Minnesota Energy Storage Cost-Benefit Analysis

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Prepared for: Minnesota Department of Commerce, Division of Energy Resources
Prepared by: Energy and Environmental Economics, Inc. (E3)

Energy+Environmental Economics

Prepared by:

Jasmine Ouyang, Senior Consultant
Gabe Mantegna, Consultant
Vivian Li, Consultant
Dan Mullen, Consultant
Kushal Patel, Partner
Arne Olson, Senior Partner

Energy and Environmental Economics, Inc. (E3)
44 Montgomery St., Suite 1500
San Francisco, CA 94104
Phone: 415.391.5100
website: www.ethree.com
Project Contact: Kushal Patel, Partner

Contract Number: 165031

Prepared for Minnesota Department of Commerce, Division of Energy Resources:
Steve Kelley, Commissioner, Department of Commerce
Joe Sullivan, Deputy Commissioner, Department of Commerce, Division of Energy Resources
Lise Trudeau, Project Manager, 651-539-1861, Clean.Energy@state.mn.us

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Authorizing Legislation

Minnesota Session Laws, 2019 Special Session 1, Chapter 7 (HF2), Article 11, Section 14

REPORT; COST-BENEFIT ANALYSIS OF ENERGY STORAGE SYSTEMS.

(a) The commissioner of commerce must contract with an independent consultant selected through a request for proposal process to produce a report analyzing the potential costs and benefits of energy storage systems, as defined in Minnesota Statutes, section 216B.2422, subdivision 1, in Minnesota. The study may also include scenarios examining energy storage systems that are not capable of being controlled by a utility. The commissioner must engage a broad group of Minnesota stakeholders, including electric utilities and others, to develop and provide information for the report. The study must:

(1) identify and measure the different potential costs and savings produced by energy storage system deployment, including but not limited to:

(i) generation, transmission, and distribution facilities asset deferral or substitution;

(ii) impacts on ancillary services costs;

(iii) impacts on transmission and distribution congestion;

(iv) impacts on peak power costs;

(v) impacts on emergency power supplies during outages;

(vi) impacts on curtailment of renewable energy generators; and

(vii) reduced greenhouse gas emissions;

(2) analyze and estimate the:

(i) costs and savings to customers that deploy energy storage systems;

(ii) impact on the utility's ability to integrate renewable resources;

(iii) impact on grid reliability and power quality; and

(iv) effect on retail electric rates over the useful life of a given energy storage system compared to providing the same services using other facilities or resources;

(3) consider the findings of analysis conducted by the Midcontinent Independent System Operator on energy storage capacity accreditation and participation in regional energy markets, including updates of the analysis; and

(4) include case studies of existing energy storage applications currently providing the benefits described in clauses (1) and (2).

(b) By December 31, 2019, the commissioner of commerce must submit the study to the chairs and ranking minority members of the senate and house of representatives committees with jurisdiction over energy policy and finance.

(c) The commission is prohibited from spending more than the amount appropriated for the study, cost-benefit analysis, and other activities required under this section.

Executive Summary

In May 2019, Minnesota lawmakers passed legislation directing the Minnesota Department of Commerce to conduct an analysis of the potential costs and benefits of deploying energy storage systems in Minnesota.[1] The Minnesota Department of Commerce hired Energy and Environmental Economics, Inc. ("E3")[2] to develop an independent cost-benefit analysis of potential energy storage systems that could be deployed in Minnesota over the next five to ten years.

The analysis shows that energy storage is at a pivotal moment and could be cost-effective in certain configurations. Based on study results, E3 recommends that within the next 5 to 10 years utilities pursue energy storage projects to gain operational experience, consider including energy storage in distribution and capacity plans, and structure bidding processes so that storage can demonstrate cost-effectiveness in comparison with other technology options. As market rules and technology costs continue to change, this study provides a potential framework for evaluating the benefits and impacts of energy storage projects on a case-by-case basis.

Key Findings

The study calculates that **solar plus storage is cost-effective today and stand-alone storage could become cost-effective in 2025.** Over the next ten years storage will show increasingly positive cost-benefit ratios for more and more use cases as technology costs decline. This means it will be an increasingly important technology for the electric grid.[3] In the next few years, utilities and the Midcontinent Independent System Operator (MISO) should operationalize the analysis of storage in planning studies, as well as inclusion in resource plans, and ultimately, procurements for new generation. In the longer-term, storage has the potential to manage the cost-effective integration of renewable energy resources like wind and solar. Given the complexity of storage as a technology as well as the changing values it can provide over time, its deployment needs to be evaluated on a case by case basis for each specific situation. For example, the value of storage for Minnesota can and most likely

[1] Minnesota Session Laws, 2019 Special Session 1, Chapter 7 (HF2), Article 11, Section 14

[2] Founded in 1989, Energy and Environmental Economics, Inc. (E3) is a leading energy consulting firm providing clear, unbiased analysis to clients from all sectors of the electricity industry, including utilities, regulators, policy makers, developers, and investors. To learn more, visit ethree.com.

[3] Specifically, for utility-scale energy storage, investment tax credit (ITC) benefits and capacity firming are key values that make systems cost-effective today. Providing ancillary services (e.g., regulation reserves) to MISO markets is currently of value, as is participating in MISO's energy market. Over time, as more generation capacity retires in MISO, capacity value will increase even if other revenues like ancillary services revenues decline. Energy storage could also provide fast-ramping reserves, which would improve overall market efficiency by freeing up traditional resources currently providing regulating reserves to instead provide energy and other services. Further, in certain electrically constrained localities, energy storage can play an important role in alleviating congestion and deferring more costly transmission and distribution upgrades.

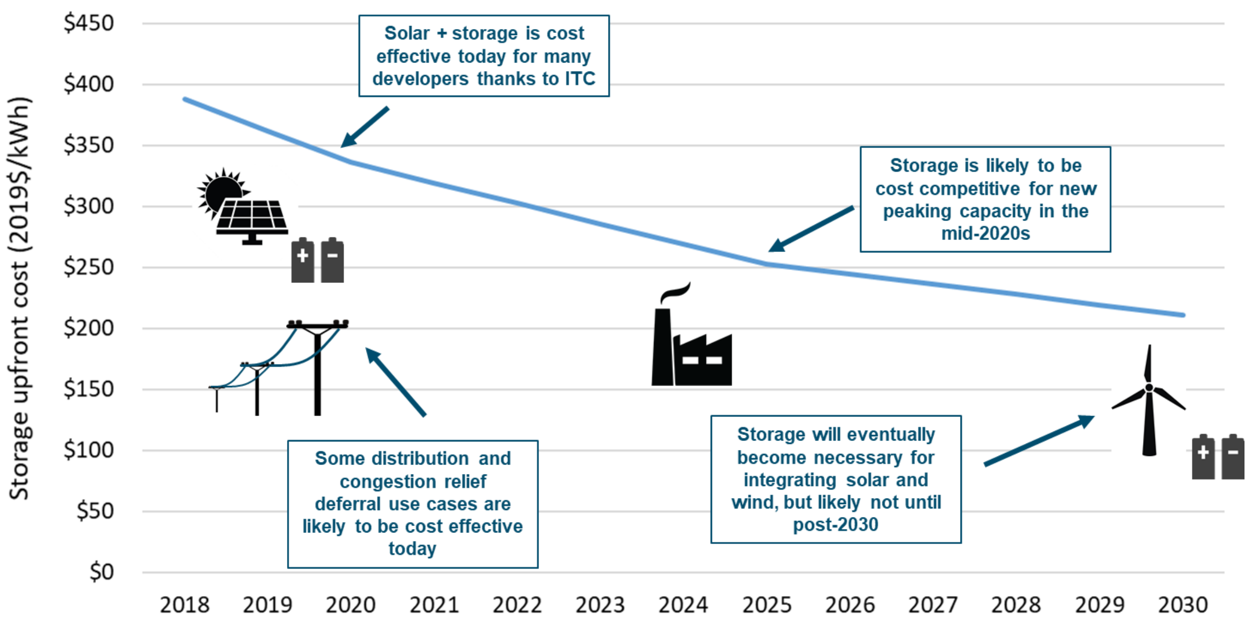
will be different than the value of storage in other parts of the U.S. because each jurisdiction is unique and the benefits of storage depend on local conditions.

E3 also analyzed the potential for energy storage to replace capacity in Minnesota that is used to serve peak electrical demand. We calculate that about 324 MW of Minnesota's "peaking capacity" had an operational profile in 2018 that would have allowed it to be "mimicked" by 4-hour energy storage. Replacing peaking units with storage could improve local air quality by shifting criteria air pollutants and air toxics away from more densely populated communities - especially in areas such as the Twin Cities where air pollution levels are approaching federal limits.[4] Further, energy storage could serve as a capacity resource for new capacity need and for the capacity that will be retiring in the next 5-10 years.

In the long-term the market potential for 4-6 hour storage in Minnesota will likely grow substantially, particularly under higher levels of renewables. At a high level E3 estimates the market potential for bulk system energy storage in the next 10-years to be between what is currently in the MISO interconnection queue for Minnesota (about 160 MW) up to over 1,000 MW.

The following chart illustrates a projection of energy storage value transition over time.

Figure 1. Energy storage value transition



Storage upfront cost is based on the NREL "Mid" Case projection (NREL, 2019)

[4] Storage operating to reduce peak load on today's grid would increase overall carbon emissions if it is charging from coal and discharging to displace gas peakers, but could provide air quality benefits nevertheless. For additional discussion, see *Emissions Analysis* on page 49.

Recommendations

Based on our analysis, this study makes the following recommendations to guide and accelerate the market for energy storage over the next 5 to 10 years:

- Include energy storage as a standard part of utility resource planning and competitive bidding processes, comparing the benefits and costs of energy storage to conventional thermal resources using a least-cost capacity expansion model or other quantitative analysis. The quantitative analysis should consider multiple technology price and load growth sensitivities and take into account emissions impact relative to other resource options as well as the various value streams that storage can provide, including sub-hourly flexibility values, peak capacity, transmission and distribution upgrade deferral, and ancillary services.
- Pursue targeted initiatives and programs in the next several years that prioritize the use cases that are identified as being cost-effective in this timeframe to further build experience and expertise on energy storage technologies and deployment. During this timeframe specifically focus on gaining experience in operating energy storage and understanding potential operational constraints as well as opportunities to increase storage's value to the grid.
    - Potential near-term use cases are: 1) solar + storage as an alternative for conventional thermal units as new peaking capacity; and 2) storage stand-alone or solar + storage for transmission and distribution upgrade deferral.
- Move from near-term targeted initiatives and programs to more wide scale deployments: consider setting up an implementation plan to operationalize the evaluation of storage as "non-wires alternatives" in distribution utility planning. The plan should include details on implementing initial steps to identify areas with high distribution upgrade deferral values, open solicitations for deferral needs, competitive bidding processes that include energy storage, and ultimately to project construction.
- Develop electric retail rate structures as soon as possible to align customer price signals with system marginal costs so that behind-the-meter (BTM) storage provides societal benefits and does not shift costs to other ratepayers.

Study Approach and Results

To identify and measure the potential costs and benefits of energy storage in Minnesota, E3 first used AURORA, a commercially available production simulation model, to simulate wholesale system operations over the next 10 years. Our production simulation modeling in AURORA focuses on three scenarios:

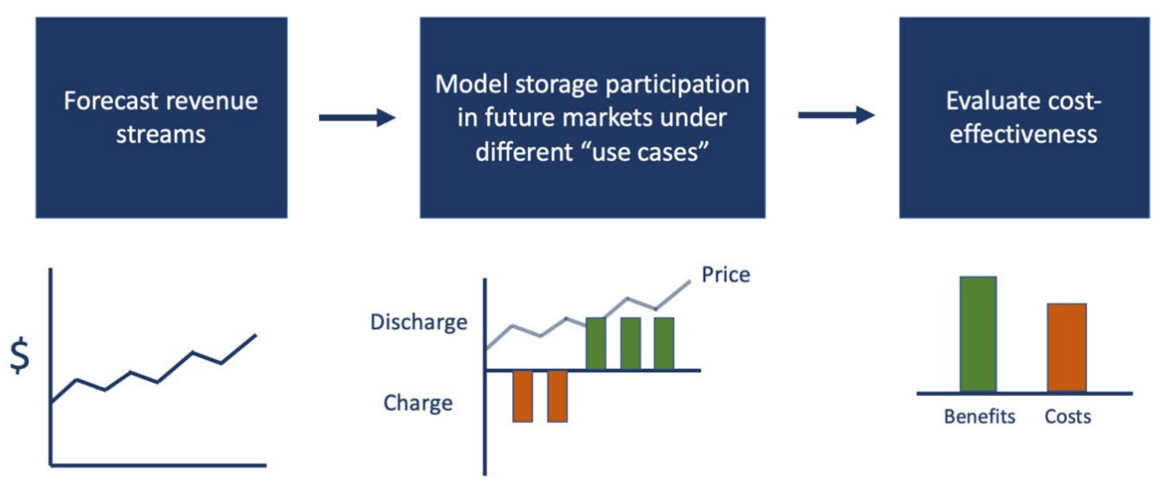
- On the lower end of the spectrum, the "*Existing Trends*" scenario is one in which renewables penetration continues at current levels.
- The second scenario, "*High Minnesota Renewables*," examines a future in which Minnesota aggressively adopts renewables.
- A third scenario, "*High Natural Gas Price,*" considers the impacts of increasing natural gas prices.

Neighboring states are assumed to continue with existing generation fleet plans. All three scenarios were designed in collaboration with the Department of Commerce staff.

E3 then used energy market prices obtained from AURORA in RESTORE,[5] E3's proprietary energy storage model. In addition to the *system* value streams identified through AURORA, RESTORE evaluates available *local* value streams (e.g., distribution deferral and emergency services). We evaluated benefits and costs from a number of perspectives, including from the state of Minnesota, the utility, ratepayers, and storage-adopting customers. By simulating storage dispatch for each use case and conducting cost-benefit analysis from different perspectives, we capture a wide spectrum of values from energy storage to better assess how that value is allocated among parties.

The figure below provides an overview of the study approach.

Figure 2. Overview of energy storage valuation methodology



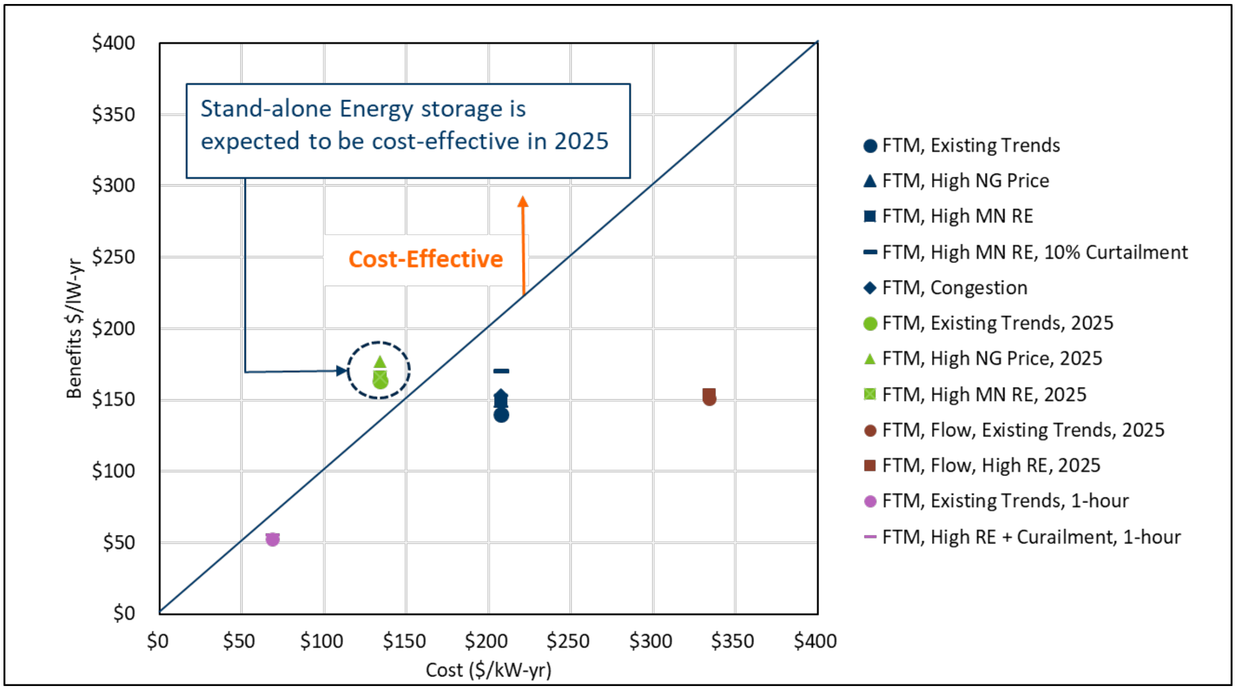
[5] www.ethree.com/RESTORE

The study examines several **use cases** which represent a wide range of likely energy storage deployment and business models that will be relevant for Minnesota over the next decade.

- The **front-of-the-meter (FTM)** use cases analyzed combinations of wholesale market services – including energy arbitrage, ancillary services, congestion reduction, and solar-plus-storage – for lithium-ion battery storage installed in 2020. Front-of-the-meter use cases are examined in all three study scenarios, as well as a "higher curtailment" sensitivity. Additional sensitivities evaluate the cost-effectiveness for a short-duration battery, a battery installed in 2025, and a flow battery.
- We also examine a **distribution system** use case for distribution deferral during peak hours and to provide other grid services in the remaining hours.
- The **behind-the-meter (BTM)** use cases examined storage applications for customer retail bill management and backup power provision during emergency events.

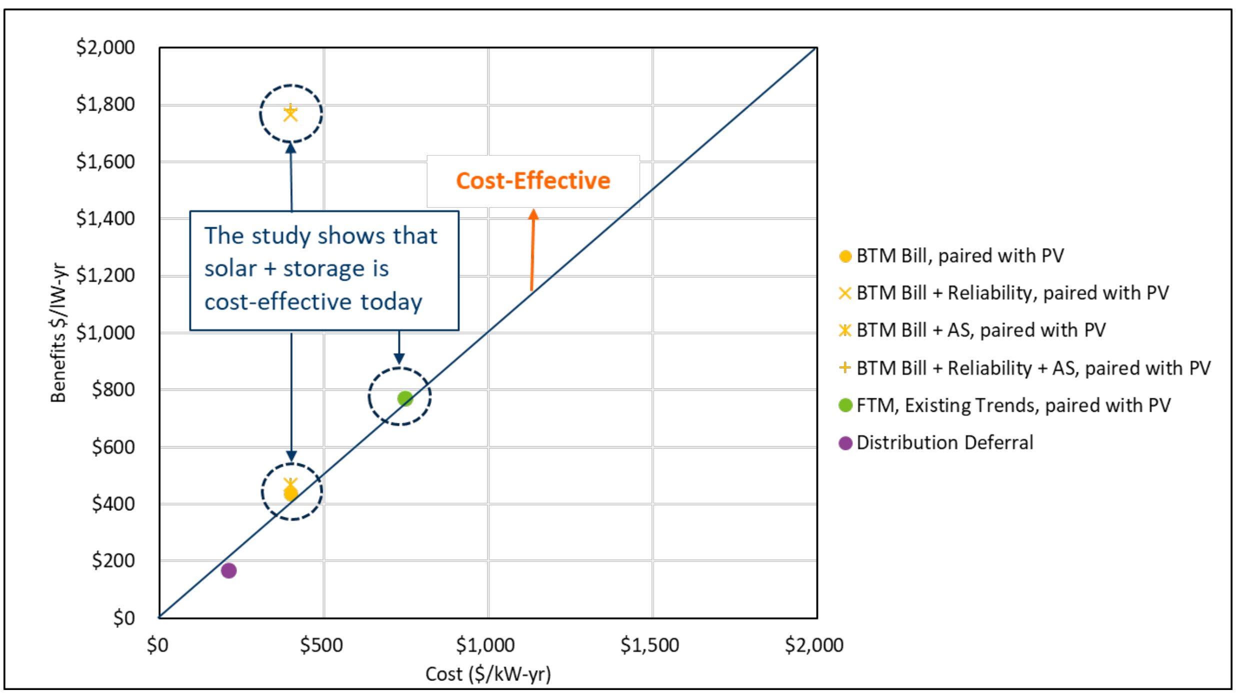
Cost-effectiveness results for the different use cases are summarized in the figures below. To facilitate comparison, stand-alone energy storage and solar plus storage are plotted in different charts. Overall, our analysis finds that solar plus storage is cost-effective today and stand-alone storage becomes cost-effective in 2025.

Figure 3. Costs and benefits summary: stand-alone energy storage



FTM: front of the meter, utility-scale; BTM: behind the meter, customer-sited

Figure 4. Costs and benefits summary: solar plus storage and distribution deferral use case, 2020



FTM: front of the meter, utility-scale; BTM: behind the meter, customer-sited

Study Caveats

Energy storage cost-benefit analysis is a broad topic. There are many forms of energy storage and many different use cases, configurations, and site specifications. Further, the electricity system is evolving toward a high-renewables system that no jurisdiction has experienced before. Consequently, analyzing the costs and benefits of a rapidly evolving technology in a fast-changing electricity system is a challenge. To provide valuable analysis within the short study period, this study focuses on providing a high-level valuation while helping to develop an evaluation framework for energy storage in Minnesota with an explicit focus on pragmatic near-term (5-10 year) use cases. Our quantitative analysis captures the important factors affecting energy storage value in Minnesota; additional considerations were addressed via sensitivity analysis or qualitative discussion.

Major study caveats are as follows:

- The high renewable scenario increased renewable generation for Minnesota only, not for neighboring states. If neighboring states add more renewables due to economic or policy-driven reasons, there may be a higher level of transmission congestion, limiting the system's ability to deliver renewable generation to load centers. In this case, energy storage could add value at congested transmission nodes and provide a timely alternative to hedge indeterminate transmission planning efforts.
- Transmission constraints: AURORA was used as a zonal model, which means transmission and distribution constraints are not considered for transferring power within zones.
- No power flow analysis was conducted.
- System sub-hourly need was not captured.
- The RESTORE model dispatches a battery optimally, assuming perfect foresight, which renders upper bounds for realized storage values. In reality, that value would not be realized due to forecast error and other factors.
- Current market participation rules were not modeled, as the study aims to provide theoretical values.
- The study does not quantify the economic value of the potential environmental impacts associated with storage.

1.0 Introduction

1.1 Overview

In May 2019, Minnesota lawmakers passed legislation directing the Minnesota Department of Commerce to conduct an analysis of the potential costs and benefits of energy storage system deployment in Minnesota.

> Minnesota Session Laws, 2019 Special Session 1, Chapter 7 (HF2), Article 11, Section 14
> REPORT; COST-BENEFIT ANALYSIS OF ENERGY STORAGE SYSTEMS.
>
> (a) The commissioner of commerce must contract with an independent consultant selected through a request for proposal process to produce a report analyzing the potential costs and benefits of energy storage systems, as defined in Minnesota Statutes, section 216B.2422, subdivision 1, in Minnesota. The study may also include scenarios examining energy storage systems that are not capable of being controlled by a utility. The commissioner must engage a broad group of Minnesota stakeholders, including electric utilities and others, to develop and provide information for the report. The study must:
>
> (1) identify and measure the different potential costs and savings produced by energy storage system deployment, including but not limited to:
>
> (i) generation, transmission, and distribution facilities asset deferral or substitution;
> (ii) impacts on ancillary services costs;
> (iii) impacts on transmission and distribution congestion;
> (iv) impacts on peak power costs;
> (v) impacts on emergency power supplies during outages;
> (vi) impacts on curtailment of renewable energy generators; and
> (vii) reduced greenhouse gas emissions;
>
> (2) analyze and estimate the:
>
> (i) costs and savings to customers that deploy energy storage systems;
> (ii) impact on the utility's ability to integrate renewable resources;
> (iii) impact on grid reliability and power quality; and
> (iv) effect on retail electric rates over the useful life of a given energy storage system compared to providing the same services using other facilities or resources;
>
> (3) consider the findings of analysis conducted by the Midcontinent Independent System Operator on energy storage capacity accreditation and participation in regional energy markets, including updates of the analysis; and
>
> (4) include case studies of existing energy storage applications currently providing the benefits described in clauses (1) and (2).
>
> (b) By December 31, 2019, the commissioner of commerce must submit the study to the chairs and ranking minority members of the senate and house of representatives committees with jurisdiction over energy policy and finance.
>
> (c) The commission is prohibited from spending more than the amount appropriated for the study, cost-benefit analysis, and other activities required under this section.

Separate legislation in 2019 also requires utilities to include an assessment of energy storage systems in their long-term resource plans.[6] Energy and Environmental Economics, Inc. ("E3") was hired by the Minnesota Department of Commerce to develop an independent cost-benefit analysis of potential energy storage systems in Minnesota that could be deployed over the next five to ten years.

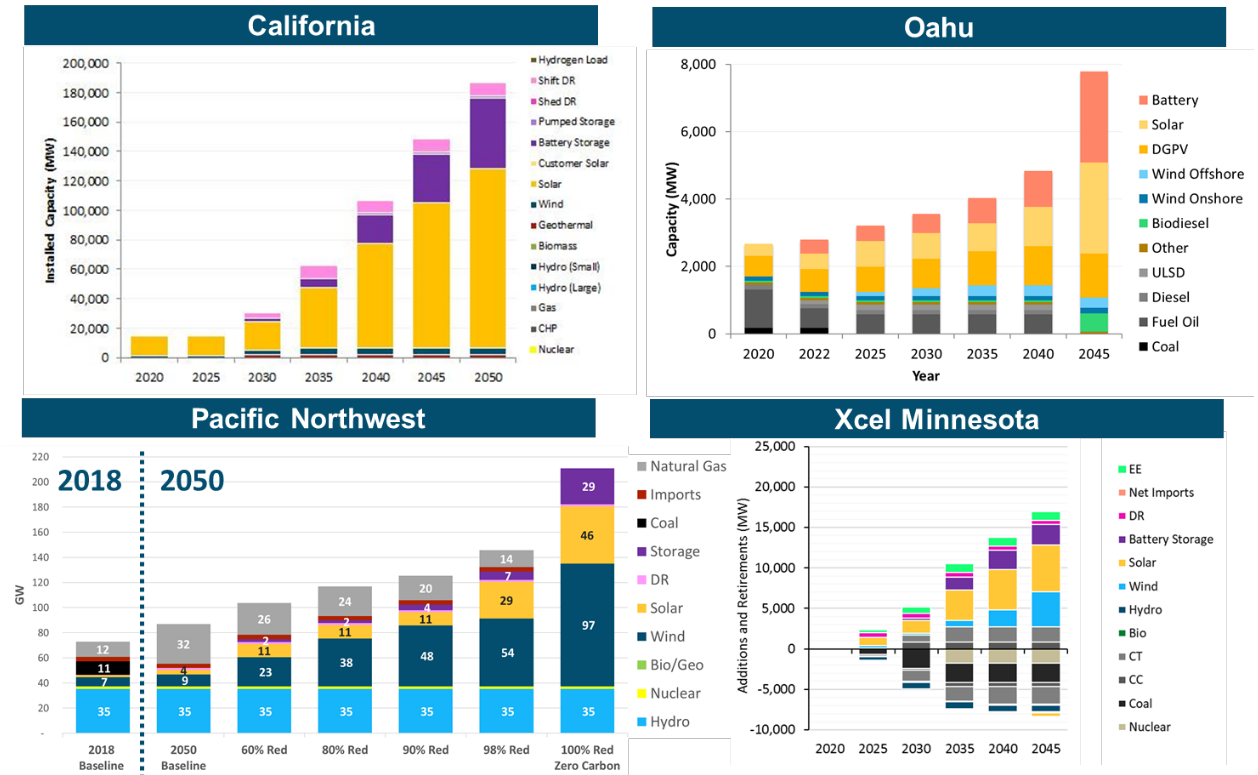
Energy storage could serve as a critical resource for enabling Minnesota's clean energy future. The state's goal to reduce greenhouse gas (GHG) emissions 80% by 2050, along with recently announced utility goals to reduce carbon emissions, will require significantly larger amounts of renewable energy, which in turn creates an opportunity for energy storage. As renewable power sources like wind and solar provide a larger portion of Minnesota's electricity needs, storage can be used to smooth and time-shift renewable generation and minimize curtailment. With a lower-carbon grid, electrification of transportation and heating could be key to achieving the state's climate goals, but will place additional demands on the grid, further necessitating flexible solutions including storage. Other near-term storage applications may also emerge.

Energy storage technologies could play a valuable role in helping to address these and other demands of a rapidly changing electric sector. According to E3's deep decarbonization studies for California, Hawai'i, the Pacific Northwest, and Xcel Minnesota shown in the figure below[7], energy storage is selected in all regions in the least-cost optimal portfolio under deep decarbonization scenarios. Total energy storage selected ranges from 2 GWs to 40 GWs in 2050 depending on the regions and scenarios. Energy storage, especially long-duration energy storage, could be an important part of a decarbonized grid. In the near-term, energy storage could provide fast-ramping reserves and improve the overall efficiency of the market.

[6] Minnesota Session Laws, 2019 Special Session 1, Chapter 7 (HF2), Article 11, Section 5

[7] Xcel Minnesota: Upper Midwest 2019 IRP Support: the 80X30 100X50 scenario shown here assumes Sherco & King coal plants early retirement and no nuclear relicensing
Pacific Northwest: Resource Adequacy in the Pacific Northwest
California: Land Conservation and Clean Energy Pathways for California Report
Oahu: Hawaiian Electric Companies' PSIP Update Report

Figure 5. In the future, storage could be a big part of a decarbonized grid



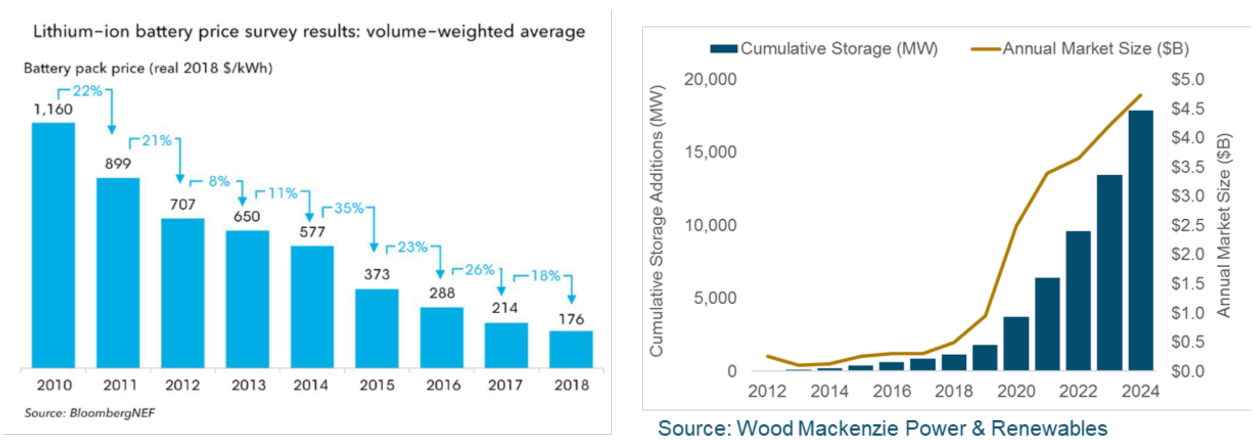
Energy storage has been called the “Swiss Army knife” of the electricity system in recognition of the many services it can perform. Some of these services are mutually exclusive; others can be “stacked” and performed either at the same time or with the same resource as shown in the figure below. For example, energy storage might not be able to provide system and local distribution capacity at the same time if two peaks are close and there is not enough time for energy storage to charge between them. This flexibility is important as the electric system evolves to become more decarbonized, decentralized and complex.[8] Ultimately, the type, number and value of services that storage can provide are likely to change as the needs of the system change and storage technology advances. Generally, storage technologies cannot perform all services of which they are capable simultaneously, which creates a need for clear performance, dispatch, and control requirements and signals. Through the right system planning, dispatch and price signals, storage can provide customer-sited benefits, distribution system relief, and wholesale services in the future. Common questions about energy storage revolve around where to site it, how much is needed, and how compensation for its many services is structured and developed.

