2021 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
CAISO	California Independent System Operator	NPRR	Nodal Protocol Revision Request
CDR	Capacity, Demand, and Reserves Report	NSO	Notification of Suspension of Operations
CFE	Comisión Federal de Electricidad	NYISO	New York Independent System Operator
CONE	Cost of New Entry	OBD	Other Binding Document
CRR	Congestion Revenue Rights	ORDC	Operating Reserve Demand Curve
DAM	Day-Ahead Market	PCRR	Pre-Assigned Congestion Revenue Rights
DC Tie	Direct-Current Tie	PRC	Physical Responsive Capability
EEA	Energy Emergency Alert	PTP	Point-to-Point
ERCOT	Electric Reliability Council of Texas	PTPLO	Point-to-Point Obligation with links to an Option
ERS	Emergency Response Service	PUC	Public Utility Commission
FIP	Fuel Index Price	PURA	Public Utility Regulatory Act
GTC	Generic Transmission Constraint	QSE	Qualified Scheduling Entity
GW	Gigawatt	RDI	Residual Demand Index
HCAP	High System-Wide Offer Cap	RENA	Real-Time Revenue Neutrality Allocation
HE	Hour-ending	RDPA	Real-Time Reliability Deployment Price Adder
Hz	Hertz	RTCA	Real-Time Contingency Analysis
ISO-NE	ISO New England	RTOLCAP	Real-Time On-Line reserve capacity of all On-Line Resources
LDF	Load Distribution Factor	RUC	Reliability Unit Commitment
LDL	Low Dispatch Limit	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		
NCGRD	Notification of Change of Generation Resource Designation		

EXECUTIVE SUMMARY

Potomac Economics provides this State of the Market Report for 2021 to the Public Utility Commission of Texas in our role as its 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 electric power to more than 26 million Texas customers – about 90% of the state's total electric demand. Every five minutes, the ERCOT markets coordinate the electricity production from more than 710 generating resources to satisfy customer demand and manage the resulting flows of power across more than 46,500 miles of transmission lines in the region. Additionally, the prices produced by the markets facilitate the long-term investment and retirements of resources in the ERCOT region. Hence, the markets' performance that we evaluate in this report is critical for maintaining reliability in Texas.

2021 was an extraordinary year for the ERCOT markets as it dealt with the effects and aftermath of Winter Storm Uri. This report includes a detailed discussion of the Winter Storm Uri event, including the lessons it provided. To isolate these effects and show the trends in other hours, we show two versions of a number of figures in this report, one for the entire year and a second one with the effects of the storm removed. In addition, we have added a new section to this report that discusses the changing grid and future needs of the market. These findings are summarized at the end of this executive summary. Key results in 2021 include the following:

Winter Storm Uri

- The defining event in ERCOT in 2021 occurred on February 13 through 19 when Winter Storm Uri hit the ERCOT region, causing widespread outages of generation, natural gas supply, and transportation equipment. These outages caused a severe supply/demand imbalance and required ERCOT to order curtailment of load to maintain the operation of the bulk electric system and prevent widespread collapse.
- Energy prices in the day-ahead market and real-time market remained at or near the offer cap for most of this time. The extended shortage pricing created extreme financial outcomes for some market participants. This was particularly true for those exposed to day-ahead or real-time prices due to insufficient coverage through financial contracts or generators unable to operate during the storm to hedge this exposure.

- The total value of electricity during this event was $59 billion.[1] Since many utilities supply some or all of their needs from owned or purchased generation, the net purchases of energy and ancillary services from ERCOT during the event was much less than that total value.

Competition and Market Power

- There is little evidence that suppliers abused market power in the wholesale market to raise system-wide prices through traditional withholding strategies.
  - However, a non-traditional withholding strategy emerged in the latter half of the year given ERCOT's increased commitment of resources through Reliability Unit Commitment (RUC) and the high RUC offer floor associated with that commitment established in the protocols.
  - This incentive issue has been subsequently addressed via a rule change proposed by the IMM and passed by the ERCOT stakeholders, the ERCOT Board of Directors, and the Public Utility Commission of Texas.[2]
- In some local areas, transmission system limitations on the amount of power that can flow into the area can increase opportunities to abuse market power. However, mitigated offer price caps in these situations effectively addressed these opportunities in 2021.

Demand for and Supply of Electricity

- The highest electricity demand in 2021 was 72,339 megawatts (MW), occurring on September 1 between 4 and 5 p.m. This was about 2,500 MW lower than the all-time peak demand set on August 12, 2019. Backcast analysis of Winter Storm Uri indicated that demand could have reached as high as 76,819 MW during the storm, had the ERCOT system been able to serve the entire demand.[3]
- Although total consumption was higher than 2020, the daily peaks were generally lower, partly because of the effects of the COVID-19 pandemic in the early part of the year.
- The supply of generation in the ERCOT region continues to evolve. Over 7,000 MW of new wind and solar resources, 820 MW of energy storage resources (ESRs), and approximately 700 MW of natural gas supply came online in 2021.
- Approximately 172 MW of wind and natural gas resources retired in 2021.

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1 We previously quantified the impact as $56 billion for February 14-19. In this report we also include February 13, which brings the total to $59 billion.

2 NPRR1092: *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision*.

3 https://www.ercot.com/files/docs/2021/03/03/Texas_Legislature_Hearings_2-25-2021.pdf

Market Outcomes and Performance

- Average energy prices increased by more than six times to $167.88 per megawatt-hour (MWh). This change was primarily due to the extreme supply shortages and resulting prices during Winter Storm Uri, and to a lesser extent due to higher average natural gas prices during the balance of the year.
- Transmission congestion in the real-time market was up 46% in 2021, totaling $2.1 billion. More than $560 million of this was generated during Winter Storm Uri.
  - Electric transmission networks become congested when power flows reach the limit on a transmission line. To resolve the congestion, costs are incurred to alter generation in different locations.
- ERCOT is increasingly limiting the flows across certain network paths to maintain the stability of the system, which increases transmission congestion costs. These stability issues have partly been caused by the increase in inverter-based resources. The congestion rent associated with these stability constraints increased from $190 million in 2020 to $400 million in 2021, roughly 20 percent of all real-time congestion costs.
- ERCOT changed its operational posture in July 2021 by increasing reserves, which substantially affected market outcomes in the second half of the year. This change included:
  - Increased non-spinning reserve requirements;
  - More routine use of RUC, including issuing instructions earlier in the day and committing more longer-lead time resources; and
  - Adjusting the selection of forecasts to more frequently rely on the highest load forecast and the lowest wind and solar forecasts.

Planned Changes to Improve Market Performance

- The most important market change underway is ERCOT's improvement of its real-time market to optimize the scheduling of its resources each five minutes for providing energy and operating reserves, also known as "real-time co-optimization" or RTC.
  - This was planned to go live in 2025. Due to significant issues identified following Winter Storm Uri, ERCOT has postponed the RTC project.
  - RTC should be prioritized given its promise to improve pricing during supply shortages and better utilize the existing generation fleet.
- ERCOT continues to plan for the integration of emerging technologies, such as ESRs and distributed generation resources (DGRs).

Below are more detailed summaries of each of the key findings of this report.

Winter Storm Uri

In February 2021, the ERCOT grid experienced unprecedented disruptions in electricity and natural gas service during Winter Storm Uri, resulting in widespread prolonged outages throughout the ERCOT region. The storm produced unusually low temperatures across the state, which were sustained over many days. Taken together, these conditions were much more severe than typical peak winter conditions.

The Dallas-Ft. Worth (DFW) area experienced 140 consecutive hours at or below freezing, with a minimum temperature of -2° F. This is 15° F colder than in the winter event in 2011 and was sustained for 39 more hours.[4] In the Austin area, these extremes were even more pronounced, with nearly 100 more hours at or below freezing temperatures compared to 2011.

Beginning on February 12, 2021, a Declaration of a State of Disaster for all counties in Texas was issued pursuant to Texas Government Code § 418.014 in response to the extreme winter weather event. These extraordinary conditions simultaneously: a) increased electric demand significantly above forecasted peak winter demand and b) reduced the available generation because of forced outages and fuel shortages. The simultaneous sharp increase in the demand and large reduction in supply produced a large supply-demand imbalance that resulted in sustained demand outages. These conditions emerged in the early morning hours of February l5, 2021 when ERCOT declared its highest state of emergency, Energy Emergency Alert Level 3 (EEA3), as the exceptional electric demand exceeded the available supply. To stabilize the rapidly deteriorating grid conditions, ERCOT ordered transmission companies to reduce demand on the system by implementing outages for customers (also termed “load shed”). These outages are designed to rotate to reduce the impact to customers, but transmission companies were unable to rotate in many cases because of the depth of the load shed. ERCOT remained in EEA3 through mid-morning February 19, 2021.

At the height of the storm, more than 52 gigawatts (GW) of generation resources in the ERCOT region were unavailable. The majority of those outages were caused by equipment failure, fuel shortages, or other weather-related issues related to the storm. ERCOT also experienced a number of transmission issues during Winter Storm Uri that impacted grid operations. Unfortunately, the load shedding caused some natural gas facilities to lose power (facilities that were facing their own weather-related issues), reducing their ability to deliver gas to natural gas-fired generators, and exacerbating the supply shortage.

We did not find any evidence of ERCOT market participants exercising market power during the event. However, as we reported in last year’s State of the Market[5], the energy and ancillary

4 https://comptroller.texas.gov/economy/fiscal-notes/2021/oct/winter-storm-impact.php

5 https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf

services markets both produced outcomes that were inefficient. These issues were resolved on a going-forward basis after the storm.

Real-time Energy Pricing Outcomes

Real-time prices during shortage conditions is critical important, particularly in ERCOT's energy-only market, because it provides the economic signals necessary for generators to be available. When supply shortages prevent ERCOT from serving the load, prices should reflect the "value of lost load" (VOLL) of $9,000 per MWh, which is also the system-wide offer cap. However, despite firm load shed at the outset of Winter Storm Uri, energy prices cleared at less than $9,000 per MWh and dipped as low as approximately $1,200 per MWh on February 16, 2021. These prices were caused by prevailing pricing rules that did not account for the firm load shed, although they account for other out-of-market actions by operators.[6] In response, the Commission directed ERCOT to account to modify the pricing rules to address this issue, which corrected the pricing after February 16.[7]

It is equally important that prices not reflect VOLL when the system is not in shortage. Transmission operators received the recall of the last of the firm load shed instructions just before midnight on February 17, but prices were held at the VOLL of $9,000 per MWh through mid-morning on February 19. This increased the valuation of energy during the event substantially, but increased settlement costs to loads by much less because of load-serving entities' owned generation and supply purchases.

Finally, the system includes a form of "circuit breaker" for extended periods of high prices called the peaker net margin (PNM) threshold, which was exceeded during February 16, 2021, for the first time in ERCOT's history. The PNM is the estimated revenues a new peaking resources would earn above its marginal operating costs. When these estimated revenues exceed the established threshold of three times the annual cost building a new peaking unit (a.k.a., the "Cost of New Entry" or CONE), the system-wide offer cap is reduced from the initial high system-wide offer cap (HCAP or $9,000 per MWh) to the low system-wide offer (LCAP) for the remainder of the calendar year. In February 2021, the LCAP was defined as the greater of either $2,000 per MWh or 50 times the natural gas price (also known as the fuel index price or FIP).

Natural gas index prices reached values over $400 per MMBtu during the load shed event, compared to around $3 per MMBtu on average during previous years. As a result, the LCAP (50 times FIP, or up to $20,000) exceeded the HCAP of $9,000. Therefore, the Commission

6 These out-of-market-actions include ERCOT issuing RUC instructions or deploying ERS.

7 See *Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control*, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 1-2 (Feb. 16, 2021).

suspended use of the LCAP[8] to avoid an outcome contrary to the purpose of the rule – to protect consumers from sustained high prices. Suspension of LCAP occurred on March 3, 2021.[9]

The Commission addressed real-time energy pricing issues following Winter Storm Uri. In PUC Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism*, the Commission deleted the provision that tied the LCAP to natural gas prices. The revised rule makes resources whole to their actual marginal costs when the LCAP is in effect. In PUC Project No. 52631, *Review of 25.505*, the Commission lowered the HCAP to $5,000 per MWh effective January 1, 2022.

Ancillary Services Pricing Outcomes

During the February 2021 Winter Storm Uri, ancillary service market clearing prices for capacity (MCPCs) reached record highs, well above the system-wide offer cap in effect at the time due to the design of the day-ahead market (DAM) clearing algorithm, which considered resources' opportunity cost of providing other services. Those opportunity costs were higher than had previously been encountered. Additionally, the ancillary service penalty factors for not awarding ancillary services, the assumed cost of being short of ancillary services, were set at levels arbitrarily higher than the system-wide offer cap. This was significant because ancillary service offers were frequently insufficient during Winter Storm Uri. Therefore, the DAM algorithm set MCPCs in excess of $25,000 per MW, far above the VOLL and HCAP of $9,000 per MWh. Because ancillary services are procured to *reduce* the probability of shedding load, it is not economically reasonable to value them in excess of VOLL. This issue overvalued ancillary services by close to $2 billion and affected participants' net settlements by roughly $900 million after accounting for utilities' owned and purchased generation.

ERCOT and the IMM subsequently cosponsored NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap* and the accompanying Other Binding Document Revision Request (OBDRR030): *Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap*, both approved in June 2021, to limit ancillary service MCPCs to the system-wide offer cap. This limitation was implemented by reducing the penalty factors to values equal to or immediately below the system-wide offer cap. This will prevent MCPCs from exceeding the system-wide offer cap, consistent with sound economic principles.

In addition to extraordinarily high ancillary services prices, there were a number of instances during Winter Storm Uri when ancillary services were not provided by individual resources in real time because of forced outages or deratings. During normal conditions, an ERCOT operator typically notes the short amount so that the day-ahead ancillary service payment will be recouped

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8 *See Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 2 (Feb. 16, 2021).*

9 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Order Reinstating Low System-Wide Offer Cap at 1-2 (Mar. 3, 2021).

the entity in settlement. However, the ERCOT operators did not complete this task during the winter event. Therefore the "failure to provide" settlements were not invoked in real time and short entities were able to keep their day-ahead payments.[10]

In response to a recommendation by the IMM,[11] the Commission directed ERCOT to resettle each entity that failed on its ancillary service supply responsibility in accordance with ERCOT Nodal Protocol section 6.4.9.1.3 for any hour of ERCOT's operating days February 14, 2021, through February 19, 2021.[12] Invoking the "failure to provide" settlement for these ancillary services ensured that market participants were not paid for services that they did not provide during Winter Storm Uri.

Moving Forward from Winter Storm Uri

The sustained shortage pricing led to billions of dollars in excess costs and numerous defaults that ERCOT and that the State of Texas will continue to grapple with for years to come. ERCOT short payments (money owed by entities that was not paid to ERCOT) during Winter Storm Uri exceeded $3 billion. Several retail electric providers were forced to exit the market and one large electric cooperative is seeking bankruptcy protection. The financial stress on the ERCOT market led to significant intervention by the Texas Legislature and the Commission discussed below, which together authorized and implemented broad securitization and financing measures to stabilize the wholesale market.[13]

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 ERCOT, but there is no evidence that suppliers abused market power in 2021 based on traditional withholding strategies. However, we identified a specific withholding strategy related to ERCOT’s new operational posture and filed a protocol change to address it.

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10 Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947, *Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities*; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to ancillary service trades, and the impending implementation of RTC.

11 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Potomac Economics' Letter to Commissioners at 1 (Mar. 1, 2021).

12 *Id.*, Second Order Addressing Ancillary Services at 2 (Mar. 12, 2021).

13 See SB 2, SB 3, SB 2154, SB 1580, HB 4492, *Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order under PURA Chapter 39, Subchapter M, and Request for a Good Cause Exception*, Docket No. 52321 (Oct. 13, 2021), and *Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order to Finance Uplift Balances under PURA Chapter 39, Subchapter N, and for a Good Cause Exception*, Docket No. 52322 (Oct. 13, 2021).

Structural Market Power

In 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 fully 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:

- Pivotal suppliers existed 18% of all hours in 2021, compared to 22% in 2020.
- Under high-load conditions, a supplier was pivotal in more than 70% of the hours, since 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 isolate these areas. Market rules cap prices that suppliers can offer in these cases, mitigating suppliers' ability to abuse market power.

Behavioral Evaluation

In addition to the structural analysis of market power, we evaluate behavior to assess whether suppliers engaged in behavior to withhold supply in order to increase prices. Economic withholding occurs when a supplier raises its offer prices to levels well above the expected marginal cost to produce electricity. This has the effect of withholding energy from the market that otherwise would have been economic to produce. Physical withholding occurs when a supplier makes a resource unavailable. Either of these strategies will result in the suppliers' other resources receiving a higher price because of the artificially decreased supply.

We examine the output gap metric to identify potential economic withholding. The output gap is the quantity of energy that is not produced by online resources even though the output would earn the supplier profits. Our analysis shows that in 2021, the output gap quantities remained very small, and only 22% of the hours in 2021 exhibited an output gap of any magnitude.

Regarding potential physical withholding, we find that both large and small market participants made more capacity available on average during periods of high demand in 2021 by minimizing planned outages and maximizing the generation offered from each resource. These results allow us to conclude that the ERCOT market performed competitively in 2021.

However, during the second half of 2021, we noted that self-commitment of a particular large supplier lagged previous trends, and we concluded that this was likely due to ERCOT's increased use of RUC and the high offer floor resulting from those actions. A market rule revision was proposed and passed by the ERCOT stakeholders to address this issue.[14]

Demand for and Supply of Electricity

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

Demand in 2021

Total demand for electricity in 2021 increased by roughly 3% from 2020 – an increase of approximately 1,300 MW per hour on average as the effects of the pandemic dissipated and the Texas economy continued to grow. The Houston area saw a 3.5% increase and the West Texas region showed an increase of 7.2% on average. The increase in the West zone is notable because it follows a 3% increase in 2020. In recent years, oil and natural gas production activity has been the driver for growing demand in the West zone, which slowed somewhat in 2020 because of the effects of the pandemic and low oil prices.

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 electricity use increases quickly as the number of cooling degree days grows because of the demand for air conditioning. In June, July and August, cooling degree days decreased 3%, 7% and 11% from 2020 in Houston, Dallas and Austin, respectively.

Peak hourly demand occurred on August 24, 2021, at 73,687 MW, lower than the record demand of 74,820 MW set in 2019.[15] The level of peak demand is important because it can affect the probability and frequency of supply shortage conditions. However, in recent years, peak *net* load (demand minus renewable resource output) has been a more important determinant of supply shortages. Supply shortage events are important in ERCOT because the very high prices during these events play a key role in supporting investment and maintaining the generation in ERCOT.

Supply in 2021

Approximately 8,800 MW of new generation resources came online in 2021, the bulk of which were intermittent renewable resources. The remaining capacity was:

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14 NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision*, was filed by the IMM and approved by the Board on April 27, 2022. As of May 13, 2022, the RUC offer floor was reduced to $250 per MWh but the RUC opt-out provision will become more limited in its applicability once ERCOT completes system implementation.

15 https://www.ercot.com/files/docs/2021/11/09/DemandandEnergy2021.xlsx

- 660 MW from combustion turbines;
- 70 MW from combined cycle; and
- 820 MW of ESRs.

ERCOT had roughly 1,800 MW of new installed wind capacity and 2,500 MW of new installed solar capacity going into summer 2021 compared to summer 2020, with an effective peak serving capacity totaling 2,400 MW. Sixteen gas-fired projects, 36 wind projects and 26 solar projects came online in 2021. The 24 storage projects that came online in 2021 increased ERCOT's storage capacity by a factor of five to around 1 GW. There were 172 MW of retirements in 2021 – 150 MW wind and 22 MW gas.

These resource changes along with changes in fuel prices led to the following changes in electricity production in 2021:

- The percentage of total generation supplied by wind resources continued to increase to more than 24% of all annual generation.
- The share of generation from coal was slightly higher than in 2021, likely because rising gas prices made coal more economic than it was in 2020.
- Natural gas generation decreased in 2021 from 46% in 2020 to less than 42% in 2021 as natural gas prices rose sharply.
- The amount of utility-scale solar capacity added in 2021 (3,600 MW by the end of the year) was the largest amount of solar added to the ERCOT system in any year so far, bringing total installed capacity to nearly 9,600 MW.

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. Although prices in 2021 did produce revenues sufficient to support profitable investment in new conventional resources, this was primarily due to Winter Storm Uri. These revenues are not likely to be expected in future years.

As described in more detail in the Future Needs of the ERCOT Market section, ERCOT adopted a more conservative posture with regard to operating the grid in July 2021. ERCOT began requiring additional operational reserves and bringing additional generation online outside of the market.[16] With this more conservative posture in ERCOT's operations and the significant market design changes being contemplated and implemented, we expect significant changes in the economic signals provided by the ERCOT markets. Therefore, it will be crucial to closely observe and evaluate the market outcomes in 2022 and beyond since these changes have implications for adequacy of ERCOT's resources in the long-term.

16 https://www.ercot.com/news/release?id=5fef298c-fbd7-34d3-39ee-d3fc63e568c2

ERCOT heads into the summer months of 2022 with a calculated reserve margin of 23.9%, notably higher than the 15.5% reserve margin for 2021, 12.6% for 2020 and the 8.6% reserve margin from 2019. Most of the increase is due to new solar and wind resources, which is a trend expected to continue in the coming years.

Review of Market Outcomes and Performance

ERCOT operates electricity markets in real-time for energy (electricity output) and in the day-ahead timeframe for both energy and ancillary services (mainly operating reserves that can 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 power is actually transacted in the real-time market (i.e., far more is transacted in the DAM or bilaterally). This is because real-time prices are the principal driver of prices in the DAM and forward markets.

There are two primary drivers for market prices: the price of natural gas and the number of hours of supply shortages during the year. We expect electricity prices to 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.

In 2021, the average natural gas price was higher than any recent year. Combined with the extreme winter event, rising natural gas prices caused real-time energy prices to average just under $170 per MWh. Removing the period of Winter Storm Uri reveals an average real-time energy price of about $41 per MWh, which is consistent with the natural gas prices that prevailed in 2021. The following table shows the trend in prices throughout ERCOT in recent years.

Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$40.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$42.78
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$41.57
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$39.98
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$35.51
($/MMBtu)									
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$3.62

This table 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 2021 differed from the last few of years, with the Houston and West zones experienced the lowest load-weighted prices because of lower load levels during Winter Storm Uri. When the effect of Winter Storm Uri is removed, the West zone has the lowest prices because of: 1) the completion of certain transmission projects in the West zone that had caused high prices in previous years; and 2) the large amount of local wind and solar generation that frequently causes export constraints to bind out of the zone.

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. Supply shortages are priced based on the value of operating reserves that ERCOT can no longer hold because of the limited supply. This value is embodied in the Operating Reserve Demand Curve (ORDC). When the system is in shortage, the relevant ORDC value will set operating reserve prices and be included in the energy price. The frequency and impacts of shortage pricing can vary substantially from year-to-year. For example, the extreme weather event in February 2021 led to prices greater than $1,000 per MWh in 166 hours in 2021 compared to only 7 hours in 2020. Additionally, in 2021 prices at or near the system-wide offer cap of $9,000 in intervals totaling roughly 98 hours.[17]

In reviewing the shortage pricing in ERCOT, it is important to note changes directed by the Commission in recent years. In 2019 and 2020, the Commission adjusted the ORDC curve to accelerate the shortage pricing toward the VOLL (normally $9,000 per MWh) at higher reserves levels. These 2019 and 2020 changes increased costs to load but also provided incentives to maintain higher operating and planning reserves. These changes were in place throughout 2021, including during Winter Storm Uri.

In the aftermath of Winter Storm Uri, the Commission made additional changes to the ORDC. Effective January 1, 2022, the Minimum Contingency Level (MCL) was increased to 3,000 MW and the HCAP and VOLL were reduced from $9,000 per MWh to $5,000 per MWh.[18] These changes will cause prices to rise more quickly at small shortage levels, but plateau at a lower

17 See *Review of the ERCOT Scarcity Pricing Mechanism*, Project No. 51871, (Jun. 24, 2021), when the Commission directed the elimination of the provision that tied the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities are able to recover their actual marginal costs when the LCAP is in effect; and *Review of 25.505*, Project No. 52631, (Dec. 2, 2021), which set the high system-wide offer cap at $5,000 per MWh effective January 1, 2022.

18 After a series of public work sessions and review of volumes of comments filed by market participant, the Commission directed ERCOT to address short- and long-term electric grid reliability concerns by enacting major reforms (see *Review of Wholesale Electric Market Design*, Project No. 52373 (pending)), at the December 16, 2021, open meeting. Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021, including the ORDC changes.

maximum price in deeper reserve shortages.[19] The effect of those changes will be examined in next year's report.

Day-Ahead and Ancillary Services Markets

The DAM 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 $157 per MWh in 2021. This price closely aligns with prices from the real-time market, but does not reflect the risk premium exhibited in other years with tight conditions, such as 2019.

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 physical 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 typically mirror the rise and fall of real-time energy prices because ancillary services prices include the profits a supplier forgoes by selling ancillary services rather than energy. Ancillary services costs rose sharply from $1 per MWh of load in 2020 to nearly $30 per MWh to 2021. This increase was due to the high ancillary services costs during Winter Storm Uri and the increase in procurement quantities in the latter half of 2021.

Transmission Congestion

Congestion arises when more power is flowing over a transmission line than it is designed to carry. Power flows over the network are almost entirely the result of where power is produced and consumed. When a transmission line is becoming overloaded, ERCOT will incur costs to shift generation to higher-cost generators in other locations to reduce the power flows over the transmission line. Hence, congestion prevents load from being served with 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 their locations and the

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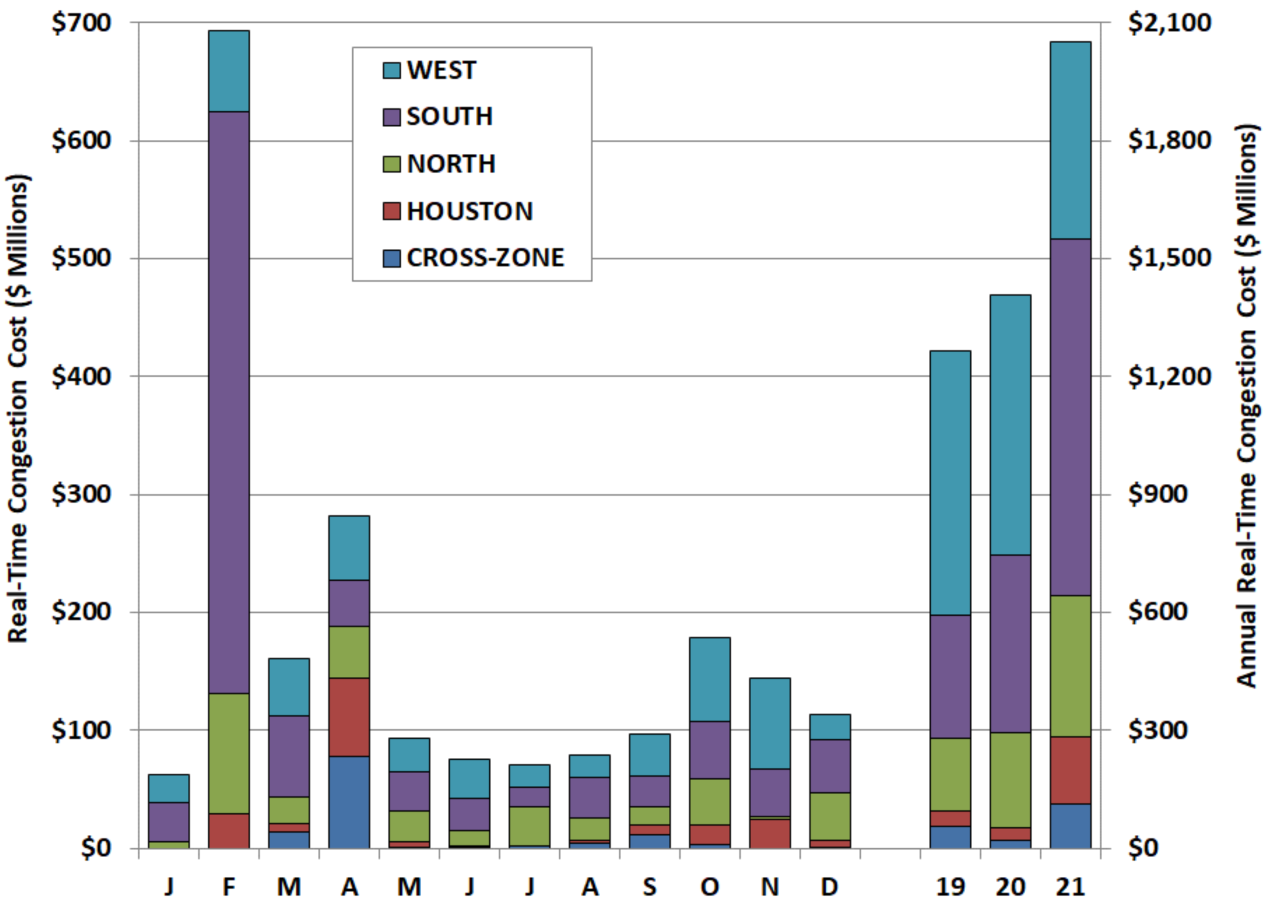
19 Subsequently, the Commission de-coupled VOLL from the system-wide offer cap in Project No. 53191, although the VOLL remains at $5,000 per MWh for the time being.

payments to generators at their locations. These costs accrue to those that hold the rights to the transmission system known as Congestion Revenue Rights (CRRs), which are discussed below.

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 2021 and a comparison with the annual costs in 2019 and 2020. The congestion costs in ERCOT's real-time market in 2021 were \$2.1 billion, up 46% from 2020. This increase is largely attributable to high levels of congestion during Winter Storm Uri which accounted for almost one third of all of the congestion costs in 2021. Higher natural gas prices and generic transmission constraints (GTCs) also contributed to the increase. Congestion costs are correlated with natural gas prices because higher gas prices tend to increase the costs of the generators that are moved to manage transmission congestion and serve customers in congested areas.

The figure below shows that the South zone experienced the highest congestion costs in 2021, which is a departure from prior years. This is primarily attributable to congestion experienced in February during to Winter Storm Uri when roughly 70% of the congestion occurred in the South zone. The West zone exhibited the second highest congestion as result of high renewable output that is limited by GTCs.

Real-Time Transmission Congestion Costs in 2021



Day-Ahead Congestion Costs. Participants' expectation of this real-time congestion is also reflected in ERCOT's DAM prices and outcomes. The transmission congestion priced in the DAM totaled $1.4 billion. Although this is 5% higher than 2020, it is significantly lower than the real-time congestion costs. This indicates that some of the congestion was not well predicted by the DAM, which was particular true of the volatile congestion that occurred during Winter Storm Uri.

Congestion Revenue Rights. Participants can hedge congestion costs in the DAM by purchasing Congestion Revenue Rights (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, totaling $832 million in 2021.

CRR auction revenues were less than the total congestion costs in 2021 mainly because the auction prices were less the CRRs were ultimately worth. This indicates that not all of the congestion was foreseen by the market. Much of this unexpected congestion occurred during the highly unusual conditions in February 2021. Other factors that contribute to the lower CRR auction revenues include the fact that 10% of the network capability is not sold in the auctions.

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 batteries that do not provide the same voltage support to the system as conventional resources. Ultimately, these GTCs increase transmission congestion and increase the total costs of serving customers in ERCOT by preventing low-cost power to be exported from these resources.

Market Improvements Underway

Real-Time Co-Optimization. The most important improvement to the ERCOT markets over the long term will be the implementation of changes to the real-time market to allow it to jointly optimize the scheduling of resources to provide energy and ancillary services in each dispatch interval (also termed real-time co-optimization or "RTC"). This Commission-approved project was delayed in 2021 and is now on hold until at least mid-2023 due to resource constraints caused by the market reform efforts described below.[20] Implementation of RTC will significantly improve the real-time coordination of ERCOT's generation and load resources,

[20] ERCOT RTC Update to TAC, January 31, 2022.

reduce overall production costs, and improve shortage pricing. These improvements will be key to helping efficiently transition to a future with a different resource mix as additional wind, solar, and storage resources enter the ERCOT market. We encourage continued focus on this important market improvement.

Market Reforms After Winter Storm Uri. The results of Winter Storm Uri raised significant concerns among policymakers in Texas and initiated a process to consider reforms to address the concerns. After a series of public work sessions and volumes of comments filed by market participants, the Commission directed major reforms to the ERCOT wholesale electricity market in PUC Project No. 52373, *Review of Wholesale Electric Market Design* at the December 16, 2021, open meeting.[21] Specifically, the Commission approved the blueprint for revisions to the design of the wholesale electric market filed in the Project on December 6, 2021.

The blueprint compiles directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint is described as providing enhancements to current wholesale market mechanisms to enhance ancillary services and improve price signals and operational reliability. Phase II of the blueprint incorporates longer-term market design and structure reforms.

Recommendations

We have identified opportunities for improvement in the current ERCOT market and make a total of nine recommendations below. Four are new items to address inefficiencies or improve incentives affecting market performance and the remaining recommendations were initially raised 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 Commission's Substantive Rules. We are also retiring two recommendations from last year. Readers can find those and the status of each recommendation in the Appendix.

We continue to advocate implementation of RTC as a top priority, because it improves both reliability and efficiency. It will result in lower overall costs of satisfying the system's energy and ancillary service needs, will more effectively manage congestion, result in fewer RUCs and out-of-market actions, and reduce shortages in operating reserves.

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.

21 See *Review of Wholesale Electric Market Design; Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT,* Project No. 52373, *(pending).*

SOM Number	Brief Description
New Recommendations to Improve Market Performance	
2021-1	Eliminate the "small fish" rule
2021-2	Implement an uncertainty product
2021-3	Reevaluate net metering at certain sites
Additional Recommended Market Improvements from Prior Years	
2020-3	Implement smaller load zones that recognize key transmission constraints
2020-4	Implement a Point-to-Point Obligation bid fee
2019-1	Exclude fixed costs from the mitigated offer caps
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 (CP) method.

New Recommendations to Improve Market Performance

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."[22] The history behind this rule shows that it originated in a market design where high offers (offers significantly above the marginal cost of production) were required to produce high prices in shortage conditions. Since the introduction of the nodal market, with the Power Balance Penalty Curve and the Operating Reserve Demand Curve, economic withholding by small participants is not required for efficient shortage pricing. In fact, it has led to inefficient pricing in some cases.

As an example from 2021, a particular thermal generation resource frequently submitted classic "hockey-stick" offers into real-time, where a small portion of the top of the offer was economically withheld at high prices that are not reflective of that resource's short-run marginal costs. Protected from market power abuse concerns by the small-fish market power rule, this resource nonetheless was occasionally pivotal and set the real-time price higher than $250 per MWh in 333 SCED intervals (approximately 28 hours) in 2021. Withholding should not be allowed by pivotal suppliers. Small entities can be pivotal when conditions are tight market-wide or when the entity is located in a constrained area where supply is tight. This is particularly

22 *See* 16 TAC § 25.504(c).

important during ramp-constrained intervals in absence of RTC. In these intervals, the market's ability to access competing resources can be extremely limited. Therefore, the IMM recommends removing this market power presumption.

2021-2 – Implement an uncertainty product

ERCOT regularly commits resources outside of the market through the RUC process to ensure sufficient generation will be available to satisfy ERCOT's stated reliability margin of 6,500 MW of reserves plus an additional 1,000 MW of non-spinning reserve in uncertain hours. In addition, ERCOT has sought and obtained a change to the non-spinning reserve requirements to essentially make it a four-hour product (primarily impacting ESRs).[23] If these requirements were reflected in a targeted market product, prices would more efficiently reflect these requirements. Additionally, the market would schedule resources to satisfy these requirements, reducing the need for out-of-market actions by ERCOT's operators and the associated uplift costs that must be borne by Texas consumers.

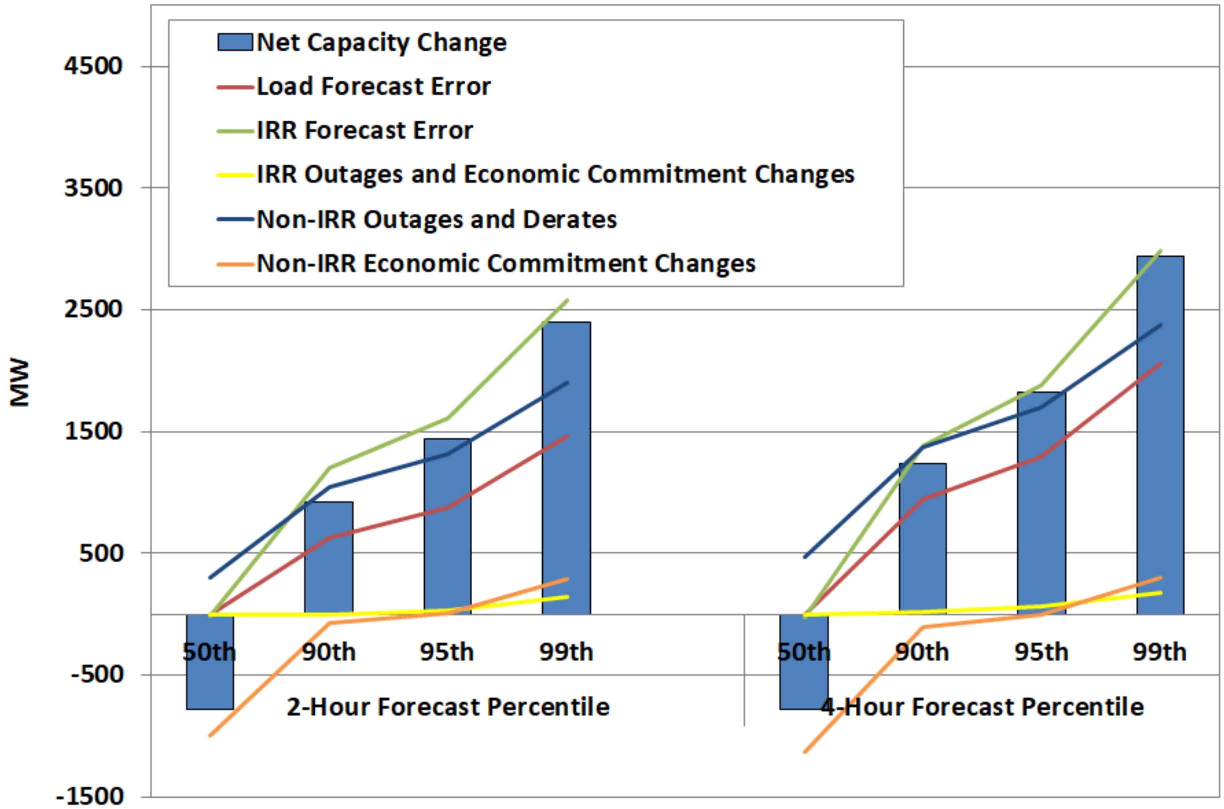
As the levels of renewable generation increase and ERCOT's conservative operations continue, these operational needs and out-of-market costs are likely to rise substantially. Hence, we recommend that ERCOT develop a DAM capacity product to account for increasing uncertainty associated with intermittent generation output, load, and other factors. This would be a two- to four-hour ancillary service that could be deployed when uncertainty results in tight real-time conditions. Such a product should be co-optimized with the current energy and ancillary services products and could be deployed to bring online longer lead-time units when ERCOT detects operating conditions are departing from expected conditions.

The figure below shows the net capacity changes (load minus supply) that ERCOT faces on average and in the worst hours, both in the two-hour ahead and four-hour ahead timeframe. This is intended to be illustrative and we have removed the highly unusual period during Winter Storm Uri. This figure shows that the worst hours, the net capacity change from two to four hours ahead to the operating timeframe can be substantial.

The markets should recognize and address this uncertainty, which can be accomplished by implementing a well-defined product that ERCOT can deploy to meet these needs. This product would: 1) be less costly than holding excessive amounts of 30-minute reserves; 2) allow co-optimized product prices to more fully reflect the value of managing uncertainty; and 3) reduce out-of-market actions and the costs associated with those actions. In the longer term, once an uncertainty product is implemented, ERCOT can return non-spinning reserve and ECRS to their previous duration requirements.

23 See NPRR1096, *Require Sustained Two-Hour Capability for ECRS and Four-Hour Capability for Non-Spin*.

Net Real-Time Capacity Changes



2021-3 – Reevaluate net metering at certain sites

The IMM agrees with the decision to implement nodal pricing for Controllable Load Resources (CLRs). However, we note that there has been a proliferation of proposed net metering schemes since adoption of NPRR945, *Net Metering Requirements*, that distorts the incentives provided by this directive. Loads that can be turned on and off quickly, such as data centers and cryptomines, should be incented to be dispatchable in real time through CLR participation rather reducing their consumption to avoid transmission cost allocation and other load charges. Net metering schemes should, at a minimum, only be allowed with affiliated entities. This would help support price formation and provide better congestion management.

Therefore, the IMM recommends requiring CLRs to have their own meters, rather than allowing net metering schemes amongst unaffiliated entities with meters at the point of interconnection.

Additional Recommended Market Improvements from Prior Years

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 (i.e., loads that can be controlled by the real-time market), transitioning to nodal pricing for those active loads will become increasingly beneficial for ERCOT and the market participants.[24] Beyond the active demand response, longer-term demand decisions may be influenced by the zonal prices. Such decisions may either relieve or aggravate congestion patterns, but are unfortunately not informed by the nodal prices.

Therefore, the IMM recommends that the load zone boundaries be re-evaluated and re-determined in future years (after the required four-year waiting period), based on prevailing congestion patterns. In particular, the new zones should minimize intra-zonal congestion.

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 DAM. 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 DAM used to manage congestion cost risk.[25] This is not a surprise because substantial increases in PTP transactions significantly increase the complexity of the optimization and the time required for the market software to find a solution.

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 DAM process. Hence, the IMM recommends that a small bid fee be applied to DAM PTP Obligation bids to more efficiently allocate DAM software resources.

[24] Nodal pricing for controllable load resources is a part of the Commission's 2021 market design blueprint.

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

2019-1 – Exclude fixed costs from the mitigated offer caps

In competitive markets, suppliers offer their resources at prices equal to their marginal costs (i.e., the incremental costs incurred to produce additional output). Offering at prices higher than this level can only reduce a supplier's profits in a competitive market because the supplier will be displaced by lower-cost resources. However, this is not true when a supplier has market power and an increase in its offer price will raise the market prices and its profits.

To effectively mitigate market power, replacement real-time energy offers used by ERCOT (such as mitigated offers) should only include short-run marginal costs. Currently, the mitigated offer cap includes a multiplier that increases the offer price as the unit runs more. The operations and maintenance portion of verifiable costs already accounts for costs that increase as a unit runs more so the multiplier is not reasonable. The exceptional fuel costs calculation during mitigation also contains a multiplier that does not correspond to a resource's marginal costs when these multipliers are included. Allowing generators with market power to raise prices is an economically inefficient means to achieve fixed cost recovery, so the IMM recommends that these two multipliers be removed to ensure that mitigated offer caps are set at competitive levels. This will help ensure that the market outcomes in ERCOT are competitive, while allowing these resources to recover fixed costs in the same manner as all other resources.

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. Each year the surplus grows, which is an indicator of the inefficient pricing in this market.

In addition, ERCOT will begin allowing non-controllable loads to participate in non-spinning reserve in 2022 but will limit their total participation. A new ancillary service, ERCOT Contingency Reserve Service (ECRS), will be implemented before 2025 and will also contain a constraint on certain resources. However, each of these services will have a single clearing price for both the limited and unlimited providers. Failure to include these constraints in the pricing of those products will require that inefficient market rules and restrictions be imposed. Such measures are not necessary when market participants' incentives are determined by efficient pricing. Therefore, the IMM recommends that the clearing price of ancillary services, both current and future, 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 (4CP) method.

The current method of allocating transmission costs, the 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.[26] This method was approved in 1996 and was intended to allocate transmission costs to the drivers of transmission build.

However, customer demand during the peak summer hours is no longer the main driver of transmission build 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 non-opt-in entities and transmission-level customers, both of which can artificially reduce their total customer demand in anticipation of a peak demand day to avoid transmission charges. Hence, the IMM continues to recommend that transmission cost allocation be changed to better reflect the true drivers for new transmission.

[26] 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 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, energy storage, and distributed generation fleet accelerates. These new generation technologies have significantly different operational characteristics than conventional generation. Changes to the market are necessary to integrate them reliably and efficiently into the system.

Second, ERCOT has adopted a very conservative operating posture since July 2021. The conservative operating posture requires more operational reserves to be online in real-time. In addition to being very costly, this posture can at times suppress real-time prices and exacerbate the "missing money" problem[27] that can sometimes be faced by generators in an energy-only market.

This section discusses the evolving needs of the future ERCOT market stemming from these two factors. The current ERCOT market design requires the following changes, at a minimum, in order to accommodate the changes described above:

- Implement RTC as soon as possible;
- Model state of charge (SOC) for ESRs;
- Introduce an uncertainty ancillary service product to increase the flexibility of the system instead of trying to adapt current ancillary service products to requirements they are not well suited for (see SOM recommendation 2021-2 above);
- Address cost allocation issues, particularly transmission cost allocation (see SOM recommendation 2015-1 above); and
- Develop a market construct to address the missing money that cannot be provided by an energy-only market in which shortage conditions are not permissible.

A. ERCOT's Future Supply Portfolio

The ERCOT market's supply portfolio has changed considerably over the last twenty years and the current interconnection queue suggests that it will continue to change. Over the past two decades, a significant fraction ERCOT's natural gas steam and coal generation retired, a large amount of combined cycle capacity was built, and the penetration of wind resources steadily increased. More recently, solar, battery energy storage, and distributed generation have been interconnecting at a rapid pace. We discuss the challenges related to these new classes of resources in the subsections below.

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27 This refers to the idea that prices for energy in electricity markets may not fully reflect the value of investment in the resources needed to meet consumers' demand for reliable electric service.

Renewable Resources

Over the last five years: 15 GW of wind, 10 GW of solar, 1.5 GW of energy storage, and 1.5 GW of gas-fired capacity was installed,[28] while 5.6 GW of coal and 0.9 GW of gas steam capacity retired.[29] Looking forward, ERCOT's current interconnection queue is comprised of more than 1,000 active projects totaling over 200 GW,[30] and most of this capacity is wind, solar, and storage. Not all of these projects will be built, but of the 31 GW of projects with a completed interconnection study and interconnection agreement, 18 GW are solar, 8 GW are wind, 4 GW are energy storage, and only 1.5 GW are natural gas-fired resources. The increase in intermittent wind and solar generation will raise new operational demands that are discussed below.

Increasing Ramp Demands. One of the new demands is a much steeper and more uncertain net load ramp. Net load is defined as the system load minus the output of intermittent renewable resources that must be served by dispatchable resources. The prediction of the future shape of this curve once a large quantity of solar has entered has been referred to as the "duck curve" or, in Texas, the "dead armadillo curve." This curve indicates that conventional resources will have to ramp rapidly each evening as the sun goes down and the solar resources' output falls sharply. Similarly, shifting weather patterns can cause wind output to fall rapidly and the timing of these decreases can be difficult to predict.

This will require ERCOT's operators to utilize flexible dispatchable resources to accommodate these sharp and uncertain ramp demands. In addition to existing and new flexible natural gas resources, ERCOT will likely need to rely more heavily on:

- Demand-side resources can respond to higher prices during the ramp by reducing their consumption if the value of the energy exceeds their value of consuming it; and
- Energy storage has the capability to produce energy very quickly when deployed, as well as storing energy when intermittent output is high.

The evolution of the market design will also improve ERCOT's ability to meet these new operational challenges. For example, a multi-interval real-time market (MIRTM) will be increasingly valuable. It allows the market software to anticipate and address ramping needs in future intervals by pre-positioning the system for those needs. ERCOT and stakeholders evaluated a MIRTM in 2016, finding that the benefits of a MIRTM were insufficient to justify its implementation costs at the time of the study, but noting that "[c]hanges in the future resource mix, the balance of supply and demand or system conditions could demonstrate more significant

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28 https://www.ercot.com/files/docs/2022/03/07/Capacity_Changes_by_Fuel_Type_Charts_February_2022.xlsx

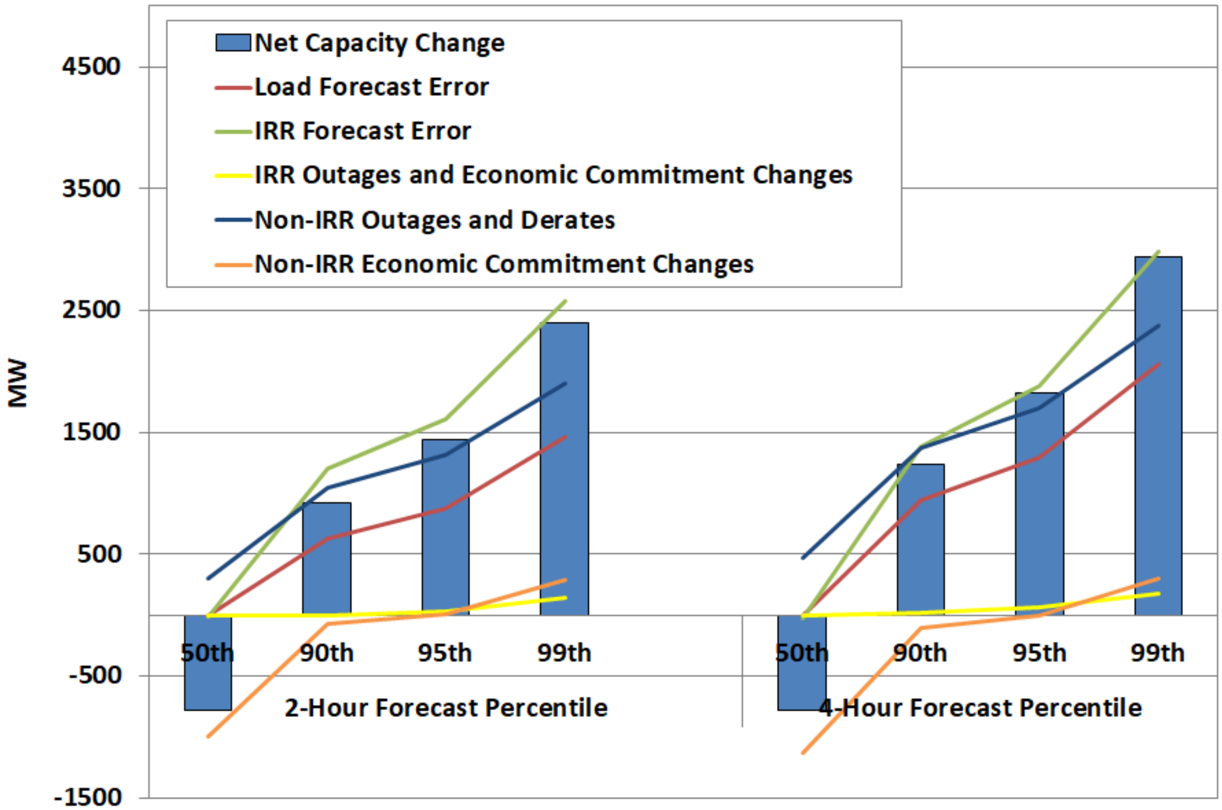
29 https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx

30 ERCOT Generation Interconnection Study Report, February 2022. https://www.ercot.com/misdownload/servlets/mirDownload?mimic_duns=000000000&doclookupId=825830714

value to MIRTM."[31] As the penetration of intermittent resources increases, the operational benefits of a MIRTM will increase because it will improve the utilization of the dispatchable fleet to manage the net load ramps.

Increasing Supply Uncertainty. As noted above, the growth in intermittent resources and distributed generation will increase supply uncertainty. As shown in Figure 1 below, thermal generation trips, load forecast errors, and wind and solar forecast errors all contribute to the net uncertainty faced by the market operator. The growth in wind and solar, coupled with increasing amounts of distributed generation that is not dispatched by ERCOT, will significantly increase the uncertainty that ERCOT faces. This uncertainty significantly affects both ERCOT's planning and operations.

Figure 1: Net Real-Time Capacity Changes



In real-time operations, RTOs manage this uncertainty by committing additional resources outside of the market to have sufficient dispatch flexibility to manage this uncertainty. To allow the markets manage and price this uncertainty, we recommend that ERCOT create a two- to four-hour uncertainty product. This product was previously discussed in SOM recommendation 2021-2 as well as in PUC Project No. 52373, *Review of Wholesale Electric Market Design*.[32]

31 https://interchange.puc.texas.gov/Documents/41837_9_935430.PDF

32 *Review of Wholesale Electric Market Design*, Project No. 52373, IMM Proposals at 6-7 (Oct. 15, 2021)

Although the figure is illustrative and not intended indicate the size of the service, it shows that ERCOT faces substantial uncertainty from multiple sources in the two to four-hour ahead timeframe. The recommended product would procure and price resources that ERCOT can utilize when the uncertainty results in tight supply-demand conditions or high ramp demands.

Increasing Generic Transmission Constraints. Another challenge brought about by the increase in inverter-based generation (including wind, solar, and energy storage) is the increased prevalence of GTCs. The flows over most transmission facilities are limited by thermal limitations because increased flows increase the temperature of the facilities. GTCs are not typical thermals constraints and are used to limit overall flows over a path to maintain the stability of the system. They are harder to manage than thermal constraints and are sometimes not well known prior to committing a resource.

GTCs have increased significantly over the last few years with the expansion of inverter-based generation, with congestion on these constraints growing from $190 million in real-time congestion in 2020 to $400 million in 2021. NPRR1070, *Planning Criteria for GTC Exit Solutions*, is currently pending, and the Commission rulemaking to implement SB1281 has recently been opened to improve economic transmission planning criteria.[33] These two items should help develop solutions to the proliferation of GTCs.

System Inertia. A final challenge associated with the proliferation of inverter-based generation is that of maintaining sufficient system inertia. System inertia needed to maintain frequency within acceptable bounds when large generators, loads, or large DC ties trip offline. Inertia is provided by online generators that are synchronously connected to the grid, which is not generally true of inverter-based resources. Alternatively, with very fast 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.[34] However, inertia should fall as a larger share of the load is served by wind, solar, and ESRs. It may be beneficial in the future to supplement the markets to compensate resources for providing inertia as ERCOT has previously discussed.[35]

Energy Storage

It is important for ERCOT to improve upon its current 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, independent devices. The dual model fits within ERCOT’s existing software capabilities, but

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33 Review of Chapter 25.101, Project No. 53403 (Mar. 19, 2022).

34 https://www.ercot.com/calendar/event?id=1520373953460

35 http://www.ercot.com/content/wcm/key_documents_lists/55752/Proposal_for_Synchronous_Inertial_Response_Service_Market_March112015.docx

has significant modeling limitations, including the inability to model the state of charge (SOC) of the ESR. ERCOT has made substantial progress towards modeling ESRs as a single device with the approval of NPRRs: 989 - *BESTF-1 Energy Storage Resource Technical Requirements*, 1002 - *BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions*, and 1026 - *BESTF-7 Self-Limiting Facilities.* Unfortunately, implementation of these changes is currently on hold due to constraints on implementation resources. However, even with these improvements, additional enhancements are needed to fully model ESRs' unique characteristics, including most importantly implementing modeling of the SOC of ESRs.

Modeling the SOC in the DAM and RUC processes or real-time market will become critical as ESRs become a substantial fraction of the fleet. Modeling the SOC of ESRs, in conjunction with RTC, is necessary to allow ESRs to provide their full value to grid reliability, flexibility, and economics.

Distributed Resources

ERCOT is also currently addressing issues related to distributed resources. There are currently over 1,300 MW of unregistered DGRs in ERCOT, and an unknown number of potential but unregistered controllable load resources.[36] These amounts are increasing yearly. ERCOT is actively grappling with visibility and uncertainty around these resources. They are generally located on the distribution system, and therefore present challenges associated with modeling their location, behavior, and market participation. The challenges presented by distributed resources include:

- Operational visibility: The location and output of distributed resources may not be certain in the real-time market, leading to potential challenges managing network congestion and balancing the system.
- Operational control: Most DGRs are not dispatchable by ERCOT on a five-minute basis.
- Economic incentives: To the extent that distributed resources are affected by retail programs or rates, wholesale market rules and settlements may result in inefficient incentives to operate the resources or inefficient co-location schemes. This is particularly true regarding costs distributed on a load-ratio share basis, such as ancillary service and transmission cost allocations.

We encourage ERCOT to develop market rules and operating procedures that address these challenges. The most immediate concern in this are relates to behind the meter demand response resources. Loads that can be turned on and off quickly, such as data centers and crypto-currency mines, are increasingly locating in Texas. These types of loads should be incentivized to register

[36] Unregistered DG Installed Capacity Quarterly Report at https://www.ercot.com/services/rq/re/dgresource.

with ERCOT and be dispatchable in real-time rather than simply providing passive demand response in order to avoid transmission cost allocation and other load charges. As discussed above in SOM recommendation 2015-1, the transmission cost allocation method currently used provides incentives for these large loads to behave in ways that do not necessarily forestall the construction of new transmission equipment and that do not apply costs equitably. In SOM recommendation 2021-3 above, we recommend requiring controllable load resources to have their own meters, rather than allowing net metering schemes amongst unaffiliated entities with meters at the point of interconnection.

B. ERCOT's New Operational Posture

After the events of Winter Storm Uri, the Texas Legislature, the Commission, and stakeholders have been engaged in a process of evaluating changes to the ERCOT market design. High load and high levels of thermal generation outages for the period of June 13-15, 2021, caused ERCOT to issue a public conservation appeal on June 14.[37] Previous conservation appeals were considered routine; however, this conservation appeal raised public concern regarding the state of ERCOT grid. This led ERCOT to decide to adopt a more conservative operating posture by requiring additional operating reserves to be available in real-time.[38] Since July 2021, ERCOT has:

- Increased non-spinning reserve requirements such that that the total of upward-moving ancillary services, excluding those provided by loads on high-set under-frequency relays, equals 6,500 MW on a typical day and a 7,500 MW on days ERCOT deems to have high load uncertainty, such as those with rapidly changing weather events;
- Used RUC more routinely to ensure that there is 6,500 MW (or 7,500 MW) of dispatchable reserves in real-time. ERCOT previously targeted lower reserve levels in the range of 3,600-5,700 MW;
- Issued RUC instructions earlier in the operating day, committing more longer-lead time resources as well as relying less on market participant response; and
- Adjusted selection of forecast to more frequently rely on the highest load forecast and the lowest wind and solar forecasts.

The results of the changes, in combination with the 2022 ORDC adjustment,[39] are that the pricing outcomes have grown disconnected from the actual operational conditions. This is discussed in more detail in the RUC section of this report. This is problematic because the

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37 https://www.ercot.com/news/release?id=9740321a-f509-31ab-8d0a-2a8421292239

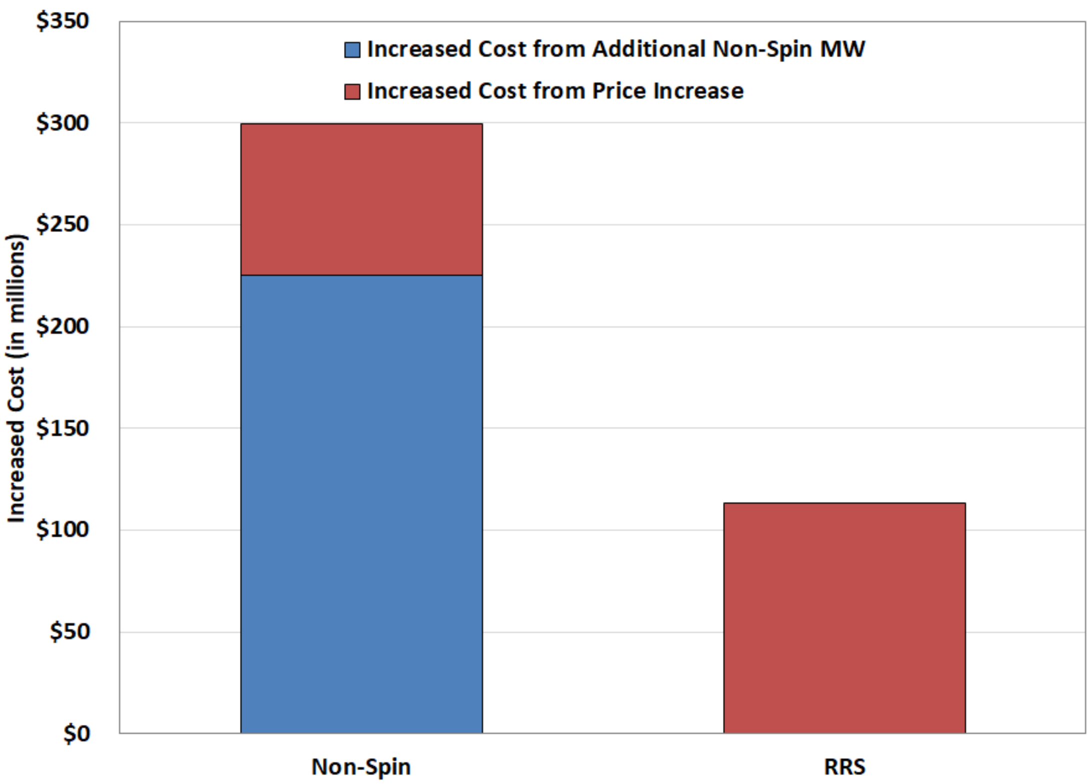
38 https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx

39 Effective January 1, 2022, the Minimum Contingency Level (MCL) was set at 3,000 MW and the high system-wide offer cap (HCAP) and value of lost load (VOLL) were set to $5,000 per MWh.

energy-only market design relies on efficient pricing that reflects the reliability needs of the system. In addition, this can increase risk for market participant if ERCOT over-commits the system and renders generation owner's decisions uneconomic.

Procuring additional non-spinning reserve also increases the costs paid by load. Although this additional procurement may increase reliability in some hours, the potential reliability benefits are difficult to justify based on the costs, particularly since the additional procurement is applied to all hours regardless of reliability need. As illustrated in Figure 2 below, we estimate that the combined cost increase of the higher procurement is in the range of $300-400 million for the period of July 12 to December 31, 2021.[40] This is based on our analysis of the effect of the increased procurement on non-spinning reserve prices and quantities, as well as the secondary effects on other ancillary service prices.

Figure 2: Non-Spin Cost Impact in 2021



While we continue to believe that an energy-only market can be successful and adapt to changing system needs, it is not compatible with ERCOT's current conservative operational posture. The distortion in the market's economic signals will diminish generators' expected revenues, which ultimately will threaten ERCOT's resource adequacy.

40 Due to the infeasibility of rerunning the DAM cases to determine price adjustments, our analysis estimates this cost based on historical pricing and modeling the range of impacts of the changes.

To address these concerns, we recommend the following:

- Develop the uncertainty produced described earlier in the section that will allow the markets to reflect ERCOT's operating posture.
- Consider adopting a form of capacity procurement that augments the economic signals provided by the energy-only market and ensures the adequacy of ERCOT's resources over the long term.

ERCOT should avoid a piecemeal approach that provides targeted payments to narrowly defined categories of resources when implementing any form of capacity procurement. A key component to any capacity proposal is defining a reliability standard. These discussions are currently underway at the Commission as part of its Phase II market design and structure reforms approach.

II. Review of Real-Time Market Outcomes

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

- Coordinates the dispatch of generating resources to serve ERCOT loads and manage flows over the transmission network; 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 ensures reliability in ERCOT with the simultaneous objective of minimizing the system's production costs. The second function is equally important because real-time prices provide key short-term incentives to commit resources and follow ERCOT's dispatch instructions, as well as long-term incentives 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 DAM and bilateral forward markets and are, therefore, the principal driver of prices in these markets where most transactions occur. Because of the interaction between real-time and all forward prices, the importance of real-time prices to overall market performance is much greater than might be inferred from the proportion of energy actually paying real-time prices. This section evaluates and summarizes electricity prices in the real-time market during 2021.

A. Real-Time Market Prices

The first analysis of the real-time market evaluates 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 3 shows the average "all-in" price of electricity for ERCOT that includes all these costs and is a measure of the total cost of serving load in ERCOT on a per 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.[41]

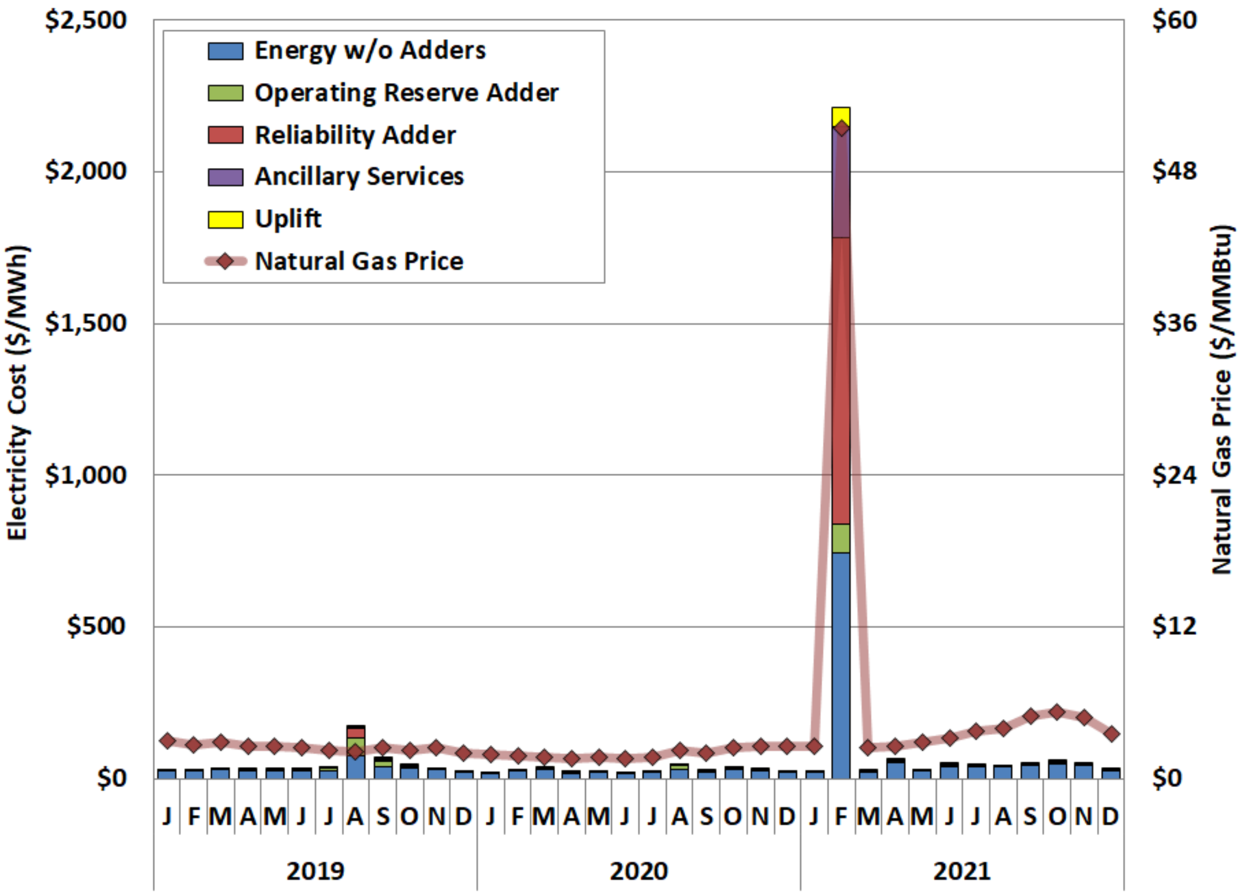
ERCOT real-time prices currently include the effects of two energy price adders that are designed to improve real-time energy pricing when conditions warrant or when ERCOT takes

41 For this analysis "uplift" includes: Reliability Deployment Adder Imbalance Settlement, Operating Reserve Demand Curve (ORDC) Adder Imbalance Settlement, Revenue Neutrality Total, Emergency Energy Charges, Base Point Deviation Payments, Emergency Response Service (ERS) Settlement, Black Start Service Settlement, and the ERCOT System Administrative Fee.

out-of-market actions for reliability. Although published energy prices include the effects of both adders, here we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately from the base energy price. The operating reserve adder was implemented in mid-2014 to account for the value of reserves based on the probability of reserves falling below the MCL and VOLL. Taken together, an estimate of the economic value of increasingly low reserves in each interval in real-time can be included in prices. The reliability adder was implemented in June 2015 as a mechanism to ensure that certain reliability deployments do not distort the energy prices.[42]

In Figure 3 and Figure 4 below, the effects of Winter Storm Uri on the average all-in price for electricity in ERCOT are examined by showing the 2021 prices with the storm and without the storm.

Figure 3: Average All-in Cost for Electricity in ERCOT (with Uri)



42 The reliability adder is calculated by separately running the dispatch software with modifications to the inputs to reflect any RUCs, deployed load capacity, or certain other reliability actions. When the recalculated system lambda (average load price) is higher than the initial system lambda, the difference is the adder.

Because of the overwhelming effects of Winter Storm Uri on energy prices, the largest component of the all-in price in 2021 was the reliability adder, unlike previous years when the energy cost was the largest component. The correlation between the gas price and the energy price in the figure above indicates that natural gas prices were a primary driver of energy prices in most months, including in February during the storm. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Because suppliers in a competitive market have an incentive to offer supply at marginal costs and natural gas is the most widely used fuel in ERCOT, changes in natural gas prices typically should translate to comparable changes in offer prices. This can be seen more clearly in Figure 4 below, showing the correlation between the all-in energy price and the natural gas price throughout the year with the severe effects of Winter Storm Uri removed from the analysis.

Average real-time prices rose to $167.88 per MWh in 2021, more than 6 times higher than in 2020, due almost entirely to the effects of Winter Storm Uri. The last time ERCOT experienced shortage pricing, in August and September of 2019, its magnitude and duration were much lower than experienced during Winter Storm Uri.

The extreme increase in shortage pricing was acutely reflected in the higher contributions from ERCOT's energy price adders: $8.32 per MWh from the operating reserve adder and almost $80.00 per MWh from the reliability adder. Both values are much higher than the 2020 values: $2.35 per MWh for the operating reserve adder and $0.01 per MWh for the reliability adder. The adders in 2021 are discussed in greater detail in Subsection F below.

Despite firm load shed across the system during the storm, energy prices were clearing at less than $9,000 per MWh, which was the system-wide offer cap at the time, pursuant to 16 TAC § 25.505(g)(6)(B). Energy prices dipped as low as approximately $1,200 per MWh on February 16, 2021. In response, the Commission directed ERCOT to account for firm load shed in EEA3, from the time of the Commission's order, in ERCOT's scarcity pricing signals.[43]

Due to the exceptionally high natural gas prices, the Commission suspended use of the low system-wide offer cap (LCAP) during Winter Storm Uri.[44] Because LCAP was calculated as "50 times the natural gas price index value," it would likely have exceeded the high system-wide offer cap (HCAP) of $9,000 per MWh and $9,000 per MW per hour under 16 TAC § 25.505(g)(6), an outcome contrary to the purpose of the rule, which was to protect consumers from substantially high prices in years with substantial generator revenues. Suspension of LCAP

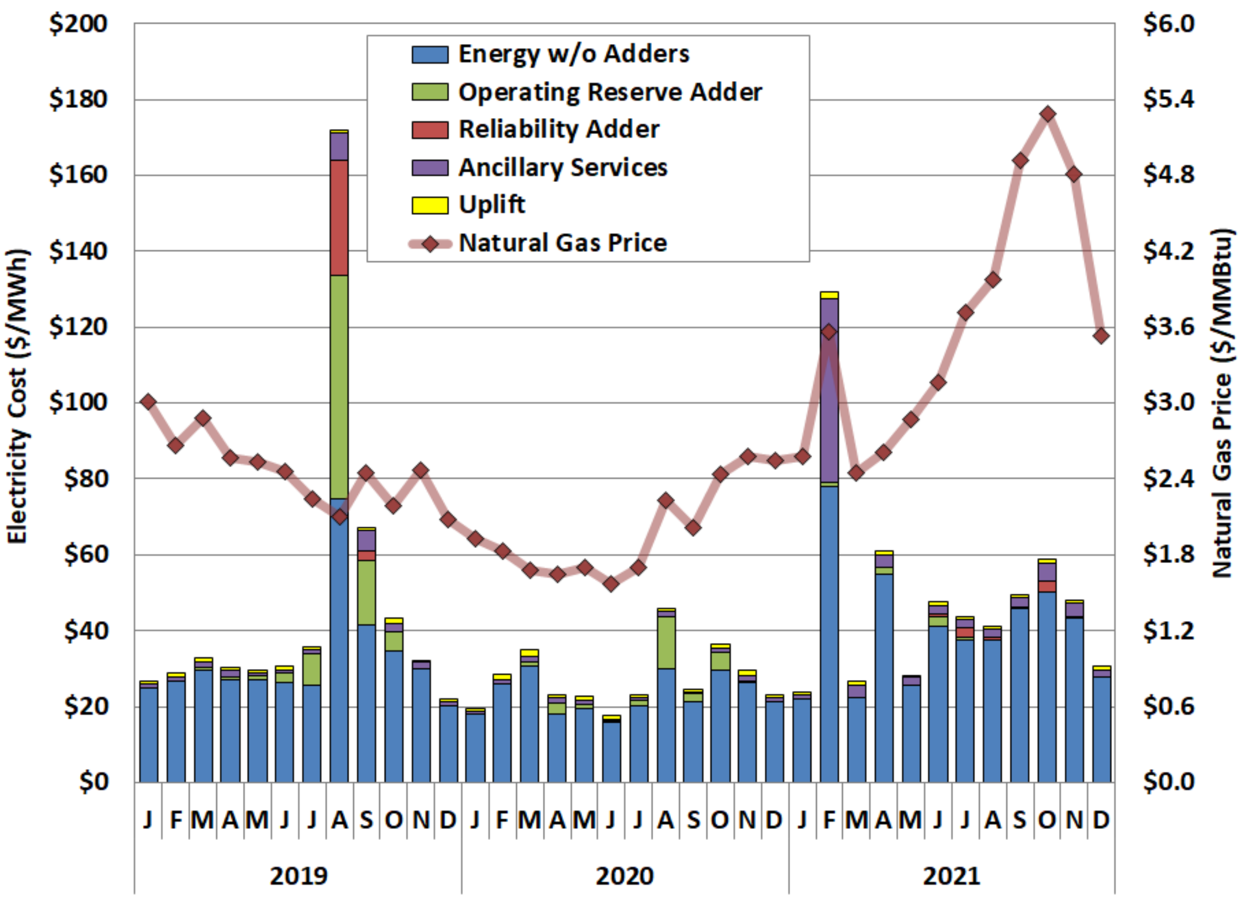
[43] See *Calendar Year 2021 - Open Meeting Agenda Items without an Associated Control*, Project No. 51617, Second Order Directing ERCOT to Take Action and Granting Exception to Commission Rules at 1 -2 (Feb. 16, 2021).

