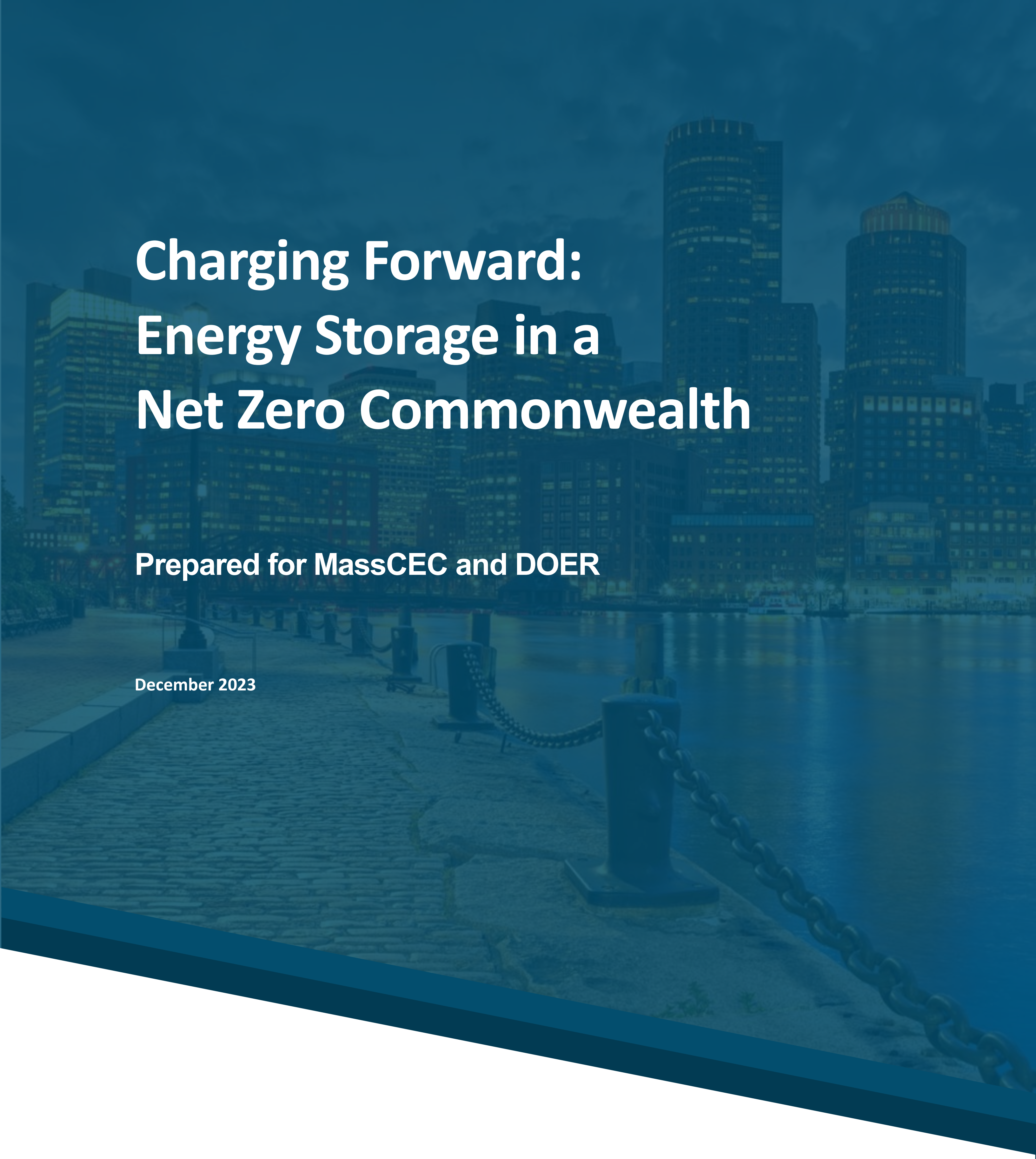

Charging Forward: Energy Storage in a Net Zero Commonwealth

Prepared for MassCEC and DOER

December 2023

Energy+Environmental Economics

Charging Forward

Energy Storage in a Net Zero Commonwealth

December 2023

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Acknowledgements

E3 would like to express our deep appreciation to the organizations and individuals who contributed to this study. First, we want to thank the stakeholders for their participation in workshops, interviews, and email exchanges. Their feedback has been critical to the study approach, key findings, and recommendations. We would also like to thank the members of the Massachusetts Clean Energy Center and the Massachusetts Department of Energy Resources who served as study partners:

- MassCEC
    - Galen Nelson
    - Sarah Cullinan
    - Corrin Moss
    - Ethan Handel
    - Rees Sweeney-Taylor*
    - Ariel Horowitz*
    - Malia Ching*
- DOER
    - Joanna Troy
    - Samantha Meserve
    - Tom Ferguson
    - Aurora Edington
    - Sarah Basham

*No longer with MassCEC

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Acronym Definitions

Acronym	Definition
ACES	Advancing Commonwealth Energy Storage Program
BCR	Benefit-Cost ratio
BTM	Behind-the-Meter
CAES	Compressed Air Energy Storage
CPEC	Clean Peak Energy Certificates
CPS	Clean Peak Energy Standard
DPU	Department of Public Utilities
EDC	Electric Distribution Company
EFSB	Energy Facility Siting Board
ELCC	Effective Load Carrying Capability
ESI	Energy Storage Initiative
FCA	Forward Capacity Auction
FTM	Front-of-the-Meter
ISO-NE	Independent System Operator of New England
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
LCOE	Levelized Cost of Energy
LDES	Long Duration Energy Storage
LFC	Levelized Fixed Costs
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MDES	Mid Duration Energy Storage
MLP	Municipal Light Plant
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
OSW	Offshore Wind
PTC	Production Tax Credit
RGGI	Regional Greenhouse Gas Initiative
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standards
RTE	Roundtrip Efficiencies
SCT	Societal Cost Test
SDES	Short Duration Energy Storage
SMART	Solar Massachusetts Renewable Target
TOU	Time-of-Use
VoLL	Value of lost load

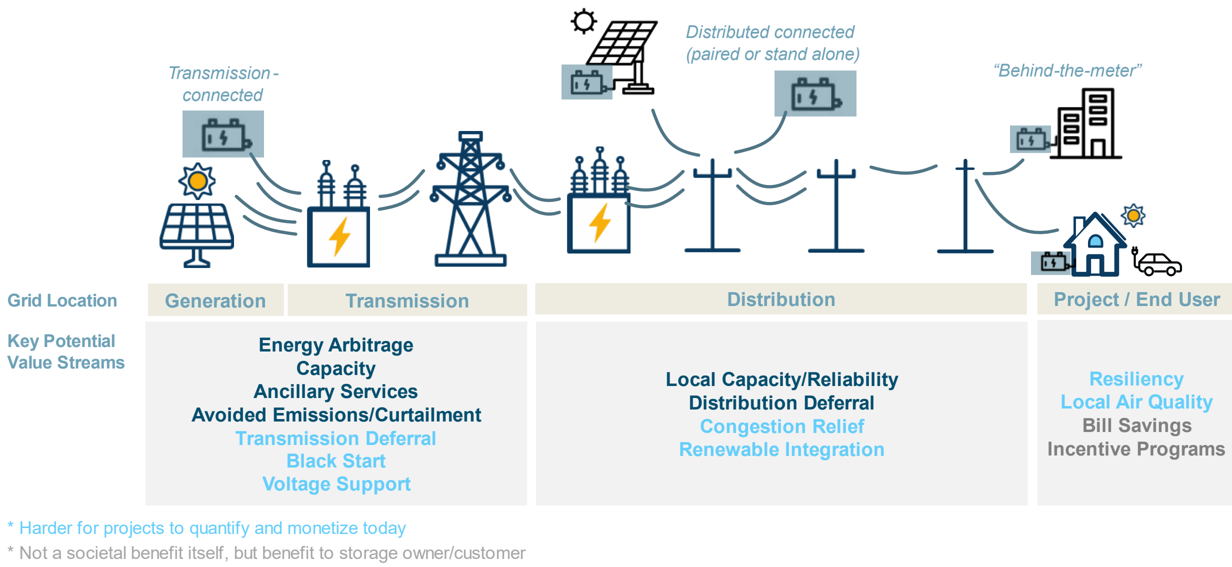
Executive Summary

On August 11, 2022, *An Act Driving Climate Policy Forward,* 2022 Mass. Acts 179 ("the 2022 Climate Act")[1] was signed into law, accelerating the Commonwealth's electric grid transformation into one that is cleaner, more affordable, and more resilient. This Act directs the state to pursue a range of clean energy actions to spur climate innovation and reduce emissions. Energy storage – often called the "Swiss army knife" of the electricity industry given the wide range of services many energy storage technologies can provide – is expected to play a key role in supporting the clean energy transition. Thus, the Act calls for an energy storage study to assess today's market and the potential for mid- and long-duration storage to contribute to the Commonwealth's emissions reduction targets and provide electric ratepayer benefits. This study fulfills that requirement, highlighting the role that energy storage can play in supporting decarbonization of the Commonwealth now and over time. This study builds on past and current analysis related to energy storage as well as directly examines the potential roles and benefits of energy storage expected over time.

As outlined in the state's first storage study, the *2016 State of Charge* report, energy storage encompasses a diverse set of technologies capable of absorbing energy, storing it, and later discharging the energy to meet customer and grid demands. This array of technologies–spanning time-tested pumped hydro (one of the earliest storage technologies), advanced lithium-ion batteries entering U.S. markets today, and numerous emerging technologies in research, demonstration, and deployment stages–can shift electric generation across minutes, hours, days, weeks or even seasons. Specific technologies vary in maturity, capabilities, and costs, but collectively can provide the grid essential services across the electricity chain from the point of generation to the point of consumption. Storage applications range from directly participating in wholesale markets providing energy, capacity, and ancillary services, to serving as "non-wires alternatives" that defer transmission and/or distribution capacity investments, to supporting customers through "behind-the-meter" applications such as providing backup power. This expansive range of use cases is illustrated in Figure ES-1, while Figure ES-2 illustrates how storage can help balance our electric grid on multiple timescales, which will be critical as decarbonization proceeds.

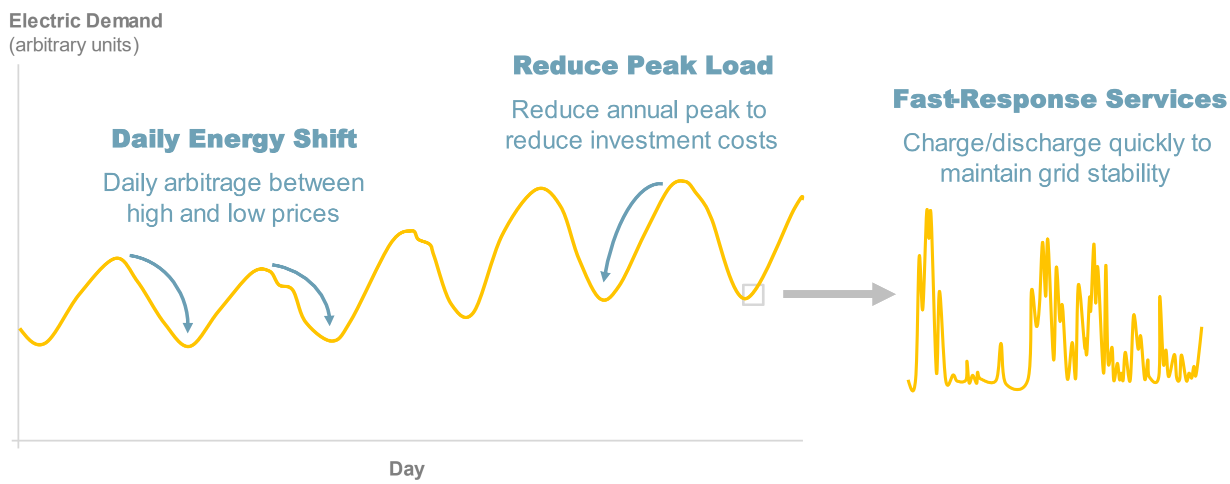
[1] Session Law - Acts of 2022 Chapter 179 (malegislature.gov)

Figure ES-1. Energy Storage Provides Multiple Potential Benefits on Path from Electricity Generation to Customers



Note: Figure ES-1 highlights potential use cases but is not exhaustive.

Figure ES-2. Example of Energy Storage Grid Services



The value of different services storage can provide to the grid will vary across location and time and evolve as the grid mix changes. In addition, mechanisms for projects to monetize the value their resources provide to the grid are emerging and remain incomplete. While New England's electric grid today is dominated by relatively large and inflexible thermal resources, many storage technologies are flexible, modular, and potentially mobile assets that will become increasingly valuable as electrification load materializes and renewable energy is deployed at scale. This study evaluates several existing and likely future use cases, which illustrate how certain value streams can be "stacked" and performed at the same time, while in other cases are mutually exclusive. Some of these value streams are directly supported by policy and regulatory actions, and the Commonwealth has several mechanisms to support energy storage deployments to date. An assessment of this evolving landscape and some key factors are highlighted in Table ES-1.

Table ES-1. Key Energy Storage Value Streams and Duration Requirements.

Value Stream	New England Grid Need Today	New England Grid Need 2050	Minimum Duration Required	Factors
Energy arbitrage	Low	Very High	Short	High RTE and low cost critical to competing in energy markets, assuming renewable integration value reflected in energy markets
Capacity	Low	Very High	Grows over time	Electrification loads will drive need for new firm capacity
Ancillary services	High	Low	Short	Storage growth expected to saturate AS needs, particularly regulation, by late 2020s
Transmission deferral	Site-specific	Site-specific	Site-specific	Very site-specific and potentially complex with variable duration requirements
Avoided emissions	Low	Very High	Short	Greater emissions reductions as renewables deployed on grid and serve as source of charging
Local capacity	Moderate	Moderate	Grows over time	Could support constrained urban areas serving new load or avoid expensive upgrades
Distribution deferral	Site-specific	Site-specific	Site-specific	Site-specific but potentially more opportunity than transmission-level given new load driving more distribution-level constraints
DER interconnection	Low	Moderate	Short	Could grow as DER penetration grows and there are more distribution constraints
Resiliency	Site-specific	Site-specific	Site-specific	Customer value in specific locations with frequent outages & high value of lost load

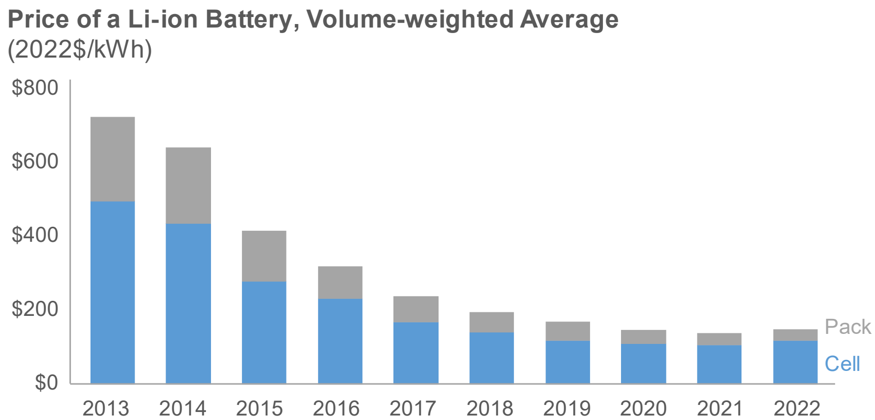
Since the release of the first storage study, the landscape for energy storage has undergone significant change, driven by cost declines of lithium-ion batteries, technology improvements and innovation, policy mandates, regulatory changes, and the deployment of renewables. As illustrated in Figure ES-3, lithium-ion battery costs fell dramatically over the last decade, with some estimates that cost declines exceeded 80%.[2,5] This downward trajectory was driven in large part by growing global demand for electric vehicles and stationary storage applications, which has catalyzed innovation in manufacturing and along the supply chain. Massive growth in deployments and storage technology innovation has also spurred cost reductions in the rest of the battery storage system (e.g., inverters), in engineering, procurement, construction, and in "soft" costs (e.g., permitting, interconnection). While the decline in costs over the last decade is remarkable, demand from burgeoning battery markets has outpaced the industry's ability to manufacture and distribute battery components and systems. As a result, the last two years have offered a notable, if short-term, reversal, as rising raw materials and other battery component costs have

[2] NREL, 2021. [Storage Futures Study: Storage Technology Modeling Input Data Report (nrel.gov)]

driven up battery system costs. While a range of industry outlook perspectives exist, many expect that cost declines will return by the mid to late 2020s as the energy storage supply chain expands to meet both electric vehicle and stationary storage demands.[5]

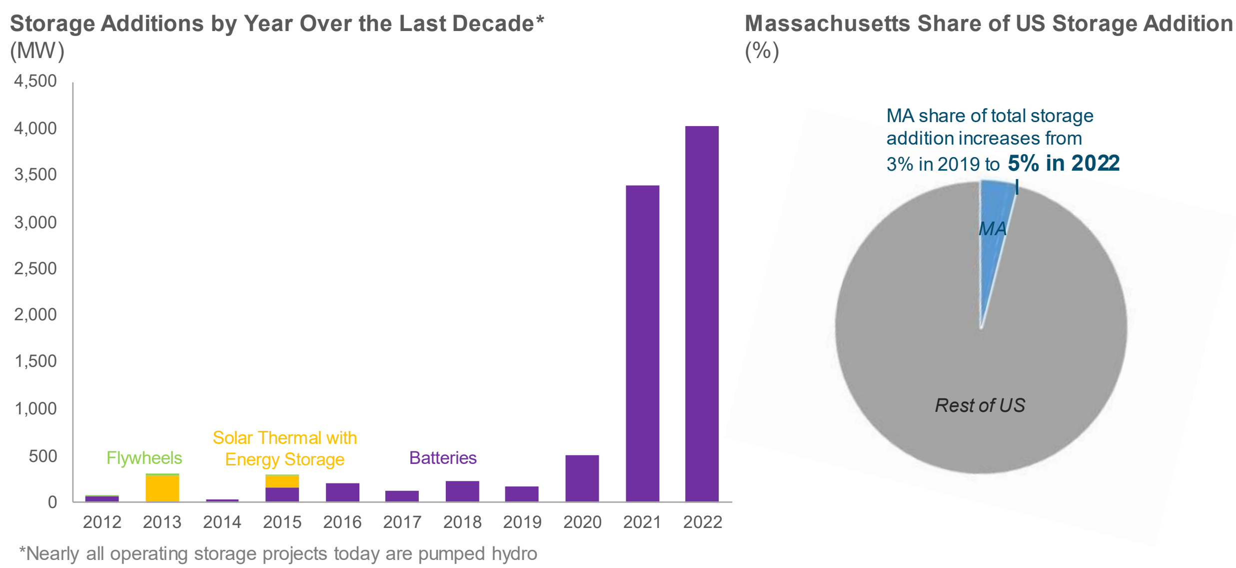
Other changes have also accelerated global and U.S. storage build out, such as increases in renewable capacity online and market reforms to create a more level playing field for storage technologies to compete. This evolution is reflected in 11.4 GW of non-hydro energy storage deployed across the U.S. as of 2022, driven almost entirely by Li-ion batteries projects[3], a majority of which has been deployed in California, Texas, and Florida.[4] The surge in recent deployment is shown in Figure ES-4.

Figure ES-3. Battery Costs from 2013-2022



Source: Data is based on BNEF Annual Battery Price Survey.[5]

Figure ES-4. U.S. and Massachusetts Storage Capacity and Deployments Over the Last Decade



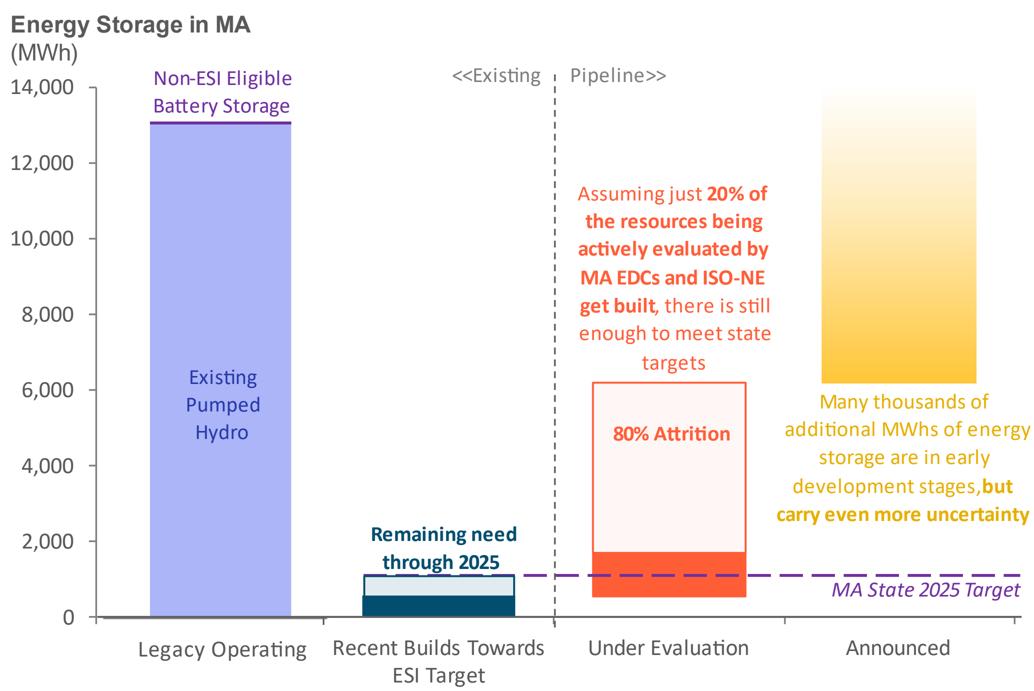
[3] 2022 Sustainable Energy in America Factbook (bcse.org)
[4] US EIA, 2023. Energy storage for electricity generation - U.S. Energy Information Administration (EIA)
[5] BNEF, 2021. https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/)

Source: Data is based on Energy Information Administration Form 860.[6]

In the Commonwealth, substantial progress has been made in recent years to enable storage deployment and reduce barriers. Key actions have included the development of the state's Energy Storage Initiative (ESI), the Advancing Commonwealth Energy Storage Program (ACES), and critically the development of multiple incentive programs such as the Clean Peak Energy Standard (CPS) and SMART to support energy storage, which are discussed in detail later in this report. Additional information regarding the state's programs can be found on the Massachusetts Energy Storage Initiative webpage.

Figure ES-5 provides a summary of existing energy storage in Massachusetts, and storage that is under development and seeking interconnection in both the electric distribution company (EDC) territory and the Independent System Operator ISO-NE Interconnection Queue. This includes an assessment of progress towards the 2025 ESI storage deployment target of 1,000 MWh of incremental storage since 2019, and some indications of what it will take for the state to meet that target based on the capacity in development considering probable attrition levels.

Figure ES-5. Energy Storage Deployments and the ISO-NE Interconnection Queue[7]



[6] US EIA, Survey-Level Detailed Data Files (eia.gov).

[7] "Under Evaluation" resources are here defined as resources with either a Facility Study or System Impact Study underway, *and* with a proposed commercial operations date prior to Dec 31, 2025. It also includes projects that have been in the EDC development pipeline since 2021 and before. "Announced" resources are other resources that have a spot in the interconnection queue but have not yet commenced detailed evaluation *or* have a commercial operations date in the 2026-2028 timeframe. It also includes projects that entered the EDC development pipeline since Jan 1, 2022.
The ISO-NE Interconnection Queue also does not include the proposed duration or energy values for queued resources; an average duration of 2 hours was assumed for the development of this chart, which is designed to provide a high-level indication of progress to date and the potential future.

This report builds on the critical findings from 2016 and generates updated and expanded findings to inform policy and deployment in the Commonwealth over the coming several years. Specifically, this study asks the following **key questions**:

1. What is the current state of energy storage in the Commonwealth? (Section 2)
2. What is the market outlook for emerging mid- and long-duration storage (LDES) technologies? (Section 3)
3. What are potential applications of mid- and long-duration storage? (Section 4)

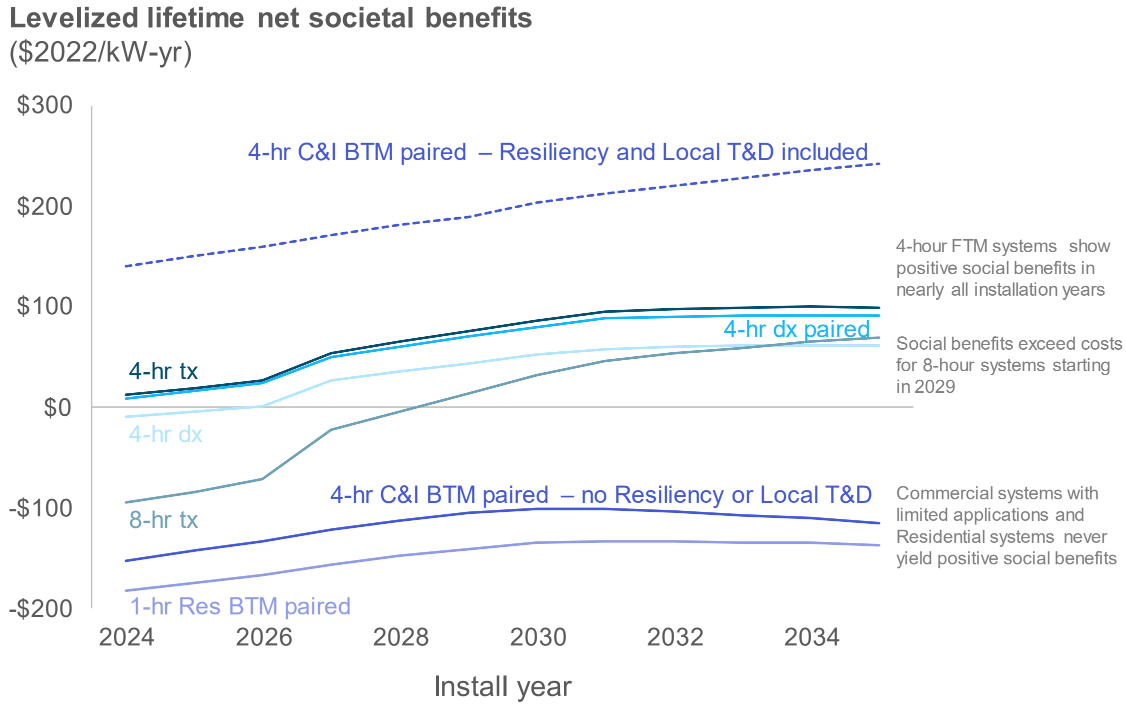
Below we summarize the key findings from the study, followed by high-level policy and regulatory recommendations informed by the study findings.

Key Findings

1. **Storage is expected to be a cost-effective element of the state's Net-Zero future electric grid. Advancing deployment in the near-term can contribute grid ancillary services, provide capacity value, and help manage the pace of interconnection to ensure that sufficient storage can support cost and emissions reductions in the late 2020s and beyond.**

    The Commonwealth's Net Zero limit by mid-century creates significant electrification loads, primarily from the adoption of electric vehicles in transportation and deployment of heat pumps for building space heating and cooling needs. This mandate creates the need for significant zero-carbon generation, primarily renewables, to serve existing electricity consumption while meeting new demands. As a result, the value of storage, today somewhat limited, is expected to grow rapidly as renewables serve a larger share of regional power generation. Currently 2- to 4-hour duration storage can help meet daily peak needs but has a negligible impact on emissions since renewables are rarely on the margin. As renewable penetration increases, storage will increasingly be able to charge from clean power off-peak and displace emitting generation during daily peak periods. The exact timing of this shift depends on when renewable penetration reaches sufficiently high levels such that storage charges from renewables on the margin or otherwise curtailed renewable generation. Near-term policy design should focus on removing deployment barriers so that adequate grid-tied storage is operating and able to provide emissions arbitrage. As the grid transitions, our expectation is that marginal pricing in the New England energy market will effectively guide storage dispatch to drive emissions reductions. Figure ES-6 lays out the increasing value of short- and mid-duration use cases as the Commonwealth's renewable penetration grows.

Figure ES-6. Estimated Lifetime Societal Net Benefits Across Installation Years



Note: Detailed assumptions for the different use cases are provided in Section 2.3

2. State and utility programs have been critical for storage deployment to date but are not sufficient to achieve deployment at the scale expected to be cost effective on a Net Zero grid, both in terms of the size and duration of storage resources.

In line with today's economic and policy conditions, most recent storage capacity is small (<5 MW), front-of-meter Li-Ion installations. Looking ahead, many larger capacity projects (50-400 MW) are in development, though none of them have reached commercial operation as of now. Both recent and near-future deployments are possible in large part due to state (and utility) programs and incentives. Clean Peak Energy Standard (CPS) program certificates are the most important source of revenue today for standalone systems, while the Solar Massachusetts Renewable Target (SMART) Energy Storage Adder drives most solar-paired deployment. The ConnectedSolutions program is essential for behind-the-meter installation economics. While each of these programs has been critical for deployment to-date, they provide little incentive for storage durations beyond 2-4 hours and may need adjustments to fully galvanize the storge market. Figure ES-7 summarizes the economics by use case for near term deployments, including the net benefits listed above each set of bars. Three of the six use cases examined are revenue positive today, though none of those would be without state support. Figure ES-8 illustrates potential project revenues for a single use case: transmission-connected 4-hour storage.

Figure ES-7. Summary of Short- and Mid-Duration Use Case Results for 2024 Install Year – Developer Perspective

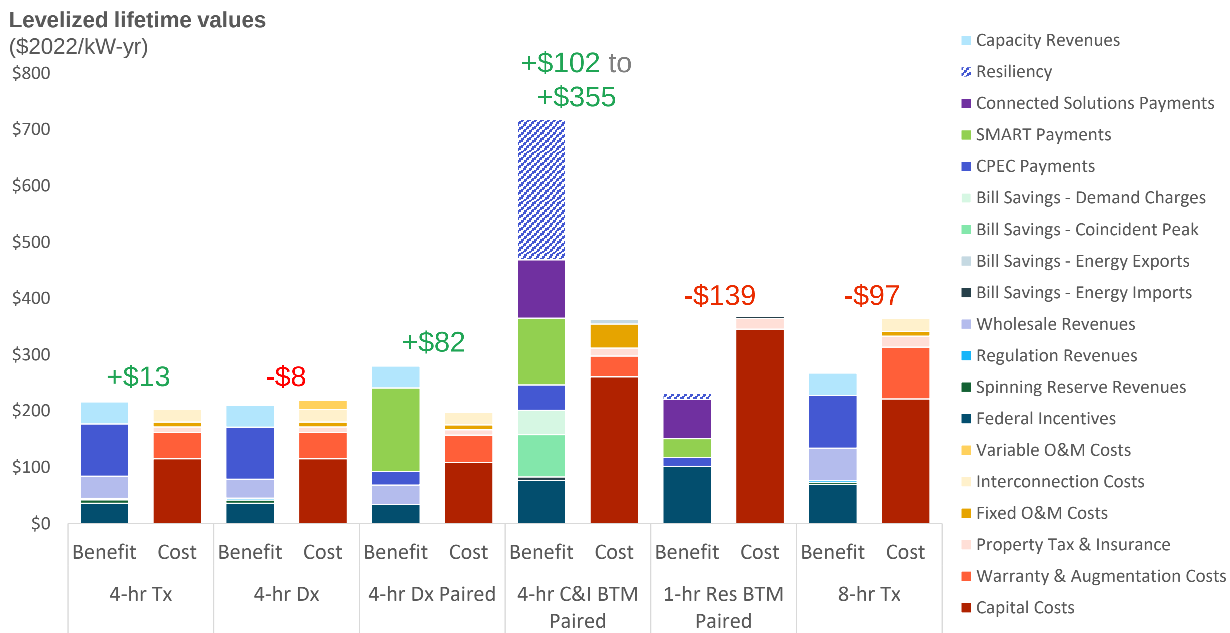
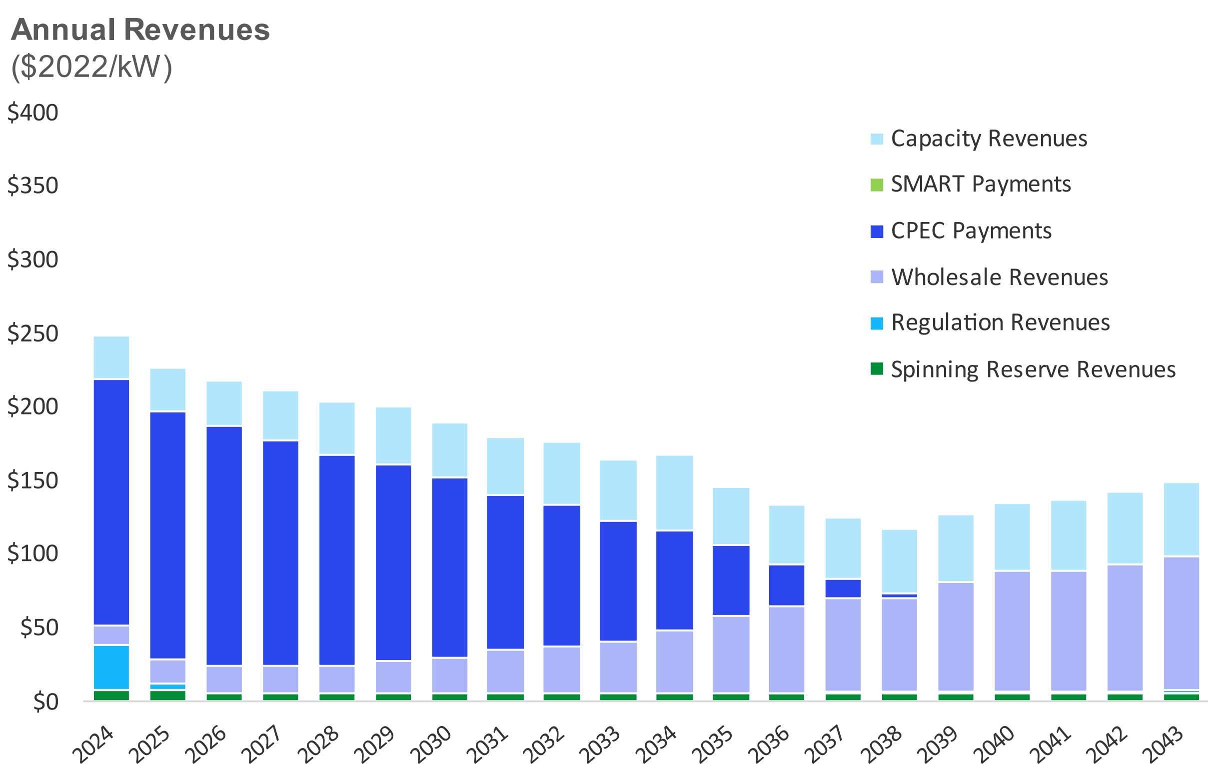


Figure ES-8. Projected Annual Revenues for a 4-hour Standalone, Transmission-connected Resource – Developer Perspective



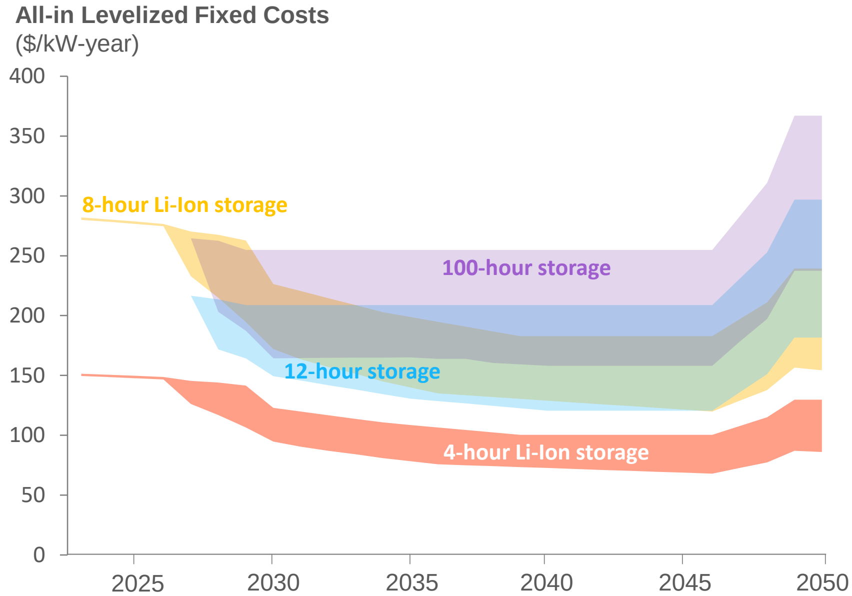
3. Financial, technological, supply chain and operational barriers slow deployment today; these barriers must be resolved to achieve deployment at anticipated scales.

Barriers vary with project scale and application: Supply chain challenges, high material costs, and a lack of guidance regarding safety best practices impact projects of all sizes. Lack of certainty around market revenues and incentive revenues that can dry up over a project's lifetime make financing difficult to secure for front-of-meter installations. Uncertainty around the best locations for storage projects adds to this challenge. These projects also struggle with slow and nonstandard permitting processes, in part due to lack of expertise from the cities and towns asked to approve projects. Interconnection queues at ISO-NE and Electric Distribution Companies (EDCs) move slowly and rely on conservative assumptions to assess upgrade needs, resulting in projects delaying and dropping out. Municipal Light Plant (MLP) installations avoid interconnection queues, but increasingly struggle to provide maximum savings as annual and monthly peak hours become less predictable. Front-of-meter distribution-connected systems suffer from underutilization due to restrictive charging tariffs and a SMART incentive that does not encourage sizing or operation beyond minimum levels. At the smallest scale, many behind-the-meter installations lack access to time-of-use rates that would allow for rate arbitrage, and none have access to wholesale markets that could provide more nuanced charge/discharge signals and additional revenue for providing more grid services. These barriers must be addressed to achieve deployment on the 5+ GW scale of energy storage in the Massachusetts Clean Energy and Climate Plan (CECP) 2050 Phased scenario for Massachusetts.

4. Energy storage is anticipated to be cost-effective in mid- and long-term resource portfolio strategies. This is driven by regional renewable adoption, increasingly stringent decarbonization policies, and ongoing innovation leading to cost reductions. Taken together, storage will grow more competitive over time, though most applications are expected to require policy support in Massachusetts to be profitable, at least over the next several years.

The state's CECP portfolio modeling and the findings of this study illustrate that storage is a cost-effective element of mid- and long-term resource portfolios. However, it's unlikely to be profitable today to developers under current market conditions without policy incentives. As the penetration of renewable resources grows, there will be better opportunities to generate revenues in energy markets and provide firm capacity to support growing electrification peak demands. As the market matures, this may obviate the need for state incentive support over time. The declining cost of storage is also critical: costs have declined significantly over the past decade, as shown above (Figure ES-3), and are expected to continue to decline going forward, as shown in Figure ES-9. These cost declines are critical to deployment and have been aided by the passage of the Inflation Reduction Act (IRA), which for the first time created a federal tax incentive for standalone storage systems. While near-term supply bottlenecks are temporarily impeding cost declines, development of the global storage supply chain is anticipated to drive down costs in the future. Assuming trends persist and energy storage remains competitive with other resources that can perform similar services, cost-effective grid-scale energy storage deployment is expected to play an important role in the Commonwealth by the 2030s.

Figure ES-9. Storage Cost Expectations over Time



Li-Ion current costs are **derived from market installation data,** with forecasts informed by global supply demand constraints, financing cost expectations, and NREL ATB learning rate projections

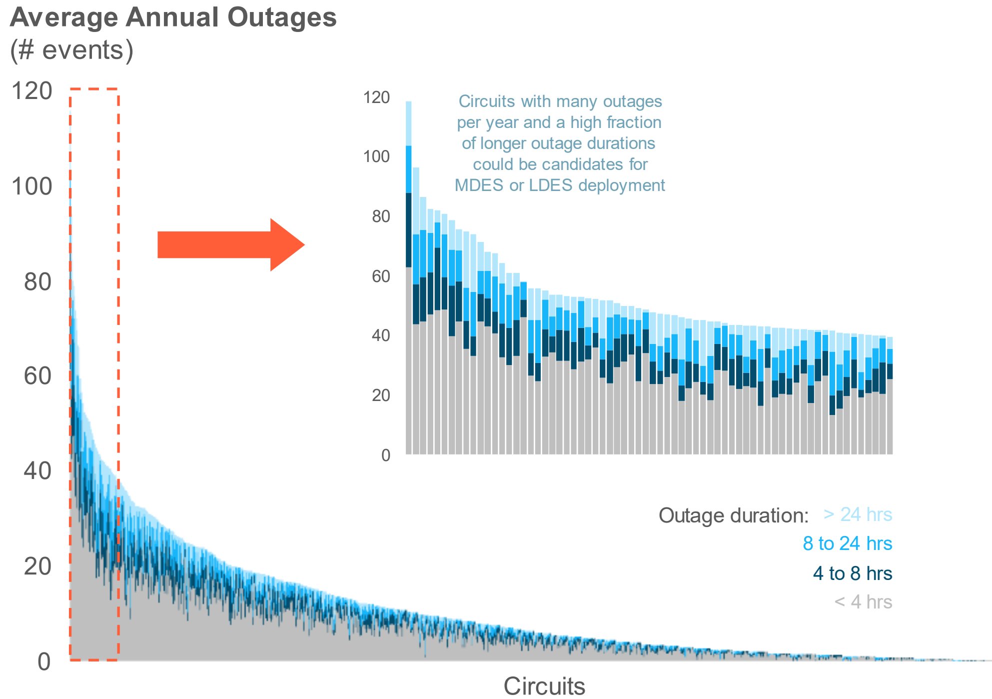
12-hour and 100-hour forecasts are based on data from the LDES Council, and **are quite uncertain given the early commercial nature of those technologies**

Most mid-and-long-duration technologies also have lower round-trip efficiencies than Li-ion, which may make it more difficult for them to operate economically in today's markets

5. Energy storage deployed at the distribution circuit level or behind the customer meter has the potential to provide valuable reliability improvements, but site-specific investigation and analysis is needed to identify the locations where this value is high enough to justify deployment.

Good candidate sites for deployment of resiliency-focused energy storage will share three key characteristics: high Value of Lost Load, relatively frequent loss-of-load events, and unavailability or unfavorability of alternative solutions such as fuel-based backup generation. Critical facilities, including hospitals, sites serving as storm shelters, and sites serving as cooling centers may be strong candidates based on high value of lost load. Radial circuits that are prone to outage may be strong candidates based on event frequency and possibly slow restoration time. Figure ES-10 provides a first pass at identifying candidate circuits by highlighting those with historically frequent outages.

Figure ES-10. Eversource and National Grid historical outages (2019-2022) by circuit



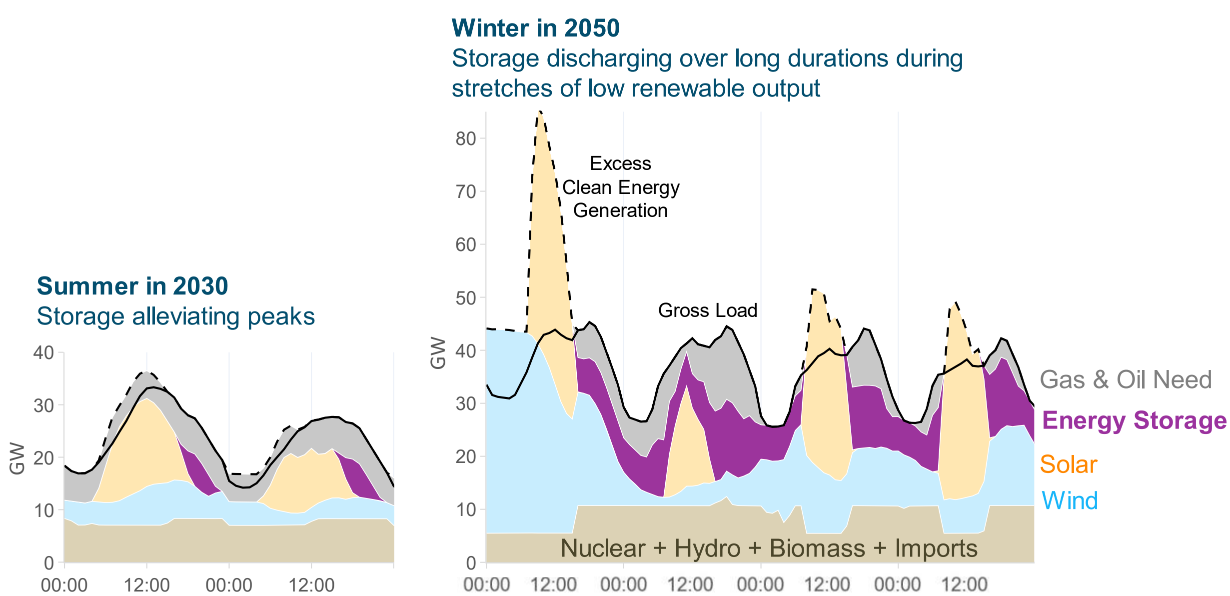
6. Longer durations of storage are being tested across the U.S. and are expected to be commercially available at scale by the end of the decade; these technologies will be valuable as their costs come down and use cases requiring longer durations become viable.

Many candidate technologies for mid- (4-10 hour) and long-duration (10+ hour) energy storage exist today at various stages of maturity. Today's use cases do not require long durations, so these technologies compete unfavorably with relatively mature and high-efficiency short-duration (<4 hour) alternatives and with emitting alternatives (e.g., natural gas) given lack of a binding carbon cap. There are some opportunities for mid- and long-duration applications at the right level of customer aggregation or for customers with high value of lost load, but cheap alternative solutions and low energy densities mean that grid scale applications will drive technology commercialization. As the grid decarbonizes, net load peaks will stretch to longer than four hours and needs for zero-carbon firm resources that can continuously dispatch will give rise to market opportunities for new technologies. These opportunities will hinge on the higher incremental capacity value of longer durations outweighing higher costs of the resource (net of energy market revenues) compared to short duration storage or clean firm resources. Some technologies will emerge as "best in class" options at various durations and will set the bar for round trip efficiency, cost, and other considerations at a given duration against which other technologies will be measured. The "learning by doing" required to move long-duration technologies into commercialization must precede the arrival of use cases that need such durations.

7. The timing and nature of the region's reliability risk will evolve in the coming decades, and storage can provide valuable capacity contributions throughout this transition.

By 2030, renewable generation, particularly solar, is expected to shift the evening "net peak", or the period of greatest resource need, into summer evenings. Storage can contribute to resource adequacy during these windows, and given they are relatively narrow, initial needs can largely be met with shorter duration resources. However, storage capacity value diminishes as more resources are added, with more rapidly declining incremental capacity values beyond 10 GW for representative short-duration resources. By 2050, electrification has created a solidly winter-peaking system (about 55 GW). Given the 100+ GW of renewable build-out in the CECP Phased scenario, the "reliability challenge" in 2050 becomes periods when consecutive low renewable generation coincide with extreme cold weather events in the winter. The system can become both capacity short at peak hours and energy short when those events last long and storage runs out of charge. It is during these periods when longer duration storage has its highest value.

Figure ES-11. Examples of Storage Dispatch During Critical Periods in 2030 and 2050



Note: Graph shows example dispatch of the electric grid on sample days, with the dotted line reflecting excess generation and the solid line reflecting gross load.

8. The capacity value provided by storage will depend on the rest of the renewable portfolio, with storage effective capacity value higher and more enduring when significant renewable build-out is achieved.

Figure ES-12 reports the duration of system need after dispatching renewable energy on the electric grid. The figure illustrates that in New England, in futures with very high renewable deployment (100+GW in 2050), the need for energy storage duration is more limited, with about half of all gaps lasting 8 hours or less. The remaining needs extend longer than 8 hours, and can be filled by longer duration storage, multiple resources dispatching sequentially, or another form of firm capacity. In contrast, a mid-century portfolio that still achieves very high but lower renewable deployment, the median duration of resource needs reaches 19 hours. Consequently, longer duration resources can help fill the longer gaps, though it will be more difficult for even 100-hour resources to meet all system needs in futures with lower levels of renewables without some form of dispatchable capacity, since over five percent of those periods are longer than 100 hours and as long as several weeks. Figure ES-13 illustrates the higher and more durable storage capacity value as a function of renewable penetration in 2050.

Figure ES-12. Length of System Resource Needs Before Firm and Energy Storage Dispatch

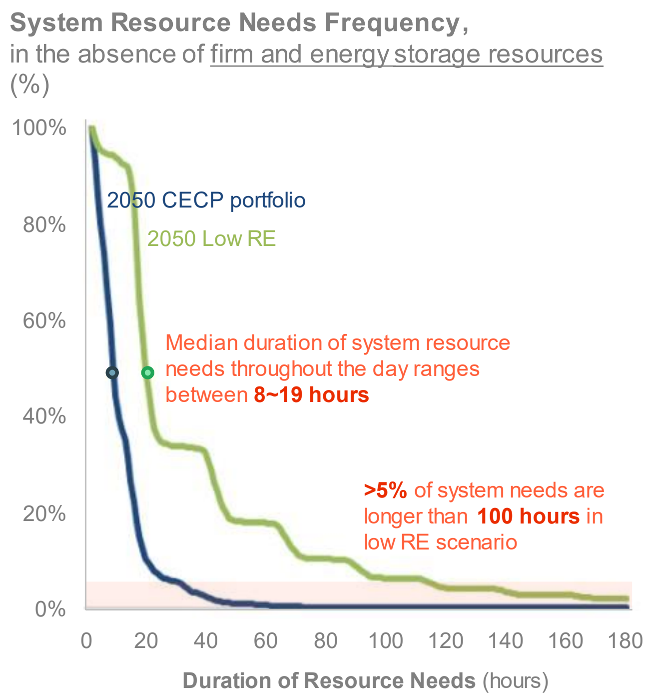
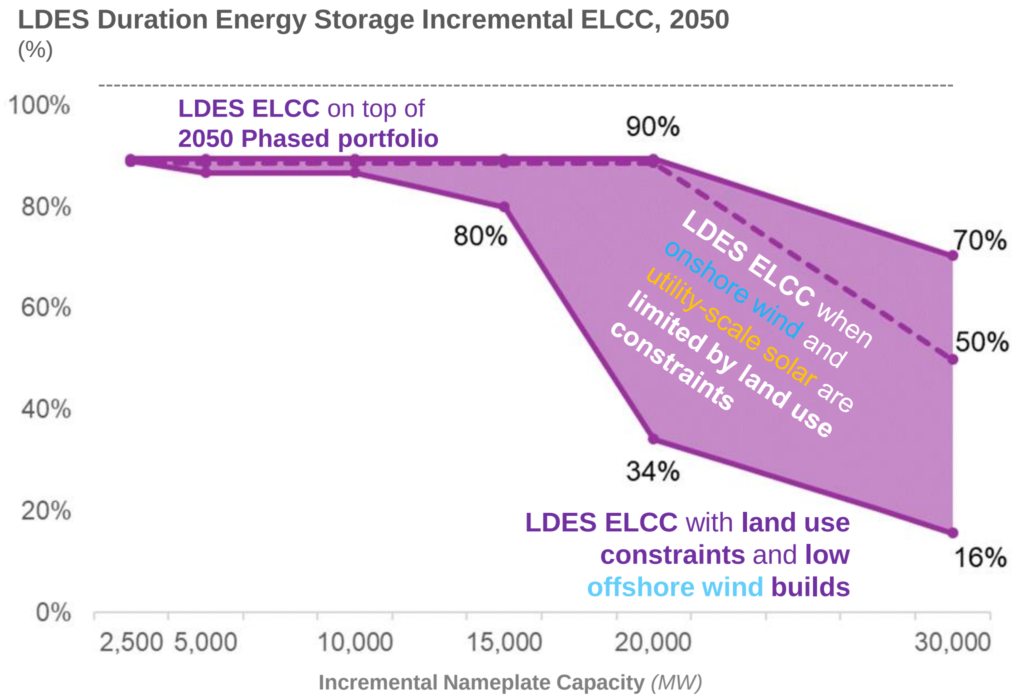


Figure ES-13. 100-Hour Storage Incremental ELCC



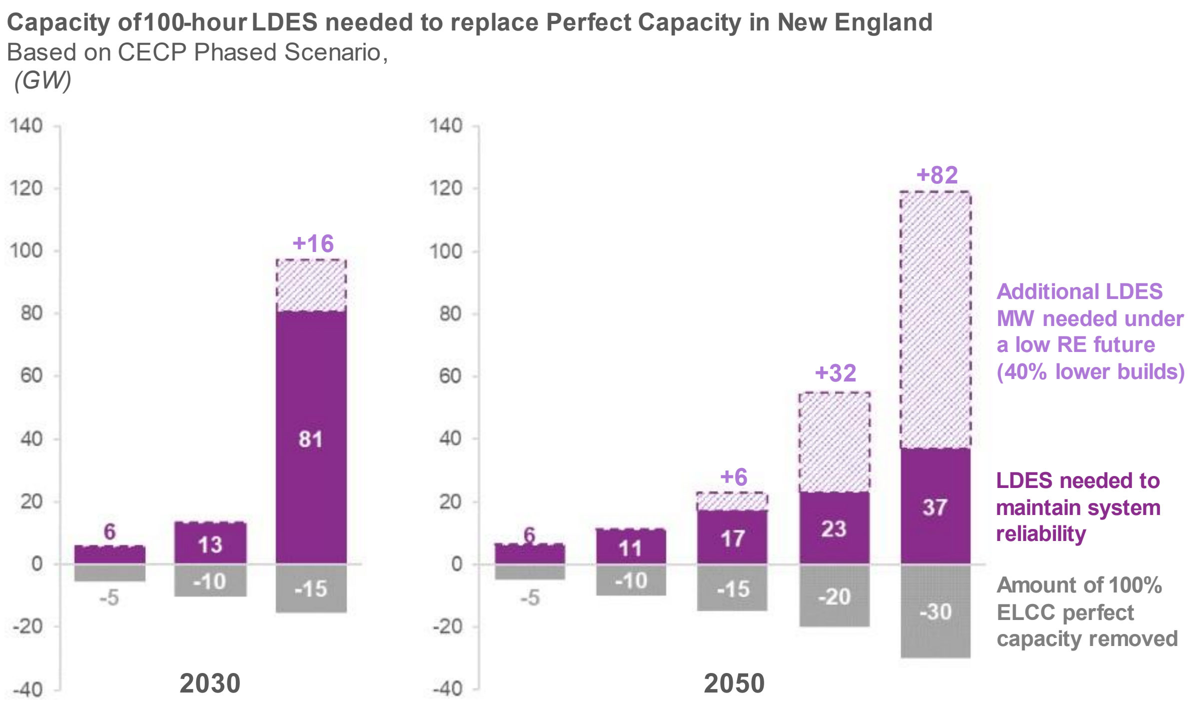
9. **Storage and offshore wind resources are highly complementary, with storage able to support renewable integration by smoothing out volatility, addressing intermittency, and reducing curtailment. This study specifically evaluated the reliability contributions of these resources when paired, and demonstrates that at high penetrations, offshore wind and long-duration storage in particular have significant "diversity benefits", with a combined capacity value exceeding their individual capacity contributions.**

Offshore wind provides energy for charging storage, particularly in the winter. It also narrows the windows during which capacity shortfalls may arise, making it easier for duration-limited resources like storage to support the grid. In New England, the "diversity benefit" between LDES and offshore wind is particularly valuable. While storage, when added independently to the grid, exhibits diminishing returns in which the marginal capacity contributions of more storage decline as the net peak flattens, storage combined with offshore wind provides more enduring capacity value. This interactive value, particularly with long-duration storage, creates total capacity value from the two resources that is significantly greater than their individual effective capacity values. At very high penetrations (30 GW OSW/30 GW LDES), these diversity benefits can create roughly 15% more capacity value than the sum of the expected individual capacity contributions, under the portfolios modeled.

10. If LDES technologies become commercially available and cost effective at scale, LDES can provide a zero-carbon alternative to significant quantities of dispatchable generation, which are otherwise needed to support system resource adequacy in futures with high levels of renewable energy.

In CECP 2050 scenarios, which include over 50 GW of renewables in Massachusetts and over 100 GW of renewables across New England, 100-hour storage could potentially replace significant quantities of thermal capacity without sacrificing reliability; that said, this finding is contingent on very high levels of renewable energy, and long-duration storage becoming demonstrated as feasible, safe, and cost competitive at scale. Significant offshore wind deployment is particularly important, given this provides energy for long-duration to charge from during multi-week stretches in the winter with high loads and lower renewable output. In systems with lower levels of intermittent generation, for example the 2030 CECP scenario, or any scenario where only a share of the CECP portfolio of renewables gets built, significantly more LDES would be required to maintain equivalent levels of reliability. Storage loses its incremental value at lower levels of penetration in those cases since net load is flatter and more sustained need exists, making opportunities to charge and discharge smaller and stretched out. Peak net load can only be further reduced through prolonged and derated storage dispatch. Figure ES-14 provides an illustration of the 100-hour resource required to replace perfect capacity in New England, under scenarios with high and very high levels of renewable energy.

Figure ES-14. LDES as an Alternative to Support System Reliability in 2030 and 2050



Policy Recommendations

Leveraging its analysis and experience across North American jurisdictions, E3 crafted several high-level policy and programmatic recommendations for the Commonwealth to bolster energy storage deployment, with a focus on mitigating deployment barriers impeding progress today. These strategic policy recommendations underscore the role storage will play in realizing the Commonwealth's Net Zero electric grid goals,[8] while recognizing that storage provides distinct ratepayer and customer benefits that will evolve and accrue over time as the needs of the electric grid and customers change. The recommendations are organized into storage incentive programs and additional market development support and recommendations.

