Assessment of Storage Procurement Mechanisms and Cost-Effectiveness in Maine

Report prepared pursuant to P.L. 2023 Chapter 374

Prepared for the Maine Governor's Energy Office

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ABBREVIATIONS

AESC Avoided Energy Supply Costs

BTM Behind-the-meter

CES Competitive Energy Services

CMP Central Maine Power

CPC Clean Peak Credits

CPS Clean Peak Energy Standard

CSO Capacity supply obligation

DASI Day-ahead Ancillary Services Initiative

DRIPE Demand Reduction Induced Priced Effect

EDC Electric distribution companies

FCM Forward capacity market

FERC Federal Energy Regulatory Commission

FTM Front-of-the-meter

GEO Governor's Energy Office

IOU Investor-Owned Utility

IPP Individual power producers

IRA Inflation Reduction Act

ISC Index Storage Credit

ITC Investment Tax Credit

MRI Marginal reliability impact

MW megawatt

MWh megawatt-hour

NREL National Renewable Energy Laboratory

NSPM National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources

NYSERDA New York State Energy Research and Development Authority

O&M Operations and maintenance

OATT Open Access Transmission Tariff

PACT Program Administrator Cost Test

PCT Participant Cost Test

PTF Pool transmission facility

RCA Resource capacity accreditation

RCPF Reserve Constraint Penalty Factor

RFI Request for Information

RIM Rate Impact Measure

RNS Regional Network Service

SATOA Storage as Transmission Only Assets

SCT Societal cost test

SGIP Self-Generation Incentive Program

T&D Transmission and distribution

TMOR Thirty-minute operating reserves

TMSR Ten-Minute Spinning Reserves

TRCT Total Resource Cost Test

UCT Utility cost test

WDAT Wholesale distribution access tariff

EXECUTIVE SUMMARY

The Maine Governor's Energy Office (GEO) contracted Synapse Energy Economics and Sustainable Energy Advantage (the Project Team) to assess storage procurement options that meet the criteria of a 2023 state law that directs the GEO to evaluate designs for a program to procure up to 200 megawatts (MW) of commercially available utility-scale energy storage connected to Maine's transmission and distribution systems and to submit recommendations for review by the Public Utilities Commission.

As demonstrated in this report, energy storage can create societal and ratepayer value that storage resource owners may not be able to monetize through wholesale markets. As a result, providing carefully crafted policy support can yield net benefits to Maine ratepayers. This report details the Project Team's inputs, assumptions, and findings. It then recommends a storage incentive structure utilizing a fixed upfront incentive paired with a performance payment based on dispatch (or, for distribution-connected resources, an agreement to be available to be dispatched) in critical hours. As demonstrated by the Project Team's analysis, this recommended approach meets the relevant criteria specified by the law. Namely, the program must be cost-effective for ratepayers, advance state policy through the development of up to 200 MW of energy storage capacity, and improve reliability and/or resilience. The proposed programs must also leverage federal incentives as much as possible and support storage projects where they are most valuable to the system.

The Project Team leveraged qualitative and quantitative analysis of these criteria, as well as stakeholder input provided in response to a request for information and an open comment period issued by GEO, to assess procurement options for transmission- and distribution-connected storage. Given the differing technical and economic impacts of transmission vs. distribution-connected storage, the Project Team assessed these two use cases separately.

The Project Team also assessed whether storage is expected to displace fossil fuel resources, and whether storage operations are expected to reduce greenhouse gas emissions—or at least not increase greenhouse gas emissions—to address the comments of several stakeholders. The analysis confirms a substantial correlation between New England wholesale energy prices and greenhouse gas emissions. This implies that storage owners will be economically motivated to charge during hours of high renewable generation (when prices and emissions are lower) and discharge during periods of scarcity (when prices and emissions are higher) to maximize arbitrage revenue. Thus, optimizing wholesale market revenues is compatible with pursuing an emissions reduction strategy.

This analysis incorporates other stakeholder considerations, including but not limited to:

- Designing program incentives based on energy capacity of storage (kWh);
- Applying a societal cost test in addition to a utility cost test when considering the statutory criteria with which to evaluate program options;
- Assessing a range of storage durations; and

- Considering a range of potential benefits, including those that may be determined by interconnection to the transmission or distribution systems.

The Project Team assessed the cost-effectiveness of storage resources through the lens of a utility cost test and a jurisdictional societal cost test. The analysis demonstrates that most transmission- and distribution-connected storage options are likely to be cost-effective for ratepayers and support state emissions reductions goals.

Based on the analysis, the Project Team recommends transmission-connected storage resources be procured using a competitive solicitation framework that incorporates an upfront incentive based on the energy capacity of the resource (i.e. kWh) paired with a performance payment based on measured performance during critical hours that provide the greatest value to ratepayers.

Procurement of distribution-connected storage through a competitive solicitation framework can also be beneficial to ratepayers if distribution benefits in the form of avoided or deferred utility infrastructure costs are realized. Therefore, it may be beneficial to procure distribution-connected storage using a framework that incorporates partial-tolling agreements, which are comprised of ongoing payments to a third-party owner of the storage asset coupled with utility-directed dispatch during critical hours. The Project Team acknowledges that utility ownership and control of storage assets is a complex topic under ongoing consideration.[1] However, given the potential value to ratepayers that can be provided by storage connected to the distribution system, the Team recommends that 40 MW of the 200 MW target should be set aside for front-of-the-meter distribution-connected storage assets. If cost-effective distribution-connected storage cannot be procured, the Team recommends the 40 MW should be re-allocated to the competitive solicitation of transmission-connected storage.

GEO engaged Synapse Energy Economics and Sustainable Energy Advantage to develop this analysis to inform recommendations prepared by the GEO pursuant to Public Law 2023, Chapter 374 §2. This report contains recommendations from Synapse Energy Economics and Sustainable Energy Advantage to the GEO. To view the GEO's recommendations submitted pursuant to P.L. 2023 Ch. 374 §2, visit https://www.maine.gov/energy/studies-reports-working-groups/completed-reports.

[1] See, for example, the Commission's March 13, 2024, Report on Utility Control or Ownership of Energy Storage and related stakeholder comments in Docket No. 2023-0316.

1. INTRODUCTION AND OVERVIEW

The Maine Governor's Energy Office (GEO) contracted Synapse Energy Economics and Sustainable Energy Advantage (the Project Team) to assess and evaluate procurement options for a program to procure commercially available utility-scale energy storage systems connected to the transmission and distribution systems that meet the criteria and objectives as described in Section 2 of Public Law 2023, Chapter 374 "An Act Relating to Energy Storage and the State's Energy Goals" (LD 1850 or "the Act"), which was enacted on June 30, 2023. These criteria and objectives are as follows:

> In evaluating programs for the procurement of energy storage systems, the office shall consider programs that are likely to be cost-effective for ratepayers and that are likely to achieve the following objectives:
>
> A. Advance both the State's climate and clean energy goals and the state energy storage policy goals established in Title 35-A, Section 3145 through the development of up to 200 megawatts (MW) of incremental energy storage capacity located in the state;
>
> B. Provide one or more net benefits to the electric grid and to ratepayers, including, but not limited to, improved reliability, improved resiliency, and incremental delivery of renewable electricity to customers;
>
> C. Maximize the value of federal incentives; and
>
> D. Enable the highest value energy storage projects, specifically energy storage systems in preferred locations, projects that can serve as an alternative to upgrades of the existing transmission system, and projects of optimal duration.[2]

The Act directs GEO to encourage stakeholders to provide input for the evaluation. GEO issued a Request for Information (RFI) to interested parties to inform the evaluation.[3] It received 18 responses

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[2] LD 1850, Section 2.

[3] GEO issued an RFI to seek public input to inform GEO's implementation of section 2 of P.L. 2023, chapter 374 on November 13, 2023, the responses to which have been reviewed by the Project Team. All comments received in response to this RFI have been made available to the public on the GEO's website at: https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/storage-procurement-study-1850.

from a range of stakeholders. The GEO also issued an Opportunity for Comment on a draft report describing the proposed program design and received 13 comments.[4]

The Project Team considered these responses in conducting both qualitative and quantitative analysis of the established criteria to assess procurement options for transmission- and distribution-connected storage. Given the differing technical and economic impacts of transmission vs. distribution-connected storage, the Project Team assessed these two use cases separately.

This report provides a review of stakeholder comments regarding LD 1850 criteria, qualitative analysis and evaluation of multiple potential storage procurement mechanisms to meet the goals of LD 1850, and a selected storage procurement mechanism. The report then details the cost-effectiveness framework utilized to assess the cost-effectiveness of storage procurement, results from this framework, and finally, the Project Team's recommendations.

2. Review of LD 1850 Criteria

In this section, the Project Team provides an overview of several important issues for consideration in relation to the criteria outlined in LD 1850 (see page 0 for legislative language).

This section includes a discussion of each criterion and relevant considerations based on the Project Team's research and stakeholder feedback solicited through GEO's RFI. The sub-sections below describe the stakeholder feedback, other points not addressed by stakeholders, and the Project Team's evaluation of the criteria. The sub-sections also discuss other important considerations that are critical to an effective program design, in addition to the LD 1850 criteria.

2.1. Cost-Effectiveness

When asked for feedback regarding how the Maine Energy Storage Program should value and prioritize net benefits to the electric grid, stakeholders emphasized the importance of choosing appropriate tests to value the program design. Overall, stakeholders encouraged consideration of the following benefits: capacity value, ancillary service value, arbitrage revenue, energy and capacity market price suppression (a corollary to Demand Reduction Induced Priced Effect, or DRIPE), reduced curtailment of renewable energy, reliability benefits, resiliency benefits, distribution benefits, and health benefits from lowered emissions.

[4] GEO issued an RFI to seek public input to inform GEO's evaluation of program designs to implement section 2 of P.L. 2023, chapter 374 on March 12, 2024. All comments received in response to this RFI have been made available to the public on the GEO's website at: https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/GEO%20Energy%20Storage%20Program%20RFI%20Responses%202024.pdf.

Central Maine Power (CMP) recommended consideration of the Rate Impact Measure (RIM) and Participant Cost Test (PCT) to ensure an economically viable program design that is in the best interest of ratepayers.[5] CMP also noted that "[c]ost-benefit tests such as the Societal Cost Test (SCT), Total Resource Cost Test (TRCT), and Utility Cost Test (UCT) or Program Administrator Cost Test (PACT) can be informative and should be utilized in a supportive manner to quantify the benefit to specific stakeholder groups, and to quantify non-energy related benefits such as emissions reduction as appropriate."[6] New Leaf and Blue Wave recommended a benefit-cost analysis test in line with what was used in Connecticut to evaluate front-of-the-meter (FTM) storage: TRCT, SCT, and the PCT.[7]

Stakeholders discussed additional factors that impact cost-effectiveness, specifically for storage assets that do not participate in wholesale capacity markets such as load reducers and Storage as Transmission Only Assets (SATOA). New Leaf and Blue Wave highlighted that distribution-connected storage can reduce peak load during annual and monthly peak hours, ultimately reducing the cost that distribution companies, and therefore ratepayers, pay to ISO New England (ISO-NE) for capacity and transmission.[8] New Leaf and Blue Wave recommended that distribution-connected energy storage projects function exclusively as load reducers, stating that this option can increase overall cost-effectiveness for ratepayers by reducing the need for future transmission buildout.[9] Stakeholders noted that reduced costs associated with grid infrastructure buildout due to effective storage deployment could help meet the LD 1850 cost-effective criteria. Competitive Energy Services (CES) reviewed how opportunities for SATOAs are limited in New England's markets in terms of siting requirements, grid contingencies they can address, and their inability to participate in wholesale markets. CES noted that the limits on SATOAs will stifle their potential benefits.[10] The Project Team agrees that the storage program should not include SATOAs due to these limitations. Therefore, SATOAs have not been assessed in this cost-effectiveness analysis.

The Project Team considered stakeholder feedback on cost-effectiveness, along with the legislative requirements. For its benefit-cost analysis, the Project Team determined it would evaluate a jurisdictional (Maine-specific) version of the SCT to assess the storage program as well as the UCT. The jurisdictional SCT includes the benefits and costs expected from a storage procurement for the state of Maine. It is designed to reflect the energy goals in Maine and provide a regulatory perspective that

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[5] Comments submitted by Central Maine Power in response to the Governor's Energy Office's RFI [hereinafter "CMP Comments"].

[6] CMP Comments.

[7] Comments submitted by New Leaf and Blue Wave in response to the Governor's Energy Office's RFI [hereinafter "New Leaf and Blue Wave comments"] (referencing https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/434aa27c309ed083852 5885d00643350/$FILE/FTM%20Energy%20Storage%20Projects%20in%20CT%20-%20BCA%20061020 22.pdf).

[8] New Leaf and Blue Wave Comments.

[9] New Leaf and Blue Wave Comments.

[10] Comments submitted by Competitive Energy Services in response to the Governor's Energy Office's RFI [hereinafter "CES Comments"].

represents the views of legislators, commissioners, and other relevant decision-makers. The UCT evaluates costs and benefits from a utility-system perspective. See Section 6 for further discussion.

For the base case analyses, the Project Team modeled transmission-connected storage projects as wholesale market participants operating primarily based on wholesale energy market signals. Distribution-connected projects were modeled as load reducers that do not participate in wholesale capacity or energy markets. In the short term, only resources located south of the Surowiec interface are considered deliverable and able to participate in ISO-NE's forward capacity market due to transmission constraints to the north. Resources located north of the Surowiec interface may be able to provide benefits of comparable value if their location-specific benefits are significant (such as if they defer a specific transmission need). This dynamic may change as New England engages in new longer-term transmission planning. As requested by the New England States Committee on Electricity, ISO-NE anticipates publishing an RFP for new transmission to increase the capacity of Surowiec-South and Maine-New Hampshire interfaces in March of 2025.[11]

The Project Team examined the robustness of the cost-effectiveness results by varying key inputs through several sensitivity analyses, discussed in Section 0.

2.2. Advance Maine's Climate, Energy, and Storage Policy Goals

Emissions Reductions

Maine law requires greenhouse gas emission reductions of 45 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. Maine also has substantial clean energy goals required by its Renewable Portfolio Standard, including a requirement that 80 percent of Maine's load be served by renewable energy resources by 2030 and a goal of 100 percent by 2050.[12] When asked how the Maine Energy Storage Program should be designed to reduce greenhouse gas emissions and meet clean energy goals, stakeholders emphasized that energy storage should complement large-scale solar and onshore wind to support the incremental delivery of clean energy while reducing transmission constraints.[13] Specifically, RENEW commented on the ability of storage to reduce the price of Renewable Energy Certificates by increasing the supply of clean energy while minimizing curtailment and associated costs.[14] Stakeholders also emphasized energy storage's ability to displace resources that emit

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[11] ISO-NE. "2025 Maine Longer-Term Transmission Planning RFP" presentation to the Planning Advisory Committee. January 23, 2025.

[12] State of Maine Governor's Energy Office, "Renewable Portfolio Standard.' Accessed: https://www.maine.gov/energy/initiatives/renewable-energy/renewable-portfolio-standard#:~:text=Maine's%20renewable%20portfolio%20standard%20(RPS,of%20100%20percent%20by%202050.

[13] New Leaf and Blue Wave, CES, CMP, and RENEW Comments.

[14] Comments submitted by RENEW in response to the Governor's Energy Office's RFI [hereinafter "RENEW comments"].

greenhouse gases and other particulate matter.[15] Stakeholders recommend incentivizing charging during hours when more renewables are generating energy and discharging during high-emission hours.[16] CES and New Leaf/Blue Wave suggest the criteria for incremental delivery of renewable electricity should focus on whether operations of an energy storage system can reduce greenhouse gas emissions from marginal combustion sources in ISO-NE's generation fleet.[17]

The Project Team considered stakeholder feedback regarding Maine's emissions reductions and clean energy goals. If wholesale prices strongly correlate with marginal emissions (i.e., prices are low during low marginal emission rate periods and prices are higher during periods with higher marginal emission rates), then storage resources that optimize dispatch according to wholesale revenues are likely to reduce emissions. Under this paradigm, resources would be incentivized to charge during periods of low prices and low emissions, and discharge during periods of high prices and high emissions. The Team generally expects to see a strong correlation between prices and emissions in systems with high renewable energy penetration since renewables have zero marginal operating costs. However, since gas units are currently frequently on the margin in New England, there is a concern that optimizing dispatch purely according to wholesale market signals could potentially lead to increased emissions.

In the long term, well-sited storage should lead to reductions in average grid emissions by enabling increased renewable energy penetration. However, the question of short-term emissions impacts is a critical one for a program expected to deploy storage in the near term. If economic dispatch (maximizing wholesale revenues) under current system conditions reduces emissions, the program would not require further incentives beyond wholesale market signals to guide

Electrical Grid Marginal Resources and Emissions

Grid operators dispatch lower-cost resources first and then bring other available resources according to current electric demand. The last resource dispatched to meet demand is the most expensive resource dispatched and dictates the wholesale market prices for that moment. This last resource is considered the "marginal resource" of the dispatched supply stack and will be the first resource displaced by newly available and less costly resources. Thus, the emissions displaced by a newly available resource such as storage will depend on the emissions of the marginal resource.

In periods of high electric demand, the higher-priced resources are typically fossil fuel (combustion) resources with higher emissions because they have higher costs to bring more generation online (due to fuel costs and other operating costs). Non-emitting renewable resources have no fuel costs and lower operating costs and so costs to bring more online (if available) are practically zero.

On a grid with an ample supply of available renewable resources, the correlation between high prices/high emissions and low prices/low emissions holds true. This means storage resources designed to buy-low/sell-high would receive market price signals that align with goals to reduce emissions. Without sufficient renewable resources, electric demand may not dip low enough to have non-emitting resources on the margin.

[15] New Leaf and Blue Wave, CES, CMP, and RENEW Comments.

[16] New Leaf and Blue Wave, CES, CMP, and RENEW Comments.

[17] CES and Blue Wave Comments.

dispatch. However, if economic dispatch leads to increased emissions, the program would require an incentive structure to mitigate this issue.