[8] This complexity will likely take the form of a system with two-way power flow characterized by more renewable, intermittent energy; increasing diversity of end-uses and customer preferences; electrification of the heating and transportation sectors; and a need for increased system resiliency and lower costs to maintain a safe, affordable, and reliable electric system.

Figure 6. How to stack value for energy storage?

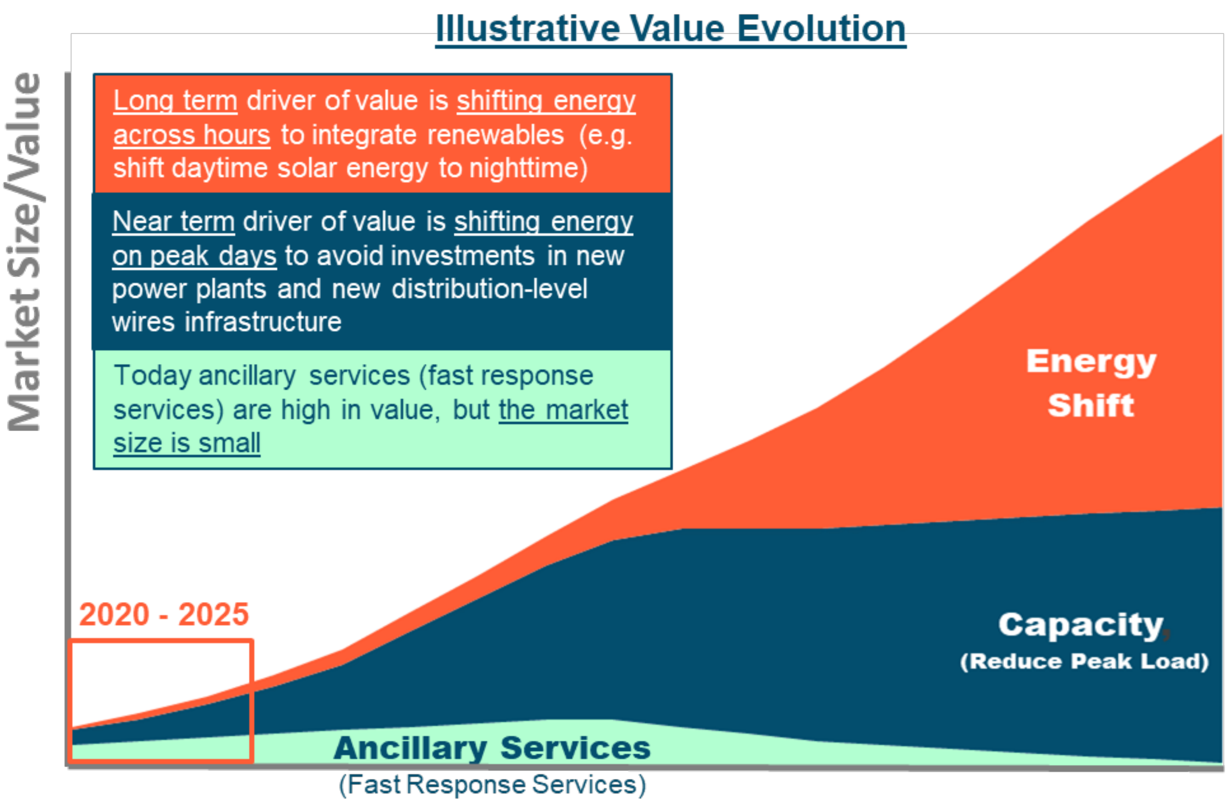
Cost declines, state clean energy goals, and ancillary service revenue opportunities have led to the growth of United States energy storage adoption in the past couple of years. As shown in the figure below, battery price has been declining continuously for 9 years by more than 10% every year and the energy storage adoption has increased significantly since 2018. The trend is expected to continue to the mid-2020s. Wood Mackenzie Power & Renewables estimated the cumulative energy storage adoption to be more than 15 GW in the United States by 2024.

Figure 7. Lithium-ion battery price trend (left) and us cumulative energy storage forecast (right)



The markets for storage and routes to market/value monetization will evolve, which is expected to encourage more diverse use cases/applications of storage technologies. The figure below is a stylized illustration of how the markets for storage value and specific use cases or applications could change over time. In the near-term, the ancillary services values, especially the fast response services if available, are high in value. When more energy storage enters the market, the ancillary services revenues could be saturated. And with the expected market mechanism improvement in utilizing energy storage for system capacity and non-wires alternative, the next high-value applications for energy storage might be providing system and local capacity. Competing with gas generators as peaking capacity and serving as non-wires alternatives to transmission or distribution upgrades could provide cost savings to the system. Eventually, as electricity systems move to a high-renewable world, energy storage could provide renewables integration value by shifting energy as needed to match variable renewable generation with load.

Figure 8. Illustrative energy storage value evolution

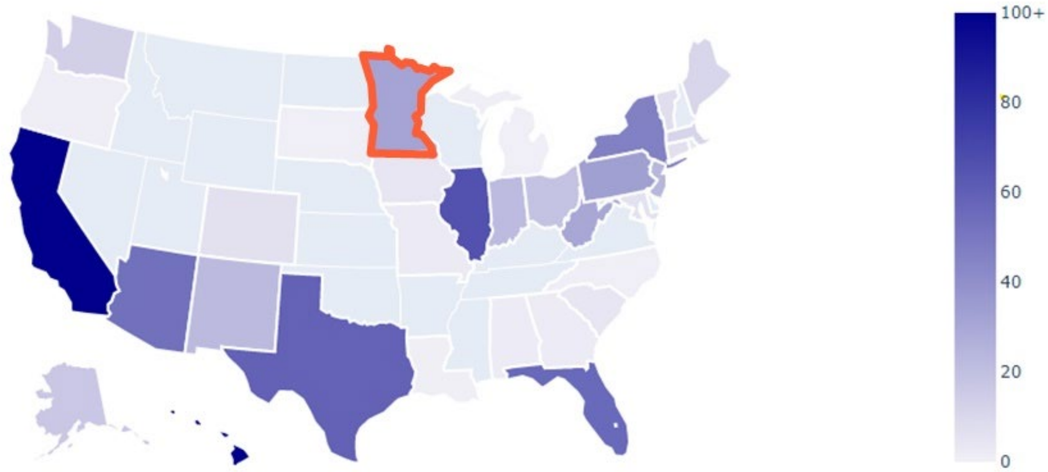


1.2 Current State of Minnesota's Energy Storage Market

California, New York, Illinois, and Hawai'i are leading storage deployment, while Minnesota is just starting to deploy storage installations. The figure below shows the cumulative energy storage deployment in MWh as of 2018. Three Lithium-ion (Li-ion) energy storage systems with a total capacity of 16.2 MW / 37.6 MWh have been deployed in Minnesota at the end of 2018. Two of them were added in 2018. These three existing batteries in Minnesota are used for system peak load shaving, demand charge management, T&D upgrade deferral, and renewables firming.

Another 160 MW of storage is in various stages of development or permitting, based on MISO's current interconnection queue.

Figure 9. Cumulative energy storage deployment through 2018* (MWh)



Using battery energy storage to provide peaking capacity is a rising use case which could provide valuable services to the grid. Based on NREL's recent study (Paul Denholm, 2019) on the potential for energy storage to provide peaking capacity, around 1,000 MW of energy storage in MISO west could receive full peak demand reduction credit in 2020 without additional wind and solar. However, the NREL study does not perform a cost-benefit analysis of using storage to provide peak capacity. Our current study takes a closer look at the costs and benefits to Minnesota of adding storage.

The current study also looks at the potential to provide peaking capacity from another angle, by examining the operations of existing peakers. The results show 324 MW of 4-hour energy storage in Minnesota could mimic the operations of about 10% of the existing 3.1 GW peaker fleet. Much of this 324 MW is already scheduled to retire in 2023, creating a potential opportunity for utility-scale storage to be installed with minimal interconnection costs, assuming the same site and interconnection capacity can be used. These results are discussed in detail later in this report.

On the behind-the-meter side, residential storage deployment grew 500% in 2018 in the United States driven by favorable policies in California, Hawai'i, Vermont, and other states. Non-residential storage also shows a growth of 35%. Minnesota currently has less than 1 MWh of residential energy storage (Mac Keller, 2019).

Previous energy storage studies (University of Minnesota, Strategen Consulting, and Vibrant Clean Energy, 2017) for Minnesota have found that energy storage is valuable to a decarbonized grid as the inclusion of energy storage would enable MISO and Minnesota to reduce GHG's sooner and at a lower cost. When deployed with the ITC incentives and GHG constraints, energy storage is selected as preferable resources by 2030. Under less optimistic assumptions, storage is selected in a later timeframe (e.g. 2045). And when comparing energy storage to gas-fired peaking plants, Strategen and VCE's study found that solar + storage was cost-effective in 2018. The storage-only resource was not found to be cost-effective in 2018 but cost-effective in 2023.

Energy storage has reached cost-effectiveness first in other areas that have higher capacity costs, solar-heavy renewables portfolios, and less regional coordination opportunities (e.g., New York, California, Massachusetts) due to:

- relatively high capacity values resulting from limited capacity supply in these systems
- Expensive new capacity due to higher labor and land costs
- California is a solar-dominant system with solar supplying a large portion of the load during the middle of the day. This results in a significant intra-day price spread where low prices are found during the day and high prices happen during the early evening. The diurnal price change pattern coincides with the operation of the 4-hour energy storage and thus allows energy storage to bring a large amount of benefits to California's system. In contrast, a large portion of Minnesota's renewable energy is wind, which produces a smaller intra-day price spread as compared to solar-dominant systems

Regional coordination through MISO (of which Minnesota is a member), including relatively inexpensive transmission expansion compared to other jurisdictions, can help absorb high levels of renewable generation, thereby reducing the need for storage resources to perform this function. Although other states have reached cost-effectiveness for energy storage first, Minnesota is well-positioned for capitalizing on larger industry trends such as continuing cost declines and technology innovation.

1.3 MISO

In February 2018, the Federal Energy Regulatory Commission (FERC) issued Order 841, which directed electric grid operators to remove barriers preventing energy storage from participating in wholesale markets. Storage has unique operating characteristics compared to conventional resources, as it can serve as generation, load, and a transmission asset, and can only charge or discharge for so long due to its limited energy capacity. Therefore, in many regions, changes to market design are required before storage is able to participate in wholesale electricity markets.

Throughout 2018, MISO facilitated a market design and stakeholder engagement process to comply with the Order 841 requirements. In December 2018, MISO filed its Order 841 compliance plan with FERC. MISO's compliance plan introduces market design rules for a new Electric Storage Resource category, which will allow energy storage to participate in MISO's energy, capacity, and ancillary services markets.

Capacity credit for energy storage will be based on a 4-hour duration—that is, 4-hour storage will get full capacity credit, and shorter-duration storage will receive a proportionally de-rated capacity credit. The capacity credit allowed for storage would also be subject to standard MISO outage rate and transmission deliverability calculations. MISO's proposed rules allow storage to bid in all appropriate operating parameters to the day-ahead market, such that MISO's dispatch software will reflect important constraints such as minimum and maximum state of charge.

An important component of MISO's proposed participation rules is the ability to participate in the Ancillary Services market. This market is an important value stream for storage, so adequate participation rules will ensure that storage can become cost-effective in the MISO footprint.

On November 21, 2019, FERC granted MISO's request to defer implementation of its energy storage provisions until June 6, 2022, subject to a compliance filing due in 60 days, and to the filing of annual reports. Thus, implementation details for MISO's Order 841 compliance plan are still in progress. Currently under consideration are important issues such as the ability for distribution-sited storage to participate in wholesale markets, and the minimum size of storage resources.

In addition to Order 841 compliance, MISO added Automatic Generation Control (AGC) for fast-ramping resources. The goal is to utilize fast-ramping resources to improve the overall efficiency of the market. Since short-duration energy storage systems are well-suited for fast-ramping services, this could be a revenue stream for energy storage in the short-term.

The benefits and costs in this study are somewhat independent of MISO market rules. We model ancillary services market participation according to MISO rules, and model storage participation in MISO's wholesale energy market, but the capacity values shown in this study are theoretical "avoided generation capacity" numbers based on the ability of storage to reduce system peak load, not the actual revenues that would be received if storage participated in MISO's capacity auctions. We also do not model a real-time market that would give more credit to resources capable of fast-ramping such as storage.

1.4 Barriers

A clear route to market exists today for only a limited number of storage services; many services cannot be monetized in current electricity markets. Consequently, the benefits of some storage services remain unrealized. This is especially true of services that can be stacked together, either at the same time or with the same resource over time. The primary challenges facing energy storage in Minnesota include:

- **The inability to monetize the full value of storage**. Restrictions and/or high costs from aggregation or telemetry that would enable monetizing multiple stacked services are one of the largest barriers for storage. This limits the value and therefore the economics and financeability of storage in today's electricity markets.
- **Limited routes to existing markets**. Regulatory and market rules, which were largely put in place before non-hydro storage as well as DERs were available, often limit the ability to receive compensation for the services and benefits that storage could provide. In some cases, these rules do not fully recognize the inherent value that near-instantaneous response can provide compared to alternative solutions.
- **Confidence in performance and lifetime**. The diversity and relative "newness" of different types of energy storage technologies, products, applications, and use cases complicate understanding and confidence among potential customers and investors.
- **Lack of common financing vehicles**. The relatively low volume of existing energy storage projects contributes to a lack of standardized and transparent processes, procedures, and documentation, which impedes investor confidence and the ability to finance projects using conventional vehicles. This also increases the transaction cost of project finance.

- **High soft costs** related to permitting, siting, interconnection, customer acquisition, and financing.
- **Insufficient data on local constraints**, which impedes efforts to site storage and DERs for maximum system benefit and to identify potential customers.
- **Storage costs** are still too high today to allow scale in many use cases, although costs have generally been declining by an average of 10-15 percent per year.

1.5 Drivers

Minnesota's forward-looking energy policies position the state as a leader on renewable generation, grid modernization, resilience, and job creation in the Midwest.

Some of the key factors driving storage's cost-effectiveness and adoption include:

- Declining costs, which are forecasted to continue declining through the 2020s
- Better performance and longevity of different storage technologies and applications
- Increasing investment appetite among developers, customers and financiers
- Improved understanding of the value provided by renewable energy, DERs, and other innovative technologies as a result of future successful Minnesota demonstration projects

2.0 Analysis Approach

2.1 Potential Market Size Estimate

To provide a high-level assessment of potential market size for energy storage in Minnesota in 2030 and 2045, E3 first conducted a literature review to summarize the market size found by three previous studies. E3 then estimated the potential market size using the capacity expansion function in AURORA.

E3 conducted a literature review of market size analysis in the following studies:

- **Minnesota Economic Analysis of Energy Storage Opportunity** by Strategen and VCE (University of Minnesota, Strategen Consulting, and Vibrant Clean Energy, 2017)
- E3's **Capacity Expansion Modeling for Xcel Energy's Upper Midwest 2019 Integrated Resource Plan** (IRP) (Xcel, 2019)
- **The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States** by National Renewable Energy Laboratory (NREL) (Paul Denholm, 2019)

The Economic Analysis of Energy Storage Opportunity study (University of Minnesota, Strategen Consulting, and Vibrant Clean Energy, 2017) simulated the optimal adoption level of energy storage in MISO through a co-optimized, blended capacity expansion and hourly production cost model: WIS-dom. The authors investigated various scenarios such as the inclusion of a greenhouse gas constraint and limited fossil fuel supply. The analysis estimated no economic energy storage adoption in 2030 but estimated between zero to 10 GW energy storage adoption in 2045.

The modeling E3 conducted to support Xcel's Upper Midwest IRP (Xcel, 2019) is also based on a resource investment model, RESOLVE.[9] Similar to the WIS-dom model, RESOLVE is an optimization model that could identify optimal long-term generation investments subject to technical and policy constraints. The analysis conducted for Xcel's Upper Midwest IRP investigated a wide range of future scenarios including different policy options for meeting the greenhouse gas goals and various coal retirement schedules. The study estimated that optimal energy storage adoption levels were between zero to 1.5 GW in 2030 and between two to 18.5 GW in 2045 for Xcel's Upper Midwest territory.

The NREL study (Paul Denholm, 2019) examined the amount of 4-hour batteries that could receive full capacity value in the U.S. The study found that nationally, about 28 GW of 4-hour batteries are able to provide peak capacity equal to the batteries' maximum discharge capability: about 11 GW for MISO. The amount of 4-hour batteries that could receive a full capacity value is by no means the potential market size. It is just a measurement of how many GWs of energy storage could provide full capacity value to the system. The potential market size could be higher or lower depending on capacity values, the cost of energy storage, and whether there are other available benefit streams. The value is included here as a reference.

[9] RESOLVE is an E3 proprietary capacity expansion model for a long-term timeframe (10-20 years).

Potential market size results from E3's AURORA capacity expansion modeling, along with the potential market size estimated through the three studies mentioned above are summarized in the table below.

Table 1. Literature review and E3 analysis of potential market size for energy storage

Studies	Study Region	2030	2045
Strategen + VCE: MN Economic Analysis of Energy Storage Opportunity[10]– Optimal MWs	MISO	0 GW	0 – 10 GW
E3: Modeling for Xcel IRP (2019)[11] – Optimal MWs	Xcel Upper Midwest	0 – 1.5 GW	2 – 18.5 GW
NREL: Peaking Capacity Study (2019)[12] – MWs with full capacity credit	MISO	11 GW	
E3 AURORA Capacity Expansion Modeling (80% RPS across MISO)	**MISO**	**1.2 GW**	**n/a**

These three studies, as well as the AURORA runs conducted by E3, estimated the market from the overall system's perspective and did not consider potential energy storage needs arising from local constraints (e.g., transmission constraints and distribution deferral). Future studies that include opportunities for storage to address local constraints (e.g., by employing detailed nodal transmission modeling and power flow analysis) could provide a more accurate estimate of the market potential for energy storage in Minnesota.

[10] (University of Minnesota, Strategen Consulting, and Vibrant Clean Energy, 2017): Results are from Alternative case B: Transmission, storage, GHG constraints and Alternative case A: Transmission, storage, no GHG constraints.

[11] (Xcel, 2019): Based on the results from reference case and sensitivities

[12] (Paul Denholm, 2019): the addressable market is estimated as the total MW of energy storage that can obtain full capacity credit

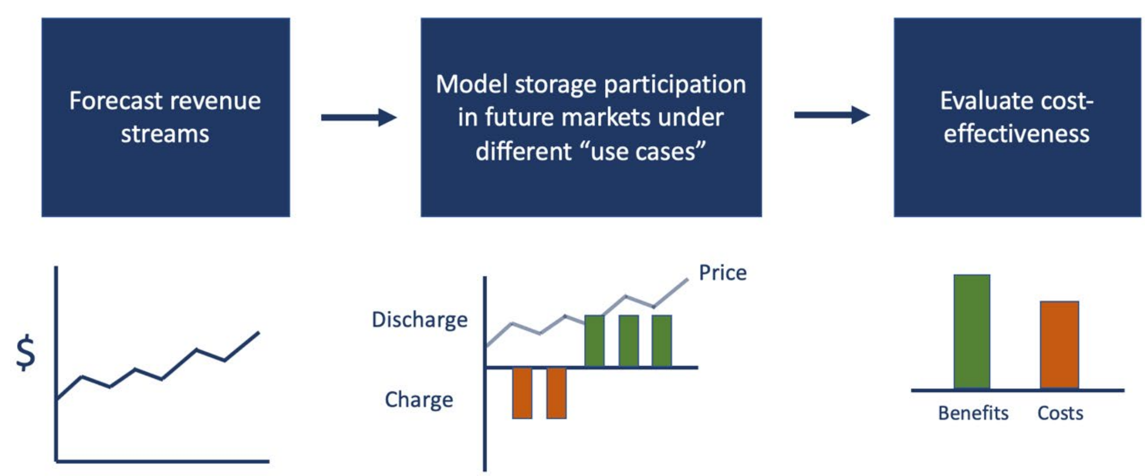
2.2 Cost-benefit Analysis

To identify and measure the potential costs and benefits of energy storage in Minnesota, E3 used a two-model approach:

- E3 used **AURORA**, a commercially available production simulation model, to simulate wholesale system operations for the next 10 years. We then derived day-ahead hourly energy prices, hourly ancillary services prices, and annual capacity prices based on the AURORA results. These prices reflect system needs in future scenarios, including both the need for new capacity due to load growth and the retirement of generation resources, as well the need for integrating renewables to support Minnesota in achieving its greenhouse gas emissions reduction goal.
- E3 then used market prices from AURORA in **RESTORE**, E3's proprietary storage dispatch and financial model. RESTORE co-optimizes multiple available revenue streams and also optimizes battery dispatch to maximize total net revenues while following battery operating parameters. In addition to the system value streams identified through AURORA, RESTORE evaluates local value streams (e.g., distribution deferral and emergency services) when available.

E3 then compared benefits and costs side-by-side to analyze cost-effectiveness. Cost-effectiveness can be viewed from a number of perspectives, including from the state of Minnesota, the utility, ratepayers, and storage-adopting customers. By simulating storage dispatch for each use case and conducting cost-benefit analysis from different perspectives, we capture a wide spectrum of values from energy storage to better assess how that value is allocated among parties.

Figure 10. Overview of energy storage valuation methodology



Our production simulation modeling in AURORA focuses on three scenarios. On the lower end of the spectrum, the "Existing Trends" scenario is one in which renewables penetration continues at current levels. The second scenario, "High Minnesota Renewables," examines a future in which Minnesota aggressively adopts renewables. A third scenario considers the impacts of increasing natural gas prices. Neighboring states are assumed to continue with existing generation fleet plans (an important assumption, as it means these states can balance fluctuations in the supply of Minnesota's renewable generation). All three scenarios were designed in collaboration with Department of Commerce staff.

- The **"Existing Trends"** scenario is a base case, meant to represent market conditions if renewable integration were to continue as it is today. This case was developed following the Limited Change scenario in Midcontinent Independent System Operator (MISO)'s 2018 Transmission Enhancement Plan (MISO, 2018).
- The **"High Minnesota Renewables"** scenario assumes increased solar and wind capacity such that over 75% of load is met by renewables by 2032. It is also assumed that all nuclear is relicensed at the expiration of their current licenses, and all coal has retired by 2030.
- The **"High Natural Gas Price"** scenario was developed as a sensitivity on the Existing Trends scenario to study how higher gas prices would impact market prices.

These "system scenarios" are used to generate market price forecasts, which are then used in RESTORE for several **use cases** for storage in Minnesota.

The **front-of-the-meter** use cases analyzed combinations of wholesale market services – including energy arbitrage, ancillary services, congestion reduction, and solar-plus-storage – for lithium-ion battery storage installed in 2020. Front-of-the-meter use cases are examined in all three study scenarios, as well as a "higher curtailment" sensitivity. Additional sensitivities evaluate the cost-effectiveness for a short-duration battery, a battery installed in 2025, and a flow battery.

We also examine a **distribution system** use case based on one of the distribution deferral candidates identified in Xcel's 2018 Integrated Distribution Plan report (Xcel Energy, 2018). In this use case, energy storage is used for distribution deferral during peak hours and is able to provide other grid services in the remaining hours.

The **behind-the-meter** use cases examined storage applications for customer retail bill management and backup power provision during emergency events using a maintenance facility in Minneapolis as an example. This use case pairs storage with a solar photovoltaic (PV) system.

2.3 Caveats

Energy storage cost-benefit analysis is a broad topic. There are many forms of energy storage and many different use cases, configurations, and site specifications. Further, the electricity system is evolving toward a high-renewables system that no jurisdiction has experienced before. Consequently, analyzing the costs and benefits of a rapidly evolving technology in a fast-changing electricity system is a challenge. To provide valuable analysis within the short study period, this study focuses on providing a high-level valuation while helping to develop an evaluation framework for energy storage in Minnesota with an explicit focus on realistic near-term (5-10 year) use cases. Our quantitative analysis captures the important factors affecting energy storage value in Minnesota; additional considerations were addressed via sensitivity analysis to provide an estimate of their impact or via qualitative discussion.

Study limitations are summarized below:

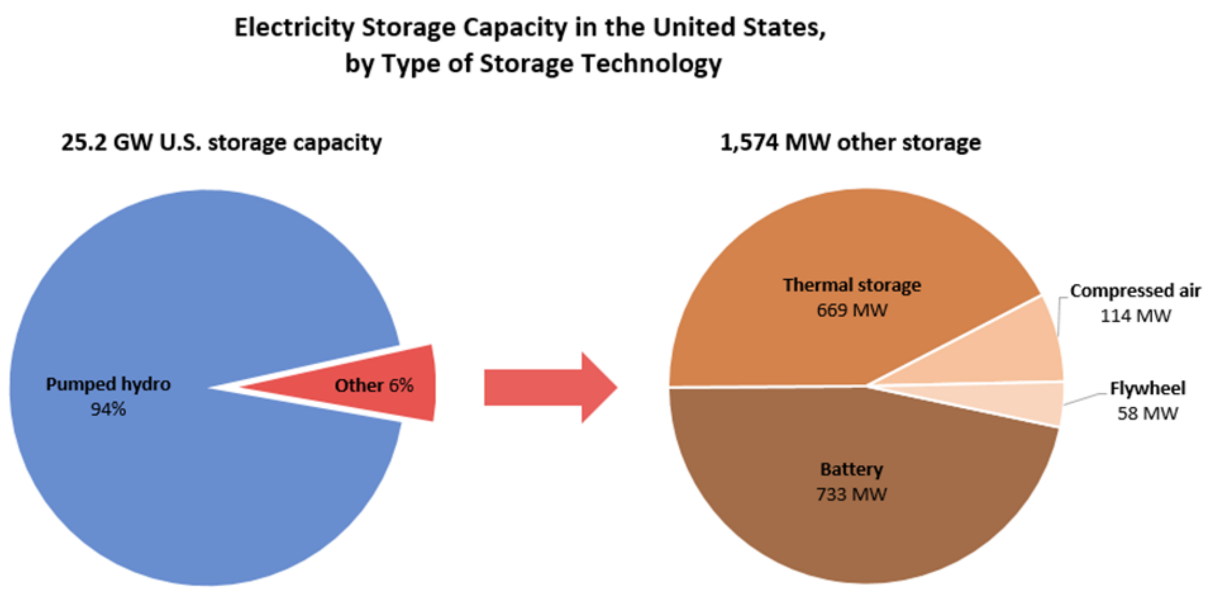
- **AURORA Production Simulation Model Caveats:**
    - Transmission constraints: the Eastern Interconnection is modeled as multiple zones in AURORA. Transmission and distribution constraints are not considered for transferring power within zones.
    - No power flow analysis is conducted
    - System sub-hourly need is not captured
    - Low-probability, high impact reliability events such as multi-day periods in MISO with no wind, as well as multi-day polar vortex events, are not modeled.
    - Load forecast for average weather years is used in the study. There is no consideration of extreme weather events.
- **The high renewable scenario increased renewable generation for Minnesota only, not for neighboring states.** If neighboring states add more renewables due to economic or policy-driven reasons, there may be a higher level of transmission congestion, limiting the ability to deliver renewable generation to load centers. In this case, energy storage could add value at congested transmission nodes and provide a timely alternative to hedge indeterminate transmission planning efforts.
- **RESTORE Model Caveats:**
    - The RESTORE model dispatches a battery optimally assuming perfect foresight, which renders upper-bounds for realized storage values
    - Current market participation rules are not modeled as the study aims to provide theoretical values
    - The impact of temperature on battery performance and storage's interconnection costs are not included
- **Study limitations when comparing energy storage and combustion turbine as new capacity addition**
    - The study didn't conduct stochastic analysis to address whether energy storage can provide capacity reliability concerns during extreme grid conditions; nor does the study consider charging constraints due to congestions and other local grid constraints for energy storage
    - This study doesn't analyze the potential changes to MISO Loss of Load Expectation (LOLE) calculations and associated increases to MISO's Planning Reserve Margin (PRM) calculations which might be impacted by energy storage serving as capacity units
    - Power flow analysis will be needed for actual project siting and interconnection

3.0 Storage Technology and Use Cases Review

3.1 Overview

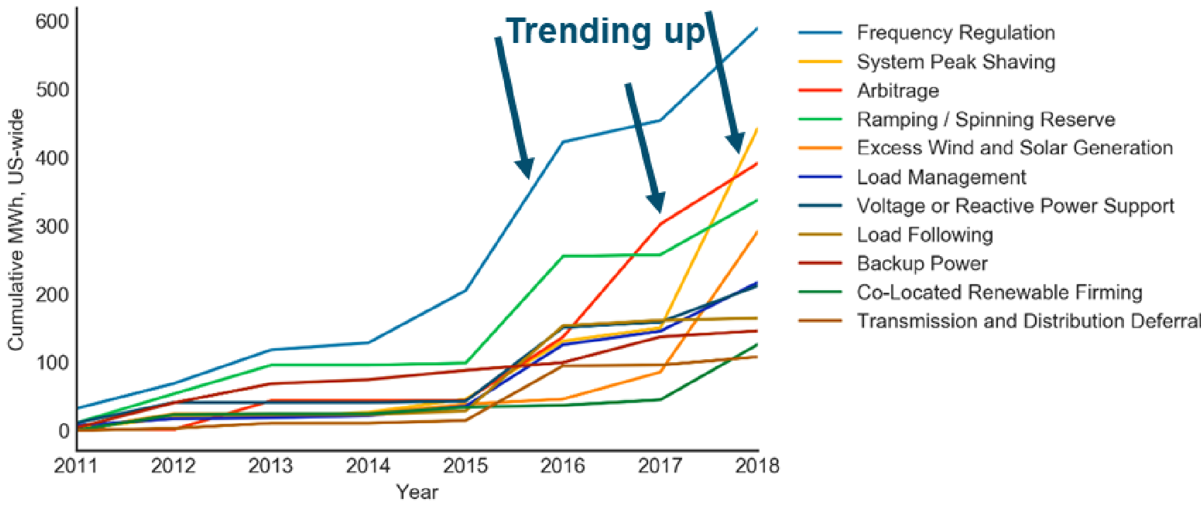
Today, the United States has a total of 25.2 GW of storage capacity, as of 2018. Most of the existing energy storage (94%) is pumped hydroelectric storage. Battery and thermal storage are the second and the third-largest by installed capacity at 733 MW and 669 MW respectively. Among the current battery storage installations, 90% are Lithium-ion, followed by sodium-based batteries at 6% and flow batteries at 1%. (US-EPA, n.d.)

