



**2025 STATE OF THE MARKET REPORT  
FOR THE  
ERCOT ELECTRICITY MARKETS**

**POTOMAC  
ECONOMICS**

Independent Market Monitor  
for ERCOT

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## TABLE OF CONTENTS

<b>Executive Summary .....</b>	<b>i</b>
Characteristics of Supply and Demand .....	i
Review of Market Performance .....	ii
Competition and Market Power .....	viii
Direction for Future Market Design .....	viii
Recommendations .....	xi
<b>I. Review of Real-Time Market Outcomes .....</b>	<b>1</b>
A. Real-Time Market Highlights .....	1
B. Real-Time Market Prices .....	2
C. Zonal Energy Prices .....	7
D. Shortage and Reliability Pricing .....	7
E. Aggregated Offer Curves .....	9
F. Impact of ECRS on Real-Time Market Prices .....	10
<b>II. Demand and Supply in ERCOT .....</b>	<b>13</b>
A. Summary of Demand and Supply in 2025 .....	13
B. ERCOT Load in 2025 .....	15
C. Generation Capacity in ERCOT .....	15
D. Wind and Solar Generation in ERCOT .....	17
E. Energy Storage Resources .....	20
F. Operating Reserve Margin .....	25
G. Demand Response .....	27
H. Imports and Exports Via DC Ties .....	36
<b>III. Ancillary Services .....</b>	<b>37</b>
A. Summary of Ancillary Services Results in 2025 .....	37
B. Ancillary Services Market .....	38
C. Ancillary Services Participants .....	41
D. RRS Aggregation Impact on Market Outcomes .....	45
E. Ancillary Service Methodology for 2026 .....	46
<b>IV. Day-Ahead Market Performance .....</b>	<b>50</b>
A. Highlights of Day-Ahead Market Performance in 2025 .....	50
B. Day-Ahead Energy Market Pricing .....	51
C. Day-Ahead Market Activity .....	52
D. Point-to-Point Obligations .....	54
<b>V. Transmission Congestion and Congestion Revenue Rights .....</b>	<b>58</b>
A. Summary of Transmission Congestion Results in 2025 .....	58
B. Background on Transmission Congestion .....	59
C. Day-Ahead Congestion .....	60
D. Real-Time Congestion .....	61
E. CRR Market Outcomes and Revenue Sufficiency .....	64
F. Congestion Cost and Load .....	69
G. Load Zone Configuration .....	71
<b>VI. Market Operations .....</b>	<b>77</b>

---

## Contents

---

A.	Summary of Market Operations Results in 2025 .....	77
B.	Reliability Unit Commitments.....	78
C.	Forecast Error .....	82
D.	QSE Operation Planning .....	83
E.	Reliability Must Run and Must Run Alternatives .....	85
F.	Thermal Generation Outages and Deratings .....	88
G.	Firm Fuel Supply Service .....	90
<b>VII.</b>	<b>Resource Adequacy .....</b>	<b>97</b>
A.	Summary of Resource Adequacy Results in 2025 .....	97
B.	Resource Adequacy Background.....	98
C.	Net Revenue Analysis .....	100
D.	Cost of New Entry .....	101
E.	Peaker Net Margin.....	103
F.	ERCOT's Reliability Standard .....	104
G.	Communicating Resource Adequacy .....	106
H.	Load Forecast .....	110
I.	SB 6 Rulemakings .....	111
J.	Transmission Investment.....	112
<b>VIII.</b>	<b>Analysis of Competitive Performance .....</b>	<b>113</b>
A.	Summary of Competitive Performance in 2025 .....	113
B.	Structural Market Power Indicators.....	114
C.	Evaluation of Supplier Conduct .....	117
D.	Voluntary Mitigation Plans .....	120
E.	Market Power Mitigation.....	121
<b>IX.</b>	<b>Recommendations .....</b>	<b>123</b>
A.	New Recommendations to Improve Market Performance .....	123
B.	Recommended Market Improvements from Prior Years .....	124
C.	Recommendations being Retired.....	133
	<b>Appendix.....</b>	<b>1</b>
<b>I.</b>	<b>Real-Time Co-Optimization.....</b>	<b>2</b>
A.	Real-Time AS Offers.....	2
B.	Convergence between DAM and RT.....	4
C.	AS Position Switching during sunrise/sunset.....	5
D.	AS Shortages .....	6
E.	NSRS relative Pricing.....	8
F.	Impact on RUC.....	9
G.	RDPA .....	10
<b>II.</b>	<b>Appendix: Statistics at a Glance .....</b>	<b>11</b>
<b>III.</b>	<b>Appendix: Ancillary Services.....</b>	<b>13</b>
A.	Ancillary Services Provided in Real-Time .....	13
B.	Supplemental Ancillary Services Market .....	16



## **LIST OF FIGURES**

Figure 1: Average All-in Cost for Electricity in ERCOT .....	2
Figure 2: Monthly and Annual Implied Heat Rates.....	4
Figure 3: Prices by Time of Day .....	5
Figure 4: Impact of Price Spikes on Real-Time Energy Price.....	6
Figure 5: Impact of the ORDC on Real-Time Prices.....	8
Figure 6: Impact of the RDPA on Real-Time Prices .....	9
Figure 7: Aggregated Generation Offer Stack – Annual, Peak and Net Peak Load .....	10
Figure 8: Excess Cost of ECRS Deployment Practice in 2025 .....	11
Figure 9: Annual Load Statistics by Zone .....	15
Figure 10: Installed Generation Capacity in ERCOT .....	16
Figure 11: Installed Capacity by Resource Type for Each Zone in 2025 .....	16
Figure 12: Percentage of Annual Generation by Resource Type .....	17
Figure 13: Wind Production and Curtailment, 2021-2025 .....	18
Figure 14: Solar Production and Curtailment, 2021-2025.....	18
Figure 15: Average Captured Prices for Wind and Solar .....	19
Figure 16: ESR Installed Capacity.....	22
Figure 17: Total and Normalized ESR Revenue.....	23
Figure 18: Net Injection of Power from ESRs.....	24
Figure 19: Average Aggregate Offers for ESRs to Buy or Sell Energy .....	25
Figure 20: Annual PRC Statistics .....	26
Figure 22: Monthly Average Aggregate Load for CLRs.....	28
Figure 23: Average Aggregate Bid Curves and Base Points for CLRs .....	29
Figure 24: Annual Energy Transacted Across DC Ties.....	36
Figure 25: Average Ancillary Service Capacity by Month .....	39
Figure 26: Ancillary Service Prices .....	40
Figure 27: Provision of AS by Resource Type for 2025.....	41
Figure 28: Real-Time Provision of AS by ESRs .....	42
Figure 29: Responsive Reserves from UFR and FFR in DAM .....	46
Figure 30: Annual Probability of Firm Load Shed vs Entering Watch Conditions.....	48
Figure 31: Convergence Between Day-Ahead and Real-Time Energy Prices .....	51
Figure 32: Day-Ahead Schedule/Forecast of Physical Generation.....	52
Figure 33: Day-Ahead Market Three-Part Offer Capacity in 2025 .....	53
Figure 34: TPE and Collateral Held by ERCOT .....	54
Figure 35: Point-to-Point Obligation Charges and Revenues.....	55
Figure 36: Volume of DAM PTP Bids and Frequency of Late Publications .....	56
Figure 37: Value of Day-Ahead Congestion by Zone .....	61
Figure 38: Value of Real-Time Congestion by Zone.....	62
Figure 39: Overload Distribution of Violated Constraints .....	63
Figure 40: Annual Sum of Base Points Awarded to ESRs Helping Congestion.....	64

## Contents

---

Figure 41: Schedule for CRR Capacity Sold in Long-Term Auctions .....	65
Figure 42: CRR Auction Revenue .....	66
Figure 43: CRR Auction Revenue and Payments .....	67
Figure 44: CRR Solvency and Surplus Payments to Load .....	68
Figure 45: Correlation between Congestion Cost and Load .....	70
Figure 46: Annual Zonal Congestion Cost .....	72
Figure 47: Geographic Distribution of Substations for the 7-Load-Zone Configuration .....	73
Figure 48: Comparison of LZ West Prices: Current vs. New 7-Load-Zone Configuration .....	74
Figure 49: Comparison of LZ South Prices: Current vs. New 7-Load-Zone Configuration .....	75
Figure 50: Distribution of Startup Times for RUC Resources .....	81
Figure 51: Distribution of Net Load Forecast Error .....	82
Figure 52: COP Commitment Error when $PRC \leq 6,500$ .....	84
Figure 53: Distribution of ESR SOC Accuracy .....	85
Figure 54: Thermal Hourly Average Outages and Derates by Month .....	89
Figure 55: Planned, Forced, and Unreported Outages and Derates .....	90
Figure 56: Net Revenues by Location .....	101
Figure 57: Combustion Turbine (CT) and Combined Cycle (CC) Net Revenues .....	102
Figure 58: Peaker Net Margin .....	104
Figure 59: Planning Reserve Margins for Summer Peak Load .....	109
Figure 60: Pivotal Supplier Frequency by Net Load Level .....	114
Figure 61: Pivotal Supplier Frequency by Hour of Day for Summer .....	115
Figure 62: Outages and Deratings by Load Level and Participant Size .....	118
Figure 63: Incremental Output Gap by Load Level and Participant Size .....	119
Figure 64: Mitigated Output Gap by Load Level .....	122

## **LIST OF TABLES**

Table 1: Average Annual Real-Time Energy Market Prices by Zone .....	7
Table 2: Aggregate Capacity Factor of Wind and Solar Generation .....	20
Table 3: RDR Assessment Hours Under NPRR 1296 .....	33
Table 4: Average Volume of Ancillary Services Provided by NCLRs .....	43
Table 5: Average Volume of Ancillary Services Provided by CLRs .....	44
Table 6: Real-Time Congestion Rent (\$MM) for the 7-Load-Zone Configuration .....	73
Table 7: Magnitude of RUC Activity .....	79
Table 8: Reported Reason for RUC .....	80
Table 9: RUC Settlement .....	80
Table 10: Firm Fuel Supply Service Deployments .....	91
Table 13: Frequency of One or More Pivotal Suppliers in Top Quartile of Net Load by Zone. ....	116

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**LIST OF APPENDIX FIGURES**

Figure A1: Aggregate Offers for AS in the RTM.....	3
Figure A2: Proportion of ESR AS Offers by Price in DAM .....	4
Figure A3: Distribution of AS Awards Shifting During Sunrise and Sunset .....	6
Figure A4: Illustration of Extended ASDC for NSRS.....	8
Figure A5: Distribution of NSRS MCPC Relative to Other Up-Reserves .....	9
Figure A6: Frequency and Magnitude of RDPA for AS .....	10
Figure A7: Responsive Reserve Providers .....	13
Figure A8: ERCOT Contingency Reserve Service Providers .....	14
Figure A9: Non-Spin Reserve Service Providers .....	14
Figure A10: Regulation Up Reserve Providers .....	15
Figure A11: Regulation Down Reserve Providers.....	15
Figure A12: Ancillary Service Quantities Procured in SASM .....	16
Figure A13: Total Cost of Procured SASM Ancillary Services .....	17

**LIST OF APPENDIX TABLES**

Table A1: Duration Requirements for Energy and AS in RTM .....	3
Table A2: Convergence in Energy and AS Prices in the Day-Ahead and Real-Time Markets.....	5
Table A3: Frequency, Magnitude, and Pricing of AS Shortages.....	7
Table A4: ERCOT 2025 Year at a Glance (Annual) .....	11
Table A5: Market at a Glance Monthly .....	12

## Guide to Acronyms

### **LIST OF ACRONYMS**

4CP	Four Coincident Peak	LZ	Load Zone
AORDC	Aggregate ORDC	MIRTM	Multi-Interval Real-Time Market
AS	Ancillary Service	MISO	Midcontinent Independent System Operator
ASDC	Ancillary Service Demand Curve	MMBtu	One million British Thermal Units
BESS	Battery Energy Storage System	MORA	Monthly Outlook for Resource Adequacy
CAES	Compressed Air Energy Storage	MW	Megawatt
CARD	CRR Auction Revenue Distribution	MWh	Megawatt Hour
CC	Combined Cycle	NCLR	Non-controllable Load Resource
CDR	Capacity, Demand and Reserves Report	NOIE	Non-Opt-In Entity
CLR	Controllable Load Resource	NPRR	Nodal Protocol Revision Request
CMWG	Congestion Management Working Group	NREL	National Renewable Energy Lab
CONE	Cost of New Entry	NSO	Notification of Suspension of Operations
COP	Current Operating Plan	NSRS	Non-Spin Reserve Service
CRR	Congestion Revenue Rights	ORDC	Operating Reserve Demand Curve
CRAH	CRR Account Holder	PCRR	Pre-Assigned Congestion Revenue Rights
CT	Combustion Turbine	PFR	Primary Frequency Response
DAM	Day-Ahead Market	PNM	Peaker Net Margin
DC Tie	Direct-Current Tie	PPA	Power Purchase Agreement
DME	Decision Making Entity	PRB	Powder River Basin
DRRS	Dispatchable Reliability Reserve Service	PRC	Physical Responsive Capability
DRUC	Day-Ahead Reliability Unit Commitment	PTP	Point-to-Point
ECRS	ERCOT Contingency Reserve Service	PTPLO	Point-to-Point Obligation with links to an Option
EEA	Energy Emergency Alert	PUCT	Public Utility Commission of Texas
EIA	U.S. Energy Information Administration	PURA	Public Utility Regulatory Act
ELCC	Effective Load Carrying Capability	PV	Photovoltaic
ERCOT	Electric Reliability Council of Texas	QSE	Qualified Scheduling Entity

## Guide to Acronyms

ERO	Electric Reliability Organization	RDI	Residual Demand Index
ERS	Emergency Response Service	RDPA	Real-Time Reliability Deployment Price Adder
ESR	Energy Storage Resource	Reg-Down	Regulation Down Reserve Service
EUE	Expected Unserved Energy	Reg-Up	Regulation Up Reserve Service
EV	Electric Vehicle	RENA	Real-Time Revenue Neutrality Allocation
FFR	Fast Frequency Response	REP	Retail Electric Provider
FFSS	Firm Fuel Supply Service	RFI	Request For Information
FFSSR	Firm-Fuel Supply Service Resource	RRS	Responsive Reserve Service
FIP	Fuel Index Price	RTC	Real-Time Co-optimization
GTC	Generic Transmission Constraint	RTCA	Real-Time Contingency Analysis
GW	Gigawatt	RTO	Regional Transmission Organization
HB	House Bill	RTOLCAP	Real-Time On-Line reserve capacity of all On-Line Resources
HCAP	High System-Wide Offer Cap	RTP	Regional Transmission Plan
HE	Hour-ending	RUC	Reliability Unit Commitment
HRUC	Hourly Reliability Unit Commitment	SARA	Seasonal Assessment of Resource Adequacy
HSL	High Sustained Limit	SASM	Supplemental Ancillary Service Market
Hz	Hertz	SB	Senate Bill
IMM	Independent Market Monitor	SCED	Security-Constrained Economic Dispatch
kW	Kilowatt	SCR	System Change Request
IRR	Intermittent Renewable Resource	SOC	State of Charge
LASCED	Look-Ahead SCED	SOM	State of the Market
LCOE	Levelized Cost of Electricity	SPP	Southwest Power Pool
LDF	Load Distribution Factor	SWCAP	System-Wide Offer Cap
LFL	Large Flexible Load	TAC	Texas Administrative Code
LFLTF	Long-Term Load Forecast	TDSP	Transmission and Distribution Service Provider
LMP	Locational Marginal Price	TSP	Transmission Service Provider
LOLE	Loss of Load Expectation	TPE	Total Potential Exposure
LOLP	Loss of Load Probability	UFR	Underfrequency Relay
LSE	Load-Serving Entity	VMP	Voluntary Mitigation Plans
LSL	Low Sustained Limit	VOLL	Value of Lost Load



## EXECUTIVE SUMMARY

In our role as the Independent Market Monitor (IMM), Potomac Economics provides this 2025 State of the Market Report to the Public Utility Commission of Texas (PUCT). This report presents our assessment of the outcomes of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT). We also recommend changes to improve the competitive performance and operation of the ERCOT markets.

ERCOT manages the production and flow of electricity for more than 27 million Texas customers—about 90% of the state's total electric demand. Every five minutes, the ERCOT market coordinates the output of more than 1,460 generating resources to satisfy customer demand and manages the resulting power flows across more than 55,000 miles of transmission lines in the region. In addition, market prices facilitate long-term investment in and retirement of resources in the ERCOT region. Hence, the market performance we evaluate in this report is critical to maintaining reliability in Texas.

This report details key trends in the ERCOT market, including changes in supply and demand and market outcomes.

### Characteristics of Supply and Demand

Changes in electricity demand and supply account for many year-to-year trends in market outcomes. We evaluate these changes and their effects on market outcomes. On the demand side, average electricity demand in 2025 was approximately 6.1% higher than in 2024 – an increase of approximately 3,205 megawatts (MW). Load in West Texas continued to grow much faster than the system-wide average, rising by 12.3% on average year on year. This trend continued to be driven by increased demand from oil and natural gas operations and data centers, mainly those used for crypto-currency mining.

Growth in demand for crypto-currency mining is particularly noteworthy. Aggregate demand for crypto-currency mining was approximately 4,600 MW in 2025. This type of facility has two features that make it well-suited to operate as controllable load resources (CLRs), making it directly dispatchable in the real-time market: 1) it is very sensitive to the price of electricity, and 2) consumption can be adjusted easily according to market conditions. Thus, hundreds of MW of crypto-mining demand have registered as controllable load resources in the last several years, but that trend reversed in 2025. Despite approximately 900 MW of new demand for cryptocurrency operations, aggregate CLR capacity decreased from 2024 to 2025. This decrease in CLR registrations was inversely correlated with the massive influx of crypto-related demand into the Emergency Reserve Service (ERS) program. By the end of 2025, cryptocurrency mining operations accounted for more than half of all ERS capacity.

Continuing a recent trend, solar and energy storage resources made up the vast majority of new entrants into the ERCOT market. More than 6 gigawatt (GW) of new solar capacity was commercialized in 2025, and annual solar generation increased by 49% compared to 2024. The share of total generation produced by solar resources increased from 10.4% in 2024 to 13.9% in 2025. Energy Storage Resource (ESR) capacity increased even more dramatically than solar capacity.

The installed capacity of ESRs increased to more than 17,000 MW and 31,500 MWh by the end of 2025, up almost 80% from the end of 2024. The increase in ESR capacity corresponds with a shift toward ESRs earning more of their revenue from energy arbitrage than from providing ancillary services. Based on hourly average ESR behavior across 2025, the hourly peak of aggregate ESR output was almost 2,400 MW, compared to only 820 MW in 2024. This increase corresponds to the major role that ESRs play in serving load during the evening down ramp for solar generation.

Changes in demand and supply have increased the average level of operating reserves in the ERCOT market, continuing a trend that started in 2022. Since then, the annual increase in supply has significantly outpaced increases in demand, resulting in a sharp decrease in the frequency of genuine shortage conditions. Our analysis indicates that the market could incorporate more than 3 GWs of new peak demand without the annual frequency of shortage conditions exceeding the norm from 2016 through 2021. This surplus of operating reserves also explains the relative infrequency of shortage pricing, as we discuss in the next section of the Executive Summary.

## Review of Market Performance

ERCOT operates three distinct wholesale markets: the real-time market and two forward markets—the day-ahead market, which allows market participants to take financial positions on energy and ancillary services, and the CRR market, a series of auctions in which market participants can bid for the right to revenues derived from congestion rent. The real-time market is the most consequential because it coordinates real-time power flows to maintain system reliability and sets expectations for the forward markets.

### *Real-time Market Performance*

The most noteworthy ERCOT real-time market development in 2025 was the long-awaited introduction of real-time co-optimization (RTC), a major market upgrade that began in January 2019. With RTC, the real-time market simultaneously procures energy and ancillary services. Previously, the day-ahead market alone procured ancillary services, and qualified scheduling entities (QSEs) could adjust those positions only within their resource portfolios or through bilateral trades reported to ERCOT. Now, ancillary service awards can be adjusted in real-time to reflect changes in system conditions. As part of the RTC project, ERCOT also implemented the single-model for ESRs, which improves the real-time market's coordination of energy and



reserve awards for ESRs. Both changes should improve market performance and economic efficiency.

Since ERCOT implemented RTC, the real-time market has functioned as expected without any major malfunctions. However, we identified some issues with real-time ancillary service price formation that are likely due to the design of the ancillary service demand curves and the duration constraints for ESRs providing ancillary services. The Appendix discusses these issues and the performance of the real-time market since RTC was implemented in detail.

One key trend in 2025 was the continued increase in operating reserves levels in the market. This trend began in 2022 when the entry of new solar and energy storage resources increased considerably. This increase in operating reserve levels has significantly reduced the prevalence of shortage pricing. For example, the shortage pricing produced by the operating reserve demand curve (ORDC) raised real-time energy prices by only \$0.02 per MWh, the lowest annual value since ERCOT implemented the ORDC in 2014.

The supply expansion also reduced the all-in price of electricity in the real-time market. The all-in price of electricity includes all costs to load that transact through the ERCOT wholesale market, i.e., the cost of energy, reserves, and any uplift costs. Energy is the main component of the all-in price of electricity and is usually heavily influenced by the price of natural gas, the most commonly used fuel in the thermal generation fleet. In 2025, the price of natural gas increased by 61%, but the all-in price of electricity increased by less than 14%. This disparity reflects the supply-and-demand fundamentals in ERCOT. The surplus of supply in ERCOT put downward pressure on electricity prices relative to gas prices in two ways. First, expensive gas peaking resources are needed less often, so the price of electricity was frequently set by lower-cost resources. Second, the high level of operating reserves directly resulted in a low frequency of shortage pricing. Together, these supply-side trends limited the increase in the all-in price of electricity.

ESRs are particularly likely to set the price of electricity during the morning demand ramp and evening solar down-ramp. In recent years, as solar development increased dramatically, these ramp periods corresponded with a high frequency of price spikes because gas peakers and high-priced ESRs were needed to balance rapid changes in net load. In the summer of 2025, however, price spikes were 40% less frequent than in the summer of 2024 as additional ESR capacity improved ERCOT's capability to manage the system's ramp needs.

### *Ancillary Services*

The most noteworthy development for ancillary services was the implementation of RTC in December. Resources can now sell ancillary services directly into the real-time market and ERCOT optimizes its utilization of resources for satisfying the system's energy and ancillary services needs. The ability to sell real-time ancillary services is particularly attractive for ESRs that dominate the provision of ancillary services in ERCOT. ESRs provide the vast majority of

regulation service and, along with non-controllable load resources (NCLRs), the majority of Responsive Reserve Service (RRS). They also provide a substantial and growing percentage of ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve Service (NSRS).

The procurement volume for ancillary services remained roughly the same between 2024 and 2025, though its composition shifted slightly. ECRS and regulation service volumes slightly decreased, while the NSRS volume slightly increased. The NSRS procurement increase in 2025 directly resulted from the input assumptions ERCOT uses in its AS Methodology, which tend to exaggerate the probability of reliability issues and inflate ancillary-service procurements, as outlined in this report. ERCOT's procurement practices raise the AS requirements to more than double the ancillary service quantities needed to achieve a reasonable standard of reliability. This includes 2 GW of reserves that provide virtually no incremental reliability value in terms of reducing the probability of load shed. We continue to recommend that ERCOT adjust the AS methodology to reflect a reasonable characterization of the operational risks these products are meant to manage.

### ***Forward Markets***

The day-ahead and CRR markets functioned as expected in 2025. The day-ahead market cleared at a modest premium to the real-time market in 2025. With the implementation of RTC, day-ahead ancillary service awards no longer represent physical obligations to provide reserves in real time. Instead, energy and ancillary services in the day-ahead market are now strictly financial positions, and ERCOT settles imbalances on those positions in real time. Another new day-ahead market feature implemented with RTC is virtual ancillary service positions, which are financial hedges on the real-time price for reserves. These virtual offers are expected to improve the liquidity of day-ahead ancillary service market and promote better convergence with the real-time market.

Participation of physical generation resources in the day-ahead market continues to be low relative to real-time load. Some of this low participation may reflect participants' response to the imbalance risk of taking day-ahead forward positions, particularly for intermittent resources and duration-limited energy storage resources. If changes in weather conditions or a depleted state of charge prevent these resources from delivering on their day-ahead positions, they must buy back the position at the real-time price. Day-ahead schedules can also reduce an ESR's market revenues when real-time changes in the optimal charging and discharging hours occur.

It is harder to explain the consistently low participation of thermal resources in the day-ahead market. Day-ahead awards to thermal resources account for only 36% of real-time load. Since before the implementation of the nodal market, a majority of real-time thermal generation in ERCOT has been self-committed, exposing it to the volatility of the real-time market and precluding the opportunity to be made whole if market revenues were insufficient to cover start-

up costs. This behavior is more surprising because of the consistent price premium in the day-ahead market.

The ERCOT forward markets clear two distinct sets of products that capture locational price spreads throughout the system: the day-ahead market for point-to-point (PTP) spreads and the CRR market. Transactions of both products continue to increase. Point-to-point obligations remained profitable in 2025, paying 11% more in real time than their day-ahead purchase cost. Profitability in the CRR market increased by 21% from 2024 to 2025. Both gains reversed a multi-year trend of declining profitability. The growing volume of PTP and CRR bids that the market must clear has prompted concerns about computing capabilities and whether the market needs new bid limits or fees to ensure that it can post on schedule.

### *Transmission Congestion*

Transmission congestion arises when network power flows are restricted by limits on transmission facilities such as power lines and transformers. Network topology, i.e., the configuration of transmission facilities, and the locations where power is injected into or withdrawn from the network determine the power flows. When flow over a transmission facility reaches its limit, the market shifts generation to higher-cost units to alter the network flows and serve load without exceeding the limit. Hence, congestion prevents the lowest-cost generators from serving load. When transmission congestion occurs, differences in the cost of delivering electricity to different locations are reflected in the differing energy prices at each location or “node” on the network. These differences in nodal prices provide efficient economic signals for generators and consumers to produce and consume at different locations. Congestion rent, which equals the difference between what consumers pay and generators receive, is based on locational price differences. The financial right to this congestion rent accrues to holders of CRRs.

The annual cost of congestion in the day-ahead and real-time markets increased by 26% and 32%, respectively in 2025, reversing the previous 3-year trend of declining annual congestion costs. The main driver of this increase were:

- The increase in natural gas prices, the fuel for the resources most frequently used to manage congestion in ERCOT;
- Higher congestion in the North zone, where ERCOT used a significant amount of RUC commitments to manage congestion;
- Higher congestion in the West Zone, where transmission projects have not kept pace with the large increase in renewables in the Panhandle and growing demand in the Permian Basin. This led the West Zone to exhibit the highest annual average zonal energy prices for the second year in a row.

Despite the increase in congestion costs, the prevalence of transmission constraints being violated because they were too expensive to resolve dropped to its lowest level since the ERCOT nodal market was implemented. This drop in the frequency of constraint violations can be partially explained by NPRR 1230, which defines a process to increase the shadow price of base-case constraints. Higher shadow price caps allow SCED to produce more expensive dispatch solutions to avoid violating these constraints. The drop in constraint violations is also influenced by the increasing role ESRs play in congestion relief. ESRs are particularly effective at managing congestion when they are located at key locations where they can influence power flows in both directions by charging or discharging.

Congestion within load zones continues to outpace congestion between load zones. Load zones are aggregations of load nodes on the system that experience similar congestion patterns. ERCOT established its current four load zones – West, North, South, and Houston – in 2003. At that time, the geographic distribution of load and generation, as well as the generation mix, was very different. Industrial load has grown substantially in West Texas, driven by electrification of oil and gas operations and data center development, and residential load has sprawled far from historical population centers. Moreover, renewable resources located far from load centers increasingly serve load. As these patterns shift, ERCOT should re-evaluate whether the current load zone boundaries still reflect meaningful economic and operational groupings. We continue to recommend that ERCOT revise the prevailing load zone configuration to reflect these evolving congestion patterns.

### ***Market Operations***

Taken together, the ERCOT wholesale markets coordinate the provision of energy and reserves from resources to maintain reliability and provide long-term economic signals governing new investment and retirement decisions. Ideally, the markets should procure and dispatch all resources needed to operate the system reliably, but operators often supplement market outcomes with out-of-market actions to address operational challenges. These actions are undesirable because they interfere with price signals that guide efficient short-term decisions and long-term investment, imposing unnecessary uplift costs on consumers. Although such interventions are sometimes necessary for reliability, persistent reliance on them indicates a misalignment between market design and system operations.

Despite high operating reserve levels in 2025, out-of-market reliability actions increased substantially from 2024, particularly the Reliability Unit Commitment process. ERCOT operators issued RUC instructions for 5,129 resource-hours in 2025, a 176% increase from 2024. Congestion accounted for approximately 77% of these commitments.

The increase in RUC commitments corresponds to higher make-whole payments, which exceeded \$21 million in 2025. The increase in make-whole payments can be partially explained by greater use of RUC and fewer resources opting out of RUC settlement. In 2025, only 3% of

resources committed through RUC opted out of RUC settlement, compared to 8% in 2024. Thus, most commitments through RUC in 2025 were eligible for make-whole payments.

Out-of-market settlement is likely greater when resources are committed through RUC to resolve congestion rather than meet capacity needs. Without a counteracting pricing mechanism, out-of-market commitments necessarily suppress market prices. The reliability deployment price adder (RDPA) is intended to account for this price suppression, but its current design does not reflect variation in nodal prices caused by out-of-market commitments. As a result, the RDPA does not significantly increase energy prices unless the commitments substantially affect system-wide prices rather than local prices. NPRR 1214, submitted in December 2023, seeks to address this RDPA shortcoming by producing node-specific price adders to reduce out-of-market make-whole payments for resources committed through RUC to manage local transmission issues. PRS has tabled this NPRR since May 2025 as ERCOT was focused on implementing RTC.

One factor increasing RUC commitments is the incorporation of ESR state of charge (SOC) into the RUC engine under NPRR 1186, which ERCOT implemented in summer 2024. ESR operators reflect their expected SOC for the beginning of each hour in their Current Operating Plan (COP). Rather than optimizing ESR charging and discharging schedules across the RUC study period, RUC uses this hourly SOC value as a fixed input. Increases in SOC are treated as energy withdrawals, and decreases are treated as energy injections. Because installed ESR capacity has increased massively in recent years and ESRs now participate extensively in the energy market, the accuracy of COP SOC strongly affects the efficiency of the commitments RUC recommends. COP overestimated aggregate ESR SOC by an average of 874 MWh relative to real-time.

Over the longer term, RUC activity in the last five years has been significantly higher than the norm before Winter Storm Uri. For example, annual resource-hours committed through RUC ranged from 202 to 613 from 2017 through 2020, whereas annual RUC commitments have consistently totaled thousands of hours since 2021. This increase in out-of-market commitments through RUC is a fundamental feature of ERCOT's conservative operating practices and has raised substantial concerns from stakeholders, particularly generation resource owners.

Resource owners are generally averse to RUC instructions because they disrupt planned operations, force uneconomic commitments, and consume emissions credits or allowances that would otherwise be conserved for higher-value periods. Stakeholders express this aversion by supporting inefficient policy changes, such as the inflated 2026 AS methodology, on which we commented extensively through the summer of 2025. They support these initiatives in hopes of reducing the heavy-handed use of RUCs, but in practice, the initiatives distort market outcomes and undermine efficient shortage pricing.

## Competition and Market Power

We evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). There has been a downtrend in uncompetitive hours over the last three years. The percentage of top-quartile net load hours with a pivotal supplier declined from over 90% in 2022 to 35% in 2025. This positive development is due in large part to milder weather and a large influx of energy storage resources held by smaller participants.

Potential economic withholding, measured by the output gap, occurs frequently but has a relatively low impact. Along with the declining frequency of uncompetitive hours, this reflects a generally positive competitive environment. Analysis of potential physical withholding indicates that large suppliers continue to have lower unavailability rates than smaller suppliers, even at higher load levels. This provides additional evidence of positive competitive conditions in the ERCOT market.

Despite the positive evidence of competitive conditions in the ERCOT market, we continue to recommend system-wide market power mitigation. With extreme projected load growth in the ERCOT footprint, the market could become structurally uncompetitive during high-load periods within a few years. If even 20 GW of new net load appears, a small fraction of the projected load growth, the operating margin will diminish significantly. This could significantly increase both the frequency of hours with pivotal suppliers and the opportunity to profitably exercise market power. Hence, we recommend that ERCOT begin this process soon to have system-level market power mitigation in place to address the extreme load growth.

## Direction for Future Market Design

Resource adequacy (RA) has been a primary topic in discussion of ERCOT markets for the past few years. Reliability issues from Winter Storm Uri and high projected load growth from new data centers have contributed to heightened awareness of potential RA shortfalls in the mid-term. Load forecast accuracy and market price signals for new investment are central to this discussion, and we address both in this section.

One half of the RA concern is load growth. Having accurate projections of future load growth is critical to interpreting RA calculations. The ERCOT footprint has experienced significant shifts in the past five years with considerable new capacity from wind, solar, and more recently energy storage resources. Project developers have indicated interest in installing a considerable amount of new large load in the form of data centers. The projected load for 2030 (base and adjusted forecast) is between 138 GW and 148 GW with a high scenario value of up to 209 GW. For context, the 138 GW and 148 GW projections reflect increases of 62% to 74% over current peak load over a five year period. There is currently a surplus of capacity in ERCOT for normal weather conditions. However, a 60%+ increase in load cannot be accommodated by current

installed capacity. This suggests a resource adequacy constraint should be applied to the load interconnection process so that ERCOT does not approve an amount of new load that is physically infeasible. Projected load in any year that exceeds feasibility can be deferred, rather than denied interconnection, to allow for generation growth to happen and create room for additional load. Significant increase in load that is physically feasible will still result in higher energy and ancillary service prices, which will provide signals for new investment in generation.

Two general approaches to applying a resource adequacy constraint in the load interconnection process are applying real-time operating reserve criteria and applying a multiple of CONE as a market revenue (cost) cap. Both approaches require market simulation some number of years into the future. For the real-time operating reserve constraint, a reliability criteria (e.g. PRC < 3,000 MW) and frequency threshold would need to be determined. The same is true for the market revenue approach (e.g. some multiple of CONE). In either case, simulations would be run depicting various system conditions and the resulting operating reserve levels or market revenue would be viewed to determine the acceptable level of new load for each of the simulated years. Both approaches will allow the market to signal new entry without approving an amount of load that is physically infeasible. New load that cannot be accommodated in one year can be deferred to a later year.

There are discussions in the ERCOT market space regarding requirements for some new load to either be curtailable or to provide its own generation. Both are intended to allow more data center load to come into the ERCOT footprint by reducing the additional demand for electricity across peak load hours. This may be effective in limiting the increase in peak load as more data centers come online. However, the increase in overall new load installations will increase load and prices in the shoulder hours around the peak hours. Further, there may be a limit to the extent the existing natural gas system can accommodate “bring-your-own-generation” during peak hours. This suggests that a natural gas availability constraint may be appropriate in developing load projections.

We note that the PUCT process P-59772 provides for the ERCOT Large Load Forecast to reflect the outcomes of the transmission planning process including the in-development Batch process. This reflects a very positive improvement in published load forecasts. Comments in this section are intended to provide some additional discussion on additional material system constraints that can be applied in future iterations to make the load forecast and load interconnection process more closely reflect real constraints on the ERCOT system.

ERCOT does not have a capacity construct and relies almost exclusively on energy and ancillary markets to facilitate investment in new resources to help achieve resource adequacy. Given this reliance, it is essential that shortages be allowed to occur and be priced efficiently by the market. The focus of ERCOT’s market design and operations should be to:

1. Avoid out of market actions and procurements that artificially reduce the frequency of ancillary service shortages as these will destroy investment incentives by reducing expected shortage revenues, and
2. Ensure the markets are properly calibrated to perceive and efficiently price shortages.

Recent market design efforts raise concerns in both areas. ERCOT has implemented and/or proposed a patchwork of market elements implemented to fill what are perceived as shortcomings of the market. The various products and proposals below all have a common flaw – they compensate entities outside of the energy and ancillary service markets to provide additional supply or reduce demand during tight conditions. While they are generally motivated by improving reliability, these types of programs will sharply reduce the expected shortage revenues that investors need to justify new dispatchable generation and to retain higher-cost existing generation nearing retirement. These products and proposals include:

- Firm Fuel Supply Service (FFSS). The FFSS program provides an out-of-market payment for qualifying assets to provide electricity and reserves during anticipated tight winter conditions. Without the program, producers would need higher prices to invest in fuel arrangements to provide this level of availability.
- Emergency Response Service (ERS). Provides out of market revenue to increase supply or reduce demand during winter conditions
- Residential Demand Response (RDR) (NPRR 1296). Pays for demand reductions during peak periods that will reduce expected shortage pricing.
- Forward Capacity Procurement (NPRR 1315). Will facilitate discriminatory out-of-market contracting to increase available energy and reserves, which will reduce expected shortage pricing.

We encourage ERCOT to focus on determining why the existing market design is not producing revenue signals that will incentivize suppliers to provide the reliability services covered by these out-of-market programs and look to change the existing market so that these gaps no longer exist. Allowing these types of services/products to undermine shortage pricing in ERCOT will lead to more apparent shortcomings or gaps to fill with additional out-of-market programs.

There is an in-market aspect of the current market practice that interferes with price signals for new investment that reflect system shortages. This is a key aspect of price formation and the market's ability to support RA. ERCOT's demand for ancillary services (AS Methodology) far exceeds what can be reasonably justified by reliability models. The quantities reflected in the AS Demand Curves (ASDC) are misaligned with reasonable reliability criteria and will make it virtually impossible for the market to produce substantial shortage revenues:

- THE ASDCs will not cause prices to rise substantially until AS levels are far below the AS requirements. This is because the ASDCs are explicitly linked to the aggregate ORDC that falls to close to zero at reserve levels less than the requirements dictated by the AS Methodology.



- ERCOT will take out of market actions (RUC) to satisfy the AS methodology, artificially increasing supply to levels with little or no shortage pricing and that suppress energy price with excess minimum load from committed resources.

Three changes are needed to address this misalignment: (i) eliminate the required linkage between the ASDCs and the aggregate ORDC, (ii) require that the ASDCs be aligned with the AS methodology instead, and (iii) require ERCOT to re-evaluate its AS methodology.

Additionally, the VOLL underlying the ASDCs is substantially less than the VOLL implied by a 1-in-10 reliability standard. Even if deep shortages are capped at \$5000, the lower segments of the ASDCs that price shallow shortages (which are by far the most frequent) could be based on a much higher VOLL. We recommend \$35 to \$40K per MWh based on recent studies.

## Recommendations

The performance of the ERCOT markets is critical because they facilitate efficient market operations to maintain reliability in the short term and produce the economic signals that govern long-term investment and retirement decisions. In an energy-only market like ERCOT, these signals are essential in allowing ERCOT to meet future reliability challenges as load rises in the coming years.

The table below summarizes the new and outstanding recommendations, along with the recommendations that we are retiring because they have been addressed or are no longer applicable. We number each recommendation based on the year we first introduced it, followed by its order in this report. We have only one new recommendation in this report to address concerns we identify with the Firm Fuel Supply Service and improve its performance.

Number	Recommendation Title
<i>New Recommendations to Improve Market Performance</i>	
2025-1	Redesign & Improve the Firm Fuel Supply Service
<i>Recommended Market Improvements from Prior Years</i>	
2024-1	Improve the Procurement and Pricing of Ancillary Services by: (a) Defining ASDCs based on the Marginal Reliability Value of Each Product, and (b) Adopting a Stochastic Risk Methodology for the AS Plan
2024-2	Set Duration Requirement for Non-Spin Reserve Service (NSRS) to One Hour
2024-3	Implement Process to Mitigate Market Power at System and Zonal Levels
2024-4	Establish Real-Time Offer Requirements, Penalties, and Proxy Pricing
2022-1	Implement a Multi-Interval Real-Time Market
2021-2	Implement an Uncertainty Product
2020-3	Reconfigure Load Zones to Reflect Prevailing Congestion Patterns
2020-4	Implement a Point-to-Point Obligation Bid Fee

## Executive Summary

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- 2019-2      Price Ancillary Services Based on the Shadow Price of Procuring Each Service
- 2015-1      Transition Away from the 4CP Method of Allocating Transmission Costs

### *Recommendations Being Retired*

- 2023-3      Improve the Procurement and Deployment of ECRS
  - 2023-4      Align FFSS Pricing and Deployment Practices with Market Operations
  - 2022-3      Allow Transmission Reconfigurations for Economic Benefits
  - 2022-4      Change the Linear Ramp Period for ERS Summer Deployments to 3 Hours
  - 2021-1      Eliminate the “Small Fish” Rule
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## I. REVIEW OF REAL-TIME MARKET OUTCOMES

### A. Real-Time Market Highlights

The performance of ERCOT's real-time market is essential for (1) coordinating resource dispatch and managing grid reliability, which allows ERCOT to maintain reliability while minimizing total production costs, and (2) setting efficient prices for energy and ancillary services that incentivize generators to provide energy or reserves in the short term and guide long-term decisions to build new resources or retire existing ones.

Only a small share of the power produced in ERCOT is settled in the real-time market. However, real-time energy prices shape price expectations in the day-ahead and bilateral forward markets. Real-time prices are, therefore, the principal driver of prices in the markets where most transactions occur and inform long-term investment and retirement decisions. The following are the key insights from this chapter:

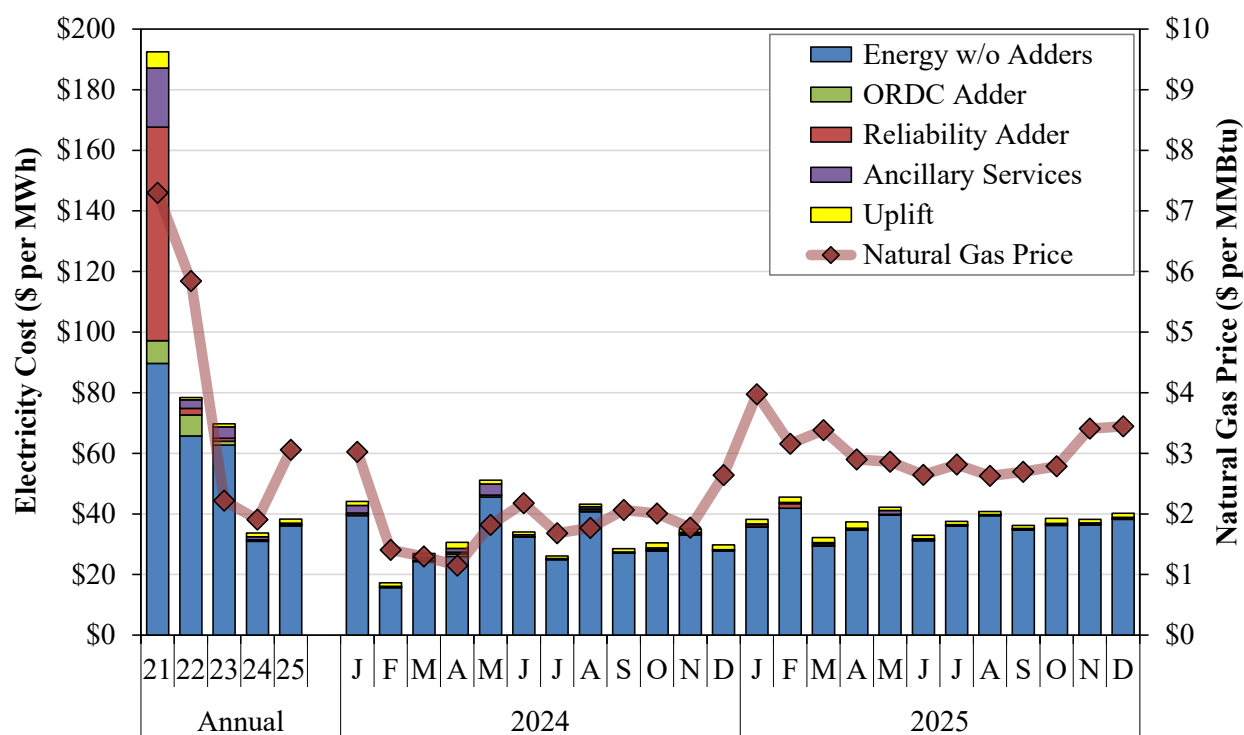
- **The all-in cost of electricity in ERCOT's real-time market increased 13.8%, from \$34 per MWh to \$38 per MWh.** Higher energy costs drove the increase, corresponding to a 61% increase in the average daily index price for natural gas.
- **The implied heat rate in the ERCOT market decreased 28% in 2025 to its lowest point in five years.** This implied heat rate is now in line with expectations based on ERCOT's generation fleet and signals a more competitive market.
- **The shift of peak prices from peak load to peak net load continued in 2025.** Peak prices occur when the system is under stress. Historically, the system experienced stress during peak load conditions, but the increasing share of solar in the ERCOT market is shifting stress to the solar down ramp in the evening hours.
- **Price spikes occurred 40% less often in 2025 than in 2024. The evening ramp accounted for 30% of all price spikes.** The sharp decrease in price spikes is likely due to the large increase in installed capacity in ERCOT, especially solar and storage resources. This concentration during the evening ramp is expected.
- **The West Zone continued to have the highest average energy price in 2025, excluding adders, at \$41.59 per MWh, compared to the ERCOT average of \$36.94 per MWh.** This high price reflects import constraints in the Permian Basin and export constraints in the Panhandle.
- **Price adders like the ORDC and the RDPA added \$0.02 per MWh and \$0.41 per MWh, respectively, to the price of energy.** This extremely low price impact reflects the genuine lack of shortage conditions on the ERCOT grid throughout 2025.

## B. Real-Time Market Prices

### 1. All-In Cost of Electricity

Figure 1 shows the monthly load-weighted average all-in cost for electricity in ERCOT for the last two years and the annual average all-in prices for the last five years.

**Figure 1: Average All-in Cost for Electricity in ERCOT  
2021-2025**



In addition to the cost of energy, loads incur ancillary service costs and several non-market-based expenses referred to as uplift. The all-in price metric includes the load-weighted average real-time market prices across all zones plus ancillary service and uplift costs, divided by real-time load to show costs on a per MWh basis.<sup>1</sup> Energy prices include nodal energy prices and the two price adders:

- The Operating Reserve Demand Curve (ORDC) Adder, implemented in 2014 and discontinued in December 2025 with the introduction of RTC, reflects increasing reliability risks when reserves begin to run short; and

<sup>1</sup> For this analysis “uplift” includes: Reliability Adder Imbalance Settlement, ORDC Adder Imbalance Settlement, Revenue Neutrality Allocation, Emergency Energy Charges, Base Point Deviation Payments, ERS Settlement, Black Start Service Settlement, Block Load Transfer Settlement, Firm Fuel Service Settlement, High Dispatch Limit Override Settlement, RMR Settlement, RUC Settlement, Voltage Services Settlement, and the ERCOT System Administrative Fee.

- The Reliability Deployment Price Adder (RDPA), implemented in 2015, ensures that prices are not inefficiently reduced when ERCOT takes out-of-market reliability actions.<sup>2</sup>

These adders are ERCOT's primary means of reflecting shortage pricing in its markets. Since RTC was implemented, shortage pricing has been incorporated into the price of energy rather than functioning as a separate adder.

The all-in cost of electricity increased 13.8% from almost \$34 per MWh in 2024 to \$38 per MWh in 2025. This increase was driven primarily by the cost of energy, with no adders or uplift, and corresponded to a 61% increase in the average daily index price for natural gas. Gas and energy prices are expected to correlate in a well-functioning, competitive market because suppliers have an incentive to offer energy according to the marginal cost of generation. Fuel costs represent the largest component of marginal production cost for most generators, and natural gas is the most widely used fuel in ERCOT.

Figure 1 provides additional insights:

- Ancillary services costs were \$0.39 per MWh of load in 2025, a 60% decrease from 2024 and the lowest since 2020. We analyze this in greater detail in Chapter III.A.
- The ORDC adder contributed \$0.02 per MWh to the all-in cost of energy in 2025, a 93% reduction from 2024. The low ORDC cost reflects a significant increase in online reserves because of growth in renewable generation and ESRs, as discussed in Section D below.
- Uplift costs accounted for \$1.38 per MWh of the all-in price in 2025, up 12% from 2024. RMR uplift was the largest contributor to this increase, accounting for \$68 million of the \$668 million in total uplift costs.
- Uplift associated with FFSS increased 36% from \$33.8 million in 2024 to \$45.9 million in 2025. This increase resulted from a 26% increase in total MW procured and a 36% increase in the offer cap for the 2024-2025 FFSS season relative to the 2023-2024 FFSS season.<sup>3</sup>

## 2. Implied Heat Rates

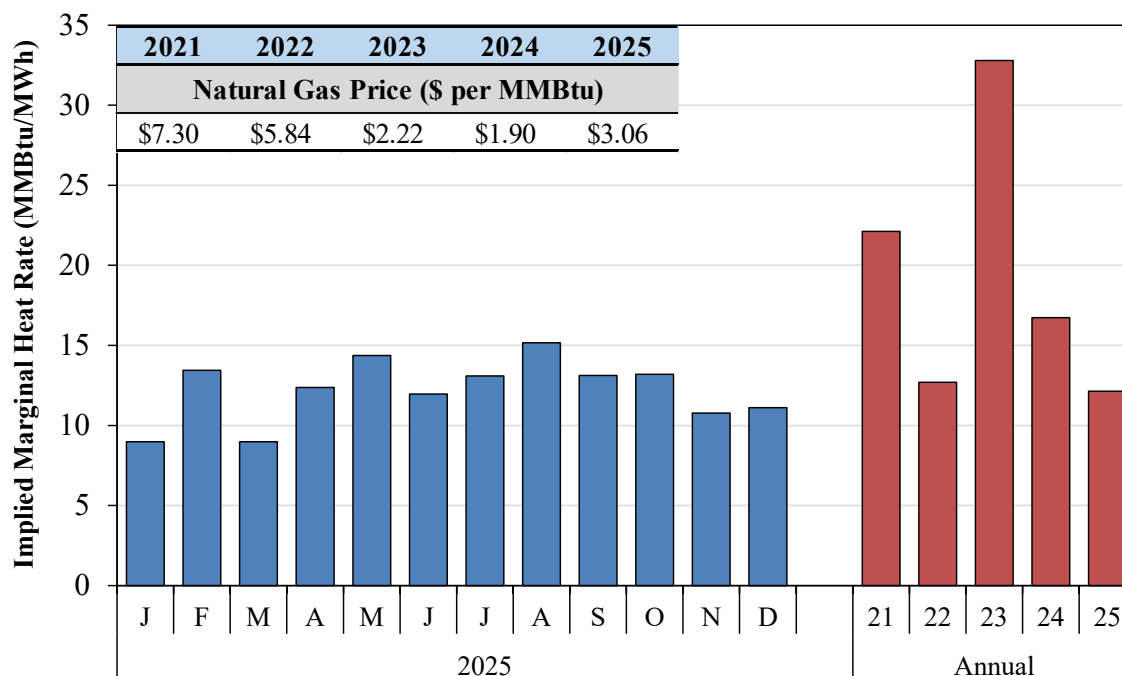
Historically, the real-time price of electricity has been directly correlated with the fuel price for the marginal generation technology, which in ERCOT is usually natural gas. To assess the competitiveness of the real-time power market at prevailing fuel costs, we calculate an implied heat rate, a market-based indicator of the fuel efficiency a gas generator would need to break

<sup>2</sup> The reliability adder uses the dispatch software to simulate the system lambda without RUCs, deployed load capacity, or certain other reliability actions. The adder is the difference in system lambda output by SCED with and without any reliability actions.

<sup>3</sup> Source for these numbers: [https://interchange.puc.texas.gov/Documents/56000\\_10\\_1516314.PDF](https://interchange.puc.texas.gov/Documents/56000_10_1516314.PDF)

even at current electricity and natural-gas prices. We calculate it by dividing the power price by the fuel price to derive the heat rate that equates revenue from selling electricity with the cost of buying gas. Accordingly, a high implied heat rate signals a less competitive market where even inefficient units can profit, while a low implied heat rate indicates a more competitive market where only the most efficient generators are in the money. Figure 2 shows the implied marginal heat rates for each month of 2025 and annually for 2021-2025.

**Figure 2: Monthly and Annual Implied Heat Rates**  
2021-2025



The average implied heat rate for 2025 was almost 28% lower than in 2024 and was the lowest annual average of the last five years. This value is now in line with the marginal heat rate of natural gas power plants in the ERCOT market. In recent years, the prevalence and impact of price spikes, shown in Figure 4, elevated the implied marginal heat rate. Those spikes had a larger effect in 2023 and 2024 relative to fuel prices than in 2025.

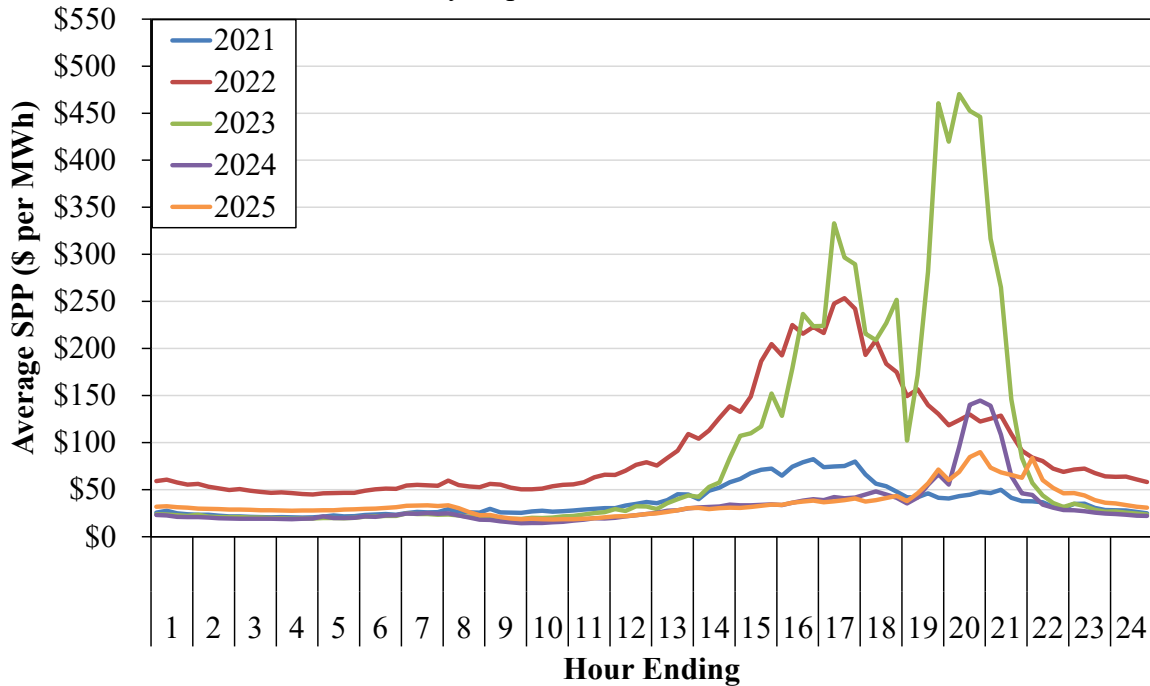
Over time, however, some factors have weakened the link between natural gas and electricity prices. The growth of zero marginal cost generation such as wind and solar has resulted in hundreds of hours with prices at or below \$0 per MWh, which lowers the market's implied heat rate. Conversely, shortage pricing results in hundreds of hours per year with prices above the marginal cost of natural gas generators, which raises the market's implied heat rate.

### 3. Prices by Time of Day

While Figure 1 shows monthly variation in the all-in cost of energy, Figure 3 illustrates how real-time energy prices vary by time of day. Specifically, Figure 3 shows load-weighted

settlement point prices for energy in each 15-minute settlement interval for May through September, when demand and prices are typically highest.

**Figure 3: Prices by Time of Day**  
May-September 2021-2025



The price trends from 2021 to 2025 show that the period when system conditions are tightest has shifted from the firm peak load hour, usually around 4 to 5 p.m., to the later evening hours (7 to 9 p.m.). This later period, called the net load peak, is calculated by subtracting renewable generation from total demand, because solar generation has ramped down while wind generation is beginning to ramp up. The shift in peak prices to the peak net load hours demonstrates the growing impact of solar generation. During this solar down-ramp, ESRs increasingly provide energy, causing peak prices to occur later in the evening. Peak prices were relatively lower in 2025 than in 2024 because scarcity conditions were less frequent in 2025. This reduction was influenced by the large increase in ESR capacity from 2024 to 2025 and the corresponding increase in competitively priced offers for energy provided by ESRs. We go into more detail on this trend in Chapter II.E.4.

#### 4. Price Spike Impacts

Figure 4 shows the frequency of real-time energy price spikes in 2024 and 2025 to illustrate the effect of the highest-priced hours on the average real-time energy price. For this analysis, price spikes are defined as 15-minute intervals when the load-weighted average energy price exceeds 18 million British thermal units (MMBtu) per MWh (i.e., an implied heat rate of 18) multiplied by the corresponding fuel index price (FIP), producing an energy price spike threshold in \$ per

MWh. Prices at this level typically exceed the marginal costs of virtually all on-line generators. The figure also shows the portion of the average hourly energy price attributable to the price spikes.

**Figure 4: Impact of Price Spikes on Real-Time Energy Price**  
2024-2025

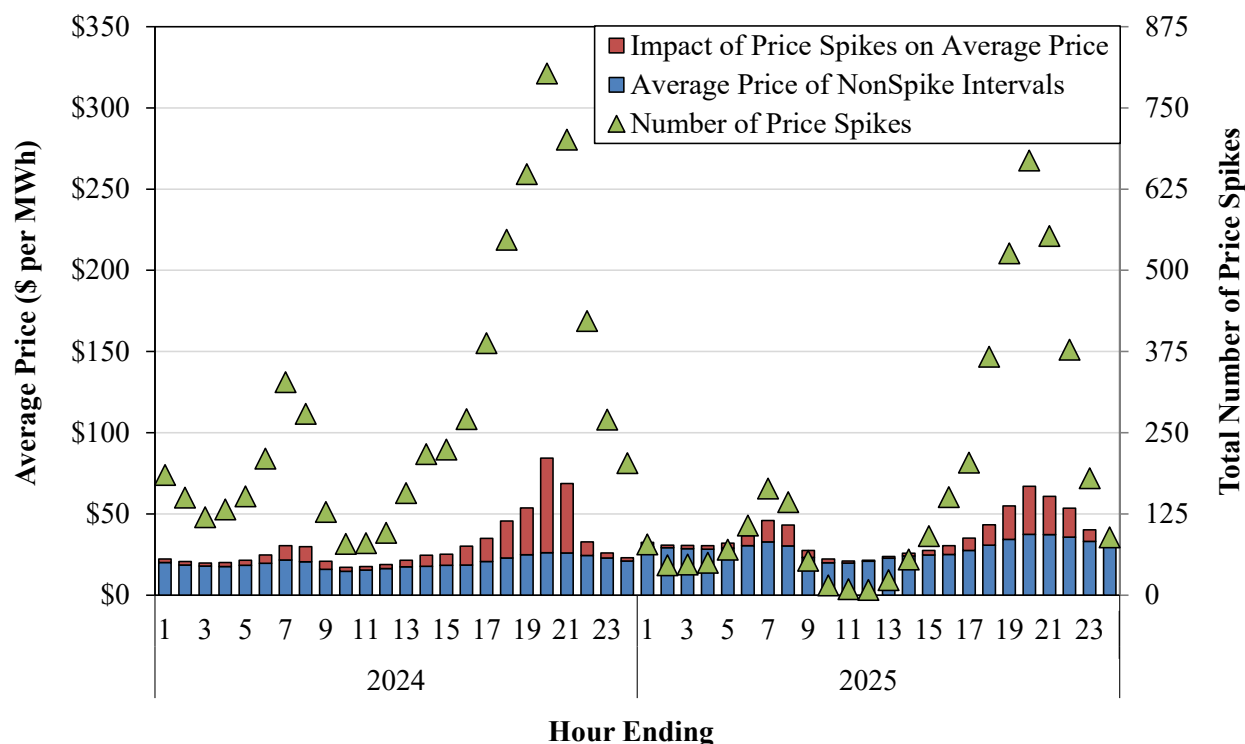


Figure 4 shows that price spikes were 40% less frequent in 2025 than in 2024. It also shows that their effect on the average hourly price of electricity was lower on both an absolute and percentage basis. This trend likely results from continued growth in installed solar and energy storage capacity, which contributes to high online reserves throughout the year. We further discuss the current surplus of operating reserves in ERCOT in Chapter II.

As in 2024, most price spikes in 2025 occurred during the peak net load hours between 7 and 9 p.m., when solar production across the state ramped down for the day. During this ramp-down period, SCED often dispatches quick-start natural gas plants or energy storage resources with high-priced energy offer curves, which results in frequent and predictable price spikes. Price spikes during this evening ramp accounted for 30% of all price spikes in 2025, up from 22% in 2024. Price spikes also occurred relatively frequently during the morning ramp hours, i.e., between 6 a.m. and 8 a.m., but they accounted for only 7.5% of the total in 2025, down from 8.9% in 2024. Conversely, the share of price spikes that occurred during the middle of the day, when solar production peaks, i.e., between 9 a.m. and 2 p.m., dropped from 9.3% in 2024 to 2.7% in 2025.



