



Energy+Environmental Economics

MN Storage Cost-Benefit Analysis Draft Results Review

In-person Workshop

10/11/2019

Arne Olson, Senior Partner
Gabe Mantegna, Consultant



Agenda

- + 9:05am-9:50am: **E3 presentation on study background, methods, and market prices**
- + 9:50am-10:00am: **Break**
- + 10:00am-10:30am: **E3 presentation on draft results**
- + 10:30am-10:50am: **Questions for E3**
- + 10:50am-11:00am: **Break**
- + 11:00am-11:50am: **Panel discussion**
- + 11:50am-12:00pm: **Closing comments from E3**



Energy+Environmental Economics

Introduction



Project Overview

- + This study is made possible by legislation* passed in 2019
- + E3 is working with the Department of Commerce to conduct an independent analysis of the potential costs and benefits of energy storage systems in Minnesota
- + A public report will be produced to summarize the findings
- + **Tasks:**
 - **Cost-Benefit Analysis**
 - Identify use-cases for modeling
 - Each use case discussed previously will be modeled
 - AURORA production simulation modeling
 - RESTORE Storage cost and benefit modeling
 - **Stakeholder Engagement**
 - **Final Report**
 - Case studies
 - Final report
 - **Presentations to the Minnesota Legislature**



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



The value of energy storage in Minnesota

- + As we look to integrate high levels of renewables into the electric grid, energy storage will become necessary to fill the gaps between supply and demand**
 - In the long term, storage will charge from surplus renewable energy, and discharge when renewable generation is insufficient
- + Utilities in Minnesota have considered storage in their resource plans, but have not included them in their preferred plans**
- + Utility-scale storage is a fast-growing market, but current economics depend on a variety of factors including policy support, expectations of future cost declines, and potential sources of revenue/value**

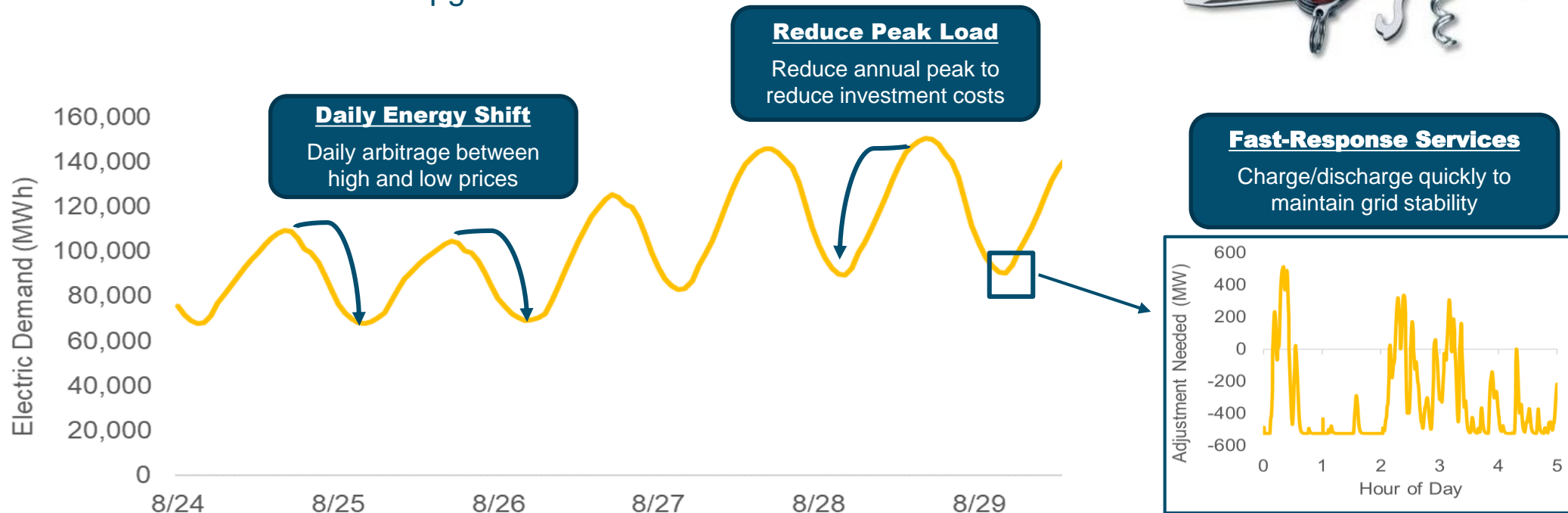




Where does storage get its value from the grid?

+ Storage can provide a very broad set of grid services but not all at the same time

- Renewables integration through energy arbitrage
- Ancillary services / grid balancing
- Peak capacity
- Transmission & distribution upgrade deferral

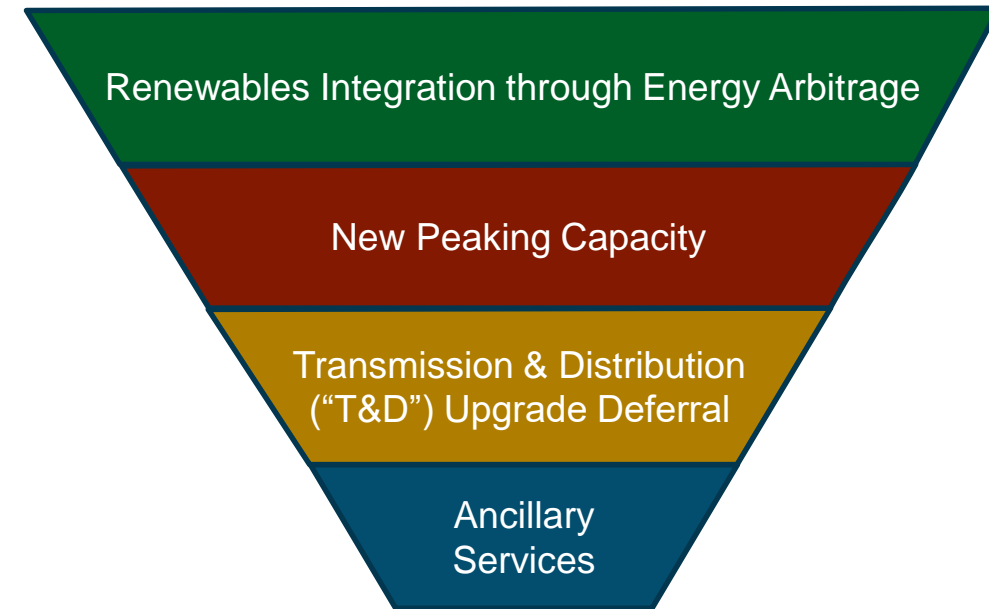


Example hourly load in the PJM market (Mid-Atlantic, OH, and parts of KY, IN, MI, and IL) in 2018 during a time period that covers the annual peak load



Storage value streams: what makes each one cost-effective?

- + Each of the value streams for storage has different necessary conditions for it to be cost effective
- + Renewables integration is less of a problem in the near term for Minnesota due to being well-connected to the rest of MISO
- + What are the near-term opportunities for storage then?





Ancillary Services

+ Ancillary Services (AS) refers to the resources needed for short-timescale grid balancing

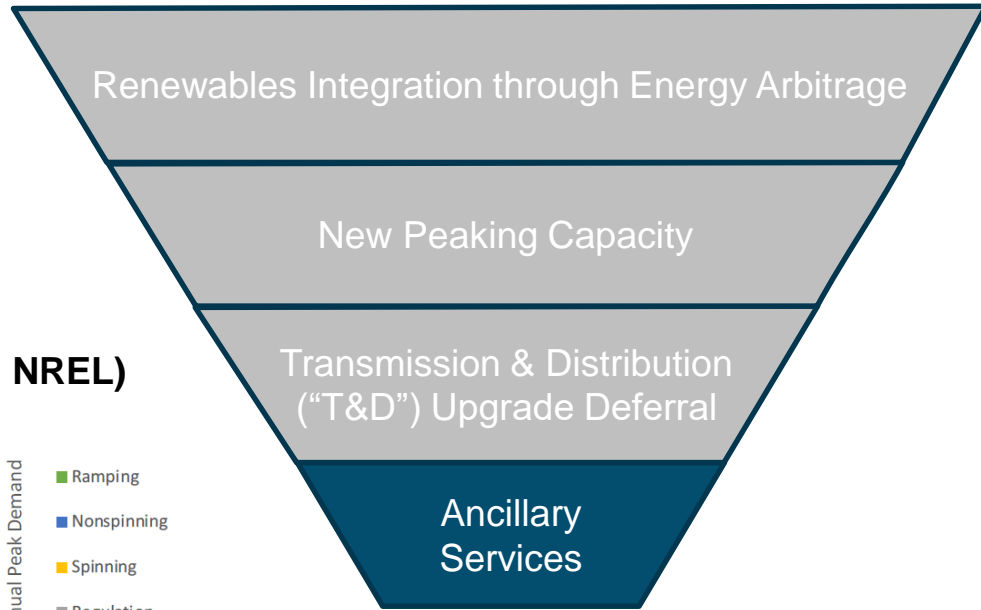
- A subset of generators are always kept on standby in case of unexpected generator outages, or different load than expected
- Storage is well-suited to provide these services due to its near-instant response time

+ Conditions that make participation in AS markets cost-effective for storage

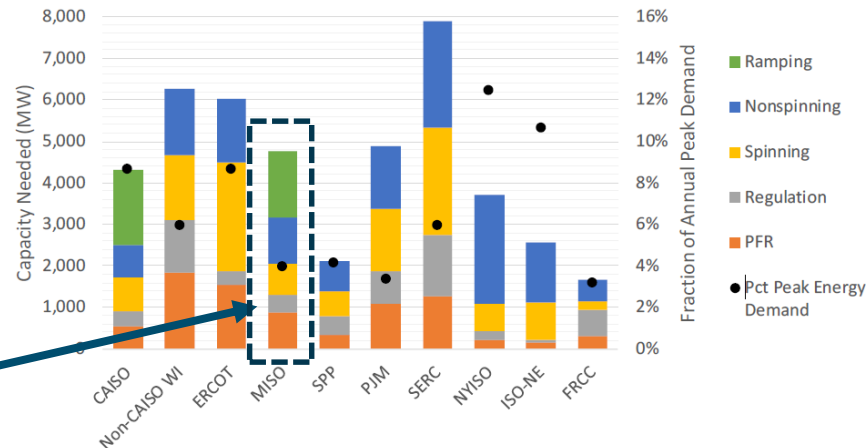
- High prices, e.g. PJM
- Storage-friendly market design
- Low market saturation

+ Total market size is small

+ Battery degradation can be an issue due to frequent cycling



Reserve market size by ISO (source: NREL)



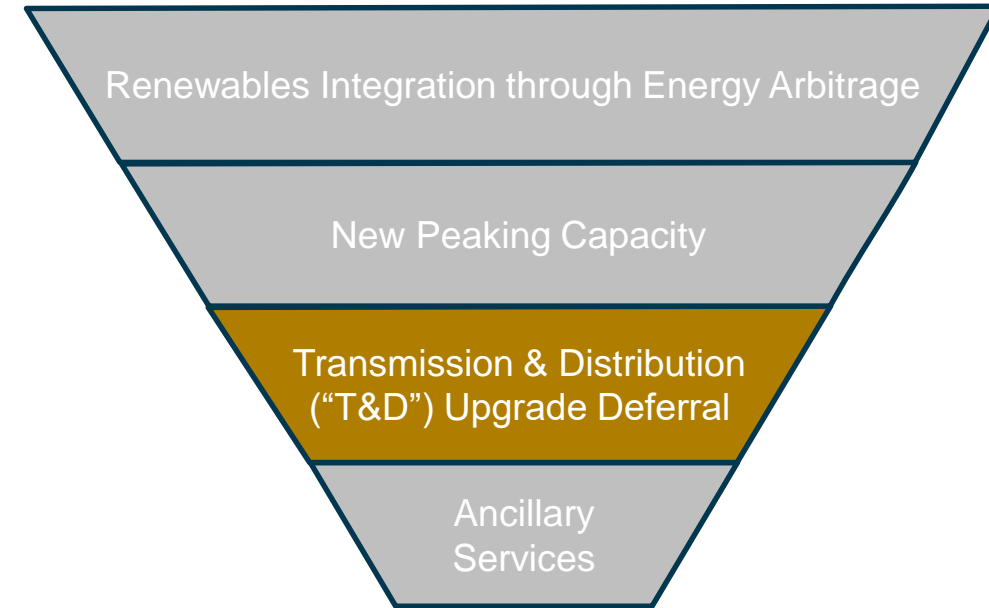
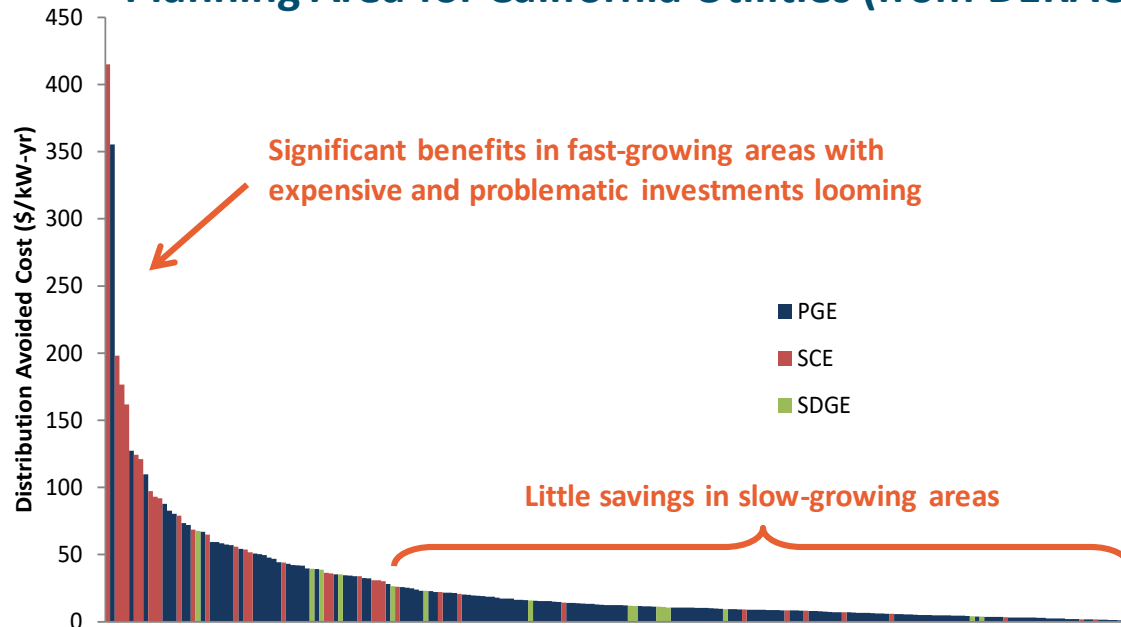
Regulating reserves, the most valuable in MISO, are only a ~400 MW market



T&D Upgrade Deferral

- + Every planning cycle, utilities and system operators identify which transmission lines and feeders have the potential to be overloaded, and make plans to build the necessary upgrades and/or add new capacity

Distribution System Avoided Costs by Distribution Planning Area for California Utilities (from DERAC)

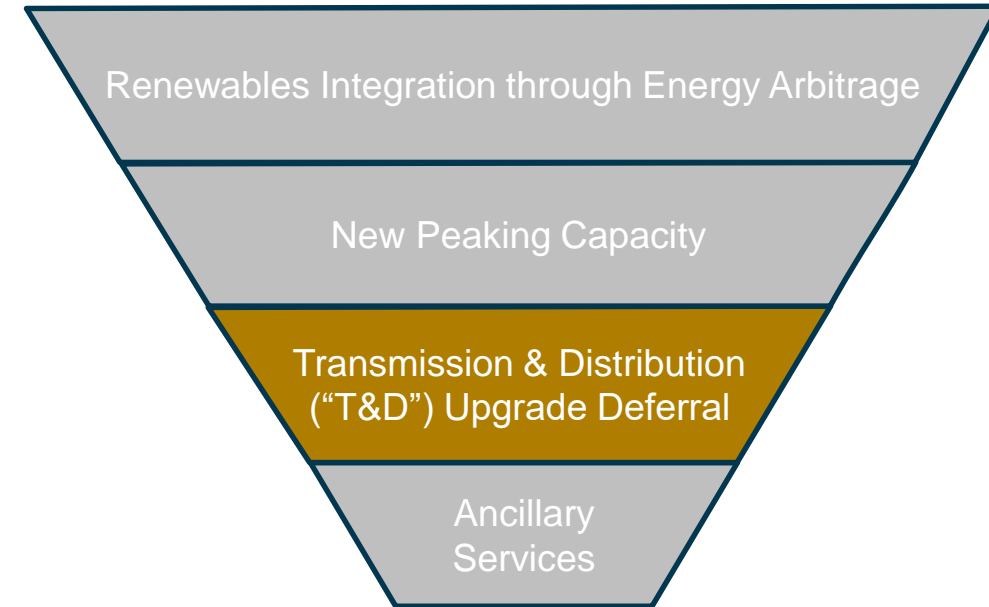




T&D Upgrade Deferral

- + **Sometimes, energy storage has the potential to defer T&D upgrades, by charging and discharging to prevent congestion or overloading**
 - Energy storage is one of many “non-wires alternatives” to expensive T&D upgrades

