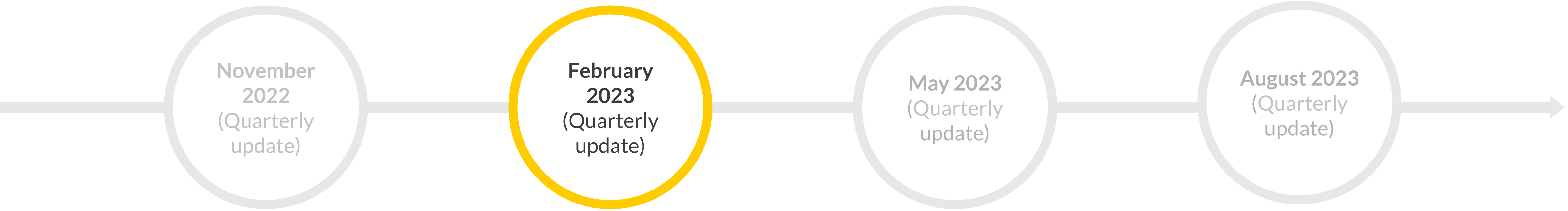
AURORA ENERGY RESEARCH

ERCOT Flexible Energy Market Outlook

February 2023

CONFIDENTIAL

Introduction & Process



Report structure and outputs

This document presents Aurora Energy Research's ERCOT Flexible Energy Market Outlook report for February 2023. This report serves as an update to our November forecast and includes updated gas futures, cost assumptions, and newly operational capacity.

I. **Executive summary** – An overview of the flexible energy market performances and KPIs over the latest quarter with a brief summary of any updates on revenue drivers and key outcomes from Aurora Standard investment cases

II. **Market and policy overview** – Provides analysis of market trends, historic battery behaviour and an introduction to merchant risk for storage assets

III. **Market outlook** – Contains a brief market overview with a focus on flexible capacity, as well as Aurora's estimated battery build-out and CAPEX trajectory

IV. **Aurora Central scenario: Key results –** Details costs and revenue streams for 1, 2 & 4 hour batteries across the ERCOT regions

V. **Scenarios and sensitivity analysis** – Shows variations of project economics based on technological and market level drivers

A comprehensive collection of data underlying this report is provided in the databooks accompanying this report

- Databook 1 Standard Investment Cases contains detailed data of the 72 battery investment cases
- Databook 2 Forecast Market Data contains Aurora's Annual market results for all scenarios plus hourly and 15-minutely Central Day-Ahead, Real-Time and AS price forecasts to 2050
- Databook 3 Historic battery operational characteristics

Source: Aurora Energy Research

Context for the report

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Caveats

- Historic battery performance is based on many different datasets and does not include some of the intricacies of operating a battery in Real-Time. The numbers presented are estimated based on the Day-Ahead AS awards, Real-Time generation/consumption and Real-Time hub prices
- AS markets are very small in size and may be saturated rapidly, thus any AS forecasts are vulnerable to unexpected new entrants, hence battery valuations may change significantly report to report due to market/policy changes.
- Aurora's assumptions on CAPEX numbers are estimates based on some of the most competitive quotes that we have seen in the market, whereas our bespoke battery consulting work has seen a wide range of CAPEX quotes that will vary by project
- Standard Investment Case batteries are modelled to have a nameplate capacity of 1MW and therefore revenue results can be scaled to any MW. However, the battery revenue analysis assumes the battery is a 'price-taker' and therefore the addition of a large (100MW+) battery that is not included in Aurora's market scenario would require a bespoke analysis
- This report is intended to be used as a directional analysis and should not be viewed as a replacement for asset specific forecasts.

What this report is not trying to do

- Not arguing for or against battery storage assets in the future energy market
- Not comparing existing batteries against each other as batteries all have different types of contracts and/or constraints that are non-public
- Not taking a position the role of storage in the future energy system
- Not using Aurora's backcast to measure existing batteries' actual performance

Source: Aurora Energy Research

Summary of key definitions

Key term	Also known as	Description
ATC	"Time Weighted Average" price (TWA), "Baseload" price	The "Around the Clock" price is the simple average of all half hourly prices during a given period
Average daily price spread	TB1, TB2, TB4	Top prices minus bottom prices in the day, 1-4 hours depending on the battery duration
State of Charge	SOC	How much energy the battery has remaining of total storage volume
Duration		How long the battery can dispatch at full output, measured in h
Capacity		Maximum output of the battery, measured in MW
Storage volume		Energy capacity of the storage asset, measured in MWh. Capacity x Duration = Storage volume
Ancillary Services	AS	Other services procured by ERCOT to control system frequency
Arbitrage		The act of buying low and selling high
Round Trip Efficiency	RTE	The percent of electricity available to sell after charging. Losses in electrical equipment mean that only a fraction of purchased energy can be resold
Percent of perfect	PoP	The percent of theoretical maximum revenues a battery can capture due to operational constraints such as state of charge and imperfect foresight

Source: Aurora Energy Research

Agenda

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Executive Summary

- With over 70GW of capacity in the ERCOT Interconnection Queue, there is considerable interest in developing storage in Texas
- In the past 2 years, battery storage assets have predominantly operated in the Ancillary Service markets and capacity has grown fifteen-fold since the start of 2020
- Aurora's Central forecast sees battery capacity in ERCOT increase from 2 GW today to over 21GW of installed capacity by 2045, evenly split between Load Zones
- Of the 24 investment cases in the Aurora Central scenario:
  - 1 hour duration assets in the West are the most profitable, with a maximum IRR of 18.2% on entry in 2023
  - Deploying a 1 hour battery in the Houston Load Zone can also achieve a comparable IRR, with 18.1% in 2023
  - A later entry date of 2026 can increase IRRs by 2-3 p.p provided forecasted battery CAPEX declines are realized
  - The additional CAPEX required to build 2 and 4 hour assets is not offset by necessary increases in revenues
  - Nodal volatility is predicted to be the highest in the North and West zones with 6-7% spread premium for a top 10th percentile node

Sources: Aurora Energy Research

70 GW of prospective battery projects are in the pipeline with almost one third of projects co-locating with a wind or solar asset

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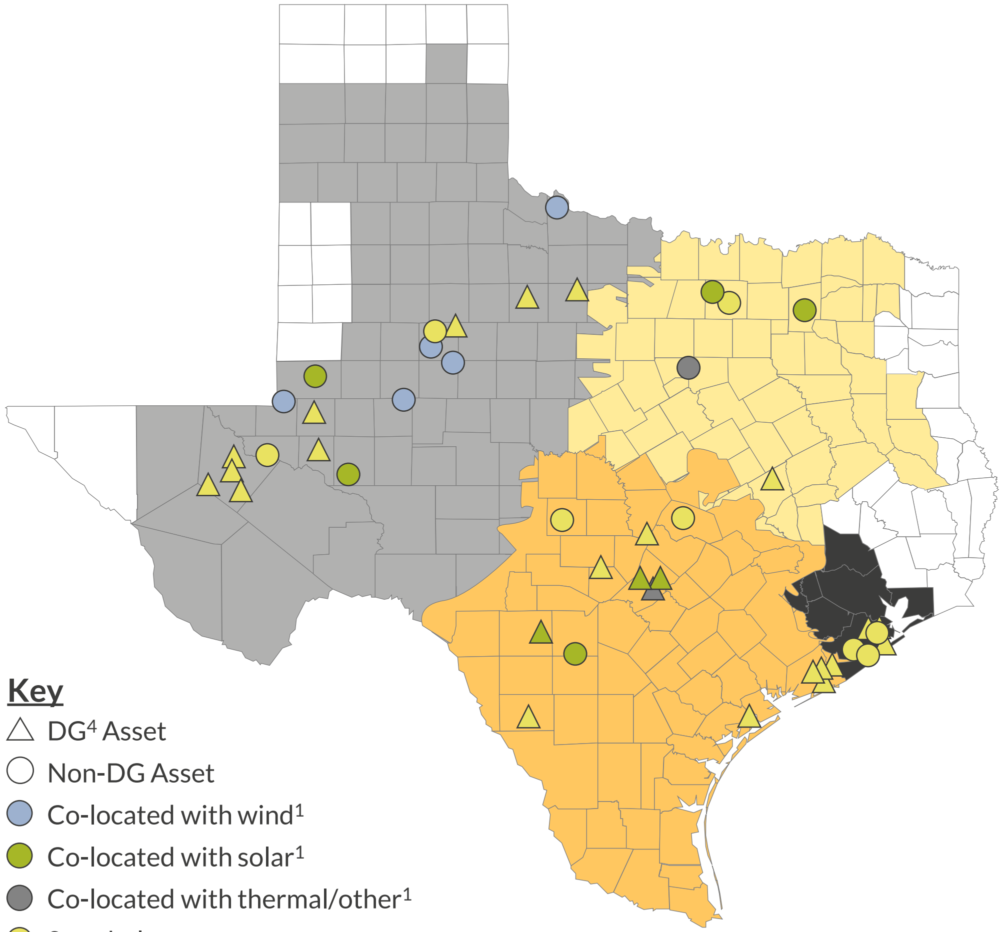
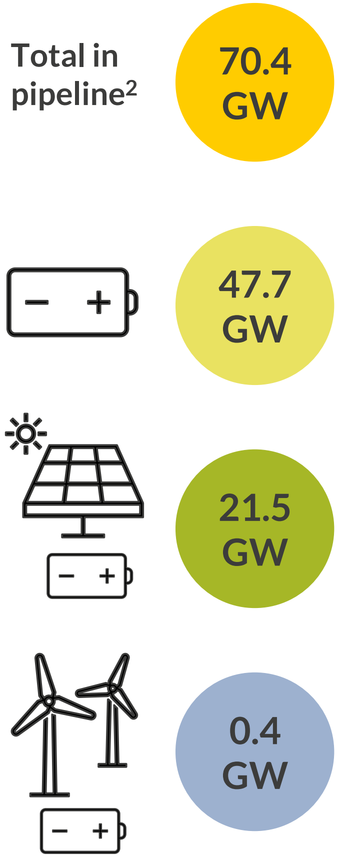
Map of operational batteries in ERCOT as of December 2022[2]



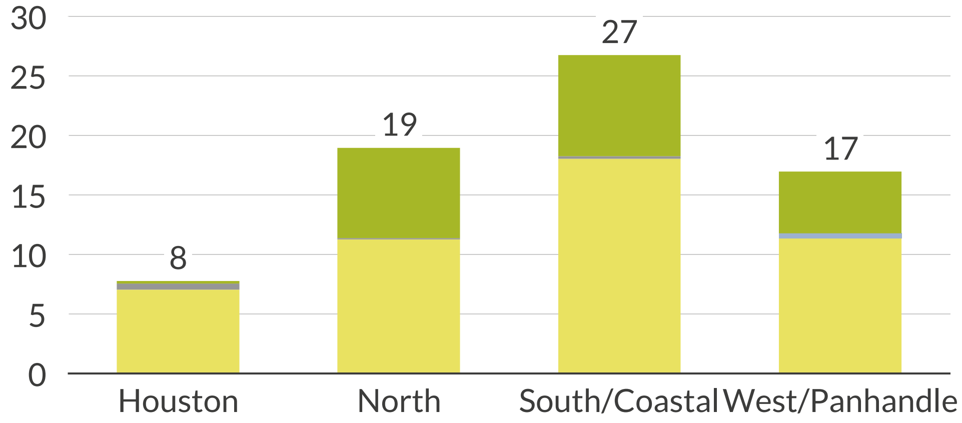
Key
- △ DG[4] Asset
- ○ Non-DG Asset
- Co-located with wind[1]
- Co-located with solar[1]
- Co-located with thermal/other[1]
- Stand-alone

Houston | North | South | West



Cumulative battery storage pipeline for ERCOT zones with completion date before end of 2027[3,5]

GW



- Some developers are opting for smaller, distributed connected assets, with approximately half the fleet by number brought on by this method
- Most assets are situated nearer to demand centers, around Houston, San Antonio and Midland/Odessa
- The vast majority of the interconnection queue are standalone, with another 1/3 co-located with solar – there are some assets trying to use older interconnection points at thermal assets, but these are uncommon

Co-located with solar | Co-located with wind | Co-located with thermal | Stand-alone

1) Includes standalone resources on same site as another generator, does not include AC/DC-coupled resources 2) May not include some batteries under 10 MW in capacity or DG connected assets 3) As of December 2022. 4) Distributed Generation. 5) ERCOT does not have information to confirm if the co-located projects will be operated as AC/DC-coupled resources, or independently. This will be remedied by RRGRR023, due in 2022

Sources: ERCOT, Aurora Energy Research

3 projects typify the current operational use cases of batteries in ERCOT

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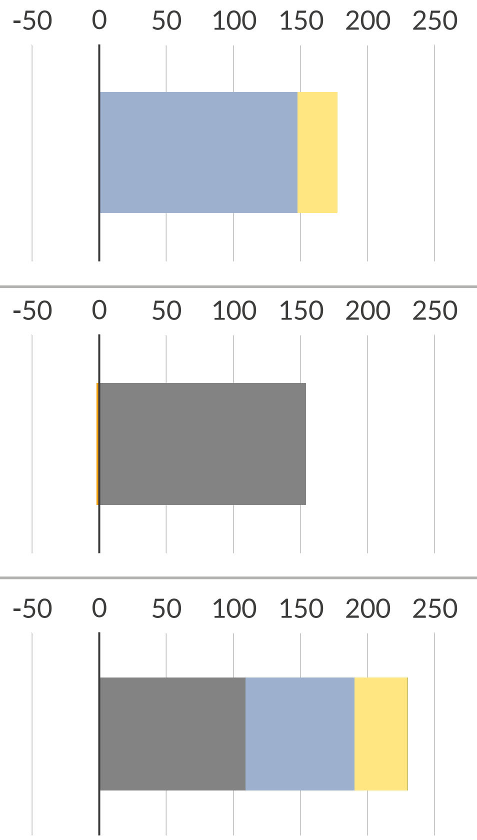
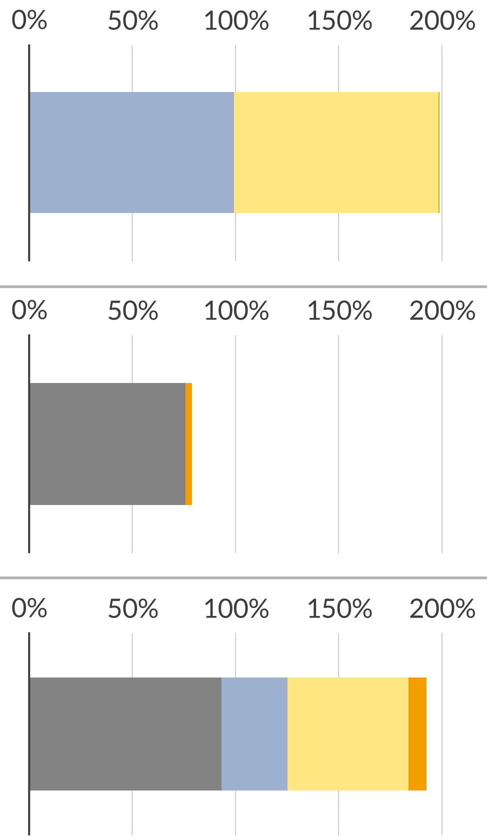
Project	Capacity MW	Duration hours	Month[1] of commission	Asset Type	Region	Operator	Business Model
Blue Summit Battery (1)	30	0.5	08/2017	Co-located with Wind	West	NEXTera ENERGY	Regulation services
Port Lavaca (2)	9.9	1.2	02/2020	Stand-alone	South	KEY CAPTURE ENERGY	RRS & energy arbitrage
BRP Odessa (3)	9.9	1	10/2020	Stand-alone	West	BROAD REACH POWER	Cross-market

2021 estimated gross margins[1,4] by market $/kW



2021 market participation[2] % of hours in 2021



(X) **Intraday deep dive**

RRS | Reg. Up | Reg. Down | Non-spin | Wholesale

1) Calculated at the hub price not LMP, may underestimate locational value 2) Proportion of hours above 100% indicates participation in 2 markets simultaneously 3) Notrees tends to be the marginal plant in the FRRS markets, so gets cleared less often 4) Annualised to account for commission part way through the year. Estimates include revenues from wholesale + AS markets and charging costs, excludes hedges including PPAs, price floors etc. May underestimate if commissioned after August

Sources: Aurora Energy Research, ERCOT, EIA

Blue Summit Battery was the highest performing battery in the fleet from September to November, making an average of $7.3/kW/month

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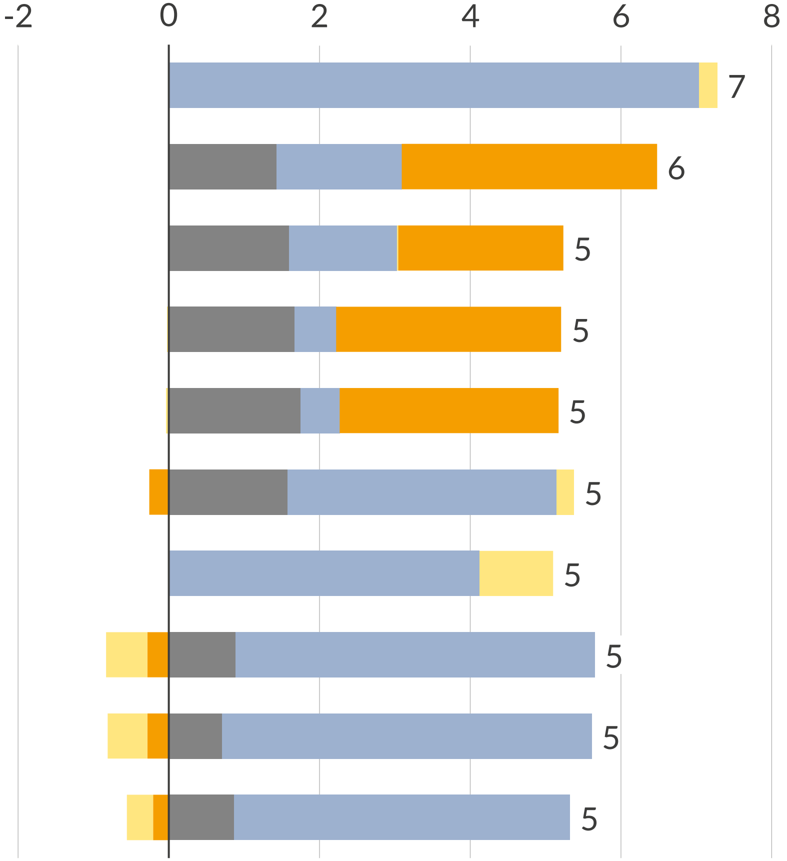
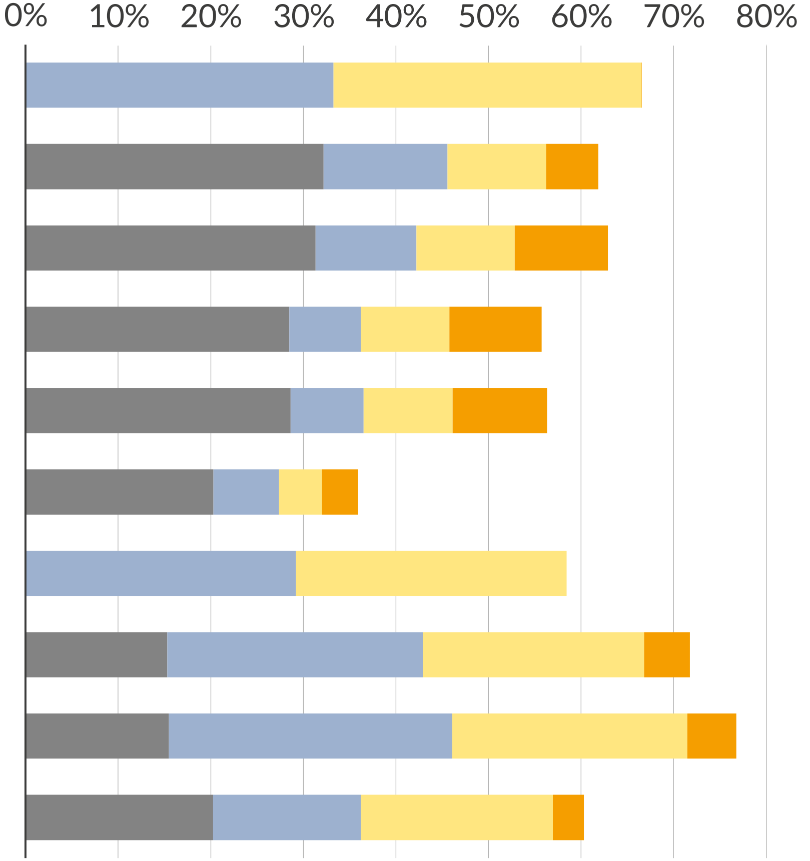
Top performing batteries in Fall 2022

Asset Owner	Duration	
NextEra Energy	2	Blue Summit
Jupiter Power	2	Flower Valley II
Jupiter Power	0.5	Flower Valley I
Jupiter Power	2	Triple Butte
Jupiter Power	2	Swoose
Tesla	2	Gambit
Duke Energy	2	Notrees
Broad Reach Power	2	BRP Magnolia
Broad Reach Power	1	BRP Odessa
Astral	2	Chisholm Grid

Average monthly margins by market, September to November 2022[2,3], $/kW



Estimated participation by market, September to November 2022[1], % hours



For the full asset database please see Databook 3

RRS | Reg. Up | Reg. Down | Non-spin | Energy

1) Total market participation percentages can exceed 100% due to participation in multiple markets in the same period. 2) Energy revenues calculated at the batteries' Real-Time nodal price. 3) September 2022 – November 2022.

Sources: Aurora Energy Research, ERCOT

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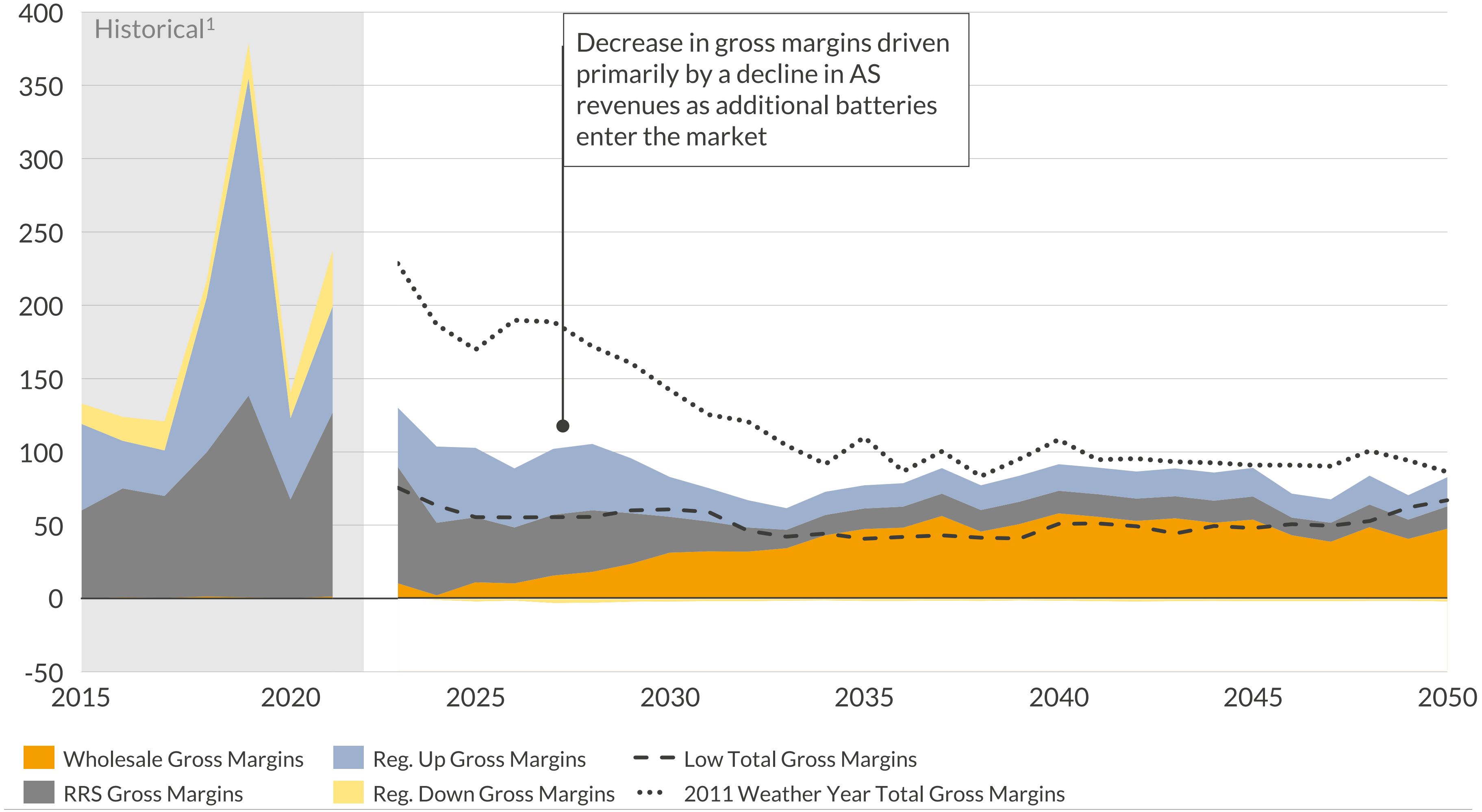
Revenues for a 1 hour asset are formed predominantly of AS, but transition to a stable $80/kW from 2030 onwards

Total annual degraded gross margins for 1-hour battery at the West Hub, 2023 start year[2]

$/kW/year, real 2021



1) Backcasted revenues, excludes February 2021. 2) Total gross margins shown do not include any Nodal Premium. This can be applied for different node percentile and premium persistence assumptions in the accompanying Investment Cases databook.

Source: Aurora Energy Research

Outlook for battery gross margins

- Gross margins for a 1-hour battery decline from $111/kW/year between 2023-25 to an average of $78/kW/year post-2030
- While AS prices remain relatively stable, increased battery entry implies a decline in capacity awards for any given battery, which reduces margins
- As ancillary markets become saturated, wholesale arbitrage revenue will make up a larger proportion of a battery's gross margins, rising from 8% in 2023 to 63% in 2035
- Reg. down is less profitable in the forecast and is used mainly to offset charging costs
- Decreases in CAPEX from 2022 onwards means assets become more economically viable with lower gross margins

Regional differences are less impactful than duration and entry year decisions for asset profitability

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Evolving nodal topography differentiates the regions, but the West zone will generate the highest margins for new build batteries, with an PV's of about 2-10% higher than other zones for 2026 entry. Houston IRR's benefit from high energy margins during scarcity hours, but these are more heavily discounted than non-scarcity-driven revenues. 1 hour batteries remain the most profitable in the near term, but medium-term declines in CAPEX will reduce the differential in profitability across durations.

Entry Year	Scenario	Duration	Present Value of Margins[1,2] ($/kW)				IRR (%)				Payback Period (yrs)			
			Houston	*North*	*South*	*West*	*Houston*	*North*	*South*	*West*	*Houston*	*North*	*South*	*West*
2023	Central	1 hour	419.3	413.1	418.2	423.5	18.1%	17.7%	18.0%	18.2%	4.8	4.9	4.8	4.8
2023	Central	2 hour	429.5	433.6	432.7	450.4	9.6%	9.6%	9.6%	10.2%	8.0	8.0	8.1	7.8
2023	Central	4 hour	507.4	532.1	521.0	557.4	4.6%	5.3%	5.0%	5.9%	13.0	12.3	12.7	11.9
2026	Central	1 hour	358.7	350.9	357.0	363.2	19.8%	19.1%	19.6%	19.7%	4.3	4.4	4.4	4.3
2026	Central	2 hour	374.6	380.4	380.1	401.6	12.0%	12.0%	12.1%	12.9%	7.3	7.4	7.3	7.1
2026	Central	4 hour	459.5	497.6	480.2	524.2	7.4%	8.4%	8.0%	9.1%	10.5	9.7	10.1	9.4

1) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). 2) Present value of margins includes all revenues, charging costs, and annual fixed costs.

Source: Aurora Energy Research

The timing and frequency of weather events creates a significant range in potential upside relative to the central case

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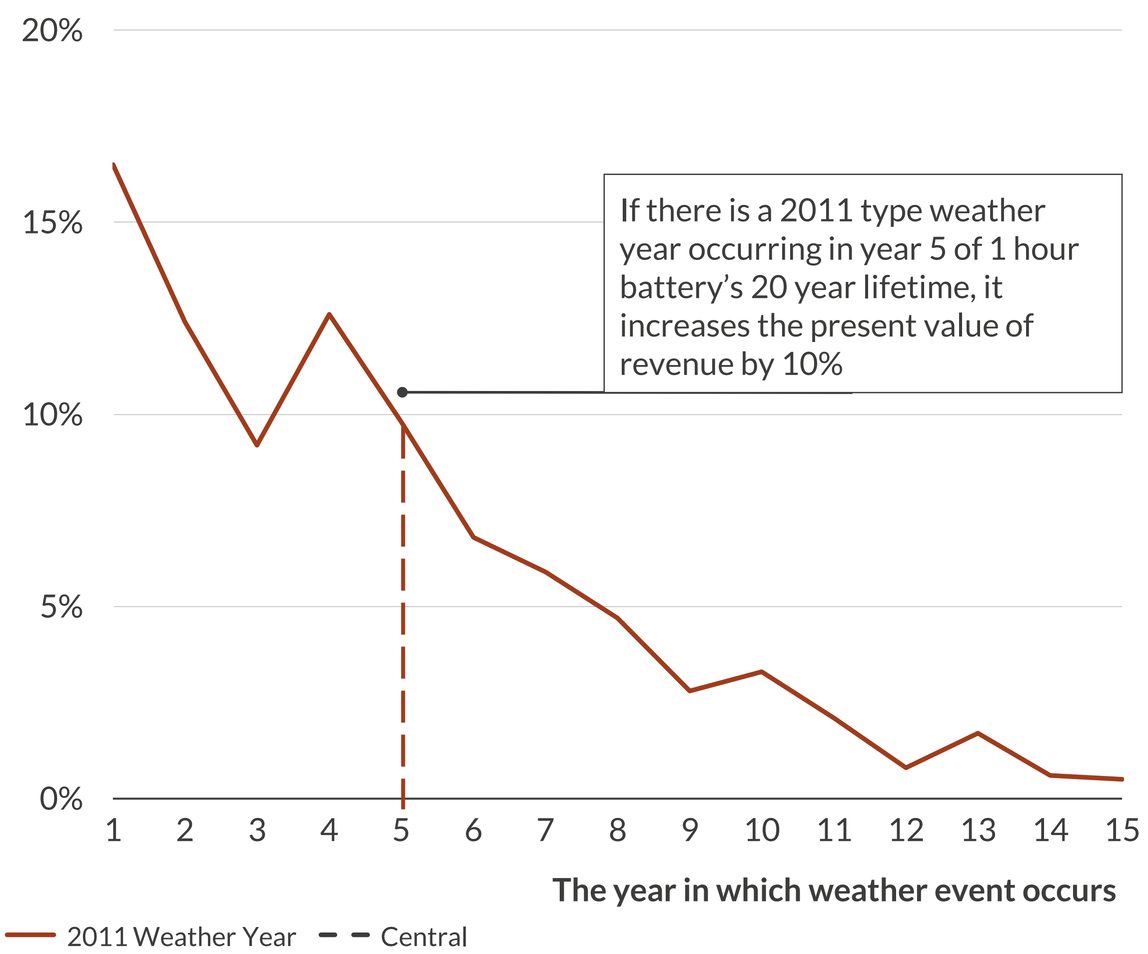
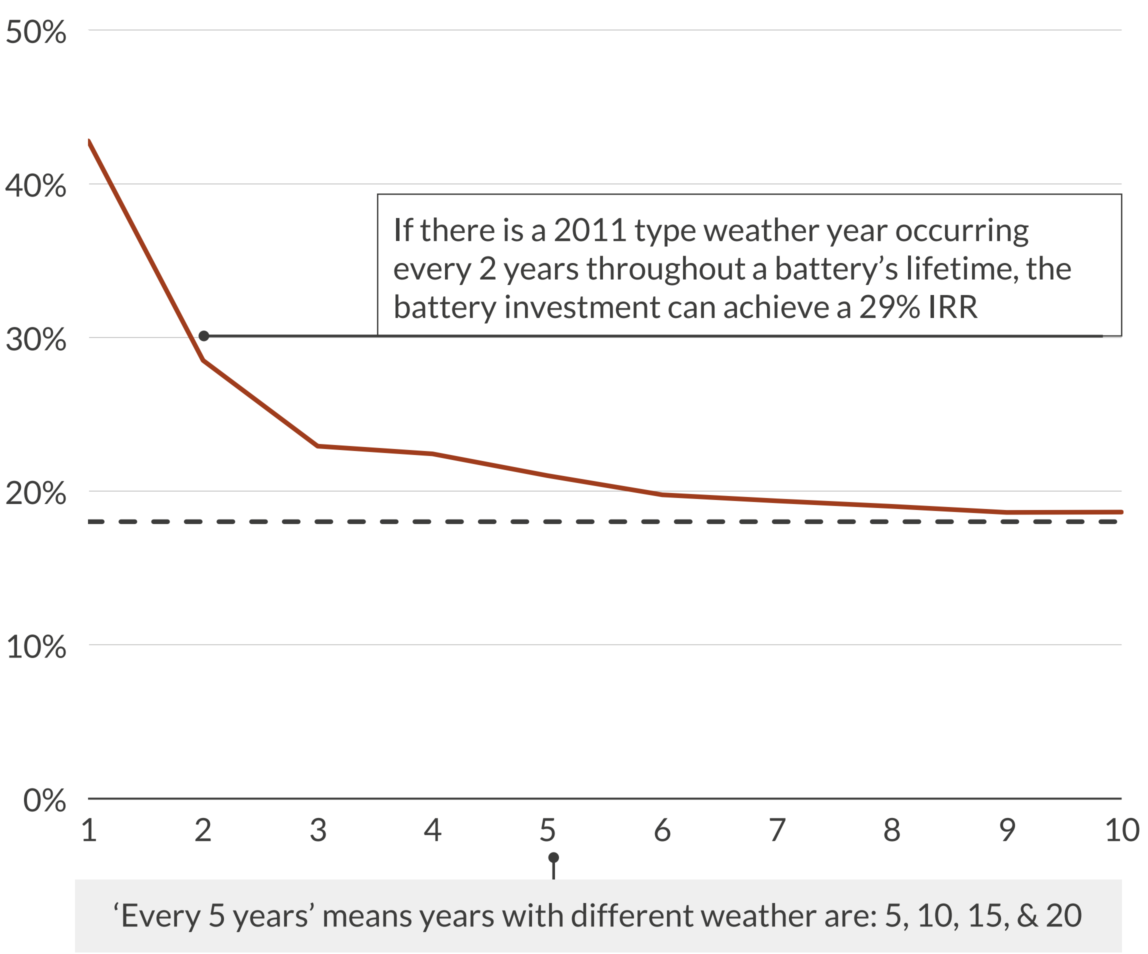
Change in present value[1] of revenue from the 2011 Weather Year Scenario – 1hr South batteries[2,3], %



1hr South Battery IRRs[1] with varying frequency of weather years occurring
%



1). Assume a discount rate of 11%. 2) 2023 start 3) Includes degradation and availability

Source: Aurora Energy Research

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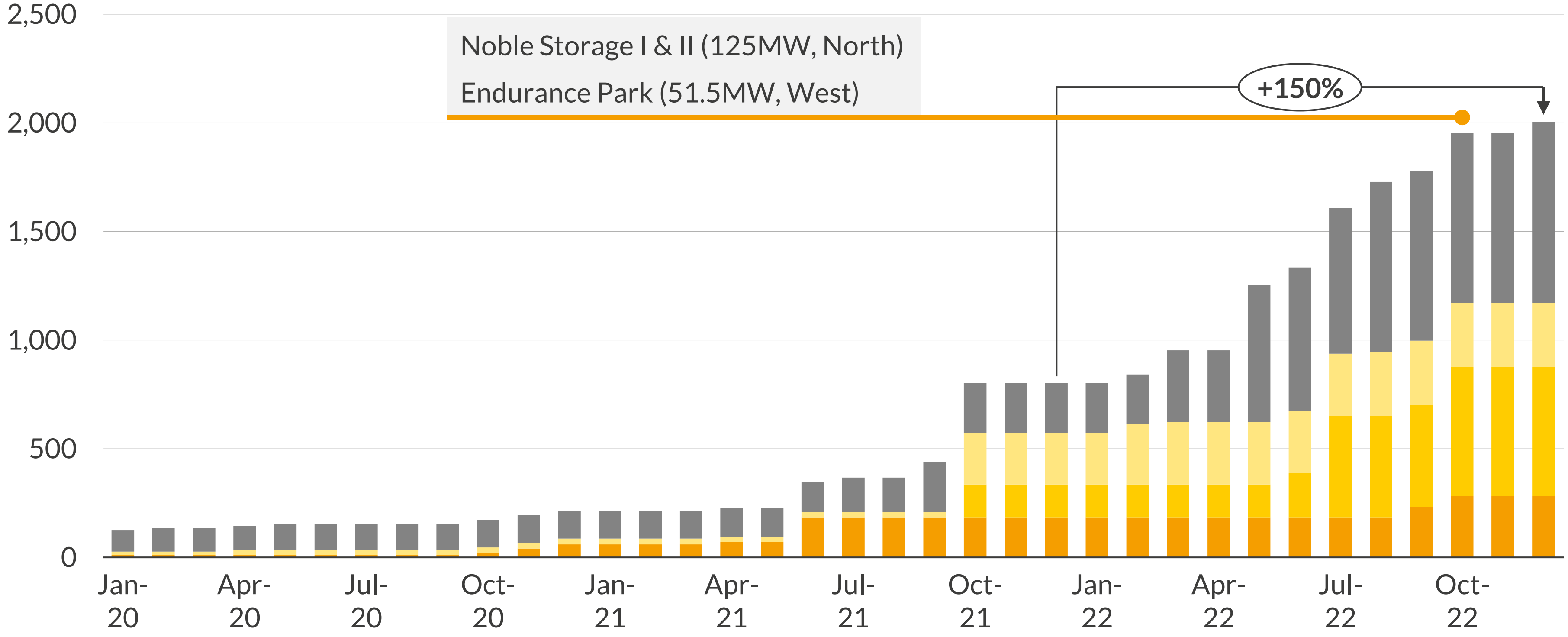
Due to a favourable landscape, battery capacity has grown considerably since December 2021, up over 100% to 2000MW