Across these recommendations, E3 emphasizes **several key themes**:

- ***Portfolio approach supporting range of long-term viable storage applications.*** E3 encourages the state to retain its 2025 storage target in the near-term and identify interim milestone targets for 2030 and beyond that support the path to deeper decarbonization and new electrification loads. These targets can serve as a policy signal (with supportive policy in place) until longer-term market signals materialize. E3 recommends a "portfolio approach" that prioritizes programs and initiatives designed to serve those use cases that are expected to be the most cost-effective over the next fifteen years, while recognizing that value streams are and will continue to evolve over time. E3 recommends both continued support for existing programs, which have largely supported smaller, distribution-based and behind-the-meter (BTM) applications, while initiating new programs to directly focus on larger, transmission-connected projects. Accelerating storage deployment today is important to help reduce "soft costs" (i.e., non-hardware costs such as permitting); to increase confidence in the ability of energy storage to meet energy system needs; to test and improve rules and processes for interconnection and operations; and to grow the overall market for energy storage in Massachusetts. Near-term deployment will also ensure that the Commonwealth is able to maximally leverage support from Inflation Reduction Act tax credits that may phase-out in the 2030s (or sooner).
- ***Flexible program designs allowing storage to respond to market signals.*** One important theme across our recommendations is that program and policy designs should enable storage to operate flexibly in the context of evolving value streams and needs. For wholesale projects, grid-connected storage applications should be able to respond to wholesale price signals, with policy intervention only appropriate if those signals do not align with state policy preferences. Today, energy storage located in EDC territories navigates signals from a variety of sources that depend on the connection point of the storage to the grid: Clean Peak specifies charge/discharge windows, the wholesale distribution tariff discourages charging during certain times to minimize costs, interconnection agreements with EDCs often come with restrictions on operational behavior, TOU rates provide another price signal, and non-TOU rates provide no signal at all. These signals, or lack thereof, are less economically efficient than storage responding to real time prices in the

[8] Massachusetts Clean Energy and Climate Plan for 2050 | Mass.gov

wholesale energy market. As the generation mix evolves, market prices will reflect changing periods of high/low carbon emissions and thus will facilitate emissions reductions. Similarly, for other use cases, programs should be designed to allow storage to maximize value through the ability to flexibly respond to price signals from the different value streams rather than being overly prescriptive and/or pegged to today's grid. Specifically, in theory storage provides the greatest value when its behavior is aligned with societal avoided costs and any locational value streams, which vary across locations and seasons and will evolve over time.

- ***Design programs and incentives to reflect the needs of the specific storage use cases and technical requirements, rather than focus on specific technologies.*** E3 encourages the state to emphasize the performance criteria required for specific storage applications when designing programs and policies, while prioritizing technology neutrality, provided a given technology meets the application technical requirements and is cost competitive. Over time, the value, cost, and technology performance attributes will change, and this approach fosters competition rather than picking "winners". In this study, for example, the analysis illustrated that storage technologies may provide valuable firm capacity, but the durability of this capacity value will depend on the rest of the electric resource portfolio, in particular the level of renewable builds. Thus, policy designs that recognize that the value of storage will depend on how the energy mix evolves as well as how different technologies compete in the commercial space will be the most valuable over time.

Massachusetts Storage Incentive Programs Recommendations

The state's CECP portfolio modeling and the findings of this study illustrate that storage is a cost-effective element of mid- and long-term resource portfolios, but unlikely to be profitable to developers under current market conditions without policy incentives. Current technology costs exceed expected revenues across most use cases, and projects face challenges in monetizing and stacking potential value streams. Near-term incentives could help accelerate deployments that drive down the costs for future projects and provide longer-term savings to customers. E3's recommendations therefore focus on incentives for near-term storage deployment that can bridge the gap to long-term, market-supported and societally valuable use cases.

1. ***Refinements to Existing State Storage Programs.*** **In the near term, enhance existing state policies to simplify program designs and ensure programs encourage projects to operate in a way that maximizes their value, including lowering overall electric system costs and reducing emissions. Enhancements that provide greater revenue certainty and lower financing costs for developers will also drive greater project deployment and in time, grid and ratepayer benefits.**

   - ***Clean Peak Standard:*** The Clean Peak standard aims to encourage resources to leverage lower-emitting generation during the day and reduce dispatch during peak hours from expensive higher emitting sources, e.g., oil. However, today, New England does not have sufficient penetration of renewables to support meaningful arbitrage between low-emitting, low-price renewable generation and high-emitting "peaking" oil and gas generation when storage losses are considered. As renewables continue to be integrated into the grid, arbitrage opportunities will become more pronounced. However, the precise timing will remain uncertain, given variable weather and the distinct generation profiles of different renewable resources, as well as the changing load patterns as customers electrify other end uses. Given this dynamic landscape, E3 recommends that the state streamline and enhance program flexibility. One approach is to enable storage to more directly respond to price signals, which will facilitate lower costs. In addition, while locational marginal pricing frequently aligns with marginal emissions rates, this correlation will strengthen as the grid decarbonizes. A simpler and more durable strategy to maximize the value of storage may involve compensating storage that is directly responding to the highest price signals over time. If instead, discharge windows are retained, the state should also consider adjustments to the discharge window to encourage dispatch from resources longer than four hours.

The state should also consider changes to reduce uncertainty in the potential revenue profile for projects, which makes it hard for projects to obtain investment and financing. Currently clean peak certificates have no floor price, and developers cannot lock in incentive levels for any period (e.g., through a contract with the state). In addition, the bonus multiplier structure is hard to predict, and thus projects cannot easily plan operations to hit these nor can they plan for those revenues in project financing. This introduces uncertainty to the revenue stream, causing project investors to require higher returns in exchange for accepting higher risk. The state could help de-risk this revenue stream by designing a contracting component that would allow developers to accurately forecast program revenues and/or introduce a price band or floor, though it will be extremely important to balance the potential additional cost of this approach with the potential cost to ratepayers. While these actions reduce the cost of capital for development and support project financing, the added benefit of new storage to the grid should be compared to the cost of the program using cost-benefit analysis that guides specific changes to the program/incentive redesign.

Today, LSEs may make alternative compliance payments (ACPs), which are penalties assessed to LSEs if they fail to meet their requirements and serve as the functional “maximum” that a clean peak certificate (on a MWh basis) could be worth. The regulation includes declining ACPs over time, which starts at $45/MWh in 2020 and declines to under $5/MWh in 2050. There are also stipulations that the pace of ACP decline can change based on the supply of credits in any given year relative to demand. Declining ACPs provide a declining incentive for LSEs to participate in this program; thus, to the extent the Commonwealth continues the program, it is recommended that the Commonwealth reform this feature to ensure that LSEs have an incentive to participate and support more energy storage rather than viewing it as a regulatory cost.

Finally, E3 recommends that the Commonwealth assess the planned scale of program envisaged over the longer-term to inform the extent to which program reforms are pursued. To the extent alternative programs focused on larger-scale resources (> 20MW) are developed, than less reform to the existing CP structure may be necessary.

- ***SMART Storage Adder:*** The SMART program is a tariff-based declining block incentive to accelerate distribution-connected and BTM solar development (less than 5 MW) in the

Commonwealth. Since updates to the program in July 2020, the program has required solar facilities include co-located storage that must charge from on-site solar. Because solar resources today experience limited curtailment, storage deployments in practice have typically been sized to the minimum capacity required (25% of solar capacity) and only utilized to the extent required by the regulation. The limited value streams available today have led to limited new storage capacity through the program.

E3 recommends that reforms to this program focus on reducing the cost of the program to ratepayers. One method to reduce the net cost of the SMART storage adder to ratepayers is to reduce the effective $/kW paid to participants. Benefits to the grid scale with storage capacity of the installed system, but incentive costs scale with the value of the storage adder, which is paid out based on the kWh produced by the paired solar. This decoupling of the incentive payment from the storage capacity results in an incentive cost that increases only modestly as storage capacity increases. For this reason, developers tend to install only the minimum energy storage capacity required to qualify for the adder (25% of the solar capacity). The state could consider adjusting the minimum qualifying capacity amount until ratepayer benefits better match costs.

A second method to reduce the net cost of the SMART storage adder to ratepayers is to increase the storage utilization such that it provides a higher value to the grid. In most hours SMART solar + storage facilities find it more advantageous to directly sell solar energy to the grid as it is generated, rather than store it for later dispatch. This is appropriate, as more storage cycling today provides little benefit given the flat energy prices. However, future increases in price volatility will strengthen the signal to cycle storage. As this happens the state should ensure that SMART’s incentive mechanism does not interfere with the participating storage responding to these signals.

The state should assess the existing and potential future total net cost to ratepayers across all SMART storage adder installations prior to any program expansion. This future analysis should also include an update to the developer perspective to understand the extent to which distribution-connected storage can make money without solar pairing. Ultimately, solar + storage pairing should be driven by market signals (i.e., developers deciding freely to pair solar and storage to improve the energy and capacity value of their projects) as opposed to incentive bonuses.

- ***ConnectedSolutions:*** This program is designed to support behind-the-meter resources that can provide demand response services, by either reducing load or exporting power to the grid during peak events. Given the ability of customer-sited energy storage to perform these services, the program provides a lucrative revenue stream for customers. However, a gap between enrolled MW and realized MW limits the value of ConnectedSolutions and the ability of grid planners to rely on load reductions from it, given the lack of required participation or penalty for non-participation. Improving this participation rate would make the program more valuable. While improved customer/grid communications and operations technologies such as DERMS (Distributed Energy Resource Management Systems) are likely to shrink this gap, we encourage the state to study and ideally quantify drivers of the gap. Some reasons may not require addressing, such as storage unavailability due to dedication to other value streams, but others may be resolvable in a way that benefits the grid and participants. The state should also look to encourage program participation in low-income communities, where increased federal incentives help to maintain participant economics and bring funding into the Commonwealth.

Under the 3-year Energy Efficiency Investment Plan framework, the Massachusetts Department of Public Utilities mandates evaluation of ConnectedSolutions based on a Total Resource Cost test. Because the method for evaluating the program is determined by regulatory guidelines and performed in another venue, further evaluation is outside the scope of this report. However, we do recommend that future evaluation of the program consider including a Ratepayer Impact Measure test to ensure that non-participant rates are not impacted meaningfully by the program. This is important given the likelihood of increasing customer-sited energy storage in the coming years and the political challenges associated with implementing program changes as enrollment grows and customers grow accustomed to the program's current state.

We also emphasize the need for program evaluation to continue assessing the definition of program windows, which allow for events only from 3 PM to 8 PM from June and September and last at most three hours. These windows capture peak events today, but they require reevaluation as the net peak of the electric system moves and flattens in response to increasing renewable and storage penetration. It is also possible that the best future call windows include regional differentiation to benefit the local grid – the timing of net load peaks in load pockets like Boston will differ from that of more rural areas with higher local renewable penetrations. The value to the grid of peak reductions will also differ by location, which could justify geographic incentive level differentiation too.

2. ***Incentive Program for Large-Scale Storage Resources:*** **Large, scalable storage projects are instrumental in the Commonwealth's path to long-term decarbonization and will help ensure storage build out achieves the magnitude required to support an electric grid dominated by renewable energy. Incentives or subsidies over the next five to seven years can support projects and help lower future storage project costs in the state, by fostering learning-by-doing and lowering other soft costs; near-term financial support can serve as a bridge to long-term market viability. Analysis from this study suggests that by the end of the 2020s, 4-hour and 8-hour assets that participate in wholesale markets and capture IRA investment tax credit benefits can deliver net benefits to Massachusetts.**

   - The analysis results illustrate that large storage projects provide the greatest societal value over the project lifetime, driven by their ability to participate in wholesale markets and their potential emissions impact given the high levels of renewables expected to be added to meet the Commonwealth's Net Zero mandate. However, high capital costs and uncertain revenues that do not materialize until later in a project lifetime when renewables are added make it hard for projects to be economically viable today without state support.

- Given the high capital costs today and the uncertain revenues over the 10 to 30-year asset life of a project (depending on technology), projects find it challenging to obtain financing. Projects with clear revenue streams are going to be more likely to obtain necessary financing, particularly for projects greater than 10 MW. E3 recommends that the state design incentives that balance minimizing ratepayer costs with helping ensure new investments can obtain financing. Two general approaches that are gaining traction in policy space are 'contract for difference' type options in which developers bid the minimum revenue required and this is contracted as a total revenue. Another option, recently proposed in New York, develops a similar variable contract amount that is paid out based on a competitively bid "strike" price and an "indexed" value reflecting expected available market revenues during a given period. These types of programs help fill the "missing money" for storage projects over their project lifetime without locking the state or the developer into contracts that are consistently in or out of the money.
- Alternative approaches, such as fixed contract amounts paid out early in a project life, are also viable and in many jurisdictions simpler to implement but lack incentives to ensure that storage projects are completed and operate within the market.

- Incentives will be most valuable under specific use cases and in specific locations. The state could consider additional incentives or carve-outs for projects that are expected to be particularly high value, for example, as hybridization of existing fossil sites, or when paired with large-scale renewable procurement, such as paired with offshore wind. These types of opportunities are discussed in greater detail below. E3 also recommends coordination with LSEs to ensure projects are sited in locations to maximize value.

3. **Prioritize low-income and energy communities through policy carve outs or additional incentives to maximize federal funding support from the IRA, especially into disadvantaged communities.**

   - The IRA contains a range of credit adders that can increase the incentive support significantly. These pertain to domestic content (requiring a certain amount of the materials needed in the facility to have been manufactured in the US), energy community designation (incentivizing siting on brownfields, in high unemployment areas, or in communities that have lost coal production or generation), or low-income community designation. Each carry a 10% additional investment tax credit, so state programs that further steer investment towards these development categories could help bring in more federal support for each dollar of state support invested.

4. **Support one or more pilot investments in long-duration storage to accelerate deployment and support lowering the costs.**

   - The analysis demonstrated that under futures with very high renewable deployment, significant quantities (10+ GW by 2050) of representative long-duration energy storage technologies (100-hour or more) can provide near perfect effective capacity value to the electric grid. However, today, long-duration storage technologies remain expensive and their technical feasibility and safety performance has not been demonstrated at large commercial scale. Financial incentives, grants, or low-interest loans could support pilot investments by fostering further innovation, helping drive down costs and providing an opportunity to test the feasibility, safety and operational capabilities of LDES technologies under real-world conditions.

- While managing near-term ratepayer impacts is important, investments in small pilots or demonstration projects, particularly those that can leverage complementary sources of federal funding, can establish Massachusetts as a first mover and contribute to innovation in LDES technology, which is critical to its ability to provide long-term value to the grid. Federal incentives and funding should be maximized to the extent possible. For example the DOE has budget for at least $505M allocated for LDES of which $325M has been awarded to a variety of MDES/LDES technologies across the U.S.[9]
- In pursuing LDES pilot or demonstration-scale projects, E3 would encourage a technology-agnostic approach. Competitive procurement that allows technologies to compete on cost and performance may be the best strategy, while recognizing that the cheapest technologies today may not represent the most cost-effective technologies further down the road. Thus, designing procurement requirements that reflect longer-term (2030) reliability and performance needs may be most appropriate.
- It will be important to site LDES demonstration or pilot projects in strategic locations on the grid. E3 encourages the Commonwealth to coordinate with utilities to choose grid locations and use cases where the pilot or demonstration will create the most value. Most importantly, it will be valuable to site a LDES project in an area with access to high levels of renewable generation, ideally with periods of excess generation that the resource may use to change. It may also be valuable to locate LDES at existing or at-risk thermal plant locations can enable interconnection. Ideally, LDES is also sited near existing or planned renewable developments, for example at the interconnection points for planned offshore wind.
- When supporting any new pilot or technology program, ongoing assessment and review will be vital. Ensuring a process for learning and adaptation associated with the program will be valuable (e.g., identifying ways to adjust how it operates on the grid in response to changes in grid conditions). Monitoring safety over time is also important.

5. ***Support Critical Facility Resiliency Use Cases:*** **Resiliency value from storage can be very high but is particularly site-specific. E3 recommends that the state conduct a screening analysis to identify candidate sites for resiliency-focused energy storage deployment, and a more detailed analysis of top candidate sites to evaluate potential benefits.**

- Energy storage deployed strategically can provide a valuable resiliency benefit for specific customers, with zero local emissions assuming charging from renewables. This benefit is highly site specific: good candidate sites must have a high Value of Lost Load (VOLL), frequent

[9] https://www.energy.gov/articles/biden-harris-administration-announces-325-million-long-duration-energy-storage-projects#:~:text=WASHINGTON%2C%20D.C.%20%E2%80%94%20As%20part%20of,energy%20storage%20(LDES)%20technologies

outage events, and available space for enough on-site energy storage capacity to serve critical load. The vast majority of sites will not meet all of these criteria, and accordingly will not benefit enough to justify the cost of installing storage primarily to improve resiliency.

- High VOLL values make critical facilities, including hospitals and data centers, clear candidates for inclusion in an initial screening. Based on high frequency outage events, circuits with many customers but few connections to the rest of the distribution grid provide another type of candidate. Disadvantaged communities should also be considered; in these cases VOLL values are unlikely to be high, but policy objectives, such as improved quality of service to LMI customers, may provide justification beyond simple outage cost avoidance.
- Projects installed to improve resiliency should be encouraged or incentivized to also participate in wholesale markets or daily operational arbitrage for bill management purposes. This will maximize the value projects provide for customers and the grid more broadly.

Market Development Support Recommendations

The refinements suggested here promote reducing soft costs. This includes enhancing coordination across parties, supporting access to data, and creating rules to streamline siting and permitting.

6. **Improve coordination among the state, developers, and utilities to identify solutions that utilize information from all parties and lower ratepayer costs.**

- Today, developers lack information on where storage would be most valuably sited on the distribution system. A coordinated planning process that, based on state deployment goals, requires EDCs to identify the most valuable sites for energy storage is a first step in the direction of more efficient storage deployment.
- Shared ownership models with utilities or tolling agreements could provide more operational predictability to EDCs. In turn, conservative assumptions driving up interconnection costs could be tempered, and deployed storage could provide grid value without needing complicated incentive structures or proxy signals provided by program windows and interconnection agreements to dictate efficient dispatch behavior.

7. **Consolidate state guidance and finalize model rules on deployment and siting best-practices would help lower barriers and reduce soft-costs for developers, businesses, and homeowners.**

- Clear guidance on fire safety and installation design components at each development scale, as well as permitting/siting templates that communities could adopt, would go a long way to lowering barriers and standardizing approaches in EDC and MLP territories across the Commonwealth.

8. **Provide access to the most efficient charge/discharge signals for storage installations of all types**.

- MLPs operating storage to trim their peak contributions want more information to help guide their discharge timing, and grid operators lament the operational challenge of hard-to-predict MLP-owned battery behavior. Transparent signals or greater coordination between these groups would help MLPs save money for their ratepayers and improve battery contributions to the grid. Better dispatch certainty also could free up MLP-owned batteries for participation in other grid services outside of the peak hours of each month. Though additional engagement with MLPs may be required to create a process through which they have access to provide these other grid services.

9. Engage with local environmental justice communities when redeveloping brownfield sites with energy storage projects.

- Former industrial and power plant sites provide convenient storage project locations because of their brownfield status and existing interconnectedness to the electric power system. Especially in the case of peaker replacement, local communities will benefit from local emissions reductions and the associated health impacts. However, residents often prefer public amenities, such as parks, to new energy infrastructure projects in their neighborhoods. Ideation and design of new projects must give these communities a voice, so that more equitable siting alternatives be considered and so they receive meaningful compensation for infrastructure sited in their backyards.

10. Allow joint procurement of storage in major offshore wind RFPs.

- Projects that combine renewable energy with storage may be able to offer improved renewable integration and lower potential for renewable curtailment. Projects also may be able to offer more competitive pricing as a result of economies of scale or cost sharing in infrastructure, siting and permitting, for example. Because the economics of a paired resource are site-specific, we would encourage the state to allow resources to jointly bid. In certain instances in which pairing of storage creates significant known benefits, for example, integration of large amounts of offshore wind, "bonus points" may also be considered as part of a holistic procurement process.

11. Support cost-effective grid modernization to improve integration and utilization of energy storage and related technologies.

- Energy storage is a valuable component of grid modernization, as it can aid grid operations (e.g. voltage support) and shift loads in order to avoid new infrastructure and better utilize existing infrastructure. The EDCs recently-filed Electric Sector Modernization Plans (ESMPs) provide a venue in which to evaluate distribution system plans across their planned sets of investments and programs. We suggest the state leverage this venue and the cooperation of the EDCs to identify opportunities for distribution-sited energy storage to reduce local T&D costs and prepare for anticipated electrification loads without grid overbuild.
- At the same time, other grid modernization investments will be key to accessing the value that energy storage can provide. As an example, DERMS will support seamless grid operator control of distributed energy storage devices. Investment in DERMS and Vehicle-to-Everything (V2X) technologies will also enable flexible load and electric vehicle batteries to provide many of the services of standalone energy storage. Leveraging these sunk-cost resources will be a valuable strategy in right-sizing the Commonwealth's energy storage buildout and reducing ratepayer costs.

12. Support and encourage rate designs that align customer price signals with societal avoided costs and locational values.

- Rate designs play an important role in different storage use cases. For front-of-meter distribution-sited systems, the wholesale distribution tariff dictates the price signals that drive dispatch behavior and the economic case for developing projects. For behind-the-meter systems, individual customer rate designs determine the demand and energy costs that can be avoided and used as revenue streams for energy exports via Net Energy Metering (NEM). While the state does not have a formal role in rate design, it can be supportive of rates that accurately reflect the value that energy storage provides to the system. Special care should be taken in the case of NEM, for which program restructuring may be required to avoid shifting costs from non-participants to participants.

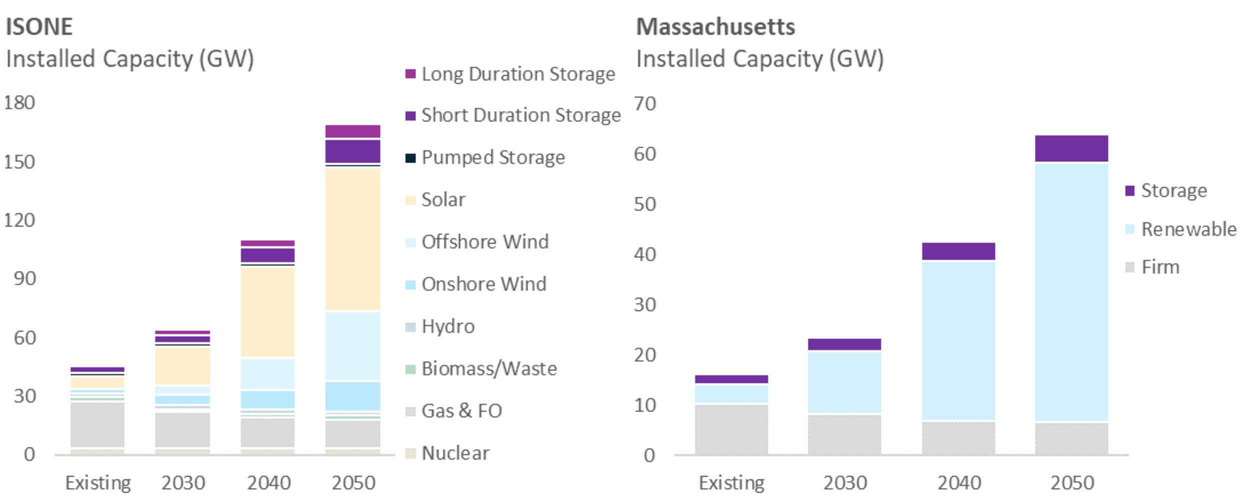
Section 1: Study Introduction

Massachusetts has committed to Net Zero by mid-century, a future that will transform how energy is generated and utilized within the Commonwealth. The power sector is pivotal to this transformation: serving new electrification loads from buildings, transportation, and industry, while decarbonizing its generation fleet through massive investments in renewable energy and storage. This transformation, laid out in detail through the Massachusetts Clean Energy and Climate Plan 2050 (CECP), relies critically on **energy storage** to support the energy system of the future. Energy storage enables wholesale electricity markets to integrate renewable energy and absorb and shift excess renewable generation, which will ultimately lower wholesale energy costs and reduce the need for new infrastructure, directly benefiting Commonwealth ratepayers. Similarly, energy storage applied by customers can provide greater control over their energy choices and allows customers to manage their electric bills.

Figure 1-1, based on the CECP Phased Scenario, illustrates the pace of storage build out expected to support a deeply decarbonized, cost-effective electric grid by 2050. The figure illustrates that both short-duration and long-duration storage are expected to support the needs of the electric grid. To accelerate deployment toward this goal, the state has implemented a range of near-term policies, including a 2025 target of 1,000 MWh of new operational storage, signed into law in 2018 as part of the *Act to Advance Clean Energy*, Chapter 227. The state has also implemented other policies – aimed at reducing generation from "peaking" fossil power plants and integrating greater amounts of renewable energy – which are described in detail in the report body.[10]

Figure 1-1. Role of Storage in CECP's Decarbonized Electric Grid

Build out Based on CECP Phased Scenario



[10] Existing policies and their relevance to storage deployment are discussed in detail in Section 2.2.

In the sections that follow, this report documents progress toward this target, outlines the locations and use cases of storage deployed today, which are primarily shorter-duration, and summarizes challenges in ensuring additional deployment as required to achieve the state's near-term target and serve the state's long-term needs. The report then outlines the existing policy landscape and the current business case for energy storage with specific use cases. In Section 3, the report transitions to an assessment of the potential value that mid- and long-duration storage technologies may have in the Commonwealth. Finally, Section 4 provides a deep dive into the role of storage in supporting resource adequacy in the Commonwealth. Taken together, these sections inform the key findings and policy recommendations identified to achieve the long-term needs of the Commonwealth.

1.1 Role of Stakeholders

Assessing the current and future role of energy storage in the Commonwealth requires understanding the on-the-ground experiences of stakeholders who are actively working with and impacted by energy storage today. We engaged stakeholders through a combination of public workshops, written comments, and interviews. Notably, the release of this report does not signal an end of stakeholder engagement, as the Commonwealth will continue to engage with storage industry stakeholders on a range of policy-related topics in the state.

The study team conducted two public workshops to update stakeholders on study approach and results and to collect stakeholder feedback. Each workshop had over 100 participants, and slides from the workshops were posted to the MassCEC website alongside recordings of the sessions.[11] The first session, conducted on June 7th, 2023, included 20 minutes of Q&A in small breakout groups to answer questions from stakeholders and collect feedback. Prior to the breakout Q&A, that session included:

- Study context and goals,
- An introduction to the study team,
- Discussion of current storage deployments in the Commonwealth,
- Review of storage value streams,
- Select draft use case results,
- Draft Short-Duration Energy Storage (SDES) cost projections,
- Review of Mid-Duration Energy Storage (MDES) and Long-Duration Energy Storage (LDES) candidate technologies,
- A conceptual introduction to reliability concerns in decarbonized portfolios, and
- Our proposed method to assess the value of energy storage in future resource portfolios.

The second stakeholder workshop occurred on August 16, 2023. This session included:

- Select high level study findings,
- A summary of stakeholder feedback gained from interviews,
- Updated use case economics across several cases,
- MDES/LDES cost projections,

[11] https://www.masscec.com/program/2023-energy-storage-study

- A discussion of MDES/LDES end user applications,
- Model results showing the nature of reliability events for New England in 2030 and 2050,
- Demonstration of the diversity benefit between offshore wind and energy storage, and
- Draft values for energy storage Effective Load Carrying Capability (ELCC) and its ability to replace firm capacity.

At both stakeholder workshops, we encouraged participants to submit written comments to DOER. DOER received over 30 emails from stakeholders providing feedback on the study approach, providing insight based on individual and project experience, and asking to participate in the study interview process.

The study team conducted interviews from June through September with interested stakeholders. In these interviews, the study team met with more than 50 stakeholders representing storage projects developers, LDES technology developers, EDCs, MLPs, ISO-NE, environmental groups, clean energy advocates, government entities, and industry organizations.

Feeback received through the workshops, written comments, and interviews was exceptionally valuable to the study, and the study team is grateful for the input from the many participants. This feedback influenced our analysis approach, helped to validate model results, informed findings and recommendations, and guided the framing of results to provide more useful study outputs. Learnings from stakeholder interactions appear throughout this report but are also summarized in Appendix A.

Section 2: The Role of Energy Storage in the Commonwealth Today

2.1 Energy Storage Deployments Today in the Commonwealth

While existing, time-tested pumped hydro remains the largest form of energy storage on the U.S. grid, *new* energy storage deployments today, both in the Commonwealth and country-wide, are dominated by short-duration energy storage (SDES) projects, defined in Massachusetts as durations shorter than or equal to four hours. In the Commonwealth, early deployments are primarily supported by state programs, in large part because many markets and value streams expected to support deployment of storage, particularly longer durations, will not materialize until the region achieves higher levels of renewable penetration. Moreover, many non-hydro mid-duration energy storage (MDES) and long-duration energy storage (LDES) technologies are less mature than SDES technologies, and today have higher costs and lower efficiencies, making them currently less viable investments.

Given today's market, this section focuses on short duration resources, their use cases, and their challenges. However, many operational and market challenges of mature MDES and LDES technologies will be similar to those of SDES technologies today, so the focus on SDES in this section does not make it irrelevant for longer durations. To the extent that MDES and LDES technologies can benefit from current learnings in the context of SDES devices, the ramp from demonstration to widescale deployment will be a more efficient process. Section 3 discusses mid- and long-duration storage technologies that are in earlier stages of commercialization and deployment.

2.1.1 Progress Toward Near-term Target and Long-term Goals

This study evaluates progress toward near-term storage deployments in line with the state's 2025 1,000 MWh target and long-term decarbonization goals.[12] As of February 15, 2023, the MA Electric Distribution Companies (EDCs) reported 550 MWh of installed energy storage towards this target, with an additional 3,200 MWh proposed to connect to EDC systems in the pipeline.

In addition to the 2025 deployment target, the state launched the Advancing Commonwealth Energy Storage (ACES) program in 2017 as part of the Energy Storage Initiative (ESI) to help accelerate the commercialization and deployment of storage technologies. Since 2017, DOER and MassCEC have awarded $20 million to 26 demonstration projects across the state.[13] The pilot projects span 14 replicable

[12] This storage must "commence commercial operation or provide incremental new capacity at an existing energy storage system on or after January 1, 2019" – as such existing pumped hydro storage operating in the Commonwealth does not contribute to this target.

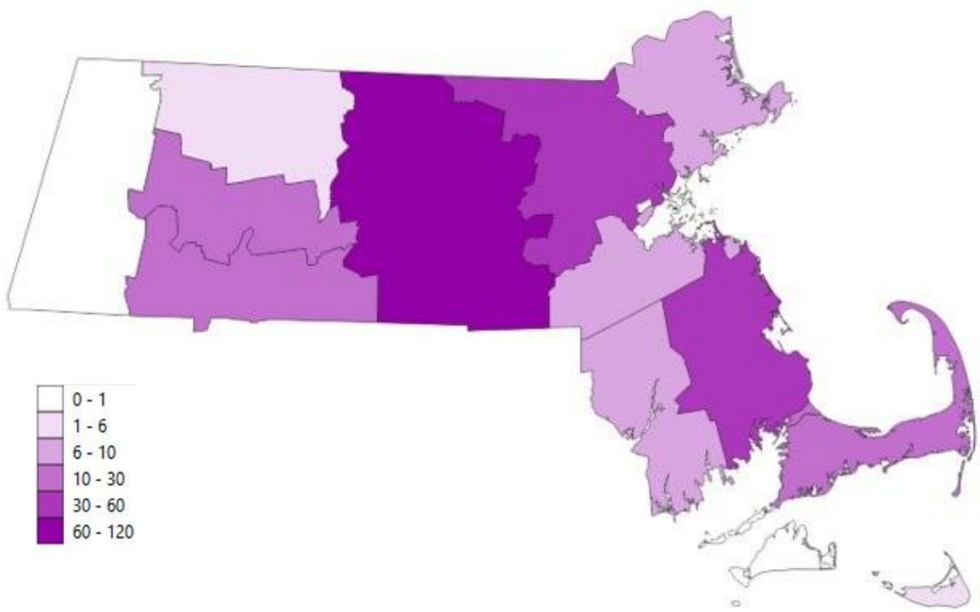
[13] These projects are in various stages of development. Updated information and periodic reports are available at https://www.masscec.com/program/advancing-commonwealth-energy-storage-aces

business models and their associated value streams. The commissioned ACES projects are now part of a growing energy storage market.

Technologically, storage that has been built to date is somewhat varied, though recent builds are predominantly lithium-ion. A handful of sodium-ion batteries and one flow battery have also been built, though these account for just 3% of the non-hydro storage discharge potential in the state. The flow battery, using a vanadium-redox chemistry, was developed as part of the ACES program.

Geographically, these builds are clustered in Worcester, Middlesex, and Plymouth counties, as shown in Figure 2-1, and are predominantly small (<5MW) front-of-meter installations.

Figure 2-1. Operating Storage Capacity (MW), Exclusive of Pumped Hydro



Energy storage capacity must accelerate to keep pace with long-term goals, and it could grow significantly in the next decade with the right policy and market signals. The interconnection queue contains 8 GW of grid-scale storage projects in the Commonwealth, with proposed online dates between now and late 2028. Even with attrition rates as high as 70-80%[14] – a not uncommon level for interconnection queue resources throughout the country in recent years – that would still represent 1,600-2,400 MW of additional storage in just a few years, a growth factor of 3X or more than the current amount, not counting pumped hydro. This is further illustrated in Figure 2-2, which extrapolates proposed energy storage amounts in the Queue as well as in the EDC storage development pipelines using an illustrative, conservative 2-hour average duration. Many newer projects have longer than 2-hour durations, but this conservative assumption still illustrates that there is plenty of development *interest* in the state to meet near- and long-term targets, though how many of those ultimately move forward is uncertain.

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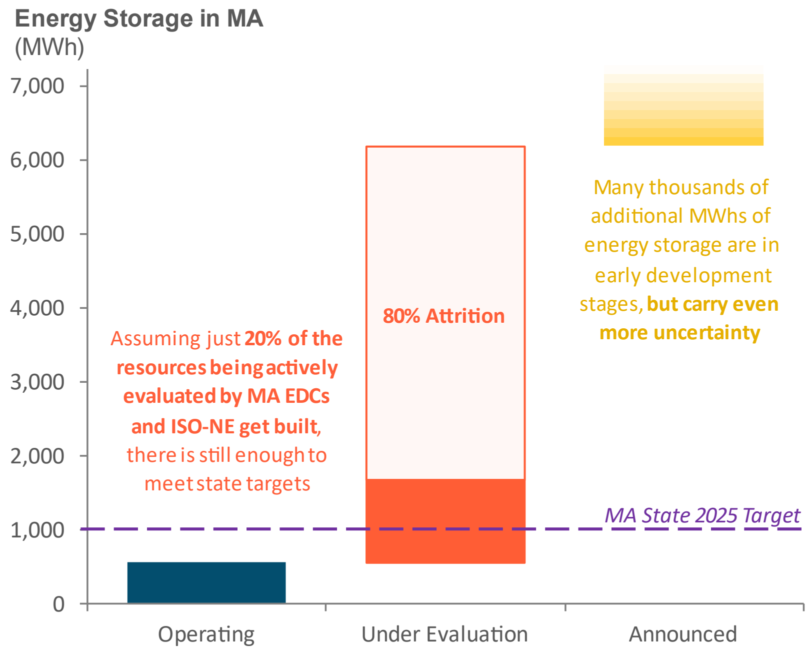
[14] For example, this recent LBNL analysis found that for resources seeking interconnection between 2000 and 2017, only 21% of projects had been built as of late 2022. This analysis included other North American ISOs, so while it is not specific to ISO-NE, it does include the ISO-NE queue: https://emp.lbl.gov/queues

Figure 2-2. Overview of Proposed Energy Storage in the ISO-NE Interconnection Queue[15]



2.1.2 Challenges to Deployment

We note several observations from the current and proposed storage deployments in the Commonwealth. Systems tend to be installed in front of the customer meter, paired with solar, sized modestly (75% of projects above 0.5 MW have durations less than or equal to 2 hours), and with an average of two hours duration. These trends suggest that certain use cases fail to provide net benefits to the storage owner. Section 2.3.4 presents a variety of use cases, with the goal of understanding the gaps between costs and benefits for different installation options. In addition to the cost/benefit pictures presented by those use cases, other non-quantified factors present challenges to energy storage deployment in the Commonwealth. We use this subsection to discuss these challenges, which have been compiled based on industry experience and interviews with stakeholders.

Supply chain and material cost

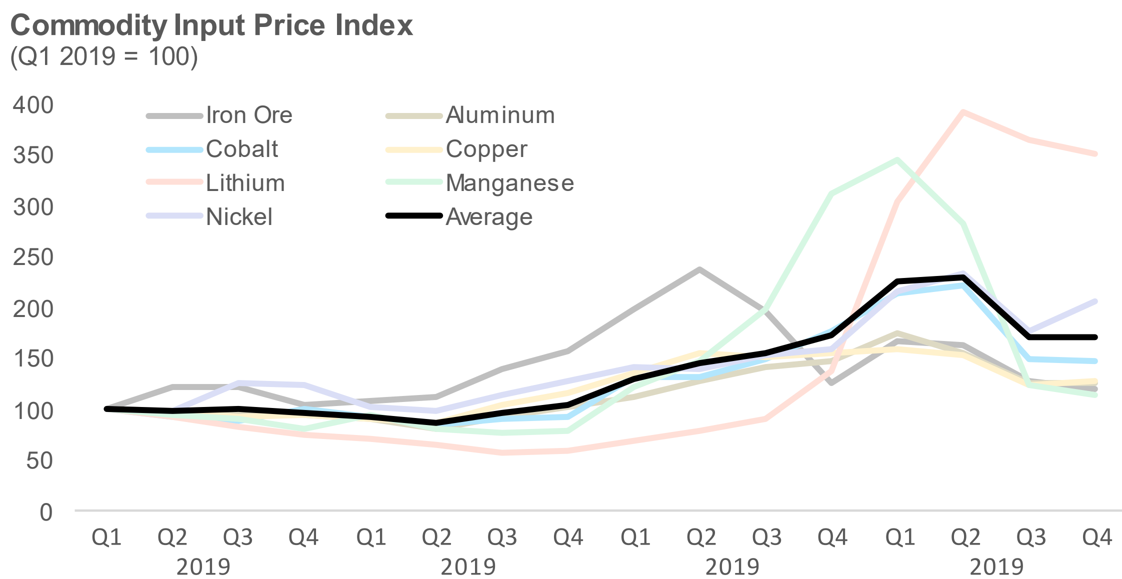
Driven initially by the COVID-19 pandemic, supply chain shortages for battery manufacturing persist today. With a rapid buildout of energy storage expected and ambitious goals for transportation electrification,

[15] "Under Evaluation" resources are here defined as resources with either a Facility Study or System Impact Study underway, *and* with a proposed commercial operations date prior to Dec 31, 2025. "Announced" resources are other resources that have a spot in the interconnection queue but have not yet commenced detailed evaluation *or* have a commercial operations date in the 2026-2028 timeframe.
The ISO-NE Interconnection Queue also does not include the proposed duration or energy values for queued resources; an average duration of 2 hours was assumed for the development of this chart.

battery supply chains will continue to be stressed. In recognition of this, the DOE issued in 2022 notices of intent to provide over seven billion dollars of investment to improve US supply chains for batteries.[16]

While demand outpaces supply, raw material costs for batteries will increase, keeping capital costs high. Figure 2-3 demonstrates the undesirable trend of material costs in recent years. Supply chain constraints and increased demand for batteries have pushed prices up such that on average, raw material prices in Q4 2022 were 70% higher than in Q1 2019.

Figure 2-3. Commodity Price Index for Common Battery Storage Raw Materials[17]



Recent emphasis on responsible mining practices may also contribute to increasing commodity prices. Globally, 87% of current and planned lithium mining projects fall on or within 100 km of Indigenous People's land or peasant's land. Across all rare earth elements, this number is 68%.[18] Given the large negative impacts that mineral extraction can have on Indigenous communities and their land, advocates are pushing for due diligence standards around mining and responsible sourcing pledges.[19] Eliminating negative impacts on Indigenous communities is essential, but we note that more responsible sourcing may slow the ability of supply to catch up with growing demand.

Novel battery chemistries may reduce dependence on transition metals, thus decoupling capital costs from these materials costs. However, the prevalence of Li-based batteries to date has created a large cost gap between Li-ion and other battery chemistries. This gap will be a challenge to overcome for new entrants to the market aiming to compete with Li-ion.

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[16] https://www.king.senate.gov/imo/media/doc/fy22_bil_battery_materials_manufacturing_and_recycling_noi_-_final_211.pdf.pdf
[17] IMF Quarterly Data as of 3/9/2023, https://data.imf.org/?sk=471DDDF8-D8A7-499A-81BA-5B332C01F8B9&sId=1390030341854
[18] https://www.nature.com/articles/s41893-022-00994-6
[19] For example: https://leadthecharge.org/

Market uncertainty

Decarbonization of the electricity sector will change the behavior of energy markets: Resources with high capital cost but low variable cost will dominate the generation mix, intermittent renewable output will provide oversupply in some hours, and weather-dependent supply will shift the timing of the system net peak. ISO-NE is considering reforms to their capacity accreditation process and debating implementation of a prompt and/or seasonal capacity market. Additionally, new market structures such as the proposed, but highly uncertain, Forward Clean Energy Market, may add value streams that are unavailable today. We discuss how anticipated market changes should drive an evolution of storage revenue streams in Section 2.3.2, but there remains a high degree of uncertainty in any forecast of future market prices. The uncertainty of revenue streams can lead to projects struggling to secure financing and being cancelled.

Customers looking to lower retail bills with energy storage face similar uncertainty. The coming change to the resource mix and the addition of new electrified loads from the building and transportation sectors require reform of retail rates. As an example, due to the high amounts of DERs and renewable generation already deployed in California, among other reasons, the state has placed an emphasis on time-of-use rates and higher fixed costs.[20][21] These changes impact the rate arbitrage opportunities available to behind-the-meter energy storage, so uncertainty in future rate designs in the Commonwealth creates uncertainty in expected revenues for customers.

Access to revenue streams

The wide-ranging operating characteristics of energy storage allow it to provide many services to customers and the grid. However, operating characteristics and compensation mechanisms prevent projects from accessing all available revenue streams. For example, energy storage installed Behind-the-Meter (BTM) can participate in retail rate arbitrage if on a time-varying rate, but has no access to wholesale energy, capacity, and ancillary service markets. Front-of-the-Meter (FTM) storage connected to the distribution system pays to charge based on a tariff that prevents access to the cheapest wholesale energy prices for charging – though this tariff is being revised. To ensure an ability to maintain grid operations regardless of storage dispatch behavior, EDCs include restrictive schedules in interconnection agreements for distribution-connected energy storage that restrict operations away from fully economic dispatch. Also, FTM installations lack access to the ConnectedSolutions incentives, whereas BTM installations have access to incentives from ConnectedSolutions, Clean Peak Energy Standard (CPS), and Solar Massachusetts Renewable Target (SMART) if paired with solar.

When a project can access multiple revenue streams, optimizing performance for one may limit the project's ability to participate in others. For example, a FTM project dispatching to maximize CPS revenue will lose opportunities for wholesale energy arbitrage when CPS hours do not align perfectly with the highest market prices for energy. Similar operational choices have to be made by BTM systems when incentive program dispatch windows do not align with Time-of-Use (TOU) rate peak periods or customer peak loads that could be mitigated.

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[20] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF
[21] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB205

FERC 2222, when fully implemented, will allow BTM storage resources to participate in wholesale markets via an aggregator. However, current rules will not allow these resources to simultaneously participate in wholesale market bidding and retail rate arbitrage. Depending on available rate structures, customers may be able to make more money through rate arbitrage than through wholesale market participation, which would limit the extent to which FERC 2222 implementation meaningfully alters revenues sought by BTM storage owners. Stakeholders also point to possible challenges attaining revenue-grade meter data for wholesale market competition, though the upcoming installation of smart meters across the state likely invalidates this concern.

Conflicting and unavailable information

Developers lack information on where storage would be most valuably sited on the distribution system. Instead of coordinating with EDCs, a “guess and check” process exists today in which developers propose sites and EDCs then perform interconnection studies. A coordinated planning process that, based on state deployment goals, asks EDCs to identify the most valuable sites for energy storage could reduce interconnection timelines, reduce project uncertainty, and ensure value to the state and ratepayers from the storage capacity being installed.

Energy storage has to navigate signals from a variety of sources that depend on the connection point of the storage to the grid: Clean Peak specifies charge/discharge windows, the wholesale distribution tariff discourages charging during certain times, interconnection agreements with EDCs often come with restrictions on operational behavior, TOU rates provide another price signal, and non-TOU rates provide no signal at all. The overlapping windows presented by combinations of these restrictions create complex landscapes of charging/discharging signals for storage operators to navigate and cause operational behavior that does not optimally reduce costs or carbon.

Municipal Light Plant (MLPs) operating storage to trim their peak contributions want more information to help guide their discharge timing, and grid operators lament the operational challenge of hard-to-predict MLP-owned battery behavior. Transparent signals or outright coordination between these groups would help MLPs save money for their ratepayers and improve battery contributions to the grid. Better dispatch certainty also could free up MLP-owned batteries for participation in other grid services outside of the peak hours of each month.

Safety concerns

There is a fire risk associated with lithium-ion batteries. The risk is low, and fires can be prevented with adequate testing, protections, and detection. In addition to fire risk, there is also the possibility of high heat release, flammable and toxic gases, and stranded energy. To address concerns surrounding these risks, codes, standards, and regulations for energy storage systems undergo continuous review and amendment.[22] Project developers must follow these evolving regulations and manufacturers’ instructions to ensure project safety.

[22] “Draft Storage/Stationary Batteries Standards List,” UL, https://www.sandia.gov/ess-ssl/docs/Stationary_Batteries_Standards_List_UL_4-1-14.pdf

To build awareness of safety practices in the context of battery technology, MassCEC teamed up with the National Fire Protection Association (NFPA) to create an online training course in which over 500 fire professionals have participated.[23] For hands-on learning experience, MassCEC has teamed up with the Boston Fire Department to install a solar plus storage system on Moon Island, where the Boston Fire Department and several other fire safety agencies train.[24]

In two decisions in May of 2023, the Energy Facility Siting Board (EFSB) determined that it lacks jurisdiction over siting of large (>100 MW) storage facilities, an authority that the board does have for large generation resources.[25] This outcome effectively cedes approval of siting to local authorities, who often lack a nuanced understanding of safety concerns surrounding the proposed storage projects they consider. Developers with non-Li-ion technologies also point to restrictions placed on their technology based on Li-ion safety concern that are sometimes irrelevant to their chemistries. Developers and municipalities alike note a need for guidance and education from the state to inform consideration of safety and environmental concerns in permitting decisions.

End-of-life considerations

Permitting for projects may require decommissioning plans, but due in part to the nascency of battery storage as a grid resource, a well-established process for disposal and recycling does not exist. The recycling piece of this process carries particular importance given the global undersupply of metals used in current battery chemistries. Most battery recycling today occurs overseas, but in June 2023 the DOE announced $192 million in funding to expand battery recycling and R&D in the US.[26]

The decommissioning process grows more challenging for technologies that require larger footprints. Generally at end of life, equipment must be dismantled and any impacted location must be returned to a brownfield or greenfield state. Technologies that take advantage of geographical features like Compressed Air Energy Storage (CAES) or pumped hydro would face the biggest decommissioning challenges of all.

Permitting

Permitting for energy storage projects is a complicated process involving local, state, and federal agencies. Movement through permitting processes is often slow, which increases a project’s chances of cancellation. Permitting may entail meeting requirements around electrical design, signage, lighting, vegetation management, noise, decommissioning, and interconnection.

In some cases, the permitting process itself is not well defined. As an example, the aforementioned EFSB decision keeps large storage projects from receiving a “certificate of environmental impact and public interest” from the EFSB. The impact of this decision is yet to be seen: projects could benefit from avoiding the sometimes slow EFSB approval process, or they could be worse off for having to seek approval by individual towns/cities who may not be well equipped to make such decisions. Certainly, the decision adds

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[23] https://www.masscec.com/energy-storage
[24] ibid
[25] https://www.mass.gov/info-details/cranberry-point-energy-storage
[26] https://www.energy.gov/articles/biden-harris-administration-announces-192-million-advance-battery-recycling-technology

another element of uncertainty to the permitting process and moves the process away from standardization.

Interconnection

As noted in Section 2.1.1, nationwide interconnection queues have a realization rate around 20%.[27] There are many reasons for this low yield: Long wait times may change developer priorities or access to financing; Misalignment between project siting and transmission/distribution planning can leave proposed projects without needed grid infrastructure; Conservative assumptions from grid operators about storage operation may add upgrade costs that erase anticipated benefits; Also, queue totals tend to be inflated by developers submitting multiple interconnection requests for the same project in an attempt to improve their odds of approval. FERC Order 2023, issued in July of 2023, looks to improve interconnection to the transmission system, in part by directing transmission providers away from conservative assumptions about storage operation. However, any impact of this Order will take time to be seen.

Utility stakeholders note that the disconnect between project siting and T&D planning could become a more severe issue in the long term. If inadequate transmission or distribution capacity is available to simultaneously serve load and charge storage during periods of high renewable generation, storage may not have the available energy later to optimize revenues or even prevent a loss-of-load event. This can play out during discharge opportunities as well: transmission congestion can keep energy storage from accessing a broad range of markets for revenue. However, a lack of congestion would also remove the ability of storage to be paid to alleviate local congestion.

Siting

The “Land Use / Footprint” column in Table 3-2 of Section 3.2 provides a qualitative indicator of how much physical space various storage technologies occupy. Similarly, the “Siting Considerations” column notes any locational needs of the technologies, such as thermal storage technologies’ needing access to water. The restrictive needs of pumped hydro and CAES stand out from these columns. These needs, and environmental concerns over the impact of pumped hydro on waterways and ecosystems, greatly limit viable sites.

Other technologies have smaller footprints due to their higher energy storage densities. Still, developers note a need for more data to identify the best locations for siting storage. This data would include distribution system constraints, existing headroom, customer load data, and more. With additional information, developers would be able to identify customers who would benefit the most from storage and locations that would maximize system benefits.

Even when storage is proposed in a location known to bring benefits, such as at the site of a retiring fossil peaker, it cannot be assumed that the storage will be able to site in the existing plant’s location. Decisions for this sort of replacement consider, and may be driven by, environmental justice considerations. Communities near existing peaker plants may prefer reclaiming a site such as this for public use instead

[27] See 14

of seeing a new energy facility in the same location. Options for siting nearby may be limited however, as real estate in load pockets tends to be more expensive.

2.1.3 Role of Existing Pumped Hydro in the Commonwealth

Massachusetts has two existing pumped hydro facilities, Northfield Mountain in Franklin County, and Bear Swamp in Berkshire County. Both were developed in the early 1970s to help balance the output of nearby nuclear facilities, by shifting excess nuclear energy generated through the night into daytime peak periods. Those nuclear facilities have since been retired, and today these pumped hydro generators draw power from the grid during low-cost, low-demand periods in order to refill their upper reservoirs, and discharge to the grid during higher priced daily peak periods. As the share of renewable generation increases in the region, these facilities will be able to pump using increasingly low or zero carbon energy, while also shifting power from periods of overgeneration to periods with higher demand or supply constraints.

Northfield Mountain has a current total capacity of roughly 1,000 MW, and when its reservoir is full it can generate at full capacity for 7 hours continuously, though operators aim to increase this to 10 hours through slower operation and increase of the upper and lower reservoir height difference. Bear Swamp has a total capacity of 600 MW, and can generate at full capacity for 6 hours continuously. Both facilities have roundtrip efficiencies of about 75%. This means that units can only make money with discharge/charge price ratios of at least 1.34. Given this constraint, operators indicate that their cycling frequency is often as low as 25% of the facilities' capability.

Both facilities had their operating licenses from the Federal Energy Regulatory Commission (FERC) expire in recent years and are operating on annual licenses while FERC evaluates new 50 year license bids. Both facilities have experienced pushback from local environmental advocates during this relicensing process based on their use of rivers as lower reservoirs. Noting the large fluctuations in river water level caused by the facilities, advocates cite environmental damage to their respective river ecosystems and to migrating fish populations. Whether and when FERC will approve new licenses or update license terms is unclear: stakeholders anticipate relicensing of Northfield in 2024 or 2025, but limited details about these bids have been made public since late 2020.

2.1.4 Flexible load and Vehicle-to-Everything as energy storage alternatives

Flexible load and Vehicle-to-Everything (V2X) can be considered types of end-user energy storage. In the case of flexible load, customer load is shifted, often taking advantage of thermal storage within homes, businesses, or appliances. In the case of vehicles, charging can be shifted or even reversed to provide power to buildings or the grid. These options take advantage of sunk costs – storage devices that will already be adopted for other purposes. However, they suffer from constraints around operability and availability: EVs are not always plugged in and need to maintain enough charge for trips, heating/cooling can only be delayed so much before discomfort or safety becomes a concern, etc. We do not consider flexible load or V2X explicitly in this study, but we note that they will provide some of the same value as standalone SDES in the future.

2.2 Existing Policy Landscape in Massachusetts and its Neighbors

The Commonwealth has three principal policies in place that are available to broad subsets of energy storage projects: ConnectedSolutions, the Clean Peak Energy Standard, and the Solar Massachusetts Renewable Target. None of these programs is designed exclusively for energy storage; the programs are built around grid needs for which energy storage is one of multiple solutions. Bearing the needs of the grid in mind, the programs collectively incent the installation and beneficial use – charging from excess renewable generation, discharging during peak load periods – of energy storage.

The following subsections describe each of the three state incentive programs, including program rules as they pertain to energy storage in particular, amounts of enrolled energy storage in each program, interactions between programs, and commentary on what the programs do and do not accomplish. A summary of some of these key elements appears in Table 2-1. The program discussions that follow are not program evaluations, and do not explore how programs apply to other technologies. We focus on incentive mechanisms to better understand what types of energy storage projects are incentivized today. We reserve quantitative investigations of how incentives impact societal and participant economics for Section 2.3.4.

After the discussion of Commonwealth programs, we note the incentives available through Net Energy Metering (NEM) as it pertains to energy storage. Then we describe policies impacting storage deployment and dispatch in neighboring jurisdictions. Then we turn to national policy to consider how the Inflation Reduction Act (IRA) will change the trajectory of energy storage costs over the next two decades.

Table 2-1. Overview of Existing Massachusetts Storage Programs

Program	Program Start	Next Steps	Program End	Storage Application	Storage Enrolled
Connected Solutions	2019 (Pilot program 2016-2019)	2022-2024 program cycle after initial 3-year program	2024 (though likely to be renewed)	BTM residential and commercial batteries that are interconnected with approved inverters can participate. Compensation based on average performance during summer call windows	30.7 MW
CPS	2020: CPECs required for 1.5% of retail sales	Annual obligation increases 1.5% each year DOER establishing distribution circuit multiplier	2050	Applicable storage is co-located with renewables or charge during wind-based and solar-based charging periods. Credits are valued differently, using multipliers based on season, system peak, SMART enrollment, resilience, etc.	109 MW
SMART	November 2018	37 MW of solar+storage capacity remaining in storage tranche 12	Once all incentive tranches are subscribed	Storage can participate if paired with solar. Must be at least 2-hour duration and 25% capacity of paired solar. Generation over 500 kW must be paired with storage. Storage must discharge at least 52 cycles per year. Compensated via variable adder that is based on the ratio of storage capacity to solar capacity and the storage duration.	>242 MW*

* As of 10/6/23. Note that SMART storage enrollment is measured in kW_AC while ConnectedSolutions and CPS are measured in kW_DC

2.2.1 MassSave ConnectedSolutions

The ConnectedSolutions program aims to reduce peak energy use by incentivizing a variety of behind-the-meter demand response mechanisms: energy storage discharge, smart thermostat control, EV charging control, and technology-neutral traditional demand response.

Customers enroll through a program administrator (Eversource, National Grid, Until, or Cape Light Compact) to receive a signal to discharge energy to the grid during peak events. Revenues for oversized energy storage systems are limited such that incentives are capped at 150% of the site's annual peak load before any storage or BTM PV load impacts. As signals are sent directly to customer inverters, participants must have an inverter approved for the program. Customers can enroll directly or via a curtailment service provider who would share incentives with the customer. Program participation does not alter the interconnection process required to become an exporter of power to the grid. Incentives from ConnectedSolutions are stackable with those from the Clean Peak Energy Standard and SMART, as well as those from ISO-NE Demand Resource Programs.

At the start of 2023, 2,900 energy storage customers were enrolled, totaling 30.7 MW, though actual contributions from these energy storage systems totaled only 13.9 MW.[28] As seen in Table 2-2, nearly two-thirds of enrolled capacity comes from the residential sector, but this capacity is the least likely to realize actual savings.

Table 2-2. ConnectedSolutions energy storage enrollment and performance, end of 2022

Program Administrator	Sector	Dispatch Type	Participants	MW Enrolled	MW Performed
National Grid	Res	Direct Load Control	1,963	11.8	4.3
National Grid	C&I	Daily	3	1.6	2.2
Eversource	Res	Direct Load Control	858	7.3	2.0
Eversource	C&I	Daily	23	8.1	4.0
Eversource	C&I	Targeted	8	1.1	0.8
Cape Light Compact	Res	Direct Load Control	82	0.6	0.4
Cape Light Compact	C&I	Daily	1	0.3	0.1

For residential participants with small energy storage projects, defined as having a battery inverter capacity of less than 50 kW, 30 to 60 discharge events may be called per season with each event lasting a maximum of three hours. The season is limited to June through September from 3 PM to 8 PM. Participating customers receive $275 per kW of dispatch performed averaged over all calls in a season. Upon enrollment, participant incentive levels lock in at these levels for five years.

