Period starting on June 1, 2024. The CPLC calculations parallel the energy settlement calculations; that is:

- For suppliers with customers in Large C&I rate classes, the CPLC is calculated as the aggregated hourly metered consumption load grossed up by deemed, voltage-specific line loss factors.
- For suppliers with customers in non-Large C&I rate classes, the CPLC is calculated as the aggregated hourly metered consumption load grossed up by deemed voltage specific line loss factors, plus hourly UFE. Because suppliers with customers in non-Large C&I rate classes are assigned the UFE energy, the suppliers of customers in these rate classes also implicitly reap the benefit of any coincident peak load reduction attributable to Load Reducers. The load reduction associated with the UFE is allocated by rate class and, per the above, is socialized to all suppliers with customers in non-Large C&I rate classes.

CMP provides a daily Supplier Peak Load Calculation (SPLC) throughout the Capability Period, and any additional ancillary impacts of load reduction which are spread over all customers we assume to be *de minimis*.

D Appendix D: Value Components Summary Table

Table 4 - Candidate Value Component Summary Table, shows the full set of values that were considered for inclusion in the analysis. Values shown in **bold** were ultimately addressed quantitatively in the model; other values were addressed qualitatively or were determined to not be meaningfully impacted by the market disposition of NEB resources.

Table 4 - Candidate Value Component Summary Table

Rolled Up Component	Different GA vs. LR?	Impact on Total Value	Impact on How Value Accrues	Modeling Approach	Notes
Energy Value	**Affects how value accrues**	**None - value of energy, whether realized as payment through energy market as a generator, or as reduction in load, is the same.**	**Different by both market disposition and kWh Credit vs. Tariff Rate program.**	**Calculate value using AESC energy values, apply to appropriate value recipients based on each permutation.**	
Reduced Share of Capacity Costs (ICAP tag management)	**Yes**	**Yes - Load Reducers can produce this value, Generator Assets (some BTM exceptions) cannot.**	**For both Generator Assets and Load Reducers, value realized through supply rates.**	**Based on projected coincidence of PV production with annual system peaks.**	
Reduced Share of Transmission Costs	**Yes**	**Recovery of Pool Transmission Facility costs is tied to calculated Regional Network Load (RNL), effectively averaged max monthly net load by Transmission Customer. Load Reducers can provide his value, Generator Assets cannot.**	**Value realized through reduction in transmission rates.**	**Based on calculated coincidence of PV production with monthly Maine peak load and actual Regional Network Service charge from ISO-NE.**	
Capacity Value	**Yes**	**ISO-NE applies a reserve margin when calculating the installed capacity requirement, thus, resources "count" as more kW when treated as reduction in demand than supply (i.e., bid into the FCM).**	**As FCM participant, value realized financially and used to defray NEB costs recovered through delivery rates. As Load Reducer ("uncleared" in the FCM), value is realized through supply rates by all ISO-NE customers.**	**AESC provides values used in modeling**	
Price Suppression - Capacity	**Yes**	**Similar considerations as discussed above for capacity value.**	**Similar considerations as discussed above for capacity value.**	**AESC provides values used in modeling.**	
Socialization of PV Production Shape	**Affects how value accrues**	**None – shifts value between different sets of customers, but does not change total value**	**Yes – shifts value from suppliers of all non-large competitive supply customers *to* suppliers of all SOS customers.**	**Based on hourly PV production profile and load profiles.**	
Program Admin	Yes (minor)	Logistics, cost of participating	n/a	Noted qualitatively	
Capacity Buyout Revenue	Not as modeled	n/a	n/a	n/a	Given extremely limited exercise of capacity buyout option to date, we assume that there will continue to be limited interest in