Battery capacity growth in ERCOT[1]
MW



Total installed battery storage capacity in ERCOT[1]
MW

123 | 213 | 801 | 2005

Houston | North | South | West

- As of December 2022 there are 60 commercially operable storage assets in ERCOT
- Operational capacity is geographically spread across ERCOT. The West has the largest installed capacity with 832 MW of the 2,000 MW total
- Decordova BESS, a 1 hour duration asset, commissioned in July 2022, is the largest storage asset in ERCOT, at 263MW

1) Includes capacity which is commercially operable

Sources: Aurora Energy Research, ERCOT

70 GW of prospective battery projects are in the pipeline with almost one third of projects co-locating with a wind or solar asset

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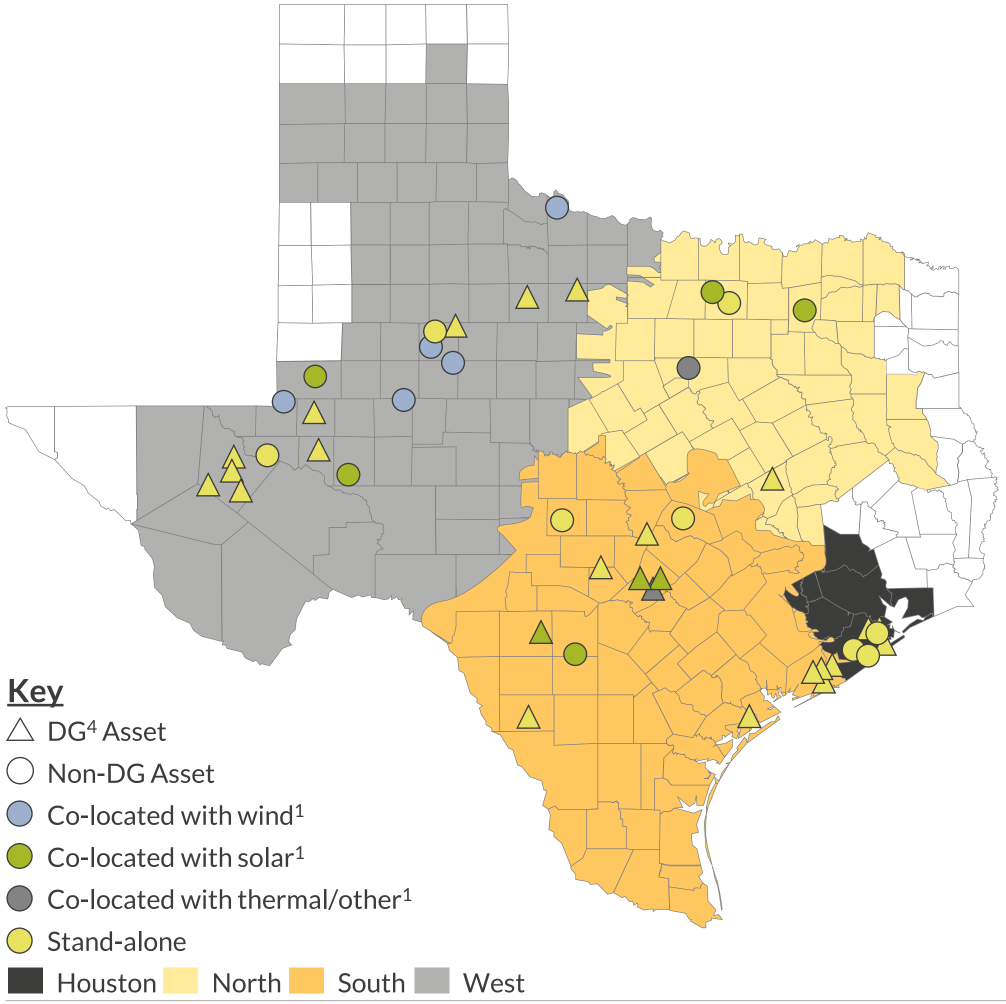
Map of operational batteries in ERCOT as of December 2022[2]



Total in pipeline[2]: 70.4 GW

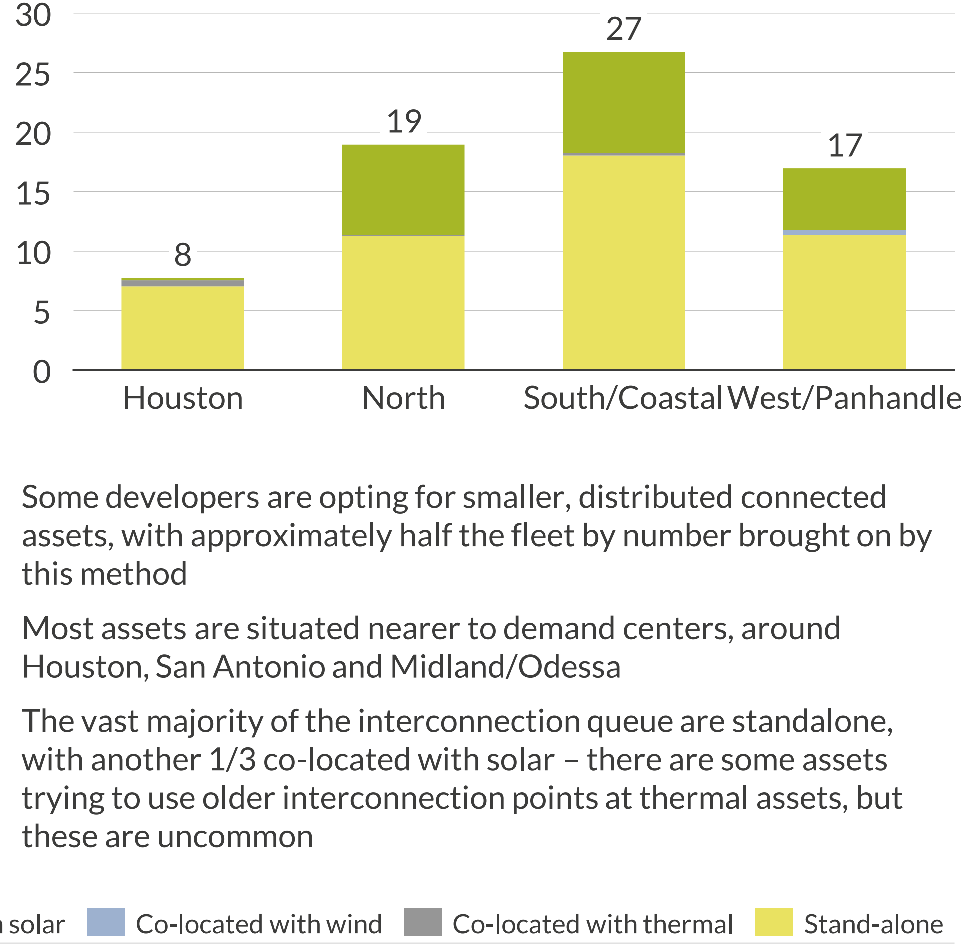
Battery: 47.7 GW

Solar + battery: 21.5 GW

Wind + battery: 0.4 GW

Cumulative battery storage pipeline for ERCOT zones with completion date before end of 2027[3,5]

GW



- Some developers are opting for smaller, distributed connected assets, with approximately half the fleet by number brought on by this method
- Most assets are situated nearer to demand centers, around Houston, San Antonio and Midland/Odessa
- The vast majority of the interconnection queue are standalone, with another 1/3 co-located with solar – there are some assets trying to use older interconnection points at thermal assets, but these are uncommon

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Sources: ERCOT, Aurora Energy Research

The project pipeline for batteries has enough planned capacity to reach 73 GW by 2027

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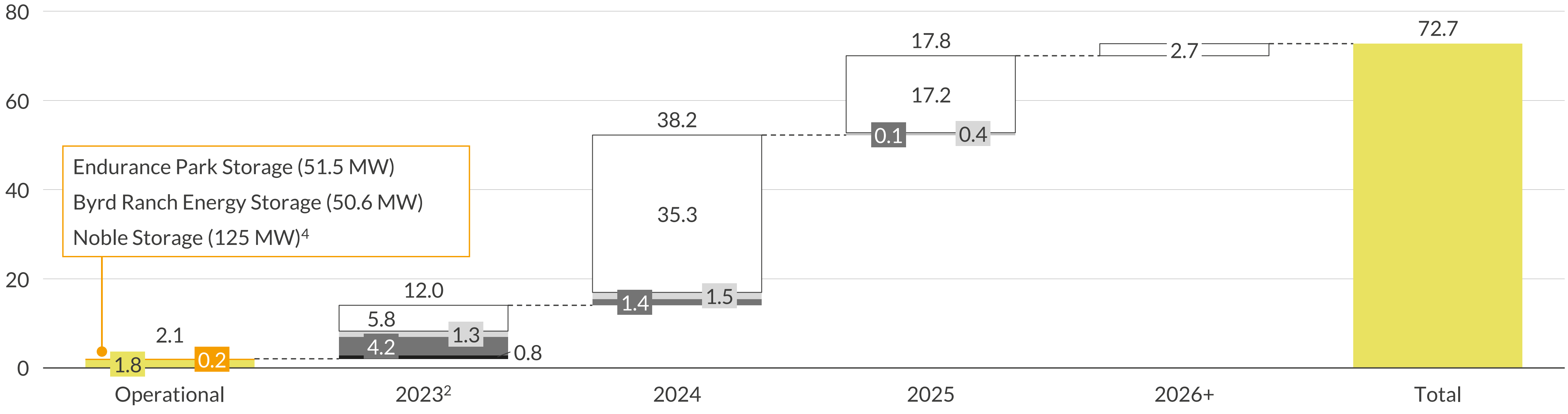
Capacity of pipeline projects by status and projected Commercial Operation Date (COD)[1]
GW



- There is currently 70.6 GW of capacity, or 467 projects, in the pipeline for batteries, 30 times the current amount of installed capacity
- Nearly 800 MW of energized capacity is expected to begin commercial operation in 2023
- 72% of pipeline projects are at least 100 MW in capacity, 11% are greater than 300 MW
- Battery installations are primarily planned for the South hub: 34% of pipeline capacity is located in the South, 27% in the North, and 24% in the West

Energized | IA signed + financial security and notice to proceed provided | IA signed + no financial security and notice to proceed provided | IA unsigned | Additions from last 3 months[3]

1) Plant details and status as in December's Generator Interconnection Status report, a monthly report published by ERCOT. 2) Includes delayed projects with CODs in 2022. 3) Projects that were commissioned in October, November and December of 2022. 4) Comprised of two plants of the same name and same size, located at same site.
Sources: Aurora Energy Research, ERCOT

Batteries can capture a variety of revenue streams, each with varying levels of risk and liquidity

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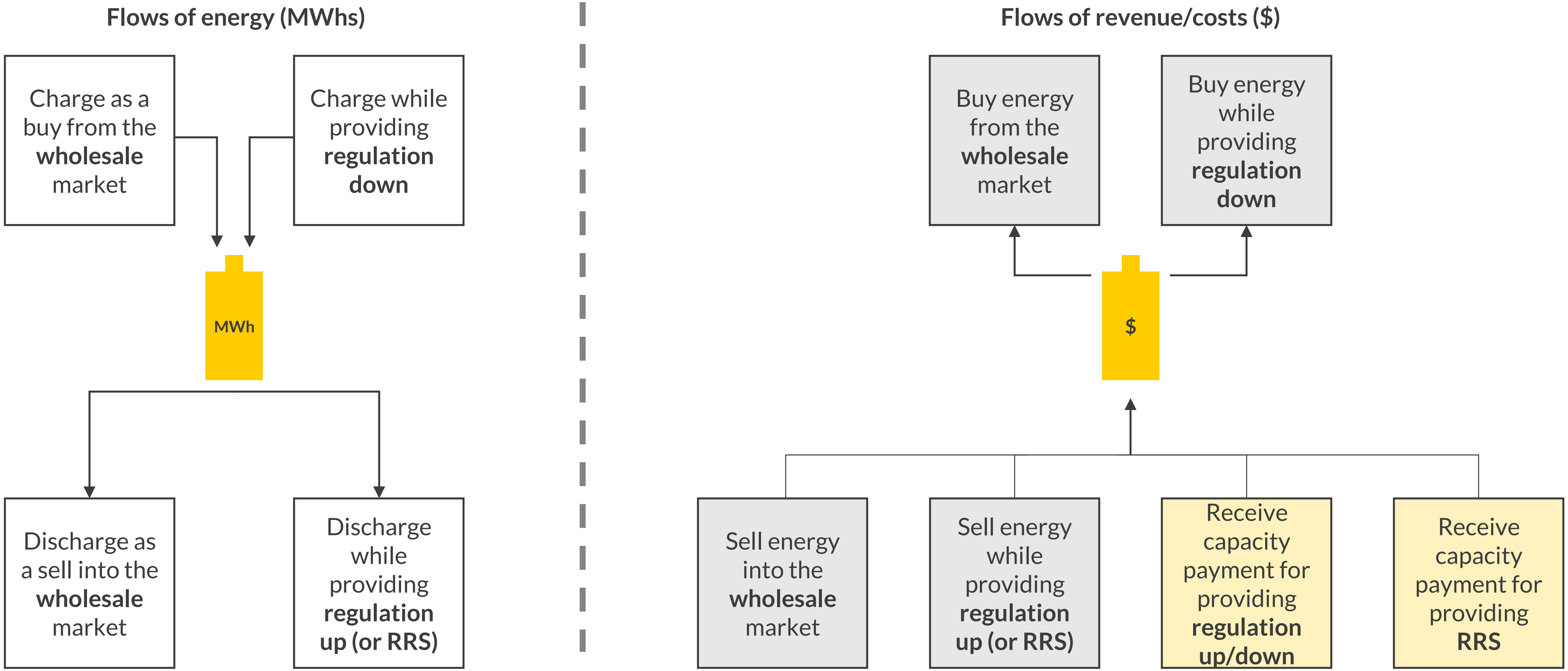
Key: Market level; Project specific

Revenue stream	Relative size of market	Opportunity
Wholesale arbitrage (Market level)	▪ Large, multi-GW ramps expected and growing	▪ Increasing deployment of renewables presents the opportunity for low charging cost ▪ Rising gas prices and high top prices ensure stable spreads over forecast
Ancillary services (Market level) • **Reg. up-down** • **Responsive reserve service** • **Non-spinning reserve** • **Contingency reserve service**	▪ Small, at risk of saturation	▪ Increased renewables deployment, retiring thermal plants and battery suitability for providing ancillary services ▪ Grid operators frequently make new ancillary services to utilise batteries better
Congestion relief, LMP arbitrage (Project specific)	▪ Small, very locational and weather/outage dependent	▪ Congested local networks and volatility ▪ Retiring thermal capacity creates location-specific value
Weather volatility (Project specific)	▪ N/A, but extreme weather expected once per 5 or 10 years	▪ Extreme weather creates large arbitrage opportunities and potential for sustained high ancillary prices
Day-Ahead/Real Time arbitrage (DART) (Project specific)	▪ Medium, often used if Real-Time is not as scarce as expected	▪ Increasing volatility of wind and solar generation ▪ Demand sensitivity to weather conditions

In general, the most successful assets will participate in most markets, with a portion of revenue coming from each

Sources: Aurora Energy Research

Grid-scale battery operation can be visualized in two parts: cash flow and energy flow



Wholesale gross margin ($)	= Wholesale sell ($) – wholesale buy ($)
AS gross margin ($)	= Regulation capacity payment ($) + RRS capacity payment ($) + energy sold providing regulation up (or RRS) ($) – energy bought providing regulation down ($)

Sources: Aurora Energy Research

ERCOT's Ancillary Services aim to maintain the frequency at 60Hz or restore the system frequency after a major deviation

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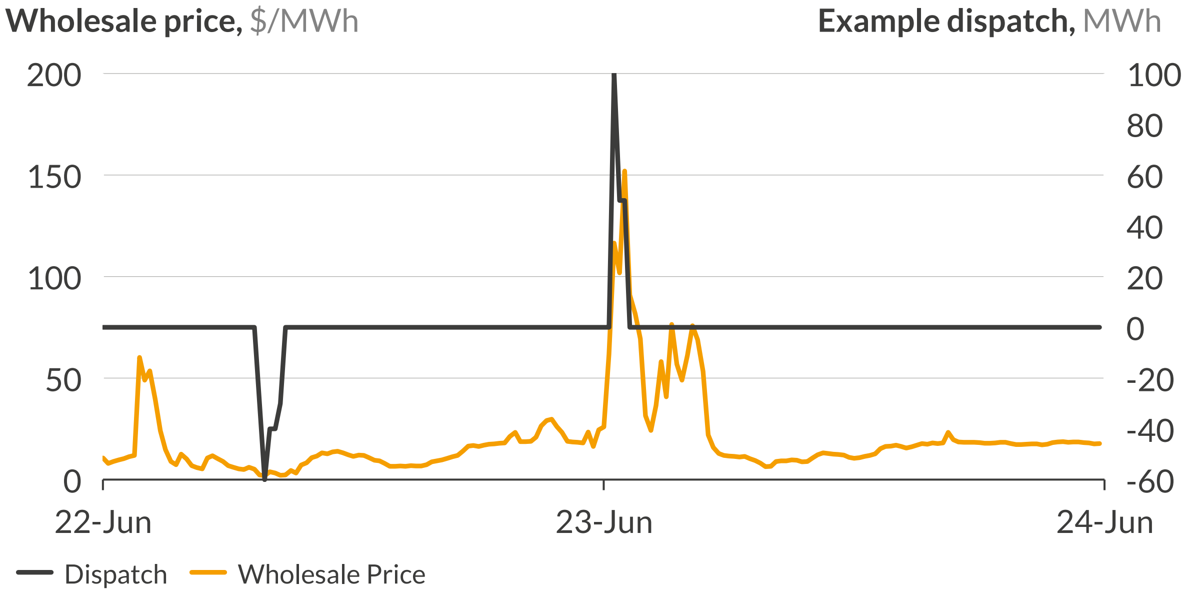
Ancillary services properties	Regulation up/down	Responsive Reserve Service (RRS)	Non-spinning reserve
Purpose	Used to balance the grid in a near-instantaneous fashion when supply and demand fluctuate. Constantly responds to frequency deviations, targeting 60Hz	Used in the event of larger frequency deviation e.g. loss of a large generator or a large load-ramp	Used for system wide capacity needs for dramatic increases in load or large ramp downs in wind generation. Also used for managing local transmission constraints.
Current market size[1]	73-684 MW (Reg-Up) 151-631 MW (Reg-Down)	2300-3335 MW (~50% reserved for load)	2540-5438 MW (more than doubled from 2021)
Response time	1-5 seconds	0.5 seconds (*load resources on Under- Frequency Relay, or UFR*) 10 minutes (*online generation and controllable load resources*)	30 minutes
Settlement	Pay-as-clear for capacity ($/MW) – headroom is reserved to perform AS If resources dispatch energy, then they are compensated at the Real-Time price		
Relative deployment duration and frequency	Instantaneous/continuous. Average of 10% to 30% dispatch as proportion of capacity	Typically < 30 minutes, but can be for consecutive hours in frequency event. Typically called upon a few times per month, a few minutes at a time	Until capacity margin recovers to over 8%
Primary technologies today	Online thermal generators, 65 MW of batteries in FRRS[2]	Online thermal generators, some hydro. Controllable load resources	Offline peaking/other quick start thermal. Controllable load resources[4]
Sub-markets	Fast Responding Regulation Service (FRRS)	Fast Frequency Response (FFR)[3] Primary Frequency Response (PFR)[3]	

1) 2022 values – values calculated by ERCOT for each month by hour of the day. 2) Fast Responding Regulation Service. 3) From late 2021. 4) Recently included as a part of PUC's ERCOT market redesign.

Sources: Aurora Energy Research, ERCOT

The wholesale market spread is the most liquid of battery revenue streams, with additional value arising from abnormal circumstances

Wholesale Energy Arbitrage



- Battery storage purchases, and charges, at low prices, and then sells the electricity back to the grid in high price periods; this is **energy arbitrage**
- Predicting high price periods is the business of many optimizing shops, and imperfect dispatch has implications on battery valuation
- Fundamental value in the market wide wholesale spreads is driven by:
  - Natural gas prices
  - Renewables penetration
  - Ramping requirements

Additional value drivers in the wholesale market

Weather volatility

Hot summers or cold winters can add material value onto wholesale spreads and prices

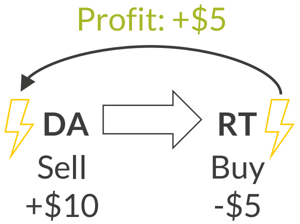
Expectation of frequency of extreme weather is the main uncertainty

Congestion relief / Nodal volatility

Generally found nearer high demand areas

Driven by outages and over generation

Can offer significant upside, but can be short term and very localized



Day-Ahead/Real-Time arbitrage (DART)

Day-Ahead and Real-Time positions can be well correlated, but when the Real-Time price is lower, QSEs can buy-back the energy on the spot market

Usually performed on days where arbitrage is less profitable

Sources: Aurora Energy Research, ERCOT

Grid-scale batteries are well placed to provide effective Ancillary Services at low cost

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1 Regulation: *for small deviations*

Regulation Up / Down
Response of generation or controllable load to a continuous signal to either increase or decrease production/consumption. Storage is well suited to rapid changes in dispatch and so can follow the second-by-second signal with ease

Sub markets[1]

FRRS (A)
Sub-market of regulation for batteries
Limited to 65MW up, 35MW down

Normal regulation (B)
Not limited to just batteries
c. 500MW up, 300MW down

2 Response: *for frequency restoration after a large deviation*

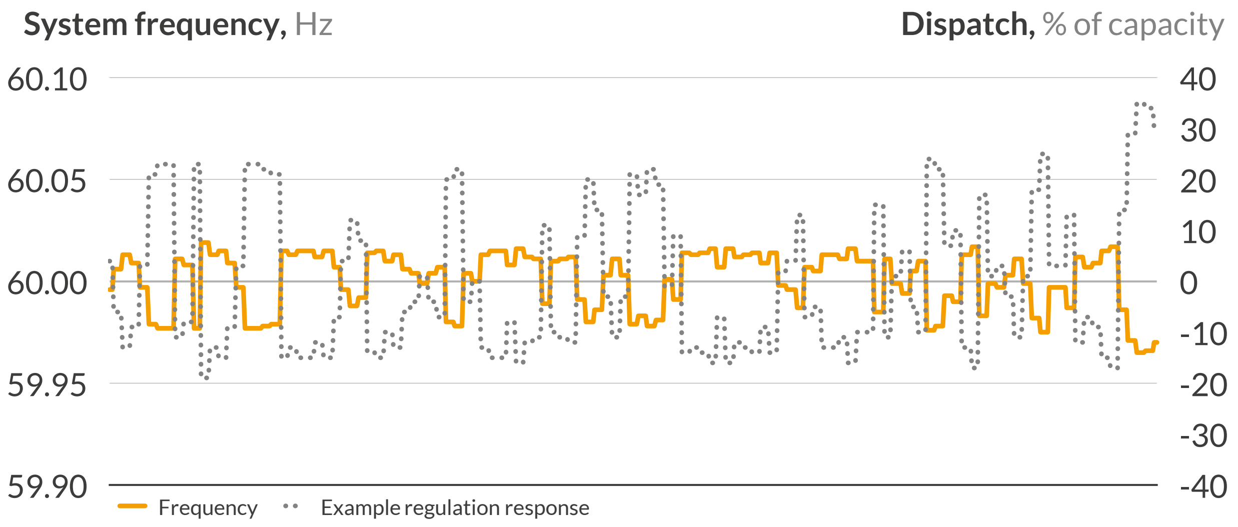
Responsive Reservice Service (RRS)
Responds quickly to major frequency deviations. Required response times make batteries ideal due to their ability to almost immediately ramp to full output if necessary

Sub markets[1]

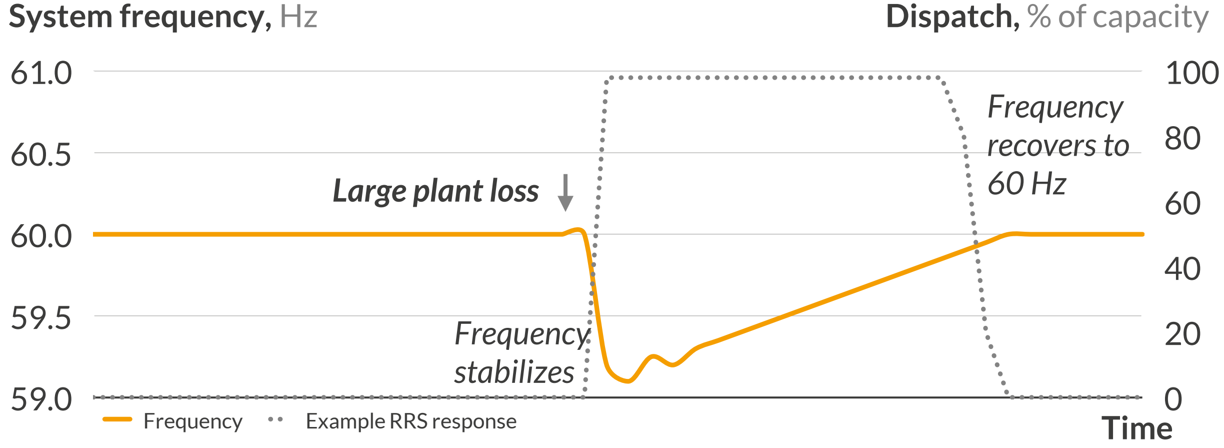
FFR[2] (A)
Sub-market of batteries, for initial quick response
Limited to 450MW

PFR (regular RRS) (B)
Not limited to just batteries
c. 1-2GW in size

Example Regulation dispatch (seconds timescale)



Example RRS dispatch (seconds/minutes timescale)



1) All submarkets are settled at the same price as the overall market 2) As of June 2022 there has not been any FFR participation, with batteries preferring to participate in PFR

Sources: Aurora Energy Research, ERCOT

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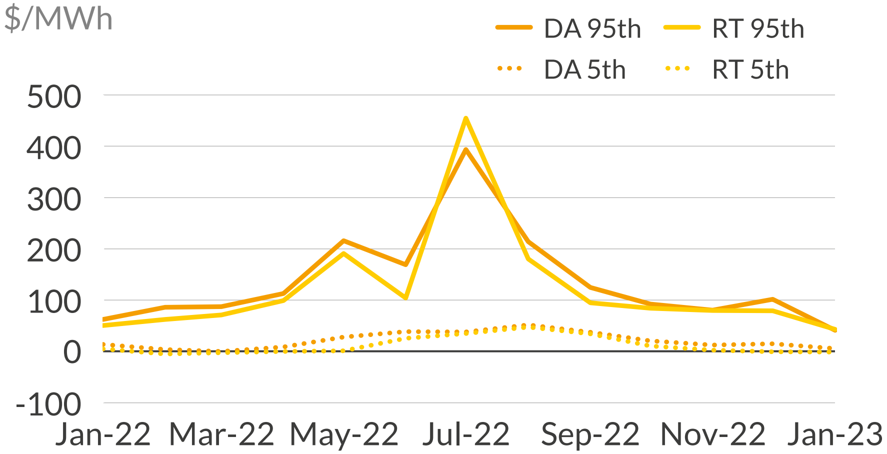
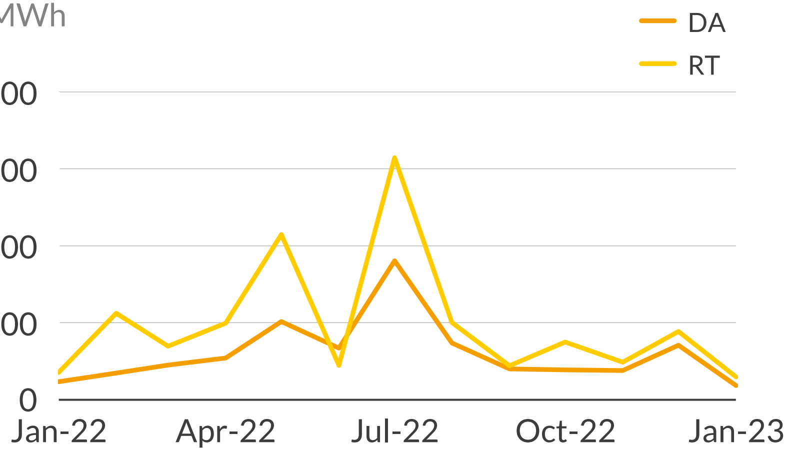
Increased procurement of ancillary services has driven high prices, while volatility has increased into the summer months of 2022

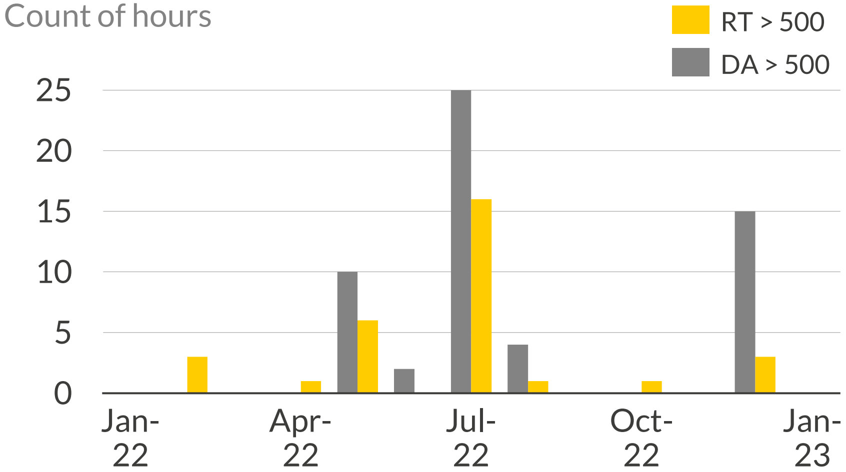
95th & 5th percentiles of ERCOT wholesale price
$/MWh



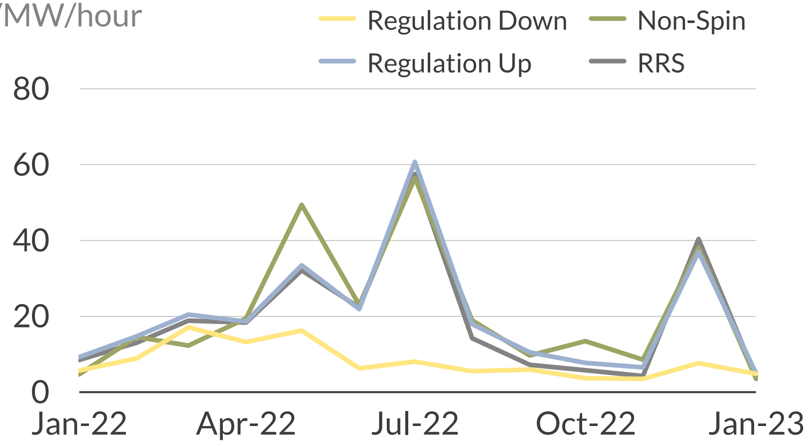
Average TB1 spread price[1]
$/MWh



Extreme wholesale prices in ERCOT[2]
Count of hours



ERCOT Ancillary Service prices
$/MW/hour



- Spreads in both the Day-Ahead and Real-Time markets were high over the summer reaching $360/MWh and $600/MWh respectively in July
  - They have since fallen; in January, they averaged $36/MWh and $59/MWh respectively
- Volatility, as expressed in high price periods, has also dropped from over 25 hours in both DA and RT in July, but December saw a spike in volatility, with 15 periods of Day-Ahead prices over $500/MWh
- Ancillary services have been closely linked to wholesale prices and have declined since July
  - RRS prices have dropped from $57.5/MW down to $3.94/MW

1) Monthly 1hr day-ahead price spread / Top Bottom 1 (TB1). For 15-min Real Time prices, no consecutive restrictions were used in the calculation. 2) Sum of 15 min periods /4 for RT. 3) January 2023 data as of 1/23/2023.

Sources: Aurora Energy Research, ERCOT

RRS and day-ahead wholesale prices have decoupled between 2018 and 2022 due to shifts in technologies procured and participant bidding

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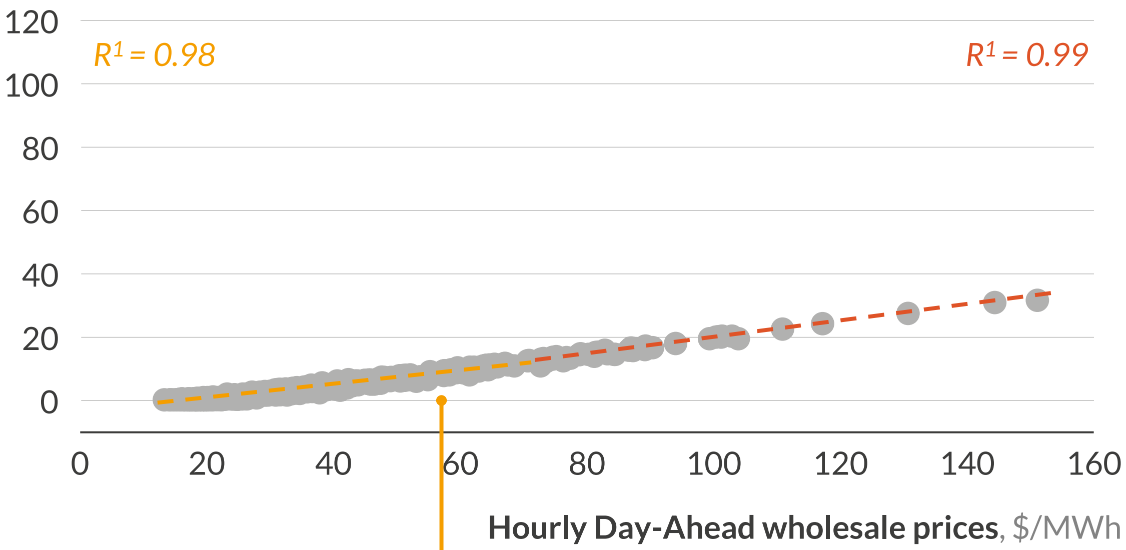
August, 2018

Average percent of total RRS procured by batteries: 0%

Hourly RRS prices, $/MW/h

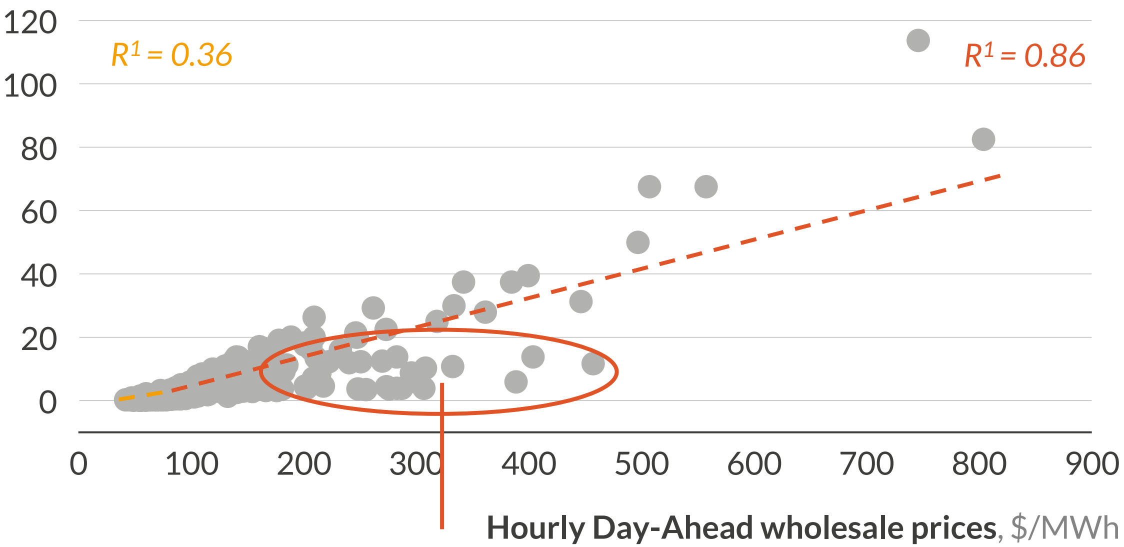


- RRS prices show a very strong correlation (>0.98) for both periods of low and high day-ahead wholesale prices
- Thermal units are primarily setting the price in both markets and thus bid according to similar marginal costs of generation to both markets

August, 2022

Average percent of total RRS procured by batteries: 53%

Hourly RRS prices, $/MW/h



- There are many hours in August 2022 with a high value in the wholesale market that is not reflected in the RRS market
- In August 2022, there are 34 hours which have an energy price >$80/MWh and RRS price <$1/MW/h, where as in August 2018, the minimum RRS price when energy prices are above $80/MWh was $14/MW/h

Prices < $75/MWh   Prices > $75/MWh

1) R value defined as the Pearson correlation coefficient between hourly RRS and Day-Ahead wholesale prices.