Figure 11. Energy storage capacity in the United States



In terms of battery applications, 88% of large-scale battery storage provides frequency regulation. And most of the energy storage (56%) provides more than one service which reflects the versatile nature of energy storage. In recent years, frequency regulation, system peak shaving, and arbitrage have emerged as the most common use cases (on an energy basis).

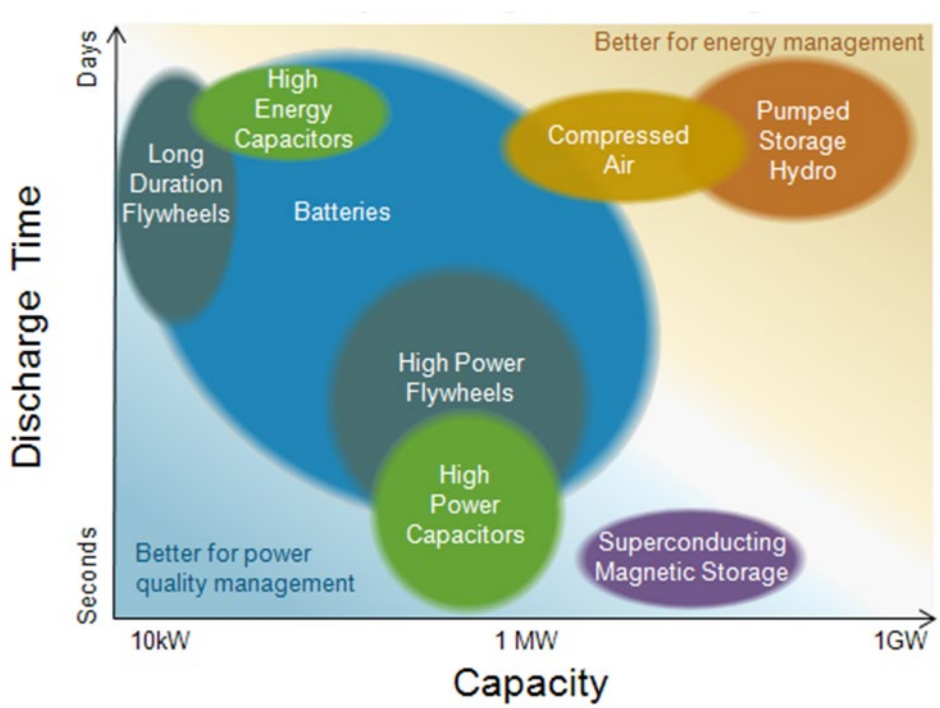
Figure 12. Applications served by U.S. large-scale battery storage over time



Source: EIA Form 860

Various types of storage technologies are designed to respond to changes on varying timescales and thus are suitable for different uses. As shown in the Figure below (US EIA, 2011), pumped storage and compressed air energy storage are most suitable for long-duration energy shifting which could be valuable to meet future renewable integration needs, while flywheels and capacitors are batter for shorter-duration needs such as frequency regulation.

Figure 13. Energy storage technologies and suitable use cases



Energy storage can be categorized into four types: electrochemical, electrical, thermal, and mechanical. Example energy storage technologies for each type are summarized in the Table below.

Table 2. Energy storage technology types and examples

Types	Examples
Electro-chemical	Battery, flow batteries
Electrical	Capacitor, supercapacitor
Thermal	Hot water storage, solar thermal
Mechanical	Pumped storage, compressed air, flywheel energy storage

3.2 Technology and Use Case Selection

Technology Selection

This study considers the following three criteria when choosing energy storage technologies for analysis:

- The energy storage technology is able to provide high-value services in the short-term and in the long-term
- The technology has low capital cost or has cost reduction potential
- The technology can be deployed in Minnesota

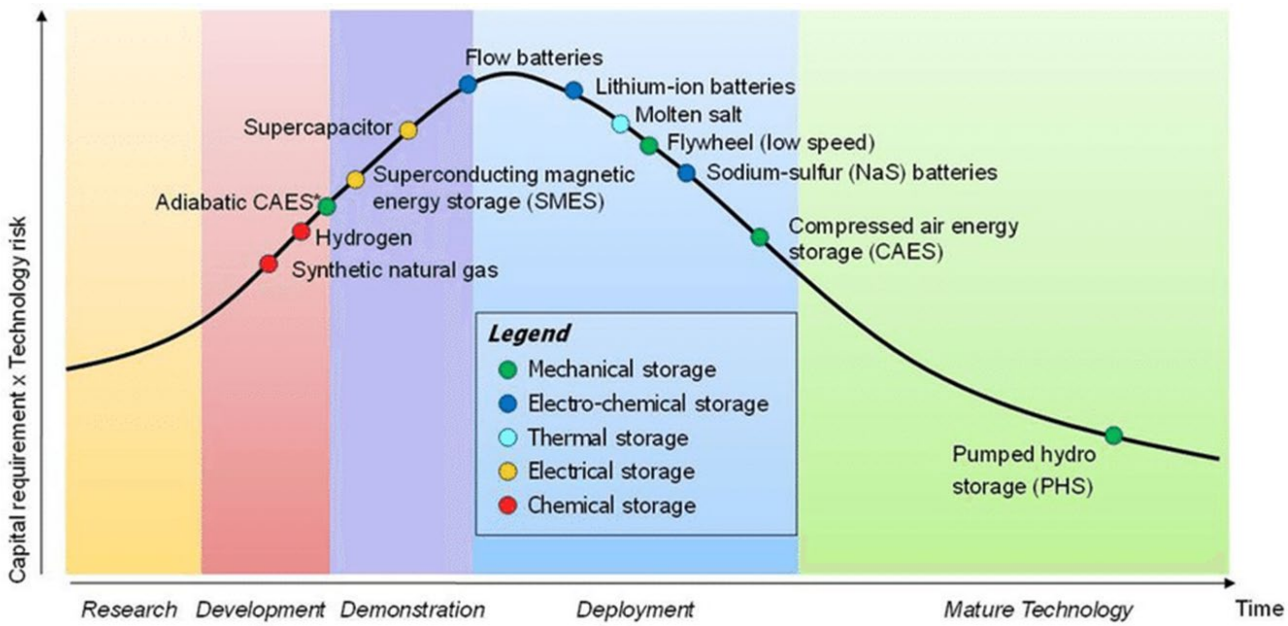
Based on the current storage market participation and the fundamental need for the system in the future, we expect that the high-value services for energy storage are ancillary services in the short-term, system and local capacity around the mid-2020s, and renewable energy shifting/integration after 2030. As shown in the Figure below, chemical and mechanical storage can provide the high-value services we identified, thus the study narrows down the technology selection to be within chemical and mechanical energy storage.

Figure 14. Energy storage types and the services they can perform

Market Segment	Service (Value / Benefit)	Timescale	Chemical	Electrical	Thermal	Mechanical
Wholesale	Frequency Regulation	Seconds, minutes	+	+	-	+
	Load Following/Ramping	Seconds, minutes, hours	+	+	-	+
	Renewable Integration	Seconds, minutes, hours, days, seasons	+	+	-	+
	Spinning Reserves	Minutes, hours	+	+	-	+
	Non-Spinning Reserves	Minutes, hours	+	+	-	+
	Voltage Support	Minutes, hours	+	+	-	+
	Black Start	Minutes, hours	+	+	-	+
	Energy (arbitrage, peak shaving, shifting)	Minutes, hours, days	+	+	Partially	+
	Emission Reductions	Minutes, hours, days, months, seasons, years	±	±	±	±
	System Capacity or Resource Adequacy	Months, years	+	-	-	+
	Transmission Deferral/Avoidance	Months, years	+	-	-	+
Distribution	Volt/VaR Control	Seconds, minutes	+	-	-	-
	Outage Mitigation	Minutes, hours, days	+	-	-	-
	Distributed Generation integration	Minutes, hours, days	+	-	-	-
	Distribution Deferral/Avoidance	Months, years	+	-	-	-
	Distribution Congestion Relief	Months, years	+	-	-	-
Retail (Customer or Ratepayer)	Power Reliability	Seconds, minutes, hours	+	-	-	-
	Backup Power	Minutes, hours	+	-	-	-
	Utility Delivery Charge Savings	Minutes, days, months	+	-	±	-
	Retail Commodity Charge Savings	Hours, days, months	+	-	±	-

The second criteria this study examines is the cost. The figure (Ramírez Torrealba, 2016) below summarizes energy storage technology maturity by development stages. This study focuses on technologies that are either in deployment or mature technology stage because its implication on current price and future price reductions. Maturity of the technology in many cases indicates whether the technology is low-cost or has the potential for future price reductions. If the technology is in the mature stage, it is likely that the technology is already cost-effective after being implemented in the market for a period of time. If the technology is in the deployment stage, the technology has the potential for aggressive price reduction in the near-term as the technology improves and soft costs are reduced.

Figure 15. Technology maturity based on a 2016 study



After the first two criteria, we narrow down our technology selection to lithium-ion batteries, flow batteries, flywheels, compressed air energy storage, and pumped hydro storage.

Mesabi Iron Range in Northern Minnesota are identified as potential candidate sites for both compressed air energy storage and pumped hydro storage. These sites are old mining locations; thus, developers could leverage the existing underground mine workings and above ground features for constructing new energy storage. Previous studies show that various sites could allow a 100 to 200 MW of compressed air energy storage and pumped hydro storage facility to be constructed. (Fosnacht, 2011) (Donald R. Fosnacht, 2015)

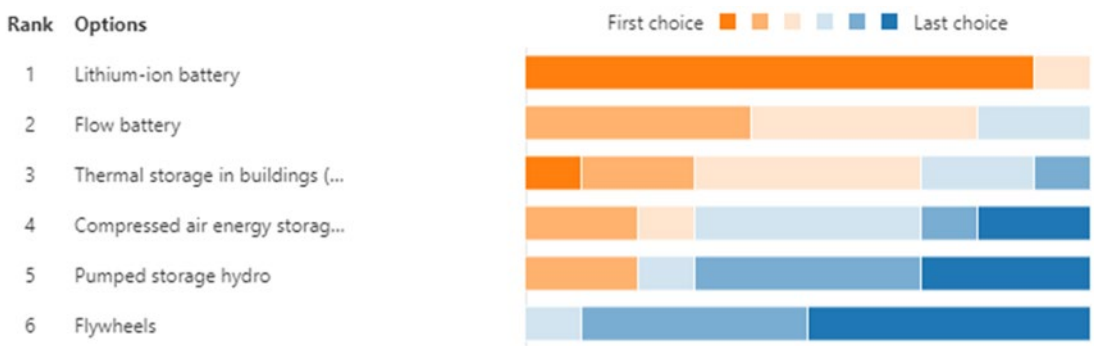
Given that there are limited opportunities and available sites for pumped hydro and compressed air energy storage, and the costs and operating requirements are also specific to each site, the study excludes these two technologies from the analysis. Detailed studies are required to examine the cost-effectiveness of compressed air energy storage and pumped hydro to capture the unique operational rules and costs for each site.

We asked stakeholders to rank the energy storage technology options in the order of importance. The figure below summarizes the results we got from 13 responses. Lithium-ion batteries are a clear winner in the priority board. Flow batteries and thermal storage are second and third on the list. Based on stakeholder feedback and other reasons we described above, the study chooses the following two energy storage technologies for analysis:

- Lithium-ion battery
- Flow battery (sensitivity)

Lithium-ion batteries are the main technology analyzed in this study. Even though flow batteries are not as cost-effective as lithium-ion batteries, Lazard (Lazard, 2018) estimates a faster price decline for flow battery (11%) than lithium-ion battery (8%) in the next five years. In addition, unlike lithium-ion batteries, flow batteries don't have degradation and flammability issues. These beneficial characteristics might make flow batteries preferable under certain circumstances, particularly in the longer term when long-duration storage is needed. This study conducts a sensitivity to examine the cost-effectiveness of a flow battery.

Figure 16. Storage technology in order of priority based on stakeholder feedback



Other Technologies

In addition to the two technologies we examined, there are other forms of energy storage that could potentially be cost-effective in the future. Those technologies are not included in the cost-benefit analysis due to the time and budget constraints. Their potential benefits are discussed below:

Thermal storage in the form of building space and water heating/cooling

Interest in thermal storage in the form of building space and water heating/cooling is growing quickly in the United States. When controlled or signaled by utilities, they can move energy around relatively flexibly at a fraction of the cost of battery energy storage.

Space conditioning and water heating is 40% of the residential electricity demand as shown in the figure below. For most residential utility customers, hot water is used largely in morning and evening hours, similar to space heating and cooling. Through pre-heating and pre-cooling, utilities can move the energy need from the potential system evening peak hours to midnight to take advantage of high wind production and to midday to take advantage of abundant solar production. (Trabish, 2017)

Minnesota has a first-of-its-kind pilot project for a grid-interactive water heater. Dakota Electric Association, in partnership with Great River Energy have been conducting a pilot project utilizing grid-integrated water heaters since 2016. The pilot project tests the grid-interactive electric thermal storage (GETS) water heaters in 81 homes in the Legacy 2 housing development in Lakeville, Minnesota. The pilot limits the charging of water heaters to the hours of 11 pm to 7 am to avoid the evening peak and to take advantage of MISO low-price hours. The GETS system allows utilities to see the state of charge of single units or a group of water heaters in aggregate. When coupled with rapid two-way communications, facilitated by cellular or Wi-Fi technology, utilities have the ability to granularly control the water heaters, opening up the possibilities of renewable energy tracking or providing ancillary services within a wholesale market. (Great River Energy, 2016)

These forms of thermal storage could provide valuable energy shifting capabilities to the grid at low costs. How to take customers' hot water needs into consideration when performing load shifting to reduce system costs will also be an important topic to investigate, so that thermal storage does not incur an inconvenience for participating customers.

Hydrogen, natural gas, and ammonia as forms of energy storage

Hydrogen energy storage is another form of chemical energy storage. Electricity is converted to hydrogen through electrolysis of water. The hydrogen can then be stored in the pipeline system or underground caverns for later use. When the electricity is needed, hydrogen can be used in a combustion turbine or a fuel cell in its gaseous form to release the energy. There are many interests in hydrogen energy storage because its usage and distribution are very similar to natural gas. It can take advantage of existing combustion appliances and natural gas pipelines, although modifications and upgrades are generally necessary at higher blending percentages. In addition, hydrogen energy storage provides seasonal storage capability which is essential for a deep-decarbonized system with a high renewables penetration. Hydrogen or other long-duration storage could provide energy during low-probability, high impact reliability events such as multi-day periods in MISO with no wind and polar vortex events.

Transportation and storage of hydrogen can be difficult and costly. To address the transportation difficulty, an additional step can be added after the electrolysis process to convert hydrogen to natural gas ("power-to-methane") or ammonia. The resultant natural gas can then be injected into the natural gas pipeline system for use in home appliances, industrial processes, engines, and power plants. (Gas, n.d.)

Siemens and others are also investigating the use of ammonia as a way to store and transport hydrogen. Ammonia has nearly two times the energy density by volume as liquid hydrogen, which makes it easier to ship and distribute. In addition, it doesn't have the potential to contribute to global warming if leaked, whereas methane is a very potent greenhouse gas. (Deign, 2019) (Service, 2018)

Hydrogen, natural gas, and ammonia as forms of energy storage are still a relatively new concept. Scientists and industry leaders are continuingly investigating and testing. These forms of storage could become valuable resources to the grid when renewable penetrations are high, and the system needs seasonal energy shifting capabilities.

The "storage-like" hydro system

Hydroelectric dams can provide storage-like services to the electric grid. They can store water by lowering output when wind and solar are abundant, and dispatch to supply energy and capacity when demand rises. MISO is connected to Manitoba Hydro, which can provide these storage-like services. A transmission expansion is currently in progress that will allow MISO to take further advantage of Manitoba Hydro's flexible hydro resources (Jordan Bakke).

Use Cases

Based on stakeholder feedback, the following core use cases and sensitivities are conducted in the analysis.

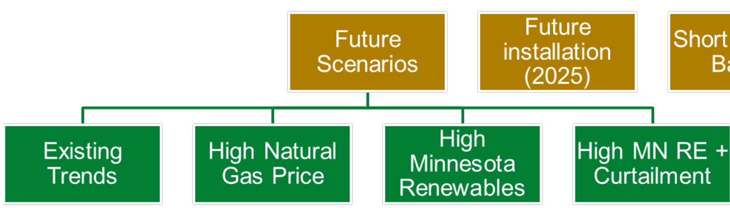
Figure 17. Core use cases

Benefit Streams →

Core Use Cases

	Wholesale			Transmission and Distribution			BTM
Core Use Cases	Energy arbitrage	Avoided generation capacity	Ancillary services	Transmission congestion relief	Transmission & Distribution deferral	Emergency services	Bill savings
Wholesale standard[1]	✓	✓	✓				
Wholesale congestion relief	✓	✓	✓	✓			
Distribution deferral	✓	✓	✓		✓		
BTM PV paired with storage	?	?					✓
FTM PV paired with storage	✓	✓	✓				

Figure 18. Sensitivities on use cases



In the "wholesale standard" case, energy storage can provide energy arbitrage, capacity, and ancillary services over the course of the modeling period. This base case represents a generic energy storage system located in Minnesota without additional local benefits. Additional local benefits including transmission congestion relief, distribution deferral, and emergency services are added in other use cases to test the additional values storage can provide when located in a constrained area. Storage systems paired with solar are also tested for both the behind-the-meter and in-front-of-the-meter use cases to evaluate the tradeoff between ITC incentives and the charging constraint it imposes[13] (). Other sensitivities including different future scenarios, 2025 installation, 1-hour duration batteries, and flow batteries are also analyzed.

[13] Storage systems in solar + storage installations must charge mostly from solar to be eligible for the ITC. Typical energy storage participating in the MISO market is likely to charge during the off-peak time when energy prices are low. Current off-peak periods in many cases have coal and natural gas units on the margin. Thus, the stored energy does not come from solar but the coal and natural gas if battery storage follows the current market signal.

Other Use Cases

There are other potential use cases for energy storage to provide value to the system. For example, co-locating energy storage with existing renewable resources as a hybrid generation could take advantage of the existing interconnection. FERC Order 845 called for creating a process for interconnection customers to use surplus interconnection service at existing points of interconnection (Maloney, 2018). This order allows energy storage to avoid the lengthy interconnection process and leverage the surplus transmission capacity that existing variable resources have. In addition, DC-coupled energy storage and solar PV could provide higher efficiency and the ability to harvest more PV generation during low voltage hours. (Ahlstrom, 2019)

Siting the energy storage with electric vehicle direct-current fast charger (DCFC) could also provide significant value to the distribution system. DCFC chargers could create large demand surge as customers charge their vehicles quickly during operation. The huge demand surge might result in expensive distribution infrastructure upgrades. Adding energy storage onsite can smooth out the DCFC charging demand and potentially avoid more costly distribution infrastructure upgrades.

4.0 Results

4.1 Forecasted system value streams

Before delving into wholesale energy price results, it is important to recognize that pricing patterns can interplay between increasing load and renewable production and are correlated more with net load than gross. E3's modeling results do not show dramatic differences between cases, suggesting that MISO North is able to integrate renewables well. Figure 19 presents all hourly prices chronologically in year 2032. There are several key observations:

- By 2032, more than 1.1 GWs of solar and wind have been added to the system in the Existing Trends scenario, resulting in distinct difference in pricing relative to the 2018 baseline. The magnitude changes relatively little overall. Prices are highest in winter followed by summer. One notable observation is the increase in a small number of peak hours, attributable to the increase in future load.

- An increase in natural gas prices is not expected to change the dispatch order. Unsurprisingly, 2032 pricing patterns in the High Gas scenario are largely the same as those seen in the Existing Trends scenario. A slight shift upwards is observed in most hours.

- In the High Renewables scenario, 18 GW of new wind and nearly 7 GW of new solar are added onto the existing Minnesota system by 2032. The substantial increase in renewable generation lowers prices on average by displacing pricier marginal thermal units with cheap renewable generation. By 2032, there is a sizable number of low-priced hours in spring and fall, coinciding with strong renewable generation and lower load. In this scenario, all coal has been retired by 2032. This effectively pushes up prices in peak hours.

Figure 19. Day-ahead energy prices in 2032 laid over historical day-ahead energy prices in 2018

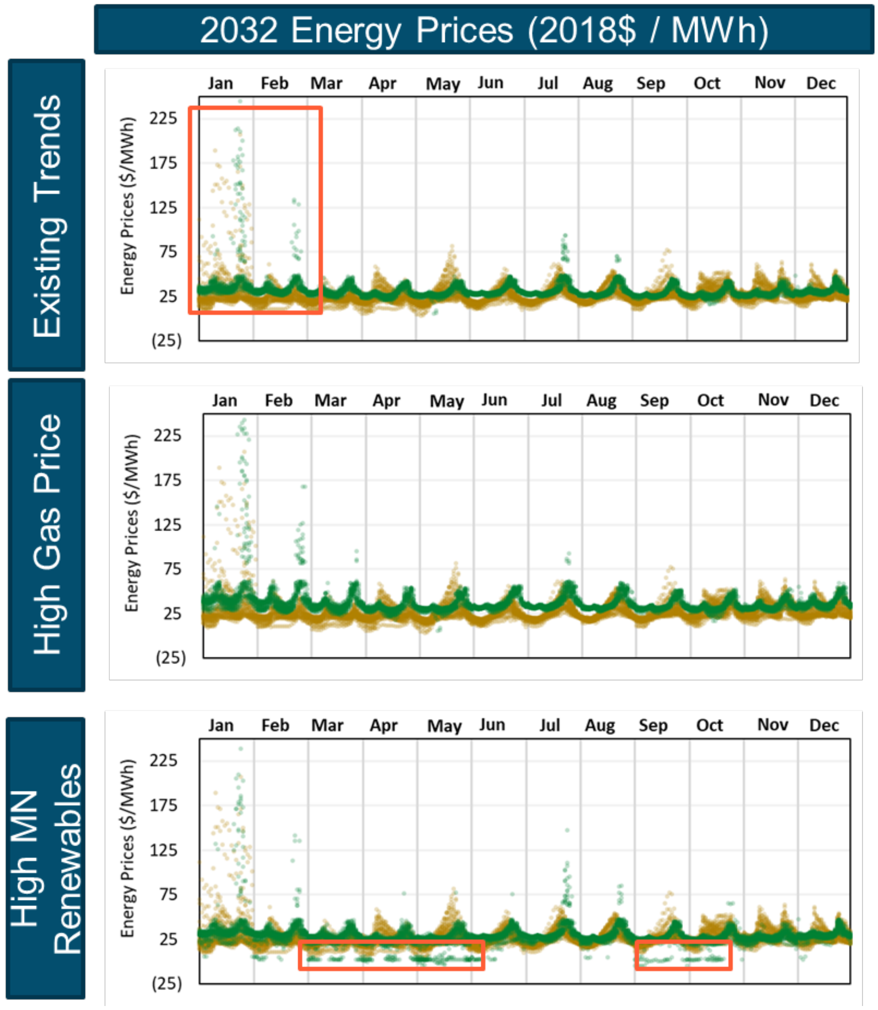


Figure 20. Month-hour averages of historical wholesale day-ahead energy prices in 2018

2018 Historical DA Energy Prices (2018$ / MWh)

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
01	$36	$31	$31	$31	$32	$31	$34	$44	$45	$51	$55	$56	$52	$50	$42	$39	$43	$59	$82	$73	$63	$53	$48	$41	$47
02	$18	$18	$18	$18	$19	$20	$21	$27	$26	$24	$24	$24	$22	$22	$22	$22	$23	$27	$39	$41	$38	$33	$30	$29	$25
03	$17	$16	$16	$16	$16	$18	$22	$25	$24	$24	$24	$24	$24	$24	$23	$22	$23	$25	$27	$32	$29	$26	$24	$23	$23
04	$18	$18	$18	$18	$19	$21	$22	$24	$25	$25	$24	$24	$23	$22	$21	$21	$22	$24	$26	$33	$33	$25	$21	$20	$23
05	$ 5	$ 5	$ 3	$ 4	$ 7	$17	$18	$19	$21	$22	$23	$26	$27	$29	$28	$29	$30	$30	$30	$32	$32	$26	$21	$18	$21
06	$22	$21	$18	$18	$18	$20	$22	$25	$29	$31	$32	$32	$34	$38	$40	$39	$34	$33	$28	$25	$23	$21	$18	$16	$27
07	$21	$20	$20	$20	$19	$20	$19	$20	$22	$24	$28	$32	$37	$42	$48	$47	$48	$43	$38	$34	$32	$28	$24	$22	$30
08	$21	$19	$19	$19	$19	$20	$21	$23	$25	$25	$29	$31	$33	$34	$36	$39	$40	$35	$32	$30	$28	$24	$23	$21	$27
09	$20	$19	$19	$19	$19	$20	$20	$21	$22	$24	$25	$26	$28	$32	$31	$33	$33	$30	$29	$26	$25	$23	$23	$21	$24
10	$19	$18	$18	$17	$19	$24	$28	$27	$29	$30	$31	$34	$35	$36	$37	$39	$39	$37	$45	$43	$36	$28	$23	$23	$30
11	$25	$24	$25	$24	$26	$30	$43	$44	$39	$39	$38	$35	$33	$33	$32	$33	$35	$39	$44	$37	$32	$29	$27	$24	$33
12	$23	$23	$23	$23	$22	$21	$22	$23	$25	$26	$28	$27	$24	$23	$22	$23	$23	$33	$31	$26	$24	$23	$21	$21	$24
Avg	$20	$19	$19	$19	$20	$22	$24	$27	$28	$29	$30	$31	$31	$32	$32	$32	$33	$35	$38	$36	$33	$28	$25	$23	$28

Figure 21. Month-hour averages of day-ahead energy prices in 2032

2032 Energy Prices (2018$ / MWh)

Existing Trends

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
01	33	32	32	32	33	36	39	39	36	34	33	33	32	32	35	41	58	81	89	75	47	36	35	33	42
02	31	30	30	30	32	34	36	35	33	31	30	29	29	29	30	31	34	41	54	50	48	38	33	31	35
03	29	28	28	28	30	31	33	31	30	28	27	27	26	27	29	31	33	37	40	40	38	33	31	29	31
04	26	26	25	26	27	28	28	27	26	25	24	24	25	25	26	28	31	35	37	37	38	33	28	27	28
05	27	26	26	26	27	28	27	27	25	25	26	26	27	27	29	31	34	37	38	37	38	33	30	28	29
06	29	28	28	28	28	29	28	28	27	28	28	29	29	30	32	34	38	42	43	40	38	34	31	30	32
07	29	28	28	27	28	29	28	27	27	28	28	29	30	31	33	36	40	53	56	46	38	33	31	30	33
08	27	26	26	26	26	28	27	26	26	26	26	27	28	30	32	35	41	48	46	41	36	32	30	28	31
09	26	26	25	25	26	26	27	26	25	25	25	26	26	27	29	32	36	40	41	40	36	30	27	27	29
10	26	25	25	25	26	27	28	27	25	25	24	25	25	25	27	29	32	37	38	38	32	28	27	26	28
11	26	26	26	26	27	28	29	29	28	28	27	27	26	26	28	29	30	35	37	36	32	31	28	27	29
12	30	29	28	29	30	31	32	32	30	30	30	29	29	29	31	31	33	40	42	39	36	33	31	30	32
Avg	28	28	27	27	28	29	30	30	28	28	27	28	28	28	30	32	37	44	47	43	38	33	30	29	32

High Gas

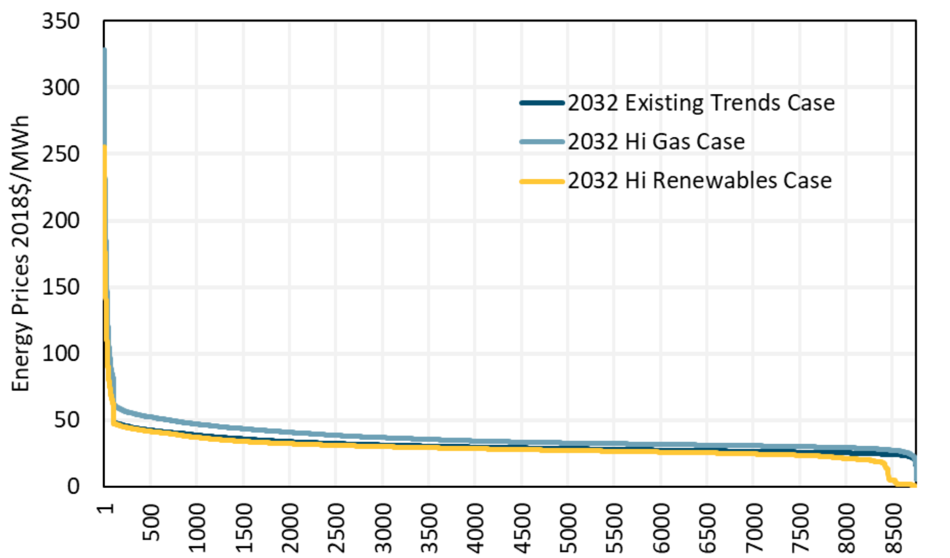
	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
01	38	38	38	39	41	47	52	52	42	40	38	37	36	37	39	50	68	108	113	98	71	49	41	39	52
02	35	34	34	35	37	43	47	46	39	36	33	32	31	31	32	34	38	52	63	68	69	51	40	37	42
03	32	32	32	32	34	37	41	38	34	32	31	30	29	30	32	33	37	46	50	52	52	41	36	33	37
04	30	30	30	30	31	33	34	32	30	29	28	27	28	28	29	31	33	41	44	44	48	38	33	31	33
05	30	30	30	30	30	32	32	30	28	28	29	29	30	30	32	34	38	44	46	44	46	39	34	32	34
06	33	32	31	31	32	33	33	32	31	31	32	33	34	35	37	40	45	49	50	49	51	43	36	34	37
07	34	33	32	32	33	34	33	32	32	32	33	34	35	36	39	43	47	55	57	50	50	43	38	36	38
08	32	32	31	31	31	33	32	31	31	31	32	32	33	34	36	40	45	51	51	49	47	38	36	34	36
09	31	30	30	30	30	32	33	32	31	30	30	31	32	32	34	37	42	44	44	47	44	36	33	32	34
10	30	30	30	30	31	33	34	32	30	29	28	28	29	30	31	34	39	42	43	45	41	34	32	31	33
11	31	31	31	31	32	34	36	36	33	32	31	30	30	30	32	33	37	40	43	43	39	36	33	32	34
12	35	34	33	33	35	38	40	40	36	35	34	33	33	33	35	37	41	46	49	50	48	42	37	35	38
Avg	33	32	32	32	33	36	37	36	33	32	32	31	32	32	34	37	43	52	54	53	50	41	36	34	37

High MN Renewables

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
01	31	30	29	29	31	34	37	40	38	33	32	31	30	31	32	40	55	78	75	65	43	35	34	31	39
02	28	27	27	27	29	31	34	34	31	30	28	27	26	27	28	29	32	40	48	46	46	35	32	30	32
03	24	23	23	24	25	28	31	30	28	26	24	23	23	23	25	27	30	35	36	36	35	29	26	24	27
04	20	20	21	21	23	26	28	26	24	23	21	20	21	21	22	24	27	32	33	32	32	27	23	21	24
05	19	17	17	18	19	24	25	24	23	22	22	21	22	23	24	26	29	34	33	31	30	27	22	21	24
06	26	25	24	24	25	27	27	26	26	26	25	27	27	28	30	32	35	40	41	37	36	32	29	28	29
07	28	27	26	26	27	28	28	27	26	26	27	28	29	30	32	35	40	55	61	48	38	32	31	29	33
08	25	24	24	23	24	27	27	26	25	25	25	26	26	28	30	33	39	47	47	40	35	30	28	27	30
09	23	23	23	23	23	24	26	25	24	24	24	24	25	25	27	30	34	39	39	38	34	28	25	23	27
10	23	23	22	22	23	25	27	25	23	22	22	22	22	22	24	28	31	36	37	37	32	27	26	25	26
11	24	24	24	24	25	27	28	28	28	27	26	26	25	25	26	27	29	31	33	32	30	28	26	25	27
12	29	27	27	27	28	30	31	31	30	29	29	28	28	28	29	30	32	39	40	38	35	32	30	29	31
Avg	25	24	24	24	25	28	29	28	27	26	25	25	25	26	27	30	35	42	44	40	35	30	28	26	29

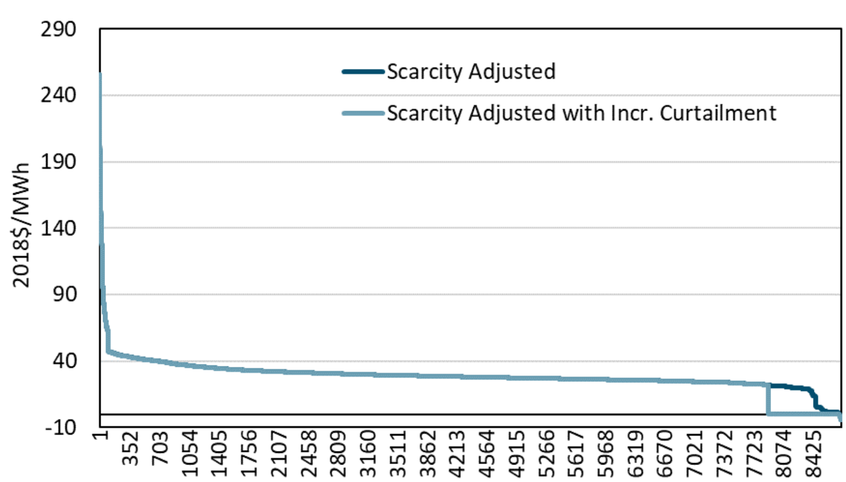
To account for scarcity pricing in the forecasted prices, E3 applies a simplified post-processing step based on 2018 historical price volatility. The price duration curve for each scenario in 2032 is presented in Figure 22.

