2023 State of the Market Report for the ERCOT Electricity Markets

POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

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4CP	4 Coincident Peak	NOIE	Non-Opt-In Entity
CDR	Capacity, Demand and Reserves Report	NPRR	Nodal Protocol Revision Request
CONE	Cost of New Entry	NSO	Notification of Suspension of Operations
CRR	Congestion Revenue Rights	ORDC	Operating Reserve Demand Curve
DC Tie	Direct-Current Tie	PCRR	Pre-Assigned Congestion Revenue Rights
EEA	Energy Emergency Alert	PRC	Physical Responsive Capability
ERCOT	Electric Reliability Council of Texas	PTP	Point-to-Point
ECRS	ERCOT Contingency Reserve Service	PTPLO	Point-to-Point Obligation with links to an Option
ERS	Emergency Response Service	PUCT	Public Utility Commission of Texas
ESR	Energy Storage Resource	PURA	Public Utility Regulatory Act
FFSS	Firm Fuel Supply Service	QSE	Qualified Scheduling Entity
FIP	Fuel Index Price	RDI	Residual Demand Index
GTC	Generic Transmission Constraint	RENA	Real-Time Revenue Neutrality Allocation
GW	Gigawatt	RDPA	Real-Time Reliability Deployment Price Adder
HCAP	High System-Wide Offer Cap	RTCA	Real-Time Contingency Analysis
HE	Hour-ending	RTOLCAP	Real-Time On-Line reserve capacity of all On-Line Resources
Hz	Hertz	RUC	Reliability Unit Commitment
LDF	Load Distribution Factor	SASM	Supplemental Ancillary Service Market
LMP	Locational Marginal Price	SCED	Security-Constrained Economic Dispatch
LOLP	Loss of Load Probability	SCR	System Change Request
LSL	Low Sustained Limit	SPP	Southwest Power Pool
MISO	Midcontinent Independent System Operator	SWOC	System-Wide Offer Cap
MMBtu	One million British Thermal Units	VMP	Voluntary Mitigation Plans
MW	Megawatt	VOLL	Value of Lost Load
MWh	Megawatt Hour		

EXECUTIVE SUMMARY

Potomac Economics provides this State of the Market Report for 2023 to the Public Utility Commission of Texas (PUCT) in our role as the Independent Market Monitor (IMM). This report presents our assessment of the outcomes of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT). Additionally, we recommend changes to improve the competitive performance and operation of the ERCOT markets.

ERCOT manages the production and flow of electricity to more than 26 million Texas customers – about 90% of the state's total electric demand. Every five minutes, the ERCOT market coordinates the electricity output from more than 1,250 generating resources to satisfy customer demand and manages the resulting flows of power across more than 54,100 miles of transmission lines in the region. Additionally, the market prices facilitate the long-term investment and retirements of resources in the ERCOT region. Hence, the market's performance that we evaluate in this report is critical for maintaining reliability in Texas.

This report details the changes to the ERCOT markets implemented in 2023 and the outcomes produced by those changes. The most impactful change made in 2023 was the introduction of the ERCOT Contingency Reserve Service (ECRS) in June 2023. Regrettably, the implementation of this product, specifically its availability to the energy market and the target quantity procured, led to artificial shortage pricing – extremely high prices when the system was not short of supply – which we estimate doubled average energy prices between June and December 2023. The nature of this concern and the steps being considered to address it are described in this report.

As in prior years, ERCOT market confronted unique challenges and issues in 2023, including load growth that led to a record-breaking summer, as well as continuing conservative operations by ERCOT. Key results in 2023 include the following:

Competition and Market Power

- The ERCOT energy markets performed competitively in 2023, and the IMM found little evidence that suppliers exercised market power in the ERCOT energy market.

- In 2022, the IMM noted a concern with competitiveness in the non-spinning reserve market. In March of 2023, the Voluntary Mitigation Plans (VMP) were modified to address these concerns and in June 2023 ERCOT began procuring lower amounts of non-spinning reserves. Both of these changes have improved the competitive performance of this market, but it will be important to continue to monitor it.

- In some local areas, transmission system limitations on the amount of power that can flow into the area can increase opportunities to exercise market power. However, mitigated offer price caps effectively addressed this concern in 2023.

Demand for and Supply of Electricity

- Hot temperatures caused ERCOT to set new demand records 49 times during the summer, the highest of which was 85.7 gigawatts (GW) on August 10, which was 3.4% higher than the peak in 2022. Average load in ERCOT also grew 3.4% from 2022.

- Despite the hot weather and record loads in 2023, conditions were less tight and produced fewer true shortages and shortage pricing than in 2022. This is largely due to the influx of new supply, including roughly 7.6 GW of new wind and solar resources, 1.9 GW of energy storage resources (ESRs), and almost 1 GW of new natural gas resources.

Market Outcomes and Performance

- Real-time and day-ahead energy prices were inflated beginning in June 2023 with the implementation of ECRS. While the energy market did perform competitively, it did not produce efficient outcomes because of the frequent episodes of artificial shortage pricing caused by ECRS. These episodes doubled real-time energy prices between June and December and generated more than $12 billion in real-time market costs. We describe how ECRS creates this artificial shortage pricing later in this executive summary.

- Price convergence between day-ahead and real-time was reasonably good in all months of 2023 except June through August, when the divergence between day-ahead and real-time prices were relatively high. This divergence was largely due to the difficulty of predicting the ECRS-driven shortage pricing in the day-ahead timeframe.

- Average real-time prices fell to roughly $65 per megawatt hour (MWh) in 2023, a reduction of more than 13% from 2022. This is a much smaller decrease than one would expect given the 62% reduction in natural gas prices in 2023 (which averaged $2.22 per million British Thermal Units or MMBtu). Instead, we attribute the pricing effects of ECRS, described above, as the primary driver for the smaller decrease in average prices.

- Average ancillary service costs increased in 2023 to $4.21 per MWh of load compared to $3.29 per MWh of load in 2022, despite the decrease in fuel and energy prices. This was driven by high ECRS prices in June, August, and September. The average ECRS price in 2023 was $76.77 per MWh, over triple the 2023 average price of responsive reserves.

- Transmission congestion in the real-time market – incurred when uneconomic generators are dispatched to reduce flows over constrained lines – was down 15% from 2022 to total $2.4 billion in 2023. This reduction is primarily due to lower natural gas prices as gas-fired resources are generally those that change output to manage transmission flows.
  - ERCOT is limiting flows across certain network paths to maintain the stability of the system. These stability issues have partly resulted from the increase in inverter-based resources.
  - The congestion associated with stability constraints decreased from $640 million in 2022 to $253 million in 2023 – representing roughly 11% of all real-time congestion.

Planned Changes to Improve Market Performance

- A critical market change underway is ERCOT's improvement of its real-time market to optimize the scheduling of its resources between energy and operating reserves every five minutes, also known as "real-time co-optimization" or RTC. This change was delayed after Winter Storm Uri in 2021, but it has been restarted and is planned to be implemented in late 2026.
- ERCOT continues to plan for the integration of emerging technologies, such as ESRs and distributed generation resources (DGRs). Modeling and market improvements for ESRs will be needed to optimize their utilization.
- Issues relating to the ECRS product are being addressed in a multi-phase effort beginning in 2024. We are providing analysis and advice on both of these phases:
  - The first phase addresses deployment criteria for ECRS, which could greatly mitigate the adverse price effects seen in 2023.
  - The second phase would include revisiting procurement quantities for all of the ancillary service products under ERCOT's ancillary services methodology.

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?). Based on our analysis, we find that structural market power continues to exist in 2023, but there is little evidence that suppliers abused market power in the real-time energy market. We identified a concern with non-competitive outcomes in the non-spin reserve product in the 2022 Report, and changes to the VMPs of larger suppliers were made in response to this concern.

Structural Market Power

For electricity markets, a more effective indicator of potential market power than traditional market concentration metrics is to analyze when a supplier is "pivotal." A supplier is pivotal when its resources are needed to satisfy customer demand or reduce flows over a transmission line to manage congestion. The results below indicate that market power continues to exist in ERCOT and requires mitigation measures to address it. Over the entire ERCOT region:

- At least one pivotal supplier existed in 9% of all hours in 2023, less than the observed 18% in 2021 and 16% in 2022.
- Under high-load conditions, a supplier was pivotal in roughly 55% of the hours, which is expected since the competing supply is more likely to already have been fully utilized.

Market power can also be a much greater concern in local areas when power flows over the network cause transmission congestion that isolates these areas. Market rules cap prices that suppliers can offer in these cases, mitigating suppliers' ability to exercise local market power.

Behavioral Evaluation

We also evaluate behavior to assess whether suppliers engaged in withholding conduct to increase prices. Economic withholding occurs when a supplier raises its offer prices to levels well above the expected marginal cost to produce electricity. Physical withholding occurs when a supplier makes a resource unavailable. Either of these strategies will reduce output from the withheld resource and thereby increase the prices paid to the supplier's other resources.

- *Economic withholding*. Our output gap metric used to measure potential economic withholding – the quantity of economic energy that is not produced by online resources – showed extremely small quantities of potential economic withholding in 2023.
- *Physical withholding*. Both large and small suppliers made more capacity available on average during periods of high demand in 2023 by minimizing planned outages and maximizing the generation offered from each resource. These results together with our ongoing monitoring indicate little potential physical withholding concerns.

In the 2022 Report, we noted that self-commitment by a large supplier lagged previous trends, which was likely due to incentives caused by ERCOT's use of Reliability Unit Commitment (RUC). Two market rule revisions have been implemented that reduce such incentives.[1]

Demand for and Supply of Electricity

Changes in the demand for and supply of electricity generally account for many of the trends in market outcomes. Therefore, we evaluate these changes to assess the market's performance.

Demand in 2023

Total demand for electricity in 2023 increased by roughly 3.4% from 2022 – an increase of approximately 1,670 megawatts (MW) per hour on average as the Texas economy continued to grow. Load in West Texas continues to grow much faster than the average (up 15.5% on average in 2023). This trend in recent years has been driven by expanding oil and natural gas production activity.

Weather impacts on demand were mixed across all zones. We measure the impact weather has on electricity use by quantifying heating and cooling degree days – the amount by which the average daily temperatures are above or below 65 °F. Residential and commercial demand rises quickly as the number of cooling degree days grows because of the demand for air conditioning.

[1] Nodal Protocol Revision Request (NPRR) 1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision* was filed by the IMM and approved by the Board. The RUC offer floor was reduced to $250 per MWh but the RUC opt-out provision will be removed once ERCOT completes implementation. NPRR 1172, *Fuel Adder Definition, Mitigated Offer Caps, and RUC Clawback,* was implemented by the PUCT on March 1, 2024.

In the summer of 2023, cooling degree days increased 8.5% on average following a substantial increase in 2022. We observed increases across major load regions throughout Texas. These increases indicate that temperatures were unusually hot during the summer of 2023, leading to numerous record load levels culminating on August 10 at a peak load of 85.7 GW. This is roughly 7% higher than the 80 GW peak load in 2022. The winter record was set in 2022 of 78.3 GW on December 23, 2022, and subsequently broken on January 16, 2024, with a winter peak load of 78.5 GW. Winter peak demands are raising reliability concerns more frequently than in the past.

Peak demand levels are important because they affect the probability and frequency of shortages. However, peak *net* load (demand minus renewable resource output) has become a more important determinant of supply shortages. We evaluate changes in net load in this report.

Supply in 2023

Approximately 10.5 GW of new generation resources came online in 2023, the bulk of which were intermittent renewable resources. ERCOT added roughly 7.6 GW of new installed wind and solar capacity going into summer 2023 compared to the prior year, with an effective peak output capacity totaling 4.7 GW.

The remaining new capacity included combustion turbines totaling 440 MW; a 530 MW combined cycle; and 1,900 MW of ESRs, which now total 4.4 GW. No natural gas-fired resources retired in 2023. These resource changes, along with changes in fuel prices, led to the following changes in the shares of electricity production in 2023:

- Wind output share decreased slightly to just over 24% from almost 25% in 2022.
- Rising solar penetration increased its output share to 7.3% in 2023 from 5.6% in 2022.
- Coal generation fell to 13.9% from 16.6% in 2022 as coal units totaling 830 MW retired.
- Natural gas generation increased to 45.1% in 2023 from 42.5% in 2022. Lower gas prices and the falling coal output contributed to this higher output share.

The influx of new supply has outpaced the growth in demand, causing ERCOT's estimated planning reserve margin for the summer of 2024 to rise to 29.4% compared to 22.2% in 2022 based on ERCOT's Capacity, Demand and Reserves (CDR) report. This margin is projected to continue to increase over the next few years.

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain an adequate set of resources to satisfy the system's needs. Prices in 2023 produced market revenues more than sufficient to support profitable investment in new conventional resources, as they have in four of the last five years. These net revenues were substantially higher in 2023 than in 2022 even though the market was tighter and produced a higher quantity of true shortage pricing in 2022. This increase in 2023 was largely driven by the problems we identify with ECRS, which accounts for roughly half of the net revenues that a new gas-fired resource would have received in 2023.

Review of Market Outcomes and Performance

ERCOT operates electricity markets in real-time for energy (electricity output) and in the day-ahead for both energy and ancillary services (mainly operating reserves that can start up and produce energy in a short period of time). We discuss the prices and outcomes in each of these markets below.

Real-Time Energy Prices

Real-time energy prices are critical in ERCOT even though only a small share of the energy is transacted in the real-time market (i.e., far more is transacted in the day-ahead market or bilaterally). This is because real-time prices are the principal driver of prices in the day-ahead and forward markets.

There are two primary drivers of market prices: natural gas prices and the number of hours of supply shortages during the year. Electricity prices will be correlated with natural gas prices in a well-functioning market because fuel costs represent the majority of most suppliers' marginal production costs, and natural gas units are generally on the margin in ERCOT.

Average Annual Real-Time Energy Market Prices by Zone

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Prices ($/MWh)									
ERCOT	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**	**$65.13**
Houston	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07	$64.72
North	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52	$68.55
South	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96	$63.34
West	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$65.53	$61.62
Natural Gas Prices ($/MMBtu)									
ERCOT	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84	$2.22

Natural gas prices declined more than 60% from 2023 to 2022, but the load-weighted average energy prices fell only 13.3%. This is largely because of the adverse effects of the ECRS implementation described in this report. Absent these effects, we estimate that the energy price reductions would have been in line with the fuel price reductions. The impacts of ECRS on prices and market costs are discussed further later in this Executive Summary and in detail in Section II of the report.

This table also shows that prices vary across the ERCOT market because of transmission congestion that arises as power is delivered across the network to consumers in different locations. The pattern of zonal pricing in 2023 is more consistent with years prior to 2022 in that there is a tighter range of average prices across zones. The West zone had the lowest prices because of the large amount of local wind and solar generation that frequently caused export constraints for delivery to other zones.

Shortage Pricing

As an energy-only market, ERCOT relies heavily on high real-time prices during shortage conditions to provide key economic signals for the development of new resources and retention of existing resources. The Operating Reserve Demand Curve (ORDC) price adder represents the reliability costs or risks of having a shortage of operating reserves. When resources are not sufficient to maintain the full reserve needs of the system, the expected cost of "losing load" rises as operating reserve levels fall. Efficient shortage pricing occurs when the shortage cost is reflected in both operating reserves and energy prices during shortages. In ERCOT, these occur by adding an ORDC adder to the energy and reserves prices when the system is short of reserves to reflect this rise in cost. The frequency and impacts of shortage pricing vary substantially from year-to-year.

In reviewing the shortage pricing in ERCOT, it is important to note changes directed by the PUCT in recent years:

- In 2019 and 2020, the PUCT adjusted the ORDC to accelerate the increase in the ORDC adder toward the highest ORDC step (then $9,000 per MWh) as reserves fall.
- In the aftermath of Winter Storm Uri, the PUCT further adjusted the ORDC on January 1, 2022.[2] This substantial adjustment was intended to strengthen incentives for generation to be available, and to build and maintain larger quantities of dispatchable resources.
- In November 2023, ERCOT implemented a multi-step ORDC price floor, a "bridge solution" to raise the incentive to build new dispatchable resources until the Performance Credit Mechanism (PCM) is implemented. This change was intended to incentivize generators to self-commit and minimize ERCOT's out-of-market RUC activity.

These changes more than doubled the size of the ORDC price adders, the market value of which totaled $550 million in 2023. The table below summarizes the shortage revenues in 2023.

ORDC Revenue by Fuel Type

	Thermal	Wind & Solar	Storage	Hydro	Biomass
ORDC Revenue ($ millions)	$462.4	$76.3	$8.6	$1.5	$1.5
% of ORDC Revenue	*84%*	*14%*	*1.56%*	*0.28%*	*0.28%*
ORDC Revenue per MWh	$1.51	$0.54	$13.50	$5.19	$6.14
Total Generation (GWh)	*305,360*	*140,073*	*638*	*294*	*250*
% of Generation	*68%*	*31%*	*0.14%*	*0.07%*	*0.06%*

[2] ERCOT set the Minimum Contingency Level (MCL) to 3,000 MW and the high system-wide offer cap and value of lost load (VOLL) were reduced from $9,000 per MWh to $5,000 per MWh.

This table shows that all resource types other than wind and solar received a higher proportion of ORDC revenues relative to their share of generation. This is appropriate because tight conditions tend to occur when these renewable technologies are producing at low levels and dispatchable resources are producing at relatively high levels.

Overall, the ORDC adder contributed just over $1 per MWh or roughly 2% of the annual average real-time energy price, significantly less than in 2022 ($6.41 per MWh). The modest levels of shortage pricing under the ORDC in 2023 underscore that most of the price spikes that occurred in June, August, and September 2023 did not reflect true shortages, but rather were the result of the sequestering of dispatchable resources scheduled to provide ECRS from the real-time market.

Impact of ECRS on Energy Prices

The most substantial factor affecting market outcomes in 2023 was the implementation of ECRS in June 2023. ECRS had sizable effects on energy prices because:

- The implementation of ECRS almost doubled the amount of 10-minute reserves procured by ERCOT (responsive reserves and ECRS);
- ECRS resources, like responsive reserves, are withheld from the real-time energy market dispatch until manually deployed, which can cause the market to falsely perceive a shortage; and
- ERCOT generally did not deploy the ECRS resources, which would have addressed the perceived shortage. Prior to ECRS, many of these resources would have been self-committed by their owners under these conditions.

True shortages in ERCOT are priced under the ORDC – as reserve levels fall under shortage conditions, the ORDC price adder rises. However, implementation of ECRS led the real-time market dispatch to perceive shortages that were true shortages, but were instead the result of:

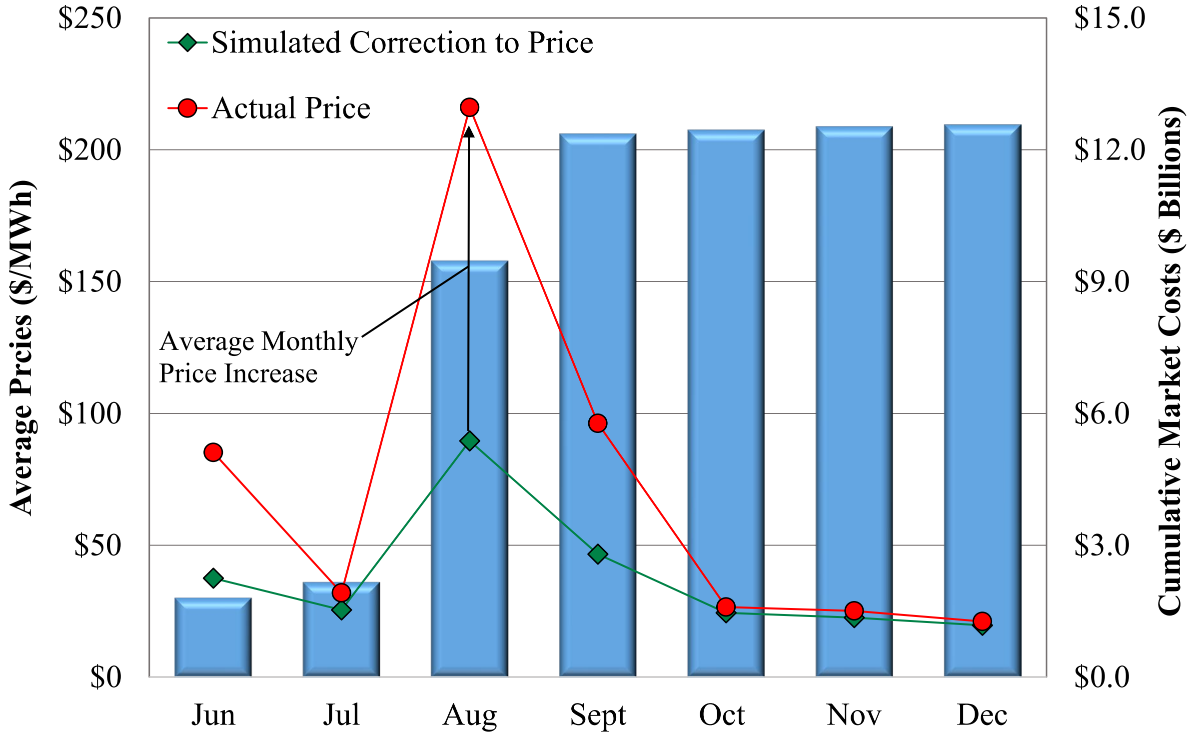
- The fact that the ECRS resources are sequestered from the energy market; and
- The large quantity of ECRS procured with no offsetting reduction in responsive reserve service (RRS) procurements.

This resulted in artificial shortage pricing as high as $5,000 per MWh when the system was not actually short of reserves. The IMM performed an analysis to estimate the impact of ECRS on real-time electricity prices by re-running the real-time market dispatch with 75% of the sequestered resources available to the market. The figure below shows these results on a monthly basis. This analysis shows that ECRS had a sizable impact on real-time prices in June, August, and September, months that experienced frequent price spikes. These price increases:

- Doubled average real-time energy prices from June through December 2023; and
- Increased real-time market costs by more than $12 billion through the end of November.

Customers in Texas likely bore only a fraction of these costs. However, because real-time prices can drive changes in forward prices, customers may bear an increasing share of these costs in the future if these inefficiencies are not addressed.

Estimated Price Effects of ECRS Procurements
June 10 – December 2023



The adverse effects of ECRS on the real-time market were partly due to the large procurement quantities, which we evaluated by estimating the marginal reliability value of the ECRS procurements in each hour during the summer. We found:

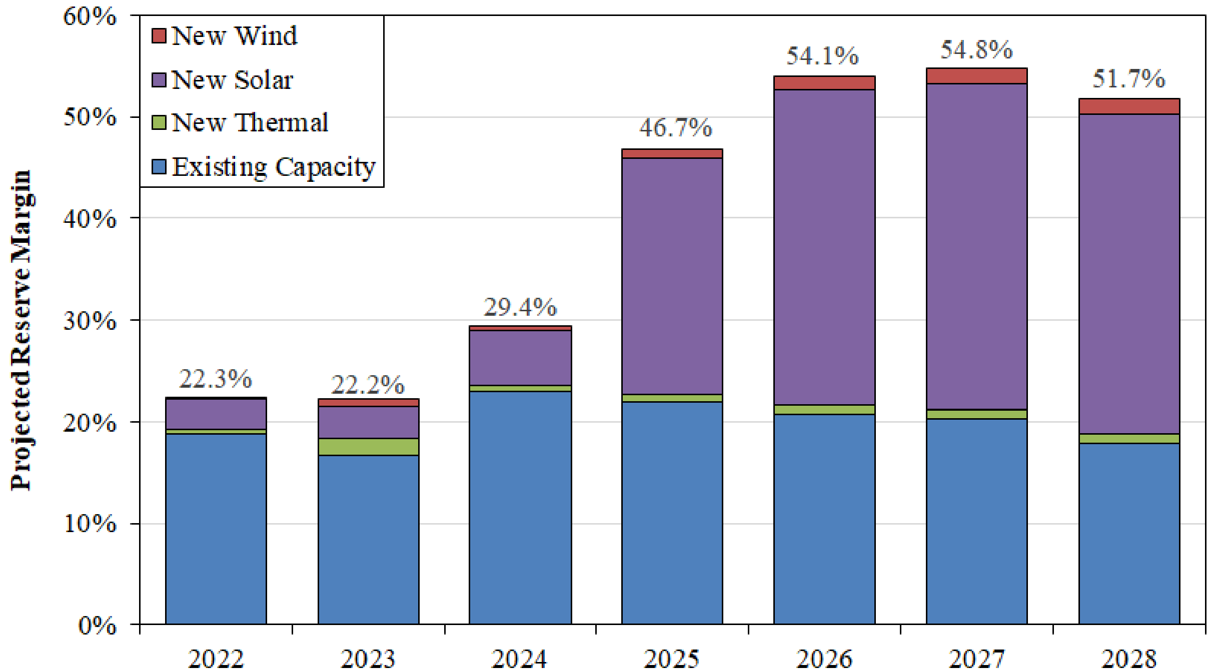
- There were no material risks of load shedding during the summer months that the ECRS procurements were needed to address, despite the hot weather and high load.
- The ECRS requirements are overstated. Modest amounts of ECRS addressed loss of load probabilities ranging from 0 to 0.2%, producing values averaging $16 per MWh. The marginal value of ECRS at the full procurement level was close to zero.
- The total reliability value of the ECRS procurements was $12 million, but the costs ERCOT incurred to procure ECRS were 50 times higher at more than $600 million.

To address these issues, we recommend that ERCOT re-evaluate ECRS and responsive reserve requirements and modify the requirements to better align with the reliability risks to be addressed (see State of the Market (SOM) Recommendation 2023-3). To that end, we will be collaborating with ERCOT to produce an Ancillary Services study, which is expected to be published in the fall of 2024. This study may allow ERCOT to improve its ancillary services methodology that determines the procurement requirements for each class of operating reserves. In the near-term, we are discussing improvements to ECRS deployment criteria that will be implemented in Summer 2024, which should mitigate the concerns discussed above. More detail concerning the IMM's analysis of price impact and marginal reliability value related to implementation of ECRS is included in Subsection G of Section II: Review of Real-Time Market Outcomes.

Revenues and Reserve Margins

The revenues observed in 2023 exceeded typical expectations with the planning reserve margin that currently exists in ERCOT – the 22.2% margin in 2023 is well above a typical one-in-ten planning requirement. This planning reserve margin is expected to increase in the coming years. The following figure shows the expected planning reserve margin over the next six years, and we note that it excludes the contribution from ESRs.

CDR Projected Reserve Margins



Source: ERCOT SARA May 2022, CDR Dec 2022, CDR Dec 2023

This figure shows that planning reserve margins are projected to exceed 40% by 2025. Much of this increase is driven by the sharp rise in solar capability. The figure also shows a mild, but consistent, reduction in existing supply from 2024 to 2028 due to the retirement of older resources. We believe these trends are overstated in the CDR calculations. The contribution of solar to reliability is lower than shown in the CDR because the output of different solar resources is highly correlated. The projected retirements are also likely overstated because the market changes underway should provide sufficient revenue to retain some or all of these resources. Taking these two offsetting items into account, we expect the planning reserve margin will likely be sustained near or above 30% in 2024 and beyond, but not as high as over 40%.

Day-Ahead and Ancillary Services Markets

The day-ahead market facilitates financial transactions to purchase or sell energy for delivery the next day. These transactions do not result in physical obligations, rather, they allow participants to manage the risks related to real-time prices and market outcomes. Day-ahead prices averaged $58 per MWh in 2023. This price closely aligns with prices from the real-time market, $51 per MWh, while still reflecting a modest risk premium.

Ancillary services include operating reserves that are purchased on behalf of consumers to provide resources that can produce electricity quickly (or voluntarily reduce consumption) when needed. Awards for these products obligate the suppliers to physically supply them in real time. These operating reserves help ensure that ERCOT can continue to satisfy consumers' demand when unexpected things happen, such as the loss of a large generator or transmission line.

Prices for ancillary services are typically correlated with real-time energy prices because ancillary services prices include the profits an ancillary services supplier forgoes by not selling energy. Ancillary services costs rose to $4.21 per MWh of load from $3.29 in 2022. This compares to an average cost of roughly $1 per MWh of load in 2020 (prior to Winter Storm Uri) and $29.59 per MWh of load in 2021 when Winter Storm Uri occurred. The increase in 2023 was due to the implementation of ECRS. The average price for ECRS in 2023 was $77 per MWh, which was over three times the 2023 average price of responsive reserve service.

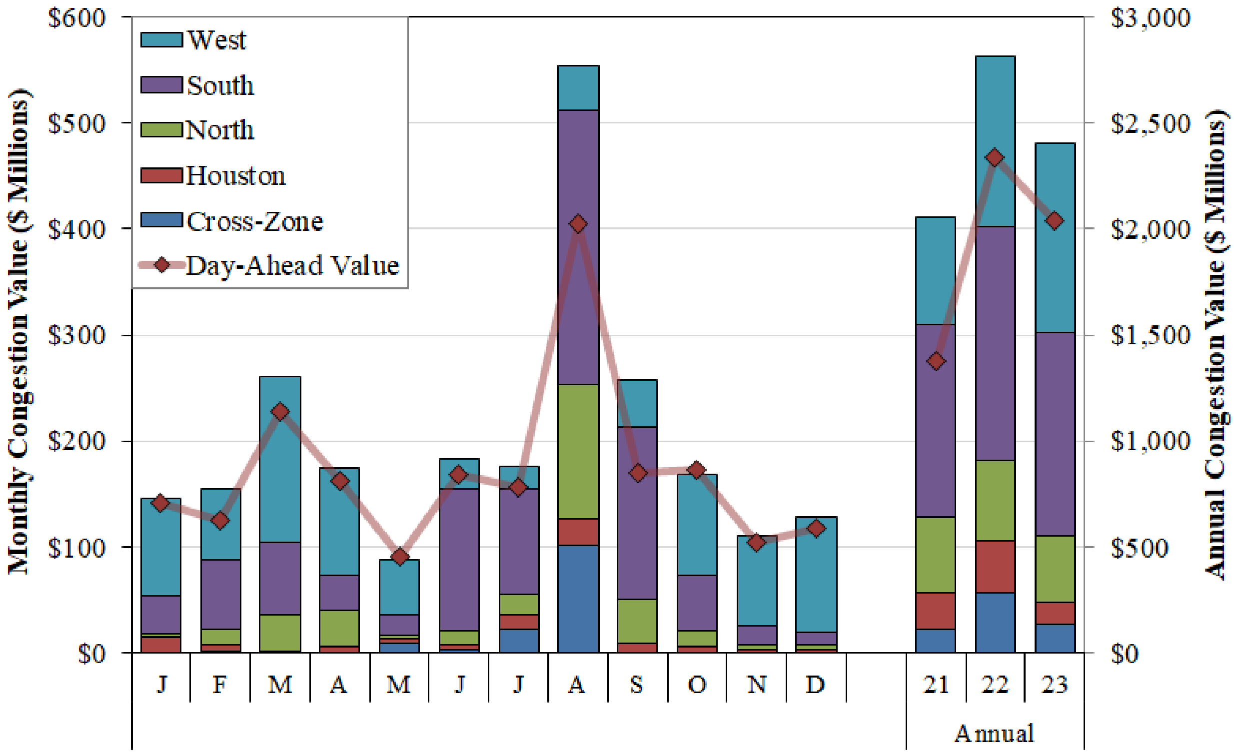
Transmission Congestion

Transmission congestion arises when network power flows are limited due to transmission facility limits. Power flows over the network are almost entirely the result of the locations where power is produced and consumed. When the flow over a transmission facility reaches its limit, the market will incur costs to shift generation to higher-cost units in other locations to reduce the flows over the constrained line. Hence, congestion prevents load from being served by the lowest-cost generators. When transmission congestion occurs, the differences in costs of delivering electricity to different locations will be reflected in the 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 electricity at different locations.

The congestion costs collected by ERCOT are based on these differences in locational prices; these costs equal the difference between the payments by loads at the location of their consumption and the payments to generators at their location. These costs accrue to holders of Congestion Revenue Rights (CRRs), the financial rights to the transmission system.

Real-Time Congestion Costs. To show the trends and fluctuations in congestion costs, the figure below shows real-time congestion costs by month and region for 2023 and the trend in annual costs from 2021 through 2023.

Real-Time Transmission Congestion Costs in 2023



The congestion costs in ERCOT's real-time market in 2023 were $2.4 billion, down 15% from 2022. This reduction is largely attributable to lower natural gas prices in 2023. Other changes in congestion patterns are affected by load levels, outages of generators in load pockets, and frequently binding generic transmission constraints (GTCs). The figure above shows:

- The South zone continued to experience the highest congestion costs in 2023. This is primarily attributable to load growth and GTCs in the Rio Grande valley.[3]
- The West zone exhibited the second highest congestion as a result of high renewable output coupled with the growth of oil and gas loads. Given the expected increase in renewable development, we expect this congestion to increase in coming years.
- Houston experienced much lower congestion due to 2022 needing to accommodate transmission upgrades which were completed prior to 2023.
- Overall cross-zone congestion decreased in 2023, except for in the month of August, which resulted from forced outages of resources around the Houston area.

Day-Ahead Congestion Costs. Participants' expectation of this real-time congestion is reflected in ERCOT's day-ahead prices and outcomes. Day-ahead congestion totaled roughly $2 billion, a reduction from 2022 comparable to reduction in real-time congestion costs. Congestion priced in the day-ahead market was lower than in in the real-time market, indicating that some of the congestion was not well predicted day-ahead, particularly the high congestion periods in August.

[3] The Lower Rio Grande Valley System Enhancement project will likely resolve much of this congestion.

Congestion Revenue Rights. Participants can hedge congestion costs in the day-ahead market by purchasing CRRs. CRRs are economic property rights that entitle the holder to the day-ahead congestion revenues between two locations on the network. They are auctioned by ERCOT in monthly and time-of-use blocks as much as three years in advance. The revenues collected through the CRR auction are given to load-serving entities to reduce the costs of paying for the transmission system. CRR auction revenues have risen steadily as transmission congestion has grown, increasing to $1.4 billion in 2023 from $1.1 billion in 2022.

CRR auction revenues were less than the total congestion costs in 2023 mainly because the auction prices were less than what the CRRs were ultimately worth. This indicates that the congestion was not fully foreseen by the market, especially during the summer months. Additionally, the market design decision to require that 10% of the network capability not be sold in the CRR auctions contributes to the lower CRR revenues.

Generic Transmission Constraints. Finally, ERCOT operators increasingly need to use GTCs to limit the flow of electricity over certain portions of the transmission network. This has been necessary to address concerns regarding the stability of the transmission system in those areas. These concerns have arisen in large part due to the increased output from inverter-based generation resources, such as wind, solar, and ESRs that do not provide the same voltage support to the system as conventional resources. Ultimately, these GTCs increase transmission congestion and the total costs of serving customers in ERCOT by preventing the export of power from low-cost resources to load centers.

The Evolution of the ERCOT Market

The ERCOT market is currently experiencing major changes and evolving needs, which are driven by two primary factors. First, the generation mix is changing rapidly as the entry of wind, solar, ESRs, and distributed generation fleet accelerates. This report shows that the installed capacity of these resources almost doubled from 2019 through 2023 and is projected to double again by 2027. These new generation technologies have significantly different operational characteristics than conventional generation, which will raise a number of operational challenges:

- Significantly higher demands on conventional resources to ramp up and down to accommodate the changes in intermittent resource output;
- Much larger uncertainties related to the forecasted output of intermittent resources;
- Growing reliance on GTCs to manage transmission challenges brought about by the increase in inverter-based generation (including wind, solar, and ESRs);
- Challenges with maintaining the inertia of the system, which is needed to maintain the frequency of the system, as well as supporting the voltage of the system. Inverter-based technologies are typically limited in their capability to provide this support to the system.

- Increasing need to model and optimize the utilization of ESRs as they become an increasingly large and important component of the supply portfolio.
- Challenges associated with the development of DGRs and flexible loads, many of which are not registered with ERCOT. These challenges included ERCOT's limited operational visibility and control of these resources, as well as poor economic incentives.

Improving the markets to address these challenges will be essential to allow these new classes of resources to be integrated reliably and efficiently into the system. The most important aspect of the market for addressing the uncertainties is efficient shortage pricing. ERCOT has strong shortage pricing in place that provides adequate incentives for key resources to be available and perform when needed to maintain reliability. The most important improvements for ERCOT to make to address the future challenges described above are the implementation of:

- Real-time co-optimization of energy and ancillary services (underway);
- A new uncertainty reserve product (being implemented as Dispatchable Reliability Reserve Service (DRRS)), along with a restructuring of the existing reserve products;
- Real-time dispatch software that optimizes over multiple timeframes (recommended).

Key Market Improvements

Real-Time Co-Optimization. In our opinion, this is the most important improvement to the ERCOT market. RTC allows the real-time market to jointly optimize the scheduling of resources to provide energy and ancillary services in each dispatch interval. This will allow the markets to more flexibly schedule resources to meet the various demands of the system. This can be critical when uncertainties arise that require rapid changes in the dispatch of ERCOT's resources, including shifting reserves to other resources on a five-minute basis. It will also allow shortage pricing to be significantly more accurate, as the ORDC will be included in the RTC optimization, eliminating the need to use adders to price shortages efficiently. RTC was delayed after Winter Storm Uri in 2021 but is now active and anticipated to be implemented in late 2026.

Uncertainty Reserve Product. In prior reports, we had recommended that ERCOT implement a longer-term reserve product that would provide access to additional resources that can start in 2 to 4 hours or faster when uncertainties manifest that may threaten reliability (see SOM recommendation 2021-2). Due to House Bill 1500, this type of product is now required under Public Utility Regulatory Act (PURA) § 39.159(d) and is referred to as DRRS.

DRRS should allow reductions in the excess procurement of faster responding reserves, while still ensuring ERCOT operators have dispatchable resources available to call on in real time to ensure the reliability of the system. Additionally, to participate in providing DRRS, a resource must: (1) be capable of running for at least four hours at the resource's high sustained limit; (2) be online and dispatchable not more than two hours after being called on for deployment; and (3) have the dispatchable flexibility to address inter-hour operational challenges.

Multi-Interval Real-Time Market. We have also recommended a multi-interval real-time market (MIRTM) that would optimize the dispatch of resources over multiple future dispatch intervals spanning an hour or more. This type of market would coordinate the commitment of resources that can start within thirty minutes, which would help anticipate and alleviate supply shortages resulting from rapid ramp periods. Managing the sharp increases in net load will create a burden on the remaining dispatchable resources to meet rapid ramping needs. To allow the market to manage these demands reliably and cost-effectively, we believe it will be essential for ERCOT to implement a look-ahead dispatch and commitment model that will optimize:

- The dispatch of slower ramping resources that may need to begin ramping 15 to 30 minutes in advance of a sharp increase in net load;
- The intra-day commitment of resources that can start in 10-minutes to 2 hours; and
- The utilization of ESRs, DGRs, and resources with energy limitations, including efficiently optimizing state of charge (SOC) for ESRs.

Therefore, we recommend implementation of an MIRTM (SOM Recommendation 2022-1).

Other Reforms Underway or Recommended

Performance Credit Mechanism. On December 6, 2021, the PUCT approved a blueprint for revisions to the design of the wholesale electric market, which included two phases.[4] Phase I provided enhancements to ancillary services and changes aimed at improving price signals and operational reliability, while Phase II addressed longer-term market design and structure reforms. On January 19, 2023, the PUCT adopted the PCM as its preferred Phase II market design change, but delayed implementation pending consideration by the Texas Legislature.[5] The PCM would provide payments to resources that were available during the tightest hours of the year.

The 88th Texas Legislature passed House Bill 1500, which provided guidance and limitations on the PCM, including an annual net cost cap of $1 billion, a limit on availability of Performance Credits (PCs) to dispatchable generation, centrally clearing PC markets, and other parameters.[6] A strawman PCM design proposal is expected to be released in fall 2024, which should provide further clarity on the design specifications of the PCM. The IMM is required by House Bill 1500 to perform a study of the proposed PCM in late 2024.

Reliability Standard. One key effort under way is the development of a new reliability standard intended to quantify the resources needed to achieve high reliability in ERCOT. ERCOT has developed an initial proposal to adopt the standard one-in-ten year probability of losing load along with two new criteria: maximum amount and duration of loss of load. It will be important

4 *Review of Wholesale Electric Market Design,* Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

5 *Wholesale Electric Market Design Implementation*, Project No. 53298, Order (Jan. 19, 2023).

6 House Bill 1500 codified these legislative guardrails for the potential design of the PCM in PURA § 39.1594.

to clarify as this effort proceeds whether this standard is mandatory. If it is deemed mandatory, it will be essential that the markets satisfy the standard and avoid out-of-market approaches, which are likely to ultimately undermine the market's ability to sustain the necessary resources. However, we would encourage the PUCT to not to make the reliability standard mandatory.

We will be providing feedback on the proposed reliability standard, but initially recommend that ERCOT not employ the maximum size and duration criteria as these outcomes are likely highly sensitive to modeling assumptions. This would be better addressed by using a single "expected unserved energy" (EUE) metric that is more robust and would capture both the magnitude and duration of potential outages. Finally, progress also was made on assessing and updating the current Value of Lost Load (VOLL) and Cost of New Entry (CONE) values, both of which will be used in defining the new reliability standard.[7] These efforts should be completed in 2024.

Improved Voltage Support. As voltage issues become more prevalent, it may be efficient to implement a voltage support service that would incentivize improved reactive capability from inverter-based resources and proactively resolve voltage stability issues. Phase I of the PUCT's blueprint for wholesale electric market design identified voltage support compensation as a market design enhancement to be developed. To support the PUCT's policy and design decisions regarding voltage support compensation, ERCOT filed a proposal with the PUCT identifying possible options in August 2023.[8] In February 2024, the PUCT opened a project to explore voltage support compensation options, including the options in ERCOT's proposal.[9]

Improved State of Charge Modeling for ESRs. Modeling the SOC in the Day-Ahead Market, RUC, and the real-time market will become increasingly important as ESRs become a more substantial portion of the fleet. In addition to the benefit of producing more accurate clearing prices, this modeling will improve the commitments of other types of generation.

Unregistered Flexible Loads. Unregistered flexible loads (e.g., data centers and crypto-currency mines) represent a significant concern, as these resources are increasingly interconnecting behind-the-meter and are often price-responsive outside of SCED. These loads should have incentives to register with ERCOT and participate in energy and ancillary services markets. This will increase their transparency and provide substantial value to the system.

Transmission Cost Allocation. The current transmission cost allocation method (4 CP) provides incentives for large loads to behave in ways that limit their exposure to transmission cost recovery without reducing the need for new transmission investments. This results in inefficient

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7 *See generally Review of Value of Lost Load in the ERCOT Market*, Project No. 55837 (pending); and *see Reliability Standard for the ERCOT Market*, Project No. 54584, ERCOT Reliability Standard Study and CONE Study Update (Apr. 4, 2024).

8 *Wholesale Electric Market Design Implementation*, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Proposal Regarding Voltage Support Compensation (Aug. 21, 2023).

9 *Voltage Support Compensation*, Project No. 56184 (pending).

dispatch and pricing during high load periods. We have recommended reform of this allocation to address these issues in SOM Recommendation 2015-1.

Recommendations

We have identified opportunities for improvement in the current ERCOT market and make fifteen recommendations in this report. Four are new items to address inefficiencies or improve market incentives, and the others were initially recommended in prior years. It is not unexpected that recommendations carry over from prior years since many of them require software changes that can take years to implement or require updates to the PUCT's substantive rules.

The table below shows the recommendations organized by category. They are numbered to indicate the year in which they were introduced and the recommendation number in that year.

Number	Brief Description
New Recommendations to Improve Market Performance	
2023-1	Increase a constraint's shadow price cap in real-time when appropriate
2023-2	Modify the Proxy Offer Curve for renewable resources without a submitted energy offer curve
2023-3	Improve the procurement and deployment of ECRS
2023-4	Improve the pricing and offer requirements of the Firm Fuel Supply Service
Additional Recommended Market Improvements from Prior Years	
2022-1	Implement a multi-interval real-time market
2022-3	Allow transmission reconfigurations for economic benefits
2022-4	Change the linear ramp period for ERS summer deployments to 3 hours
2022-5	Change historical lookback period for ORDC mu and sigma calculations
2021-1	Eliminate the "small fish" rule
2021-2	Implement an uncertainty product
2021-3	Reevaluate net metering at certain sites
2020-3	Implement smaller load zones that recognize key transmission constraints
2020-4	Implement a Point-to-Point Obligation bid fee
2019-2	Price ancillary services based on the shadow price of procuring each service
2015-1	Modify the allocation of transmission costs by transitioning away from the 4 Coincident Peak method.

New Recommendations to Improve Market Performance

2023-1 Increase a constraint's shadow price cap in real-time when appropriate

The shadow price cap for a constraint does two important things: a) limits the actions taken by the dispatch model to manage a transmission constraint; and b) sets the price for the constraint when it is violated. To enable the real-time dispatch model to manage the constraint flows while not setting excessive prices when the constraint is violated, it is key that the shadow price cap be set at a level that reflects the reliability risk or costs of violating the constraint.

In certain cases, the currently established maximum shadow price caps for thermal constraints are too low and do not appropriately value violations of the constraint. When this happens, the real-time market may not dispatch sufficient local resources to resolve the constraint, and prompt manual actions that can result in higher prices system-wide. Reliability concerns associated with a severe violation on September 6, 2023, prompted ERCOT to curtail 1,500 MW of generation, including 1,300 MW of wind. These curtailments occurred simultaneously with rising demand and resulted in the system frequency falling below 59.91 hertz for 15 consecutive minutes and ERCOT's declaring an Energy Emergency Alert Level 2.

The September 6 manual curtailments highlight that reliability concerns regarding transmission violations can exceed the established shadow price caps. On this day, the marginal costs of the manual curtailments were much higher than the shadow price caps, which is why the real-time market did not curtail the resources. The manual curtailments had much broader market effects. Allowing the market to optimize the dispatch to balance the system-wide reliability needs of the system with the reliability costs of managing the constraint would lower costs and improve reliability. To achieve this, operators should have the authority to raise the shadow price caps as needed to reflect the severity of the reliability concerns related to violating a transmission constraint. ERCOT has proposed a similar change in March 2024.[10]

To demonstrate the value of this change, the IMM reran the September 6 manual curtailment period using a significantly higher shadow price cap for relevant constraint ($15,000 per MWh) and without the manual curtailments lifted. The results of this simulation are shown in the Appendix Section V.B.6. This simulation shows that:

- The real-time dispatch found a dispatch solution that avoided the constraint violation; and
- Reduced power balance violation in the period when system frequency started falling.

This recommendation will have both economic and reliability benefits and is consistent with the authority of other regional transmission organizations (RTOs).

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10 See *Reports of the Electric Reliability Council of Texas*, Project No. 55999, ERCOT Notice Regarding New South Texas Export and Import Generic Transmission Constraints (Mar. 18, 2024).

2023-2 Modify the Proxy Offer Curve for renewable resources without a submitted energy offer curve

The existing practice of inserting an administrative proxy offer curve for Intermittent Renewable Resources (IRR) that do not themselves submit an offer curve can result in an inefficient dispatch to resolve congestion where much higher-cost resources are utilized before the IRRs.

Currently, if an IRR does not submit an Energy Offer Curve, a steeply sloped proxy curve is constructed for it. As the penetration of IRRs grows, the frequency of these occurrences should increase. Roughly 700 MW[11] of IRRs operated without an energy offer curve in 2023 on average. The proxy curve is priced at -$250 per MWh from the Low Sustained Limit of the resource to just below the High Sustained Limit (HSL), and then it rises to $1,500 at the HSL.

The problem with this practice is that curtailing a -$250 per MWh resource to manage congestion is generally going to appear very expensive to the dispatch model, typically more expensive than the shadow price cap for constraints in ERCOT. When this occurs, the real-time market will not be able to curtail the IRR and the constraint may ultimately go into violation, as occurred on September 6, 2023. Therefore, we recommend that ERCOT enter a proxy offer curve that is more closely aligned with IRRs' production costs. For example, a proxy offer priced at $0 over the entire dispatch range of the resource would be a substantial improvement. Any IRR owner that believes this does not reflect its costs is free to submit a more accurate offer.

2023-3 Improve the procurement and deployment of ECRS

As discussed in detail in Section II and elsewhere in this report, the implementation of ECRS in June 2023 created artificial shortage conditions that doubled the average real-time price after its implementation and generated enormous market costs. These problems arose because:

- The introduction of ECRS roughly doubled the amount of 10-minute reserves ERCOT was procuring and such resources are limited in quantity;
- The procured resources are sequestered from the real-time market dispatch, regardless of how valuable they would be in serving the energy demand;
- Prior to ECRS, such resources would often be self-committed by their owners as conditions began tightening. After ECRS, ERCOT generally avoided deploying the resources even when the real-time dispatch model ran out of available resources and prices rose as high as $5,000 per MWh.
- In some cases, ECRS resources were needed to manage congestion, but could not be utilized. This is again a situation where, before ECRS, the owner would likely have self-committed the resource after seeing the high congestion prices in the area.

11 This only includes resources telemetering a dispatchable status, e.g., "ON" but not "ONTEST."

To address these concerns, we recommend ERCOT consider a series of improvements:

- Re-evaluate the ECRS requirements and other reserve products based on a stochastic reliability analysis to align the requirements with the reliability risks they address.
- Reduce the duration requirement for ECRS to one hour, which would allow more ESRs capacity to provide ECRS.
- Develop a deployment trigger for ECRS that will release ECRS as the real-time dispatch model approaches insufficiency.
  - This will eliminate artificial shortage pricing produced by the real-time dispatch model, while preserving legitimate shortage pricing under the ORDC.
  - One reasonable approach would be to employ a price-based trigger that is above the costs of running the ECRS units, which would simulate the market incentive to self-commit the resources that had existed prior to ECRS.

After raising these concerns in 2023, we began discussing potential changes with ERCOT. As of the time this Report was published, ERCOT staff have begun development of a first phase deployment trigger that will release ECRS capacity to the real-time energy market dispatch is moderately short of capacity for 10 minutes or more.[12]

Ultimately, RTC will allow for the economically efficient use of all available capacity, especially in periods of tight demand-supply conditions. In the transition from ERCOT's management of ECRS in 2023 to RTC at some future date, a sensible deployment process is needed to make ECRS capacity available to the real-time electricity market to avoid artificial shortage pricing.

ERCOT has not yet evaluated the method for establishing procurement targets, however, this should be within the scope of the required Ancillary Services Study. The PUCT has requested that the IMM collaborate with ERCOT in producing this study.

2023-4 Improve the pricing and offer requirements of the Firm Fuel Supply Service

Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of dual-fuel generators to purchase fuel to be stored on site. As of July 1, 2023, FFSS also pays certain gas-fired resources that have owned natural gas stored offsite and have it accompanied by firm transportation and storage agreements.

FFSS was deployed three times in 2023 during the first obligation period in the winter of 2022/2023. During these instances, we identified that operating reserve levels (8,000 to 9,000 MW) and pricing outcomes (roughly $40 per MWh) did not reflect the need for FFSS. Since utilizing Firm Fuel Supply Service Resources (FFSSRs) is costly, we encourage ERCOT to develop clear procedures for deploying FFSS capacity.

[12] NPRR 1224, *ECRS Manual Deployment Triggers*, see: https://www.ercot.com/mktrules/issues/NPRR1224.

There are two issues with FFSS that can lead to inefficient market outcomes and higher costs. First, the capacity of the deployed FFSSRs is removed from reserves when calculating ORDC adders. This can cause the market to set inefficiently high prices through the ORDC when the system is not short of reserves. Absent the FFSS programs, these resources would likely be running, so removing them from the ORDC adder calculation can lead to unjustified shortage pricing. Second, FFSSRs have their fuel costs covered by the FFSS payment, which causes them to have the incentive to run at any price even though they may actually be burning expensive fuel oil that consumers must reimburse. This is inefficient and raises the costs of the FFSS and potentially reduces the amount of firm fuel that may be available for future deployments.

To address these issues, we recommend ERCOT consider modifying the FFSS rules to:

- Include the capacity of the FFSSRs in the ORDC; and
- Require FFSSRs to offer at costs that accurately reflect costs of the firm fuel.

Recommended Market Improvements from Prior Years

2022-1 Implement a multi-interval real-time market

The real-time market efficiently dispatches online resources for the next five minutes and sets nodal prices that reflect the marginal value of energy at every location, but ERCOT lacks software and processes to:

- Look beyond five minutes to optimize the dispatch instruction for online resource that must begin moving to satisfy a large change in demand in the near future, or
- Facilitate efficient commitment and decommitment of peaking resources that can start quickly (i.e., within 30 minutes); or
- Efficiently dispatch the charging and discharging of ESRs because a single interval dispatch cannot determine whether to preserve an ESR's SOC for a future interval when it may be more valuable.

For these reasons, other markets have implemented this type of MIRTM software. As ERCOT attracts more intermittent wind and solar resources, the value an MIRTM to allow the market to efficiently and reliability meet the increasing fluctuations in net load will grow.

This is a recommendation that we made previously. In 2016, ERCOT evaluated the potential benefits of a multi-interval real-time market and decided not to move forward because the costs were greater than the projected benefits.[13] However, much has changed since then – we believe the benefits will be much higher in the future and it will become essential for managing the renewable fleet. Hence, we recommend it be reevaluated and prioritized for implementation.

13 *See PUCT Review of Real-Time Co-Optimization in the ERCOT Region,* Project No. 41837, ERCOT Report on the Multi-Interval Real-Time Market Feasibility Study (Apr. 6, 2017).

2022-3 Allow transmission reconfigurations for economic benefits

Currently, ERCOT's approval processes only allow constraint management plans for reliability reasons.[14] However, there are times in which a transmission reconfiguration can relieve congestion without negatively affecting reliability.[15] Such plans should be developed and utilized. Both Midcontinent ISO (MISO) and Southwest Power Pool (SPP) are moving forward with this effort, though MISO is farther along.[16]

We recommend that ERCOT accept a limited number of proposals and independently identify options to reconfigure transmission elements in the network operations model when they are physically feasible and economically beneficial. A process can be established to identify which limited number of reconfiguration options have the biggest benefits. ERCOT is currently considering such a process through NPRR 1198, Congestion Mitigation Using Topology Reconfigurations.[17]

2022-4 Change the linear ramp period for ERS summer deployments to 3 hours

In all summer Emergency Response Service (ERS) deployments to date, resources returned to pre-instruction levels in approximately three hours.[18] However, the current time value parameter for returning to the pre-instruction level in the reliability deployment price adder calculation (an output of the Security-Constrained Economic Dispatch (SCED) pricing run) is 4.5 hours. This difference artificially inflates the reliability deployment price adder. We recommend that there instead be a separate summer value of 3 hours. A non-summer value of 4.5 hours can remain until such time as we have more ERS deployment data for non-summer months.

2022-5 Change the lookback period for ORDC mean and standard deviation calculations

The current ORDC statistical values of the mean and standard deviation used as inputs to the ORDC shape are based on historical data going back to the introduction of the nodal market. The ORDC uses these historical values because the values are meant to be self-correcting as

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14 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.

15 These are not post-contingency actions and so should have a negligible impact on the control room.

16 *See, e.g.*, https://cdn.misoenergy.org/20230228%20RSC%20Item%2006%20Reconfiguration%20for%20Congestion%20Cost%20Update628023.pdf.

17 NPRR 1198, *Congestion Mitigation Using Topology Reconfigurations*, available at: https://www.ercot.com/mktrules/issues/NPRR1198.

18 https://www.ercot.com/files/docs/2022/09/13/DSWG%20-%20ERS%20event%20deployment%207-13-2022.pptx.

hour-ahead errors rise and fall over time. Because the resource mix has changed substantially in the last 12 years, the self-correcting nature of the ORDC is not able to capture the more recent data appropriately. Therefore, we recommend a rolling 5-year lookback period for the mean (mu) and standard deviation (sigma) parameters. Our analysis shows that this may reduce mu but raise sigma. The effect of this in 2022 would have been a savings of over $160 million. The importance of reducing the historical lookback period will increase over time and this change over the longer term is likely to raise revenues for suppliers in ERCOT.

2021-1 Eliminate the "small fish" rule

Under the so-called "small fish" rule, generators with less than 5% of the capacity installed in ERCOT are deemed not to have "ERCOT-wide market power."[19] This rule was originally implemented before ERCOT had effective shortage pricing under the ORDC and was intended to allow high offers (offers significantly above the marginal cost of production) to produce high prices in shortage conditions. The rule was rendered unnecessary by the introduction of the ORDC because small suppliers no longer have to raise their offer prices in order for prices to rise during shortages. Nonetheless, economic withholding by small participants has led to some instances of inefficient pricing. Withholding should not be allowed by any pivotal supplier, and small entities can be pivotal when conditions are tight market-wide or when the system is ramp constrained. Therefore, the IMM recommends elimination of the small fish rule.

2021-2 Implement an uncertainty product

Operational uncertainties have grown as the penetration of intermittent renewable resources and load have both been growing considerably. ERCOT has responded to these uncertainties by increasing its use of the RUC process and procuring more short-lead operating reserves. Neither of these strategies is ideal for addressing the growing uncertainties ERCOT faces. Therefore, we have recommended that ERCOT implement a longer-term reserve product procured in the day-ahead market that would provide access to additional resources that can start in 2 to 4 hours or faster when uncertainties manifest that may threaten reliability.

This product would: 1) provide operating reserves that can be used to resolve reliability concerns arising from uncertain system conditions; 2) be less costly than holding excessive amounts of 30-minute reserves; 3) allow co-optimized market prices to better reflect the value of managing uncertainty; and 4) reduce out-of-market actions and the substantial costs associated with them. The longer start-up and availability time for this product may complicate a direct co-optimization in a short-horizon dispatch model. We encourage a design and implementation approach that will account for the energy and reserve values of units providing this product in both the day-ahead and real-time markets consistent with co-optimization principles.

19 *See* 16 TAC § 25.504(c).

This type of product is now required under PURA § 39.159(d) and is referred to as DRRS. DRRS should allow reductions in the excess procurement of faster responding reserves, while still ensuring ERCOT operators have dispatchable resources available to call on in real time to ensure the reliability of the system.

The IMM is closely following the process surrounding implementation of DRRS to ensure the product will ultimately address the IMM's concerns that lead to the recommendation for an uncertainty product. Further details concerning implementation of DRRS are described in Section I of the Appendix. Implementation timing is expected to generally align with implementation of RTC.

2021-3 Reevaluate net metering at certain sites

The IMM agrees with the decision to implement nodal pricing for CLRs, which is being pursued through NPRR 1188. However, we note that there has been a proliferation of proposed net metering arrangements since adoption of NPRR 945, *Net Metering Requirements*, which distorts the incentives provided by this directive. Loads that can be turned on and off quickly, such as data centers and crypto-currency mines, should be incented to be dispatchable in real time through CLR participation rather than reducing their consumption to avoid transmission cost allocation and other load charges. This would help support price formation and provide better congestion management.

However, allowing net metering for flexible loads and not for CLRs may disincentivize flexible loads from registering as CLRs. Thus, the IMM recommends that net metering be reconsidered for any loads behind the meter of unaffiliated entities. We also note that our proposed changes to transmission cost recovery (2015-1) would tend to reduce the incentives to use net metering to avoid transmission cost allocations.

2020-3 Implement smaller load zones that recognize key transmission constraints

The four competitive load zones contain a large amount of load, particularly the North and South zones, relative to when they were defined in 2003. This zonal configuration has not changed even through many years of load growth and changing congestion patterns. The highly aggregated load zones distort the incentives of both price-responsive demand and active demand response to manage congestion. This is particularly noticeable in the South load zone where there is significant congestion inside the zone, not just between it and other zones.

Incenting demand to respond to the load zone price often makes the local congestion worse. As active demand response grows in the future, transitioning to nodal pricing for those active loads will become increasingly beneficial for ERCOT and market participants and is being pursued through NPRR 1188.[20] Beyond the active demand response, longer-term demand decisions may be influenced by the zonal prices. Such decisions may either relieve or aggravate congestion but are not informed by the nodal prices.

Therefore, the IMM recommends that the load zones be re-evaluated and defined in future years (after the required four-year waiting period), based on prevailing congestion patterns. In particular, the new zones should be defined to minimize intra-zonal congestion. This is currently under consideration in ERCOT's Congestion Management Working Group.

2020-4 Implement a Point-to-Point Obligation bid fee

Over the last few years, there have been numerous delays in running and posting the results of the day-ahead market. These delays are disruptive to the market and create unnecessary risk for market participants. ERCOT analysis of the cause points to a significant increase in bids for point-to-point (PTP) obligations, a financial transaction cleared in the day-ahead market used to manage real-time market congestion cost risk.[21] This is not a surprise because large increases in PTP transactions greatly increases the complexity of the optimization and the time required for the market software to solve.

Charging no fee for PTP bids, as ERCOT currently does, allows participants to submit numerous bids that are unlikely to clear and provide very little value to the market. Applying a small bid fee to the PTP bids is consistent with cost causation principles and would incentivize participants to submit fewer bids that are more valuable and more likely clear. Because even a small fee would likely reduce or eliminate the bids that are very unlikely to clear, this should substantially eliminate the delays in the day-ahead market process. Hence, the IMM recommends that a small bid fee be applied to day-ahead market PTP obligation bids to more efficiently allocate day-ahead market software resources. ERCOT has indicated that they would be willing to impose such a fee, though they have not yet submitted an NPRR.

2019-2 Price ancillary services based on the shadow price of procuring each service.

Clearing prices should reflect the constraints that are used by ERCOT to purchase ancillary services. However, this is not currently the case with certain ancillary services. ERCOT's procurement requirements for Responsive Reserve Service effectively limit the amount of under-frequency relay response that can be purchased from non-controllable load resources. Because these limits are not factored into the clearing prices, there is usually a surplus of relay response offered into the market. However, the surplus does not drive clearing prices down as one would expect in a well-functioning market. There is significant surplus year after year, which is an

20 Nodal pricing for controllable load resources is a part of the PUCT's 2021 market design blueprint but has not yet been implemented.

21 ERCOT's regression analysis can be found at http://www.ercot.com/calendar/2021/1/25/221086-WMWG.

indicator of the inefficient pricing in this market.[22] Similarly, ECRS can be provided by both limited resources (e.g., non-controllable load resources) and unlimited resources (e.g., gas peakers). Limited resources are manually deployed, and unlimited resources are dispatched by SCED. However, there is a single clearing price for both the limited and unlimited providers.

Failure to account for these constraints in the pricing of those products requires the imposition of inefficient market rules and restrictions. Such measures are not necessary when efficient prices determine market participants' incentives. Therefore, the IMM recommends that the clearing price of all ancillary services be based on all the constraints used to procure the services.

2015-1 Modify the allocation of transmission costs by transitioning away from the Four Coincident Peak method.

The current method of allocating transmission costs, the four coincident peak (4CP) method, does not apply transmission costs equitably to all loads. Additionally, it does not forestall the need to invest in new transmission as intended when this method was implemented. Currently, transmission costs are allocated based on an entity's maximum 15-minute demand in each month of June through September.[23] This method was approved in 1996 and was intended to allocate transmission costs to the drivers of new transmission.

However, customer demand during the peak summer hours is no longer the main driver of new transmission in ERCOT today. Decisions to build transmission are based on transmission congestion patterns throughout the year and an analysis of whether generation can be delivered to serve customers reliably. Additionally, the method of allocating these costs provides a cost-avoidance signal to large consumers that can artificially reduce their metered load in anticipation of a peak demand day to avoid transmission charges. Demand response driven by the incentive to avoid transmission costs is likely inconsistent with real-time price signals and can significantly distort market outcomes. Hence, the IMM continues to recommend that transmission cost allocation be changed to better reflect the true drivers for new transmission.

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22 We include a chart showing the surplus later in this Report.

23 16 Tex. Admin. Code §25.192. Transmission Service Rates; http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.192/25.192.pdf

I. Future Needs of the ERCOT Market

The Electric Reliability Council of Texas (ERCOT) market is experiencing major changes and evolving needs, driven by two primary factors. First, the generation mix is changing rapidly as the entry of wind, solar, energy storage resources (ESR), and distributed generation fleet accelerates. These new generation technologies have significantly different operational characteristics than conventional generation, and changes to the market are necessary to integrate them reliably and efficiently into the system.

Second, ERCOT has adopted a very conservative operational posture since July 2021. This conservative operational posture requires more operating reserves to be online in real-time. Specifically, an online reserve level target of 6,500 megawatts (MW) for real-time (or 7,500 MWs during certain conditions) has been used. In addition to being very costly, this operational posture can interfere with efficient market signals in real-time. It has also led to inefficiencies in ancillary services pricing due to the increased procurement.

The large online reserve level target was the driver for a significant increase in RUCs through 2022. In 2023, RUCs decreased, and the online reserve level target was met, in part, through very large procurements of ERCOT Contingency Reserve Service (ECRS). This practice of trying to maintain an online reserve margin with operational reserves has resulted in large distortions to market outcomes, particularly as ECRS quantities are held in reserve and not available to the real-time energy dispatch unless specific deployment triggers are hit. Without RTC, the held amounts of ECRS are assigned infinite value, and MW quantities that would have been effective in serving demand or in managing congestion are unavailable to do so. This leads to extremely inefficient and costly real-time pricing outcomes.

This section discusses the evolving needs of the future ERCOT market. The IMM recommends the following changes, at a minimum, to address the needs described above:

- Implement RTC as soon as possible;
- Complete single model implementation of ESRs and incorporate SOC in market clearing;
- Design the DRRS to increase the flexibility of the system instead of attempting to adapt current ancillary service products to requirements they are not well suited for (see Recommendation 2021-2 above);
- Address cost allocation issues, particularly transmission cost allocation (see Recommendation 2015-1 above); and
- Re-evaluate ancillary service procurement and deployment to ensure that reasonable quantities are being purchased to serve reliability needs and to ensure all ancillary service products are being utilized effectively and efficiently (see Recommendation 2023-3).

A. ERCOT's Future Supply Portfolio

The ERCOT market's supply portfolio has changed considerably over the last 20 years, and the current interconnection queue suggests that it will continue to change. Over the past two decades, a significant fraction of ERCOT's natural gas steam and coal generation facilities have retired, a large amount of combined cycle capacity has been built, and the penetration of wind resources significantly increased. More recently, solar resources and ESRs have been interconnecting at a rapid pace, while the addition of wind resources has been slowing. Figure 1 shows the trends in the development of these major new classes of resources. The new resources shown in this figure include only those with interconnection agreements.

Figure 1: Development of Renewable Resources and Energy Storage
2017-2027

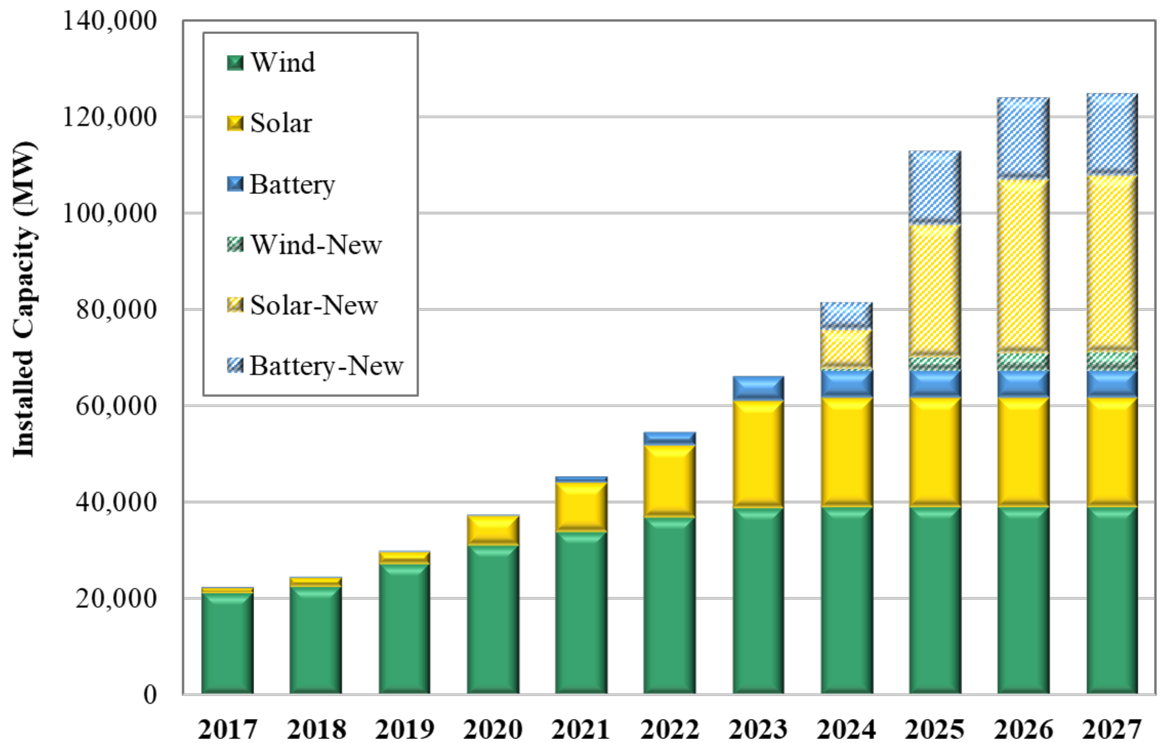

Figure 1 shows that the capacity of these technologies almost doubled from 2019 through 2023 and is projected to double again by 2027. This rapid growth raises operational and market design challenges that we discuss in the subsections below.

B. Operational Challenges of the Evolving Supply

Over the last five years, 16 gigawatts (GW) of wind resources, 20 GW of solar resources, and 5 GW of ESRs entered the ERCOT system.[24] Over the same period, 2 GW of coal and 1.1 GW of

[24] https://www.ercot.com/files/docs/2024/03/06/Capacity_Changes_by_Fuel_Type_Charts_February_2024.xlsx.

gas steam capacity retired.[25] Looking forward, ERCOT's interconnection queue is comprised of more than 1,700 active projects totaling over 348 GW,[26] and the vast majority of this projected capacity is wind resources, solar resources, and ESRs. Although not all of these projects will be built, Figure 1 shows that 47 GW of projects have a completed interconnection study and agreement, of which 28 GW are solar resources, 8 GW are wind resources, and 10 GW are ESRs. The growth in each of these classes of generation will present challenges that we discuss in this subsection. Subsection C describes the key market design elements that will position ERCOT to address these challenges.

1. Renewable Resources

The rapid increase in intermittent wind and solar generation raises different operational demands and challenges. They also provide benefits specific to their operating profile, including:

- The correlation of solar output with ERCOT's peak demand helps address resource adequacy risk during the summer peak; and
- The ESR projects that are co-locating with renewable resources can mitigate some of the operational demands discussed in this section.

Nonetheless, the magnitude and pace of the growth of intermittent resources in ERCOT will create new operational challenges, which are discussed below.

Increasing Ramp Demands. Increased wind and solar penetration will lead to a much steeper and more uncertain need for dispatchable resources, which we refer to as "net load." Net load is the system load minus the output of intermittent renewable resources, which must be served by dispatchable resources. Net load can rise sharply when weather conditions cause the output from ERCOT's fleet of almost 40 GW of wind capacity to decline rapidly. Likewise, with over 20 GW of installed solar capacity in the ERCOT market, dispatchable resources must ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. This challenge is felt even more acutely on days when wind generation remains low into the evening as solar generation ramps down.

Managing these sizable and uncertain ramp demands requires flexible and dispatchable resources. A large share of these needs will be met by existing and new flexible natural gas resources. The actions taken by both the Public Utility Commission of Texas (PUCT) and ERCOT have increased the incentives to build and retain these resources, as discussed in Section I of the Appendix. Additionally, ERCOT will likely need to rely more heavily on:

- ESRs that can produce energy very quickly when deployed and store energy when intermittent output is high relative to demand; and

25 https://www.ercot.com/files/docs/2023/12/07/CapacityDemandandReservesReport_Dec2023.xlsx.

26 ERCOT Generation Interconnection Study Report, February 2024.

- Demand-side resources that can respond to higher prices during high ramp demand periods or transitory periods of supply insufficiency.

Increasing Supply Uncertainty. The growth in wind and solar, coupled with rising amounts of distributed generation that is not dispatched by ERCOT, will significantly increase the uncertainty that ERCOT faces. Forecasting intermittent output will always be a challenge, because both the magnitude and timing of changes in intermittent output are uncertain. While the timing of changes in solar output changes are not as uncertain as those for wind, uncertainty regarding cloud cover can be substantial.

Ideally, this uncertainty should be addressed through the market. However, many Independent System Operators (ISOs) or RTOs manage this uncertainty in real-time operations by committing additional resources outside of the market. ERCOT is currently addressing this uncertainty through procurement of excessive amounts of 10-minute (ECRS) and 30-minute (non-spinning) reserves, and to a lesser extent, by committing units through RUC for capacity.

Increasing Generic Transmission Constraints. Another challenge brought about by the increase in inverter-based generation (including wind, solar, and ESRs) is the increased prevalence of generic transmission constraints (GTCs). Typically, the flows over most transmission facilities are constrained by thermal limitations because increased flows raise the temperature of the facilities. GTCs are not thermal constraints but are used to limit overall flows over a given path to maintain the stability of the system. They are harder to manage than thermal constraints, and their limits are sometimes not well-known prior the operating timeframe. This can result in divergence between market outcomes and reliability needs.

