2020 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	PTP	Point-to-Point
EEA	Energy Emergency Alert	PTPLO	Point-to-Point Obligation with links to an Option
ERCOT	Electric Reliability Council of Texas	PUC	Public Utility Commission
ERS	Emergency Response Service	PURA	Public Utility Regulatory Act
FIP	Fuel Index Price	QSE	Qualified Scheduling Entity
GTC	Generic Transmission Constraint	RDI	Residual Demand Index
GW	Gigawatt	RENA	Real-Time Revenue Neutrality Allocation
HCAP	High System-Wide Offer Cap	RTCA	Real-Time Contingency Analysis
HE	Hour-ending	RDPA	Real-Time Reliability Deployment Price Adder
Hz	Hertz	RUC	Reliability Unit Commitment
ISO-NE	ISO New England	SASM	Supplemental Ancillary Service Market
LDF	Load Distribution Factor	SCED	Security-Constrained Economic Dispatch
LDL	Low Dispatch Limit	SCR	System Change Request
LMP	Locational Marginal Price	SPP	Southwest Power Pool
LOLP	Loss of Load Probability	SWOC	System-Wide Offer Cap
LSL	Low Sustained Limit	VMP	Voluntary Mitigation Plans
MISO	Midcontinent Independent System Operator	VOLL	Value of Lost Load
MMBtu	One million British Thermal Units		
MW	Megawatt		
MWh	Megawatt Hour		
NCGRD	Notification of Change of Generation Resource Designation		

EXECUTIVE SUMMARY

Potomac Economics provides this State of the Market Report for 2020 to the Public Utility Commission of Texas in our role as its Independent Market Monitor (IMM). The report assesses the outcomes of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT) region. Additionally, the report recommends improvements for the competitiveness and efficiency of the wholesale market and to ERCOT's operating procedures.

ERCOT manages the flow of electric power to more than 26 million Texas customers, or about 90% of the state's total electric demand. Every five minutes, ERCOT coordinates the electricity production from more than 710 generating resources those that will make electricity to satisfy customer demand and manage the resulting flows of power across the more than 46,500 miles of transmission lines in the region.

Overall, the ERCOT wholesale market performed competitively in 2020. Key results from 2020 include the following:

Market Power

- There is little evidence that suppliers abused market power in the wholesale market to raise system-wide prices.
- In some smaller areas of the region, transmission system limitations on the amount of power that can flow into the area can increase opportunities to abuse market power. However, offer price caps in these areas effectively addressed these opportunities in 2020.

Demand for and Supply of Electricity

- The highest electricity demand in 2020 was 74,328 megawatts, occurring on August 13th between 4 p.m. and 5 p.m. This was about 500 MW lowers than the all-time peak demand on August 12, 2019.
- Although the summer was generally warmer in 2020, which predictably increases electricity consumption, average consumption was slightly lower than in 2019 partly because of the effects of the COVID-19 pandemic.
- The supply of generation in the ERCOT region continues to evolve. More than 7,000 MW of new wind and solar resources and about 400 MW of natural gas supply started commercial operations in 2020.
- Approximately 1,000 MW of fossil-fuel resources were retired in 2020.

Market Outcomes and Performance

- Average energy prices decreased by 45% to $25.73 per megawatt-hour (MWh). This change was due primarily to a nearly 20% drop in natural gas prices and fewer instances of supply shortages, which result in very high market prices.
- Electric transmission networks can become congested when power flows reach the limit on a transmission line. The market resolves and prices such congestion results by incurring costs to alter generation in different locations.
  - Transmission congestions in the real-time market was up 11% in 2020, totaling $1.4 billion.
  - The expectation of this congestion is also reflected in ERCOT's day-ahead market prices and outcomes.
- In addition, ERCOT operators are increasingly reducing the amount of power that can flow across parts of the network to protect the stability of the system, which results in additional transmission congestion costs. These stability issues have partly been caused by the increase in renewable resources.

Changes to Improve Market Performance

- ERCOT continues its work to implement allowing its real-time market to optimize the scheduling of resources to provide energy or operating reserves every five minutes. Real-time co-optimization is planned to go live in 2025 and promises to significantly lower costs and improve pricing during supply shortages.
- ERCOT implemented two changes to accelerate the increase in prices as supply shortages emerge. These changes increased generator revenues by $400 million in 2020, and will have larger effects in years with more frequent supply shortages.
- ERCOT continues to plan for the integration of future technologies, such as Energy Storage Resources (ESRs) and Distribution Generation Resources (DGRs). Both technologies are beginning to enter, with ESRs entering more rapidly as their costs decline.

Winter Storm Uri

- While this report focuses on market outcomes from 2020, we find it important to raise a few initial issues related to Winter Storm Uri now so that the Public Utility Commission and market participants may consider corrective actions soon. A full analysis of the impacts of the February 2021 winter storm will be included in a future report.
- We offer two recommendations to address market design flaws that resulted in costly and inefficient pricing during the sustained winter event.

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

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 little evidence that suppliers abused market power in 2020.

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. Over the entire ERCOT region:

- Pivotal suppliers existed 22% of all hours in 2020, compared to 24% in 2019.
- Under high-load conditions, a supplier was pivotal in more than 80% of the hours since competing supply is more likely to already be fully utilized.
- These results indicate that market power continues to exist in ERCOT and requires mitigation measures to address it.

Market power can also be a much greater concern in smaller 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 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 one of its resources unavailable for use. 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 2020, the output gap quantities were very small, and only 22% of the hours in 2020 exhibited an output gap of any magnitude.

Regarding potential physical withholding, we find that both large and small market participants made more capacity available to the market during periods of high demand in 2020 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 2020.

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 review and analyze these changes to assess these outcomes and the market's overall performance.

Demand in 2020

Although the summer was generally warmer in 2020, total demand for electricity in 2020 decreased by roughly 1% from 2019 – a decrease of approximately 360 MW per hour on average. This decrease partly reflect the effects of the COVID-19 pandemic.

Despite this overall reduction, the Houston area saw a 1.7% increase and the West Texas region showed an increase of 2.8%. The increase in the West zone is notable because it follows a 13% increase experienced in 2019. Continued oil and natural gas production activity in the West zone has been the driver for growing demand. However, the pandemic and low oil and gas prices slowed this growth trend in 2020.

Weather impacts on demand were mixed across all zones. We measure the impact weather has on electricity use by quantifying the amount by which the average daily temperatures are above or below 65° F. For example, cooling degree days are the number of days and degrees by which temperatures exceed 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 increased 6% and 2% from 2019 in Dallas and Austin, respectively. In contrast, Houston experienced a 2% decrease from 2019.

Peak demand occurred on August 13, 2020, reaching 74,328 MW, slightly lower than the record demand. The level of peak demand is important because it affects 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 based in ERCOT.

Supply in 2020

Approximately 7,700 MW of new generation came online in 2020, including 7,250 MW of wind and solar resources. The amount of utility-scale solar capacity added in 2020 was the largest amount added to the ERCOT system in any one year, bringing total installed capacity to over 5,600 MW. In addition, 70 MW of battery energy storage resources began commercial operations in 2020. In addition, three resources retired permanently, representing a decrease of 1,030 MW.

These resource changes along with changes in fuel prices led to the following changes in electricity production in 2020:

- The percentage of total generation supplied by wind resources continued to increase, totaling almost 23% of all annual generation.
- The share of fossil-fuel generation declined in 2020: coal-fired generation dropped to roughly 18% and natural gas generation was flat at 46% of total generation in 2020.

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain an adequate set of resources to satisfy the system's needs. Prices in 2020 did not produce revenues sufficient to support profitable investment in new conventional resources, primarily because shortage pricing was infrequent and modest. Given the current reserve margins, this is expected and raises no substantial concerns.

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

Review of Market Outcomes and Performance

ERCOT operates electricity markets in the real-time and day-ahead timeframes for: energy (electricity output) 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 day-ahead market or bilaterally). This is because real-time prices are the principal driver of prices in the day-ahead market 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 track the rise and fall of natural gas prices in a well-functioning market because fuel costs represent the majority of most suppliers' production costs.

In 2020, the average natural gas price was lower than it has been in many years. Combined with the absence of significant supply shortage events, falling natural gas prices caused real-time energy prices to decrease to just under $26 per MWh. 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
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58
($/MMBtu)							
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99

In addition to the falling prices in recent years, this table shows that prices vary across the ERCOT market because of transmission congestion that arises as power is delivered to consumers. The pattern of zonal in 2020 was fairly consistent with recent years, with the West zone experiencing the highest prices because of localized transmission congestion that raises prices in the area. The growth in renewable generation in the West can also cause congestion exporting the power from the area that lowers prices sharply in some hours.

As an energy-only market, ERCOT relies heavily on high real-time prices that occur during shortage conditions to provide key economic signals that govern the development of new resources and retention of existing resources.

The frequency and impacts of shortage pricing can vary substantially from year-to-year:

- Moderate weather and improved planning reserve margin in the summer of 2020 led to prices that exceeded $1,000 per MWh in just 7 hours in 2020 and prices did not exceed $5,000 in any hour.
- In comparison, prices were higher than $1,000 per MWh in more than 28 hours in 2019 and above $7,000 for more than 5 hours, including roughly 2 hours at the system-wide offer cap of $9,000 per MWh during the peak week of August 12, 2019.

In reviewing the shortage pricing in ERCOT, it is important to note the changes made by ERCOT over the past two years. 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.

On March 1, 2020, ERCOT implemented the second of two rightward shifts to the ORDC.[1]

- The shifts accelerate the rise in prices to the Value of Lost Load (VOLL) of $9,000 per MWh as reserve shortages emerge and were made to ensure that shortage pricing effectively facilitates long-term investment and retirement decisions.
- These shifts increased the total effects of shortage pricing on average prices by $1 per MWh in 2020. This relatively small effect is attributable to the modest shortage conditions experienced in 2020.

Day-Ahead and Ancillary Services Markets

The day-ahead market allows participants to make financial commitments for purchases or sale of energy to be delivered the next day. There are no physical obligations that result from participation in the day-ahead market; rather, it serves as a method for participants to manage the risks related to exposure to real-time prices during the operating day. Day-ahead prices averaged $24 per MWh in 2020. This price closely aligns with prices from the real-time market and represents a change from the day-ahead premium in 2019. The relative stability of real-time prices and reduction of tight conditions reduced the risk premium reflected in day-ahead prices.

Ancillary services are products purchased in the ERCOT market on behalf of consumers to provide resources that can produce electricity quickly (or voluntarily reduce consumption). 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 prices in the real-time energy market because the cost of selling ancillary services includes the profits a supplier would give up by not producing electricity. The average prices for most ancillary services fell by more than 50% in 2020 from 2019. This caused the total costs of ancillary services per MWh of electricity consumption to fall from $2.33 per MWh in 2019 to $1.00 per MWh in 2020, down. This decrease was largely because of the absence of extreme shortage pricing in 2020.

Transmission Congestion

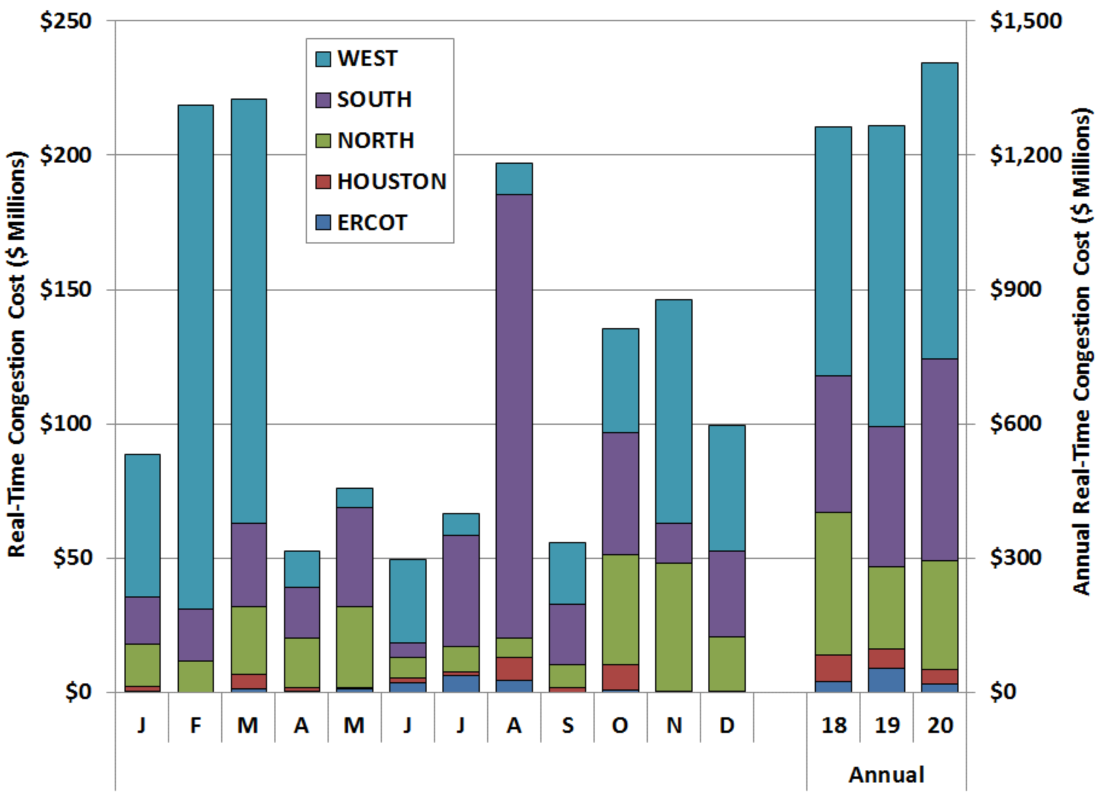
Similar to an interstate highway system, congestion can arise when more power is flowing over a transmission line than it is designed to carry. Unlike a traffic jam, however, where cars can exit the highway and travel on side streets, power flows over the network are almost entirely the result of where power is produced and where it is consumed. Therefore, when a transmission line is becoming overloaded, ERCOT will incur costs to shift generation to other higher-cost generators in different locations to reduce the transmission congestion.

1 These changes were made to the Other Binding Document: "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder" (OBDRR011). The changes were directed by the Commission and approved by the ERCOT Board of Directors on February 12, 2019.

When transmission congestion occurs, the differences in costs of delivering electricity to some locations rather than others 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 in ERCOT's real-time market in 2020 $1.4 billion, up 11% from 2019. This increase is notable given the 20% decrease in natural gas prices. Lower gas prices tend to reduce the costs of the generators that are moved to manage transmission congestion and to serve customers in congested areas. To show the trends and fluctuations in congestion costs, the figure below shows real-time congestion costs by month and region for 2020 and a comparison with the annual costs in 2018 and 2019.

Real-Time Transmission Congestion Costs in 2020



The largest contributor to congestion costs in 2020, as was the case in 2019, was the congestion in the West zone. Congestion continued to be a result of the high demand caused by oil and gas development in the Permian Basin, alongside transmission outages in the area required for maintenance, new construction, and upgrades. The South zone experienced weather-related outages due to Hurricane Hanna in July 2020, which led to the high congestion costs in August.

Participants' expectation of this congestion is also reflected in ERCOT's day-ahead market prices and outcomes. Hence, the transmission congestion priced in the day-ahead market totaled

$1.3 billion, up 19% from 2019. This congestion can be hedged by participants 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 blocks as much as three years in advance. The revenues collected through the CRR auction help pay for the transmission system. CRR auction revenues have risen steadily as transmission congestion has grown, totaling $726 million in 2020. This value is less than the total congestion costs in 2020 in part because participants paid less to buy the CRRs than they were ultimately worth. This indicates that not all of the congestion in 2020 was not foreseen by the market.

Finally, ERCOT operators are increasingly using generic transmission constraints 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 renewable energy resources that do not provide the same voltage support to the system as conventional resources. Ultimately, these generic transmission constraints increase transmission congestion and increase the total costs of serving customers in ERCOT.

Market Improvements Underway

ERCOT made progress in 2020 on the Commission-approved implementation of co-optimization of energy and ancillary services in the real-time market, which is now planned to go live in 2025. Implementation will significantly improve the real-time coordination of ERCOT's resources, lower overall production costs, and improve shortage pricing. These improvements will be key for helping efficiently transition to a future with a different resource mix as additional wind and solar resources enter the ERCOT market. Unfortunately, the go-live date has been delayed due to staffing resources at ERCOT, Inc., but we encourage continued focus on this important market improvement.

Additionally, ERCOT continues to work with stakeholders to plan for the market integration of future technologies, such as Energy Storage Resources (ESRs) and Distribution Generation Resources (DGRs). Declining costs is accelerating its growth from the more than 300 MW existing today. Several hundred MWs of ESRs are planned to enter soon. DGRs that connect at the distribution level (< 60 kV) are also beginning to enter the ERCOT system and will require significant changes in the market rules.

Winter Storm Uri

We have not conducted our full analysis on the outcomes of market events during the week starting February 14, 2021. Data is still being collected through requests for information sent to both individual market participants and ERCOT operations. We anticipate a complete report will be available in 2022. However, we offer this short initial discussion to provide context for the two storm-related recommendations detailed in the next section.

Winter storm Uri produced unusually low temperatures, which were sustained over many days. The Dallas-Ft. Worth area, for example, experienced 140 consecutive hours at or below freezing, with a minimum temperature of -2° F. Compared with the winter event in 2011, this represents 39 more hours and minimum temperatures that were 15° F colder. In the Austin area, these extremes were even more pronounced. Austin had nearly 100 more hours at or below freezing temperatures.

At the height of the storm event, more than 52 gigawatts of generation resources in the ERCOT region were unavailable. Eighty-five percent of those outages were in some way related to winter storm Uri, whether due to equipment failure, fuel supply shortages, or other weather-related issues. In some instances, the same units tripped offline, were restored to service, and then tripped offline again. At the same time, the cold temperatures resulted in electricity demand as high as the hottest day in the summer. Ultimately, this led to widespread and extended power outages in ERCOT. Unfortunately, some of these outages caused natural gas facilities to lose power, leading to less available natural gas and higher outages of gas-fired generators.

It is too early for us to conclude whether any market participants exercised market power during the event. However, we can report that the market did not perform efficiently. Both the ancillary services market and the real-time energy market produced outcomes that were inconsistent with sound economic principles. Those inefficiencies resulted in:

- Prices for ancillary services that substantially exceeded the true value of the ancillary services during the shortages; and
- Real-time energy prices that continued to reflect the costs of the energy shortage artificially for 32 hours after the shortage was over.

These issues have led to billions of dollars in excess costs and numerous defaults that ERCOT and the state of Texas will be grappling with for some time to come. We detail these inefficiencies and recommendations to address them below.

Recommendations

Although ERCOT markets performed well in 2020, we have identified certain opportunities for improvement. We make a total of seven recommendations below. While a full review and analysis of the February 2021 arctic event will be contained within the eventual 2021 State of the Market report, two of our recommendations address pricing flaws revealed by that event that merit urgent attention. The remaining recommendations contain two made in previous years and three new items to address inefficiencies or improve incentives affecting market performance. We are also retiring six recommendations from prior years. Readers can find those and a discussion of the status of each in the appendix.

Recommendations to Address Pricing Flaws Revealed in 2021

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

Real-time energy prices should reflect that shedding firm load is an out-of-market action with a cost equal to the Value of Lost Load (VOLL), a number usually equal to the system-wide high offer cap of $9,000 per megawatt-hour. This is clear because one additional MW of energy under these conditions would allow ERCOT to serve an additional MW of load, so the value of this energy must equal VOLL. Efficient pricing during these extreme shortages is essential in an energy-only market because it provides necessary economic signals to increase the electric generation needed to restore the load in the short term and service it reliably over the long term.

During the February 2021 winter event, firm load shed was initially excluded from the reliability adder, causing settlement prices to be well below $9,000 per MWh. The PUCT issued an emergency order on February 16 to address this issue.[2] However, later in the event, ERCOT decided to include other load that had not been restored in the calculation of the reliability adder, even though it was not subject to a load shedding instruction from ERCOT. This caused prices to clear at $9,000 per MWh for 32 hours after the load shedding ceased, resulting in substantial inefficient costs to be incurred.

We recommend that the protocols be modified to designate that firm load shedding directed by ERCOT be included in the calculation of the reliability deployment price adder, and specify that load reductions that are not directed by ERCOT *not* be included in this calculation.

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

ERCOT operates its day-ahead market in manner that may incur extremely high costs attempting to procure all available ancillary services up to its ancillary services requirement. During the 2021 arctic event, this resulted in day-ahead market prices for ancillary services as high as over $25,000 per MW.[3] Ancillary service prices more than VOLL violate fundamental economic principles and generate inefficient market outcomes. Since reserves are procured to reduce the probability of losing load, the value of reserves should not exceed the cost of actually losing load – VOLL. This economic inconsistency will be resolved with the implementation of real-time co-optimization in 2025.

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2 PUC Project No. 51617, Calendar Year 2021 – Open Meeting Agenda Items without an Associated Control; Item No. 4, *Second Order Directing ERCOT to take Action and Granting Exception to Commission Rules* at 1-2 (Feb. 16, 2021); PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Item No. 31, *Order Directing ERCOT to take Action and Granting Exception to Commission Rules* (Mar. 1, 2021).

3 PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Item No. 149, Potomac Economics' *Follow Up Letter*, (Mar. 11, 2021).

In the meantime, we recommend that ERCOT address this issue by: a) utilizing a penalty price for ancillary services that is equal to or less than VOLL, and b) capping the ancillary service MCPCs at VOLL. This will prevent future irrational ancillary services pricing until 2025.

Recommendations to Improve Market Performance

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

In competitive markets, suppliers offer their resources at prices equal 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. 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, therefore, 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. Given that allowing generators with market power to raise prices is a poor means to achieve fixed cost recovery, the IMM recommends that these two multipliers be removed to ensure that only marginal costs are included in the mitigated offer caps. 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.

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. This zonal configuration has not changed even through many years of load growth and changing congestion patterns. Consequently, the highly aggregated load zones and inability to price demand more granularly negatively impacts congestion management by distorting the incentives of both price-responsive demand and active demand response. 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., load that can be controlled by the real-time market), transitioning to nodal pricing for those active loads may become beneficial for ERCOT and the market participants. Beyond the active demand response participants, longer-term demand decisions may be influenced by the zonal prices. Such decisions may relieve or aggravate congestion patterns, but are unfortunately not informed by the wholesale power prices.

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

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

Recently, there have been numerous delays in running and posting the results of the day ahead market. These delays are disruptive to the market and create unnecessary risk for market participants. ERCOT analysis of the cause points to a significant increase in bids for point-to-point obligations, a financial transaction cleared in the day-ahead market used to manage congestion cost risk.[4] This is not a surprise because substantial increases in PTP transactions significantly increase the complexity of the optimization and the time required to find a solution.

Charging no fee for PTP bids, as ERCOT currently does, allows participants to submit very large quantities of 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 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 day-ahead market process. Hence, the IMM recommends that a small bid fee be applied to DAM PTP Obligation bids to more efficiently allocate scarce DAM software capabilities.

Additional Recommended Market Improvements from Prior Year(s)

2015-1 – Modify the allocation of transmission costs by transitioning away from the 4 Coincident Peak (CP) method.

The current method of allocating transmission costs provides incentives for load to behave in ways that do not necessarily forestall the construction of new transmission equipment and that do not apply transmission costs equitably to all loads.

Currently, transmission costs are allocated based on an entity's maximum 15-minute demand in June through September. This method was approved in 1996 and intended to allocate transmission costs to the drivers of transmission build. Today, however, customer demand during the peak summer hours is no longer the main driver of transmission build in ERCOT.

Rather, decisions to build transmission are based on transmission congestion patterns throughout the year and an analysis of whether generation can be delivered to serve customer reliably. Additionally, the method of billing these costs provides a price signal to non-opt-in entities and

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

transmission-level customers, both of which can artificially reduce their total customer demand in anticipation of a peak demand day to avoid transmission charges.

The IMM continues to recommend that transmission cost allocation be changed such that the resulting incentive better reflects the true drivers for new transmission.

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 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, an indicator of the inefficient pricing in this market.

In addition, a new ancillary service, ERCOT Contingency Reserve Service, will be implemented before 2025 and will contain a constraint on certain resources. However, a single price is envisioned for that service as well. Failure to include this constraint in the pricing of that product 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.

I. 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 day-ahead market 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 2020.

A. Real-Time Market Prices

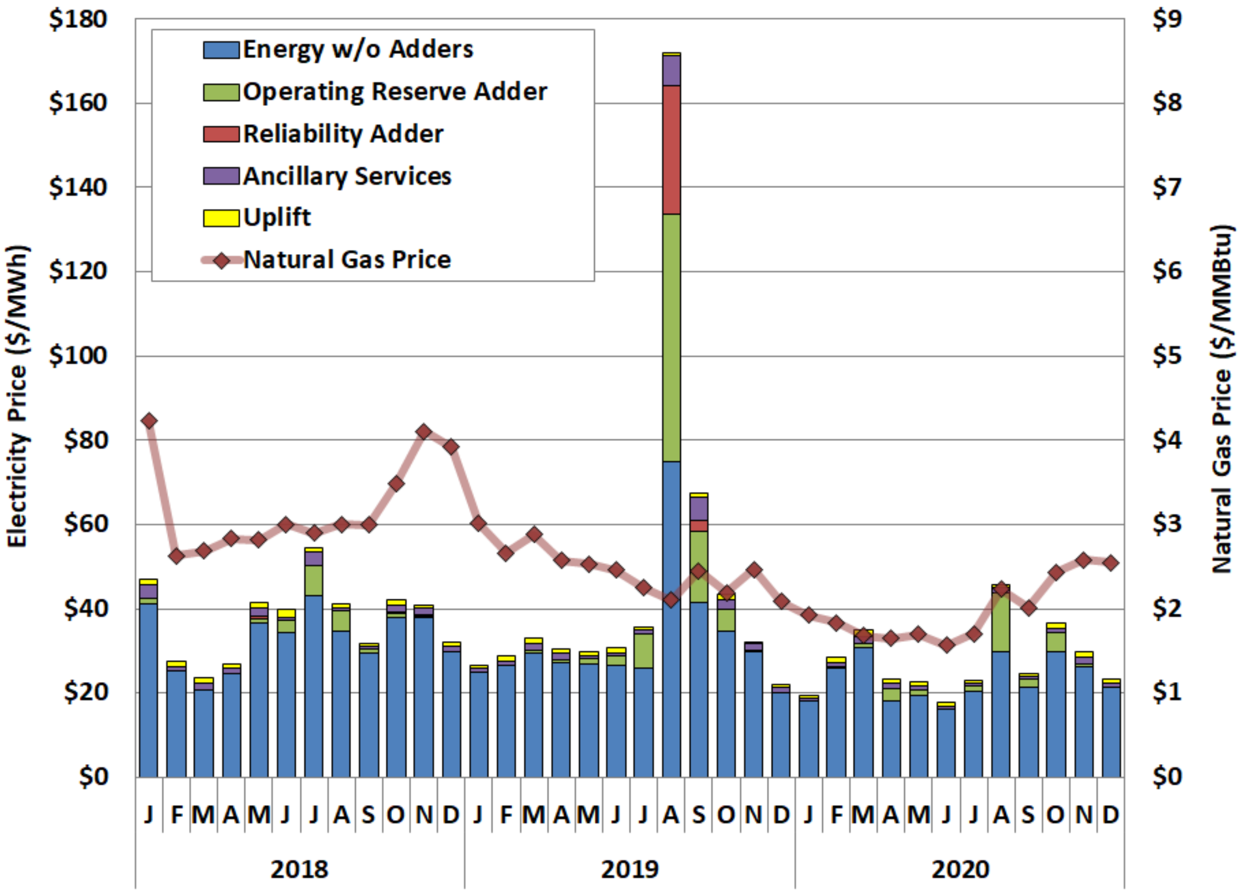
The first analysis of the real-time market evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 1 shows 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 basis.[5]

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

5 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, we show the ORDC adder (operating reserve adder) and the Reliability Deployment Price Adder (reliability adder) separately here 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 minimum contingency level and the value of lost load. 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.[6]

Figure 1: Average All-in Price for Electricity in ERCOT



The largest component of the all-in price is the energy cost. The figure above indicates that natural gas prices continued to be a primary driver of energy prices in most months. 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-

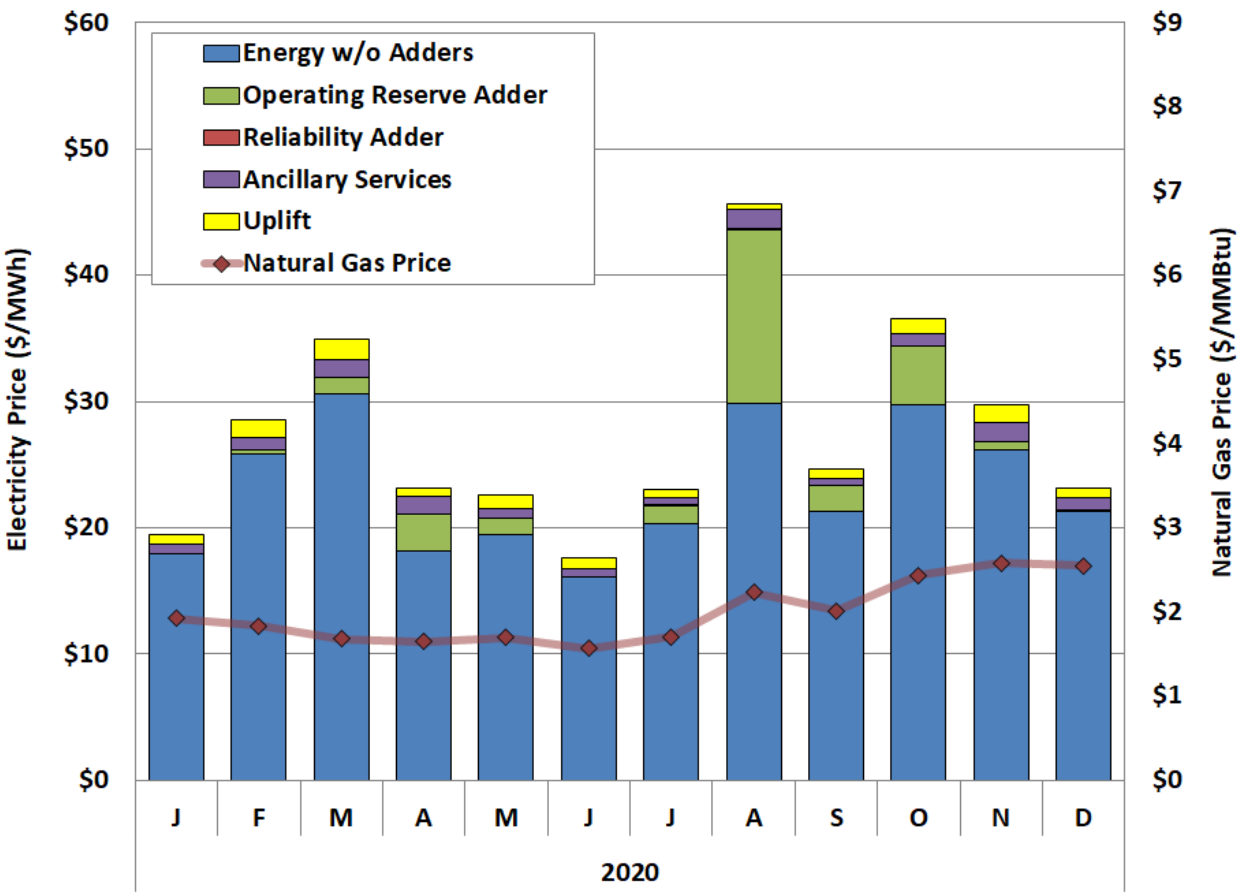
6 The reliability adder is calculated by separately running the dispatch software with any reliability unit commitments (RUC) or deployed load capacity removed and recalculating prices. When the recalculated system lambda (average load price) is higher than the initial system lambda, the increment is the adder.

used fuel in ERCOT, changes in natural gas prices typically should translate to comparable changes in offer prices.

Average real-time prices dropped by 45% (to $25.73 per MWh) in 2020 compared to 2019, due in large part to the absence of both tighter conditions and shortages of dispatchable capacity. In times where there are shortages of dispatchable capacity, such as in August and September of 2019, shortage pricing mechanisms will drive the price significantly higher. This decrease in average real-time prices occurred in conjunction with historically low average natural gas prices in 2020, under $2.00 for the year.

The decrease in shortage pricing was acutely reflected in the lower contributions from ERCOT's energy price adders: $2.64 per MWh from the operating reserve adder and $0.01 per MWh from the reliability adder. Both values are significantly lower than the comparable values in 2019: $9.76 per MWh for the operating reserve adder and $3.55 per MWh for the reliability adder. The adders in 2020 are discussed in greater detail in Subsection F: ORDC Impacts and Prices During Shortage Conditions.

Figure 2: All in Prices 2020

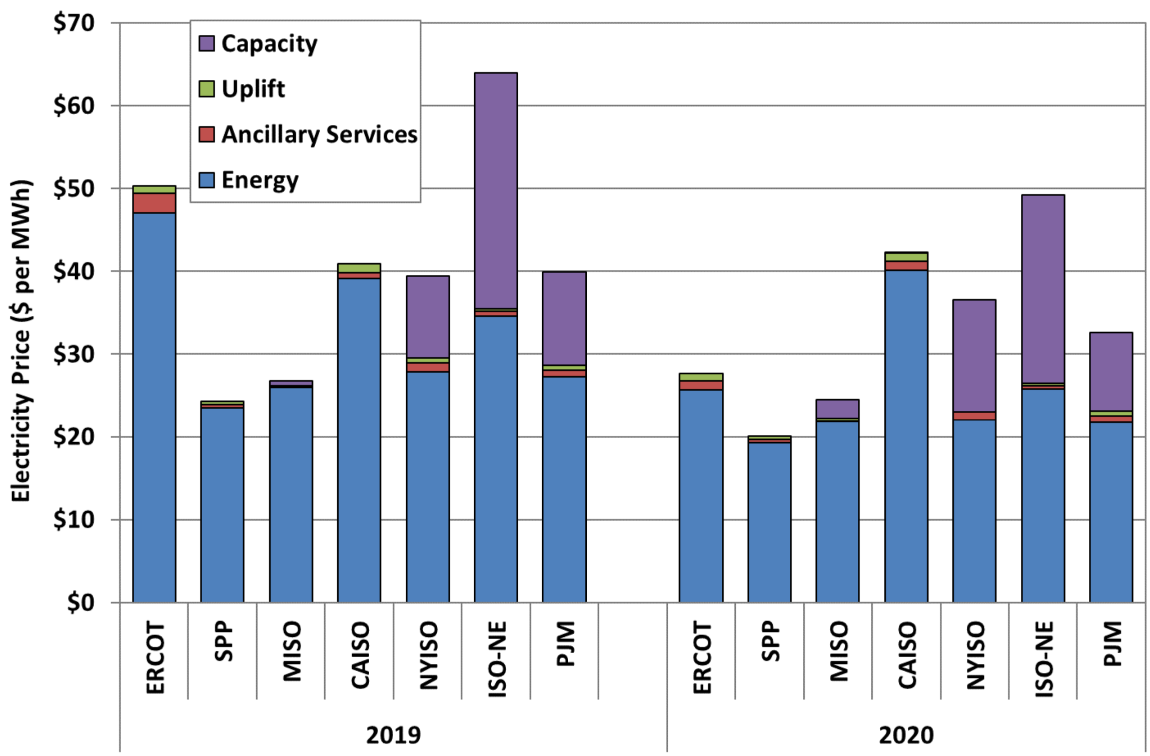


Other cost categories continue to be a relatively small portion of the all-in electricity price. Ancillary services costs were $1.00 per MWh in 2020, down from $2.33 per MWh in 2019 for reasons described in Section III: Day-Ahead Market Performance. Uplift costs accounted for $0.97 per MWh of the all-in electricity price in 2020, up from $0.88 per MWh in 2019. The total amount of uplifted costs in 2020 was approximately $359 million, up from $338 million in 2019. There are many costs included as uplift, but the largest components are the ERCOT system administrative fee ($212 million or $0.56 per MWh), Emergency Response Service (ERS) program costs ($46 million or $0.12 per MWh) and the real-time revenue neutrality allocation (RENA), which totaled $75 million or $0.20 per MWh in 2020.

To provide additional perspective on the outcomes in the ERCOT market, Figure 3 below compares the all-in price in ERCOT with other organized electricity markets in the United States: Southwest Power Pool (SPP), Midcontinent ISO (MISO), California ISO (CAISO), New York ISO (NYISO), ISO New England (ISO-NE), and the PJM Interconnection. The figure separately shows the components of the all-in price, including energy, capacity market costs (if applicable), uplift, ancillary services (reserves and regulation), and energy.

Figure 3 also shows that all-in prices were generally lower across U.S. markets in 2020, with CAISO as the exception.

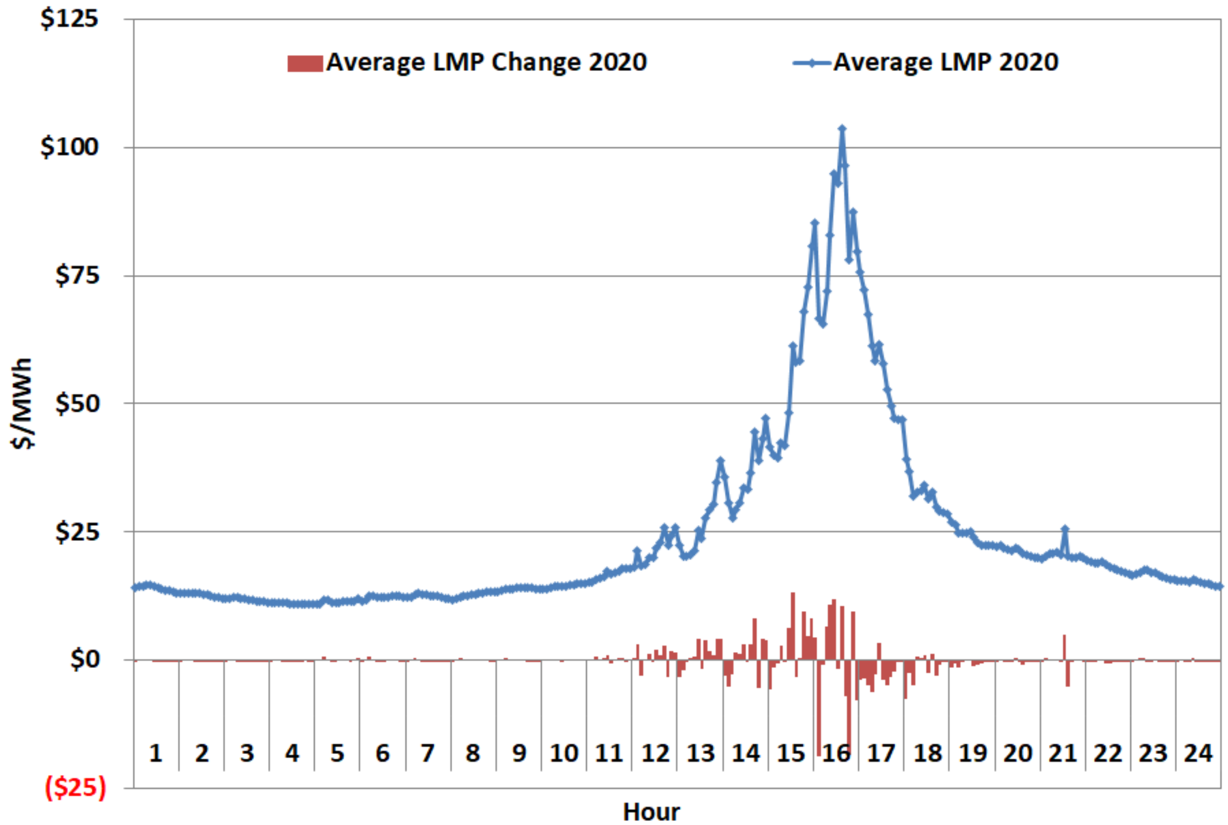
Figure 3: Comparison of All-in Prices Across Markets



Real-time energy prices vary substantially by time of day. Figure 4 shows the 2020 load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices were the highest. It also shows in red the average change in the 5-minute prices in each interval.