The increase in solar capacity primarily drove the reduction in daytime price spikes from 2024 to 2025, while growth in energy storage capacity largely drove the decline in price spikes during solar ramp periods. As discussed further in Chapter II.E.4, the expanding participation of energy storage resources in energy markets has played a central role in this shift.

### C. Zonal Energy Prices

Congestion causes the cost to serve load to vary by location, resulting in differences in electricity prices between Load Zones. Table 1 lists the annual load-weighted average prices for each zone for 2021-2025. These prices differ slightly from the all-in costs discussed in Section B.1 because they exclude imports and exports to and from the ERCOT grid through DC ties.

**Table 1: Average Annual Real-Time Energy Market Prices by Zone**

	2021	2022	2023	2024	2025
<b>Energy Prices (\$ per MWh)</b>					
<b>ERCOT</b>	<b>\$179.24</b>	<b>\$76.41</b>	<b>\$73.28</b>	<b>\$32.41</b>	<b>\$36.94</b>
<b>Houston</b>	\$136.69	\$82.47	\$72.88	\$30.24	\$34.95
<b>North</b>	\$221.52	\$77.30	\$78.01	\$30.42	\$35.34
<b>South</b>	\$200.35	\$74.39	\$71.12	\$34.66	\$37.59
<b>West</b>	\$111.56	\$66.62	\$67.56	\$35.88	\$41.59

Continuing the trend from 2024, the West zone had the highest average price in 2025, followed by the South zone. The West zone includes both the Panhandle, which has abundant wind and solar resources but is export-constrained, and the Permian Basin, which has seen rapid demand growth and is import-constrained. This duality explains why the West zone experienced the highest number of intervals with negative prices and the greatest frequency of price spikes of any load zone. We expand in Chapter V on how the load zones in ERCOT have not been updated since 2003 and we recommend updating them to reflect ERCOT's current, more complex topology.

### D. Shortage and Reliability Pricing

Before RTC was implemented, ERCOT's market design featured two distinct price adders, the ORDC and the RDPA. This section summarizes the rationale and methodology for each adder and reviews its impact on 2025 real-time energy prices.

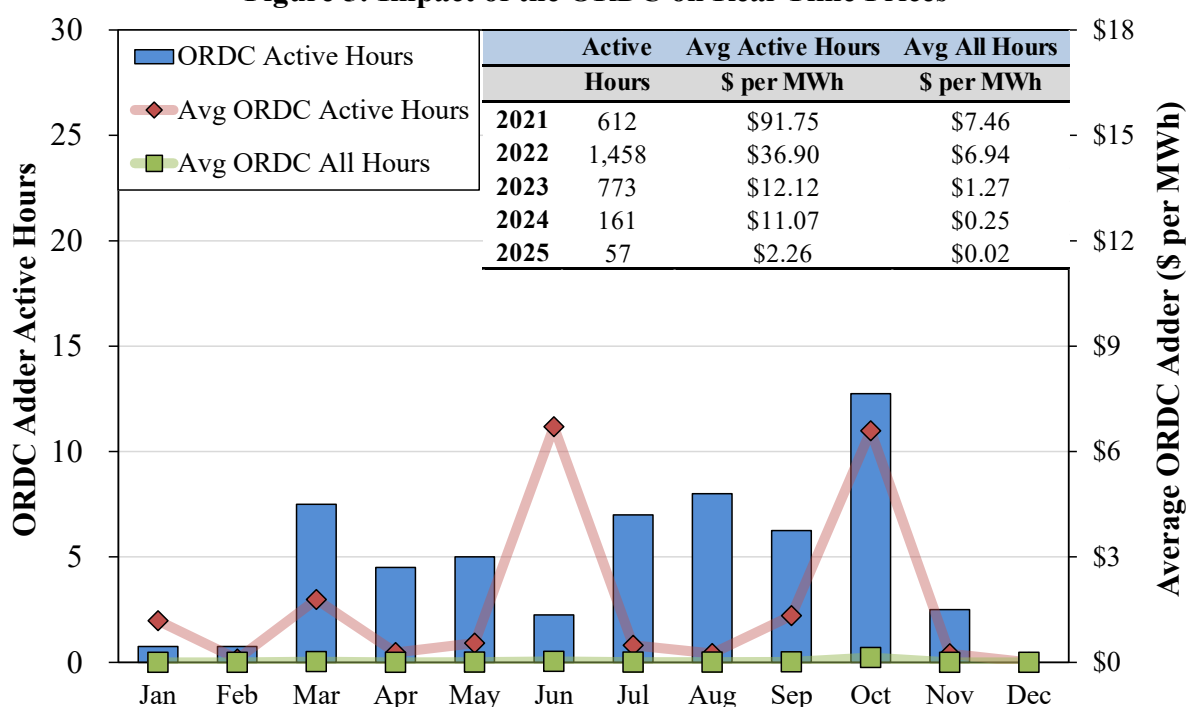
#### 1. ORDC

The ORDC reflects the relationship between operating reserves and the probability of load shed; as operating reserves decrease, the likelihood of involuntary load shed increases. The ORDC magnitude is scaled to the Value of Lost Load (VOLL). Shortage pricing is efficient when the product of VOLL and the probability of load shed is built into energy and reserve prices during

shortages. In ERCOT's market design before RTC went live on December 5, 2025, ERCOT did this by adding an ORDC price adder to energy and reserve prices when reserves were low.

In 2025, the ORDC was active for only 57 hours,<sup>4</sup> just over one-third of the previous year's total and less than 8% of the annual average for 2021-2024, as shown in Figure 5. This decline continues a multi-year trend that reflects the significant increase in installed generation capacity in ERCOT, particularly solar and ESRs, without a comparable increase in peak demand. As a result, there have been fewer instances of reserve shortages and non-zero prices produced by the ORDC. Overall, the ORDC contributed less than \$0.02/MWh to the annual average real-time energy price. Figure 5 summarizes the impact of the ORDC on real-time prices, showing the number of hours these mechanisms were active, their price impact during those hours, and their average impact across all hours of each year for 2021-2025.

**Figure 5: Impact of the ORDC on Real-Time Prices**

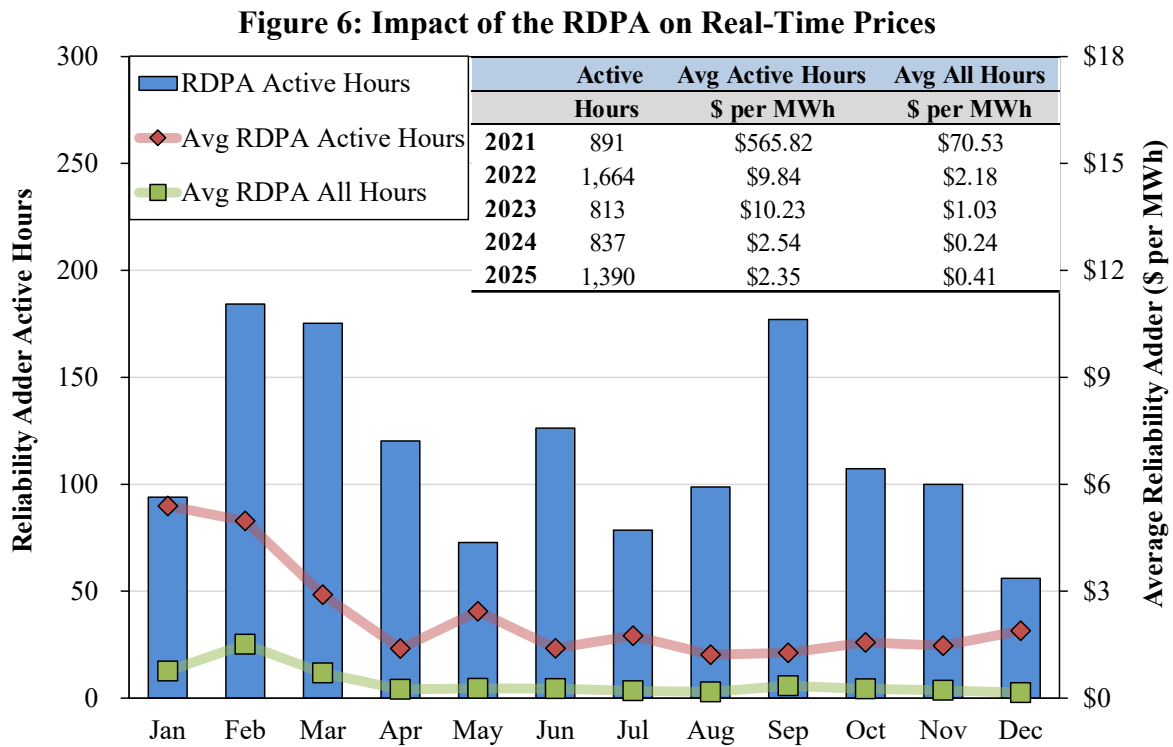


## 2. RDPA

The Reliability Deployment Price Adder adjusts prices to account for the price-suppressing effects of ERCOT's out-of-market reliability actions. Actions such as Reliability Unit Commitments (RUCs) and deployment of ERS demand response can artificially lower prices by increasing supply or reducing demand outside the normal market process. The RDPA corrects this suppression by increasing real-time prices when these actions occur, ensuring prices continue to reflect true market conditions and reliability risks.

<sup>4</sup> "Active" is defined as a settlement interval where the ORDC price was at least \$0.01 per MWh.

Figure 6 summarizes how often the RDPA was activated and its effect on prices. The RDPA was active 71% more hours in 2025 than in 2024. The main driver of this increase was the large increase in RUC commitments from 2024 to 2025, as shown in Table 7. Despite the increase in hours when the RDPA was \$0.01/MWh or greater, its overall effect on prices remained modest at \$0.41 per MWh for the year. This indicates a lack of genuine scarcity conditions in 2025 that would have produced an RDPA of hundreds or thousands of dollars per MWh.



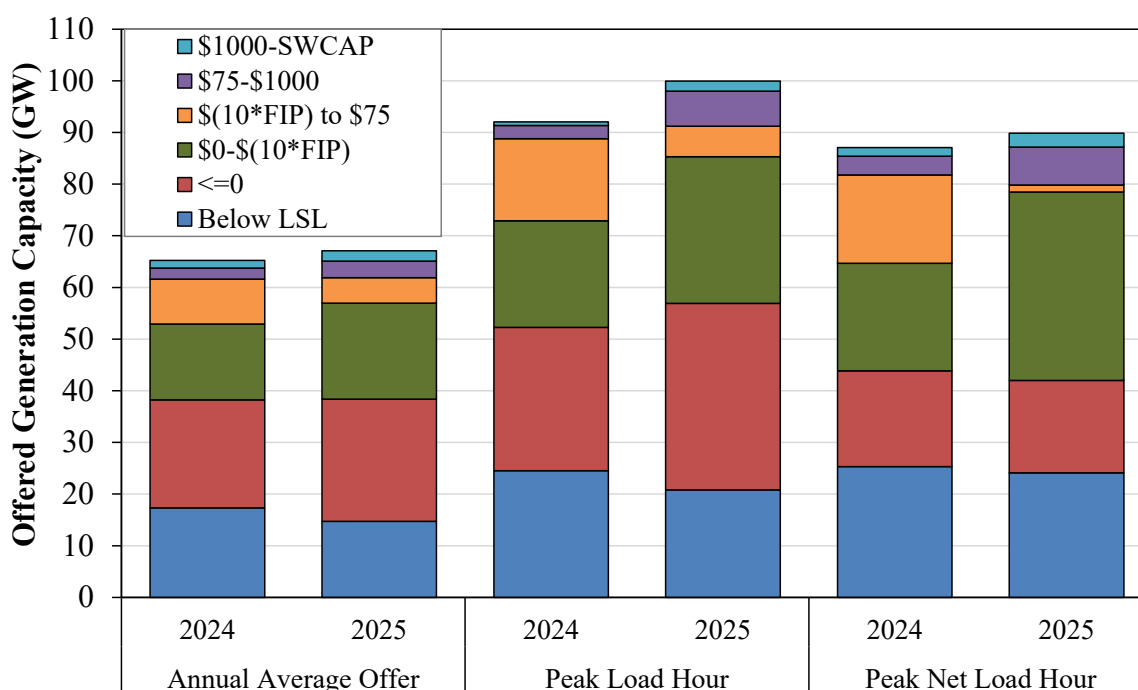
### E. Aggregated Offer Curves

The next exhibit compares the quantity and price of generation offered in 2025 and 2024. Figure 7 shows the average aggregated generator offer stacks for all hours of the year, the peak load hour, and the peak net load hour. The 2024 values have been adjusted because of methodological changes in how the aggregate offer stacks are formulated. The figure shows:

- 22% of real-time generation capacity was not dispatchable because it was below generators' Low Sustained Limit (LSL) in 2025, compared to 27% in 2024. This trend indicates lower committed thermal capacity on average.
- 35% of real-time generation capacity was offered at less than or equal to \$0 in 2025 compared to 32% in 2024. These offers are primarily associated with wind and solar resources that are incentivized to produce even when prices are negative because many receive federal production tax credits.

- 28% of capacity was priced between zero and 10 times the daily natural gas price (known as the FIP) in 2025 compared to 23% in 2024. This range represents the incremental fuel price for the vast majority of the ERCOT generation fleet.
- Roughly 15% of capacity was offered above this level in 2025, compared to 19% in 2024. The \$75 level corresponds to the energy offer floor for capacity providing online Non-Spin Reserve Service (NSRS), which averaged approximately 1,000 MW throughout 2025.

**Figure 7: Aggregated Generation Offer Stack – Annual, Peak and Net Peak Load**



## F. Impact of ECRS on Real-Time Market Prices

The implementation of ECRS in June 2023 had a profound impact on the ERCOT wholesale market because its restrictive deployment criteria created high prices from artificial shortage conditions. Our analysis in the 2023 State of the Market report indicated that ECRS deployment practices resulted in approximately \$12 billion in excess costs in the real-time market. Since then, the pricing impact of ECRS has been less severe, largely because of supply and demand fundamentals.

Solar and energy storage capacity have increased significantly since 2023, and neither 2024 nor 2025 had as many days of extreme summer heat as 2023. The net effect was a marked reduction in hours where reserves were tight enough to trigger the artificial scarcity conditions in the real-time market that were present in 2023. That said, the manual deployment process for ECRS still

had shortcomings in 2025 until RTC was implemented in December, which we address later in this section.

To estimate the excess costs of ECRS deployment practices in 2025, we identified real-time market conditions where deploying ECRS would have significantly reduced costs. We focused on events with at least two consecutive SCED intervals showing 10 MW or more of under-generation.<sup>5</sup> In these situations, deploying ECRS would have clearly improved both economic efficiency and reliability. Importantly, deploying ECRS generally does not reduce the 10-minute reserves available to ERCOT. It simply makes them available to SCED and transfers them to online resources. In fact, deploying ECRS often increases available reserves by preventing storage resources from having to discharge to satisfy demand.

We then simulated each event assuming full release of ECRS capacity to SCED and compared the outcomes with the actual SCED results. We calculated excess cost as the difference between the original and simulated results, measured as system lambda multiplied by load. Figure 8 presents the estimated excess costs for each identified event.

**Figure 8: Excess Cost of ECRS Deployment Practice in 2025**

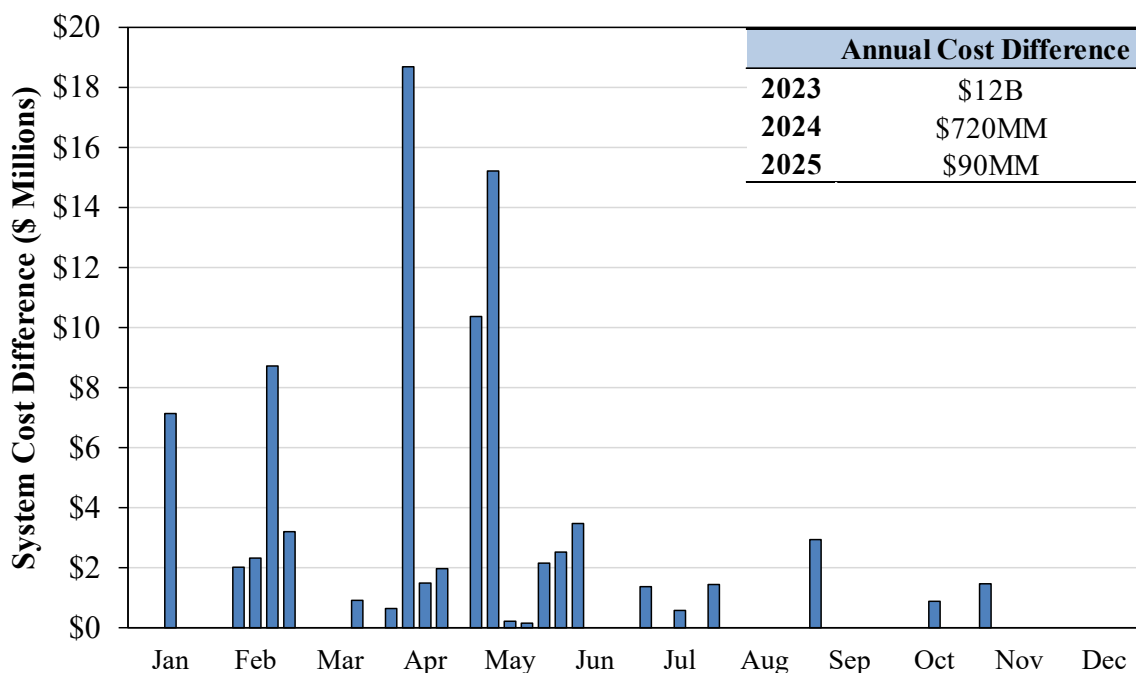


Figure 8 shows that the excess cost of ECRS deployment practices decreased by an order of magnitude each year from 2023 to 2025. This cost decrease was not primarily caused by any

<sup>5</sup> SCED generally procures enough energy through base points to satisfy demand, but it can go short on energy according to the Power Balance Penalty Curve. The volume of shortage is referred to as “Under-generation.”

change in ERCOT's operational practices. Instead, it mainly reflects the increase in online reserves and the corresponding decrease in even modest shortage conditions.

Figure 8 identifies 23 events where more flexible deployment of ECRS would have saved the market approximately \$90 million in total. Three of these events each produced more than \$10 million in excess costs. These same three events included ECRS deployments under the criteria defined by NPRR 1224, and their combined excess cost was more than \$40 million.

In addition to the financial impact, the ECRS deployment criteria before RTC negatively affected reliability by dispatching ESRs excessively for energy while keeping gas turbines in reserve. Simulations that released ECRS in these events preserved ESR state of charge (SOC) by reducing ESR net injections by 10% throughout the events.

With RTC's implementation in December 2025, ERCOT operators no longer manually deploy ECRS. Instead, SCED can make economic trade-offs between procuring energy and ancillary services in real time using reserve shortage prices under an ancillary service demand curve (ASDC). This eliminates the need for manual deployments and enables more efficient, market-driven decisions.<sup>6</sup>

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<sup>6</sup> The ASDCs defined by NPRR 1268 sponsored by the IMM, should result in further improvements in market performance vis a vis ECRS. See <https://www.ercot.com/mktrules/issues/NPRR1268> for more details.

## II. DEMAND AND SUPPLY IN ERCOT

### A. Summary of Demand and Supply in 2025

Many of the market outcome trends described in Chapter I stem from changes in the supply portfolio or load patterns. This chapter summarizes supply and demand trends, including wind and solar generation, the dramatic increase in market participation from energy storage resources, and the behavior of demand response resources and other price responsive loads. The following are the key insights from this chapter:

- **Average load in ERCOT increased by 6.1% in 2025, while peak load declined by 1.8%.** The West load zone led this growth by a large margin, primarily because cryptocurrency mines and oil and gas operations have sited there.
- **14.8 GW of capacity entered the ERCOT market in 2025.** The new supply comprised 6.2 GW of solar, 7.3 GW of ESRs, 1.2 GW of wind, and 280 MW of gas turbines. Of this capacity, 37% sited in the North zone, 26% in the Houston zone, 22% in the South zone, and 16% in the South zone.
- **Wind generation grew by only 2.9% in 2025.** Because wind resources are concentrated in locations with the best resource potential, curtailment has a major impact on wind project economics, and 4.7% of wind generation was curtailed in 2025.
- **Solar generation grew by 49% in 2025, and 6% of total generation was curtailed.** Although solar potential is strong across Texas, solar resources are more likely to be curtailed at midday, when simultaneous production peaks.
- **Wind resources have an overall capacity factor of 31.6%, while solar resources have an overall capacity factor of 23.8%.** However, the wind capacity factor during peak net load hours has increased, while the solar capacity factor has plummeted because the net peak load hour has continued to shift into the evening.
- **Total energy storage capacity exceeded 17 GW, and average duration increased from 1.67 hours to 1.83 hours.** The increase in average duration corresponds to ESR market participation shifting from AS to energy arbitrage.
- **Annual revenue per unit of ESR capacity declined by 37% in 2025 as revenues from providing AS fell by the same amount.** This revenue decline further explains why ESRs are shifting their business model to energy arbitrage because of strong competition in AS.
- **ESRs are offering more competitively. In 2025, 55% of energy offers were priced between \$0-100 per MWh, up from 46% in 2024.** Still, 18% of offers were submitted at the system-wide offer cap.

- **Supply margins have grown substantially – the number of hours when PRC was less than 6.5 GW has fallen sharply and PRC has not dropped below 3 GW since 2023.** The operating reserve margin increased mostly because of the rapid entry of renewable resources and energy storage resources.
- **The monthly average aggregate load from controllable load resources dropped to 240 MW in 2025.** CLRs still consist entirely of cryptocurrency mines. Many of these mines deregistered as CLRs and migrated to ERCOT's Emergency Reserve Service, where they now account for 64% of ERS volume.
- **Aggregate demand from cryptocurrency mines in ERCOT is 4.6 GW.** We support measures that incentivize these price-responsive loads to register as CLRs, including NPRR 1188, which will introduce nodal pricing for CLRs, and NPRR 1244, which allows loads to register as CLRs even if they cannot provide primary frequency response. Both NPRRs are scheduled for implementation in January 2027.
- **ERCOT proposed a residential demand response program through NPRR 1296 that we find will undermine ERCOT's energy only market and its economic signals.** Despite the significant subsidy needed to overcome residential consumers' limited price sensitivity, a resident may receive only up to \$4 per month while being curtailed for up to 27 hours per month. The program will suppress market prices by \$1.5 billion each year.
- **The ADER pilot program has grown significantly over the last year.** Aggregate Distributed Energy Resources currently consist entirely of home batteries. ERCOT plans to evaluate further improvements to address technical challenges, such as modeling ADERs as ESRs and settling them nodally.
- **SB 6 introduced the Large Load Demand Management Service in 2025, and its rulemaking will be complete sometime in 2026.** The LLDMS could be a targeted reliability tool during extreme events that threaten ERCOT grid reliability.
- **Participation in TDSP Load Management Programs increased by 12%.** The summer program enrolled 289 MW, and the winter program enrolled 127 MW.
- **ERCOT was a net importer of energy in 2025.** It imported energy from the Southwest Power Pool while remaining a net exporter to Mexico, as in recent years.



## B. ERCOT Load in 2025

Figure 9 shows peak and average load by zone from 2021 through 2025.<sup>7</sup> Average load characterizes the aggregate demand for energy over the entire year, while the peak load reflects the instantaneous demand for available generation capacity.

**Figure 9: Annual Load Statistics by Zone**  
2021-2025

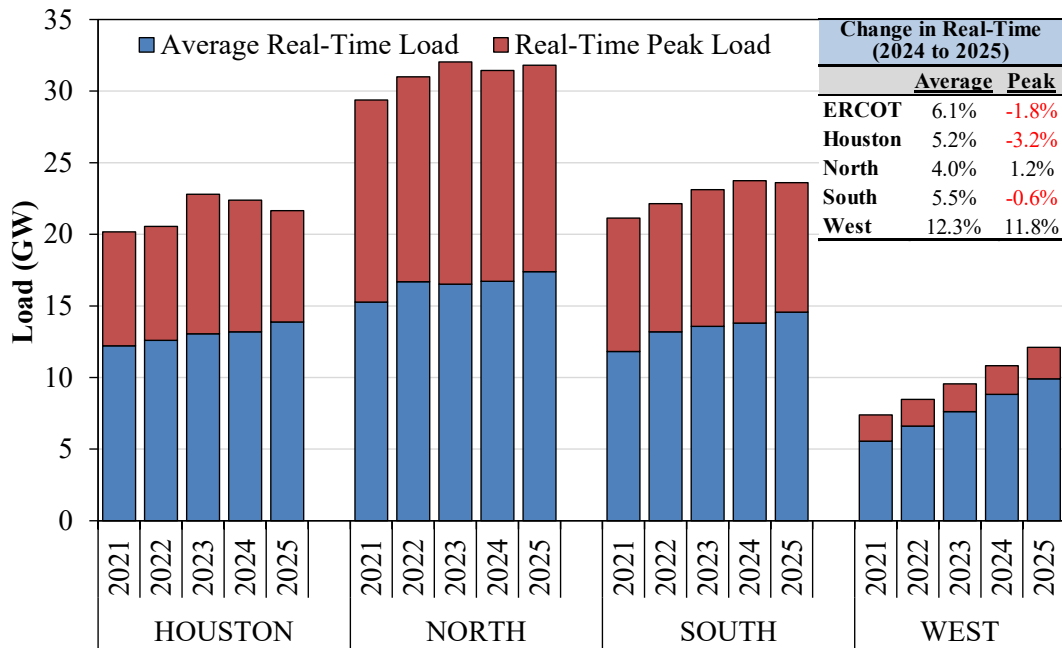


Figure 9 shows that average load in ERCOT in 2025 increased by 6.1%, while peak load declined by 1.8%, continuing both trends from 2024. Continued population and economic growth in Texas explain the overall load growth. The 12.3% increase in average load and 11.8% increase in peak load in the West zone also reflect growing demand from cryptocurrency mining, which can effectively capitalize on price volatility, and oil and gas operations. We include more in-depth commentary on price responsive loads such as cryptocurrency mining facilities in Section G.1 of this chapter.

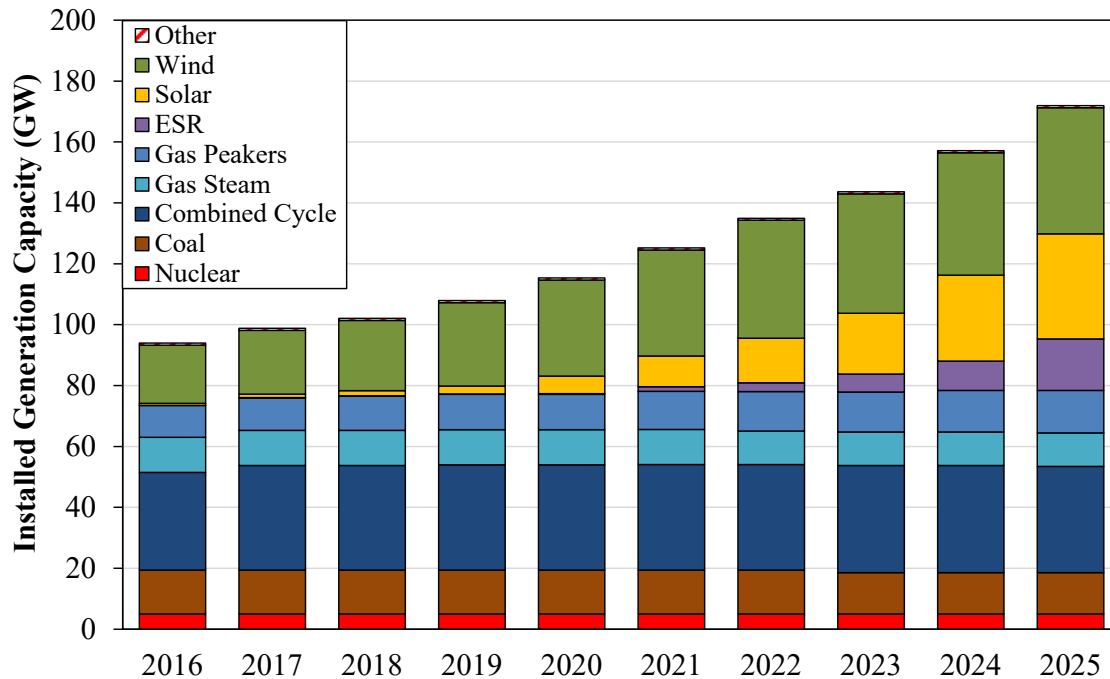
## C. Generation Capacity in ERCOT

ERCOT's installed generation capacity at the end of 2025 reflects continued growth in solar and storage. Figure 10 shows total installed capacity approved to operate at its High Sustained Limit (HSL) from 2016 through 2025. In 2025, approximately 14.8 GW of new capacity entered commercial operation, including 6.2 GW of solar, 7.3 GW of energy storage resources (ESRs), 1.2 GW of wind, and 280 MW of combustion turbines. Since 2021, most new capacity has come from solar and ESRs, averaging 5.7 GW and 3.3 GW of annual additions, respectively.

<sup>7</sup>

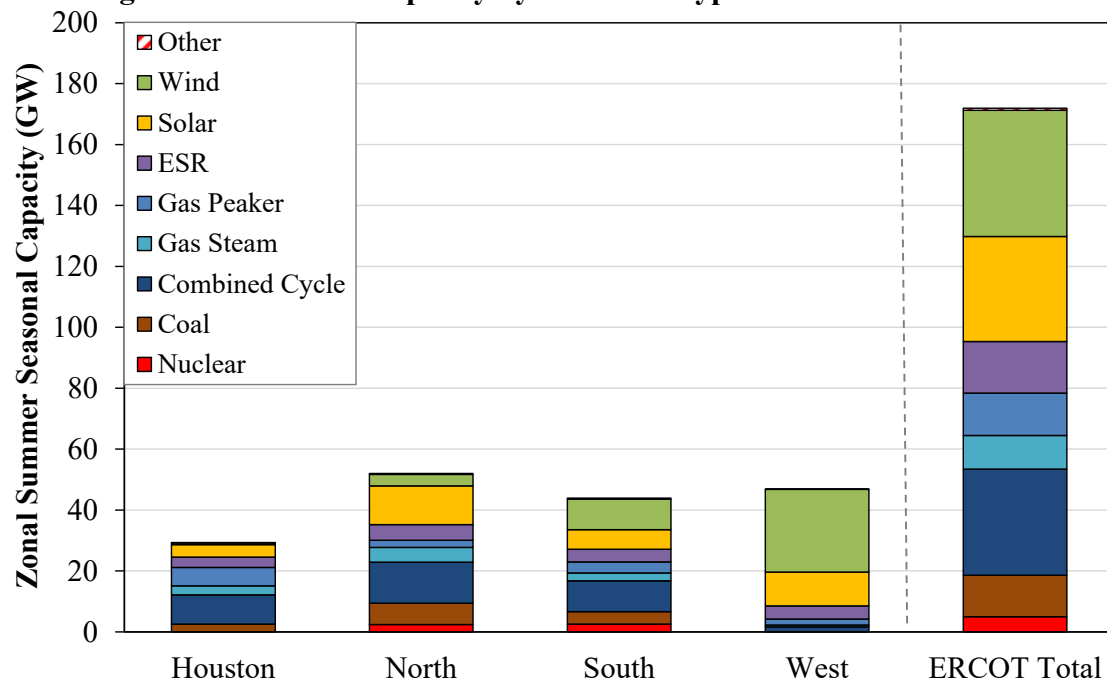
Non-Opt-In Entity (NOIE) load zones have been included with the proximate geographic zone.

**Figure 10: Installed Generation Capacity in ERCOT  
2016-2025**



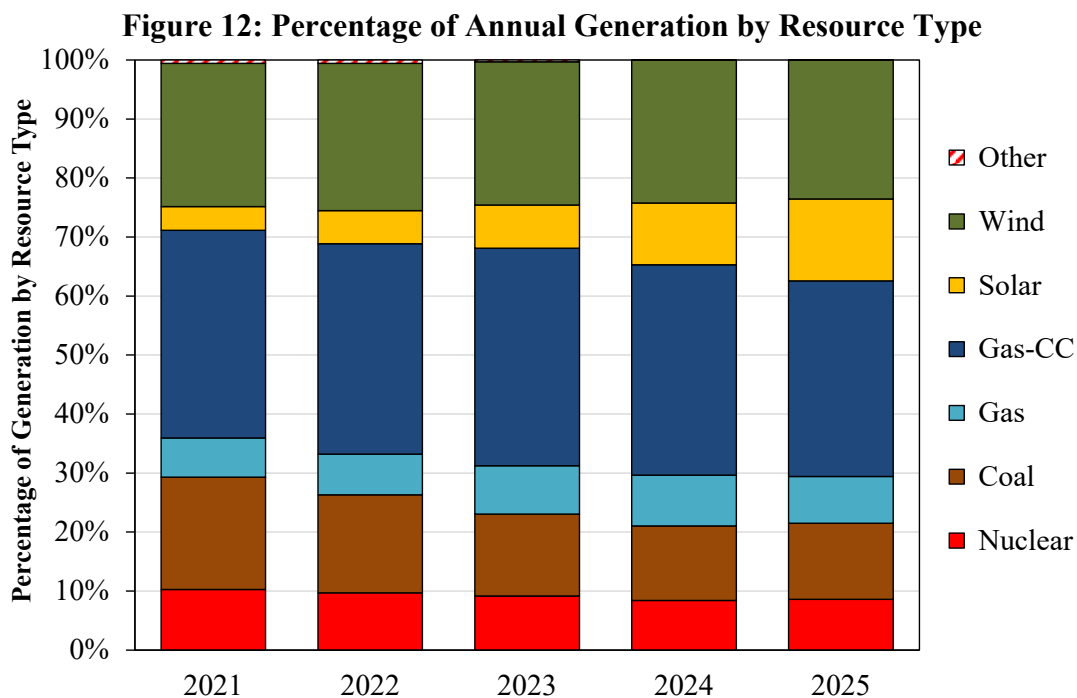
As in 2024, the most new resources were added in the North zone – 37% of all new capacity in 2025. Unlike in 2024, the Houston zone saw the second highest amount of new resources – 26% of all new resources. New resources in the West and South zones accounted for 22% and 16% of new capacity, respectively. Figure 11 shows total installed capacity by resource type and zone.

**Figure 11: Installed Capacity by Resource Type for Each Zone in 2025**



The geographic distribution of capacity in the North and South zones mirrors the demand pattern shown in Figure 9. The Houston zone is increasingly dependent on imports from other areas, but it has added substantial energy storage capacity, which has a smaller footprint and is not subject to the same emission constraints as fossil-fuel generation. In the West zone, the Permian Basin remains import-constrained, but strong renewable generation in the Panhandle more than offsets those imports, making the zone a substantial net exporter of power.

The composition of output has changed along with changes in capacity as shown in Figure 12. Over the past year, the share of output from wind has been nearly flat while the solar share increased from 10.4% in 2024 to 13.9% in 2025. The share of output from coal was flat at 12.9%. Generation from natural gas resources decreased from 44.3% in 2024 to 41.1% in 2025.



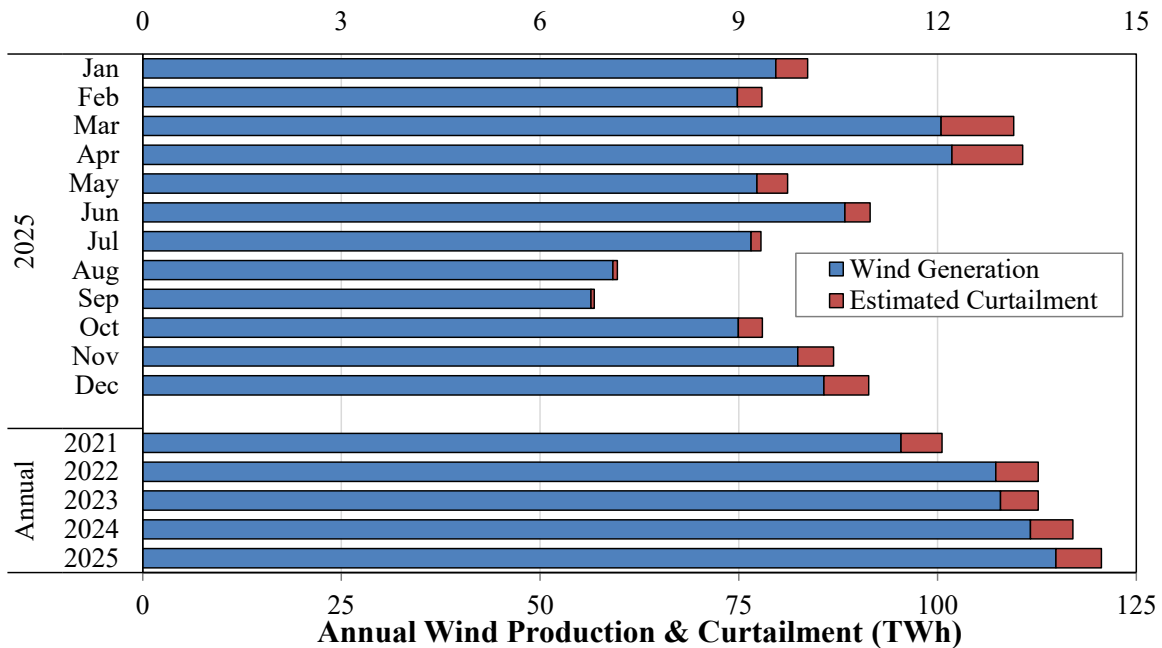
#### D. Wind and Solar Generation in ERCOT

The output of wind and solar resources has been growing and varies substantially by season. Figure 13 and Figure 14 show the trends in wind and solar generation. They also show the total amount of wind and solar curtailment due to congestion, which is particularly relevant for renewable generation as we describe in more detail later in this section.

##### 1. Production and Curtailment

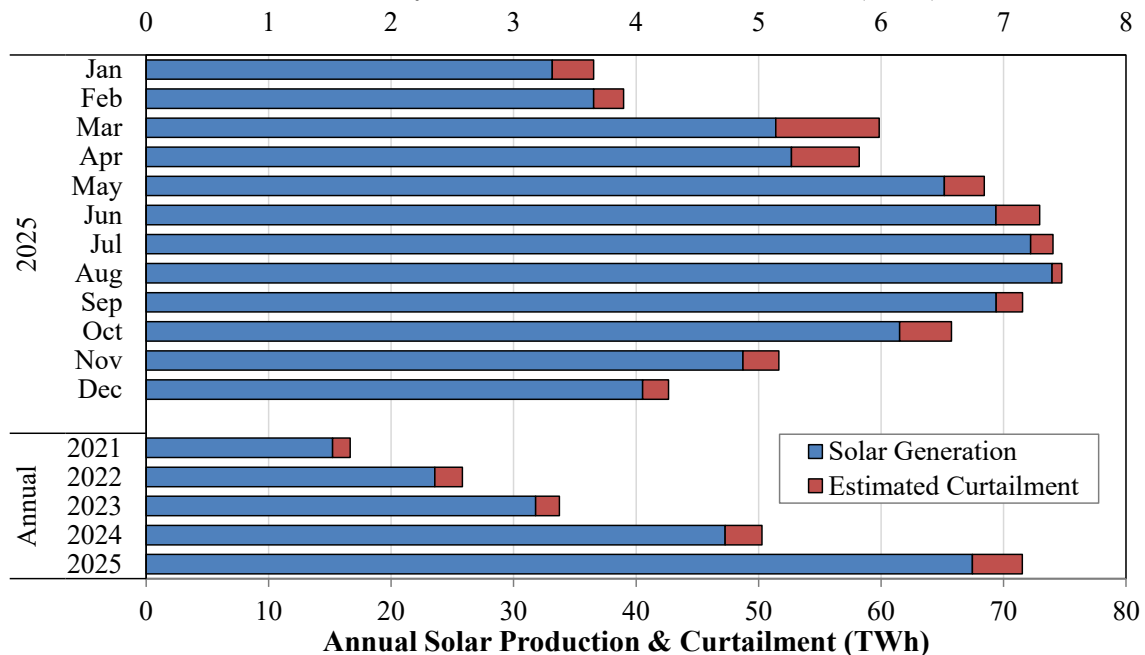
Wind generation grew by only 2.9% in 2025, continuing a trend of relatively low wind-capacity growth since 2022. Roughly 4.7% of wind generation was curtailed in 2025, consistent with the trend over the last five years. In general, the economics of renewable generation have shifted in favor of solar development, as shown by the sharp increase in solar generation.

**Figure 13: Wind Production and Curtailment, 2021-2025**  
**Monthly Wind Production & Curtailment (TWh)**



In contrast to the relatively low growth in wind generation, solar generation grew by almost 49% in 2025. Roughly 6% of solar generation was curtailed in 2025, similar to 2024 levels. One explanation for this relatively low curtailment is that solar projects can be sited closer to load and are less prone to congestion than wind resources sited in areas with the highest wind potential.

**Figure 14: Solar Production and Curtailment, 2021-2025**  
**Monthly Solar Production & Curtailment (TWh)**



## 2. Congestion Impact

Congestion is most acute for renewable generation because these resources must be sited where wind or solar potential is strongest. Thermal generation, excluding geothermal, has far more siting flexibility and can often locate closer to load at injection points less likely to create additional congestion, although some sites remain limited by cooling-water requirements or local air-quality standards. By contrast, renewable development is driven to high-quality resource areas that are often distant from load centers and more vulnerable to transmission constraints.

This geographic dynamic contributes to congestion in two distinct ways. First, the geography of renewable generation potential concentrates capacity in the same regions, directly causing congestion as large volumes of renewable generation are injected into the same areas of the network. Second, the distance between renewable generation and load creates stability issues on the network. ERCOT manages these issues through Generic Transmission Constraints (GTC), which function similarly to conventional transmission constraints by limiting the flow of power across defined interfaces within the network. ERCOT had 26 active GTCs in 2025, compared to 18 in 2021.

## 3. Captured Prices for Wind and Solar

The net effect of this congestion is lower nodal prices in regions with high renewable capacity and more frequent renewable resource curtailments. Figure 15 shows the captured energy price, which is the weighted-average energy price paid to generators for the energy they produce.

**Figure 15: Average Captured Prices for Wind and Solar**  
2021-2025

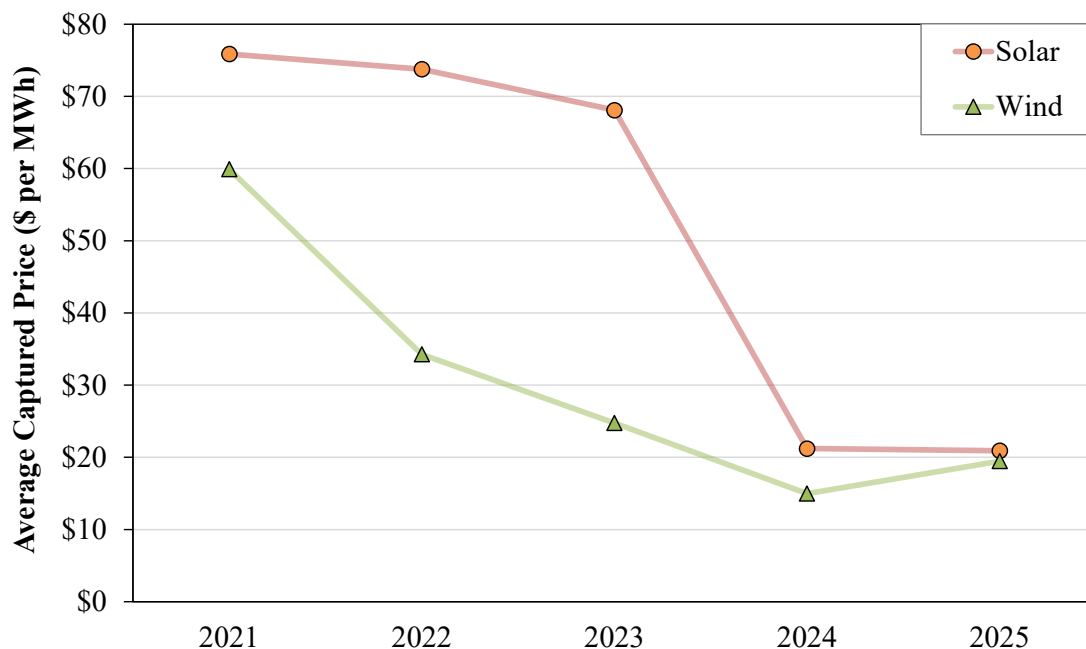


Figure 15 shows that the average captured energy price by renewable generation tends to decrease as installed renewable capacity increases. After years in which solar captured a premium relative to wind, the average captured price for solar at \$21 per MWh was nearly at parity with wind at \$19 per MWh. This trend is likely to continue as solar capacity increases and shifts peak net demand later to the evening, when wind generation tends to increase.

To mitigate congestion risks in resource-rich locations, renewable developers often expand into regions with lower renewable potential but less concentration and congestion. This strategy is particularly applicable when the capital cost of renewable generation declines over time, as it has for solar, allowing projects to meet their ROI targets despite lower annual output. As renewable capacity penetration increases, the aggregate renewable resource capacity factor can decrease if curtailments increase.

#### 4. Capacity Factors for Wind and Solar Resources

While wind has a higher overall capacity factor than solar, it is less aligned with daily peak load.<sup>8</sup> As shown in Table 2, wind resources had a 28.5% capacity factor during daily peak load intervals in 2025, compared to over 48% for solar. However, as solar output has increased, it has shifted the timing of peak net load into later in the evening when solar production declines. Consequently the solar capacity factor during the daily net peak net load interval has fallen each year since 2020, reaching just 1.7% in 2025. In contrast, wind maintained a capacity factor of 29.3% during the same interval, a slight increase from recent years.

**Table 2: Aggregate Capacity Factor of Wind and Solar Generation  
2021-2025**

Year	Wind			Solar		
	Overall	Daily Peak Load	Daily Net Peak Load	Overall	Daily Peak Load	Daily Net Peak Load
2021	33.0%	30.6%	25.6%	23.1%	41.2%	31.1%
2022	33.6%	31.3%	27.6%	23.9%	41.4%	21.4%
2023	31.7%	28.5%	26.7%	22.6%	40.4%	10.1%
2024	31.4%	29.0%	27.8%	22.2%	42.5%	3.9%
2025	31.6%	28.5%	29.3%	23.8%	48.4%	1.7%

#### E. Energy Storage Resources

Energy storage resources are technologies that consume and store energy for later use. ESRs include pumped hydro storage systems, compressed air energy storage (CAES), hydrogen and

<sup>8</sup> The capacity factor is the ratio of a resource's energy output to its maximum capability. Here, we use the term overall capacity factor to describe this ratio across all hours while the capacity factor associated with peak load and net load captures this ratio only during these respective time frames.

other power-to-gas systems, and other technologies. Because battery energy storage systems (BESSs) constitute virtually all ESRs in ERCOT, this report uses the term ESR interchangeably with batteries. This section overviews ESR fundamentals and summarizes the rapid influx of ESR capacity into ERCOT in recent years. It also discusses the evolution of ESR participation in the energy market and the associated revenue trends. A detailed discussion of ESR participation in the ancillary services markets is included in Chapter III.C.1.

## 1. ESR Fundamentals

ESRs have operating characteristics that distinguish them from traditional generation:

- **They are duration limited** – ESRs are limited by their state of charge (SOC), which is the amount of energy stored at a given time. The average duration of batteries in ERCOT at the end of 2025 was 1.83 hours, up from 1.67 hours in 2024. This limitation affects how ESRs participate in the energy and operating reserve markets.
- **They are a net load to the grid** – Although ESRs operate as both generation and load, they are a net load on the system. ESRs must consume energy to charge before they can discharge, and losses occur throughout that cycle. The National Renewable Energy Lab (NREL) cites a roundtrip efficiency of 85% in its 2024 Annual Technology Baseline.<sup>9</sup>
- **Batteries ramp quickly** – Unlike thermal generators, which require time to start up and adjust output, batteries are always online and can adjust their charging and discharging rate almost instantly. This flexibility makes them well suited to provide fast-responding ancillary services such as regulation or responsive reserves to manage fluctuations in load or renewable generation.
- **They are driven by opportunity cost** – The charging/discharging cycle and duration limits create unique economics for ESRs. ESRs must optimize these cycles to maximize their revenues. Because the market software does not optimize intertemporally and instead optimizes only one five-minute interval at a time, ESR owners must offer strategically to manage their SOC and maximize value. These strategies can introduce market inefficiencies. A Multi-Interval Real-Time Market (MIRTM) would allow SCED to optimize ESR charging and discharging over time and reduce the need for ESRs to do so themselves. We have recommended that ERCOT consider implementing a MIRTM since our 2022 State of the Market report as part of Recommendation 2022-1.

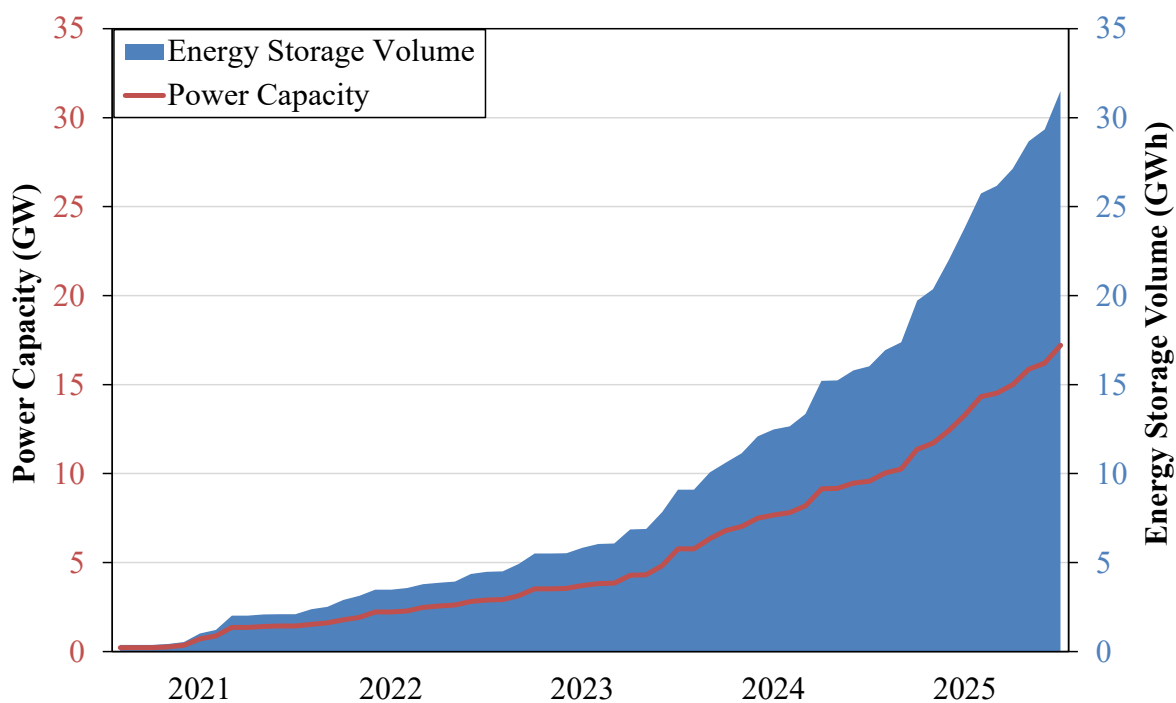
## 2. ESR Capacity Trends

The first batteries started commercial operations in ERCOT in 2012. Their installed capacity remained below 300 MW until 2021, when it increased from 300 MW to 1,600 MW in

<sup>9</sup> [https://atb.nrel.gov/electricity/2024b/utility-scale\\_battery\\_storage](https://atb.nrel.gov/electricity/2024b/utility-scale_battery_storage)

12 months. ESR capacity has grown exponentially since then, reaching more than 17,000 MW by the end of 2025, as shown in Figure 16. Figure 16 also shows that battery energy storage volume has grown faster than capacity, indicating that ESR developers increasingly favor longer-duration ESRs.

**Figure 16: ESR Installed Capacity**  
2021-2025



The preference for longer-duration ESRs stems from increasing reliance on energy-market arbitrage rather than ancillary service participation for revenue. As ESRs have flooded the AS markets, AS prices have fallen. To capitalize on revenue opportunities throughout the day, particularly during the morning and evening ramps, battery developers increasingly focus on duration rather than power capacity.

### 3. ESR Revenue Trends

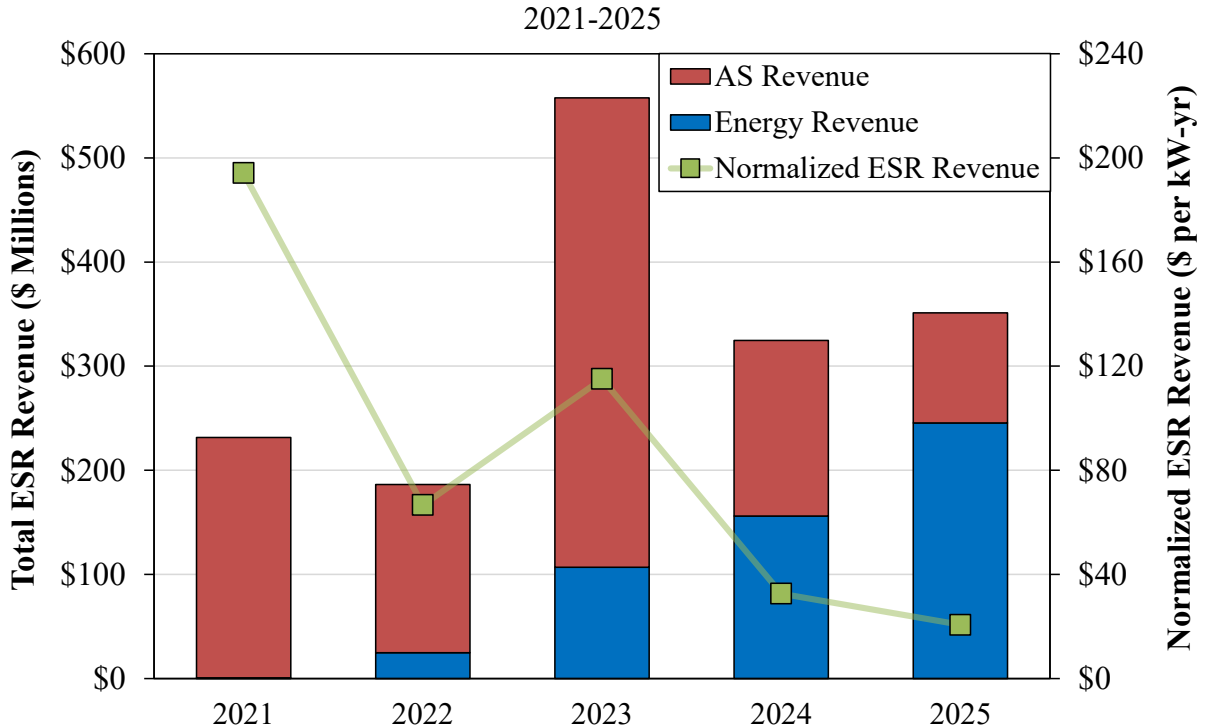
Economic fundamentals suggest that as more ESRs enter the market, revenue per unit of capacity will decline as the ancillary services market saturates and energy arbitrage price spreads tighten. The revenue trend in Figure 17 generally supports this expectation, with some exceptions. Events such as Winter Storm Uri in 2021 and the artificial scarcity caused by the implementation of ECRS in 2023 created revenue spikes that obscure year-over-year trends in revenue per kilowatt (kW) and total revenue growth.

Annual revenue per unit of ESR capacity declined significantly in 2025, falling by almost 37% from 2024 after normalization for the larger volume of ESR capacity in the market. This decline occurred even though total net ESR revenue increased by about 8%, driven mainly by the



substantial expansion of ESR capacity. Net energy revenue rose by 57% after accounting for charging costs. However, ancillary services revenue fell by more than 37% because the additional ESR capacity increased ancillary services supply and reduced prices.

**Figure 17: Total and Normalized ESR Revenue**



#### 4. ESR Participation in Energy Markets

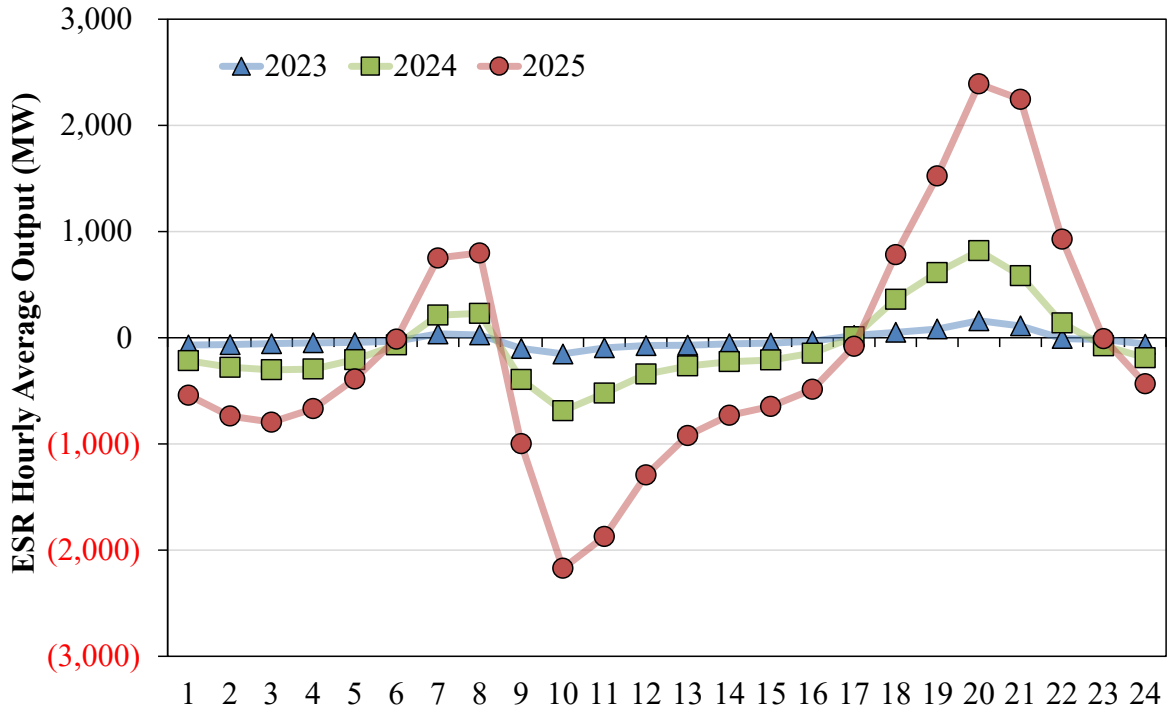
Prior to 2024, ESRs participated in the wholesale market primarily through ancillary services because they can respond quickly to fluctuations in supply and demand. As ESRs saturated the market for several AS products, they began shifting toward energy arbitrage in 2024. Energy arbitrage is the practice of buying electricity when prices are low and selling it back to the grid when prices are high. The continued rapid influx of solar generation into the ERCOT market has also facilitated ESR growth by enabling low-cost charging throughout the day. As solar generation has surged during the midday hours, real-time prices have dropped correspondingly, sometimes even to negative prices. This has allowed batteries to charge inexpensively or even get paid to consume energy that would otherwise be curtailed.

##### *ESR Net Injection of Power*

Figure 18 shows the growth in hourly net energy injections from ESRs from 2023 through 2025. A positive injection value indicates aggregate discharging to the grid, and a negative value indicates aggregate charging. The figure shows a dramatic year-by-year increase in ESR charging and discharging since 2023. The maximum average hourly discharge across all ESRs in ERCOT increased by 191% to 2,390 MW in 2025, and the maximum average hourly charging

rate increased by 215% to 2,171 MW. Together, those increases amount to roughly triple the volume of energy arbitrage in 2025 compared to 2024.

**Figure 18: Net Injection of Power from ESRs**  
2023-2025



### *ESR Aggregate Offers*

To further examine how ESR participation in the real-time energy market has evolved, we consider the aggregate bid and offer curves that ESRs submitted from 2021-2025, which are summarized in Figure 19. This figure shows the following trends:

- The volume of energy offers that ESRs submitted continued to grow exponentially, more than doubling or tripling each year since 2021. It increased from roughly 3,000 MW in 2024 to 6,700 MW in 2025.
- The share of ESR offers priced at normal market clearing price ranges continued to increase. In 2025, 55% of energy offers were priced between \$0-100 per MWh, compared to 46% in 2024 and 25% in 2023. As more ESRs enter the market, they must offer more competitively to maximize revenue from energy sales.
- ESRs still submit a substantial percentage of offers priced at the System-Wide Offer Cap (SWCAP), 18% in 2025 compared to 32% in 2024. This tendency can be partially attributed to SOC management. ESRs must maintain sufficient SOC to satisfy their AS obligations, even if they use some capacity for energy arbitrage.