GTCs have increased significantly over the last few years with the expansion of inverter-based generation. The PUCT rulemaking to implement Senate Bill 1281 is intended to improve economic transmission planning criteria.[27] For example, the rule establishes a congestion cost savings test for evaluating economic transmission projects and requires the PUCT to consider historical load, forecasted load growth, and additional load seeking interconnection when evaluating the need for transmission projects.[28] ERCOT has been working to incorporate those directives into protocol revisions. These changes should help address the proliferation of GTCs by allowing approval of transmission projects beyond those that primarily focus on reliability.

System Inertia. Proliferation of inverter-based generation has also raised concerns on maintaining sufficient system inertia. System inertia is needed to maintain frequency within acceptable bounds when large generators, loads, or large direct current ties (DC tie) trip offline. Inertia is provided by the spinning mass of generators that are synchronously connected to the

27 *Review of Chapter 25.101*, Project No. 53403, Order Adopting Amendments to 16 TAC 25.101 as Approved at the November 30, 2022, Open Meeting (Dec. 7, 2022).
28 *See* 16 TAC § 25.101.

grid. Typically, inverter-based resources do not provide inertia. However, with modern power electronics control systems, "synthetic" inertia is possible from inverter-based resources or even loads. ERCOT has studied inertia previously and has procedures in place to ensure sufficient inertia is maintained. However, as an increasing share of the load is served by wind resources, solar resources, and ESRs, system inertia will continue to fall. This may lead to a need to supplement the markets to compensate resources for providing inertia.

Voltage support. A final challenge associated with the rapid increase in inverter-based generators is voltage support. A noteworthy example of this issue was the Odessa disturbance event on June 4, 2022, which resulted in a loss of 1.7 GW of intermittent renewable resources and a system frequency decline to 59.706 hertz (Hz).[29] Since that event, there have been multiple stakeholder discussions on tightening interconnection requirements and instituting more stringent voltage ride-through rules in order to prevent repeat large-scale resource trips in the future. One example of such a rule is ERCOT's proposed NOGRR 245, which would impose revised voltage ride-through standards on both new and existing inverter-based resources.[30]

Similar discussions and standards development have also been undertaken by NERC based on the Odessa event.[31] Additionally, ERCOT has noted instances where intermittent renewable resources have oscillated with unstable reactive power control at low output and has approved a rule change on intermittent renewable resource reactive capability.[32]

2. Energy Storage Resources

The challenges related to ESRs are very different than those presented by intermittent resources described above. ESRs do not increase supply uncertainties the way that intermittent resources do; they actually help mitigate those uncertainties. However, they have unique operational characteristics and limitations that ERCOTs' markets and software are not designed to fully optimize.

Therefore, it will be important for ERCOT to improve its modeling of ESRs to enable these resources to offer their full value to grid reliability and the market. In the current "dual model" or "combo model," the load and generation sides of an ESR are modeled as separate devices. The dual model fits within ERCOT's existing software capabilities, but this type of model has significant limitations. These limitations include the inability to incorporate the SOC of the ESRs in market clearing and difficulties measuring basepoint deviations of these resources.

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29 https://www.ercot.com/files/docs/2022/11/10/Odessa%20Disturbance%202_JuneMeeting.pdf.

30 NOGRR 245, *Inverter-Based Resource (IBR) Ride-Through Requirements*, available at: https://www.ercot.com/mktrules/issues/NOGRR245.

31 https://www.nerc.com/comm/RSTC/IRPS/2022_Odessa_Disturbance_Webinar.pdf.

32 https://www.ercot.com/mktrules/issues/NPRR1138.

ERCOT has made substantial progress toward modeling ESRs as a single device with the approval of the following Nodal Protocol Revisions (NPRR):

- NPRR 989 – BESTF-1 Energy Storage Resource Technical Requirements
- NPRR 1002 – BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions
- NPRR 1026 – BESTF-7 Self-Limiting Facilities

ERCOT restarted its effort to implement these changes in the RTC+B task force. Even with these improvements, additional changes are needed to fully model and optimize ESRs and better reflect ESR performance attributes in markets. Subsection C discusses these enhancements.

3. Unregistered Distributed Resources

ERCOT is also addressing issues related to unregistered distributed resources. Currently, there are approximately 2,600 MW of unregistered DGRs in ERCOT, and an unknown number of potential CLRs that are unregistered.[33] The capacity from this class of resource in ERCOT is continuing to increase. As such, ERCOT is actively grappling with visibility and uncertainty around unregistered DGRs. These resources are generally located on the distribution system and behind the customer's meter, and there are challenges associated with modeling their location, behavior, and market participation. The challenges presented by unregistered DGRs include:

- Operational visibility: The location and output of unregistered DGRs can be uncertain, so they may not be accurately represented in the real-time market. This can lead to potential challenges in managing network congestion and balancing the system.
- Operational control: Unregistered DGRs are not dispatchable by ERCOT on a five-minute basis.
- Economic incentives: To the extent that unregistered DGRs are affected by retail programs or rates, the resources may have inefficient operating incentives or inefficient co-location schemes. This is particularly true for any costs allocated on a load-ratio share basis, such as ancillary service and transmission cost allocations.

C. Key Market Design Changes

As the challenges presented by these new types of resources continue to grow, it will be essential for the markets to evolve to meet these challenges. This evolution will ensure that prices remain efficient, that all market participants face incentives that are well-aligned with the reliability needs of the system, and that ERCOT operators are not compelled to increasingly rely on out-of-market actions to maintain reliability.

33 Unregistered DG Installed Capacity Quarterly Report, available at: https://www.ercot.com/services/rq/re/dgresource.

The most important aspect of the market for addressing the uncertainties and resulting transitory market tightness is efficient shortage pricing. ERCOT has strong shortage pricing in place that provides adequate incentives for key resources to be available and perform when needed to maintain reliability. The most important improvements for ERCOT to make to address the future challenges described above are the implementation of:

- Real-time co-optimization (underway);
- A new uncertainty reserve product (being implemented as DRRS), along with a restructuring of the existing reserve products;
- Real-time dispatch software that optimizes over multiple intervals (recommended).

We discuss these two key recommended improvements, along with other changes that would address the specific challenges outlined in the prior subsection.

1. Real-Time Co-Optimization

Real-time co-optimization allows the real-time market to jointly optimize the scheduling of resources to provide energy and ancillary services in each dispatch interval. This will allow the market to have more flexibility in scheduling resources to meet the various demands of the system. This can be critical when uncertainties arise that require rapid changes in the dispatch of ERCOT's resources, including shifting reserves to other resources on a five-minute basis. It will also allow shortage pricing to be significantly more accurate, as reserve demand curves will be included in RTC, eliminating the need to use adders to price shortages efficiently. The PUCT-approved project to implement RTC was delayed after Winter Storm Uri in 2021, but it is now active again and anticipated to be implemented in 2026.

2. Uncertainty Reserve Product

Operational uncertainties have grown as the penetration of intermittent renewable resources and load have both been growing considerably. ERCOT has responded to these uncertainties by increasing its use of the RUC process and procuring additional short-lead operating reserves. Neither of these strategies is ideal for addressing the growing uncertainties ERCOT faces.

Therefore, we have recommended that ERCOT implement a longer-term reserve product that would provide access to additional resources that can start in 2 to 4 hours or faster when uncertainties manifest that may threaten reliability (see SOM recommendation 2021-2). This type of product is now required under Public Utility Regulatory Act (PURA) SC § 39.159(d) and is referred to as the DRRS. DRRS should allow reductions in the excess procurement of faster responding reserves, while still ensuring ERCOT operators have dispatchable resources available to call on in real time to ensure the reliability of the system.

3. Multi-Interval Real-Time Market

To address several of the challenges described in the prior subsection, we recommend ERCOT implement a MIRTM that would optimize the dispatch of resources over multiple future dispatch intervals spanning an hour or more. This type of market would coordinate the commitment of resources that can start within thirty minutes, which would help anticipate and alleviate supply shortages resulting from rapid ramp periods. A multi-interval market could also more efficiently manage the SOC for ESRs, ensuring that these resources have energy available when it is most valuable to the system.

As described above, managing the sharp increases in net load will create extreme ramp needs for the remaining dispatchable resources. Although these ramp demands can be managed in a variety of ways, most would require significant manual out-of-market intervention by the operators that would likely be costly. Therefore, we believe it will be essential for ERCOT to implement a look-ahead dispatch and commitment model that will optimize:

- The dispatch of slower ramping resources that may need to begin ramping 15 to 30 minutes in advance of a sharp increase in new load;
- The intra-day commitment of resources that can start in 10-minutes to 2 hours; and
- The utilization of ESRs, DGRs, and resources with energy limitations. This includes accounting for ESRs' SOC in the dispatch optimization.

Optimizing the commitment and dispatch of resources over a much longer timeframe than 5 minutes will substantially reduce the costs of managing net load fluctuations and reduce the uplift costs that could otherwise be considerable. As the penetration of intermittent resources, DGRs, and ESRs increases, these benefits will increase, and the look-ahead dispatch will be increasingly critical for meeting the reliability needs of the system.

ERCOT and stakeholders evaluated a MIRTM in 2016, and at the time of the study, they found that the benefits of an MIRTM were insufficient to justify the implementation costs.[34] As Figure 1 shows, the supply portfolio has changed substantially since that time. We believe a MIRTM is highly and will be increasingly essential as intermittent resources and ESRs continue to expand. Therefore, we recommend that implementation of a MIRTM, as discussed in SOM Recommendation 2022-1.

4. Other Improvements

Improved Voltage Support. As voltage issues become more prevalent, it may be efficient to implement a voltage support service that would incentivize improved reactive capability from

[34] *See PUCT Review of Real-Time Co-Optimization in the ERCOT Region,* Project No. 41837, ERCOT Report on the Multi-Interval Real-Time Market Feasibility Study (Apr. 6, 2017).

inverter-based resources and proactively resolve reliability concerns arising from voltage stability issues. Phase I of the PUCT's blueprint for wholesale electric market design identified voltage support compensation as an enhancement to the market design that will be developed.[35] To support the PUCT's policy and design decisions regarding voltage support compensation, ERCOT filed a proposal with the PUCT identifying possible options in August 2023.[36] In February 2024, the PUCT opened a project to explore voltage support compensation options, including the options in ERCOT's proposal.[37]

Improved State of Charge Modeling for ESRs. Modeling the SOC in the Day-Ahead Market, RUC, and the real-time market will become increasingly important as ESRs become a more substantial portion of the fleet. In addition to the benefit of more efficient clearing prices, this will improve the commitments of other types of generation.

Unregistered Flexible Loads. Unregistered flexible loads (e.g., data centers and crypto-currency mines) represent an area of concern, as these resources are increasingly interconnecting behind-the-meter and are often price-responsive outside of SCED.[38] These loads should have incentives to register with ERCOT, as they have the capability to actively participate in energy and ancillary services markets.

In SOM Recommendation 2021-3, we recommend establishing a requirement for CLRs to have their own meters (rather than allowing net metering amongst unaffiliated entities) and implement nodal pricing for CLRs.

Transmission Cost Allocation. The current transmission cost allocation method (4 CP) provides incentives for large loads to behave in ways that limit their exposure to transmission cost recovery without reducing the need for new transmission investments. This results in inefficient dispatch and pricing during high load periods. We have recommended reform of this allocation to address these issues in SOM Recommendation 2015-1.

35 *Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

36 *Wholesale Electric Market Design Implementation*, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Proposal Regarding Voltage Support Compensation (Aug. 21, 2023).

37 *Voltage Support Compensation*, Project No. 56184 (pending).

38 Of the 4,479 MW of large loads that have received approval to energize, ERCOT has observed a noncoincident peak consumption of 2,587 MW.

II. Review of Real-Time Market Outcomes

The performance of the real-time market in ERCOT is essential because it:

- Coordinates the dispatch of resources to serve load and manage network flows; and
- Establishes real-time prices that efficiently reflect the marginal value of energy and ancillary services throughout ERCOT.

The first function of the real-time market facilitates reliability in ERCOT while minimizing the system's production costs. The second function, to establish efficient prices, is equally important because real-time prices provide key short-term incentives to commit resources and follow ERCOT's dispatch instructions. They also provide long-term signals that govern participants' investment and retirement decisions.

Real-time prices have implications far beyond the settlements in the real-time market. Only a small share of the power produced in ERCOT is transacted in the real-time market. However, real-time energy prices set the expectations for prices in the day-ahead market and bilateral forward markets. Real-time prices are, therefore, the principal driver of prices in these markets where most transactions occur.

In general, we have found that the real-time markets have performed well and produced prices that are competitive and efficient. Unfortunately, that was not the case in 2023. Implementation of ECRS in June 2023 created frequent artificial shortage pricing during the summer. The pricing was artificial because it occurred when the system was not close to being short of reserves or energy. We estimate that this issue roughly doubled average real-time prices from June to December 2023 and generated approximately $12.5 Billion in market costs.

These costs represent the magnitude of the inefficient price increases multiplied by the real-time load in the affected periods. Customers bore only a share of these costs, as much of the load is hedged in the short term through bilateral contracts and owned resources. However, because real-time price increases drive higher day-ahead and forward bilateral prices, customers will increasingly bear these costs if this is not addressed going forward. A detailed evaluation of this issue is provided in subsection G of this section after a broader discussion of the real-time market outcomes and performance during 2023.

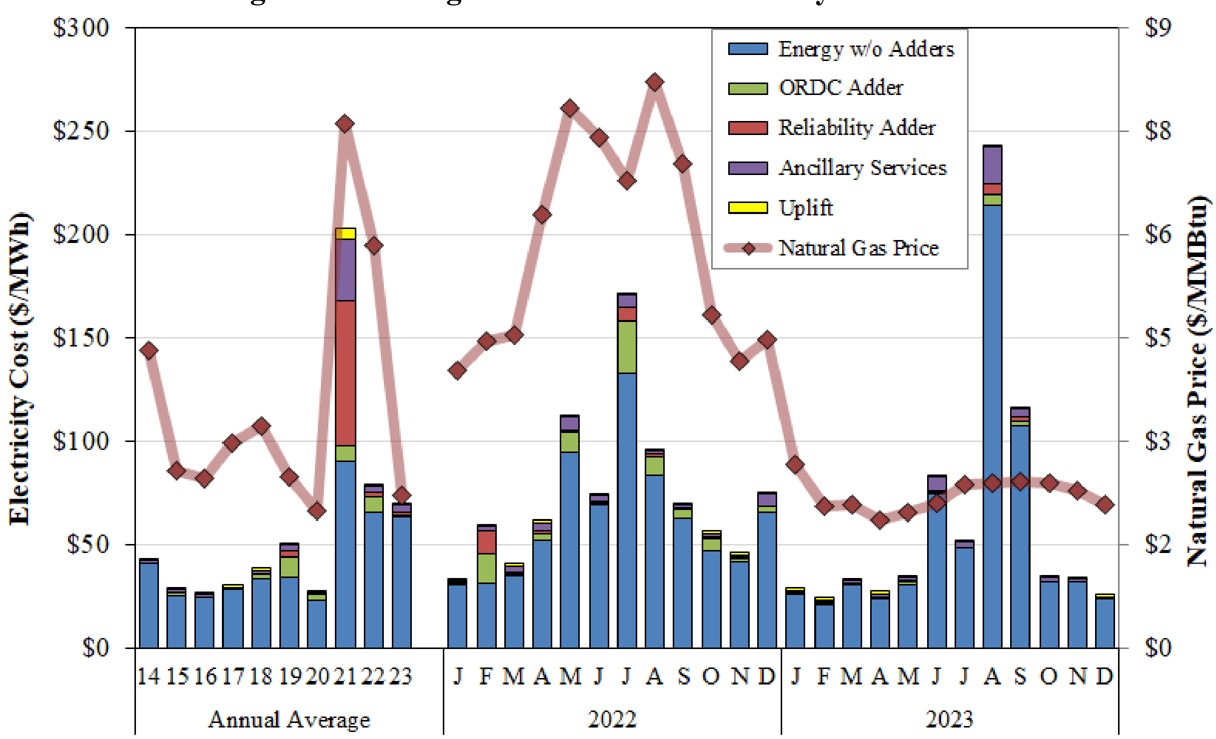
A. Real-Time Market Prices

The first analysis of the real-time market summarizes the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 2 shows the average "all-in" wholesale price of electricity for ERCOT that includes all of these costs and is a measure of the total cost of serving load in ERCOT on a per megawatt hour (MWh) basis. The all-in price metric includes the load-weighted average of the real-time market prices from all zones, as well as ancillary services costs and uplift costs divided by real-time load to show costs on a per MWh of load basis. [39] The energy prices are divided to separately show the two energy price adders:

- The Operating Reserve Demand Curve (ORDC) Adder, implemented in 2014 to allow prices reflect the increasing reliability risks when reserve begin to run short; and
- The Reliability Deployment Price Adder, implemented in 2015 to ensure prices are not inefficiently reduced when ERCOT takes out-of-market reliability actions.[40]

These adders are the primary means for ERCOT to reflect shortage pricing through its markets. Figure 2 shows the monthly load-weighted average all-in prices for electricity in ERCOT the last two years and the annual average all-in prices for the last ten years.

Figure 2: Average All-in Cost for Electricity in ERCOT



The average real-time prices fell roughly 13% to $65 per MWh in 2023. This is a much smaller decrease than one would expect given the 62% reduction in natural gas prices in 2023, which

39 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, and the ERCOT System Administrative Fee.

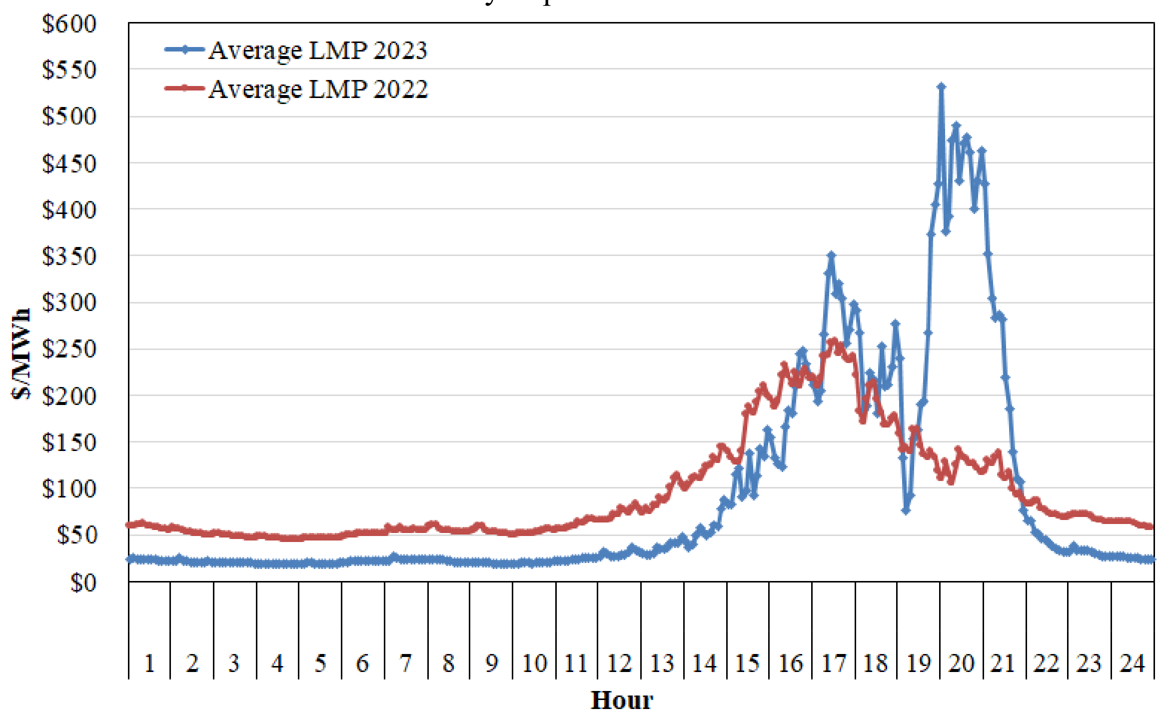
40 The reliability adder uses the dispatch software to simulate the system lambda without RUCs, deployed load capacity, or certain other reliability actions. The adder is any increase in the simulated system lambda.

averaged $2.22 per one million British thermal units (MMBtu). Correlation between gas price and energy price is expected in a well-functioning, competitive market because suppliers in a competitive market have the incentive to offer resources at their marginal costs. Fuel costs represent the largest component of marginal production costs for most generators and natural gas is the most widely used fuel in ERCOT. This correlation was not evident in 2023 because the price distortions caused by ERCOT's ECRS implementation limited the reduction in average prices that would otherwise have occurred. Other results shown in Figure 2 above include:

- Ancillary services costs were $4.21 per MWh of load in 2023, a 28.1% increase from 2022. This is discussed in more detail in Section IV.
- Uplift costs accounted for $0.90 per MWh of the all-in price in 2023, up from $0.77. Uplift costs in 2023 were almost $400 million, a 16.5% increase from 2022. This was due in part to the increase in the Real-Time Revenue Neutrality Allocation (RENA).
  - The increase in RENA of $109 million or $0.24 per MWh in 2023 can be attributed to differences between the load distribution factors (LDF) used and transmission network modeling inconsistencies in day-ahead and real-time.
  - There are many other costs included as uplift, but the largest are the ERCOT System Administrative Fee ($247 million or $0.55 per MWh) and Emergency Response Service (ERS) program costs ($44 million or $0.39 per MWh).

Because real-time energy prices can vary by time of day, Figure 3 shows the load-weighted average prices in each 5-minute interval during the summer when prices are typically the highest.

Figure 3: Prices by Time of Day
May-September 2023



To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 4 shows the frequency of real-time energy price spikes in 2023. For this analysis, price spikes are defined as 15-minute intervals when the load-weighted average energy price is greater than 18 MMBtu per MWh (i.e., an implied heat rate of 18) multiplied by the prevailing fuel index price (FIP) which produces an energy price spike threshold in $/MWh. Prices at this level typically exceed the marginal costs of virtually all on-line generators and are likely times when generators are recovering some fixed costs. The figure also shows the portion of the average energy price in the month that is attributable to the price spikes.

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

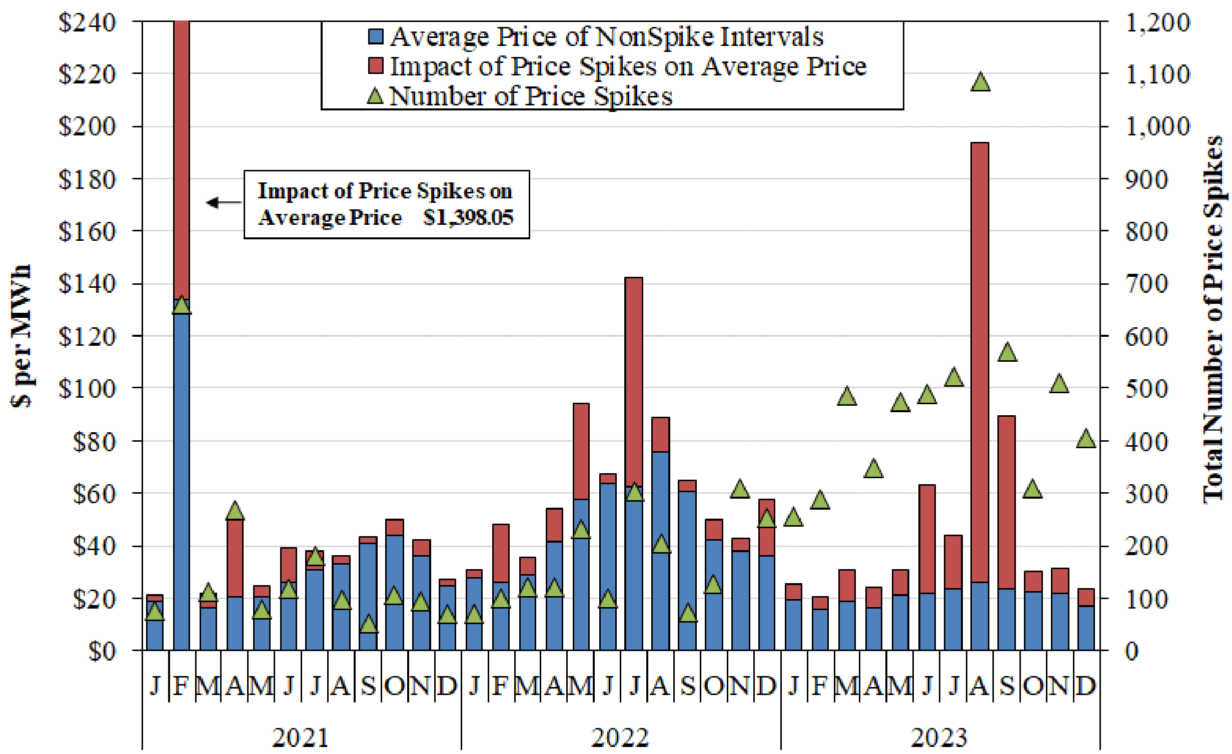


Figure 4 shows that price spikes were much more frequent and impactful in 2023 than in 2022. The effects of price spikes accounted for 46% of the total average price in 2023. This trend was especially pronounced during the summer months, with months prior to the summer experiencing price spikes during the solar ramp off hours. A small share of these price spikes in the summer can be attributed to high peak loads, resulting in price spikes that reflect legitimate shortage pricing under the ORDC. Unfortunately, most of the price spikes reflected artificial shortages caused by ERCOTs ECRS implementation, which is discussed below in subsection G.

B. Zonal Average Energy Prices in 2023

Energy prices vary across the ERCOT region because of congestion that is incurred as power is delivered over the network. Table 1 provides the annual load-weighted average price for each zone as well as the annual average natural gas price for the past eight years.

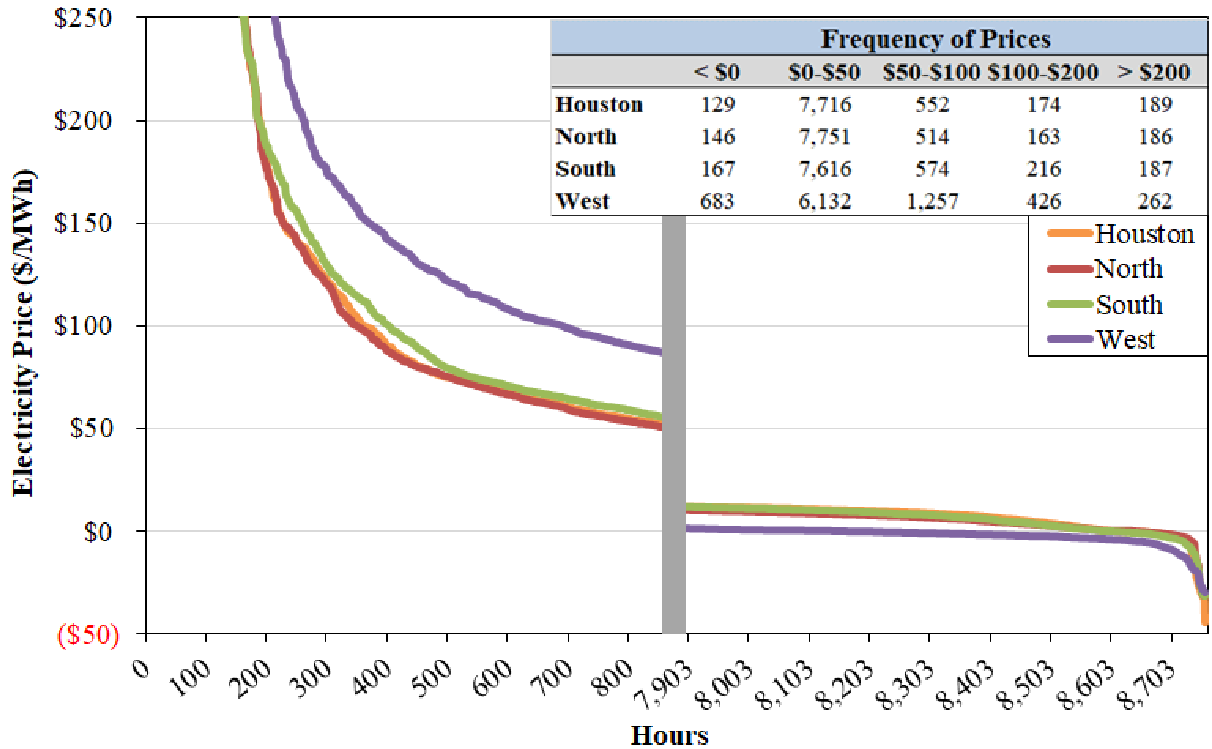
Table 1: Average Annual Real-Time Energy Market Prices by Zone

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Prices ($/MWh)									
ERCOT	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$74.92**	**$65.13**
Houston	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$81.07	$64.72
North	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$75.52	$68.55
South	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$72.96	$63.34
West	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$65.53	$61.62
Natural Gas Prices ($/MMBtu)									
ERCOT	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84	$2.22

Table 1 shows that the relative average prices of the four zones were different in 2023 than in previous years. The North zone had the highest prices, primarily due to high demand in North Texas and transmission constraints limiting the transfer of generation from South Texas to North Texas. A more detailed discussion of transmission constraints that influenced zonal energy prices is provided in Section V.

To examine the variation in zonal real-time energy prices more closely, Figure 5 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2023 for the four zones.

Figure 5: Zonal Real-Time Price Duration Curves



Frequency of Prices	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	129	7,716	552	174	189
North	146	7,751	514	163	186
South	167	7,616	574	216	187
West	683	6,132	1,257	426	262

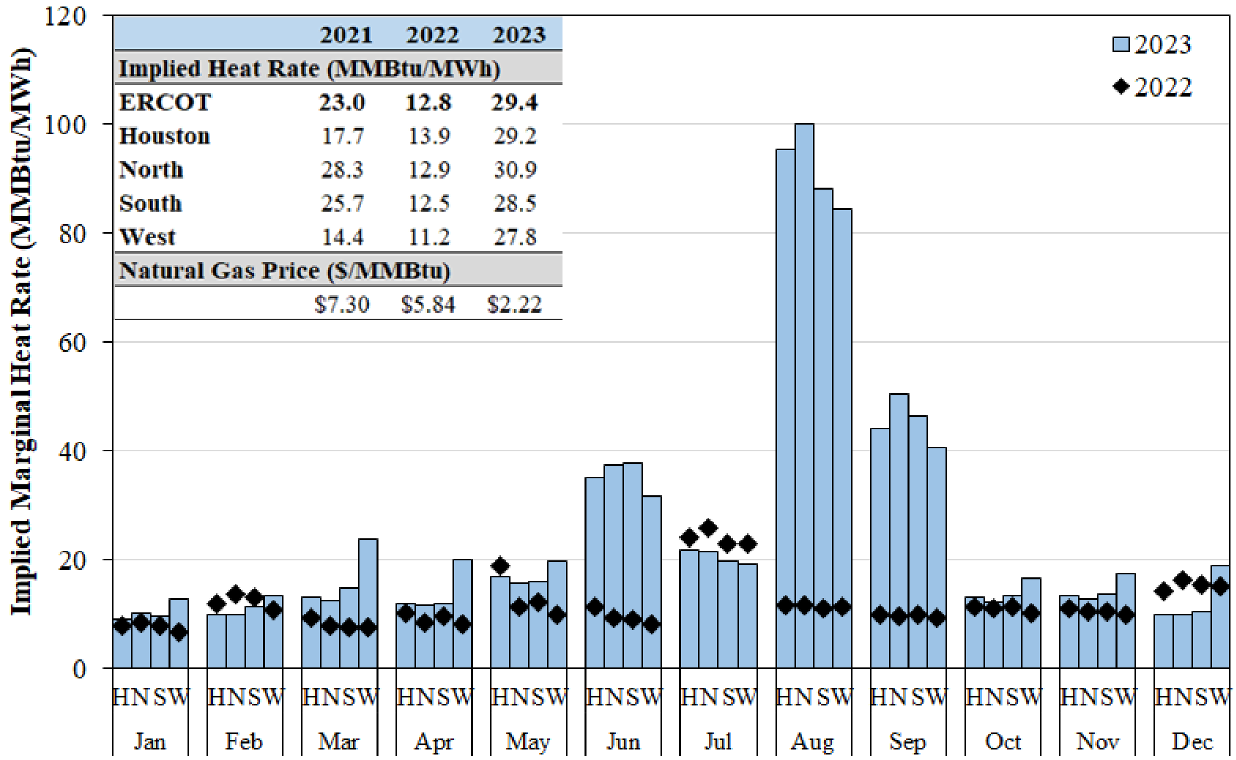
The lowest prices in the West zone were much lower than the lowest prices in the other zones because of congestion caused by high wind and solar output, particularly when load was low.

These congestion patterns caused the West zone to experience a much higher frequency of negative prices than any of the other zones. The West zone also exhibited much higher prices than the highest prices in the other zones, which was caused by local constraints limiting the flow of electricity to the increasing loads in the West, typically oil and gas loads. This congestion typically occurred when the load was high and wind and solar energy output was low.

C. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven largely by changes in natural gas prices, they are also influenced by other factors. To summarize the changes in energy price that were related to these other factors, we produce an "implied marginal heat rate" that is calculated by dividing the real-time energy price by the natural gas price. Figure 6 shows the implied marginal heat rates monthly in each of the ERCOT zones. For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A6 and Table A3 in the Appendix.

Figure 6: Monthly Average Implied Heat Rates



	2021	2022	2023
Implied Heat Rate (MMBtu/MWh)			
ERCOT	**23.0**	**12.8**	**29.4**
Houston	17.7	13.9	29.2
North	28.3	12.9	30.9
South	25.7	12.5	28.5
West	14.4	11.2	27.8
Natural Gas Price ($/MMBtu)			
	$7.30	$5.84	$2.22

Figure 6 shows that the implied heat rate varied between zones in some months when congestion was substantial. The most notable change in 2023 was the sharp increase in implied heat rate in June, August, and September. These increases were almost entirely due to the artificial shortages caused by the implementation of ECRS, which is discussed in detail in subsection G.

Figure 7 shows how the implied heat rate has varied by load level over the past three years.

Figure 7: Implied Heat Rate and Load Relationship

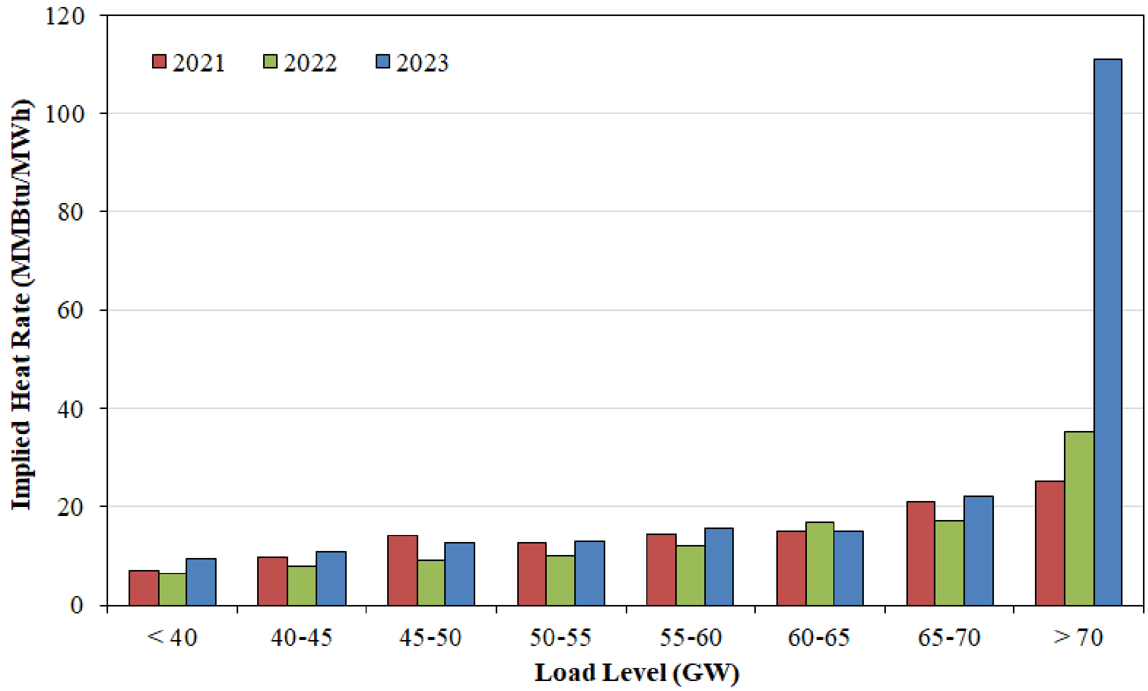


Figure 7 shows that the implied heat rate continued to be positively correlated with load levels in 2023, which is expected since prices tend to rise with demand. Most of the effects of the artificial shortages caused by sequestering the ECRS market occurred in the highest load hours when such withholding is most likely to cause the real-time dispatch model to perceive a shortage. We recommend changes in this report to address these ECRS concerns going forward.

D. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2023 and 2022. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 8 provides the average aggregated generator offer stacks for the year in all hours, the peak load hour, and peak net load hour of the year. This figure shows that:

- 40% of the capacity was not dispatchable because it is below generators' Low Sustained Limit (LSL) and will produce at any price.
- 30% of the capacity in 2023 was offered below zero from wind, solar, and other resources. These resources have the incentive to produce when prices are negative because most of them receive production tax credits.
- 18% of the capacity was priced at levels between zero and a value equal to 10 times the daily natural gas price (known as the FIP). This price range represents the incremental fuel price for the vast majority of the ERCOT generation fleet.
- Roughly 12% of the capacity was offered above this level in 2023.

Figure 8: Aggregated Generation Offer Stack – Annual, Peak and Net Peak Load

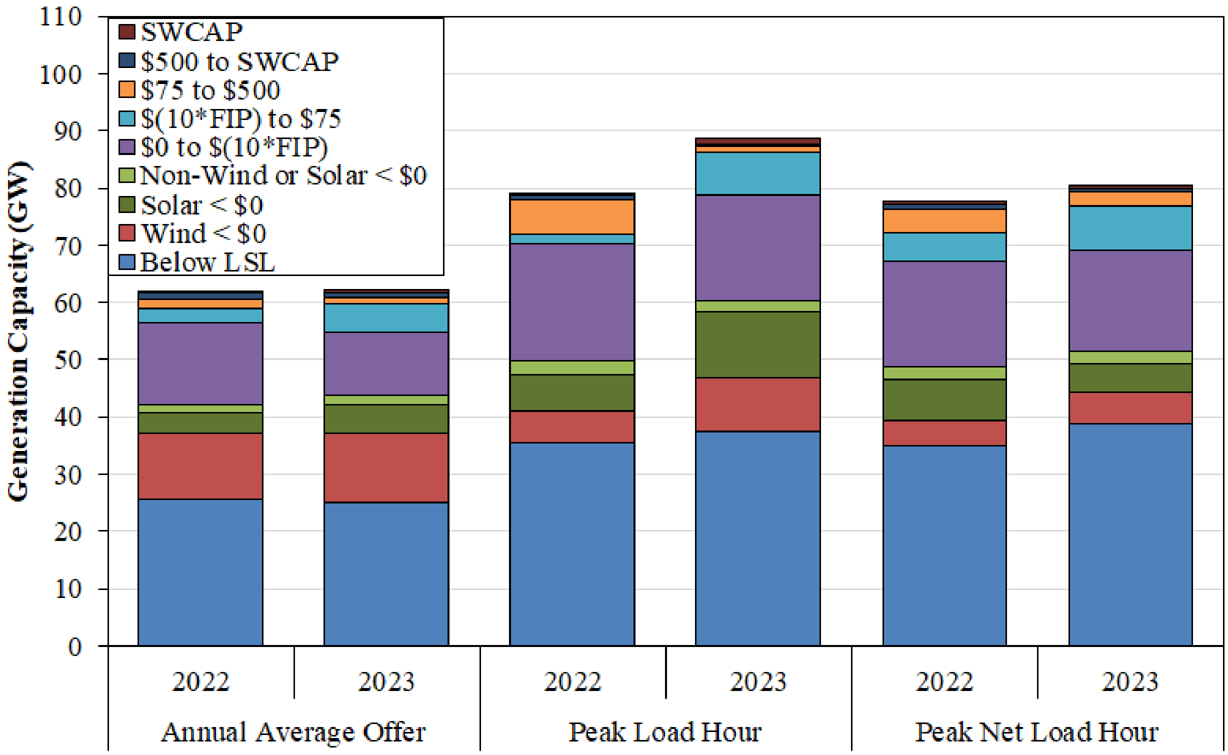


Figure 8 shows that the amount of real-time capacity offered in 2023 increased roughly 240 MW on average in all hours, but by 9.6 GW in the peak load hour. These increases are mainly driven by additional offers from solar generation.

E. ORDC Impacts and Prices During Shortage Conditions

The ORDC represents the reliability costs or risks of having a shortage of operating reserves. When resources are not sufficient to maintain the full reserve needs of the system, the probability of shedding load rises as operating reserve levels fall. The marginal reliability cost of the shortage is equal to the probability of losing load times the VOLL. Efficient shortage pricing occurs when the shortage cost is reflected in both operating reserves and energy prices during shortages. In ERCOT, these occur by adding the ORDC price adder to the energy and reserves prices when the system is short of reserves.

Implementation of and Adjustments to the ORDC

ERCOT implemented its ORDC in 2013, including setting VOLL at $9,000 per MWh. The ORDC places an economic value on the reserves being provided in real-time, with separate pricing for online and offline reserves. It has been modified a number of times in recent years:

- In 2019, the PUCT approved a phased process to change the ORDC and directed ERCOT to use a single blended ORDC curve.

- ERCOT also implemented a two-phase shift in the ORDC in March of 2019 and 2020, respectively, to accelerate the increase in prices toward VOLL as reserve levels fall.[41]
- In the aftermath of Winter Storm Uri, the PUCT further adjusted the ORDC on January 1, 2022.[42] This adjustment to the ORDC was significant and consistent with the PUCT's objectives to greatly strengthen incentives for generation to be available, and for suppliers to build and maintain larger quantities of dispatchable resources.
- In November of 2023, ERCOT implemented a multi-step ORDC price floor, the chosen "bridge solution" to increase the incentive to build new dispatchable generation until the Performance Credit Mechanism (PCM) can be implemented.[43] This ORDC change was intended to incentivize generators to self-commit and minimize ERCOT's out-of-market RUC.

Revenue Effects of the ORDC

The following two analyses illustrate the contributions of the ORDC adder and the RTORDPA to real-time prices. Figure 9 shows the number of hours in which the ORDC adder raised prices in each month of 2023, as well as the average price effect in these hours and all hours.

Figure 9 shows that hours in which the ORDC adder was non-zero in 2023 were half as frequent in 2023 as in 2022, and the average magnitude of the adder in 2023 (roughly $7 per MWh) was much lower than in 2022 ($37 per MWh). Together, this indicates that market conditions were substantially tighter in the peak hours in 2022 than in 2023, despite the numerous peak demand records that were set in 2023. Overall, the ORDC adder contributed just over $1 per MWh or roughly 2% of the annual average real-time energy price.

The modest levels of shortage pricing that occurred under the ORDC in 2023 underscore that the many price spikes that occurred in June, August, and September of 2023 did not reflect actual shortages, but rather were the result of the sequestering of dispatchable resources that were scheduled to provide ECRS from the real-time market.

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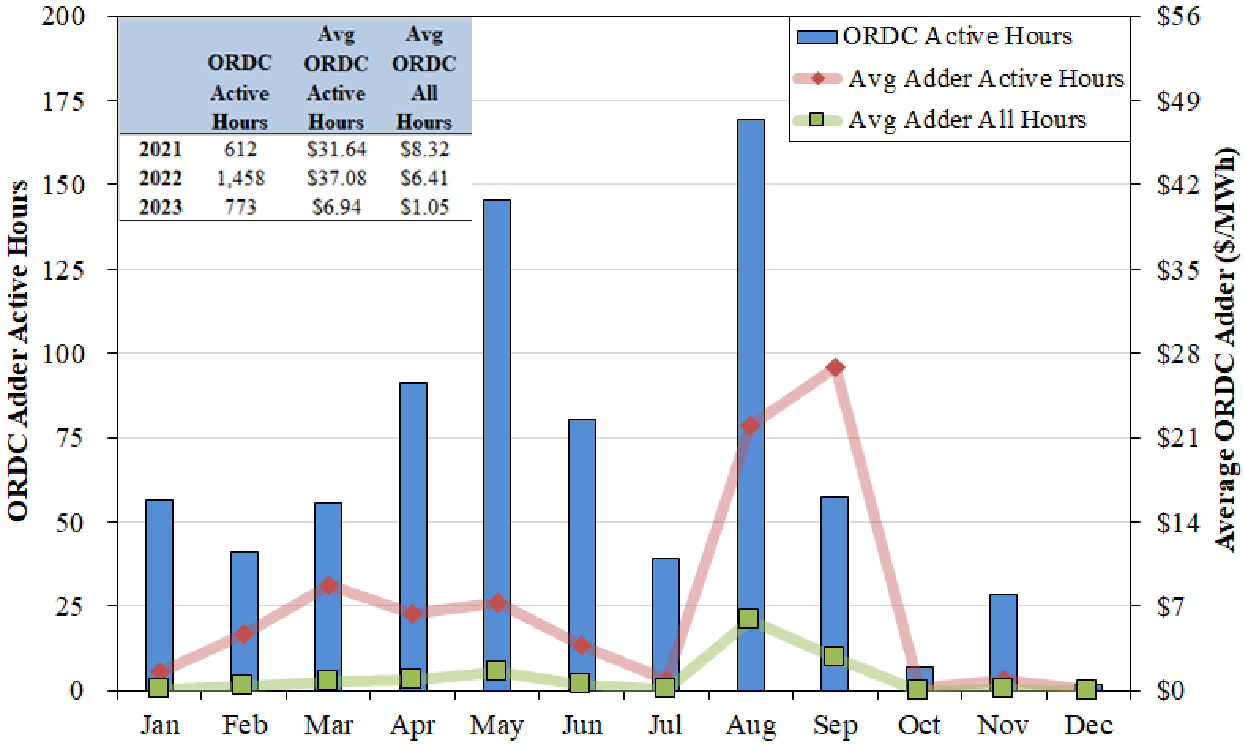
41 ERCOT implemented two standard deviation shifts of 0.25 in the Loss of Load Probability (LOLP) calculation in March of 2019 and 2020 via Other Binding Document Revision Request (OBDRR) 011, *ORDC OBD Revisions for PUCT Project No. 48551*.

42 ERCOT set the Minimum Contingency Level (MCL) to 3,000 MW and the high system-wide offer cap (HCAP) and VOLL were reduced from $9,000 per MWh to $5,000 per MWh. *See Review of Wholesale Electric Market Design*, Project No. 52373, at the December 16, 2021, open meeting. The PUCT approved the blueprint for the redesign of the wholesale electric market filed in the project on December 6, 2021, including the ORDC changes.

43 This change to the ORDC added two price floors to the ORDC, one at reserve levels below 6,500 MWs ($20 per MWh), and another between 6,500 MW and 7,000 MW ($10 per MWh). See Section I of the Appendix for more details regarding the multi-step ORDC price floor.

Figure 9: Average ORDC Adder in 2023



	ORDC Active Hours	Avg ORDC Active Hours	Avg ORDC All Hours
2021	612	$31.64	$8.32
2022	1,458	$37.08	$6.41
2023	773	$6.94	$1.05

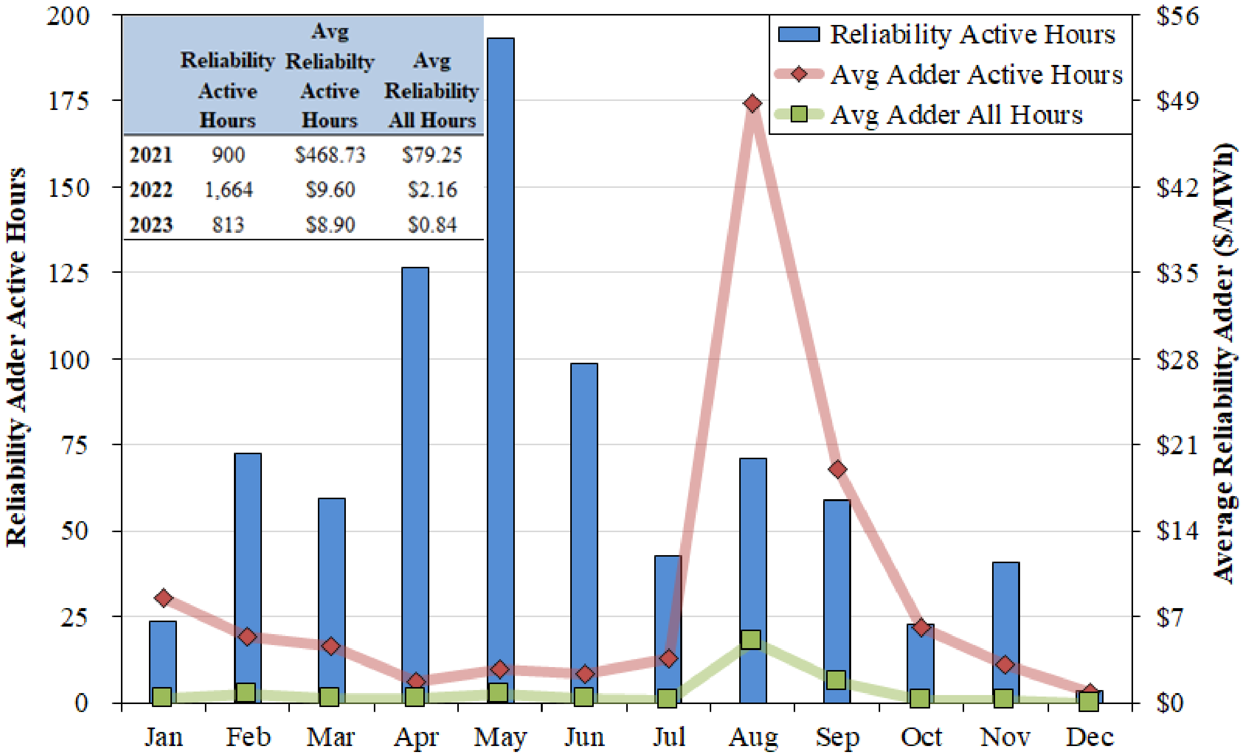
One reason that the ORDC adders fell in 2023 is that ERCOT substantially increased its procurements of operating reserves when it implemented ECRS in June 2023. These increased procurements, which do not appear aligned with the reliability needs of the system, inflated operating reserve levels, and reduced the likelihood and severity of reserve shortages. For more information on the ORDC adder, see Figure A3.

Effects of the Reliability Adder

The second adder is the reliability adder. The reliability adder is intended to mitigate the price-suppressing effects of out-of-market reliability actions taken by ERCOT, including RUCs and deployed load response. Absent this adder, prices will generally fall when these actions are taken because they increase supply or reduce demand. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during August and September. The reliability adder was non-zero for approximately 9% of the hours in 2023. ERCOT's more conservative operations raised to the reliability adder contribution to the real-time energy price.

Figure 10 shows the impacts of the reliability adder in 2023. The reliability adder was non-zero roughly half as often in 2023 than in 2022. The overall effects were only slightly lower than the ORDC adder, adding $0.84 per MWh to real-time energy prices on average during the year.

Figure 10: Average Reliability Adder in 2023



	Reliability Active Hours	Avg Reliabilty Active Hours	Avg Reliability All Hours
2021	900	$468.73	$79.25
2022	1,664	$9.60	$2.16
2023	813	$8.90	$0.84

As an energy-only market, ERCOT relies heavily on energy and ancillary services pricing to provide economic signals and guide decisions by market participants. However, the frequency and impacts of shortages can vary substantially from year-to-year. We show a summary of the shortage pricing that has occurred since 2021 in Figure A8.

F. Real-Time Price Volatility

We examine price volatility in this subsection. Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. To present a summary of price volatility, Table 2 shows the average 15-minute absolute change in the settlement point prices expressed as a percentage of annual average price for the four geographic zones over the past ten years.

Table 2: Zonal Price Variation as a Percentage of Annual Average Prices

Load Zone	2015	2016	2017	2018	2019	2020	2021	2022	2023
Houston	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%	8.1%	19.7%	35.3%
South	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%	7.7%	16.9%	33.4%
North	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%	7.4%	16.2%	35.3%
West	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%	7.7%	19.3%	37.2%

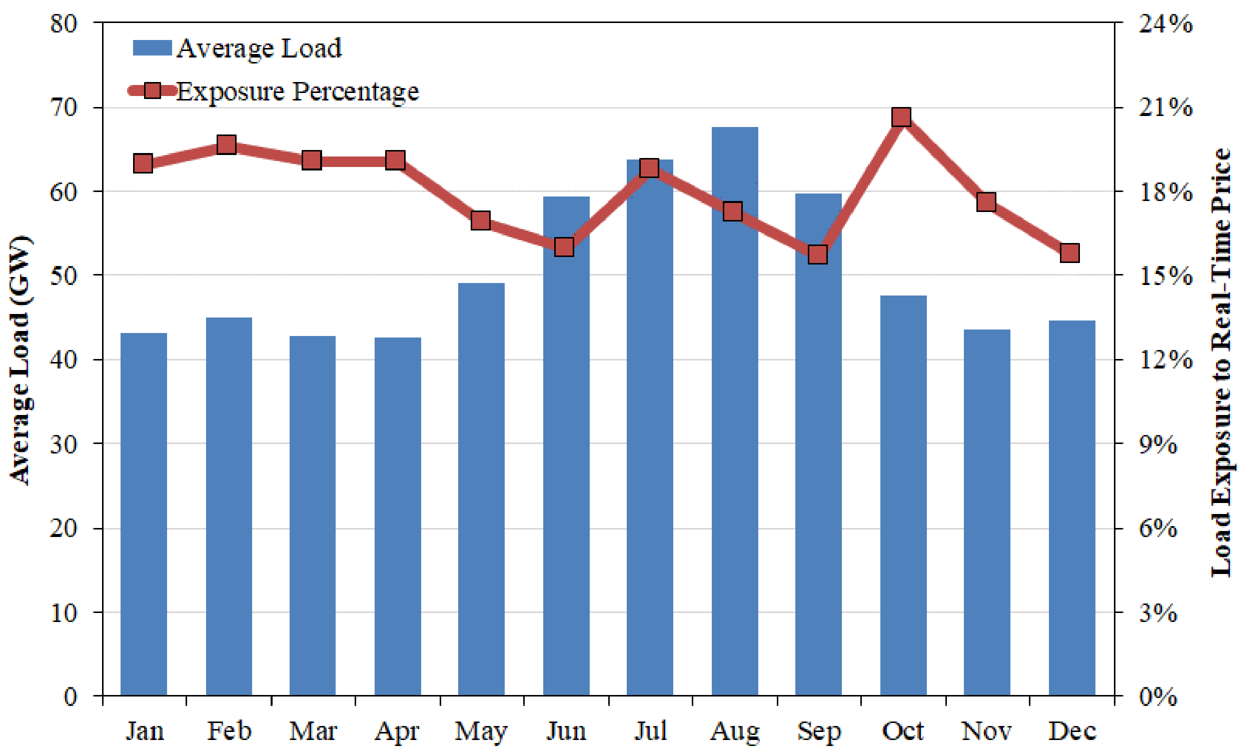
These results show that volatility was highest in the West zone in 2023 because of higher congestion affecting this area. However, the most striking result is the sharp increase in volatility in all zones in 2023 compared to all prior years shown. This is attributable to the increase in price spikes in 2023 associated with the artificial shortages that resulted from ERCOT's ECRS implementation, which is discussed in detail in subsection G below. For additional analysis of real-time price volatility, see Figure A7 and Figure A8.

G. Exposure of Load to Real-Time Prices

As an energy only market, ERCOT relies heavily on shortage pricing and associated real-time price volatility to generate the economic signals necessary to maintain adequate dispatchable resources to satisfy its reliability needs. Shortage pricing can vary dramatically from year to year. As described above, 2023 exhibited an extraordinary amount of artificial shortage pricing that was caused by ERCOT's implementation of ECRS.

Load is not fully exposed to these real-time prices to the extent that load-serving entities (LSEs) may own generation or bilaterally contract for supply ahead of the real-time market. This is good because it greatly reduces the fluctuation in the costs borne by ERCOT's customers. Unfortunately, we do not have information on the bilateral contracts held by ERCOT's LSEs. Therefore, Figure 11 below shows the percentage of load exposed to real-time energy prices in 2023 based only on settlements through the ERCOT markets.

Figure 11: Monthly Average Load Exposure



This figure shows that less than 20% of the load is exposed to real-time prices on average. This may underestimate loads' true exposure because purchases in the day-ahead market would reduce the load exposure shown in this figure. In reality, day-ahead purchases provide very little protection for load because day-ahead prices in a well-performing market will reflect the expected real-time prices. Therefore, frequent shortage pricing in the real-time market will generally result in sharp increases in day-ahead prices.

H. Impact of ECRS on Real-Time Market Prices

Implementation of ECRS in June 2023 had a profound impact on the wholesale market and is referenced throughout this report. This section provides our detailed evaluation of the ECRS product and its implementation.

1. Changes in Operating Reserve Procurements

We begin by showing the effect of ECRS on ERCOT's operating reserve procurements. Figure 12 shows the ERCOT's average 10-minute and 30-minute reserve procurements from 2020 to 2023, compared to the typical procurements by other RTOs. Prior to ECRS, ERCOT procured one class of 10-minute reserves – RRS. Because ECRS is a 10-minute reserve product, Figure 12 aggregates RRS and ECRS. ERCOT's 30-minute reserves are its non-spinning reserves.

Figure 12: Increase in Ancillary Services Procurement

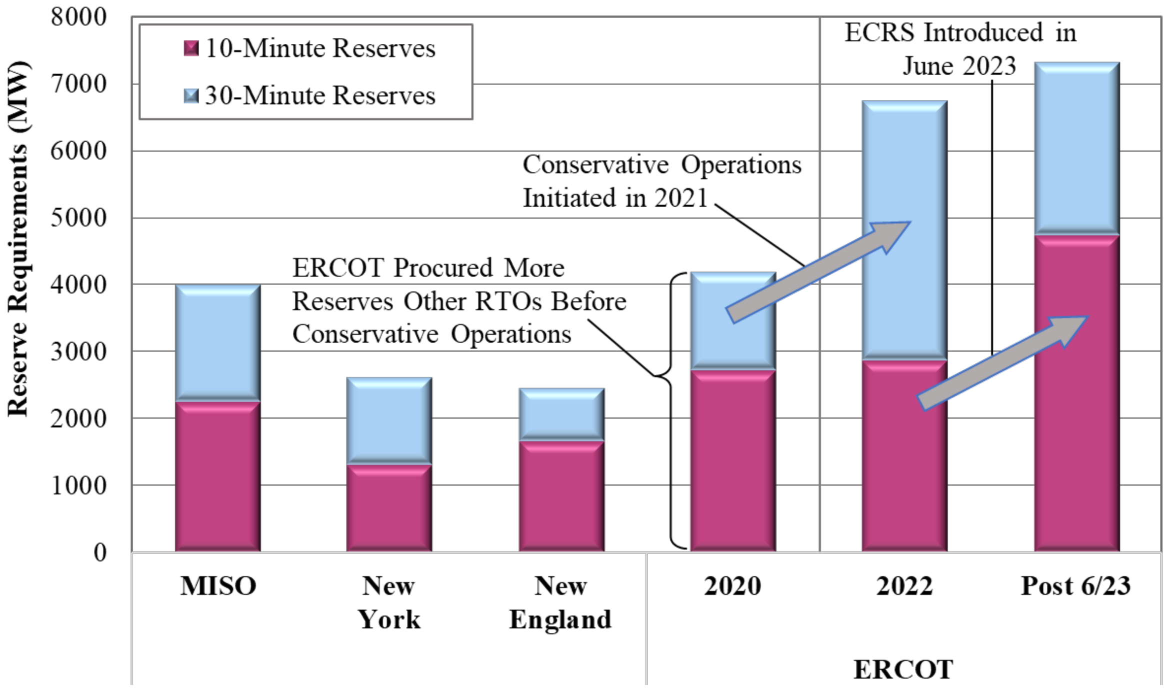


Figure 12 shows that in 2020, ERCOT procured higher levels of operating reserves than the levels procured by other RTOs, totaling an average amount of 4,000 MWs. This is understandable because ERCOT is effectively an electrical island that must have the ability to respond to system contingencies quickly and effectively. Therefore, it had procured slightly more 10-minute reserves than the other RTOs, as well as more 30-minute reserves that can be used to replenish the 10-minute reserves after they are deployed.

Figure 12 also shows the remarkable increase in operating reserve procurements in ERCOT from 2020 to 2023. After Winter Storm Uri in February 2021, ERCOT adopted a more conservative operational posture by procuring a much higher quantity of 30-minute reserves, bringing its average total procurement of operating reserves up to roughly 7,000 MWs from 4,000 MWs. This sharp increase in 30-minute reserves generated substantial increases in reserve procurement costs but did not significantly affect real-time energy prices because these 30-minute reserves are not withheld from the energy market.

However, when ERCOT implemented the ECRS product in June 2023, the reserve procurements rose again with major implications for the real-time market for energy. ERCOT adopted a procurement methodology that resulted in nearly doubling its 10-minute reserve procurements in many hours, although this was partially offset by a reduction in 30-minute reserve procurements.[44] In total, this brought ERCOT's average operating reserve procurements up to 8,000 MWs, double the procurement levels prior to Winter Storm Uri. The significance of this change is twofold. 10-minute reserves:

- Are withheld from the real-time market dispatch, so they can cause the dispatch model to struggle to meet the energy demands of the system and manage congestion; and
- Have a more limited supply than 30-minute reserves, causing more frequent scarcity in the markets for 10-minute reserves, resulting in higher prices for those reserves.

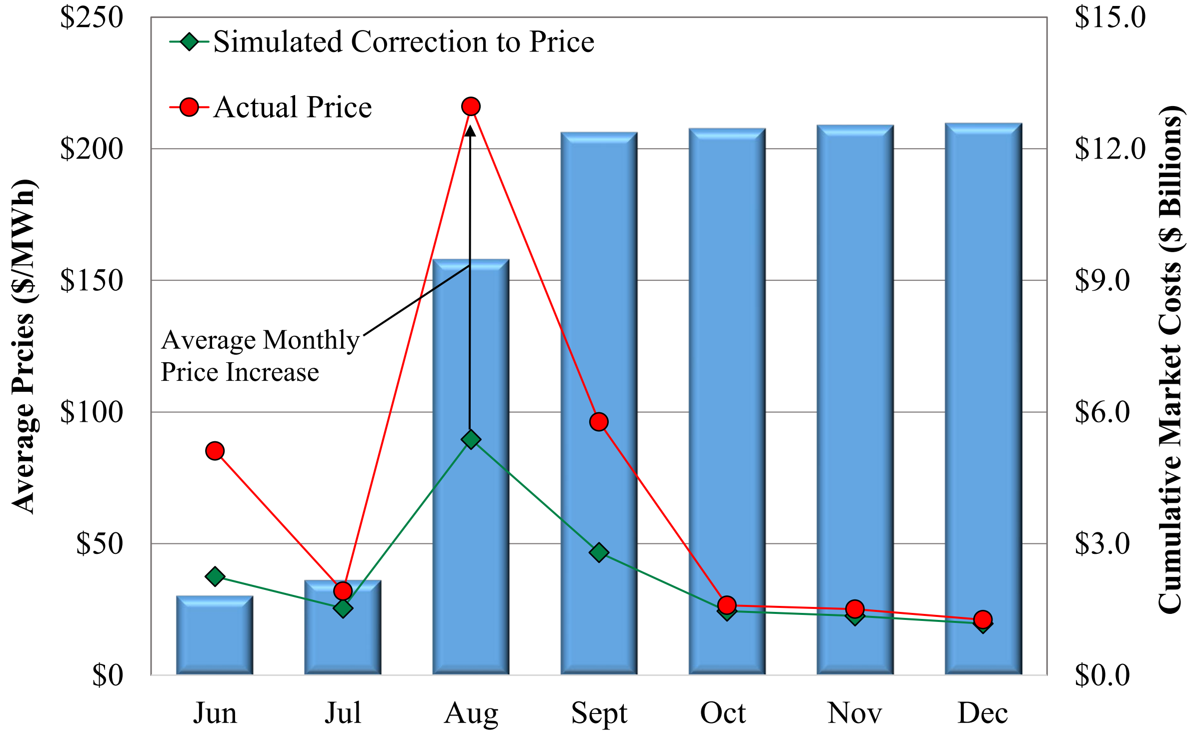
As discussed earlier in this section, shortages in ERCOT are identified and priced by applying the ORDC. However, implementation of ECRS led to shortage pricing as high as $5,000 per MWh when the system was not short of reserves under the ORDC. This was caused by the sharp increase in 10-minute reserve procurements, comprised primarily of dispatchable resources. Sequestering this quantity of dispatchable resources from the energy market can cause it to be short of the resources it needs to serve load. This occurred frequently during high-load periods in the summer of 2023, leading to apparent shortage pricing when ERCOT's shortage pricing mechanism (i.e., the ORDC adder) was not triggered.

2. Effects of ECRS on Real-Time Energy Prices

The IMM performed an analysis to estimate the impact of ECRS on real-time electricity prices. The analysis involved releasing 75% of the withheld ECRS and re-running ERCOTs real-time market software to determine what a more efficient price level would have been in each interval. The results of this analysis are shown in Figure 13.

44 *See generally* %20Determining%20Minimum%20Ancillary%20Service%20Requirements.pdf.

Figure 13: Estimated Price Effects of ECRS Procurements
June 10 – December 2023



As shown in the figure above, the increased procurement of 10-minute reserves, including ECRS, had a pronounced impact on real-time electricity prices in June, August, and September. Ultimately, these price increases:

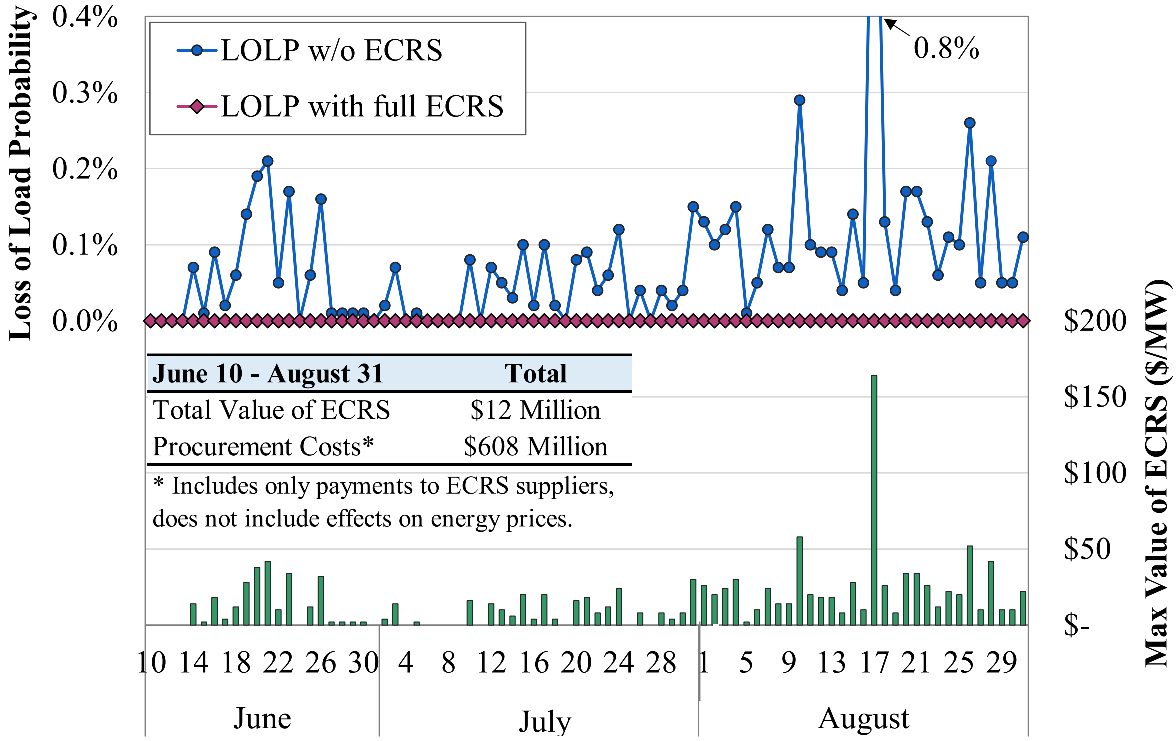
- Doubled average real-time energy prices from June through December 2023; and
- Increased real-time market costs by roughly $12 billion from June 10 through the end of November.

Customers in Texas likely bore only a fraction of these costs for the reasons discussed in subsection G. However, because real-time prices drive changes in forward prices, customers will bear an increasing share of these costs in the future if these inefficiencies are not addressed.

3. Assessment of ECRS Procurement Quantities

As described above, the adverse effects of ECRS on real-time market performance are largely related to the significant quantity of ECRS that ERCOT procured with no offsetting reduction in its responsive reserve service, its other 10-minute reserve service. Hence, we evaluated the quantity of ECRS procured by ERCOT by estimating the marginal reliability value of the ECRS procurements in each hour during summer 2023. To perform this evaluation, we used a stochastic model and ERCOT data on generation and forecast errors to quantify the LOLP assuming a) no ECRS purchases, and b) full ECRS purchases. The marginal value of ECRS was then calculated by multiplying the probabilities by an assumed VOLL of $20,000 per MW, a reasonable estimate based on the credible studies. Figure 14 shows these results.

Figure 14: Marginal Value of ECRS Procurements



This analysis shows that there were no material risks of load shedding during these summer months, despite the hot weather and high load. Modest amounts of ECRS addressed LOLPs ranging from 0 to 0.2%, producing values averaging $16 per MWh. As the procurements increased to the full value of ECRS, the marginal value of ECRS fell close to zero.

Finally, these results indicate that the total value of the ECRS procurements was $12 million, but the cost ERCOT incurred to procure ECRS was 50 times higher, at more than $600 million. This indicates that ERCOT's ECRS procurements were much higher than reliability would dictate.

4. ECRS Conclusions and Recommendation

This evaluation shows that ERCOT's implementation of ECRS has had substantial adverse impacts on market outcomes. In also shows that the ECRS procurements substantially exceeded levels that could be justified by reliability. Further, because ERCOT did not release ECRS when the real-time dispatch was short of resources, it priced energy as high as $5000 per MWh.

To address these issues, we recommend that ERCOT re-evaluate the ECRS and RRS requirements and modify the requirements to better align with the reliability risks to be addressed. To that end, we will be collaborating with ERCOT to produce an Ancillary Services study, which is expected to be published in the fall of 2024.[45] This study may allow ERCOT to improve its ancillary services methodology that sets each of its operating reserve requirements.

45 *See Review of Ancillary Services in the ERCOT Market*, Project No. 55845.

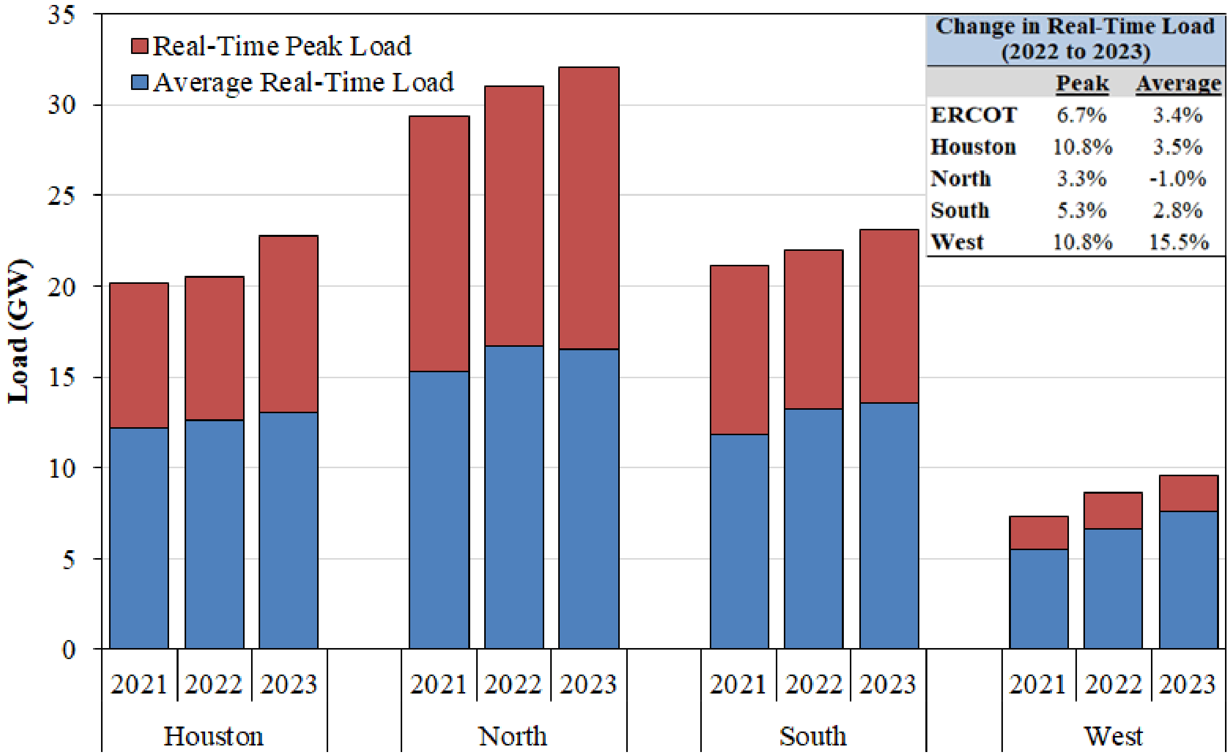
III. Demand and Supply in ERCOT

Many of the trends in market outcomes described in Section II are attributable to changes in the supply portfolio or load patterns in 2023. Therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements in this section. We include a specific analysis of the large quantity of installed wind and solar generation, along with discussion of the daily generation commitment characteristics. This section concludes with a review of the contributions from demand response resources.