The figure shows that the downward changes in five-minute prices were highest at the top of peak hour 16. This is largely caused by changes in generator commitments at the top of the hour. When additional resources come online, supply expands, and prices sometimes fall sharply. Average changes in other intervals are far more random and generally driven by changes in load or supply. Note that prices in the peak load hours were much lower in 2020 than in 2019. This was primarily attributable to the relative absence of shortage conditions in 2020 that prevailed during the peak hours in August 2019.

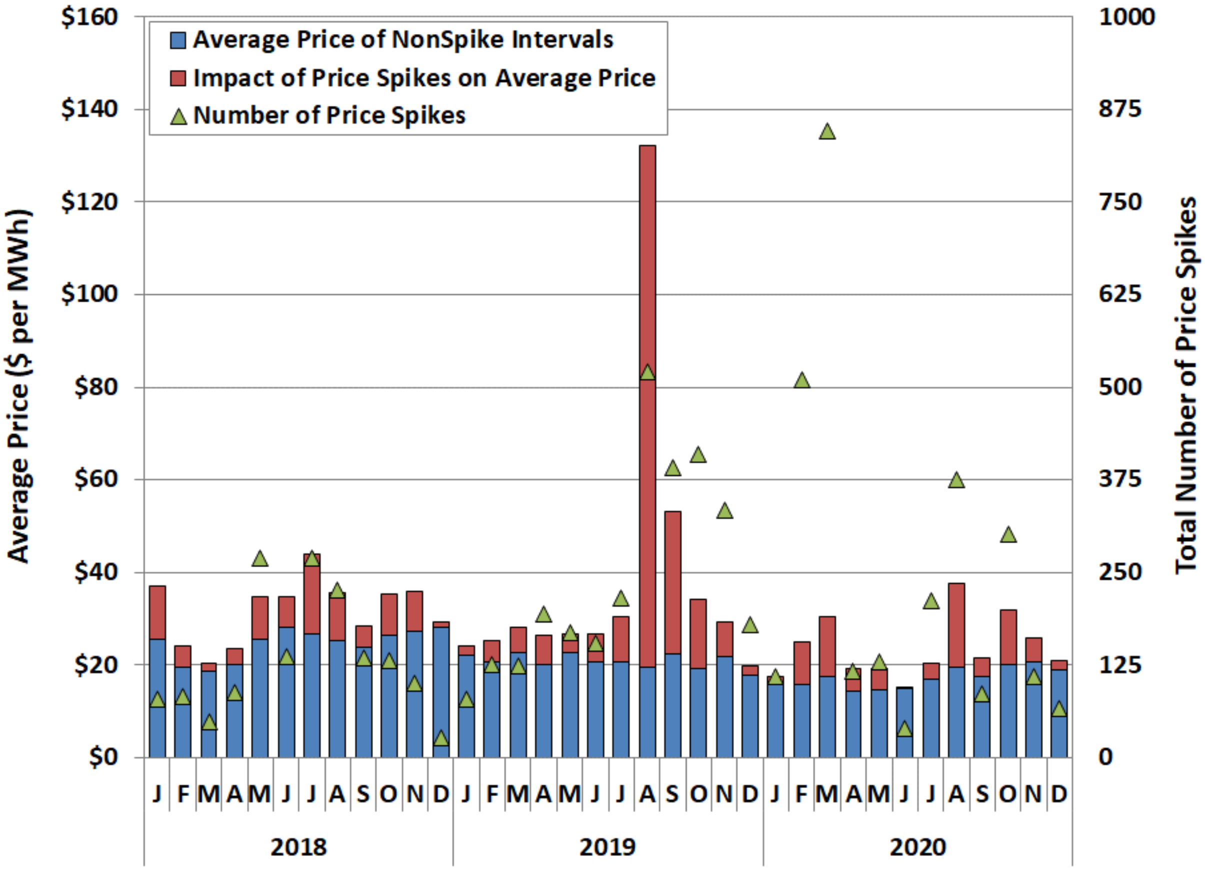
Figure 4: Prices by Time of Day
May-September 2020



For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2020, see Figure A1 in the Appendix.

To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 5 shows the frequency of price spikes in the 2020 real-time energy market. For this analysis, price spikes are defined as 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.

Figure 5: Average Real-Time Energy Price Spikes



Price spikes were more frequent in 2020 compared to 2019 but less consequential on prices because of smaller contributions from the changed operating reserve adder during scant periods of reduced reserve availability as well as ultra-low gas prices (below $2.00/MMBtu). With average gas prices so low throughout the year, energy prices have less correlation with heat rate as the other components of operations and maintenance costs become more relevant. This is an outlier in how energy prices are typically viewed. The overall impact of price spikes in 2020 was $6.57 per MWh, or 26% of the total average price.

B. Zonal Average Energy Prices in 2020

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 for the past seven years and includes the annual average natural gas price. Like Figure 1, Table 1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price, including 2020. This relationship is consistent with competitive expectations in ERCOT where natural gas generators predominate and set prices in most hours. However, we note that in 2019, this trend diverged as substantial shortage pricing led to higher energy prices as expected in periods with low reserve margins or extreme weather. The average natural gas price was lower in 2020 than it has been since 2014, and average real-time energy prices dropped back down from historic highs in 2019 to more typical levels in 2020. 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: Average Annual Real-Time Energy Market Prices by Zone

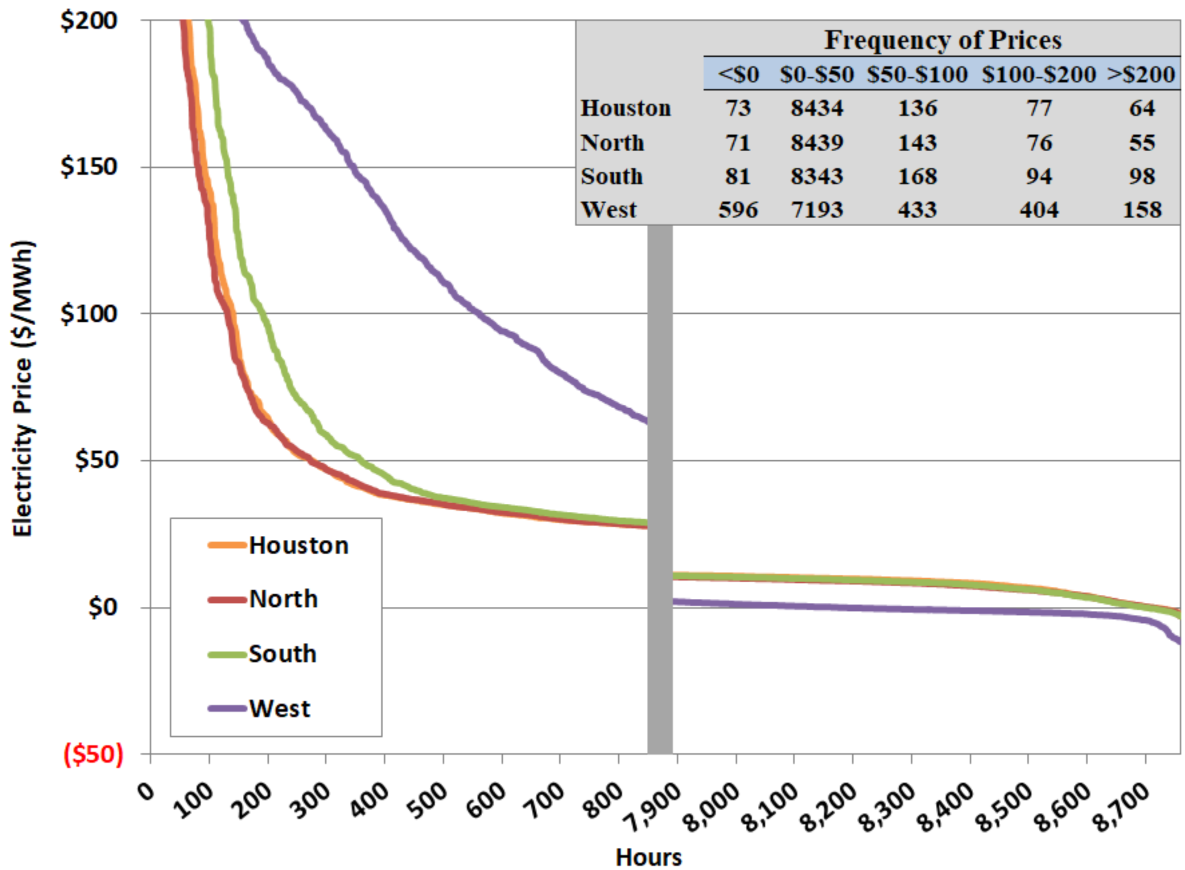
($/MWh)	2014	2015	2016	2017	2018	2019	2020
ERCOT	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**	**$25.73**
Houston	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45	$24.54
North	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77	$23.97
South	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44	$26.63
West	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77	$31.58
($/MMBtu)							
Natural Gas	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99

Table 1 also shows that the pattern of zonal prices in 2020 was fairly consistent with the pattern seen in recent years. The West zone again had the highest prices, primarily because of multiple localized real-time transmission constraints. Prices in this zone have varied substantially as the growth in wind generation created export congestion from the West zone prior to 2012 and from 2015 to 2017, resulting in the lowest zonal average prices in ERCOT in these years. In other years, including 2020, localized constraints resulted in the highest zonal prices in ERCOT. For additional analysis on monthly load-weighted average prices in the four geographic ERCOT zones during 2020, see Figure A3 in the Appendix.

The South zone was again the second highest-priced zone in 2020 because of congestion caused by the forced outages from Hurricane Hanna in the Rio Grande Valley. More details about the transmission constraints influencing zonal energy prices are provided in Section IV: Transmission Congestion and Congestion Revenue Rights. 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 A4 in the Appendix.

To more closely examine the variation in zonal real-time energy prices, Figure 6 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2020 for the four zones. Compared to the other zones, both low and high prices in the West zone were noticeably different 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 noticeably 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 burgeoning oil and gas loads in the West explain the higher prices, typically in times where wind and solar energy resource output is low.

Figure 6: Zonal Price Duration Curves



For additional analysis of price duration curves, see Figure A5 and Figure A6 in the Appendix.

C. Evaluation of the Revenue Neutrality Allocation Uplift

As shown in the all-in price analysis above, uplift costs increased substantially. Much of this increase was due to higher RENA, which increased 52% to $49 million ($0.13 per MWh) in 2020 to $75 million ($0.20 per MWh). We evaluate the drivers of RENA in this subsection.

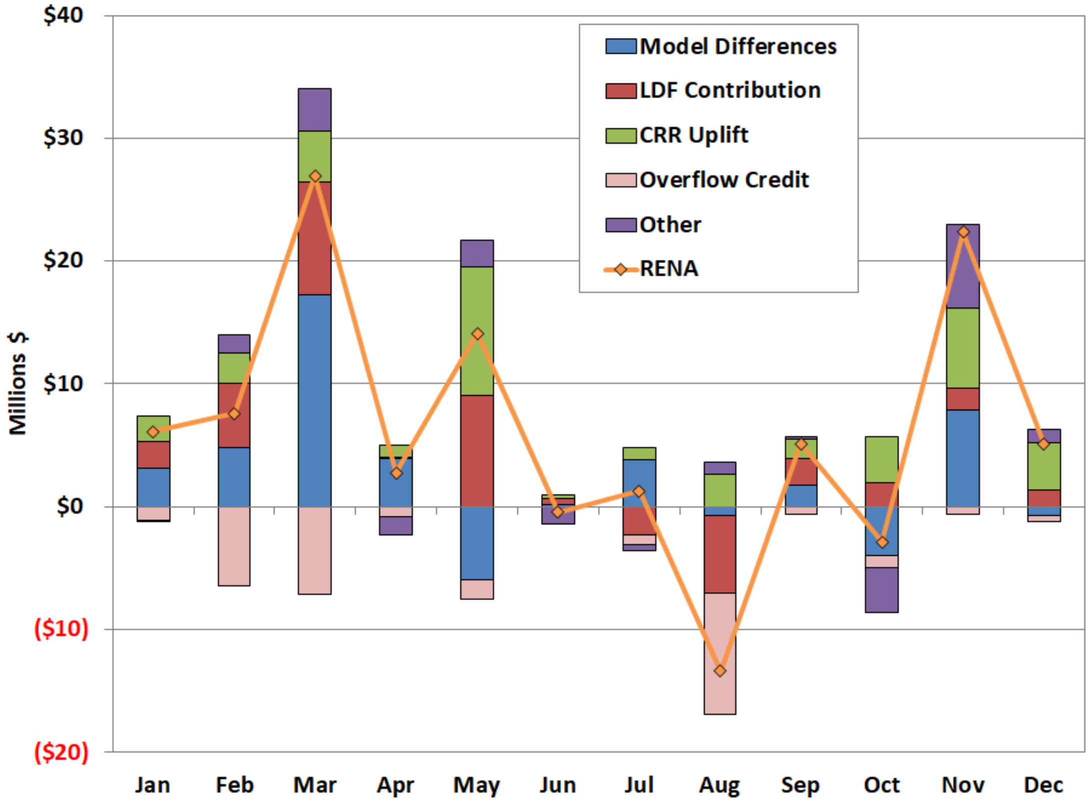
In general, RENA uplift occurs when there are certain differences in power flow modeling between the day-ahead and real-time markets. These factors include:

- 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[7] 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 7 provides an analysis of RENA uplift in 2020, separately showing the components of RENA on a monthly basis. Net negative uplift represents an overall payment to load.

Figure 7: ERCOT RENA Analysis



Detailed studies show that almost all the RENA uplift occurred in market hours when there was transmission congestion. The largest contributors to RENA uplift in 2020 were NOIE PTP obligations settled as options and model differences, contributing $40 million and $31 million, respectively. These uplift costs were offset by $31 million in negative uplift related to overflow credits when the shadow price reached the shadow price cap for a transmission constraint.

Figure 7 above also shows that RENA uplift from the settlement of day-ahead PTP obligations linked to options, described as CRR Uplift, was relatively high in March and November, as was

7 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 PTP Obligations with Links to an Option shall be settled as if they were a PTP Option.

the uplift from transmission modelling differences. Uplift from the contributions of load distribution factor differences between day-ahead and real-time, described as LDF Contribution, was mostly positive in 2020, with the most notable contributions in March and May.

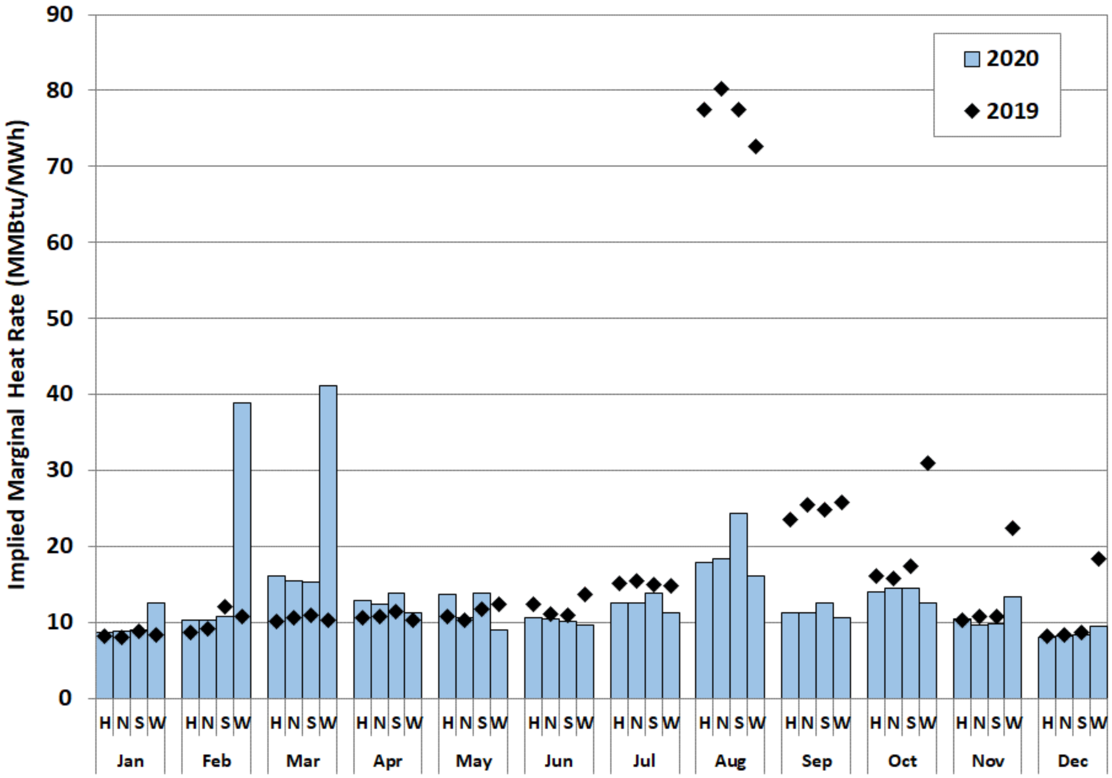
The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict accurate load distribution factors across all markets, RENA impacts will persist. In 2020, a new process was created for determining the load distribution factors used in the Congestion Revenue Rights (CRR) Auctions and day-ahead market clearing using load forecasting models and existing validation and error correction to determine daily load distribution factors, which represents a significant improvement over the previous process.[8]

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 heat rate" is calculated by dividing the real-time energy price by the natural gas price. Figure 8 shows the implied marginal heat rates monthly in each of the ERCOT zones. This figure is the fuel price-adjusted version of Figure A3 in the Appendix.

8 NPRR1004, *Load Distribution Factor Process Update* (approved on August 11, 2020).

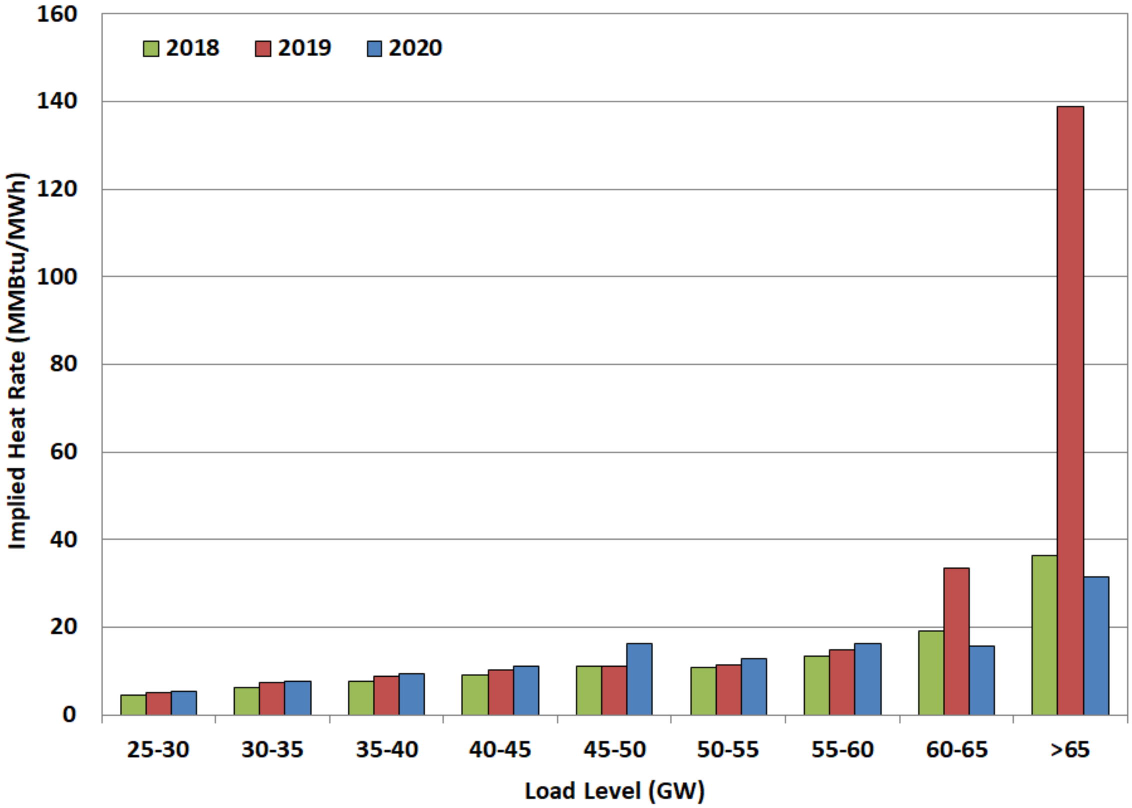
Figure 8: Monthly Average Implied Heat Rates



The implied heat rate varied substantially among zones. The most significant increase occurred in August as hot weather led to high load levels and prices. Transmission congestion drove zonal differences, particularly for the West zone in February and March 2020. Overall, average implied heat rates were as expected for a year without frequent operating reserve shortages.

Figure 9 shows how the implied heat rate varies by load level over the past three years. As expected in a well-performing market, 2020 exhibited a positive relationship between implied heat rate and load level. 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 A7, Figure A8, and Table A2 in the Appendix.

Figure 9: Implied Heat Rate and Load Relationship

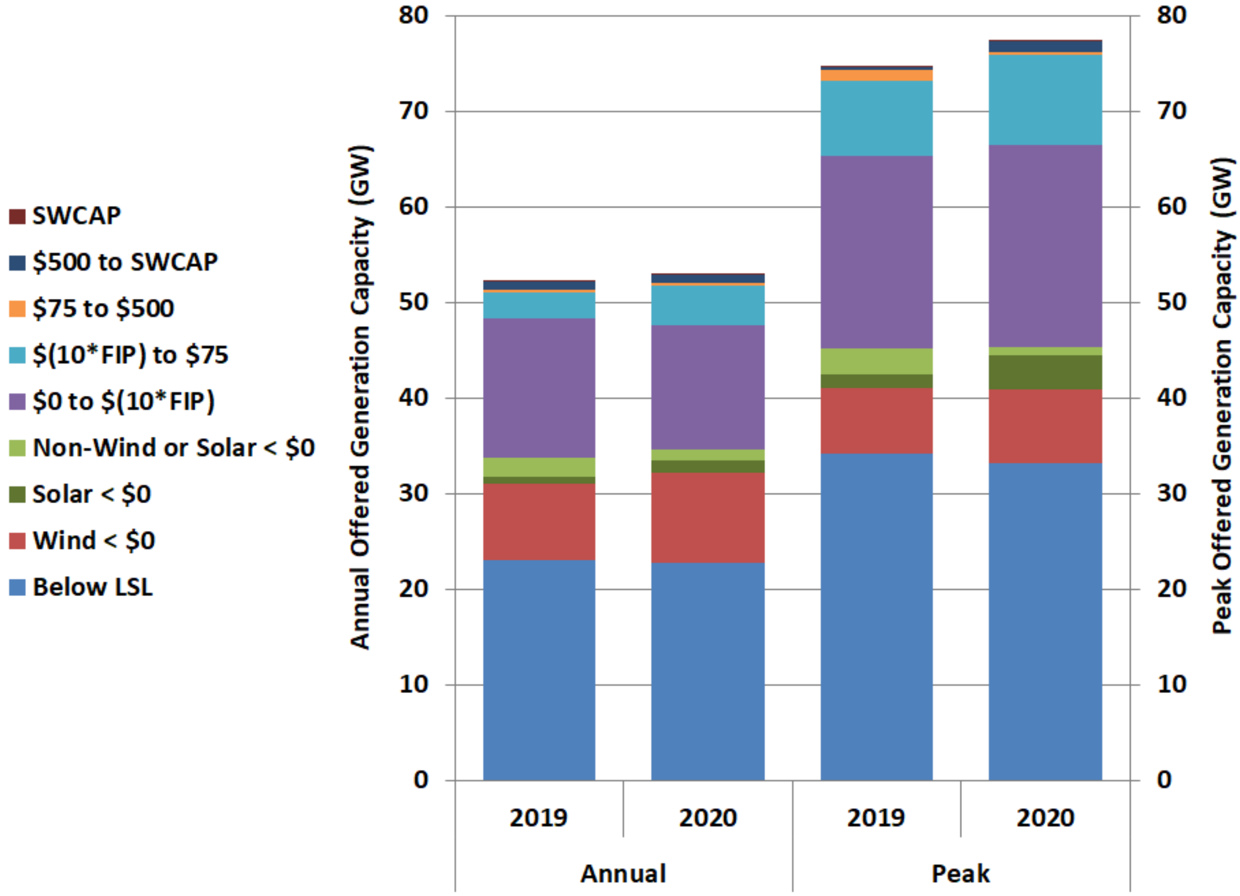


E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2020 to that offered in 2019. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 10 provides the average aggregated generator offer stacks for the entire year, as well as the offers in the summer.

This figure shows that in both periods, 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 10: Aggregated Generation Offer Stack - Annual and Peak



The average annual offer patterns shown in Figure 10 reveal that in 2020:

- The amount of capacity offered at prices less than zero attributable to wind and solar increased by more than 1,000 MW, while non-wind and solar capacity offered at less than zero decreased by more than 500 MW;
- Approximately 1,600 MW less capacity was offered between $0 and $(10*FIP). This was likely related to the low natural gas price and the higher contribution of other components of short-run marginal costs in the offers;
- The amount of capacity offered at prices between $(10*FIP) and $75 per MWh increased by 1,400 MW from 2019 to 2020; and
- The aggregate amount of generation capacity offered into ERCOT's real-time market increased by nearly 650 MW in 2020.

Figure 10 also shows that the changes in the aggregated offer stacks between the summers of 2019 and 2020 were somewhat different than those in the annual aggregated offer stacks for those years. The changes that occurred in 2020 during the summer included:

- The aggregate offer stack increased by approximately 2,750 MW from the previous year.

- The amount of capacity offered at negative prices increased overall, with 880 MW of additional negative-priced offers from wind generators and 2110 MWs from solar, but 1870 MW less from thermal generators.
- There was an increase of approximately 1,000 MW capacity offered at prices between $0 and $(10*FIP), and of 1,500 MW of capacity offered at $(10*FIP) and $75 per MWh.

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 value leads to efficient shortage pricing as it is reflected in both operating reserves and energy prices during shortages.

The ORDC reflects the loss of load probability (LOLP) at varying levels of operating reserves multiplied by the deemed value of lost load (VOLL).[9] 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, with separate pricing for online and offline reserves. On January 17, 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.[10]

Effectively, these shifts accelerate the increase in prices toward the Value of Lost Load ($9,000 per MWh) and cause the market to set prices at VOLL when load shedding remains a small risk. Inflating the shortage pricing above the expected VOLL increases costs as described above, but will also provide incentives for ERCOT to maintain a higher planning reserve. Though these shifts remain significant, their effects were more muted in 2020 because of the COVID-19 pandemic and absence of shortage events throughout the summer months.

The effects of these changes are shown in Figure 11. This figure depicts single blended ORDC curves and magnitude of the first and second 0.25 standard deviation shifts in the LOLP calculation.

9 At the open meeting on September 12, 2013, the Commission directed ERCOT to move forward with implementing ORDC, including setting the Value of Lost Load at $9,000.

10 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 PUCT Project 48551.

Figure 11: Blended Operating Reserve Demand Curves

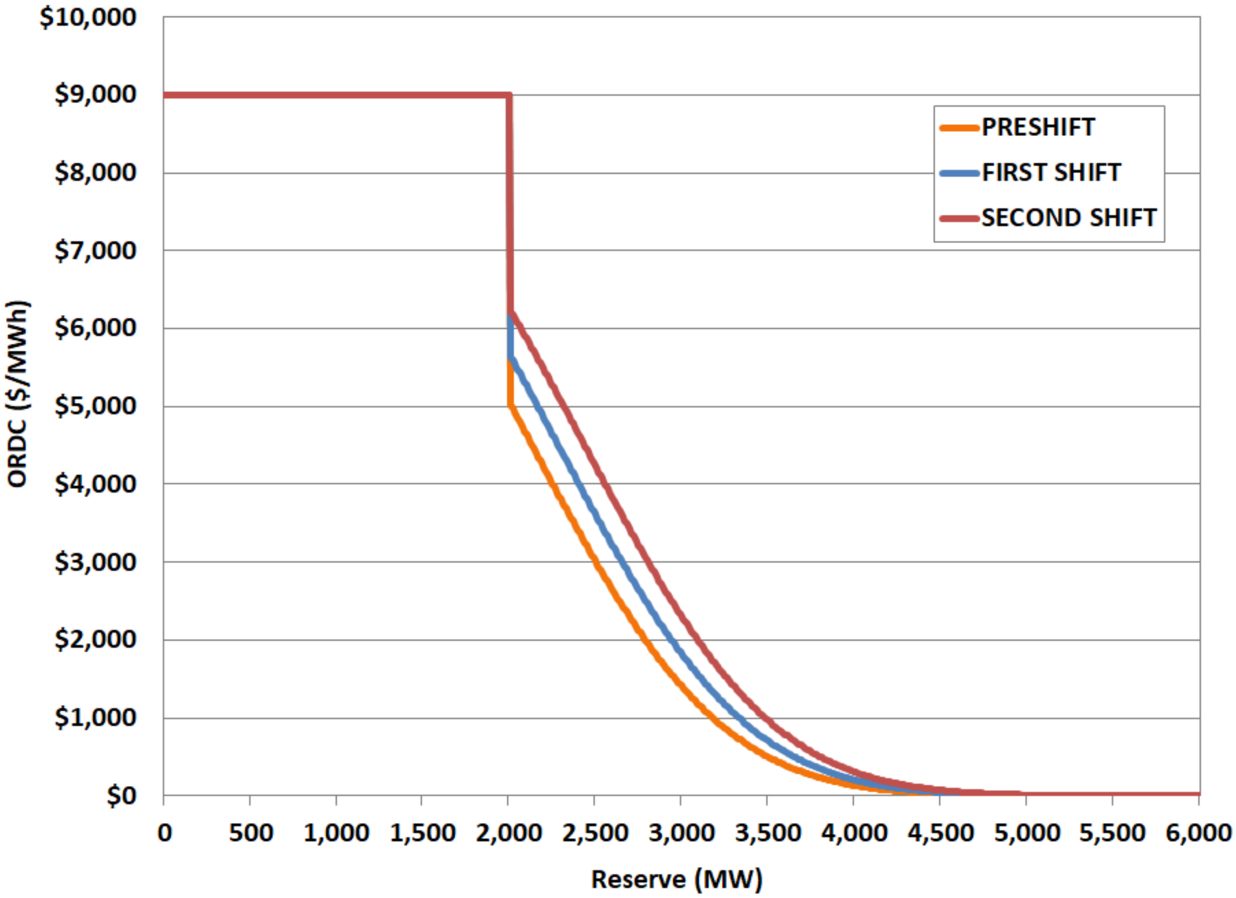
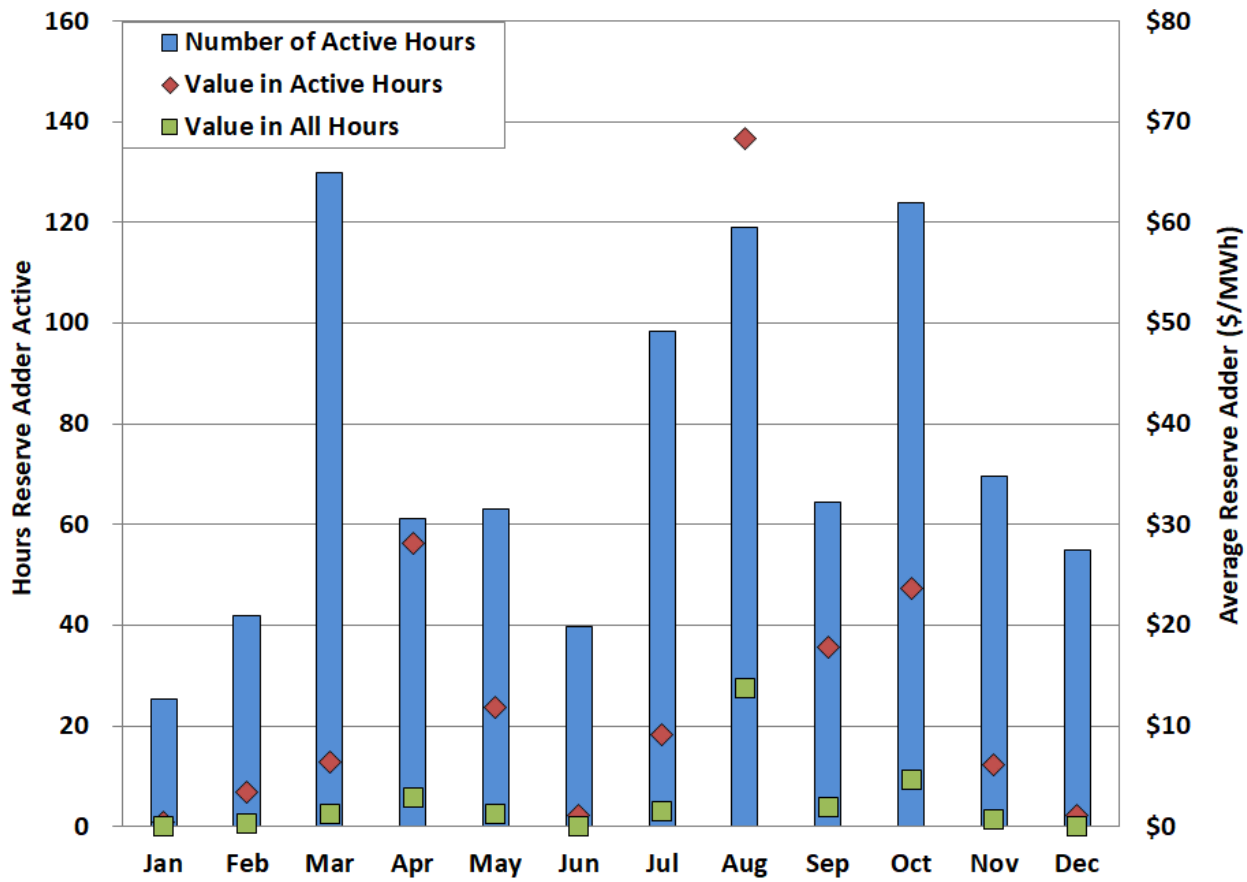


Figure 11 shows how each incremental shift increased the level of ORDC contributions to price as reserve capacity drops. For example, the price at 3,000 MW reserve level rises from roughly $1,400 per MWh on the pre-shift curve to approximately $1,800 per MWh on the first shift curve, and approximately $2,300 per MWh on the second shift curve. Regardless of the shifts, once available operating reserve levels decrease to 2,000 MW, prices will always rise to $9,000 per MWh.

The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. The first adder, the operating reserve adder, is a shortage value intended to reflect the expected value of lost load given online and offline reserve levels.

Figure 12 shows the number of hours in which the adder affected prices in 2020, and the average price effect in these hours and all hours. This figure shows that in 2020, the operating reserve adder had the largest price impacts in August because of the relatively small but still significant shortage conditions that occurred. The contribution from the operating reserve adder in 2020 was much lower than in 2019 because of the decrease in shortage conditions, despite the modifications to the ORDC described above.

Figure 12: Average Operating Reserve Adder



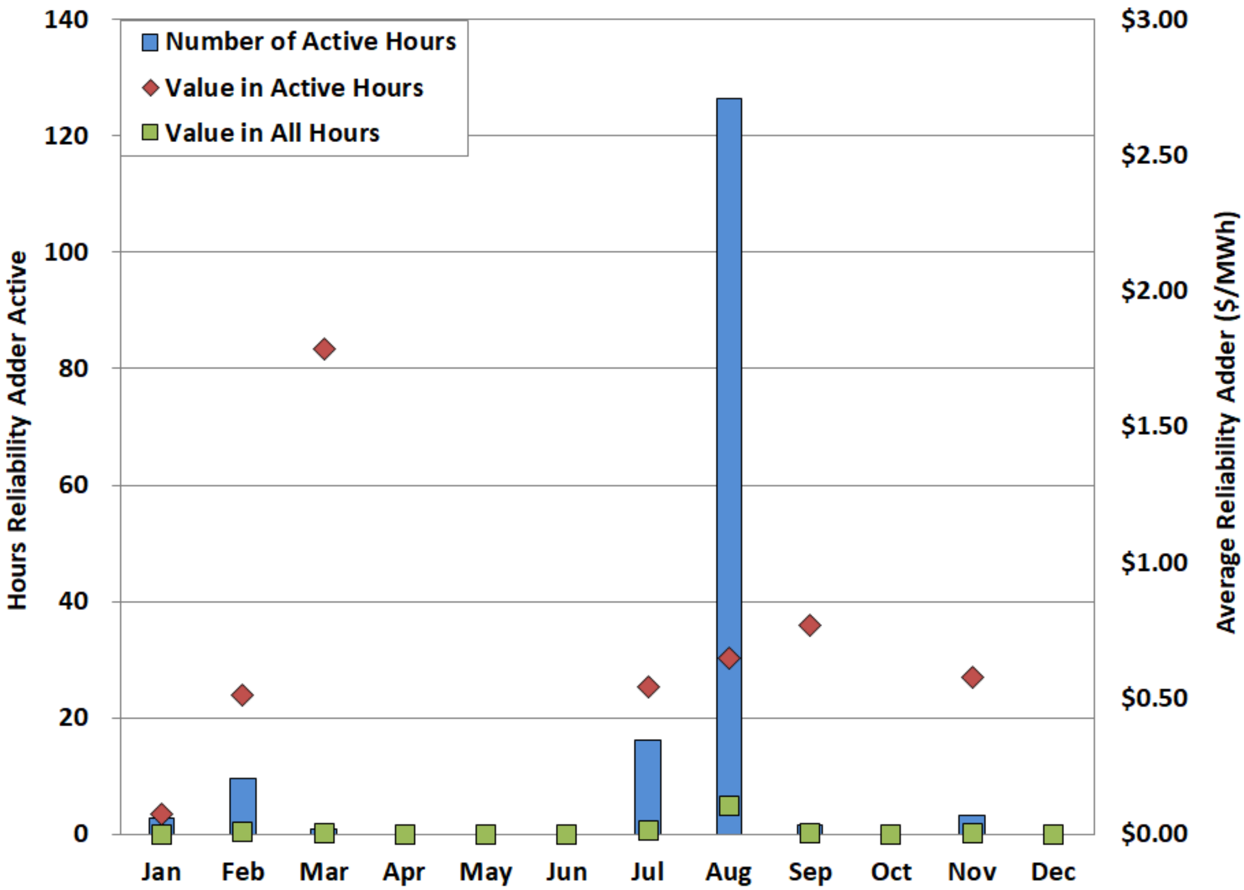
Overall, the operating reserve adder contributed $2.64 per MWh, or approximately 10% of the annual average real-time energy price of $25.73 per MWh in 2020. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, more like the market experienced in 2019 than those experienced in 2020.