To determine whether a storage procurement program must include an emissions-based performance incentive, or whether economic dispatch is expected to be sufficient to meet emissions reduction goals, the Project Team conducted an analysis of projected emission impacts under economic dispatch. The Team modeled energy storage systems of 2-, 4- and 6-hour durations, optimizing to maximize energy arbitrage revenues based on hourly wholesale market energy prices. This analysis utilized hourly prices and hourly marginal emissions data from New England's 2024 *Avoided Energy Supply Costs* study (AESC 2024).[18]

Figure 1 shows the projected cumulative net carbon dioxide (CO_2) impact over the 20-year modeling period (note that positive values indicate net reductions in CO_2 emissions). Overall, the Team found that battery systems that dispatch economically to maximize energy arbitrage revenues are projected to cause a net decrease in marginal CO_2 emissions in most years, and a cumulative net decrease over the study period for all three system durations. In the short run, it is possible that marginal emissions may sometimes increase by a small amount, due to round-trip efficiency losses, if the actual correlation between prices and emissions is not as strong as projected, or if individual operators follow different dispatch patterns than those modeled.

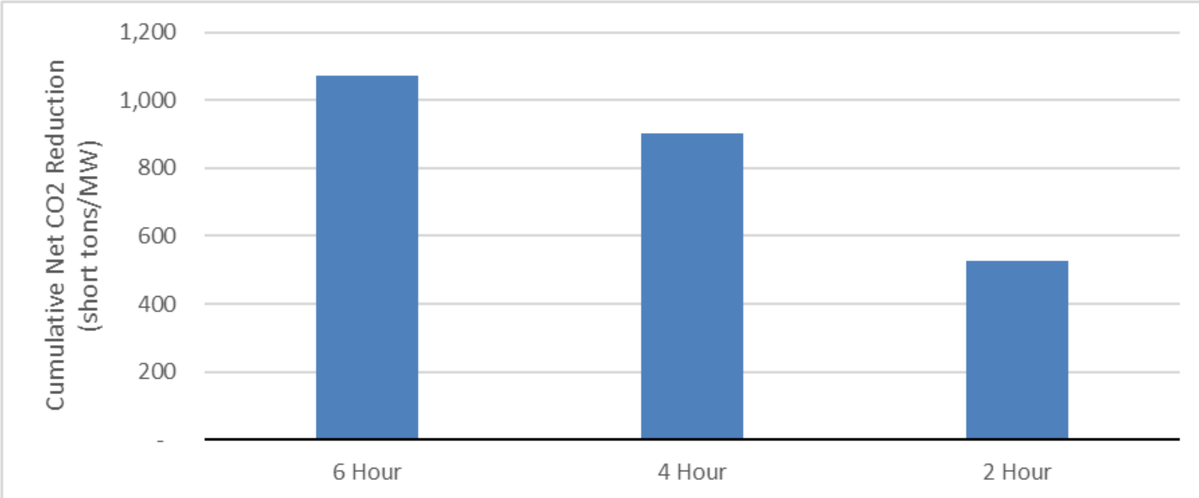
However, viewed from a long-run perspective, energy storage is expected to substantially reduce systemwide greenhouse gas emissions when considering the impact of storage on structural change (including new generation, retirements, and transmission buildout).[19] One of the key benefits of energy storage is that it enables a greater level of renewable energy penetration, fundamentally changing the resource mix on the grid. Energy storage can help balance intermittent renewable energy by storing excess energy and releasing it when needed. This type of build impact is not captured in a short-run marginal emissions analysis but has been quantitatively assessed and validated in other studies.[20] Furthermore, energy storage arbitrage is expected to reduce energy prices, which can help drive increased electrification, resulting in emissions reductions outside of the power generation sector.

[18] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. 2024. Avoided Energy Supply Components in New England: 2024 Report. Prepared for AESC 2024 Study Group. https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc.

[19] Gagnon, Pieter et al. 2022. "Planning for the evolution of the electric grid with a long-run marginal emission rate." *iScience,* Volume 25, Issue 3, 103915. National Renewable Energy Laboratory (NREL). https://www.cell.com/iscience/fulltext/S2589-0042(22)00185-7?_returnURL=https%3A%2F%2Flinkinghub.elsevier.com%2Fretrieve%2Fpii%2FS2589004222001857%3Fshowall%3Dtrue#%20.

[20] Synapse Energy Economics. 2023. *Modeling the Benefits of Energy Storage in Maryland.* Accessed: https://www.synapse-energy.com/sites/default/files/23-006%20FINAL%20Modeling%20the%20Benefits%20of%20Energy%20Storage%20in%20Maryland%204.11.2023.pdf.

Figure 1. Cumulative CO_2 emissions reduction over 20-year study period (positive values indicate reductions)



The Project Team does not currently recommend that a storage procurement program include an incentive to reduce emissions. Further, the Team notes that generators cannot make operational decisions that consider their emissions impact without real-time data on marginal emissions to which they can respond. Maine does not currently have this data available. However, given the uncertainty around how actual storage resources will dispatch, the Project Team recommends that the program include an annual evaluation that will feature a retrospective analysis of the real-world resource emission impacts. If this evaluation shows that grid emissions are, in fact, increasing due to storage dispatch, the program may need modifications to incorporate an emission price signal.

Incrementality of Storage Projects

While the program design should incentivize the deployment of projects that are "additional"–i.e. would not be constructed but for a program to support them—the Project Team recommends the program account for the barriers facing storage developers. Storage facilities can be quick to construct, but interconnection can take a long time. Recent timelines have reached as long as five years. Throughout the lengthy interconnection process, many projects withdraw. Nine (640MW) of the eleven (831 MW) standalone projects that entered the ISO-NE queue since 2017 have withdrawn. Projects currently in the queue will benefit from incentives and may be better able to stay in the queue, rather than withdraw as challenges arise.

On the other hand, projects that are further along in the development process and have already received financial compensation through markets or incentives should not qualify for additional incentives. CES's responses to the RFI emphasized the need to procure additional incremental energy storage. Specifically, it recommends that the 200 MW solicitation exclude storage projects that have already acquired a capacity supply obligation (CSO) in ISO-NE's forward capacity market (FCM), as well as active projects co-located with generation enrolled in net energy billing. The latter is already being developed based on net billing incentives and would not offer additionality.[21] The Project Team agrees with this assessment.

2.3. Net Benefits to the Grid and Ratepayers

When asked how the Maine Energy Storage Program should value and prioritize net benefits to the grid, stakeholders emphasized the importance of maximizing transmission and distribution benefits, along with emissions reduction. CES states that benefits can vary depending on the storage system design, how it interconnects to the grid, location, and operational practices.[22] CES encourages the deployment of behind-the-meter (BTM) storage.[23] CMP suggests the Maine Energy Storage Program define net benefits or "improved electric resiliency" as the reduction of the frequency and duration of outages during severe weather conditions and major storms.[24] CMP also recommends that GEO "prioritize benefits such as reliability- and resiliency-based avoided costs, avoided energy, capacity costs, transmission and distribution benefits, monetized reliability, and energy storage's effect on wholesale energy prices."[25] RENEW states that increasing energy storage capacity to lower peak demand will help Maine improve the reliability of power delivery to customers and may provide resilience under changing conditions.[26]

New Leaf and Blue Wave also suggested that in the context of Maine's geographical and electric system, smaller energy storage facilities located closer to load will better enhance reliability and resilience.[27] Furthermore, they note that, because Maine has a large pipeline of distributed solar in the interconnection queue and a transmission system that requires upgrades, distribution-connected storage can provide multiple values to ratepayers because it is located closer to the load (compared with transmission-connected storage).[28]

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[21] CES Comments.

[22] Comments submitted by Competitive Energy Services in response to the Governor's Energy Office's RFI [hereinafter "CES Comments"].

[23] CES Comments.

[24] Comments submitted by Central Maine Power in response to the Governor's Energy Office's RFI [hereinafter "CMP Comments"].

[25] CMP Comments.

[26] Comments submitted by RENEW in response to the Governor's Energy Office's RFI [hereinafter "RENEW comments"].

[27] "New Leaf and Blue Wave comments"] (referencing https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110 e3e852576190052b64d/434aa27c309ed083852 5885d00643350/$FILE/FTM%20Energy%20Storage% 20Projects%20in%20CT%20-%20BCA%20061020 22.pdf).

[28] New Leaf and Blue Wave Comments.

The Project Team finds the program should seek to procure both distribution- and transmission-connected storage as both are needed to fully maximize the benefits of energy storage. The Team assessed the value of net benefits using a robust cost-effectiveness framework to accurately account for multiple benefits provided by energy storage. Furthermore, wholesale market participation will promote operations that yield reliability benefits and net benefits to ratepayers. As more storage comes online, particularly in the long term, the resource deployment will likely lead to the larger-scale impacts referenced by stakeholders. However, for this report, the analysis considers net benefits to ratepayers based on the scale of the program anticipated by LD 1850 and batteries with 2- to 6-hour durations, which are currently commercially available.

2.4. Maximizing Federal Incentives

Per LD 1850, energy storage projects should aim to maximize federal incentives, most notably the Investment Tax Credit (ITC), established by Section 48 of the *Inflation Reduction Act* (IRA).[29] Previously, only co-located storage projects were eligible for the ITC, but the August 2022 passage of the IRA made standalone energy storage projects with a minimum capacity of 5 kWh eligible as well.[30]

To maximize the value of the ITC, projects should begin construction before 2033, when tax credits may begin to phase out.[31] Projects can achieve a base ITC value of 30 percent of upfront capital costs if prevailing wage and apprenticeship requirements are fulfilled.

If the project meets certain domestic content sourcing requirements, the ITC is increased by 10 percent above the base 30 percent.[32] The U.S. Internal Revenue Service domestic content criteria requires two equipment sourcing conditions: (1) 100 percent of construction materials that are structural in nature and are comprised of iron or steel must have all steel and iron manufacturing processes take place in the United States, except metallurgical processes involving refinement of steel additives; and (2) a specified percentage of manufactured products (measured in product cost) that are components of the energy storage system must be produced in the United States.[33] Current supply chain challenges will likely make it difficult to cost-effectively achieve the U.S. Internal Revenue Service requirements for domestic content, and the tradeoff between the additional 10 percent ITC credit and the increased capital costs may not be worth it. Therefore, the Project Team recommends that the Maine storage program not

[29] 26 USC § 48.

[30] Utility Dive, "IRA sets the stage for US energy storage to thrive" (Nov. 7, 2022). Accessed: https://www.utilitydive.com/spons/ira-sets-the-stage-for-us-energy-storage-to-thrive/635665/.

[31] The ITC will phase out in the later of 2032 or when the United States reduces its electric sector emissions by 75 percent greenhouse gas emissions reduction.

[32] 26 USC § 48(10).

[33] CES comments.

include domestic content as a selection criterion despite the potential to maximize federal incentives.[34] If domestic sourcing costs go down, this could be re-evaluated later.

The ITC can also increase by 10 percent if an energy storage project is sited in an energy community.[35] An energy community, as defined in the IRA, includes brownfield sites, communities affected by coal mine and/or coal plant closures, and areas that have a minimum level of fossil fuel industry activity and an unemployment rate at or above the national average. There are no municipalities in Maine that qualify as an energy community under the second two categories of the definition.[36] Therefore, storage projects would need to be located on a qualifying brownfield property in Maine to qualify for the energy community bonus adder. Siting a battery project on a qualifying brownfield property will also provide local tax revenues and productive use of property that likely would not be developed or otherwise reused.

When asked how Maine Energy Storage should be designed to maximize federal incentives, stakeholders reinforced that the Maine program should be designed to maximize all federal funding. CMP states that while federal funding should be maximized, it is not always guaranteed and, therefore, should be considered case by case.[37] CES notes that the selection criteria for procurement should focus on supporting projects that maximize the ITC and the energy community bonus adder.[38]

While the Project Team believes a competitive solicitation will incentivize bidders to include tax credits to ensure price competitiveness, the Project Team recommends that the solicitation require vendors to indicate what tax credits they anticipate receiving as part of the bidding process.

2.5. Achieving the Highest Value Storage

When asked how Maine could provide the highest value energy storage, specifically in preferred locations and optimal duration, stakeholders raised multiple considerations.

Preferred Locations

Regarding a preferred location, stakeholders responding to the RFI raised several potential preferred locations to consider: low-income communities, export-constrained areas, microgrids, and areas of expected load growth (which can also defer distribution or transmission investment). There appear to be a range of stakeholder opinions on this issue. In response, New Leaf and Blue Wave suggested that the program not prescribe specific locations for development (e.g., certain circuits on the distribution

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[34] 26 USC § 48(12).

[35] 26 USC § 48(14).

[36] CES comments; US Department of Energy, Energy Community Tax Credit Bonus Map. Accessed: https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d.

[37] CES comments.

[38] CES comments.

system, which is an approach included in the Massachusetts Clean Peak Energy Standard). On the other hand, RENEW suggested placing storage where it can meet specific transmission constraints and increase reliability.

The Project Team finds that while cost-effectiveness evaluations of particular bids should include locational benefits and costs, the program should not prescribe specific locations *ex-ante*. The Team finds it is appropriate to include land-use and locational considerations when scoring bids, given that, for example, projects in locations that can provide reliability, air quality, or other benefits to vulnerable populations may help improve energy equity in Maine. However, the Team agrees with stakeholders that suggest the solicitation need not include requirements for certain locations. The Project Team also considered whether there should be requirements for (or are incremental benefits associated with) storage that is physically co-located with renewable resources. At a bulk power system level, there are clear and significant capacity synergies associated with increasing deployment of storage and intermittent resources. Realizing these capacity diversity benefits does not, however, require physical co-location of resources. Benefits to physical co-location may include resiliency benefits (to the extent that the system can be islanded or otherwise operated to provide resiliency benefits), interconnection optimization, or congestion management (reduced curtailment and energy arbitrage). As discussed in Section 6.2, realizing resiliency benefits from FTM paired storage and renewables would require additional investments that are not considered in this study; furthermore, the Team determined that interconnection optimization and its potential benefits are best determined by developers on a case-by-case basis. Therefore, this report does not explicitly consider storage co-located with renewables. Physically co-located projects, however, could still be eligible to participate in the proposed programs.

Lastly, stakeholders noted that resilience and reliability can be supported through consideration of distribution-connected storage that enables microgrids; this would allow certain loads connected to the microgrid to “island” from the broader system during storms or other outage events. The Project Team agrees that microgrids can provide resilience and reliability. However, the Team did not specifically model the value of microgrids for two primary reasons. First, microgrids involve more than the deployment of storage—often renewables or fossil fuel generators must be deployed in conjunction with storage to operate a microgrid for more than a few hours. This is beyond the scope of the Team’s analysis. Second, utility investment to island portions of the grid during an outage must be considered. This is a cost which is highly project-specific and likely unique to each utility’s system. In sum, the fact that microgrids are a distinct use case that include, but are not limited to storage, precluded consideration of microgrids in the analysis.

Alternative to Transmission System Upgrades

Regarding alternatives to transmission system upgrades, New Leaf and Blue Wave proposed a program designed around distribution-connected storage registered as load reducers with ISO-NE, which would reduce the allocation of Regional Network Service (RNS) charges to Maine ratepayers (a significant value). CMP states that energy storage should be considered as an alternate solution to transmission upgrades if it is the most cost-effective option.

There are two primary potential transmission-related benefits that can accrue to Maine ratepayers. As referenced above, the first potential benefit is reducing the portion of pool transmission facility (PTF) costs recovered from Maine ratepayers due to past incurred investment. This benefit does not require altering the trajectory of total PTF buildout, but, instead, reduces the portion of these costs paid for by Maine ratepayers relative to other New England electric customers. The second potential transmission benefit is reducing total transmission buildout. This benefit is more challenging to quantify, as it hinges upon the transmission planning process, both as it exists today and as it evolves in the future. As discussed in subsequent sections, the Team modeled resources to discharge during coincident peaks, a mode of operation most likely to avoid future transmission buildout. The Project Team recommends moving ahead with designing a program around this mode of operation. At the same time, policymakers will need to actively engage in the transmission planning process to ensure that storage of different configurations can contribute to avoided transmission costs.[39]

Optimal Duration

Currently, only a small portion of energy storage systems can provide their nameplate power for more than four hours. Longer-duration storage will be needed as Maine and the rest of New England shift from summer to winter peaks that coincide with less renewable output. As technology rapidly evolves, much-longer-duration storage may become more widely available. Still, shorter-duration storage can provide substantial value today and well into the future. For this reason, stakeholders recommend that GEO, and in turn, the Commission, not be overly prescriptive about duration within procurement processes to leave space for that development.[40] CES noted that, because a system's energy capacity drives its installation costs, the program should not impose a single uniform design specification for all storage projects. However, CES ultimately recommended that battery systems need to have a minimum of four to six hours of duration to enable transmission investment deferral.

The Project Team agrees with stakeholders that there is no need to be overly prescriptive about the exact duration of storage projects sought for procurement. A well-crafted program should provide incentives for battery dispatch that will yield benefits to ratepayers, allowing developers to make decisions about the configuration that will optimize value subject to the design of the program and other potential market revenues. Given that LD 1850 directed GEO to evaluate designs for a program to procure "commercially available utility-scale energy storage," the Team's analysis focused on assessing battery storage durations ranging from two to six hours. If longer-duration technologies become commercially available at cost-competitive prices, these resources would be eligible to participate in the program. At current levels of technology development and pricing, the Team finds 4–6-hour battery durations to be the most beneficial to ratepayers and society (discussed further in Section 5). As

[39] Future solicitations could focus on areas with anticipated transmission needs. For example, ISO-NE's 2050 Transmission Study identifies key areas of constraints that will require transmission upgrades.

[40] New Wave and Blue Leaf and CMP Comments.

renewable energy penetration levels increase and grid needs evolve, the program may target longer-duration resources.

2.6. Other Considerations

There are a few other important considerations for evaluating a storage procurement mechanism that were not included as criteria in LD 1850. For example, the “finance-ability” of projects is not a legislative criterion. However, stakeholders raised concerns about the potential for overly prescriptive or complicated procurement options to make projects overly expensive.[41] The Project Team agrees that the selected procurement mechanism should be relatively simple and allow for flexibility.