Figure 22. Day-ahead energy prices in 2032 for three scenarios



Additional sensitivities were conducted to study the impacts of pervasive over-generation. Energy prices were adjusted so that those in the lowest 10th percentile in each year reflect energy prices set by renewables units on the margin, as demonstrated in Figure 23

Figure 23. Price duration curve of day-ahead energy prices with curtailment sensitivity modification



Future capacity prices and ancillary services prices are summarized in the figure below. The AURORA modeling methodology is documented in Appendix A: AURORA. Details about the post-processing, curtailment sensitivity, and capacity and ancillary services prices forecast methodology are included in Appendix C: Quantified Benefits.

Figure 24. Capacity prices by year

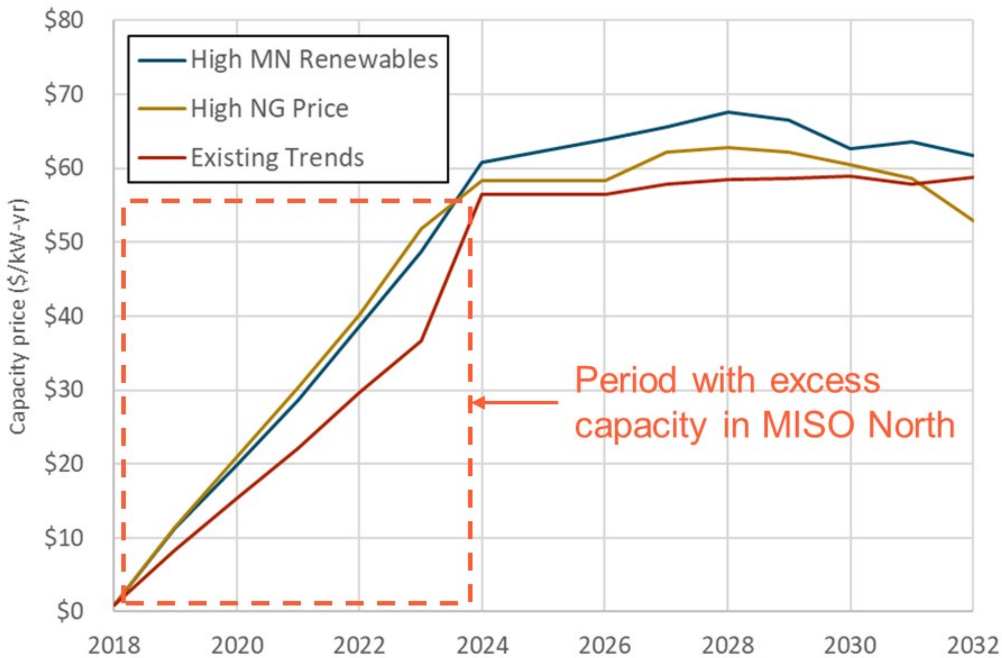
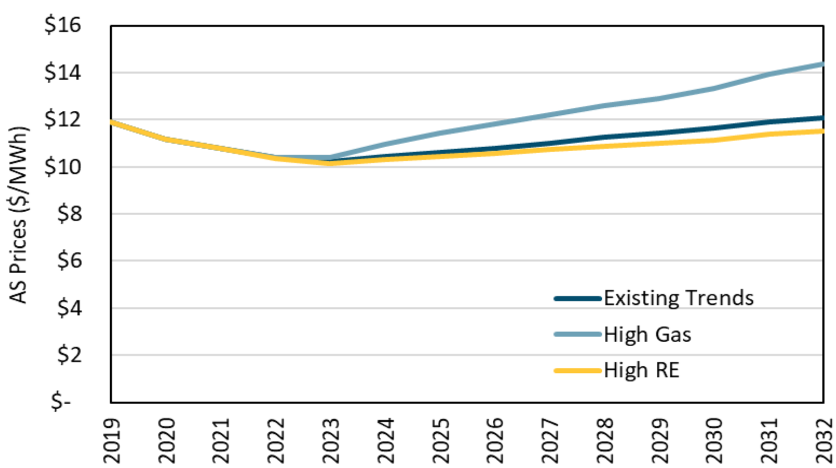


Figure 25. Average ancillary services prices by year



4.2 Energy storage cost-effectiveness

Summary

Cost-effectiveness results for the different use cases are summarized in the figures below. Costs and benefits for each case are plotted on the x- and y-axes, respectively. Costs and benefits are calculated based on the Total Resource Cost test for front-of-the-meter (FTM) systems and the Participant Cost Test for behind-the-meter (BTM) installations. Stand-alone energy storage and solar plus storage are plotted in different charts to facilitate comparison. Overall, our analysis finds that batteries installed in 2025 and solar plus storage systems are cost-effective.

Figure 26. Costs and benefits summary: stand-alone energy storage

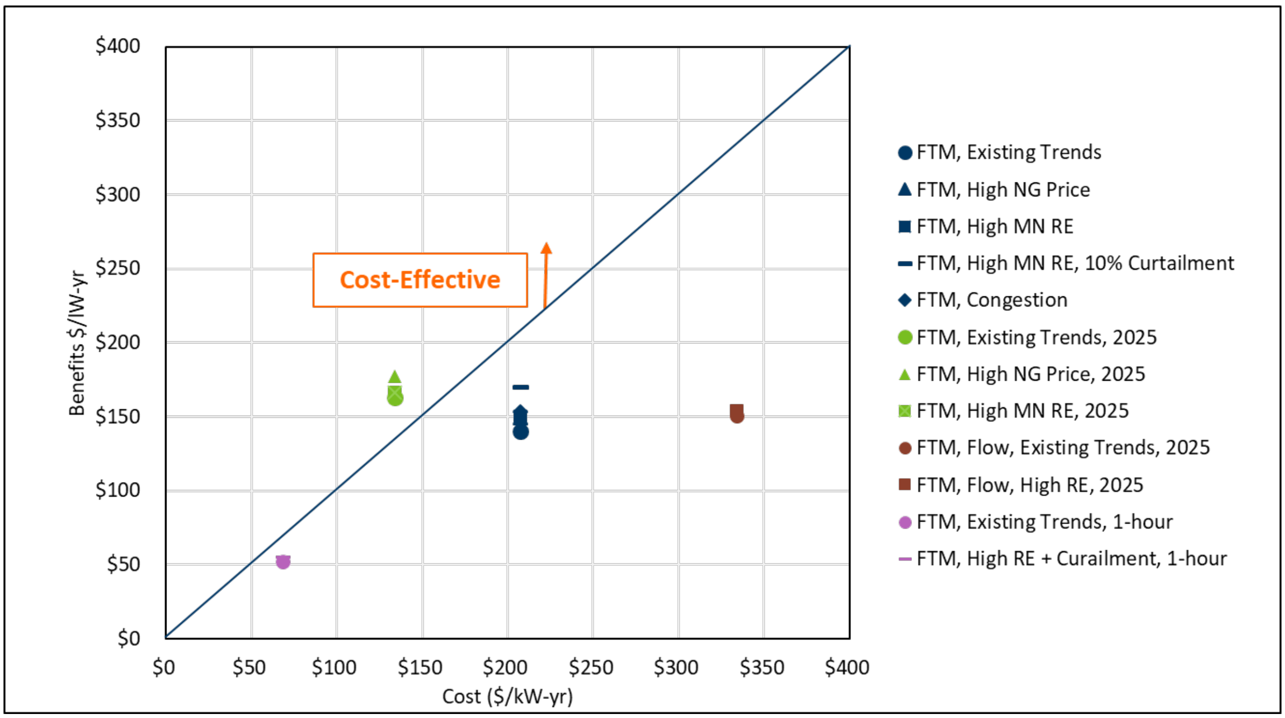
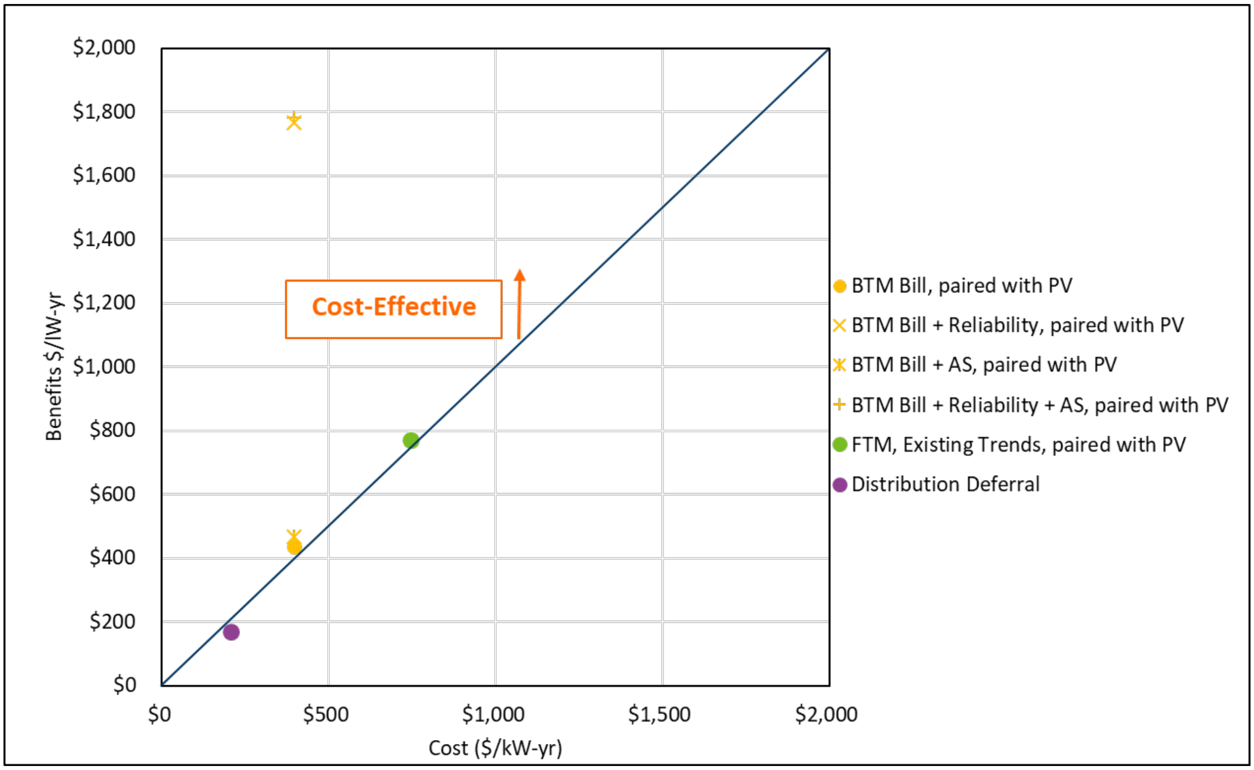


Figure 27. Costs and benefits summary: solar plus storage + distribution deferral use case



For utility-scale energy storage, the study shows solar + storage being cost-effective today due to investment tax credit (ITC) benefits and the capacity firming provided by energy storage. This is consistent with the fact that there are solar plus storage systems installed or under development in Minnesota.

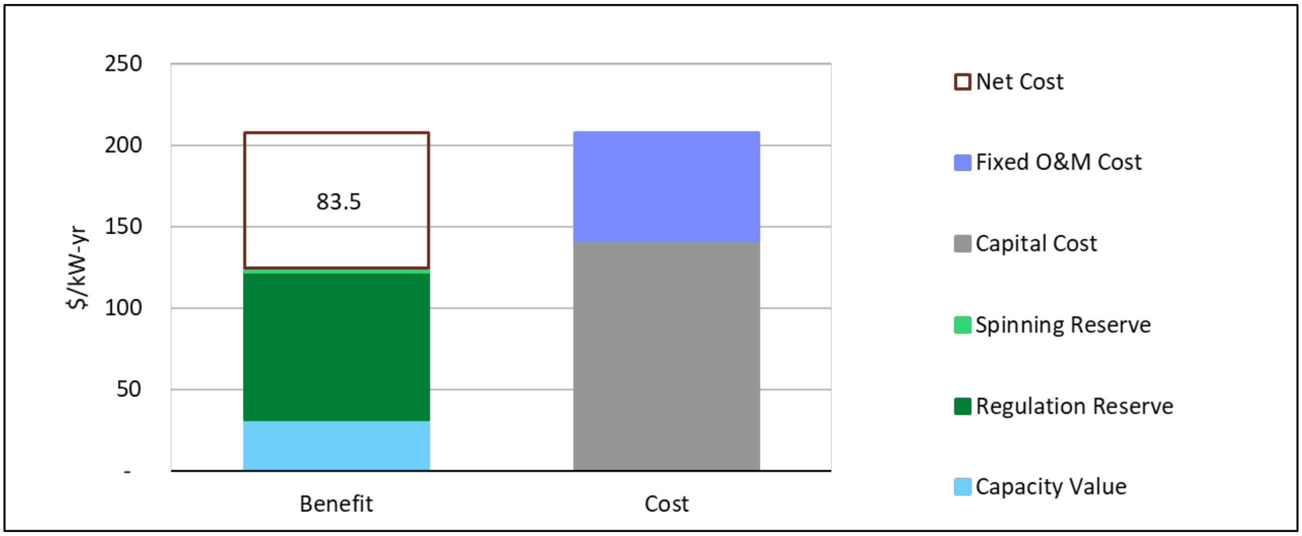
In certain local constrained areas, energy storage can play an important role in alleviating congestion and deferring more costly distribution upgrades. Looking forward, this study calculates that energy storage installed in 2025 is cost-effective due to technology price declines and an increase in capacity value (as MISO North evidences a capacity need in the mid-2020s). Moving beyond 2030, when solar and wind penetration has increased substantially in both Minnesota and MISO, storage (and especially long-duration storage) will become necessary for integrating renewables.

Results for each use case are discussed in detail in the remaining part of the chapter.

Front-of-the-meter (FTM) Energy Storage

Our primary “base case” is our modeling of a 1 MW, 4-hour duration battery participating in MISO wholesale markets, for a 2020 installation. We found that this use case does not become cost-effective until 2025 based on the cost reduction predicted by NREL in their “mid” scenario (NREL, 2019), using a Total Resource Cost Test. This cost test can be thought of as looking at the total lifetime costs and benefits to the state of Minnesota.

Figure 28. Total Resource Cost test for a 4-hour Li-ion battery installed in 2020, "existing trends" price scenario

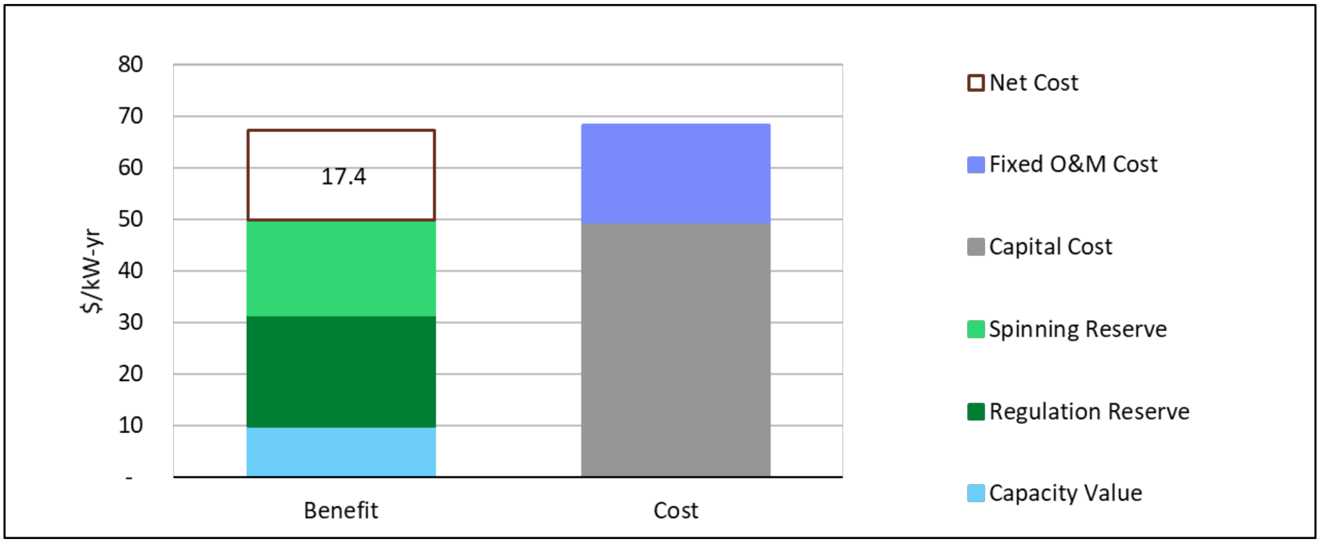


One significant finding from our results is that participating in the ancillary services markets is currently more lucrative for storage than performing energy arbitrage or providing capacity. Therefore, most of the monetized benefits came from participating in the regulation reserve market, the most valuable of MISO's ancillary services markets. The second most significant value stream is the capacity value. Capacity value is calculated as avoided generation capacity to the state of Minnesota based on a peak capacity allocation factor (PCAF) method, which takes into account the amount of energy storage is able to discharge during peak load hours. This value is different (but theoretically similar) to what a storage resource would earn from participating in MISO's capacity market. More about the capacity accreditation method in the study is discussed in Appendix C: Quantified Benefits.

The calculated breakeven cost for 4-hour storage in this use case is $160/kWh, compared to the cost of approximately $330/kWh we assumed for 2020. Note that this is lower than the approximately $250/kWh cost we assume in our 2025 use cases, which show cost-effectiveness, because these 2025 use cases also assume a higher capacity value over the lifetime of the storage device.

Given that a 4-hour duration battery is not necessarily needed for participating in ancillary services markets, and a shorter duration battery would cost significantly less on a kW basis, we also modeled a 1-hour duration battery installed in 2020, with all other parameters held the same. The battery in this use case is closer to cost-effectiveness, and the study calculated that it is expected to become cost-effective in 2022.

Figure 29. Total Resource Cost test for a 1-hour Li-ion battery installed in 2020, "existing trends" price scenario



The plots below illustrate how 4-hour storage modeled in our base case is dispatching on both a typical day, where it mainly participates in the regulation reserve market, and on a system peak day, where it dispatches to reduce system peak.

Figure 30. Storage dispatch for a typical day in the 4-hour Li-ion base case

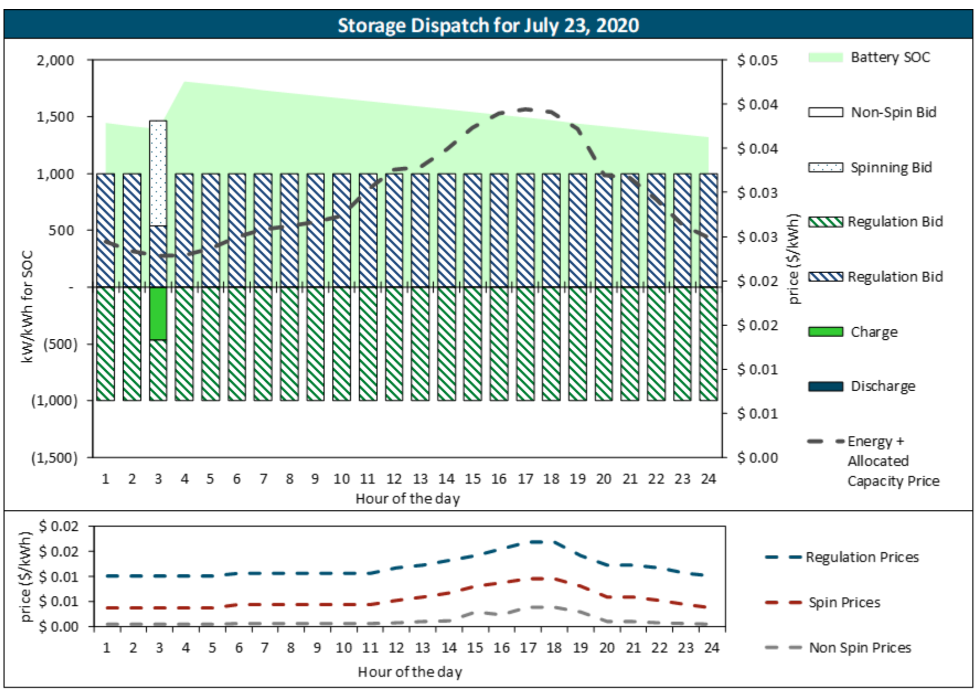
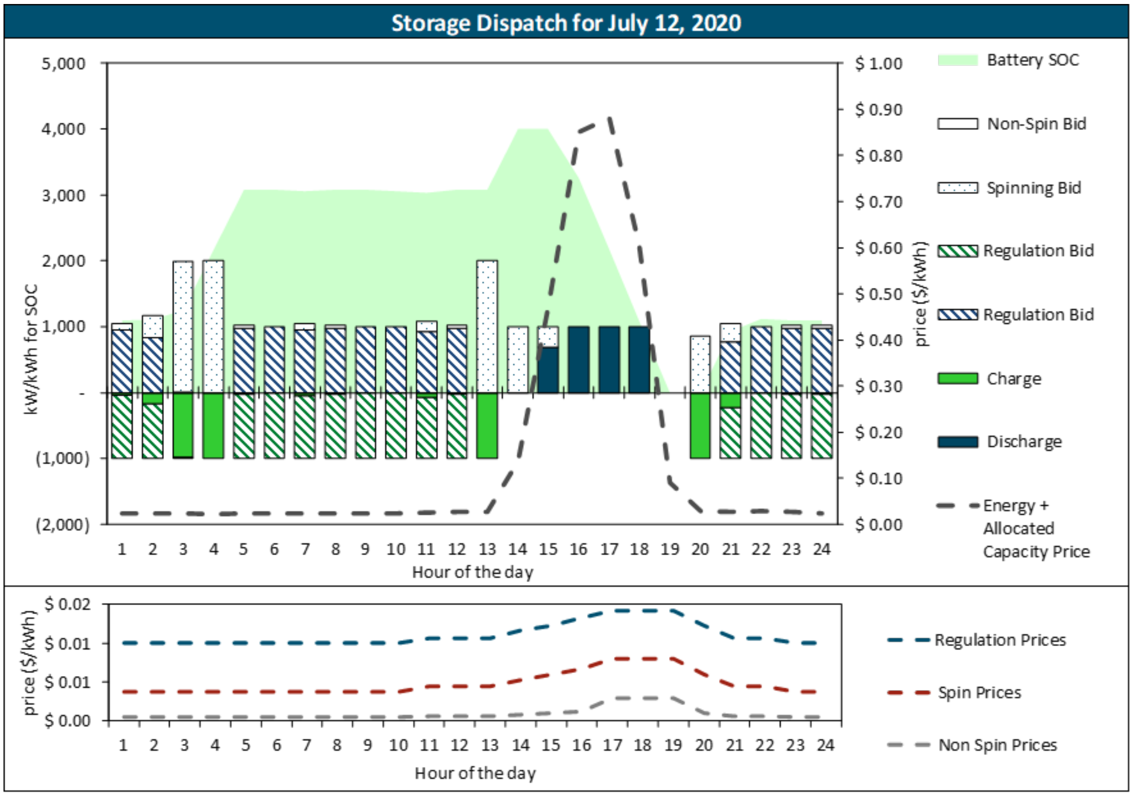


Figure 31. Storage dispatch for a system peak day in the 4-hour Li-ion base case



Emissions Analysis

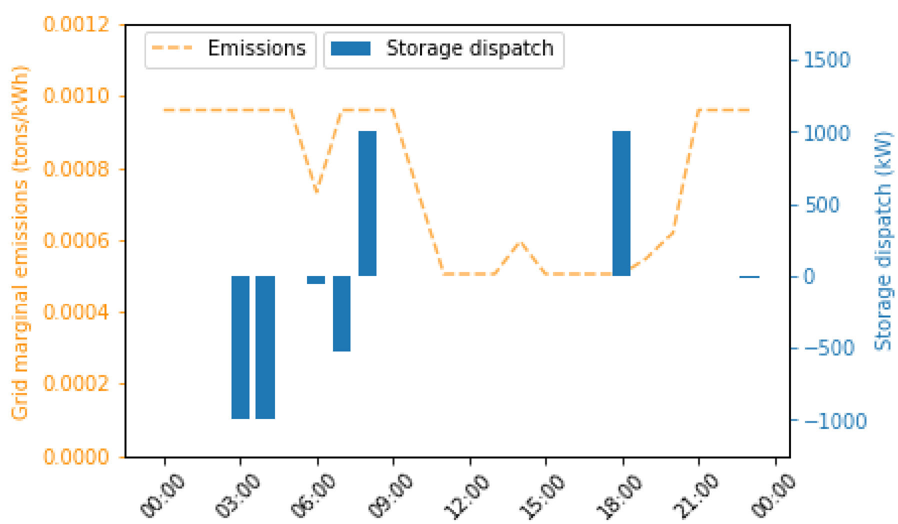
In addition to costs, we also examined the effect of storage on system emissions. If storage dispatches to serve as peak capacity, it will be displacing a peaker plant, and emissions will be reduced in that peak hour accordingly. Crucially, however, storage must charge from somewhere, and it could increase overall grid emissions in the hours it is charging. How much it increases emissions is dependent on the marginal generator—that is, the generator at the top of the supply stack that will have to turn up its output by 1 MW to serve an additional 1 MW of storage charging load. Currently, coal is often the marginal resource during off-peak hours. Coal has much higher greenhouse gas emissions than natural gas, so storage operating to reduce peak load on today's grid would generally increase emissions if it is charging from coal and discharging to displace gas peakers.

These dynamics will continue until renewables penetrations are high enough that storage can charge when wind or solar is on the margin. When that tipping point will happen is hard to predict, but it could be within the lifetime of a storage resource.

It is important to note that there could still be an air quality benefit from storage displacing gas peaker plants on today's grid. If storage discharges to displace a gas peaker located near a densely populated community, then it could shift NOx emissions (important precursors for ozone and smog) away from that community, which could provide a mitigation option in areas where ozone levels are approaching federal limits. Storage charging from coal power and discharging to replace gas peakers would shift NOx emissions from the peaker plant to the coal plant, which can reduce air quality impacts to a larger population if many more people live near the peaker plant.