Commercial and Industrial customers with larger energy storage systems are eligible for two different program options: Daily Dispatch Demonstration and Targeted Summer Dispatch. A Targeted Winter Dispatch offering was once offered as well but is now unavailable. Table 2-3 provides the specifics of each option.

Table 2-3. ConnectedSolutions program options for large energy storage systems

Program Option	Daily Dispatch Demonstration	Targeted Dispatch, Summer
Max Events per Season	60	8
Maximum Event Length	3 hours	3 hours
Season Definition	June-September	June-September
Time of Day	3 PM to 8 PM	3 PM to 8 PM
Eligible Dispatch Days	All days	All non-holidays
Incentive Lock	5 years	None
Incentive	$200/kW	$35/kW +$10/kW bonus on weekends

Like many demand response programs, ConnectedSolutions faces the challenge of inconsistent realization of enrolled MW during dispatch calls. This diminishes societal benefits as planners can rely only on a fraction of the program's potential to reduce procurement needs. Dispatch windows in previous years ran

[28] https://ma-eeac.org/results-reporting/quarterly-reports/ 4th Quarter 2022 Program Administrators' KPIs, "Bi-Annual 1" tab

the risk of missing the system net peak as it shifts later, but the windows were updated in 2023 for this purpose. Continued monitoring of seasonal and time-of-day alignment with system needs will be necessary to maintain cost and carbon benefits from the program.

2.2.2 Clean Peak Energy Standard

Established by DOER, Massachusetts's Clean Peak Energy Standard promotes the use of clean energy to meet peak demand, which would otherwise be met with GHG-emitting resources. The standard incents clean generation technologies that produce during peak periods, resources that reduce demand during peak periods, and storage technologies that shift clean energy into peak periods.

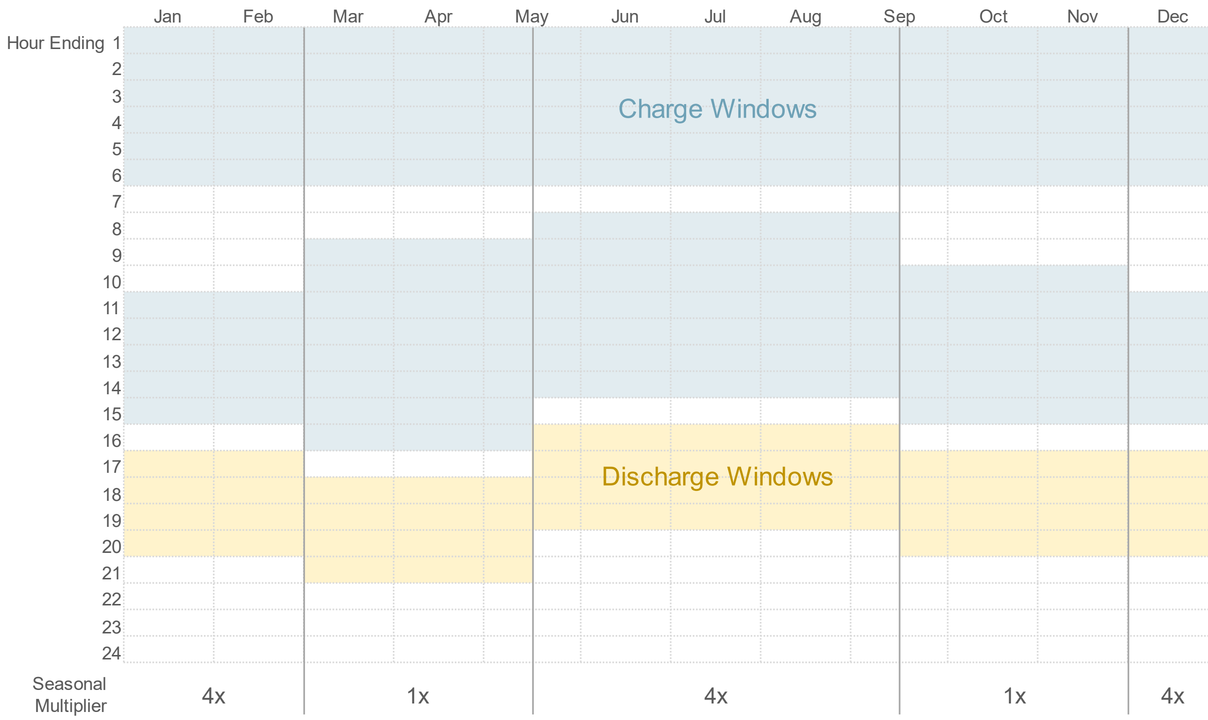
Compliance with the Clean Peak Energy Standard requires that electric retailers purchase Clean Peak Energy Certificates (CPECs) to certify that a minimum percentage of their sales come from qualified sources. The minimum percentage started at 1.5% in 2020 and increases by 1.5% each year until 2050.[29] In lieu of procuring the minimum required CPECs in a given year, a retail electricity supplier may purchase Alternative Compliance Credits. The price of these credits is set at $45/MWh through 2024, after which the price declines by $1.54 per year until a floor price of $4.96.[30]

CPECs are produced by qualified resources that provide energy (or in some cases reduce load) during the predefined peak periods shown in Figure 2-4. MWh provided by qualifying resources produce varying amounts of CPECs based on several multipliers that reflect the value of the resource to the program's goals. As indicated by the table, peak MWh in the Winter and Summer are more valuable than those in the spring and fall. MWh provided during the peak hour of each month receive a larger multiplier of 25x. Locational multipliers are being determined now and will assign multipliers either of 1x or 2x to distribution circuits based on loading conditions.

[29] Prior to 2030, the annual change increases to 3% after any year in which market supply of CPECs exceeds 100% of sales, or 4.5% after any year in which market supply of CPECs exceeds 120% of sales.

[30] This annual price decline increases to $3.08 after any year in which market supply of CPECs exceeds 100% of sales, or $4.62 after any year in which market supply of CPECs exceeds 120% of sales.

Figure 2-4. Clean Peak Energy Standard peak definitions



Energy storage discharge produces CPECs if the storage resource is discharged into the distribution company's service territory, has a commercial operation date on or after January 1, 2019, and charges primarily from renewable energy. This charging criterion met if the energy storage is:

- Co-located with a Qualified RPS Resource. The Qualified RPS Resource must have a nameplate capacity of at least 75% of the energy storage;
- Contractually paired with a Qualified RPS Resource, subject to the same sizing constraints as above;
- Operationally scheduled to ameliorate load flow or power quality issues associated with intermittency of renewables; or
- Charged during periods when renewable generation is a large fraction of total generation, defined as shown in Figure 2-4.

Behind-the-meter storage resources also produce CPECs and can receive a 1.5x multiplier due to their ability to provide resiliency benefits if they are paired with a Qualified RPS Resource at a facility with nonparasitic on-site load.[31] BTM energy storage resources participating in SMART may also participate in the Clean Peak Energy Standard but receive a 0.3x multiplier on CPECs produced. Resources participating in both the Clean Peak Energy Standard and ConnectedSolutions programs do not receive a penalty multiplier.

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[31] https://www.mass.gov/doc/cps-resiliency-multiplier-guide/download

As of October 2023, the list of CPS qualified units included 147 MW of energy storage spread over 49 projects.[32] This includes the 33 MW second unit of the Bear Swamp pumped hydro facility. All but 21 of these 49 projects also participate in SMART, with about two-thirds of non-participating projects coming online in the last year. Only five of the 49 receive the aforementioned 1.5x resiliency multiplier.

Allowing a load-shifting resource to participate in the CPS program risks increasing GHG emissions in the absence of adequate criteria to ensure that the storage is charging on renewable energy. The CPS program design is careful of this, but relatively flat marginal emissions profiles today mean that storage is more likely to increase emissions in the near term. Unless renewables are otherwise being curtailed, even storage charging from a paired renewable resource will increase total emissions due to efficiency losses in charging/discharging. Additionally, grid operators note that only charging from paired renewables and never from the grid limits the storage's utility to the grid (e.g. unable to participate in regulation down and unable to charge completely during renewable drought periods). The actual emissions savings provided by energy storage participating in CPS will increase in importance as the system peak shifts away from hours of high renewable production, likely leaving energy storage representing a larger fraction of the CPS qualified resources list.

The penalty multiplier for participation in CPS and SMART reduces CPS revenues enough that customers tend to focus more on SMART for paired installations. They find it more lucrative to fully optimize SMART revenues instead of cannibalizing some of this benefit to participate in CPS more intentionally. This tradeoff is examined in Section 2.3.4. Developers also note that the uncertain approach to the floor price creates uncertainty in project revenue projections.

2.2.3 SMART

The Solar Massachusetts Renewable Target Program is a declining block incentive program where solar system owners receive a fixed payment per kWh of energy produced. The program is primarily a behind-the-meter solar incentive program, but it includes adders to the fixed payment for location-based attributes, off-taker-based attributes, tracking, pollinator encouragement, and pairing with energy storage.

The SMART program is designed to incentivize 3,200 MW of solar. This total amount is allocated among the service territories of Unitil, Eversource, and National Grid based on relative electric sales in each territory and further split into tranches, each of which is associated with a specified compensation rate and maximum enrollment. All applicants enrolled in a tranche receive payment for all energy produced by the solar at a rate that is locked-in for ten or twenty years, depending on installed solar capacity. As each tranche fills, the next tranche, which offers a lower compensation rate, opens for enrollment. Note that customers are paid an amount equal to the compensation rate minus any bill savings achieved by the storage, so that kWh offsetting usage are not doubly incentivized.

[32] https://www.mass.gov/info-details/clean-peak-energy-standard-guidelines#actual-monthly-system-peak-report- CPS Qualified Units List

An adder augments the compensation rate for solar generation if the solar is paired with storage that meets the following criteria:

- Having a duration of at least two hours;
- Having a round trip efficiency of at least 65%;
- Having a capacity of at least 25% of the solar with which it is paired; and
- Cycling at least 52 times per year.

Developers note that compliance with the first criterion can be met by a shorter-duration system by derating the capacity to a level that could be maintained for two hours of discharge. They also note that the cycles-per-year criterion leads to occasional storage charge/discharge with no goal other than to satisfy the requirement.

It is also worth noting that solar generation over 500 kW must be paired with storage. Like the solar-only compensation, these adders lock-in upon enrollment, but decline for new applicants as each 80 MW tranche of solar paired with storage becomes fully subscribed. To reflect the relatively higher values of longer duration and higher capacity storage, adders vary based on the values in Table 2-4. The ratios between values in the table are maintained for other program tranches, while an overall scale factor of -4% is applied to the adders between one tranche and the next. This means that current Tranche 12 adders are approximately 64% of the Tranche 1 adders.

Table 2-4. Current (Tranche 12) SMART energy storage adder values ($/kWh)

Storage Capacity as a fraction of solar capacity	Storage Duration (hrs)								
	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0
25%	$0.0158	$0.0173	$0.0185	$0.0196	$0.0205	$0.0213	$0.0221	$0.0227	$0.0233
30%	$0.0205	$0.0225	$0.0241	$0.0255	$0.0267	$0.0277	$0.0286	$0.0295	$0.0303
35%	$0.0244	$0.0268	$0.0287	$0.0303	$0.0318	$0.0330	$0.0341	$0.0352	$0.0361
40%	$0.0273	$0.0300	$0.0322	$0.0340	$0.0356	$0.0370	$0.0382	$0.0394	$0.0404
45%	$0.0293	$0.0322	$0.0345	$0.0365	$0.0382	$0.0397	$0.0411	$0.0423	$0.0434
50%	$0.0307	$0.0337	$0.0361	$0.0382	$0.0399	$0.0415	$0.0429	$0.0442	$0.0454
55%	$0.0315	$0.0346	$0.0371	$0.0392	$0.0410	$0.0427	$0.0441	$0.0454	$0.0466
60%	$0.0320	$0.0352	$0.0377	$0.0399	$0.0417	$0.0434	$0.0448	$0.0462	$0.0474
65%	$0.0324	$0.0355	$0.0381	$0.0403	$0.0422	$0.0438	$0.0453	$0.0467	$0.0479
70%	$0.0326	$0.0358	$0.0383	$0.0405	$0.0424	$0.0441	$0.0456	$0.0470	$0.0482
75%	$0.0327	$0.0359	$0.0385	$0.0407	$0.0426	$0.0443	$0.0458	$0.0471	$0.0484
80%	$0.0328	$0.0360	$0.0386	$0.0408	$0.0427	$0.0444	$0.0459	$0.0473	$0.0485
85%	$0.0328	$0.0360	$0.0387	$0.0409	$0.0428	$0.0445	$0.0460	$0.0473	$0.0486
90%	$0.0329	$0.0361	$0.0387	$0.0409	$0.0428	$0.0445	$0.0460	$0.0474	$0.0486
95%	$0.0329	$0.0361	$0.0387	$0.0409	$0.0428	$0.0445	$0.0460	$0.0474	$0.0487
100%	$0.0329	$0.0361	$0.0387	$0.0409	$0.0429	$0.0445	$0.0461	$0.0474	$0.0487

As of May 2023, 892 MW of solar in the SMART program is paired with energy storage, with another 12 MW pending.[33] Given the sizing requirement for storage to be enrolled in SMART, this implies that at least 223 MW (at least 446 MWh) of energy storage participate in the program. However, interconnection delays for solar+storage installations hold up hundreds more MW of potential SMART energy storage systems.

One advantage of the SMART program for DC-coupled systems is that compensation is based on solar production and not storage output. This means that energy storage is not penalized for round trip efficiency losses.

SMART's energy storage incentive focuses only on getting solar+storage projects built in the Commonwealth, leaving incentivization of preferred dispatch behavior to other programs. The program does favor longer durations and higher storage capacities relative to paired solar, which makes clear the intent of building storage capable of shifting renewable production into low-renewable hours. Few projects take advantage of the higher compensation rates for longer durations: the average duration among SMART energy storage units is only 2.3 hours.[34]

2.2.4 Net Energy Metering

Net Energy Metering allows customers to use BTM generation to offset consumption that would otherwise be billed at the customers' retail rate. In certain cases, customers can also receive compensation for energy generated behind the meter and exported to the grid. The compensation rate for exported energy depends on a customer's retail rate and the size of their behind the meter generation.

Energy storage is eligible for net metering only if paired with behind the meter generation. If the storage charges only from its paired generation, it is eligible to both offset load and to export excess energy to the grid. If the storage charges from both its paired generation and the grid, it is only eligible to offset load.[35]

Given that the retail rate tends to be higher than the wholesale cost of energy/capacity being avoided, customers on NEM have an opportunity to benefit more from reduced bills than they would from participation in markets. The downside of this mismatch between retail rates and the value of avoided supply is that customers not on NEM end up subsidizing the part of NEM customers' bills that pertains to fixed costs that are not avoided by the BTM generation.

2.2.5 Policies of Note in Neighboring States

For comparison to the incentive programs in the Commonwealth, Appendix B summarizes key programs in neighboring jurisdictions. These summaries aim to provide examples of alternative mechanisms that the state may consider in future program design.

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[33] https://masmartsolareversource.powerclerk.com/MvcAccount/Login
[34] https://www.mass.gov/doc/smart-solar-tariff-generation-units
[35] https://www.mass.gov/info-details/energy-storage-and-net-metering

From that appendix, we draw attention to the proposed Index Storage Credit mechanism for bulk energy storage projects in New York. This program would have project developers bid a “Strike Price” for their proposed projects in a competitive solicitation. For the selected project, the Strike Price would become the project’s guaranteed revenue stream for its lifetime. Realized revenues below or above this price would be trued up via payments made from New York State Research and Development Authority (NYSERDA) to the developer or from the developer to NYSERDA. This mechanism would give developers much sought-after revenue certainty and responds naturally to changing developer costs and state-specified energy storage needs.

For more distributed storage projects, Green Mountain Power offers a bookend example of storage operations. In their program, customers receive upfront incentives to purchase BTM energy storage, and in exchange the utility is given control of the storage (or a fraction of it) to relieve grid stress during peak events. This operation maximizes the T&D deferral value of storage and offers grid operators predictable dispatch, but the focus on limited value streams leaves other revenue on the table.

2.2.6 Implications of the Inflation Reduction Act

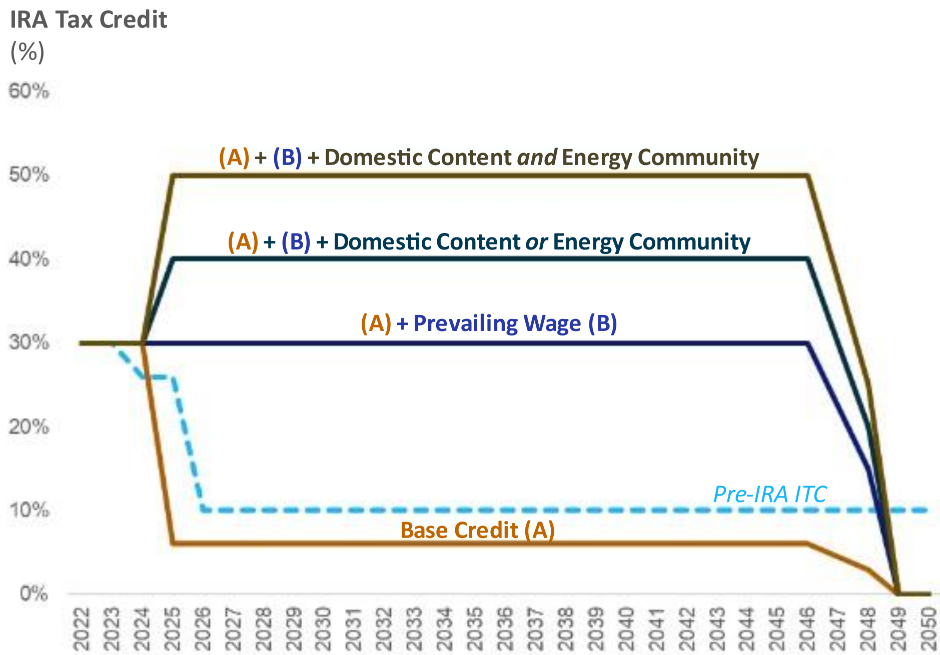
The Inflation Reduction Act – a landmark federal law passed in August 2022 and focused in large part on investment in domestic energy production and deployment of clean energy technologies – will have profound implications for the deployment of energy storage in the Commonwealth and throughout the country. Prior to the IRA, developers of energy storage systems were unable to directly access the federal tax incentives that had long been used to subsidize other key technologies in the transition to a zero-carbon economy. Storage could benefit from tax incentives under specific limited situations, such as if the storage facility was collocated with and exclusively charged from a solar generation plant. However this policy design limitation, coupled with the expected near-term step-down of those tax incentives between 2023 and 2026, meant that federal incentives did not play a meaningful role in long term system planning for energy storage.

Now with the IRA in effect, many standalone storage technologies are eligible for federal tax incentives, and those incentives have been extended to 2032 at a minimum, though will likely be accessible for much longer than that, as discussed further below. Under the IRA, tax incentives take two forms: the investment tax credit (ITC) and the production tax credit (PTC), and both have been designated as “technology neutral,” meaning eligible technologies for federal incentives can access either of these credits. The choice will ultimately be determined by the developer or investor behind a given project, based on their internal assessment of which credit will be most beneficial for their technology and site conditions.

Most forms of energy storage are likely to select the ITC – which provides a lump sum credit scaled to the amount of capital invested – rather than the PTC which provides credits for the first 10 years of operations, scaled to the total MWh of energy produced. Since storage systems are not generators and do not produce new electrons, the PTC is not generally an advantageous option. The exception to this is for green hydrogen, which can receive a production tax credit for each kilogram of hydrogen produced.

Under the IRA, the base ITC is going to step down from the current 30% level to 6% starting in 2025. However projects will be able to qualify for a bonus credit that will multiply the base by 5x (returning the total credit to 30%) by meeting new labor standards concerning prevailing wage and apprenticeship requirements. Additional 10% bonus credits are available for projects that meet domestic content requirements (which requires a certain amount of the materials needed in the facility to have been manufactured in the US), energy community requirements (which incentivize siting on brownfields, in high unemployment areas, or in communities that have lost coal production or generation), or low-income community requirements. These options have been laid out illustratively in Figure 2-5.

Figure 2-5. Illustrative ITC Credit Levels Under the IRA



In this analysis, all cost projections assume that eligible utility and commercial scale projects receive the base + prevailing wage and apprenticeship bonus (e.g. 30%) but not the other bonuses. This analysis also assumes that credits will remain available until 2045, at which point they will begin a 3-year phase out. The timing of this phase-out is uncertain; the language in the IRA states that credits will remain available at the full levels until the later of 2032 or when the US hits 75% emissions reductions below 2022 levels. E3's expectation is that this level of national emissions reductions is likely to occur around the mid 2040s, and thus credits are assumed available until that point.

For details on specific storage cost trajectories, which include the cost reductions associated with obtaining IRA tax credits, see Section 2.3.3.

2.3 The Business Case for Short-duration Energy Storage

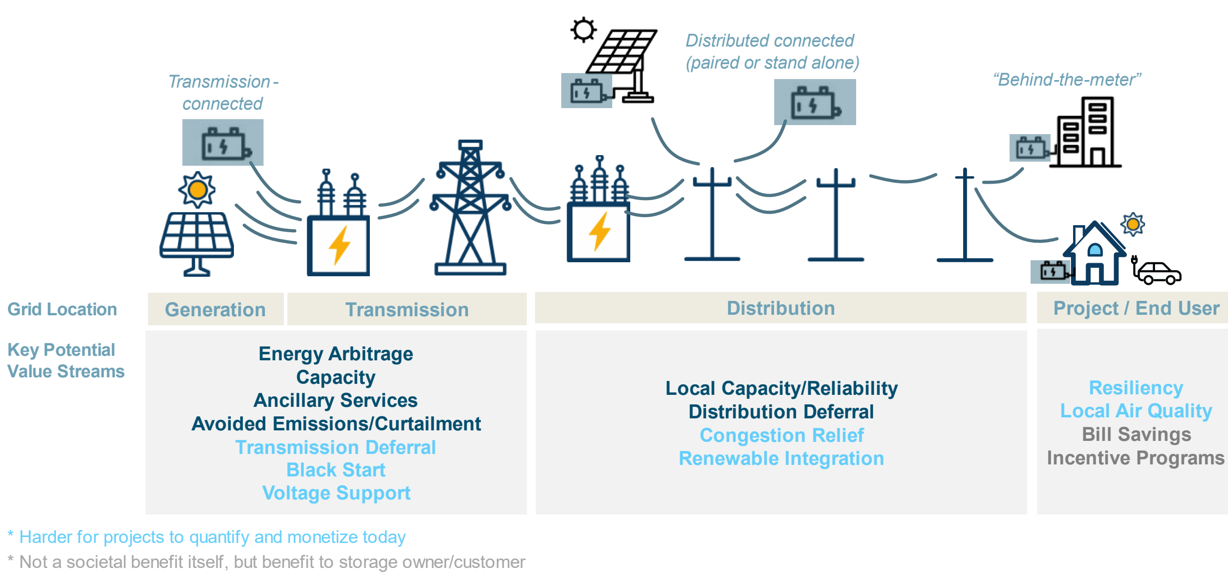
Given the unique ability of energy storage to charge and discharge at multiple timescales and to connect at multiple levels of the grid, it has many use cases that target a variety of value streams. The presence of storage on the grid has already pushed market rules to evolve to better monetize storage's ability to stack value streams.

This section explores the ways storage is being deployed today and the ways that we expect storage to be deployed through the lens of project economics. We talk through revenue streams, costs, and show use case examples highlighting the economic factors that drive adoption today and in the near future. We also include a societal view of storage benefits and costs to further motivate the case for deployment.

2.3.1 Storage Use Cases

Storage deployed provides different services depending on the location in the grid where it is installed. As suggested by Figure 2-6, a transmission-connected system can flatten system peaks, provide grid services, and balance bulk grid renewables. Connected to the distribution grid, storage can defer local investments or reduce a large user's (such as an MLP's) contributions to monthly and annual peaks. Behind the customer meter, energy storage provides bill savings and resiliency value. We note that some of these use cases can also be served by types of storage and flexibility not explicitly discussed in this report. For example, load flexibility and EV batteries may be harnessed to provide several of the values to the end user and distribution system.

Figure 2-6. Energy storage values at different grid scales



To better understand the sizes of costs and revenue in different configurations, we provide six representative use cases in Section 2.3.4:

1. A utility scale standalone FTM transmission-connected system
2. A commercial scale standalone FTM distribution-connected system
3. A commercial scale solar-paired FTM distribution-connected system
4. A commercial scale solar-paired BTM system
5. A residential scale solar-paired BTM system
6. A utility scale mid-duration standalone FTM transmission-connected system

The high-level design specifications for each of these use cases appear in Table 2-5. This set of use cases allows us to understand how system size, system duration, and access to different revenue streams impact dispatch patterns and benefit prioritization for optimal project economics. We consider each use case from three different perspectives: that of the developer, that of the ratepayer, and that of the state (in benefit cost analysis argot, these are referred to respectively as the Participant Cost Test, Ratepayer Impact Measure, and Societal Cost Test). The developer view assesses how likely a project is to earn a profit and therefore its likelihood of getting built. The ratepayer view assesses how utility rates and subsequently other utility customers would be affected by the combination of ratepayer funded incentive programs and avoided utility costs. The state perspective assesses the extent to which the project benefits the Commonwealth and its residents as a whole.

Table 2-5. Storage use cases summary

Use Case	Interconnection Level	Paired with Solar? [Solar Size]	Storage Capacity	Storage Duration (hours)	Installation Year
4-hr tx	Transmission	No	50 MW	4	2024
4-hr dx	Distribution	No	5 MW	4	2024
4-hr dx paired	Distribution	Yes [4 MW]	1 MW	4	2024
4-hr Com BTM paired	BTM	Yes [4 MW]	1 MW	4	2024
1-hr Res BTM paired	BTM	Yes [10 kW]	10 kW	1	2024
8-hr tx	Transmission	No	50 MW	8	2024

The use cases in this section focus on near-term grid needs. In the longer term, reliability is expected to become the most valuable grid need. However, assessing the ability of storage to contribute to this need requires a reliability-focused framework. Accordingly, we devote Section 4: to understanding the long-term system reliability need and the ability of storage to provide value in this context. Table 2-6 lists the full set of cost and benefit components considered in each cost test perspective. Explanations of the values streams and data sources used for their quantification appear in Sections 2.3.2 and 2.3.3.

Table 2-6. Benefit and cost components for each cost test perspective

Cost/Benefit Element	Developer Perspective	Ratepayer Perspective	State Perspective
Capital cost	Cost		Cost
Interconnection cost	Cost		Cost
Property tax and insurance	Cost		Cost
Fixed O&M	Cost		Cost
Variable O&M	Cost		Cost
Warranty and augmentation	Cost		Cost
Federal Incentives	Benefit		Benefit
SMART storage adder	Benefit	Cost	
ConnectedSolutions payments[36]	Benefit	Cost	
Clean Peak payments	Benefit	Cost	
Bill savings – energy	Benefit	Cost	
Bill savings – demand	Benefit	Cost	
Resiliency	Benefit		Benefit
Wholesale energy revenues	Benefit		
Capacity revenues	Benefit		
Spinning reserves revenues	Benefit		
Regulation revenues	Benefit		
Avoided energy cost		Benefit	Benefit
Avoided capacity		Benefit	Benefit
Avoided spinning reserves		Benefit	Benefit
Avoided regulation		Benefit	Benefit
Avoided local T&D		Benefit	Benefit
Avoided emissions			Benefit

2.3.2 Benefits of Short-duration Energy Storage

As previously mentioned, energy storage is unique in its ability to provide multiple value streams simultaneously. This value-stacking is essential to storage projects realizing net revenues. Depending on the storage configuration, it may be able to take advantage of potential revenues from the ISO-NE electricity markets, Massachusetts incentive programs, and retail rate arbitrage.

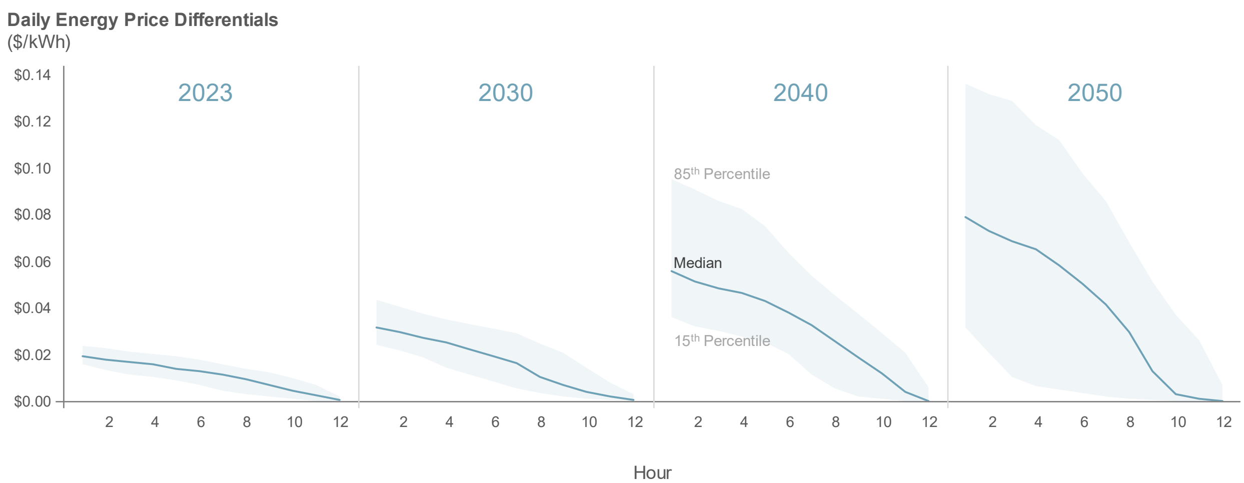
FTM installations have access to the ancillary services market, the capacity market, and the wholesale energy market. Though significant today, relative to other regions the market for ISO-NE ancillary services is small and we assume that these prices become saturated due to increased competition to provide those services from resources like new batteries. We have observed this trend in markets like California and

[36] This evaluation of Connected Solutions is consistent with other storage-supportive systems listed. Because it is funded through the Massachusetts 3-Year Energy Efficiency Investment Plan, the program is typically evaluated under a Total Resource Cost (TRC) framework. The TRC looks at costs and benefits to the total system rather than the ratepayer or society.

Texas that have more energy storage installed today. Capacity revenues are determined by the Forward Capacity Auction (FCA) which is held each year to ensure adequate capacity three years into the future.

Access to energy markets allows systems to charge during low-cost hours and discharge during high-cost hours. The evolving opportunity for this energy arbitrage is illustrated in Figure 2-7. The data in the chart show the range of price differentials between highest and lowest hours of each day in the given year. In 2040 for example, the most valuable arbitrage opportunity for 50% of the days in the year would give a perfectly efficient battery net revenue of $0.056 per kW charged during the cheapest hour and discharged during the most expensive hour. However, this opportunity drops after the first hour: charging/discharging during the 4th cheapest/most expensive hour would net a median of only $0.046 per kW, and this value drops to $0.026 per kW by hour 8. This demonstrates the diminishing incremental potential for energy arbitrage with longer storage durations and highlights that daily energy arbitrage alone will not create a market for long duration projects. The value of energy arbitrage today is small and has little variance, but this opportunity is expected to grow significantly as renewable energy penetration increases.

Figure 2-7. Daily differentials between highest and lowest price hours



We note that not all FTM systems can fully take advantage of these price differentials: distribution connected systems are subject to a special tariff, which uses price signals to constrain charge and discharge timing and accordingly mutes the opportunity for arbitrage. These tariffs – typically referred to as either “wholesale distribution tariffs” or “ESS tariffs” are being actively developed by investor-owned EDCs in the state under direction from the MA Department of Public Utilities (DPU). So far draft versions have been released, though final rate proposals are expected by late-fall of 2023. The proposed versions of these tariffs may include two primary rate components: a contract demand charge ($/kW) that will be based on the rated capacity in the system’s interconnection agreement, and an as-used on-peak demand charge ($/kW) based on the highest usage each month during an on-peak demand window. This last component is intended to capture the shared costs of distribution system assets and ensure storage owners pay a fair amount for any on-peak usage. In practice it strongly disincentivizes storage from charging during those peak periods at all, which can meaningfully restrict storage operational behavior. The most recent versions of these proposed tariffs include a shorter on-peak window definition, and better align the rate structure with other charging and discharging priorities (such as to capture CPS Credits) and so the impact on discharge flexibility is smaller than earlier draft versions, though does still lead to less flexibility than transmission connected systems. For more information, the challenges and tradeoffs of this use case and rate structure are further explored in Section 2.3.4, Use Case 2 below.

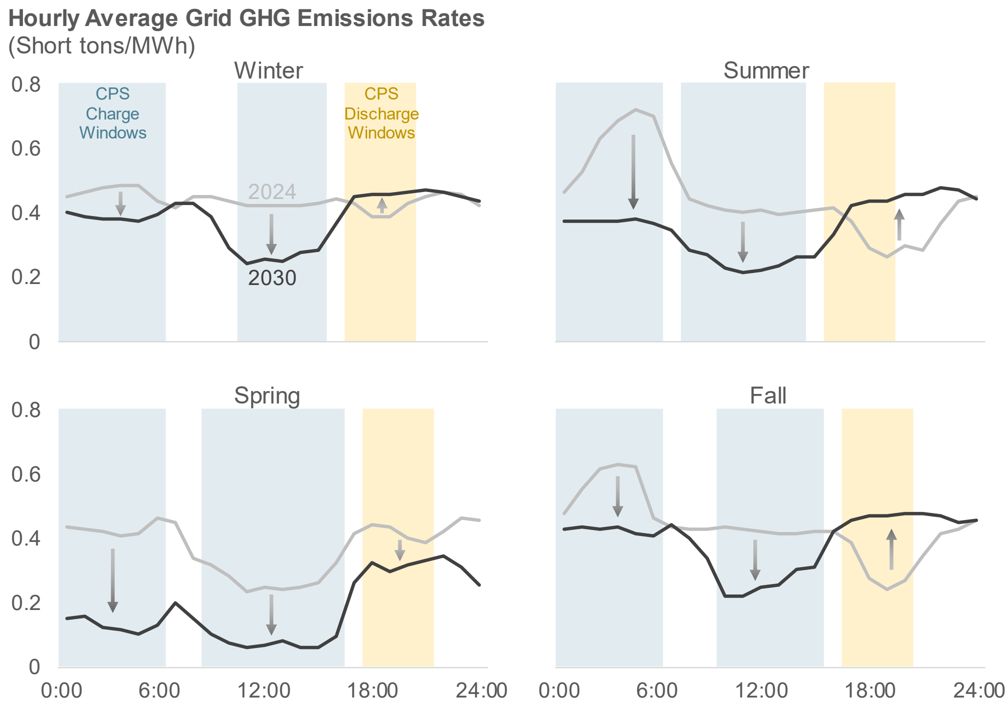
The Massachusetts incentive programs described in Section 2.2 can be leveraged all at once, but only if the criteria required by each are all met. For example, ConnectedSolutions is only available to BTM installations, SMART is only available to solar-paired installations, and programs have requirements around the storage system specifications such as size and/or duration. The lucrative nature of programs like SMART and Clean Peak tends to drive both operational decisions and decision-making in the installation process.

BTM installations can strategically dispatch storage to arbitrage between TOU periods in volumetric rate components, or to reduce demand charges should these features exist in their rate structures. Additionally, BTM installations can reduce lost load for customers by discharging during outages. This resiliency benefit can be large for critical facilities.

Energy storage deployed strategically on the distribution grid can obviate, or at least delay, the need for infrastructure upgrades triggered by new loads and generators coming online. The dependence of this benefit on distribution system context makes it highly site-specific. For many sites, the value is small or even zero, but for a nontrivial fraction, the value can be large. Similar to distribution deferral, energy storage can also provide value avoiding or deferring transmission investments. This benefit is realized over a wider geographic region, which means that transmission-connected projects contribute to it and that it varies little among projects in the same area. However, realization of quantifiable benefits from T&D deferral has been historically rare, as evidenced by the lack of non-wires alternative projects selected by the EDCs. For local or wider T&D deferral, it is important that storage receive operational signals consistent with providing this grid benefit. Lack of transparent access to the right dispatch signals (price or otherwise) could result in storage providing no benefit, or even exacerbating grid conditions.

By charging from low emissions resources and discharging when higher-emitting resources are on the margin, energy storage provides an avoided emissions benefit. Today in Massachusetts, hourly grid emissions factors do not vary enough to make up for round trip efficiency losses, but future higher renewable penetrations will put zero-carbon generation on the margin more frequently. Figure 2-8 highlights this dynamic by showing the average hourly marginal emissions factors for 2024 and 2030, broken out by season as defined by the Clean Peak Standard program. Generally, midday emissions drop as solar penetration increases, and evenings become the highest emitting times regardless of season. Of note, the beginning-of-day CPS charging window, which is expected to align with eventual off-shore wind production, does not align with particularly low emissions factors today or at the end of the decade. In fact, this period shows higher emissions factors than any other time of day today.

Figure 2-8. AESC grid emissions factors by season and hour



When zero-carbon generation is on the margin, energy storage can dispatch to shift otherwise-curtailed carbon-free energy to displace fossil generation that would have run at other times of day. Outside of Regional Greenhouse Gas Initiative (RGGI), the costs of which show up in market prices, there is no mechanism to monetize avoided emissions today. We model them as a benefit to society at $393 per ton (2021 dollar year) in alignment with the latest AESC guidance.[37]

We list key data sources for benefits in Table 2-7, alongside an explanation of how we model dispatch behavior to optimize storage benefits.

The benefits monetizable today and in the future through wholesale electricity markets and/or bill savings represent only a portion of the overall benefits associated with deployment of energy storage. While some benefit streams are expected to be monetizable through ongoing market reforms, others may not materialize until the long-term when there are higher levels of renewables on the electric grid or may never be clearly monetized. In particular, local air quality benefits should accrue in disadvantaged communities as storage utilization replaces peaker plant operation. Also the growth of the storage industry required to meet future needs will produce long term jobs in manufacturing, installation, and in the back office.

[37] https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf

2.3.3 Costs of Short-Duration Energy Storage

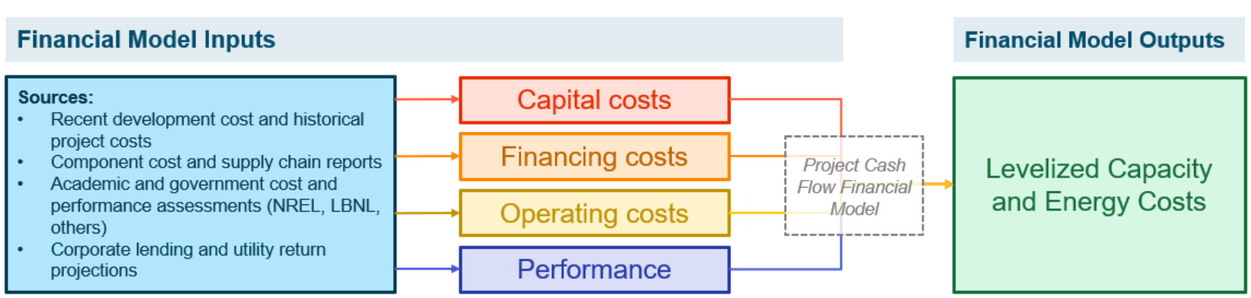
Cost assumptions for new technologies – both today and in the future – are critical for assessing the relative benefits each technology may provide for individual adopters, the rate base as a whole, and the grid system here in Massachusetts. Costs are a key determinant of what is deemed commercially viable, and so accurately capturing known costs today, estimated cost evolution into the future, and the bounds of uncertainty for those projections is an important component of this study.

To date, there are several short duration energy storage technologies – defined here as up to 4-hour dispatch capability – that are currently commercially viable. However here in the Commonwealth and in most parts of the country, lithium ion (Li-ion) is the dominant technology type and has been for most of the past decade. This is driven jointly by its high energy density, its high roundtrip efficiency relative to other technologies, and its cost advantage at short durations. As is explored in subsequent sections, other technologies are beginning to emerge as more cost effective at longer durations (10+ hours) but Li-ion remains the leading commercially viable option today at 4-hour duration and below, and as such is the focus of our short duration storage cost assessment.

Cost projections in this analysis were developed using E3's in-house project cash flow financial model, referred to here as the Pro Forma model. The Pro Forma aggregates key cost and operational inputs for a wide range of resources and generates levelized cost forecasts via detailed project cash flow accounting.

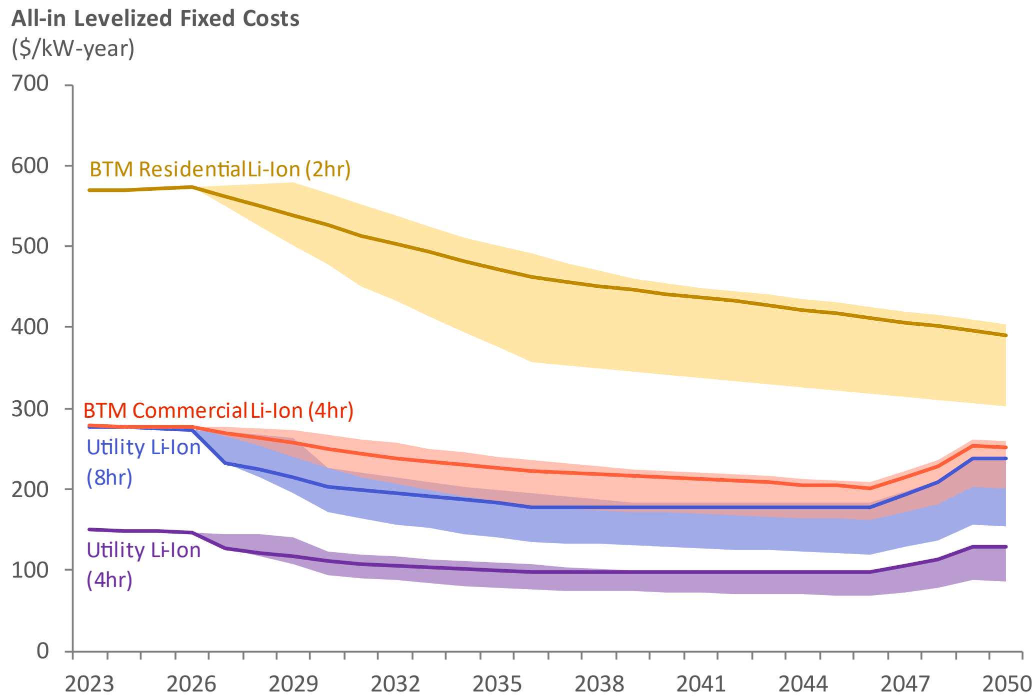
There are four primary categories of inputs required for the Pro Forma: capital costs (typically $/kW overnight costs), financing costs (e.g. cost of capital, debt/equity ratios), operating costs (FO&M, warranty and augmentation to counter degradation), and performance assumptions (cycling assumptions, roundtrip efficiency, etc.). To source these, E3 relied primarily on reports and installation data in the public domain, particularly the Lazard Levelized Cost of Storage (LCOS) 8.0 report released in May 2023, National Renewable Energy Laboratory (NREL)'s Annual Technology Baseline, and select Lawrence Berkeley National Laboratory (LBNL) studies on interconnection cost evolution. Where possible, the E3 team cross referenced the cost input data with developers and other stakeholders during the interview process, to ensure strong alignment with the on the ground experience in the Commonwealth.

Figure 2-9. Pro Forma framework



The Pro Forma then generates levelized capacity and energy cost forecasts. These levelized costs reflect both financing and federal incentive impacts, and so serve as the best way to compare resource economics across storage applications and durations. The Levelized Fixed Costs (LFC), reported in $/kW-year, are used as our primary comparison metric for storage resources. Though also calculated but not shown, the Levelized Cost of Energy (LCOE) is a less useful metric for storage as it typically does not account for the cost to charge the storage system. In our modeling, charging costs are accounted for in the storage dispatch logic directly, and so are netted out of the benefits streams rather than included separately in the cost accounting.

Figure 2-10. Short-Duration Storage Cost Forecasts



Across our forecasts, utility scale 4-hour Li-ion developments are the most cost effective, with a projected long-term range of $85-$130/kW-year, once IRA tax credits roll off. 4-hour commercial behind-the-meter systems are expected to be broadly cost-competitive with 8-hour utility scale systems in the long run, both landing in the $180-$250/kW-year range in 2050. Behind-the-meter residential systems are substantially high cost today, however those cost are expected to come down significantly during the forecast period as global supply chains catch-up with demand and installation costs reduce.

2.3.4 Use Case Examples

To model different business cases and storage applications in the Commonwealth, our team developed a detailed dispatch model that enables short-duration storage systems to operate optimally under a range of configurations. These include front-of-meter and behind-the-meter installations at different scales (residential, commercial, utility), solar-paired and standalone systems, and durations ranging from 1-8 hrs. Each of these options can be turned on or off for a given business case, and the resulting selection informs the operational behavior of the system.

The dispatch logic is informed by both the generation or load signals of the configuration (e.g. a solar-paired system will charge exclusively from solar; a BTM system will discharge based on the load profile of co-located facilities) and the corresponding hourly price streams in which such a system would operate.

For example, a BTM residential system will operate to reduce energy bills for the residence, with charge and discharge timing driven largely by the demand charges in the residential rate tariff. In contrast, an FTM, transmission connected standalone storage system charges and discharges based on hourly prices in the wholesale markets, using daily top-bottom price rankings along with efficiency losses of the system to govern charge and discharge cycles. It is worth noting that because price ranking is conducted daily, intraday dispatch is not possible in this model construct, and so it is unsuitable for durations longer than 8 hours. As such our long duration business case analysis is conducted using a different set of tools.

In addition to the dispatch logic itself, there are many inputs that govern the storage operations and benefits accounting of each system. Key inputs are summarized in Table 2-7.

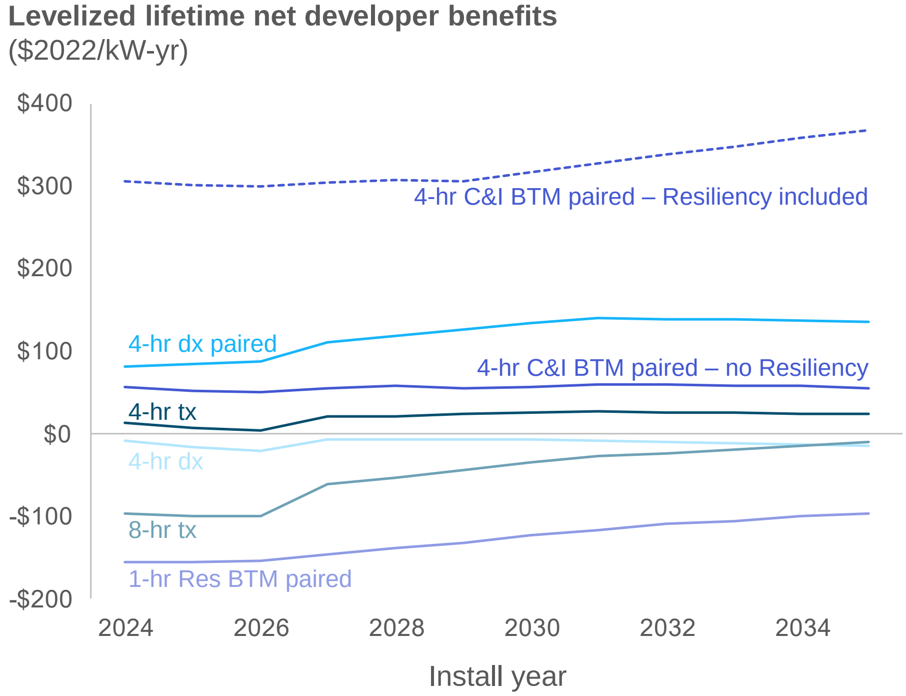
Table 2-7. Dispatch Model Input Data

Category	Data Type	Source Information
Prices	Wholesale price forecasts for energy, AS, and capacity	Prices derived from the most recent AESC New England forecast, with long term shaping based on E3's internal market price forecasting[38]
	Wholesale distribution tariffs for distribution connected FTM systems	National Grid proposed ESS tariff, Eversource G3 tariff
	Electric service rates for residential and commercial BTM installations	National Grid and Eversource rate sheets
	Value of Lost Load	EIA Reliability Metrics
Incentives	IRA Tax credits	Federal IRA documentation around eligibility, credit levels, etc. and E3 judgement on timing, monetization, etc.
	Clean Peak Program credits and optional parameters	MA State documentation
	SMART Incentive Tranches, eligibility requirements	MA State documentation
	ConnectedSolutions incentive levels and compensation structure	MA State documentation
Operating Parameters and Profiles	Roundtrip efficiency assumptions	Historical operational data, developer feedback
	Solar generation profiles	NREL
	On-site demand profiles for representative commercial and residential properties	Efficiency Maine Trust

Figure 2-11 provides the modeled net benefits from the developer point-of-view for the use cases, each of which is examined in greater detail below. Few use cases see much change in net benefits over time, but we note the improvement of economics for the 8-hour storage as it takes advantage of the increasing price spreads highlighted by Figure 2-7 more completely than similar 4-hour systems.

[38] Additional shaping captures impact of high renewable energy penetration, but is not meant to represent the full volatility of real-time market, so energy arbitrage revenues can be regarded as slightly conservative.

Figure 2-11. Developer Net Benefits Across Installation Years



Use Case 1: Utility Scale Standalone FTM System

System Details

Size and Duration: 50 MW, 4hr

Interconnection Type: Transmission

Pairing: None

Installation Year: 2024

Few utility scale front-of-meter systems have been developed to date in Massachusetts, but there are many in the interconnection queue, and a number in advanced stages of development, so developer interest in this use case in the Commonwealth is strong. The economics in our modeling bear out this interest, as these systems see a benefit cost ratio above 1 in all years of our forecast. We consider a 50 MW, 4-hour development installed in 2024, the full levelized costs and benefits of which appear in Figure 2-12.

Figure 2-12. FTM Tx Connected Benefits and Cost Stack – Developer Perspective

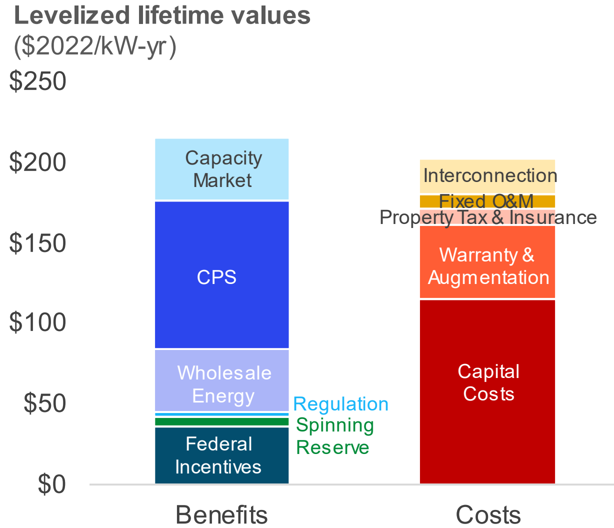
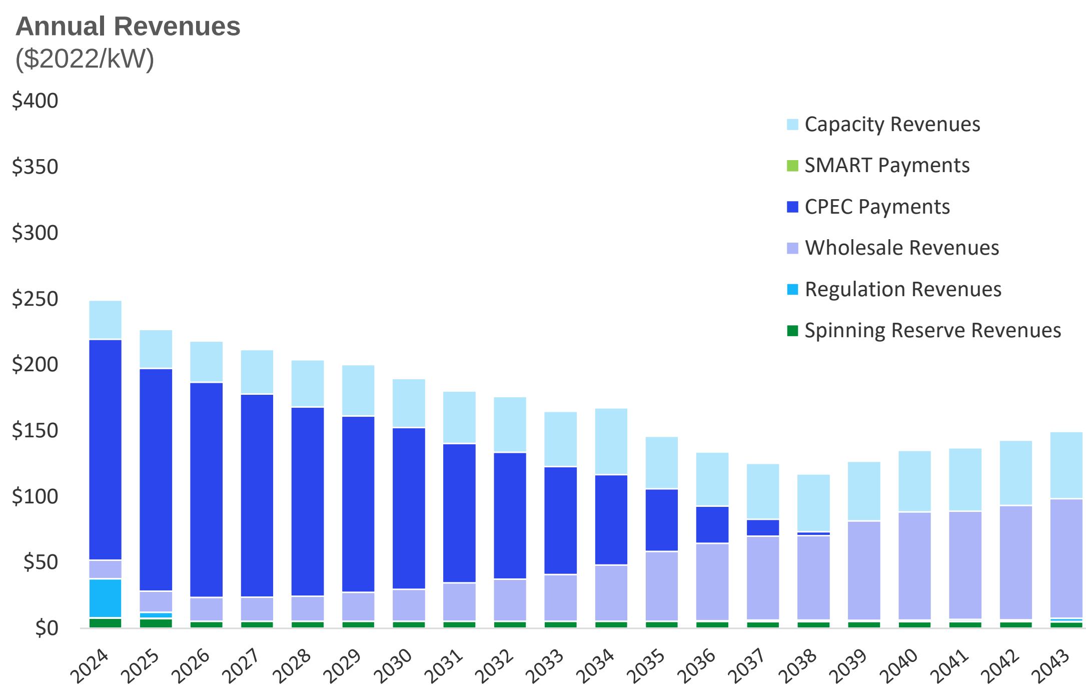


Figure 2-13. FTM Tx Connected Annual Revenues – Developer Perspective

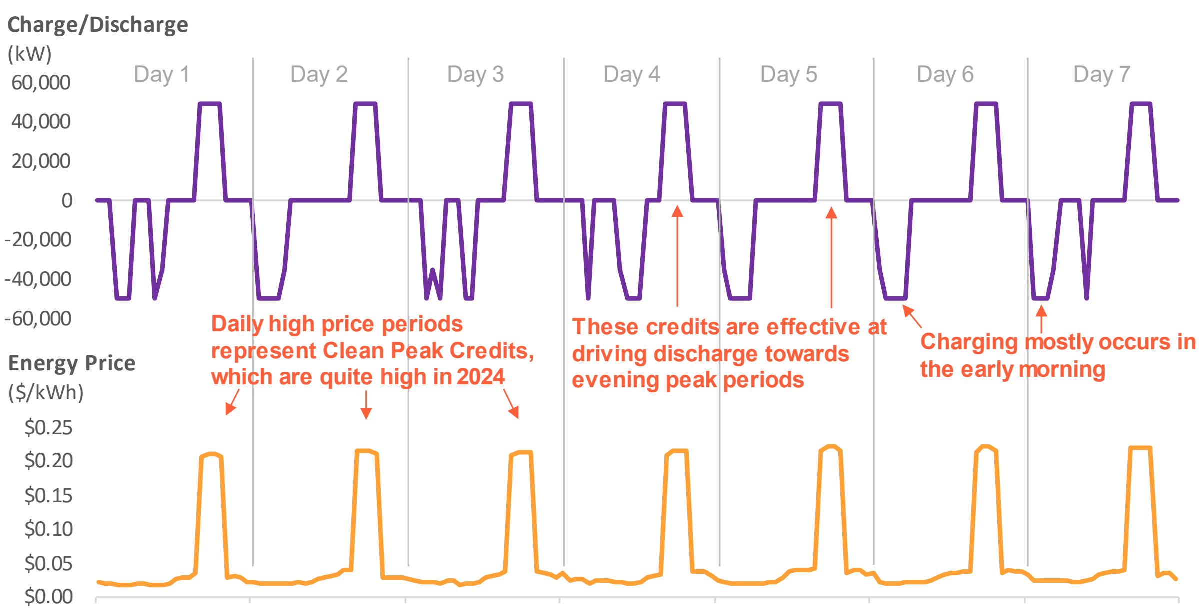


The benefit-cost ratio (BCR) for this example is 1.06, with Clean Peak credits providing the largest revenue share. As shown in Figure 2-13, these revenues drop to zero by the late 2030s based on our forecasts of over compliance in the market, but the benefit stream remains the most substantial for this example. Capacity and energy arbitrage revenues from wholesale market participation are also forecast to be substantial. Ancillary services revenues provide a much smaller portion of the revenue stack; the regulation market is expected to saturate within the next few years and spinning reserves are less lucrative. Federal incentives in the form of the investment tax credit also play a critical role in making this use-case revenue positive, which helps underline how much the Inflation Reduction Act could shift market economics going forward, particularly for standalone storage.

On the cost side, capital costs to develop the system unsurprisingly form the largest share. These include equipment costs, engineering, procurement, and construction costs, and interest costs during construction. Warranty and augmentation costs also form a meaningful portion of the cost stack. Lithium-Ion storage systems degrade over time, so our modeling follows the industry standard practice of augmenting the storage capacity on a periodic basis to allow it to maintain full capacity for the duration of its useful life. Interconnection is also a sizable cost driver, and one that will hopefully come down in the future with process reform requirements associated with FERC's recent Order 2023. Property tax and insurance plus operations and maintenance are the final cost categories accounted for.