Rolled Up Component	Different GA vs. LR?	Impact on Total Value	Impact on How Value Accrues	Modeling Approach	Notes
					this option and therefore consider qualitatively.
Avoided Transmission Costs	No	ISO-NE intends to model all DG as generators (whether market participants or not) for transmission planning, thus there would be no distinction.	n/a	n/a	
Emissions	No	n/a	n/a	n/a	
Expired, rolled over/accumulated kWh Credit Value	No	n/a	n/a	n/a	Considerable implications for Standard Offer Service (SOS) customers, but not affected by market disposition.
Improved Generation Reliability	No	n/a	n/a	n/a	
Lost Utility Revenues (kWh Credit)	No	n/a	n/a	n/a	
Interconnection Upgrade Benefits	No	n/a	n/a	n/a	
Price Suppression - Electric/Gas	No	n/a	n/a	n/a	
Price Suppression - Energy	No	n/a	n/a	n/a	
Resource PPA Expenses (Tariff Rate)	No	n/a	n/a	n/a	This specifically means no impact on gross expenses. Net expenses (i.e., stranded costs) can be impacted by other value streams, which are addressed individually elsewhere.
REC Price Suppression	No	n/a	n/a	n/a	
Reduced Distribution Costs	No	n/a	n/a	n/a	
Reduced RPS Obligation	No	n/a	n/a	n/a	There is a difference between BTM and FTM resources here, discussed in the report, but this is not based on whether the resource is a Generator Asset or Load Reducer
Reduced T&D Losses - Capacity	No	n/a	n/a	n/a	
Reduced T&D Losses - Energy	No	n/a	n/a	n/a	

E Appendix E: Value Components Excluded from Analysis

In the following sections, we discuss issues and value streams that had been considered in our research but for which there was no significant difference between Generator Assets and Load Reducers or would not change this report's findings or recommendations. These values were excluded from our quantitative analysis.

E.1 Avoided Transmission Investments

Distribution-connected resources that generate energy during periods of high demand could reduce future needed transmission investments. The AESC provides estimates of these avoided transmission costs. As discussed in Section 3.5.3, Generator Assets and Load Reducers are treated differently with respect to calculating the allocation of costs associated with Pool Transmission Facilities through Regional Network Service (RNS) charges. Given this, we hypothesized that Generator Assets and Load Reducers might also be treated differently during the transmission planning processes, which could, in turn, lead to different levels of future transmission costs.

Based on our review of ISO-NE transmission planning documents and discussion with representatives from CMP, however, we determined that the treatment of resources as Generator Assets versus Load Reducers is unlikely to lead to different future transmission system costs. For transmission studies, the projections for the buildout of distribution-connected solar PV are derived from ISO-NE's Capacity, Energy, Loads, and Transmission (CELT) report.[23] While, in the past, there may have been some nuanced differences in how BTM and FTM solar PV were treated in transmission planning processes, based on our discussion with CMP, we understand that, moving forward, all solar PV will be modeled as generation, regardless of its metering configuration or wholesale market disposition. Given this, an NEB resource's wholesale market disposition would not lead to different future transmission costs. Accordingly, this value stream was excluded from this analysis.

E.2 Energy and Cross-Fuel Price Suppression

Price suppression benefits (also referred to as Demand Reduction Induced Price Benefits (DRIPE))[24] 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").

We further detail our approach to calculating capacity price suppression in Section 3.5.1. Because of the design of the capacity market, we are able to identify different capacity values, and, in turn, capacity price suppression values for Generator Assets and Load Reducers. The energy market, however, does not yield different $/MWh values for an incremental increase in supply vs. an incremental decrease in demand. Therefore, there is also no difference in energy price suppression for Load Reducers versus Generator Assets.[25] Cross-fuel DRIPEs, which capture interactions between electricity and natural gas markets, are tied primarily to energy markets; therefore, we also exclude cross-fuel DRIPE from our analysis.

[23] See Section 2.3.9 of ISO-NE's Transmission Planning Technical Guide.

[24] Note that the AESC refers to price suppression as Demand Reduction Induced Price Effects (DRIPE). In this report, we use the term price suppression as an acknowledgement that considering the addition of generation resources can yield impacts labeled demand reductions. However, the effects are the same, and our inputs are based on the AESC DRIPE values.