A. ERCOT Load in 2023

We track the changes in average load levels from year to year to better understand the load trends, which capture changes in load over a large portion of the hours during the year. However, changes in the load during the highest-demand hours are important because they affect the probability and frequency of shortage conditions.[46] Figure 15 shows peak load and average load by geographic zone from 2021 through 2023.[47]

Figure 15: Annual Load Statistics by Zone



46 In recent years, peak net load (load minus intermittent renewable output) is a more direct cause of shortages.

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

Figure 15 shows that the total ERCOT load in 2023 increased 3.4% from 2022, which is an increase of approximately 1,670 MW on average. The West zone showed the largest increase in average real-time load in 2023 at 15.5%, continuing a pattern of significant increases seen year over year. Robust oil and natural gas production activity in the West zone has been the driver for high load growth.

ERCOT broke the all-time peak demand record 49 times during the summer of 2023, with the record all-time peak demand occurring on August 10, 2023, at 85.7 GW. Summer 2023 was drier and hotter than the prior year with an average temperature of 85.3° F, which was one half of a degree higher than in 2022. This contributed to an increase in peak demand, which is typically driven by summer conditions. Cooling degree days are a measure of weather that is highly correlated with the electricity used for air conditioning and is, therefore, highly correlated with summer load. Cooling degree days were up for all of Texas by as much as 8.5%.

Generation Capacity in ERCOT

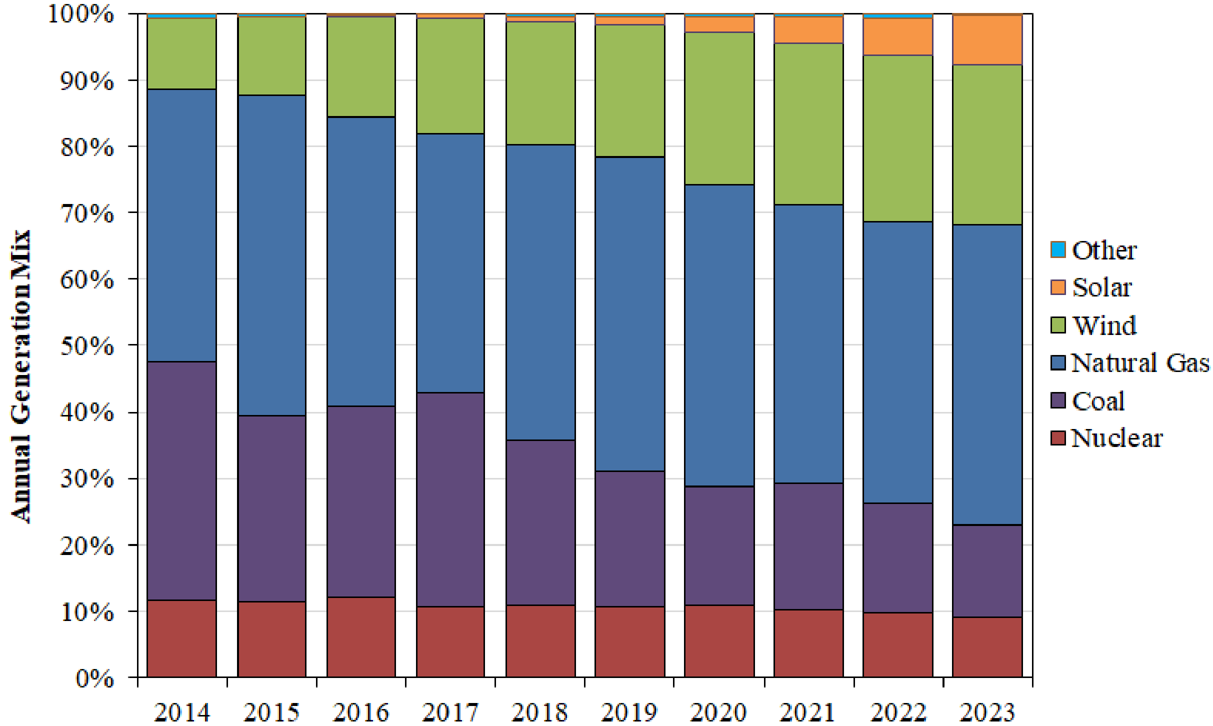
In this section we evaluate the generation portfolio in ERCOT in 2023. The distribution of capacity in the North and South zones was similar to the distribution of demand. The West zone exports more power than it consumes. The Houston zone has increasingly relied on imports from the rest of the state as load has increased in the area.

Approximately 10.5 GW of new generation resources came online in 2023. The bulk of the new capacity was renewable resources, and the remaining capacity included 10 new combustion turbines totaling 440 MW, a 530 MW combined cycle, and 1.9 GW of ESRs. The 39 new ESRs increased ERCOT's storage capacity to 4.7 GW. Roughly 1.8 GW of newly installed wind and 5.8 GW of newly installed solar capacity entered the market with an effective peak serving capability of 4.9 GW.[48] Two 420 MW coal resources retired in 2023. These changes are detailed in Section III of the Appendix, along with a review of the vintage of the ERCOT fleet.

Figure 16 shows the annual composition of the generating output in ERCOT from 2014 to 2023. This figure shows the transition of ERCOT's generation fleet away from coal-fired resources to natural gas and renewable resources. Combined cycle gas capacity was the predominant technology choice for new investment throughout the 1990s and early 2000s. However, between 2006 and 2019, wind has been the primary technology for new investment. Since 2020, substantial quantities of new solar capacity have entered the market. The 5.8 GW of utility-scale solar capacity added in 2023 was the largest amount of solar added to the ERCOT system in any year, bringing total installed capacity to nearly 19.5 GW. This capacity was particularly valuable for helping satisfy the peak summer demands in 2023.

48 The percentages of installed capacity to serve peak demand assumes availability of 29% for panhandle wind, 60% for coastal wind, 22% for other wind, and 76% for solar.

Figure 16: Annual Generation Mix in ERCOT



This figure shows:

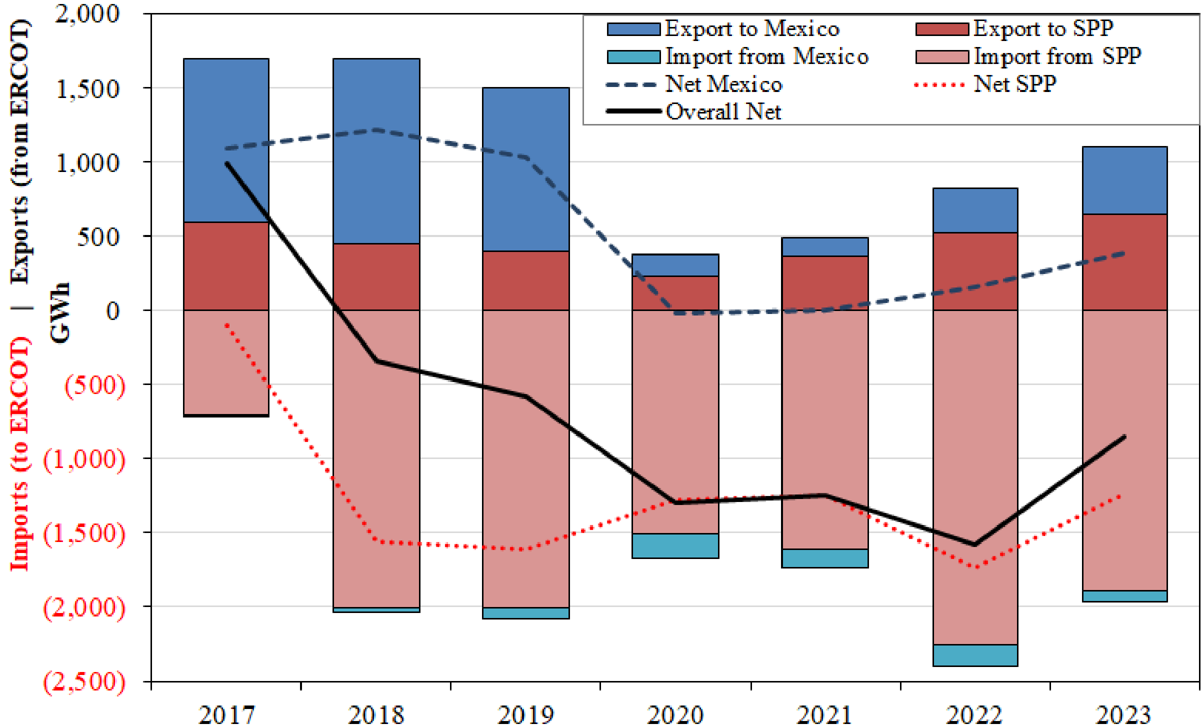
- The generation share from wind has increased every year up until 2023, falling slightly from 24.9% in 2022 to 24.3% in 2023.
- Solar increased from 5.6% of annual generation in 2022 to 7.3% in 2023.
- The share of generation from coal dropped from 16.6% in 2022 to 13.9% in 2023.
- Natural gas generation increased from 42.5% in 2022 to 45.1% in 2023 as additional resources entered and gas prices fell to historically low levels.

Figure A10 in the Appendix shows the vintage of ERCOT installed capacity. The installed capacity by technology type for each zone is shown in Figure A11 in the Appendix.

B. Imports to ERCOT

The ERCOT region is connected to other regions in North America via multiple DC ties. Two DC ties totaling 820 MW connect ERCOT with the SPP, and two DC ties totaling 400 MW connect ERCOT with Comisión Federal de Electricidad in Mexico. Transactions across the DC ties can be in either direction, into or out of ERCOT. These transactions can increase demand (exports) or increase supply (imports). Figure 17 shows the total energy transacted across the DC ties for the past several years.

Figure 17: Annual Energy Transacted Across DC Ties



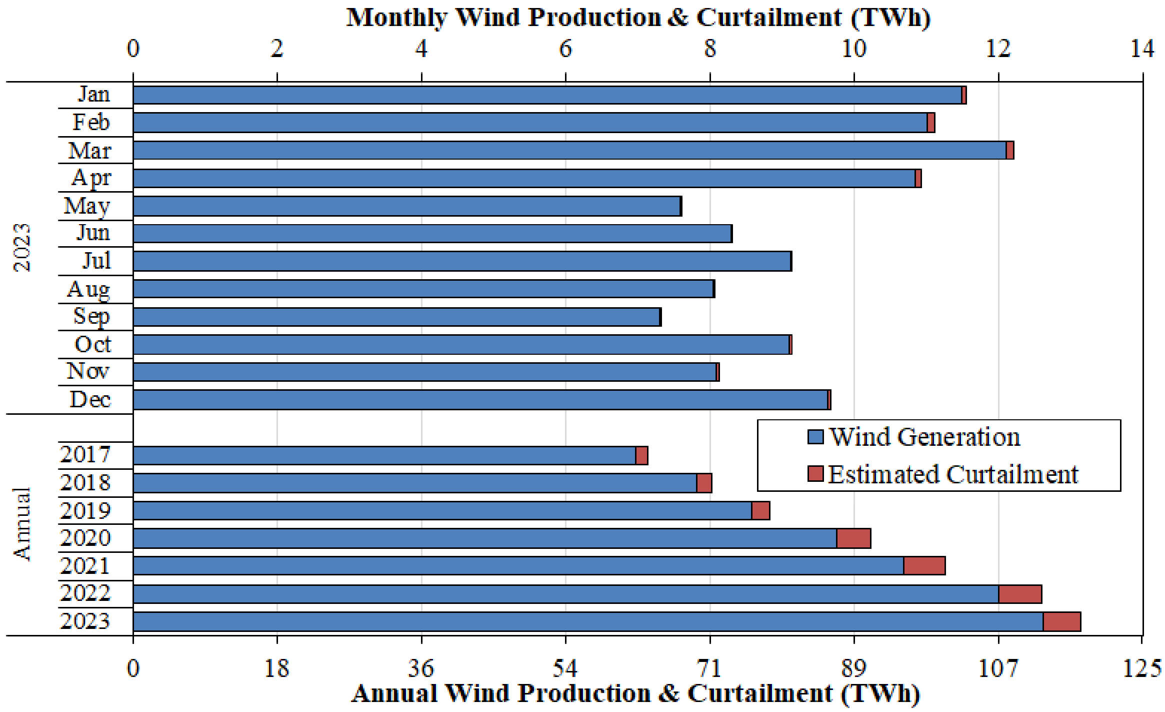
The figure shows that ERCOT remained a net importer in 2023. This trend began in 2018 because of tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. Even though ERCOT remained a net importer in 2023, ERCOT imported less in 2023 than in 2022. However, the amount of tie activity in 2023 was still higher than the activity in 2021.

C. Wind and Solar Output in ERCOT

More than 38 GW of wind capacity was installed in ERCOT as of the end of 2023. Although much of the wind generation is in the West zone, more than 9 GW of wind generation is located in the South zone, as well as 3 GW in the North zone. The value of wind in satisfying ERCOT's peak summer demand is limited by its negative correlation with load in most areas (excluding the Gulf Coast area). The highest wind output occurs during non-summer months, and mainly during off-peak hours. Wind output during high load periods will continue to be a pivotal determinant of shortages, though this may be mitigated by the increased penetration of solar and ESRs.

Figure 18 shows the monthly average output of wind resources in 2023 and annual average over the past seven years, along with the average curtailment quantities needed to manage binding transmission constraints. The figure reveals that the total production from wind resources continued to increase in 2023. The quantity of curtailments implemented to manage congestion decreased slightly from a 5% reduction in wind output in 2022 to a 4.2% reduction in 2023.

Figure 18: Wind Production and Curtailment



Solar resources, although still a smaller component of overall generation than wind today, have been growing rapidly. Figure 19 shows comparable data to Figure 18 for solar resources.

Figure 19: Solar Production and Curtailment

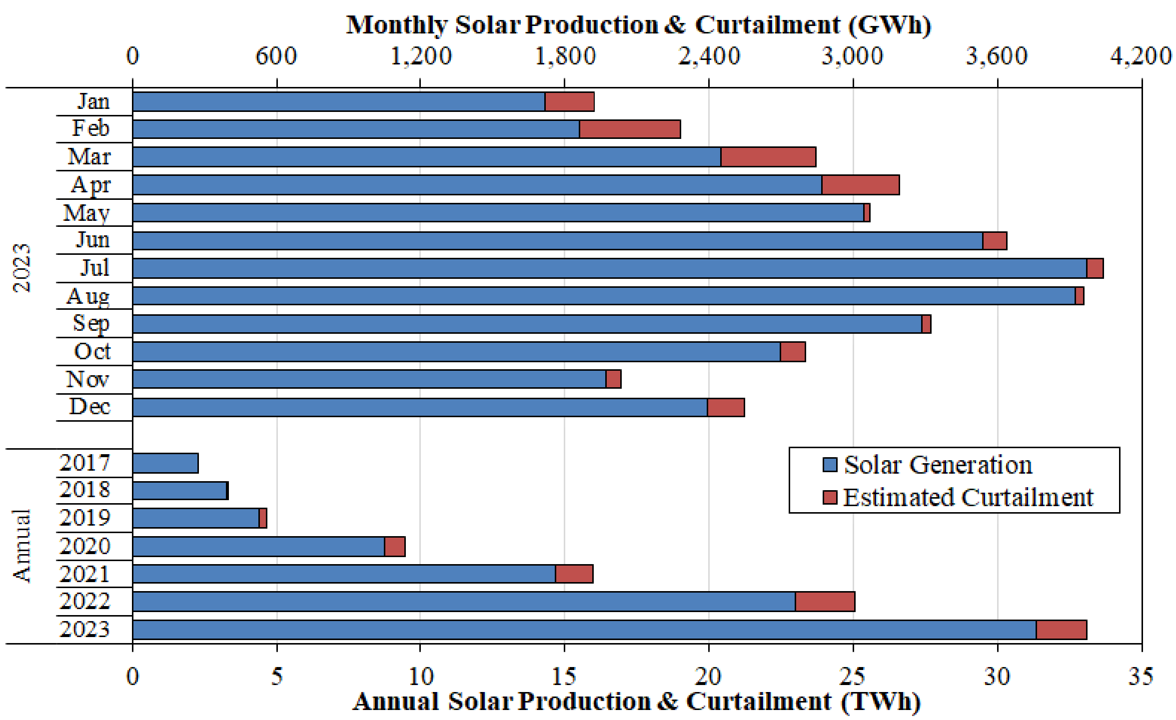


Figure 19 shows that total solar production in 2023 was approximately 33,733 GWh, and close to 3% of that production was curtailed to manage congestion caused by solar resources. Solar resources are positively correlated with summer load and produce at much higher capacity factors during summer peak hours. The average capacity factor of the solar resources during these hours was 72.1% in 2023. Hence, they provide a larger resource adequacy benefit than wind resources. For additional analysis of wind and solar output in ERCOT, see Figure A12 and Figure A13 in the Appendix.

Rising wind and solar output has important implications for other types of resources by changing the shape of the remaining load they must serve. This also has important implications for resource adequacy in ERCOT. Figure 20 shows net load in the highest and lowest hours in 2023.

Figure 20: Top and Bottom Deciles (Hours) of Net Load

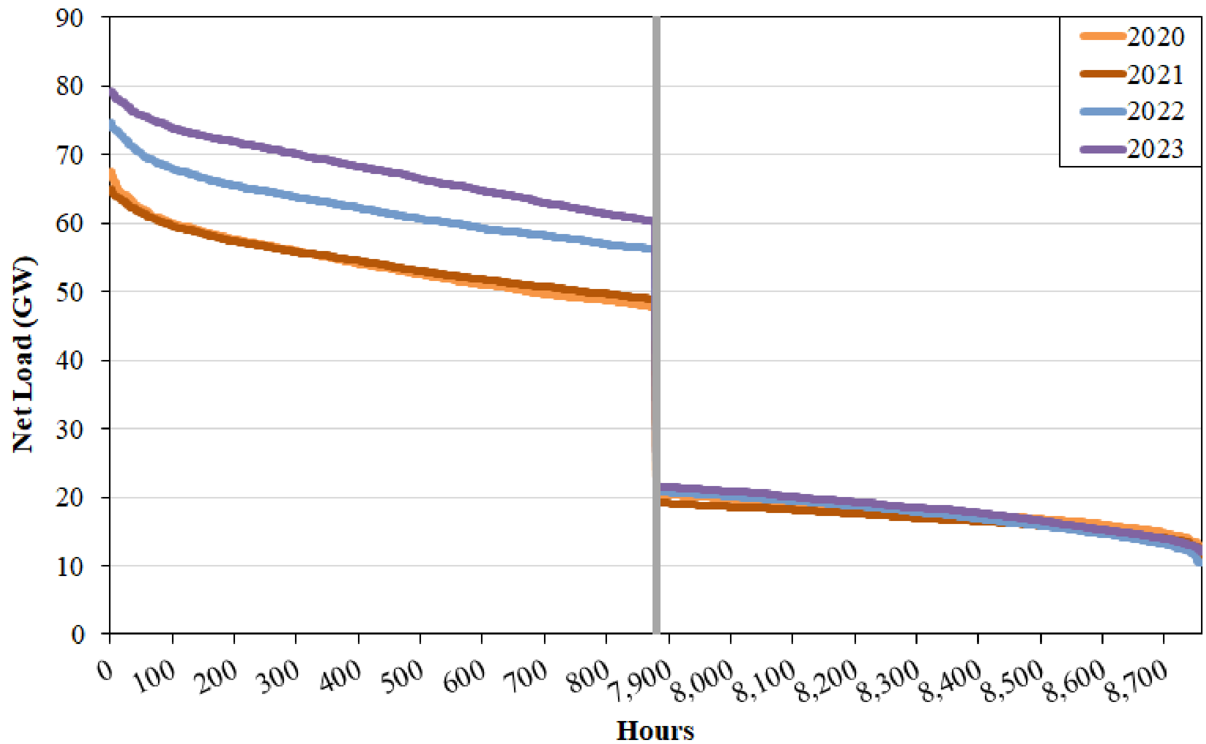


Figure 20 shows the peak net load was 79.3 GW in 2023 with the 95th percentile of peak net load at 67.6 GW. The net load values across the highest 440 net load hours reflect a 9% increase from 2022. This continues a trend of increasing load that must be served by non-renewable resources.

The minimum net load dropped from roughly 15 GW in 2022 to about 12 GW in 2023. This reflects the sizable increase in wind and solar output in off-peak hours in recent years. Although less load must be served by baseload resources in these hours (such as nuclear and coal), we believe the increases in real-time prices and net revenues discussed earlier in the report provide sufficient economic signals to retain these baseload resources.

D. Demand Response Capability

Demand response is a term that refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT for the sake of maintaining reliability or in response to economic incentives. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to generating resources.

The primary ways that loads participate in the ERCOT-administered markets are through participation in reserve markets and ERCOT-dispatched reliability programs. Outside of ERCOT's markets, demand can be affected by: (i) transmission and distribution utilities (TDUs) that administer demand response programs, and (ii) self-dispatch by load in response to energy prices, the transmission charge allocations, or public calls for conservation. We discuss loads' participation in the markets and self-dispatched load in this subsection.

1. Reserve Markets

ERCOT allows qualified load resources to offer into the day-ahead ancillary services markets. Under-frequency relay response can be a highly effective mechanism for maintaining system frequency at 60 Hz. Non-controllable load resources (NCLRs) providing responsive reserves have relay equipment that enables the load to be automatically tripped when the system frequency falls below 59.7 Hz (i.e., when load exceeds generation), or they can be manually deployed in Energy Emergency Alert (EEA) Level 2. These events rarely occur, and in some years, there are none.

As of November 2023, roughly 8,700 MW of responsive reserves can be provided by qualified NCLRs, an increase of almost 400 MW during 2023.[49] However, the responsive reserves procured from load resources was limited to a maximum of 1,867 MW per hour. In 2023, there was one manual deployment of responsive reserve service from NCLRs on September 6, 2023; 1,593 MW of NCLRs were deployed due to an EEA Level 2 event.

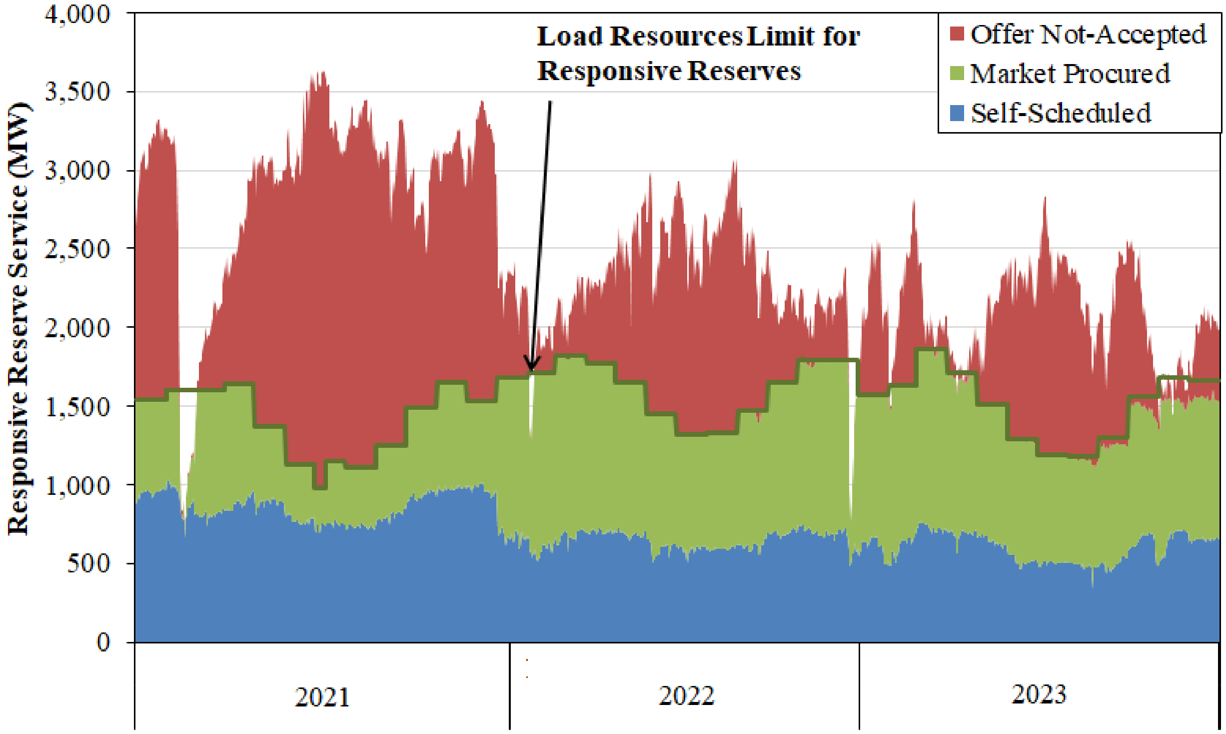
Figure 21 below shows the daily average amount of responsive reserves provided from load resources operating on under-frequency relays for the past three years.[50] This figure shows that a surplus of load resource continues to be offered as responsive reserves beyond the limit placed on load resource participation. This surplus is partly the result of the fact that the price does not

[49] *See* 2023Annual Report of Demand Response in the ERCOT Region (Dec. 2023), available at https://www.ercot.com/mp/data-products/data-product-details?id=NP3-110.

[50] Until June 1, 2018, non-controllable load resources could provide a maximum of 50% of responsive reserves. NPRR 815, *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS) Service* increased this cap to 60%, while also requiring that at least 1,390 MW of responsive reserves be provided from generation resources. Beginning with calendar year 2024, NERC standards decreased the floor to 1,185 MW. Necessarily, this increased the amount of capacity that can come from load resources.

fall to efficiently reflect the procurement limitation. SOM Recommendation 2019-2 discussed in this report would address this issue.

Figure 21: Responsive Reserves from Loads with High-Set Under Frequency Relays



NCLRs first began participating in providing non-spinning reserves in November 2022 after the implementation of NPRR 1093 and NPRR 1101. During May 2023, NCLRs provided an hourly average of 270 MW of non-spinning reserves. In June 2023, ERCOT introduced a new ancillary service, the ECRS. ECRS is available to all load resources, including NCLRs with and without under-frequency relays and CLRs. As of the end of November 2023, there were 132 resources participating in ECRS providing an hourly average of 242 MW. In 2023, there was one deployment of ECRS from NCLRs – 113 MW were deployed September 6, 2023, during the EEA Level 2 event.

2. Reliability Programs

There are two main reliability programs in which ERCOT loads can participate: i) ERS, which is administered by ERCOT, and ii) demand response programs administered by the TDUs. The ERS program is defined by a PUCT rule enacted in March 2012, which set a program budget of $50 million.[51] In August 2022, the PUCT increased the budget to $75 million. The capacity-weighted average price for ERS over the contract periods from December 2022 through

51 16 TAC § 25.507.

November 2023 ranged from $1.80 to $12.76 per MWh. This price was lower than the average price paid for both responsive reserves and non-spinning reserves in 2023.

The deployment of ERS may occur prior to the declaration of an EEA when Physical Responsive Capability (PRC) falls below 3,000 MW and is not expected to rise above that threshold within 30 minutes. ERS was deployed twice in 2023 – once on August 17 and again on September 6 when ERCOT's PRC dropped below 3,000 MW. During the August 17 event, the ERS response was approximately 35 MW, or 120% of the 29 MW obligation. For the September 6 event, the overall event performance factor was 94%.

There were roughly 260 MW of load participating in demand response programs administered by TDUs during the summer in 2023.[52] Energy efficiency and peak load reduction programs are required by statute and PUCT rule. At ERCOT's request, TDU load reduction programs may be deployed by the TDU during an EEA Level 2 event.

3. Self-dispatch

In addition to these programs, loads in ERCOT can observe system conditions and reduce consumption voluntarily. This response comes in two main forms:

- By participating in programs administered by competitive retailers or third parties to provide shared benefits of load reduction with end-use customers.
- Through voluntary actions taken to avoid the allocation of transmission costs or in response to calls for conservation.

Of these two methods, the most significant impacts are related to actions taken to avoid incurring transmission costs that are charged to certain classes of customers based on their usage at system peak. Transmission costs are allocated based on load contribution to the highest 15-minute loads during each of the four months from June through September. This allocation mechanism is routinely referred to as Four Coincident Peak (4CP).

By reducing demand during peak periods, load entities seek to reduce their share of transmission charges, which are substantial. Transmission costs have more than doubled since 2012, increasing an already significant incentive to reduce load during probable peak intervals in the summer. ERCOT estimates as much as 3,500 MW of load reduction during the 4CP intervals in 2023, higher than the 2022 estimate.[53]

52 *See* 2023Annual Report of Demand Response in the ERCOT Region (Dec. 2023), available at https://www.ercot.com/mp/data-products/data-product-details?id=NP3-110.

53 *See* ERCOT, 2023 Annual Report of Demand Response in the ERCOT Region (Jan. 2024) at 18, available at http://www.ercot.com/services/programs/load.

Voluntary load reductions to avoid transmission charges distort prices during peak demand periods because it is not an efficient response to wholesale prices. To address these distortions, we continue to recommend that modifications to ERCOT's transmission cost allocation methodology be explored (see SOM Recommendation 2015-1).

4. Demand Response and Market Pricing

When SCED clears supply offers to meet demand, it issues dispatch instructions for resources and produces the associated real-time prices. Two elements in the ERCOT market are intended to address the pricing effects of demand response in the real-time energy market. The participation of CLRs in SCED was implemented in 2014, allowing loads that can respond to 5-minute dispatch instructions to submit bids to buy electricity at certain price quantity pairs, which allows them to be dispatched down when the clearing price exceeds these bids. Second, for loads not participating in SCED (such as ERS and NCLRs), SCED has a pricing run feature that will adjust for the impact of deploying those resources. The pricing run may result in a reliability deployment price adder adjustment to the published prices.

CLRs in SCED in recent years data centers that have hundreds of servers that can be turned off on demand. The data centers use fast acting control systems to respond to frequency, similar to the governors on a conventional thermal plant, which gives them the ability to follow base points from SCED. These CLRs have over 600 MW of online capacity and can participate in responsive reserve service, regulation service, and non-spinning reserve service. As this segment grows, completing implementation of nodal pricing for CLRs will become more important and impactful.

IV. Day-Ahead Market Performance

ERCOT's day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Bids and offers can take the form of either a:

- *Three-part supply offer*. Allows a seller to reflect the unique financial and operational characteristics of a specific generation resource, such as startup costs; or an
- *Energy-only bid or offer*. Location-specific offers to sell or bid to buy energy that are not associated with a generation resource or load.

In addition to the purchase and sale of power, the day-ahead market also includes ancillary services and point-to-point (PTP) obligations. PTP obligations allow parties to hedge the incremental cost of congestion between day-ahead and real-time markets.

Except for ancillary services, the day-ahead market is a financial-only market, i.e., there are no operational obligations resulting from the day-ahead market. However, all bids and offers are cleared respecting the limitations of the transmission network. In addition to allowing participants to manage exposure to real-time prices or congestion, or arbitrage real-time prices, the day-ahead market also helps inform participants' generator commitment decisions. Hence, effective performance of the day-ahead market is essential.

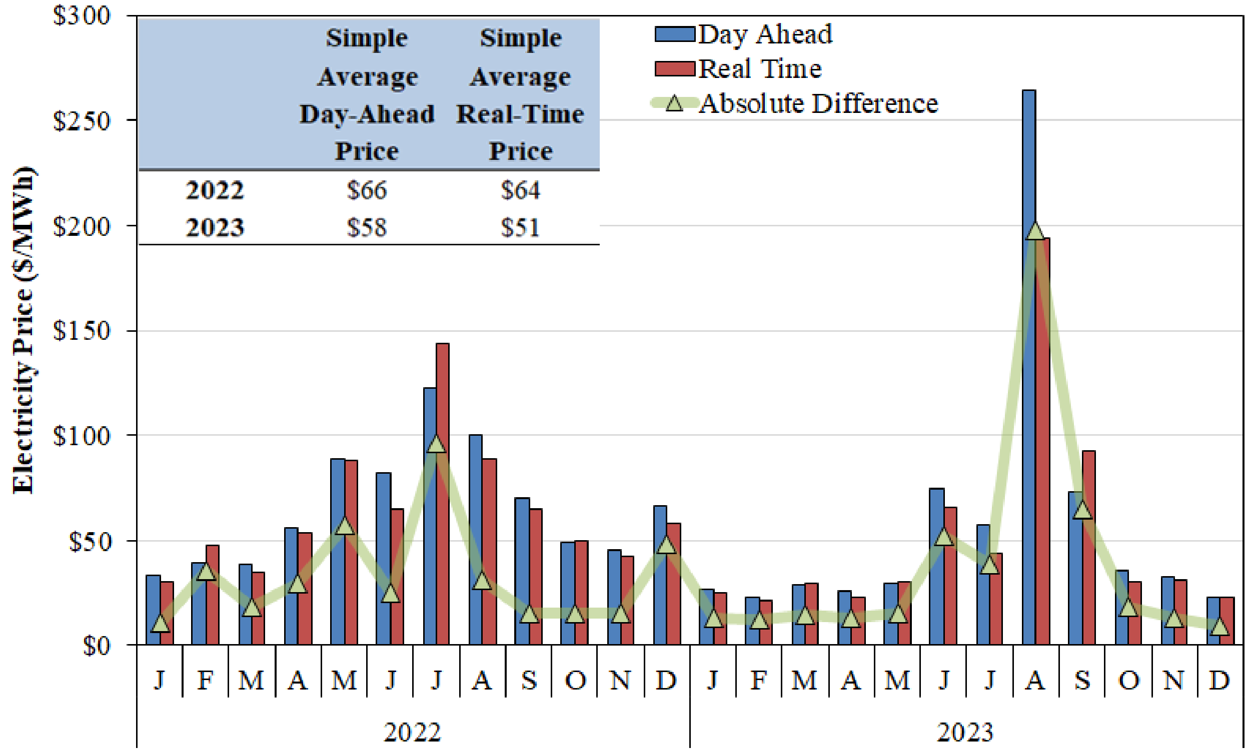
In this section, we examine day-ahead energy prices in 2023 and their convergence with real-time prices. We also review the activity in the day-ahead market, including a discussion of PTP obligations. This section concludes with a review of the day-ahead ancillary service markets.

A. Day-Ahead Energy Market Performance

The day-ahead market allows market participants to hedge real-time price risk. A primary indicator of forward market performance is the extent to which forward prices converge with spot prices over time. This price convergence will occur when: (1) there are low barriers to purchases and sales in either market; and (2) sufficient information is available to allow market participants to develop accurate expectations of the real-time prices. This allows participants to arbitrage predictable differences between day-ahead prices and real-time prices and bring about price convergence. Price convergence between the day-ahead and real-time markets is important because it leads to more efficient commitment of resources to be used in real-time.

This average price difference between day-ahead prices and real-time spot prices reveals whether persistent and predictable differences exist that participants should arbitrage over the long term. Figure 22 shows the monthly average day-ahead and real-time prices for the past two years. It also shows the average of the absolute value of the difference between the daily average day-ahead and real-time price. This measure captures the volatility of the daily price differences, which may be large even if the prices converge on average.

Figure 22: Convergence Between Day-Ahead and Real-Time Energy Prices



Price convergence was not very good overall as day-ahead prices and real-time prices simple averaged $58 and $51 per MWh in 2023, respectively.[54] Price convergence was reasonably good in all months of 2023 except June through August, when the divergence between day-ahead and real-time prices were relatively high. These divergences were largely due to the artificial real-time price spikes caused by the excessive procurements of ECRS and the artificial shortages these procurements caused, which are very difficult to predict in the day-ahead timeframe. The average absolute difference between day-ahead and real-time prices was $38.59 per MWh in 2023, which was higher than previous non-Uri years ($27.63 MWh in 2019 and $16.21 in 2018). For additional discussion, see Figure A7, Figure A8, and Figure A14 in the Appendix.

B. Day-Ahead Market Activity

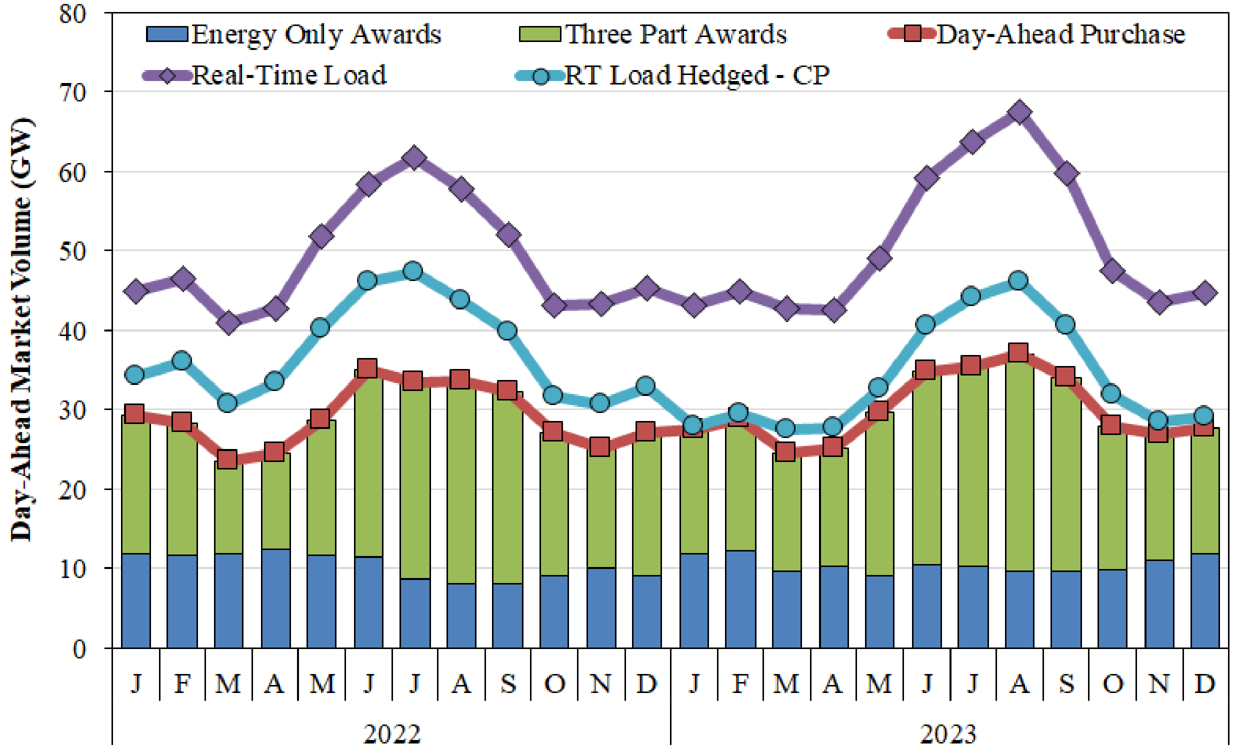
Figure 23 summarizes the day-ahead market activity by month, which includes both purchases and sales of energy, for the last two years. The additional load shown as hedged in this figure (the difference between the red day-ahead purchases and the blue real-time load hedged) is load served by PTP obligations scheduled to a load zone from other locations.

Figure 23 shows that the volume of day-ahead energy purchases provided through a combination of generator-specific offers (also known as three-part offers) and virtual energy offers was 59% of real-time load in 2023, remaining at the volume observed in 2022. Although it may appear

54 The values are simple averages, rather than load-weighted averages as shown in Figures 2 and 4 and Table 1.

that many loads are still subjecting themselves to greater risk by not locking in a day-ahead price and exposing themselves to real-time volatility, other transactions or arrangements outside the organized market are used to hedge real-time prices. In these cases, PTP obligations are often scheduled to hedge real-time congestion costs associated with those transactions.

Figure 23: Volume of Day-Ahead Market Activity by Month



PTP obligations are financial transactions purchased in the day-ahead market. Although PTP obligations do not themselves involve the direct supply of energy, a PTP obligation allows a participant to, in effect, buy the network flow from one location to another.[55] When coupled with a self-committed generating resource, the PTP obligation allows a participant to serve its load while avoiding the associated real-time exposure. PTP obligations are also scheduled by financial participants seeking to arbitrage locational congestion differences between the day-ahead and real-time markets.

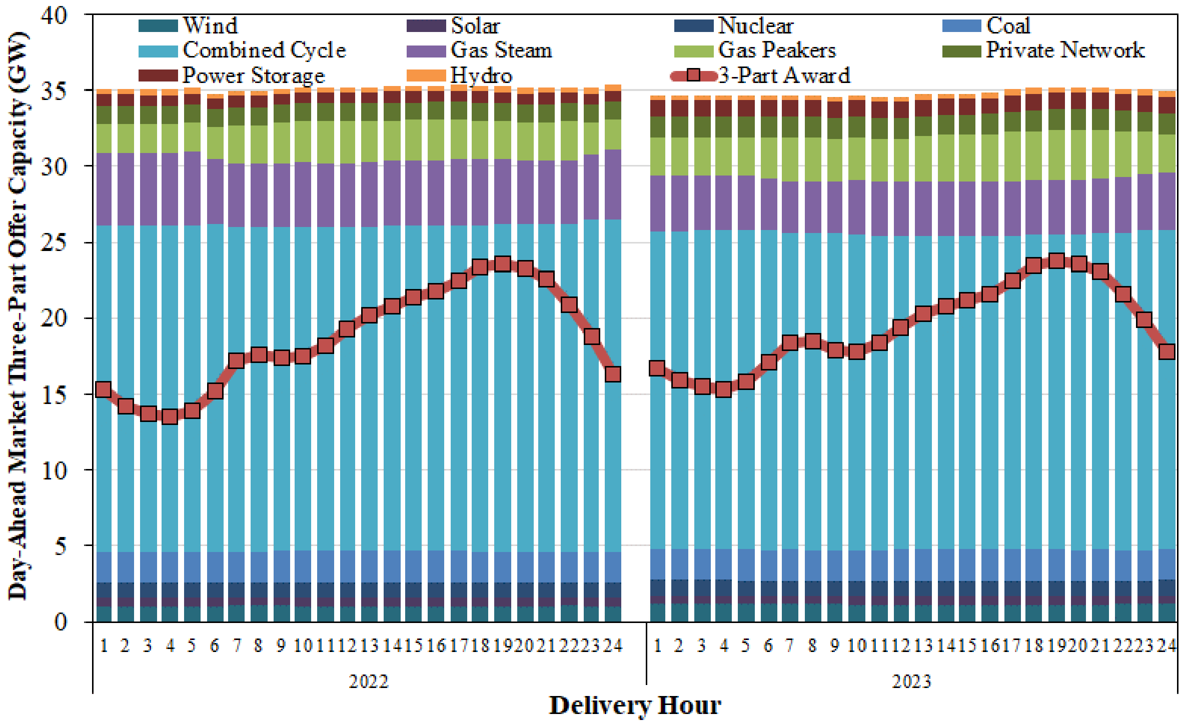
PTP volumes have grown substantially in recent years and have caused day-ahead market performance issues related to ERCOT's ability to publish within the protocol timeline. The bids for PTP obligations have increased four-fold over the last decade. The strongest determinant of day-ahead market performance issues is unawarded PTP obligation bids, i.e., the volume of bids submitted is affecting performance. Further, many of the bids being submitted are highly unlikely to be awarded because the bid price is not a reasonable expectation of the real-time

55 PTP obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

congestion based on recent patterns. Figure 23 also shows the portion of the real-time load that is hedged either through day-ahead energy purchases or PTP obligations scheduled by Qualified Scheduling Entities (QSEs).[56] Although QSEs are the parties financially responsible to ERCOT, their financial obligations are aggregated and held by a counterparty. When measured at this level, the percentage of real-time load hedged dropped to 67% in 2023, down from 76% in 2022.

In 2023, the volume of three-part offers comprised less than half of day-ahead market transactions that cleared. The market design anticipates a potentially low volume of physical supply in the day-ahead market relative to expected load. The market can benefit from both physical sourced and financial participation, and a reliability run subsequent to the day-ahead market ensures that sufficient supply will be available in real-time to operate the grid reliably. To determine whether this was due to small volumes of three-part offers being submitted versus those clearing, Figure 24 shows the total capacity from three-part offers in the day-ahead market for 2023. The submitted capacity has been averaged by hour and is significantly more than the amount of capacity cleared, i.e., three-part offers awarded.

Figure 24: Day-Ahead Market Three-Part Offer Capacity



Combined cycle units submit the largest quantity of offers in the day-ahead market and because they are typically marginal, offering them economically allows a market participant to determine whether its unit is profitable to run. Conversely, few wind units are offered in the day-ahead market because of uncertainty regarding their potential output in real time.

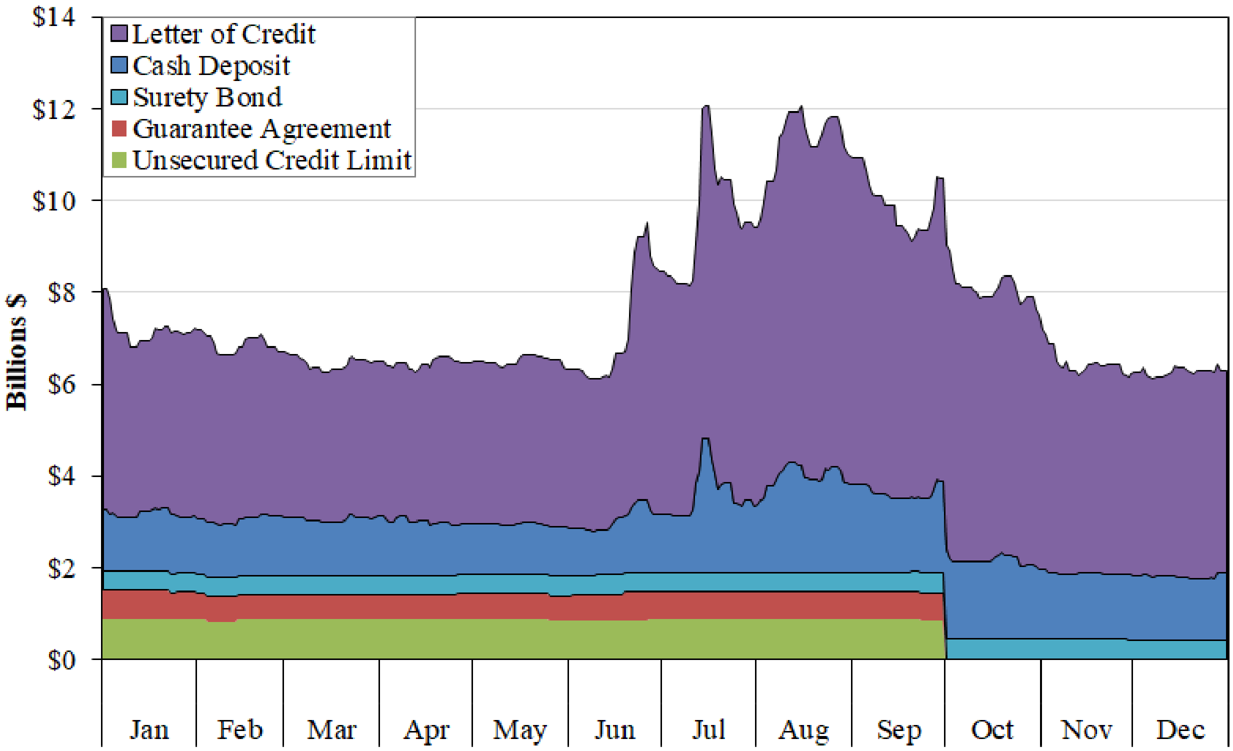
56 To estimate the volume of hedging activity, energy purchases are added to the volume of PTPs scheduled by QSEs with load that source or sink in load zones, then aggregated to the counterparty (CP) level.

To participate in ERCOT's day-ahead market, a market participant must have sufficient collateral with ERCOT. Credit requirements are a constraint on submitting bids in the day-ahead market. When the available credit of a QSE is limited, its participation in the day-ahead market will necessarily be limited as well. The total collateral requirements for 2023 are shown below in Figure 25.

The average daily collateral total in 2023 was approximately $7.7 billion, nearly 20% higher than the average daily collateral total in 2022. This continued the year-over-year increasing trend that was observed in 2022, during which the market experienced a 26.7% increase relative to 2021. The months June through October were associated with the highest daily collateral totals.

After the 2021 winter storm event, there were payment defaults by Counter-Parties with Unsecured Credit Limits, thereby increasing the potential default uplift amounts to other Market Participants. In response to this, ERCOT implemented NPRR 1112 on October 1, 2023, to eliminate all Unsecured Credit Limits and guarantee amounts in the ERCOT credit system.

Figure 25: Daily Collateral Held by ERCOT

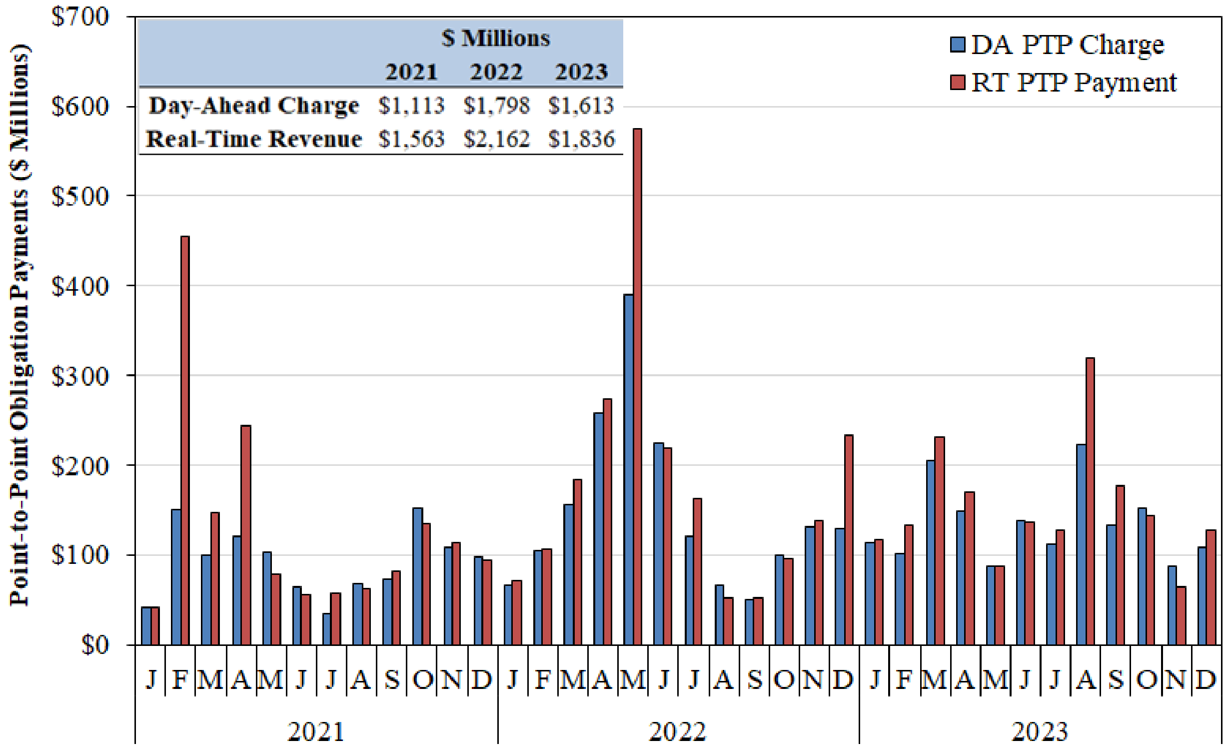


C. Point-to-Point Obligations

Purchases of PTP obligations comprise a significant portion of day-ahead market activity. Participants buy PTP obligations by bidding to pay the difference in prices between two locations in the day-ahead market. They are both similar to and can be used to complement Congestion Revenue Rights (CRRs). PTP obligations are acquired in the day-ahead market and accrue value in real-time based on the difference in prices between two locations caused by congestion costs. CRRs are acquired via monthly and annual auctions and allocations, and they accrue value to their owner based on locational price differences in the day-ahead market. A participant that owns a CRR can use its CRR proceeds from the day-ahead market to buy a PTP obligation between the same two points to transfer its hedge to real-time. CRRs are more fully described in Section V.

Because PTP obligations represent such a substantial portion of the transactions in the day-ahead market, this subsection summarizes the quantities and profitability of PTP obligations. The first analysis of this subsection, shown in Figure 26, compares the total day-ahead payments made to acquire these products with the total amount of revenue received by the owners of PTP obligations in the real-time market for the last three years. When the payments made to buy are lower than the real-time revenues, the PTP obligations are profitable for the participant.

Figure 26: Point-to-Point Obligation Charges and Revenues



Total congestion costs declined in 2023 from 2022. Real-time revenue received by the owners of PTP obligations decreased in 2023 from 2022 by around 15%.

Figure 26 shows that the aggregated total revenue received by PTP obligation owners in 2023 was approximately 13% more than the amount charged to the owners to acquire them, similar to previous years in which buyers of PTP obligations profited, in aggregate, from the transactions (~20% for 2022, ~40% for 2021, ~8% for 2020). During many months in 2023, congestion priced in the day-ahead market was lower than the congestion in real time. Real-time payments significantly exceeded day-ahead charges in August and September, while charges significantly exceeded payments in November.

To provide additional insight on the profits that have accrued to PTP obligations, Figure 27 shows the profitability of PTP obligation holdings for all physical parties and financial parties (those with no real-time load or generation), as well as the profitability of PTP obligations with links to options (PTP options) in 2023. PTP options are available only to NOIEs and allow them to receive congestion revenue without being subject to congestion charges.

Figure 27: Average Profitability of Point-to-Point Obligations

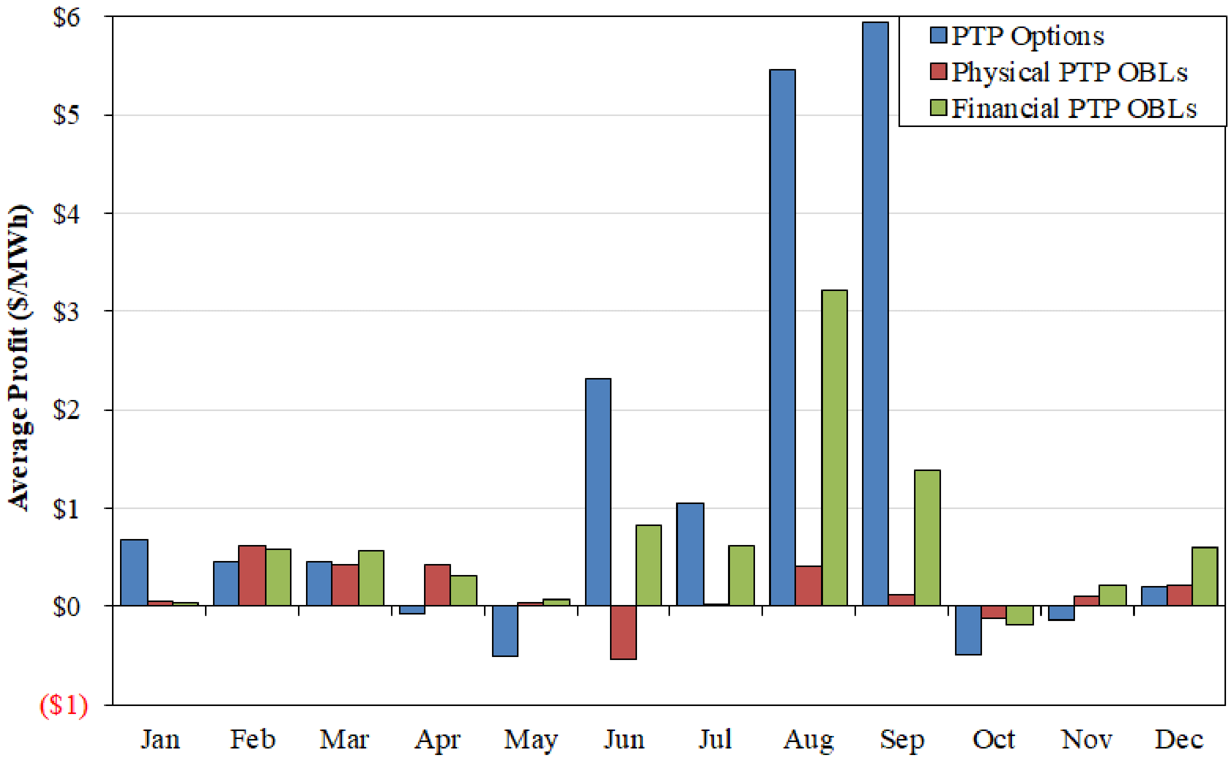


Figure 27 shows that, in aggregate, PTP obligation transactions in 2023 were profitable for the year, yielding an average profit of $0.51 per MWh. PTP obligations were profitable for all types of parties largely because of the profits that accrued during high-congestion periods in August and September. Profits averaged $0.13 per MWh for physical parties, $0.75 per MWh for financial parties, and $1.24 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2023, see Figure A15 in the Appendix.

D. Ancillary Services Market

The primary ancillary services before June 2023 were regulation up, regulation down, responsive reserves (10-minute reserves), and non-spinning reserves (30-minute reserves). In addition, on June 10, 2023, ERCOT launched ECRS, a daily procured 10-minute reserve product. ERCOT predetermines the amount of ancillary services to be procured and assigns an obligation to all market participants that serve load.[57] Market participants may self-schedule ancillary services or have ERCOT purchase them on their behalf.

In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (e.g., unplanned generator outages), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from either online resources or from offline resources that can start quickly to respond to contingencies and to restore responsive reserve capacity.

Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to keep generation and load in balance from moment to moment. The quantity of regulation needed is contingent on the accuracy of the 5-minute dispatch instructions for supply to balance anticipated demand.

ERCOT's newest ancillary service, ECRS, is provided by resources capable of being ramped to a specified output level within 10 minutes and that can sustain a specified output level for two consecutive hours. ECRS can be provided from either online resources or offline resources that can start quickly. ERCOT's stated purpose for ECRS is to restore frequency within 10 minutes of a significant frequency deviation for recovery of deployed regulation service, to compensate for intra-hour net load forecast uncertainty and variability on days in which large amounts of online thermal ramping capability is not available, or to compensate for times during which there is a limited amount of capacity available to Security-Constrained Economic Dispatch (SCED).[58]

1. Ancillary Services Requirements

Ancillary services are procured based on ERCOT's ancillary services methodology that is reviewed and approved in advance of the year. Figure 28 below displays the average quantities of ancillary services procured for each month in 2023.

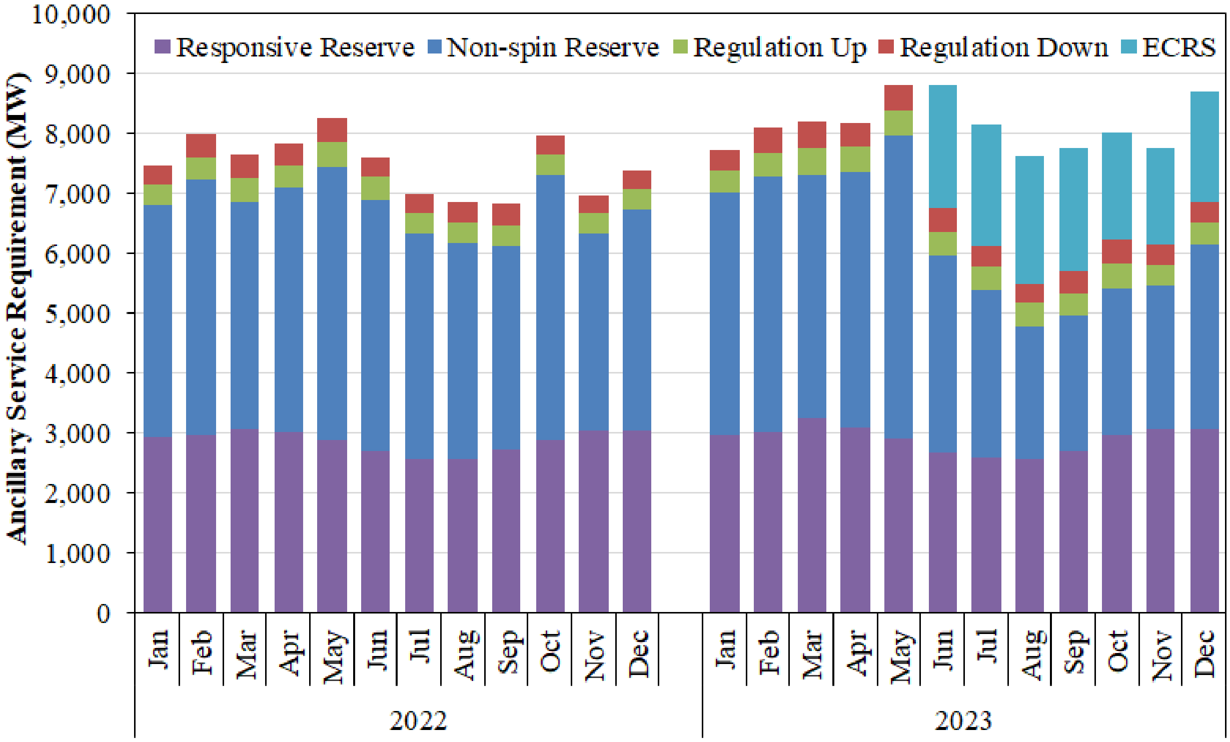
This figure shows the substantial quantities of responsive reserves, non-spinning reserves, and ECRS procured by ERCOT throughout 2023. In July 2021, ERCOT adopted a new operating posture causing it to increase its total amount of upward ancillary services from an average of roughly 4 GW to 6.5 GWs for every hour and 7.5 GW when forecast variability is high.[59]

57 Satisfying NERC standards and meeting other objectives established by ERCOT determine the AS amounts.

58 https://www.ercot.com/files/docs/2022/12/13/13.3%202023%20ERCOT%20Methodologies%20for%20Determining%20Minimum%20Ancillary%20Service%20Requirements.pdf.

59 https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx.

Figure 28: Average Ancillary Service Capacity by Month



The ancillary services requirements were further affected by a number of changes that occurred during 2023, as described in more detail below:

- *Regulation*. The regulation service requirements are set to ensure sufficient regulation will be available to cover the 95th percentile of deployed regulation or net load variability for the same month of the previous two years. The requirements averaged 380 MW in 2023.
- *Responsive Reserves*. Since June 2015, ERCOT has calculated responsive reserve requirements based on a variable hourly need. The responsive reserve requirements averaged 2,900 MW and was typically roughly 2,800 MW in peak hours. These requirements did not change materially after the implementation of ECRS, a complementary 10-minute reserve product. ERCOT changed the minimum amount of responsive reserve service procured from resources providing responsive reserve service using Primary Frequency Response to almost 1,400 MW in 2023 (1,240 MW in 2022) and placed a limit of 450 MW on resources providing Fast Frequency Response (FFR).
- *Non-Spinning Reserves*. Prior to implementation of ECRS, ERCOT determined the non-spin requirement using the 85th to 95th percentile of hourly 10-hour ahead net load uncertainty from the same month of the previous three years. After implementation of ECRS, ERCOT reduced its non-spin procurements by using the 75th to 95th percentile of hourly 6-hour ahead net load uncertainty. ERCOT will always procure a minimum quantity of non-spinning reserves greater than or equal to the largest online generation unit

during on-peak hours. The decrease in requirements that occurred when ECRS was implemented was much smaller than the ECRS quantities procured.

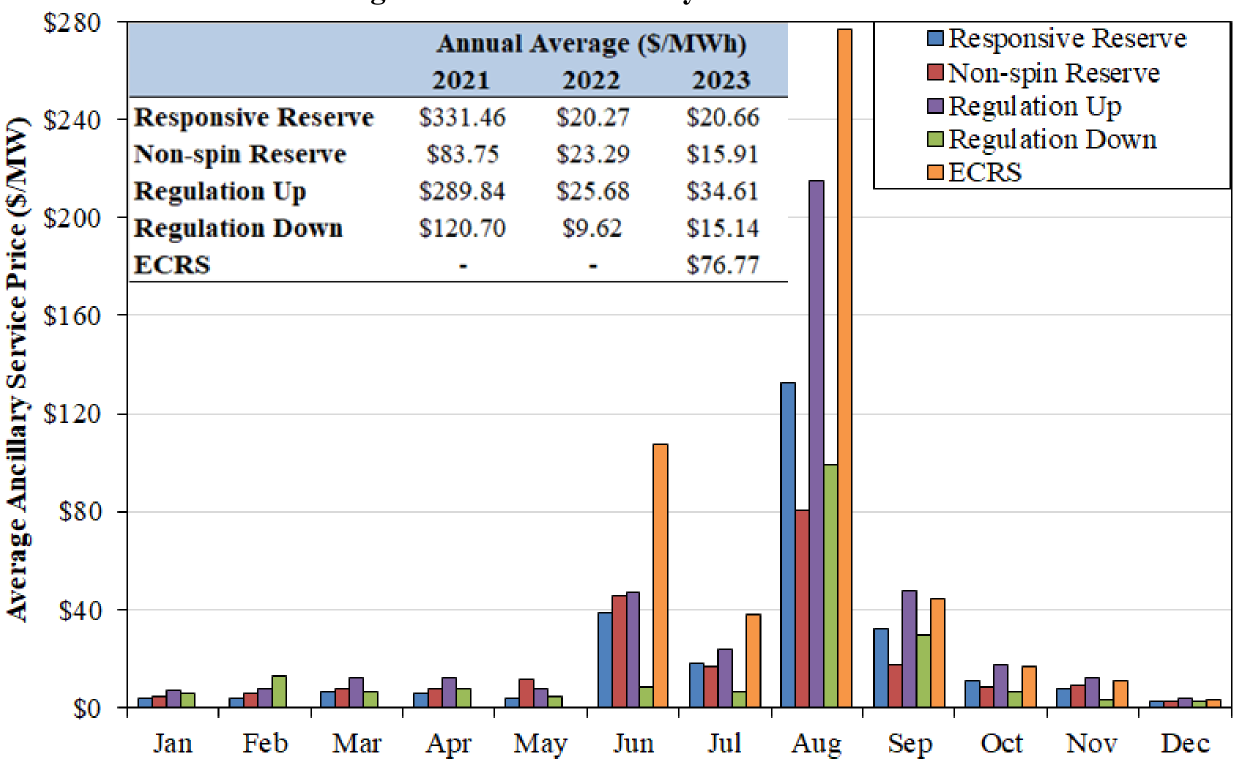
- *ECRS*. ERCOT initially computed minimum requirements for ECRS as the sum of the capacity needed to recover frequency following a large unit trip and the 85th to 95th percentile of 30-minute ahead intra-hour net load forecast error.[60] This produced requirements that averaged 1,930 MW in all hours and 2,400 MW in peak hours.

- *Total Requirements*. The changes described above caused the total ancillary services to rise by 8.9% on average from 2022 to 2023, and 14.9% in peak hours. The increase was even sharper for total 10-minute reserves (responsive reserves plus ECRS), which rose by 51% after the implementation of ECRS.

2. Ancillary Services Prices

Figure 29 below presents the monthly average clearing prices of capacity for the five ancillary services in 2023, and the inset table shows the average annual prices over the last three years.

Figure 29: 2023 Ancillary Service Prices



	Annual Average ($/MWh)		
	2021	2022	2023
Responsive Reserve	$331.46	$20.27	$20.66
Non-spin Reserve	$83.75	$23.29	$15.91
Regulation Up	$289.84	$25.68	$34.61
Regulation Down	$120.70	$9.62	$15.14
ECRS	-	-	$76.77

Figure 29 shows the prices for ancillary services were highest in June, August, and September in 2023 after the implementation of ECRS. Overall, the average ancillary service cost per MWh of

60 https://www.ercot.com/files/docs/2022/12/13/13.3%202023%20ERCOT%20Methodologies%20for%20Determining%20Minimum%20Ancillary%20Service%20Requirements.pdf.

ERCOT load increased to $4.21 in 2023 from $3.29 in 2022. Most notably, the average ECRS price in 2023 was $76.77 per MWh, over triple the 2023 average price of responsive reserves. Much of the increase in prices was caused by the substantial increase in 10-minute reserves and total reserves that occurred with ECRS implementation. We have recommended that ERCOT re-evaluate its ancillary services methodology because these increases were not linked to an analysis of the marginal value of reliability risks addressed by the ancillary services.

Some of the increase in prices was also due to higher clearing prices for energy in the day-ahead market in June, August and September (primarily due to weather conditions) because ancillary services and energy are co-optimized in the day-ahead market. Ancillary service prices should generally be correlated with day-ahead energy prices because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the day-ahead market. Figure A16 in the Appendix shows the monthly total ancillary service costs per MWh of ERCOT load, and Table A1 shows the annual market value of these services.

The elevation in responsive reserve and non-spinning reserve prices from 2020 prices continues to be due to ERCOT's conservative operational posture. The increase in procurements associated with this posture substantially reduces excess supply and causes large suppliers of the service to frequently be pivotal for satisfying the non-spinning reserve requirements. Pivotal suppliers often have market power and can raise market price by choosing to offer at a higher price in the market. We find that such price increases occurred in 2023 as the market continued to be substantially less competitive than in prior years.

3. Provision of Ancillary Services by QSEs

Day-ahead ancillary services are procured by resource, but the responsibility to provide them is aggregated up to the QSE. Table 3 shows the share of ancillary services that were provided from the top ten QSE providers of the services, while Table 4 shows the share of day-ahead ancillary service awards to the top ten QSEs. This allows us to evaluate the market concentration for each product. The tables also show the total number of QSEs that represent the supply of each product. Table 3 shows that concentration was modest for regulation and responsive reserves in 2023:

- The largest suppliers of regulation up and down have been supplying larger shares of the service since 2021. In 2023, the largest three suppliers provided roughly 40% of the regulation up service and 57% of the regulation down service. The changes in the provision of regulation services over the past few years have largely been caused by the rapid increase in penetration of ESRs in ERCOT.
- The supply of responsive reserves was not highly concentrated, with the largest QSE providing only 15% of ERCOT's responsive reserves. This QSE is not the largest QSE in the table, as it did not provide any other ancillary services in real-time.

Table 3: Share of Reserves Provided by the Top QSEs in 2022-2023

	2022				2023				
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	ECRS	Non-Spin	Reg Up	Reg Down
# of Suppliers	**60**	**45**	**45**	**47**	**76**	**43**	**60**	**57**	**57**
QLUMN	3%	19%	9%	35%	7%	3%	20%	9%	36%
QTEN23	0%	18%	0%	0%	0%	24%	13%	0%	0%
QEDF21	0%	3%	0%	0%	0%	28%	8%	0%	0%
QBRD11					2%	0%	0%	19%	11%
QSHEL2	1%	7%	0%	0%	5%	8%	8%	0%	0%
QBROAD	4%	0%	23%	17%	0%	0%	0%	10%	10%
QNRGTX	9%	8%	5%	3%	6%	4%	4%	6%	0%
QLCRA	9%	4%	3%	4%	9%	1%	5%	3%	1%
QCPSE	3%	4%	4%	5%	3%	4%	6%	2%	3%
QTEN22	5%	0%	5%	3%	3%	4%	0%	6%	3%
Total	***33%***	***63%***	***50%***	***66%***	***34%***	***76%***	***64%***	***53%***	***65%***

Table 3 also shows that the provision of other ancillary services was only slightly more concentrated, but markets for these products did not perform competitively.

- The market concentration of the provision of non-spinning reserves remained comparable to the concentration in 2022. Luminant ("QLUMN") provided approximately 20% of the requirements in 2023, down from 56% in 2017. As discussed above, the sharp increase in procurements caused suppliers capable of selling non-spinning reserves to be pivotal in a much higher share of hours and allowed these suppliers to raise non-spinning reserve prices.
- Likewise, ECRS was highly concentrated and did not perform competitively. More than 50% of the ECRS in 2023 was provided by QTEN23 and QEDF21. Like the non-spinning reserve market, the high levels of ECRS caused suppliers to often be pivotal and able to raise ECRS prices above competitive levels.

Table 4: Share of DAM AS Capacity Awarded to the Top QSEs in 2022-2023

	2022				2023				
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	ECRS	Non-Spin	Reg Up	Reg Down
# of Suppliers	**43**	**35**	**35**	**35**	**68**	**41**	**41**	**44**	**46**
QBRD11					3%	2%		32%	26%
QLUMN	1%	20%	8%	27%	1%	5%	19%	8%	25%
QMP2EN	13%				11%	21%			
QBROAD	3%	0%	40%	32%	1%			13%	16%
QTEN23		20%	0%	0%		14%	14%	0%	0%
QPRIO1	30%	0%			25%	0%	0%		
QEDF21		3%				17%	8%		
QLCRA	4%	6%	5%	6%	4.0%	2%	7%	4.4%	2%
QENRWI	20%				16.6%				
QSHEL2	1%	8%	1%	1%	1%	7%	7%	0%	0%
Total	***71%***	***56%***	***55%***	***84%***	***63%***	***69%***	***55%***	***57%***	***69%***

Table 4 above shows that the market concentration in the day-ahead awards in 2023 was comparable to the real-time market concentration discussed above in real time.