The reliability adder is intended to allow prices to reflect the costs 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 13 below shows the impacts of the reliability adder in 2020. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during March. A fast-starting unit was brought online via RUC instruction for congestion, and the adders for that hour indicate the RUC offer floor impacted the energy price. The reliability adder was non-zero for 1.83% of the hours in 2020, most of which occurred in August. The highest contribution to the real-time energy price were in February, March, July, August, September, and November. The reliability adder in these months was a product of the

RUC instructions issued by ERCOT, discussed in Section V: Reliability Commitments. The contribution from the reliability adder to the annual average load-weighted real-time energy price was $0.01 per MWh.

Figure 13: Average Reliability Adder

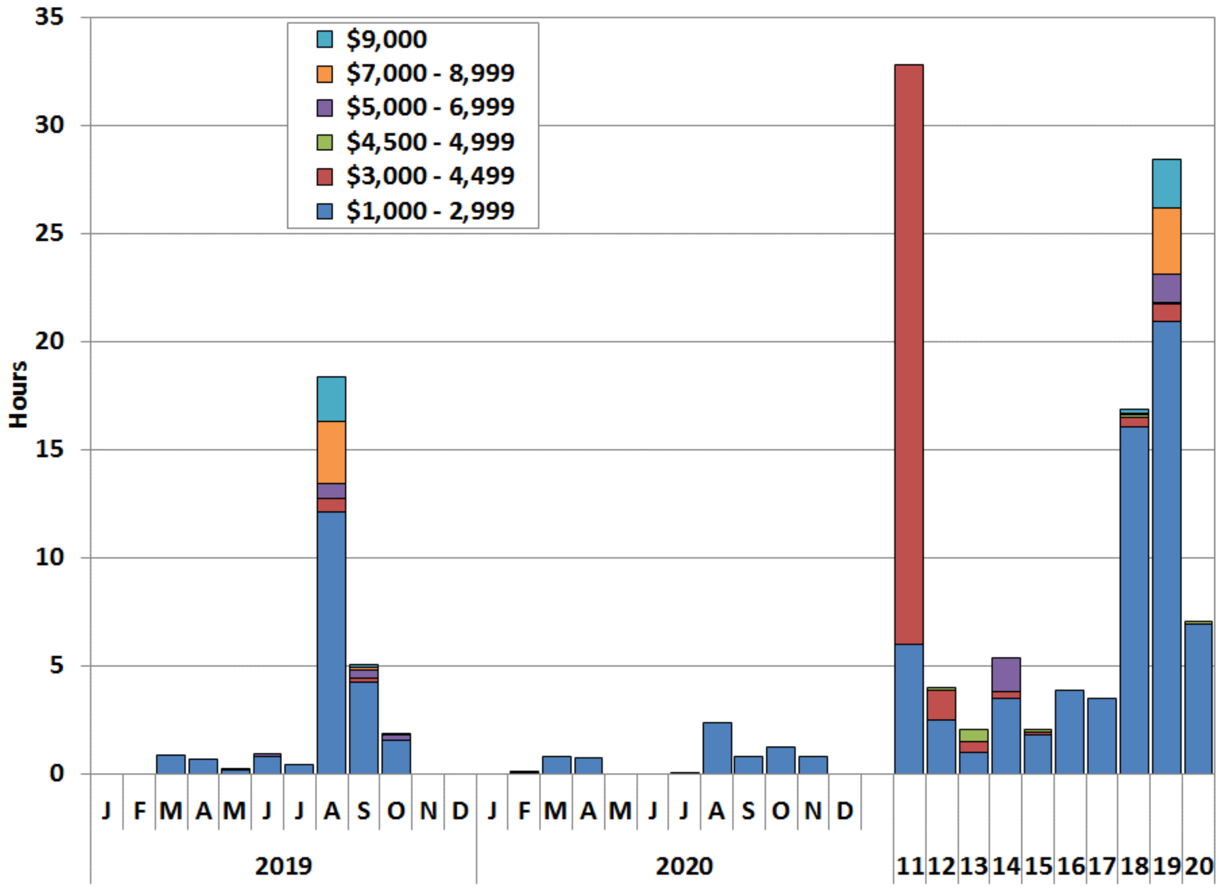


A weakness in the implementation of the reliability deployment adder was identified in 2019 and addressed in 2020. The primary flaw identified the restoration presumption adopted through Nodal Protocol Revision Request (NPRR) 626, *Reliability Deployment Price Adder ("formerly ORDC Price Reversal Mitigation Enhancements")*, caused prolonged high Real-Time On-Line Reliability Deployment Price Adder values for many hours after Energy Emergency Alert (EEA) conditions subsided during the summer of 2019. In June 2020, NPRR1006, *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data* was approved, returning the ERS resources in a linear curve over a four and a half-hour period following recall, rather than ten hours, to account for the data seen from summer 2019 as well as winter 2014 with the recognition that three days' data does not provide definitive information for further reduction. The NPRR also changed the process for updating this parameter in the future so that it can be updated by the ERCOT Technical Advisory Committee each year as appropriate, without the need to file a new NPRR.

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 14 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 2020, as well as annual summaries for 2011 through 2020.

Figure 14: Duration of High Prices



This figure shows that the frequency of high prices in 2020 remained relatively strong from a historic perspective, but considerably lower than the frequency and magnitude found in 2019. Prices greater than $1,000 per MWh occurred in about 7 hours in 2020 and were between $4,500 and $4,999 for just shy of 1 hour. Prices greater than $1,000 per MWh occurred in more than 28 hours in 2019 and were between $7,000 and $8,999 for more than 3 hours. In 2019, the system-wide offer cap was reached for intervals totaling more than two full hours during the peak week of August 12. Prices never approached those levels in 2020.

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 variation in 15-minute settlement point prices, expressed as a percentage of annual average price, for the four geographic zones for years 2014-2020. Larger values represent higher deviation from the mean.

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

Load Zone	2014	2015	2016	2017	2018	2019	2020
Houston	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%	21.2%
South	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%	21.7%
North	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%	19.8%
West	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%	26.5%

These results show overall volatility dropped in all zones except the West zone in 2020. This overall decrease is consistent with the rising operating reserve margins that led to less frequent instances of tight supply conditions in 2020.

Congestion explains most of the inter-zonal differences in price volatility. Volatility was again highest in the West zone in 2020 because of increased congestion, frequently related to planned outages. 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 A9 and Figure A10 in the Appendix.

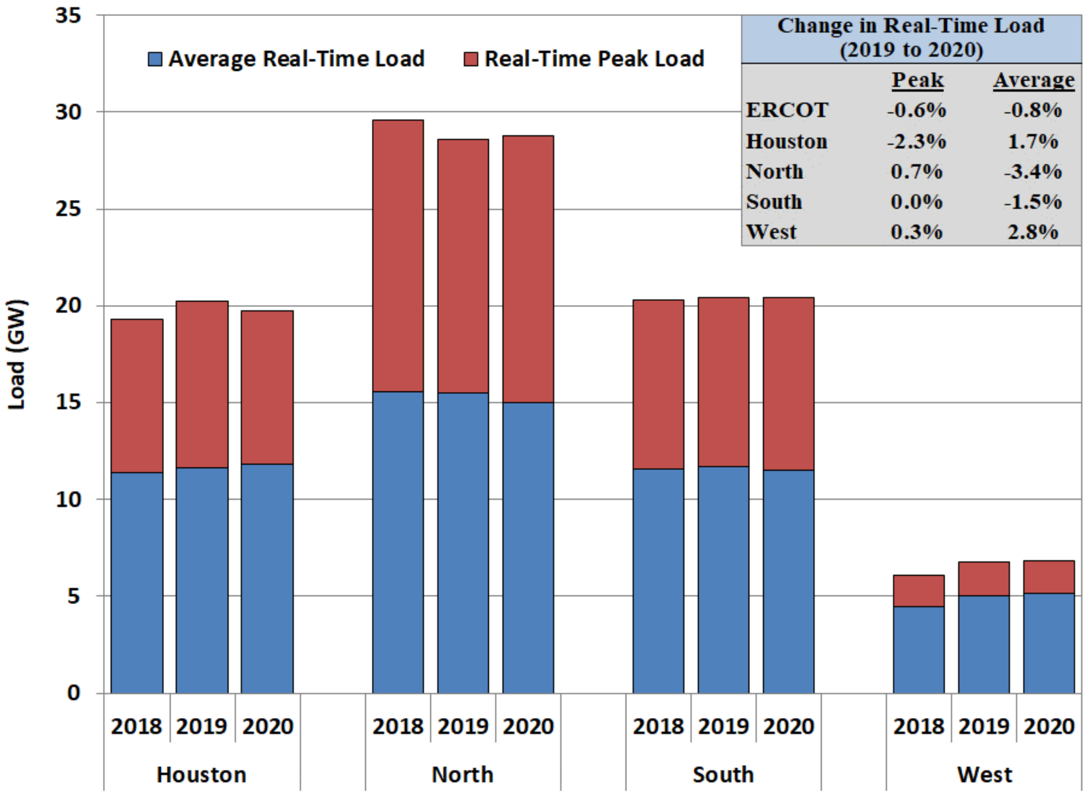
II. DEMAND AND SUPPLY IN ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2020. 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 2020

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.[11] Figure 15 shows peak load and average load by geographic zone from 2018 through 2020.[12]

Figure 15: Annual Load Statistics by Zone



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

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

Figure 15 shows that the total ERCOT load in 2020 decreased by roughly 1% from 2019, a decrease of approximately 360 MW per hour on average. The Houston and West zones showed an increase in average real-time load in 2020 ranging from 1.7% in Houston to 2.8% in the West. The increase in the West zone is particularly notable in that it comes on top of a 13% increase in 2019. Continuing robust oil and natural gas production activity in the West zone has been the driver for high load growth, though the pandemic and associated low oil and gas prices slowed this down in 2020. Weather impacts on load in 2020 were mixed across the zones.

Peak demand occurred on August 13, 2020, reaching 74,328 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 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 6% increase from 2019 in cooling degree days in Dallas. Cooling degree days is a metric that is highly correlated with summer loads. In the same timeframe, Austin had a 2% increase and Houston had a decrease of 2% in cooling degree days from 2019.

Peak demand impacts were the largest in April 2020 due to "stay-at-home" recommendations in response to COVID-19, which declined beginning in late June. By the end of the summer, there were no discernable impacts due to COVID-19. A more detailed analysis of the load, via hourly load duration curves, is available in the Appendix in Figure A11 and Figure A12.

B. Generation Capacity in ERCOT

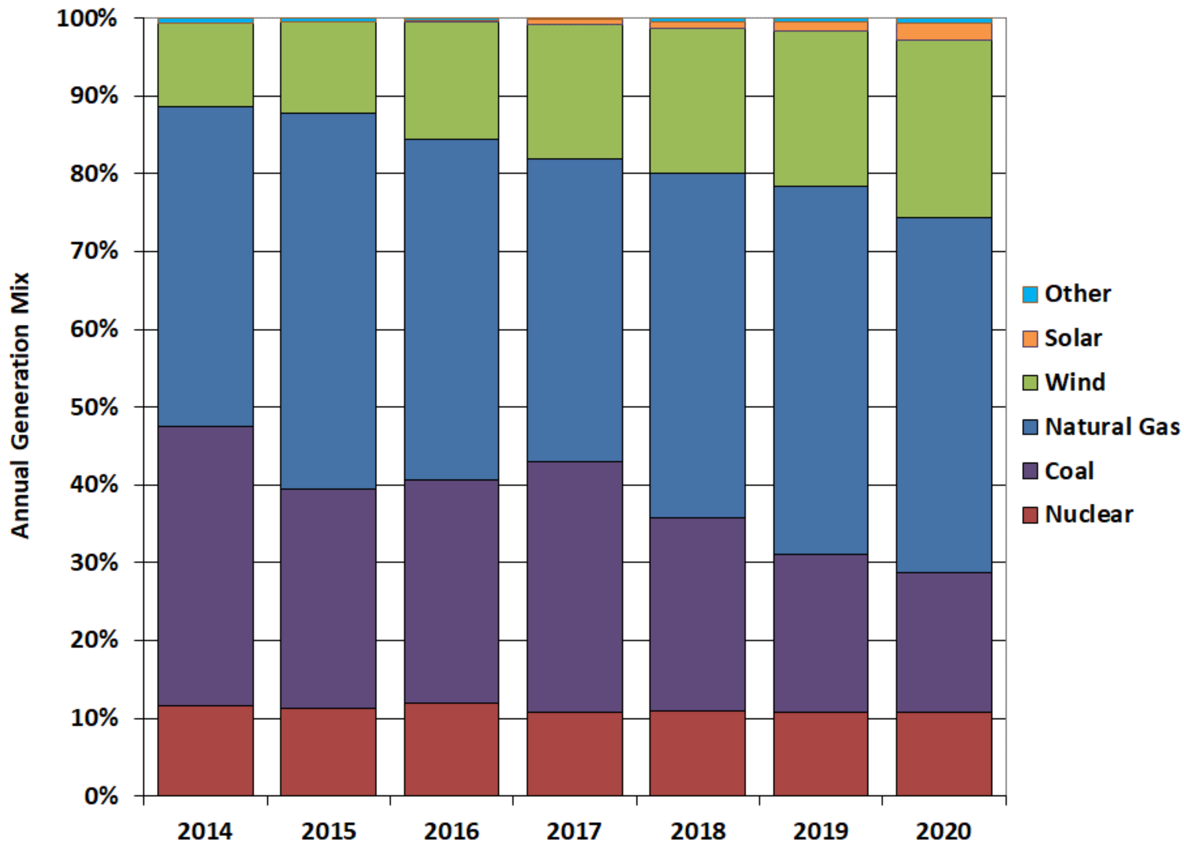
In this section we evaluate the generation portfolio in ERCOT in 2020. The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand for the North and South zone. Houston is generally importing while the West is generally exporting. The Houston zone has increasingly relied on imports from the rest of the state as resources have been mothballed and the reliance on intermittent resources has increased.[13]

Approximately 7.7 GW of new generation resources came online in 2020, the bulk of which were intermittent renewable resources and the remaining capacity was 390 MW from combustion turbines and 70 MW of power storage. ERCOT had roughly 4,000 MWs of new installed wind capacity and 2,100 of new installed solar capacity going into summer 2020 compared to summer 2019, with an effective peak serving capacity totaling 3.5 GW. Two gas-fired projects, 20 wind projects and 16 solar projects came online in 2020. The nine storage projects that came online in 2020 doubled ERCOT's storage capacity to around 200 MW. There were 1,030 MW of retirements in 2020, 650 MW coal and 380 MW gas. These changes are detailed in Section IV of the Appendix, along with a review of the vintage of the ERCOT fleet.

13 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.

Figure 16 shows the annual composition of the generating output in ERCOT from 2014 to 2020. This figure shows the transition of ERCOT's portfolio away from coal-fired resources to natural gas and renewable resources. Some of this transition has been driven by the vintage of the generating fleet in ERCOT. For example, 70% of the total coal capacity in ERCOT was at least thirty years old in 2020. Combined cycle gas capacity was the predominant technology choice for new investment throughout the 1990s and early 2000s. However, since 2006, wind has been the primary technology for new investment. The contribution from solar is steadily growing.

Figure 16: Annual Generation Mix in ERCOT



This figure shows:

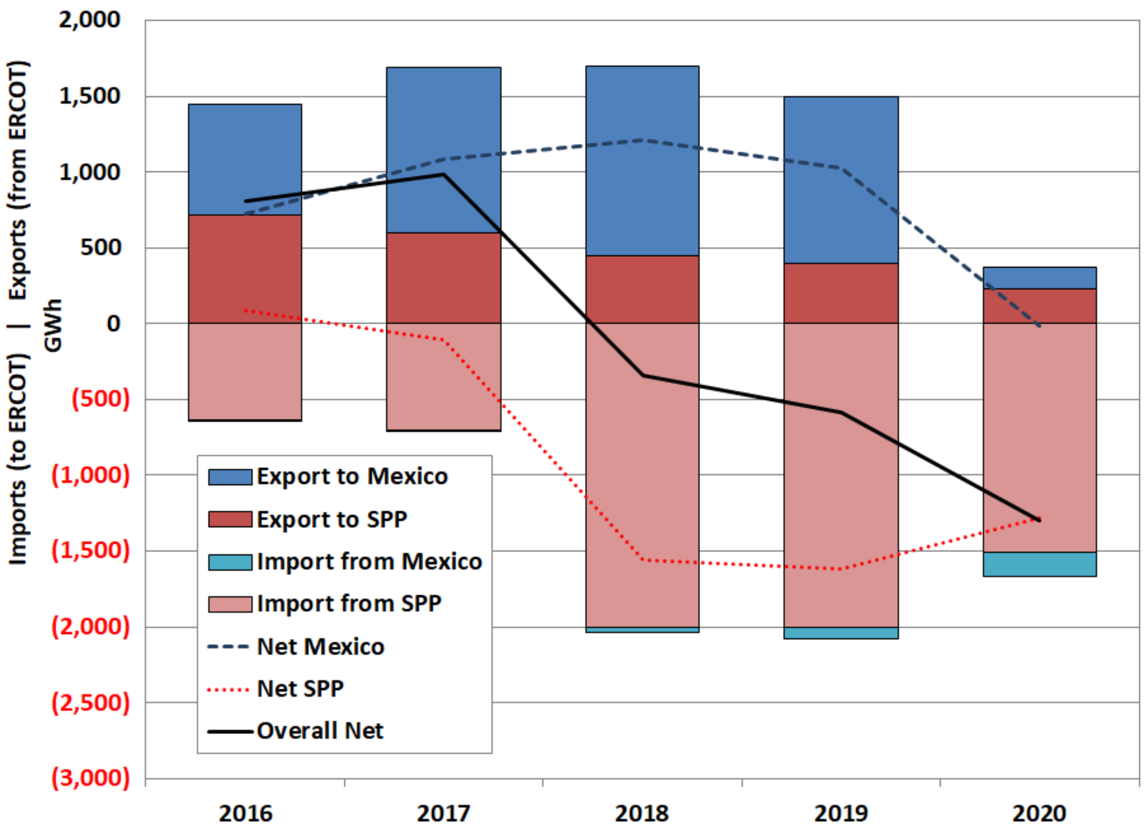
- The generation share from wind has increased every year, reaching almost 23% of the annual generation in 2020.
- The amount of utility-scale solar capacity added in 2020 (2,983 MW) was the largest amount of solar added to the ERCOT system in any given year, bringing total installed capacity to nearly 5,500 MW.
- The share of generation from coal continues to fall, down to approximately 18% in 2020.
- Natural gas generation decreased slightly, from 47% in 2019 to less than 46% in 2020.

We expect these trends to continue because of the continued growth of wind, solar, and storage resources. Figure A13 in the Appendix shows the vintage of ERCOT installed capacity. The installed generating capacity by type in each zone is shown in Figure A14 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 three ties totaling 430 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 17 shows the total energy transacted across the ties for the past several years.

Figure 17: Annual Energy Transacted Across DC Ties



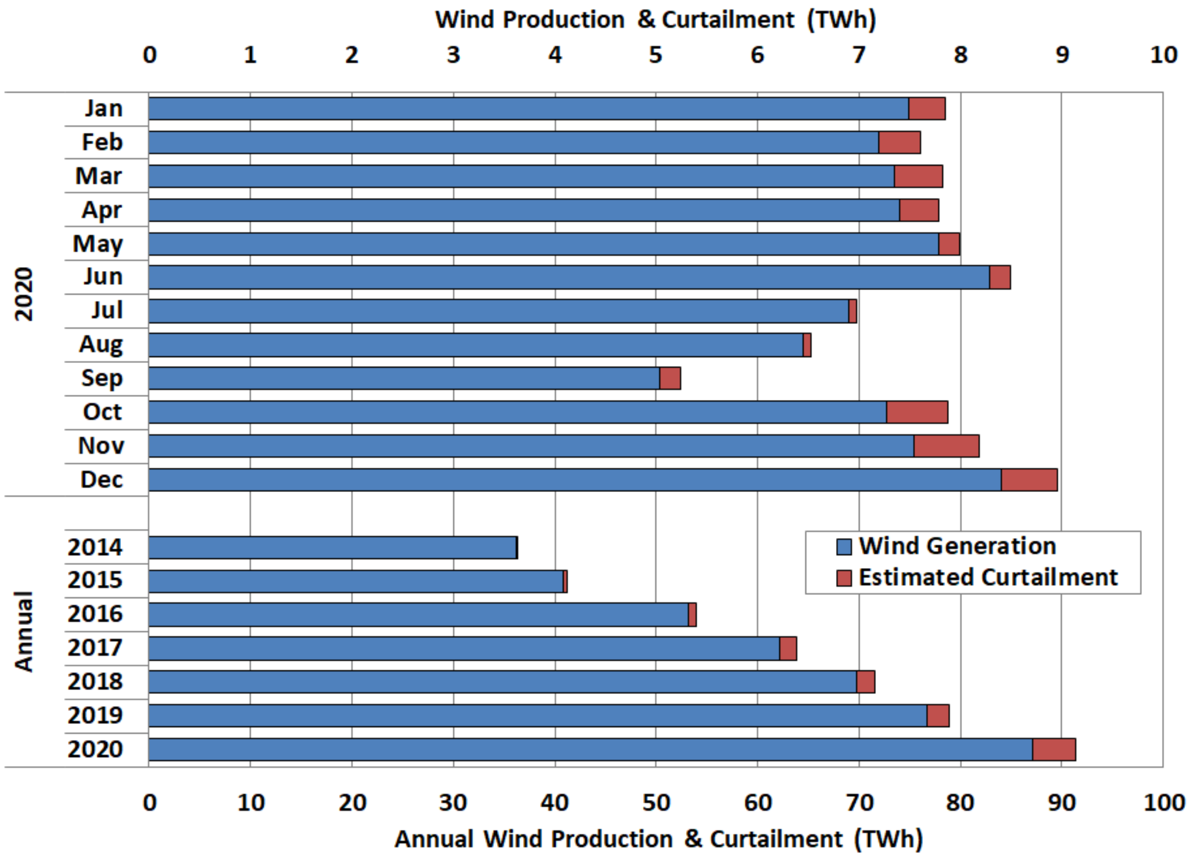
The figure shows that ERCOT remained a net importer in 2020. This trend began in 2018 due to tightening supply in ERCOT and the resulting higher prices in 2018 and 2019. But while that trend continued in 2020, total activity over the ties decreased, as both imports and exports on average were significantly lower in 2020. The only increase in 2020 were imports from Mexico, while exports to Mexico decline quite a bit. The decrease in tie activity is likely attributable to lower prices across the larger region 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 31 GW at the end of 2020. Although most wind generation is in the West zone, more than 7.8 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.[14] 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 increased the demand on other generation units. Wind output during high load periods will continue to be a pivotal determinant of shortages.

Figure 18: Wind Production and Curtailment



ERCOT continued to set new records for peak wind output. A new wind output record was set on December 22, 2020 (21,972 MW). The amount of power produced by wind resources (23%) outpaced coal (18%) in 2020.

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

Figure 18 reveals that the total production from wind resources continued to increase in 2020, while the quantity of curtailments implemented to manage congestion caused by the wind resources also increased. These curtailments reduced wind output by less than 5%, compared to a peak of 17% in 2009.

Increasing wind output has important implications for non-wind resources, reducing the energy available for them to serve while not offering substantial contributions to serving the system's peak load requirements. This also has important implications for resource adequacy in the ERCOT. For additional analysis of wind output in ERCOT, see Figure A15, Figure A16, and Figure A17 in the Appendix.

Figure 19: Top and Bottom Deciles (Hours) of Net Load

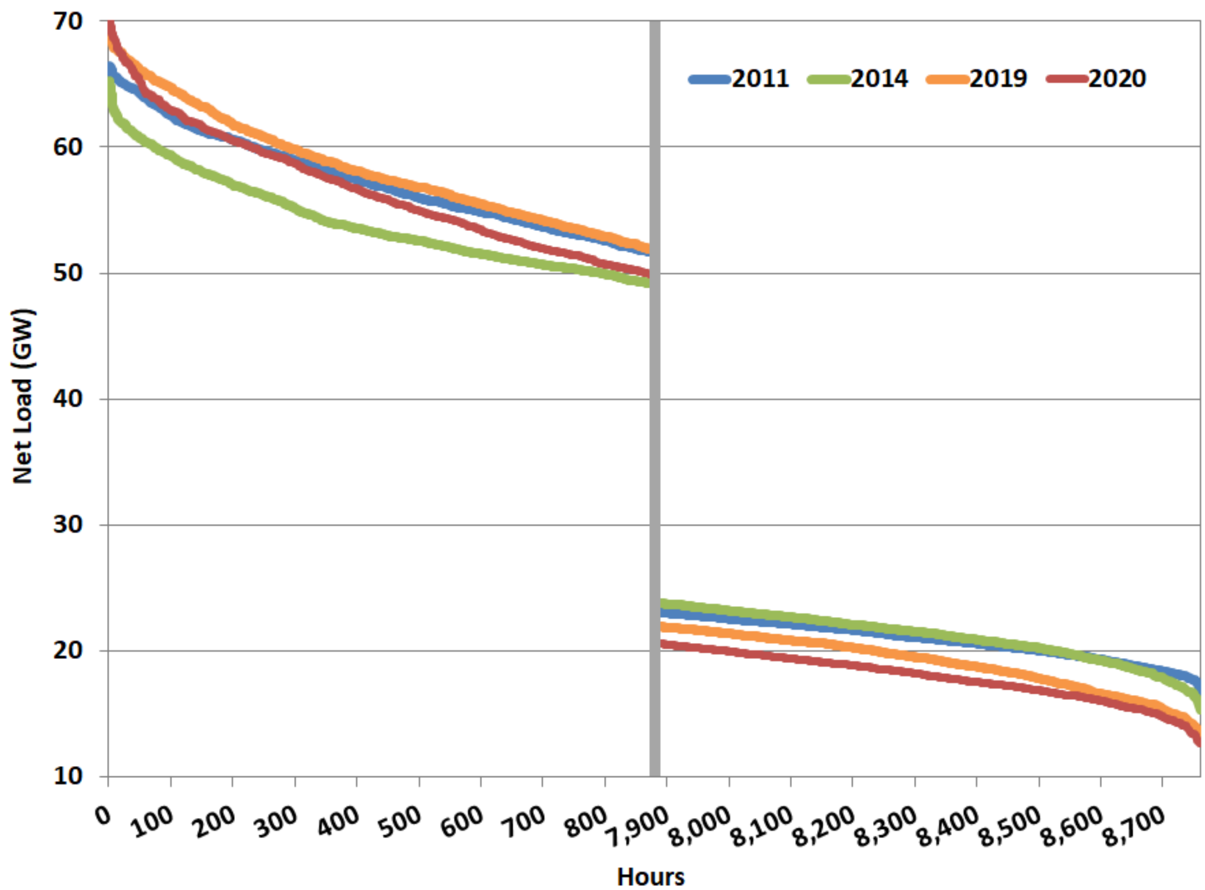


Figure 19 shows net load in the highest and lowest hours in 2020. Even with the increased development activity in the coastal area of the South zone, 67% of the wind resources in ERCOT are in West Texas (including the Panhandle). The wind profiles in this area result in only modest reductions of the net load relative to the actual load during the highest demand hours, but much larger reductions in the net load in the other hours. Hence, wind output displaces the load served by baseload units that often must produce at their minimum output level, particularly at night. This decreases the need for baseload resources and increasing the need for peaking resources.

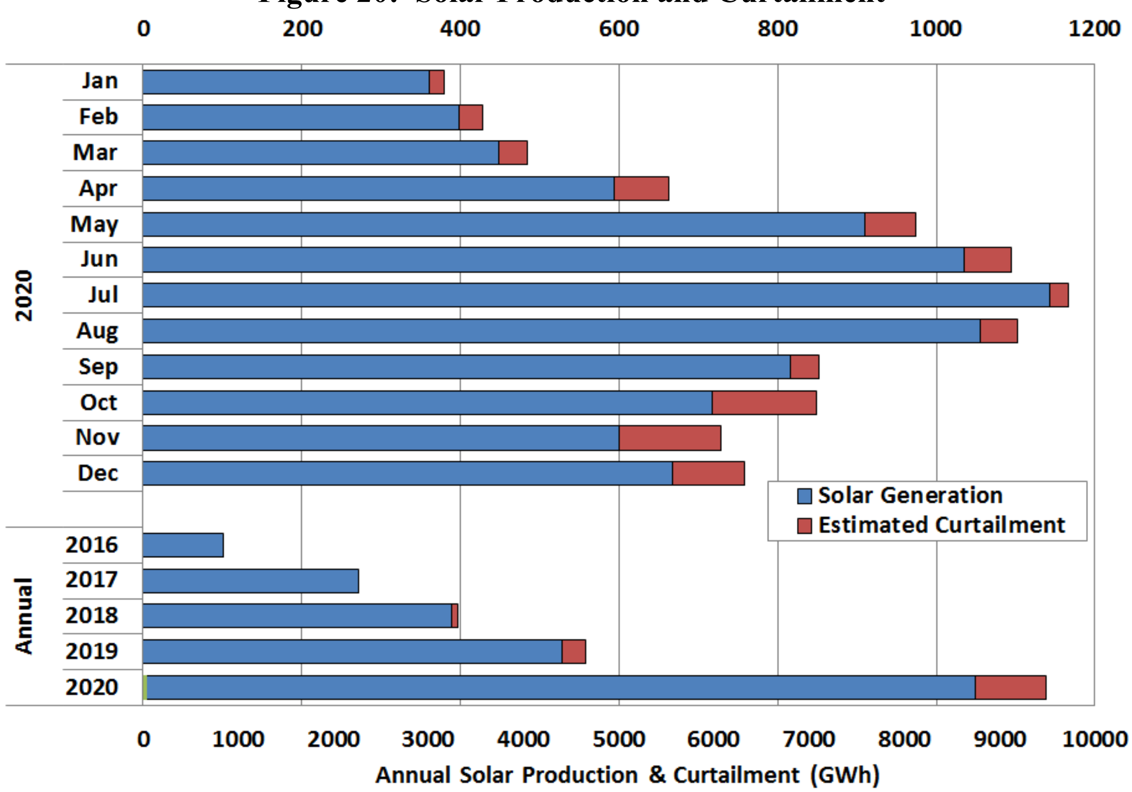
Figure 19 shows:

- In the hours with the highest net load (the left panel), the difference between the peak and the 95th percentile of net load was approaching 15 GW in 2020. This means that 15 GW of non-wind capacity is needed to serve load in less than 440 hours of the year in 2020.
- In the hours with the lowest net load (the right panel), the minimum net load has dropped from roughly 20 GW in 2007 to below 12.7 GW in 2020, despite the sizable growth in annual load. This trend has put economic pressure on nuclear and coal generation.

Peak net load is projected to continue to increase and create a growing need for non-wind capacity to satisfy ERCOT's reliability requirements. However, the non-wind fleet can expect to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly in the context of the ERCOT energy-only market design. For an historical perspective on net load duration curves in ERCOT, see Figure A18 in the Appendix.

We note that solar resources, although a relatively small component of overall generation today, are positively correlated with load and produce at much higher capacity factors during summer peak hours. The capacity factors during these hours was almost 81% for facilities located in the west and 70% for those in central Texas. Hence, these resources provide a larger resource adequacy benefit than wind resources. Figure 20 shows that total solar production in 2020 was 8,700 GW, which was curtailed by 8% to manage congestion caused by solar resources.

Figure 20: Solar Production and Curtailment



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 frequency 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. Load resources 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). These events typically occur only a few times each year.

As of December 2020, approximately 6,926 MW of qualified load resources could provide responsive reserve service, an increase of approximately 1,420 MW during 2020.[15] However, the total amount of responsive reserves procured by ERCOT was a maximum of 1,856 MW per hour. During 2020, there were no deployments of load resources providing responsive reserve service. Figure 21 below shows the average amount of responsive reserves provided from load resources on a daily basis for the past three years.

Until June 1, 2018, 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.[16]

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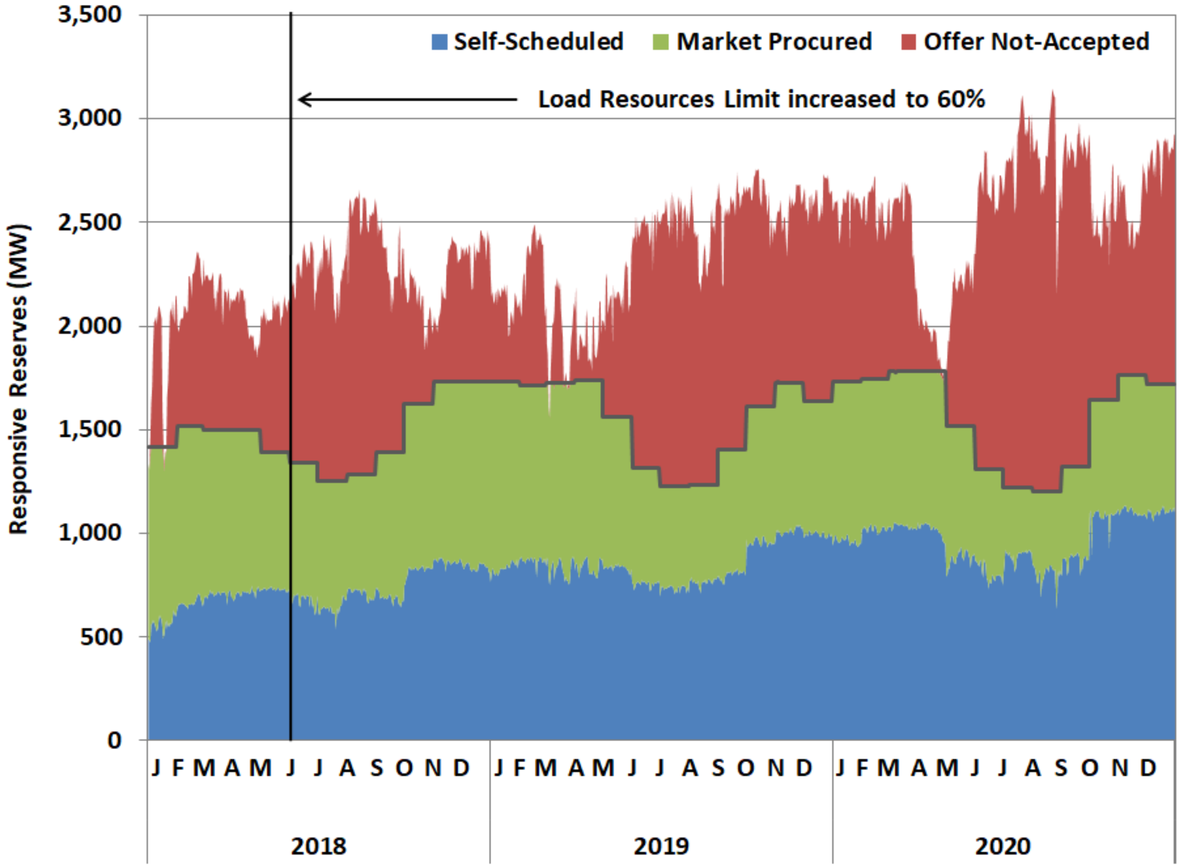
15 *See* ERCOT 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020), available at http://www.ercot.com/services/programs/load.

16 *See* NPRR815: *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS)* Service (http://www.ercot.com/mktrules/issues/NPRR815).

Figure 21: Daily Average of Responsive Reserves Provided by Load Resources



Beginning with calendar year 2021, NERC standards will require an increase in this floor to 1,420 MW. Necessarily, this will decrease in the amount of capacity that can come from load resources. There were more offers for load providing responsive reserve than the limit for almost all of 2020, and the total amount of surplus offer MWs grew by nearly 20% 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) 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.[17] The time- and capacity-weighted average price for ERS over the contract periods from February 2020 through January 2021 was $6.06 per MWh, down from $6.59 per MWh the previous program year. This price was lower than the average price paid responsive reserves ($11.40 on average) in 2020 but higher than non-spinning reserves ($4.45 on average).

17 *See* 16 TAC § 25.507.

There were slightly more than 285 MW of load participating in load management programs administered by the TDUs in 2020, which grew to 308 MWs in the months of August and September.[18] 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.[19] 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. For decades, transmission costs have been 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 doubled since 2012, increasing an already significant incentive to reduce load during probable peak intervals in the summer. ERCOT estimates that as much as 2,800 MW of load were actively pursuing reduction during the 4CP intervals in 2020, higher than the 2019 estimate.[20]

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. 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).

18 *See* ERCOT 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020) at 10, available at http://www.ercot.com/services/programs/load.

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

20 See ERCOT, 2020 Annual Report of Demand Response in the ERCOT Region (Dec. 2020) at 18, available at http://www.ercot.com/services/programs/load.

4. Demand Response and Market Pricing

When SCED clears the supply to meet the demand, it issues set point 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 2020, 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, considering nodal pricing for CLRs will become more important and impactful.

Second, the reliability deployment price adder (RDPA), discussed in more detail in Section I, includes a separate pricing run of the dispatch software to account for reliability actions. A flaw in this was revealed in 2021 in that it does not directly account for firm load shed instruction by ERCOT, and thus the adder is undervalued during EEA. We recommend that this be changed, as noted in recommendation No. 2020-1 above.

III. 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 day-ahead market also includes ancillary services and Point-to-Point (PTP) obligations. PTP obligations allow parties to hedge the incremental cost of congestion between day-ahead and real-time markets.

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

In this section, we examine day-ahead energy prices in 2020 and their convergence with real-time prices. We also review the activity in the day-ahead market, including a discussion of PTP obligations. This section concludes with a review of the day-ahead ancillary service markets. Overall, 2020 day-ahead prices were lower than 2019 for both energy and ancillary services, as expected given the higher reserve margin. Liquidity in the day-ahead market was similar to previous years, which included active trading of congestion products in the day-ahead market.

Table 3 below compares the average annual price for each ancillary service over the last three years, showing that the prices were lower for each product in 2020. The decrease in ancillary services prices caused the average ancillary service cost per MWh of load to decrease to $1.00 per MWh in 2020 from $2.33 per MWh in 2019.