[44] *Id.* at 2.

was terminated on March 3, 2021, once the natural gas price index had stabilized and the LCAP was no longer expected to exceed the HCAP, and the Commission directed ERCOT to resume application of the LCAP when administering the scarcity pricing mechanism as provided by Commission rule.[45]

When the effects of Winter Storm Uri are removed from the analysis, as shown below in Figure 4, average real-time prices rose by 58% (to $40.73 per MWh) in 2021 compared to 2020, driven by higher natural gas prices throughout the year. The energy price adders in 2021 without the effects of Winter Storm Uri increased slightly from 2020 values – $0.55 per MWh for the operating reserve adder and $0.70 per MWh for the reliability adder in 2021.

Figure 4: Average All-in Cost for Electricity in ERCOT (without Uri)

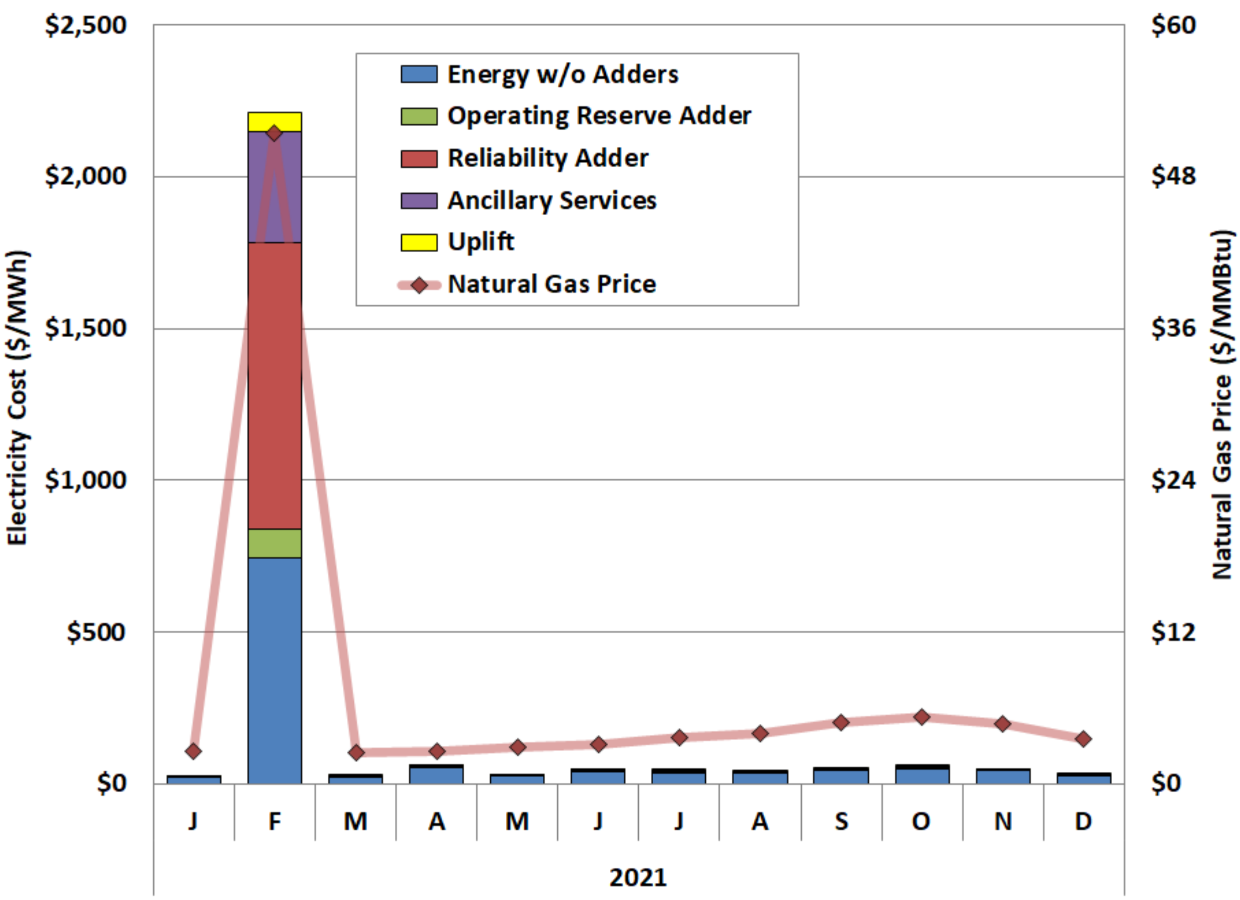


Other cost categories of the all-in electricity price were similarly altered by Winter Storm Uri, as shown in Figure 5 below. Ancillary services costs were $29.59 per MWh of load in 2021, up from $1.00 per MWh in 2020, discussed in more detail in in Section IV: Day-Ahead Market

[45] *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Order Reinstating Low System-Wide Offer Cap at 1-2 (Mar. 3,2021).

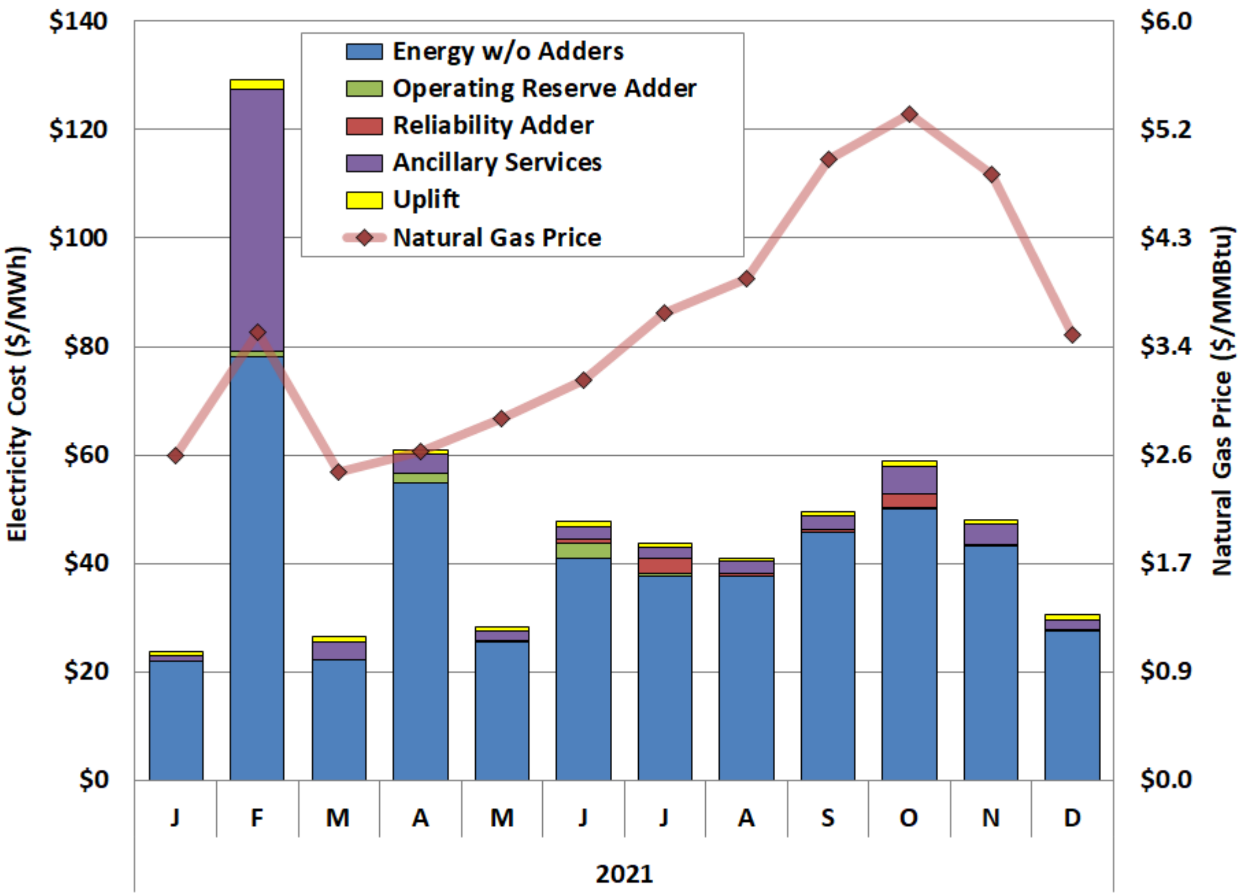
Performance. Uplift costs accounted for $5.34 per MWh of the all-in electricity price in 2021, up from $0.94 per MWh in 2020. The total amount of uplifted costs in 2021 was approximately $2.1 billion, vastly higher than the $359 million in 2020. The largest driver of this massive uplift value is the ancillary service imbalance settlement. There are many other costs included as uplift, but the largest components are the ERCOT system administrative fee ($218 million or $0.55 per MWh), Emergency Response Service (ERS) program costs ($35 million or $0.09 per MWh) and the real-time revenue neutrality allocation (RENA), which totaled less than $1 million or less than $0.01 per MWh in 2021. The dramatic decrease in RENA, down from $75 million in 2021, is attributable to high negative RENA during Winter Storm Uri.

Figure 5: All-in Electricity Costs in 2021 (with Uri)



As show in Figure 6 below, ancillary services costs without the period of Winter Storm Uri would have been $6.00 per MWh in 2021, up from $1.00 per MWh in 2020. This was still a large increase and was driven by high ancillary services prices that persisted for several days after Winter Storm Uri, and to a lesser extent the additional ancillary services quantities that ERCOT purchased during the second half of the year. Uplift costs would have accounted for $0.91 per MWh of the all-in electricity price in 2021, about the same as in 2020 ($0.94). The total amount of uplifted costs in 2021 would have been approximately $356 million, in line with the $338 million in 2019 and $359 million in 2020.

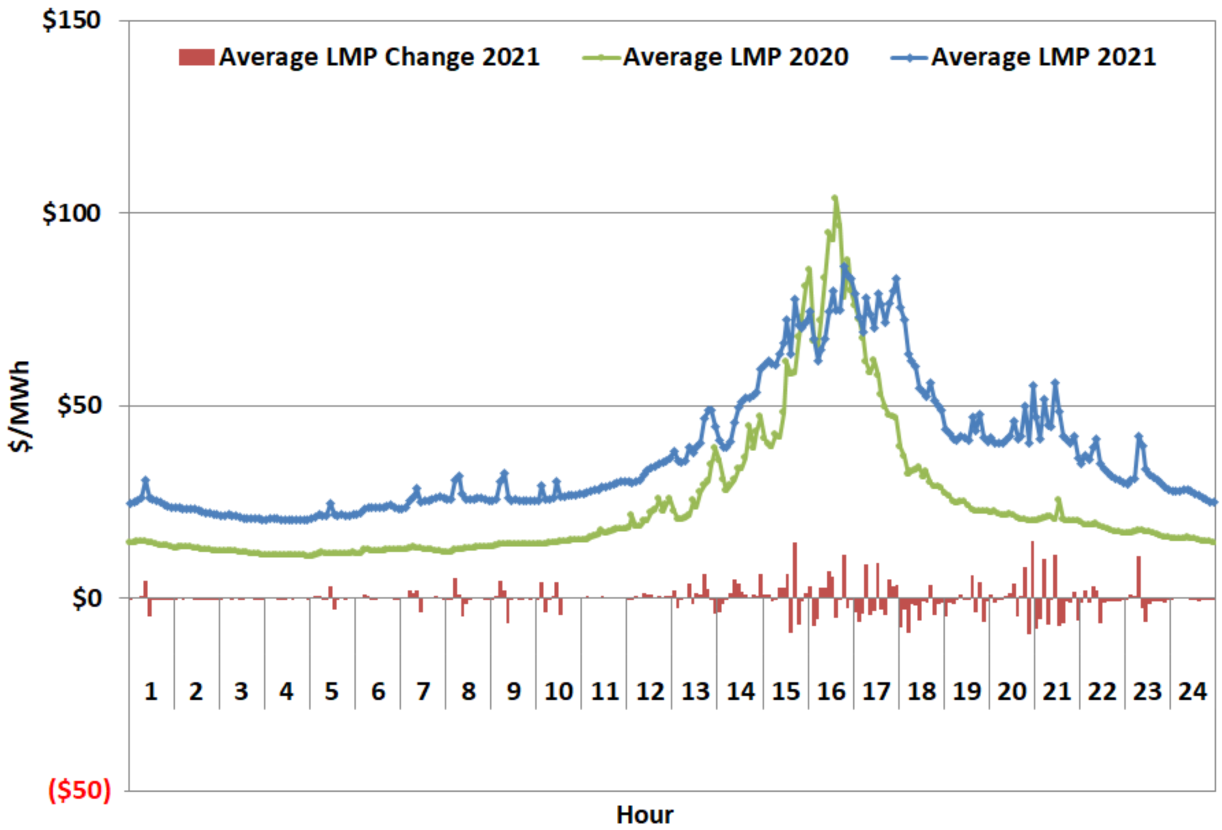
Figure 6: All in Prices 2021 (without Uri)



Real-time energy prices vary substantially by time of day. Figure 7 shows the 2021 load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices are typically the highest. It also shows in red the average change in the 5-minute prices in each interval. Average changes are mostly random and generally driven by changes in load or supply. Note that prices in the peak load hours were actually lower in 2021 than in 2020, and higher in all other hours. This was likely attributable to demand alterations in the earlier part of the year caused by the Covid-19 pandemic as well as a cooler summer weather and higher solar output during peak.

For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2021, see Figure A1 in the Appendix.

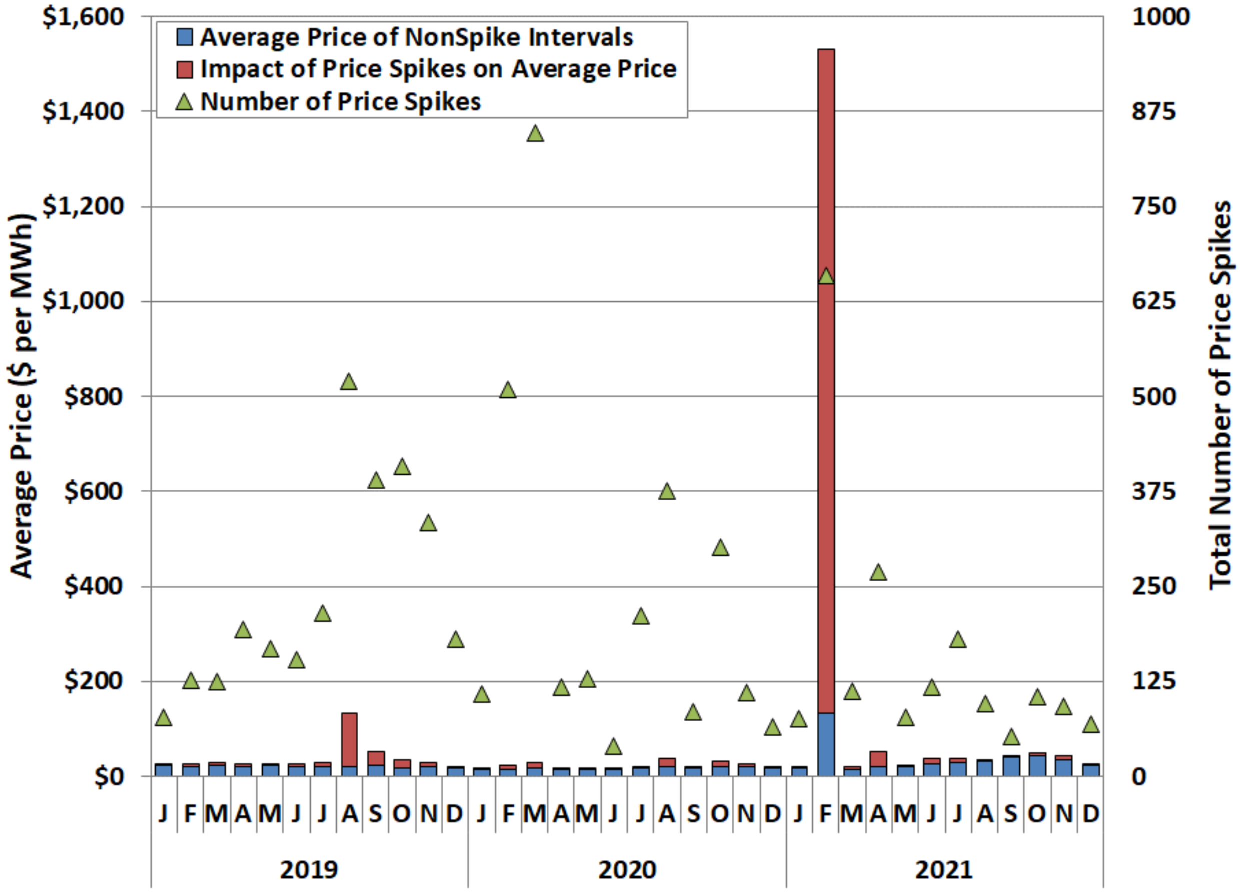
Figure 7: Prices by Time of Day
May-September 2021



To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 8 shows the frequency of price spikes in the 2021 real-time energy market. 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 multiplied by the prevailing natural gas price (i.e., a heat rate of 18). Prices at this level typically exceed the marginal costs of virtually all on-line generators. As with many market outcomes in 2021, this analysis is once again dominated by the events of February 2021 and Winter Storm Uri.

Price spikes were less frequent in 2021 compared to 2020 in part due to higher gas prices and in part due to ERCOT's conservative operational posture but were far more consequential on prices because of the larger magnitude of prices during Winter Storm Uri as well as much higher average gas prices (above $7.00/MMBtu) throughout the year. With average gas prices so high throughout the year, energy prices have a much stronger correlation with heat rate as the other components of operations and maintenance costs become less impactful. This is typical in energy markets. The overall impact of price spikes in 2021 was $123.45 per MWh, or 74% of the total average price.

Figure 8: Average Real-Time Energy Price Spikes



B. Zonal Average Energy Prices in 2021

Energy prices vary across the ERCOT market because of congestion costs that are 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 seven years, plus an additional column containing 2021 without Winter Storm Uri (February 13-19, 2021).

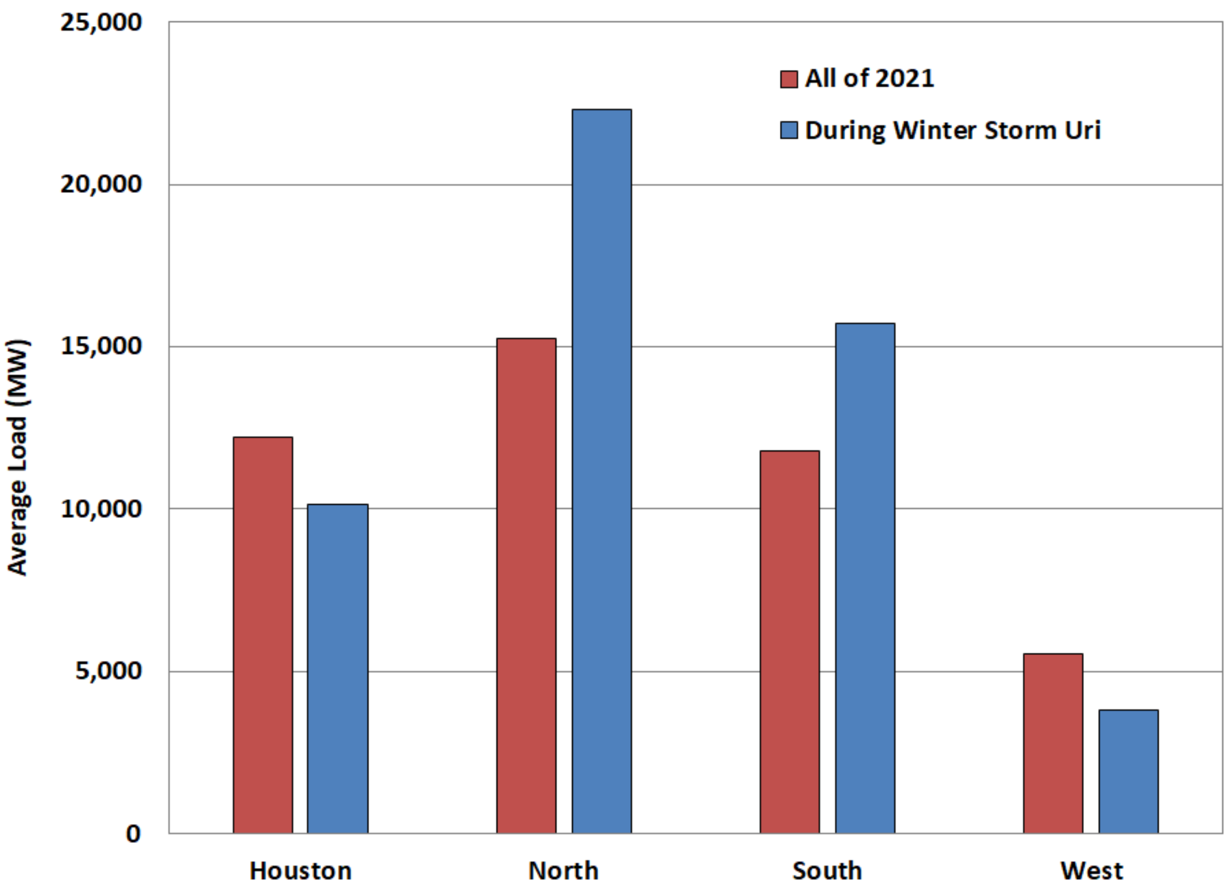
Table 1: Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**	**$167.88**	**$40.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54	$129.24	$42.78
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97	$206.39	$41.57
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63	$187.47	$39.98
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58	$105.27	$35.51
($/MMBtu)									
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$3.62

Like Figure 3, Table 1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price, including 2021. This relationship is consistent with competitive expectations in ERCOT where natural gas generators predominate and set prices in most hours. The average natural gas price was higher in 2021 than it has been in many years, and average real-time energy prices reflect that. For additional analysis on ERCOT average real-time energy prices as compared to the average natural gas prices, see Figure A2 in the Appendix.

Table 1 also shows that the relative prices of the four zones was different in 2021 compared to previous year, again due to Winter Storm Uri. The table contains load-weighted averages, and as shown in Figure 9, the North zone and South zone had higher load values than their yearly averages during Winter Storm Uri while the Houston and West zones had the opposite, so the extreme high prices during Winters Storm Uri influenced the annual averages of the North and South zones more than the Houston and West zones. With the effects of Uri removed, the Houston zone had the highest average price, due to multiple localized real-time transmission constraints in the area. For additional analysis on monthly load-weighted average prices in the four geographic ERCOT zones during 2021, see Figure A3 in the Appendix.

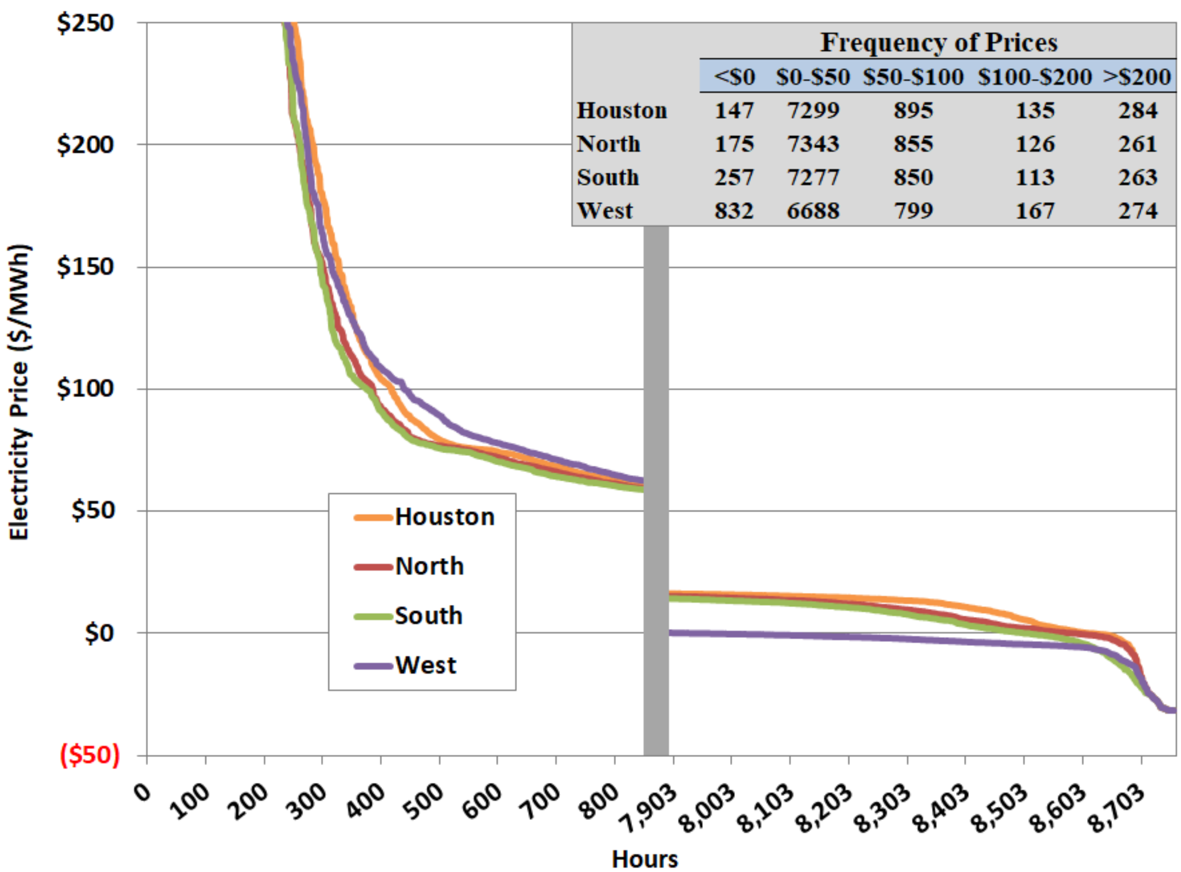
Figure 9: Average Load by Load Zone



More details about transmission constraints that influenced zonal energy prices are provided in Section V. That section also discusses Congestion Revenue Right (CRR) auction revenue distributions, which affect the ultimate costs of serving customers in each zone. For additional analysis of the effect of CRR auction revenues on the total cost to serve load borne by a QSE, see Figure A5 in the Appendix.

To examine the variation more closely in zonal real-time energy prices, Figure 10 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2021 for the four zones. Compared to the other zones, both low and high prices in the West zone were noticeably different in 2021, continuing a pattern seen in 2020. The lowest prices in the West zone were much lower than the lowest prices in the other zones and the highest prices in the West zone were also generally higher than high prices in the other zones. The differences on both ends of the curves can be explained by the effects of transmission congestion. Constraints limiting the export of low-priced wind and solar generation to the rest of the state explain low prices, whereas localized constraints limiting the flow of electricity to the increasing oil and gas loads in the West explain the higher prices, typically in times where wind and solar energy resource output is low.

Figure 10: Zonal Price Duration Curves



For additional analysis of price duration curves, see Figure A6 and Figure A8 in the Appendix.

C. Evaluation of the Revenue Neutrality Allocation Uplift

As shown in the all-in price analysis above, uplift costs increased substantially in 2021. However, this was not due to higher Revenue Neutrality Allocation Uplift (RENA, further described below), which decreased in 2021 to less than $1 million (less than $0.01 per MWh), down from $75 million ($0.20 per MWh) in 2020 (RENA would be about $57 million in 2021 but for the effects of February, representing what would otherwise be a drop of 24% from 2020). We evaluate the drivers of RENA in this subsection.

In general, RENA uplift occurs when there are certain differences in power flow modeling between the day-ahead and real-time markets. These factors include:

- Transmission network modeling inconsistencies between the day-ahead and real-time market (Model Differences);
- Differences between the load distribution factors used in day-ahead and the actual real-time load distribution (LDF Contribution);
- Day-ahead Point-to-Point (PTP) obligations linked to options[46] 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 11 provides an analysis of RENA uplift in 2021, separately showing the components of RENA on a monthly basis, with the effects of Winter Storm Uri included. Net negative uplift represents an overall payment to load.

Almost all the RENA uplift occurred in market hours when there was transmission congestion. The largest positive contributor to RENA uplift in 2021 was the LDF Contribution, contributing $120 million. The next largest positive contributor was CRR Uplift, related to NOIE PTP Options. Uplift from the contributions of transmission model differences between day-ahead and real-time, described as Model Differences, was mostly negative in 2021, with the most notable contribution in February during Winter Storm Uri. The negative and positive uplift almost completely offset each other over the course of the year, leaving less than $1 million in net overall RENA.

[46] A Point-to-Point obligation linked to an option (PTPLO) is a type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation in the DAM 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 11: ERCOT RENA Analysis (with Uri)

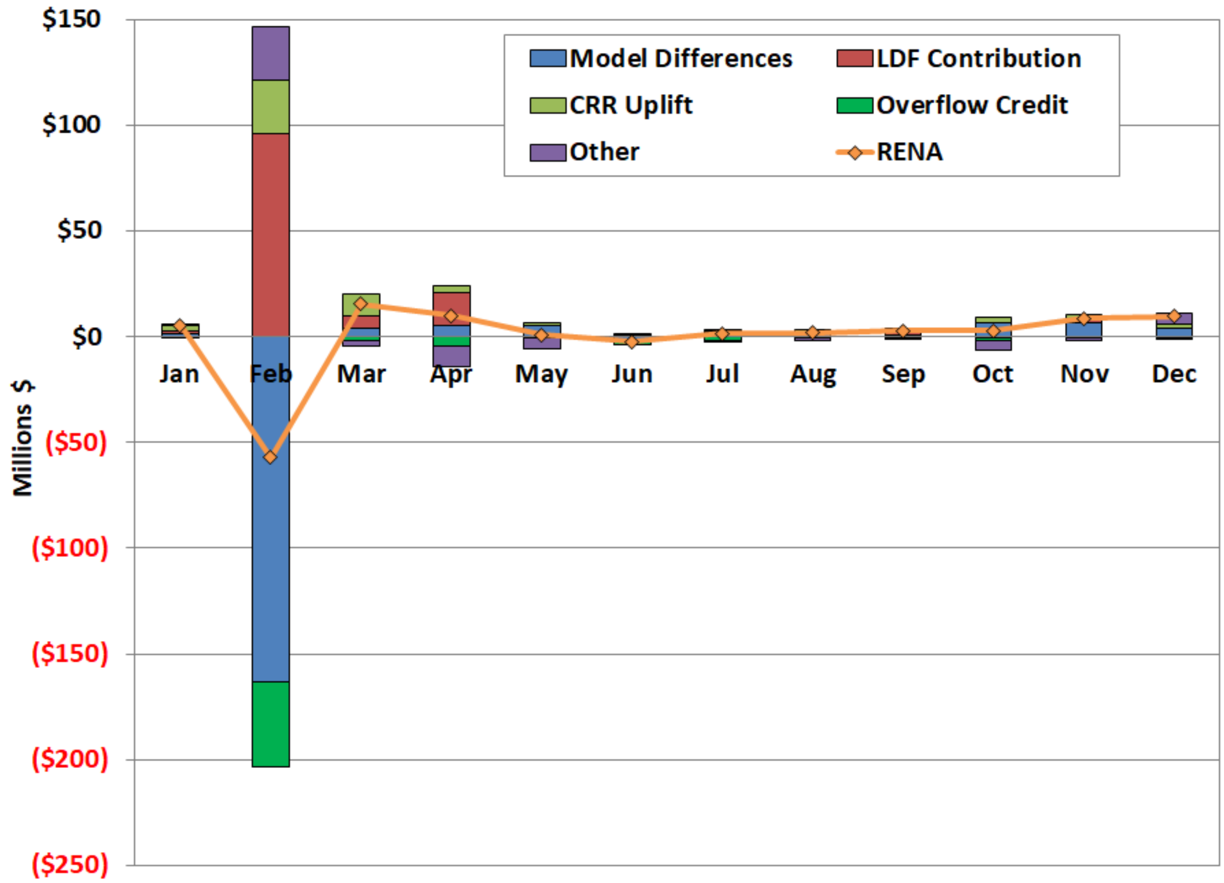
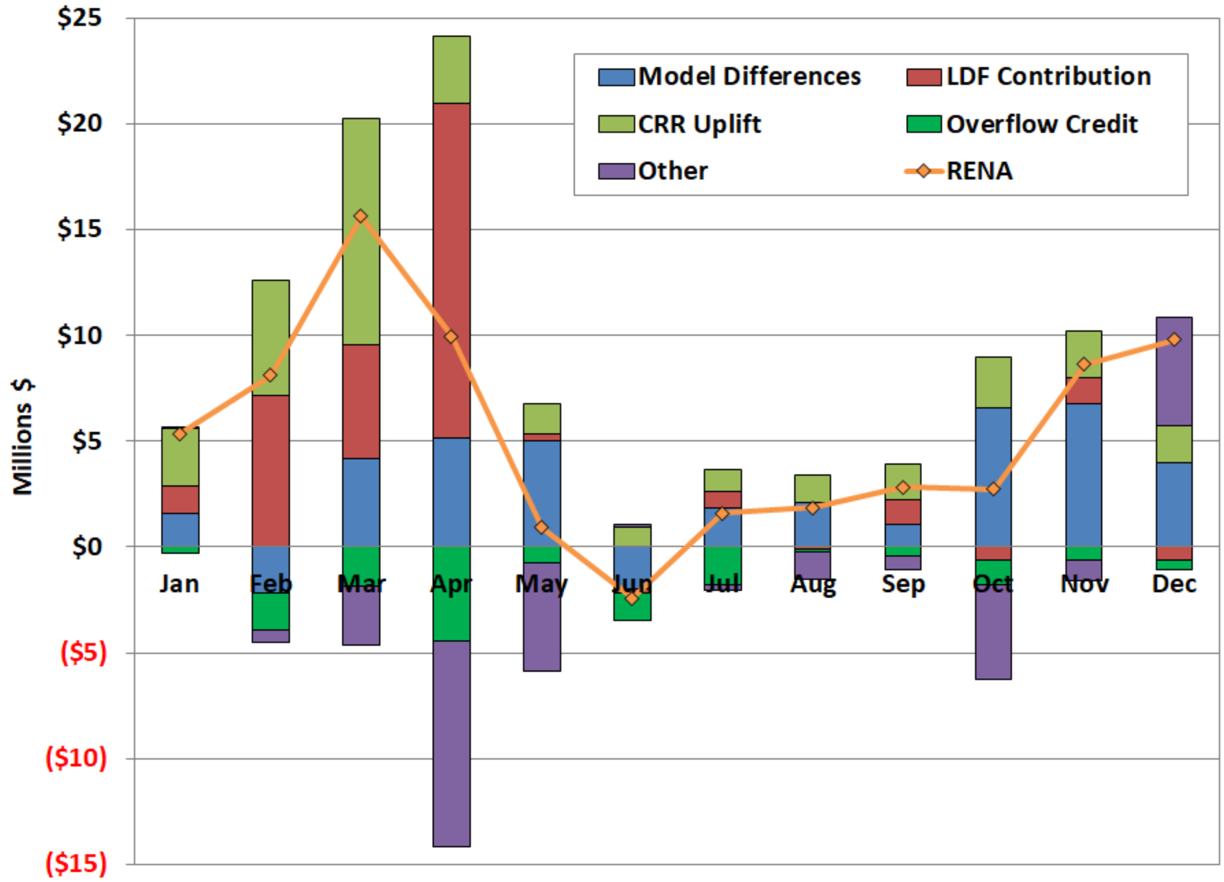


Figure 12 below provides an analysis of RENA uplift in 2021, separately showing the components of RENA on a monthly basis, without the effects of Winter Storm Uri included. Under this analysis, the largest contributors to RENA uplift in 2021 were due to oversold amounts in the DAM, contributing $66 million, and model differences, contributing $34 million. These uplift costs were partially offset by $15 million in negative uplift related to overflow credits when the shadow price reached the shadow price cap for a transmission constraint, and other negative uplift of $21 million.

Figure 12 also shows that RENA uplift from the settlement of DAM PTP obligations linked to options, described as CRR Uplift, was relatively high in March, and the uplift from transmission modelling differences was high in October and November.

Figure 12: ERCOT RENA Analysis (without Uri)



The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict accurate load distribution factors across all markets, RENA impacts will persist. NPRR1004, *Load Distribution Factor Process Update*, (approved on August 11, 2020) is still pending an implementation date and should help reduce this uplift.

D. 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, an "implied marginal heat rate" is calculated by dividing the real-time energy price by the natural gas price. Figure 13 and Figure 14 show the implied marginal heat rates monthly in each of the ERCOT zones with and without the effects of Winter Storm Uri. This figure is the fuel price-adjusted versions of Figure A3 and A4 in the Appendix.

Figure 13: Monthly Average Implied Heat Rates (with Uri)

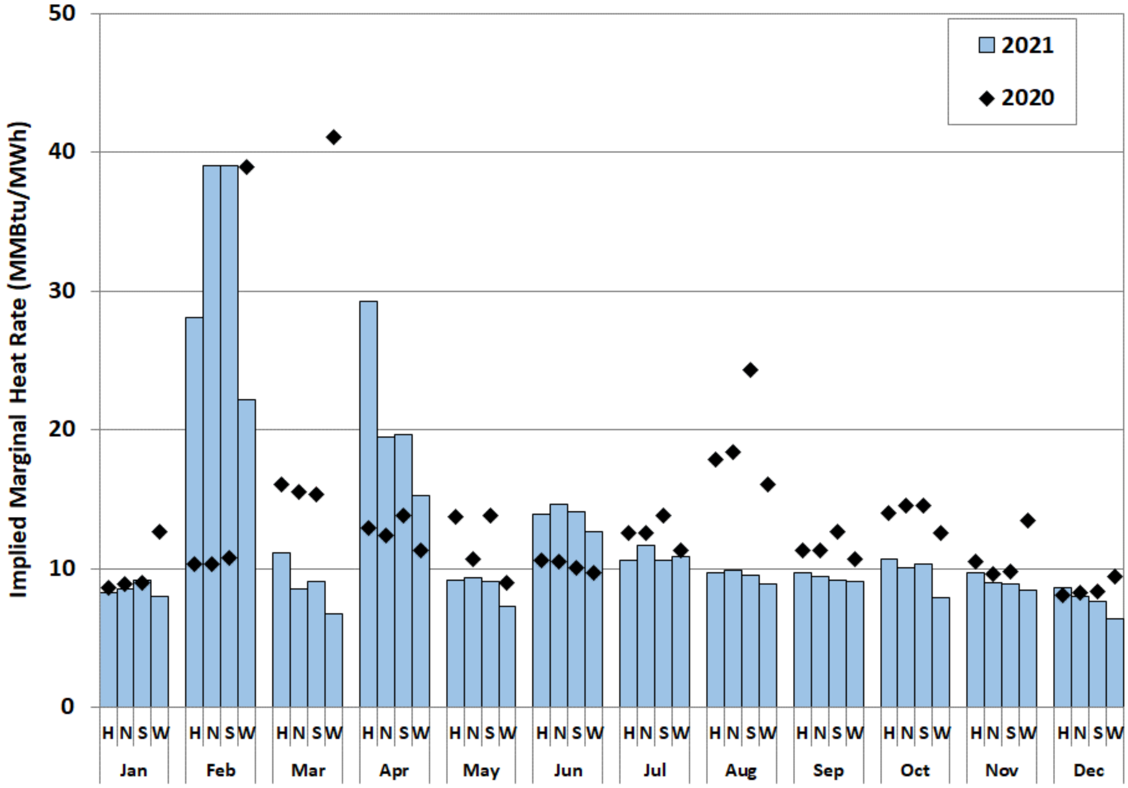
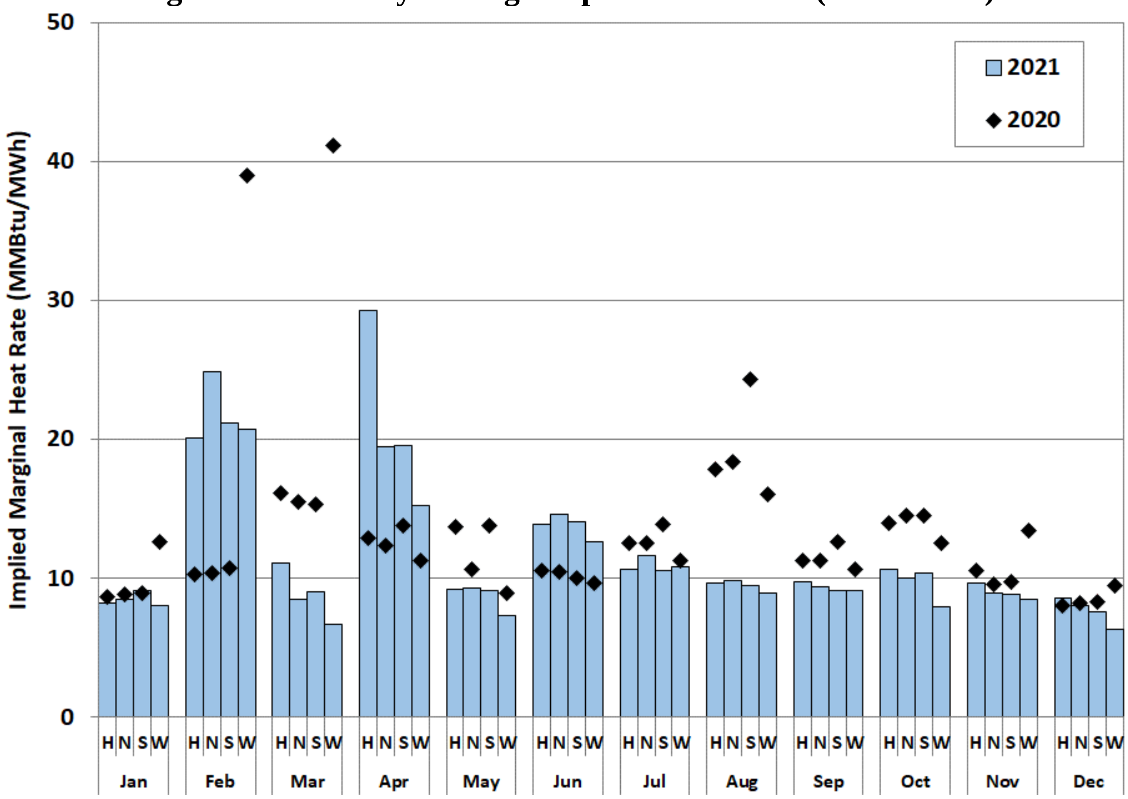


Figure 14: Monthly Average Implied Heat Rates (without Uri)

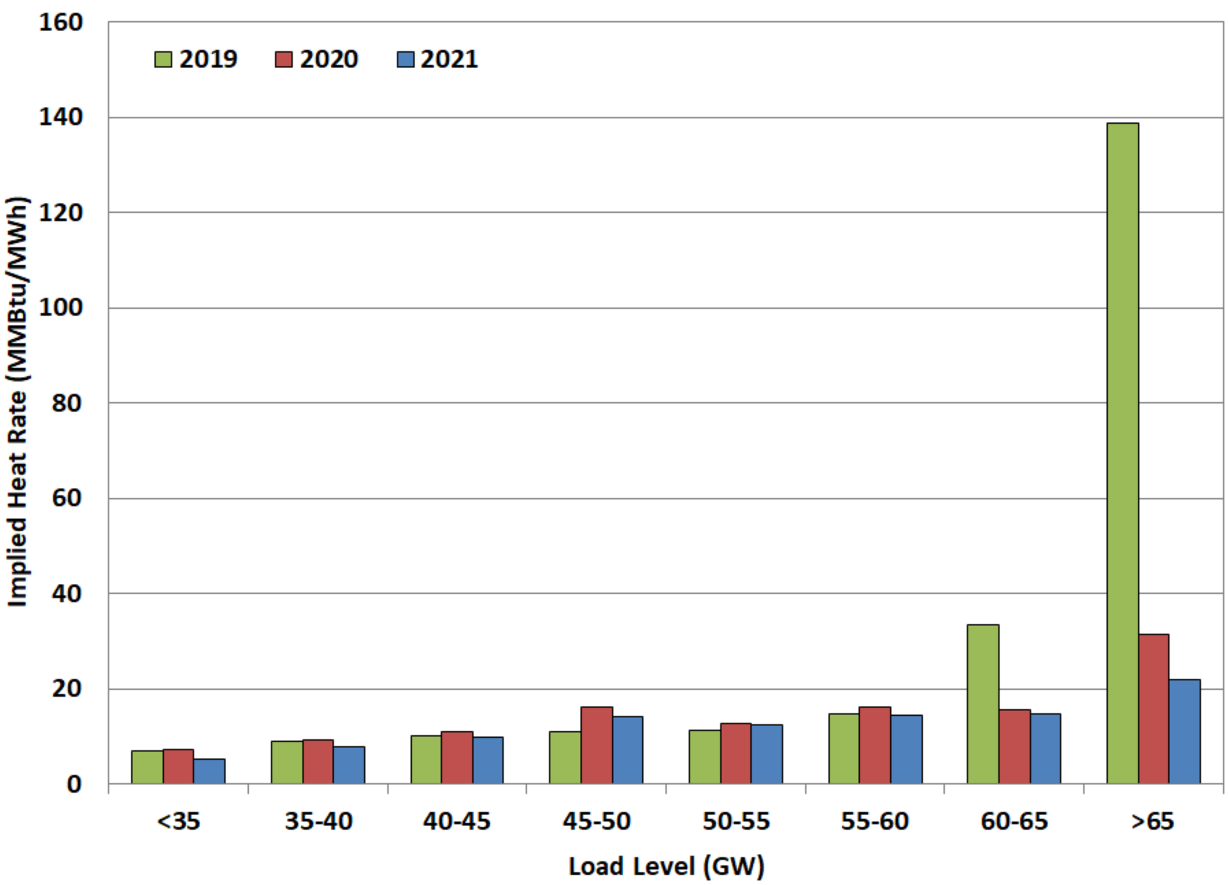


The implied heat rate varied substantially among zones in 2021, particularly in February as extreme cold weather led to high load levels and prices. Transmission congestion and differences in load levels drove zonal differences, particularly for the Houston and West zones in February and April 2021. Overall, average implied heat rates were as expected for a year with periods of extreme operating reserve shortages in February and minimal reserve shortages during the summer.

The implied heat rate is mostly lower than 2020 when the effects of the extreme cold weather of February are removed from the analysis, especially during the second half of the year. This can be attributable to more coal output due to the high natural gas prices, as well as the effect of more conservative operations in the latter half of the year.

Figure 15 shows how the implied heat rate varies by load level over the past three years. As expected in a well-performing market, 2021 exhibited a positive relationship between implied heat rate and load level, though the magnitude of the change is somewhat lower than the previous few years. Resources with higher marginal costs were dispatched as load approached peak. For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A9, Figure A10, and Table A2 in the Appendix.

Figure 15: Implied Heat Rate and Load Relationship



E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2021 to that offered in 2020. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 16 provides the average aggregated generator offer stacks for the entire year, as well as the peak load hour of the year.

This figure shows that in both periods, as in previous years, the largest amount of capacity is not dispatchable because it is below generators' Low Sustainable Limit (LSL) and is a price-taking portion of the offer stack. The second largest share of capacity is priced at levels between zero and a value equal to 10 times the daily natural gas price (known as the Fuel Index Price, or FIP): $(10*FIP). This price range represents the incremental fuel price for the vast majority of the ERCOT generation fleet.

Figure 16: Aggregated Generation Offer Stack - Annual and Peak

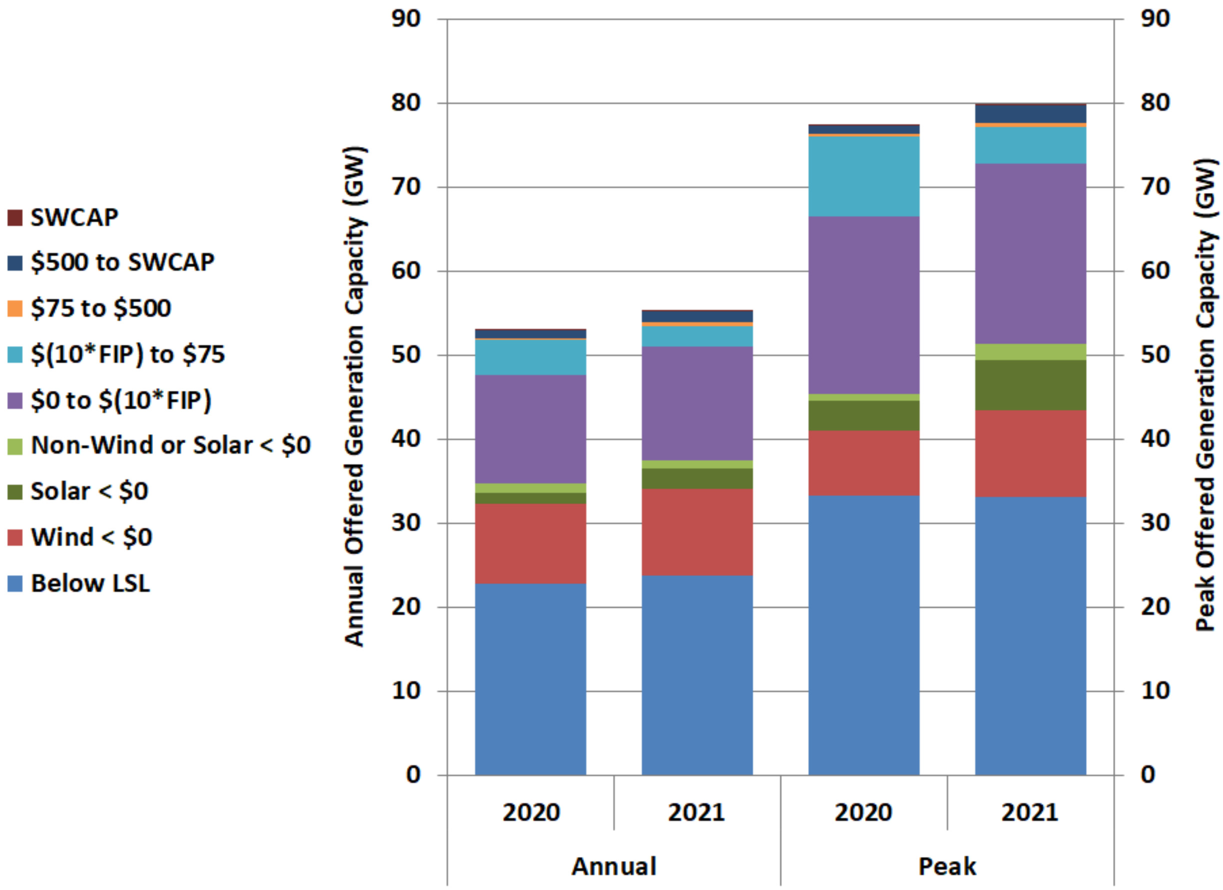


Figure 16 shows that in 2021, on average:

- The amount of capacity offered below LSL increased by about 1,000 MW
- The amount of capacity offered at prices less than zero attributable to wind and solar increased by approximately 1,900 MW.

- Non-wind and non-solar capacity offered at less than zero decreased by about 140 MW;
- Approximately 600 MW more capacity was offered between $0 and $(10*FIP);
- The amount of capacity offered at prices between $(10*FIP) and $75 per MWh decreased by 1,800 MW from 2020 to 2021; and
- The amount of capacity offered between $75 per MWh and the SWCAP increased by about 799 MW
- The total amount of generation capacity offered into ERCOT's real-time market increased by over 2,200 MW in 2021.

Figure 16 also shows that the changes in the aggregated offer stacks between the peak load hours of 2020 and 2021 were relatively consistent with those in the annual aggregated offer stacks for those years. In comparison to the 2020 peak load hour, in the 2021 peak load hour:

- The amount of capacity below LSL decreased by about 80 MW.
- The amount of capacity offered below $0 per MWh by wind and solar generators increased by about 5,000 MW.
- The amount of capacity offered below $0 per MWh by non-wind and non-solar generators increased by about 1,100 MW.
- Approximately 150 MW more capacity was offered between $0 and $(10*FIP).
- Approximately 4,900 MW less capacity was offered between $(10*FIP) and $75 per MWh.
- Approximately 1,200 MW more capacity was offered between $75 per MWh and SWCAP.
- The aggregate offer stack increased by approximately 2,500 MW from the previous year.

F. ORDC Impacts and Prices During Shortage Conditions

The Operating Reserve Demand Curve (ORDC) represents the reliability costs or risks of having a shortage of operating reserves. When resources are not sufficient to maintain the full operating reserve requirements of the system, the probability of "losing load" increases as operating reserve levels fall. This VOLL leads to efficient shortage pricing as it is reflected in both operating reserves and energy prices during shortages.

The Public Utility Commission directed ERCOT to move forward with implementing ORDC on September 12, 2013, including setting VOLL at $9,000 per MWh. Selected at the time as an easier-to-implement alternative to real-time co-optimization of energy and ancillary services, the ORDC places an economic value on the reserves being provided in real-time, with separate pricing for online and offline reserves. In 2019, the Commission approved a phased process to change the ORDC and directed ERCOT to use a single blended ORDC curve and implement a

0.25 standard deviation shift in the LOLP calculation implemented on March 1, 2019. The second step, consisting only of an additional 0.25 standard deviation shift in the LOLP calculation, was implemented on March 1, 2020.[47]

Effectively, these shifts accelerated the increase in prices toward VOLL at higher reserve levels. The changes made in 2019 and 2020 increased costs to load but also provided incentives for maintaining higher operating and planning reserves. These changes were in place throughout 2021, including during Winter Storm Uri in February 2021.

In the aftermath of Winter Storm Uri, the Commission further refined the ORDC. Effective January 1, 2022, the Minimum Contingency Level (MCL) was set at 3,000 MW and the HCAP and VOLL were reduced from $9,000 per MWh to $5,000 per MWh.[48]

The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. Figure 17 shows the number of hours in which the operating reserve adder affected prices in each month of 2021, and the average price effect in these hours and all hours. This figure shows that in 2021, the operating reserve adder had the largest price impacts in February because of Winter Storm Uri and the extreme shortage conditions that occurred. The contribution from the operating reserve adder in 2021 was much higher than in 2020 because of the significant increase in shortage conditions.

The figure shows that April and June also had average operating reserve adders over $1, and there were minimal average adders in the remaining months of the year. Overall, the operating reserve adder contributed $8.32 per MWh, or approximately 5% of the annual average real-time energy price of $167.88 per MWh in 2021. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, like the market experienced in 2019 and 2021.

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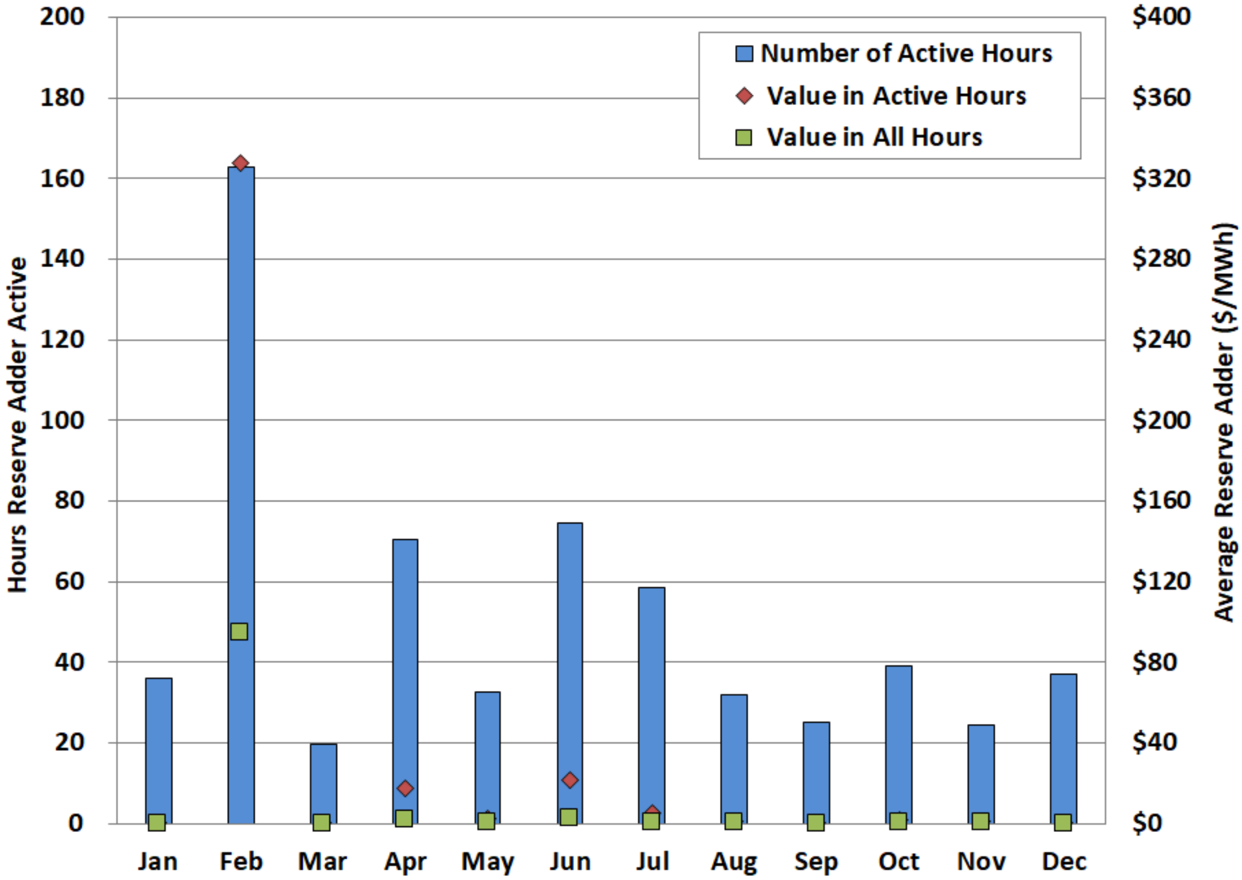
47 The ORDC changes were approved by the ERCOT Board of Directors at its February 12, 2019, meeting and implemented via OBDRR011, *ORDC OBD Revisions for PUC Project No. 48551*.

48 After a series of rigorous public work sessions and review of volumes of comments filed by market participant, the Commission directed ERCOT to address short- and long-term electric grid reliability concerns by enacting major reforms (see *Review of Wholesale Electric Market Design*, Project No. 52373 (pending)), at the December 16, 2021, open meeting. Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021, including the ORDC changes.

Figure 17: Average Operating Reserve Adder (with Uri)

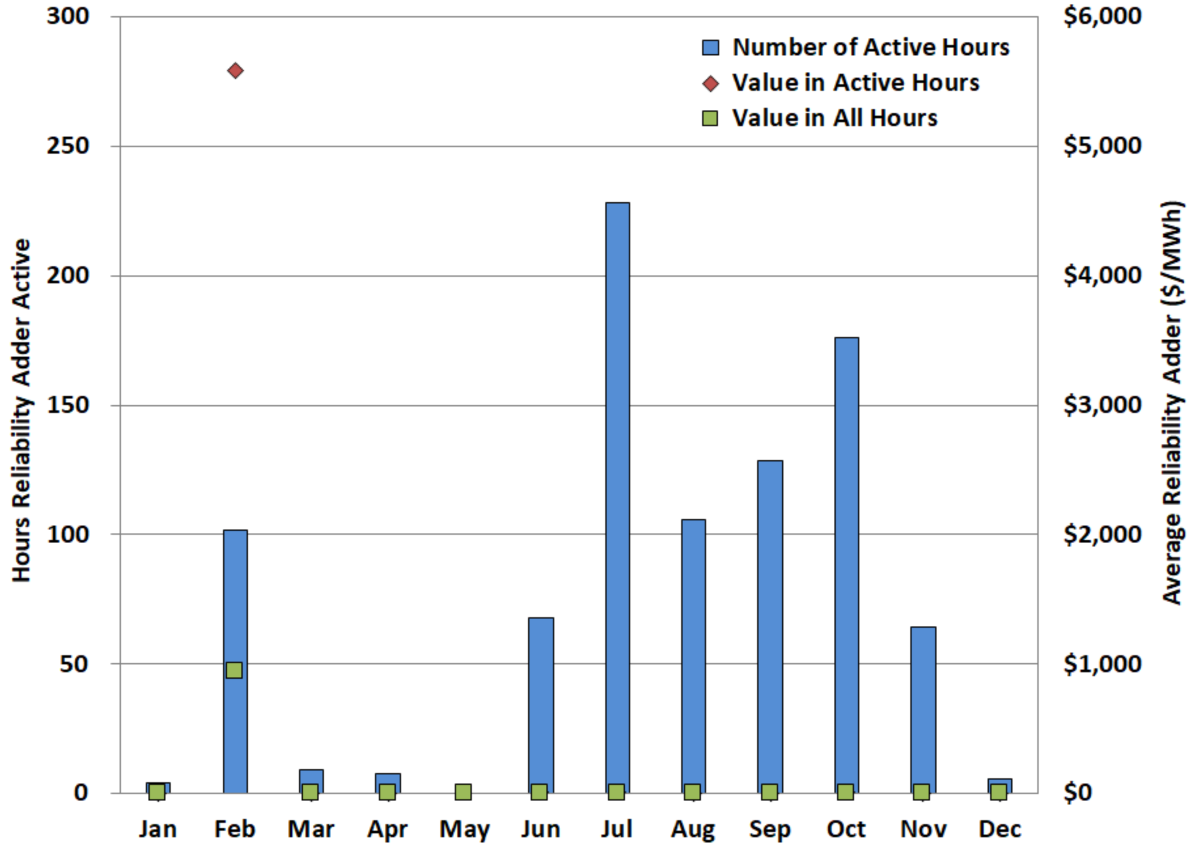


The second adder is the reliability adder. The reliability adder is intended to mitigate the price-suppressing effects of reliability actions taken by ERCOT, including RUCs and deployed load capacity. Absent this adder, prices will generally fall when these actions are taken because they increase supply or reduce demand outside of the market.

Figure 18 below shows the impacts of the reliability adder in 2021. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during February. The reliability adder was non-zero for 10.2% of the hours in 2021.

The highest contribution to the real-time energy price besides February were in June, July and October because of the evolution of ERCOT's more conservative operations after Winter Storm Uri and their increased reliance on RUCs, discussed in Section VI. The contribution from the reliability adder to the annual average load-weighted real-time energy price was almost $80 per MWh, primarily due to the extremely high reliability adders during Winter Storm Uri. Excluding Winter Storm Uri, the reliability adder in February would have been close to zero.

Figure 18: Average Reliability Adder (with Uri)



As an energy-only market, the ERCOT market relies heavily on pricing to provide key economic signals to guide decisions by market participants. However, the frequency and impacts of scarcity can vary substantially from year-to-year, as shown in the figure below.

To summarize the shortage pricing that has occurred since 2011, Figure 19 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2019 through 2021, as well as annual summaries for 2011 through 2021. Figure 20 shows the same analysis excluding Winter Storm Uri.

Figure 19 shows that the duration of high prices in 2021 was far greater than anything the ERCOT market had previously experienced. Prices greater than $1,000 per MWh occurred in about 166 hours in 2021, when they occurred in only 7 hours in 2020. Prices were between $7,000 and $8,999 for nearly 34 hours, and the high system-wide offer cap of $9,000 was reached for intervals totaling more than 64 hours.[49]

Figure 20 shows that prices greater than $1,000 per MWh occurred in just under 20 hours, and never exceeded $5,000 per MWh in any other interval throughout the year.

[49] See *Review of 25.505*, Project No. 52631, (Dec. 2, 2021), in which the Commission reduced the high system-wide offer cap to $5,000 per MWh effective January 1, 2022.

Figure 19: Duration of High Prices (with Uri)

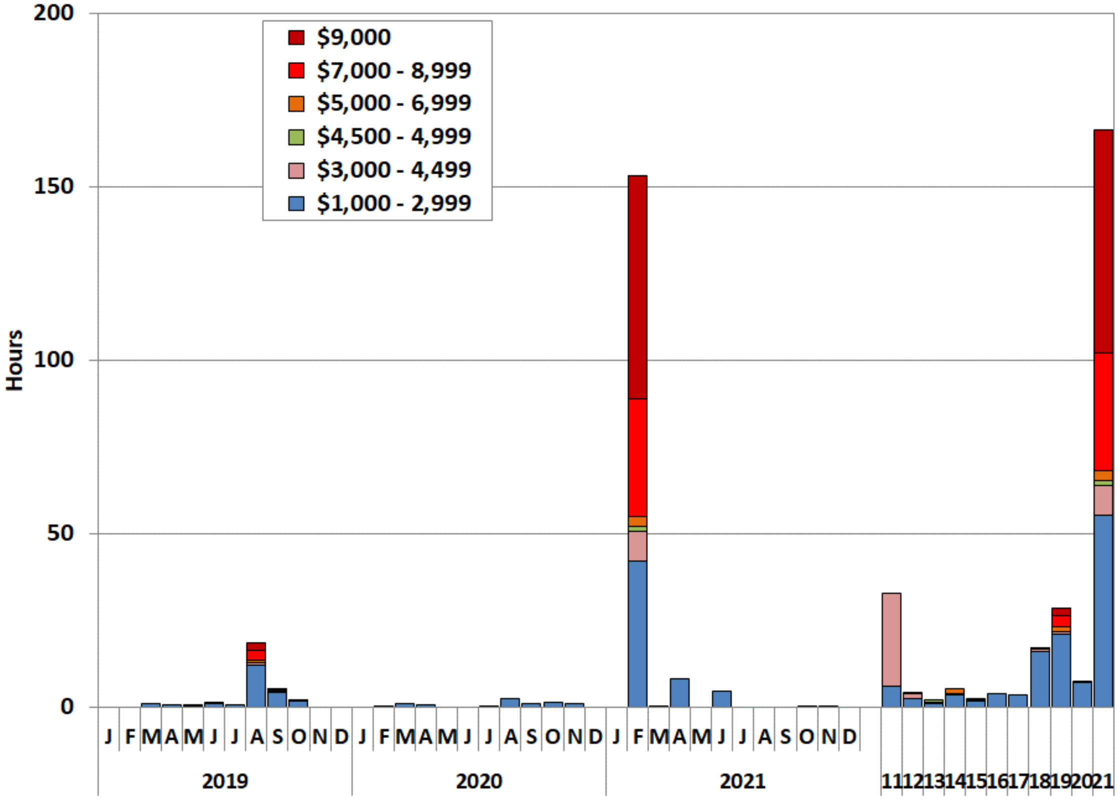
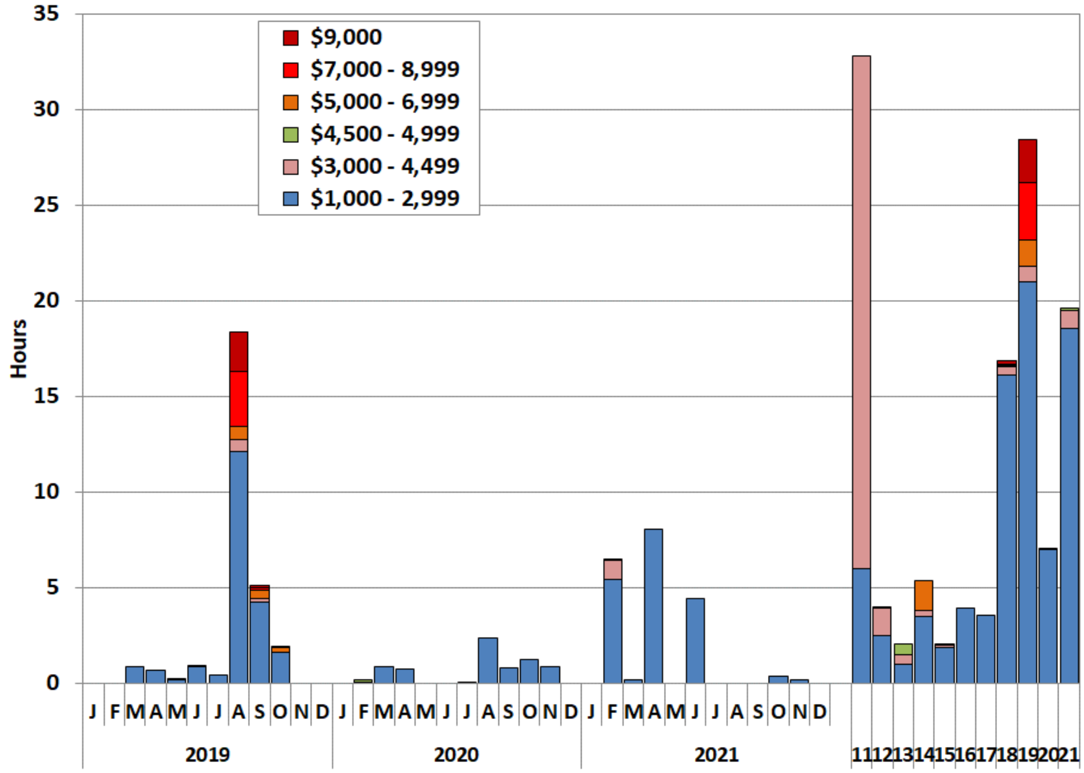


Figure 20: Duration of High Prices (without Uri)



G. Real-Time Price Volatility

To conclude our review of real-time market outcomes, 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 view of price volatility, Table 2 below shows the average 15-minute absolute change in the 15-minute settlement point prices expressed as a percentage of annual average price for the four geographic zones for years 2013-2021. Larger values represent higher deviation from the mean.

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

Load Zone	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021 w/o Uri
Houston	14.8%	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%	8.1%	21.9%
South	15.4%	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%	7.7%	21.1%
North	13.7%	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%	7.4%	20.5%
West	17.2%	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%	7.7%	23.1%

These results show overall volatility dropped markedly in all zones in 2021 when including the period of Winter Storm Uri. This overall decrease is explained by high system-wide pricing during February 2021 which significantly increased the average prices. For comparison, price volatility in 2021 would have been comparable with 2020 without the effects of Winter Storm Uri.

Congestion explains most of the inter-zonal differences in price volatility. Volatility was again highest in the West zone in 2021 because of higher congestion, though not quite as much volatility as seen in 2020. A similar set of factors in 2017 and 2018 caused the South zone to exhibit the highest price volatility in those years.

For additional analysis of real-time price volatility, see Figure A11 and Figure A12 in the Appendix.