The poor competitive performance of the non-spinning reserve and ECRS markets highlights the importance of modifying the ERCOT ancillary service market design and implementing real-time co-optimization (RTC). Simultaneously optimizing all ancillary services and energy in the real-time market will allow the market to adjust schedules in each interval to:

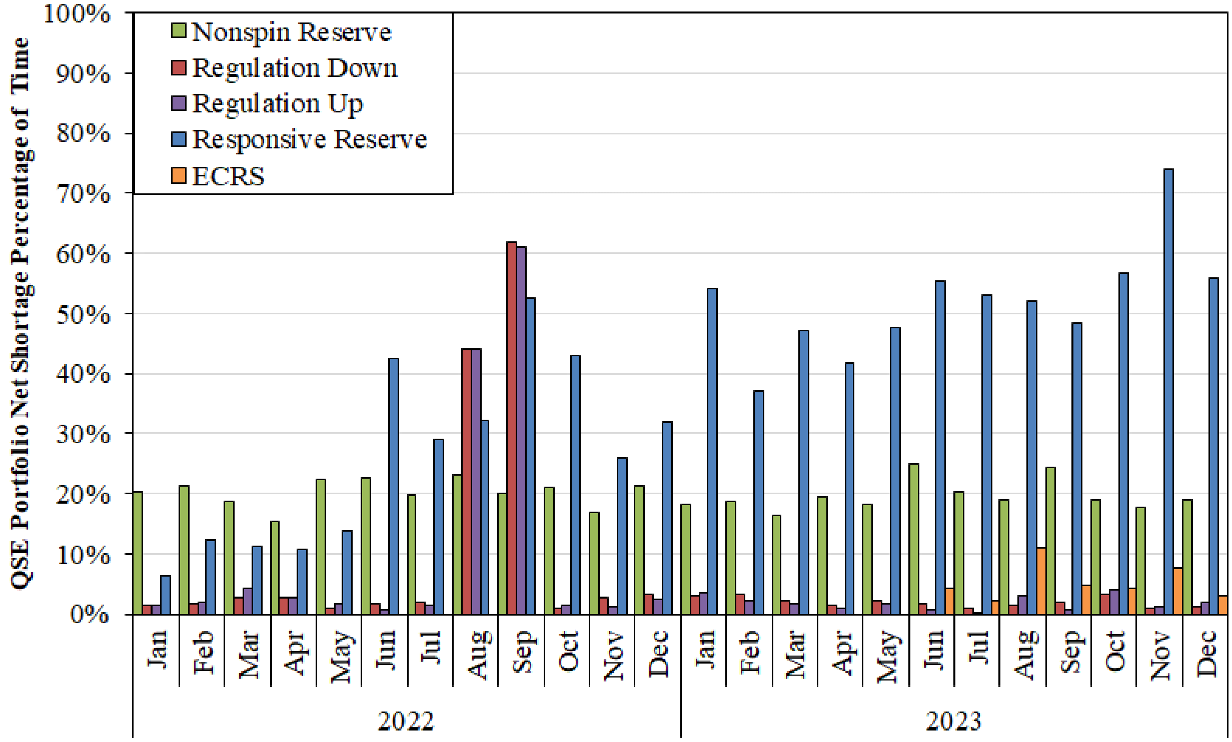
- Minimize the costs of meeting all of the system requirements;
- Avoid shortages by shifting the schedules to maximize energy and ancillary services when the system becomes tight;
- Set efficient prices that reflect the actual shortages when the system is short of one or more classes of ancillary services; and
- Increase profits to suppliers by scheduling ancillary services most economically.

Co-optimization will also allow QSEs who have fewer qualified resources to better compete in the ancillary services markets. Such QSEs face higher risk than QSEs that represent a high number of qualified resources (i.e., a large portfolio) when selling ancillary services because of the replacement risk of purchasing in a SASM if it suffers an outage. ERCOT runs a SASM when additional ancillary services need to be procured, and prices in this market can be very high. A QSE with a large portfolio can often avoid a SASM by shifting the ancillary services from one resource to another within its fleet. RTC will address this issue by providing a liquid market for replacement of ancillary services and obviate the need for SASMs. See Section IV of the Appendix for more information on SASM activity in ERCOT in 2023.

Finally, QSEs do not always provide the ancillary services that they are responsible for providing under their day-ahead awards, self-arrangement, or trades. Figure 30 below shows the percentage of each month during which there was at least one QSE that did not satisfy its full ancillary services responsibility. A shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour. It does not necessarily mean that the QSE was charged for the shortage.

Figure 30 shows that deficiencies of QSEs in meeting their ancillary service responsibilities were pervasive again in 2023, especially in August and September. For market participants that do not meet their ancillary service responsibility, ERCOT can claw back the payment the QSE received in the day-ahead market for the amount it was paid to provide the service in real time but did not. This claw-back process does not occur automatically; rather, it must be completed manually. NPRR 1149, *Implementation of Systematic Ancillary Service Failed Quantity Charges* was approved by the PUCT in March 2023 and updates the protocols to automate this process.

Figure 30: QSE-Portfolio Net Ancillary Service Shortages in 2022 - 2023



V. Transmission Congestion and Congestion Revenue Rights

An essential function of any electricity market is to efficiently manage power flows on the transmission networks. Congestion management occurs as the markets coordinate the dispatch of generation to ensure that the resulting power flows do not exceed the operating limits of the transmission facilities. This coordination occurs through the real-time market dispatch software, which optimizes based on each generator's energy offer curve and incorporating each generator's impact on constraint violations. The result of this market dispatch is a set of locational prices that vary across the network and resulting congestion costs that are collected from participants. Congestion exists most of the time – at least one constraint was binding (with the dispatch flow at the constraint's limit) in real time 78% of the time in 2023.

The locational difference in prices caused by congestion can result in costs or risks for parties in long-term power contracts who are liable for the price differences between the locations of the generator and the load. CRRs are economic property rights between two locations funded by the congestion collected through the day-ahead market. They allow participants to hedge day-ahead congestion and to convert them into a real-time congestion hedge. The CRR markets enable parties to purchase CRRs in monthly blocks as much as three years in advance.

This section of the Report evaluates congestion costs and revenues in 2023. We first discuss the value of congestion in the day-ahead and real-time markets, which totaled approximately $2 billion and $2.3 billion, respectively. We then discuss the CRR markets and funding in 2023.

A. Value of Day-Ahead and Real-Time Congestion

As the day-ahead market clears financially binding supply, demand, and PTP obligation transactions, it respects the transmission system limitations. This can result in widely varying locational prices and associated congestion. This congestion can be affected by planned transmission outages, load, and renewable forecasts, which also inform market participants' decisions on how to hedge portfolios before real-time. The day-ahead and real-time congestion values are calculated as the flows over each constraint multiplied by the shadow price of the constraint, which represents the marginal economic cost of the constraint. In real time, this is determined by the costs of dispatching generators to manage the flows. To the extent congestion is settled in the day-ahead market, the congestion is not collected again in the real-time market.

Figure 31 summarizes the monthly and annual value of real-time congestion. The values are aggregated by geographic zone. This value will not always match the congestion value in the day-ahead market because constraints may bind more or less severely in real time than day-ahead. Therefore, the red line in the figure shows the aggregate value of day-ahead congestion.[61]

[61] The disaggregated congestion values by zone are shown in the Appendix in Figure A25.

Figure 31: Value of Real-Time Congestion by Zone

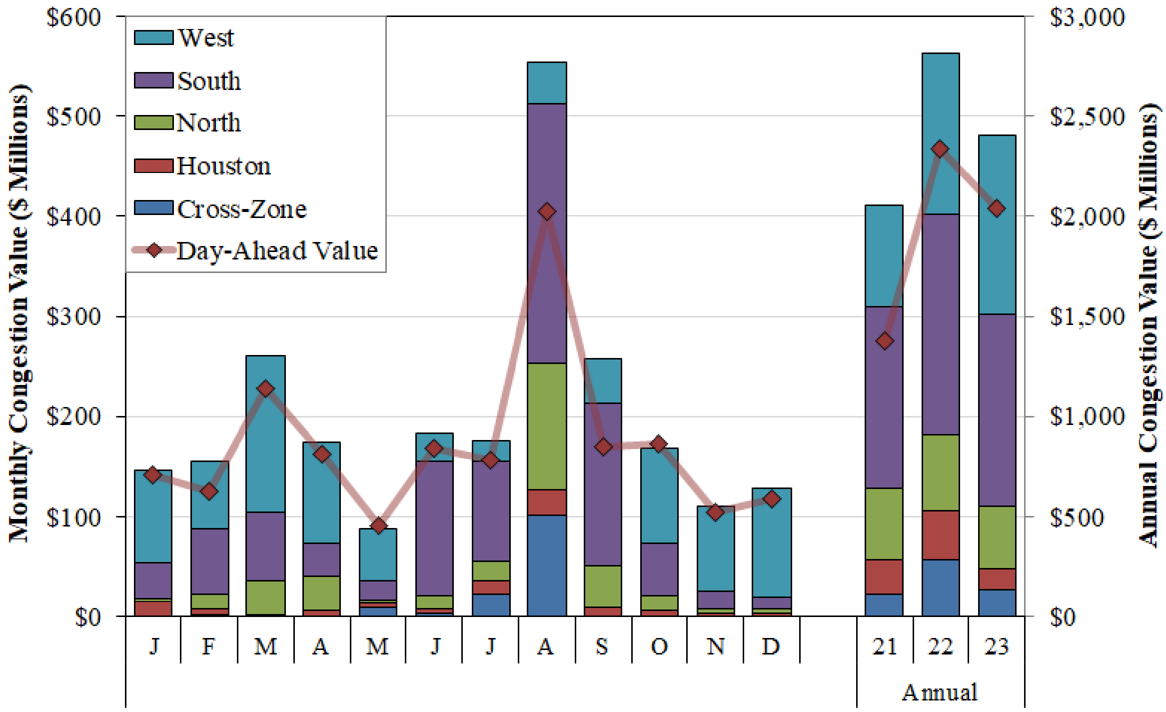


Figure 31 shows that the value of real-time congestion fell by 15% in the real-time markets in 2023. The reduction in congestion from 2022 was partly due to falling natural gas prices, which play a key role in determining congestion costs because dispatchable natural gas resources are generally those that are dispatched up or down to manage congestion. The value of day-ahead congestion similarly fell by 13% in 2023, which tracked the real-time congestion trends. As in prior years, the value of congestion in the day-ahead market was slightly lower than in the real-time market, which indicates that spikes in real-time congestion are often not foreseen day ahead.

Figure 31 shows that congestion was highest in August when load was high, and the dispatch was hampered by the ECRS issues discussed in Section II. Congestion was also relatively high in September, including during the EEA2 event on September 6 where transmission violations led to the curtailment of approximately 1,500 MW of generation, of which 1,300 MW was wind resources. The largest zonal congestion was in the South zone, caused by higher congestion in the Rio Grande Valley. Congestion costs were also relatively high in the West zone, primarily driven by high renewable output coupled with oil and gas loads. The top individual constraints contributing to this congestion are described in the next subsection.

B. Real-Time Congestion

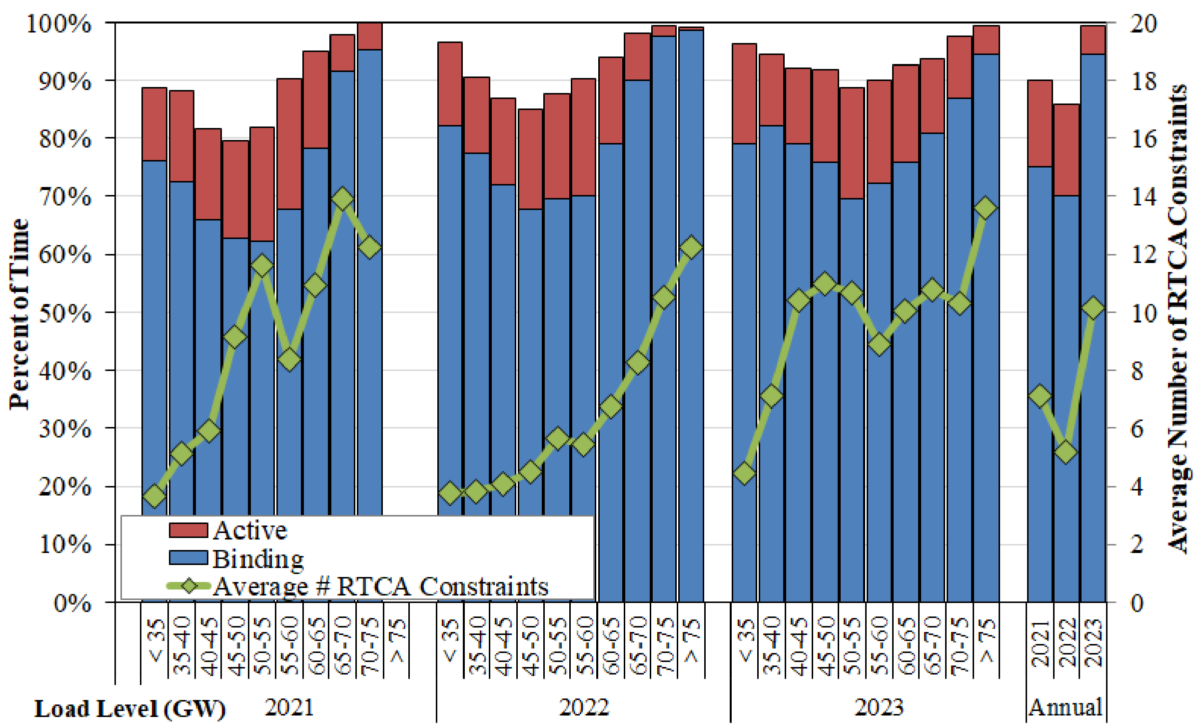
While the expected costs of congestion are reflected in the day-ahead market, physical congestion occurs only in the real-time market. ERCOT operators manage power flows across the network as physical constraints become binding in real time. Therefore, we evaluate and discuss real-time constraints and associated congestion in this section.

1. Types and Frequency of Constraints in 2023

ERCOT activates constraints in the real-time market from: a) Real-Time Contingency Analysis (RTCA) that runs on an ongoing basis; and b) GTCs that are determined by off-line studies, with limits determined prior to the operating day.[62]

The RTCA evaluates the resulting network flows under many contingency scenarios. A base-case constraint exists if the flow on a transmission element exceeds its normal rating. A thermal contingency constraint exists if the outage of a transmission element (i.e., a contingency) would result in a flow higher than the rating of an in-service element.[63] Active transmission constraints are those that are modeled in the dispatch software. The active constraints are "binding" when dispatch costs are incurred to maintain transmission flows below the constraint limit, and "not binding" when they do not require a redispatch of generation and have no effect on prices. Figure 32 summarizes the active and binding constraints during 2023, showing the percent of time (y-axis) at different load levels and annually (x-axis) with a binding or active constraint. The green line also shows the average number of constraints at different load levels.

Figure 32: Frequency of Binding and Active Constraints by System Load Level



62 A GTC is a transmission constraint made up of one or more grouped Transmission Elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly in ERCOT's power flow and contingency analyses and are based on offline studies (i.e., RTCA will not provide indication of concerns).

63 Typically, a contingency constraint is described as a contingency name plus the name of the overloaded element. This section will refer to a constraint based solely on the overloaded element.

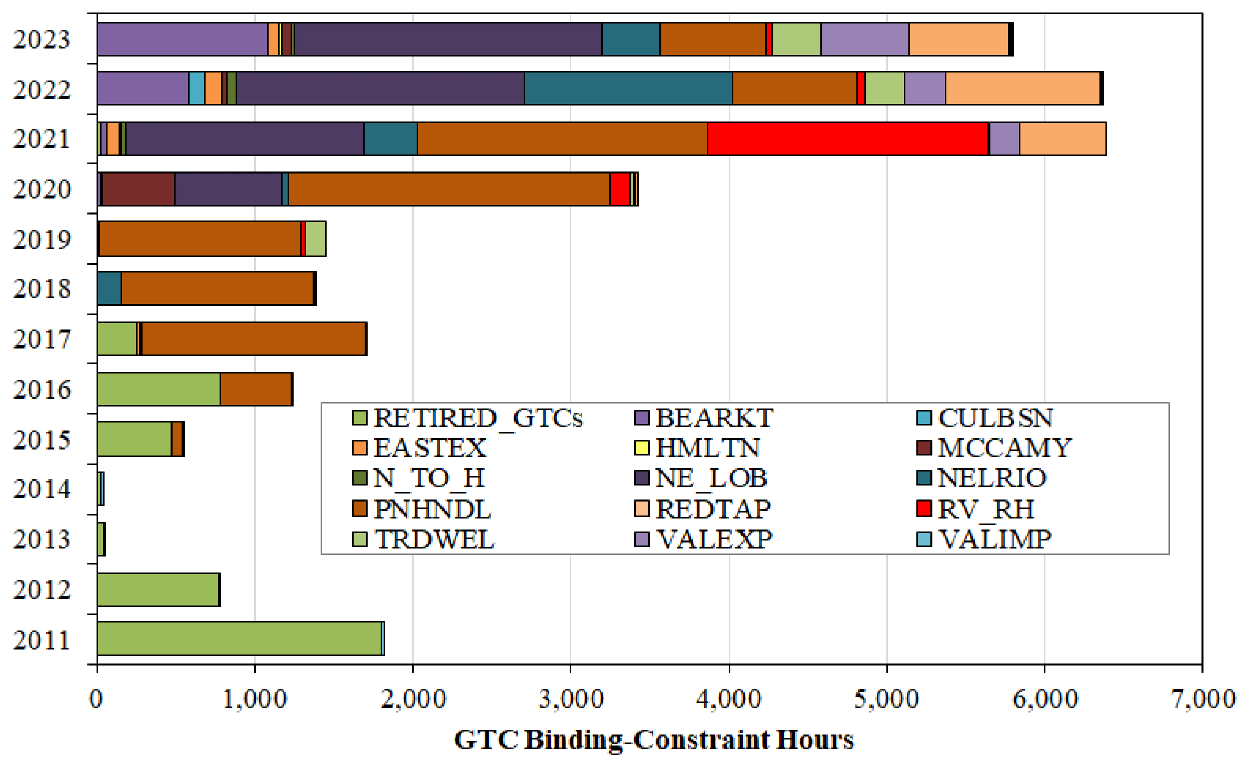
Figure 32 shows the following:

- The ERCOT system had at least one binding constraint 78% of the time in 2023, an increase from 75% in 2022 and 70% in 2021.
- Consistent with previous years, the average number of active constraints generally decreased with increasing load level.
- On average, eleven constraints were identified for the higher load levels (greater than 60 GW), up from approximately nine in 2022.

Roughly 11% of real-time congestion was associated with GTCs. GTCs are used to ensure that the generation dispatch does not violate a transient or voltage stability condition. Certain GTC limits are determined in real-time using the Voltage Stability Assessment Tool (VSAT) or the Transient Stability Assessment Tool (TSAT). These tools are used continuously to evaluate the East Texas, North to Houston, the Rio Grande Valley Import, and Panhandle limits, and provide a more accurate real-time limit than could be achieved through offline studies.

Because GTCs play an important role in driving congestion in ERCOT, it is important to show the frequency and trends in binding GTCs. To that end, Figure 33 shows the aggregate number of hours in which GTCs were binding from 2011 to 2023.[64]

Figure 33: GTC Binding Constraint Hours



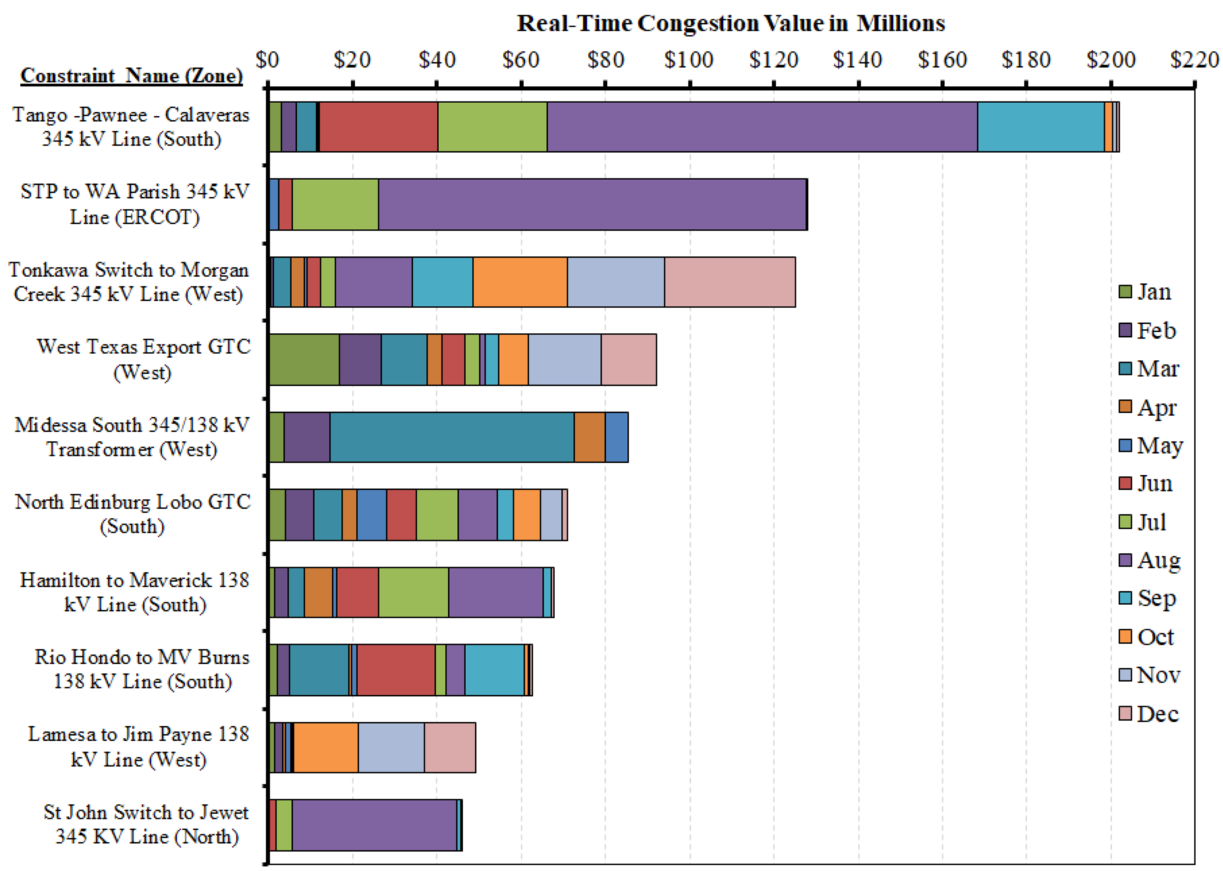
64 Table A4: Generic Transmission Constraints in the Appendix shows the effective date for individual GTCs and the number of binding hours during 2022 and 2023.

In 2023, there was a decrease in the GTC binding hours from 2022 and 2021, however they continued to be much higher than the binding hours in prior years. ERCOT has been working on getting better data for the full range of inverter technologies, which will allow all GTC limits to be calculated in real time rather than using more conservative offline studies. This should result in less congestion and generation curtailment. Apart from the North to Houston, Rio Grande Valley Import, and East Texas constraints, all GTCs resulted from issues identified in the generation interconnection process. As more renewable resources and ESRs enter the ERCOT market, the benefits of these dynamic VSAT and TSAT models will grow.

2. Real-time Constraints and Congested Areas

Our review of real-time congestion is based on its economic value, calculated by multiplying the shadow price of each constraint by the flow over the constraint. The shadow price is the marginal cost of the redispatch necessary to manage the constraint and, therefore, the benefit of relieving the constraint. For this discussion, a congested area is identified by consolidating multiple real-time transmission constraints if the constraints are determined to be similar because of geographic proximity and constraint direction. Figure 34 displays the ten most costly real-time constraints with their respective zones measured by congestion value.

Figure 34: Most Costly Real-Time Congested Areas



There were 665 unique constraints that were either binding or violated at some point during 2023, with a median financial impact of approximately $139,000. We have the following observations about real-time congestion on ERCOT's individual constraints:

- The constraint with the highest congestion value in 2023 ($202 million) was the Tango Pawnee Calaveras 345 kV Line. This circuit serves the load in the San Antonio region and any small generation outage in the region will tend to overload the line. This constraint exhibited the highest congestion values in the day-ahead market as well.
- The high congestion rent in August 2023 was driven by the loss of the double circuit 345 kV contingency from Elmcreek to San Miguel Gen, overloading the 345 kV transmission line from Pawnee Switching Station to Calaveras. The PUCT has approved the San Antonio South Reliability project to address this issue. The West Texas Export GTC had the most congestion in 2022 but was fourth most in 2023.
- The second highest-value constraint in 2023 resulted from the STP to WA Parish 345 kV line. Forced outages of resources around the Houston area caused the majority of the congestion value in August.
- Congestion on the Midessa South 345/138-kV transformer and Lamesa to Jim Payne 138 kV line was caused by multiple planned outages in the West region.
- Congestion on the West Texas Export GTC, North Edinburg Lobo GTC, and Rio Hondo Area constraints are typically attributed to generation output from inverter-based resources.

ERCOT highlighted these areas in the 2023 Long-Term System Assessment report within the ERCOT Constraints and Needs Report.[65] Figure A29 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2023.

3. Irresolvable Constraints

The shadow price of a constraint represents the marginal cost of managing a constraint (i.e., the cost of achieving the last MW of needed relief through the real-time dispatch). A constraint is "violated" or irresolvable when the market dispatch flows exceed the transmission limit for the constraint. Such violations impose reliability costs or risks on the system that are embedded in the shadow price caps used by ERCOT to dispatch the system and set prices.[66] When the marginal costs of procuring relief through the market dispatch exceeds the reliability costs 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 the congestion prices at locations that affect the violated constraint.

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65 *See* Report on Existing and Potential Electric System Constraints and Needs, (December 2023), available at: https://www.ercot.com/files/docs/2023/12/22/2023-Report-on-Existing-and-Potential-Electric-System-Constraints-and-Needs.pdf.

66 See *Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints*.

The shadow price caps during 2023 were:

- $5,251 per MW for base-case (non-contingency) constraints or voltage violations,[67]
- $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.
- GTCs are considered base-case stability constraints (for voltage or transient conditions) with a shadow price cap of $5,251 per MW.

Figure 35 shows the distribution of violated constraints at the various violated constraint overload percentages since 2014. A more detailed review of violated constraints can be found in Figure A28 in the Appendix.

Figure 35: Overload Distribution of Violated Constraints

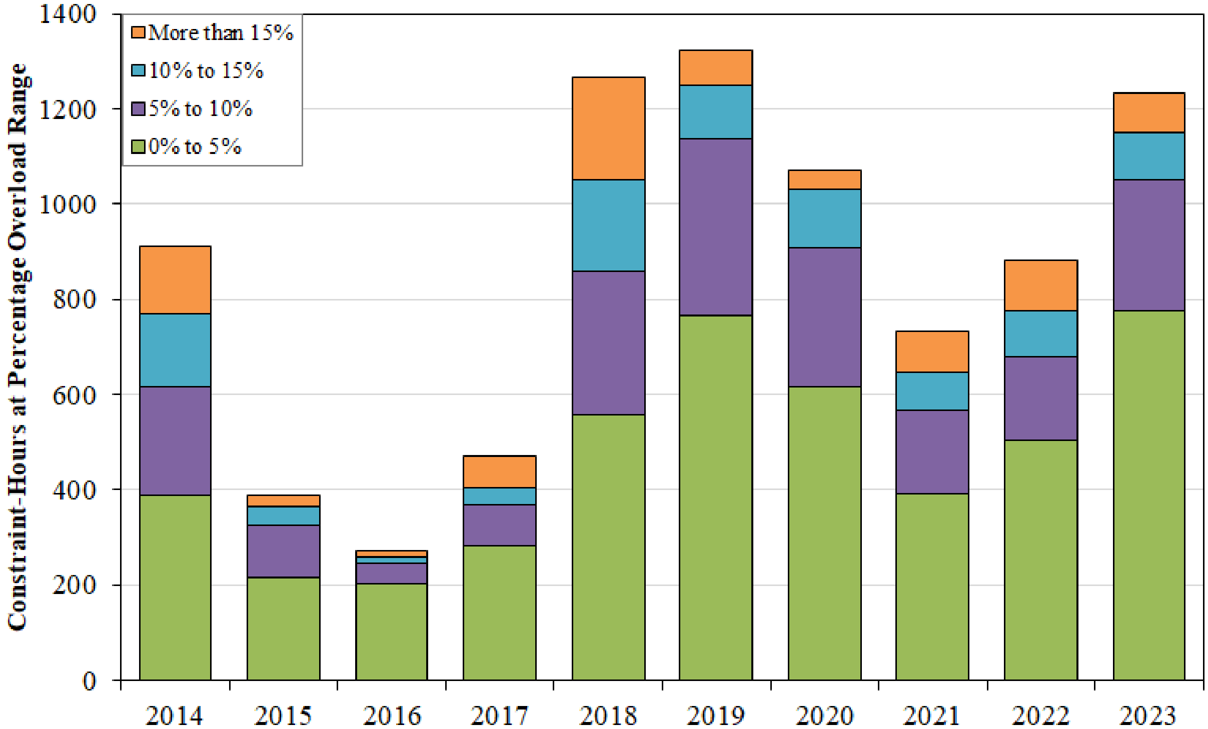


Figure 35 shows that 63% of the constraint-hours in 2023 were in violation between 0-5% of the transmission element rating, yet they are priced at the same shadow price cap as the more severe violations. This raises some concerns because the use of a single shadow price cap causes the pricing of the violations to not vary with the severity of the violation. Hence, it may be advisable to reconsider implementing transmission demand curves, which would recognize that the

67 OBDRR 037, *Power Balance Penalty and Shadow Price Cap Updates to Align with PUCT Approved High System-Wide Offer Cap*, reduced the shadow price cap for base-case constraints from $9,251 per MW to $5,251 per MW effective April 1, 2022.

reliability risk of a post-contingency overload increases as the violation amount increases. Small violations should have lower shadow prices than large violations. The IMM filed a revision request to implement transmission constraint demand curves, which was ultimately withdrawn in 2022 for lack of support.[68]

Violations may be resolved in ensuing intervals as resources ramp up to provide relief. A constraint-specific peaker net margin mechanism is nonetheless applied such that once local price increases reach a predefined threshold, the constraint is deemed irresolvable and the constraint's shadow price cap is recalculated based on the mitigated offer cap of existing resources and their ability to resolve the constraint.[69] Table A5 in the Appendix shows that 13 elements were categorized as irresolvable in 2023 and had a shadow price cap imposed according to this methodology.

C. CRR Market Outcomes and Revenue Sufficiency

As discussed above, CRRs are valuable economic property rights entitling the holder to the day-ahead congestion payments or charges between two locations. CRRs are modeled as a power flow injection at the "source" and a withdrawal at the "sink." In this subsection, we discuss the results of the CRR auctions, the allocation of the revenues from the CRR auctions, and the funding of CRRs from the day-ahead market congestion.

1. CRR Auction Revenues

CRRs may be acquired in semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to NOIEs based on generation units owned or contracted for prior to the start of retail competition. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same locations.

ERCOT has implemented three-year CRR auctions, which caused more transmission capacity to be sold in advance of the monthly auctions. Opportunities to purchase CRRs earlier improve forward hedging and add liquidity. However, purchases made three-years in advance can also increase differences between CRR auction revenue and day-ahead payouts because advance sales

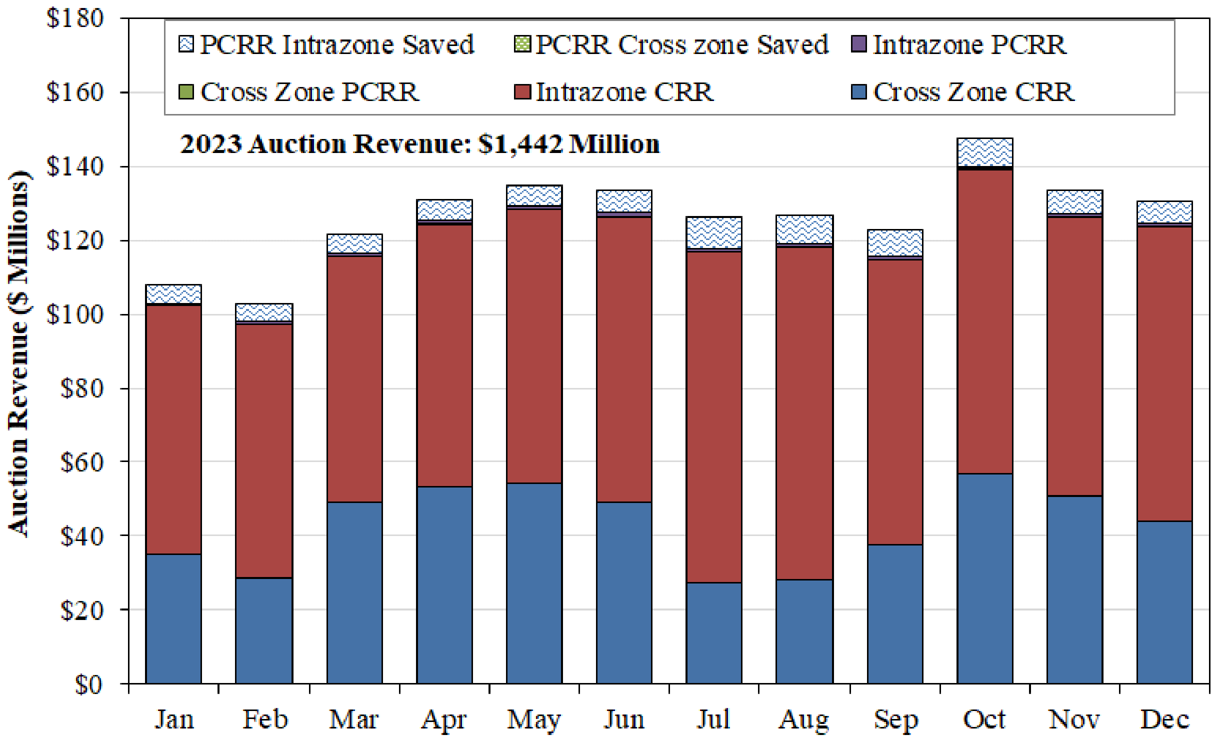
68 Filed on January 21, 2020, by the IMM, OBDRR 026, *Change Shadow Price Caps to Curves and Remove Shift Factor Threshold*, proposed to make certain congestion management changes for contingency constraints. This OBDRR would have 1) changed the default Shadow Price caps to curves (the change lowers the value for small violations and raises the value for large violations); and 2) removed the Shift Factor threshold as a factor for determining eligibility for Security-Constrained Economic Dispatch (SCED) consideration. Currently, a constraint is only eligible for resolution by SCED if at least one Resource exists that has a Shift Factor of greater than 2% or less than negative 2%. This OBDRR also proposed minor cleanup items and simplifications to Section 3, Elements for Methodology for Setting the Network Transmission System-Wide Shadow Price Caps. The revision request was withdrawn on January 6, 2022.

69 *See* Section 3.6.1 of the document, Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch, which can be found in the Other Binding Document, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints.

contain more uncertainty regarding the status of transmission elements, generator availability, and load levels.

ERCOT distributes CRR auction revenues to loads in one of two ways. First, revenues from cross-zone CRRs are allocated to loads ERCOT-wide. Second, revenues from CRRs that have the source and sink in the same geographic zone are allocated to loads within that zone. Figure 36 summarizes the revenues collected by ERCOT in each month for all CRRs, including both auctioned and allocated. We also show the amount of the discount provided to the PCRR recipients: the PCRR discount ("PCRR Intrazone Saved" and "PCRR Cross Zone Saved") is the difference between the auction value and the value charged to the purchaser.

Figure 36: 2023 CRR Auction Revenue



The total amount of CRR auction revenue increased 31% from last year to $1,442 million in 2023 (and up significantly from $831 million in 2021 and $725 million in 2020). These increases reflect participant expectations based on the trend of rising congestion over the past few years. Additionally, the total PCRR discount decreased slightly to $76 million in 2023.

2. CRR Profitability

CRRs are purchased well in advance of the operating horizon when actual congestion revenues are uncertain. Therefore, they may be purchased at prices below their ultimate value (based on CRR payments) and referred to as "profitable," or may be purchased at prices higher than their ultimate value and be "unprofitable." Historically, CRRs have tended to be profitable, and this was the case again in 2023, although results for individual participants and specific CRRs varied. To evaluate these results, Figure 37 shows the 2022 to 2023 monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the payout to the CRR owners.

Figure 37: CRR Auction Revenue, Payments, and Congestion Rent

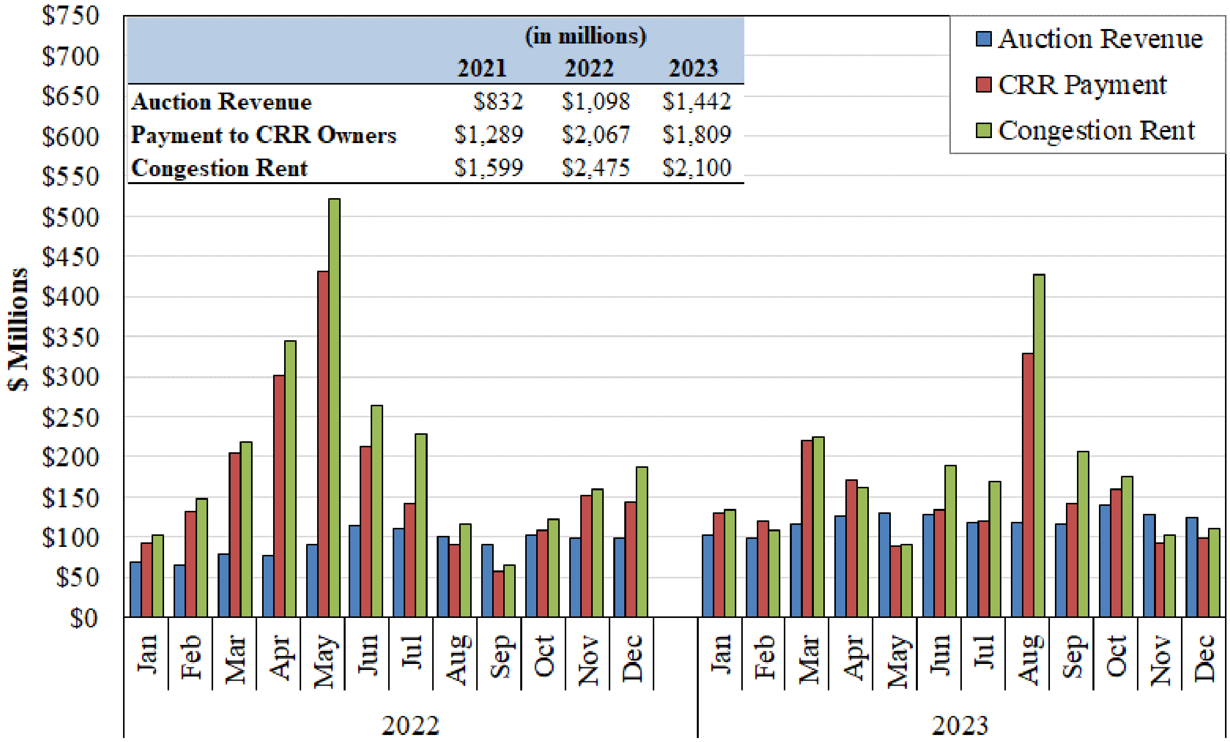


Figure 37 shows that for the entire year, participants purchased CRRs at roughly a 20% discount ($1,442 million to purchase the CRR compared to $1,809 million in payments). In 2023, the months of March and August were associated with the highest payment levels and the greatest differences between auction revenues and payments. This indicates that the market did not foresee these spikes in congestion. Because many CRRs are purchased months (if not years) in advance, the factors that contributed to the congestion in 2023 were not apparent when the bulk of the CRRs were purchased.[70]

Conversely, the CRR auction revenue in some months was higher than the CRR payouts when congestion was milder than expected. This occurred in November and December due to milder winter than expected in 2023.

Finally, the CRR payments can be less than the congestion rent collected in the day-ahead market when the quantity of CRRs sold is less than the day-ahead network flows. This occurred in 2023 as the payments in aggregate were approximately $290 million less than the day-ahead

70 Note that this "profit" does not account for the time value of money, which is notable because a CRR is paid for at the time of the auction and those auctions can be as much as three years in advance.

congestion rent. One reason this occurs in ERCOT is that the CRR network model uses line ratings that are 90% of a conservative estimate of the lowest line ratings for the month. Therefore, CRRs tend to be undersold on average. We discuss the resulting excess congestion rent in the next subsection. However, it is instructive to review the trends in these values over a longer timeframe, which we show in Figure 38 over the past 10 years.

Figure 38: Trends in CRR Auction Revenues and Payments

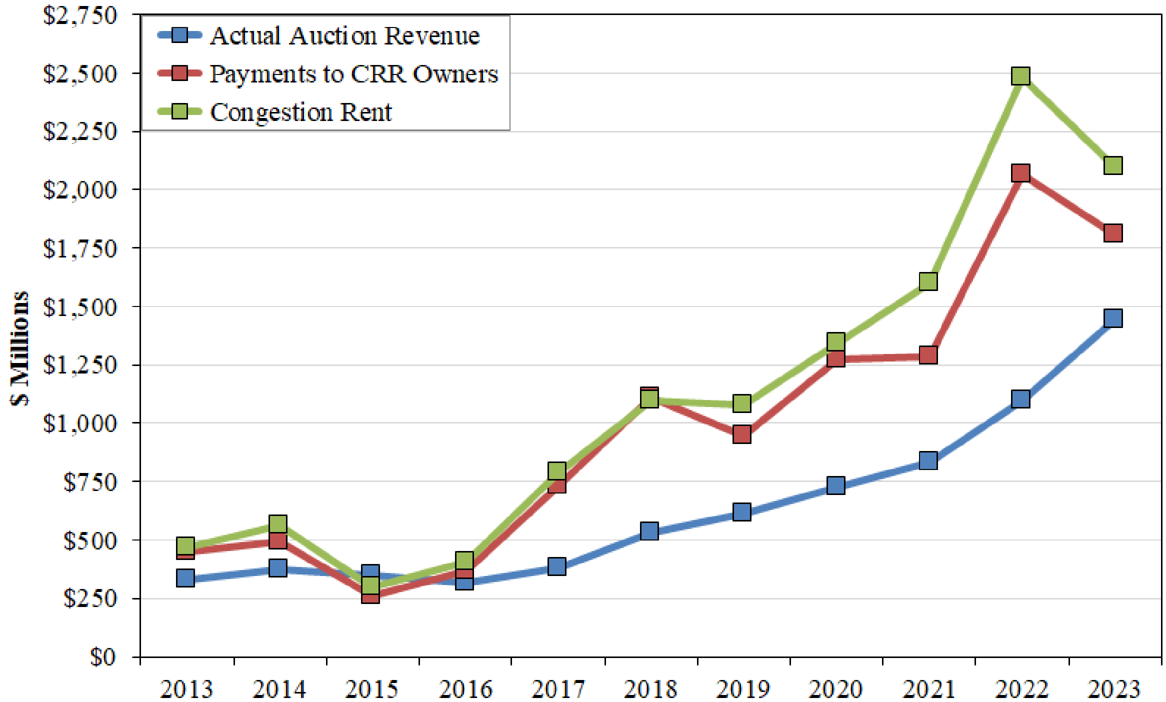


Figure 38 shows that 2023 marked a reversal of the trend in recent years of CRR payments becoming increasingly profitable relative to the initial CRR auction revenues. While CRR auction revenues continued to increase in 2023, CRR payments only exceeded such revenues by roughly 25%, a significant decrease from the 88% ratio observed in 2022. The figure shows that CRR auction prices and revenues have been rising steadily, but the actual congestion that drives CRR payments has grown more rapidly and been relatively volatile year to year.

3. CRR Funding Levels

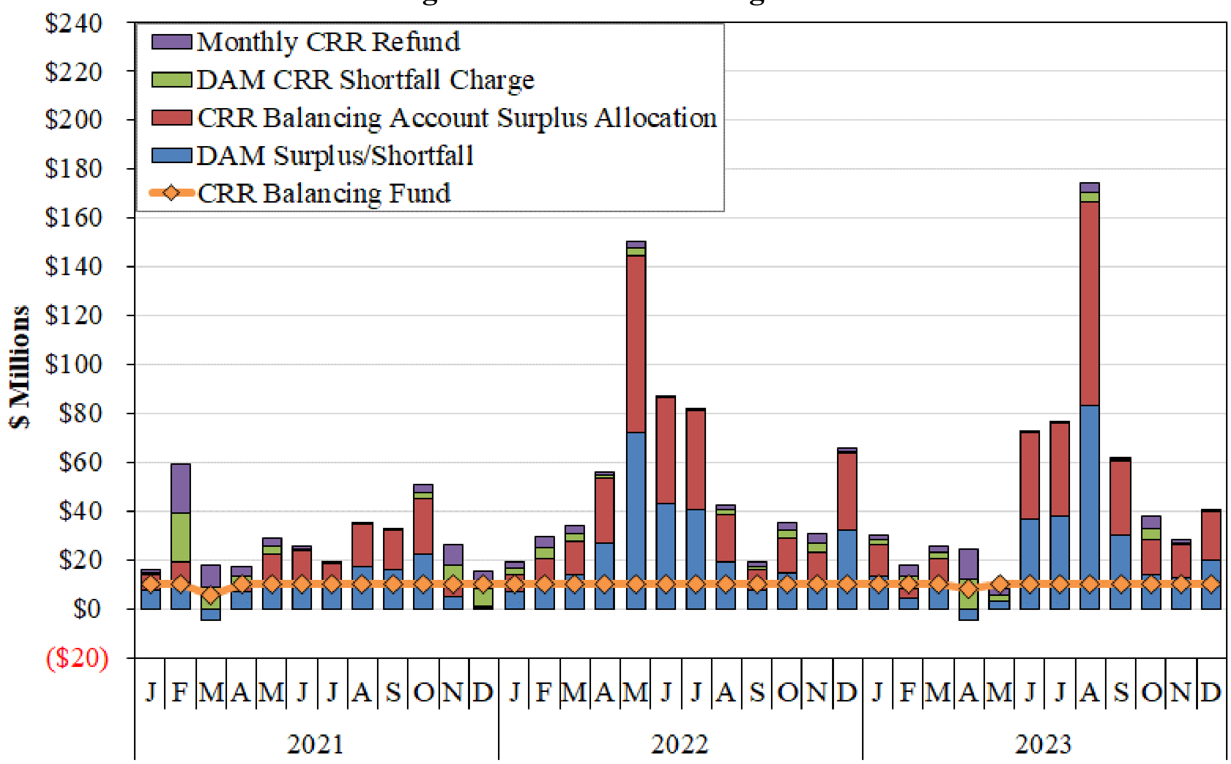
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payments to fully equal the target value because it makes the CRR more valuable to the holder and ultimately will increase the CRR auction revenues. While the target value is paid to CRR account holders most of the time, ERCOT will pay less than the target value when the day-ahead congestion rent is insufficient (i.e., CRRs are not "fully funded"). This occurs when the CRRs' network flows exceed the capability of the day-ahead network. This is generally the result of unforeseen outages or other factors that reduce the transmission capability between the CRR auction and the day-ahead market.

Settlement of CRR shortfalls. If this occurs on a specific facility (i.e., the flows on the facility are "oversold"), payments will be reduced to CRRs that sink at resource nodes (generator locations) that affect the flows on the oversold transmission element based on the reduction in day-ahead capability. After this derate of the CRR payments, if there are residual revenue shortfalls, all holders of positively valued CRRs will receive a prorated shortfall charge, which lowers the aggregate CRR payments.

Settlement of CRR Surpluses. When day-ahead congestion rent exceeds CRR obligations, ERCOT tracks the excess congestion rent in a monthly settlement process referred to as the balancing account. It uses the excess congestion rent residing in this balancing account to make the CRR holders that received shortfall charges whole, i.e., they are refunded their shortfall charges. If there is not enough excess congestion rent in the current month, the rolling CRR balancing fund from prior months can be used to fully pay CRR account holders.

Figure 39 shows the CRR balancing fund since the beginning of 2021. The CRR balancing fund has a $10 million cap, beyond which ERCOT disperses the remaining amount to load.

Figure 39: CRR Balancing Fund



The fact that ERCOT's processes are designed to only sell 90% of the forecasted transmission capability makes funding shortfalls much less likely. Figure 39 shows that the total day-ahead surplus was approximately $260.5 million, a decrease of approximately 13% from 2022. The total monthly CRR balancing account allocation to load grew by 32.1% to approximately $35.1 million as the balancing account remained at the $10 million cap in most months.

Importantly, even though the day-ahead market produced sufficient revenues to fully fund the CRRs, many CRRs were derated in 2023 because of the mandatory deration process. In total, CRR deratings resulted in a $15.5 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to approximately 99%, comparable to the previous year. Derating CRRs when the market is producing sufficient revenue introduces unnecessary risk to those buying CRRs, which ultimately results in lower CRR auction revenues. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A31 in the Appendix.

4. Real-Time Congestion Shortfalls

Just as reductions in network capability from the CRR auctions to the day-ahead market can result in CRR shortfalls, reductions in the network capability between the day-ahead market and the real-time market can result in real-time congestion shortfalls. In addition to outages or limit changes, binding real-time constraints that are not modeled in the day-ahead market can produce real-time congestion shortfalls. Shortfalls are costs incurred by ERCOT to lower the real-time flows when day-ahead scheduled flows exceed the flows the network can support in real time. These real-time congestion shortfall costs are paid for by charges to load as part of the uplift charge known as RENA.

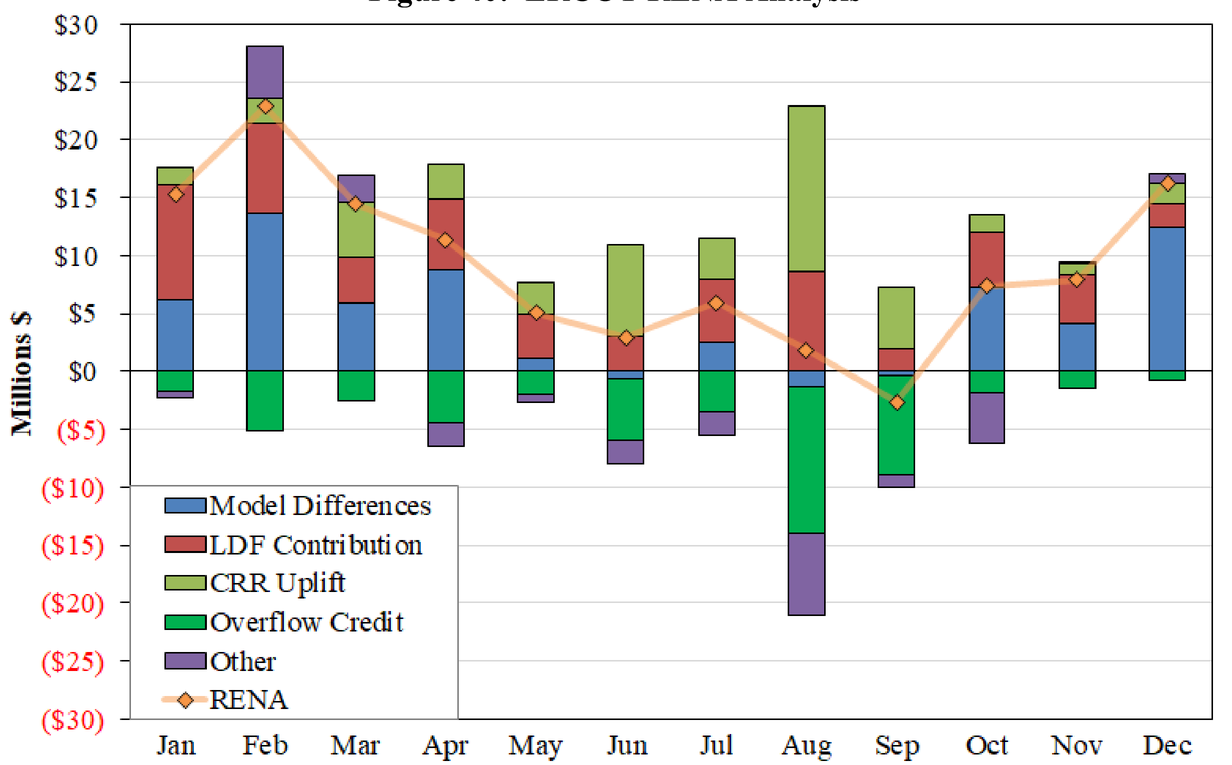
RENA exists to ensure that ERCOT remains revenue neutral, with payments equaling charges. In general, RENA uplift occurs when there are differences in power flow modeling between the day-ahead and real-time markets, including:

- Transmission network modeling inconsistencies between the day-ahead and real-time market (Model Differences);
- Differences between the LDF used in day-ahead and the actual real-time load distribution (LDF Contribution);
- Day-ahead PTP obligations linked to options[71] settlements (CRR Uplift);
- Extra congestion rent that accrued when real-time transmission constraints were violated (Overflow Credit); and
- Other factors, including the price floor in the real-time market at -$251 per MWh (Other).

Figure 40 below provides an analysis of RENA uplift in 2023, separately showing the components of RENA on a monthly basis. Net negative uplift represents a net payment to load.

[71] A PTP obligation linked to an option (PTPLO) is a type of CRR that entitles a NOIE's PTP Obligation in the day-ahead market to reflect the NOIE's PTP Option that it acquired in the CRR auction or allocation. Qualified PTPLOs are modeled as obligations but settled as if they were options.

Figure 40: ERCOT RENA Analysis



RENA uplift grew to total $109 million in 2023. Figure 40 shows that the largest positive contributor to RENA uplift in 2023 was the LDF Contribution totaling $61 million. Uplift associated with differences in the transmission models between the day-ahead and real-time markets was also one of the largest causes of RENA uplift, accounting for $60 million in RENA.

The task of maintaining accurate and consistent LDFs across all markets is a difficult one, made more so in areas with large amounts of localized load growth. To the extent ERCOT is unable to predict accurate LDFs across all markets, RENA impacts will persist. NPRR 1004, *Load Distribution Factor Process Update,* approved on August 11, 2020, is still pending implementation, but should help reduce this uplift.[72] This change will introduce load forecast models to calculate daily LDF rather than the current seasonal LDF based on historical patterns.

We encourage ERCOT to seek continuous improvement in aligning the transmission models between the day-ahead and real-time markets. This is a challenge for all wholesale market operators but must be a high priority because it facilitates efficient day-ahead market performance and eliminates opportunities for participants to extract rents associated with differences that ultimately raise the RENA uplift and the costs to ERCOT's consumers.

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72 NPRR 1004, *Load Distribution Factor Process Update*, available at: https://www.ercot.com/mktrules/issues/NPRR1004.

VI. Market Operations

One important characteristic of any electricity market is the extent to which it meets the reliability needs of the system. Ideally, the market would efficiently schedule resources to meet these needs at the lowest cost and minimize or eliminate entirely the need for ERCOT operators to take manual out-of-market actions. This section evaluates key aspects of ERCOT operations, with an emphasis on out-of-market operating actions.

A. Reliability Unit Commitments

The ERCOT market does not include a mandatory centralized unit commitment process. The decision to start-up or shut-down a resource is made by the market participant (i.e., "self-scheduling"). ERCOT's day-ahead market informs these decisions, but schedules are only financially binding. There is no physical obligation to start a resource, but the market participant must buy back the energy at real-time prices if it does not start a resource that was committed in the day-ahead market. Self-scheduling depends on price signals to ensure an efficient combination of units are online and available for dispatch. In its role as reliability coordinator, ERCOT may commit units outside the market via the RUC process to ensure the reliable operation of the grid.

RUC-committed resources are eligible for make-whole payments, but forfeit some, or all, market profit through a claw-back provision. Generators complying with a RUC instruction are guaranteed to recover their costs, but any market revenue received in excess of their costs are either partially or fully clawed back depending on whether it submitted a day-ahead offer. However, suppliers can opt to forfeit the make-whole payments and waive the claw-back charges, effectively self-scheduling the resource and accepting the market risks.

From a market pricing perspective, ERCOT applies an offer floor of $250 per MWh to the resource's offer and calculates a Real-Time On-Line Reliability Deployment Adder (RTORDPA) that was described in Section II. The RUC process is carried out both on a day-ahead and hourly basis. Additional resources may be needed for two primary reasons:

- To satisfy the forecasted system-wide demand (89% of RUC commitments in 2023); or
- To manage a transmission constraint (11% of RUC commitments in 2023).

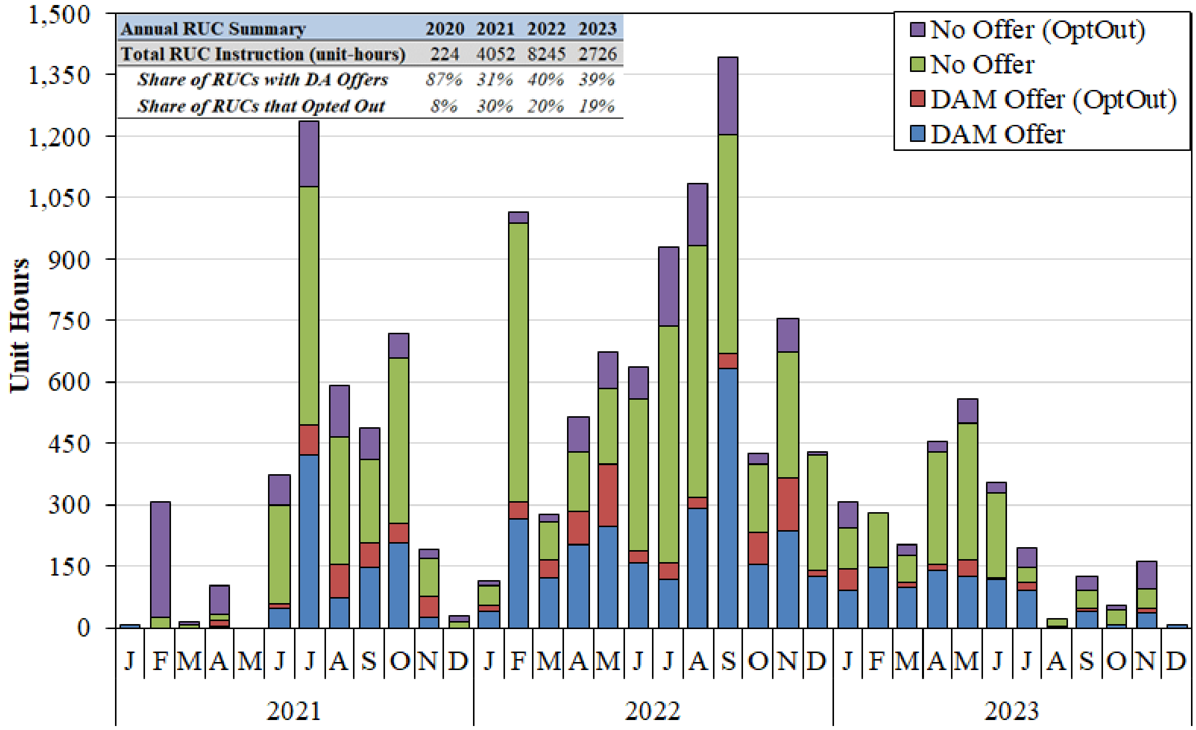
Finally, RUC make-whole payment costs are allocated to:

- QSEs that do not provide enough capacity to meet their short real-time position, rendering them "capacity short;" and
- All QSEs on a load-ratio share basis.

In this subsection, we summarize the trends in RUC commitments by ERCOT and discuss its effects on participants and overall costs.

Figure 41 shows RUC activity by month for the past three years, indicating the volume of generators receiving a RUC instruction that had offers in the day-ahead market or chose to opt-out of the RUC instruction.

Figure 41: Day-Ahead Market Activity of Generators Receiving a RUC



ERCOT adopted process improvements leading up to 2021 that resulted in very low levels of RUCs, and prior to 2021, most RUCs were made to manage transmission congestion. This ended suddenly in June 2021 when ERCOT adopted a much more conservative operational posture.[73] This posture included committing more generation and doing so earlier in the day. This resulted in a sharp increase in RUC activity from mid-2021 to mid-2023. Most of these commitments were made to satisfy market-wide capacity needs, rather than to manage congestion.

Figure 41 shows that RUC commitments declined significantly in 2023, which may be due to:

- The sizable increase in 10-minute reserve procurements with the implementation of ECRS, which made more capacity available to ERCOT, on average;
- Higher levels of self-commitment caused by the higher prevailing prices in 2023 after ECRS implementation; and
- Significantly higher solar output during the peak hours in the summer.

73 For a complete list of the historical changes in the RUC processes and rules, see Section I in the Appendix.

Figure 41 also shows that roughly 20% of RUC-committed capacity opted-out, consistent with 2022, relinquishing entitlement to make-whole payments. The remaining 80% of RUC resources were subject to partial clawback of revenues (50% for those with day-ahead offers) or full clawback of revenues (those without offers).

It is important to note that economic resources with day-ahead offers frequently do not opt out of RUC commitment. This is because receiving full operational cost recovery via RUC make-whole, while also retaining half of any revenues above cost, can undermine the incentive to self-commit resources when they would likely be economic.[74] To address this issue, in April of 2023, consumers filed NPRR 1172, *Fuel Adder Definition, Mitigated offer Caps, and RUC Clawback,* which proposed elimination of the 50% clawback for RUC resources with day-ahead offers and implementation of a 100% clawback for economic RUC resources.[75] The NPRR was approved by the PUCT in February of 2024 and went into effect on March 1, 2024.[76]

B. Thermal Generation Outages and Deratings

At any given time, some portion of ERCOT's generation is unavailable because of outages and deratings. Derated capacity is the difference between the registered summer maximum capacity of a resource and its actual capability. It is common for generating capacity to be partially derated because the resource cannot achieve its installed capacity level due to technical or environmental factors (e.g., equipment failures or ambient temperatures).

Figure 42 shows outages and derates of thermal capacity for ERCOT on an average hourly basis during 2023.[77] The two shades of blue in the figure are the planned or forced outages or derates that participants reported to ERCOT. The two shades of maroon show the outages and derates that participants did not report.

74 It is notable that there is no requirement that the day-ahead market energy offer that triggers the reduced claw-back percentage be feasible, i.e., able to be awarded by the day-ahead market engine based on resource temporal constraints.

75 The IMM recommended that ERCOT eliminate the 50% claw-back for day-ahead offers and implement a 100% claw-back for economic RUC resources in its 2022 State of the Market Report (see Recommendation 2022-2) and filed comments supporting NPRR 1172.

76 NPRR 1172, *Fuel Adder Definition, Mitigated offer Caps, and RUC Clawback*, available at: https://www.ercot.com/mktrules/issues/NPRR1172.

77 Due to limitations in outage data, we infer the outage type by cross-referencing unit status information provided to ERCOT with outage submissions, assuming that all scheduled outages are planned outages. The designation of "Forced" includes outages and deratings reported in the outage scheduler less than 7 days before the start of the outage. The designation of "Planned" includes outages and deratings reported more than 7 days before the start of the outage. "Unreported outages or deratings" are resources with 'OUT' status codes or deratings below the summer capacity levels that are not reported in the outage scheduler.

Figure 42: Thermal Hourly Average Outages and Derates

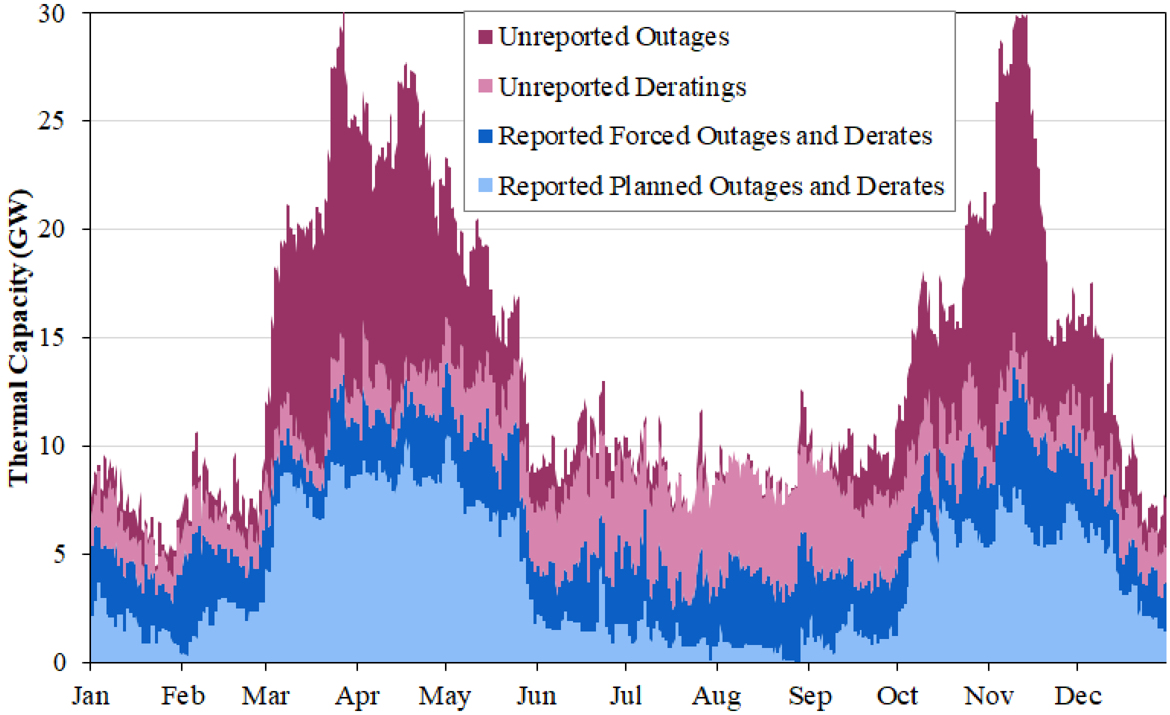


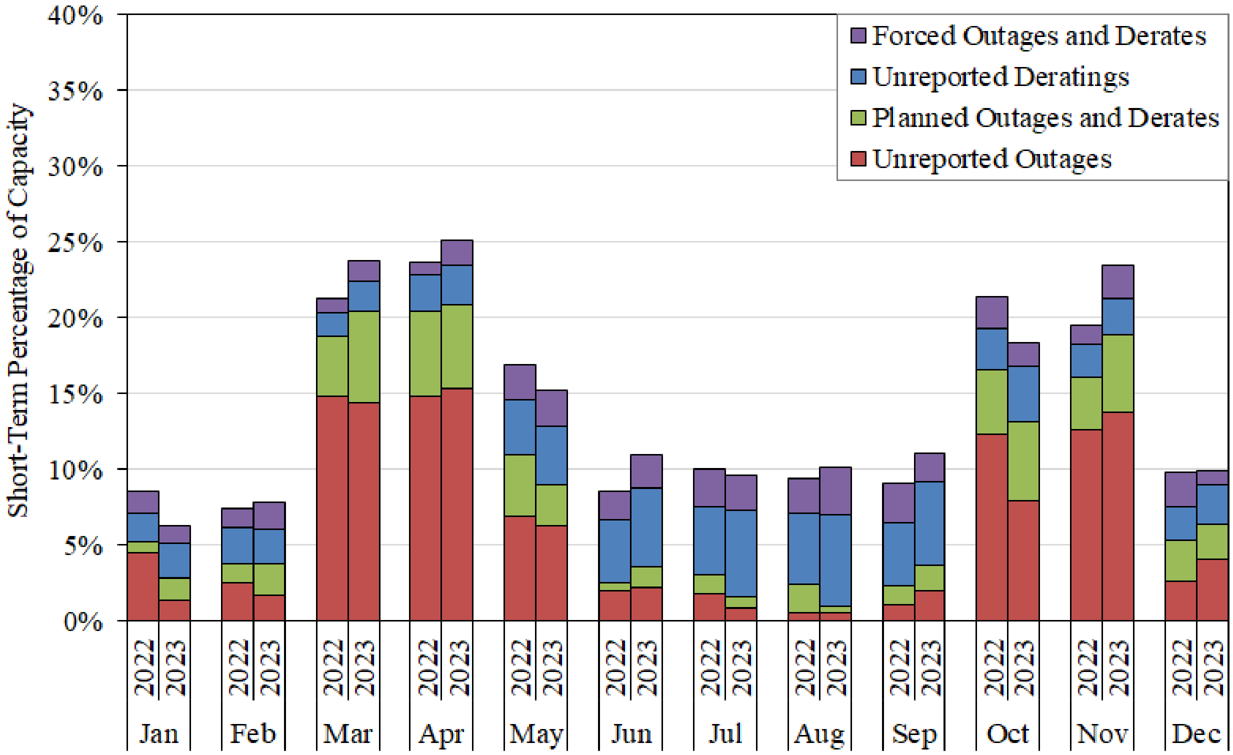
Figure 42 provides key results, some of which are expected and others that raise concerns:

- Reported planned and forced outages followed expected patterns. Planned outages fell to very low levels in the summer. Forced outages fluctuated in an expected range and rose slightly in the summer when more resources were running.
- Average unreported deratings rose in the summer, peaking at 6 GW, which may reflect the fact that high ambient temperatures reduce the maximum output of thermal resources.
- Unreported outages fluctuated remarkably and peaked at almost 17 GW in the shoulder seasons but fell to very low levels in the summer and winter months. These outages are not randomly distributed and track closely with the pattern of planned outages.

Unreported outages and deratings are the most troubling because they can impact ERCOT's ability to plan for and coordinate the operation of the system. Hence, it would be beneficial to strengthen the requirements for suppliers in ERCOT to report their known outages and derates.

In the next analysis, we focus specifically on reported and unreported short-term (<30 days) planned and forced outages and deratings of thermal resources. Figure 43 provides a comparison of the monthly average outage and derating values for 2022 and 2023. It shows that short-term outages and deratings in 2023 followed very similar patterns to the prior year with planned outages and deratings and unreported outages all falling in the summer and winter months when energy is likely most valuable and rising in shoulder months when load (and net load) tends to be low. Conversely, unreported deratings have tended to rise to their highest levels in the summer, which may reflect the higher ambient temperatures as discussed above.

Figure 43: Short-Term Deratings and Outages



At the end of 2022, NPRR 1084, *Improvements to Reporting of Resource Outages, Derates, and Startup Loading Failures*, was implemented to improve reporting of resource outages, derates, and startup load failures. However, Figure 43 indicates that a majority of the MWs were still not reported in the outage scheduler. Figure A33 in the Appendix shows the average amount of short-term outages and deratings lasting less than 30 days for the year and for each month during 2023. Figure A34 in the Appendix includes long-term outages.

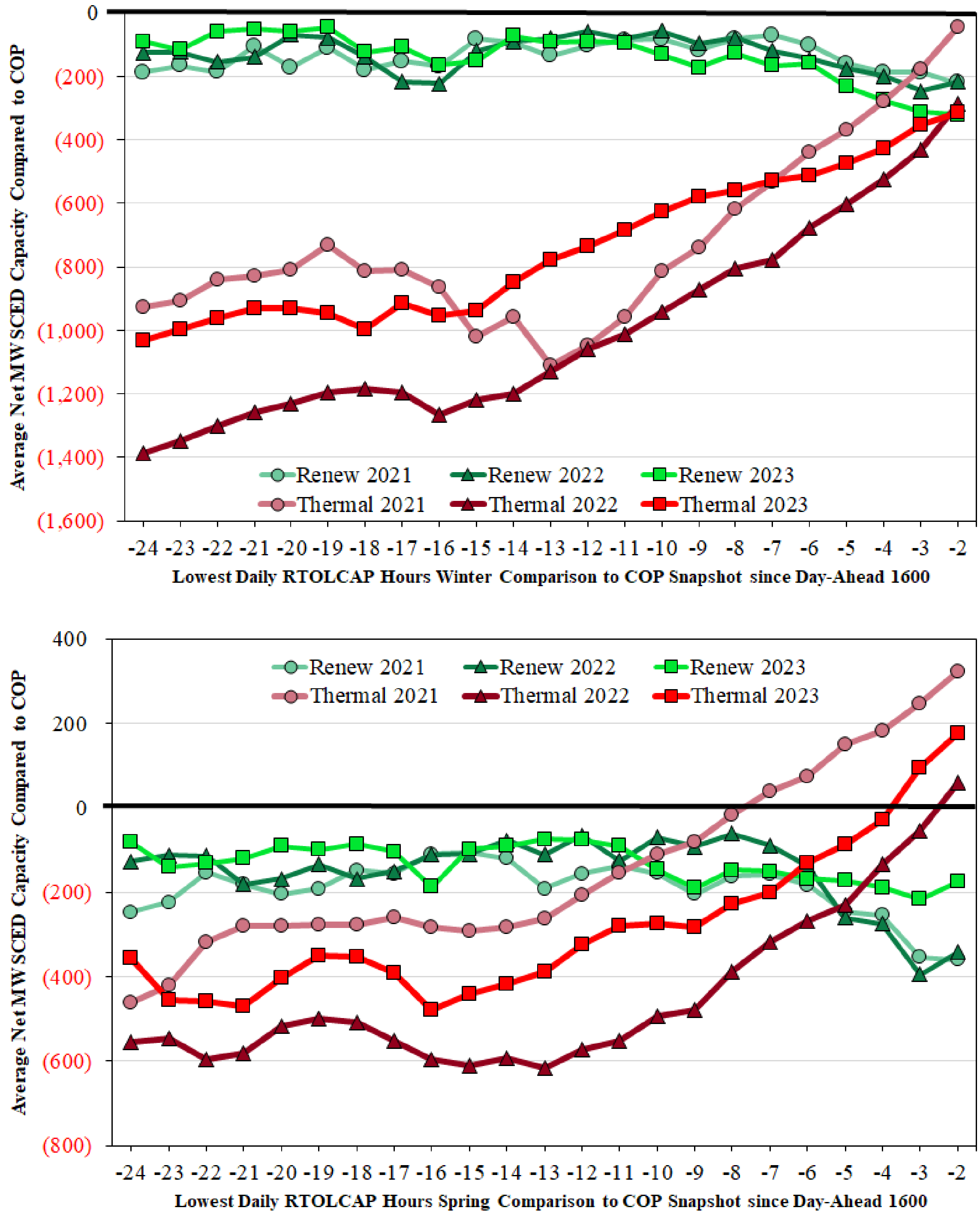
C. QSE Operation Planning

The Current Operating Plan (COP) is the mechanism used by QSEs to communicate the expected status of the QSE's resources to ERCOT. After aggregating COP information about the amount of capacity that QSEs expect to be online every hour, ERCOT identifies any potential locational or system-wide capacity deficiency. If a deficiency is identified, and ERCOT determines that there is insufficient time to allow for self-commitment, ERCOT will issue a RUC instruction.