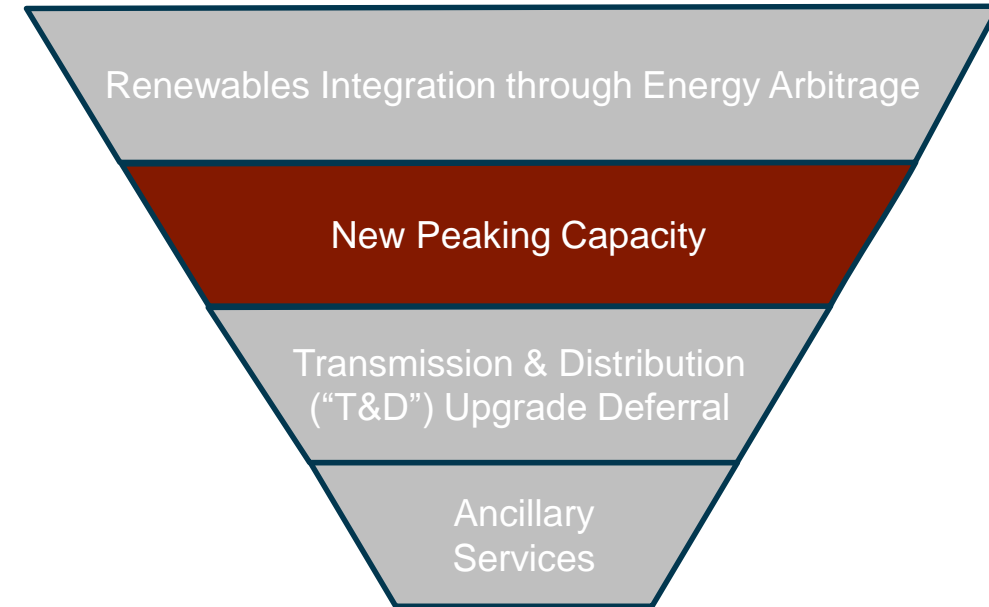
- + **Conditions that make this a cost-effective use case for storage:**
 - Expensive T&D upgrade alternative
 - Low load growth
 - Short duration of overload potential (i.e. only a few hours throughout the year that have the potential to overload a feeder)





New Peaking Capacity

- + **Minnesota is one of many areas that has identified a need for new “peak capacity” due to load growth, coal retirements, and renewable energy balancing needs**
 - Peak capacity is provided by a number of resources such as natural-gas fired combustion turbines (CTs)
- + **Given recent cost declines, storage is increasingly cost-competitive with CTs for providing new peaking capacity**



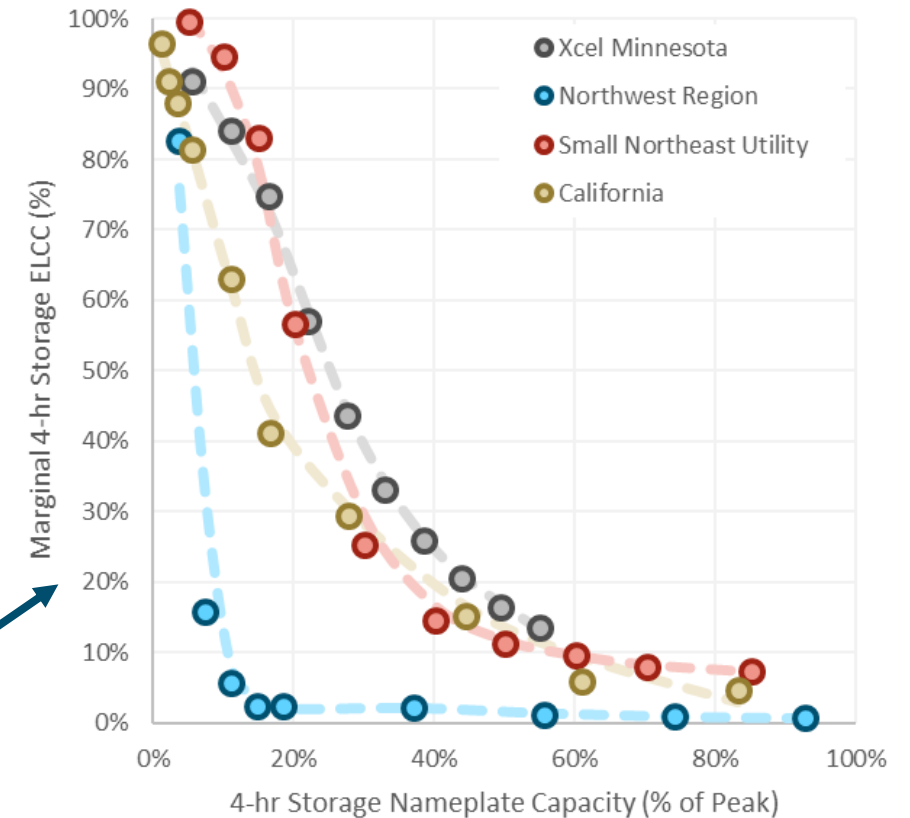


New Peaking Capacity

+ What are the conditions where this is a cost-effective use case?

- Short duration and low frequency peaking capacity need- i.e. peak hours don't last very long, and don't happen very often
- High capacity price
- Possible local air quality benefits (although a net CO2 increase in the near term)

+ As storage penetration increases, effective capacity contribution decreases



Data Sources

Xcel Minnesota: [Upper Midwest 2019 IRP Support](#)

Northwest Region: [Resource Adequacy in the Pacific Northwest](#)

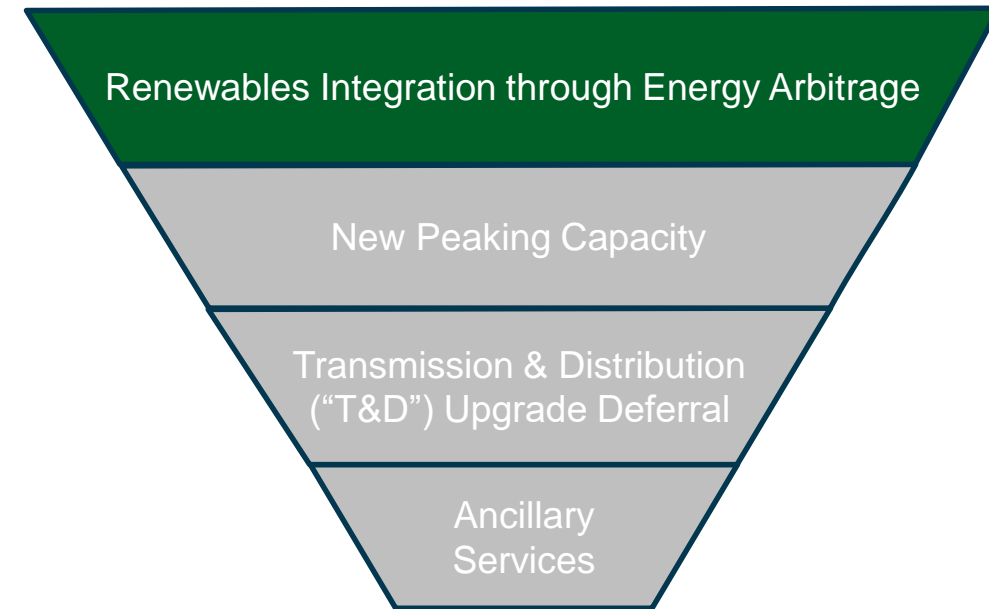
Small Northeast Utility: confidential internal analysis

California: internal E3 analysis



Energy Arbitrage

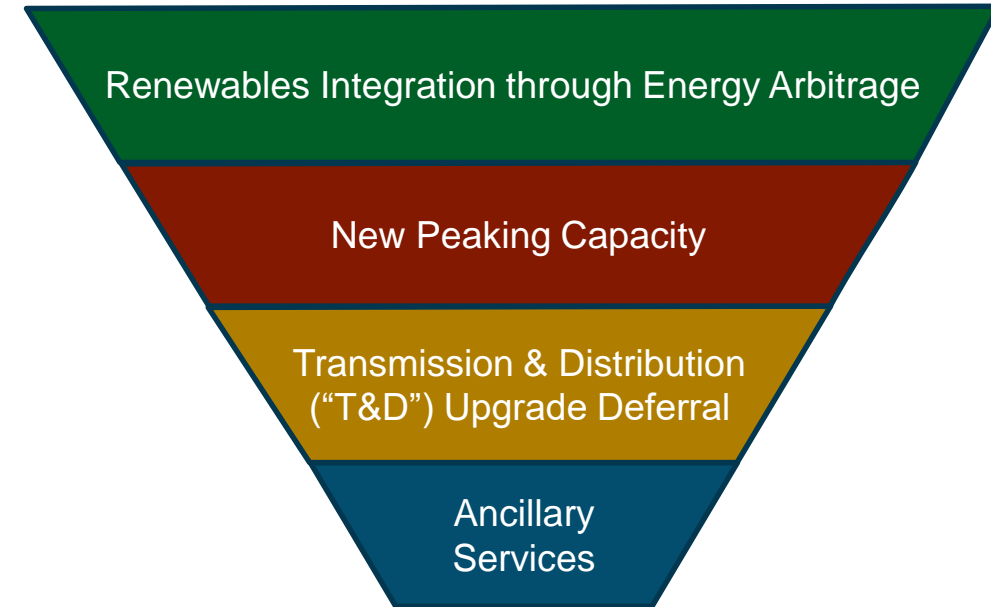
- + Buying “low” or charging and selling “high” or discharging is an obvious use case for energy storage
- + In organized markets like MISO this is how storage will facilitate renewable integration by charging when there is excess renewable generation, and discharging when renewable generation is scarce
- + For storage to contribute to renewable integration, there needs to be curtailment (surplus renewables) that storage can help avoid
- + What are the conditions that make energy arbitrage cost-effective?
 - Large differentials in energy prices
 - High penetration of renewables
 - Concentration on solar rather than wind (matches better with diurnal energy storage cycle)
 - Low transmission capability to “average” renewables over a larger area





Key Takeaways for Minnesota

- + There is a valuable ancillary services market in MISO
- + Some potential for deferring upgrades to distribution feeders and transmission lines
- + Potential for much higher capacity prices in the next 10-20 years
 - Need identified for new peaking capacity to accommodate load growth and coal retirements
- + As virtue of being connected to MISO there is good flexibility with integrating higher levels of wind and solar in the near term
 - Low energy arbitrage opportunity in the near term which will increase in the future with greater renewable penetration





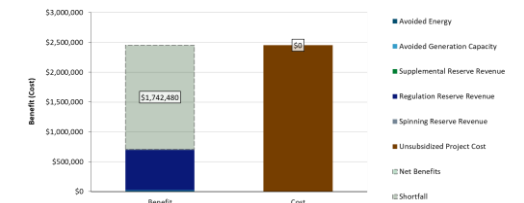
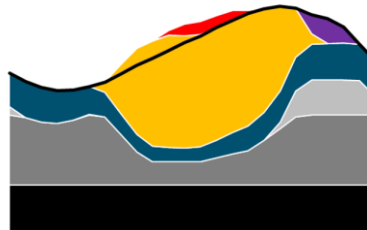
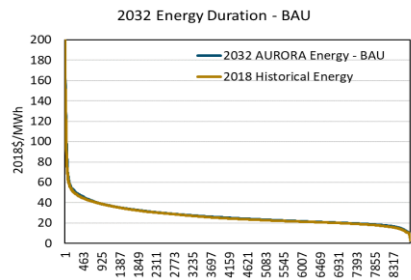
Energy+Environmental Economics

Valuation Methodology



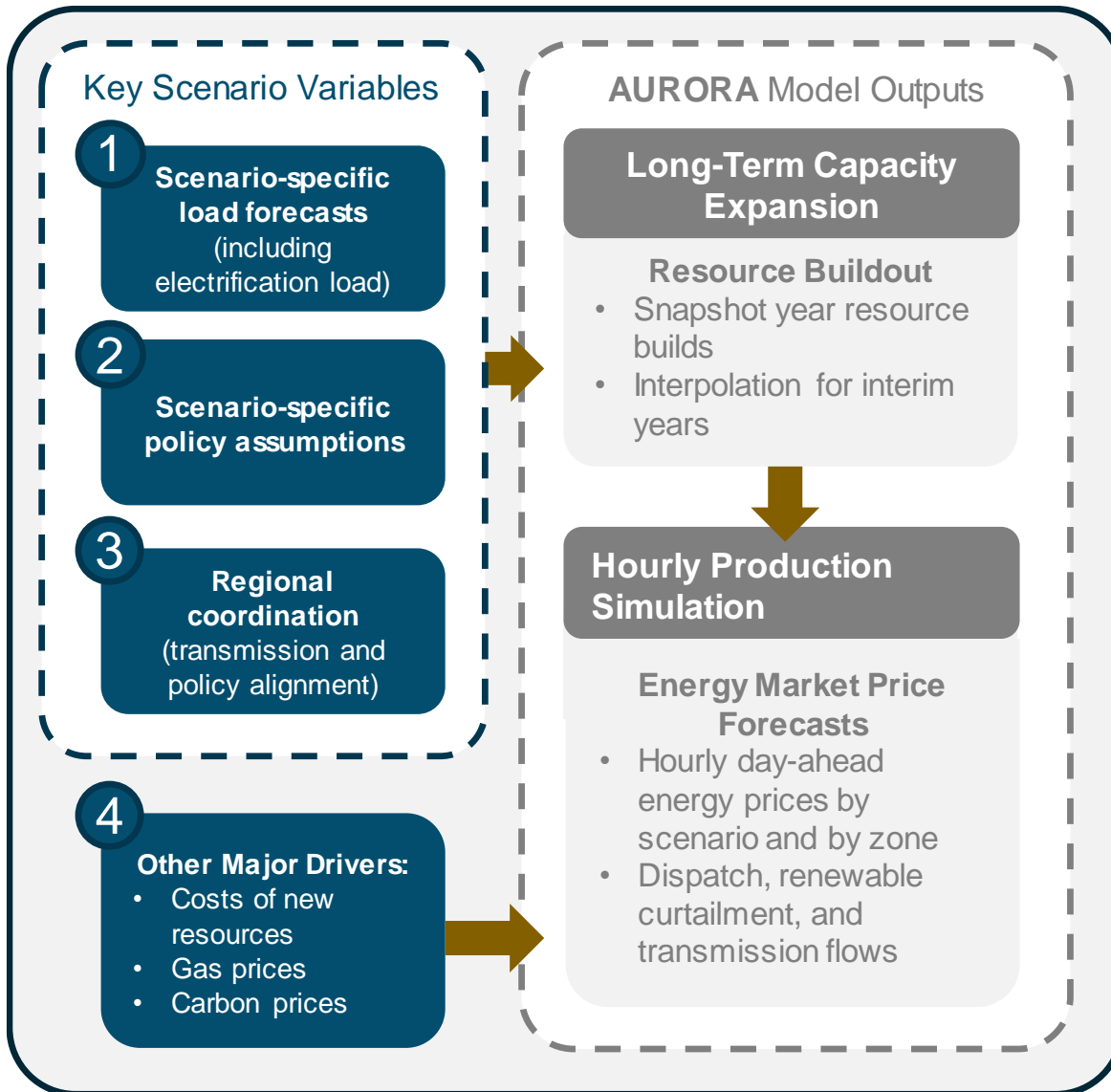
Overview of valuation methodology

- + Determine projected value of storage using forecasted price streams and cost declines- not just current prices