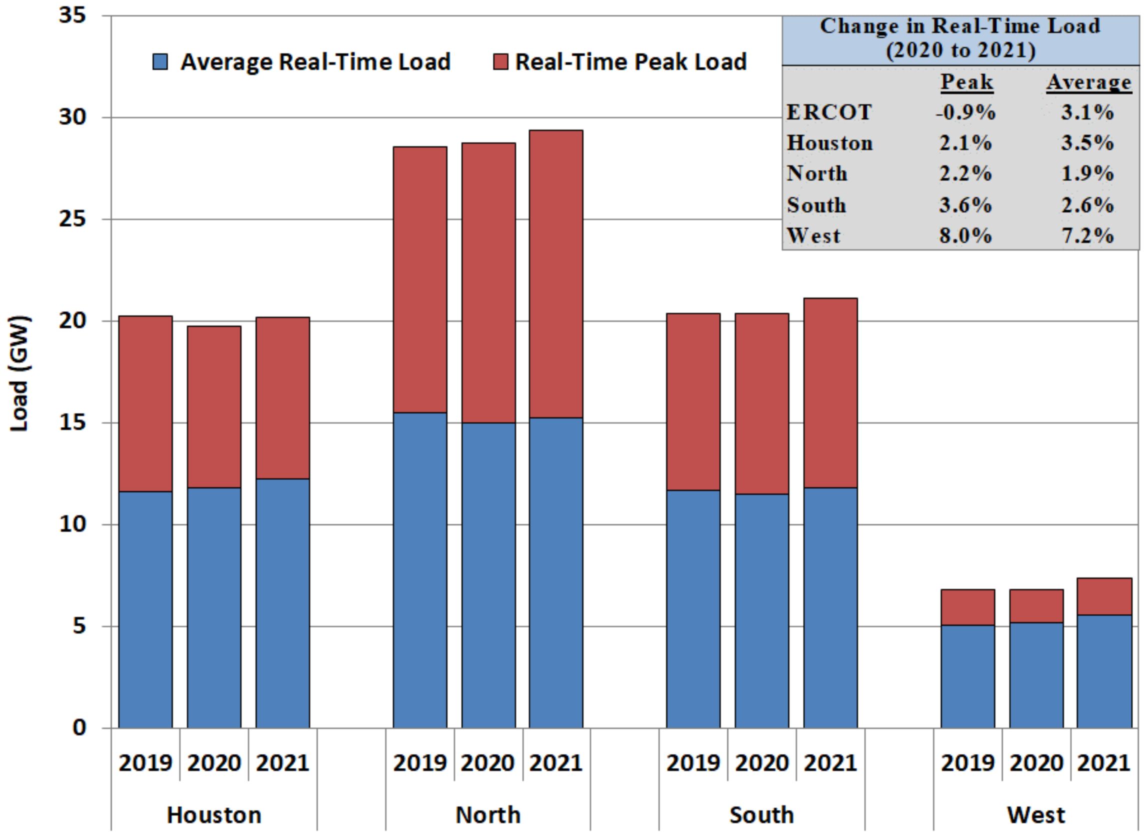
III. Demand and Supply in ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2021. In this section, therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements. 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 2021

We track the changes in average load levels from year to year to better understand the load trends, which captures changes in load over a large portion of the hours during the year. However, changes in the load during the highest-demand hours is important because it affects the probability and frequency of shortage conditions.[50] Figure 21 shows peak load and average load by geographic zone from 2019 through 2021.[51]

Figure 21: Annual Load Statistics by Zone



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

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

Figure 21 shows that the total ERCOT load in 2021 increased over 3% from 2020, which is an increase of more than 1,300 MW on average. The Houston and West zones showed an increase in average real-time load in 2021 ranging from 3.5% in Houston to 7.2% in the West. The increase in the West zone continues a pattern of significant increases seen year over year. Continuing robust oil and natural gas production activity in the West zone has been the driver for high load growth.

Peak demand occurred on August 24, 2021, reaching 73,687 MW between 4 and 5 p.m., lower than the all-time peak demand record of 74,820 MW set on August 12, 2019. Fluctuations in peak and average load are usually driven by summer conditions. Cooling degree days is a measure of weather that is highly correlated with the demand for electricity for air conditioning. In June through August, there was a decrease in Houston, Dallas, and Austin (-3%, -7%, and -11%, respectively) compared to 2020. Cooling degree days is a metric that is highly correlated with summer loads.

A more detailed analysis of the load, via hourly load duration curves, is available in the Appendix in Figure A13 and Figure A14.

B. Generation Capacity in ERCOT

In this section we evaluate the generation portfolio in ERCOT in 2021. The distribution of capacity in the North and South zones is similar to the distribution of demand, and Houston generally imports more power than it generates and the West zone exports more power than it consumes. The Houston zone has increasingly relied on imports from the rest of the state as local resources have been mothballed and the reliance on intermittent resources has increased.

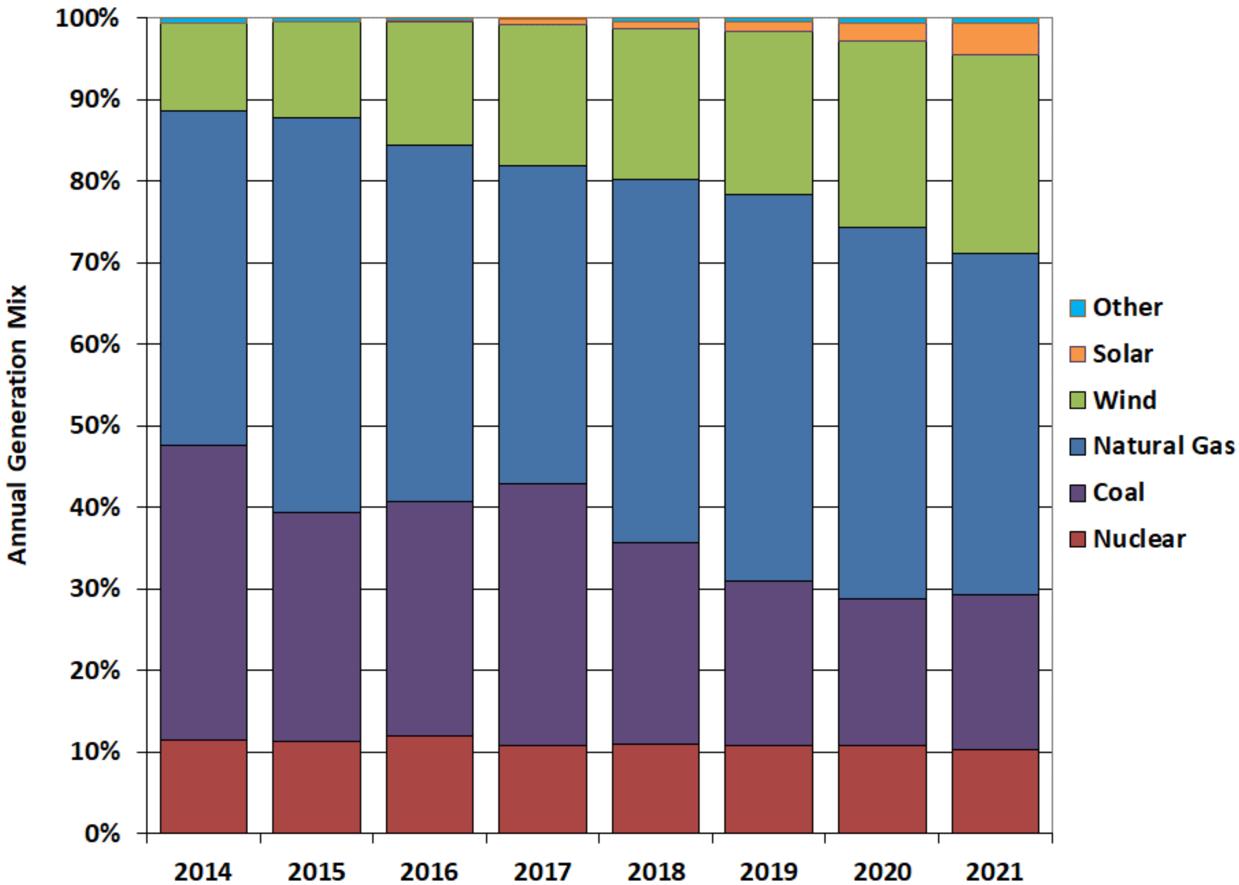
Approximately 8.8 GW of new generation resources came online in 2021. The bulk of this capacity was intermittent renewable resources and the remaining capacity was 660 MW of combustion turbines, 70 MW of combined cycle, and 820 MW of ESRs. ERCOT had roughly 1,800 MW of new installed wind capacity and 2,500 of new installed solar capacity going into summer 2021 compared to summer 2020, with an effective peak serving capacity totaling 2.4 GW.[52] Sixteen gas-fired projects, 36 wind projects, and 26 solar projects came online in 2021. The 24 energy storage projects that came online in 2021 increased ERCOT's storage capacity by about five times to around 1 GW. There were 172 MW of retirements in 2021, including 150 MW wind and 22 MW gas. These changes are detailed in Section V of the Appendix, along with a review of the vintage of the ERCOT fleet.

Figure 22 shows the annual composition of the generating output in ERCOT from 2014 to 2021. This figure shows the transition of ERCOT's generation fleet away from coal-fired resources to

52 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 61% for coastal wind, 19% for other wind, and 80% for solar.

natural gas and renewable resources. Some of this transition has been driven by the vintage of the generating units in ERCOT. For example, 70% of the total coal capacity in ERCOT was at least thirty years old in 2021. 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, and in 2020 and 2021 wind and solar both saw large increase in capacity. The amount of utility-scale solar capacity added in 2021 (3,600 MW) was the largest amount of solar added to the ERCOT system in any given year, bringing total installed capacity to nearly 9,600 MW

Figure 22: Annual Generation Mix in ERCOT



This figure shows:

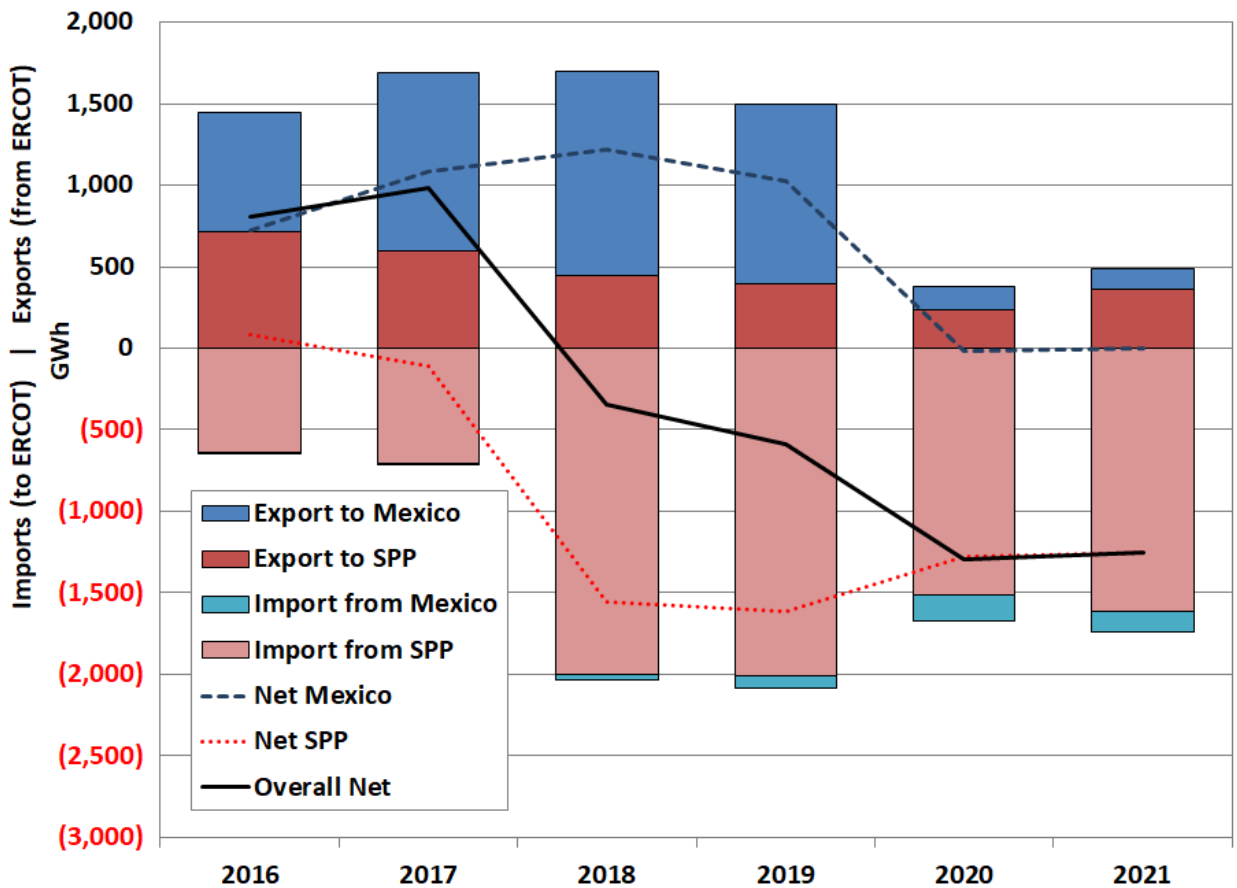
- The generation share from wind has increased every year, reaching over 24% of the annual generation in 2021.
- Solar increased from 2.3% of annual generation in 2020 to 4% of annual generation in 2021.
- The share of generation from coal was similar to 2021.
- Natural gas generation decreased again in 2021, from 46% in 2020 to less than 42% in 2021.

We expect these trends to continue because of the continued growth of wind, solar, and storage resources. Figure A15 in the Appendix shows the vintage of ERCOT installed capacity. The installed generating capacity by type in each zone is shown in Figure A16 in the Appendix.

C. Imports to ERCOT

The ERCOT region is connected to other regions in North America via multiple asynchronous ties. Two ties totaling 820 MW connect ERCOT with the Southwest Power Pool (SPP) and two ties totaling 400 MW connect ERCOT with Comisión Federal de Electricidad (CFE) in Mexico. Transactions across the direct current (DC) ties can be in either direction, into or out of ERCOT. These transactions can have the effect of increasing demand (exports) or increasing supply (imports). Figure 23 shows the total energy transacted across the ties for the past several years.

Figure 23: Annual Energy Transacted Across DC Ties



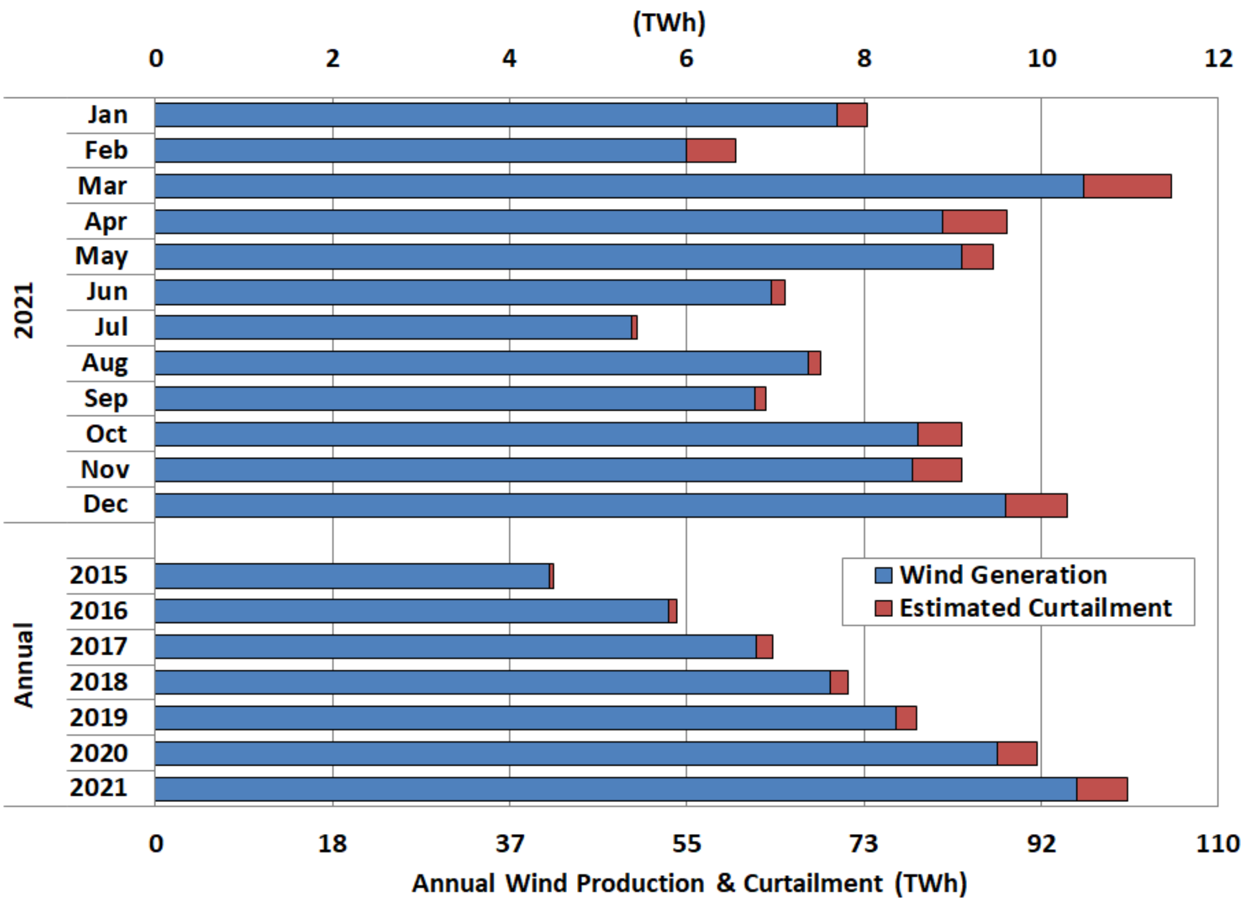
The figure shows that ERCOT remained a net importer in 2021. This trend began in 2018 due to tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. The amount of tie activity in 2021 was comparable to the activity in 2020.

D. Wind and Solar Output in ERCOT

Investment in wind resources has continued to increase over the past few years in ERCOT. The amount of wind capacity installed in ERCOT was more than 34 GW at the end of 2021. Although much of the wind generation is in the West zone, more than 8 GW of wind generation is located in the South zone and 2 GW are in the North zone.

The value of wind in satisfying ERCOT's peak summer demand is limited by its negative correlation with load.[53] The highest wind production occurs during non-summer months, and predominately during off-peak hours. Peak prices ($9,000 per MWh) in August 2019 coincided peak *net* load – when wind output was low and therefore the demand was higher on other generation units. Wind output during high load periods will continue to be a pivotal determinant of shortages.

Figure 24: Wind Production and Curtailment



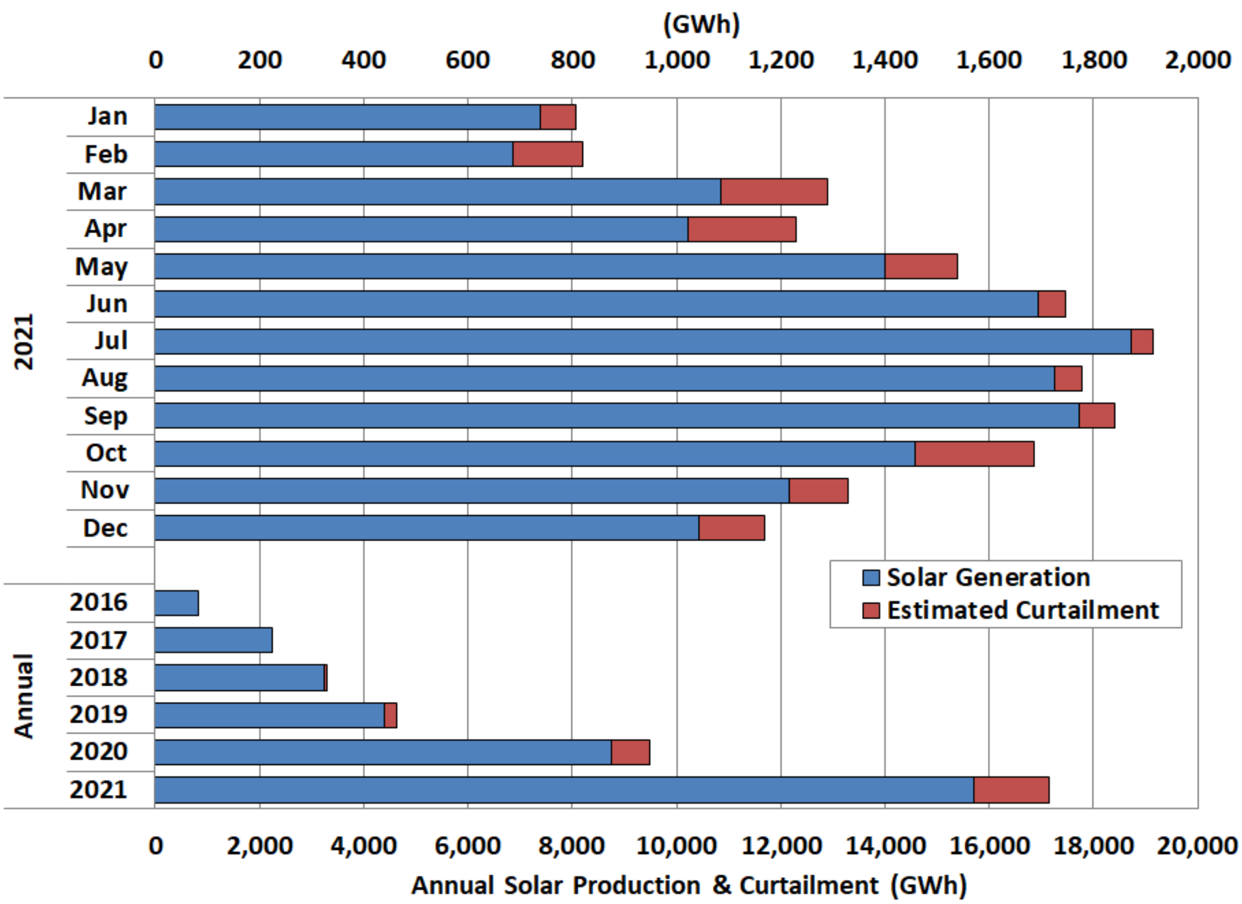
ERCOT continued to set new records for peak wind output. A new wind output record was set on October 21, 2021 (23,657 MW). The amount of power produced by wind resources (24%) continued to outpace coal (19%) in 2021.

53 Wind units in some areas do not exhibit this negative correlation, including the Gulf Coast.

Figure 24 reveals that the total production from wind resources continued to increase in 2021, while the quantity of curtailments implemented to manage congestion caused by the wind resources also increased from the prior year. These curtailments reduced wind output by less than 6%, compared to a peak of 17% in 2009.

Solar resources, although still a smaller component of overall generation than wind today, are positively correlated with load and produce at much higher capacity factors than wind during summer peak hours. The capacity factors during these hours was approximately 69% for facilities located in the west and 54% for those located in other areas of Texas. Hence, these resources provide a larger resource adequacy benefit than wind resources. Figure 25 shows that total solar production in 2021 was 15,700 GW, and an additional 8% was curtailed to manage congestion caused by solar resources.

Figure 25: Solar Production and Curtailment



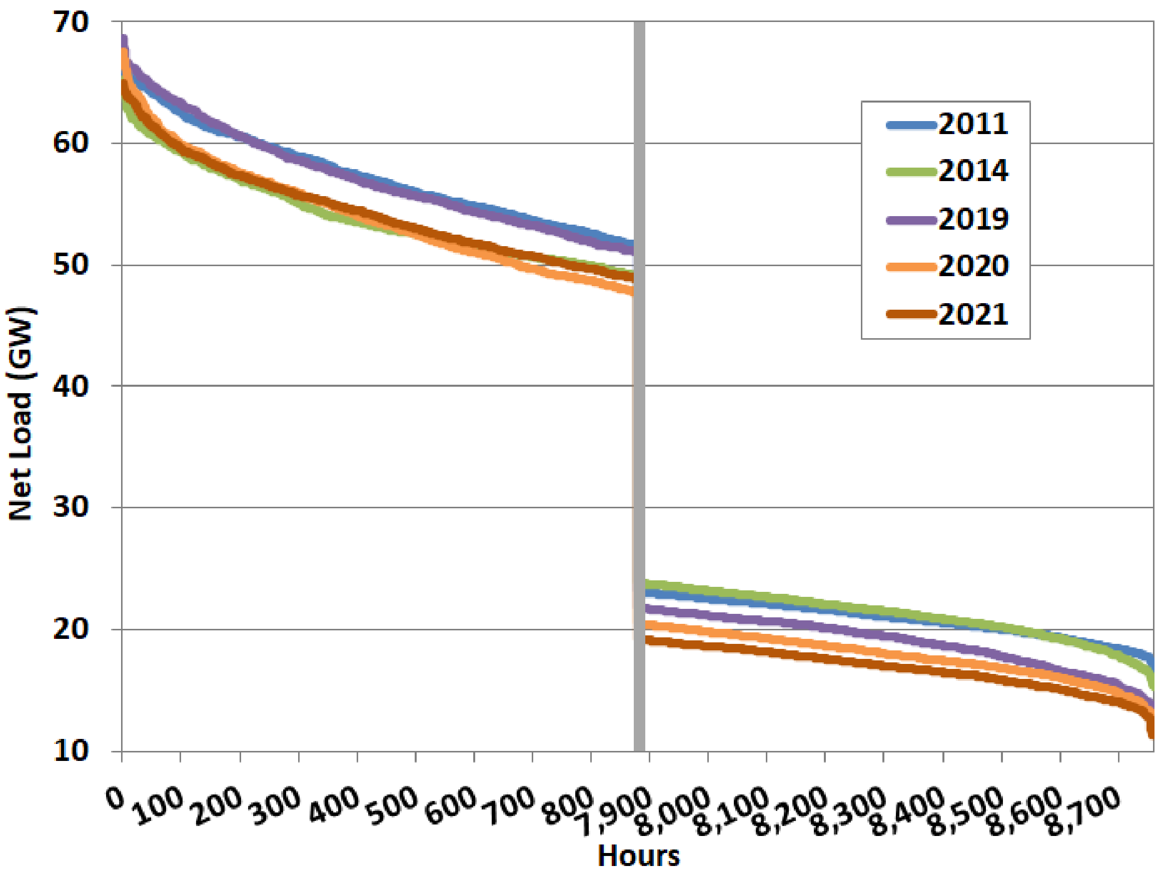
Increasing wind and solar output has important implications for other types of resources, by changing the shape of the remaining load available for them to serve. This also has important implications for resource adequacy in the ERCOT. For additional analysis of wind and solar output in ERCOT, see Figure A17, Figure A18, Figure A19, and Figure A20 in the Appendix.

Figure 26 shows net load in the highest and lowest hours in 2021. Figure 26 shows:

- In the hours with the highest net load (the left panel), the difference between the peak and the 95th percentile of net load was roughly 11 GW in 2021. This means that 11 GW of non-wind and non-solar capacity was needed to serve load in less than 440 hours of the year in 2021.
- In the hours with the lowest net load (the right panel), the minimum net load has dropped from roughly 20 GW in 2007 to about 11.3 GW in 2021, despite the sizable growth in annual average load. This trend has put economic pressure on baseload generation such as nuclear and coal.

For an historical perspective on net load duration curves in ERCOT, see Figure A21 in the Appendix.

Figure 26: Top and Bottom Deciles (Hours) of Net Load



E. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to other 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:

- The responsive reserves market;
- ERCOT-dispatched reliability programs, including ERS that responds prior to the reduction of firm load; or
- Statutorily-mandated demand response programs administered by the transmission and distribution utilities in their energy efficiency programs.

Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges.

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Load relay response can be a highly effective mechanism for maintaining system frequency at 60Hz. 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 (when demand exceeds supply), or they can be manually deployed in EEA Level 2. These events typically occur a very small number of times each year.

As of December 2021, approximately 7,624 MW of qualified NCLRs could provide responsive reserve service, which is an increase of approximately 700 MW during 2021.[54] However, the total amount of responsive reserves procured by ERCOT from load resources was a limited to a maximum of 880 to 1,780 MW per hour.

In 2021, there were two deployments of responsive reserve. The first was a system-wide deployment as a result of Emergency Conditions associated with Winter Storm Uri. The NCLR fleet was deployed at 01:09 on February 15, 2021, and remained deployed until a system recall at 09:05 on February 19, 2021. The initial response showed approximately a 70% response rate, which was short of the 95% requirement. The response rate improved throughout the early hours of the event and by 04:30 was at or above 95% for the remainder of the storm. It should also be noted that even though the deployment event occurred in February there were extended impacts affecting the capacity offered from the NCLRs up to approximately March 10, 2021.[55] There was a second deployment of responsive reserve on November 10, 2021, when two load resources were dispatched due to a Transmission Emergency Condition. Approximately 70 MW of load resource capacity was deployed starting at 11:03. The deployed load resources responded within the 10-minute ramp period and were recalled at 11:38.[56]

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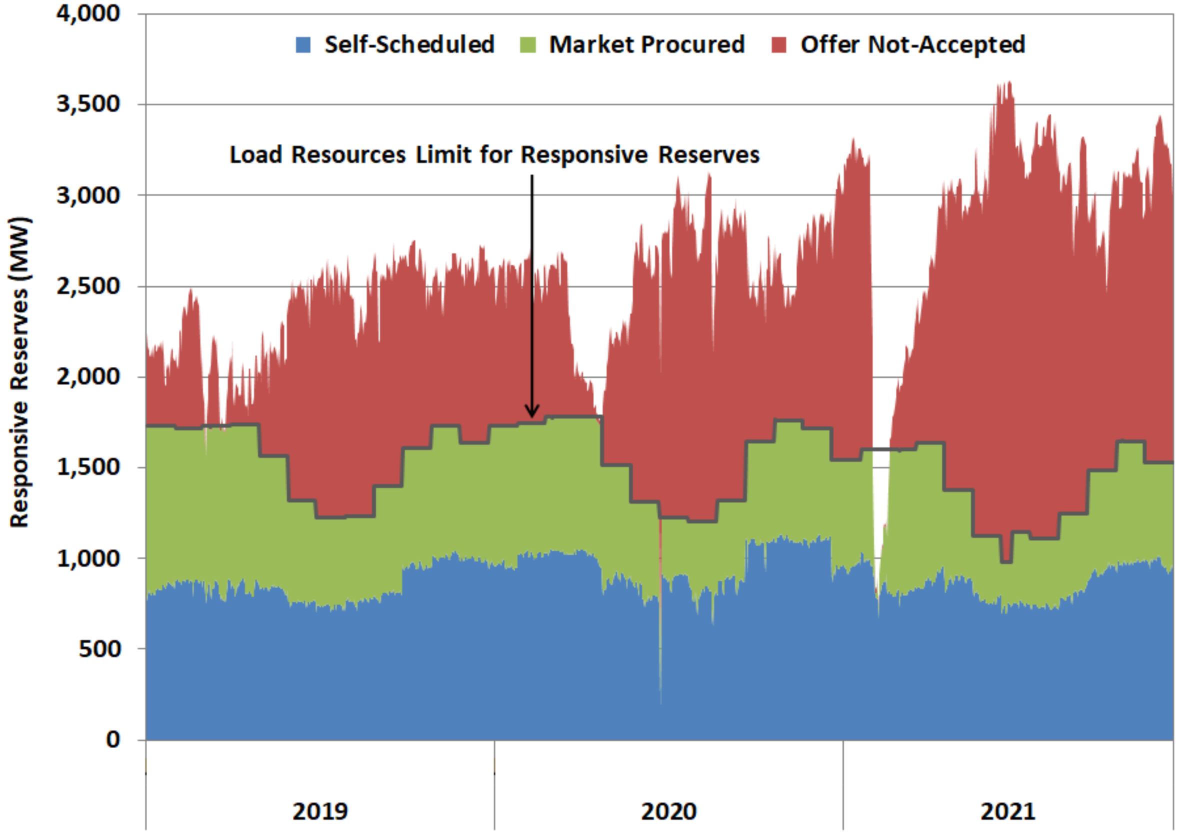
54 *See* ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021), available at http://www.ercot.com/services/programs/load.

55 *Id.*

56 *See* ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021), available at http://www.ercot.com/services/programs/load.

Figure 27 below shows the daily average amount of responsive reserves provided from load resources operating on relays for the past three years.[57]

Figure 27: Responsive Reserves from Loads with High-Set Under Frequency Relays



There were more offers for loads providing responsive reserve than the limit for much of 2021, especially in the summer. The total MWh of surplus offers grew by over 70% from the previous year. Modifying the pricing structure, as discussed in recommendation No. 2019-2 above, would remove the inappropriate incentives that are leading to this oversupply.

2. Reliability Programs

There are two main reliability programs in which demand can participate: i) Emergency Response Service (ERS), administered by ERCOT, and ii) load management programs offered by the transmission and distribution utilities (TDUs). The ERS program is defined by a Commission rule enacted in March 2012, which set a program budget of $50 million.[58] The capacity-weighted average price for ERS over the contract periods from February 2021 through

57 Until June 1, 2018, non-controllable load resources could provide a maximum of 50% of responsive reserves. NPRR815, *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS) Service* increased this cap to 60%, while also requiring that at least 1,150 MW of responsive reserves be provided from generation resources. Beginning with calendar year 2021, NERC standards required an increase in this floor to 1,420 MW. Necessarily, this decreased the amount of capacity that can come from load resources.

58 16 TAC § 25.507.

November 2021 ranged from $4.35 to $6.83 per MWh. This price was lower than the average price paid for both responsive reserves and non-spinning reserves in 2021.

During Winter Storm Uri in February 2021, the majority of the ERS fleet was deployed and exhausted within 12 hours of deployment. The overall ERS fleet generally met or exceeded the aggregate obligation for the duration of the event, although ERS Loads generally over-performed while ERS Generators generally under-performed.59

There were slightly more than 204 MW of load participating in load management programs administered by the TDUs in 2021, which grew to 325 MW in the months of August and September.[60] Energy efficiency and peak load reduction programs are required by statute and Commission rule and most commonly take the form of load management, where participants allow electricity to selected appliances (typically air conditioners) to be curtailed.[61] These programs administered by TDUs may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

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.

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, or 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 that as much as 4,000 MW of load was actively pursuing reduction during the 4CP intervals in 2021, higher than the 2020 estimate.[62]

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59 ERCOT 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021) at 10, available at http://www.ercot.com/services/programs/load.

60 *Id.*

61 *2016 Energy Efficiency Plans and Reports Pursuant to 16 TAC §25.181(n)*, Project 45675; SB 7. Section 39.905(a)(2) (http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007F.htm).

62 *See* ERCOT, 2021 Annual Report of Demand Response in the ERCOT Region (Dec. 2021) at 18, available at http://www.ercot.com/services/programs/load.

Voluntary load reductions to avoid transmission charges are likely distorting prices during peak demand periods because the response is targeting peak demand reductions, rather than responding to wholesale prices. This was readily apparent in 2018 when significant reductions were observed on peak load days in June, July, and August when wholesale prices were less than $40 per MWh. The trend continued in 2019 with reductions in June when prices were only $65 at peak, and even starker in 2020 when prices were less than $35 for each of the four months. In 2021, there were reductions on July, August, and September when prices were less than $80. To address these distortions, we continue to recommend that modifications to ERCOT's transmission cost allocation methodology be explored (see recommendation No. 2015-1 above).

4. Demand Response and Market Pricing

When SCED clears the supply offers to meet the demand, it issues instructions (base points) for resources to follow and it publishes 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. First, the initial phase of "Loads in SCED" was implemented in 2014, allowing controllable loads that can respond to those 5-minute dispatch instructions, or base points, to specify the price at which they no longer wish to consume.

For the first time, there were loads qualified to participate in real-time dispatch. In 2021, three new controllable load resources (CLRs) were registered and added to the ERCOT Network Model. These CLRs consist of data centers that have hundreds of servers that can be turned on and 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 100 MW of online capacity and can participate in responsive reserve service, regulation service, and non-spinning reserve service. This represents the first substantial amount of conventional load to participate in the ancillary services market as a CLR. As this segment grows, implementing nodal pricing for CLRs will become more important and impactful.

Second, the reliability deployment price adder, discussed in more detail in Section I, includes a separate pricing run of the dispatch software to account for reliability actions. The pricing run did not account for firm load shed instructed by ERCOT, which led to prices below the VOLL during the first hours of Winter Storm Uri. The Commission directed ERCOT to account for the firm load shed instructed by ERCOT late on February 15, 2021, and following implementation of that change the pricing run did account for firm load shed. After the storm, NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed*, was approved on June 28, 2021, and it modified the calculation of the reliability deployment price adder so that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to VOLL when ERCOT is directing firm load shed during EEA3.

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

In this section, we examine day-ahead energy prices in 2021 and their convergence with real-time prices. We also review the activity in the DAM, including a discussion of PTP obligations. This section concludes with a review of the day-ahead ancillary service markets.
Overall, 2021 day-ahead prices were higher than 2020 for both energy and ancillary services, as expected given the increased operating shortages. Liquidity in the DAM was similar to previous years, which included active trading of congestion products in the DAM.

Table 3 below compares the average annual price for each ancillary service over the last three years, showing that the prices were orders of magnitude higher for each product in 2021 because of Winter Storm Uri. The increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase from $1.00 per MWh in 2020 to $29.59 per MWh in 2021. We also include the prices without the effect of Winter Storm Uri, and the result shows an increase in prices due to increased procurement of ancillary services.

Table 3: Average Annual Ancillary Service Prices by Service

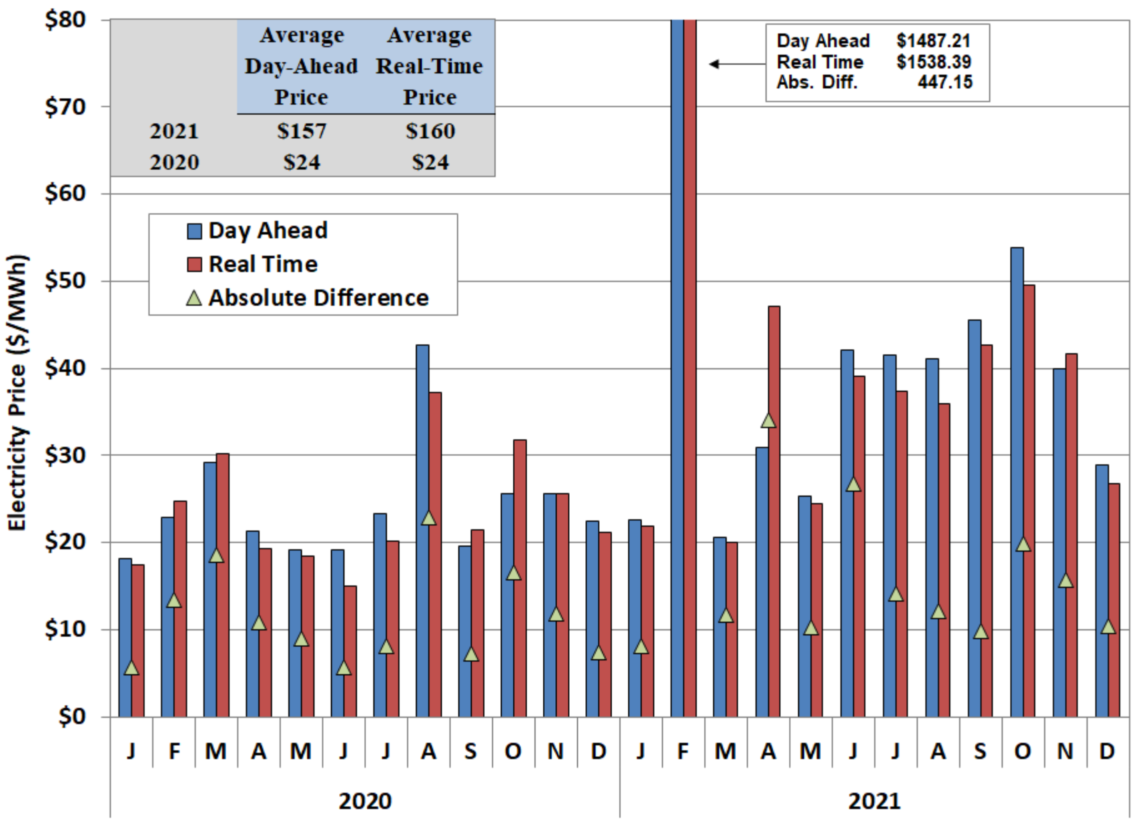
	2019 ($/MWh)	2020 ($/MWh)	2021 ($/MWh)	2021 without Uri ($/MWh)
Responsive Reserve	**$26.61**	**$11.40**	**$331.46**	**$60.57**
Non-spin Reserve	**$13.44**	**$4.45**	**$83.75**	**$21.03**
Regulation Up	**$23.14**	**$11.32**	**$289.84**	**$54.33**
Regulation Down	**$9.06**	**$8.45**	**$120.70**	**$20.08**

A. Day-Ahead Market Prices

Forward markets provide hedging opportunities for market participants. A primary indicator of the performance of any forward market is the extent to which forward prices converge with real-time 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 future real-time prices. These two factors allow participants to arbitrage predictable differences between forward prices and real-time spot prices and bring about price convergence. Price convergence between the day-ahead and real-time markets is important because it leads to improved (more efficient) commitment of resources needed to satisfy the system's real-time needs. In this subsection, we evaluate the price convergence between the day-ahead and real-time markets.

This average price difference between forward prices and real-time spot prices reveals whether persistent and predictable differences exist between day-ahead and real-time prices that participants should arbitrage over the long term. Figure 28 shows the average day-ahead and real-time prices by month for the past two years. It also shows the average of the absolute value of the difference between the day-ahead and real-time price, calculated on a daily basis. This measure captures the volatility of the daily price differences, which may be large even if the prices converge on average.

Figure 28: Convergence Between Day-Ahead and Real-Time Energy Prices (with Uri)

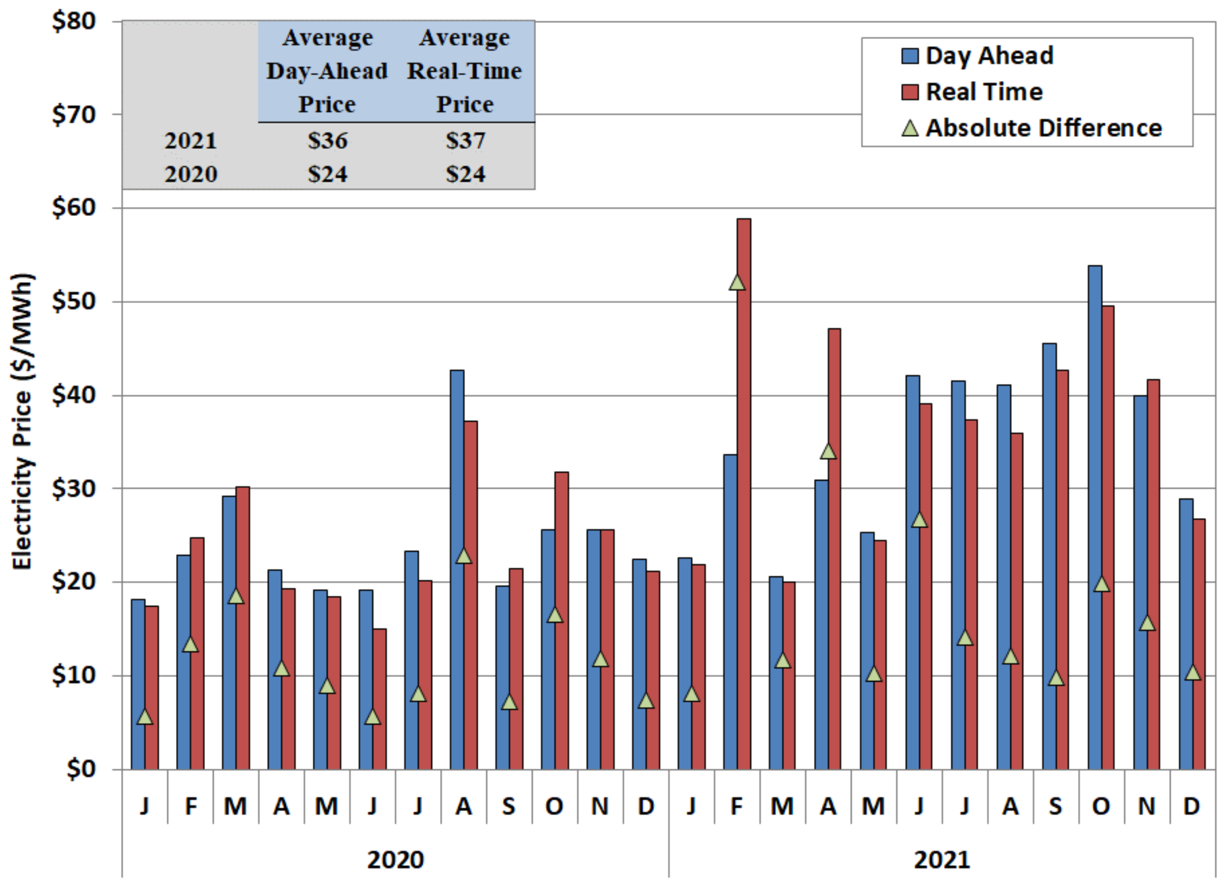


Day-ahead prices averaged $157 per MWh in 2021, while real-time prices averaged $160 per MWh.[63] This divergence was a change from the stability in 2020, which occurred throughout the year but especially in February because of the effects of Winter Storm Uri. The relative instability of real-time prices and persistence of tight conditions increased the risk premium associated with day-ahead hedges.

Price divergence was pronounced in February, April, the summer months and October in 2021, when conditions were tighter, real-time prices were higher, and ERCOT began a more conservative approach to operations, creating less price convergence on average for the year than recent years.

The average absolute difference between day-ahead and real-time prices was $52.70 per MWh in 2021, a sharp increase from $11.60 in 2020, $27.63 MWh in 2019 and $16.21 in 2018, respectively. The largest absolute difference primarily occurred in February, an astonishing $447.15, as expectations were rendered virtually meaningless as shortage conditions resulted in rolling blackouts.

Figure 29: Convergence Between Day-Ahead and Real-Time Energy Prices (without Uri)



63 These values are simple averages, rather than load-weighted averages as presented in Figures 1 and 2.

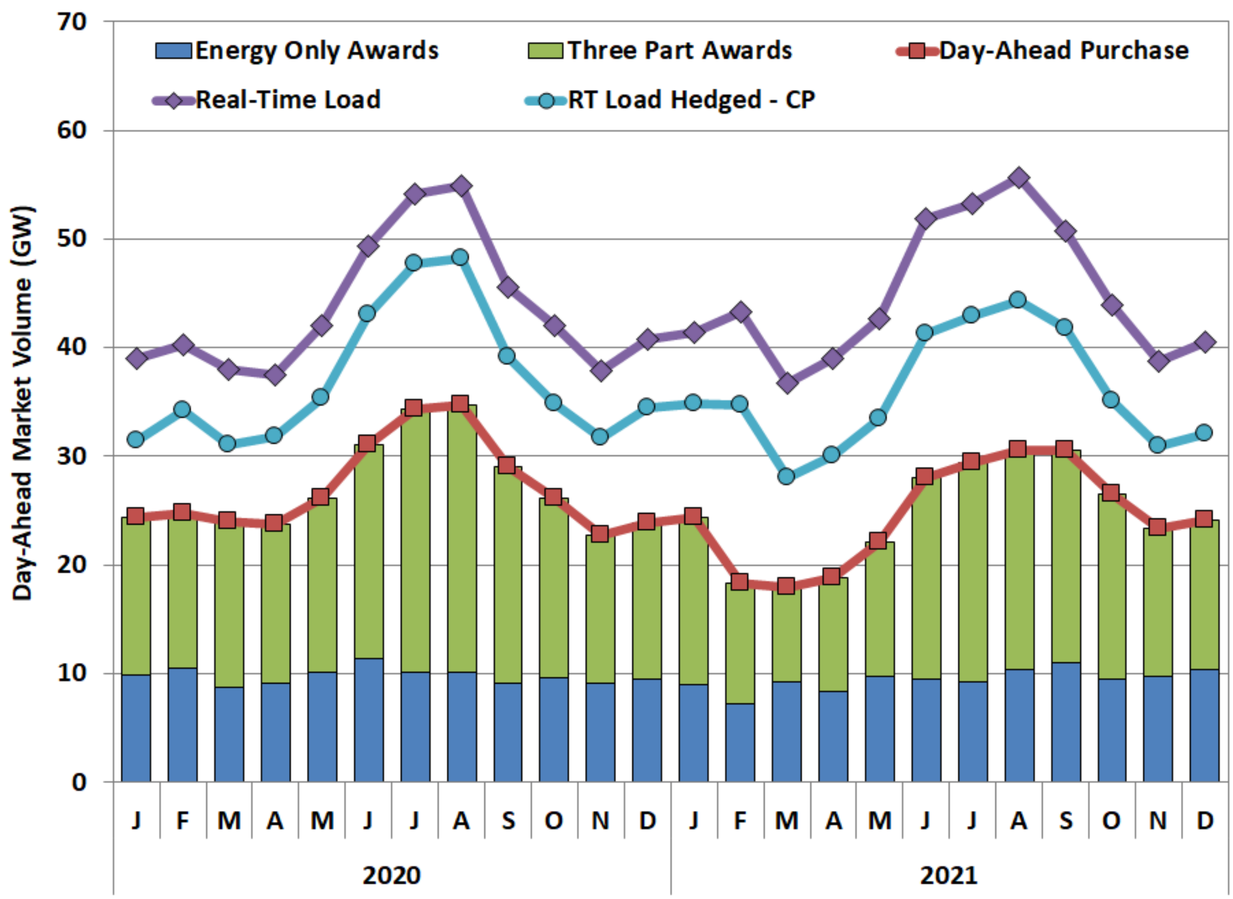
Even without the extreme effects of Winter Storm Uri included, there was significant divergence between day-ahead and real-time prices as demonstrated above in Figure 29. For additional price convergence results in 2020, see Figure A11, Figure A12, and Figure A22 in the Appendix.

B. Day-Ahead Market Volumes

Figure 30 summarizes the volume of DAM 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 30 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 55% of real-time load in 2021, a decrease from 64% in 2020. Although it may appear that many loads are still subjecting themselves to greater risk by not locking in a day-ahead price and instead exposed to real-time volatility, other transactions or arrangements outside the organized market are used to hedge real-time prices. In these cases, often PTP obligations are scheduled to hedge real-time congestion costs to complement those transactions.

Figure 30: Volume of Day-Ahead Market Activity by Month



PTP obligations are financial transactions purchased in the DAM. 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.[64] 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 because the only remaining settlement would correspond to the congestion costs between the locations. 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 been growing quickly in recent years, with important implications for the DAM performance and ability to publish within the protocol timeline. They have increased four-fold over the last decade. According to ERCOT, the highest correlation to DAM performance issues in unawarded PTP obligations bids, i.e., the volume of bids submitted that are unlikely to be awarded is driving the problem.

Because the large and increasing quantities of PTP transactions are the principal cause of the delays, and the delays are costly to the market at large, cost causation principles dictate that PTP volumes bear some of the costs they are causing to provide incentives to resolve the issue. DAM software capability can be thought of as a scarce resource that must be allocated efficiently. Charging no fee for PTP bids allow participants to submit numerous bids that are unlikely to clear and provide very little value to the market. Additionally, they bear no share of ERCOT's administrative expenses even though they are consuming a large portion of the software and supporting resources. Applying a small bid fee to the PTP bids is consistent with cost causation principles and would incent participants to submit smaller quantities of 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 DAM process. In recommendation No. 2020-4 above, the IMM recommends a PTP bid fee as an economically rational way to manage this volume.

Figure 30 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).[65] Although QSEs are the party 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 slightly to 80% in 2021, slightly down from 85% seen in 2020.

The volume of three-part offers comprised less than half of DAM clearing. To determine whether this was due to small volumes of three-part offers being submitted versus three-part

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

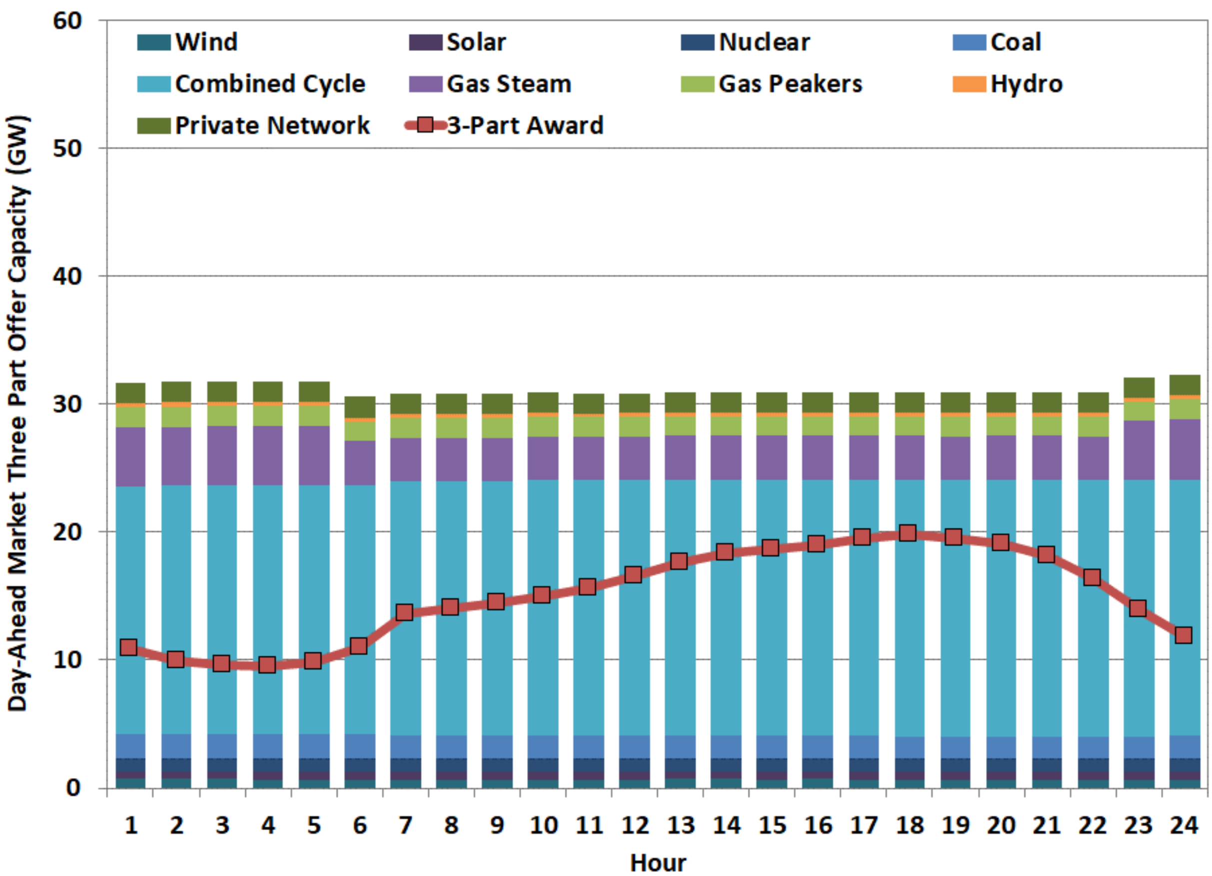
65 To estimate the volume of hedging activity, energy purchases are added to the volume of PTPs scheduled by QSEs with load that source or sink in load zones, then aggregated to the counterparty (CP) level.

offers being cleared, Figure 31 shows the total capacity from three-part offers submitted in the DAM for 2021.

The submitted capacity has been averaged for each month and is shown to be significantly more than the amount of capacity cleared. This is not unusual, given that load in most periods does not require all available generation to be scheduled. The portion of the generation cleared in the peak hours increases as one would expect.

With the largest share of installed capacity, it follows that combined cycle units are the predominant type of generation submitting offers in the DAM. More importantly, because combined cycle units are typically marginal units, offering that capacity into the DAM allows a market participant to determine whether its unit is economic. Conversely, few wind units offer in day-ahead because of uncertainty on whether wind will be available in real-time to cover any award. Further analysis on DAM activity volume can be found in Figure A24 in the Appendix.

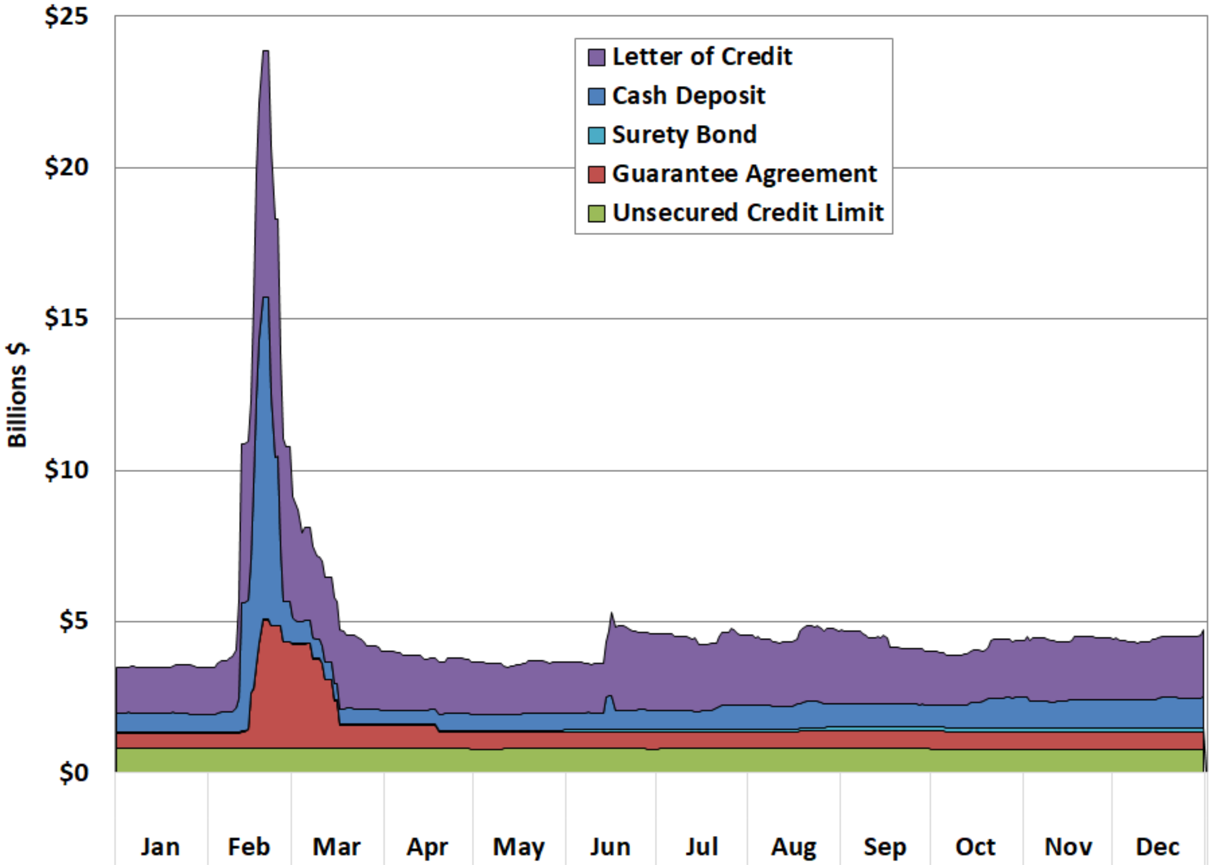
Figure 31: Day-Ahead Market Three-Part Offer Capacity



To participate in ERCOT's DAM, a market participant must have sufficient collateral with ERCOT. The total collateral requirements for 2021, significantly higher than anything seen before due to Winter Storm Uri, are shown below in Figure 32. ERCOT short payments (amounts owed but not paid) during the storm exceeded $3 billion, with several retail electric providers exiting the market and one electric cooperative seeking bankruptcy protection.

Credit requirements are a constraint on submitting bids in the DAM. When the available credit of a QSE is limited, its participation in DAM will necessarily be limited as well. Credit likely represented a barrier to participating in the DAM in February 2021 and into March due to the high requirements.

Figure 32: Daily Collateral Held by ERCOT

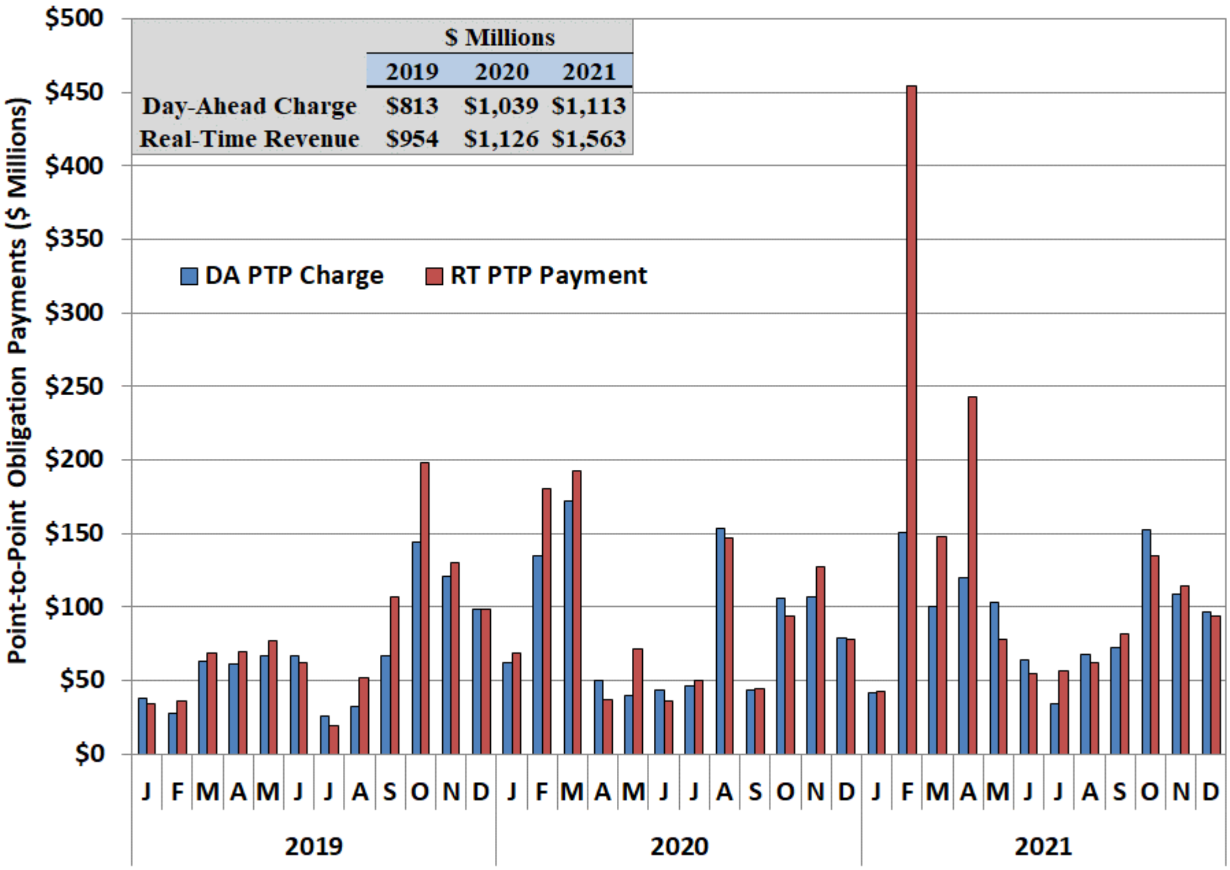


C. Point-to-Point Obligations

Purchases of PTP obligations comprise a significant portion of DAM activity. They are both similar to and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section V, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the DAM.

Participants buy PTP obligations by bidding to pay the difference in prices between two locations in the DAM. The holder of the PTP obligation then receives the difference in prices between the same two locations in the real-time market. Hence, a participant that owns a CRR can use its CRR proceeds from the DAM to buy a PTP obligation between the same two points to transfer its hedge to real-time. Because PTP obligations represent such a substantial portion of the transactions in the DAM, additional details about the volume and profitability of these PTP obligations are provided in this subsection. The first analysis of this subsection, shown in Figure 33, 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.

Figure 33: Point-to-Point Obligation Charges and Revenues



As prices and total congestion costs have increased substantially in recent years, so have the costs and revenues associated with PTP obligations. This trend was reinforced again in 2021. The average volume of PTP obligations has been stable for the past three years from a quantity standpoint, although the numbers of individual transaction submissions have risen.

Figure 33 shows that the aggregated total revenue received by PTP obligation owners in 2021 was greater than the amount charged to the owners to acquire them, as in prior years. This indicates that, in aggregate, buyers of PTP obligations profited from the transactions, and occurs when real-time congestion costs are greater than DAM congestion costs. Profits were spread throughout 2021 (January, February, March, April, July, September and November), accruing when congestion priced in the DAM was lower than the congestion in real time. The profits were highest in February when payments were more than $454 million.

To provide additional insight on the profits that have accrued to PTP obligations, Figure 34 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" in 2021. These are instruments available only to Non-Opt-In Entities and allow them to receive congestion revenue but not have congestion charges. As such, we show them below as "PTP Options," because they are settled as options, not obligations.

Figure 34: Average Profitability of Point-to-Point Obligations

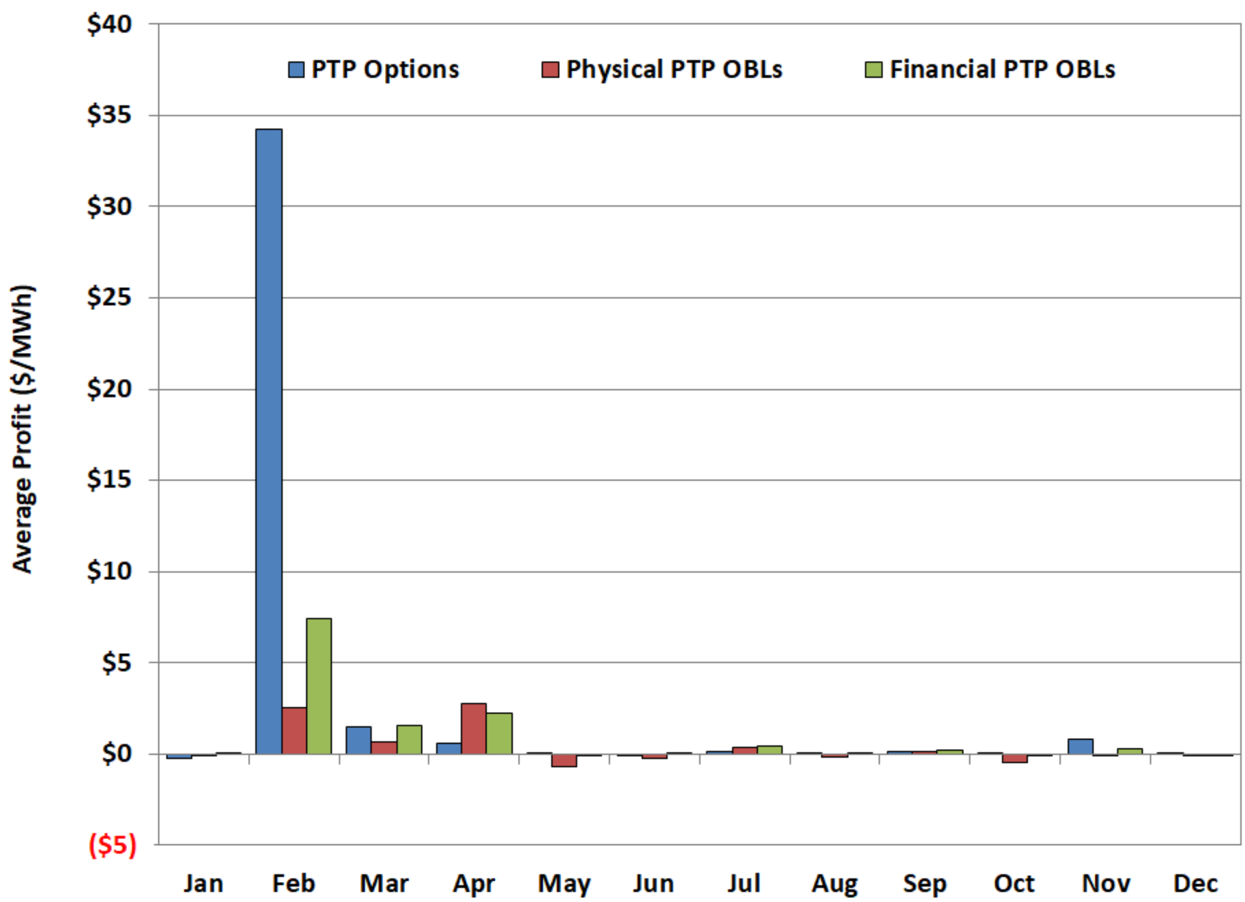


Figure 34 shows that in aggregate, PTP obligation transactions in 2021 were profitable for the year, yielding an average profit of $0.66 per MWh, higher than the average profit of $0.13 per MWh in 2020. PTP obligations were profitable during 2021 for all types of parties, with average profits of $0.33 per MWh for physical parties, $0.93 per MWh for financial parties, and $2.66 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2021, see Figure A25 in the Appendix.

D. Ancillary Services Market

The primary ancillary services are regulation up, regulation down, responsive reserves, and non-spinning reserves. 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, load or wind forecast errors), 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 output and load in balance from moment to moment. The quantity of regulation needed is affected by the accuracy of the supply and demand reflected in the 5-minute dispatch. In late 2021, NPRR1113, *Clarification of Regulation-Up Schedule for Controllable Load Resources in Ancillary Service Imbalance* was sponsored by ERCOT, which would adjust the definitions in Section 6.7.5 of the ERCOT Protocols to prohibit double-counting of the Regulation-Up (Reg-Up) Ancillary Service Schedule when calculating capacity in the Ancillary Service Imbalance Settlement for Controllable Load Resources available to Security-Constrained Economic Dispatch (SCED).

1. Ancillary Services Requirements

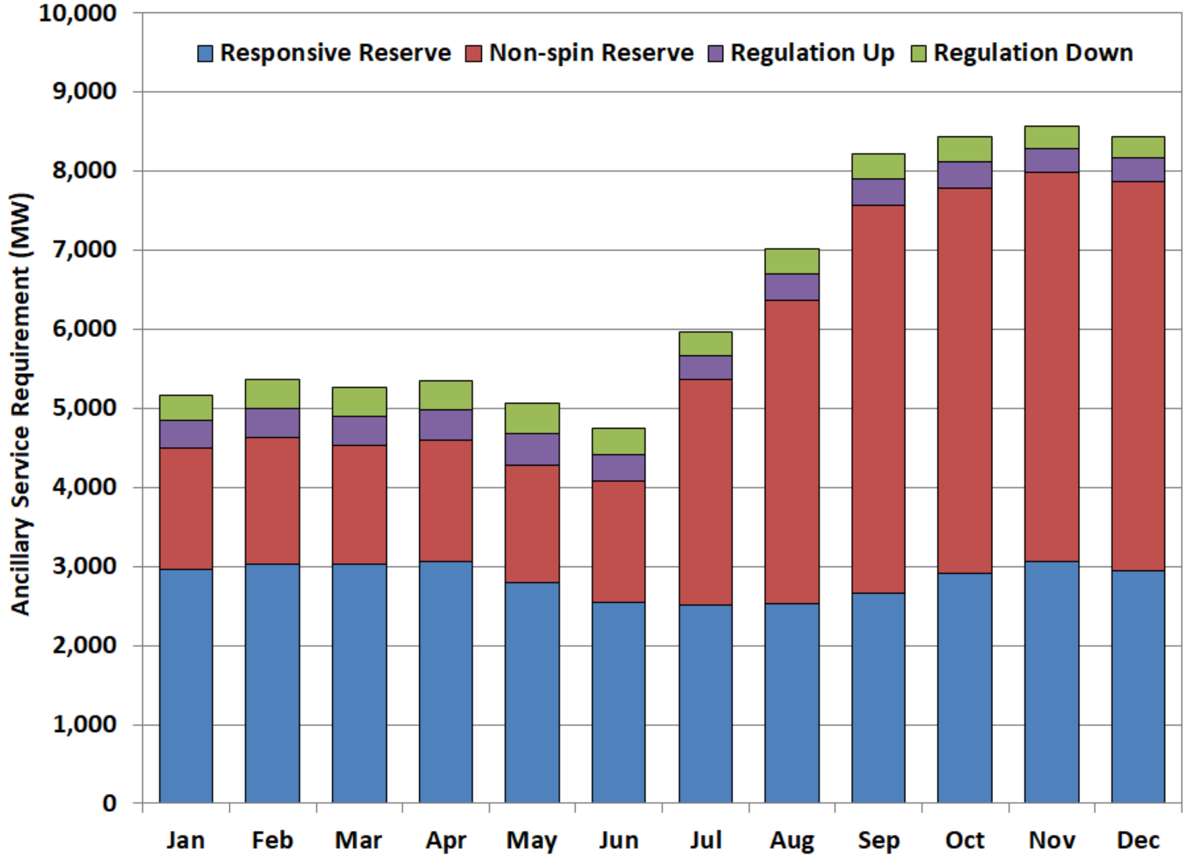
Since June 2015, ERCOT has calculated responsive reserves requirements based on a variable hourly need. This requirement is posted in advance for the year. Historically, ERCOT procured non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95% of the calculated net load forecast error. ERCOT will always procure a minimum quantity of non-spinning reserves greater than or equal to the largest generation unit during on-peak hours. ERCOT did place a limit of 450 MW on resources providing Fast Frequency Response (FFR) when phase 1 of NPRR863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve*, was implemented.

In late 2020, for calendar year 2021, ERCOT changed the minimum RRS from generators to 1,420 MW, and changed each of the methodologies used for computing non-spinning reserve and regulation reserves to account for growth in installed solar capacity.[66] In July 2021, ERCOT changed the procurement such that procures 2,800 MW of responsive reserve service over peak

[66] https://www.ercot.com/files/docs/2020/12/01/8_2021_ERCOT_Methodologies_for_Determining_Minimum_Ancillary_Service_Requirements.pdf

hours and additional non-spinning such that the total amount of upward ancillary services equals 6,500 MW (increasing to 7,500 MW when forecast variability is high).[67] However, ERCOT chose not to include load resources providing responsive reserve in this calculation, discounting the reliability service they provide, with the reason given that they were excluded since they can only be deployed in EEA. Figure 35 below displays the average quantities of ancillary services procured for each month in 2021, and Figure A26 in the Appendix shows ERCOT's yearly average ancillary service capacity by hour in 2021.

Figure 35: Average Ancillary Service Capacity by Month



This new conservative posture for operations in the aftermath of Winter Storm Uri is clear from the above figure. The cost of this additional AS procurement was discussed in the Future Needs section of this document.

ERCOT also adjusted its non-spinning reserve deployment methodology in 2021:

- Starting July 12, ERCOT added a condition for deploying non-spinning reserve when PRC is less than 3,200 MW and is not expected to recover within 30 minutes. This allows operators to deploy non-spinning reserve in advance of potential Emergency Conditions.