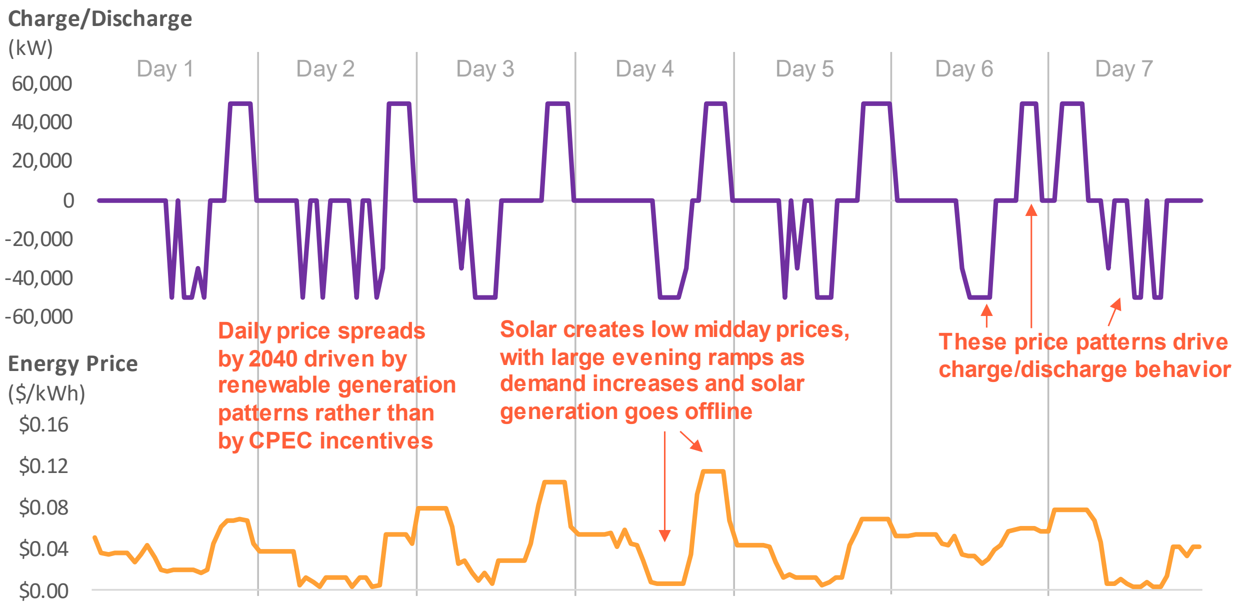
Transmission connected, FTM systems such as this operate fully in the wholesale market, with charge and discharge signals based on hourly wholesale prices fluctuations. As such, the ability for storage to generate revenue and provide maximum system value is contingent on its ability to shift power between low price, low demand and/or high renewable generation periods, and high price, high demand periods. For the first half of this system forecast (2024-2038), this behavior is driven directly by the CPS credits. The storage charges primarily during early morning hours when demand is low and wind is frequently on the margin, and discharges during the administratively designated clean peak windows. These dynamics are illustrated in Figure 2-14.

Figure 2-14. Example of a 2024 summer week – Clean Peak Credits drive dispatch behavior



Once the value of Clean Peak credits drops to zero, daily price spreads will be driven solely by the supply-demand balance. By 2040, significant amounts of solar and wind are expected to be on the system, and these resources will set clearing prices during large portions of the day. Particularly, low price periods during solar generating hours are large and persistent in our market price forecast, and they provide a strong signal for the storage to charge. As the sun goes down and solar generation reduces, the system sees a large net demand spike in the evening most days which must be met with dispatchable resources whose marginal operating costs drive prices back up. This serves as a strong signal for storage discharge and encourages the storage to regularly shift midday renewable power into higher-emission evening peak periods. In this way, wholesale market pricing drives similar charge/discharge behavior during the latter part of the system forecast (2038-2043), when Clean Peak credits are no longer available. These 2040 system dynamics are illustrated in Figure 2-15.

Figure 2-15. Example of a 2040 summer week – renewable generation drives price spreads



Challenges and Opportunities:

One fundamental challenge with this use case that could have material effects on both operations and system economics is that none of these revenue streams can currently be contracted in MA, and so each comes with some risk and uncertainty. In stakeholder interviews, developers flagged this issue time and again: lacking the ability to secure some of these revenue streams through long-term contracts, investors view them as high risk, and so will only invest with very high return expectations. Put differently, the cost of equity for these systems is much higher than it would be if they could secure bilateral contracts, and these added financing costs can make the difference between a profitable development, and an unprofitable one.

Developers flagged that the clean peak revenues in particular are viewed very cautiously by investors – since there is no floor price, and there is considerable uncertainty as to how quickly credit pricing will drop, investors discount those revenues considerably. Developers argue that that same level of state incentive will go a lot further just by improving a project's certainty that they will receive those credits as forecast, and that the best way to do this is to allow for long-term contracting.

Arbitrage revenues in the wholesale market are viewed with similar caution. Our price forecasts – which reflect decarbonization levels consistent with state and regional targets – show plenty of daily price volatility for storage to operate effectively and economically. Our expectation is that this is how the market will evolve, and that arbitrage will form an important component of storage revenue in the near future. However developers necessarily pose the question of what happens if those spreads do not materialize, either due to delays in renewable resource deployment or due to some unforeseen regulatory intervention. Lacking contracts, this also introduces risk, which further drives up financing costs.

Use Case 2: Commercial Scale Standalone FTM Distribution System

System Details

Size and Duration: 5 MW, 4hr

Interconnection Type: Distribution

Pairing: None

Installation Year: 2024

Distribution connected front-of-meter systems have similar operating patterns as transmission connected systems since both interact directly with the wholesale market. However the economics for distribution connected systems are more challenging, driven directly by the fact that they are on the distribution network, and so must share in the costs to maintain that network. This creates a challenge of designing a fair rate that accurately reflects their portion of the shared maintenance costs for the network, while also promoting the operational flexibility of storage that can yield meaningful system benefits, and that reasonably passes through energy costs.

In recent years, the most common rate option for distribution connected systems has been the G3 time-of-use rate[39], which was designed for very high demand customers whose usage is flexible enough to respond to on-peak and off-peak pricing. If installed under this tariff, storage systems would charge at the G3 rate levels, and discharge into the wholesale market, while also navigating demand charges under that rate. The challenge with this construct is those rates really were not designed for energy storage systems: the rates include bi-modal pricing that does not maximize storage flexibility, and includes demand charges that better reflect EV charging patterns than energy storage. Under the G3 rate, distribution connected energy storage systems have been cost prohibitive.

The EDCs are now in the process of developing new rates specifically for energy storage systems, under direction from the MA Department of Public Utilities. The new rates aim to better match storage operational parameters, while still reflecting the appropriate shared costs of maintaining the distribution network and disincentivizing storage from charging during peak demand windows. This use case reflects latest version of this new tariff as proposed today[40], and is intended to model a system that goes online in 2024, the earliest time when this new tariff could be in effect.

Unlike the structure under G3 rates, systems under the wholesale distribution tariff will be able to charge and discharge based on wholesale market price signals. This will make their operations and economic profile much more similar to transmission connected systems, though distribution connected systems may still be subject to more operational restrictions depending on feeder location and relevant EDCs

[39] National Grid G3 rate description available here: https://www9.nationalgridus.com/niagaramohawk/business/rates/4_tou.asp

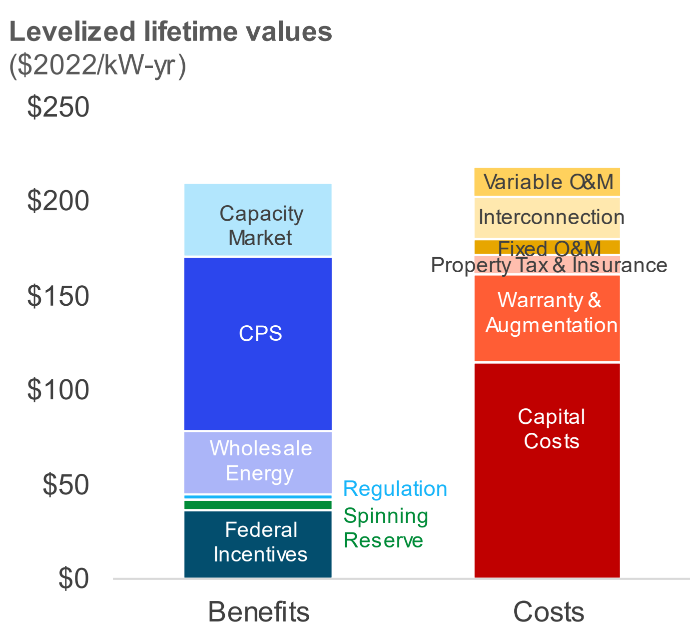
[40] The EDCs must provide notice to the DPU of their intent to promptly file a wholesale distribution tariff with FERC by October 31st, 2023, and rate analysis is still ongoing, so the specific rate levels within this tariff could still shift before being submitted. This use case analysis reflects the proposed rate structure from September 21st, 2023. The EDCs also had to file by October 31st, 2023 an electric rate tariff that addressed operational parameters for energy storage systems interconnected to their distribution systems.

operational parameters tariff. The wholesale distribution tariff also contains demand charges, which may be broken into two components – contract demand and as-used on-peak demand. The contract demand charge as proposed will be based on the rating of the system in the interconnection agreement, and the as-used on-peak demand charge will be based on the highest metered on-peak usage each month. This latter component is the primary mechanism for disincentivizing peak time charging and is priced aggressively enough to be an effective deterrent.

Though the version of this rate as proposed on September 21, 2023 is substantially better and more flexible than the G3 rate, our modeling shows that distribution connected FTM storage is still cost prohibitive throughout the 2020s under this rate. Part of the reason these distribution systems are cost-prohibitive while transmission systems are not relates to the contract demand charges, which cannot be avoided, and which are shown under the Variable O&M cost category in Figure 2-16. However that may be unavoidable if the contract demand charges are accurately reflecting the cost to utilities of maintaining the distribution infrastructure. Another key difference is the as-used on peak demand charges, which in our modeling are a strong enough disincentive to prevent the storage from ever charging during those peak periods. While these then do not show up directly in the cost stack in Figure 2-16, they do constrain the operations of the distribution connected system which could reduce arbitrage revenues in some periods.

Figure 2-16 shows a 2024 install using the National Grid primary feeder wholesale distribution tariff rates, and yields a BCR of 0.96. The proposed Eversource rates would lower this ratio to 0.94, and the National Grid secondary feeder rates would lower it further to 0.93.

Figure 2-16. FTM Distribution Connected Benefits and Cost Stack – Developer Perspective



Challenges and Opportunities:

Two potential levers that could help flip the benefit cost ratio for these systems include A) interconnection reform to reduce the time and bring down costs associated with interconnection, and B) the addition of a new multiplier to the Clean Peak Standard for distribution connected systems, which is actively under development by the state. The financial projection here is close enough that a small additional incentive or cost change could flip the benefit cost ratio.

Stakeholders have suggested a number of other potential changes that could move the needle for distribution connected systems. The first relates to a more direct compensation structure for the ability of storage systems to help avoid peak demand on the distribution system, and thereby defer or avoid costly system upgrades. The wholesale distribution tariff as written is able to penalize storage systems that charge during peak periods, which is appropriate, but it does not compensate storage for the peak avoidance benefits it provides. By contrast, MLPs who own storage rely on this type of peak avoidance as their most lucrative revenue stream. This comes across clearly in the ACES Aggregated Project Reports, which track data from the state funded Advancing Commonwealth Energy Storage projects, many of which are sited in MLP territory.[41] As the latest report identified, “The bulk (over 90%) of the [MLP] achieved revenues were through ISO-NE peak hour (ICAP tag) and transmission zone (RNS) demand reductions.”

Developers have flagged that this has been an easy path in MLP territory since MLPs are motivated to reduce their peak charges and have the ability to approve and interconnect projects more nimbly than EDCs. The same is not currently true for the investor owned EDCs in the Commonwealth – addressing that gap could help with both the siting and economics of storage, and with maximizing that storage’s value to the system once online.

Use Case 3: Commercial Scale, Solar-paired FTM Distribution System

System Details

Size and Duration: 1 MW, 4hr

Interconnection Type: Distribution

Pairing: DC Paired Solar

Solar Size: 4 MW

Installation Year: 2024

Solar paired systems on the distribution network have stronger economics due to their eligibility for funding through the MA SMART program. Our modeling indicates that the storage component of solar-paired systems installed in 2024 receives a majority of its revenues from the SMART storage adder, which provides a direct per kWh incentive for eligible storage systems.[42] These systems are still eligible for Clean Peak Energy Credits and arbitrage revenues from operations in the wholesale markets, so their revenue options are more diverse than other use cases, at least in the near term at the current SMART development tranche level. However, Clean Peak Energy Credits receive a 0.3x multiplier for systems also participating in SMART. Similar to use cases 1 and 2, the storage components of these paired systems are also eligible to receive capacity revenues. However developers do not by default own the capacity rights to the solar components of these systems, and instead would have to buy those capacity rights back from the EDCs if they would like to receive the solar capacity revenues. While that may be beneficial for certain developers, particularly if it

[41] Latest ACES Aggregated Report available here: https://www.masscec.com/sites/default/files/documents/ACES%20DNV%20Q4%20Aggregated%20Report_revised_clean.pdf

[42] See the SMART program description in Section 2.2.3 for storage eligibility requirements

would boost the capacity accreditation of the paired storage system, we did not model that situation and instead only consider the storage capacity revenues in this case analysis.

In this use case, we model a 1 MW, 4-hour storage system paired with a 4 MW solar system. Developers indicate this ratio to be common; since the SMART storage adder is the most lucrative element of adding storage to SMART solar systems today, developers indicated there is little incentive to size the storage any larger than the 25% of solar capacity needed to qualify for that adder.

Figure 2-17 shows the cost and benefits stacks for this solar paired system. Overall this system achieves a benefit cost ratio of 1.41 with the two largest revenue streams being the SMART adder payments, and wholesale energy revenues. Though modeled as a paired system, these revenues and costs represent just the storage portion of the development – for example the wholesale revenues represent just the added revenues the storage system can generate by selling cheaper daytime solar energy during higher priced evening hours.

Figure 2-17. FTM Solar Paired Benefits and Cost Stack – Developer Perspective

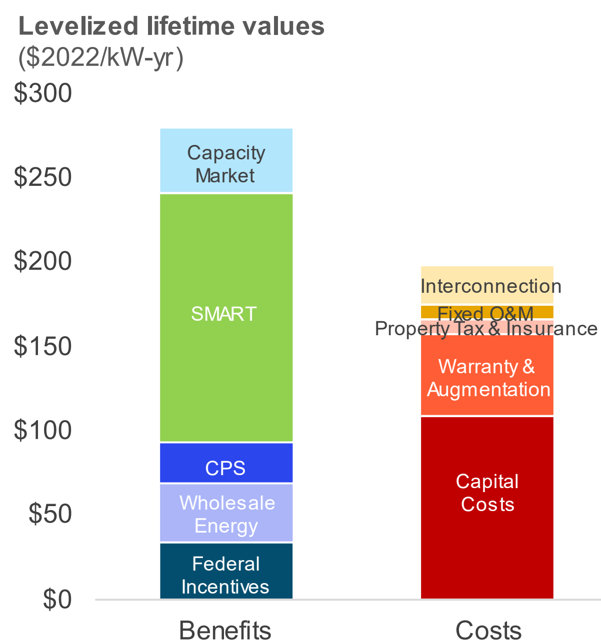


Figure 2-18. FTM Solar-paired storage dispatch (example week in June)

Figure 2-18 shows battery charge and discharge behavior in a paired system. During daytime hours when prices are low, the battery charges from solar. In peak times, the battery discharges, capturing both higher wholesale prices and CPS incentives. The combined impact is an effective shifting of the solar generation into a later part of the day to help meet the post-sunset peak of system net load.

Use Case 4: Commercial Scale, Solar-paired BTM System

System Details

Size and Duration: 1 MW, 4hr

Interconnection Type: BTM

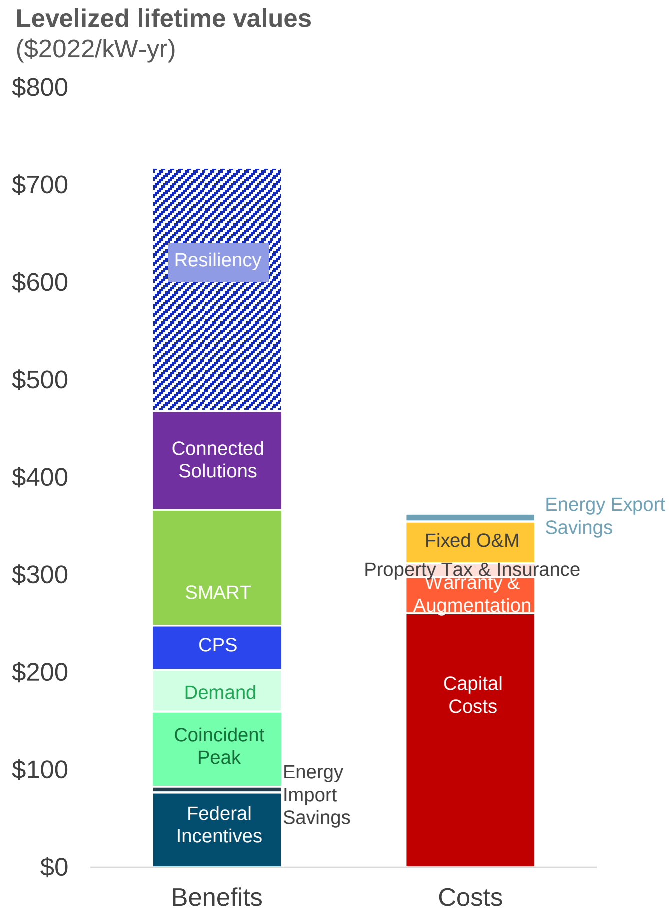
Pairing: Solar

Solar Size: 4 MW

Installation Year: 2024

Behind-the-meter systems have been implemented at commercial and industrial locations in MA to lower energy bills. The majority of existing BTM storage resources in MA are paired with solar. Both standalone and solar-paired BTM systems are economically profitable, and as a result, interest in this use case is strong. In our forecast, this example 1 MW, 4-hour system has a benefit-cost ratio of 1.97, the breakdown of which appears in Figure 2-19. Resiliency, demand charge reduction, and state incentives are major revenue streams.

Figure 2-19. C&I BTM solar-paired storage benefits and cost stack – developer perspective



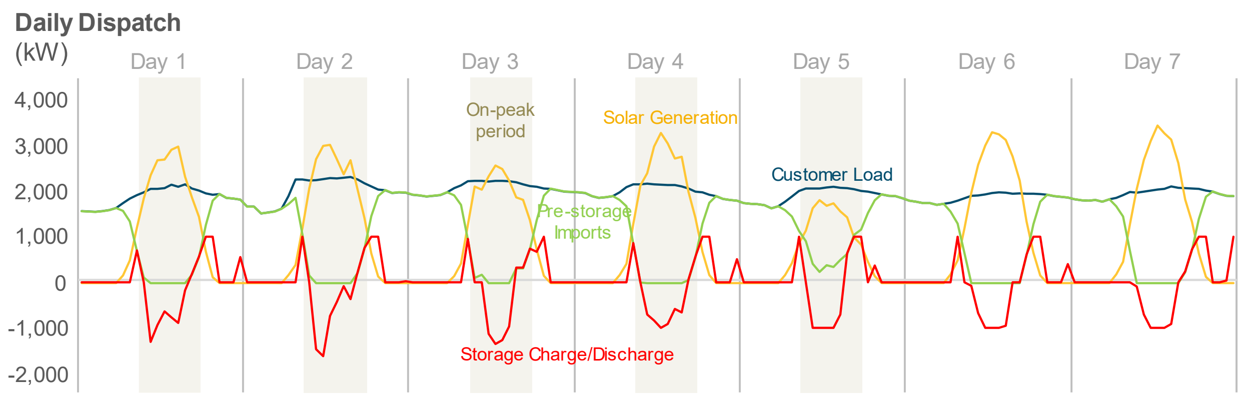
BTM batteries have the potential to provide power in the event of a grid outage. Serving critical load can be valuable for many commercial operations, but estimating and incorporating this value is challenging, as it varies significantly between users. In our modeling, resiliency is determined by the state of charge of the battery and the value of lost load (VoLL), based on an average value for C&I customers and the average outage probability. An advantage of batteries over other back-up resources, is that while the grid is operational, the battery is dispatched to other values streams. We note that even without the somewhat uncertain resiliency benefit, this use case is still cost effective.

Unlike FTM systems, BTM assets do not operate in the wholesale market. As such, their charge and discharge signals are solely based on their retail electricity rate structure and applicable incentives. Their ability to generate revenue is contingent upon their ability to shift load to off-peak hours and to reduce peak demand charges. This example uses the Eversource G-4 (52) General – Time of Use rate, but revenue will vary depending on rate structure; rates with higher demand charges exist and make BTM storage even more attractive to customers.

These revenues and costs represent just the storage portion of the development, incremental to the solar portion. In a solar system without a battery, excess energy would be exported for revenue. In this case, energy exports enter the battery instead. Thus, exports provide negative revenue when compared to the counterfactual.

Figure 2-20 shows the cycling behavior for this BTM system for an example summer week. The "customer load" line shows load prior to solar or storage, and the "pre-storage imports" line indicates load net of solar generation. Cycling behavior is dependent on the Clean Peak program and ConnectedSolutions, which incentivize storage to decrease consumption in peak hours. ConnectedSolutions revenues are calculated from battery performance during calls of peak demand reduction from the EDC. Program agreements determine the incentive rate per kW performed, per season. Notable in the figure is the disconnect between Clean Peak period definitions and those of the time-of-use rate. The rate defines the summer peak as 9 am to 6 pm, while Clean Peak encourages summer charging from 7 am to 2 pm and discharging from 3 pm to 7 pm. In this example, meeting the Clean Peak criteria outweighs avoiding on-peak billing rates, but better alignment would improve storage economics and send a clearer signal to customers.

Figure 2-20. C&I BTM solar-paired storage dispatch (example week in June)



Use Case 5: Residential scale, solar-paired BTM System

System Details

Size and Duration: 10 kW, 1hr

Interconnection Type: BTM

Pairing: Solar

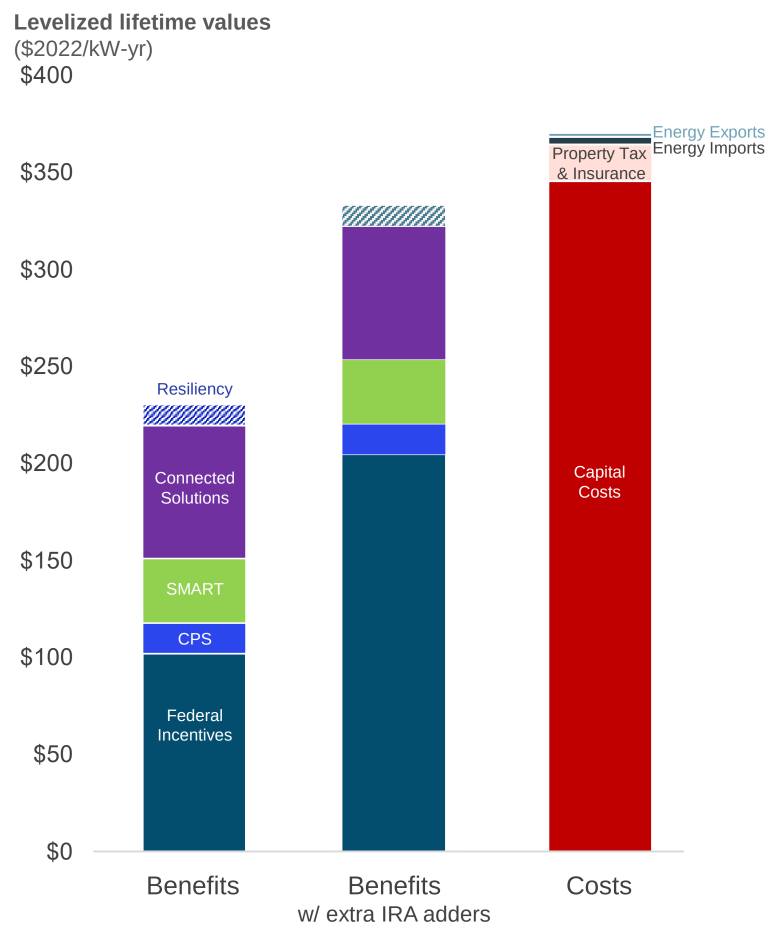
Solar Size: 10 kW

Installation Year: 2024

BTM Residential Paired systems operate similarly to C&I systems. However, as shown by Figure 2-21, the economics for residential systems are far inferior, driven by their rate structure and smaller scale. On the costs side, residential systems still face a large capital cost burden that is distributed over a shorter operating lifetime. On the benefits side, there are fewer potential revenue streams: The average VoLL for a residential building is lower, decreasing the value of resilience. Time of use rates are unavailable for rate arbitrage. We include CPS revenues, though there are no residential systems enrolled. Stakeholder input suggests this is due to the 15-minute metering requirement. Without demand from customers, there has been no investment in metering capability at this scale, though this stands to change with mass Advanced Metering Infrastructure deployment approved by the DPU in December 2022.[43]

Figure 2-21 also include a second benefit stack based on an increased federal tax incentive. This incentive includes a 10% adder for being in an IRA-designated "energy community", plus a 20% adder for serving a low-income community. The former applies in Massachusetts for census tracts and adjoining census tracts of three former coal plants: Salem Harbor (Salem, retired in 2014, now site of a gas plant), Mount Tom (Holyoke, retired in 2014 decommissioned), and Brayton Point (Somerset, retired in 2017). The latter 20% bump is available if the project is part of a qualified low-income residential building project or a qualified low-income economic benefit project but can only be realized by submitting an application to the Treasury for approval. Even this case that has 60% of capital cost covered by incentives does not achieve cost-effectiveness given the high capital costs and lack of TOU rates.

Figure 2-21. Residential BTM solar-paired storage benefits and costs – developer perspective

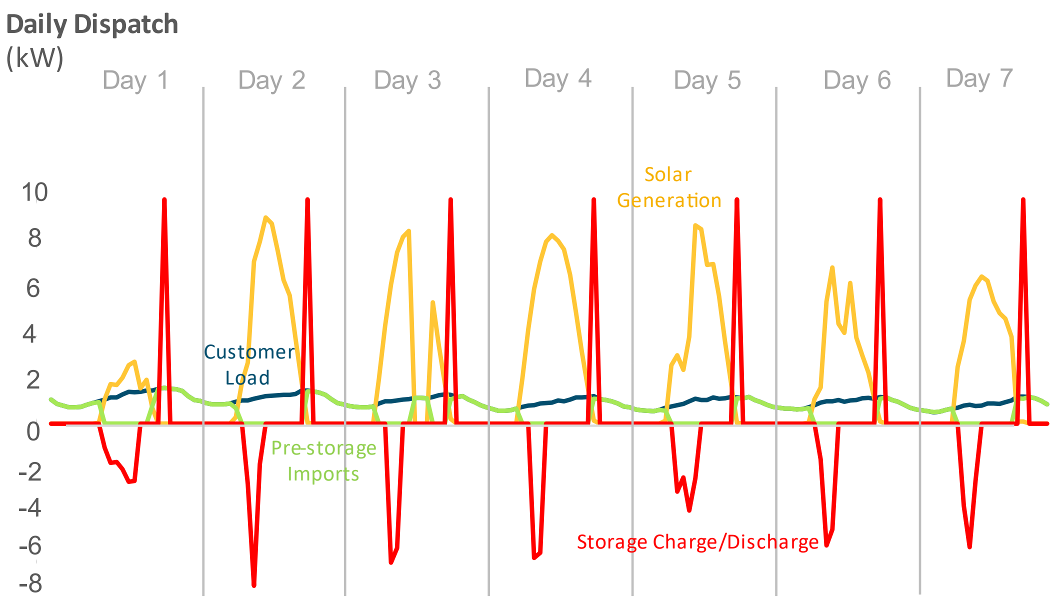


There are no Massachusetts residential TOU rates from Eversource or National Grid and the existing rates do not have demand charges. With this flat rate structure, there is no revenue associated with shifting

[43] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15824178

load from peak hours. Savings from importing less energy are offset by exporting less energy due to round trip efficiency losses. ConnectedSolutions calls create an operational signal for the battery, and the battery operates within the CPS windows, but as shown by Figure 2-22, no other signals drive dispatch. However, revenues from both these programs are compromised by the short battery duration, which is based on typical installs today. We observe a recent trend of increasing durations, which will better take advantage of the 4-hour CPS and 2- to 3-hour ConnectedSolutions dispatch windows. However, increasing duration in this use case to two hours minimally impacts the benefit-cost ratio as marginal benefits are countered by the capital cost increase associated with adding duration.

Figure 2-22. Residential BTM solar-paired storage dispatch (example week in June)



Use Case 6: Utility scale, Mid-duration Standalone FTM System

System Details

Size and Duration: 50 MW, 8hr

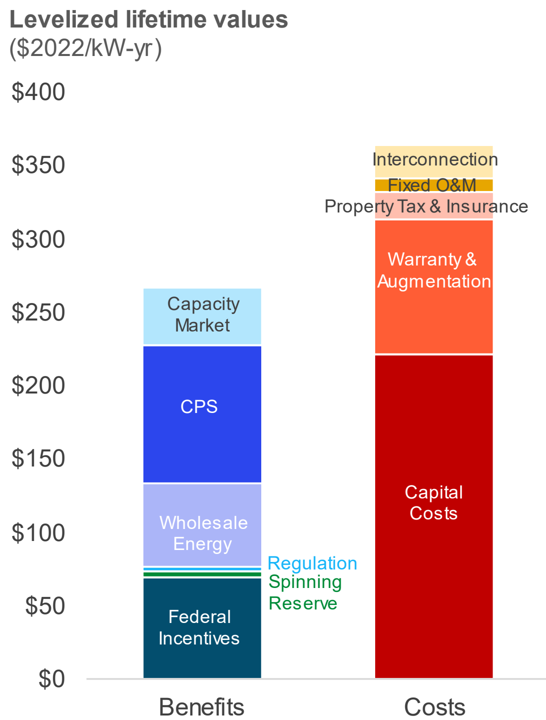
Interconnection Type: Transmission

Pairing: None

Installation Year: 2024

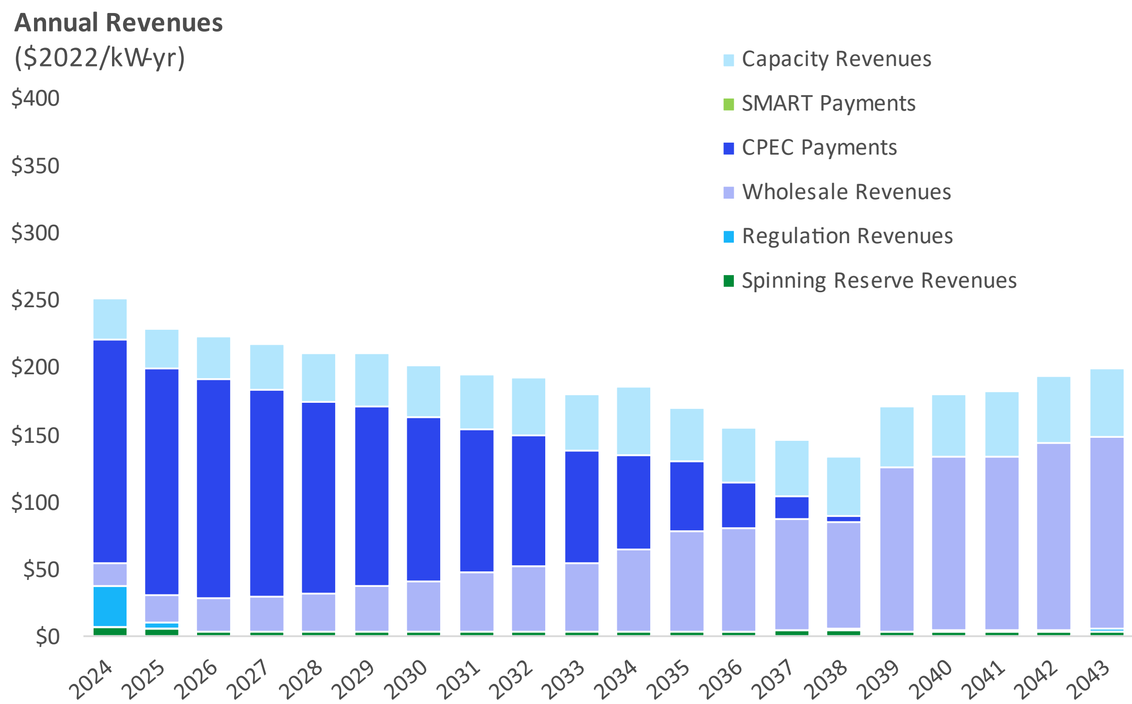
Although longer-duration, grid scale batteries can be used to maintain electric system reliability in a decarbonized grid, very few projects have been planned and built because of the challenging economics. Figure 2-23 shows that mid-duration resources fall short of benefit cost parity. This example has a benefit-cost ratio of 0.73; a similar system installed in 2030 is projected to have a higher benefit-cost ratio of 0.88, driven by higher energy arbitrage revenues as renewable penetration increases. Without additional revenue streams, warranty, augmentation, and capital costs must have a steeper cost reduction curve for these installations to generate profit.

Figure 2-23. Mid-duration, Grid-Scale, FTM Standalone Benefits and Cost Stack – Developer Perspective



The 8-hour transmission connected asset operates very similarly to the 4-hour system shown in Use Case 1 (Figure 2-13). The Clean Peak revenues are identical because the Clean Peak discharge window is 4 hours, so the added duration of this system does not result in any incremental clean peak revenue. Federal incentives increase due to the higher storage capital costs needed for the longer duration resource. Ancillary service revenues are minimal due to market saturation in 2025. And wholesale energy market revenues increase due to prices increasing over time and the longer duration allowing for more hours of arbitrage. However, revenue increases due to longer duration do not scale linearly; the price spread between the highest and lowest hours diminishes outside of the top few hours that are already captured by a 4-hour system, as shown previously in Figure 2-7. Figure 2-24 shows the annual revenues for the 8-hour system, highlighting the minimal differences relative to a 4-hour system when installed in the near-term. In the medium-term, as the renewable penetration increases, there will be a larger number of hours with meaningful price spreads that 8-hour can capitalize on. It will also retain more capacity value as 4-hour storage Effective Load Carrying Capability (ELCCs) begin to saturate at higher deployment levels, so while the value proposition for 8-hour may be small today, it is likely to increase in the 2030s.

Figure 2-24. 8-hour, Grid-Scale, FTM Standalone Annual Revenues – Developer Perspective



2.3.5 Societal Impacts

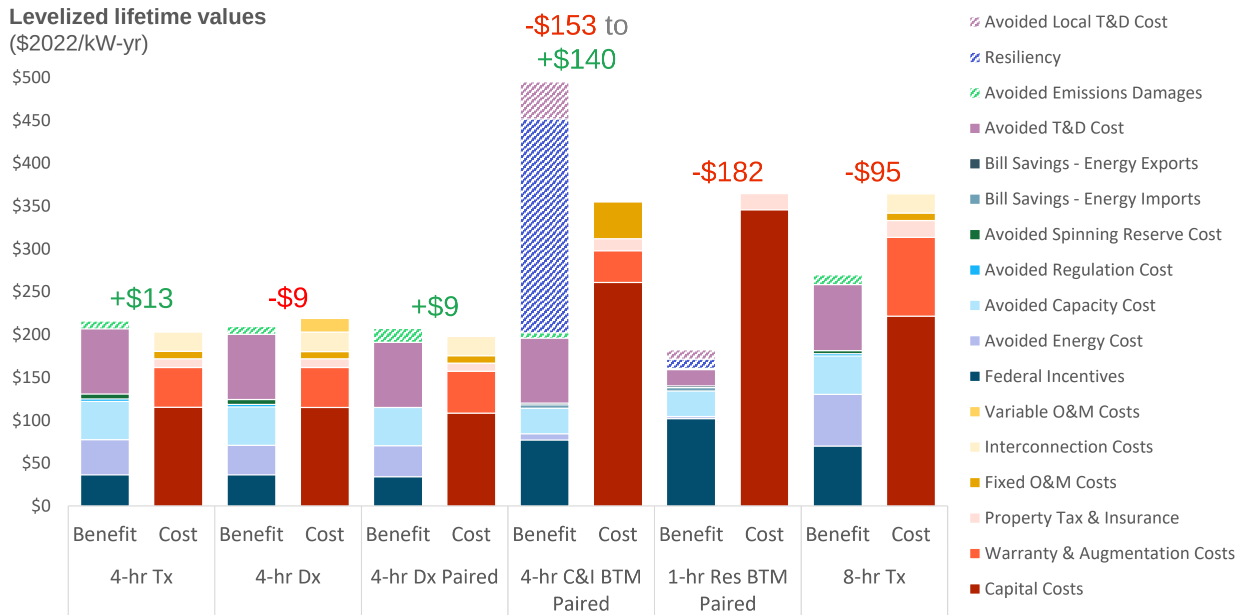
In addition to the developer perspective, our model evaluates the societal benefit and cost streams for each use case presented above, evaluated through a Societal Cost Test (SCT). The SCT seeks to capture the costs/benefits to everyone in MA and includes a range of benefits categories that are both captured in current markets (such as avoided energy, capacity, and T&D costs), and not monetized in current markets (such as avoided emissions beyond those captured in RGGI, and resiliency benefits). The results of the SCT – typically summarized with a single benefit-cost ratio where values greater than 100% indicate positive social benefits – can be a valuable indicator of whether deployment in that category should be a policy priority.

The results of this analysis appear In Figure 2-25. For half these use cases, societal benefits already outweigh the costs. These include FTM transmission connected storage, FTM solar-paired distribution connected storage, and BTM C&I solar-paired storage. Non-paired FTM distribution connected systems, residential systems, and 8-hour systems do not yet see higher social benefits than costs, though for different reasons – distribution connected systems are limited by the tariff structure, while residential and 8-hour transmission connected simply still have high cost hurdles that currently outweigh benefits.

Across all use cases, the most consistent social benefits are avoided T&D and avoided capacity costs. Most front of meter systems also provide meaningful avoided energy costs, given their ability to shift load away from high cost hours and sometimes into renewable overproduction hours. The exception to this is the distribution connected system which does not have enough operational flexibility to provide this value. Resiliency is also a major benefit category for the 4-hour C&I BTM paired system, based on the solar +

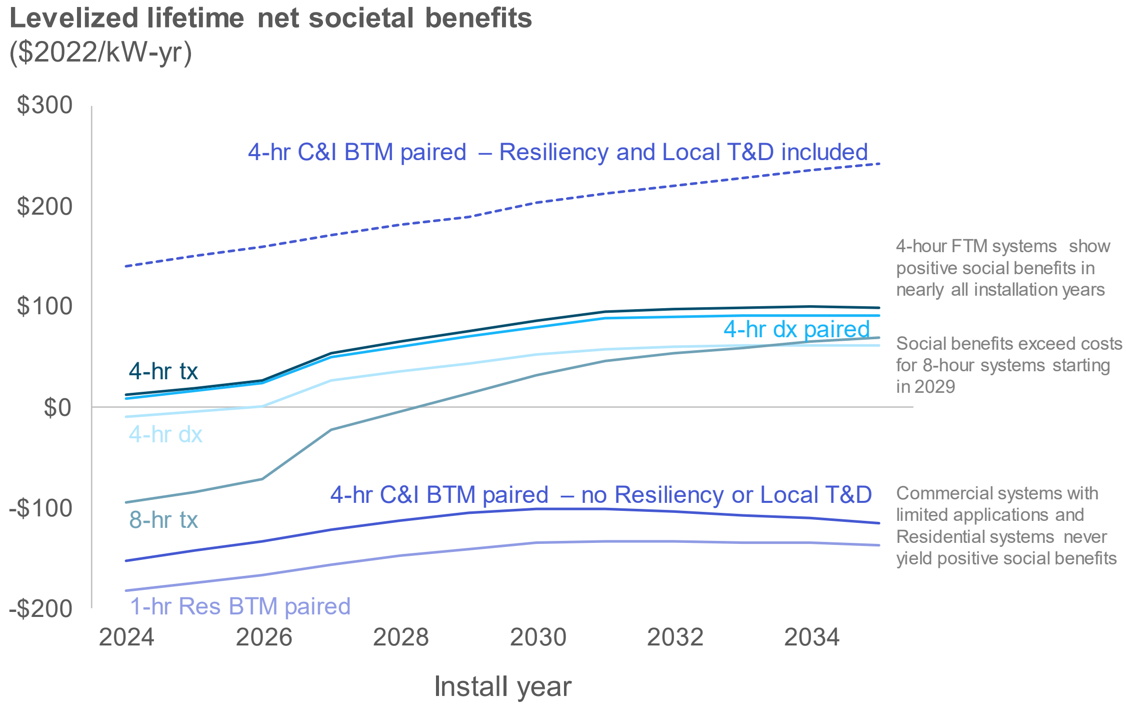
storage paired system's ability to provide onsite power even if disconnected from the grid. Though we do not assume resiliency benefits for FTM systems, specific microgrid applications would also provide resiliency value, as discussed further in Section 3.5.1.

Figure 2-25. Societal Benefit and Cost Stacks for Use Cases – 2024 Installation Year



Societal BCRs across installation years are shown in Figure 2-26. Importantly, as we look forward costs decline and societal benefits grow quite substantially as the grid transitions to a lower carbon, higher renewable mix, such that by 2030, every FTM use case provides significant benefits to society. This shift towards net benefits is most pronounced for the longer duration use case, which takes advantage of additional hours of daily energy arbitrage opportunity as price spreads increase over time.

Figure 2-26. Societal Net Benefits Across Installation Years



The fact that the 1-hour BTM residential use case modeled here does not yield positive social benefits does not necessarily mean it should not be deployed, but this is an indicator that it should not be a policy priority, and that incentive funding might be better directed towards other applications. It is certainly possible that other BTM residential configurations would yield different results (such as one that harnessed more federal funding, or one with longer duration). We see this result that we see for Commercial BTM systems: cost-effectiveness depends strongly on realization of site-specific resiliency and local T&D benefits.

Overall, the current and near-future social cost test results for these short duration use cases indicate that there is a valuable role for storage in the Commonwealth, and market development and deployment are a worthwhile policy goal. With that said, there are many challenges and limitations inherent in attempting to quantify these benefits *in the abstract for an archetypal use case*, rather than for a specifically sited resource. The most significant of these is the value of avoided local T&D, which can vary massively from site to site, rendering a storage system in one site hugely beneficial, while an identical system in another site might be on the margin or negative if either T&D in that site cannot be avoided or there is sufficient local headroom on the existing system and so there is no needed upgrade to avoid in the first place. Our approach was to model that benefit stream conservatively, applying some average site assumptions to quantify that benefit where relevant, but it is critical to make clear the uncertainty there.

As noted previously, resilience is also site specific. Our modeling includes it only for BTM systems assuming onsite power support, but certain FTM systems will also provide resiliency benefits, particularly those supporting microgrids. This is explored further in Section 3.5.1.

2.3.6 Ratepayer Impacts

Our final method for evaluating these use cases involves assessing them from the perspective of other ratepayers, using a cost test methodology known as the Ratepayer Impact Measure (RIM). A positive RIM finding indicates that benefits to ratepayers overall outweigh costs and so socialized rates could go down as a result, while a RIM below 100% indicates costs outweigh benefits so non-participating ratepayers are likely to see higher rates. RIM provides an interesting perspective, because many of the core benefits realized by participants (such as state and utility program incentives, which typically are funded through rates or other on-bill measures) show up as a cost in the RIM test, since those bills are ultimately footed by ratepayers at large.

In our results, we see a common dynamic where use cases that are positive and deployable today from the participant perspective are negative from a RIM perspective. This occurs when an important driver of application economics is the incentive transfer from the broader rate base to the individual developer/adopter. This is particularly apparent for Use Case 3 and Use Case 4, both of which are solar paired and so receive SMART benefits in addition to CPS credits and, for the Use Case 4 which is behind-the-meter, ConnectedSolutions too. Other use cases, such as the three non-paired FTM systems, have strongly positive RIM results, in part because those use cases receive less incentive funding.

On the benefits side, RIM includes some of the same benefits categories as the societal cost test, but it limited to those that have direct rate impacts such as avoided energy, capacity, and T&D costs. RIM test results for our six use cases are summarized in Figure 2-27 for a 2024 installation year, and in Figure 2-28 across several installation years.

Figure 2-27. Ratepayer Benefit and Cost Stacks for Use Cases – 2024 Installation Year

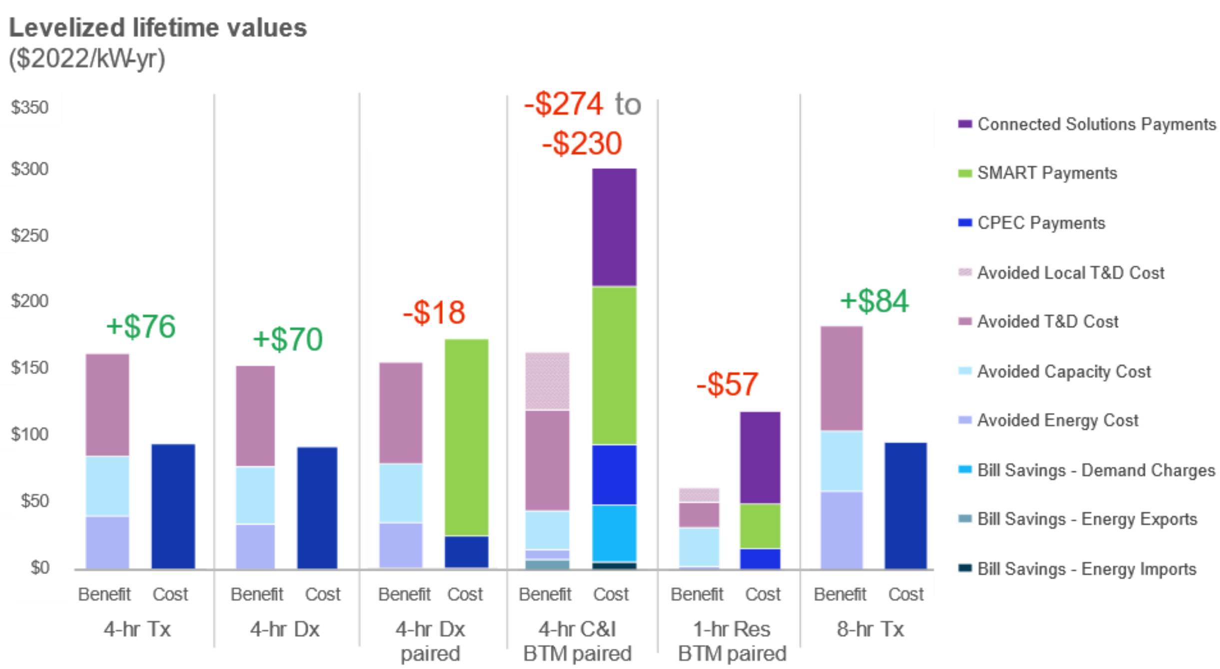
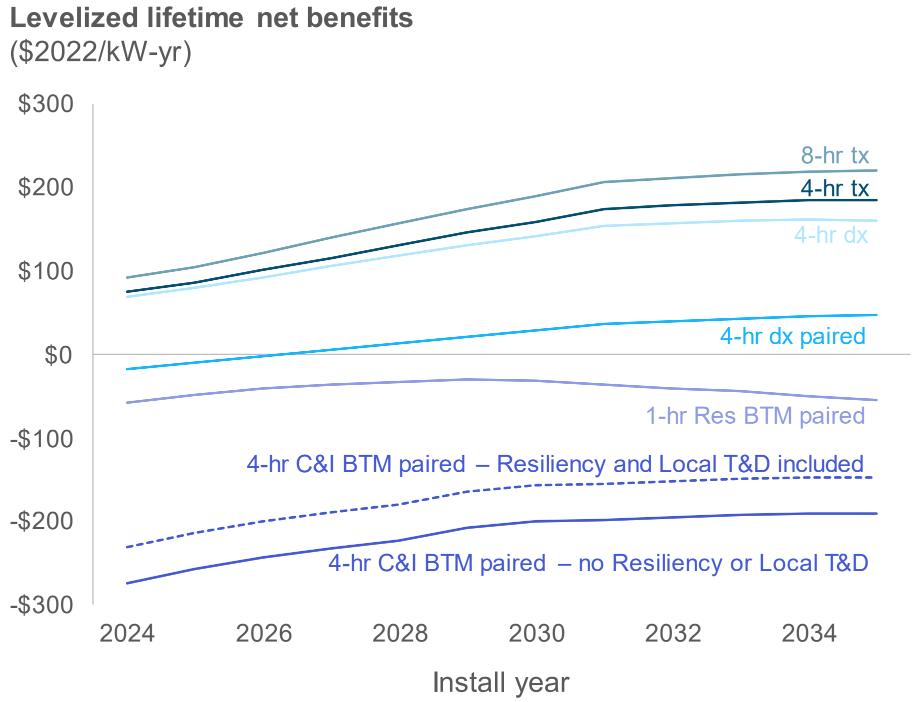


Figure 2-28. Ratepayer Net Benefits Across Installation Years



RIM benefit cost ratios increase when we look at near future installation years. This is driven primarily by the ability for the market to better support storage system economics as the grid decarbonizes and renewables provide a larger share of energy – improved dispatch economics raise the value of storage to all ratepayers. As currently structured, CPS program revenues for participants are designed to decline over time, yielding small ratepayer costs by 2030 and beyond. These together result in beneficial RIM results for FTM storage for installations between now and 2035. BTM systems take advantage of rate structures and state incentives with less certain declines and do not show benefits to ratepayers, though any changes to programs and/or rates would warrant reexamination of this conclusion.

Similar to the social cost test, some of these benefits categories are difficult to quantify in the abstract rather than for a specifically sited resource. RIM results for avoided local T&D in particular could shift across specific applications, which could make or break the benefits calculations for a given site. Overall, these ratepayer impact results capture some of the tradeoffs inherent to market development for nascent technologies but indicate significant ratepayer value from galvanizing that market here in Massachusetts.

Section 3: Mid- and Long-Duration Storage Technology and Cost Outlook

Short duration storage provides grid support and bill management for customers by shaving peak demand. However, as the grid transitions to predominately renewable generation, short-duration resources will be insufficient to support the full needs of a highly weather-dependent grid during occasional but expected multi-day periods with low output from solar and wind resources, particularly in the winter during times of high demand. To support these conditions, a range of emerging technologies offer solutions more innate to storing large amounts of energy required to meet the several-hour to multi-day needs of the future.

This section starts by describing the electric grid value streams that longer-duration storage will be better equipped to serve. Then we describe several candidate technologies for providing mid- and long-duration storage and comment on their development progress and challenges and possible cost trajectories. We also discuss the role of innovation in supporting commercialization and scaling of longer duration technologies, and the gap in market structures and compensation to promote deployment of LDES.

This report does not rank LDES technologies or allocate future storage needs to specific ones. High uncertainty in the future of these technologies makes that sort of judgement impossible, and maintaining a diversity of options provides hedging and competition. Ultimately, any technology that can cost-competitively provide the services to the grid identified in this report will be an important asset in the Commonwealth's future storage portfolio.

3.1 Potential Electric Grid Value from Mid- and Long-Duration Storage

Energy storage can provide many applications to the electric grid, particularly in 2030 and beyond as the state achieves higher levels of decarbonization and retires existing fossil fuels. The electric system requires a range of energy services, which will evolve and, in some cases, only become valuable as the grid decarbonizes. Table 3-1 highlights key services that the electricity system needs today and will continue to need as it decarbonizes.

Table 3-1. Key Electric System Services

Value Stream	New England Grid Need: Today	New England Grid Need: 2050	Minimum Duration Required	Factors
Energy arbitrage	Low	Very High	Short	Low RTE and cost critical to competing in energy markets, assume renewable integration value reflected in energy markets
Capacity	Low	Very High	Grows over time	Electrification loads will drive need for new firm capacity
Ancillary services	High	Low	Short	Storage growth expected to saturate AS needs, particularly regulation, by late 2020s
Transmission deferral	Site-specific	Site-specific	Site-specific	Very site-specific and potentially complex with variable duration requirements
Avoided emissions	Low	Very High	Short	Greater emissions reductions as renewables deployed on grid and serve as source of charging
Local capacity	Moderate	Moderate	Grows over time	Could support constrained urban areas serving new load or avoid expensive upgrades
Distribution deferral	Site-specific	Site-specific	Site-specific	Site-specific but potentially larger opportunity given load growth / constraints at the distribution level
DER interconnection	Low	Moderate	Short	Could grow as DER penetration grows and there are more distribution constraints
Resiliency	Site-specific	Site-specific	Site-specific	Customer value in specific locations with frequent outages & high value of lost load

Different storage technologies have technological, operational, and physical characteristics that will influence their ability to support different use case/storage applications. Arguably the most valuable service that longer duration can provide to the electric grid is resource adqucy, or "capacity value". Resource adequacy is the ability of the electric grid to maintain sufficient generation to meet demand reliably. As introduced in Section 4.1, in all electricity systems, there are expected to be infrequent multi-day periods of low output from weather-dependent wind and solar resources. In grids with only renewables and short-duration storage, this leads to low electricity output, and requires either "overbuilding" of renewable resources and short duration storage; large amounts of new transmission and firm imports; or some form of non-weather dependent generation to provide remaining electric demand needs. While today in Massachusetts, natural gas typically fills this need, in the future, this need could be filled by non-emitting clean, dispatchable generation or long-duration energy storage.

In addition to the value of standalone storage in providing capacity contributions to the electric grid, storage combined with renewable generation may provide even greater capacity value to the grid. This is a result of the complementary features of the two resources, which can provide a contribution to resource adequacy that exceeds the sum of the individual contributions of each resource. In particular, it is expected that storage coupled with offshore wind (OSW) will provide contributions to resource adequacy that are greater than the contributions of each resource Independently. This effect is described in more detail in Section 4:, which also presents those modeling results.

3.2 Candidate Technologies Overview

Candidate technologies for long duration storage can be split into three main categories based on their underlying principles: mechanical storage, thermal storage, and chemical/electrochemical storage. Mechanical methods store energy as gravitational potential energy or confined kinetic energy. Thermal methods store energy as heat. Chemical/electrochemical methods store energy in chemical bonds.

Appendix D describes leading LDES technologies within each of these categories. Summary data on the technologies appears in Table 3-2. The table shows that no candidate technology is a clear winner: Technologies with high roundtrip efficiencies (RTEs) tend to have low durations and/or difficult to fulfill siting requirements. Many technologies remain unproven at scale, and many rely on approaches deemed experimental. Costs (not shown in the table) have little certainty. Results from initial pilot deployments will be critical to improve these estimates.

Specific mid- and long-duration storage technologies have a range of project development considerations, many of which are technology-specific. For example, the development of new pumped hydro storage or Compressed Air Energy Storage is unlikely in Massachusetts due to geological and geographical constraints, as well as ecological concerns for pumped hydro.

Though not considered explicitly in this report, the role of hydrogen vis-à-vis long duration energy storage is worth noting here alongside these technologies. Excess energy generated by renewables can be used to produce hydrogen instead of to charge one of the storage systems described. Hydrogen is versatile and can be used in industry, burned for electricity, burned for heating, or used for transportation. Hydrogen produced via electrolysis can be considered a form of long-duration energy storage for the electric grid since production, storage and consumption can happen in separate systems of independent location and size. Using hydrogen for storage, however, suffers from low round trip efficiency and high costs.

Given the broad set of potential hydrogen use cases, the nature of storing energy as a fuel, and the possibility of using hydrogen as a drop-in fuel for existing combustion generators, we regard hydrogen as unique and do not include it as a LDES option in this report. However, given that hydrogen can perform similar to long-duration energy storage, it is another viable tool for providing firm capacity in a decarbonized future. Both hydrogen and LDES are unproven at commercial scale and competitive costs, and realization of either will require investment and demonstration today to reach appropriate scale by 2050. For this reason, pursuing parallel progress in LDES and hydrogen serves as a method of hedging against uncertainty in nascent technologies that are likely candidates to provide clean reliability by mid-century.