Sources: Aurora Energy Research, ERCOT

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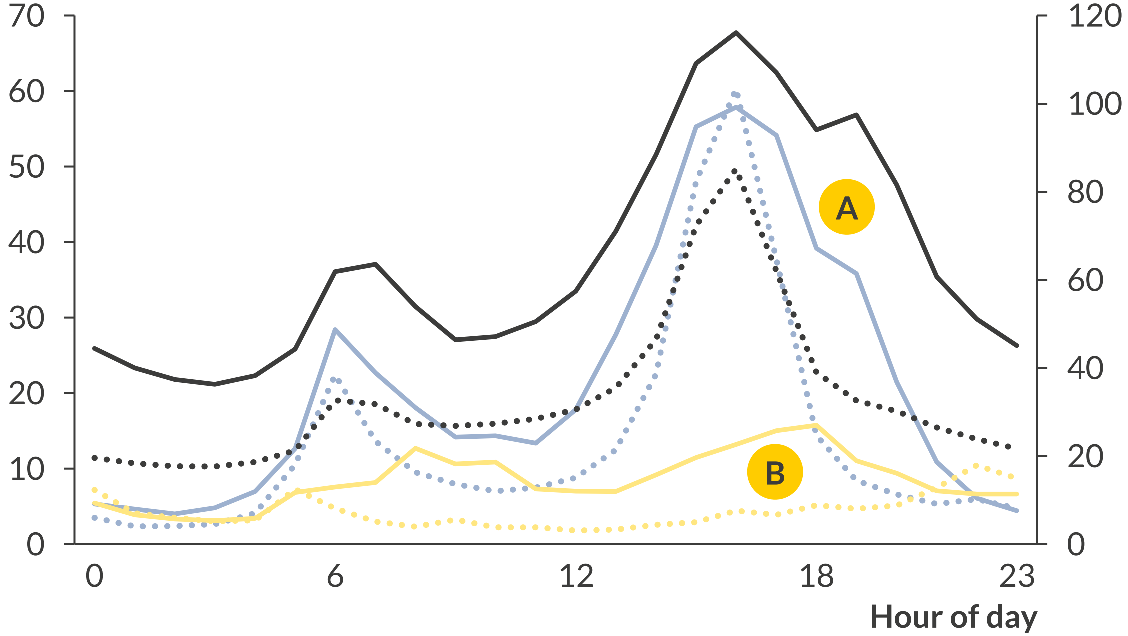
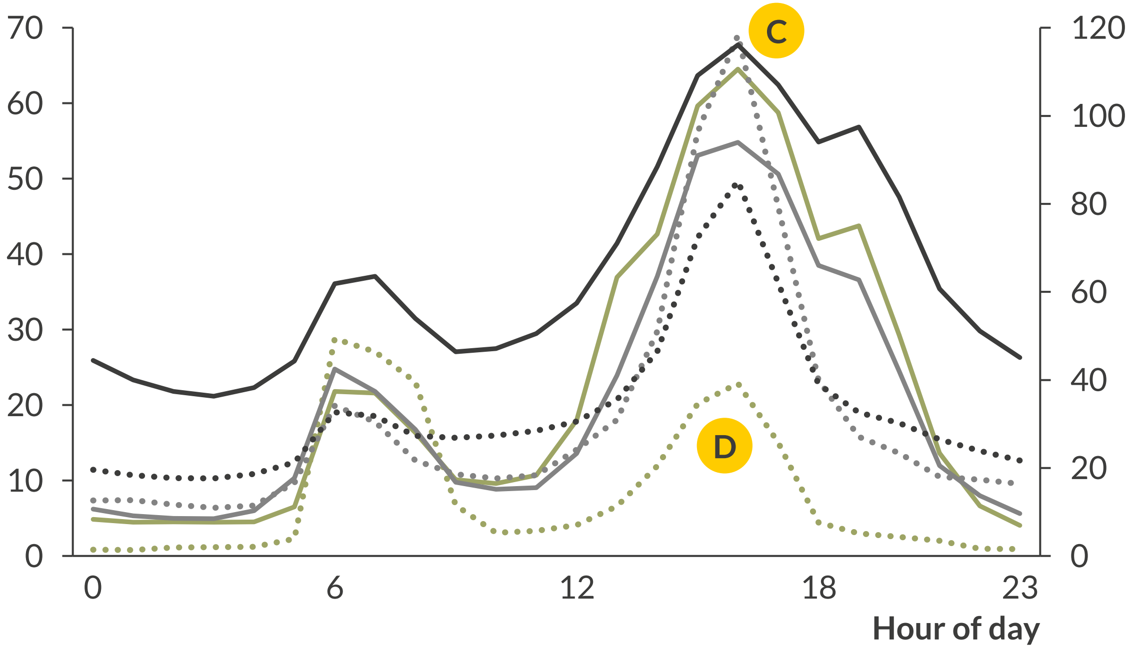
Intraday ancillary shapes have evolved between 2018 and 2022 as market procurement and battery participation levels grew over time

Average intraday Regulation and Day-Ahead market prices
Left: $/MW/hour; Right: $/MWh



Average intraday RRS, Non-Spin, and Day-Ahead market prices
Left: $/MW/hour; Right: $/MWh



A The daily shape of wholesale and Ancillary prices has shifted between 2018 and 2022: there are more high prices in the late evening hours (6-8PM) and a sharper drop in prices 7-9AM after the morning peak

B Reg. Down has grown to show stronger morning and evening peaks between 2018 and 2022

C RRS sees a similar trend to Reg. Up and has seen a shift in value to the later evening hours

D After Storm Uri in February 2021, Non-Spin procurement increased 2-fold. This forced more expensive plants to fulfill the service during peak net load hours such that Non-Spin prices now peak during evening hours with the DAM, Reg. Up, and RRS markets

2022 DAM · 2018 DAM · 2022 RegUp · 2018 RegUp · 2022 RegDown · 2018 RegDown · 2022 Non-Spin · 2018 Non-Spin · 2022 RRS · 2018 RRS

Sources: Aurora Energy Research, ERCOT

The majority of batteries made between $2-5/kW/month on average over the fall, with only two above the $6/kW/month threshold

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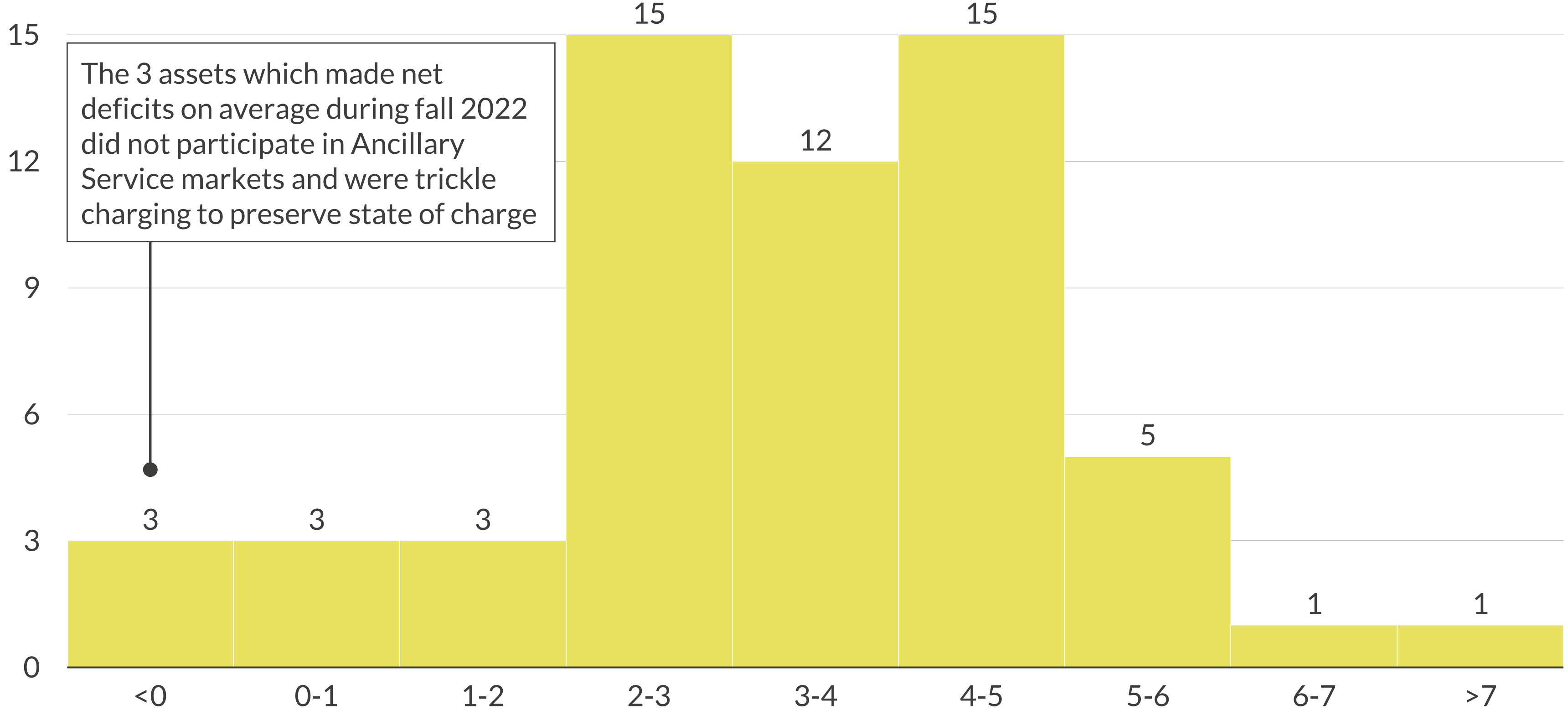
Frequency of batteries with margins[1]
Count



Average monthly margins, September to November 2022[2,3] $/kW

- There was a large difference in average monthly margins made in fall 2022 compared to summer 2022, nearly a 5x reduction:
  - Over half the assets in summer made between $18-24/kW/month, whereas in the fall, only 12% of batteries made over $5/kW/month
  - 3 batteries made net deficits due to lack of ancillary market participation
- The tight grouping of earnings seen around $2-5/kW/month is representative of similar trading strategies between the assets
  - This is primarily due to assets having the same owner/operator
  - Lower performing assets performed less ancillary services or had prolonged outages in the period

For the full asset database please see Databook 3

1) Only includes assets fully commercially operable from September and November 2022. 2) Energy revenues calculated at the batteries' Real-Time nodal price 3) September 2022 – November 2022.

Sources: Aurora Energy Research, ERCOT

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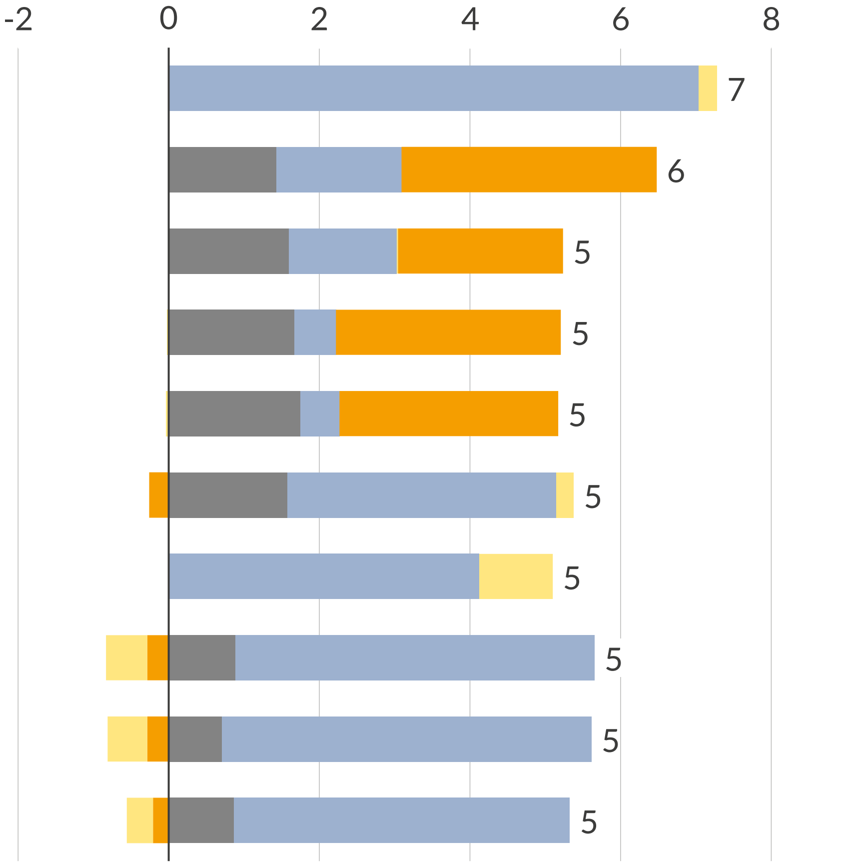
Blue Summit Battery was the highest performing battery in the fleet from September to November, making an average of $7.3/kW/month

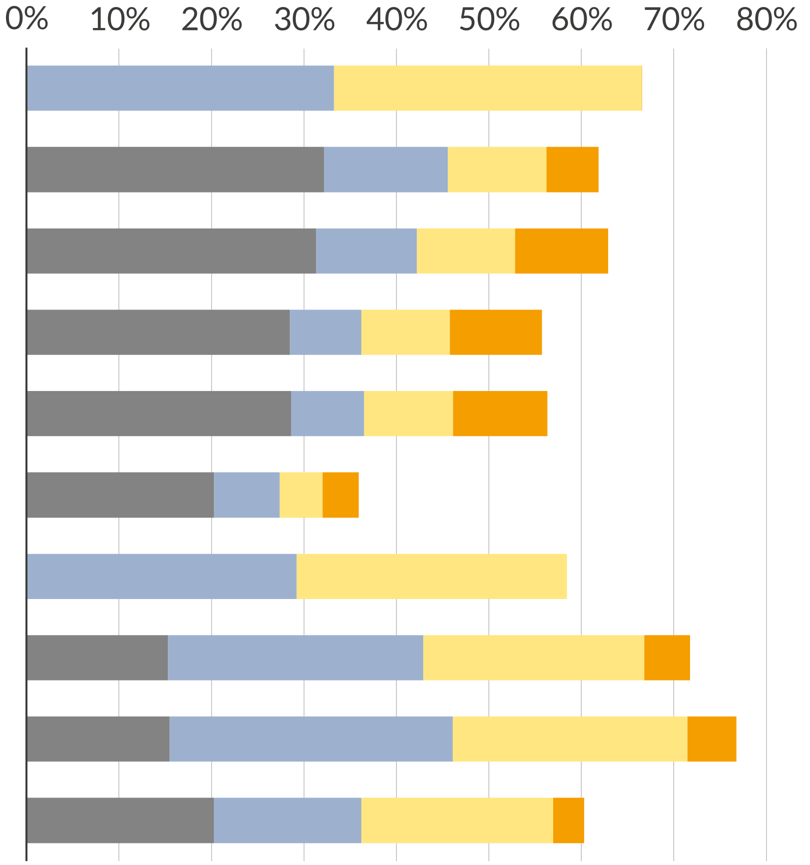
Top performing batteries in Fall 2022

Asset Owner	Duration	
NextEra Energy	2	Blue Summit
Jupiter Power	2	Flower Valley II
Jupiter Power	0.5	Flower Valley I
Jupiter Power	2	Triple Butte
Jupiter Power	2	Swoose
Tesla	2	Gambit
Duke Energy	2	Notrees
Broad Reach Power	2	BRP Magnolia
Broad Reach Power	1	BRP Odessa
Astral	2	Chisholm Grid

Average monthly margins by market, September to November 2022[2,3], $/kW



Estimated participation by market, September to November 2022[1], % hours



For the full asset database please see Databook 3

RRS, Reg. Up, Reg. Down, Non-spin, Energy

1) Total market participation percentages can exceed 100% due to participation in multiple markets in the same period. 2) Energy revenues calculated at the batteries' Real-Time nodal price. 3) September 2022 – November 2022.

Sources: Aurora Energy Research, ERCOT

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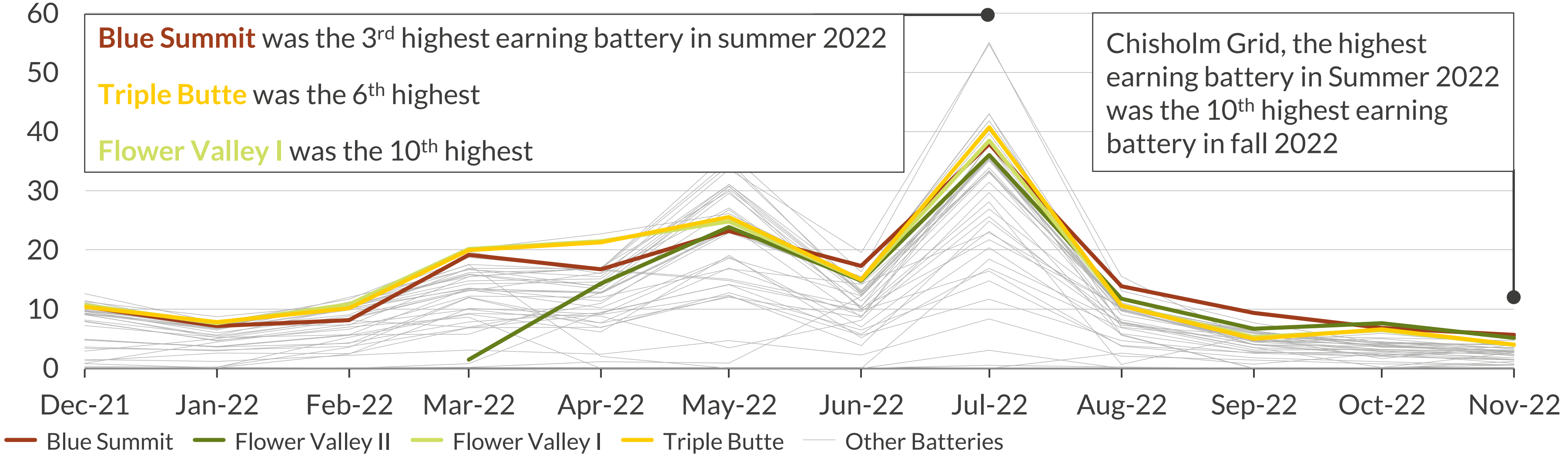
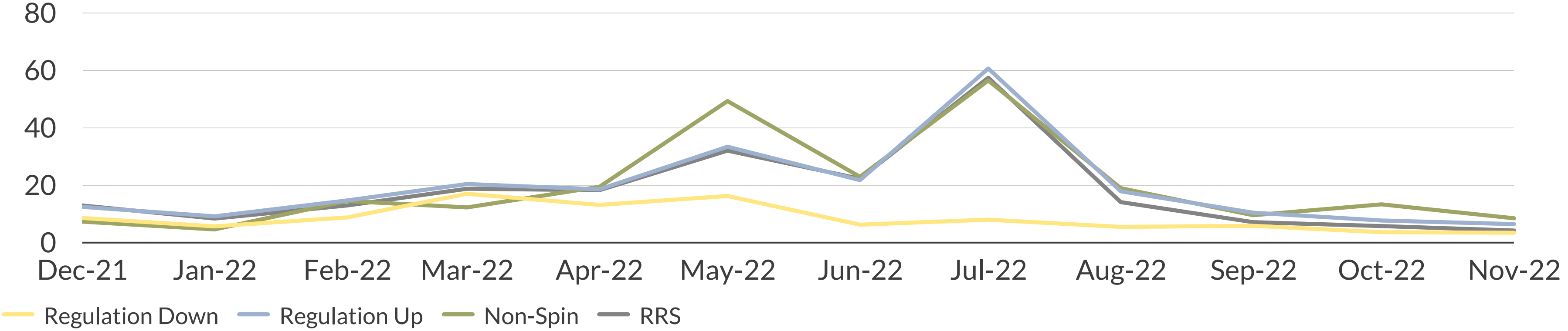
Monthly margins have plummeted since summer 2022 in line with dropping Ancillary prices

Total gross margins[1]
$/kW/month



ERCOT Ancillary Service prices
$/MW/hour



1) Calculated total gross margins have a floor of $0/kW//month applied.

Sources: Aurora Energy Research, ERCOT

- Battery margins have historically correlated very strongly with ancillary prices
- RRS and Reg. Up prices in November 2022 were 14x lower than in July 2022
- This has lead to a dramatic reduction in monthly margins over the last several months
  - Blue Summit Battery, Flower Valley Battery I&II, and Triple Butte Battery – the highest performing batteries in Fall 2022 – earned on average only 13% of what they earned in Summer 2022

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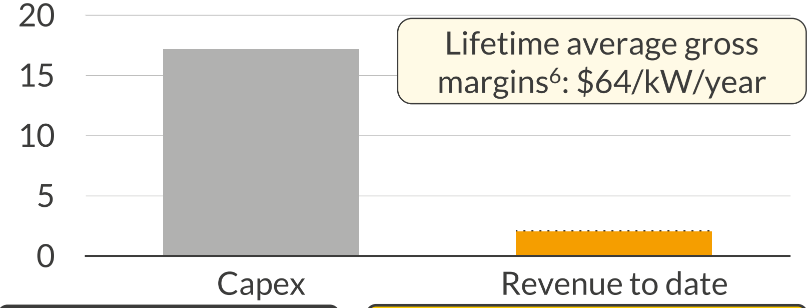
If gross revenues continue at $65-225/kW/yr, these existing batteries will see payback periods of 3 to 25+ years

Capital expenditure (estimate) and gross revenue-to-date[5] for existing batteries

$ (million)

Castle Gap Battery[1] (ERCOT West)

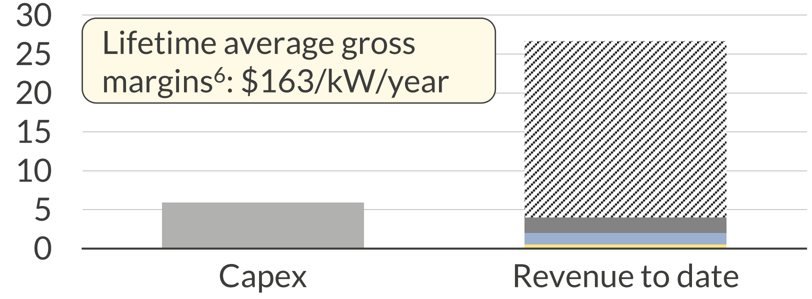
9.9MW, 41.6MWh



Asset age[5]: 3.4 years | **Payback period[6]: 27 years**

BRP Odessa[2] (ERCOT West)

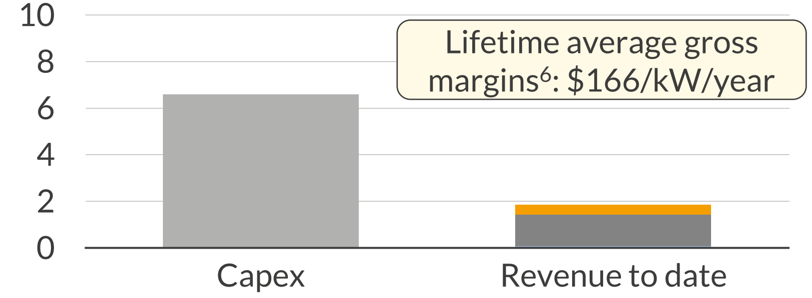
9.9MW, 9.9MWh



Asset age[5]: 2.1 years | **Payback period[6]: 3.6 years**

Triple Butte[3] (ERCOT West)

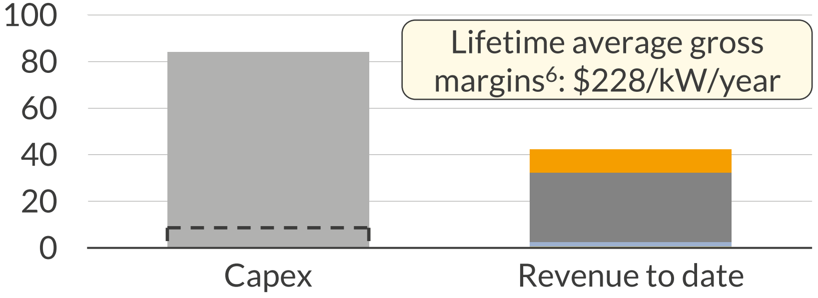
7.5MW, 15MWh



Asset age[5]: 1.3 years | **Payback period[6]: 5.3 years**

Flower Valley I & II[4] (ERCOT West)

109.9MW, 219.8MWh



Asset age[5]: 1.4 years | **Payback period[6]: 3.4 years**

Flower Valley I CAPEX[4] | Total CAPEX | Wholesale | RRS | Reg. Up | Reg. Down | Non-Spin | Revenues earned Feb 2021

- Aurora looked at 4 batteries covering a range of durations, commissioning dates, and market participation strategies to estimate potential payback periods for operational batteries in ERCOT
- CAPEX values for each battery are estimated from NREL's Storage Futures Study[7]
  - Early standalone battery projects in ERCOT were ineligible for the ITC
- February 2021 experienced many (consecutive) hours of maximum value RRS prices, but also many hours where RRS contracted assets were called to dispatch. Thus, while the capacity payments were substantial, there were many incurred penalties as assets were unable to dispatch when called in RRS that these estimates do not capture

1) Commissioned in Jun 2019. 2) Commissioned in Oct 2020. 3) Commissioned in Jul 2021. 4) Flower Valley I commissioned in Jun 2021 as a 9.9MW/19.8MWh system. Flower Valley II commissioned in Mar 2022 as a 100MW/200MWh system. 5) As of Nov 2022. 6) Excludes Feb 2021. 7) US-wide all-in cost estimate. There may be regional variation.

Sources: Aurora Energy Research, ERCOT

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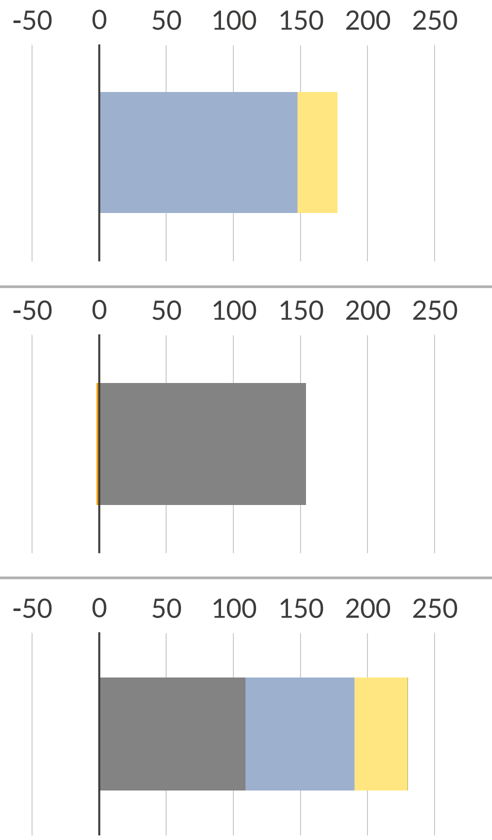
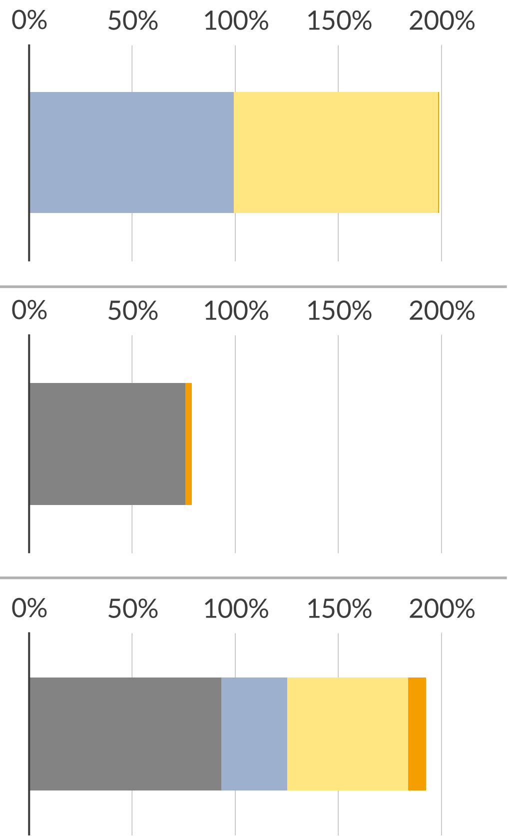
3 projects typify the current operational use cases of batteries in ERCOT

Project	Capacity MW	Duration hours	Month[1] of commission	Asset Type	Region	Operator	Business Model
Blue Summit Battery (1)	30	0.5	08/2017	Co-located with Wind	West	NEXTera ENERGY	Regulation services
Port Lavaca (2)	9.9	1.2	02/2020	Stand-alone	South	KEY CAPTURE ENERGY	RRS & energy arbitrage
BRP Odessa (3)	9.9	1	10/2020	Stand-alone	West	BROAD REACH POWER	Cross-market

2021 estimated gross margins[1,3] by market $/kW



2021 market participation[2] % of hours in 2021



(X) **Intraday deep dive**

RRS | Reg. Up | Reg. Down | Non-spin | Wholesale

1) Calculated at the hub; may underestimate locational value. 2) Proportion of hours above 100% indicates participation in 2 markets simultaneously. 3) Estimates include revenues from wholesale + AS markets and charging costs, excludes hedges including PPAs, price floors etc.

Sources: Aurora Energy Research, ERCOT, EIA

Blue Summit operates predominantly in regulation services, in both directions, in all hours

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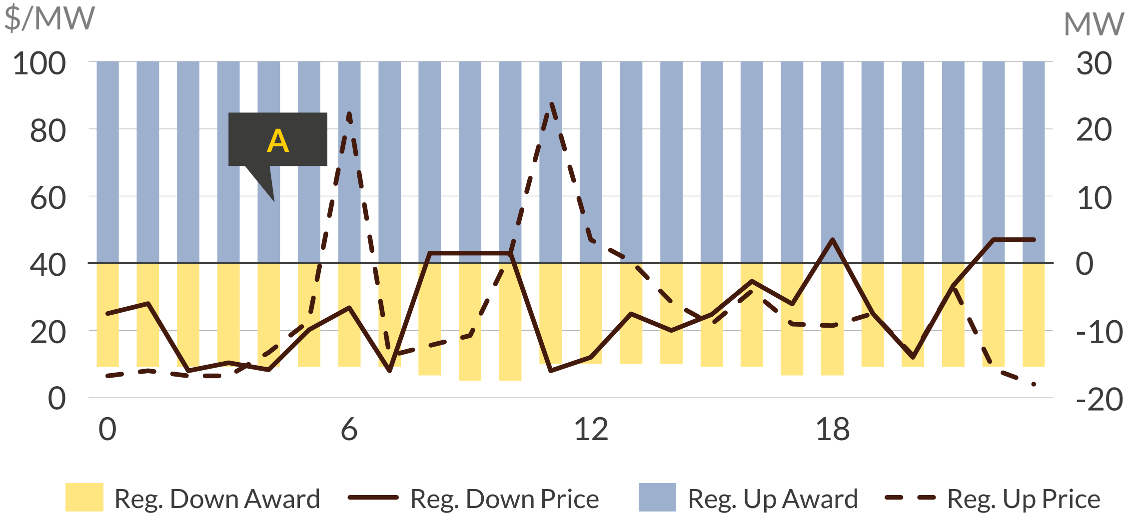
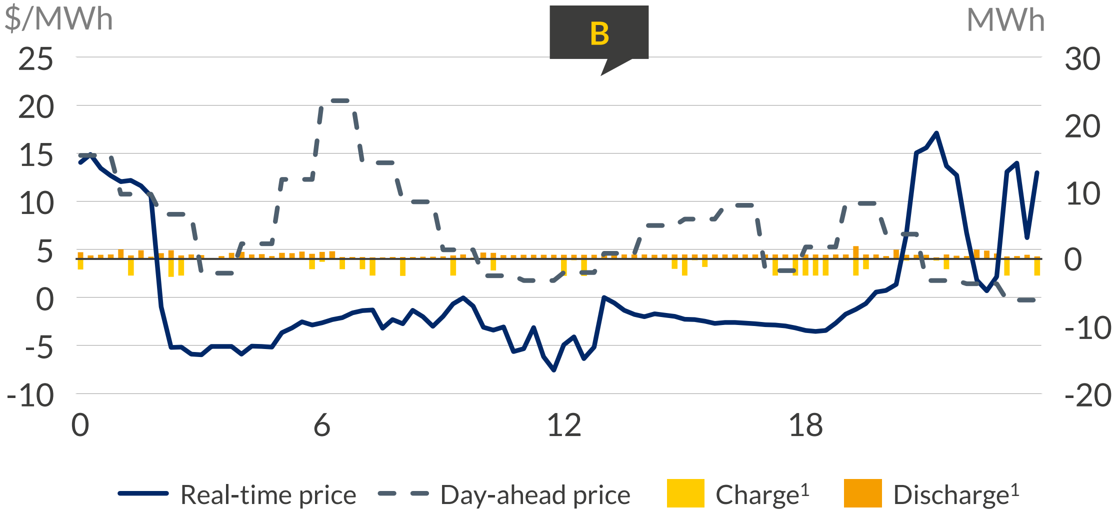
Blue Summit Battery performance – May 7th 2021

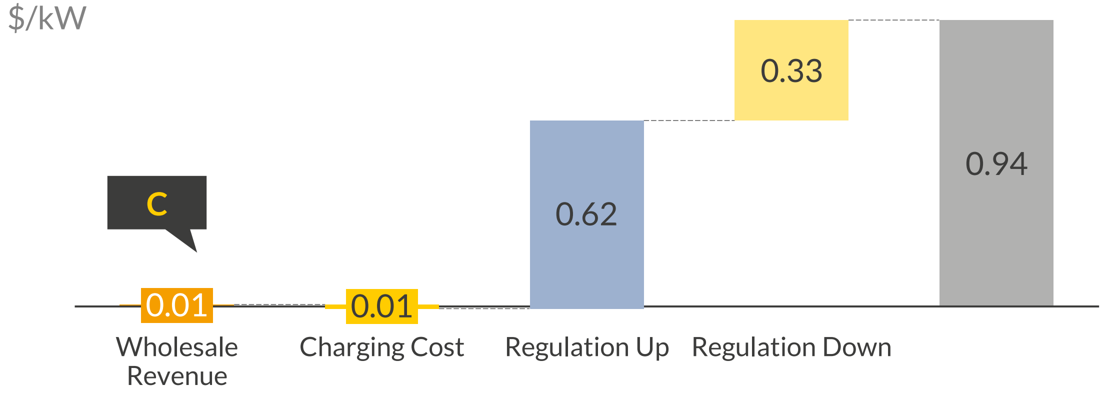
Ancillary Service awards & prices



Energy dispatch & prices



May 7th 2021 revenue breakdown



A Participating in both regulation up and regulation down (likely in the FRRS market) simultaneously, with adjustments made on the load side for State of Charge (SOC) management.

B No price responsiveness – indicates a purely regulation-based business model

C Makes very little money on the real-time market – likely due to following regulation signals rather than performing arbitrage

1) Wholesale Charge and Discharge MWh includes energy required from the participation in regulation markets. 2) Energy revenues based on arbitrage at the battery's trading hub. For Blue Summit this is the West Hub. Does not consider hedges including PPAs, price floors etc.