Visualization of E3's market price forecast modeling approach

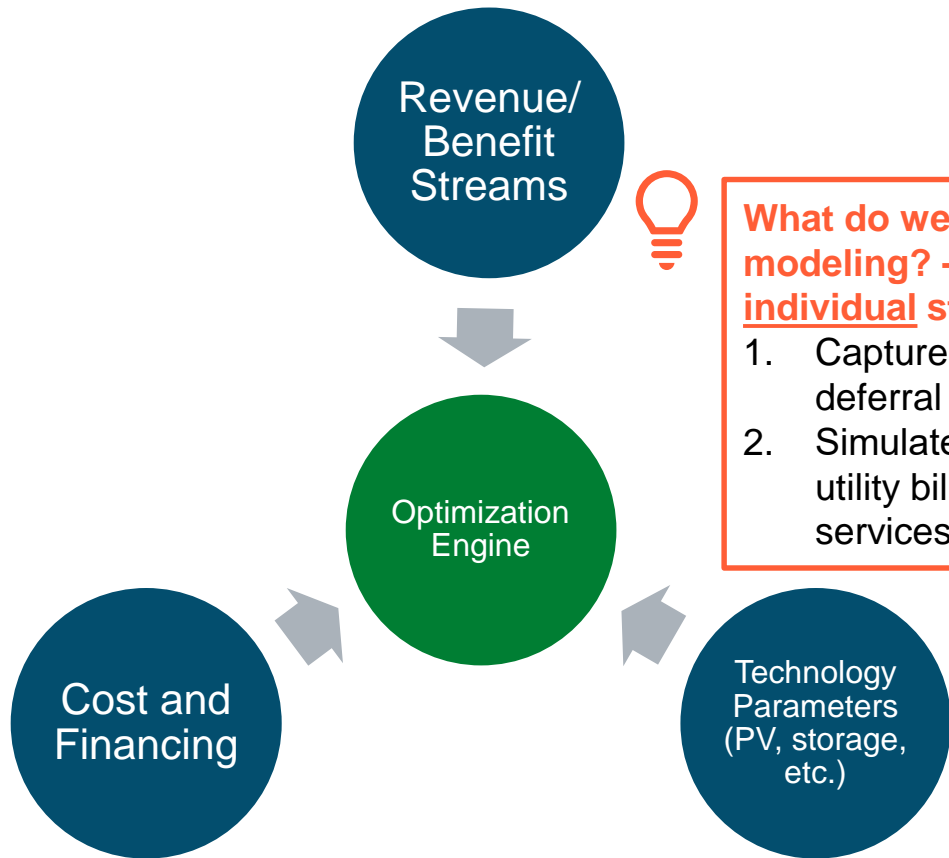


What can we learn from the AURORA results?

1. Future system operations and build out under different policy and prices scenarios
2. Expected storage installation in MWh and the values of the selected storage portfolio



+ A E3 in-house storage valuation tool with an optimization engine for dispatch



What do we learn from RESTORE modeling? - The cost-effectiveness of individual storage projects:

1. Capture the locational values: T&D deferral and congestion relief
2. Simulate owners' specific use cases: utility bill management, emergency services, and power quality

Results

- NPV and annual benefits and costs
- Cost tests
- DER optimal dispatch
- ...

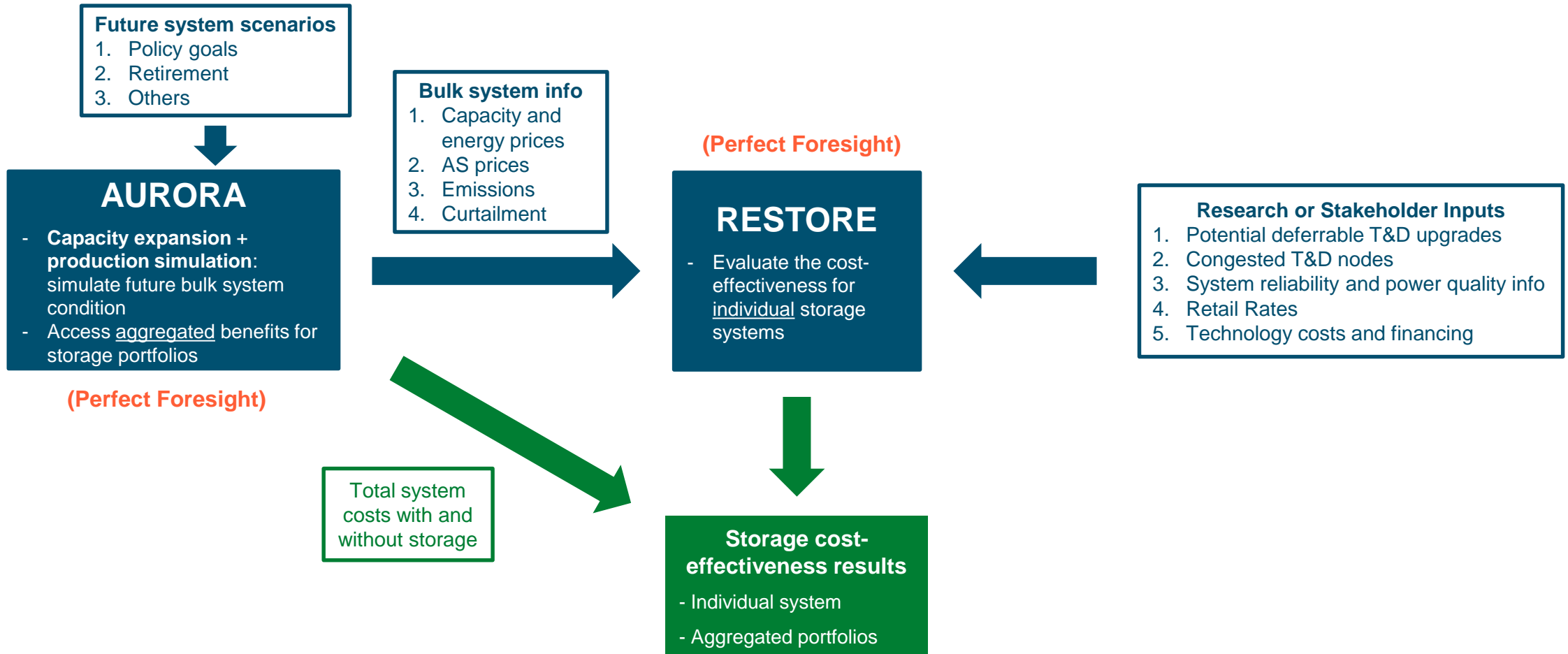
The charts show the following data:

- Hourly Dispatch:** A bar chart showing kWh/MWh for SOC (left axis, -150.00 to 150.00) and price (\$/MWh) (right axis, 0.00 to 0.06) over 24 hours. The dispatch is positive during peak hours (10-18) and negative during off-peak hours (19-24).
- Benefit and Cost:** A stacked bar chart comparing Benefit and Cost. The Benefit bar is composed of blue, green, and red segments. The Cost bar is a single green segment with a value of \$52,995.
- Annual Benefit (Cost):** A bar chart showing annual Benefit (Cost) from 2018 to 2038. The y-axis ranges from 0 to 30,000. The bars show a general upward trend in benefit over the period.



Cost-Benefit Analysis Framework

+ A production simulation model, AURORA, and an E3 in-house storage dispatch and cost-benefit analysis tool, RESTORE, are used in the project





RESTORE Optimization Algorithm

- + **Objective function: minimizing net costs**
 - Subject to technology and market constraints
 - Hourly or sub-hourly resolution
 - Daily, weekly, monthly, or annual optimization windows
- + **Co-optimize multiple benefit streams with perfect foresight**
- + **Price taker: storage operation has no impact on market prices**

Bulk System

- Resource adequacy program
- Wholesale energy market
- Ancillary services revenue
- Project specific transmission deferral
- Renewable firming services

Distribution System

- Project specific T&D deferral
- Interconnection costs reduction
- Reliability
- System avoided costs or Bulk system revenues

Customer sided

- Demand charge management
- TOU energy charge management
- Utility Program Revenue (e.g. DR program)
- Back-up power



Storage Market Participation Assumptions

- + Assume storage is dispatched with perfect foresight for energy prices, ancillary services prices, and timing for resource adequacy calls
 - Price-taker; no simulation of potential bidding strategies
- + Value stacking: energy storage can be compensated for both generation and ancillary services provision in the same period as long as the capacities allocated to each do not overlap and energy storage has sufficient SOC to cover both services
 - For example, if the battery is committed to provide 1 MW regulation and 1 MW energy in the market, the model makes sure 1) the discharge limit is > 2 MW, and 2) the remaining battery SOC is able to discharge and fulfill the regulation bid even if it is called at the bid capacity for the whole hour; so the SOC is required to be $\geq (1\text{MWh} + 1\text{MWh} + \text{efficiency losses})$ and has at least 1 MWh head room to provide regulation down.
- + **Modeled values:**
 - DA market: energy and ancillary services (we do not model ramp reserve)
 - RT sensitivities: energy



AURORA Scenarios

+ Three scenarios:

1. Existing Trends
2. High Natural Gas Price
3. High Minnesota Renewables

+ Existing Trends scenario uses capacity additions from MISO MTEP18 Limited Change Scenario

- 750 MW wind, 400 MW solar, 1,200 MW CCGT and 3,800 MW CT added linearly by 2032

+ High MN Renewables scenario features over 75% of load met by renewables by 2032

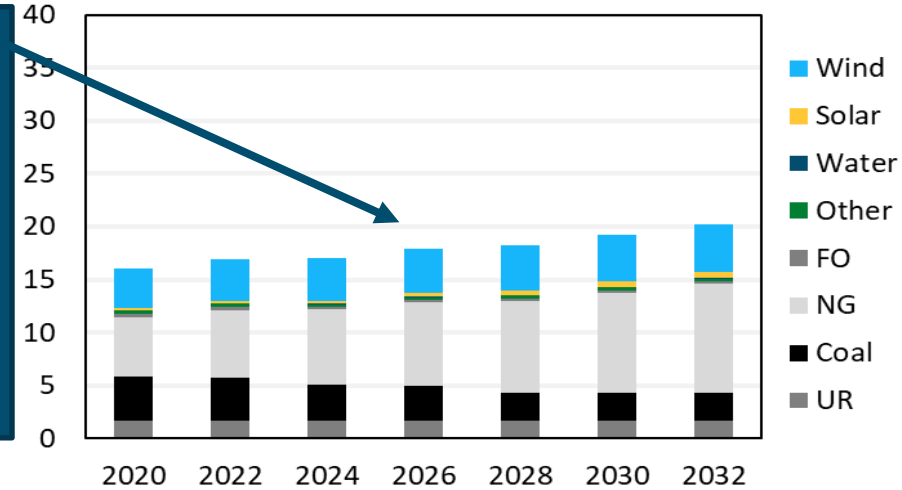
- All nuclear is relicensed
- Gas generation < 12% of load
- All coal is retired

+ High NG price scenario uses forecast from Xcel's 2018 IRP 'High Gas' assumptions

Generation mix stays largely the same in Existing Trends and High NG Price scenarios

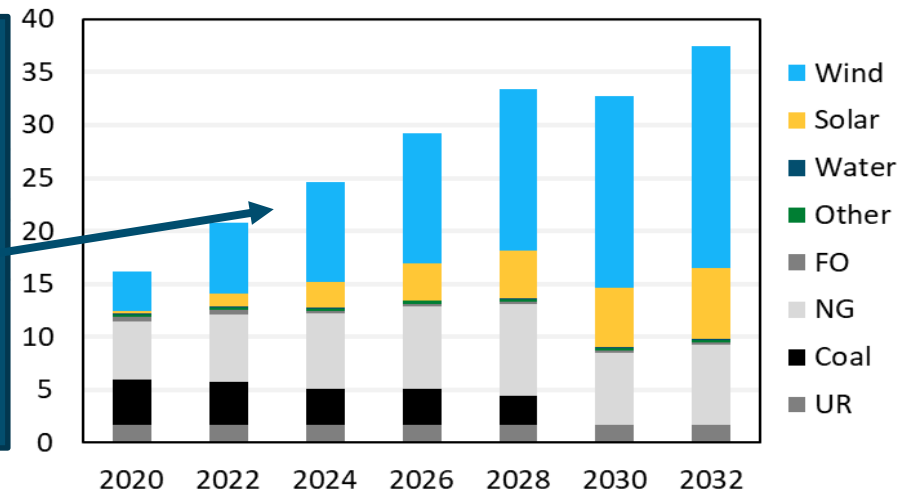
Existing Trends + High NG Price

MN Capacity (GW)



In High MN Renewables scenario, wind and solar ramp up quickly, and coal is retired

High MN Renewables





Use Cases

+ Proposed core use cases:

- Being able to access additional benefits reduces the opportunity to obtain the original benefits

Not a societal benefit unless retail rates are aligned with system values

Benefit Streams →

Use Cases	Wholesale			Transmission and Distribution				BTM
	Energy arbitrage	Avoided generation capacity	Ancillary services	Transmission congestion relief	Transmission & Distribution deferral	Emergency services	Power quality improvement	Bill savings
Wholesale standard ¹	✓	✓	✓					
Wholesale congestion relief	✓	✓	✓	✓				
Distribution deferral	✓	✓	✓		✓			
Emergency services	✓	✓	✓			✓		
Power quality	✓	✓	✓				✓	
BTM / Co-op bill savings	?	?						✓
PV paired with storage	✓	✓	✓					

1. Price signal for reducing GHG emission and curtailment is imbedded in the forecasted energy prices, thus there is no separate use cases for GHG emission and curtailment reduction.



Model Runs Summary

+ Core runs for the AURORA + RESTORE process (Installation year: 2020)

- The marginal prices produced by AURORA have an hourly resolution, can be viewed as the DA prices

Sensitivities

Use Cases / Storage Technology	Li-ion	Flow Battery	Wholesale Standard	Li-ion	Flow Battery
Wholesale standard	✓	✓	High Natural Gas Scenario	✓	
Wholesale congestion relief	✓		High MN Renewables Scenario	✓	
Transmission and Distribution deferral	✓		Real-time Market	✓	
Emergency services	✓		2025 installation	✓	✓
Power quality	✓				
BTM bill savings	✓				
PV paired with storage	✓				

+ Additional analysis

- Peaker replacement ability screening:** examine energy storage’s ability to provide the same services as the existing peaker fleet in MN by replicating the historical operations of the peaker fleet

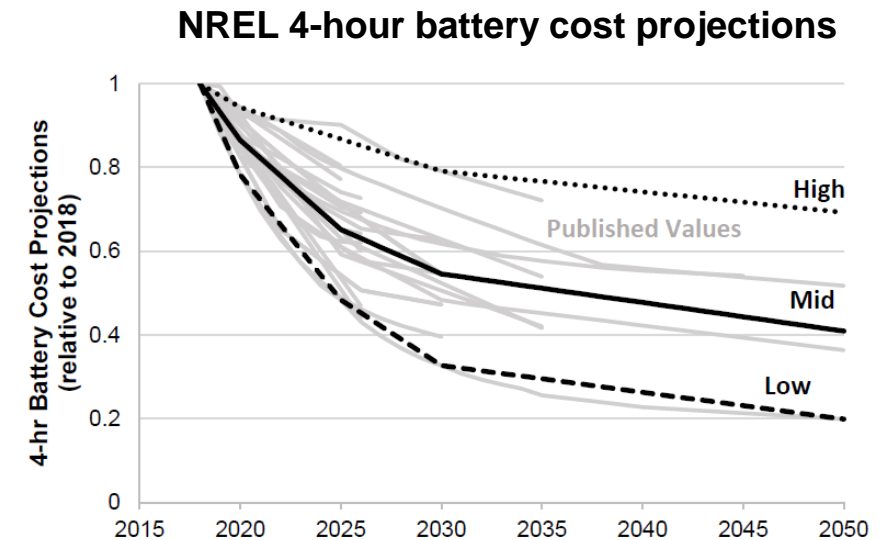


Input Assumptions for Storage Modeling

+ Source for most battery cost and performance parameters: NREL 2019 cost projections for utility-scale battery storage