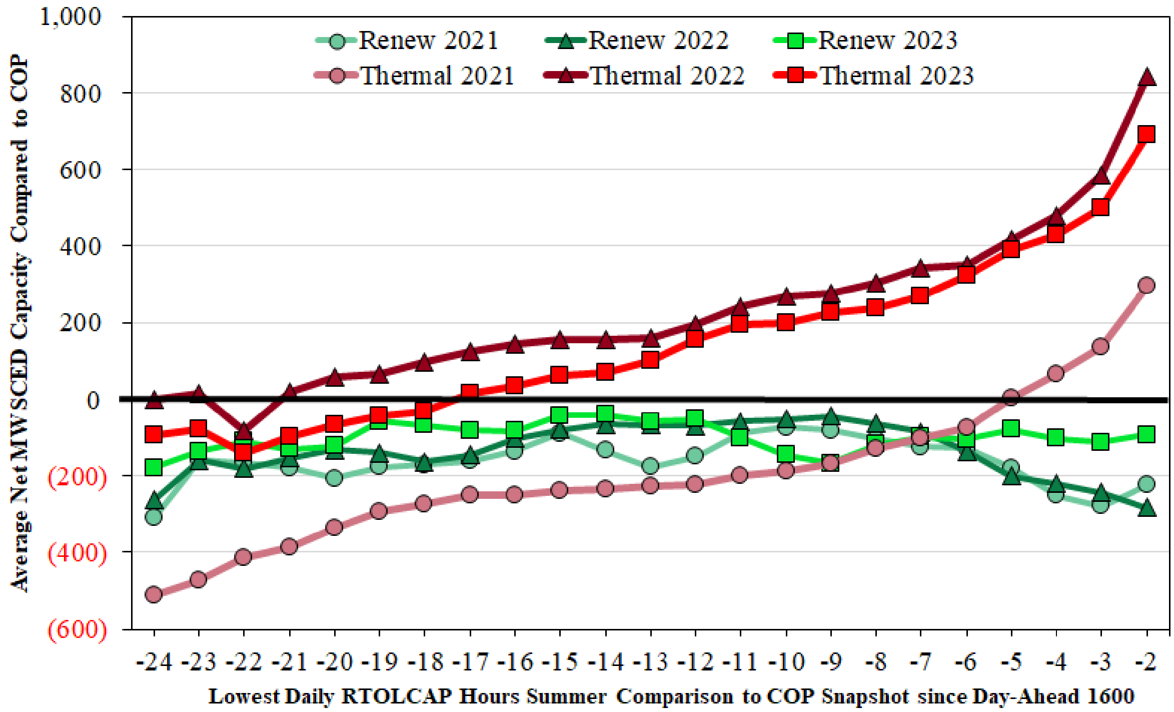
The accuracy of COP information greatly influences ERCOT's ability to effectively commit resources through the RUC process. COPs are updated on an ongoing basis by QSEs for each operating hour. QSE expectations about which units will be online in a particular hour should be most accurate in the COP submitted just before the operating hour.

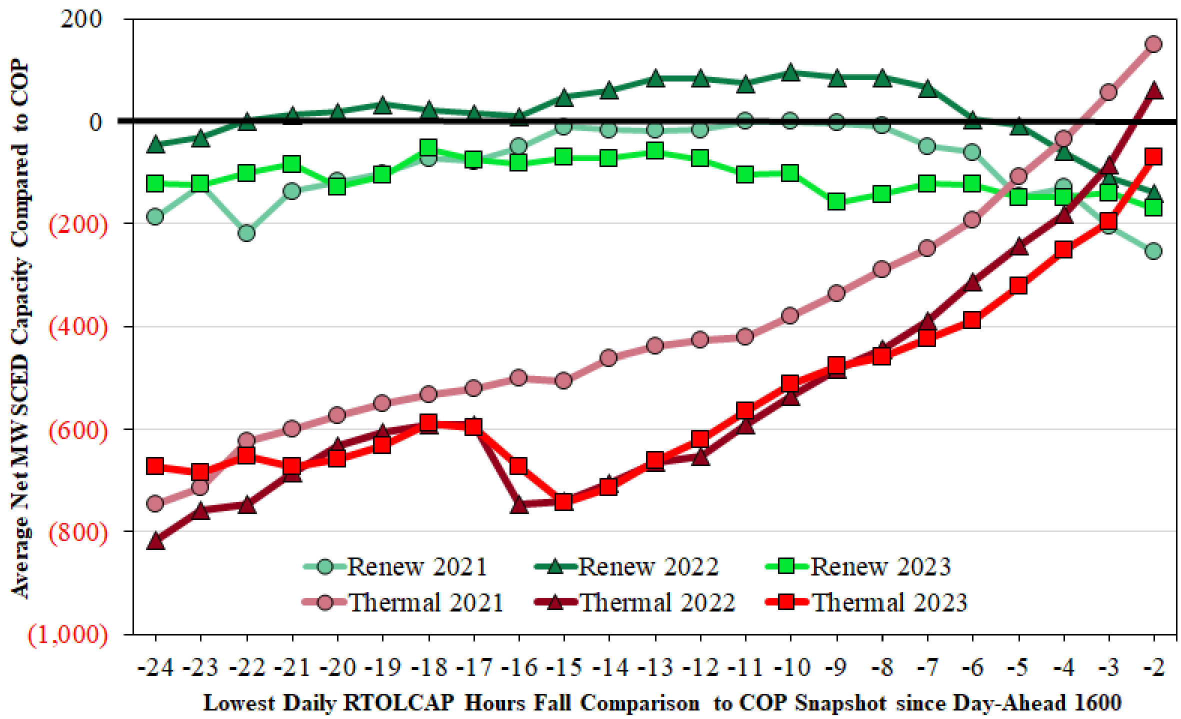
Figure 44 evaluates the accuracy of the COPs by showing the average differences between: a) the actual available online capacity for thermal and renewable resources and b) the forecasted available online capacity for thermal and renewable resources in the COPs leading up to the hour. We show these averages seasonally for the hour with the lowest operating reserves (RTOLCAP), which is the tightest market hour.[78]

Figure 44: Capacity Commitment Timing for Daily Lowest RTOLCAP Hours Per Season



78 "Thermal" includes coal, gas steam, combustion turbines, combined cycles, and nuclear resources. "Renew" includes wind and solar resources.





Thermal Resources. Figure 44 generally shows large substantial values for the thermal resources in most seasons and values rise closer to real-time. The negative values correspond to COPs that over-report the resources they will have online. Reporting higher levels of available capacity may reduce QSE's exposure to uplift cost allocations associated with RUC commitments. In all seasons, the thermals resource values rise in the hours approaching real time, which indicates that online thermal capacity is being revised downward. This is most likely explained by participants deciding not to commit some resources based on prevailing prices, or resources experiencing outages or derates. However, by two hours ahead of real time, the values are positive in all seasons except the winter, indicating that the COPs close to real-time tend to understate the amount of online capacity that will be available to the real-time market.

Renewable Resources. Figure 44 shows that COPs for wind and solar resources provide a relatively stable view for the 24 hours prior to tightest hour of each day for all of the 2023 seasons. This is expected because these values are driven by the resource forecasts (rather than commitment decisions), which should not change substantially unless the weather forecasts are changing. It also shows that the amounts are generally over-forecasted by a small amount, which may be due to curtailments in real-time that are not predicted in the COPs or by forced outages.

Accurate COP statuses are important for many reasons, including their use to forecast reserve levels in the RUC process. There are currently no ERCOT-automated penalties or other consequences for submitting inaccurate COPs or failing to update COPs as generator commitments change. As ERCOT has transitioned to a much more conservative operating posture, COP inaccuracies will predictably lead to more RUC commitments and higher costs for ERCOT's customers. Hence, we encourage ERCOT to actively review COP inaccuracies and work with suppliers to improve their performance. In the longer term, it may be beneficial to consider new provisions that would provide economic incentives for suppliers to submit accurate COPs. Additional analysis on COP behavior is presented in Section VI of the Appendix.

D. Firm Fuel Supply Service

A new Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of dual-fuel generators to purchase fuel to be stored on site. [79] As of July 1, 2023, FFSS also pays certain gas-fired resources that have owned natural gas stored offsite and accompanied by firm transportation and storage agreements.[80] Implementation of FFSS was part of the PUCT's Phase I Market Design effort and in response to Texas Senate Bill 3.

ERCOT issued Requests for Proposals (RFP) to provide FFSS for the November 15 to March 15 obligation period during the winters of 2022/2023 and 2023/2024.[81] FFSS was deployed three times in 2023, which are shown in Table 5. All the 2023 deployments were associated with the first obligation period during the winter of 2022/2023.

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79 *See* https://www.ercot.com/services/programs/firmfuelsupply; NPRR 1120, *Create Firm Fuel Supply Service*, available at: https://www.ercot.com/mktrules/issues/NPRR1120.

80 NPRR 1169, *Expansion of Generation Resources Qualified to Provide Firm Fuel Supply Service in Phase 2 of the Service*, available at: https://www.ercot.com/mktrules/issues/NPRR1169.

81 *Wholesale Electric Market Design Implementation*, Project No. 53298, ERCOT Letter Regarding FFSS Phase I Procurement Results (Sept. 27, 2022). ERCOT Report of the Second Procurement of the Reliability Product, Firm Fuel Supply Service (FFSS) (Sept. 21, 2023).

Table 5: Firm Fuel Supply Service Deployments

Day	Firm Fuel Supply Service MWs	Average RT Price	Operating Day Online Reserves Minimum
1/31/2023	757.5	$40.11	8,943
2/1/2023	757.5	$41.07	8,121
2/2/2023	38.5	$40.13	8,941

Table 5 indicates that operating reserve levels (8000 to 9000 MW) and pricing outcomes (roughly $40 per MWh) did not reflect the need for FFSS on the three days. Since utilizing Firm Fuel Supply Service Resources (FFSSRs) is costly, we encourage ERCOT to develop clear procedures for deploying FFSS capacity. For example, it would be reasonable to trigger the deployment of FFSS capacity based on a forecasted shortage or near-shortage of operating capacity or the identification of an unresolvable transmission constraint.

In evaluating FFSS, we have identified two issues that can lead to inefficient market outcomes and higher costs:

- ERCOT removes the capacity of the deployed FFSSRs from reserves when calculating operating reserve adders. This can cause the market to set inefficiently high prices through the ORDC when the system is not short of reserves. Absent the FFSS programs, these resources would likely be running, so removing them from the ORDC adder calculation can lead to unjustified shortage pricing.
- FFSSRs have their fuel costs covered by the FFSS payment, which causes them to have the incentive to run at any price even though they may actually be burning expensive fuel oil that consumers must reimburse. This is inefficient and raises the costs of the FFSS unnecessarily and potentially reduces the amount of firm fuel that may be available for future deployments.

To address these issues, we recommend ERCOT consider modifying the FFSS rules to: a) include the capacity of the FFSSRs in the ORDC, and b) requiring FFSSRs to offer at costs that accurately reflect costs of the firm fuel. These changes would produce more efficient prices during deployments, help conserve the firm fuel so it is available when most needed and ultimately lower the cost of FFSS.

VII. Resource Adequacy

One of the primary functions of the organized wholesale electricity market is to provide economic signals that will facilitate investment needed to maintain a set of resources adequate to satisfy the system's needs. Without revenues from a capacity market, energy and ancillary service prices provide the only source of revenue for generators. To ensure that revenues will be sufficient to maintain resource adequacy in an energy-only market, prices should rise during shortage conditions to reflect the diminished reliability and increased possibility of involuntary curtailment of service to customers. The sufficiency of revenues is an average, long-term expectation, while actual revenues may vary greatly from year to year.

The ERCOT market has seen many years of excess generation capacity, with revenues less than the estimated costs of investing in new generation (known as the cost of new entry (CONE)). If long-term expectations of revenues sufficient to support resource adequacy are to be met, revenues that far exceed the CONE must occur in some years as well, as they have in recent years. This principle of cyclical revenue sufficiency to maintain resource adequacy is applied in the evaluation in this section. Nonetheless, it is critical that the peaks in revenues be driven by fundamental supply and demand.

This section begins with an evaluation of these economic signals in 2023 by estimating the "net revenue" that resources received from the ERCOT energy and ancillary services markets, including comparing ERCOT to other markets. Next, we review the effectiveness of the Scarcity Pricing Mechanism.[82] We present the current estimate of planning reserve margins for ERCOT, followed by a description of the factors necessary to ensure resource adequacy in an energy-only market design, as also discussed in the Section I. Finally, we conclude with a brief discussion of the Reliability Must Run and Must Run Alternative (MRA) processes.

A. Net Revenue Analysis

We calculate net revenue by determining the total revenue that could have been earned by a generating unit, less its variable production costs. Put another way, net revenue is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. In ERCOT's energy-only market, the net revenues from the energy and ancillary services markets alone provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. To the extent that revenues are available through the day-ahead market or other forward bilateral contract markets, these revenues are ultimately derived from the expected real-time energy and ancillary service prices. Although the net revenues we present are based on past prices, it is important to note that

82 *See* 16 TAC §25.505(g). This report generally employs the more accurate "shortage pricing" terminology in place of "scarcity pricing," except in cases where "Scarcity" is part of a name.

suppliers will typically base investment decisions on expectations of future electricity prices, including the likelihood of whether shortage pricing may occur.

Figure 45 and Figure 46 show historical net revenues available to support investment in new natural gas combustion turbines and combined cycle generators, respectively. These two units represent the marginal new supply that may enter when new resources are needed. We compute the energy net revenues based on the generation-weighted settlement point prices from the real-time market, assuming they will sell energy or reserves in any hour it is profitable to do so.[83]

The figures also show the estimated CONE for each technology for comparison purposes. The CONE values in 2023 were roughly the same as in 2022, with the CONE for these resources ranging from roughly $80 to $130 per kW-year. The figures show that the ERCOT markets provided net revenues substantially above CONE in 2023. For example, net revenues for:

- Combustion turbines ranged from $224 per kW-year to $257 per kW-year; while
- Combined-cycle units ranged from $228 per kW-year to $272 per kW-year.

These values are substantially higher than the net revenues in 2022, which while above CONE, were below $200 per kW-year. In an energy-only market, shortages typically play a key role in delivering the net revenues an investor needs to recover its investment. Such shortages will tend to be clustered in years with unusually high load or poor generator availability. Such was the case in 2022 when shortage pricing during tight conditions led to relatively high net revenues in comparison to most of the years before 2021.

However, shortage pricing was not a significant driver of the increase in net revenues in 2023. As described in detail in Section 2, ERCOT's implementation of the new ECRS product in June 2023 resulted in frequent spikes in prices as high as $5000 per MWh, even when no actual shortages were occurring. These shortages were largely the result of ERCOT procuring large quantities ECRS from dispatchable resources and then sequestering them from the real-time energy market dispatch. This caused the dispatch model to perceive shortages that were not real.

These price spikes doubled real-time energy prices between June and December 2023, which substantially increased the net revenues for all types of resources. Figure 45 and Figure 46 show that we estimate that roughly half of the net revenues for the two hypothetical new resources were derived from the inefficient price effects of ERCOT's ECRS implementation. Absent these effects, their net revenues would have been very close to their respective CONE values, with net revenues decreasing approximately 30% from 2022 levels. This is not surprising because 2022 exhibited much higher true shortage pricing derived from the ORDC than did 2023.

83 For purposes of this analysis, we used the following assumptions: heat rates of 7 MMBtu per MWh for a combined-cycle unit, 10.5 MMBtu per MWh for a gas turbine, and $4 per MWh in variable operating and maintenance costs. A total outage rate (planned and forced) of 10% was assumed for each technology. It does not include: 1) start-up and minimum energy costs; or 2) ramping restrictions that can prevent generators from profiting during brief price spikes.

Figure 45: Combustion Turbine Net Revenues

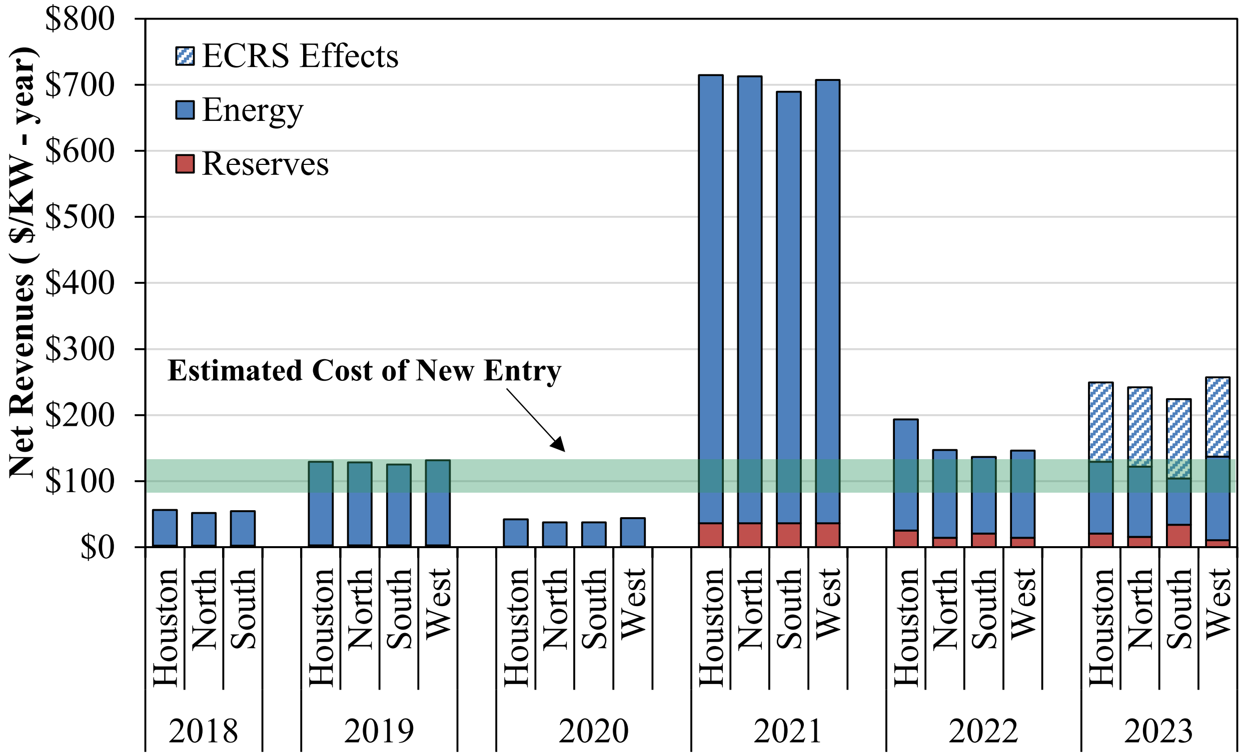
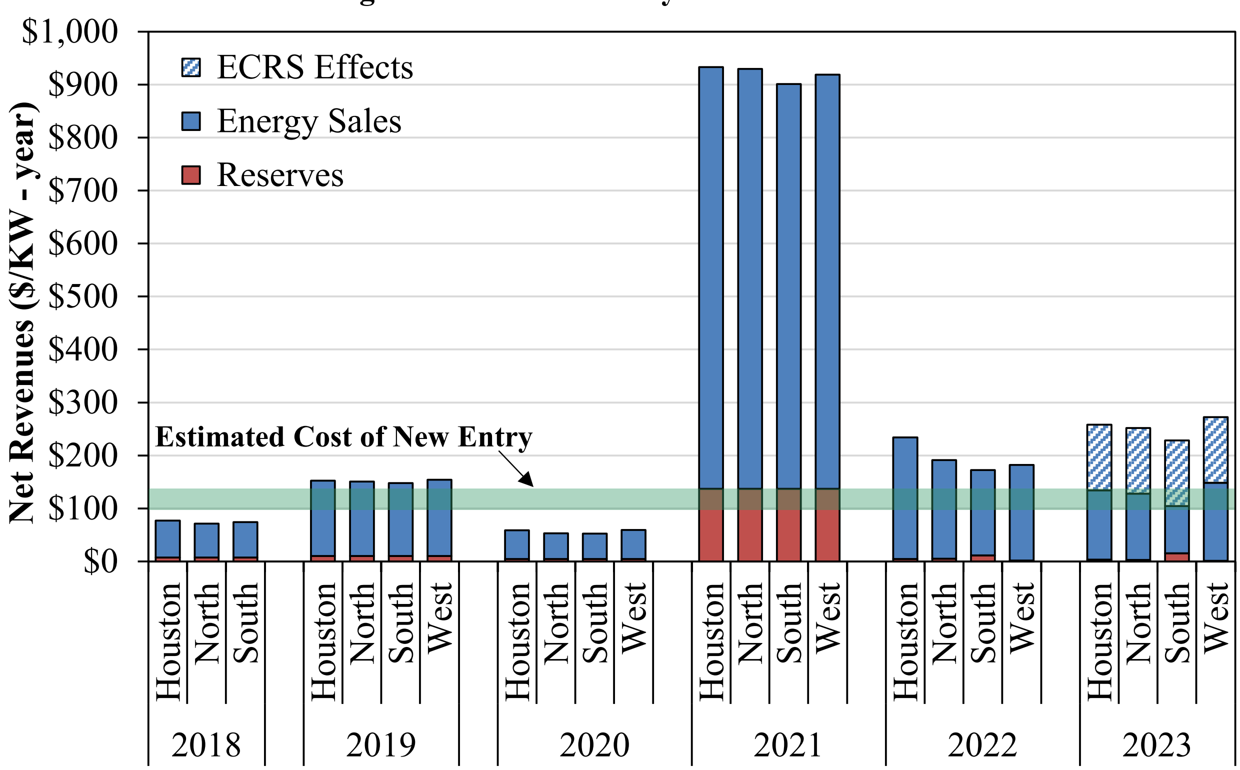


Figure 46: Combined Cycle Net Revenues



These figures also show modest differences between the net revenues in different zones – the average net revenues were highest in the West zone in 2023 because frequent congestion raised prices in that zone. We also saw the expected separation in natural gas prices between the Waha and Katy locations in 2023. Lower fuel costs at Waha increased the net revenues for resources in areas served by the Waha location relative to resources served by Katy. In Section VII of the Appendix, we show the fuel price trends at these locations and the differences in net revenues that they would produce for the two new resources. This analysis shows that the new resources would produce net revenue roughly 10% higher at the Waha location than at Katy based on 2023 revenues.

B. Net Revenues of Existing Units

Resource adequacy depends not only on motivating developers to invest in new resources, but also providing efficient economic incentives for existing resources to remain in operation. We evaluate these incentives in this subsection.

Given the high correlation of natural gas prices on energy prices, we evaluate the economic viability of existing coal and nuclear units that have experienced fluctuations in net revenues in recent years. Non-shortage prices, which are substantially affected by the prevailing natural gas prices, are the primary determinant of the net revenues received by these baseload units.

1. Discussion of the Profitability of Different Resource Classes

Nuclear Profitability. According to data published by the Nuclear Energy Institute at the end of 2023, the average total generating cost for nuclear energy was $30.92 per MWh in 2022.[84] The 2022 total generating costs were similar to those in 2021 ($31.17 per MWh). Assuming that operating costs in ERCOT are similar to the U.S. average, and that nuclear operating costs have either continued to be stable or are declining, ERCOT's 5 GW of nuclear capacity should have costs around $30 per MWh. Given the average energy price in 2023 of $65 per MWh, it is likely that the nuclear units in ERCOT were highly profitable in 2023.

Coal Profitability. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.84 per MMBtu in 2023, lower than in 2022. At these average fuel prices, coal units in ERCOT that stayed online during shortage conditions in the summer were likely receiving sufficient revenue to cover operating costs.

Natural Gas-Fired Resource Profitability. As shown in the prior subsection, net revenues for new natural gas-fired resources were substantially higher in 2023. This is likely also the case for all existing gas-fired resources that were available during the periods when energy prices were spiking during the summer.

84 https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context.

2. Net Revenues by Technology and Location

Figure 47 shows the net revenues at different locations for a variety of technologies. Because natural gas prices can vary widely, the revenues for natural gas units are shown for the Houston zone (reflecting Katy hub prices) and the West zone (for Waha). Historically, the 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 basis difference in the two natural gas prices continued in 2023.

Figure 47: Net Revenues by Generation Resource Type

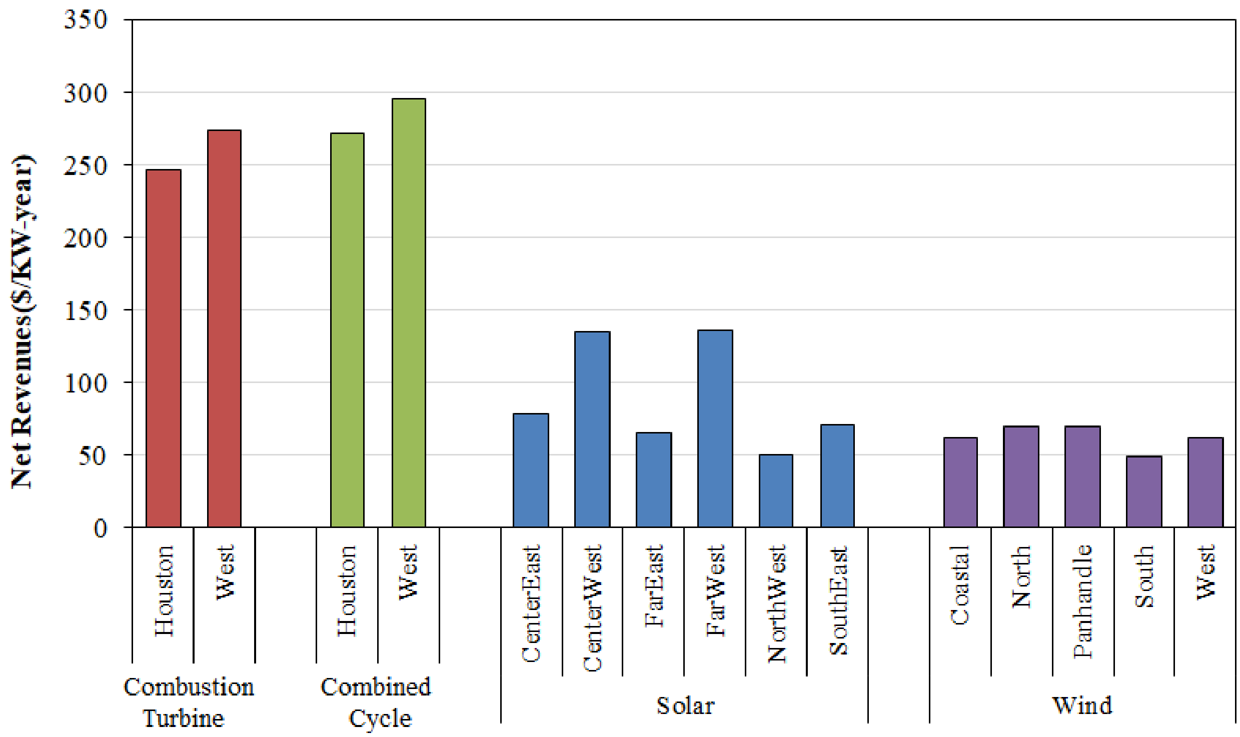


Figure 47 also shows the net revenues for wind and solar generation at multiple locations. The profitability of those resources is chiefly determined by the available natural resource and the prevailing price in high-output hours. Net revenues for wind and solar generation were lower than gas technologies in 2023 in all areas. This is partly because wind resources tend to produce less output during hot summer conditions.

More importantly, price spikes generally occur in the highest "net load" hours, when load is high and wind and solar generation output is low. Therefore, their net revenues will tend to be much lower than dispatchable resources that have the flexibility to maximize their output when prices are highest. This is not true of wind and solar generation, which are typically producing at relatively low levels when prices are highest.

3. Interpreting Single-Year Net Revenues

These results indicate that on a stand-alone basis during 2023, the ERCOT markets provided sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Net revenues were unusually high for a year without frequent shortage conditions, largely due to the impact of the implementation of ECRS on energy prices, as described in the Review of Real-Time Market Outcomes. The response of investors in natural gas resources to these prices will depend on their future revenue expectations in the long run.

The prevailing capacity surplus may limit these expectations, although policymakers and ERCOT have been pursuing market changes that would increase expected future revenues (e.g., the ORDC Floor "bridge solution" and the PCM). It is also important to recognize that investors may invest in new technologies, such as ESRs or load-flexible renewables, which have different value propositions than traditional generation.

For all these reasons, it is important to be cautious when interpreting single-year net revenues and projecting their long-term effects. However, net revenues in four of the last five years have exceeded CONE for new gas resources. Please see Section VII of the Appendix for additional detail and discussion of the net revenue results in 2023.

C. Planning Reserve Margin

Ultimately, the importance of the market signals discussed above is that they facilitate the long-term investment and retirement decisions by market participants that will maintain an adequate resource base. This subsection discusses the trends in the planning reserve margin, which is one measure of the adequacy of the resource base.

The market responds to high prices in several ways, which all raise planning reserve margins:

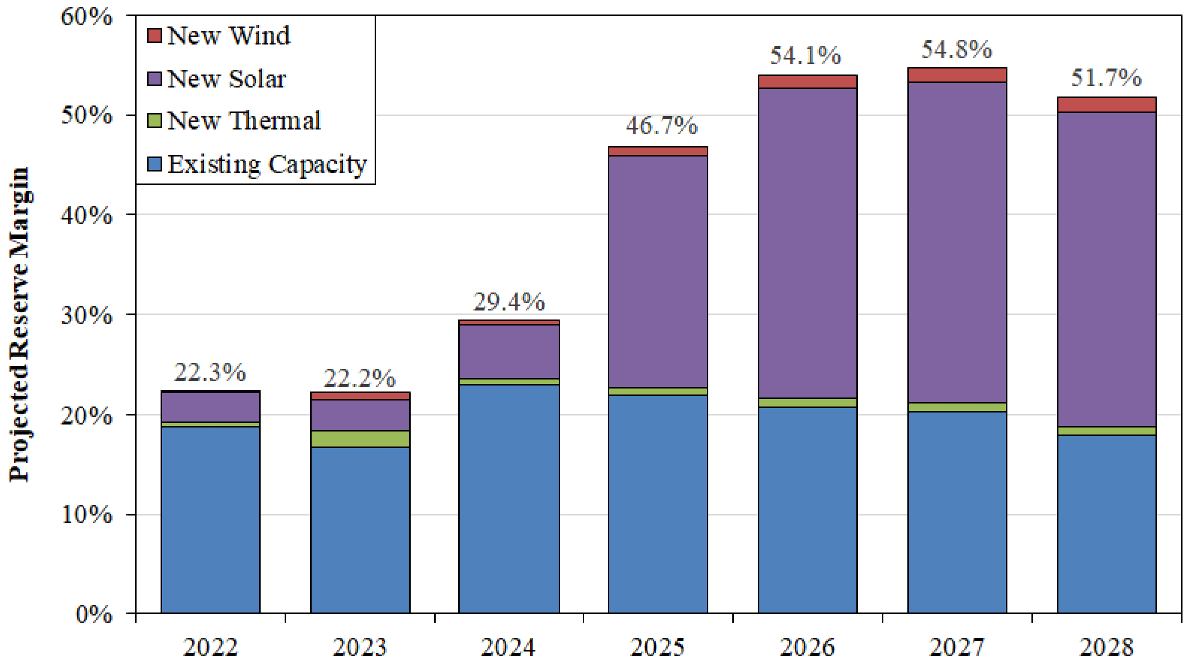
- Building new generation facilities;
- Increasing investment in existing resources, including more maintenance to improve availability or forestall retirement, as well as capital investment to increase the capability of the resource; and
- Increasing investment in load systems and procedures to enable reduced consumption during shortage pricing events (demand response).

In 2023, there were no significant expected or actual shortages, which is consistent with the prevailing planning reserve margin in ERCOT. It is important to be cautious in predicting the potential frequency of shortages based on the level of planning reserves. Although they are closely correlated, shortages may occur even when the planning margin is relatively high if the right confluence of supply and demand contingencies occur simultaneously.

Figure 48 shows ERCOT's previous and forecasted planning reserve margins over the next five years, including the new generators that account for the changes in the reserve margin. ERCOT continued to see significant increases in utility-scale solar resources in 2023. Based on ERCOT's interconnection queue, this trend should continue over the next several years, increasing the forecasted planning reserve margin for 2024 through 2026 up to around 54%.[85]

Figure 48 indicates that Texas heads into the summer months of 2024 with a healthy planning reserve margin of 29.4%, an increase of approximately 7% from the reserve margin for 2023. We note that the current Capacity, Demand and Reserves (CDR) report does not consider the capacity from ESRs in the planning reserve margin calculation (however the 2023 spring, summer, and fall Seasonal Assessment of Resource Adequacy (SARA) report and the new Monthly Outlook on Resource Adequacy (MORA) report do). Including an expected contribution to peak demand by the growing quantity of ESRs would further increase the reserve margin. Additionally, the CDR relies solely on the hour-ending (HE) 5 p.m. (the peak hour). The peak net load hour is likely a more accurate predictor of shortage conditions, particularly as solar generation continues to enter the ERCOT system.[86]

Figure 48: Projected Planning Reserve Margins



Source: ERCOT SARA May 2022, CDR Dec 2022, CDR Dec 2023

85 *See* Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2024-2033 (Dec. 8, 2023), available at: https://www.ercot.com/files/docs/2023/12/07/CapacityDemandandReservesReport_Dec2023.pdf.

86 The December 2023 version of the CDR includes a scenario using HE 8 p.m. and a scenario with ESRs. Together, those bring the 2024 summer reserve margin to 23.2% from 32.1%.

D. Effectiveness of the Shortage Pricing Mechanism

One of the primary goals of an efficient electricity market is to ensure that, in the long term, there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. Generators earn revenues from three sources: energy and ancillary services prices during non-shortage, energy prices during shortage, and capacity payments. Without a capacity market in ERCOT, suppliers' revenues are derived solely from energy prices under shortage and non-shortage conditions. Revenues during non-shortage conditions tend to be more stable as planning margins fluctuate, but shortage revenues are the primary means to provide investment incentives when planning margins fall (or incentives to keep existing units in operation). Therefore, the performance of shortage pricing in the ERCOT market is essential.

1. Background on Shortage Pricing in ERCOT

Shortage pricing refers to the price escalation that occurs when supply is not sufficient to satisfy all the system's energy and operating reserve requirements. In these cases, prices should reflect the reliability risks borne by the system as the shortage deepens. Ideally, the value of the shortage should be priced based on the LOLP at varying levels of operating reserves multiplied by VOLL.

Shortage pricing in ERCOT occurs through the ORDC that was implemented in 2014, which automatically increases the prices as reserve levels drop. The ORDC is described in more detail in Section II. Since it has been in effect, the ORDC has had a growing impact on real-time prices, especially since 2019 when lower reserves led to higher shortage pricing. Additionally, the ORDC calculation has been systematically changed over time, which generally involved shifting the curve so it delivers higher revenues during shortages.

The highest step on the ORDC adder was set to \$9,000 per MWh in June 2014 and changed to \$5,000 per MWh in January 2022.[87] The real-time prices are increased by the value of the remaining reserves in the system as specified by the predefined ORDC.

The Scarcity Pricing Mechanism includes a provision termed the Peaker Net Margin (PNM) threshold that is designed to provide a pricing "fail-safe" measure. Over the course of a calendar year, if the PNM exceeds a threshold of three times the annual cost of new entry of new generation plants (\$315,000 \$/MW-year) the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[88]

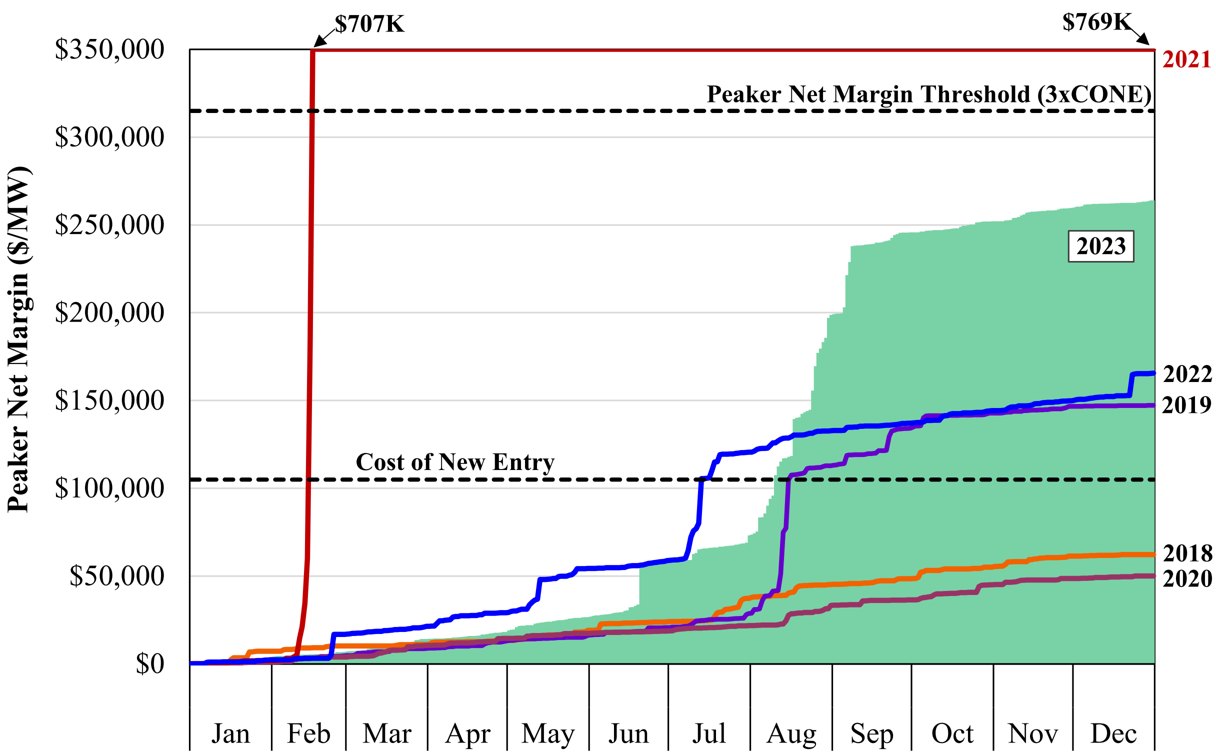
87 Prior to April 29, 2022, the VOLL was equal to the System-Wide Offer Cap. After the PUCT's approval of the Proposal in Project No. 53191, the ERCOT VOLL was decoupled from the System-Wide Offer Cap.

88 The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

2. Shortage Pricing and the Peaker Net Margin in 2023

Section II summarizes and discusses the shortage pricing that occurred in 2023, which was relatively modest. The shortage pricing adders increased real-time prices by an average of less than $2 per MWh over all hours. However, prices were very high in many periods for reasons other than ERCOT's shortage pricing framework. To place these prices in perspective and provide a comparison with the results from other years, Figure 49 shows the cumulative PNM results for 2023 and a selection of historical years.

Figure 49: Peaker Net Margin



This figure shows that PNM results in 2023 were higher than any other year except 2021, totaling approximately $263,968, but still well below the $315,000 PNM threshold. The PNM threshold was exceeded for the first and only time in ERCOT's history during the ERCOT operating day of February 16, 2021.[89] The relatively high PNM results in 2023 were largely due to the impact of the implementation of ECRS on real-time energy prices, as the first spike in the metric occurred in mid-June immediately after ECRS was introduced. Most subsequent increases were also due to the effects of the increased sequestering of resources providing 10-minute reserves from the real-time energy market. Absent these inefficient price effects, the PNM in 2023 would have been well-below 2019 and 2022, which both exhibited much more frequent true shortage pricing than 2023.

89 Once the peaker net margin threshold is achieved, the system-wide offer cap is set at the low system-wide offer (LCAP), which is currently set at $2,000 per MWh.

3. Changes to the ORDC

The PUCT directed notable changes to the ORDC in 2019 and 2020. These changes transitioned the ORDC to a blended curve and shifted the ORDC so that it would produce higher adders. Over the past two years, more significant changes have been made to the ORDC curve with the intent of strengthening incentives to invest in dispatchable resources and motivate participants to self-commit resources earlier as market conditions tighten. We discuss these changes below.

Following Winter Storm Uri, the PUCT worked with participants to develop a blueprint for reforms to the design of the wholesale electric market to improve price signals and operational reliability.[90] The first set of significant changes to the ORDC were implemented on January 1, 2022 as part of Phase I of the blueprint, which included setting: a) the MCL at 3,000 MW and b) the high system-wide offer cap to $5,000 per MWh. Although lowering the top step of the ORDC to $5,000 would reduce revenues under the most extreme conditions, raising the MCL causes prices to rise more quickly at lower reserve levels. This increases incentives to bring generation online and prompt consumer demand response earlier. The effect of these changes was substantial in 2022, raising shortage revenues by $1.7 billion, but were much lower in 2023 when shortage conditions were less frequent and less severe.

The second set of changes were implemented in 2023 to serve as a bridge solution that would further increase revenues for dispatchable resources until the PCM can be implemented (see Section I of the Appendix for more details on the PCM).[91] After evaluating several options, ERCOT recommended a multi-step floor to the On-Line ORDC price adders: 1) $10 per MWh when reserve levels are between 6,500 and 7,000 MWs, and 2) $20 per MWh when reserves are less than 6,500 MW. The stated purpose of this multi-step floor is to provide targeted increases in resource revenues that align with the level of revenue increases expected from the PCM.[92] ERCOT implemented these floors in November 2023.

ORDC naturally accrues to generators that are running during tight conditions, which are often the times that renewable generation is low. Table 6 shows the ORDC revenue in 2023 by generation type, compared to that generator type's contribution to the total energy production for the year. This table shows that thermal resources (coal, gas, and nuclear) produced 68% of the total generation and received 84% of the ORDC revenues.

90 *Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

91 Wholesale Electric Market Design Implementation, Project No. 53298, Order (Jan. 19, 2023).

92 Specifically, the back-cast analyses performed by ERCOT for 2020 and 2022 indicated that, by applying the proposed price adder floors to the ORDC, the total revenue increase would be in the range of $500 million, a level of increase that aligns with the average revenue that the PCM is expected to provide as calculated by E3 in its report to the PUCT. Wholesale Electric Market Design Implementation, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Report and Recommendation on Bridge Solution (Apr. 20, 2023).

Table 6: ORDC Revenue by Fuel Type

	Thermal	Wind & Solar	Storage	Hydro	Biomass
ORDC Revenue ($ millions)	$462.4	$76.3	$8.6	$1.5	$1.5
% of ORDC Revenue	*84%*	*14%*	*1.56%*	*0.28%*	*0.28%*
ORDC Revenue per MWh	$1.51	$0.54	$13.50	$5.19	$6.14
Total Generation (GWh)	*305,360*	*140,073*	*638*	*294*	*250*
% of Generation	*68%*	*31%*	*0.14%*	*0.07%*	*0.06%*

Table 6 shows that ORDC revenues in 2023 decreased to approximately $550 million, a significant reduction from the high $3B revenue in 2022. ORDC revenue decreased because peak market conditions were not as tight in 2022 and because of the higher system lambdas in 2023, as described in Section II: Review of Real-Time Market Outcomes.

Table 6 also shows solar and wind resources received a combined 14% of the ORDC revenues while representing 31% of total generation. The ORDC is an effective mechanism to reward generators that are producing during tight conditions. The ORDC is designed to automatically adjust over time to reflect the changes in market uncertainty in order to ensure it will continue to provide efficient incentives to resources. Recommendation 2022-5 is intended to ensure this adjustment mechanism works effectively.

4. Reliability Must Run and Must Run Alternatives

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability. A Reliability Must Run (RMR) Unit is a resource operated under the terms of an agreement with ERCOT that would not otherwise be operated, except that the resource is necessary to provide voltage support, stability, or management of local transmission constraints under credible single contingency criteria.

If ERCOT determines a resource is needed to maintain electric stability, it can enter into an RMR agreement to pay the plant an “out-of-market” payment to continue operating. ERCOT also has a process to consider other resources, known as Must-Run Alternatives (MRA). In lieu of paying an uneconomic resource to remain operational to ensure grid reliability, ERCOT may issue a Request for Proposals for alternative solutions that can address the specific reliability concern. A Notice of Suspension of Operations (NSO) is required of any generator suspension that lasts greater than 180 days.

A number of NSOs were submitted in 2023.[93] One such NSO was B_Davis_B_DAVIG1(Barney Davis), which was subsequently withdrawn. The Barney Davis NSO was withdrawn after ERCOT issued a RFP for capacity for winter 2023-2024.[94] In ERCOT's market notice announcing the RFP, ERCOT identified Barney Davis as one of the Resources potentially eligible to offer capacity in response to the RFP, stating that ERCOT intended to inquire with the Resource about its capability to return to service under the RFP requirements.[95]

Ultimately, ERCOT determined that none of the units that had submitted NSOs in 2023 were necessary to support ERCOT transmission system reliability; therefore, no RMR contracts were awarded in 2023.[96]

93 https://www.ercot.com/services/comm/mkt_notices/archives?page=1&sf=&order=down&category=&keyword=NSO&sd=2023-01-01&ed=2023-12-31&pageSize=25.

94 https://www.ercot.com/files/docs/2023/10/02/M-A100223-01-Issuance-of-Request-for-Proposals-for-Capacity-for-Winter-2023-24-under-ERCOT-Protocols-Section-6.5.1.1(4).pdf.

95 *Id.*

96 The last RMR contract was executed in 2016, for Greens Bayou 5, a 371 MW natural gas steam unit built in 1973 and located in Houston. That RMR contract was ultimately cancelled, effective May 29, 2017.

VIII. Analysis of Competitive Performance

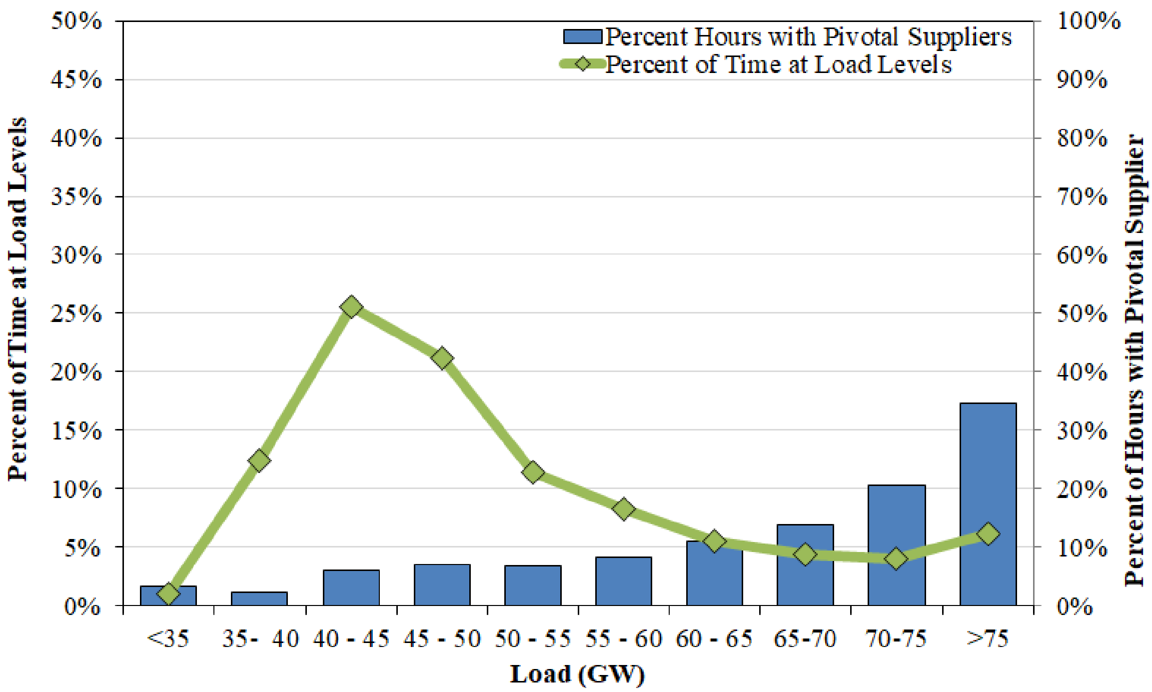
In this section, we evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). This section begins by evaluating a structural indicator of potential market power, then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, this section includes a summary of the Voluntary Mitigation Plans (VMPs) in effect during 2023.

Based on these analyses, we find that the ERCOT wholesale markets performed competitively in 2023. However, the introduction of ECRS in June 2023 tended to make the market less competitive, as the higher reserve requirements made large suppliers more pivotal in meeting the requirements. The impact of ECRS on real-time electricity prices is discussed in Section II.

A. Structural Market Power Indicators

Traditional market concentration measures are not reliable market power indicators in electricity markets. They do not include the impacts of load obligations that affect suppliers' incentives to raise prices. They also do not account for excess supply, which affects the competitiveness of the market. A more reliable indicator of market power is whether a large supplier is "pivotal," i.e., whether its resources are required to meet demand or manage a constraint. Figure 50 shows the results of our pivotal supplier analysis by showing the portion of time at each load level there was a pivotal supplier. The figure also displays the portion of time each load level occurred.

Figure 50: Pivotal Supplier Frequency by Load Level



At loads greater than 75 GW, there was a pivotal supplier greater than 30% of the time in 2023, down from approximately 50% in 2022 for loads greater than 70 GW. A relatively high pivotal supplier percentage is expected at high load levels because the largest suppliers' resources are more likely to be needed as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed in approximately 9% of all hours in 2023, lower than the 15% of all hours in 2022. These reductions in the pivotal supplier frequencies are likely due to the influx of resources developed by smaller generation developers, including solar resources and ESRs.

We cannot make inferences regarding market power solely from pivotal supplier data because it does not consider the contractual position of the supplier. Bilateral and other financial contract obligations can affect whether a supplier has the 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 recommend that the "small fish" rule be eliminated 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).

It should be noted that the analysis above evaluates the structure of the entire ERCOT market. In general, local market power in smaller geographic areas of the power region that can become isolated by transmission constraints raise more substantial competitiveness concerns. As more fully discussed in Section V, this local market power is addressed through: (a) structural tests that determine "non-competitive" constraints that can create local market power; and (b) the "mitigation" or application of limits on offer prices in these areas.

B. Evaluation of Supplier Conduct

This subsection provides the results of our evaluation of actual conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. First, we examine unit deratings and forced outages to detect physical withholding, and then we review the "output gap" used to detect economic withholding.

In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher prices, allowing the supplier to profit from its other sales in the market. Because forward prices are highly correlated with spot prices, price increases in the real-time energy market can also increase a supplier's profits in the bilateral energy market. This strategy is profitable if the incremental profit exceeds the foregone profits from its withheld capacity.

1. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes unavailable for dispatch resources that are otherwise physically capable of providing energy and are economic at market clearing prices. A plant operator can withhold either by derating a unit or declaring the unit as forced out of service. Because generator deratings and forced outages are unavoidable, the goal of the analysis in this subsection is to differentiate justifiable deratings and outages from physical withholding. We conduct a test for physical withholding by examining deratings and outage data to ascertain whether the data are correlated with conditions under which physical withholding would likely be most profitable.

The pivotal supplier results shown in Figure 50 indicate that the potential for market power abuse rises at higher load levels, as the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources because their output is generally most profitable in peak periods.

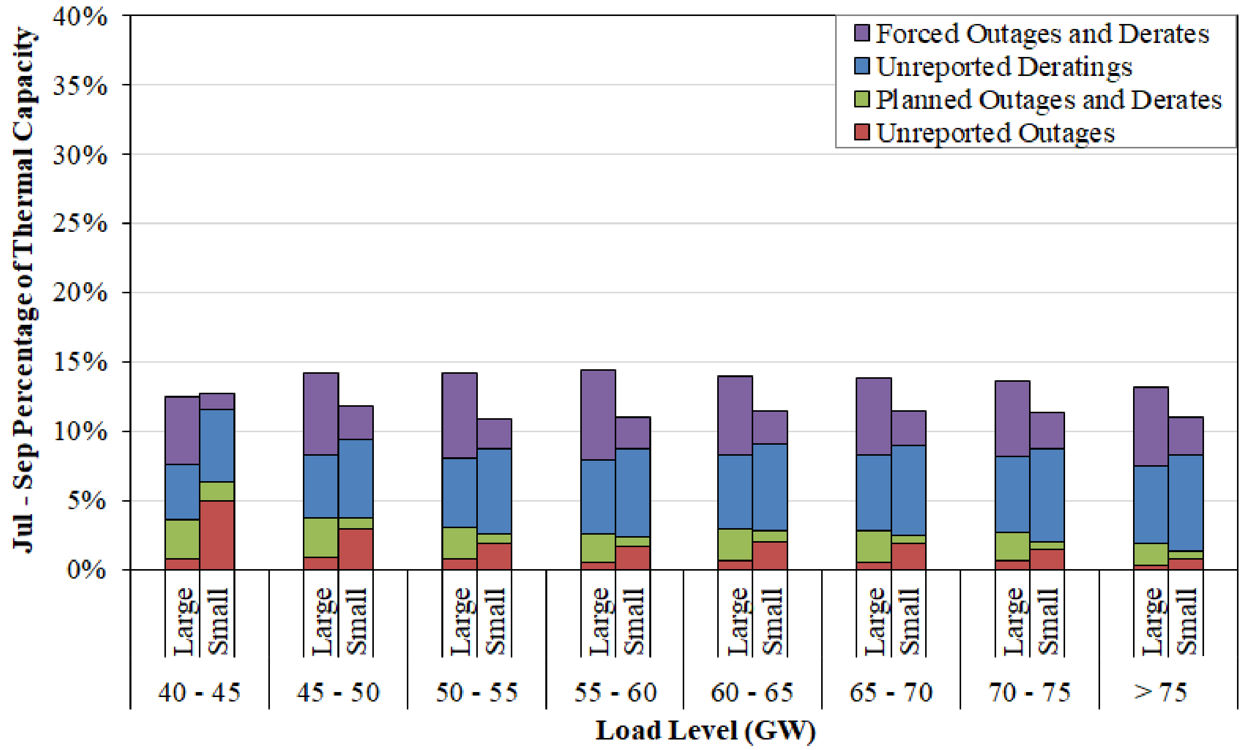
Figure 51 shows the average short-term deratings and forced outages as a percentage of total installed capacity for large and small suppliers under different real-time load levels during the months of July through September. Figure A44 in the Appendix shows the same results for the other quarters of the year. Like the description of COP Accuracy in Section VI, outage percentages representing the entire year are presented in this section. Portfolio size is important in determining whether suppliers have incentives to withhold available resources. Hence, we compare the patterns of outages and deratings of large and small suppliers.

Long-term deratings are unlikely to constitute physical withholding given the cost of such withholding and are, therefore, excluded from this analysis. Wind, solar, ESR, and private-use networks also are excluded from this analysis because of the high variation in the availability of these classes of resources. The large supplier category includes the five largest suppliers in ERCOT. The small supplier category includes the remaining suppliers.

Figure 51 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' capability to fall. This effect can be seen in the growing Unreported Derates for large and small suppliers alike. However, this is more than offset by the reduction in planned outages and derates.

Because small participants have less incentive to physically withhold capacity, the outage rates for small suppliers serve as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels modestly exceeded those for small suppliers, but remained at levels that are small enough to raise no competitiveness concerns.

Figure 51: Outages and Deratings by Load Level and Participant Size



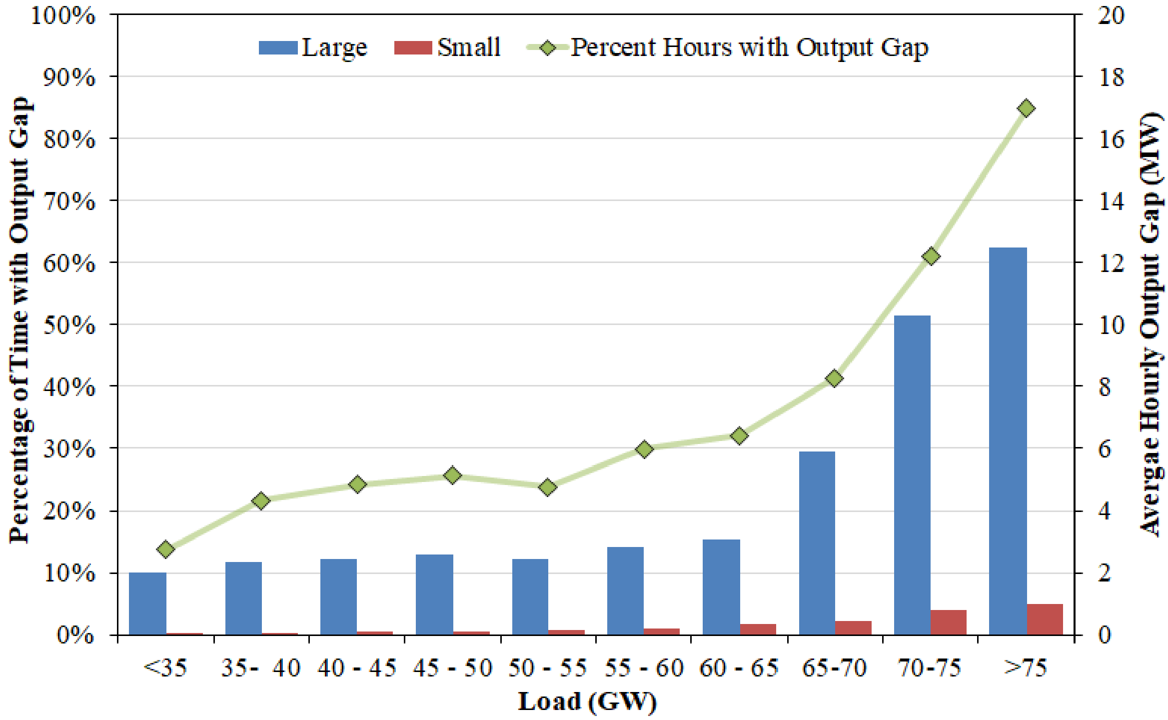
2. Evaluation of Potential Economic Withholding

In this subsection, we evaluate potential economic withholding by calculating an "output gap." The output gap is the quantity of energy that is not being produced by online resources even though the output is economic to produce by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers for a resource to reduce its dispatch level.

Resources included in the output gap are those that are committed and producing at less than full output. Energy not produced from a committed resource is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $30 per MWh. The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

Figure 52 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer (i.e., the unit's mitigated offers), but with a few changes. We use generic costs instead of verifiable costs for quick-start units since verifiable costs may contain startup costs that are inappropriate for comparison here. In addition, fuel adders are removed since they represent fixed costs. Finally, we do not include quick-start units if they have zero output.

Figure 52: Incremental Output Gap by Load Level and Participant Size



In 2023, roughly 31% of the hours exhibited an output gap of any magnitude. At higher load levels, an extremely small percentage of generating capacity exhibited an output gap for a large percentage of time. An even smaller percentage of generating capacity exhibited an output gap at lower load levels. Taken together, these results show that potential economic withholding in the real-time energy market were low in 2023. Based on the analyses presented in this Section and other evaluations performed throughout the year, we conclude that the ERCOT energy market performed competitively in 2023.

C. Voluntary Mitigation Plans

The PUCT has discretion to approve VMPs filed by market participants.[97] 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 behaviors addressed by the plan. However, House Bill 1500, which was passed during the 88th Legislative session and went in effect on September 1, 2023, modified the statutory requirements related to VMPs. Adherence to a VMP is no longer considered an absolute defense against allegations of market power abuse with respect to the behaviors addressed by the VMP; instead, adherence to a VMP must be considered in determining whether a violation occurred and, if so, the penalty to be assessed.[98]

97 PURA § 15.023(f).

98 *Id.* Also, the PUCT amended its rules to implement these statutory changes on April 25, 2024.

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 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.[99] The PUCT modified these three VMPs on March 23, 2023 to address competitiveness concerns that the IMM raised in 2022 related to ERCOT's greatly increased procurement of non-spinning reserve service.[100] In February of 2024, NRG filed a letter with the PUCT expressing NRG's intent to exercise its right to terminate its VMP, effective March 1, 2024.[101] Further details of all three VMPs are found in Section VIII of the Appendix.

VMPs should promote competitive outcomes and prevent abuse of market power through economic withholding in the ERCOT real-time energy market. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market), but the prices in forward energy markets are informed by expectations for real-time energy prices (where mitigation is applied). The forward energy market is voluntary, and the 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 serve to discipline the potential abuse of market power in the forward energy markets.

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."[102] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of competition would typically involve profitably raising prices materially above the competitive level for a significant period.

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99 *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); and *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).

100 See *Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 54739 (Mar. 23, 2023); *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket 54740, Order (Mar. 23, 2023); and *Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket 54741, Order (Mar. 23, 2023).

101 *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 54740, NRG Notice Regarding Voluntary Mitigation Plan (Feb. 23, 2024).

102 PURA § 39.157(a).

A key authority in the VMPs that provided leverage in 2023 was 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 PUCT.[103] 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.

D. Market Power Mitigation

In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to prevent the 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.

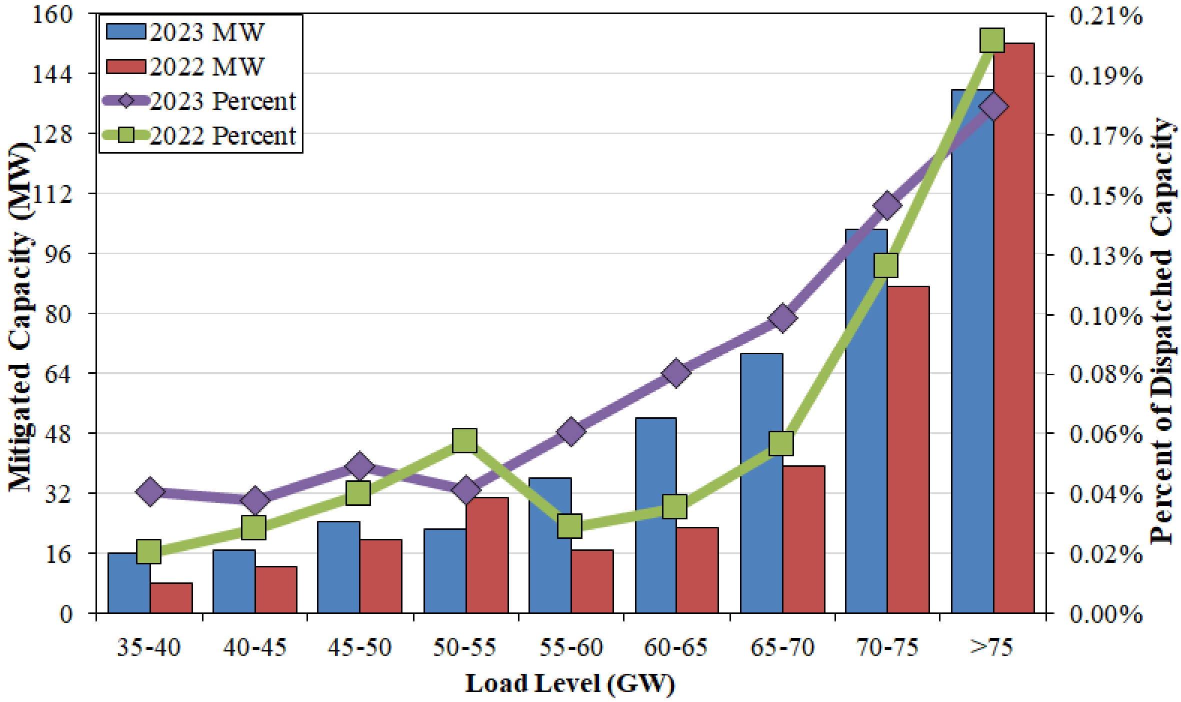
Mitigation applies whether the unit is self-committed or receives a RUC instruction. Prior to 2021, ERCOT typically issued RUC instructions to resolve transmission constraints. However, starting in summer 2021, RUCs for system-wide capacity become common and continued through early 2023. When units that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

- The dispatch software calculates output levels (base points) and prices using the participants' offer curves and considering only the "competitive" transmission constraints. The higher of: a) resulting prices at each generator location and b) the generator's mitigated offer cap is used to formulate the mitigated offer curve for the generator in the second step of the dispatch process.
- The dispatch software then uses mitigated offer curve to determine the final dispatch levels and prices taking all transmission constraints into consideration.

This approach is intended to limit the ability of a generator to exercise local market power by raising its offer price to increase prices in a transmission constrained area. In this subsection, we analyze the amount of mitigation that occurred in 2023. The automatic mitigation under the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active and binding in SCED. Figure 53 shows the average amount and percentage of capacity that was mitigated at different load levels. The amount of energy that could be produced within one interval is deemed mitigated for the purposes of this analysis.

[103] Further, Luminant's VMP will automatically terminate on the earlier of ERCOT's go-live date for RTC, seven years after approval of the VMP, or the day Luminant's Installed Generation Capacity drops below five percent of the total ERCOT Installed Generation Capacity.

Figure 53: Mitigated Capacity by Load Level



The quantity of mitigation shown in Figure 53 is very low compared to the total quantity of capacity online. Additionally, the two-step process in ERCOT will sometimes mitigate conduct that is not significantly increasing prices and, therefore, cannot be argued to be a legitimate exercise of market power. Therefore, these results do not raise competitiveness concerns.

Nonetheless, the amount of mitigation in 2023 was generally higher than in 2022, partly because more non-competitive constraints bound in 2023 than in 2022. In general, when resources are necessary to resolve a local constraint, it is more likely that the constraint will be deemed non-competitive and result in mitigation. Figure 53 also shows that mitigation tends to increase as load increases. This is also likely because higher loads can lead to more frequent non-competitive constraints binding into load pockets.

Analysis of mitigation specific to units receiving RUC instructions is presented and discussed in Section VI of the Appendix

CONCLUSION

As the IMM for the PUCT, Potomac Economics is providing this Report to review and evaluate the outcomes of the ERCOT wholesale electricity market in 2023. The ripple effects of Winter Storm Uri in 2021 continued to reverberate in all corners of the market and system throughout 2023. The results of that extreme event exposed reliability deficiencies in the ERCOT system and prompted much more conservative operations of the system by ERCOT, as well as the development of a number of market reforms. We will provide support to the PUCT and ERCOT as they develop and implement these reforms, as well as continue to evaluate the performance of the markets in future reports.

Overall, our evaluation suggests that the market performed competitively in 2023 with one exception. The introduction of ECRS in June 2023 resulted in costs in both operating reserve and energy that were far in excess of efficient and competitive levels. We are actively working with ERCOT and the PUCT to address this concern.

In the longer term, we continue to look to the implementation of RTC as the most significant change to improve the reliability and competitive performance of the ERCOT markets. We also recommend a number of other improvements to the design and operations of the ERCOT market that will be key in the future as the system transitions to much heavier reliance on intermittent renewable resources.

APPENDIX

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Introduction

This Appendix provides supplemental analysis of certain topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, our conclusions from these analyses and how they relate to the performance of the markets are discussed in the main body of the Report. In addition, the body of the Report includes a discussion of our recommendations to improve the design and competitiveness of the market.

I. Appendix: Key Changes and Improvements in 2023

Key changes or improvements implemented or proposed by the Texas Legislature, the PUCT, and ERCOT in 2023 are outlined below. During the 87th and 88th sessions, the Texas Legislature approved several measures to address market outcomes and reliability concerns related to Winter Storm Uri. In 2023, the PUCT and ERCOT continued implementation of the measures approved during the 87th session and began implementation of the measures approved during the 88th session. PUCT proceedings and ERCOT protocol changes associated with these reforms and other key changes or improvements made in 2023 are highlighted below, along with a brief overview of the legislation from the 88th session associated with major ERCOT wholesale market changes.

88th Legislative Session

In May 2023, the Texas Legislature approved House Bill 1500, an omnibus bill aimed at improving the operation of the ERCOT market.[104] The bill created the Grid Reliability Legislative Oversight Committee, requires procedures related to verbal directives from the PUCT to ERCOT, and added a Commissioner as a non-voting member to the ERCOT Board of Directors. Concerning VMPs, the bill requires the PUCT to review VMPs at least once every two years, allows an administrative penalty of up to $1,000,000 for a violation of a VMP, and removes the ability of a market participant to claim adherence to a VMP as an absolute defense against allegations of violations related to a VMP.

The bill also requires ERCOT to establish a new ancillary service product, the Dispatchable Reliability Reserve Service (DRRS), and it establishes guardrails for a new market design program, the Performance Credit Mechanism (PCM), as described below. Finally, the bill requires the PUCT to establish firming requirements for new generation as of January 1, 2027.[105]

The Legislature also passed Senate Bill 2627, creating a low interest loan program to support the construction, maintenance, modernization, and operation of electric generating facilities. Under the loan program, there are three general categories of funding: up to $1 billion of grants for

104 https://capitol.texas.gov/BillLookup/History.aspx?LegSess=88R&Bill=HB1500.

105 https://capitol.texas.gov/BillLookup/History.aspx?LegSess=88R&Bill=SB2627.

outside of the ERCOT power region; up to $7.2 billion of low interest loans and completion bonuses for the ERCOT power region; and up to $1.8 billion of low interest loans for backup power packages. There is a sunset date of September 1, 2050, for the ERCOT power region loan program. On November 3, 2023, Texas voters approved Senate Joint Resolution 93, a constitutional amendment creating the Texas Energy Fund (TEF) to provide the grants and loans described in Senate Bill 2627.

Review of Wholesale Electric Market Design (Phases I and II)

After a series of rigorous public work sessions and review of comments filed by market participants, the PUCT directed ERCOT to enact major reforms in PUCT Project No. 52373, *Review of Wholesale Electric Market Design* at its December 16, 2021, open meeting.[106] Specifically, the PUCT approved the blueprint for the design of the wholesale electric market filed in the project on December 6, 2021. The blueprint compiled directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint, implemented throughout 2022, provided enhancements to current wholesale market mechanisms to enhance ancillary services and improve price signals and operational reliability. Phase II of the blueprint incorporates long-term market design reforms to promote the supply of dispatchable generation and develop a backstop reliability service, and extends beyond 2023, as outlined below.

Blueprint Phase I

By the end of 2023, most directives from Phase I of the PUCT's blueprint for the design of the wholesale electric market were fully implemented, including modifications to the ORDC, ERS reform, expansion of Non-Spinning Reserve Service to allow certain load participation, FFSS, Fast Frequency Response Service (FFRS), and ECRS.[107] Necessary background and notable developments that occurred in 2023 concerning these fully implemented Phase I directives are outlined below.

The only outstanding directives from Phase I of the PUCT's blueprint at the end of 2023 were Locational Marginal Pricing (LMP) for Load Resources, higher performance standards for energy efficiency programs, and voltage support compensation, all of which are in progress.[108] Regarding LMP for Load Resources, NPRR 1188, *Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources*, was filed on June 27, 2023 and is currently proceeding through the ERCOT stakeholder process.[109] Regarding higher performance standards

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106 *Review of Wholesale Electric Market Design,* Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT (Jan. 13, 2022).

107 *Id.*, Staff Memo to Close the Project (Jan 23, 2024).

108 *Id.*

109 https://www.ercot.com/mktrules/issues/NPRR1188.

for energy efficiency programs, the PUCT requested funding from the Texas Legislature to develop and implement an energy efficiency program, which was approved during the 88th session.[110] Regarding voltage support compensation, ERCOT filed information to inform the PUCT's policy and design decisions for this topic on August 21, 2023.[111]

ERCOT Contingency Reserve Service

At the end of 2021, during Phase I of the market redesign effort, the PUCT instructed ERCOT to accelerate the implementation of a new ramping ancillary service product called ECRS. ERCOT started the ECRS project in January 2022, and the new service went live on June 10, 2023.[112] Prior to implementation of ECRS, RRS bundled frequency response and replacement reserves into one service.[113] ECRS was recommended as a means to unbundle RRS into two products: (1) a new RRS to continue providing primary frequency response to the system and (2) ECRS to provide 10-minute spinning reserves for restoration of RRS or increasing the system's ramping capacity.[114]

Soon after the implementation of ECRS, the IMM began to identify certain price formation issues associated with the service, as discussed in more detail in SOM Recommendation 2022-3. The IMM informed the PUCT and ERCOT of its concerns regarding ECRS, providing associated analysis and potential solutions based on such analysis. The IMM also presented its concerns and potential solutions during ERCOT stakeholder meetings and at the December 2023 Technical Advisory Committee (TAC) and Reliability and Markets Committee meetings.[115] Ultimately, ERCOT revised parts of its proposed 2024 methodology to determine ancillary service requirements, removing the 2,800 MW floor on RRS and adjusting the frequency recovery portion of ECRS.[116] While these adjustments addressed some of the IMM's concerns, many remain outstanding.