Table 3: Average Annual Ancillary Service Prices by Service

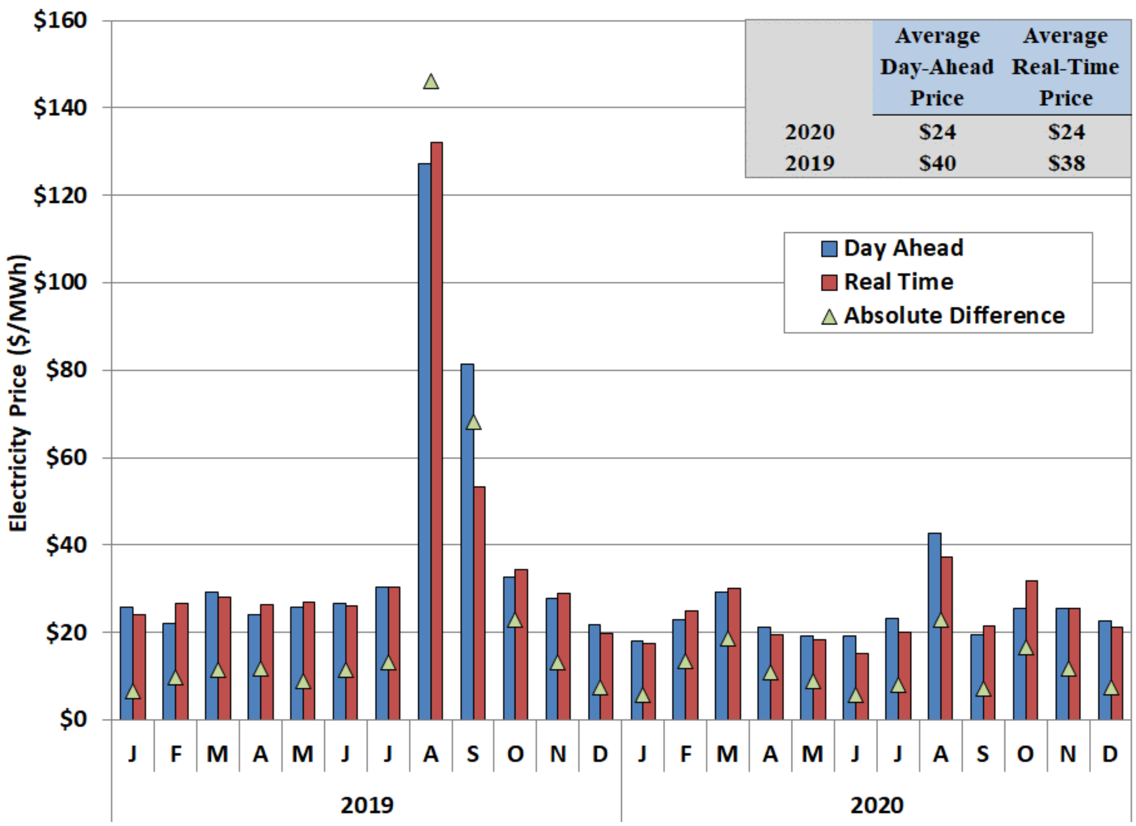
	2018 ($/MWh)	2019 ($/MWh)	2020 ($/MWh)
Responsive Reserve	$17.64	$26.61	$11.40
Non-spin Reserve	$9.20	$13.44	$4.45
Regulation Up	$14.03	$23.14	$11.32
Regulation Down	$5.19	$9.06	$8.45

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, i.e., 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 22 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 22: Convergence Between Day-Ahead and Real-Time Energy Prices



	Average Day-Ahead Price	Average Real-Time Price
2020	$24	$24
2019	$40	$38

Day-ahead and real-time prices both averaged $24 per MWh in 2020.[21] This convergence was a change from the day-ahead premium in 2019, which occurred in the summer months and reflected the value of day-ahead energy purchases as a hedge against the volatility of real-time prices under tight conditions. The relative stability of real-time prices and absence of tight conditions reduced the risk premium associated with day-ahead hedges.

Price convergence was evident in all months of 2020 except August, when day-ahead prices were higher, and October, when real-time prices were higher, likely offsetting and creating price convergence on average for the year. Slightly larger quantities of installed reserves for the summer of 2020, coupled with milder temperatures, led to expectations of less frequent shortage conditions and lower associated prices in real-time.

The average absolute difference between day-ahead and real-time prices was $11.60 per MWh in 2020, a sharp decrease from $27.63 MWh in 2019 and $16.21 in 2018, respectively. The largest absolute difference primarily occurred in August as expectations of shortages in the day-ahead market and actual reserve shortages in the real-time market led to relatively larger hourly differences. The largest zonal average absolute price differences occurred in the West zone as transmission congestion led to wide swings in West zone prices. For additional price convergence results in 2020, see Figure A9, Figure A10, and Figure A19 in the Appendix.

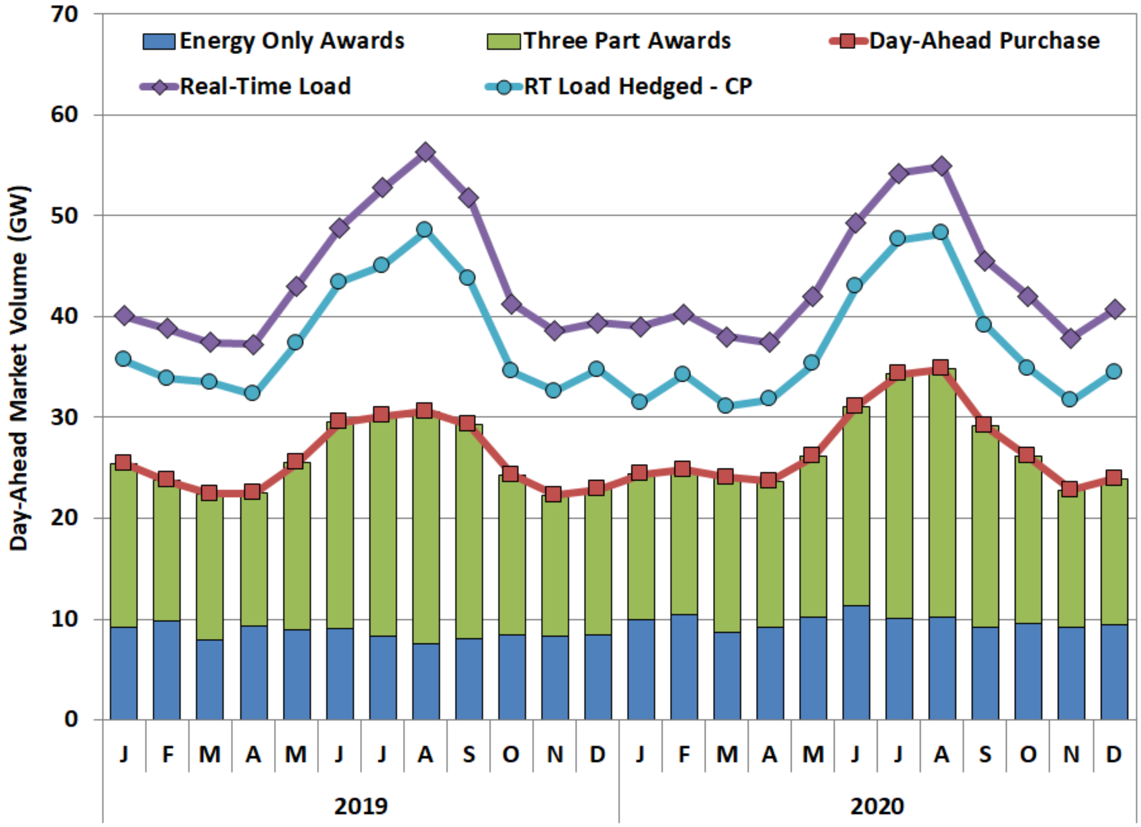
B. Day-Ahead Market Volumes

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

Figure 23 shows that the volume of day-ahead energy purchases provided through a combination of generator-specific offers (also known as three-part offers) and virtual energy offers was 64% of real-time load in 2020, an increase from 59% in 2019. 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.

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

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



PTP obligations are financial transactions purchased in the day-ahead market. Although PTP obligations do not themselves involve the direct supply of energy, a PTP obligation allows a participant to, in effect, buy the network flow from one location to another.[22] 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 day-ahead market 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 day-ahead market 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

[22] PTP obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

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 very large quantities of bids that are unlikely to clear 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 day-ahead market process. In recommendation No. 2020-4 above, the IMM recommends a PTP bid fee as an economically rational way to manage this volume.

Figure 23 also shows the portion of the real-time load that is hedged either through day-ahead energy purchases or PTP obligations scheduled by Qualified Scheduling Entities (QSEs).[23] 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 85% in 2020, similar to the 87% seen in 2019.

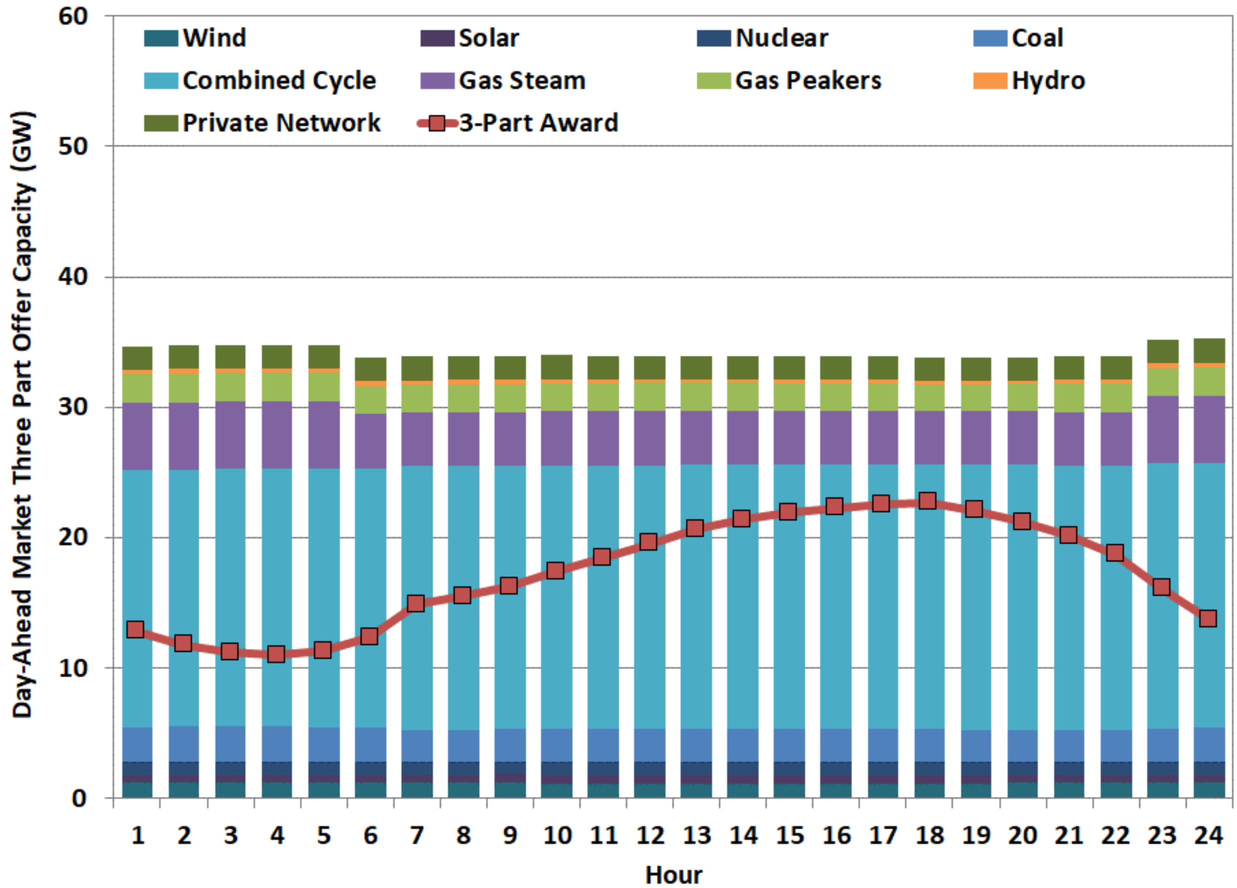
The volume of three-part offers comprised less than half of day-ahead market clearing. To determine whether this was due to small volumes of three-part offers being submitted, Figure 24 shows the total capacity from three-part offers submitted in the day-ahead market for 2020.

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 day-ahead market. More importantly, because combined cycle units are typically marginal units, offering that capacity into the day-ahead market 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 day-ahead market activity volume can be found in Figure A20 in the Appendix.

23 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.

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



To participate in ERCOT's day-ahead market, a market participant must have sufficient collateral with ERCOT. In 2018, ERCOT introduced forward prices as a determinant in calculating collateral requirements.[24] With even smaller installed reserves in 2019, forward prices were especially high for the summer months of 2019. The effect that forward prices had on the total collateral held by ERCOT throughout the year was quite significant. That trend was reversed in 2020 as installed reserves were higher and forward prices for the summer month of 2020 were down from 2019 levels. The total collateral requirements for 2020, significantly lower than in 2019, are shown below in Figure 25.

Credit requirements are a constraint on submitting bids in the day-ahead market. When the available credit of a QSE is limited, its participation in day-ahead market will necessarily be limited as well. We see no indication that credit represented a barrier to participating in the day-ahead market in 2020.

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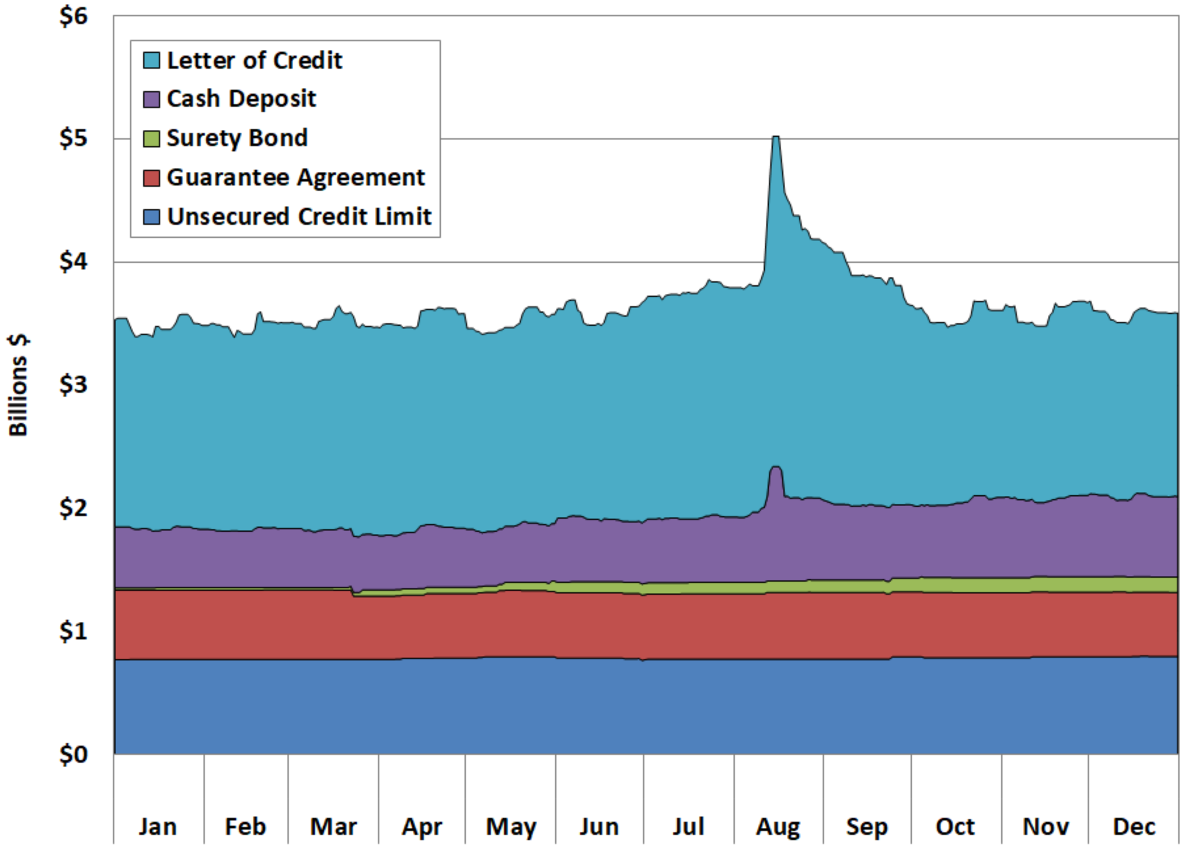
[24] NPRR800: *Revisions to Credit Exposure Calculations to Use Electricity Futures Market Prices*

Figure 25: Daily Collateral Held by ERCOT

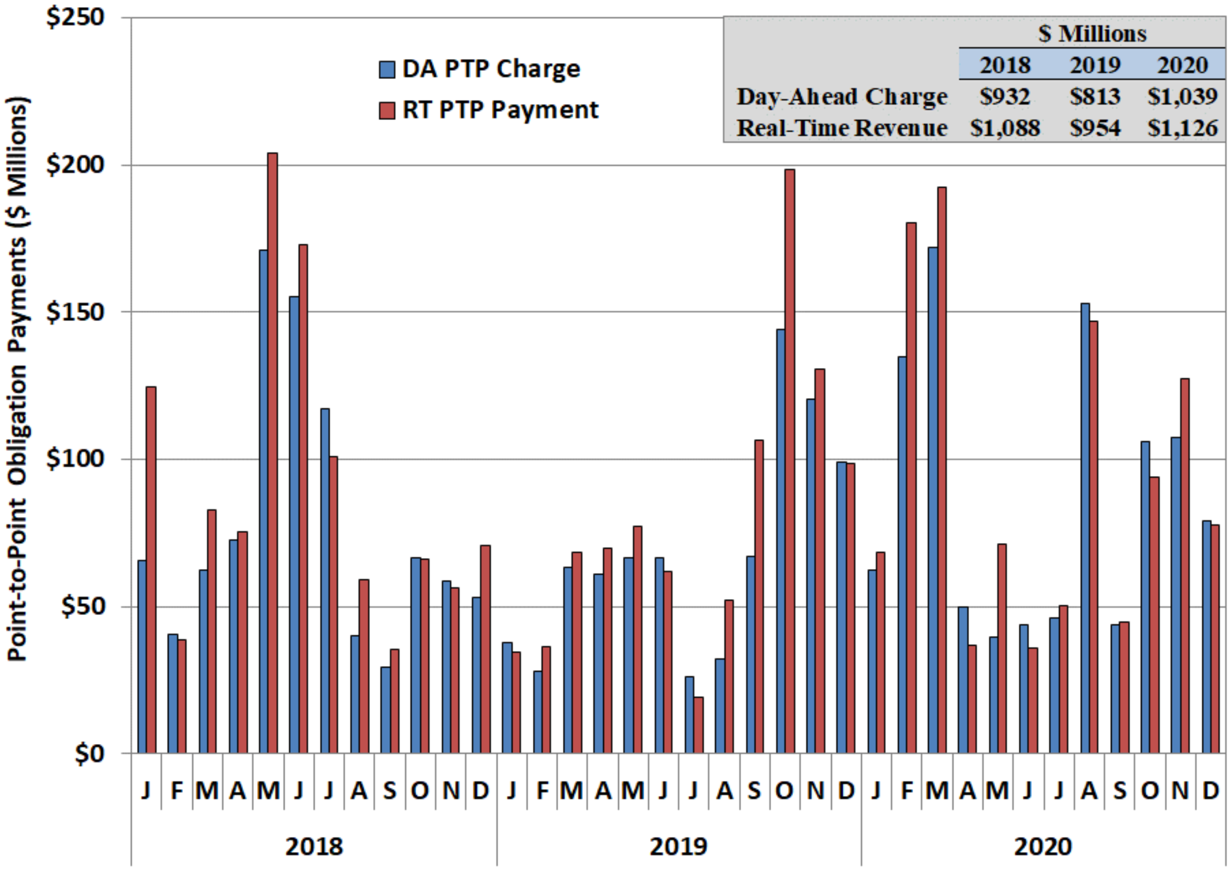


C. Point-to-Point Obligations

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

Participants buy PTP obligations by paying the difference in prices between two locations in the day-ahead market. 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 day-ahead market 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 day-ahead market, 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 26, compares the total day-ahead payments made to acquire these products, with the total amount of revenue received by the owners of PTP obligations in the real-time market.

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



	$ Millions		
	2018	2019	2020
Day-Ahead Charge	$932	$813	$1,039
Real-Time Revenue	$1,088	$954	$1,126

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 2020 after a slight dip in 2019. 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 26 shows that the aggregated total revenue received by PTP obligation owners in 2020 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 day-ahead market congestion costs. Profits were spread throughout 2020 (January, February, March, May, July, September and November), accruing when congestion priced in the day-ahead market was lower than the congestion that occurred in real time.

To provide additional insight on the profits that have accrued to PTP obligations, Figure 27 shows the profitability of PTP obligation holdings for all physical parties and financial parties (those with no real-time load or generation), as well as the profitability of "PTP obligations with links to options" in 2020. 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 27: Average Profitability of Point-to-Point Obligations

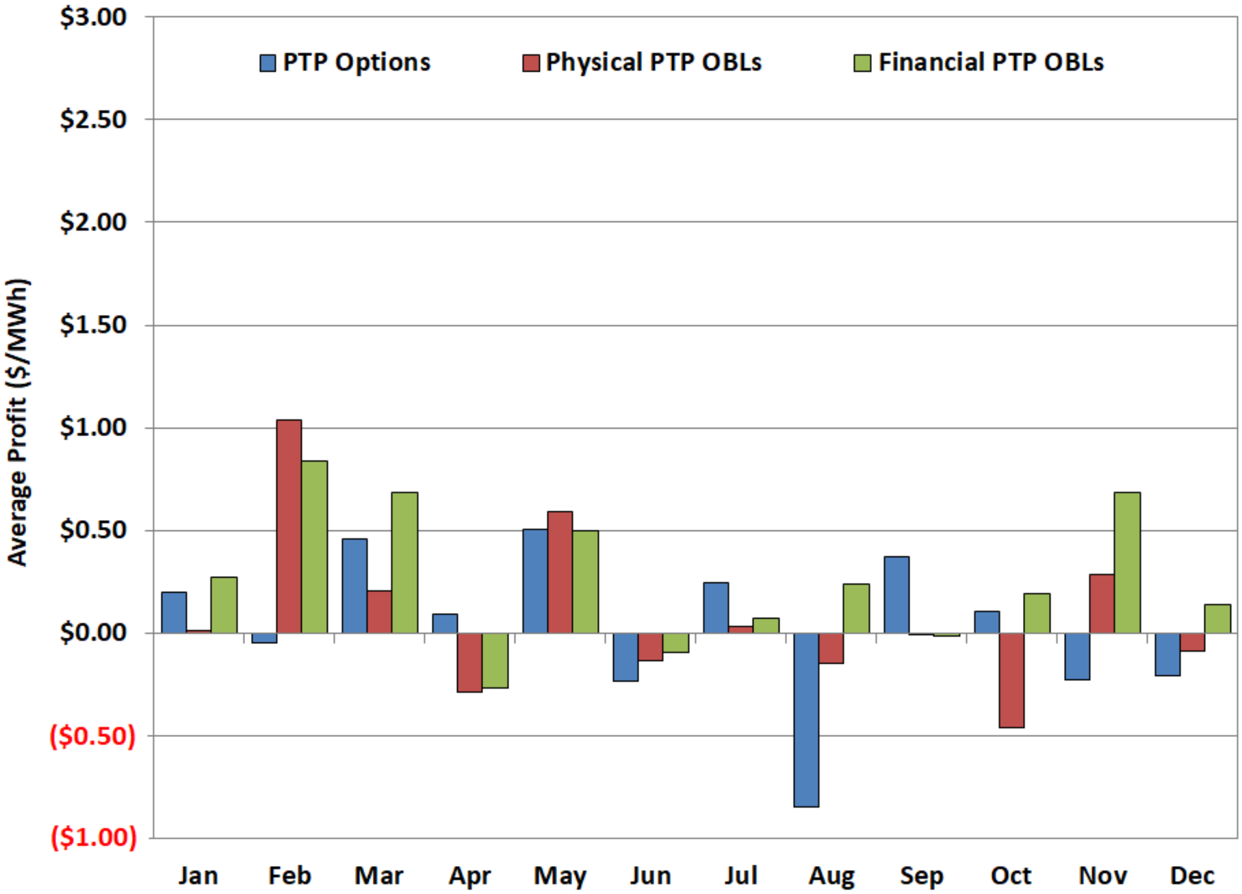


Figure 27 shows that in aggregate, PTP obligation transactions in 2020 were profitable for the year, yielding an average profit of $0.13 per MWh. This is however much less than the average profit of $0.22 per MWh in 2019. PTP obligations were profitable during 2020 for all types of parties, with average profits of $0.07 per MWh for physical parties, $0.27 per MWh for financial parties, and $0.02 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2020, see Figure A21 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 them purchased on their behalf by ERCOT. 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 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. ERCOT increased this accuracy in 2018 by including a new factor in the determination of generation to be dispatched in the 5-minute dispatch based on the wind forecasts. ERCOT tuned the new parameters multiple times in 2019 to improve the dispatch of other generators and the efficiency of regulation deployments. These improvements continued with the implementation in late 2020 of SCR811, *Addition of Intra-Hour PhotoVoltaic Power Forecast to GTBD Calculation*, updating generation to be dispatched again to include a predicted five-minute solar ramp component. On March 1, 2020, Phase 1 of NPRR 863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve* became effective, implementing Fast Frequency Response (FFR), the automatic self-deployment and provision by a resource of their obligated response within 15 cycles after frequency meets or drops below a preset threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes.[25]

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. ERCOT procures 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. In 2019, ERCOT removed the 1,375 MW floor on non-spinning quantities during on-peak hours, which slightly reduced the average quantity of reserves held by ERCOT.[26] There were no changes to the methodology for determining Ancillary Services amounts in 2020. ERCOT did place a limit of 450 MW on Resource providing Fast Frequency Response (FFR) when phase 1 of NPRR 863 was implemented.

The average total ancillary services requirement in 2020 was just shy of 4,800 MW, although the quantity of reserves held varies hour to hour. For example, on average ERCOT held roughly

25 Resources capable of automatically self-deploying and providing their full Ancillary Service Resource Responsibility within 15 cycles after frequency meets or drops below a preset threshold and sustaining that full response for at least 15 minutes may provide Responsive Reserve (RRS).

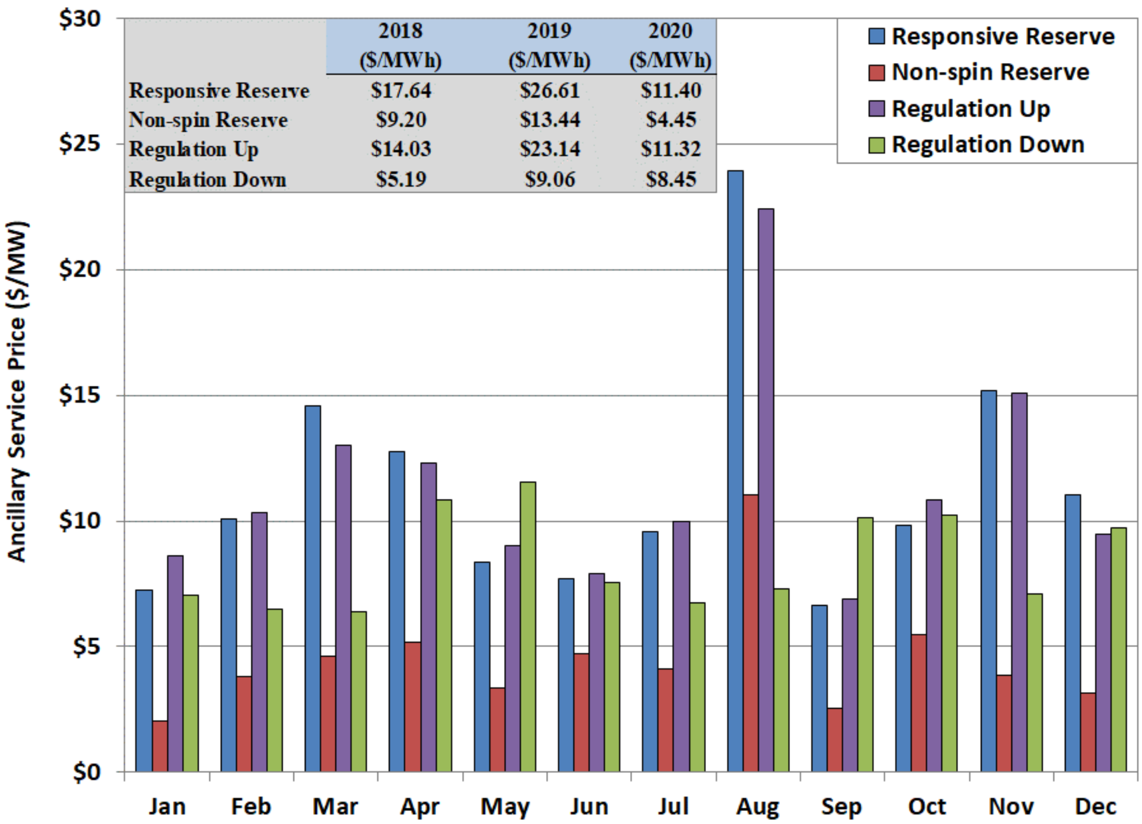
26 2020 Methodology for Determining Minimum Ancillary Service Requirements (approved by the Board on December 11, 2019).

5,400 MW of total reserves in the hour ending at 6 a.m., while it held less than 4,500 MW of reserves in hour ending 10 p.m. The primary reason ERCOT holds more reserves in some hours is that the demand for resources change output (i.e., to ramp up) is higher in some hours than others, which can cause the system to be more vulnerable to contingencies. Figure A22 and Figure A23 in the Appendix shows ERCOT's average monthly and hourly ancillary service requirements in 2020.

2. Ancillary Services Prices

Figure 28 below presents the monthly average clearing prices of capacity for the four ancillary services in 2020, while the inset table shows the average annual prices over the last three years. The prices for ancillary service were highest in August. This outcome is consistent with the higher clearing prices for energy in the day-ahead market for August because ancillary services and energy are co-optimized in the day-ahead market. 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 day-ahead market, ancillary service prices should generally be correlated with day-ahead energy prices.

Figure 28: 2020 Ancillary Service Prices



	2018 ($/MWh)	2019 ($/MWh)	2020 ($/MWh)
Responsive Reserve	$17.64	$26.61	$11.40
Non-spin Reserve	$9.20	$13.44	$4.45
Regulation Up	$14.03	$23.14	$11.32
Regulation Down	$5.19	$9.06	$8.45

The decrease in ancillary services prices caused the average ancillary service cost per MWh of load to decrease to $1.00 per MWh in 2020 from $2.33 per MWh in 2019. Figure A24 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 2020 ancillary services that are 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 2019-2020

	2019				2020			
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	Non-Spin	Reg Up	Reg Down
# of Suppliers	43	39	30	32	46	32	30	30
QLUMN	2%	37%	14%	43%	3%	27%	13%	40%
QLCRA	11%	6%	4%	3%	12%	7%	3%	4%
QNRGTX	8%	2%	1%	0%	11%	4%	6%	5%
QEDF26	1%	1%	5%	1%	2%	0%	18%	4%
QBRAZO	4%	6%	13%	3%	3%	6%	10%	2%
QAEN	2%	7%	3%	7%	3%	7%	4%	7%
QCALP	1%	2%	1%	3%	1%	3%	4%	10%
QOCCID	12%	0%	2%	5%	10%	0%	4%	3%
QFPL12	0%	0%	9%	4%	0%	0%	9%	4%
QEXELO	4%	0%	13%	5%	2%	0%	6%	4%

During 2020, 46 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market. The number of providers has been roughly the same for the past five years, with three additional providers in 2020 from the previous year. A breakdown of ancillary service providers by QSE, by type of service provided, can be found in Figure A25, Figure A26, Figure A27, and Figure A28 in the Appendix.

Regarding the concentration of the supply for each product, Table 4 shows that in 2020:

- The supply of responsive reserves has not been highly concentrated, just as in 2019, with the largest QSE providing only 12% of ERCOT's responsive reserves (QLCRA as opposed to QOCCID in 2019).
- The provision of non-spinning reserves is still more concentrated than responsive reserves, but less so than 2019. A single QSE (Luminant, shown above as "QLUMN") bore almost 40% of the requirements in 2019 but only 27% in 2020. Luminant's share has continued to fall from a high of 56% in 2017. The change in composition of Luminant's generation fleet, due to mergers and retirements, likely explains this trend.

- Regulation up is provided by many different QSEs and the supply is not concentrated because, in general, many different units can ramp up to provide regulation.
- Regulation down in 2020 exhibited similar concentration to regulation down (and non-spinning reserves) in 2019. Luminant remained the dominant supplier, selling 40% of all regulation down in 2020, with Calpine also providing 10%.

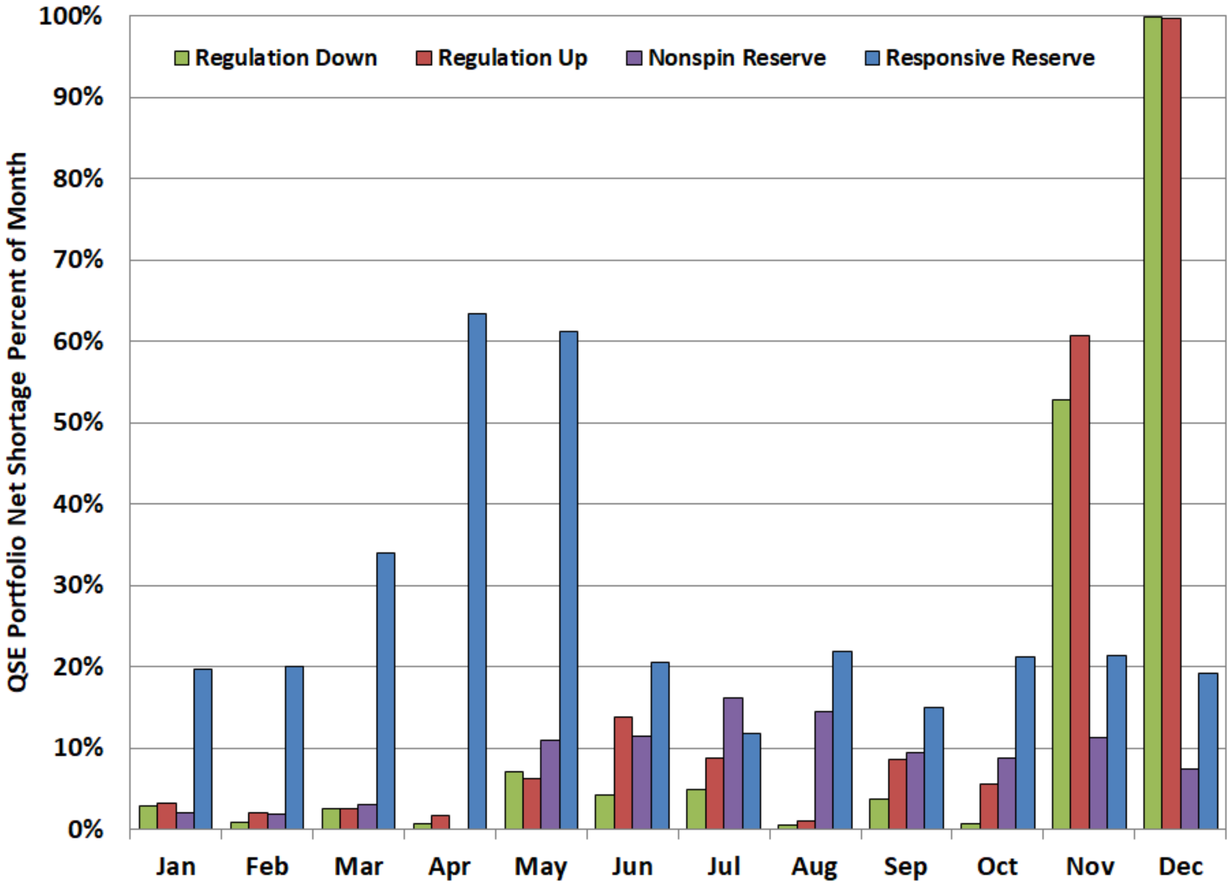
The ongoing concentration in the supply of non-spinning reserves and regulation down highlights the importance of modifying the ERCOT ancillary service market design and implementing real-time co-optimization. Jointly optimizing all products in each interval will allow the market to substitute its procurements among units on an interval-by-interval basis to minimize costs and set efficient prices. Doing so will reduce the competitive advantage of larger 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 day-ahead market. 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 real-time co-optimization.

Further, QSEs without large resource portfolios are effectively precluded from selling ancillary services because of the replacement risk faced in having to rely on a supplemental ancillary services market (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 can be up to 200 times greater than annual average clearing prices from the day-ahead market. Large portfolios can often replace ancillary services without a SASM. Real-time co-optimization will address these issues. Because real-time co-optimization is set to be implemented in 2025 and will obviate the need for SASMs, we will not discuss SASM deficiencies and issues here, but we have discussed these issues in previous reports. See Section III of the Appendix for more information on SASM activity in ERCOT in 2020.

Finally, QSEs do not always provide the ancillary services that they are obligated to, due to a combination of day-ahead awards, self-arrangement, or trades. Figure 29 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 29: QSE-Portfolio Net Ancillary Service Shortages



Deficiencies of QSEs in meeting their ancillary service responsibilities were pervasive in 2018. However, that trend reversed over the course of 2019, most notably for regulation down service. In 2020, this trend reversal did not continue, perhaps because NPRR 947 was withdrawn. The positive effective from ERCOT's altered approach to ancillary shortages was muted due to the lack of automation of the process. The NPRR had refined the ERCOT process for determining when a QSE has failed on its ancillary service supply responsibility and, relatedly, ERCOT's process for charging QSEs for a failed ancillary service quantity, creating a mechanism to reduce payment for ancillary service awards in situations when the QSE has not fully met the award.[27] We note that there were significant shortages for RRS in April and May with multiple responsible QSEs and that for November and December, one QSE accounted for almost all the regulation shortages.

[27] See NPRR 947: Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities, later withdrawn in August 2020.

IV. 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 at different locations across the network and resulting congestion costs that are collected from participants. Congestion exists most of the time; at least one constraint was binding (the flow at the constraint's limit) in real time during three-quarters of 2020.

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 day-ahead market. 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 can easily be converted into a real-time congestion hedge.

This section of the Report evaluates congestion costs and revenues in 2020. We first discuss the congestion costs in the day-ahead and real-time markets, which totaled $1.3 billion and $1.4 billion respectively, in 2020. We then discuss the CRR markets and funding in 2020.

A. Day-Ahead and Real-Time Congestion

As the day-ahead market 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 30 and Figure 31 summarize the monthly and annual congestion costs in the day-ahead and real-time markets. The values are aggregated by geographic zone.

Figure 30 shows that the total day-ahead congestion costs in 2020 were roughly 19% higher than costs in 2019; similarly, real-time congestion costs increased 11%. Most of the differences in congestion costs between day-ahead and real-time were in the West zone, which constituted approximately half of all the congestion in ERCOT. The differences in these costs in the West zone reflect the uncertainty surrounding outages and severity of constraints in the area. Congestion costs were much higher in the first quarter of 2020.