- \$380/kWh for a 4-hour battery in 2018, declining to \$250/kWh by 2025.
- Fixed O&M costs assumed to be high enough to cover addition of battery cells over time due to degradation: \$38/kW-yr
- 85% round-trip efficiency, including parasitic losses
- Limited to 365 cycles/year to comply with manufacturer warranty
- 20-year lifetime

+ 2020 battery installation, with 2025 sensitivity



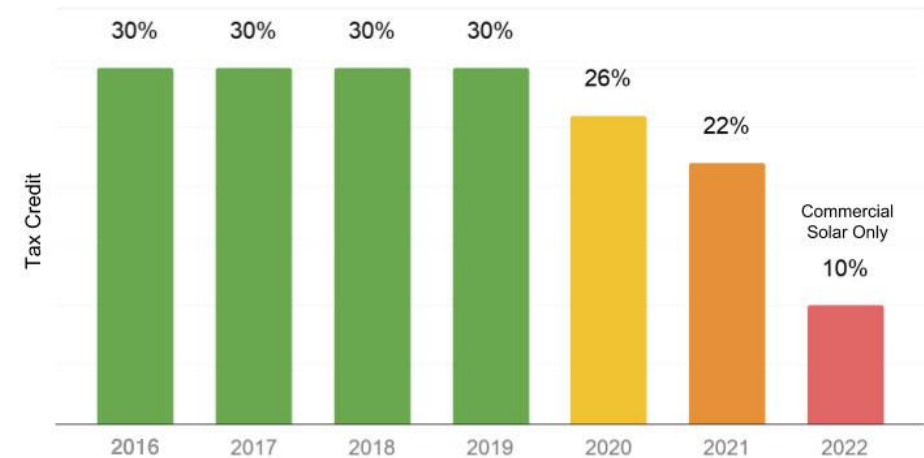


Input Assumptions for Storage Modeling

+ Financing assumptions

- Assume IPP-owned using E3 WECC Pro Forma financing assumptions for 2020 (20% debt share, 9% WACC)
- 20-year financing lifetime
- 7-year accelerated depreciation when not paired with solar, 5-year when paired with solar
- Solar paired with storage gets 26% Investment Tax Credit (ITC) in 2020
 - 2020 is the first year the ITC starts to ramp down

Solar Investment Tax Credit (ITC) Ramp-down
(applies to storage when charging from solar)





Incorporation of stakeholder feedback

- + Stakeholder suggestions adopted for congested node to model (from MTEP congestion analysis) and distribution deferral site (Xcel NWA feeder)
- + Stakeholders also suggested:
 - Include discussion of the role for storage in resource planning, particularly for providing new peaking capacity
 - Noted. We will prioritize this.
 - Potential for storage to change net system peak
 - Will incorporate in final results
 - Calculate breakeven cost for storage under various use cases
 - We are including this– more detail in final results
 - Provide more detail on assumptions
 - Detailed assumptions document was provided to stakeholders.





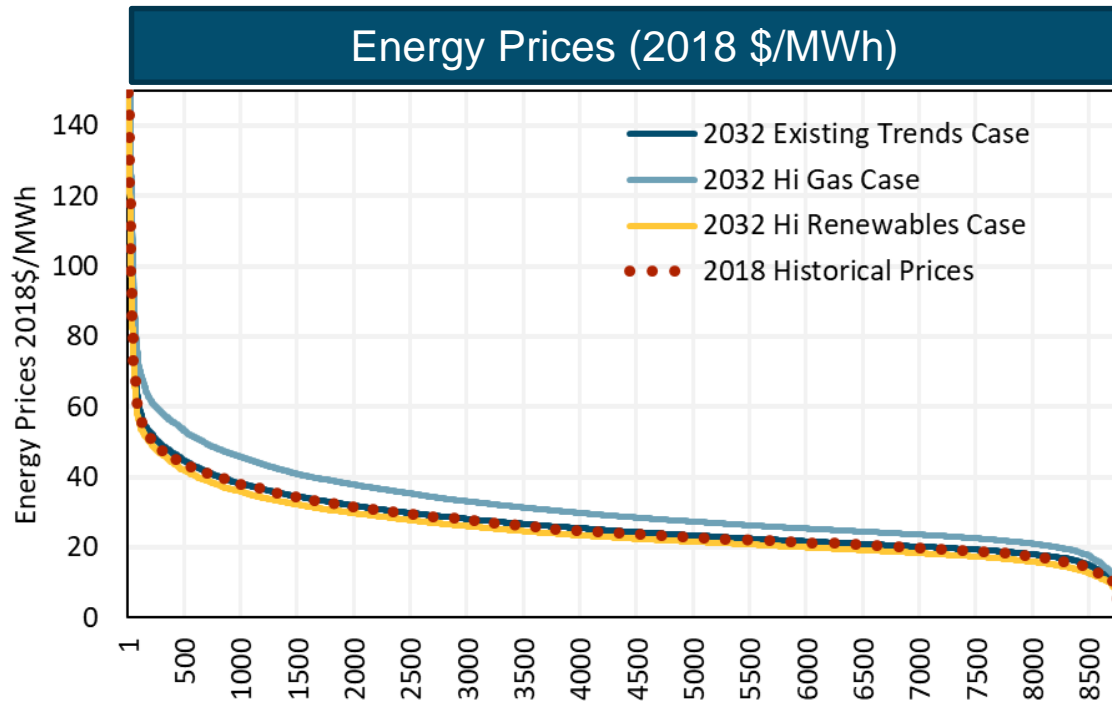
Energy+Environmental Economics

AURORA Price Results

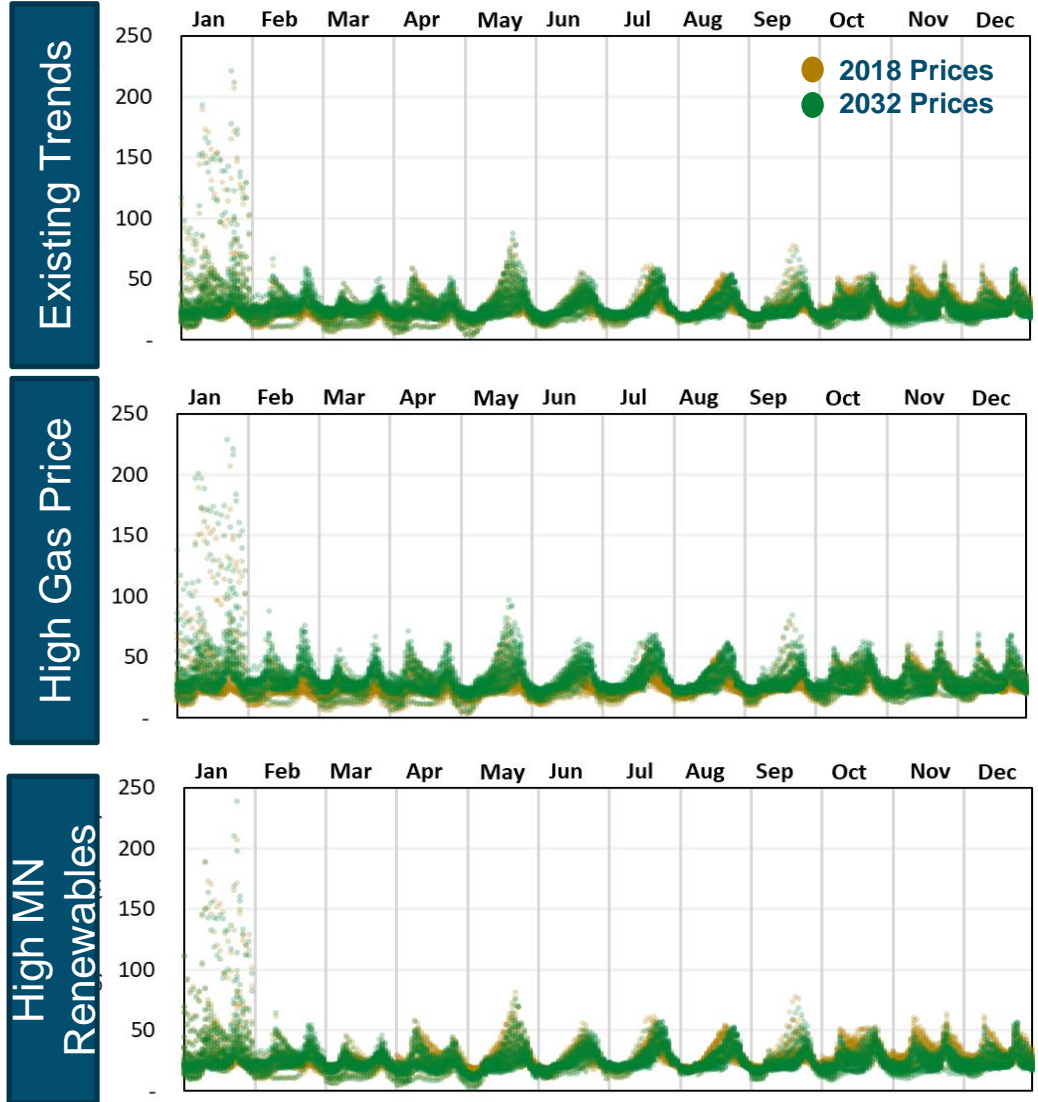


AURORA Energy Prices

- + Overall, energy prices are not significantly impacted by renewable penetration
- + Increased gas prices push marginal energy prices upwards
- + Increased renewable capacity pushes some gas units off the supply stack
- + Prices are benchmarked to MINN.HUB prices in 2018



2032 Energy Prices (2018\$ / MWh)





Energy Prices: Average Hourly Patterns

+ Energy prices are driven by *net load*, i.e. load net of renewable energy

- Increased load pushes prices up
- Increased wind and solar production pushes prices down

+ Average price spreads by 2032 are low even in the high renewables case

- New storage may be difficult to sustain on energy arbitrage alone

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	\$23	\$27	\$39	\$41	\$38	\$33	\$30	\$29	\$25	\$25
03	\$17	\$16	\$16	\$16	\$16	\$18	\$22	\$25	\$24	\$24	\$24	\$24	\$24	\$23	\$22	\$23	\$25	\$27	\$32	\$29	\$26	\$24	\$23	\$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	\$32	\$32	\$26	\$21	\$18	\$21	\$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

2032 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	31	28	27	27	27	28	35	46	42	41	39	38	36	35	35	35	39	54	64	51	42	37	34	30	37
02	24	24	24	23	23	24	28	33	30	29	28	28	28	27	27	27	28	34	41	39	34	29	26	25	29
03	22	22	21	21	22	24	27	28	25	24	24	24	23	23	24	24	26	29	32	34	31	26	23	22	25
04	20	20	20	20	21	27	32	31	29	27	26	24	23	23	23	23	25	27	29	34	33	27	21	19	25
05	19	18	17	17	18	21	22	23	24	25	27	29	31	34	37	40	42	41	37	38	39	30	24	22	28
06	20	19	18	18	18	20	20	22	22	23	25	26	28	29	32	34	36	36	37	36	33	26	24	22	26
07	22	21	21	20	20	21	21	21	22	24	26	28	29	30	33	37	41	43	46	43	35	27	25	24	28
08	20	20	19	19	19	20	21	20	21	23	25	26	27	29	29	33	37	40	43	39	33	26	24	22	26
09	19	19	18	18	19	21	23	22	22	22	23	24	25	27	28	30	33	36	39	38	33	25	21	20	25
10	20	20	19	19	20	25	30	28	27	27	27	27	28	29	29	30	32	38	42	36	30	25	23	21	27
11	21	20	20	20	20	22	25	30	27	26	26	25	24	24	24	25	27	38	41	31	27	25	23	22	26
12	22	21	21	21	21	22	24	30	27	26	27	26	25	25	25	25	27	40	41	31	27	26	25	22	26
Avg	22	21	20	20	21	23	26	28	27	27	27	27	27	28	29	30	33	38	41	38	33	28	24	22	27

	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	34	32	32	33	36	45	60	50	48	45	44	41	39	40	42	48	69	82	65	56	48	41	35	46	
02	27	27	27	27	28	31	37	44	36	33	31	31	30	29	29	29	32	43	51	51	44	37	31	29	34	
03	25	25	24	24	25	29	35	33	29	28	27	26	25	25	26	27	29	36	41	45	40	32	27	25	30	
04	24	24	23	24	25	32	38	36	33	31	29	27	27	26	25	25	26	32	35	41	42	32	25	23	29	
05	22	21	20	20	21	24	25	26	27	28	30	33	35	38	40	43	47	48	45	45	47	35	28	24	32	
06	23	21	21	20	21	23	23	25	25	26	28	30	32	34	37	40	42	42	44	45	43	33	27	25	31	
07	26	25	24	24	24	25	24	25	26	29	31	33	35	36	38	44	48	50	53	49	46	35	31	29	34	
08	24	23	23	23	24	24	24	24	26	27	29	31	32	33	33	38	41	45	49	47	43	31	28	26	31	
09	23	22	22	22	22	25	27	27	26	27	28	29	31	32	32	35	38	39	42	45	40	30	26	24	30	
10	23	24	23	23	24	31	37	34	32	31	31	31	32	33	34	35	40	43	48	43	37	30	27	24	32	
11	24	24	24	24	24	26	30	37	32	30	30	28	27	27	28	28	33	43	48	37	33	30	27	25	30	
12	25	25	24	24	25	27	30	38	32	30	30	29	28	27	28	29	33	45	48	40	37	33	29	26	31	
Avg	25	24	24	24	25	28	31	34	31	31	31	31	31	31	32	33	35	38	45	49	46	42	34	29	26	32

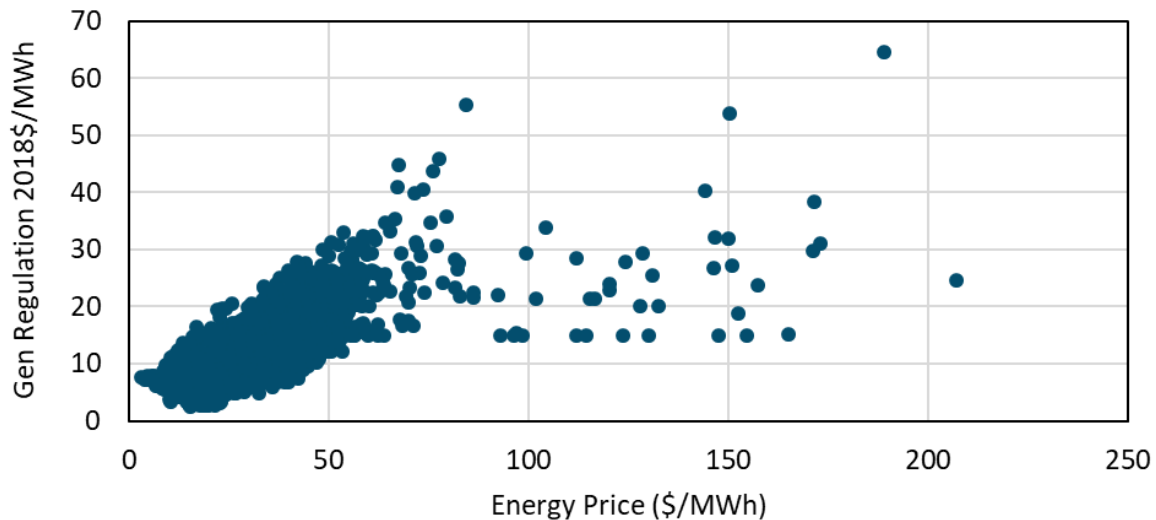
	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg
01	29	26	25	24	25	27	34	45	42	39	37	36	35	33	33	33	38	51	60	47	40	36	33	28	36
02	22	21	21	21	21	23	27	32	29	27	27	26	25	25	25	25	27	32	38	37	33	28	25	23	27
03	18	18	18	18	19	22	26	26	24	22	21	20	20	19	20	22	22	25	29	28	22	17	15	22	22
04	16	16	16	17	19	25	31	30	27	25	23	20	20	19	19	20	22	25	29	28	22	17	15	22	22
05	13	12	11	12	13	18	20	21	21	22	23	24	26	28	30	34	36	36	33	32	31	24	19	16	23
06	18	17	16	16	17	19	20	20	21	22	23	25	26	27	30	32	33	35	35	34	31	24	19	20	24
07	22	20	19	19	19	21	21	21	22	23	25	27	28	29	32	36	40	42	45	41	34	27	25	23	27
08	19	18	18	17	18	20	20	20	21	22	23	25	25	27	28	32	36	39	42	38	32	25	22	20	25
09	17	17	16	16	17	19	21	21	21	22	23	24	25	26	28	30	35	37	36	31	23	20	17	24	24
10	18	18	17	17	18	23	29	26	25	25	24	24	24	25	26	29	31	36	40	34	29	25	21	19	25
11	19	19	19	19	19	21	24	29	27	27	26	24	23	23	23	23	26	34	37	28	25	23	22	20	24
12	21	20	19	19	20	21	23	29	27	26	26	25	24	24	24	24	27	39	40	31	26	26	24	21	25
Avg	19	18	18	18	19	21	25	27	25	25	25	25	25	25	26	28	31	36	38	35	31	26	22	20	25