Table 3-2. Long-Duration Energy Storage Technologies

	Technology	Technology Readiness	Market Readiness	Land Use / Footprint	Siting Considerations	Max. Duration (hrs)	Avg. Roundtrip Efficiency (%)	Max. Deployment (MW)	Lifetime (yrs)
Mechanical	Pumped Hydro	Mature	Commercial	High	Geologic formations, potential water well	0-15	70-85%	10-100	30-60
	Gravity-based energy storage	Experimental	Pilot	Medium	N/A	0-15	70-90%	20-1,000	30-50
	Compressed Air Energy Storage (CAES)	Mature	Pilot	High	Geologic formations, underground caverns	6-24	40-70%	200-500	30-50
	Liquid Air Energy Storage	Emerging	Pilot	Low	N/A	10-25	40-70%	50-100	30-50
Thermal	Sensible Heat	Mature	Commercial	Low	Access to water	10-200	40-60%	10-100	30-50
	Latent Heat	Experimental	Pilot	Low	Access to water	25-100	40-50%	10-100	20-40
	Thermochemical Heat	Experimental	R&D	Medium	Access to water	N/A	N/A	N/A	TBD
Chemical / Electrochemical	Aqueous Flow Battery	Emerging	Pilot	Medium	N/A	25-100	50-80%	10-100	5-20
	Hybrid Flow Battery	Emerging	Pilot	Medium	N/A	25-50	55-75%	100-200	5-20
	Metal Anode Battery	Experimental	Pilot	Medium	N/A	50-200	40-55%	10-100	15-30

3.3 Mid- and Long-Duration Storage Costs

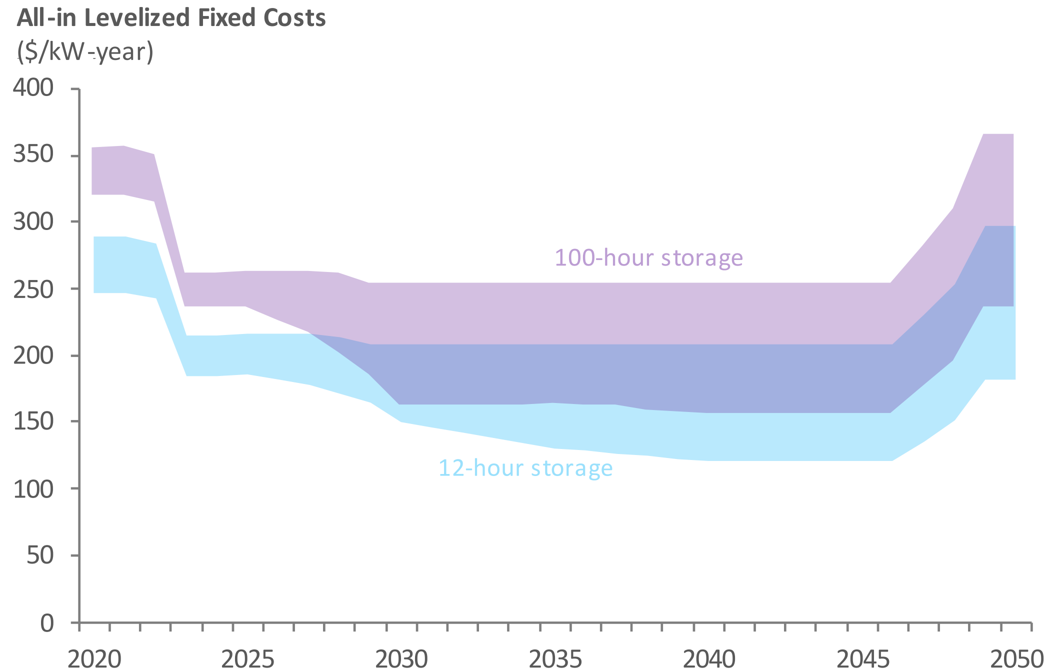
Cost forecasts for mid and long duration technologies were derived from data gathered by the Long Duration Energy Storage Council in their November 2022 report[44] on Long Duration Energy Storage technology evolution. These data were sourced from a variety of developers and represent the range of technologies that are expected to be competitive at each duration. Levelized cost forecasts for these technologies were developed using a similar methodology as for short duration resources: Key inputs such as capital costs, operating and maintenance costs, financing costs, and performance characteristics for these technologies were input into E3's Pro Forma project cash flow model, and the Pro Forma output levelized cost projections. We describe this process in more detail in Section 2.3.3. The impact of the IRA on costs is the same as described in the context of short duration costs in Section 2.2.6.

Critically, many of these technologies have lower round-trip efficiencies than lithium ion batteries, which is one of the reasons they are typically less competitive at shorter durations. However they are very good at storing large amounts of energy with minimal incremental costs, which will likely enable them to outcompete lithium ion for longer duration applications.

Figure 3-1 shows the cost expectations for 12-hour and 100-hour storage resources. The impact of the IRA is evident from the large price drop in 2023 and increase after 2045. In comparing these two ranges, or in comparing these ranges with those shown in Figure 2-10 for shorter duration Li-ion, it is important to recognize the different energies of the different duration resources. 1 MW of 100-hour storage in 2020 costs about 1.3 times an equivalent *capacity* (1 MW) of 12-hour storage but provides more than 8 times the *energy* (100 MWh vs 12 MWh). Another important distinction between these costs and the costs for shorter duration energy storage is the more speculative nature of long-duration costs given the early commercial nature of these technologies. This is in comparison to SDES costs, which are informed by market installation data.

[44] This report, titled NET-ZERO HEAT: LONG DURATION ENERGY STORAGE TO ACCELERATE ENERGY SYSTEM DECARBONIZATION, is accessible at https://www.ldescouncil.com/insights/

Figure 3-1. Mid- and Long-Duration Storage Cost Forecast



3.4 Markets for Monetizing Storage Value

Today, contributions to wholesale electric reliability in New England are compensated through the forward capacity market. However, in the future, emerging changes to the structure of capacity markets and the capacity provided by various resources will affect the value and compensation of energy storage in this market. Given the importance of the capacity contributions of longer-duration storage, the value of these contributions is assessed dedicatedly in Section 4:. This section includes analysis of the value of energy storage in the event of transmission outage that severs the connection between load and generation pockets.

Another key application for MDES/LDES, as well as shorter duration storage, is its abilty to integrate large quantities of intermittent renewable generation, particularly offshore wind. Fast-responding forms of energy storage can smooth the output of this resource, minimize curtailment, and ensure that clean generation is shifted to periods of peak energy demands. This energy-shifting value is likely to be particularly important in Massachusetts as the state pursues 5.6 GW of offshore wind by 2027, and significantly higher amounts by mid-century.

A third potential application for storage of a range of durations, but particularly MDES, is in potentially reducing the state's reliance on "peaker" plants. Peaker plants operate infrequently but provide critical support during hours with the highest customer demand, often at the cost of high amounts of greenhouse gas emissions. In addition to the greenhouse gas benefits, the ability of storage to displace peaker plant generation will create equally and sometimes more valuable local air quality benefits, associated with reductions in particulate matter and its precursors.

3.4.1 Market Structures Required to Support Mid- and Long-Duration Storage

Today's wholesale markets compensate resources for the key electricity grid needs – energy, capacity, and a range of ancillary services. These market values are supplemented by state programs that aim to provide revenues for services not captured by the markets. As shown in Figure 2-13 and Figure 2-24, the values associated with markets and programs will change over time with the changing needs of the grid. Specifically, ancillary services will cease to provide revenue, Clean Peak revenues will decrease and vanish, and energy price differentials will be better taken advantage of by shorter duration batteries with high round trip efficiencies.

The most significant remaining value stream for standalone storage will be the FCM. However, the size of revenues from this market remain uncertain. Auction prices for the last four years have been at or below $2.61/kW-month, a level far below what would be needed as the primary revenue stream for an emerging technology. Additionally, accreditation for resources in the FCA is slated to change as ISO NE considers incorporating ELCCs into the process instead of the current heuristic method. A possible added value stream would be the proposed Forward Clean Energy Market, which aims to reflect clean energy policy goals through a market mechanism, but the final implementation of this market is far from settled.[45]

Without certainty in revenue streams, developers are unable to secure financing to build mid- and long-duration projects. While the specific need for long-duration storage deployed at scale in the Commonwealth may be 10 to 20 years away, action is required in the near term to prepare for this need. The near term provides a runway during which the industry can refine designs, grow experience building and operating facilities, streamline permitting and interconnection processes, narrow in on the most favorable technologies, and begin to realize economies of scale. These steps are essential to ensure successful deployment by the time these resources are needed. This need for near term advancement coupled with a lack of certain revenue streams highlights a gap for incentivization of mid- and long-duration systems.

3.4.2 Innovation Gap and the Role of the Commonwealth

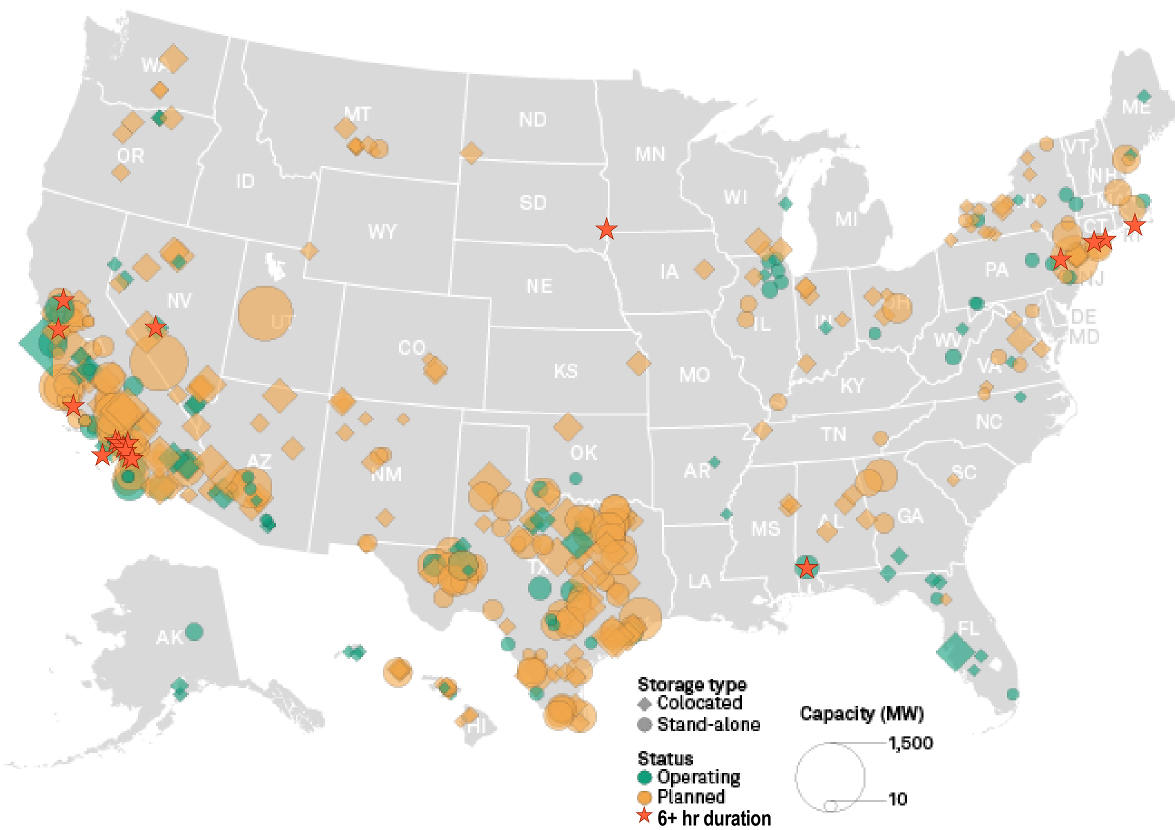
Pumped hydro aside, mid- and long-duration storage technologies have not reached commercial scale and widespread deployment. Even at the pilot project level, few installations exist nationally as shown by Figure 3-2, which shows installed energy storage projects with duration greater than or equal to six hours as red stars over the background of shorter duration utility-scale projects. Though longer duration pilots are planned, only the McIntosh CAES plant has a duration longer than 10 hours, and the starred projects total a mere 270 MW of installed capacity, 220 MW of which comes from two projects. The projects also represent a fairly thin technological slice: aside from one CAES project and one molten salt project, only Li-ion and Sodium-air appear in the list.

Like short-duration energy storage installations, this mid-duration capacity is mostly located in California and New York, where favorable decarbonization policy, pathways to monetization, and high renewable penetration (in the case of California) provide support for storage innovation. Texas, the other leading

[45] https://www.mass.gov/doc/ma-doer-fcem-design-proposal/download

region for SDES capacity, lacks the policy levers of the New York and California, but has high renewable penetration and a need for capacity-providing resources. As attention turns to longer duration deployment, these regions are expected to continue their leadership. With aggressive decarbonization targets, opportunity for synergy with offshore wind, and technology innovation occurring in-state, Massachusetts may join this short list with the right supportive program design.

Figure 3-2. Utility-Scale Energy Storage Projects[46]



Given the large anticipated off-shore wind buildout, and the diversity benefits of long-duration storage on a highly renewable grid, the investment in long-duration energy storage at reasonable cost is a no-regrets action for the Commonwealth. With the ACES program, the state found that MLPs' ability to act nimbly makes them apt spaces for innovation, however mid- and long-duration value streams are more likely to materialize at the bulk grid scale. The state could work on solutions, such as access to additional grid services and revenue streams, that would make MLP ownership of LDES viable and take advantage of their ability to move quickly. However, larger-than-pilot sized LDES deployments will still be most likely deployed on the larger EDC grids.

[46] Base layer from S&P Global Market Intelligence; longer duration projects layered on top. Map credit: Joe Felizadio. Data complied August 2022. Excludes pumped hydro, projects <10 MW, and projects with incomplete data (no in-service year or geographic coordinates)

3.5 Mid- and Long-duration Storage Applications for End Users

The most apparent use case for LDES is providing reliability in a highly decarbonized grid. Accordingly, Section 4: is dedicated to exploring the reliability challenges of New England's future grid and how energy storage of different durations can contribute firm capacity. However, use cases also exist for LDES installed and operating closer to customer load. In this section, we describe possible use cases for LDES operating at the distribution scale. Due to the speculative nature of these benefits, most are discussed only qualitatively, but quantification is included where appropriate.

3.5.1 Critical Facility or Microgrid Backup

As described in Section 2.3.2, energy storage deployed behind-the-meter can provide valuable resiliency benefits. Since these benefits are proportional to the VOLL of the site, a potentially high value use case for MDES or LDES could be deployment to provide backup power at critical facilities. The worth of this use case depends on three key factors: site VOLL, frequency/duration of loss-of-load events, and availability of alternative solutions.

Only if site VOLL times expected outage hours per year exceeds the all-in levelized cost of storage might the use case warrant consideration. The statewide average SAIDI (including major event days) of 376 between 2020 and 2021 implies about 6 hours of lost load per year.[47] So a facility with VOLL of $15 per kWh – a typical rate for large commercial sites over long durations – could see a $90 per kW-year resiliency benefit.[48] This would not be enough to recover the anticipated per-kW costs of MDES and LDES from Figure 3-1; around $200/kW and $250/kW. We note that both VOLL and frequency of outage vary over substantial ranges for specific sites, so it is not unreasonable to imagine a site with VOLL above the break-even price of $35 to $40 per kWh at which cost recovery may become possible. For example, an NREL study of critical facilities in New York estimated VOLL for a school used as a storm shelter, a senior center used as a cooling center, and a rural fire station at $110/kWh, $64/kWh, and $157/kWh respectively.[49] Actual value is highly site-dependent; proper assessment would require detailed data on critical site loads, outage likelihood, and availability of physical space for siting.

If a project were able to serve many customers in a high SAIDI location, outage frequency may grow enough to justify the cost even without high-end VOLL values. We demonstrate this microgrid backup possibility with Figure 3-3, which provides the average number of outage events per year for each circuit that experienced an outage from 2019 to 2022.[50] Different color bars represent different outage durations, and indicate that, at the circuit level of aggregation, there are many circuits for which SDES can provide appropriate backup coverage. Indeed, as we saw in Section 2.3.4, resiliency can be a large part of a

[47] Data from U.S. Energy Information Administration, https://www.eia.gov/electricity/annual/, Table 11.2

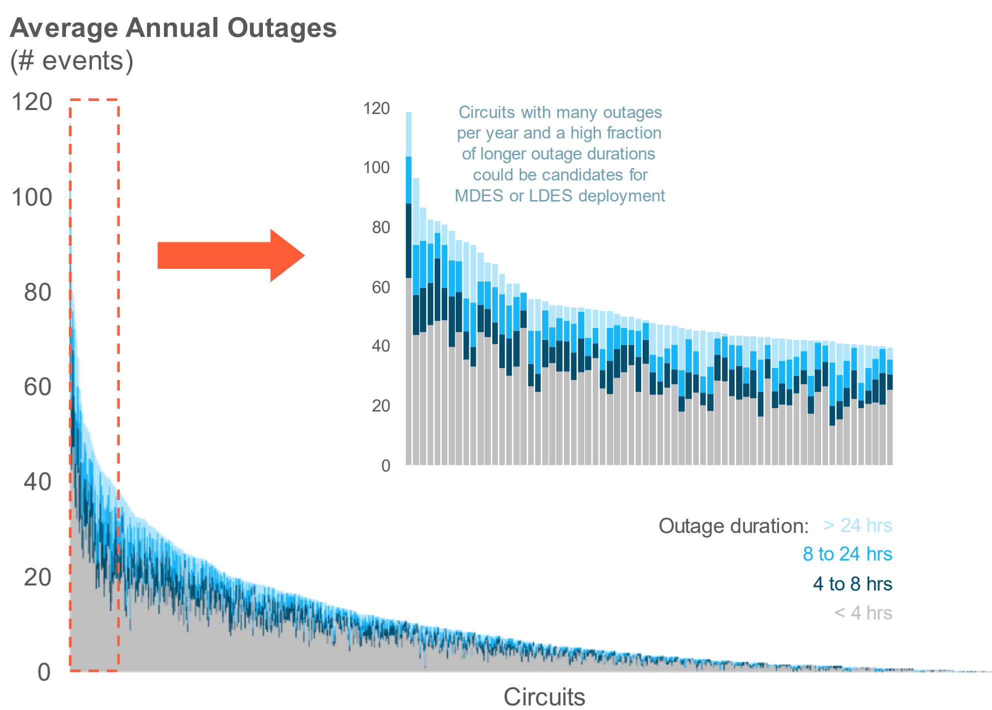
[48] Sullivan, M.J. Schellenberg, J., Blundell, M., Nexant, inc. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Berkeley: LBNL, 2015. LBNL-6941E. https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf

[49] Anderson, K., et al., *New York Solar Smart DG Hub-Resilient Solar Project: Economic and Resiliency Impact of PV and Storage on New York Critical Infrastructure,* Technical Report, NREL/TP-7A40-66617, 2016. https://www.nrel.gov/docs/fy16osti/66617.pdf. Values from Appendix B converted to 2023 dollar year from 2016.

[50] Data from Emergency Resource Plan Dockets as described in https://www.mass.gov/info-details/power-outages

battery's value for even a single customer. The incremental benefit of longer durations is limited, but substantial enough in some places to warrant further consideration. The important consideration becomes the fraction of customers on a given circuit that remain connected to a single MDES or LDES device during an outage event. In some configurations, that fraction could be large, but those are unlikely to be the areas with high outage frequency. Ultimately, answering this question would require a detailed representation of the distribution grid for each potential locale, which is beyond the scope of this discussion.

Figure 3-3. Eversource and National Grid Historical Outages (2019-2022) by Circuit



In spite of this possible sweet spot for MDES and LDES, we must bear in mind that other solutions may also be able to fill this need. Most importantly, energy storage would need to displace fuel-based backup generation, the current choice technology for backup power. Without policy to push building owners away from GHG-emitting backup generation, they are unlikely to stray from a cheaper incumbent technology. Even with GHG requirements on backup generation, building owners may opt for renewable drop-in fuels over energy storage because of the high energy density of liquid fuel and low annual backup energy requirement, which would limit operating cost despite the switch to more expensive fuel. Also, thermal LDES technologies tend to lose efficiency at small scales, making the technology solution space smaller for distribution-scale applications.

3.5.2 Backup Power for Disadvantaged Communities

A related use case is to enhance community resiliency through pairing of MDES or LDES with Fault Location, Isolation, and Service Restoration (FLISR). FLISR is a grid modernization application that automatically detects faults and reconfigures the grid around them to minimize their impact. LDES could be deployed alongside and dispatched by FLISR to potentially eliminate outage impacts for targeted areas.

The value of long duration over short duration for such a use case depends on typical outage length. Longer durations may see an advantage in recovery from major storm events, such as a hurricane or other superstorms. Such events have been historically rare, but we recognize the increase in frequency of superstorm events due to the changing climate. Disadvantaged communities tend to be most impacted by superstorms because of higher rates of below-code infrastructure and the challenges of egress from and aid delivery to high-density urban areas.[51] Targeting deployment of LDES incorporated into FLISR for disadvantaged communities could improve resiliency for a critical subset of the population.

The specific value of such a system would need to be calculated on a case-by-case basis. At a high level, the value of lost load in primarily residential areas will be low, but targeting disadvantaged communities and recognizing the potential for loss of life resulting from superstorm events could make this use case worthwhile. Though the primary cause of death during superstorm events tends to be drowning from storm surge and not attributable to loss of power.[52] The need for physical space to deploy an LDES project complicates this idea further, especially given the high premium on space in many disadvantaged communities.

3.5.3 Electric Vehicle Fleet Charging

A final potential application mentioned by stakeholders is the possibility of using MDES or LDES at an EV fleet charging depot to avoid vehicle charging during expensive periods. This concept is a form of rate arbitrage: the MDES or LDES device would charge during the lowest-cost times of the day and would discharge to charge EV batteries during high-cost hours, thus avoiding using the grid during these high-cost times.

A few considerations temper our excitement for this use case. The first and most important is that fleet owners are already utilizing (or planning to utilize) vehicle grid integration to take advantage of the batteries within their EV fleets. In its most basic form, this involves managing charging patterns to avoid high electricity use during peak hours. More ambitious plans may also leverage vehicle-to-grid technology to operate EV batteries as stationary storage when EVs are idle. These abilities come at little to no cost after the initial vehicle purchase, so little-to-no value would remain to make investment in additional standalone storage worthwhile.

It is possible that specific circumstances could warrant installation of MDES or LDES, for example if fleet driving patterns obviate an ability to avoid charging during high-cost hours. However, economics of such exceptions would require analysis tailored to specific charging rates and driving patterns. However, the

[51] Burger J, Gochfeld M, Lacy C. Concerns and future preparedness plans of a vulnerable population in New Jersey following Hurricane Sandy. Disasters. 2019 Jul;43(3):658-685. doi: 10.1111/disa.12350. Epub 2019 Apr 16. PMID: 30990925; PMCID: PMC9647963.

[52] https://www.cdc.gov/mmwr/preview/mmwrhtml/mm6220a1.htm

incremental benefit of longer duration for these use cases will be unlikely to justify the incremental cost since the primary use case is rate arbitrage, for which short duration storage tends to be sufficient.

Section 4: The Role of Storage in Supporting Electric Grid Resource Adequacy in Massachusetts

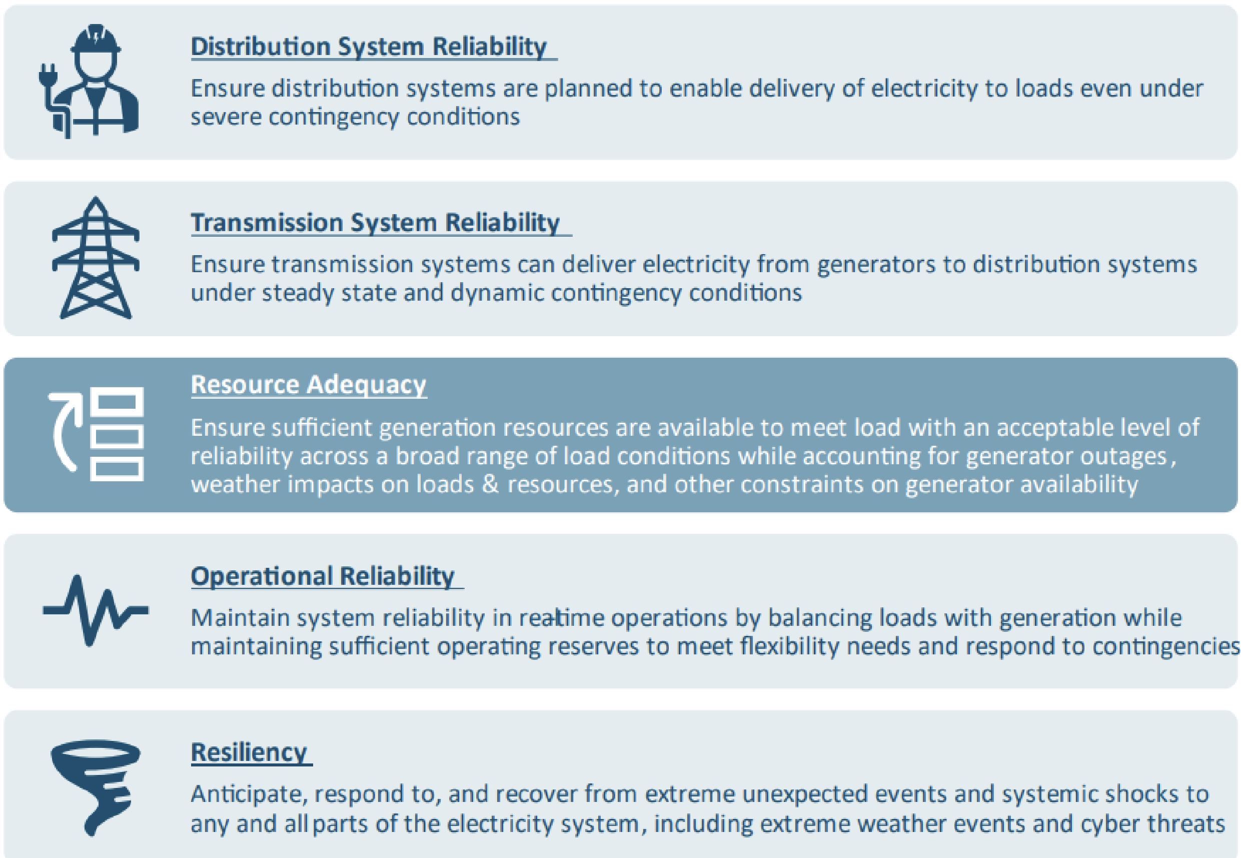
Maintaining electric reliability is essential to the health, safety and security of the Commonwealth, and energy storage can play a valuable role in supporting state and regional reliability as the region pursues deep decarbonization. This section of the report focuses on the potential for energy storage resources to support **resource adequacy**, defined as ensuring that the New England electric grid has sufficient supply to meet demand across a range of weather and operating conditions, subject to a reliability standard. Because the grid is planned and operated at the New England-wide level, this section models and evaluates storage on the New England grid, while discussing implications specific to Massachusetts.

4.1 Context: Electric System Reliability and the Potential Role of Storage

4.1.1 Defining Reliability and Resource Adequacy

Maintaining reliable electric service, from the point of generation to ultimate consumption, involves planning efforts across generation, transmission, and distribution systems. While events like the Northeast blackout of August 2003 represent widespread reliability events, there are many localized events, like those caused by storms or even squirrels knocking down power lines. The major elements of reliability planning are outlined in Figure 4-1.

Figure 4-1. Major Elements of Reliability Planning



Storage can support multiple aspects of electric grid reliability. This section focuses on potential resource adequacy contributions, as defined above and in Figure 4-1, given the study focus on storage.[53,54] Many factors affect resource adequacy, including the characteristics of load (magnitude, seasonal patterns, weather sensitivity, hourly patterns) and resources (size, dispatchability, forced outage rates, and other limitations on availability).

In the analysis that follows, E3 assesses the relative reliability risks of the system over time and estimates the effective capacity contributions of storage to the New England grid. By convention, for the resource adequacy modeling, we apply a reliability standard of 1-day-in-10 years, consistent with how ISO-NE plans its system, determines capacity requirements, and procures resources in the Forward Capacity Market. This standard requires that there be sufficient generation and transmission resources to serve load during all but one day every ten years.

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[53] This is also consistent with the North American Electric Reliability Council (NERC) definition of Resource Adequacy: "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.", https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf .

[54] We note that 3.5 discusses potential distribution system reliability events.

4.1.2 Measuring Resource Adequacy Contributions of Storage using Effective Load Carrying Capacity

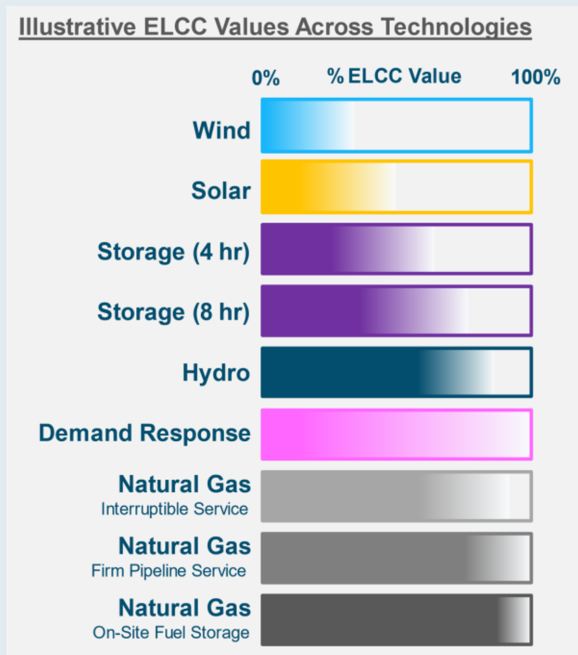
As the electric grid integrates higher amounts of renewable energy and storage, assessing resource adequacy becomes increasingly complex. While historically, simple heuristics have been used to assign capacity credits for resources that are intermittent or energy-limited, these simplifications are increasingly inappropriate as higher penetrations of these resources change the reliability dynamics, including the shifting of peak hours and the shape of peaks, as described below.

To provide a consistent measure for the ability of resources to support the system during periods most at risk of loss of load, we rely on effective load carrying capability, or "ELCC". The ELCC is a measure used to express the capacity contribution of any electric resource in terms of its equivalent "perfect capacity". This measure is the preferred approach across North America today, increasingly utilized by utilities and RTOs to accredit resources toward the system's resource adequacy needs. Conceptually, the idea is that if a 100 MW resource has an ELCC of 50 MW, that means that that this resource could displace the need for 50 MW of perfect capacity with no impact on system reliability. The ELCC can also be expressed in percentage terms by dividing MW value by the nameplate capacity (i.e., 50% in this example).

The ELCC calculation is performed within a loss-of-load probability model, which simulates the system thousands of times under different load and resource conditions. The model is described in more detail in Section 4.2, and additional information about the ELCC calculation process can be found in the appendix.

ELCC for Measuring Effective Capacity

Effective load carrying capability measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraint.



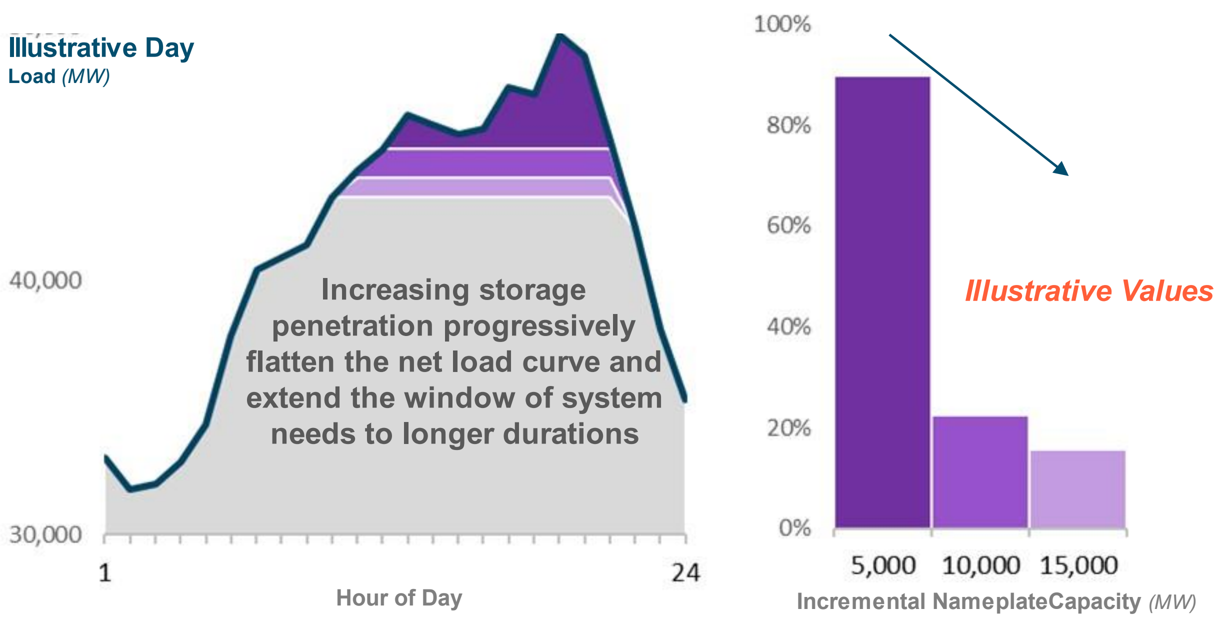
This study focuses on the role of storage in supporting electric resource adequacy in New England, but throughout, we emphasize that its ability to contribute to the region's capacity needs will depend on the rest of the resource portfolio. For example, at its most extreme, we know that if the system were entirely storage-based, there would be no energy to charge storage resources. Similarly, a system with only solar resources would not be able to operate reliably given the lack of generation at night. Yet together, these resources will be able to support the system over a broader range of resources and load conditions.

A key dynamic captured by effective capacity is the diminishing marginal returns of a specific resource with increasing scale. With energy-limited resources like storage, in particular, the duration of the storage resource will limit its ability to meet demand over extended periods. The implications of this are two-fold:

(1) the marginal ELCC of storage with a given duration will decline as more of it is added to the system; and (2) storage will need increasingly longer duration to sustain high capacity value (on a percentage basis).

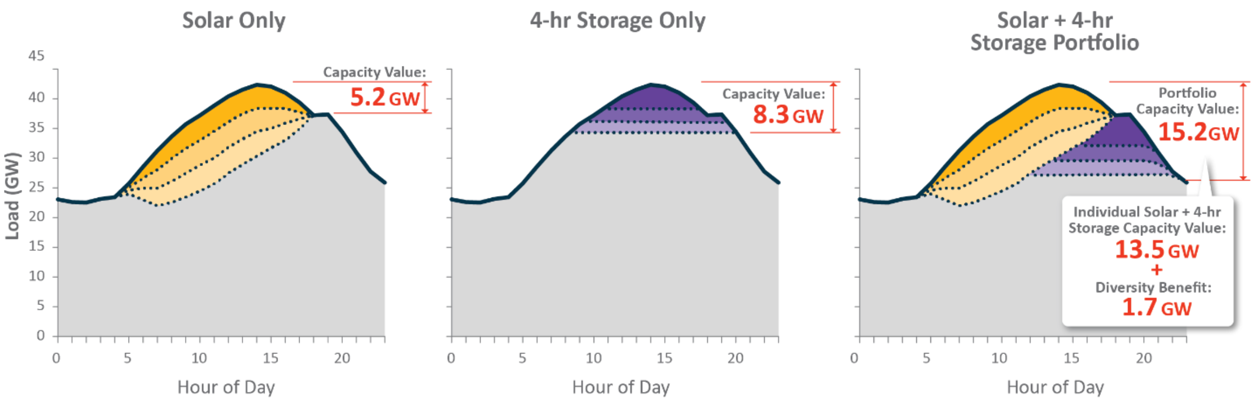
These features of ELCC are illustrated in Figure 4-2. This shows how for a given day, the first tranche of storage added (in this case 5 GW) can fully reduce the peak load an equal amount, when discharging at full capacity. However, the remaining "net peak" (in grey) gets increasingly longer and flatter. Thus, the next tranche of storage added must discharge at much less than full capacity (in this case 8-hours) in order to cover the entire period and reduce system peak. Thus, to reduce the net peak for the next 5 GW, the system either needs a longer duration storage operating at max output over the longer period, *or* more capacity of shorter duration storage operating (on average) at much less than their maximum capacity output in order to cover the entire period, at the expense of derated peak-shaving capability.

Figure 4-2. Illustration of Declining ELCC for 8-hour Energy Storage as Function of Penetration



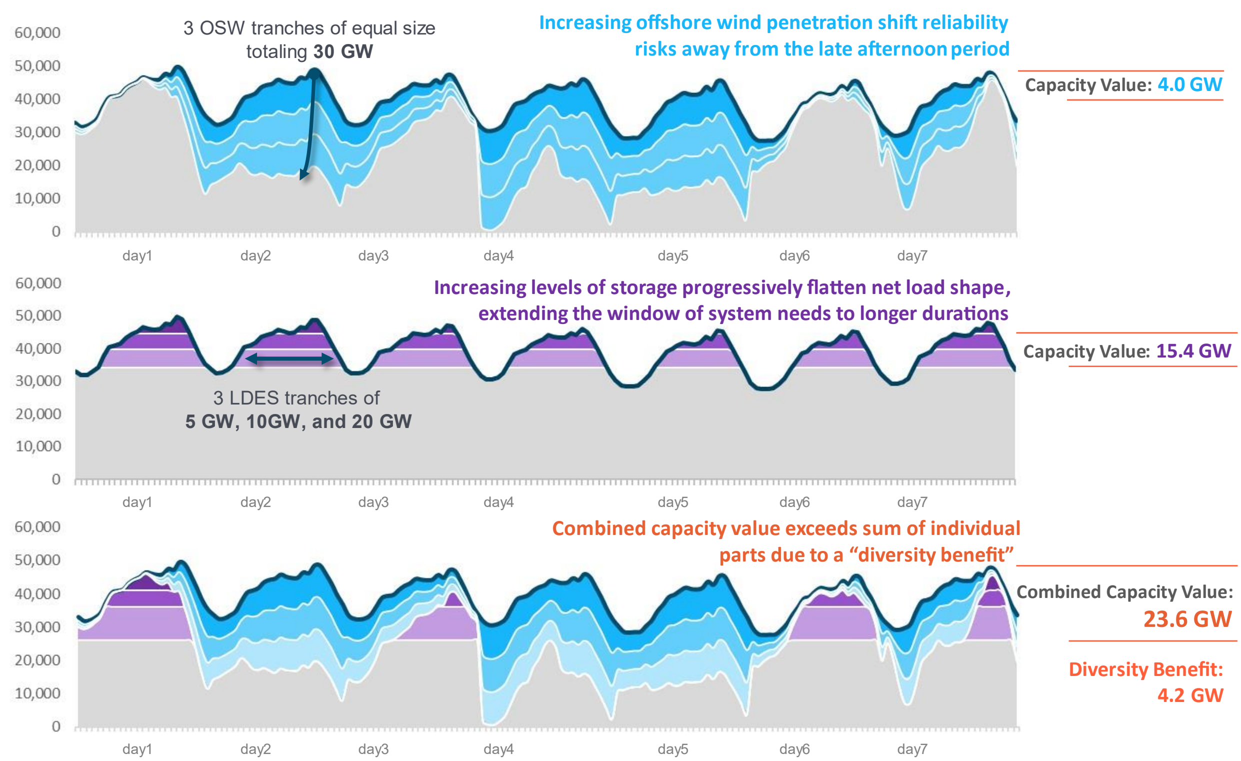
A second important feature of ELCC to highlight is the diversity impact across different resources. While adding more of the same resource will lead to diminishing returns, resources with complementary output profiles can produce "diversity benefits", providing a total capacity contribution that is greater than the sum of their individual capacity contributions. A common example of this is the interaction between solar and storage. As Figure 4-3 illustrates, successive solar additions act to create a sharper "net peak" demand on the system, which reduces the hours over which storage must discharge to reduce peak; solar also provides a source of energy for charging. Thus, the combined impact of the two resources is greater than the sum of the two parts.

Figure 4-3. Illustration of Diversity Benefit Between Solar and SDES Resources



A key theme in this study will be the diversity value provided by offshore wind and storage, particularly storage of longer durations. In a system with high offshore wind penetration, generation from wind alone can saturate the needs in net peak load hours, mitigating the spiky later afternoon peaks driven by electrification load. System resource needs are spread across the whole day, which provides an opportunity for long duration storage resources to dispatch for multiple hours and further shave peak. Offshore wind also serves as a source of excess energy for storage to charge from, which provides a zero-carbon source to recharge the energy storage between long stretches of system needs.

Figure 4-4. Illustration of Diversity Benefit between LDES and OSW Resources



4.2 Scenario Design

As described above, the ability of storage to contribute to system reliability will depend on the shape of the load and the rest of the resource portfolio. This study evaluates the role of storage to support electric sector firm capacity needs under a range of conditions, though it cannot capture all of them. E3 relies on the CECP 2050 as the major input, but given the uncertainty about future resource deployment, and the sensitivity of outcomes to the assumptions related to rest of the portfolio, particularly at high renewable penetrations, we report a range of outcomes in most figures and tables. We also use sensitivity analysis to illustrate both the reliability challenge and the variation it generates in effective capacity contributions.

Table 4-1. Primary Scenarios Evaluated in this Study

Reliability Scenario Inputs		Primary Outcomes		Years		
Scenario	**Loads & Resources***	**Relative Reliability Risk**	**Storage ELCC**	**2030**	**2040**	**2050**
Base Scenario: The region achieves CECP Phased plan	CECP Phased	✓	✓	✓	✓	✓
No Massachusetts OSW: Achieves CECP Phased, but transmission that connects MA OSW go down	CECP Phased w/o MA OSW	✓		✓	✓	✓
No Transmission North: Achieves CECP Phased, but transmission to North (NH/VT/ME) goes down	CECP Phased w/o loads or resources from NH/VT/ME	✓		✓	✓	✓
No Imports: Achieves CECP Phased, but no market reliance accounted	CECP Phased w/o Imports	✓		✓	✓	✓
Low Renewables: Region hits lower renewable levels than projected in CECP Phased	CECP Phased load, but reduced renewable builds	✓	✓	✓ *(Reliability Risk Only)*		✓
100% Renewable: Region retires all remaining firm capacity and imports		✓		✓		✓

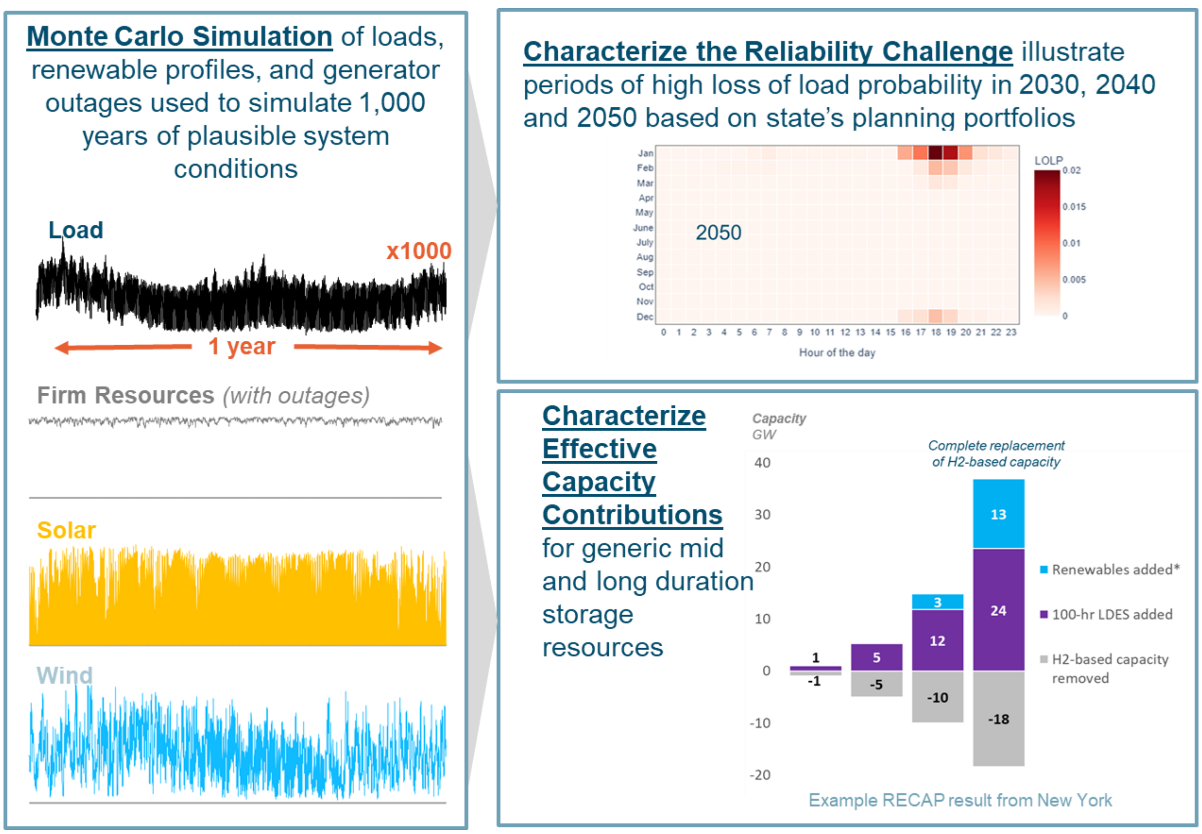
- **Range of storage ELCCs are calculated for representative 4-hour, 8-hour, 24-hour, and 100-hour resources for selected scenarios**
- **Full ELCC surface tables for selected scenarios to evaluate <u>extended range</u> of storage effective capacity contributions as a function of a range of renewable penetration levels**

* Note: All scenarios remove electrolysis load and the associated renewables required to support that load, given the significant uncertainty about the shape and flexibility of potential electrolysis loads, and what fraction of hydrogen loads will be generated via electrolysis within versus outside of New England. In the CECP Phased scenario, this load is 2% of total load in 2030, growing to 17% of load in 2050. The renewables required to support that load include 11.9 GW solar, 4.7 GW onshore wind and 5.6 GW offshore wind, by 2050.

4.3 Modeling Approach

This study assesses the capacity value of representative storage resources using E3's Renewable Energy Capacity Planning (RECAP) model. RECAP is a proprietary loss-of-load probability (LOLP) model used to determine regional capacity sufficiency and resource reliability value.[55] By simulating the availability of electric supply to meet demand across a broad range of conditions, RECAP accounts for factors such as weather-driven variability of electric demand, forced outages of power plants, the natural variability of resources such as solar, wind and offshore wind, and operating constraints for energy-limited resources like storage and hydro. This characterizes key factors influencing reliability and provides the basis for measuring resource capacity towards meeting resource adequacy.

Figure 4-5. Overview of E3's RECAP Model



The hourly simulation of the ISO-NE system over a broad range of weather and load conditions is essential to constructing a robust assessment of the system's ability to meet its reliability targets. This ensures that RECAP captures a wide distribution of potential outcomes, including unlikely tail events (e.g., renewable droughts), which may not occur in a "typical" year. Relevant correlations are preserved within the model

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55 E3's industry-leading tool has been used in regulatory proceedings and planning across North America. Recent clients include, for example, CAISO, PJM, NYISO, NYSERDA, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, Hawaii Electric Company (HECO), Public Utility Commission of Texas, Salt River Power, El Paso Electric, Xcel Minnesota, NV Energy, Portland General Electric, Oregon PUC, Black Hills Energy, Florida Power and Light, Nova Scotia Power, and more.

to ensure linkage among load, weather, and renewable generation conditions based on historical observations. Additional detail regarding the treatment of load and renewable data in the model is described in the following section.

4.4 Inputs and Assumptions

Characterizing the ability of storage to contribute to system reliability in New England using a LOLP model requires a broad range of inputs related to the electric system. A summary of these inputs is provided in Table 4-2. More details on key categories are provided in the subsections that follow.

Table 4-2. Summary of Key RECAP LOLP Modeling Inputs

Category	Inputs
Electricity Demand	• Annual energy demand based on CECP Phased Scenario, with adjustments to remove load to serve electrolysis demands. • Annual peak demand based on the CECP Phased Scenario. • Hourly load profiles developed for 39 years of weather data from 1980-2018.
Firm Resources	• Model state-level gas, oil, nuclear, and biomass capacity based on CECP forecasts. • Model stochastic forced outage rate by resource category for each individual generator. Leverages outage rate assumptions used in prior E3 work in ISO-NE region[56].
Variable and Hydro Resources	• Create state-level renewable profiles using NREL simulation tools for multiple historical weather years. • Allow hydro to dispatch flexibly up to an energy budget, subject to minimum and max flow constraints. Hydro availability is determined based on a historical record of hydro production data (2000-2015) published by ISO-NE.
Storage Resources	• Model representative storage duration and round-trip-efficiencies based on CECP modeling assumptions. • A 10% forced outage rate for all storage technologies is applied.
Imports	• Use ISO-NE's Forward Capacity Auction (FCA) results to estimate the firm capacity benefits of transmission relative to nameplate capacity – ratios from the most recent FCA results were used for future builds[57]

4.4.1 Electricity Demand

E3 relies on projections developed by the State of Massachusetts as part of the CECP 2050 to reflect total annual energy demand and hourly system peak for the New England system under an economy-wide Net Zero by 2050 future. For the analysis that follows, E3 leveraged the base portfolio from the CECP 2050

[56] E3 (2020), Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

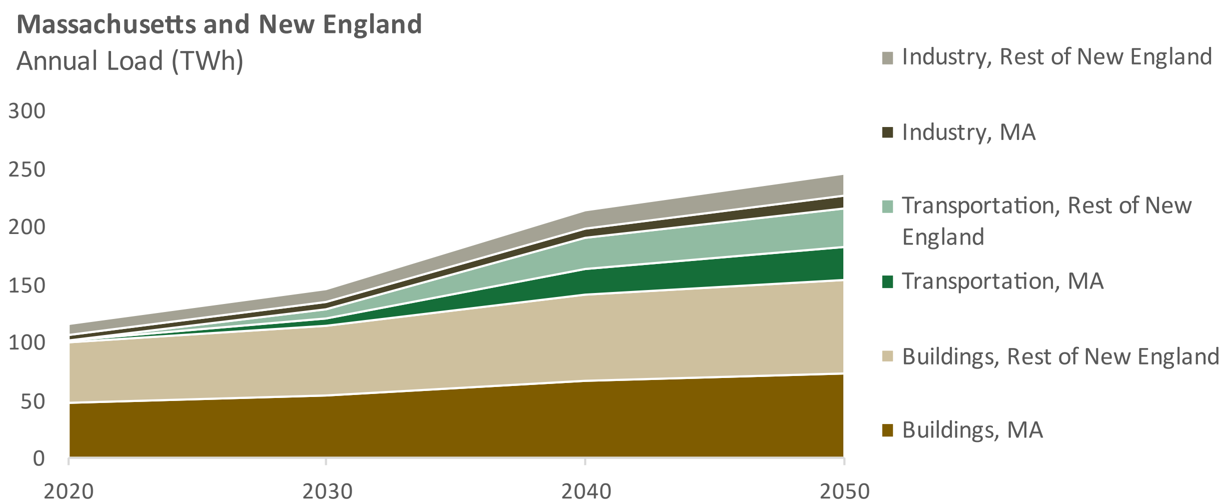
[57] Ratio for each interface is estimated based on nameplate capacity, interface limit and firm tie benefits reported in FCA17 results. Nameplate capacity expansion for each interface in the next three decades are based on CECP forecasts.

"Phased" scenario.[58] Forecasts reflect several important trends expected to accelerate across New England over the coming decade, notably[59]:

1. **Energy efficiency**: 8% of households weatherized by 2030, 47% by 2050
2. **Residential Building electrification**: 38% of households by 2030, 92% by 2050
3. **Commercial Building electrification**: 14% of service demand by 2030, 54% by 2050
4. **Light-Duty Transportation electrification**: 19% of vehicles by 2030, 97% by 2050
5. **Medium and Heavy-Duty Transportation electrification**: 10% of vehicles by 2030, 93% by 2050
6. **Industrial Electrification**: 32% of service demand by 2030, 38% by 2050

Figure 4-6. New England and Massachusetts Load Forecast, based on CECP 2050 (2011 Weather)

Annual Load (TWh)	New England			Massachusetts		
	2020	2030	2050	2020	2030	2050
Buildings	100.3	114.0	153.1	46.4	53.2	73
Transportation	0.4	14.6	62.6	0.2	6.7	28.3
Industry	14.4	16.3	30.7	4.6	5.3	11.0
Electricity Losses (T&D)	*8.8*	*12.2*	*27.8*	*3.8*	*5.2*	*11.4*
Total	**124**	**157**	**274**	**55**	**70**	**124**

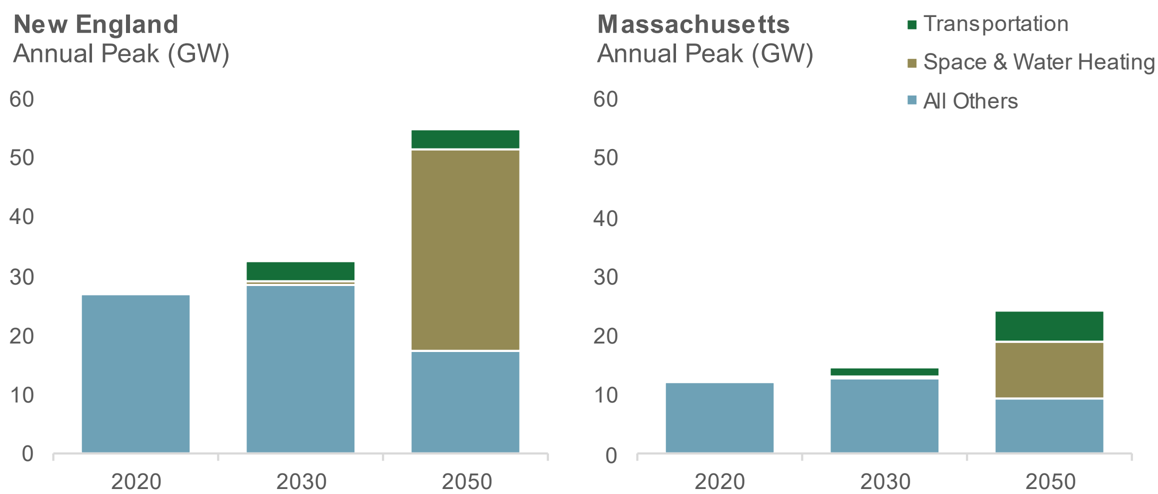


[58] These annual loads include demand served by behind-the-meter resources such as rooftop solar. The electrolysis loads from the CECP scenario have not been included in this analysis. The generating resources modeled have been adjusted accordingly, assuming hydrogen must be generated by clean energy resources.

[59] While loads are modeled as static inputs, *additional* demand-side management, such as EV load shifting or additional energy efficiency, could contribute to additional resource adequacy beyond the contributions already assumed in this study.

Figure 4-7. New England and Massachusetts Peak Load Forecast, based on CECP 2050 (2011 Weather)

Peak Load (GW)	New England			Massachusetts		
	2020	2030	2050	2020	2030	2050
Season	Summer	Summer	Winter	Summer	Summer	Winter
Space & Water Heating	0.3	0.6	33.9	0.2	0.5	9.6
Transportation	0.1	3.1	3.4	0.04	1.4	5.1
All Others	26.0	28.8	17.4	12.1	12.7	9.4
Peak Load	**27.4**	**32.5**	**54.7**	**12.3**	**14.6**	**24.1**

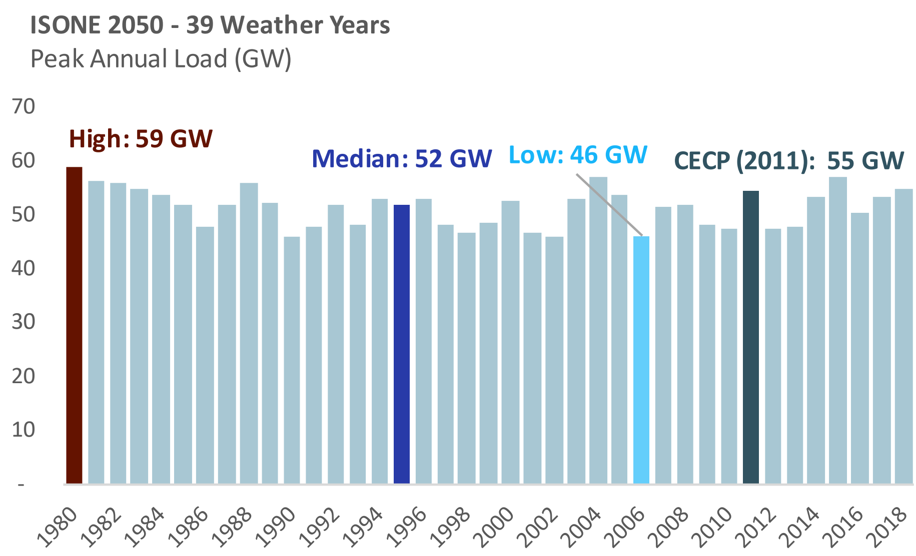


The loads and peak load reported in Figure 4-7 are based on the 2011 weather year, as was utilized in the CECP 2050, to illustrate the change over time. The year 2011 represents an average weather year, as shown in Figure 4-8. E3's reliability estimates, however, rely on simulations of the system over a broad range of possible weather conditions, developed based on 39 years of historical data (1980-2018). We note that our modeling also leverages distinct load shapes differentiated by state and relevant end use, such as electric vehicle charging and electric space heating. The process for developing these profiles is outlined in Section 4.4.3.

The characterization of load and renewable generation across years of historical data lead to a wide range of peak load and peak net load. Primarily driven by temperature extremes and electric heating demand, the 2050 system sees annual peak loads ranging from 46 GW to 59 GW. The 1-in-2 median peak[60] is 52 GW.

[60] A "1-in-2 peak" year measures what a typical planning demand year looks like. It is valuable to look at the "1-in-2 peak" input because peak load growth is typically reported for a median year like this.