**Figure 19: Average Aggregate Offers for ESRs to Buy or Sell Energy**  
2021-2025

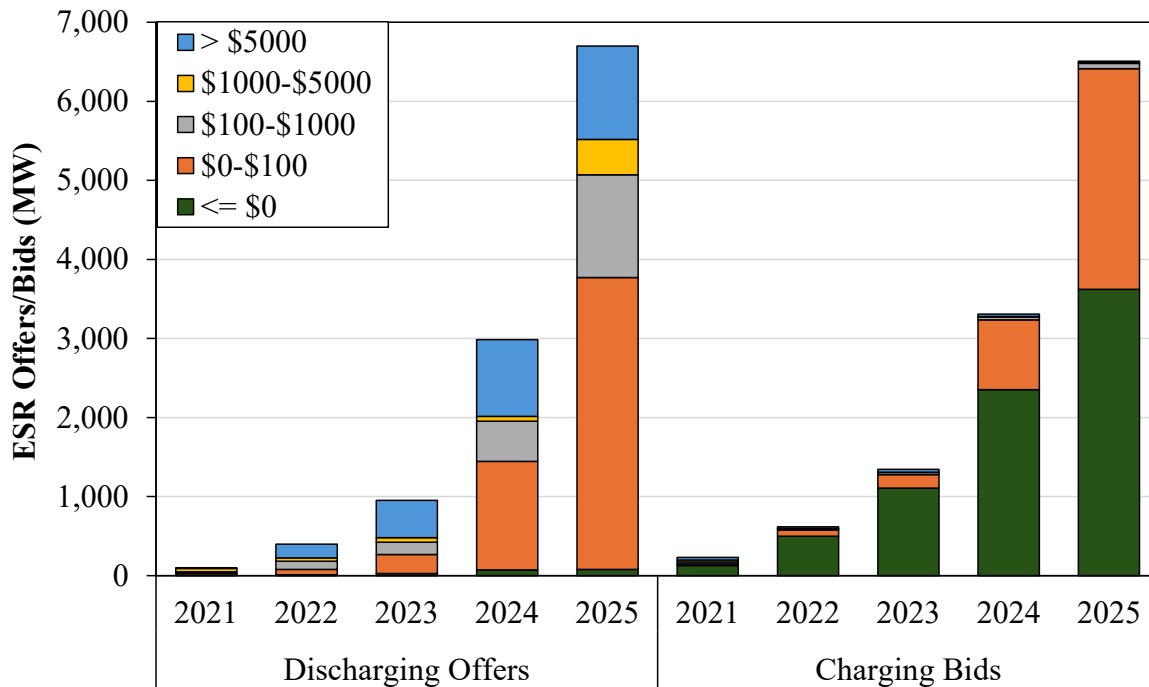


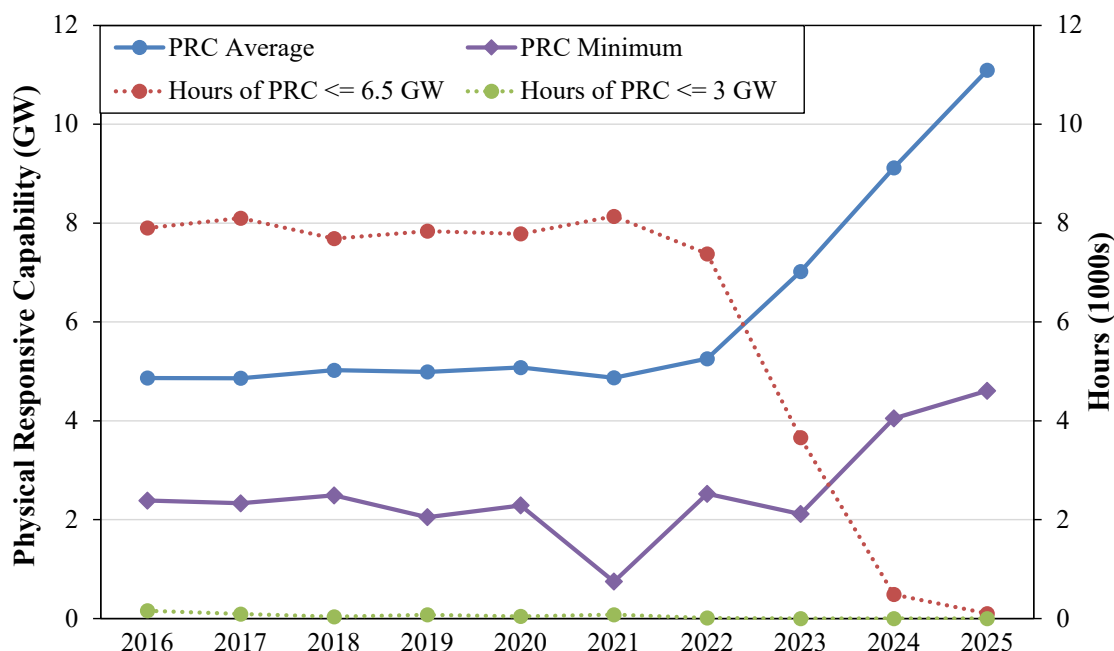
Figure 19 also shows the aggregated bid curves for ESRs to purchase energy for charging. Historically, ESRs could charge for free (i.e. at bids priced at \$0 or less) during most charging periods, but this trend is changing rapidly. The share of bids priced at or below \$0 fell from 82% in 2023 to 71% in 2024 and 56% in 2025. ESR capacity offering to buy energy far exceeds the capacity offering to sell. This likely reflects that ancillary services, such as up-reserves, commit much of the ESR discharging capacity and make it unavailable to SCED.

## F. Operating Reserve Margin

In evaluating the current supply and demand conditions, one key factor is the average level of surplus capacity in the real-time market that can be measured by the operating reserve margin or PRC. Since 2022, increases in solar and ESR capacity have raised the average operating reserve margin by approximately 1,945 MW per year, as shown in Figure 20. This figure also shows the minimum PRC in each year and the length of time in hours per year when PRC fell below either 6,500 MW or 3,000 MW.

Prior to 2022, the annual average PRC was less than 5,000 MW, and PRC remained below 6,500 MW for most of the year. In 2025, PRC was below 6,500 MW for only 102 hours. The frequency of PRC below 3,000 MW also dropped sharply. It averaged 82 hours from 2016 through 2021, but no such hours have been observed since 2023. The last time PRC dropped below 3,000 MW was in 2023 for 1.22 hours in total.

**Figure 20: Annual PRC Statistics**  
2016-2025



Higher operating reserve margins and fewer shortage conditions, as measured by PRC, primarily explain the decrease in shortage pricing described in Chapter I. This level of operating reserves and its effect on shortage pricing indicate that the market has a significant surplus of capacity. The data on operating reserves and shortage pricing directly contradict the prevailing narrative about grid reliability.

### 1. Increased Reliability Risks due to Renewables and Batteries

In recent years, the immense growth in renewable and energy storage capacity has sparked concerns about the intermittent and duration-limited nature of these resources. Despite the average PRC increasing by 128% from 4.9 GW in 2021 to over 11 GW in 2025, forecast errors associated with load, renewables, and battery SOC could produce hours in which the PRC is very low, resulting in a load-shed scenario. In response, ERCOT increased its procurements of operating reserves – beyond the level at which any there is any potential risk of load shedding. We have termed this posture “conservative operations” in recent filings.<sup>10</sup>

While forecast errors and uncertainty associated with intermittent renewable generation should be factored into operating reserves requirements, it should be done so reasonably. In our commentary on the AS Methodology for 2026, discussed in greater detail in Chapter III.E, our stochastic risk methodology accounts for forecast error for renewable generation and produces annual probabilities of a load-shed scenario. Duration-limited resources pose reliability risks

<sup>10</sup> August 2025 TAC Discussion: <https://www.ercot.com/files/docs/2025/08/25/15.-AS-Methodology-v3.zip>

related to energy rather than capacity shortfalls but if these risks were substantial under prevailing conditions, they would manifest through shortage conditions. Instead, the frequency of shortage conditions has dropped precipitously in recent years.

## 2. Accounting for Reliability Actions and Conservative Operations

Some might argue that elevated PRC may result from ERCOT's reliability actions, including the Reliability Unit Commitments (RUC) that increase real-time supplies and Emergency Reserve Service (ERS) resources. However, even after accounting for the effects of RUC and ERS, shortage conditions have declined substantially since 2022.

In 2025, removing the aggregate HSL of RUC-committed resources would have increased the frequency of PRC below 3,000 MW to only 1.2 hours in 2025, which remains well below the average frequency observed from 2016 to 2021. In addition, ERCOT has not deployed ERS system wide since September 6, 2023, which was the result of transmission-related contingencies rather than insufficient capacity. In short, the level of operating reserves and the infrequency of shortage conditions indicate that the system had surplus capacity in 2025.

## 3. Potential Impacts of Load Growth

Finally, it is important to consider how sharply increasing demand erode the excessive operating reserve margins experienced in 2025. ERCOT's load interconnection queue has grown to more than 410 GW of additional load by 2030, of which 87.6% is data centers.<sup>11</sup> We understand that even a small fraction of this load growth coming online could quickly eliminate the current supply surplus. However, our analysis of operating reserves in ERCOT indicates that the system can serve several GW of additional demand from large loads while maintaining operating reserves and a frequency of shortage conditions comparable to those prevalent before 2022.

To make this determination, we estimated the frequency of shortages that would have occurred in 2025 by reducing PRC on a one-to-one basis with new load additions. This is a very conservative assessment because higher load would likely prompt additional commitments that would mitigate the PRC reduction. Nonetheless, we found that ERCOT could accommodate more than 3 GW of new load without the frequency of shortages exceeding the 2016 to 2022 annual average. It also would not introduce any hours in which load shed would have occurred. These results confirm that the rapid entry of solar and ESRs have resulted in generation supplies in ERCOT that are more than adequate currently and in the near term.

## G. Demand Response

Demand response refers to actions that can be taken by consumers to reduce their load in response to instructions from ERCOT or economic incentives. Examples of demand response in

<sup>11</sup> [https://www.ercot.com/files/docs/2026/03/27/March-TAC-Report-Updated\\_03262026.pptx](https://www.ercot.com/files/docs/2026/03/27/March-TAC-Report-Updated_03262026.pptx)

ERCOT include price-responsive dispatch through SCED, self-curtailment based on economic incentives, and reliability programs administered by ERCOT and transmission and distribution service providers (TDSPs). We cover the participation of load resources in the ancillary services markets in detail in Chapter III.C.

### 1. Controllable Load Resources

The participation model of controllable load resources (CLRs) in SCED was implemented in 2014. It allows loads that can respond to 5-minute dispatch instructions to submit bids to buy electricity at specified price-quantity pairs. ERCOT can then dispatch them down when the clearing price exceeds those bids. A few years ago, a substantial volume of load, predominantly cryptocurrency mines, began participating in the market as CLRs. In 2025, all 12 registered CLRs are cryptocurrency mines.<sup>12</sup> The monthly average volume of demand from CLRs for 2023-2025 is shown in Figure 21 below.

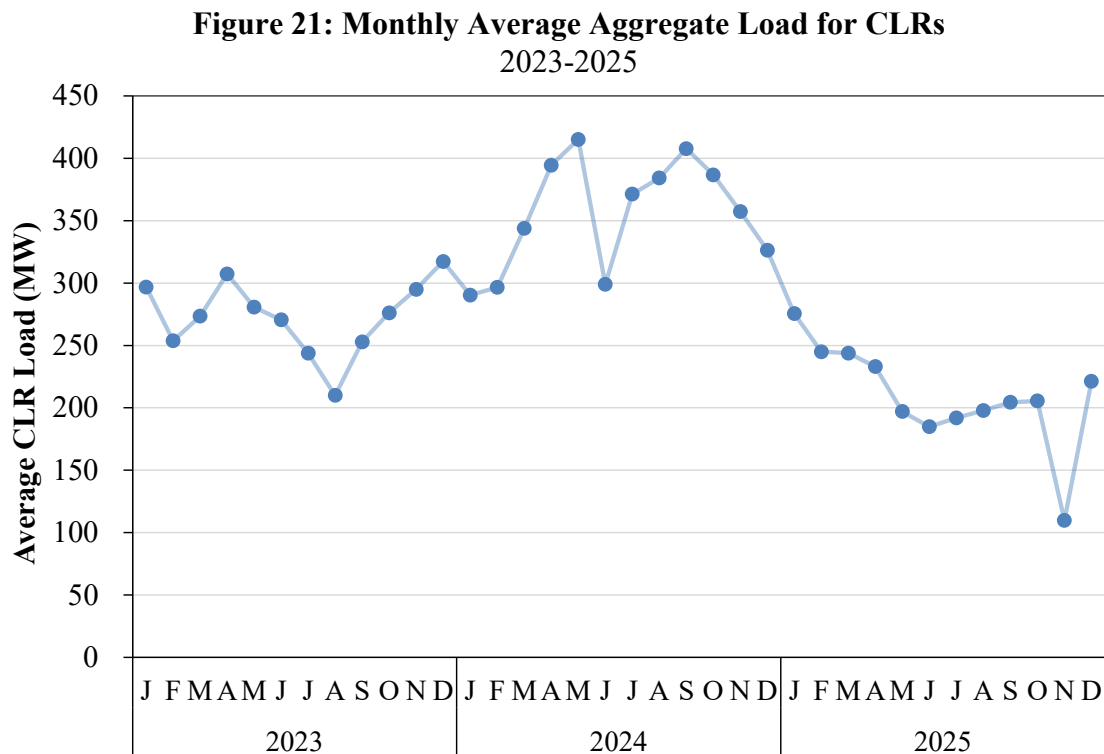


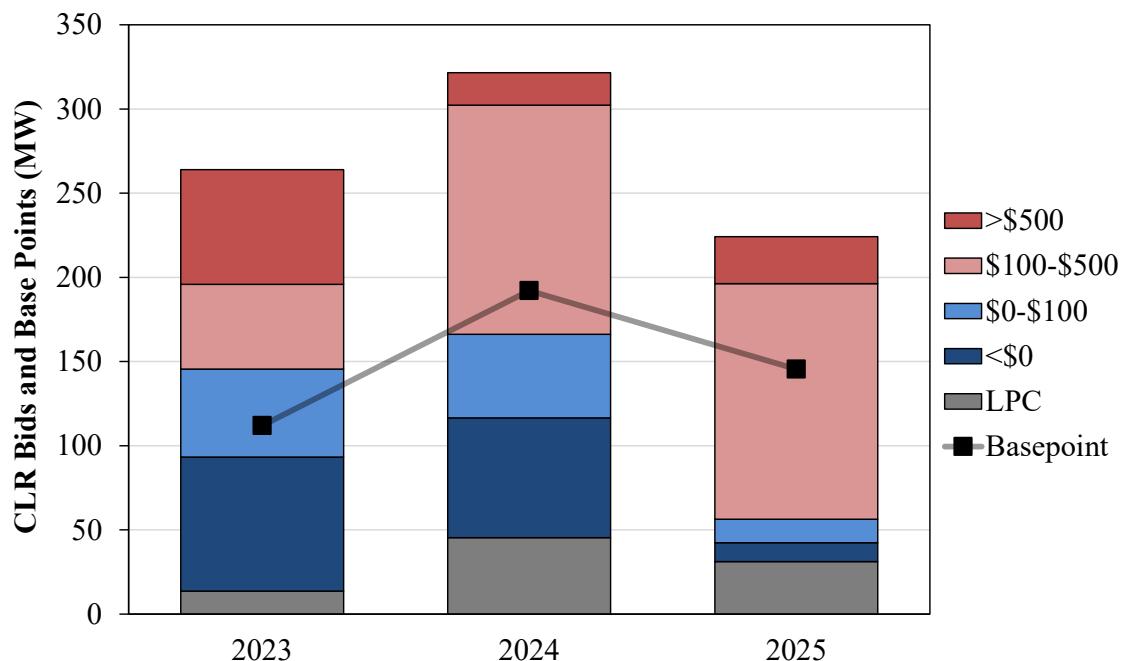
Figure 21 shows that, after years of increasing CLR participation in SCED, 2025 marked a substantial decrease in average CLR load. This decrease is even more noteworthy because the maximum load from cryptocurrency operations increased by more than 900 MW from 2024 to 2025. The primary explanation is that many cryptocurrency mining facilities deregistered as CLRs. As a result, although they remain responsive to electricity prices, they no longer operate

<sup>12</sup> ERCOT Annual Report on Demand Response:  
<https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=1188179018>

as CLRs dispatched through SCED. Instead, many of these loads choose to participate in demand response outside of SCED through ERCOT's ERS program, discussed later in this section. Despite this reduction in CLR activity, CLRs still averaged more than 240 MW of demand in 2025.

Cryptocurrency mines are particularly sensitive to electricity prices, which comprise most of the marginal costs of mining cryptocurrency. Figure 22 shows annual average bid prices and the sum of corresponding base points for CLRs in ERCOT from 2023-2025. Note that LPC refers to the aggregate low power consumption level of CLRs, or the minimum level to which SCED can dispatch them.

**Figure 22: Average Aggregate Bid Curves and Base Points for CLRs**  
2023-2025



Year-to-year variation in CLR bid prices reflects the changing economic value of their output, including fluctuations in cryptocurrency prices and the associated break-even cost of electricity consumption. For example, despite a 41% decrease in average load from CLRs, the volume of CLR bids priced above \$100/MWh increased by over 19%. Note that the volume of base points shown in Figure 22 is significantly lower than the average load values shown in Figure 21. That's because, prior to the go-live of RTC, CLRs commonly operated outside of SCED and without a bid curve under certain conditions, such as when they carried AS on all or most of their online capacity.

The decrease in CLR activity is inconsistent with recent policy changes that have increased incentives for loads to register as CLRs. Two notable developments are the resolution of a patent dispute over exclusive rights to operate CLRs and the implementation of RTC. The patent

dispute was resolved in April 2025, allowing cryptocurrency facilities to license the relevant patents at no cost and register and operate as CLRs.

RTC allows CLRs to sell ancillary services in real-time with less risk of exposure to excessively high energy prices. Before RTC, if a CLR received an AS award in the day-ahead market, it had to run in real-time according to the volume of the award. With RTC, CLRs can sell out of their day-ahead positions or forego the day-ahead market entirely and only sell AS in real-time when energy prices are favorable.

Another major improvement is NPRR 1188, which the PUCT approved in November 2024 and<sup>13</sup> which will introduce nodal pricing for CLRs.<sup>14</sup> Currently, CLRs are dispatched and settled using zonal prices. This creates an economic challenge for CLRs at nodes with structurally low energy costs, such as those in the Panhandle near large volumes of renewable generation, where the zonal price is often higher than the cost of serving their load.

A related rule change also approved in November 2024,<sup>15</sup> NPRR 1244, will allow loads to register as CLRs even if they cannot provide primary frequency response (PFR). This change expands participation to wholesale consumers that SCED can dispatch, improving reliability and real-time price formation even if those loads cannot provide the full suite of ancillary services. Taken together, these market design improvements substantially increase the amount of load that can operate as CLRs and reduce the risks inherent in operating as a CLR. We recommend that ERCOT continue to incentivize loads to register as CLRs rather than participate in out of market programs like ERS or engage in self-curtailment outside of SCED.

## 2. Self-curtailment

In addition to participating in demand response programs in which ERCOT directly instructs them to reduce consumption, loads also engage in self-curtailment outside the formal wholesale market process. Self-curtailment takes two primary forms. The first is price response, in which a load voluntarily reduces consumption to avoid high prices without receiving a dispatch instruction from SCED. The second is 4CP response, in which a load reduces consumption during system peaks to lower its share of transmission cost allocation.

Steel mills and cryptocurrency mines are examples of price responsive load in ERCOT, but we have limited visibility into price response outside of SCED. For example, how much cryptocurrency demand is economical at different electricity prices? What we do know is that

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<sup>13</sup> NPRR 1188: <https://www.ercot.com/mktrules/issues/NPRR1188>

<sup>14</sup> Although NPRR 1188 was approved in November 2024, its implementation is not complete yet. According to ERCOT project management, NPRR 1188 will be implemented in January 2027: [https://www.ercot.com/files/docs/2022/01/27/Revision\\_Requests\\_2026\\_04\\_14.xlsx](https://www.ercot.com/files/docs/2022/01/27/Revision_Requests_2026_04_14.xlsx)

<sup>15</sup> NPRR 1244 is slated for implementation at the same time as NPRR 1188 in January 2027: <https://www.ercot.com/mktrules/issues/NPRR1244>



cryptocurrency mines accounted for a substantial aggregate load, with peak demand reaching 4,600 MW in 2025. This creates challenges for grid operations and market design.

For price-based curtailment outside of SCED, economic dispatch does not capture sudden drops in load. As this type of curtailment has grown, ERCOT has needed additional reserves to maintain the real-time balance between supply and demand. To address this issue, ERCOT should encourage more flexible loads to register as CLRs so that their load can be curtailed directly through SCED.

We have noted that voluntary load reduction should be factored into operating practices, and especially in the RUC process on days with tight system conditions. Recognizing voluntary load reduction can significantly reduce the capacity that is committed via RUC and preserve real-time price formation. We recognize the tension that may exist within ERCOT to operate around an expected reduction from firm load. A potential resolution is to factor in a minimum level of voluntary load reduction based on the past several years. An approach like this will not put ERCOT in a position where operational practices did not respect the firm attribute of the load served.

### 3. 4CP Response

Historically, 4CP response has been the most consequential form of self-curtailment, while large-scale price responsiveness outside SCED is a relatively recent development. The 4CP mechanism allocates transmission costs to load serving entities based on their load ratio share during the highest 15-minute system load intervals in each of the four months from June through September. By reducing demand during these intervals, entities can lower their share of transmission charges, which have ranged from \$8 to \$9 per MWh in inflation-adjusted terms since 2021.<sup>16</sup> ERCOT estimates that load fell by about 1,500 MW during the 4CP interval for August 2025.<sup>17</sup>

4CP response is associated with several adverse market outcomes. Load reductions during peak intervals can suppress prices and reduce generator revenues, particularly when those intervals no longer correspond to system scarcity. As a result, 4CP response can weaken scarcity pricing and erode the revenue signals needed to support long-term resource adequacy. Stakeholders and the PUCT are currently reviewing the 4CP mechanism and the broader transmission cost recovery mechanism. We discuss this in greater detail in Chapter V.F.3.

<sup>16</sup> ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2025, <https://www.ercot.com/files/docs/2025/12/23/2025-Report-on-Existing-and-Potential-Electric-System-Constraints-and-Needs.pdf>

<sup>17</sup> See ERCOT, Summer 2025 Operational and Market Review <https://www.ercot.com/files/docs/2025/09/15/12-Summer-2025-Operational-and-Market-Review.pdf>

#### **4. Emergency Reserve Service**

The ERS program was established by 16 TAC §25.507 and has a \$75 million budget.<sup>18</sup> Industrial and commercial electricity consumers submit offers to provide ERS through a centralized auction, and ERCOT deploys ERS during Energy Emergency Alerts (EEAs) or when Physical Responsive Capability (PRC) falls below 3,000 MW. Since its inception, ERS has been deployed for nine events, most recently in September 2023. For the 2025 program year (December 2024 through November 2025), ERCOT procured an average of 1,666 MW per hour, a 45% increase from 2024, at an average clearing price of \$4.36 per MWh, a 41% decrease from the prior year.

The increase in ERS procurement volume and the decrease in the ERS clearing price likely reflect the influx of cryptocurrency mining facilities into the program. ERCOT started reporting the composition of ERS providers by load type only in summer 2025, when cryptocurrency mining already accounted for almost 56% of total ERS volume.<sup>19</sup> That proportion increased through the fall and into spring 2026 and now exceeds 64% of total ERS volume.

The growing participation of cryptocurrency mines in the ERS program is problematic for two reasons. First, cryptocurrency mines that were previously registered as CLRs have migrated to the ERS program and are no longer price-responsive in SCED. Second, because cryptocurrency mines are fundamentally price sensitive, allowing them to provide ERS essentially pays them to do what they would already do, i.e., curtail when system conditions are tight and energy prices are high. We recommend that ERCOT change ERS eligibility or performance criteria to shift cryptocurrency mines out of the program and incentivize them to register as CLRs. This change would improve the reliability and market efficiency benefits of price-responsive loads.

#### **5. Residential Demand Response**

Over the last year, ERCOT has promoted a residential demand response (RDR) program. Given the concerns about load growth discussed in Section F of this chapter, exploring residential demand response is understandable. However, this concept presents significant challenges and adverse market impacts.

##### ***Price-Sensitivity of Residential Consumers***

A residential consumer is unlikely to participate in a program that curtails their load if prices reach \$100 per MWh or \$200 per MWh because that is much lower than most customers' value of consumption. Recognizing this lack of incentive, ERCOT proposed a subsidy through NPRR 1296 to make up the shortfall.<sup>20</sup>

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<sup>18</sup> 25.507: <https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.507/25.507.pdf>

<sup>19</sup> <https://www.ercot.com/files/docs/2026/01/05/05.-ERS-Crypto-Mining-Load-Presentation.pptx>

<sup>20</sup> NPRR 1296: <https://www.ercot.com/mktrules/issues/NPRR1296>

A subsidy to make up the shortfall between residential consumers' price sensitivity and the wholesale market would have to be enormous. The Brattle Group, which ERCOT engaged to analyze the benefits and impacts of the RDR program, notes that the "maximum incentive payment that can be offered by REPs to participants is the monetizable DR value minus both DR implementation costs and the share of the value retained by the REP for facilitating the DR opportunity." Annually, retail electric providers (REPs) can pass through \$30 to \$50 to residents, or roughly \$4 per month.<sup>21</sup> We are pessimistic that this amount is sufficient to incentivize demand response, especially because residents would be curtailed for an estimated 50 to 80 hours, as discussed in the next subsection.

### *Residential Consumer Exposure to Real-Time Prices*

The PUCT phased out exposing residential consumers to real-time wholesale prices following Winter Storm Uri in 2021, as part of 16 TAC §25.475(c)(3)(F)(ii).<sup>22</sup> Accordingly, demand response actions and compensation for those actions must be decoupled. NPPR 1296 proposes to compensate participating REPs based on the number of top load reduction hours within the highest net load hours outlined in Table 3.

**Table 3: RDR Assessment Hours Under NPPR 1296**

	<b>Top Load Reduction</b>	<b>Top Net Load Reduction</b>	<b>Capacity Cap</b>
<b>Season</b>	<b>Hours</b>	<b>Hours</b>	<b>MWh</b>
Summer	6	8	3,000
Fall	3	5	1,500
Winter	6	8	3,000
Spring	3	5	1,500
<b>Total</b>	<b>18</b>	<b>26</b>	<b>9,000</b>

Since the highest net load hours in a season are not known in advance, the REP would have to curtail the residential consumer for many hours to maximize compensation during the 5 or 8 highest net load hours of the season. The Brattle Group estimates that a REP would need to curtail residential consumers for ten times the number of highest net load hours, or 50 to 80 hours per season, to capture all of them.

### *Market Impact*

From a market design perspective, providing compensation outside of the market to motivate consumers to reduce demand undermines ERCOT's energy-only market. Because these demand

<sup>21</sup> Brattle Report on Residential Demand Response in ERCOT:

<https://www.ercot.com/files/docs/2026/01/16/1296NPPR-14b-Joint-Sponsors-Comments-011626.pdf>

<sup>22</sup> §25.475: <https://ftp.puc.texas.gov/public/puct-info/agency/ruleslaws/subrules/electric/25.475/25.475.pdf>

reductions are not consistent with the prevailing energy prices, that will artificially suppress energy prices and reduce the economic signals that participants rely on to invest in new resources and retain existing resources.

The Brattle Group estimates that, on a load-weighted basis, the proposed RDR program would suppress \$1.5 billion in generator revenue. The latest proposal to address price formation concerns would attempt to counteract some or all of this revenue impact through the reliability deployment price adder (RDPA). It would trigger when net load exceeds a pre-defined threshold.<sup>23</sup> This application of the RDPA seems implausible because ERCOT does not know in real-time when REPs deploy demand response or how much they deploy. Stakeholders continue to discuss solutions to these challenges but it would be far better to simply not pursue a residential demand response programs to avoid these adverse market impacts.

### 6. Aggregate Distributed Energy Resources

Aggregate Distributed Energy Resources, or ADERs, are a pilot participation model that allows aggregations of small, distribution-connected resources participate in the ERCOT wholesale market. Each resource is limited to 1 MW or less, but when combined under a QSE, the aggregation can receive dispatch instructions and provide market services. In Phase 3, ADERs may participate as Aggregate Load Resources or NCLRs and ERCOT dispatches and settles them at the load zone level. The pilot is meant to test reliability impacts, market integration, and congestion effects before ERCOT considers any permanent protocol changes.<sup>24</sup>

In practice, home battery systems have driven all ADER participation. Batteries are easy to integrate because they can charge and discharge, respond quickly to dispatch instructions, and meet ERCOT's telemetry and validation requirements. Although Phase 3 allows other technologies such as rooftop solar and controllable load, ADERs must always appear as a net load in telemetry and settlements, which often requires static MW offsets. As a result, batteries are far more viable than smart thermostats, which currently face limitations related to telemetry, dispatch precision, and SCED integration.

Participation limits for the ADER pilot increased several times as the program progressed. Phase 3, introduced in June 2025, increased the energy cap to 160 MW and the NSRS and ECRS caps to 80 MW each.<sup>25</sup> In October 2025, ERCOT increased these caps again to 200 MW for energy

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<sup>23</sup> Board Presentation April 2026 & Charles River Associates Report: <https://www.ercot.com/files/docs/2026/04/13/11.1-Strategic-Discussion-on-Resource-Adequacy-and-the-Role-of-Demand-Response.pdf>

<sup>24</sup> ADER Phase 3.2 Governing Document: [https://www.ercot.com/files/docs/2026/03/02/ERCOT\\_Aggregate-Distributed-Energy-Resource-Pilot-Project-Phase-3.2-Governing-Document-.docx](https://www.ercot.com/files/docs/2026/03/02/ERCOT_Aggregate-Distributed-Energy-Resource-Pilot-Project-Phase-3.2-Governing-Document-.docx)

<sup>25</sup> Phase 3 Updates in June 2025: [https://interchange.puc.texas.gov/Documents/53911\\_126\\_1511268.PDF](https://interchange.puc.texas.gov/Documents/53911_126_1511268.PDF)

and 100 MW for NSRS and ECRS.<sup>26</sup> In March 2026, ERCOT increased the energy cap again to 500 MW, while the ECRS and NSRS caps remained at 100 MW.<sup>27</sup>

The main policy challenges for ADERs are scaling the program without creating dispatch inefficiencies or reliability risks. Continued reliance on zonal dispatch and pricing can distort congestion signals as participation grows. An open question is whether ADERs should continue to be modeled as load resources or transition to being modeled as ESRs with explicit SOC management. In addition, ERCOT and stakeholders must resolve telemetry standards and dispatch frameworks before demand-side technologies such as smart thermostats can participate at scale.

A residential consumer that registers a home battery in the proposed RDR program cannot also participate in an ADER. Because the ADER program is integrated into market dispatch, we do not oppose the ADER program but reiterate our opposition to the RDR program because it operates outside of the market.

## 7. Large Load Demand Management Service

The Large Load Demand Management Service (LLDMS) introduced by the 89<sup>th</sup> Texas Legislature in Section 4 of SB 6, may become the largest form of demand response in ERCOT.<sup>28</sup> The LLDMS is intended to procure demand reductions competitively from large loads (75 MW or greater) during an extreme event that may threaten the reliability of the ERCOT grid. The new service disqualifies price-responsive loads from participating.

The LLDMS could be an important tool for ERCOT to procure significant demand reductions during high-risk conditions that materially threaten grid reliability. Accordingly, we have recommended using the LLDMS as a targeted reliability tool whose procurement quantity and budget can be tailored to the severity of an extreme event. We have also recommended formulating a risk methodology that produces hourly probabilities of load shed to determine whether a given event warrants deployment of the LLDMS. We filed more comprehensive comments in PUCT Project 58482, which contains the rulemaking record.<sup>29</sup>

## 8. TDSP Load Management Programs

TDSP Load Management programs procure demand response capacity from end-use customers for the summer and winter peak seasons. Although TDSPs generally manage the testing and deployment of their enrolled load resources, ERCOT may also dispatch those resources during an EEA Level 2 event. In 2025, approximately 127 MW of load participated in the winter

<sup>26</sup> ADER Market Notice November 2025: [https://www.ercot.com/services/comm/mkt\\_notices/M-A102425-01](https://www.ercot.com/services/comm/mkt_notices/M-A102425-01)

<sup>27</sup> ADER Market Notice March 2026: [https://www.ercot.com/services/comm/mkt\\_notices/M-A030226-01](https://www.ercot.com/services/comm/mkt_notices/M-A030226-01)

<sup>28</sup> SB 6: <https://capitol.texas.gov/tlodocs/89R/billtext/html/SB00006F.htm>

<sup>29</sup> IMM Commentary on P-58482: [https://interchange.puc.texas.gov/Documents/58482\\_5\\_1617200.PDF](https://interchange.puc.texas.gov/Documents/58482_5_1617200.PDF)

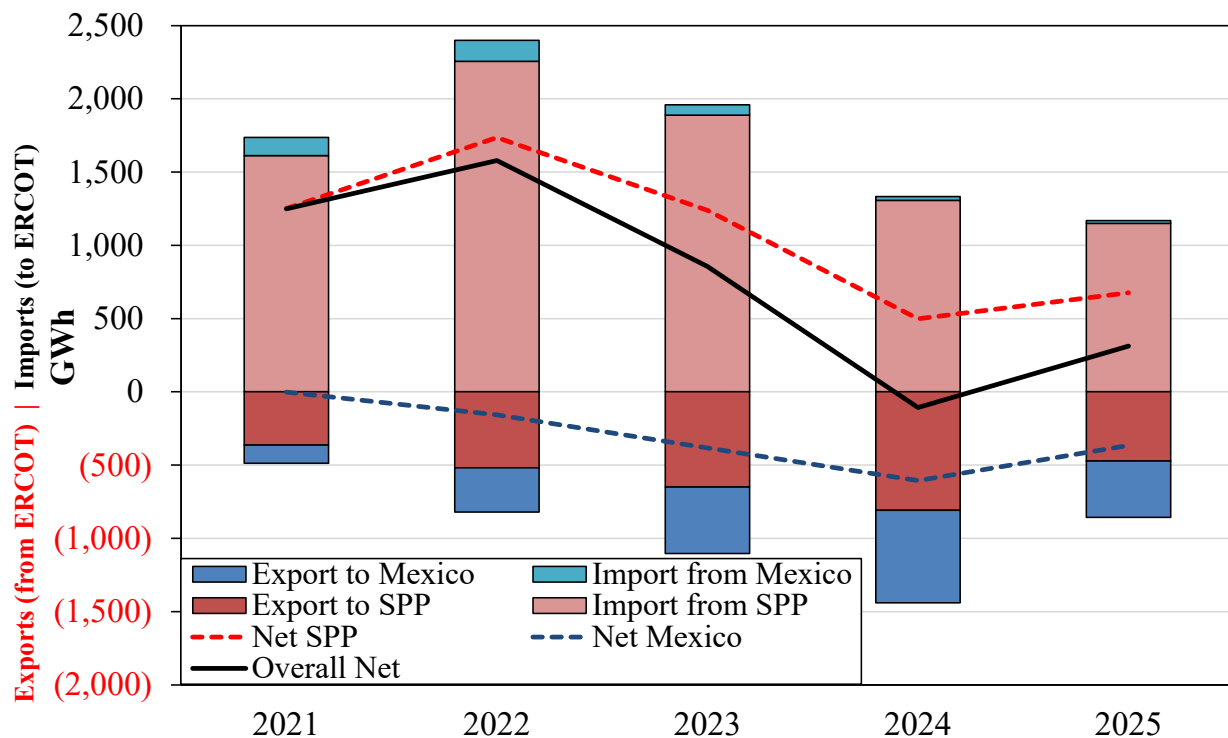
program and 289 MW participated in the summer program. This reflected a year-over-year increase of 12% in the winter program, while summer program procurement totals across all participating TDSPs remained unchanged.

## H. Imports and Exports Via DC Ties

The ERCOT region is connected to neighboring systems through several direct current (DC) ties. Two ties with the Southwest Power Pool (SPP) provide 820 MW of transfer capability, and two ties with Mexico's Comisión Federal de Electricidad provide 400 MW. Power can flow in either direction across these ties; exports increase demand and imports increase supply in ERCOT.

Figure 23 shows the total energy transacted across the DC ties annually since 2021.

**Figure 23: Annual Energy Transacted Across DC Ties**  
2021-2025



In 2025, ERCOT reverted to a net importer of energy through its DC ties with neighboring regions. ERCOT remained a net exporter to Mexico and a net importer from SPP. These volumes are shown on an energy basis. For context, the average net power flowing into ERCOT was very small relative to system-wide demand, approximately 36 MW for all of 2025.

### III. ANCILLARY SERVICES

#### A. Summary of Ancillary Services Results in 2025

Ancillary services (AS) are reliability products that maintain system balance and frequency by ensuring sufficient reserves are available to respond to contingencies and uncertainty. With Real-Time Co-Optimization (RTC), the market can now procure ancillary services can now be procured in real-time in addition to the day-ahead market (DAM), with DAM awards serving primarily as a financial obligation rather than a physical commitment. As a result, ancillary service price formation and procurement outcomes increasingly reflect real-time system conditions. Ancillary services also play a central role in market design by shaping operational incentives for resources and directly influencing system reliability and scarcity outcomes. The following are the key insights about ancillary services in 2025:

- **The procurement volume of the AS Plan stayed roughly the same between 2024 and 2025, but its composition shifted somewhat.** ECRS procurement volume decreased by 19%, Reg-Up and Reg-Down procurement volumes increased by 7.4% and 3.3%, respectively, and NSRS procurement volume increased by 7.5% from 2024. RRS procurement volume did not materially change.
- **May had the highest average AS procurement targets and the highest AS prices.** NSRS prices were particularly high and were influenced by operator actions.
- **Energy storage resources continued to dominate most AS markets and increased their market share across all AS products.** On average, ESRs provided 94% of Reg-Up, 86% of Reg-Down, 51% of RRS, 42% of ECRS, and 24% of NSRS.
- **At the end of 2025, 505 NCLRs were registered in ERCOT with a combined capacity of 10,550 MW.** On average throughout the year, they provided 1,480 MW of RRS, 190 MW of ECRS, and 18 MW of NSRS.
- **The average load from CLRs in 2025 was only 240 MW, and they provided 9 MW of RRS, 11 MW of ECRS, and 58 MW of NSRS.** CLRs shifted to NSRS in 2025 because NSRS was the highest-priced AS product throughout the year.
- **At the end of this chapter, we recommend an AS Methodology that uses assessment criteria rooted in real reliability risks rather than arbitrary benchmarks.** Using excessively conservative parameters in its AS Methodology, the volume of reserves set by ERCOT's AS Plan is 140% larger than a 1-in-10 reliability standard for load shed would require. These raises serious concerns in ERCOT's energy only market because it raises costs and inefficiently reduces the frequency of shortage pricing that is necessary to support investment in new dispatchable generating resources.



## B. Ancillary Services Market

Ancillary Services are operating reserves that ERCOT procures to address risks associated with contingencies, variations in supply and demand, and forecast errors for load and renewable generation. Before ERCOT implemented RTC in December 2025, ancillary services were only sold in the day-ahead market, where they represented a physical obligation to provide reserves in real time. Since ERCOT implemented RTC, it has also procured ancillary services in real-time, and day-ahead AS awards have represented a financial rather than physical obligation.

Consumers pay the cost of AS procured through the market. Specifically, ERCOT allocates procurement costs to Load Serving Entities (LSEs) based on their real-time adjusted metered load. Market participants representing qualified resources may self-schedule ancillary services using those resources to reduce their exposure to ancillary service procurement costs. Since June 2023, ancillary services in the ERCOT market include the following:

- **Regulation Up/Down Service (Reg-Up, Reg-Down).** Regulation reserves include capacity that responds to Load Frequency Control (LFC), which sends instructions every four seconds to increase or decrease generation or demand as needed to balance generation and load from moment to moment and maintain system frequency.
- **Responsive Reserve Service (RRS).** Responsive reserves can respond within 10 minutes and are needed to restore system frequency during rapidly developing contingencies such as unplanned generator outages, rather than to meet normal load fluctuations. ERCOT procures three types of responsive reserves: (1) primary frequency response (PFR), which all generators must be able to provide and which responds automatically to deviations in system frequency; (2) Under Frequency Relay (UFR), which deploys by tripping NCLRs after a sufficient drop in frequency; and (3) Fast Frequency Response (FFR), which is overwhelmingly provided by energy storage resources (ESRs) that can respond to deviations in frequency within 30 cycles.
- **ERCOT Contingency Reserve Service (ECRS).** ECRS is the latest addition to ERCOT's suite of ancillary services. Its purpose is to restore frequency within 10 minutes of a significant frequency deviation and recover deployed regulation service. It also compensates for intra-hour net load forecast uncertainty. ECRS can be provided by online and offline units.
- **Non-Spin Reserve Service (NSRS).** NSRS resources can respond within 30 minutes and are needed to compensate for intra-hour net load forecast uncertainty that results in under-commitments of capacity or inefficient dispatch instructions. Online and offline units can provide NSRS.

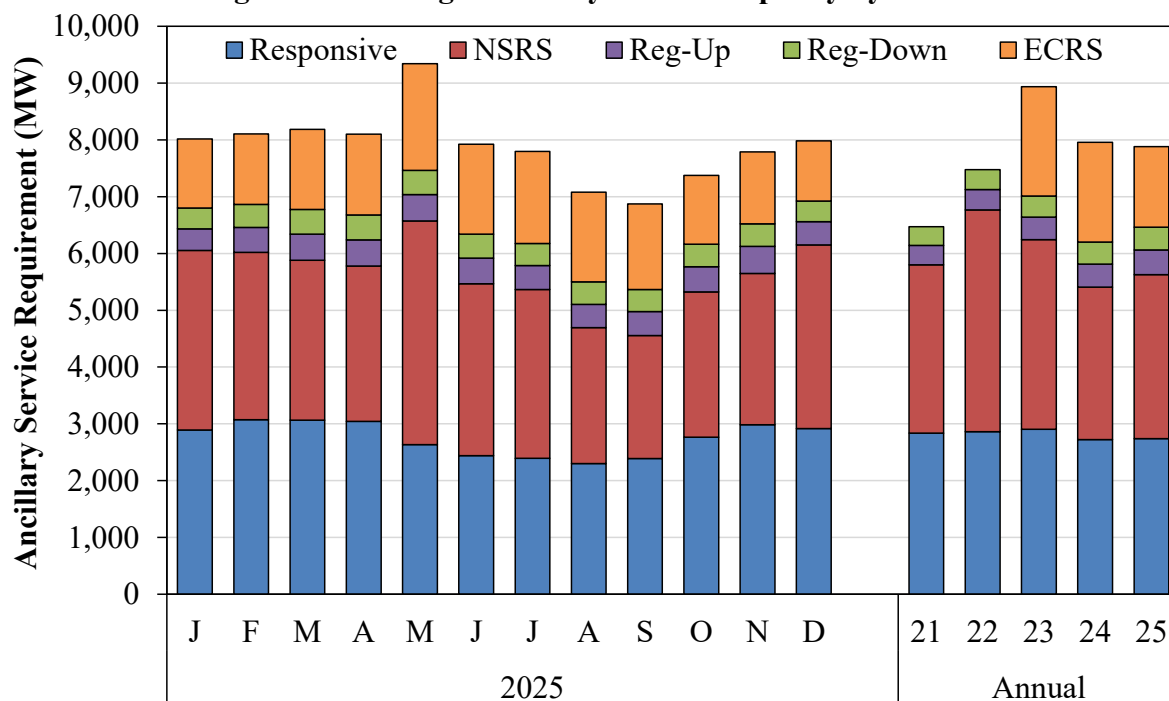


## 1. Ancillary Services Procurement Targets

The corresponding AS Methodology determines the volume of each ancillary service procured in the ERCOT markets on a month-hour basis.<sup>30</sup> The resulting schedule, called the AS Plan, is shown on a monthly basis for 2025 and on an annual basis for 2021-2025 in Figure 24. The average magnitude of the AS Plan increased substantially from 2021 to 2023, then decreased in subsequent years and remained roughly the same from 2024 to 2025.<sup>31</sup> Despite the consistent total volume of ancillary services, procurement volumes changed notably across products:

- ECRS volume decreased by over 19% because of the removal of the “adjustment for risk coverage” during sunset hours.
- Reg-Up and Reg-Down volumes increased by 7.4% and 3.3%, respectively, because of higher five-minute net load forecast error.
- NSRS volumes rose by 7.5%, driven by higher net load and solar forecast errors. Our section on ERCOT’s AS Methodology provides more detail on this topic.

**Figure 24: Average Ancillary Service Capacity by Month**



As in 2024, May had the largest average volume in the AS Plan in 2025, driven by volatility in the net load forecast. Despite flat reserve procurement from 2024 to 2025, ERCOT still procures a greater volume of operating reserves than other Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

<sup>30</sup> <https://www.ercot.com/files/docs/2022/06/07/ERCOT-Methodologies-for-Determining-Minimum-AS-Requirements-040125.zip>

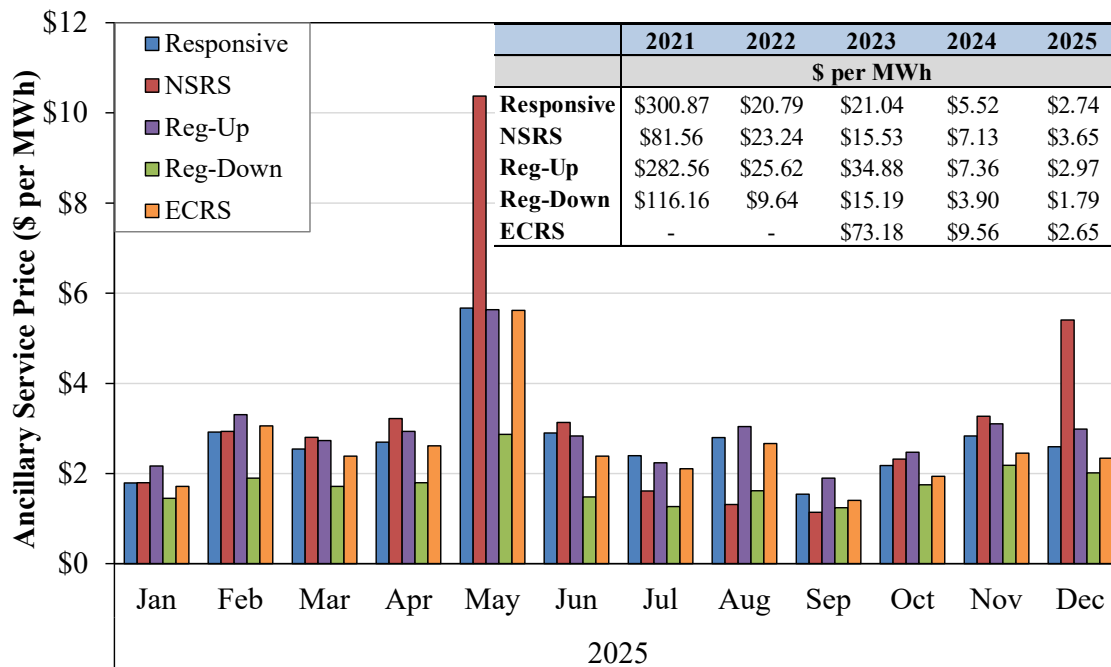
<sup>31</sup> See AS Methodology materials for TAC on Sept 19, 2024. <https://www.ercot.com/calendar/09192024-TAC-Meeting>

## 2. Ancillary Services Prices

Figure 25 presents the monthly average DAM clearing prices for the five ancillary services in 2025, and the inset table shows the annual average prices for the last five years. Prices fell across all AS products from 2024 to 2025. This decrease was partly caused by the continued growth in ESR capacity and the increase in AS provision by ESRs, which we discuss later in this chapter.

Until RTC was implemented, the entire AS plan was procured in the day-ahead market, often producing very high prices. The high prices shown for May in Figure 25 are an example. ERCOT operators increased an already high procurement target for NSRS in that month. Exercising their discretion, they increased the procurement target by an additional 1,000 MW for HE 19-22 on May 20, 2025, causing the price of NSRS to average \$320 per MWh during this period. These four hours accounted for 27% of the increase in the NSRS price across May.

**Figure 25: Ancillary Service Prices**  
2021-2025



## 3. AS Prices under RTC

High NSRS prices also occurred in December, likely because of uncertainty about RTC. Looking at hourly day-ahead market prices for NSRS for the month of December, 15 of the 24 highest-priced hours occurred on the RTC go-live date, December 5, 2025. The day-ahead market that day did not include virtual bids for AS, so the high prices reflect elevated offers from physical resources. AS prices normalized again a few days after RTC go-live.

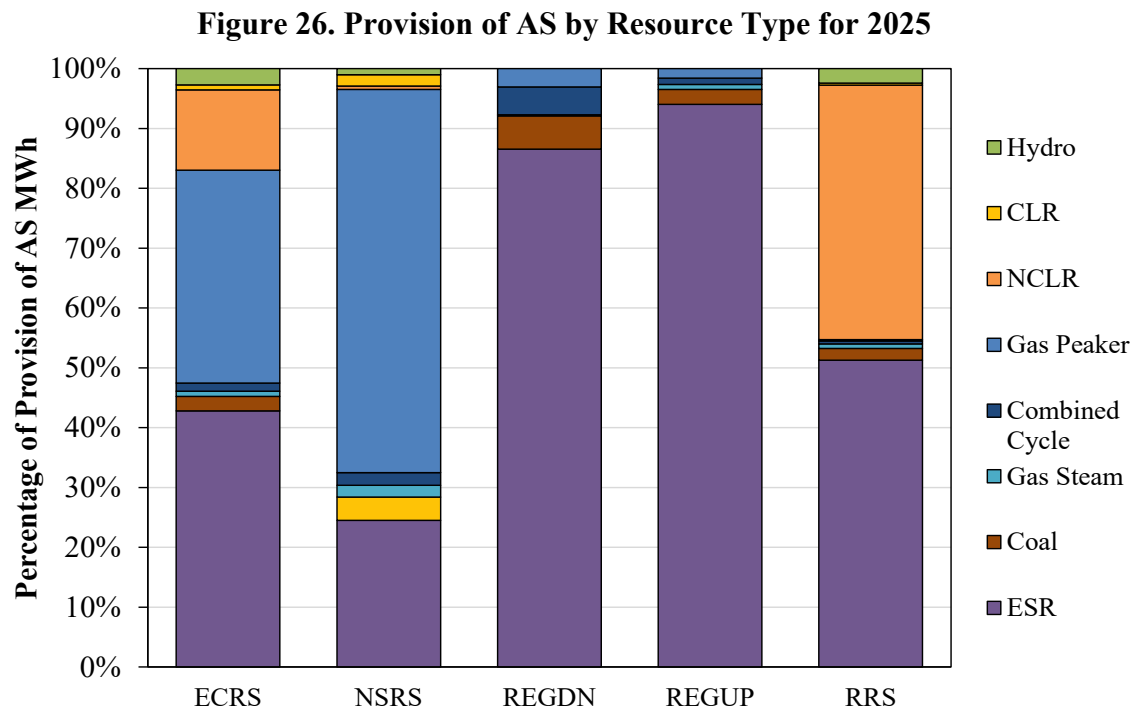
In 2025, NSRS was the most expensive ancillary service on average for the first time. This outcome is inconsistent with expectations for a well-functioning market, particularly in a year

without material shortages. Two structural factors drove this price premium: oversized NSRS procurement volume on a capacity basis and the associated four-hour duration requirement. To provide NSRS, an energy storage resource must carry four hours of energy corresponding to its NSRS award, which significantly increases the effective cost of participation. In SOM Recommendation 2024-2, we propose reducing this duration requirement to one hour.

After NPRR 1282 took effect, RTC-SCED explicitly enforced the four-hour duration requirement for NSRS, reinforcing a structural design flaw that predictably inflated NSRS prices.<sup>32</sup> We also showed that, under scarcity conditions, the constraint discourages ESR from providing reserves and instead incentivizes them to sell energy. This depletes their state of charge and increases the risk of a supply shortfall during prolonged scarcity events. We discuss the implications of this duration constraint for price formation in greater detail in Appendix I regarding RTC.

### C. Ancillary Services Participants

In 2025, NSRS was the only ancillary service for which thermal resources, particularly gas peakers, supplied most of the volume, as shown in Figure 26. This trend represents a departure from historical patterns, when unloaded headroom on thermal resources carried a significant share of ancillary services across products. By contrast, ESRs or a combination of ESRs and NCLRs provided most other AS products in 2025.



<sup>32</sup>

NPRR 1282: <https://www.ercot.com/mktrules/issues/NPRR1282>

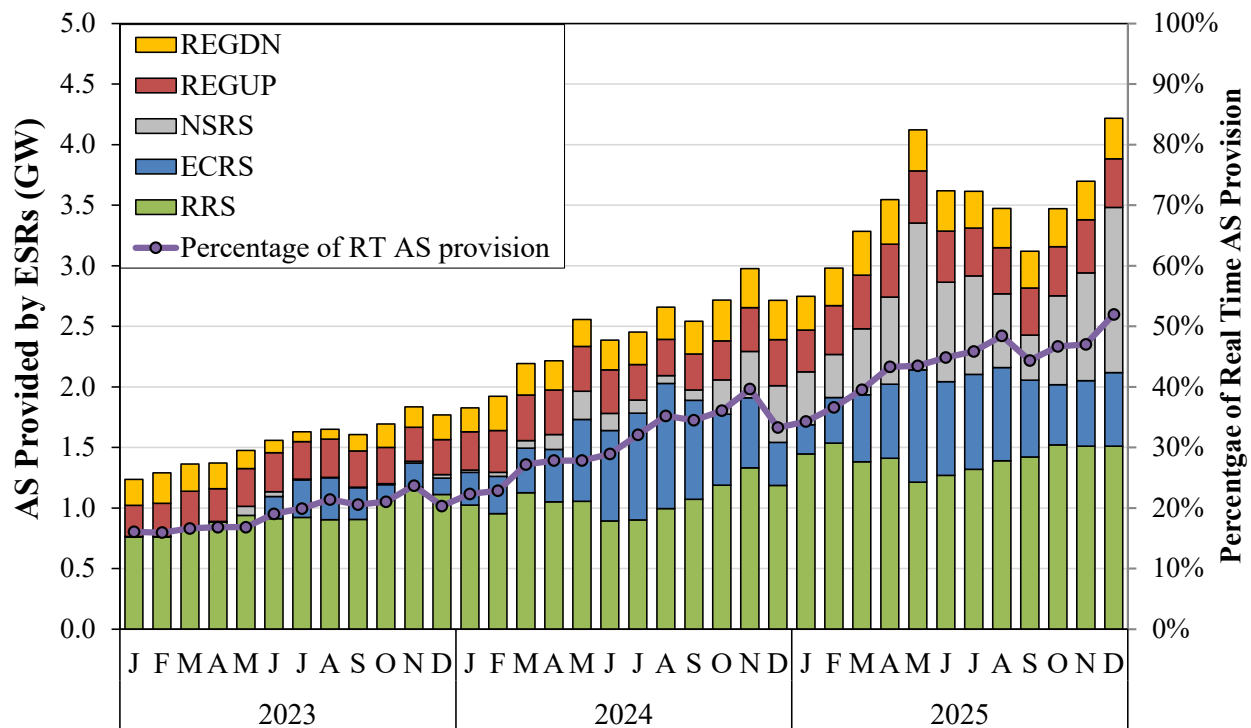
## 1. ESR Participation in Ancillary Services

In 2025, ESRs continued to increase their market share across all AS products, as shown in Figure 27. On average, ESRs provided 94%, 86%, and 51% of Reg-Up, Reg-Down, and RRS, respectively.

### *RRS Provision from ESRs*

Batteries can provide two distinct types of responsive reserves. In addition to the primary frequency response capability that conventional generators provide, batteries can also provide fast frequency response, a variant of RRS that operates via relay in response to frequency deviations. The share of responsive reserves composed of resources providing FFR is capped at 450 MW. In this section, we note additional limits on RRS that restrict participation by the type of RRS capability or resource type. In section D of this chapter, we describe how aggregating the three RRS capabilities into one product affects offer behavior and market outcomes.

**Figure 27: Real-Time Provision of AS by ESRs**  
2023-2025



### *ECRS and NSRS Provision by ESRs*

ESRs' provision of ECRS and NSRS increased to 42% and 24%, respectively, in 2025. This increase is noteworthy because the duration requirements for ECRS and NSRS imply higher opportunity costs for ESRs providing these products. The ECRS duration requirement was two hours until RTC was implemented, at which point it to one hour according to NPRR 1282.

As of this report, the NSRS duration requirement remains four hours, despite mounting evidence that this constraint distorts market outcomes. However, NPRR 1309, which has been approved by the ERCOT Technical Advisory Committee, would set the duration for NSRS at two hours upon the implementation of the long-foretold Dispatchable Reliability Reserve Service (DRRS). DRRS is statutorily required to carry a four-hour duration requirement. Reducing the NSRS duration requirement to two hours would be a step in the right direction. However, we continue to recommend that ERCOT adopt a one-hour duration requirement for both ECRS and NSRS, as detailed in Recommendation 2024-2.

## 2. NCLR Participation in Ancillary Services

ERCOT allows qualified load resources to offer into the ancillary services markets. In addition to CLRs, discussed in Chapter II.F.1, there are also NCLRs that are not controlled by SCED. Because CLRs and NCLRs differ in their response to system conditions and dispatch signals, they face different limits on the types and volumes of ancillary services they can provide.

### *AS Volume from NCLRs*

NCLRs account for the vast majority of AS provision from LR. As of January 2026, 505 NCLRs were registered in ERCOT, with a combined capacity of 10,550 MW.<sup>33</sup> NCLRs can qualify to provide RRS, NSRS, and ECRS. Historically, they have primarily provided RRS. Table 4 shows the time-weighted average volumes of ancillary services that NCLRs supplied from 2023 through 2025.

**Table 4: Average Volume of Ancillary Services Provided by NCLRs**

	RRS	ECRS	NSRS
	Average Volume (MW)		
<b>2023</b>	1,742	67	70
<b>2024</b>	1,700	164	3
<b>2025</b>	1,480	190	18

### *RRS Provision from NCLRs*

Although 7,568 MW of NCLRs were qualified to provide responsive reserves, they provided only 1,480 MW on average in 2025. One reason for this gap is that ERCOT requires that PFR-capable resources must provide at least 1,365 MW or 40% of the AS Plan. NCLRs cannot provide PFR and instead provide responsive reserves primarily through an under-frequency relay. UFR is a variant of RRS that automatically disconnects the load resource when system frequency drops below 59.7 Hertz (Hz) or when ERCOT issues manual deployment instructions during an Energy Emergency Alert Level 2.

<sup>33</sup>

See 2025 Annual Report of Demand Response in the ERCOT Region (Jan 2026), available at <https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=1188179018>

### ***ECRS Provision from NCLRs***

NCLR participation in ECRS has increased in recent years, although ERCOT limits NCLRs to no more than 50 percent of the ECRS Ancillary Services Plan. In 2025, ECRS prices did not clear at a premium to RRS, unlike in 2023 and 2024. However, initial RTC results show that ECRS consistently clears above RRS, driven in part by differences in duration requirements across ancillary service products in RTC. If this price premium persists, more NCLRs may shift from RRS to ECRS.

### ***NSRS Provision from NCLRs***

Although NCLRs have participated in NSRS since November 2022, after ERCOT implemented NPRR 1093<sup>34</sup> and NPRR 1101,<sup>35</sup> participation has remained limited. To qualify to provide NSRS, NCLRs cannot have an active UFR, so they must choose between providing NSRS and RRS.<sup>36</sup> Because RRS is deployed less frequently than NSRS, most NCLRs participate in RRS. However, NSRS prices were considerably higher than RRS prices in 2025, and initial observations since RTC go-live indicate that this trend is continuing into 2026. If this trend continues for several years, more NCLRs may disconnect their UFR to provide NSRS rather than RRS.

## **3. CLR Participation in Ancillary Services**

CLRs that can provide PFR are eligible to provide regulation, RRS, NSRS, and ECRS, with no cap on the share of responsive reserves provided by CLRs. Prior to 2023, CLRs primarily provided RRS. In 2023, after ERCOT introduced ECRS, CLR participation shifted toward ECRS, which cleared at higher prices than RRS in 2023 and 2024. In 2025, CLR provision of RRS and ECRS dropped significantly as participation shifted to NSRS. Table 5 shows the average volume of operating reserves CLRs provided from 2023 through 2025.