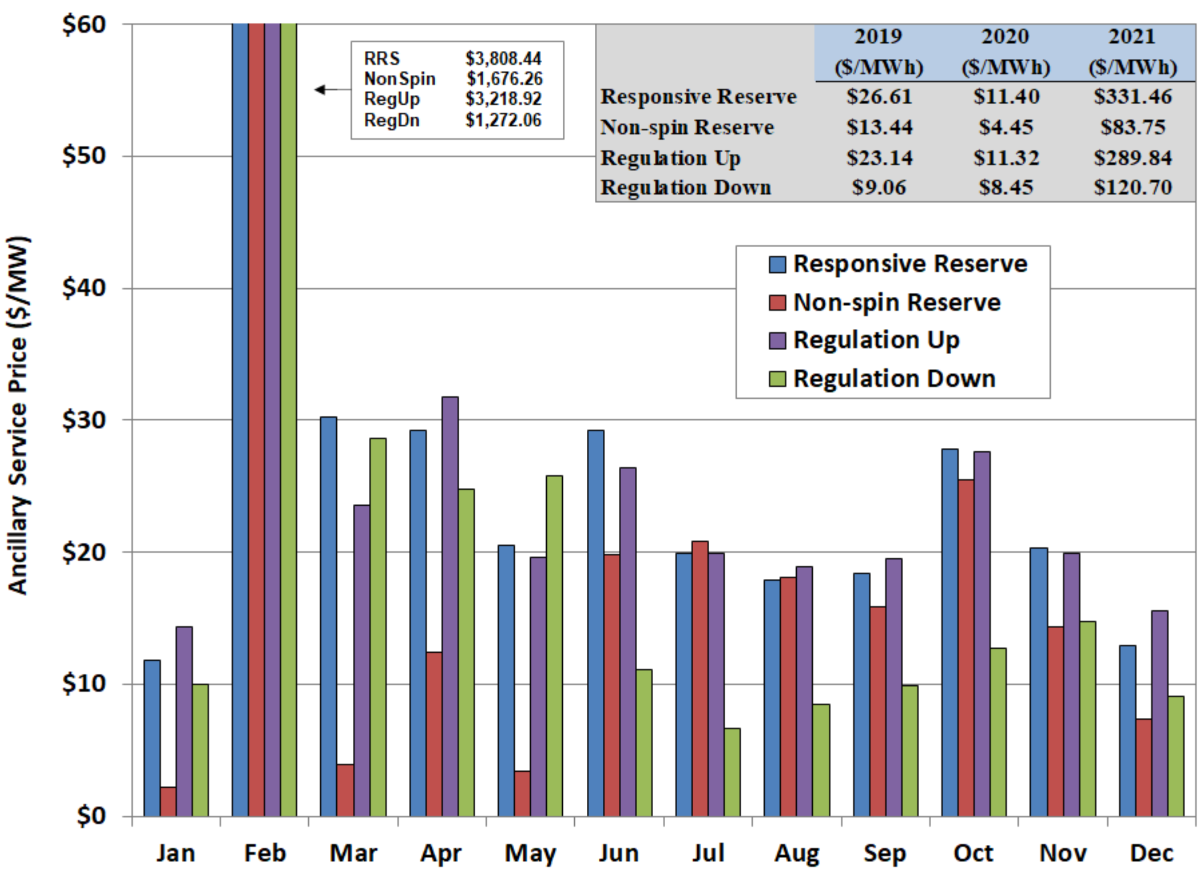
67 https://www.ercot.com/files/docs/2021/06/30/ERCOT_Addtional_Operational_Reserves_06302021.pptx

- Starting August 2, ERCOT changed the calculation for deploying non-spinning reserve currently based on High Ancillary Service Limit (HASL) less generation less the forecasted 30-minute load ramp such that it includes intermittent renewable resource (IRR) curtailment and 30-minute net load ramp instead of 30-minute load ramp.

2. Ancillary Services Prices

Figure 36 below presents the monthly average clearing prices of capacity for the four ancillary services in 2021, while the inset table shows the average annual prices over the last three years. The prices for ancillary service were by far highest in February because of Winter Storm Uri. This outcome is consistent with the higher clearing prices for energy in the DAM for August because ancillary services and energy are co-optimized in the DAM. This means that market participants need not include expectations of forgone energy sales in their ancillary service capacity offers. Because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the DAM, ancillary service prices should generally be correlated with day-ahead energy prices.

Figure 36: 2020 Ancillary Service Prices (with Uri)



The extraordinary increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase from $1.00 per MWh in 2020 to $29.59 per MWh in 2021. This is due to both the effects of Winter Storm Uri and the increased costs associated with the additional reserve procurement beginning July 2021. Figure A27 in the Appendix shows the monthly total ancillary service costs per MWh of ERCOT load.

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 4 shows the share of the 2021 ancillary services that were procured from the top ten QSE providers of ancillary services, in terms of volumes, compared to last year. This allows us to determine how concentrated the supply is for each product. The table also shows the total number of QSEs that represent resources that can supply each ancillary services product.

Table 4: Share of Reserves Provided by the Top QSEs in 2020-2021

	2020				2021			
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	Non-Spin	Reg Up	Reg Down
# of Suppliers	46	32	30	30	58	36	38	40
QLUMN	3%	27%	13%	40%	4%	20%	16%	37%
QNRGTX	11%	4%	6%	5%	13%	13%	9%	7%
QLCRA	12%	7%	3%	4%	12%	4%	3%	7%
QCALP	1%	3%	4%	10%	2%	7%	7%	8%
QCPSE	2%	5%	3%	2%	4%	5%	6%	5%
QEDF26	2%	0%	18%	4%	2%	0%	11%	5%
QAEN	3%	7%	4%	7%	2%	5%	3%	6%
QBRAZO(P)	3%	6%	10%	2%	3%	3%	8%	0%
QBROAD					2%	0%	5%	5%
QFPL12	0%	0%	9%	4%	0%	0%	8%	4%

During 2021, 58 different QSEs self-arranged or were awarded responsive reserves as part of the DAM. The number of providers had been roughly the same before 2021, with 12 additional providers in 2021 from the previous year.[68] Regarding the concentration of the supply for each product, Table 4 shows that in 2021:

- The supply of responsive reserves has not been highly concentrated, just as in 2020, with the largest QSE providing only 13% of ERCOT's responsive reserves (QNRGTX in 2021 as opposed to QLCRA in 2020).
- The provision of non-spinning reserves is still more concentrated than responsive reserves, but less so than in 2020. A single QSE (Luminant, shown above as "QLUMN") bore almost 27% of the requirements in 2020 but only 20% in 2021. Luminant's share has continued to fall from a high of 56% in 2017.
- Regulation up is provided by many different QSEs and the supply is not concentrated.

68 A breakdown of ancillary service providers by QSE, by type of service provided, can be found in Figure A29, Figure A30, Figure A31, and Figure A32 in the Appendix.

- Regulation down in 2021 exhibited similar concentration to regulation down (and non-spinning reserves) in 2020. Luminant remained the dominant supplier, selling 37% of all regulation down in 2020, with no other provider exceeding 10%.

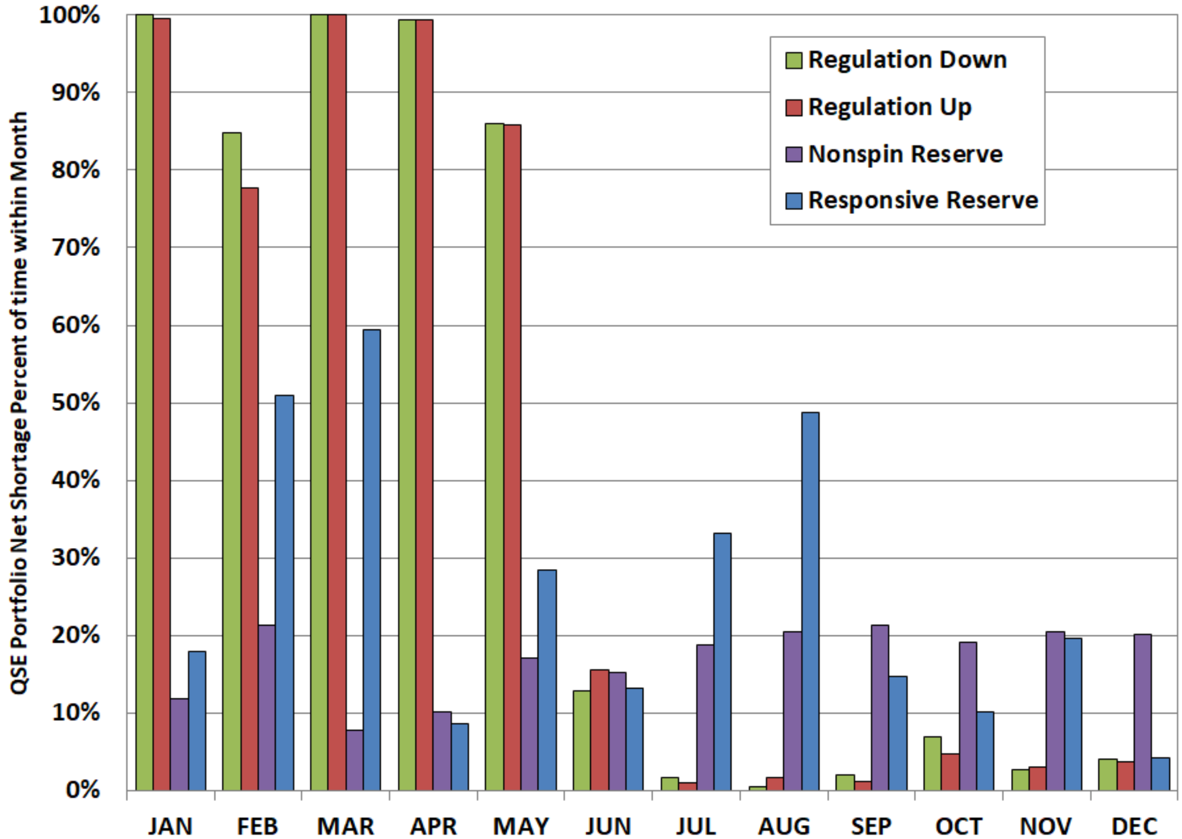
The ongoing concentration in the supply of non-spinning reserves and regulation down highlights the importance of modifying the ERCOT ancillary service market design and implementing RTC. Jointly optimizing all products in each interval will allow the market to substitute its procurements among units on an interval-by-interval basis to minimize costs and set efficient prices. Doing so will reduce the competitive disadvantage faced by smaller entities and should reduce concentration in these markets. Additionally, the use of ancillary service demand curves in the day-ahead co-optimization rather than absolute requirements will improve the efficiency of the day-ahead purchases by allowing those curves to set prices when there is a relative shortage of offers.

In addition to the procurement of ancillary services discussed above, our final evaluation relates to QSEs' delivery of the ancillary services sold in the DAM. Between the time an ancillary service is procured and the time that it is needed, a QSE with multiple units may review and adjust the resources that will provide its ancillary services, presumably to reduce the costs of providing the ancillary service. However, when all ancillary services are continually optimized in response to changing market conditions, the efficiencies will be much greater than can be achieved by QSEs acting individually. These efficiencies will be achieved through RTC.

Further, QSEs without large resource portfolios face higher risk than larger QSEs when selling ancillary services because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). Whereas a QSE with a large portfolio can often replace ancillary services within its fleet without the need for a SASM, if there is a forced outage in a small portfolio, the replacement risk is substantial because the clearing prices for ancillary services procured in SASM are often much higher than the clearing prices from the DAM. RTC will address this issue by providing a liquid replacement for ancillary services awarded in the DAM. Because RTC is on the horizon for future implementation and will obviate the need for SASMs, we will not discuss SASM deficiencies and issues further, but we have discussed these issues in previous reports. See Section IV of the Appendix for more information on SASM activity in ERCOT in 2021.

Finally, QSEs do not always provide the ancillary services that they are obligated to provide via a combination of day-ahead awards, self-arrangement, or trades. Figure 37 below shows the percentage of each month during which there was at least one QSE that did not satisfy its full ancillary services obligation. A shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour.

Figure 37: QSE-Portfolio Net Ancillary Service Shortages



Deficiencies of QSEs in meeting their ancillary service responsibilities were pervasive in 2021, not just during February because of forced outages or derations. For market participants that are not able to meet their ancillary service responsibility, the ERCOT operator typically marks the short amount in the software, causing the ancillary service responsibility to be effectively removed and the day-ahead ancillary service payment to be clawed back in settlement.

ERCOT operators did not complete this task during the winter event, and therefore the "failure to provide" settlements were not invoked in real time. Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947, *Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities*; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to ancillary service trades, and the then-anticipated implementation of RTC. This item may need to be reconsidered given the delay in RTC and the significant shortages observed above.

Relying on a recommendation of the IMM,[69] the Commission directed ERCOT to settle each qualified scheduling entity that failed on its ancillary service supply responsibility in accordance

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69 *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Project No. 51812, Potomac Economics' Letter to Commissioners at 1 (Mar. 1, 2021).

with ERCOT Nodal Protocol section 6.4.9.1.3, entitled Replacement of Ancillary Service Due to Failure to Provide, for a particular ancillary service for any hour of ERCOT's operating days February 14, 2021 through February 19, 2021.[70] Invoking the "failure to provide" settlement for all ancillary services that market participants failed to provide during Winter Storm Uri produced market outcomes and settlements consistent with underlying market principles. Market participants should not be paid for services that they do not provide. Whether ERCOT marked the short amount in real-time or not should not affect the settlement of these ancillary services.

[70] *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Project No. 51812, Second Order Addressing Ancillary Services at 2 (Mar. 12, 2021).

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 how much of its output will flow across the overloaded transmission element. 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 flow at the constraint's limit) in real time during 70% of 2021.

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 location of the generator and the location of the load. CRRs are economic property rights that are funded by the congestion collected through the DAM. CRR markets enable parties to purchase the rights to locational price differences in monthly blocks as much as three years in advance. Hence, CRRs provide a hedge for day-ahead congestion, and if desired can easily be converted into a real-time congestion hedge.

This section of the Report evaluates congestion costs and revenues in 2021. We first discuss the congestion costs in the day-ahead and real-time markets, which totaled $1.4 billion and $2.1 billion respectively, in 2021. We then discuss the CRR markets and funding in 2021.

A. Day-Ahead and Real-Time Congestion

As the DAM clears financially-binding supply, demand and PTP obligation transactions, it does so while also respecting 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. In real-time, congestion costs represent the cost of managing the network flows resulting from physical dispatch of generators. Figure 38 and Figure 39 summarize the monthly and annual congestion costs in the day-ahead and real-time markets. The values are aggregated by geographic zone.

Figure 38 shows that the total day-ahead congestion costs in 2021 were roughly 5% higher than costs in 2020; similarly, real-time congestion costs increased 46%. Most of the differences in congestion costs between day-ahead and real-time were in the South zone, which constituted approximately 45% of all the congestion in ERCOT. The increase in congestion costs were driven by congestion during the extreme events of Winter Storm Uri.

Figure 38: Day-Ahead Congestion Costs by Zone

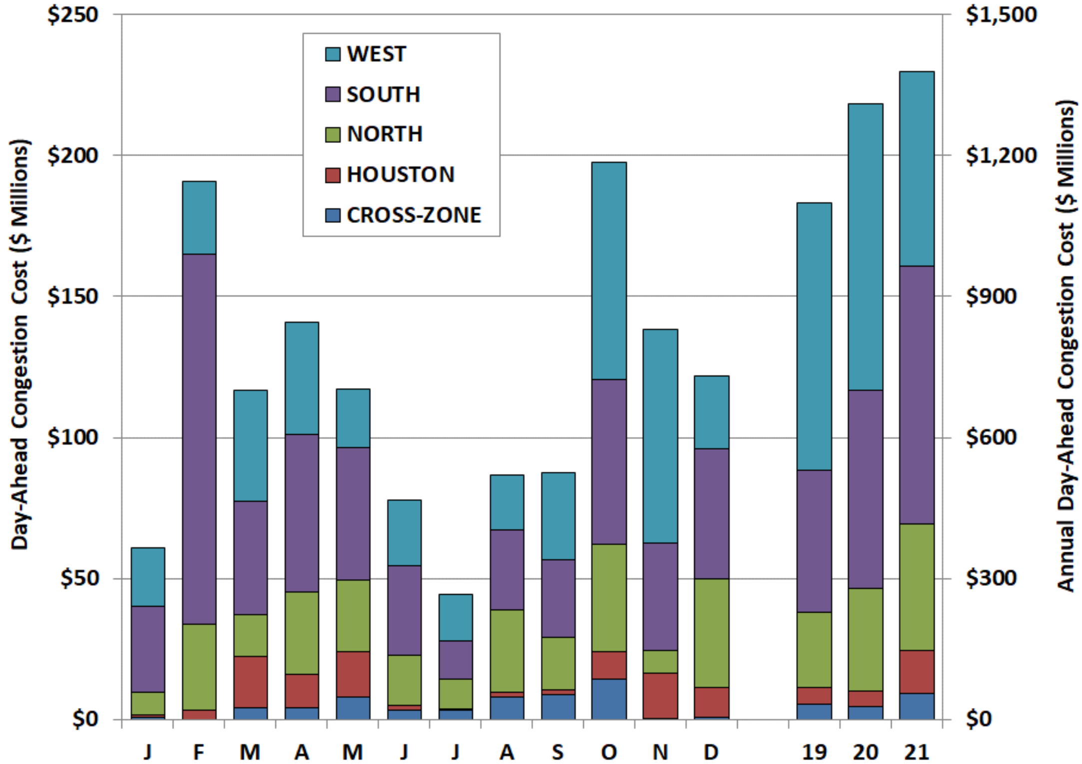
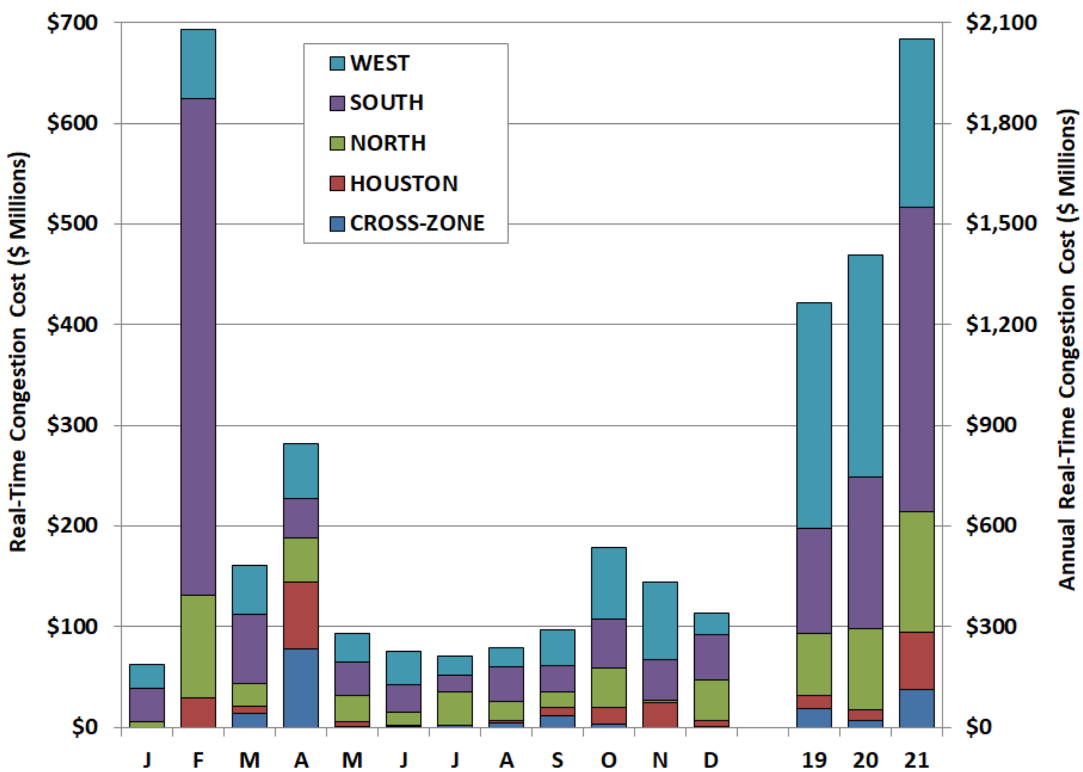


Figure 39: Real-Time Congestion Costs by Zone



The 2021 monthly congestion profile shows that congestion was highest in the winter and fall, which is an expected pattern, but especially in February during Winter Storm Uri. In typical years, most transmission and generation outages for maintenance and upgrades occur in shoulder months. The increased congestion in March and April was likely due to an increase in significant transmission and generation maintenance outages and repairs because of the operational issues encountered in February. Also, the limitation on allowing any outages occurring over the summer months has become highly significant with regard to outage scheduling.

The largest zonal contributor to congestion costs in 2021 was the South zone during Winter Storm Uri. The West zone, which had similar aggregate congestion costs between 2021 and 2020, had congestion driven by high intermittent renewable output. Specific top constraints in terms of dollars contributing to the real-time congestion costs are described in the next subsection.

B. Real-Time Congestion

While the expected costs of congestion are reflected in the DAM, 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, any review of congestion must focus on the real-time constraints and resulting congestion, which we evaluate and discuss in the section.

1. Types and Frequency of Constraints in 2021

Constraints arise in the real-time market through:

- Real-Time Contingency Analysis (RTCA) that runs on an ongoing basis; and
- GTCs that are determined by off-line studies, with limits determined prior to the operating day.[71]

RTCA is the process that evaluates the resulting flows on the transmission system under many different 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.[72] Active transmission constraints are those that are passed by the operator to the

[71] 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 analysis applications and are based on offline studies (i.e. RTCA will not provide indication of encroaching concerns.)

[72] Typically, a contingency constraint is described as a contingency name plus the name of the resulting overloaded element. This section will refer to a constraint based solely on the overloaded element to identify the bottleneck in the electric grid.

dispatch software and that evaluated them, whereas some constraints are identified but not activated by the operator for various reasons. The active constraints are "binding" when positive 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 thus have no effect on prices.

Our review of the active and binding constraints during 2021, Figure 40, shows the following:

- The ERCOT system had at least one binding constraint 70% of the time in 2021, a decrease from 75% in 2020.
- Consistent with previous years, the average number of active constraints generally increased with increasing load level
- On average, slightly more than ten constraints were identified for the higher load levels, up from approximately seven in 2020.

Figure 40: Frequency of Binding and Active Constraints by System Load Level

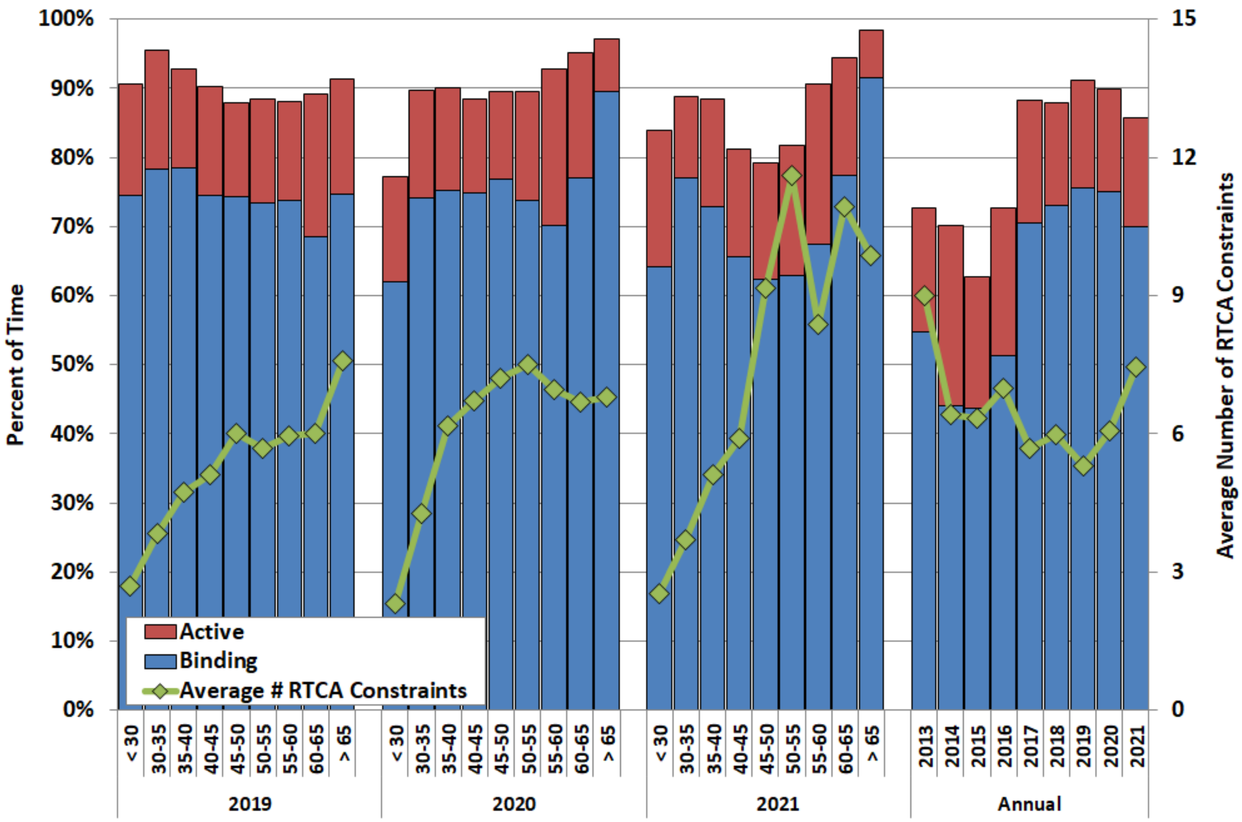


Table 5 below shows the GTCs and the number of binding intervals during 2020 and 2021. The number of GTC binding intervals in 2021 almost doubled compared to 2020 and represented 20 percent of real-time congestion rent. GTCs are used to ensure that the generation dispatch does not violate a transient 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 North to Houston and the Rio Grande Valley Import limits, which provides a more accurate real-time limit than could be achieved through offline studies.

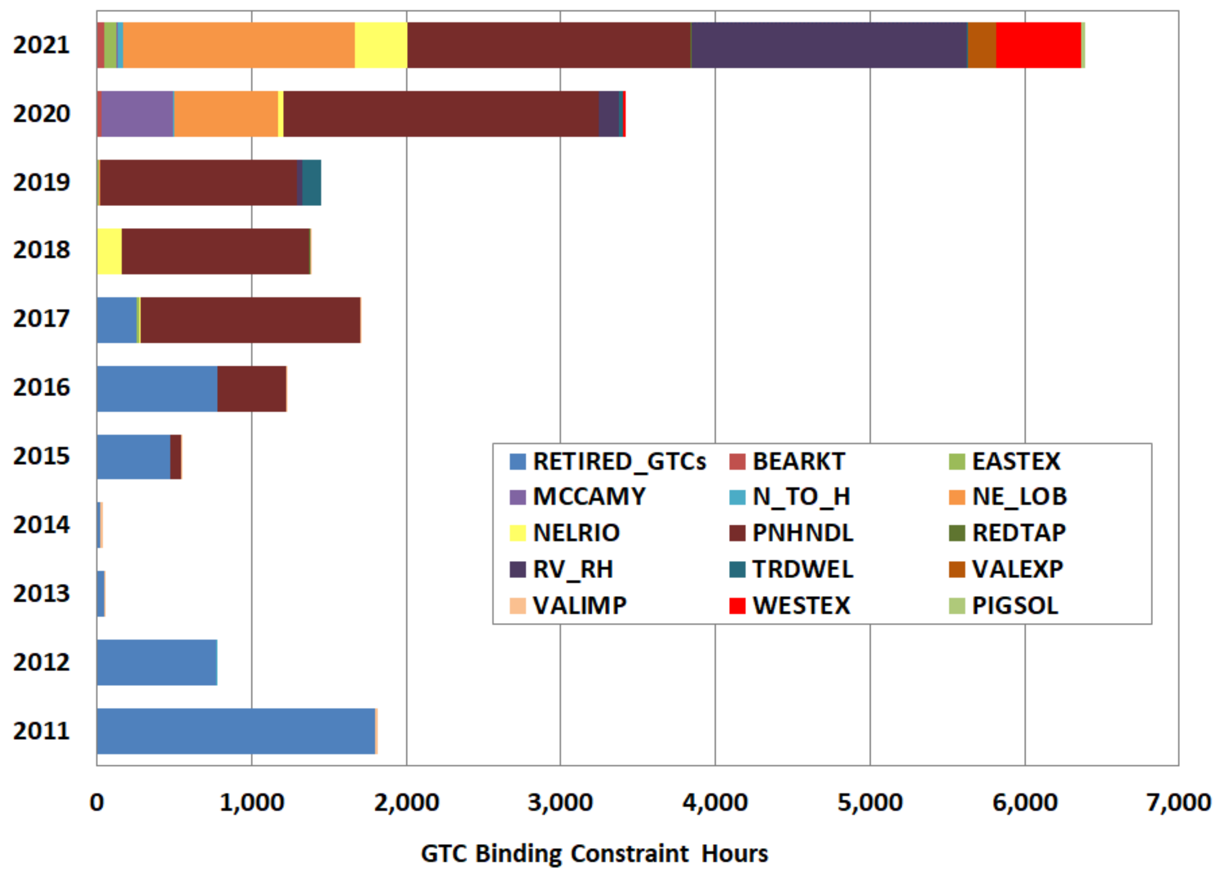
ERCOT has been working on getting better data for the full range of inverter technology, which over time will allow all GTC limits to be calculated in real-time rather than using more-conservative offline studies. This should result in less generation curtailment. Apart from the North to Houston, Rio Grande Valley Import, and East Texas constraints, all GTCs resulted from issues identified during the generation interconnection process. As more renewable generation and ESRs come online in the ERCOT region, the benefits of these dynamic VSAT and TSAT models will grow.

Table 5: Generic Transmission Constraints

Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2020	# of Binding Intervals in 2021
North to Houston	December 1, 2010	37	377
Rio Grande Valley Import	December 1, 2010	-	-
Panhandle	July 31, 2015	24,762	22,416
Red Tap	August 29, 2016	-	64
North Edinburg - Lobo	August 24, 2017	8,230	18,451
Nelson Sharpe - Rio Hondo	October 30, 2017	524	4,271
East Texas	November 2, 2017	34	967
Treadwell	May 18, 2018	239	103
McCamey	March 26, 2018	5,660	152
Raymondville - Rio Hondo	May 2, 2019	1,703	21,884
Bearkat	November 20, 2019	354	547
Westex	October 1, 2020	235	6,720
Zapata - Starr	Novemeber 5, 2020	-	-
Valley Export	Novemeber 5, 2020	65	2,351
Pigcreek Solstice	November 16, 2020	-	265

The frequency in which GTCs are binding is also shown in Figure 41, depicting the aggregate total of GTC binding constraint hours from 2011 to 2021. GTCs were binding much more frequently in 2021 than in previous years.

Figure 41: GTC Binding Constraint Hours[73]



The next subsection describes where and some reasons why these constraints occurred.

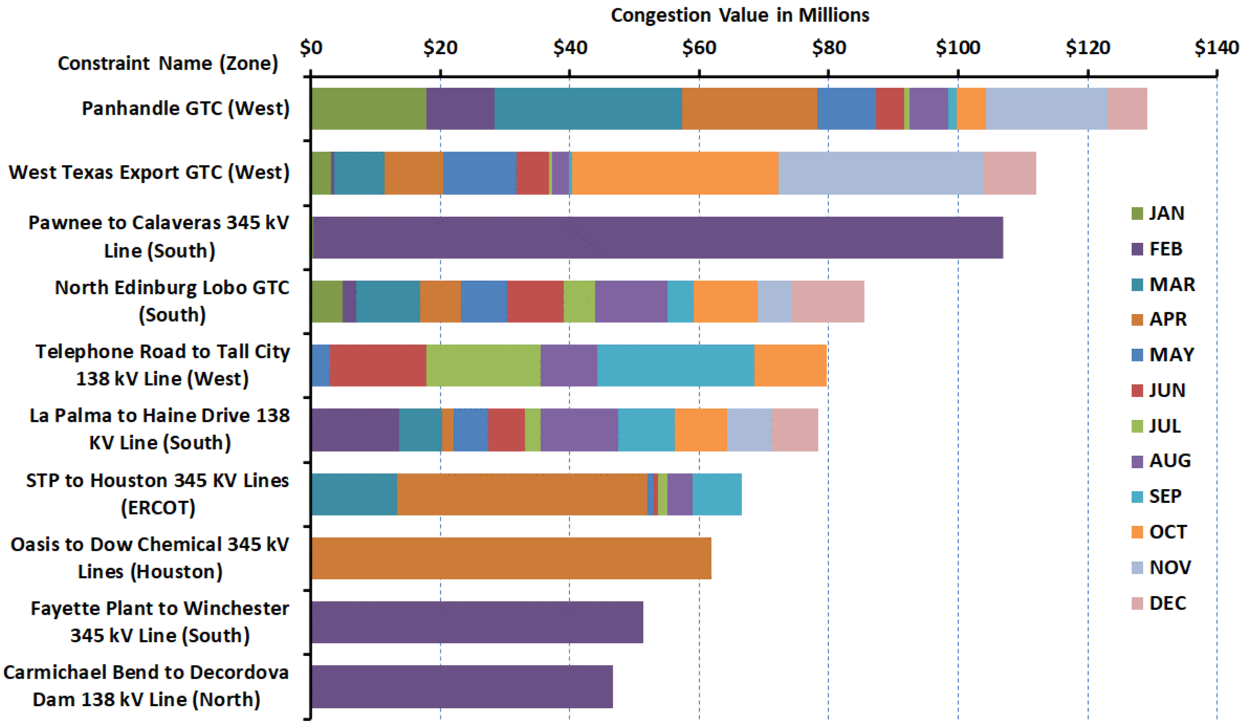
2. Real-time Constraints and Congested Areas

Our review of congested areas starts with describing the areas with the highest financial impact from real-time congestion. 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. We calculate the real-time congestion value by multiplying the shadow price of each constraint by the flow over the constraint. This gives the total dollar amount of the associate re-dispatch, where the shadow price represents the per-MW redispatch cost, defined as the marginal cost of the constraint (i.e., the dollar amount that would be avoided if the transmission element limit were 1 MW larger). Multiplying the shadow price by the flow over the transmission element itself gives that total cost of the constraint. The flow over the transmission element will be equal to the transmission element limit when the constraint is binding but may be over the limit if the constraint is violated.

73 Retired GTCs are Ajo to Zorillo, Bakersfield, Laredo, Liston, Molina, North to West, SOP110, West to North, and Zorillo to Ajo.

There were 526 unique constraints that were either binding or violated at some point during 2021, with a median financial impact of approximately $310,000. In 2020, there were 450 unique constraints with a median financial impact of $222,000. Figure 42 displays the ten most costly real-time constraints with their respective zone measured by congestion value.

Figure 42: Most Costly Real-Time Congested Areas



The constraint with the highest congestion value in 2021 ($129 million) was the Panhandle GTC constraint, which was mostly caused by the interaction of high intermittent resources and planned transmission outages, including ETT maintenance outages, in the area. ETT maintenance is on track to complete work in 2022. Compared the Panhandle constraint's congestion cost of $139 million in 2020, the congestion cost in 2021 was about 10% lower in 2021.

The constraints on the Pawnee to Calaveras 345 kV Line, Fayette Plant to Winchester 345 kV Line and Carmichael Bend to Decordova Dam 138 kV Line solely occurred in February in conjunction to Winter Storm Uri. The STP to Houston 345 KV Lines and Oasis to Dow Chemical 345 kV Lines were due to planned and forced outages in the area. The other constraints were due to output from inverter-based resources; Panhandle GTC, West Texas Export GTC, North Edinburg Lobo GTC, Telephone to Tall City 138 kV Line, and La Palma to

Haine Drive 138 kV Line. ERCOT highlighted these areas in the 2021 Long-Term System Assessment (LTSA) report within the ERCOT Constraints and Needs Report. [74]

Day-ahead congestion costs were highest on the top three paths discussed above, with day-ahead congestion costs totaling roughly $1,380 million, somewhat less than the $2,050 million that accrued in the real-time market. This difference generally reflects the divergence between expectations in the DAM and actual real-time outcomes. This was more significant in 2021 due to transmission and generation outages from Winter Storm Uri. In the other months, less wind generation scheduled in the DAM is generally the factor. Figure A38 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2021.

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). However, because some constraints are more costly to manage than the reliability cost of allowing them to be violated, ERCOT caps the shadow price. Without the cap, the dispatch costs and shadow price could rise to unreasonable prices. When the dispatch model cannot find a solution to manage the constraint at a marginal cost less than the shadow price cap, the constraint will be "violated" in that interval, and the shadow price will be at the cap.[75] The shadow price caps during 2021 were:

- $9,251 per MW for base-case (non-contingency) constraints or voltage violations,[76]
- $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 $9,251 per MW. Figure 43 shows the distribution of the percentage overload of violated constraints between 2020 and 2021. A more detailed review of violated constraints can be found in Figure A37 in the Appendix. Violated constraints continued to occur in a small fraction of all constraint intervals – 10% in 2021, up from 8% in 2020.

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74 *See* Report on Existing and Potential Electric System Constraints and Needs, December 2021; https://www.ercot.com/files/docs/2021/12/23/2021_Report_Existing_Potential_Electric_System_Constraints_Needs.pdf

75 Shadow price caps are intended to reflect the reduced reliability that occurs when a constraint is irresolvable. See Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints.

76 OBDRR037, *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 $5,251 per MW effective April 1, 2022.

Figure 43: Overload Distribution of Violated Constraints

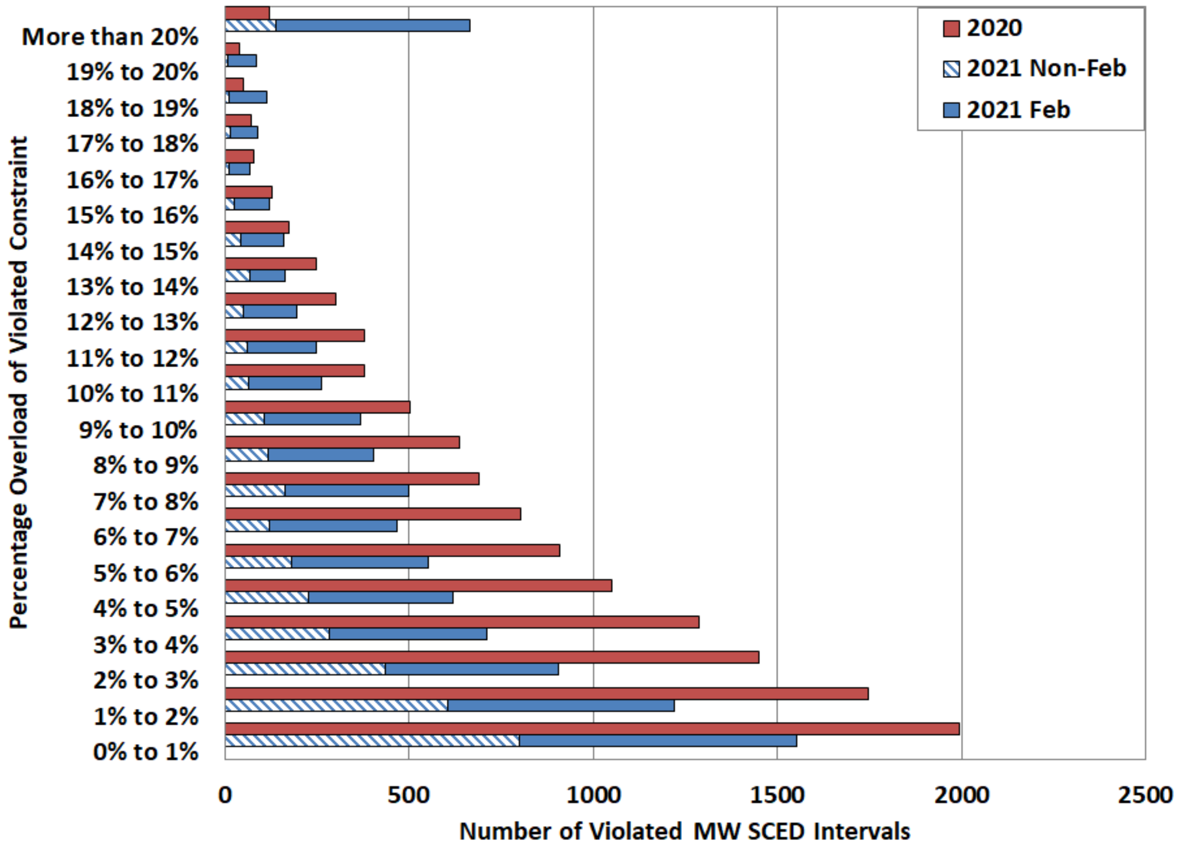

Figure 43 shows that there were less SCED intervals at the various violated constraint percentages in 2021 than in 2020, except for those above 17% of the constraint value. The month of February incurred the highest percentage in those categories in 2021. Finally, 16% of the violated constraints in 2021 were only slightly in violation (less than 1% over the rating), yet they are priced at the shadow price cap like the more severe violations. Almost 30% of the constraints are in violation by only small amount (between 0-2% of the transmission element rating) and these violations should be targeted for reduced shadow price caps. Implementing a well-designed transmission demand curve would recognize that the reliability risk of a post-contingency overload increases as the overload 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 for lack of support.[77]

[77] Filed on January 21, 2020, by the IMM, OBDRR026, *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.

Violations may be resolved in subsequent intervals as generators ramp to provide relief. Nonetheless, a constraint-specific peaker net margin mechanism is 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 upon the mitigated offer cap of existing resources and their ability to resolve the constraint.[78] Table A4 in the Appendix shows that 16 elements were deemed irresolvable in 2021 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 DAM congestion.

4. CRR Auction Revenues

CRRs may be acquired in semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to certain participants (Non Opt-In Entities or NOIEs) based on generation units owned or contracted for prior to the start of retail competition in Texas. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same locations. To summarize the CRR market results, Figure 44 shows the revenues, calculated by multiplying the shadow price by the flow on binding constraints in the CRR auctions.

Our calculation of the zonal CRR revenue is based on the binding constraint location, which is different from the method used to allocate CRR revenues to loads. The costs are separately shown by whether they were incurred in a monthly auction (labeled "monthly") or one of the six-month long-term auctions (labeled "forward"). The "Cross-Zone" category contains costs associated with constraints having sources and sinks in different zones (for example North to Houston).

Figure 44 shows that aggregate CRR revenues have risen steadily since 2016. We note that all forward auction revenues for each of the zones increased between 2020 and 2021 except the Houston zone, whereas the monthly auction revenues increased except in the Houston and West zones. In general, monthly auctions will produce prices that reflect the most accurate expectations of actual congestion because they are closest to the operating horizon.

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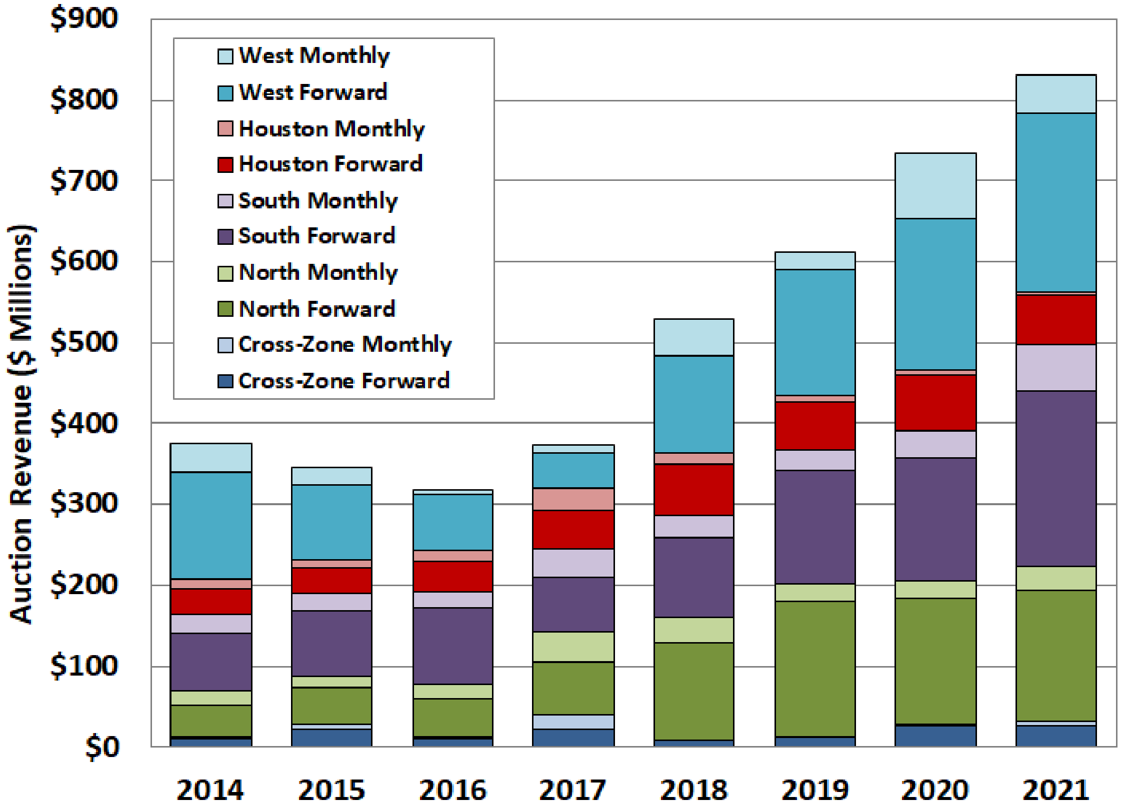
78 *See* Section 3.6.1 of the document, Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch, which can be found in the Other Binding Document (OBD), Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints.

Figure 44: CRR Auction Revenues by Zone

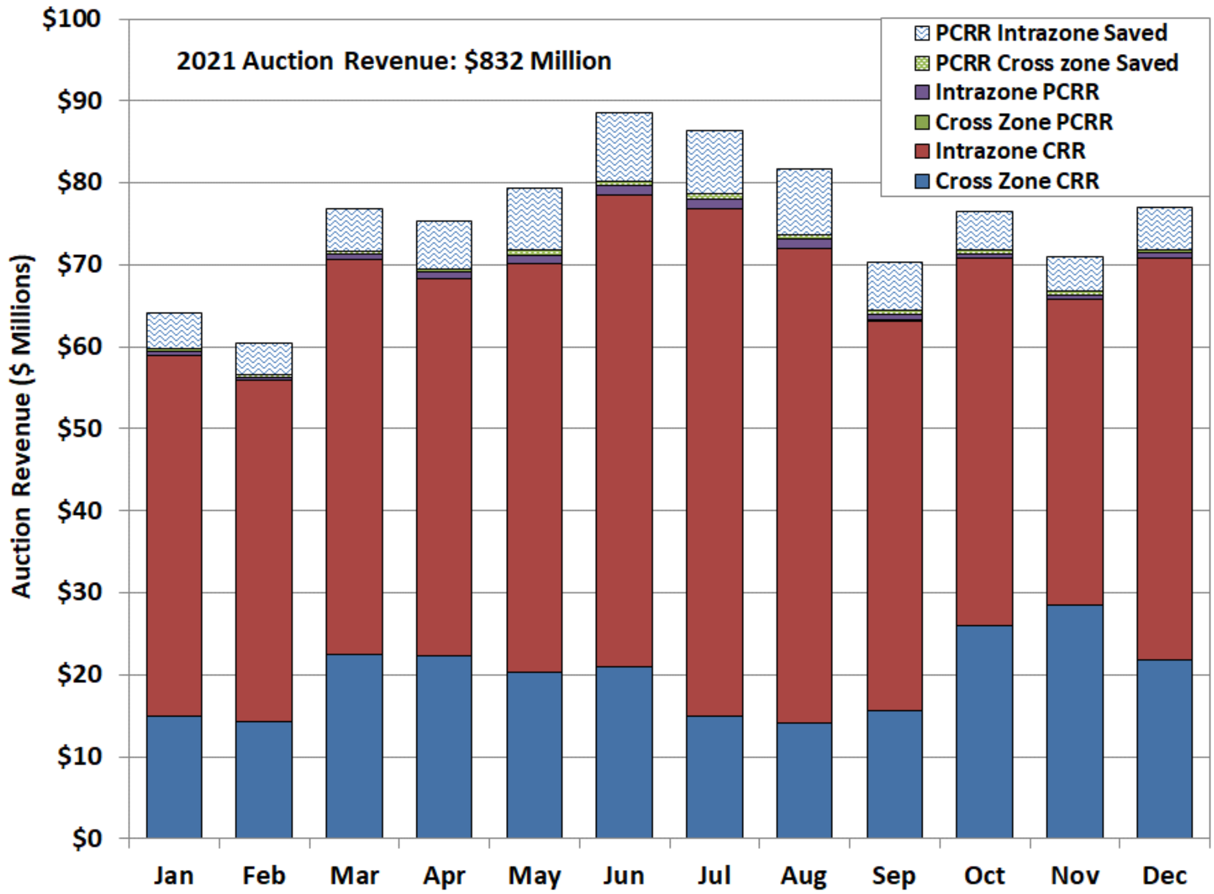


ERCOT has implemented third year CRR auctions, which caused more of the transmission capacity to be sold in advance of the monthly auctions. Opportunities to purchase CRRs earlier improve forward hedging and add liquidity. However, earlier purchases can also increase differences between CRR auction revenue and day-ahead payouts because more of the CRRs are sold when there is higher 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 45 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 Avoided" and "PCRR Cross Zone Avoided") is the difference between the auction value and the value charged to the purchaser.

The total amount of CRR auction revenue increased to $831 million in 2021, up from $725 million in 2020 and $612 million in 2019, while the total PCRR discount increased from $61 million in 2020 to $76 million in 2021. These increases reflect a yearly trend of an increased expectation of congestion in 2021.

Figure 45: 2021 CRR Auction Revenue

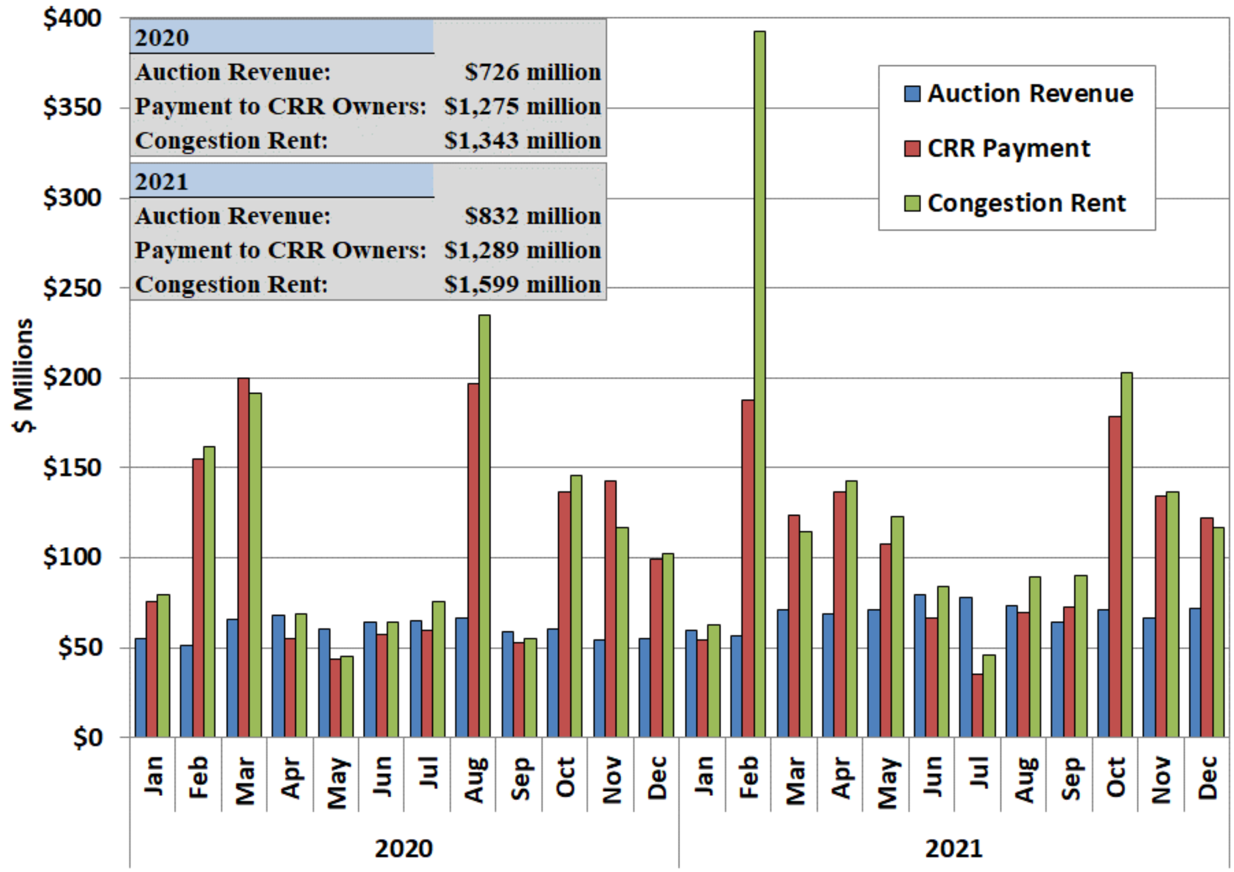


5. CRR Profitability

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 in aggregate to be profitable. Although results for individual participants and specific CRRs varied, this trend continued in 2021 with participants again paying much less for CRRs they procured than their ultimate value. To evaluate these results, Figure 46 shows the monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the payout to the CRR owners.

Figure 46 shows that for the entire year, participants spent $832 million to procure CRRs and in aggregate received $1,289 million, as shown below. In general, this difference occurred because of the increase in congestion that occurred in 2021 was not foreseen by the market in the forward auction periods, in conjunction with the time value of money and with CRR obligation risk. The period of congestion that accounted for most of this difference was February, because of Winter Storm Uri, and October because it was a shoulder month with a lot of outages.

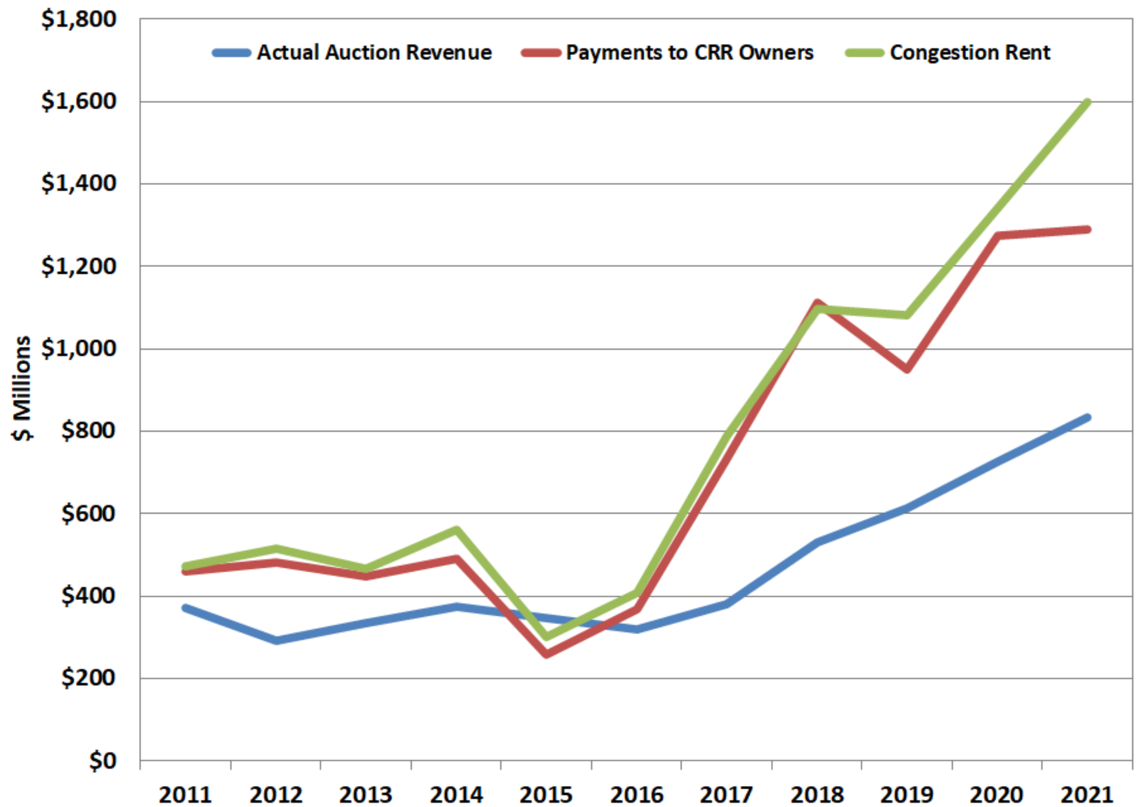
Figure 46: CRR Auction Revenue, Payments and Congestion Rent



Prices paid for CRRs represent the market expectations as of the time of the auction. Because many CRRs are purchased months (if not years) in advance, the factors that drove up the congestion costs in 2021 were likely not apparent when the bulk of the CRRs were purchased. Conversely, the CRR auction revenue in some months was higher than the CRR payouts when congestion was milder than expected. This occurred in June through August in 2021.

Finally, the payout can be less than the congestion rent collected in the DAM when the quantity of CRRs sold is less than the day-ahead network flows. This occurred in 2020, when the payout in aggregate was approximately $110 million less than the day-ahead 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 a little undersold. Excess congestion rent will be discussed in the next subsection. It is instructive to review these three values over a longer timeframe, so Figure 47 provides the annual CRR auction revenues, payments to CRR owners and day-ahead congestion rent.

Figure 47: CRR History



In 2021, like the four years prior, CRRs were profitable in aggregate because of unanticipated factors that led to much higher congestion. 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 that auctions can be as much as three years in advance.

Figure 47 above shows that actual congestion continues to rise more quickly than CRR auction revenues, although these revenues have been increasing in recent years. This is not unexpected because the markets must forecast the actual revenues and, even after the congestion has begun to materialize, must determine whether it will be sustained. Figure A39 in the Appendix shows the price spreads between each hub and its corresponding load zone separately at: the average of the six semi-annual CRR auctions, at the monthly CRR auction, day-ahead, and real-time.

6. CRR Funding Levels

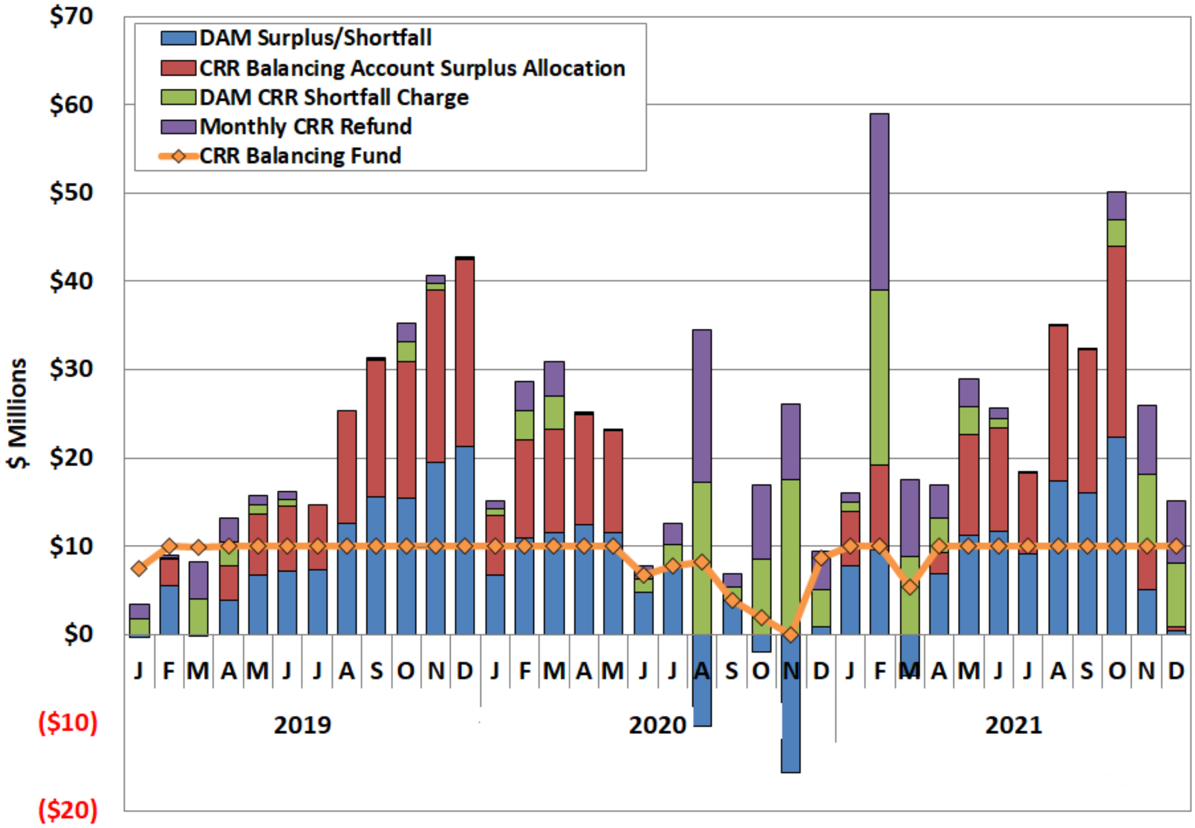
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payout to fully equal the target value because it makes the CRR more valuable to the holder and ultimately will increase the CRR auction revenues. While the target 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 not able to be modeled in the CRR auction but that are modeled in the DAM, reducing the network's transfer capability.

If this occurs on specific line or transformer (i.e., the flows on the line or transformer are "oversold"), CRRs that sink at resource nodes (generator locations) that affect the flows on the oversold transmission element have the potential to be "derated" based on the day-ahead capability of the element. Here, derated means that the CRR owner is not paid the full target value. After this deration process, if there are residual shortfalls then all holders of positively valued CRRs will receive a prorated shortfall charge. This shortfall charge has the effect of lowering the net amount paid to CRR account holders in the day-ahead settlement.

Sometimes there is excess day-ahead congestion rent that has not been paid out to CRR account holders at the end of the month (undersold hours). In that case, the excess congestion rent is tracked in a monthly settlement process referred to as the balancing account. Excess congestion rent residing in this balancing account is used to make the CRR account holders that received shortfall charges whole, i.e., they are refunded their shortfall charges. If there is not enough excess congestion rent from the current month to refund all shortfall charges, the rolling CRR balancing fund from prior months can be used to fully pay CRR account holders that received shortfall charges. Figure 48 shows the CRR balancing fund since the beginning of 2019. The CRR balancing fund has a $10 million cap, beyond which the remaining is dispersed to load.

The fact that ERCOT's processes are designed to only sell 90% of the forecasted transmission capability makes funding shortfalls less likely. Figure 48 shows that in 2021, despite this design, CRR holders experienced shortfalls in March due to the unmodeled outages in the auction. The total day-ahead surplus was nearly about $111 million, much higher than the $42 million surplus in 2020, but similar to the surplus of $115 million in 2019. From the perspective of the load, the monthly CRR balancing account allocation to load totaled amount of $56 million at the end of the year.

Figure 48: CRR Balancing Fund



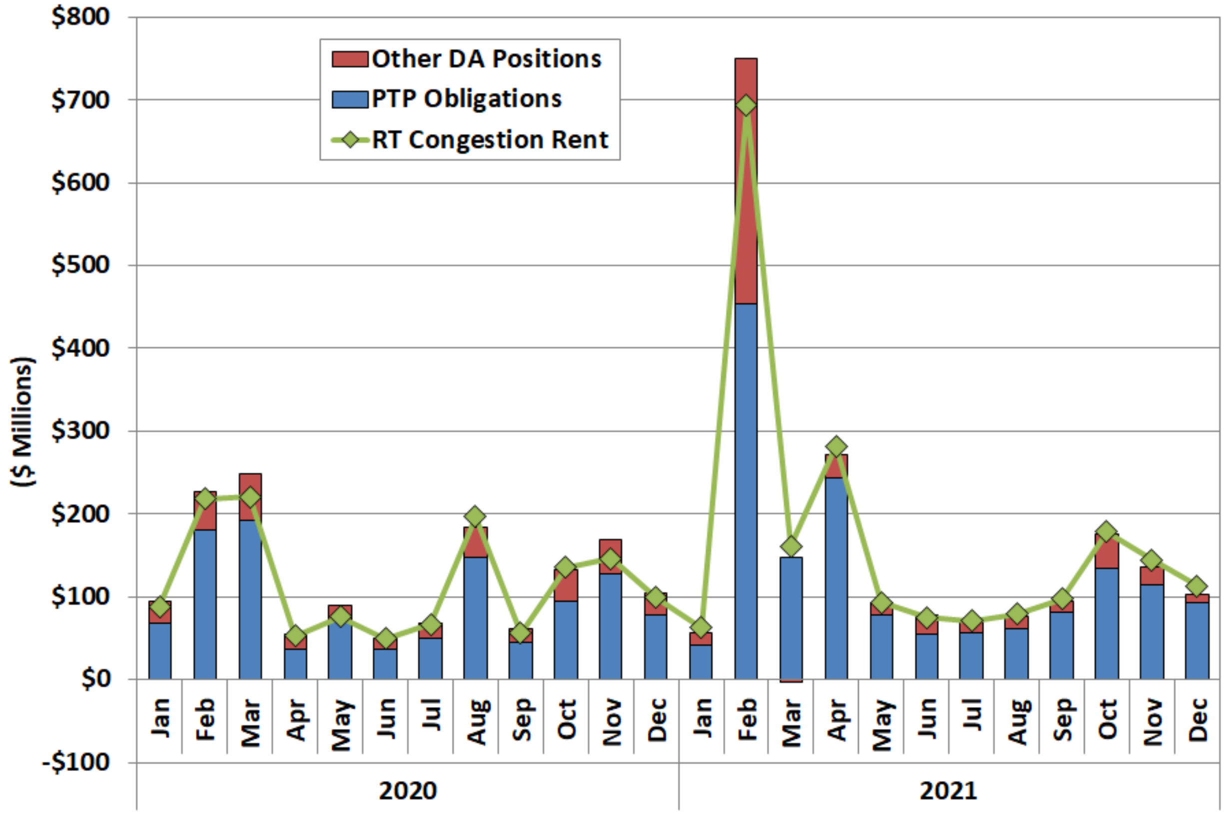
Importantly, even though the DAM produced more than enough revenues to fully fund the CRRs, many CRRs were derated in 2021 and not paid the full target value due to the mandatory deration process. In total, CRR deratings resulted in a $32 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to 98%, about the same as the previous year. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A40 in the Appendix. Derating CRRs, especially when the market is producing sufficient revenue to fully fund them, introduces unnecessary risk to those buying CRRs, which ultimately results in lower CRR auction revenues.

7. Real-Time Congestion Shortfalls

Just as reductions in network capability from the CRR auctions to the DAM can result in CRR shortfalls, reductions in the network capability between the DAM and the real-time market can result in real-time congestion shortfalls. In addition to outages or limit changes, a binding real-time constraint that is not modeled in the DAM can result in real-time congestion shortfalls. In summary, if ERCOT schedules more flows in the DAM over the network than it can support in real time, there may be more financial rights sold than congestion rent generated in real time. These real-time congestion shortfall costs are paid for by charges to load as part of the uplift charge known as Real-Time Revenue Neutrality Allocation or "RENA".

The day-ahead schedule flows are comprised of PTP obligations and other day-ahead positions that generate flows over the network. Figure 49 shows the combined payments to all these day-ahead positions compared to the total real-time congestion rent.

Figure 49: Real-Time Congestion Rent and Payments



In 2021, real-time congestion rent was $2,052 million, while payments for PTP obligations (including those with links to CRR options) were $1,563 million and payments for other day-ahead positions were $489 million. This resulted in a shortfall of approximately $80 million for the year. By comparison, payments for PTP obligations and options were $1,125 million in 2020 and payments for other day-ahead positions were $356 million, resulting in a shortfall of approximately $75 million for the year. Higher congestion cost can tend to also drive higher shortfall amounts; in general, ERCOT has improved in coordinating the network capability in its day-ahead and real-time market. Continuous improvement in this area should be the goal of all ISOs.

VI. Reliability Commitments

One important characteristic of any electricity market is the extent to which market dynamics result in the efficient commitment of generating resources. Under-commitment can cause shortages in the real-time market and inefficiently high energy prices, while over-commitment can result in excessive production costs, uplift charges, and inefficiently low energy prices.

The ERCOT market does not include a mandatory centralized unit commitment process. The decision to start-up or shut-down a generator is made by the market participant. ERCOT's DAM informs these decisions but is only financially binding. When a generator's offer clears in the DAM, there is no requirement to actually start that unit, although it must buy back the energy at real-time prices if it does not. Hence, this decentralized commitment depends on price signals to ensure an efficient combination of units are online and available for dispatch. In its role as reliability coordinator, ERCOT has the responsibility to commit units outside the market to ensure the reliable operation of the grid. In this way, ERCOT bridges any gaps between the economic decisions of its suppliers and the reliability needs of the system.

When ERCOT makes these RUCs, the units become eligible for a make-whole payment, but also forfeit some or all market profit through a "clawback" 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 taken away. However, suppliers can opt to forfeit the make-whole payments and waive the clawback charges, effectively self-committing the resource and accepting the market risks.

From a market pricing perspective, ERCOT applies an offer floor of $1,500 per MWh the resource and calculates a Real-Time On-Line Reliability Deployment Adder (reliability adder) that was described in Section I. In the past three years, ERCOT made several improvements to the RUC process relating to fast-starting generators and switchable generators that are dually connected to other control areas. These improvements had caused the number of RUCs to drop dramatically, a trend that is ended suddenly in June 2021 when ERCOT adopted its conservative operational posture. For a complete list of the historical changes in the RUC processes and rules, see Section VI in the Appendix.

In this section, we describe the outcomes of RUC activity in 2021, including the significant increase in RUC activity due to ERCOT's more conservative operating posture. In 2021, RUC activity picked up significantly after high thermal outages in June 2021 when ERCOT adopted more conservative operating procedures. Part of that approach included bringing more generation online and doing so earlier in the day. We evaluate how that affected the relationship of the Physical Responsive Capability (PRC) to ORDC reserves (RTOLCAP). We also describe the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC, whether for capacity or local congestion.

A. RUC Outcomes

ERCOT continually assesses the adequacy of market participants' resource commitment decisions using the RUC process, which executes both on a day-ahead and hourly basis. Additional resources may be needed for two primary reasons:

- To satisfy the forecasted system-wide demand (80% of RUC commitments in 2021); or
- To make a specific generator available resolve a transmission constraint (20% of RUC commitments in 2021).

In 2020, all RUC commitment reasons were all issued to manage transmission congestion. However, that changed in 2021 with an overall increase to the number of RUC instructions, most of them for capacity. The 4,052 unit-hours of RUC instructions were issued in 2021, compared to the 224 unit-hours in 2020, and were the highest number since the start of the nodal market.

Figure 50 shows RUC activity by month for the past three years, indicating the volume of generators receiving a RUC instruction that had offers in the DAM or chose to opt-out of the RUC instruction. It shows the shows the tremendous increase in RUC in the latter half of the year, peaking in July under ERCOT's new conservative operational posture.

Figure 50: Day-Ahead Market Activity of Generators Receiving a RUC

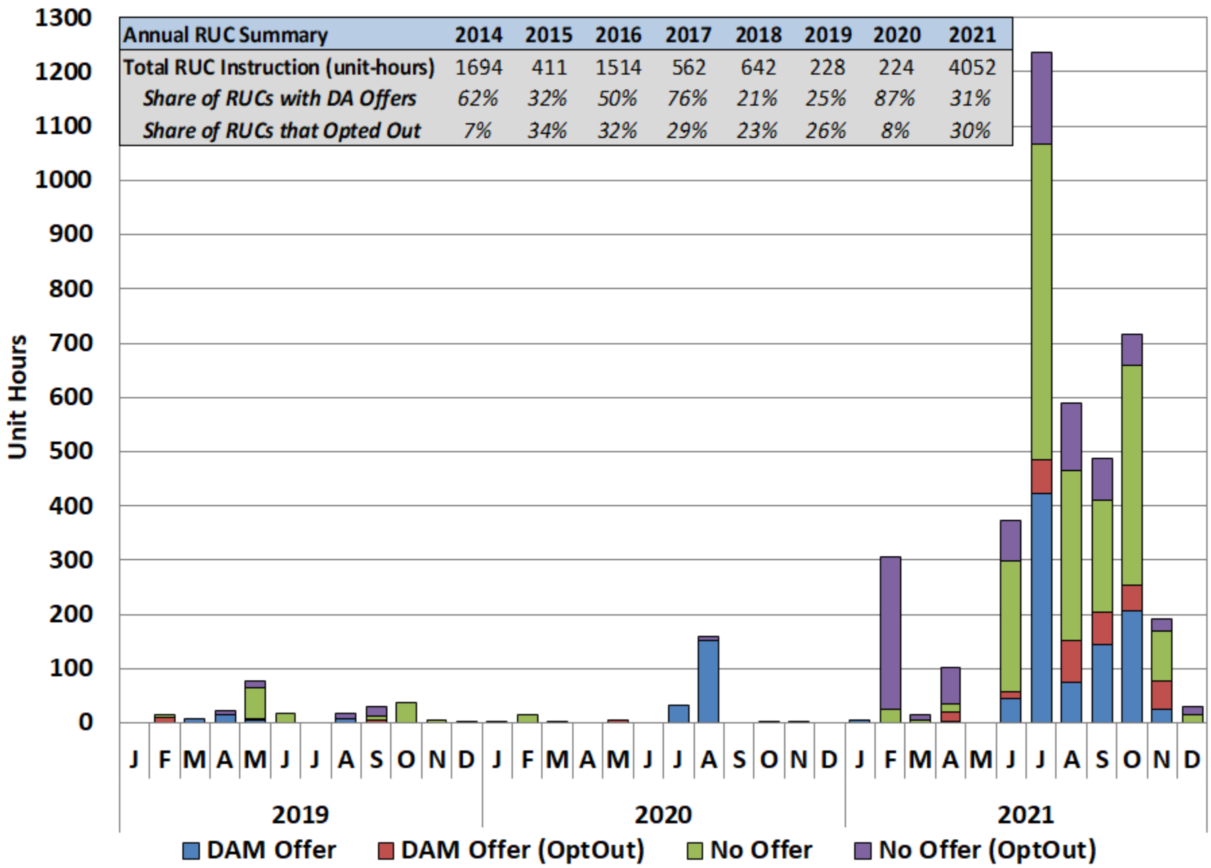


Table 6 below lists the generation resources that received the most RUC instructions in 2021 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. The unit highlighted in gray received similar RUC instructions in 2020. About 80% of the RUC-Resource hour instructions for 2021 were for capacity, and the other 20% was for congestion. The RUC instructions were geographically distributed as follows: 19% in the South zone, 10% in the West zone, 7% in the Houston zone, and the remaining 64% in the North zone.