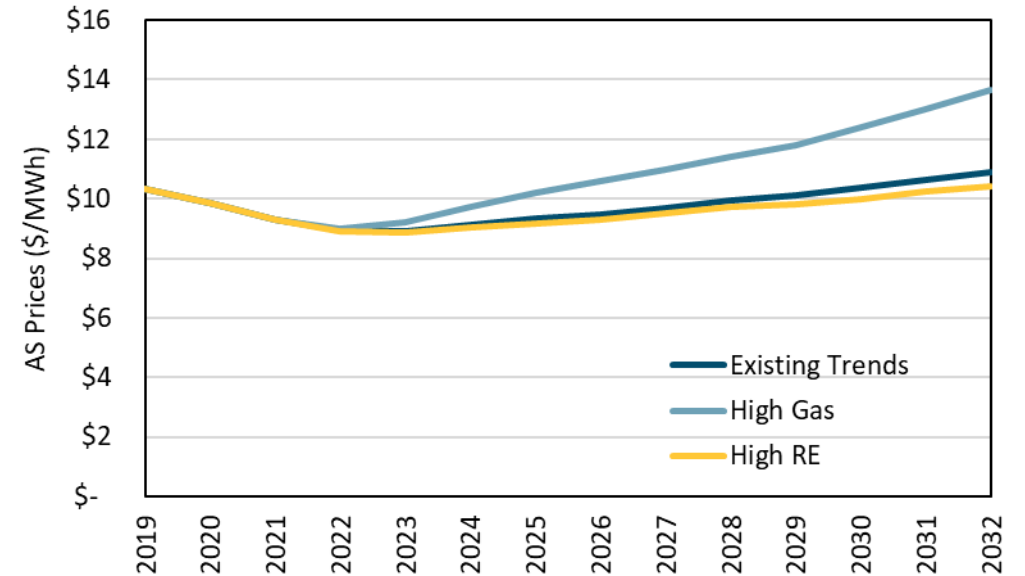
Ancillary Services Prices

- + **Historically, energy and AS prices are strongly correlated**
 - This correlation is assumed to hold into the future
- + **When thermal units predominantly on the margin, AS tends to trend with energy prices**
 - System is long on capacity in the near-term until coal retirements in the middle of the 2020s

Historical Regulation Prices (\$/MWh)



Forecasted Regulation Prices (\$/MWh)





Capacity Prices

- + **MISO has a capacity market, designed to fill the gap between what resources can earn by selling energy, and what they need to cover their costs**
 - Capacity payments can be a significant value stream for storage
 - Currently, MISO North has excess capacity, so capacity prices are low
- + **With many upcoming coal retirements planned, MN is projected to have a capacity need, which could result in higher capacity prices in the future**
- + **Once a capacity shortage is realized, capacity prices will be set by the payments needed to allow for the building of a new Combustion Turbine (CT)– this amount is known as the “Net Cost of New Entry” or “Net CONE”**
 - Storage could eventually be the marginal capacity resource as well

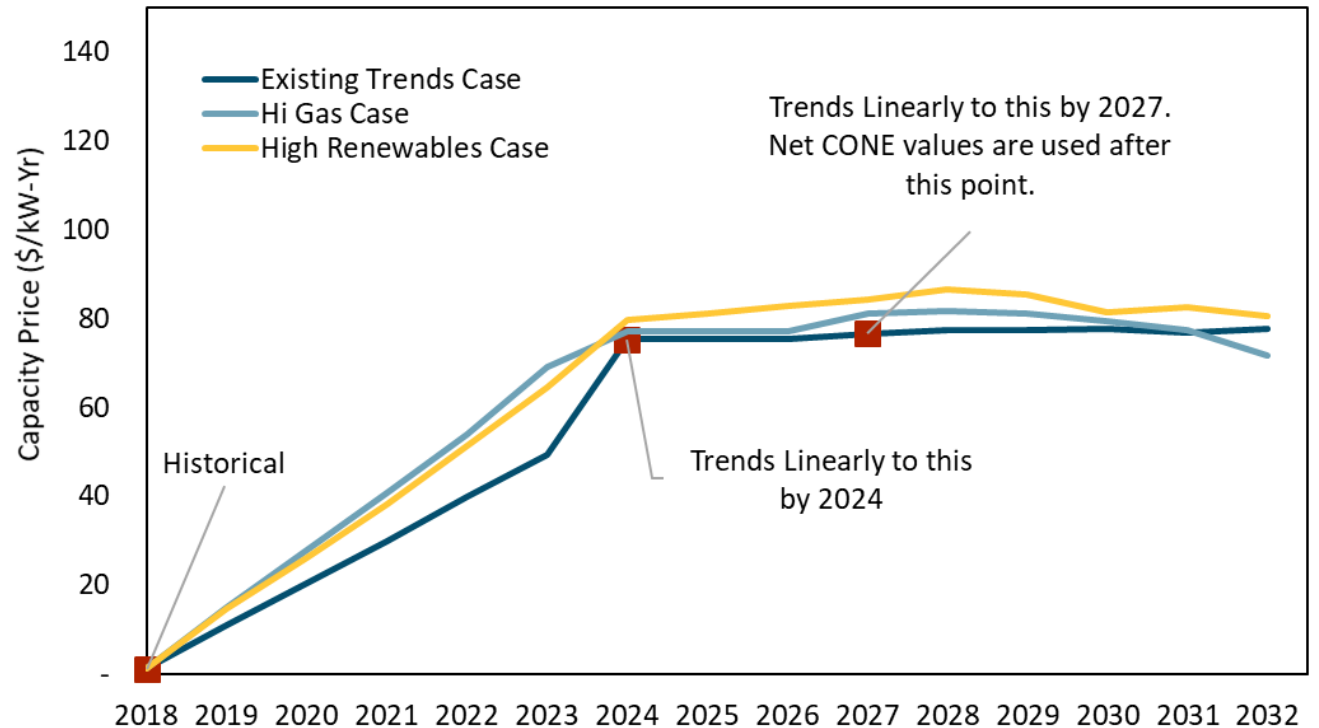
Year	MISO Zone 1 Capacity Prices (\$/kW-yr)
2014-2015	\$1.20
2015-2016	\$1.27
2016-2017	\$7.20
2017-2018	\$0.55
2018-2019	\$0.37
2019-2020	\$1.09



Capacity Price Forecast

- + **Historical prices are linearly increased to meet projected CT net CONE**
 - Trajectory is derived from coal retirement schedules
 - Resource costs for greenfield CT adopted from Xcel's 2018 IRP
- + **Net CONE is estimated with AURORA results**
- + **The same escalation trajectory from historical to net CONE is applied to all scenarios**

Capacity Prices (\$/kW-yr) - Existing Trends Scenario





Energy+Environmental Economics

Break



Energy+Environmental Economics

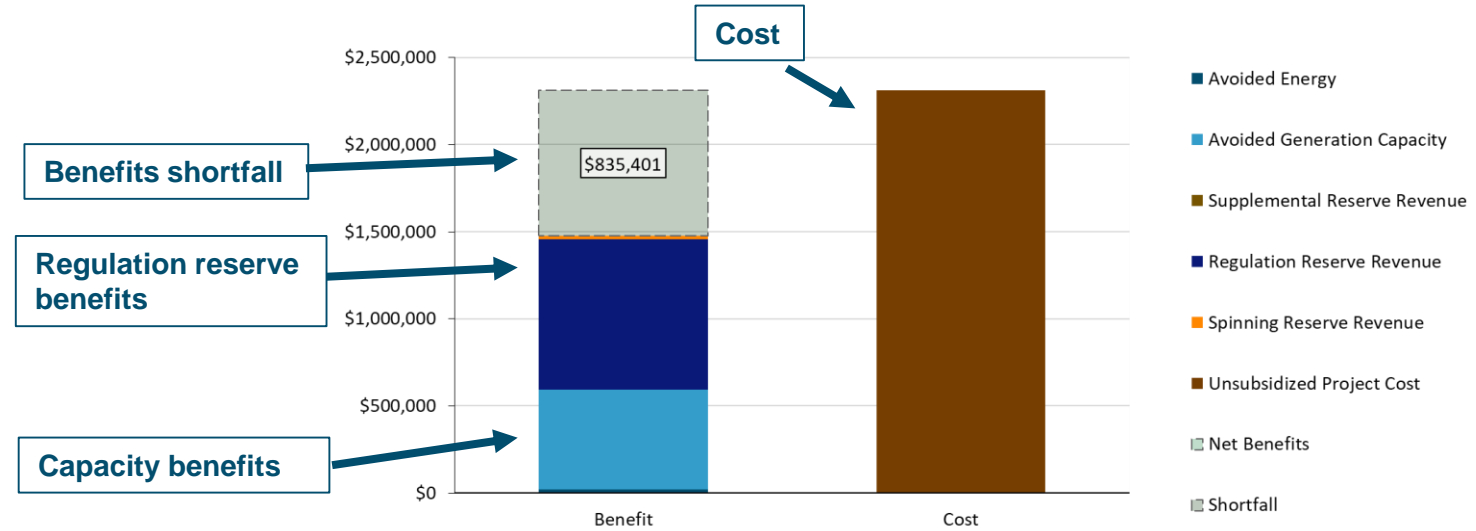
Results



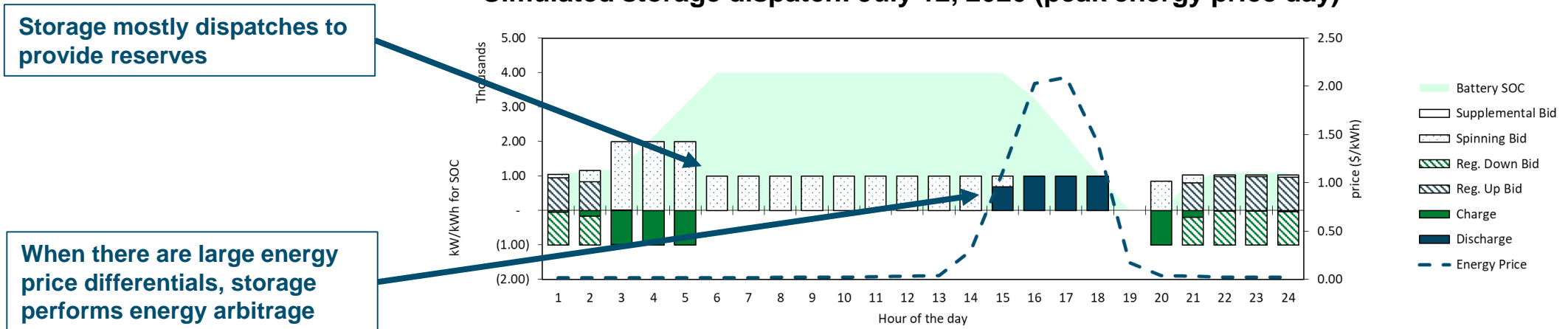
Wholesale Base Case

- + Base case storage installation, for participating in energy and capacity markets with no additional revenue streams, is not cost effective at today's storage costs
- + Revenue streams that do exist are driven by capacity revenue, and reserve market participation

Total Resource Cost: 4-hr Li-ion battery, Existing Trends Scenario



Simulated storage dispatch: July 12, 2020 (peak energy price day)

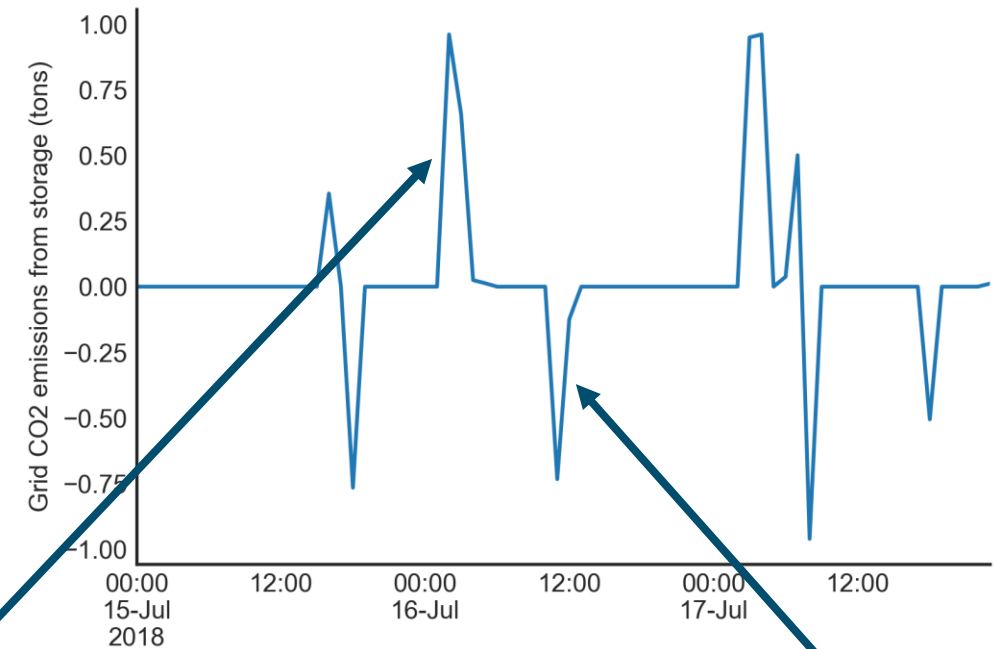




Wholesale Base Case: Emissions

- + To get an idea of the potential effect on emissions, we also ran a battery simulation using 2018 historical real-time prices, and used MISO “real time fuel on the margin” data to estimate grid emissions resulting from storage
- + On the current grid, storage generally charges from coal at night, and discharges on-peak to displace some coal/gas
- + In our historical run, storage increased grid emissions by about 168 tons over the course of a year (the equivalent of about 37 passenger vehicles’ worth of yearly emissions)
- + Until the grid changes composition to the point where storage can charge from mostly renewables on the margin, these dynamics will continue

Storage indirect electric grid emissions: July 15-17, 2018



Storage generally charges at night from off-peak coal, causing some (high) emissions...