The storage program should also consider the administrative burden that would come with a procurement mechanism. Any mechanism that is overly complicated, costly, or otherwise burdensome to implement could delay the procurement of energy storage, drive up ratepayer costs, or simply not be worth the burden to procure 200 MW of storage, which is a smaller amount than other states have procured with more administratively complex mechanisms.

Risk allocation is another key consideration. It is important to consider which parties bear financial risk with any procurement mechanism. For example, if a developer bears all of the risk for an investment, this would minimize risk to ratepayers and place the risk on the party with the greatest control and ability to manage that risk. However, such a set up could increase financing costs or make a project too risky for a developer to pursue at all. This could ultimately prevent ratepayers from realizing the benefits of storage. Therefore, the selected procurement mechanism needs to strike the right balance for risk allocation.

Finally, there will be different considerations for transmission- and distribution-connected storage based on which parties control infrastructure and are tasked with managing risk. Transmission infrastructure is managed by ISO-NE in New England. The ISO conducts regional transmission planning for economic and reliability purposes, works with many different parties, and maintains data on potential constraints. At the distribution level, electric distribution companies (EDC) control the infrastructure and data, and are tasked with managing risks to the system.

3. EVALUATION OF STORAGE PROCUREMENT MECHANISMS

Storage incentive programs are becoming increasingly common as more states pass legislative storage targets. Across the country, states use differing mechanisms, incentive policies, and a range of ownership models to reach their goals. This section reviews potential procurement program designs and

[41] New Wave and Blue Leaf and CMP Comments.

examines other states' assessments, including any relevant difficulties encountered. It then considers the implications of each mechanism for Maine.

The Project Team considered the following program designs to procure storage based on a review of existing state programs and responses to the RFI:[42] pay-for-performance incentives, clean peak credits, index storage credits, and tolling agreements.[43]

Table 1. Procurement program parameters

	Pay for Performance + Upfront Incentive	Index Storage Credit	Clean Peak Credit	Tolling Agreement
Ownership	Third party	Third party	Third party	Third party
Dispatch control	Third party and/or utility	Third party	Third party	Utility
Incentive timing	Upfront and ongoing throughout project operations	Ongoing throughout project operations	Ongoing throughout project operations	Ongoing fixed payment
Dispatch logic	Depends on performance criteria	Maximize wholesale revenues	Scheduled based on system peaks / administratively determined	At the utility discretion depending on the purpose of procurement

3.1. Tolling Agreements

Description of Procurement Option

An energy storage tolling agreement is a long-term contract that operates similarly to a standard tolling contract for traditional power plants or solar installations.[44] Under this mechanism, a project owner is responsible for obtaining site control, permits, interconnection rights, equipment, construction contracts, and an agreeable operation date with the buyer of the system's output (often the EDC). The EDC pays for the electricity used to charge the battery storage system and receives the right to charge or discharge the system for energy, capacity, and ancillary services in the wholesale markets to maximize revenue.[45] The project owner receives a fixed payment called "a tolling fee" from the EDC, often in the form of a capacity and variable operations and maintenance (O&M) payment. A "partial-tolling agreement" balances utility-owned storage and a third-party-owned project by allowing the project to

42 CES, CMP, Blue Wave and New Leaf, and RENEW Comments.

43 Maine Governor's Office. Accessed February 26, 2024. https://www.maine.gov/energy/sites/maine.gov.energy/files/2024-01/RFI%20Responses%20combined%20file.pdf.

44 Staff, RENEW. "Public Act 21-53 Procurement for Energy Storage." RENEW Northeast, December 2, 2021. https://renewne.org/public-act-21-53-procurement-for-energy-storage/.

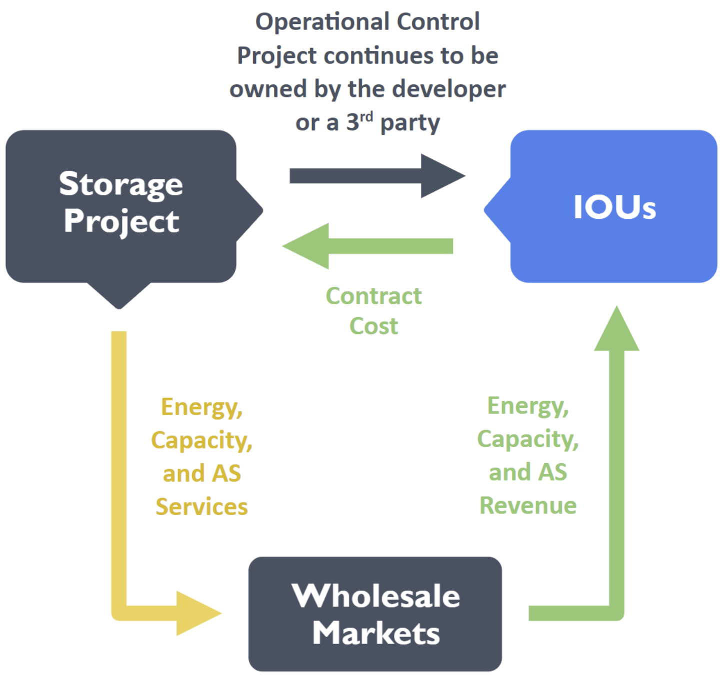
45 Energy Storage Handbook. https://www.klgates.com/epubs/Energy-Storage-Handbook-Vol2/offline/download.pdf.

operate on a merchant basis on most days in exchange for EDC control on the most valuable days of the year.[1]

Over the last several decades, utilities have used tolling agreements to finance battery energy storage systems in states where utilities are allowed to own and manage generation.[46] In states where this is prohibited, tolling agreements have been more challenging to implement. In New York, the State directed electric utilities to solicit storage through a tolling agreement called bulk storage dispatch rights.[47]

Figure 2 depicts a tolling agreement arrangement in which an Investor-Owned Utility (IOU) pays a third-party developer to deploy storage but retains operational control (dispatch control). The project is dispatched to optimize wholesale market revenues. These ultimately flow back to the utility, avoiding certain costs to the benefit of ratepayers.

Figure 2. Illustrative tolling agreement framework



Source: Adapted from image in the 2022 New York State Energy Research and Development Authority (NYSERDA) Report: "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." "AS" stands for ancillary services.

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[46] Key Capture Energy. 2024. "Building the Grid of Tomorrow; How Indexed Energy Storage Contracts Can Deliver Low-cost, High-value Battery Storage." https://keycaptureenergy.com/.

[47] Key Capture Energy. 2024. "Building The Grid of Tomorrow; How Indexed Energy Storage Contracts can deliver Low-cost, High-value Battery Storage." https://keycaptureenergy.com/.

Benefits and Risks

Under a tolling agreement, ratepayers and developers face risks inherent to a fixed-price contract. Ratepayers risk overpaying for assets above the actual revenue requirement if the solicitation process is uncompetitive. On the other hand, developers face the risk of rising capital costs if there is a delay between when the contract and project come to fruition.

If structured correctly, tolling agreements can mutually benefit utilities, ratepayers, and developers. Tolling agreements can be especially beneficial in markets relying on bilateral agreements between utilities and individual power producers (IPP), namely vertically integrated markets.[48] In these contexts, utilities have more information regarding transmission availability and congestion than IPPs. The utility is better positioned to optimize system dispatch, whereas the IPP is best positioned to operate and maintain the asset cost-effectively. This division of responsibilities can reduce costs and maximize either wholesale revenues or other system benefits, like distribution or transmission deferral opportunities, where utilities have greater visibility.[2]

Utility dispatch through a full tolling agreement has two main benefits. First, while there is some publicly available information about the operation (historical and in real time) of the bulk distribution system that can be leveraged by third parties to optimize dispatch, there is currently limited visibility for third parties into the real-time needs of specific substations or feeders. Second, a utility may only elect to defer distribution upgrades if it has the certainty associated with the type of dispatch control offered by a tolling agreement.

The Project Team finds that while tolling agreement structures are well understood and widely utilized, they do not necessarily incentivize optimal storage dispatch to maximize storage revenues. Nevertheless, these agreements are relatively simple to implement, which can help Maine achieve its state goals for deploying incremental storage, particularly in instances when maximizing wholesale market revenues is less important to project value.

3.2. Clean Peak Credit

Description of Procurement Option

Clean Peak Energy Credits provide incentives to clean energy technologies, including energy storage, for each megawatt-hour (MWh) of energy generated during seasonal peaks.[49] Storage projects receive compensation for discharging at pre-determined peak hours.[50] Under this procurement mechanism, energy storage projects sell their clean peak credits (CPC) to an off-taker, which could include a state

[48] Proadmin. "Emerging Trends in Utility-Scale Renewables." EDF Renewables North America, February 19, 2021. https://www.edf-re.com/emerging-trends-in-utility-scale-renewables.

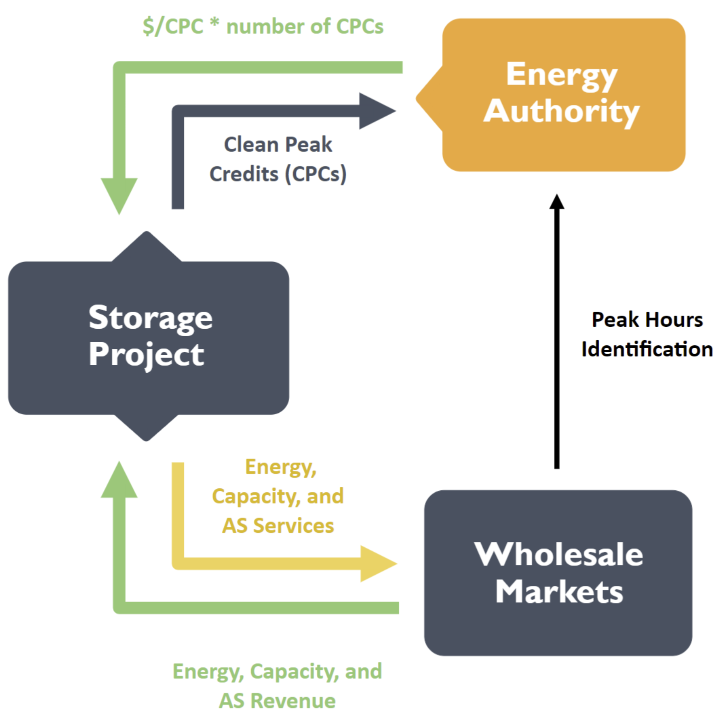
[49] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage

[50] *Id.,* p.42.

energy authority or a load-serving entity, depending on how the policy is designed. In return, storage projects receive the monetary equivalent of their credits based on a dollar amount ($/CPC * CPC).[51] Storage must serve an increasing portion of load during peak hours. Depending on the design of the policy and other constraints, projects may also receive revenue from wholesale energy and capacity markets.

Massachusetts currently uses Clean Peak Energy Credits for storage procurement through the Clean Peak Energy Standard (CPS). Load-serving entities in the state must regularly acquire a minimum quantity of Clean Peak Energy Certificates, which is intended to signify the amount of clean energy placed on the grid during peak hours.[52] CPS also includes various multipliers, which increase the volume of certificates produced. One such multiplier is for production during the monthly coincident peak, defined as the highest net demand for electricity in a calendar month in the ISO-NE area.[53]

Figure 3. Illustrative Clean Peak Credit framework



Source: Adapted from the 2022 NYSERDA Report: "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." "AS" stands for ancillary services.

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[51] *Id.,* p.42.

[52] Massachusetts, *Clean Peak Energy Standard Guidelines,* https://www.mass.gov/info-details/clean-peak-energy-standard-guidelines#cps-guidelines-.

[53] Massachusetts Clean Energy Center, *Clean Peak Standard,* https://www.masscec.com/clean-peak-standard-cps.

Benefits and Risks

Several stakeholders suggested that a program target the replacement of fossil fuel peaker plants with new storage located in priority, disadvantaged communities through a Clean Peak Credit design. The Project Team chose not to recommend this option for several reasons, including the complexity of program design and administration, as well as the preference for locational flexibility in cost-effectively procuring storage as described in several responses to the RFI. Further, the Team finds a less restrictive program solicitation can achieve emissions reductions and provide cost savings for all customers more effectively than more restrictive procurement options.

The New York State Energy Research and Development Authority's (NYSERDA) assessment of the Clean Peak Energy Standard in its energy storage roadmap found that setting peak hours is highly complex and incompatible with the dispatch and bidding requirements in the wholesale market.[54] It also raised concerns about the cost-effectiveness of this mechanism, as operational requirements at peak hours may limit alternative revenue sources and increase cost and uncertainty for developers.[55] However, NYSERDA also noted that the procurement mechanism is likely to result in certainty in revenues, resulting in relatively low attrition.[56]

Comments submitted by New Leaf and Blue Wave criticized the Massachusetts Clean Peak Credit Program design, specifically the Distribution Circuit Multiplier, which incentivizes projects to be located on heavily loaded circuits.[57] According to New Leaf and Blue Wave, a program that is overly prescriptive of preferred locations "seems reasonable but, in practice, results in high upgrade costs for projects to interconnect."[58] They recommend an incentive design with broader categories of preferred locations.[59]

Other assessments of the Clean Peak Credit found that the Massachusetts Clean Peak Standard could clean up and reduce infrastructure costs by allowing an increasingly large portion of peak demand to be served by local renewable energy sources (through storage charge and discharge) instead of greenhouse-gas-emitting resources operating under expensive reliability-must-run contracts.[60] However, lack of consideration for the marginal generation unit would misalign the mechanism with emission reduction goals. The current design of the Massachusetts Clean Peak Standard incentivizes

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[54] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage

[55] *See Id* p.42

[56] *See Id* p.42

[57] "New Leaf and Blue Wave Comments"] (referencing https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/434aa27c309ed083852 5885d00643350/$FILE/FTM%20Energy%20Storage%20Projects%20in%20CT%20-%20BCA%20061020 22.pdf.)

[58] New Leaf and Blue Wave Comments.

[59] New Leaf and Blue Wave Comments.

[60] Lin, Roger. "Massachusetts' Clean Peak Standard - a Trailblazer in the Nation's Clean Energy Transition." *Utility Dive*, June 9, 2020. https://www.utilitydive.com/news/massachusetts-clean-peak-standard-a-trailblazer-in-the-nations-clean-en/579245/.

charging impacts using the average grid emissions intensity during charging and discharging times.[61] Therefore, the CPS is unable to capture changes in marginal operating emissions rates.[62] Energy storage resources have the potential to increase emissions if they charge when the marginal generation unit is emissions-intensive (such as natural gas or coal) and discharge when the marginal unit is less or equally emissions-intensive.[63]

CPS programs have not always been implemented in the most effective manner. For example, Columbia University and New York University modeled the effects of the Massachusetts Clean Peak Standard policy, and found a $30 Clean Peak Credit price had roughly the same emissions reduction as a $1 carbon tax, representing a significant economic efficiency issue in program design.[64] This was due to the design of the CPS, which did not factor in the marginal emissions resource during charging and discharging.

3.3. Upfront Incentives with Pay-for-Performance or Operational Requirements

Description of Procurement Option

Under a pay-for-performance mechanism, projects receive ongoing payments based on their ability to satisfy specified performance metrics. These metrics are often either based on the resource's ability to dispatch during critical hours or on the net system emissions impact that the resource's dispatch has on the grid. Pay-for-performance programs are often paired with an upfront incentive to help partially de-risk capital costs, which lowers financing costs. Transmission- and distribution-connected storage systems may have different performance criteria since they tend to provide different services to the grid.

Several states, including California, Connecticut, Massachusetts, New Hampshire, New Jersey, and Rhode Island, have either proposed or implemented storage programs with pay-for-performance elements.

Connecticut's Energy Storage Solutions program provides incentives for BTM storage for residential, commercial, and industrial customers through performance-based incentives, as well as an upfront

[61] Jeffrey G. Shrader, R.T. Carson, J.S. Holladay, J.S. Graff Zivin, et al. "(Not so) Clean Peak Energy Standards." *Energy*, March 6, 2021. https://www.sciencedirect.com/science/article/abs/pii/S0360544221003649?via%3Dihub.

[62] Jeffrey G. Shrader, R.T. Carson, J.S. Holladay, J.S. Graff Zivin, et al. "(Not so) Clean Peak Energy Standards." *Energy*, March 6, 2021. https://www.sciencedirect.com/science/article/abs/pii/S0360544221003649?via%3Dihub.

[63] Lim, Elwin. "Explainer: Can Clean Peak Standards Make Energy Economics Meet Energy Justice?" Clean Energy Finance Forum, March 29, 2022. https://www.cleanenergyfinanceforum.com/2022/03/29/explainer-can-clean-peak-standards-make-energy-economics-meet-energy-justice.

[64] Lim, Elwin. "Explainer: Can Clean Peak Standards Make Energy Economics Meet Energy Justice?" Clean Energy Finance Forum, March 29, 2022. https://www.cleanenergyfinanceforum.com/2022/03/29/explainer-can-clean-peak-standards-make-energy-economics-meet-energy-justice.

incentive. Performance incentives are paid twice a year for 10 years and are based on how much average power the battery discharges during critical periods.[65] The utility usually gives notification of a critical period 24 hours before an active dispatch event and will not call events for the two days preceding anticipated severe outage events or emergency conditions.[66] The upfront incentive element of the program uses a declining block structure, meaning payment amounts will start to decline once the state's cumulative storage capacity reaches certain thresholds in each market segment. The performance-based incentives are the same for all systems, but medium and large commercial and industrial customers receive smaller upfront incentives than residential and small commercial and industrial customers.[67]

California's Self-Generation Incentive Program (SGIP) also provides incentives for BTM storage with a combination of an upfront payment and ongoing performance payments for non-residential customers (residential customers receive an upfront lump sum). Non-residential customers receive 50 percent of the total incentive in the upfront payment and then have the opportunity to receive the remaining 50 percent over the following 5 years based on the amount of energy that a resource discharges annually at any time. However, to qualify for the full performance-based incentive, resources need to reduce annual greenhouse gas emissions by at least 5 kg of CO_2-equivalent per kWh of storage capacity. For example, a non-residential storage system with 100 kWh of storage capacity must reduce grid greenhouse gas emissions by 500 kg in a given year to receive its full performance payment. If a resource does not reduce grid emissions sufficiently, its performance payments are scaled down.