Figure 4-8. Variation in Expected Gross Peak Load Across 40 Years of Weather Conditions



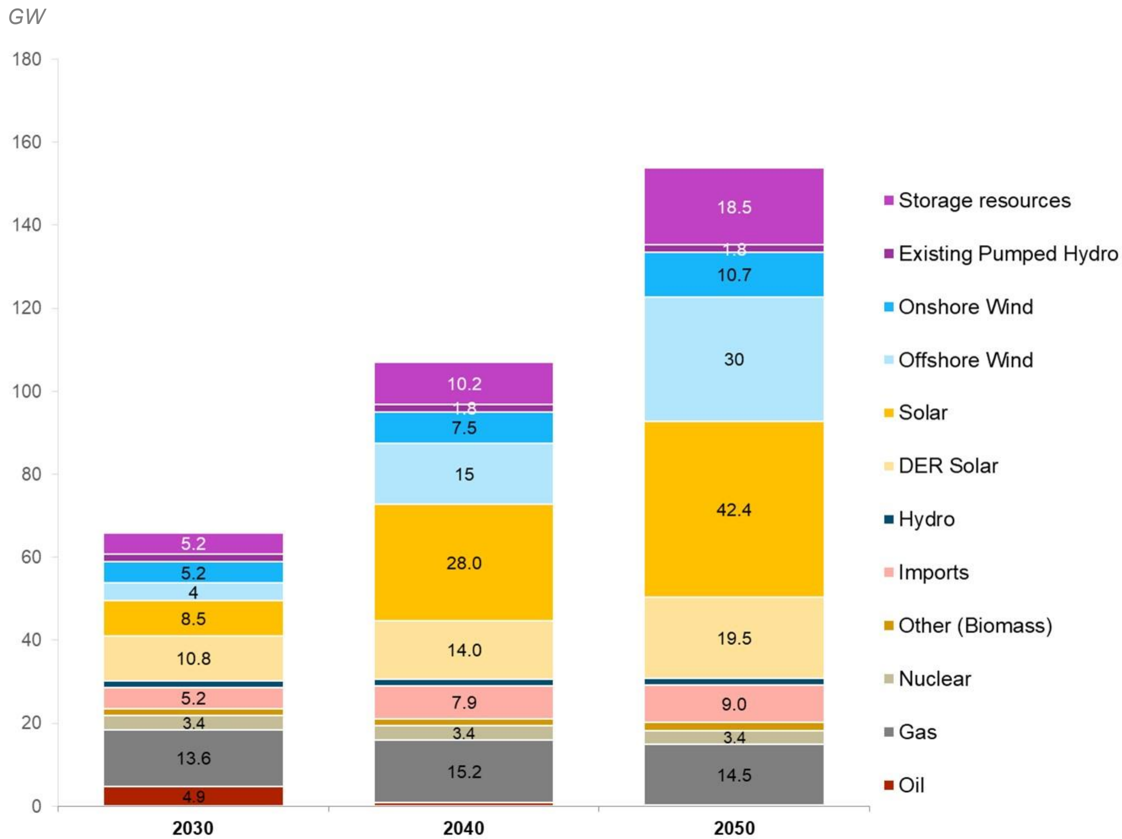
4.4.2 Resource Portfolios

As described above, the effective capacity of storage will be a function of the overall portfolio, specifically the mix and penetration of renewables. While we analyze a range of renewable build outs in the primary ELCC assessment, we could not assess every combination of inputs for every representative storage asset and sensitivity scenario, and therefore for most results, we start with an initial portfolio and show a range reflecting different renewable builds. We also provide full ELCC "surfaces" for key combinations (e.g., offshore wind and long-duration storage) reflecting the ELCC values at different levels of each resource.

For this study, we start with a base portfolio developed by the state and consistent with the demand projections from the CECP Phased scenario.[61] This scenario represents a decarbonization strategy in which electrification of buildings is gradually "phased-in" over the next three decades and drives the needs to procure and deploy more clean energy resources to meet increasing electricity demand. Figure 4-9 shows the composition of regional resource portfolios at three modeling years, 2030, 2040 and 2050. Notably, over 100 GW of renewable resources are incorporated in New England by 2050, more than triple the total capacity size of the New England grid today. By 2050, the cumulative total nameplate capacity for solar, wind and energy storage in ISO-NE region is roughly 62 GW, 41 GW, and 19 GW, respectively. While certain quantities of firm resources (gas turbines, nuclear energy, and market imports) are retained for reliability, the vast majority of system energy is provided from renewables. In addition, by 2040, most of the oil units in the region are retrofitted and transformed to gas-only generators.

[61] This was chosen based on guidance from the state.

Figure 4-9. CECP 2050 Resource Portfolio, with Adjustments*



Note: * This figure is after the removal of electrolysis loads and associated renewable capacity to support those loads. These were removed so that the load and resource portfolios were aligned, and because electrolysis was not the focus of this particular study.

The CECP 2050 assumes major additions of energy storage to the ISO-NE system in the next three decades. Including existing pumped hydro resources in the region, these sum up to roughly 7 GW in 2030, 12 GW in 2040, and over 20 GW in 2050. The operational characteristics for different types of energy storage technologies modeled in RECAP are summarized in Table 4-3.

Table 4-3. Operational Characteristics Modeled for Storage Technologies

	Short-Duration	Mid-Duration	Pumped Hydro	(Shorter) Long-Duration	Long-Duration
Duration (hours)	4	8	8	24	100
Round Trip Efficiency	91%	80%	80%	50%	50%
Maximum power output	100%	100%	100%	100%	100%

For selected modeling years, this study also evaluated sensitivity portfolios assuming forecasted builds in the CECP Phased portfolio are delayed due to constraints associated with transmission bottlenecks and interconnection. The sensitivities also address key contingencies relevant to Massachusetts. Table 4-4 summarizes the portfolio variations in key sensitivity cases for modeling year 2050.[62] For the portfolio in the 100% renewable sensitivity, E3 constructed a 100% renewable plus storage portfolio that achieves the same reliability performance as the 2050 CECP Phased portfolio. See Section 4.10 for a detailed description.

Table 4-4. Change in Portfolio Composition in Sensitivity Cases Relative to Base Case

2050	Resource Capacity (GW)					Annual Loads (TWh)
	Utility-scale Solar	**Offshore Wind**	**Onshore Wind**	**Thermal**	**Imports**	
Base case	-	-	-	-	-	-
No MA OSW	-	**-21.5**	-	-	-	-
No Tx North	**-15.9**	**-5.7**	**-9.7**	**-4.7**	-	**-75.7**
No Imports	-	-	-	-	**-8.9**	-
Low Renewables	**-20.4**	**-18.9**	**-1.4**	-	-	-

4.4.3 Load and Renewable Profiles

Understanding how load and renewable generation vary over a wide range of weather conditions is essential to a robust estimate of reliability risk. This variation is important given the relationship between temperature and heating and cooling demand, while solar irradiance and wind speed drive renewable generation.[63] Given the relatively short historical record of load and renewable generation data that is available, RECAP uses probabilistic sampling techniques to synthesize and extend the record of simulation data for correlated load and renewable generation. The probabilistic re-sampling techniques rely on meteorological data that spans multiple decades, which allows the model to simulate a broader range of weather conditions, including rare or extreme weather conditions that impact system reliability. Thousands of potential realizations of load and resource generation are produced using Monte Carlo simulation to calculate reliability metrics like LOLE (Loss of Load Expectation, denoted as days per year when there are expected lost load events) and ELCC. Figure 4-10 summarizes the chronological extent of the data used to generate the hourly profiles for this study.

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[62] Note that "No Tx North" scenario modeled Southern New England as an island and therefore reduces the amount of load the system needs to serve. For other scenarios, this study still focuses on the New England system as a whole and only assumes resource installation contingencies caused by transmission issues or land use constraints, etc.

[63] Some amount of load flexibility is included in the load shapes (e.g., managed EV charging to shift charging to times of lower demand and higher renewable output) but this study does not model additional dependable, dynamic load flexibility. In practice, any additional flexible load will compete with SDES and may absorb some of its market value. However, the value of load flexibility is limited since duration is limited, dispatch is constrained, and dependability is unclear compared to energy storage.

Figure 4-10. Overview of Key Load and Renewable Data Sources

Statistical techniques used to extend renewable data back to 1980

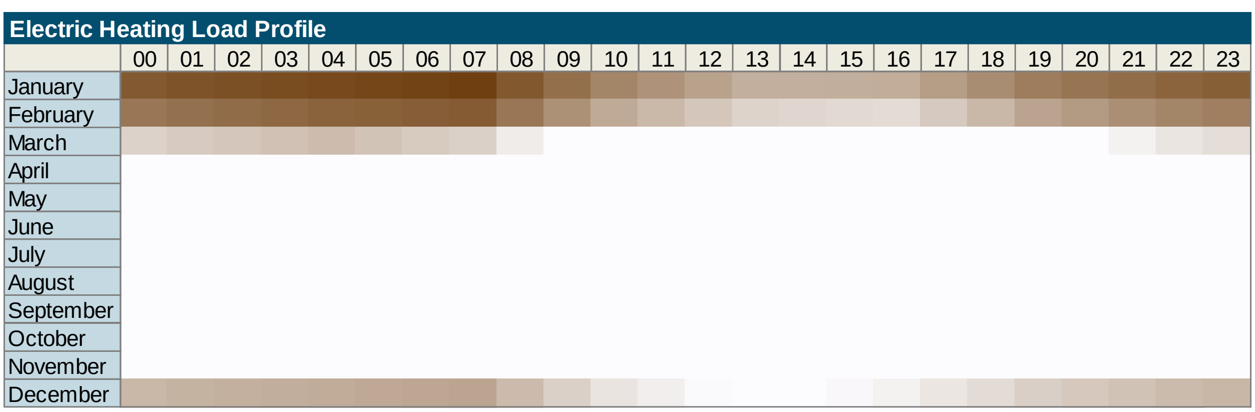
Profile	Primary Source(s)	Weather Conditions Captured
Loads	**CECP study** "Phased" scenario **E3's Extended Load Profiles** 39 weather years of load profiles	1980 2018
Wind (Onshore & Offshore Wind)	**NREL** WIND Toolkit	2007 2012
Solar	**NREL** System Advisor Model	1998 2019

Load Profile Development

Temperature dependent baseline load profiles are first derived from historical loads linked to historical temperature data. In addition, specific profiles for heating demand are developed for the same period. It is important to use a distinct profile to properly represent the increase in electric heating demand, which will occur in the coming decades and will represent a significantly larger share of total load in the region. A distinct load profile is also used for electric vehicle charging. This process yields hourly load profiles that represent 39 years of historical weather.

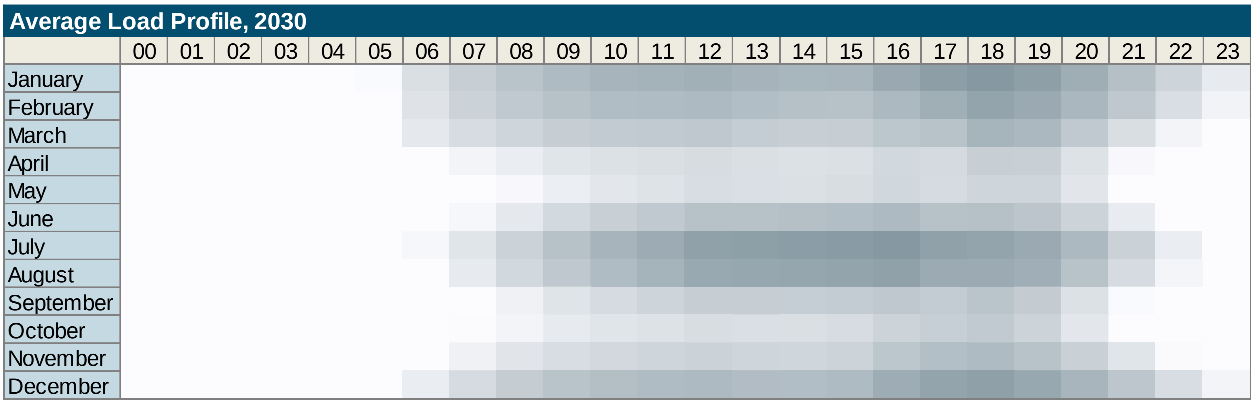
Figure 4-11. Month-Hour Average Electric Heating Loads, 2030

Darker color indicates higher loads



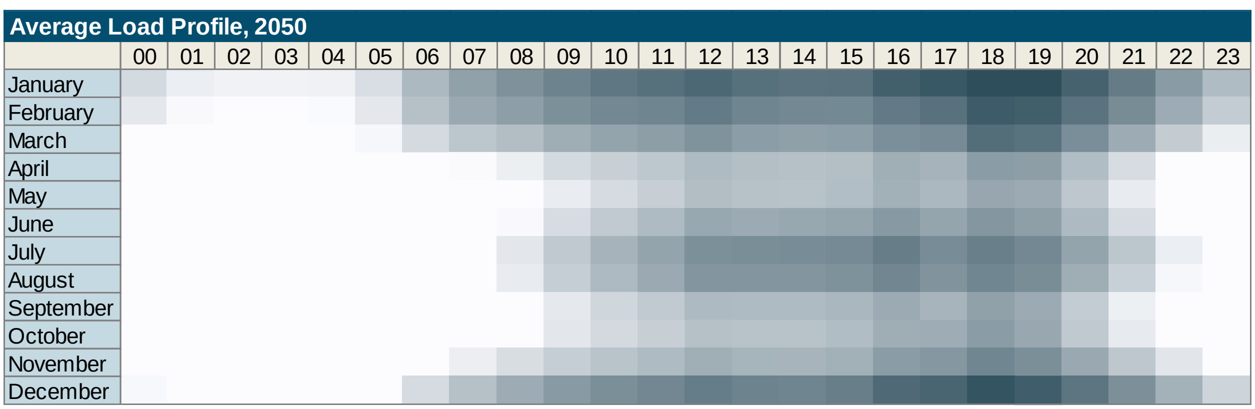
The New England system in 2030 sees space heating loads start to increase in the daytime of winter months. However, on aggregate, it still sees the highest loads in the summer afternoons due to space cooling demand. The evening loads also start to increase from electric vehicle charging when those are plugged in at the end of the workday.

Figure 4-12. Month-Hour Average Total Loads in New England, 2030



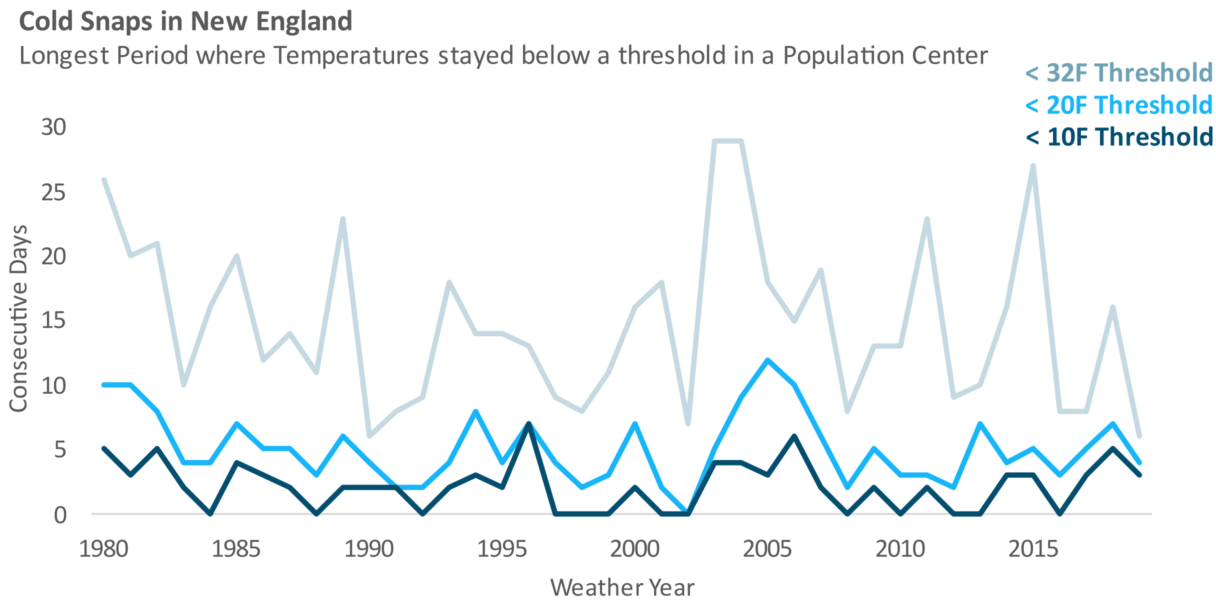
Space heating has a more significant impact on New England system loads in 2050, when winter becomes the highest energy demand period. With average electric heating loads peak in both morning and later afternoon, they drive the system peaks in the evening as they coincide with other loads and electric vehicle charging.

Figure 4-13. Month-Hour Average Total Loads in New England, 2050



Extending load profiles to cover 39 years of temperature data in New England allows us to capture more extreme temperatures in the winter as well as cold snaps–- when those low temperatures are sustained through multiple days. This is important for characterizing periods of continuous high electric heating demand, especially considering how heat pump efficiency rapidly declines with temperature. Figure 4-14 illustrates the year-to-year winter cold snap length variation across the weather years RECAP models. When looking at consecutive periods where temperature stayed below 20°F, an average year sees a 5 day long cold snap and the worst year sees a 12 day long one.

Figure 4-14. Cold Snaps Captured in Extended Weather Year Simulation

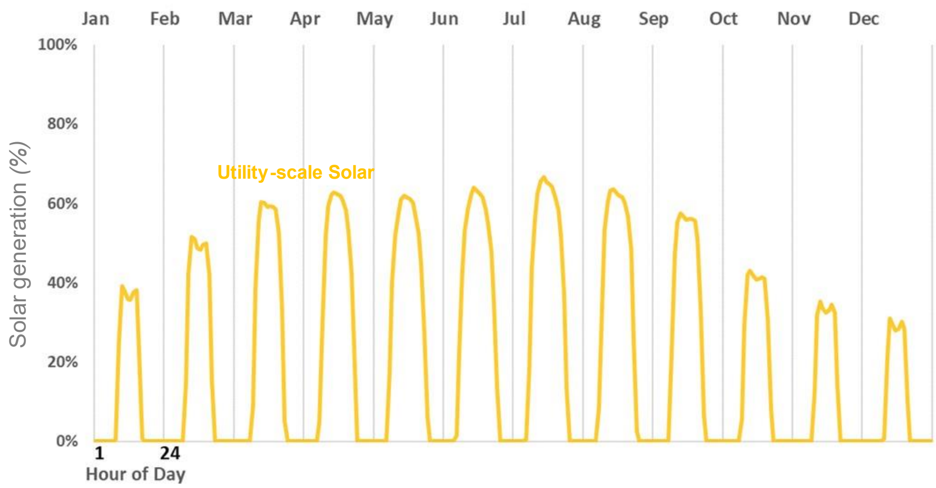


Renewable Profile Simulation

Solar generation profiles were simulated based on NREL's National Solar Radiation Database (NSRDB) for the period of 1998 through 2019. Generic plant locations by state and specific solar array configuration assumptions (i.e., inverter loading ratio and tilt angle) for utility-scale solar were assumed based on industry trends. Profiles for behind-the-meter/distributed solar were also simulated under similar assumptions. For onshore and offshore wind, profiles were simulated based on wind speed data from NREL's WIND Toolkit for the period of 2007 through 2012.

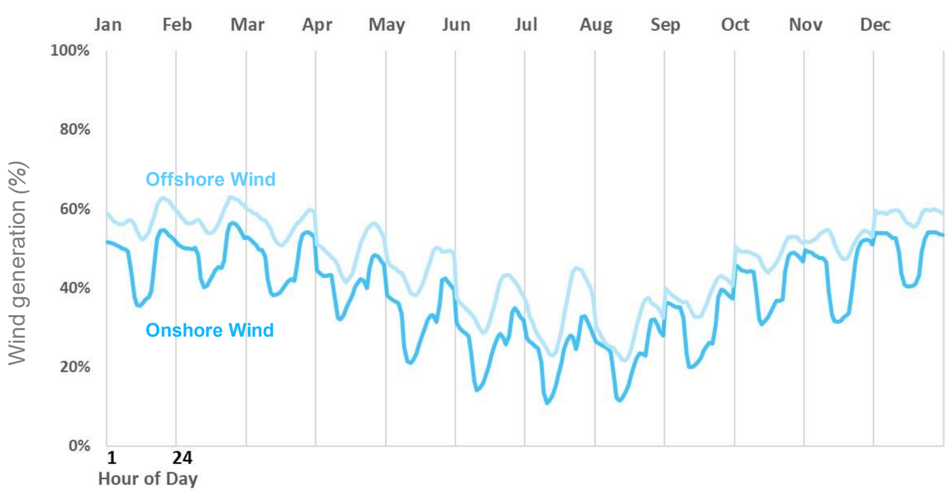
Figure 4-15 and Figure 4-16 show the month-hour shape as well as weighted average monthly capacity factor for utility-scale solar, onshore wind, and offshore wind in the region. On average, solar generation peaks in summer and in the middle of the day, while wind exhibits generation patterns that are higher at night and in winter. Offshore wind generally has higher capacity factors due to a lack of land barriers and high-quality wind.

Figure 4-15. Utility-scale Solar Month-hour Average Capacity Factor



CF	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Solar	11%	17%	23%	26%	28%	29%	30%	28%	23%	15%	11%	9%	**21%**

Figure 4-16. Wind Month-hour Average Capacity Factor

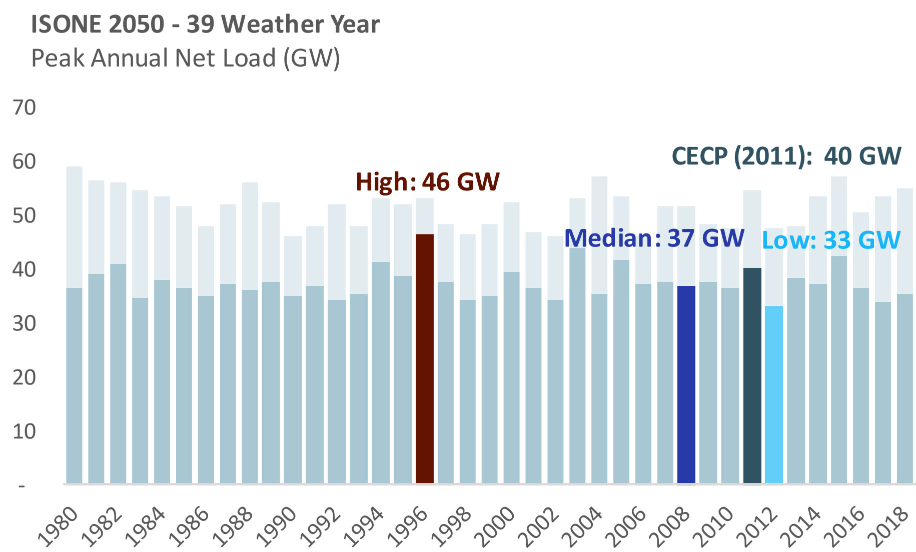


CF	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Onshore Wind	47%	49%	47%	41%	33%	26%	24%	23%	31%	41%	44%	50.0%	**38%**
Offshore Wind	58%	58%	56%	50%	45%	37%	34%	29%	38%	49%	52%	59%	**47%**

Illustrative System Net Load Modeled Across 39 Weather Years

With gross load and weather-matched renewable profile, we can look at the net load after we account for renewable generation. The net load does not necessarily peak coincidentally with gross load and the distribution across weather years is different. This depends on the modeled combination of load profiles and renewable profiles, which RECAP varies to capture the range of potential conditions. Figure 4-17 is the net peak across the 39 weather years resulting from one of many simulations RECAP made with varying thermal outages, solar, wind, and hydro generation patterns. In this set of simulations, net load peaks range from 33 GW to 46 GW across all weather years.

Figure 4-17. Example Simulation: Average Net Peak Realization from Various Weather Years



4.5 Results: The Reliability Challenge in 2030 and 2050

4.5.1 New England Grid in 2030

The electric system in New England will evolve in the next decade, driven by current trends in building and transport electrification as well as procurements and investments in clean energy generation to replace today's fossil fuel sources. Annual loads increase throughout the year, driving up overall resource needs. Loads in the winter increase most dramatically, with electric heating demand high in mornings and evenings from commercial and residential buildings. At the same time, evening loads grow as electric vehicles are plugged in to charge. The system peak load increases from 27 to 33 GW in the summer and 21 to 27 GW in the winter, with summer peak load in the late afternoons of July, when high space cooling demand overlaps with electric vehicle charging.

Renewables in 2030 also start to have a significant impact on the need for firm dispatchable generation. Under base conditions in the CECP, the New England system is assumed to have 28.7 GW of renewables – 19.3 GW of it coming from solar. This means that the load net of renewables, to be met by firm dispatchable generation, generally peaks in late afternoons when sun sets. As a result, in 2030, the greatest resource need in ISO-NE system, and associated loss-of-load risk, occurs from 5-7 pm in the summer months. Figure 4-18 and Figure 4-19 illustrate the shift in timing of system's net load peak in an example summer week as well as the month-hour average resource needs in the system.

Figure 4-18. Increased Renewable Penetration in New England in 2030 Narrows Peak and Pushes it into the Evening

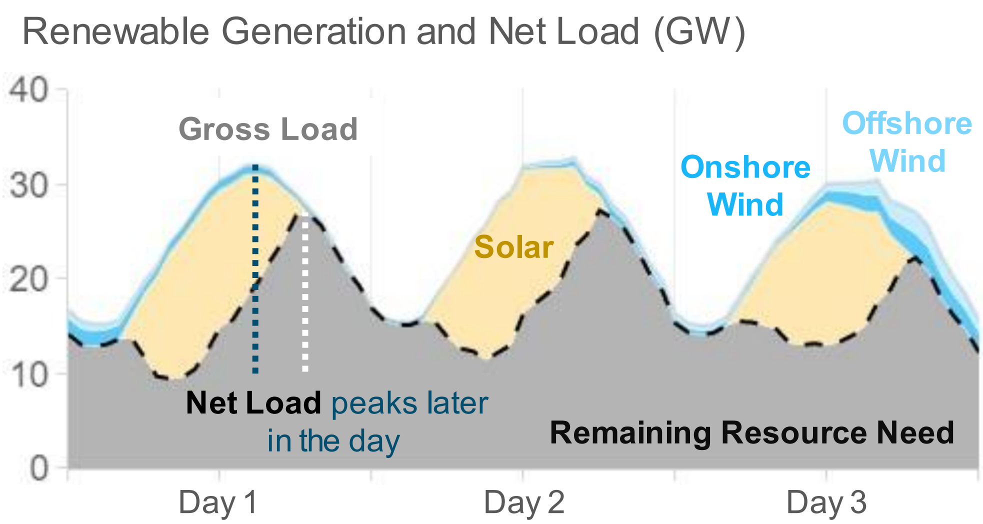
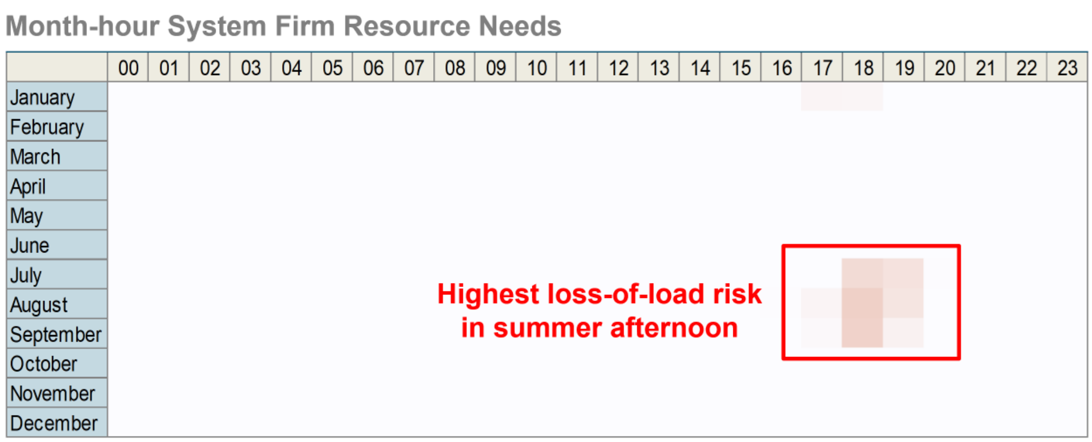


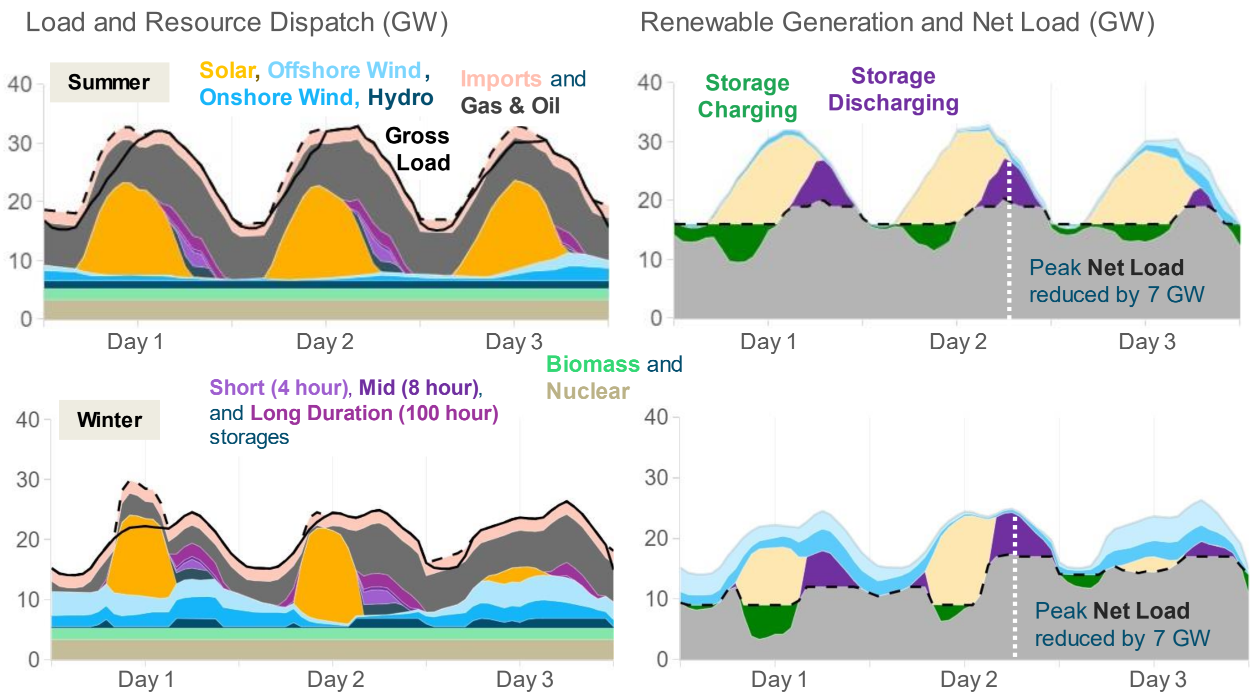
Figure 4-19. Average System Resource Need for ISONE under CECP Portfolio, 2030



Despite remaining a summer peaking system, winter becomes more challenging due to increasing heating and electrification loads in the morning and nighttime. While in summer, renewable (especially solar) generation are generally well aligned with loads, winter does not benefit from these capacity additions as much as the summer, therefore driving need for firm resources to meet system demands.

The capability of storage resources to fill in the gap and serve as firm resource replacements is illustrated in Figure 4-20. For each season, a detailed "Load and Resource Dispatch" chart shows how each type of resource in the 2030 CECP portfolio generates to meet system demands; the "Net Load" chart takes the dispatch chart and focuses on the role of storage resources in shaving net load peaks. For example, in summer when loads are much higher, abundant solar generation shifts system peak to later afternoon and creates a short window of resource need immediately after sunset. Storage resources (including existing pumped hydro units) are able to charge ahead and effectively "clip" or reduce this pronounced net peak. The story is similar in winter, despite that the time windows in need are more spread out in both morning and evening.

Figure 4-20. Illustrative System Dispatch and Role for Storage, 2030



Another takeaway from these charts is that the shape of remaining system resource need is often driven by solar due to its high penetration relative to wind in 2030. Thus, the system almost always observes spiky peaks in the early evening (and sometimes morning in the case of winter). Since storage is primarily clipping peaks and not necessarily absorbing most excess renewable generation, storage with the low costs and high round-trip-efficiency (RTE) is expected to fill this need, with longer duration storage less valuable to the system. This will be true until the system reaches a level of renewable penetration where there is significant excess generation for longer than a few hours in the middle of the day.

4.5.2 New England Grid in 2050

In 2050, as building and transportation electrification accelerate, the New England system peak load increases to 47 GW in the summer and to 55 GW in the winter under CECP Phased scenario, solidly a winter-peaking system. There is also potential dual-peaking in the winter between the morning and the evening.

Similar to 2030, various policy tools as well as the GHG emissions reduction mandate continue to push the system away from gas and oil-fired generators and promote clean energy adoption to meet electricity demand in the future. Based on the forecasts of CECP Phased scenario, by 2050, ISO-NE system will need roughly 103 GW of renewable resources to serve loads, of which 62 GW is utility-scale PV and distributed solar, and 41 GW comes from onshore and offshore wind farms. As a larger amount of wind resources is integrated on the system, the load shape net of renewables starts to become more volatile, widening the need that dispatchable resources are needed to meet. There still exists a spiky and short later afternoon peak but the system resource needs are stretched out across the day in cold winter months. Figure 4-21 and Figure 4-22 show the volatile net load shape in an example winter week and average system resource needs in New England in 2050.

Figure 4-21. High Electrification and Periods of Low Renewable Output in 2050 New England Winters Spread Resource Need Over Longer Stretches, with Greatest Net Need on Coldest Evenings and Mornings

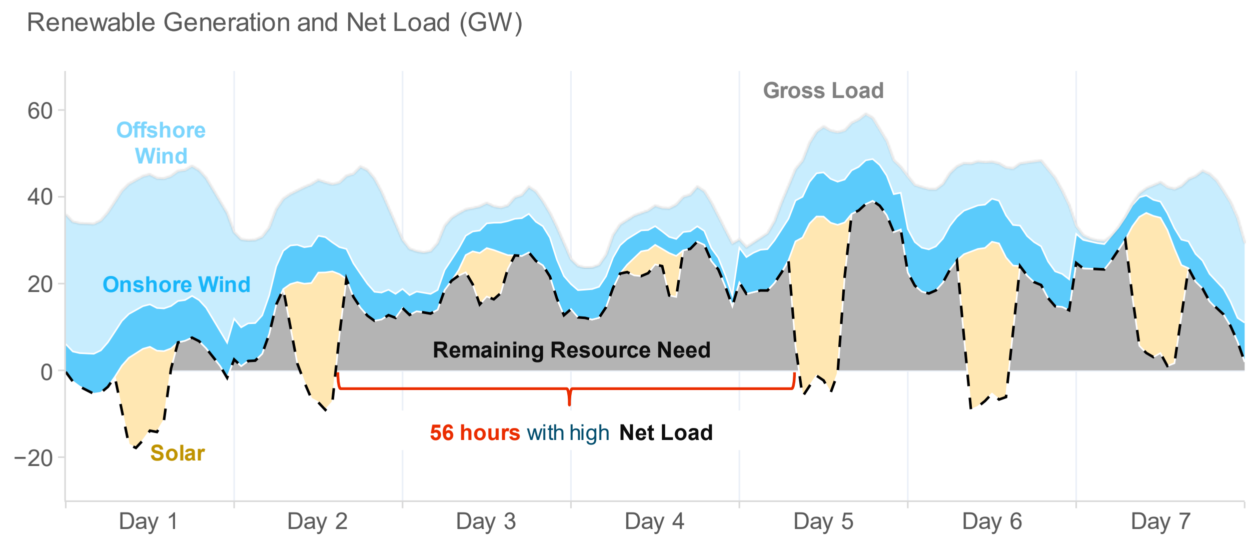
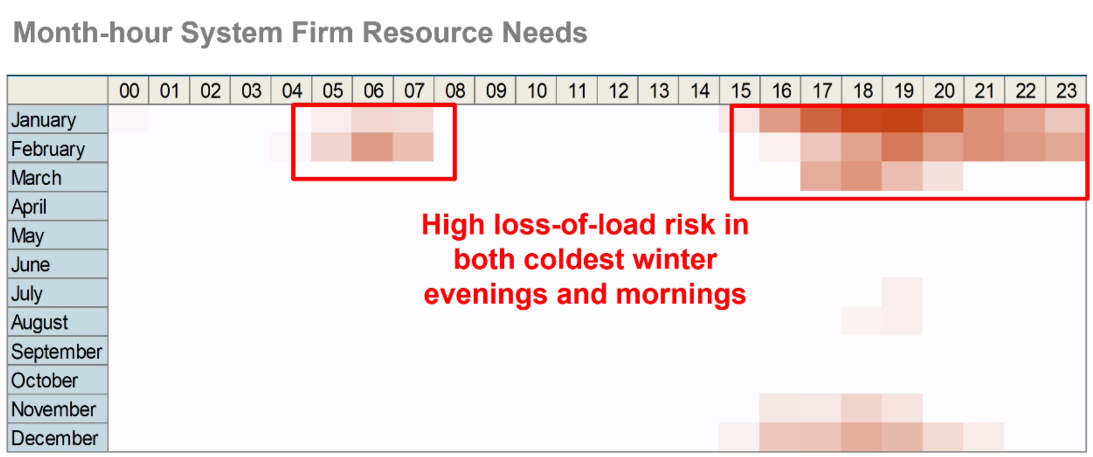
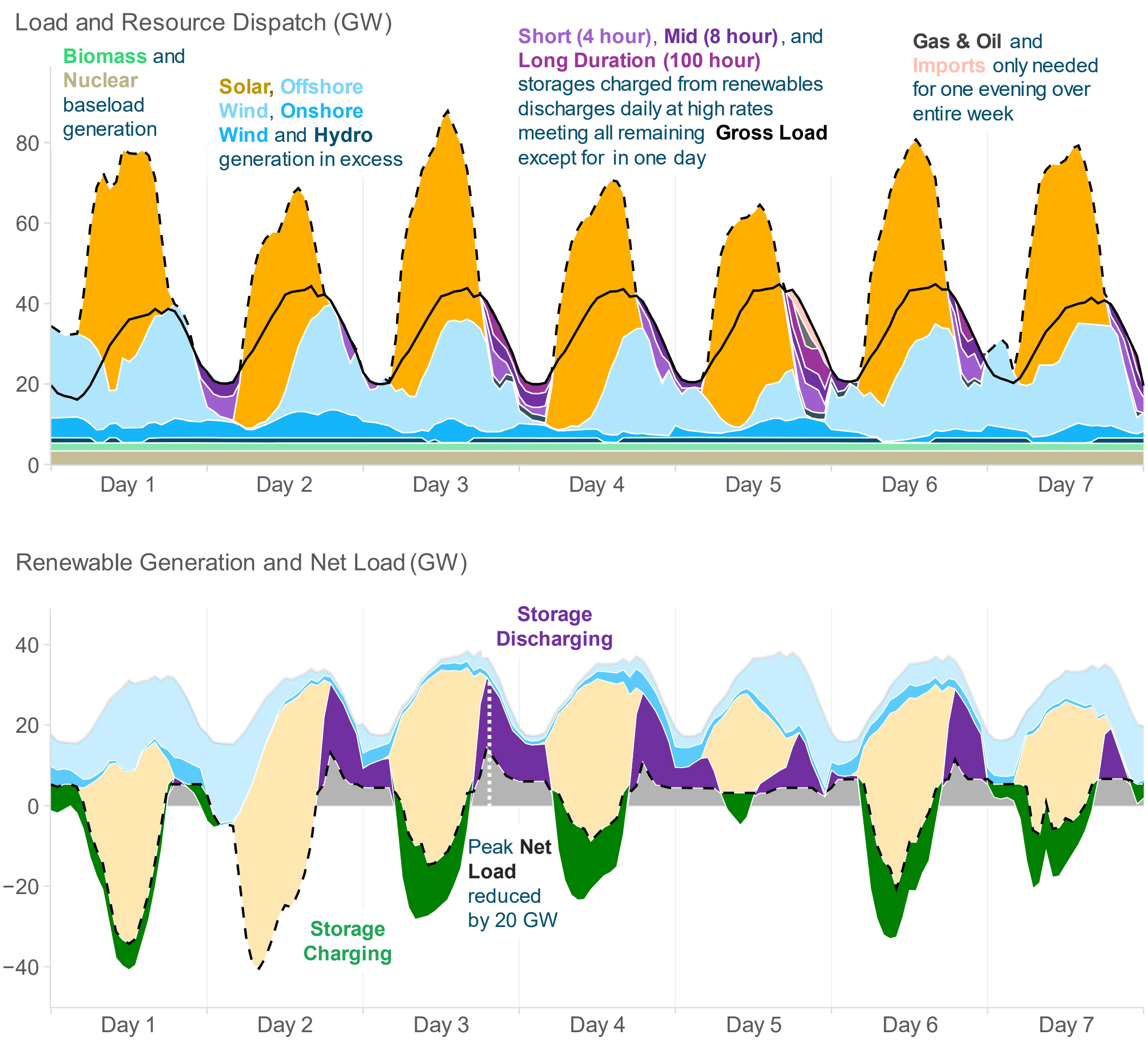


Figure 4-22. Average System Resource Need for ISO-NE under CECP Portfolio, 2050



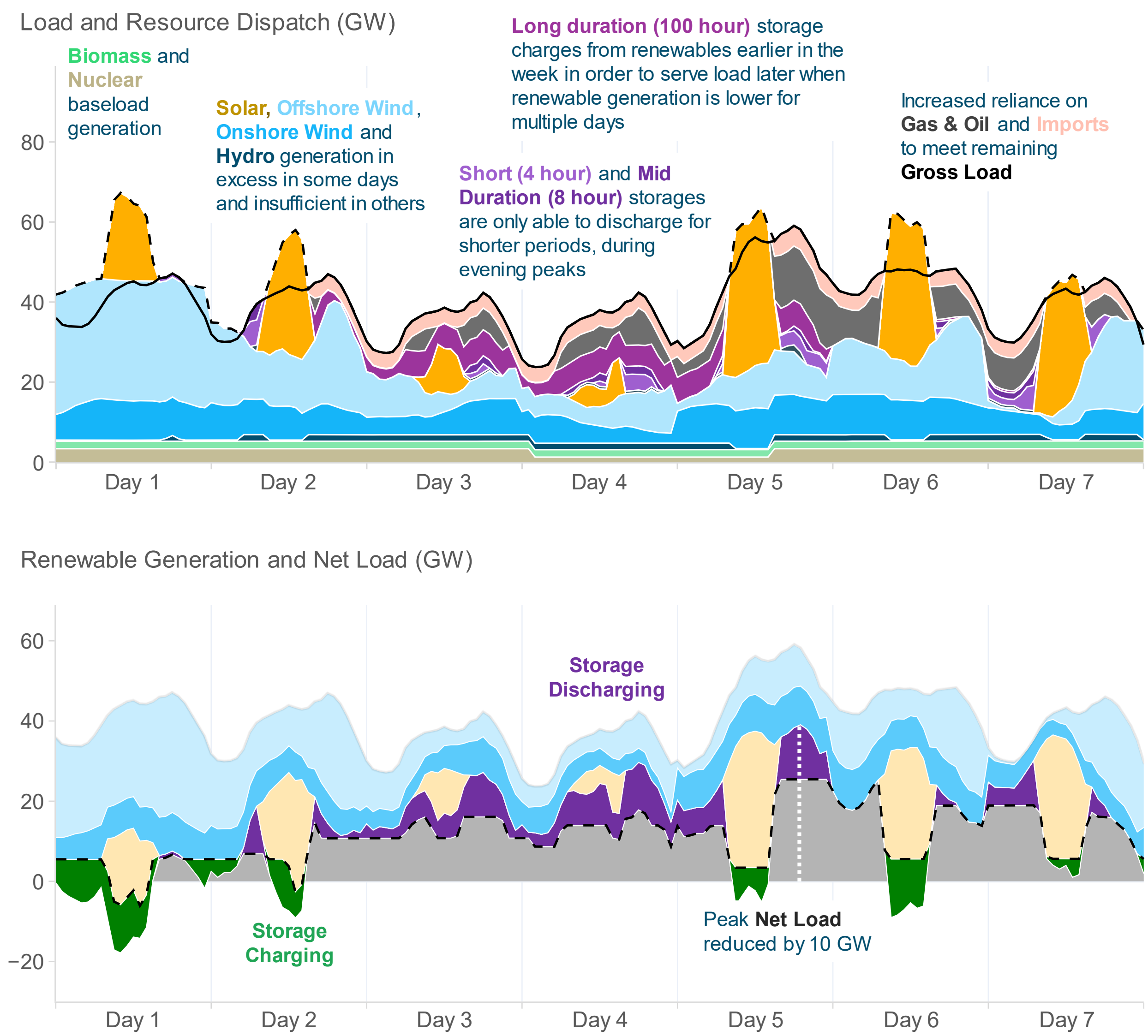
With large renewable additions, summer firm resource needs and associated loss-of-load risk are substantially mitigated. Abundant solar generation at noon and wind generation across the day are sufficient to meet most of the system demands, requiring storage or other firm resources to generate only during the short late afternoon periods. The excess renewable generation can also be soaked up by a combination of 20 GW storage resources assumed to be deployed in New England by 2050. Figure 4-23 shows how each resource type contributes to meeting system needs and how storage resources are dispatched to shift excess generation and serve load in times of need. Even in the time when wind generation is low or not enough to meet system demands after sun set, short, mid, and long duration storage resources can charge from excess middle-of-day solar generation and discharge in the late evening.

Figure 4-23. New England System during Average Summer Weeks in 2050



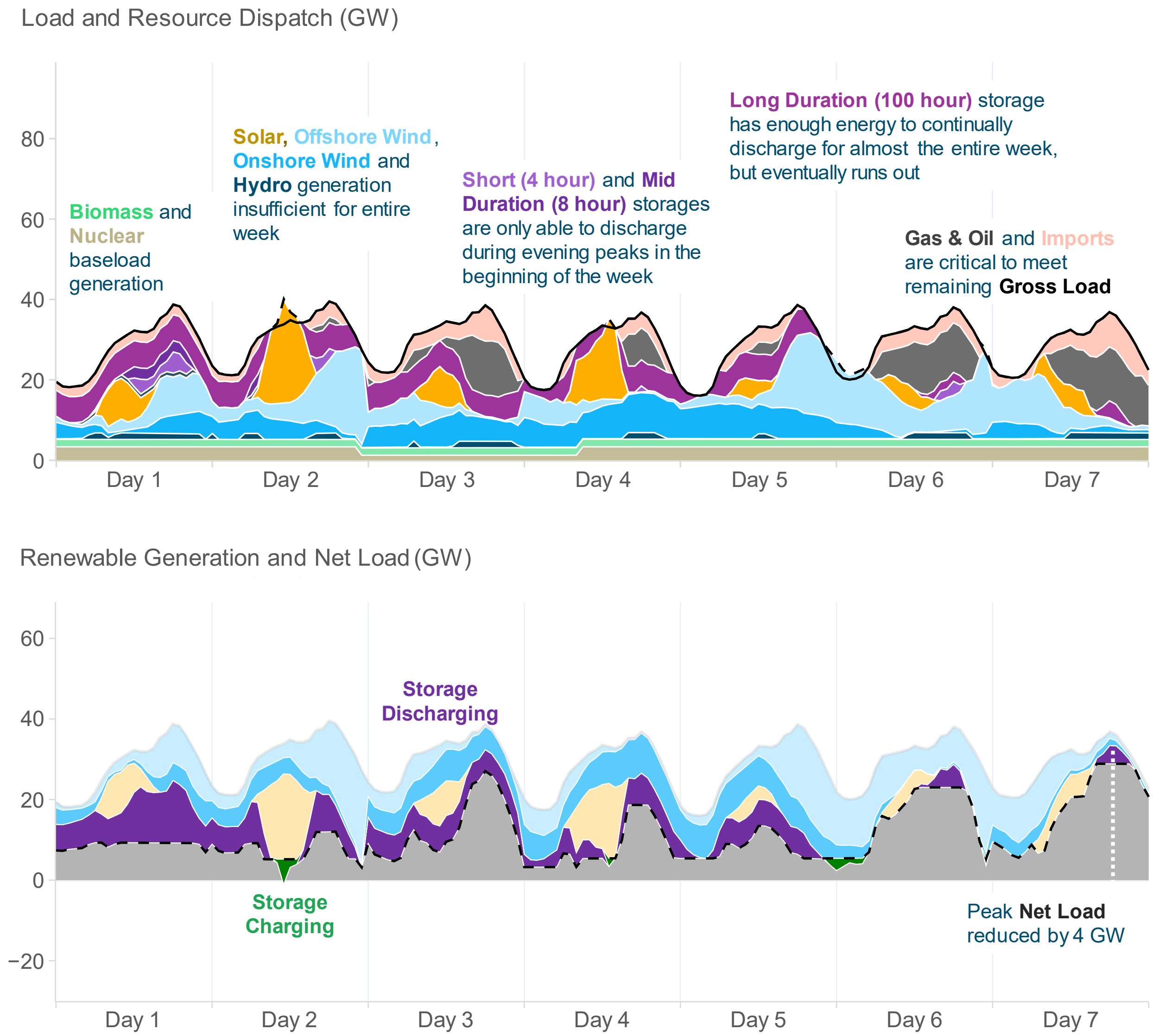
The true reliability challenge in 2050 New England, partially brought by the high renewable penetration in the system, is when periods of consecutive low renewable generation coincide with extreme cold weather events in the winter. The system can become both capacity short at peak hours and energy short when those events last long and storage runs out of charge.[64] The dispatch charts in Figure 4-24 and Figure 4-25 show how resources perform in a cold winter week where there are days of low renewable contribution. Different from in summer, renewables alone are insufficient to ensure system reliability, and the system needs to rely on gas or oil-fired generators and external market imports to serve loads. Storage that discharges in consecutive days without mid-of-day excess renewable energy for charging also drives the need for non-zero emission resources.

Figure 4-24. New England System during Peak Load Winter Week in 2050



[64] These challenges can be exacerbated by firm generators going offline due to extreme cold temperatures, fuel shortages, and import unavailability – the last two due to neighboring regions also likely facing reliability challenges at the same time. These are not the focus of this study.

Figure 4-25. New England System during Low Renewables Winter Week in 2050



4.6 Results: Short-Duration Storage Effective Capacity

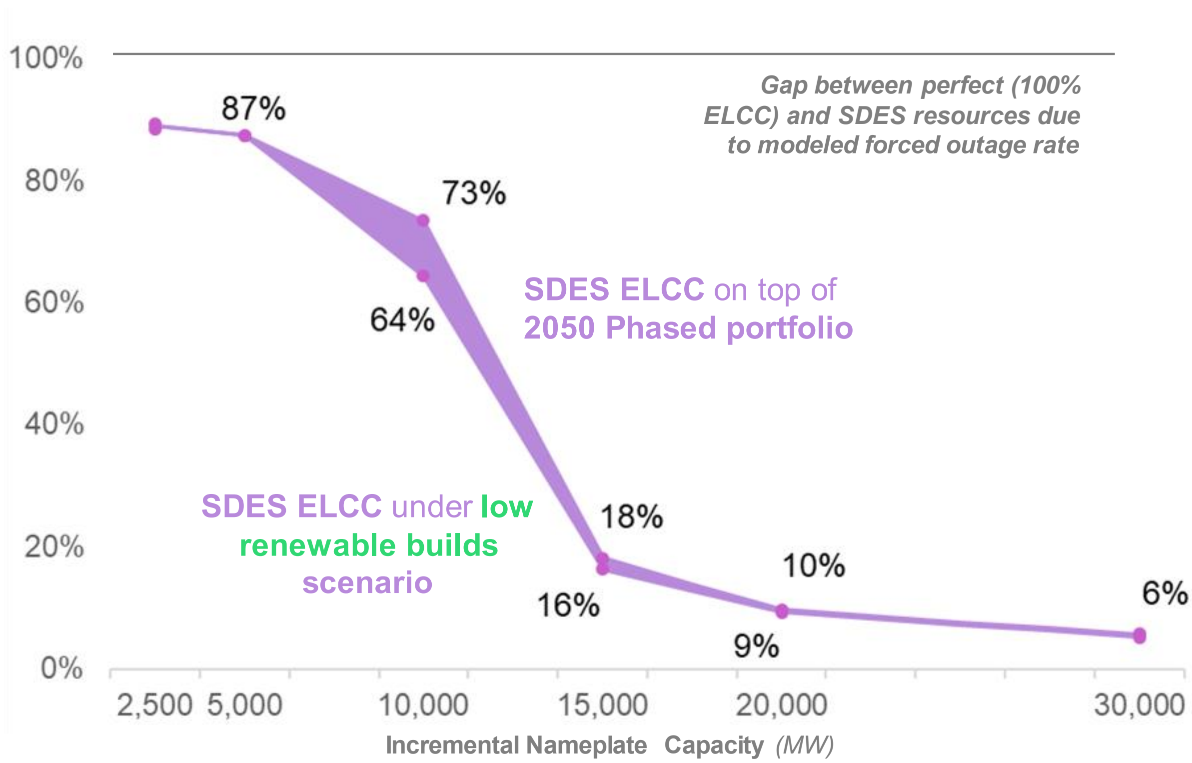
E3 modeled the capacity value of a 4-hour storage asset, representative of short duration storage technologies (SDES) expected to be on the market in the coming decade, with results illustrating the effective capacity value under a range of renewable levels.[65] Specifically, Figure 4-26 reports the incremental ELCC of SDES in 2030 and 2050 under two scenarios: Base Scenario assuming CECP Phased portfolio is achieved, and Low Renewables scenario, where ISO-NE achieves fewer renewable builds than projected. The range of ELCC values reflect the additional capacity value the region can get from each increment of SDES added to the system. SDES ELCC is relatively high for the first 5-10 GWs added in 2030,

[65] Modeling assumes resource has a 91% RTE and a 10% FOR.

but declines as more storage is added, the remaining peak flattens, and saturation effects become evident. SDES ELCC is less sensitive to renewable builds given the resource dispatches fewer hours each day, thus requires less energy than longer storage durations to refill between charging cycles.

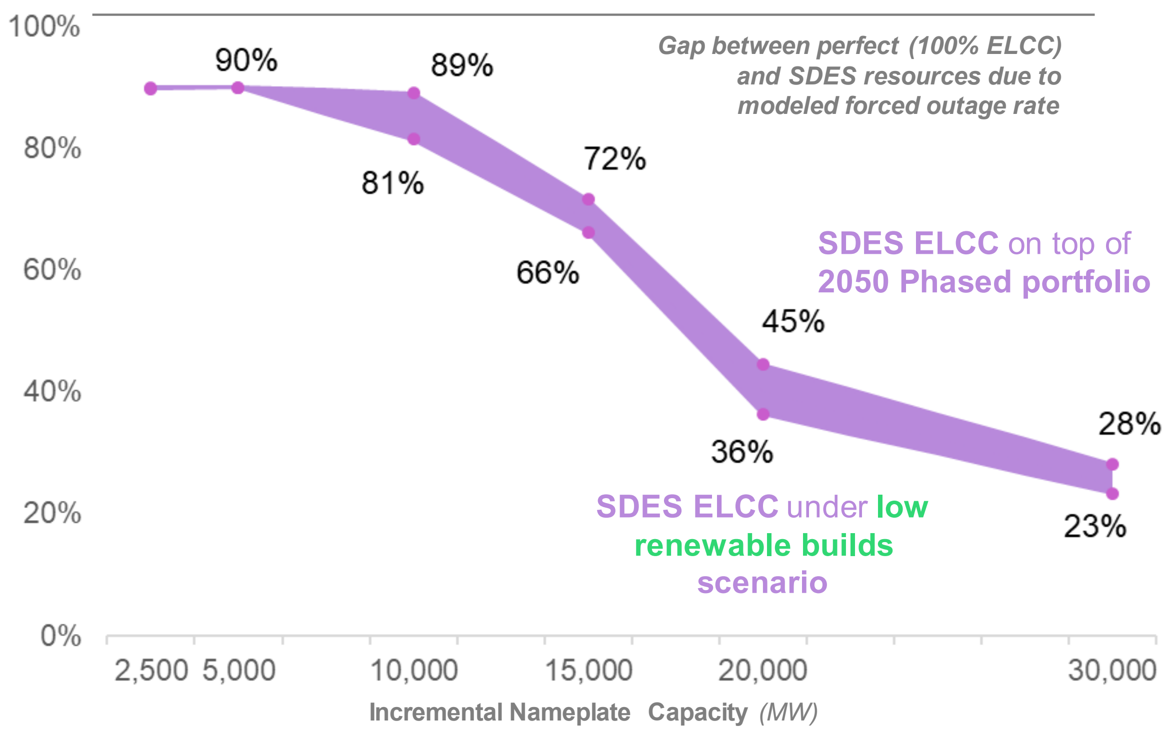
SDES ELCC values are higher in 2050 for two reasons. First, the 2050 system is larger, with higher loads, which effectively slows down the saturation effect of SDES ELCCs. Second, while the 2030 system is summer-peaking and therefore typically meeting a need over a narrow window after the sun sets in the summer, the 2050 resource need is spread over a longer window. This creates more opportunities for SDES to shave the peak before its ability to support resource adequacy diminishes given a longer remaining net peak, which requires longer duration storage resources in order to completely meet the need (though as noted above, short-duration resources can meet the need by not discharging at full capacity, which is precisely what is reflected by the lower ELCC value, which effectively reflects how it could lower output to meet the need).