Sources: Aurora Energy Research, ERCOT

Combining RRS and energy dispatch, Port Lavaca Battery trickle charges during low price hours then dispatches during the evening peak

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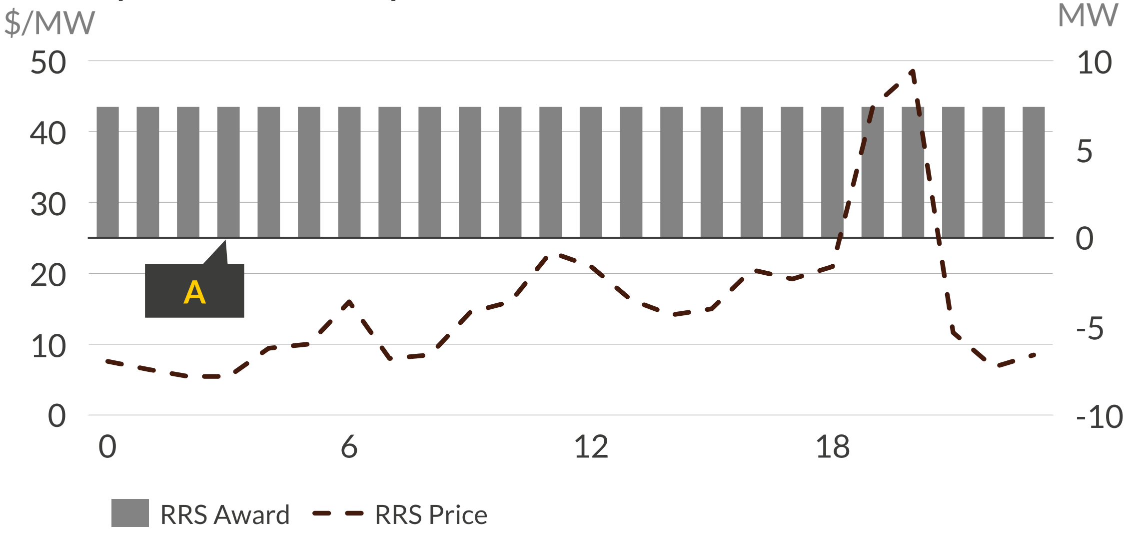
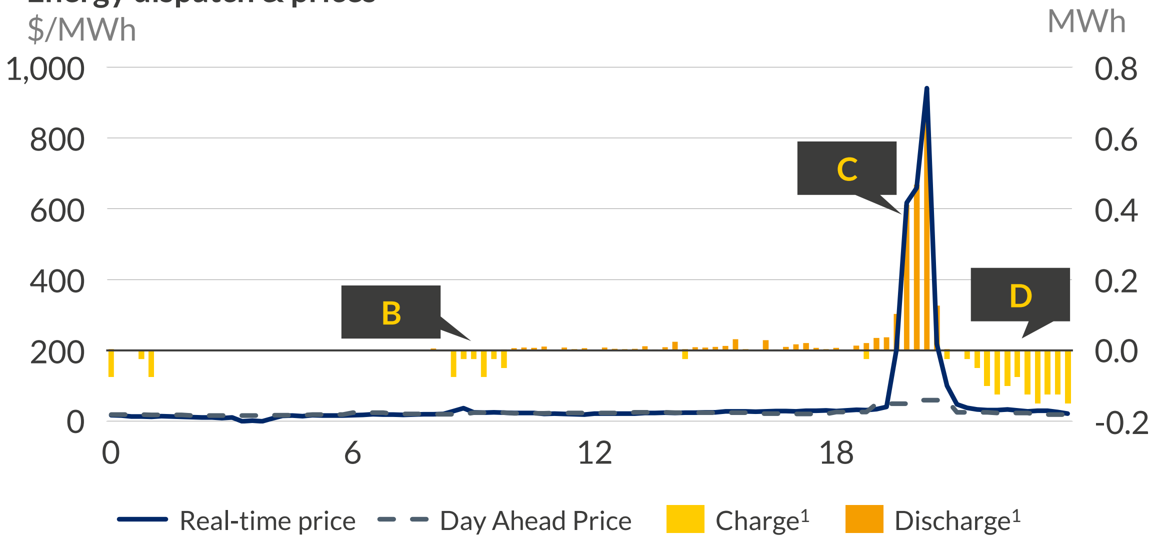
Port Lavaca Battery performance – May 4th 2021

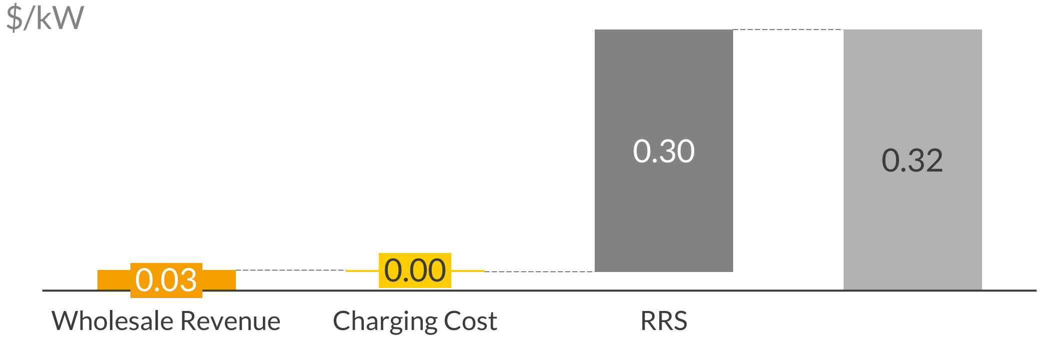
Ancillary Service awards & prices



Energy dispatch & prices[2]



May 4th 2021 revenue[2] breakdown



- **A** Battery participates in RRS in every hour but withholds 2.4MW of capacity for participation in the energy market
- **B** Charges slowly through lower price hours of the night and mid-morning
- **C** Discharges reserved capacity during an evening peak in Real-Time prices
- **D** Charges again post evening peak to regain state of charge

1) Wholesale Charge and Discharge MWh may include energy required from the participation in RRS market. 2) Energy revenues and prices based on arbitrage at the battery's trading hub in the real-time market. For Port Lavaca this is the South Hub. Does not consider hedges including PPAs, price floors etc.
Sources: Aurora Energy Research, ERCOT

BRP Odessa simultaneously operates in both RRS and regulation down services

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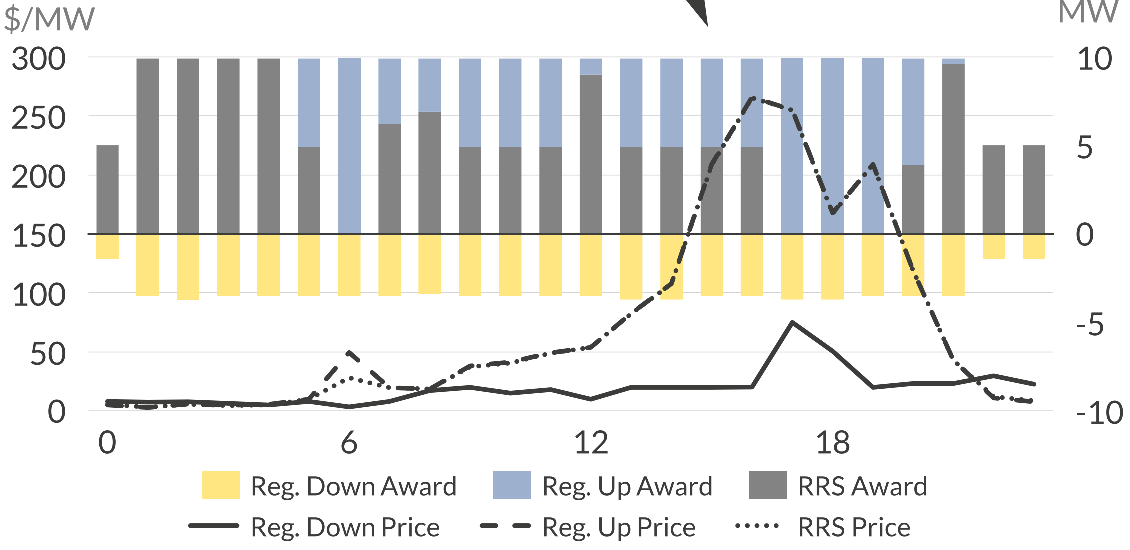
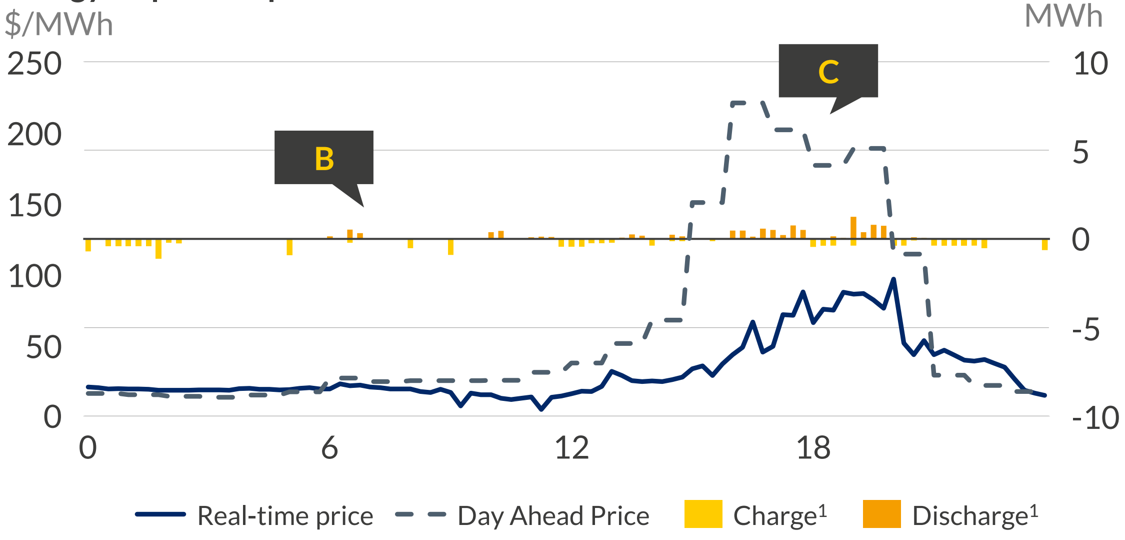
BRP Odessa performance – April 8th, 2021

Ancillary Service awards & prices

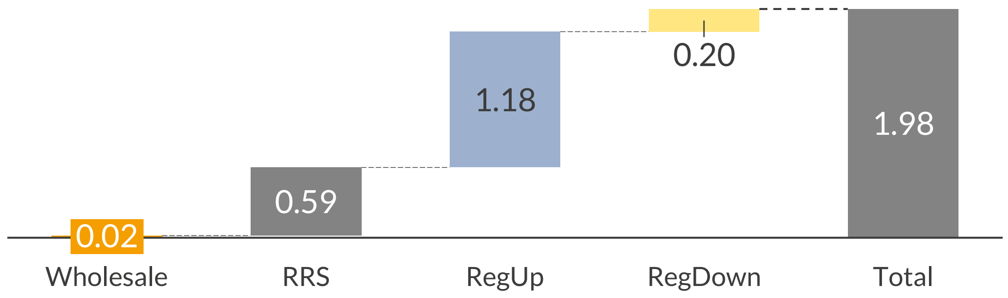


Energy dispatch & prices



April 8th, 2021 revenue[2] breakdown

$/kW



A Battery participates in a combination of all 3 ancillary services in every hour

B Charges and discharges evenly throughout the day, adjusting Upward services to account for imbalances

C Small discharge in response to evening peak prices

1) Wholesale Charge and Discharge MWh includes energy required from the participation in regulation markets. 2) Energy revenues based on arbitrage at the battery's trading hub. For BRP Odessa this is the West Hub. Does not consider hedges including PPAs, price floors etc.

Sources: Aurora Energy Research, ERCOT

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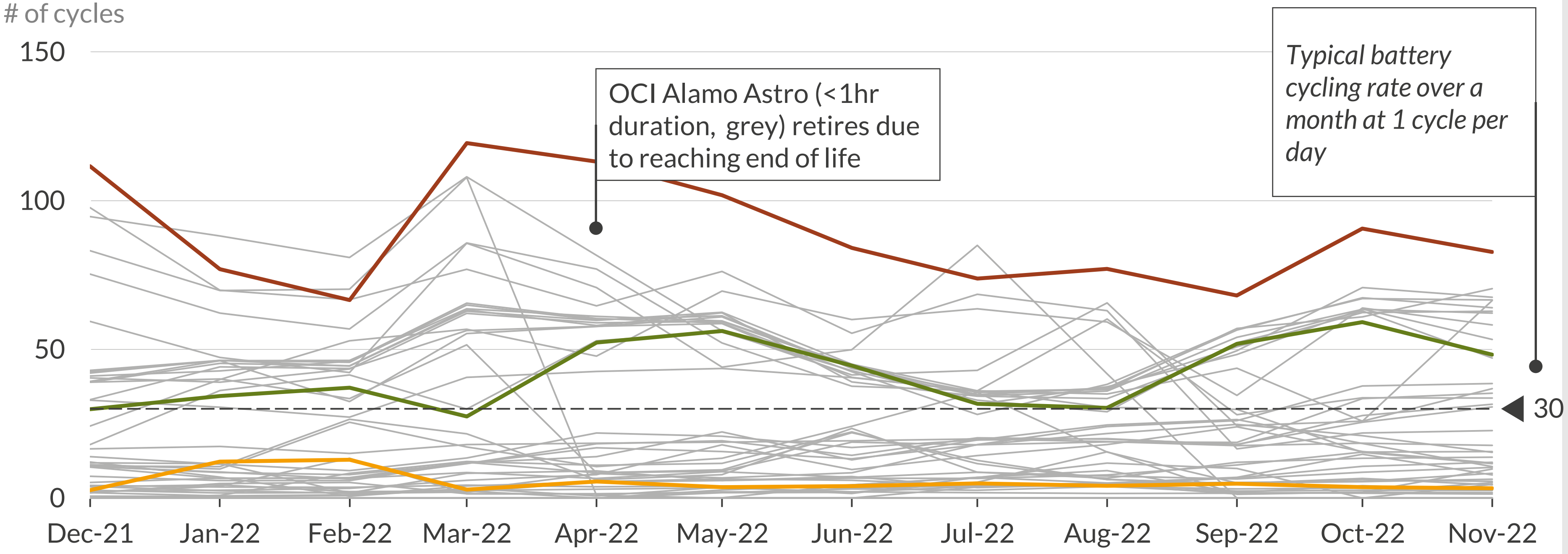
Batteries participating in the regulation markets see greater than 1 cycle per day, but there is huge variation between assets

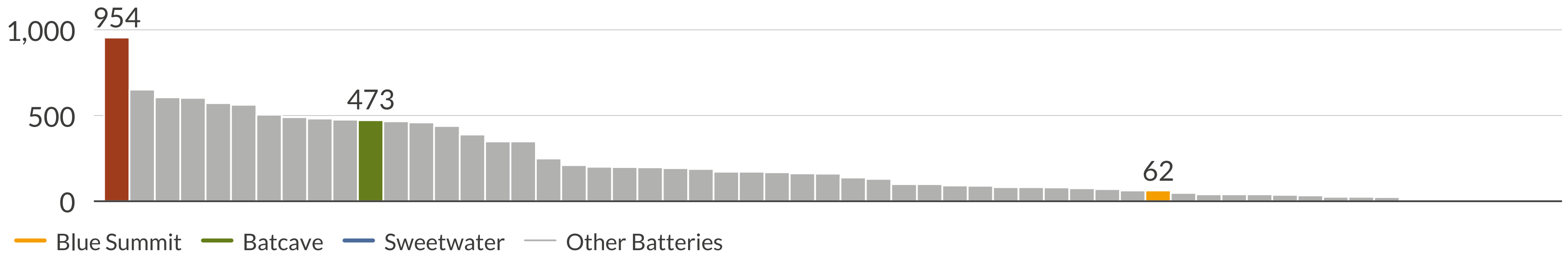
Implied number of monthly cycles[1,2]

# of cycles



Cumulative implied cycles between 1 January 2022 and 30 November 2022[2]

# of cycles



- Together with duration, choice of business model directly impacts how much a battery dispatches into a market and therefore the average number of cycles that are performed
- Battery warranties vary across manufacturers and use cases but typically see up to around 30 cycles per month or 1 cycle per day
  - **Blue Summit:** Operates solely in regulation services and cycles at about 3 times per day
  - **Batcave:** Operates predominantly in regulation and RRS, cycling at 1.5 times per day
  - **Sweetwater:** Operates predominantly in RRS, with some wholesale arbitrage and cycles at less than 1 per day

1) Implied number of cycles is calculated as the ratio of the battery's dispatch MWh against the battery's MWh storage capability. Intended to be used a close approximation. 2) Some months are omitted due to poor data availability

Sources: Aurora Energy Research, ERCOT

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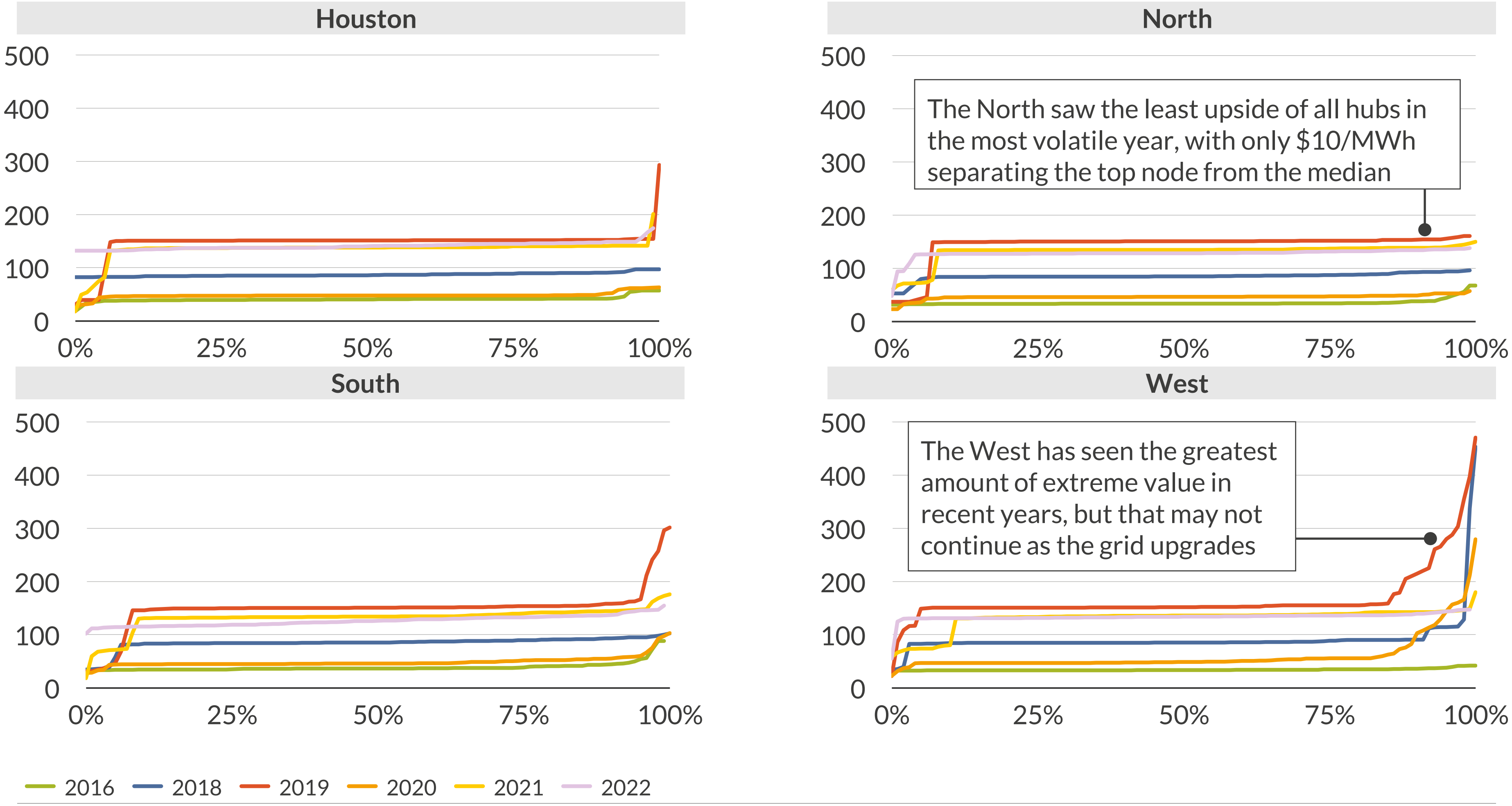
Historically, c.90% of nodes exhibit similar price spreads– only the top and bottom 5% of nodes out- or underperform

Average Day-Ahead TB1 spread percentile distribution by hub[1]
$/MWh (real 2021)



1) 2021 annual spreads include the impact of Storm Uri in February

Sources: Aurora Energy Research

- In both 2019 and 2020, the West hub saw more nodes that held very high spreads (~15%) due to growing Permian Basin congestion. This was resolved by 2021 and the difference can be seen in the distribution of spreads shown here
- Less than 5% of nodes would have been considered less volatile for these historic years, with 2016 containing a particularly low amount of depression in the bottom end
- 2022 saw generally higher spreads for most nodes than many previous years. Rather than being primarily due to weather-driven scarcity, this was largely due to high gas prices increasing the marginal cost of thermal plants

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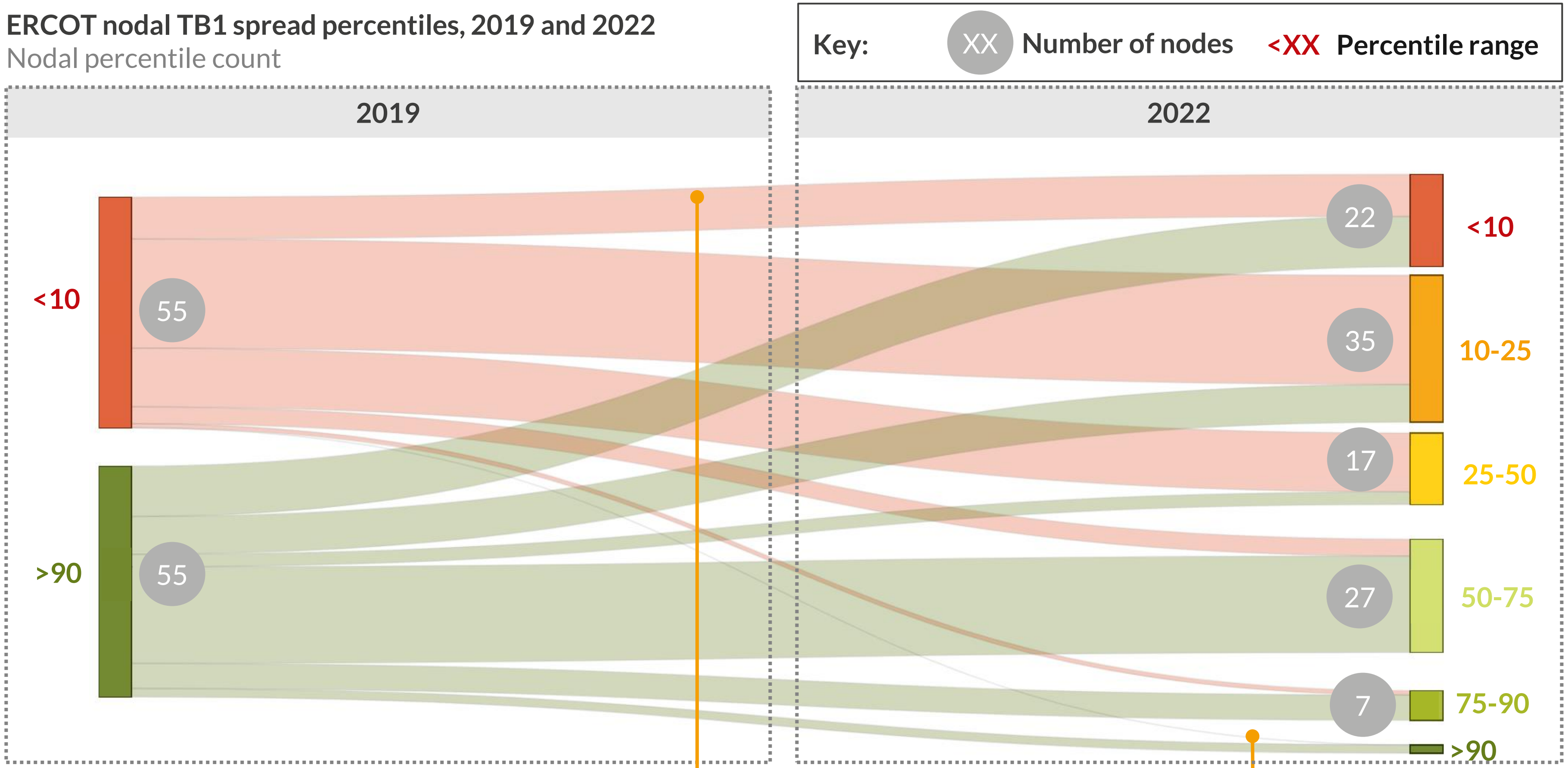
Nodal spread premiums exhibit high volatility, with only one third of top nodes in 2019 landing in the top quartile in 2022

ERCOT nodal TB1 spread percentiles, 2019 and 2022
Nodal percentile count



There is a greater persistence of poor nodal value than there is of higher nodal value: **two thirds** of nodes from the **10th percentile** bucket in 2019 remained below the **25th percentile** threshold by 2022

Low persistence of high nodal premiums arises as the system tries to resolve constraints limiting power delivery: only **4%** of nodes in the **90th price percentile** in 2019 remained in the top 10th percentile in 2022 **(2 of 55 nodes)**.

- Nodal 1-hour spread premiums have exhibited greater volatility between 2019 and 2022, reflecting large changes in the generation profile of ERCOT as more renewable assets penetrate the market
- Transmission upgrades in multiple regions of ERCOT, including the Far West, lead to large swings in nodal value through historic years
- The bottom 10th percentile nodes for TB1 spread value tend to be resource nodes with thermal generation, such as coal and gas plants, and are concentrated further from load

Sources: Aurora Energy Research, ERCOT

Spreads experience high nodal volatility in ERCOT: only 10% of nodes retained significant premiums to hub spreads for longer than 3 years

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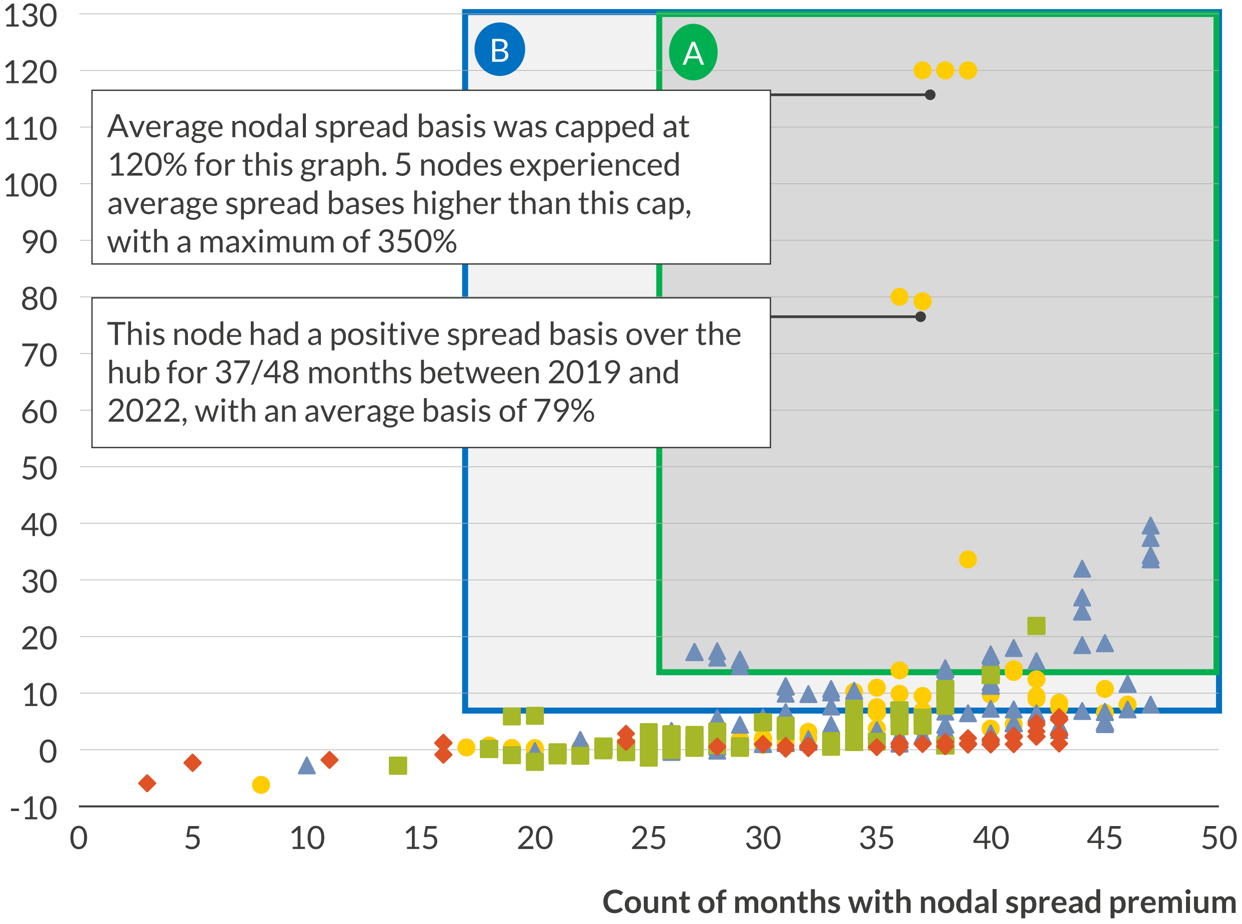
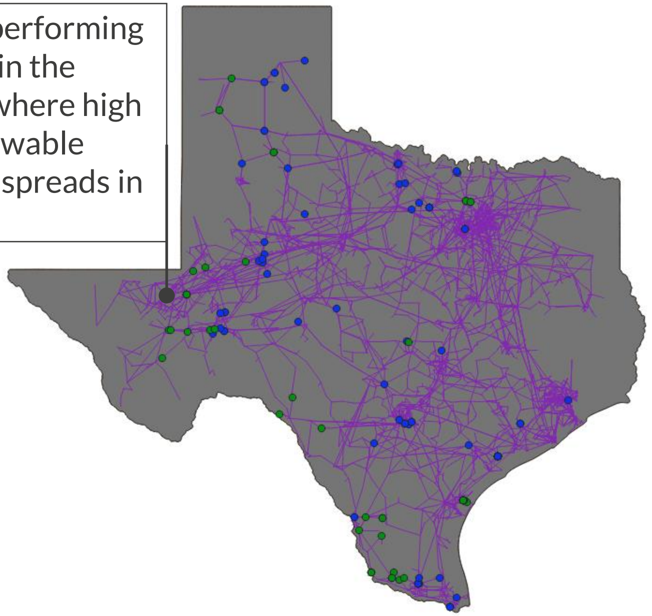
Persistence of nodal[1] TB1 spread premiums and average TB1 spread premium by hub

Count of months and basis percentage



Top quartile of nodes[1] with persistent nodal spread premiums

The consistently highest performing nodes are predominantly in the West and South regions, where high congestion and large renewable buildout have led to large spreads in the past



A Top 10th percentile nodes

B Top 25th percentile nodes

- The top 10th percentile nodes saw an average nodal premium of 40% over the hub
- However, consistently high value nodes in ERCOT are rare: all of the West nodes in quadrant A returned to the median percentile or below after two key transmission upgrades in the Far West region of ERCOT in 2021.
- A similar upgrade is planned for the Far South, projected to finish in 2027

1) This evaluation includes only settlement point nodes with data for all months between January 2019 and December 2022

Sources: Aurora Energy Research, ERCOT

There are many ongoing reforms to the ERCOT market which will impact battery economics and asset operation

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As interest in battery investment continues to grow, ERCOT is adapting their market structure and operating principles such that it can more efficiently manage battery participation and take advantage of their unique properties.

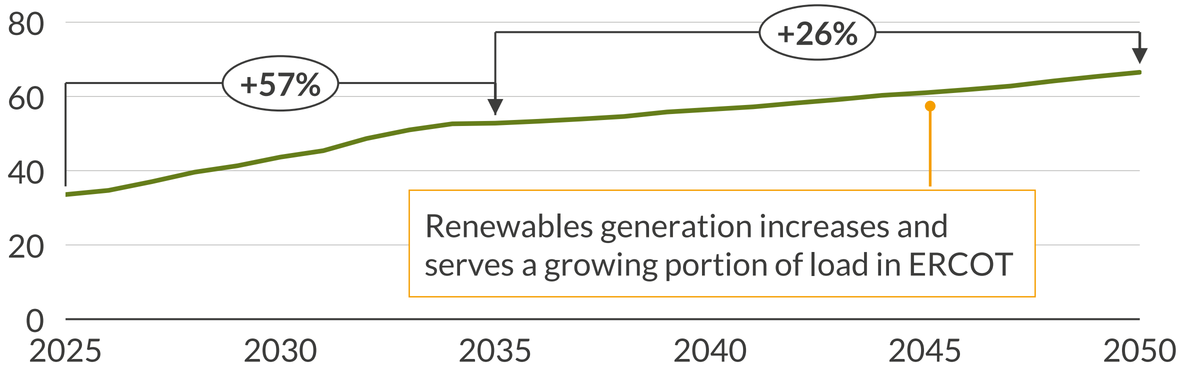
Proposed change	Previous Status	Change proposal	Impact	Status
ERCOT Contingency Reserve Service (ECRS) *Deep dive 1 to follow*	▪ Regulation Up dispatched to maintain grid stability during the evening peak in net load	▪ Addition of a new Ancillary Service with the purpose of maintaining grid stability during daily ramp down in solar production and intermittent drops in wind production ▪ Participation limited to 2+ hour dispatchable resources, including 2-hour+ duration batteries	▪ Short term: will reduce saturation levels of total AS markets, providing larger revenue opportunities ▪ Long term: will incentivize more capacity to enter the system to meet Ancillary Service requirements	▪ Due to be implemented in July 2023
Energy Storage Resource (ESR) single model	▪ Batteries dispatched as both load and generation resources by ERCOT EMS[1]	▪ A single model for battery charging and dispatching ▪ Operators will bid for both charging and discharging simultaneously	▪ Will aid battery operators in State of Charge management and may provide more simplicity in 'zero-crossing' trades	▪ Due to be implemented in 2024
Real-Time Co-Optimization	▪ All ancillary services are co-optimized in the Day-Ahead market ▪ SASM[2] resolves infeasibilities or imbalances identified post-DA solve	▪ Ancillary Services included in the Real-Time SCED solve ▪ AS contracts will have 15-minute granularity	▪ Removal of the opportunity cost of not participating in the Real-Time market by locking in an Ancillary contract in the Day-Ahead market	▪ Aimed for implementation 2026-2027
Performance Credit Mechanism (PCM) *Deep dive 2 to follow*	▪ Novel design – all system reliability requirements met via scarcity pricing in the DAM and Ancillary Services	▪ Retroactive payments given to eligible resources based on availability during high-risk hours ▪ Will use a centrally-set payment curve	▪ Will likely shift value towards longer-duration batteries and thermal assets as they will have higher accredited availability during "high-risk hours"	▪ The PUC recommended a PCM on January 19, 2022 ▪ Awaiting direction from the 88th Legislative Session

1) Energy management system.

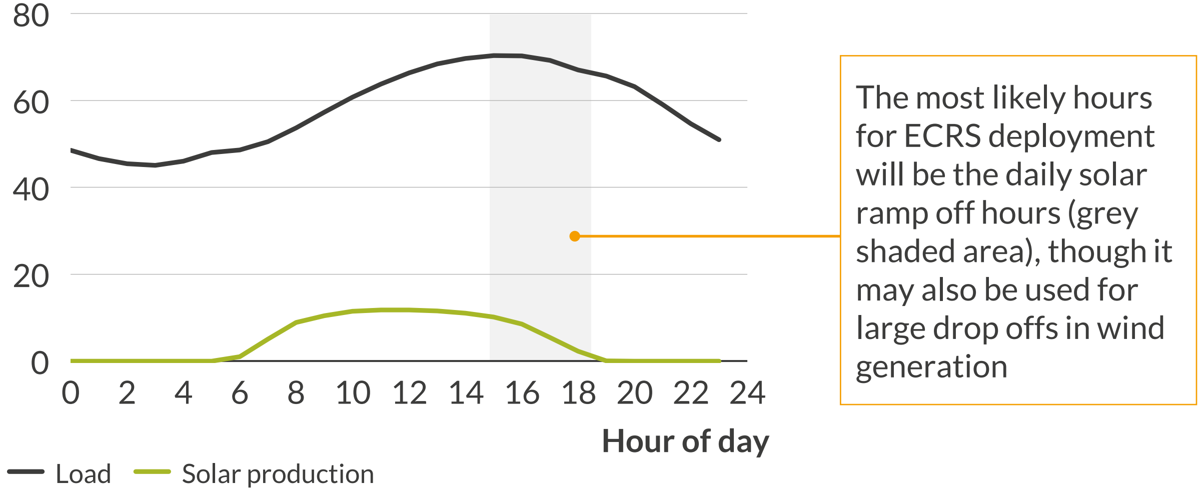
Sources: Aurora Energy Research, ERCOT

ERCOT is developing ECRS[1] to deal with system flexibility and large net load ramps, filling a gap between RRS and Non-Spin

Renewables penetration in ERCOT
% of load served



Sample day in August, solar generation and total load
GW



Service	Procurement, MW	Ramping requirement	Duration requirement
RRS	2,300-3,335	0.25 seconds (FFR) or 15 min (PFR)	1 hr +
ECRS[1]	1,209-3,039	10 min	2 hr +
Non-Spin	1,923-4,112[2]	30 min	4 hr +

- The purpose of ECRS is to **maintain grid stability during the daily ramp down in solar production and intermittent drops in wind production**; it will also be used to stabilize the grid in frequency events and extreme weather events
- Participation is limited to 2 hr + dispatchable resources, including 2 hr + duration batteries
- Unlike RRS, ECRS has two triggers: i) manually if the PRC[3] drops below 3,200 MW; or ii) automatically based on a frequency trigger (59.8 Hz)
- ECRS would be **deployed before Non-Spin** (which is reserved until the PRC hits 2500 MW or the 30 min ramping capacity is insufficient). ECRS is designed to ramp faster and earlier to better combat net load error and frequency deviations. In turn, **Non-Spin procurement would decline** by 0.5 - 1.5 GW
- Therefore there is higher deployment opportunity in ECRS and it **could have a higher impact on asset revenues than other ancillary services**

1) ERCOT Contingency Reserve Service. 2) Post ECRS Implementation. 3) Physical Responsive Capacity.