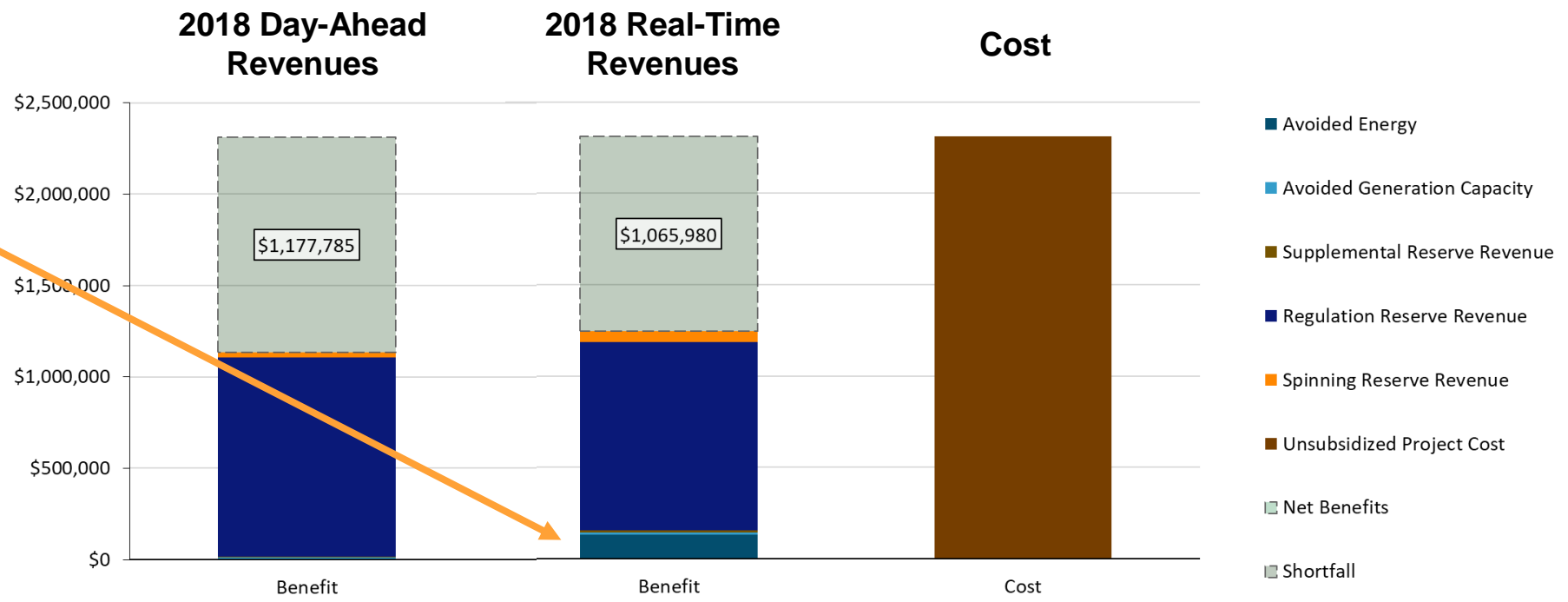
... and discharges on-peak during the day, frequently displacing lower-emitting natural gas



Wholesale Base Case: Real-Time Pricing

- + The prices in AURORA are day-ahead prices; to estimate how much revenue could increase from participating in the real-time market, we compared simulations using historical data, for storage participating in the 2018 day-ahead and real-time markets
- + The ability to participate in real-time markets enabled more energy arbitrage than was happening in the day-ahead, resulting in about \$100,000 of additional benefits

Storage arbitrage is economic in real-time market, but not the day-ahead



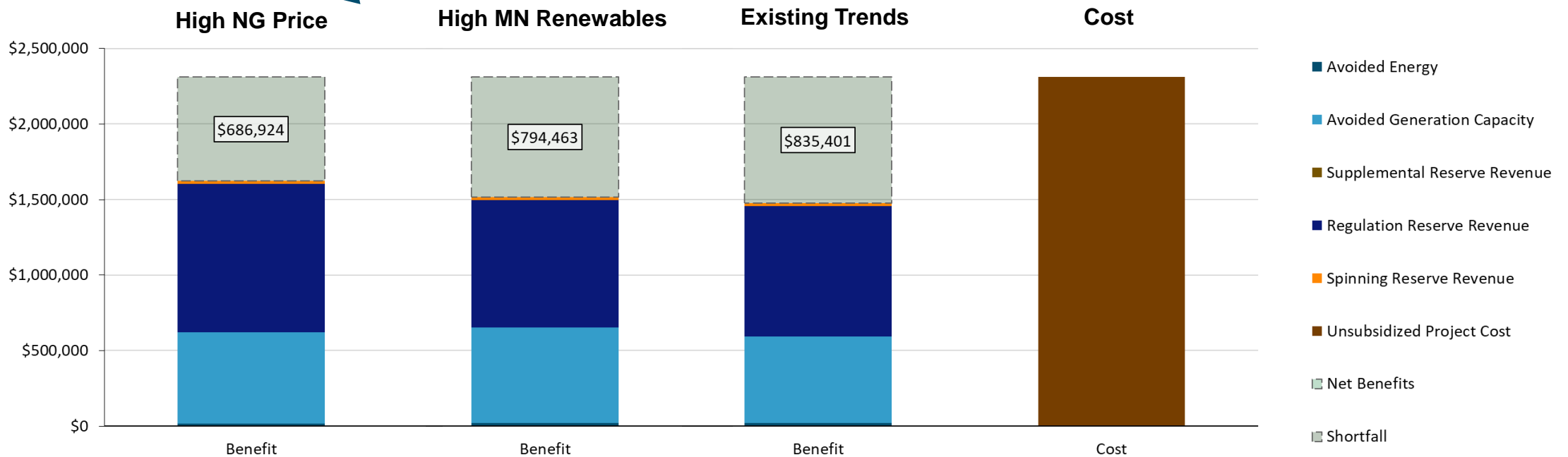


Scenario Sensitivities: Market Prices

+ Small differences between scenarios for 2020 installation

- As mentioned before, renewables are relatively easy to integrate into MISO in the short term

High NG price scenario shows highest benefit for storage due to increased energy prices, following by high MN renewables scenario





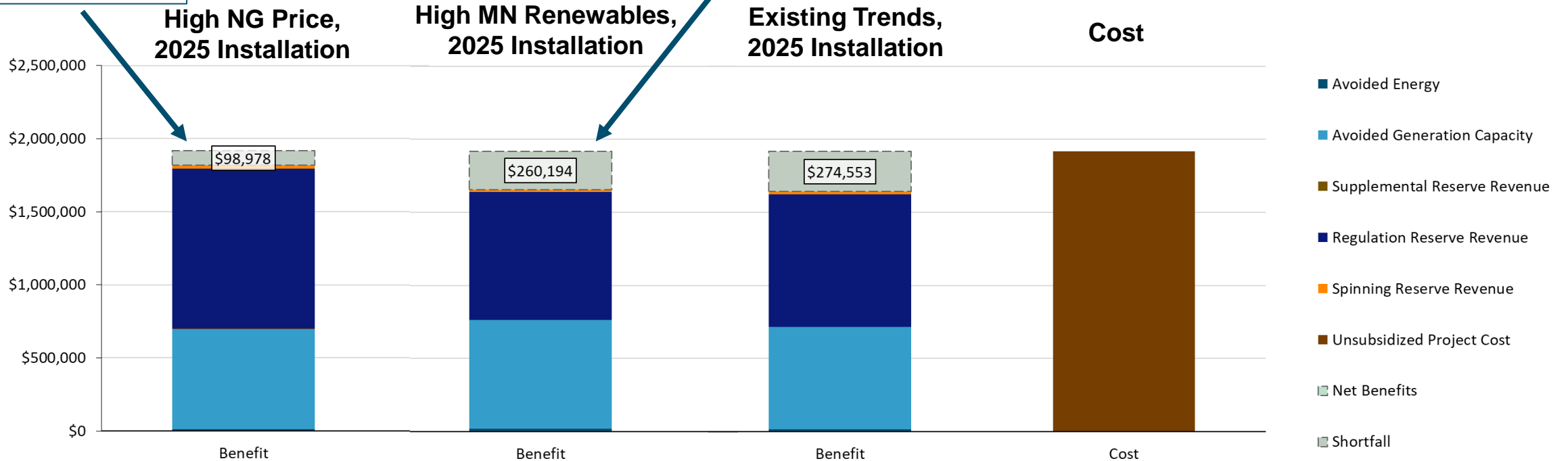
Scenario Sensitivities: 2025 Installation

+ For a 2025 installation, 4-hr storage becomes closer to cost-effectiveness

- Upfront cost becomes much cheaper
- Capacity prices increase
- Shorter duration battery could be cost-effective (lower cost would be balanced by lower capacity market revenues)

High NG Price scenario is almost cost effective for a 2025 installation

Breakeven cost for High MN Renewables scenario is \$245/kWh, expected to happen in 2026 according to NREL projections

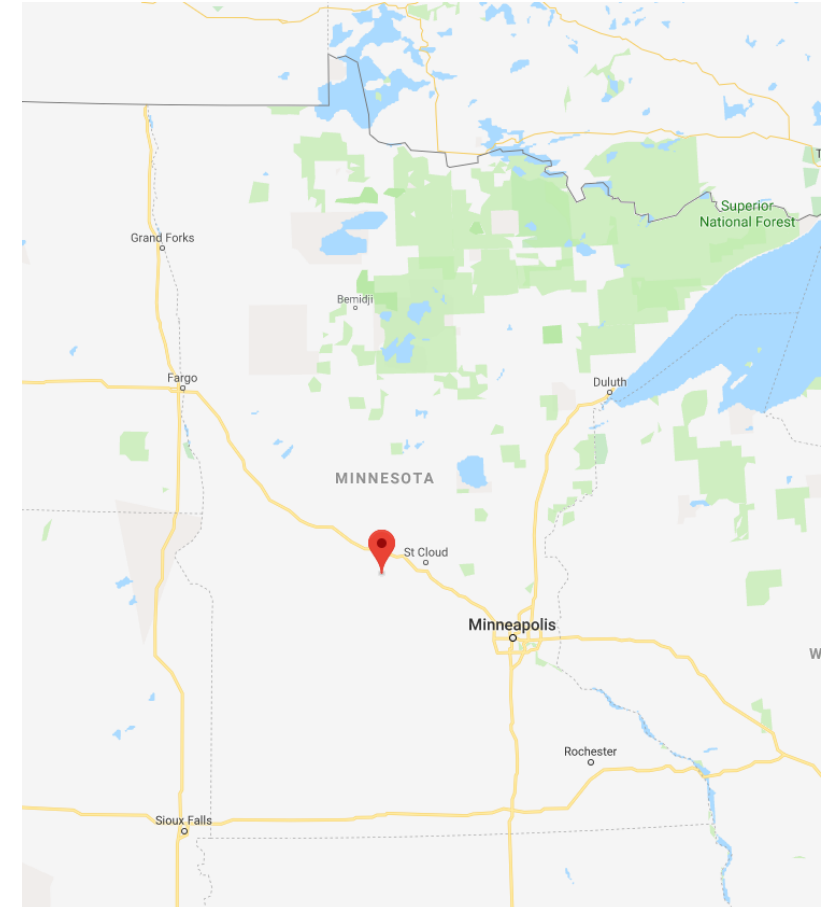
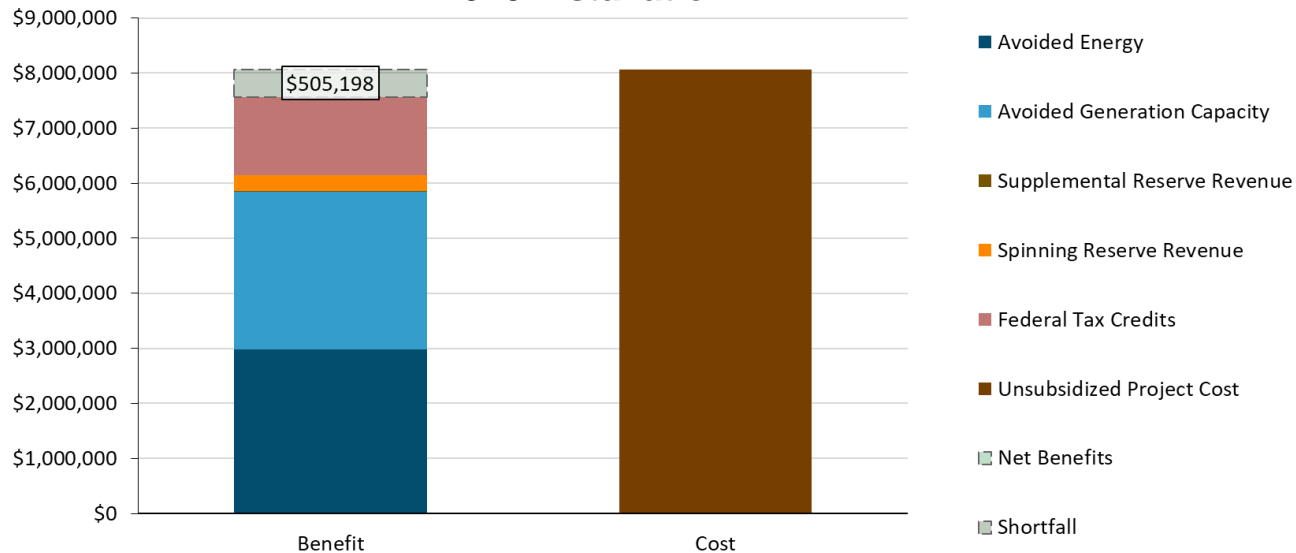




Solar + Storage

- + Modeled a theoretical 4 MW solar system paired with 1 MW / 4 MWh storage, charging only from solar for ITC eligibility, in Xcel service territory west of St. Cloud
- + Assumed IPP-owned solar at \$1075/kW in 2020
- + Not quite cost-effective for 2020 installation
 - 2019 installation with full 30% ITC, and shorter-duration storage, would likely be cost effective (similar to Connexus projects)

Total Resource Cost: Solar + Storage, Existing Trends Scenario, 2020 Installation

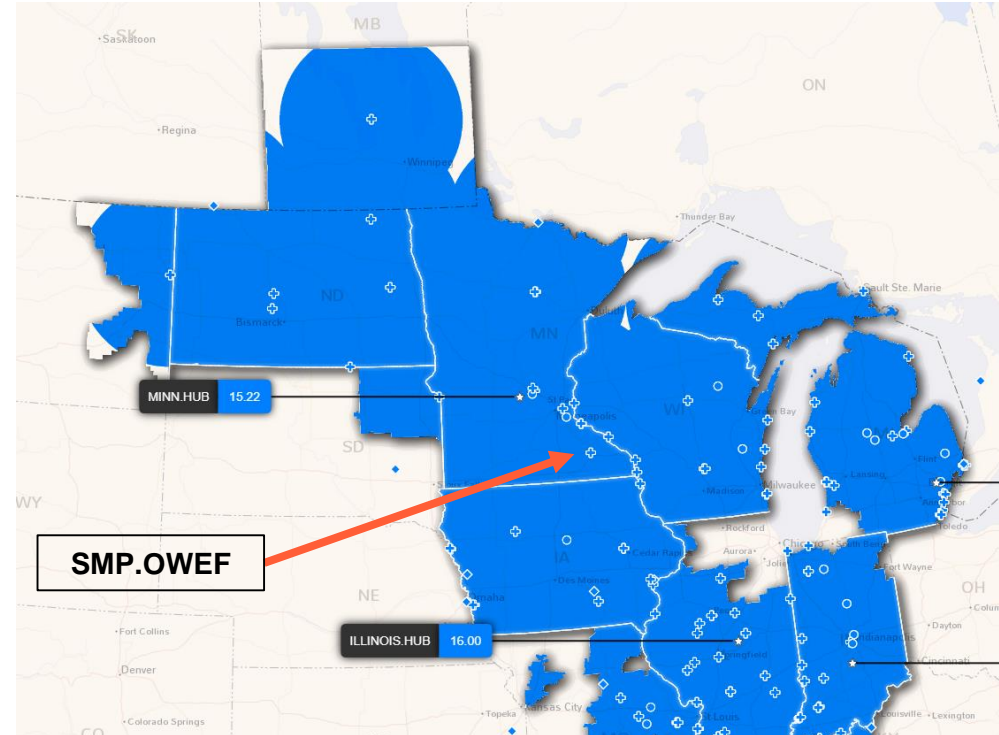
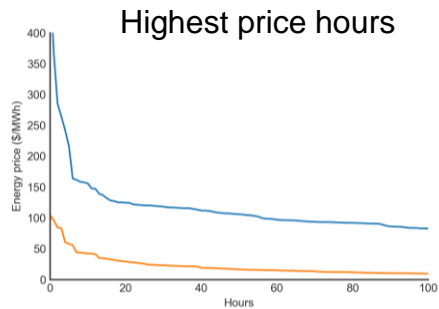
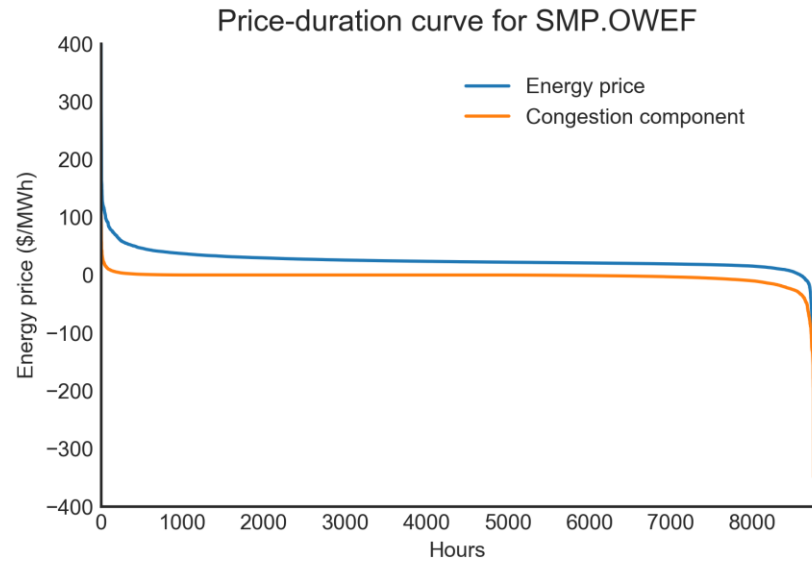