**Table 5: Average Volume of Ancillary Services Provided by CLRs  
2023-2025**

	<b>RRS</b>	<b>ECRS</b>	<b>NSRS</b>
	<b>Average Volume (MW)</b>		
<b>2023</b>	36	58	9
<b>2024</b>	34	37	47
<b>2025</b>	9	11	58

<sup>34</sup> NPRR 1093: <https://www.ercot.com/mktrules/issues/NPRR1093>

<sup>35</sup> NPRR 1101: <https://www.ercot.com/mktrules/issues/NPRR1101>

<sup>36</sup> Note that NCLRs can provide ECRS with or without an active UFR

### ***NSRS Provision from CLRs***

NSRS was attractive for CLRs in 2025 for several reasons. First, NSRS was the most expensive AS product in ERCOT on average in 2025. Second, the implementation of NPRR 1131<sup>37</sup> in August 2024 allowed CLRs to provide online NSRS. Prior to NPRR 1131, CLRs could provide only offline NSRS, which required a CLR to maintain a level of power consumption equivalent to its NSRS award until ERCOT manually deployed it. This could expose the CLR to high real-time prices. Between NPRR 1131 and the implementation of RTC, ERCOT treated NSRS capacity awarded to CLRs as a standing deployment that SCED could dispatch down based on an energy bid curve priced at no less than \$75 per MWh. As a result, the volume of NSRS provided by CLRs increased substantially after August 2024.

### ***CLR AS Paradigm under RTC***

The primary risk for CLRs that provide AS has been exposure to elevated real-time energy prices, but RTC has substantially mitigated that risk. Going forward, CLRs can choose to forego the day-ahead market entirely and only sell AS in real-time. There, ERCOT co-optimizes their AS offers against their bids to buy energy, so they no longer risk losing money on energy purchases because of an obligation to provide reserves. If they do participate in the day-ahead market, they can sell out of their day-ahead AS positions in real-time without a penalty for failure to provide, leaving only the imbalance risk. CLR owners will be able to hedge this imbalance risk more effectively once ERCOT implements NPRR 1188, which incorporates co-optimization of energy and AS for CLRs into the day-ahead market. ERCOT approved NPRR 1188 in November 2024, and the project to implement this NPRR was initiated after the implementation of RTC. This project is scheduled for completion in early 2027.

Currently, ERCOT does not co-optimize energy and ancillary services for LR in the day-ahead market. Generators and energy storage resources receive energy awards that are directly linked to particular resources, but energy purchases are not linked to a specific resource. Energy is purchased only on an LSE-specific rather than resource-specific basis, so the clearing price for energy is not factored into each resource's AS awards. With co-optimization in the day-ahead market, a CLR can be guaranteed that the net value of energy and ancillary services implied by its offers will be reflected in its awards and the corresponding clearing prices. Thus, implementing NPRR 1188 should encourage greater AS provision from CLRs.

## **D. RRS Aggregation Impact on Market Outcomes**

PFR, FFR, and UFR are three separate mechanisms through which resources can provide RRS, subject to various caps and floors. Instead of clearing each type of responsive reserve separately at distinct prices, ERCOT clears them together and prorates UFR and FFR awards when the combined limit is binding. Figure 28 illustrates this dynamic by comparing the UFR and FFR

<sup>37</sup> NPRR 1131: <https://www.ercot.com/mktrules/issues/NPRR1131>

volumes that are self-scheduled or awarded in the DAM, the remaining uncleared offers, and the ERCOT limit.

**Figure 28: Responsive Reserves from UFR and FFR in DAM**

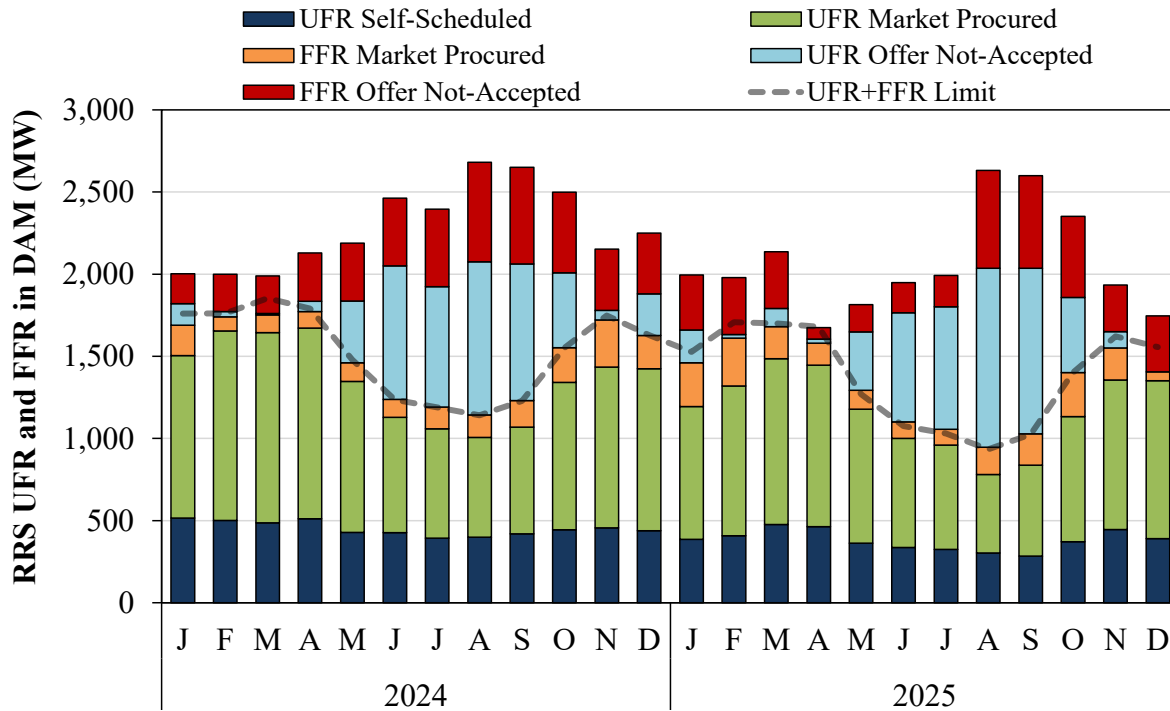


Figure 28 shows that the volumes of UFR capacity that are self-scheduled, offered into the market, and/or awarded in the market all decreased from 2024 to 2025. The main driver was the increase in the minimum PFR volume requirement from 1,185 MW to 1,365 MW in the 2025 AS Methodology. No comparable change occurred in FFR offers and awards, which continued to clear below the 450 MW limit.

Since PFR is similarly costly for ESRs to provide, many prefer to offer PFR to avoid the risk that their FFR offers will be prorated when the combined limit is reached. This behavior likely results directly from ERCOT clearing multiple forms of responsive reserves together rather than treating them as distinct products with separate clearing prices, addressed in Recommendation 2019-2.

## E. Ancillary Service Methodology for 2026

### 1. Background and Summary

As mentioned in Chapter III.A.1, the AS volume procured through the ERCOT markets is defined by the ancillary service methodology. The AS methodology is the set of criteria ERCOT uses to determine the levels of ancillary services needed to maintain system reliability.

Historically, the ERCOT AS Methodology was based on a combination of NERC requirements and statistical parameters meant to quantify the reliability risks ancillary services are meant to



protect against. For example, the procurement target for Regulation is set according to the 95<sup>th</sup> percentile of net load forecast error based on a five-minute look-ahead.

This deterministic statistical approach works reasonably well for a product like Regulation, which is meant to account for forecast errors over a relatively short time horizon and variability between regular runs of the real-time market clearing process. For ancillary services meant to address risks that materialize across multiple SCED intervals and up to an hour, such as ECRS and NSRS, this statistical approach tends to produce excessively high procurement targets. Instead, a stochastic approach that accounts for the probabilistic risks these products are meant to address – namely forecast errors and forced outages – is better suited to determine the procurement targets for such reserves.

To ERCOT’s credit, it implemented a stochastic risk methodology to determine the production targets for ECRS and NSRS, as we recommended in our 2024 State of the Market report (see Recommendation 2024-1b). However, we remain concerned that ERCOT continues to set excessively high procurement targets for these ancillary services despite adopting a probabilistic methodology. Our concerns focus on two key issues: (1) the proposed methodology is not aligned with reliability outcomes and results in excessive AS procurements, and (2) it will undermine the performance of ERCOT’s energy-only market. We first outline our comments and conclusions on these issues, then discuss each model input’s contribution to the excessive procurement volumes in more detail.

## 2. The AS Methodology is Misaligned with Reliability Outcomes

The following list describes the parameters used in ERCOT’s 2026 AS Methodology for ECRS and NSRS and each parameter’s impact on the procurement targets for these ancillary services:

- Setting operating reserve targets to meet a one-in-ten standard for the probability of entering a “Watch,” defined as reserves dropping below 3,000 MW, rather than for the probability of firm load shed, defined as reserves dropping below 1,500 MW. This parameter increases the AS Plan target level by approximately 43%.
- Assessing the operational risk that NSRS is meant to manage based on the six hour-ahead forecast error for demand and generation from intermittent renewables. This parameter inflates the target level of the AS Plan by 57% more than our recommendation of one hour-ahead forecast error.
- Accrediting the available headroom of ESRs for NSRS based on the power output they can sustain for four hours rather than our recommendation of one hour. This parameter inflates the target level of the AS Plan by another 29%.

Together, these inputs yield the proposed AS Methodology, which procures 140% more than required to satisfy the 1-in-10 reliability standard for load shed. As Figure 29 shows, the last 2 GW provide no additional reliability benefit. The blue curve represents the probability of firm load shed at different procurement levels of ECRS and NSRS. It reflects the IMM base case and

uses a one-hour load forecast error and a one-hour duration requirement for ESRs. The orange curve represents the probability of entering a Watch condition at different procurement levels of ECRS and NSRS. It reflects the ERCOT base case and uses a six-hour load forecast error and a four-hour duration requirement for ESRs. The procurement level required to achieve a one-in-ten (or 10%) probability of each outcome is identified by the intersection of the horizontal black line with the two curves.

**Figure 29: Annual Probability of Firm Load Shed vs Entering Watch Conditions**

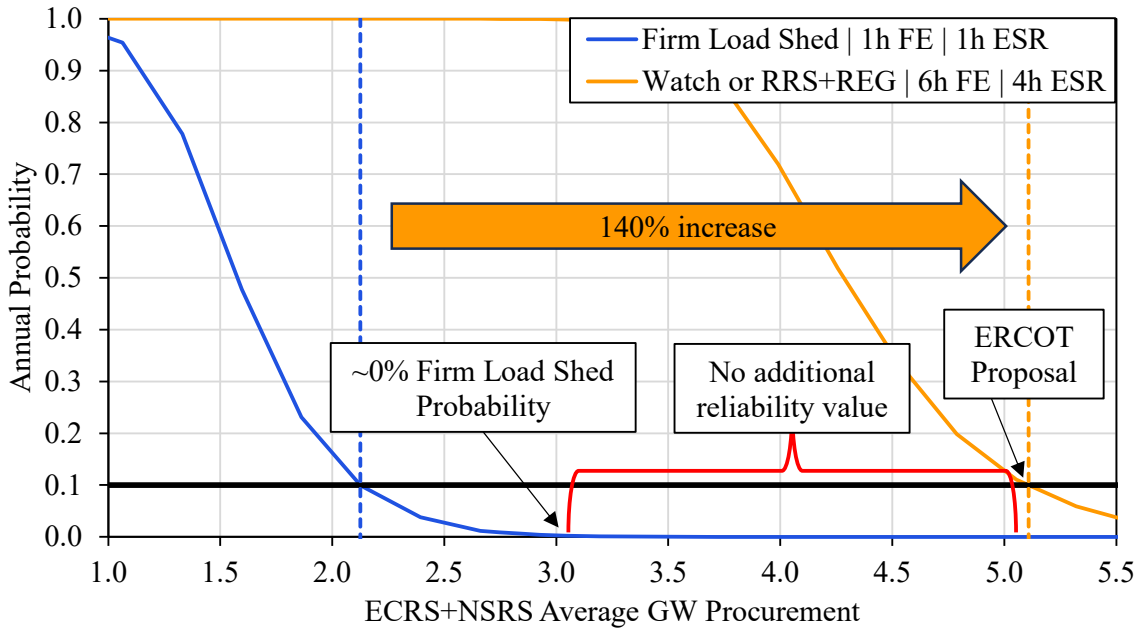


Figure 29 shows that total ECRS and NSRS needed to meet the one-in-ten (0.1 probability) reliability standard would average roughly 2.1 GW. In contrast, ERCOT's proposal would procure 5.1 GW of reserves, about 2 GW of which would have no reliability value.

### 3. The AS Methodology and the Energy-Only Market

ERCOT's energy-only market design must allow scarcity pricing to send market signals that incent investment in new generation. Procuring excessive volumes of ancillary services will inefficiently inject additional non-price-setting energy into the real-time market and reduce prices. Ultimately, it can undermine the ability of shortage pricing to provide efficient long-term signals for new investment.

With RTC, a set of sloped ancillary service demand curves (ASDCs) defines shortage pricing in the day-ahead and real-time markets. These ASDCs are intended to reflect the marginal reliability value of reserves and define the penalty price when the market goes short on them. At the extremity of a well-designed ASDC, the shortage price should approach \$0, reflecting the low marginal reliability value of additional reserves and allowing the market to go short on AS. This dynamic contrasts with the previous market design where the day-ahead market necessarily

procured the entirety of the AS Plan and is how RTC is meant to function. Shortages of operating reserves priced according to a sloped demand curve are a critical aspect of price formation in an energy-only market with co-optimization of energy and operating reserves.

ERCOT operations, however, has signaled skepticism about this feature of RTC and indicated that it intends to use reliability unit commitment (RUC) instructions to increase operating reserves when the market does not procure the full AS Plan. To avoid this outcome, because many stakeholders are averse to RUC, ERCOT imposed a \$15 per MWh floor on any shortages of AS in the day-ahead and real-time markets through NPRR 1269. ERCOT argues that this price floor reduces the likelihood of real-time shortages of ancillary services that would prompt operators to commit resources through RUC.

In practice, this excessively conservative operating reserve policy will increase consumer costs while suppressing the price signals needed to maintain resource adequacy. Consumers will incur higher costs because of uplift from RUC, DAM make-whole payments, and from the \$15 per MWh floor on the AORDC. At the same time, excess supply of reserves and a reluctance to endure any reserve shortage will suppress the price signal that the ASDCs are meant to produce. Ultimately, suppressing genuine shortage pricing will reduce incentives for new generation investment, while the modest increase in revenues under minimal shortage conditions will serve only as a transfer payment to resource owners above the reliability value their resources provide.

Beyond our recommendations on the AS Methodology, we call for a broader reconsideration of ERCOT's conservative operations to cost-effectively achieve objective reliability targets. ERCOT should apply this reconsideration to both the AS Methodology and the corresponding formulation of the ASDCs. The ASDCs and the AS Methodology should be explicitly linked so that the shortage pricing represented by the ASDCs reflects the marginal reliability value of the corresponding ancillary service. We elaborate on the proper formulation of the ASDCs and the AS Methodology in recommendation 2024-1. For more detail on our perspective on ERCOT's AS Methodology for 2026, see the materials we presented at the August 2025 TAC meeting<sup>38</sup> and the corresponding memo we sent to the PUC.

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<sup>38</sup> <https://www.ercot.com/calendar/08272025-TAC-Meeting>

## IV. DAY-AHEAD MARKET PERFORMANCE

### A. Highlights of Day-Ahead Market Performance in 2025

ERCOT's day-ahead market (DAM) allows participants to take financially binding forward positions to hedge against real-time market outcomes. These positions include purchases and sales of energy for delivery in real-time, point-to-point (PTP) obligations and options, and sales of ancillary services for provision in real-time.

The DAM plays a critical role in coordinating generator commitment decisions and helping participants manage or arbitrage real-time price exposure. Until RTC was implemented, ancillary services awarded in the DAM implied a physical obligation to provide reserves. Otherwise, the DAM is a voluntary financial market that creates no physical obligations from market awards. Key insights from about the ERCOT day-ahead market in 2025 include:

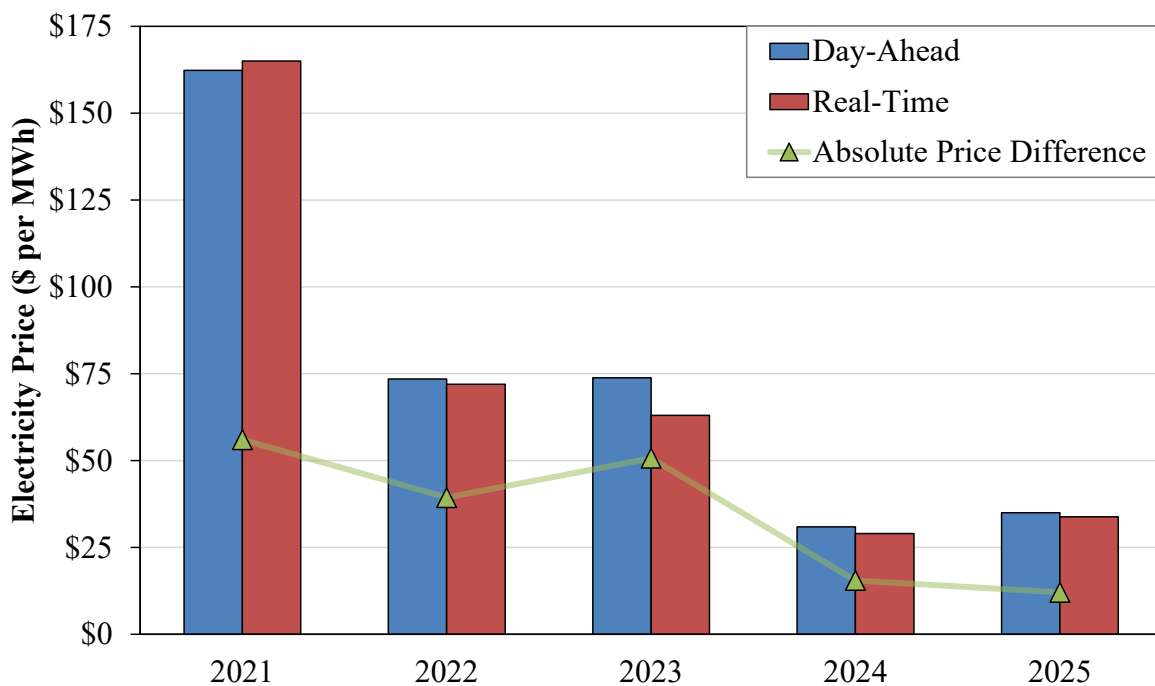
- **The average price premium in the day-ahead market was \$1.17 per MWh, while the average absolute price difference was only \$12 per MWh.** This spread is low compared to prior years because fewer price spikes occurred
- **The day-ahead market cleared 62% of real-time load in 2025.** This is in line with recent years in ERCOT, but other RTOs in the US clear more than 90% in the day-ahead market.
- **Three-part offers account for only 58% of the energy sold in the day-ahead market and serve only 36% of real-time load.** Thermal resources not awarded through three-part offers risk not recovering their start-up and minimum generation costs. Most renewables intentionally do not submit three-part offers because of their zero marginal cost of production and uncertainty in their forecast.
- **ERCOT's total collateral remained unchanged in 2025 at \$6.9 billion.** For the last two years, exposure to positional risks from CRRs has driven most of this collateral.
- **Point-to-point obligations remained profitable in 2025, paying 10.9% more in real time than their day-ahead purchase cost.** This ended a multi-year trend of declining PTP profitability.
- **The volume of PTP bids has grown by 258% over the last decade.** This increase lengthens the time ERCOT needs to solve the DAM optimization. Although there have been few late publications of DAM results, optimization runtime may pose a risk if bid-volume inflation continues. ERCOT has indicated that it may draft an NPRR to impose a bid fee on PTP bids that are unlikely to clear.

## B. Day-Ahead Energy Market Pricing

A primary indicator of forward market performance is the extent to which forward prices converge with real-time prices. Prices should converge when: (1) barriers to purchases and sales in either market are low, (2) sufficient information is available for market participants to develop accurate expectations of real-time prices, and (3) both markets accurately reflect the physical limitations of the transmission network. These conditions allow market participants to arbitrage predictable differences between day-ahead and real-time prices, resulting in price convergence. Price convergence between the day-ahead and real-time markets is important because it leads to more efficient commitment of resources for use in real-time.

The average difference between day-ahead and real-time spot prices shows whether persistent, predictable differences exist that participants should arbitrage over time. Figure 30 shows the annual average day-ahead and real-time prices for the past five years. It also shows the average absolute difference between the daily average day-ahead and real-time price. This measure captures variation in daily price differences, which may be large even if prices converge on average.

**Figure 30: Convergence Between Day-Ahead and Real-Time Energy Prices**  
2021-2025



Compared to 2021 through 2023, the price spread between the day-ahead and real-time markets was relatively low in 2025. The average price premium in the day-ahead market was \$1.17 per MWh, slightly lower than in 2024, but the average absolute price difference was only \$12 per MWh, the lowest since 2020.

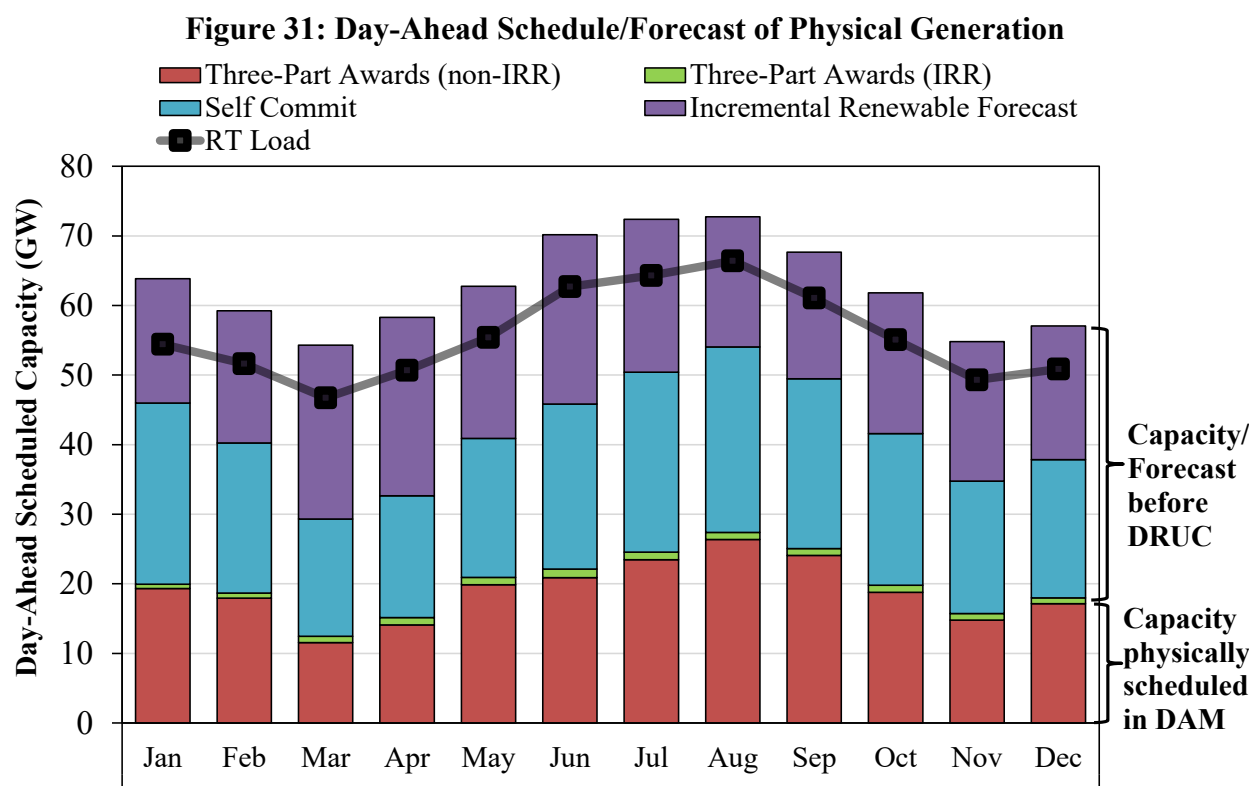
## C. Day-Ahead Market Activity

Market participants participate in the day-ahead market by submitting bids to buy electricity or offers to sell electricity for real-time delivery. These bids and offers include either (1) a three-part supply offer, which lets a seller include startup cost, minimum generation cost, and an incremental energy offer curve or (2) an energy-only, or virtual, bid or offer, which is a location-specific transaction submitted either as a hedge or for speculative purposes.

### 1. Day Ahead Market Volume

The day-ahead market clears offers and bids by matching supply and demand. In 2025, day-ahead energy purchased through generator-specific offers and virtual energy offers equaled 62% of real-time load, in line with recent years. Participants also use PTP obligations scheduled in the day-ahead market to hedge congestion and to hedge exposure to real-time prices from transactions outside the ERCOT wholesale market.

Less than half of physical real-time generation in ERCOT is scheduled through the day-ahead market, so resources scheduled after the DAM must provide the remaining supply needed to satisfy real-time load, as shown in Figure 31. Figure 31 shows awards for three-part offers (i.e., three-part awards) for thermal and intermittent renewable resources (IRR), thermal capacity self-scheduled in Current Operating Plans (COPs) prior to the day-ahead RUC process (DRUC), and the day-ahead forecast for renewable generation.

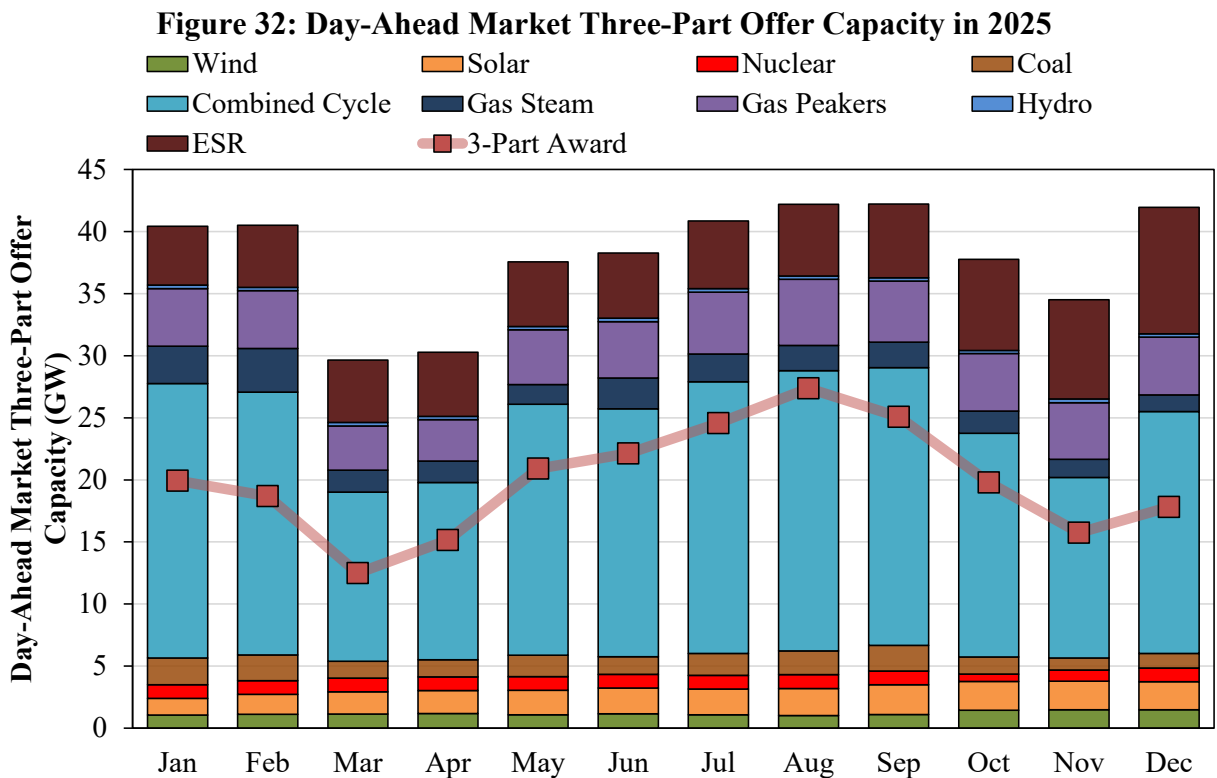


Although generation cleared through three-part offers is limited, self-scheduled thermal resources and expected renewable output regularly supplement these awards. As a result, ERCOT typically does not need to rely on RUC to serve most real-time load.

## 2. Three-Part-Offer Behavior

Physical generation scheduled through awards to three-part offers continues to play a limited role in the day-ahead market. These awards account for just 58% of energy sold in the day-ahead market and serve only 36% of real-time load.

To evaluate these outcomes, we review the volume and clearance rates of three-part offers submitted by QSEs. Figure 32 presents the average monthly capacity of three-part offers in 2025 by resource type. QSEs regularly submitted substantial three-part-offer capacity, and on average, 53% of that capacity cleared in the day-ahead market. Clearance rates increased during the summer because higher demand made thermal resources more economically competitive. Combined cycle natural gas plants accounted for the majority of three-part offers, indicating active participation by dispatchable resources.



With only 36% of real-time load covered by these awards, many resources self-schedule and accept real-time price exposure. For thermal resources, this exposure means market revenues might not cover start-up and minimum generation costs. Renewable resources, however, tend to avoid three-part offers because output uncertainty creates a risk of imbalance payments if real-time generation is less than what they sold in the day-ahead market.

### 3. Collateral Requirements

ERCOT requires market participants to post collateral to ensure they have sufficient funds to cover their positions in ERCOT-administered markets. ERCOT quantifies collateral requirements by Total Potential Exposure (TPE), which has two components. The first, TPEA (TPE-Any), is based on variation in wholesale prices and increases when prices are high. The second, TPES (TPE-Secured), is based on exposure to positional risk from CRRs. Market participants generally post significantly more collateral than necessary to avoid sudden exclusion from market participation because spot prices may vary drastically from day to day. Figure 33 shows the distributions of TPEA and TPES, as well as annual averages for TPE and total collateral held by ERCOT.

**Figure 33: TPE and Collateral Held by ERCOT**  
2021-2025

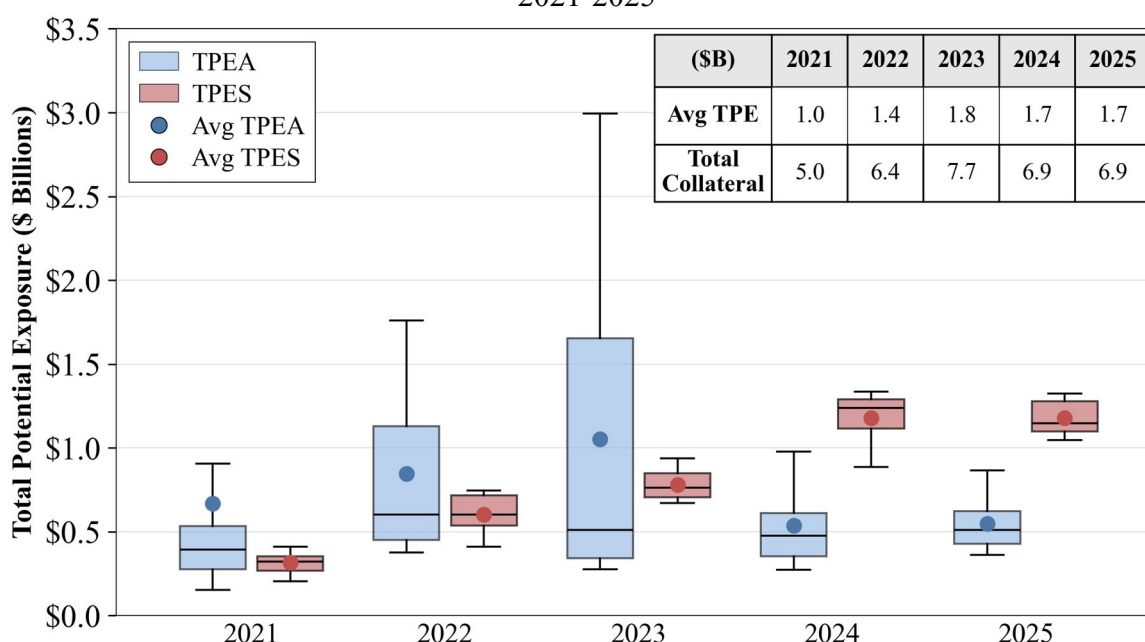


Figure 33 shows that over the last two years, TPES has been the larger component of TPE by a significant margin on average. Both years had relatively low wholesale energy prices and high CRR market participation. Although TPEA was lower on average, its variation was greater than TPES's, reflecting the relative volatility of wholesale prices. Taken together, TPE was almost the same in 2025 as in 2024. Similarly, the total collateral ERCOT held, which amounted to \$6.86 billion in 2025, was nearly unchanged in nominal terms from 2024. This stability in total collateral corresponds to similar stability in TPE in 2025.

#### D. Point-to-Point Obligations

Although Chapter V covers PTPs in greater detail, we discuss them briefly here because they represent a significant share of day-ahead market activity and directly reflect participants'



expectations of congestion. PTP obligations are a key part of day-ahead market activity because they allow participants to hedge or speculate on congestion between two locations in the day-ahead and real-time markets. A PTP represents a scheduled flow from a source node to a sink node. Its purchase cost equals the product of the day-ahead price difference between those nodes and the flow volume in MWh. The participant realizes its value in real time when the position is liquidated based on the real-time price difference between the same nodes.

## 1. PTP Profitability

The net value of the PTP reflects the change in congestion between the day-ahead and real-time markets. A PTP is profitable when the participant pays less to purchase it than it earns in real time. Figure 34 compares total day-ahead payments to acquire these products with total revenue PTP holders received in the real-time market over the last three years.

**Figure 34: Point-to-Point Obligation Charges and Revenues**  
2021-2025

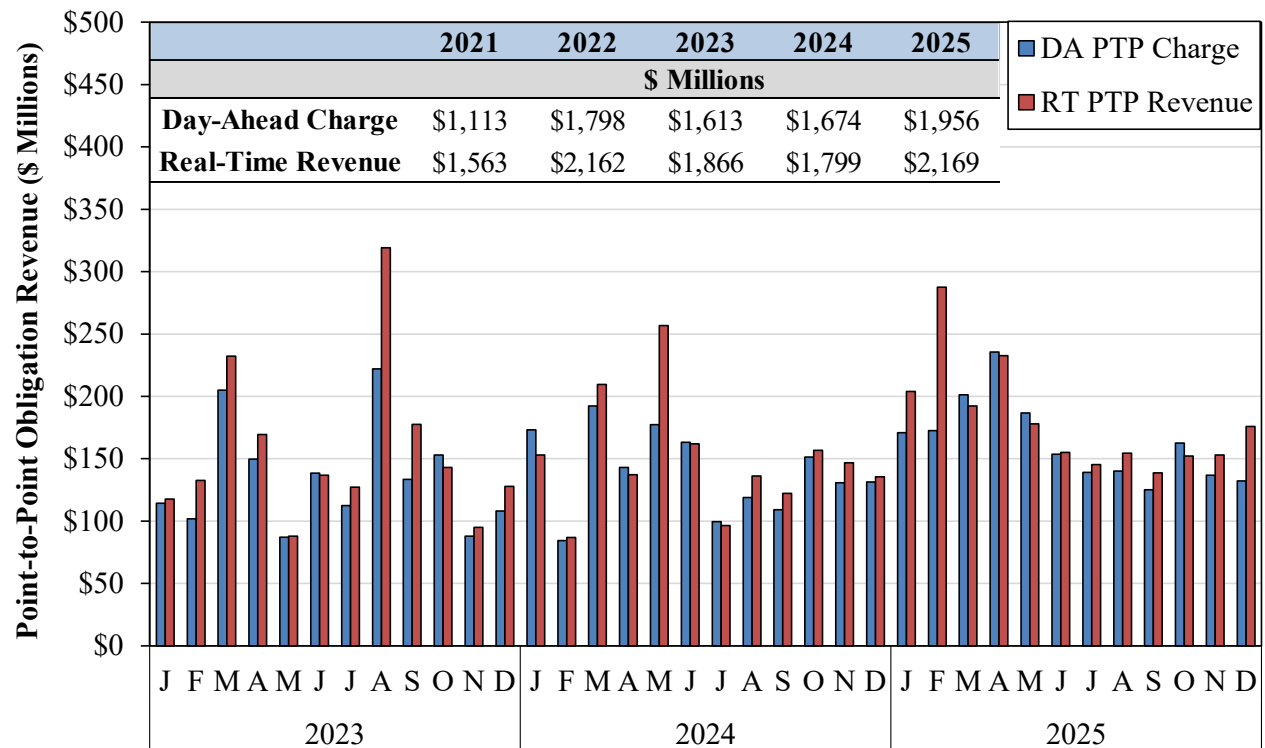
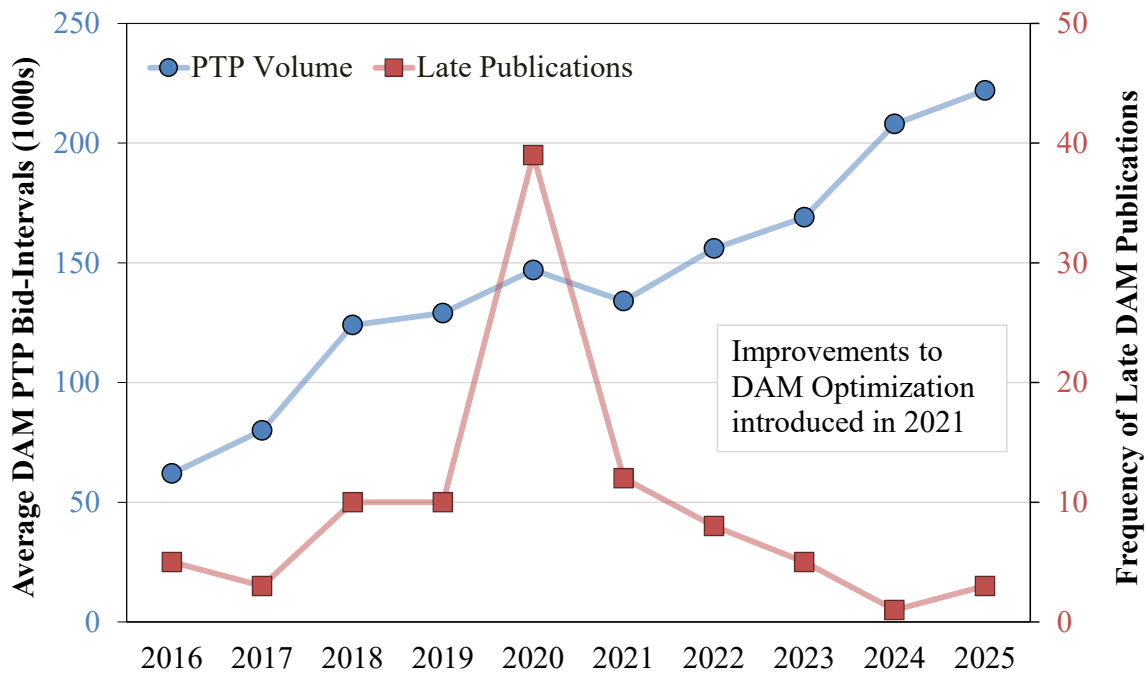


Figure 34 shows that PTPs remained profitable in 2025, receiving 10.9% more in real-time than their day-ahead purchase cost, up from a 7.5% profit margin in 2024. This higher margin ended a multi-year trend of declining PTP profitability even as PTP bid volume continued to increase.

## 2. PTP Bid Volume

The volume of PTP bids<sup>39</sup> has grown by 258% over the past decade, affecting both PTP profitability and day-ahead market performance. Higher bid volumes lead to clearing prices that more closely reflect real-time congestion, reducing the net value of awarded PTPs and limiting opportunities for profit. At the same time, the growing number of PTP bids has increased the complexity of the day-ahead market optimization. This makes it more difficult for ERCOT to produce and publish market results within the timeline required by protocol. Many of these PTP bids are unlikely to clear because their prices do not reflect a realistic expectation of real-time congestion based on recent conditions. However, ERCOT must consider all PTP bids when clearing the day-ahead market. Figure 35 shows PTP bid volume in recent years.

**Figure 35: Volume of DAM PTP Bids and Frequency of Late Publications**  
2016-2025



ERCOT has improved the day-ahead market optimization process in recent years, reducing solve times and the frequency of late publications. There were three late DAM publications in 2025, up from only one in 2024, but still few enough that they are not an immediate concern. However, if PTP bid volume continues to grow, it will remain a concern whether improvements in optimization processes and computing capacity can keep pace.

39 This volume is the total number of hourly PTP bid-intervals, including obligations linked to CRR options

ERCOT has sought to manage this situation by capping the volume of PTP bids each counterparty can submit. However, PTP traders can evade this cap by working across an arbitrary number of counterparties.

### **3. PTP Bid Fees**

Alternatively, we have recommended a fee-based approach. In Recommendation 2020-4, we recommend that ERCOT impose a small fee on PTP bids to discourage uncompetitive bids that are extremely unlikely to clear. The fee should be small enough not to deter bids that have a reasonable probability of clearing and that therefore contribute liquidity to the day-ahead market and promote efficient price formation.

ERCOT has responded to this recommendation and sought feedback on potential design options. The Congestion Management Working Group (CMWG) is considering two options. The first would place a fee on all PTP obligation bids, while the second would charge a fee only on unawarded PTP bids that do not meet certain threshold criteria.<sup>40</sup> These criteria would include both absolute clearing price thresholds and relative thresholds, i.e., a fraction or multiple deviation of the clearing price. Work on the fee and threshold criteria is ongoing. We have updated Recommendation 2020-4 to support this approach.

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<sup>40</sup>

<https://www.ercot.com/files/docs/2026/04/10/CMWG-PTP-Bid-Fee-NPRR-Update.pptx>

## V. TRANSMISSION CONGESTION AND CONGESTION REVENUE RIGHTS

### A. Summary of Transmission Congestion Results in 2025

An essential function of any electricity market is to manage power flows on the transmission network efficiently. The markets manage congestion by coordinating generation dispatch so the resulting power flows do not exceed the operating limits of the transmission infrastructure. This coordination occurs through the real-time market dispatch model, i.e., SCED, which schedules generation to meet demand based on each generator's energy offer curve and its corresponding impact on transmission constraints. This market dispatch produces a set of locational prices that vary across the network and congestion costs collected from participants. Key insights on transmission and congestion in ERCOT in 2025 include:

- **Day-ahead congestion in ERCOT increased 26% in 2025, ending a trend over the previous 3 years of declining annual congestion costs.** The main drivers were the North zone, where ERCOT used significant RUC commitments to manage congestion, and the West Zone, where transmission projects have not kept pace with large increases in renewables in the panhandle and demand in the Permian Basin.
- **Real-time congestion was 7% higher in the RTM than in the DAM.** This disparity is reasonable because forecast error persists for both load and renewable generation.
- **Violated transmission constraint hours continued to drop in 2025 to only 64 constraint-hours, the lowest annual total ever.** NPPR 1230 can partially explain this decline in constraint violations because it allows SCED to produce more expensive dispatch solutions to avoid violating these constraints.
- **CRR auction revenues increased 6% in 2025, slower growth than the 14-32% annual growth rates from 2021 to 2024.** Intrazonal CRRs drove the increase, whereas CRR revenue across zones decreased to its lowest value since 2021.
- **CRR profitability increased by 21% in 2025, reversing a multi-year decline.** By contrast, CRRs posted a net loss of 1.5% in 2024.
- **CRR surplus payments to load totaled \$293 million, up 22% from the prior year.** The balancing account was sufficiently funded to cover CRRs in every month of 2025.
- **The last two sections of this chapter cover recommendations on the ongoing review of 4CP and load zone reconfiguration in ERCOT.** Both recommendations would significantly improve market signals and cost allocation practices.

## B. Background on Transmission Congestion

The following concepts are foundational to understanding how the transmission network and associated grid congestion affect price formation in the day-ahead and real-time markets.

### 1. Locational Marginal Prices

Locational marginal prices (LMPs) are the primary mechanism for reflecting transmission constraints in wholesale electricity market prices. LMPs represent the marginal cost of serving an incremental unit of load at a specific location, accounting for generation costs and the physical limits of the transmission network. When transmission constraints bind, the cost of delivering power differs across locations, causing prices to vary geographically. These locational price differences result directly from congestion on the network. Thus, nodal pricing reflects the cost of delivering electricity based on the physical limitations of the transmission network.

By embedding transmission constraints into prices, LMPs play a central role in guiding efficient operational and investment decisions. Higher prices in constrained areas signal the value of generation that can relieve congestion, while lower prices in unconstrained areas reflect relative surplus. In ERCOT's design, LMPs are calculated at individual generation and load nodes, but load is settled at the load-weighted average price of its load zone. Zonal settlement smooths short-term volatility and facilitates hedging, but it also means some congestion costs are averaged across customers. As a result, LMPs' effectiveness in conveying accurate signals depends on how well load zones align with persistent transmission constraints, directly linking locational pricing to transmission planning and zone design.

### 2. Congestion Rent

Transmission congestion gives rise to congestion rent, which reflects the price differences created by locational marginal pricing. When transmission constraints bind, load on the higher-priced side of a constraint pays more than generators on the lower-priced side receive, so total load payments exceed total generator revenues. This surplus, known as congestion rent, results from enforcing physical transmission limits through prices. The day ahead market collects congestion rent and allocates it through congestion revenue rights (CRRs).

### 3. Congestion Revenue Rights

Congestion revenue rights are economic property rights funded by congestion rent collected in the day ahead market. A CRR entitles its holder to congestion payments based on the price difference between two locations: a source, where energy is injected into the system, and a sink, where energy is withdrawn. CRRs are defined by specific source-sink pairs, referred to as paths, and are denominated in megawatts. The volume of CRRs available on each path is limited by the modeled physical transmission capacity between the two locations, directly linking CRR

availability to the transmission system. Market participants purchase CRRs through auctions and may acquire them in monthly blocks up to three years in advance to manage congestion risk.

CRRs can be purchased as obligations or options. A CRR obligation entitles the holder to the price difference between the sink and source in the day ahead market, but it also requires the holder to pay if the price at the source exceeds the price at the sink. A CRR option entitles the holder to positive price differences while limiting downside when the price difference is negative. In addition to auctioned CRRs, ERCOT allocates a subset known as Pre-Assigned Congestion Revenue Rights, or PCRRs, to Non-Opt-In Entities (NOIEs) based on generation ownership or contractual arrangements that predate retail competition. Parties receiving PCRRs pay only a fraction of the auction value of comparable CRRs, reflecting their legacy transmission access rights.

#### 4. Generic Transmission Constraints

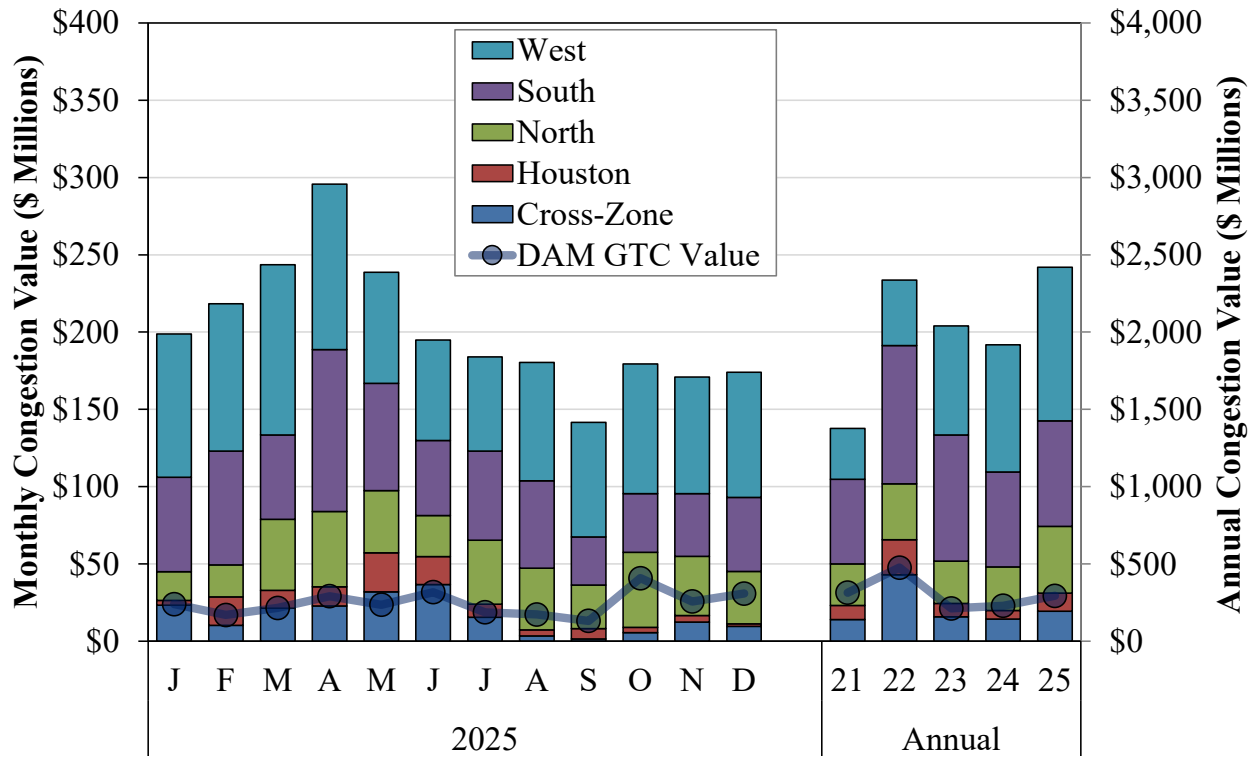
A Generic Transmission Constraint (GTC) is a transmission constraint made up of one or more grouped Transmission Elements. ERCOT uses GTCs to constrain flow between geographic areas to manage stability, voltage, and other constraints that its power flow and contingency analyses cannot model directly and that are based on offline studies (i.e., Real-Time Contingency Analysis (RTCA) will not indicate concerns). GTCs manage grid stability across geographic regions rather than enforce thermal transmission limits for specific transmission paths. They are especially relevant in areas with significant renewable generation, which are often far from load centers and can contribute to system stability concerns.

#### C. Day-Ahead Congestion

The day-ahead market produces financially binding schedules for supply, demand, and point-to-point (PTP) transactions that reflect transmission system limits. When these limits bind, congestion increases dispatch costs and causes energy prices to vary across locations in the network. Planned transmission outages and forecasts for load and intermittent renewable generation influence congestion in the day-ahead market. These factors shape how market participants hedge their positions before real time.

Figure 36 shows how the day-ahead market values congestion and highlights the role of GTCs in managing system stability. It calculates day-ahead congestion values as the product of power flows over each constraint and the constraint's shadow price, which reflects that constraint's marginal economic cost. Figure 36 presents congestion values within and across zones, including congestion linked to GTCs. It shows that day-ahead congestion increased by 26% from 2024 to 2025, ending the recent trend of declining annual congestion cost. Congestion costs increased in all four zones, across zones, and for GTCs. The largest drivers of the cost increase were congestion in the West and North zones. Congestion in the North zone corresponds to the large increase in RUC commitments to manage congestion.

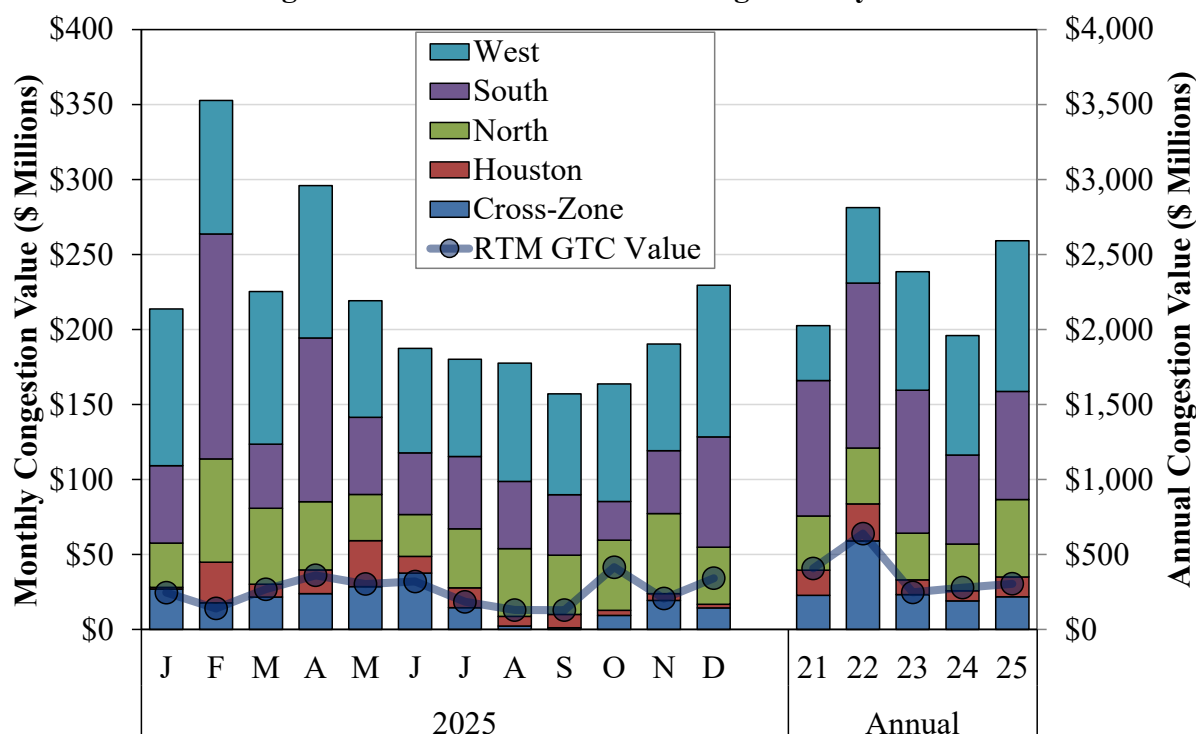
Figure 36: Value of Day-Ahead Congestion by Zone



#### D. Real-Time Congestion

The day-ahead market reflects the expected costs of congestion, but physical congestion occurs only in the real-time market. SCED manages power flows across the network as physical constraints become binding in real time. Unexpected changes in system conditions between the day-ahead and real-time markets often lead to differences in congestion values. These changes include net load forecast errors, forced outages, and other deviations from expected conditions.

Figure 37 summarizes monthly real-time congestion for 2025 and annual values from 2021 through 2025. This figure shows that real-time congestion in 2025 followed trends similar to those in the day-ahead market. Overall, congestion was approximately 7% higher in the real-time market than in the day-ahead market, likely because of forecast error for load and renewable generation and differences in thermal resource commitments between day-ahead and real time.

**Figure 37: Value of Real-Time Congestion by Zone**

## 1. Violated Constraints

The shadow price of a constraint represents the marginal cost of redirecting the flow of energy around a binding constraint. A constraint is violated when market dispatch flows exceed its transmission limit. Such violations impose reliability costs or risks on the system, which ERCOT embeds in the shadow price caps it uses to dispatch the system and set prices.<sup>41</sup> When the marginal cost of procuring relief through market dispatch exceeds the reliability cost of violating the constraint, the shadow price caps will: a) prevent the market from incurring additional dispatch costs; and b) set the shadow price for the constraint, which determines congestion prices at locations that affect the violated constraint.

The 2025 shadow price caps were:

- \$5,251 per MW for base-case (non-contingency) constraints or voltage violations,
- \$4,500 per MW for 345 kV constraints,
- \$3,500 per MW for 138 kV constraints, and
- \$2,800 per MW for 69 kV thermal violations.
- ERCOT treats GTCs as base-case stability constraints (for voltage or transient conditions) with a shadow price cap of \$5,251 per MW.

<sup>41</sup>

See [Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints](#).



At the end of 2024, ERCOT implemented NPRR 1230 to increase the shadow price cap on base-case constraints in response to IMM recommendation 2023-1. The higher shadow price cap allows SCED to produce more expensive dispatch solutions to avoid violating these constraints. Figure 38 shows the distribution of violated constraints by overload percentage since 2021.

**Figure 38: Overload Distribution of Violated Constraints**

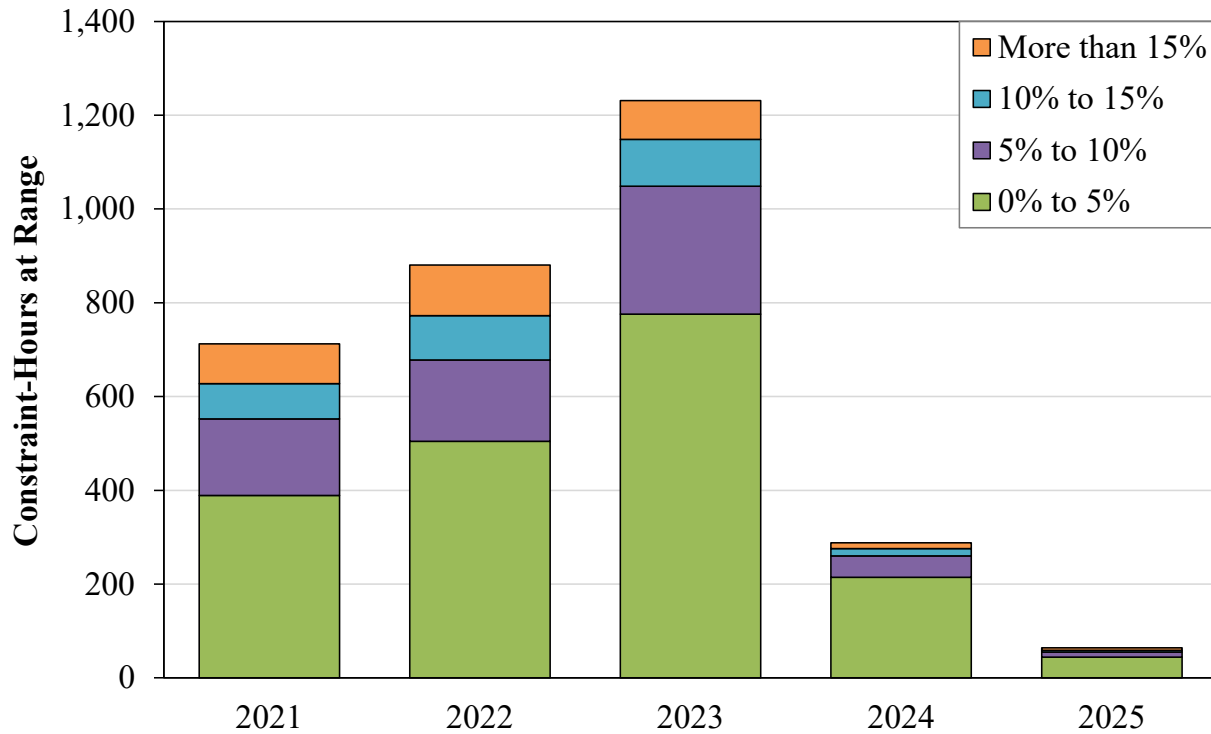


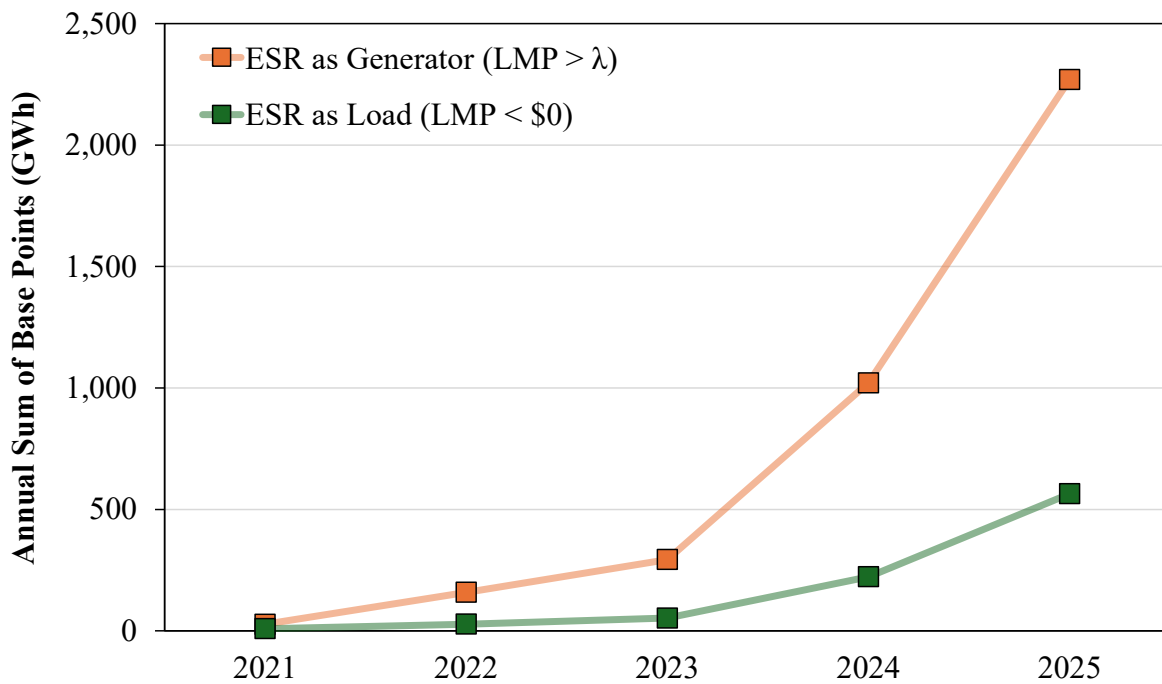
Figure 38 shows that the overall rate of violated transmission constraints continued to drop precipitously to 64 constraint-hours in 2025, by far the lowest annual total. The next lowest year was 2016, with 271 constraint-hours of violations. This drop in the frequency of constraint violations continued despite the increase in the frequency and cost of congestion from 2024 to 2025. The sharp decline may be partly explained by the growing participation of energy storage resources (ESRs) in the real-time energy market. As the ancillary services market has become saturated, a larger share of ESR revenue has depended on energy arbitrage, accelerating this shift toward real-time market activity.