Figure 30: Day-Ahead Congestion Costs by Zone

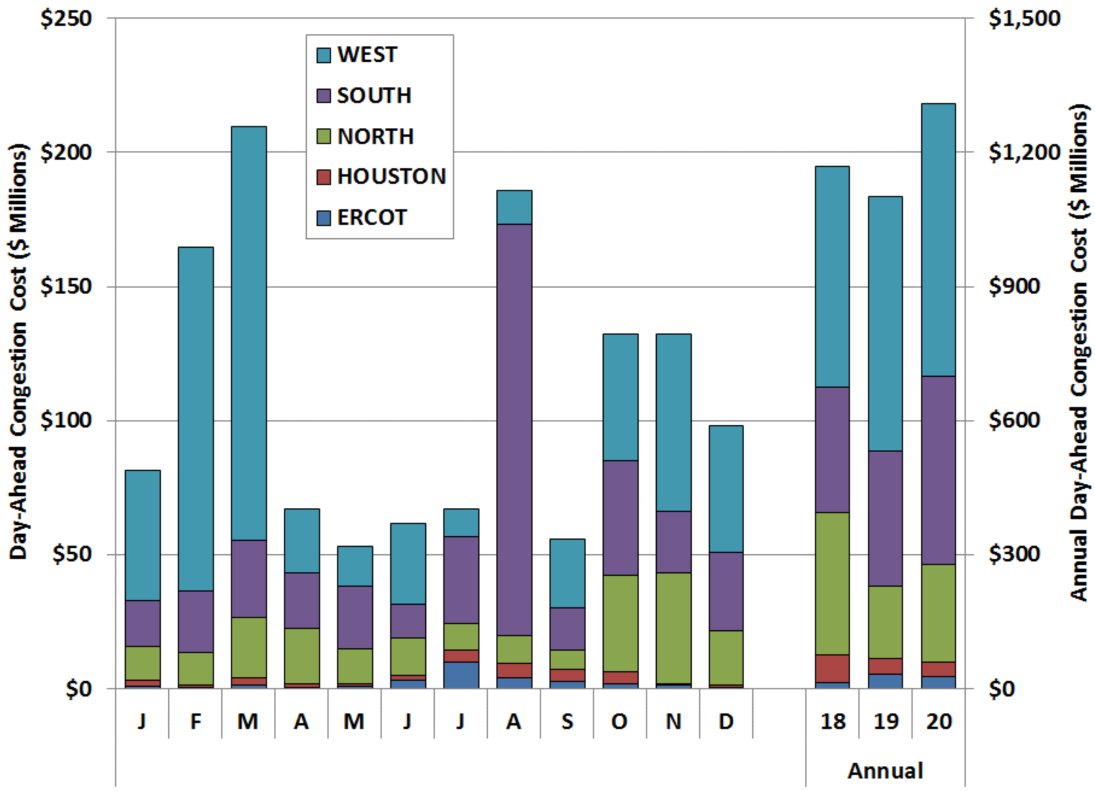
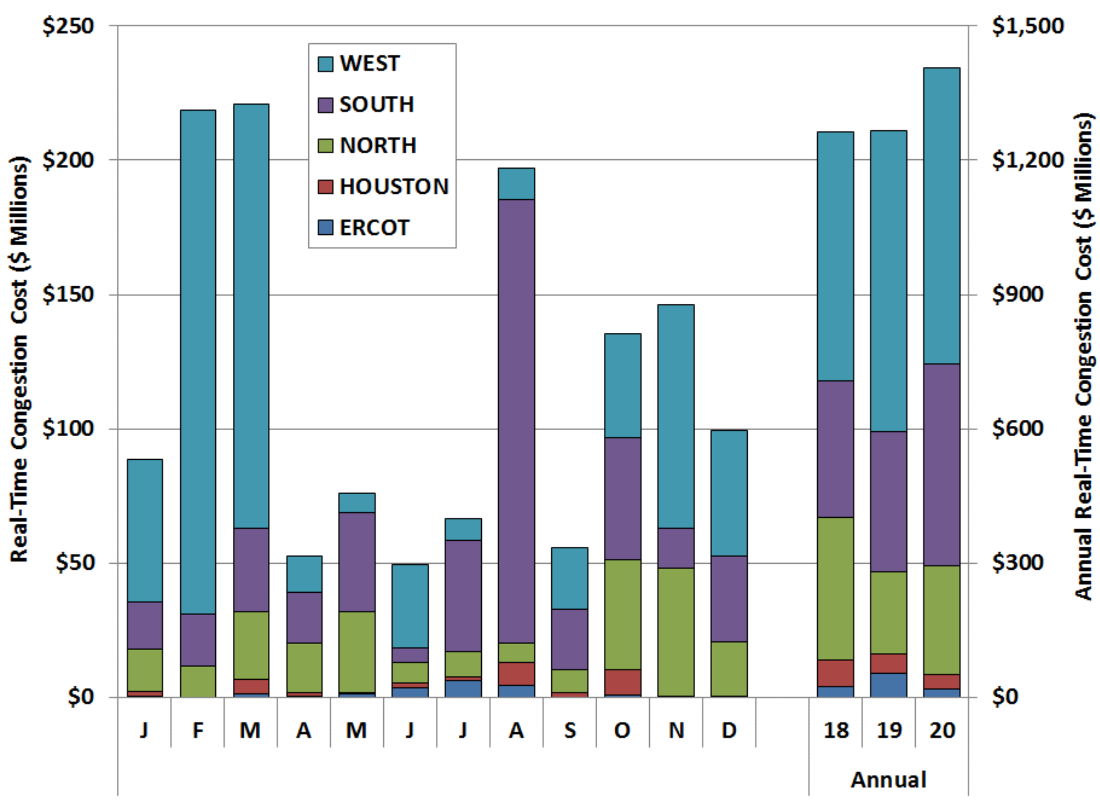


Figure 31: Real-Time Congestion Costs by Zone



The 2020 monthly congestion profile shows that congestion was highest in the winter and fall, which is an expected pattern. Shoulder months are typically when most transmission and generation outages for maintenance and upgrades occur. The increased congestion in January through May was likely due to an increase in significant transmission and generation outages, some of which were postponed to increase resource availability in the summer.

The ERCOT cross-zonal and Houston zone saw a decrease in congestion in 2020 because of the continued benefits of the North to Houston transmission project completion in April of 2018. The largest contributor to congestion costs in 2020, as was in 2019 with similar totals, was the congestion in the West zone. The congestion continued to be north of Odessa in 2020, a result of the high load caused by oil and gas development in the Permian Basin, concurrent to transmission outages for maintenance, new construction, and upgrades in the far west. The south zone experienced some weather-related outages due to Hurricane Hanna in July 2020, which led to the congestion costs in August and September. 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 day-ahead market, physical congestion occurs only in the real-time market. ERCOT operators manage power flows across the network as physical constraints become binding in real time. Therefore, 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 2020

Constraints arise in the real-time market through:

- Real-Time Contingency Analysis (RTCA) that runs on an ongoing basis; and
- Generic Transmission Constraints (GTCs) that are determined by off-line studies, with limits determined prior to the operating day.[28]

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-

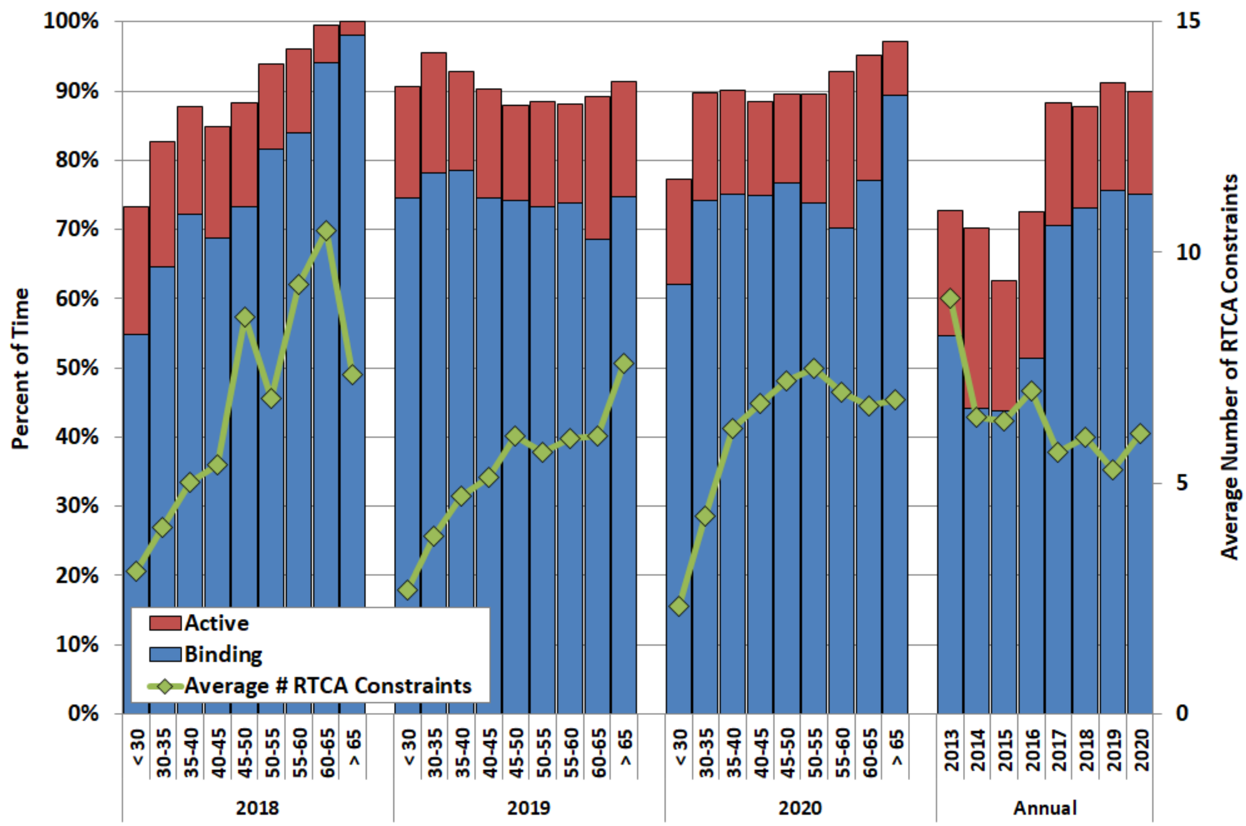
[28] A Generic Transmission Constraint (GTC) is a transmission constraint made up of one or more grouped Transmission Elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly 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.)

service element.[29] Active transmission constraints are those that are passed by the operator to the 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 re-dispatch of generation and thus have no effect on prices.

Our review of the active and binding constraints during 2020, Figure 32, shows the following:

- The ERCOT system had at least one binding constraint 75% of the time in 2020, a slight decrease from 76% in 2019.
- On average, slightly more than seven state estimator constraints were identified for each load bucket, up from approximately six in 2019.
- The state estimator RTCA constraints were relatively consistent across above the 35 GW load levels, although the average number of state estimator constraints were highest when load was in the 50 to 55 GW load bucket and lowest when load was less than 30 GW.

Figure 32: Frequency of Binding and Active Constraints



29 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.

GTCs doubled in binding intervals since 2019, increasing from 16% of the time to 33% in 2020 likely due to the increase in inverter-based generation in certain areas. 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, Inc., 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 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 energy storage resources comes online in the ERCOT region, the benefits of these dynamic models will grow.

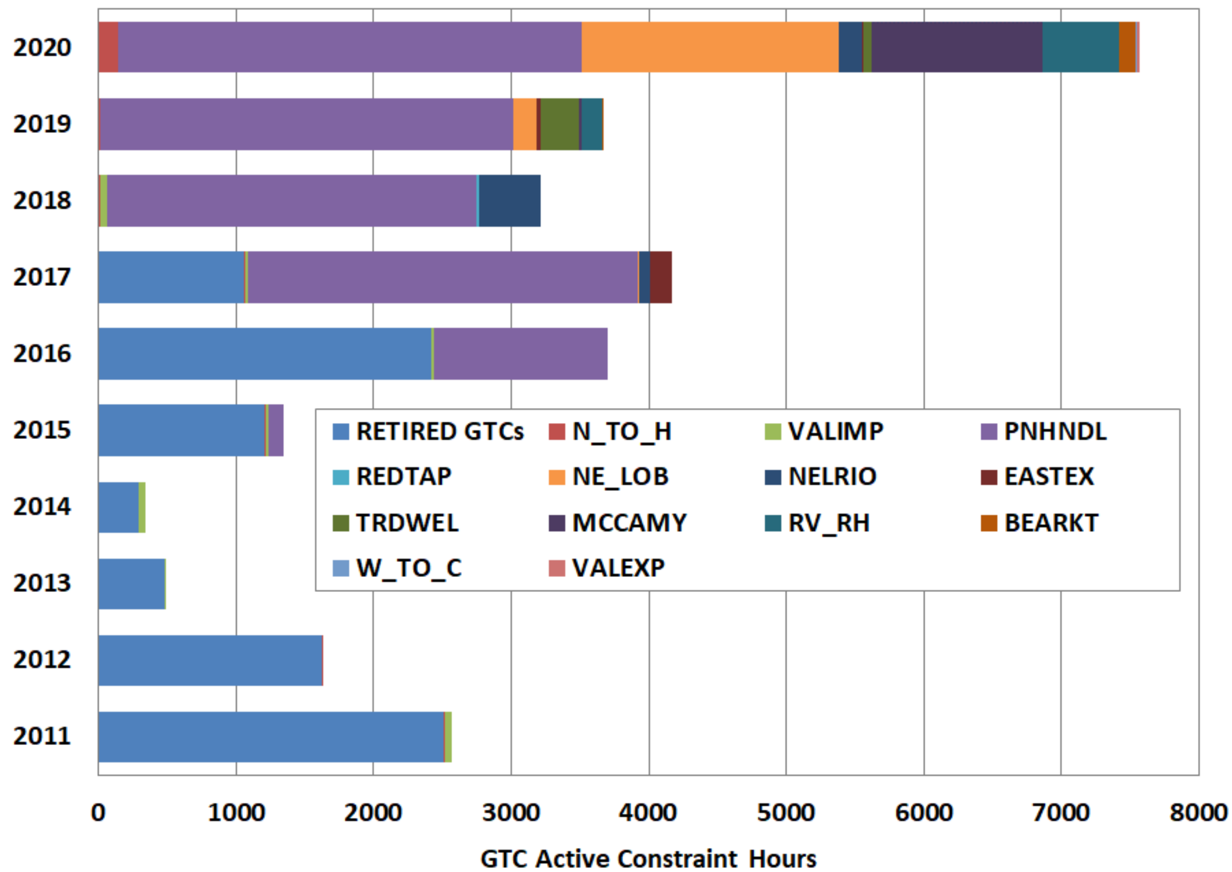
Table 5 below shows GTCs that were implemented and the number of binding intervals during 2019 and 2020.

Table 5: Generic Transmission Constraints

Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2019	# of Binding Intervals in 2020
North to Houston	December 1, 2010	-	37
Rio Grande Valley Import	December 1, 2010	-	-
Panhandle	July 31, 2015	15,352	24,762
Red Tap	August 29, 2016	-	-
North Edinburg - Lobo	August 24, 2017	59	8,230
Nelson Sharpe - Rio Hondo	October 30, 2017	-	524
East Texas	November 2, 2017	155	34
Treadwell	May 18, 2018	1,539	239
McCamey	March 26, 2018	3	5,660
Raymondville - Rio Hondo	May 2, 2019	385	1,703
Bearkat	November 20, 2019	14	354
West to Central	June 24 to Oct 1, 2020	-	-
Westex (replacing West to Central)	October 1, 2020	-	-
Zapata - Starr	Novemeber 5, 2020	-	-
Valley Export	Novemeber 5, 2020	-	65
Pigcreek Solstice	November 16, 2020	-	-

The frequency in which GTCs are binding is better shown in Figure 33 depicting the aggregate total of GTC binding constraint hours from 2011 to 2020. GTCs were binding more frequently in 2020 than in previous years.

Figure 33: GTC Binding Constraint Hours[30]



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

2. Real-time Constraints and Congested Areas

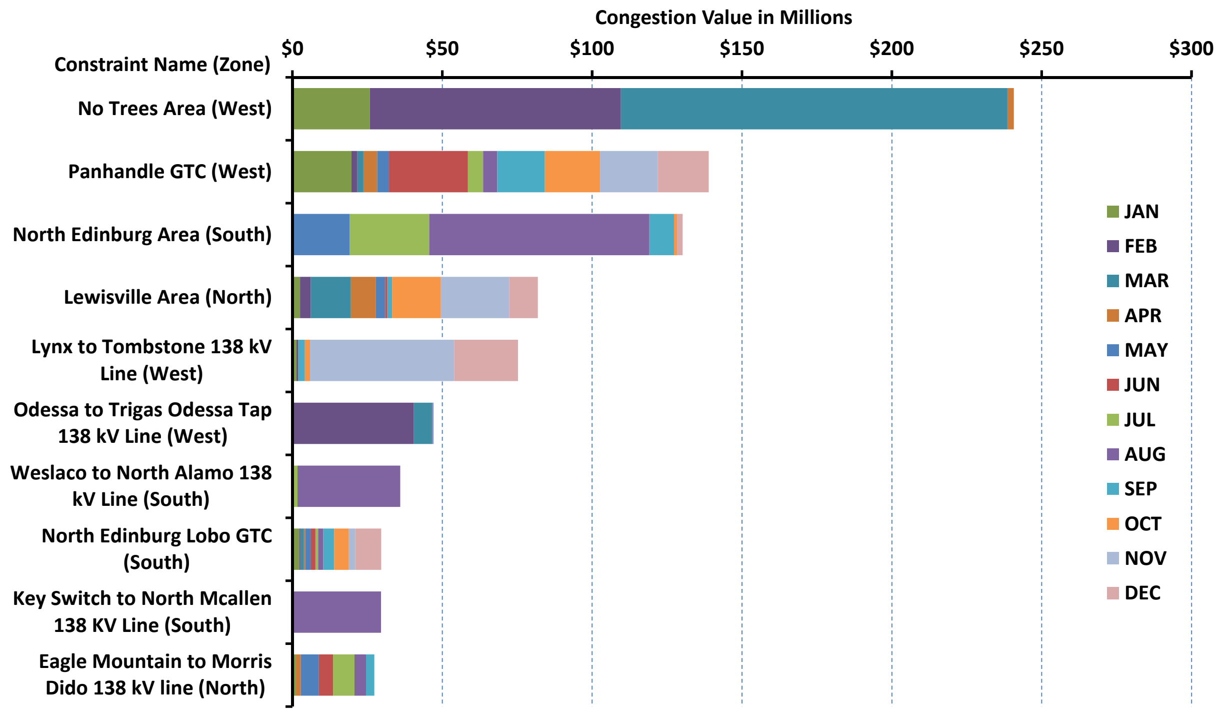
Our review of congested areas starts with describing the areas with the highest financial impact from real-time congestion. For this discussion, a congested area is identified by consolidating multiple real-time transmission constraints if the constraints are determined to be similar because of geographic 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

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

redispatch cost, defined as the marginal cost of the constraint (i.e., the dollar amount that would be avoided if the transmission element limit was 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.

There were 450 unique constraints that were either binding or violated at some point during 2020, with a median financial impact of approximately $220,000. In 2019, there were 450 unique constraints with a median financial impact of $197,000. Figure 34 displays the ten most costly real-time constraints with their respective zone measured by congestion value.

Figure 34: Most Costly Real-Time Congested Areas



The constraint with the highest congestion value in 2020 ($240 million) was the No Trees Area, consisting of the 138 kV lines Dollarhide to No Trees Switch and Andrews County South to Amoco Three Bar Tap. Much of the congestion value was generated on the line between Dollar Hide and No Trees Switch, which accounted for $193 million of real-time congestion. The congestion value associated with the No Trees Area in 2020 was $30 million less than the same congestion within the area in 2019. Most of this congestion occurred in January through April and was resolved with the 138 kV line upgrades in the area. However, the load growth from oil and gas development in Permian Basin, in conjunction with variable renewable output and outages required for transmission upgrades, continues to cause other congestion in the far west, such as Lynx to Tombstone 138 kV line and Odessa to Trigas Odessa Tap 138 kV line.

The second most costly constraint in 2020 was the Panhandle GTC constraint, which was mostly caused by planned outages, including ETT maintenance outages, in the area. The Panhandle constraint caused $140 million of congestion in 2020, a 30% increase from 2019. By the end of 2020, there was almost 4.6 GW of generation capacity in the Panhandle area, about 90% of which was wind generation. The GTC limit average for 2020 was approximately equivalent to 2019 at 3,200 MW. This average Panhandle GTC limit is attributable to the continued maintenance activity performed by Electric Transmission Texas (ETT) on its transmission structures located in the Panhandle, starting in 2017 and continuing through 2021. ETT continually monitors structures to find any additional damage and ETT has been providing updates to the market participants via the outage scheduler and market notices.

The congestion in Lewisville and Eagle Mountain has been a consistent concern as output from the Panhandle is deployed to meet the continuing load growth in the DFW area. ERCOT highlighted the aforementioned areas in the 2020 Long-Term System Assessment (LTSA) report within the ERCOT Constraints and Needs Report.[31] The report also mentions that congestion resulting from renewable output is linked to policy discussions around regional differences between the geographic location of generators and large loads. The congestion occurring in the South zone was due to the forced outages in the Rio Grande Valley from Hurricane Hanna in July 2020.

Day-ahead congestion costs were highest on the top three paths discussed above, with day-ahead congestion costs totaling roughly $456 million, somewhat less than the $510 million that accrued in the real-time market. This difference generally reflects the difference between expectations in the day-ahead market and actual real-time outcomes, and the fact that less wind generation is scheduled in the day-ahead market. Figure A34 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2020.

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 theoretically rise to infinity, resulting in unreasonable prices. When the dispatch model cannot find a solution to manage the constraint at a marginal cost less than the shadow

[31] See Report on Existing and Potential Electric System Constraints and Needs, December 2020; http://www.ercot.com/content/wcm/key_documents_lists/89026/2020_Report_on_Existing_and_Potential_Electric_System_Constraints_and_Needs.pdf

price cap, the constraint will be "irresolvable" or "in violation" in that interval, and the shadow price will be set at the cap.[32] The shadow price caps are:

- $9,251 per MW for base-case (non-contingency) constraints or voltage violations;
- $4,500 per MW for 345 kV constraints;
- $3,500 per MW for 138 kV, and
- $2,800 per MW for 69 kV thermal violations.

GTCs are considered stability constraints (for voltage or transient conditions) with a shadow price cap of $9,251 per MW.

Figure 35: Percentage Overload of Violated Constraints

presents the distribution of the percentage overload of violated constraints between 2019 and 2020. Violated constraints continued to occur in a small fraction of all the constraint intervals, 8% in 2020, down from 10% in 2019.

32 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.

Figure 35: Percentage Overload of Violated Constraints

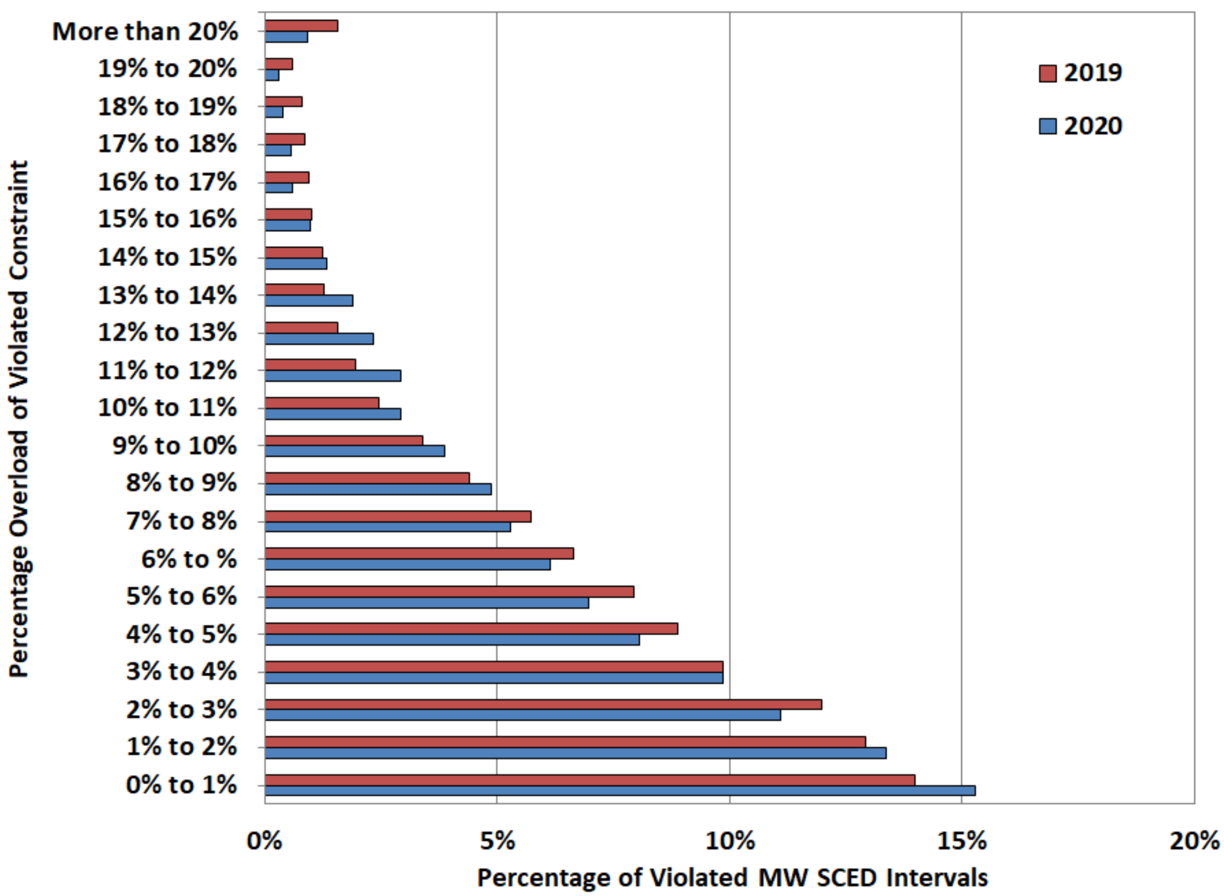


Figure 35: Percentage Overload of Violated Constraints

shows that the share of violated constraints in 2019 and 2020 were similar, with similar levels of severity of violations in both years as well. For example, none of the violated constraints levels in 2020 deviated by more than 1%, plus or minus, from the previous year. This suggests a maintained level of quality in ERCOTs ability to manage the flows in 2020.

Finally, 15% of the constraints were only slightly in violation (less than 1% of 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. Hence, we filed a revision request to implement transmission constraint demand curves.[33]

In general, violations can be resolved in subsequent intervals as generators ramp to provide relief. Nonetheless, a regional 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.[34] A more detailed review of the number of violated constraints can be found in Figure A33 in the Appendix. Table A4 in the Appendix shows that 16 elements were deemed irresolvable in 2020 and had a shadow price cap imposed according to this methodology.

C. CRR Market Outcomes and Revenue Sufficiency

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

1. CRR Auction Revenues

CRRs may be acquired in semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to 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 36 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-

33 Filed on January 21, 2020 by the IMM, OBDRR026, *Change Shadow Price Caps to Curves and Remove Shift Factor Threshold*, makes certain congestion management changes for contingency constraints. This OBDRR 1) changes the default Shadow Price caps to curves (the change lowers the value for small violations and raises the value for large violations); and 2) removes 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 proposes minor cleanup items and simplifications to Section 3, Elements for Methodology for Setting the Network Transmission System-Wide Shadow Price Caps.

34 See Section 3.6.1 of the business practice 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.

month long-term auctions ("forward"). The "ERCOT" category contains costs associated with constraints having sources and sinks in different zones (for example North to Houston).

Figure 36: CRR Revenues by Zone

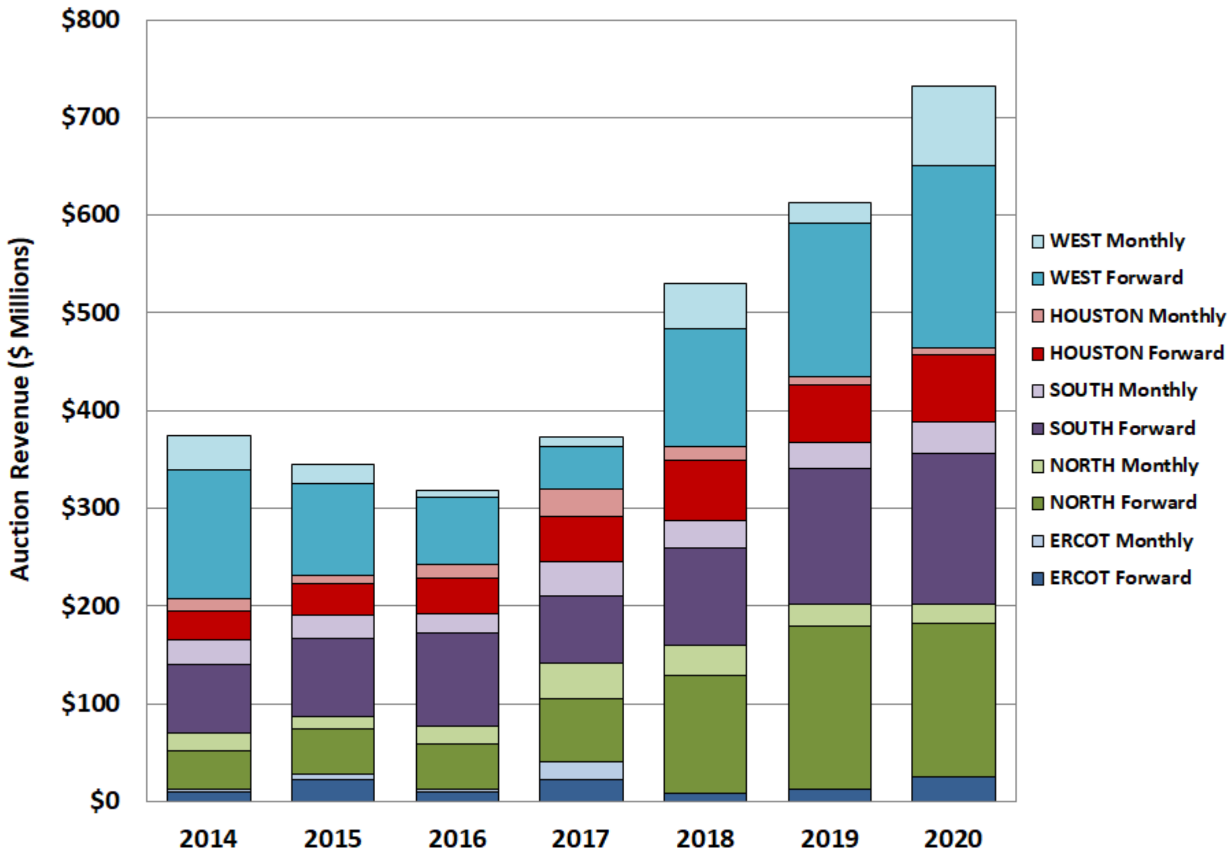


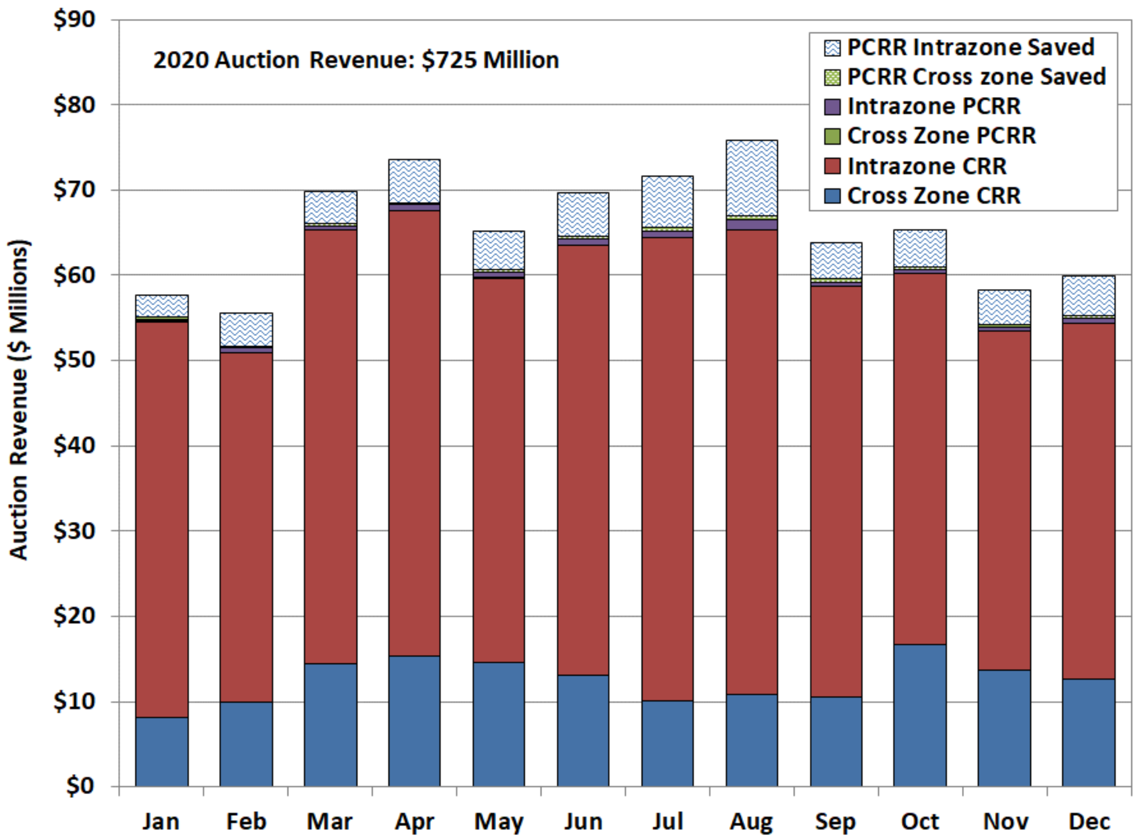
Figure 36 shows that aggregate CRR revenues have risen steadily since 2016. We note that all forwards for each of the categories increased between 2019 and 2020 except the North zone, whereas the monthly auction revenues either increased or decreased depending on zone. In general, monthly auctions will produce prices that reflect the most accurate expectations of actual congestion because they are closest to the operating horizon.

From early 2018 to early 2020, ERCOT was implementing third year CRR auctions for the first time.[35] These new auctions 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.

35 See NPRR 808: *Three Year CRR Auction*. Approved on April 4, 2017 and implemented on September 1, 2017, this NPRR extended the CRR Auction process into the third year forward; revised the percentages sold in the CRR Long-Term Auction Sequence; and made aligning changes to the timetable for modifying load zones. The first block containing months three years in the future was posted in April 2018, and the first full cycle completed in April 2020.

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 37 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.

Figure 37: 2020 CRR Auction Revenue



The total amount of CRR auction revenue increased to $725 million in 2020 from $612 million in 2019, while the total PCRR discount increased from $45 million in 2019 to $61 million in 2020. These increases reflect a yearly trend of an increased expectation of congestion in 2020.

2. CRR Profitability

CRRs are purchased well in advance of the operating horizon when actual congestion revenues are uncertain. Therefore, they may be purchased at prices below their ultimate value (based on CRR payments) and referred to as "profitable," or may be purchased at prices higher than their ultimate value and be "unprofitable". Historically, CRRs have tended in aggregate to be profitable. Although results for individual participants and specific CRRs varied, this trend continued in 2020 with participants again paying much less for CRRs they procured than their ultimate value. To evaluate these results, Figure 38 shows the monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the payout to the CRR owners.

Figure 38: CRR Auction Revenue, Payments and Congestion Rent

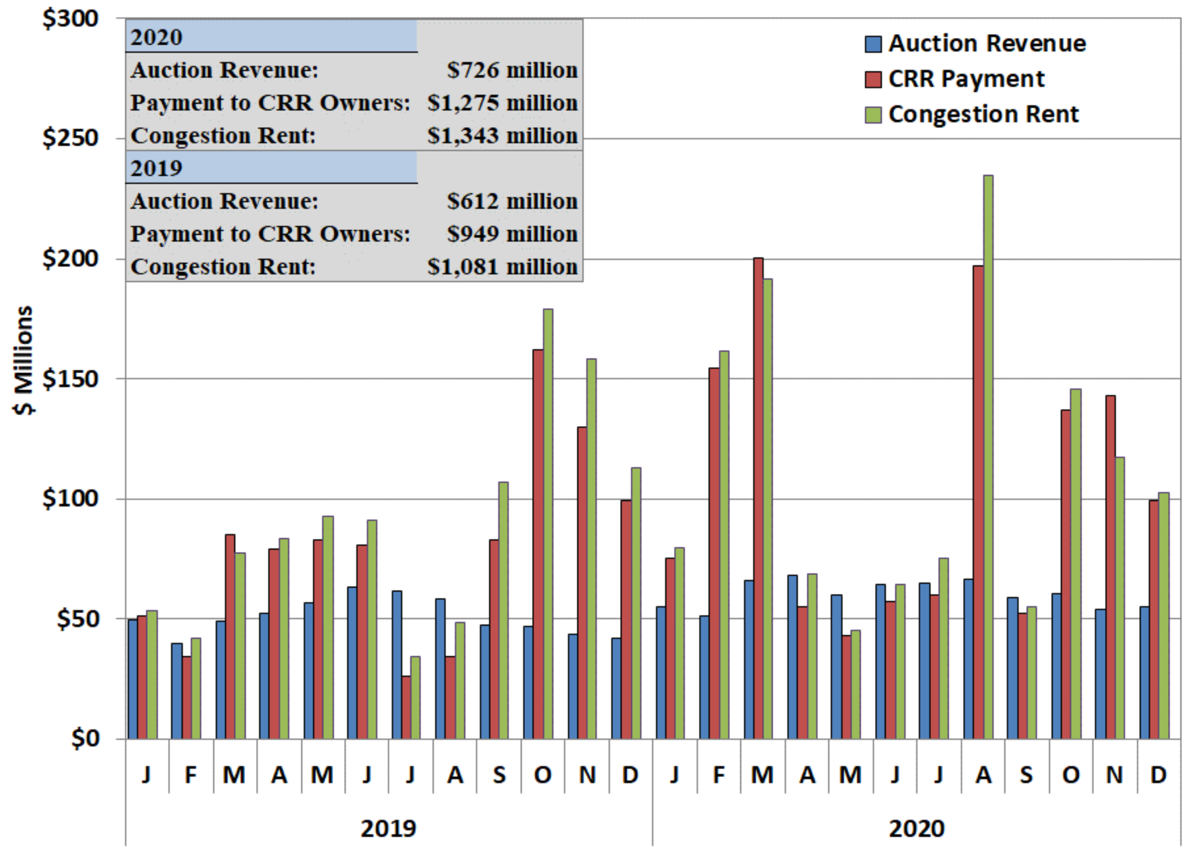
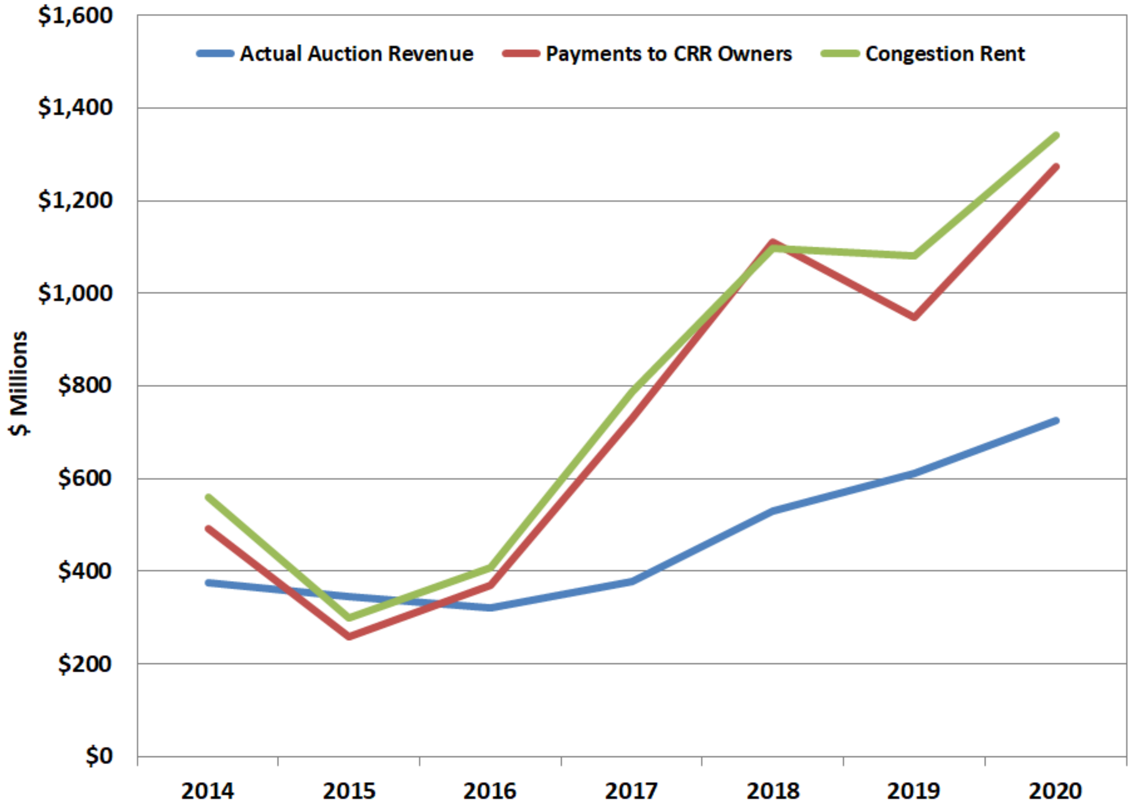


Figure 38 shows that for the entire year, participants spent $726 million to procure CRRs and in aggregate received $1,275 million, as shown in above. In general, this difference occurred because of the increase in congestion that occurred in 2020 was not foreseen by the market in the forward auction periods. The period of congestion that accounted for most of this difference was February, March, and August, which resulted in CRR payments that were $368 million higher than the auction revenue. 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 load growth in far West that drove up the congestion costs was likely not apparent. Conversely, the CRR auction revenue in some months was higher than the CRR payouts when congestion was milder than expected. This occurred in April through July and in September in 2020.