Congestion Reduction

+ Modeled the base case 4-hr storage system located at a congested node in SE MN (SMP.OWEF)

- Near the congested Wabaco-Rochester 161 kV transmission line mentioned in the MTEP 18 Market Congestion Planning Study



Many negative-priced hours due to surplus wind

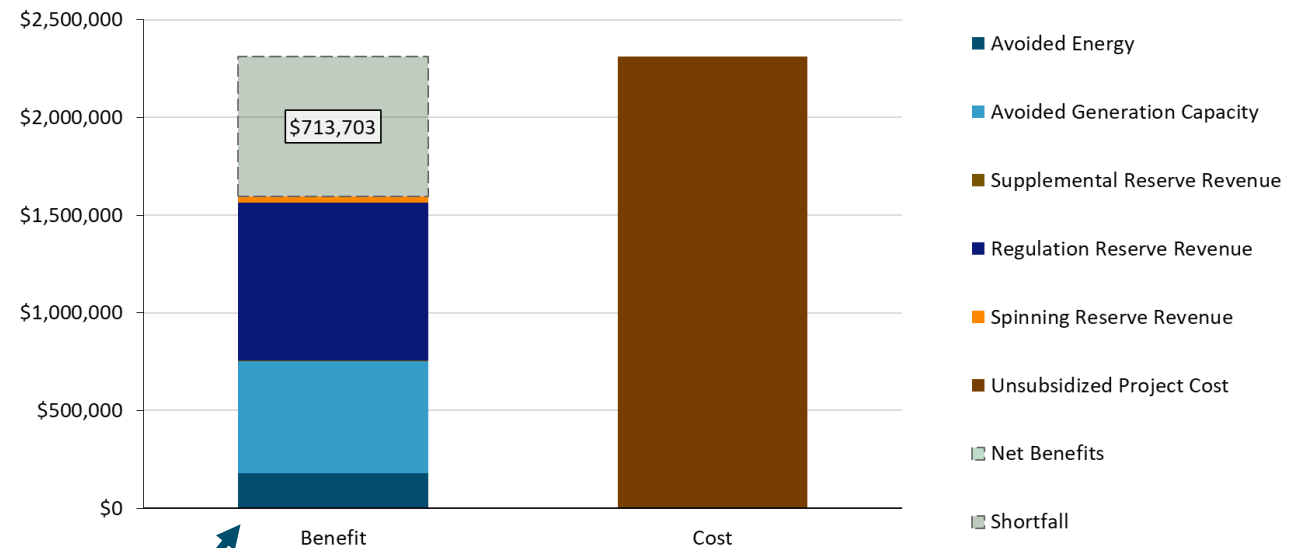


Congestion Reduction

+ Not quite cost effective, but better than the wholesale base case

- Base case has a benefits shortfall of \$835,000
- This type of use case may represent a situation increasingly common in the future, where many negative-priced hours in the energy market allow storage to arbitrage and make money

Total Resource Cost: Congestion management use case, Existing Trends Scenario

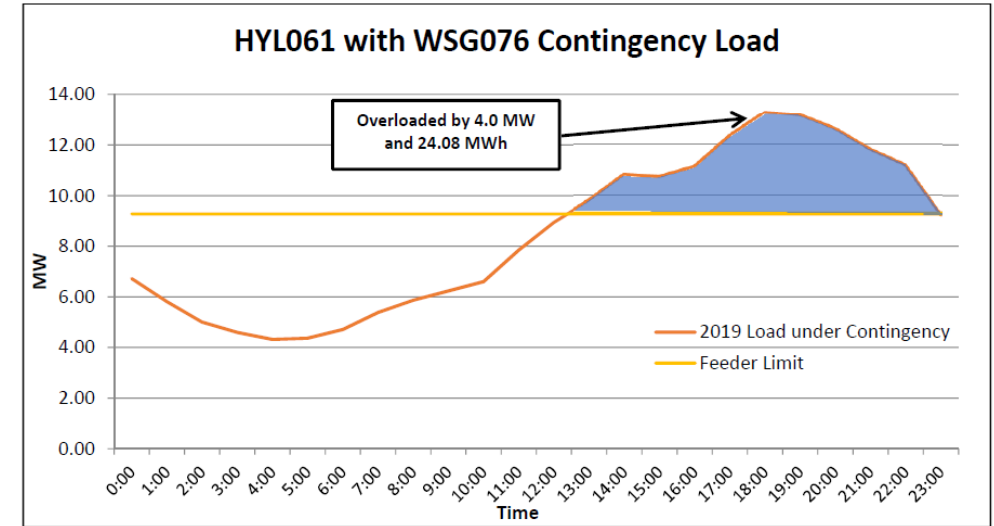


Storage arbitrages more than other cases due to many negative-priced hours



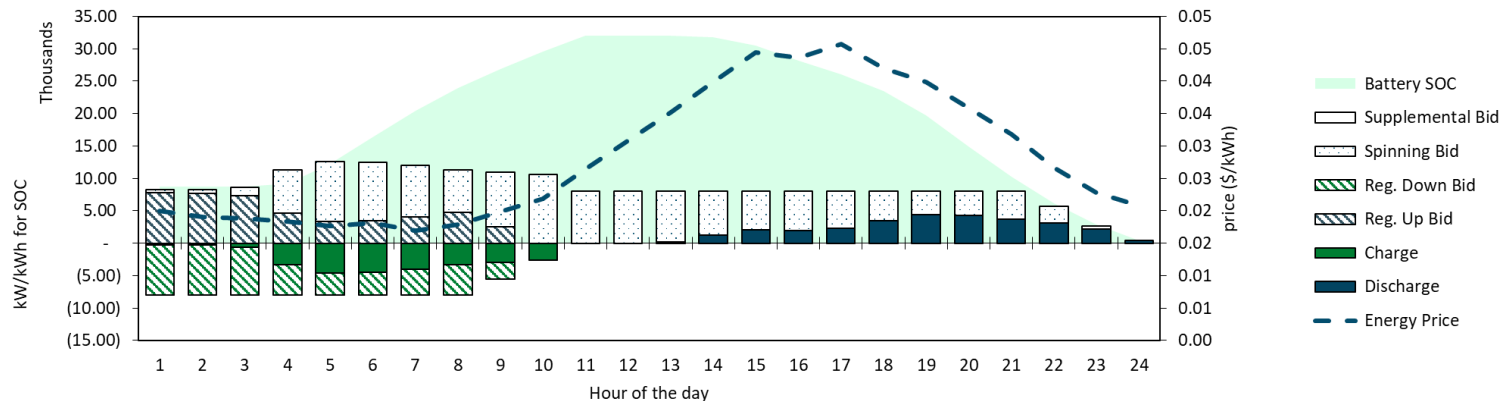
Distribution Upgrade Deferral

- + Used the Viking NWA analysis from Xcel's IDP filing as an example candidate for storage as an NWA
- + Storage was determined to be an order of magnitude more costly than the distribution upgrade for this NWA analysis. However, energy market revenues were not considered
- + We modeled a storage system sized to relieve the overload on HYL061, that participates in energy markets the rest of the year



Source: Xcel

Storage dispatch on contingency load day

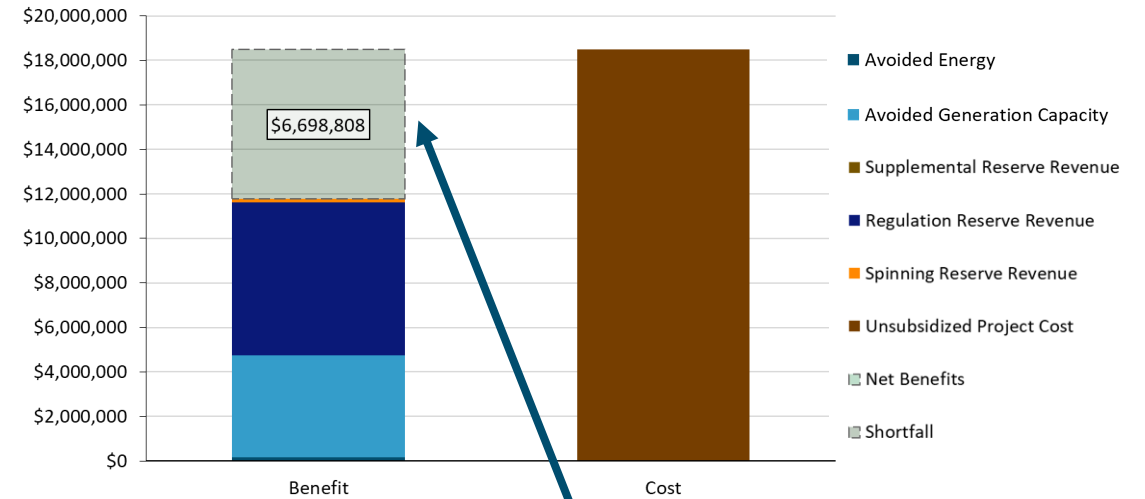




Distribution Upgrade Deferral

- + Assumed an 8 MW, 32 MWh battery to cover peak load day, plus load growth
- + Storage cost-effectiveness on its own shows the same results as the base case, but this provides a more appropriate “net cost” to use in an NWA analysis (storage NPV cost net of energy and capacity market revenues)

Total Resource Cost: Distribution upgrade deferral



Xcel IDP: Viking feeder NWA

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

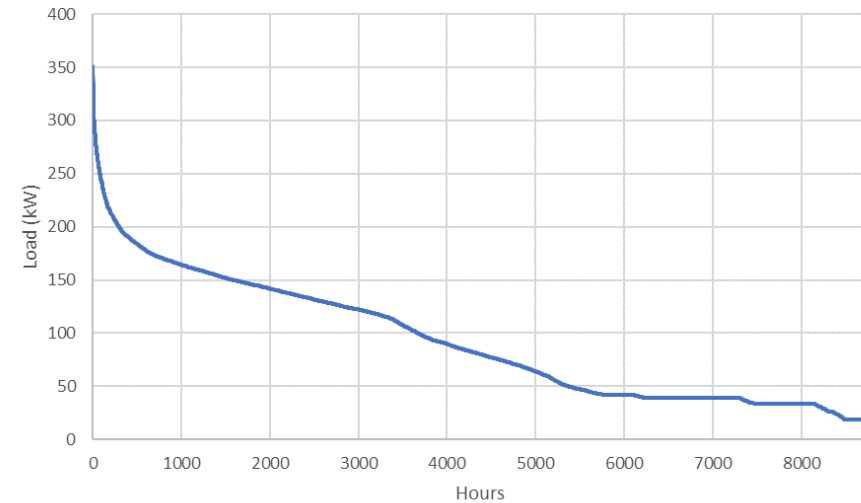
Storage cost included in future NWAs could be net of energy/capacity revenues



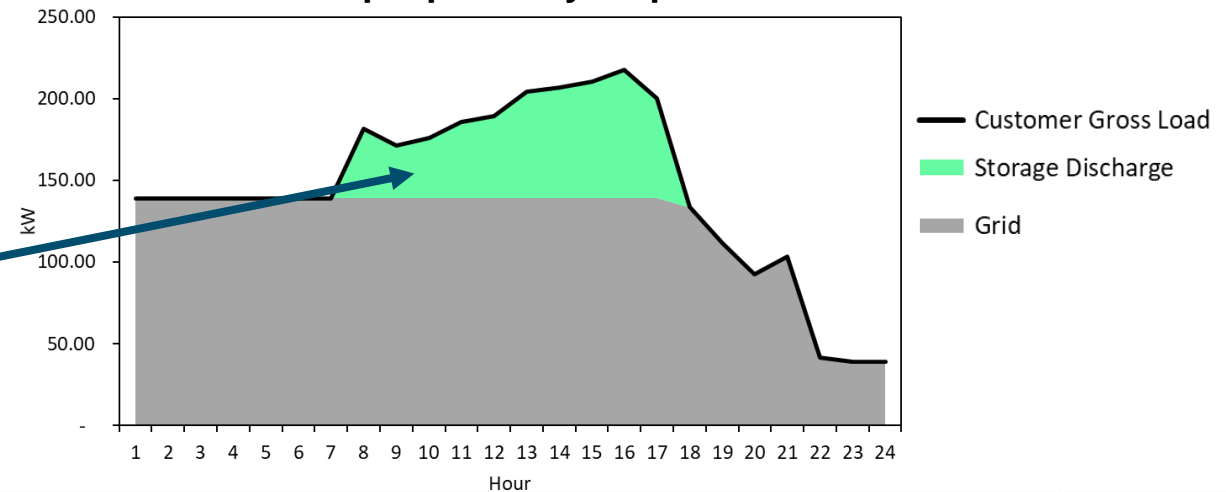
Behind-the-meter case

- + Modeled a sample “Medium Office Building” in St Cloud, using DOE “Reference Building” model data
- + Modeled Xcel A14 non-residential rate with high demand charge
 - Assumed 150 kW, 600 kWh battery
- + Peaky load shape means storage has the potential to provide demand charge savings

Load-duration curve for Medium Office Building in St. Cloud



Sample peak day dispatch



Storage dispatches to flatten load seen by grid, to reduce demand charges



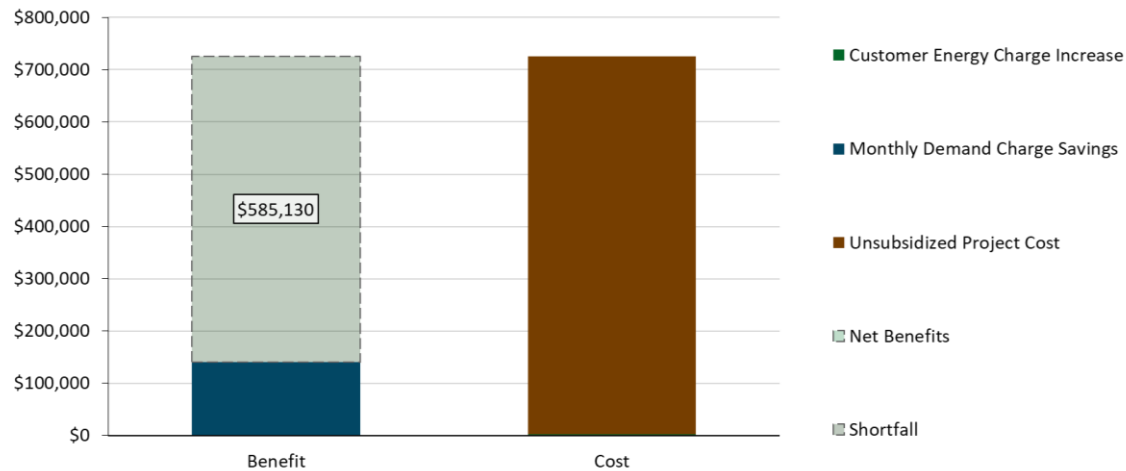
Behind-the-meter case

+ Storage not found to be cost effective on this particular rate by any metric

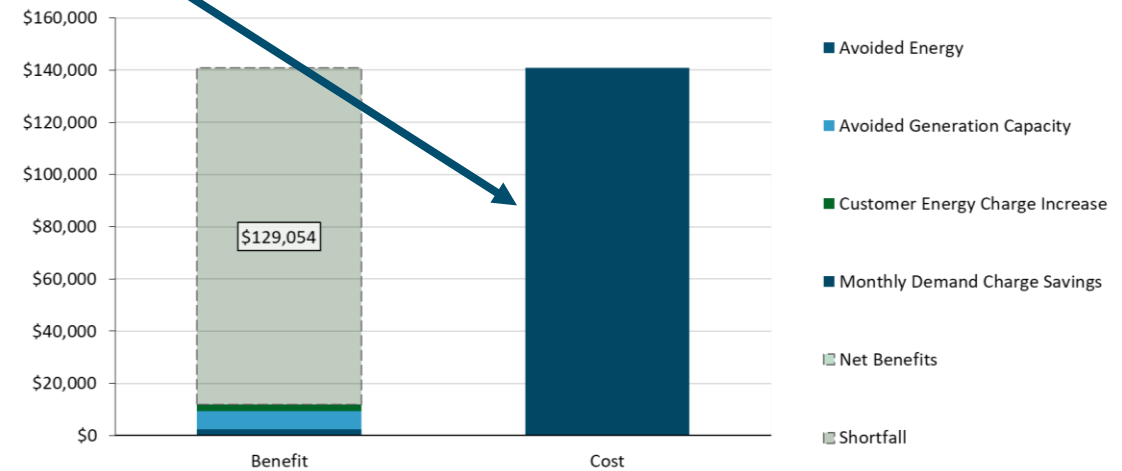
- No ancillary services revenues for customer to monetize
- No opportunity to get capacity credit or perform energy arbitrage (since all a behind-the-meter storage system can see is the customer rate)
- Rates better aligned with grid energy costs would increase the opportunity for behind-the-meter storage to serve as peak capacity