## 2. Congestion Management by ESRs

ESRs are particularly well suited to help resolve congestion because they can act as both supply and demand. When increasing load at a particular location can resolve congestion, ESRs can often charge at prices below \$0. Conversely, when increasing supply at a particular location can resolve congestion, ESRs can discharge and earn higher prices that reflect the value of serving load subject to binding transmission constraints.

Figure 39 illustrates this trend by showing the annual total base points awarded to ESRs that help manage congestion as generators or loads. For ESRs acting as generators, we aggregate base points awarded at an LMP greater than the system lambda, indicating that energy injections at that location help manage congestion. For ESRs acting as loads, we aggregate base points awarded at an LMP less than zero, meaning ESR load provides enough value in resolving congestion that the system pays them to charge. Figure 39 shows that both trends have increased at an accelerating rate over the last five years.

**Figure 39: Annual Sum of Base Points Awarded to ESRs Helping Congestion**



As in previous years, a large majority of constraint violations in 2025 were less than or equal to 5% above the constraint limit. These relatively small violations are priced at the same shadow price cap as more severe violations. This raises concerns because a single shadow price cap does not scale the cost of violating a constraint with the severity of the violation. Hence, it may be advisable to reconsider implementing transmission demand curves, which would recognize that the reliability risk of a post-contingency overload increases as the violation amount increases. Small violations should have lower shadow prices than large violations.

### E. CRR Market Outcomes and Revenue Sufficiency

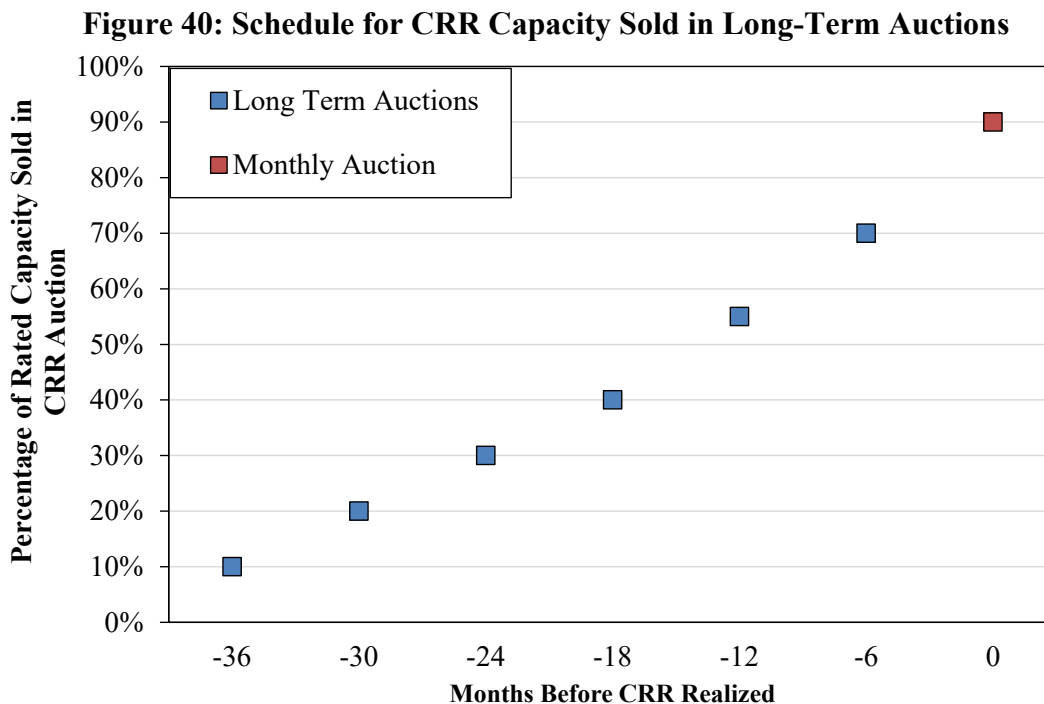
This section discusses the CRR auction timeline and inputs, the allocation of CRR auction revenues to load, CRR profitability trends, and the funding of CRRs through day-ahead market congestion rent.

## 1. CRR Auction Timeline

Each CRR is valid for the full month for which it is purchased. CRRs are sold through two recurring auction types: long-term and monthly. ERCOT holds long-term auctions twice each year and offers CRRs up to three years, or 36 months, in advance of the real-time market. It conducts subsequent long-term auctions every six months, with the final auction occurring six months prior to real-time. ERCOT conducts monthly auctions closer to delivery, holding the auction for a given operating month in the preceding calendar month.

Historically, long-term auctions allowed participants to purchase CRRs either for individual months or as blocks of consecutive months within a single auction. NPPR 1288, approved in November 2025, eliminated this block purchase option by removing multi-month blocks to reduce auction optimization time. As a result, participants now purchase CRRs only for individual months, even in long-term auctions that cover multiple future months.

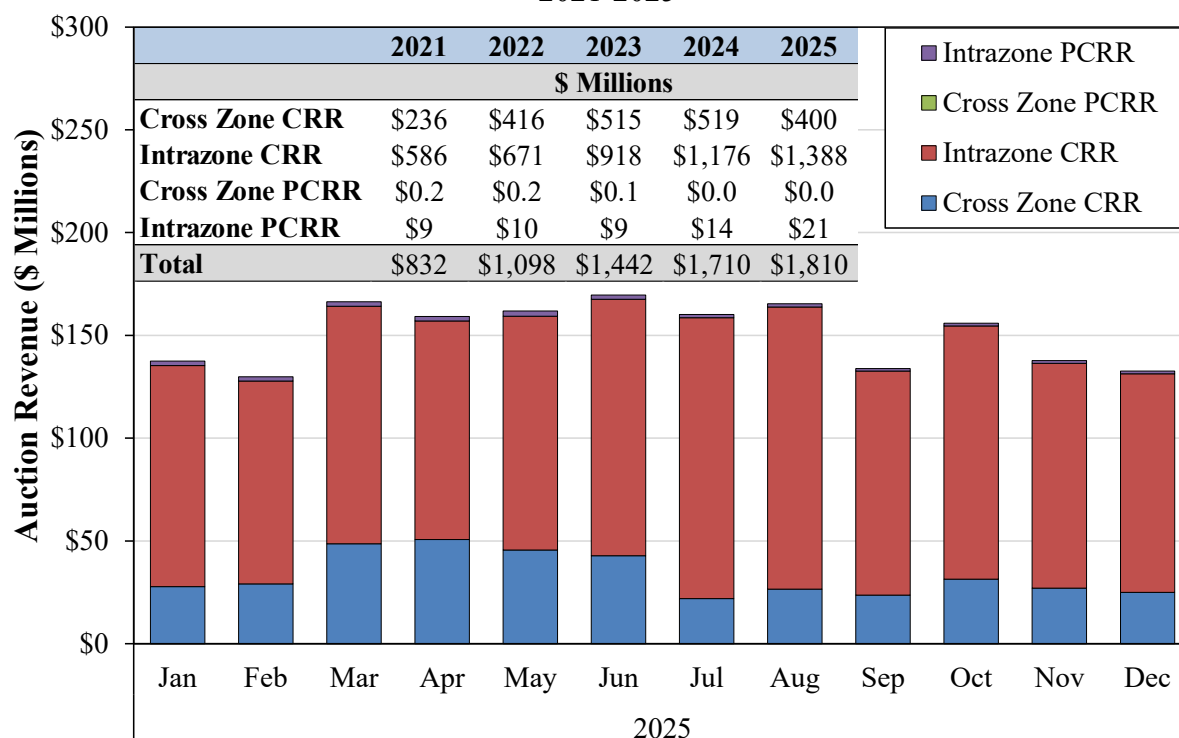
Running CRR auctions years in advance of real time provides market participants with additional hedging opportunities and supports forward price formation. However, forecasting congestion becomes more uncertain over longer time horizons because congestion outcomes depend on load growth, generation development, transmission outages, and variable renewable output. This uncertainty increases the risk that payments to CRR account holders could exceed the congestion rent collected in the day-ahead market and create a revenue shortfall. To mitigate this risk, ERCOT sells only a portion of the rated transmission capacity for each CRR path in long-term auctions, then increases the percentage of capacity available in successive auctions until the final monthly auction, as illustrated in Figure 40.



## 2. CRR Auction Revenues

The total value of CRR auction revenue increased by almost 6% from 2024 to 2025. This growth rate was notably lower than in prior years, as annual CRR revenue growth from 2021-2024 ranged from around 14% to 32%. Intrazonal CRRs drove the increase in total CRR revenue, while revenue for Cross Zone CRRs fell to its lowest value since 2021.

**Figure 41: CRR Auction Revenue**  
2021-2025



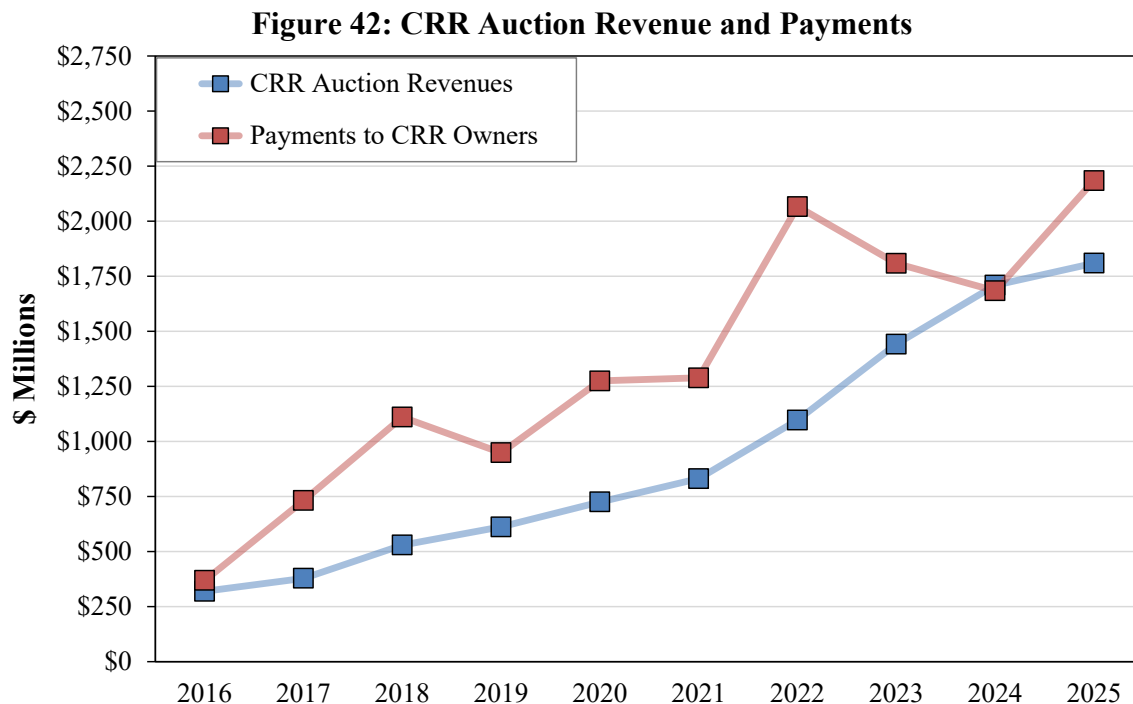
ERCOT distributes the revenues it receives from selling CRRs to Load Serving Entities (LSEs) through the CRR Auction Revenue Distribution (CARD) process. CARD allocates revenues from cross-zone CRRs to LSEs ERCOT-wide based on their system-wide load ratio share during each month's coincident peak interval, and it allocates revenues from CRRs with source and sink in the same zone to loads in that zone based on their zonal load ratio share during the same coincident peak interval.

As revenues from CRR purchases and corresponding CARD payment distributions have increased, this methodology has drawn greater scrutiny because it can create adverse economic incentives for loads to increase consumption during periods of high demand, when high energy prices should incentivize loads to decrease consumption. To date, only DC tie operators have clearly exhibited such behavior. To remove these adverse incentives, ERCOT approved NPRR 1030 in August 2020, which allocates CARD payments for DC ties based on their monthly load

ratio shares.<sup>42</sup> This methodology sharply reduces the incentive for DC ties to increase consumption to increase their CARD revenue.

### 3. CRR Profitability

Figure 42 shows annual aggregate CRR auction revenue and payments to CRR owners, whose difference represents CRR profitability. Overall, CRRs have been profitable annually in every year except 2024, when they produced a loss of approximately 1.5%. In 2025, CRR profitability increased by almost 21%, reversing a two-year decline.



### 4. CRR Funding Levels

The integrity of the CRR market depends on fully funding CRRs with congestion rent. ERCOT pays less than the target value only when day-ahead congestion rent is insufficient, which can occur when the network flows modeled in the CRR auction exceed the flows in the day-ahead market. This occurrence is often the result of unforeseen outages or other factors that reduce transmission capability between the CRR auction and the DAM.

#### *CRR Shortfall Settlement*

When oversold flows cause a shortfall on a specific transmission facility, ERCOT reduces payments to CRRs that sink at generator locations affecting that facility. These reductions are

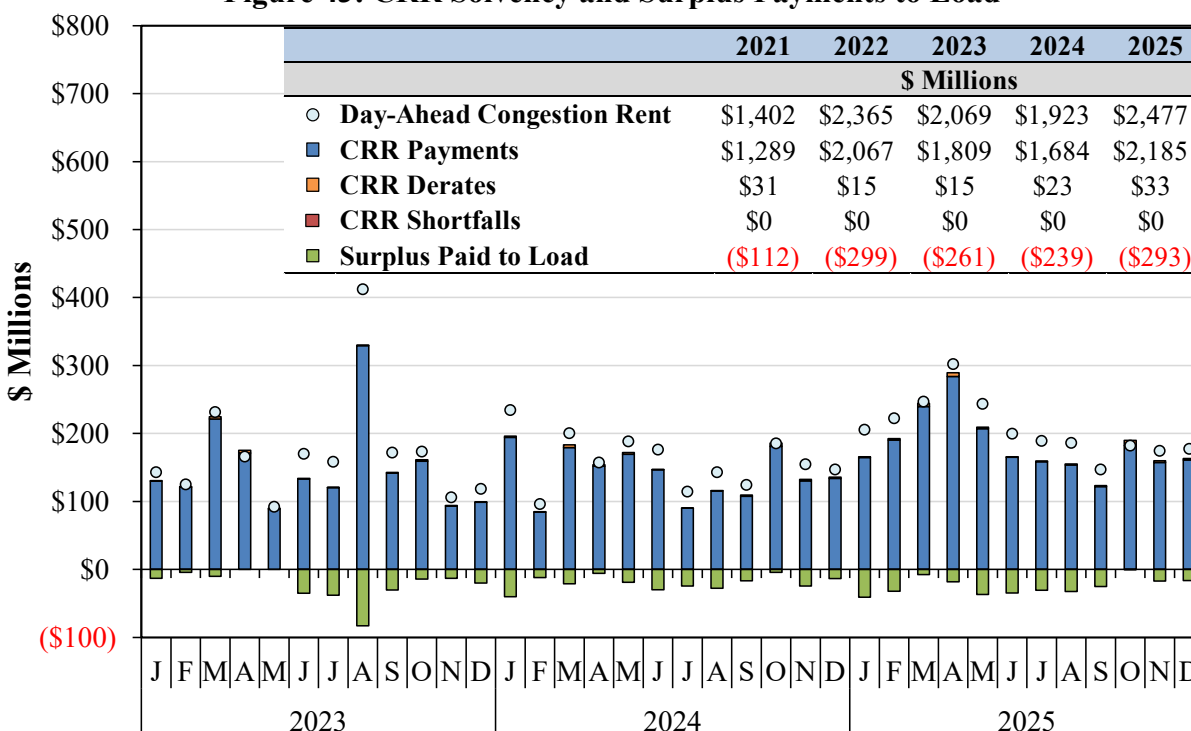
<sup>42</sup> Despite being approved in 2020, the project to implement NPRR 1030 has not been initiated yet. [https://www.ercot.com/files/docs/2022/01/27/Revision\\_Requests\\_2026\\_04\\_14.xlsx](https://www.ercot.com/files/docs/2022/01/27/Revision_Requests_2026_04_14.xlsx)

based on the decrease in day-ahead transfer capability. If revenue remains insufficient after this adjustment, ERCOT allocates the remaining shortfall across all holders of positively valued CRRs through a prorated charge, which reduces their overall payments. The last CRR short payment occurred in November 2020.

### *CRR Surplus Settlement*

When day-ahead congestion rent exceeds the amount owed to CRR holders, ERCOT tracks the excess in a monthly settlement process called the balancing account. ERCOT uses this excess congestion rent to repay CRR holders previously assessed shortfall charges, effectively refunding those amounts. If current-month excess congestion rent is insufficient, ERCOT can use the rolling CRR balancing fund from prior months to fully pay CRR holders. The CRR balancing fund has a \$10 million cap, beyond which ERCOT disperses the remainder to LSEs. Figure 43 shows monthly CRR surpluses and shortfalls since 2021.

**Figure 43: CRR Solvency and Surplus Payments to Load**



In 2025, the total day-ahead surplus was approximately \$293 million, up 22.4% from 2024. Congestion rent from the day-ahead market was sufficient to fully fund CRRs in every month of the year. As a result, the balancing account remained at its \$10 million cap, and ERCOT returned all surplus congestion rent above that threshold to LSEs. ERCOT's practice of offering only 90% of forecasted transmission capability in CRR auctions reduces the likelihood of future funding shortfalls.

Although the day-ahead market produced enough revenue to fully fund CRRs, ERCOT derated many CRRs in 2025 under the mandatory deration process. CRR deratings reduced payments to CRR holders by \$33 million and reduced ERCOT's overall funding percentage to approximately 99%, comparable to the previous year. Derating CRRs when the market produces sufficient revenue introduces unnecessary risk for CRR buyers and could ultimately reduce CRR auction revenues.

## **F. Congestion Cost and Load**

As the ERCOT grid has grown in size and complexity, transmission costs have become a larger share of overall system costs. Rapid load growth, changes in the geographic distribution of generation, and the need to manage congestion and reliability have driven substantial investment in new transmission infrastructure. The growing share of transmission costs has raised concerns about whether it remains appropriate to socialize those costs across all ERCOT ratepayers and whether the current transmission cost allocation methodology fairly assigns costs to those who benefit from new investment. These questions have become more prominent as transmission spending has increased and congestion patterns have evolved across the system.

### **1. The Case Against 4CP**

ERCOT currently allocates transmission costs under the four coincident peak, or 4CP, methodology, which assigns transmission cost responsibility based on a customer's load during the four highest system peak intervals in the summer months.<sup>43</sup> The PUCT implemented this approach during the transition to a competitive market because it was simple to administer and reflected the notion that peak demand drives the need for transmission investment. Whatever virtues this methodology may have had once upon a time, it no longer effectively allocates transmission costs in today's system.

As transmission costs have grown, 4CP has created strong incentives for certain loads to avoid cost responsibility through strategic behavior that does not meaningfully reduce congestion or defer transmission investment. These incentives differ from true demand response, distort market price signals, and weaken the link between cost causation and cost allocation, raising concerns about efficiency and fairness under the current methodology. In addition, some loads, including data centers and cryptocurrency mines, can operate strategically to game their transmission cost allocation.

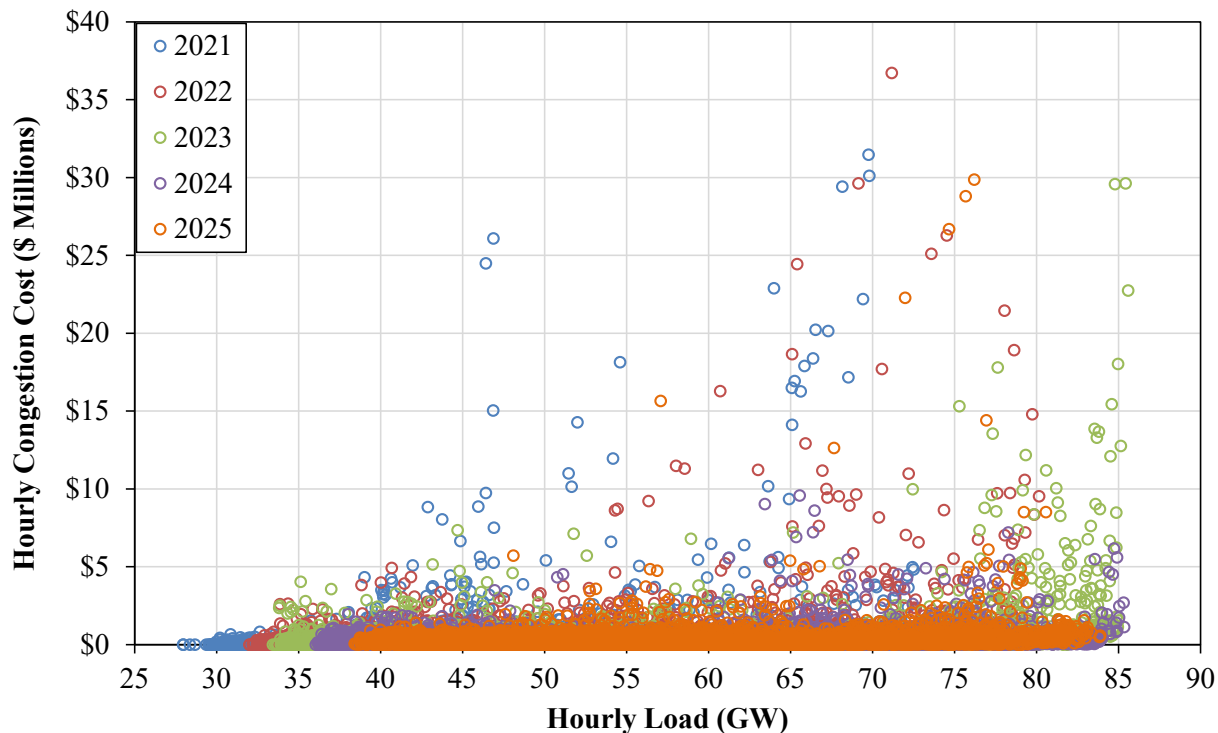
### **2. Correlation with Peak Demand**

A key consideration in allocating transmission costs is whether the assumptions underlying the current system remain valid. The idea that transmission costs should be allocated according to

<sup>43</sup> The summer months as they relate to 4CP comprise June, July, August, and September.

each load's contribution to peak demand is rooted in the notion that peak demand drives the need for new transmission infrastructure. However, the data only weakly supports this hypothesis. Figure 44 shows the correlation between congestion costs in ERCOT and peak demand over the last five years. Although Figure 44 shows some correlation between the two, it is not strong enough to justify allocating transmission costs on that basis, especially given the impact that forecasted transmission costs will have on ratepayer electricity bills.

**Figure 44: Correlation between Congestion Cost and Load**  
2021-2025



### 3. SB 6 – Transmission Cost Recovery

Recognizing the need to review the 4CP methodology, the 89<sup>th</sup> Texas Legislature passed SB 6 in June 2025.<sup>44</sup> SB 6 has many sections, and we cover most of them in Chapter VII. Section 6, which addresses transmission cost allocation, is relevant to this discussion because it calls for a review of 4CP and for a proposal of an alternative if the 4CP methodology no longer serves its intended purpose. The PUCT organized Section 6 of SB 6 into PUC Project 58484.<sup>45</sup> The PUCT has not approved a rulemaking for this project yet. Our recommendations for the rulemaking are in the link in the following footnote.<sup>46</sup>

<sup>44</sup> SB 6: <https://capitol.texas.gov/tlodocs/89R/billtext/html/SB00006F.htm>

<sup>45</sup> PUC Project 58484: <https://interchange.puc.texas.gov/Search/Filings?ControlNumber=58484>

<sup>46</sup> IMM Comments on Project 58484: [https://interchange.puc.texas.gov/Documents/58484\\_74\\_1561771.PDF](https://interchange.puc.texas.gov/Documents/58484_74_1561771.PDF)



## G. Load Zone Configuration

ERCOT established the four current load zones in 2003: North, West, South, and Houston. Load zones aggregate nodal prices to settle load and communicate congestion conditions to the market through price signals. By averaging nodal prices within each zone, they provide clear price signals that reflect persistent transmission constraints between regions, including signals that transmission investment may be needed when congestion costs persist. However, when a load zone contains substantial internal congestion, those costs are averaged across loads and are no longer clearly associated with specific transmission limitations. As a result, the economic signal that would otherwise indicate the value of relieving congestion through transmission upgrades or reconfiguration is obscured, which reduces the effectiveness of zonal prices in guiding efficient planning and investment decisions.

### 1. The Case for Updating the Load Zones in ERCOT

The case for improving the current load zone configuration has grown stronger in recent years. Renewable development, especially solar, has expanded rapidly, while load growth patterns have become increasingly misaligned with the existing load zone map. For example, the Permian Basin, a major hub for oil and gas production, has become a high-cost, import-constrained load pocket, while the Texas Panhandle is export constrained, leading to frequent curtailment of abundant wind generation. Placing both regions within the same load zone (West) produces inefficient prices that fail to reflect the underlying differences in system conditions.

The growing divergence in load and generation patterns in ERCOT led us to Recommendation 2020-3, that ERCOT should update the load zone configuration and introduce new load zones to recognize key transmission constraints and minimize intra-zonal congestion. A regular process for updating ERCOT's load zone configuration is critical for zonal pricing to send efficient signals to load for consumption and investment. This is especially important because ERCOT's topology will continue to become more complex, while any approved load zone configuration will take effect four years after approval.

### 2. Congestion Impact

Load zones group areas with broadly similar transmission and congestion characteristics so that congestion pricing occurs primarily between zones rather than within them. When congestion is reflected in price differences across load zones, zonal prices provide clear and efficient signals about where transmission constraints are binding and where investment may be needed.

However, when congestion occurs within a load zone, the market averages those costs across the zone and obscures the underlying transmission limitations, weakening price signals. Figure 45 illustrates the share of congestion costs that occur intrazonally versus across load zones and, therefore, the extent to which the current zonal structure makes congestion visible to the market.

**Figure 45: Annual Zonal Congestion Cost**  
2016-2025

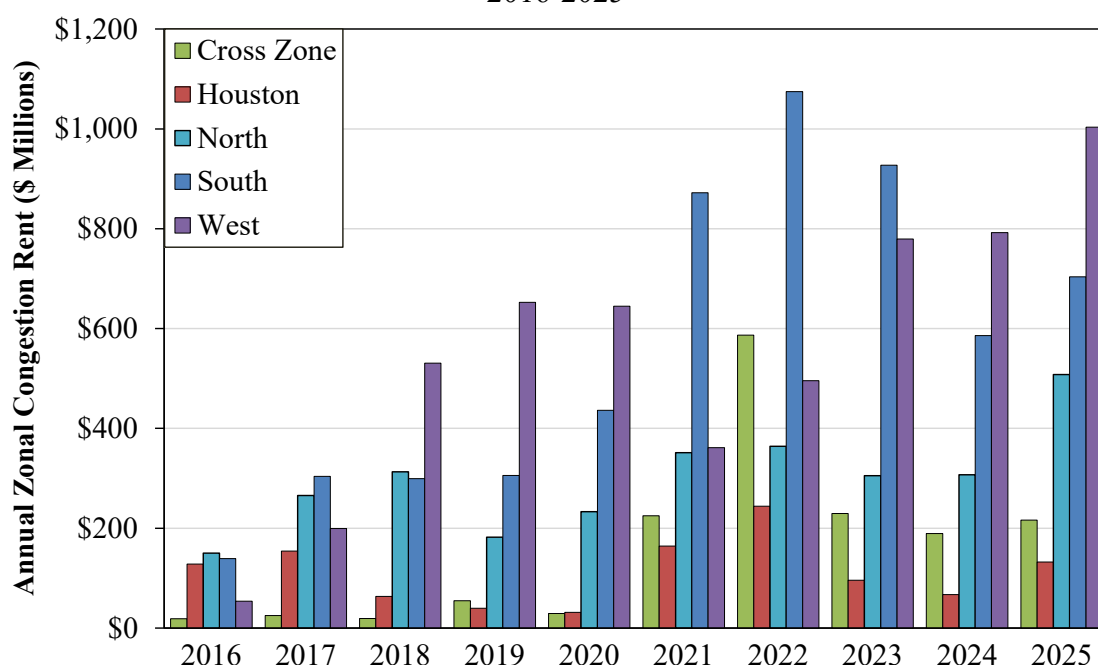


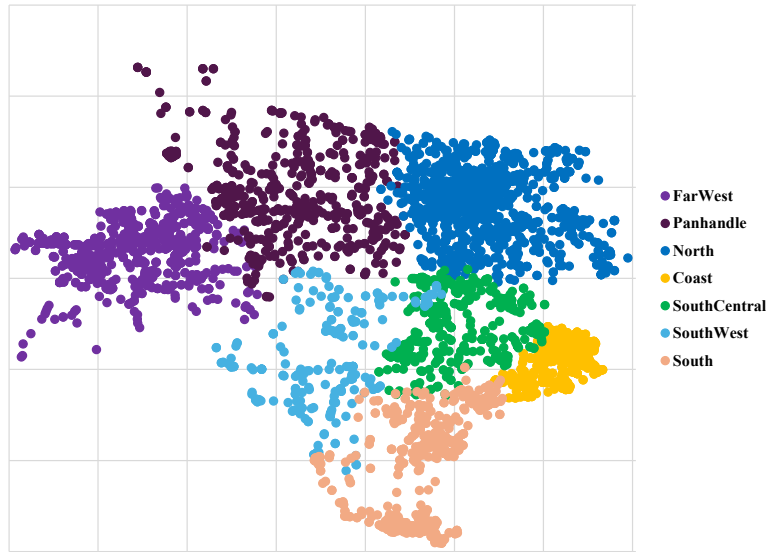
Figure 45 shows that a growing share of congestion costs materializes as intrazonal congestion costs. In 2025, roughly 9% of congestion costs were interzonal, down from 11% in 2024. The West Zone is the largest contributor to intrazonal congestion costs because it is export constrained in the panhandle because of the abundance of renewables in the area and import constrained in the Permian Basin. Congestion costs within the West increased by 27% between 2024 and 2025. Next, we discuss a methodology to define load-zone boundaries based on geographic coordinates and historical pricing outcomes.

### 3. Methodology for Defining Load Zones

Our methodology groups substation-level load nodes into new load zones based on geographic coordinates and historical price data.<sup>47</sup> We chose these metrics to define load zones by proximity and congestion conditions. We evaluated a 7-load-zone configuration using data from January 2022 through December 2025. Figure 46 illustrates the resulting distribution of load nodes within the proposed 7-load-zone configuration.

<sup>47</sup>

The methodology uses k-means clustering refers to a machine learning algorithm used to group data into clusters based on their similarities. This algorithm incorporates geographic proximity, congestion data, and a specified number of load zones to arrive at a grouping of substations into a new set of load zones.

**Figure 46: Geographic Distribution of Substations for the 7-Load-Zone Configuration**

To evaluate how this updated load zone configuration improves zonal pricing, we consider the resulting decrease in intrazonal congestion rent shown in Table 6. This data indicates that this reconfiguration would significantly reduce intrazonal congestion compared to the current load zone map. It also produces more congestion rent between zones because price disparities efficiently reflect geographic differences in the cost of serving load across the grid.

**Table 6: Real-Time Congestion Rent (\$MM) for the 7-Load-Zone Configuration**

	Cross Zone	Coast	North	South	SouthCentral	SouthWest	FarWest	Panhandle
	\$ Millions							
2021	\$392.9	\$297.3	\$282.5	\$271.8	\$232.9	\$127.1	\$139.7	\$230.3
2022	\$959.1	\$377.4	\$224.2	\$332.6	\$206.1	\$190.2	\$263.3	\$212.7
2023	\$580.9	\$229.8	\$245.1	\$228.3	\$222.6	\$168.7	\$350.6	\$311.5
2024	\$513.1	\$92.0	\$173.3	\$254.2	\$164.0	\$162.2	\$277.8	\$305.1
2025	\$646.3	\$206.4	\$335.4	\$191.8	\$171.6	\$194.5	\$517.7	\$300.4

Figure 47 and

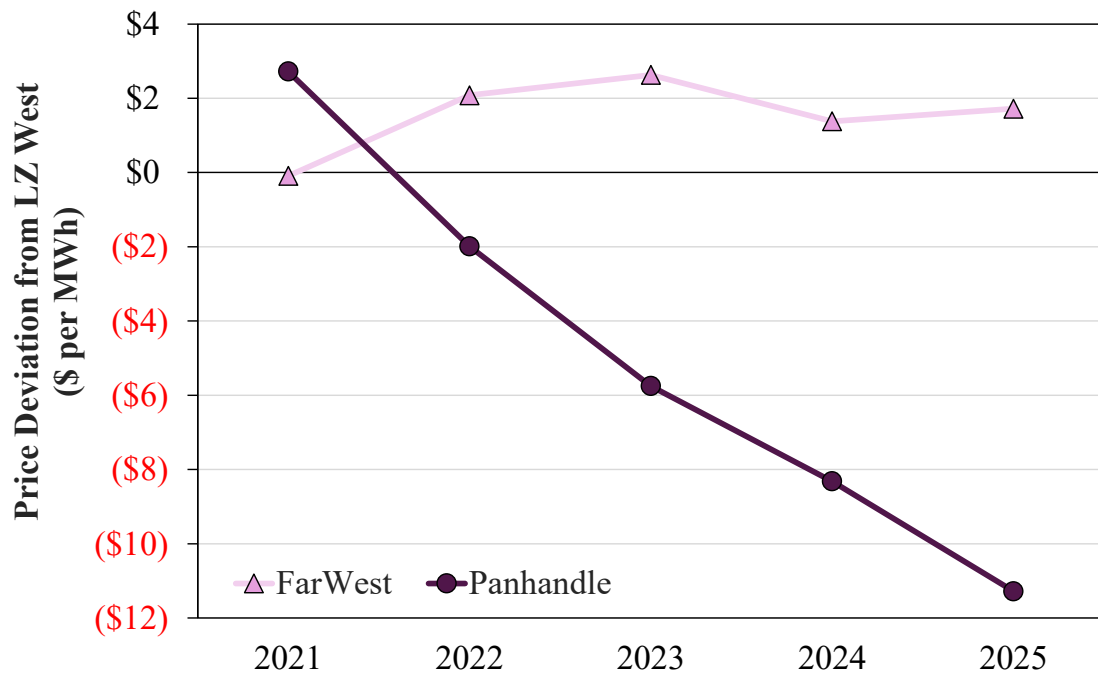
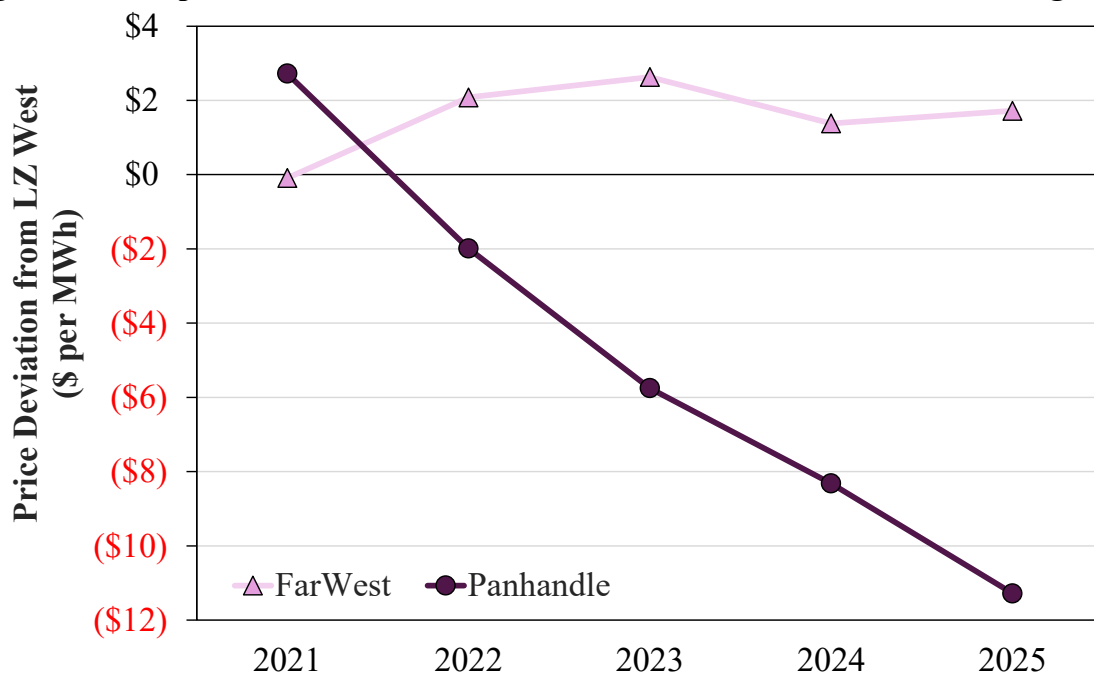


Figure 48 compare pricing in the West and South load zones with the prices that would emerge if those zones were subdivided into the proposed new load zones. In the West, the figures illustrate how prices diverge between the Panhandle and FarWest areas. In the South, they show distinct pricing patterns across the South, SouthCentral, and SouthWest areas.

**Figure 47: Comparison of LZ West Prices: Current vs. New 7-Load-Zone Configuration**

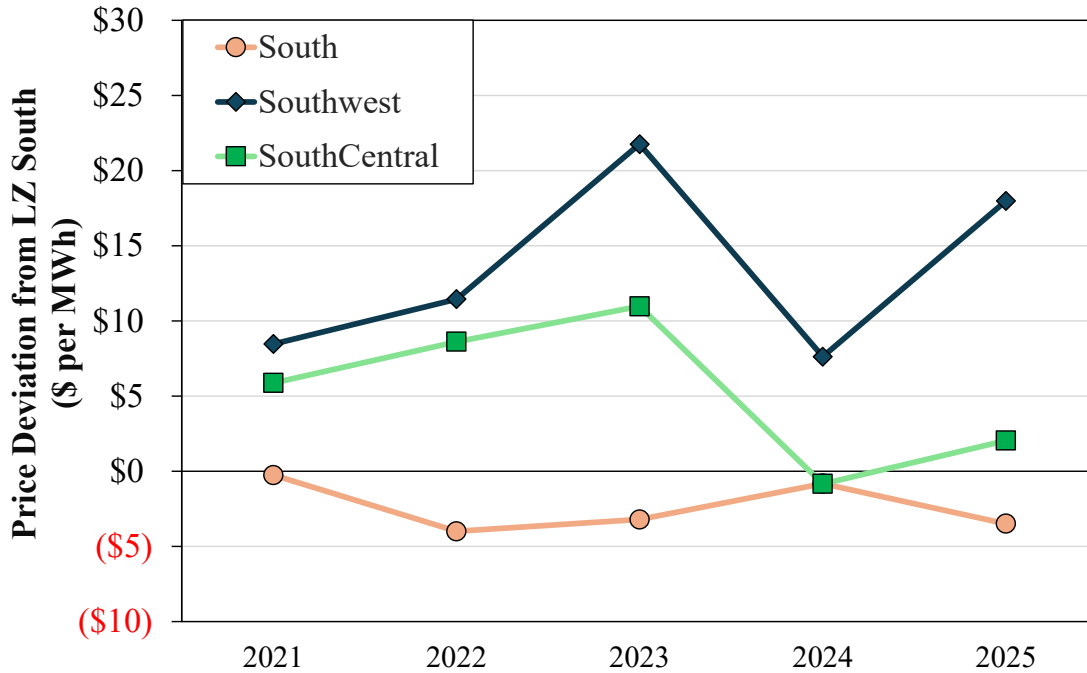
**Figure 48: Comparison of LZ South Prices: Current vs. New 7-Load-Zone Configuration**

Figure 47 shows a significant pricing difference between the Panhandle and FarWest. Prices in the Panhandle load zone have plummeted because of the magnitude of renewable generation in the area, so the zone would average prices that differ significantly from those in the FarWest load zone. The FarWest load zone approximately corresponds to the Permian Basin, where prices would understandably be higher because it remains import constrained until more transmission is built into the area. Despite the very different characteristics of these two areas, they aggregate to the current West load zone.

Similarly,

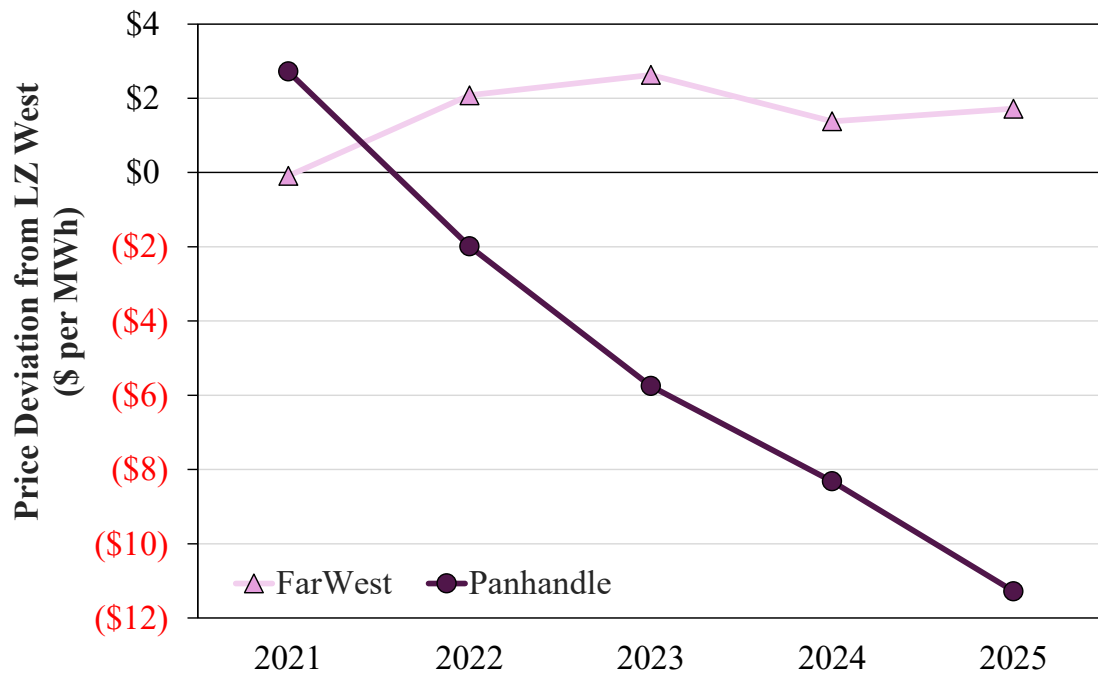


Figure 48 shows large pricing differences between the new South load zone, which extends from Corpus Christi to the Rio Grande Valley, and the new SouthWest and SouthCentral zones. These pricing differences between regions in the same load zone indicate that the current load zones obscure large differences in the cost of serving load within the zone.

#### 4. Conclusion

ERCOT has effectively acknowledged that the current four-zone configuration does not accurately characterize the network topology. In its engagement with PowerGem to evaluate the reliability standard of the ERCOT system that accounts for transmission constraints, PowerGem proposed an eight-zone configuration using a topology-based approach.<sup>48</sup> Such an approach may be better-suited to account for planned improvements to the transmission network that are already underway such as the Permian Basin Reliability Plan.

Our analysis supports Recommendation 2020-3 that ERCOT develop a process to redefine the load zones so they better reflect current congestion conditions on the grid. We have presented one viable approach based on historical nodal prices and geographic proximity, but we would also support ERCOT implementing an approach more like PowerGem's topology-based method. Either option would form zonal prices more effectively and promote more efficient consumption and investment decisions by load customers.

<sup>48</sup> [https://www.ercot.com/files/docs/2026/01/29/2\\_SAWG\\_Trial\\_Simulation\\_Results\\_Amended\\_20260127.pptx](https://www.ercot.com/files/docs/2026/01/29/2_SAWG_Trial_Simulation_Results_Amended_20260127.pptx)

## VI. MARKET OPERATIONS

### A. Summary of Market Operations Results in 2025

Ideally, markets should procure and dispatch all resources needed to operate the system reliably. In practice, however, operators often supplement market outcomes with out-of-market actions to address reliability concerns. These actions are undesirable because they interfere with price signals that guide efficient short-term decisions and long-term investment, shift costs, reduce transparency, and complicate settlements. Although such interventions are sometimes necessary, persistent reliance on them indicates a misalignment between market design and system operations. This chapter examines the role and implications of these out-of-market operator actions. The following are the key insights from this chapter:

- **RUC commitments have risen sharply since 2021 when ERCOT adopted a more conservative operating posture.** This approach aims to reduce reliability risk, but it also disrupts resource plans and contributes to market distortion and muted scarcity pricing.
- **Reliability unit commitments totaled 5,129 resource-hours in 2025, a 176% increase over 2024.** The RDPA exceeded \$0 in 76% of active intervals, consistent with the trend over the last five years.
- **In 77% of cases, RUC instructions were issued to manage congestion rather than capacity.** This reversed the pattern in recent years, when RUC instructions were mainly issued for capacity.
- **Make-whole payments during RUC settlement exceeded \$21 million in 2025, while total claw-backs were only \$4.5 million.** This disparity reflects relatively low market prices in 2025 that did not cover the start-up and minimum generation costs of RUC-committed units.
- **ERCOT has meaningfully improved its forecast accuracy since 2022, reducing the average net load forecast error to 452 MW.** This error is down from more than 1,000 MW in 2023 and 2024, but ERCOT still systematically underforecasts renewable generation and overforecasts load.
- **RUC now incorporates ESR SOC from the COP, which has a major impact on out-of-market commitment decisions.** On average, aggregate ESR SOC in the COP exceeded real-time values by 874 MWh.
- **The PUCT has approved a rulemaking for the firm fuel supply service.** We are concerned that including natural gas units in the program will have adverse impacts, and we propose an alternative framework at the end of this chapter.

## **B. Reliability Unit Commitments**

### **1. RUC Fundamentals**

Shortfalls in market-procured capacity can arise from how generators participate in the market. Most generators in ERCOT decide whether to start up on their own, a practice known as self-commitment. This approach contrasts with other Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), where a much larger share of generation is scheduled through the day-ahead markets. ERCOT's day-ahead market is financially binding and does not create physical obligations in real time. In other words, a generator scheduled in the day-ahead market is not required to commit in real-time. Instead, it can choose not to run and buy back its day-ahead schedule at the real-time price. Conversely, if it delivers more than its day-ahead award, it is paid the real-time price for generation in excess of its day-ahead schedule. Nonetheless, if ERCOT projects that insufficient generation will be available in real-time, it may issue an out-of-market commitment instruction through the Reliability Unit Commitment (RUC) process described below.

Through the RUC process, ERCOT can commit additional generators that were neither self-committed nor scheduled day ahead. RUC commitments can occur in the day-ahead timeframe, known as Day-Ahead RUC (DRUC), or closer to real time through Hourly RUC (HRUC). The vast majority of RUC instructions come through the HRUC process. For resources that submitted a valid three-part offer in the day-ahead market, RUC uses those offers. For all other resources, RUC uses either verifiable cost data or, if verifiable cost data are unavailable, generic cost data for different resource classes.

Operators issue RUC commitments to meet forecasted system-wide demand or manage congestion. In the latter case, specific units may be required to serve load in transmission-constrained areas, provide counterflow on a constraint, or support local reliability. The criteria for making RUC commitments should be transparent and grounded in objective reliability risks rather than an arbitrarily conservative operational approach. Risk-based standards help ensure that the RUC process is used only when necessary, supporting market efficiency and maintaining stakeholder confidence in ERCOT's operational decisions.

### **2. Market Impacts of RUC**

#### ***Suppression of Real-Time Prices***

RUC commitments increase generation supply in the market, putting downward pressure on prices. To reduce this distortion, ERCOT uses the Reliability Deployment Price Adder (RDPA) to adjust real-time prices upward and preserve the shortage signals that would have existed without the out-of-market commitment. See Figure 6 in Chapter I.D.2 for more information on the frequency and magnitude of the RDPA for 2021-2025.



ERCOT also applies a \$250-per-MWh offer floor to RUC-committed units. This high minimum-offer price reduces the likelihood that these resources will be economically dispatched or set the market clearing price, which limits their direct influence on real-time prices. Together, these tools limit the extent to which RUC suppresses prices.

### ***Make-Whole Payments, Clawbacks, and Opt-Outs***

Generator operating costs are incorporated into the RUC process through three-part offers, verifiable costs, or generic cost inputs by resource type. When ERCOT commits a generator through RUC based on these costs, it uses the cost data to determine whether the unit is entitled to a make-whole payment. These payments ensure that RUC-committed units do not lose money when their market revenues fall short of their costs. Conversely, if a RUC-committed unit earns more revenue than its costs, ERCOT will claw back the excess revenues.

ERCOT first allocates make-whole payment costs to Qualified Scheduling Entities (QSEs) that do not provide enough capacity to cover their real-time obligations and are therefore capacity short. Second, all QSEs share the remaining costs on a load-ratio-share basis. Suppliers may opt out of both the make-whole payment and any associated clawback, effectively self-committing the unit and accepting full exposure to market outcomes. ERCOT's RUC commitment practices influence the magnitude of make-whole payments and clawbacks and the frequency of opt-outs. The following subsections discuss trends in RUC activity.

### **3. RUC Activity**

Table 7 shows trends in ERCOT's aggregate use of RUC from 2021 through 2025. In 2025, ERCOT issued the most RUC commitment instructions in resource-hours and had the greatest effect on the market's energy supply since 2022. Comparing RUC Active Hours with the hours that show non-zero RDPA values in Figure 6, the RDPA was non-zero for 76% of the intervals when RUC resources were online, consistent with the trend over the last five years. As discussed in Chapter I, the average RDPA value when activated was greater in 2025 than in 2024, but both years were considerably lower than the three prior years.

**Table 7: Magnitude of RUC Activity**  
2021-2025

	Active Hours	Resource- Hours	RUC LSL Capacity-Hours (MWh)
<b>2021</b>	1,187	3,863	257,603
<b>2022</b>	2,139	7,910	609,322
<b>2023</b>	975	2,501	155,553
<b>2024</b>	1,066	1,861	191,393
<b>2025</b>	1,820	5,129	364,991

#### 4. Reasons for RUC

Next, we consider trends in the reported rationale for each RUC commitment, loosely categorized as congestion or capacity, shown in Table 8. The operators who issue the instruction designate the rationale for each RUC commitment as either congestion or capacity to indicate the system conditions that precipitated the instruction. Table 8 shows a large increase in the use of RUC to manage congestion. This increase drove the overall increase in RUC instructions and corresponding market impact in 2025.

**Table 8: Reported Reason for RUC**  
2021-2025

	Congestion	Capacity
	Frequency (%)	
2021	9	91
2022	18	82
2023	8	92
2024	34	66
2025	77	23

Combined, Table 7 and Table 8 show a large increase in RUC instructions in 2025, most of it attributable to congestion. This trend coincided with fewer resources opting out of RUC settlement and higher make-whole payments, as shown in Table 9.

#### 5. RUC Settlement

In 2024, the rate of RUC-committed resources that opted out of RUC settlement dropped significantly below its long-term trend, largely because of the implementation of NPRR 1172. This rule imposed a full rather than partial claw-back for resources that opted out of RUC settlement. The most likely explanation for the even lower level of opt-outs in 2025 is that market prices were not expected to be high enough to warrant opting out. This is reflected in the large increase in make-whole payments from 2024 to 2025 and the relatively low total for claw-back charges despite the large volume of energy settled through RUC.

**Table 9: RUC Settlement**  
2021-2025

	Opt-Out of RUC Settlement	Claw-Back	Make-Whole
	Frequency (%)	(\$ Millions)	(\$ Millions)
2021	39	\$3.09	\$5.38
2022	24	\$22.69	\$70.13
2023	23	\$3.45	\$3.69
2024	8	\$7.14	\$3.35
2025	3	\$4.53	\$21.84

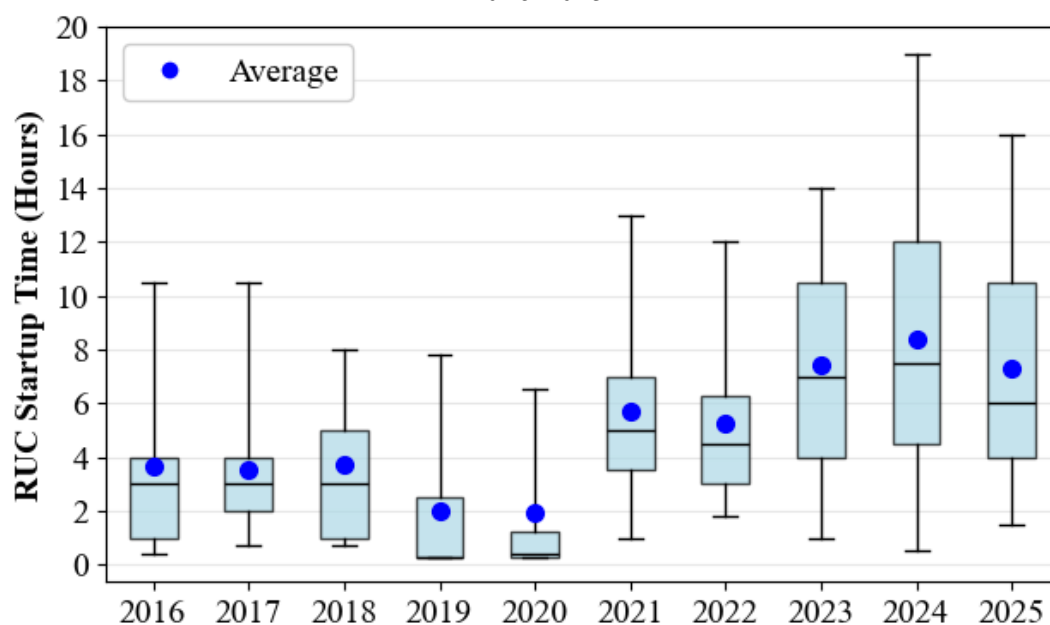
Out-of-market settlement is likely higher when resources are committed through RUC to resolve congestion rather than capacity needs. Without a counter-veiling pricing mechanism, out-of-market commitments necessarily suppress market prices. The RDPA is intended to address this price suppression, but it currently does not address local nodal price effects. As a result, the RDPA does not significantly increase energy prices unless the commitments affect system-wide prices. NPRR 1214, submitted in December 2023, seeks to address this shortcoming of the RDPA by producing price adders that vary across nodes to reduce out-of-market make-whole payments for resources committed through RUC to manage local transmission issues. This NPRR has been tabled at PRS since May 2025 as ERCOT was focused on implementing RTC.<sup>49</sup>

## 6. Conservative Operations & RUC

Over the longer term, RUC activity in the last five years has been significantly higher than the norm before Winter Storm Uri. For example, resource-hours committed through RUC per year ranged from 202 to 613 from 2017 through 2020, whereas annual RUC commitments have consistently totaled thousands of resource-hours since 2021.

The increase in out-of-market commitments through RUC is a fundamental feature of ERCOT's practice of conservative operations. By anticipating a worst-case scenario, ERCOT more frequently committed units with longer startup times to prevent even modest real-time shortages. Figure 49 shows the distribution of startup times for resources committed through RUC from 2016 through 2025.

**Figure 49: Distribution of Startup Times for RUC Resources  
2016-2025**



<sup>49</sup>

NPRR 1214: <https://www.ercot.com/mktrules/issues/NPRR1214>

Prior to 2021, the average startup time for resources committed through RUC was approximately three hours, reflecting a less conservative operational policy that gave resources more time to self-commit based on market conditions. From 2021 through 2025, the average startup time for resources committed through RUC increased to almost seven hours.

The shift toward committing resources through RUC far in advance of real-time is central to conservative operations. Resource owners generally oppose RUC instructions because they disrupt planned operations, force uneconomic commitments, and consume emissions credits or allowances that they would otherwise conserve for higher-value periods. Stakeholders express this opposition by supporting conservative policy changes, such as the inflated 2026 AS methodology, which we discussed extensively in Chapter III.E. Stakeholders support these initiatives in hopes of reducing the heavy-handed use of RUC, but in practice, the initiatives distort market outcomes and undermine genuine shortage pricing.

### C. Forecast Error

Effective market operations must account for forecast error in demand and supply. The net demand forecast, defined as demand minus expected generation from intermittent renewable resources (IRRs), is a major determinant of thermal resource commitment decisions. An over-forecast of net demand can lead to sub-optimal commitment decisions that reduce market efficiency. An under-forecast can lead to insufficient thermal commitments and real-time shortfalls that are often addressed through RUC. Figure 50 illustrates the distribution of net load forecast errors eight hours ahead of real-time.

**Figure 50: Distribution of Net Load Forecast Error**  
H2 2022-2025

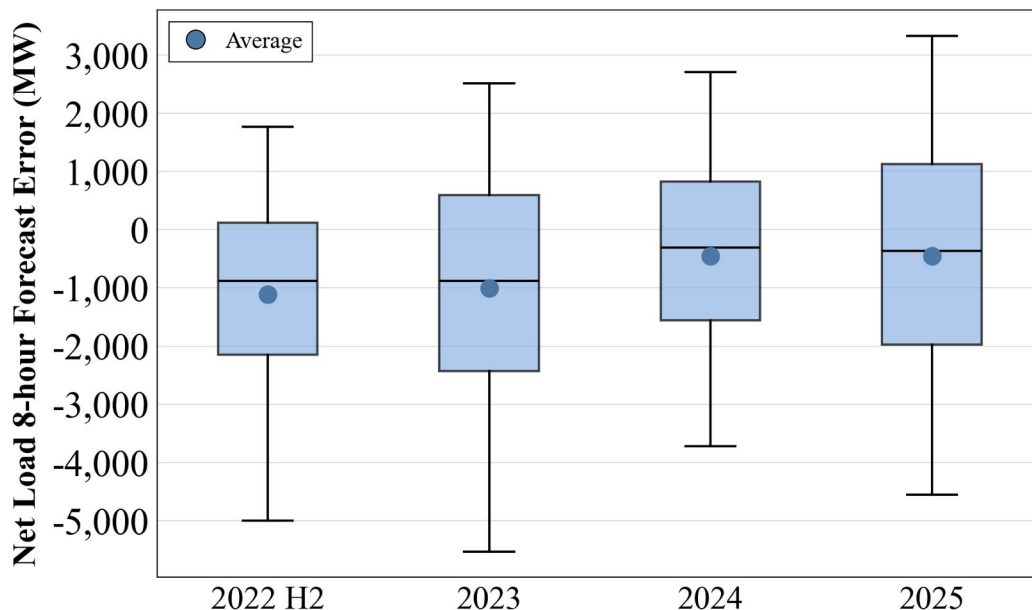


Figure 50 shows that forecast accuracy for net load and IRR generation has improved meaningfully since the second half of 2022, with substantial reductions in average error. However, some structural biases and growing variability remain. By 2025, the average net load forecast error had declined to about 452 MW, down from more than 1,000 MW in 2023 and 2024. Yet forecasts continue to systematically under-forecast IRR generation and over-forecast load. IRR generation itself was under-forecast by only 89 MW on average in 2025, indicating improved accuracy. However, forecast variance has increased alongside the rapid expansion of installed IRR capacity, particularly solar. Despite this growth in solar resources, wind generation continues to dominate total IRR forecast error variance because of its higher volatility and lower predictability.

#### **D. QSE Operation Planning**

The Current Operating Plan (COP) is the mechanism QSEs use to communicate the expected status of their resources to ERCOT. QSEs update COPs continuously for each operating hour. Two COP elements are especially important for the RUC process: the hourly schedules for resource status, i.e., when each resource is expected to be online and available, and the expected state of charge (SOC) schedule for ESRs.

The RUC optimization engine uses the schedules for resource commitments and expected SOC in the COP with the net load forecast to determine whether out-of-market commitments are necessary to manage a system-wide supply shortage or transmission constraints. Resources shown as offline but available in their COP are eligible for commitment through RUC, subject to start-time constraints. Thus, the accuracy of COP information greatly influences ERCOT's ability to effectively commit resources through the RUC process.

##### **1. COP Commitment Error**

To assess the accuracy of COP commitment statuses when RUC may be needed for capacity, we considered all intervals where online reserves were less than or equal to 6,500 MW. We compared the real-time status of all resources in SCED with the status in the last submitted COP that ERCOT would have seen before it had to decide whether to commit a unit based on its start time. For example, if a resource has a start time of six hours, we compared its real-time status with the status reported in its COP six hours prior. Figure 51 summarizes the disparity between real-time and COP statuses using this methodology for 2021 through 2025.

Figure 51 illustrates several trends in the accuracy of COP commitment schedules in advance of tight system conditions. Commitment error occurs when resources report an offline status in their COP but are ultimately online in real-time, whereas decommitment error occurs when resources report an online status but are ultimately offline in real-time. The average magnitude of net commitment error in advance of scarcity conditions has increased consistently over the last five years and is inversely proportional to the frequency of scarcity conditions as measured by PRC.