Finally, the payout can be less than the congestion rent collected in the day-ahead market when the quantity of CRRs sold is less than the day-ahead network flows. This occurred in 2020, when the payout in aggregate was approximately $68 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 39 provides the annual CRR auction revenues, payments to CRR owners and day-ahead congestion rent.

Figure 39: CRR History



In 2020, like the three 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 39 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 A35 in the Appendix shows the price spreads between all hub and load zones 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.

3. CRR Funding Levels

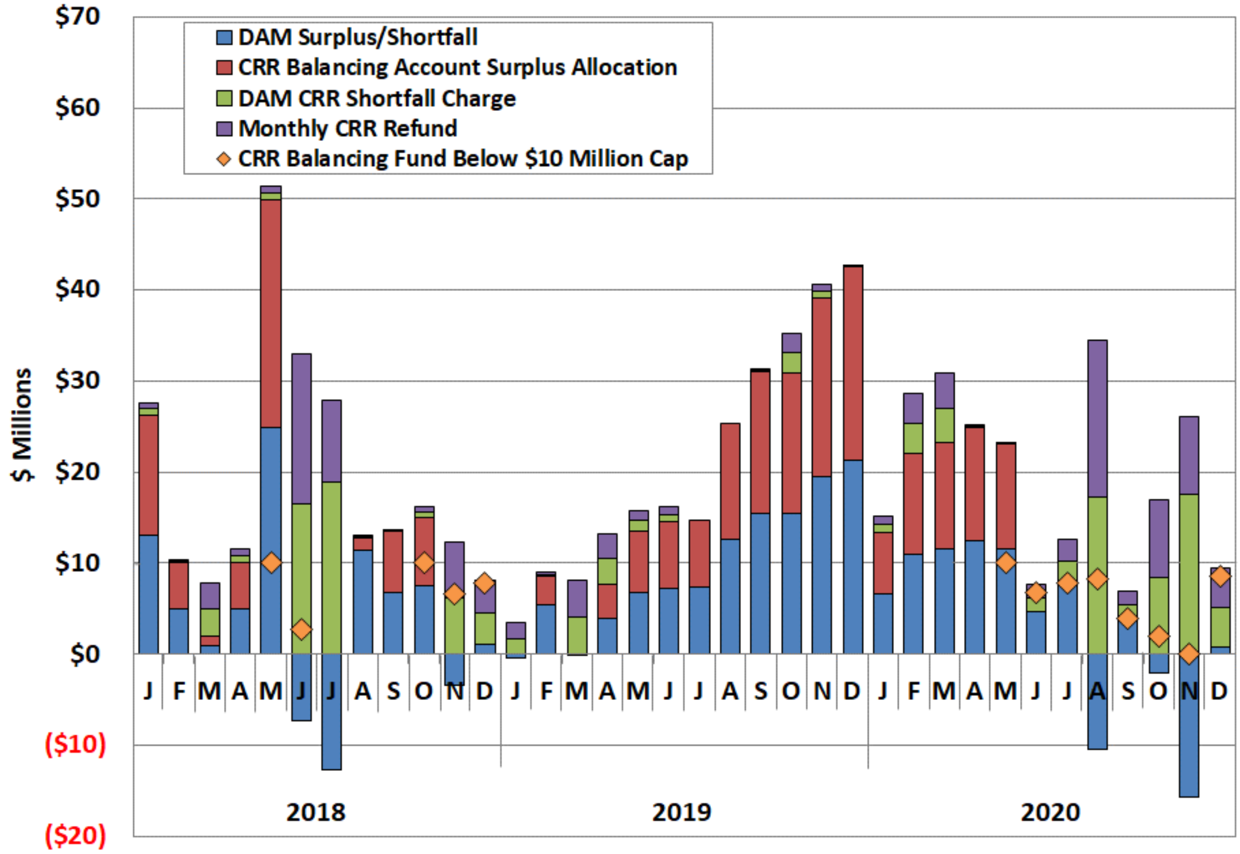
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payout to fully equal the target value because it makes the CRR more valuable to the holder and ultimately will increase the CRR auction revenues. While the target 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 day-ahead market, 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 40 shows the CRR balancing fund since the beginning of 2018. 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 40 shows that in 2020, despite this design, CRR holders experienced shortfalls in the latter half of the year due to outages that were not reflected in the CRR model. The total day-ahead surplus was nearly about $42 million, much lower than the surplus of $115 million in 2019. From the perspective of the load, the monthly CRR balancing account allocation to load totaled amount of $53 million at the end of the year.

Figure 40: CRR Balancing Fund



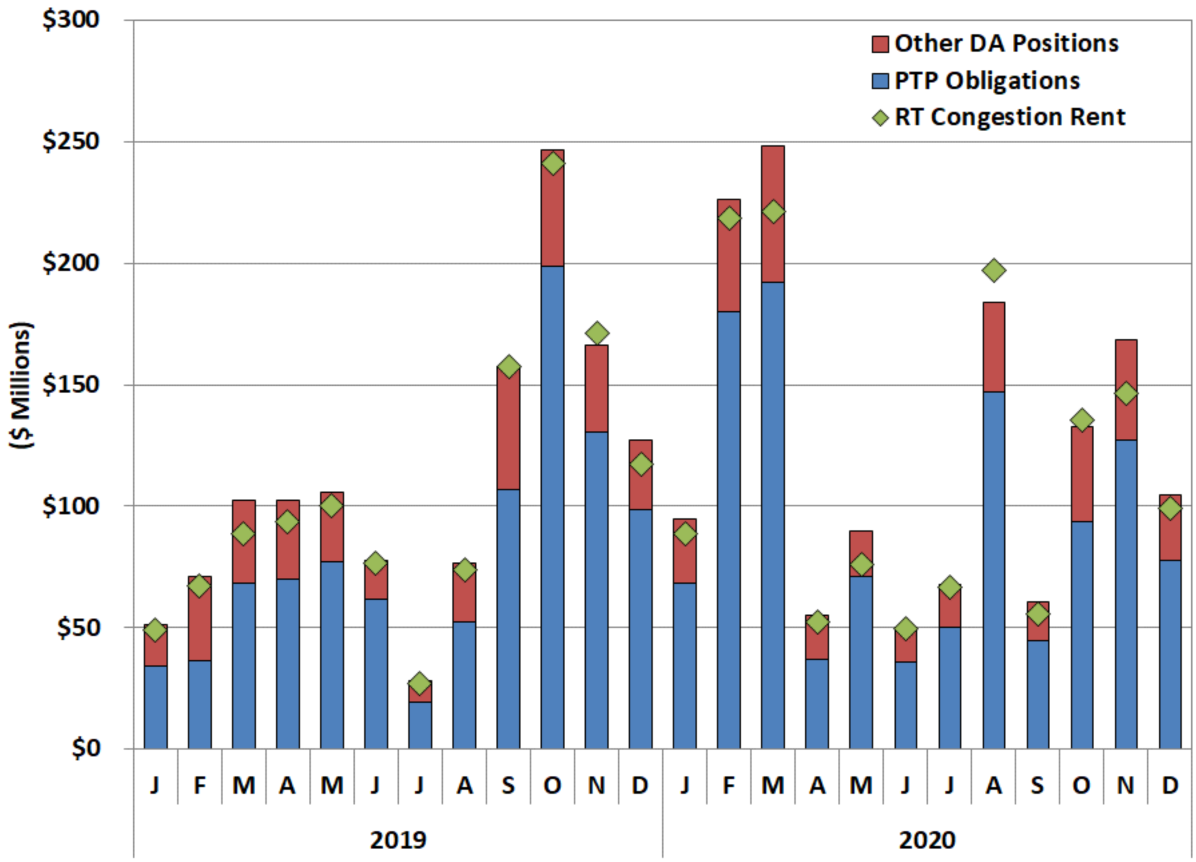
Importantly, even though the day-ahead market produced more than enough revenues to fully fund the CRRs, many CRRs were derated in 2020 and not paid the full target value due to the mandatory deration process. In total, CRR deratings resulted in a $24 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to 98%, slightly higher than the previous year. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A36 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.

4. Real-Time Congestion Shortfalls

Just as reductions in network capability from the CRR auctions to the day-ahead market can result in CRR shortfalls, reductions in the network capability between the day-ahead market and the real-time market can result in real-time congestion shortfalls. In addition to outages or limit changes, a binding real-time constraint that is not modeled in the day-ahead market can result in real-time congestion shortfalls. In summary, if ERCOT schedules more flows in the day-ahead market over the network than it can support in real time, it will incur cost to "buy-back" the flow. These real-time congestion shortfall costs are paid for by charges to load as part of the uplift charge known as "RENA".

The day-ahead schedule flows are comprised of PTP obligations and other day-ahead positions that generate flows over the network. Figure 41 shows the combined payments to all these day-ahead positions compared to the total real-time congestion rent.

Figure 41: Real-Time Congestion Rent and Payments



In 2020, real-time congestion rent was $1,406 million, while payments for PTP obligations (including those with links to CRR options) were $1,125 million and payments for other day-ahead positions were $355 million. This resulted in a shortfall of $74 million for the year.

By comparison, payments for PTP obligations and real-time CRRs were $954 million in 2020 and payments for other day-ahead positions were $359 million, resulting in a shortfall of approximately $49 million for the year. This represents an increase over 2019 but was still lower than 2018. 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 RTOs.

V. 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 day-ahead market informs these decisions but is only financially binding. That is, when a generator's offer to sell is selected (cleared) in the day-ahead market, there is no corresponding 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 clear 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 it deems necessary to ensure the reliable operation of the grid. In this way, ERCOT bridges the gaps between the economic decisions of its suppliers and the reliability needs of the system. In the event of these gaps, ERCOT uses its discretion to commit additional units to ensure reliability.

When ERCOT makes these reliability unit commitments (RUCs), the units become eligible for a make-whole payment, but also forfeit any market profit through a "clawback" provision. Generators complying with a RUC instruction are guaranteed to recover their costs, but any market revenue received over these 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) based on the low sustained limit of that resource that we described in Section I, which is intended to negate the price-lowering effects of the RUCs. In the past three years, ERCOT has 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 have caused the number of RUCs to drop dramatically, a trend that is expected to continue. For a complete list of the historical changes in the RUC processes and rules, see Section V in the Appendix.

In this section, we describe the outcomes of RUC activity in 2020. 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 hour-ahead basis. Additional resources may be needed for two primary reasons:

- To satisfy the forecasted system-wide demand (0% of RUC commitments in 2020); or
- To make a specific generator available resolve a transmission constraint (100% of RUC commitments in 2020).

This is the first year since the start of nodal market that the RUC commitment reasons were all issued to manage transmission congestion. However, the number of RUC instructions in 2020 was almost identical to the number in 2019:

- The 224 unit-hours of RUC instructions were issued in 2020, down only slightly from the 228 unit-hours in 2019 and again the lowest number of instructions since the start of the nodal market.
- 82% of the RUC instructions of 2020 were issued to generators in the south zone in late July and August as a result from the damage caused by Hurricane Hanna in July 2020.
- The balance of the RUC instructions were issued as follows: 88% in the South zone, 7% in the West zone, and the remaining 5% were issued in the North zone.

The low number of RUC instructed hours had minimal make-whole payments and clawback revenues. Table 6 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. If those charges are insufficient to cover all make-whole payments, the remaining make-whole amount is uplifted to all QSEs on a load-ratio share basis.

Table 6: RUC Settlement

	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

Table 6 shows that the make-whole payments rose to roughly $400,000 in 2020, an average level since the start of the market in 2011 (the average being about $380,000). This increase from 2019 was likely due to increased transmission congestion for which specific resources were needed for resolution. The clawback amount was slightly higher than the make-whole payment in 2020. 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. In 2020, approximately 8% of RUC units opted out, much lower than past years because of the high amount of congestion from forced outages in the aftermath of Hurricane Hanna, which made it difficult to predict the profitability of the "opt-out" ahead of time.

RUC Generators with Day-Ahead Offers. Generators that participate in the day-ahead market forfeit only 50% of markets revenues above cost through the clawback, rather than 100%. Given this incentive to offer in the day-ahead market, it is somewhat surprising that all units do not submit day-ahead offers. In 2020, 87% of the total RUC unit-hours had day-ahead offers, a sharp increase from 2019 when only 25% of the total RUC unit-hours had day-ahead offers, likely attributable to reliability needs of the grid after Hurricane Hanna in the Rio Grande Valley in July 2020.

Funding of RUC Payments. 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. If those charges are insufficient to cover all make-whole payments, the remaining make-whole amount is uplifted to all QSEs on a load-ratio share basis. RUC make-whole payments in 2020 were collected almost exclusively from QSEs that were capacity short, while the amount of make-whole that was uplifted to load was de minimis.

Section V 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 2020 because of the mitigation of some of the resources committed to resolve non-competitive constraints. That mitigation can effectively eliminate the $1,500 per MWh offer floor for those resources in those RUC intervals.

B. 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.

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 42 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 two years.

Figure 42: Capacity Commitment Timing – July and August Hour Ending 12 through 20

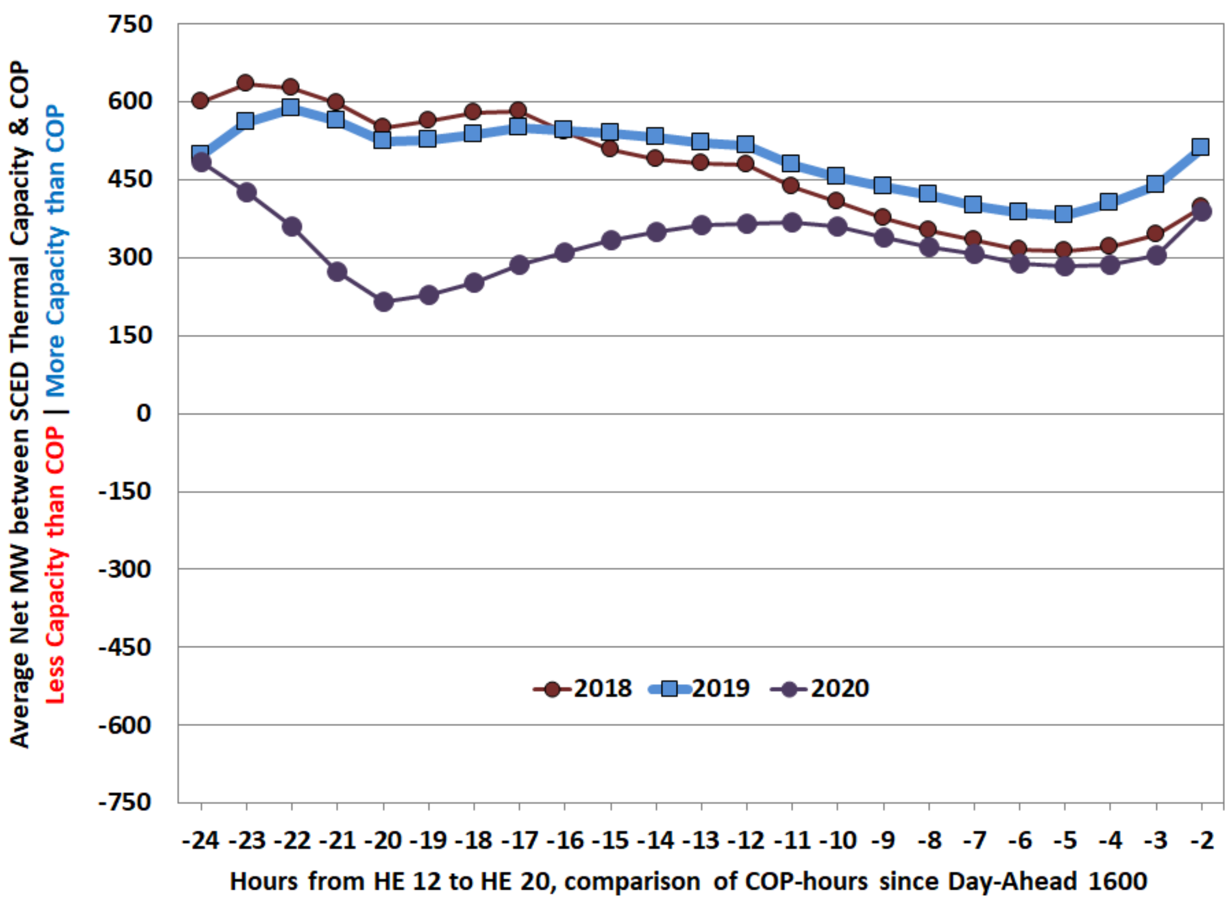


Figure 42 shows that the amount of online capacity needed exceeded the thermal capacity represented in COPs at the end of the adjustment period, signifying that generators changed their commitment decisions within the operating period. Commitment of resources for hours ending 12 to 20 show that 2020 had earlier commitments on average, approximately 20 hours before the operating hour. The difference in the last COP on average decreased from 500 MW in 2019 to 350 MW in 2020.

An average of the hours from hour-ending (HE) 12 through HE 20 masks the changes market participants may make closer to real-time. In 2019, when we focused on HE 17 during July and August, it was apparent that two QSEs (one a large supplier and one a NOIE) tended to make large changes to capacity commitments relative to their size shortly before the operating hour. This creates additional uncertainty for ERCOT operators as they fulfill their responsibility to ensure that sufficient capacity is available in the right locations to meet real-time requirements.

However, only a small portion of total RUC instructions were issued to ensure system-wide capacity sufficiency. This is testament to the restraint exhibited by ERCOT operators, allowing market participants to make their own commitment decisions, including the nearly 500 MW of near real-time thermal capacity commitments. The commitment decisions of both QSEs in 2020 indicate that they were able to represent COP capacity more accurately than they were in 2019, with COP capacity more closely aligning the with real-time capacity.

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

VI. 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 sufficient generation, 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 2020 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.[36] 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. Finally, we conclude with a discussion of the Reliability Must-Run (RMR) process in ERCOT in 2020.

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 day-ahead market 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 contracts, the spot prices produced in the real-time energy market should drive bilateral

[36] 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.

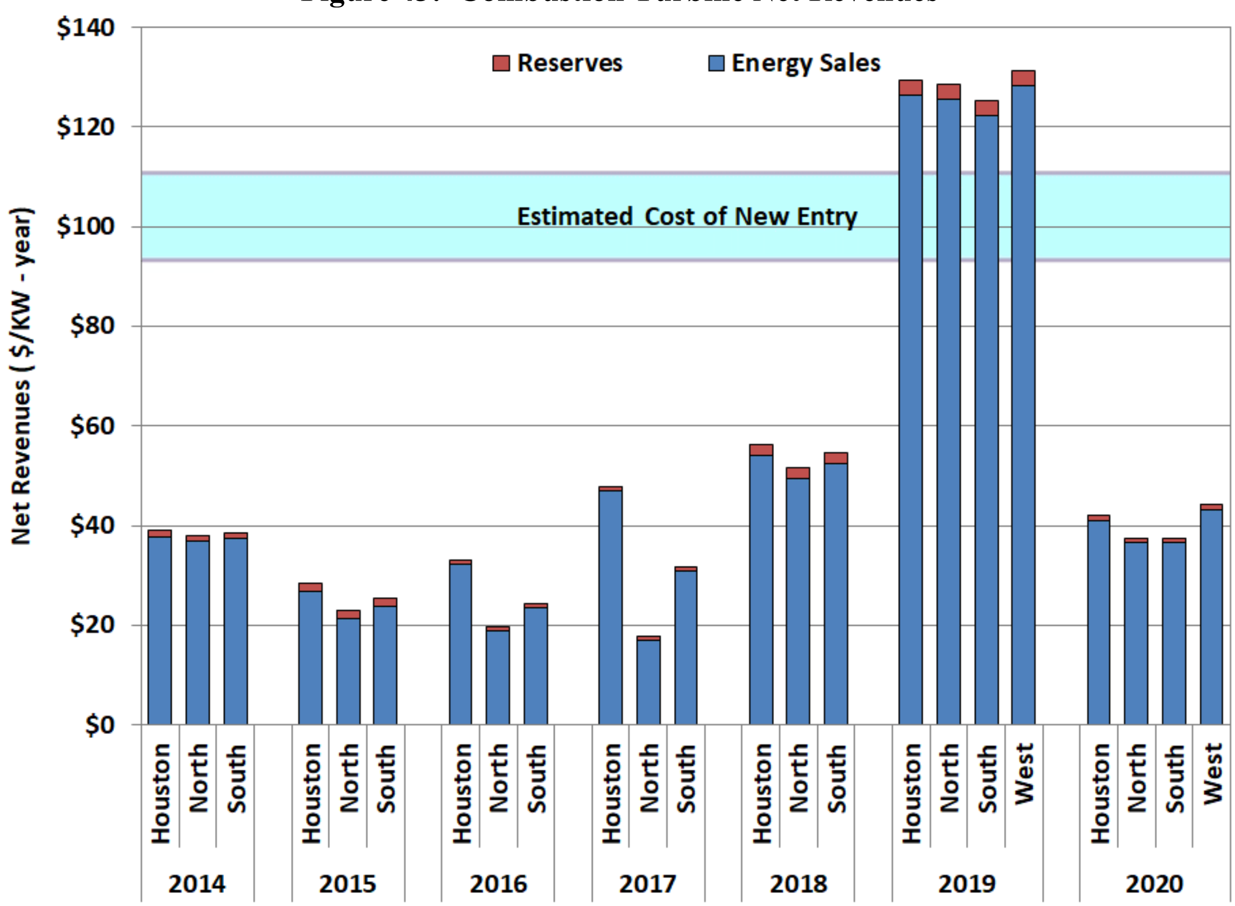
energy prices over time and thus are appropriate to use for this evaluation. It is important to note that this net revenue calculation is a look back at the estimated contribution based on actual market outcomes. Suppliers will typically base investment decisions on expectations of future electricity 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.[37] 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 two figures provide an historical perspective of the net revenues available to support investment in a new natural gas combustion turbine (

Figure 43) and combined cycle generation (Figure 44), which we selected to represent the marginal new supply that may enter when new resources are needed.

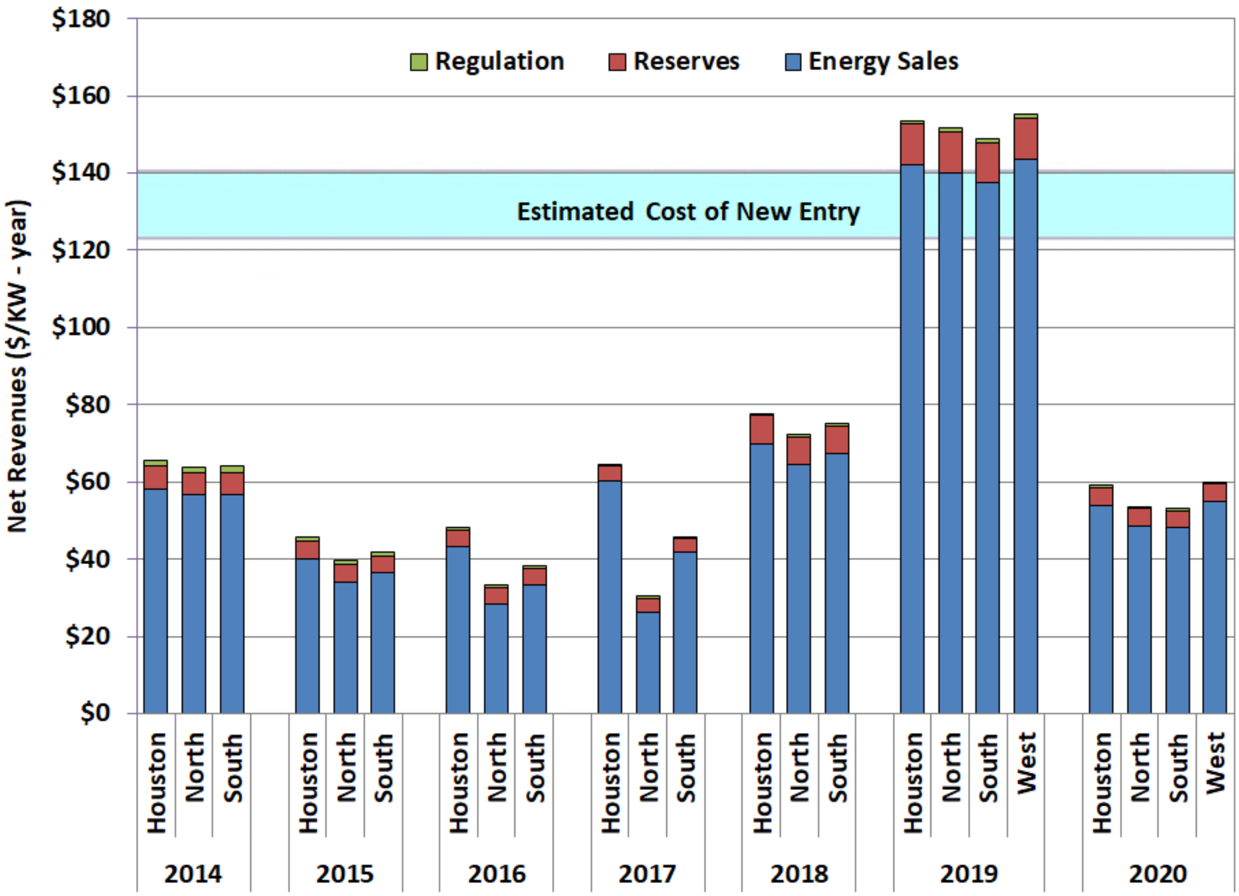
Figure 43: Combustion Turbine Net Revenues



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

We calculate net revenues for these units by assuming they will produce energy in any hour for 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 spinning or non-spinning reserves in other hours, and that combined cycle units can provide regulation.[38] The figures also show the estimated CONE for each technology for comparison purposes.

Figure 44: Combined Cycle Net Revenues



In 2020, 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. The ERCOT market did not provide net revenues above the CONE level needed to support new investment in 2020:

- Net revenues for combustion turbines fell to less than $37 per kW-year in the South zone to roughly $41 per kW-year in Houston; while
- Net revenues for combined-cycle units ranged from approximately $48 to $54 per kW-year, depending on the zone.

38 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.

These sharp decreases in net revenues back to 2018 levels were primarily caused by the absence of significant shortages in 2020, even with the additional adjustment to the ORDC in 2020. The decreases in the frequency of sustained shortages is consistent with the improving reserve margin going into the summer of 2020. 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, neither of which were present in 2020.

The figures above also show that average net revenues were highest in the West zone in 2020 as congestion led to higher prices in that zone. Variations in fuel prices were also an important factor 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 of the separation in natural gas prices between the Waha and Katy locations in the West. Increased drilling activity in the Permian Basin has produced a glut of natural gas and consequently, much lower prices at the Waha location, coupled with the COVID-19 oil demand shock in the spring of 2020. Waha prices dipped below $0 several times throughout 2020 and were much more volatile than prices at Katy.

Because of this lower fuel cost, generators served by the Waha location would have significantly higher net revenues than those procuring gas at Katy. In Section VI 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 $70 to $82 per KW-year at the Waha location, compared to net revenues of $43 to $55 per KW-year at Katy.

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 $25.73 per MWh. Table 7 shows the output-weighted average price by generation type based on the generator's specific locational price in 2020.

Table 7: Settlement Point Price by Fuel Type

Generation Type	Output-Weighted Price		
	2018	2019	2020
Coal	$33.31	$43.92	$24.84
Combined Cycle	$35.53	$47.06	$24.60
Gas Peakers	$71.64	$126.16	$60.26
Gas Steam	$66.09	$135.16	$41.90
Hydro	$34.40	$42.90	$23.88
Nuclear	$29.00	$35.38	$20.31
Power Storage	$103.19	$154.80	$80.50
Private Network	$34.41	$46.16	$24.08
Renewable	$39.84	$141.09	$35.23
Solar	$35.37	$61.45	$25.49
Wind	$19.26	$20.54	$11.45

Table 7 shows that the prices and associated net revenues were lower at all resources' locations in 2020 than the previous two years. This is again explained by the absence of significant shortage pricing in 2020.

Nuclear Profitability. According to data published by the Nuclear Energy Institute, the total generating cost for nuclear energy in the U.S. was $30.41 per MWh in 2019.[39] The 2019 total generating costs were 7.6% lower than in 2018, and nearly 32% below the 2012 costs. 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 $31 per MWh. The table above shows an average price for the nuclear units of approximately $20 per MWh making it likely that the nuclear units in ERCOT are not profitable in 2020.

Coal Profitability. The generation-weighted price of all coal and lignite units in ERCOT during 2020 was $24.84 per MWh, a decrease from $43.92 per MWh in 2019. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.55 per MMBtu in 2020, similar to 2019. At these average fuel prices, coal units in ERCOT are likely receiving more than enough revenue to cover operating costs.

Natural Gas-Fired Resource Profitability. Figure 45 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 only for the Houston zone to reflect Katy hub prices and the West zone for Waha. This figure also underscores the effects of the increase in natural gas production in the Permian Basin with insufficient transportation capacity to export the natural gas. This has resulted in low gas prices at the Waha location, and much higher net revenues for these gas resources. New transportation projects have been identified and are currently underway so it is unclear how much longer the large basis difference in natural gas prices will continue.

[39] https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context

Figure 45: Net Revenues by Generation Resource Type

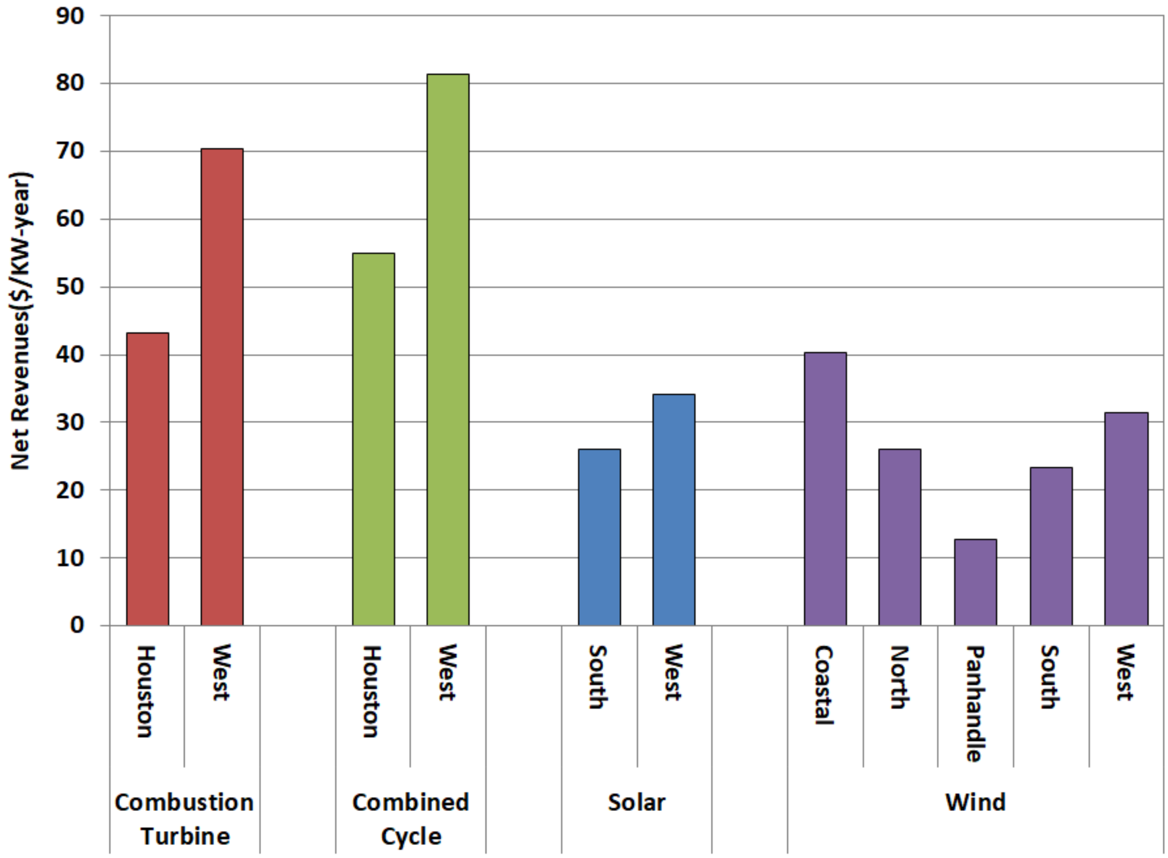


Figure 45 also shows the net revenues for wind and solar generation at multiple locations. As the cost to install wind or solar does not vary much by location, the profitability of those resources is chiefly determined by the available natural resource and the prevailing price to be received. Net revenues for wind and solar were less than gas technologies in 2020 in all areas. This is partly because intermittent technologies cannot maximize its output and associated revenues during shortage conditions. This is particularly true for wind resources that tend to produce less output during hot summer conditions.

Interpreting Single-Year Net Revenues. These results indicate that on a stand-alone basis during 2020, the ERCOT markets did not provide sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Net revenues were down as result of lower shortage pricing in 2020 than in 2019. Investors' response to these prices will depend on whether they expect them to reoccur in the future. Additionally, investors may invest instead in new technologies, such as battery energy storage or load-flexible renewables, which have different value propositions from traditional generation. Ultimately, investment decisions are driven by multiple factors:

- Historical net revenue analyses do not provide a view of the forward price expectations that will spur new investment, which can vary widely by supplier. For example, small differences in expectations about the frequency of shortage pricing can greatly influence revenue expectations.

- Bilateral contracts may offer additional revenue because they allow risk-averse buyers to hedge against high shortage pricing.
- Prices and revenues over multiple years may fluctuate in a manner than causes average expected net revenues to be quite different than the net revenues in any one year.
- The CONE for any particular project may be quite different than the generic CONE values we have derived based on average development costs in the Texas market on undeveloped greenfield sites. Companies may have opportunities to build generation at much lower cost than these estimates because of lower cost equipment, access to an existing site, or access to superior financing.

For all these reasons, it is important to be cautious in interpreting single-year net revenues and projecting their long-term effects. Please see Section VI 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.

Prior to the summer of 2018, there were expectations by many market participants of shortage driven prices in the ERCOT market that mainly went unrealized. Significant shortages were not realized until 2019, due in some part to the impact of the first step of the ORDC change. 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;
- Loads investing in systems and procedures to enable non-consumption during shortage pricing events (demand response).

In 2020, there were no such expectations of shortage conditions, and that expectation bore out. There were also circumstances that were unique to 2020, such as the COVID-19 pandemic quarantine and relatively moderate summer weather conditions. 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 2019 Capacity, Demand, and Reserves (CDR) report, the 2020 summer reserve margin was projected to be 10.6%, up slightly from 10.5% from the May 2019 CDR report.[40] ERCOT adjusted its peak load forecast to 75,200 MW to account for economic impacts related to COVID-19 and the planning reserve margin for summer 2020 ultimately increased to 12.6% based on the resource updates in the final summer 2020 SARA report.[41] Recent market outcomes and pre-existing investment plans are causing expected increases in the planning margins. Figure 46 shows ERCOT's current projection of planning reserve margins.

Figure 46: Projected Planning Reserve Margins

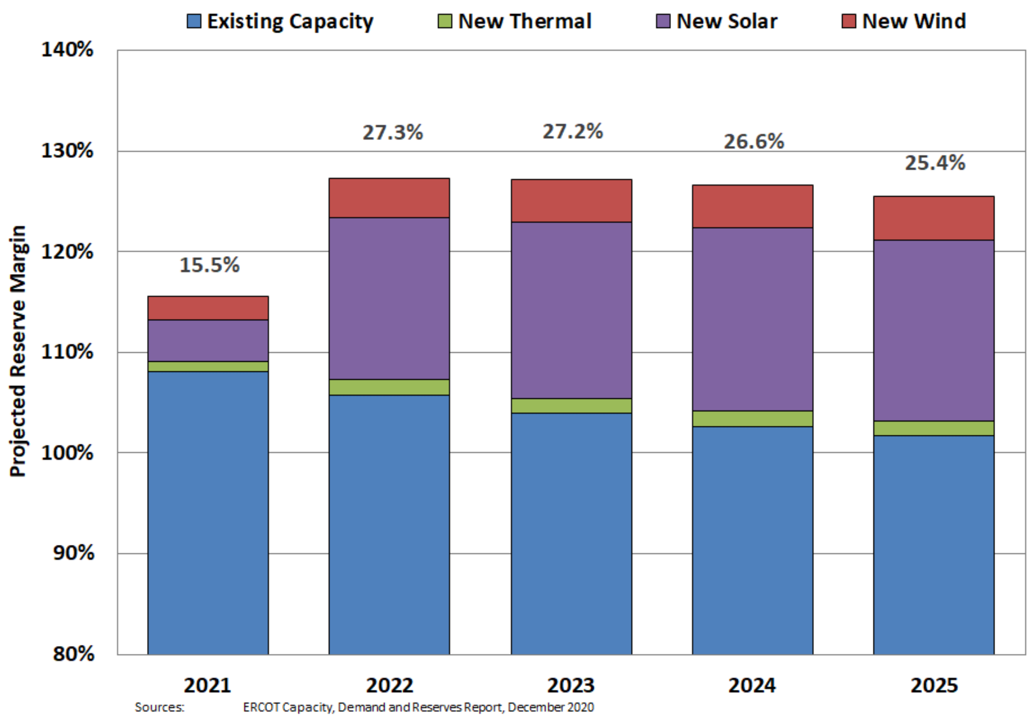


Figure 46 indicates that Texas heads into the summer months of 2021 with an improved reserve margin of 15.5%, higher than the 12.6% reserved margin for 2020. It is worth noting that the current methodology of performing the CDR does not consider power storage resources (e.g., batteries). Including storage resources would increase the reserve margin, potentially by a greater amount than planned thermal generation. Ensuring that the market can efficiently price and dispatch energy from newer technologies will become increasingly important. In addition,

40 See Report on the Capacity, Demand and Reserves in the ERCOT Region, 2019-2028 (December 5, 2019), http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReserveReport-Dec2019.pdf

41 See Seasonal Assessment of Resource Adequacy (SARA) (May 13, 2020), http://www.ercot.com/content/wcm/lists/197378/SARA-FinalSummer2020.pdf.

the CDR relies solely on hour ending 5 p.m. (as the peak hour), when the peak net load hour is likely a more accurate predictor of scarcity conditions, particularly as solar generation continues to be added to the ERCOT system.