New Jersey has not yet implemented its Energy Storage Incentive Program (NJ SIP). The Board of Public Utilities released a straw program proposal in 2022, which is currently undergoing a stakeholder review process. Under the NJ SIP program proposal, at least 30 percent of the incentive will be a fixed annual payment, contingent on satisfactory uptime performance metrics. The remaining incentive will be provided through a pay-for-performance mechanism. For transmission-connected resources, performance payments will be based on the amount of carbon emissions abated through the operations of the energy storage facility. These emissions reductions will be calculated using the relative marginal carbon intensities of the PJM Interconnection wholesale electric grid during charging and discharging periods. For distribution-connected storage, the performance criteria are based on the successful injection of power into the distribution system when called upon by the EDCs during certain critical hours.[68]

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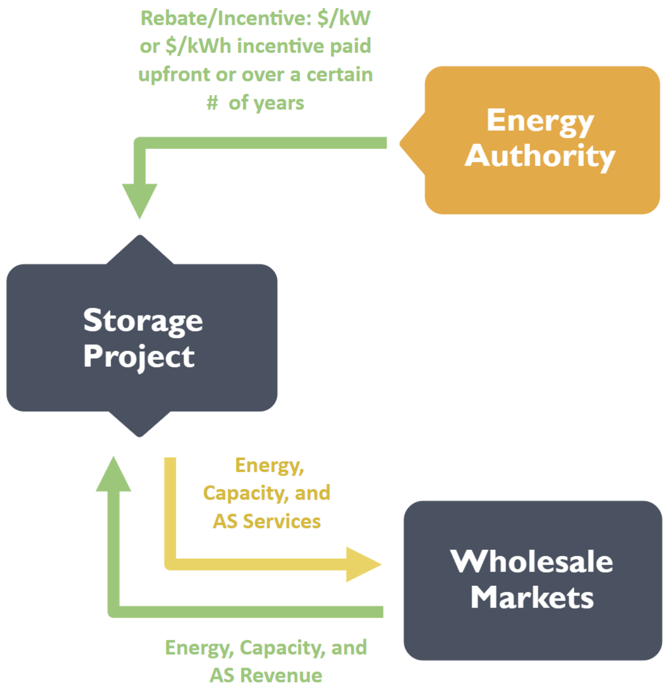
[65] CT PURA. 2024. "Energy Storage Solutions for Buildings & Communities." Available at: https://energystoragect.com/energy-storage-solutions-for-buildings-communities/.

[66] CT PURA. 2024. "Homeowner FAQ." Available at: https://energystoragect.com/homeowner-faq/.

[67] Proposed Final Decision Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles, Docket No. 17-12-03RE03 (July 1, 2021).

[68] New Jersey Storage Incentive Proposal, Meeting on 10/21/22, https://www.njcleanenergy.com/files/file/Energy%20Storage/FY23/SIP%20Stakeholder%20Process%20Day%201_presentation.pdf.

Figure 4. Illustrative upfront incentive with pay for performance



Source: Adapted from image in the 2022 NYSERDA Report: "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." "AS" stands for ancillary services.

Benefits and Risks

NYSERDA's assessment of the Upfront Incentive/Standard Offer found that the design is relatively simple to implement and administer.[69] The upfront incentive is also compatible with market signals and will allow projects to pursue revenue streams without conforming to specific dispatch requirements.[70] However, when the administration sets levels, implementing the design becomes more complex. NYSERDA also found that fixed upfront incentives do not provide long-term revenue certainty to support financing.[71] This is less attractive to developers and can potentially increase costs compared to other programs. A gap analysis would help identify uncertainty between wholesale market revenue and battery energy storage system financing. However, there is a high risk of attrition since capital costs and the future market for battery energy storage systems are unknown and may be volatile. Because of this,

[69] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage.

[70] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage.

[71] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage.

investors are unlikely to finance a project with this risk. An alternative design would be to provide fixed payments over time rather than an upfront incentive. However, there is still uncertainty regarding market revenues, which can result in higher project costs and, therefore, increased costs to ratepayers.

Stakeholders, specifically CES, recommended a capacity-based construct with pay-for-performance incentives. CES recommends that the design "require [a] project owner to maximize wholesale market value from storage system operations and this value could be returned to ratepayers by designating an appropriate lead market participant."

3.4. Index Storage Credit

Description of Program

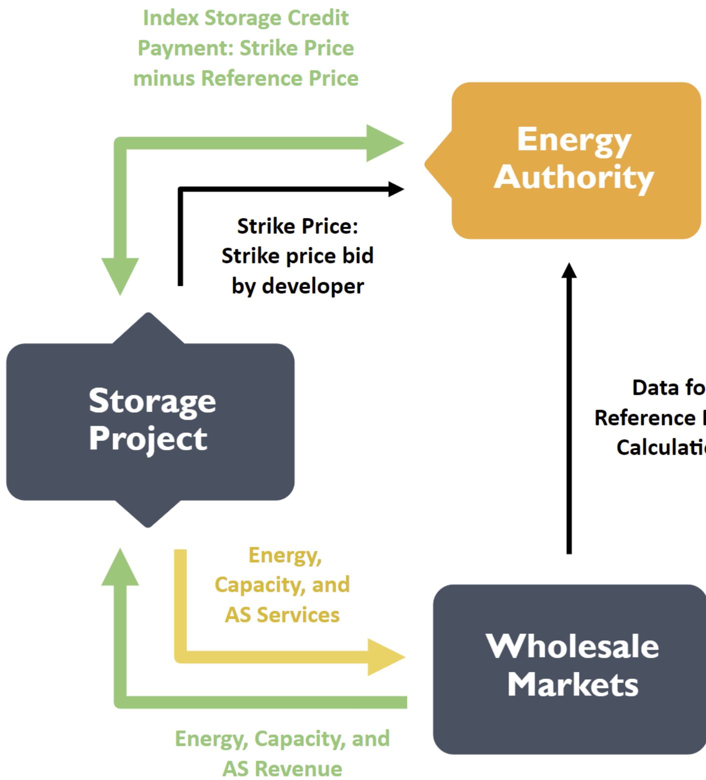
An Index Storage Credit (ISC) mechanism establishes certainty around a project's revenue stream by providing gap payments between a revenue requirement that a project developer deems necessary for economic viability and the achieved wholesale market revenue.

With an ISC mechanism, storage project developers submit "Strike Price" bids through a competitive solicitation process. These Strike Price bids should reflect the project's revenue requirement. Using one or more price indices, the energy authority calculates a "Reference Price" to indicate an approximation of available market revenue that projects could reasonably expect to earn. If the Reference Price is less than the Strike Price, meaning the available market revenue is less than the project needs to be economically viable, projects will get paid the difference. If the Reference Price exceeds the Strike Price, meaning available market revenue exceeds the project's minimum needs, the project will pay the difference to the program administrator (EDC or state entity). Figure 5 depicts the ISC.

The Reference Price includes market revenues that are captured through the range of opportunities available to storage facilities, including energy arbitrage and capacity market revenue. However, awarded projects are not actually required to participate in any market. While projects have the autonomy to pursue actual revenues above or different than those indicated by the indices used to calculate the Reference Price, without any market revenue, the ISC payments would not be expected to make projects economically viable. This incentivizes projects to maximize market revenues.[72]

[72] This program structure is analogous to the "Index REC" approach currently used in NYSERDA's offshore wind and onshore large-scale renewables procurement. NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Page 40. Available at: https://www.nyserda.ny.gov/energy-storage.

Figure 5. Illustrative Index Storage Credit mechanism



Source: Adapted from image in the 2022 NYSERDA Report: "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." "AS" stands for ancillary services.

The primary use case for the ISC mechanism to date is in the NYSERDA energy storage roadmap. The roadmap outlines a proposed plan for how New York could achieve its goal of 6 GW of storage capacity by 2030. NYSERDA's proposal to procure 3 GW of bulk storage through a new ISC mechanism is an important roadmap element.[73] While the New York Public Service Commission is still reviewing the energy storage roadmap, the ISC mechanism has garnered significant attention due to its novel design and the critical role it could play in achieving New York's ambitious storage targets if the roadmap is approved.

Benefits and Risks

Stakeholders raised several concerns about the ISC mechanism in their comments to GEO. Several raised concerns about the program's complexity, both in terms of administrative burden as well as the potential room for error when calculating the Reference and Strike Prices. CMP highlighted the difficulty

[73] NYSERDA. 2022. "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage." Available at: https://www.nyserda.ny.gov/energy-storage.

of forecasting long-term revenue streams appropriately and accurately for a technology that is still a nascent entrant to wholesale power markets. CMP noted that this could pose a long-term risk since uncertainty around available market revenues could potentially lead to greater deltas between the Strike Price and Reference Price than expected. CES stated that the mechanism may be time-consuming and costly to manage and that a daily reference price construct creates room for potential mistakes.

One key consideration centered around the inability of resources north of the Surowiec interface in Maine to qualify for capacity payments in ISO New England's Forward Capacity Market since 2021. Due to transmission constraints in the state, resources located north of this interface are not considered deliverable to the rest of the region. According to New Leaf and Bluewave's comments, capacity payments can account for 25 to 40 percent of a transmission-scale storage system's wholesale revenues in other states. Without capacity market revenue, the Reference Price will likely generally be significantly lower than the Strike Prices, which would increase the amount of financial support required.

An ISC mechanism has many advantages for policymakers and utilities. Under an ISC mechanism, battery energy storage system operators have incentive to optimize the storage value and follow wholesale market price signals. The mechanism is theoretically also cost-efficient as it provides the correct financing opportunities for owners without ratepayers bearing high costs. However, while a portion of the revenue stream is "de-risked," developers will still likely bear substantial market risk. There could be a significant mismatch between the stipulated Reference Price and wholesale market revenues if certain revenue streams are not represented accurately in the Reference Price calculation. Furthermore, there is uncertainty around the extent to which revenues are hedged and how expensive an ISC program would end up being for a state agency to administer, since long-term market-based revenues are difficult to forecast.[74]

[74] Sustainable Energy Advantage. 2023. "New York's Index Storage Credits: Panacea or Pipedream?" Available at: https://www.seadvantage.com/blog-post/new-yorks-index-storage-credits/.

4. SELECTION OF PROPOSED PROCUREMENT MECHANISMS

The Project Team performed a qualitative assessment of the procurement mechanisms discussed above to evaluate them against the criteria established in LD 1850 and ultimately select the procurement mechanism for this program. After reviewing potential procurement program designs and examining how they have been implemented or proposed in other states (along with any relevant difficulties other states have encountered, see above) the Team considered the implications of each mechanism for Maine.

Figure 6 provides the Project Team's qualitative analysis of the LD 1850 criteria. All procurement mechanisms are assumed to be coupled with a competitive solicitation process.

Figure 6. Procurement program evaluation

Evaluation Criteria	Pay for Performance + Upfront Incentive	Index Storage Credit	Clean Peak Credit	Tolling Agreement
Cost-effective for Ratepayers	Depends on the relative magnitude of the incentive vs avoided costs.	Depends on how close the reference price is to the strike price. May lower financing costs by mitigating market risk or increase financing costs due to program complexity.	Depends on the relative magnitude of the incentive vs the avoided costs.	Depends on contracting terms. May lower financing costs by mitigating market risk.
Advance the State's climate and clean energy goals.	We project that optimizing dispatch based on wholesale prices will not increase emissions.		Storage can potentially charge during high emission periods. This framework can over-constrain efficient/ optimal dispatch. Uncertain whether incentive would be sufficient to ensure deployment.	Depends on utility operation of asset.
Advance the State's state energy storage policy goals established in Title 35-A.	This mechanism is simple and transparent which would encourage participation.	The relative implementation of complexity may be a barrier to storage policy goals.		Well-understood contract structure but not a way to transform markets. Utilities have experience and finances to bring storage online. But utilities currently not allowed to operate storage.
Improved reliability and resiliency	Resources can be paid based on their ability to dispatch during critical hours.	Vendors do not have incentive to improve reliability or resiliency without additional payment.	Can over-constrain dispatch such that key hours may not be served.	Utilities have responsibility to improve reliability and resiliency of the system. Utility financial incentives and greater experience addressing reliability through traditional utility investment may hinder EDC adoption of storage in reliability and resiliency applications in the absence of specific performance requirements or incentives.
Incremental delivery of renewable electricity to customers	Market-based dispatch generally aligns low-price renewable hours with storage charging.	Market-based dispatch generally aligns low-price renewable hours with storage charging.	May not be sufficient incentive to align with market-based dispatch.	Likely insufficient incentive to locate in areas with high renewable penetration.
Maximize the value of federal incentives	In a competitive solicitation, we expect bidders will be incentivized to price in and seek out federal incentives. Bids that do not do this will not be selected for procurement due to higher costs.			
Enable the highest value energy storage projects - energy storage systems in preferred locations	Developers are incentivized to maximize wholesale revenues, in particular locational marginal prices, which are location specific. Areas where transmission or distribution upgrades can be deferred or avoided will not necessarily receive adequate compensation to justify siting, but may be deployed through this procurement mechanism. We note that siting storage in areas where transmission or distribution upgrades are necessary does not guarantee benefits will be realized.			Adds less incentive to maximize wholesale revenues, but utilities likely have the greatest insight into areas requiring transmission or distribution upgrades. We note that siting storage in areas where such upgrades are necessary does not guarantee benefits will be realized.

Actively furthers state goals | Depends on program implementation | Neutral | Does not satisfy performance criteria

Performance against the legislative criteria varied: for some criteria it was clear that certain mechanisms performed better or worse, while for others there was less disparity. For example, any program could be cost-effective or not, generally depending on the magnitude of incentive costs compared to the avoided costs. Choices regarding program design can have more of an impact on cost-effectiveness than the type of mechanism. Similarly, in a competitive solicitation process, bidders should already be incentivized to maximize their incentive from the ITC and achieve as many of its adder requirements as possible. That should not change depending on the procurement mechanism.

The way procurement mechanisms for storage ultimately impact climate goals and incremental delivery of renewable energy to customers is determined by the correlation between financial dispatch signals (both wholesale market prices and programmatic incentives) and emissions rates. As discussed in Section 2.2, the Project Team's analysis found that economic dispatch based on wholesale markets in New England is not projected to cause emissions to increase. The Team therefore concluded that aligning procurement incentives with wholesale market signals results in economically optimal dispatch, without an increase in emissions over the resource's lifetime. However, the Project Team recommends that this assumption be evaluated based on real-world battery operations once the program is active. If a program evaluation finds that there is a net increase in emissions, program administrators should consider adding an emissions-based performance component in future rounds of procurement.

Financial dispatch signals will impact the renewable energy delivery and emissions rates resulting from increased storage on the system. These signals will come from a combination of specific program incentives and wholesale markets. If storage resources charge during low-price hours, often when more renewables are online and discharge during higher-cost hours with higher fossil use, they can cut emissions and enable the delivery of more renewable energy. However, this theoretical trend does not play out perfectly in the market. There will likely be times low-price hours coincide with when gas is the marginal unit. The Massachusetts Clean Peak Credit was set up with incentives for dispatch at specific times. The program was ultimately found to provide a weak incentive for greenhouse gas reductions (see discussion above).

The complexity of each procurement mechanism is likely to affect how the state of Maine will meet its goals. For example, a pay-for-performance mechanism is transparent, straightforward for participants to understand, and easy for administrators to implement. That accessibility and ease will encourage participation and could enable a program to begin more quickly. This contrasts with the ISC, which would create a high administrative burden for an agency calculating the Reference Price. Participants would also have to work to calculate their Strike Price, while potentially having less transparency into Reference Price calculation processes. Plus, creating this process is more complex and could delay the implementation of the program. Several stakeholders also noted that the ISC may increase their financing costs by being an unknown mechanism, adding another barrier to achieving Maine's goals.[75]

[75] New Leaf and Blue Wave Comments, p.4; CES comments, p.11.

The selected procurement mechanism should also maximize storage resources' potential to contribute to resiliency and reliability in Maine. To accomplish this, storage resources need to dispatch during critical hours and shave peaks. A Clean Peak Credit aims to do this but may ultimately over-constrain dispatch times for resources and reduce their overall benefits. Furthermore, limiting the dispatch time of an entire fleet will reduce flexibility for storage resources to respond to different peaks or patterns that arise. The ISC would not have any specific incentives related to resiliency or reliability without an additional payment or component, which would require adding an additional layer on an already complex mechanism. The pay-for-performance incentive, however, offers flexibility around a performance incentive structure where it is easier to pay resources for the ability to dispatch at critical hours.

As the evaluation matrix above indicates, the Project Team found that an incentive that is split between an upfront payment and pay-for-performance payments based on ability to dispatch during the highest value hours to ratepayers is most consistent with RFI feedback and LD 1850 criteria. At the same time, as discussed below, achieving key distribution system benefits may only be possible by including elements of a tolling agreement. The Team therefore recommends distinct procurement mechanisms/program designs for transmission-connected and distribution-connected resources, described below.

In order to fully inform the recommended procurement mechanism, the Project Team also considered the relative magnitude of potential sources of values relevant to FTM storage, as certain procurement mechanisms may be incompatible or ill-suited to maximizing specific sources of value. For example, a Clean Peak program, because it prescribes so much of a storage resource's operations, may not be ideal for maximizing wholesale energy arbitrage value.

Achieving distribution system benefits requires that energy storage resources operate differently than those focused on optimizing for transmission system benefits. Therefore, the Project Team recommends distinct mechanisms for transmission- and distribution-connected resources.

The Project Team did not evaluate BTM standalone storage and storage paired with renewable energy, such as virtual power plants and microgrids. Existing programs, offered by the Efficiency Maine Trust, provide incentives for BTM storage.

4.1. Selected Transmission-Connected Procurement Mechanism

For transmission-connected resources, the Project Team proposes an upfront incentive coupled with a pay-for-performance mechanism designed to achieve avoided transmission system costs; resource owners would retain flexibility to maximize wholesale market revenues during non-event hours. While avoided transmission costs (primarily pool transmission facilities, or PTF) represent significant potential savings to Maine (and New England) ratepayers, individual resource owners cannot directly monetize these benefits. Thus, providing an incentive to operate in such a way intended to capture avoided transmission costs can produce net benefits to ratepayers. Further, providing flexibility for resources to earn wholesale market revenues reduces the required incentive level.