Demand charge savings for customer show up as a cost to other ratepayers, that is not made up for by benefits

Participant Cost Test



Ratepayer Impact Measure





Flow battery sensitivity

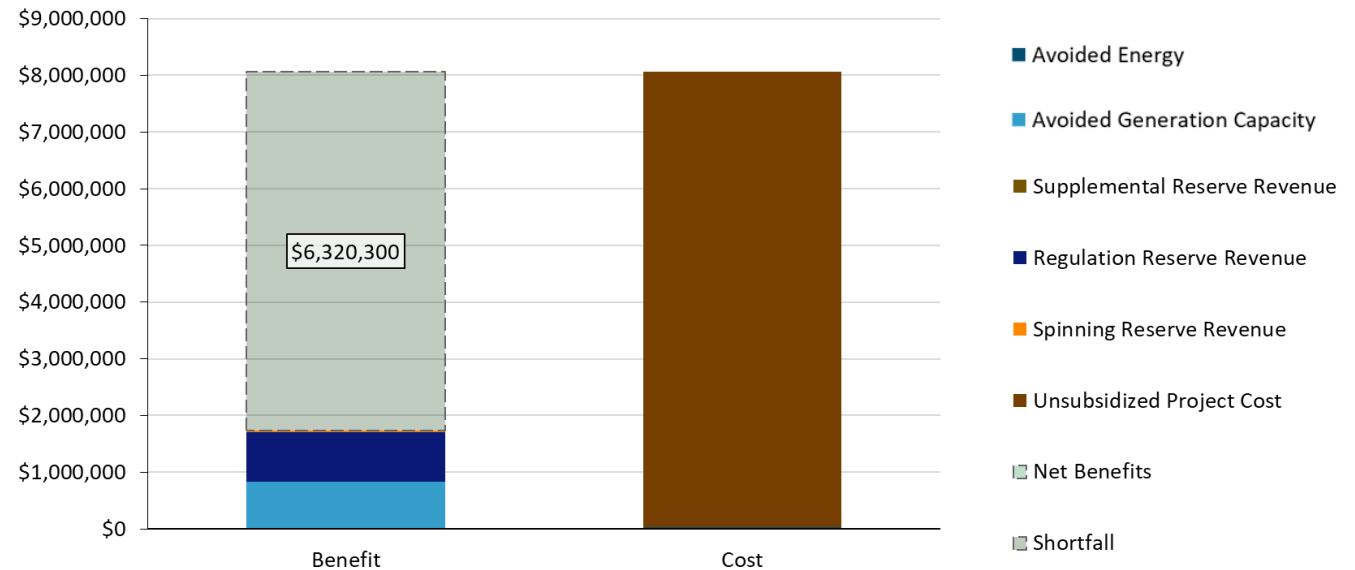
+ Examined an 8-hr Redox Flow battery installed in 2025 (using PNNL 2019 cost projections) to examine the potential for longer-duration flow batteries

- Flow batteries have the potential to be cheaper than Li-ion for longer duration (6+ hrs) in the long term

+ Much higher cost of longer duration is accompanied by only slightly increased benefits

+ Need a clear system need in terms of renewables integration to justify longer duration (and no system need is present in our modeled scenarios)

Total Resource Cost: 8-hr Flow Battery, 2025 installation





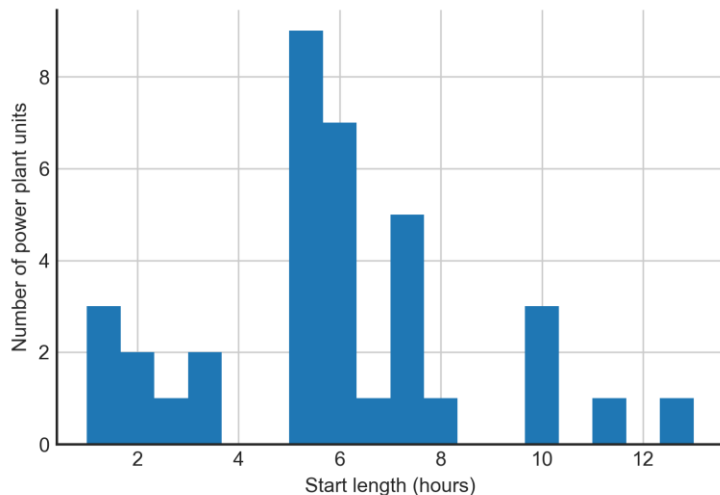
Peaking capacity analysis

+ E3 analyzed the potential for storage to provide peaking capacity in Minnesota on a “bottom-up” (unit-by-unit) basis

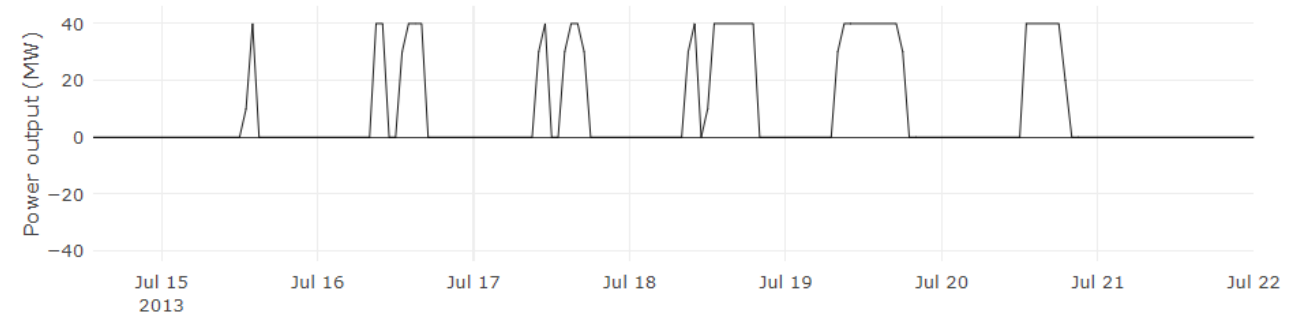
- We looked at whether storage could mimic each individual unit’s operations, using EPA CEMS data

+ We tried to answer the question: what duration of storage is needed to address MN’s peaking capacity need?

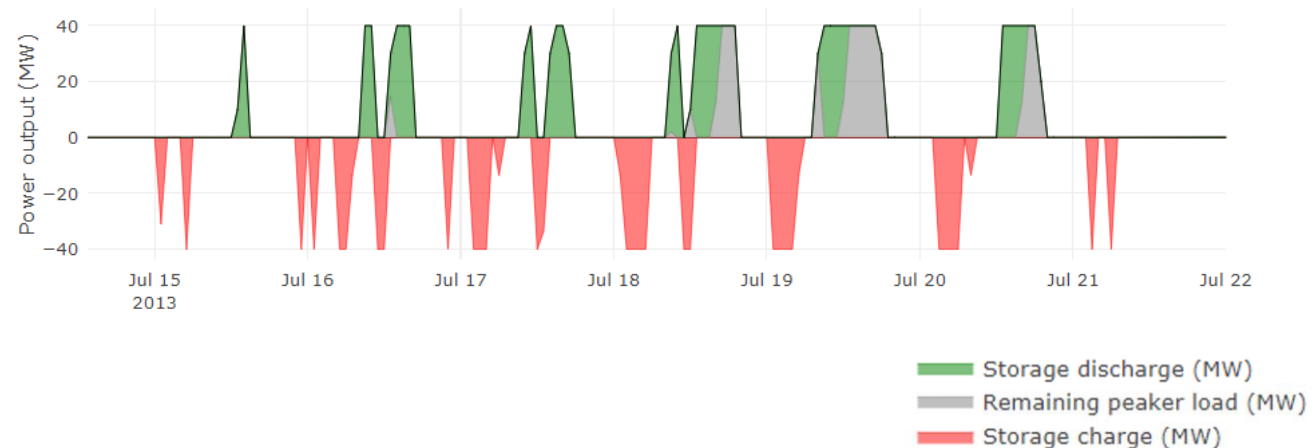
MN Peaker Fleet: Median Start Lengths Histogram



Sample peaker operations



Sample storage operations when attempting to “mimic” peaker

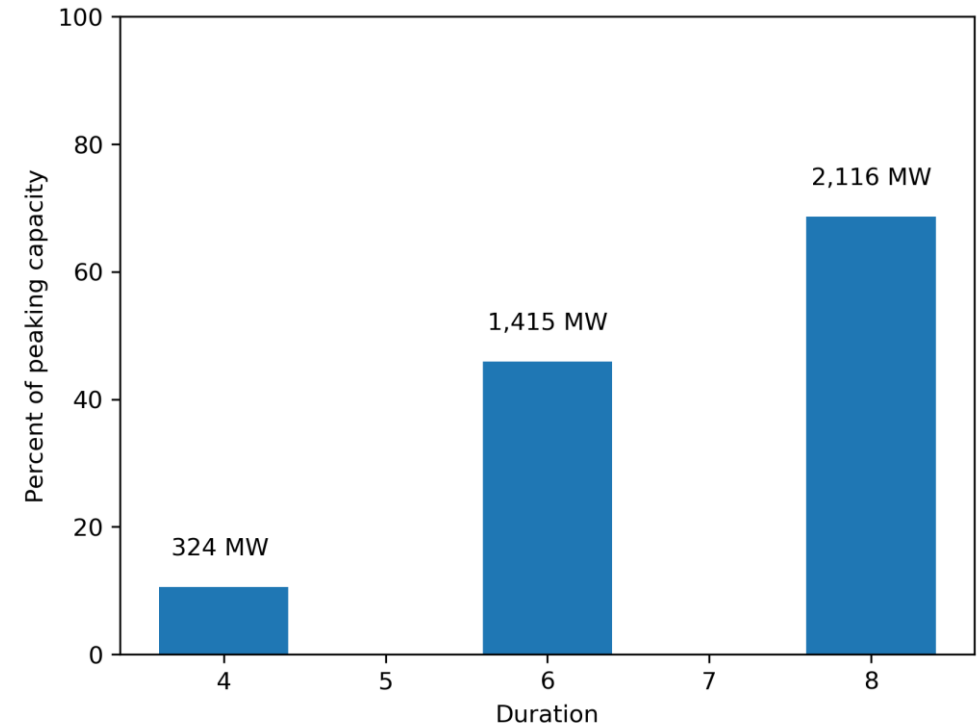




Peaking capacity analysis

- + The potential for storage to “mimic” each individual unit in the peaker fleet was examined for 4, 6, and 8-hour storage
- + 324 MW of 4-hour storage could perfectly mimic the operations of about 10% of MN’s 3.1 GW peaker fleet, on a unit-by-unit basis
- + These results are most useful when looking at the potential for storage to provide new peaking capacity moving forward

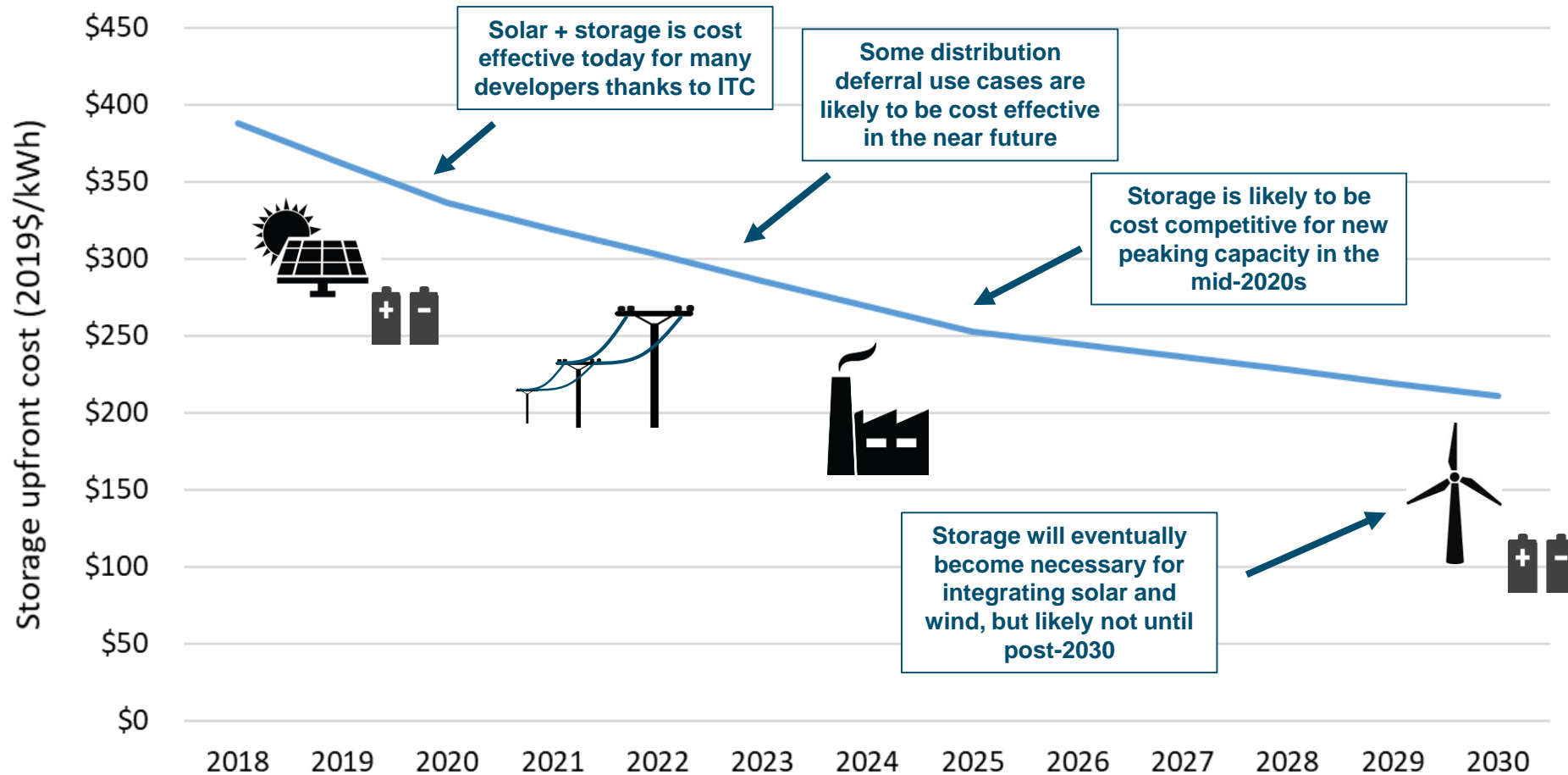
Percent of MN peak capacity that could have been provided by storage in 2018, as a function of duration





Key takeaways: breakeven costs over time

NREL “Mid” Utility-Scale Storage Cost Projections



Source: “Cost Projections for Utility-Scale Battery Storage”, NREL, June 2019



MISO and storage: next steps

- + New rules for allowing storage participation in capacity and AS markets will go into effect December 2019
- + 4-hour storage can get full capacity credit as long as it bids in for a 4-hour period overlapping with the projected peak, into the day-ahead market
- + Increased transmission connectivity with Manitoba will allow for many MW of inherent storage





Still to come

+ Behind-the-meter case

- Modeling real commercial buildings in MSP that currently have solar and are considering storage

+ Emergency services and power quality cases



Energy+Environmental Economics

Thank you! Questions?