**Figure 51: COP Commitment Error when PRC  $\leq$  6,500**  
2021-2025

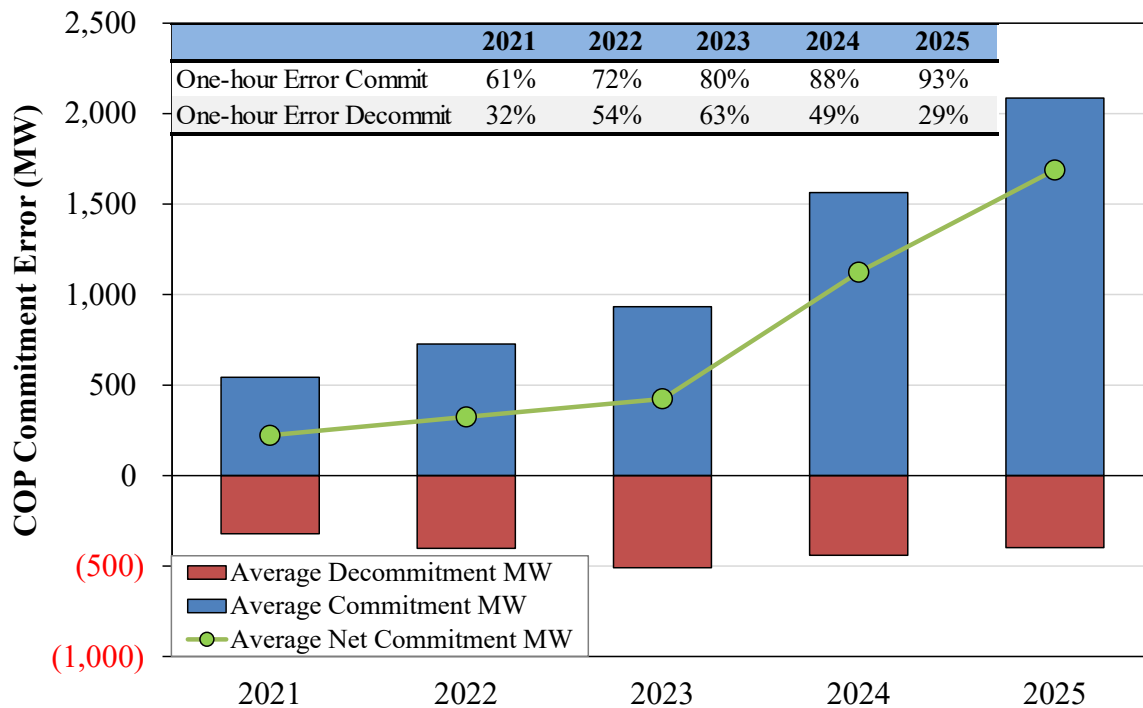


Figure 51 also shows that resources with hot-start times of one hour or less have been the largest contributor to net commitment error since 2021. These resources can most readily self-commit opportunistically when economics are favorable, as they generally are when system conditions are tight. Thus, commitment inaccuracy in the COP is less problematic than it may first appear because waiting until closer to real-time to commit units with shorter start times poses less risk.

## 2. COP State of Charge Error

The schedule for ESR SOC as reported in the COP was only incorporated into the RUC process in the second half of 2024 following the implementation of NPRR 1186. Rather than optimizing ESR charging and discharging schedules across the RUC study period, RUC takes hourly SOC as a fixed input. Increases in SOC are treated as withdrawals of energy, and decreases in SOC are treated as injections of energy. Because installed ESR capacity has increased massively over the last several years and ESRs have participated more in the energy market, COP SOC accuracy strongly affects the efficiency of the commitments RUC recommends. The distribution of COP SOC accuracy for the second half of 2024 through all of 2025 is shown in Figure 52.

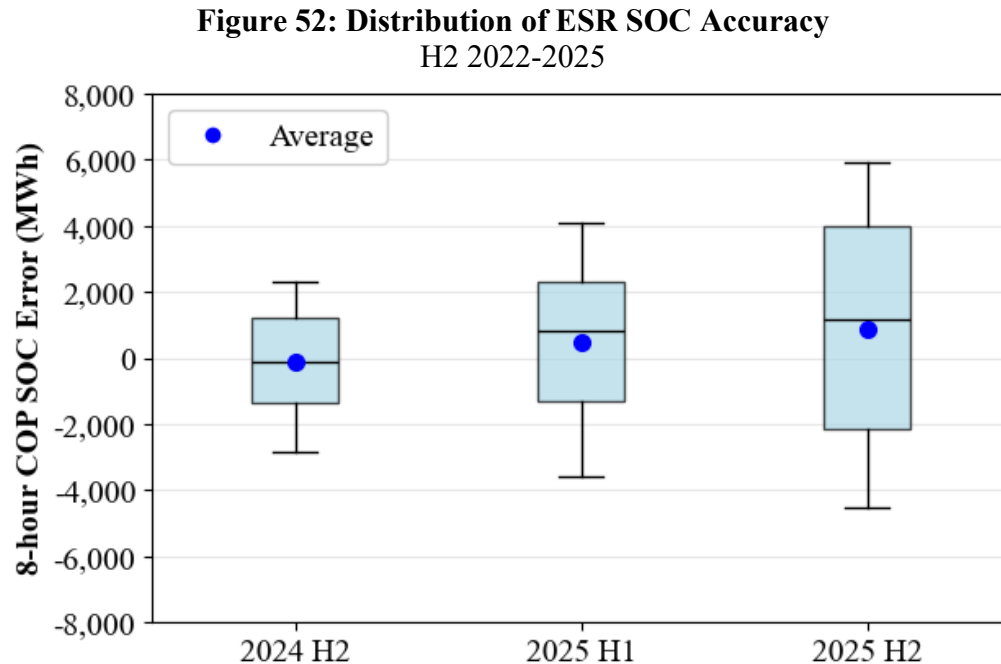


Figure 52 indicates that, on average, aggregate COP SOC is overestimated by approximately 874 MWh, and the magnitude of the overestimate has increased over time. The variance of COP SOC error has also increased, corresponding to the large increase in installed ESR capacity. This COP SOC inaccuracy has been suggested as one factor leading to the large increase in commitments through RUC from 2024 to 2025.<sup>50</sup>

## E. Reliability Must Run and Must Run Alternatives

### 1. RMR Basics

ERCOT's Reliability Must-Run (RMR) process addresses local reliability needs when market-based solutions are insufficient. When a generation resource owner plans to suspend or retire a unit for more than 180 days, ERCOT must conduct a reliability analysis to determine whether the resource is necessary to maintain grid stability, provide voltage support, or prevent transmission overloads in the affected area. If ERCOT's analysis finds that losing the unit would create unacceptable reliability risks and no market-based solution is available, PUCT Rule §25.502 requires ERCOT to consider an RMR agreement or seek alternative solutions.<sup>51</sup>

The RMR process involves several steps. After receiving a Notification of Suspension of Operations (NSO), ERCOT has 60 days to complete its evaluation. If ERCOT deems the unit necessary, it must issue an RFP for Must-Run Alternatives (MRAs), which may include demand

<sup>50</sup> Discussion on Recent Trends in Reliability Unit Commitment (RUC):

[https://www.ercot.com/files/docs/2025/11/12/CWMG\\_RUC\\_Case\\_Analysis\\_20251117.pdf](https://www.ercot.com/files/docs/2025/11/12/CWMG_RUC_Case_Analysis_20251117.pdf)

<sup>51</sup> 25.502: <https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.502/25.502.pdf>

response or other generation resources. If ERCOT finds no suitable alternative, it may seek Board approval to enter into an RMR agreement with the resource owner. RMR and MRA agreements are temporary, short-term measures, and ERCOT must also identify and pursue long-term transmission upgrades or other permanent solutions to address the underlying reliability concern.

RMR units are subject to specific requirements and restrictions. Only resources essential for voltage support, stability, or management of localized transmission constraints are eligible. ERCOT must contract for each RMR unit's full capacity, and the unit must meet ERCOT's technical and operational standards. RMR units cannot participate in the competitive energy market or provide AS during the contract period. ERCOT cannot compel a resource owner to enter an RMR contract, so participation is voluntary.

RMR agreements typically last one year or less but may be extended if significant capital expenditures are required to maintain the unit's availability. ERCOT must re-evaluate the need for any multi-year RMR agreement annually. When the reliability need is resolved, such as through transmission upgrades or new market entry, the RMR agreement should be terminated. The unit may then return to the competitive market after refunding any capital contributions received from ERCOT.

Compensation for RMR units is based on the eligible costs needed to keep the unit operational. These include direct labor, materials, maintenance, taxes, and fuel supply costs. Owners must provide detailed cost estimates during negotiations and submit actual costs monthly for settlement and true-up. Eligible fuel costs are recovered based on actual energy produced. RMR units receive a standby payment based on the approved budget or actual eligible costs, adjusted for performance and availability. An incentive factor equal to 10% of eligible costs, excluding fuel, may be applied, but it is reduced if the unit fails to meet contracted capacity or availability targets. ERCOT allocates costs incurred under RMR agreements to LSEs.

## 2. RMRs in 2025

In March 2024, ERCOT received Notifications of Suspension of Operations (NSOs) stating that three CPS Energy Braunig gas units planned to suspend operations in early 2025.<sup>52</sup> ERCOT's reliability analysis found that retiring these units would significantly increase the risk of overloading key 345-kV transmission lines south of San Antonio and could lead to cascading outages and widespread uncontrolled load loss.

On February 24, 2025, the ERCOT Board approved RMR service for Braunig Unit 3, which has an HSL of approximately 410 MW. The resulting RMR agreement between ERCOT and CPS

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<sup>52</sup> ERCOT Trending Topics Publication from June 2025:  
[https://www.ercot.com/files/docs/2025/06/05/ERCOT\\_Trending\\_Topic\\_Reliability\\_Solutions\\_Aging\\_Resources.pdf](https://www.ercot.com/files/docs/2025/06/05/ERCOT_Trending_Topic_Reliability_Solutions_Aging_Resources.pdf)



covers March 2, 2025, through no later than March 1, 2027. For Units 1 and 2, the ERCOT Board later approved 15 mobile diesel-fired generation units from Life Cycle Power (LCP), with HSLs ranging from 12 to 28 MW, as a temporary reliability solution in lieu of RMR agreements. ERCOT selected these mobile generators because they offer faster startup times and lower forced-outage risk. ERCOT would deploy them only during emergency or pre-emergency conditions for up to two years.

These RMR resources have a total capacity of around 730 MW. Since the beginning of the RMR period, the mobile generating units have produced approximately 1,226 MWh, and the maximum aggregate output of RMR units has been less than 40 MW. Total uplift associated with these RMR units in 2025 was approximately \$68 million.

As an exit strategy, ERCOT identified the acceleration of the San Antonio South Reliability II Transmission Project to rebuild key 345-kV transmission lines. Expediting this work could allow new circuits to be energized in 2026–2027, reducing or eliminating the need for temporary RMR or mobile generation solutions. ERCOT requested good-cause exceptions from the PUCT to expedite the project and finalized agreements with LCP, CPS Energy, and CenterPoint to relocate and prepare the mobile units for operation beginning in summer 2025. The ERCOT Board authorized the mobile-generation agreement on February 25, 2025, and ERCOT completed the necessary contractual arrangements on June 4, 2025.

### 3. RMR Policy Changes

Because rapidly evolving supply and demand dynamics in Texas may create reliability concerns in some regions, ERCOT has proposed protocol changes through a few NPRRs that are at various stages of the stakeholder process. At an October 2025 workshop on out-of-market contracts, ERCOT proposed, among other changes, (1) increasing the NSO notice period from 5 months to 15-21 months, (2) obtaining retirement plans annually through an RFI process from units above a certain age, and (3) changing the budget structure to frontload costs and align budget timelines with actual expenditures.<sup>53</sup>

Some of these proposals have taken shape as NPRRs. NPRR 1313 changes the calculation of the initial standby cost for RMR Resources from a constant to a variable hourly value that may vary by month during the term of the Agreement based on a monthly budget. The ERCOT Board of Directors approved NPRR 1313 in April 2026, and the PUC will take these up at the May 29 Open Meeting.<sup>54</sup> More recently, ERCOT proposed NPRR 1330 in April 2026 to establish a process for setting mitigated offer caps for RMR units so they do not interfere with market outcomes.<sup>55</sup>

<sup>53</sup> RMR-C4C Workshop October 2025: <https://www.ercot.com/files/docs/2025/10/13/RMR-MRA-C4C-Workshop-20251017.pptx>

<sup>54</sup> NPRR 1313: <https://www.ercot.com/mktrules/issues/NPRR1313>

<sup>55</sup> NPRR 1330: <https://www.ercot.com/mktrules/issues/NPRR1330>

#### **4. Contracts for Capacity**

Although contracts for capacity (C4Cs) have been part of the nodal protocols since 2011, they have recently gained attention because ERCOT aims to expand use of the construct in anticipation of local supply shortfalls. Both the RMR and MRA constructs are initiated in response to a resource suspending its operations, whereas the C4C construct uses this RFP process without receiving an NSO.

The current proposal to expand the C4C construct is organized under NPRR 1315. The NPRR would expand the study period from the current and next season to two years, broaden the set of eligible resources that may participate in the C4C construct, and revise settlement and mitigated offer cap rules to reduce market distortion.<sup>56</sup> While we agree that out-of-market constructs are necessary when the market does not solve a local constraint issue, we oppose the current draft of NPRR 1315 until it addresses the following concerns.

- **System-Wide Application.** Although NPRR 1315 would not expand the study period for system-wide capacity shortfalls, we oppose any scenario in which a C4C is considered a solution to a system-wide capacity shortfall.
- **Emergency Condition.** ERCOT initiates the C4C process based on its determination of what constitutes an emergency condition. We recommend establishing reliability criteria to determine whether a forecasted shortfall is indeed an emergency condition.
- **Forecasting Methodology.** In addition to not defining what could qualify as an emergency condition, ERCOT has not defined the forecasting methodology and assumptions it would use to forecast supply and demand during an anticipated emergency condition.

#### **F. Thermal Generation Outages and Deratings**

At any given time, a portion of ERCOT's generation is unavailable because of outages and deratings. Derated capacity is the difference between a resource's registered maximum capacity and its actual capability. Generating capacity is often partially derated when the resource cannot achieve its installed capacity due to technical or environmental factors, such as equipment failures or ambient temperatures.

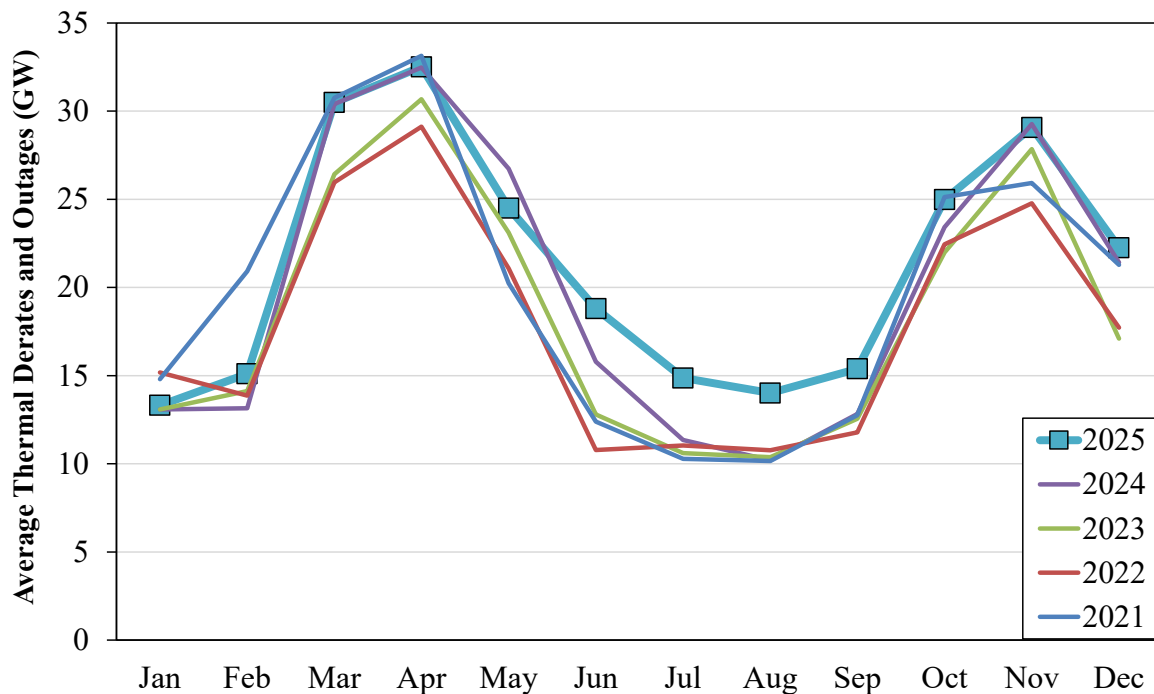
Outages and deratings of thermal power plants are especially important because they can affect reliability when other resources are limited. As ERCOT has become more reliant on wind and solar, overall generating capacity has become more sensitive to weather conditions. During periods of high demand and low renewable output, thermal units often become essential to

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<sup>56</sup> ERCOT's latest proposal as of April 2026: <https://www.ercot.com/files/docs/2026/04/07/1315NPRR-11-ERCOT-Comments-040726.docx>

meeting system needs. However, thermal generators tend to schedule more outages in the spring and fall, when demand and prices are typically lower. Figure 53 illustrates this seasonal pattern.

**Figure 53: Thermal Hourly Average Outages and Derates by Month**

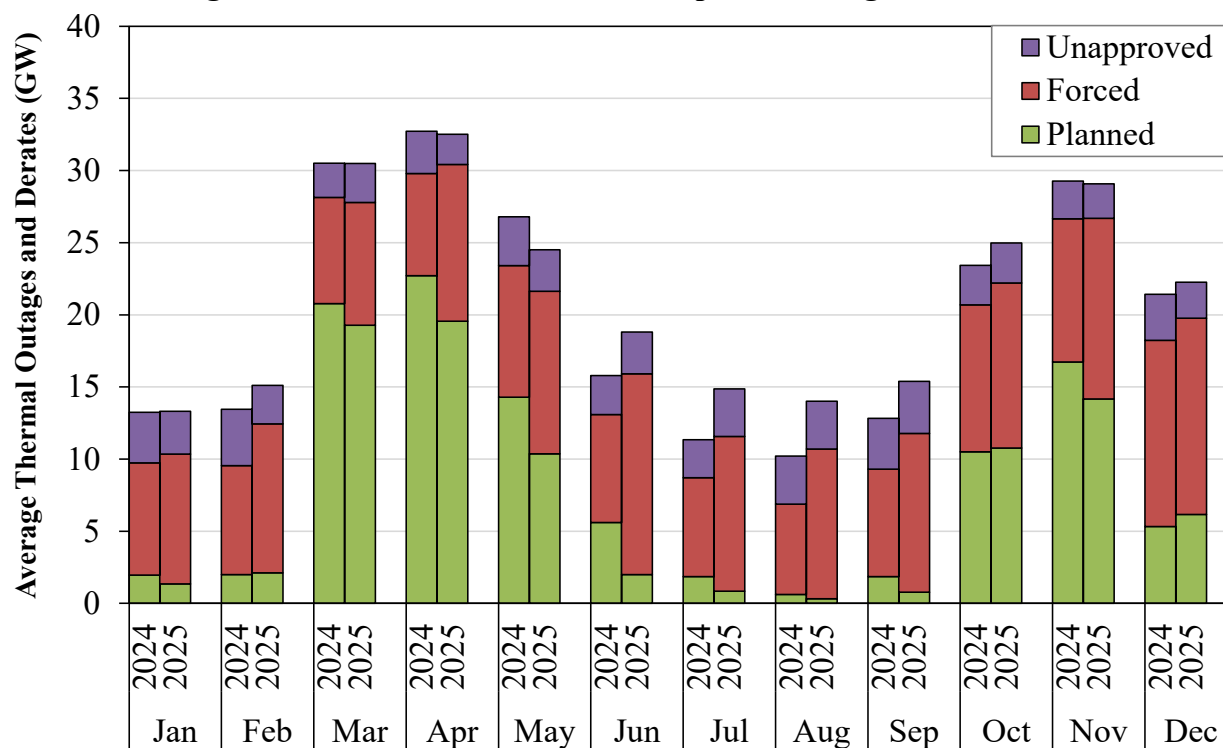


Outages and derates introduce uncertainty for ERCOT operators and market participants by complicating real-time assessments of supply and prices. To help operators manage this uncertainty, generators are expected to schedule planned outages in advance, which provides visibility into unavailable capacity. However, planned outages account for only part of the total because many outages are forced by unexpected failures that take units offline. Although most forced outages are eventually reported, many remain unreported, which makes it harder for ERCOT to plan and operate the system reliably. Stronger outage and derate reporting requirements would improve system coordination and transparency. Figure 54 shows monthly totals of planned, forced, and unreported outages and derates of thermal resources for 2024 and 2025. For records in the outage scheduler spanning less than 30 days, a notification submitted more than seven days before a scheduled outage was considered planned, and a record submitted less than seven days before an outage was considered forced. Outages not logged in the outage scheduler are shown as “Unapproved.”

The most noteworthy change from 2024 to 2025 was the higher rate of forced outages and derates, particularly in the summer months. Otherwise, outage patterns in 2025 were similar to those in 2024. Planned and unapproved outages were lowest during the summer, when energy is most valuable, and highest in the spring and fall, when system load and net load are typically lower. Despite protocol changes to improve outage reporting practices through NPRR 1084,

implemented at the end of 2022, a non-trivial share of outages and derates in 2025 still not reported in the outage scheduler.

**Figure 54: Planned, Forced, and Unreported Outages and Derates**



## G. Firm Fuel Supply Service

ERCOT implemented the Firm Fuel Supply Service (FFSS) through NPRR 1120 which the PUC approved in 2022. It pays a subset of dual-fuel generators to purchase fuel for on-site storage.<sup>57</sup> In July 2023, ERCOT expanded FFSS to include certain gas-fired generation resources with owned natural gas stored offsite and backed by firm transportation and storage agreements.<sup>58</sup> The FFSS program has a fixed budget of \$54 million.

### 1. FFSS Deployments in 2025

To date, ERCOT has issued four RFPs for FFSS, each with an obligation period from November 15 to March 15. In the 2024-2025 contract period, ERCOT procured 4,195 MW across 32 dual-fuel resources and one natural gas resource. The offer cap was set at \$12,240 per MW based on a Fuel Oil Index price of \$17 per MMBtu, a heat rate of 15 MMBtu per MWh, and a 48-hour obligation period. The same parameters were proposed for the 2025-2026 contract period.<sup>59</sup>

<sup>57</sup> NPRR 1120: <https://www.ercot.com/mktrules/issues/NPRR1120>

<sup>58</sup> NPRR 1169: <https://www.ercot.com/mktrules/issues/NPRR1169>

<sup>59</sup> PUCT Report on FFSS: [https://interchange.puc.texas.gov/Documents/56000\\_10\\_1516314.PDF](https://interchange.puc.texas.gov/Documents/56000_10_1516314.PDF)

In 2025, ERCOT deployed FFSS over three consecutive days in February. During that time, 4 FFSS Resources (FFSSRs) were deployed for a maximum of 470 MW, as shown in Table 10.

**Table 10: Firm Fuel Supply Service Deployments**

	Maximum Aggregate FFSS Deployment	Average Real- Time Price	Operating Day Online Reserves Minimum
Day	MW	\$ per MWh	MW
2/19/2025	470	\$102.09	9,052
2/20/2025	280	\$83.39	8,232
2/21/2025	95	\$69.03	10,273

ERCOT's FFSS Deployment Report for this event states that ERCOT decided to deploy FFSS based on information about potential gas supply restrictions that could affect generation resources. However, if such restrictions occurred, they did not cause a scarcity of operating reserves or a corresponding rise in real-time price, as shown in Table 10.

FFSS deployments were highest on February 19, 2025, coinciding with the highest real-time electricity prices observed during the event. Despite this increase in FFSS activity, the maximum ORDC price remained below \$62 per MWh. Throughout the day and the remainder of the event, the ORDC continued to produce non-zero prices, but at levels that did not indicate a significant shortage of operating reserves.

These market outcomes raise questions about whether FFSS deployments were necessary under the conditions experienced in 2025. However, the lack of transparency about the real-time status of the intrastate natural gas network in Texas complicates any comprehensive assessment. Without clear information on prevailing gas supply conditions, it is difficult to determine whether FFSS deployments were warranted or whether the observed market prices accurately reflected system scarcity.

## 2. FFSS Market Impact

Procuring and deploying FFSS costs ERCOT consumers up to \$54 million each year and creates additional costs because it distorts market prices. FFSS resources are also eligible for make-whole payments if their market revenues during a deployment are less than the cost of replacing their spent fuel, which contributes to inefficient market outcomes and excess costs. This make-whole payment reduces the incentive for FFSS resources to offer at prices that reflect the marginal cost of replacement.

If FFSS resources had to offer at the marginal cost of fuel replacements, SCED would dispatch them less and make-whole payments would fall. Further, when FFSSRs offer below their marginal cost, they displace more economic resources, and those below-cost offers suppress clearing prices because they do not accurately reflect the marginal cost of generation. This price

suppression raises long-term resource adequacy concerns in a market where the prevalence of scarcity pricing is supposed to drive investment.

To address these issues, we proposed Recommendation 2023-4, which called for FFSS deployments to be backed by clear reliability metrics, for offers to be sized according to the marginal cost of replacing fuel, and for FFSS capacity to be included in the calculation of the ORDC. Because ERCOT implemented RTC in December 2025 and discontinued the ORDC, we retired the last part of this recommendation. We consolidated the first two recommendations into a new recommendation on the FFSS program, which we describe at the end of this section.

### **3. FFSS Rulemaking**

Unlike some ERCOT reliability services that begin with a PUCT rulemaking and are later implemented in the nodal protocols, the FFSS program began in the nodal protocols and did not receive a rulemaking until February 2026.<sup>60</sup> This rulemaking significantly departs from the current administration of the program and may adversely affect market efficiency and the reliability benefits that this program provides.

#### ***Highlights of 16 TAC 25.520***

16 TAC §25.520 divides eligible resources into three categories: (1) dual-fuel-capable resources with onsite storage, (2) resources with on- or off-site storage,<sup>61</sup> and (3) natural gas resources with firm transport agreements. Each category would have its own market clearing structure and fixed offer cap. At least 70% of the FFSS budget must be used to procure resources in the first two categories. The offer cap calculation will be based on the projected price of fuel oil or natural gas for the upcoming season.

FFSSRs must be represented by a QSE. If a QSE fails to deploy consistent with its award when called upon, ERCOT may reduce or claw back its payment and suspend it from further participation until it meets reinstatement requirements determined through the stakeholder process. ERCOT uplifts most FFSS program costs to LSEs based on load-ratio share. Next, we discuss key concerns with the rulemaking.

#### ***Inclusion of Gas-Fired Generation***

Incentivizing availability through fuel storage is the core idea behind the FFSS. Severe winter storms occur infrequently, and the resulting lack of higher energy prices does not support the economics for oil-fired resources to procure and maintain infrastructure to store large volumes of fuel oil for the few winter storms the Texas climate experiences, if any. If a winter storm does occur, an oil-fired resource may be out of commission for the few days when its supply chain is

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<sup>60</sup> PUC order approving 25.520: [https://interchange.puc.texas.gov/Documents/58434\\_30\\_1582113.PDF](https://interchange.puc.texas.gov/Documents/58434_30_1582113.PDF)

<sup>61</sup> If the storage is offsite, the resource or the QSE needs to own and control the storage infrastructure as well as the pipeline that delivers the fuel to the resource.

interrupted and it cannot be refueled. The FFSS was created to incentivize resources that *can* store their fuel, i.e. oil-fired resources or dual-fuel-capable resources, to do so in case they need to be called on for a longer deployment.

Including gas-fired resources undermines these principles in three key ways. First, gas-fired resources do not store their fuel because storing natural gas in compressed natural gas tanks or maintaining a cooled liquefied natural gas storage facility long-term is uneconomic. Second, gas-fired resources are already incentivized to maintain a firm supply of natural gas to take advantage of high prices during a winter weather event. Consequently, the additional subsidy through the FFSS program provides no additional reliability benefit. Third, gas-fired resources will outcompete and displace oil-fired resources because they are generally more efficient than oil-fired resources.

### ***Separate Clearing Structures***

Through §25.520(e)(3), the PUC aimed to account for the different heat rates of oil-fired and gas-fired resources by setting different offer caps based on separate heat rates for each category outlined in section (c) of the rule. FFSSRs provide a single reliability benefit, and participating resources should compete in a single price-clearing mechanism to offer that benefit. To further limit gas-fired resources from outcompeting oil-fired resources under the fragmented offer structure, the rule requires that at least 70% of the budget be allocated to procure resources from the first two eligible categories. We propose a more elegant solution to these challenges at the end of this section.

### ***Lack of Replacement Charge***

Nonperformance by an FFSSR creates market impacts beyond the immediate failure to deliver fuel-assured capacity. Although the rule includes suspension and reinstatement provisions, it understates the broader consequences of nonperformance. When a resource fails to meet its FFSS obligation, the market loses a reliability service for which it has already paid and may face higher prices if the shortfall contributes to operational stress or scarcity conditions the program was intended to mitigate.

These outcomes reflect two distinct harms. First, consumers pay for a service that is not delivered. Second, prices increase because expected, paid-for capacity is unavailable when needed. The rule's payment reductions, clawbacks, and suspension provisions address the first harm but largely leave the second unaddressed. As a result, the price impacts from the absence of FFSS capacity will fall on consumers rather than the nonperforming resource. This structure also weakens incentives to reflect relative reliability in offers and increases the risk that less reliable resources receive FFSS awards ahead of more reliable alternatives.



### ***No Dynamic Budget***

The fixed \$54 million FFSS budget simplifies administration, but it does not reflect the system's changing reliability needs. We interpret PURA 39.159(b)(2) to require the PUC and ERCOT to evaluate annually the quantity of reliability services ERCOT should procure, including FFSS. The annual FFSS budget should be based on risk criteria that evaluate the grid's preparedness for winter events. As ERCOT implements additional reliability tools and strengthens system infrastructure, the amount of FFSS needed each year should reasonably decline.

## **4. Recommendation for the FFSS**

The FFSS can deliver meaningful reliability benefits, despite being an out-of-market program, by ensuring the availability of stored fuel during extreme winter events that threaten fuel supply. Without the FFSS, generators would have little incentive to incur the cost of maintaining onsite fuel inventories for rare but high-impact winter disruptions. This subsection outlines a framework for the FFSS that preserves this reliability benefit, minimizes opportunities for the exercise of market power, and reduces the risk of inefficient use of the program's budget. This recommendation, which reiterates many of the points from our filing in the rulemaking,<sup>62</sup> also constitutes Recommendation 2025-1 of this document.

- **Eligibility.** Restrict FFSS eligibility to resources that can store their fuel onsite or offsite. Limit eligibility to the resources currently described in 16 TAC 25.520(c)(1)-(2).
- **Budget.** The FFSS budget should be established annually based on risk criteria that evaluate the grid's preparedness for winter events. As ERCOT implements additional reliability tools and strengthens system infrastructure, the amount of FFSS needed should reasonably decline.
- **Clearing Structure.** The FFSS should use a single clearing structure because it provides a single reliability benefit. The program should select only the most efficient eligible resources each year.
- **Offer Requirements.** Specify offer caps for each resource based on historical heat rates established through the verifiable cost process. Base fuel prices on the projected fuel price for the upcoming FFSS obligation period. Require resources to offer energy at prices that accurately reflect the true marginal cost of using firm fuel.
- **Noncompliance.** In addition to the current provisions that reduce or claw back the FFSS award and suspend the QSE from further participation in the program, we recommend charging the FFSSR for the market price impact of its failure to deploy.

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<sup>62</sup> IMM Comments in Project 58434: [https://interchange.puc.texas.gov/Documents/58434\\_28\\_1560275.PDF](https://interchange.puc.texas.gov/Documents/58434_28_1560275.PDF)



- **Deployment Criteria.** The FFSS should be deployed when there is a demonstrated disruption in the fuel supply that meaningfully threatens the reliability of the ERCOT grid.

The rulemaking process discounted our comprehensive recommendation by evaluating its individual parts rather than the recommendation as a whole. For example, the process rejected our recommendation not to fragment the clearing structure of the FFSS, reasoning that a unified structure would cause gas-fired resources to outcompete oil-fired resources, while excluding the part of our recommendation that would make gas-fired resources with firm supply contracts ineligible in the first place. We support revisiting this rulemaking later if the adverse market impacts described in this section materialize.



## VII. RESOURCE ADEQUACY

### A. Summary of Resource Adequacy Results in 2025

Resource adequacy is fundamental to the reliability and stability of the electricity market. It refers to the availability of sufficient generation and demand-side resources to meet expected electricity demand and ancillary services under normal and extreme conditions. A well-functioning market must send clear price signals that incentivize investment in new generation, maintenance of existing resources, and demand-side participation. Without these signals, the market risks underinvestment in generation and transmission, which can lead to reliability challenges. The following are the key insights from this chapter:

- **Net revenues for natural gas generators varied significantly by location in 2025.** A combustion turbine in the Houston zone could expect to earn roughly \$59 per kW-year in net revenue, while the same CT could earn up to \$177 per kW-year in the West zone. The price gap is driven by the import-constrained Permian Basin where congestion costs drive up prices in the West zone.
- **The planning Cost of New Entry has received renewed attention in ERCOT because it may affect the market design options that ERCOT proposes to meet the reliability standard in 2029 as part of its 2026 assessment.** In 2024, the PUCT approved a CONE of \$140 per kW-year while leaving the legacy CONE of \$105 per kW-year in place to determine the peaker net margin threshold.
- **Net revenues in 2024 and 2025 were significantly lower than in previous years.** Years with lower net revenues occur often and are not a threat to resource adequacy.
- **The peaker net margin in ERCOT reached almost \$79 per kW in 2025, roughly 21% lower than in 2024.** The PNM did not reach the PNM threshold that would reduce the system-wide offer cap in ERCOT. The threshold has been reached only once in ERCOT's history, in February 2021 during Winter Storm Uri.
- **ERCOT is currently conducting its 2026 Reliability Standard Assessment.** The assessment evaluates whether ERCOT meets the standard in 2026 and models whether the ERCOT power system is likely to meet it in 2029.
- **The most impactful legislation from the 89<sup>th</sup> legislative session for the ERCOT market was SB 6.** SB 6 addresses large-load interconnection and treatment in ERCOT, introduces a new reliability service for those loads, and calls for a review of the current 4CP transmission cost allocation.
- **By the end of 2025, ERCOT had endorsed over \$14 billion in transmission projects.** This investment was 271% higher than the \$3.78 billion ERCOT endorsed in 2024.

### B. Resource Adequacy Background

Generators assess resource adequacy to identify investment opportunities and the potential for higher revenues during shortage conditions. Load-Serving Entities (LSEs) and large consumers monitor adequacy to anticipate price volatility and manage costs through strategies such as demand response. A well-functioning market provides price signals that help all participants plan effectively, adapt to changing conditions, and support long-term system reliability.

The following concepts are important for understanding revenue sufficiency and investment in new generation:

- **Cost of New Entry (CONE):** CONE represents the estimated fixed cost of building and operating a new power plant. Investors evaluate whether expected future market revenues will justify these costs before committing to new projects.
- **Shortage Pricing:** In electricity markets, prices rise during periods of tight supply to reflect the higher value of available generation. These price spikes allow generators to recover fixed costs and incentivize new investment. In ERCOT's energy-only market, shortage pricing is the primary mechanism that drives revenue and signals investment decisions.
- **Peaker Net Margin (PNM):** PNM estimates the annual net revenue a peaking unit could have earned based on observed energy and ancillary service prices. Comparing PNM with CONE helps market participants determine whether revenues are sufficient to support new generation or whether additional incentives may be needed before they decide to invest in new generation.

#### 1. Key Reports

ERCOT communicates future resource adequacy expectations through several reports that give market participants insight into conditions over different timeframes.

- The Monthly Outlook for Resource Adequacy (MORA) provides a short-term assessment of expected supply and demand conditions and highlights potential risks in the coming months.
- The Capacity, Demand, and Reserves (CDR) report provides a 5-year forecast of load growth and generation capacity to help participants evaluate future resource adequacy.
- The Long-Term Load Forecast (LTLF) complements these reports by projecting demand trends for up to ten years and offering a broader perspective on future needs.

Together, these reports help market participants anticipate challenges, identify investment opportunities, and plan accordingly.

## 2. Resource Adequacy through Markets

Economic signals from the wholesale electricity markets guide long-term investment and retirement decisions that maintain an efficient level of capacity consistent with those signals. In general, there are three primary approaches to achieving resource adequacy through competitive wholesale electricity markets:

- **Energy-Only Market.** An energy-only market relies primarily on expected shortage revenue in the energy and ancillary services markets to motivate investment in new generation. Although the shortage pricing mechanism provides a clear and simple revenue signal to investors, it also requires the market to go short on capacity to enable such revenue opportunities. Accordingly, energy-only markets can struggle to satisfy a reliability standard, such as the 1-in-10 standard adopted by most RTOs in the US.
- **Capacity Markets.** Capacity markets are designed to procure enough capacity to meet a defined reliability standard. Their key advantage is that they predictably generate the revenues needed to supplement the energy and ancillary service net revenues to support the investment needed satisfy the reliability requirements. Capacity markets also require more complex rules for accrediting both generation and load resources.
- **Capacity Requirements.** Some markets impose capacity requirements that obligate load-serving entities to self-supply or procure capacity to meet a specified reliability target, which functions as a decentralized and largely bilateral version of a capacity market. This approach increases the likelihood of meeting the intended reliability standard by making each entity responsible for securing adequate resources. However, it can also result in prices that are neither efficient nor competitive, which may increase costs relative to a centralized capacity market.

All markets ultimately rely on shortage pricing, which is grounded in the value of lost load. The value of lost load represents the economic value customers implicitly place on avoiding an interruption of service. In practice, VOLL takes two distinct forms. One is the implied VOLL that policy choices produce, such as a particular reliability standard or other performance metric. The other is the operational VOLL that RTOs use to settle prices during shortage conditions. These two forms of VOLL can differ substantially even though they arise from the same concept.

Because energy-only markets rely heavily on shortage pricing to provide investment signals, the VOLL in these markets must be extremely high to satisfy a given reliability standard. Meeting such a standard solely through shortage prices requires a level of VOLL that is often difficult to implement in practice. This challenge explains why most RTOs have adopted capacity constructs, which make it easier to achieve the required level of reliability without relying entirely on very high shortage pricing.

## C. Net Revenue Analysis

Net revenue is the key determinant of investment incentives because it is the earnings available to recover fixed and capital expenses, including a return on investment, after covering short-run operating costs. In ERCOT's energy-only market, net revenues from the energy and ancillary services markets are the primary economic signals for investment and retirement decisions for generation. Revenues may also come from the day-ahead market or forward bilateral contracts, but these ultimately reflect expectations of real-time energy and ancillary service prices.

We calculate net revenue by subtracting a generating unit's variable production costs from its total potential revenue. Net revenue is the earnings available beyond short-run operating costs to recover fixed and capital expenses, including a return on investment. Although this report presents net revenues based on historical prices, investment decisions typically reflect expectations of future market conditions, including the potential for shortage pricing.

### 1. Peaker Net Margin and Shortage Pricing

The peaker net margin (PNM) and the shortage pricing mechanism play a crucial role in shaping net revenue and investment signals in the electricity market. The PNM estimates the annual net revenue a peaking unit could earn from the energy and ancillary service markets and serves as a benchmark for whether market conditions support new investment. If the PNM approaches or exceeds the CONE, it suggests that market revenues are sufficient to support new generation for that year. Shortage pricing supports revenue by raising energy prices when operating reserves fall below predefined thresholds, ensuring that generators are compensated for providing reliability during shortage conditions. The Reliability Deployment Price Adder (RDPA) also raises energy prices by accounting for operator actions that impact the market prices.

### 2. Net Revenue by Location

Figure 55 shows net revenues at different locations for several types of new generators. Because natural gas prices can vary widely by location, the figure shows revenues for natural gas units in the Houston zone (reflecting Katy hub prices) and the West zone (reflecting Waha hub prices).

Figure 55 shows a wide gap in net revenues between the West and Houston. Historically, high natural gas production in the Permian Basin and limited export capability have resulted in low gas prices at the Waha location and, as a result, much higher net revenues for gas resources in this area. The price gap between the two hubs widened in 2025 because the import constraint in the Permian Basin substantially increased congestion costs in the region. As work on these projects concludes, we expect the gap between the two hubs to narrow again.

**Figure 55: Net Revenues by Location**  
2025

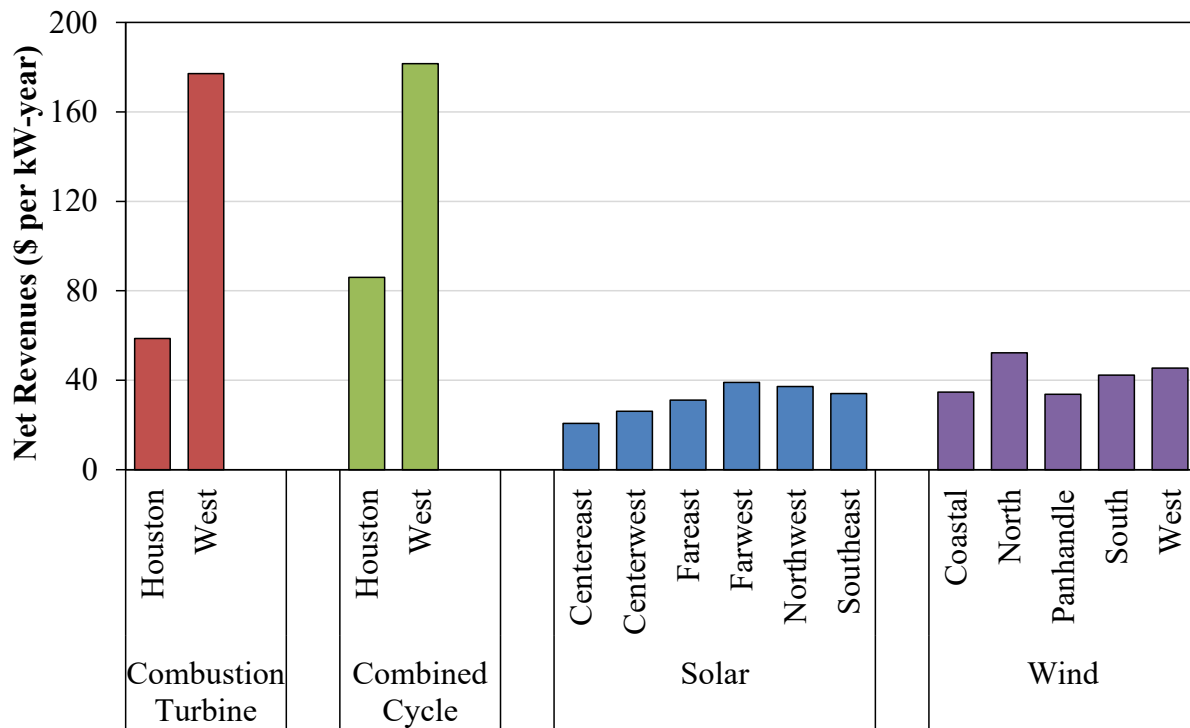


Figure 55 also shows net revenues for wind and solar generation at multiple locations. The profitability of these resources depends primarily on local wind or solar penetration and market prices during periods of high output. In 2025, net revenues for wind and solar were lower than net revenues for gas-fired technologies in all areas.

#### D. Cost of New Entry

CONE represents the estimated annualized revenue requirement for a marginal new generating resource, typically a gas-fired unit, to recover capital and fixed operating costs over the resource's economic life. The reference technology reflects the type and configuration of generation that a merchant investor would most likely develop in response to market price signals. Functionally, CONE serves as a levelized capacity cost benchmark, expressed on a per-kW-year basis, that captures the amortized cost of adding incremental firm capacity needed to support system reliability. CONE is commonly anchored to gas-fired generation because these resources often represent the marginal reliability option in ERCOT's energy-only market and therefore provide a useful reference point for evaluating whether market price signals are sufficient to attract new investment.

##### 1. Updates to CONE

CONE has become a focal parameter in ERCOT planning because rising load growth expectations and gas turbine costs have raised the assumed cost of maintaining system reliability.

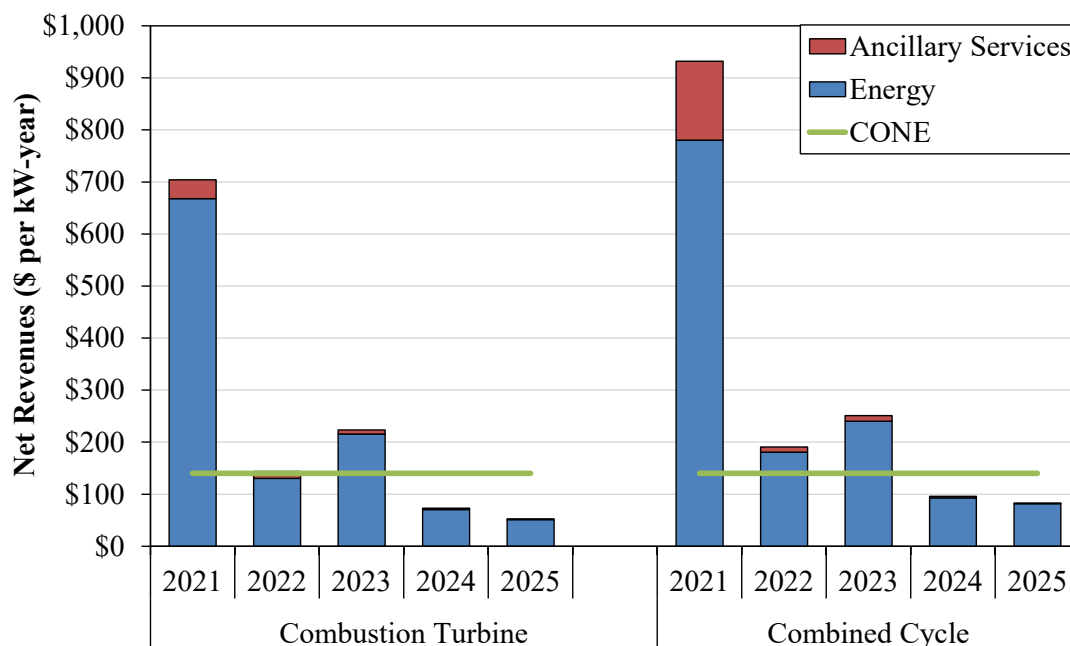
For more than a decade prior to 2024, ERCOT used a CONE value of \$105 per kW-year as an input to planning and reliability studies and as the basis for the peaker net margin threshold in scarcity pricing design. In July 2024, the Public Utility Commission of Texas approved an updated CONE value of 140 per kW-year for planning purposes in ERCOT, reflecting more recent cost estimates for new entry, while retaining the legacy \$105 per kW-year value for the peaker net margin threshold.

In parallel with ERCOT’s 2026 Reliability Standard Assessment (RSA), ERCOT is conducting an additional review of CONE to align cost assumptions with potential reliability pathways. Although CONE is not a direct input to the RSA, ERCOT has noted that certain recommendations for achieving the standard may depend on CONE, which makes an updated assessment appropriate. To support this effort, ERCOT engaged the Brattle Group to perform an accelerated CONE study informed by Brattle’s recent work for PJM. Because the 2025 PJM CONE study produced an estimated value of approximately \$220 per kW-year, and because combustion turbine procurement costs are relatively uniform across U.S. markets, the accelerated ERCOT study could result in a CONE value above \$200 per kW-year.<sup>63</sup>

## 2. CONE vs Net Revenue

Figure 56 presents historical net revenues available to support investment in new natural gas combustion turbines (CTs) and combined cycle (CC) generators.

**Figure 56: Combustion Turbine (CT) and Combined Cycle (CC) Net Revenues 2021-2025**



<sup>63</sup>

Updates to CONE: [https://interchange.puc.texas.gov/Documents/58777\\_5\\_1575180.PDF](https://interchange.puc.texas.gov/Documents/58777_5_1575180.PDF)



These technologies in Figure 56 are commonly considered the marginal new supply because they are the units most likely to be built when market signals indicate a need for additional capacity. We calculate energy net revenues using generation-weighted real-time settlement point prices, assuming each unit sells energy or ancillary services in any hour when it is profitable to do so.

Net revenues for a CT were \$52.59 per kW-year and \$82.96 per kW-year for a CC generator. Comparing 2025 net revenues with the planning CONE of \$140 per kW-year, set by the PUCT, shows that 2025 net revenues were not high enough to incentivize new investment. CONE typically differs by technology, but we adopted the planning CONE for both technologies in this chart for simplicity. More importantly, years like 2024 and 2025 occur often and are not a threat to resource adequacy because one should expect tighter conditions to occur in other years that can produce revenues substantially above CONE. The years 2021 and 2023 are such examples.

### 3. The Role of CONE for New Investment

CONE is not a target that market net revenues are expected to meet every year, but rather a long-run benchmark assessed over the life cycle of generating investments. Generators earn returns over many years, not annually, and periods of lower net revenues can naturally discourage new investment in the short term. When investment slows, tighter supply conditions increase the likelihood of scarcity, which raises net revenues through shortage pricing. Those higher-revenue periods then restore investment incentives, leading to additional entry and subsequent periods of lower net revenues. Viewed in this context, years with lower net revenues are not inherently problematic, but instead reflect the cyclical dynamics of an energy-only market balancing supply, demand, and investment over time.

#### E. Peaker Net Margin

PNM is a simplified benchmark for the annual net revenue that a hypothetical gas peaking unit could earn in the ERCOT market. If PNM exceeds three times the CONE over a calendar year, or \$315 per kW-year, the System-Wide Offer Cap (SWCAP) is reduced from \$5,000 per MWh to \$2,000 per MWh for the rest of that year. This mechanism is designed to limit excessive shortage pricing once investment signals are sufficient. Notably, this threshold has been exceeded only once in ERCOT's history, on February 16, 2021, during Winter Storm Uri. Figure 57 shows the PNM values for the past seven years.

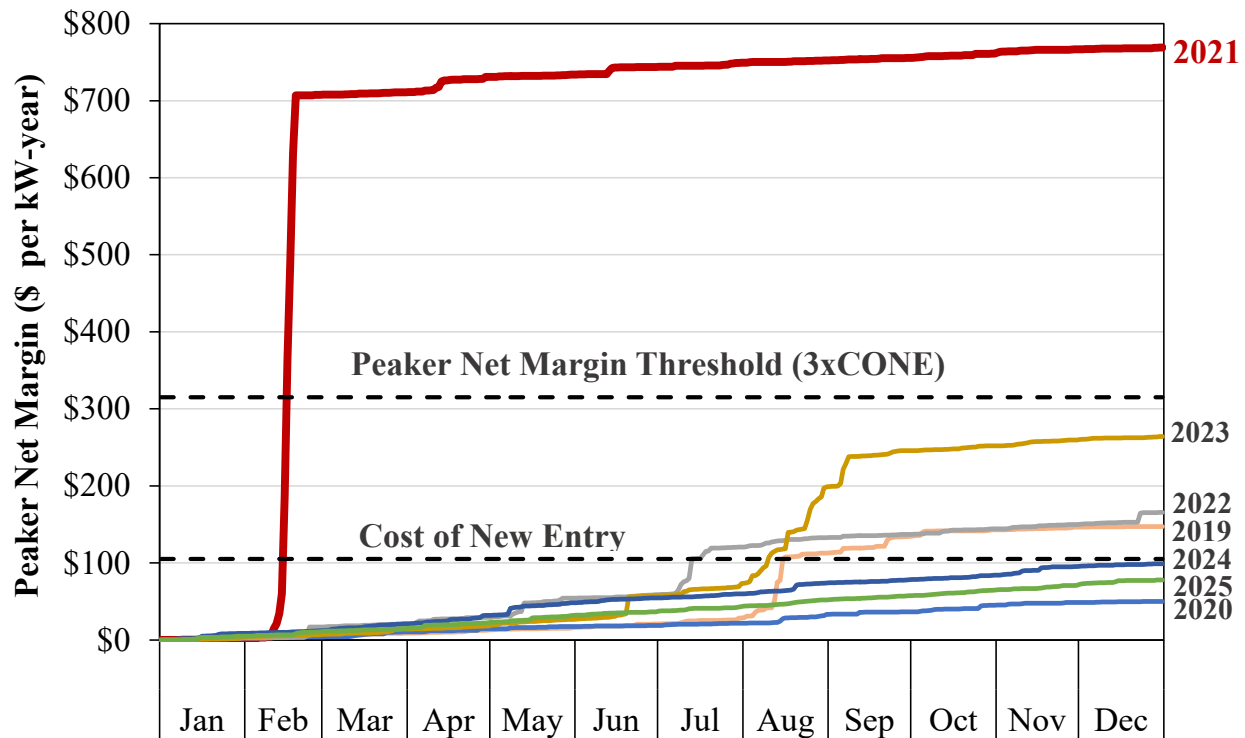
ERCOT's PNM calculation differs from a net revenue calculation because it uses protocol-specified values rather than dynamic values based on market conditions. Specifically, ERCOT calculates PNM using a 10.0 MMBtu per MWh heat rate and excludes both variable O&M costs and outage rates.<sup>64</sup> As discussed earlier, the value for CONE used to calculate the peaker net margin threshold is still the legacy value of \$105 per kW-year, as illustrated in Figure 57.

<sup>64</sup>

Based on §25.509(b)(2):

<https://ftp.puc.texas.gov/public/puct-info/agency/ruleslaws/subrules/electric/25.509/25.509.pdf>

**Figure 57: Peaker Net Margin**  
2019-2025



## F. ERCOT's Reliability Standard

### 1. Background

A reliability standard prescribes the level of supply required to meet specified reliability criteria. The assessment used to set the standard, in terms of installed capacity, evaluates potential reliability under various system conditions. Generally, the standard serves as a benchmark for determining whether the system has sufficient capacity for reliable operation. If a reliability standard is mandatory, it creates imposed demand for installed capacity that can drive new investment when the standard would not otherwise be met.

Senate Bill (SB) 3, which the 87th Texas Legislature passed in the aftermath of Winter Storm Uri in 2021, established the foundation for ERCOT's reliability standard. SB 3 directed the PUCT to develop and implement a formal reliability standard for the ERCOT power region. In response, the PUCT adopted 16 Texas Administrative Code (TAC) §25.508,<sup>65</sup> which formalized a probabilistic reliability standard based on loss of load expectation (LOLE) and additional criteria for the duration and magnitude of load shed events.

<sup>65</sup> 25.508: <https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.508/25.508.pdf>

## 2. TAC §25.508 Requirements

The new rule establishes a probabilistic reliability standard for the ERCOT system based on three key metrics:

- **Frequency:** The LOLE must not exceed 0.1 events per year, or one event every ten years on average.
- **Duration:** The maximum expected duration of a loss of load event must be less than 12 hours, with a 1.00% exceedance tolerance.
- **Magnitude:** The expected highest hourly level of load shed must be less than the amount of load that ERCOT determines can be safely rotated, also with a 1.00% exceedance tolerance. ERCOT is required to annually determine and file the maximum amount of load that can be safely rotated during an event, along with the methodology used to calculate it.

ERCOT must conduct a reliability standard assessment at least once every three years to determine whether the system meets the standard and is likely to continue meeting it for the next three years. If the assessment shows the standard is not met, ERCOT must propose market design changes, and we (the IMM) must independently review those proposals.

## 3. 2026 Reliability Standard Assessment

The 2026 RSA has already begun, and ERCOT is conducting the assessment based on modeling assumptions it filed in January 2026. Stakeholders and the PUC reviewed these assumptions in February and March of 2026, and PUC staff filed final recommendations in April 2026.<sup>66</sup> The RSA schedule requires ERCOT to file its reliability assessment results in August 2026, along with market design options if the model outputs suggest that ERCOT is unlikely to meet the reliability standard in 2029. Our IMM review of ERCOT's assessment follows in September 2026. From October through December, PUC staff will hold workshops and open meetings to develop a final set of recommendations, and the Commissioners will consider them.<sup>67</sup> This timeline is subject to change.

## 4. Additional Notes on the RSA

The reliability standard is significant because it creates a formal pathway to consider a broad range of market design options to improve reliability in ERCOT. Many PUCT rules and the ERCOT nodal protocols that flow from them are effectively fixed absent a statutory change to PURA or another major event that prompts a comprehensive review. The RSA is one of the few structured opportunities to revisit these frameworks and evaluate whether changes to market

<sup>66</sup> PUC Staff RSA Recommendations: [https://interchange.puc.texas.gov/Documents/58777\\_37\\_1619958.PDF](https://interchange.puc.texas.gov/Documents/58777_37_1619958.PDF)

<sup>67</sup> RSA Project Schedule: [https://interchange.puc.texas.gov/Documents/58777\\_4\\_1565749.PDF](https://interchange.puc.texas.gov/Documents/58777_4_1565749.PDF)

design, planning assumptions, or reliability mechanisms are warranted. To that end, the RSA functions not only as an assessment of future system risk, but also as a rare opportunity to make coordinated market design improvements across ERCOT.

As we have previously noted, meeting the reliability standard defined in 16 TAC §25.508 through price signals alone would imply an operational VOLL that is extraordinarily high for an energy-only market like ERCOT's. The final recommendations emerging from the RSA are not expected to rely exclusively on increasing VOLL. Instead, they are expected to evaluate a range of potential market design options. This context underscores how difficult it is to meet the reliability standard in an energy-only market like ERCOT. The Commission should clarify whether the reliability standard is intended to function as a binding requirement that the market must meet or as an aspirational benchmark against which alternative market design options are evaluated to improve reliability outcomes over time.

### **G. Communicating Resource Adequacy**

How ERCOT communicates resource adequacy plays a critical role in shaping the expectations and decisions of market participants. Generators, LSEs, and other stakeholders rely on ERCOT's resource adequacy assessments to inform long-term investment strategies, operational planning, and risk management. Although market participants may interpret market signals differently based on their risk tolerances and business models, ERCOT's formal reports and forecasts serve as widely referenced benchmarks. These reports frame expectations about future supply and demand conditions and influence market behavior in tangible ways.

In this section, we review the primary reports ERCOT uses to communicate resource adequacy to the market. We discuss how ERCOT's Monthly Outlook for Resource Adequacy (MORA), the Long-Term Load Forecast (LTLF), and the Capacity, Demand, and Reserves (CDR) report convey expectations about system conditions over varying time horizons. We also highlight key limitations in ERCOT's current resource adequacy communications.

#### **1. Monthly Outlook for Resource Adequacy**

The MORA provides an early assessment of the risk that ERCOT may need to issue an Energy Emergency Alert or initiate controlled outages during the reporting month. It offers granular, month-ahead insight into near-term system conditions using probabilistic modeling to estimate the likelihood of insufficient operating reserves during peak demand periods. It includes scenario-based analyses of expected demand and resource availability to inform operational awareness. Specifically, the report includes hourly probabilities of shortage conditions for the peak-load day in each month.

Despite the significant surplus of capacity in ERCOT discussed throughout Chapter III, empirical evidence on the frequency of shortage conditions suggests that the MORA report may over-estimate the likelihood of shortage conditions and outages. In practice, reliability was not

meaningfully threatened in ERCOT during 2025. The lowest Physical Responsive Capability observed in any interval was 4,607 MW, indicating substantial remaining operating reserves even during periods of relative system tightness. To that end, we conducted an empirical assessment of the MORA using the hourly probabilities to estimate the following implied values:

- Minimum Annual Loss of Load Probability (LOLP):** LOLP is the probability of any firm load shed over a defined period because of insufficient capacity. This value is a minimum because it is based only on the probability of load shed during the 12 monthly peak-load days, rather than over every day of the year. Implicitly, the probability of load shed for the other 353 days of the year is assumed to be zero. If the probability of load shed outside of peak-load days is non-zero, the calculated annual LOLP would be higher.
- Duration of Shortage Conditions and Outages Across Peak-Load-Days:** Shortage conditions are defined as operating reserves less than 3,000 MW, and firm load shed is assumed to occur when they drop below 1,500 MW. Again, because we have probabilities of shortage conditions only for peak-load-days, we can infer only an expected value for the duration of shortage conditions across these twelve days. To estimate the annual probability of shortage conditions from these values, we would have to scale the estimates from twelve days to a full year. Because peak-load-days likely account for a disproportionate share of shortage conditions during the year, this scaling would likely overestimate the annual probability.

The minimum annual LOLP implied by ERCOT's MORA reports for 2025 is approximately 49%, indicating that, under prevailing system conditions, a firm load shed event due to insufficient capacity should occur roughly every other year. However, there has not been such an event in over five years as of this writing. Moreover, if anything, the LOLP has *decreased* considerably since 2022 because operating reserves have increased dramatically. Therefore, this implied LOLP seems implausibly high. A closer review of the monthly MORA reports shows that most of this outage probability is concentrated in January through March 2025. The implied LOLP for those three months alone was over 43%, compared to less than 10% for the remainder of the year. This decrease in the forecasted probability of firm load shed reflects methodological changes, such as the inclusion of large loads that have not yet been energized. The LOLP for the remainder of the year after March is more reasonable, so the projections reported in MORA going forward may be better calibrated to realized firm load shed events.