To quantify the effect of a 1 MW, 4-hour Lithium-ion battery on system carbon emissions, we ran a dispatch simulation using historical 2018 MISO market prices, and historical MISO fuel-on-the-margin data. It is much more difficult to quantify the exact effect of storage on grid emissions of criteria air pollutants and air toxics, which is why we focus on carbon emissions here. We found that storage increased grid carbon emissions by about 168 tons over the course of a year, equivalent to about 37 passenger vehicles' worth of yearly carbon emissions. The figure below shows an example of storage dispatch and grid emissions that leads to this result.

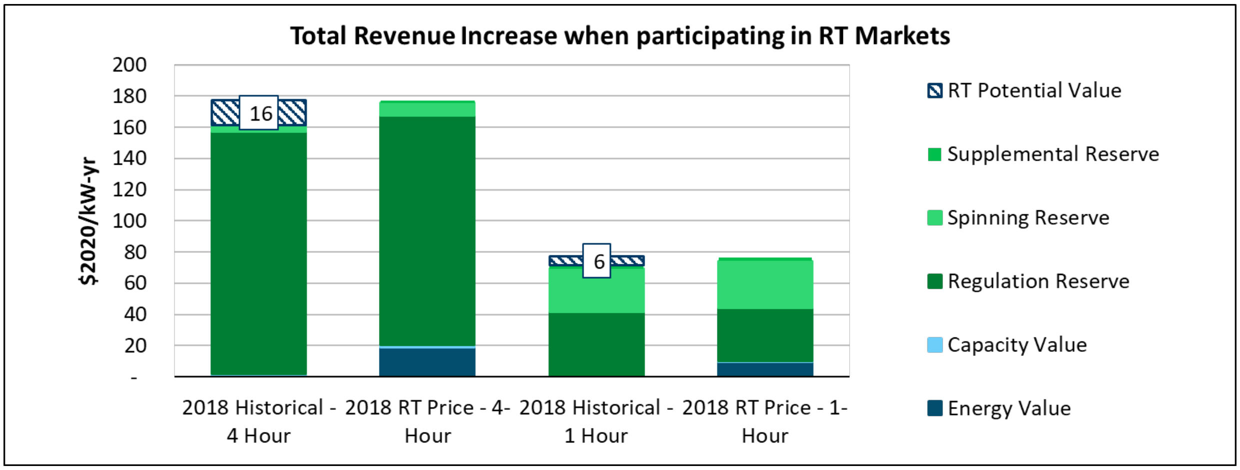
Figure 32. Storage indirect electric grid emissions of CO_2 on July 17, 2018



Real-time vs day-ahead market prices

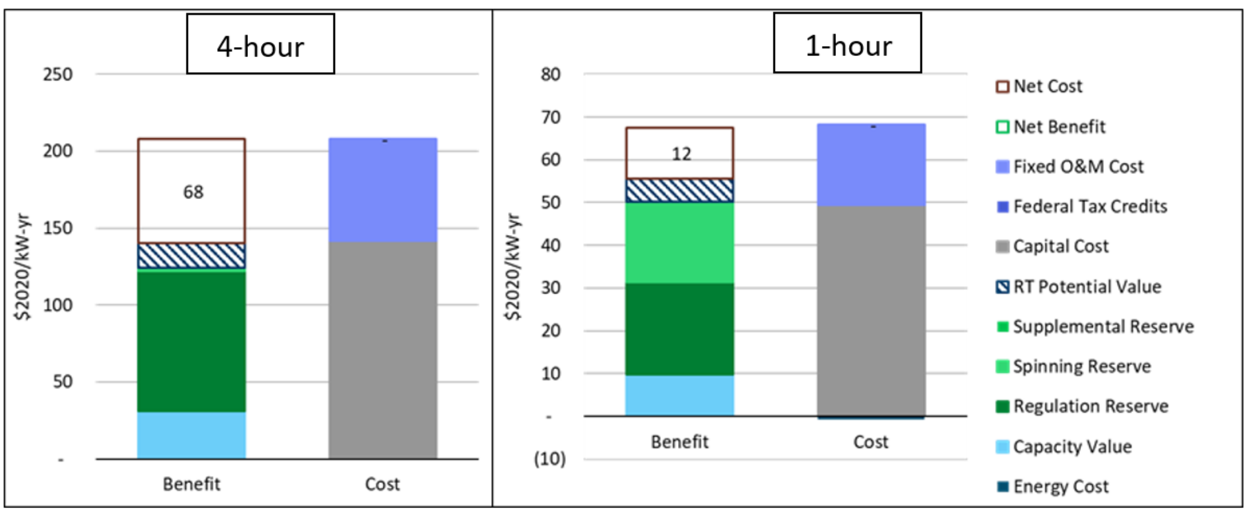
An important limitation of our study is that our market price forecasts used in our storage modeling are day-ahead prices. The real-time market is more volatile than the day-ahead market, meaning storage is able to exploit more price differentials and earn more revenue than would come from participating in the day-ahead market alone. The real-time market also represents, to some extent, system's sub-hourly flexibility need. To quantify what the expected increase in benefits is from participating in the real-time market, we ran a simulated dispatch model on 2018 prices comparing day-ahead and real-time, and looked at the corresponding increase in revenues. We then apply this "real-time adder" to reflect the potential value increase from providing sub-hourly flexibility to the system or the values from participating in the real-time market.

Figure 33. Storage revenue increased from participating in real-time markets



Including the real-time market potential in our base case results gets this use case closer to cost-effectiveness, but both the 4-hour and 1-hour cases are still not calculated to be cost-effective for 2018 installation.

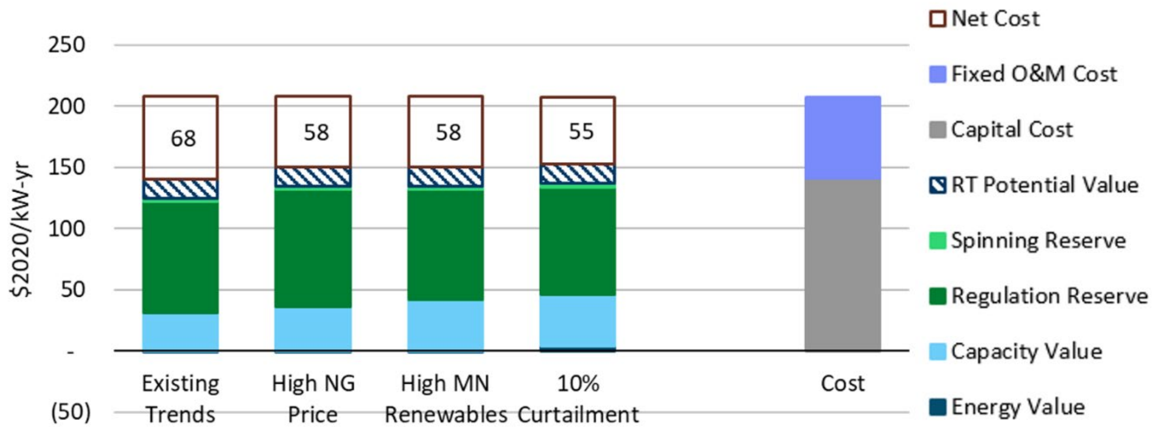
Figure 34. Total Resource Cost tests with the additional real-time market potential (2020 installation, Li-ion, "Existing Trends" price scenario)



Future Scenarios

The other two price forecast scenarios—"High Natural Gas prices" and "High Minnesota Renewables"—are closer to cost-effectiveness than existing trends but are not cost-effective for a 2020 installation. We also included a sensitivity in the High MN Renewables scenario of how cost-effectiveness would change if curtailment was increased from 0% in 2020 to 10% in 2030 (a curtailment of 10% was applied, for example, by dropping prices in the lowest-price 10% of hours to zero, if they were above zero). The figure below shows the cost test results for each of these scenarios.

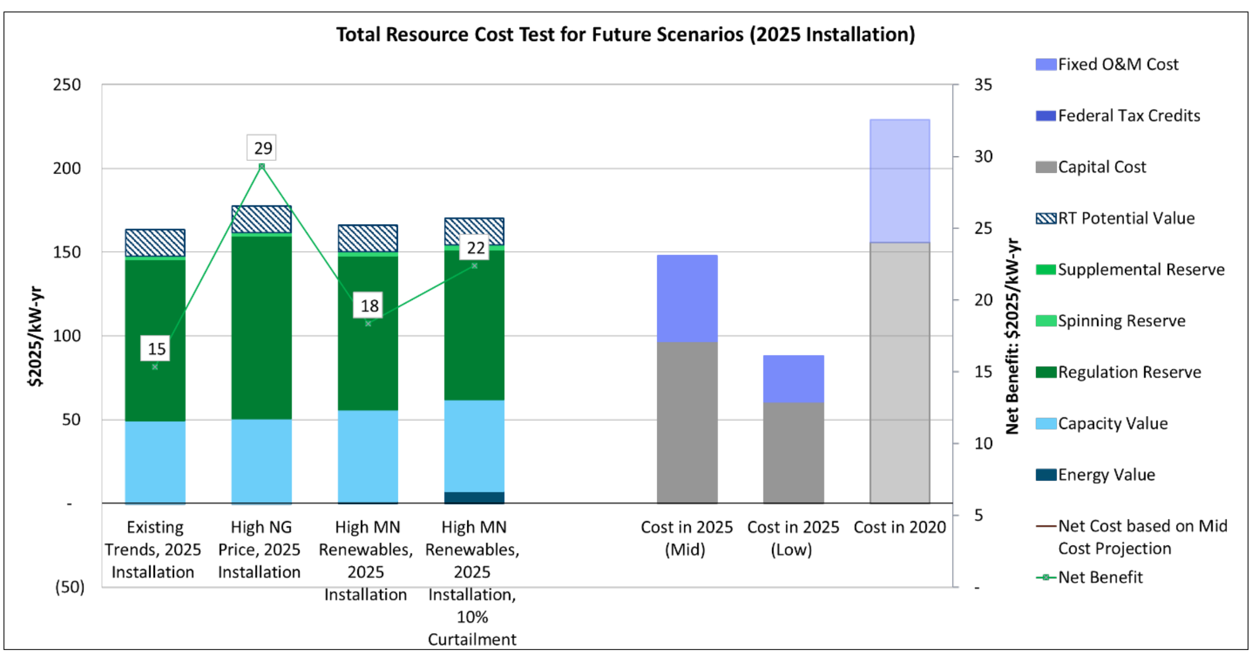
Figure 35. Total Resource Cost test results for 2020 installation, 4-hr Li-ion battery, comparing price scenarios



Installation Year 2025

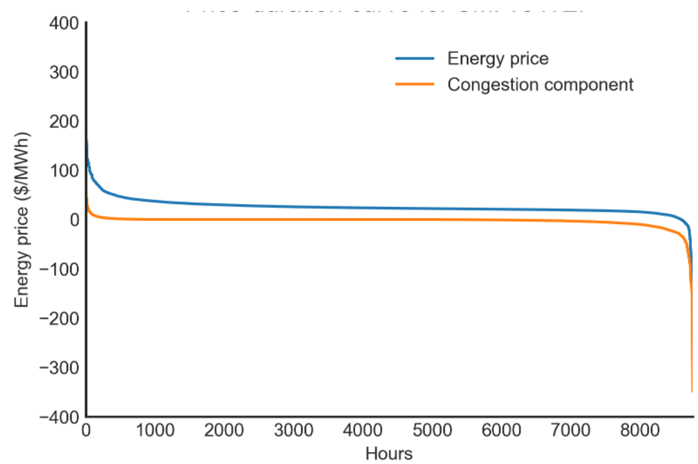
For a 2025 installation, we calculated that a 1 MW, 4-hour Lithium-ion battery does become cost-effective in all price scenarios examined. The main drivers of this result are the increasing capacity value, and the lower upfront storage costs. If the “Low” price trajectory for storage upfront costs is assumed (from NREL’s cost decline projections) (NREL, 2019), then this use case becomes more cost-effective. Net benefits, assuming the standard “Mid” battery costs, range from $15/kW-yr in the “Existing Trends” scenario to $29/kW-yr in the “High Natural Gas Price” scenario.

Figure 36. Total Resource Cost test results for 2025 installation, 4-hr Li-ion battery



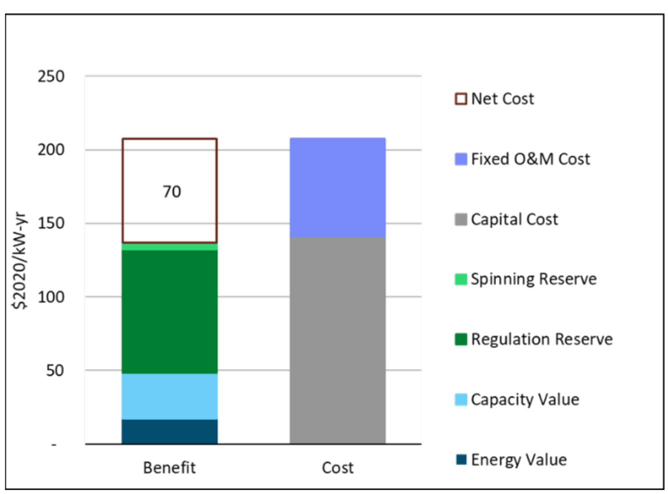
For the congestion management use case, we examined the cost-effectiveness of storage operating at a congested node on today's grid. A congested node will have larger price differentials, and potentially negative prices, meaning storage is more likely to be cost-effective. We selected the congested SMP.OWEF node in Southeast Minnesota for this use case, and ran our model using historical 2018 prices for this node. Note the small amount of negative priced hours shown at the right end of the price-duration curve for this node.

Figure 37. Price-duration curve for SMP.OWEF node in SE MN



The results from this use case are similar to what we found when comparing day-ahead and real-time prices for the Minnesota hub node, to get our real-time price adder. About $13/kW-yr of additional benefits are obtained in this use case, compared to the base case ($83/kW-yr net cost vs $70/kW-yr net cost). It is important to note that the benefits in practice for this use case could be much higher than we calculated here, if a storage installation is able to defer an expensive transmission upgrade. This value of transmission deferral is not included in this analysis but should be examined more thoroughly in future studies and by transmission planners.

Figure 38. Total Resource Cost test for 4-hour storage installed at congested node, assuming 2018 real-time prices



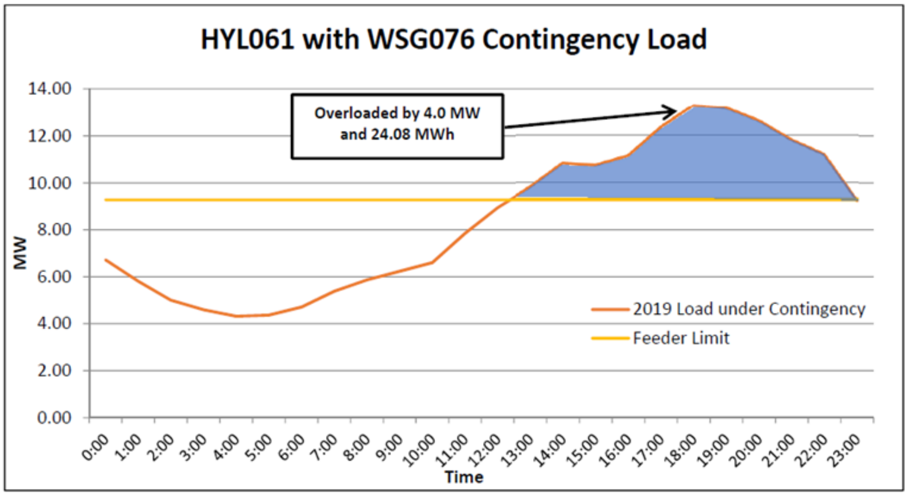
Distribution Deferral

For the distribution deferral use case, we examined the potential for storage to defer a distribution upgrade identified in Xcel's 2018 Integrated Distribution Plan (IDP) (Xcel Energy, 2018). The distribution upgrade is a planned upgrade to the Viking substation (appropriately named as it serves the U.S. Bank Stadium, where the Vikings play). The cost of this conventional distribution upgrade is estimated at $2.5 million in the IDP, and a non-wires alternative analysis is performed in the IDP to identify the cost of installing energy storage to defer this upgrade. The non-wires alternative analysis identifies the cost of storage at four different feeders, which would all be needed to defer the upgrade at the Viking feeder. The total cost of installing storage at these four feeders is about $22 million. However, the benefits of storage outside of deferring the distribution upgrade are not included in this analysis—namely, the market revenues that storage could earn when it is not needed for mitigating distribution risks on peak days. Here, we demonstrate how a "net cost" methodology could be used in future non-wires alternatives analyses to include all the benefits that storage can provide.

Figure 39. Cost of battery storage estimated by Xcel to be needed to defer Viking substation upgrade in 2018 IDP

Capacity Risk	Overload Magnitude		Optimal DER Solution		Estimated Cost
	MW Overload	MWh Overload	Solar PV (MW)	Battery Storage (MWh)	
EDP073 N-0 overload, 107%	0.71	0.99	0	0.99	$595,000
N-1 overload on WSG065 for loss of EDP073, 2.3 MVA at risk	2.04	11.50	0	11.50	$6,900,000
HYL061 N-0 overload, 101%	0.04	0.04	0	0.04	$26,000
N-1 overload on HYL061 for loss of WSG076, 4.2 MVA at risk	4.00	24.08	0	24.08	$14,450,000
Total			0	36.61	$21,971,000

Figure 40. Deficiency identified for HYL061 feeder in Xcel 2018 IDP



For our distribution deferral use case, we took the last feeder identified in Xcel's four storage installations shown above, and estimated an appropriate "net cost" that could be used instead of a simple upfront cost. To do this, we assumed that an appropriately sized storage installation would operate to eliminate the deficiency on the peak day identified by Xcel, and operate to obtain market revenues for the rest of the year. In our analysis, we assumed an 8 MW, 32 MWh (4-hour) battery to cover the deficiency, with a margin for load growth. This is slightly bigger than the 24 MWh battery modeled by Xcel, which does not include room for load growth. The figures below show the results of our analysis.

Figure 41. Storage operation on peak day

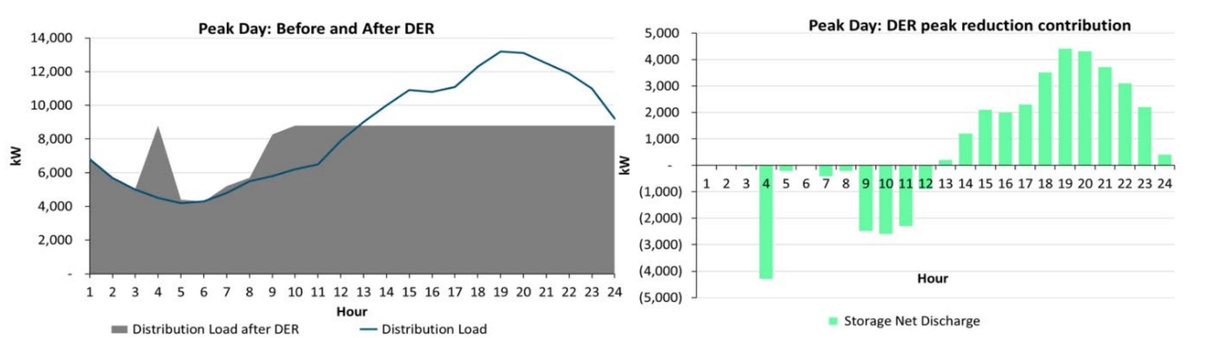
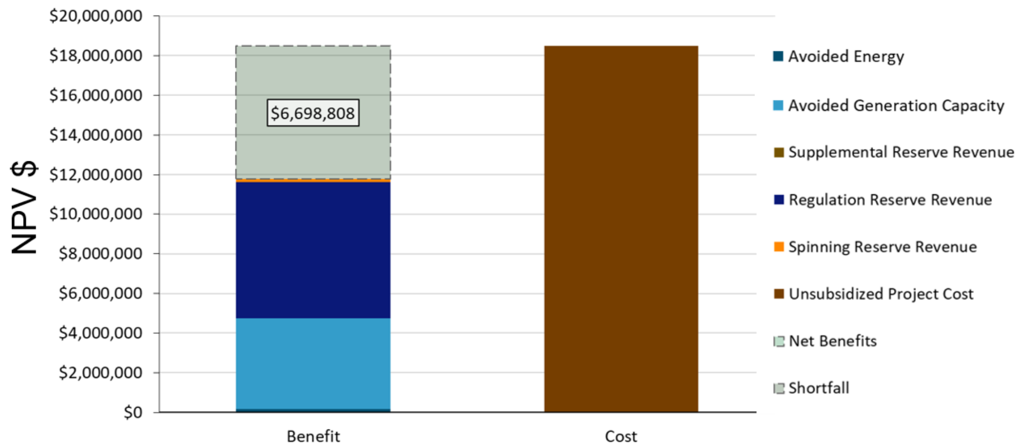


Figure 42. Total Resource Cost test for 8 MW / 32 MWh battery to eliminate deficiency at HYL061 feeder



Our analysis identifies a net cost of $6.7 million. While this is still more expensive than the relevant distribution upgrade ($2.5 million, not to mention the other three feeders that also would need storage), it is an example of how future non-wires-alternative (NWA) analyses could consider a "net cost" of storage to defer distribution upgrades, rather than a simple total cost.

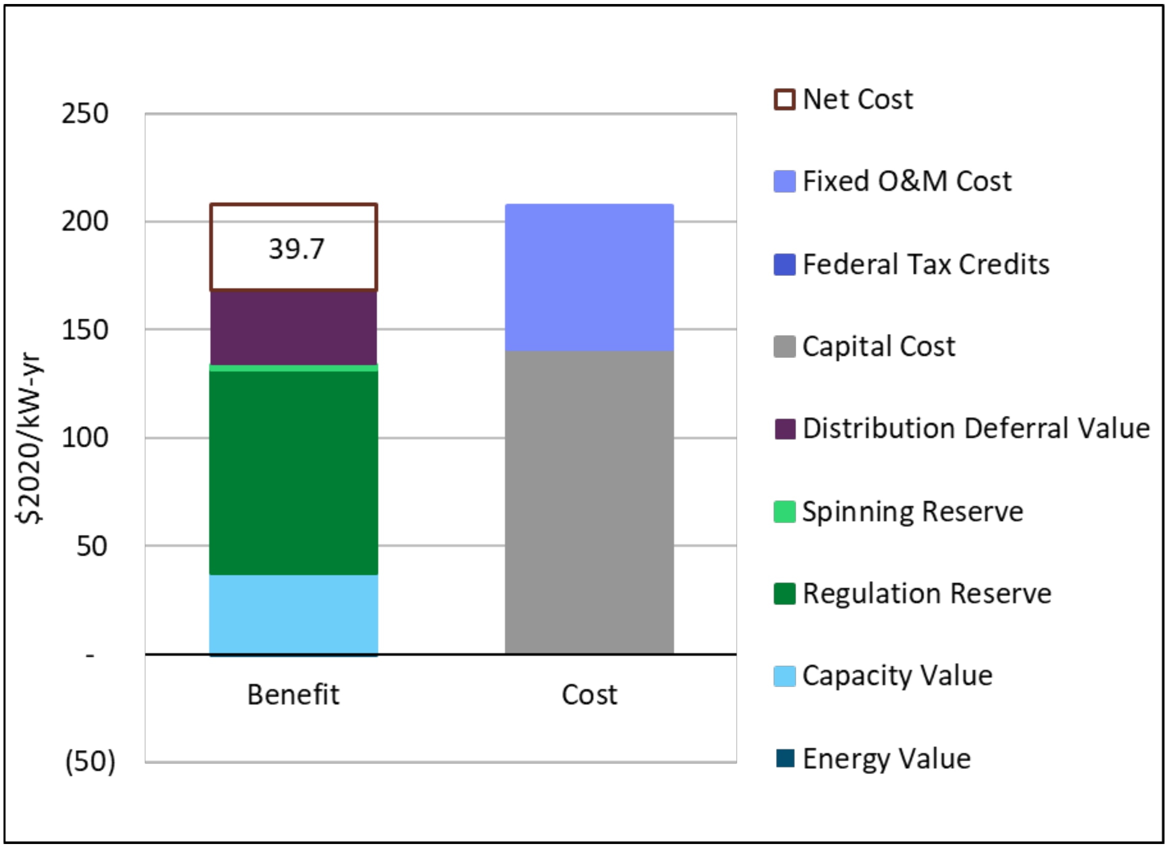
To illustrate the framework for quantifying distribution deferral values, the study used the Viking upgrade as an example assuming the designed energy storage system can alleviate the distribution issues covered by the $2.5 million conventional upgrade. The following table summarizes the assumptions.

Table 3. Distribution upgrade assumptions

Items	Value
Distribution upgrade capital cost	2.5 Million
Revenue requirement multiplier	1.6
Operation and Maintenance	2% of the capital cost/year
Inflation Rate	2%
Book life	20 years

The deferral values of the DER are the cost differences in the net present value of the T&D capacity project before and after the DER installation. Based on the analysis, the 8 MW / 32 MWh battery defer the upgrade for 10 years, resulted in total deferral values of $2.9 million. This deferral value is higher than the original distribution upgrade capital costs because it includes the deferral of operation and maintenance costs and the admin and overhead collected in revenue requirements. If utilities can rate base the non-wires alternative as their conventional wire solutions, the revenue requirement overhead should be included in energy storage's costs for a fair comparison.

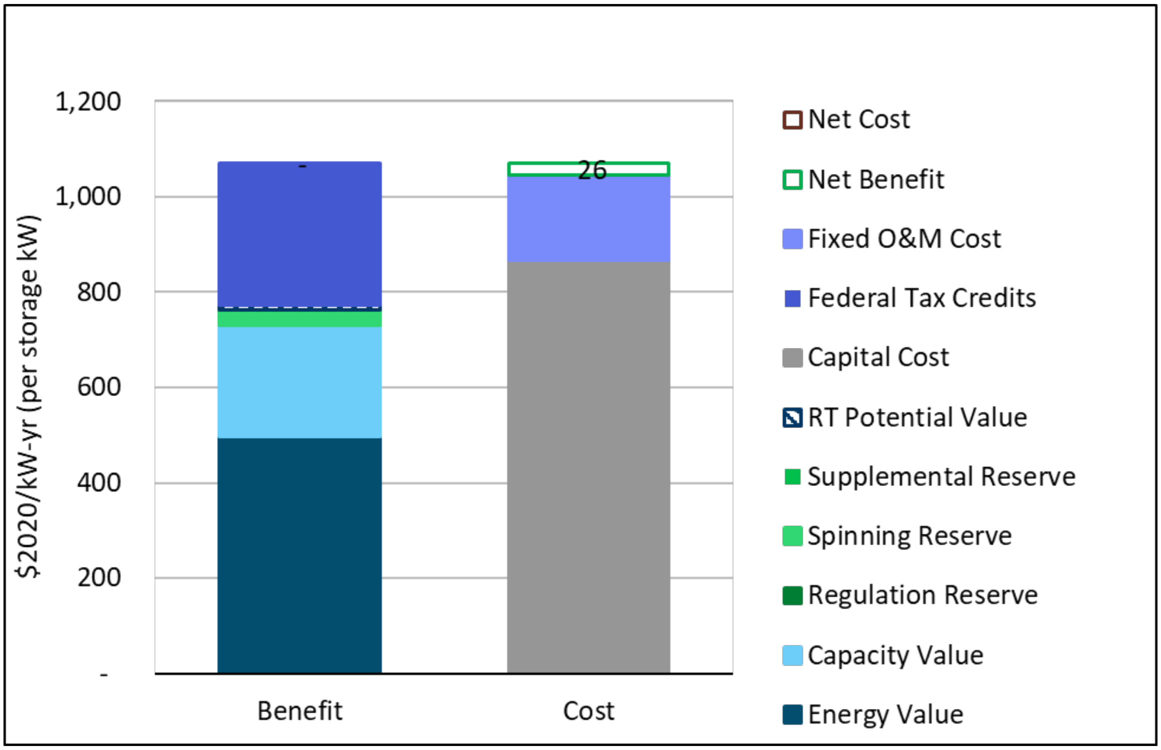
Figure 43. Total Resource Cost test including the deferral value



FTM Solar plus storage

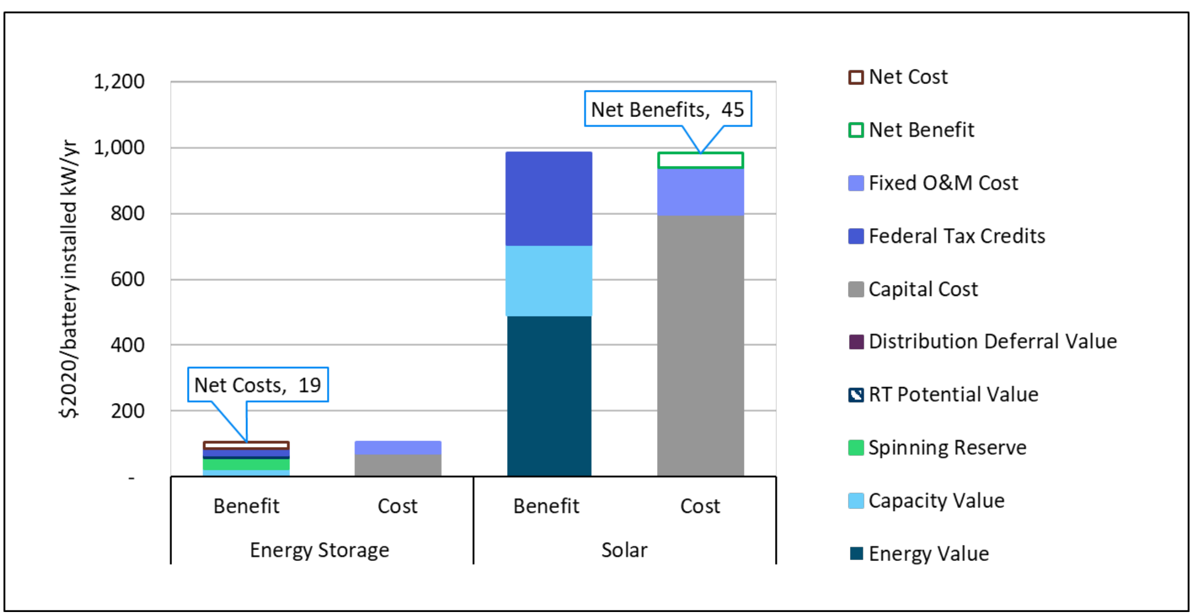
For our solar plus storage use case, we modeled an 8 MW Solar PV system paired with a 1 MW, 2 MWh battery, for a rural area near Saint Cloud in Xcel service territory. We found that this installation is cost-effective for installation in 2020, using a Total Resource Cost metric.

Figure 44. Total Resource Cost for solar plus storage (2020)



If we break down the benefits and costs by solar and batteries as shown in the figure below, the energy storage system is not cost-effective while the solar system is. Solar provides a large amount of energy value, and thus the cost-effectiveness for the combined system comes mainly from the solar. Values provided by energy storage are mostly from spinning reserve, capacity, and energy value.