Transmission planning is complex,[76] which complicates efforts to develop a storage dispatch approach that will yield avoided PTF costs. While the methodology for estimating some benefits is reasonably consistent with realizing avoiding costs, for example reducing the RNS charges borne by Maine ratepayers through reducing Regional Network Load,[77] there is not a similarly straightforward approach to estimating avoided future (marginal) PTF costs, though the methodology employed provides a reasonable estimate.

Under our selected procurement mechanism, participating resources would receive payments tied to their performance during event windows. These events would be determined by a third party. This approach places the responsibility to call appropriate events on the program administrator, while placing the risk of nonperformance on participating resource owners. This distribution of risk and responsibility enables each party to focus on activities at which they are most adept: third parties at forecasting the system peak, and energy storage resource operators at appropriately dispatching based on events and wholesale market price signals.

During non-event hours, resources owners would be free to maximize revenues through wholesale markets. By creating a competitive solicitation tied to proposed incentive levels, bidders with the lowest costs, most optimistic projections of wholesale market opportunities, and greatest confidence in their ability to operate the battery to capture all of the revenue opportunities would be positioned to submit the most competitive bids while also providing the greatest value to ratepayers.

4.2. Selected Distribution-Connected Procurement Mechanism

As discussed above, the Project Team recommends a distinct procurement mechanism for distribution-connected battery resources. Here, the primary value of the energy storage resources would be avoided distribution system costs.

As with avoided transmission costs, avoided distribution costs yield a large potential source of savings to ratepayers. However, storage resources cannot directly monetize these benefits, thus necessitating a mechanism to incent the development and operation of energy storage resources to achieve distribution system savings. We find that partial-tolling agreements, which provide fixed payments to a third-party and utility-directed dispatch, are the best procurement mechanism for distribution-connected storage, based on both LD 1850 criteria and the particular needs of the distribution-connected use case. There are three primary reasons for this:

1. While data needed to operate storage in ways that benefit the bulk power system (e.g., energy prices, data needed to produce load forecasts, etc.) is publicly available, a similar level of

[76] For example, there are multiple types of potential transmission projects, including Reliability, Market Efficiency, and Public Policy, though effectively all projects to date have been Reliability projects. Further, we expect that, over the course of the study period, the transmission planning process will continue to evolve.

[77] See, for example, ISO-NE's December 2023 Monthly Regional Network Load Cost report: https://www.iso-ne.com/static-assets/documents/100008/2023_12_nlcr_final.pdf.

transparency does not exist for the distribution system. More specifically, only EDCs have direct visibility into current loading conditions on their system. This could still work with a pay-for-performance mechanism, with the understanding that only EDCs would be able to effectively issue event calls/dispatch resources.

2. Resources dispatched to realize benefits at the bulk power system level, by definition, work over larger geographical areas than those at the distribution level. This makes it less critical for every single resource to perform during every single transmission-level event. For example, if a fleet of energy storage resources located in Maine is being dispatched to try to reduce the state's peak net load, if a subset of these resources does not perform during peak hours, the value achieved is reduced proportionally but not lost altogether. If, however, a single energy storage resource is installed on a distribution feeder to manage peak loading on that feeder, failure of that single resource to perform eliminates the potential value entirely. This inability to distribute risk over a larger portfolio of resources may not work well for a pay-for-performance mechanism: While there is a financial incentive to perform, an EDC may not have sufficient confidence that resources will operate when called upon.

3. EDCs have an obligation to provide reasonably reliable service to customers. If energy storage resources are being installed to avoid distribution system investments, these resources are effectively directly impacting distribution system reliability. As the party accountable for reliable service, EDCs, as a result, are unlikely to defer or forego more traditional poles and wires upgrades to address load growth in favor of the use of energy storage resources unless the EDCs can direct dispatch these energy storage resources. This suggests that a form of tolling agreement may be necessary for the potential value of storage to the distribution system to be realized.[78] The impacts of EDC control (or lack thereof) on how EDCs treat the value of a dispatchable resource are discussed in a study commissioned by the Massachusetts Clean Energy Center, *Value of Distributed Energy Resources for Distribution System Grid Services*, affirming that EDCs effectively "derate" the potential contribution of a dispatchable distributed resource for the purposes of grid planning. This, in turn, degrades the value realized by ratepayers.[79]

The Project Team acknowledges the current policy limitations to implementing partial-tolling agreements, however. Since the energy markets were deregulated in 1997, utility companies in Maine

[78] Proceedings in Docket 2023-00103 provide some insight into how EDCs view the operation of storage, through the lens of the interconnection study process and required controls. For example, while economic signals make it unlikely that energy storage would charge during high-load hours, the adopted Chapter 324 rules effectively require the installation of protective relays or other means of controlling exports to guarantee operations within any limits established in the interconnection agreement.

[79] Massachusetts Clean Energy Center. 2024. *Value of Distributed Energy Resources for Distribution System Grid Services* https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf.

have not been allowed to own or operate generation assets, including storage.[80] Though some stakeholders are advocating for changes to that policy, it would be impractical to plan to structure a procurement mechanism around utility ownership immediately as it would face significant barriers to advancing Maine's storage goals.

Distribution utility companies are currently in the best position to understand preferred locations for storage to avoid or defer future investments and benefit consumers. However, there still would be no guarantee of those consumer benefits. Unlike with the transmission system that is planned and overseen by a regional organization with public-facing data, distribution systems are managed by EDCs who maintain relevant data and are accountable for system reliability. The value of distribution-connected storage is unlocked when energy can be delivered during specific hours, and utilities are the actors with the data and infrastructure control to do this. Any other program design or procurement mechanism will be limited in its ability to unlock this key value to the distribution system, making other procurement mechanisms for distribution-connected storage impractical or imposing undue risk on ratepayers regarding the degree to which benefits are attained.

As discussed in greater detail in the Storage Dispatch Modeling section, below, the Project Team produced simulated distribution feeder data to inform the recommended approach to achieving distribution system benefits. The design was also informed by the need to ensure that EDCs reflected the operation of the storage in distribution system planning and investment, as discussed above. Based on these considerations, the Project Team recommends a mechanism that would provide EDCs with dispatch rights to storage for winter months (December, January, and February). The Team assumes no other direct use of the storage resource during these periods, as they are held in reserve to address potential distribution system needs. During the remaining months, storage resources can earn a performance incentive by responding to events called by an EDC or other program administrator, similar to the mechanism for transmission-connected resources. These events are intended to reduce RNS charges. Because the intention is to affect RNS charges, however, these resources are dispatched based on projected monthly peak loads for the state of Maine.

As discussed above and noted by several stakeholders, resources participating in wholesale markets may not be able to impact RNS charges. More specifically, as described in Section II.21.2 of the ISO-NE Open Access Transmission Tariff,[81] Generator Assets do not affect the calculation of Monthly Regional Network Load (effectively, the monthly peak load which is multiplied by the applicable RNS rate to calculate monthly PTF charges). As a result, resources can participate directly in energy markets or provide RNS benefits, but they cannot accomplish both. Given that RNS benefits exceeded the wholesale market revenue that resources could earn outside of winter months, the Project Team assumed that the

[80] Singer, Stephen. "Energy Storage Is Growing in Maine, and Utilities Want to Own It. Opponents Are Pushing Back." *Press Herald*, January 29, 2024. https://www.pressherald.com/2024/01/29/energy-storage-is-growing-and-utilities-want-to-own-it-opponents-are-pushing-back/.

[81] ISO-NE, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

distribution-connected resources would act as load reducers and not participate directly in wholesale markets.

Some stakeholders recommended that distribution-connected resources could be dispatched based on wholesale market price signals, but instead of participating directly in wholesale markets be compensated by the relevant EDC based on the implied arbitrage revenue. Given the magnitude of potential benefits achievable here relative to other benefits (primarily, avoided distribution costs and RNS) and some of the practical questions raised by this approach, the Project Team did not include this activity in its modeling. Section 5 provides additional detail on simulated call windows, the wholesale market opportunities, and resulting simulated storage dispatch.

4.3. Incentive Design and Administration

Upfront incentive

The Project Team recommends that the upfront incentive be denominated in dollars per usable kWh_{AC} of installed storage capacity. This upfront incentive would be subject to a claw-back provision should resources not meet a minimum performance threshold for the performance-based event hours. To reduce the number of variables needed to be considered when conducting solicitations for storage, these incentive rates (different for transmission and distribution-connected resources) could be specified in the solicitation and made available only to winning bidders. The upfront incentive should be set to be approximately 30–50 percent of total anticipated incentive. This is because putting too much of the total incentive value in the upfront rebate risks installers installing longer-duration storage than may be necessary to respond to event windows; it also increases risk of resource non-performance (as claw-back provisions may be challenging to enforce).

Connecticut’s Energy Storage Solutions program and New York’s Bulk Storage Incentive program have both provided upfront incentives.

Performance-based incentive

Performance-based incentives would be denominated in $/kW performed, based on a resource’s average output during a season’s event hours. A third-party administrator would be selected to call these events. The Team recommends that the events, by default, be called on a day-ahead basis, with the option for the third-party administrator to call events with shorter notice. Performance during these short-notice events would not reduce a resource’s calculated seasonal performance, but capacity during these events would be subject to a bonus (e.g., performance during these short-notice events would be increased by 25 percent), compensating resources for responding to short-notice calls. The Team recommends that the contracts for performance-based incentives fix incentive levels for multiple years, with an option to extend contracts at offered incentive levels after the initial term.

In order for bidders to appropriately configure their system (e.g., decide on system duration) and develop a bid price, they would need some guidance on the duration and frequency of events. Specifically, the Team recommends defining a maximum event length and frequency by season and year for the 10-year initial contract term. The Project Team recommends that a third-party administrator responsible for calling event windows be hired in advance of conducting solicitations for storage resources to participate. This third-party administrator, since it would be responsible for calling events, would be in the best position to define the event duration and length. In hiring this administrator, the Team recommends an approach that incentivizes the shortest and least frequent events possible, while still accurately capturing all (or the vast majority of) monthly and annual coincident peak hours.

This general approach to a performance-based incentive is comparable to the Connected Solutions program and Connecticut's Energy Storage Solutions program.

Partial-tolling agreement for distribution-connected resources during winter months

The Project Team recommends that payments for distribution-connected resources be provided on a dollar per kW of available capacity basis (with sufficient duration to meet identified distribution need, which may mean payments are not on the basis of full nameplate capacity) with uptime guarantees that would include penalties for non-performance during critical events. The contract could also include a payment based on total energy discharged during critical events to cover additional O&M expenses incurred due to required cycling of the battery. Crucially, in order to ensure that distribution system benefits are realized, these tolling agreements would likely need to have a specified minimum duration.

As discussed in the preceding section, successfully realizing benefits to the distribution system and resulting costs will require coordination with the EDCs. This coordination would include both identifying sites where storage could effectively defer or eliminate investments and providing the dispatch signal required to operate the resources beneficially once they are installed. One approach would be that the Commission would direct EDCs to both identify the sites and provide the dispatch signal, while the Commission would conduct the solicitation. EDCs would be required to report incentives on the performance of individual systems under the partial-tolling agreement commitments to the program administrator.

Conducting solicitations

As noted above, the Project Team recommends that solicitations specify the upfront incentive, and then ask for respondents to provide bids for $/kW performance payments. Bidders could propose payment rates that are fixed or variable over the 10-year contract; the bid evaluation would make comparisons on a net present value basis. Utility-scale lithium-ion storage can have a useful life of 15 years or more and a longer contract term could then reduce the incentive paid by reducing the period for which a resource would not have a contracted revenue stream. On the other hand, the complex and evolving understanding of how to best derive the greatest value from storage means that there are policy risks associated with longer-term contracts. For both distribution- and transmission-connected solicitations, the Team recommends specifying a minimum duration of 4 hours, but not specifying a minimum or maximum per project MW.

5. STORAGE DISPATCH MODELING METHODOLOGY

The Project Team used the procurement mechanism it selected to inform modeling of optimized dispatch of storage. For transmission-connected storage, the modeling primarily optimized storage dispatch around reducing future PTF projects by discharging at the system peak each year (for other hours, it sought to maximize revenues in the wholesale market). The modeling optimized distribution-connected storage to defer or avoid distribution peaks in the winter, while in other seasons storage was used to reduce RNS charges, discharging during Maine's monthly peak. The optimized hourly dispatch (charging and discharging) informed both estimated market revenues and cost-effectiveness, as discussed in Section 3.

5.1. Event Window Methodology

Modeling both transmission- and distribution-connected resources requires establishing hours of events associated with the performance-based incentive. For transmission-connected resources, while future PTF buildout will be driven primarily by annual coincident peaks, the Team assumes that events are also called to coincide with monthly peaks, to increase the probability that storage would affect transmission buildout. For distribution-connected resources, events are modeled based on monthly coincident peak hours during non-winter months.

Notably, these events require consideration of the ease with which a program administrator could correctly predict coincident peaks. The Team adopted assumptions, by month and year, for the duration and frequency of events that would need to be called in order for an administrator to have a high probability of accurately calling all or most coincident peak hours. Current programs, such as Connected Solutions and Energy Storage Solutions, generally have a maximum event duration of 3 hours. Factors such as flattened loads resulting from storage deployment and more flexible loads (responding to increasingly granular time-varying rates), increased deployment of variable resources, and increasingly volatile weather are likely to make calling coincident peaks more challenging. Based on these factors, a review of historical Connected Solutions event calls, and a review of unserved load hours associated with AESC modeling, the Project Team developed assumptions for the duration and frequency of events, as represented in the tables below. The Project Team identified the top *n* hours in a given month, where *n* is represented by the number of events in the pertinent month and year. The event durations below were applied to these selected peak hours. See below for more on dispatch strategy and operational assumptions.

Table 2. Count of events per month

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Jan	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8
Feb	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8
Mar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Apr	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
May	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jun	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Jul	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Aug	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Sep	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Oct	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Nov	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Dec	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8

Table 3. Event duration (hours)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Jan	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6
Feb	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6
Mar	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Apr	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
May	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jun	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jul	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Aug	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sep	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Oct	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Nov	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Dec	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6

The duration of events has important implications for the storage configurations developers would select and how they would generate their bid price. The frequency of events, as it may affect opportunities to earn wholesale market revenues, would also affect bid prices. Therefore, refining these values is important. As discussed in Section 4.3, the Project Team recommends that an entity hired to call these events would be in the best position to provide guidance on the maximum duration and frequency of events.

5.2. Transmission-Connected Storage

The benefits that accrue to ratepayers, and the market revenues to the asset owners and operators of a storage resource, are in large part, a function of the hourly dispatch schedule for the resource over the modeling period. Given the procurement mechanism it selected, the Project Team simulated dispatch that aligns with an expectation of how asset operators seek to maximize revenues while adhering to technical and contractual limitations and requirements.

The following sub-sections describe the market revenue streams modeled and the Team's assumptions related to quantifying them, followed by key assumptions and methodology underlying the dispatch strategy and attaining market revenues.

Market Revenue Streams

The market revenue streams likely to be available to storage resources in Maine (transmission- and distribution-connected) over the modeled years are as follows.

***Energy Revenues*–** Energy storage resources can charge during low-priced hours and sell the stored energy during hours when prices are higher, thus arbitraging the price differentials in the ISO-NE wholesale markets. Accordingly, the potential energy arbitrage revenues will be driven in large part by the assumed energy prices during the modeled years.

The Project Team's assumed energy and reserve prices are based on future price trends from AESC 2024. However, given that the AESC projections have less volatility than observed in recent market activity, the Team utilized the average month-to-hour ratios of prices from AESC and a historical year (2021 in this analysis) to scale the hourly price series to develop our projections for energy prices.

The Federal Energy Regulatory Commission (FERC) has recently approved market changes proposed under the Day-ahead Ancillary Services Initiative (DASI), which among other impacts, is likely to put upward pressure on day-ahead energy prices. The DASI-related market changes will be in effect starting March 2025. As such, the impacts of DASI are not captured in actual historical prices. Accordingly, the Team used hourly profiles from ISO-NE's simulation data for 2021 from the DASI impact analysis to develop energy price projections.[82]

The Team further adjusted prices based on assumed dispatch (described below) to estimate day-ahead market revenues for the battery storage resource. These revenue estimates were subsequently adjusted to include two additional potential revenue streams for battery storage resources:

- **Balancing revenues:** Batteries can earn additional revenues in the real-time market by deviating from their day-ahead positions in response to unforeseen circumstances, which could include price spikes/ periods of low prices in the

[82] See prices from DASI impact assessment at ISO-NE, https://www.iso-ne.com/committees/key-projects/day-ahead-ancillary-services-initiative.

real-time market. As such, the Team incorporated a 5 percent adder to reflect these additional balancing revenues.[83]

- **Reserve scarcity revenues:** As noted above, the Team assumes an increase in the number of reserve scarcity events (i.e., Pay-for-Performance events) as renewable penetration increases. This assumption would increase the real-time and day-ahead prices due to the activation of administrative shortage pricing set by the Reserve Constraint Penalty Factor (RCPF) during these intervals. The potential increase in the annual revenues for storage resources was estimated as the product of expected number of reserve scarcity hours in a year and the RCPF corresponding to shortage of 30-minute reserves (thirty-minute operating reserves, known as TMOR).[84]

***Spinning Reserves* -** In addition to energy arbitrage, energy storage resources can earn revenues by selling 10-minute spinning reserves (i.e., Ten-Minute Spinning Reserves, or TMSR, which is the more valuable of the three existing reserve products). As such, storage resources face a choice between selling energy and reserves in many hours of the day. The value of revenues from the reserve market in ISO-NE is likely to increase because, as discussed above, the ISO created a day-ahead market for three reserve products, which is expected to increase compensation for flexible resources in the day-ahead market. Under DASI, ISO-NE has developed several new day-ahead ancillary services products (structured as call-options on energy) whose procurement will be co-optimized with that of energy.