Table 6: Most Frequent Reliability Unit Commitments

Resource	Location	Unit-RUC Hours	Unit OPTOUT Hours	Average LSL during Dispatchable Hours	Average LDL during Dispatchable Hours	Average Dispatch during Dispatchable Hours	Average HSL during Dispatchable Hours
R W Miller STG 2	DFW	279	59	39	41	43	105
Stryker Creek Unit 1A	East Texas	227	65	35	50	53	169
Lake Hubbard Unit 1	DFW	153	97	59	127	137	386
Graham Unit 1	DFW	171	71	46	84	102	236
Trinidad Unit 6	DFW	188	50	51	69	79	237
Lake Hubbard Unit 2A	DFW	163	32	48	116	122	518
Braunig VHB2	San Antonio	176	18	91	91	91	230
Stryker Creek Unit 2	DFW	128	49	35	115	124	472
Graham Unit 2	DFW	110	17	36	62	66	391
Handley Unit 3	DFW	123	-	100	102	103	375
R W Miller STG 3	DFW	100	16	43	50	53	199
Mountain Creek Unit 8	DFW	50	47	160	201	210	562
Spencer Unit 4	DFW	56	40	15	16	17	43
Braunig VHB1	San Antonio	55	39	61	81	94	217
Ray Olinger CTG 3	DFW	93	1	25	25	25	134

Our next analysis compares the average real-time dispatched output of the reliability-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 capacity limit.

- The average quantity dispatched exceeded the respective average low-sustainable limit (LSL) for all months in 2021 with RUC instructions.
- No RUC activity occurred in May.
- In February through December, excluding May 2021, the average dispatch level was more than the average low limit because of scarcity in February and mitigation of the resource in the other months.
- Also, in the same months previously mentioned, the average dispatch level was higher due to some RUC resources choosing to opt out and thus not being subject to the $1,500 per MWh offer floor.

Figure 51: Average Reliability Unit Commitment Capacity and Dispatch Level

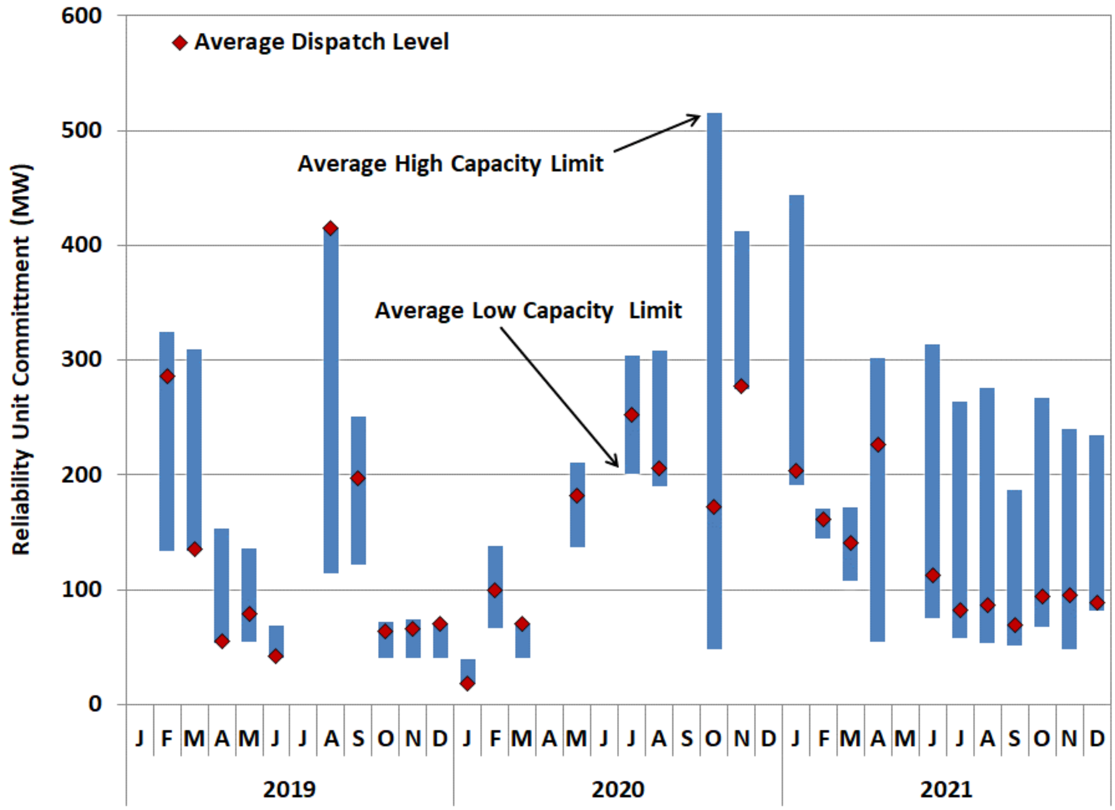


Table 7 displays the total annual amounts of make-whole payments and clawback charges attributable to RUCs since 2011. There are two sources of funding for RUC make-whole payments. The first is from QSEs that do not provide enough capacity to meet their short real-time position, rendering them "capacity short." The remaining make-whole amount is uplifted to all QSEs on a load-ratio share basis. RUC make-whole payments in 2021 were collected almost exclusively from QSEs that were capacity short.

Table 7: RUC Settlement Quantities

	Claw-Back from Generator in millions	Make-Whole to Generator in millions
2011	$8.54	$27.80
2012	$0.34	$0.44
2013	$1.15	$2.88
2014	$2.81	$3.83
2015	$0.34	$0.48
2016	$1.41	$1.24
2017	$1.20	$0.54
2018	$3.07	$0.61
2019	$0.90	$0.05
2020	$0.48	$0.40
2021	$3.11	$5.25

Table 7 shows that the make-whole payments rose significantly to roughly $5.3 million in 2021, higher than any year since the early part of the nodal market in 2011. This increase from preceding years was due to ERCOT's desire to have at least 6,500 MW in reserve above the load forecast, which began in July 2021. The clawback amount was lower than the make-whole payment in 2021. In theory, the clawback amount should be low because units that are economic (and therefore subject to the clawback provision) would generally benefit by opting out of the RUC instruction, if such profitability is foreseeable. However, that will diverge if ERCOT is relying on more conservative forecasts than the market participants are using in their commitment decisions. In 2021, approximately 30% of RUC units opted out.

RUC Generators with Day-Ahead Offers. Generators that participate in the DAM forfeit only 50% of markets revenues above cost through the clawback, rather than 100%. In 2021, 31% of the total RUC unit-hours had day-ahead offers within the RUC-hour, a sharp decrease from 2020 when 87% of the total RUC unit-hours had day-ahead offers, likely attributable to the pivot in conservative operations in the latter half of 2021.

Section VI in the Appendix provides more detail on the RUC activity, showing total activity by month, statistics on day-ahead offers and decisions to opt-out of the RUC instruction, as well as the RUC instructions issued to individual generating resources. Section V also summarizes the dispatch levels of the RUC resources, which is generally at their low dispatch limit (LDL) given the $1,500 per MWh offer floor. However, RUC resources were dispatched above their LDLs in 2021 because of the mitigation of some of the resources committed to resolve non-competitive constraints. That mitigation eliminates the $1,500 per MWh offer floor for those resources in those RUC intervals and dispatches them on their mitigated offer curve.

B. Operational Reserves Compared to Market Reserves

The IMM performed an analysis comparing the operational reserves to the market reserves (Physical Responsive Capability[79] or PRC vs Real-Time On-Line Reserve Capacity[80] or RTOLCAP) for 2019 through 2021. The two reserve calculations 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 additional non-spinning reserve procurement and increased RUC activity have contributed to both higher PRC and a more marked divergence in the two measures of reserve in the second half of 2021. It is important for the real-time market prices to reflect the underlying reliability conditions such as loss of load probability.

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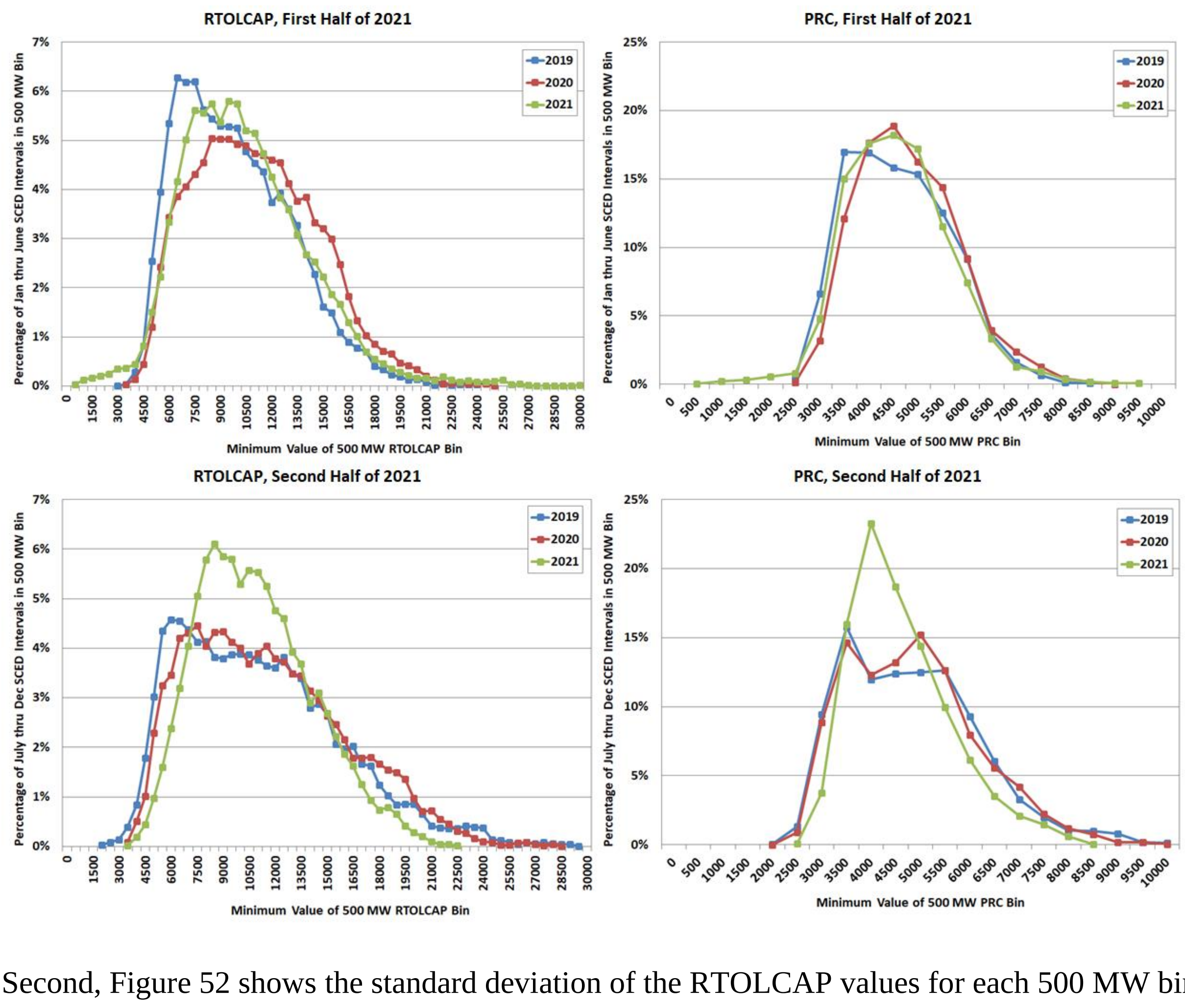
79 A representation of the total amount of frequency responsive online reserve capacity.

80 Real-Time On-Line reserve capacity of all On-Line Resources that remains after SCED dispatch instructions.

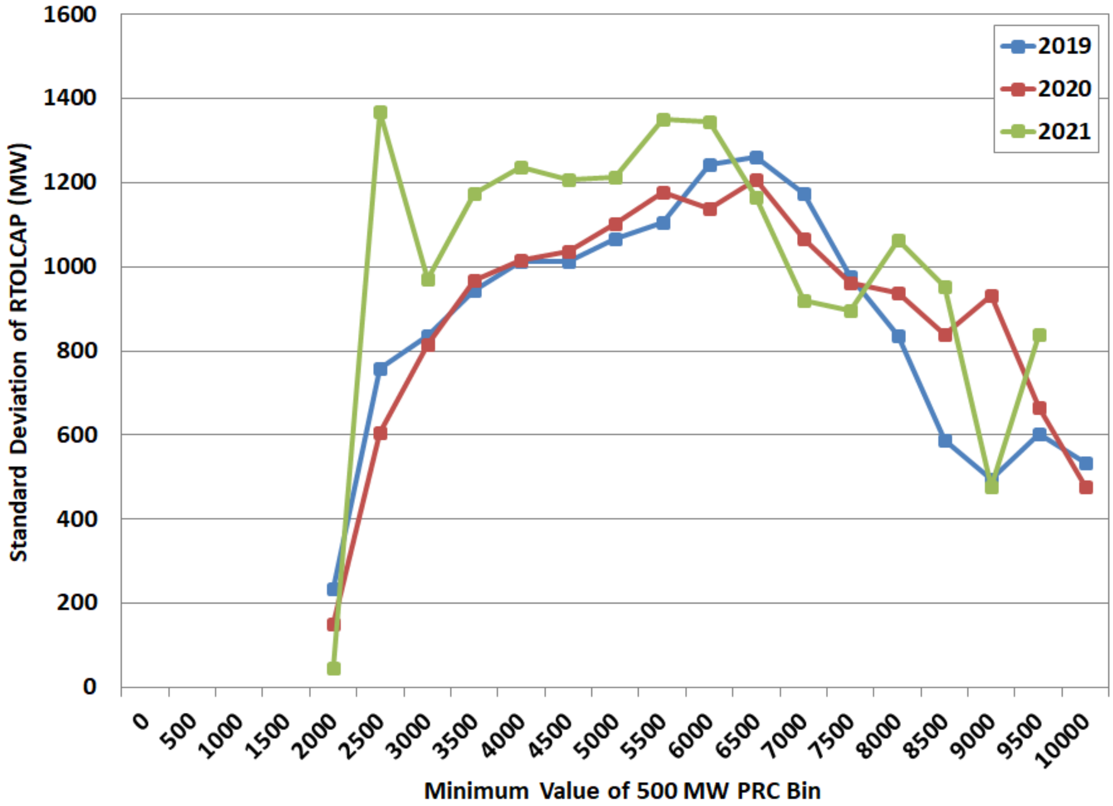
First, we evaluate histograms of the distributions of PRC (a measure of frequency responsive online reserves) and RTOLCAP (a measure of total online reserves) for the first and second halves of the years 2019 through 2021. The top part of Figure 52 shows histograms for the first half of the year and the bottom part shows histograms for the second half of the year. Each year line represents somewhat different shape, driven by the unique grid and market conditions of that year. However, the second half of 2021 shows a more marked departure from the other two recent years. This time period coincides with ERCOT's new conservative operational posture, which includes significantly higher frequency and magnitude of RUC commitments. In comparison to the other years, the second half of 2021 has markedly fewer intervals in the range of PRC below 3,500 MW and RTOLCAP below 6,000 MW, more intervals in the range of PRC between 3,500 MW and 5,000 MW and RTOLCAP between 7,500 and 12,500 MW.

Figure 52: RTOLCAP and PRC Histograms



Second, Figure 52 shows the standard deviation of the RTOLCAP values for each 500 MW bin of PRC, for 2019 through 2021. Note that this figure excludes both the week of Winter Storm Uri as well as the week after, since they are outliers on both ends of the spectrum. Due to the pendulum effect of that event, in the week after the storm many generators stayed online for several days despite negative prices. The increase in the standard deviation is attributable to increased variability in the relationship between PRC and RTOLCAP in the months following ERCOT's change in operational posture. During this time there are periods where there are large amounts of capacity that was under RUC instruction and therefore contributing to PRC but not to RTOLCAP. RUC activity can cause operational reserves and market reserves to diverge from their historical relationship and therefore prices to diverge from the historical relationship with grid reliability conditions.

Figure 53: Standard deviation of RTOLCAP at different levels of PRC[81]



C. QSE Operation Planning

The Current Operating Plan (COP) is the mechanism used by QSEs to communicate the expected status of their resources to ERCOT. After aggregating COP information about the amount of capacity that QSEs expect to be online every hour, ERCOT then evaluates any potential locational or system-wide capacity deficiency. If such a deficiency is identified and there is insufficient time remaining in the adjustment period to allow for self-commitment, ERCOT will issue a RUC instruction to ameliorate the shortfall.

81 Data for all 3 years except February 13-26, 2021.

The accuracy of COP information greatly influences ERCOT's ability to effectively perform supplemental commitment using the RUC process. COPs are updated on an ongoing basis by QSEs, providing multiple views of their expectations for a particular operating hour. Presumably, QSE expectations about which units will be online in a particular hour are most accurate for the COP submitted just before the operating hour. Figure 54 evaluates the accuracy of the COPs by showing the average difference between the actual online unit capacity and the capacity represented in the COPs in the peak hours (hour ending 12-20) in July and August, as submitted each of the 24 hours leading up to the close of the adjustment period. We show these differences for each of the past three years.

Figure 54: Capacity Commitment Timing – July and August Hour Ending 12 through 20

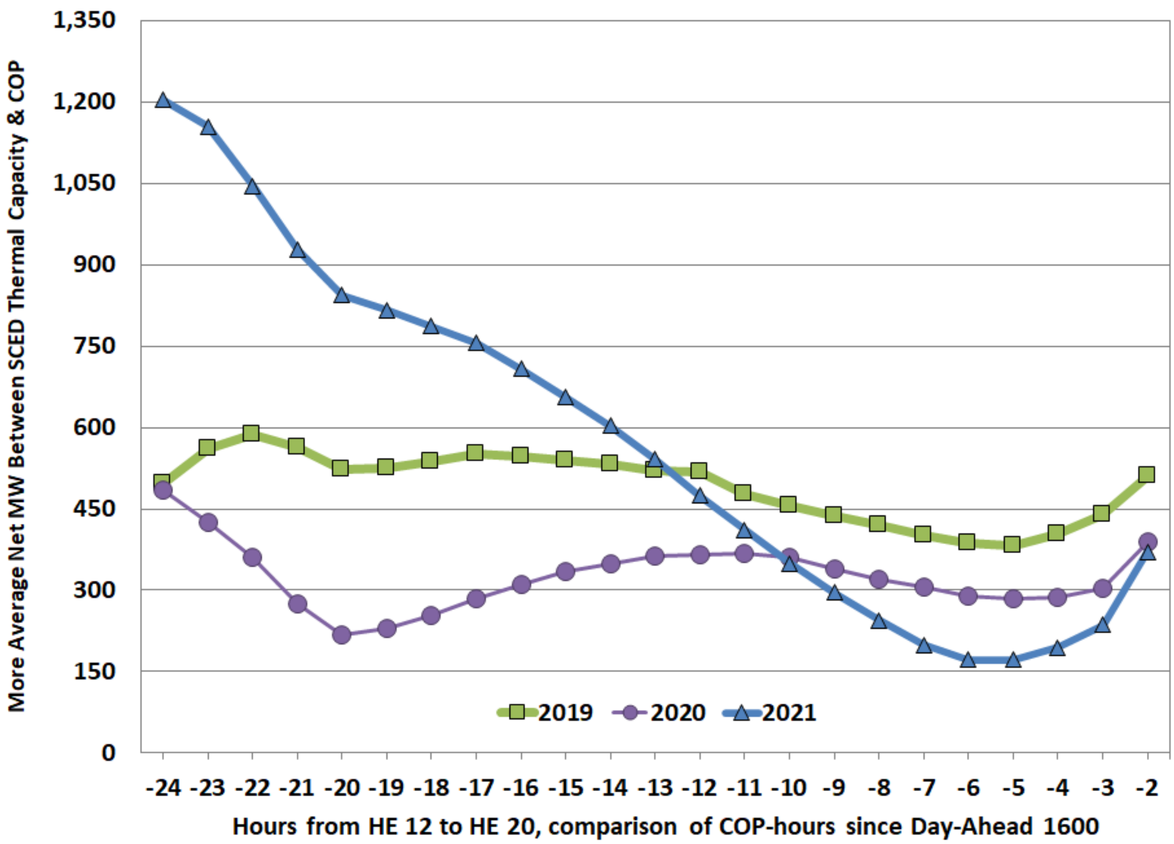


Figure 54 shows that the amount of online capacity in real-time exceeded the thermal capacity represented in COPs at the end of the adjustment period, signifying that generators either did not reflect their commitment decisions in their COPs or changed their commitment decisions within the operating period. Commitment of resources for hours ending 10 to 24 show that 2021 had much later commitments on average than in 2020. The difference in the last COP on average was very similar, however, in 2021 as it was in 2020.

Additional analysis on COP behavior is presented in the Section VI of the Appendix, which includes the analysis of hour ending 17 discussed above.

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 revenue contributions from an installed capacity market, energy and reserve prices provide the only funding for compensation to 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 a long-term expectation and will not necessarily be met in any one year: actual revenues may vary greatly from year to year.

The ERCOT market has seen many years of excess generation capacity, with revenues less than estimated costs of investing in new generation (known as the "cost of new entry" or 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. This principle of cyclical revenue sufficiency to maintain resource adequacy is applied in the evaluation in this section.

This section begins with our evaluation of these economic signals in 2021 by estimating the "net revenue" that resources received from the ERCOT real-time and ancillary services markets and providing comparisons 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, subject to the previous discussion in the Future Needs section. Finally, we conclude with a discussion of the Reliability Must Run and Must Run Alternative (MRA) processes in ERCOT in 2021.

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, it 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 ancillary services and real-time energy markets alone provide the economic signals that inform suppliers' decisions to invest in new generation or, conversely, to retire existing generation. To the extent that revenues are available through the DAM or other forward bilateral contract markets, these revenues are ultimately derived from the expected ancillary service and real-time energy prices. Although most suppliers are likely to receive the bulk of their revenues through bilateral

[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.

contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and thus are appropriate to use for this evaluation. It is important to note that this net revenue calculation is a look back at the estimated contribution based on actual market outcomes. Suppliers will typically base investment decisions on expectations of future electricity prices. Although expectations of future prices are informed by history, they also factor in the likelihood of shortage pricing conditions that may or may not actually occur.

In this analysis, we compute the energy net revenues based on the generation-weighted settlement point prices from the real-time energy market.[83] The analysis may over-estimate the net revenues because 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. Despite these limitations, the analysis provides a useful summary of signals for investment in ERCOT.

The next figures provide an historical perspective of the net revenues available to support investment in a new natural gas combustion turbine (Figure 55 includes Winter Storm Uri and Figure 56 excludes Winter Storm Uri) and combined cycle generation (Figure 57 includes Winter Storm Uri and Figure 58 excludes Winter Storm Uri), which we selected to represent the marginal new supply that may enter when new resources are needed. We calculate net revenues for these units by assuming they will produce energy in any hour in which it is profitable to do so. We further assume that when they are not producing energy, that both types of units will be available to sell responsive or non-spinning reserves in other hours, and that combined cycle units can provide regulation.[84] The figures also show the estimated CONE for each technology for comparison purposes.

These figures show that in 2021, the estimated CONE values for both types of resources increased, with the CONE values for natural gas combustion turbines ranging from $70 to $117 per kW-year. Due to the extreme prices during Winter Storm Uri, the ERCOT market did provide net revenues above the CONE level needed to support new investment in 2021:

- Net revenues for combustion turbines rose to almost $700 per kW-year across all zones (net revenues would have ranged from $60 per kW-year to $78 per kW-year but for Winter Storm Uri); while
- Net revenues for combined-cycle units rose to almost $800 per kW-year across all zones (net revenues would have ranged from $81 per kW-year to $105 per kW-year but for Winter Storm Uri).

In an energy-only market, shortages 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 – both of which occurred during Winter Storm Uri.

83 This can mask the effects of unusually high or low prices at a specific generator location.

84 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.

Figure 55: Combustion Turbine Net Revenues (with Uri)

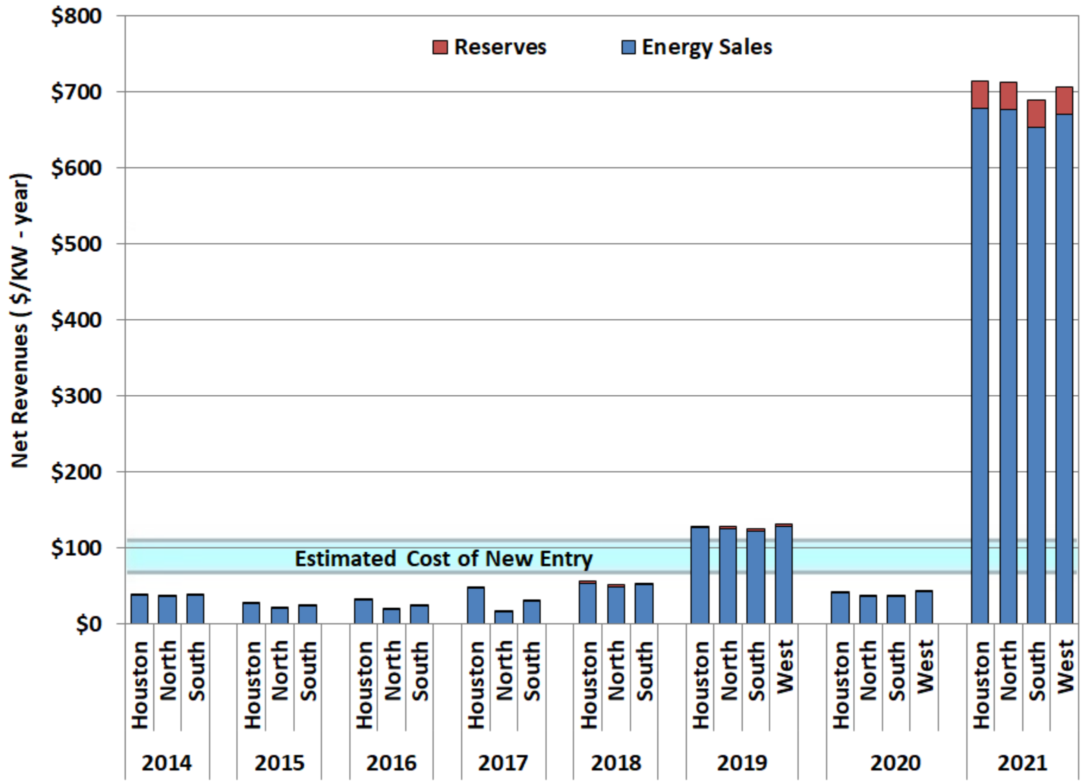


Figure 56: Combustion Turbine Net Revenues (without Uri)

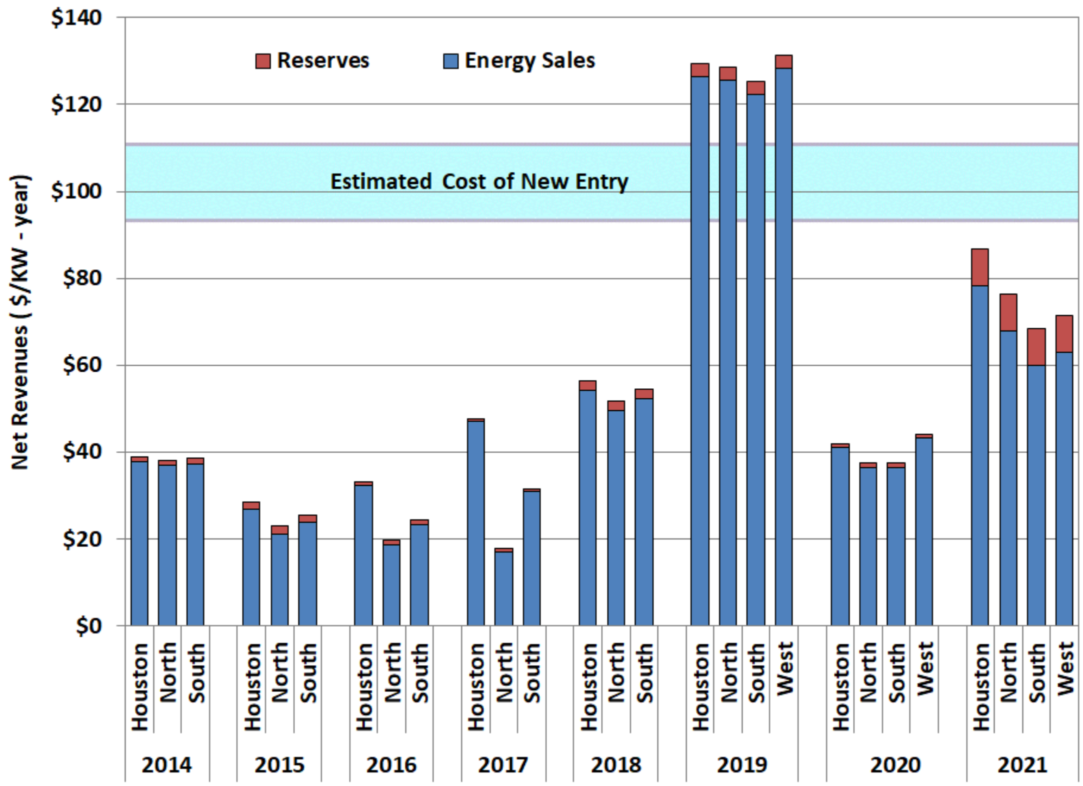


Figure 57: Combined Cycle Net Revenues (with Uri)

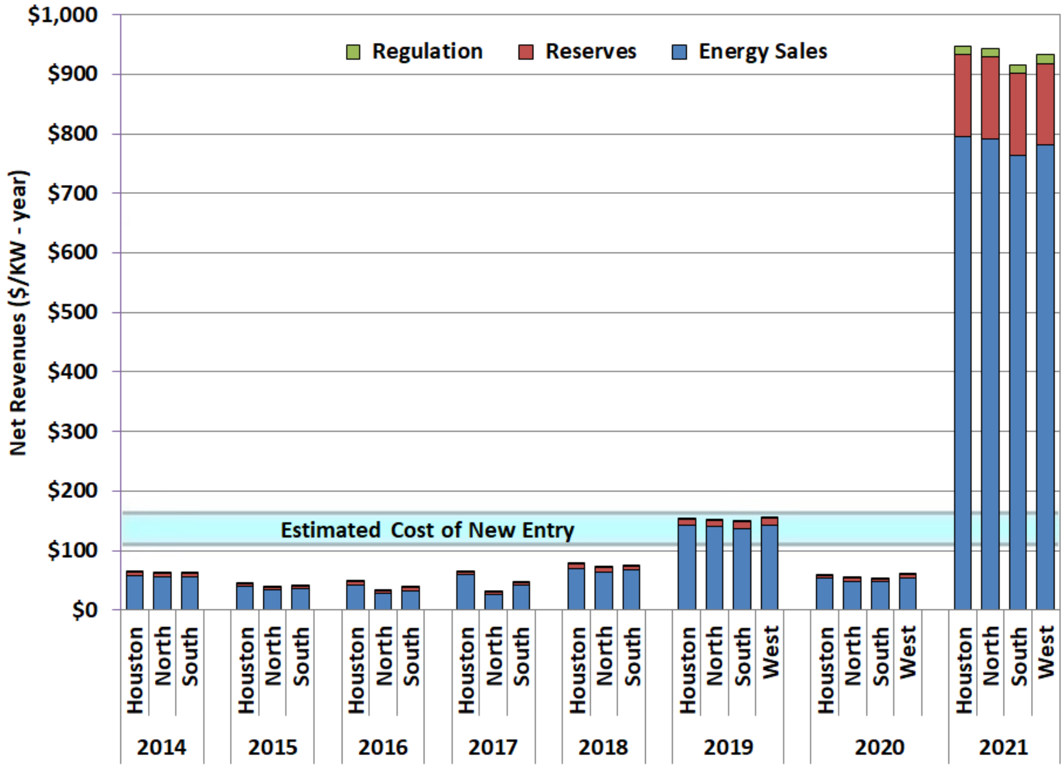
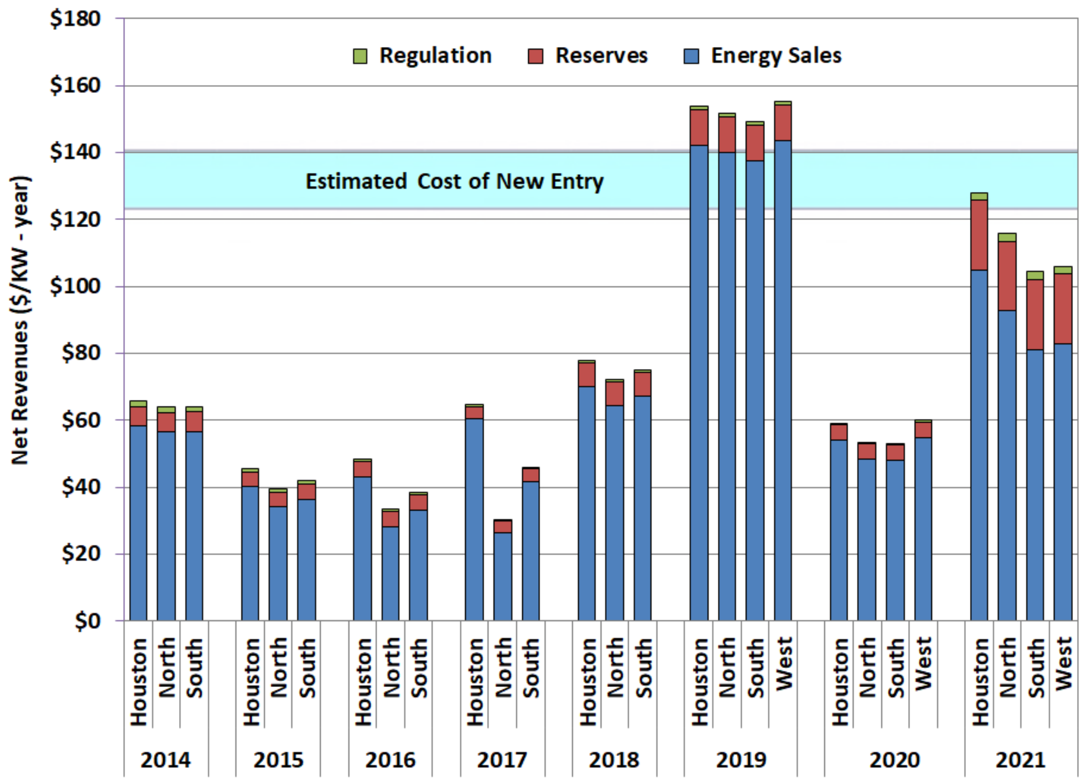


Figure 58: Combined Cycle Net Revenues (without Uri)



The figures above also show that average net revenues were highest in the Houston zone in 2021 as congestion led to higher prices in that zone. In 2021, we saw the continuing trend of the separation in natural gas prices between the Waha and Katy locations lessen versus the last couple of years.

Because of lower fuel cost at Waha, generators served by the Waha location would tend to have higher net revenues than those procuring gas at 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 ranging from $770 to $850 per KW-year at the Waha location, compared to net revenues of $700 to $800 per KW-year at Katy, based on 2021 revenues.

B. Net Revenues of Existing Units

Given the continuing effects of low natural gas prices, we evaluate the economic viability of existing coal and nuclear units that have experienced falling net revenues. Non-shortage prices, which have been substantially affected by the prevailing natural gas prices, are the primary determinant of the net revenues received by these baseload units. Low natural gas prices tend to lead to lower system-wide average prices, but it is the prices at these units' specific locations that matter; the prices at these locations have tended to be lower than the ERCOT-wide average prices. As previously described, the load-weighted ERCOT-wide average energy price in 2020 was $167.88 per MWh. Table 8 shows the output-weighted average price by generation type based on the generators' specific locational prices in 2021.

Table 8: Settlement Point Price by Fuel Type

Generation Type	Output-Weighted Price		
	2019	2020	2021
Coal	$43.92	$24.84	$148.06
Combined Cycle	$47.06	$24.60	$207.84
Gas Peakers	$126.16	$60.26	$1,023.09
Gas Steam	$135.16	$41.90	$405.10
Hydro	$42.90	$23.88	$305.15
Nuclear	$35.38	$20.31	$137.71
Power Storage	$154.80	$80.50	$109.29
Private Network	$46.16	$24.08	$176.76
Renewable	$141.09	$35.23	$43.54
Solar	$61.45	$25.49	$75.97
Wind	$20.54	$11.45	$60.53

Table 8 shows that the prices and associated net revenues were high at all resources' locations in 2021 than the previous two years. This is again explained by the effects of Winter Storm Uri.

Nuclear Profitability. According to data published by the Nuclear Energy Institute, the average total generating cost for nuclear energy was $29.37 per MWh in 2020. The 2020 total generating costs were not only 4.6% lower than in 2019 but also were 35% below 2012 costs.[85] 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 declining, ERCOT's 5 GW of nuclear capacity should have costs less than $30 per MWh. The table above shows an average price for the nuclear units of approximately $138 per MWh making it likely that the nuclear units in ERCOT that were able to stay online during Winter Storm Uri were profitable in 2021. The prices prices during Winter Storm Uri and subsequent profitability are not expected to continue at that level in the coming years due to the rarity of that event.

Coal Profitability. The generation-weighted price of all coal and lignite units in ERCOT during 2021 was $148.06 per MWh, an increase from $20.98 per MWh in 2020, although that level of increase is deceiving based on the extraordinary events of February 2021. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.78 per MMBtu in 2021, slightly higher than 2020. At these average fuel prices, coal units in ERCOT that were able to stay online during Winter Storm Uri are likely receiving more than enough revenue to cover operating costs.

Natural Gas-Fired Resource Profitability. In 2021, the revenues rose significantly because of Winter Storm Uri in February. The shortage pricing for energy and ancillary services produced a spike in net revenues for natural gas resources, although many gas-fired generators failed to stay online during the storm. This caused them to miss the opportunity for these net revenues and, in some cases, to have to buy back energy back at the extreme prices that they sold day ahead.

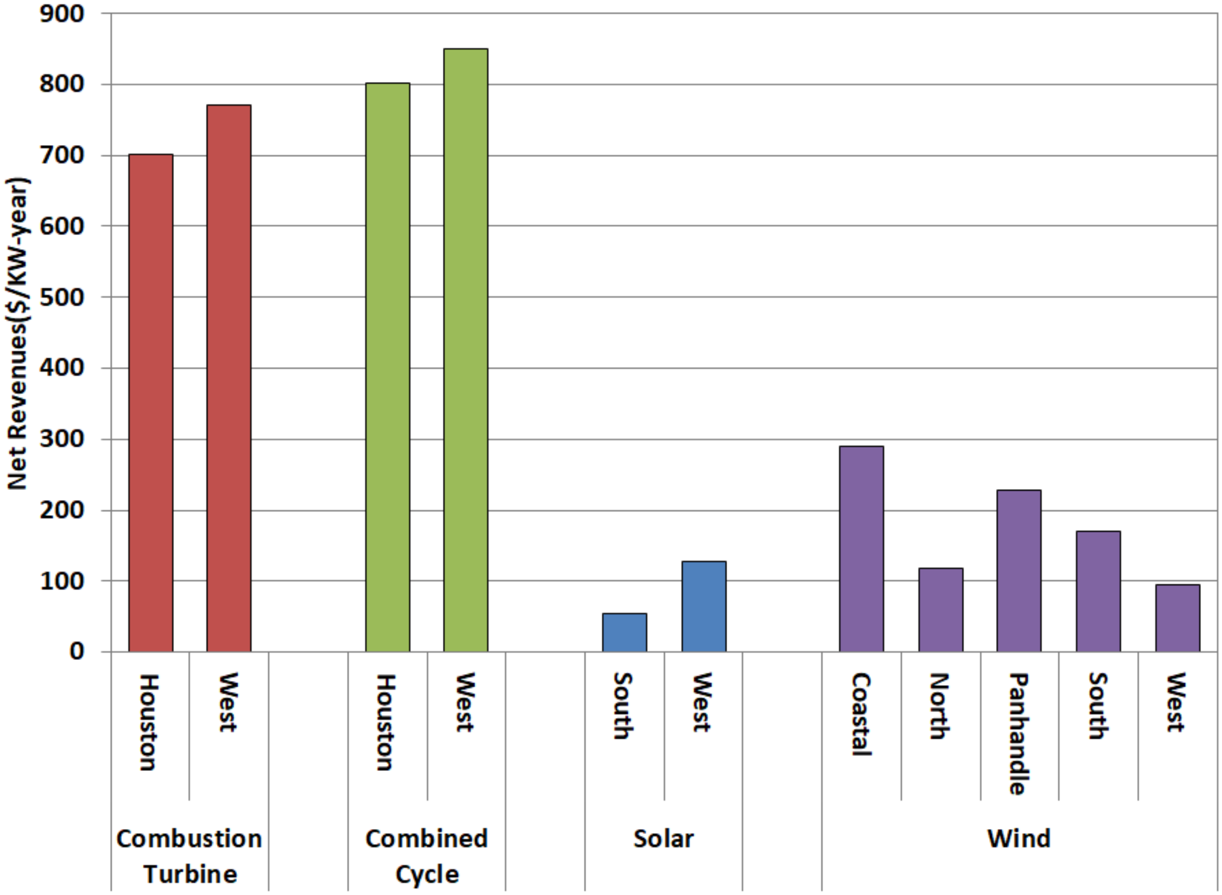
Net Revenues by Technology and Location. Figure 59 shows the net revenues at different locations for a variety of technologies. Because natural gas prices can vary widely, the revenues for natural gas units are shown for the Houston zone (reflecting Katy hub prices) and the West zone (for Waha). Historically, the high natural gas production in the Permian Basin and limited export capability has resulted in low gas prices at the Waha location and much higher net revenues for gas resources in this area. New transportation projects are currently underway and thus that basis difference in natural gas prices has decreased.

Figure 59 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 to be received. Net revenues for wind and solar were lower than gas technologies in 2021 in all areas. This is partly because intermittent technologies cannot maximize their output and associated revenues during shortage conditions. This is particularly

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

true for wind resources that tend to produce less output during hot summer conditions. In 2021, these differences were more pronounced because of Winter Storm Uri.

Figure 59: Net Revenues by Generation Resource Type



Interpreting Single-Year Net Revenues. These results indicate that on a stand-alone basis during 2021, the ERCOT markets did provide sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Net revenues were the highest they have ever been as result of the extreme shortage pricing in 2021. Investors' response to these prices will depend on their future revenue expectations over a number of years. The prevailing capacity surplus and the changes in how policymakers and ERCOT will be managing the system going forward are likely to limit these expectations. However, it is also important to recognize that investors may invest instead in new technologies, such as battery energy storage or load-flexible renewables, which have different value propositions than traditional generation.

For all these reasons, it is important to be cautious in interpreting single-year net revenues and projecting their long-term effects, especially in a year where revenues were higher than they likely to ever be again. Please see Section VII of the Appendix for additional detail and discussion of the net revenue results presented in this subsection.

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.

There are many ways that the market can respond to high prices, all of which result in rising planning reserve margins:

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

In 2020, there were no significant expected or actual shortages, partly because the effects of the COVID-19 reduced load and the summer weather was mild. In 2021, those same expectations were subverted by Winter Storm Uri. The extreme conditions in February 2021 could not have been expected by participants. Resources were not properly winterized, coordination with the natural gas industry was insufficient, and exposure to real-time prices at the cap for more than four days was a catastrophic reality for many market participants. The year was an outlier in ERCOT market history and it will take time to fully understand how the market will evolve.

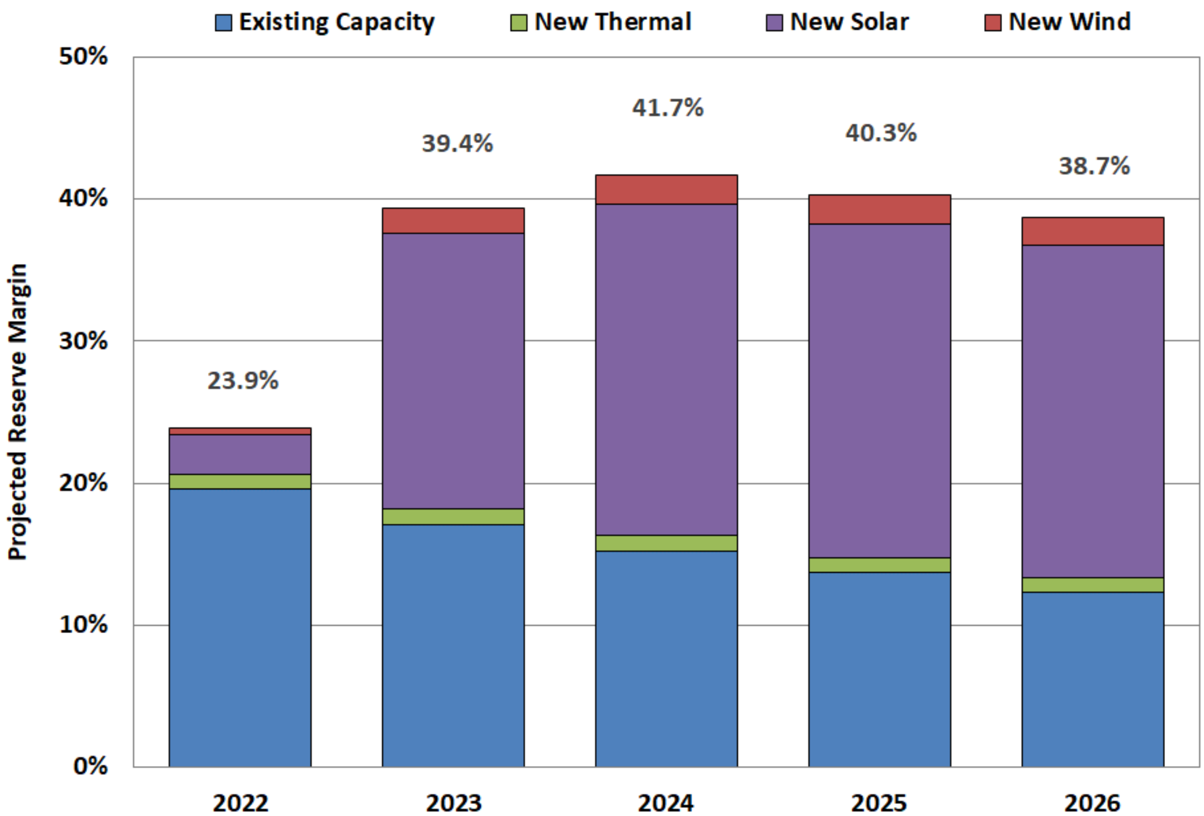
Similar to the analysis of net revenues year over year above, it is important to be cautious in interpreting single-year lack of shortage pricing and projecting the long-term based on planning reserves, as shortages can occur in peak net load intervals that may be different than those studied in the planning horizon. Planning reserves take a more holistic and long-term view of market conditions and may not indicate the frequency of shortage conditions in any given year.

In the December 2020 Capacity, Demand, and Reserves (CDR) report, the 2021 summer reserve margin was forecasted to be 15.5%, based on resource updates provided to ERCOT from generation developers and an updated peak demand forecast. This was down 1.8% from what was reported in the May 2020 CDR due to solar and wind project delays and cancellations.

In 2021, ERCOT saw a significant increase in utility-scale solar resources. Based on ERCOT's interconnection queue, this trend is expected to continue over the next several years and increase the forecasted planning reserve margin for 2022 through 2025 up to 40 to 42%.[86] Figure 60 shows ERCOT's current projection of planning reserve margins over the next five years, including the new generators that account the changes in the reserve margin.

86 *See* Report on the Capacity, Demand and Reserves in the ERCOT Region, 2022-2031 (December 29, 2021), https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.pdf.

Figure 60: Projected Planning Reserve Margins



Source: ERCOT Capacity, Demand and Reserves Report, December 2021

Figure 60 indicates that Texas heads into the summer months of 2022 with an improved planning reserve margin of 23.9%, much higher than the 15.5% reserve margin for 2021. We note that the current methodology of performing the CDR does not consider ESRs. Including the growing quantity of storage resources would increase the reserve margin. In addition, the CDR relies solely on hour ending 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 be added to the ERCOT system.

D. Effectiveness of the Shortage Pricing Mechanism

One of the primary goals of an efficient electricity market is to ensure that, over 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 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 loss of load probability 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 reserves levels drop. The ORDC is described in more detail in Section I. Over the time it has been in effect, ORDC has had an increasingly material impact on real-time prices, especially in 2019 when reduced installed reserves led to higher expectations of shortage pricing. The ORDC adder reflects VOLL, which was set to $9,000 per MWh in June 2014. The real-time prices are increased by the Real-Time Reserve Price, which is determined based on 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. If the PNM threshold is exceeded, the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[87] Section I contains several summaries and discussions of the shortage pricing that occurred in 2021. The next section compares pricing in prior years to 2021, the first year that the PNM threshold was ever reached.

2. Peaker Net Margin in 2021

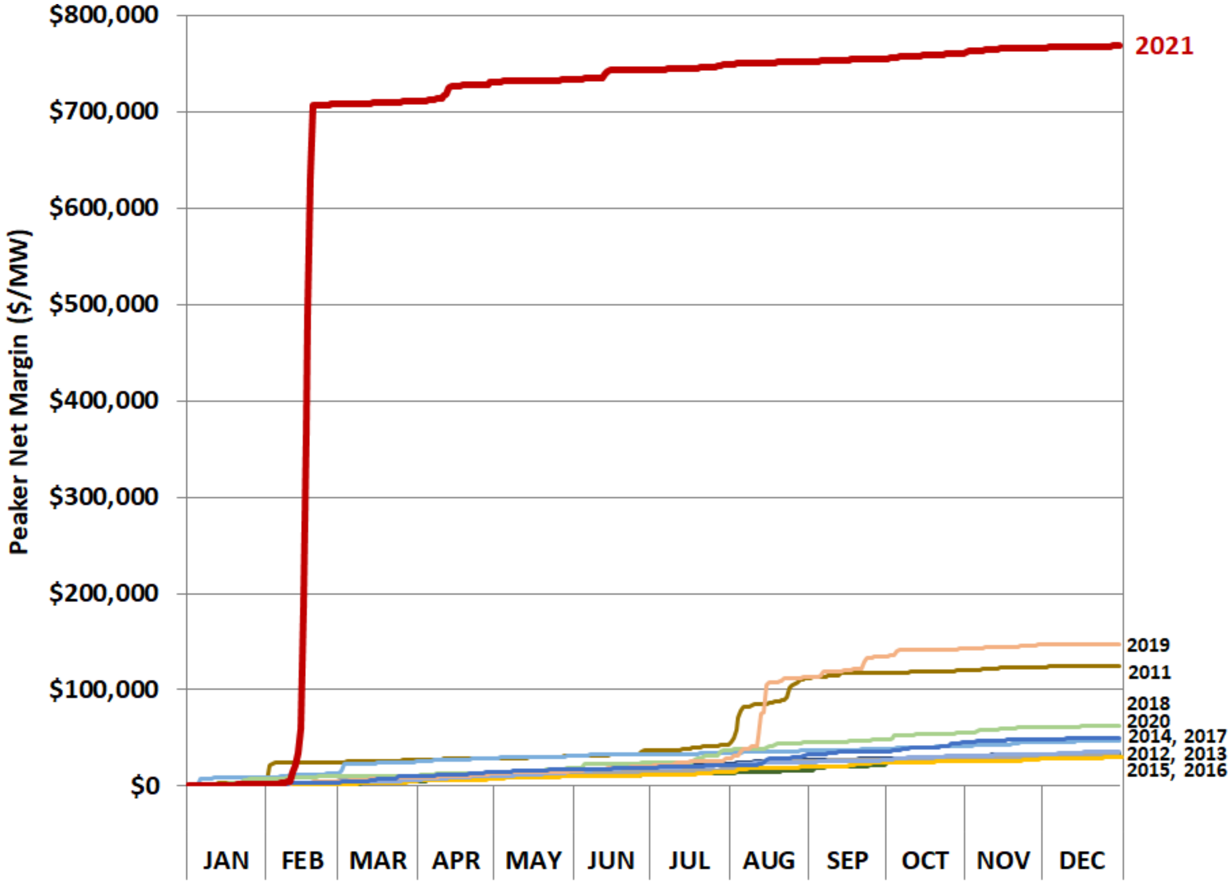
Figure 61 shows the cumulative PNM results for each year since the creation of the Scarcity Pricing Mechanism. When administering the scarcity-pricing mechanism in ERCOT under 16 TAC § 25.505, the system-wide offer cap is set equal to the high system-wide offer cap (HCAP) at the beginning of each calendar year and maintained at this level until the PNM during a calendar year exceeds a threshold of three times the annual cost of new entry of new generation plants ($315,000). This figure shows that the $315,000 PNM threshold was exceeded for the first time in ERCOT's history during the ERCOT operating day of February 16, 2021.

Once the peaker net margin threshold is achieved, the system-wide offer cap is set at the low system-wide offer (LCAP) for the remainder of the calendar year. The LCAP is set at the greater of either $2,000 per MWh and $2,000 per MW per hour or 50 times the natural gas price index value determined by ERCOT. However, the exceptionally high natural gas prices $400/MMBtu during Winter Storm Uri (up to $400/MMBtu or more than 100 times normal levels) caused the LCAP rise to more than double the HCAP. Therefore, the Commission suspended use of the

[87] 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.

LCAP on March 3 to avoid outcomes contrary to the purpose of the rule, which was to protect consumers from sustained high prices in years with exceptional generator revenues.[88] Once the natural gas prices had stabilized and the LCAP was no longer expected to exceed the HCAP, and the Commission reinstituted the application of the LCAP.[89]

Figure 61: Peaker Net Margin



The Commission made an additional change to the LCAP in PUC Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism*, when it eliminated the provision that tied the value of the LCAP to natural gas prices. The revised rule instead makes resources whole to their actual marginal costs when the LCAP is in effect.

3. Changes to the ORDC

The Commission directed notable changes to the ORDC in 2021. In previous years, the Commission considered proposals modifying various defining aspects of the ORDC, including

88 *See Calendar Year 2021 - Open Meeting Agenda Items*, Project No. 51617, Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules at 2 (Feb. 16, 2021).

89 *Issues Related to the State of Disaster for the February 202 1 Winter Weather Event*, Project No. 51812, Order Reinstating Low System-Wide Offer Cap at 1-2 (Mar. 3, 2021).

shifting the LOLP portion of the curve.[90] The LOLP portion of the curves used to determine the ORDC price adder has typically been constructed using normal probability distributions defined by two factors: a) the average of historical differences between expected and actual operating reserves ("mu"), and b) the standard deviation in those values ("sigma").[91] On January 17, 2019, the Commission approved a two-part process to modify the ORDC in two steps:

1. Transitioning to a single blended ORDC curve and implementing a 0.25 standard deviation shift in the LOLP calculation in the spring of 2019, and
2. Implementing a second 0.25 standard deviation shift in the spring of 2020. The second step of the ORDC change was implemented on March 1, 2020.

Following Winter Storm Uri, the Commission worked with participants to develop a blueprint for reforms to the design of the wholesale electric market.[92] The blueprint compiles directives and reforms to be implemented in two phases. Phase I of the blueprint focuses on enhancements to current wholesale markets to improve price signals and operational reliability. Part of Phase I of the blueprint included significant changes to the ORDC.

Aimed at rewarding reliable generation assets that are available as shortage conditions emerge, the modified ORDC is designed to cause prices to rise more quickly as conditions start to become tight. This provides incentives to bring generation units online and prompt consumer demand response earlier to help enhance regular market operations and avoid conservation appeals. Changes to the ORDC were made effective January 1, 2022, to set the MCL at 3,000 MW and set the high system-wide offer cap and VOLL to $5,000 per MWh.

After that initial implementation, the Commission committed to considering decoupling of the system-wide offer cap and VOLL. This includes establishing a new VOLL based on quantitative analysis of new revenue to the market that would be directed to reliable generation assets during shortage events. The Commission also required a report from ERCOT to the Commission by November 1 of every even-numbered year analyzing the efficacy, utilization, related costs and contribution of the ORDC to grid reliability in ERCOT.

E. 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.[93] A Reliability Must Run (RMR) Unit is a resource

90 *Review of Summer 2018 ERCOT Market Performance*, Project No. 48551.

91 Mu and sigma are separately calculated for each of the twenty-four curves currently used (six time of day blocks and four seasons).

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

93 http://www.ercot.com/content/wcm/lists/89476/OnePager_RMR_May2016_FINAL.pdf

operated under the terms of an agreement with ERCOT that would not otherwise be operated except that it is necessary to provide voltage support, stability or management of localized transmission constraints under credible single contingency criteria where market solutions do not exist. 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 to stay open 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 2021.[94] ERCOT determined that none of the units were necessary to support ERCOT transmission system reliability, therefore no Reliability Must-Run (RMR) contracts were awarded in 2021.[95]

94 South Houston Green Power LLC (RE) – AMOCOOIL_AMOCO_S2; Petra Nova Power I LLC (RE) – PNPI_GT2; Snyder Wind Farm LLC – ENAS_ENA1; City of Austin dba Austin Energy (RE) – DECKER_DPG2; Sherbino I Wind Farm LLC – KEO_KEO_SM1; City of Garland – OLINGR_OLING_1; Wharton County Generation LLC – TGF_TGFGT_1.

95 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.

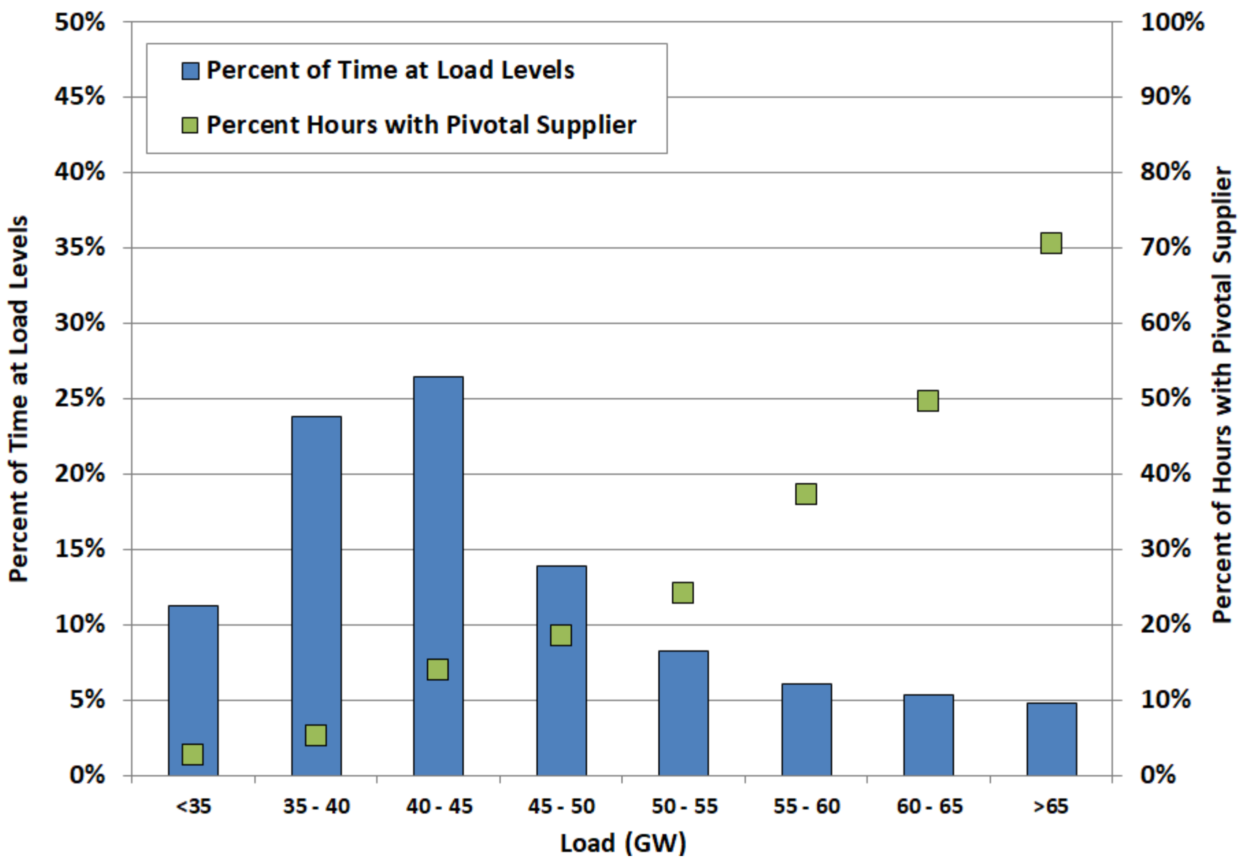
VIII. Analysis of Competitive Performance

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 in effect during 2021. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2021.

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 supplier is "pivotal", i.e., when its resources are necessary to satisfy load or manage a constraint. Figure 62 summarizes the results of the 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 62: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW, there was a pivotal supplier approximately 71% of the time in 2021. This high percentage is expected because at high load levels the largest suppliers' resources are more likely to needed as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed 18% of all hours in 2021, which was slightly lower than 2019 and 2020. Even with this reduction, market power continues to be a potential concern in ERCOT, requiring effective mitigation measures to address it. More detailed analysis of the pivotal supplier issue is presented in Figure A46 in the Appendix.

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 only 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 removed to address this concern (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 narrower areas that can become isolated by transmission constraints raise more substantial competitive concerns. As more fully discussed in Section VI, 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 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 on 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. Generation Outages and Deratings

At any given time, some portion of the generation is unavailable because of outages and deratings. 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. Derated capacity is the difference between the summer maximum capacity of a resource as registered with ERCOT 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). Wind generators rarely produce at the installed capacity rating because of variations in wind speed. Due to the high numbers, we show wind separately in our evaluation of deratings. As discussed in Section VI above, summer availability has been increasing since 2017 in ERCOT because of the incentives provided by the recent increase in shortage pricing.

Figure 63 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2021. This analysis includes all in-service and switchable capacity. From the total installed capacity, we subtract the following: (a) capacity from private networks not available for export to the ERCOT grid; (b) wind capacity not available because of the lack of wind input; (c) short-term deratings; (d) short-term planned outages; (e) short-term forced outages; and (e) long-term outages and deratings greater than 30 days. What remains is the available capacity.

Figure 63: Reductions in Installed Capacity

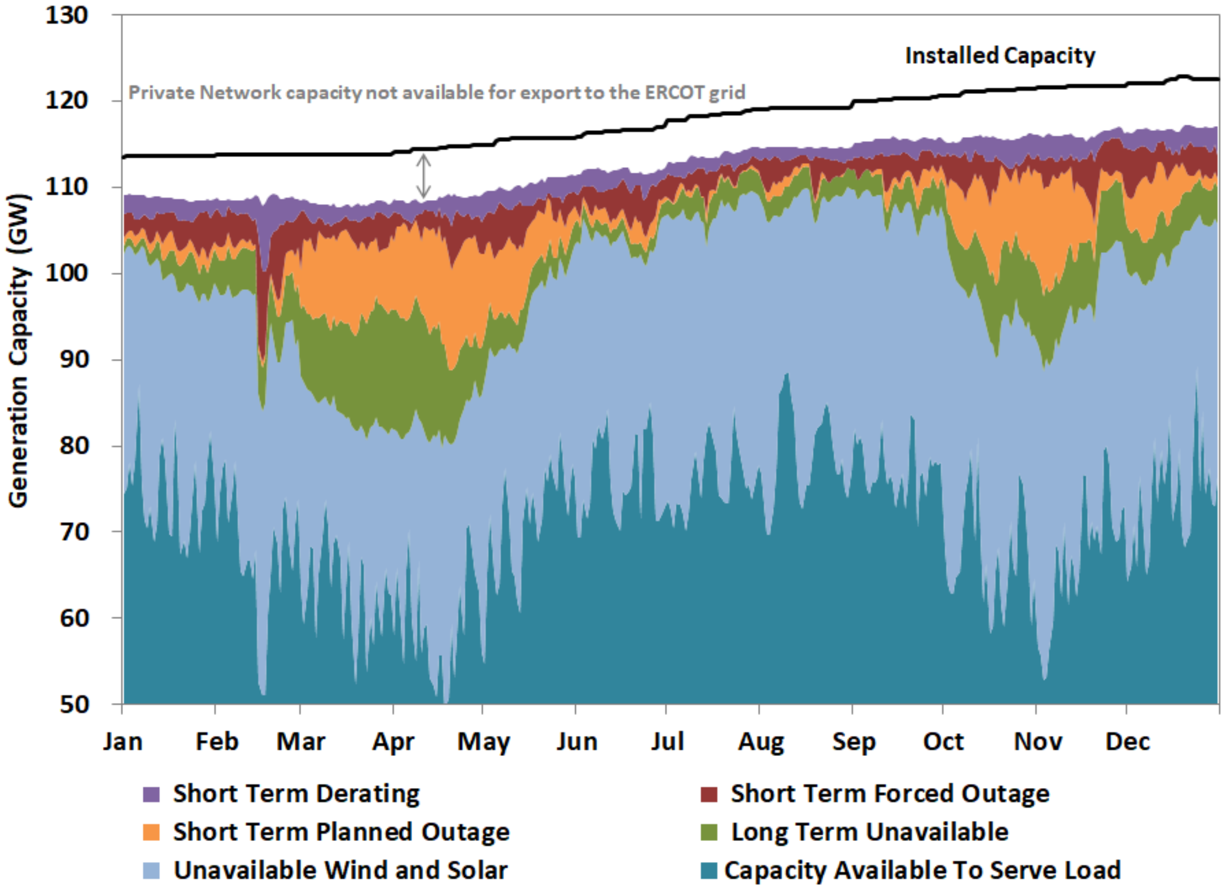


Figure 63 shows that short-term outages and deratings of non-wind generators fluctuated between 1.4 to 21.4 GW, while wind unavailability varied between 7.5 and 30 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent with our expectations. Short-term forced outages and deratings spiked in February during Winter Storm Uri which led to more long-term outages in the following months to perform repairs. The quantity of long-term (greater than 30 days) unavailable capacity peaked in March at more than 14 GW, with almost all capacity returned to service in anticipation of any warm temperatures and shortage conditions in the summer of 2021.

In the next analysis, we focus specifically on short-term planned outages and forced outages and deratings of non-wind units because these classes of outages and deratings are the most likely to be used to physically withhold units in attempts to raise prices. The following Figure 64 provides a comparison of the monthly outage and derating values for 2020 and 2021.

Figure 64: Short-Term Deratings and Outages

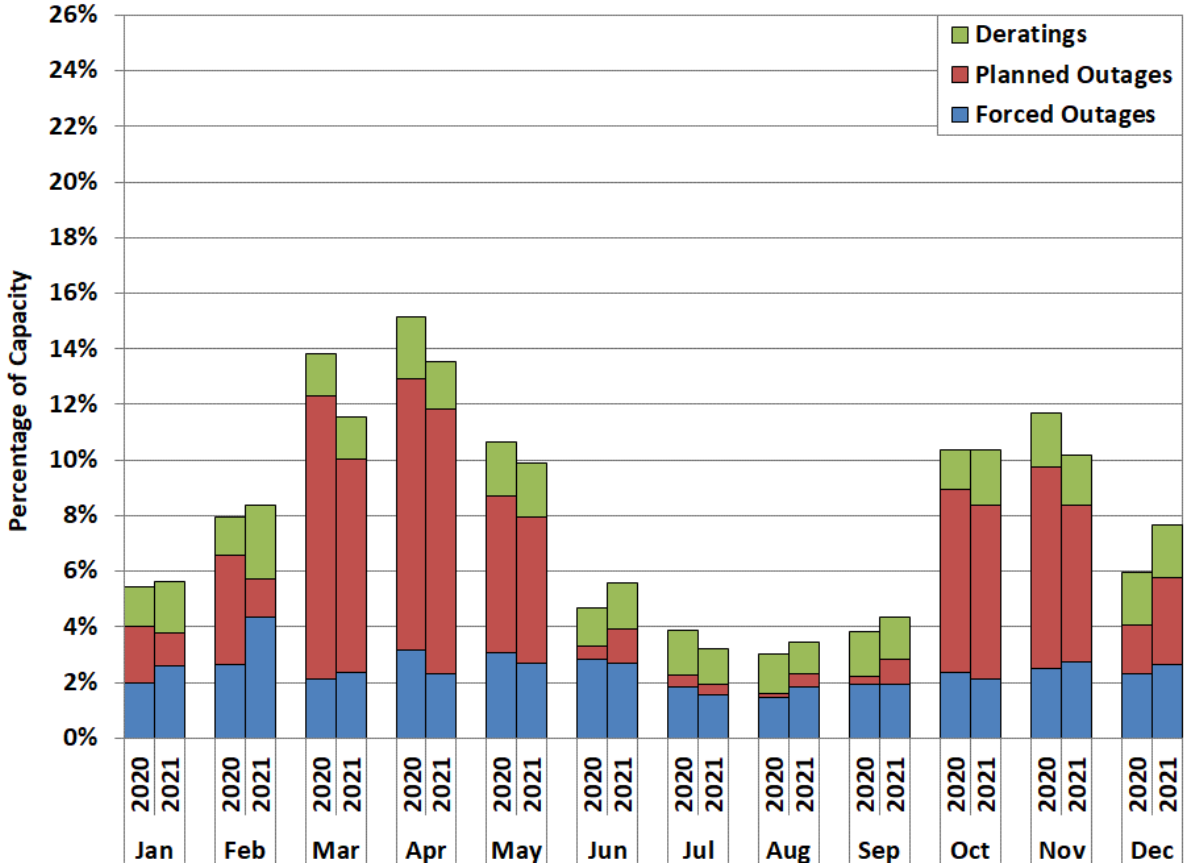


Figure 64 shows a general consistency of forced outages from last year, with the exception of the forced outages that occurred during Winter Storm Uri in February. Planned outages were low in February 2021, indicating that there was deferral of some outages in anticipation of the winter event. However, those actions likely were at the cost of higher outage rates in October and November in both years. Finally, the significant increase in planned outages scheduled during spring and fall in both years is an indicator of preparation for summers in which the ability to capture shortage pricing is the highest.

The consistently modest amount of deratings across most months of 2021 indicates that generators were intent on maximizing generator availability. The low forced outage rates during July and August 2021 and the low level of derations overall are likely a result of increased planned maintenance activities. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours. Figure A47 in the Appendix shows the average magnitude of the short-term outages and deratings lasting less than 30 days for the year and for each month during 2021. Figure A48 in the Appendix also includes long-term outages, which rose sharply in March and April as generators made repairs and upgrades after Winter Storm Uri.

2. 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 prevailing market 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 62 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 65 shows the average short-term deratings and forced outages as a percentage of total installed capacity for large and small suppliers during summer months, as well as the relationship to different real-time load levels. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, we look at the patterns of outages and deratings of large suppliers and compare them to the small suppliers' patterns.