Sources: Aurora Energy Research, ERCOT

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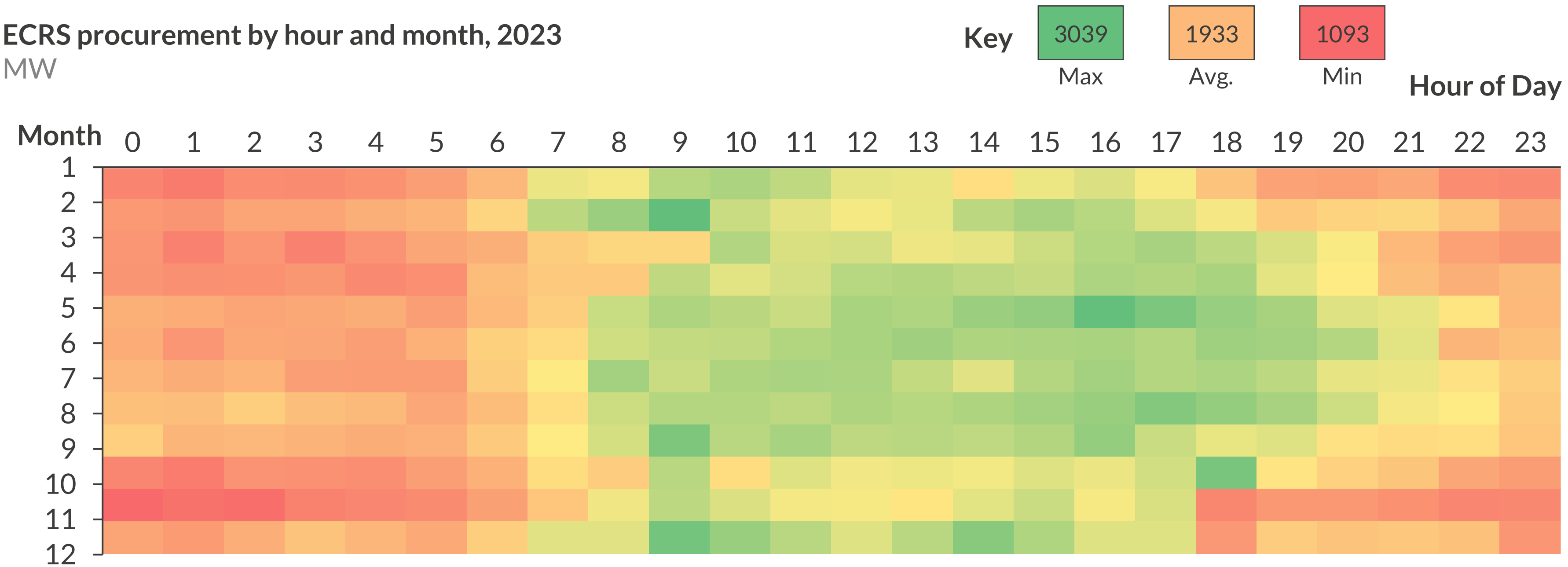
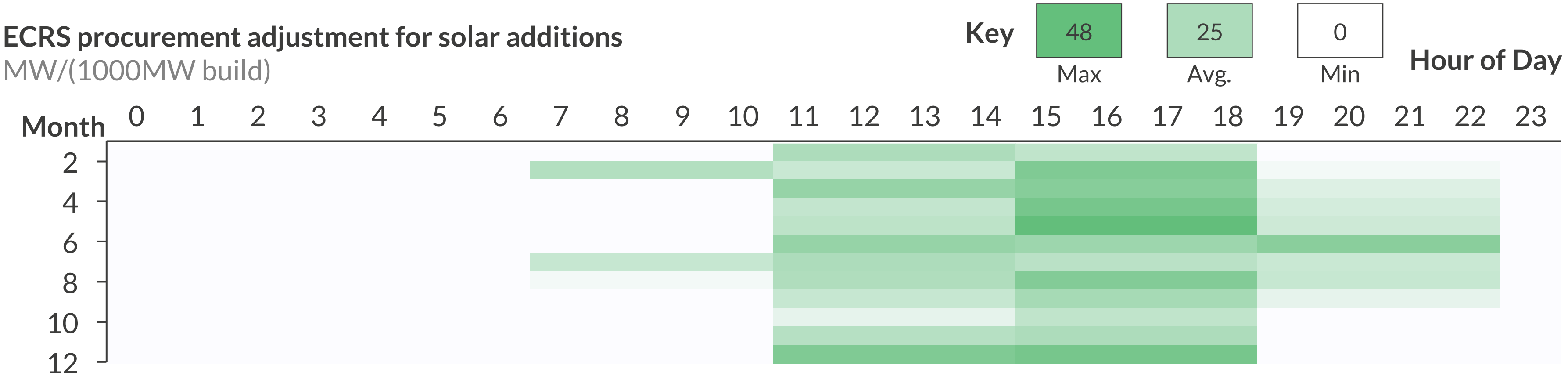
ECRS is modelled as planned by ERCOT, with procurement varying by hour and month, up to a maximum of 3039 MW in 2023

ECRS procurement by hour and month, 2023
MW



ECRS procurement adjustment for solar additions
MW/(1000MW build)



ECRS is additional capacity to:

- recover frequency following a large unit trip
- support sustained net load ramps (with solar adjustment)
- Provide flexibility through fast ramping capacity
- Ensure the regulation services can be restored if near depletion

ERCOT gives guidance on

- additional ECRS per 1,000 MW increase in solar capacity – thus the ECRS procurement target increases over the forecast horizon

Sources: Aurora Energy Research, ERCOT

PRELIMINARY

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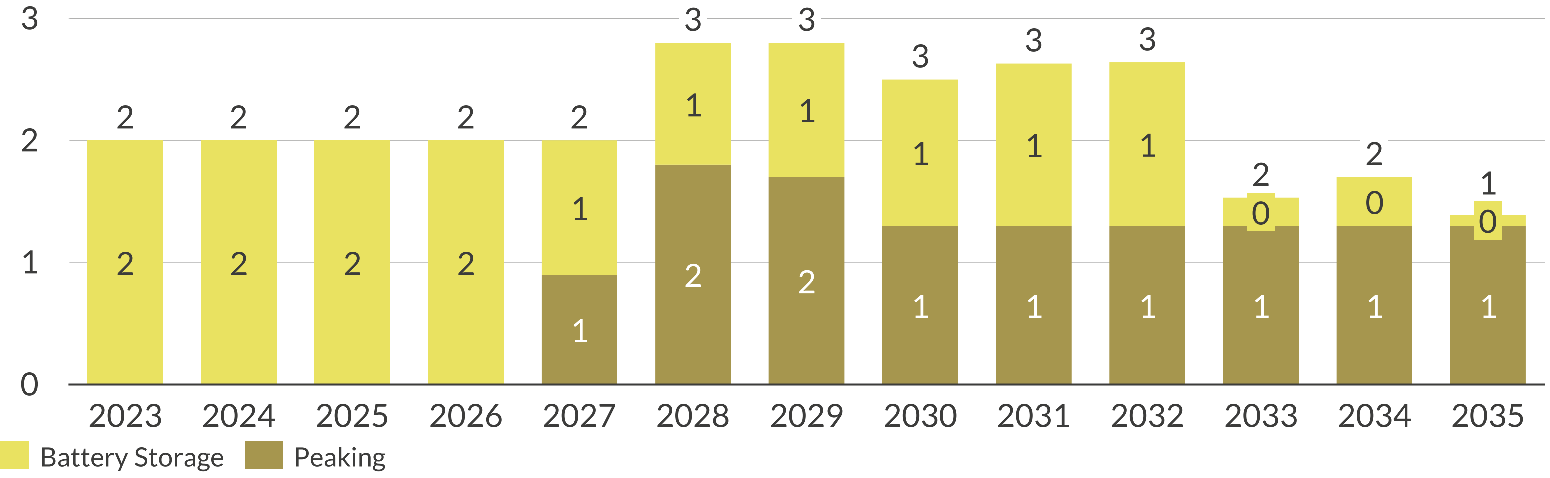
If peaking build is not realized, ECRS has the potential to bring forward battery build into the early 2020s, and will clear at $8-10/MW/h

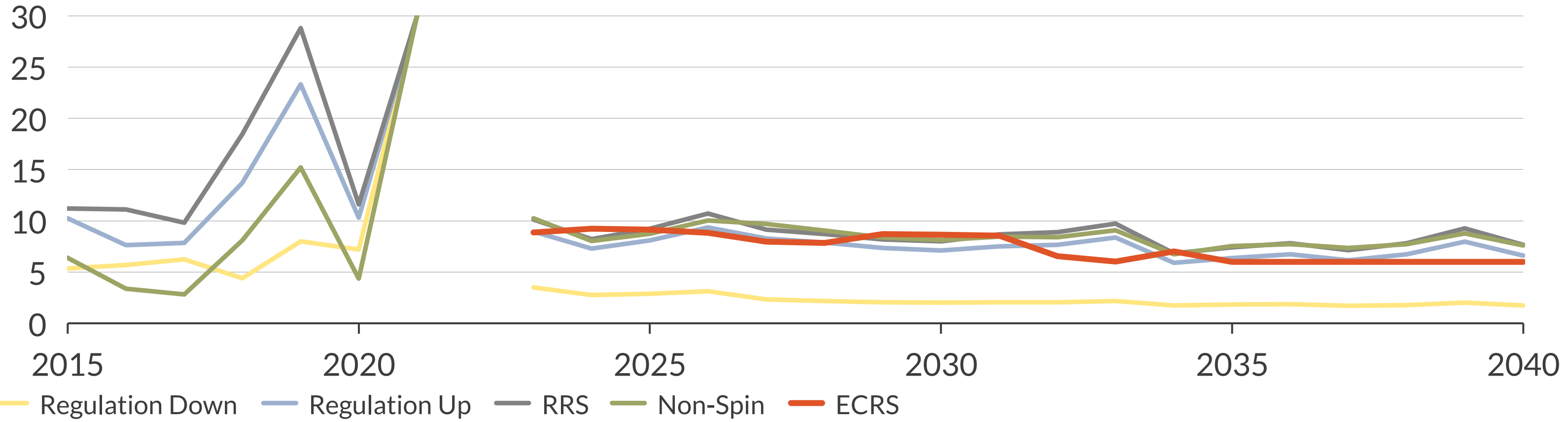
Delta in battery build from ECRS implementation[1]

GW



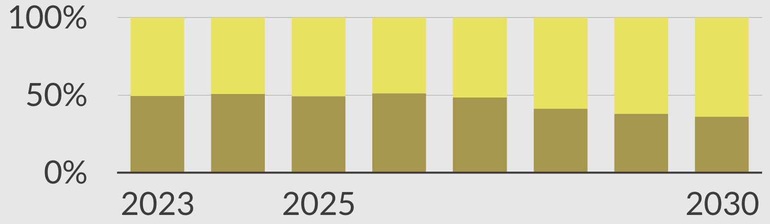
Ancillary service clearing prices

$/MW



ECRS Participation by technology

%



- Implementation of ECRS extends the trading options in the ancillary service markets for 2+ hour assets
- ECRS capacity is held behind HASL, such that there will be some wholesale price increases, which also feeds through into AS prices in higher price periods
- 2 GW of additional battery builds in response to the addition of ECRS
  - 2 hour duration assets will be favoured by the addition of ECRS due to the increase in revenue from the service

1) Using a restricted peaking asset build scenario (with WACC at 20%), results are likely to be less severe in the Aurora central scenario. 2) Results from November 2022 Flex report.

Sources: Aurora Energy Research

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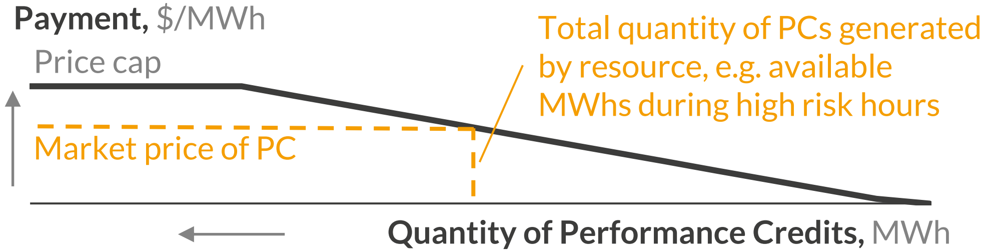
The Performance Credit Mechanism would retroactively pay generators based on contribution during set periods of time

The Performance Credit Mechanism (PCM) is a novel design involving retroactive payments to eligible resources based on availability during high risk hours and a centrally-set payment curve. The PUC voted 5-0 to recommend a PCM on January 19, though its future remains unclear as the redesign process is halted and awaiting direction from the 88th Legislative Session.

Aspect	Details	Uncertainty[1]
Participation	Eligible resources bid into the the Day-Ahead market for wholesale and ancillary services	The PCM is technology-agnostic under current proposal, however PUC Chair Lake is pushing to exclude wind and solar technologies. Cmsr. Glotfelty is pushing to include DERs[3]
Timing	"High reliability risk" hours are predefined, recommended by E3 as lowest 30 reserve margin hours of the year	Uncertainty lies both in the standard for "high risk" hours (peak net load or time of lowest reserve margin) and quantity of hours (top 30 hours, top hour by summer month like 4CP, etc.)
Payment	Quantity of Performance Credits will be determined after settlement period, with the payment per Performance Credit determined by a centrally-administered price curve, awarded to generators after the close of a compliance period	Exact details surrounding price curve are unclear. Will be centrally-administered, adjusted annually and designed to target 0.1 days/year loss of load expectation reliability standard (as opposed to ERCOT load forecast). The predetermined number of PCs will vary from actual PCs post-settlement period
Interaction	After the high risk hours are identified, Load-Serving Entities are required to buy the Performance Credits from the eligible resources on a load-share basis	Unclear impact on other market elements, such as ancillary service procurement quantities or shape of Operating Reserves Demand Curve, as well as other market distortions such as gaming the high risk hours, complicating battery dispatch

Example Performance Credit (PC) price curve



Longer-duration batteries may be favored going forward – less risk than a 1 or 2 hr duration battery lacking charge during expected high risk hours

If the PCM works as intended to bring online dispatchable generation, it will shift value from the energy-only market to PC revenues

- Texas Governor Greg Abbott and Texas Competitive Power Advocates[2] support the PCM, the latter claiming generators will build 4.5 GW natural gas plants if PUC adopts the PCM
- Texas Senators have expressed concern over the design, asking the PUC to hold off on any substantial decisions until the Legislature weighs in
- Primary critiques of the PCM include: i) complex design and retroactive price signals are difficult to implement/ forecast for participants; ii) act as wealth transfer to incumbent generators; iii) complexity and volatility means it will not be bankable for new generators; iv) introduce market power; and v) doesn't consider cost savings from renewables

1) Additional uncertainty in the possibility for PCM requirements to vary by zone. 2) Industry group comprised of generators and traders, such as Vistra, Calpine, and NRG. 3) Distributed Energy Resources. Includes rooftop solar, home batteries, electric vehicles, energy efficiency. Cmsr. Glotfelty cited how PJM incorporates energy efficiency into capacity payments.

Sources: Aurora Energy Research, Public Utilities Commission, E3

The IRA bill has overall positive impact on spreads and battery build, and is fully integrated into this report

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	Driver	Description	Impact dynamic	Spread Impact
Inflation Reduction Act	PTC/ITC for renewables	Production Tax Credits (PTC) of up to \$31.2/MWh (inflation-linked) for solar and wind for 15 years, as well as an Installation Tax Credit (ITC) of up to 60% for solar, wind, and batteries	High impact on solar and battery build and power prices in ERCOT, limited impact on wind buildout as other constraints counteract increased PTC	↑
Inflation Reduction Act	PTC for CCUS	Tax credits of up to \$85/tCO_2 sequestered for 12 years, leading to an effective ~\$20/MWh credit for a combined cycle natural gas turbine	Tax credit provides a strong incentive for power generation with CCS, thereby strongly lowering short-run marginal costs for generators with credit, reducing power prices	↑
Inflation Reduction Act	Tax credit for EV purchase	Tax credit of up to \$7500 for the purchase of a new EV, provided domestic production criteria are met. A 5% increase in EV uptake is incorporated into Aurora Central	Higher EV uptake increases total demand in ERCOT. EVs are a mixture of smart and dumb charging, which varies the impact on power prices	-
Inflation Reduction Act	PTC for nuclear generation	Tax credit of up to \$30/MWh for nuclear generation	Nuclear plants receive support when power prices fall. Aurora Central assumes no nuclear retirements in ERCOT through 2050	↓
Other updates	Increased natural gas price	Long-term increase of \$2/MMBTu due to increased global demand forecast for natural gas	A higher gas price through the horizon results in higher marginal costs – the same gas-fired plants are setting the price at higher marginal costs	↑
Other updates	Adjusted thermal economics	Revised retirement schedule for operating thermal assets, increased discount rate for new build gas CCGT and no unabated CCGT plants able to build from 2040 onwards	Higher cost of thermal assets favors battery storage but results in higher scarcity value	↑
Other updates	Updated CAPEX forecast	Revised CAPEX forecast upwards for wind, solar, and battery technologies	Higher cost of CAPEX requires higher merchant price to support new entry and offsets the increase in tax credit support	↑↓

1) Indicative impact. 2) Refers to Henry Hub. 3) Short ton.

Sources: Aurora Energy Research

Agenda

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The investment case for battery storage in ERCOT is governed by 4 main principles

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Batteries are well placed to aid the grid's flexibility moving forward with higher penetration of non-dispatchable assets, and retirement of thermal

1 Declining CAPEX trajectory

- Despite current supply chain issues, long term battery storage CAPEX is expected to reduce from current levels
- This is due to more economies of scale through the supply chain
- Falling CAPEX reduces the required gross margins for new entry

2 Stable, liquid, wholesale opportunities

- High wind and solar generation can produce large swings/steep gradients in residual load, therefore the system will require more flexible capacity which can quickly ramp production up and down
- Conventional baseload technologies are not suited to fast ramping and there is limited capital for new build peaking
- This leads to stable spreads throughout the forecast horizon

3 Retained Ancillary Service value due to opportunity costs

- The retirement of large thermal generation (especially coal) will lead to a reduction in system inertia, among other operability challenges
- Forecast errors mean there is a need for balancing actions in real time, using flexible generators and loads
- Speed of saturation of these services is a key uncertainty, as is the potential for new services

4 Nodal volatility yielding upside

- Due to their small land footprint, batteries can be installed in many locations, which allows great flexibility with choosing sites
- Unless transmission upgrades keep pace with renewables deployment there could be high levels of concentrated congestion
- Additional stressors such as line outages or extreme weather can result in high volatility at specific location on the network

Source: Aurora Energy Research

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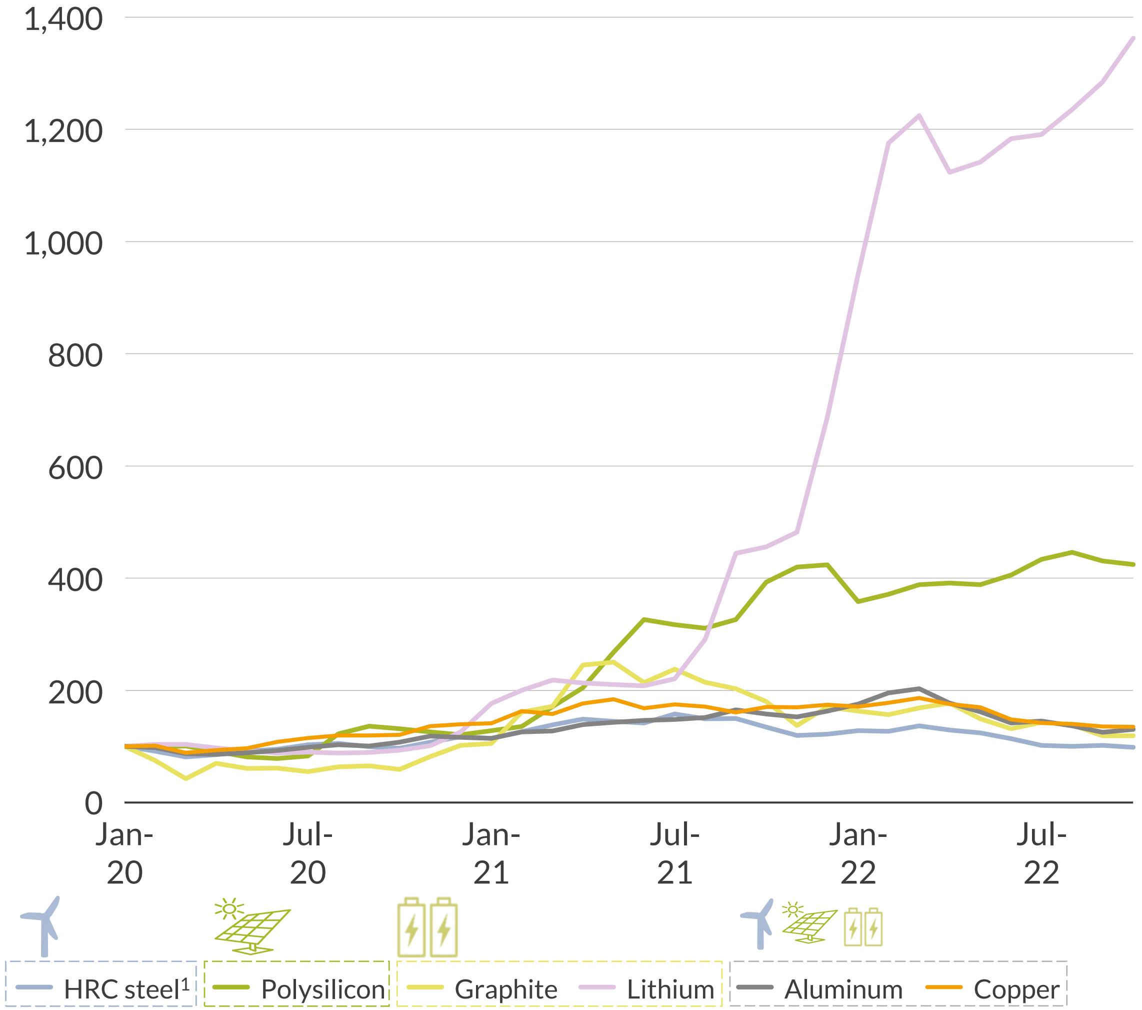
Supply shortages coupled with high demand have increased prices for key minerals used in battery production

Commodity price futures
Normalized to 100 in January 2020



Price increase since Jan 2020
%

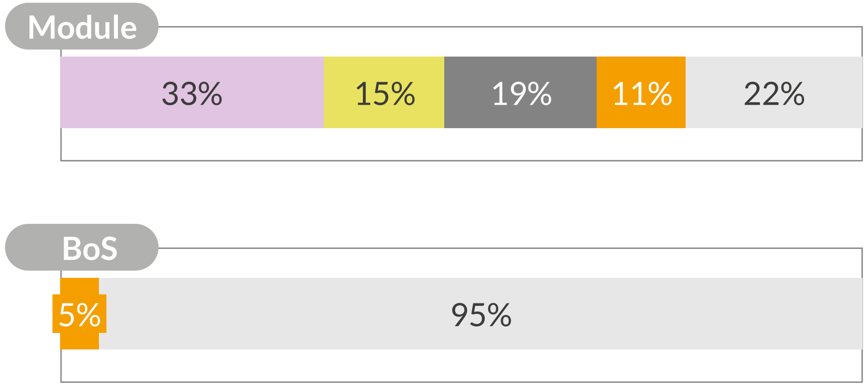
1300

19

30

35

Battery raw material components
By weight



- Commodity prices increased in Q1 2022 due to a strong rebound in demand, supply shortages and higher energy costs
- In the case of copper, steel, aluminium, and graphite, prices in Q3 2022 have begun to fall as global supply chains ease. Polysilicon and lithium prices remain high:
  - Polysilicon, a key component of solar panels, remains high in part due to high demand from corporations and governments worldwide
  - Lithium, a key component of lithium-ion batteries, also remains high due to strong demand against current supply

Aluminium Copper Graphite Lithium Other

Sources: Aurora Energy Research, Investing.com, Bank of America

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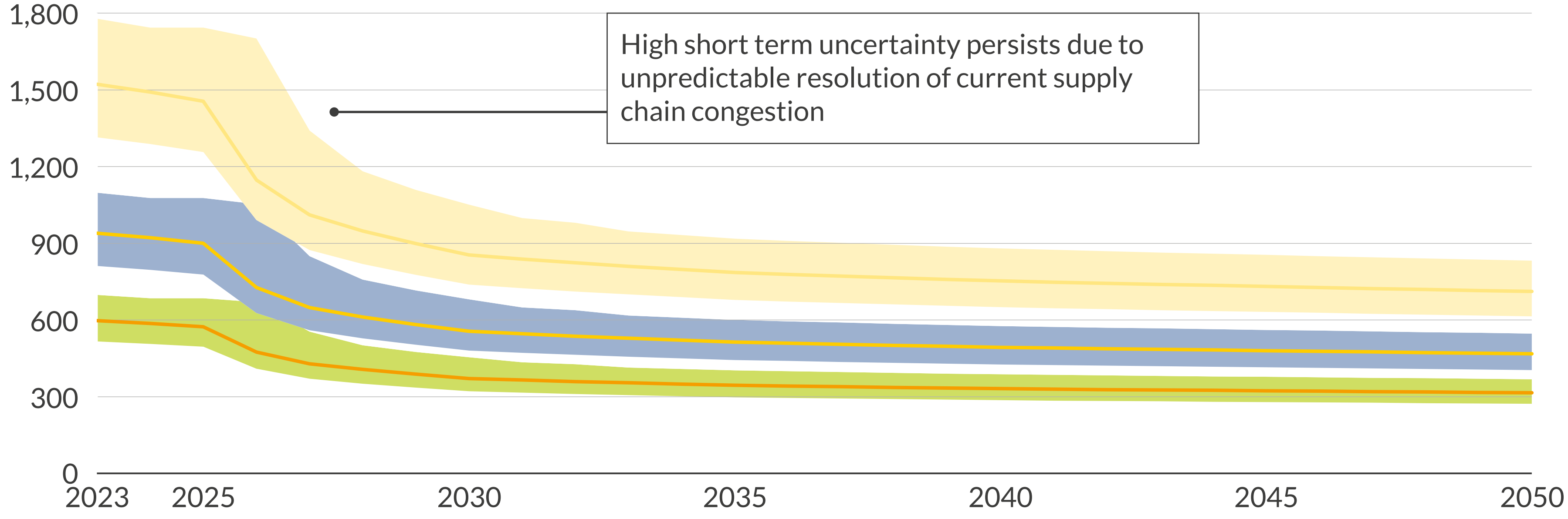
Supply chain constraints persist for battery CAPEX until 2025 and then decline from innovation and economies of scale

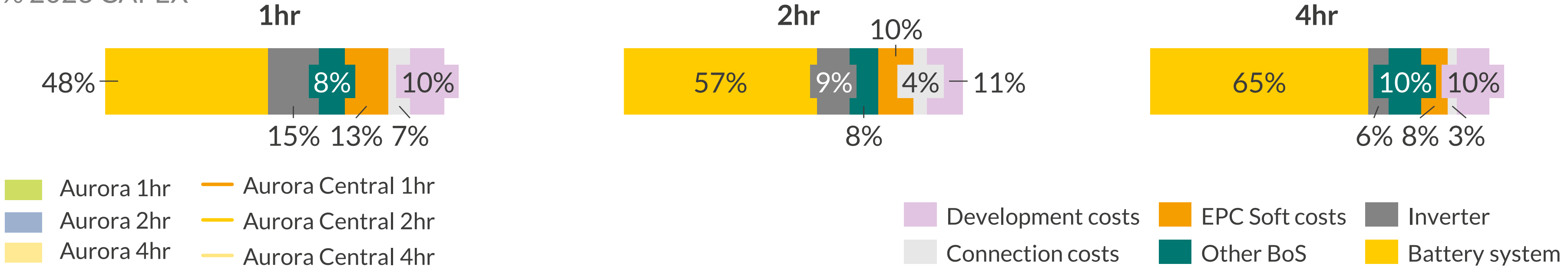
Li-ion Battery CAPEX[1] trajectory

$/kW, real 2021



Breakdown of 2023 CAPEX by duration

% 2023 CAPEX



1) Does not include the Battery ITC. CAPEX refers to year of COD.

Sources: Aurora Energy Research, ERCOT

Outlook for battery CAPEX

- Battery supply chains are currently under pressure, both for manufacturing and sourcing raw materials. Combined with rising demand this is causing higher battery CAPEX which are expected to persist out to the end of 2025
- Beyond 2025, battery CAPEX are expected to decline due to continued economies of scale, scaling up of raw materials mining and further technological innovations. However, there is a high level of uncertainty around how long supply pressures will last
- There is a potential tradeoff between building a battery earlier and accessing the higher gross margins in the short term, versus delaying and waiting for battery CAPEX to decline

Standalone storage is now eligible for the Investment Tax Credit, with the potential to recover up to 60% of initial expenditure

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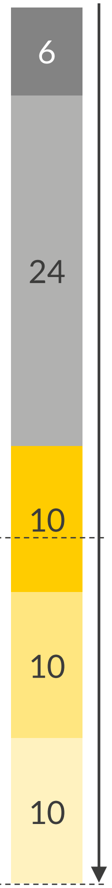
The updates to the clean energy tax credit system include the adoption of a tiered structure with a base rate for all projects and bonus rates for meeting additional requirements

ITC Breakdown

% of capex



Aurora assumes a **36%[3] credit** for all standalone storage in ERCOT

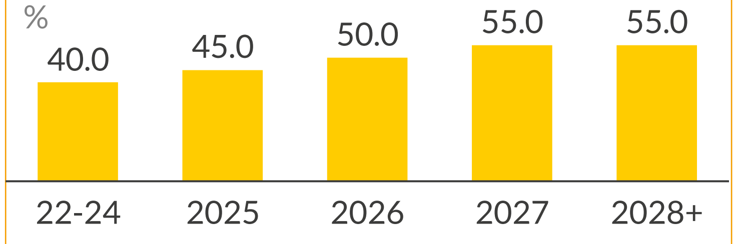
The maximum credit, if all criteria are met, is 60%

Provision	Requirements
Base rate	Available to **all projects meeting the basic requirements** of: i) construction start deadline[1]; and ii) subsequent technology/emissions requirements
Prevailing wage and apprenticeship	Bonus credit for **meeting: i) prevailing wage[2] requirements**, paid to any laborers employed by contractors and subcontractors during construction and the relevant credit period; **and ii) apprenticeship requirements**, which the required amount increases over time by construction start year
Domestic content	Bonus credit for the **sourcing of domestic products**. The percentage of total project costs for components mined, produced, or manufactured in the US. Reduced to 2% for ITC given prevailing wage and apprenticeship requirements not met
Energy community	Bonus credit for **facilities located near retired coal infrastructure**, or had high employment levels post 1999 in coal, oil, or natural gas industries. Reduced to 2% for ITC given prevailing wage and apprenticeship requirements not met
Low-income community	Bonus credit for **facilities located in low-income communities or tribal lands**; project installed capacity must equal or be less than 5 MW_{AC}. Only available for ITC

Total labor hours performed by qualified apprentices %

Domestic content requirement

%



1) For construction start years 2022-2033. 2) Rates at least equivalent to the average wage paid to similarly employed workers in a specific occupation in the area of intended employment. 3) We assume that standalone storage will be located in an energy community, resulting in a total of 40%, but 10% (4 p.p) of the Tax Credit is forfeit due to transaction costs

Sources: Aurora Energy Research, US Department of Labor, Foley & Lardner LLP

Over 67% of the planned battery storage in the ERCOT queue is situated in an energy community, and is eligible for an extra 10% credit

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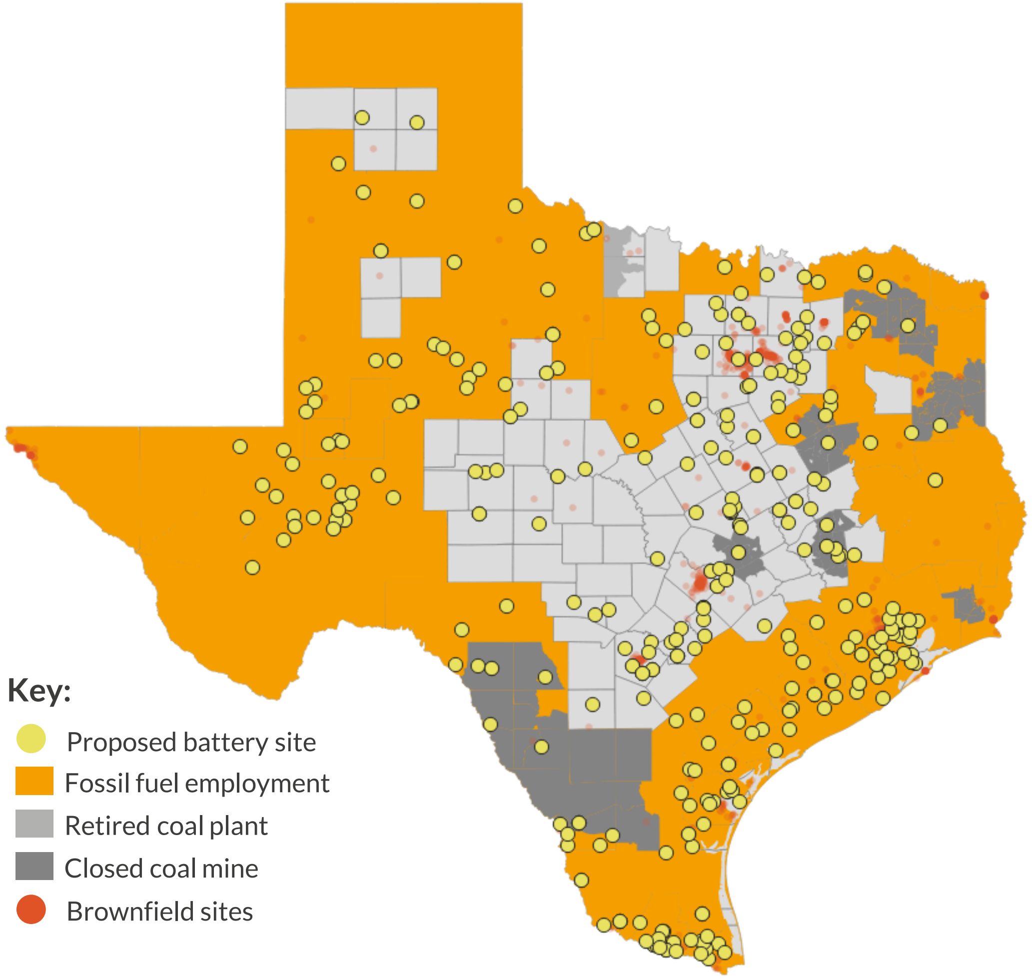
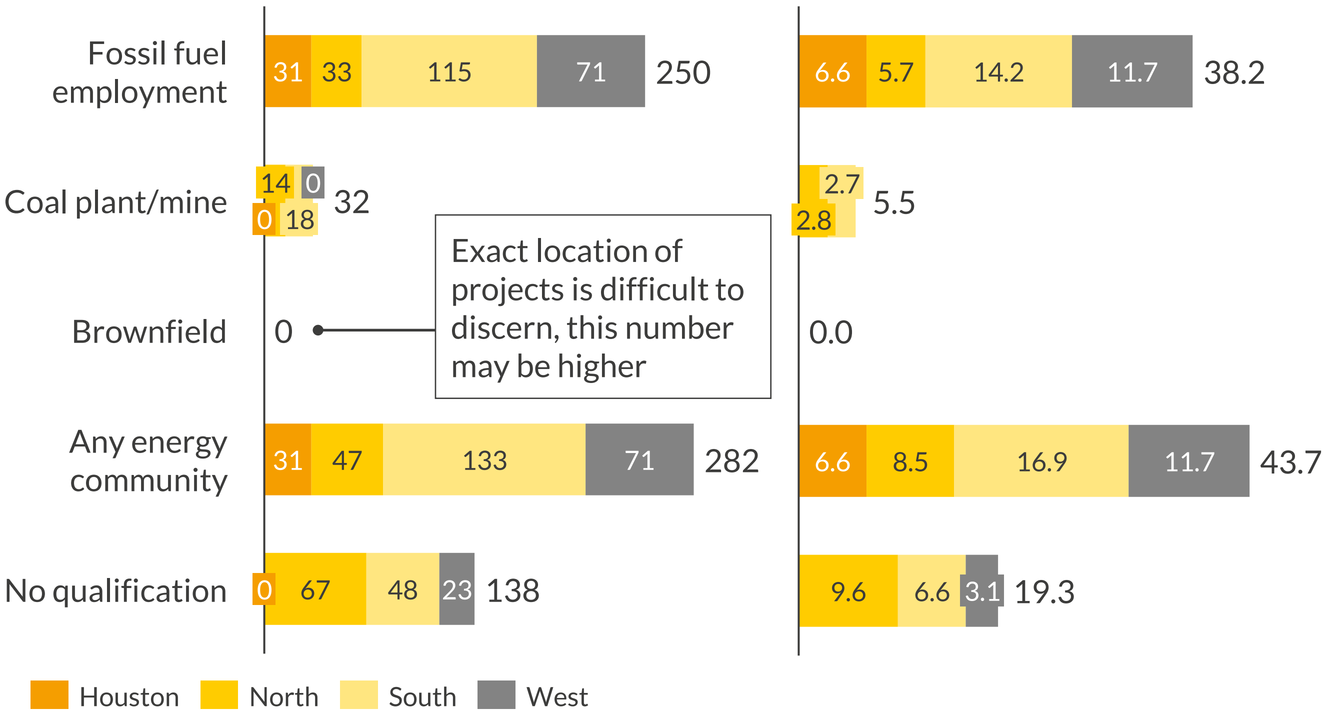
Location of proposed battery sites and energy community boundaries[5]



Number of projects qualifying[5]
Count

Capacity of projects[5]
GW



- 282 of 420 (67%) of proposed battery sites are within the boundaries of the proposed IRA energy communities
- This results in over 44GW of ITC eligible standalone storage, with the vast majority situated in fossil fuel employment zones

1) For construction start years 2022-2033. 2) Rates are inflation-linked. 3) In 2025 the ITC becomes technology-neutral, available to any power generation that is net-zero. 4) We assume that standalone storage will be located in an energy community, but 4% of the Tax Credit is forfeit due to transaction cost. 5) As of October 2022.

Sources: Aurora Energy Research, US Department of Labor, Foley & Lardner LLP, data compiled by Resources.org from: EIA, Texas County Information Program, US Bureau of Labor Statistics, US DoE, EPA

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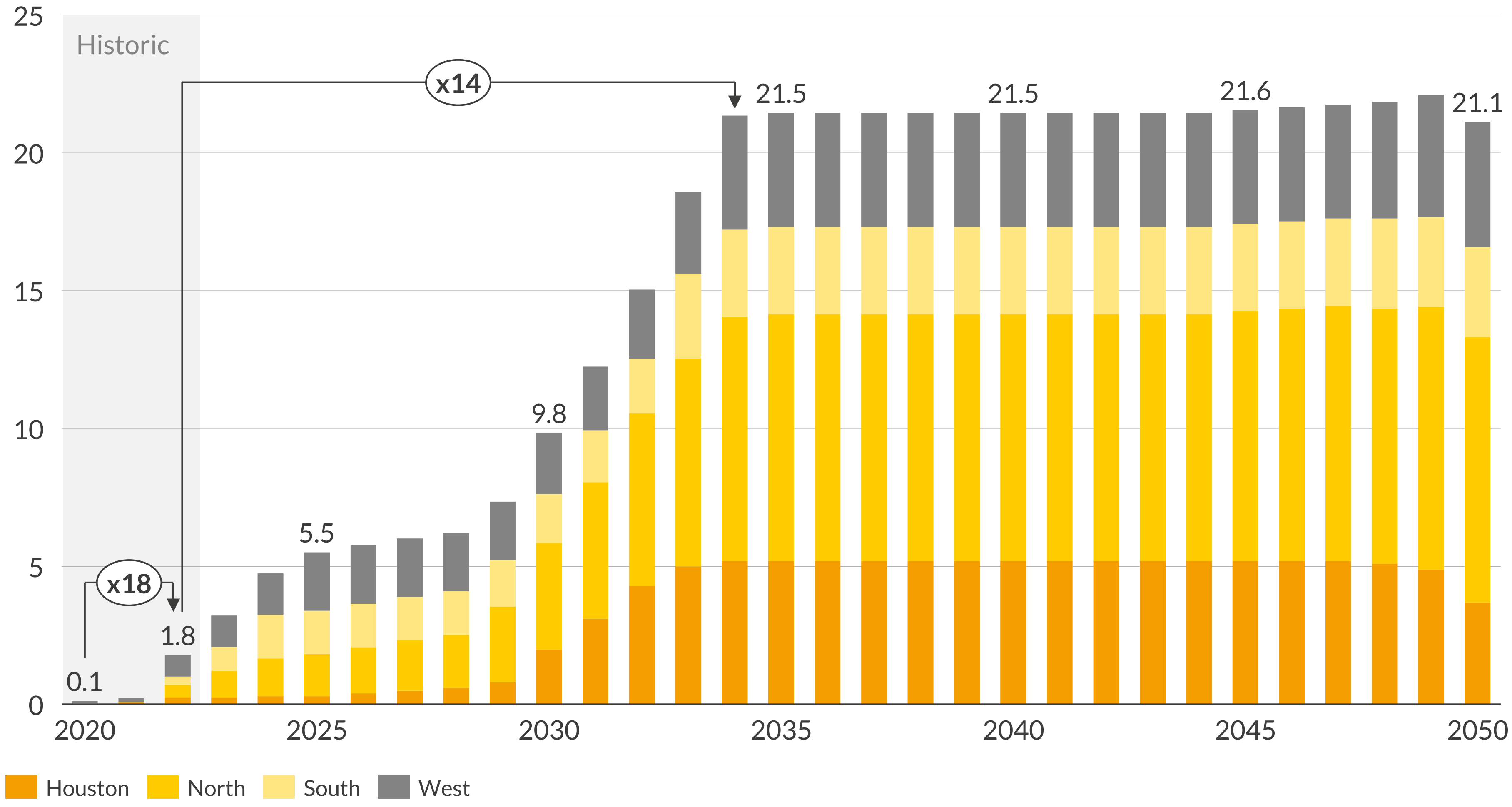
Given the new level of Tax Credits, battery build speeds up in the early 2030s, reaching 21.5GW by 2035

Battery capacity timeline under Aurora Central

GW



- Declining battery CAPEX and high renewables deployment creates a favorable environment for battery buildout under the provisions of the IRA
  - An assumed step-down of the ITC from 36% to 23% net in 2034 slows growth until technology improvements drive costs down
- Introduction of the solar PTC drives a faster build in the late 2020/early 2030s period
- ERCOT has seen the operating capacity grow by 18-fold since the start of 2020, with another circa 14-fold increase by 2035
- There is revenue potential in each region, and Aurora sees relatively even build between them, although North is the most profitable due to high congestion and spreads

Sources: Aurora Energy Research, ERCOT

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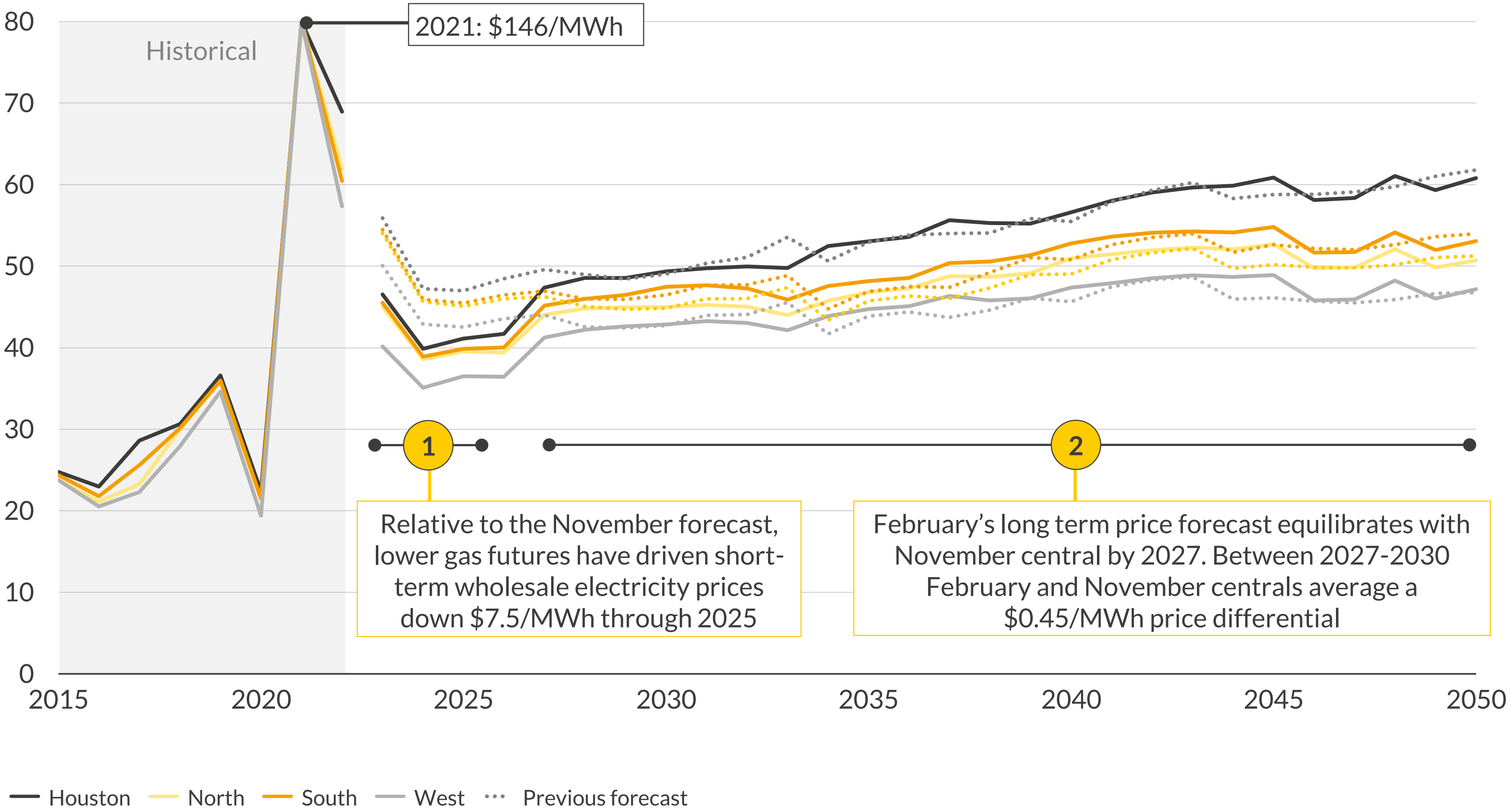
Natural gas futures have declined since Q4 2022 release; ATC prices in 2023 have decreased by an average of $9.3/MWh

ATC wholesale price[1] by hub
$/MWh (real 2021)



1) Around The Clock wholesale power price is the same as the Time Weighted Average price.