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110 Project No. 52373, Staff Memo to Close the Project.

111 *Wholesale Electric market Design Implementation*, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Proposal Regarding Voltage Support Compensation (Aug. 21, 2023).

112 https://www.ercot.com/services/comm/mkt_notices/M-A060723-01.

113 *See* NPRR 863: Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve (https://www.ercot.com/mktrules/issues/NPRR863).

114 *Id.*

115 *See* https://www.ercot.com/files/docs/2023/09/15/imm-as-methodology-for-wmwg-091523-v2.pdf; 07 IMM As Methodology For Wms 10112023, available at: https://www.ercot.com/calendar/10112023-WMS-Meeting; 06 IMM As Methodology For Wms 2023-11, available at: https://www.ercot.com/calendar/11012023-WMS-Meeting; 13 As Methodology, available at: https://www.ercot.com/calendar/12042023-TAC-Meeting; https://www.ercot.com/files/docs/2023/12/11/13%20Independent%20Market%20Monitor%20(IMM)%20Report.pdf.

116 https://www.ercot.com/services/comm/mkt_notices/W-A122023-01.

At the December 2023 ERCOT Board meeting, the Board approved ERCOT's proposed 2024 methodology to determine ancillary service requirements, including the changes to the RRS floor and the frequency recovery portion of ECRS, with a commitment from ERCOT to bring the methodology back for TAC review by April 30, 2024.[117] As a part of this commitment, ERCOT has been working with the IMM to revisit some of the IMM's concerns with ECRS that were not addressed in the 2024 methodology that was approved at the December 2023 Board meeting.

Firm Fuel Supply Service

A new Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of gas generators to purchase fuel to be stored on site, and as of July 1, 2023, pays certain gas-fired resources with owned natural gas stored offsite and accompanied by firm transportation and storage agreements.[118] The PUCT directed ERCOT to develop and procure this product as part of the PUCT's Phase I Market Design efforts and in response to Senate Bill 3.[119] Approved on March 31, 2022, NPRR 1120, Create Firm Fuel Supply Service, created this new reliability service, to be procured via request for proposal (RFP).[120]

For the first FFSS procurement, which spanned an obligation period of November 15, 2022, through March 15, 2023, ERCOT received proposals from 5 different Qualified Scheduling Entities (QSEs), offering 19 Generation Resources to act as FFSS Resources during the obligation period.[121] Further details from this first FFSS procurement are outlined below:

- All 19 Generation Resources were awarded at a clearing price of $6.19/MW/hr ($18,000/MW);
- 18 of the 19 Generation Resources offered fuel oil as the reserve fuel type;
- 1 Generation Resource offered natural gas storage;
- A total of 2940.5 MW of FFSS capacity was procured; and
- The total cost of procurement was $52.9 million before clawbacks.

117 https://www.ercot.com/files/docs/2023/12/15/14.1%20ERCOT%20Recommendation%20re%202024%20ERCOT%20Methodologies%20for%20Determining%20Minimum%20Ancillary%20Service%20Requirements%20REVISED.pdf; https://www.ercot.com/files/docs/2023/12/11/14.1%202024%20ERCOT%20Methodologies%20for%20Determining%20Minimum%20Ancillary%20Service%20Requirements.pdf.

118 https://www.ercot.com/mktrules/issues/NPRR1169#summary.

119 https://www.ercot.com/services/programs/firmfuelsupply

120 https://www.ercot.com/mktrules/issues/NPRR1120

121 *Wholesale Electric market Design Implementation*, Project No. 53298, ERCOT Letter Regarding FFSS Phase I Procurement Results (Sept. 27, 2022).

Before the second FFSS procurement, NPRR 1169 was filed and implemented, expanding the qualifications by which a Generation Resource can provide FFSS to include certain natural gas-fired resources with owned natural gas stored offsite and accompanied by firm transportation and storage agreements.[122] Additionally, PUCT Staff consulted with the IMM to develop recommendations for the second FFSS procurement.[123] PUCT Staff recommended that all of the parameters from the first procurement be kept in place except for the offer cap, which PUCT Staff recommended be reduced to $9,000/MW (based on a fuel oil price of $12 per MMBtu and heat rate of 15).[124] Both the parameters of NPRR 1169 and PUCT Staff's recommendations were incorporated into the RFP for the second FFSS procurement.[125]

For the second FFSS procurement, which spanned an obligation period of November 15, 2023, through March 15, 2024, ERCOT received proposals from 5 different QSEs, offering 32 Generation Resources to act as FFSS Resources during the obligation period.[126] Further details from this second FFSS procurement are outlined below:

- All 32 Generation Resources were awarded at a clearing price of $9,000/MW, the offer cap established by the PUCT;
- 31 of the 32 Generation Resources offered fuel oil as the reserve fuel type;
- 1 Generation Resource offered natural gas storage;
- A total of 3,319.9 MW of FFSS capacity was procured; and
- The total cost of procurement was $29,879,100.00.

This second procurement of FFSS resulted in approximately 13% more awarded capacity at an estimated cost of 43% less than the first procurement. However, all 32 Generation Resources that were offered and awarded in the second procurement met the qualification criteria for the first procurement (i.e., no Generation Resources were offered under the expanded NPRR 1169 qualification criteria).[127]

The IMM's concerns regarding potential price formation issues with FFSS remain outstanding. More rigorous deployment criteria should be considered; once that is done and the PUCT has

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122 https://www.ercot.com/mktrules/issues/NPRR1169#summary

123 *Wholesale Electric Design Implementation*, PUCT Project No. 53298, Staff Recommendations for Firm Fuel Supply Service (FFSS)-Phase 2 Program Parameters to be Defined by PUCT (Jun 22, 2023).

124 *Id.*

125 https://www.ercot.com/services/programs/firmfuelsupply

126 *Wholesale Electric market Design Implementation*, Project No. 53298, ERFCOT Report of the Second Procurement of the Reliability Product, Firm Fuel Supply Service (FFSS) (Sept. 21, 2023).

127 *Id.*

finalized the expansion of the FFSS details, those price formation issues should be addressed. It has been recommended that the PUCT direct PUCT Staff to evaluate our concerns and to provide associated recommendations before the 2024 through 2025 FFSS contract period.[128]

Blueprint Phase II

Phase II of the market design blueprint, adopted by the PUCT on December 6, 2021, called for a study of specific long-term market design principles, including novel hybrid design that maintains the unique ERCOT energy-only market. To that end, the PUCT commissioned a report from Energy and Environmental Economics, Inc. (E3) titled Assessment of Market Reform Options to Enhance Reliability of the ERCOT System, released on November 10, 2022. E3 performed a quantitative and qualitative review on a range of proposed market designs that were initially discussed in Project No. 52373, *Review of Wholesale Electric Market Design,* in producing the report. One design proposal that emerged from the report was the Performance Credit Mechanism (PCM). The PCM, as described by E3, establishes a requirement for LSEs to purchase "performance credits" (PCs) – earned by generators based on their availability to the system during the top 30 hours of highest risk – at a centrally determined clearing price. The PC requirement is a fixed quantity that is determined in advance of the compliance period, while the settlement process occurs retroactively based on the quantity of PCs that are actually produced.[129]

On January 19, 2023, the PUCT adopted the PCM as its preferred market design, specifying a set of principles for the design and identifying decision points needing further PUCT, ERCOT, and IMM analysis.[130] Additionally, the PUCT directed PUCT Staff and ERCOT to delay implementation of the PCM until such time as the 88th Texas Legislature had an opportunity to render judgment on the merits of the design or establish an alternate solution.[131]

During the 88th Texas Legislature, House Bill 1500 was passed, which provided guidance for moving forward with the PCM, including certain guardrails that must be maintained if the PCM is implemented, which are listed below:[132]

- Annual net cost cap of $1 billion;
- PCs available only to dispatchable generation;

128 *Id.*, Staff Recommendations for FFSS Phase 2 (Jun. 22, 2023).

129 *Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3)*, Project No. 54335, E3 Report, staff memo and updated questions (Nov. 10, 2022).

130 *Wholesale Electric Market Design Implementation*, Project No. 53298, Order (Jan. 19, 2023).

131 *Id.*

132 House Bill 1500 codified these legislative guardrails for the potential design of the PCM in PURA § 39.1594.

- Centrally clearing PC markets;
- PC cap based on forward market offers;
- Electric generator availability based on availability to perform in real-time during the tightest intervals of low supply and high demand;
- Seasonal PCM market construct;
- Penalty structure for failing to meet forward obligation;
- No locational attribute to PCs;
- No unfair advantage to Load Serving Entities that own generation;
- Secured financial credit and collateral requirements;
- Market power mitigation.

On October 25, 2023, ERCOT filed a document providing a framework for further development of the PCM.[133] This framing document described which of the decision points from the PUCT's January 2023 Order were narrowed or removed by House Bill 1500 and provided recommendations for next steps with respect to each PCM decision point. Many of the decision points will be addressed in a strawman PCM design proposal to be released in 2024.[134]

Before implementation of the PCM, ERCOT and the IMM are required to complete an assessment on the costs and benefits of the design and submit the results of such evaluation to the PUCT and the Texas Legislature.[135] The assessment must include:

- An evaluation of the cost of new entry and the effects of the proposed reliability program on consumer costs and the competitive retail market (e.g., can retailers hedge their procurement of PCs?);
- A compilation of detailed information regarding cost offsets realized through a reduction in costs in the energy and ancillary services markets and through use of RUCs (i.e., a methodology for measuring the net cost of PCM capped at $1B);

133 *Wholesale Electric Market Design Implementation*, Project No. 53298, ERCOT Update on Performance Credit Mechanism Framing (Oct. 25, 2023).

134 In February 2024, ERCOT filed E3's Draft PCM Design Parameters Options Memorandum laying out options for each design parameter decision and a proposed evaluation methodology for selection of the final design parameters. *Performance Credit Mechanism (PCM)*, Project No. 55000, PCM Draft Design Parameters Options Memorandum (Oct. 25, 2023). The final strawman design will be developed in 2024 after further PUCT and stakeholder feedback on the options memorandum. Such feedback will be obtained through multiple workshops, the ERCOT stakeholder process, PUCT Open Meetings, and public comments.

135 PURA § 39.1594(d).

- A set of metrics to measure the effects of the proposed reliability program on system reliability;
- An evaluation of the cost to retain existing dispatchable resources in the ERCOT power region;
- An evaluation of the planned timeline for implementation of real-time co-optimization; and
- Anticipated market and reliability effects of new and updated ancillary service products.

It is expected that the IMM and ERCOT will complete this assessment by the end of 2024 in time for the 89th Texas Legislature to consider the results. If the PCM is ultimately implemented, the IMM will be required to evaluate the reliability benefits compared to the costs of the design every two years and report such evaluation to the Texas Legislature.[136]

Reliability Standard

Historically, there has not been a mandatory reliability standard in the ERCOT region. Instead, ERCOT has had a target reserve margin of 13.75% based on a 0.1 Loss of Load Expectation and a traditional dispatchable fleet of generators. However, in 2021, the 87th Texas Legislature passed Senate Bill 3, requiring that ERCOT establish a reliability standard for the ERCOT power region.[137] Additionally, in January 2023, the PUCT Order adopting the PCM made clear that defining a reliability standard is pertinent for implementation of the PCM.[138]

In early 2023, PUCT Staff opened a project to evaluate and establish the reliability standard, and, throughout 2023, significant progress was made in this project.[139] ERCOT worked with PUCT Staff and market participants to gather input concerning the metrics to be used for the reliability standard study. Ultimately, ERCOT proposed that it would use the Strategic Energy & Risk Valuation (SERVM) model for the study and that the study would be defined by three probabilistic metrics: magnitude, frequency, and duration.

In June 2023, ERCOT filed preliminary modeling results with the PUCT and recommended incorporation of an exceedance probability for the reliability standard.[140] The PUCT confirmed that ERCOT should move forward with the proposed metrics and directed ERCOT to continue

136 PURA § 39.1594(f).

137 The section of Senate Bill 3 requiring establishment of a reliability standard is now codified under PURA § 39.159(b).

138 The strawman PCM design proposal to be released in 2024 will provide additional details concerning use of the reliability standard in the PCM design.

139 *Reliability Standard for the ERCOT Market*, Project No. 54584 (pending).

140 *Id.*, ERCOT Letter Regarding ERCOT Reliability Standard Preliminary Results (Jun. 13, 2023).

its SERVM modeling analysis. During the remaining months of 2023, ERCOT used SERVM to model different portfolio scenarios, each of which were designed to simulate frequency, duration, and magnitude outcomes across a range of resource mixes. ERCOT provided the results of each iteration of the study to the PUCT to receive feedback on model and scenario refinements.

In 2023, ERCOT also made progress regarding an updated analysis of the ERCOT Value of Lost Load (VOLL).[141] The PUCT articulated the fundamental nature of such an updated analysis, as the updated VOLL will ultimately inform the new reliability standard. The VOLL represents a customer's willingness to pay for reliable electric service, and the ERCOT VOLL prior to and throughout 2023 was $5,000 per MWh.[142] At the March 23, 2023, Open Meeting, the PUCT directed ERCOT to issue a Request for Proposal (RFP) to engage a consultant to conduct an updated analysis of VOLL. ERCOT selected The Brattle Group (Brattle) and Brattle's subcontractor, PlanBeyond, to perform the VOLL study and entered into an agreement with the Lawrence Berkeley National Labs (LBNL) to allow ERCOT and Brattle to utilize LBNL's Interruption Cost Estimate (ICE) Calculator 2.0 for the VOLL study. On November 21, 2023, ERCOT filed an update with the PUCT regarding the study, indicating that the study would ultimately consist of a literature review, development of an interim VOLL, and customer surveys.[143] In December of 2023, ERCOT filed a plan presenting the approach to be used for the customer surveys, the VOLL literature review, and recommendations on an interim VOLL.[144]

Finally, in December of 2023, ERCOT hired a consultant to assess the CONE value currently being used in ERCOT and determine an update.[145] CONE is an estimate of the annualized net revenue that a new generation resource would need in order to recover its capital investment and fixed costs. CONE supports capacity reserve margin studies and will be used as an input value to inform the PUCT's new reliability standard. ERCOT currently uses a CONE value of $119,000 per MW-year. The new CONE will consist of the updated total net revenue on an annualized basis in dollars-per-MWh that a new combined-cycle combustion turbine generation resource would require to recover its capital investment and fixed costs.

141 *See Review of Value of Lost Load in the ERCOT Market*, Project No. 55837 (pending).

142 Prior to April 29, 2022, the VOLL was equal to the System-Wide Offer Cap. After the PUCT's approval of the Proposal for Adoption in Project No. 53191, the ERCOT VOLL was decoupled from the System-Wide Offer Cap.

143 *Review of Value of Lost Load in the ERCOT Market*, Project No. 55837, ERCOT VOLL Study Update (Nov. 21, 2023).

144 Review of Value of Lost Load in the ERCOT Market, Project No. 55837, VOLL Survey Work Plan (Dec. 7, 2023); *Id.*, VOLL Study Literature Review and Interim VOLL (Dec. 21, 2023).

145 *Reliability Standard for the ERCOT Market*, Project No. 54584, ERCOT Reliability Standard Study and CONE Study Update (Apr. 4, 2024). House Bill 1500 § 23, codified under PURA § 39.1594(d)(1), requires completion of an assessment that includes an evaluation of CONE as a precondition to implementation of the PCM. As such, the PUCT directed ERCOT to engage a consultant to evaluate ERCOT's CONE value.

It is expected that ERCOT will complete the reliability standard, VOLL, and CONE studies in 2024, allowing the PUCT to move forward with a rulemaking to establish a reliability standard for ERCOT. The IMM looks forward to working with the PUCT, ERCOT, and market participants on these endeavors, identifying meaningful enhancements to ERCOT's wholesale market along the way.

ORDC Price Floors

In the January 2023 PUCT Order adopting the PCM, the PUCT directed ERCOT to evaluate bridging options to retain existing assets and build new dispatchable generation until the PCM can be fully implemented.[146] After evaluating options and receiving stakeholder feedback, ERCOT recommended an enhancement to the ORDC as the preferred bridge option to the PCM. The ERCOT Board approved this option for recommendation to the PUCT at its April 18, 2023, meeting, and, subsequently, the PUCT adopted the recommended option with a November 1, 2023, implementation date.[147]

The bridging solution is a multi-step floor to the online ORDC price adders, with the first step of the floor at $10 per MWh when reserve levels are equal to or less than 7,000 MWs and the second step at $20 per MWh when reserves are equal to or less than 6,500 MW. The stated purpose of this multi-step floor is to provide targeted increases in resource revenues that align with the level of revenue increases expected from the PCM.[148] Since the ORDC multi-step floor was only implemented on November 1, 2023, more time is needed to assess its effectiveness and any associated market impacts. By November 1, 2024, ERCOT is required to provide the PUCT with the following quantifiable metrics in its biennial ORDC report[149] and in each subsequent report:

- The amount of new revenue specifically resulting from the ORDC multi-step floor;
- The specific type of generation resources that received the new revenue from the ORDC multi-step floor; and

146 *Wholesale Electric Market Design Implementation*, Project No. 53298, Order (Jan. 19, 2023).

147 *Wholesale Electric Market Design Implementation*, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Report and Recommendation on Bridge Solution (Apr. 20, 2023); *Id.*, PUCT Staff Memo Summarizing the Decision at the August 3, 2023 Open Meeting Regarding Implementation of ORDC Price Adder Floors; https://www.ercot.com/services/comm/mkt_notices/M-A101623-01.

148 Specifically, the back-cast analyses performed by ERCOT for 2020 and 2022 indicated that, by applying the proposed price adder floors to the ORDC, the total revenue increase would be in the range of $500 million, a level of increase that aligns with the additional average revenue that the PCM is expected to provide as calculated by E3 in its report to the PUCT. *Wholesale Electric Market Design Implementation*, Project No. 53298, Electric Reliability Council of Texas, Inc.'s Report and Recommendation on Bridge Solution (Apr. 20, 2023).

149 This report is required under 16 Texas Administrative Code (TAC) § 25.505.

- Performance data showing whether the ORDC multi-step floor reduced ERCOT's use of Reliability Unit Commitment (RUC), specifically for RUCs based on capacity as opposed to congestion.[150]

Others Key Changes and Improvements in 2023

In addition to the Blueprint Phases I and II changes to wholesale market, other key changes and improvements were introduced or implemented in 2023. Such key changes included the establishment of an emergency pricing program for the wholesale electric market and statutory creation of a new ancillary service aimed at reducing RUCs.

Emergency Pricing Program

The 87th Texas Legislature passed Senate Bill 3, which, in part, amended Chapter 39 of the Utilities Code to add PURA § 39.160.[151] PURA § 39.160 requires that the PUCT establish an emergency pricing program (EPP) for the ERCOT wholesale electric market that must take effect if the HCAP has been in effect for 12 hours in a 24-hour period after initially reaching the HCAP.

On January 20, 2023, the PUCT opened a rulemaking project for implementation of the EPP.[152] Throughout the rulemaking process, the IMM filed two sets of comments. In the first set of comments, the IMM recommended (1) a cessation trigger of 96 hours; (2) a formula for the EPP cap that would naturally lead to the low system-wide offer cap being in place upon reaching the cessation trigger; (3) equal price caps for energy and ancillary services; (4) reimbursement to generators of any energy costs that ERCOT would accept under the RUC Make-Whole payment mechanism (i.e., marginal costs); and (5) biennial review of the system-wide offer cap programs, as well as biennial review of CONE and VOLL.[153] In its second set of comments, the IMM reemphasized one of its recommendations from its first set of comments, namely, that reimbursable costs exceeding the EPP cap should be limited to marginal costs to ensure exclusion of costs such as fixed costs.[154]

150 *Wholesale Electric Market Design Implementation*, Project No. 53298, PUCT Staff Memo Summarizing the Decision at the August 3, 2023, Open Meeting Regarding Implementation of ORDC Price Adder Floors (Aug. 3, 2023).

151 https://capitol.texas.gov/tlodocs/87R/billtext/pdf/SB00003F.pdf#navpanes=0.

152 *Emergency Pricing Program,* Project No. 54585, Questions for Comment (Deadline: August 15, 2023) (Jul. 25, 2023); *Id.*, IMM Comments (Aug. 15, 2023).

153 *Emergency Pricing Program,* Project No. 54585, IMM Comments (Aug. 15, 2023).

154 *Emergency Pricing Program*, Project No. 54585, IMM's Comments on Proposal for Publication (Oct. 13, 2023

Ultimately, the rule the PUCT adopted (1) sets the EPP cap equal to $2,000 per MWh for energy and ancillary services, which is the value of the low system-wide offer cap; (2) sets the termination of the EPP as the latter of (a) 24 hours after activation of the EPP, or (b) if ERCOT has entered into or remained in emergency operations while the EPP is active, 24 hours after ERCOT exits emergency operations without re-entering emergency operations; (3) requires ERCOT to reimburse resource entities for any actual marginal costs in excess of the larger of the EPP cap or the real-time energy price for the resource; and (4) requires the PUCT to review each of the system-wide offer cap programs every five years.[155] Additionally, the adopted rule required immediate implementation of the EPP, allowing ERCOT to utilize a manual process to activate the EPP until any system and protocol changes are complete.[156] On January 23, 2024, ERCOT filed NPRR 1216, *Implementation of Emergency Pricing Program*, which proposes revisions to incorporate the EPP into the ERCOT Nodal Protocols and provide a framework for automating components of the EPP.[157]

Dispatchable Reliability Reserve Service

Since the IMM's 2021 State of the Market Report, the IMM has recommended that ERCOT develop a day-ahead, two- to four- hour capacity product to account for increasing operating uncertainties associated with intermittent generation output, load, and other factors.[158] ERCOT has addressed this uncertainty by committing resources through the RUC process, procuring additional reserves, and revising specific ancillary service requirements. The IMM's recommended uncertainty product is meant to reduce the substantial costs associated with these measures used by ERCOT to handle reliability concerns arising from operational uncertainties.

In May 2023, the 88th Texas Legislature passed House Bill 1500, which, in part, amended PURA § 39.159 to require that ERCOT develop and implement an ancillary services program with similar characteristics to the uncertainty product recommended by the IMM.[159] The new ancillary service will be called Dispatchable Reliability Reserve Service (DRRS), and it must reduce the capacity hours of RUCs by the amount of DRRS procured. Additionally, to participate in providing DRRS, a resource must (1) be capable of running for at least four hours at the resource's high sustained limit; (2) be online and dispatchable not more than two hours after being called on for deployment; and (3) have the dispatchable flexibility to address inter-hour operational challenges. Finally, ERCOT must determine the procurement amount of DRRS

155 *Id.*, Order Adopting Amendments to 16 TAC § 25.509 (Dec. 1, 2023).

156 *Id.*

157 As of May 31, 2023, NPRR 1216 is still under review in ERCOT's stakeholder process. https://www.ercot.com/mktrules/issues/NPRR1216#summary.

158 *See* Recommendation 2021-2—Implement an Uncertainty Product.

159 https://capitol.texas.gov/tlodocs/88R/billtext/pdf/HB01500F.pdf#navpanes=0; PURA § 39.159.

based on historical variations in generation availability for each season, including intermittency of non-dispatchable resources and forced outage rates of dispatchable resources. The procurement amount also must be based on a targeted reliability standard or goal.

On June 26, 2023, ERCOT made a filing with the PUCT summarizing two implementation options for DRRS.[160] The first option involved repurposing of non-spinning reserve service to allow participation by longer lead time resources in conjunction with procuring more ECRS to cover the gap created by the modified non-spinning reserve service longer lead time. The second option involved the creation of an entirely new ancillary service fitting the specifications under PURA § 39.159. Only the first option could be implemented within the statutory deadline of December 1, 2024.

At the June 29, 2023, Open Meeting, ERCOT received direction from the PUCT to focus on the first option. In accordance with the PUCT's direction, ERCOT submitted NPRR 1203, OBDRR 049, and OBDRR 050 to codify creation of DRRS as a sub-type of non-spinning reserve service.[161] Subsequently, on October 17, 2023, three Texas Legislators filed a letter with the PUCT expressing concern that ERCOT's proposal to implement DRRS as a sub-type of non-spinning reserve service did not meet the purpose behind the statutory creation of DRRS.[162] As such, the legislators urged the PUCT to direct ERCOT to implement DRRS as a standalone ancillary service, even if doing so would cause a delay in the implementation timeline.[163]

At the November 2, 2023 Open Meeting, the PUCT expressed support for implementation of DRRS as a standalone service, and soon after, ERCOT filed comments with the PUCT stating its intent to withdraw NPRR 1203, OBDRR 049, and OBDRR 050 and initiate development of DRRS as a standalone product.[164] The IMM filed comments in support of ERCOT's plan, reasoning that designation of DRRS as a sub-type of non-spinning reserve service would only result in inefficient valuation of both products.[165] ERCOT submitted a request for withdrawal of the revision requests on December 1, 2023, which was approved by the Technical Advisory

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160 *Implementation Activities 88th Legislature (R.S)*, Project No. 55156, ERCOT Letter Re DRRS Implementation Options (Jun. 26, 2023).

161 NPRR 1203, Implementation of Dispatchable Reliability Reserve Service, available at: https://www.ercot.com/mktrules/issues/NPRR1203; OBDRR 049, ORDC Changes Related to NPRR1203, available at: https://www.ercot.com/mktrules/issues/OBDRR049; OBDRR 050, Non - Spin Changes Related to NPRR1203, available at: https://www.ercot.com/mktrules/issues/OBDRR050.

162 *Implementation Activities 88th Legislature (R.S)*, Project No. 55156, Dispatchable Reliability Reserve Services (DRRS) Letter (Oct. 17, 2023).

163 *Id.*

164 *Dispatchable Reliability Reserve Service (DRRS)*, Project No. 55797, ERCOT Update on Standalone DRRS In Project 55797 (Nov. 15, 2023).

165 *Id.*, IMM Letter Supporting Standalone DRRS (Nov. 22, 2023).

Committee on December 1, 2023. In ERCOT's request, it noted its intent to file a new NPRR for implementation of DRRS as a standalone service and stated that implementation timing is expected to generally align with implementation of Real-Time Co-optimization.[166]

ERCOT Market Rule Revisions

ERCOT approved or introduced a number of NPRRs and OBDRRs in 2023 to reflect and implement the changes authorized by the Texas Legislature and PUCT and to implement general market improvements, as outlined below.

Nodal Protocol Revision Requests (NPRRs)

- NPRR 1128, Allow FFR Procurement up to FFR Limit Without Proration
  - Status: Approved on January 26, 2023
  - Description: This NPRR sets a -$0.01 per MW lower ancillary service offer floor for Fast Frequency Response (FFR) Responsive Reserve (RRS) rather than for other RRS categories, thereby allowing, depending on relative ancillary service offers, FFR procurement up to the current FFR limit without proration with other RRS categories in the ancillary service procurement process.
- NPRR 1143, Provide ERCOT Flexibility to Determine When ESRs May Charge During an EEA Level 3
  - Status: Approved on July 20, 2023, effective on August 1, 2023
  - Description: This NPRR allows ERCOT the ability to decide when ESRs may charge during an EEA Level 3.
- NPRR 1145, Use of State Estimator-Calculated ERCOT-Wide TLFs in Lieu of Seasonal Base Case ERCOT-Wide TLFs for Settlement
  - Status: Approved on May 11, 2023
  - Description: This NPRR changes the 15-minute level ERCOT-wide Transmission Loss Factors (TLFs) that are used in the Settlement process from seasonal base case TLFs to State Estimator-calculated TLFs in Energy Management System (EMS). It also clarifies the use of NOIE deemed actual TLFs to remove behind-the-meter Transmission Losses.
- NPRR 1147, Update and Improve Notification and Evaluation Processes Associated with Reliability Must-Run

[166] 1203NPRR-12 Request for Withdrawal 120123, available at: https://www.ercot.com/mktrules/issues/NPRR1203#keydocs.

  - Status: Approved on March 23, 2023, effective on April 1, 2023
  - Description: This NPRR adds a 20 MW capacity threshold for conducting a Reliability Must-Run (RMR) reliability analysis; requires that an RMR study be conducted when a resource entity gives notice that a generation resource is ceasing operation permanently due to a forced outage; and updates Section 22, Attachment E to require resource entity to provide information about deactivation of transmission facilities as part of the suspension of operations of the unit.

- NPRR 1148, Language Cleanup Related to ERCOT Contingency Reserve Service (ECRS)
  - Status: Approved on January 26, 2023, effective on June 9, 2023
  - Description: This NPRR addresses Protocol gaps found during the creation of the ECRS system change requirements. Specific changes include: Language was added to Section 4.4.7.2.1 to align NPRR 863, Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve, implementation to a pre-Real-Time Co-Optimization (RTC) system design. Clarification was added about simultaneous awarding and Real-Time provision of Responsive Reserve (RRS), ECRS, and Non-Spinning Reserve by Load Resources that are not Controllable Load Resources; Language was added to paragraph (1) of Section 6.5.7.6.2.4 to clarify that ECRS will also be deployed to provide energy upon detection of insufficient available capacity for net load ramps. (Such use is in addition to the uses already included in the Protocols: use for frequency restoration, energy during an EEA, or as a backup to Regulation Up Service; and Language was added to paragraph (2)(e) of Section 6.5.7.3.1 to clarify that ECRS deployments from Load Resources that are not Controllable Load Resources will be considered at a ten-minute linear ramp for the calculation of the Real-Time On-Line Reliability Deployment Price Adder. This is similar to the approach taken with RRS deployments from Load Resources that are not Controllable Load Resources.

- NPRR 1149, Implementation of Systematic ancillary service Failed Quantity Charges
  - Status: Approved on March 23, 2023
  - Description: This NPRR charges a Qualified Scheduling Entity (QSE) an ancillary service failed quantity if the ancillary service supply responsibility held by the QSE is not met by Resources in their portfolio in Real-Time, based on a comparison of their Real-Time telemetry. The changes will be done systematically without ERCOT control room operators having to take additional action.

- NPRR 1154, Include Alternate Resource in the Availability Plan for the Firm Fuel Supply Service
  - Status: Approved on January 26, 2023, effective on October 6, 2023
  - Description: This NPRR updates language to allow for a qualified alternate Resource to be considered in the calculation of the availability reduction factor for the FFSSR. Additionally, this NPRR provides a new Settlement billing determinant that will provide the FFSS award amount per Qualified Scheduling Entity (QSE) per FFSSR by hour.
- NPRR 1165, Revisions to Requirements of Providing Audited Financial Statements and Providing Independent Amount
  - Status: Approved on October 12, 2023
  - Description: This NPRR strengthens ERCOT's market entry eligibility and continued participation requirements for ERCOT Counter-Parties (i.e., Qualified Scheduling Entities (QSEs) and CRR account holders). Specific changes include removing minimum capitalization requirements; requiring all ERCOT Counter-Parties to post Independent Amounts; removing references to guarantors; clarifying the requirement for financial statements; and referencing International Financial Reporting Standards (IFRS) rather than retired International Accounting Standards (IAS).
- NPRR 1167, Improvements to Firm Fuel Supply Service Based on Lessons Learned
  - Status: Approved on June 29, 2023, effective on July 1, 2023
  - Description: This NPRR implements several improvements to FFSS. Specific changes include: amending the definition of an Availability Plan to include a requirement that, in cases where a Resource is required to have a submitted Availability Plan and has a change in availability, the Availability Plan must be updated within 60 minutes of that change in availability; adding more detailed direction to incorporate the concept of having an alternate Generation Resource that may be designated to become the FFSS Resource (FFSSR) in providing FFSS; adding a requirement for ERCOT to post a disclosure report of FFSS offers after each procurement period, in alignment with the expiration of confidentiality captured in the first FFSS Request for Proposal (RFP); clarifying language regarding procedures for communication between ERCOT and Qualified Scheduling Entities (QSEs) regarding restocking of fuel post deployment of FFSS; changing the directive for ERCOT to report to the Technical Advisory Committee (TAC) at the end of the obligation period (March 15) if deployment(s) occurred instead of within 45 days of each deployment; incorporating

requirements for FFSS that were previously only captured in the FFSS RFP; enhancing language and processes around the qualification process, including moving the obligation to test prospective FFSSRs (both primary or alternate Generation Resources) to be prior to the FFSS procurement process. Results from this test will then be used to limit the MW quantity that the QSE can offer for that Resource into the FFSS procurement process; and introducing language and processes for disqualification and decertification of a generator in being an FFSSR, including a process for remediation and recertification.

- NPRR 1169, Expansion of Generation Resources Qualified to Provide Firm Fuel Supply Service in Phase 2 of the Service
  - Status: Approved on June 29, 2023, effective on July 1, 2023
  - Description: This NPRR expands the qualifications by which a Generation Resource may be an FFSS Resource (FFSSR) or an alternate to include those meeting the following characteristics: the Generation Entity that owns the Generation Resource (or an Affiliate) must own and have good title to sufficient natural gas in the offsite storage facility for the offered Generation Resource to deliver the offered MW for at least the duration specified in the Request for Proposal (RFP) and must commit to maintain such quantity of gas in storage at all times during the obligation period; the Generation Entity (or an Affiliate) must either own, or have a Firm Gas Storage Agreement for, sufficient natural gas storage capacity for the offered Generation Resource to deliver the offered MW for at least the duration specified in the RFP; the Generation Entity for the Generation Resource (or an Affiliate) must have entered into a Firm Transportation Agreement on a Qualifying Pipeline; and a number of ongoing compliance obligations must be satisfied, including a requirement that the Generation Entity for the FFSSR must provide a report to ERCOT with certain information and data if the FFSSR fails to deploy due to a Force Majeure Event. Revisions in this NPRR also include categorizing certain information provided to ERCOT as Protected Information; adding definitions; and addressing requirements for recovery of replacement-fuel costs if ERCOT approves restocking of fuel after deployment of an FFSSR.
- NPRR 1171, Requirements for DGRs and DESRs on Circuits Subject to Load Shedding
  - Status: Approved on October 12, 2023
  - Description: This NPRR clarifies various reliability requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are seeking qualification to provide ancillary service(s) and/or participate in Security-Constrained Economic Dispatch (SCED).

- NPRR 1172, Fuel Adder Definition, Mitigated Offer Caps, and RUC Clawback
  - Status: Approved on February 1, 2024, effective March 1, 2024
  - Description: This NPRR creates a definition for Fuel Adder to provide clarity for which costs are included as routine and predictable versus which costs are exceptional. This NPRR also removes the Mitigated Offer Cap (MOC) multipliers and creates a 100% clawback for Reliability Unit Commitment (RUC).
- NPRR 1175, Revisions to Market Entry Financial Qualifications and Continued Participation Requirements
  - Status: Approved October 12, 2023, effective November 1, 2023
  - Description: This NPRR strengthens ERCOT's market entry qualification and continued participation requirements for ERCOT Counter-Parties i.e., Qualified Scheduling Entities (QSEs) and CRR account holders, classifies information provided in the background check as Protected Information, modifies application forms for QSEs and CRR account holders, and adds a new background check fee to the ERCOT Fee Schedule.
- NPRR 1176, Update to EEA Trigger Levels
  - Status: Approved October 12, 2023, effective November 1, 2023
  - Description: This NPRR revises the EEA procedures to require a declaration of EEA Level 3 when PRC cannot be maintained above 1,500 MW and will require ERCOT to shed firm Load to recover 1,500 MW of reserves within 30 minutes. This NPRR also modifies the trigger levels for EEA Level 1 and EEA Level 2, changes the trigger for ERCOT's consideration of alternative transmission ratings or configurations from Advisory to Watch when PRC drops below 3,000 MW, and restores a frequency trigger for the declaration of EEA Level 3 if the steady-state frequency drops below 59.8 Hz for any period of time.
- NPRR 1177, Enhance Exceptional Fuel Cost Process
  - Status: Approved on June 29, 2023, effective June 30, 2023
  - Description: This NPRR enables Generation Resources to file Exceptional Fuel Costs that include contractual cost and pipeline-mandated costs and enhances the process for ERCOT and the Independent Market Monitor (IMM) to verify these costs.

- NPRR 1178, Expectations for Resources Providing ERCOT Contingency Reserve Service
  - Status: Approved on June 29, 2023, effective on July 1, 2023
  - Description: This NPRR provides clarifications and updates regarding expectations for Resources providing ECRS. First, this NPRR provides clarity on expectations for Resource Status for Load Resources, other than Controllable Load Resources, when the Resource is providing ECRS simultaneously with Responsive Reserve (RRS). Under the current Protocols, the choice of Resource Status by the Qualified Scheduling Entity (QSE) may not be apparent. Second, to align with NPRR 892, Non-Spin Reserve Energy Floor Clarification, this NPRR places an offer floor on capacity for Resources providing ECRS concurrently with On-Line Non-Spinning Reserve (Non-Spin). This change ensures that On-Line capacity for providing Non-Spin is priced above the $75/MWh offer floor. NPRR 892 addressed this requirement for when a Resource is providing RRS and/or Regulation Up Service (Reg-Up) in addition to On-Line Non-Spin, however the timing of that NPRR was such that ECRS was not included in the proposed language. Lastly, this NPRR updates the ECRS deployment obligation requirements for Load Resources, other than Controllable Load Resources. The proposed language makes the requirement consistent with what will be in place with the implementation of Real-Time Co-optimization (RTC) of energy and ancillary services and states that any response to a deployment must remain in effect until recalled by ERCOT.
- NPRR 1179, Fuel Purchase Requirements for Resources Submitting RUC Fuel Costs
  - Status: Approved on April 11, 2024, effective May 1, 2024
  - Description: This NPRR ensures that Qualified Scheduling Entities (QSEs) representing Generation Resources that have an executed and enforceable transportation contract and file a Settlement dispute to recover their actual fuel costs incurred when instructed to operate due to a RUC, procure fuel economically. This NPRR also adds an adjustment to the RUC Guarantee to reflect the cost difference between the actual fuel consumed by the Resource to start and operate during the RUC-Committed Intervals and the fuel burn calculated based on Verifiable Cost parameters. Finally, the NPRR clarifies that fuel costs may also include penalties for fuel delivery outside of RUC-Committed Intervals in accordance with the ratable delivery obligations and costs as specified in the enforceable transportation agreement.
- NPRR 1180, Inclusion of Forecasted Load in Planning Analyses

- Status: Posted on May 11, 2023, and still pending as of the end of 2023
- Description: This NPRR revises the Protocols to address recent amendments to P.U.C. SUBST. R. 25.101, Certification Criteria, which became effective on December 20, 2022. Specifically, NPRR 1180 incorporates the requirement in P.U.C. SUBST. R. 25.101(b)(3)(A)(ii)(II) for any reliability-driven transmission project review conducted by ERCOT to incorporate the historical load, forecasted load growth, and additional load seeking interconnection, in the ERCOT independent review. NPRR 1180 also requires a Regional Planning Group (RPG) project submitter to provide such information to ERCOT, when available, for inclusion in ERCOT's project analysis.

- NPRR 1182, Inclusion of Controllable Load Resources and Energy Storage Resources in the Constraint Competitiveness Test Process
  - Status: Approved on October 12, 2023
  - Description: This NPRR incorporates Controllable Load Resources (CLRs) and ESRs into both the Long-Term and Security-Constrained Economic Dispatch (SCED) versions of the Constraint Competitiveness Test (CCT). In the case of CLRs, the Resources will not themselves be mitigated but will be used to identify if a Market Participant has market power in resolving a constraint on the transmission system. As is the case for other Resources, registration data will be used for these Resources in the Long-Term CCT process and Real-Time telemetry will be used in the SCED CCT process.
- NPRR 1185, HDL Override Payment Provisions for Verbal Dispatch Instructions
  - Status: Approved on October 12, 2023, effective November 1, 2023
  - Description: This NPRR adds in a provision for recovery of a demonstrable financial loss arising from a Verbal Dispatch Instruction (VDI) to reduce real power output.
- NPRR 1186, Improvements Prior to the RTC+B Project for Better ESR State of Charge Awareness, Accounting, and Monitoring
  - Status: Approved on April 11, 2024
  - Description: This NPRR is the first of two NPRRs that ERCOT has prepared to improve the awareness, accounting, and monitoring of the State of Charge (SOC) for an ESR. This particular NPRR is for the interim period which is described as the time period before the RTC+B project goes live. The target go-live date for the RTC+B project is expected to be several years away and the language and changes in this first NPRR are aimed to strategically improve SOC awareness,

accounting, and monitoring with minimal system changes so that the improvements can be in place while the RTC+B project is completed. This NPRR does NOT specify that ERCOT manage the SOC for an ESR. It specifies existing and new information to be provided by the QSE so that ERCOT can better understand each ESR's current energy capability and expected energy capability in future hours. Grey-boxed language related to DC-Coupled Resources was not revised with this NPRR.

- NPRR 1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Status: Posted on June 27, 2023, and still pending at the end of 2023
  - Description: This NPRR changes the dispatch and pricing of Controllable Load Resources (CLRs) in response to items in Phase 1 of PUCT's market design blueprint related to demand response and increasing the "...utilization of load resources for grid reliability". Specifically, this NPRR is focused on the blueprint language discussing the pursuit of "…market modifications and technical measures to improve transparency of price signals for load resources, such as changing demand response pricing from zonal to locational marginal pricing (LMP)." To address the above directive from the PUCT, this NPRR changes the market participation model for CLRs that are not Aggregate Load Resources (ALRs) such that they are dispatched at a nodal shift factor and settled for their energy consumption at a nodal price.
- NPRR 1189, Updates to Language to Clarify the Allowable Regulation Ancillary Service Trades
  - Status: Approved on October 12, 2023, effective November 1, 2023
  - Description: This NPRR makes changes to the grey-boxed NPRR 1136, Updates to Language Regarding a QSE Moving Ancillary Service Responsibility Between Resources, language in Section 4.4.7.3, to align the language with existing requirements in paragraph (10) in Section 3.16, Standards for Determining Ancillary Service Quantities, which states that "Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the day-ahead market for that particular Resource, up to the awarded quantity".
- NPRR 1196, Correction of NCLR Ancillary Service Failed Quantity Calculations under NPRR1149
  - Status: Approved on February 1, 2024

- Description: This NPRR makes corrections and updates to equations used to determine ancillary service failed quantity calculations for Load Resources other than Controllable Load Resources (NCLRs) which were developed under NPRR 1149, Implementation of Systematic Ancillary Service Failed Quantity Charges. Specific Protocol changes include: updates to the calculation of ancillary service failed quantities to account for the allowances and restrictions on ancillary services that NCLRs can and cannot carry simultaneously with the implementation of ECRS; updates to specify the snapshot components to be used for the "Telemetered Ancillary Service for the NCLRs As Calculated" variable; and inclusion of an additional non-zero check to be added for the "Telemetered ECRS Responsibility for the Resource As Calculated" variable.

- NPRR 1197, Optional Exclusion of Load from Netting at ERCOT-Polled Settlement (EPS) Metering Facilities which Include Resources
  - Status: Posted on Aug 31, 2023, and still pending at the end of 2023
  - Description: This NPRR adds the ability for Resources to separately meter and settle Load(s) located behind the EPS metering point at the Resource's POI.
- NPRR 1198, Congestion Mitigation Using Topology Reconfigurations
  - Status: Posted on Aug 31, 2023, and still pending at the end of 2023
  - Description: This NPRR defines Extended Action Plan (EAP), revises the defined term Remedial Action Plan (RAP), adds EAP and RAP as types of Constraint Management Plan (CMP) suitable for the market use of the ERCOT Transmission Grid, and removes language limiting the application of these CMPs to congestion issues for which there exists no feasible Security-Constrained Economic Dispatch (SCED) solution. The related NOGRR 258 proposes changes that add language to allow the use of RAPs and EAPs to facilitate the market use of the ERCOT Transmission Grid, adds guardrails to ensure that topology reconfiguration requests meet basic reliability and economic criteria, and defines the process for submission, review, and approval of EAPs. This NPRR and NOGRR 258 leverage ERCOT's existing CMP process to quickly mitigate critical transmission congestion impacts by establishing a scalable process for topology reconfiguration requests that is transparent, predictable, equitable, workable, reliable, and compatible with existing planning processes. ERCOT already leverages topology optimization in the CMP processes. Since NPRR 529, CMP was introduced in 2013 with the limitations that this NPRR proposes to revise, the power industry has evolved and there have been technological improvements that make transmission topology reconfigurations a powerful option to mitigate congestion beyond just use cases for which there is no feasible SCED solution.

- NPRR 1199, Implementation of Lone Star Infrastructure Protection Act (LSIPA) Requirements
  - Status: Approved on April 11, 2024
  - Description: This NPRR revises the Protocols to reflect new requirements added to the LSIPA as part of Senate Bill (SB) 2013 during the 88th regular legislative session. Specifically, this NPRR makes the following changes to the Protocols: adds definitions of "Critical Electric Grid Equipment," "Critical Electric Grid Services," "Lone Star Infrastructure Protection Act (LSIPA) Designated Company," and "Lone Star Infrastructure Protection Act (LSIPA) Designated Country" to Section 2.1; adds paragraph (5) to Section 16.1.3, reflecting ERCOT's statutory authorization, established in SB 2013, to immediately suspend or terminate a Market Participant's registration or access to any of ERCOT's systems if ERCOT has a reasonable suspicion that the Entity meets any of the criteria described by Section 2274.0102(a)(2), Government Code, as added by Chapter 975 (S.B. 2116), Acts of the 87th Legislature, Regular Session, 2021; adds Section 16.1.4, establishing new reporting and attestation requirements for Critical Electric Grid Equipment and Critical Electric Grid Services procurements by Market Participants and entities that seek to register as Market Participants; amends Section 23 to add Form S, which shall be used by Market Participants and applicants for Market Participant registration to comply with the reporting and attestation requirements in Section 16.1.4; updates Section 16.1.3 and Section 23, Form Q using the new defined terms, where appropriate; and amends Section 1.3.2.1 to provide that certain information submitted on Form S shall constitute ERCOT Critical Energy Infrastructure Information (ECEII) under the Protocols.
- NPRR 1204, Considerations of State of Charge with Real-Time Co-Optimization Implementation
  - Status: Approved on February 1, 2024
  - Description: This NPRR implements the State of Charge (SOC) concepts necessary for awareness, accounting, and monitoring of SOC for ESRs within the RTC+B implementation and allow the design to evolve from the interim solutions being proposed under NPRR 1186.
- NPRR 1205, Revisions to Credit Qualification Requirements of Banks and Insurance Companies
  - Status: Posted on October 24, 2023, and still pending at the end of 2023
  - Description: This NPRR strengthens ERCOT's market entry eligibility and continued participation requirements for ERCOT Counter-Parties (i.e., Qualified Scheduling Entities (QSEs) and CRR account holders). Specific changes include

strengthening and clarifying minimum credit quality qualifications for: Banks, which issue letters of credit on behalf of Market Participants to ERCOT; and Insurance companies, which issue surety bonds on behalf of Market Participants to ERCOT.

- NPRR 1213, Allow DGRs and DESRs on Circuits Subject to Load Shed to Provide ECRS and Clarify Language Regarding DGRs and DESRs Providing Non-Spin
  - Status: Approved on April 11, 2024
  - Description: This NPRR amends requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are seeking qualification to provide ECRS, as follows: Paragraph (1)(c) of Section 3.8.6 allows for DGRs and DESRs on circuits subject to disconnection during Load shed events to provide ECRS; and Section 3.16 recognizes that ERCOT will establish limits on ECRS, which may be provided by DGRs and DESRs on circuits subject to disconnection during Load shed events. This NPRR also modifies requirements for ancillary service self-arrangement and ancillary service trades for DGRs and DESRs on circuits subject to Load shed that provide Non-Spinning Reserve (Non-Spin).
- NPRR 1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  - Status: Posted on December 7, 2023, and still pending at the end of 2023
  - Description: This NPRR revises the Real-Time On-Line Reliability Deployment Price Adder (RTORDPA) to: send appropriate locational price signals to avoid counterproductive Load and Resource responses to current RTRDPA price signals; limit Resource payment to the actual "indifference payment" (consistent with its definition), thereby reducing associated uplift by eliminating current RTRDPA payments to Resources that exacerbate constraints and eliminating payments to available capacity not requiring an indifference payment; eliminate Ancillary Service Imbalance Payments or Charges (ASIP/C) associated with RTRDPA, thereby reducing the risk associated with providing ancillary services; provide Resources an indifference payment under Real-Time Co-optimization (RTC) to eliminate the potentially large incentive to ignore Base Point instructions; and provide a stronger locational price signal around Resources committed by the Reliability Unit Commitment (RUC) process or other reliability actions for congestion, thereby reducing RUC Make-Whole Payment-related charges and uplifts and appropriately compensating impacted Qualified Scheduling Entities (QSEs).

Other Binding Document Revision Requests (OBDRRs)

- OBDRR 044, Related to NPRR1085, Ensuring Continuous Validity of Physical Responsive Capability (PRC) and Dispatch through Timely Changes to Resource Telemetry and Current Operating Plans (COPs)
  - Status: Approved on May 11, 2023
  - Description: This OBDRR aligns the ORDC pricing with the Protocol revisions of NPRR 1085 related to the ONHOLD status treatment of Resources.
- OBDRR 046, Related to NPRR 1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Status: Posted on June 27, 2023, and still pending at the end of 2023
  - Description: This OBDRR aligns the Procedure for Identifying Resource Nodes with the revisions from NPRR 1188 to accommodate nodal Dispatch and Settlement of Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs).
- OBDRR 047, Revision to ERS Procurement Methodology regarding Unused Funds from Previous Terms
  - Status: Approved on September 14, 2023, and effective on September 15, 2023
  - Description: This OBDRR clarifies treatment of unused funds from previous ERS Standard Contract Terms.
- OBDRR 048, Implementation of Operating Reserve Demand Curve (ORDC) Multi-Step Price Floor
  - Status: Approved on October 12, 2023
  - Description: The OBDRR adds two price floors to the ORDC: one at reserve levels below 6,500 MWs ($20 per MWh), and another between 6,500 MW and 7,000 MW ($10 per MWh).

II. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of 2023 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2023, including ancillary services charges by type. This does not reflect the total cost of each ancillary service, as it only accounts for the net charges after self-arrangement. Also, for energy, we calculated the real-time energy value based on MWs generated rather than settlement data, as energy imbalance charges net out (plus RENA).

Table A1: ERCOT 2023 Year at a Glance (Annual)

Cost Type	Annual Total ($M)
Energy	$28,965
Regulation Up	$119
Regulation Down	$48
Responsive Reserve	$407
Non-Spin	$426
ECRS	$669
CRR Auction Distribution	($1,442)
Balancing Account Surplus	$261
CRR DAM Payment	$1,807
PTP DAM Charge	$1,613
PTP RT Payment	$1,836
Emergency Response Service	$39
Revenue Neutrality Uplift	$109
AS Imbalance Uplift	($7)
ERCOT Fee	$247
ERO Passthrough Fee	$25
Firm Fuel Supply Service	$34
Other Load Allocation	$5
Net Cost of Electricity	$35,161

Table A2 presents the monthly aggregate costs of various ERCOT market settlement totals in 2023, including ancillary services costs by type.

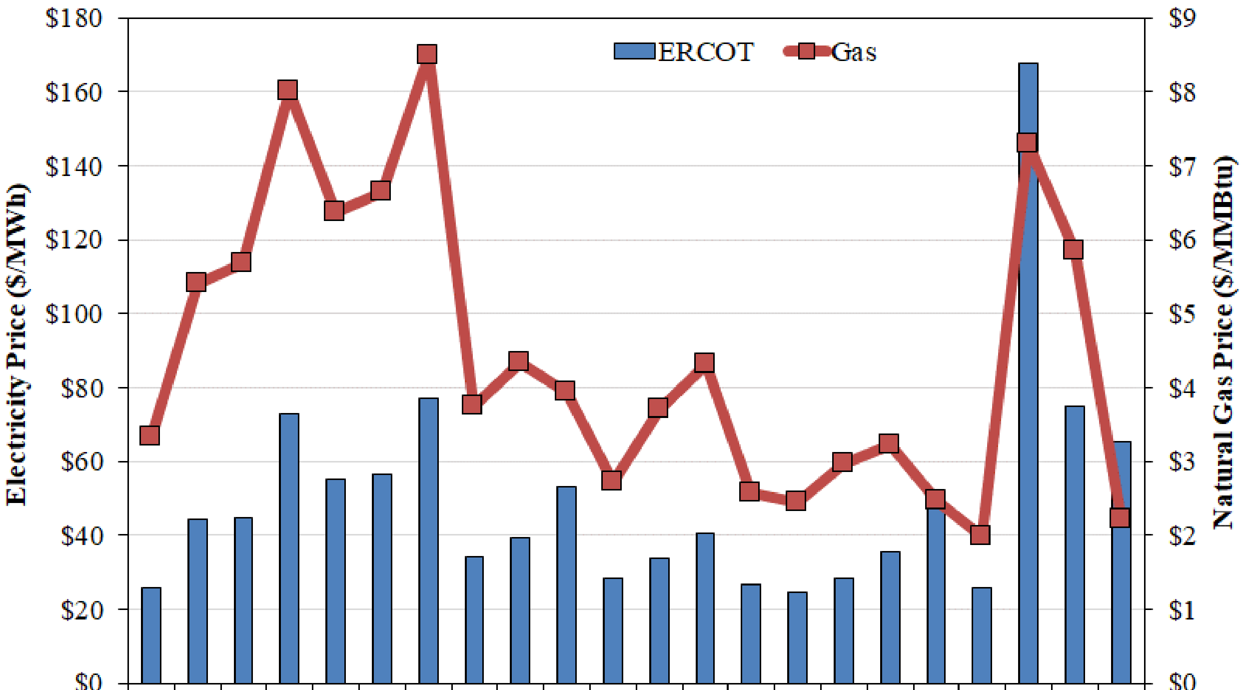
Table A2: Market at a Glance Monthly

	Monthly Totals (Millions)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Energy	$858	$663	$990	$750	$1,184	$3,224	$2,307	$11,281	$4,790	$1,127	$994	$797
Regulation Up	$2	$2	$4	$4	$2	$14	$7	$62	$13	$5	$3	$1
Regulation Down	$1	$4	$2	$2	$1	$2	$2	$23	$7	$2	$1	$1
Responsive Reserve	$7	$6	$11	$10	$7	$57	$26	$198	$48	$19	$13	$4
Non-Spin	$13	$16	$23	$24	$43	$98	$32	$117	$25	$14	$15	$6
ERCOT Contingency Reserve Service	-	-	-	-	-	$105	$54	$409	$62	$22	$13	$5
CRR Auction Distribution	$103	$98	$116	$125	$129	$127	$118	$119	$115	$140	$127	$124
Balancing Account Surplus	$13	$4	$10	-	-	$35	$38	$83	$30	$14	$13	$20
CRR DAM Payment	$130	$121	$221	$170	$89	$133	$121	$329	$142	$159	$93	$99
PTP DAM Charge	$114	$102	$205	$150	$87	$139	$112	$222	$133	$153	$88	$108
PTP RT Payment	$118	$133	$232	$169	$88	$137	$127	$319	$177	$143	$64	$128
Emergency Response Service	$5	$5	$5	$1	$1	$6	$6	$6	$6	-	-	-
Revenue Neutrality Uplift	$15	$23	$14	$11	$5	$3	$6	$2	$3	$7	$8	$16
AS Imbalance Uplift	$1	$2	$0.3	$1	$1	-	$0.3	$10	$3	$0.2	$0.3	-
ERCOT Fee	$18	$17	$18	$17	$20	$24	$26	$28	$24	$20	$17	$19
ERO Passthrough Fee	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Firm Fuel Supply Service	$8	$10	$5	-	-	-	-	-	-	-	$4	$8
Other Load Allocation	$0.3	$0.7	$0.4	$0.2	$0.3	$0.1	$0.5	$0.8	$0.5	$0.8	$0.4	$0.3

A. Zonal Average Energy Prices in 2023

Figure A1 below provides additional historic perspective on the ERCOT average real-time energy prices as compared to the average natural gas prices in each year from 2002 through 2023.

Figure A1: ERCOT Historic Real-Time Energy and Natural Gas Prices

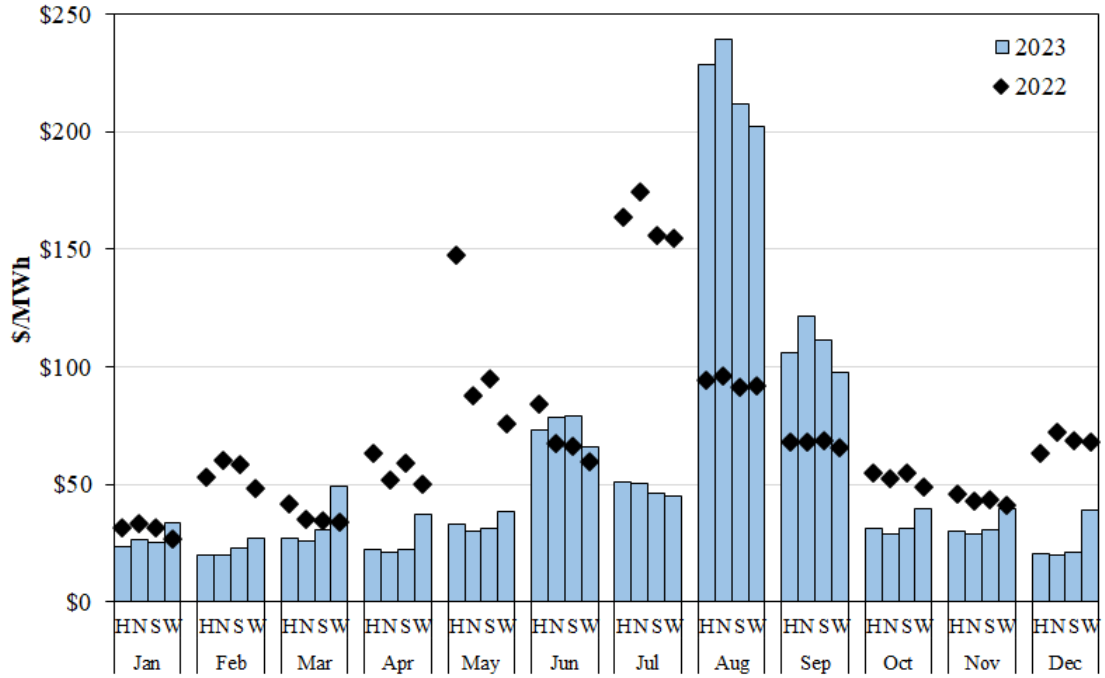


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77	24.62	28.25	35.63	47.06	25.73	167.8	74.92	65.13
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57	2.45	2.98	3.22	2.47	1.99	7.30	5.84	2.22

Like Figure 2 in the body of the report, Figure A1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price. Such relationship is consistent with expectations in ERCOT where natural gas generators are the largest contributor to the generation mix and have tended to set the marginal price; this is an indication that the price of electricity is reflective of the cost of production. This correlation was not evident overall in 2023 because the price distortions caused by ERCOT's ECRS implementation limited the reduction in average prices that would otherwise have occurred.

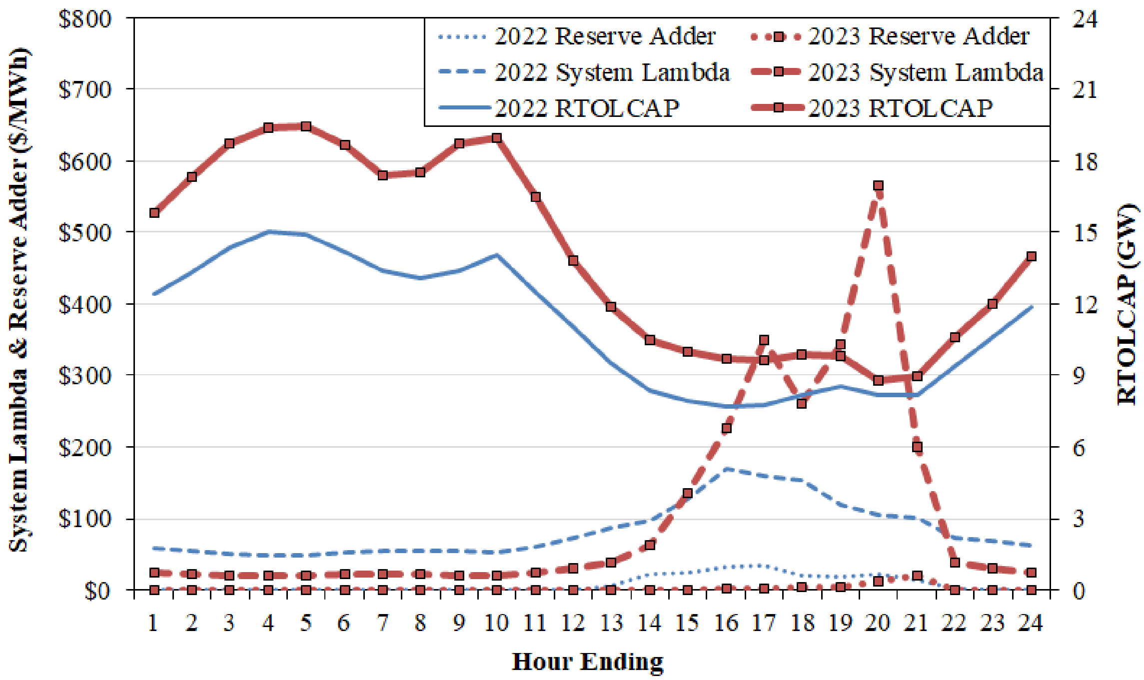
Figure A2 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2022 and 2023. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral or other forward contract prices.

Figure A2: Average Real-Time Energy Market Prices by Zone



Another factor influencing zonal price differences is CRR auction revenue distributions. These are allocated to Qualified Scheduling Entities (QSEs) representing load, based on both zonal and ERCOT-wide monthly load-ratio shares. The CRR auction revenues have the effect of reducing the total cost to serve load borne by a QSE. Figure A3 shows how online reserves (RTOLCAP), system lambda, and the ORDC adders changed from summer 2022 to 2023 (June-September).

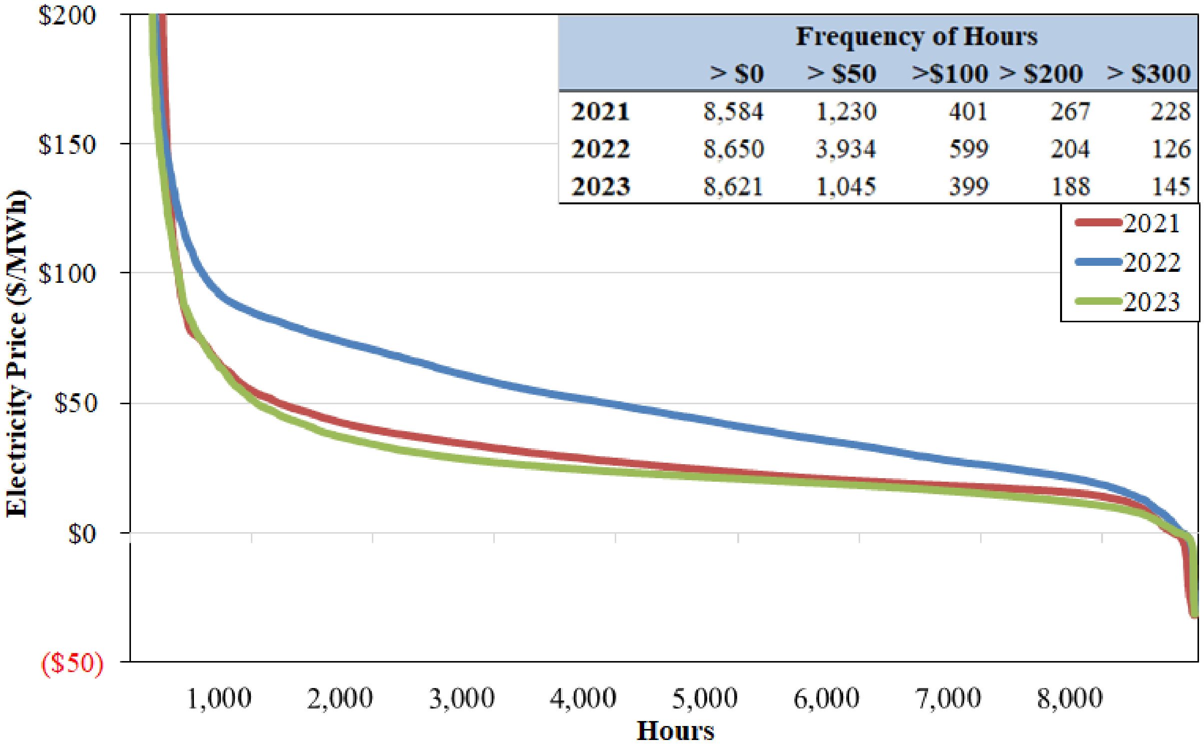
Figure A3: Summer 2022 and 2023 RTOLCAP, System Lambda, and ORDC Adders



There were more online reserves during the summer months in 2023 than in 2022, largely due to increases in solar generation. There was also a large increase in system lambda in 2023 relative to 2022, mainly due to the implementation of ECRS and additional reserves being inaccessible to SCED. Both of these factors contributed to the ORDC adders being lower in 2023 than in 2022.

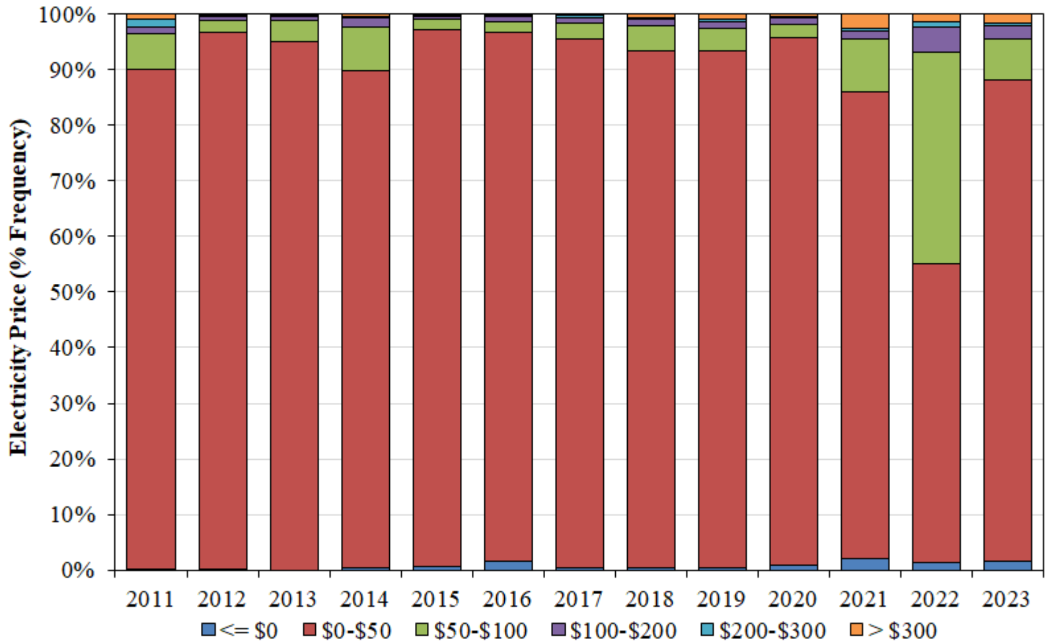
Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure led to increased occurrences of negative prices over the past few years. In 2023, there were 139 hours with ERCOT-wide prices at or below zero, an increase from 110 hours in 2022. Figure A4 and Figure A5 present price duration curve and range data to demonstrate this effect. In 2023, there was a 61% increase in the duration of prices in the lower range ($0 - $50) and a broad decrease in the duration of prices across the $50 - $300 ranges when compared with 2022.

Figure A4: ERCOT Price Duration Curve



Frequency of Hours	> $0	> $50	>$100	> $200	> $300
2021	8,584	1,230	401	267	228
2022	8,650	3,934	599	204	126
2023	8,621	1,045	399	188	145

Figure A5: ERCOT Price Duration Range



B. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven largely by changes in fuel prices, they are also influenced by other factors. To show changes in energy price that were related to other factors, we calculate an "implied heat rate" by dividing the real-time energy price by the gas price. Figure A6 shows the load-weighted implied heat rate, showing the number of hours (on the horizontal axis) that the implied heat rate is at or above a certain level (on the vertical axis).

Figure A6: Implied Heat Rate Duration Curve – All Hours

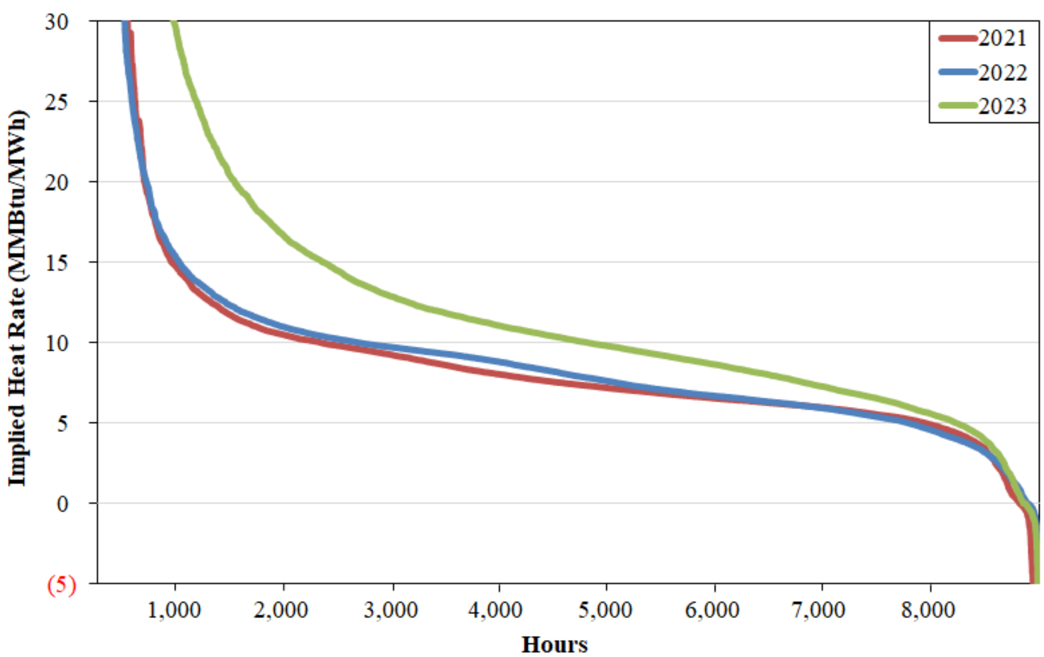


Table A3 displays the annual average implied heat rates by zone for 2014 through 2023. Adjusting for natural gas price influence, Figure A6 above shows that the annual, system-wide average implied heat rate was relatively consistent from 2020 to 2022 and then increased substantially from 2022 to 2023, largely driven by pricing outcomes caused by the increase in peak demand and procurement of additional reserves.

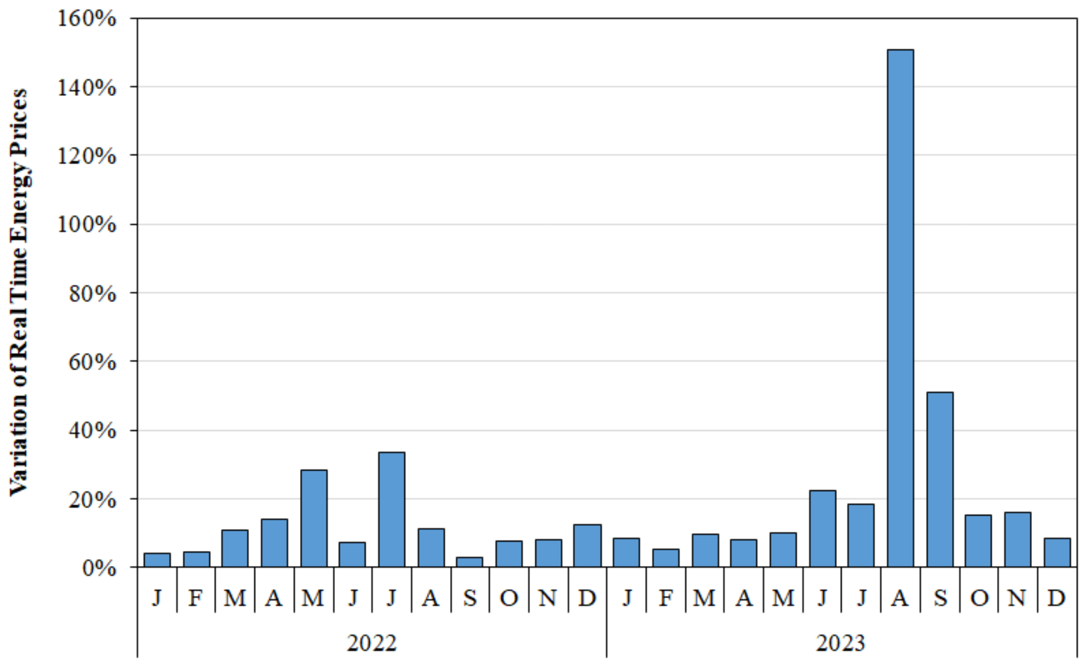
Table A3: Average Implied Heat Rates by Zone

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Natural Gas (MMBtu/MWh)										
ERCOT	**9.4**	**10.4**	**10.1**	**9.5**	**11.1**	**19.0**	**12.9**	**23.0**	**12.8**	**29.4**
Houston	9.2	10.5	10.8	10.7	10.7	18.4	12.3	17.7	13.9	29.2
North	9.3	10.2	9.7	8.6	10.9	18.9	12.0	28.3	12.9	30.9
South	9.6	10.6	10.1	9.9	11.2	19.2	13.4	25.7	12.5	28.5
West	10.1	10.4	9.0	8.2	12.3	20.5	15.9	14.4	11.2	27.8
Natural Gas Price ($/MMBtu)										
	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84	$2.22

C. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly, and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. Expanding the view of price volatility, Figure A7 below shows monthly average changes in five-minute real-time prices by month in comparison to the annual average for 2022 and 2023.