Long-term deratings are unlikely to constitute physical withholding given the cost of such withholding and are therefore excluded from this analysis. Wind and private network resources are also 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 65: Outages and Deratings by Load Level and Participant Size, June-August

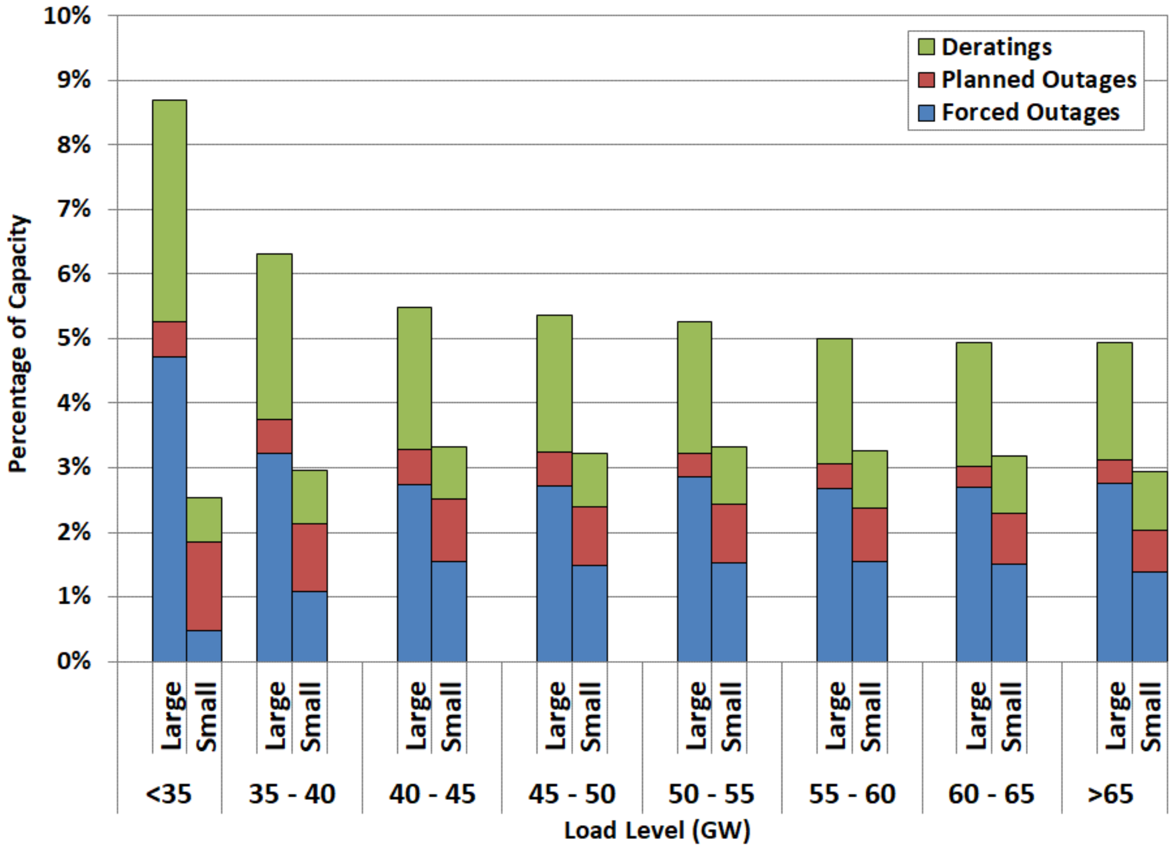
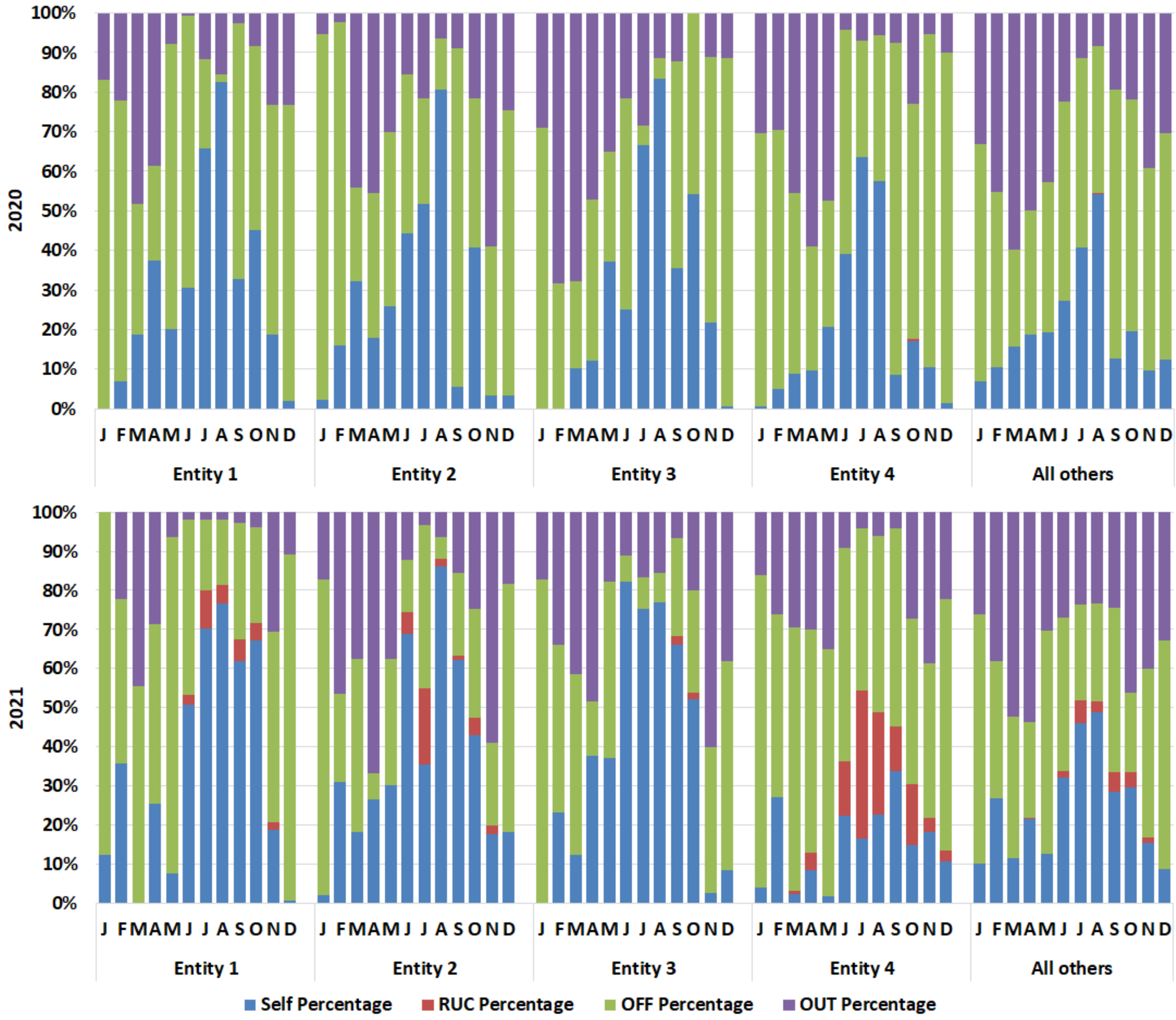


Figure 65 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the outage rates for small suppliers serves as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels exceeded those for small suppliers, but remain at levels that are small enough to raise no competitiveness concerns. Small suppliers have the most incentive to ensure generator availability because each unit in their fleet makes up a larger percentage of the total, which means that any outage has the potential for larger financial impacts.

We did identify a withholding strategy that arose out of the frequent use of the RUC tool in the latter half of 2021. Given the predictability of the RUC instructions, the ability to opt out of RUC settlement during the operating hour if conditions changed, and the high RUC offer floor which economically withheld MWs under a RUC instruction, a disincentive to self-commit existed for large suppliers. One large supplier did in fact adjust its self-commitment behavior and was far more likely to run under RUC commitment than was seen in prior years. Figure 66 below depicts the difference in behavior of entities between 2020 and 2021 for resource-daily decisions for gas steam resources. Entity 4 exhibited a marked reduction in self-commitment for these resources, a pattern that did not exist for other entities.

Figure 66: Monthly Commitment Percentages of Gas-Steam Units



To address this incentive issue with the frequent use of RUCs and the high RUC offer floor, we filed NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.* This rule change reduced the RUC offer floor to $250 per MWh and made the RUC opt-out provision limited in its applicability. The rule change was approved by the Board on April 27, 2022, and partially implemented on May 13, 2022.

3. 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 so as not to be dispatched.

A resource is evaluated for inclusion in the output gap when it is 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 67: Incremental Output Gap by Load Level and Participant Size – Step 2

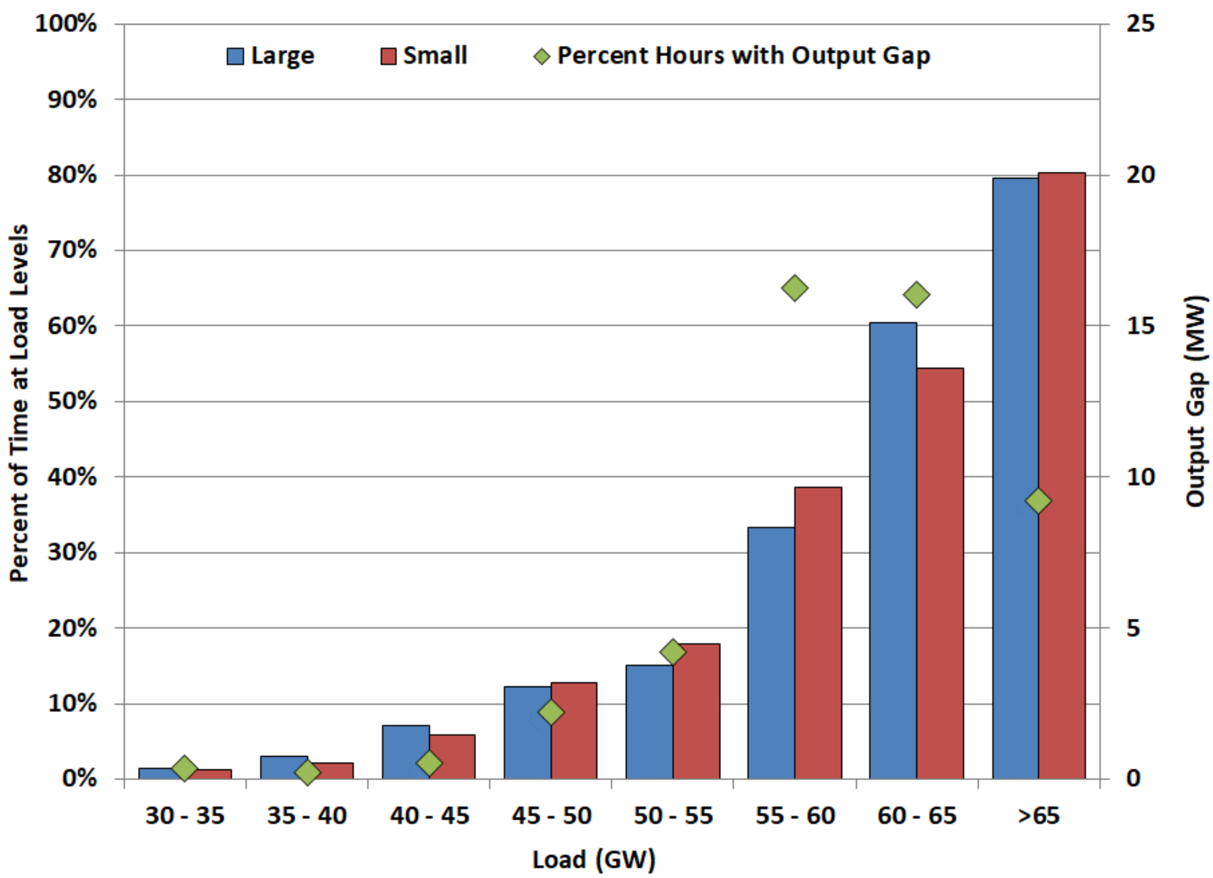


Figure 67 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer, i.e., the mitigated offers, but with a few changes. We use generic costs instead of verifiable for quick-start units since verifiable costs may contain startup costs inappropriate for comparison here. In addition, fuel adders are removed since they represent fixed costs.

Finally, we do not count quick-start units if they have zero output. Relatively small quantities of capacity are considered part of this output gap, although 22% of the hours in 2021 exhibited an output gap. Taken together, these results show that potential economic withholding levels were low in 2021 and considering all of our evaluation of the market outcomes presented in this Report, allow us to conclude that the ERCOT market performed competitively in 2021.

C. Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) can be filed and if subsequently approved by the Commission, adherence to such plans constitute an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. In 2021, Calpine, NRG and Luminant had active and approved VMPs filed with the Commission.[96] Further details of all three VMPs can be found in Section VII of the Appendix. Generator owners are 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).

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 DAM) because the prices in forward energy markets are derived from expectations for real-time energy prices. Forward energy markets are voluntary, and the market rules do not inhibit arbitrage between the forward energy markets 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.

Key elements in the three existing VMPs are the termination provisions. The approved VMPs may be terminated by the Executive Director of the Commission with three business days' notice, subject to ratification by the Commission.[97] 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."[98] 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 of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner.

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96 *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 *Commission 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).

97 Further, Luminant's VMP will terminate on the earlier of ERCOT's go-live date for RTC or seven years after approval.

98 PURA § 39.157(a).

D. Market Power Mitigation

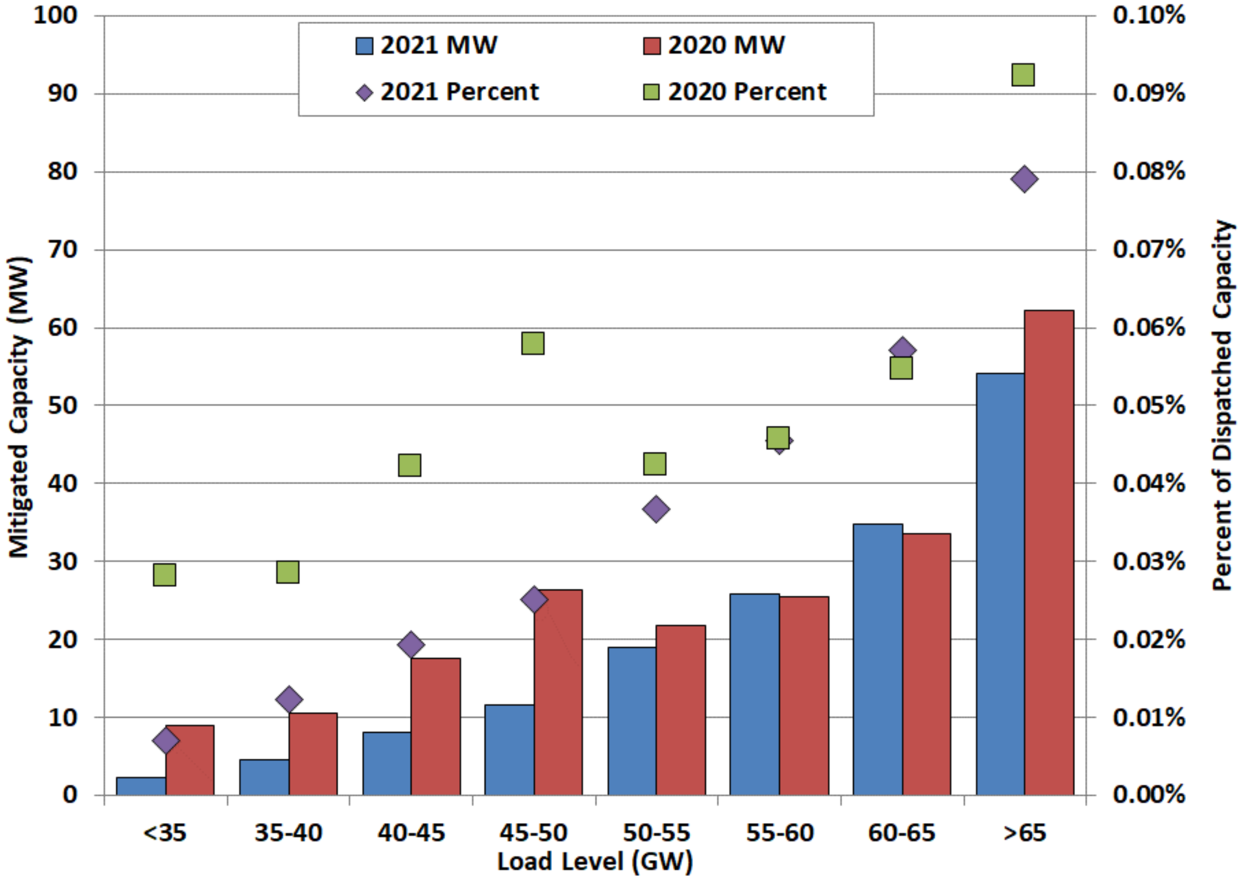
In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to a level that approximates competitive offers. ERCOT's real-time market includes a mechanism to mitigate offers for resources that are required to resolve a transmission constraint. Mitigation applies whether the unit is self-committed or receives a RUC instruction. RUC instructions were typically given to resolve transmission constraints in previous years, though in 2021 RUC for system-wide capacity was common. When units that receive RUC instructions are required to resolve a non-competitive transmission constraint, they often end up mitigated in real-time.

ERCOT's dispatch software includes an automatic, two-step mitigation process. In the first step, the dispatch software calculates output levels (base points) and associated locational marginal prices using the participants' offer curves and considers only the transmission constraints that have been deemed competitive. These "reference prices" at each generator location are compared with that generator's mitigated offer cap, and the higher of the two is used to formulate the offer curve used for that generator in the second step in the dispatch process. The resulting mitigated offer curve is used by the dispatch software to determine the final dispatch levels and locational marginal prices, taking all transmission constraints into consideration.

This approach is intended to limit the ability of a generator to exercise market power, i.e., to limit its ability use its offer to raise prices in the event of a transmission constraint that requires its output to resolve. In this subsection, we analyze the quantity of mitigated capacity in 2021. The automatic price mitigation aspect of 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 68 shows the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level. The amount of mitigation in 2021 was generally lower than in 2020. This was due to fewer non-competitive constraints binding in 2021 than in 2020. In particular, when resources are necessary to resolve a local constraint, it is more likely to be deemed non-competitive and result in mitigation. Only the amount of capacity that could be dispatched within one interval is counted as mitigated for the purpose of this analysis. More analysis of mitigation is presented and discussed in Section VI in the Appendix.

Figure 68: Mitigated Capacity by Load Level



Conclusion

As the IMM for the Commission, Potomac Economics is providing this Report to review and evaluate the outcomes of the ERCOT wholesale electricity market in 2021. The year saw unprecedented shortages and outages because of severe cold weather in February, culminating in record levels of shortage pricing. The ripple effects of the Winter Storm Uri reverberated in all corners of the market and system throughout the remainder of the year. The results of that extreme event prompted much more conservative operations of the system by ERCOT, as well as the development of a number of market reforms. We will monitor and evaluate these changes in future reports.

Overall, our evaluation of a number of factors suggests that the market performed competitively in 2021. We identified one incentive concern related to the increase in RUC activity. Our proposed resolution of this concern was implemented in 2022. 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 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. Below are the two retired previous IMM recommendations this year, indicating the status of each.

2020-1 – Include firm load shed in the calculation of the reliability adder

Status: Resolved via NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed*.

2020-2 – Cap ancillary services prices in the day-ahead market

Status: Resolved via NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap*.

I. APPENDIX: KEY CHANGES AND IMPROVEMENTS IN 2021

Key changes or improvements implemented or proposed by the Texas Legislature, the PUC and ERCOT in 2021 are outlined below. In the aftermath of Winter Storm Uri, the Texas Legislature, during 87th session, approved several measures to address market outcomes and reliability concerns. Other key changes include PUC dockets and ERCOT protocol changes as a result of these reforms or other initiatives.

Legislative ERCOT & PUC Reforms

In May 2021, the Texas Legislature approved Senate Bill 2 overhauling the ERCOT Board of Directors, making it fully independent.[99] Senate Bill 2 increased legislative oversight of ERCOT and reformed and restructured its Board of Directors in several ways, including requiring members to live in Texas. The bill requires that the Chairman of the Board and its five unaffiliated members be appointed by the Governor and confirmed by the Senate. The independent members are now selected by a search firm based on executive level experience in a range of fields, including finance, business, engineering, risk management, law, and electric market design. None of them may own a financial interest in the companies operating in the ERCOT market. Once selected, those members must be confirmed by the newly created Board Selection Committee consisting of three appointees: one each from the Governor, the Lt. Governor and the Speaker of the House. This committee will also select the Chair and Vice-

[99] https://capitol.texas.gov/billlookup/text.aspx?LegSess=87R&Bill=SB2

Chair. Senate Bill 2 additionally requires all major protocol changes at ERCOT to be reviewed by the PUC before adoption, giving the PUC veto authority over those changes.

The Legislature also passed Senate Bill 3, the omnibus reform bill related to Winter Storm Uri.[100] This bill included a number of changes including the creation of a power outage alert system, formalizing the Texas Energy Reliability Council (TERC), creating the Texas Electric Supply Chain Mapping Committee, requiring weatherization and providing for increased administrative penalties as well as the inspection of facilities by ERCOT. The bill called for a study on ancillary services, established an emergency pricing program, and made changes to help improve the load shedding process. Senate Bill 3 limited weatherization requirements to "critical" facilities and excluded an amendment to provide grants for backup power at health care facilities.

Finally, the Legislature overhauled the Public Utility Commission of Texas by moving the number of Commissioners from three to five and made changes to Commissioner qualifications with the passing of Senate Bill 2154.[101] The bill required that all five Commissioners be Texas residents, and that only two are well informed and qualified in the field of utility regulation.

Securitization and Financing

The Legislature authorized different forms of financing to "serve[] the public purpose of allowing the commission to stabilize the wholesale electricity market in the ERCOT power region." PURA § 39.651(c). To address the unpaid balances of electric cooperatives and retail energy providers to the wholesale power market totaling over $3 billion, the Legislature passed House Bill 4492 and Senate Bill 1580, which authorize the use of securitization and financing from the state's "rainy day" fund balance, the Economic Stabilization Fund (ESF), to be repaid by ERCOT market participants through default charges established by the PUC.

Senate Bill 1580 establishes a securitization mechanism specifically for electric co-ops to finance the costs incurred during Winter Storm Uri.[102] The broader House Bill 4492 provides a financing program available to retail electric providers for ancillary service charges and reliability deployment price adders above the $9,000 system-wide off cap.[103] The bill allows electric companies and retail electric providers to finance up to $2.1 billion for electricity that companies paid for but never received during the storm, as well as additional charges from the high wholesale power prices while specifically disallowing securitizing amounts that were part of the prevailing settlement point price. Another $800 million would be loaned to pay off debts

100 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB3

101 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB2154

102 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=SB1580

103 https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=87R&Bill=HB4492

to ERCOT, which functions as the transaction house for the electricity market. The ESF's 2020 ending balance was approximately $10 billion.

PUC Dockets & Projects

Addressing specific issues arising from Winter Storm Uri as well as the clear directives from the Texas Legislature, a number of projects and dockets were opened to implement reform to the wholesale market.

Scarcity Pricing Mechanism

Project No. 51871, *Review of the ERCOT Scarcity Pricing Mechanism* eliminated the provision that tied the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities are able to recover their actual marginal costs when the LCAP is in effect. In PUC Project No. 52631, *Review of 25.505*, the HCAP was set at $5,000 per MWh effective Jan. 1, 2022.

PUC Implementation of Securitization and Financing

In Subchapter M of PURA Chapter 39, the Legislature approved a process by which ERCOT could seek approval of a Debt Obligation Order authorizing financing of the Default Balance, which is defined by PURA to include: (1) amounts owed to ERCOT by competitive wholesale market participants from the Period of Emergency that otherwise would be or have been uplifted to other wholesale market participants; (2) financial revenue auction receipts used by ERCOT to temporarily reduce amounts short-paid to wholesale market participants related to the Period of Emergency; and (3) reasonable costs incurred by a state agency or ERCOT to implement a debt obligation order, including the cost of retiring or refunding existing debt. PURA § 39.602(1).[104]

In Subchapter N of PURA Chapter 39, the Legislature authorized ERCOT to seek approval of a Debt Obligation Order to finance the Uplift Balance, including Reliability Deployment Price Adder ("RDPA") charges and Ancillary Service costs above the Commission' s system-wide offer cap as that term is defined in PURA § 39.652.[105] Accordingly, ERCOT filed applications for Debt Obligation Orders pursuant to Subchapter M and N of Chapter 39 of the Public Utility Regulatory Act (PURA), to finance the Winter Storm Uri Default and Uplift Balances in July 2021. The Debt Obligation Orders were issued on October 13, 2021.

In the Subchapter M Order, the Commission directed the following:

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[104] *Application of Electric Reliability Councill of Texas, Inc. for a Debt Obligation Order to Finance Default Balances Under PURA Chapter 39, Subchapter M and Request for Good Cause Exception,* Docket No. 52321 (Oct. 13, 2021).

[105] *Application of the Electric Reliability Councill of Texas, Inc. for a Debt Obligation Order to Finance Uplift Balances Under PURA Chapter 39, Subchapter N, and for a Good-Cause Exception,* Docket No. 52322, (Oct. 13, 2021).

- the default balance in an aggregate amount of up to $800 million;
- the assessment of default charges to all wholesale market participants, except those expressly exempted by PURA, in an amount sufficient to ensure the recovery of amounts expected to be necessary to timely provide all payments of debt service and other required amounts and charges in connection with the issuance of debt obligations (referred to in this Order as subchapter M bonds);
- the issuance of subchapter M bonds in one or more series in an aggregate amount of up to $800 million for the payment of the default balance;
- the financing or securitization of default charges and the creation of default property.

A compliance docket was opened in accordance with ordering paragraph 45C of the Debt Obligation Order for all filings required by the Debt Obligation Order.[106] Approved on December 16, 2021, NPRR1103, *Securitization – PURA Subchapter M Default Charges*, established processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRRAHs pursuant to the Debt Obligation Order (DOO) issued in PUC Docket No. 52321, *Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of PURA.*

In the Subchapter N docket, an agreement was filed resolving many issues after a hearing on the merits of the application was held. All parties that filed testimony signed the agreement and no party opposes the agreement. The parties agreed on issues related to opting out, allocating the uplift balance, and distributing the proceeds of the financing. A parallel project was opened to accommodate the requirements of PUC Docket No. 52322.[107] The Debt Obligation Order approved, ensured, and established the following:

- the mechanisms that allow the uplift balance to be determined, the amount of the financing proceeds to be distributed, and the documentation and calculations required to determine these amounts;
- the mechanisms to calculate and assess uplift charges to repay the uplift balance and other amounts necessary to implement this Order and the financing mechanism established by this Order;
- that uplift charges are non-bypassable and establishes mechanisms to ensure that uplift charges are reviewed and adjusted on a quarterly basis to ensure sufficient amounts of revenue are available to make timely payments of debt service and other required amounts related to the debt obligation;

106 *Compliance Filing for Docket No. 52321 (Application of the Electric Reliability Council of Texas, Inc. for a Debt Obligation Order under PURA Chapter 39, Subchapter M, of the Public Utility Regulatory Act),* Docket No. 52709, (Oct. 13, 2021).

107 *Proceeding for Eligible Entities to File and Opt-Out Pursuant to § 39.653(d) and for Load-Serving Entities to File Documentation of Exposure to Costs Pursuant to the Debt Obligation Order in Docket No. 52322,* Project No. 52364, (Dec. 3, 2021).

- ERCOT's proposal to issue bonds through a special purpose entity to finance the uplift balance providing security of uplift property and the use of credit enhancements to minimize uplift charges;
- the securitization of uplift charges and the creation of uplift property;
- certain criteria in this Order that must be met for the approvals and authorizations granted in this Order to become effective, requiring specified documents and other information be filed with the Commission so that it can ensure compliance with this Order.

Posted on December 29, 2021, and approved on March 31, 2022, NPRR1114, *Securitization – PURA Subchapter N Uplift Charges*, established processes to assess and collect Uplift Charges to QSEs representing LSEs pursuant to the DOO issued in PUC Docket No. 52322.

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

After a series of rigorous public work sessions and review of volumes of comments filed by market participants, the Commission directed ERCOT to enact major reforms in PUC Project No. 52373, *Review of Wholesale Electric Market Design* at the December 16, 2021, open meeting.[108] Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021. The blueprint compiles directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint provides 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.

The Commission approved the following directives as part of **Phase I** of the blueprint as the end of 2021 (not an exhaustive list):

Operating Reserve Demand Curve (ORDC)

- Changes to the ORDC should be made effective January 1, 2022, to set the MCL at 3,000 MW and set the HCAP and VOLL to $5,000 per MWh.

Demand Response

- Pursue market modifications and technical measures to improve transparency of price signals for load resources, such as changing demand response pricing from zonal to LMPs;
- Set higher performance standards for energy efficiency programs;
- Direct ERCOT to evaluate actions that have already been taken to accommodate customer aggregation participation - i,e., virtual power plants (VPPs)-in the

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

ERCOT market, determine how much customer aggregations currently participate in the ERCOT market, and identify current barriers for VPP participation in the ERCOT real-time and ancillary services markets.

Emergency Response Service (ERS) Reform

- Codify good cause exception ordered by the Commission in the Fall of 2021 directing ERCOT to deploy ERS at MCL.
- Determine whether the ERS procurement methodology should be changed to provide for the procurement of a specific MW quantity or some other measure than a fixed dollar amount;
- Determine whether the ERS program should include seasonal apportionment.

Firm Fuel Product[109]

- Determine whether this stand-alone, discrete service can be incorporated into a load-side reliability mechanism in the future.
- Determine whether this product should be procured by ERCOT through a competitive auction, competitive request for proposal (RFP) process (similar to ERCOT's current Black Start program), or some other competitive procurement method.

Voltage Support Compensation

- Analyze and develop a product to compensate resources for voltage support.

ECRS (New Ramping Ancillary Service Product)

- ERCOT will accelerate the implementation of this new reliability product.
- Determine options for sizing the product.
- Allocate cost of ECRS consistent with cost-causation principles, in a nondiscriminatory manner pursuant to SB 3.

Additionally, the Commission committed to opening rulemaking proceedings and other projects to request technical feedback and provide rate recovery of reasonable and necessary distribution voltage reduction costs and review DG interconnection procedures.

As part of **Phase II** of the market design blueprint, the Commission agreed to investigate and develop the following concepts:

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109 NPRR1120, *Create Firm Fuel Supply Service*, approved on March 31, 2022, creates a new reliability service, Firm Fuel Supply Service (FFSS). This new reliability service will be procured via request for proposal (RFP) and the NPRR focused on components that require accommodation in the Settlement and Billing system. Additional requirements will be reflected in the RFP that will be forthcoming; see also *Wholesale Electric Market Design Implementation*, Project No. 53298 (pending).

1. Load-side reliability mechanism
2. Backstop Reliability Service

The Commission committed to exploring a load-side reliability mechanism (either a Load-Serving Entity (LSE) Obligation, Dispatchable Energy Credits (DECs), or a combination of the two) with the stated purpose of ensuring the supply of dispatchable generation is sufficient to meet system demand in ERCOT. The Commission also committed to exploring a Backstop Reliability Service, either alone or in conjunction with a load-side reliability mechanism. The backstop reliability service will be used to procure accredited new and existing dispatchable resources to serve as an insurance policy to help prevent emergency conditions in ERCOT.

The IMM looks forward to working with the Commission and market participants to explore these options and identify meaningful enhancements to ERCOT's wholesale market.

ERCOT Protocols Revisions

ERCOT approved or at least began deliberating a number of Nodal Protocol Revision Requests (NPRRs) to reflect and implement the changes authorized by the Texas Legislature and PUC, as well as a suite of general market improvements, outlined below.

- NPRR1075, *Update Telemetered HSL and/or MPC for ESRs in Real-Time to Meet Ancillary Service Resource Responsibility*.
  - Status: Approved on June 8, 2021; effective on June 9, 2021.
  - Description: This NPRR allows ESRs to update their High Sustained Limit (HSL) and/or Maximum Power Consumption (MPC) in Real-Time for the purposes of maintaining sufficient energy to meet an Ancillary Service Resource Responsibility. The ability for ESRs to update their Real-Time HSL and/or MPC would expire at the earlier of system implementation of RTC or implementation of a Mitigated Offer Cap for ESRs other than the System-Wide Offer Cap.

- NPRR1080, *Limiting Ancillary Service Price to System-Wide Offer Cap*; OBDRR030, *Related to NPRR1080, Limiting Ancillary Service Price to System-Wide Offer Cap*.
  - Status: Approved on June 28, 2021; effective on July 1, 2021.
  - Description: ERCOT and the IMM cosponsored an NPRR and accompanying OBDRR to limit ancillary service MCPCs to the system-wide offer cap. This limitation was achieved by reducing the ASPFs to values equal to or immediately below the system-wide offer cap, which prevents ancillary service shadow prices, and in turn, MCPCs, from exceeding the system-wide offer cap, consistent with economic market design principles. Because ancillary services are procured to reduce the probability of losing load, such principles dictate that the value of reserves should not exceed VOLL, which is equal to the system-wide offer cap. However, reducing ASPFs to the system-wide offer cap increases the likelihood

of ancillary service insufficiency during tight conditions because the DAM algorithm will have the option of forgoing an ancillary service offer at a lower cost.

- NPRR1081, *Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed*.
    - Status: Approved on June 28, 2021,
    - Description: This NPRR modifies the calculation of the Real-Time On-Line Reliability Deployment Price Adder so that the combination of System Lambda, the Real-Time On-Line Reserve Price Adder, and the Real-Time On-Line Reliability Deployment Price Adder will be equal to the VOLL when ERCOT is directing firm Load shed during EEA3.

- NPRR1086, *Recovery, Charges, and Settlement for Operating Losses During an LCAP Effective Period*.
    - Status: Approved on August 19, 2021; effective on August 20, 2021
    - Description: This NPRR aligns the Protocols with the order amending 16 TAC § 25.505 in PUC Project No. 51871 (51871 Order), which modifies the value of the Low System-Wide Offer Cap (LCAP) by eliminating a provision that ties the value of LCAP to the natural gas price index, and adding a provision that ensures that a Resource Entity (through its Qualified Scheduling Entity (QSE)) can recover its actual marginal costs when a scarcity pricing situation occurs while the LCAP is in effect (LCAP Effective Period). An LCAP Effective Period occurs when the Peaker Net Margin (PNM) during a calendar year exceeds a threshold of three times the cost of new entry for new generation plants. During an LCAP Effective Period, the System-Wide Offer Cap (SWCAP) will be set to the LCAP for the remainder of the calendar year.

- NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision*.
    - Status: Approved by the Board on April 28, 2022; effective date of May 13, 2022, for Section 6.5.7.3, Security Constrained Economic Dispatch, and upon system implementation for the remainder.
    - Description: Posted on August 11, 2021, by the IMM, this NPRR as filed would have reduced the value of the offer floor on Resources that have the status of ONRUC to $75/MWh and removed the ONOPTOUT status. This NPRR was still pending at the end of 2021, but a modified version was approved in 2022. That version sets a $250/MWh RUC offer floor and allows ONOPTOUT status in more limited circumstances.

- NPRR1093, *Load Resource Participation in Non-Spinning Reserve*.

- Status: Approved on October 28, 2021, effective upon system implementation.
- Description: This NPRR changes the Protocols to allow Load Resources that are not Controllable Load Resources to provide Non-Spin. The NPRR largely reinstates Protocol requirements that were in place during the first five years of the Nodal Market implementation that were subsequently changed to enable Controllable Load Resource participation in Security-Constrained Economic Dispatch (SCED) and Non-Spin. Additionally, it also incorporates market design changes that have been made for the Operating Reserve Demand Curve (ORDC) and Reliability Deployment Price Adder process when deploying Ancillary Services from Load Resources that are not Controllable Load Resources.

- NPRR1096, *Require Sustained Six Hour Capability for ECRS and Non-Spin*.
    - Status: Posted on September 28, 2021, by ERCOT and still pending at the end of 2021, but approved by the Board on April 28, 2021.
    - Description: This NPRR would require Resources that provide ECRS and/or Non-Spinning Reserve (Non-Spin) to limit their responsibility to a quantity of capacity that is capable of being sustained for six consecutive hours. Additionally, this NPRR would also require ERCOT to conduct unannounced tests on ESRs that are providing ECRS and/or Non-Spin in Real-Time.

- NPRR1103, *Securitization – PURA Subchapter M Default Charges*.
    - Status: Approved on December 16, 2021, with Phase 1 effective December 17, 2021.
    - Description: This NPRR established processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRRAHs pursuant to the Debt Obligation Order (DOO) issued in PUC Docket No. 52321, *Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of PURA*.

- NPRR1114, *Securitization – PURA Subchapter N Uplift Charges*.
    - Status: Posted on December 29, 2021, and still pending at the end of 2021, but approved on March 31, 2022.
    - Description: This NPRR would establish processes to assess and collect Uplift Charges to QSEs representing LSEs pursuant to the DOO issued in PUC Docket No. 52322.

II. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of 2021 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2021, including AS charges by type. This does not reflect the total cost of each AS because it is the net charges after self-arrangement.

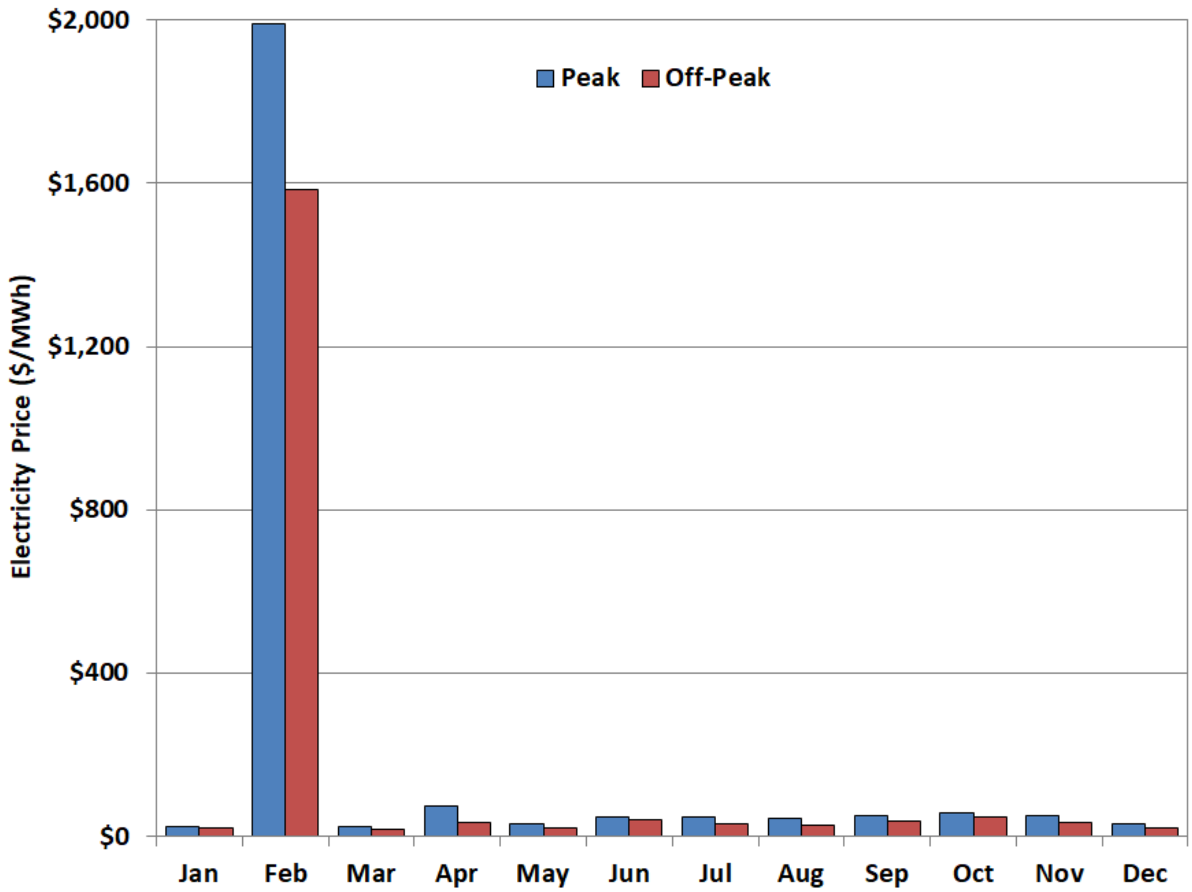
Table A1: ERCOT 2021 Year at a Glance (Annual)

Cost Type	Annual Total ($M)
Energy	$65,946
Regulation Up	$869
Regulation Down	$348
Responsive Reserve	$8,232
Non-Spin	$2,176
CRR Auction Distribution	$831
Balancing Account Surplus	$111
CRR DAM Payment	$1,289
PTP DAM Charge	$1,113
PTP RT Payment	$1,563
Emergency Response Service	$59
Revenue Neutrality	$1
ERCOT Fee	$218
Other Load Allocation	$1,831

A. Real-Time Market Prices

Real-time energy prices vary substantially by time of day. Figure A1 shows the load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2021. The Peak block includes hour ending (HE) 7 to HE 22 on weekdays; the Off-Peak block includes all other hours. These pricing blocks align with the categories traded in forward markets.

Figure A1: Peak and Off-Peak Pricing



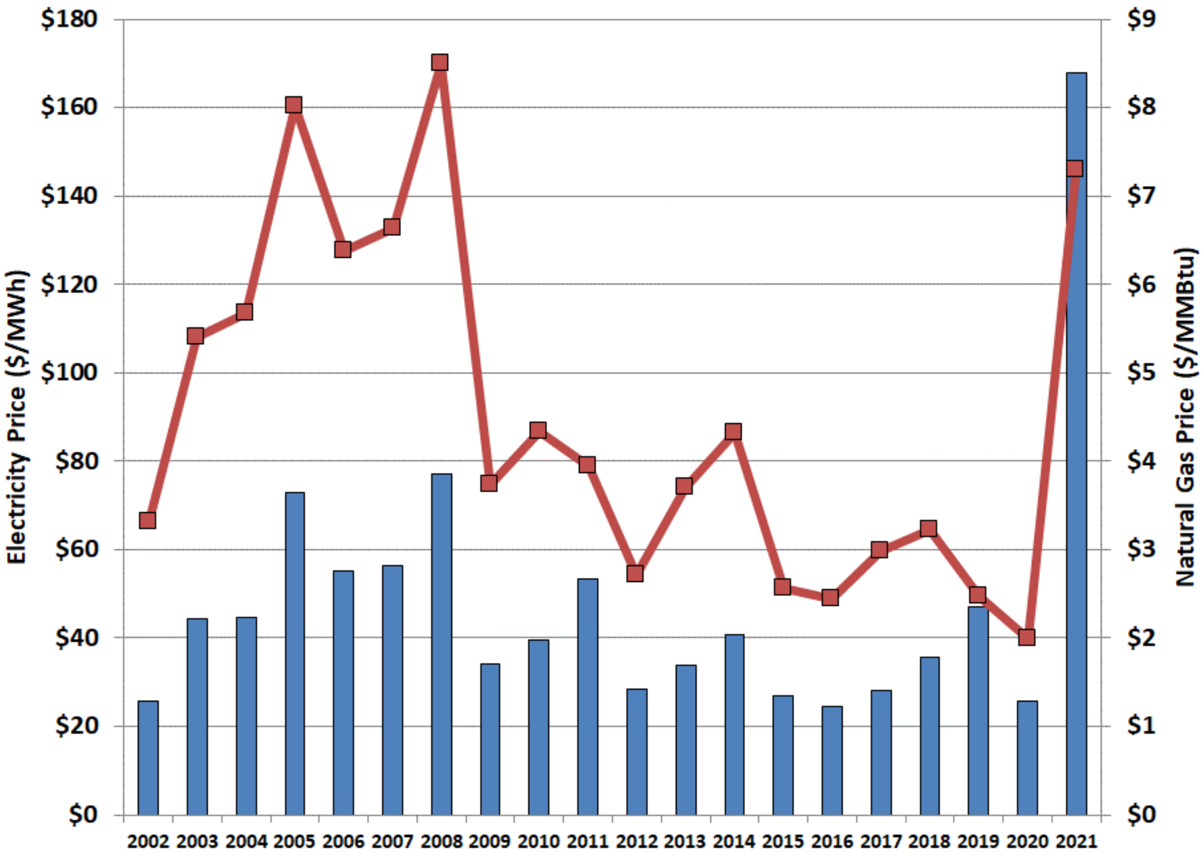
As expected, Peak hours were higher priced than Off-Peak hours for every month in 2021, with prices in February (both Peak and Off-Peak) far exceeding all other months due to Winter Storm Uri. In February, the difference between Peak and Off-Peak was $408.21. For all other months, the difference ranged from a minimum of $2.71 per MWh in January to a maximum of $39.34 per MWh in April due to low renewable output in April.

The extreme price differential in February even surpassed the differential seen in August 2019, the most recent example of significant shortage pricing prior to 2021, when the difference was $275.00 per MWh due primarily to shortage conditions and the resulting high prices (multiple intervals at the HCAP of $9,000 per MWh) seen during peak hours in the week of August 12, 2019. The average difference between monthly Peak and Off-Peak pricing in 2021 was $46.45 per MWh with February included, but only a more modest $13.56 with February excluded.

B. Zonal Average Energy Prices in 2021

Figure A2 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 2021.

Figure A2: ERCOT Historic Real-Time Energy and Natural Gas Prices



Like Figure 3 in the body of the report, Figure A2 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 predominate and tend to set the marginal price; this is an indication that the price of electricity is reflective of the cost of production.

Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2020 and 2021, both with and without the effects of Winter Storm Uri. 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. Aside from the month of February, these prices in 2021 were not particularly volatile month-to-month.

Figure A3: Average Real-Time Energy Market Prices by Zone (with Uri)

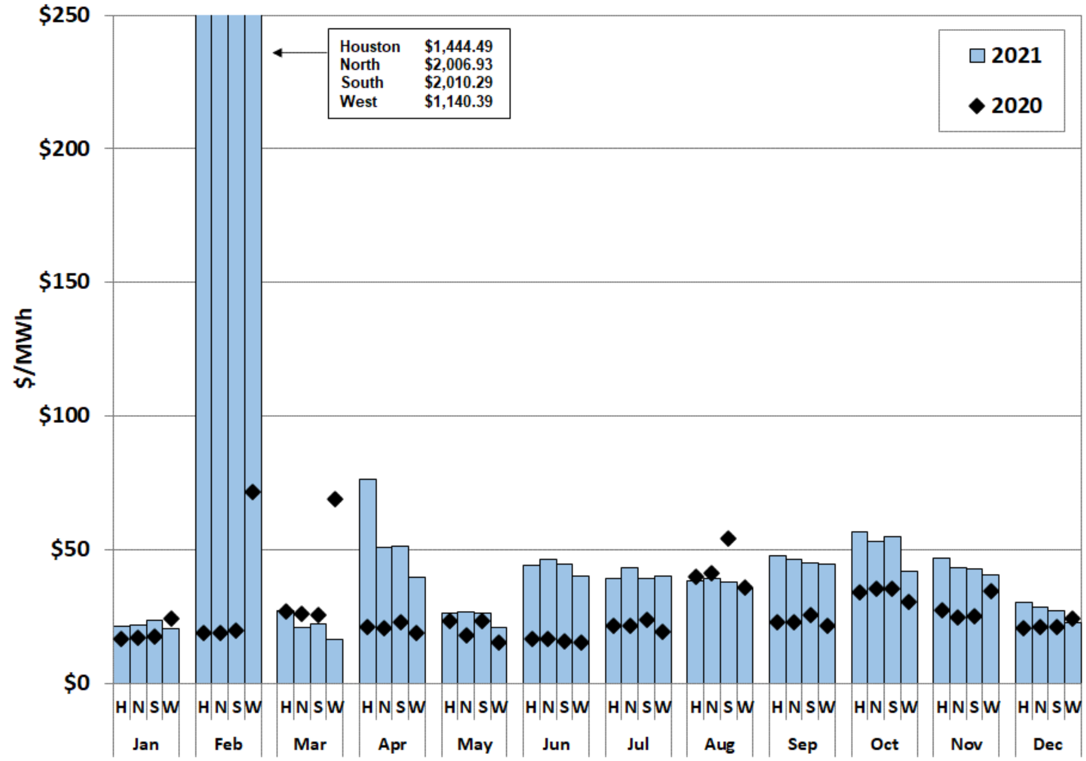
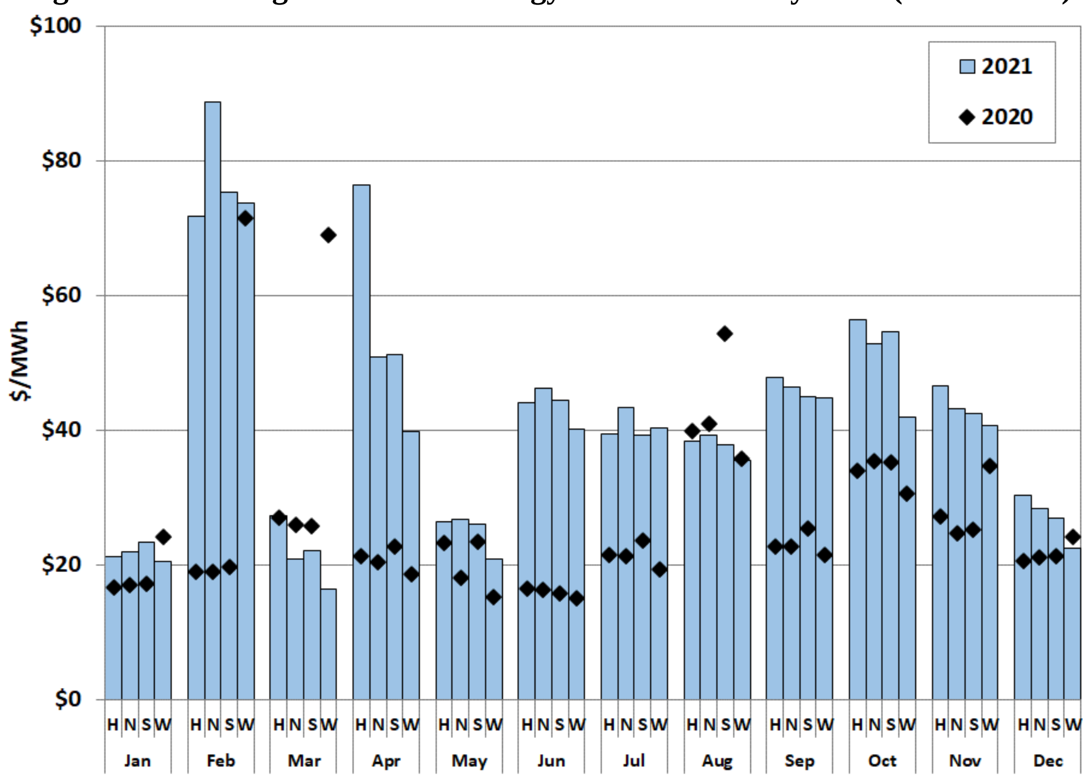


Figure A4: Average Real-Time Energy Market Prices by Zone (without Uri)



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 A5 shows the effect that this reduction has on a monthly basis, by zone, in 2021. However, it is difficult to view the credit due to the skewing effects of Winter Storm Uri. Therefore, we remove the effect of Winter Storm Uri so that the other details can be visualized and present the same chart as Figure A6.

Figure A5: Effective Real-Time Energy Market Prices (with Uri)

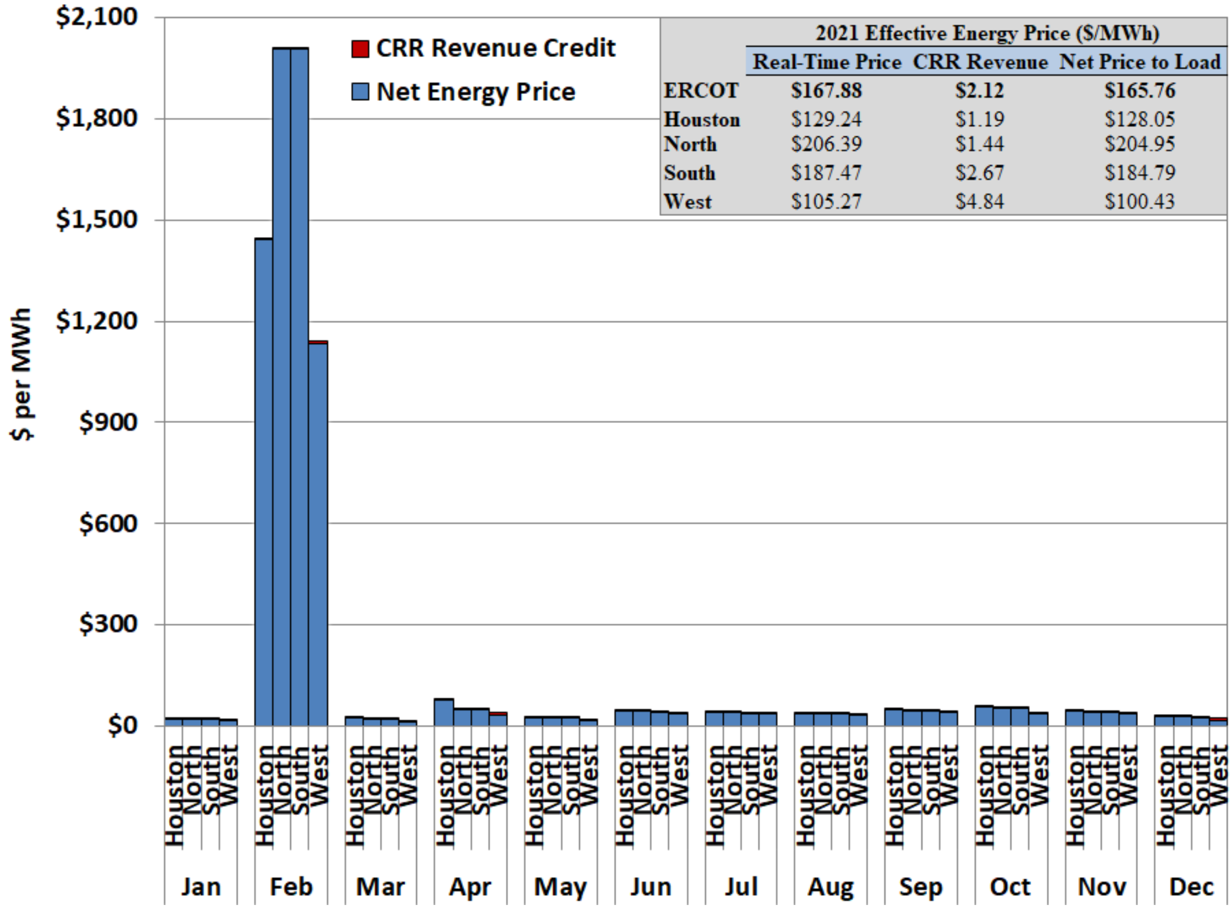
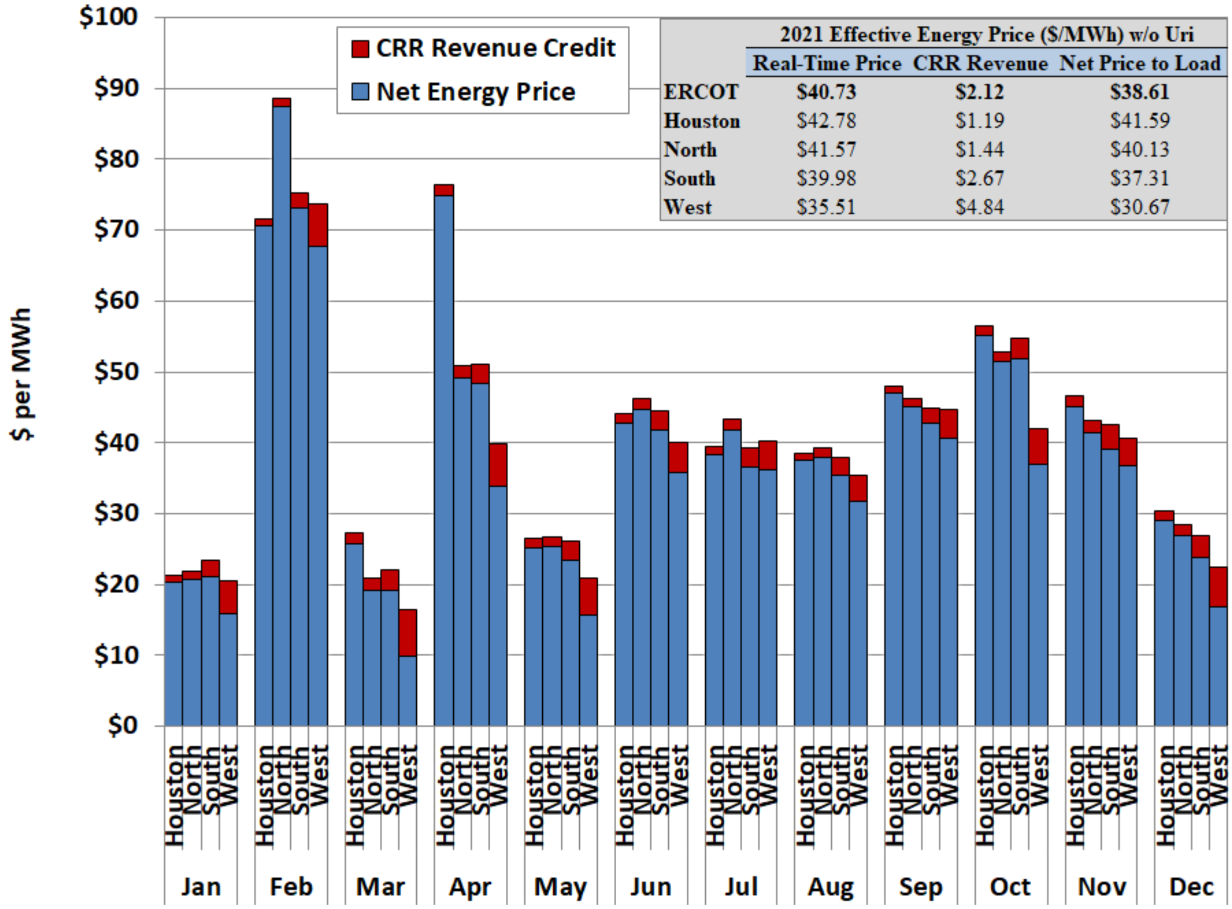


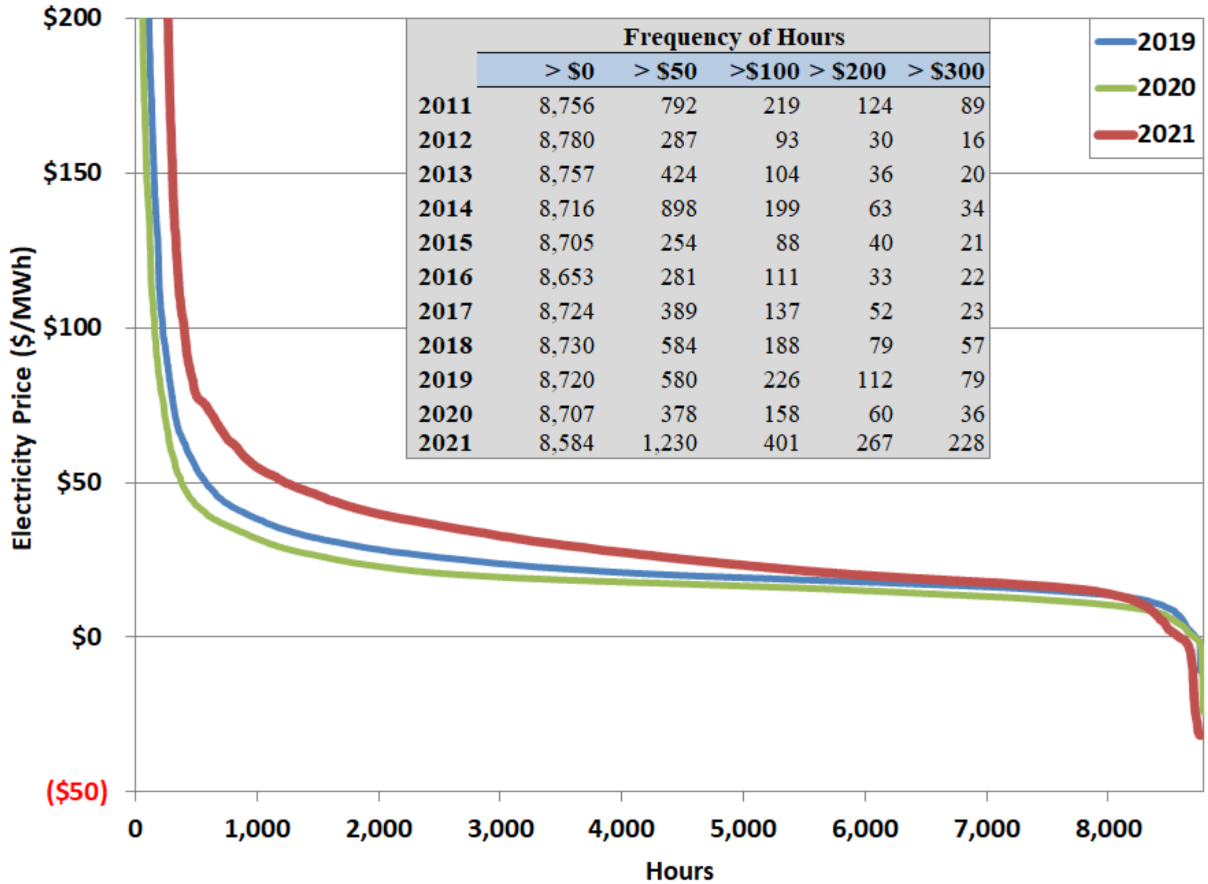
Figure A6: Effective Real-Time Energy Market Prices (without Uri)



A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). Figure A5 shows price duration curves for the ERCOT energy market for 2019 through 2021, with 2019 showing the most shortage pricing hours since the nodal market implementation before the extreme impacts of Winter Storm Uri in 2021. The prices in this figure are the hourly ERCOT average prices derived by load weighting the zonal settlement point prices.

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 2021, there were 176 hours with ERCOT-wide prices at or below zero, an increase from the 77 hours in 2020. Figure A7 represents a price duration curve to show this effect.

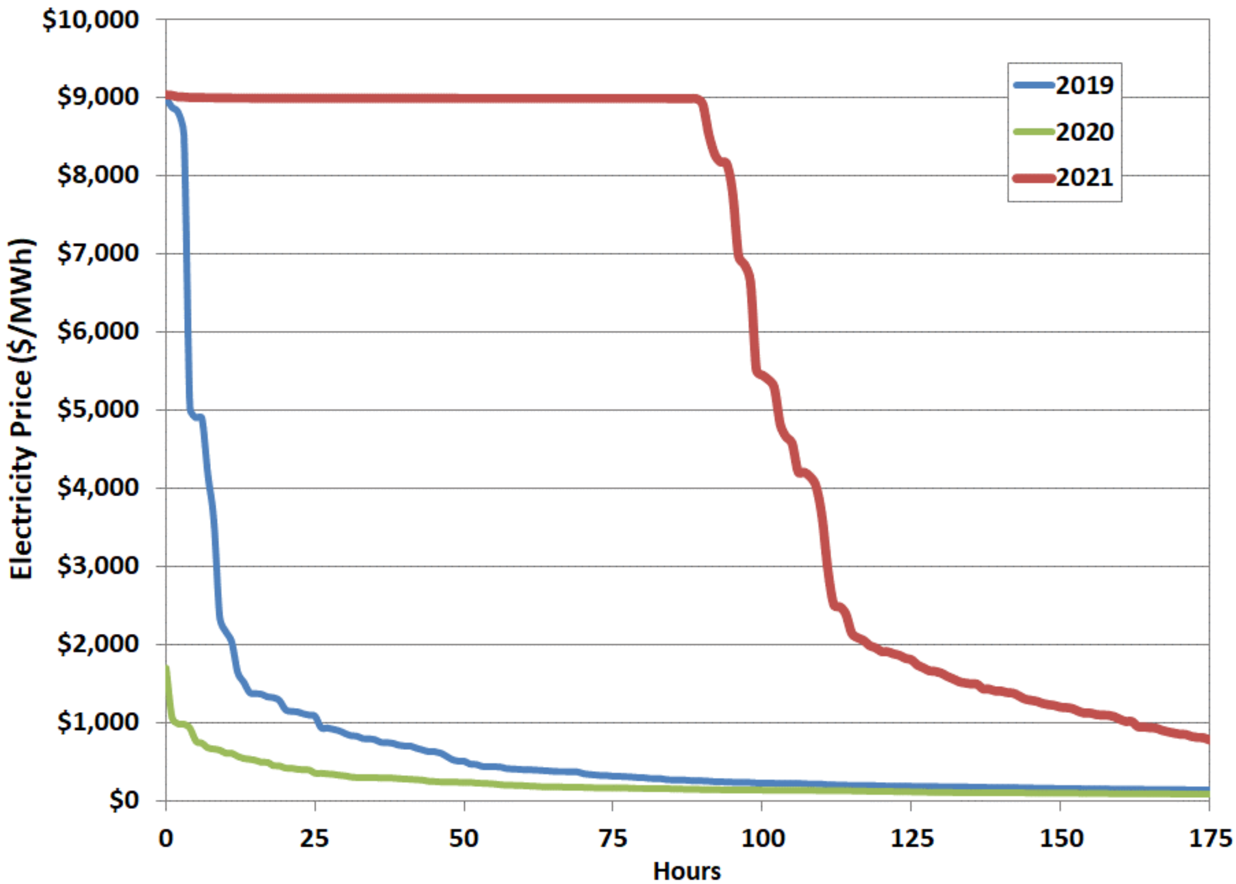
Figure A7: ERCOT Price Duration Curve



Frequency of Hours					
	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79
2020	8,707	378	158	60	36
2021	8,584	1,230	401	267	228

Figure A8 compares prices for the highest-priced 2% of hours in 2019 through 2021. Energy prices for the highest 100 hours of 2021 were significantly higher than those in 2019 and 2020, with Winter Storm Uri driving 2021 to be the peak year since the nodal market implementation by a significant margin. The higher prices in 2019 and again in 2021 illustrate the effects of the changes to the shortage pricing mechanism over recent years, most importantly the increase of the System Wide Offer Cap to $9,000 per MWh, the implementation of the Operating Reserve Demand Curve and subsequent changes to its parameters, and the implementation of the Reliability Deployment Adder.

Figure A8: ERCOT Price Duration Curve – Top 2% of Hours



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, an “implied heat rate” is calculated by dividing the real-time energy price by the natural gas price.

Figure A9 and Figure A10 show the load-weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart displays the number of hours (shown on the horizontal axis) that the implied heat rate is at or above a certain level (shown on the vertical axis).

Figure A9: Implied Heat Rate Duration Curve – All Hours

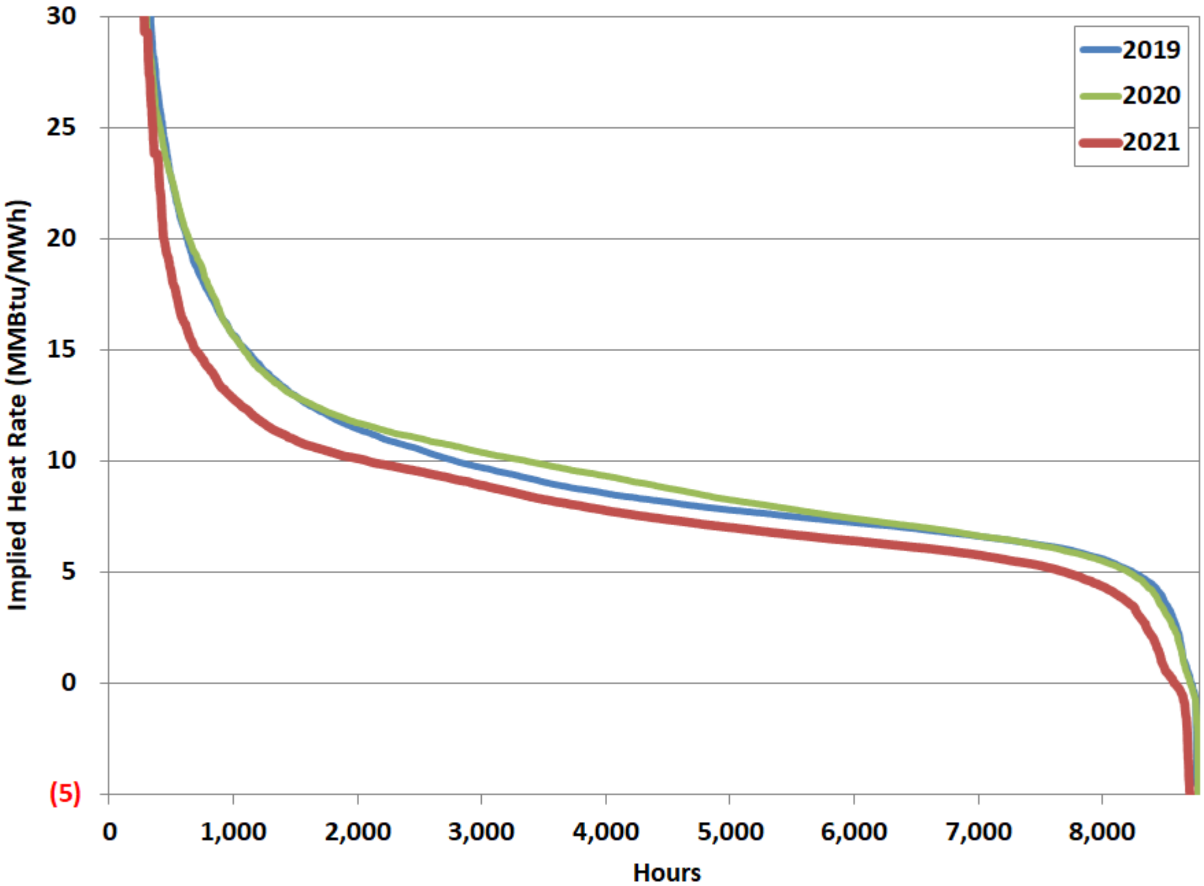


Figure A10 shows the implied marginal heat rates for the top 2% of hours from 2019 to 2021. The implied heat rate duration curve for the top 2% of hours in 2020 and 2021 were much lower than 2019 despite significant contributions from shortage pricing in 2021, due to the high natural gas prices during 2021 especially during Winter Storm Uri, and due to mild conditions and an absence of significant shortage pricing in 2020

Figure A10: Implied Heat Rate Duration Curve – Top 2% of Hours

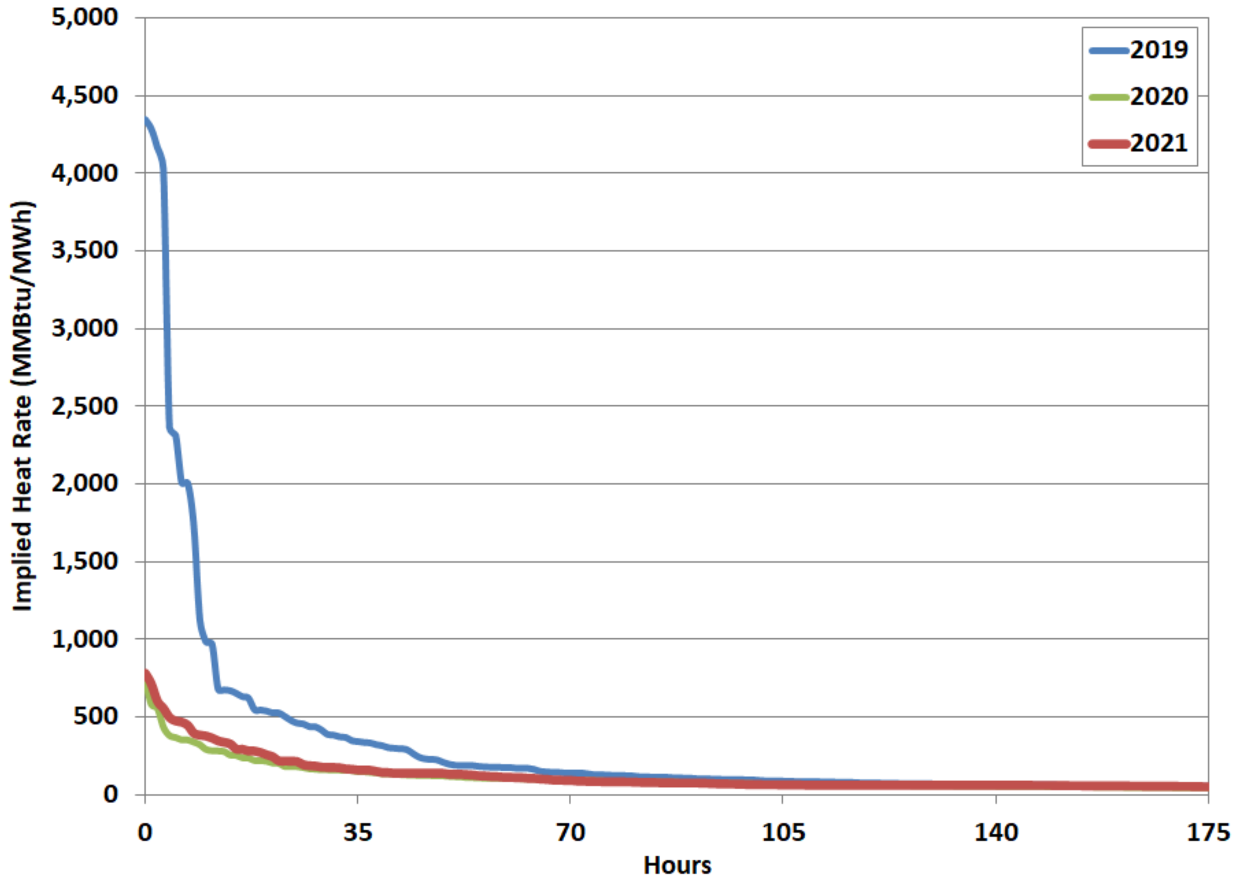


Table A2 displays the annual average implied heat rates by zone for 2014 through 2021. Adjusting for natural gas price influence, Figure A10 above shows that the annual, system-wide average implied heat rate was relatively consistent from 2020 to 2021. Zonal variations in the implied heat rate were greater in 2021 because of the differences in load levels during Winter Storm Uri.