Sources: Aurora Energy Research

- Prices in 2022 averaged between $57-69/MWh across hubs in ERCOT. Power prices are expected to be lower in 2023 than 2022 due to falling natural gas prices
- ATC prices are forecasted to fall between now and 2024, in line with gas futures, and then increase from 2024 onwards:

1. ATC wholesale prices drop from $40-47/MWh in 2023 to $35-40/MWh in 2024 across all hubs, in line with natural gas futures
2. Beyond 2030, upwards pressure is placed on prices by high demand and commodity prices, however these increases are partially offset by increased renewables buildout

Price spreads remain stable in line with increased battery capacity and system flexibility

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Average Day-Ahead wholesale price spreads[1,2]
$/MWh (real 2021)

- Price volatility remains mostly stable across the horizon as battery and peaking capacity grows in tandem with inflexible renewable capacity:
  - Flexible capacity increases by 5.2-fold by 2050; renewables capacity increases by 3.2x in the same period
- 4-hour price spreads tend to be lower, highlighting the lower average spread available when targeting longer duration batteries
- The difference between 1 and 4-hour price spreads is very similar across hubs, an average of $60.9/MWh. This value decreases from $81.5/MWh in 2023 to $58.3/MWh, incentivizing longer duration batteries in the longer-term

1) Also known as TB: Top - Bottom prices. 2) The 1-hour price spread takes the highest settlement price within a day and subtracts the lowest settlement price in that day. The 2-hour and 4-hour price spread follows a similar logic, though the periods are not necessarily sequential.
Sources: Aurora Energy Research

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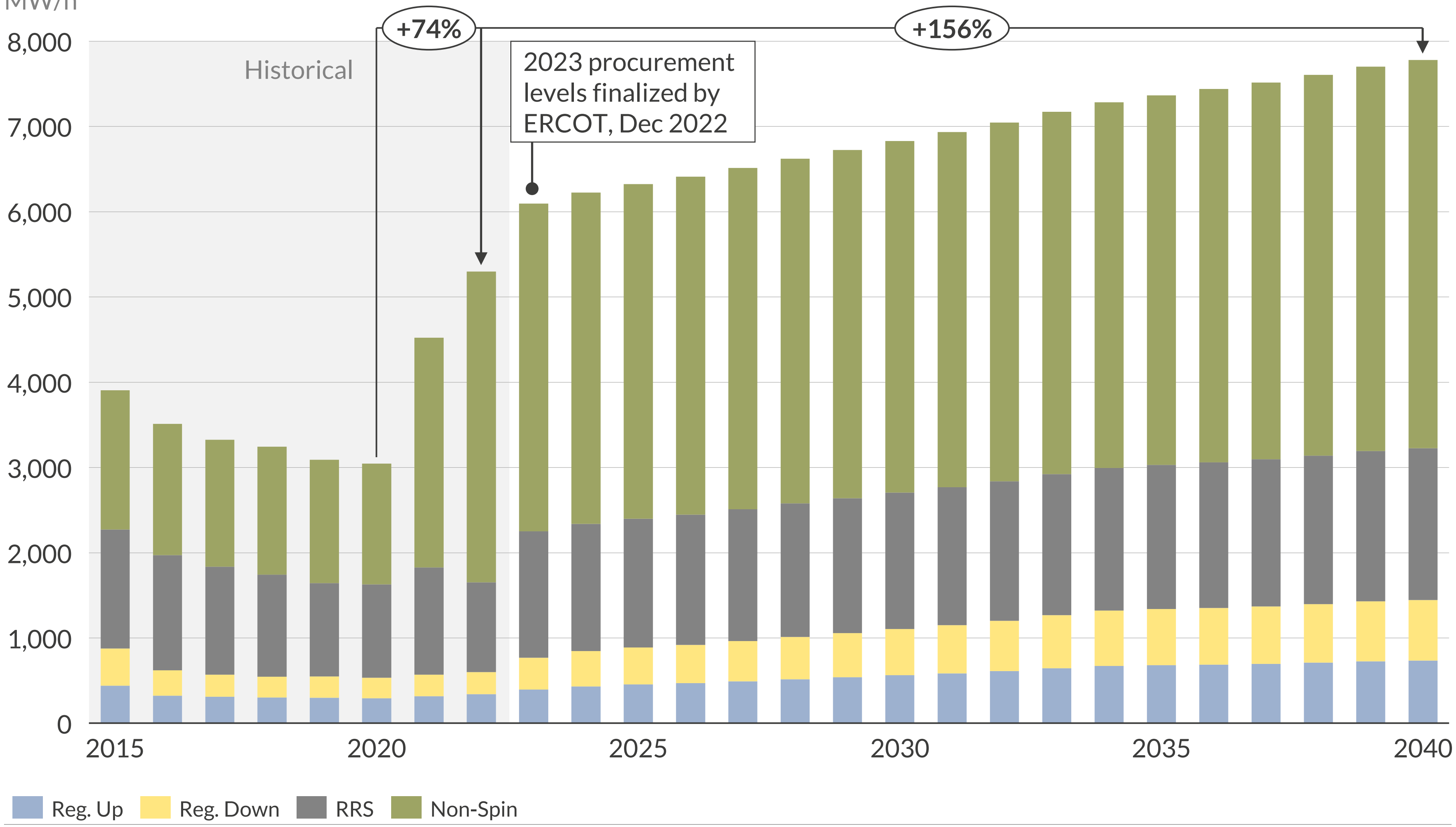
Ancillary service requirements will increase in line with renewables deployment and load growth

Reference case average hourly procured Ancillary Services[1,2]

MW/h



1) Capacity adjustments post SCR811, effective June 1, 2021. 2) Does not include RRS procurement served by load.

Sources: Aurora Energy Research

- Non-spin average hourly volumes increased by 2200 MW/h in 2021 as a result of a change in policy after the Storm Uri. These increases are expected to persist, amounting to a 700 MW/h delta, or 18%, between 2023 and 2040, in line with system growth
- Average volume for RRS is expected to increase by 20% between 2023 and 2040 while volumes for Regulation Up and Down are expected to increase by more than 80%. Increases are driven by the deployment in wind and solar capacity and load increases
- Aurora's power model calculates required AS volumes on an hourly basis, using ERCOT's 2022 profile as a base year and derives each year ERCOT's stated adjustments alongside the market outcomes of wind and solar capacities

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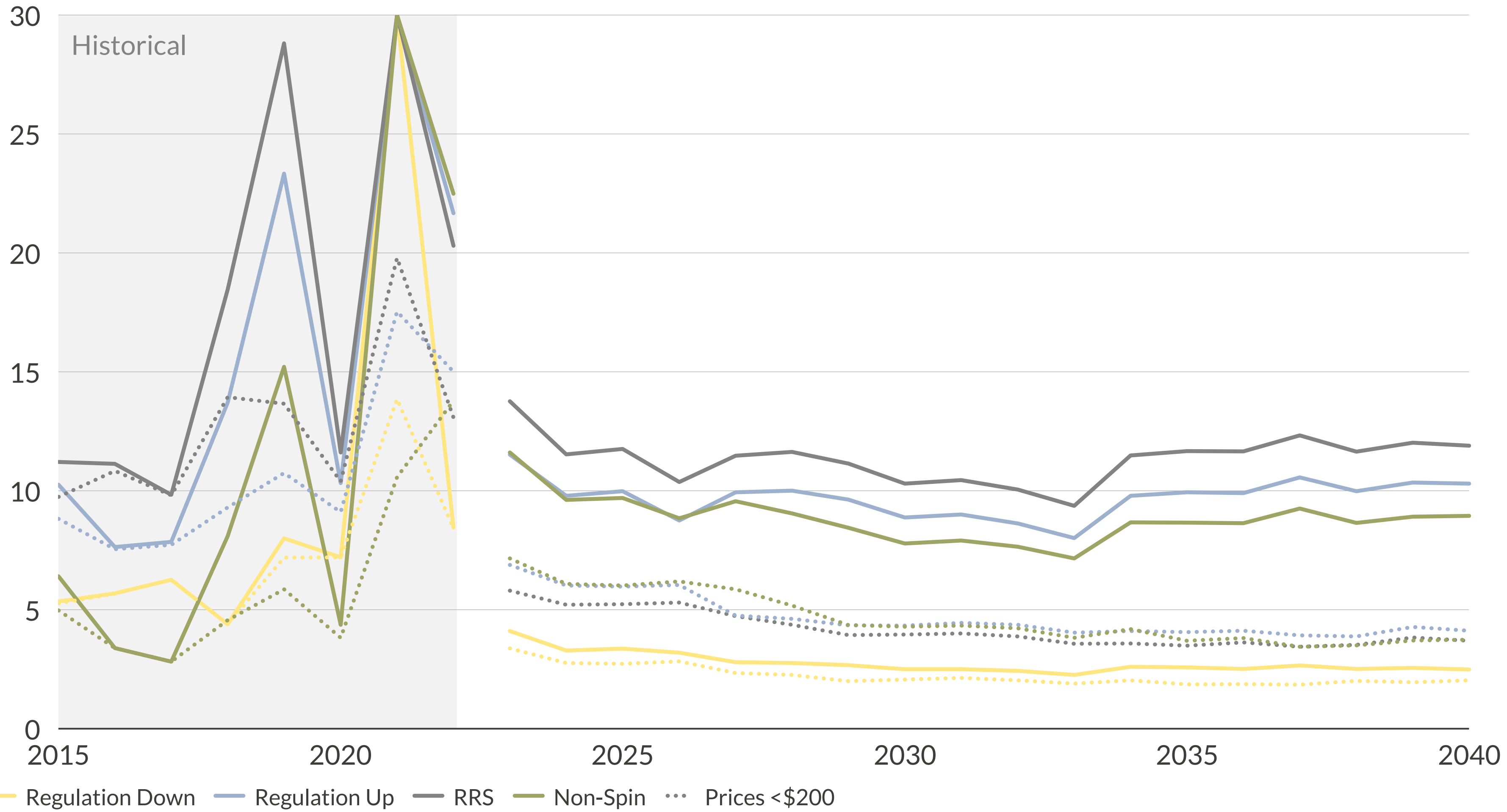
Ancillary prices remain stable out to 2040, with stability coming from persistent wholesale scarcity and opportunity costs

Yearly average MCPC[1,2,3] by ancillary service
$/MW (historic, nominal; future, real 2021)



1) Market Clearing Price for Capacity 2) 2021 prices capped at $30/MW for display

Sources: Aurora Energy Research, ERCOT

- Fundamental value in the AS prices decrease as the markets become more saturated from new build battery entry
- Battery capacity is expected to be 3.2GW by the end of 2023 and prices are expected to be similar to those seen in 2018
- RRS is consistently $1-2/MW/h higher than regulation services, a difference driven by expectation of being called in the Regulation service
- Scarcity in the day-ahead market drives a significant amount of value in AS markets due to the opportunity cost of forgoing wholesale participation. Prices over $200/MW drive 50% of the annual average of the services, with the exception of Reg Down

Locating at a good node can boost wholesale revenues up to 25+%, with demand centers creating robust volatility in the long-term

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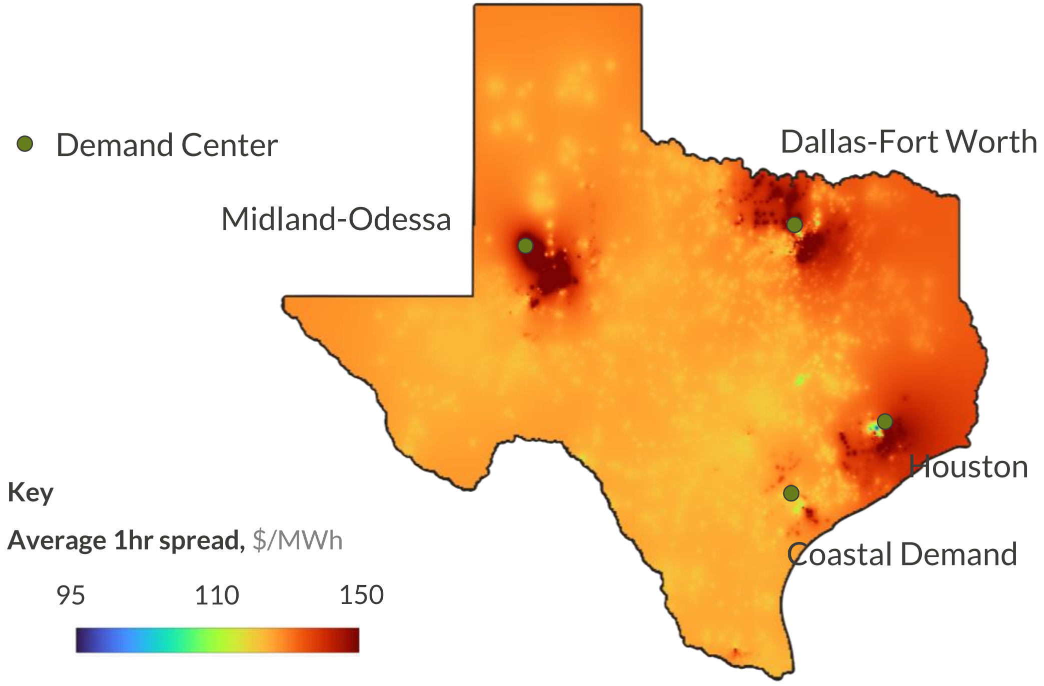
Average 1hr spread relative to zonal average, 2030



Driver	Renewables	Thermal	Imports	Demand
Impact	High renewables leads to large load swings and cheap charging prices	Thermal assets set the price high and retirements require replacing with flexible assets	Influence of imported cheap energy on the price (or lack thereof) creates high spreads	If demand outpaces capacity, spreads are likely to be higher due to increased need for congestion management

Fundamental drivers: long term drivers influencing the deployment of batteries

Node robustness: likelihood of future severe congestion and volatile pricing. High robustness indicates nodes in this region may be more likely to experience high spreads

	Fundamental drivers	Robustness	**Expected premium**[1], % of wholesale revenue
Houston	Renewables: Low Thermal: High Imports: High Demand: Med	High	6-17%
North	Renewables: Med Thermal: Med Imports: Very High Demand: High	High	7-27%
South	Renewables: Med Thermal: Med Imports: Low Demand: Med	Medium	3-16%
West	Renewables: Very high Thermal: Low Imports: Low Demand: Low	Medium	6-33%

1) Premium for siting at the top 10%-top 1% of nodes, which would be the middle of the given range; graph on LHS details areas where this premium exists in 2040, in red

Sources: Aurora Energy Research

Agenda

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Technical battery parameters assumed under Aurora's standard investment cases

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	Standard battery parameters[1]	Impact on revenues	Comment
Entry year	2023 / 2026		Later entry means lower AS prices, although potentially offset by lower capex
Duration	1 hour / 2 hour / 4 hour		Longer durations add more revenue, particularly in energy arbitrage, but this is not a linear increase
Lifetime	20 years		Longer life means more opportunity to earn revenues
Round-trip efficiency	86%		This typically has little impact, unless this is a very high/low value
Degradation	2.5% pa for first 3 years, 1% pa thereafter		Both average rate of degradation and the year-on-year trajectory matters for wholesale margins
Regulation assumed dispatch	15%		Determines the revenues and change in state of charge from regulation participation
RRS assumed dispatch	0%		Due to the low likelihood of major outages RRS is not frequently called upon to dispatch in an average year
Maximum annual cycles	365		This determines available throughput for wholesale and regulation trades
Availability	99%		This typically does not have a major impact, unless outages coincide with high price events

Battery parameter inputs

- When analyzing battery investment cases, there are a wide range of technical input parameters that can influence outcomes
- These parameters vary across manufacturers, battery use cases, market rules, etc.
- This table represents the typical parameters that Aurora has seen for grid scale storage across markets and is based on extensive transaction support and broader collaboration with clients and battery suppliers

1) Other constraints/parameters not included in this modelling but should be considered are state of charge restrictions 2) Can only do regulation with ability to provide energy in assumed dispatch
Source: Aurora Energy Research

Aurora has modelled 72 investment cases across 3 market scenarios, 3 durations, 2 different entry years and 4 zones

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Entry Year	Scenario	Description	1-hr battery		2-hr battery		4-hr battery	
2023	**Central**	Aurora 2023 Q1 Central scenario	1. Houston 2. North	3. South 4. West	5. Houston 6. North	7. South 8. West	9. Houston 10. North	11. South 12. West
	Low	Aurora 2023 Q1 Low scenario	13. Houston 14. North	15. South 16. West	17. Houston 18. North	19. South 20. West	21. Houston 22. North	23. South 24. West
	2011 Weather Year	Aurora 2023 Q1 2011 Weather Year scenario	25. Houston 26. North	27. South 28. West	29. Houston 30. North	31. South 32. West	33. Houston 34. North	35. South 36. West
2026	**Central**	Aurora 2023 Q1 Central scenario	37. Houston 38. North	39. South 40. West	41. Houston 42. North	43. South 44. West	45. Houston 46. North	47. South 48. West
	Low	Aurora 2023 Q1 Low scenario	49. Houston 50. North	51. South 52. West	53. Houston 54. North	55. South 56. West	57. Houston 58. North	59. South 60. West
	2011 Weather Year	Aurora 2023 Q1 2011 Weather Year scenario	61. Houston 62. North	63. South 64. West	65. Houston 66. North	67. South 68. West	69. Houston 70. North	71. South 72. West

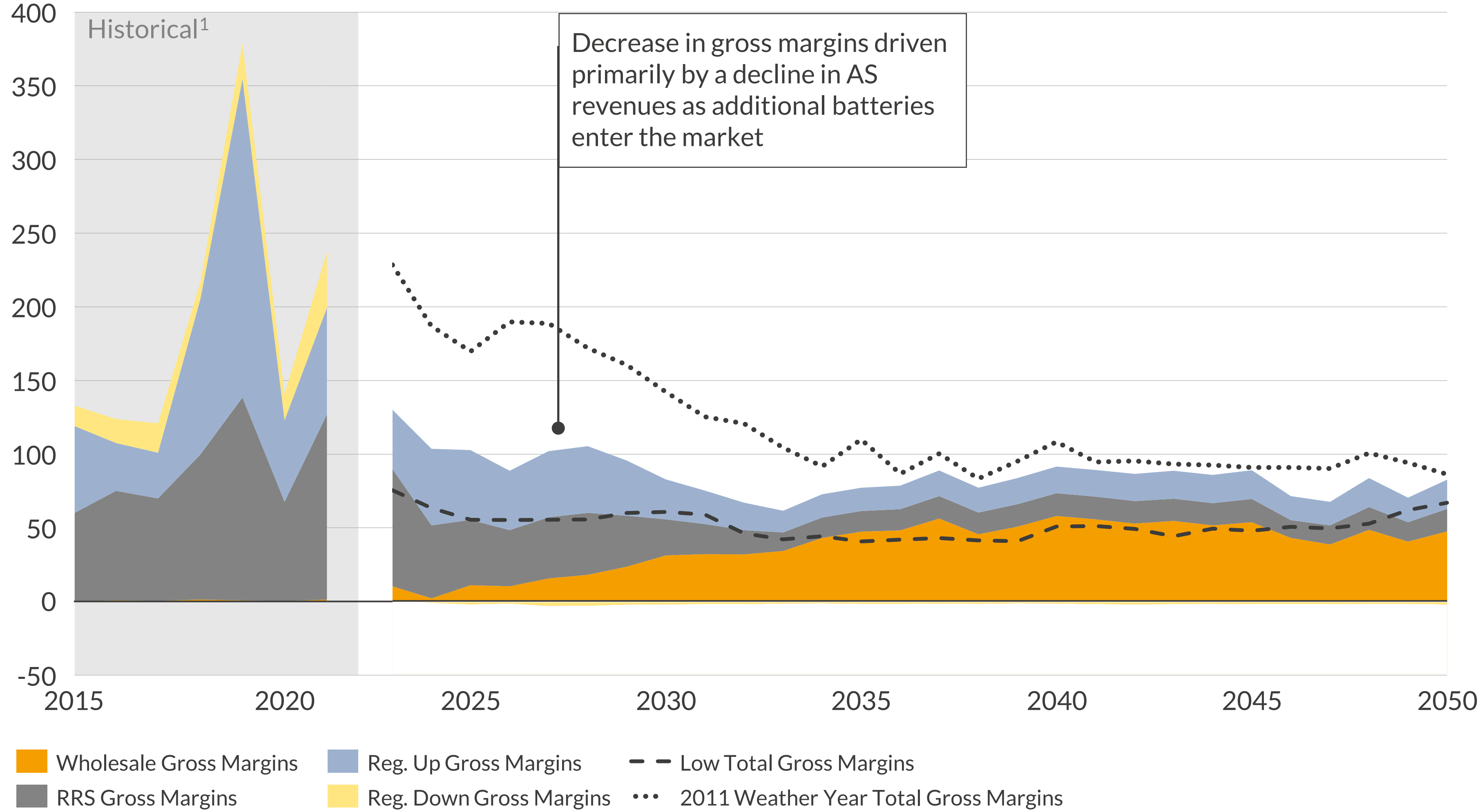
Source: Aurora Energy Research

AURORA

Revenues for a 1 hour asset are formed predominantly of AS, but transition to a stable $80/kW from 2030 onwards

Total annual degraded gross margins for 1-hour battery at the West Hub, 2023 start year[2]

$/kW/year, real 2021



1) Backcasted revenues, excludes February 2021. 2) Total gross margins shown do not include any Nodal Premium. This can be applied for different node percentile and premium persistence assumptions in the accompanying Investment Cases databook.

Source: Aurora Energy Research

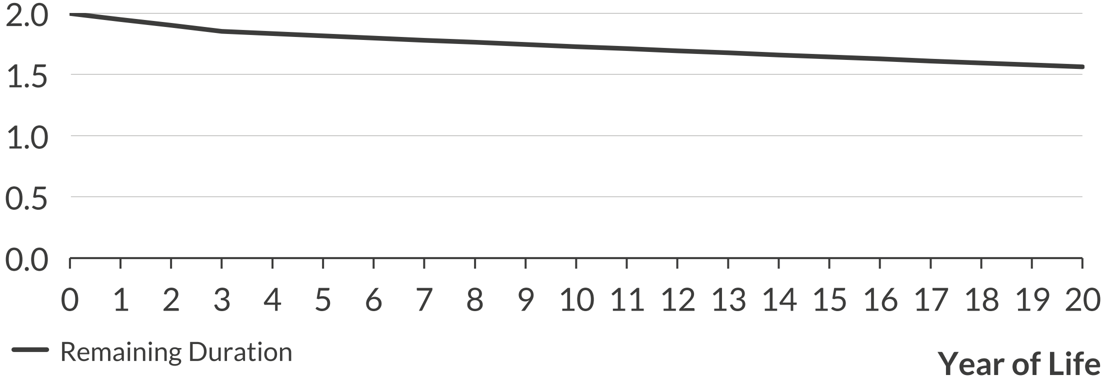
Outlook for battery gross margins

- Gross margins for a 1-hour battery decline from $111/kW/year between 2023-25 to an average of $78/kW/year post-2030
- While AS prices remain relatively stable, increased battery entry implies a decline in capacity awards for any given battery, which reduces margins
- As ancillary markets become saturated, wholesale arbitrage revenue will make up a larger proportion of a battery's gross margins, rising from 8% in 2023 to 63% in 2035
- Reg. down is less profitable in the forecast and is used mainly to offset charging costs
- Decreases in CAPEX from 2022 onwards means assets become more economically viable with lower gross margins

Both degradation and ancillary services participation affect the long term revenue of a battery storage asset

AURORA

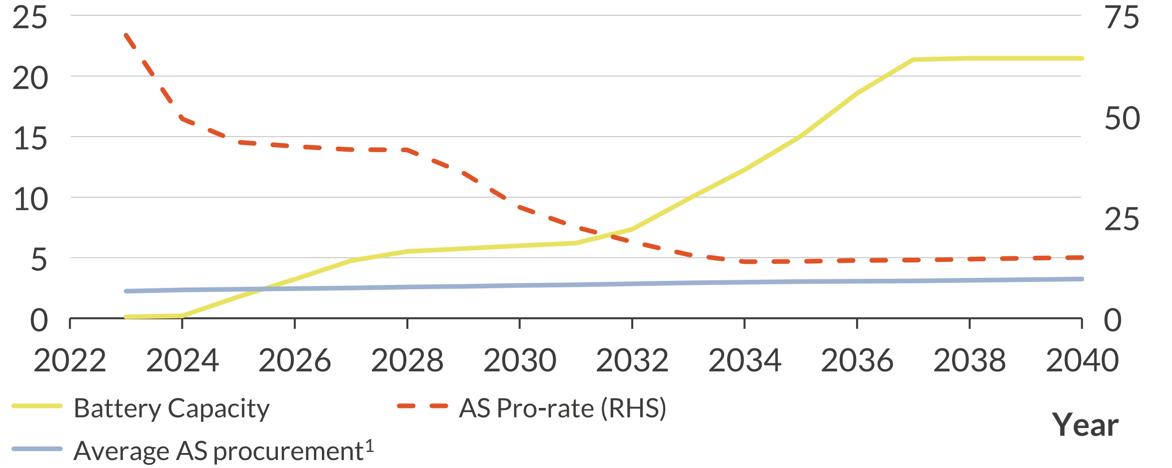
Remaining duration of a 2hr asset after degradation
hours



- Degradation affects both the wholesale revenue achieved, by allowing for less charging and discharging, and the regulation revenues, due to smaller capacity for dispatch. RRS revenues are unaffected
- In general, degradation levels are guaranteed by the manufacturers warranty, and can be either monthly, yearly, or per full discharge/charge cycle

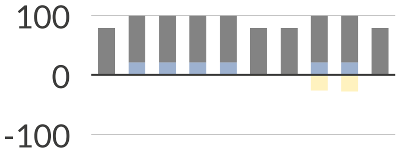
Battery and AS capacity
GW

Ancillary Service pro-rate
%

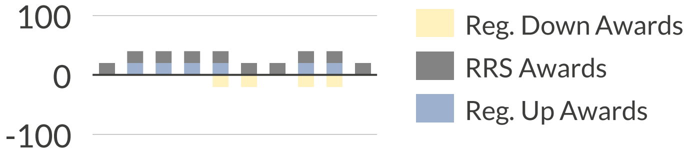


- Due to the level of battery penetration into the Ancillary Services markets, Aurora factors in a pro-rate into the trading strategy of the imperfect foresight trader, limiting AS participation in later years
- Pro-rating awards is consistent with how ERCOT has cleared the FRRS markets in times of oversupply and identical bids, and still allows the battery to perform arbitrage on top of AS awards
- Materially changes the day-to-day operations of the asset (example below)

80% Pro-Rate



20% Pro-Rate



1) This is the sum of RRS, Regulation Up and Regulation Down. For Non-Spin, this calculation changes to only include the 4 hour battery capacity and capacity procured for Non-Spin.

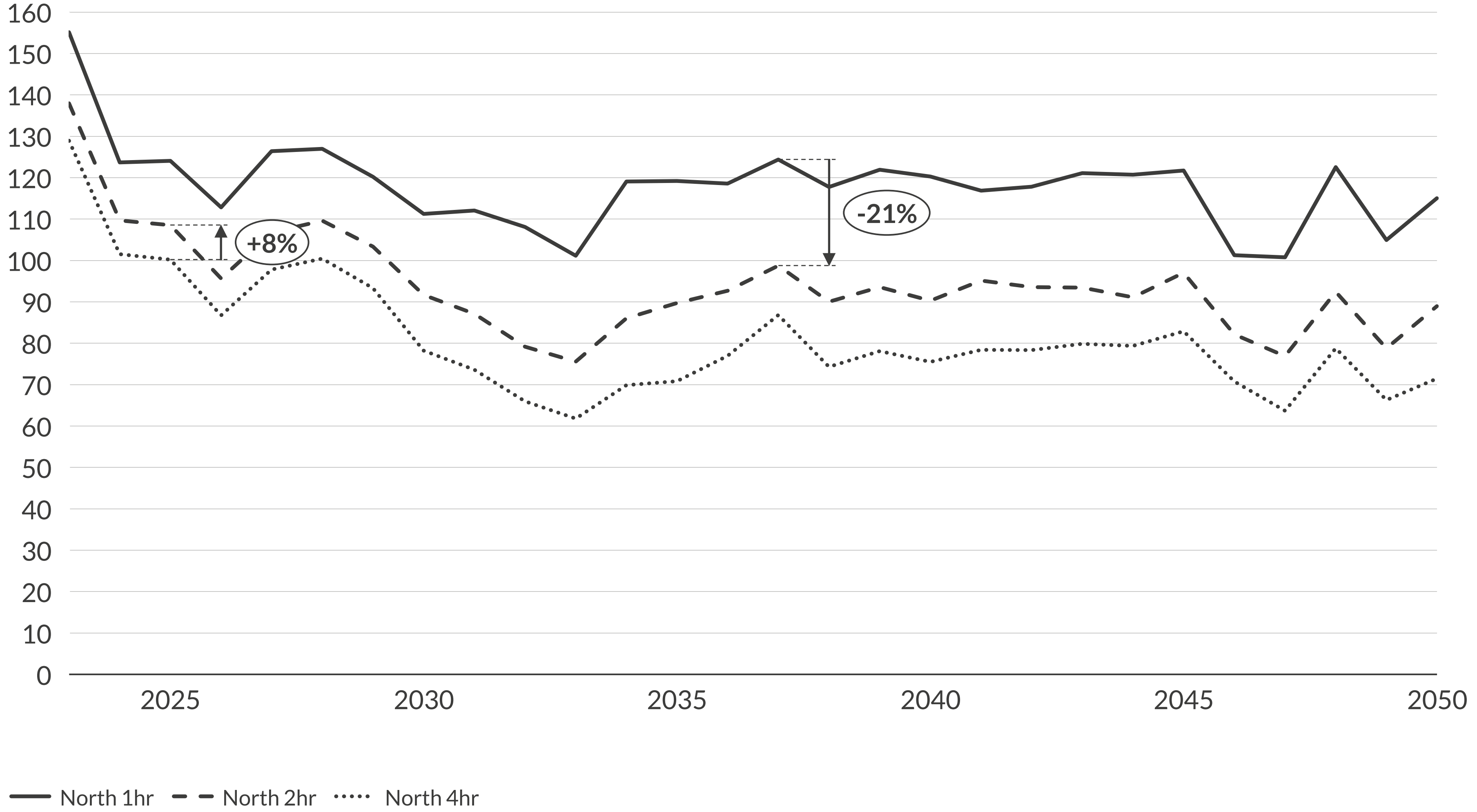
Sources: Aurora Energy Research

AURORA

2-hour batteries realize approximately 14% higher gross margins than 1-hour batteries in the first 8 years

Total degraded gross margins for different battery durations in ERCOT North (2023 entry year)[1]

$/kW, real 2021



Outlook for battery gross margins

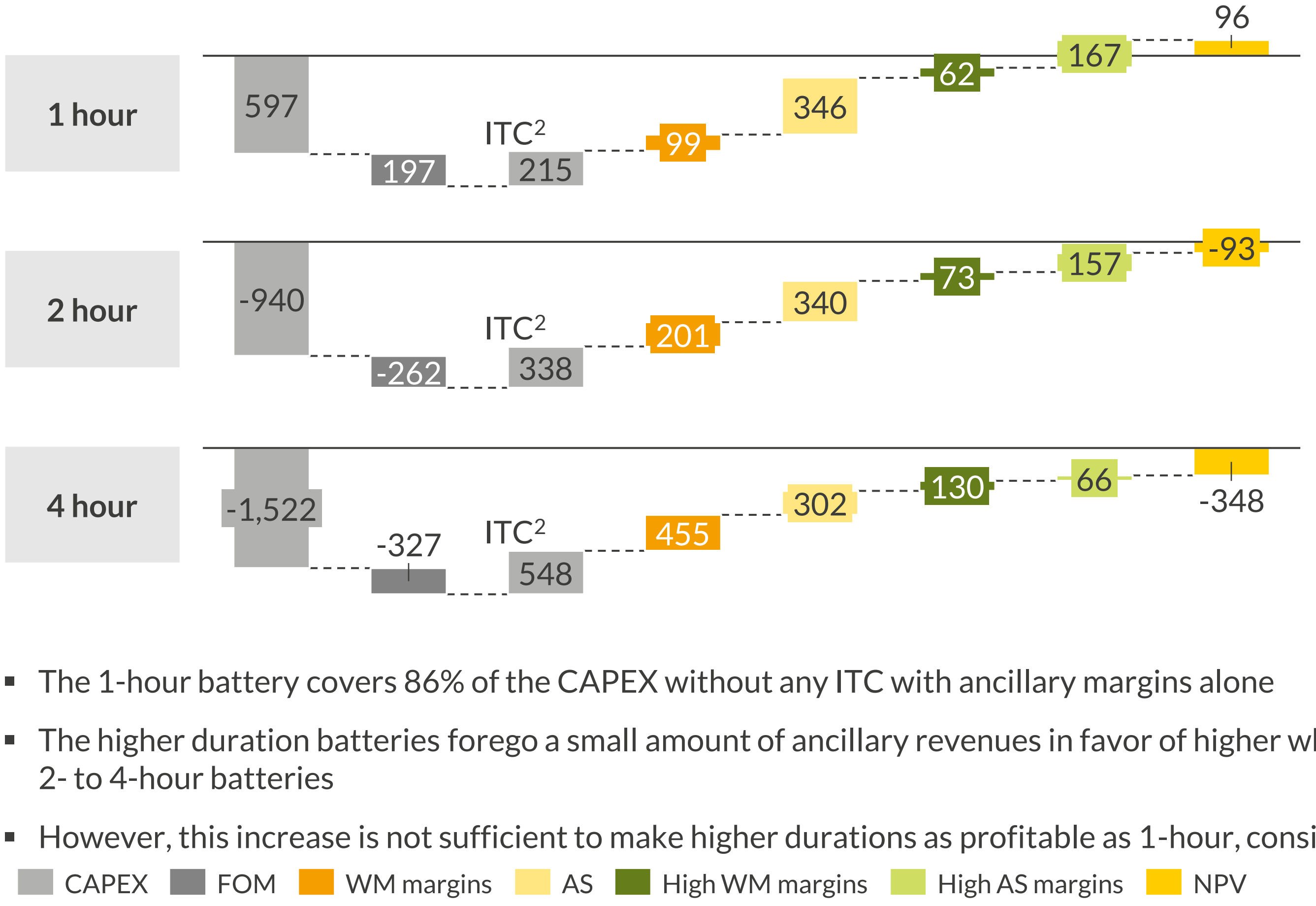
- Longer duration batteries will consistently capture higher gross margins, and the magnitude grows over time as arbitrage in the wholesale market becomes the dominant revenue stream
- In 2035, 2hr batteries earn 8% more than 1hr batteries, 4hr batteries earn an additional 14% over 2hr
- Total gross margins converge at ~$80/kW/year for a 1hr system; margins converge at ~$/120/kW/year for a 4hr system

1) Total gross margins shown do not include any Nodal Premium. This can be applied for different node percentile and premium persistence assumptions in the accompanying Investment Cases databook.