ERCOT's MORA reports for 2025 imply 1.5 hours of shortage conditions across the twelve monthly peak-load days. In reality, there were only 1.2 hours with PRC less than 3,000 in the last three years, all of which occurred in 2023. This disparity indicates that the probability of shortage conditions presented in the MORA reports is likely substantially overstated. However, without forecasted probabilities of shortage and outage conditions for the full year, it is impossible to quantify the extent of the overestimate. The MORA values also imply 0.66 hours of firm load shed conditions across the twelve peak-load days. Scaling this value across the

entire year yields an estimate of over 20 hours of expected firm load shed conditions. The MORA methodology likely would estimate a significantly lower annual duration because the peak-load days likely represent a disproportionate share of the risk of firm load shed.

In summary, ERCOT's MORA reports for 2025 seem to overestimate the probability of shortage and firm load shed conditions based on current supply and demand conditions. The reports for April 2025 through the end of the year appear to present more reasonable forecasts, but it is difficult to say definitively whether they effectively represent the annual probability of shortage and load shed conditions because they present such forecasts only for peak-load days. Given the large volume of operating reserves and the absence of realized shortage conditions, the forecasts in the MORA report should also reflect a lower likelihood of shortages than in recent years.

## 2. Capacity, Demand, and Reserves Report

The CDR report is ERCOT's primary long-term resource adequacy forecast. Published twice a year, the CDR provides a five-year outlook on expected system conditions by projecting capacity additions and retirements, and forecasted peak demand. The report informs market participants, regulators, and stakeholders whether anticipated resources will be sufficient to meet projected demand under normal weather conditions. Unlike the MORA, a near-term operational tool, the CDR is a planning tool that provides a broad view of medium-term resource adequacy trends.

While the CDR report has improved meaningfully in recent years, several significant deficiencies still limit its usefulness for stakeholders to assess long-term resource adequacy. These limitations can produce an incomplete or misleading view of future supply and demand conditions and affect how market participants plan. The key deficiencies are as follows:

**Excludes most demand response resources:** The CDR report does not account for demand response capacity outside Emergency Response Service (ERS). According to the January 2026 Annual Report on ERCOT Demand Response, 10,550 MW of Non-Controllable Load Resources (NCLRs) and 915 MW of Controllable Load Resources (CLRs) are available.<sup>68</sup> Combined, these resources total 11.5 GW of flexible load that reliably reduces consumption during periods of system strain. These are the conditions the CDR is intended to evaluate. During these events, these load resources would likely reduce to a fraction of their peak demand.

**Unreliable beyond two-year horizon:** The CDR does not account for new generation resources that may enter the interconnection queue in the later years of its five-year forecast horizon. Many of these resources could feasibly become operational by the end of the forecast period, yet the CDR excludes them from the analysis. As a result, the CDR may not accurately reflect the evolving resource mix and may present an overly conservative, potentially misleading view of long-term resource adequacy.

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<sup>68</sup> 2025 Annual Report on Demand Response:  
<https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=1188179018>

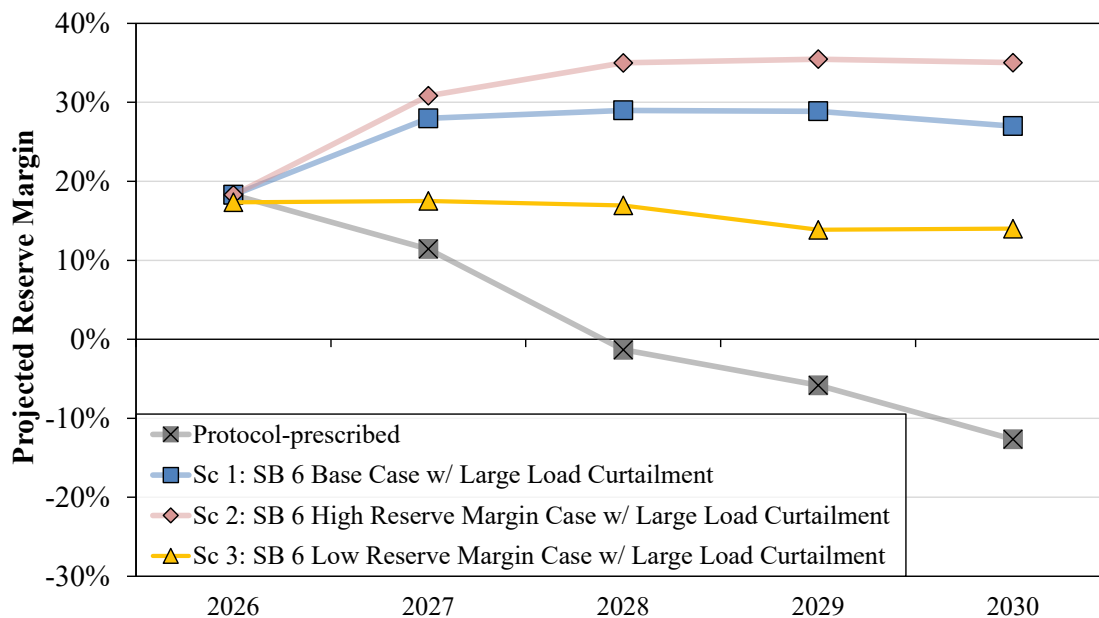
**Relies on planning data:** The CDR relies heavily on planning data that market participants submit, including projected capacities and operational dates for future generation resources. This information is often incomplete or inaccurate because market participants report it voluntarily, and ERCOT does not reconcile it against actual operational outcomes. Without a systematic process to reconcile this planning data with operations data, the CDR's forecasts remain vulnerable to errors and may misrepresent the true state of resource adequacy.

### 3. Impact on Reserve Margin

The planning reserve margin measures the difference between total available generation capacity and expected peak demand, expressed as a percentage of peak demand. It is a simple indicator of whether capacity is sufficient to meet demand under typical system conditions. A higher reserve margin indicates more available capacity and a lower risk of shortages, while a lower margin suggests tighter supply conditions. A negative reserve margin means that projected generation capacity is insufficient to meet peak demand, increasing the likelihood of reliability concerns, price spikes, and load-shedding events.

We previously criticized how the CDR report portrayed the planning reserve margin because the protocol-prescribed methodology did not fully reflect how system conditions would likely materialize in practice. The December 2025 CDR addressed this concern by including additional scenarios to account for large load curtailment under the new Senate Bill 6 framework.<sup>69</sup> Figure 58 illustrates these scenarios for summer peak load in the December 2025 CDR.

**Figure 58: Planning Reserve Margins for Summer Peak Load**  
December 2025 CDR



<sup>69</sup>

December 2025 CDR Report:

[https://www.ercot.com/files/docs/2025/12/19/CapacityDemandandReservesReport\\_December2025.pdf](https://www.ercot.com/files/docs/2025/12/19/CapacityDemandandReservesReport_December2025.pdf)



In addition to the protocol-prescribed scenarios, the December 2025 CDR presents three cases that explicitly assume varying degrees of large load curtailment and corresponding load and generation growth. These scenarios include a base case in Scenario 1, a higher reserve margin case in Scenario 2 with lower load growth and higher generation growth, and a lower reserve margin case in Scenario 3 with higher load growth and lower generation growth.

#### 4. Long-Term Load Forecast

ERCOT publishes the LTLF annually as its primary tool to project system load growth over a ten-year horizon. The LTLF provides detailed forecasts of future peak demand and energy consumption using econometric models informed by economic and demographic trends, weather data, and other variables. The forecast includes five major components: base economic load, large flexible loads (LFLs), electric vehicle (EV) load, rooftop photovoltaic (PV) generation, and large loads. ERCOT forecasts base load using traditional economic indicators such as population growth, housing stock, and employment data. It models other categories, including EVs and rooftop PV, based on adoption trends and historical patterns.<sup>70</sup>

Since the adoption of 16 TAC §25.370, large loads are now included in the LTLF and other ERCOT load forecast reports based on milestones these loads have reached in their development process, replacing the previous method of including both loads for which an interconnection agreement had been signed and loads for which an officer of the TDSP attested to the intention of the load energizing according to a provided schedule.

#### H. Load Forecast

ERCOT's load forecasts have changed significantly over the past two years, reflecting new policies, evolving forecasting methodologies, and a rapidly changing load landscape. We discussed some of these developments in last year's report. This year we will submit our detailed analysis of the load forecast through the stakeholder process rather than include it here because ERCOT published its most recent load forecast only shortly before this report's deadline.

Under ERCOT's standard Request for Information process, transmission and distribution service providers typically must submit planned load ramp schedules and other planning data for large loads by the end of January each year. In the current cycle, however, ERCOT extended this deadline until April to allow more time for SB 6 rulemakings to progress, particularly the rulemaking on large load interconnection standards. The preliminary forecast projects a peak demand of 367,790 MW in the ERCOT Region by 2032, which would more than quadruple ERCOT's highest recorded peak demand of 85,508 MW.<sup>71</sup> The next section presents several SB 6 rulemakings.

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<sup>70</sup> [https://www.ercot.com/files/docs/2025/04/08/2025\\_LTLF\\_Report.docx](https://www.ercot.com/files/docs/2025/04/08/2025_LTLF_Report.docx)

<sup>71</sup> Preliminary Long-Term Load Forecast:  
[https://interchange.puc.texas.gov/Documents/58777\\_38\\_1622647.PDF](https://interchange.puc.texas.gov/Documents/58777_38_1622647.PDF)



## I. SB 6 Rulemakings

The most significant legislation affecting the ERCOT wholesale electricity markets during the 89<sup>th</sup> legislative session was SB 6. Passed in June 2025, SB 6 introduced new net metering requirements for large loads, changed how ERCOT forecasts large loads, introduced additional interconnection standards for large loads, established the Large Load Demand Management Service as a reliability service, and called for an investigation of the current methodology for allocating transmission costs in the ERCOT region.<sup>72</sup>

The PUCT organized the implementation of SB 6 primarily under Project 58317<sup>73</sup> and the associated rulemakings into five additional projects. We already covered the Large Load Demand Management Service in Chapter II.G.7 and the review of the 4CP transmission cost allocation method in Chapter V.F.3. This section summarizes the remaining three SB 6 rulemaking projects.

### 1. Net Metering Arrangements with Large Loads

Net metering arrangements with large loads are defined in 16 TAC §25.205.<sup>74</sup> This rule requires PUC approval for any net metering arrangement in ERCOT in which a new large load customer is co-located with an existing generation resource. Before approving the arrangement, ERCOT must study its effects on resource adequacy, transmission security, and whether transmission assets become stranded or underutilized. The commission may approve, deny, or impose conditions such as load curtailment, required availability of dispatchable generation during emergencies, or cost-allocation protections. If any transmission assets become stranded or significantly underutilized as a result of large-load net metering arrangements, the rule requires a hold-harmless proceeding. This process removes the associated costs from general rates and assigns them directly to the generator and large load customer.

### 2. Large Load Forecasting Criteria

Large Load Forecasting Criteria are defined under §25.370.<sup>75</sup> This rule establishes when large load customers may be included in ERCOT load forecasts for transmission planning and resource adequacy reports. It requires a large load customer to have an executed interconnection agreement, verified disclosures, site control, and substantial financial commitments before its load will be included in ERCOT's resource adequacy forecasts. The rule also imposes formal attestation obligations on DSPs and TSPs that submit load data. ERCOT can validate, adjust, or exclude load data subject to commission oversight. It also must conduct annual forecast accuracy assessments and protect customer-specific information as confidential. Overall, the rule is

<sup>72</sup> SB 6: <https://capitol.texas.gov/tlodocs/89R/billtext/html/SB00006F.htm>

<sup>73</sup> Project 58317: <http://interchange.puc.texas.gov/Search/Filings?ControlNumber=58317>

<sup>74</sup> 25.205: <https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.205/25.205.pdf>

<sup>75</sup> 25.370: <https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.370/25.370.pdf>

intended to improve forecast accuracy and prevent speculative or non-viable large loads from driving unnecessary transmission investment or distorting reliability planning.

### **3. Large Load Interconnection Standards**

The rulemaking for large load interconnection standards is still underway. The most recent proposal for §25.194, published in Project 58481, establishes comprehensive large load interconnection standards in ERCOT to implement PURA §37.0561.<sup>76</sup> The rule requires large load customers to post \$50,000 per MW in financial security and execute an intermediate agreement before entering an ERCOT interconnection study. It then requires them to sign a full interconnection agreement with additional fees, construction cost payments, and equipment security. The rule also establishes milestones, withdrawal penalties, phased energization rules, and refund terms to support development, and reduce stranded transmission risk.

## **J. Transmission Investment**

We conclude this chapter with a discussion on transmission investment. The transmission network supports large load growth and incentivizes generation growth by connecting large renewable supply additions in West Texas to the rest of the state, managing stability impacts from intermittent renewables and fast-ramping loads, and enabling continued economic development without compromising reliability.

ERCOT has historically invested an average of \$3 billion per year to build or upgrade transmission infrastructure, and that figure rose to \$3.78 billion in 2024.<sup>77</sup> In last year's report, we predicted that if transmission investment scaled proportionally with the load growth projected at that time, ERCOT would have to multiply its annual transmission investment by three to six times. That projected load growth was less than half of the current projection based on ERCOT's RFI results. By December 31, 2025, ERCOT endorsed just over \$14 billion in transmission projects, manifesting this prediction.<sup>78</sup>

The cost of new transmission infrastructure in ERCOT is socialized across all market participants, in line with Texas' open access laws. Under this structure, entities seeking to interconnect are not directly responsible for the full cost of system transmission upgrades required to serve their load, which lowers the barrier to entry and supports Texas' reputation as an attractive market for investment. However, this model also means that the financial burden falls on existing ratepayers, who ultimately fund transmission expansion through regulated transmission charges. We discuss rulemaking that revisits the way transmission costs are allocated in Texas in Chapter V.F.3.

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<sup>76</sup> Proposed 25.194: [https://interchange.puc.texas.gov/Documents/58481\\_122\\_1600475.PDF](https://interchange.puc.texas.gov/Documents/58481_122_1600475.PDF)

<sup>77</sup> 2024 RTP: <https://www.ercot.com/files/docs/2025/01/27/2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf>

<sup>78</sup> ROS Report: [https://www.ercot.com/files/docs/2026/02/02/06.-SystemPlanningROS\\_Dec2025.docx](https://www.ercot.com/files/docs/2026/02/02/06.-SystemPlanningROS_Dec2025.docx)

## VIII. ANALYSIS OF COMPETITIVE PERFORMANCE

### A. Summary of Competitive Performance in 2025

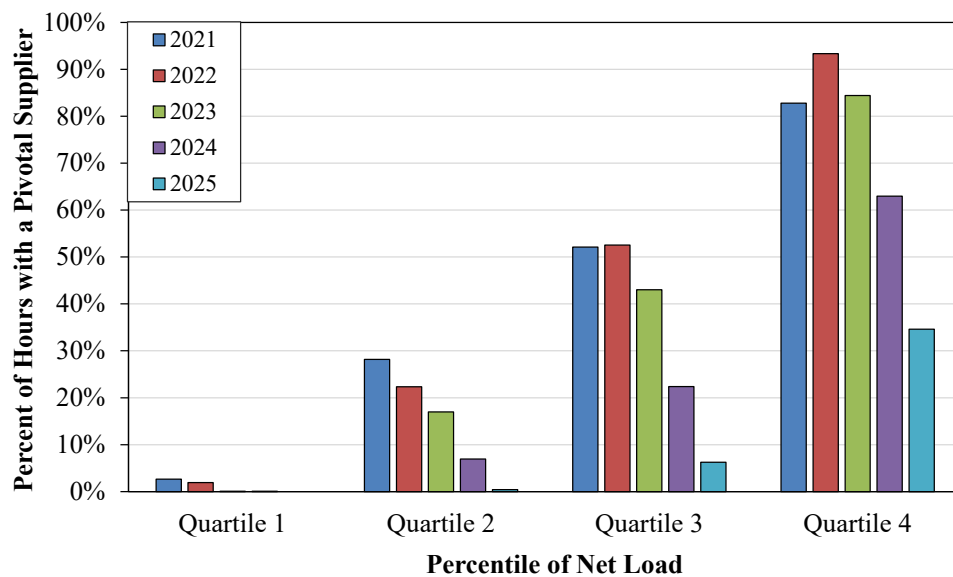
This section evaluates market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). It begins by evaluating a structural indicator of potential market power and then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, it provides a high-level summary of the Voluntary Mitigation Plans (VMPs).

- **Structural competitiveness has consistently improved since 2022.** The percent of top-quartile net load hours with a pivotal supplier has declined from over 90% in 2022 to 35% in 2025. However, extreme projected load growth in ERCOT will reverse this trend.
- **There is a high frequency of uncompetitive offer prices.** The frequency of an output gap is high, however in many hours the output gap is relatively small. This also has the potential to change significantly as projected load growth becomes commercial.
- **Potential physical withholding by large suppliers is not a concern.** Outage rates for large suppliers during stressed conditions remain low, as in prior years.
- **Mitigation remains effective.** By the end of 2025, only one VMP was in effect (Luminant). ERCOT's local market power mitigation method continues to reduce the potential impact of economic withholding.
- **Anticipated load growth may expose ERCOT to uncompetitive system-level pricing.** Uncompetitive conditions have trended downward the past three years. However, extreme load growth may reverse this trend. A system-level market power mitigation provision will help protect price formation from the exercise of market power.

## B. Structural Market Power Indicators

The market is most competitive when no participant can withhold capacity, whether physically or economically, to benefit from substantially higher prices. Traditional market concentration measures are not reliable indicators of market power in electricity markets partly because they do not consider overall load and operating reserve obligations that must be met by supply. A more reliable indicator of market power is whether a supplier is “pivotal,” i.e., whether a supplier’s resources are required to meet demand for energy and ancillary services or manage congestion. Figure 59 shows the results of our pivotal supplier analysis, including the frequency of hours with a pivotal supplier, grouped by net load level (quartile).

**Figure 59: Pivotal Supplier Frequency by Net Load Level**



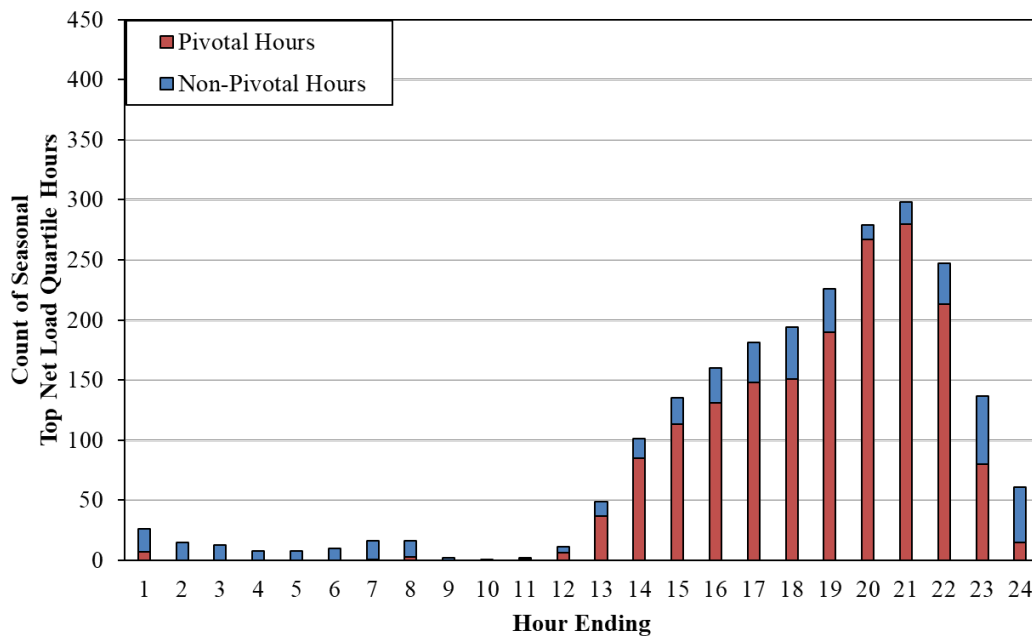
The percent of hours in the top quartile of net load with at least one pivotal supplier has declined since 2022. Pivotal suppliers, market participants with structural market power, existed in 10.3% of all hours in 2025, compared to 23.1% in 2024, 36.1% in 2023, and 42.5% in 2022.<sup>79</sup> We expect this trend to reverse as more of the ERCOT load projection becomes commercial. High net load indicates substantial demand that generation resources and net imports, excluding wind and solar, must satisfy. System conditions, including winter cold snaps, summer heat waves, and high generation outages, can significantly affect the supply-demand balance. These conditions can directly affect the extent to which participants possess market power. Decision Making Entities (DMEs) with large portfolios of non-intermittent generation are important contributors during these hours. The frequency of hours with pivotal suppliers is expected to increase with net

<sup>79</sup> The methodology for identifying pivotal suppliers has been modified prior to the publishing of this report. This has resulted in a more stringent identification process and a lower frequency of hours with one or more pivotal suppliers.

load. As load reserve requirements increase, excess supply declines. This increases participants' potential market power.

In the 2024 State of the Market Report, we recommended implementing a system market power mitigation provision in the ERCOT market. The frequency of uncompetitive hours is declining; however, a more granular review of hours with a high frequency of pivotal suppliers reveals greater predictability during peak net load hours in Summer and Winter.

**Figure 60: Pivotal Supplier Frequency by Hour of Day for Summer**  
(Top Quartile of Net Load)



The figure shows how often a pivotal supplier exists in each hour of the day during the Summer season and includes data for 2023–2025. Market power is more predictable in hours 16 through 22, especially in hours 20 through 22. While aggregate statistics show that the frequency of uncompetitive conditions has declined over time, the predictability of the hours when market power exists remains strong. The extreme load growth ERCOT predicts likely will both reverse the downward trend in uncompetitive conditions over time and expand the hours of the day when market power is more predictable. Even 20 GW of new net load materializing over the next few years would significantly reduce operating reserve margins in ERCOT and could materially increase uncompetitive conditions within the ERCOT market. No system-level market power mitigation measure, other than the offer cap, currently prevents uncompetitive high prices from persisting under these conditions. Because market design changes take time to develop and implement, we recommend drafting and implementing a system market power mitigation provision in the existing ERCOT market design.

We also evaluate competitiveness at a zonal level. The methodology follows the same structure as the system-wide evaluation with two exceptions. First, the zonal approach does not consider

reserve requirements at the zonal level. ERCOT does not have zonal demand curves for reserves, so there is no explicit requirement that some reserves be sourced within a specific zone. Second, import capability into a zone is competing with zonal supply and is addressed through netting observed net imports into a zone from the load in that zone. The figures in show, by zone, the percentages of hours during the top quartile of load where one or more pivotal suppliers existed.

**Table 11: Frequency of One or More Pivotal Suppliers in Top Quartile of Net Load by Zone**

	Pivotal Frequency				
	2021	2022	2023	2024	2025
Houston	64%	37%	51%	20%	5%
North	51%	57%	42%	28%	19%
South	15%	21%	25%	32%	14%
West	7%	4%	11%	1%	1%

This analysis focuses on hours when net load was in the highest 25% of the year, when supply was most likely to be tight and market power could be exercised. The Houston and North zones had the highest prevalence of structural market power during these high-load hours. The North zone also experienced a relatively high frequency of structural market power in 2025, as in prior years.

We cannot infer market power solely from pivotal supplier data because it does not consider the supplier’s contractual position. Bilateral and other financial contract obligations can affect whether a supplier has an incentive to raise prices. For example, a small supplier selling energy solely in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. We recommended eliminating the “small fish” rule because these small suppliers are sometimes pivotal and because high offer prices are not necessary to ensure efficient pricing under tight conditions (see SOM Recommendation 2021-1). The PUCT elected to remove the small fish rule beginning June 1, 2026 (Project P-58379).

The analysis above evaluates the structure of the entire ERCOT market and by zone. In general, local market power in smaller geographic areas that transmission constraints can isolate raises greater competitiveness concerns. ERCOT addresses local market power through: (a) structural tests that identify “non-competitive” constraints that can create local market power; and (b) “mitigation”, or limits on offer prices in these areas. This local market power mitigation applies to zones as well as topological areas within zones. Our recommendation last year to consider additional market power mitigation applied to both system and zonal regions. We are narrowing the focus of our recommendation to only system market power this year.

## C. Evaluation of Supplier Conduct

This subsection presents our evaluation of actual conduct to determine whether market participants attempted to exercise market power through physical or economic withholding. We first examine unit deratings and forced outages to detect physical withholding, then review the “output gap” to detect economic withholding.

In a single-price auction such as the real-time energy market, suppliers may attempt to exercise market power by withholding resources. By withholding resources, a supplier can cause higher-cost resources to set prices and increase profits on its other sales in the market. Because forward prices are highly correlated with spot prices, higher real-time energy market prices can also increase a supplier’s profits in the bilateral energy market. This strategy is profitable if the incremental profit exceeds the foregone profit from the withheld capacity.

### 1. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch even though they are physically capable of providing energy and are economic at market clearing prices. A plant operator can withhold resources by derating a unit or declaring it forced out of service. Because some generator deratings and forced outages are unavoidable, this subsection analyzes whether deratings and outages are in an expected range or may constitute physical withholding. We test for physical withholding by examining derating and outage data to determine whether they are correlated with conditions under which physical withholding would likely be most profitable.

The pivotal supplier results shown in Figure 59 indicate that the potential for market power abuse rises at higher net load levels because the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding occurs, one would expect increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a competitive market will tend to decrease as load approaches peak levels. Suppliers that lack market power will maximize the availability of their resources because their output is generally most profitable in peak periods.

Figure 61 shows average aggregate planned, forced, and unreported outages as a percentage of total installed capacity for large and small suppliers at different real-time load levels. Portfolio size is important in determining whether suppliers have incentives to withhold available resources. Hence, we compare outage and derating patterns for large and small suppliers. Aggregate outages are important to consider because pivotal supplier hours occur frequently.

This analysis also excludes wind, solar, and energy storage resources (ESRs) because the availability of these resource classes varies widely. The large supplier category includes ERCOT’s four largest suppliers (DMEs). The small supplier category includes the remaining suppliers.



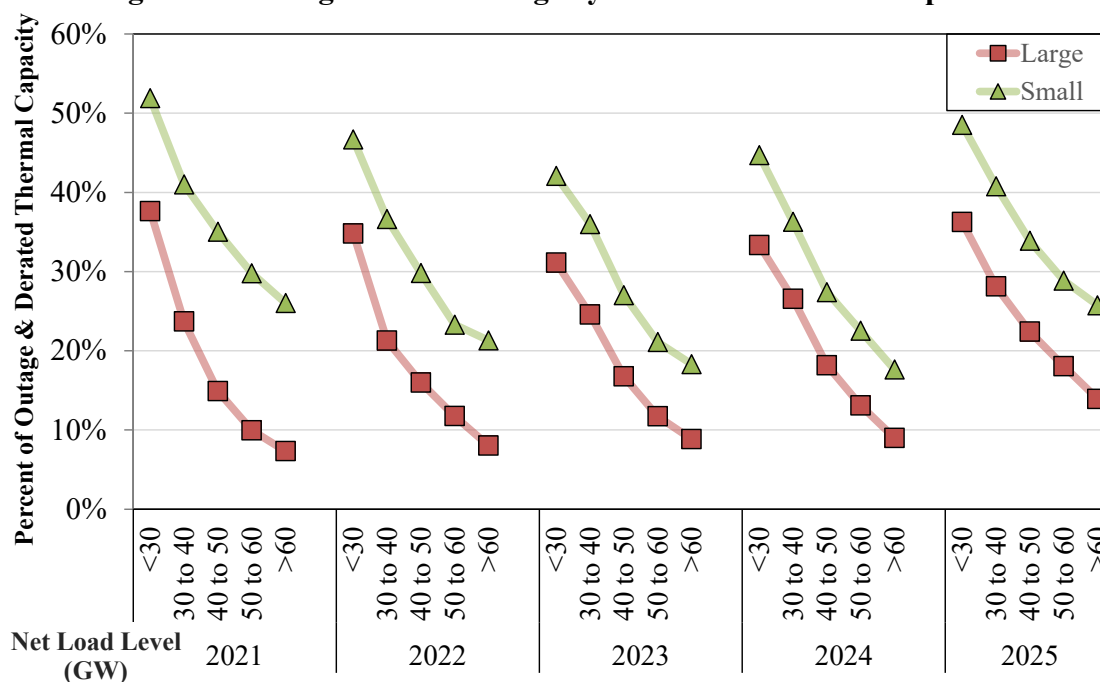
**Figure 61: Outages and Deratings by Load Level and Participant Size**

Figure 61 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants generally make slightly more capacity available to the market by scheduling planned outages during low load periods. The fact that available capacity tends to be higher under the highest load conditions is particularly notable because rising ambient temperatures generally cause thermal units' capacity to fall.

Because small participants generally are less able to physically withhold capacity and profitably exercise market power, the outage rates for small suppliers provide a good benchmark for the competitive behavior expected from larger suppliers. Outage rates for large suppliers at all load levels modestly exceeded those for small suppliers but remained low enough to raise no competitiveness concerns.

## 2. Evaluation of Potential Economic Withholding

This subsection evaluates potential economic withholding by calculating an “output gap”. The output gap is the quantity of energy not produced by online resources even though producing that output would be economic by a substantial margin at the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising a resource's energy offers to reduce its dispatch level.

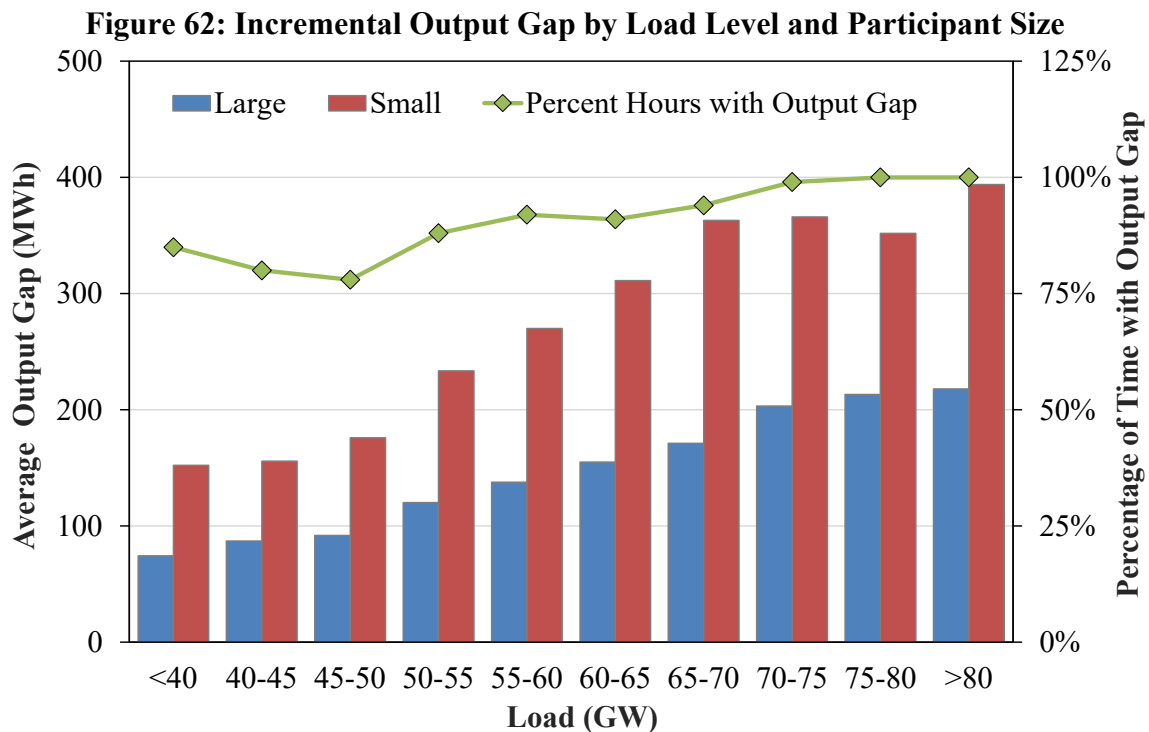
The output gap includes resources that are committed and producing at less than full output. It also includes energy not produced from a committed resource if the offer price exceeds both (a)



the mitigated offer price and (b) the LMP plus the lesser of \$10/MWh or 15%. The mitigated offer cap serves as a proxy for the resource's marginal production cost of energy.

Figure 62 shows the average output gap levels, measured as the difference between a unit's operating level and the output level it would have delivered over an hour if it had been offered to the market based on a proxy for a competitive offer (i.e., the unit's mitigated offers), with a few changes. We use generic costs rather than verifiable costs for quick-start units because verifiable costs may include startup costs that are inappropriate for this comparison. In addition, we remove fuel adders because they represent fixed costs. Finally, we include quick-start units if they were in quick-start mode and available for real-time dispatch. Figure 62 the average positive output gap by load level and, for reference, the percentage of hours in each load-level category.

In 2025, over 80% of hours exhibited an output gap, indicating a potential attempt to exercise market power through economic withholding. At higher load levels, an extremely small percentage of generating capacity exhibited an output gap for a large percentage of the time. An even smaller percentage of generating capacity exhibited an output gap at lower load levels. The quantities withheld implied by the output gap were relatively low, even in the upper quartile of net load hours. These results show that potential economic withholding in the real-time energy market was low overall, but not trivial, in 2025. While the ERCOT market may have performed competitively in general, the level of market power and the moderate evidence of potential economic withholding are cause for concern. Anticipated increases in system load over the coming years can result in more frequent structural market power and stronger incentives to exercise that market power.



#### D. Voluntary Mitigation Plans

The PUCT has discretion to approve VMPs filed by market participants.<sup>80</sup> Before September 1, 2023, a market participant's adherence to a PUCT-approved VMP constituted an absolute defense against an allegation of market power abuse with respect to the behaviors addressed by the plan. However, House Bill 1500, passed during the 88<sup>th</sup> Legislative Session and effective September 1, 2023, modified the statutory requirements for VMPs. Adherence to a VMP no longer constitutes an absolute defense against allegations of market power abuse with respect to the behaviors addressed by the VMP; instead, it must be considered in determining whether a violation occurred and, if so, the penalty to assess.<sup>81</sup>

VMPs should promote competitive outcomes and prevent abuse of market power through economic withholding in the ERCOT real-time energy market. Forward energy markets (e.g., the ERCOT day-ahead market) do not require the same restrictions, but prices in those markets reflect expectations for real-time energy prices, where mitigation applies. The forward energy market is voluntary, and market rules do not inhibit arbitrage between the forward energy market and the real-time energy market. Therefore, competitive outcomes in the real-time energy market discipline potential abuse of market power in forward energy markets.

Generation owners are often motivated to enter into VMPs, and the increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market must be balanced by appropriate protections against a potential abuse of market power in violation of Public Utility Regulatory Act (PURA) §39.157(a) and 16 TAC §25.503(g)(7). In 2023, Calpine, NRG, and Luminant had active and approved VMPs filed with the PUCT.<sup>82</sup> By the end of 2024, NRG had eliminated their VMP and only Calpine and Luminant had effective VMPs. In 2025, Calpine eliminated their VMP during the process of merging with Constellation which left only Luminant. Luminant's VMP was amended in late 2025 and in early 2026 to reflect market changes that resulted from transitioning to the Real-Time Co-optimization Imarket framework. The VMPs for Calpine and Luminant included provisions that specify competitive benchmarks for offers in both energy and reserves. Further, the provisions address different generation technologies and fuel types and also address on-line versus off-line states in consideration of competitive cost on which to base the offer cap. The IMM reviews the VMPs on a cycle and when significant changes to market rules may change the competitiveness of the

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<sup>80</sup> PURA § 15.023(f).

<sup>81</sup> *Id.* Also, the PUCT amended its rules to implement these statutory changes on April 25, 2024. *Review of Voluntary Mitigation Plan Requirements*, Docket No. 55948, Order (Apr. 25, 2024)

<sup>82</sup> *See Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013); *Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Docket No. 40488, Order (Jul. 13, 2012); *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 42611, Order (Jul. 11, 2014); *PUCT Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e)*, Docket No. 49858, (Dec. 13, 2019).

market or one or more participants' degree of market power. Assessment and recommendations regarding VMP provisions are provided to PUCT staff.

PURA defines market power abuses as “practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition.”<sup>83</sup> The *exercise* of market power may not constitute an *abuse* if the actions in question do not unreasonably impair competition. Impairment of competition typically involves profitably raising prices materially above the competitive level for a significant period.

A key aspect in the VMPs is the termination provisions. Each of the VMPs could be terminated by the Executive Director of the PUCT with three business days' notice, subject to ratification by the Commission. Although the offer thresholds provided in the VMPs are intended to promote competitive market outcomes, the short-lead termination provision provides additional assurance that any unintended consequences associated with potential exercise of market power can be addressed in a timely manner.

## E. Market Power Mitigation

When competition is not robust and suppliers have market power, an independent system operator must mitigate offers to prevent offer prices from diverging substantially from competitive levels. ERCOT's real-time market includes a mechanism to mitigate offers for resources that may have local market power because they are required to manage a transmission constraint.

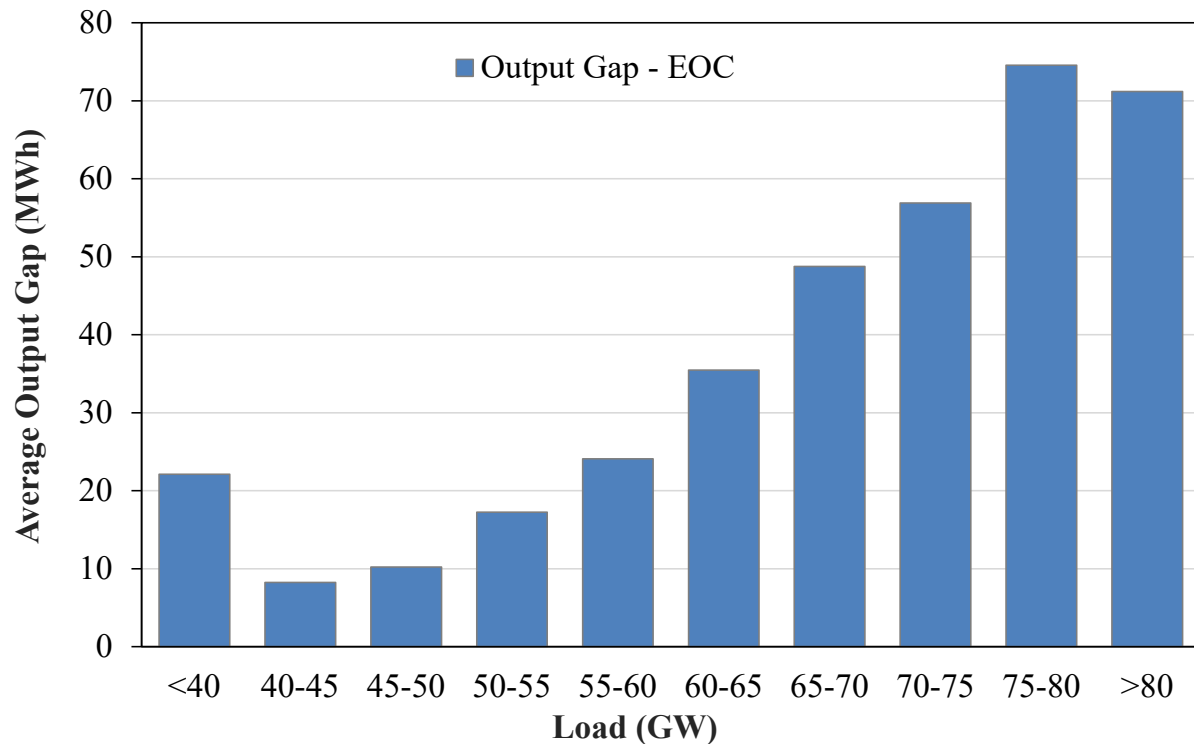
Mitigation applies whether the unit is self-committed or receives a Reliability Unit Commitment (RUC) instruction. Prior to 2021, ERCOT typically issued RUC instructions to resolve transmission constraints. However, RUCs for system-wide capacity became common in summer 2021 and continued through early 2023. When a unit that receives a RUC instruction is required to resolve a non-competitive transmission constraint, ERCOT often dispatches it in real time with its offer prices capped at mitigated levels. ERCOT's dispatch software includes an automatic two-step mitigation process:

- The dispatch software calculates output levels (base points) and prices using participants' offer curves and considering only the “competitive” transmission constraints. In the second step of the dispatch process, the software formulates the generator's mitigated offer curve using the higher of a) the resulting prices at each generator location and b) the generator's mitigated offer cap.
- The dispatch software then uses the mitigated offer curve to determine the final dispatch levels and prices, considering all transmission constraints.

<sup>83</sup> PURA § 39.157(a).

- This approach is intended to limit a generator’s ability to exercise local market power by raising its offer price to increase prices in a transmission-constrained area. In this subsection, we analyze the impact of mitigation on offer curves in 2025. Automatic mitigation under the two-step dispatch process can affect outcomes only when a non-competitive transmission constraint is active and binding in SCED. Figure 63 shows the average implicit reduction in the output gap resulting from mitigation.

**Figure 63: Mitigated Output Gap by Load Level**



Mitigated offer curves have a material effect on the output gap shown in Figure 63. This measure shows the average in-market quantity made available through mitigation. Although this quantity may not appear material on a system-wide basis, it can be impactful in congested areas where ERCOT applies mitigation. The output gap increases as load increases. Higher loads can lower operating reserve margins (tighten supply conditions) and increase the frequency or severity of congestion, creating greater opportunity to exercise market power through higher offer prices. The ERCOT process for identifying and mitigating local market power appears to function as intended and to mitigate offer prices that are out of the competitive range.

## IX. RECOMMENDATIONS

Each year, we produce recommendations to improve market efficiency, enhance reliability, and mitigate the potential for market participants to exercise market power. Some recommendations are new and reflect emerging challenges or current-year developments. Others carry over from prior years because they remain relevant and unaddressed. We retire past recommendations when they have been implemented, are no longer applicable, or have been folded into a broader or updated recommendation. We number each recommendation based on the year we first introduced it, followed by its order in this report.

### A. New Recommendations to Improve Market Performance

#### 2025-1: Redesign & Improve the Firm Fuel Supply Service

ERCOT implemented the Firm Fuel Supply Service (FFSS) in 2022 in response to widespread generation shortfalls from fuel supply disruptions during Winter Storm Uri. The program provides a seasonal payment to selected generators in exchange for maintaining fuel storage during the winter months, from mid-November through mid-March. These generators, designated as Firm Fuel Supply Service Resources (FFSSRs), must be ready to operate for up to 48 hours if fuel supply disruptions threaten system reliability. ERCOT can deploy FFSSRs during declared winter weather watches; however, the criteria for deployment beyond this trigger remain unclear and are left to operator discretion.

The PUCT approved a rulemaking for the FFSS program in February 2026 that significantly departs from the operational framework ERCOT currently uses to administer the program, largely because it includes natural gas resources that have firm supply contracts rather than store fuel. Including these resources likely provides very little reliability benefit because total gas supply and transportation capability is limited. In a winter storm, one should expect that this capability will be fully utilized so firm contracting will largely simply shift the gas between generators rather than increasing the total amount of available gas during an event.

Instead, the FFSS is intended to incentivize availability by increasing fuel storage inventories. Because severe winter storms are infrequent and higher energy prices rarely follow, oil-fired resources, primarily dual-fuel resources that could store fuel oil, may not perceive adequate economic incentives to procure and maintain infrastructure to store large volumes of fuel oil for the few winter storms, if any, that Texas experiences each year. Accordingly, we recommend the following reforms to the FFSS program, which includes elements from Recommendation 2023-4 that we are retiring this year:

- **Eligibility.** FFSS eligibility should be limited to resources that can store their fuel onsite or offsite, which are currently described in 16 TAC 25.520(c)(1)-(2).

- **Budget.** ERCOT should establish the annual FFSS budget based on risk criteria related to the grid's preparedness for winter events. As ERCOT implements new reliability tools and strengthens system infrastructure, the amount of FFSS needed should decline.
- **Clearing Structure.** The FFSS should use a single clearing structure because it provides a single reliability benefit. Eligible resources should compete so that the program selects only the most efficient resources each year.
- **Offer Requirements.** ERCOT should specify offer caps for each resource based on historical heat rates established through the verifiable cost process, projected fuel prices for the upcoming FFSS obligation period, and potential opportunity costs of using firm fuel. This would ensure resources' energy offers reflect their true marginal costs.
- **Noncompliance.** In addition to the current provisions to reduce or claw back the FFSS award and suspend the QSE from further participation in the program, we recommend charging the FFSSR for the market price impact of its failure to deploy.
- **Deployment Criteria.** The FFSS should be deployed when there is a demonstrated disruption or shortage in the fuel supply that meaningfully threatens the reliability of the ERCOT grid.

Our comprehensive recommendation on the rulemaking process in Project 58434 appears to have been discounted based on its individual parts rather than as a whole. We believe it is essential to consider these recommendations together. A more comprehensive discussion on this topic is covered in Chapter VI.G.

### **B. Recommended Market Improvements from Prior Years**

#### **2024-1: Improve the Procurement and Pricing of Ancillary Services by: (a) Defining ASDCs based on the Marginal Reliability Value of Each Product, and (b) Adopting a Stochastic Risk Methodology for the AS Plan**

For the shortage pricing mechanism to function properly, the ASDCs should reflect the marginal reliability value of each reserve product. A well-structured ASDC framework must be based on a probabilistic assessment of the specific risks each reserve product is intended to manage. This assessment determines the marginal value of the reserve product as the quantity of the reserves rises or falls. Ideally, the ASDCs will reflect this marginal value, falling to zero when additional reserves provide no contribution to system reliability.

The two components of this recommendation address these components of the ASDC framework, which are necessary to procure and price ancillary services efficiently. The first component (2024-1a) recommends designing the ASDCs based on the marginal reliability value of each product. The second component (2024-1b) recommended that ERCOT implement a

probabilistic risk-based methodology to set the target volume of real-time operating reserves. ERCOT did develop a probabilistic methodology, but its parameters do not accurately reflect the risks that ancillary services address and result in excessive procurement targets. In our update to 2024-1b, we propose alternative parameters.

### **2024-1a: Define ASDCs According to Marginal Reliability Value of Each Product**

Prior to December 2025, ERCOT produced shortage pricing using the Operating Reserve Demand Curve (ORDC). When ERCOT implemented RTC, it replaced the ORDC with a set of Ancillary Service Demand Curves (ASDCs) that define the penalty prices for shortages of each ancillary service. The individual ASDCs must aggregate to the same shape as the ORDC by Commission policy, which is why the combined ASDCs are referred to as the Aggregate ORDC (AORDC). Unfortunately, requiring the ASDCs to conform to the shape of the AORDC undermines market signals for both shortage pricing and reliability in two ways.

A static Aggregate ORDC undermines the market signal for shortage pricing when it does not vary with underlying system conditions. Forcing the ASDCs to conform to a predetermined AORDC causes scarcity prices to reflect an outdated administrative construct instead of the actual severity and type of reserve shortages. As a result, shortage pricing provides a weaker signal of true system stress and marginal scarcity.

The aggregation requirement also undermines reliability because it prevents each ASDC from reflecting the reliability value of its corresponding ancillary service. Different reserve products address different risks, and their reliability value varies with system conditions. Constraining all ASDCs to fit a fixed aggregate curve limits their ability to adapt to changing supply and demand conditions. This weakens incentives to procure and provide the services that most effectively reduce reliability risk.

Accordingly, we recommend removing the requirement for the ASDCs to aggregate to the AORDC and constructing each ASDC individually to reflect the reliability value of the corresponding reserve product. ERCOT lists “ASDC Review” as its top priority in its inventory of RTC Issues to Consider in 2026.<sup>84</sup>

### **2024-1b: Set Parameters for AS Methodology According to Probabilistic Risks**

Since 2022, ERCOT has dramatically increased the volume of ancillary services procured in the market. This over-procurement stems from an AS Methodology that fails to reflect the probabilistic risks that operating reserves are meant to manage. In the AS Study mandated by PURA 35.004(g), we showed how a stochastic risk-based approach can set more appropriate targets for real-time operating reserves.

<sup>84</sup> ERCOT Issues to Consider 2026: <https://www.ercot.com/files/docs/2026/02/11/Inventory-of-RTCBTF-Issues-to-Consider-in-2026-021826-RTCBTF-Update-and-Discussion.xlsx>



Our approach used historical supply and demand data to simulate the probability of load shed at various levels of real-time operating reserves. It captured (1) net load forecast error, which can lead to inefficient commitments, and (2) forced outages, which suddenly reduce supply. It also used a forecast-error time horizon consistent with the short-term reliability risks that operating reserves are meant to manage. Our analysis found that ECRS and NSRS procurement volumes could be substantially reduced while maintaining a load shed probability of just 5% per year.

While ERCOT developed a similar probabilistic approach for the 2026 AS Methodology for ECRS and NSRS, many model inputs overstate the risks these products are meant to manage, resulting in excessive procurement targets in the wholesale markets. In our commentary on the 2026 AS Methodology, we estimated how the following parameters affect AS Plan procurement targets:

- Setting operating reserve targets to achieve a one-in-ten standard for the probability of entering a “Watch,” nominally defined as dropping below 3,000 MW, rather than for the probability of firm load shed, defined as reserves dropping below 1,500 MW, inflates the target level of the AS Plan by approximately 43%.
- Assessing the operational risk that NSRS is meant to manage based on the six hour-ahead forecast error for demand and generation from intermittent renewables. This parameter inflates the target level of the AS Plan by an additional 57% compared to our recommendation to use a one hour-ahead forecast error.
- Accrediting the available headroom of ESRs to provide NSRS based on the power output they can sustain for four hours, rather than our recommended one hour. This parameter inflates the target level of the AS Plan by an additional 29%.

Together, these inputs produce the proposed AS Methodology that procures 140% more than required to satisfy the 1-in-10 reliability standard for load shed. *The last 2 GW provide no additional reliability.* We discuss the AS Methodology in greater detail in Chapter III.E.

We commend ERCOT for implementing a probabilistic risk-based approach for the 2026 AS Methodology, but its use of parameters that overstate the reliability risks ECRS and NSRS are meant to manage undermines long-term resource adequacy. Excessively high operating reserves suppress the prices needed to signal new investment and lead to inefficient dispatch solutions and uplift to consumers. We recommend that ERCOT adjust these parameters to produce AS procurement targets that more accurately reflect the system’s reliability needs.

### **2024-2: Set Duration Requirement for NSRS to One Hour**

Recommendation 2024-2 previously called for setting the duration requirement for both ECRS and NSRS to one hour. The title of this recommendation has since been updated to reflect ERCOT’s reduction of the ECRS duration requirement to one hour when it implemented RTC, consistent with our recommendation. ERCOT still maintains a four-hour duration requirement



for NSRS for energy storage resources, which must maintain a state of charge four times their NSRS obligation. For example, a 10 MW NSRS award would require 40 MWh of stored capacity. We recommend reducing the NSRS duration requirement to one hour for two reasons:

First, requiring ESRs to maintain four hours of state of charge to provide operating reserves limits their ability to supply reserves, increasing the likelihood of shortages of both energy and ancillary services. This occurs because a four-hour obligation produces an opportunity cost for selling reserves that is four times the prevailing energy price – a resource that can discharge 4 MW of energy for an hour can only sell 1 MW of reserves (so it can inject 4 MWh over 4 hours). Since this tradeoff for thermal units is 1-to-1, this obligation will encourage the real-time market to procure reserves from thermal units and schedule storage resources to sell energy. This undermines overall reliability by reducing limited state of charge of the storage resources inefficiently. It would lower costs and improve reliability in this case to dispatch the thermal units for energy and hold ESRs to provide reserves.

Second, a one-hour requirement better aligns with the short-term reliability risks NSRS is designed to address. NSRS is intended to manage short-duration energy shortfalls caused by sudden net load ramps or forecast errors, rather than sustained energy shortfalls. Treating NSRS as a long-duration reserve product dilutes its purpose by imposing requirements that reflect energy adequacy needs rather than near-term operational reliability needs.

We recognize the need for some longer-duration operating reserve capacity to manage uncertainty in supply and demand under extreme weather or volatile market conditions. Accordingly, Recommendation 2021-2 would create an uncertainty product that could serve this purpose more effectively than imposing NSRS duration requirements longer than one hour. Therefore, we recommend setting the NSRS duration requirement at one hour.

### **2024-3: Implement Process to Mitigate Market Power at the System Level**

Anticipated high net load growth over the next five years will reverse the recent downtrend in the frequency of uncompetitive hours in the ERCOT market. ERCOT currently has a mitigation procedure to address local market power, but not for market power at the system level. Even a 20 GW increase in new net load in the ERCOT system will reduce the operating reserve margin considerably and increase the opportunity to exercise market power successfully at the system level. We recommend beginning the development of these measures in the near term before serious concerns arise.

A well-established and effective approach to mitigate these market power concerns is the conduct-impact framework employed in MISO, the New York ISO, and ISO New England markets. It limits the application of mitigation to clear instances of market power by requiring that two tests be satisfied before mitigation is applied:

- (i) A market participant with market power has attempted to exercise it through economic or physical withholding (conduct test), and
- (ii) The attempt to exercise market power would materially affect price (impact test).

For market participants that fail these two tests, the participant's real-time offer is capped at a competitive level or a sanction is applied once the conduct is investigated, such as in the case of physical withholding. Both tests require the application of a threshold. For example, a supplier must raise its real-time energy offer above a competitive level by more than the conduct threshold to warrant mitigation. These thresholds would be developed and discussed with market participants through the stakeholder process.

#### **2024-4: Establish Real-Time Offer Requirements, Penalties, and Proxy Pricing**

QSEs must submit offer curves that specify the prices that they are willing to provide energy or ancillary services in the real-time market now that RTC is implemented. These offer curves are expected to cover each resource's full operational capacity, but they are frequently incomplete. Incomplete offer curves for energy and ancillary services limit the market's access to available capacity and trigger steep proxy offers that inflate scarcity pricing and distort dispatch. ERCOT currently imposes no penalty for submitting incomplete offers. As a result, QSEs may intentionally withhold offers or mistakenly fail to submit complete offers.

If a QSE submits an incomplete offer curve for energy or ancillary services, ERCOT substitutes proxy offers to maintain a solvable dispatch solution. ERCOT sets proxy offers for energy at \$1,500 for IRRs and at the system-wide offer cap (SWCAP) for non-IRRs. ERCOT sets proxy offers for ancillary services at the lesser of \$2,000 or the ASDC price corresponding to 95% of the target procurement level. This methodology creates steep, non-competitive offer curves that lead to inefficient, costly dispatch outcomes.

We recommend the following:

1. Proxy offers should reflect competitive pricing for energy and ancillary service products.
2. ERCOT should make its must-offer requirement explicit for all QSEs.
3. ERCOT should impose penalties on QSEs that fail to submit complete offers.
4. ERCOT should flag proxy-constructed offers in SCED data to enable continuous evaluation of their effect on market performance.

On point 4, ERCOT currently creates proxy offers for ancillary services up to a resource's HSL regardless of its capability to provide ancillary services. Proxy offers should be defined only up to a resource's qualified capability for ancillary services to streamline data processing.

**2022-1: Implement a Multi-Interval Real-Time Market**

ERCOT's real-time market currently considers a single interval and optimizes dispatch instructions based only on forecasted system conditions over the next five minutes. This limited forward-looking window reduces the market's ability to efficiently dispatch and coordinate resources, particularly as intermittent renewables and energy storage resources account for a larger share of generation in the ERCOT system. A Multi-Interval Real-Time Market (MIRTM) produces a dispatch solution based on forecasted system conditions across multiple future intervals, looking at least thirty minutes ahead and ideally an hour or more. This offers several important benefits:

- It would schedule ESRs more efficiently by considering the value of preserving or adjusting state of charge over multiple intervals;
- It would improve NSRS utilization, much of which offline resources provide, by enabling the real-time market to commit these thirty-minute reserve units more efficiently.
- It would help address the sharp evening net load ramp from increasing solar entry, often referred to as the "duck curve," by pre-positioning slow-ramping resources earlier and reducing reliance on expensive ESRs and quick-start units.

Because of recent resource development trends, particularly the considerable influx of storage resources, we continue to recommend that ERCOT prioritize MIRTM implementation.

**2021-2: Implement an Uncertainty Product**

Rapid growth in intermittent renewable generation and duration-limited energy storage resources has introduced new reliability challenges from forecast uncertainty. Forecast errors for load and renewable generation can result in under-commitment of thermal resources and premature discharging of energy storage resources, leading to tight system conditions. ERCOT has managed this uncertainty by increasingly relying on RUC instructions and procuring larger quantities of 30-minute reserves, both of which distort market outcomes and impose excess costs on consumers. To address this issue, we have recommended that ERCOT implement a longer-term reserve product from resources that can start within 2 hours when forecast errors become evident.

In 2023, HB 1500 directed ERCOT to implement such a product, now referred to as DRRS. We recommend the following two design principles:

1. Both online and offline resources should be able to provide DRRS.  
Allowing both resource types to participate ensures ERCOT can secure reserves at the lowest cost without discouraging self-commitment of thermal resources under favorable market conditions.

2. ERCOT should co-optimize DRRS with energy and other ancillary services in the day-ahead and real-time markets and price shortages through a sloped demand curve. This approach ensures that DRRS procurement reflects its marginal value, supports efficient price formation, and sends appropriate investment signals for resource adequacy.

ERCOT's current proposal for DRRS an operating reserve under NPRR 1309 incorporates both design principles. If ERCOT implements it correctly, DRRS should reduce reliance on costly out-of-market actions and lower reserve procurement costs compared to holding excessive 30-minute reserves.

As installed wind, solar, and storage capacity grows, reliability risks from forecast errors will increase. A fast, flexible unit commitment process for DRRS would support broader reliability needs while complying with HB 1500. We continue to recommend that ERCOT implement DRRS using the design principles outlined above.

### **2020-3: Reconfigure Load Zones to Reflect Prevailing Congestion Patterns**

Load zones are groups of load nodes in the ERCOT grid that experience similar congestion patterns. Unlike generators, which settle at the nodal level and receive payments based on their specific locational marginal prices (LMPs), loads are billed at the load zone price. This price reflects a load-weighted average of nodal prices within the zone. By aggregating prices this way, the system shields loads from nodal price volatility and simplifies market settlements.

Beyond simplifying settlements, load zone prices also provide important short- and long-term economic signals. When they accurately capture congestion patterns, they can inform consumption and hedging decisions for existing loads and signal to prospective loads the most cost-effective locations for new demand. These price signals also factor into other long-term infrastructure decisions, such as transmission planning.

ERCOT's current four load zones – West, North, South, and Houston – were established in 2003. At that time, the geographic distribution of load and generation, as well as the generation mix, differed substantially from today. Industrial load has grown substantially in West Texas, driven by electrification of oil-and-gas operations and data center development, and residential load has shifted away from historical population centers. Moreover, renewable resources located far from load centers increasingly serve load. These shifts make it increasingly important to re-evaluate whether the current load zone boundaries still reflect meaningful economic and operational groupings.

One indication that the current load zone groupings no longer reflect congestion patterns adequately is the growth in congestion within several zones, especially the South and West zones. The broad aggregation of nodal prices within each zone now conceals important differences in the cost of serving load. This disparity distorts pricing signals and can lead to inefficient consumption and siting decisions. For example, the Panhandle consistently

experiences lower-than-average nodal prices because a concentration of renewable generation frequently creates a local surplus and causes curtailment. In contrast, the Permian Basin, which is in the same load zone, faces significantly higher nodal prices driven by oil and gas-related demand that higher-cost units often must serve because the region is import-constrained. Both areas face the same zonal price for settlement despite their very different cost and congestion profiles.

We recommend that ERCOT re-evaluate the current load zone configuration to reflect these evolving congestion patterns. Because of the CRR auction design, any change to the configuration must take effect at least four years after approval. In Chapter V.G, we present a potential methodology to reconfigure load zones that would better align settlement prices with actual system conditions. To date, ERCOT has not indicated that it intends to revisit or revise the current load zone structure.

#### **2020-4: Implement a Point-to-Point Obligation Bid Fee**

Point-to-point (PTP) obligations are financial instruments that allow market participants to take positions on congestion between the day-ahead and real-time markets. Market participants submit PTP bids into the day-ahead market, and the market optimization process evaluates them. Over the past decade, the day-ahead market has experienced numerous delays in solving and posting results. ERCOT has identified the large and growing volume of PTP obligation bids as a key contributor to these delays. While computational and optimization improvements have reduced delays in recent years, the consistent year-on-year increase in PTP volume continues to risk delays in clearing the day-ahead market. These delays disrupt the market and create unnecessary risk for participants who rely on timely information to guide real-time decisions.

Because ERCOT charges no fee to submit PTP bids, participants have no incentive to limit their bids. Many of these bids are uncompetitive, so they are unlikely to clear and add little market value through liquidity or price formation. Including so many uncompetitive bids increases the complexity of the optimization problem and the time the market software needs to arrive at a solution. We recommend that ERCOT impose a small fee on uncompetitive PTP bids to reduce the volume submitted into the day-ahead market.