Figure 45 Total Resource Cost Broken Down by Solar and Storage (2020)



Integrating energy storage with solar PV could improve the predictability of the solar generation, thus, could increase the capacity value of the solar system. The amount of increase in capacity value varies among jurisdictions since it is based on the effective load carrying capability (ELCC) quantification methods for solar only and solar + storage systems in each jurisdiction. The ELCC of variable resources are often calculated based on the stochastic simulation of loads, renewable profiles, and generator outages over a large number of years (e.g. 1000 years).

RESTORE simplifies the accreditation method based on the limited one-year load and renewable profiles it has. The ELCC calculation method used in RESTORE is based on the energy generation or battery net discharge during the top 3% of system peak hours. Using this method, the effective load carrying capability (ELCC) for solar is 72%. This is relatively high because the solar generation overlaps with the MISO system peak in summer afternoon. When adding in energy storage, thanks to the discharge during peak hours, the overall ELCC increases to 78%. The differences between the ELCC for solar only and the ELCC for solar + storage are calculated as the incremental capacity value provided by energy storage. More about the RESTORE capacity accreditation method can be found in appendix C.

Many states and ISOs are still in a process of defining the capacity credit of solar, energy storage, and paired system as the market evolves. MISO gives a class-average capacity credit of 50% of the nameplate capacity for solar generation in the 2018-2019 planning year (MISO, 2018). MISO is still in the process of creating capacity accreditation rules for solar + storage systems. If MISO assigns an ELCC of 70% after adding in the 1 MW 2-hour battery into the 8 MW solar system, the increase of capacity value will be 20% instead of the 6% as calculated by RESTORE.

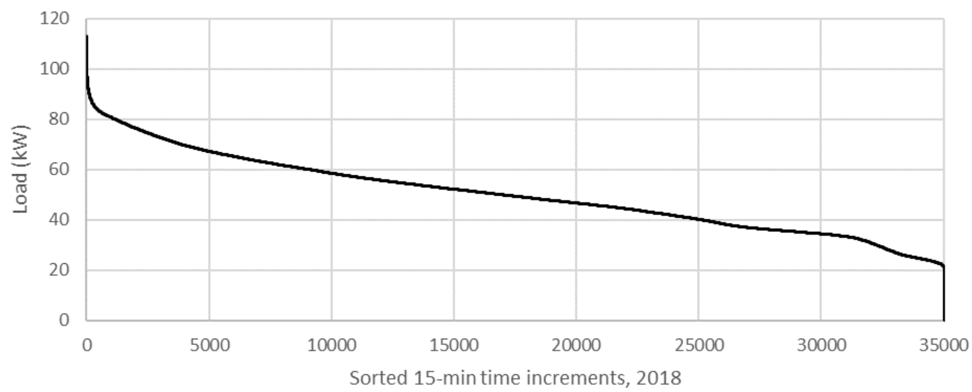
Adding in energy storage can help improve the deliverability of solar, and in many cases, provides an increase in capacity value. However, the exact amount of capacity value increase will be based on the market rules in each jurisdiction.

The cost-effectiveness of solar plus storage in the near-term are likely to be shifted by two opposite forces. As the solar Investment Tax Credit (ITC) phases out, incentives are decreasing. However, this will be balanced by decreasing solar and storage capital costs. Additionally, the potential for storage to increase the capacity credit of solar will become increasingly important in the near-term. Solar plus storage is likely to be one of the preferable use cases in the near-term.

Behind-the-meter (BTM) Solar plus storage

We also examined a behind-the-meter solar plus storage case, using a load shape for the Royalston maintenance facility in Minneapolis. This facility already has solar; however, we modeled a theoretical new solar installation and used the pre-solar load shape in order to provide a more broadly representative use case. We modeled a 20 kW solar system and a 10 kW, 1-hour duration battery. This facility is on a relatively standard demand charge of $14.79/kW on-peak; one of the main benefit streams for this facility is the potential for demand charge reduction due to solar plus storage.

Figure 46. Raw load-duration curve before solar for Royalston maintenance facility in Minneapolis



We found that this particular use case is cost-effective given our assumptions. The cost-effectiveness here is coming mainly from the solar, similar to our front-of-the-meter solar plus storage use case. To illustrate these dynamics we looked at the Participant Cost Test results for both the paired solar plus storage and the energy storage only.

Figure 47. Participant Cost Test for behind-the-meter solar plus storage

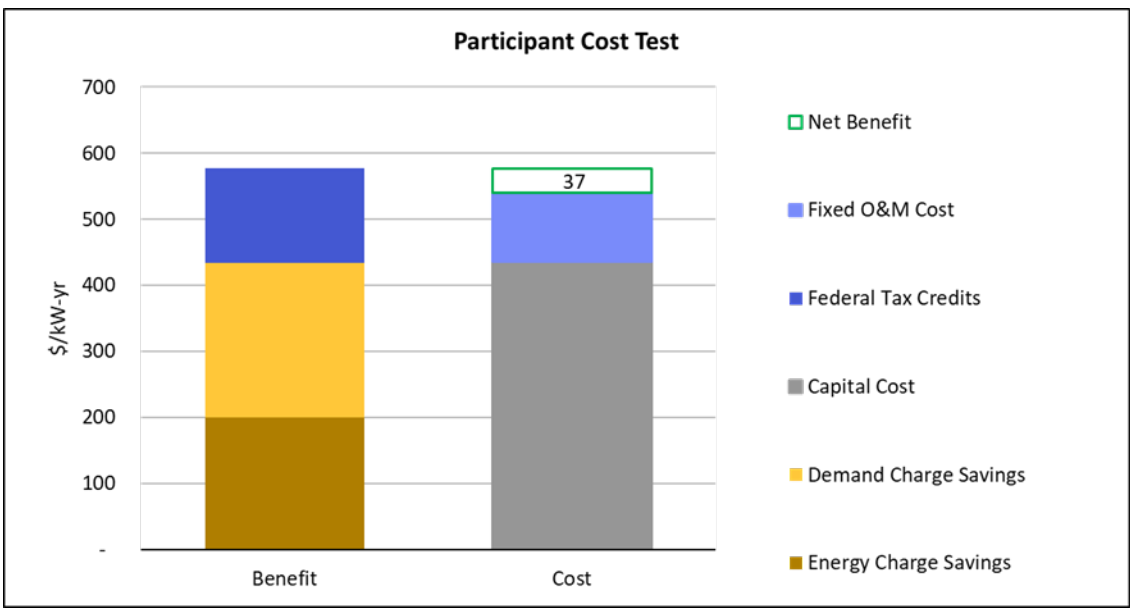
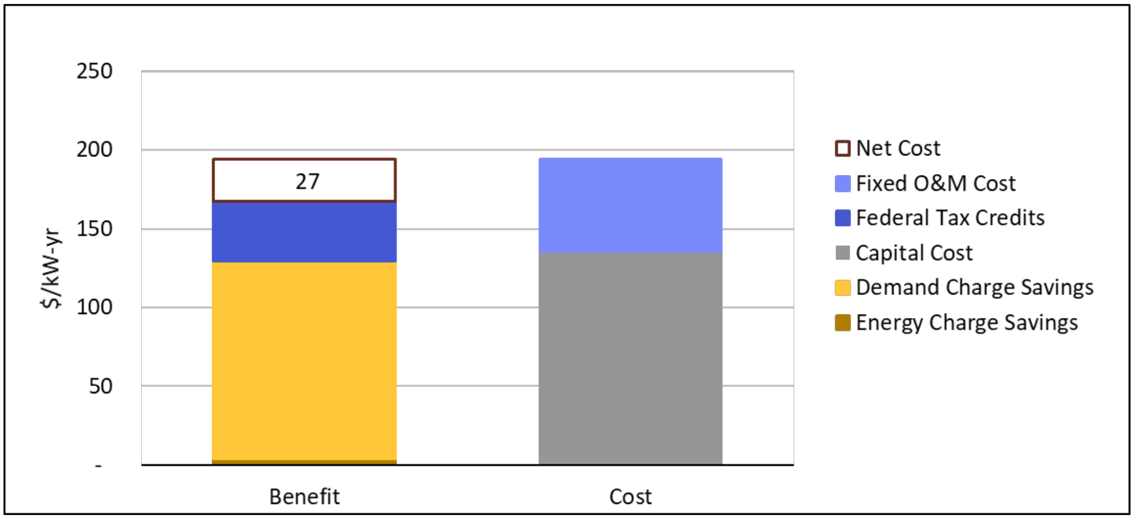


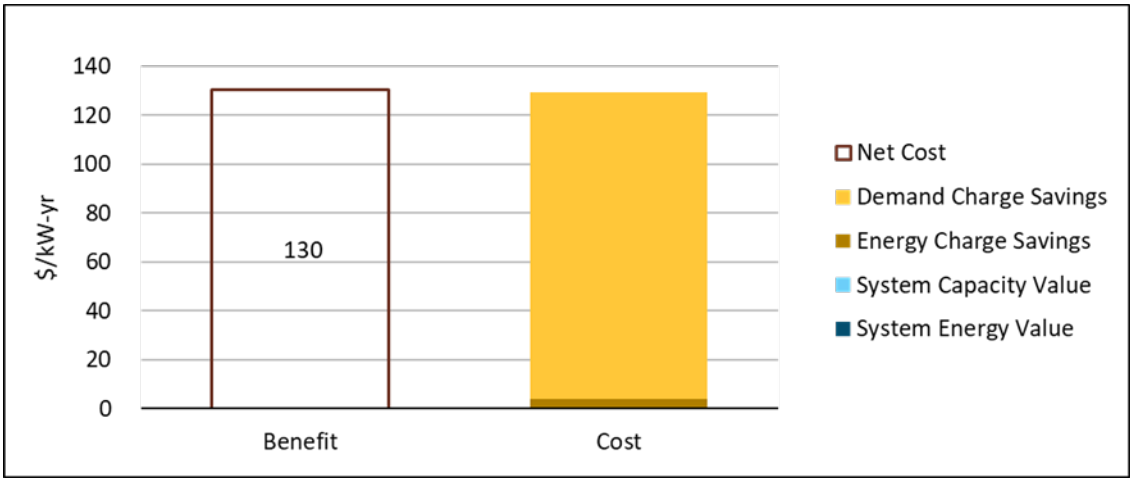
Figure 48. Participant Cost Test for energy storage only



Customers with a higher demand charge are likely to see even higher cost-effectiveness results. Energy storage is likely to be cost-effective on its own when used for demand charge reduction under a higher demand charge. This study quantifies the demand reduction provided by solar as the customer's peak reduction (by measure) after the solar installation. The reduction quantified is a coincidental reduction. Some people might argue that solar won't be able to provide a "firm" peak reduction. If the credit for helping firming solar peak reduction is allocated to energy storage, energy storage alone might be cost-effective.

However, even though this use case (and even more so, use cases with a higher demand charge) is cost-effective to the participant, using storage for demand charge reduction can create a cost shift for other ratepayers. Demand charges are based on a customer's non-coincident peak, not the system peak, so if these are not aligned, reducing a customer's peak does not lower costs to maintain the electric grid. Therefore, the customer installing storage will see a lower bill, but this bill difference must be made up by other ratepayers. This dynamic is reflected in the Ratepayer Impact Measure cost test, where the demand charge savings to the customer show up as a cost to other ratepayers.

Figure 49. Ratepayer impact measure for energy storage only

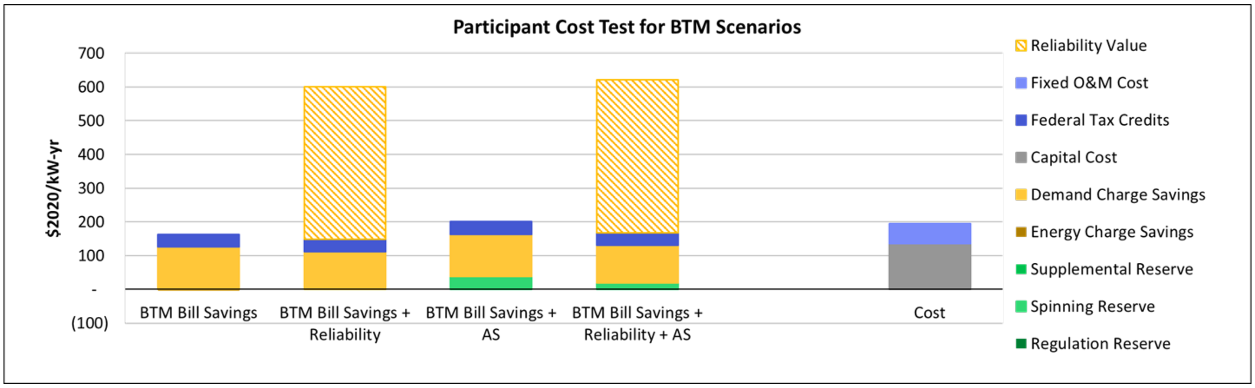


This cost shift can be mitigated if behind-the-meter storage can receive price-signals to fulfill system needs that benefit all ratepayers. For example, utility programs could be created to control behind-the-meter storage on peak days to reduce peak system load and therefore capacity need. Even simple rate changes such as time-of-use (TOU) rates and critical peak pricing can create useful system signal. However, if the only price-signal for behind-the-meter storage is to reduce non-coincident demand charges, these storage systems are not likely to provide benefits to other ratepayers.

We also examined the ability for behind-the-meter (BTM) storage to provide two additional benefits: customer reliability and ancillary services. Reliability is a potentially significant benefit for many commercial and industrial (C&I) customers, particularly those that provide community services during a power outage or those with a very high economic value of lost load such as hospitals or manufacturing facilities. Participation in ancillary services markets is another potential benefit stream for behind-the-meter storage, but this either requires MISO allowing BTM participation or an aggregator to bid into wholesale markets. This is an emerging field with manufacturers starting to aggregate BTM storage to bid into wholesale markets.

We quantified these two additional benefits using a Value of Lost Load of $265/kWh from the Lawrence Berkeley National Lab Interruption Cost Estimate Calculate (NREL, 2019) and Xcel NSP reliability metrics, and by assuming the same ancillary service price streams used in the rest of this study. For the reliability cases, we assume that 50% of the battery's energy capacity is reserved for outage protection. We calculate that both of these benefit streams could be enough to make BTM storage cost-effective on its own for this use case and particular customer.

Figure 50. Participant Cost Test for BTM Storage at Royalston maintenance facility, examining additional value streams of reliability and ancillary services

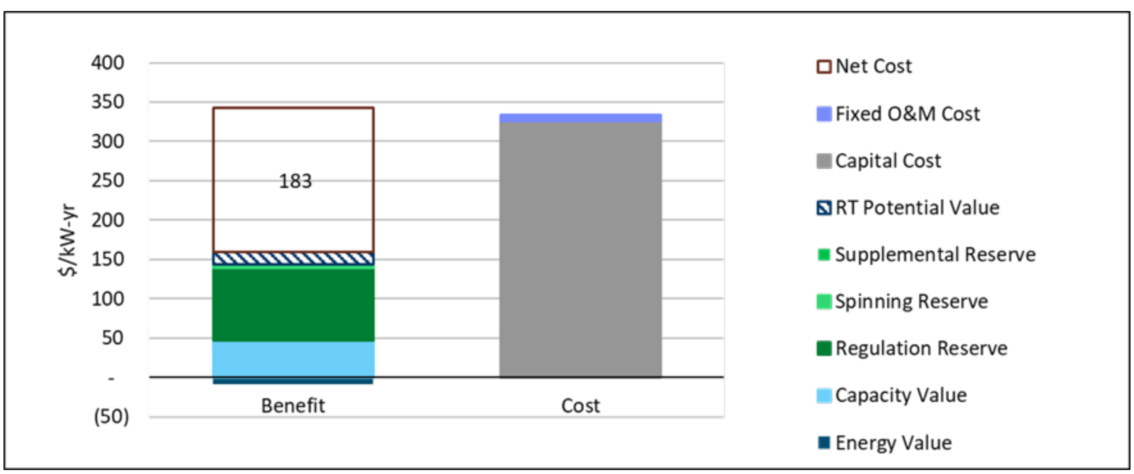


Note that the reliability benefits will be very customer-specific; thus, these results should only be taken as an example and as a starting point. Also note that since this is one-hour storage sized to below the facility's minimum load, only minimal outage protection is received in reality from this storage installation (although the storage would certainly allow some subset of the facility to continue operating during an outage lasting less than an hour). Installing a larger storage device would increase costs, meaning cost-effectiveness must be examined on a case-by-case basis.

Flow Battery

Finally, we examined the potential cost-effectiveness of a 4-hour flow battery installed in 2025. Even under the 2025 cost projections assumed, flow batteries are still more expensive than their Lithium-ion counterparts, and they have a lower round-trip efficiency. Therefore, this flow battery use case is less cost-effective than the comparable 4-hour Lithium-ion battery use case.

Figure 51. Total Resource Cost test for a 4-hour flow battery, 2025 installation, existing trends scenario



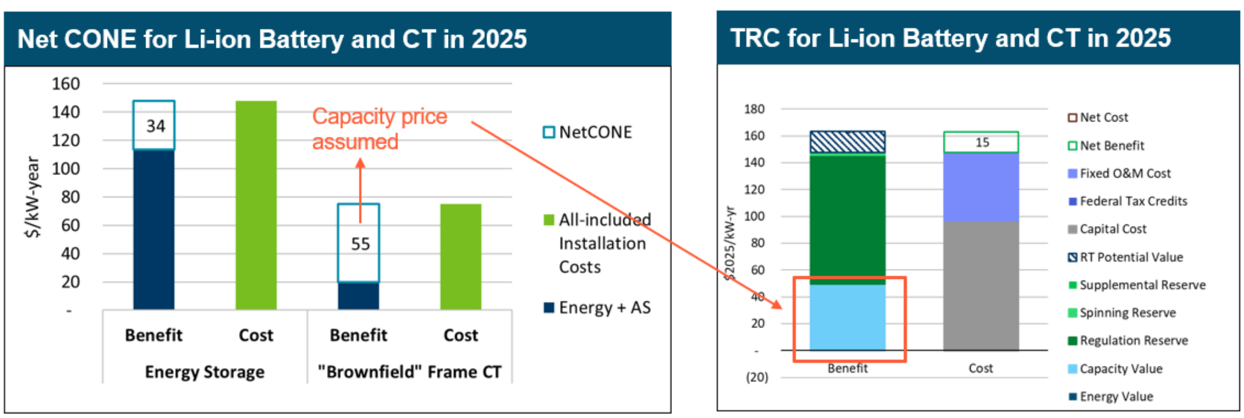
4.3 Peaker Replacement Screening

An economic cost-benefit analysis of the ability for storage to replace new peaking capacity is included in our main results. This value shows up as the "Capacity Value" in our charts. The capacity prices are derived from the cost of a new entry (CONE) of a combustion turbine (CT), net of the expected energy revenue.

For use cases where the Total Resource Cost for storage shows a cost-benefit ratio greater than 1, this means that this use case is **more cost-effective than procuring a new CT**. Our calculations show that solar plus storage is cost-effective today and stand-alone storage is cost-effective in 2025; therefore, solar plus storage could be cost-effective today for new peaking capacity, and stand-alone storage could be cost-effective in 2025. Note, however, that solar plus storage with a larger ratio of storage size to solar size might not be cost-effective today. The findings in our analysis are based on the theoretical maximum values energy storage can provide assuming perfect foresight, whether those can be realized in the current market depends many factors including the market rule improvement to allow energy storage to provide multiple services, the improvement in load and generation forecasting, and an advanced energy storage dispatch algorithm. In order to fully examine whether energy storage can serve as a new peaking capacity, we need detailed studies to examine the reliability and interconnection constraints.

The figure below illustrates how the cost of a new CT is incorporated into our cost-benefit analysis.

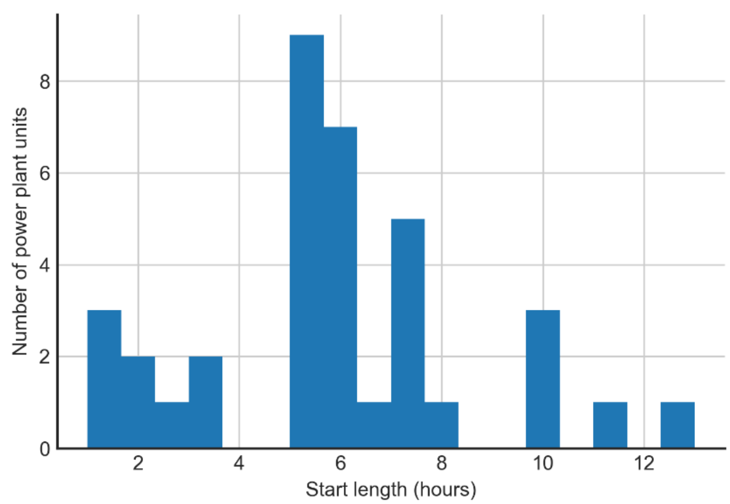
Figure 52. Illustration of how a comparison to new peaking capacity is incorporated into our analysis



In addition to the potential for storage to economically replace a new CT, we also examined the operations of existing CTs in Minnesota to determine whether 4-hour storage could operate similarly to the current peaker fleet on today's grid. **Storage need not perform exactly the same as CTs to serve as useful peaking capacity**; however, this analysis tells us to what degree we can expect storage to be able to "mimic" peakers, because a common concern with storage serving as peaking capacity is that it can only discharge for so long. If this "peaker replacement" analysis were to show that 4-hour storage can operationally mimic 100% of the peaker fleet in Minnesota (which it does not), for example, then this would mean that in fact, 4-hour storage does have sufficient energy to cover Minnesota's peaking needs. It is important to note that peaking needs will change over time, particularly under higher levels of renewables, so this analysis is only an initial screen. This analysis also tells us if there are any peakers that run infrequently enough that they can be readily replaced with storage. If these peakers are located in a densely populated area where replacing them would provide an air quality benefit to local communities, then replacing them with storage could be beneficial, although a more detailed reliability analysis would be needed to ensure grid reliability is not compromised.

The graphic below shows the distribution of median start lengths of Minnesota's combustion turbine (CT) fleet in 2018. A "start" refers to an instance that a peaker started up and ran. The cluster at the bottom left tells us that there is a meaningful portion of Minnesota's peaker fleet that does not generally run for 4 hours, meaning these peakers could likely be replaced with 4-hour storage.

Figure 53. Histogram of median "start" lengths for MN CT fleet in 2018

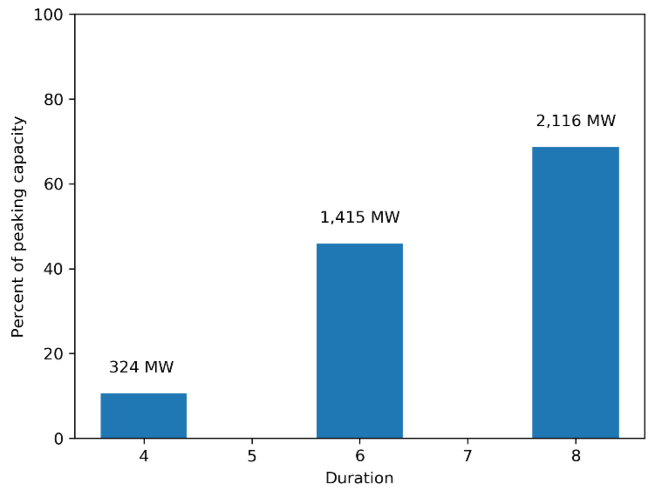


To take a closer look at the ability for storage to mimic existing peakers, we used our RESTORE optimization model to assess whether hypothetical 4, 6, and 8-hour storage installations could mimic each of the 50 CT units in Minnesota (representing about 3.1 GW of nameplate capacity), using data from the EPA Continuous Emissions Monitoring System (CEMS) for 2018. Our modeling results tell us to what degree each of these 50 units could be operationally replaced by storage.

We calculate that about 324 MW of peaking capacity in Minnesota had an operational profile in 2018 that would have allowed it to be "mimicked" by 4-hour storage. Note that the actual market potential for 4-hour storage in Minnesota is potentially much bigger than this in the long-term, particularly under higher levels of renewables, but this initial screen tells us which peaker plants today could be potential candidates for replacement with storage, especially if doing so could provide local air quality benefits and the units were near the end of their operational life.

This potential for mimicking operations jumps significantly higher for 6- and 8-hour storage. As can be seen from the previous graphic, most of Minnesota's peaker fleet typically has "starts" in the 6-hour range, making them easy to mimic with 6- or 8-hour storage. The graphic below shows our results for 4, 6, and 8 hours.

Figure 54. Percent of peaking capacity in 2018 that could have been mimicked by storage, as a function of storage duration



These results tell us that Minnesota's current need for peaking capacity could be about 50% fulfilled by 1,415 MW of 6-hour storage, or equivalently by 2,123 MW of 4-hour storage (since 4-hour storage can also run at a lower output for a longer duration). However, to reiterate, this is only an analysis of existing operations, and does not tell us the market potential for 4-hour storage in the future under a changing grid on both the generation and load sides. However, it does give us an idea of where to look for near-term opportunities to replace peakers that do not run very often and are near the end of their useful life. Note that 227 MW of peaking capacity, at the Blue Lake power plant in Scott County, is currently scheduled to retire in 2023 according to EIA Form 860, so this could be an ideal location for installing storage in the future since interconnection costs could be much lower than a "greenfield" site. These units make up the bulk of the 324 MW indicated by our results as a potential for 4-hour storage. Each of the four units had a capacity factor lower than 0.1% in 2018.

5.0 Case Study

5.1 Renewable Integration: Kaua'i Island Utility Cooperative (KIUC)

As the cost of renewable resources and battery storage declines, more and more states, whether they have a greenhouse gas emission reduction target or not, has experienced balancing renewables in their system. Energy storage is one of the potential candidates for renewable integration. Hawai'i might be the first state to actively use energy storage for balancing renewables in the system scale as they are moving toward its target to provide electricity through 100% renewables by 2045.

Kaua'i Island Utility Cooperative (KIUC) in Hawaii is committed to generating 70% of Kauai's power using renewables by 2030. In 2019, roughly 55 percent of the electricity generated on Kauai is coming from a mix of renewable resources. To balance the system and provide peaking capacity, two utility-scale solar plus battery storage generation facilities are installed in 2017 and 2019. The first one in 2017 is a 52 MWh Tesla battery storage system paired with 13 MW solar and the second one in 2019 is located in Lawai and has 100 MWh battery coupled with 20 MW PV. The batteries charges from solar during daytime hours and are used to move solar energy to the evening peak hours. (KIUC, n.d.)

As for today, 40% of Kauai's evening peak load can now be met with dispatchable solar plus storage.

5.2 Bill Savings and Emergency Services: Blue Lake Rancheria in Northern California

Extended blackouts due to natural disasters could be a major source of public risk and financial loss. Recent blackouts in the United States due to wildfires, Superstorm Sandy and Hurricanes Irma and Maria have again highlighted the need for customer and communities to have a more resilient grid. Traditionally, customers use fossil generators to provide backup power during emergency events. Lately, there are increasing interests in using PV and storage for providing backup power due to rapid technology price declines. Increasing awareness of climate change and the need for greenhouse gas emissions reduction have also made solar plus storage a preferable alternative to diesel generators.

The project led by Humboldt State University Sponsored Programs Foundation (HSUSPF) aims to address key market barriers to deploy the solar+ technology in the small to medium size commercial buildings (SMB). The deployment of solar+ technology can be used to reduce commercial building's utility bills. During grid outage events, the commercial sites can then be turned to a community emergency center to supply food and power.

The pilot project to test out this idea is sited at a gas station in the Blue Lake Rancheria area of Humboldt County, California. Humboldt County is located in Northern California and is at risk for wildfire dangers during dry seasons. Humboldt County has experienced unreliable electricity due to transmission constraints and risks a chance of rolling blackouts related to wildfires. In addition, it is particularly important for the site host to use zero-emission generations for backup power. The gas station is on a large commercial customer rate: PG&E E19 rate. This rate has expensive overall demand charges and multiple TOU demand charges for peak, part-peak, and off-peak hours. Using energy storage for demand charge clipping can significantly reduce the overall electricity bills for the site host.

A gas station was chosen as an appropriate site for several reasons:

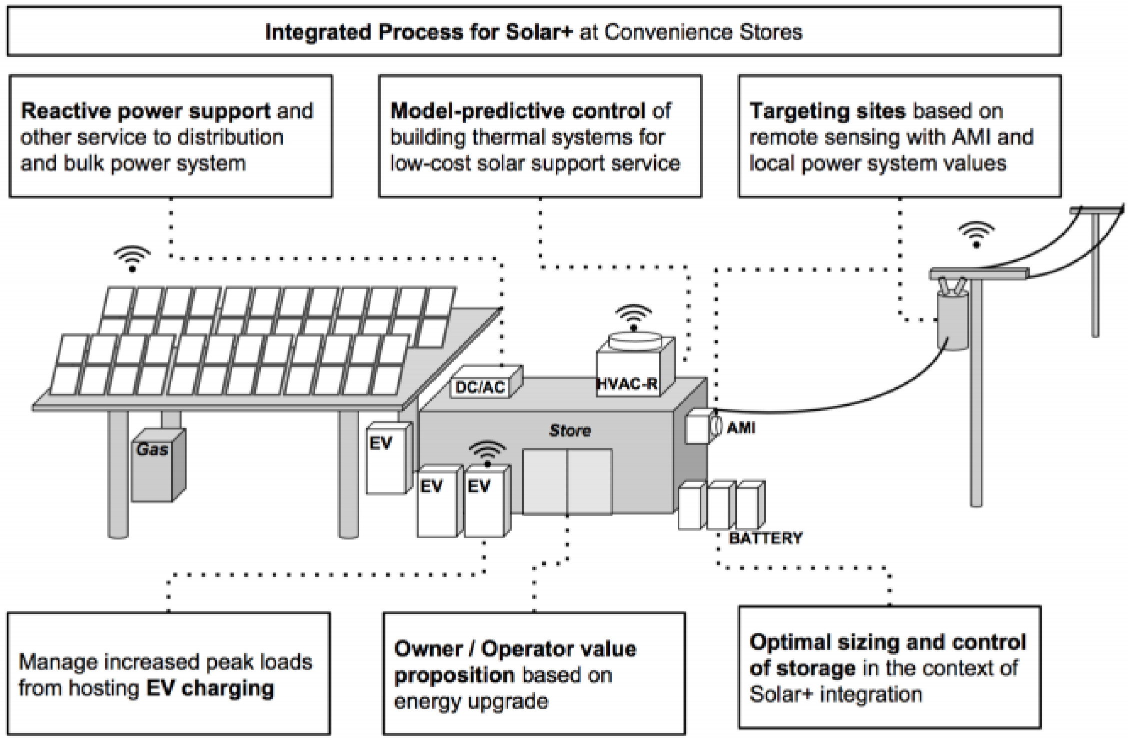
- The project could provide high value for reliability or emergency services (as it is both a potential emergency meeting point and supplier of emergency gas)
- The site has an in-built canopy on which to mount solar PV
- The station includes flexible refrigeration loads that could provide demand response value
- A successful pilot model could be scaled to other gas stations
- The potential to include electric vehicle charging stations in the future

The solar + systems include solar PV at 60kW DC, energy storage sized at 109 kW / 174 kWh, and advanced controls for communicating with thermostats and refrigeration. The following figure illustrated the research objectives[14].