The range of planning reserve margins going into 2020 and beyond are consistent with expectations for ERCOT's energy-only market. On December 1, 2020, ERCOT filed a draft report with the Commission titled "*Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*."[42] The report estimates the Market Equilibrium Reserve Margin (MERM) and Economically Optimal Reserve Margin (EORM) for ERCOT's wholesale electric market with projected system conditions for 2024. ERCOT retained Astrapé Consulting to perform a study, and Astrapé calculated a MERM of 12.25% under projected 2024 market conditions. This was higher than the MERM projection of 10.25% in the 2018 study, however, the projections of system reliability were nearly identical at 0.5 Loss of Load Expectation.

Finally, with growing installed reserve margins for summer of 2020, the retirement of uneconomic generation should be viewed as essential to resource adequacy. Facilitating efficient decisions by generators to retire uneconomic units is nearly as important as facilitating efficient decisions to invest in new resources. With expectations for future natural gas prices to remain low, the economic pressure on coal units in ERCOT is not expected to subside soon. American Electric Power's (AEP) 650 MW Oklaunion coal unit was permanently decommissioned on October 1, 2020, which accounted for 5% of ERCOT's summer coal capacity.

D. Effectiveness of the Shortage Pricing Mechanism

One of the primary goals of an efficient and effective 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 long-term 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, which we evaluate in this subsection.

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42 The final version of the report, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024*, was published on January 15, 2021; http://www.ercot.com/content/wcm/lists/219844/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf.

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 the value of lost load.

Shortage pricing in ERCOT occurs through the ORDC, implemented in 2014 to ensure electricity prices more accurately reflect shortage conditions. The ORDC is described above in Section I: Review of Real-Time Market Outcomes. 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. For a variety of reasons discussed throughout this report, the impact on 2020 real-time prices was more muted.

The ORDC automatically increases the price of power as reserves get tighter. The ORDC adder reflects the Value of Lost Load (VOLL), which was set to $9,000 per MWh in June 2014. The real-time prices determined by Security Constraint Economic Dispatch (SCED) 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.

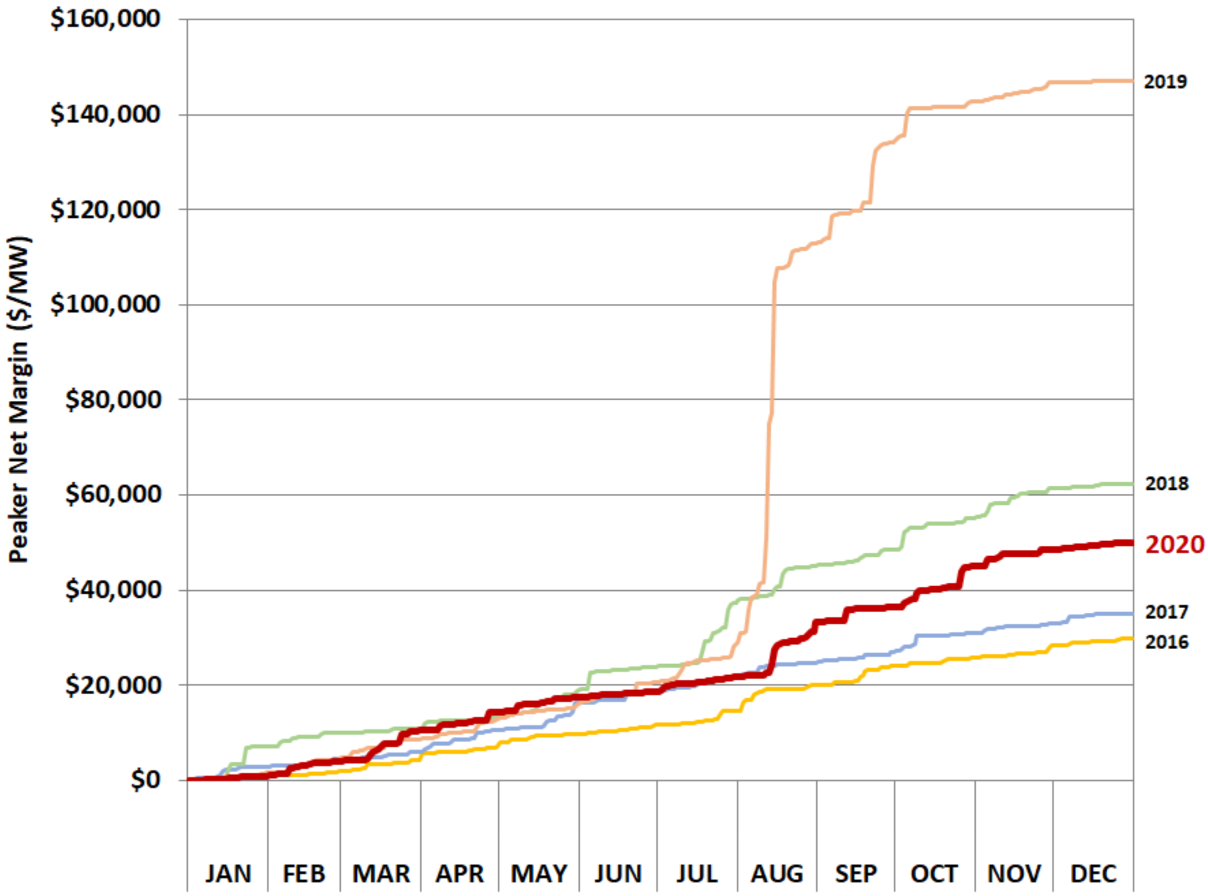
The Scarcity Pricing Mechanism includes a provision termed the Peaker Net Margin (PNM) that is designed to provide a pricing "fail-safe" measure. If the PNM is exceeded, the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[43] Section I contains several summaries and discussions of the shortage pricing that occurred in 2020. The next section, however, reviews pricing in 2020 showing the PNM in 2020 compared to prior years.

2. Peaker Net Margin in 2020

Figure 47 shows the cumulative PNM results for each year since the creation of the Scarcity Pricing Mechanism. This figure shows that PNM in 2020 was middling, higher than both 2016 and 2017 but far below the high of 2019. PNM was initially defined to provide a "circuit breaker" trigger for lowering the system-wide offer cap. However, as of the end of 2020, PNM had not approached levels that would dictate a reduction in the system wide offer cap, even after 2019, when it reached the highest level to date. The PNM outcomes in 2020, significantly lower than 2019, only reinforce that position.

[43] 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.

Figure 47: Peaker Net Margin



3. Changes to the ORDC

The Commission directed a significant change to the ORDC in 2019. The Commission considered proposals modifying various defining aspects of the ORDC, including shifting the LOLP portion of the curve.[44] 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").[45] On January 17, 2019, the Commission approved a two-part process to modify the ORDC by implementing a .25 standard deviation shift in the LOLP calculation and transitioning to a single blended ORDC curve, and a second step of .25 in the spring of 2020. The second step of the ORDC change was implemented on March 1, 2020 and we have estimated the effects in 2020. These results are shown below in Table 6.

44 See PUCT Project No. 48551, *Review of Summer 2018 ERCOT Market Performance*.

45 MU and Sigma are separately calculated for each of the twenty-four curves currently used (six time of day blocks and four seasons).

Table 8: Effect of ORDC Shift on Price

	Average RT price $ per MWh	ORDC contribution $ per MWh	ORDC Price increase $ per MWh	Percent increase %	Total RT Market Cost $ in Millions	RT Market Cost Increase $ in Millions
January	17.82	0.02	0.01	0.04	516	0
February	25.28	0.24	0.11	0.45	706	3
March	31.14	1.21	0.52	1.66	874	15
April	21.01	2.84	1.18	5.64	564	32
May	20.73	1.22	0.53	2.56	645	17
June	16.13	0.07	0.03	0.21	569	1
July	21.65	1.45	0.68	3.15	869	27
August	43.13	13.64	5.17	11.98	1,751	210
September	23.23	1.96	0.79	3.39	759	26
October	34.18	4.56	2.03	5.92	1,065	63
November	26.65	0.63	0.28	1.06	725	8
December	21.32	0.08	0.04	0.18	645	1
Total	25.48	2.62	1.06	4.15	9,688	402

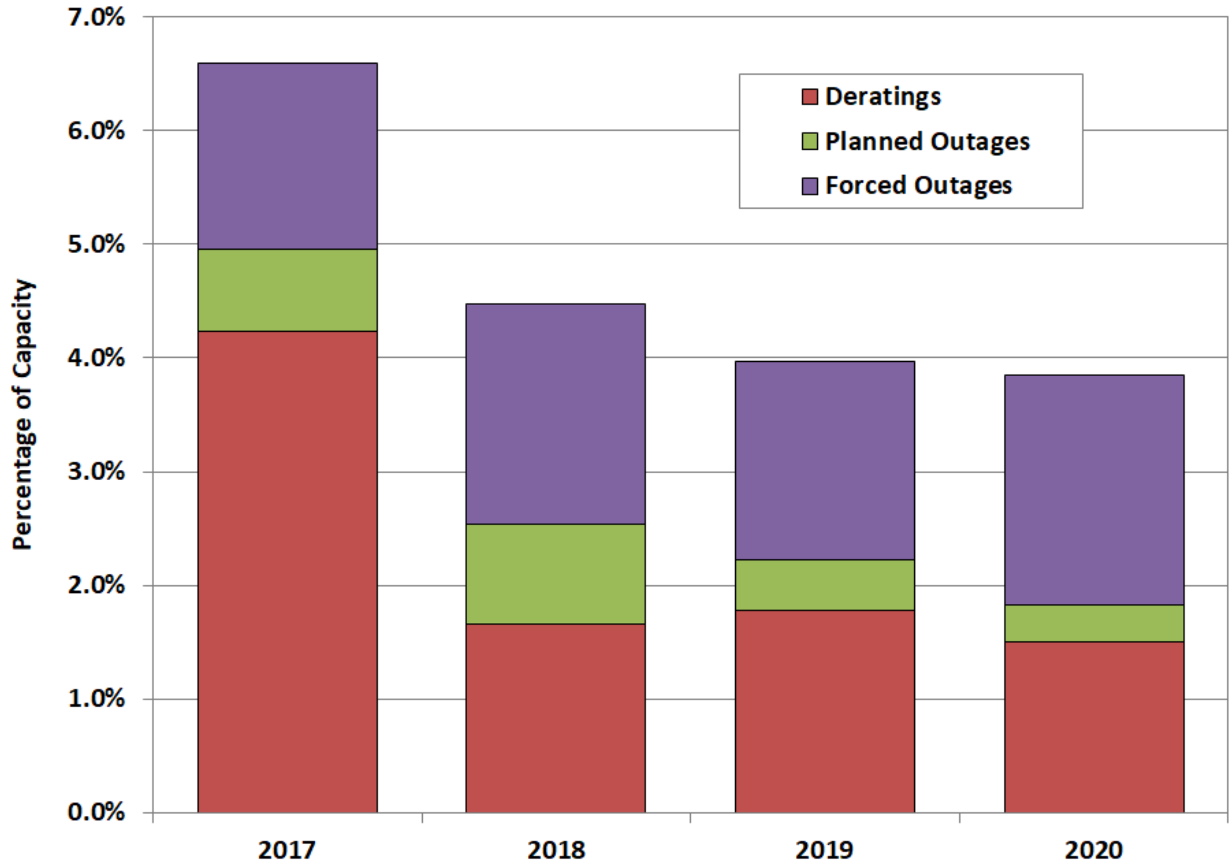
Table 8 above shows that the 2020 second step ORDC change increased the effects of shortage pricing by an estimated 4% -- increasing the total impact of the ORDC on average prices by $1 per MWh. This led to increased market costs and revenues to generators of roughly $400 million in 2020. Because planning reserve margins rose as projected in 2020, shortage pricing fell well short of 2019 levels. The first step of the ORDC change, particularly blending the curves, was a significant driver of the higher impact realized in 2019. No further changes to the ORDC are scheduled prior to the implementation of real-time co-optimization, when the ORDC will be retired.

4. Short-Term Effects of Shortage Pricing in 2020

In addition to the long-term incentives that shortage pricing creates to facilitate investment and retirement decisions, it also creates important short-term incentives. For example, it creates a strong incentive for generators to be available at the times when they are expected to be needed most. Figure 48 shows the level of outages and deratings that have occurred during summer peak conditions over the past four years.

This figure shows that as expectations of shortages remain strong, outages have decreased substantially, even as the planning reserve margin rebounded in 2020. Most of these outage reductions were in planned outages and deratings, the class for which the suppliers have the most control. These results demonstrate that the suppliers in ERCOT respond to price signals and associated incentives.

Figure 48: Summer Month Outage Percentages



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.[46] A Reliability Must Run (RMR) Unit is a resource operated under the terms of an agreement with ERCOT that would not otherwise be operated except that 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.

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

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 2020.[47] 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 2020.[48] However, review of the RMR and MRA evaluation processes continued in 2020, resulting in the approval of Nodal Protocols Revision Request (NPRR) 964, which removed the term Synchronous Condenser Unit from the Protocols, and clarified the ERCOT evaluation process related to reliability analysis and aligns the review process of a seasonal mothball unit with non-seasonal mothball unit.[49]

47 Petra Nova Power I LLC - PNPI_GT2; South Texas Electric Cooperative Inc. - RAYBURN_RAYBURG1 and RAYBURN_RAYBURG2; Luminant Generation Company LLC - TRSES_UNIT6; Wharton County Generation, LLC - TGF_TGFGT_1; City of Austin dba Austin Energy - DECKER_DPG1; Nacogdoches Power LLC - NACPW_UNIT1; City of Garland (RE) - SPNCER_SPNCE_4 and SPNCER_SPNCE_5; and Gregory Power Partners, LLC (RE) - LGE_LGE_GT1, LGE_LGE_GT2, and LGE_LGE_STG.

48 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.

49 NPRR964, *Improvement of RMR Process and Removal of Synchronous Condenser Unit and Agreement*.

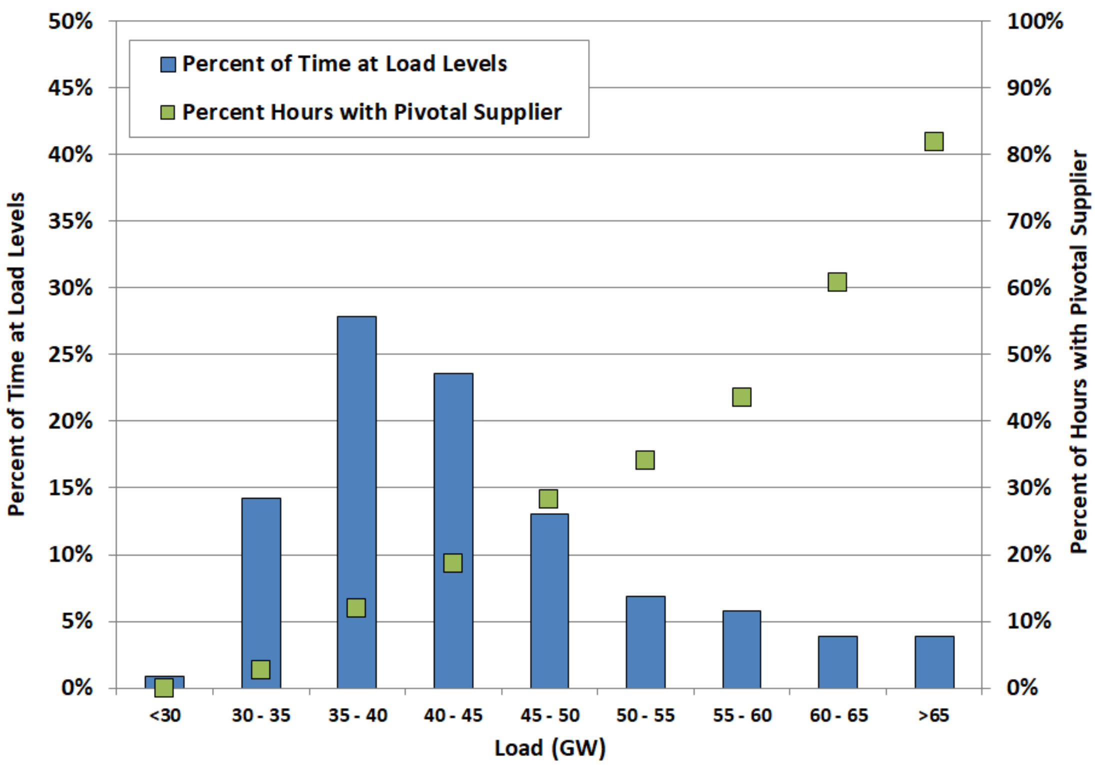
VII. Analysis of Competitive Performance

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 also includes a summary of the Voluntary Mitigation Plans in effect during 2020. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2020.

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 49 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 49: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW, there was a pivotal supplier approximately 82% of the time. This is high percentage expected because at high load levels the largest suppliers are more likely to be pivotal as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed 22% of all hours in 2020, which was on par with 2019 when pivotal suppliers existed in 24% of all hours. Even with this small 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 analysis is presented in Figure A46 in the Appendix.

We cannot make inferences regarding market power solely from pivotal supplier data. 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. The pivotal supplier results shown in the previous figure does not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

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 V, this local market power is addressed through: (a) structural tests that determine "non-competitive" constraints that can create local market power; and (b) the application of limits on offer prices in these areas.

B. Evaluation of Supplier Conduct

This subsection provides the results of our evaluation of actual participant 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. We then examine potential physical and 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 will generally be 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 only if the withholding firm's incremental profit as a result of higher price is greater than the lost profit from the foregone sales of 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 V above, summer availability has been increasing since 2017 in ERCOT because of the incentives provided by the recent increase in shortage pricing as well as a decline in summer outages.

Figure 50 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2020. 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 50: Reductions in Installed Capacity

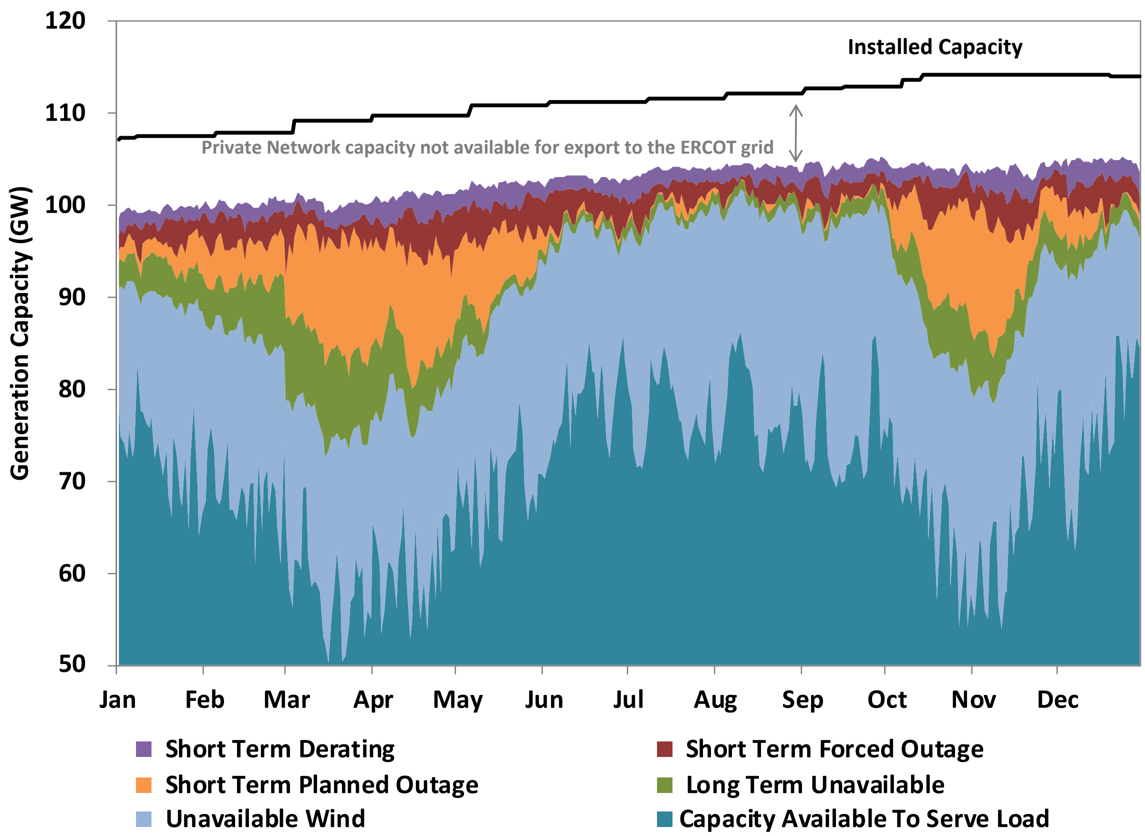


Figure 50 shows that short-term outages and deratings of non-wind generators fluctuated between 1.4 to 21.4 GW, while wind unavailability varied between 7.5 and 30 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent with our expectations. Short-term forced outages and deratings had no discernable seasonal pattern, occurring throughout the year, also consistent with our expectations. The quantity of long-term (greater than 30 days) unavailable capacity, peaked in March at more than 10 GW, with almost all capacity returned to service in anticipation of warm temperatures in the summer of 2020.

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 51 provides a comparison of the monthly outage and derating values for 2019 and 2020.

Figure 51: Derating, Planned Outages and Forced Outages

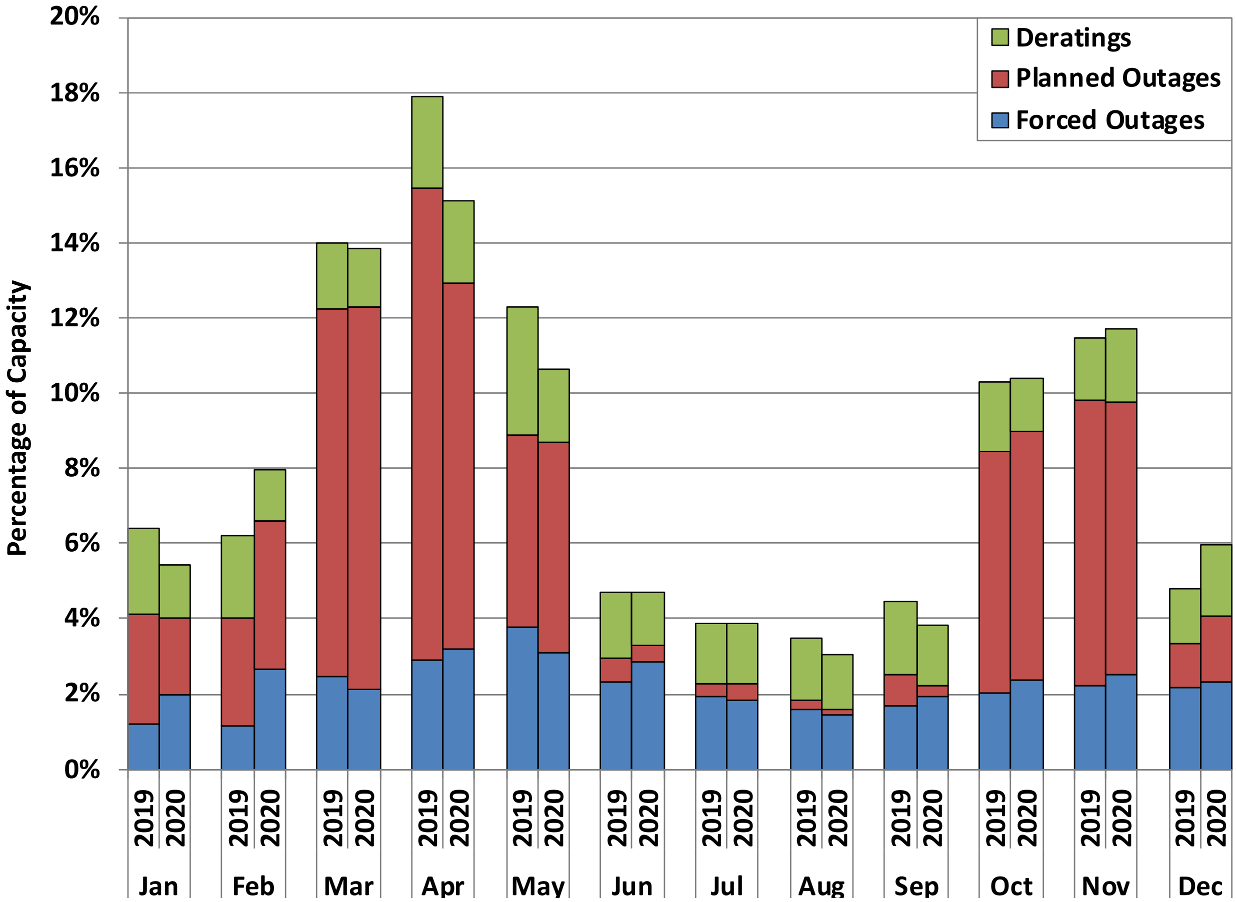


Figure 51 shows a general consistency of forced outages from last year, implying that expectations for 2020 were similar to those in 2019, and that generator operators were again able to defer the impacts of unexpected equipment limitations through September. However, those actions likely were at the cost of higher outage rates in October and November both years. 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 scarcity pricing is the highest. The consistently small number of deratings across all months of 2020 indicates that generators were intent on maximizing generator availability. The low outage rates during August 2020, even lower than those in August 2019, 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 outages and deratings lasting less than 30 days for the year and for each month during 2020.

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 49 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 52 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 52: Outages and Deratings by Load Level and Participant Size, June-August

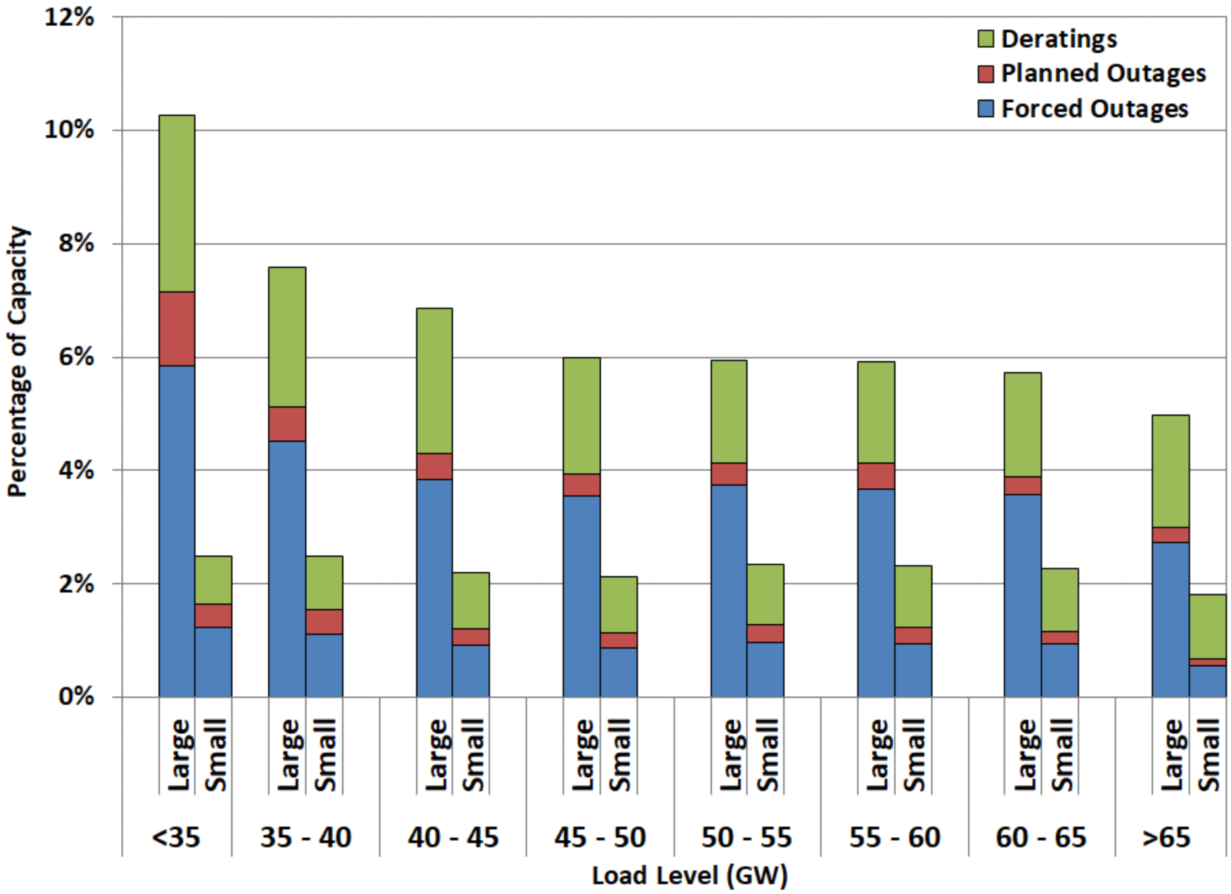


Figure 52 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, 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. Outages rates for small suppliers were historically low in 2020, while large suppliers were up minimally from 2019. 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.

3. Evaluation of Potential Economic Withholding

To complement the prior analysis of physical 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 53: Incremental Output Gap by Load Level and Participant Size – Step 2

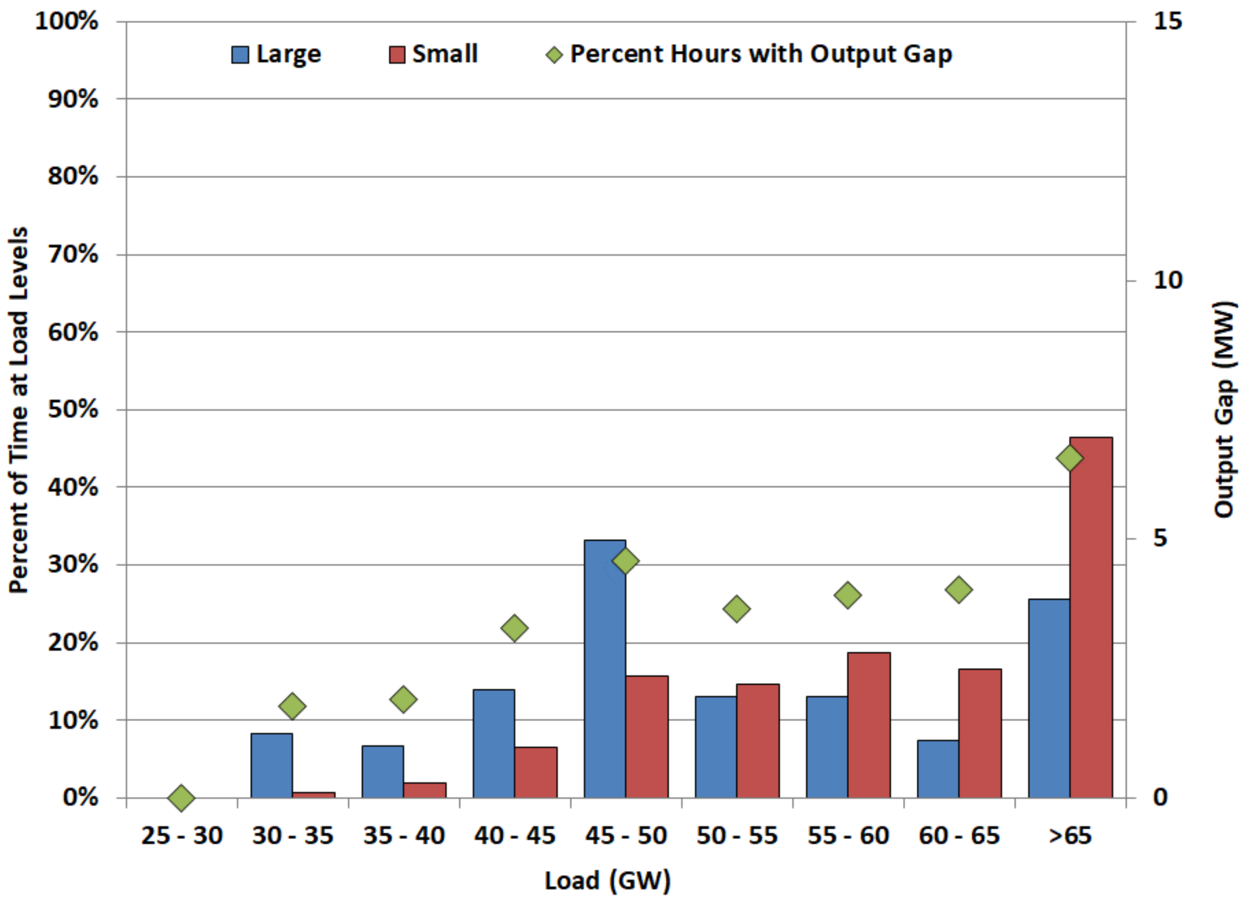


Figure 53 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer, i.e., the mitigated offers, but with a few changes. We use generic costs instead of verifiable 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 2020 exhibited an output gap. Taken together, these results show that potential economic withholding levels were low in 2020, 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 2020.

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. VMPs existed for three market participants in 2020. By the end of 2019, Calpine, NRG and Luminant had active and approved VMPs that remained unchanged in 2020.[50] 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 day-ahead market) 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.[51] 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."[52] 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,

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50 See PUCT Docket No. 40545, Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan, Order (Mar. 28, 2013); PUCT Docket No. 40488, 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), Order (Jul. 13, 2012); PUCT Docket No. 42611, Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies, Order (Jul. 11, 2014); and PUCT Docket No. 49858, 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) (Dec. 13, 2019).

51 Further, Luminant's VMP will terminate on the earlier of ERCOT's go-live date for real-time co-optimization or seven years after approval.

52 PURA § 39.157(a).

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.

D. Market Power Mitigation

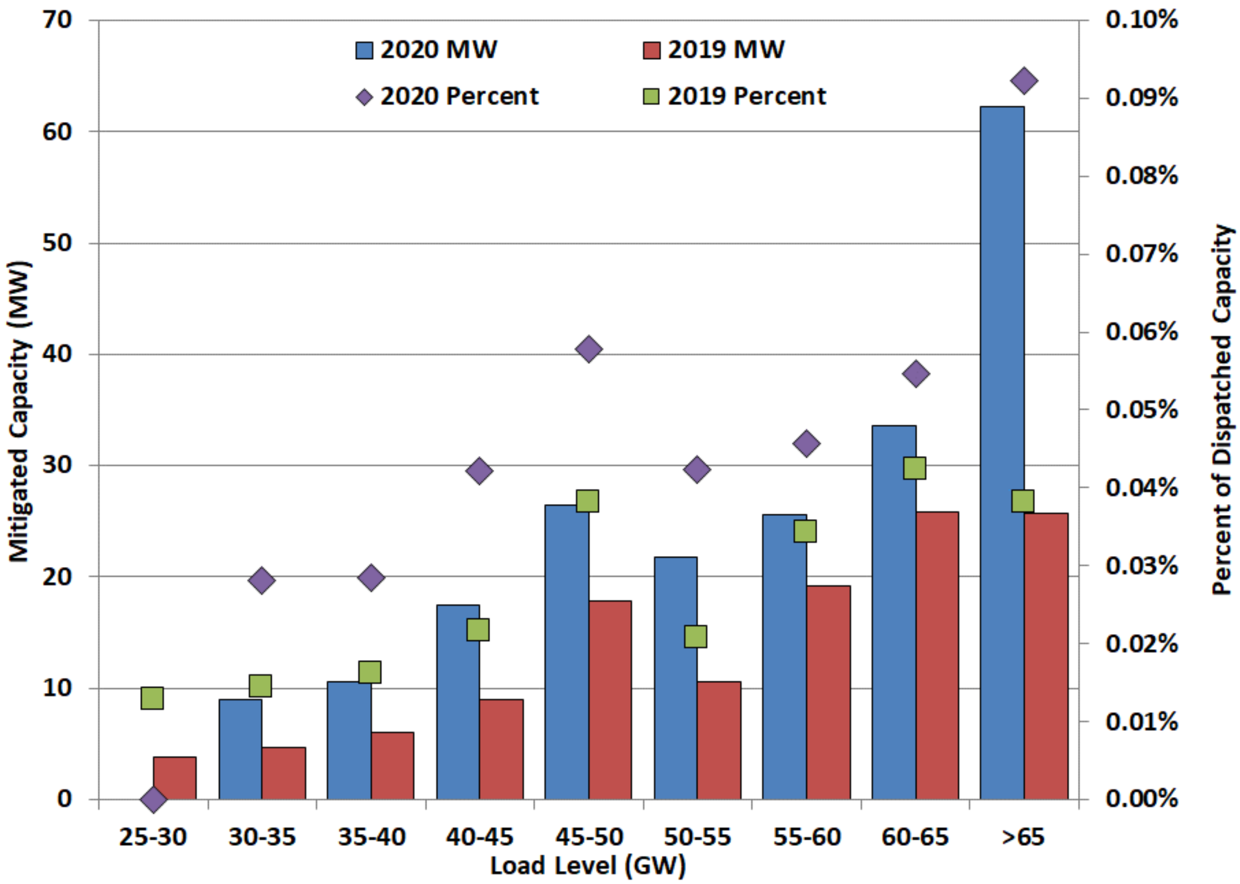
In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to a level that approximates competitive offers. ERCOT's real-time market includes a mechanism to mitigate offers for resources that are required to resolve a transmission constraint. Mitigation applies whether the unit is self-committed or receives a RUC instruction. RUC instructions are typically given to resolve transmission constraints. Thus, units that receive RUC instructions are typically required to resolve a non-competitive transmission constraint, and therefore end up mitigated in real-time. As discussed previously in Section V, units that received a RUC instruction were dispatched above their low sustained limits in 2020. This higher dispatch was most often the result of the RUC units being dispatched based on their mitigated offer to resolve non-competitive constraints, and mitigated offers are lower than the RUC offer floor of $1,500 per MWh.

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 2020. Although executing at all times, 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.

The analysis shown in Figure 54 computes the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level.

Figure 54: Mitigated Capacity by Load Level



The amount of mitigation in 2020 was mostly higher than in 2019. This is somewhat expected given the increase in transmission congestion in 2020. If particular resources are necessary to resolve a local constraint, that constraint is more likely to be deemed noncompetitive, resulting 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 V in the Appendix.

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 2020. The year contained high peak demand but more robust reserve margins, culminating in lower shortage pricing than the previous year. Our evaluation of a number of factors suggests that the market performed competitively in 2020. We recommend several corrections and improvements to continue the evolution of the market design.

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.