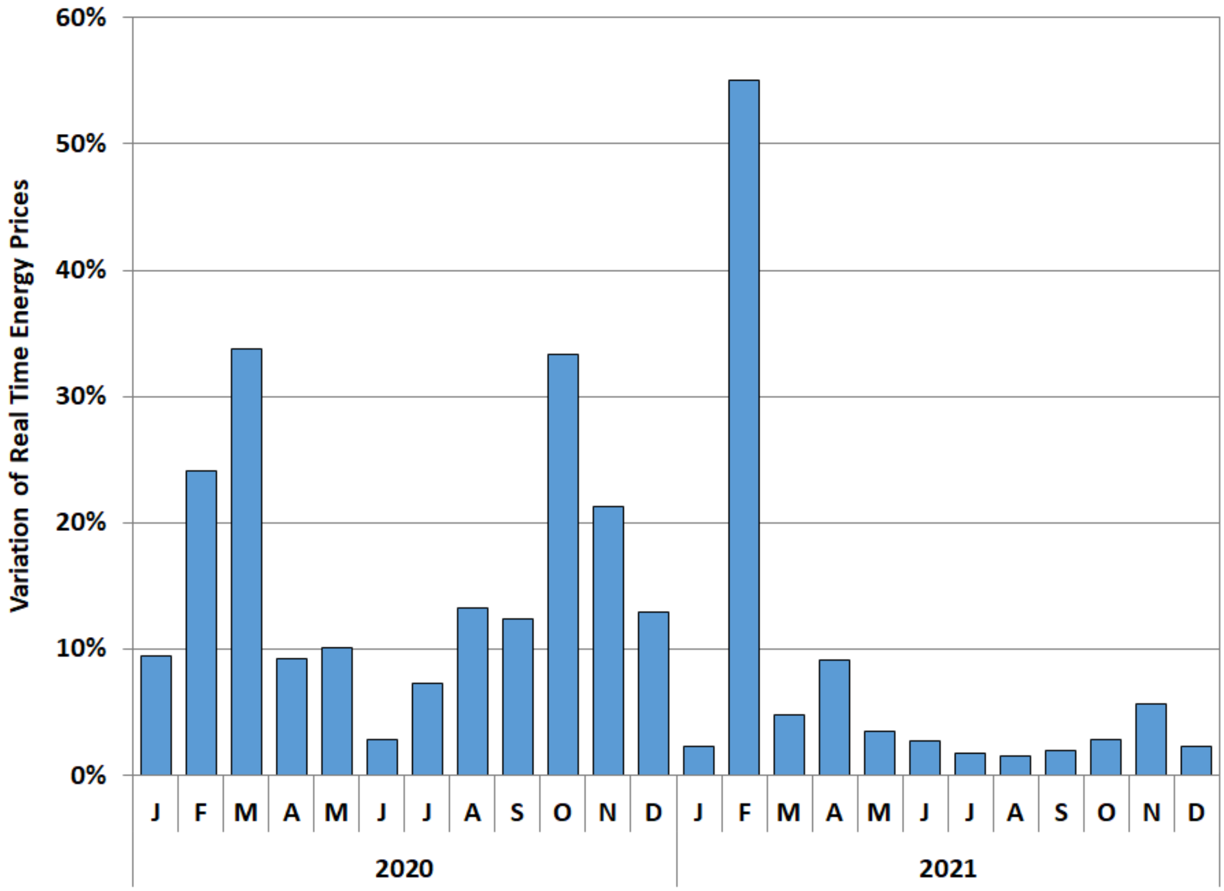
Table A2: Average Implied Heat Rates by Zone

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

D. 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 A11 below shows monthly average changes in five-minute real-time prices by month for 2020 and 2021.

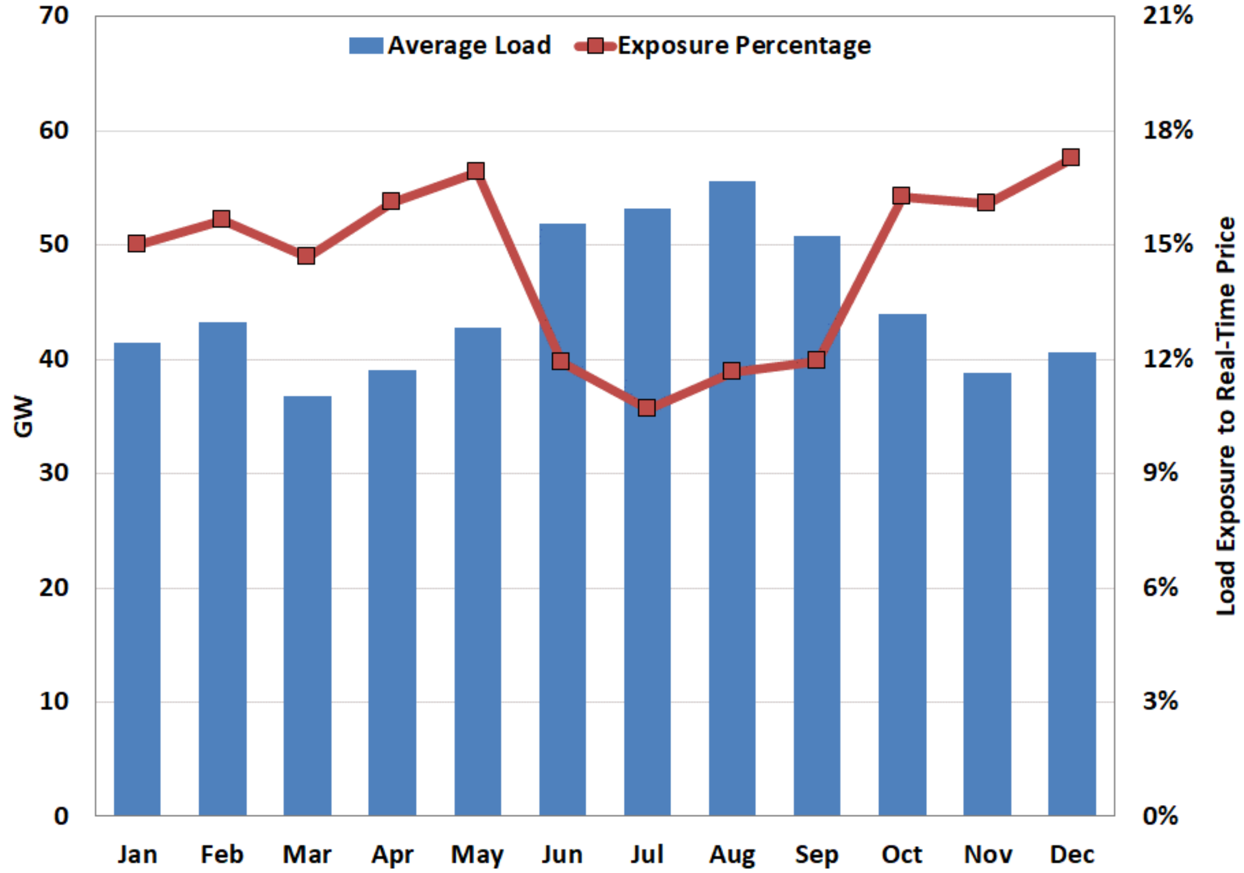
Figure A11: Monthly Price Variation



As expected, the high price variability that occurred during February 2021 when occurrences of shortage pricing was unlike anything seen in 2020, or any other year. However, April and November 2021 saw higher than normal price variability because of outages reducing available transmission capacity as well as variability in renewable output.

Finally, Figure A12 below shows the percentage of load exposed to real-time energy prices.

Figure A12: Monthly Load Exposure



This determination of exposure is based solely on ERCOT-administered markets and does not include any bilateral or over-the-counter (OTC) index purchases. The smallest portions of load potentially exposed to real-time prices in 2021 was lowest in the summer months with the lowest exposure occurring in July. Unhedged loads would be vulnerable to any shortage conditions that may occur during the year, and it is therefore expected that hedging activity would increase during months with the highest likelihood of extreme weather and shortage conditions (typically, though obviously not exclusively, summer in Texas).

The highest portions of load potentially exposed to real-time prices in 2021 occurred during April and May, and at the end of the year in October, November, and December. Likely this is due to higher real-time price expectations over the summer months plus January and February for potential cold weather. Although the overwhelming majority of load is not exposed to real-time prices, these prices do form the foundation for all pricing expectations, which inform both supplier and consumer contracting decisions.

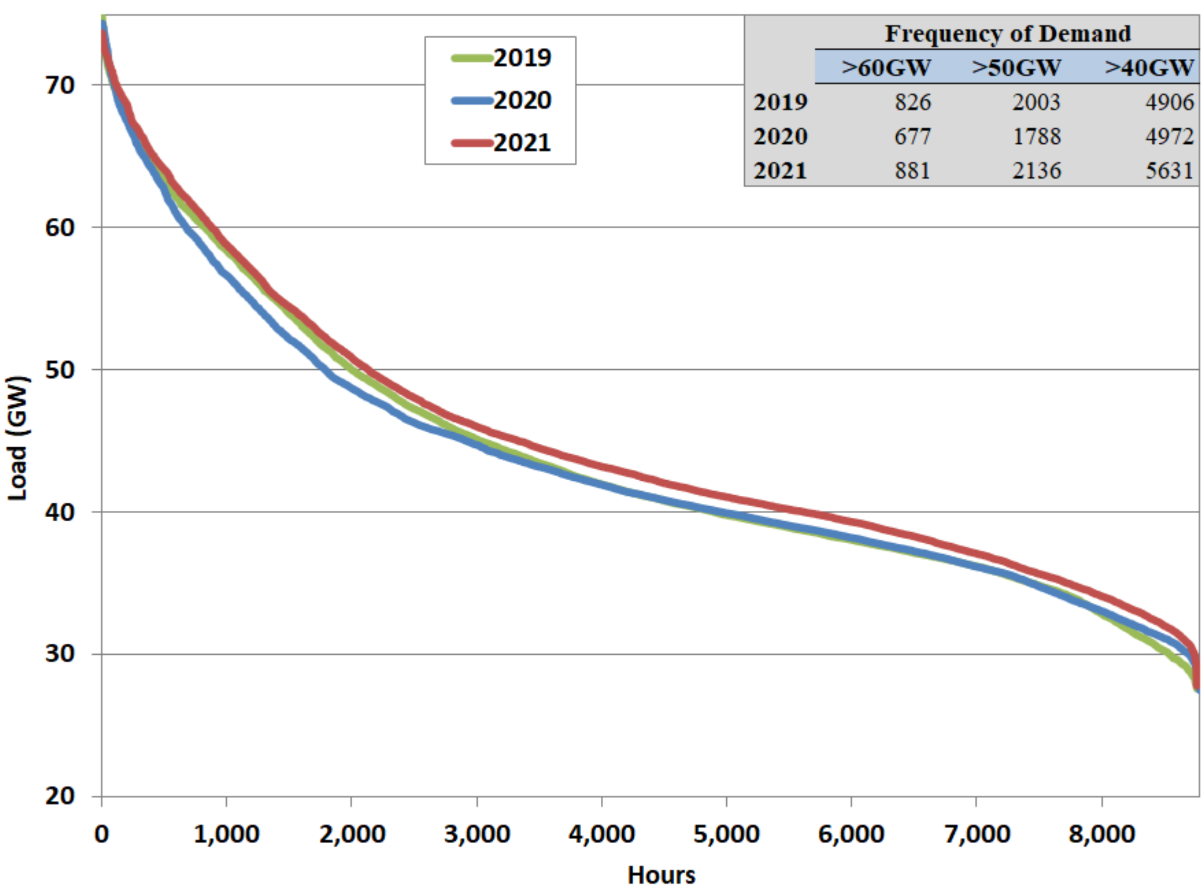
III. Appendix: Demand and Supply in ERCOT

In this section, we provide supplemental analyses of load patterns during 2021 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2020

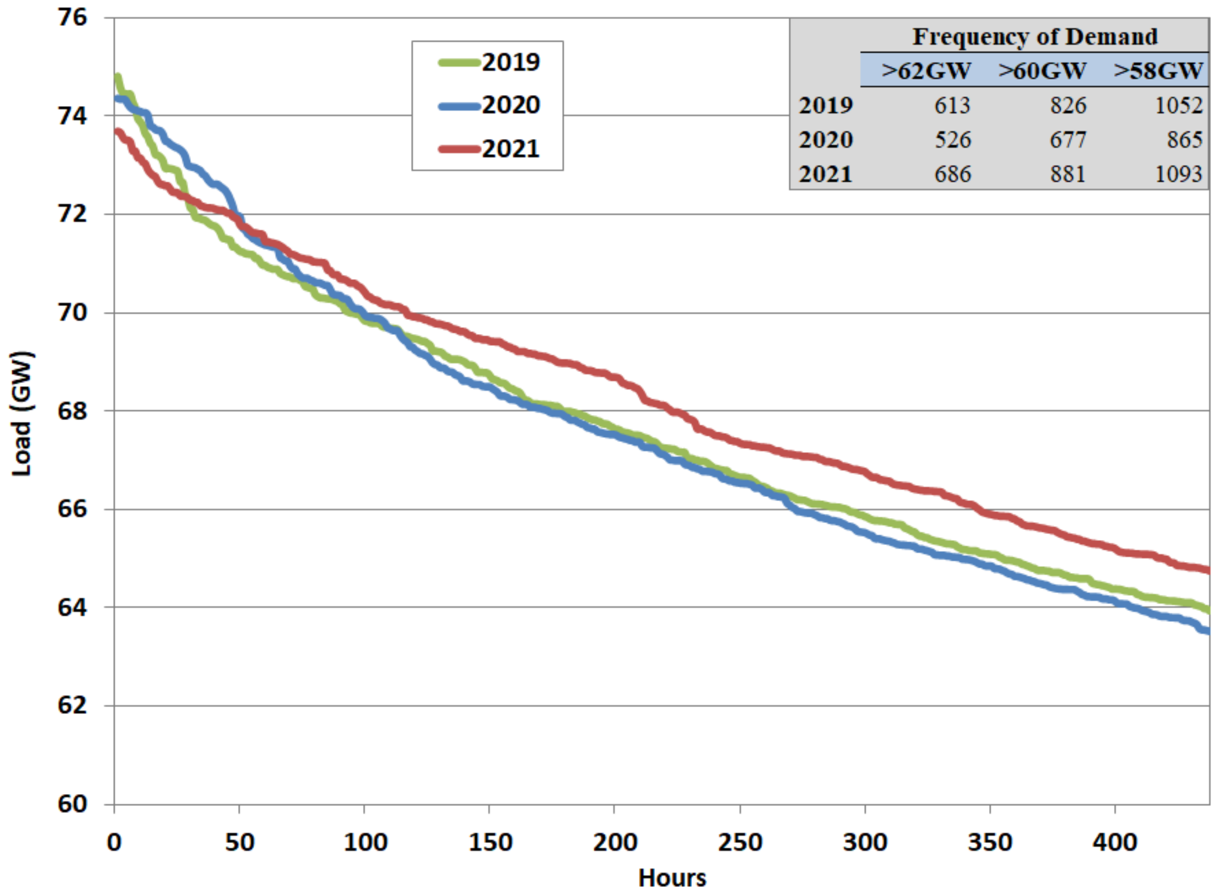
To provide a more detailed analysis of load at the hourly level, Figure A13 compares load duration curves for each year from 2019 through 2021. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT 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 and early evening hours of days with exceptionally high temperatures. The load duration curve in 2021 was similar to both 2019 and 20120, though slightly higher as load growth continues in ERCOT.

Figure A13: Load Duration Curve – All Hours



To better illustrate the differences in the highest-demand periods between years, Figure A14 below shows the load duration curve for the 5% of hours with the highest loads for the last three years. This figure also shows that the peak load in each year was significantly greater than the load at the 95th percentile of hourly load. Since 2011, the peak load has averaged 13% to 19% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – at times more than 10 GW – is needed to supply energy in less than 5% of the hours.

Figure A14: Load Duration Curve – Top 5% of Hours with Highest Load



B. Generation Capacity in ERCOT

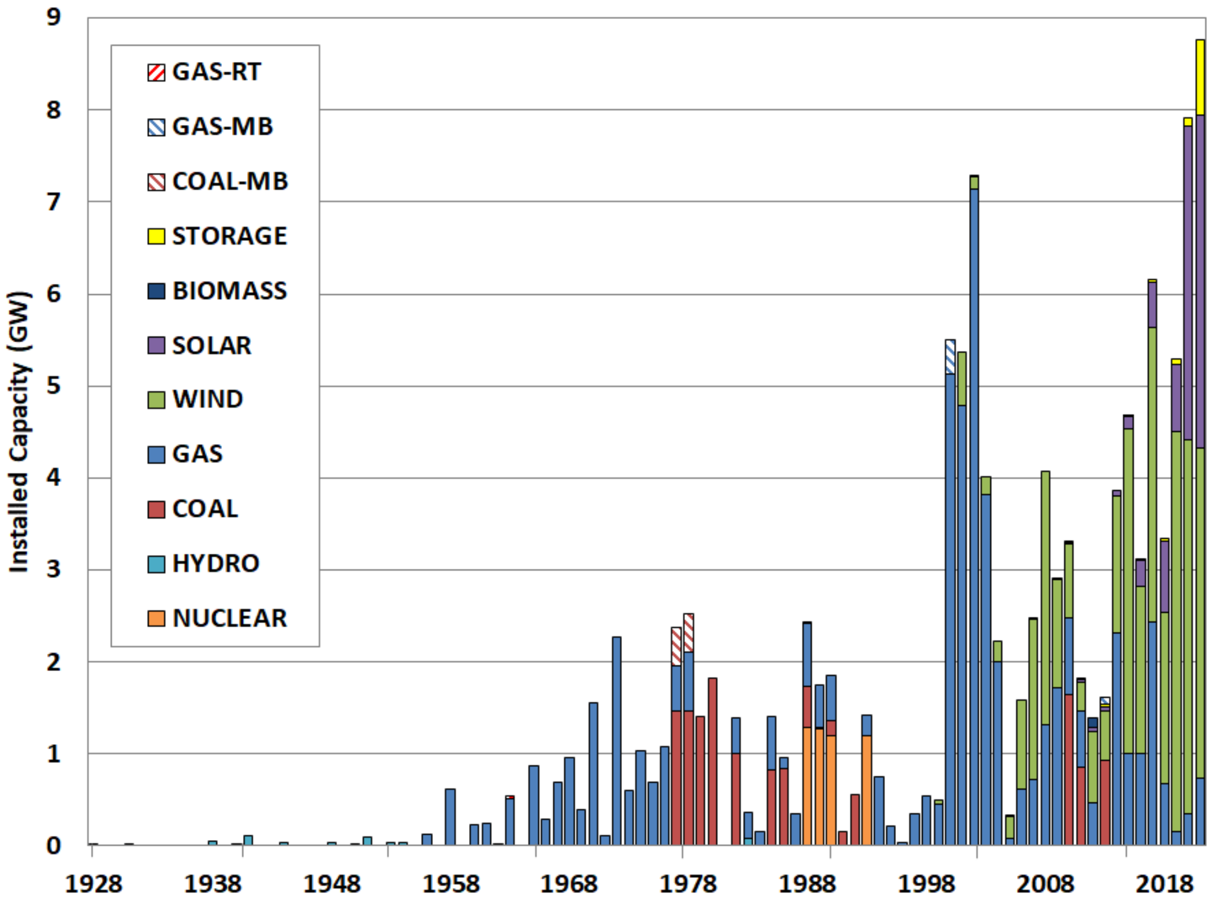
The generation mix in ERCOT is presented in this subsection. Figure A15 shows the vintage of generation resources in ERCOT shown as operational in the December 2021 Capacity, Demand, and Reserves (CDR) report[110] and it also includes resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR.

110 ERCOT Capacity, Demand, and Reserves Report (Dec. 29, 2021), available at https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.pdf.

The "GAS-RT" label applies to gas-fired units that were retired in 2021, and the "GAS-MB" and "COAL-MB" label applies to gas- or coal-fired units that were mothballed in 2021.

The figure shows several distinct periods of time where different technologies were added. The period prior to 1954 is entirely hydro generation additions. Between 1955 and 1977, the majority of additions were gas-fired boiler units. Additions during the period of 1978 to 1985 were primarily nuclear capacity. Between 1986 and 2006 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 storage were added. In 2020, almost 39% of new capacity was solar, and in 2021, that number was over 40%.

Figure A15: Vintage of ERCOT Installed Capacity

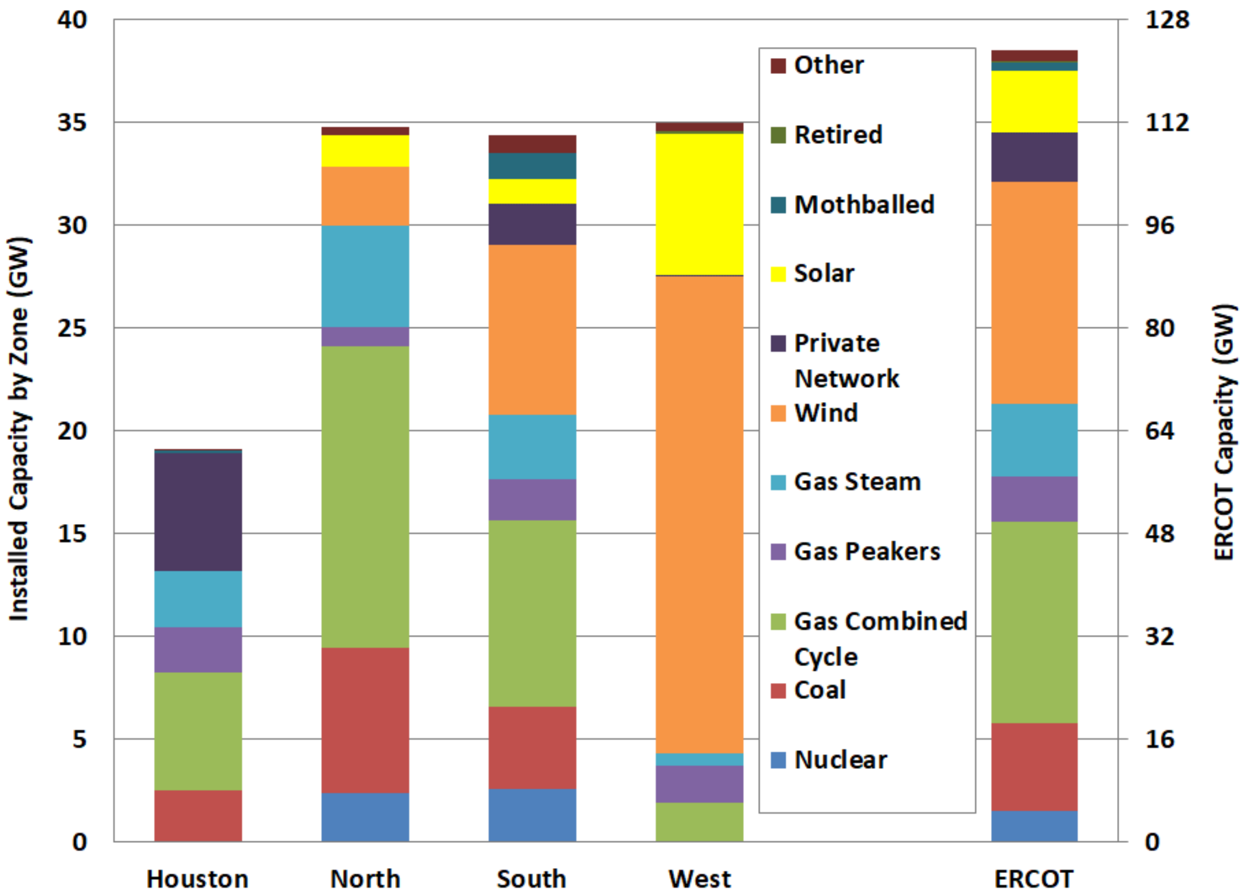


When excluding mothballed resources and including only the fraction of wind capacity deemed available to reliably meet peak demand, the distribution of capacity among the North, South, and West zones was nearly the same.[111] Based on that metric, the North zone accounted for

[111] The percentages of installed capacity to serve peak demand assume availability of 30% for panhandle wind, 57% for coastal wind, 20% for other wind, and 81% for solar.

approximately 34% of capacity, the South zone 29%, the Houston zone 20%, and the West zone 17% in 2021. The installed generating capacity by type in each zone is shown in Figure A16.

Figure A16: Installed Capacity by Technology for Each Zone



Approximately 8.8 GW of new generation resources came online in 2021; the 3.6 GW of wind resources has a deemed effective peak serving capacity of about 0.8 GW and the 3.6 GW of solar resources has a deemed effective peak serving capacity of 3 GW. The remaining new capacity is from 660 MW of combustion turbines and 820 MW of ESRs. Half of the new resources were located in the West, 23% in the North, and 15% in the South. In addition, two resources retired permanently, representing a total capacity of 172 MW.

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 A17 shows average wind production for each month in 2020 and 2021, 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 remained steady from 2020 to 2021 at about 7 GW, 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 A17: Average Wind Production

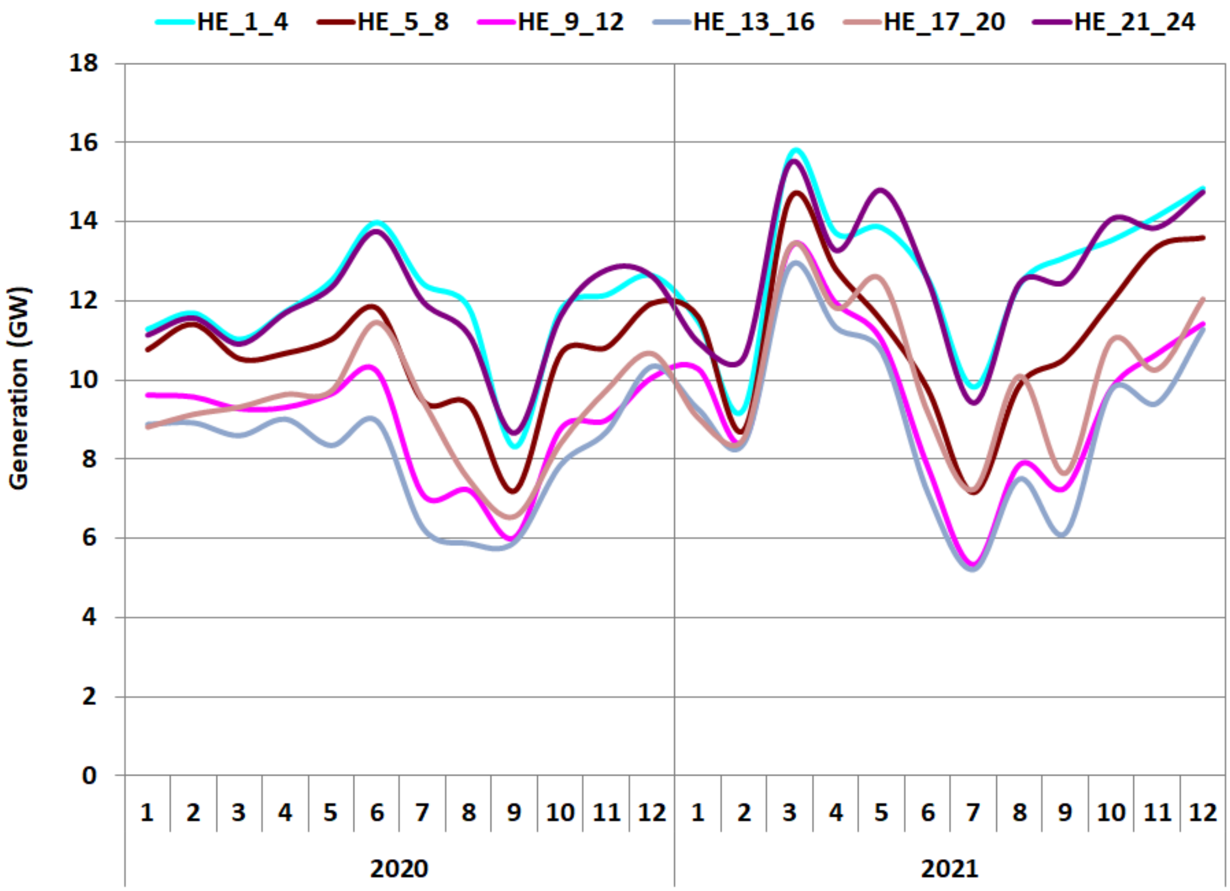
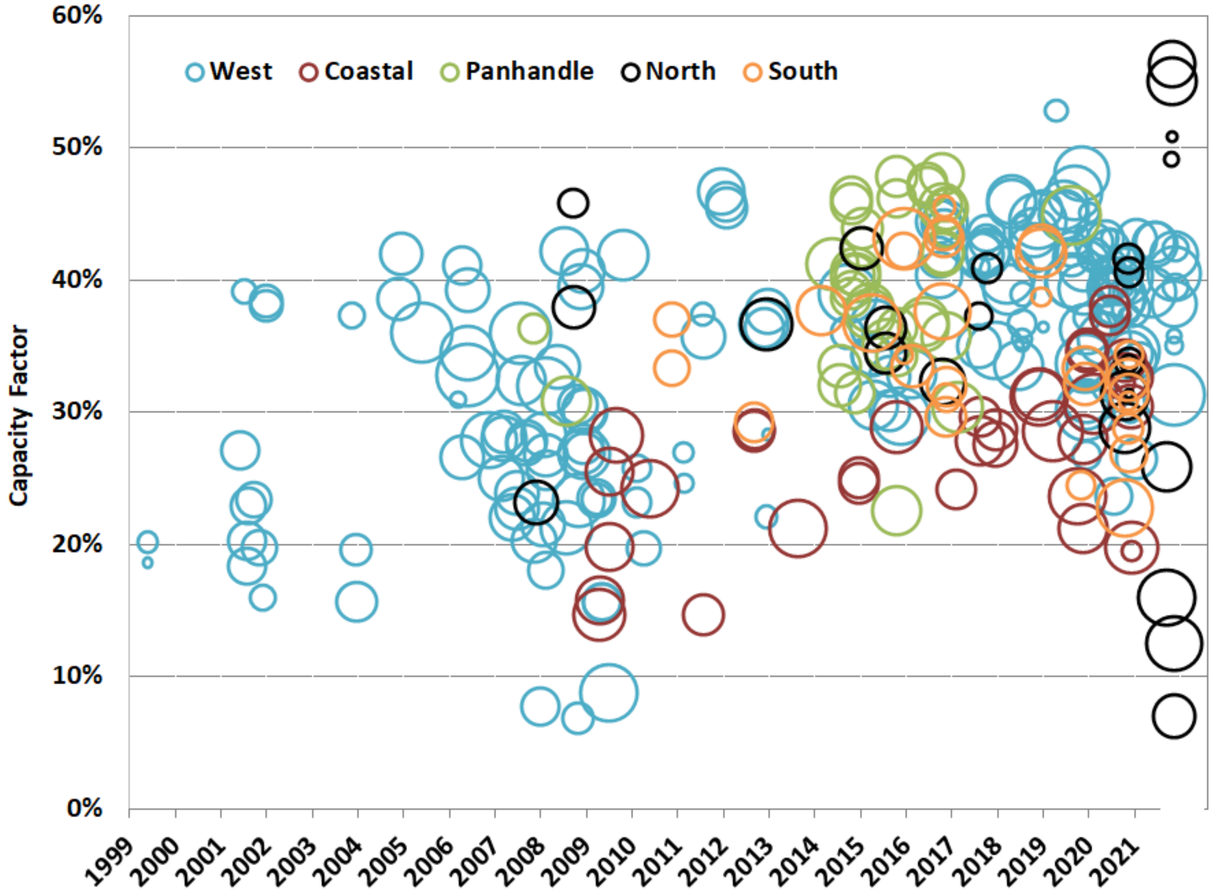


Figure A18 shows the capacity factor (the ratio of actual energy produced by a resource to the hypothetical maximum possible at is full rating) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles for each location. Resources in the north showed both the highest and lowest capacity factors due to the relationship between individual locations and the West Texas Export GTC.

Figure A18: Wind Generator Capacity Factor by Year Installed



As more wind generation capacity is installed in ERCOT, more energy from that capacity will be produced. However, the amount of energy produced will vary depending on actual wind speeds, which can vary from year to year. The next figure shows the annual average wind speed in ERCOT, as weighted by the locations of the installed wind generation. Figure A19 provides a means to compare the weighted wind speeds on an annual basis and indicates that the weighted average wind speed increased in 2020 and again in 2021 compared to previous years.

Figure A19: Historic Average Wind Speed

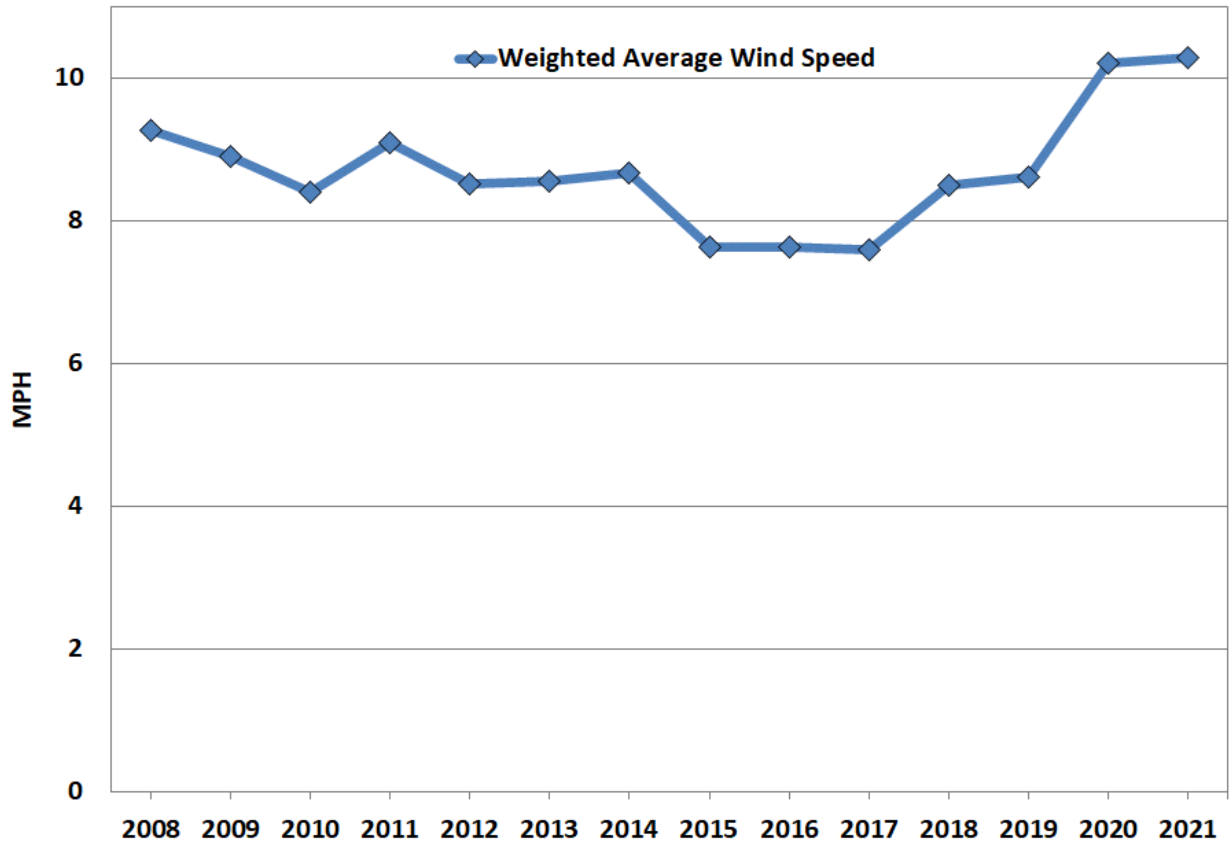


Figure A20 below shows average solar production for each month in 2020 and 2021, with the average production in each month divided into four-hour blocks. The average solar output nearly doubled from 2020 to 2021 due to a significant increase in solar capacity of 2,500 MW along with increased geographic diversity of those resources.

Figure A20: Average Solar Production

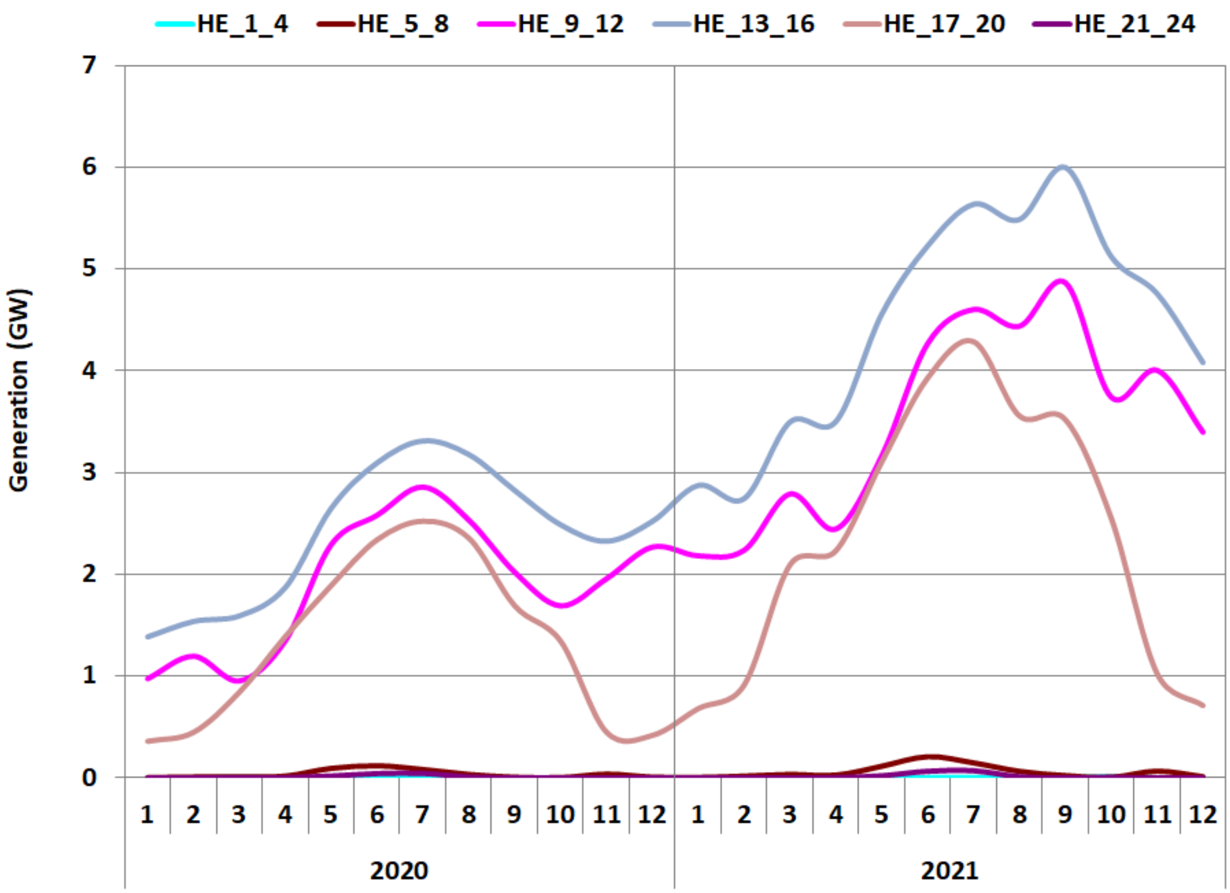
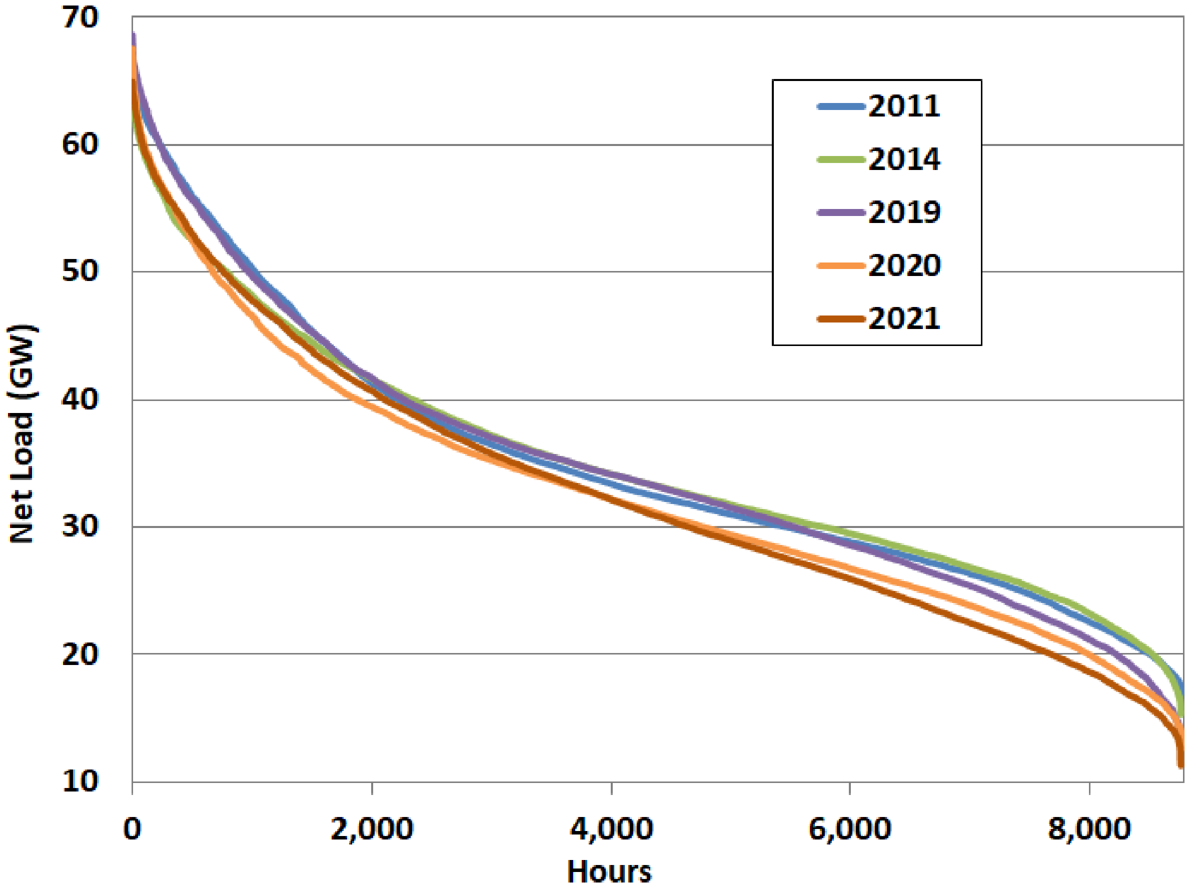


Figure A21 shows the net load duration curves for the years 2011, 2014, 2020 and 2021. Years 2011 and 2014 are included for historical context as they were years with stressed operating conditions. Volatility in the net load amounts continues to increase. Increasing wind output has important implications for non-wind resources and for resource adequacy in the ERCOT region as growth in peak demand requires additional resources to be added, but the energy available to be served by non-wind resources overall is reduced.

Figure A21: Net Load Duration Curves



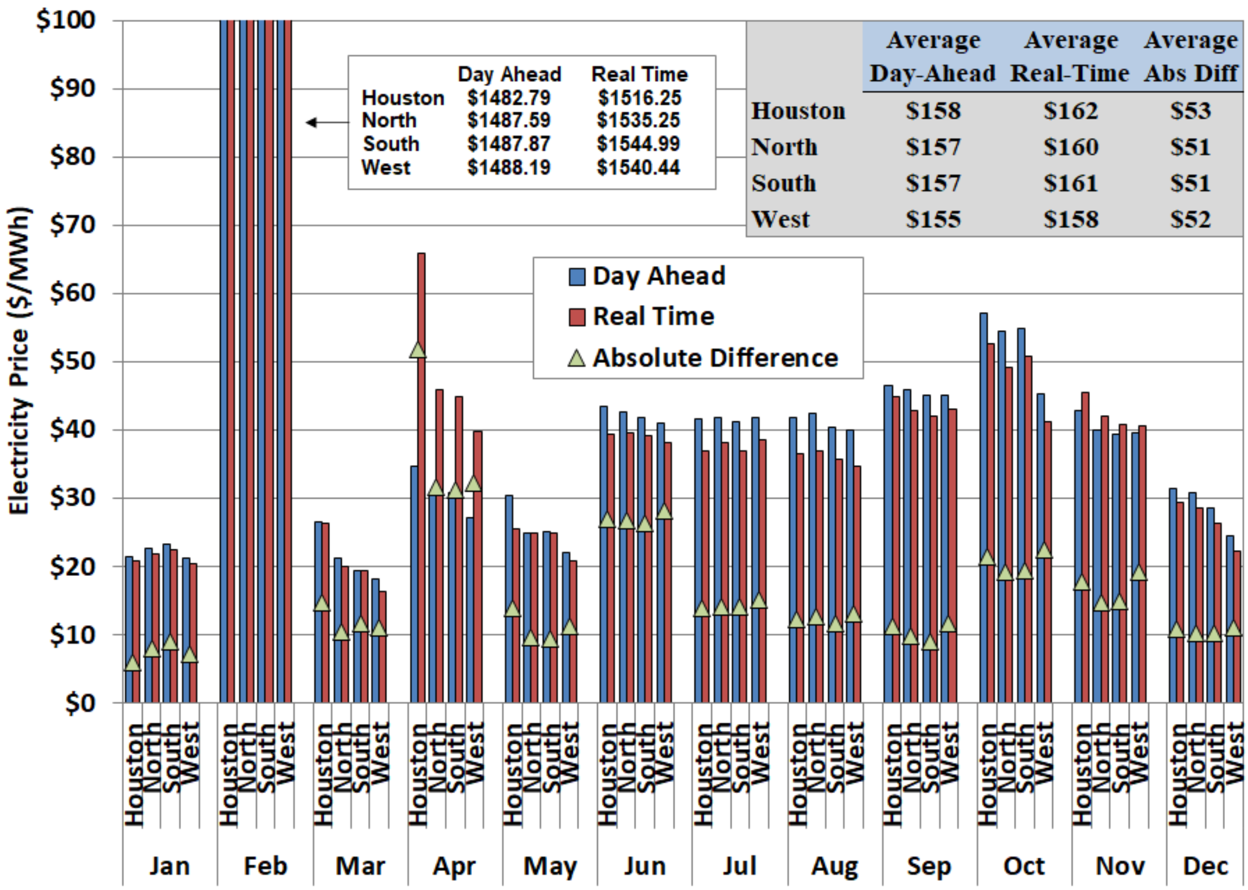
IV. Appendix: Day-Ahead Market Performance

In this section, we provide supplemental analyses of 2020 prices and outcomes in ERCOT's day-ahead energy market.

A. Day-Ahead Market Prices

In Figure A22 and Figure A23 below, monthly day-ahead and real-time prices for 2021 are shown for each of the geographic zones, including and excluding the impacts of Winter Storm Uri respectively. Overall volatility was relatively high in 2021 across all zones, as shown in Figure A19. February 2021 witnessed the most pronounced price differences, with an average difference between day-ahead and real-time prices of $445 per MWh due to the extraordinary weather and outage event. Although the average day-ahead and real-time prices were similar in all zones, the average absolute difference in the Houston zone was the largest. This trend is explained by wide swings in Houston zone prices, the result of transmission congestion in the area related to high load in real-time.

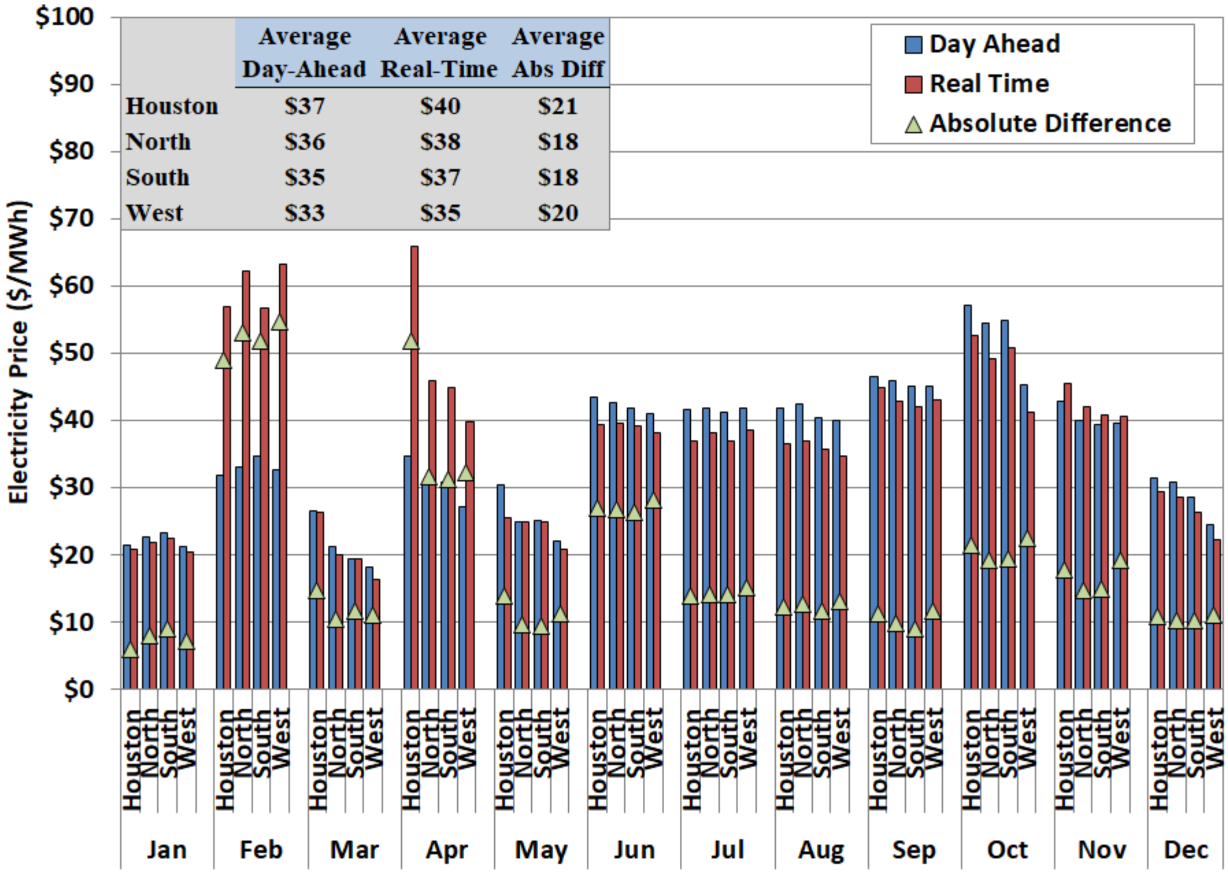
Figure A22: Day-Ahead and Real-Time Prices by Zone (with Uri)



	Average Day-Ahead	Average Real-Time	Average Abs Diff
Houston	$158	$162	$53
North	$157	$160	$51
South	$157	$161	$51
West	$155	$158	$52

Without the impacts of Winter Storm Uri, as shown below in Figure A22, February still had the most pronounced price differences due to cold weather before Winter Storm Uri, but the difference in April 2021 was also exceptionally high, with an average difference between day-ahead and real-time prices of $36.77 per MWh due to two days with scarcity conditions in real-time that were not predicted by day-ahead pricing.

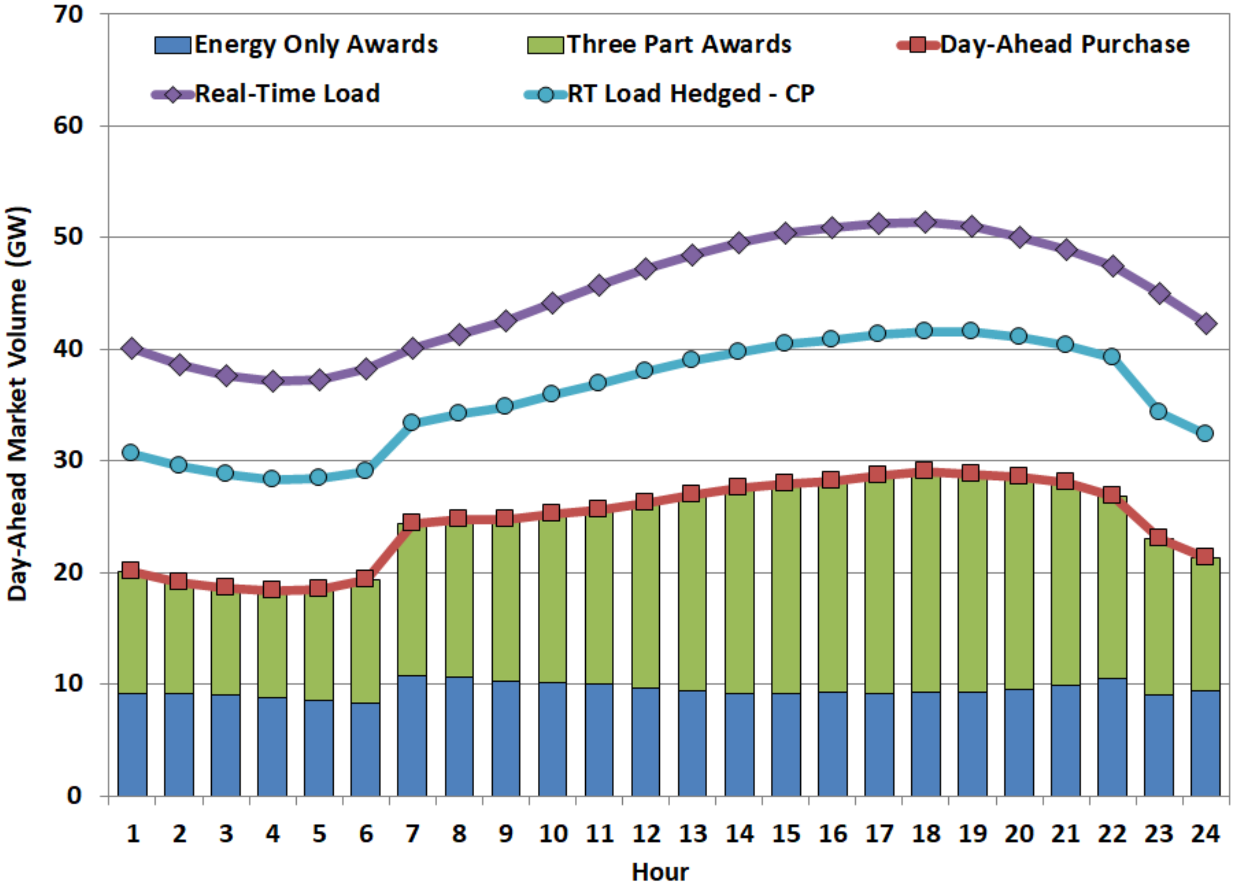
Figure A23: Day-Ahead and Real-Time Prices by Zone (without Uri)



B. Day-Ahead Market Volumes

Figure A24 below presents the same DAM activity data in 2021 summarized by hour of the day. In this figure, the volume of DAM transactions is disproportionate with load levels between hour ending 7 and 22. Because these times align with common bilateral and financial market transaction terms, the results in this figure are consistent with market participants using the DAM to trade around those positions.

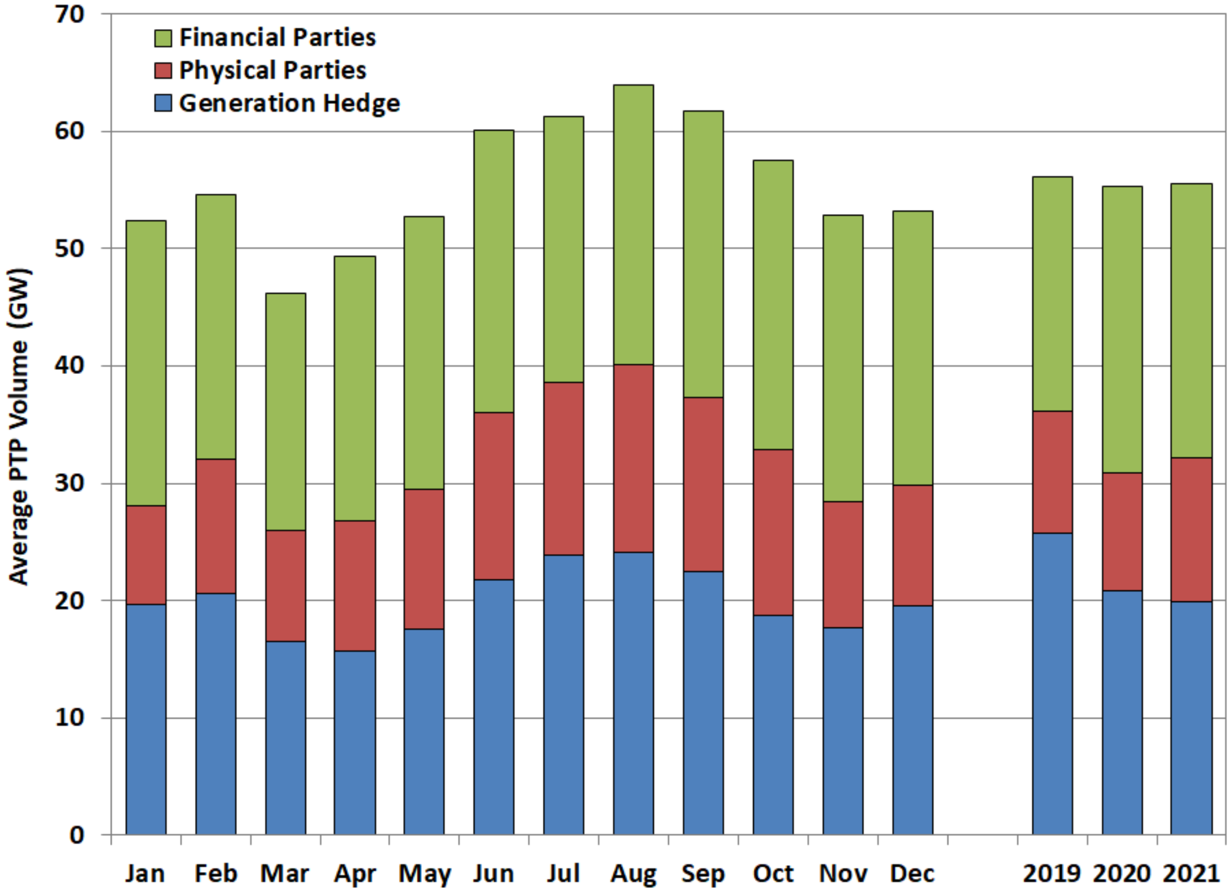
Figure A24: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A25 below presents the total volume of PTP obligation purchases in 2021 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. Average purchase volumes are presented on both a monthly and annual basis. The total volume of PTP obligation cleared purchases has been fairly stable in recent years, with 2021 falling in between 2019 and 2020.

Figure A25: 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 2021, like in 2020, financial parties comprised the plurality of the volume of PTP obligations purchased (41%), although generation hedging comprised a similar volume of PTP obligations purchased for the year (37%). Other than generation hedging, the volumes of PTP obligations are not directly linked to a physical position. They are assumed to be 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 type of market participant.

Physical parties are those that have actual real-time load or generation, whereas financial parties have neither. Financial parties purchased 41% of the total volume of PTP obligations in 2021, consistent with the 42% in 2020 and 36% in 2019. Financial parties increasing volumes can have liquidity benefits but also strains the software, particularly those bids that are unlikely to be awarded. As discussed in our recommendation No. 2020-4, a bid fee would better allocate the scarce labor and hardware resources in the DAM, especially since these parties do not contribute otherwise to the administration of ERCOT.

D. Ancillary Services Market

Figure A26 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the larger variation in quantities between some adjacent hours seen in 2020 was not apparent in 2021 due to the adjusted methodology in July 2021 that procured a stable amount on non-spinning reserve throughout the day.

Figure A26: Average Ancillary Service Capacity by Hour for all of 2021

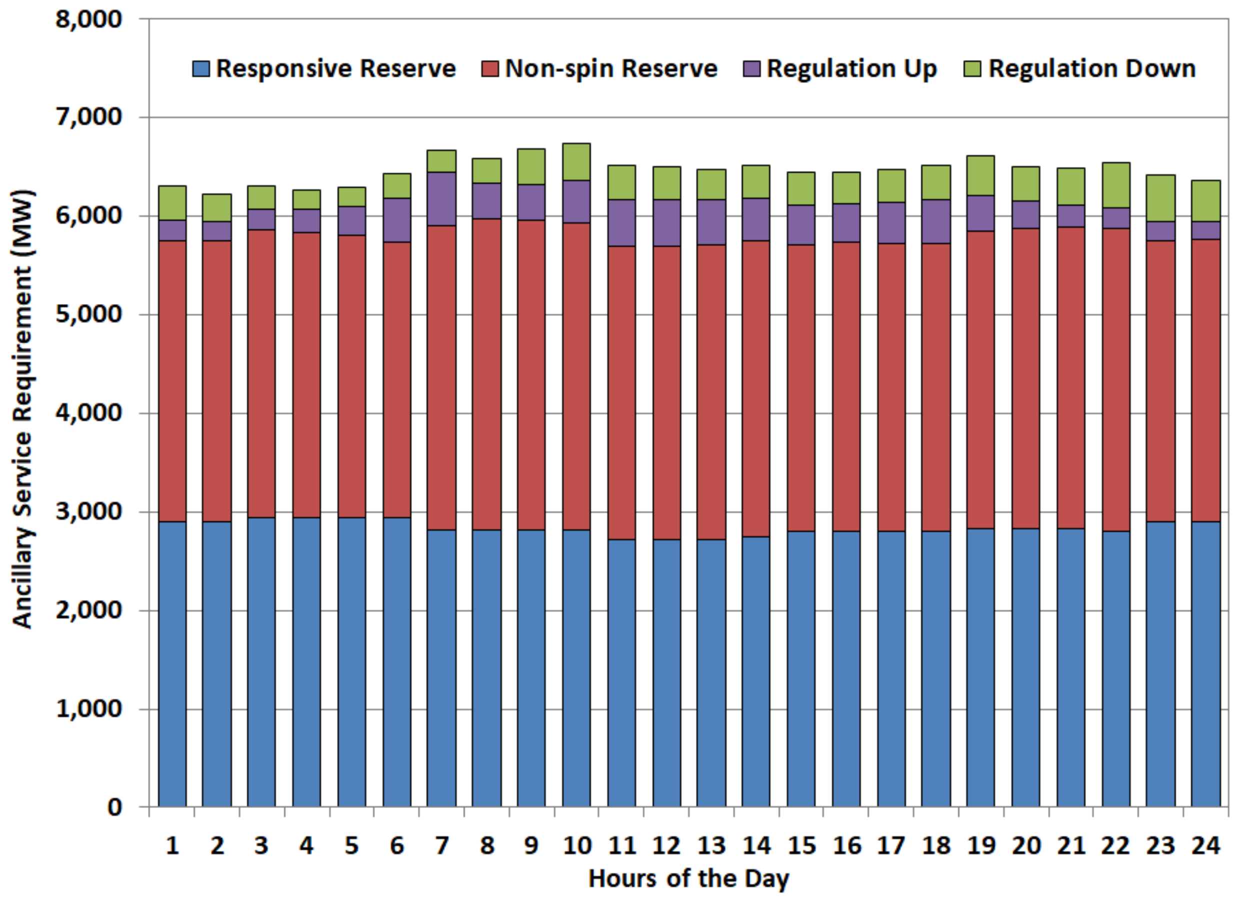


Figure A27 below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2019 through 2021. Figure A28 includes the same analysis but removes the impacts of Winter Storm Uri.

Figure A27: Ancillary Service Costs per MWh of Load (with Uri)

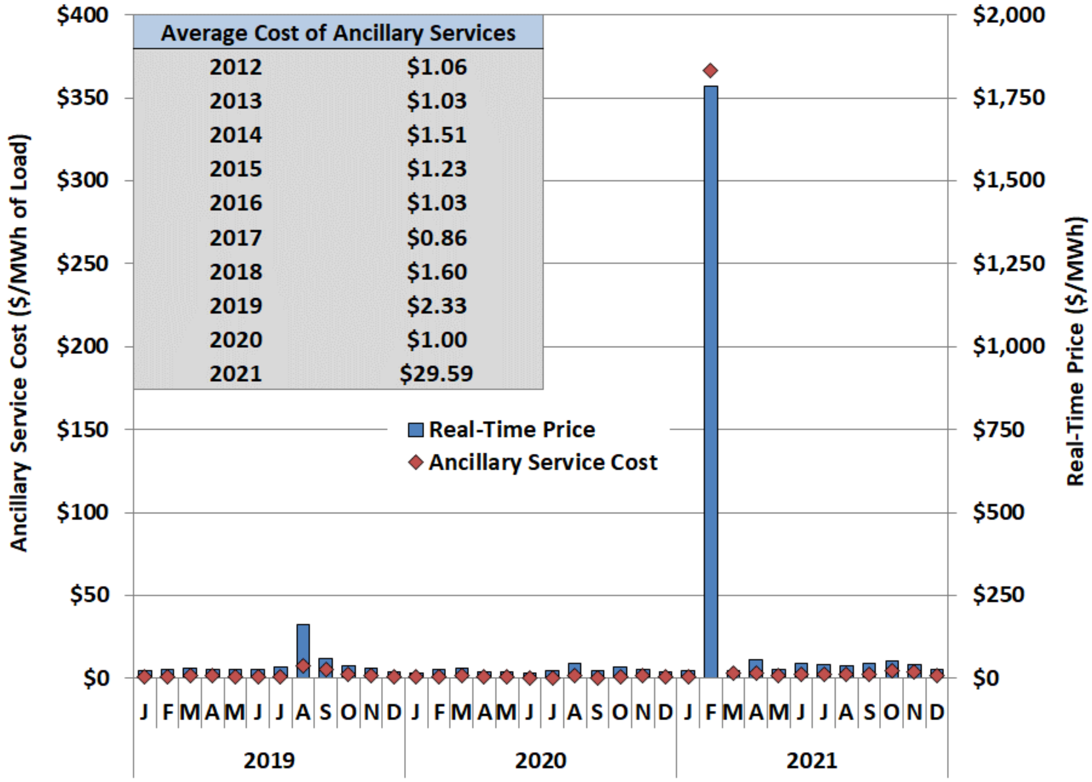
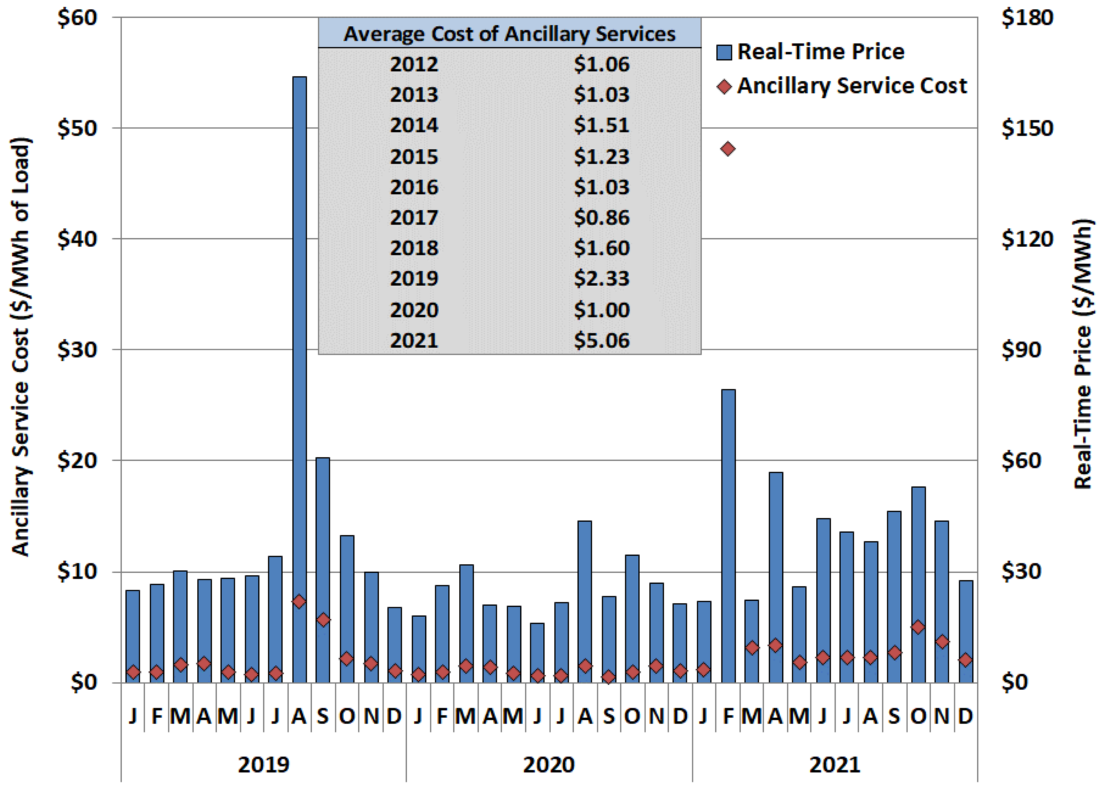


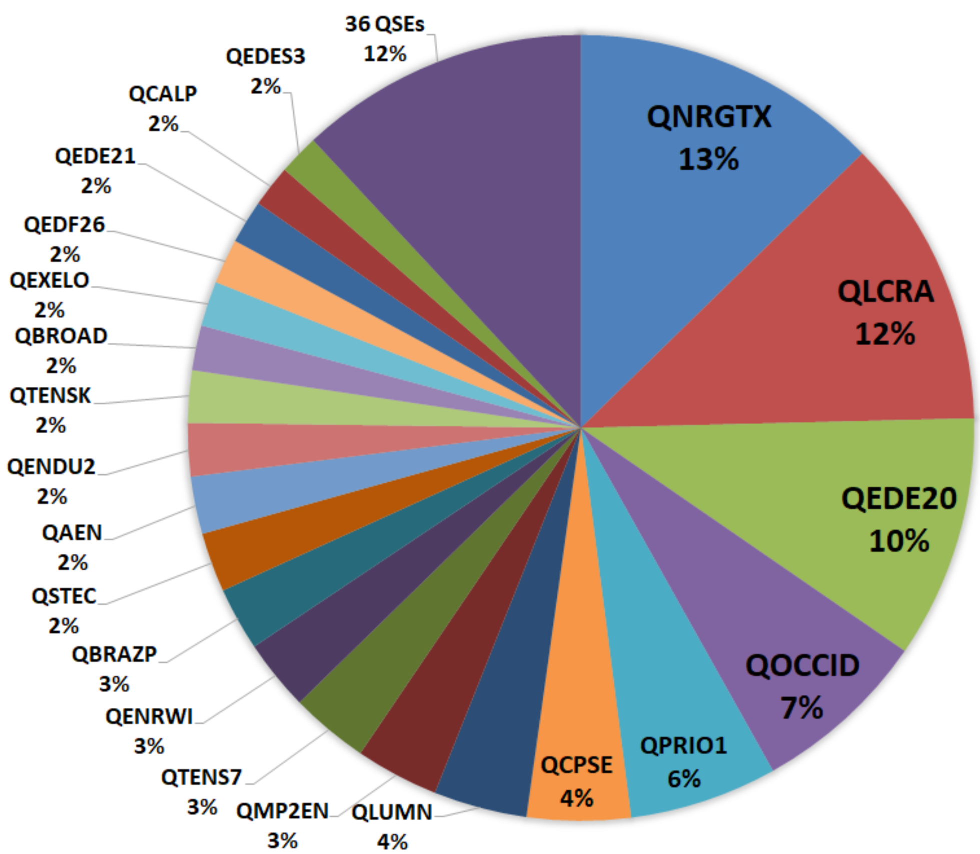
Figure A28: Ancillary Service Costs per MWh of Load (without Uri)



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. When the time period of the storm is removed from the analysis, the average ancillary service cost per MWh of load was $5.06 in 2021, still over double the next highest year (2019). Part of this increase is due to the week after Winter Storm Uri when ancillary service prices remained high, part is due to higher natural gas prices throughout the year, and part is due to the higher AS procurement volumes.

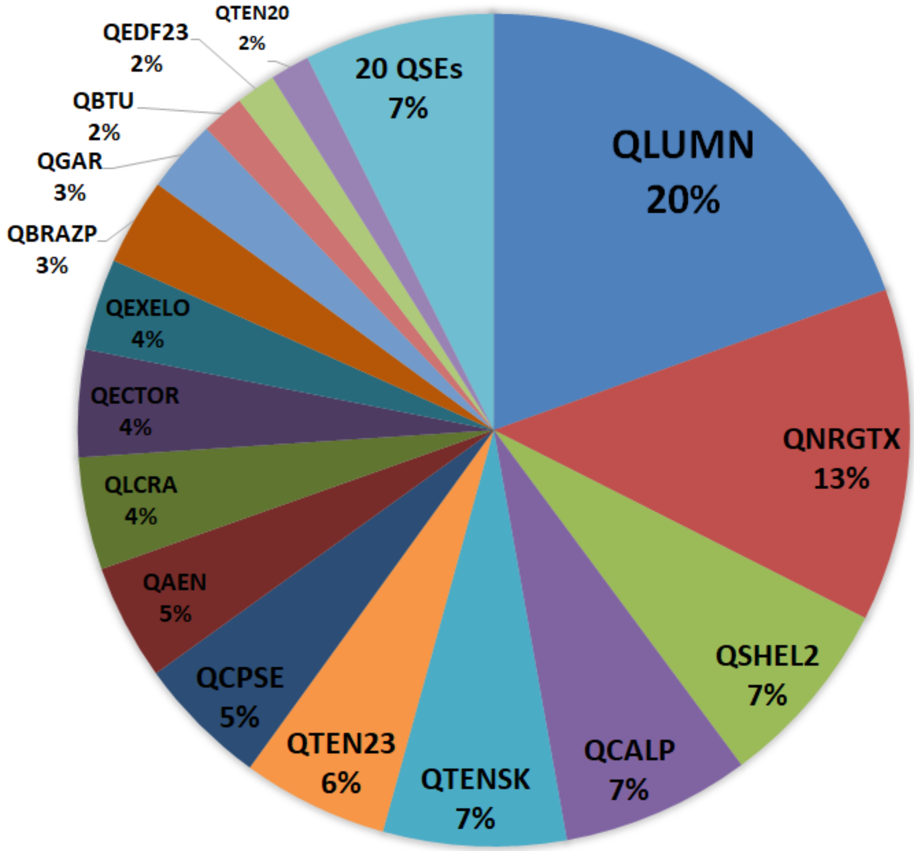
Figure A29 below shows the share of the 2021 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2020, 58 different QSEs self-arranged or were awarded responsive reserves as part of the DAM. The number of providers had been roughly the same for the past five years (46 in 2020, 43 in 2019 and 2018, 45 in 2017, 42 in 2016, and 46 in 2015). 2021 represents a significant increase due to the increasing ancillary service requirements in the second half of 2021. NRG (QNRGTX) and LCRA (QLCRA) were again the largest providers of responsive reserves in 2021, and generally there were no significant changes from 2020 in the largest providers or in the share of responsive reserve provided.