The project is currently conducting operational testing. The pilot ends in June 2020.

[14] https://schatzcenter.org/docs/solarplus-factsheet-dec2017.pdf

Figure 55. Solar+ at convenience stores



6.0 Stakeholder Engagement

Stakeholder engagement was a key component of this study. Stakeholders who contributed to the study included representatives from electric utilities, renewable energy developers, academia, government, non-governmental organizations, and more. Stakeholder involvement allowed us to tailor our analysis to Minnesota-specific conditions, and make sure we captured as many value streams as we could in the time that was available.

During this study, three stakeholder workshops were held to present progress to stakeholders and received feedback. The three workshops focused on, sequentially, modeling methodology and assumptions, draft results, and final results.

In the first workshop, we presented an overview of our planned study, detailed our market price scenarios and use cases, and reviewed planned modeling assumptions. After this workshop, we sent out a survey requesting stakeholder feedback on what was presented so far. Feedback received focused on the following main points:

- Modeling should focus on Lithium-ion batteries and wholesale market participation
- Transmission upgrade deferral should look at work done in MISO Transmission Expansion Plan 2018 (MTEP18) and distribution upgrade deferral should look at utility Integrated Distribution Plans
- Compressed Air Energy Storage should not be a focus for modeling
- Greenhouse gas reductions should be calculated, if any
- The potential for storage to provide peaking capacity should be analyzed in detail
- Resilience benefits for behind-the-meter storage should be included
- Sub-hourly benefits (e.g. fast-ramping capability) should be modeled
- Report should discuss low-probability, high-impact events such as long no-wind events and polar vortex events
- Report should discuss how findings in other jurisdictions transfer over to Minnesota, and why or why not

All of these feedback points were incorporated into our study, except the explicit modeling of sub-hourly benefits. We did, however, include a “Potential Real-Time Benefits” adder in our cost-effectiveness tests, estimated based on the difference in benefits between storage operating in the real-time and day-ahead markets today. Examining the sub-hourly benefits of storage in further detail is an important topic for future study.

In the second workshop, held in-person in Saint Paul, we presented our draft results, and discussed why we did or did not show value from each value stream. None of the use cases presented at this point were shown to be cost-effective in the near-term. We received the following main points of feedback from this workshop:

- The effects of electrification on load should be included
- None of the use cases presented thus far are cost-effective—what, if anything, is in fact cost-effective?
- The lack of curtailment in the market price results is surprising; why is this happening and what would happen to the economics of storage if there was curtailment?
- It is important to emphasize what is and is not cost-effective to Minnesota, so as not to make unnecessary investments with ratepayer funds.
- Study timeline should be extended to incorporate material from Xcel's 2019 Integrated Distribution Plan (IDP)
- Study should use the NREL "Low" cost trajectory for storage, or at least consider this as a sensitivity

These stakeholder suggestions were incorporated to the extent possible. The effects of electrification on loads under a moderate adoption forecast are included in the load forecast. Building electrification and electric vehicle adoptions on a large scale could create new opportunities for battery storage to provide values by smoothing out the peak for the additional load. Given the limited timeline and budget of this project, the impacts of aggressive electrification is not modeled, but this is an important area for future study. The Minnesota Department of Transportation "Pathways to Decarbonizing Transportation in Minnesota" study is an example of a starting point for what levels of electrification could be considered. Further, we are not able to incorporate the results of the 2019 IDP, as the timeline for this study is earlier than the final release of the IDP. However, all other stakeholder concerns were addressed. Details for updates are summarized below.

- The surprising curtailment results were thoroughly explained in the third workshop, and a sensitivity was included to examine the effects of increased curtailment.
- We adjusted the relative ratio of the solar plus storage systems to more realistically reflect the sizing ratios that are currently deployed.
- Further, we revised our AURORA energy price benchmarking methodology to better reflect historical volatility.
- In addition, we included a real-time benefits adder to represent the potential values added by participating in the real-time market and provide sub-hourly flexibility.

These last two changes, the adjustment of benchmarking method and the inclusion of real-time benefits, made the stand-alone battery storage installed in 2025 cost-effective. Finally, both the NREL "Mid" and "Low" storage upfront cost trajectories were considered in the final results.

In the second workshop, we also hosted a panel discussion featuring experts from across the Minnesota clean energy transition sphere. Panelists were asked to comment on topics such as the potential risks for energy storage, how energy storage fits into Minnesota's broader clean energy goals, and the potential for storage to help underserved communities. This panel discussion helped to inform the possible next steps that will come out of this project—for example, looking further into the potential for avoided curtailment under higher renewables penetrations, looking further into local emissions benefits to underserved communities that could result from installing storage instead of new combustion turbines (CTs), and understanding the role storage will play in longer-term utility resource plans.

The final results were presented in a third workshop. Stakeholder feedback received focused on the following points:

- The study does not include an estimate of the system-wide potential for cost-effective storage installations, for example, post-2025 when we are projecting that storage will be cost-effective.
- The study should recommend that utility planning in Minnesota use the most up-to-date storage cost estimates, use methods to evaluate the sub-hourly value of storage, and consider programs that allow behind-the-meter storage to contribute to peak demand reductions through utility control.
- The value of storage and/or solar-plus-storage to replace peakers should be made clear in the study.
- The value of storage as a transmission asset should be examined in more detail, if not in this study then in future studies.
- The study should clarify the role that storage will play in a highly renewable grid in the long-term.
- Suggested pilots should include emerging energy storage technologies that are capable of providing much longer duration storage, which will be critical to the highly renewable grid of the future.
- The study should consider the potential societal environmental benefits associated with storage, particularly for the solar-plus-storage case.

We incorporated these comments into our final report to the extent possible. To address the first bullet, we included the results for system-wide optimal storage builds from running a capacity expansion model for Minnesota using AURORA in the final report. To address the second bullet, we considered these factors into the recommendations made in our report. To address the concerns on articulating the value of storage for peaker replacement, we made a dedicated section for this topic in our final report. The remaining concerns were addressed to the extent possible as discussion points in our report.

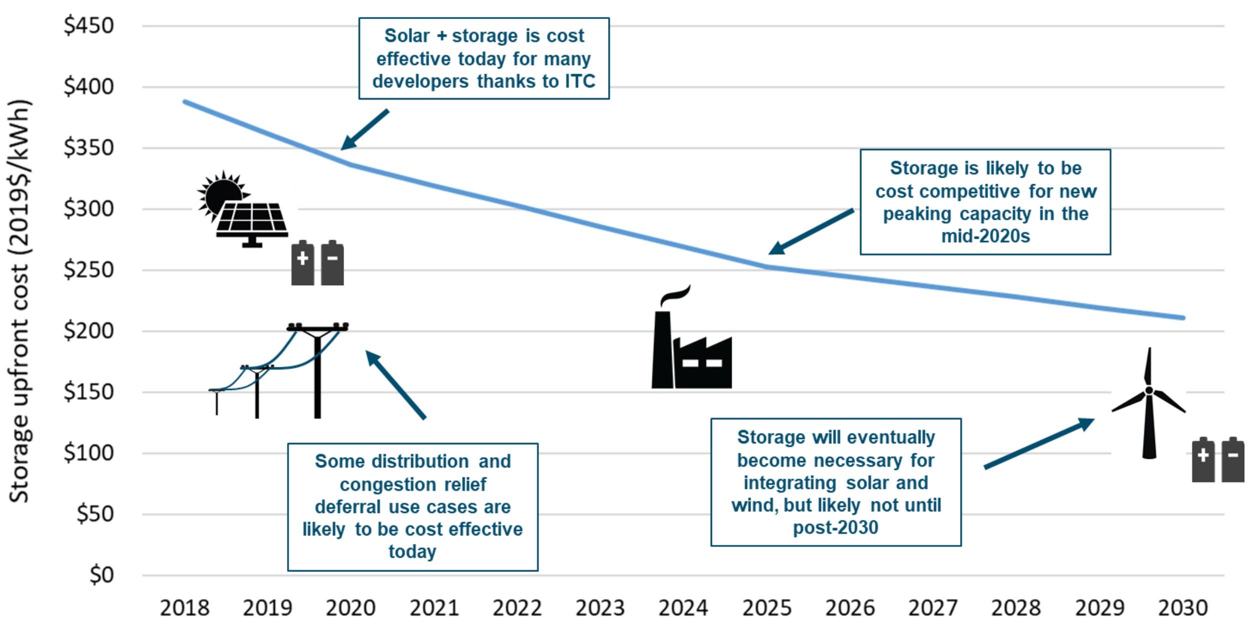
7.0 Conclusions

7.1 Key Takeaways

For utility-scale energy storage, the study calculates that solar + storage can be cost-effective today due to investment tax credit (ITC) benefits and the capacity firming provided by energy storage. This is consistent with the emergence of initial solar plus storage system installation and development in Minnesota.

In certain local constrained areas, energy storage can play an important role in alleviating congestion and deferring more costly distribution upgrades. Looking forward, this study calculates that stand-alone energy storage installed in 2025 could be cost-effective due to technology price declines and an increase in capacity value (as MISO North evidences a capacity need in the mid-2020s). Moving beyond 2030, when solar and wind penetration has increased substantially in both Minnesota and MISO, storage (and especially long-duration storage) will likely become an important option for integrating renewables cost-effectively.

Figure 56. Energy storage breakeven costs over time (NREL "Mid" Case)



Key takeaways from E3's analysis are summarized below:

1. **Front-of-the-meter (FTM) solar plus storage is likely to be cost-effective in 2020**
    a. The federal Investment Tax Credit (ITC) provides additional incentives for storage but also limits the opportunities for storage to provide regulating reserves (because eligible storage systems must charge from solar)

   b. Some amount of solar + storage could take the place of new thermal capacity resources

2. **Stand-alone energy storage installed in 2020 could be cost-effective if it is located in constrained areas with high system and local capacity values and is able to defer T&D investments to alleviate congestion.**
   a. Stand-alone energy storage is not yet cost-effective from the system's perspective if it only provides capacity, hourly energy, and ancillary services benefits (including regulation reserve)
   - Regulation reserve value is the largest value stream for storage installed in 2020, followed by capacity value
   - Participating in real-time markets and providing sub-hourly flexibility to the system would increase energy storage's overall value, but quantifying these value streams in detail is outside the current study's scope
3. **Energy storage installed in 2025, in particular, Lithium-ion, could be cost-effective as a capacity resource due to lower capital costs and increased capacity value as MISO starts to procure capacity, but installments are subject to saturation. Cost-effectiveness could occur sooner if storage costs decline even faster than expected**
   - Some amount of energy storage could take the place of new thermal capacity resources
   - These findings are based on theoretical maximum values that can be provided by Lithium-ion storage including the potential revenues from participating in the real-time market. Detailed, site-specific studies and pilots are needed before implementing storage as a capacity resource. Such studies would, for example, conduct stochastic analysis to ensure reliability and conduct power flow analysis to understand charging constraints.
4. **Behind-the-meter (BTM) storage paired with solar is likely to be cost-effective from the participant's perspective**
   a. Demand charge clipping is a significant value stream for these installations, but this can create a cost shift for other ratepayers if the state and utilities do not provide signals that align with system benefits
   b. However, solar + storage systems could provide significant value to the system if the state and utilities offer programs – e.g., time-of-use (TOU) energy charges, demand response programs, and allowing the utility to dispatch storage during system peak days – that align customer benefits with system benefits
5. **Paired storage or even stand-alone storage could serve as a backup generator during emergency events, which could provide benefits to communities**
6. **Flow batteries are not as cost-effective as Lithium-ion batteries in 2020 or 2025 because of their higher capital cost**
   a. Flow batteries (which can provide similar services as Lithium-ion batteries) might become cost-competitive in the future given their more aggressive cost decline projections and potential to provide long-duration storage at a lower cost than Lithium-ion

7. **If neighboring states adopt more renewables due to economic or policy-driven reasons, there may be a higher level of transmission congestion, limiting the ability to deliver renewable generation to load centers. In this case, energy storage could add value at congested transmission nodes and provide a timely alternative to hedge indeterminate transmission planning efforts.**
8. **The three key factors driving energy storage cost-effectiveness, as identified by our analysis, are:**
   a. Battery capital cost
   b. System and local capacity need (including T&D deferral opportunities)
   c. Renewable integration needs in the long-term
9. **The results from this study are broadly consistent with Minnesota's previous studies**
   a. A 2017 study conducted by the University of Minnesota (University of Minnesota, Strategen Consulting, and Vibrant Clean Energy, 2017) selected energy storage – when deployed with ITC incentives and GHG constraints – as a preferable resource by 2030; and, under less optimistic assumptions, in a later timeframe (e.g., 2045). Further, the study found solar + storage to be cost-effective in 2018, but did not find the storage-only resource to be cost-effective until 2023. Both of these findings are consistent with E3's current study.
   b. In the reference case of E3's recent analysis for the Xcel Minnesota IRP proceeding (Xcel, 2019), the optimal resource portfolio starts to include energy storage in 2030. And the finding is consistent with this study which calculates that stand-alone energy storage is cost-effective beginning in 2025 with the inclusion of potential value added from real-time market participation.

7.2 Recommendations

Based on our analysis, this study makes the following recommendations to guide and accelerate the market for energy storage over the next 5 to 10 years:

- Include energy storage as a standard part of utility resource planning and competitive bidding processes, comparing the benefits and costs of energy storage to conventional thermal resources using a least-cost capacity expansion model or other quantitative analysis. The quantitative analysis should consider multiple technology price and load growth sensitivities and take into account emissions impact relative to other resource options as well as the various value streams that storage can provide, including sub-hourly flexibility values, peak capacity, transmission and distribution upgrade deferral, and ancillary services.
- Pursue targeted initiatives and programs in the next several years that prioritize the use cases that are identified as being cost-effective in this timeframe to further build experience and expertise on energy storage technologies and deployment. During this timeframe specifically focus on gaining experience in operating energy storage and understanding potential operational constraints as well as opportunities to increase storage's value to the grid.

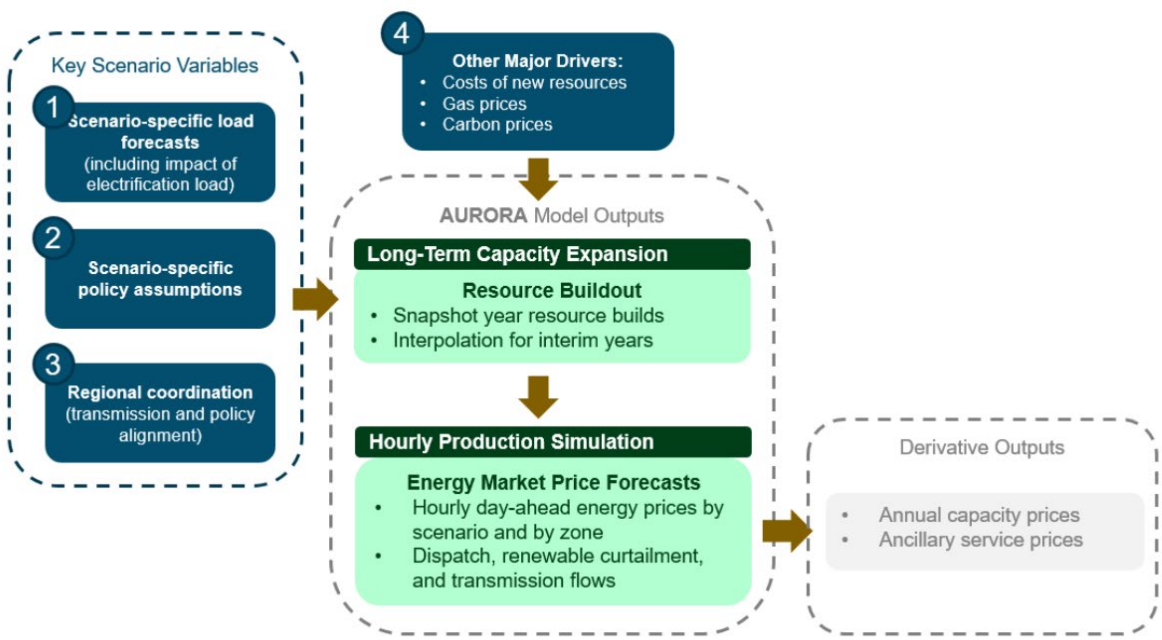
  - Potential near-term use cases are: 1) solar + storage as an alternative for conventional thermal units as new peaking capacity; and 2) storage stand-alone or solar + storage for transmission and distribution upgrade deferral.
- Move from near-term targeted initiatives and programs to more wide scale deployments: consider setting up an implementation plan to operationalize the evaluation of storage as “non-wires alternatives” in distribution utility planning. The plan should include details on implementing initial steps to identify areas with high distribution upgrade deferral values, open solicitations for deferral needs, competitive bidding processes that include energy storage, and ultimately to project construction.
- Develop electric retail rate structures as soon as possible to align customer price signals with system marginal costs so that behind-the-meter (BTM) storage provides societal benefits and does not shift costs to other ratepayers.

Appendix A: AURORA

AURORA

E3's wholesale energy market price forecasts are developed using AURORA, a widely used commercial production simulation software. In this study, zonal wholesale energy market prices for years 2018-2032 were developed for the MISO North region. Hourly wholesale prices are determined by AURORA's production simulation and set by the cost of serving the marginal unit of load. In the scenarios modeled, thermal resources dominate in MISO North as the marginal unit. These units have variable costs driven largely by fuel costs and heat rate. AURORA's wholesale energy prices serve as the basis from which capacity market prices and ancillary services prices are derived. Figure 57 summarizes AURORA's model flow. Long-term capacity expansion was not run for MISO North; Rather, a portfolio of expected new build was manually inserted. Details on capacity build are provided under the subsequent "Scenarios" section. AURORA simulation model diagram is shown in the following chart:

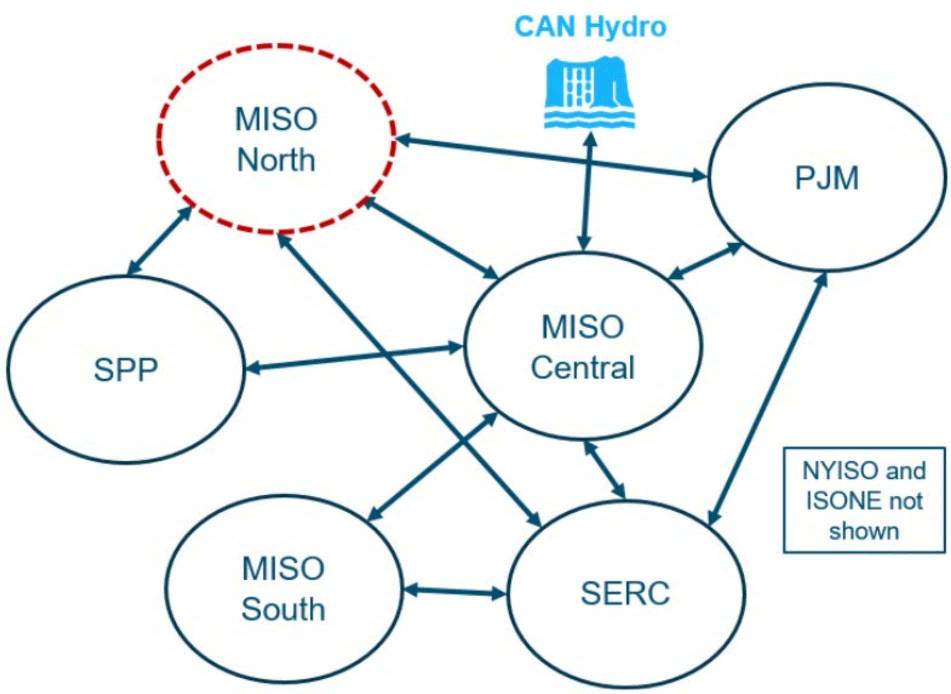
Figure 57. Diagram of AURORA model inputs and outputs



Major drivers of wholesale prices include gas prices, the generation portfolio, transmission limits, and fuel prices. Certain assumptions are tied to policy assumptions, including new renewable adoption and electrification of load. The policy assumptions regarding surrounding markets are also pertinent, as they impact the availability to balance renewable generation. To better capture interactions between markets, E3 chooses to develop its market prices as part of a broader area that encompasses the entire Eastern Interconnect.

The Eastern Interconnect topology is comprised of 33 regions ("zones"), which broadly align with balancing areas. Figure 58 presents a simplified diagram of the network modeled. Each zone is assigned a representative hourly load profile (shape, annual peak, and annual load) as well as a set of generation resources consistent with the existing portfolio of each region. Minnesota, along with North Dakota and Iowa form the Northern MISO region. Together, this aggregation covers the territory of MISO Zones 1 and 3. Transmission line constraints within zones are ignored while transmission capacity between zones are simplified into aggregated lines with flow limits in the positive and negative directions. The primary implication of the modeling topology design is that regions within a single zone are allowed to rely generously upon each other for load balancing. These simplifying assumptions were necessary given the complexity of the problem, as well as the tight project scope and timeline.

Figure 58. Simplified visualization of the Eastern Interconnection's topology in AURORA



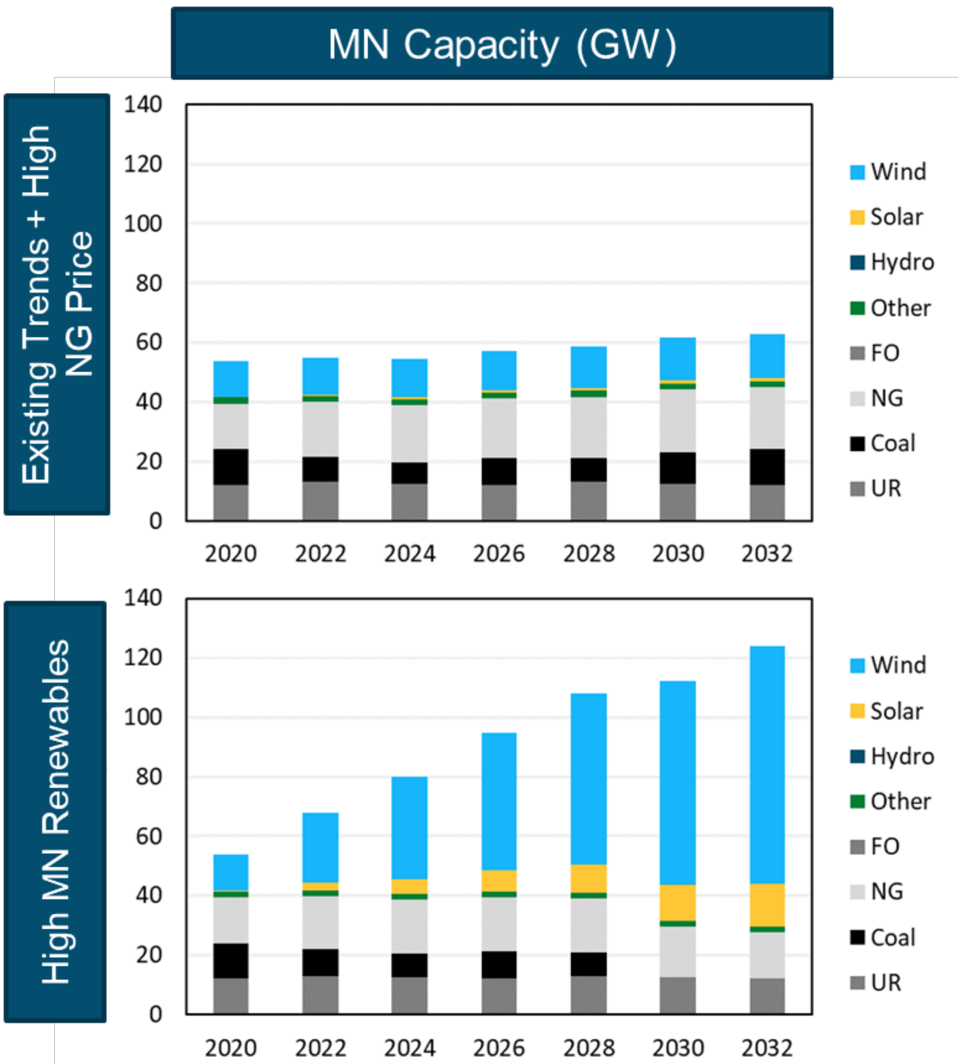
Scenarios

E3's pricing scenarios were developed to reflect the market conditions under three scenarios. The lower end of the spectrum is the case in which renewables penetration continues only at current trends; the higher end is the case under which renewables are aggressively adopted. A third scenario was also developed to study the impacts of increasing gas prices.

- The "Existing Trends" scenario was created as a base case, meant to represent market conditions if renewable integration were to continue at current rates. This case was developed following the 2018 MTEP Continuing Trends scenario. 750 MW of new wind, 400 MW of new solar, 1.2 GW of new combined cycle (CCGT) and 3.8 GW of new combustion turbine (CT) are forced online by 2032 in linear increments annually.
- The "Higher Renewables" scenario captures the effect of high renewable penetration in Minnesota on market conditions. As renewable capacity increases, less efficient and more costly units are displaced. This effectively lowers market prices, particularly in hours in which wind or solar availability is high. With enough price suppression, conditions for energy arbitrage become increasingly more economic. Specifically, the Higher Renewables case is built on top of the Existing Trends scenario. Additional modifications include increased solar and wind capacity such that over 75% of load is met by renewables by 2032. It is also assumed that all nuclear is relicensed at the expiration of their contracts, and all coal has retired by 2030.
- The "High Gas" scenario was developed to study the impact of high gas prices on market prices. Rather than simply moving gas prices upwards in the MISO zones, the Henry Hub price was adjusted upwards in the model. This is done to avoid any convolution resulting from gas units from lower-priced hubs being dispatched to displace gas units in higher-priced zones. The relationship between High and Base case gas prices in the 2018 Xcel IRP was referenced to inform the upwards adjustment between high and low prices. All other modeling assumptions are the same as those in the Existing Trends case.

The generation portfolio of Minnesota is shown in Figure 59. Overall, E3's modeling results show low levels of curtailment in MISO North even under aggressive renewable adoption. While numerous studies have demonstrated MISO's aptitude for renewable integration, the extent of it, as reflected in these results, may be enhanced by the modeling assumptions. In addition to the lack of transmission constraints within the MISO North zone, all scenarios assume neighboring states to Minnesota follow their existing clean energy policy trends. None are not especially ambitious. Provided ample transmission capacity, these zones can help absorb generation excesses from MISO North and mitigate curtailment.

Figure 59. Total generation capacity in Minnesota by year

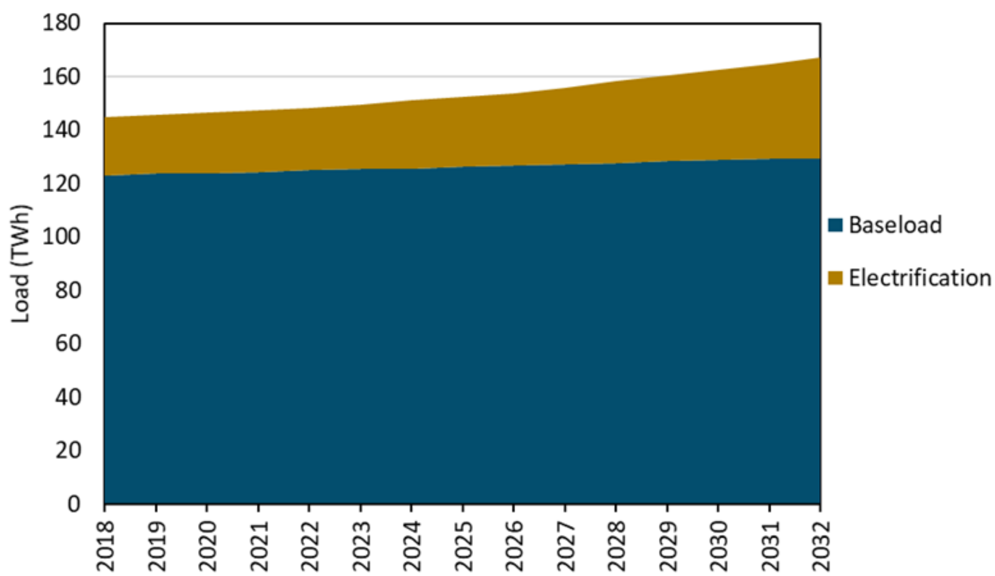


Demand

Figure 60 presents the assumed annual demand in MISO North. The three scenarios use the same load forecast. Baseline demand is assumed to grow at an annual rate of 0.4% on average. Incremental electrification loads resulting from EV, electric heat pump and water heater adoption are assumed to grow steadily through the years. By 2032, electrification makes up approximately 25% of total load in MISO North.

Load data for all zones in the model are sourced from 2018 NREL Electrification Study, Moderate Advancement, Medium Adoption (Jadun, et al., 2017). Demand inputs represent retail demand and are built from end-use estimates. As such, it is inherently net of energy efficiency measures.

Figure 60. Total retail demand in miso north



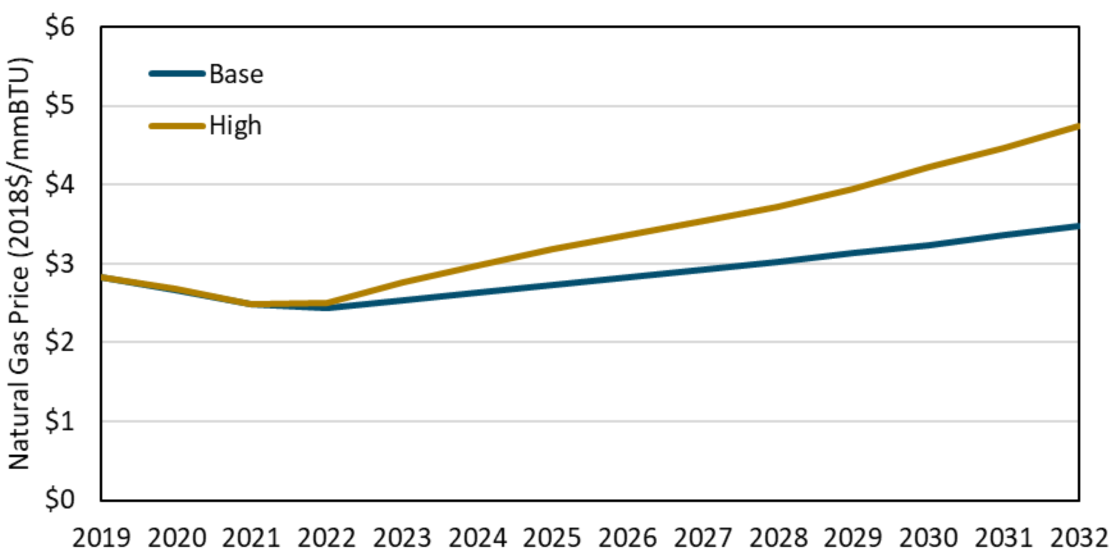
Natural Gas Prices

Gas prices in AURORA are by hub and structured as a series of adders on top of the Henry Hub price. These adders are meant to capture both hub price differentials relative to the Henry Hub as well as delivery adders. Each gas unit in the model is mapped to its corresponding gas hub.