[25] In the context of a supply/demand graph, an increase in supply would represent shifting the supply curve to the right (the impact of treating resources as Generator Assets), while a decrease in demand would shift the demand curve to the left (the impact of treating resources as Load

E.3 Renewable Energy Certificates

Renewable Portfolio Standard (RPS) costs are a function of the cost of Renewable Energy Certificates (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 resources provide benefits in the form of reductions in total RPS costs. This also, however, results in having the effect of double counting the impact of BTM resources (as they simultaneously reduce the demand for and increase the supply of RECs). To address this, in its orders granting new RPS certification, the Commission requires that for BTM facilities, "the facility owners must retain [RECs] or otherwise obtain [RECs] necessary to satisfy Maine's RPS for that portion of the BTM load that is served by the facilities." As such, in the context of Maine, the total volume of RECs retired should not change because of BTM load reductions, but the party responsible for fulfilling RPS requirements with such load does change. This dynamic does not depend on wholesale market disposition, as this selection does not affect the volume of RECs minted or the volume of metered kWh load.

E.4 Cost of Capital (Resettlement Lag)

Appendix C describes the load settlement and resettlement processes. For suppliers serving customers receiving kWh credits from kWh Credit resources, there is a lag of up to approximately one month between when they are assigned load obligations through the daily settlement process, and when they see a reduction in load associated with kWh Credit program credits being assigned to their load obligations through the load resettlement process. This lag would require an increase in working capital for the suppliers serving customers receiving kWh Credits.

As described in Section 3.4.2, this dynamic could change if resources in the kWh Credit Program were to be treated as Generator Assets, as there would be no reduction in a supplier's load obligation associated with kWh credits during the resettlement process. Instead, suppliers would receive payments from the EDCs equal to wholesale revenues from energy associated with kWh Credits assigned to the relevant supplier's customer accounts. This would result in a similar lag between daily load settlement and receipt of offsetting wholesale energy revenue. Therefore, we do not find that there would be a significant difference between Generator Assets and Load Reducers. Furthermore, we expect that the impact of the working capital requirements discussed in this section is small relative to other impacts included in this analysis.

E.5 NEB kWh Credit Banking

One feature of the kWh Credit program is the ability of customers to bank kWh Credits for up to 12 months from the month in which the credits were generated. While banking kWh credits affects the load billed to customers (that is, the kWh for which a customer must pay in a given month), it does not have any impact on the wholesale load obligation of suppliers. That is, banking kWh credits, or using banked kWh credits, does not affect the supplier's load obligation in a given month.[26]

Reducers). The intersection of the two curves would be at different points along the x axis depending on whether you shifted the supply curve to the right or the demand curve to the left, representing a different volume of energy transacted in the wholesale market. However, regardless of whether you shift the demand or supply curve, the intersection will still be at the same position of the y axis, indicating that change in price would be the same. This is why there is not a difference in energy price suppression effects regardless of whether resources are treated as Load Reducers or Generator Assets.

[26] This does not mean that the ability of customers to bank kWh credits does not affect the cost of suppliers to serve customers these customers. The narrow conclusion here (that banking or drawing down on banked kWh credits does not affect a supplier's wholesale load obligation) is critical to establishing that the ability of kWh credits to be banked does not yield different outcomes based on different NEB resource disposition.

We demonstrate this in Table 5 – NEB Credit Banking, below. This table illustrates the impacts of banking on a supplier serving a single customer receiving kWh credits. The table illustrates how when kWh credits (column b) received exceed customer consumption (a) in a given month, credits can be banked (d). Critically, however, the supplier's wholesale load obligation (after resettlement, column e) is always equal to the difference between customer consumption (a) and credits received (b), *regardless of whether any banking occurs*. In this example in which there is a single customer, this means that a supplier's load obligation would be negative in months in which credits received exceed customer consumption (in practice, this does not happen, as credits received never exceed customer consumption when aggregated over a supplier's full set of customers). Still, the example illustrates how banking *does not change the wholesale load obligation of a supplier*. The same would hold true regardless of whether kWh Credit resources were treated as Load Reducers or Generator Assets. While the value of NEB resources treated as Generator Assets would be realized as a direct payment from the EDC instead of a reduction in wholesale load obligation when treated as Load Reducers, the impact on the supplier would remain effectively the same.