Source: Aurora Energy Research

A new build 1-hour battery in the West is the most profitable region due to high ancillary revenues and lower costs

Economics for new-build battery (various durations, West zone, 2023 entry year, no repower)
PV[1] $/kW real, 2021



	PV of Margins[1]	NPV[1]	Project IRR	Payback period
1 hour	$478/kW	$96/kW	18.2%	4.7 yrs
2 hour	$508/kW	-$93/kW	10.2%	7.7 yrs
4 hour	$625/kW	-$348/kW	5.9%	11.7 yrs

- The 1-hour battery covers 86% of the CAPEX without any ITC with ancillary margins alone
- The higher duration batteries forego a small amount of ancillary revenues in favor of higher wholesale revenues, which increase by 70% from 1- to 2-hour and 114% from 2- to 4-hour batteries
- However, this increase is not sufficient to make higher durations as profitable as 1-hour, considering the 155% increase in 1- to 4-hour CAPEX

1) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). 2) 36% ITC assumed for 2023 entry (assumes a 40% ITC total value with a 10% transaction fee applied).

Source: Aurora Energy Research

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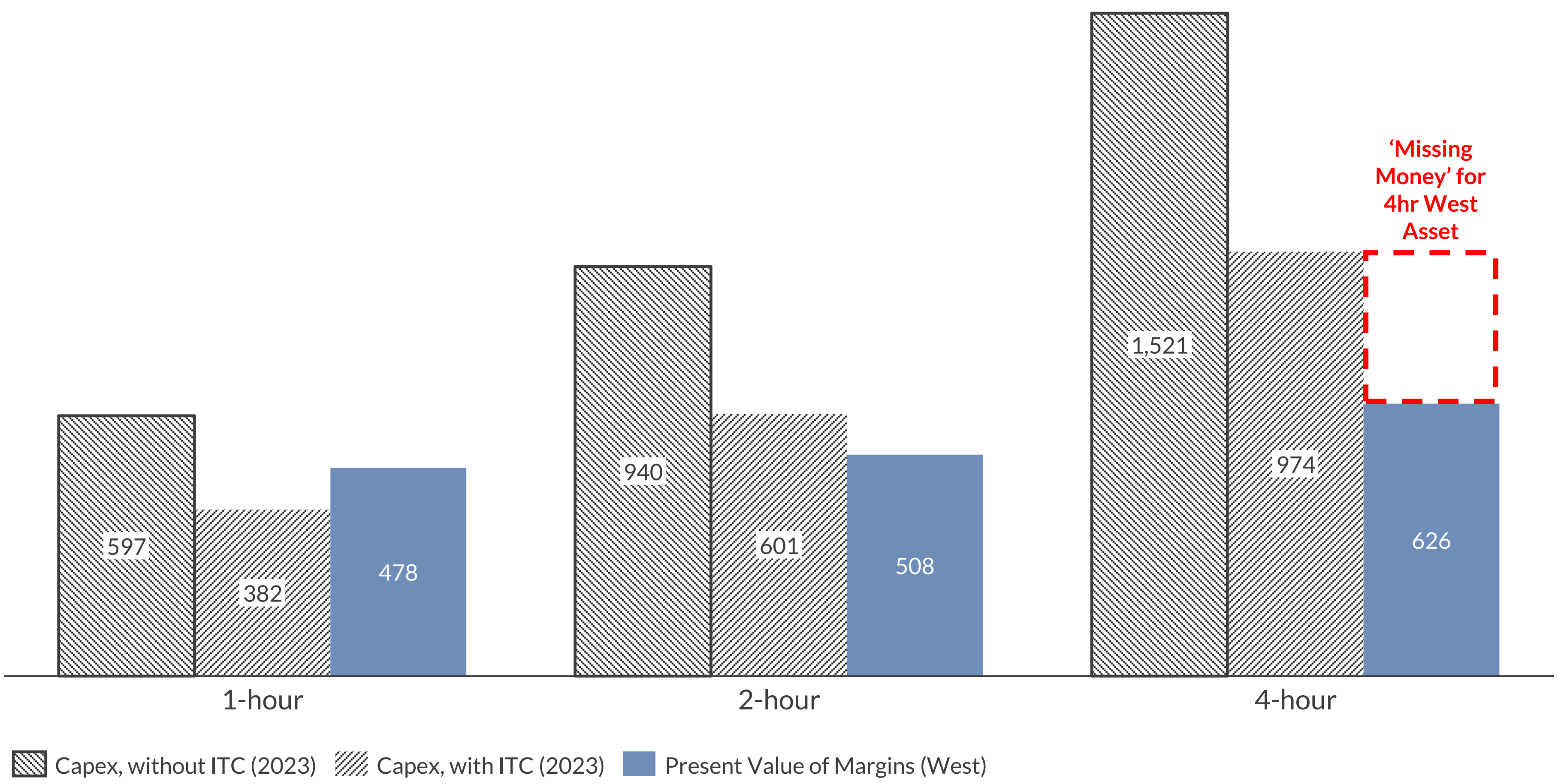
Increasing battery durations lead to lower marginal return, long duration fully merchant investment cases do not yet stack up

Present Value[1,2,3] of Gross Margins and Capex for West batteries of various durations (2023 Entry Year)
$/kW, real 2021



1) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). 2) Aurora's in-house capex assumption, inclusive of recent capex increases due to raw materials prices and supply chain issues.
Source: Aurora Energy Research

Comparison of various durations

- The concept of 'missing money' is the difference between the battery's Capex and the Present Value of the battery's revenue
- Capex increases incrementally by 57% moving from 1- to 2-hour batteries and 62% further to 4-hour batteries. Assuming a 36% net ITC, this amounts to a $582/kW additional cost for a 4-hour battery compared to a 1-hour battery
- However, battery PV of revenues only increases by $148/kW for a 4-hour West battery compared to its 1-hour counterpart
- These diminishing returns manifest in $348/kW of missing money for a 4-hour West battery, whereas its 1-hour counterpart produces an IRR over 18%

Regional differences are less impactful than duration and entry year decisions for asset profitability

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Evolving nodal topography differentiates the regions, but the West zone will generate the highest margins for new build batteries, with an PV's of about 2-10% higher than other zones for 2026 entry. Houston IRR's benefit from high energy margins during scarcity hours, but these are more heavily discounted than non-scarcity-driven revenues. 1 hour batteries remain the most profitable in the near term, but medium-term declines in CAPEX will reduce the differential in profitability across durations.

Entry Year	Scenario	Duration	Present Value of Margins[1,2] ($/kW)				IRR (%)				Payback Period (yrs)			
			Houston	*North*	*South*	*West*	*Houston*	*North*	*South*	*West*	*Houston*	*North*	*South*	*West*
2023	Central	1 hour	419.3	413.1	418.2	423.5	18.1%	17.7%	18.0%	18.2%	4.8	4.9	4.8	4.8
		2 hour	429.5	433.6	432.7	450.4	9.6%	9.6%	9.6%	10.2%	8.0	8.0	8.1	7.8
		4 hour	507.4	532.1	521.0	557.4	4.6%	5.3%	5.0%	5.9%	13.0	12.3	12.7	11.9
2026	Central	1 hour	358.7	350.9	357.0	363.2	19.8%	19.1%	19.6%	19.7%	4.3	4.4	4.4	4.3
		2 hour	374.6	380.4	380.1	401.6	12.0%	12.0%	12.1%	12.9%	7.3	7.4	7.3	7.1
		4 hour	459.5	497.6	480.2	524.2	7.4%	8.4%	8.0%	9.1%	10.5	9.7	10.1	9.4

1) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). 2) Present value of margins includes all revenues, charging costs, and annual fixed costs.

Source: Aurora Energy Research

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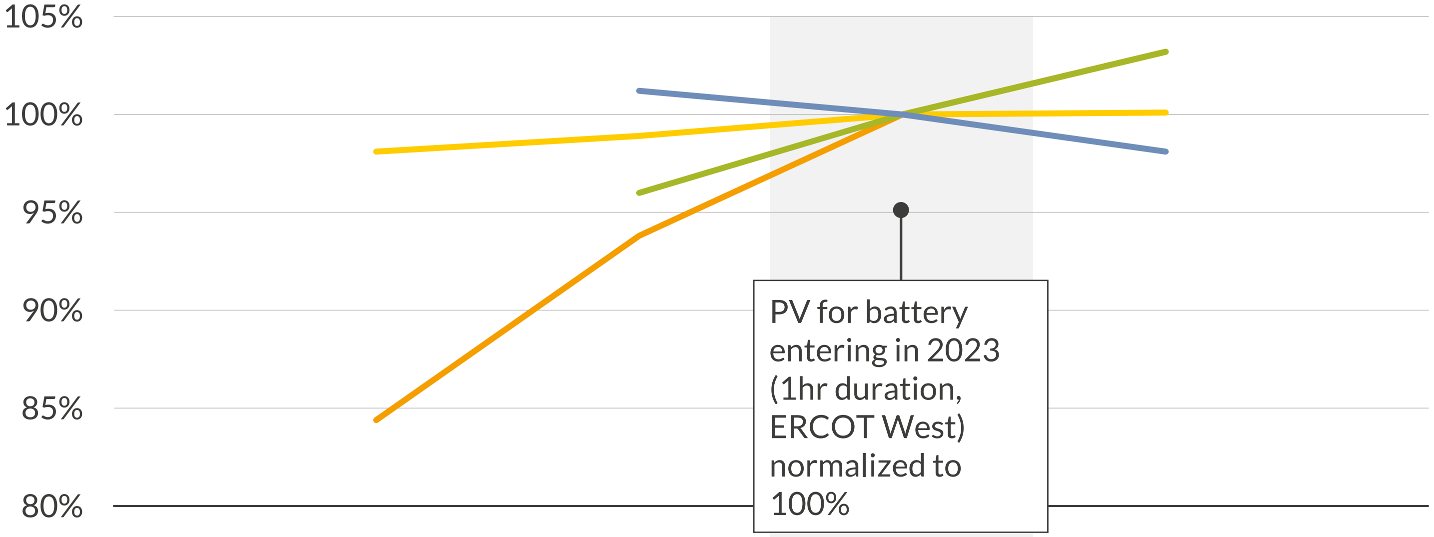
Lifetime, cycles and round-trip efficiency can influence PV of margins by more than 20%

PV[1] of margins relative to central assumptions for new build battery (1hr, 2023 entry in West Hub)[4], %



Lifetime	Years	10	15	**20**	25
RTE[2]	%	75	80	**86**	90
Cycles	#/year		250	**365**	550
Degradation[3]	% p.a.		1.3% pa, for 3 years, 0.5% pa thereafter	**2.5% pa for 3 years, 1% pa thereafter**	3.8% pa for 3 years, 1.5% pa thereafter

- Aurora selected 4 input assumptions to test the sensitivities for a change in the Present Value of margins
- A change in the round-trip efficiency of the battery causes a relatively minor delta in the Present Value of margins – there is only a 2% difference in PV of margins between a 90% RTE and 75% RTE business case
- Lifetime and cycling have the most substantial impacts on PV:
  - Using only 250 cycles/year drops PV of margins by 4% net, which includes any savings in degradation from the lower cycling rate;
  - The impact of different cycling rates should be considered alongside degradation and lifetime as these measures are relatively interdependent.

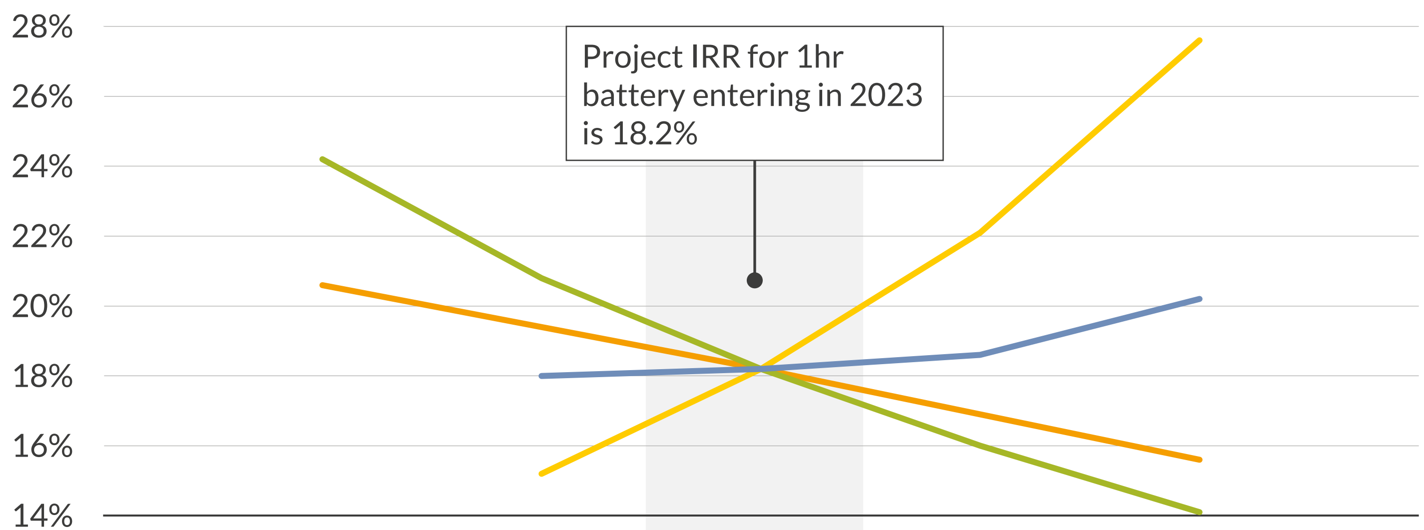
1) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). Present value of margins includes all revenues, charging costs, and annual fixed costs. 2) Round Trip Efficiency. 3) Assuming 365 cycles per year.
Sources: Aurora Energy Research

AURORA

Sensitivities to financing parameters can affect CAPEX costs and annual margins, impacting project economics for new-build batteries

Project IRR[1] under financing sensitivities for new-build battery (1hr, 2023 entry, ERCOT West)

%



OPEX	$/kW per year	-30%	-15%	**24.7**	+15%	+30%
ITC[1,2]	%		30	**40**	50	60
CAPEX	$/kW	-20%	-10%	**597.3**	+10%	+20%
Nodal Premium[3]	$/MWh		-2%	**0**	+6%	+33%

- Aurora selected 4 financial factors to test the impact of sensitivities on project IRRs
- Project IRRs are especially sensitive to changes in CAPEX and OPEX costs. A 20% decrease in CAPEX can increase project IRRs by over 6pp. Securing the full 60% ITC can increase IRRs to 28%
- Batteries located on favorable nodes can also see significant increases in project IRRs:
  - A battery on a 90th percentile node experiences a $7/kW increase in NPV and can see project IRRs of 19%.
  - A battery on a 99th percentile node experiences a $38/kW increase in NPV and can see project IRRs of more than 20%.

1) Excludes transaction costs or fees. 2) Meeting domestic content, energy community, and low-income community requirements to secure the 60% ITC may increase costs. 3) Nodal premium increases wholesale arbitrage revenue in line with spread increases and reflects value of forecasted 10th, 90th, and 99th percentile node for the battery's lifetime. Does not affect dispatch behavior.

Sources: Aurora Energy Research

We explore key market uncertainties through a range of scenarios

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Central	Considers current policies alongside our internally consistent central view of technological change and commodity prices. Assumes implementation of the Inflation Reduction Act (IRA) with a continuation of Tax Credits at lower levels after IRA expiration in 2035
Low	Represents a downside case, incorporating low underlying demand and low commodity prices. This envisages a world with slower overall GDP and population growth
2011 Weather Year	Weather years impact the market outcomes through their impact on demand and renewables generation. This scenario takes the 2011 weather year profiles and capacity mix as in Central. This scenario is intended to represent a potential upside for individual years.

Sources: Aurora Energy Research

Summary of scenario input assumptions

AURORA

As per *Central* scenario unless otherwise indicated

		Impact on Battery economics	Aurora Central	Low	2011 Weather Year
Demand	Underlying demand		+300 TWh to 2050 driven by population and industrial growth	-3% in 2025, -15% in 2050	2011 hourly demand shape; Change in total demand: +14 TWh in 2025 (+3%), +19TWh in 2050 (+2%); Change in peak demand: +6GW in 2025 (+7%), +5GW in 2030 (+4%)
	EVs		3m EVs by 2030 and 19m by 2050	Low EV uptake	
	Bitcoin mining		2 GW of load by 2023, 3.5 GW by 2025		
	Hydrogen electrolysis		Demand for hydrogen electrolysis begins in 2028, reaches 5 GW by 2050		
Commodities	Gas price		Increase to \$3.80 in 2030 and \$4.70/MMBtu in 2050	Henry Hub prices fall to \$2.5/MMBtu across horizon	
	Coal price		Stable coal price across forecast horizon	\$3.6/ton across horizon	
Technology	Renewables		Between now and 2050 wind CAPEX falls by 39% and solar by 59%		2011 hourly wind and solar capacity factors
Policy	Pollution standards		Plants face increasing environmental costs at end of lifetime but are not mandated to close		
	Reliability		New entry determined by market economics	+6 GW in 2023 growing to +12GW by 2050 of firm capacity contracted out-of-market	
	Renewables incentives		Inflation Reduction Act provisions for wind, solar and battery out to 2035. 40% ITC available to batteries. Beyond this point Tax Credit support is kept at final year values. 45Q available to new build and refurbishing Gas CCGT CCS plants	Solar additions reach 50% of central in 2050, whilst wind reaches 25%	
	Carbon price		No carbon price introduced		
	Transmission upgrades		Strengthening of network increases transmission capacity between most regions by ~50% by 2050		

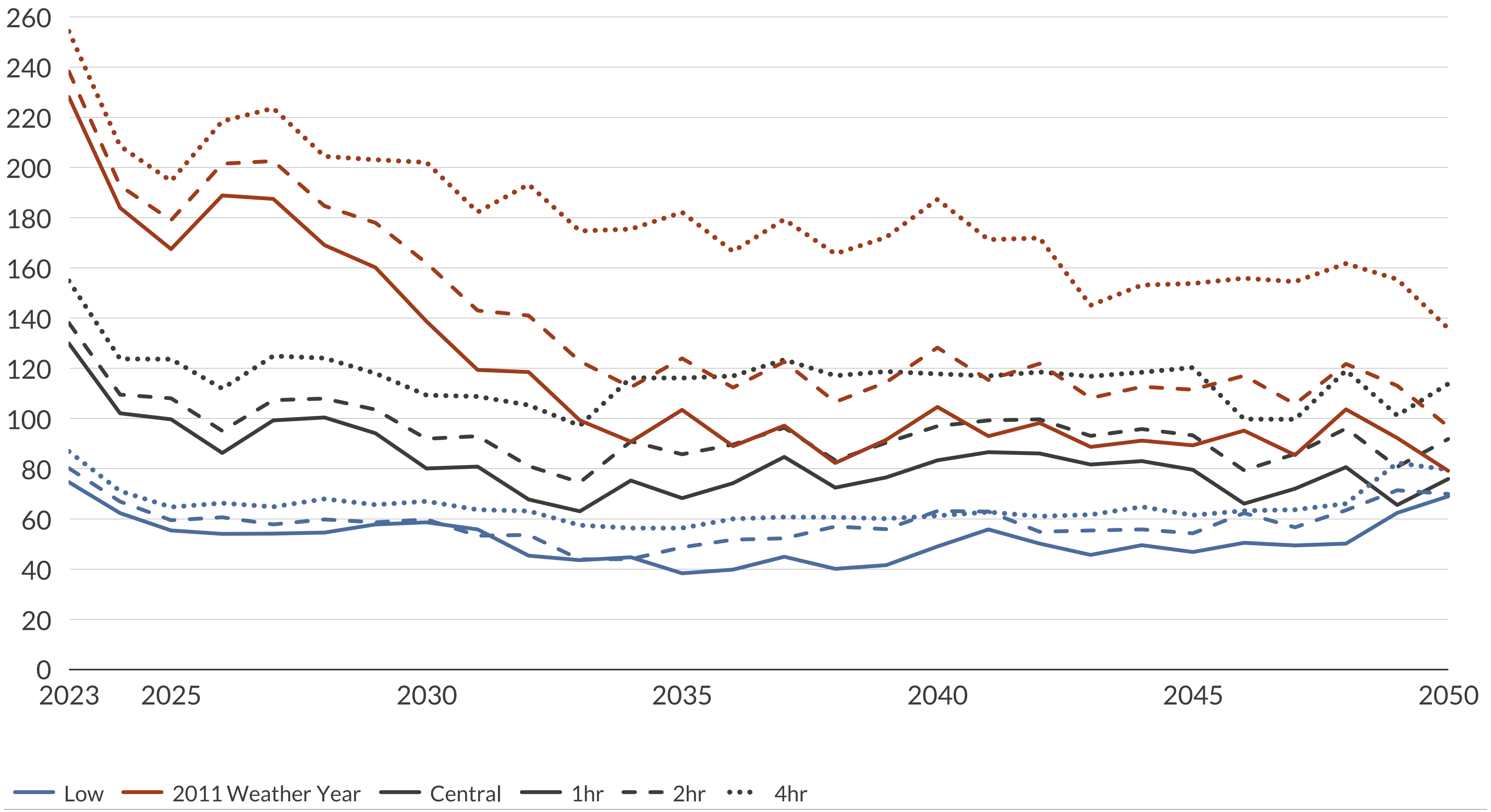
1) Benchmark intensity based on point source emissions, not including upstream emissions.

Sources: Aurora Energy Research

AURORA

Changing scarcity and ancillary prices produces a ~$140/kW range in battery gross margins for the first 5 years

Total degraded gross margins for different battery durations in ERCOT South (2023 entry year)
$/kW, real 2021



Source: Aurora Energy Research

Comparison between Central and alternative scenario results

- Gross margins for 4hr batteries are most significantly reduced in the Low Case as they can capture the most scarcity value in arbitrage: they see a reduction of about $60/kW/year in the long-term. 1hr batteries only see a $30/kW/year reduction in margins.
- An 80% potential upside over Central in 2025 gross margins is available to 1hr batteries in a 2011 Weather Year. This impact declines over time due to:
  - i. increased importance of energy arbitrage- batteries are limited in capturing consecutive high price hours;
  - ii. high solar generation reducing peak load
  - iii. greater flexibility in the system due to peaking build and EV charging

Wholesale margins contribute the lions' share of NPV delta between a Low and Central investment cases

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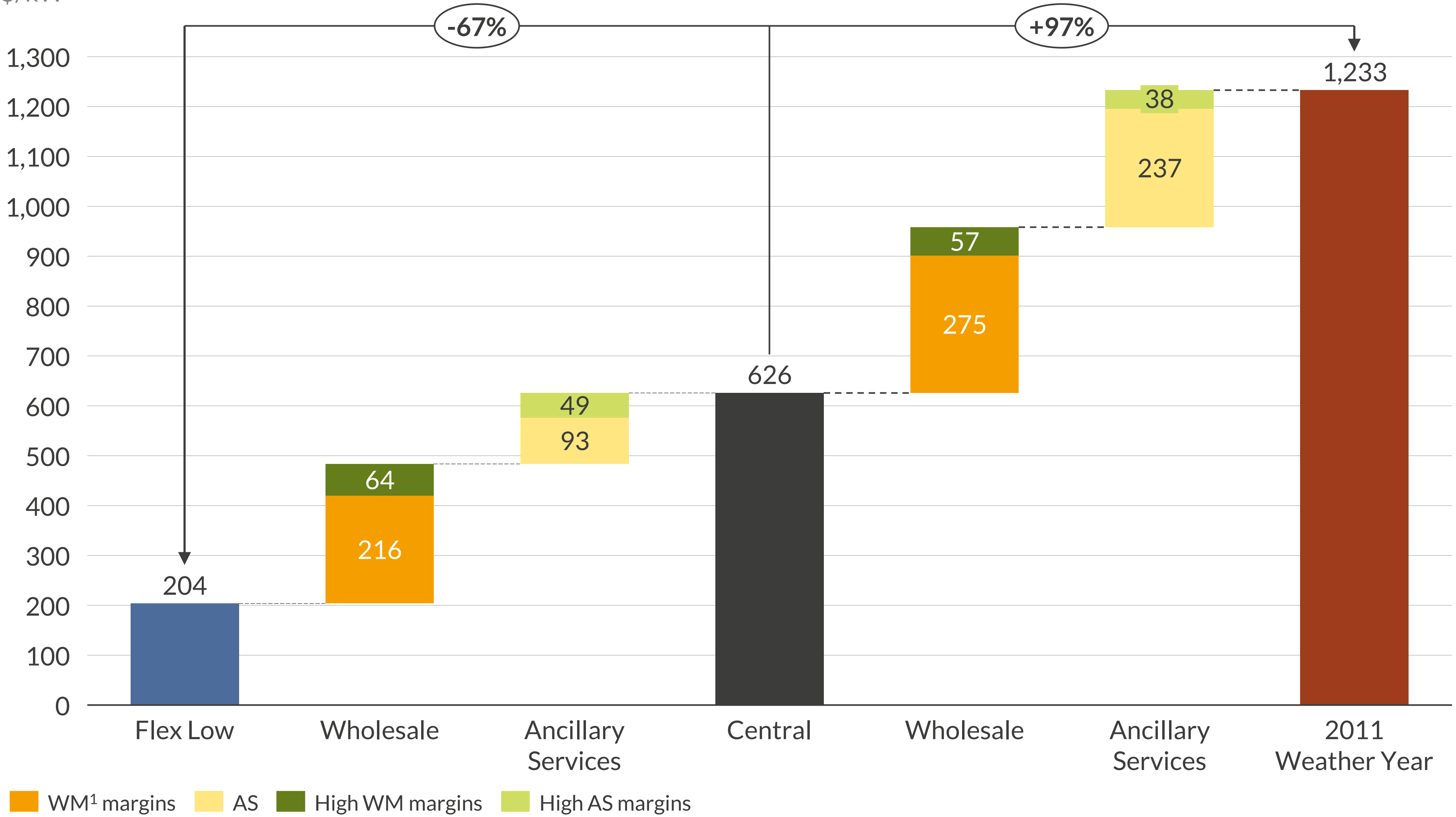
Breakdown of PV of margins under different Aurora scenarios for a 4hr battery in ERCOT West with 2023 entry year
$/kW



- For a 4hr battery system, lower energy and ancillary prices in the Low case produce only 67% of Central PV of margins
- High scarcity in the 2011 Weather Year scenario increases PV of margins by 97% over Central
- Wholesale PV of margins increases from Low to Central by 92% and by 200% from Low to 2011 Weather Year
- While some additional revenue in the 2011 Weather Year case comes from scarcity periods, there is also additional value in the fundamental hours due to changes in demand and renewables generation

1) Wholesale market. 2) Discount rate of 11% for revenues and costs, and 15% for high price periods (>$500/MWh for WM prices or $200/MW/h for AS prices). Present value of margins includes all revenues, charging costs, and annual fixed costs.
Source: Aurora Energy Research

The timing and frequency of weather events creates a significant range in potential upside relative to the central case

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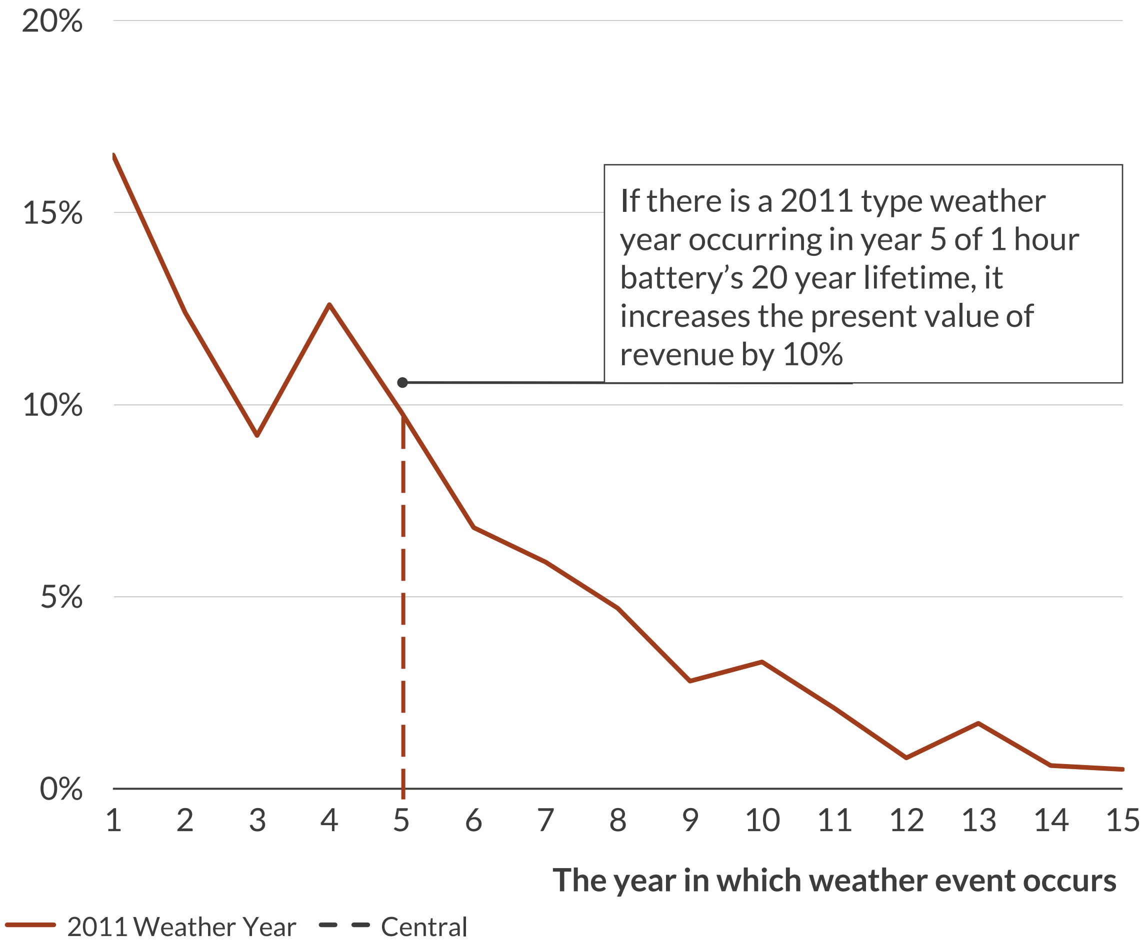
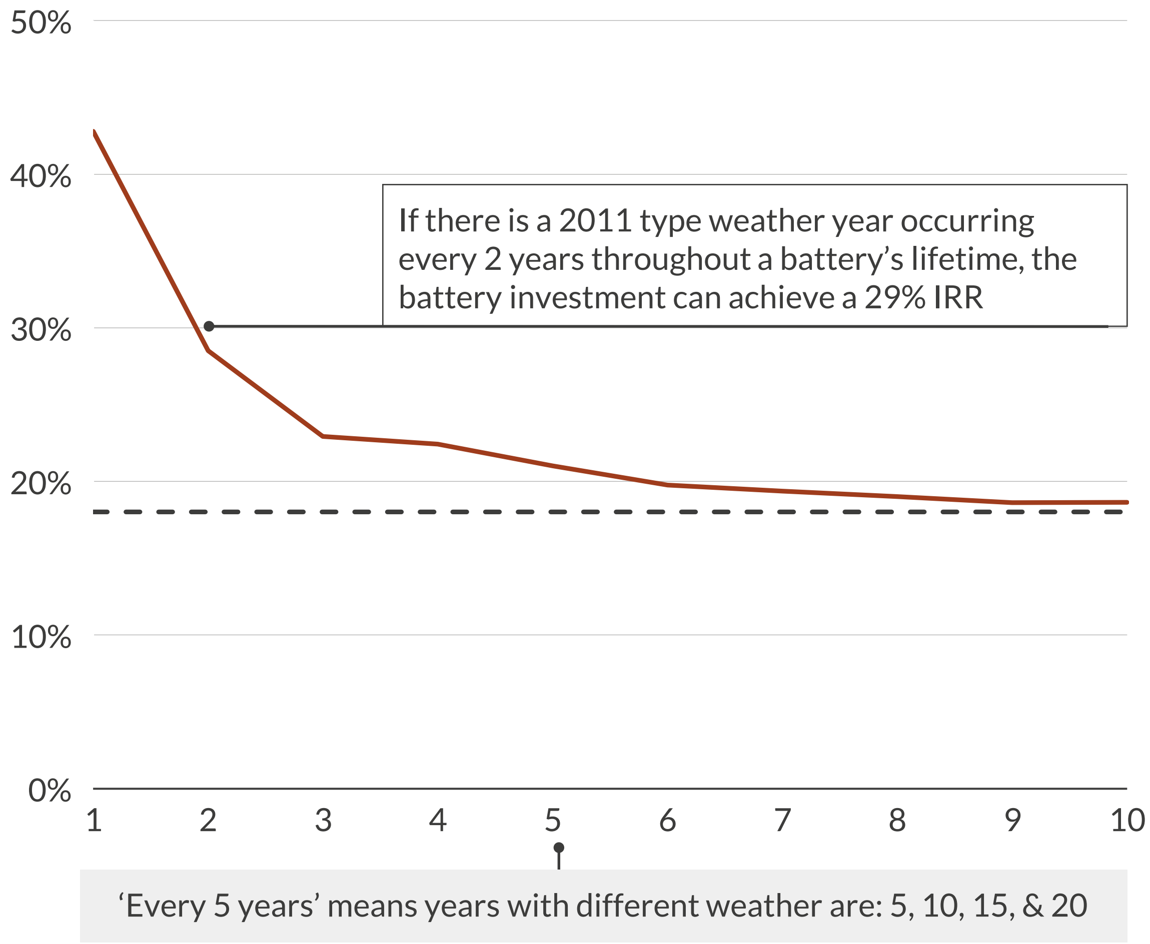
Change in present value[1] of revenue from the 2011 Weather Year Scenario – 1hr South batteries[2,3], %



1hr South Battery IRRs[1] with varying frequency of weather years occurring
%



1). Assume a discount rate of 11%. 2) 2023 start 3) Includes degradation and availability

Source: Aurora Energy Research

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Aurora provides market leading forecasts & data-driven intelligence for the global energy transition

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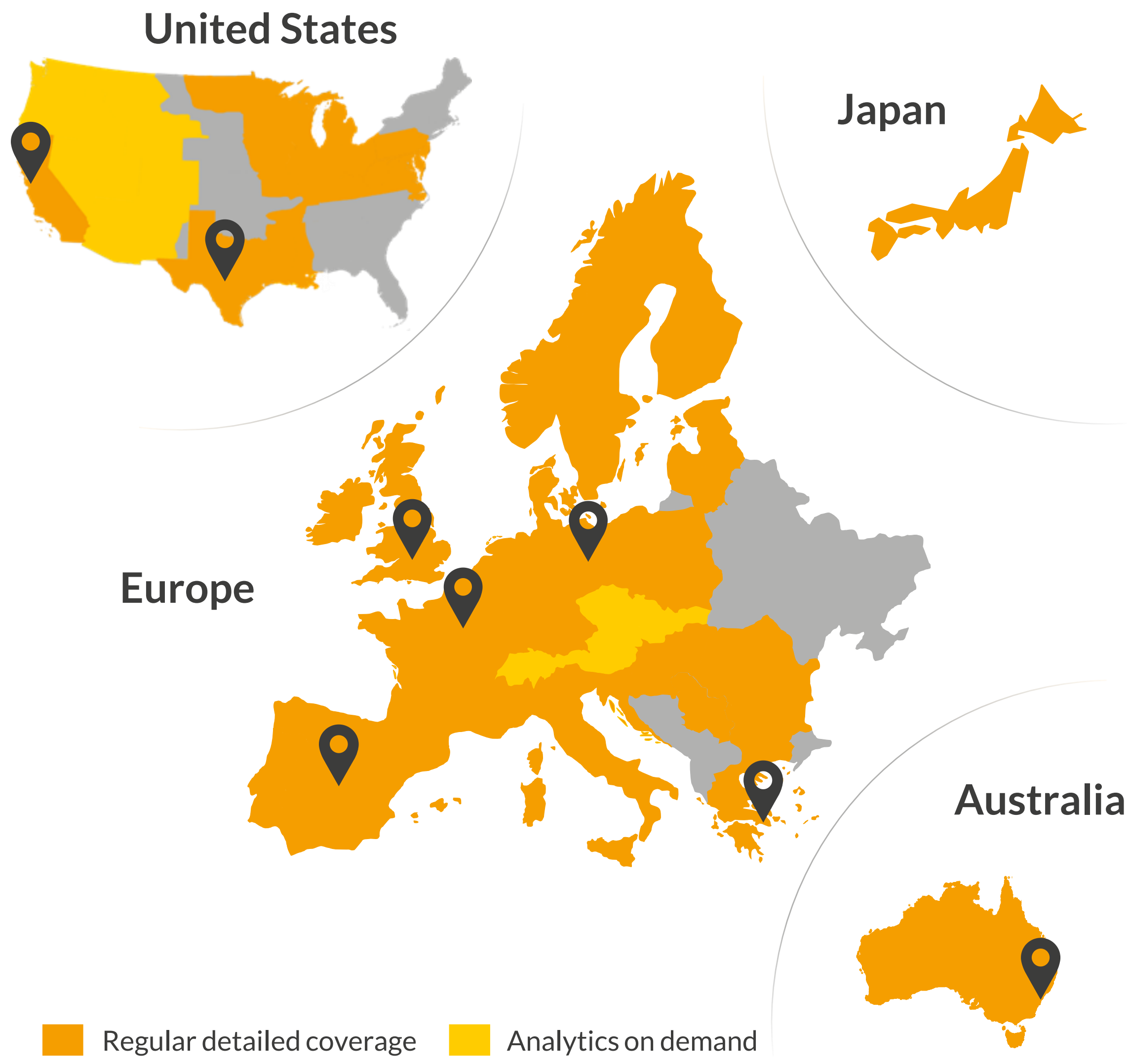
- Power markets
- Renewables
- Storage
- Electric vehicles
- Hydrogen H_2
- Carbon CO_2
- Natural gas



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market experts, 35+ in the US

600+
subscribing companies

120+
transactions supported in 2021

Source: Aurora Energy Research

Our market leading models underpin a comprehensive range of seamlessly integrated services to best suit your needs

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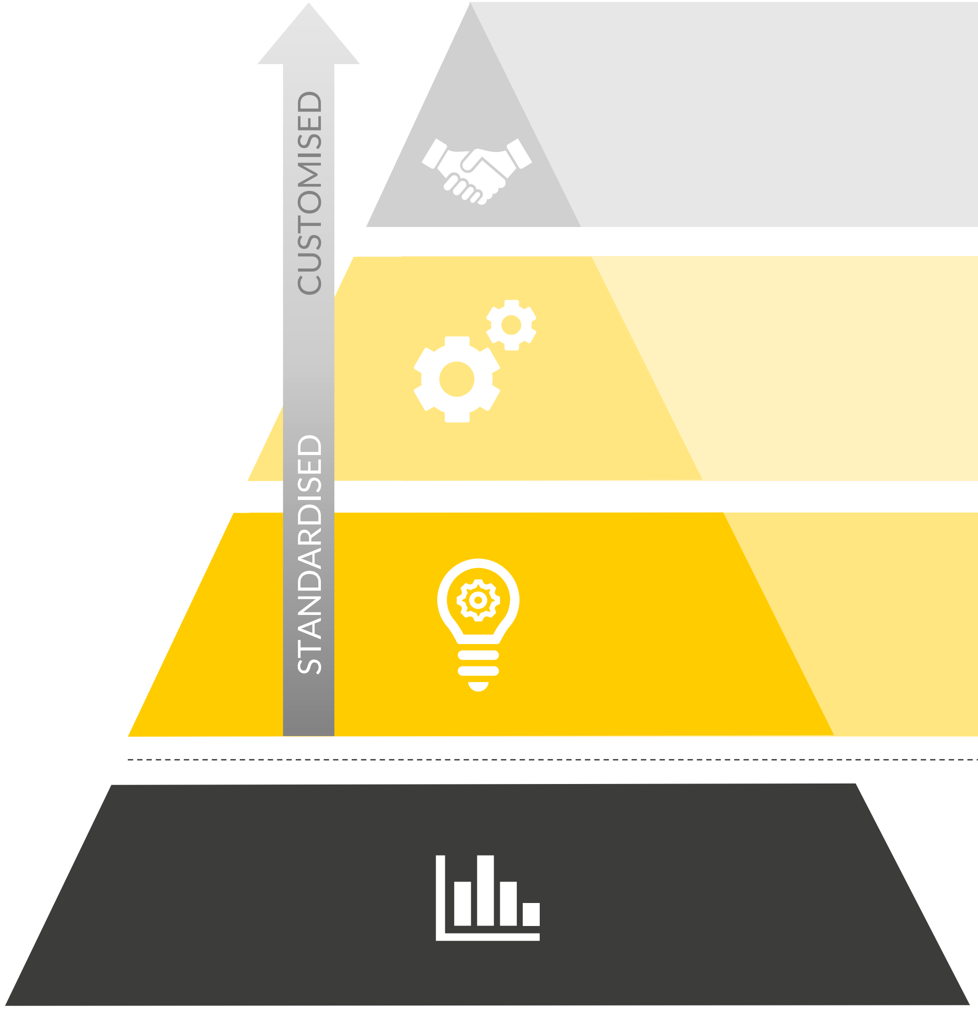

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Developed over 10 years, 40+ dedicated modellers

Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

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5 Integrated Models

- Global Commodities (AER-GLO)
- Hydrogen (AER-HY)
- Gas (AER-GAS)
- Power markets (AER-ES)
- Nodal/network model (AER-EN)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70 specifications modelled for each plant

c. 85k investment hours on modelling capabilities

~15k model runs per week

30+ strength of modelling team globally

Quarterly updates through subscription research

1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source: Aurora Energy Research

Aurora invests significantly in developing and maintaining cutting-edge models

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General principles	Detailed description in USA context
A Own the code	▪ Aurora has a dedicated team of 30+ modelers to develop, adapt and maintain our bespoke models that fully reflect the market – including market design, grid-code, etc.
B Solve for all key power markets simultaneously	▪ Aurora integrates major markets to produce fully internally consistent market outcomes (wholesale and ancillary) and reflect the potential dispatch of assets between markets
C Model granularly – particularly for flex assets	▪ Aurora models the ERCOT market at 1 hour granularity out to 2050 – critical to fully capture price volatility, price uplift, and scarcity, as well as reflect available revenue capture for flexible assets
D Optimize for investment decisions, not lowest system cost	▪ Aurora's model captures the investment decisions of each additional marginal unit of a given technology – technologies only build until cannibalized revenues lead to the marginal unit becoming uneconomic ▪ Allows Aurora to forecast scarcity pricing required to deliver new capacity in wholesale-only market, as well as prevents uneconomic build because it generates 'lowest total system' cost
E Invest in modelling commodity markets	▪ Aurora has its own global commodities model to provide an independent view on key commodities (gas, coal, carbon) that is not dependent on IEA, etc.
F Remain transparent on assumptions and methodology	▪ Aurora is transparent on assumptions so that clients can stress-test or shift any assumption to reflect their view on the market – vital for giving investment committees confidence in relative outcomes under scenarios

Sources: Aurora Energy Research

The battery dispatch model combines the outputs from the Aurora modelling suite into a consistent, nodal-calibrated, dispatch solution

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Step 1: Model consistent price series across markets

Wholesale market assumptions
- Technology, commodity, demand, policy assumptions etc.