In addition to reserves, battery storage resources can sell frequency regulation. However, the volume of batteries entering the market is likely to significantly exceed the procured quantity for this product. Hence, it is generally expected that a battery resource's revenues from the regulation market will decline to an insignificant level in the near term. Accordingly, the Project Team did not model revenues from the regulation market for this analysis.

The demand for other ancillary service products is also considerably low relative to the volume of storage resources that are projected to enter the ISO-NE market. Nonetheless, the Team modeled revenues from the reserve market for the following reasons:

1. The demand for ancillary services is likely to increase in the future as an increasing portion of the load is served by intermittent resources.[85]

83 For instance, a 2019 filing by the External Market Monitor found that a dispatch based on real-time prices would result in 13 percent higher revenues relative to a day-ahead dispatch from March 2017 through February 2019. Similarly, in New York, the Analysis Group found the contribution of real-time/ balancing revenues to be (approximately) 2-8 percent in NYISO.

84 The usage of the RCPF corresponding to TMOR is slightly conservative as some of the shortages could be of ten-minute reserves as well. The 2021 CONE and ORTP study by ISO-NE's consultants also considered a scarcity premium in estimating the energy and ancillary service revenues for various technologies.

85 For instance, the NYISO, as part of its Balancing Intermittency project, is considering increasing its operating reserve requirements to account for higher uncertainty in its forecast due to higher penetration of intermittent renewable resources.

2. ISO-NE and other wholesale market operators in the region are considering additional ancillary service products that will support mid- to longer-duration storage resources as the resource mix continues to evolve.[86]

Recognizing the above, the Team used TMSR prices from ISO-NE's DASI impact study, adjusted them to reflect future conditions using the ratios used for energy price projections, and scaled them down further to reflect a preference for longer-duration storage resources in the future. Specifically, the modeling assumed that 6-hour resources will be able to realize the full price while 2-hour and 4-hour resources will be able to realize only 33 percent and 67 percent, respectively, of the reserve price in any given hour in the future.

Capacity Revenues– Energy storage resources in Maine can also earn revenues from the capacity market operated by ISO-NE. In ISO-NE, the capacity market compensation is comprised of the base payment (based on the FCM price and the resource's Capacity Supply Obligation, or CSO), and a performance payment (under the Pay-for-Performance framework), which provides payments under scarcity conditions.[87] Resources in most of Maine have historically not been able to qualify for the FCM due to limited transfer capability. Nonetheless, these resources may still be able to realize Pay-for-Performance revenues.

In this analysis, to the extent that a resource could qualify for a CSO, the Team evaluated the tradeoff between storage either (a) taking on a CSO or (b) operating without a CSO and instead relying on higher Pay-for-Performance payments. The Team assumed that the resource would maximize its expected capacity revenues between these two options each year.

ISO-NE is in the process of finalizing its resource capacity accreditation (RCA) and other capacity market reforms, which could have considerable bearing on the clearing prices, accredited capacity, and, ultimately, the capacity revenues for energy storage resources.[88] Recent data from analysis carried out by ISO-NE and other entities suggest substantial impact on the qualified capacity of storage (most notably in the winter season) due to the RCA reforms, particularly for shorter duration resources.

Overall, the Team's capacity revenue estimates were based on the following assumptions:

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[86] For instance, ISO-NE will evaluate need for new, longer-duration reserve products as part of a flexible response services assessment in 2025. The NYISO will consider a 4-hour 'sustainability requirement' for its reserve providers as part of its Balancing Intermittency project.

[87] ISO-NE, *Pay for Performance*, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rules.

[88] The studies that we reviewed in developing assumptions include:

1. A January 2024 study by AGI for ISO-NE Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets.
2. ISO-NE's Feb 6-7, 2024 presentation on Resource Capacity Accreditation in the Forward Capacity Market.
3. External Market Monitor's 2021 NYISO State of the Market Report.
4. External Market Monitor's 2022 Assessment of ISO-NE Markets.

- Capacity prices from counterfactual 6 of AESC 2024, which removes the effect of BTM battery storage on market prices.

- Seasonal marginal reliability impact (MRI - effectively, the percent of nameplate capacity that is compensated through the FCM) values of 2-, 4-, and 6-hour storage resources.

The table below provides assumed seasonal MRI values.

Table 4. Seasonal marginal reliability impact of storage resources assumptions

Year	2-hr Storage		4-hr Storage		6-hr Storage	
	Summer	Winter	Summer	Winter	Summer	Winter
2027	1	1	1	1	1	1
2028	0.62	0.37	0.87	0.50	0.91	0.63
2029	0.57	0.33	0.82	0.47	0.90	0.61
2030	0.52	0.30	0.77	0.45	0.89	0.59
2031	0.46	0.27	0.73	0.42	0.87	0.57
2032	0.41	0.23	0.68	0.39	0.86	0.55
2033	0.36	0.20	0.64	0.37	0.85	0.53
2034	0.31	0.17	0.59	0.34	0.84	0.51
2035	0.26	0.14	0.54	0.32	0.82	0.50
2036	0.26	0.13	0.54	0.30	0.82	0.47
2037	0.26	0.12	0.54	0.28	0.81	0.44
2038	0.26	0.11	0.53	0.26	0.80	0.41
2039	0.26	0.10	0.53	0.24	0.80	0.38
2040	0.26	0.10	0.52	0.23	0.79	0.36
2041	0.26	0.09	0.52	0.21	0.78	0.33
2042	0.25	0.08	0.52	0.19	0.78	0.30
2043	0.25	0.07	0.51	0.17	0.77	0.27
2044	0.25	0.07	0.51	0.16	0.76	0.25
2045	0.25	0.06	0.50	0.14	0.76	0.22
2046	0.25	0.05	0.50	0.12	0.75	0.19

The Project Team developed assumptions for the number of reserve scarcity hours, i.e., the hours during which the Pay-for-Performance payments and penalties would apply, based on:

- the annual average number of scarcity hours since the inception of the Pay-for-Performance framework since 2018,

- the increase in hours of shortage pricing relative to the increase in the renewable penetration in other markets with large penetration of intermittent renewable resources, and

- projected growth in renewable penetration in ISO-NE in AESC 2024.

Performance of storage resources during hours of scarcity in absolute terms, and in relation to the average performance of storage resources during recent Pay-for-Performance events, will likely increase in duration and will shift towards a greater number of winter events in the future.[89]

Dispatch Strategy and Operational Assumptions

For transmission-connected storage resources, an hourly dispatch strategy was developed that prioritized (a) responding to EDCs' or other responsible entities' calls for discharging during critical hours, followed by (b) maximizing energy and ancillary services revenues during all other hours.

The Team utilized hourly load data from AESC 2024 to identify the hours during which discharging is most likely to be beneficial to the transmission system, specifically, during monthly system peak hours. To reflect the challenges associated with accurately predicting the peak monthly hour, the Team modeled multiple events per month, varying by month and generally increasing over time. Similarly, the Team modeled events of different durations, starting at 2 hours and increasing over time to up to six hours in winter months (starting in 2030). In establishing the assumed frequency and duration of events, the Project Team reviewed projected trends in the timing, duration, and frequency of scarcity events developed as a part of the AESC process. In general, the increasing difficulty in projecting peak load hours is a reflection of increasing variable and dispatchable distributed energy resources (including flexible load), which the Team incorporated into its modeling assumptions.

As noted above, the Team's dispatch model prioritized dispatch calls from a third party, requiring the battery to discharge during these hours at the maximum possible levels, subject to power rating and duration constraints. During the other hours, projected energy and reserve prices were utilized (treating them as the proxy for day-ahead prices) to estimate the optimal dispatch schedule, subject to several operational constraints.[90]

The Team modeled the dispatch of 2-, 4- and 6-hour batteries assuming that each battery will be dispatched up to one cycle a day and has a roundtrip efficiency of 86 percent.

Battery Duration

The Team modeled the dispatch of batteries of 2-, 4- and 6-hour duration. The Project Team's research suggests that the vast majority of the capacity from recent entrants (approximately 85 percent) and

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[89] Under the Pay-for-Performance framework, the compensation/ penalty to a resource during a scarcity hour is determined as: PPR x (A – Br x CSO), where: (a) PPR – payment performance rate, (b) A – actual energy/ reserves provided by the resource during a scarcity event, (c) Br – balancing ratio or the resource's share of the system requirement during the scarcity event, and (d) CSO – the resource's capacity supply obligation.

[90] See Section Market Revenue Streams, for the methodology used to derive energy and reserve prices. In estimating the reserve revenues, we adjusted the reserve prices down by 75 percent to account for the closeout charges that resources taking on a reserve obligation will incur in the real-time market (i.e., when the real-time prices exceed the Strike Price, as defined by ISO-NE). In its DASI impact analysis, ISO-NE estimated the total closeout charges to be approximately 75 percent of the total charges associated with purchase of ancillary services in the day-ahead market under DASI.

projects in advanced stage of development in New England are 2- and 4- hour batteries.[91] Nonetheless, given the increasing potential for longer-duration potential loss of load events in later years, the analysis includes 6-hour resources in this analysis. Given that LD 1850 directed GEO to evaluate designs for a program to procure “commercially available utility-scale energy storage,” the Project Team focused its analysis on modeling systems reflective of proven technologies that are currently available at cost-competitive pricing. As technology development of longer-duration storage progresses and grid needs evolve, the program may target longer-duration resources in the future.

Location

For the purpose of this analysis, the Project Team evaluated dispatch using prices from the Maine hub. Given the transmission topology and location of supply resources, Maine experiences congestion in several different load pockets. Revenue potential for batteries in several locations across Maine were evaluated; it was observed that the variation in potential revenues has not been significant (less than 7 percent).[92] Furthermore, the contribution of energy arbitrage and reserve revenue to the value stack is ultimately not as significant as some of the other benefits of energy storage, and recent analysis from ISO-NE suggests that the most bottlenecked constraint is likely to shift to Maine-New Hampshire in the future, under resource mix assumptions that are consistent with those underlying AESC 2024.[93] While public data on curtailed renewable energy output is limited, based on the Project Team’s review of confidential data, the volume of curtailed energy is very low. Accordingly, the Project Team did not evaluate the benefits of energy storage at other locations in Maine.

5.3. Distribution-Connected Storage

The Project Team did not have access to utility-specific load profiles in Maine, nor was data available regarding which specific distribution circuits may need upgrades due to capacity constraints in the near future and what these specific upgrades are expected to cost.[94] Furthermore, the modeling suggests that assumptions related to the pace and pattern of space heating electrification is likely as important as historical load data. Given these limitations, the model utilized data from the National Renewable

[91] We utilized data on projects under development from the S&P Market Intelligence platform and supplemented it with our primary research to understand trends in duration of battery entrants.

[92] We utilized 5-year historical pricing data from representative nodes that considered the following constraints: Downeast export, Keene Road export, Wyman hydro export, Rumford export, Orrington-South, and Surowiec-South.

[93] See Dec 20, 2023, ISO-NE presentation to PAC on Economic Planning for the Clean Energy Transition (EPCET) Pilot Study.

[94] CMP’s 3/25 RFI response to GEO provides a link to existing utility hosting capacity maps. Nexamp notes that there is significant information filed by utilities in non-wires alternative dockets, and that the Project Team should work with utilities to analyze distribution circuit loading data. The Project Team notes that the hosting capacity maps do not provide load profiles or future investment data. Pursuant to 35-A M.R.S. § 3132, Maine has an existing non-wires alternative process, which includes conducting benefit-cost analysis. See, for example, Docket No., 2020-00125. Typically, however, benefits in these cases are limited exclusively to the deferred transmission and or distribution investments.

Energy Laboratory (NREL) "ResStock" dataset[95] and Synapse's proprietary heat pump load model, based on a weather year that aligned with assumptions in AESC 2024.

The Project Team simulated distribution feeders serving residential load with varying levels of space heating electrification. The analysis focused on residential load profiles because this class drives noncoincident peak load in Maine, and thus it is likely to be responsible for driving distribution system investments on most portions of the distribution system.

Based on these load profiles, the illustrative distribution feeder is expected to peak in winter months. The model therefore assumes batteries must be held in reserve from December through February to be available to respond to dispatch calls to address the distribution system peak. For the remaining months, the Project Team simulated resources responding to calls similar to those simulated for the transmission-connected resources, except that the events were tied to monthly Maine system peaks as opposed to ISO-NE system peaks because the targeted benefit for these events is RNS savings. The Team did not assume that resources would take on a capacity supply obligation, in order to ensure that during winter months the entity dispatching the battery can meet the requirements of the distribution system. Further, taking on a capacity supply obligation would likely require the resource to operate as a Generator Asset, which would eliminate potential RNS savings.

Because of the heterogeneity of load shapes on different parts of the distribution system, opportunities for storage to effectively defer investments will vary significantly. Furthermore, the Project Team did not have access to feeder-specific data that would enable directly modeling the use of storage to address particular distribution system peaks. Given this, the Team assumed that 2-hour resources will yield a kilowatt deferral equal to 25 percent of nameplate capacity; 50 percent of nameplate capacity for 4-hour resources; and 75 percent for 6-hour resources. These assumptions are based primarily upon a review of the simulated feeder data, which included several significant peaks occurring during winter months, generally lasting approximately 8 hours.[96] As noted above, given the heterogeneity of loads on the distribution system, it is reasonable to expect there will be areas in which storage will be able to have a larger impact on the distribution system than assumed and others where the impact would be lower. These values are reasonable assumptions that help establish the potential distribution system value and provide a benchmark for the level of benefit that may be needed in order for a project to be cost-effective.

In addition to avoided distribution and RNS costs, as discussed in Section 4.2, the Project Team evaluated potential energy arbitrage revenue for these resources and decided, given the potential incremental value and some of the potential implementation challenges, to omit modeling of arbitrage

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95 NREL, https://resstock.nrel.gov/datasets.

96 For perspective, a report commissioned by the Maine Office of the Public Advocate in Docket No. 2020-00125 found that a battery required to meet the identified need would need to have a nameplate capacity of at least 1.99 MW, provide 12.57 MWh of energy, and operate continuously (though not at full nameplate capacity) for a 10-hour period. The power and energy ratings imply an approximately 6-hour, 2 MW resource.

outside energy markets. As also discussed, these resources would not participate in wholesale energy markets directly, as doing so would eliminate the potential for RNS benefits.

In modeling the distribution-connected resources, the Team assumed the resources would be subject to a retail tariff for charging. CMP filed a request for approval[97] of a wholesale distribution access tariff (WDAT) with FERC on February 1, 2023, in Docket ER24-1177. WDATs are intended to set rates for and govern the terms of service for distribution-connected resources that primarily participate in wholesale markets (in CMP's case, specifically designed for energy storage). However, because it is assumed that distribution-connected storage resources would not participate in wholesale markets, these resources would likely not be eligible to take service under the WDAT if and when approved.

Therefore, it is assumed that CMP's retail "B-ES" rate, specifically, LGS-P-TOU, would apply to storage resources.[98] This rate includes time-varying demand charges, flat volumetric charges, and a fixed monthly charge. While there are a number of differences in rates between the current retail B-ES rate and the filed WDAT, perhaps the most impactful is the difference in the fixed monthly service charge (which is $9,661 per month under the retail tariff and $890 under the proposed WDAT). Based on the WDAT filing letter, it appears that the difference is driven by assignment of stranded costs to the retail fixed charge, which are excluded in the filed WDAT. This is a substantial cost that merits further examination of whether resources, as modeled under the recommended solicitation mechanism, could become eligible for the WDAT, if and when it is adopted.

[97] CMP request to FERC for tariff revisions, 2/1/23, https://seadvantage.com/Documents/Eyes_and_ears_Library/20240201-5191.PDF.

[98] CMP tariff, https://www.cmpco.com/documents/40117/46385123/b-es_06.29.23.pdf/00512f58-ffd1-a571-0e6d-3afb5ccb2725?t=1688039585661.

6. Cost-Effectiveness

6.1. Cost-Effectiveness Framework

The Project Team conducted a quantitative analysis of the cost-effectiveness of transmission- and distribution-connected storage under the procurement and storage dispatch parameters described above.

A benefit-cost analysis is a systematic approach for assessing the cost-effectiveness of investments by comparing their benefits and costs to achieve a benefit-cost ratio. This ratio is calculated based on all of the relevant benefits and costs in a project's lifetime to see how benefits compare with project costs. This process is widely used to assess investments in the energy system, and in other sectors, to assist with decision-making and enable easy comparisons among investments and programs.[99]

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM) recommends establishing a jurisdiction-specific test that reflects the applicable energy policy goals of the jurisdiction, as guided by statutes, regulations, commission orders, and stakeholder input. Any such test should adhere to fundamental benefit-cost analysis principles and should represent the "regulatory perspective," which is meant to represent the views of legislators, commissioners, and other relevant decision-makers.[100]

Jurisdiction-specific tests focused on the regulatory perspective evaluate utility system impacts and then apply relevant policy goal impacts. Compared to more traditional types of tests, which do not change based on a jurisdiction's priorities, these types of tests are adaptable to encompass the goals of that jurisdiction specifically.