Table 5 – NEB Credit Banking

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

At the same time, choosing to treat kWh Credit resources as Generator Assets would not impact how kWh credit banking functions from a customer perspective. Therefore, while banking kWh credits certainly has critical implications for suppliers, we identify no difference in these impacts attributable to the wholesale market disposition of the kWh Credit resources and therefore do not include any of these impacts in this analysis.

E.6 Capacity Buyout Revenue

In Section 3.5.1, we discuss our approach to modeling the Capacity Value from NEB resources, including monetizing capacity by selling it into the FCM. In the Tariff Rate program, the EDC, by default, owns the rights to the resource's capacity value, but the resource owner may elect a buyout option, effectively purchasing the capacity rights back from the EDC.[27] In practice, extremely few resource owners elect to buy out capacity rights for their systems. Given this, for the purposes of this analysis, we do not separately model capacity buyout revenue. Instead, given that neither EDCs nor NEB resource owners are registering NEB resources in the FCM in meaningful numbers, we assume that FCM participation would be a result of Commission direction to the EDCs to monetize capacity. In this case, even if some resource owners did elect to

[27] See pp. 11-12 of CMP's Customer Net Energy Billing Agreement template.

purchase capacity rights, this revenue would have a similar effect as revenue from the FCM, in that it would be used to defray NEB costs recovered from ratepayers.

E.7 Program Administration Costs

Any changes to the implementation of the NEB programs will have implications for the EDCs as program administrators. The primary functions that would be impacted by any changes to the wholesale market disposition of NEB resources would be enrollment and ongoing management of wholesale market participation, distribution of NEB payments, and allocation of energy associated with credits in the kWh Credit program.

The EDCs already carry out some form of all the functions above. The main incremental responsibility that could result from the options considered in this report would be enrolling NEB resources in the FCM. EDCs already participate in wholesale markets through the NEB resources as they enroll Tariff Rate resources as Settlement-Only Generators, though FCM participation would represent incremental effort. We do not attempt to estimate a specific cost associated with this incremental responsibility. Simultaneously, we do not attempt to specify savings that may be associated with not having to enroll NEB resources in wholesale energy markets. While these both represent real costs or savings, relative to the magnitude of the other effects modeled, these impacts would be small.

E.8 Meter Upgrade Costs

Generation resources must have Revenue Quality Metering (RQM) meters and associated telecommunications infrastructure (i.e., telephone service) to participate in ISO-NE wholesale markets. Conversely, resources that do not participate in wholesale markets use CMP-provided AMI meters. Accordingly, for Load Reducers to become Generator Assets, the resource owners must pay for metering upgrades and corresponding ongoing operations and maintenance (O&M) expenses. While SEA has not quantified these costs – primarily, because it does not suggest a change from the status quo – they are likely significant.

F Appendix F: Rest of Pool Results

The results included in Section 4 exclude benefits that accrue to other ISO-NE customers outside of Maine (rest of pool or ROP). Figure 11, below, shows results including ROP benefits. The additional benefits that accrue to ISO-NE customers outside of Maine are significant. The figure illustrates how resources that do not bid into the FCM produce substantially larger capacity price suppression impacts. As discussed in Section 3.5.5, the timing of when capacity price suppression benefits occur is different for monetized and unmonetized resources. In this case, unmonetized resources have decay schedules that better line up with higher capacity price years and solar coincidences (that is, percent of nameplate capacity applied to the generic $/kW benefit, based on solar output during peak periods). Interestingly, the results also indicate that, unlike the Tariff Rate program, the kWh Program has higher total benefits when Generator Assets do not participate in the FCM when including ROP benefits. This is because the BTM resources included in the kWh Credit program are able to generate more Capacity Price Suppression benefits (which largely flow to ROP customers) when not bid into the FCM (FTM resources do not produce Capacity Price Suppression if enrolled in any wholesale market).

Figure 11 - Value Summary, Including Rest of Pool