Figure A7: Monthly Price Variation



Price variability was higher overall in 2023 than in 2022. The main driver behind this volatility was the implementation of ECRS, which caused the demand constraint to be binding even when there were sufficient reserves on the grid. This caused prices to spike acutely even as reserves remained at a relatively high level.

D. Frequency of High Prices in ERCOT

As an energy-only market, ERCOT relies heavily on energy and ancillary services pricing to provide economic signals and guide decisions by market participants. However, the frequency and impacts of shortages can vary substantially from year-to-year, as shown in the figure below. To summarize the shortage pricing that has occurred since 2021, Figure A8 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2021 through 2023, as well as annual summaries for 2021 through 2023.

Figure A8: Duration of High Prices

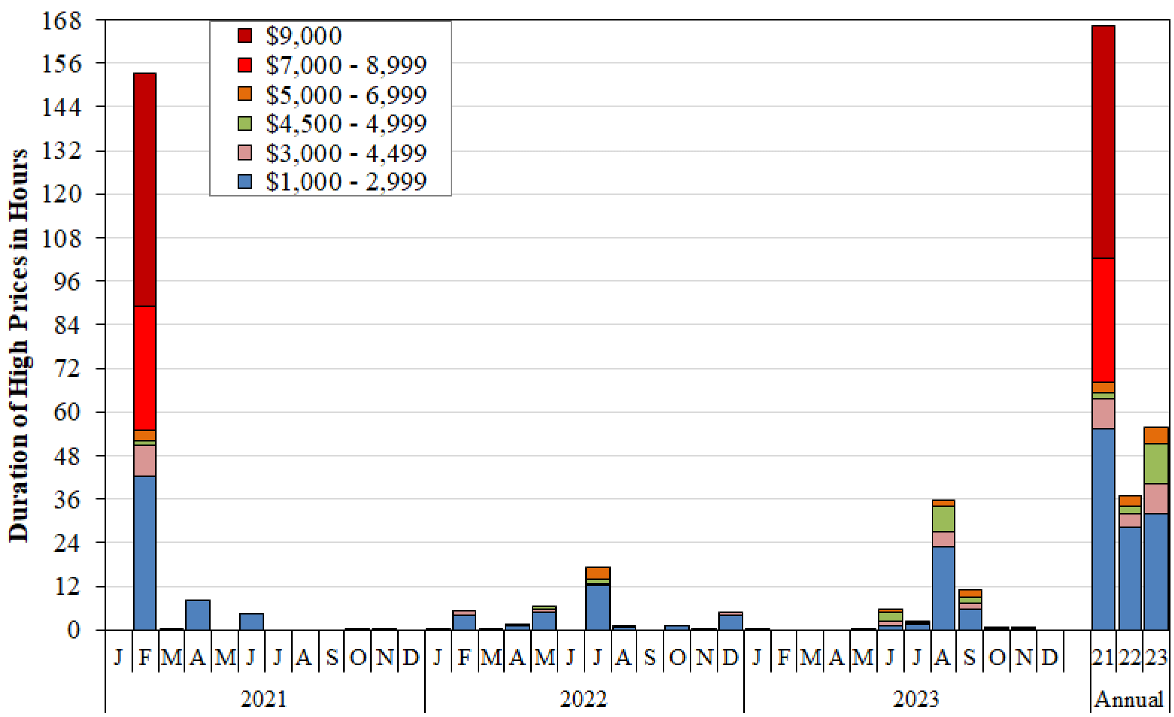


Figure A8 shows that the frequency of high prices in 2023 was the second highest in the history of the ERCOT market, second only to 2021 because of the extreme pricing event experienced during Winter Storm Uri. The increased frequency of high prices in 2023 was likely due to the record high summer temperatures, as well as the implementation of ECRS in June 2023.

Prices were greater than $1,000 for more than 55 hours in 2023, exceeding all of the previous ten years except for 2021 due to Winter Storm Uri. Prices above $1,000 were primarily concentrated during the summer months of June, August, and September. Prices reached the system-wide offer cap of $5,000 for more than four hours during 2023, mainly on August 17 and September 6.

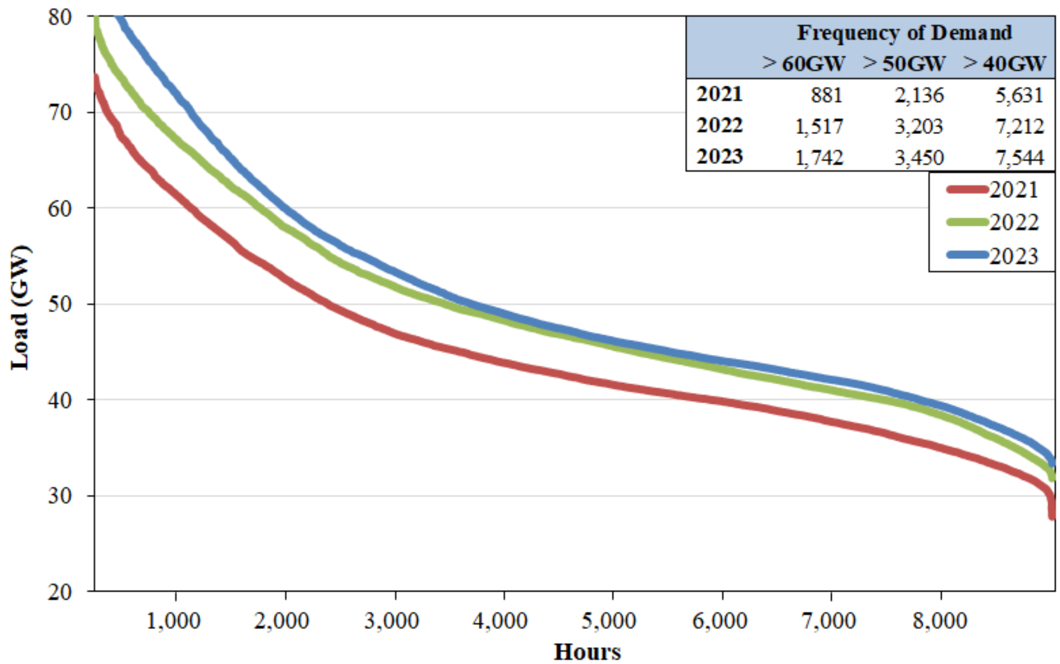
III. Appendix: Demand and Supply in ERCOT

In this section, we provide supplemental analyses of load patterns during 2023 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2023

To provide a more detailed analysis of load at the hourly level, Figure A9 compares load duration curves for each year from 2021 through 2023. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT has a fairly smooth load duration curve, typical of most electricity markets, with low to moderate electricity demand in most hours, and peak demand usually occurring during the late afternoon on days with especially high temperatures. Although the load duration curve was higher in 2023 than in 2022 because of continuing load growth in ERCOT.

Figure A9: Load Duration Curve – All Hours



Frequency of Demand	> 60GW	> 50GW	> 40GW
2021	881	2,136	5,631
2022	1,517	3,203	7,212
2023	1,742	3,450	7,544

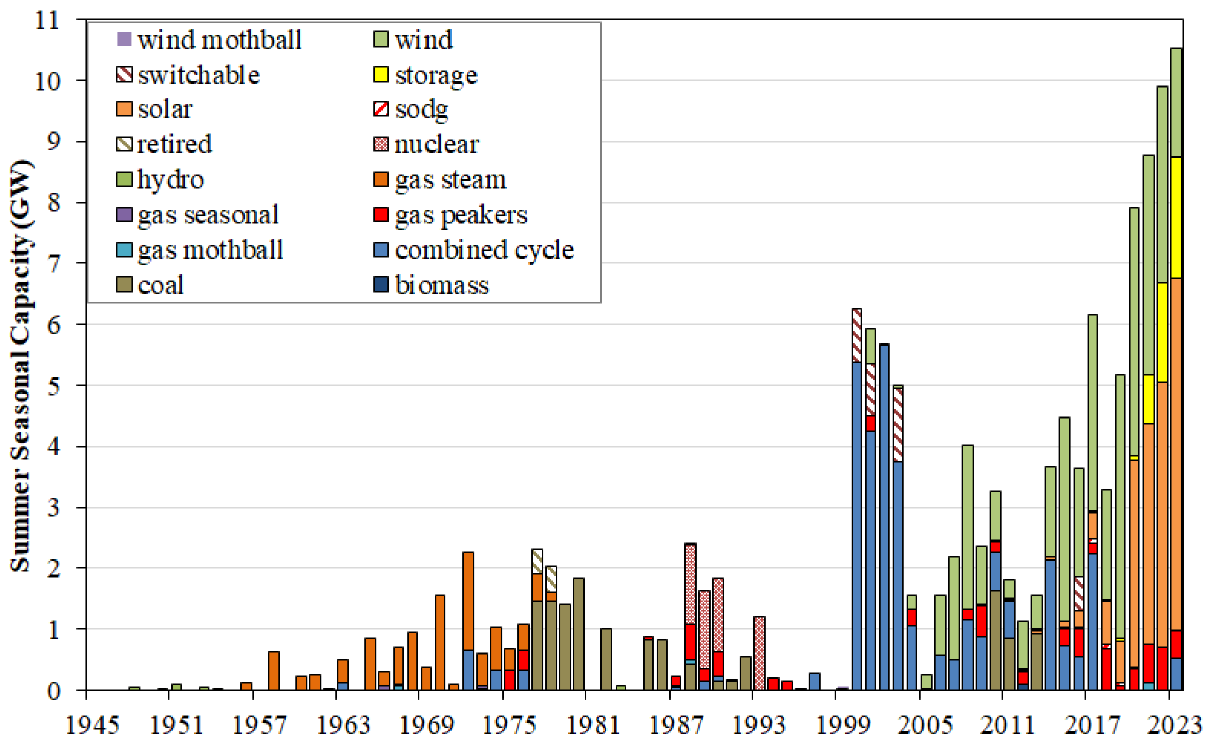
B. Generation Capacity in ERCOT

The generation mix in ERCOT is presented in this subsection. Figure A10 shows the vintage of generation resources in ERCOT which were shown as operational in the December 2023 CDR report,[167] including resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR.

167 Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2024-2033 (Dec. 8, 2023), available at https://www.ercot.com/files/docs/2023/12/07/CapacityDemandandReservesReport_Dec2023.pdf.

The figure shows several distinct periods of time where different technologies were added. The period prior to 1954 consists entirely of hydro generation additions. Between 1955 and 1977, the majority of additions were gas-fired boiler units. Additions during the period of 1986 to 1993 were primarily nuclear capacity. Between 1996 and 2004, the additions were primarily gas-fired combined cycle generators. Between 2006 and 2019, the additions were primarily wind, and beginning in 2020, a substantial amount of solar and some ESRs were added. Since 2020, the addition of solar has gradually increased with almost 39% of new solar capacity in 2020, 41% in 2021, 43% in 2022, and 55% in 2023. In 2022 and 2023, additions of ESR capacity were pronounced (18% of new capacity in 2022, and almost 18% in 2023).

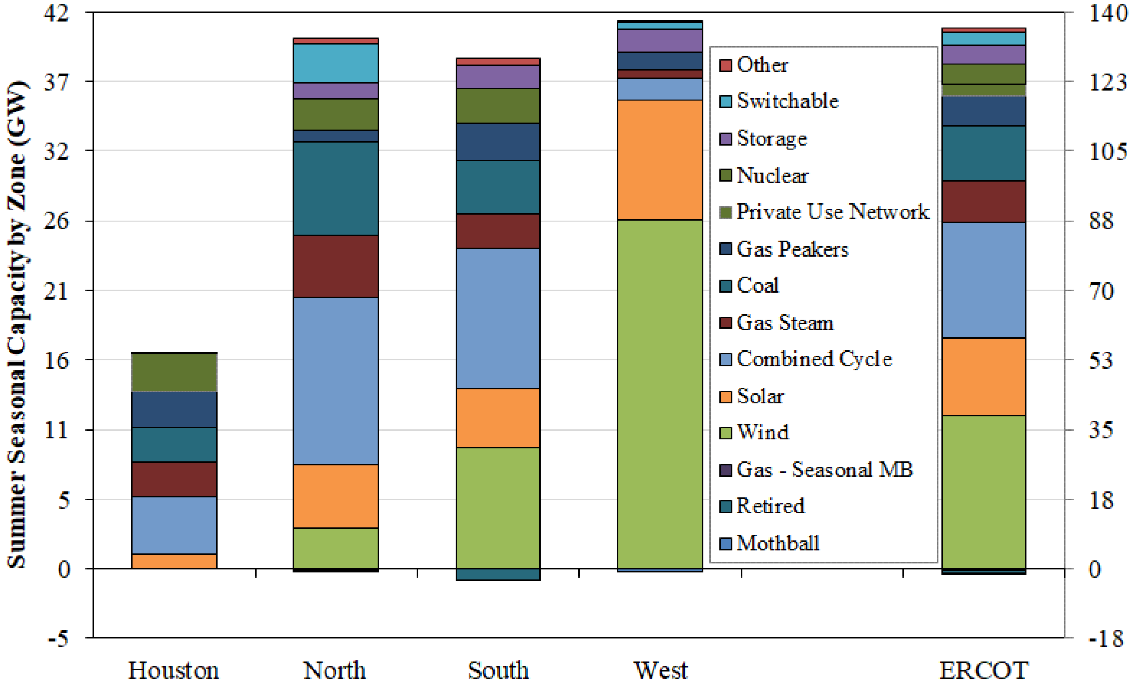
Figure A10: Vintage of ERCOT Installed Capacity



In 2023, when excluding mothballed resources and including only the fraction of wind capacity deemed available to reliably meet peak demand, the North zone accounted for approximately 29% of capacity, the South zone 28%, the Houston zone 12%, and the West zone 30%. The installed generating capacity by type in each zone is shown in Figure A11.

Approximately 10.5 GW of new generation resources came online in 2023, including 1.8 GW of wind resources with an effective peak serving capacity of about 500 MW, 5.8 GW of solar resources with an effective load carrying capability of 4.4 GW. The remaining capacity was from 430 MW of combustion turbines, 540 MW from a combined cycle, and 1900 MW of power ESRs. The location of the new resources was distributed as follows: 30% in the South, 29% in the West, 23% in the North, 12% in Coastal, 5% in Panhandle, and 2% in Houston.

Figure A11: Installed Capacity by Technology for Each Zone



C. Wind and Solar Output in ERCOT

The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months and, predominately, during off-peak hours. Figure A12 shows average wind production for each month in 2022 and 2023, with the average production in each month divided into four-hour blocks. The lowest wind output generally occurs during summer afternoons, and the average wind output during summer peak period increased from about 8 GW in 2022 to 8.3 GW in 2023 due to a strong presence of wind capacity in ERCOT, along with increased geographic diversity of those resources. This may be a small fraction of the total installed capacity, but it indicates that wind generation is a significant contributor to generation supply.

Figure A12: Average Wind Production

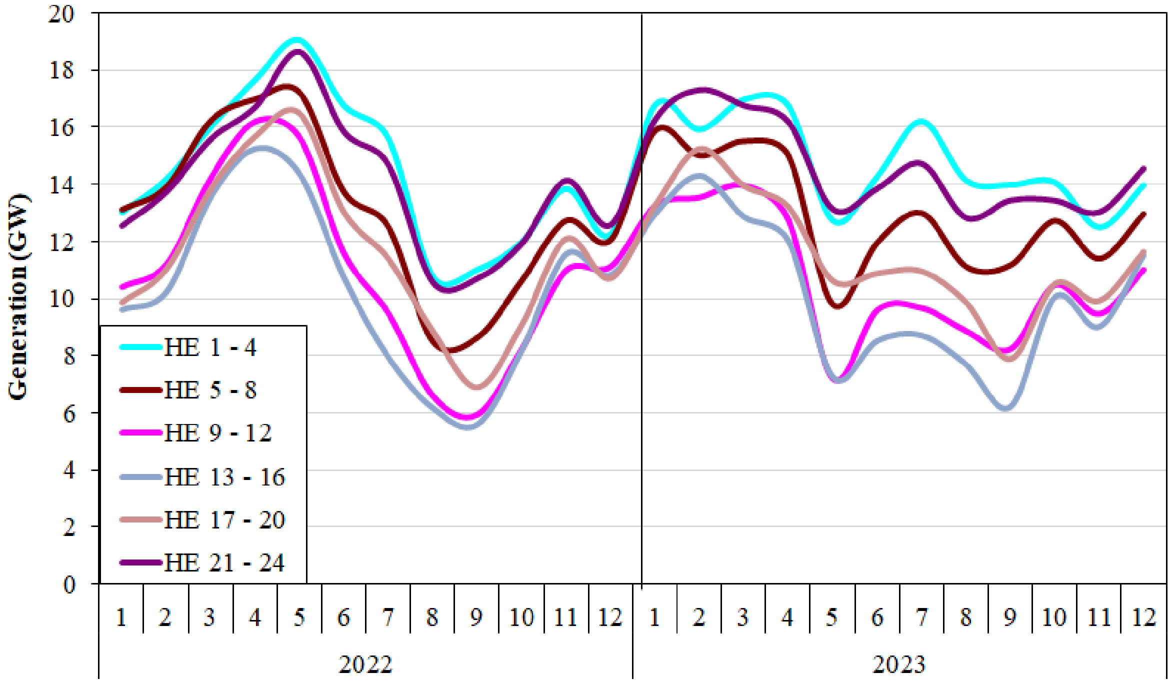
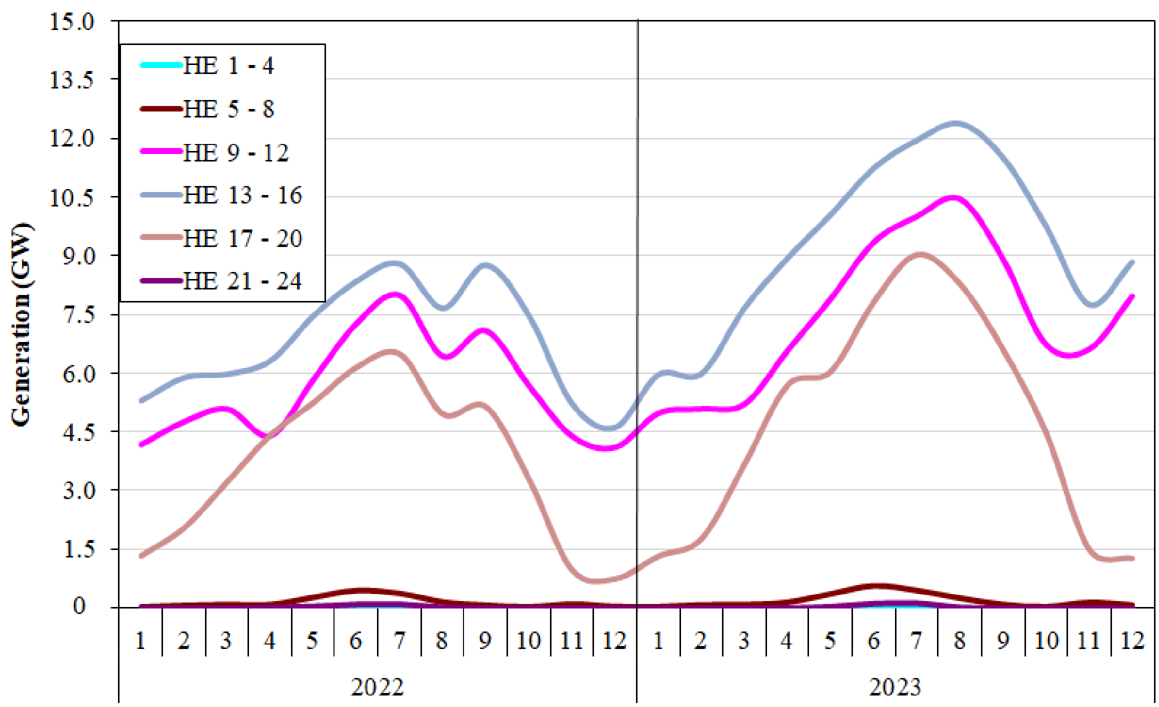


Figure A13 below shows average solar production for each month in 2022 and 2023, with the average production in each month divided into four-hour blocks. The average solar output increased by a third in 2023 when compared to 2022. This was due to a significant increase in solar capacity of 5,790 MW, along with increased geographic diversity of those resources.

Figure A13: Average Solar Production



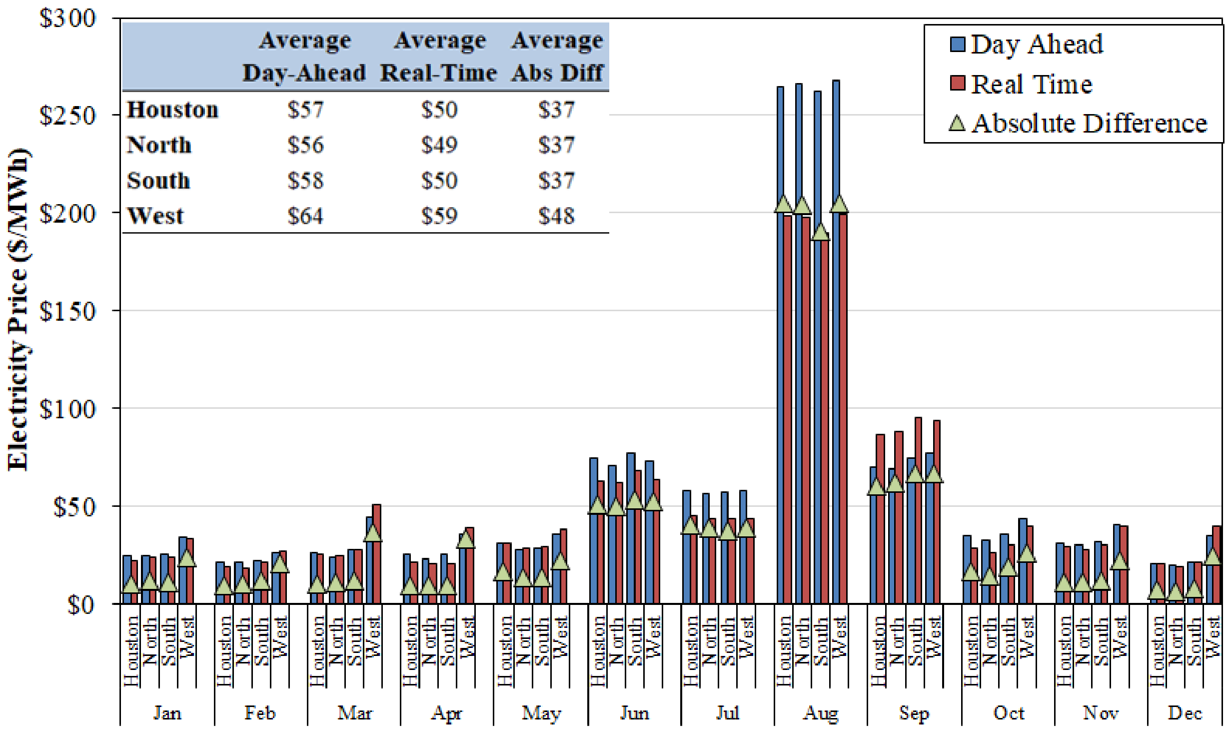
IV. APPENDIX: DAY-AHEAD MARKET PERFORMANCE

In this section, we provide supplemental analyses of 2023 prices and outcomes in ERCOT's day-ahead energy market.

A. Day-Ahead Market Prices and Convergence

In Figure A14, monthly day-ahead and real-time prices for 2023 are shown for each of the geographic zones. August saw the highest prices overall, with real-time prices diverging higher than day-ahead prices because of the exceptionally high and sustained temperatures throughout the month. Although the average day-ahead and real-time prices were similar in all zones, the average absolute difference in the West zone was the largest. This trend is explained by wide swings in West zone prices resulting from transmission congestion in the area that typically occurs at times when wind energy output is low.

Figure A14: Day-Ahead and Real-Time Prices by Zone

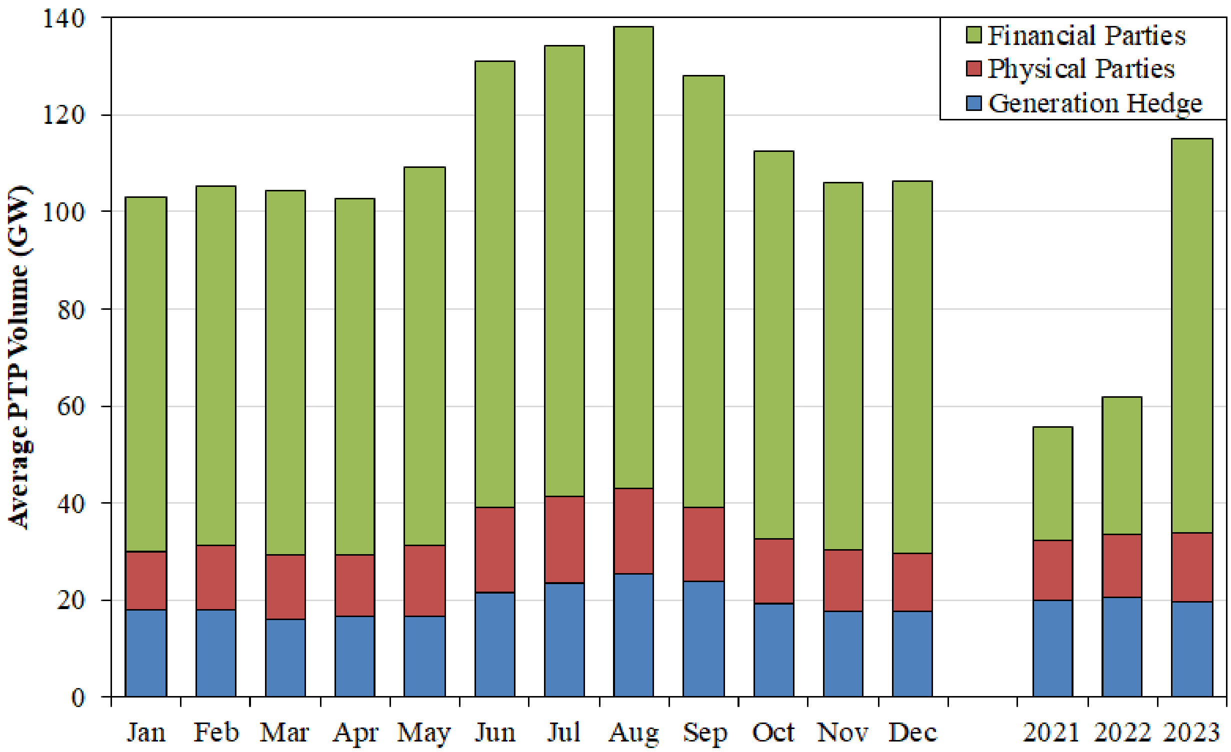


	Average Day-Ahead	Average Real-Time	Average Abs Diff
Houston	$57	$50	$37
North	$56	$49	$37
South	$58	$50	$37
West	$64	$59	$48

B. Point-to-Point Obligations

Figure A15 below presents the total volume of PTP obligation purchases in 2023 divided into three categories. There can be multiple PTP obligations sourcing and sinking at the same settlement point; however, the volumes in this figure do not net out those injections and withdrawals and, thus, could overestimate the volumes. Average purchase volumes are presented on both a monthly and annual basis. The total volume of PTP obligation purchases has been fairly stable in recent years, with the volume in 2023 higher than in previous years because of high congestion rent attracting more hedging activity.

Figure A15: Point-to-Point Obligation Volume



For all PTP obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that in 2023, like in 2020 and 2021, financial parties comprised the majority of the volume of PTP obligations purchased (68%), with generation hedging comprising a somewhat smaller volume of PTP obligations purchased for the year (19%). Other than generation hedging and load hedging, the volumes of PTP obligations are not directly linked to a physical position. It is assumed they are purchased primarily to arbitrage anticipated price differences between two locations, or to hedge trading activities occurring outside of the ERCOT market. This arbitrage activity is further separated by the type of market participant.

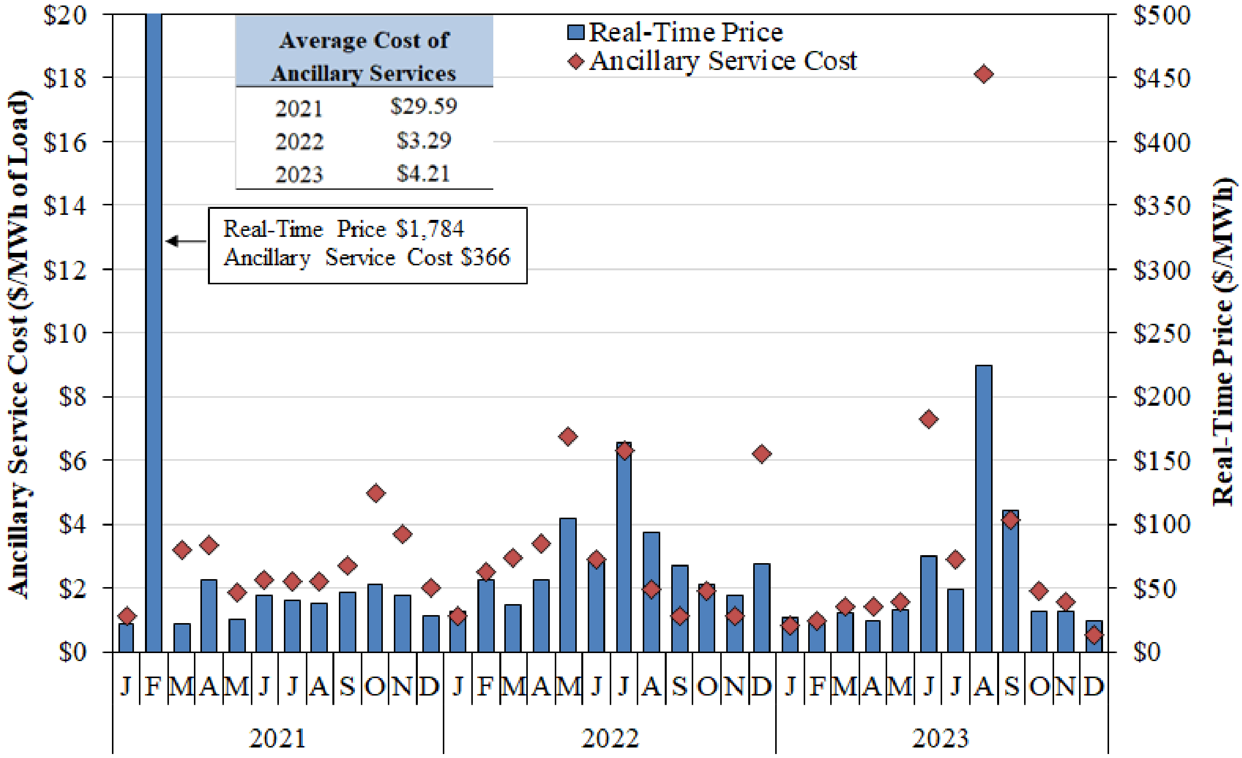
Physical parties are those that have actual real-time load or generation, whereas financial parties have neither. Financial parties purchased 68% of the total volume of PTP obligations in 2023, much higher than the 44% share in 2022. The increasing volume of PTP obligations purchased by financial parties can have liquidity benefits but can also strain the software due to large amounts of bids being submitted, particularly those bids that are unlikely to be awarded. Starting August 10, 2023, ERCOT implemented System Change Request (SCR) 798, *PTP Obligation Bid*

ID Limit, lowering the day-ahead market PTP Obligation bid limit per Counter-Party (CP) to 1,000 bid IDs per Operating Day.

C. Ancillary Services Market

Figure A16 below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2021 through 2023.

Figure A16: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load increased from $1.00 per MWh in 2020 to $29.59 per MWh in 2021, mostly due to the effects of Winter Storm Uri, and back down again to $4.21 per MWh in 2023. The 2023 average ancillary service cost per MWh of load was still significantly higher than any other non-Uri year. Part of this increase was due to the higher ancillary service procurement volumes and the higher prices that resulted from increased procurement.

Figure A17: Responsive Reserve Providers

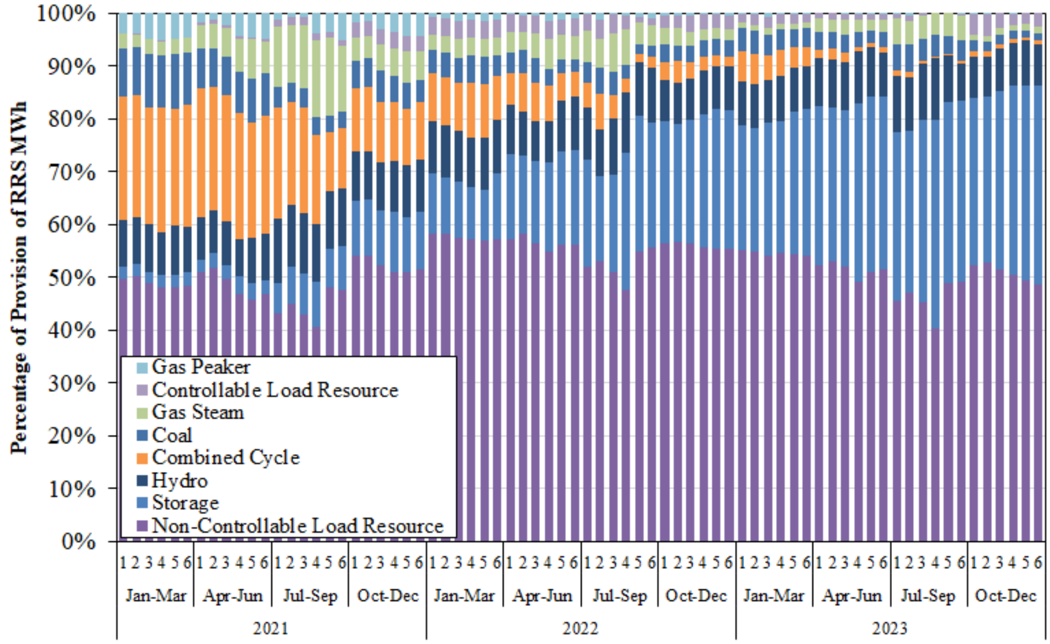
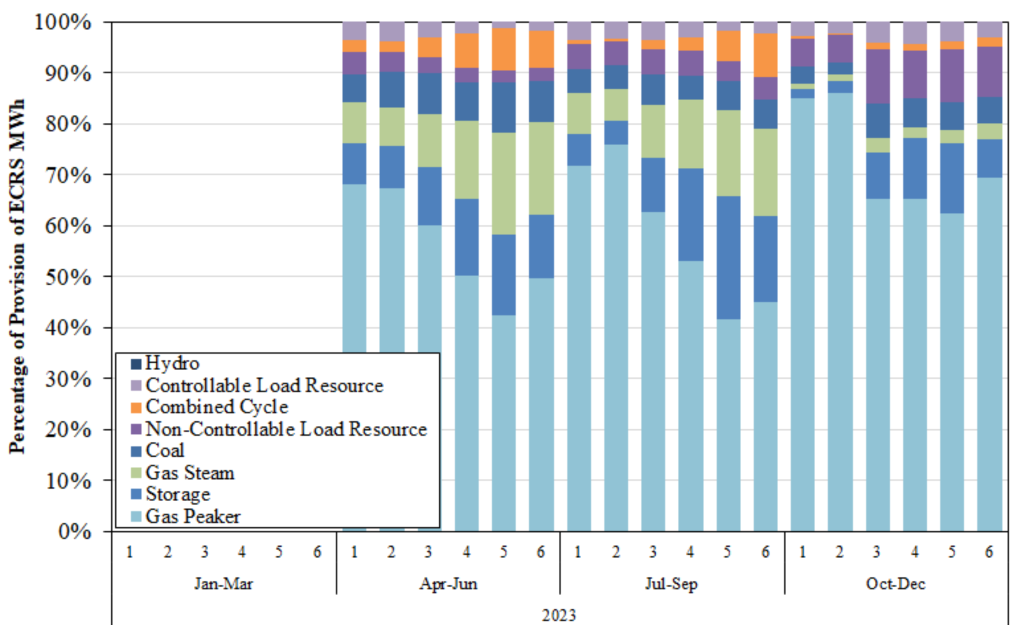


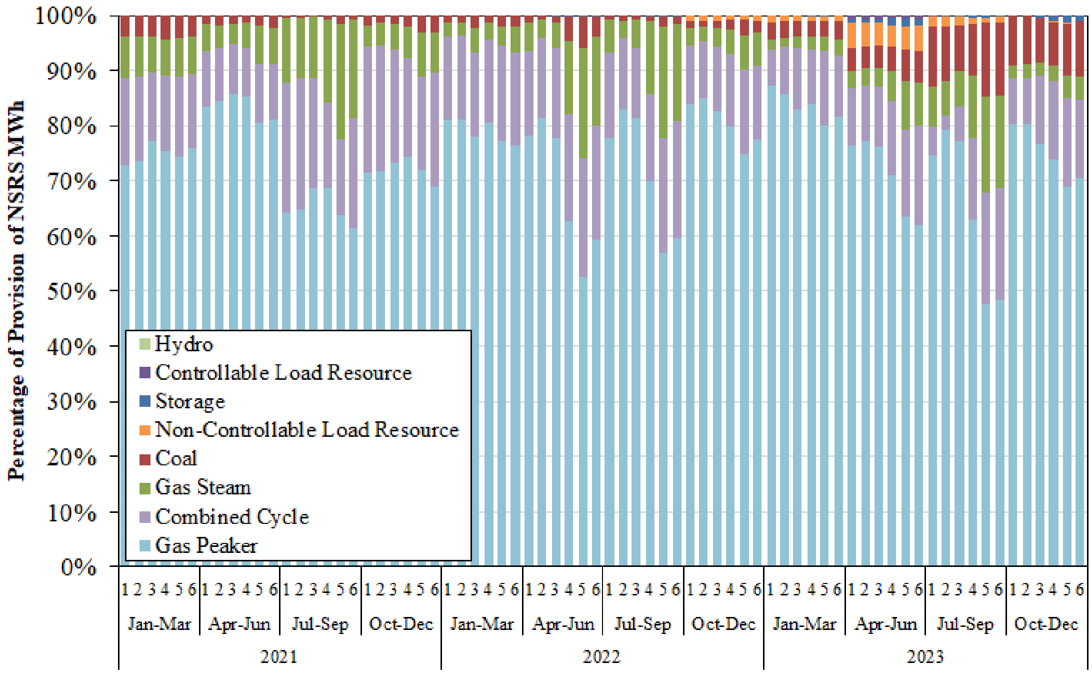
Figure A17 above shows the share of the annual responsive reserve service that was provided in real-time by different types of resources for the past three years. Responsive reserve provision from combined cycle units reduced significantly from 2021 to 2023. In this figure, as well as in the subsequent ancillary service provider figures, the labels 1 to 6 refer to delivery hour ranges in the calendar quarters: 1) HE 23, 24, and 1; 2) HE 3-6; 3) HE 7-10; 4) HE 11-14; 5) HE 15-18; 6) HE 19-22. Combined cycle units were providing as high as 24% of the reserves in 2021, in contrast to 6% of the total responsive reserves in 2023. Responsive reserves provided by ESRs increased from 2021 to 2023; at a maximum, 40% of the service was provided by ESRs.

Figure A18: ERCOT Contingency Reserve Service Providers



ECRS is a service provided using capacity that is capable of being ramped to a specified output level within 10 minutes and can be sustained at a specified level for two consecutive hours. Figure A18 above shows the share of ECRS that was provided in real-time by different types of resources since its introduction in June 2023. A large share of ECRS is provided by gas peakers.

Figure A19: Non-Spinning Reserve Providers



Similar to ECRS, a majority of non-spinning reserves were provided by gas peakers, followed by combined cycle units. Figure A19 above shows that the share of non-spinning reserves from coal units has increased from 2021 to 2023. Coal units were providing as high as 4% of non-spinning reserves in 2021, in contrast to 14% of the total non-spinning reserves in 2023.

Figure A20 below shows the distribution for regulation up providers by type of resource in 2023, and Figure A21 shows the distribution for regulation down providers by type of resource in 2023. Figure A20 shows the emergence of ESRs as a major player in the regulation market, with as high as approximately 83% of regulation up provided by ESRs in 2023. CLRs and combined cycle units provided most of the regulation down service.

Figure A20: Regulation Up Reserve Providers

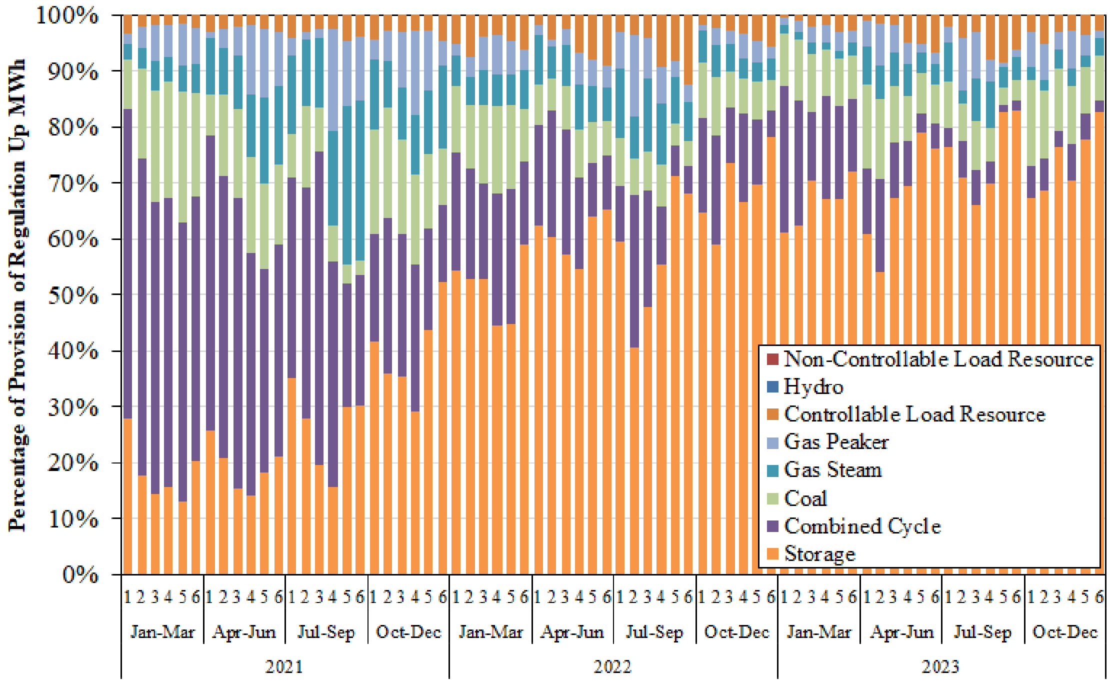
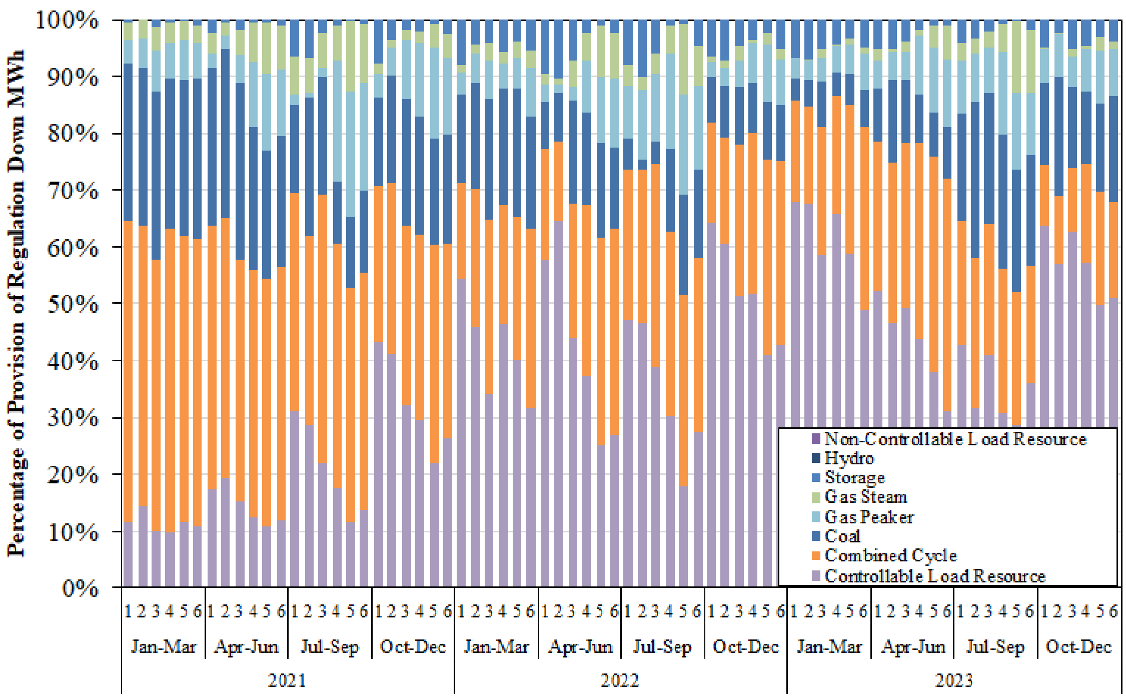


Figure A21: Regulation Down Reserve Providers



1. Supplemental Ancillary Services Market

The ERCOT market appropriately reflects the tradeoff between providing capacity for ancillary services versus providing energy in its co-optimized day-ahead market. Those same tradeoffs exist in real-time. Until comprehensive, market-wide real-time co-optimization is implemented, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest, and, therefore, are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios still face larger risks than QSEs with small portfolios because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in a SASM are often three to four times greater than clearing prices from the day-ahead market.

SASMs were executed 44 times in 2023, with SASM awards providing 289 service-hours. SASMs were less frequent and for less total hours in 2023; in 2022, SASMs were executed 64 times, and 448 service-hours were awarded. In addition to more frequent shortages, it appears that ERCOT operators were more proactive regarding ancillary service shortages in 2023 than in previous years and took the steps to procure replacement MWs more often. Figure A22 below provides the quantity of each service-hour that was procured via SASM over the last three years.

Figure A22: Ancillary Service Quantities Procured in SASM

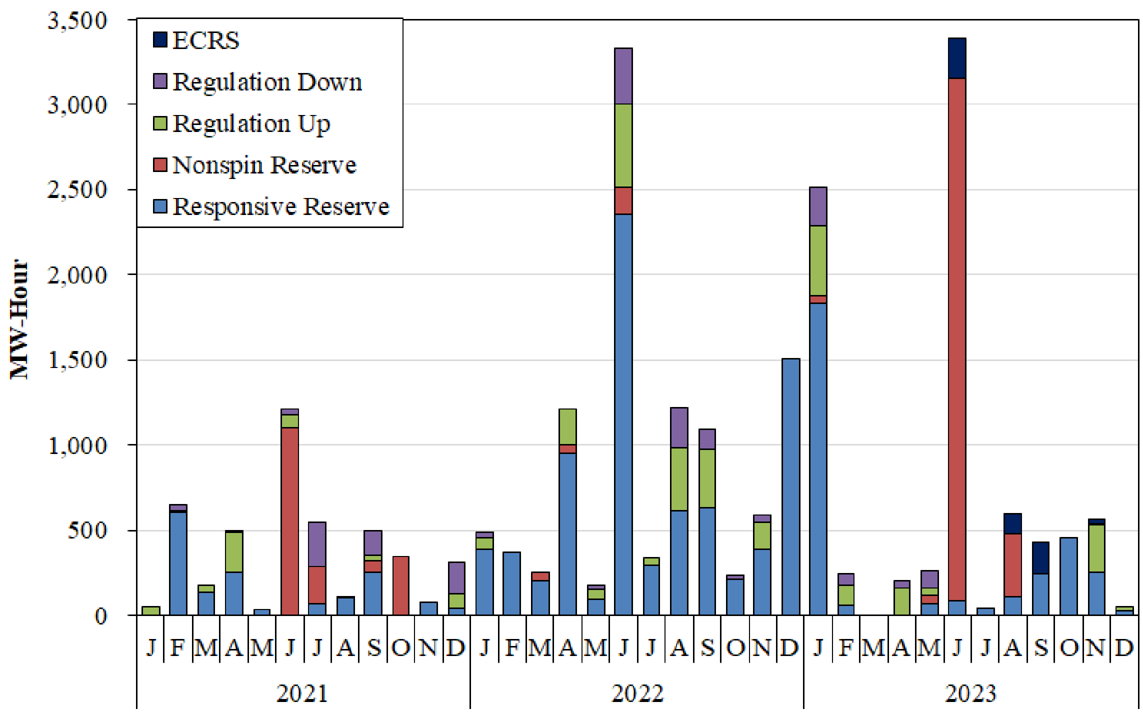
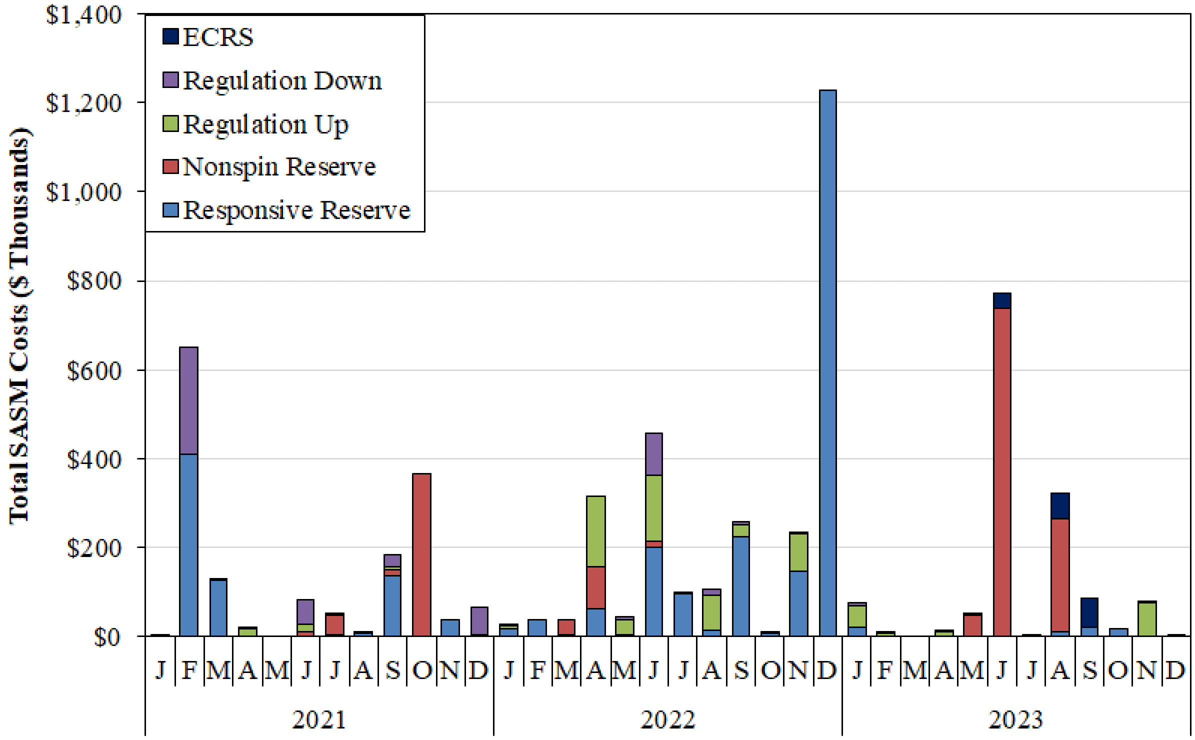


Figure A22 shows the volume of service-hours procured via SASM over 2023. 8,740 MW of service-hours were procured, which is very small when compared to the total ancillary service requirement of nearly 42 million MW of service-hours.

Figure A23 shows the average cost of the replacement ancillary services procured by SASM over the last three years. The total SASM costs throughout 2023 were much lower than the costs in 2022.

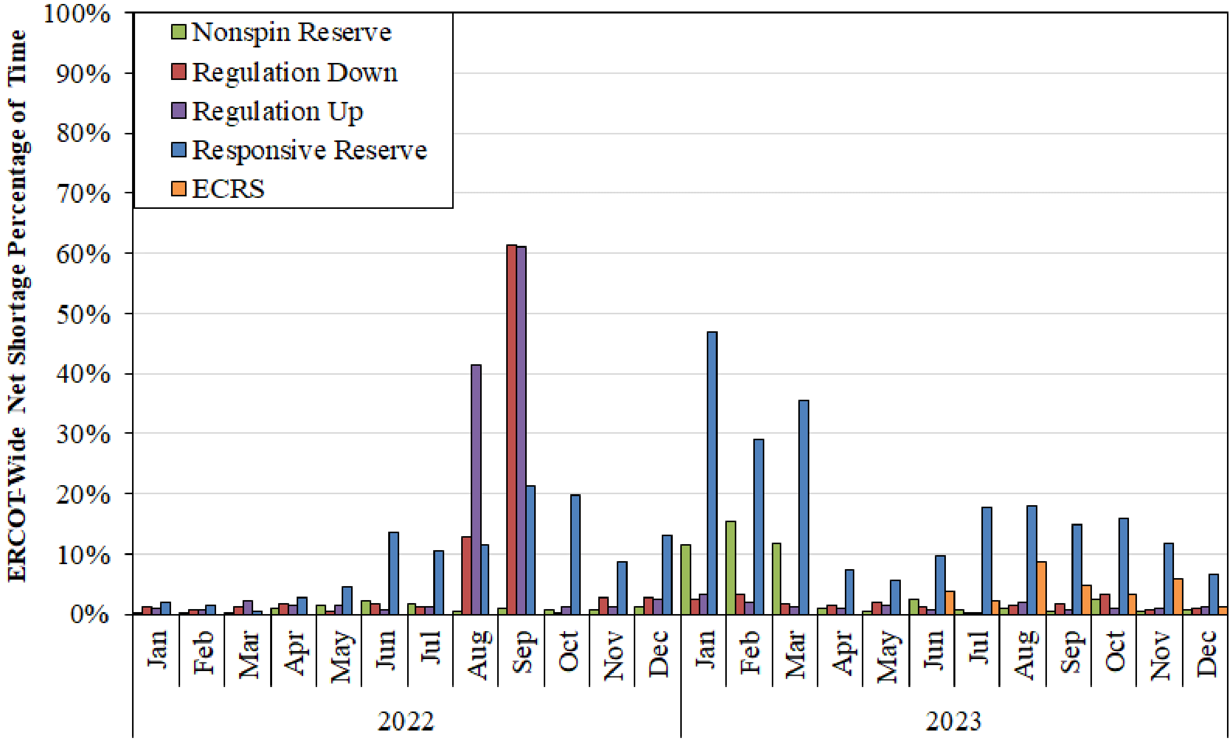
Figure A23: Average Costs of Procured SASM Ancillary Services



Co-optimizing energy and ancillary services in real-time will not require entities to estimate opportunity costs between providing energy or reserves, will eliminate the need for the SASM mechanism, and will allow ancillary services to be continually shifted to the most efficient provider. The greatest benefit will be to effectively handle situations where entities that had day-ahead ancillary service awards are unable to fulfill that commitment, e.g., because of a generator forced outage. Thus, RTC will provide benefits across the market in future years.

In addition to its other weaknesses, a SASM is only useful for replacing ancillary services as part of a forward-looking view of the grid conditions. However, there are instances where the system is short ancillary services in real-time. Figure A24 depicts the percentage of hours in each month of 2023 where there was an ERCOT-wide shortage in the respective ancillary service. For this analysis, a shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour. The analysis does not identify whether the QSE was charged for the shortage.

Figure A24: ERCOT-Wide Net Ancillary Service Shortages



Instances of net shortage in the reserve products did not reach high levels in 2023 as compared with prior years. Frequency of net shortage by month and product over the past five years indicates net shortage within a product is driven by system conditions (temperature and duration, generation outages, and other factors). Compared to prior years, the frequency of reserve shortage in 2023 did not reach higher frequency levels in any of the services. This may be due to more conservative operation practices and procurement that results and is likely also due to numerous differences in system and ambient conditions from year to year. There is no distinct factor that explains the low frequency of net shortage compared to the prior several years.

V. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2023, review the costs and frequency of transmission congestion in both the day-ahead and real-time markets, as well as review the activity in the CRR market.

A. Day-Ahead Congestion

In this subsection, we provide a review of the aggregate congestion and transmission constraints from the day-ahead market in 2023. Figure A25 shows the day-ahead congestion value by zone, calculated by summing the product of the transmission flows over each binding constraint times the shadow prices of the constraint.

Figure A25: Day-Ahead Congestion Value by Zone

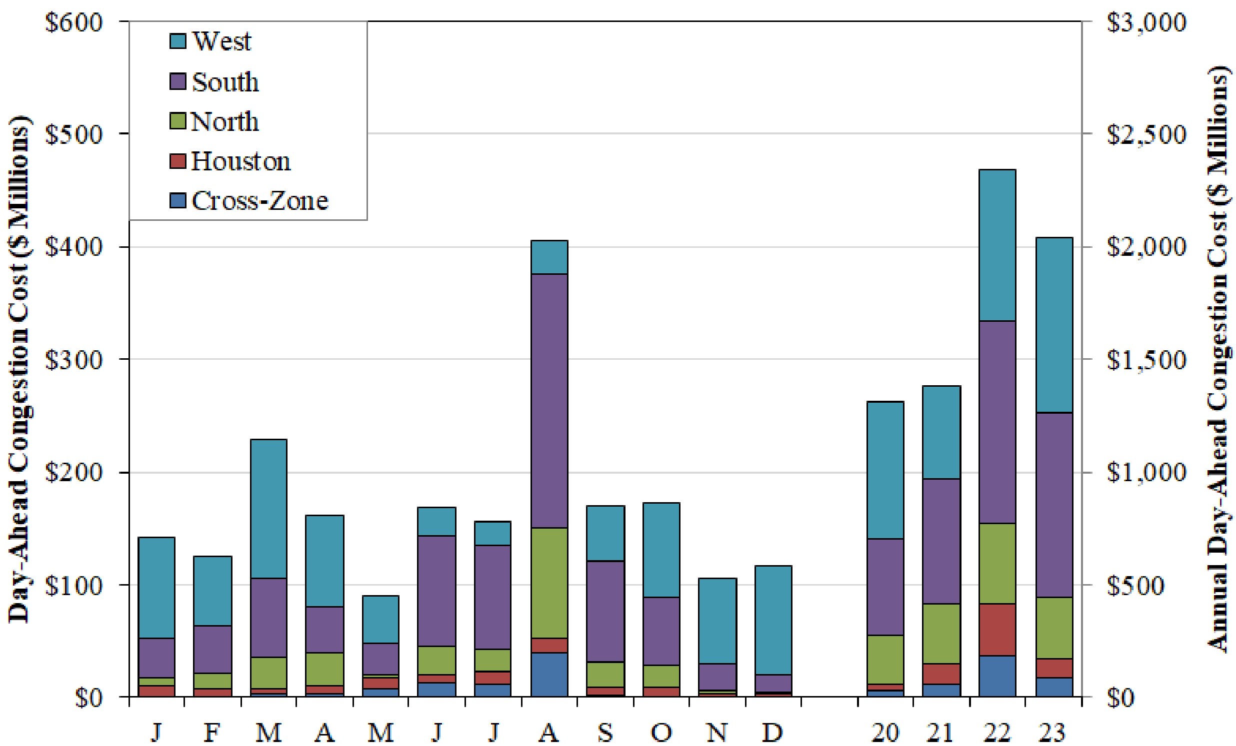
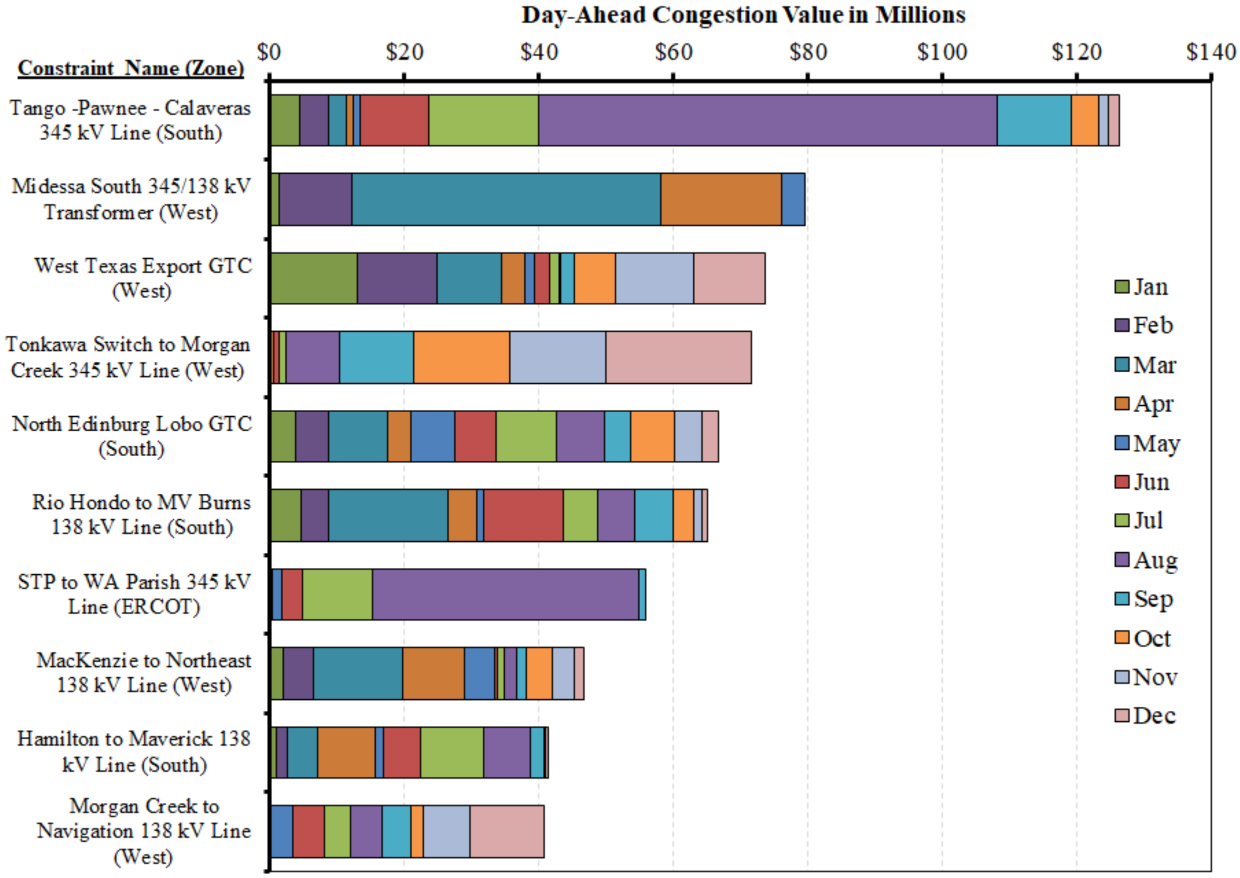


Figure A26 presents the ten most congested areas from the day-ahead market, ranked by their value. Eight of the constraints listed here were described in Figure 34: Most Costly Real-Time Congested Areas. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the day-ahead market similar to how energy flows in real-time, the same transmission constraints are expected to appear in both markets.

Figure A26: Most Costly Day-Ahead Congested Areas



Since the start of the nodal market, it had been common for the day-ahead constraint list to contain many constraints that were unlikely to occur in real-time. However, for the sixth year in a row, the majority of the costliest day-ahead constraints in 2023 were also costly real-time constraints. All of the constraints that exist in both the top ten real-time market and the top ten day-ahead market incurred less congestion value in the day-ahead market than the real-time market. This is a result of less wind generation participating in the day-ahead market, likely because of the uncertainty associated with predicting its output.

B. Real-Time Congestion

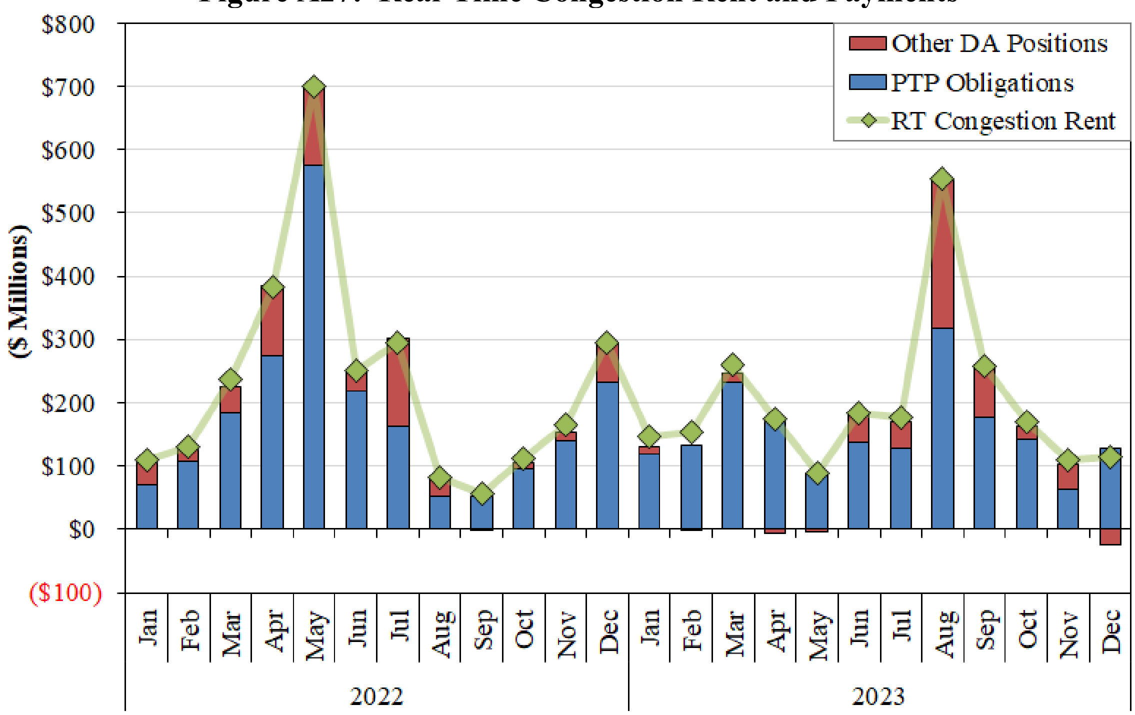
All actual physical congestion occurs in real-time and the real-time market and ERCOT operators manage power flows across the network. The expected costs of this congestion are reflected in the day-ahead market, but the ultimate source of the congestion is the physical constraints binding in real time.

1. Real-Time Congestion Rents and Payments

The day-ahead schedule flows are comprised of PTP obligations and other day-ahead positions that generate flows over the network. Figure A27 shows the combined payments to all these day-ahead positions compared to the total real-time-congestion rent.

In 2023, real-time congestion rent was $2,400 million, while payments for PTP obligations (including those with links to CRR options) were $1,836 million and payments for other day-ahead positions were $450 million. This resulted in a surplus of approximately $102 million for the year. Higher congestion cost can also drive higher shortfall amounts. In general, ERCOT has continued to improve its coordination of the network modeling in its day-ahead and real-time market by working with TDSPs to better understand causes of chronic constraints and properly model network elements. Continuous improvement in this area should be the goal of all ISOs.

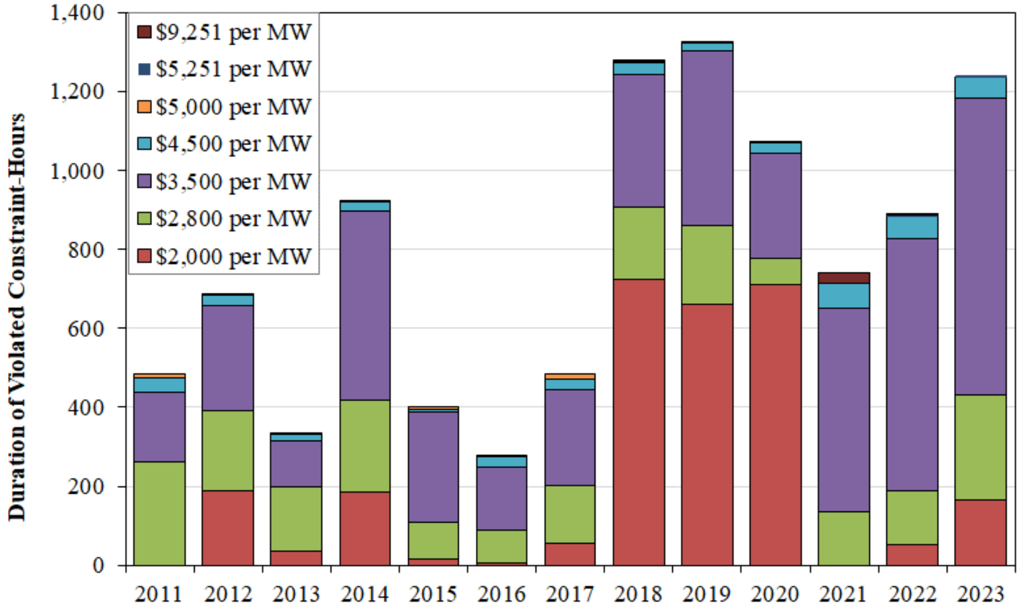
Figure A27: Real-Time Congestion Rent and Payments



2. Types and Frequency of Constraints in 2023

Figure A28 below depicts constraints were violated (i.e., at maximum shadow prices) more frequently in 2023 than they were in 2022, reversing the downward trends beginning in 2019. While upgrades have resolved many of the concerns in the West zone in spring 2020, thus eliminating previously irresolvable constraints, the congestion around the San Antonio area caused the majority of the constraints. In 2023, like 2022, the majority of the violated constraints occurred at the $3,500 per MW value. Violated constraints continued to occur in a small share at all the constraint-intervals, 9% in 2023, 3% in 2022, 4% in 2021, 5% in 2020 and 7% in 2019.

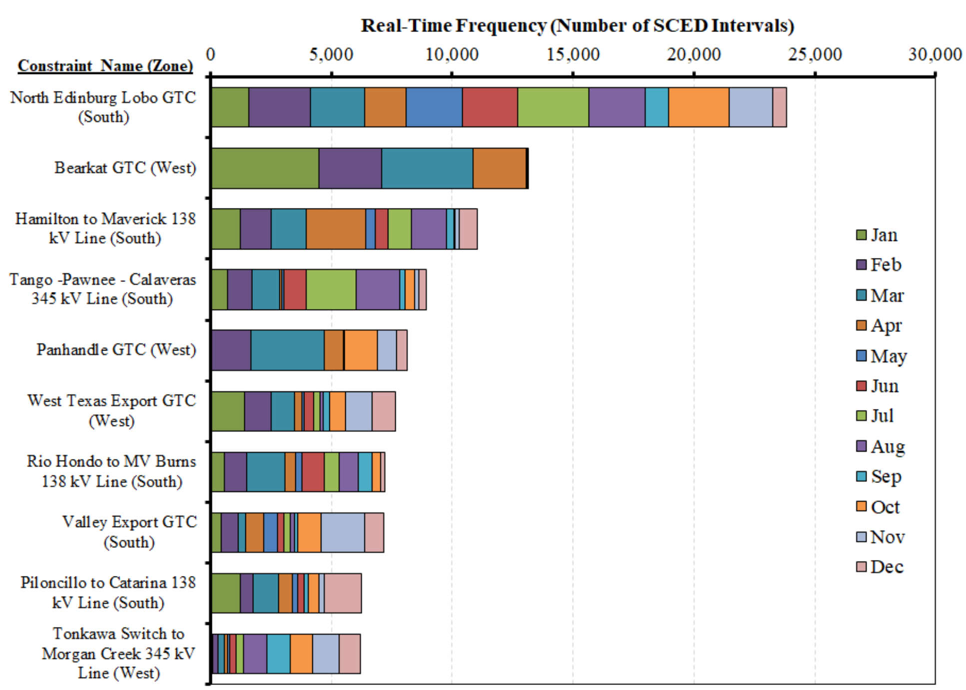
Figure A28: Frequency of Violated Constraints



3. Real-time Constraints and Congested Areas

Two GTCs (West Texas Export, North Edinburg Lobo) were in the top ten congested areas in 2023, down from 4 in 2022. The congestion rent contributed by the GTC constraints decreased to $255 million in 2023 from $640 million in 2022. ERCOT continues to study and analyze models and future needs as congestion continues to persist. All constraints listed in Figure A29 were frequently constrained in 2023 due to variable renewable output.

Figure A29: Most Frequent Real-Time Constraints



The top ten most congested valued real-time constraints totaled $928 million, whereas the top ten most frequently constrained constraints totaled $711 million.

4. Individual GTCs

To provide a greater understanding of use of GTCs, Table A4 shows the effective date for individual GTCs and the number of binding hours during 2022 and 2023.