Figure 4-26. Incremental ELCC for Representative 4-hour Storage Resource, 2030



			SDES (GW)						
Utility-scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	0	2.5	5	10	15	20	30
8.5	5.2	4.2	-	89%	87%	73%	18%	10%	6%
5.6	5	1.6	-	89%	87%	64%	16%	9%	5%

Figure 4-27. Incremental ELCC for Representative 4-hour Storage Resource, 2050



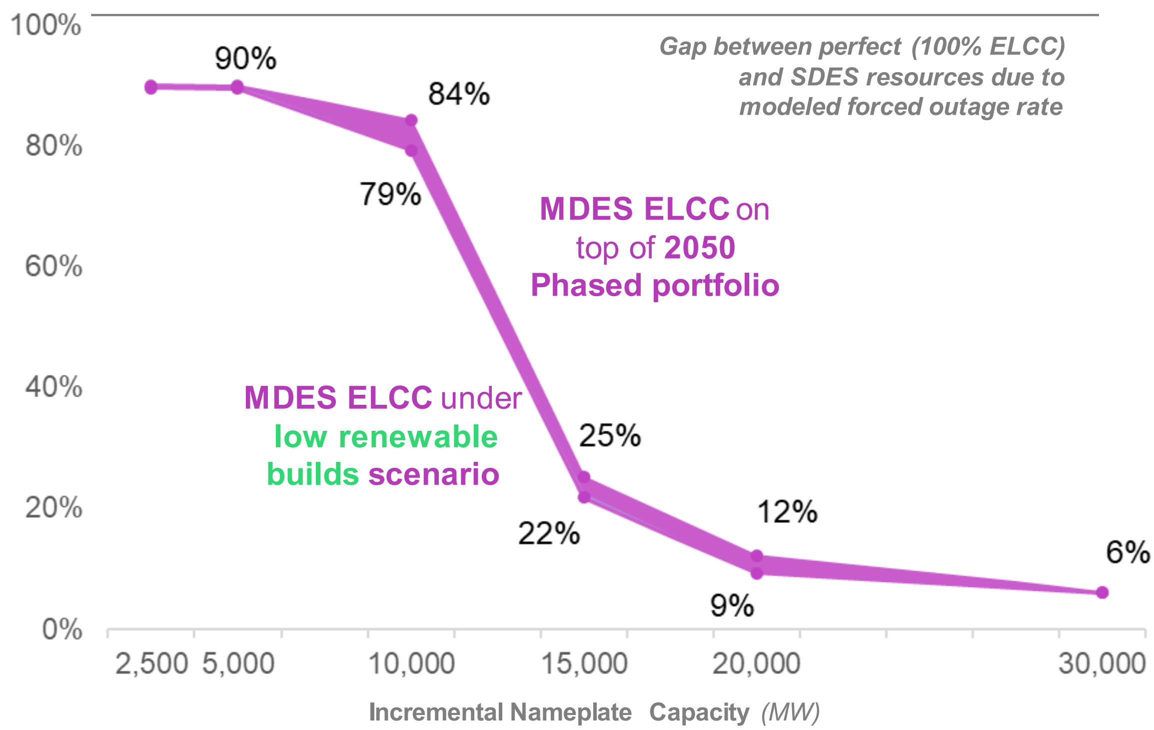
			SDES (GW)						
Utility -scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	0	2.5	5	10	15	20	30
42.4	10.7	30	-	90%	89%	89%	72%	45%	28%
22.1	9.4	11.1	-	90%	86%	81%	66%	36%	23%

4.7 Results: Mid-Duration Storage Effective Capacity

For mid-duration energy storage (MDES) resources, this study examined the capacity contribution for an 8-hour duration storage resource in the ISO-NE system under a range of scenarios and sensitivities. Figure 4-28 and Figure 4-29 show the incremental ELCC of MDES in 2030 and 2050 under the same two scenarios as the 4-hour storage resource.

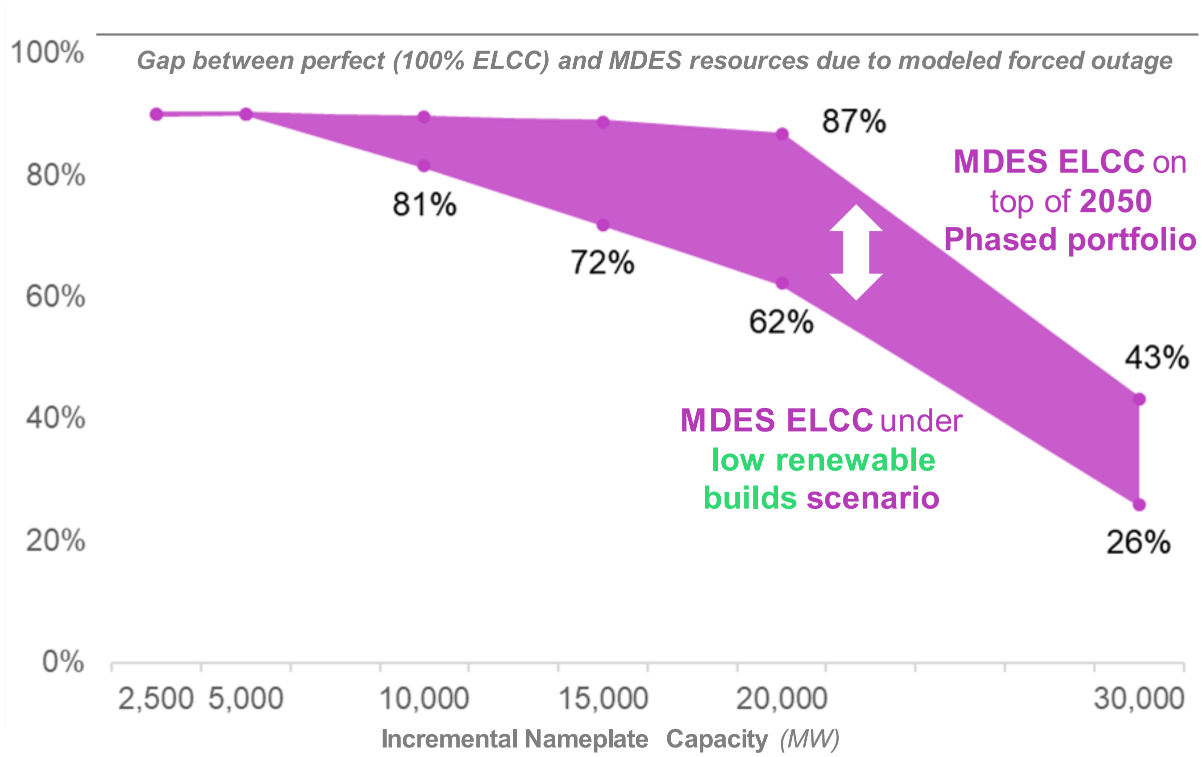
The dynamics of MDES incremental ELCC are generally similar to SDES in 2030: the capacity value exhibits saturation effects after about 10-15 GW penetration; after this point, even 8-hour storage resources are limited by their ability to dispatch over the longer time window required to provide effective capacity. However, unlike SDES in 2050, MDES incremental ELCC remains relatively high through 20 GW of resource additions in 2050. This is because as ISO-NE transitions to a winter dual-peaking system, 8-hour duration resources are more capable of mitigating loss-of-load risks spanning the whole day. Another major takeaway from the chart is that in 2050, MDES ELCC is very similar in the base case and the low renewable sensitivity until relatively high penetrations. There are two reasons for the faster decline in the low renewable case: first, in the low renewable builds future, there is less energy available to re-charge the MDES, thus limiting its capability to shave peak in times of need; second, with less renewables, especially lower wind generation in the portfolio, the system has a net load shape in which fewer periods with risk of loss of load can be adequately addressed by intraday charge/discharge, which reduces the need for an 8-hour duration storage resource.

Figure 4-28. Incremental ELCC for Representative 8-hour Storage Resource, 2030



			MDES (GW)						
Utility -scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	0	2.5	5	10	15	20	30
8.5	5.2	4.2	-	90%	90%	84%	25%	12%	6%
5.6	5	1.6	-	90%	90%	79%	22%	9%	6%

Figure 4-29. Incremental ELCC for Representative 8-hour Storage Resource, 2050



			MDES (GW)						
Utility -scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	0	2.5	5	10	15	20	30
42.4	10.7	30	-	90%	90%	89%	89%	87%	43%
22.1	9.4	11.1	-	90%	90%	81%	72%	62%	26%

4.8 Results: Long Duration Storage Effective Capacity

For long-duration energy storage (LDES) resources, this study measured the ELCC for a representative 100-hour duration storage resource on the ISO-NE system.[66] Different from prior SDES and MDES results where capacity value is valued incremental to a portfolio where no storage resources are present except for existing pumped hydro units, accreditation of LDES assumes the amount of short and mid-duration resources expected in the 2030 or 2050 CECP Phased portfolio has already been achieved.[67] The ELCC results for LDES thus reflect its reliability value incremental to all other CECP assumed renewable and

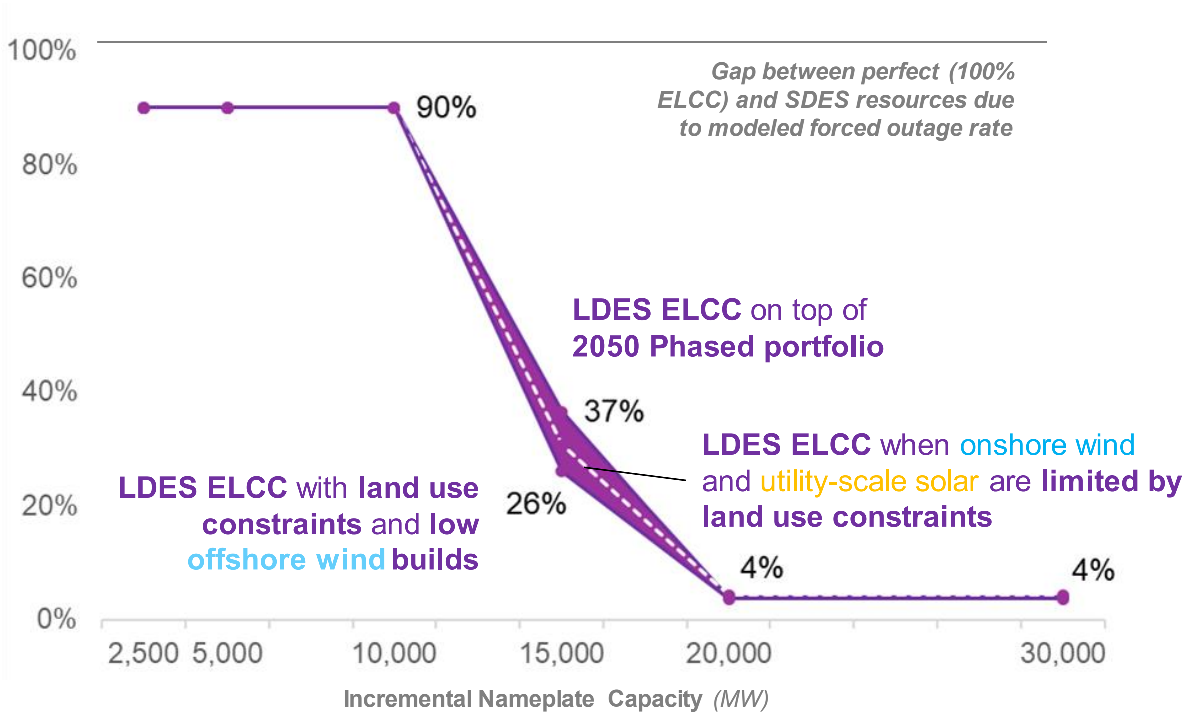
[66] This study also assessed the ELCC for a 24-hour duration long-duration energy storage resource. Please see Appendix E for detailed results and comparison to 100-hour LDES ELCC.

[67] In this way, the capacity value of LDES incorporates the saturation effect among various durations of other storage resources expected to be on the system. Given that LDES is not today cost competitive for large-scale deployments on the grid, assuming certain amount of short and mid duration storage resources are already interconnected to the grid before LDES allows a better characterization of potential capacity contribution from incremental long duration storage resources.

storage resources. Figure 4-30 and Figure 4-31 show the LDES ELCC values in 2030 and 2050, under a range of scenarios.

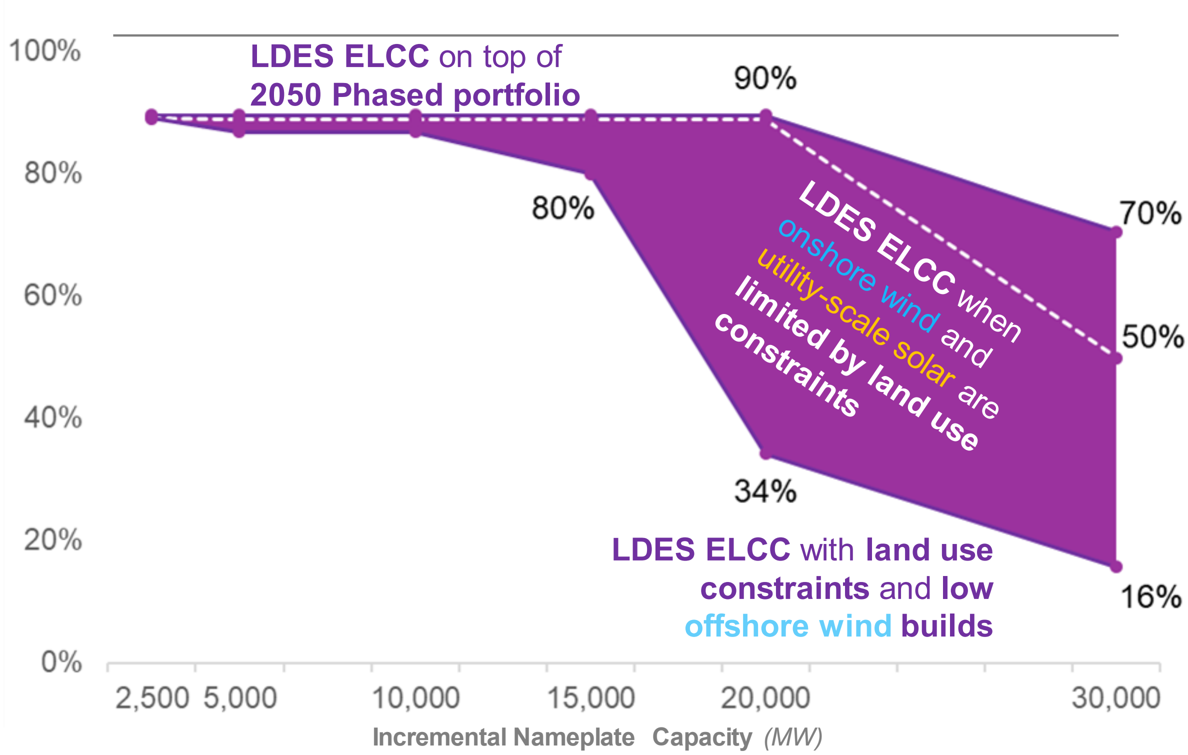
Similar to SDES and MDES, ELCC for LDES in 2030 remains high at low penetrations but then declines sharply as the hours of need spread from the short late afternoon peak to a much longer time window. In addition, demand and the overall system has not yet grown significantly from electrification. In 2050, as the winter dual-peaking pattern starts to become evident, LDES charging from off-peak renewables or other firm resources becomes more capable of filling in the gaps created from the transition to a high renewable grid, effectively shaving all peaks and leading to a higher ELCC.

Figure 4-30. Incremental ELCC for Representative 100-hour Storage Resource, 2030



					LDES (GW)						
Utility -scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	SDES (GW)	MDES (GW)	0	2.5	5	10	15	20	30
8.5	5.2	4.2	2.2	2.3	-	90%	90%	90%	37%	4%	4%
5.6	5	4.2	2.2	2.3	-	90%	90%	90%	31%	4%	4%
5.6	5	1.6	2.2	2.3	-	90%	90%	90%	26%	4%	4%

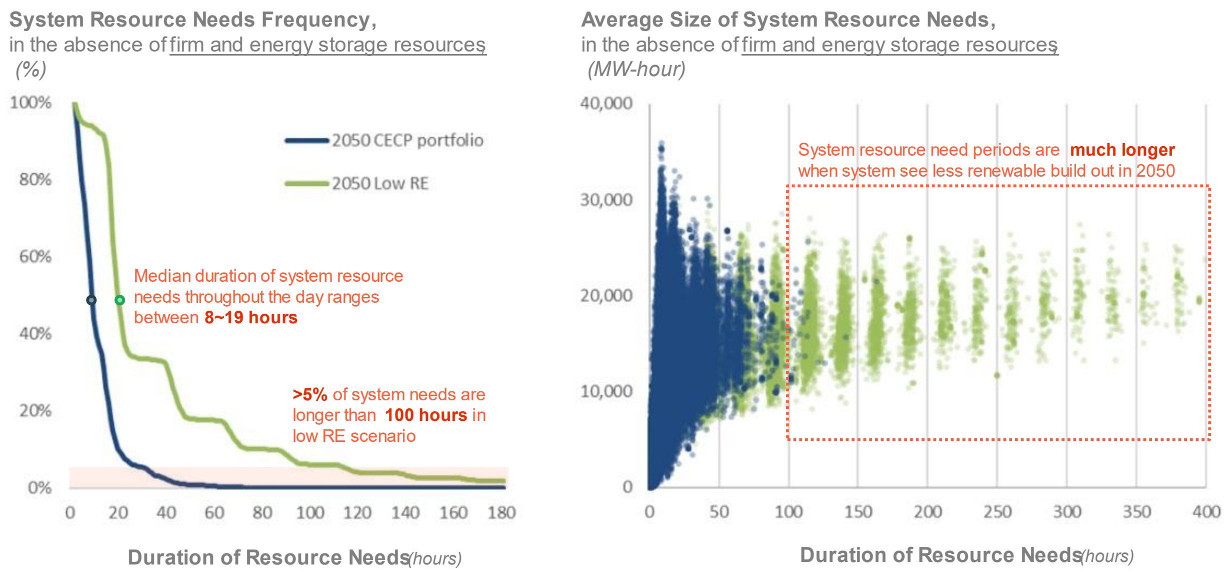
Figure 4-31. Incremental ELCC for Representative 100-hour Storage Resource, 2050



					LDES (GW)						
Utility -scale Solar (GW)	Onshore Wind (GW)	Offshore Wind (GW)	SDES (GW)	MDES (GW)	0	2.5	5	10	15	20	30
42.4	10.7	30	2.2	2.3	-	90%	90%	90%	90%	90%	70%
22.1	9.4	30	2.2	2.3	-	89%	89%	89%	89%	89%	50%
22.1	9.4	11.1	2.2	2.3	-	89%	87%	87%	80%	34%	16%

The chart also compares LDES ELCCs under multiple renewable penetrations: the top line represents LDES reliability value under a renewable build aligned with the CECP 2050 Phased case; the bottom line shows LDES ELCC assuming a lower renewable buildout scenario; alternately, the dash line in the middle depicts a future where primarily utility-scale solar and onshore wind builds are constrained by the amount of land that is available for constructing solar panels and wind farms. There is a divergence between LDES ELCCs across the three scenarios even at low levels of penetration, indicating that the presence of renewable resources can have the most substantial impact on long-duration energy storage resources. As established above, this is because levels of renewable penetration (particularly wind) shape system resource needs in a different way, which requires back-up storage resources to dispatch over various timeframes for mitigating potential loss-of-load events. Figure 4-32 shows the duration of system resource needs in the two scenarios examined here. In a low-renewable future where both utility-scale solar, onshore wind and offshore wind build out face are delayed, over five percent of system resource needs in the absence of firm thermal generation would be longer than 100 hours and as high as several weeks. A 100-hour duration resource in this portfolio will be less valuable than a higher renewable builds scenario where the majority of system needs are shorter than 100 hours.

Figure 4-32. Illustration of System Resource Need Size and Duration Assuming Different Renewable Penetration, 2050



4.9 Diversity Benefits

As established above, while adding energy storage alone generates saturation effects beyond a certain penetration, combinations of energy storage resources, especially longer duration resources, and offshore wind, can produce interactive benefits and lead to outcomes where the total capacity value provided by the portfolio is greater than the sum of resource capacity values independently. This section illustrates such dynamics, with a focus on LDES and offshore wind, though this is not the only interaction which would provide diversity benefits. The analysis assumes all LDES and offshore wind resources are added to the 2050 CECP Phased portfolio, at a point in which all solar and other storage capacity builds are achieved.

Table 4-5 and Table 4-6 demonstrate the incremental ELCC of each resource when it is added to the base portfolio individually, with varying, fixed penetrations of the other resource. For example, with 10 GW offshore wind on the system, the incremental capacity value of the first 10 GW LDES is 89%, but then falls to 17% by 30 GW penetration; similarly, when fixing LDES capacity at 15 GW, the first 2.5 GW of offshore wind addition can provide roughly 57% of equivalent capacity value, but only 7% incremental ELCC by 30 GW penetration. The presence of a diversity benefit, i.e., a higher combined ELCC, is clear when varying the penetration of both resources. Take LDES as an example: while LDES incremental ELCC drops to 17% by 30 GW penetration in a system where there is 10 GW offshore wind, its value remains relatively high at 70% when 30 GW of offshore wind is interconnected to the New England system. Evidently, supplementary offshore wind additions mitigate some of the decline in LDES ELCC as excess wind generation enables more charging and shifts resource needs to time windows that allow long-duration resources to effectively shave peak. The increased value from 17% to 70% reflects such diversity benefits when crediting them all to LDES. The same story applies to offshore wind – incremental ELCC of offshore wind at 30 GW penetration rises from 7% to 42% when doubling LDES capacity from 15 GW to 30 GW. In this case, incremental diversity benefits that result from two resources combined are credited to offshore wind resources.

Table 4-5. LDES Incremental ELCC (%) when Fixing Offshore Wind Penetration, 2050

	LDES (MW)						
OSW (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0		90%	89%	89%	77%	27%	16%
2,500		90%	90%	90%	73%	27%	16%
5,000		92%	91%	90%	73%	31%	16%
10,000		89%	89%	89%	87%	50%	17%
20,000		90%	90%	90%	87%	87%	36%
30,000		89%	89%	89%	89%	89%	70%

Table 4-6. Offshore Wind Incremental ELCC (%) when Fixing LDES Penetration, 2050

	LDES (MW)						
OSW (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0							
2,500	67%	67%	67%	64%	57%	58%	58%
5,000	45%	47%	49%	50%	50%	56%	56%
10,000	21%	20%	19%	18%	32%	52%	54%
20,000	12%	12%	13%	13%	13%	32%	51%
30,000	6%	6%	6%	6%	7%	9%	42%

Table 4-7 presents the diversity benefit dynamics in another way. Each number in the table shows incremental diversity benefits relative to the sum of nameplate MW of the two resources, on a percentage basis. The major takeaway is that diversity benefits between offshore wind and LDES are more evident at a higher penetration, when offshore wind alone could saturate the needs in late afternoon net peak load hours, and LDES shifting excess energy generation can further shave peak and achieve higher combined capacity value.

Table 4-7. Illustration of the Diversity Benefit (%) between Offshore Wind and LDES, 2050

	LDES (MW)						
OSW (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0							
2,500		0%	0%	0%	0%	0%	0%
5,000		1%	1%	0%	0%	0%	0%
10,000		0%	0%	0%	2%	5%	4%
20,000		0%	0%	0%	1%	9%	11%
30,000		0%	0%	0%	1%	8%	15%

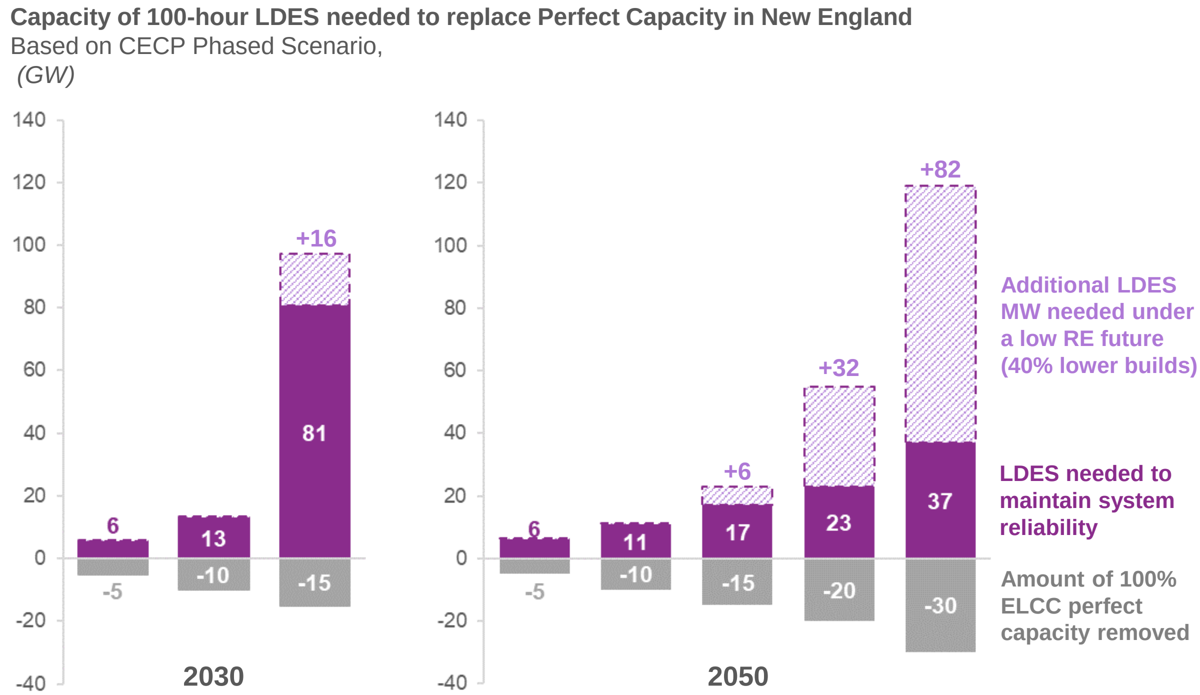
4.10 LDES Replacement for Grid "Perfect" Capacity

In Figure 4-32, we have shown what the residual system needs look like, from both the size and duration perspective, after renewable generation gets dispatched in New England in 2050. For the CECP Phased portfolio, these system needs are met by a combination of gas-fired generators, biomass, nuclear, external market imports, and various durations of storage resources. These resources play a critical role in maintaining the system reliability, especially in winter and during renewable drought periods. However, given that most of these system needs are lower than 100 hours in duration, LDES could provide an alternative to replacing these firm resources and retain system reliability performance.

This potential goes beyond the 7 GW of LDES resources included in the same planning scenarios from the CECP but is tied to the levels of renewables as was shown in Figure 4-31. Up to certain levels, LDES can replace thermal capacity in the system on a roughly one-to-one basis, depending on the relative forced outage rates. As total penetration increases, storage incremental ELCC decreases since net load becomes flatter from the other storage resources dispatching during peaks. This results in the opportunities to charge being smaller, and to discharge being stretched out, respectively. Additional storage then can only decrease peak net load and displace thermal capacity through dispatch prolonged over 100 hours and at derated levels. This potential is limited in systems with lower levels of intermittent generation, such as in 2030, or in 2050 in a scenario where only a share of the CECP portfolio of renewables gets built. Figure 4-33 shows how much long-duration storage is needed to displace different amounts of hypothetical "perfect capacity" in 2030 and 2050, under the CECP portfolio and in a low renewable energy future[68].

[68] The low renewables future refers to the case in 4.8 with land-constrained solar and onshore wind along with low offshore wind builds.

Figure 4-33. LDES as an Alternative to Support System Reliability in 2030 and 2050



4.11 100% Renewables Plus Storage Scenario

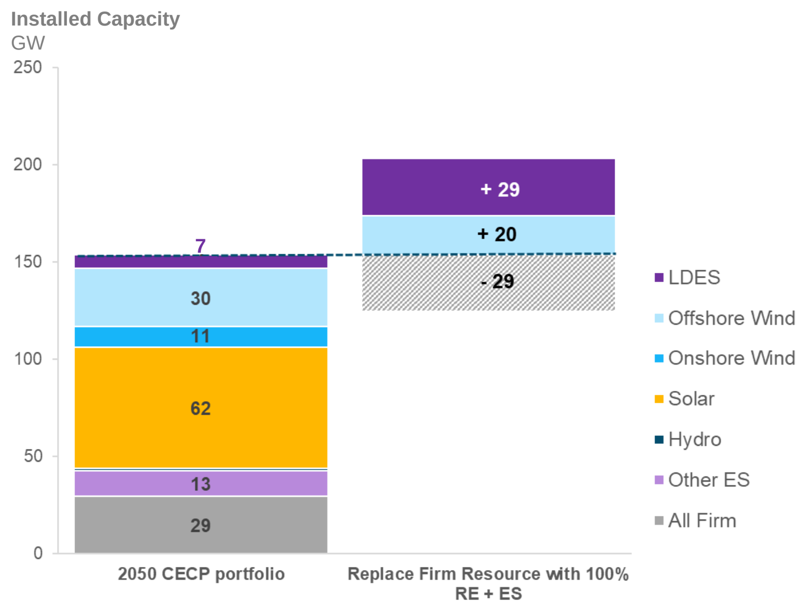
E3 also performed a separate sensitivity to better understand what a 100% deeply decarbonized scenario with LDES might look like, from a total capacity need perspective. Based on the capacity value assessed for LDES as well as its interaction with the offshore wind, this study identified a 100% deeply decarbonized portfolio where renewables complemented with 100-hour duration storage resources are sufficient to meet system demands. In this scenario, relative to above, the system is allowed to add additional offshore wind to help drive up the ability of LDES to replace firm capacity on the system[69].

Figure 4-34 summarizes this example replacement portfolio that could meet the same level of reliability as the 2050 CECP Phased portfolio. In addition to all renewable and other short and mid-duration resources forecasted in the CECP Phased portfolio, the New England grid could achieve equivalent reliability from adding 20 GW more offshore wind and an extra 29 GW LDES, to replace 29 GW firm resources. In this scenario, a *significantly* higher renewable penetration future with 60 GW of wind (including both onshore and offshore wind) and 62 GW of solar (including both utility-scale and distributed

[69] A subtle point to make is that Section 4.10 focuses on removing generic "perfect" capacity on the grid and replacing it with LDES. Alternately, in Section 4.11, we remove the specific "firm" capacity resources in the New England grid (with their associated outage characteristics).

solar), in addition to the 100-hour duration LDES, is needed to replace all existing dispatchable firm capacity in 2050[70].

Figure 4-34. 100-hour Duration LDES and Offshore Wind Additions to Replace CECP Firm Resources, 2050 – Example Portfolio with Equivalent Reliability



4.12 Storage Impact on Curtailment and Emissions

Energy storage on an annual basis allows the New England system to reduce energy curtailment and avoid emissions from thermal generation. E3 evaluated the role of storage in reducing curtailment for selected scenarios. Outside of challenging periods when storage discharge helps maintain system reliability, storage resources leverage over half of the renewable generation that exceeds load in the CECP 2050 portfolio, for example. In the summer, solar generation alone will often surpass even the highest midday energy demand on the system. In the fall and spring, wind, especially from offshore turbines, generates at high levels at most hours of the day, often above load. Storage leverages this excess renewable generation to shift carbon-free energy to peak demand hours each day.

On a low energy demand weather year as shown in Figure 4-35, renewable energy curtailment is significant in every week of the year – summing up to 70 TWh. However, when we add energy storage to the system, it can charge and absorb 37 TWh of excess energy in the period. Some energy will still be generated in excess due to the nature of renewable resources which for shorter periods of time can produce at peak levels much higher than the available storage capacity. This can occur even in the winter in the same weeks that thermal generation might be necessary.

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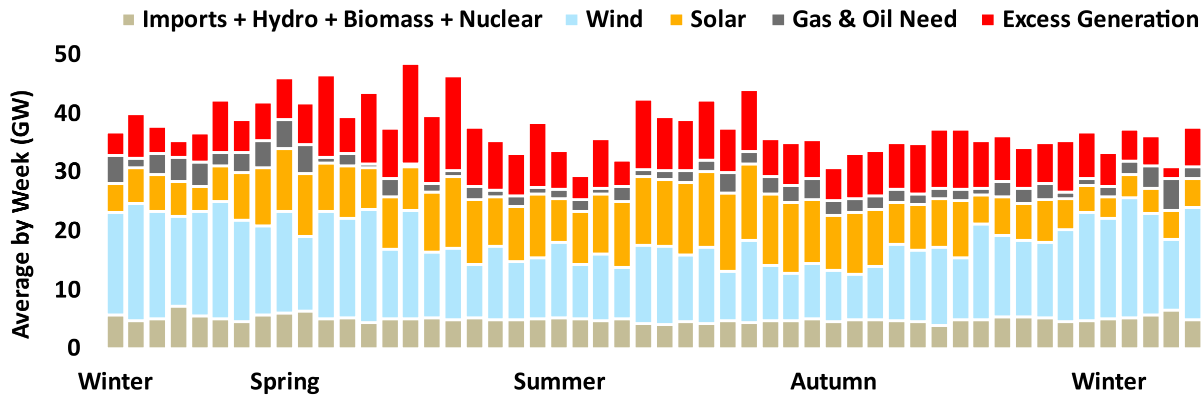
[70] This does not take into account potential project delays associated with interconnection or transmission issues. Further analysis will be needed to study pathways for realizing a renewable penetration at this scale.

Figure 4-35. Example Simulated Low Peak and High Energy Excess Year

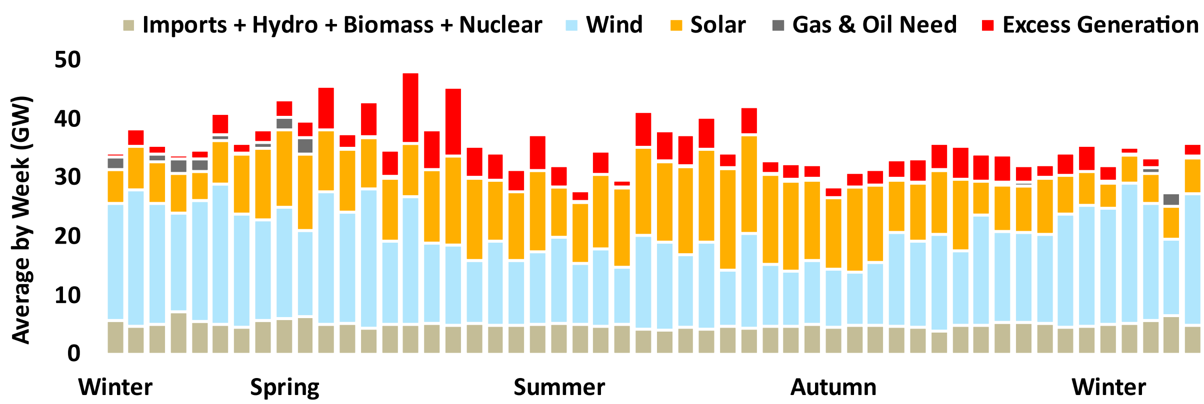
Before Energy Storage

Peak Load	Peak Net Load	Annual Imports	Annual Gas & Oil	Annual Excess
GW	*GW*	*GWh*	*GWh*	*GWh*
46	37	11,458	21,192	69,881



After Energy Storage

Peak Load	Peak Net Load	Annual Imports	Annual Gas & Oil	Annual Excess
GW	*GW*	*GWh*	*GWh*	*GWh*
46	*37 ->* 24	*11,458 ->* 3,808	*21,192 ->* 3,981	*69,881 ->* 32,541

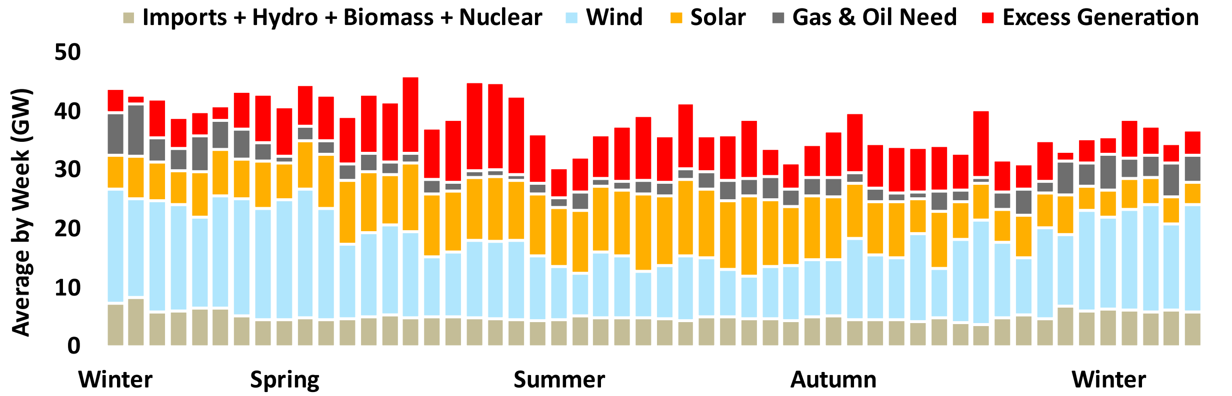


Avoiding emissions is another significant impact of energy storage in the system beyond improved reliability. As seen in the example year in Figure 4-35, storage uses that stored excess energy to displace the need for thermal generation from natural gas and oil. This is even more relevant when we consider a colder weather year where energy demand is much higher in the winter. Without storage in the system, this could drive up to 27 TWh of emitting generation in New England. When we add energy storage to the system, it can discharge and reduce that need down to less than 9 TWh.

Figure 4-36. Example Simulated High Peak Net Load Year

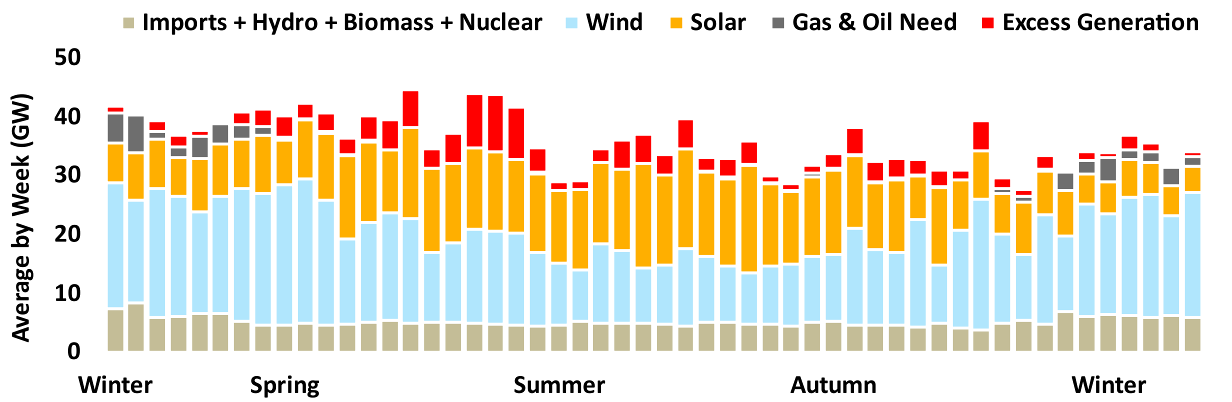
Before Energy Storage

Peak Load	Peak Net Load	Annual Imports	Annual Gas & Oil	Annual Excess
GW	*GW*	*GWh*	*GWh*	*GWh*
53	46	13,741	27,168	64,334



After Energy Storage

Peak Load	Peak Net Load	Annual Imports	Annual Gas & Oil	Annual Excess
GW	*GW*	*GWh*	*GWh*	*GWh*
53	*46 ->* 28	*13,741 ->* 6,541	*27,168 ->* 8,482	*64,334 ->* 26,047



In sum, excess energy and thermal generation will vary across weather years but is expected to be significantly – but not entirely – displaced by storage. On average, storage reduces excess energy by half and displaces almost 20 TWh of thermal generation – making sure the system is operating within emissions constraints.

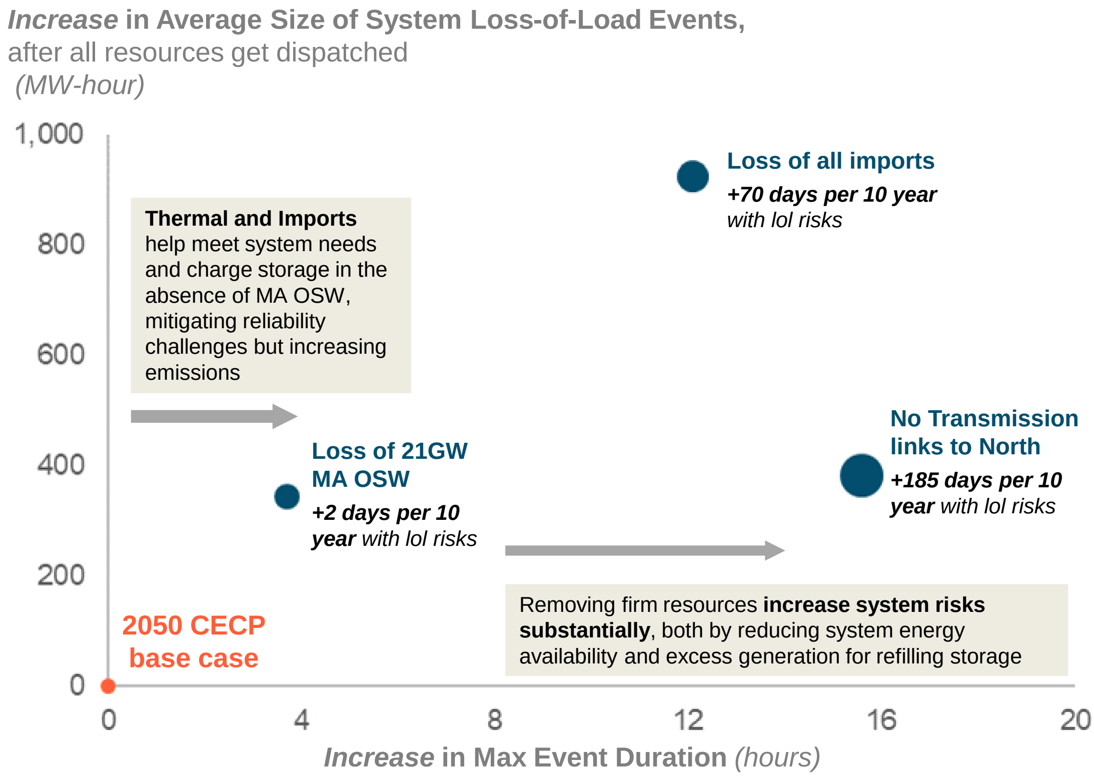
4.13 Results: Reliability Risk Under Key Sensitivities

To capture the uncertainties in ISO-NE system reliability due to risks associated with a range of factors, including transmission bottlenecks and outages, as well as market reliance, this study also explores how a variety of sensitivities could potentially impact reliability in ISO-NE 2050 system and in the Commonwealth. These include:

1. **No Massachusetts Offshore Wind**: assuming transmission links that interconnect MA OSW go down, therefore modeling New England system in the absence of MA OSW generation.
2. **No Transmission Nort**h: assuming grid constraints between Northern and Southern New England cuts down the connection between NH and MA, therefore modeling Southern New England system alone.
3. **No Imports:** assuming no market reliance from New York or Quebec, modeling the New England system without imports.

Figure 4-37 shows the change in system loss-of-load risk under different sensitivities. In the absence of Massachusetts' offshore wind, the ISO-NE system maintains a similar likelihood of loss-of-load compared to 2050 CECP Phased portfolio. This means that other resources in the portfolio combined with storage are largely sufficient to meet system needs during off-peak hours. However, during system risky periods, losing access to MA offshore wind both directly intensifies system resource shortages, but also shrinks excess energy available for refilling long-duration storage resources. This elongates the window of system needs and undermines storage resources' capability to effectively shave peak. Therefore, although the system portfolio is able to sustain similar levels of loss-of-load expectation (LOLE), the magnitude and duration of loss-of-load events increase. In the loss-of-imports sensitivity, ISO-NE sees a substantial increase in system LOLE. There are two primary reasons for this phenomenon. First, there is a direct energy availability decrease in the system, as out-of-market imports are not accessible in the timeframes when there is insufficient resources to meet load. Second, the amount of energy generation available for energy storage re-charging becomes limited, especially during off-peak hours when storage resources need to refill before discharging in the next net load peak window. The loss-of transmission to North case, which focuses only on Southern New England system alone, tells a similar story: when a substantial amount of thermal resources are taken offline, there are insufficient renewable and storage resources to fill the gap.

Figure 4-37. System Contingency Event Characteristics Comparison in Sensitivity Cases, 2050



The impact on storage ELCCs vary across different sensitivities, but generally follow the same pattern. In the loss-of-Massachusetts offshore wind sensitivity, the capacity value of storage resources (especially LDES) can be lower as the shape of system resource need becomes more dominated by solar, which creates the peaky late afternoon peaks. In the no-transmission-to-North sensitivity, storage ELCCs are largely dependent on the relative composition of renewables and firm resources in the system portfolio. Since offshore wind is a major part of renewable resources that interconnect to the Southern New England system, storage ELCC will generally benefit from it and could achieve a relatively high value. However, since the system size is smaller, ELCCs will also saturate quicker and drop after a few tranche additions. Finally, the loss-of-imports sensitivity is a unique hypothetical case when it comes to storage ELCC. Since imports in the base case are already derated to what can be considered firm, flat MW availability, losing imports will not impact the shape of system net load and thus size and duration of system needs. Therefore, storage ELCC will remain the same as 2050 base case[71].

[71] This assumes storage resources can charge sufficiently from other firm resources in the system. If instead the absence of imports results in an inability of energy storage to adequately charge in advance of potential reliability events, ELCC values would decrease.

Section 5: High Level Takeaways and Recommendations

This study provides an updated assessment of the role of storage in the state, and an assessment of the potential value that mid- and long-duration storage may provide to the system as the Commonwealth pursues its decarbonization goals. The study evaluates and emphasizes the potential capacity value provided by storage, particularly longer duration storage.

We show that the role of energy storage changes to suit grid needs: providing ancillary services, arbitraging prices to match otherwise curtailed renewable generation to load, providing reliable capacity in a deeply decarbonized system, and in select cases improving local resilience. In spite of these many use cases, the value of storage today is limited, and state programs remain critical to drive deployment. However, current programs will not be enough to achieve deployment at the scale suggested by the CECP. For this, additional state programs will be required, as will dedicated efforts to reduce existing financial, technological, supply chain, and operational barriers to deployment.

The value of energy storage will grow as renewable penetration increases, producing more volatile energy prices and marginal emissions rates, leading to more revenue for storage operators, ratepayer savings, and lower emissions from the electric sector. Alongside this increasing value, storage costs for all durations are expected to continue their decline through innovation, “learning by doing”, and competition among storage technologies and other resources that can provide similar services. In the near term, short windows of need will drive deployment of high efficiency short duration storage. However, we anticipate a shift towards mid- and long-duration energy storage in the 2030s and beyond as net load needs lengthen beyond a few hours and as these newer technologies benefit from earlier pilots and broader innovation.

Longer storage durations will be valuable in providing capacity as the New England grid shifts to become a winter peaking system with possible multiday periods of high electrified heating need and low renewable production. The ability of storage to provide firm capacity during such periods depends strongly on the rest of the renewable portfolio; higher renewable builds afford more charging opportunities and fewer long gaps of capacity need. In particular, energy storage and offshore wind are highly complementary, with significant “diversity benefits” resulting in a combined capacity value that exceeds the individual capacity values of the resources. In the context of a high renewable build-out, 100-hour storage could replace several GW of thermal capacity on a nearly one-to-one basis with no decrease in reliability. However, a lower achieved renewable build-out would significantly increase the amount of storage required to replace the same amount of thermal capacity.

To better position the Commonwealth for efficient deployment of energy storage as part of Net Zero electric grid goals, we lay out a series of policy recommendations based on this analysis and experience across North America. These recommendations appear in full detail in the Executive Summary, but we summarize key elements of them here. These recommendations focus on incentives for near-term storage deployment that can bridge the gap to long-term, market-supported and societally valuable use cases.

We suggest refining operational signals in existing state programs – Clean Peak Standard, ConnectedSolutions, and the SMART storage adder – to better align with grid needs, and we suggest the creation of mechanisms to provide improved revenue certainty to developers who rely on these programs for benefits. We see the need for state action to motivate deployment of storage that is not being built today, including incentives aimed at large scale storage resources, support of one or more long-duration storage pilot projects, and encouragement of storage deployed to provide resiliency where this value is high. Across all these components, the Commonwealth should prioritize benefits to low-income and energy communities through policy carve outs or additional incentives to maximize federal funding support from the IRA, especially into disadvantaged communities.

We recommend additional efforts to support energy storage market development. These include improving coordination among the state, developers, and utilities for data/information sharing and project identification, as well as engagement with local environmental justice communities for transparent and collective decision-making around brownfield site development. We also suggest planning improvements such as joint procurement of storage in offshore wind RFPs and consideration in utilities' Energy Sector Modernization Plans of investments to improve integration of storage and enablement of storage-like technologies (e.g., flexible load, vehicle-to-grid). Finally, we call for a streamlining of guidance on siting and permitting to lower barriers for developers, municipalities, businesses, and homeowners.

Appendix A. Summary of Stakeholder Involvement

This appendix includes a summary list of key feedback received through the two workshops, written comments, and interviews with stakeholders. We note that the summary provides feedback received from stakeholders, but that this commentary may not represent consensus opinion across all stakeholders or even all stakeholders within a group (e.g., not all developers may agree with the statements attributed to developers in the summary). Please note that feedback is current as of October 2023.

A.1 Key Use Cases and Revenue Streams

- EDCs point out that Vehicle-to-Grid EV capabilities may usurp some of the value of distributed SDES. However, they note that there is uncertainty in the timeline and magnitude of Vehicle-to-Grid showing up as a reliable grid resource. Environmental stakeholders note that Vehicle-to-Grid, similar to flexible load, has no land use and suggest that the state push EDCs to include these capabilities appropriately in integrated system planning.
- EDCs suggest possible end user applications for MDES and LDES, including pairing storage with FLISR to improve resiliency/reliability in underserved communities, using energy storage to manage EV fleet charging load, as bridging solutions to allow faster interconnection of new load before slower-built infrastructure comes online, and to improve utilization factors of existing electrical assets.
- Developers note that solar+storage installations can be profitable today, but that standalone storage economics are unfavorable. However, EDCs note that they see more interconnection requests for standalone storage presumably due to the impact of the IRA.
- Pumped hydro operators note that their resources run little today (~25% utilization) due to low round trip efficiency and small price spreads. Environmental stakeholders worry that larger price spreads in the future could result in more cycling of pumped hydro and therefore more water level fluctuations at lower reservoirs. They request that the state create guardrails around pumped hydro operations to minimize impacts to the ecosystem.
- Developers note that resiliency can be a large value stream for commercial use cases, but that backup gas generation is cheap and often used instead. They also see demand charge suppression as a key value stream for large commercial BTM installations and MLPs. Arbitrage against TOU rates is also an applicable value stream, but the long peak period windows can mute this benefit.
- Developers find residential rates in the Commonwealth to be non-starters for BTM residential storage. They also note that current residential metering does not meet the latency standard required for participation in CPS.
- MLPs note that their most valuable uses are to reduce ICAP and RNS charges. However, predicting the hours for these is getting more and more challenging, such that MLPs are considering installing longer storage durations just to have a better chance of aligning dispatch with the peak hours. They note a need for coordination with ISO-NE and the EDCs to improve certainty of this process. Meanwhile, grid operators express concern that MLPs are installing

large storage resources that are effectively invisible to them and have somewhat unpredictable behavior in the eyes of the grid operators.

- Developers note that they have no way to be compensated for the T&D value that their installations provide. Clean energy advocates agree that the state should create mechanisms to monetize currently non-monetized benefits.
- EDCs appreciate energy storage as an NWA because this arrangement includes contractual obligation for storage to dispatch based on signals from the EDCs. This is preferable to utility ownership because rate based assets cannot bid into markets in ISO-NE and EDCs cannot access the full incentives and tax credits available to developers. They wonder about joint ownership models between developers and EDCs.
- EDCs point to the Provincetown battery as a success story that improved reliability in a place where it would be challenging and environmentally damaging to build additional lines. However, EDCs also cite a failed proposal on Martha’s Vineyard, which fell through because aggressive electrification goals rendered energy storage inadequate to avoid the need to install additional undersea cables.
- EDCs see the Storage As a Transmission Only Asset (SATOA) criteria as too limiting to justify building these projects. ISO-NE agrees that these assets would sit around too much to be justified and see firming of offshore wind as a better use case at the transmission level.
- Advocates view storage buildout as an opportunity to improve resiliency in environmental justice communities via microgrids and other solutions. However, they note that importance of education and demonstration to get community members on board. They recognize that startup for these projects is resource intensive.

A.2 Existing State Programs

General

- Environmental groups note that the combination of state programs that support energy storage seems overly complicated and bespoke. They request evaluation of the programs to understand how each is working and to improve transparency on program performance. Similarly, developers note that the existing policies were crafted under different conditions than today. They also request evaluation and a mechanism to trigger program updates based on the changing context in which the programs operate.
- Clean energy advocates request a larger role for equity in the state’s storage plans. This includes things like equity adders or carveouts in programs, on-bill payment, models for leasing or owning, and financing. They note that getting incentives to residents can be tricky, because giving someone a rebate check might make them ineligible for some low income programs.
- Many stakeholders note that incentive programs are needed to support energy storage today. Market revenues alone cannot create favorable project economics. However, developers seek better certainty in program revenues: they request procurement, long term contracts, and/or some mechanism that fills in missing money based on dynamic market conditions.

Clean Peak Standard

- Developers stress that the structure of Clean Peak does not allow them to bank on CPS revenues, which makes it challenging to secure financing. They suggest a price lock or a price floor to improve certainty of this key revenue stream. Environmental groups recognize this too: they note that CPS incentivizes behavior but not buildout of storage and suggest contracting mechanisms instead.
- EDCs note that the statewide CPS dispatch windows leave no room for subtlety – a project sited near urban load should get different dispatch signals than a project sited near a rural solar farm. They would prefer to play a bigger role in determining storage operations.
- MLPs note that they cannot participate in any of the state incentive programs, but wonder if Clean Peak rules could be amended to allow them to opt-in to the program.
- Developers note that the CPS dispatch window incentivizes projects with exactly four hours of duration based on the set discharge window length.

SMART

- Developers explain that the have no incentive to install more than the minimum required storage capacity to receive the SMART storage adder, and that their dispatch behavior is mostly just to shift otherwise clipped solar production. The CPS incentive with the SMART multiplier and low arbitrage opportunities combine to create no justification storing power (and incurring efficiency losses) otherwise.
- Developers note that inflexible timeline requirements to lock in their storage adder tranche are too tight given uncertainty in interconnection timelines and lack of developer control over this process. They also note that SMART's colocation rules for solar and storage can be tricky to fulfill at sites with limited space.
- EDCs suggest only providing the SMART storage adder to systems that are DC-coupled, since inverters on these systems can cap output and ensure no harm to the system.
- ISO-NE notes that requirements on storage to charge only from paired solar can result in suboptimal operations. They would prefer to remove this constraint to make all storage available for operation that helps the grid.

ConnectedSolutions

- Developers note that ConnectedSolutions is a valuable revenue stream for BTM installations.
- Clean energy advocates suggest adding an equity component to ConnectedSolutions.

A.3 Barriers to Deployment

Supply chain and material cost

- Developers note that cost reductions from the IRA have been offset by cost increases due to supply chain issues and interconnection. They also point out that landowners now understand the value of their land, which also drives cost up and forces developers to consolidate capital across fewer projects.

- Environmental groups note that the mining of lithium and rare earth metals to support many battery technologies poses an environmental/humanitarian problem, but that these lifecycle impacts need to be considered alongside impacts of fossil fuel extraction.

Market uncertainty

- Developers express interest in tolling agreements in which EDCs would pay a flat amount and get operational control of storage, but recognize that the state may not support this because it transfers risk to ratepayers. EDCs raise the possibility of some kind of insurance to help with revenue certainty.
- EDCs note that current price spreads are too small to promote frequent cycling of energy storage and that continuation of this trend would keep storage out of the money as incentives weaken.
- Developers note that the capacity accreditation rules under consideration by ISO-NE now will strongly impact capacity revenues for future storage projects. These rules will play a large part in determining the durations of future storage projects.
- MLPs note that they often lack the ability to fix storage systems when things are broken due to proprietary operations software and no remote fixing. They find that small issues can take down large fractions of a battery array for long periods of time while they wait for maintenance.
- MLPs note that chasing regulation revenue has led to faster-than-anticipated system degradation, which lessens the storage's peak reduction ability.
- ISO-NE notes that the day ahead market is not designed for energy-limited resources and may require rethinking as storage penetration grows.

Access to revenue streams

- Developers note that the wholesale distribution tariff that applies to FTM distribution-connected systems is detrimental to project economics. Specifically, they point to high demand charges and price-induced restrictions on operational hours that increase the cost of charging and obscure market signals. However, we note that this tariff is being reformulated, and developers do not yet have experience with the newest proposed tariffs.
- Developers note that paring storage with offshore wind makes sense, but that storage and offshore wind developers tend to be two different parties, and there is no clear norm around how costs/revenues are split between the two.
- EDCs note that value stacking across the many possible revenue streams of energy storage is challenging to achieve in practice, so a project cannot simultaneously prioritize reliability, T&D value, energy arbitrage, and capacity revenue all at once. Developers add that value stacking is generally more challenging in deregulated markets.

Conflicting and unavailable information

- EDCs note a need for a coordinated planning process or some mechanism to share knowledge. Without this sharing, they find that developers overpopulate the interconnection queue based on insufficient information available to them in hosting capacity maps.

- ISO-NE notes that FERC 2222 will help get prices to load (including BTM storage), but admits there is much to iron out, including data quality, before this vision becomes reality.
- MLPs note that utility control of storage operations can be challenging to establish due to different communication platforms and control systems used by manufacturers.
- Developers and EDCs both note the need for geographically diverse dispatch signals – for example, storage in Boston may not have much local solar to charge from compared to storage in the western part of the state. They also note that real-time marginal emission data from ISO-NE would be helpful in place of static “low carbon” windows.
- MLPs note a need for technical assistance with public engagement and planning. Environmental groups note that this need extends beyond MLP territories since many communities do not have the experience or resources to evaluate proposals from developers.

Safety concerns

- MLPs note that previously-offered training for fire chiefs was helpful; they hope more trainings of this sort will be available going forward. Similarly, clean energy advocates request the standardization of safety codes, fire codes, building codes, and others to help unify the market across states and within states.
- MLPs note that residents may be more accepting of storage projects when they are partial owners of the projects, as is the case for MLP-owned storage.
- Developers note that safety standards need to differ by technology, so low-fire-risk technologies are not subject to the same prevention and suppression requirements as technologies with higher fire risk.
- Environmental groups do not support operation or expansion of the existing pumped hydro facilities in the Commonwealth. They cite concerns regarding erosion, water quality, and habitat loss that cause loss of land and increased mortality of wildlife that depend on the rivers used as lower reservoirs.

End-of-life considerations

- Clean energy advocates envision a future in which storage is a commoditized plug-and-play product, such that users do not need to think about recycling, how to operate, insurance, etc.