A small bid fee on uncompetitive PTP bids would discourage superfluous bid submissions without deterring legitimate hedging or trading strategies. ERCOT would determine a bid's competitiveness based on how close the bid is to the final clearing price on the path in absolute and relative terms. By incentivizing participants to submit bids with a meaningful likelihood of clearing, the fee would streamline the market-solving process and reduce the frequency of day-ahead market delays. ERCOT has presented our proposal for a PTP Bid Fee at CMWG and indicated its intention to submit a corresponding NPRR.<sup>85</sup>

<sup>85</sup>

<https://www.ercot.com/files/docs/2026/04/10/CMWG-PTP-Bid-Fee-NPRR-Update.pptx>

**2019-2: Price Ancillary Services Based on the Shadow Price of Procuring Each Service**

Clearing prices for ancillary services should reflect the shadow price of procuring each service. ERCOT currently nests multiple variations of operating reserves under a single ancillary service, sets procurement volume limits for each sub-product, and clears all sub-products at the same price. This practice violates this principle. For example, Responsive Reserve Service (RRS) effectively includes three separate products, each of which clears at the same price:

- Primary Frequency Response (PFR), an automatic response proportional to frequency deviations provided by generators, storage resources, and controllable load resources;
- Fast Frequency Response (FFR), a relay-like response provided almost exclusively by batteries;
- Under-Frequency Relay (UFR), a type of relay response that non-controllable load provides and that trips loads offline if system frequency drops significantly.

Of the total procurement volume for RRS, FFR can provide at most 450 MW, and FFR and UFR together can provide only 60 percent. Because this second limit usually binds, the market has a surplus of offers for both FFR and UFR. However, this surplus does not lower clearing prices as one might expect because all products clear at the same price.

To resolve this issue, ERCOT should set separate procurement volumes for PFR, FFR, and UFR and allow each product to clear at the shadow price of the associated constraint. If PFR is inherently preferable to FFR or UFR, excess PFR offers should be substitutable for either service when offered at a lower price. This change in ancillary service design would produce prices that more accurately reflect the value of each product and offers that reflect the marginal cost of providing each product. Therefore, we recommend basing the clearing price of all ancillary services on all constraints used to procure the services.

**2015-1: Transition Away from the 4CP Method of Allocating Transmission Costs**

ERCOT allocates the costs of the transmission system to consumers using the 4CP method. Under this methodology, each consumer's transmission tariff for the following year is based on its load-ratio share during the 15-minute intervals with the highest monthly system-wide demand from June through September.<sup>86</sup> Approved in 1996, the 4CP method was intended to allocate transmission costs to those who contributed most to system-wide peak demand. It also was designed to signal consumers to reduce load during peak periods, thereby forestalling the need for new transmission investments. Whatever virtues this methodology once had, it no longer aligns with cost-causation principles and fails to send efficient signals for new transmission investments.

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<sup>86</sup> 16 Tex. Admin. Code §25.192. Transmission Service Rates:  
<http://www.puc.texas.gov/agency/ruleslaws/subrules/electric/25.192/25.192.pdf>

Today, peak demand does not primarily drive transmission upgrades. Instead, congestion patterns throughout the year and the need to reliably serve evolving load patterns drive them. The geography of growth has shifted: industrial load for oil and gas production and computing is growing rapidly in West Texas, while residential load growth is sprawling into exurbs farther from population centers. Transmission costs now depend heavily on the distance between generation and load growth. Connecting remote renewable generation to distant load centers requires significant investment in long-distance transmission infrastructure. Because the 4CP method is based solely on system-wide summer peaks, it does not reflect the complex, location-specific drivers of today's transmission needs.

The Permian Basin Reliability Plan further exacerbates this misalignment. It is estimated to cost more than \$13 billion<sup>87</sup> and is intended to support electrification of oil and gas operations and data center development in West Texas. These customers are well positioned to game the 4CP methodology by strategically curtailing demand during intervals when they anticipate a coincident peak. As a result, they impose significant transmission costs by siting in remote, less developed parts of the network but avoid paying their fair share of those costs. Because 4CP charges are based solely on contribution to peak demand, operationally flexible loads, such as cryptocurrency mines, can shift a disproportionate share of transmission costs onto other consumers. This behavior undermines the fairness and efficiency of transmission cost allocation.

We support allocating transmission costs on an annual load ratio share basis. Alternatively, in our Commentary on Transmission Cost Allocation P-58484, we proposed a hybrid methodology that would allocate a portion of T-COS based on a predetermined number of floating coincident peaks during the year and increase the duration of the coincident peaks to one hour rather than fifteen minutes. These changes would further limit the ability of savvy consumers to avoid paying their fair share of T-COS and reduce the impact of uneconomic load curtailments on the wholesale electricity market.

### C. Recommendations being Retired

We expect to remove these recommendations from future editions of the State of the Market report because ERCOT protocol changes have already addressed them, they are no longer relevant, or we have incorporated them into a new recommendation. For some, protocol changes were approved several years ago but have not yet been implemented. We will continue to list those recommendations in this section until implementation occurs.

#### 2023-3: Improve the Procurement and Deployment of ECRS

When ECRS was implemented in June 2023, ERCOT did not establish clear, consistent deployment criteria. This lack of transparency contributed to artificial energy shortages in the

<sup>87</sup> Permian Basin Reliability Plan Recap & Next Steps, June 28, 2024, <https://www.ercot.com/files/docs/2024/06/28/Permian%20Basin%20Recap%20and%20Next%20Steps.pdf>

real-time market because operators often delayed releasing ECRS capacity for dispatch until scarcity pricing had already begun. As a result, ECRS deployment practices caused significant, unnecessary market costs in 2023, which we estimated at approximately \$12 billion.

After 2023, the impact of ERCOT's ECRS deployment practices decreased substantially, falling to \$720 million in 2024 and \$90 million in 2025. This reduction in excess cost primarily resulted from increased supply from new solar and energy storage resources. These resources created enough market surplus to make ECRS deployment practices less impactful on real-time market outcomes. ERCOT maintained a policy of releasing ECRS only after ten consecutive minutes of at least 40 MW of under-generation, effectively forcing the real-time market into artificial shortage conditions.

RTC's implementation in December 2025 largely resolved this issue. Under RTC, the real-time market will automatically go short on reserves according to the prices set by the ASDCs, eliminating the need for manual ECRS deployment decisions. In addition, several of our other recommendations on ancillary services under RTC are intended to ensure that reserve procurement and deployment align with real-time reliability risks and system conditions.

### **2023-4: Align FFSS Pricing and Deployment Practices with Market Operations**

This recommendation is being retired because its contents are being incorporated into new Recommendation 2025-1, which discusses the new design of the FFSS program. The remaining points incorporated into Recommendation 2025-1 are (1) the lack of clear and objective deployment criteria and (2) FFSS offer behavior because the current market design incentivizes offers well below the marginal cost of firm fuel. A third point regarding the ORDC is no longer relevant because implementing RTC removed the ORDC.

### **2022-3: Allow Transmission Reconfigurations for Economic Benefits**

This recommendation was addressed by NPRR 1198, which was approved in July 2024 and is scheduled for implementation by February 2027 according to ERCOT Projects. Currently, ERCOT's approval processes only allow constraint management plans for reliability reasons.<sup>88</sup> However, there are times in which a transmission reconfiguration can relieve congestion without negatively affecting reliability.<sup>89</sup> Such plans should be developed and utilized. Both Midcontinent ISO (MISO) and Southwest Power Pool (SPP) are moving forward with this effort,

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<sup>88</sup> A constraint management plan is a set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme, which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system.

<sup>89</sup> These are not post-contingency actions and so should have a negligible impact on the control room.



though MISO is further along.<sup>90</sup> This recommendation will remain in this section until NPRR 1198 is implemented.

#### **2022-4: Change the Linear Ramp Period for ERS Summer Deployments to 3 Hours**

This recommendation was addressed by NPRR 1006, which ERCOT approved in June 2020 but has not yet implemented. ERCOT Projects currently earmarks it for implementation in October 2027. In all summer ERS deployments to date, resources returned to pre-instruction levels within approximately three hours.<sup>91</sup> However, the time value parameter for returning to the pre-instruction level in the reliability deployment price adder calculation, an output of the SCED pricing run, was 4.5 hours. This difference artificially inflated the reliability deployment price adder. We recommended adjusting this parameter to 3 hours during summer hours. This recommendation will remain in this section until NPRR 1006 is implemented.

#### **2021-1: Eliminate the “Small Fish” Rule**

Under the so-called “small fish” rule, generators with less than 5% of installed capacity in ERCOT were presumed not to have “ERCOT-wide market power.” Economic withholding by small participants has caused inefficient pricing. No supplier that can be pivotal should be permitted to withhold, and small entities can become pivotal during system-wide tight conditions or when the market is ramp constrained.

This recommendation is retired because the PUC removed the small fish rule from 25.504(c) through Project 58379.<sup>92</sup>

<sup>90</sup> See, e.g., <https://cdn.misoenergy.org/20230228%20RSC%20Item%2006%20Reconfiguration%20for%20Congestion%20Cost%20Update628023.pdf>

<sup>91</sup> <https://www.ercot.com/files/docs/2022/09/13/DSWG%20-%20ERS%20event%20deployment%207-13-2022.pptx>

<sup>92</sup> [https://interchange.puc.texas.gov/Documents/58379\\_26\\_1555387.PDF](https://interchange.puc.texas.gov/Documents/58379_26_1555387.PDF)



## APPENDIX

## **I. REAL-TIME CO-OPTIMIZATION**

Wholesale electricity markets rely on a set of optimization models that schedule generation to serve load at the lowest cost while respecting transmission constraints. Co-optimization is a market-model feature that can simultaneously schedule energy and a set of operating reserve products, i.e., ancillary services, and make economic trade-offs among them. In ERCOT prior to December 5, 2025, co-optimization between energy and operating reserves was only incorporated into the day-ahead market. Ancillary service awards from the day-ahead market represented physical obligations to provide reserves in real time, and the market withheld these reserves from the capacity available for real-time energy. With the implementation of RTC, the real-time market dispatch now co-optimizes energy and ancillary services.

Fundamentally, real-time co-optimization produces more economically efficient awards for energy and ancillary services and satisfies the grid's reliability needs more effectively than the day-ahead market alone. The day-ahead market relies on expectations of real-time grid conditions, which are inherently subject to a substantial degree of uncertainty. By contrast, the real-time market incorporates the most up-to-date information about grid conditions, e.g., supply and demand or congestion, when producing a dispatch solution for energy and ancillary services. Because the real-time market runs every five minutes, RTC can better account for intra-hour variation in system conditions than the day-ahead market, which co-optimizes energy and AS on an hourly basis. The merits of RTC are so incontrovertible that it has been implemented by every ISO in North America.

This section summarizes our initial observations of market performance since RTC was implemented. Because ERCOT implemented RTC near the end of 2025, this analysis includes data from December 5, 2025, through February 2026 to provide a richer set of information for identifying trends and observations.

Our summary of RTC outcomes thus far is that it is operating largely as expected without major dysfunctions. New efficiencies are evident in the frequency of AS awards shifting among resources within an operating hour, the real-time market's ability to go short on AS during shortage conditions, and the reduction in out-of-market commitments through RUC. Despite these apparent improvements, we have observed issues that need to be resolved, particularly in the formulation of the ASDCs and duration constraints for AS, NSRS in particular.

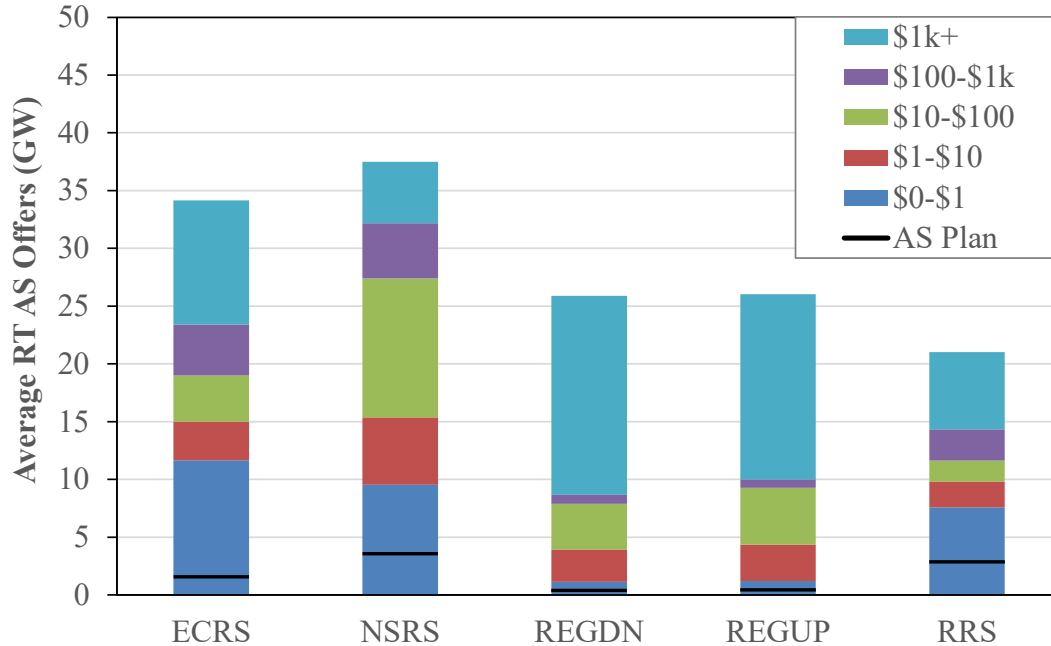
### **A. Real-Time AS Offers**

For the real-time market dispatch to produce energy and ancillary service awards that respect the economics of different reserve suppliers across the grid, resources have to submit real-time offers for AS. Figure A1 shows the average AS offers in the real-time market, aggregated by price level, from December 5, 2025, through February 2026. These data are similar to the offers from

the day-ahead market prior to go-live. Regulation service has the most expensive offers, consistent with its higher opportunity cost.

**Figure A1: Aggregate Offers for AS in the RTM**

December 5, 2025 through February 2026

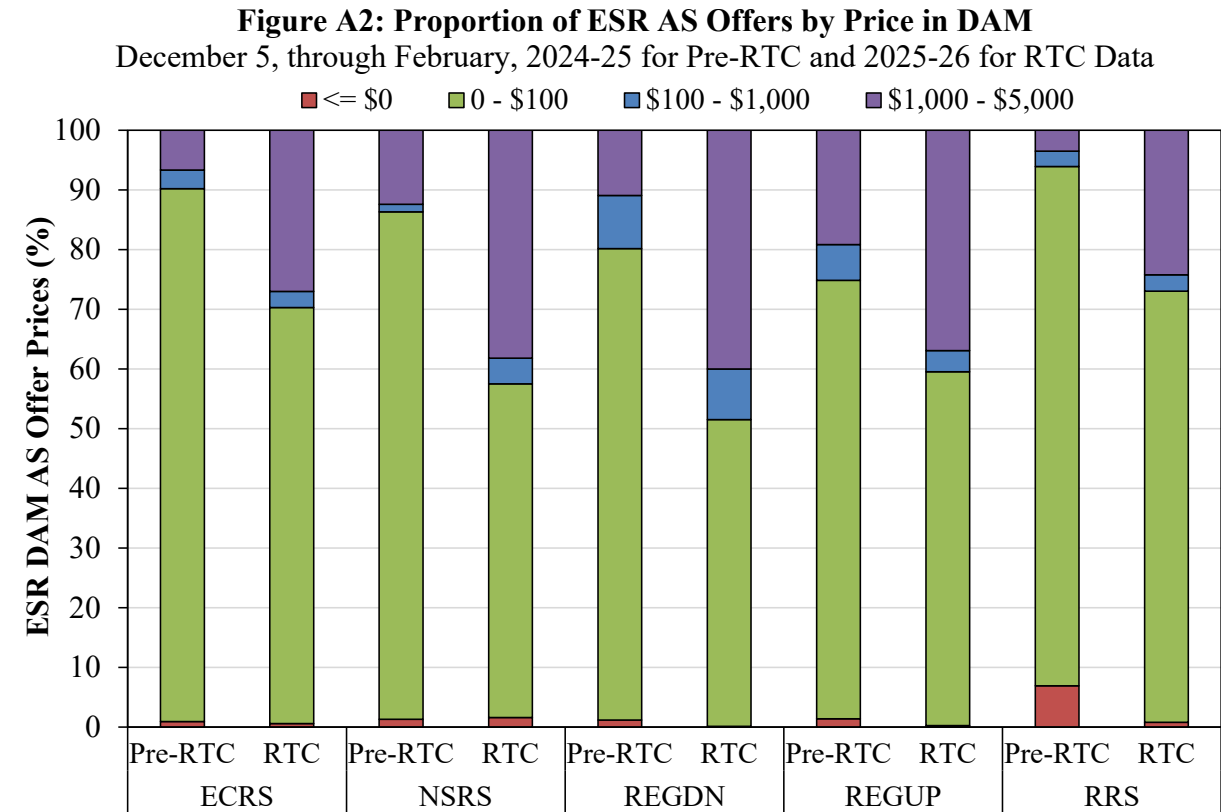


Although RTC has been our main focus, another major market upgrade that went live on December 5, 2025, was a set of features related to how ESRs are modeled in the real-time market. One feature is that SCED now explicitly accounts for ESR SOC in its energy and AS awards. Together with the duration requirements for energy and AS shown in Table A1, this SOC accounting limits the real-time awards that ESRs can receive.

**Table A1: Duration Requirements for Energy and AS in RTM**

Product	Duration
Energy	5 mins
RegUp	30 mins
RRS	30 mins
ECRS	1 hour
NSRS	4 hours

These duration constraints introduce some imbalance risk for ESRs that sell reserves in the day-ahead market. At the same time, RTC allows AS providers to forego the day-ahead market and sell AS directly into the real-time market. Thus, ESR AS offers in the day-ahead market would be expected to increase to reflect the higher risk and lower benefit of selling AS there. Initial observations validate that expectation, as Figure A2 shows.



## B. Convergence between DAM and RT

In the previous market design, AS awards from the day-ahead market effectively created a physical obligation to provide reserves in real time. With the implementation of RTC, AS awards in the day-ahead market now function as financial positions, like energy awards. Since December 6, 2025, the day-ahead market has also allowed transactions in virtual AS, i.e., strictly financial positions that are not associated with any physical resources. Ultimately, including virtual AS positions in the day-ahead market clearing should lead to greater convergence between day-ahead and real-time prices for AS. Table A2 shows the average prices for energy and each AS product in the day-ahead and real-time markets, as well as the corresponding DART premium.

**Table A2: Convergence in Energy and AS Prices in the Day-Ahead and Real-Time Markets**  
December 5, 2026, through February 2026

	Average Day-Ahead Price	Average Real-Time Price	Average DART Premium
	\$ per MWh	\$ per MWh	%
Energy	\$50.21	\$37.03	36
Responsive	\$3.30	\$0.41	698
NSRS	\$3.94	\$1.10	257
Reg Up	\$3.57	\$1.20	197
Reg Down	\$1.79	\$1.13	59
ECRS	\$3.67	\$0.71	420

Compared to recent trends in convergence for energy between the day-ahead and real-time markets, the day-ahead premium for AS has been very high in the early days of RTC. Two events account for a disproportionate share of this premium. Excluding RegDown, elevated day-ahead market prices on December 5, 2025, and during Winter Storm Fern on January 21-27, 2026, account for 57-75% of the average day-ahead market premium for energy and up-reserve products. Virtual offers for AS were not introduced to the day-ahead market until December 6, so physical-resource offers drove the elevated prices. We expect this premium to diminish over the year and to be significantly lower in the 2026 annual average.

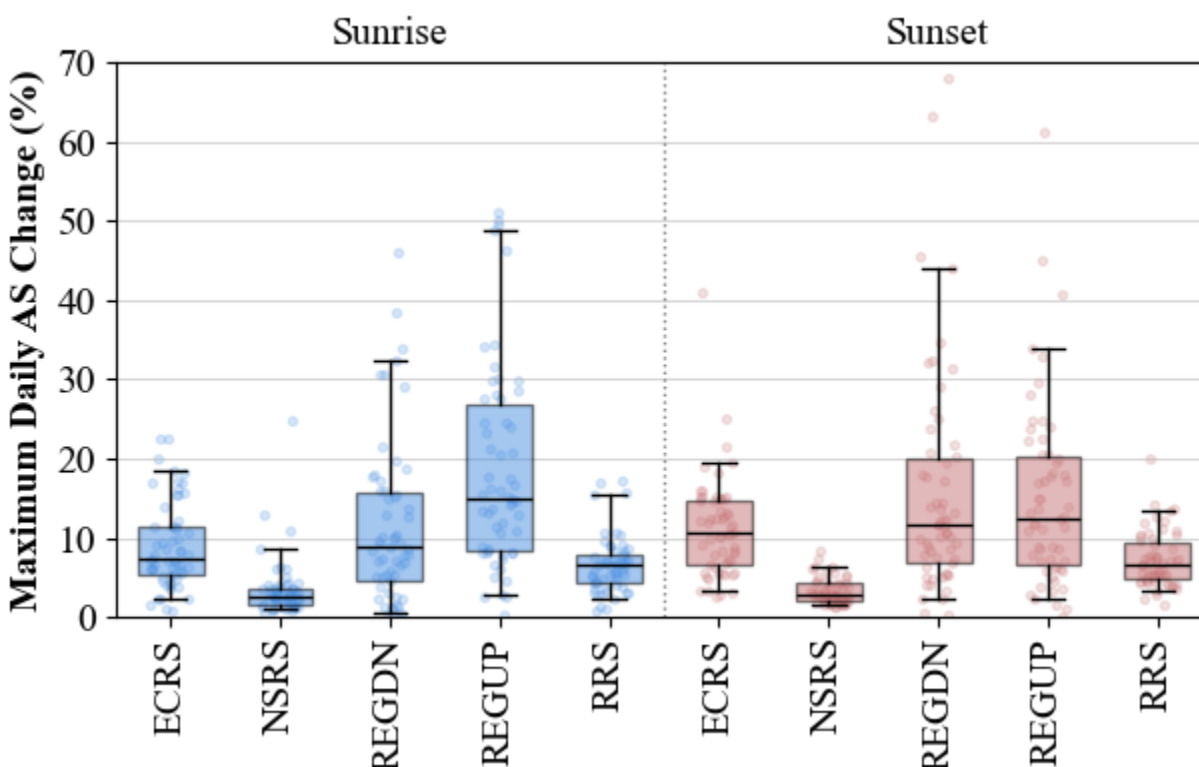
### C. AS Position Switching during sunrise/sunset

One benefit of RTC is that the time resolution of the real-time market allows intra-hour variation in AS awards in response to changes in system conditions. To evaluate the extent of this variation, we examined SCED intervals during sunrise and sunset from December 5, 2025, through February 2026. These periods are characterized by significant intra-hour variation in system conditions that benefit from repositioning of reserves across the operating hour.

We defined sunrise as the intervals between 7:00 and 7:30 and sunset as the intervals between 17:30 and 18:00. For each interval, we calculated the total change in AS positions across resources from one interval to the next. For each day, we then selected the sunrise and sunset interval with the greatest aggregate change in AS awards across resources. Figure A3 shows the distribution of those daily values.

**Figure A3. Distribution of AS Awards Shifting During Sunrise and Sunset**

December 5, 2025, through February 2026



These data show that more than 10% of total AS awards commonly shift across resources within a single SCED interval, particularly for faster responding reserves like RegUp and RegDn. This trend indicates a substantial efficiency gain over the previous market design, in which AS positions were fixed for the hour and could shift only within a given QSE's portfolio of resources.

#### D. AS Shortages

A key feature of RTC is that the real-time market can go short on AS in favor of energy when system conditions are tight. In the previous market design, AS capacity was treated as a fixed quantity that could not be dispatched for energy through SCED unless ERCOT operators manually deployed it.<sup>93</sup> This constraint often resulted in significantly more expensive energy dispatch solutions than when the market can go short on AS.

To allow the market to go short on reserves, the real-time market uses a set of Ancillary Services Demand Curves (ASDC). These demand curves define the penalty price for shortages of each AS product and allow real-time market dispatch to make economic tradeoffs between energy and reserves. In addition to producing more efficient real-time market outcomes, the shortage pricing

93 With the exception of online NSRS, which was treated as a standing deployment that could be dispatched for energy with an offer floor of \$75 per MWh



from these curves is the primary mechanism for signaling the need for new capacity investment in the ERCOT market. These ASDCs effectively replace the ORDC price adder used to produce scarcity pricing in the previous market design.

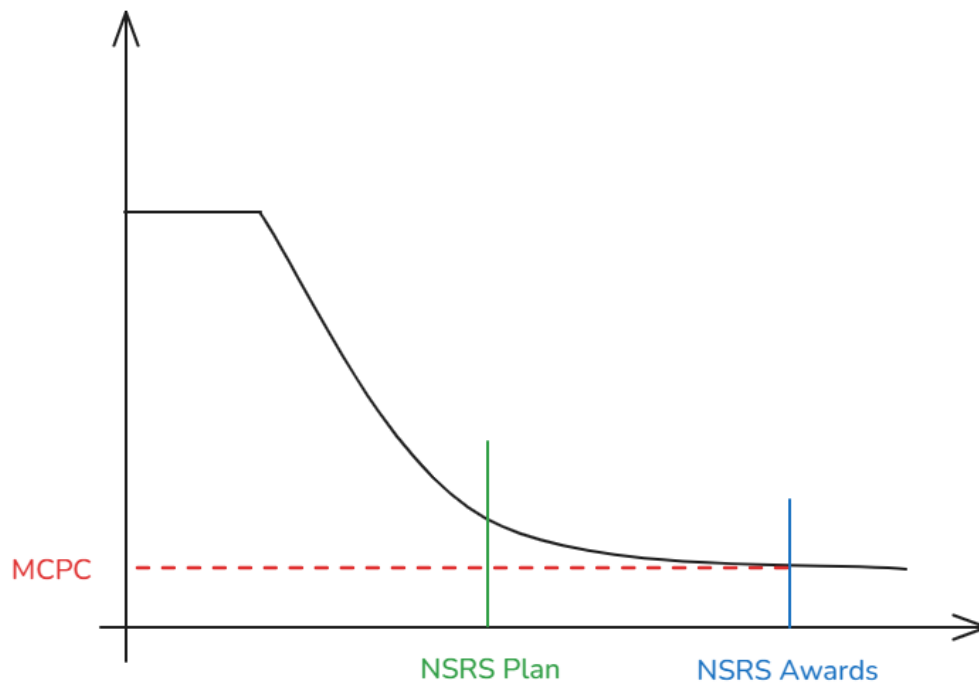
Table A3 shows the frequency, magnitude, and pricing of AS shortages in ERCOT since RTC go-live. Shortage conditions have been infrequent since go-live. This infrequency is consistent with the high levels of operating reserves in the last several years, as discussed throughout the report. NSRS had the most frequent shortages and the lowest penalty price. Approximately 45% of the volume of NSRS shortages occurred during Winter Storm Fern.

**Table A3: Frequency, Magnitude, and Pricing of AS Shortages**  
December 5, 2025, through February 2026

RTC Ancillary Service Shortages			
Ancillary Service	# of Hours	Average MW	Average MCPC (\$ per MWh)
ECRS	4.0	214.6	78.0
NSRS	25.9	702.2	22.5
REGDN	-	-	
REGUP	-	-	
RRS	1.6	35.2	131.6

In fact, rather than going short on AS, ERCOT consistently goes *long* on NSRS. This outcome is a consequence of Commission policy that the individual ASDCs for the up-reserve products,<sup>94</sup> when aggregated together into one demand curve, should conform to the Aggregate Operating Reserve Demand Curve (AORDC). The AORDC is a fixed curve that was formulated based on empirical pricing outcomes produced by the ORDC before the implementation of RTC. The AORDC is defined to 10,000 MW, but for much of the year, the sum of the AS Plan for all four up-reserve products is less than 10,000 MW. To satisfy the constraint that the ASDCs conform to the ASDC when the AS Plan is less than 10,000 MW, one or more of the ASDCs has to be extended to include the excess volume. This excess volume is currently assigned to the ASDC for NSRS, which causes the real-time market to procure excess NSRS as illustrated in Figure A4.

<sup>94</sup> That is, everything except for Reg-Down

**Figure A4: Illustration of Extended ASDC for NSRS**

From December 5, 2025, through February 2026, ERCOT procured nearly 1,400 MW of NSRS above the NSRS plan, on average. Thus, this extension of the ASDC for NSRS effectively increases demand for NSRS in the real-time market dispatch model. As discussed in the AS Methodology section, the NSRS plan is already vastly oversized, yet the ERCOT real-time market is designed to procure even more. In our updated Recommendation 2024-1, we recommend that ERCOT reformulate the ASDCs based on the marginal reliability value of each product. This reformulation would produce ASDCs that scale according to the AS Plan for each product and eliminate the possibility that the real-time market over-procures reserves relative to the AS Plan.

### **E. NSRS relative Pricing**

Since RTC go-live, NSRS has consistently been more expensive than ECRS and RRS. This trend is a continuation of the pricing outcomes from the rest of 2025, where NSRS was the most expensive AS product on average for the year. Two factors related to the implementation of RTC have reinforced this trend: 1) the extension of the ASDC for NSRS with the excess volume from the AORDC, and 2) the 4-hour duration constraint for NSRS. As discussed in the previous section, the extended ASDC for NSRS effectively increases the demand for NSRS above what is defined by the already excessing AS Plan. The duration constraint, on the other hand, limits the supply of ESR capacity that can provide NSRS and increases the opportunity cost for ESRs to provide NSRS compared to other AS products with lower duration requirements. This opportunity cost impact is implicitly accounted for in the price formation produced in the real-

time market and can be seen by comparing the distribution of clearing prices for NSRS to the clearing prices for the other AS products, as shown in Figure A5.

**Figure A5: Distribution of NSRS MCPC Relative to Other Up-Reserves**  
December 5, 2025, through February 2026

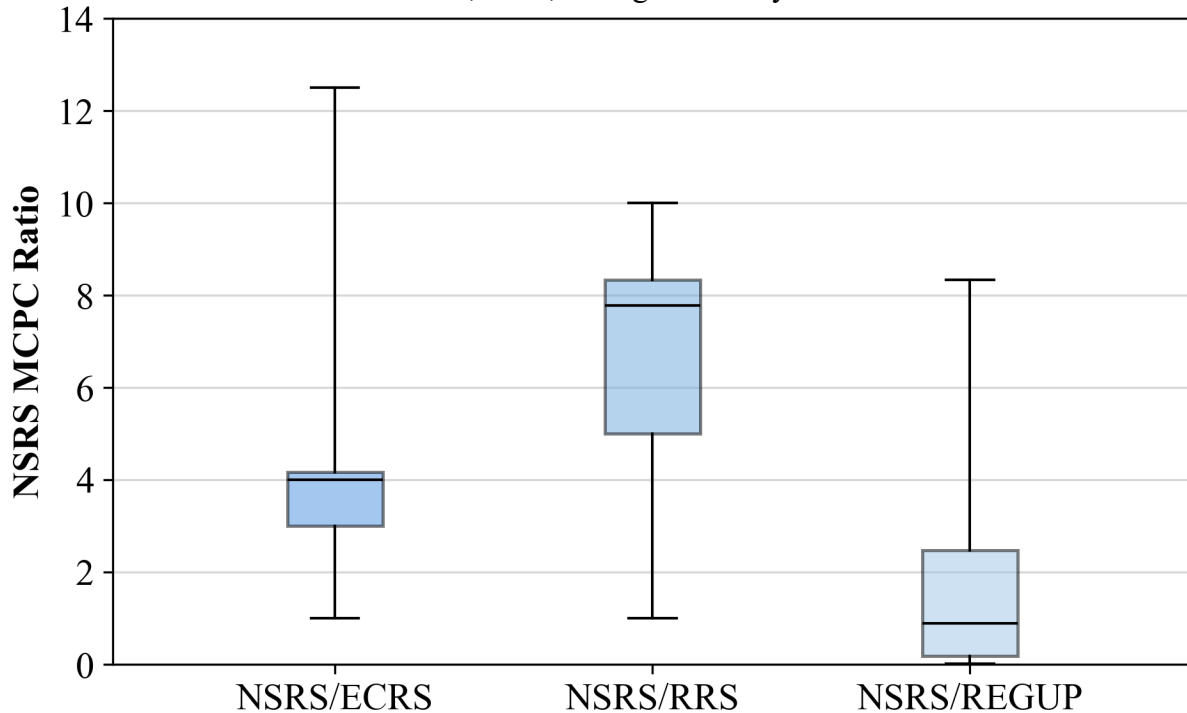


Figure A5 shows that NSRS clears four times higher than ECRS and eight times higher than RRS on average, consistent with the ratio of their duration requirements shown in Table A1. The average ratio of clearing prices between NSRS and Reg-Up is lower because Reg-Up offers are generally priced higher than NSRS offers, as shown in Figure A3. We continue to recommend (see Recommendation 2024-2) reducing the duration requirement for NSRS to one hour to reflect the short-term reliability risks it is designed to address and to produce pricing that reflects the relative reliability value of each AS product.

## F. Impact on RUC

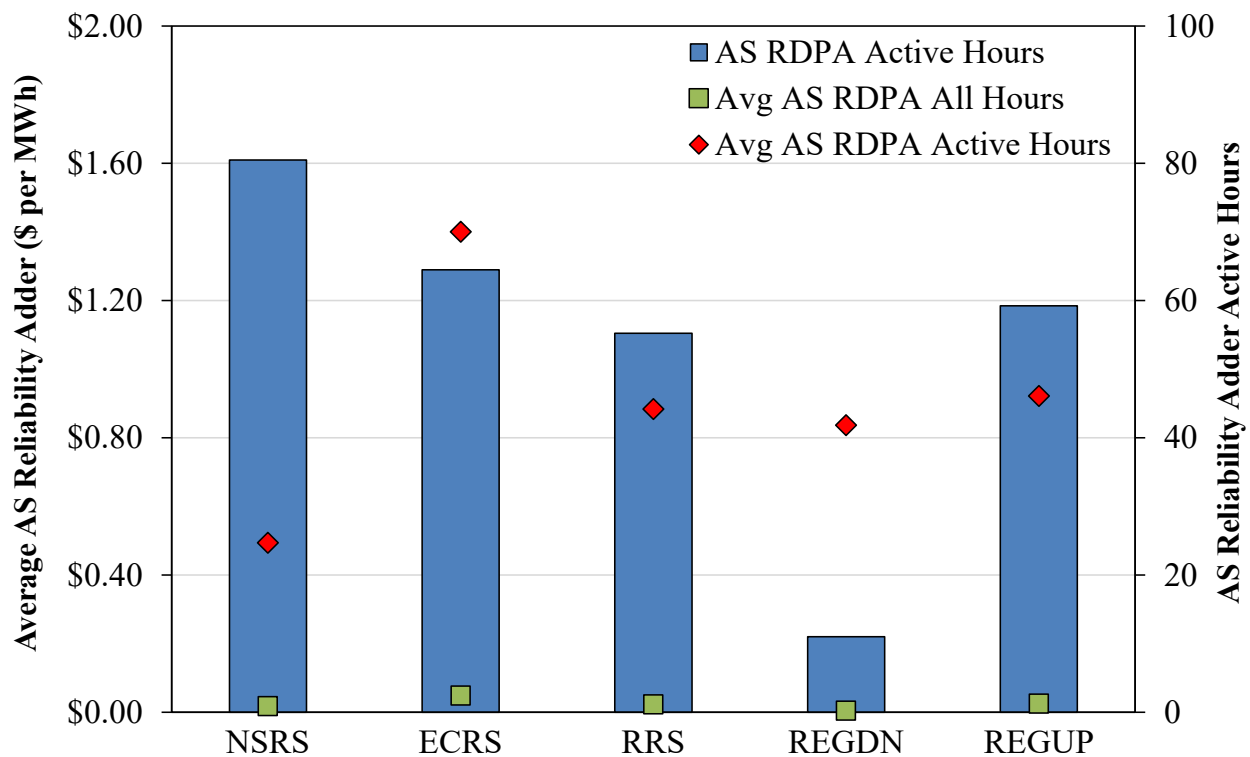
As part of the RTC project, ERCOT also incorporated co-optimization between energy and AS into the RUC process so it could shift AS awards among resources and produce more efficient commitment solutions. Although less than three months of data make it impossible to definitively assess RTC's effect on the rate of RUC commitments, initial indications suggest that incorporating co-optimization into RUC has reduced out-of-market commitments. The following statistics indicate RTC's impact on RUC:

- For December 2025, approximately 54% of RUC commitments occurred in the four days before go-live.
- From December 5, 2025, through February 2026, 42% of all RUC commitments occurred during Winter Storm Fern, January 21 to 27.
- Compared to the same period a year before RTC go-live, December 5, 2024, through February 2025, RUC commitments fell by 80% after go-live.

## G. RDPA

Before RTC, two distinct prices were added to the LMP to determine settlement prices in the ERCOT real-time market. The ORDC price adder, which reflected the value of reserves under shortage conditions, was replaced by a set of ASDCs. The Reliability Deployment Price Adder, which accounts for the price suppression effects of out-of-market actions by ERCOT operators, remains after RTC is implemented but includes a new feature. The RDPA process now produces separate price adders for energy and each AS product. The real-time market is run in two instances: one based on realized operating conditions and one counterfactual, as if no reliability actions had been taken. The AS RDPA is the difference in MCPCs for each AS product between these two runs. Figure A6 illustrates AS RDPA outcomes for December 5, 2025, through February 2026.

**Figure A6: Frequency and Magnitude of RDPA for AS**  
December 5, 2025, through February 2026



## II. APPENDIX: STATISTICS AT A GLANCE

This appendix section provides supplemental analyses of 2025 prices and outcomes in ERCOT's real-time energy market. Table A4 shows the annual aggregate costs of various ERCOT charges and payments in 2025, including ancillary services charges by type and different forms of uplift.

**Table A4: ERCOT 2025 Year at a Glance (Annual)**

	<b>Annual Total (\$ Millions)</b>
Energy	\$17,659
Regulation Up	\$11
Regulation Down	\$6
Responsive Reserve	\$52
NSRS	\$81
ECRS	\$30
CRR Auction Distribution	(\$1,810)
Balancing Account Surplus	(\$293)
Emergency Response Service	\$69
Revenue Neutrality Uplift	\$154
AS Imbalance Uplift	\$27
ERCOT Fee	\$308
ERO Passthrough Fee	\$30
Firm Fuel	\$46
Other Load Allocation	\$0
<b>Net Cost of Electricity</b>	<b>\$16,371</b>

Table A5 presents monthly aggregate costs for various ERCOT market settlement totals in 2025, including ancillary service costs by type.

**Table A5: Market at a Glance Monthly**

	Monthly Totals (\$ Millions)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Energy	\$1,456	\$1,468	\$1,039	\$1,259	\$1,632	\$1,413	\$1,721	\$1,941	\$1,527	\$1,490	\$1,293	\$1,420
RegUp	\$ 0.6	\$ 1.0	\$ 0.9	\$ 1.0	\$ 1.9	\$ 0.9	\$ 0.7	\$ 0.9	\$ 0.6	\$ 0.8	\$ 1.1	\$ 0.3
RegDn	\$ 0.4	\$ 0.5	\$ 0.5	\$ 0.6	\$ 0.9	\$ 0.4	\$ 0.4	\$ 0.5	\$ 0.3	\$ 0.5	\$ 0.6	\$ 0.2
RRS	\$ 3.2	\$ 5.1	\$ 4.8	\$ 5.0	\$ 9.4	\$ 4.3	\$ 3.6	\$ 4.0	\$ 2.2	\$ 3.7	\$ 5.1	\$ 1.4
NSRS	\$ 4.0	\$ 5.6	\$ 5.7	\$ 6.1	\$ 29.4	\$ 6.6	\$ 3.5	\$ 2.3	\$ 1.7	\$ 4.4	\$ 6.3	\$ 5.2
ECRS	\$ 1.5	\$ 2.4	\$ 2.4	\$ 2.6	\$ 7.6	\$ 2.6	\$ 2.5	\$ 3.0	\$ 1.5	\$ 1.7	\$ 2.1	\$ 0.6
CRR Auction Distribution	(\$138)	(\$130)	(\$166)	(\$159)	(\$162)	(\$170)	(\$160)	(\$165)	(\$134)	(\$156)	(\$138)	(\$133)
Balancing Account Surplus	(\$41)	(\$32)	(\$7)	(\$18)	(\$37)	(\$35)	(\$31)	(\$32)	(\$25)	(\$0)	(\$17)	(\$16)
ERS	\$0	\$0	\$0	\$34	\$0	\$2	\$0	\$0	\$0	\$32	\$0	\$2
Revenue Neutrality Uplift	\$23	\$22	\$15	\$12	\$13	\$13	\$12	\$10	\$10	\$7	\$8	\$9
AS Imbalance Uplift	\$3.9	\$7.7	\$3.7	\$1.3	\$1.1	\$1.4	\$1.1	\$1.1	\$2.2	\$1.5	\$1.4	\$1.1
ERCOT Fee	\$26	\$22	\$22	\$23	\$26	\$28	\$30	\$31	\$28	\$26	\$22	\$24
ERO Passthrough Fee	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5	\$2.5
Firm Fuel	\$10	\$11	\$6	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$6	\$13
Other Load Allocation	(\$0.2)	\$0.0	\$0.0	(\$0.2)	\$0.0	(\$0.1)	\$0.0	(\$0.0)	\$0.0	(\$0.0)	\$0.0	\$0.4
Total	\$1,352	\$1,386	\$928	\$1,169	\$1,526	\$1,271	\$1,587	\$1,799	\$1,416	\$1,414	\$1,193	\$1,330

### III. APPENDIX: ANCILLARY SERVICES

This section provides supplemental data on ancillary services provided through the day-ahead market, real-time market, and supplemental ancillary services market (SASM).

#### A. Ancillary Services Provided in Real-Time

Figure A7 through Figure A11 break down the provision of each AS product by resource type. Notable trends include the following:

- ESRs and NCLRs dominate the provision of RRS
- ESRs provide the vast majority of regulation reserves.
- ESRs and gas peakers supply most ECRS, and the share provided by ESRs has grown substantially in the last year
- Gas peakers provide most NSRS, but the share provided by ESRs has grown substantially in the last year

**Figure A7: Responsive Reserve Providers**  
2023-2025

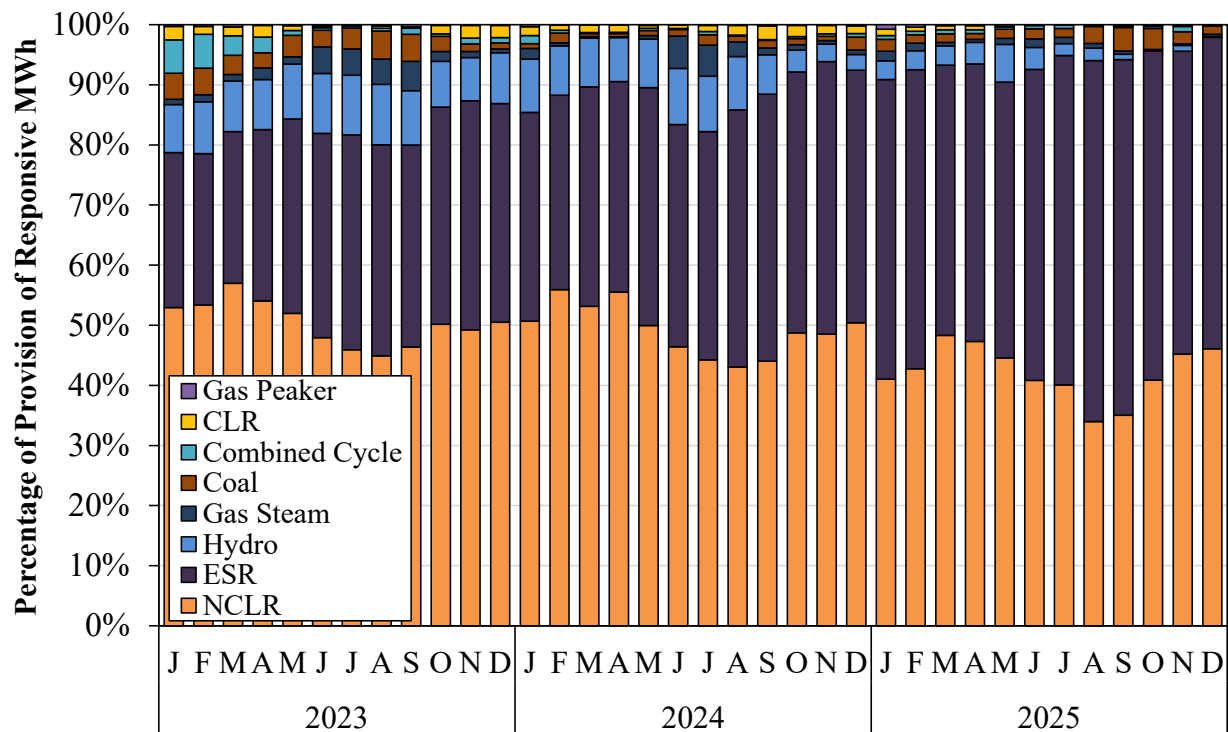


Figure A8: ERCOT Contingency Reserve Service Providers  
2023-2025

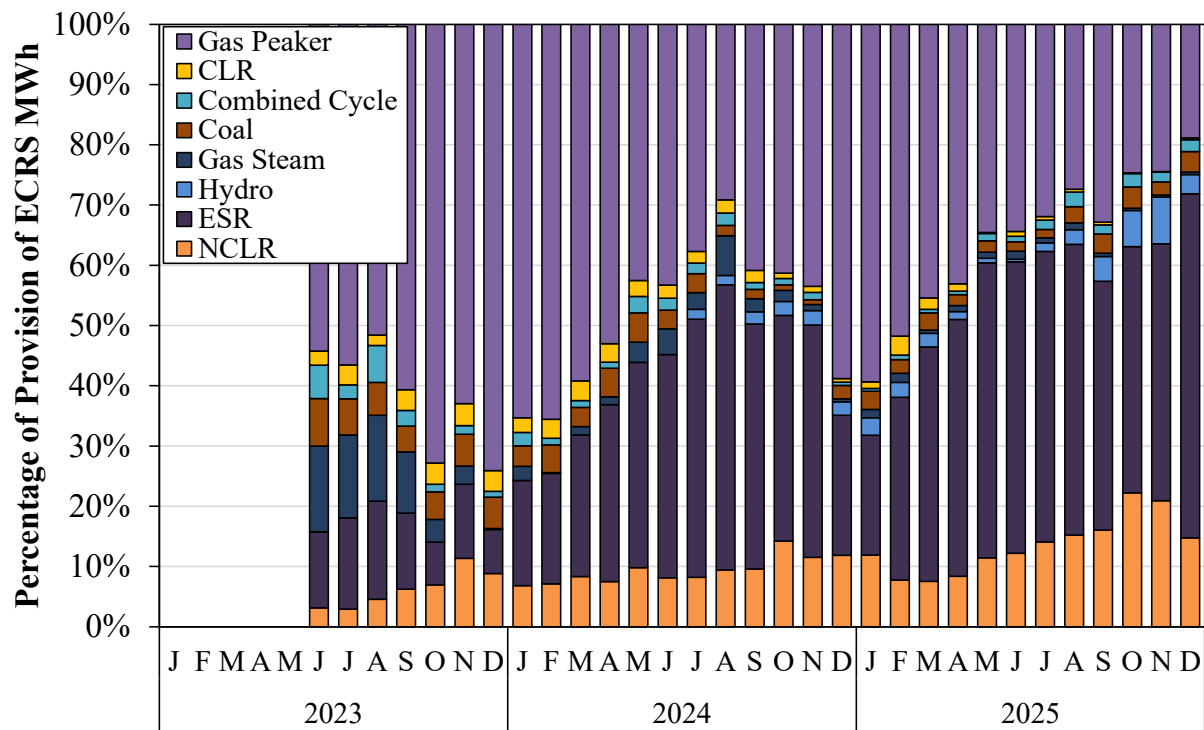
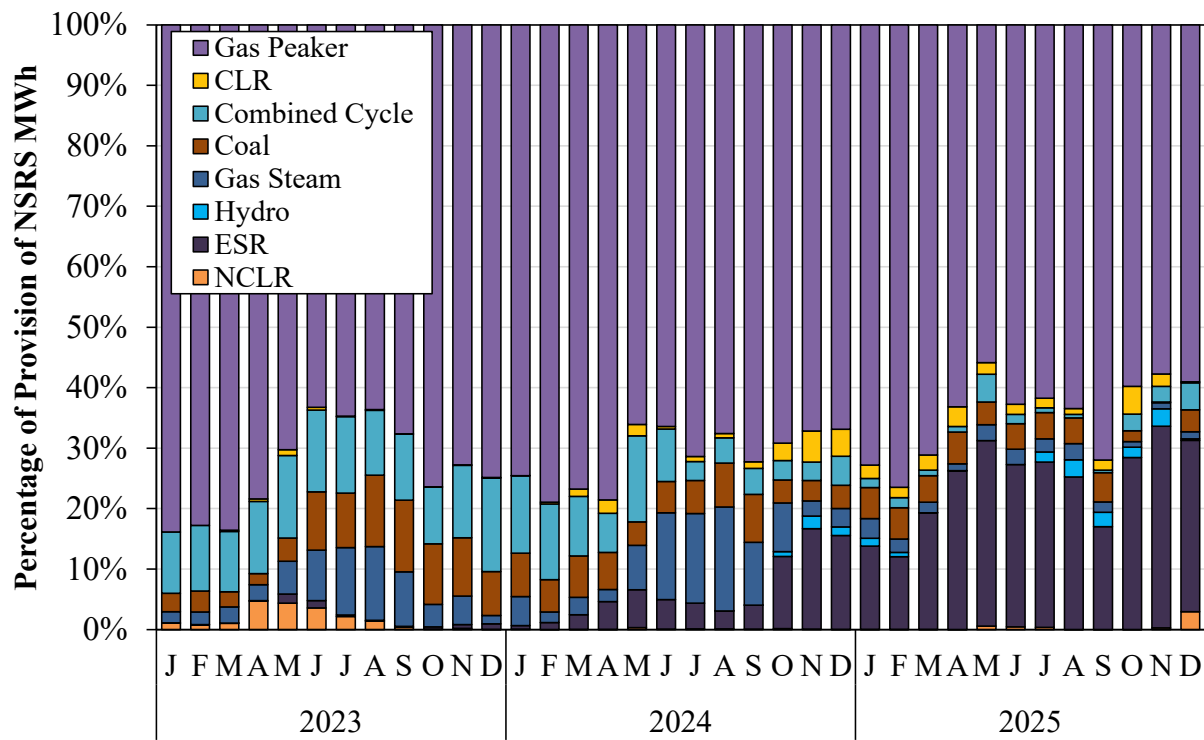
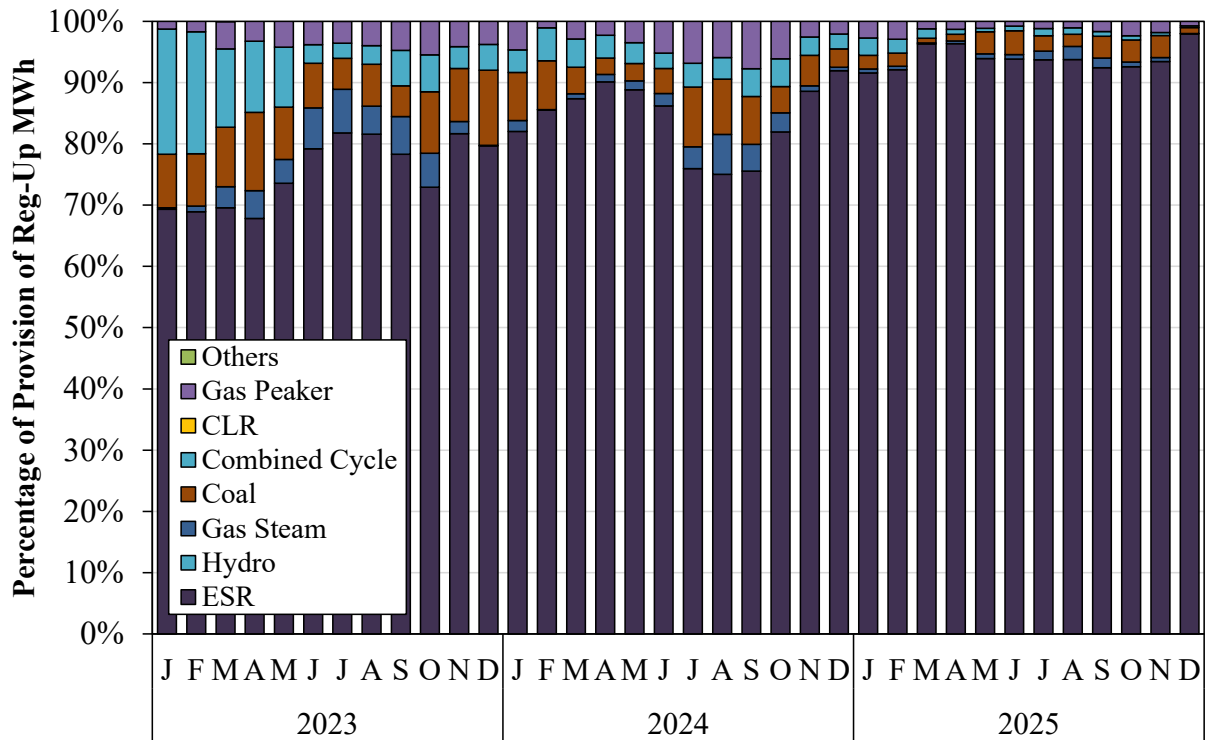


Figure A9: Non-Spin Reserve Service Providers  
2023-2025

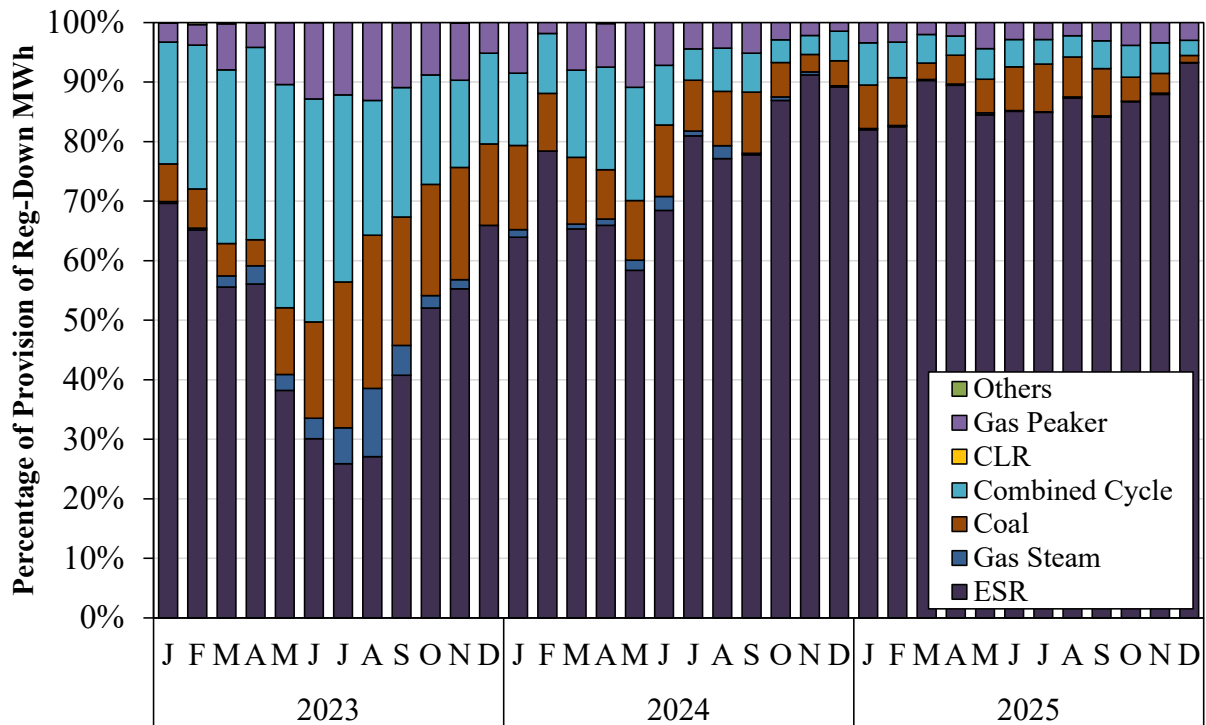




**Figure A10: Regulation Up Reserve Providers**  
2023-2025



**Figure A11: Regulation Down Reserve Providers**  
2023-2025



## B. Supplemental Ancillary Services Market

Until RTC was implemented, ancillary service awards from the day-ahead market were physically binding in real time on a QSE basis. If the day-ahead market awarded an ancillary service to a resource, that resource's QSE could shift the obligation to carry that award in real time to any other qualified unit in its fleet. This allowed the QSE to optimize which resources provided energy and which provided ancillary services. Although these choices were likely to be in the QSE's best interest, they were unlikely to produce the most economic provision of energy and ancillary services for the market as a whole. In addition, QSEs without large resource portfolios faced greater risks than those with larger portfolios because they may have needed to procure replacement ancillary services through the SASM, where prices could be high and uncertain. This replacement risk was substantial. Clearing prices for ancillary services procured in the SASM were often three to four times higher than clearing prices in the day-ahead market.

The volume of reserves procured through the SASM for 2021-2025 is shown in Figure A12. SASMs were executed 76 times in 2025 to procure a total of more than 20 GWh of operating reserves, 26% less than was procured by SASM in 2024 but still the third highest annual volume of ancillary services procured through SASM since the implementation of the nodal market.

**Figure A12: Ancillary Service Quantities Procured in SASM**  
2021-2025

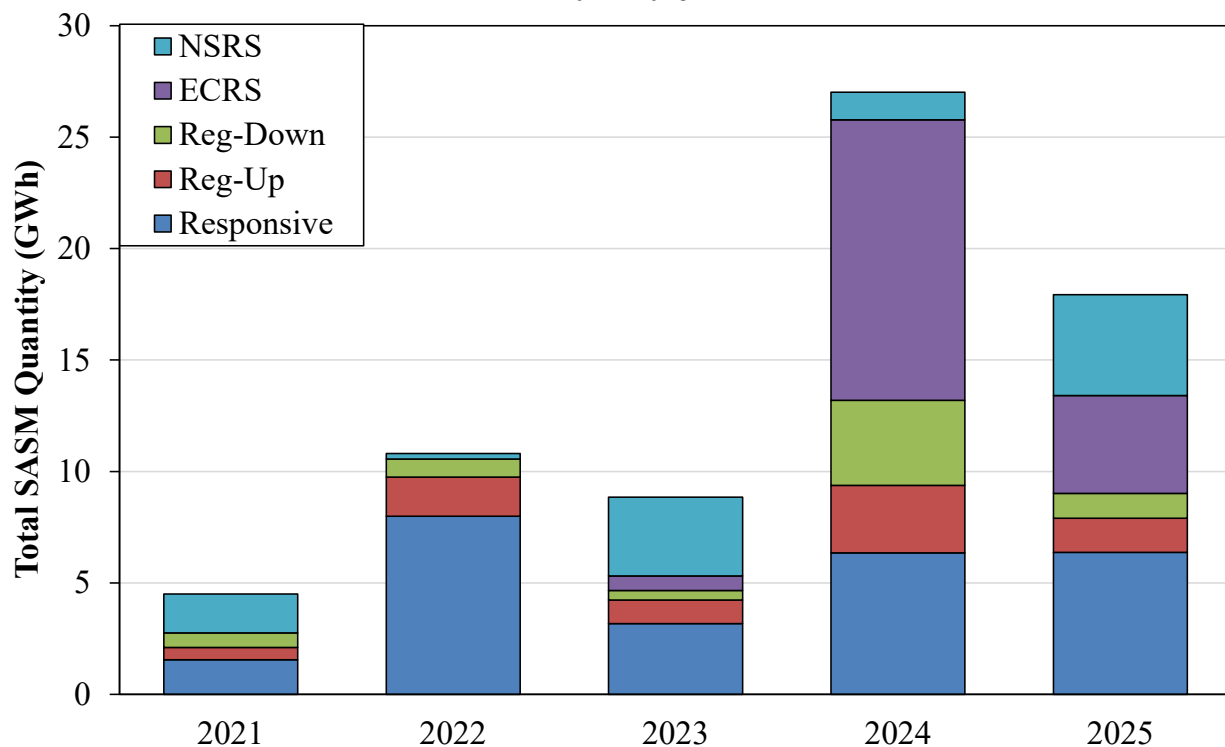


Figure A13 shows the average cost of the replacement ancillary services that SASM procured from 2021-2025. Total SASM costs in 2025 were \$495 thousand, the lowest annual value since

2018. This result is notable because SASM procured a relatively high volume of ancillary services. It indicates the surplus reserve capacity in the market in 2025 that we have discussed throughout this report.

**Figure A13: Total Cost of Procured SASM Ancillary Services**  
2021-2025