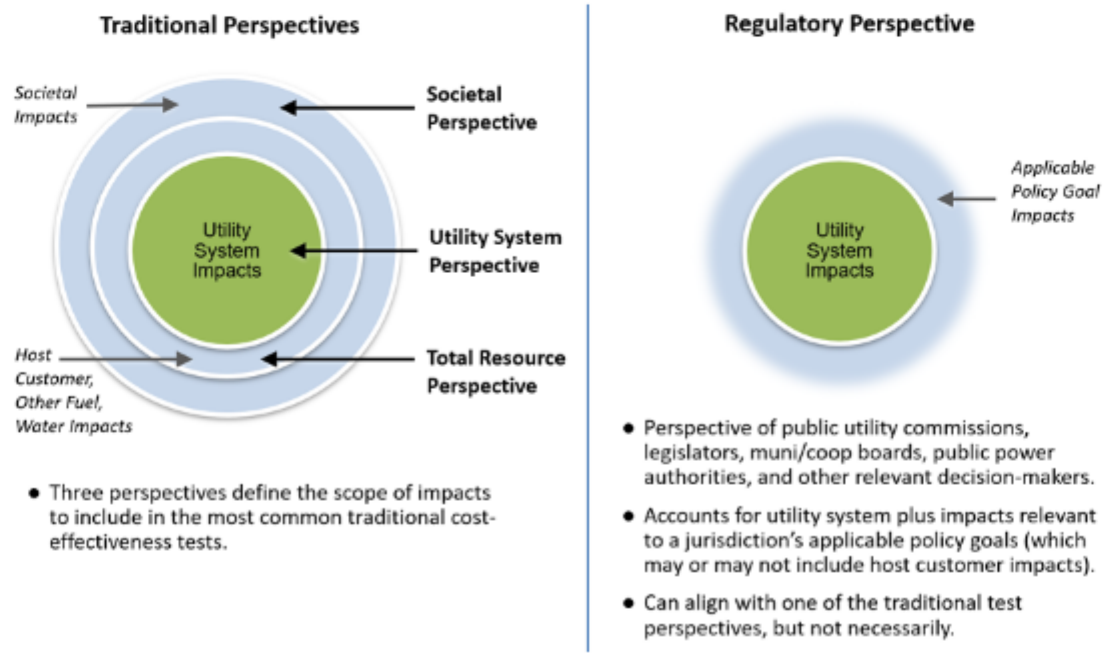
Jurisdiction-specific tests may align with traditional test perspectives but do not necessarily have to. Traditional perspectives are centered on utility system impacts, which represent the utility system perspective. A total resource cost test then layers on impacts such as those related to host customers, other fuels, and water use. A social cost test would then also add social impacts to the evaluation. This type of perspective is particularly helpful for assessing distributed energy resources such as battery storage, which are often the subject of specific policy goals.

Figure 7 illustrates the differences between the regulatory perspective and traditional perspectives.

[99] NPSM, 1-2.

[100] *Id*. at 3-2

Figure 7. Developing a jurisdictional-specific societal cost test



[101]

Based on stakeholder feedback in the RFI, legislative criteria, and guidance from the NSPM, the Project Team selected the UCT and jurisdictional SCT[102] for its assessment of storage. Together, these two tests capture (1) the expected impact of storage on the utility system / ratepayers and (2) the expected impact of storage on Maine, merging elements of jurisdiction-specific tests and the SCT. Table 5 lists the benefits and costs included in these two tests.

[101] *Id*. at 3-3.

[102] See NSPM, Synapse Energy Economics, https://www.synapse-energy.com/national-standard-practice-manual-benefit-cost-analysis-distributed-energy-resources. This was also used in Synapse's evaluation of distributed generation successor programs in Maine, see https://www.nationalenergyscreeningproject.org/wp-content/uploads/2023/06/Maine-DG-Successor-Program-Evaluation_Synapse-Energy.pdf.

Table 5. Benefits and costs in UCT and Jurisdictional SCT

Benefits included	Costs included
UCT: Perspective of utility / ratepayers	
• Avoided capacity • Avoided energy and capacity DRIPE (net of charge and discharge) • Avoided transmission and distribution (T&D) costs • Risk (net of charge and discharge) • Reliability	• Program incentive, calculated as the difference between storage costs and market revenues.[103] And: • Utility administration costs
Jurisdictional SCT: Perspective of society / state	
• Avoided energy and capacity DRIPE (net of charge and discharge) • Avoided transmission and distribution (T&D) costs • Risk (net of charge and discharge) • Reliability • Market revenues (for developers) [104] • Greenhouse gas impact (net of charge and discharge)	Project Costs, including the following: • Tax incentives • Developer capital and O&M expenses And: • Utility administration costs

The Project Team included many, but not all, of the utility system impacts in its UCT assessment. The UCT includes program incentive costs, utility administration costs, avoided energy and capacity costs, avoided energy and capacity DRIPE, avoided transmission and distribution costs, avoided risk, and avoided reliability.[105] The UCT test does not include utility performance incentives, avoided credit and collection costs, avoided renewable portfolio standards costs, and improved resilience.[106]

The Project Team selected impacts for inclusion in its jurisdictional SCT based upon state policy. The market revenues for developers are included along with greenhouse gas emissions as this was the focus of the legislation. The jurisdictional SCT does not include: other environmental impacts such as other air

[103] Energy arbitrage, reserves, capacity revenues, and pay for performance. The Team's estimates include premiums to AESC prices based on real-time markets and scarcity event revenues.

[104] Energy arbitrage, reserves, capacity revenues, and pay for performance. Our estimates include premiums to AESC prices based on real-time markets and scarcity event revenues.

[105] Pages 17 and 18 of AESC 2024 state that the reliability analysis addresses the effect of increased reserve margins based on generation reliability, the potential, and obstacles in estimating the reliability associated with reduced load levels on T&D, and value of lost load (VoLL). The study also estimates the value of increased generation reliability per kilowatt of peak load reduction. The study applies the VoLL to the calculation of reliability benefits resulting from dynamics in New England's FCM to estimate cleared and uncleared benefits linking to improving generation reliability. The 15-year levelized values are $0.38 per kW-year for cleared benefits and $4.82 per kW-year for uncleared benefits.

[106] The GEO's *2022 Maine Energy Storage Market Assessment Study* quantified a resilience value for BTM systems based on the VoLL. In this report, the VoLL is used to quantify reliability benefits which apply to both transmission- and distribution-connected storage systems based on AESC's 2024 VoLL results (AESC 2024, pp. 319-325). Other types of utility, host customer, and societal resilience benefits are not captured in this analysis.

emissions, solid waste, land, water, and other environmental impacts; public health impacts such as health impacts, medical costs, and productivity affected by health; economic and job impacts; energy security impacts; low-income customer impacts; and resilience impacts beyond those experienced by utilities.

The Project Team modeled 12 scenarios for standalone storage including: 2-hour, 4-hour, and 6-hour storage in two sizes for transmission-connected storage (5 MW and 60 MW) and two sizes for distribution-connected storage (1 MW and 5 MW). The Project Team did not assess larger transmission-connected storage, BTM storage, or microgrids (discussed above). The sizes studied are representative and should not be viewed as recommended minimum or maximum sizes.

The Project Team utilized values, inputs, and assumptions from AESC 2024[107] to estimate the expected benefits of storage in Maine. Capital cost estimates are from the National Renewable Energy Laboratory (NREL).[108] It is important to note that the intent of the analysis was to robustly assess cost-effectiveness of storage in Maine rather than to precisely forecast storage prices and revenues or precisely quantify the necessary incentives, given the recommendation that compensation rates be set through a competitive process.

It is assumed that storage is operational for a 20-year period beginning in 2027. A nominal discount rate of about 4 percent, 1.74 percent real, is assumed for modeling purposes. This is a default value provided in AESC 2024 that is also aligned with a societal perspective, thus aligning with the perspective of both of the selected cost-effectiveness tests. Table 6 contains further detailed information on modeling inputs and assumptions.

[107] Synapse, *AESC 2024 Materials*, https://www.synapse-energy.com/aesc-2024-materials.

[108] The Project Team utilized storage costs from NREL's 2023 Annual Technology Baseline (ATB) data set. See NREL, https://atb.nrel.gov/.

Table 6. Detailed benefit-cost analysis assumptions

Category	Unit	Value	Transmission-connected?	Distribution-connected?	Notes
Overall benefit-cost analysis assumptions					
Measure life	*Years*	20	X	X	-
Program year	-	2027	X	X	-
Energy losses	*%*	9		X	From AESC 2024.
Peak demand losses	*%*	16		X	From AESC 2024.
Wholesale risk premium	*%*	8	X	X	From AESC 2024. The risk premium is used to convert wholesale prices to retail prices.
Inflation rate	*%*	2.25	X	X	From AESC 2024.
Real discount rate	*%*	1.74	X	X	Calculated using a nominal discount rate of 4.03% and an inflation rate of 2.25%, from AESC 2024.
Cost assumptions					
Administrative costs	*2024$ per yr*	600,000	X	X	Estimated total administrative costs for a 200 MW portfolio.
Incentive costs	*2024$ per kWh*	$74-1,126	X	X	Net present value of incentive calculated by netting out present value of all developer costs and any projected wholesale revenues. See Table 7 for further detail.
Capital expense	*2024$ per kWh*	$362-826	X	X	NREL's 2023 ATB.
Fixed O&M	*2024$ per kWh-yr*	$9-21	X	X	NREL's 2023 ATB.
Investment Tax Credit (ITC)	*%*	30%	X	X	Inflation Reduction Act clean energy ITC, assuming wage and apprenticeship requirements are satisfied, with no additional adders.
Developer cost of capital	*%*	9.5%	X	X	Calculated assuming a 7% cost of debt and 12% cost of equity and 50/50 debt-equity ratio. Used to inform the developer incentive.
Fixed service charge	*2024 thousand $ per yr*	$119-143		X	B-ES Tariff, LGS-P-TOU (See discussion in Section 5.3)
Demand charges	*2024 $ per kW*	$6-15		X	B-ES Tariff, LGS-P-TOU.
Benefit assumptions					
Pooled transmission facility (PTF)	*2024$ per kW-yr*	Transmission: $6.31 (UCT); $69 (J-SCT)	X	X	Value from AESC 2024, derated for the UCT by Maine's contribution to ISO-NE's coincident annual peak, multiplied by discharge at annual peak.

Category	Unit	Value	Transmission-connected?	Distribution-connected?	Notes
RNS	*2024$ per kW-yr*	$154		X	Full value from AESC 2024, multiplied by discharge at Maine's monthly peak (year 1); after year 1, derated RNS value by 10.87 percent times discharge at monthly peak. This is due to analysis of year 1 RNS under-collection that is socialized and reduces the effect of storage on avoided RNS rates when accounted for in later years.
Avoided capacity costs	*2024$ per kW-yr*	Cleared: $30-102 Uncleared: $0-123	Cleared	Uncleared	From AESC 2024. Uncleared capacity value is multiplied by applicable uncleared scaling factor calculated using AESC 2024's Appendix K.
Capacity DRIPE	*2024$ per kW-yr*	Cleared: $0-211 Uncleared: $0-164	Cleared	Uncleared	From AESC 2024. Uncleared capacity value is multiplied by applicable uncleared scaling factor calculated using AESC 2024's Appendix K.
Avoided distribution costs	*2024$ per kW-yr*	$291		X	From Maine average avoided distribution costs used by Efficiency Maine, multiplied by discharge at Maine.
Avoided greenhouse gas costs	*2024$ per short ton*	$178-248	X	X	New England electric sector marginal abatement costs from AESC 2024.
Reliability	*2024$ per kW-yr*	Cleared capacity: $0-15 Uncleared capacity: $0-$32	Cleared	Uncleared	From AESC 2024, quantifies additions to system reliability. Team did not consider location-specific reliability benefits.
Electric DRIPE	*2024$ per MWh*	$1-9	X	X	Seasonal peak and off-peak values taken from AESC 2024 and applied to modeled charging profiles. Electric DRIPE effects due to discharging and charging are netted out.
Wholesale market revenues	*2024 $ per kW-yr*	$32-129	X		Include energy arbitrage, reserves, real-time premium, scarcity adders, capacity and Pay-for-Performance payments. Described further in Section 5.2.

Storage Incentives

To model the necessary costs to encourage storage development, the Team assumed an upfront incentive that is equal to the difference between storage costs and revenues, assuming a developer's cost of capital of 10 percent.[109]

Table 7 shows the modeled net present value of the incentives. For modeling purposes, the Team assumed incentive costs/payments are incurred upfront. However, the Team recommends at least 50 to 70 percent of performance incentives be paid for dispatch during critical hours (i.e. through performance payments).

As indicated in the table, incentives are energy-based ($/kWh) and vary depending on the capacity in both energy and power terms. For example, based on an analysis of the difference between costs and revenues described above, a 60 MW / 120 MWh battery requires a $100 per kWh incentive.

Under the UCT, the modeled incentive is explicitly counted as a cost. From the utility system's perspective, the cost of the project is simply the cost of the incentive. Since the full project costs and wholesale revenues flow through the developer, they do not appear in either the benefits or the costs from the utility system's perspective. This differs from the jurisdictional SCT, where the incentive is a transfer payment between two parties that are both within the scope of the jurisdiction. Therefore, the incentive does not appear as an explicit cost under the jurisdictional SCT. In this test, the full project costs and wholesale revenues are accounted for directly in the costs and benefits, respectively.

Table 7. Modeled incentives

2024$/kWh	2 Hour	4 Hour	6 Hour
Transmission-connected			
60 MW	$100	$74	$80
5 MW	$214	$116	$99
Distribution-connected			
5 MW	$562	$380	$310
1 MW	$1,126	$648	$479

Actual incentive levels should be determined and administered by the program administrator.

[109] Calculated assuming a 7% cost of debt and 12% cost of equity and 50/50 debt-equity ratio. A cost of capital at approximately this level assumes that project capital stacks include some debt; securing such debt would likely be contingent upon the availability of incentives that reduce the project's exposure to wholesale market price volatility.

6.2. Cost-Effectiveness Results

In general, the cost-effectiveness modeling indicates systems with larger capacities tend to have greater benefit-cost ratios than systems with smaller capacities. This is primarily due to economies of scale in project costs: larger storage systems have lower capital expenses on a unit-cost basis than smaller installations, while at the same time most of the benefits scale proportionally with the size of the system. There is not a monotonic relationship between project duration and cost-effectiveness. Different values scale differently with changes in duration. For example, energy arbitrage opportunities have diminishing returns to increased duration, while capacity-denominated values scale proportionally.

Transmission-Connected Storage Results

The Team assumed that transmission-connected storage could participate in wholesale capacity, energy, and reserves markets. Dispatch was based on responding to performance calls during critical hours and otherwise assumed to optimize wholesale market revenues. Figure 8 and Figure 9 display the benefit-cost ratios results for all transmission-connected storage systems under the UCT and jurisdictional SCT respectively. For transmission-connected storage, all combinations of durations and capacities, except for the 5 megawatt- 2-hour duration program, were cost-effective under both tests.

Figure 8.Transmission-connected storage: UCT result

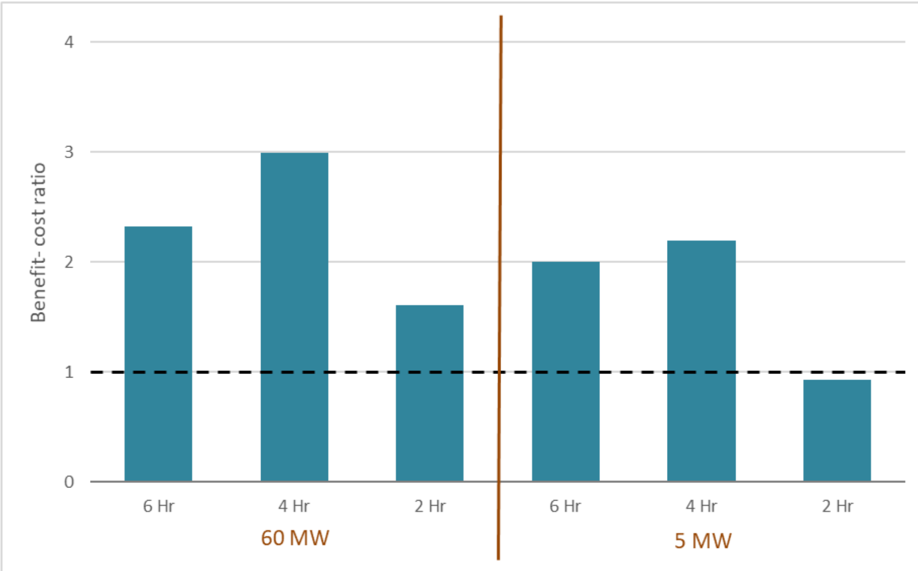


Figure 9. Transmission-connected storage: jurisdictional SCT results

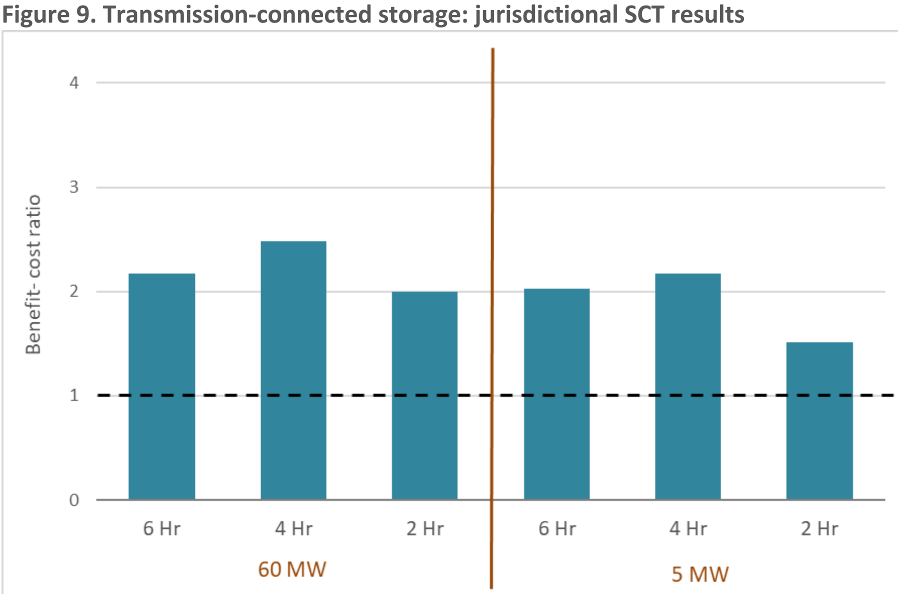
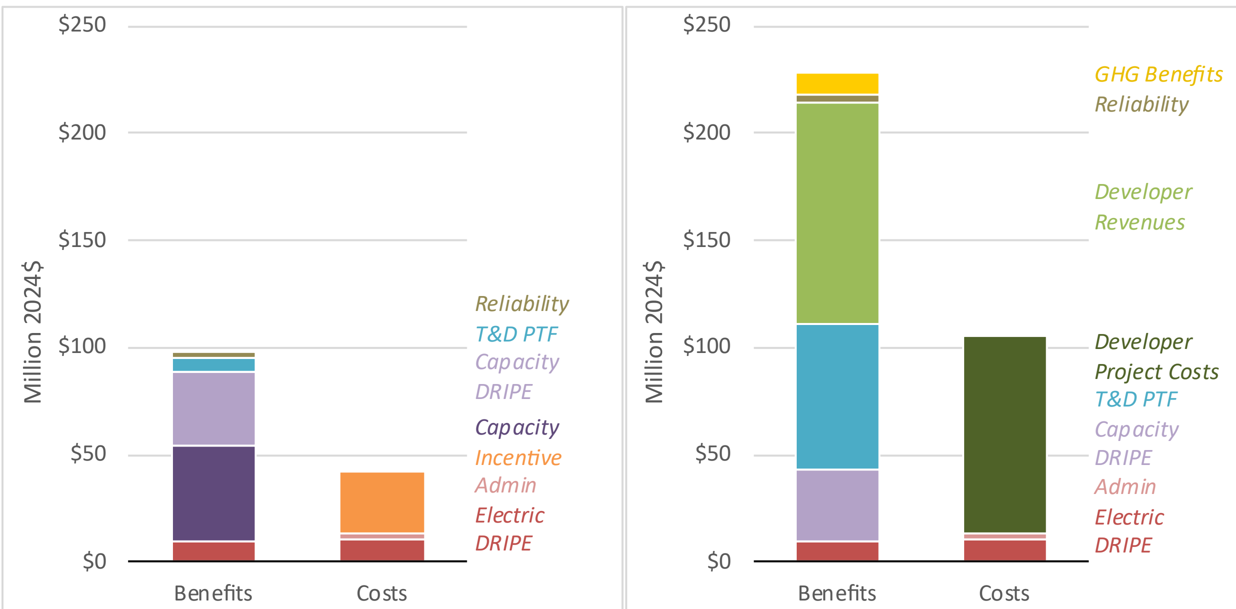


Figure 10 shows the breakdown of benefits and cost results for the 60 MW, 6-hour duration system. These charts indicate that transmission-connected storage systems can provide a wide range of benefits, largely driven by avoided capacity costs in addition to avoided capacity DRIPE costs. From the utility system perspective, the most significant cost valued under the UCT is the program incentive. The program incentive, which will be paid out by the utility system, is calculated by netting out the present value of projected wholesale revenues from the present value of developer project costs, assuming a discount rate consistent with a developer's cost of capital (the Team assumes 10 percent). The UCT does not explicitly include developer wholesale revenues and project costs since these accrue to the developer.. These values are only relevant to the UCT in that they are used to calculate the program incentive.