Figure A29: Responsive Reserve Providers



In contrast, Figure A30 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE (Luminant, QLUMN) still bearing are large share of the total responsibility, but a smaller share than in years past. Luminant's 20% share of non-spin responsibility in 2021 was a decrease from the 27% share it held in 2020, down from 37% in 2019, 41% in 2018, and 56% in 2017. As Luminant's non-spin responsibility decreased again in 2021, many other suppliers such as NRG (QNRGTX) and Calpine (QCALP) noticeably increased their shares as well.

Figure A30: Non-Spinning Reserve Providers



The ongoing concentration in the supply of non-spinning reserve highlights the importance of modifying the ERCOT ancillary service market design and implementing RTC. Jointly optimizing all products in each interval will allow the market to substitute its procurements among units on an interval-by-interval basis to minimize costs and set efficient prices. Additionally, it will allow higher quality reserves (e.g., responsive reserves) to be economically substituted for lower quality reserves (e.g., non-spinning reserves), potentially distributing the provision of ancillary services among even more entities.

Figure A31: Regulation Up Reserve Providers

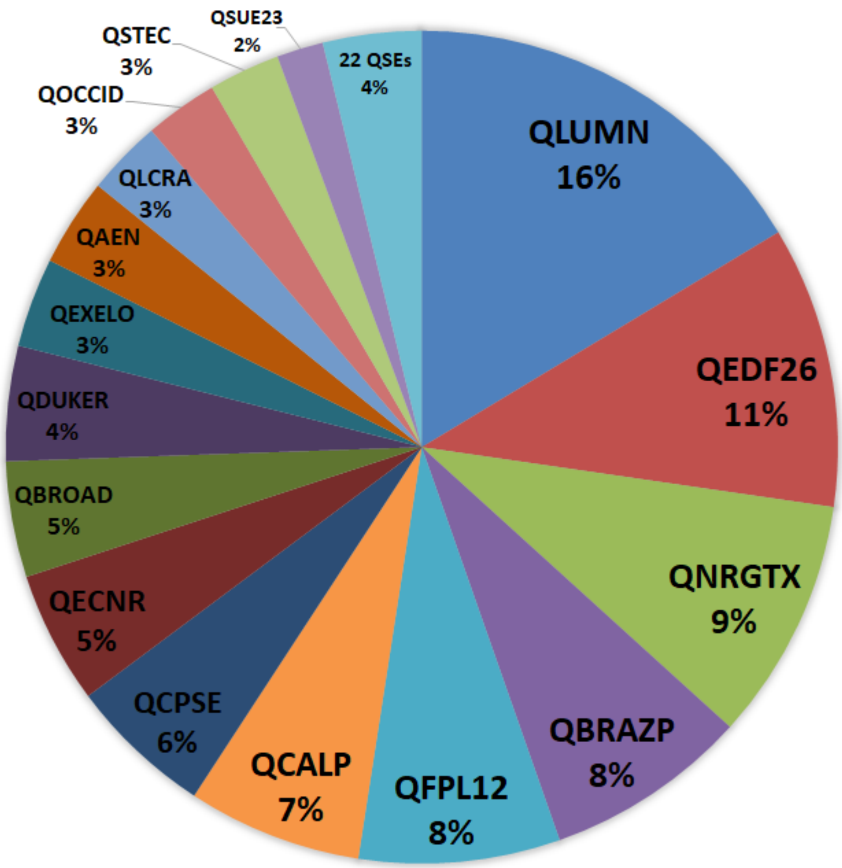
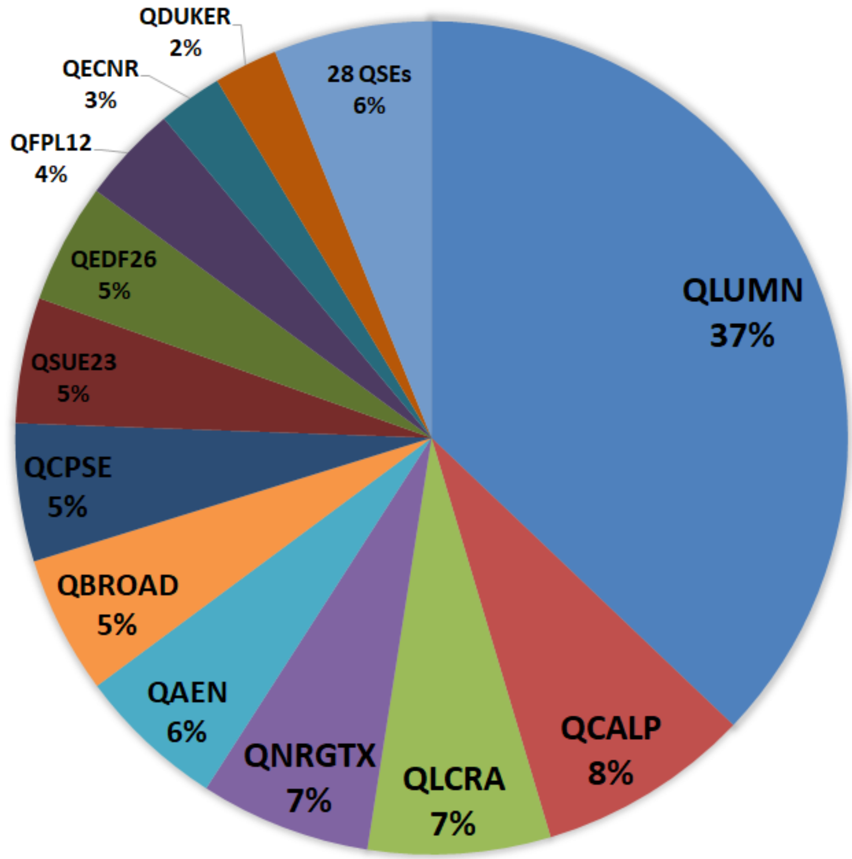


Figure A31 above shows the distribution for regulation up reserve service providers and Figure A32 shows the distribution for regulation down reserve providers in 2021. Figure A31 shows that regulation up was spread more evenly, with Luminant (QLUMN) once again providing the most regulation up reserve service in 2021. Figure A32 shows that that regulation down had similar concentration to non-spinning reserves in 2021. Luminant once more had a dominant position in the provision of regulation down. Its 37% share of the regulation down responsibility in 2021 was on par with the 40% it provided in 2020, and the 43% in 2019.

Figure A32: Regulation Down Reserve Providers



Ancillary service capacity is procured as part of the DAM clearing. Between the time an ancillary service is procured and the time that it is needed, changes often occur that prompt a QSE to move all or part of its ancillary service responsibility from one unit to another. These changes may be due to a unit outage or to other changes in market conditions affecting unit commitment and dispatch. In short, QSEs with multiple units are continually reviewing and moving ancillary service requirements, presumably to improve the efficiency of ancillary service provision, at least from the QSE's perspective. Moving ancillary service responsibility is assumed to be in the QSE's self-interest. When all ancillary services are continually reviewed and adjusted in response to changing market conditions when RTC is implemented, the efficiencies will flow to all market participants and be greater than what can be achieved by QSEs acting individually.

1. Supplemental Ancillary Services Market (SASM)

The ERCOT market appropriately reflects the tradeoff between providing capacity for ancillary services versus providing energy in its co-optimized DAM. Those same tradeoffs exist in real-time. Until comprehensive, market-wide 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 SASM are often three to four times greater than clearing prices from the DAM.

A SASM may also be opened if ERCOT changes its ancillary service plan, although this did not occur during 2021. A SASM was executed 37 times in 2021, with SASM awards providing 340 service-hours. SASMs were more frequent but for fewer total hours in 2021; in 2020, a SASM was executed 25 times, and 490 service-hours were awarded. In addition to more frequent shortages, it appears that ERCOT operators were more sensitive to AS shortages in 2021 than in previous years and took the step to procure replacement MWs more often. Figure A33 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years.

Figure A33: Ancillary Service Quantities Procured in SASM

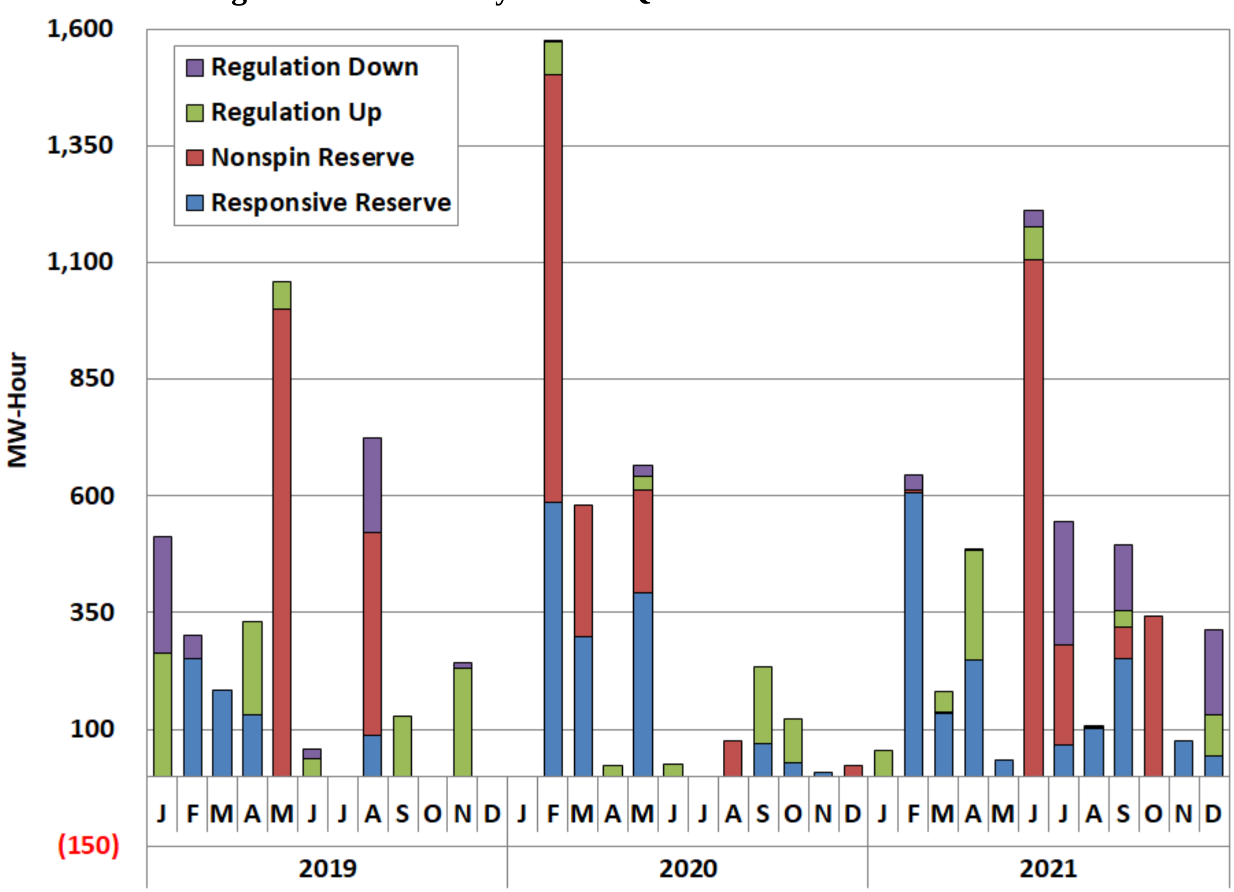
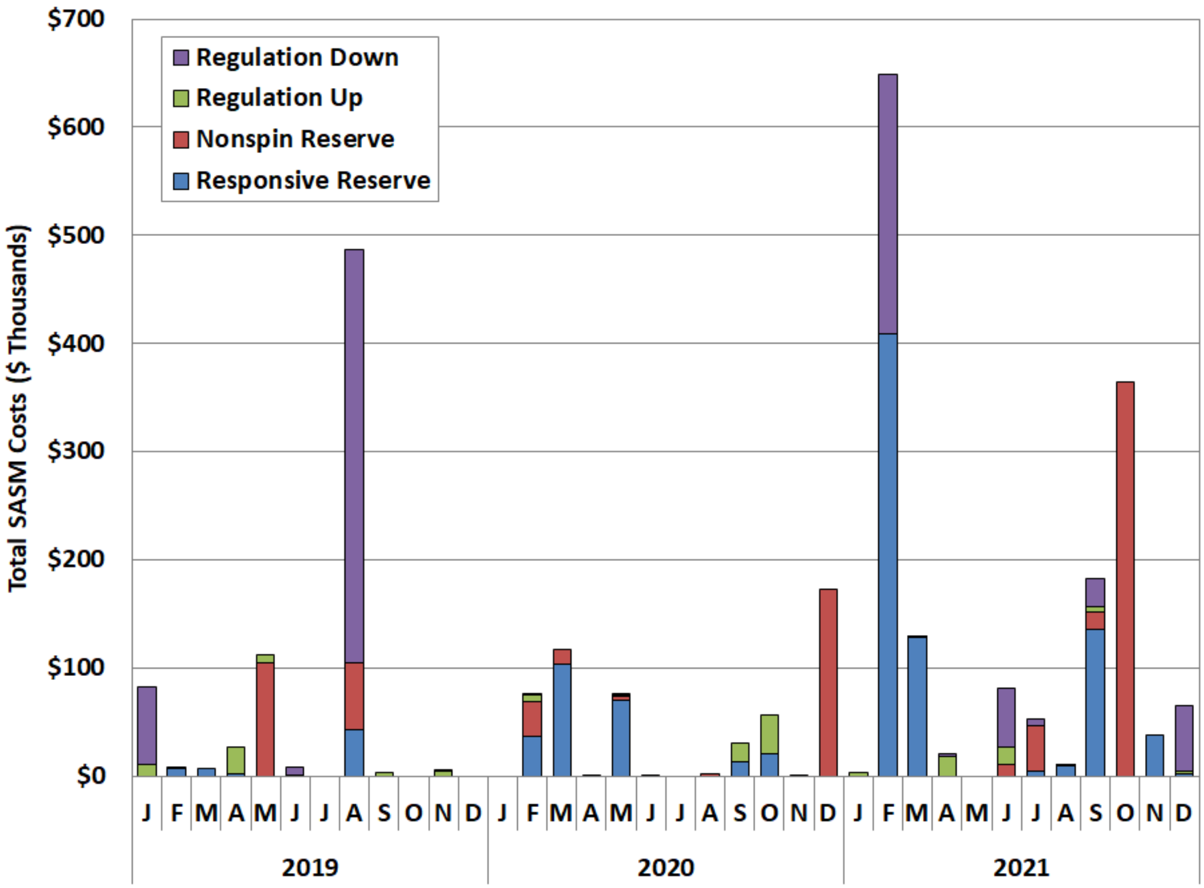


Figure A33 shows that the volume of service-hours procured via SASM over the year (4,486 MW of service-hours in 2021) is very small when compared to the total ancillary service requirement of nearly 42 million MW of service-hours.

Figure A34 shows the average cost of the replacement ancillary services procured by SASM over the last three years. The total SASM costs seen in February 2021 exceeded the previous high of August of 2019, which were the highest SASM costs up to that point in time. If a resource has reserve responsibilities under tight shortage conditions, the QSE would factor in the risk of covering responsibilities for those who could not provide ancillary services when they themselves might need to provide energy, so they have high reserve costs to cover their energy requirements if they end up providing reserves. However, because of the extreme shortage conditions in February, and tighter than expected conditions throughout the year, especially in October, resources were more likely to be diverted to provide energy rather than reserves, thus raising the cost of ancillary services in 2021.

Figure A34: Average Costs of Procured SASM Ancillary Services

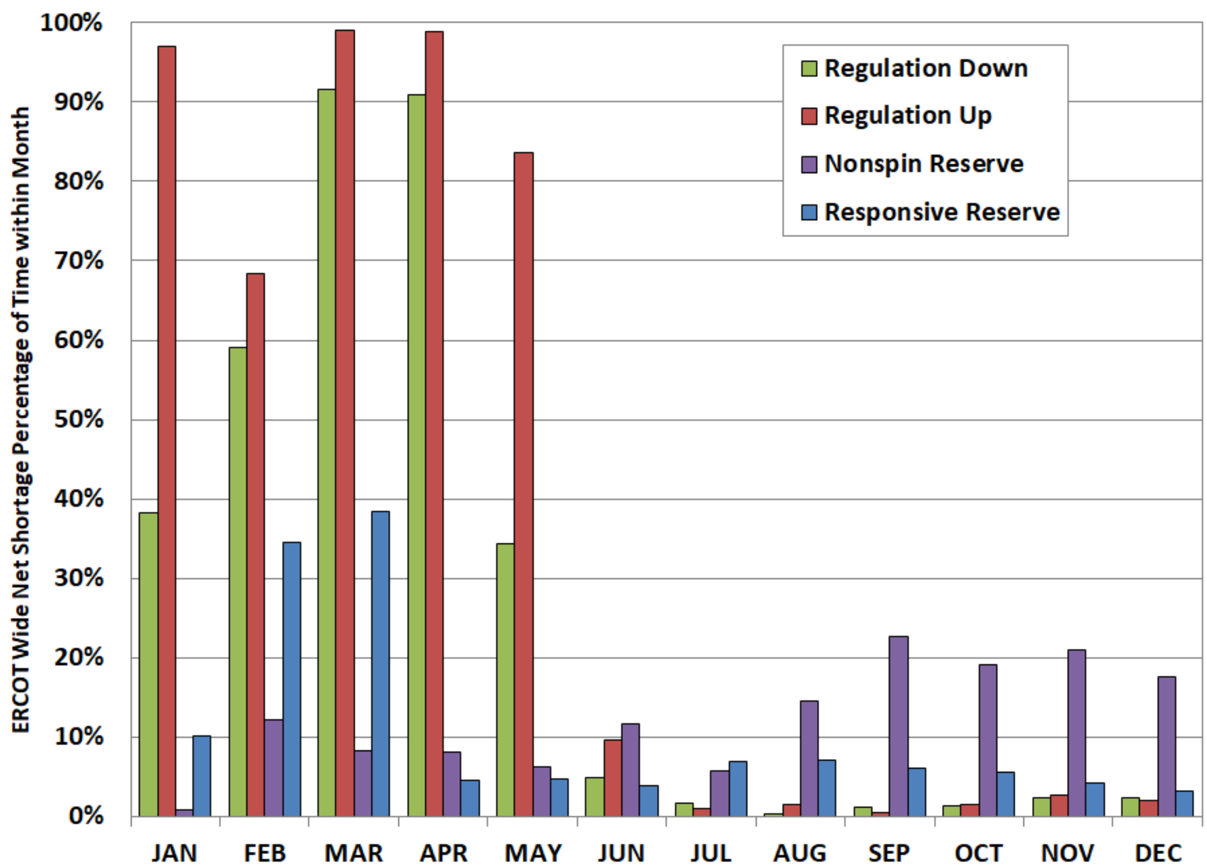


Real-time co-optimization of energy and ancillary services will not require resources to estimate opportunity costs between providing energy or reserves, will eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider.

The greatest benefit will be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g., because of a generator forced outage. Thus, implementation of 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 as per the resource details telemetered to ERCOT. Figure A35 depicts the percentage of hours in each month of 2021 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.

Figure A35: ERCOT-Wide Net Ancillary Service Shortages



This analysis shows that ERCOT-wide shortages for all ancillary services were extraordinarily high in 2021, with shortages of regulation up and down particularly pronounced from January through May. Again, this analysis is based on the telemetered status provided by the parties with the responsibility.

Table A3 is the monthly aggregate costs of various ERCOT market settlement totals in 2021, including AS costs by type.

Table A3: Market at a Glance Monthly

	Monthly Totals (Millions)											
	Jan	**Feb**	**May**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
Energy	$677	$51,915	$610	$1,593	$819	$1,661	$1,616	$1,582	$1,688	$1,730	$1,219	$835
Regulation Up	$4	$809	$7	$9	$6	$7	$5	$5	$5	$7	$4	$3
Regulation Down	$2	$307	$8	$6	$7	$3	$1	$2	$2	$3	$3	$2
Responsive Reserve	$26	$7,738	$68	$64	$43	$54	$37	$34	$35	$60	$45	$28
Non-Spin	$2	$1,807	$4	$14	$4	$22	$44	$52	$56	$93	$51	$27
CRR Auction Distribution	$59	$56	$71	$69	$71	$80	$78	$73	$64	$71	$66	$72
Balancing Account Surplus	$6	$10	$0	$2	$11	$12	$9	$17	$16	$22	$5	$0
CRR DAM Payment	$54	$187	$124	$137	$108	$67	$35	$69	$72	$178	$134	$122
PTP DAM Charge	$41	$151	$100	$120	$103	$64	$34	$68	$73	$153	$109	$97
PTP RT Payment	$42	$455	$148	$243	$78	$55	$57	$62	$81	$135	$114	$94
Emergency Response Service	$0	$19	$0	$0	$0	$16	$0	$0	$0	$14	$0	$9
Revenue Neutrality	$5	($57)	$16	$10	$1	($2)	$2	$2	$3	$3	$9	$10
ERCOT Fee	$17	$16	$15	$16	$18	$21	$22	$23	$20	$18	$16	$17
Other Load Allocation	$1	$1,821	$1	($1)	$1	$2	$4	$1	$1	($0)	$1	$1

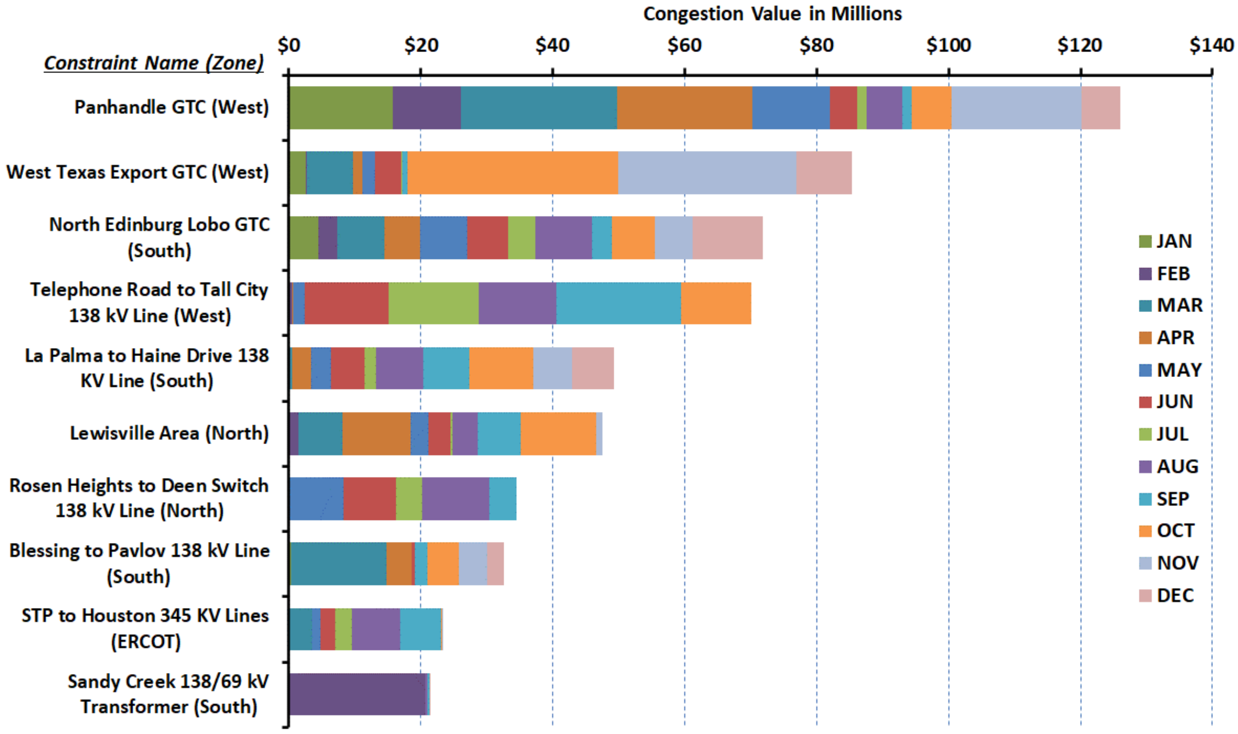
V. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2020, 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 and Real-Time Congestion

In this subsection, we provide a review of the transmission constraints from the DAM in 2021. Figure A36 presents the ten most congested areas from the DAM, ranked by their value. Eight of the constraints listed here were described in Figure 42: Most Costly Real-Time Congested Areas. To the extent the model of the transmission system used for the DAM matches the real-time transmission system, and assuming market participants transact in the DAM similar to how energy flows in real-time, the same transmission constraints are expected to appear in both markets.

Figure A36: 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 fourth year in a row, the majority of the costliest day-ahead constraints in 2021 were also costly real-time constraints. Aside from the Lewisville Area, Rosen Heights to Deen Switch, Blessing to Pavlov and Sandy Creek, the rest of the constraints that exist in both the top ten real-time market and the top ten DAM incurred less congestion value in the DAM than the real-time market. This is a result of less wind generation participating in the DAM, likely because of the uncertainty associated with predicting its output. The Sandy Creek constraint was a result of transmission conditions from Winter Storm Uri.

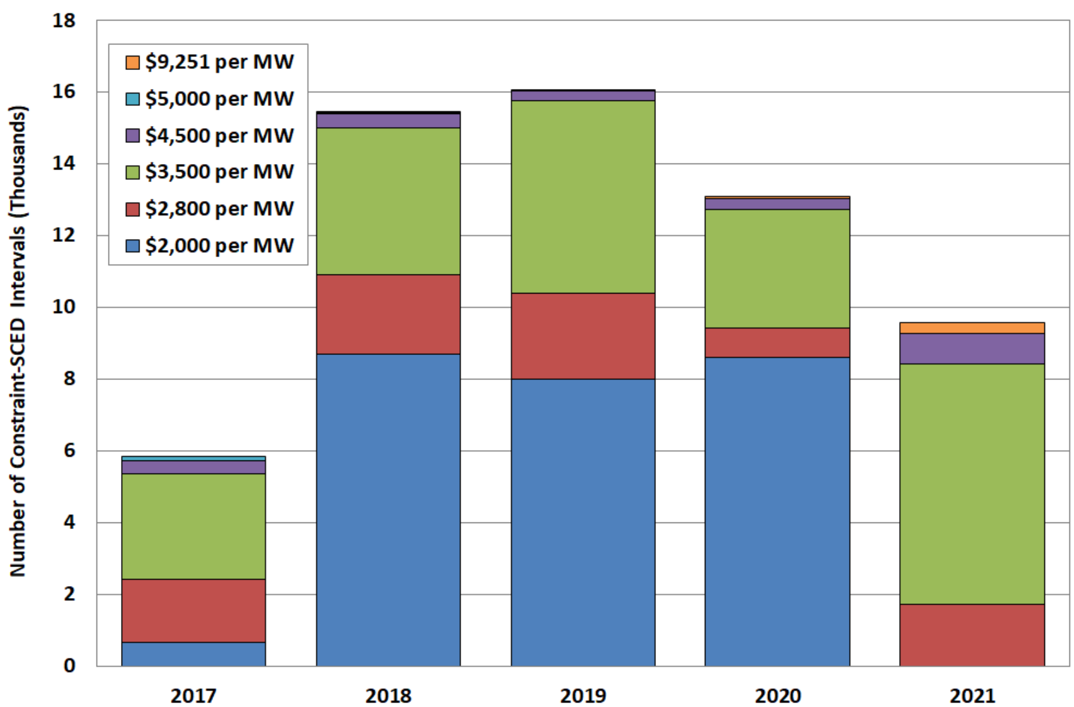
B. Real-Time Congestion

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 DAM, but the ultimate source of the congestion is the physical constraints binding in real time.

1. Types and Frequency of Constraints in 2021

Figure A37 below depicts constraints were violated (i.e., at maximum shadow prices) less frequently in 2021 than they were in 2020, continuing the trend form 2019. In 2019, the majority of the violated constraints occurring at the $2,000 per MW value were related to the Dollarhide to No Trees 138 kV line irresolvable element but dropped to 30% in 2020 due to the upgrades addressing the irresolvable element completed in spring 2020. In 2021, the majority of the violated constraints occurred at the $3,500 per MW value, the 138kv level, because of congestion due to Winter Storm Uri in the south zone. Violated constraints continued to occur in a small share of all the constraint-intervals, 4% in 2021, down from 5% in 2020 and 7% in 2019.

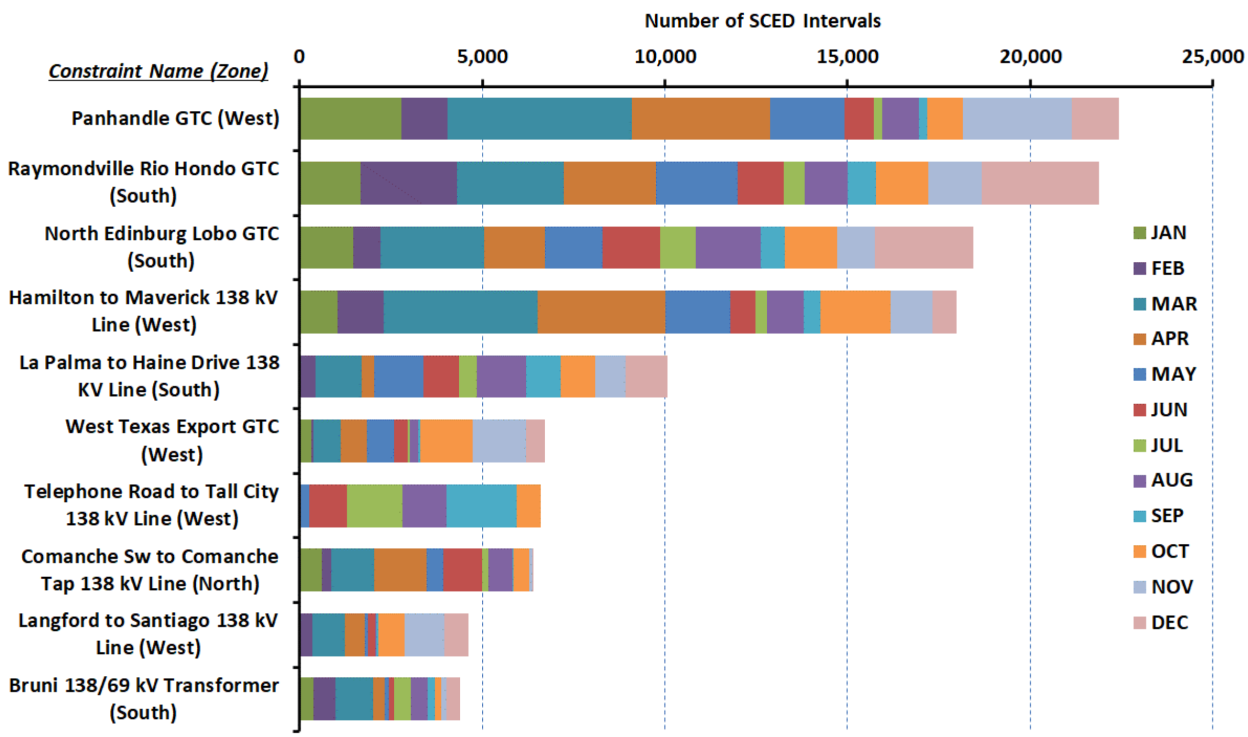
Figure A37: Frequency of Violated Constraints



2. Real-time Constraints and Congested Areas

Three GTCs (Panhandle, West Texas Export, and North Edinburg Lobo GTC) were in the top ten congested valued areas in 2021, up from 2 in 2020. GTC constraints doubled in congestion value to approximately $410 million from $190 million in 2020. While there were planned transmission upgrades to previously congested areas, such as Pig Creek and Lewisville, congestion continues due to inverter-based resource output. ERCOT continues to create workshops and taskforces to study and analyze models and future needs. While within the top ten constraints in terms of congestion cost, four of the top ten accrued congestion costs during and after Winter Storm Uri. However, all constraints listed in Figure A38 were frequently constrained in 2021 due to variable renewable output. The top ten most congested valued real-time constraints totaled to $820 million, whereas the top ten most frequently constrained constraints totaled $566 million.

Figure A38: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

As shown in Table A4, 14 element combinations were deemed irresolvable in 2021 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[112] and are intended to reflect the level of reduced reliability that occurs when a constraint is irresolvable. The shadow price caps are $9,251 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 $9,251 per MW.

Table A4: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price ($ per MWh)	2021 Adjusted Max Shadow Price ($ per MWh)	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2021
Base Case	Valley Import GTC	9,251	2,000	1/1/12	-	South	-
SSOLFTS8	Fort Stoctkon to Barilla 69 kV Line	2,800	2,000	5/13/19	1/30/21	West	-
XFRI89	Sonora 138/69 kV Transformer	2,800	2,000	5/24/19	1/30/21	West	-
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	2,800	2,000	9/23/19	1/30/21	West	-
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	10/15/19	1/30/21	West	-
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	10/23/19	1/30/21	West	-
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	3,500	2,000	11/29/19	1/30/21	West	-
SHACPB38	Rio Pecos to Woodward 2 138 kV Line	3,500	2,000	1/1/20	1/30/21	West	-
DWINDUN8	Andrews County South to Amoco Three Bar Tap 138 kV Line	3,500	2,000	3/24/20	1/30/21	West	-
DNEDWED8	Hidalgo Energy Center to Azteca Sub 138 kV Line	3,500	2,000	8/5/20	-	South	-
SMV_ALT8	Weslaco Switch to North Alamo 138 kV Line	3,500	2,000	8/7/20	-	West	-
SPHAWES8	Key Switch to North McAllen 138 kV Line	3,500	2,000	8/10/20	-	West	-
SHACPB38	Lynx to Tombstone 138 kV Line	3,500	2,000	11/30/20	-	West	-
SBEVASH8	Hamilton to Maverick 138 kV Line	3,500	2,000	2/18/21	-	West	435
SCRDJON5	Decordova Dam to Carmichael Bend Switch 138 kV Line	3,500	2,000	2/20/21	-	West	425

112 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.

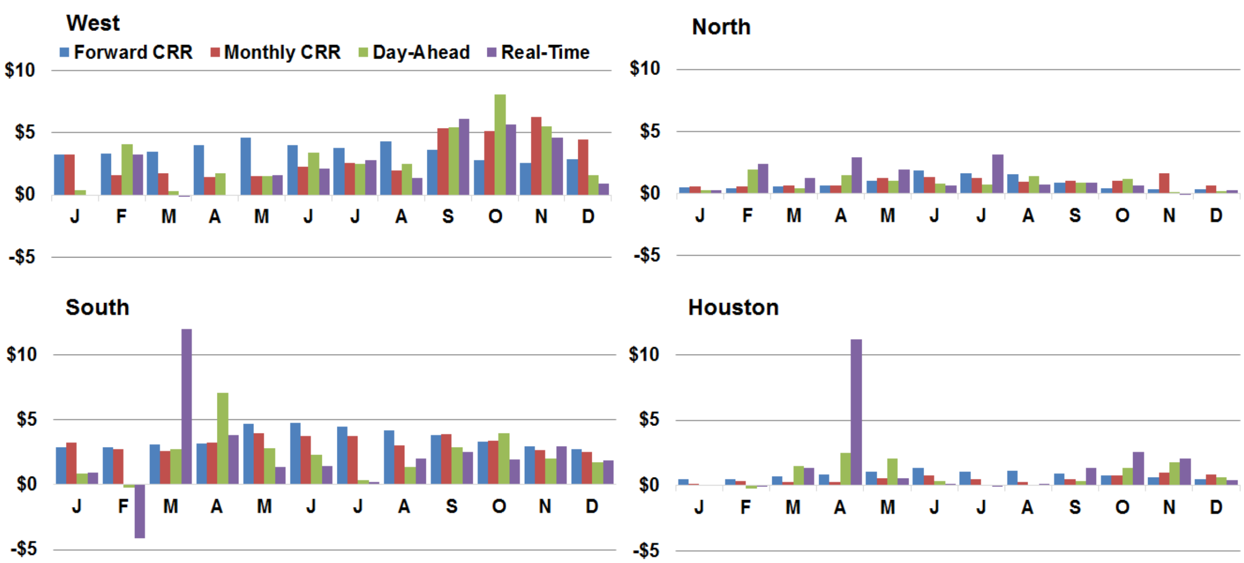
Eight constraints identified with a termination date of 1/30/21, were deemed resolvable during ERCOT's annual review and were removed from the list. All irresolvable constraints are located in the West zone with the exception of the Valley Import GTC and Hidalgo Energy Center to Azteca 138 kV line, which is located in the South zone.

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A39 below shows the price spreads between all hub and load zones in 2021 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.

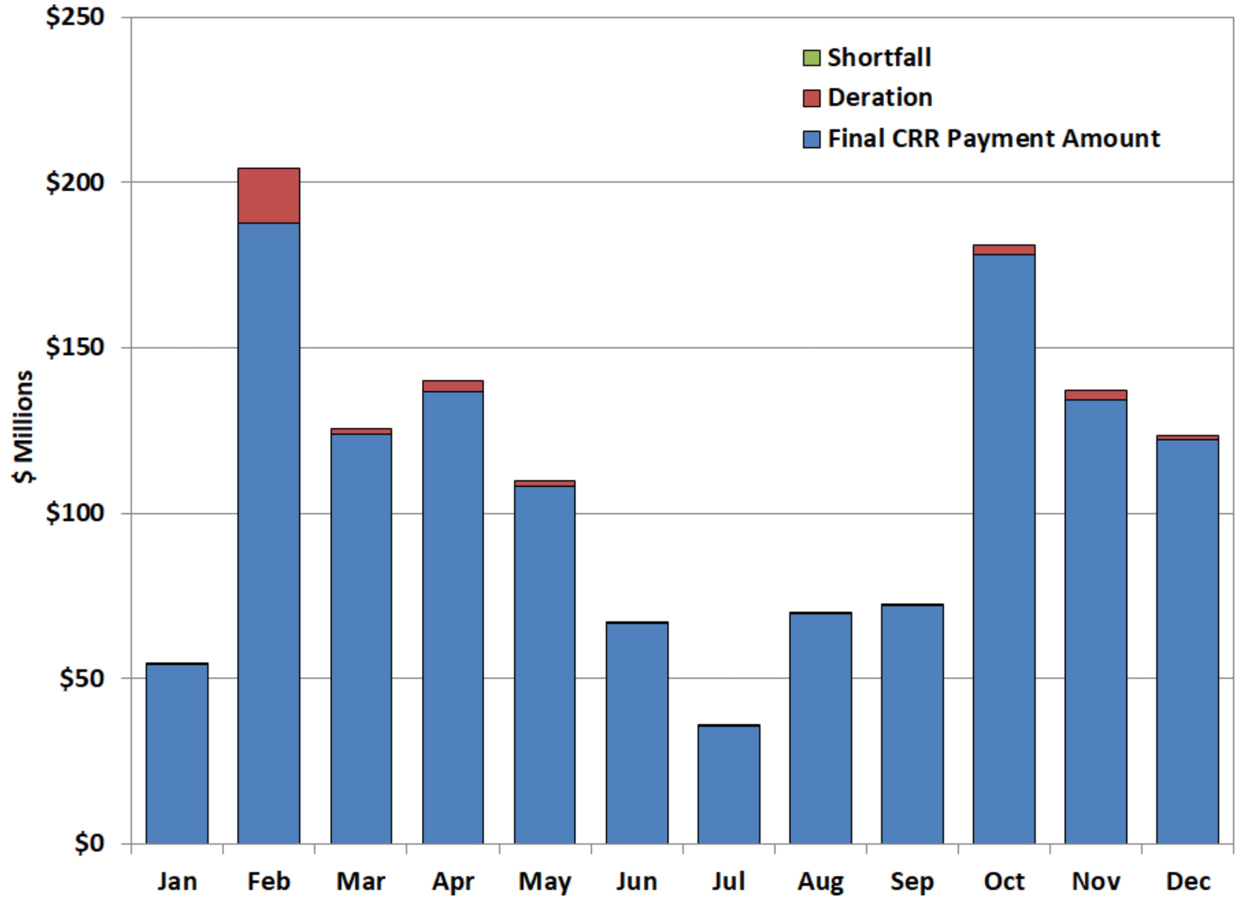
Figure A39: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A40 shows the amount of target payment, deration amount, and final shortfall for 2021. In 2021, the total target payment to CRRs was approximately $1.3 billion, similar to 2020; there were approximately $32 million of derations but no shortfall charges resulting in a final payment to CRR account holders of $1.23 billion. This final payment amount corresponds to a CRR funding percentage of 98%, the same as the funding percentage in 2020.

Figure A40: CRR Shortfall and Derations



VI. Appendix: Reliability Unit Commitments

In this section, we provide supplemental analyses of RUC activity in 2021 as well as the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC.

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 in an effort 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 Low-Sustained Limit (LSL) for units committed through RUC, and it is currently set at $1,500 per MWh. Resources committed through the RUC process are eligible for a make-whole payment but also forfeit any profit through a clawback provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the clawback 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 (reliability adder). ERCOT systems now automatically set the energy offer floor at $1,500 per MWh when a resource properly telemeters a status indicating it has 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 is 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 NPRR901, *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 now prevents the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource was awarded a resource-specific offer in the DAM. 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.[113]

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.[114] The effects of this new conservative approach and the resulting increase in RUC activity are outlined below.

B. 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 peak hours of 12 through 20 for the summer months of July and August. Multiple COP submissions

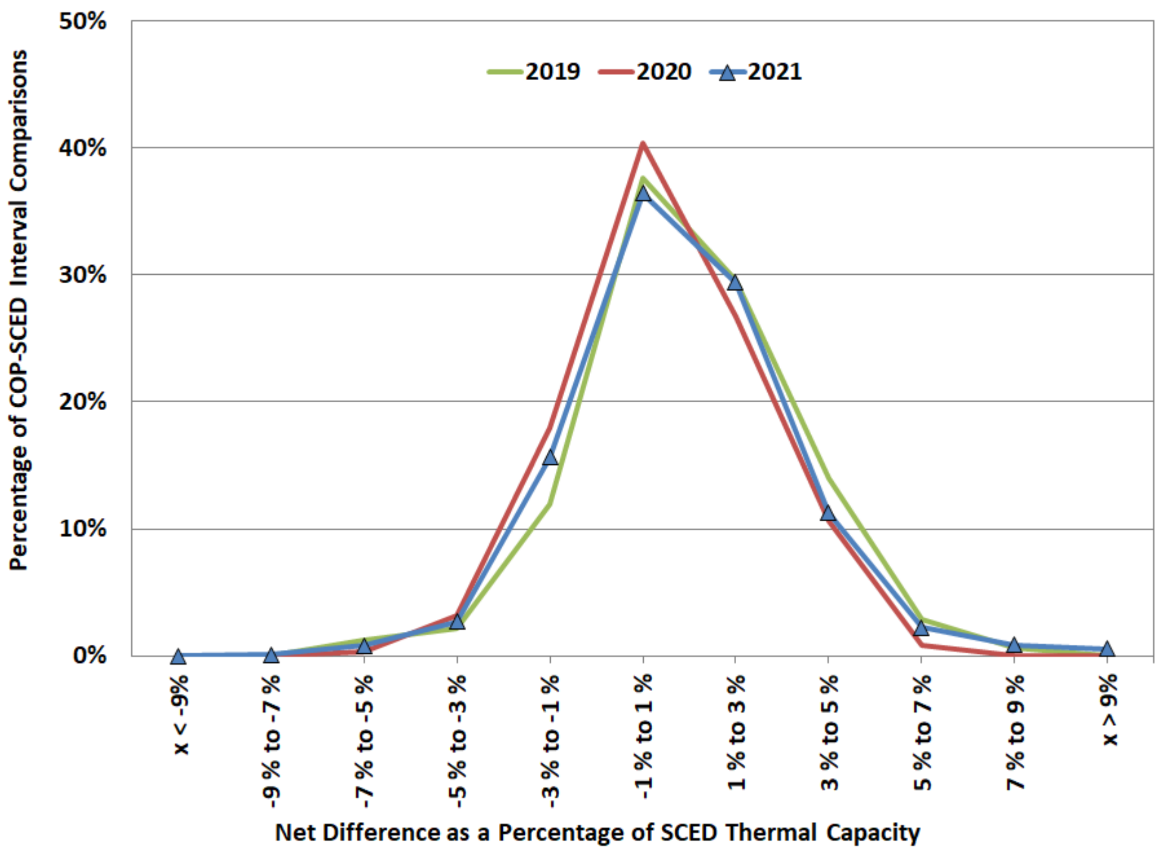
113 *See* NPRR856, *Treatment of OFFQS Status in Day-Ahead Make Whole and RUC Settlements* (implemented May 2020); NPRR884, *Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources* (implemented May 2020); NPRR970, *Reliability Unit Commitment (RUC) Fuel Dispute Process Clarification* (implemented March 2020); NPRR977, *Create MIS Posting for RUC Cancellations* (implemented May 2020); NPRR1019, *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); NPRR1028, *RUC Process Alignment with Resource Limitations Not Modeled in the RUC Software* (approved December 2020); and NPRR1032, *Consideration of Physical Limits of DC Ties in RUC Optimization and Settlements* (approved December 2020).

114 https://www.ercot.com/news/release?id=5fef298c-fbd7-34d3-39ee-d3fc63e568c2

as of day-ahead 1600 provide data for each of the hours being evaluated, and there can be large variations in unit commitment expectations reflected in those multiple COPs, even for the same operating hour. 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 A41 summarizes the frequency of percentage error between SCED thermal capacity and its respective COP. The comparisons include relevant COPs since day-ahead 1600 - 24 hours prior to HE 12 through HE 20, to the COP at the end of the adjustment period. The analysis focuses on the net difference as a percentage of the SCED thermal capacity due to load fluctuations between years. The last three years have shown a tendency towards an error greater than 1%. In 2019, 15.3% of the COP-SCED interval comparisons were below -1% error, 37.6% occurring within 1%, 47.1% had a percentage error greater than 1%, and 17.5% were greater than 3%. In 2020, 21.4% of the COP-SCED interval comparisons were below -1% error, 40.4% occurring within 1%, 38.2% had a percentage error greater than 1%, and 11.5% were greater than 3%. In 2021, 19.9% of the COP-SCED interval comparisons were below -1% error, 35.6% occurring within 1%, 44.5% had a percentage error greater than 1%, and 16.0% were greater than 3%.

Figure A41: Real-Time to COP Comparisons for Thermal Capacity

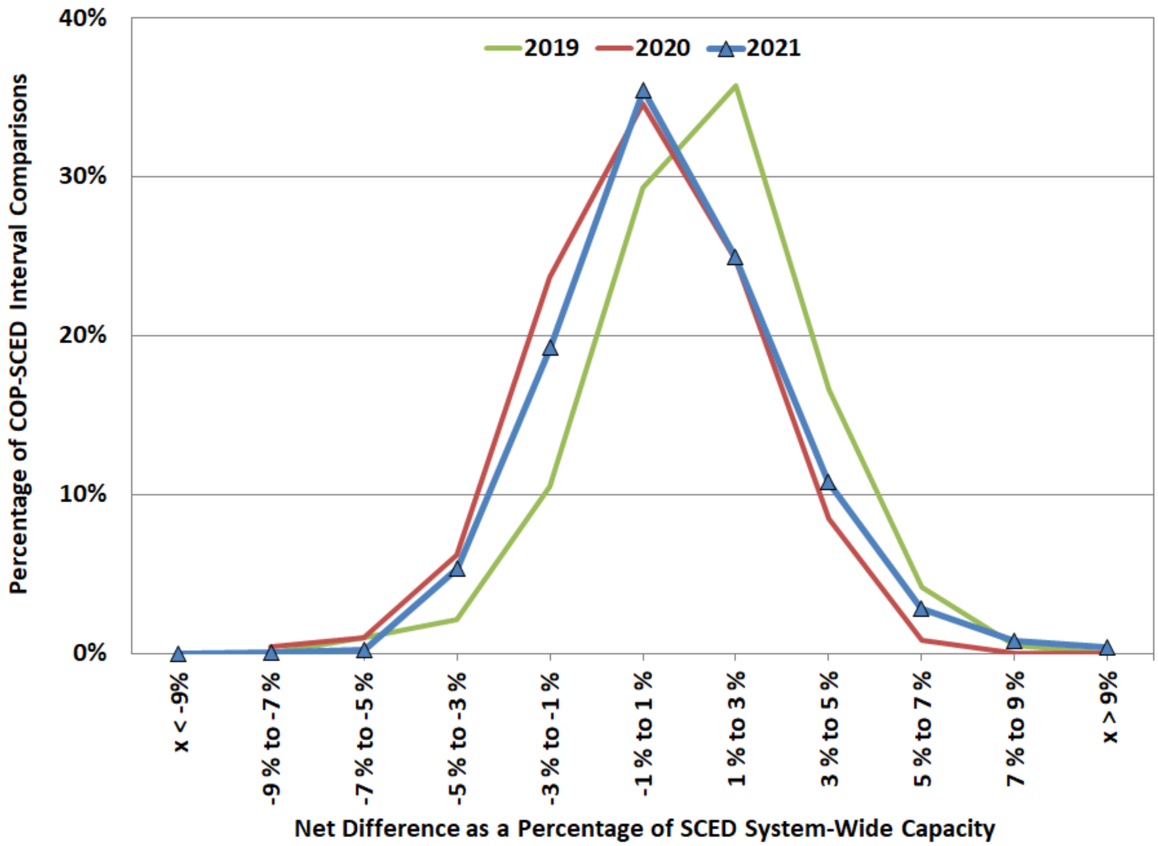


When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then under-report the COP at the end of the adjustment period a small percentage of the time. The curve from 2021 is similar to the curves from the previous two years, with 2021 exhibiting a slightly smaller contrast.

In 2019, there was a bias towards under-representing the amount of capacity that would materialize in real-time. In 2020 and 2021, the shape of the curve indicates a more evenly distributed representation of capacity in real-time versus the COP capacities.

Figure A42 summarizes the same analysis as above, but for system-wide capacity. 2021 shows a similar about of capacity occurring in real-time at the system-wide level, including intermittent renewable resources, as occurred in 2020. A possible explanation for this is better forecast for the renewables leading up to the operating hour.

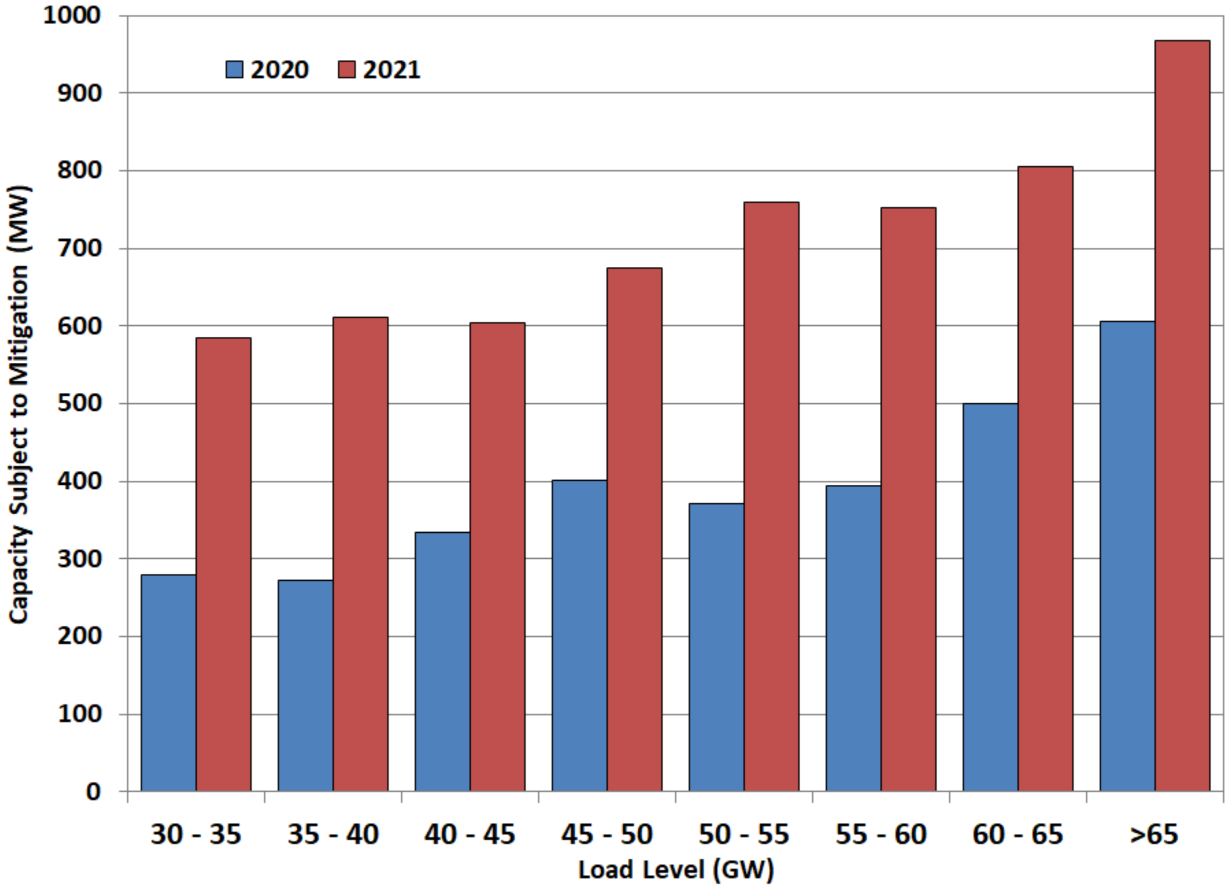
Figure A42: Real-Time to COP Comparisons for System-Wide Capacity



C. 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 A43.

Figure A43: Average Capacity Subject to Mitigation



The average amount of capacity subject to mitigation in 2021 was higher than 2020 in all load levels. 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.

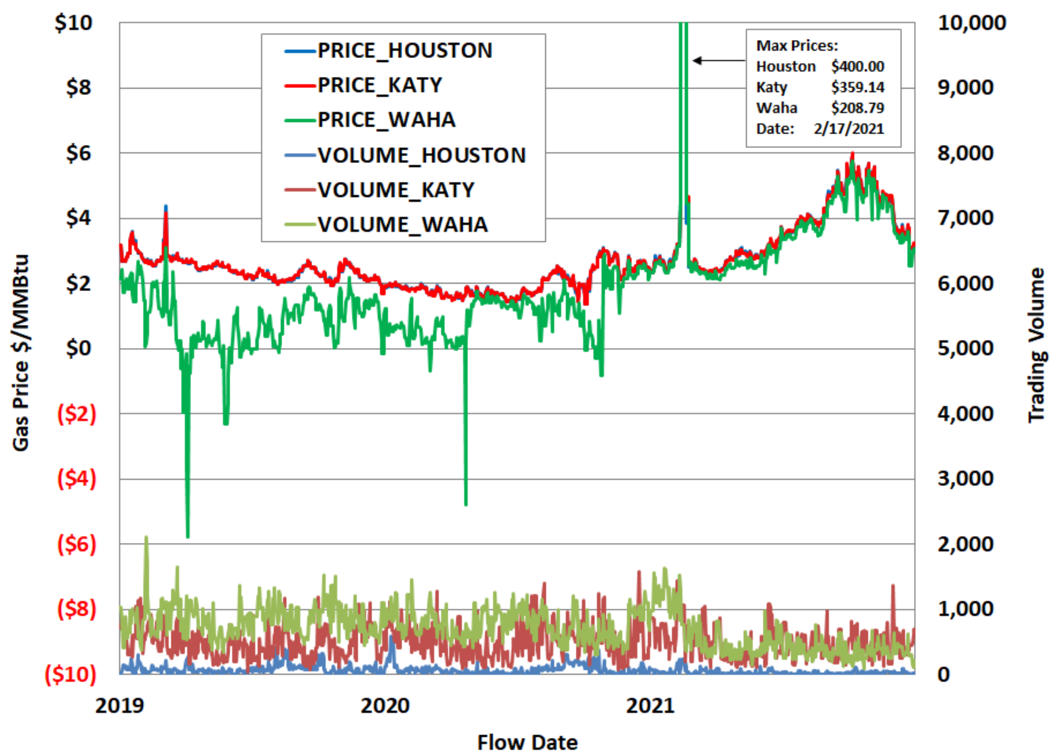
VII. Appendix: Resource Adequacy

In this section, we provide a supplemental analysis of the economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's needs by estimating the "net revenue" resources received from ERCOT real-time and ancillary services markets and providing comparisons to other 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 saw a continuing trend evident of the growing separation in natural gas prices between the Waha and Katy locations in the West.[115] Drilling activity in the Permian Basin of far west Texas has produced a glut of natural gas and consequently, much lower prices at the Waha location. In 2021, the rise in natural gas prices in February, across all indices, was unprecedented during the freezing conditions of Winter Storm Uri. As seen in Figure A44 below, Waha prices dipped below $0 multiple times throughout 2021, and were more volatile than Katy.

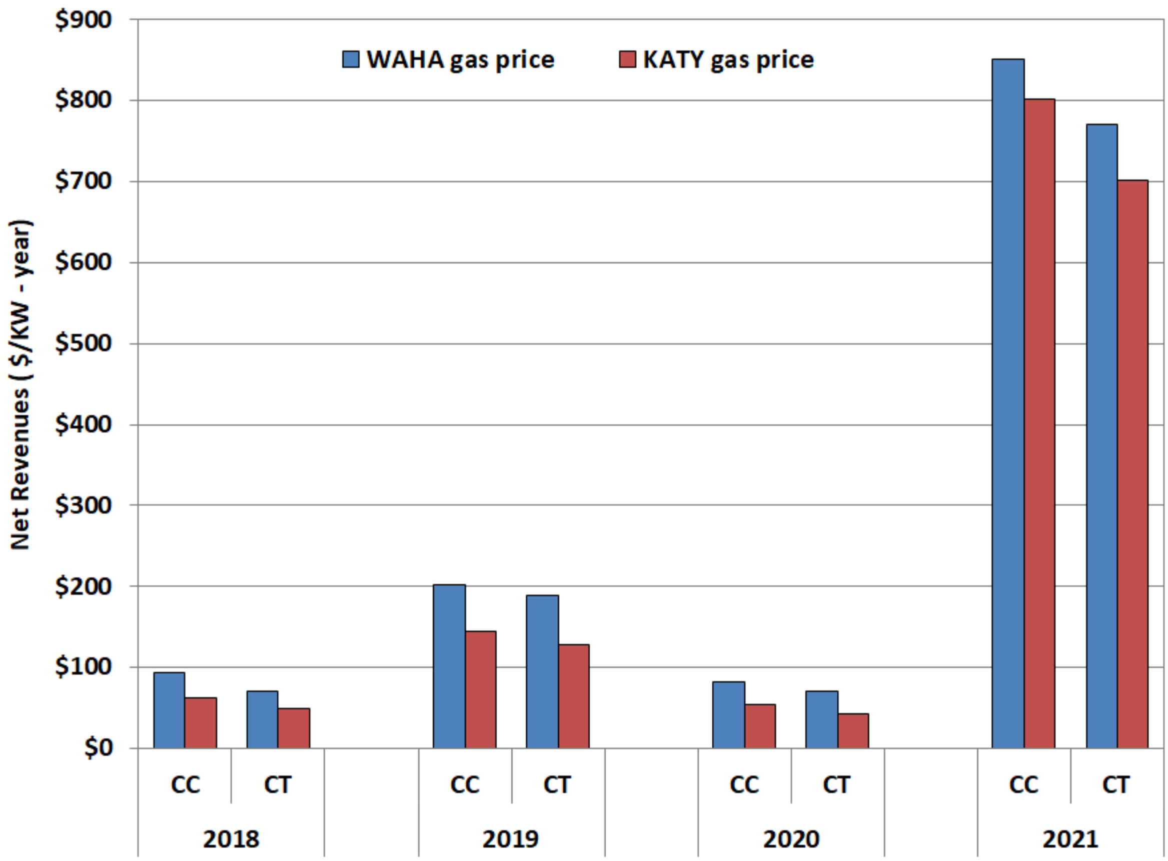
Figure A44: Gas Price and Volume by Index



115 Effective December 12, 2019, the Katy Hub replaced Houston Ship Channel as the reference for the Fuel Index Price (FIP) for natural gas in ERCOT's systems. See NPRR952, *Use of Katy Hub for the Fuel Index Price*. ERCOT has the flexibility to select an appropriate natural gas price index for the purposes of calculating the Peaker Net Margin (PNM) threshold and the Low System-Wide Offer CAP (LCAP).

Historically, resources in the West zone have had lower net revenues that resources in the other zones, but that was not the case in 2019 through 2021. Additionally, the divergence between Waha and Katy gas prices contributed to greater net revenues for West Texas gas-fired generators. Figure A45 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 are higher than in the other three zones.

Figure A45: 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 2020, a number of Notice of Suspension of Operations (NSO) were submitted in 2020.[116] ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

116 South Houston Green Power LLC (RE) – AMOCOOIL_AMOCO_S2; Petra Nova Power I LLC (RE) – PNPI_GT2; Snyder Wind Farm LLC – ENAS_ENA1; City of Austin dba Austin Energy (RE) – DECKER_DPG2; Sherbino I Wind Farm LLC – KEO_KEO_SM1; City of Garland – OLINGR_OLING_1; Wharton County Generation LLC – TGF_TGFGT_1.

On January 22, 2021, ERCOT received an NSO for Sherbino I Wind Farm LLC's KEO_KEO_SM1 resource. The NSO indicated that the resource had ceased operations due to a forced outage and would be decommissioned and retired permanently as of February 1, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 120 MW (Operating). Pursuant to ERCOT Protocol Section 3.14.1.1(3), the Generation Resource was not evaluated for RMR status, and the NSO was not posted on the Market Information System (MIS).

On January 27, 2021, ERCOT received an NSO for South Houston Green Power LLC (RE)'s AMOCOOIL_AMOCO_S2 resource. The NSO indicated that operation of the resource would be suspended due to forced outage with a planned to bring the resource back to service on December 31, 2022. The NSO further indicated that the resource has a summer Seasonal Net Max Sustainable Rating of 125 MW, and a summer Seasonal Net Minimum Sustainable Rating of 25 MW.

On January 27, 2021, ERCOT received an NSO for Petra Nova Power I LLC (RE)'s PNPI_GT2 resource. The NSO indicated that the resource would be mothballed indefinitely as of June 26, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 71 MW and a summer Seasonal Net Minimum Sustainable Rating of 65 MW.

On May 26, 2021, ERCOT received an NSO for Snyder Wind Farm LLC's ENAS_ENA1 resource. The NSO indicated that operation of the resource had ceased due to a forced outage and would be decommissioned and retired permanently as of June 1, 2021. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 63 MW. Pursuant to ERCOT Protocol Section 3.14.1.1(3), the resource was not evaluated for RMR status, and the NSO was not posted on the Market Information System (MIS).

On November 1, 2021, ERCOT received an NSO for City of Austin dba Austin Energy (RE)'s DECKER_DPG2 resource. The NSO indicated that the resource would be decommissioned and retired permanently as of March 31, 2022. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 420 MW, and a summer Seasonal Net Minimum Sustainable Rating of 50 MW.

On November 4, 2021, ERCOT received an NSO for City of Garland's OLINGR_OLING_1 resource indicating that operation of the resource would be suspended indefinitely as of April 5, 2022. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 78 MW, and a summer Seasonal Net Minimum Sustainable Rating of 15 MW.

On December 17, 2021, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for Wharton County Generation LLC's TGF_TGFGT_1 resource. The NCGRD indicated that the resource, which was then decommissioned and retired, would change its resource designation to operational as of February 4, 2022.

VIII. Appendix: Analysis of Competitive Performance

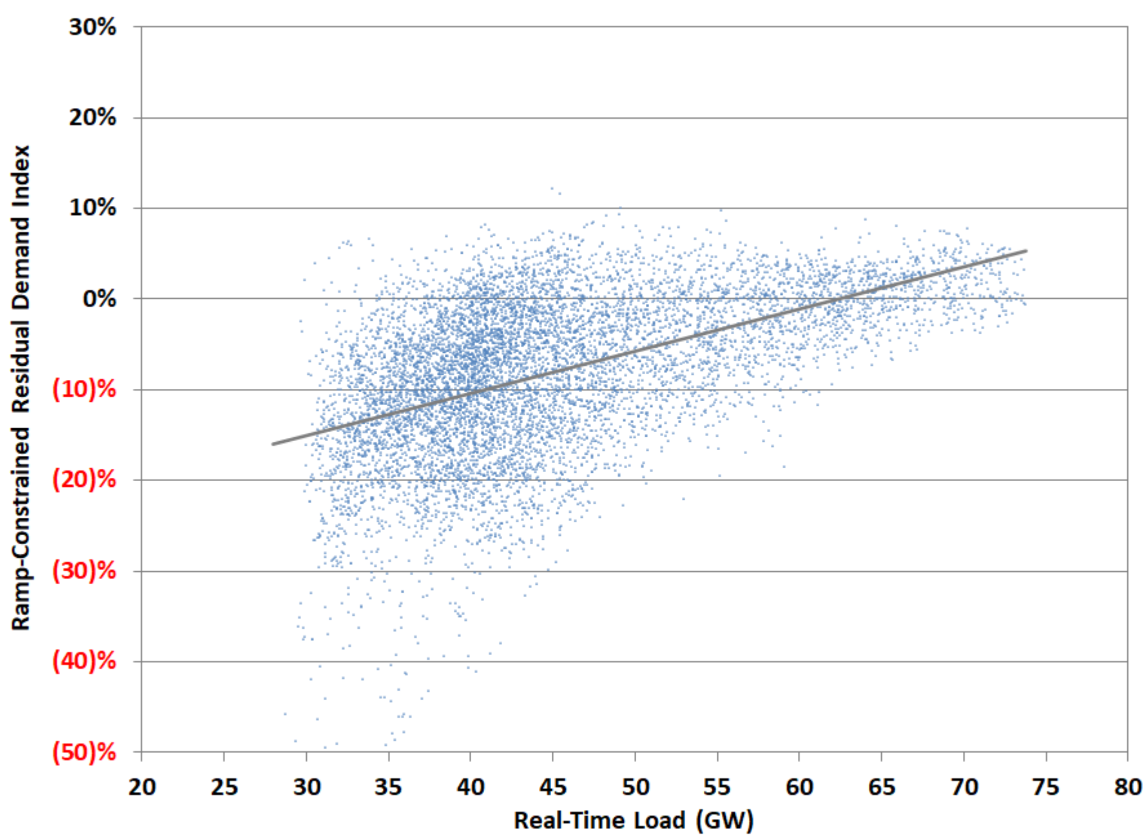
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a 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.

Figure A46 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2021. The occurrences of a pivotal supplier are not limited to just the high load summer period. This analysis indicated the existence of a pivotal supplier for some fraction of time at load levels as low as 30 GW. The trend line indicates a strong positive relationship between load and the RDI.

Figure A46: Residual Demand Index



1. Voluntary Mitigation Plans

In 2021, three market participants had active VMPs that remain unchanged throughout the year. Calpine's VMP was approved in March of 2013.[117] 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. With additions to Calpine's generation fleet made since the VMP was approved, its current amount of offer flexibility has increased to approximately 700 MW. Calpine's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or Calpine.

NRG's plan, initially approved in June 2012 and modified in May 2014,[118] 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 low sustained limit – 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. NRG's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or by NRG.

Luminant received approval from the Commission for a new VMP in December 2019.[119] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[120] 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

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117 *Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013).

118 *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).

119 *Commission 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).

120 *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 Commission terminating its VMP upon closing of the proposed transaction approved by the Commission 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).

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 high system-wide offer cap (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.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A47 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2021.

Figure A47: Short-Term Outages and Deratings

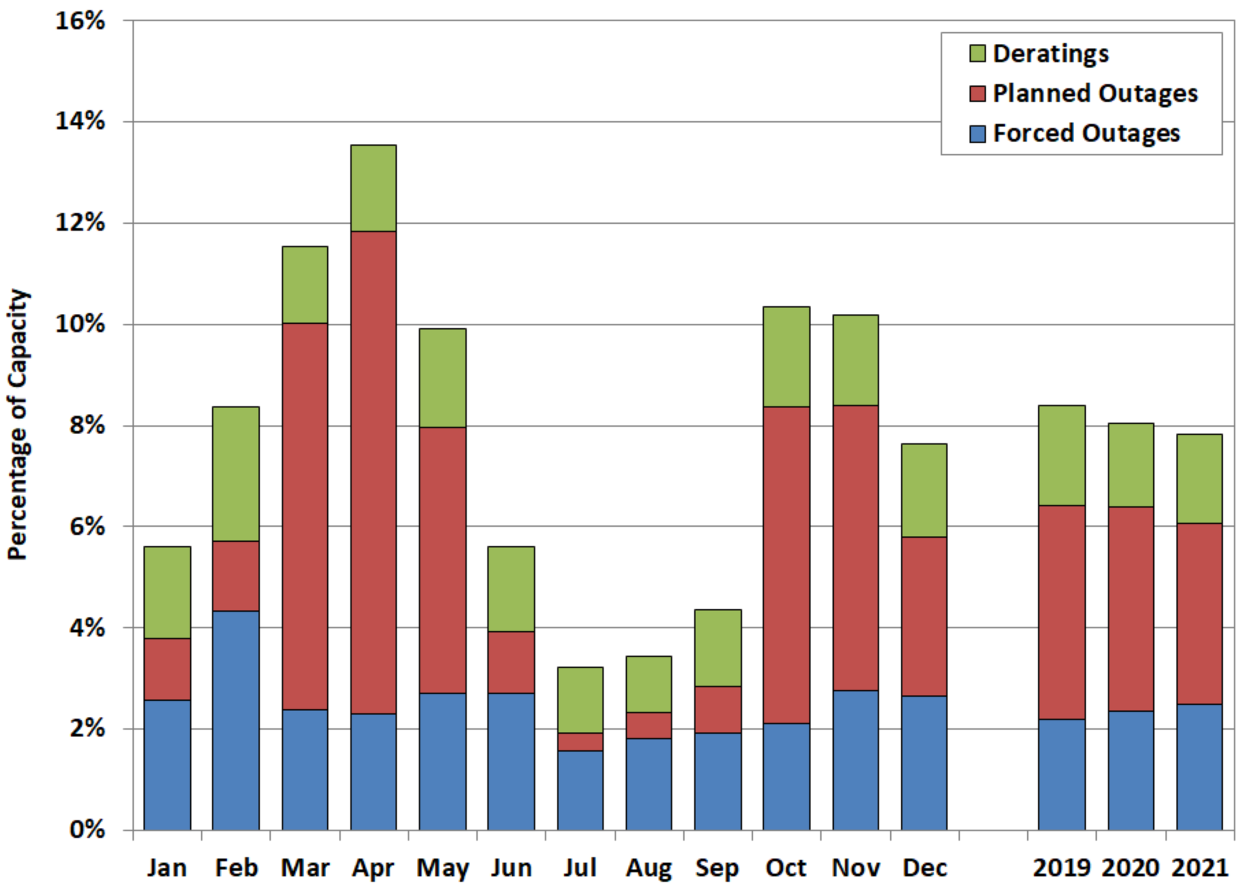

Figure A47 shows that short-term outages and deratings in 2021 followed a pattern similar to what occurred in 2019 and 2020, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2021 were approximately 13.5% of installed capacity in April (down 15.2% in 2020) and dropped to less than 4% during July and August (the same as in 2019 and 2020).

Most of this fluctuation was due to planned outages. Winter Storm Uri did not significantly impact short-term outages and deratings in 2021. The amount of capacity unavailable during 2020 averaged 7.8% of installed capacity, a modest decrease from the 8.0% in 2020 and 8.3% experienced in 2019. The numbers of planned outages dropped slightly in 2021, 3.6% on average, down from 4.0% in 2020 and 4.2% in 2019. This slight downward trend can be explained by the heightened expectations for shortages during the summer and generators taking outage time to ensure higher availability. The low levels of deratings the last three years may be similarly explained by generators operating in modes that would allow them to maximize generation.

While we only focus on short-term outages for the purposes of this evaluation, it is of some interest to also look at long-term outage rates to see the impact of Winter Storm Uri on maintenance activities. We performed this analysis, and the results are shown in the Figure A48 below. When both lengths of outages are included, there were consistently higher rates of planned and forced outages in April through December 2021 than there were in those same months in 2020, although the magnitude is fairly small.

Figure A48: Short- and Long-Term Deratings and Outages