ERCOT Power Market Model
- Simultaneously models wholesale and ancillary service markets
  - Hourly granularity
  - Iterative modelling
- Capacity build / exit / mothballing
  - IRR / NPV driven
- Detailed technology assessments

Continuous iteration until an equilibrium is reached

Ancillary service prices
- All main services consistent with ERCOT DA prices

Nodal Wholesale prices
- DA prices at 1 hour granularity
- RT prices at 15 min granularity

ERCOT Network Model
- Clears least cost dispatch under transmission constraints
- Calibrated on historic prices and flows

Step 2: Model the battery asset dispatch

Asset business models
- Business model: Energy only, Ancillary service only, optimized across markets
  - Connection: Standalone/ co-located with solar/thermal/wind asset with/without DC coupling

Storage asset dispatch model
- Model trading strategy against hourly prices in sequence
- Lifetime impact of degradation

Storage asset dispatch model
- Monthly and yearly granularity
  - Gross margins by market

Storage technical parameters and constraints
- Technology: lithium ion/ pumped storage/ flow
  - Size
  - Duration
- Degradation
- Cycling constraints
- Round trip efficiency
- Co-location charging

In-house model | Input | Output

Sources: Aurora Energy Research

Aurora has developed a Real-Time price forecast, for use in the battery dispatch model

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Aurora Real-Time price forecast interpolation methodology

1) Identify fundamental drivers

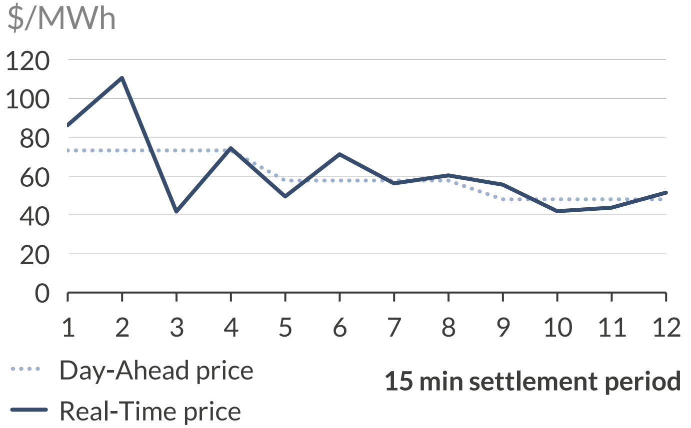
- The value of the hourly Day-Ahead price is the primary driver of the Real-Time price volatility and the observed standard deviation of Real-Time prices
- Renewables generation and capacity margins are also key factors
- Extreme hourly Day-Ahead prices (i.e. +$500/MWh prices) have a different relationship with 15 min prices than non-extreme Day-Ahead prices and therefore can be treated separately

2) Define statistical approach

- Calibrate the distribution of Real-Time outcomes to historically observed levels according to the fundamental drivers of Day-Ahead to Real-Time price separation, including:
  - Renewables Generation
  - Capacity margin
- Metrics for calibration are: historic averages deltas, price distributions and correlations/ autocorrelation
- Apply a Markov Chain approach to add extreme Real-Time prices (above $500/MWh) to reflect sustained high prices and increase accuracy of pricing behaviour

3) Apply to Day-Ahead price forecast

- Apply method and verify historically consistent
- This creates a Real-Time price forecast that is consistent with the underlying Day-Ahead price forecast that varies through to 2050



Caveats

- This does not fully take into account the impact of potential future changes in asset bidding behaviour, market structure, etc. but aims to provide a reasonable interpretation of Real-Time volatility, given the volume traded on the Real-Time market is much smaller than Day-Ahead
- ORDC effects are generally captured well by Day-Ahead prices, and so this is implicit in our Real-Time forecast

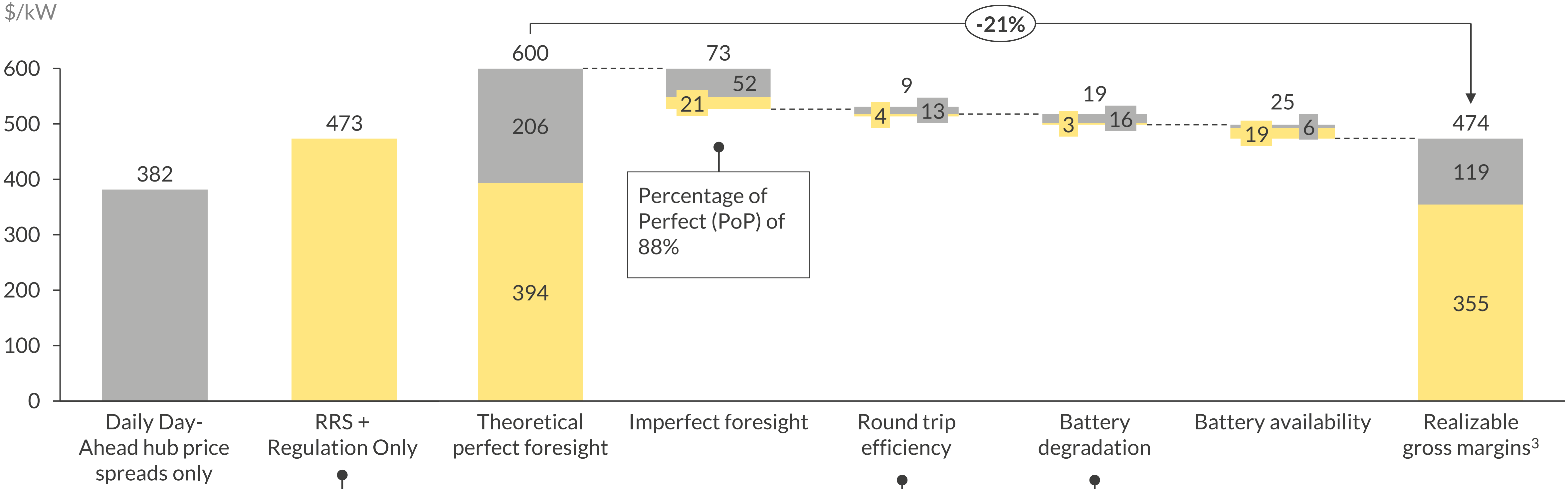
Sources: Aurora Energy Research

Properly accounting for imperfect battery dispatch and technical parameters reduces the present value of revenue by $126/kW

AURORA

Present Value[1] of revenue (2023-2042) for battery entering in 2023 (1 hour duration, ERCOT West)[3]

$/kW



Equivalent to participating in the RRS and Regulation markets maximally according to the proration factor of market saturation

Round Trip Efficiency affects charging costs and dispatch optimization

Lifetime degradation equates to about 20% of battery capacity over 20 years. It has the biggest impact at the end of battery's lifetime, when cashflows are more heavily discounted. It does not affect capacity revenues.

Wholesale Market | Ancillary Services

1) Discount rate of11% for all revenues. 2) Includes nodal bonus. Does not include OPEX or End of Life value. 3) Results are from July 2023 Flex report

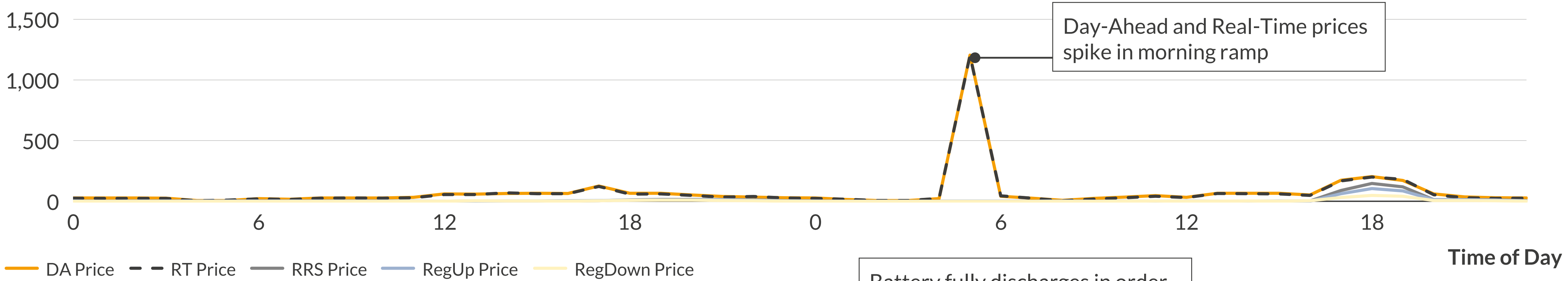
Sources: Aurora Energy Research

During a time with particularly volatile Day-Ahead prices, asset wholesale awards follows the shape in order to capture value

AURORA

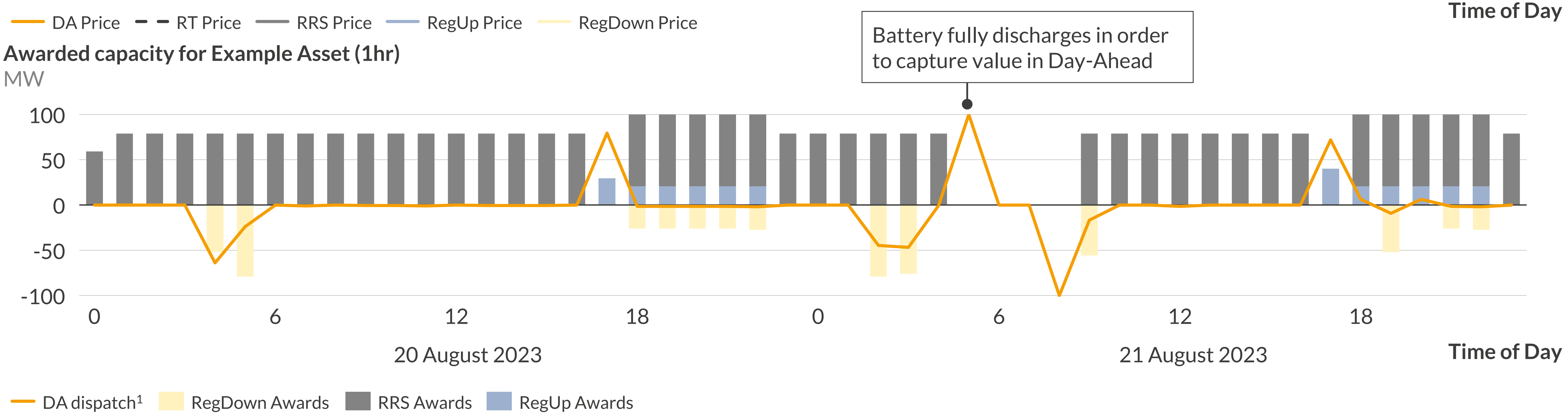
Day-Ahead ancillary prices and wholesale prices for 20-21 August, 2023

$/MWh



Awarded capacity for Example Asset (1hr)

MW



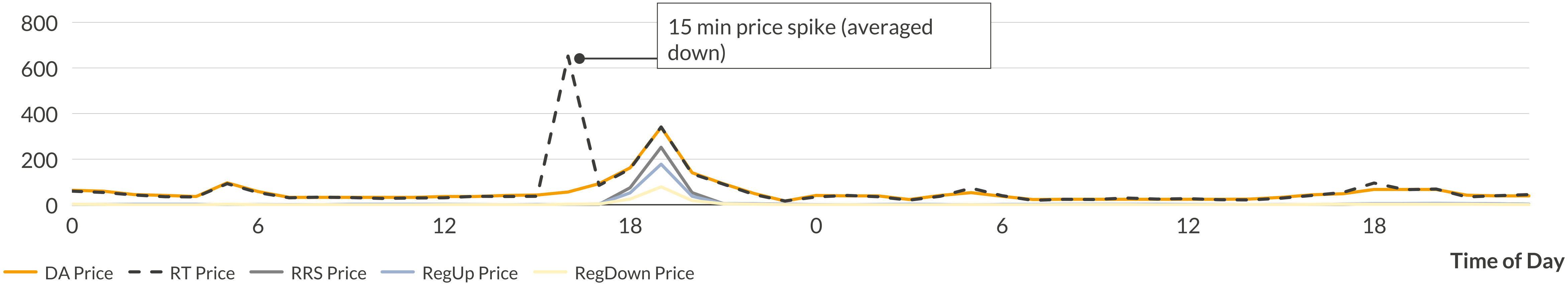
1) Includes dispatch from Ancillary Services

Source: Aurora Energy Research

During a time with particularly volatile Real-Time prices, asset foregoes Day-Ahead revenue to capture the value

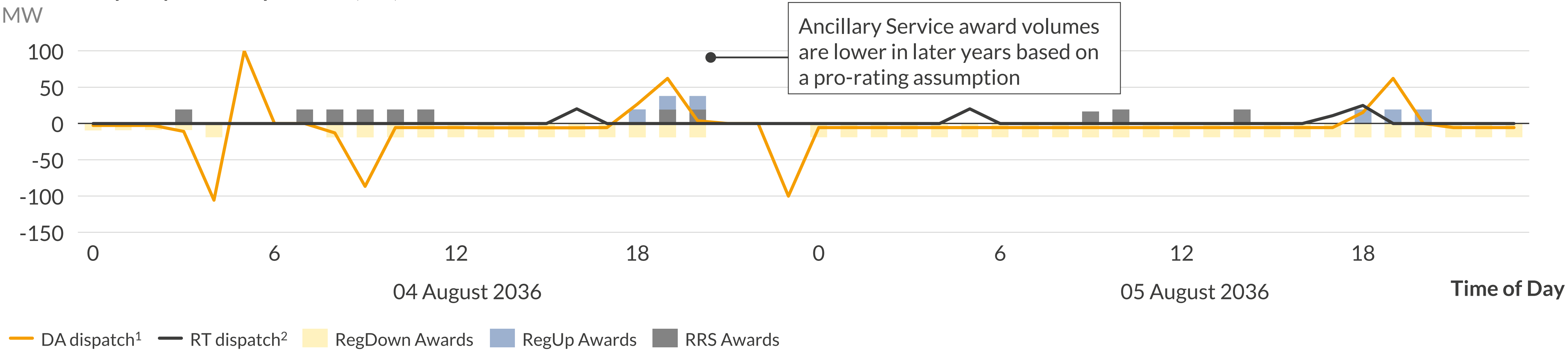
Day-Ahead ancillary prices and wholesale prices for 04-05 August, 2036

$/MWh



Awarded capacity for Example Asset (1hr)

MW



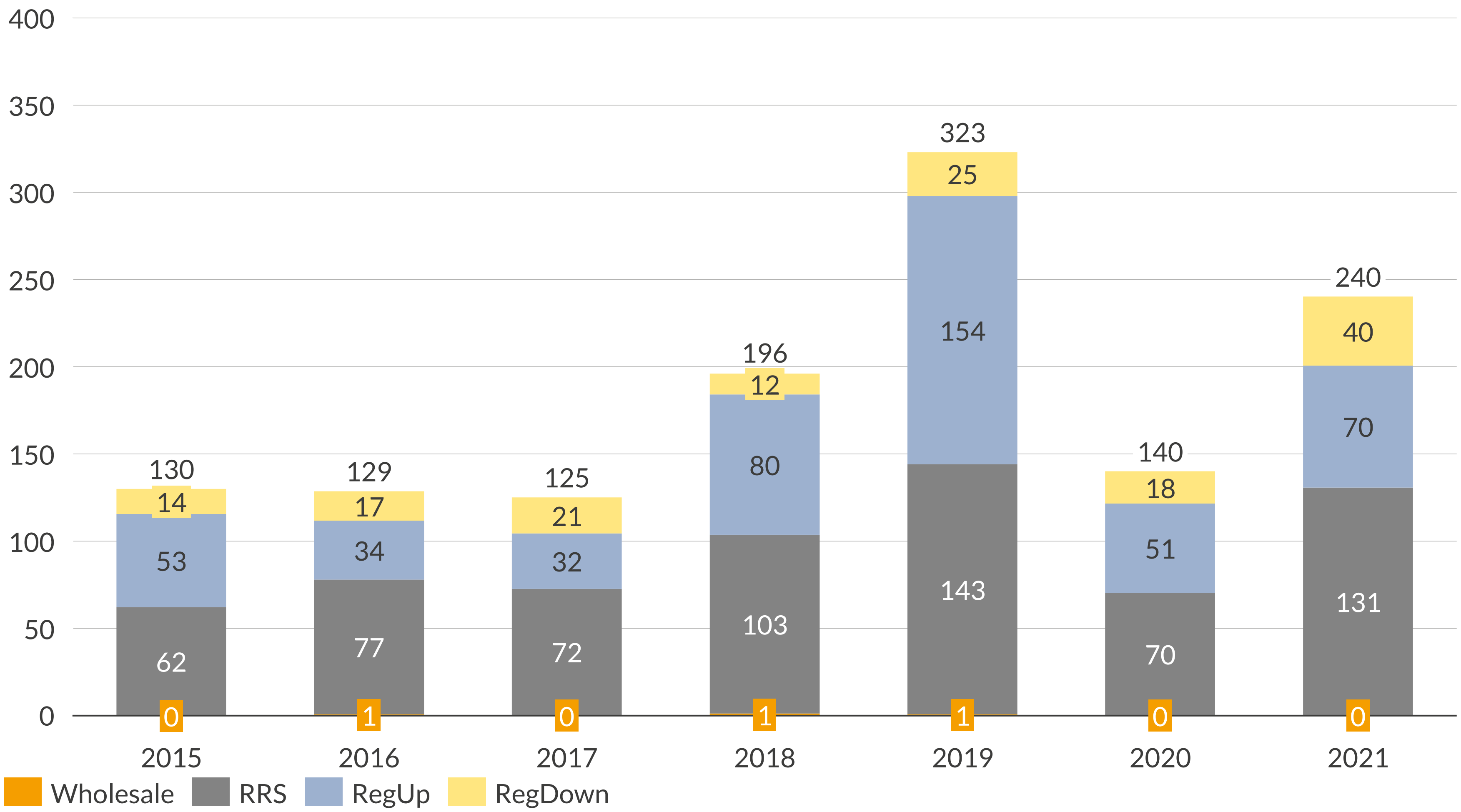
1) Includes dispatch from Ancillary Services 2) Average dispatch over the hour – 0.25 would be max output for 15 mins

Source: Aurora Energy Research

Aurora's backcasted imperfect foresight trader makes over $300/kW in historic years

AURORA

Total annual gross margins for 1-hour battery at the West Hub[1]
$/kW/year, real 2021



1) Excludes February 2021

Source: Aurora Energy Research

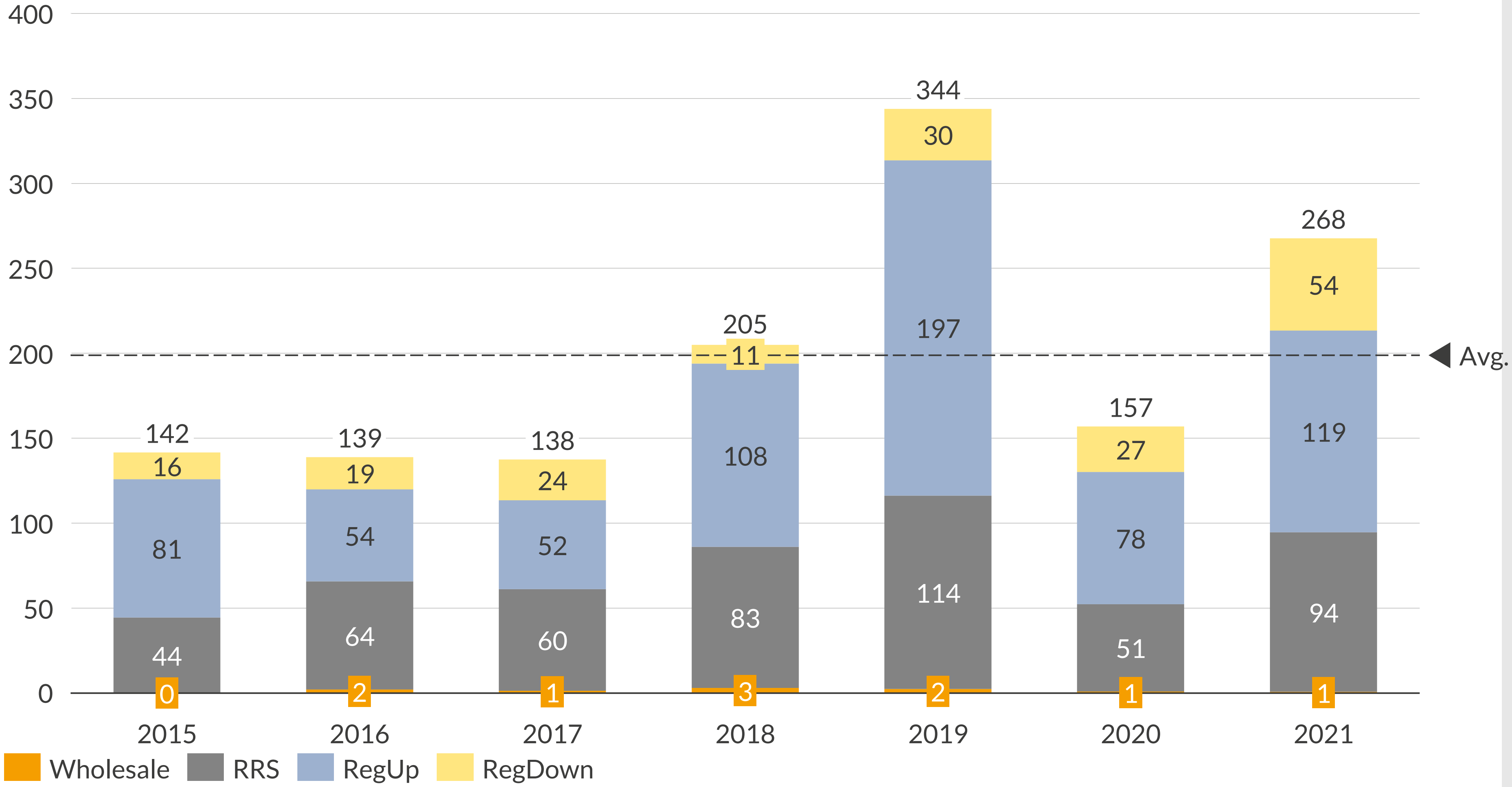
Comments

- The trader participates almost exclusively in ancillary services
- In most years RRS is the backbone of the trading strategy
- Regulation Down is profitable in all years
- Regulation Up is particularly profitable in 2018 and 2019

AURORA

Aurora's backcasted imperfect foresight trader averages almost $200/kW/year for a 2-hour asset

Total annual gross margins for 2-hour battery at the West Hub[1]
$/kW/year, real 2021



1) Excludes February 2021

Source: Aurora Energy Research

Comments

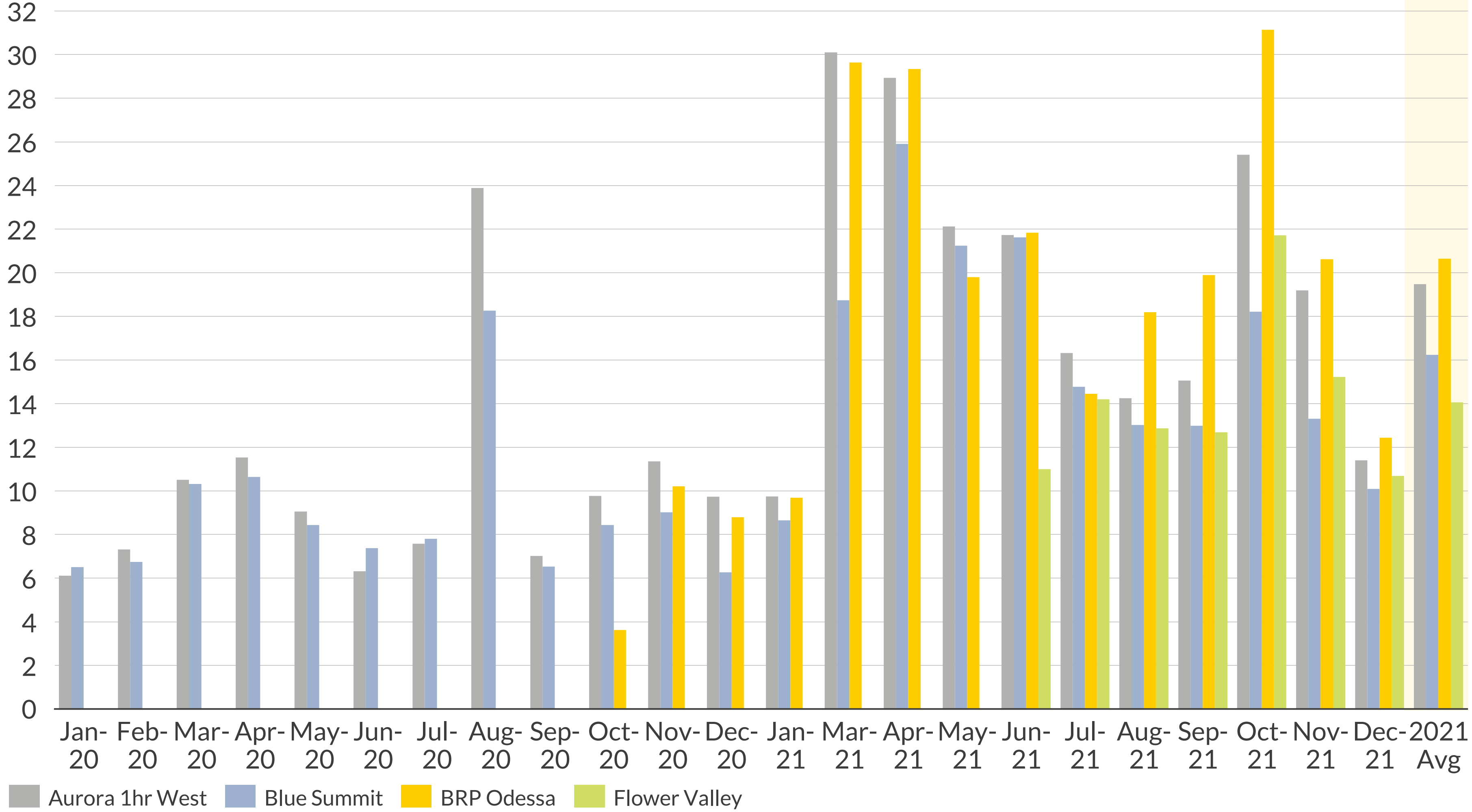
- The trader participates almost exclusively in ancillary services
- In most years RRS is the backbone of the trading strategy
- Regulation Down is profitable in all years
- Regulation Up is particularly profitable in 2018 and 2019

AURORA

Aurora's battery dispatch shows similar revenues to current operational battery estimates

Monthly gross margin for 2020-21[1] (Historical vs. Aurora)
$/kW/month

Average 2021 gross margins, $/kW/month



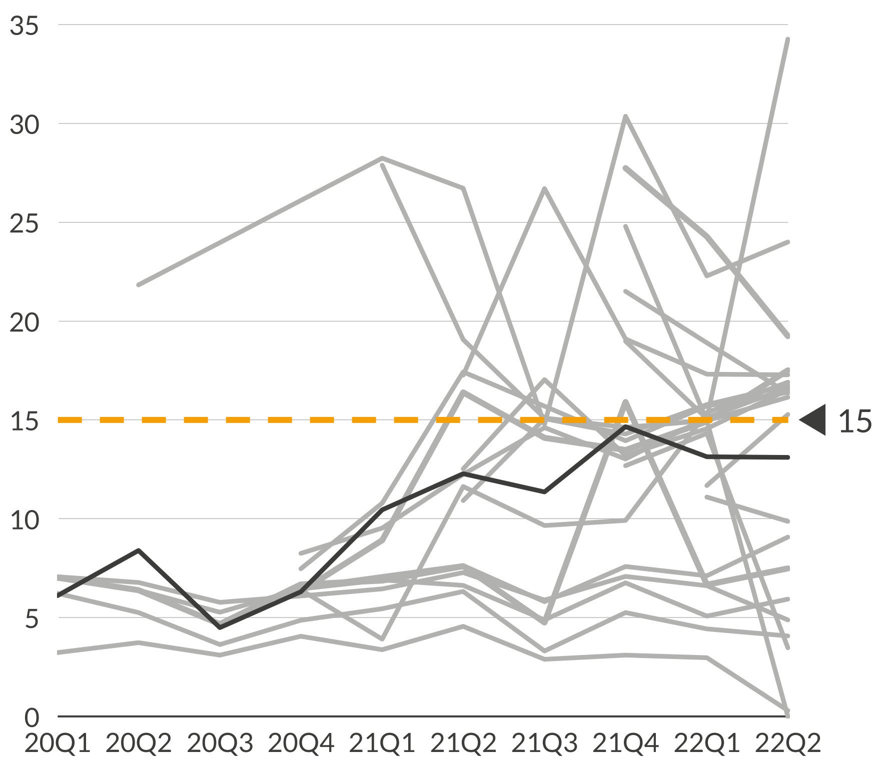
1) Excluding February 2021

Sources: Aurora Energy Research, ERCOT

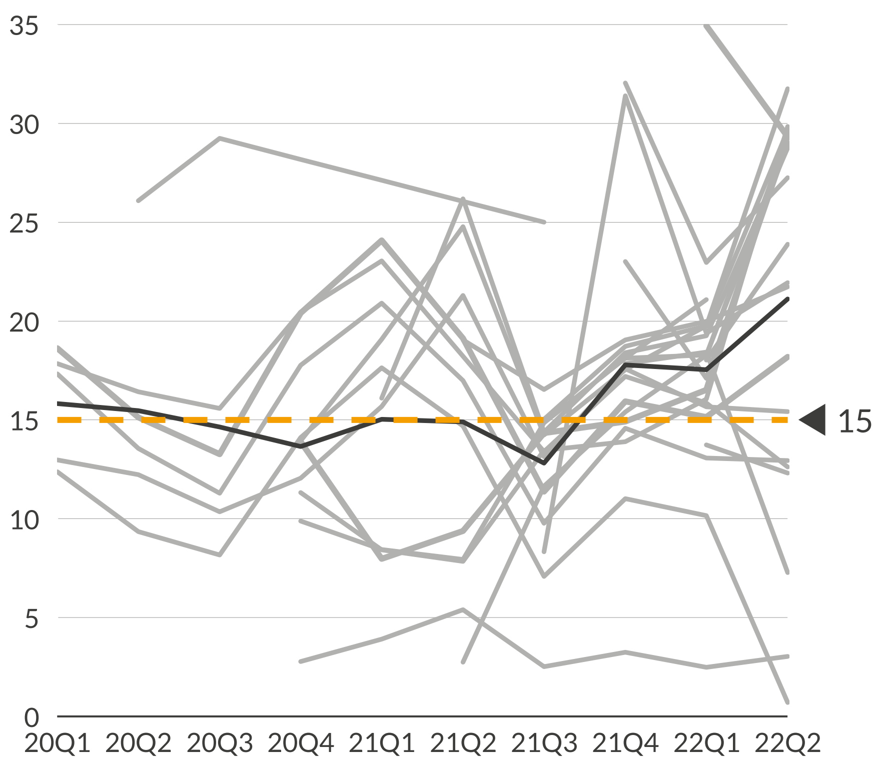
- The Aurora imperfect foresight battery trader performs similarly to how existing batteries performed in 2020 and 2021
- Differences from actual trading strategies include:
  - Hedges, buy-backs and other virtual financial instruments
  - Outages and other operational constraints
  - Cycling rate (Aurora uses a per year limit, whereas some warranties work monthly or daily)

Aurora analysis of ERCOT generator data has allowed us to extract and monitor historical utilisation rates in ancillary markets

Regulation Up utilisation rates
Proportion of utilisation, %



Regulation Down utilisation rates
Proportion of utilisation, %



Historical Battery Utilisation Rates — Average Historic Utilization Rate

Sources: Aurora Energy Research, ERCOT

Identifying ancillary market utilisation rates:

- ERCOT generator data provides generators' initial power output and consumption on a 15 min basis
- The Aurora team have extracted and examined this data to identify those intervals where a battery asset has generated in the same time periods as having a regulation contract
- As such this generation is assumed to be directed towards ancillary markets
- The generation observed is then compared to ancillary market procurement data to determine the proportion of utilisation
- This ratio is anticipated to vary significantly over short periods, as such we monitor historical utilisation at the quarterly level and model a utilisation rate that is reflective of current market dynamics

List of key acronyms

Acronym	Meaning
4CP	4-Coincident Peak
AS	Ancillary Services
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CDR	Capacity, Demand and Reserves report
CHP	Combined Heat and Power
CLR	Controllable Load Resource
CONE	Cost of New Entry
DA	Day-Ahead Market
DG	Distributed Generation
EEA	Energy Emergency Alert
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
EV	Electric Vehicle
FCM	Forward Capacity Market
FFR	Fast Frequency Response
FRRS	Fast Responding Regulation Service
GTC	Generic Transmission Constraint
GWA	Generation Weighted Average
HCAP	High System-Wide Offer Cap

Acronym	Meaning
IRR	Internal Rate of Return
ITC	Investment Tax Credit
LMP	Locational Marginal Pricing
LoLP	Loss of Load Probability
LSE	Load Serving Entity
LSERO	Load Serving Entity Reliability Obligation
LTSA	Long-Term System Assessment
MCPC	Market Clearing Price for Capacity
NPRR	Nodal Protocol Revision Requests
NPV	Net Present Value
NSRS	Non-Spinning Reserve Service
OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditure
ORDC	Operating Reserve Demand Curve
PFR	Primary Frequency Response
PoP	Percentage of Perfect
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PTP	Point to Point
PV	Present Value

Acronym	Meaning
QSE	Qualified Scheduling Entity
RPM	Rotations per Minute
RRS	Responsive Reserve Service
RT	Real-Time Market
RTE	Round Trip Efficiency
RUC	Reliability Unit Commitment
SASM	Supplemental Ancillary Service Market
SCED	Security Constrained Economic Dispatch
SOC	State of Charge
SPP	Settlement Point Pricing
SRMC	Short Run Marginal Cost
TWA	Time Weighted Average
TBx	Top-Bottom spread, “x-hour”
UFR	Under Frequency Relay
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

Sources: Aurora Energy Research

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Details and disclaimer

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