From a societal perspective, the incentive is a transfer payment between two parties that are both within the jurisdiction. Therefore, the transfer payment does not appear as a cost or benefit under the jurisdictional SCT. Instead, the jurisdictional SCT quantifies the full project costs and wholesale revenues that flow through the developer. Another difference between the UCT and the jurisdictional SCT is how capacity benefits are valued. To avoid double-counting capacity benefits of a project, the jurisdictional SCT does not include avoided capacity costs as a benefit, because capacity payments are included as a benefit under the developer's wholesale market revenues.

Figure 10.Transmission-connected storage: UCT (left) and jurisdictional SCT (right) results for the 60 MW, 6-hour battery



Avoided PTF values differ significantly between the two tests because the UCT is from the perspective of Maine's ratepayers, who receive a portion of the total avoided PTF benefits based on Maine's share of RNS charges (see Table 6). The jurisdictional SCT includes the entire PTF value which accrues to all states in ISO-NE.

Distribution-Connected Storage Results

The Team assumed distribution-connected storage would not participate in wholesale markets to allow it to capture avoided RNS costs when dispatched during Maine monthly peak hours. Avoided RNS and avoided distribution costs are the primary drivers of benefits for this use case. All combinations of capacities and durations were cost-effective under the UCT. Under the jurisdictional SCT, modeled storage was cost-effective with the exception of the 1 MW, 2-hour duration system, which was not cost-effective.

Figure 11. Distribution-connected storage: UCT results

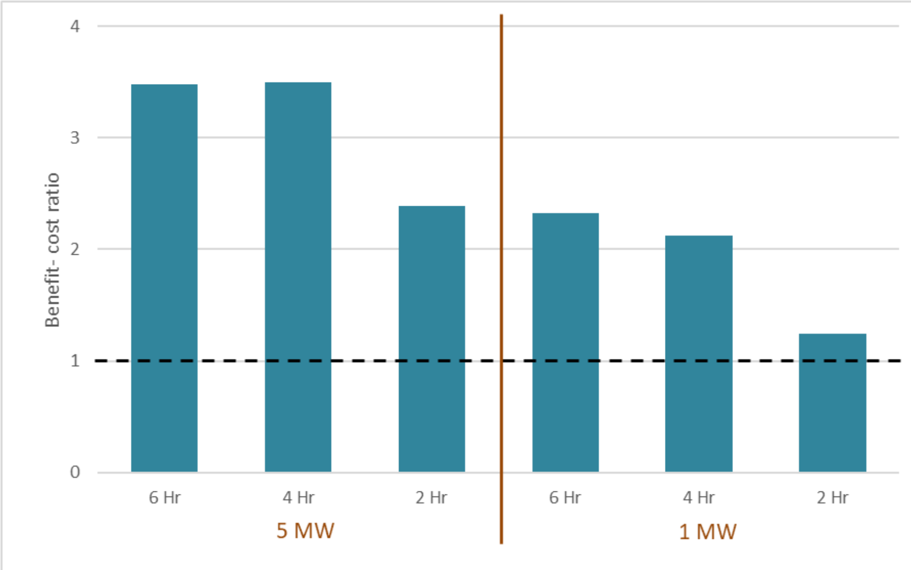


Figure 12. Distribution-connected storage: jurisdictional SCT results

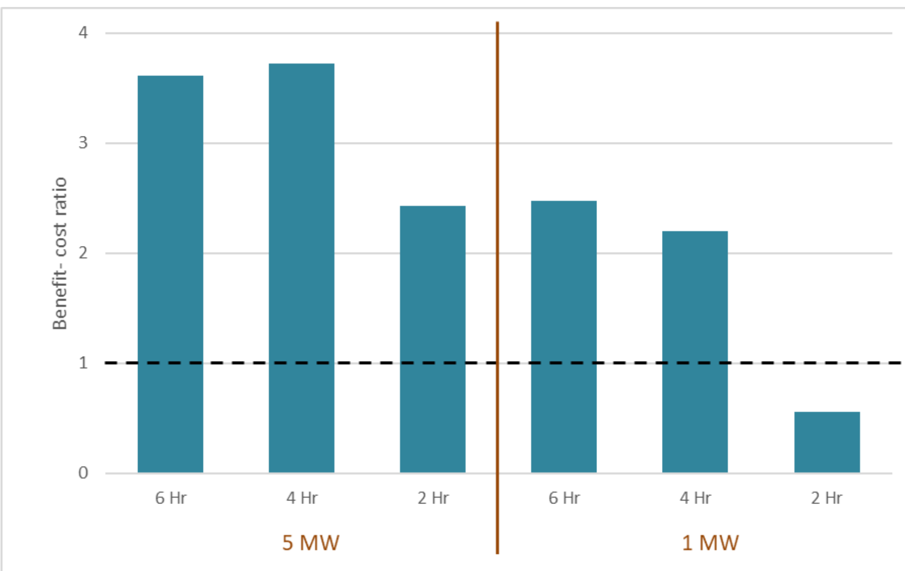
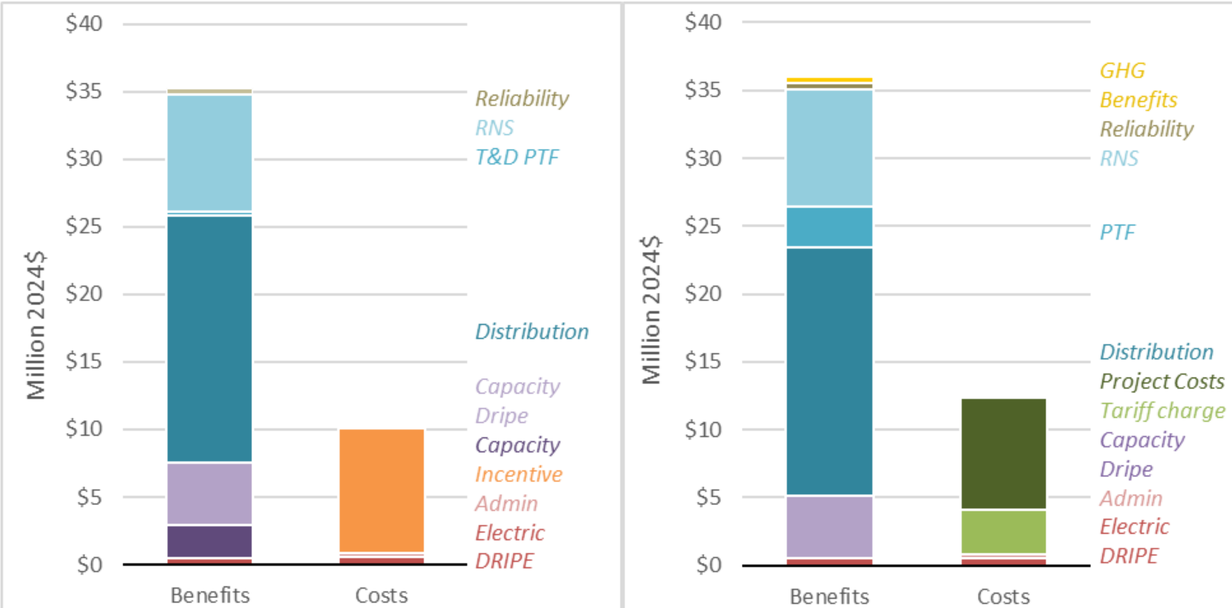


Figure 13. Distribution-connected storage: UCT (left) and jurisdictional SCT (right) results for the 5 MW, 6-hour battery



Sensitivities

The Team performed several sensitivities to assess the robustness of the cost-effectiveness results based on a reasonable range of key assumptions. Base case results are shown on the right side of each table for comparison with the performed sensitivity.

Inclusion of RNS Reduction as a Benefit for Transmission-Connected Storage

The first sensitivity conducted examined a scenario where transmission-connected storage that participates in wholesale energy and capacity markets and is able to reduce RNS charges. Although storage that participates in wholesale markets is not currently able to reduce RNS charges, if ISO New England were to update the Open Access Transmission Tariff (OATT) to enable batteries that participate in wholesale markets to help states manage their peak loads used to calculate RNS allocations, this would represent a significant potential value stream.[110]

As would be expected, all transmission-connected storage configurations become more cost-effective due to avoidance or deferral of some RNS charges, a significant value that is higher than marginal PTF

[110] In discussions that led to an ISO-NE petition with FERC (later docketed as ER21-2337, in which ISO-NE altered portions of its Open Access Transmission Tariff governing how BTM assets and load reducers affected the calculation of RNS charges), ISO-NE explicitly chose to exclude resources participating in wholesale markets (specifically, Generator Assets) from the calculation of RNS charges, that is, made it so that these resources could not reduce RNS charges. Still, it is not unreasonable to consider a future in which the policy imperative to realize the full benefits of energy storage and other distributed energy resources leads to a revision of this treatment.

avoided costs ($6.31kW-year for future marginal PTF projects versus a starting value of $154.35/kW-year for RNS charges).

Table 8. Transmission-connected storage with RNS

Benefit-cost ratio	RNS sensitivity		Base case	
	UCT	SCT	UCT	SCT
60 MW				
6 Hour	3.91	2.92	2.32	2.17
4 Hour	5.65	3.59	2.99	2.48
2 Hour	3.85	2.94	1.60	2.00
5 MW				
6 Hour	3.47	2.75	2.00	2.03
4 Hour	4.31	3.16	2.19	2.17
2 Hour	2.32	2.25	0.93	1.52

Higher Discount Rate

The Team also analyzed a higher, more market-based discount rate rather than the societal discount rate used in the cost-effectiveness analysis. Instead of the 1.74 percent (real) rate used in the base case, the Team applied a real discount rate of 6.94 percent, which aligns with CMP's nominal return on equity of 9.35 percent agreed upon by stipulating parties in CMP's most recent rate case.[111] With this discount rate, all benefit-cost ratios are lower; even so, all resources, with the exception of the 2-hour distribution-connected resource were still cost-effective (had a benefit-cost ratio greater than one in the UCT). Table 9 shows the results for this sensitivity for transmission-connected storage and Table 10 shows the results for distribution-connected storage.

Table 9. Transmission-connected storage with higher discount rate

Benefit-cost ratio	Higher discount rate sensitivity		Base case	
	UCT	SCT	UCT	SCT
60 MW				
6 Hour	1.78	1.43	2.32	2.17
4 Hour	2.47	1.71	2.99	2.48
2 Hour	1.42	1.39	1.60	2.00
5 MW				
6 Hour	1.51	1.33	2.00	2.03
4 Hour	1.74	1.48	2.19	2.17
2 Hour	0.77	1.04	0.93	1.52

[111] Order Approving Stipulation, Central Maine Power Company Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. § 307. Available at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7bA12D1F4F-4BA9-46F0-9C82-680A48D58DC4%7d&DocExt=pdf&DocName=%7bA12D1F4F-4BA9-46F0-9C82-680A48D58DC4%7d.pdf.

Table 10. Distribution-connected storage with higher discount rate

Benefit-cost ratio	Higher discount rate sensitivity		Base case	
	UCT	SCT	UCT	SCT
5 MW				
6 Hour	2.04	2.33	3.48	3.61
4 Hour	2.07	2.45	3.50	3.73
2 Hour	1.43	1.63	2.39	2.43
1 MW				
6 Hour	1.34	1.65	2.32	2.47
4 Hour	1.25	1.53	2.13	2.20
2 Hour	0.73	0.50	1.24	0.56

Removal of Capacity Market Revenues and Uncleared Capacity Benefits

The Project Team also considered a case where transmission-connected storage is unable to receive capacity revenues, and distribution-connected storage is unable to provide uncleared capacity benefits. In effect, this scenario assesses cost-effectiveness for resources located north of the Surowiec interface, which are not currently considered deliverable to the rest of New England under FCM eligibility requirements. The absence of capacity revenues and uncleared capacity benefits reduces the benefit-cost ratios significantly for all battery durations and capacity combinations, relative to the base case ratios with capacity revenues. In the absence of capacity revenues and uncleared capacity benefits, no modeled transmission-connected storage configurations are cost-effective under the UCT. All distribution-connected batteries, except for the 1 MW, 2 hour battery, however, remain cost effective under the UCT and jurisdictional SCT without uncleared capacity benefits.

This indicates that most resources located north of the Surowiec interface may not be cost-effective, since they are not able to participate in the FCM. However, if the project-specific avoided distribution costs are greater than the model assumptions, individual projects could be cost-effective. Resources that cannot participate in the FCM will also require a greater incentive than resources that are deliverable to the FCM. This will drive down their cost-effectiveness relative to resources that are able to partially offset their costs with capacity market payments. Table 11 shows the results for this sensitivity for transmission-connected storage and Table 12 shows the results for distribution-connected storage.

Table 11. Transmission-connected storage without capacity market revenues

	No capacity market revenues		Base case	
	UCT	SCT	UCT	SCT
60 MW				
6 Hour	0.30	1.48	3.48	3.61
4 Hour	0.35	1.69	3.50	3.73
2 Hour	0.28	1.48	2.39	2.43
5 MW				
6 Hour	0.27	1.38	2.32	2.47
4 Hour	0.28	1.48	2.13	2.20
2 Hour	0.18	1.12	1.24	0.56

Table 12. Distribution-connected storage without uncleared capacity benefits

	No uncleared capacity benefits		Base case	
	UCT	SCT		UCT
5 MW				
6 Hour	2.79	3.10	3.48	3.61
4 Hour	2.65	3.07	3.50	3.73
2 Hour	1.80	1.95	2.39	2.43
1 MW				
6 Hour	1.86	2.00	2.32	2.47
4 Hour	1.61	1.63	2.13	2.20
2 Hour	0.93	0.18	1.24	0.56

7. RECOMMENDATIONS

Based on an analysis of cost-effectiveness and legislative criteria, the Project Team finds that up to 200 MW of storage in Maine is likely to be beneficial to utility ratepayers and society. This conclusion is based on storage procurement that adheres to the following criteria:

1. A competitive solicitation overseen by a neutral third party.
2. An upfront incentive with a performance requirement for transmission-connected projects that allows for storage dispatch during critical periods that best achieve ratepayer value. The specific purpose and strategy of calling events will differ for the distribution- and transmission-connected resources.
3. The reservation of 40 MW for partial-tolling agreements for distribution-connected storage that enables utilities to dispatch storage at optimal times to defer or avoid infrastructure costs. This should be reserved until one year following the successful implementation of the procurement program for transmission-connected storage.
4. Ongoing review and evaluation of actual program performance and impacts.

The Project Team recommends 30–50 percent of the total incentive be paid up front, with the remainder allocated to performance payments and dispatch at critical times to achieve value for ratepayers that are not adequately compensated by market mechanisms. During program implementation, utilities should provide specific location and deferred or avoided investment possibilities to site cost-effective storage resources, which should be evaluated by the program administrator.

Regarding the fourth criterion above, the energy landscape in Maine (and the whole United States) is set to change tremendously over the next 10 to 20 years, and it is impossible to predict the precise nature of these changes and their effect on storage that is procured in the near term. For example, the New England region is currently summer peaking, but around 2035 there is currently an expectation that the region will be winter peaking, as seen in the example above of a residential distribution feeder with high heat pump penetration. Intermittent wind and solar resources will achieve greater penetration. This will significantly affect the economic operation of storage resources, as will additional loads from beneficial electrification such as heat pumps and electric vehicles. The interaction of these dynamics and their overlap with the economic dispatch of storage and effects on overall emissions are complex. While the Team captured many of these dynamics in its modeling, assumptions must be vetted through real-world assessment of storage economics and behavior.

The Project Team therefore recommends an annual or bi-annual review of any storage program(s) initiated at the Commission. Benefits and costs of storage should be regularly assessed; if behavior of storage is significantly different from the assumptions outlined in this report, it may be necessary for the program administrator to adjust the program structure and/or incentives ultimately adopted.