Table A4: Generic Transmission Constraints

Generic Transmission Constraint	Effective Date	# of Binding Hours in 2022	# of Binding Hours in 2023
North to Houston	December 1, 2010	54.4	23.4
Rio Grande Valley Import	December 1, 2010	-	0.3
Panhandle	July 31, 2015	783.0	670.8
Red Tap	August 29, 2016	-	-
North Edinburg - Lobo	August 24, 2017	1,830.4	1,948.3
Nelson Sharpe - Rio Hondo	October 30, 2017	1,318.6	361.2
East Texas	November 2, 2017	114.7	68.2
Treadwell	May 18, 2018	249.7	311.2
McCamey	March 26, 2018	26.4	57.3
Raymondville - Rio Hondo	May 2, 2019	52.0	43.9
Bearkat	November 20, 2019	579.0	1,081.7
West Texas Export	October 1, 2020	977.0	634.4
Zapata - Starr	Novemeber 5, 2020	-	3.7
Valley Export	Novemeber 5, 2020	258.1	551.1
Culberson	March 4, 2021	103.1	-
Williamson-Burnet	May 6, 2021	1.7	4.0
Wharton County	May 5, 2022	7.8	9.3
Hamilton	August 3, 2022	-	22.2
Kinney	November 1, 2023	NA	-
Total Hours		**6,355.9**	**5,791.0**

5. Irresolvable Constraints

As shown in Table A5, 13 element combinations were deemed irresolvable in 2023 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[168] and are intended to reflect the level of reduced reliability that occurs when a constraint is irresolvable. The shadow price caps are $5,251 per MW for base-case (non-contingency) or voltage violations, $4,500 per MW for 345 kV constraints, $3,500 per MW for 138 kV, and $2,800 per MW for 69 kV thermal violations. GTCs are considered stability constraints either for voltage or transient conditions with a shadow price cap of $5,251 per MW.

[168] Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (ERCOT Board Approved December 8, 2020, effective December 10, 2020), available at http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Setting_Maximum_Shadow_Prices_for_Network_and_Power_Balance_Constraints.zip.

Table A5: Irresolvable Elements

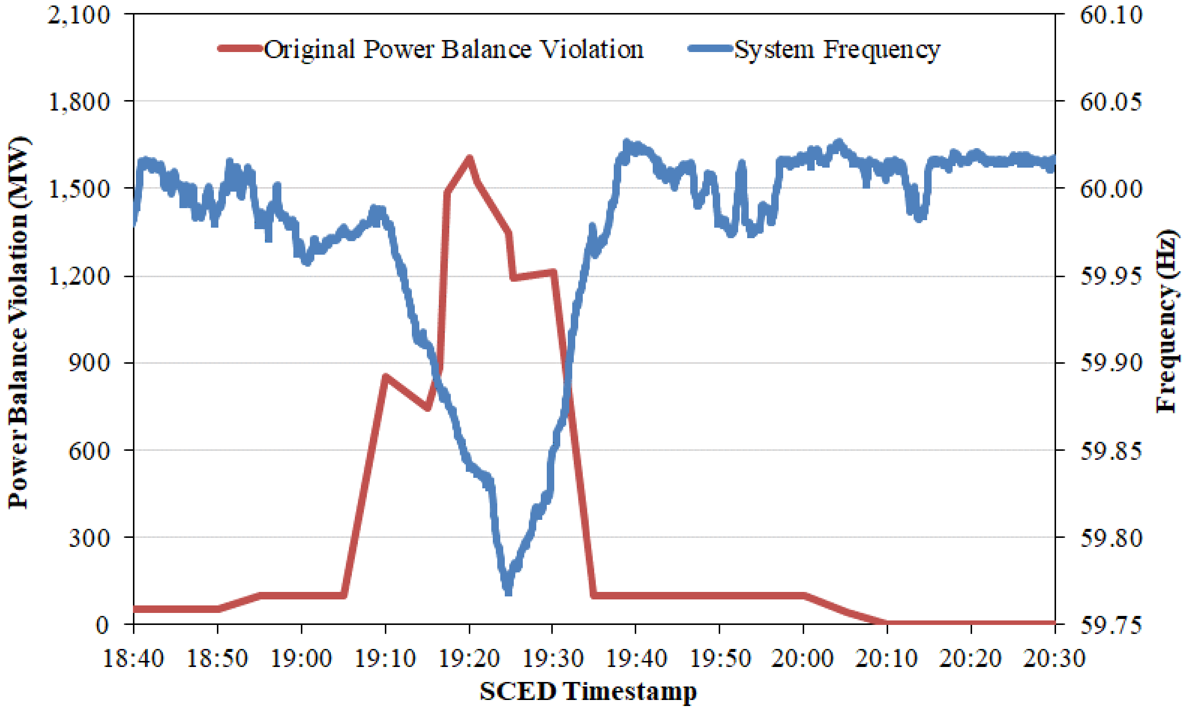
Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price ($ per MWh)	2023 Adjusted Max Shadow Price ($ per MWh)	Irresolvable Effective Date	Termination Date	Load Zone	Duration of Binding SCED Intervals in 2023 (hours)
Base Case	Valley Import GTC	5,251	2,000	4/1/22	-	South	0.3
SBEVASH8	Hamilton to Maverick 138 kV Line	3,500	3,500 2,000	12/28/22 7/24/23	7/23/23 -	South	- -
SCRDJON5	Decordova Dam to Carmichael Bend Switch 138 kV Line	3,500	2,000	2/20/21	1/30/23	West	-
XFRE89	Gillespie 138/69 kV Transformer	3,500	3,117	2/5/22	-	South	-
SBE2ASH8	Hamilton to Maverick 138 kV Line	3,500	3,500 2,000	12/28/22 7/24/23	7/23/23 -	South	0.2 0.2
MCOMPR28	Royse Switch 138/69 kV Transformer	3,500	3,500	12/28/22	-	North	4.2
SSKYSB28	Consavvy Switch to Cottonfield 138 kV Line	3,500	2,000	1/9/23	-	West	101.7
MCONQAL5	Morgan Creek to Forest Creek & Sand Bluff 138 kV Line	3,500	2,000	4/24/23	-	West	44.8
SLP3LPL9	MacKenzie to Erskine 69 kV Line	2,800	2,000	5/9/23	-	West	106.4
SDIMBEV8	Hamilton to Maverick 138 kV Line	3,500 3,500	3,500 2,000	7/13/23 7/24/23	7/23/23 -	South	97.3 117.0
DAUSDUN8	Sim Gideon to Bastrop City 138 KV Line	3,500	3,500	9/7/23	-	South	46.5
SCARBU28	Magnesium Plant to Northland 138 kV Line	3,500	2,000	9/25/23	-	South	20.7
SMCEABS8	Capella to Merkel 69 KV Line	2,800	2,000	11/13/23	-	West	30.2

Only one constraint was identified with a termination date of January 30, 2023, during ERCOT's annual review and the adjusted max shadow price returned to the administered element shadow price cap, leaving four constraints remaining from 2022. Two irresolvable constraints were deemed irresolvable, but the adjusted shadow price remained at the same level as the administered value for that element voltage type. One more alternative contingency code for Hamilton to Maverick 138 kV line was added bringing the total to three on July 13, 2023; and all three irresolvable combinations for the line were re-evaluated resulting with a lower adjusted shadow price after the element exceeded the net margin of $95,000/MW on July 23, 2023. Four constraints were added in the West zone; two on 138 kV lines and two on 69 kV lines and two constraints were identified in the South zone on 138 kV lines.

6. Simulation of Higher Shadow Price Cap on September 6

Figure A30 below shows the specific period of manual curtailments on September 6 during which the frequency dropped and there was a large power balance violation.

Figure A30: September 6th, 2023, Power Balance and System Frequency



Focusing on the frequency decline starting time of 19:10 to the frequency recovery time of 19:40, the below are the rerun results for system-wide values, as well as values specific to the constraint:

Figure A31: September 6th Power Balance Violation Simulation

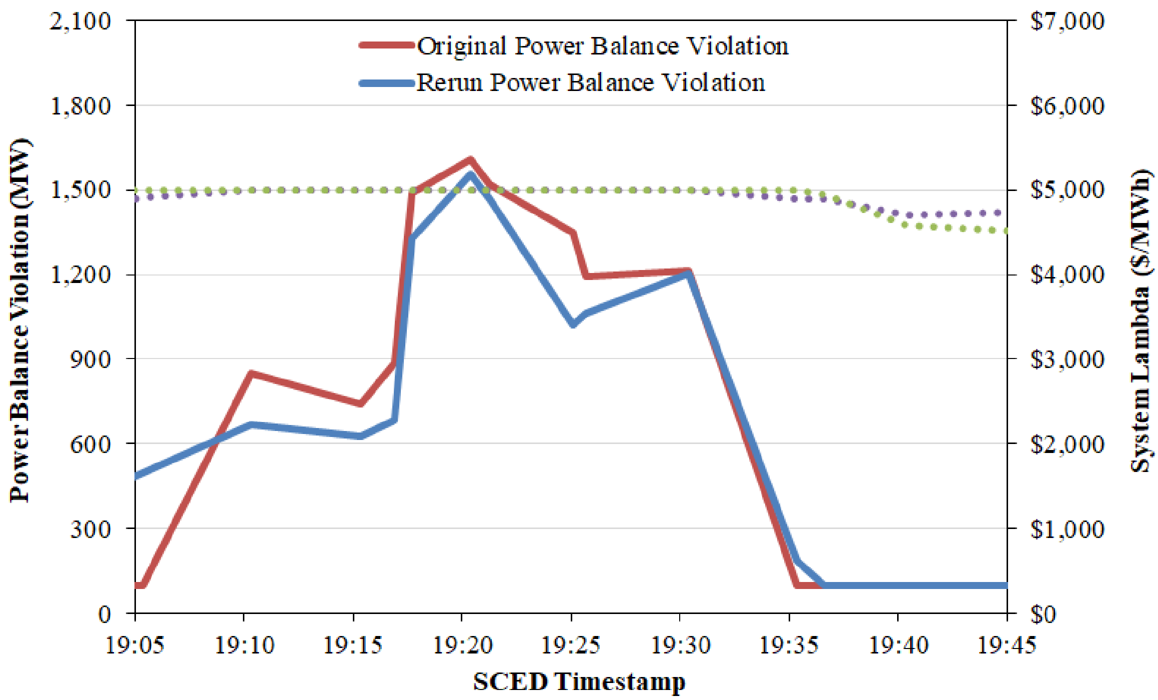
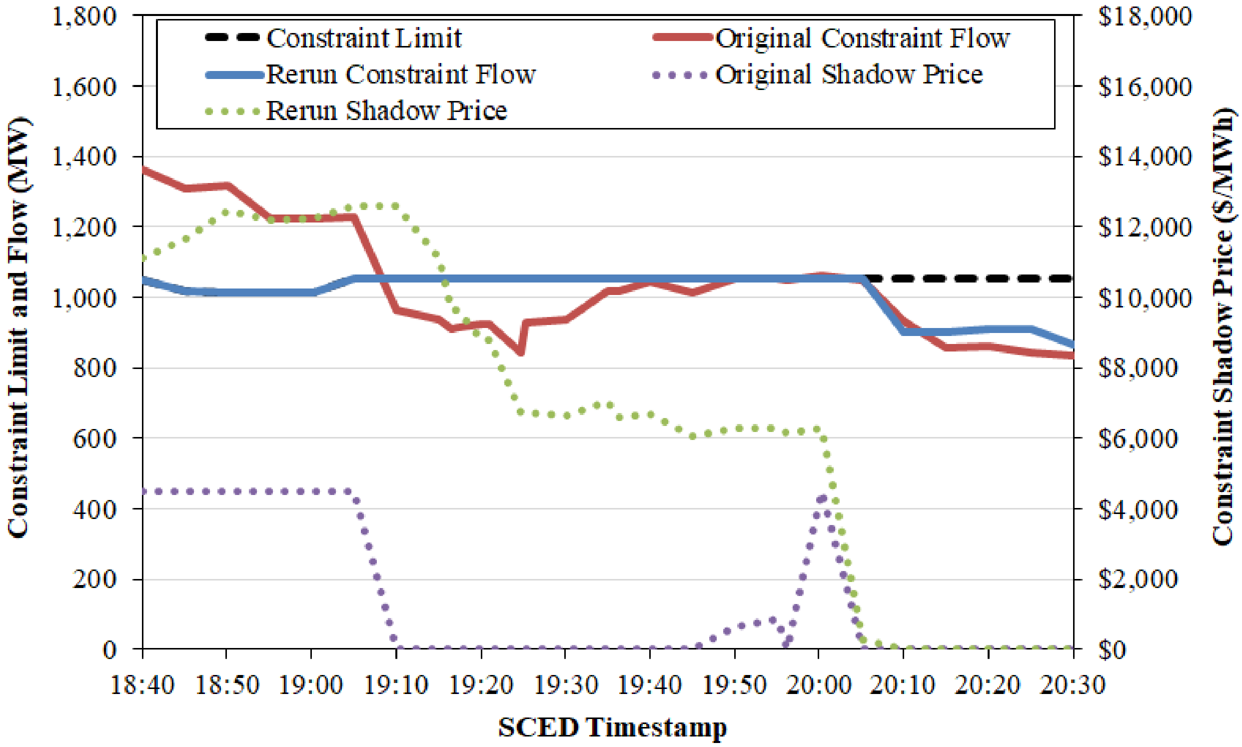


Figure A32: September 6th Simulation Details



As evidenced above, SCED was able to find a dispatch solution that did not result in constraint violation and that also reduced power balance violation in the period when system frequency started steadily decreasing. Additionally, a higher shadow price on the constraint would send stronger locational price signals. In conclusion, we recommend giving ERCOT operators the option to raise the maximum shadow price caps on activated constraints that may lead to cascading issues and that are not being solved by SCED, instead of relying on manual curtailment instructions to manage the constraint.[169]

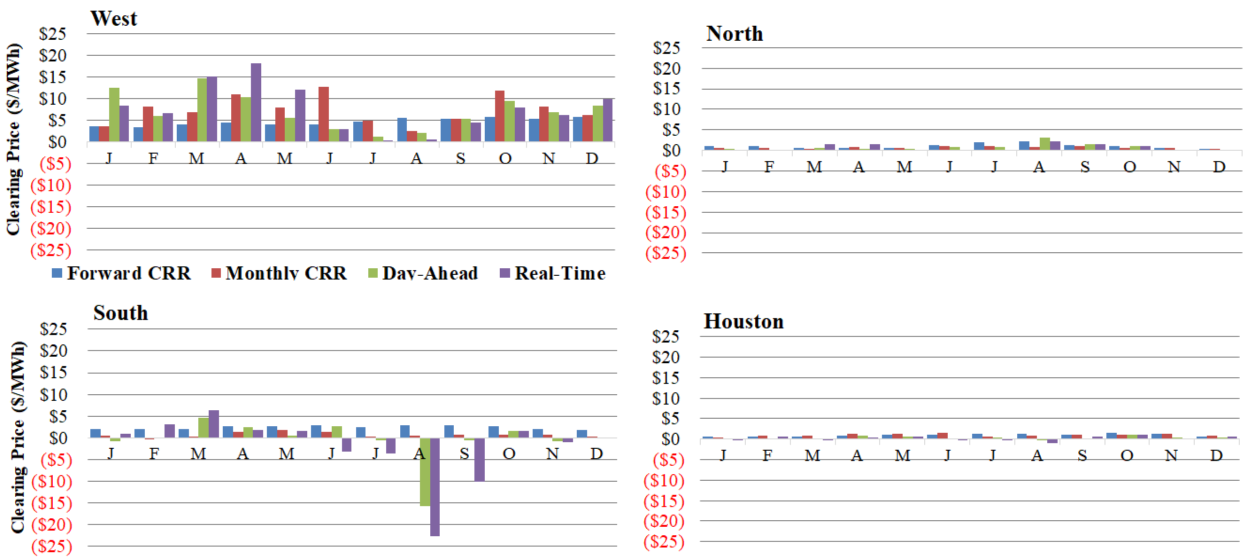
169 In March 2024, ERCOT proposed a similar recommendation as a measure to mitigate overloads of transmission lines associated with the South Texas Export GTCs. *Reports of the Electric Reliability Council of Texas*, Project No. 55999, ERCOT Notice Regarding New South Texas Export and Import Generic Transmission Constraints (Mar. 18, 2024). ERCOT provided additional details on its recommendation in a subsequent filing, and at the April 25, 2024, Open Meeting, the PUCT indicated support for the recommendation. *Id.*, Electric Reliability Council of Texas, Inc.'s Update Regarding South Texas Export Constraint Mitigation Solutions (Apr. 22, 2024). Accordingly, it is expected that ERCOT will soon file an NPRR to increase the shadow price cap for Interconnection Reliability Operating Limits.

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Prices

Figure A33 below shows the price spreads between all hub and load zones in 2023 as valued at four separate points in time – at the average of the four semi-annual CRR auctions, monthly CRR auction, day-ahead, and real-time.

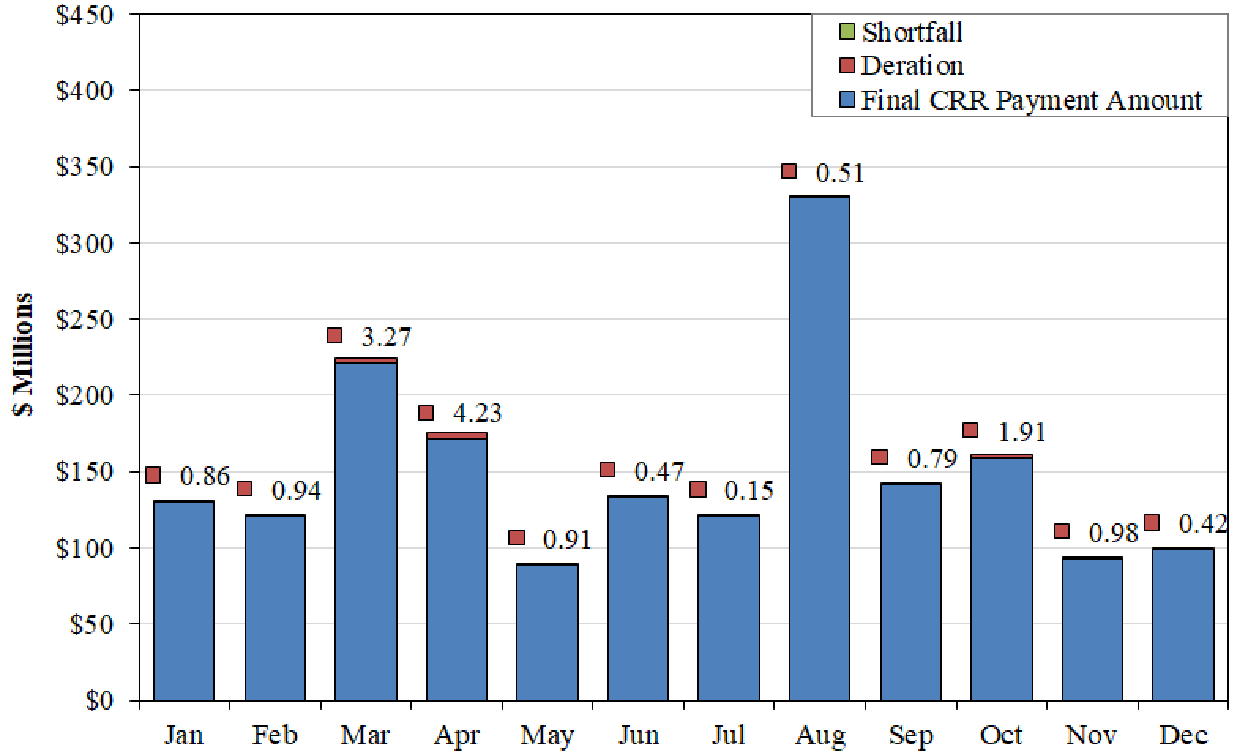
Figure A33: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A34 shows the amount of target payment, deration amount, and final shortfall for 2023. In 2023, the total target payment to CRRs was approximately $1.8 billion, a decrease from the $2.1 billion in 2022; there was approximately $15.5 million of derations in 2023, compared to $14.9 million in 2021, but no shortfall charges resulting in a final payment to CRR account holders of approximately $1.8 billion. This final payment amount corresponds to a CRR funding percentage of 99.2%, roughly the same as the funding percentage in 2022 (99.3%).

Figure A34: CRR Shortfall and Derations



VI. Appendix: Market Operations

In this section, we provide supplemental information about RUC activity in 2023, the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC, as well as mitigation.

A. History of RUC-Related Protocol Changes

The RUC process has undergone several modifications since the nodal market began in 2010. Changes have been implemented to improve the commitment process and market outcomes associated with RUC. In March 2012, an offer floor was put in place for energy above the LSL for units committed through RUC, and, at the time, was set at $250 per MWh. Resources committed through the RUC process are eligible for a make-whole payment but also forfeit any profit through a claw-back provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the claw-back charges, effectively self-committing and accepting the market risks associated with that decision. This buyback or “opt-out” mechanism for RUC initially required a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.

On June 25, 2015, ERCOT automated the RUC offer floor of $1,500 per MWh and implemented the Real-Time On-Line Reliability Deployment Adder (RTORDPA). ERCOT systems automatically set the energy offer floor at $1,500 per MWh when a resource properly telemetered a status indicating it had received a RUC instruction. The reliability adder, as discussed more in Section II: Review of Real-Time Market Outcomes, captures the impact of reliability deployments, such as RUC, on energy prices.

The RUC process was modified again in 2017. On June 1, 2017, ERCOT began using a telemetered snapshot at the start of each RUC instruction block as the trigger to calculate the reliability adder. This was an improvement over the previous calculation trigger, which required the QSE to telemeter the correct resource status. Another impact of the change was that resources could opt-out of RUC settlement after the close of the adjustment period, because the opt-out decision is no longer communicated via the COP.

In 2018, the RUC engine was modified to consider fast-start generators (those with a start time of one hour or less) as self-committed for future hours, allowing ERCOT to defer supplementary commitment decisions, and allowing market participants full opportunity to make their own unit commitment decisions. RUC-related improvements in 2019 included approval and implementation of NPRR 901, *Switchable Generation Resource Status Code*, which created a new resource status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area to provide additional transparency for operations and reporting. New logic was implemented that prevents the triggering of the Real-Time Reliability Deployment

Price Adder and the application of a RUC offer floor when a RUC Resource is awarded a resource-specific offer in the day-ahead market. A new settlement structure for SWGRs that receive a RUC instruction was approved and implemented in 2019 to address concerns of inadequate compensation for SWGRs that were instructed to switch from a non-ERCOT control area to the ERCOT Control Area.

RUC-related improvements in 2020 included updates to ERCOT systems to effectively manage cases where ERCOT issues a RUC instruction to a combined cycle resource that is already QSE-committed for an hour, with the instruction being that the resource operate in a configuration with greater capacity for that same hour. Further, the maximum amount that may now be recovered for fuel oil disputes is the difference between the RUC Guarantee based on the actual price paid and the adjusted Fuel Oil Price (FOP). And finally, ERCOT systems now automatically create a proxy Energy Offer Curve with a price floor of $4,500 per MWh for each RUC-committed SWGR, as opposed to requiring QSEs to submit Energy Offer Curves reflecting the $4,500 per MWh floor.[170]

In 2021, RUC activity picked up significantly after Winter Storm Uri in February. ERCOT committed to taking a more conservative approach to operating the grid. According to ERCOT, their grid management is at its most aggressive since the market was created two decades ago. ERCOT is increasing operational reserves to ensure adequate generation is available to Texas homes and businesses and is bringing more generation online sooner if it is needed to balance supply and demand. ERCOT is also purchasing more reserve power, especially on days when the weather forecast is uncertain.[171]

In May of 2022, NPRR 1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision*, was approved. As filed by the IMM on August 11, 2021, this NPRR would have reduced the value of the offer floor to $75 per MWh on Resources with the status of ONRUC and removed the ONOPTOUT status. The approved version sets a $250 per MWh RUC offer floor and allows ONOPTOUT status in more limited circumstances.
NPRR 1124, *Recovering Actual Fuel Costs through RUC Guarantee*, also approved in May of 2022, ensures generation resources recover their actual fuel costs when instructed to start due to

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170 *See* NPRR 856, *Treatment of OFFQS Status in Day-Ahead Make Whole and RUC Settlements* (implemented May 2020); NPRR 884, *Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources* (implemented May 2020); NPRR 970, *Reliability Unit Commitment (RUC) Fuel Dispute Process Clarification* (implemented March 2020); NPRR 977, *Create MIS Posting for RUC Cancellations* (implemented May 2020); NPRR 1019, *Pricing and Settlement Changes for Switchable Generation Resources (SWGRs) Instructed to Switch to ERCOT* (partially implemented June 2020; automation of offers will be delivered separately as part of a future project); NPRR 1028, *RUC Process Alignment with Resource Limitations Not Modeled in the RUC Software* (approved December 2020); and NPRR 1032, *Consideration of Physical Limits of DC Ties in RUC Optimization and Settlements* (approved December 2020).

171 https://www.ercot.com/news/release?id=5fef298c-fbd7-34d3-39ee-d3fc63e568c2.

a RUC. Specifically, this NPRR establishes that the Startup Price per start (SUPR) and the Minimum-Energy Price (MEPR) will be set to the Startup Cap (SUCAP) and the Minimum-Energy Cap (MECAP), respectively, utilizing the actual approved fuel price paid.

In April of 2023, NPRR 1172, *Fuel Adder Definition, Mitigated Offer Caps, and RUC Clawback*, was filed, proposing elimination of the 50% claw-back for day-ahead offers and implementation of a 100% claw-back for economic RUC resources.[172] NPRR 1172 was approved by the PUCT in February of 2024 and went into effect on March 1, 2024.[173] The revision addresses the inappropriate incentive that was caused by the 50% claw-back for day-ahead offers: generation that anticipated being economic in real-time was less likely to self-commit because of the ability to retain 50% of market gains after RUC commitment.

B. RUC Activity in 2023

Table A6 below lists the generation resources that received the most RUC instructions in 2023 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement.

Table A6: Most Frequent Reliability Unit Commitments

Resource	Location	Unit-RUC Hours	Unit-OPTOUT Hours	Average LSL during Dispatchable Hours	Average Dispatch during Dispatchable Hours	Average HSL during Dispatchable Hours
R W Miller STG 2	DFW	356	-	39	37	107
V H Braunig STG 2	San Antonio	207	129	60	74	227
R W Miller STG 3	DFW	127	-	41	41	205
Lake Hubbard STG 1	DFW	115	17	90	136	346
Mountain Creek STG 6	DFW	111	32	15	30	122
Sand Hill Energy Ctr CC1	Austin	108	-	118	118	214
Ray Olinger STG 2	DFW	98	-	20	21	87
Ray Olinger STG 3	DFW	96	8	25	24	84
Lake Hubbard STG 2	DFW	95	18	123	187	475
Mountain Creek STG 7	DFW	95	40	15	40	115
Powerlane Plant STG 2	DFW	92	4	10	9	19
Handley Unit 3	DFW	67	7	100	100	363
Stryker Creek Unit 1A	East Texas	67	32	35	60	170
Barney M Davis STG 1	Corpus Christi	60	-	56	58	243
Powerlane Plant STG 2	DFW	59	-	13	12	32

172 The IMM recommended that ERCOT eliminate the 50% claw-back for day-ahead offers and implement a 100% claw-back for economic RUC resources in its 2022 State of the Market Report (see Recommendation 2022-2) and filed comments supporting NPRR 1172.

173 https://www.ercot.com/mktrules/issues/NPRR1172.

Almost 89% of the RUC-Resource hour instructions for 2023 were for capacity, and the other 11% were for congestion. The RUC instructions were geographically distributed as follows: 25% in the South zone, 5% in the West zone, 9% in the Houston zone, and the remaining 61% in the North zone, similar to the distribution in 2022.

Figure A35 compares the average real-time dispatched output of the RUC-committed units, including those that opted out, with the average operational limits of the units. It shows that:

- The monthly average SCED dispatch of units receiving RUC instructions has rarely been close to the average high limit, with 2023 being no exception.
- The average quantity dispatched is very close to the respective average LSL for all months in 2023 with RUC instructions, primarily because of the $250 per MWh offer floor.

Some RUC resources are dispatched above their LSLs because they are mitigated when resolving non-competitive constraints. That mitigation eliminates the $250 per MWh offer floor for those resources in those RUC intervals and dispatches them on their mitigated offer curve.

Figure A35: Average Reliability Unit Commitment Capacity and Dispatch Level

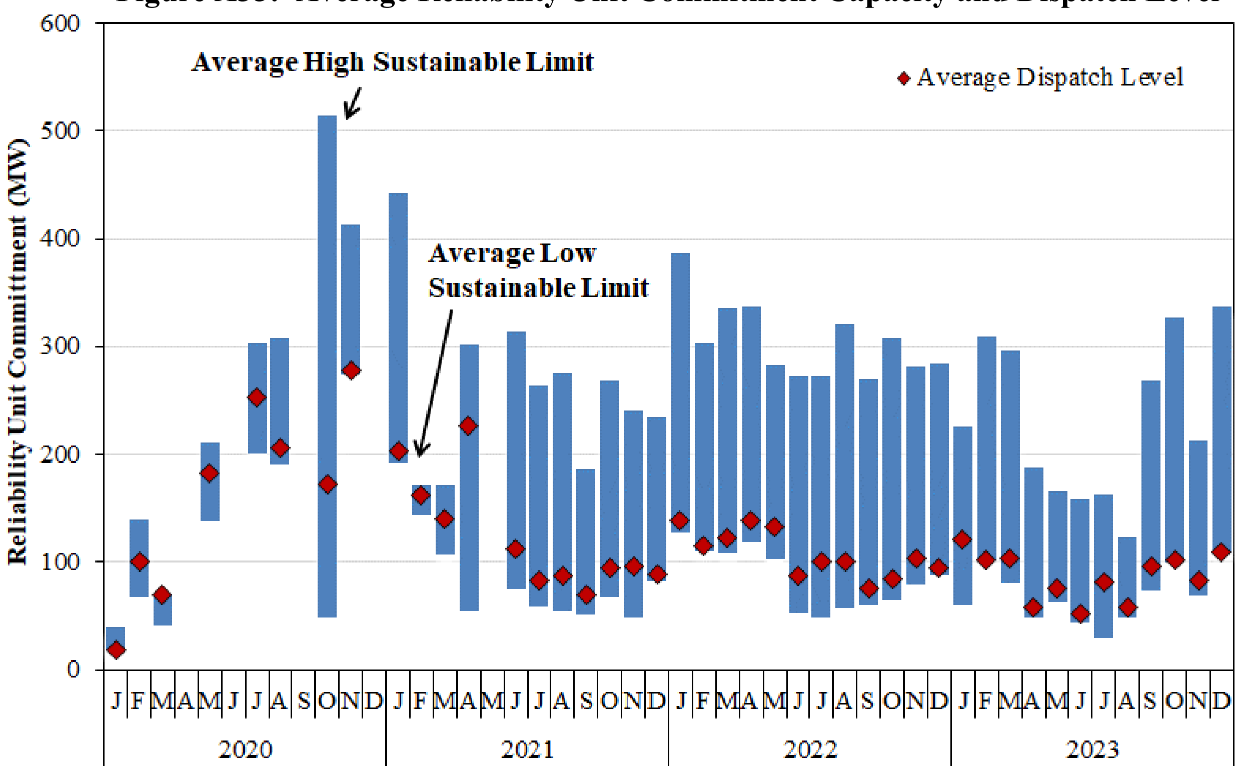


Table A7 below shows the total make-whole payments and claw-back charges for RUCs since 2018.

Table A7: RUC Settlement Quantities

	Claw-Back from Generator in millions	Make-Whole to Generator in millions
2018	$3.07	$0.61
2019	$0.90	$0.05
2020	$0.48	$0.40
2021	$3.09	$5.38
2022	$23.74	$42.78
2023	$3.07	$3.63

Table A7 shows that both claw-back and make-whole payments declined sharply in 2023, down to roughly $6.7 million in total. This amount is substantially lower than claw-back and make-whole payments in the prior two years. This change was mainly due to the significant decrease in the RUC commitments in 2023. In theory, the claw-back amount should be low, as economic units would generally benefit by opting out of the RUC instruction if such profitability is foreseeable.

C. Generation Outages and Deratings

Figure A36 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2023.

Figure A36: Short-Term Outages and Deratings

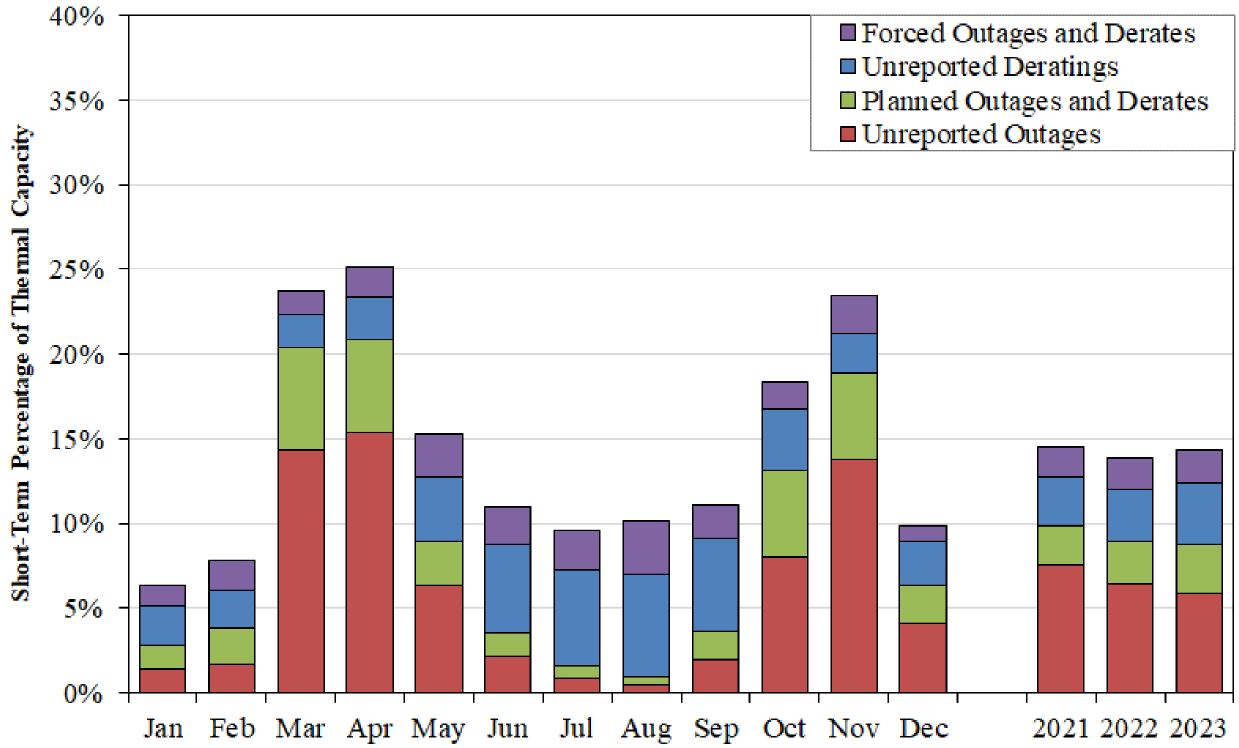
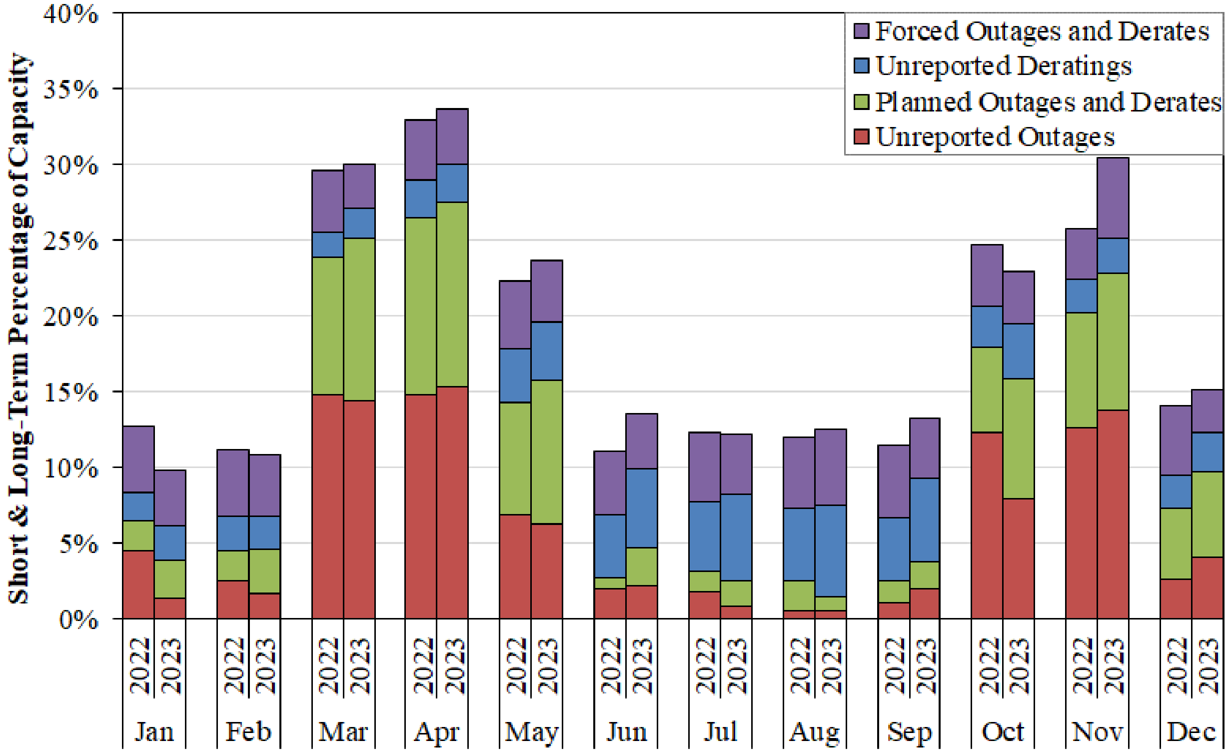


Figure A36 shows smaller percentages of short-term outages and deratings in January, February, June, July, and August, likely due to expectations of high loads in the summer and winter. The amount of unavailable capacity during 2023 averaged 14.3% of installed thermal capacity, similar to 13.8% in 2022 and 14.5% in 2021.

Figure A37 below includes both short- and long-term outages. The amount of unavailable capacity during 2023 averaged 19% of installed thermal capacity, similar to 18.4% in 2022 and 20% in 2021.

Figure A37: Short- and Long-Term Deratings and Outages



D. Operational Reserves Compared to Market Reserves

The IMM performed an analysis comparing the operational reserves to the market reserves (PRC[174] vs Real-Time On-Line Reserve Capacity[175] or RTOLCAP) for 2020 through 2023. The two reserve calculations (PRC and RTOLCAP) can diverge because different types of capacity are counted in the two metrics. Additionally, when units with RUC instructions are online, the capacity provided by those units is excluded from the ORDC capacity calculation. The addition

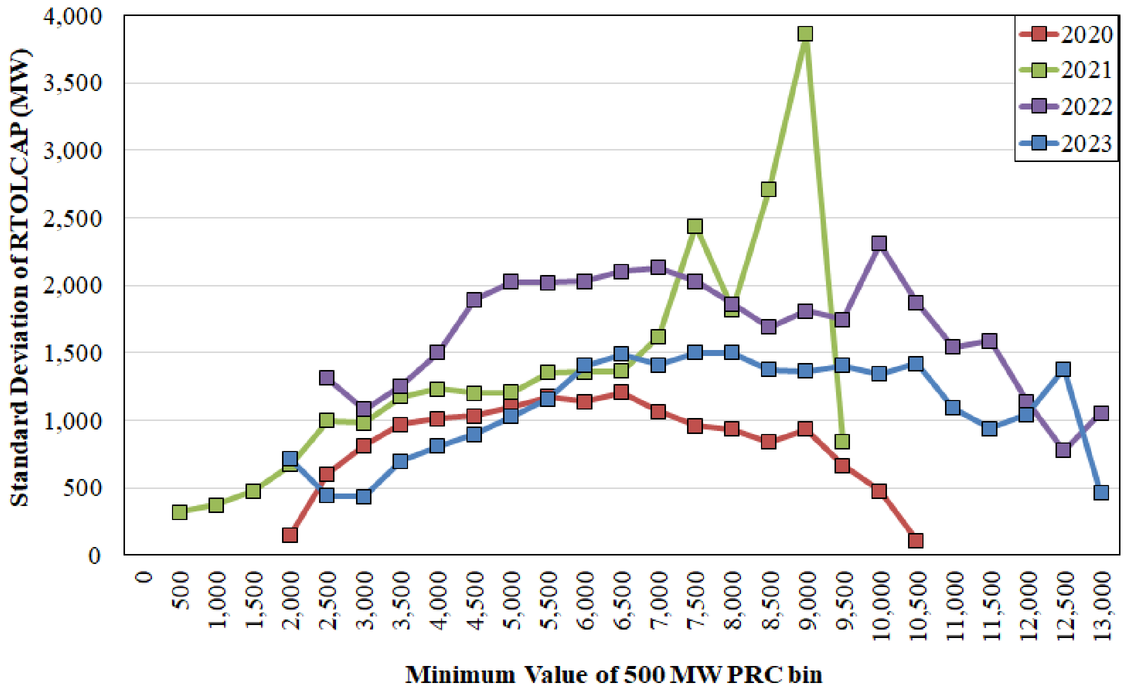
174 A representation of the total amount of frequency responsive online reserve capacity.

175 Real-Time On-Line reserve capacity of all On-Line Resources that remains after SCED dispatch instructions.

of the capacity from Load Resources carrying ECRS and the increased ESR capacity contributed to the PRC in 2023.

Figure A38 shows standard deviation of RTOLCAP at different levels of PRC for the last four years. The extent of RUC commitment can influence the variability of RTOLCAP relative to PRC, as seen in the increase in the standard deviation in the last three years when compared to 2020. Even though the RUC activity was lower in 2023 in comparison to 2022, it still contributed to the divergence between RTOLCAP and PRC. This can be attributed to ERCOT's change in operational posture. Because of this change, there are periods during which large amounts of capacity under RUC instruction are contributing to PRC, but not to RTOLCAP. RUC activity can cause operational reserves and market reserves to diverge from their historical relationship, in turn, causing prices and grid reliability conditions to diverge from their historical relationship.

Figure A38: Standard Deviation of RTOLCAP at different levels of PRC

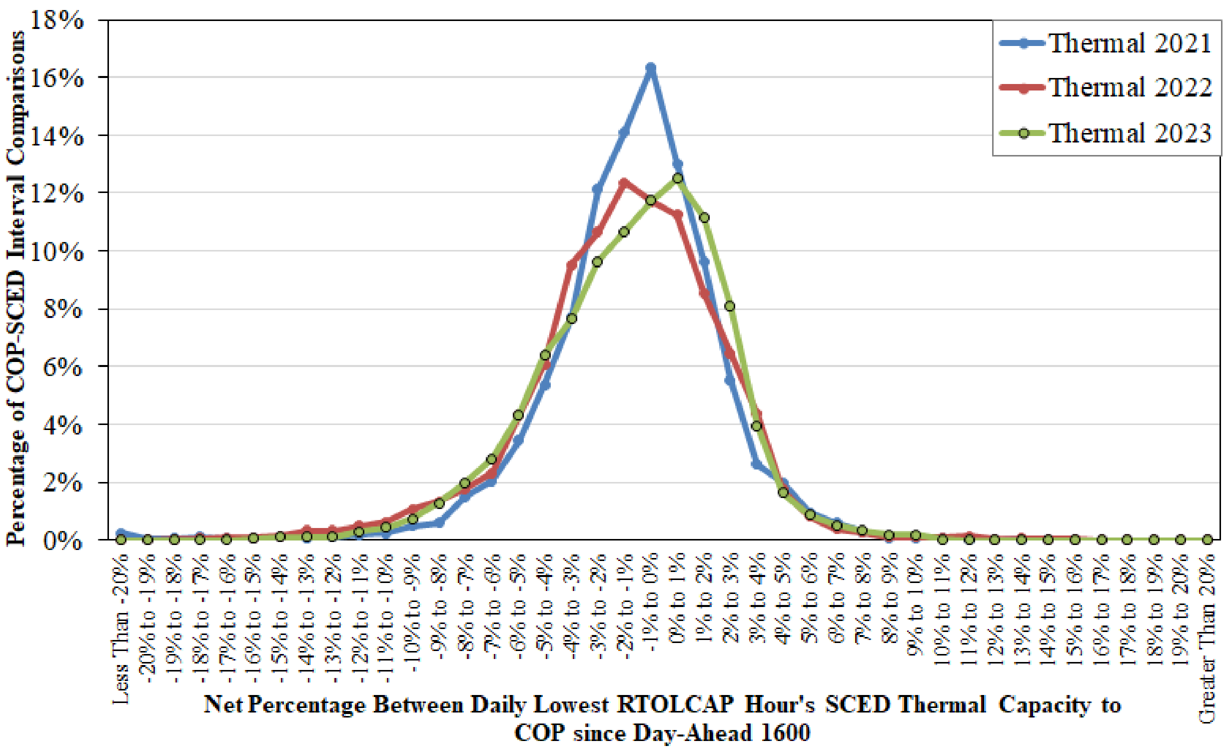


E. QSE Operation Planning

The following set of analyses quantify the difference between the aggregated capacity commitments as described by all the COP submissions, and the actual capacity commitments as a percentage of the actual capacity observed in real-time. These analyses are limited to the operating hour of each day where the lowest RTOLCAP was observed. Multiple COP submissions as of day-ahead 1600 provide data for the hour being evaluated, and there can be large variations in unit commitment expectations reflected in those multiple COPs. Because unit commitment decisions for renewable resources are influenced by the solar and wind forecasts, which are discussed in Section III: Appendix: Demand and Supply in ERCOT, the differences will not be highlighted here.

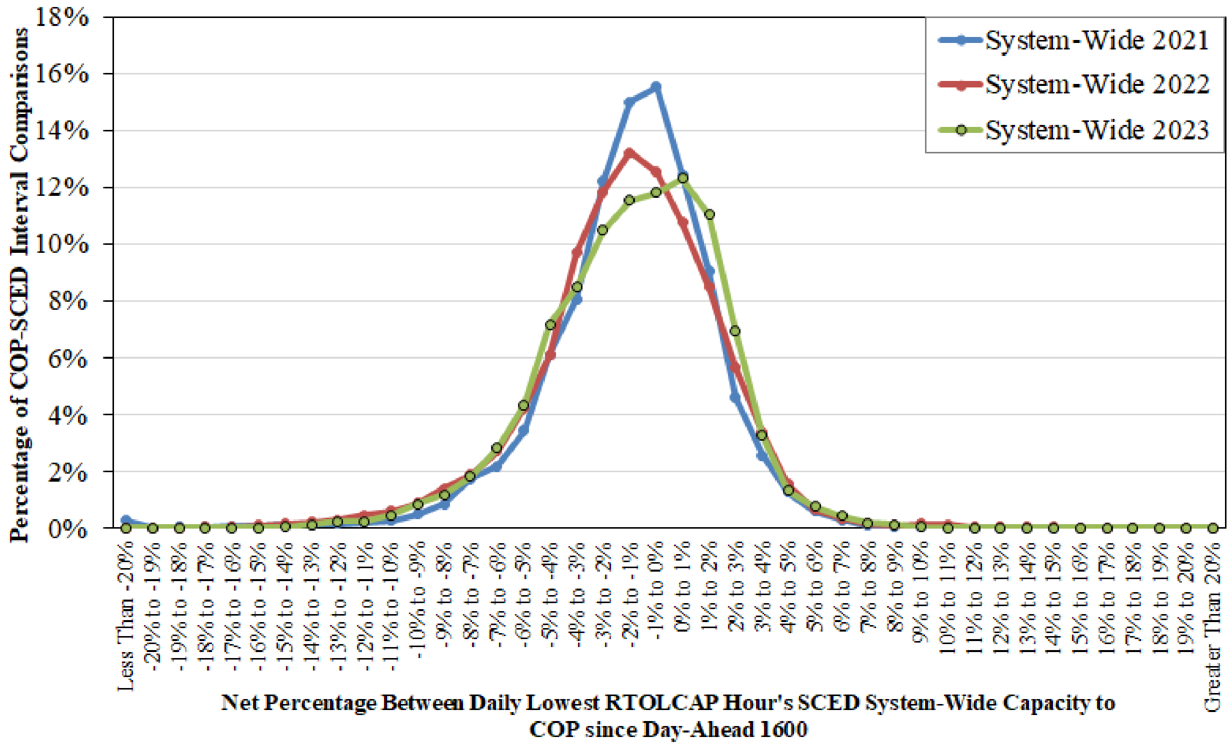
Figure A39 shows the frequency of percentage error between SCED thermal capacity and its respective COP for the daily operating hour experiencing the lowest RTOLCAP for the full year. The comparisons include applicable COP comparisons 24 hours up to the operating hour starting with the day-ahead COP snapshot at 1600. The analysis focuses on the net difference as a percentage of the SCED thermal capacity to control for load fluctuations between years. The last three years have shown a trend towards an error greater than 1%. The bucket granularity is very small as to be able to capture the minutiae differences in the curve between 2022 and 2023.

Figure A39: Real-Time to COP Comparisons for Thermal Capacity



When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then decommit at the end of the adjustment period a small percentage of the time. The curve from 2021 is generally similar to the curves from the previous two years, but 2022 and 2023 are notably more depressed, exhibiting a much smaller contrast. This is because there were more instances of COP errors than in previous years for the low RTOLCAP hours. The curve in 2023 shows an increased bias towards under-representing the amount of thermal real-time capacity for the low RTOLCAP hour as compared to 2022. Figure A40 summarizes the same analysis as above, but for system-wide capacity for the daily lowest RTOLCAP operating hour of each year. The curves in 2022 and 2023 are similar to those viewed in Figure A39, whereas there is a clearer depression in the peak for the 2021 COP when viewing the low RTOLCAP hours and their respective COP snapshots. Solar and wind forecasts indicate less hours for the low RTOLCAP hours 24 hours prior to the operating hour.

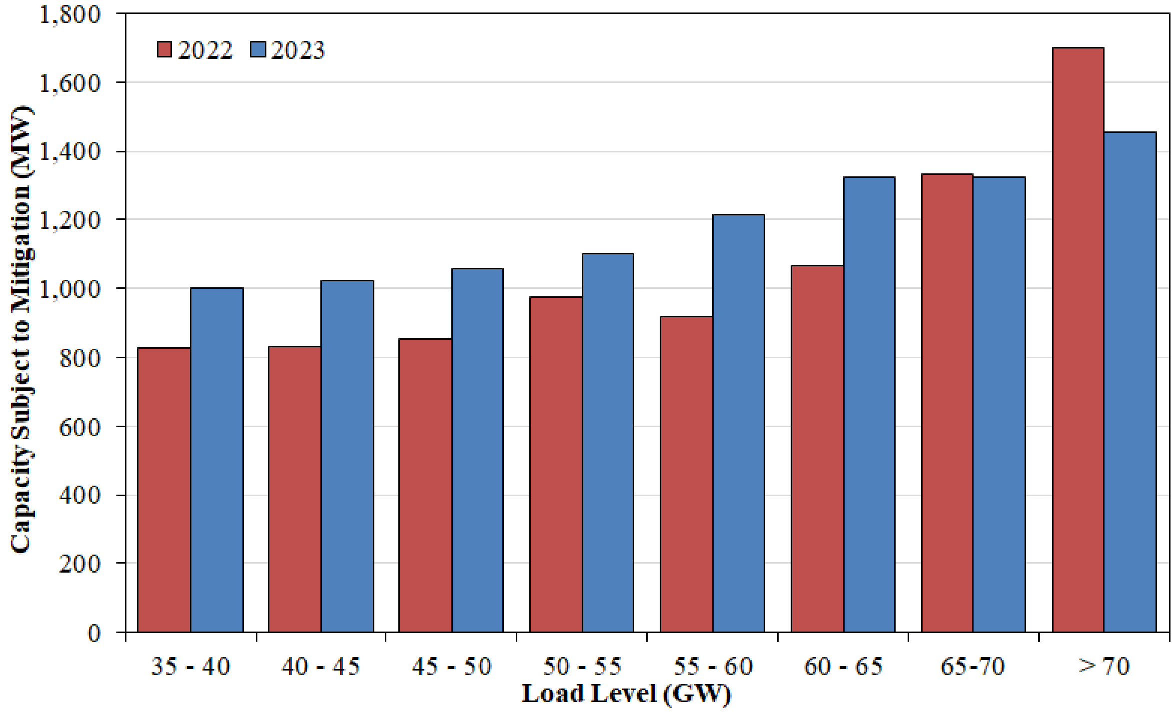
Figure A40: Real-Time to COP Comparisons for System-Wide Capacity



F. Mitigation

The next analysis computes the total capacity of RUC and self-committed resources subject to mitigation by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. The difference between the total unit capacity and the capacity at the point the curves diverge is calculated for all units and aggregated by load level. The results are shown in Figure A41.

Figure A41: Average Capacity Subject to Mitigation



The average amount of capacity subject to mitigation in 2023 was higher than in 2022 at all load levels except for the highest two load levels (65-70 and >70). It is important to note that this measure includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

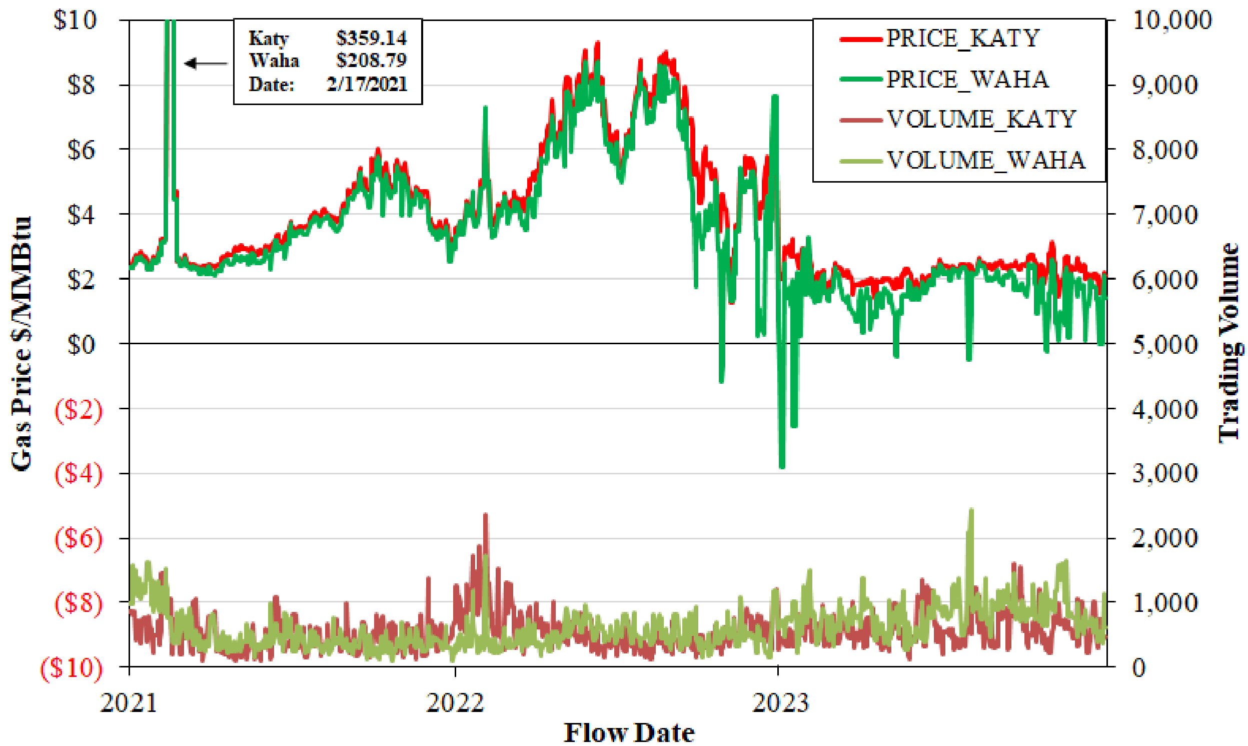
VII. APPENDIX: RESOURCE ADEQUACY

In this section, we provide a supplemental analysis of the economic signals present in 2023 that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's needs. We provide the estimate of the level of "net revenue" that resources received from ERCOT real-time and ancillary services markets.

A. Locational Variations in Net Revenues in the West Zone

Fuel prices are a substantial determinant of net revenues because they are the primary offset from market revenues when calculating net revenues. In 2020, we noted the growing separation in natural gas prices between the Waha location in the west and Katy locations in the east. Drilling activity in the Permian Basin of Far West Texas has produced a surplus of natural gas, and consequently, much lower prices at the Waha location. As seen in Figure A42 below, prices were down overall in 2023. Waha prices in 2023 dipped below $0 multiple times and were once again more volatile than Katy.

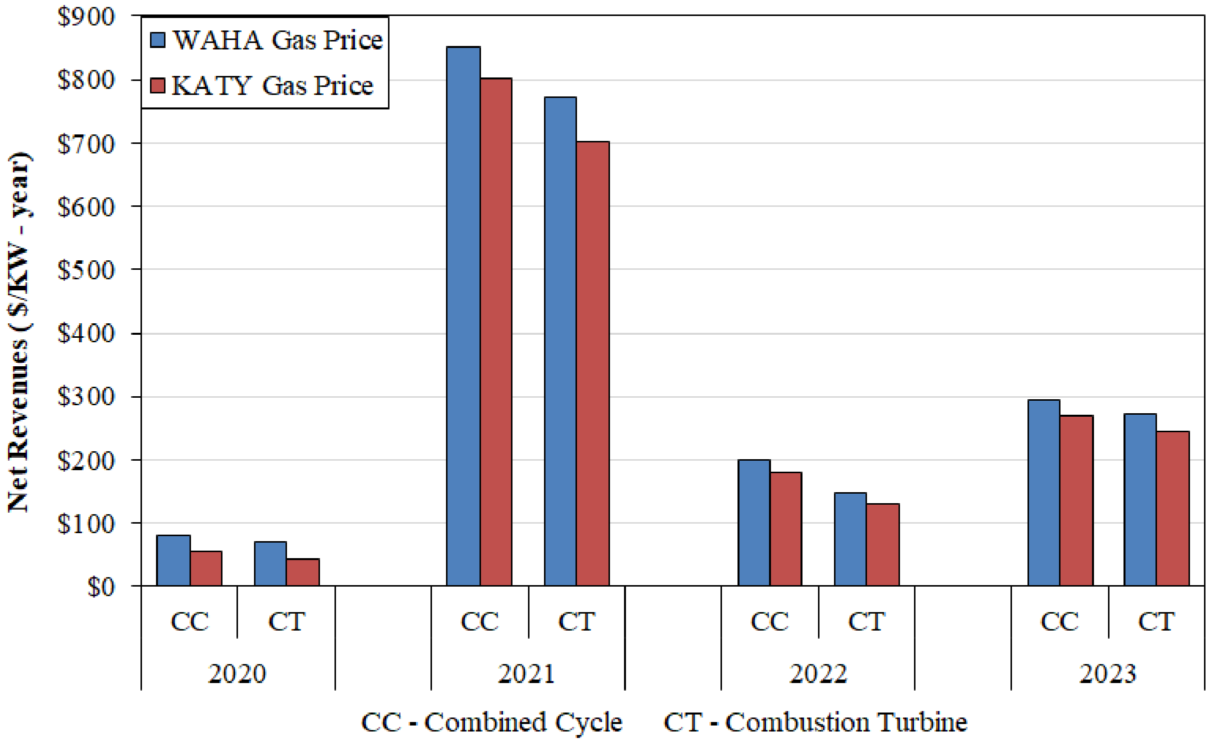
Figure A42: Gas Price and Volume by Index



Historically, resources in the West Zone have had lower net revenues than resources in the other zones, but that was not the case in 2021 through 2023. The divergence between Waha and Katy gas prices contributed to greater net revenues for West Texas gas-fired generators. Figure A43 provides a comparison of net revenue for both types of natural gas units, assuming Katy and

Waha gas prices. Net revenues based on Waha gas prices contributed to higher West Zone revenues.

Figure A43: West Zone Net Revenues



B. Reliability Must Run and Must Run Alternative

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability. Although no new Reliability Must-Run (RMR) contracts were awarded in 2023, a number of NSOs were submitted, as detailed below. ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

Five resources suspended operations (i.e., mothballed) in 2023: one combined cycle, two gas turbines, one wind, and a portion of a combined cycle.[176] One ESR with an HSL of 101.7 MW submitted an NSO to temporarily suspend operation for a designated timeframe due to some reason other than a forced outage.[177] Two resources experienced forced outages resulting in

176 https://www.ercot.com/services/comm/mkt_notices/M-E050523-01; https://www.ercot.com/services/comm/mkt_notices/M-B072723-01; https://www.ercot.com/services/comm/mkt_notices/M-A061423-01.

177 https://www.ercot.com/services/comm/mkt_notices/M-C102023-01; https://www.ercot.com/services/comm/mkt_notices/M-C102023-02.

submission of NSOs, totaling 72 MW. One Private-Use Network of 61 MW was permanently decommissioned and retired. [178]

Two NSOs submitted in 2023 had different outcomes. Deer Park Refining Limited Partnership converted four Private-Use Network resources into Settlement Only Transmission Self-Generators, totaling 120 MW. [179] Barney Davis G1, a resource with an HSL of 292 MW, submitted an NSO on July 23, 2023, to become effective on November 24, 2023; however, the NSO was withdrawn on October 27th, 2023.[180]

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178 https://www.ercot.com/services/comm/mkt_notices/M-B020323-01.

179 https://www.ercot.com/services/comm/mkt_notices/M-E052623-01.

180 https://www.ercot.com/services/comm/mkt_notices/M-B062723-04.

VIII. APPENDIX: ANALYSIS OF COMPETITIVE PERFORMANCE

In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal at higher load levels. Market participant conduct is evaluated by reviewing measures of physical and economic withholding. These withholding patterns are examined relative to the level of demand and the size of each supplier's portfolio.

A. Structural Market Power Indicators

When the Residual Demand Index (RDI) is greater than zero, the largest supplier is pivotal (i.e., its resources are needed to satisfy the market demand). When the RDI is less than zero, no single supplier's resources are needed to serve the load if the resources of its competitors are available.

1. Voluntary Mitigation Plans

In 2023, three market participants had active VMPs. Each of these VMPs went through significant modifications regarding non-spinning reserves in March of 2023. Pursuant to those modifications, NRG's ancillary services offers are no longer covered by their VMP; Luminant has a $20 per MWh non-spinning reserve offer cap; and Calpine has a dynamic formula based on its offers for other ancillary services.

i. Calpine VMP

Calpine's VMP was initially approved in March of 2013.[181] Because its generation fleet consists entirely of natural gas fueled combined cycle units, the details of the Calpine plan are somewhat different than the others. Calpine may offer up to 10% of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5% of the dispatchable capacity of its portfolio at prices no higher than the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW.

In March of 2023, Calpine's VMP was amended to eliminate the provision allowing non-spinning reserve offers in the day-ahead market to be made up to and including the high system-wide offer cap.[182] A dynamic formula for non-spinning reserve offers was substituted for the

181 *Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013).

182 *Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket 54741, Order (Mar. 23, 2023).

eliminated provision.[183] The new formula is based on Calpine's offers for other ancillary services, recognizing that non-spinning reserves are of lower value to the ERCOT system than responsive reserve service, regulation up, or ECRS. Calpine's VMP remains in effect from the date it was approved by the PUCT until terminated by the Executive Director of the PUCT or Calpine.[184]

ii. NRG VMP

NRG's plan, initially approved in June 2012 and modified in May 2014,[185] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12% of the difference between the high sustained limit and the LSL – the dispatchable capacity – each natural gas unit (5% for each coal or lignite unit) may be offered no higher than the greater of $500 per MWh or 50 times the natural gas price. Additionally, up to 3% of the dispatchable capacity for each natural gas unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions is approximately 500 MW.

Before March of 2023, NRG's VMP provided that offers or bids for energy and ancillary services in the day-ahead market could be submitted at prices up to and including the high system-wide offer cap.[186] In March of 2023, the PUCT terminated, in part, NRG's VMP, ensuring that the VMP no longer provided NRG with an absolute defense for offer or bids made in the day-ahead ancillary services market at prices up to and including the HCAP.[187] In February of 2024, NRG filed a letter with the PUCT expressing NRG's intent to exercise its right to terminate its VMP, effective March 1, 2024.[188]

183 *Id.*

184 *Id.*

185 *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).

186 *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 42611, Order (Jul. 11, 2014).

187 *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket 54740, Order (Mar. 23, 2023).

188 *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 54740, NRG Notice Regarding Voluntary Mitigation Plan (Feb. 23, 2024).

iii. Luminant VMP

Luminant received approval from the PUCT for a new VMP in December 2019.[189] The PUCT terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[190] The new VMP provides for small amounts of capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable capacity for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the HCAP. When approved in late 2019, the amount of capacity covered by these provisions was less than 900 MW. In addition, the plan defines allowable limits for energy offers from Luminant's quick start combustion turbines.

Before March of 2023, Luminant's VMP provided that offers in the day-ahead market for ancillary services could be made up to and including the high system-wide offer cap. In March of 2023, Luminant's VMP was amended to place a cap on offers in the day-ahead market for non-spinning reserve service of $20 per MWh for all resources.[191]

B. Evaluation of Supplier Conduct

Figure A44 below shows the relationship of short-term outages and derates to load levels during the winter, spring, and fall quarters of 2023.

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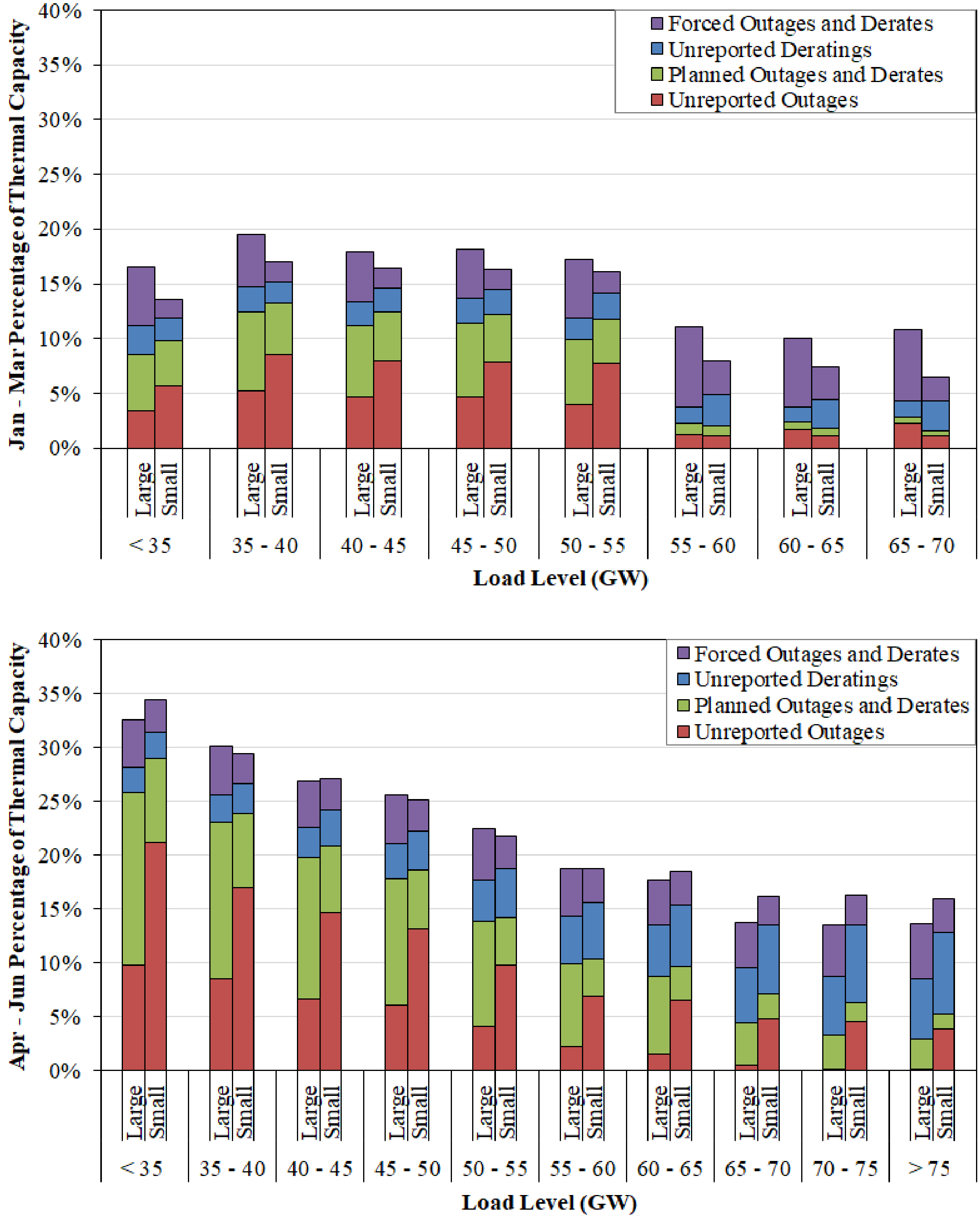
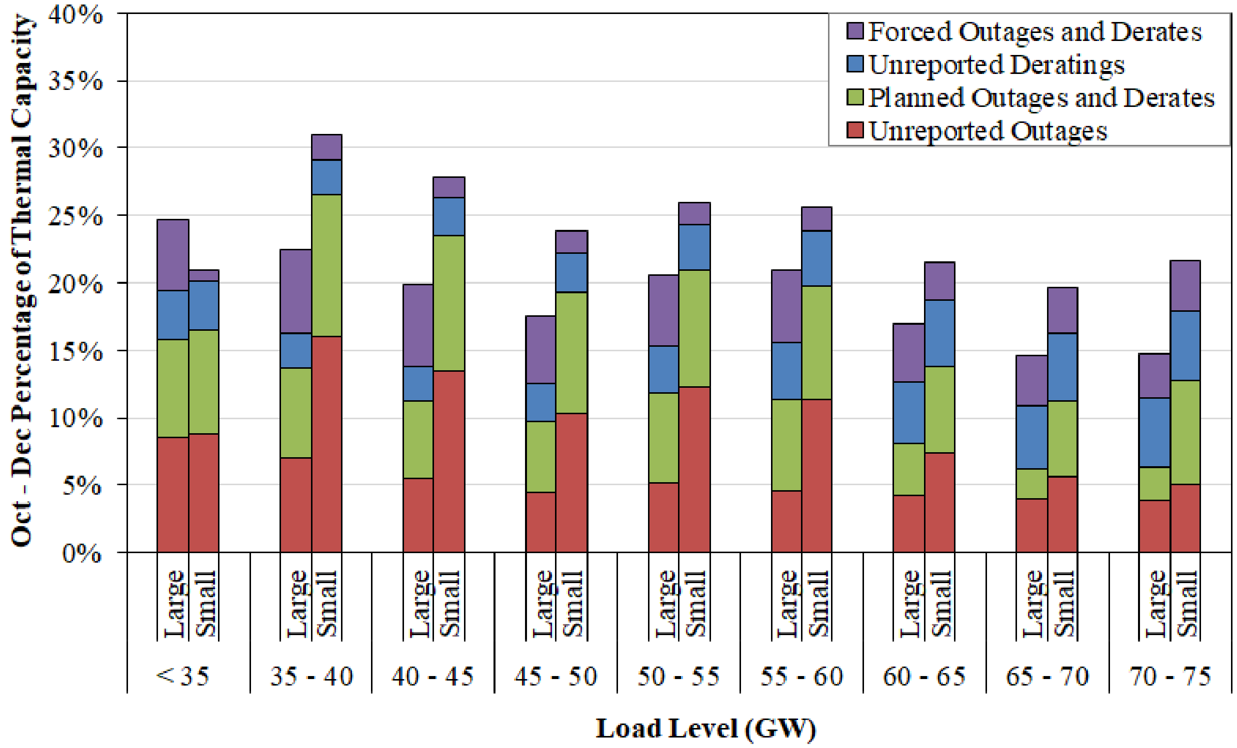
189 *PUCT Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e)*, Docket No. 49858, (Dec. 13, 2019).

190 *See Application of Luminant Power Generation LLC, Big Brown Power Company LLC, Comanche Peak Power Company LLC, La Frontera Holdings LLC, Oak Grove Management Company LLC, and Sandow Power Company Under Section § 39.158 of the Public Utility Regulatory Act*, Docket No. 47801 (Nov. 22, 2017); on April 9, 2018, Luminant filed a letter with the PUCT terminating its VMP upon closing of the proposed transaction approved by the PUCT in Finding of Fact No. 36 of the Order in Docket No. 47801, see also *Request for Approval of a Voluntary Mitigation Plan for Luminant Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Docket No. 44635, Order Approving VMP Settlement (May 22, 2015).

191 *Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 54739 (Mar. 23, 2023).

Figure A44: Outages and Deratings by Load Level and Participant Size




Forced Outages and Derates
Unreported Deratings
Planned Outages and Derates
Unreported Outages
Oct - Dec Percentage of Thermal Capacity
40%
35%
30%
25%
20%
15%
10%
5%
0%
Large
Small
< 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
Load Level (GW)