Permitting

- Developers note that a lack of standardized process/rules means that every project requires unique treatment and negotiation. This includes inconsistent or nonexistent bylaws, tax treatment, fire safety requirements, etc. MLPs note a project that was nearly abandoned because the town initially planned to tax the project at a normal property rate. Other stakeholders recall the late cancellation of a project at Boston Medical Center due to fire safety concerns.
- Developers also note that satisfying noise ordinances can be an unexpected road block.
- Developers note that the decision determining lack of jurisdiction of EFSB over large storage projects creates further uncertainty around the approval process.

Interconnection

- Developers cite interconnection as one of their biggest challenges. They recall impact studies that take over a year, and feel that there is no incentive for EDCs to make interconnection an easier process. They appreciate the formation of the Interconnection Implementation Review Group (IIRG), but have yet to see progress from it.
- Developers note that EDCs and ISO-NE make unreasonably conservative assumptions about storage operation in their interconnection studies, which results in slower timelines and higher costs. EDCs argue that without the guarantee of an operational schedule, they have to assume charging could occur during high load hours since CPS and market signals are not strong enough deterrents to this. They note the future possibility of localized market signals through DERMS to ensure grid-beneficial dispatch behavior, but caution that the technology needs to develop more before this is realized. Developers note that ISO-NE implementation of FERC 2023 should reduce conservative assumptions in interconnection, but the actual implementation of this is unknown today.
- MLPs note that interconnection is a non-issue for them. They can often approve a project in a week due to their simple structures and lack of “red tape”.

Siting

- Developers note that siting in the Commonwealth is a challenge compared to states with more available space. They also note the lack of an incentive to site in Boston, where storage could be very useful but siting is especially expensive. EDCs echo this sentiment, and note that siting LDES close to load would be useful, but will be challenging if 10-20 acres are needed for a project. MLPs also feel this challenge, as many of them lack undeveloped space.
- Developers note the high value in siting at old power plant locations like Brayton Point, but that communities tend to prefer parks or other public space to new energy infrastructure projects. Environmental groups emphasize this point and note the need to engage with community members and not just local officials.
- Environmental groups wonder how the newly established Commission on Clean Energy Infrastructure Siting and Permitting (CEISP) might improve siting. Government representatives note that CEISP has not yet met, but that their objectives include improving siting and permitting processes for onshore clean energy infrastructure (including storage).
- Environmental groups note that greenfield solar & storage is still the path of least resistance for developers, which is not the signal the state should be sending. They see that the possibility of land development for solar/storage raises the cost of ecologically valuable land and makes it difficult for land owners to make environmental responsible choices. Environmental groups stress the need to target siting at brownfield sites and strip malls, and they acknowledge the challenge of balancing renewable development, housing needs, and other criteria in policy and practice.
- EDCs note their appreciation for having input in the forthcoming CPS distribution multiplier values, but they contemplate the best method for communicating where storage is most valuable. They note that short term load forecasting at the feeder level seems to be the right mechanism to determine this locational need. They also note that drawing a map with

actionable information about siting on the transmission system is difficult because of the highly networked nature of that system.

A.4 Mid- and Long-Duration Energy Storage

- Developers note the need for near term incentives so technologies can mature long before they are needed on the grid. They add that no current programs support LDES and that contracts or procurement specific to LDES would be best because these technologies cannot compete with SDES technologies given today's use cases given their relatively low efficiency and agility.
- Developers speculate that their most promising use cases are wind firming, reliability, and capacity. They are eager to deploy demonstration projects, but hope to move quickly after that to large installations (10 MW or more) to take advantage of economies of scale.
- MLPs note their ability to move faster with innovative projects compared to EDCs. They pride themselves on this and look forward to partnering with developers of novel technologies and/or a new grant program similar to ACES, which spurred much storage interest in MLPs.
- EDCs and ISO-NE noted that delivery of a large project often takes more than five years due to permitting, interconnection, supply chain, and other delays. This highlights the need to "learn by doing" today even though need for large amounts of storage and especially LDES may be years away.

A.5 Study Approach

- Developers provided valuable feedback specific to use cases presented in Section 2.3 to ensure that the use cases reflect their experience with real projects.
- Developers provided valuable feedback on the MDES/LDES candidate technology specs in Table 3-2.
- Developers noted study outputs that would be most useful to them. To the extent possible, we have complied with these requests in the final version of this report. Examples of requested outputs include:
  - The value of storage in portfolios other than the CECP Phased scenario,
  - Results for storage with 24 hours of duration, and
  - Insight into tradeoffs between different durations in a deeply decarbonized portfolio.

Appendix B. Storage Incentive Policies in Neighboring States

B.1 Energy Storage Solutions (CT)

Connecticut's Energy Storage Solutions program is intended to reduce grid demand during critical times of peak grid stress.[72] It is sponsored by the CT Public Utilities Regulatory Authority and executed by the Connecticut Green Bank, Eversource Energy, and United Illuminating. The program has separate investment and performance incentives for residential and commercial/industrial customers.

All customers installing battery storage systems are eligible for investment and performance incentives if they allow utilities to dispatch electricity from these systems during times of peak grid stress. Only eligible equipment installed by eligible contractors is covered. The utility will not dispatch if storms are forecast in order to preserve battery power to cover potential post-storm service interruptions.

Investment incentives are paid out based on installed storage energy up to a cap. Qualifying residential and commercial/industrial installations receive a "Grid Edge" or "Priority Customer" adder.

Residential investment incentives are capped at $7,500 and are conditioned on both the total amount of battery capacity installed on the grid (the "step") and several household modifiers. Table B-1 illustrates these incentives. An "Underserved Household" is defined by the CT Department of Energy and Environmental Protection list of Distressed Municipalities. A "Low-Income" household is defined as at or below 60% of the state median income, adjusted for family size. The "grid edge" adder applies to sites that reside on circuits that fall in the top ten percent of both number and duration of outages per customer due to major storms outages since July 1, 2012.

Table B-1. Residential investment incentives ($/kWh)

	Total Grid Installed Capacity	Baseline	Underserved Household	Low-Income Household
Step 1	10 MW	$200	$300	$400
Step 2	15 MW	$170	$300	$400
Step 3	25 MW	$130	$300	$400
Grid Edge Adder	+50%	+50%	+50%	+50%

Commercial/Industrial investment incentives are capped at 50% of the battery's cost with rates modified by the customer's peak demand and their status as a "Priority Customer". Table B-2 illustrates these incentives. "Priority Customers" are defined as any of the following:

- small businesses with less than 200 kW annual peak demand;

[72] https://energystoragect.com/energy-storage-for-your-home/

- "critical facilities" as defined by Governor Lamont's Executive Order 7H;
- customers replacing fossil fuel generators; or
- "grid edge" customers as defined above.

Table B-2. Commercial/Industrial investment incentives ($/kWh)

	Small Commercial	Medium Commercial	Large Commercial
Peak Demand	<200 kW	200-500 kW	>500 kW
Baseline	$200	$175	$100
Priority Customer Adder	+25%	+25%	+25%

Performance incentives function identically across all customer classes. The incentives are not capped, and the compensation rate is determined by both the season and number of years since a battery storage system's installation. These rates are not affected by the installation incentive modifiers. Table B-3 illustrates these incentives. The incentive amount is calculated based on the average kW-AC contribution of the system during the season as determined by actual system performance during events as indicated by inverter data.

Table B-3. Residential and commercial/industrial performance incentives ($/kW)

Season	Years 1-5	Years 6-10
Summer	$200	$115
Winter	$25	$15

Like ConnectedSolutions in the Commonwealth, the performance incentive component of the Energy Storage Solutions program intends to promote BTM dispatch that will reduce system peaks. The choice to provide an investment incentive gives the utility less control over how energy storage is used but may help some customers overcome the barrier of high capital cost. The investment incentive also allows the utility to promote energy storage projects in places that will benefit from it the most and to promote equity through non-declining blocks for underserved and low-income households.

B.2 Green Mountain Power incentives (VT)

As Vermont's sole investor-owned utility, Green Mountain Power (GMP) offers a home battery storage incentive program in order to reduce grid stress during times of peak demand.[73] The program is limited to adding 5 MW of additional storage capacity annually. The program is divided into two components: a battery lease option and a "bring your own device" option. Both options offer investment incentives only.

In the battery lease program, customers are eligible to lease a home battery at a discount from GMP for a 10-year period. Customers may then use these batteries to provide backup power to their households during periods of grid interruption. Customer 10-year lease costs for each are listed in Table B-4. However,

[73] https://greenmountainpower.com/rebates-programs/home-energy-storage/

customers do not own either the battery or the stored energy. Customers may not use the battery for any purpose other than for backup power during grid outages. Furthermore, GMP, at their sole discretion, may discharge some or all the battery's capacity to support grid operations. GMP acknowledges that this may leave customers with no backup power during a grid outage.

Table B-4. Battery leasing costs

Brand	Monthly Payment Option	One-Time Payment Option
Enphase IQ	$65 ($7,800 total)	$6,500
Tesla Powerwall	$55 ($6,600 total)	$5,500

Under the Bring Your Own Device program, customers independently purchase an eligible home battery storage system and offer services to GMP. The battery may be operated in one of two modes: backup only or self-consumption. Incentive levels for these modes of operation appear in Table B-5, and are capped at $10,500. Customers in grid constrained areas, as identified by GMP's solar map, receive higher incentives. Additionally, the backup only incentives differ based on the battery's duration.

Table B-5. Bring Your Own device investment incentives

Option	Investment Incentive	Grid Constrained Modifier
Backup Only (3-Hour Storage)	$850 / kW	+ $100 / kW
Backup Only (4-Hour Storage)	$950 / kW	+ $100 / kW
Self-Consumption	$850	+ $100

Under the backup only option, customers offer a predesignated amount of capacity to GMP. GMP may then use this capacity to relieve grid stress during peak events. While GMP retains the right to discharge the battery's offered capacity at any time, GMP also commits to minimizing the use of the battery equipment during periods of expected system outages. During grid outages, customers may use the battery's remaining capacity to power their home. GMP's investment incentives are determined by the size and duration of storage offered.

Under the self-consumption option, customers commit to self-supplying their households electricity from their battery during peak events. GMP will not draw additional power from the battery to support the grid. GMP offers flat investment incentives under this option.

GMP's storage incentive program targets customers who want a BTM home battery system to mitigate grid outages, not customers seeking to make a profit from their battery's performance. The utility control of enrolled devices ensures reliable performance during peak periods but offers customers little/no power over the storage installed in their own homes.

B.3 Market Acceleration Bridge Incentive (NY)

The New York State Energy Research and Development Authority (NYSERDA) operates three separate programs for incentivizing energy storage deployment. First, the Bulk Storage Incentive program is a contract-based investment incentive program designed for projects above 5 MW. Second, the Retail Storage Incentive Program is an investment incentive program targeting distribution-connected projects under 5 MW. Third, the Long Island Single-Family Residential Storage Incentive is an investment incentive program for individual households.

Bulk Storage Incentive Program

NYSERDA's Bulk Storage Incentive Program supports >5 MW projects that provide wholesale services to the NYISO-managed energy markets. The program provides a fixed, up-front investment incentive based on the project's energy capacity in kilowatt-hours (kWh). Projects can provide wholesale, capacity, or ancillary services and be connected at the transmission, sub-transmission, or distribution level.

Incentive payments are delivered in four equal annual payments beginning when the project is completed. After meeting the program requirements, project developers are eligible for the investment incentives with modifiers shown in Table B-6.

Table B-6. NYSERDA bulk storage incentives ($/kWh)

Type	2019	2020	2021	2022	2023	2024	2025
<= 20 MW	$110	$100	$90	$80	$70	$60	$50
> 20 MW	$85	$85	$85	$85-75	$75	$75	$75
Wholesale Capacity	Full Rate						
Arbitrage / Ancillary	75% of Rate						
1-4 Hour	Full Rate						
5-6 Hour	25% of Rate						
6+ Hour	0% of Rate						

For example, a customer installing 100 kWh of wholesale capacity storage in 2024 fully dischargeable over 2 hours would receive ($60/kWh * 100kWh) = $6,000. A customer installing the same amount of storage at the same date, but needing 5 hours to fully discharge, would receive ($60/kWh * 80kWh) + ($60/kWh * 20kWh * 0.25) = $5,100.

Project requirements include but are not limited to: must be located in New York; must have a 70% round-trip energy efficiency; cannot be experimental, beta, or prototype equipment; must have at least a facility study in progress; cannot receive compensation from the NYSERDA REC program, the retail storage incentive, or an IOU bulk dispatch rights contract; cannot be owned by an IOU or the NY Power Authority; and must meet regular project development milestones as set by NYSERDA.

Retail Storage Incentive Program

NYSERDA's retail storage incentive program supports energy storage projects < 5 MW in size primarily used for load management or shifting generation to more beneficial time periods. The program provides eligible projects with a one-time investment payment determined by project size. Projects must be interconnected behind a customer's meter or on the distribution system and cannot be single-family residential systems.

The incentive funding pool is divided into several regions, each of which has separate funding blocks with declining incentive rates. Once a block's funding is fully allocated, it closes and is no longer available to future applicants. Incentive payments are delivered in a single payment once project conditions are met, with incentives capped at 15 MWh such that cap dollar amounts change with the changing blocks. Table B-7 illustrates current and historic incentives with modifiers:

Table B-7. NYSERDA retail storage incentives ($/kWh)

Region	Block 1	Block 2	Block 3	Block 4
New York City	N/A	$300 (Closed)	$240 (Closed)	$100 (Closed)
Long Island	$250 (Closed)	N/A	N/A	N/A
Westchester Con Edison	$175 (Open)	N/A	N/A	N/A
Rest of State	$350 (Closed)	$250 (Closed)	$200 (Closed)	$125 (Closed)
1-4 Hour	100% of Rate			
5-6 Hour	25% of Rate			
6+ Hour	0% of Rate			

Project requirements include but are not limited to: must be located in New York; must have a 70% round-trip energy efficiency; must be enrolled in a demand response program, NWA contract, VDER value stack tariff, or a more granular delivery rate; cannot be owned by an IOU, utility, or the NY Power Authority; and cannot receive REC compensation or NYSERDA bulk storage incentives.

<u>Long Island Single-Family Residential Storage Incentive</u>

The Long Island Residential Incentive is noteworthy as NYSERDA's first-ever residential energy storage incentive program. It is intended to drive the adoption of residential storage paired with solar PV to enable clean resiliency and access to Long Island's Dynamic Load Management program, which provides a financial incentive to residential storage projects that discharge during utility-defined peaking events.

Installation incentives are determined by size, and the current rate is $250/kWh. Projects may be either new solar + storage projects or retrofitted storage on existing solar installations. Only NY-SUN approved contractors may install the system, and the contractor applies for the incentive on behalf of the resident.

The Market Acceleration Bridge program complements other NY programs by requiring enrollment in programs/rates that encourage beneficial dispatch behavior. The program clearly targets peak reduction through an incentive downgrade for projects doing energy arbitrage and/or ancillary services. Though penalties for longer duration systems dissuade participants from sizing to meet future system peaks, which are expected to flatten over time.

B.4 Value of Distributed Energy Resources Compensation (NY)

New York's Value of Distributed Energy Resources (VDER) framework is a performance incentive for eligible energy resources in the state. Replacing the old net metering policy, this framework uses the VDER, or "Value Stack", to determine the compensation rate for energy created using distributed energy resources. Compensation is delivered in the form of electric bill credits.

Value Stack compensation rates are re-calculated each month using the following factors:

- Energy Value (LBMP), based on the NYISO day-ahead hourly marginal price of the NYISO Zone in which the DER project is located.
- Capacity Value (ICAP), calculated based on the NYISO monthly capacity auctions. Three different pricing structures ("Alternatives") are available to other DER technologies.
- Environmental Value (E Value), available to certain technologies and set as the higher of the Social Cost of Carbon as calculated by DPS Staff, or the latest NYSERDA Tier 1 REC price.
- Demand Reduction Value (DRV), where each utility's DRV rate is based on a DER's expected contribution of value to the local distribution system, as calculated in the Marginal Cost of Service (MCOS) studies. DERs receive DRV compensation for each kilowatt-hour exported to the distribution network during a utility-defined set of peak hours.
- Locational System Relief Value (LSRV), similar to the DRV and awarded per kilowatt-hour exported to distribution network during local peaking events. LSRV zones are determined by each distribution utility company and are available for a finite MW capacity per zone.
- Market Transition Credit (MTC) and Community Credit (CC) are awarded exclusively to community distributed generation projects. The MTC and CC provide additional value stack revenue per each kilowatt-hour exported to the distribution network. At this time, each utility has fully exhausted its MTC and CC allocations.

Standalone storage projects are eligible to receive the Energy, Capacity (Alternative 3 only), DRV, and LSRV elements of the Value Stack. Storage projects paired with and charged by an eligible renewable generation technology, such as solar PV or wind, are eligible for all Value Stack elements. Developers of distributed energy storage projects typically attempt to maximize revenue from ICAP, DRV, and LSRV by shifting energy into higher-compensated peaking hours. Some projects also attempt to maximize energy revenue by charging the storage system during low-cost hours and discharging during high-cost hours.

Long Island, under the Long Island Power Authority, uses a separate Value Stack with slightly different methods for calculating compensation for community distributed generation credits, the Demand Reduction Value, and the Capacity Value.

Proposed tariffs for implementation of FERC Order 2222 would enable storage resources to operate as wholesale market resources and distribution resources. The tariffs would enable standalone storage to select only the DRV component of the Value Stack and participate directly in the energy, capacity, and ancillary services markets at the NYISO.

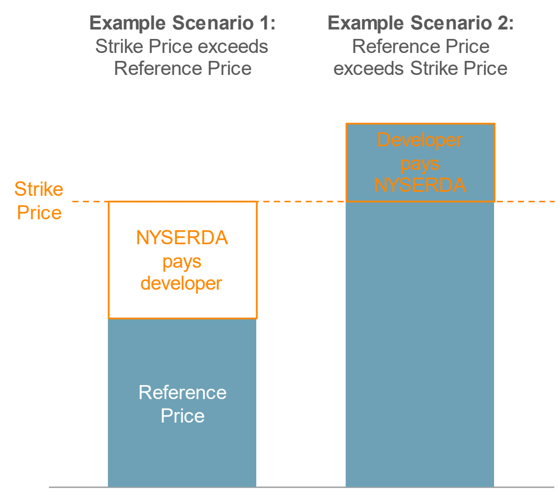
NY's VDER compensation mechanism incentivizes storage deployment by making many value streams available to customers. However, the transient nature of the Value Stack does not offer developers much certainty over project lifetime.

B.5 Index Storage Credit Program (NY, proposed)

The Index Storage Credit Program, proposed by NYSERDA in December 2022, is a proposed incentive mechanism for bulk energy storage projects.[74] It is intended to guarantee a revenue stream to energy storage project developers while being more flexible than traditional upfront rebates.

The program operates similarly to the "Index REC" approach applied to offshore wind and large-scale onshore renewable energy projects. When a competitive solicitation is announced, storage project developers bid a "Strike Price" for their proposed project. For the selected project, the Strike Price becomes the project's guaranteed revenue stream for its lifetime. As the project operates, NYSERDA regularly determines a "Reference Price" that represents the estimated revenues the project should be expected to earn for a given time period as derived from one or more price indices. If the Reference Price is lower than the Strike Price, NYSERDA would issue a support payment to the project developer to bring their revenue up to the guaranteed Strike Price. If the Reference Price is higher than the Strike Price, the project developer would pay NYSERDA the excess to bring their revenue down to the agreed-upon Strike Price. This dynamic is illustrated in Figure B-1.

Figure B-1. Index Storage Credit operation example



NYSERDA would select and contract with storage projects using price and non-price factors. Price factors would be based on comparing the bid's Strike Price with projected Reference Prices to determine overall project costs to NYSERDA. Non-price factors include project viability and social/economic benefits to New York. This proposed mechanism may be favorably viewed by developers because of the guaranteed revenue stream. Meanwhile, the state benefits from a competitive solicitation process, allowing for least cost procurement of storage capacity that has been determined to be required for decarbonization targets.

The Index Storage Credit incentivizes storage deployment by stabilizing a storage project's revenue stream. This complements the more unpredictable VDER compensation mechanism while also encouraging market-based competition to meet identified storage needs.

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[74] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage-roadmap.pdf

Appendix C. Short Duration Use Case Annual Revenue Streams

Figure C-1. *Use Case 1:* ***Utility Scale Standalone FTM System – 4hr, 50 MW, 2024 Installation Year***

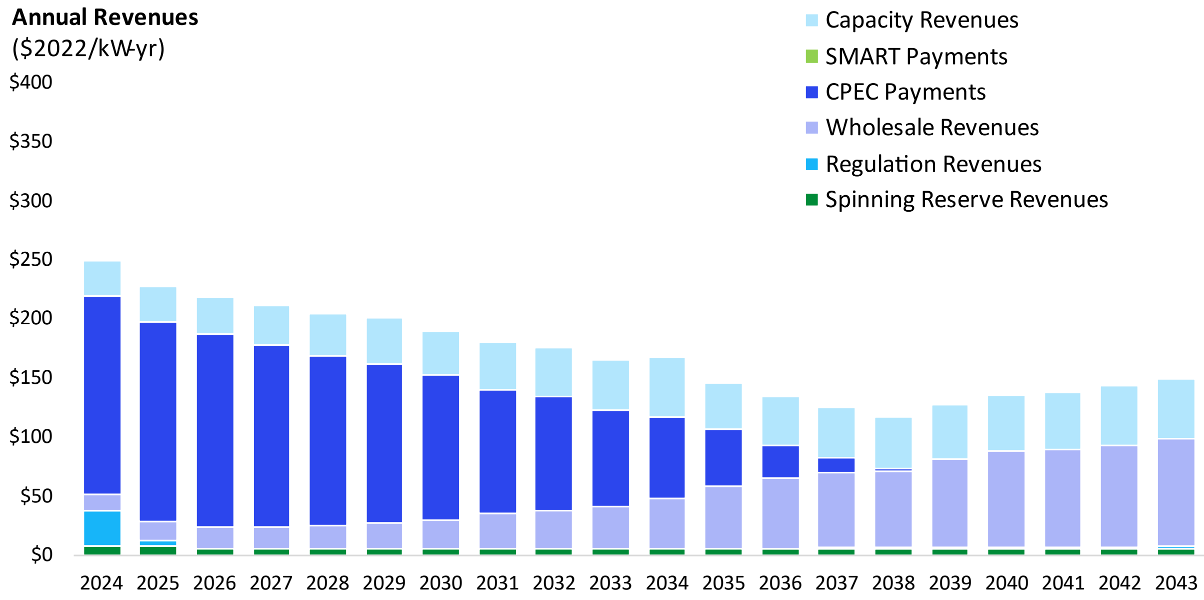


Figure C-2. *Use Case 2:* ***Commercial Scale Standalone FTM Distribution System – 4hr, 5 MW, 2024 Installation Year***

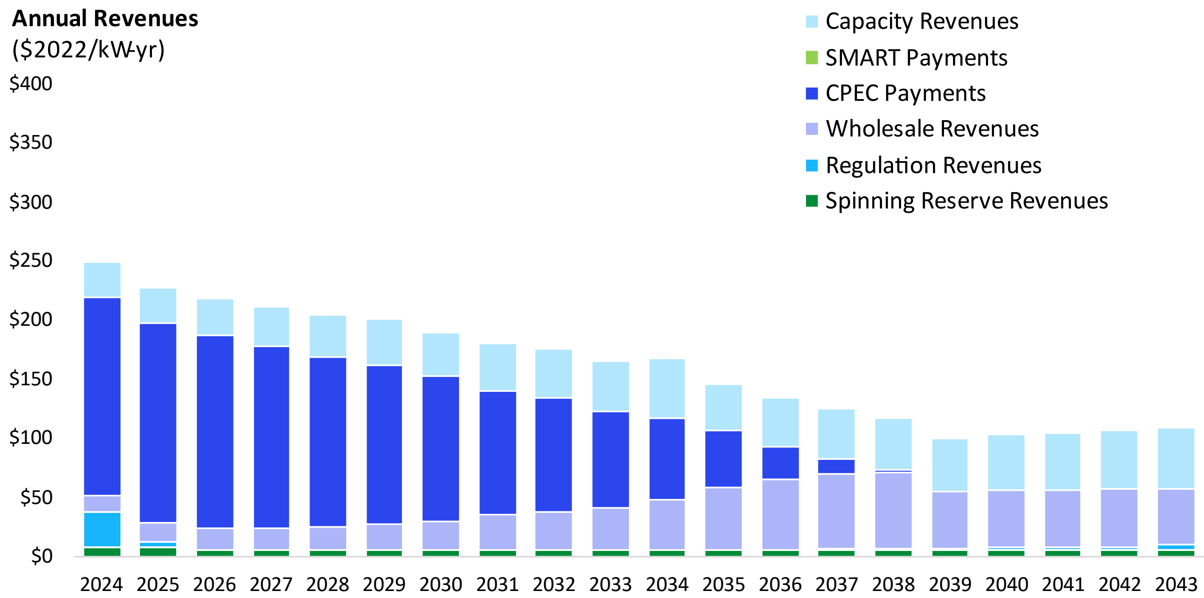


Figure C-3. *Use Case 3:* ***Commercial Scale, Solar-paired FTM Distribution System – 4hr, 1 MW, with 4 MW paired solar system, 2024 Installation Year***

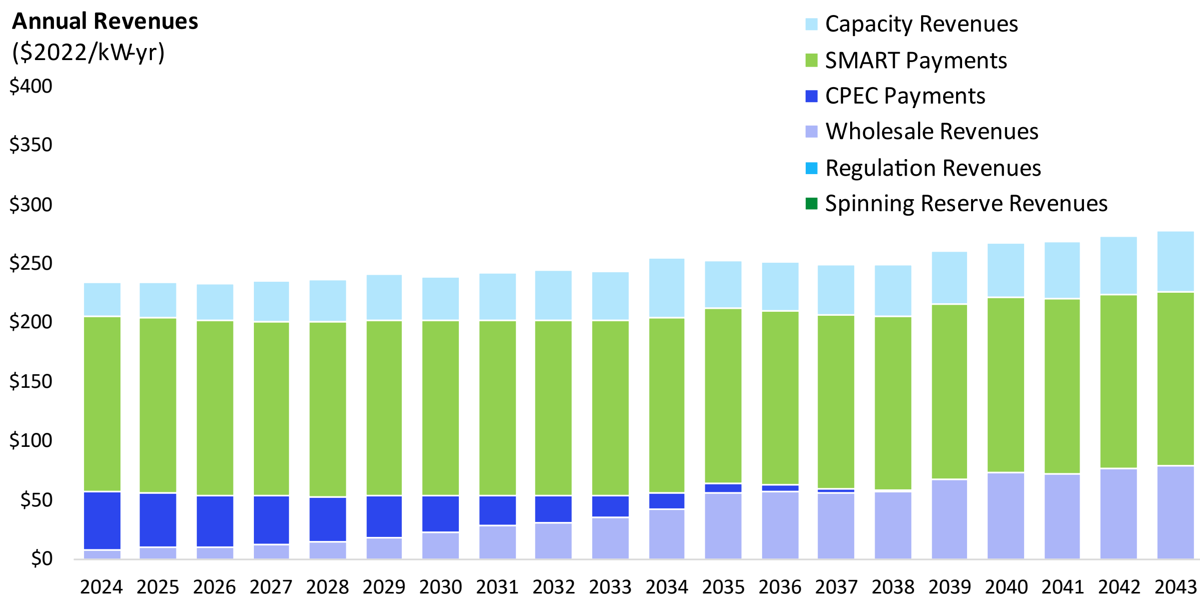


Figure C-4. *Use Case 4:* ***Commercial Scale, Solar-paired BTM System – 4hr, 1 MW, with 4 MW paired solar system, 2024 Installation Year***

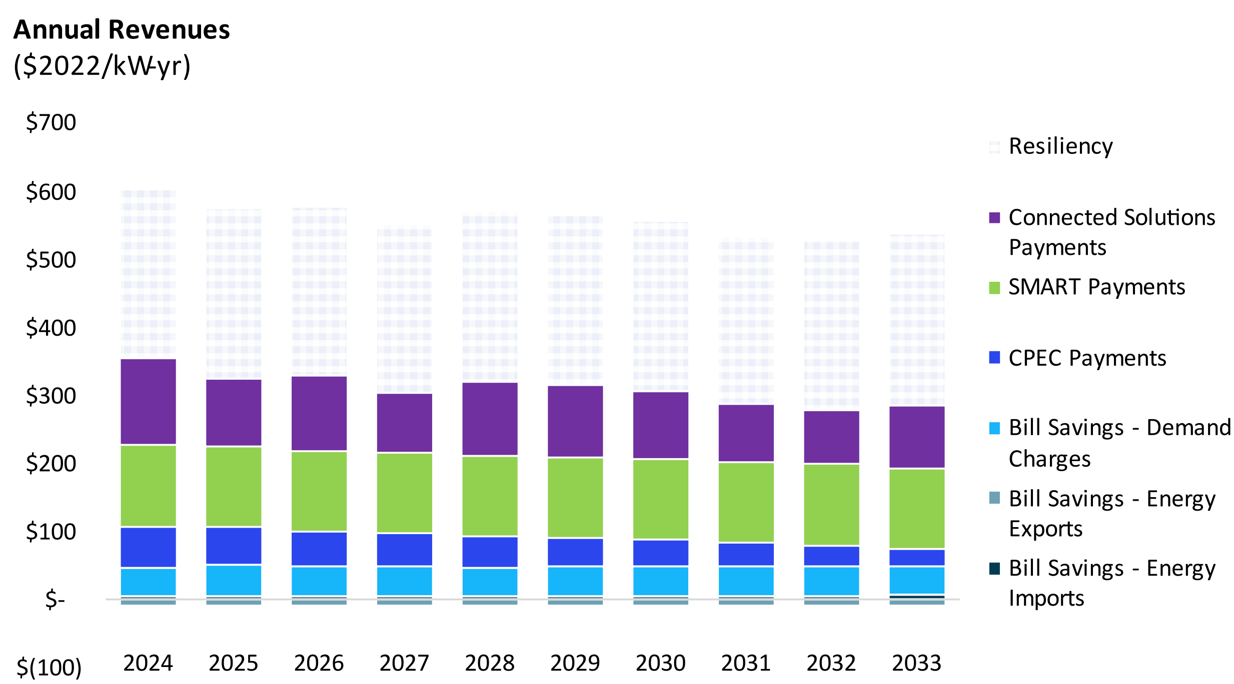


Figure C-5. *Use Case 5:* ***Residential scale, solar-paired BTM System – 1hr, 10 kW, with 10 kW solar paired system, 2024 Installation Year***

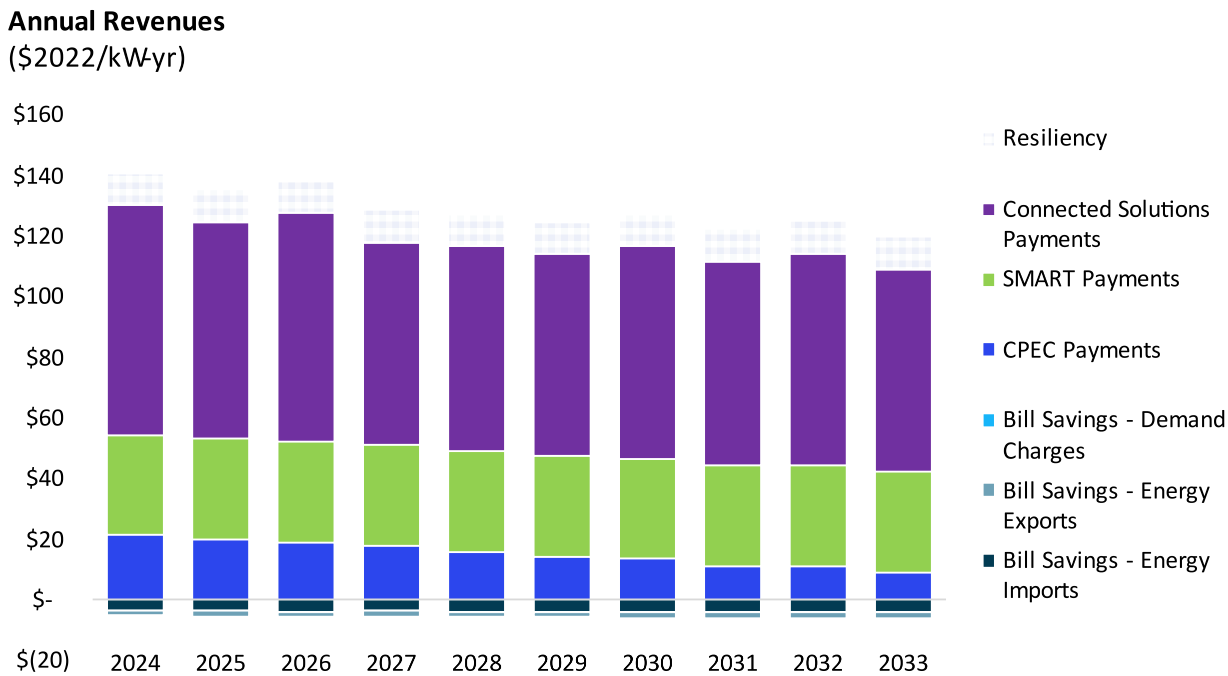
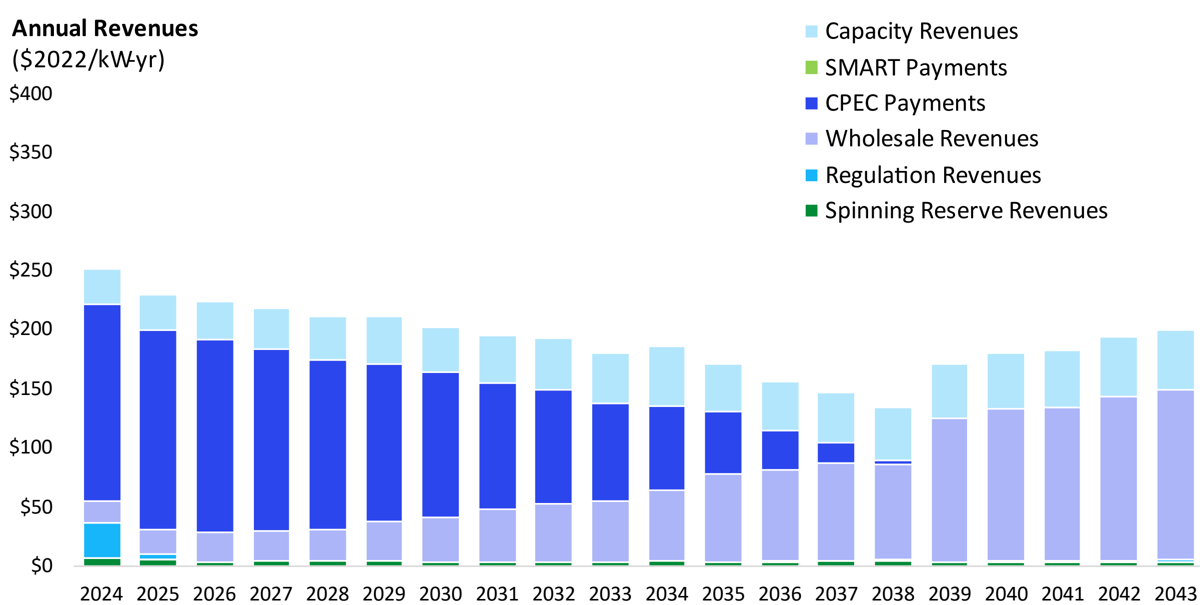


Figure C-6. *Use Case 6:* ***Utility scale, Mid-duration Standalone FTM System – 8hr, 50 MW, 2024 Installation Year***



Appendix D. Mid- and Long-duration storage candidate technologies

Mechanical storage technologies

Pumped hydro uses electricity to pump water to higher elevation reservoirs and discharges electricity by releasing water through hydro-powered turbines. Existing systems were built on river dams and pumped water upstream, but alternatives are being tested using artificial reservoirs built for this specific purpose. This technology is limited by its heavy use of land and water. Despite being the most common type of storage today, environmental concerns and geological constraints make it an unlikely candidate for new development in Massachusetts.

Gravity-based energy storage operates on a similar principle as pumped hydro. Electricity is converted to gravitational potential energy by lifting heavy blocks. When those are released and lowered, electricity is discharged back. This process can apply and absorb energy through hydraulic pressure or mechanical winches. This method of storage is in its pilot stage but could become interesting as it does not require large volumes of water or rare resources to deploy.

Compressed Air Energy Storage (CAES) stores energy by pumping and compressing air into a constant-volume vessel. Energy is created during discharge by heating and expanding the compressed air which then drives a turbine-generator. Siting is a major concern as it requires large underground caverns or more expensive above-ground storage reservoirs to store the compressed air. Adiabatic CAES (A-CAES) is similar to traditional CAES but instead stores the heat released by compression to later reheat the compressed air during discharge, which can reduce emissions and increase efficiency. This technology has limited potential in Massachusetts due to its geographic constraints and low roundtrip efficiency.

Liquid Air Energy Storage cools and liquifies air into storage tanks when charging. The liquid is then heated turning into high pressure air which drives a turbine. This technology can exchange waste heat with other processes for improved efficiency. No rare materials are needed but costs are high since air requires cryogenic temperatures to liquify. Instead of air, CO2 can be used in a closed loop since it can be liquified at much higher temperatures which are cheaper to maintain. This technology is in early development, but it has a potential long duration while requiring little space.

Thermal storage technologies

Sensible heat stores energy through increasing the temperature of certain materials. Electricity can then be discharged by creating steam that powers a turbine. This form of thermal energy storage is the most mature as it has already been deployed for a wide range of industrial applications as a way of capturing waste heat. Materials with high specific heat, thermal conductivity, and density are preferred. Due to availability, molten salt has been the most common material used. This technology is costly but has a low footprint and high potential duration.

Latent heat is based on the same heat exchange principle as sensible heat storage. Organic or inorganic materials are heated on charging and release heat on discharging through phase changes and not temperature changes. This means that this storage operates as materials gasify, liquify, or solidify. A common material expected to be used is aluminum, since it is widely available, and it melts at relatively low temperatures. This technology is in an earlier stage and facing more uncertainties than sensible heat storage.

Thermochemical heat operates through absorbed and released heat from chemical reactions. This technology is the most nascent of all listed here. A wide range of chemical reactions are being explored in order to find the most appropriate for this application. This means there are no specific estimates on how costly, efficient, or scalable this type of energy storage would be.

Chemical/electrochemical storage technologies

Aqueous flow batteries are liquid batteries using the same electrochemical principles as lithium-Ion batteries. Liquid anolytes and catholytes are the vessels for electron transfer and are pumped through large storage tanks. These batteries are larger than lithium-ion ones because the liquid electrolytes have lower specific energy. The liquid tank configuration allows for expandable storage for lower costs and thus much longer duration setups. Similar to lithium-ion batteries, this technology also benefits from near instantaneous response and can provide ancillary services to the grid. Larger scale deployment of flow batteries will depend on the material costs to make the electrolytes and how well tanks can be developed to hold the heavy electrolyte solutions.

Metal anode batteries are solid batteries with the same electrochemical principles as lithium-Ion batteries. The entire anode of these batteries is made with a metal instead of using graphite as the medium for metal ions. This energy-dense configuration allows for longer storage duration for the same volume and weight. For this reason, the technology may become popular in the auto industry and not only for utility-scale energy storage. This technology is still in early development due to the challenges in preventing fires while choosing electrolyte materials that are widely available and charge/discharge efficiently.

Hybrid flow batteries intersect aqueous flow batteries and metal anode batteries by combining liquid electrolyte tanks with metal anode blocks. This versatile configuration allows for a balance between specific needs and resource constraints. Similar to aqueous flow batteries, slightly larger spaces and heavier installations are needed because of the tanks which also imply higher costs. One of the main benefits of this technology is its use of common and non-toxic materials such as iron and salt.

Appendix E. Modeling Tools & Additional Results

E.1 Additional Information on RECAP

E3's **Renewable Energy Capacity Planning Model (RECAP)** is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge.

Model Inputs

RECAP is designed to allow loss of load probability simulation on a wide range of electricity systems that may comprise a diverse mix of generating resources, each with different constraints and characteristics that affect their availability to serve load at different times. RECAP enables a robust evaluation of loss-of-load-probability that can account for a broad variety of technologies and resource types, including:

+ **Firm resources** capable of producing at their full rated capacity when called upon by operators (except during periods of maintenance and unforced outages);
+ **Variable resources**, typically wind and solar, whose availability will vary on an hourly basis as a result of weather and solar irradiance patterns;
+ **Hydroelectric resources** that can be dispatched relatively flexibly but have constraints related to streamflow and underlying hydrological conditions;
+ **Storage resources** that can be dispatched flexibly but have limited durations across which they are available due to limits on state of charge.

Loss of Load Probability Simulation

Based on the inputs described above, RECAP simulates the loss of load probability for an electric system using a Monte Carlo approach to capture plausible combinations of load, variable renewables, and outages across hundreds of potential years. For each broad class of resource enumerated above, RECAP includes a module that evaluates the ability of each resource in that class to contribute to load in each hour of the simulation.

Table E-1. Overview of Methodology Used to Compare Load and Resource Availability

Module	Methodology
Load	The hourly profile of electricity demand is determined based on an hourly load shape that covers a broad range of historical weather conditions (multiple decades) that is scaled to the desired level of annual and peak demand. The underlying load shape itself is a result of a pre-processing neural network regression that simulates hourly load shapes for the full available weather record based on recent historical loads and a longer record of weather data.
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).
Variable Resources *(e.g. wind, solar, run-of-river hydro)*	Availability of variable renewable resources is simulated stochastically based on the rolling probabilistic day-matching algorithm described above. This results in an hourly timeseries profile for all variable resources that aligns with the hourly load profile.
Imports/Market Purchases	Availability of generic resources from external areas (i.e. assumed wholesale market purchases) can be specified at an hourly, monthly, or annual level. This is an input to RECAP.
Hydroelectric Resources	To determine hydro availability, the model uses a monthly historical record of hydro production. For every simulated load year, a hydro year is chosen stochastically from the historical database. Associated hydro budgets are typically assigned on either a weekly or daily basis and then "dispatched" to minimize net load (load less variable resources and hydro) during that period while accounting for a number of constraints, including: • Minimum output levels that capture the lower limit on the level of generation that a system may produce when considering hydrological and other physical constraints on the system • Sustained peaking limits, which limit the output of the hydro system across a range of rolling time windows (e.g. 1-hour, 2-hour, 4-hour, and 10-hour) to capture how hydrological factors may limit the ability to discharge water through a dam for sustained periods of time.
Storage Resources *(e.g. batteries, pumped storage)*	The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives).

To the extent the portfolio of resources whose availability is determined through the steps above is insufficient to meet demand in any hour, a loss of load event is recorded. After simulating hundreds of years of possible Monte Carlo outcomes, RECAP calculates the system's LOLH and a variety of other reliability statistics.

E.2 Effective Load Carrying Capability Calculation

The simulation of LOLE for a given electric system enables the calculation of "effective load carrying capability" ELCC for individual resources, or, in more colloquial terms, their capacity value: the equivalent amount of "perfect capacity" that could be replaced with the addition of a specified resource while maintaining the same level of reliability. ELCC for individual resources (or combinations of resources) is calculated through iterative simulations of an electric system:

1. The LOLE for the electric system without the specified resource is simulated. If the resulting LOLE does not match the specified reliability target, the system is "adjusted" to meet a target reliability standard (most commonly, one day in ten years). This adjustment occurs through the addition (or removal) of perfect capacity resources to achieve the desired reliability standard.
2. The specified resource is added to the system and LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available generation has increased.
3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to percentage terms by dividing by the installed capacity of the specified resource.

Figure E-1. Summary of ELCC calculation algorithm

This approach can be used to determine the ELCC of any specific resource type evaluated within the model. In general, ELCC is not widely used to measure capacity value for firm resources (which are generally rated either at their full or unforced capacity) but provides a useful metric for characterizing the capacity value of renewable, storage, and demand response resources.

The ELCC of a resource depends not only on the characteristics of load in a specific area (i.e. how coincident its production is with load) but also upon the resource mix of the existing system (i.e. how it interacts with other resources). For instance, ELCCs for variable renewable resources are generally found to be higher on systems with large amounts of inherent storage capability (e.g. large hydro systems) than on systems that rely predominantly on thermal resources and have limited storage capability. ELCCs for a specific type of resource are also a function of the penetration of that resource type; in general, most resources exhibit declining capacity value with increasing scale. This is generally a result of the fact that continued addition of a single resource or technology will lead to saturation when that resource is available and will shift reliability events towards periods when that resource is not available. The diminishing impact of increasing solar generation as the net peak shifts to the evening illustrates this effect.

E.3 Reliability Characterization of 2040 New England System

While focusing on 2030 and 2050 as two bookends of the system revolution in the next three decades, this study also evaluated the reliability challenges in 2040 New England system. The reliability challenge in 2040 is similar to 2050 despite that the New England system needs to rely more on thermal and import resources. This is primarily due to the mismatch between the pace of renewable capacity builds and load growth. In the winter peak load example illustrated in Figure E-3, renewable generation are generally insufficient to meet system needs, even in mid-of-day when solar generation peaks. The system relies substantially on thermal and market imports to serve loads as well as charge storage resources in time of need.

Figure E-2. Peak Load Summer Week in 2040

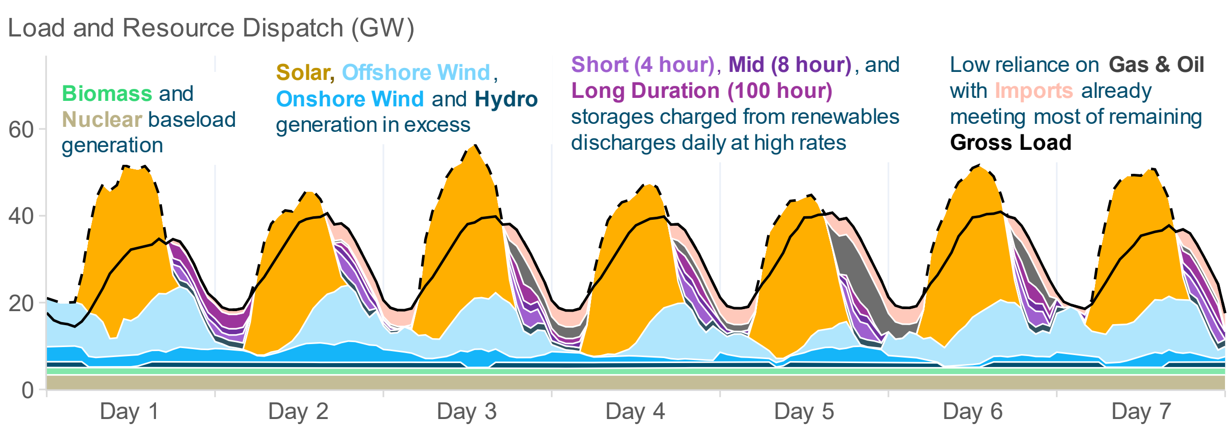
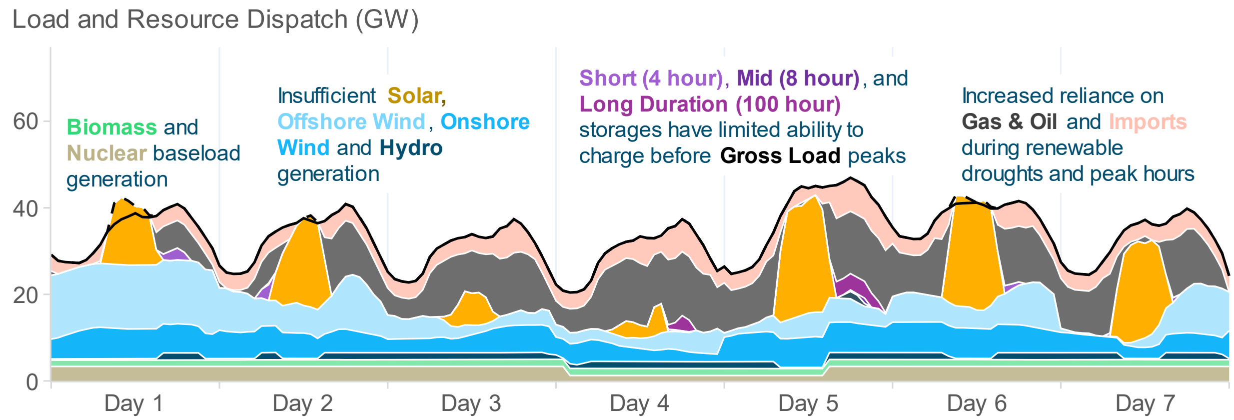


Figure E-3. Peak Winter Week in 2040



E.4 Diversity Benefit between SDES and Solar

This study evaluated the diversity benefit presented by adding utility-scale solar and 4-hour duration energy storage resources to the 2050 CECP base portfolio simultaneously, assuming distributed solar and all wind forecasts are achieved, and there exists no mid-duration and long-duration storage resources in the system yet (except for the existing pumped hydro resources).

In this example, since the New England system has transitioned to winter peaking in 2050 and sees most of the resource need in early morning and late afternoon hours when solar does not generate, the capacity contribution of utility-scale solar is very low in 2050. This remains true until there is a high penetration of energy storage resources to shift intra-day solar generation to the net peak load hours that are most important to determining ELCC.

Incremental SDES ELCC generally follows a similar pattern as explained in Section 4.6: adding SDES alone initially provides significant value to the system, but beyond 15 GW its value drops off sharply as the net load curve becomes flatter and requires storage resources to discharge for longer periods. The complementary effects between SDES and solar is less evident in the 2050 system compared to those between offshore wind and LDES. This is due to the nature misalignment of solar generation with peak load hours as well as the limitation in duration of SDES output.

Table E-2. Utility-scale Solar incremental ELCC (%) when fixing SDES penetration, 2050

	SDES (MW)					
Solar (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0							
5,000	0%	0%	0%	0%	5%	5%	7%
10,000	0%	0%	0%	0%	2%	4%	7%
20,000	0%	0%	0%	0%	1%	4%	5%
30,000	0%	0%	0%	0%	1%	3%	4%
40,000	0%	0%	0%	0%	1%	2%	4%
60,000	0%	0%	0%	0%	0%	1%	3%

Table E-3. SDES incremental ELCC (%) when fixing Utility-scale Solar penetration, 2050

	SDES (MW)						
Solar (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0		90%	89%	89%	59%	31%	20%
5,000		90%	89%	89%	64%	31%	21%
10,000		90%	89%	89%	66%	34%	23%
20,000		90%	89%	89%	67%	39%	24%
30,000		90%	89%	89%	69%	43%	26%
40,000		90%	89%	89%	71%	44%	28%
60,000		90%	89%	89%	72%	48%	31%

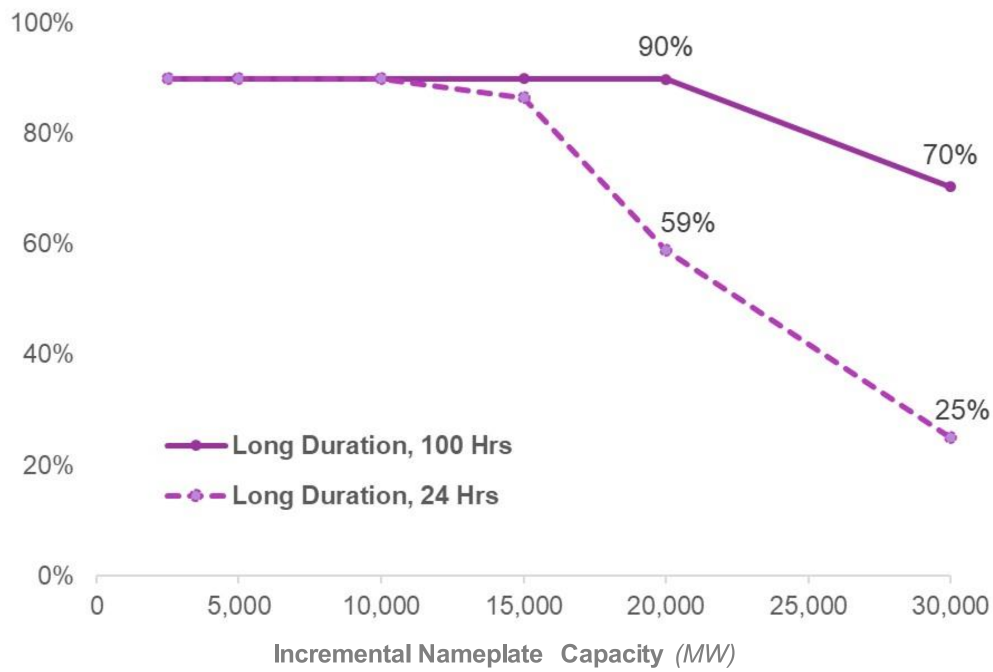
Table E-4. Illustration of the diversity benefit (%) between Utility-scale Solar and SDES, 2050

	SDES (MW)						
Solar (MW)	0	2,500	5,000	10,000	15,000	20,000	30,000
0							
5,000		0%	0%	0%	1%	1%	1%
10,000		0%	0%	0%	1%	2%	2%
20,000		0%	0%	0%	1%	2%	2%
30,000		0%	0%	0%	1%	2%	3%
40,000		0%	0%	0%	1%	2%	3%
60,000		0%	0%	0%	1%	2%	3%

E.5 24-hour Duration LDES ELCC Results

This study evaluated a 24-hour duration storage resource as an intermediate LDES between 8-hour mid-duration and 100-hour long-duration energy storage resources. The comparison of incremental ELCCs for two LDES resources when measured against the 2050 CECP phased portfolio is illustrated in Figure E-4. The capacity value for 24-hour LDES is very close to 100-hour resources in the first 15 GW additions but start to diverge when there's over 20 GW incremental storage resources in the system, where net load curve is flattened and storage is required to dispatch more than 24 hours to effectively shave peak.

Figure E-4. Incremental ELCC comparison between 24-hour and 100-hour duration LDES, 2050



E.6 Representative Dispatch Charts for Sensitivity Cases

Figure E-5. Example winter week dispatch around loss-of-load event, 2050

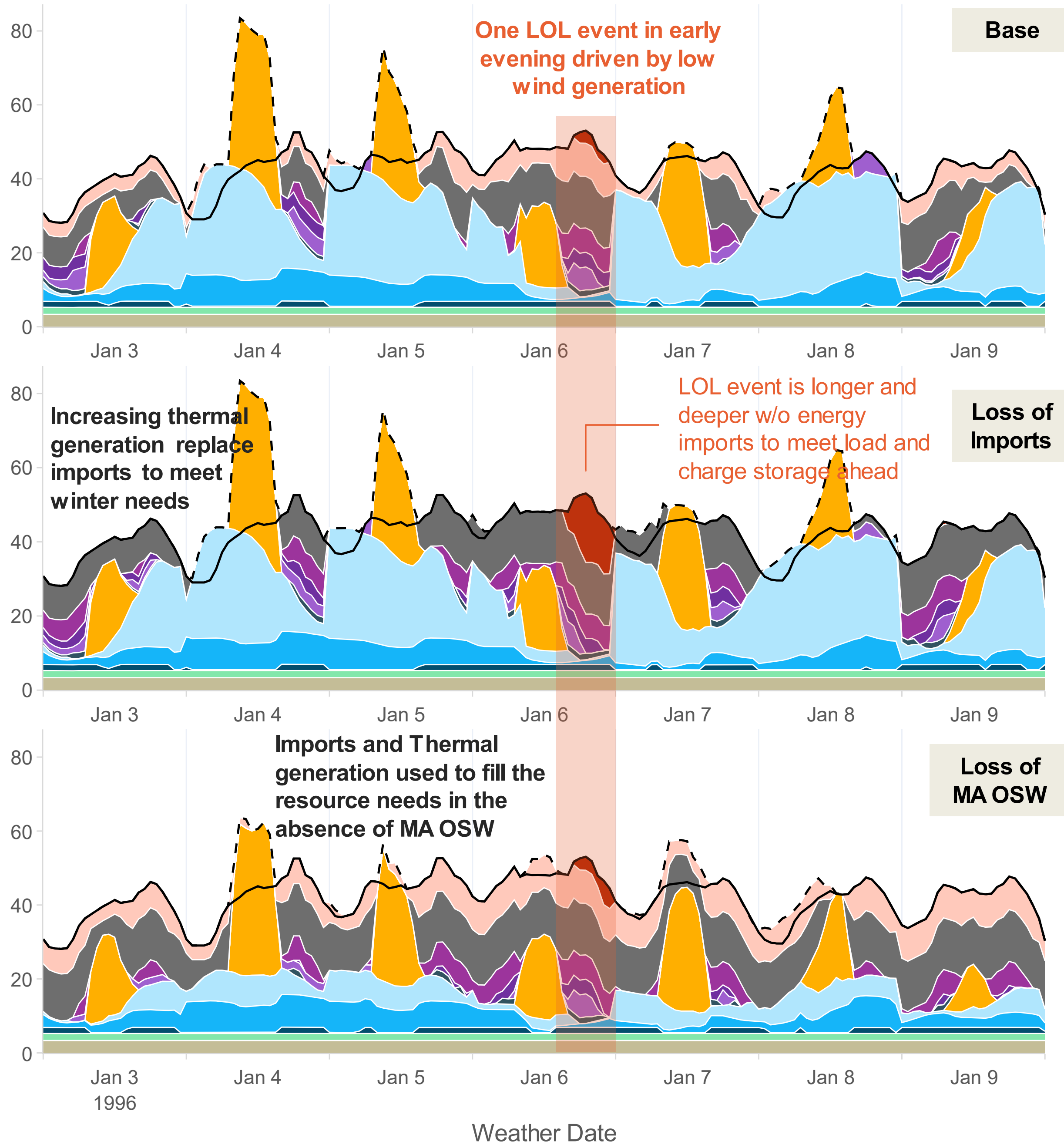


Figure E-6. Example summer week dispatch, 2050