E3's base gas prices are developed using a combination of forward prices in the near-term and AEO fundamentals-based forecasts in the longer term. SNL forwards are available for only the next three years and are extrapolated to EIA forecasts by 2040 to derive a continuous price trajectory. Average delivered gas prices as seen by generators in MISO North are shown in Figure 61. The average difference in gas prices diverges in 2022 and this differential increases in magnitude into the future. By 2032, the high gas price is approximately 36% higher than the base price.

While the base gas price forecast is used in the Existing Trends and High Minnesota Renewables scenarios, the Higher Gas Scenario relied on a more aggressive gas trajectory. E3's high gas price forecast was developed using the gas price forecast reported in Xcel Energy's 2018 IRP. Base Henry Hub gas prices were scaled based on the difference between the projected average annual mid and high prices of the Ventura Hub.

Figure 61. Annual average delivered gas prices in MISO North



Appendix B: RESTORE

As the market for energy storage (ES) assets has emerged, E3 developed the RESTORE tool[15], which simulates optimal operation over the life of different types of ES assets. The core "engine" of the tool is a price-taker optimal dispatch algorithm, which identifies the profit-maximizing operation pattern for the ES facility given its size and performance characteristics, the revenue streams to which it has access, the market in which it is expected to operate, and a forecast of the applicable market prices for the services the ES asset will be providing (i.e., behind-the-meter bill savings or front-of-meter energy, capacity, regulation, reserves, resource adequacy prices, etc.). The tool is quite flexible in the types of ES asset types that can be evaluated (e.g., lithium-ion, flow, pumped hydro, etc.) and it has been used for variety of purposes such as analyzing ES operational patterns and estimating lifecycle market revenues for developers, asset owners, and potential investors.

E3's RESTORE tool can dispatch both stand-alone storage and solar plus storage with co-optimization of multiple value streams by a mixed-integer linear programming (MILP) algorithm. Value streams can include system-level avoided costs, distribution avoided costs, ancillary services, customer demand charges, energy charges, and back-up power reliability values. The tool can be dispatched in customer or utility control mode. In customer control mode, the storage is dispatched to maximize customer revenue: reduce bills, increase back-up power reliability values, and increase ancillary services revenue if customers have access to AS markets. In utility control mode, storage is dispatched to reduce system costs.

The tool outputs hourly and annual dispatch and operational data, value streams and avoided costs.

[15] https://www.ethree.com/tools/restore-energy-storage-dispatch-model/

Appendix C: Quantified Benefits

Energy Value

Future energy hourly prices are estimated based on the production simulation model AURORA.

As typical of optimization models, AURORA's assumption of perfect foresight makes it difficult to fully capture the constraints, market behavior, and frictions present in the real market. The raw outputs from AURORA are "over-optimal". This consequence manifests as the tendency for AURORA's simulated prices to be flatter (less volatile) than real market data (Figure 62). This benchmark illustrates how the top priced hours has difficulty capturing those prices seen in the real market. To account for scarcity pricing in the forecast, E3 applies a simplified post-processing step. The top 100 prices in each year are adjusted upwards based on a benchmark of 2018 AURORA raw outputs to real 2018 historical prices. The price duration curve of scarcity adjusted prices in 2032 are presented in Figure 63.

Figure 62. Price duration curve of AURORA simulated day-ahead energy prices in 2032 compared against 2018 historical day-ahead energy prices

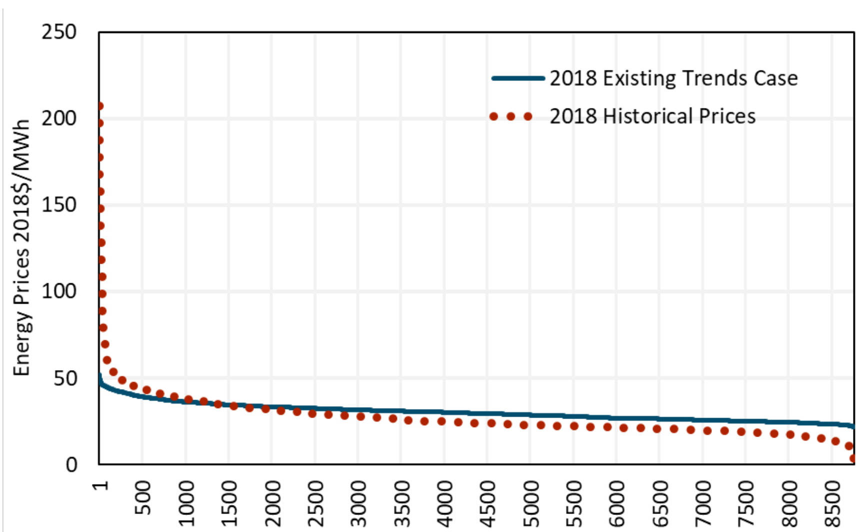
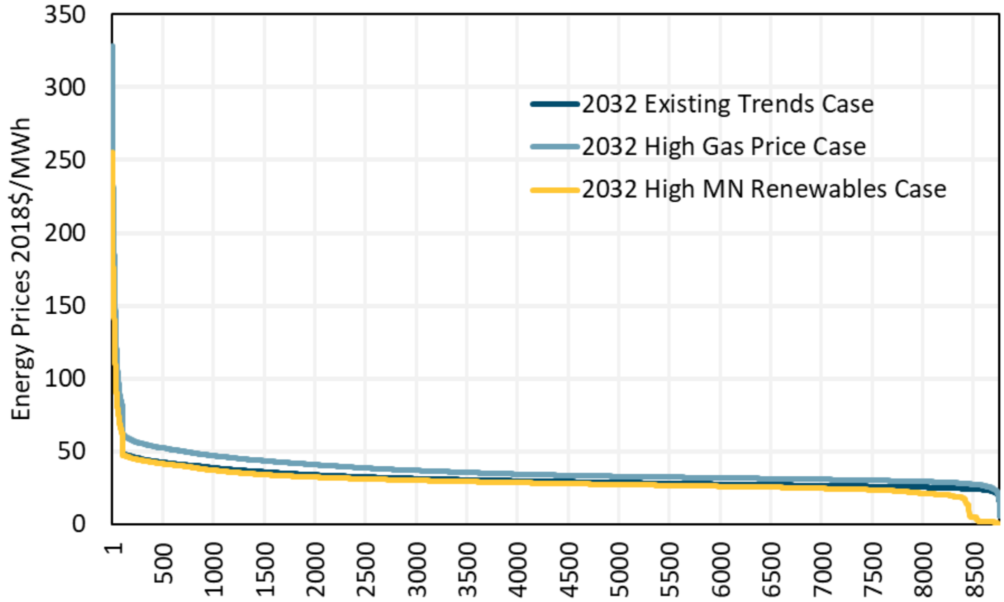
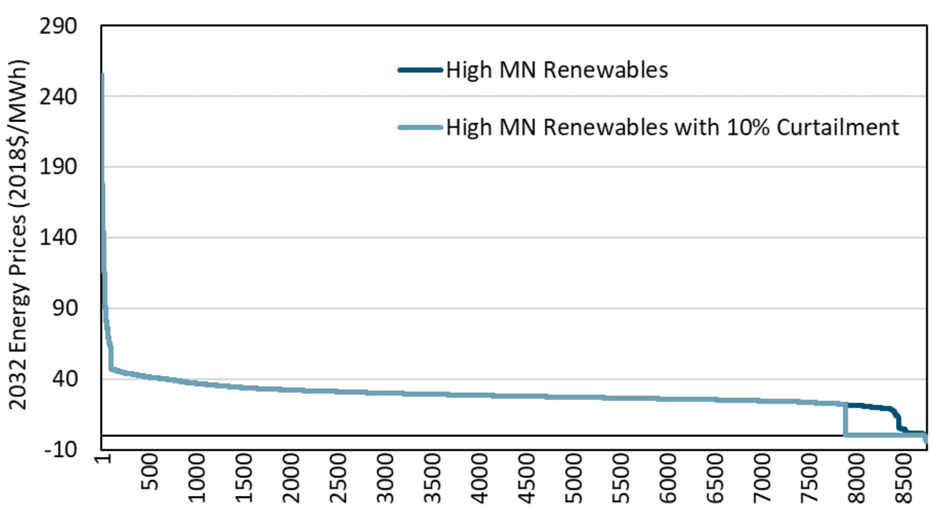


Figure 63. Scarcity adjusted day-ahead energy prices in 2032



Additional sensitivities were conducted to study the impacts when the frequency of renewables on the margin increases to 10%, setting prices in these hours to zero. Energy prices were manually adjusted so that those in the lowest 10th percentile in each year reflect energy prices set by renewables units on the margin, as demonstrated in Figure 64. This assumes that these lowest priced hours are also the most impacted by the downward pressure of increasing renewable production. Specifically, negative prices in the raw data are retained while positive prices in the bottom 10th percentile are set to 0. The instances of negative prices are low; less than 20 instances are observed in the most aggressive case (2032 High Minnesota Renewable scenario).

Figure 64. Price duration curve of day-ahead energy prices with the scarcity and curtailment sensitivity modification

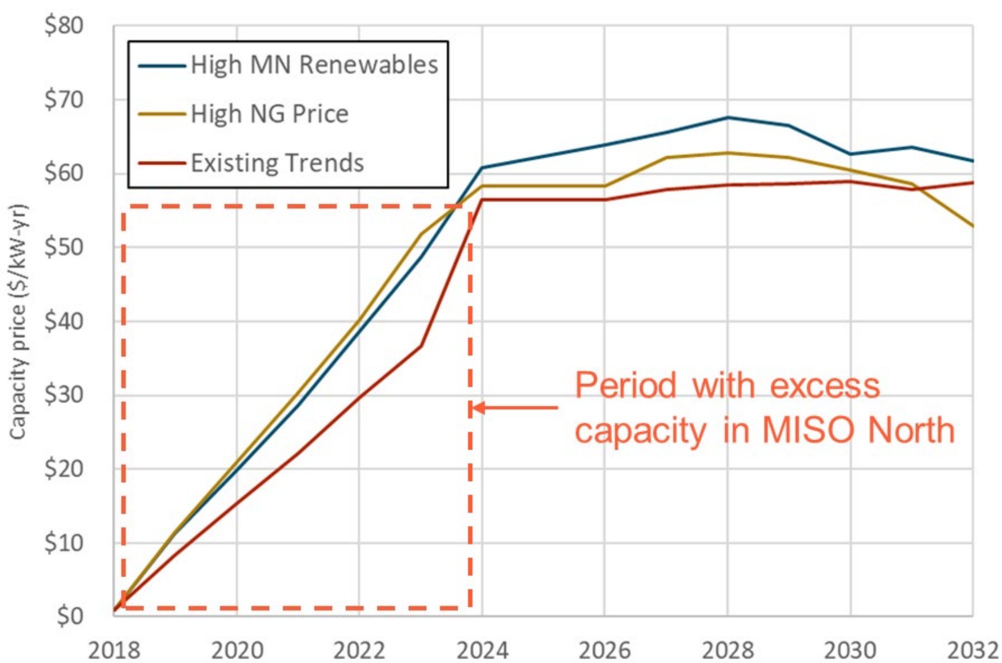


Capacity Value

Future capacity prices for Minnesota are estimated based on the cost of new entry (CONE) for a new capacity resource and the revenues it can earn from the market.

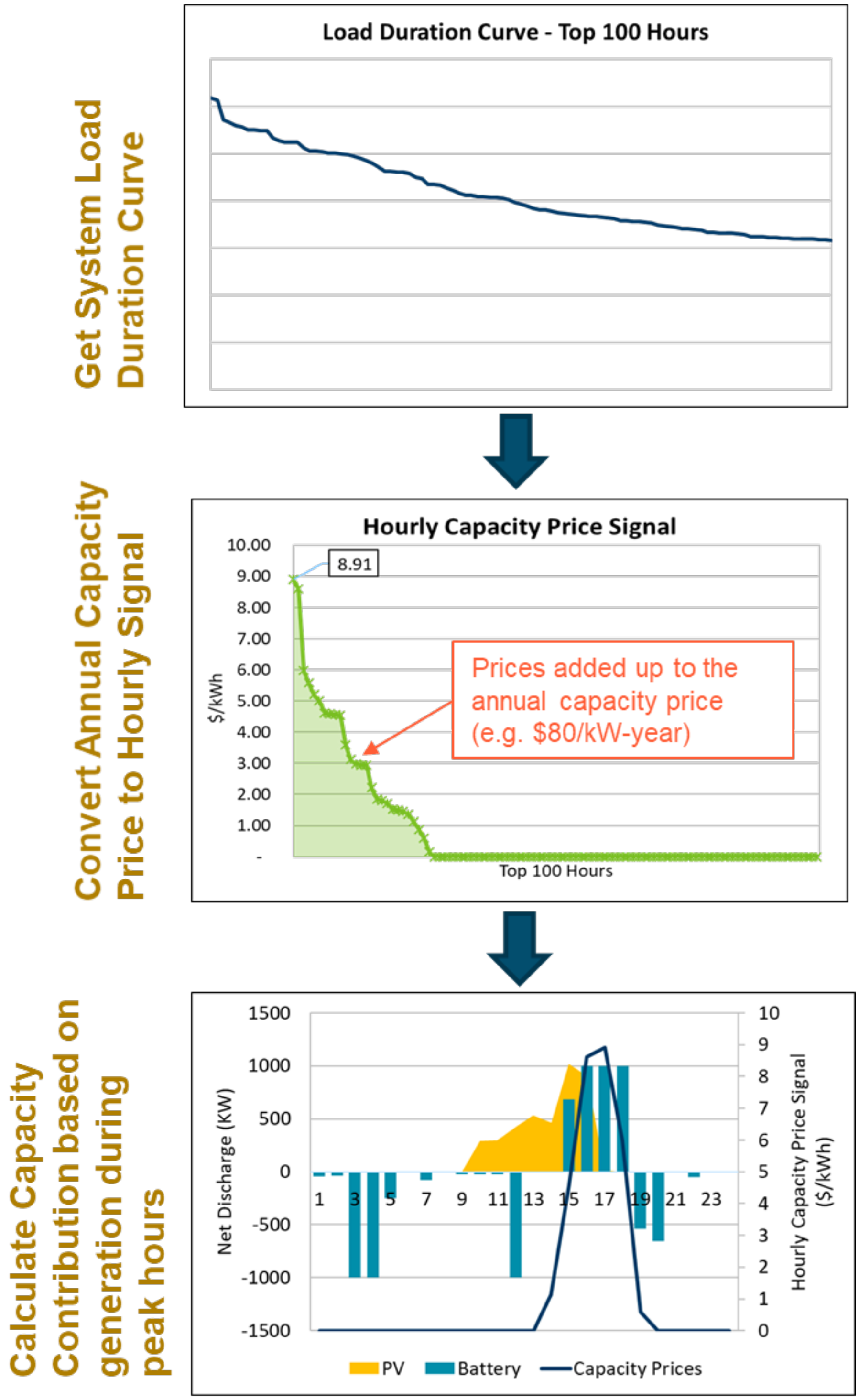
MISO North is estimated to be long on capacity until the retirement of coal generation midway through the 2020s (as detailed in Xcel's 2018 Upper Midwest Integrated Resource Plan). New capacity will be needed past this point. Following the conventional regime, E3 assumes that the marginal capacity resource is a "brownfield" Frame CT. Capacity prices are derived from the CONE of a CT, net of the expected energy revenue. AS revenue is assumed to be negligible for CTs and is not included. Historical prices are linearly increased to meet the project CT net CONE in the resource balance year of 2024 (highlighted in Figure 65). From this point forward, capacity prices are set at the net CONE.

Figure 65. Derived capacity prices by year



After the annual capacity values are estimated, RESTORE takes in the annual price and allocate it to each hour depending on how peaky the load is in that hour. Peak hours get allocated with higher hourly capacity prices. During optimization process, energy storage is dispatched against the capacity prices along with other available value streams (e.g. energy prices, regulation prices). The model will discharge the batteries during peak hours if providing capacity value is more valuable than other services. Finally, the capacity values for solar and energy storage are calculated based on their generation during peak hours. The figure below illustrates the process above with examples. This method assumes the system operator has perfect knowledge and total control of the storage system, and thus renders a theoretical maximum total value that can be provided by energy storage

Figure 66. Capacity value accreditation in RESTORE



Regulation, Spinning, and Supplemental Reserve Value

Future ancillary services (AS) prices are estimated based on both the forecasted AURORA energy prices and the trends we observed from historical prices.

Ancillary services (AS) markets dominated by conventional power systems have historically had thermal units being the primary provider of ancillary services. The AS bids of these units generally reflect the opportunity cost of holding back from the energy markets. Historical data under conventional regimes has shown a strong correlation between wholesale energy prices and AS prices, as seen in Figure 68.

AURORA's energy price forecasts suggest that the energy market in MISO North remains dominated by marginal gas units through 2032. Given this, it is assumed that historical will likewise hold. The E3's methodology utilizes the hourly implied heat rate as the basis from which the relationship between historical 2018 AS prices to energy prices are calculated. This relationship is then used to derive the future AS prices based on AURORA's forecasted energy prices. Average regulating reserve prices are presented in Figure 67. As expected, the final forecasted AS prices trend with wholesale energy prices (Figure 67 serves as an exemplification).

Figure 67. Average regulating reserve prices by year and by scenario

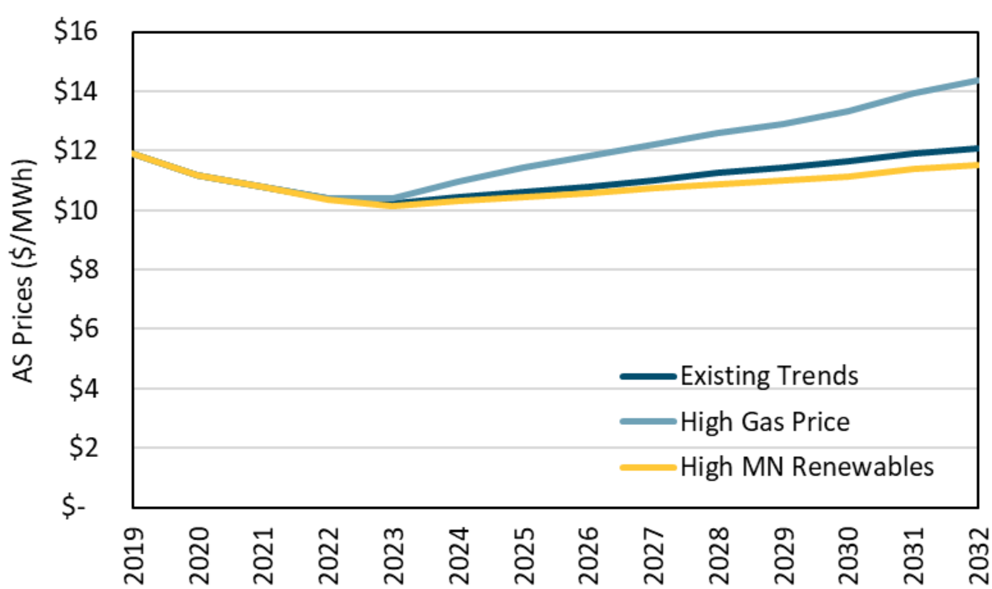
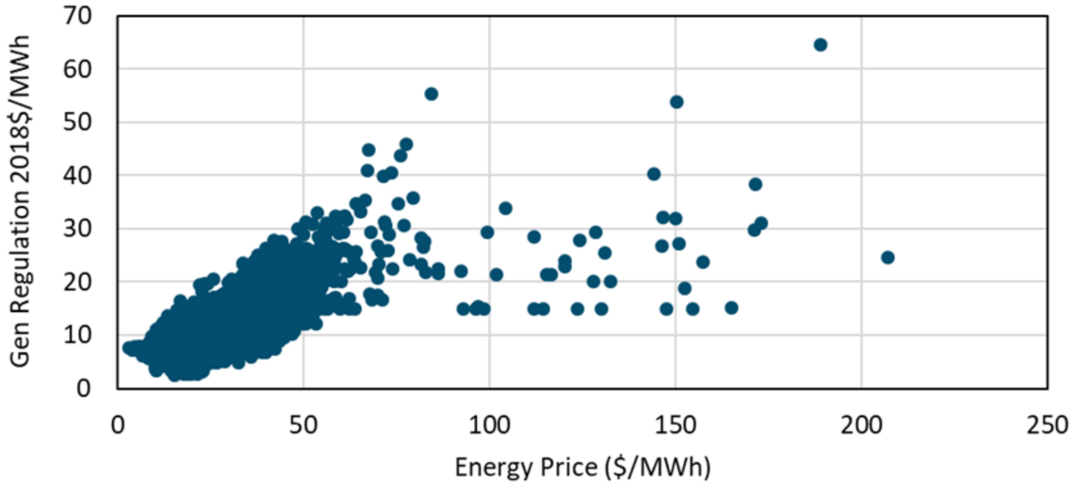


Figure 68. Historical regulation prices vs. historical energy prices in 2018



Real-Time Potential Value

To estimate the potential real-time values, E3 simulated the optimal operations of energy storage under 2018 historical day-ahead and real-time prices. The additional values the battery can earn from the real-time market compared to the day-ahead market is used as an estimate for future real-time potential value adders. Values are shown below.

Table 4. Real-time potential value adders

Battery Duration	1-hour	4-hour
Value ($/kW-yr)	6	16

Congestion Reduction Value

To estimate the value provided by energy storage when located in a congested area, we examined a storage operating at a congested node on today's grid. We selected the congested SMP.OWEF node in Southeast Minnesota the analysis.

Distribution Upgrade Deferral

The deferral values of the DER are the costs differences in the net present value of the T&D capacity project before and after the DER installation. The distribution upgrade deferral values are estimated based on the distribution upgrade identified for non-wires alternative in Xcel's 2018 IDP (Xcel Energy, 2018). The conventional upgrade solution is estimated at $2.5 million. E3 uses the following assumptions for revenue requirement and O&M assumptions for this conventional upgrade.

Table 5. Distribution upgrade assumptions

Items	Value
Distribution upgrade capital cost	2.5 Million
Revenue requirement multiplier	1.6
Operation and Maintenance	2% of the capital cost/year
Inflation Rate	2%
Book life	20 years

Appendix D: Data Sources

Battery and solar cost parameters mainly come from the E3 WECC Pro Forma (Energy and Environmental Economics. Inc, 2019), which sources primarily from the 2019 NREL Annual Technology Baseline (ATB) (NREL, 2019) and Lazard's Levelized Cost of Storage 4.0 analysis (Lazard, 2018), and cost decline projections for storage mainly come from the NREL document "Cost Projections for Utility-Scale Battery Storage" released in July 2019 (Cole, 2019). The E3 WECC Pro Forma was developed to estimate all-in resource costs for the Western Electricity Coordinating Council (WECC). Our assumptions are described in detail in the tables below.

Table 6. Li-ion battery assumptions for front-of-the-meter storage

Description	Assumption	Source	Notes
Upfront cost	2020: $173/kW + $280/kWh (2018$)	E3 WECC Pro Forma (Energy and Environmental Economics. Inc, 2019), sourced from Lazard LCOS (Lazard, 2018) and using NREL "Mid" cost decline projections (Cole, 2019)	The effective cost per kWh ($323.25/kWh) is similar to the $330/kWh assumed in the NREL cost projections document. We used the Pro Forma version in our final results so that we could also model a 1-hour battery, as NREL only gives $/kWh for a 4-hour battery.
	2025, **Mid**: $130/kW + $211/kWh (2018$)	E3 WECC Pro Forma with NREL "Mid" cost decline projections	
	2025, **Low**: $96/kW + $157/kWh (2018$)	E3 WECC Pro Forma with NREL "Low" cost decline projections	
Fixed O&M	2020: $0.77/kW + $4.06/kWh (2018$), with 2% annual escalation	E3 WECC Pro Forma	
	2025 **Mid**: $0.58/kW + $3.06/kWh (2018$), with 2% annual escalation	E3 WECC Pro Forma	
	2025 **Low**: $0.43/kW + $2.27/kWh (2018$), with 2% annual escalation	E3 WECC Pro Forma	
Annual Warranty Extension Cost	1.5% of upfront costs; 2 yr initial warranty length	E3 WECC Pro Forma	
Annual Augmentation Cost	4.2% of $/kWh	E3 WECC Pro Forma	
Round-trip efficiency	85%	NREL Cost Projections document	Includes parasitic losses
Storage lifetime	20 years	E3 WECC Pro Forma; assumption from Lazard	
Cycling limit	365 cycles/year	E3 experience working with manufacturers	

Table 7. Utility-scale solar + storage assumptions (storage costs are same as above, except ITC is included)

Description	Assumption	Source
Solar upfront costs	$1,444/kW-ac in 2020 (2018$)	E3 WECC Pro Forma, sourced from NREL ATB which reports mainly as kW-DC
Fixed O&M of solar	$17/kW-yr in 2020 (2018$), 2% annual escalation	E3 WECC Pro Forma
Lifetime	35 years	E3 WECC Pro Forma
Investment Tax Credit (ITC)	26% in 2020, with 95% of capital costs eligible	N/A

Table 8. Behind-the-meter solar + storage assumptions

Description	Assumption	Source
Storage upfront costs	$234/kW + $523/kWh in 2020 (2018$)	E3 WECC Pro Forma with NREL Cost Decline projections (cost decline projections are for utility-scale, but stuck with same projections for consistency)
Storage fixed O&M	$7.25/kW + $16.15/kWh in 2020 (2018$) plus 2% annual escalation	E3 WECC Pro Forma with NREL Cost Decline projections
Annual Warranty Extension Cost	1.6% of upfront costs, 2 yr initial warranty length	E3 WECC Pro Forma
Annual Augmentation Cost	5% of $/kWh	E3 WECC Pro Forma
Storage lifetime	10 years	E3 WECC Pro Forma
Solar upfront costs	$2,182/kW in 2020 (2018$)	E3 WECC Pro Forma, from NREL ATB, for “Solar - Commercial”
Solar fixed O&M	$22/kW in 2020 (2018$) plus 2% annual escalation	E3 WECC Pro Forma
Solar lifetime	35 years	E3 WECC Pro Forma
Investment Tax Credit (ITC)	26% in 2020, with 95% of capital costs eligible	N/A
Cycling limit	365 cycles/year	E3 experience working with manufacturers

Table 9. Financial assumptions

Description	Assumption	Source
Front-of-the-meter Li-ion battery financing assumptions	18 year debt period, 9.13% WACC, 4.73% Debt Cost, 20% Debt Fraction	E3 WECC Pro Forma for Independent Power Producer (IPP)
Utility-scale solar in solar+storage case financing assumptions	20 year debt period, 7.18% WACC, 4.73% Debt Cost, 40% Debt Fraction	E3 WECC Pro Forma for Independent Power Producer (IPP)
BTM solar financing assumptions	20 year debt period, 7.18% WACC, 4.73% Debt Cost, 40% Debt Fraction	E3 WECC Pro Forma for Independent Power Producer (IPP)
BTM storage financing assumptions	8 year debt period, 9.13% WAC, 4.73% Debt Cost, 20% Debt Fraction	E3 WECC Pro Forma for Independent Power Producer (IPP)
Tax rate	21% federal + 9.8% Minnesota = 30.8%	N/A
Depreciation schedule	7-year MACRS for standalone storage, 5-year MACRS for solar+storage	Federal tax code

Table 10. Aurora data sources

AURORA Data	Description	Source
Annual Load	Total demand and peak demand expected in each year	2018 NREL Electrification Study (Jadun, et al., 2017), Moderate Advancement, Medium Adoption
Load Shape	Hourly demand shape	AURORA default database[16]
Natural Gas Prices	Delivered gas prices seen by generators. E3 relies on gas futures compiled by S&P Global for near-term gas forecasts (2020-2023) and derives long-term gas forecasts from the EIA AEO.	S&P Global Gas Price Futures[17], 2018 EIA AEO (U.S. Energy Information Administration (EIA), 2018)
Coal Prices	Delivered coal prices seen by generators	AURORA default database
Generation Portfolio	Existing units in each zone and their associated operational constraints	AURORA default database
Transmission Network	Flow capacity, wheeling charges, and line losses	AURORA default database
New Generation Portfolio	New generation that is expected to come online in future years	Developed in conjunction with the MN Department of Commerce
Wind Generation Profile	Expected wind production in each hour as a fraction of the capacity	AURORA default database
Solar Generation Profile	Expected solar production in each hour as a fraction of the capacity	AURORA default database

[16] Energy Exemplar, the developer of the software tool AURORA, maintains default databases for usage in modeling simulations by subscribers to their modeling license.

[17] S&P Global curates data relevant to the energy sector on its "Market Intelligence" platform. These data are made available to subscribers.

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Definition of Terms and Acronyms

Term	Definition
AGC	Automatic Generation Control
BTM	Behind-The-Meter
CCGT	Combined Cycle Gas Turbines
CONE	Cost of a New Entry
CT	Combustion Turbine
E3	Energy and Environmental Economics, Inc.
FERC	Federal Energy Regulatory Commission
FTM	Front-Of-The-Meter
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
MISO	Midcontinent Independent System Operator
MN	Minnesota
MTEP18	MISO Transmission Expansion Plan 2018
NOx	Nitrogen Oxide
PCAF	Peak Capacity Allocation Factors
PCT	Participant Cost Test
PV	Photovoltaics
RPS	Renewable Portfolio Standard
SOx	Sulfur Oxide
TOU	Time-of-Use
TRC	Total Resource Cost

Term	Definition
Ancillary Services	The services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. In MISO, ancillary service products include regulation, spinning reserve, and non-spinning reserve.
Energy Arbitrage	The practice of purchasing electricity from the electricity grid when it is cheap, and storing it for later use when grid electricity is expensive.