Key changes or improvements implemented or proposed in 2020 included:

- A number of revision requests posted by the Battery Energy Storage Task Force were either posted or approved in 2020, including NPRR986 BESTF-2, *Energy Storage Resource Energy Offer Curves, Pricing, Dispatch, and Mitigation*, approved on February 11, 2020, NPRR987 BESTF-3, *Energy Storage Resource Contribution to Physical Responsive Capability and Real-Time On-Line Reserve Capacity Calculations*, approved on June 9, 2020, NPRR989 BESTF-1, *Energy Storage Resource Technical Requirements*, approved on June 9, 2020, NPRR1002 BESTF-5, *Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions*, approved on August 11, 2020, NPRR1014 BESTF-4, *Energy Storage Resource Single Model*, approved on December 8, 2020, NPRR1026 BESTF-7, *Self-Limiting Facilities*, approved on December 8, 2020, NPRR1029, BESTF-6, *DC-Coupled Resources*, approved on December 8, 2020, NPRR1038 BESTF-8, *Limited Exemption from Reactive Power Requirements for Certain Energy Storage Resources*, approved on October 13, 2020, and NPRR1053 BESTF-9, *Exemption from Ancillary Service Supply Compliance Requirements for Energy Storage Resources Affected by EEA Level 3 Charging Suspension*s, filed on October 28, 2020.

- On March 1, 2020, Phase 1 of NPRR 863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve* became effective, implementing Fast Frequency Response (FFR), the automatic self-deployment and provision by a resource of their obligated response within 15 cycles after frequency meets or drops below a preset threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes.[53]
- On March 1, 2020, ERCOT implemented certain changes to the Other Binding Document titled, "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder" described in OBDRR011. Specifically, ERCOT implemented the second of two rightward shifts of 0.25 standard deviations to the

53 Resources capable of automatically self-deploying and providing their full Ancillary Service Resource Responsibility within 15 cycles after frequency meets or drops below a preset threshold and sustaining that full response for at least 15 minutes may provide Responsive Reserve (RRS).

Loss of Load Probability (LOLP) curve as instructed by the Public Utility Commission of Texas and as approved by the ERCOT Board of Directors on February 12, 2019.

- Effective April 3, 2020, NPRR929, *PTP Obligations with Links to an Option DAM Award Eligibility*, provided a new criteria for determining whether a Point-to-Point (PTP) Obligation with Links to an Option bid is eligible to be awarded based on the Current Operating Plan (COP) Resource Status of the Resource at the Resource Node where the bid sources. Such a bid will no longer be eligible for award if it sources at a Resource with a COP Resource Status of OUT, or a COP Resource Status of OFF and the Resource is not offered into the Day-Ahead Market (DAM).
- Effective on May 29, 2020, NPRR856, *Treatment of OFFQS Status in Day-Ahead Make Whole and RUC Settlements*, provided language for accurate Reliability Unit Commitment (RUC) and Day-Ahead make-whole Settlement of Quick Start Generation Resources (QSGRs).
- Also effective on May 29, 2020, NPRR884, *Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources*, introduced into the ERCOT Nodal Protocols various changes needed for ERCOT systems to effectively manage cases where ERCOT issues a Reliability Unit Commitment (RUC) instruction to a Combined Cycle Generation Resource that is already Qualified Scheduling Entity (QSE)-committed for an hour, with the instruction being that the Resource operate in a configuration with greater capacity for that same hour.
- On June 9, 2020, NPRR1006, *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data* was approved, returning the ERS resources in a linear curve over a four and a half-hour period following recall, rather than ten hours, to account for the data seen from summer 2019 as well as winter 2014 with the recognition that three days' data does not provide definitive information for further reduction. The NPRR also changed the process for updating this parameter in the future so that it can be updated by the ERCOT Technical Advisory Committee each year as appropriate, without the need to file a new NPRR.
- On June 9, 2020, NPRR1019, *Pricing and Settlement Changes for Switchable Generation Resources (SWGRs) Instructed to Switch to ERCOT*, was approved, which provided that ERCOT systems automatically create a proxy Energy Offer Curve with a price floor of $4,500/MWh for each Reliability Unit Commitment (RUC)-committed SWGR as opposed to requiring Qualified Scheduling Entities (QSEs) to submit Energy Offer Curves reflecting the $4,500/MWh floor, and included a lost revenue cost component to the Switchable Generation Cost Guarantee (SWCG) to ensure that Combined-Cycle Generation Resource SWGRs are made whole to their costs when switching from a non-ERCOT Control Area to the ERCOT Control Area.

- On August 5, 2020, NPRR947, *Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities*, was withdrawn because of the system cost, some complexities related to AS trades, and the implementation of real-time co-optimization. The NPRR would have removed the operator intervention step and automated the "failure to provide" settlement treatment.

- On August 11, 2020, NPRR1004, *Load Distribution Factor Process Update*, was approved, incorporating load forecasting methods into a daily LDF update. Under the NPRR, a new process was created for determining the load distribution factors used in the Congestion Revenue Rights (CRR) Auctions and day-ahead market clearing using load forecasting models and existing validation and error correction to determine daily load distribution factors, which represents a significant improvement over the previous process.

- Also on August 11, 2020, NPRR1030, *Modify Allocator for CRR Auction Revenue Distribution*, was approved. It changed how CRR Auction revenues will be allocated based on DC Tie transactions, and prohibited Market Participants from engaging in DC Tie export transactions that are reasonably expected to be uneconomic.

- August 11, 2020 also saw the approval of SCR810, *EMS System Change to Count DC Ties toward the 2% Constraint Activation Criterion*, adding logic to ERCOT's Energy Management System (EMS) system to remove the flag that indicates to the ERCOT Operator that a unit representing a Direct Current Tie (DC Tie) does not count toward the 2% criterion for activating transmission constraints.

- On September 23, 2020, NPRR1025, *Remove Real-Time On-Line Reliability Deployment Price from Ancillary Service Imbalance Calculation* was rejected by the Technical Advisory Committee (TAC) because of concerns expressed by the Independent Market Monitor (IMM) regarding conflicting incentives and effects on ORDC. The NPRR would have amended Sections 6.7.5 and 6.7.6 of the ERCOT Nodal Protocols to remove the Real-Time On-Line Reliability Deployment Price (RTRDP) from Ancillary Service imbalance Settlement.

- On October 13, 2020, SCR811, *Addition of Intra-Hour PhotoVoltaic Power Forecast to GTBD Calculation*, was approved, updating the formula used by the Resource Limit Calculator to calculate the Generation To Be Dispatched (GTBD) value to include a predicted five-minute solar ramp (PSRR) component.

- On November 24, 2020, NPRR1058, *Resource Offer Modernization for Real-Time Co-Optimization*, was filed, which would allow all resources to update their offers in Real-Time to reflect their current costs.

- On December 8, 2020, NPRR1055, *Market Notice and ERCOT Discretion re Late-Filed NOIE Eligibility Attestations for PTP Obligations with Links to an Option Bid Awards*, was approved, giving ERCOT the discretion to accept for good cause, and on a case-by-case basis, attestations from NOIEs under paragraph (3) of Section 4.4.6.3 after the October 1 annual deadline. Further, the NPRR requires ERCOT to post a Market Notice by September 1 of each year reminding NOIEs of the annual deadline.

- Also on December 8, 2020, a suite of real-time co-optimization revisions posted by the Real-Time Co-Optimization Task Force was approved, including NPRR1007- RTC NP 3, *Management Activities for the ERCOT System*, NPRR1008- RTC NP 4, *Day-Ahead Operations*, NPRR1009- RTC NP 5, *Transmission Security Analysis and Reliability Unit Commitment*, NPRR1010- RTC NP 6, *Adjustment Period and Real-Time Operations*, NPRR1011- RTC NP 8, *Performance Monitoring*, NPRR1012- RTC NP 9, *Settlement and Billing*, NPRR1013- RTC NP 1, 2, 16, 25, *Overview, Definitions/Acronyms, Registration and Qualification of MPs, and Market Suspension and Restart*, as well as NOGRR211- RTC Nodal Operating Guides 2 and 9, *System Operations and Control Requirements and Monitoring Programs* and OBDRR020- RTC, *Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints*, as part of the implementation of real-time co-optimization and anticipated go live date in 2025.
- Regarding improvements to the RMR process, effective December 12, 2020, NPRR964 removed the term Synchronous Condenser Unit from the Protocols and clarified the ERCOT evaluation process related to reliability analysis and aligns the review process of a seasonal mothball unit with non-seasonal mothball unit.

Retirement of Previous IMM Recommendations

Remove the "opt out" option for resources receiving RUC instructions.

Status: This recommendation was not addressed. While the incentive exists for resource owners to show as "off and available" in the COP for future hours some resources that they reasonably expect to commit, the issue can be monitored and resurfaced if issues are identified.

Implement transmission demand curves

Status: Resolution of this recommendation is underway. On January 21, 2021, the IMM filed OBDRR26, *Change Shadow Price Caps to Curves and Remove Shift Factor Threshold*, which would implement this recommendation. It now resides in the stakeholder process.

Eliminate the "2% rule" and price all congestion regardless of generation impact.

Status: Resolution of this recommendation is underway. Like the prior recommendation, the IMM filed OBDRR26, *Change Shadow Price Caps to Curves and Remove Shift Factor Threshold* on January 21, 2021, to implement this recommendation. It must now proceed through the stakeholder process.

Modify the reliability deployment adder and operating reserve adder to improve pricing during deployments of Emergency Response Service (ERS).

This recommendation has been partially addressed. On June 20, 2020, the ERCOT Board approved NPRR1006, *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data*, which accomplishes the update to the ERS restoration time. As for the other two pricing improvements, they are either obviated with real-time co-optimization or face software limitations that cannot be surmounted at this time.

Improve the mitigated offers for generating resources

Resolution of this recommendation is underway. VCMRR31, *Clarification Related to Variable Costs in Fuel Adders*, was filed by ERCOT on February 3, 2021, and the IMM supports its approval. Regarding price formation when RUC resources are mitigated, the priority of this item is now low because RUC has become relatively infrequent. Both issues will continue to be monitored.

Implement a locational reliability deployment price adder (RDPA)

This recommendation is suspended. As described above, the priority of this item is now low because RUC has become relatively infrequent. However, it will continue to be monitored.

I. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of 2020 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2020, including AS costs by type.

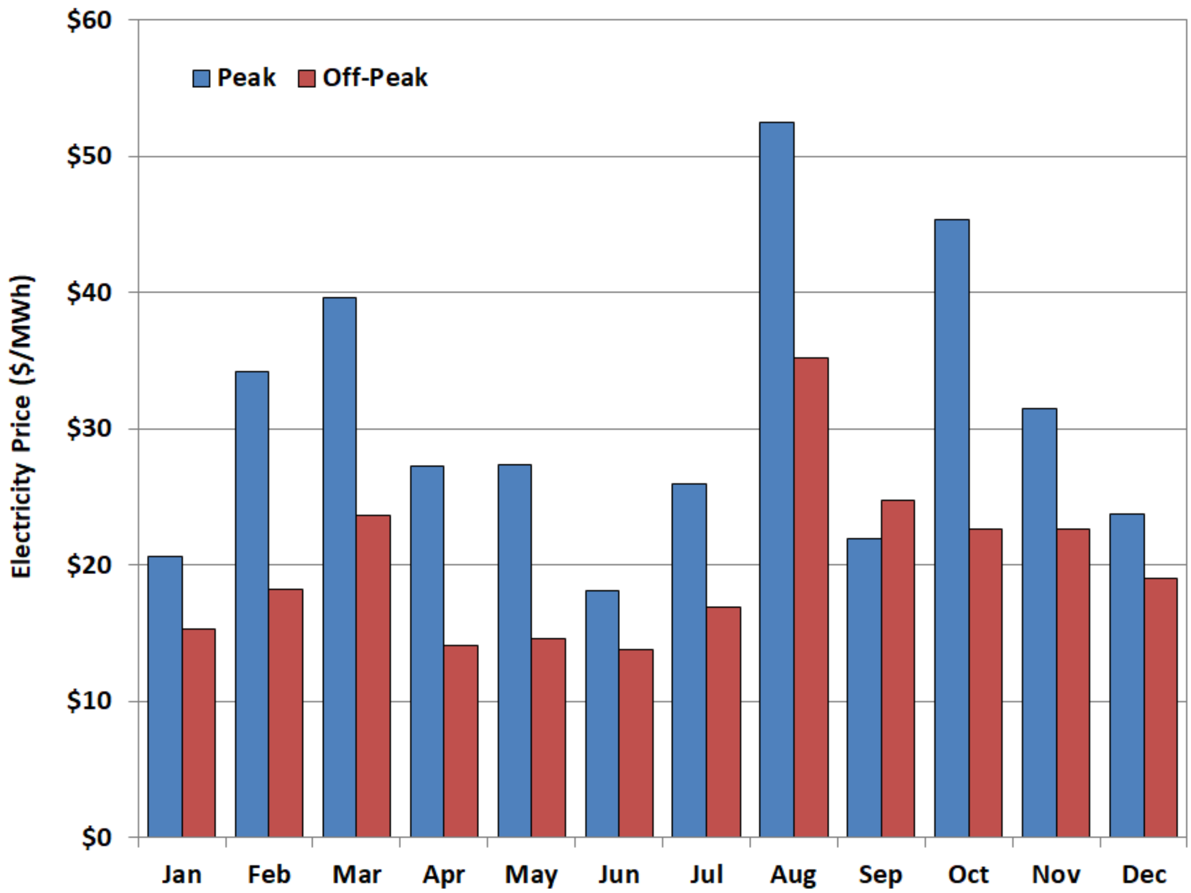
Table A1: ERCOT 2020 Year at a Glance (Annual)

	Annual Total ($M)
Energy	$9,827.5
Regulation Up	$30.1
Regulation Down	$21.3
Responsive Reserve	$272.7
Non-Spin	$57.4
CRR Auction Distribution	$725.5
Balancing Account Surplus	$53.4
CRR DAM Payment	$1,275.0
PTP DAM Charge	$1,038.7
PTP RT Payment	$1,125.9
Emergency Response Service	$44.8
Revenue Neutrality	$75.6
ERCOT Fee	$212.2
Other Load Allocation	$26.6

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 2020. 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

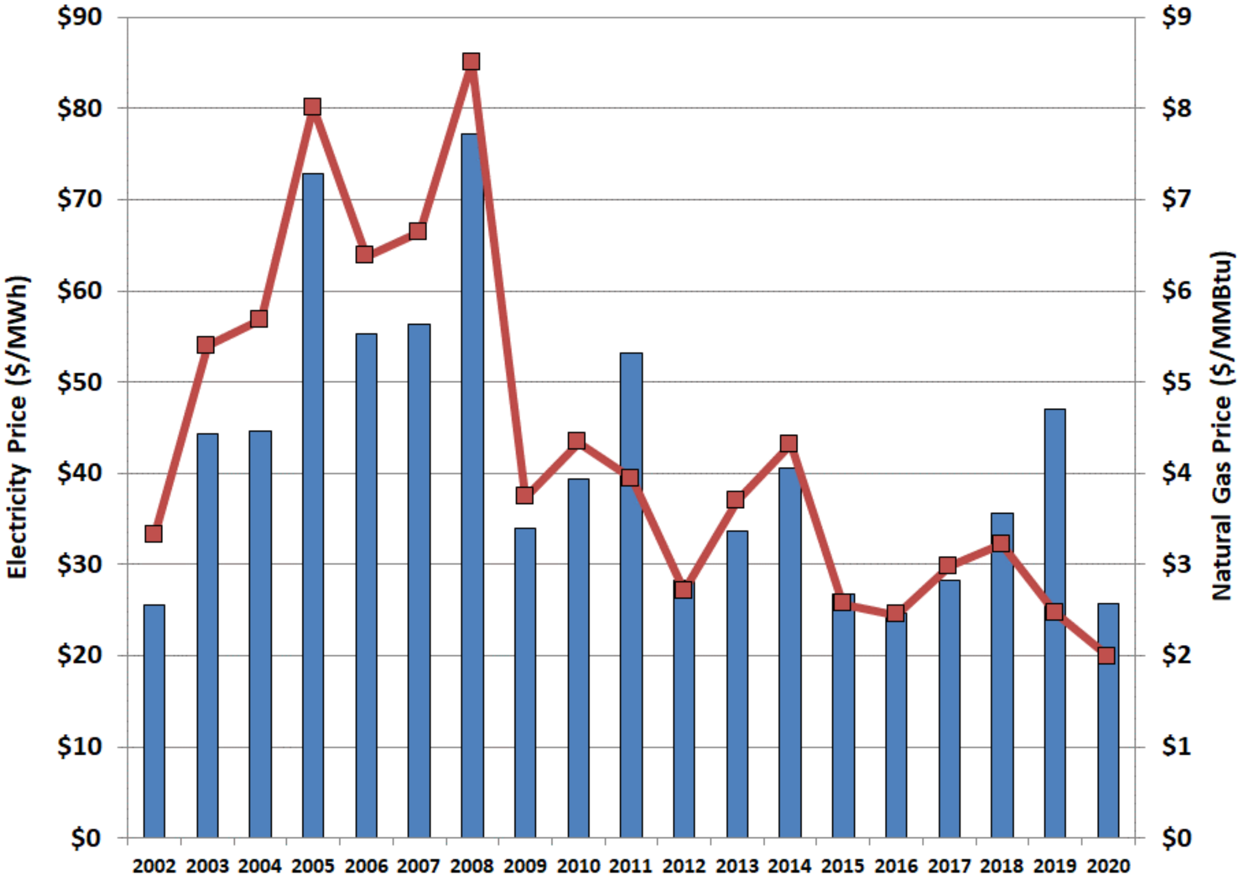


As expected, Peak hours were higher priced than Off-Peak hours for every month in 2020, with the exception of September, when Off-Peak hour prices were $2.84 per MWh higher than peak hour prices. The September Off-Peak price average was impacted by a weekend of high prices on Saturday, September 12 due to exceptionally low wind output over the load peak. For all other months, the difference ranged from a minimum of $4.30 per MWh in June to a maximum of $22.71 per MWh in October. Because of the relative absence of severe shortage conditions during the summer of 2020, no months in 2020 were comparable to August 2019, when the difference was $275.00 per MWh due primarily to shortage conditions and the resulting high prices (multiple intervals at the high system-wide offer cap (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 2020 was $10.61 per MWh.

B. Zonal Average Energy Prices in 2020

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 2020.

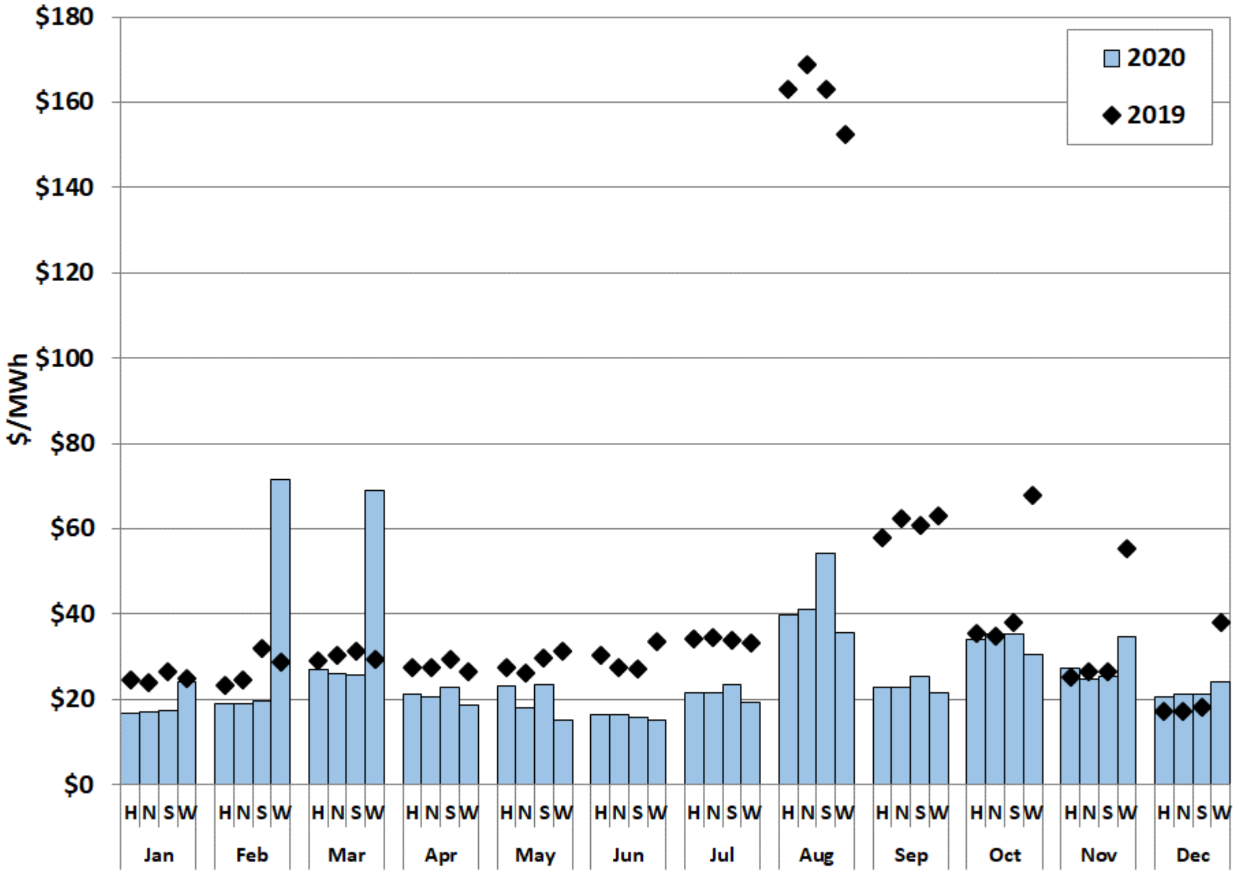
Figure A2: ERCOT Historic Real-Time Energy and Natural Gas Prices



Like Figure 1 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. Only in 2011 and 2019 did those trends diverge; in both those years there was significant shortage pricing; that is, the cost of electricity reflected both the cost of production and shortage conditions. This outcome is expected in years with low reserve margins or extreme weather. Neither of those factors were prevalent in 2020.

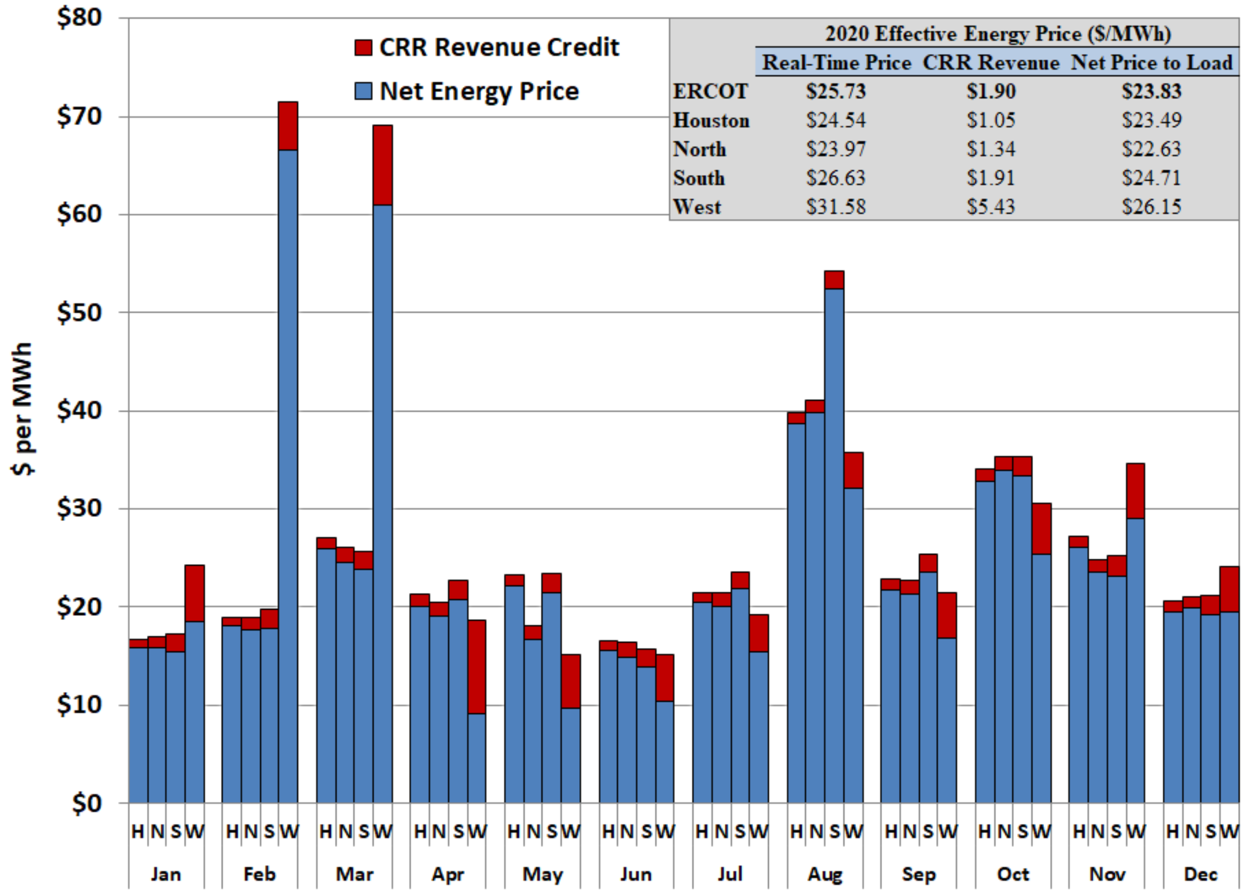
Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2019 and 2020. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative 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. These prices in 2020 were not particularly volatile month-to-month, especially in comparison to 2019.

Figure A3: Average Real-Time Energy Market Prices by Zone



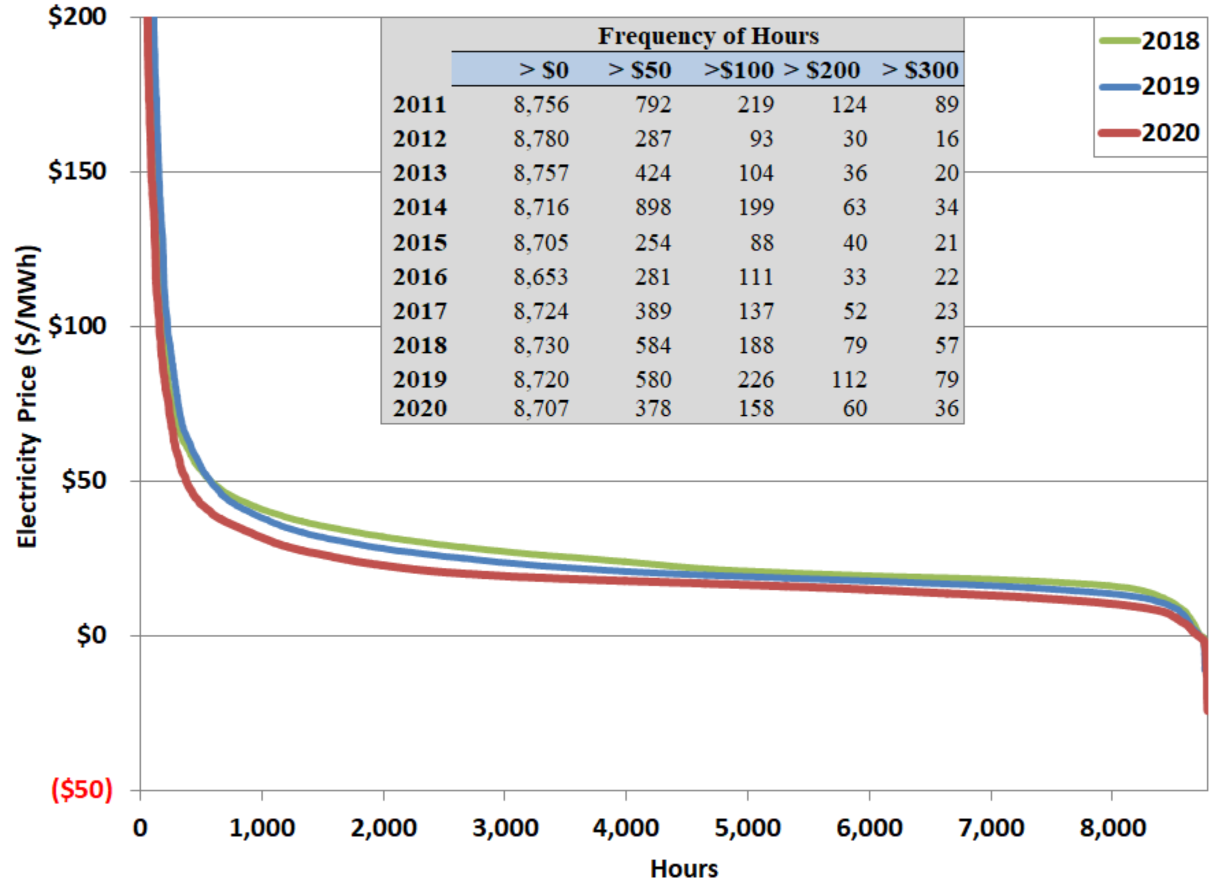
Another factor influencing zonal price differences is CRR auction revenue distributions. These are allocated to Qualified Scheduling Entities (QSEs) representing load, based on both zonal and ERCOT-wide monthly load-ratio shares. The CRR auction revenues have the effect of reducing the total cost to serve load borne by a QSE. Figure A4 shows the effect that this reduction has on a monthly basis, by zone, in 2020.

Figure A4: Effective Real-Time Energy Market Prices



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 2018 through 2020, with 2019 showing the most shortage pricing hours since the nodal market implementation. The prices in this figure are the hourly ERCOT average prices derived by load weighting the zonal settlement point prices.

Figure A5: ERCOT Price Duration Curve

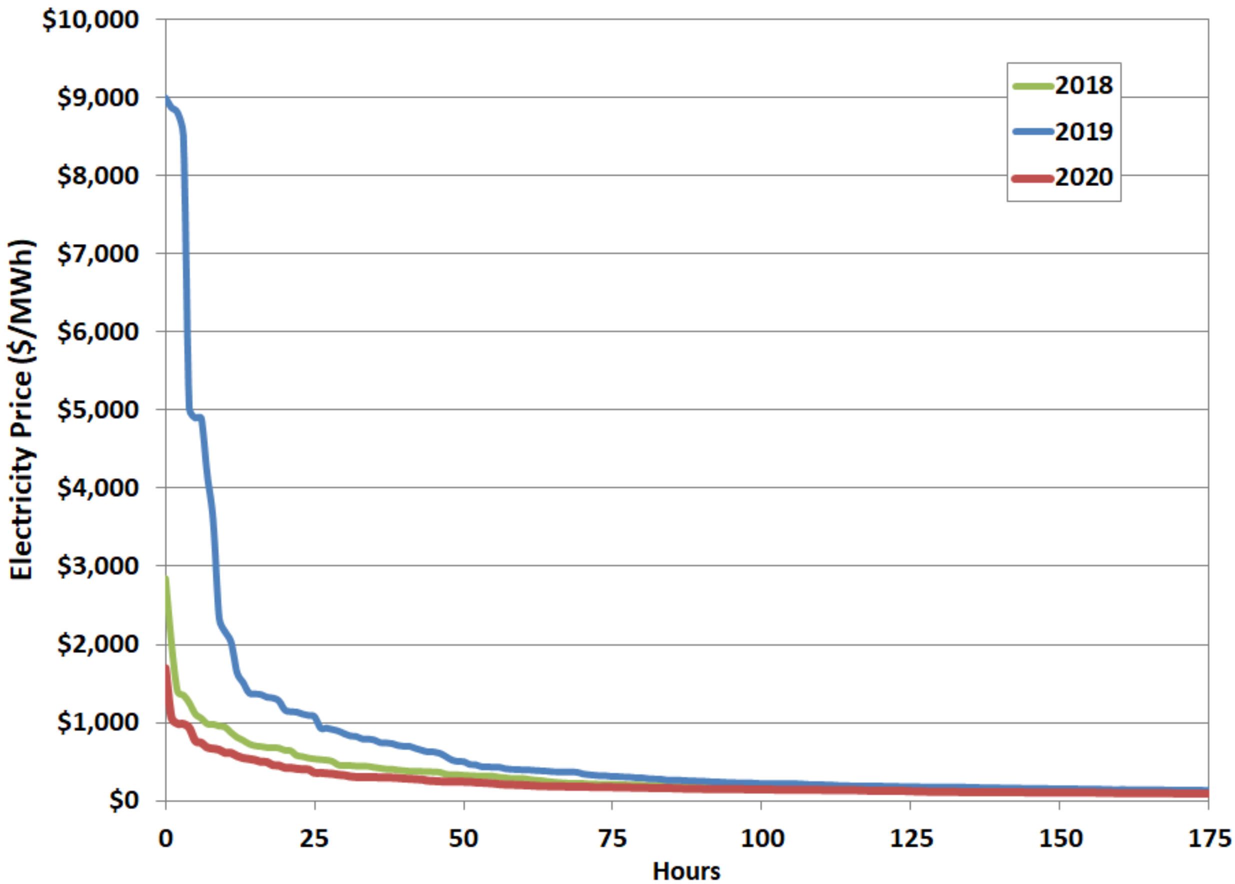


	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79
2020	8,707	378	158	60	36

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, reaching a high of 131 hours in 2016. That trend reversed in 2017, when there were 36 hours with ERCOT-wide prices at or below zero. In 2020, there were 77 hours with ERCOT-wide prices at or below zero, an increase from the 40 hours in 2019.

Figure A6 compares prices for the highest-priced 2% of hours in 2018 through 2020. Energy prices for the highest 100 hours of 2019 were significantly higher than those in 2018 and 2020, with 2019 being the peak year since the nodal market implementation. The higher prices in 2019 illustrate the effects of the changes to the shortage pricing mechanism over the past decade, most importantly the increase of the System Wide Offer Cap to $9,000/MWh, the implementation of the Operating Reserve Demand Curve and subsequent changes to its parameters, and the implementation of the Reliability Deployment Adder. The lower prices in 2020 suggest that 2019 was not the start of a trend, but rather an example of extreme summer conditions that are unlikely to repeat annually, depending on system capacity availability.

Figure A6: 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 A7 and Figure A8 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 A7: Implied Heat Rate Duration Curve – All Hours

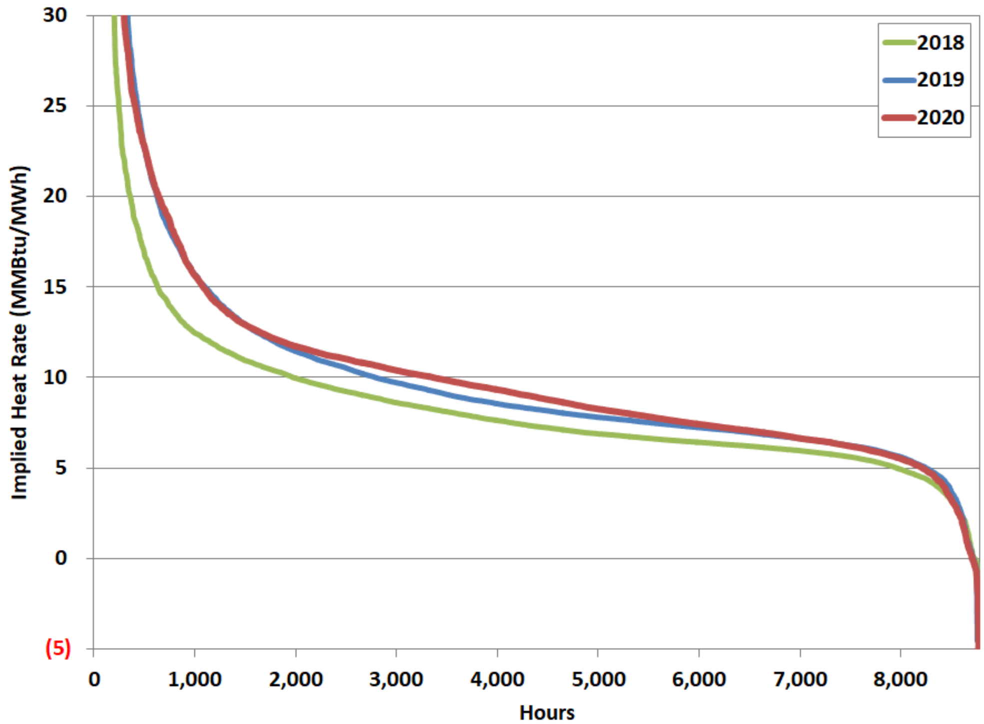


Figure A8 shows the implied marginal heat rates for the top 2% of hours from 2018 to 2020. The implied heat rate duration curve for the top 2% of hours in 2020 was much lower than 2019, and more similar to 2018, because of the lack of significant contributions from shortage pricing.

Figure A8: Implied Heat Rate Duration Curve – Top 2% of Hours

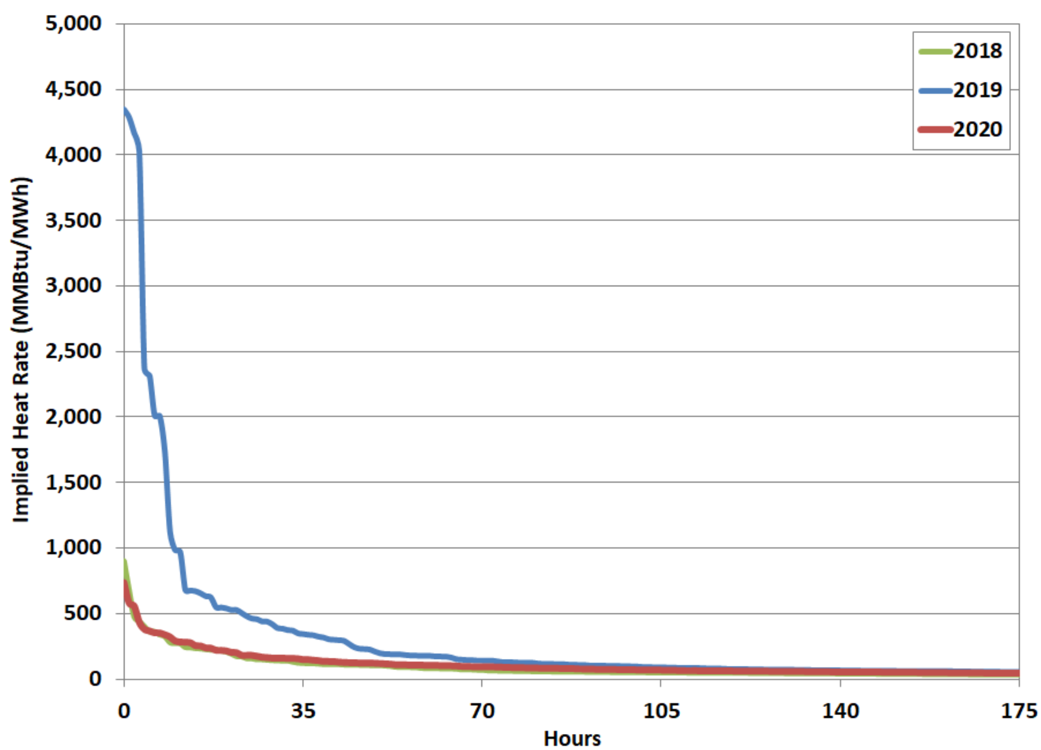


Table A2 displays the annual average implied heat rates by zone for 2014 through 2020. Adjusting for natural gas price influence, Figure A8 shows that the annual, system-wide average implied heat rate decreased significantly in 2020 compared to 2019. Zonal variations in the implied heat rate were greater in 2020 because increased transmission congestion.

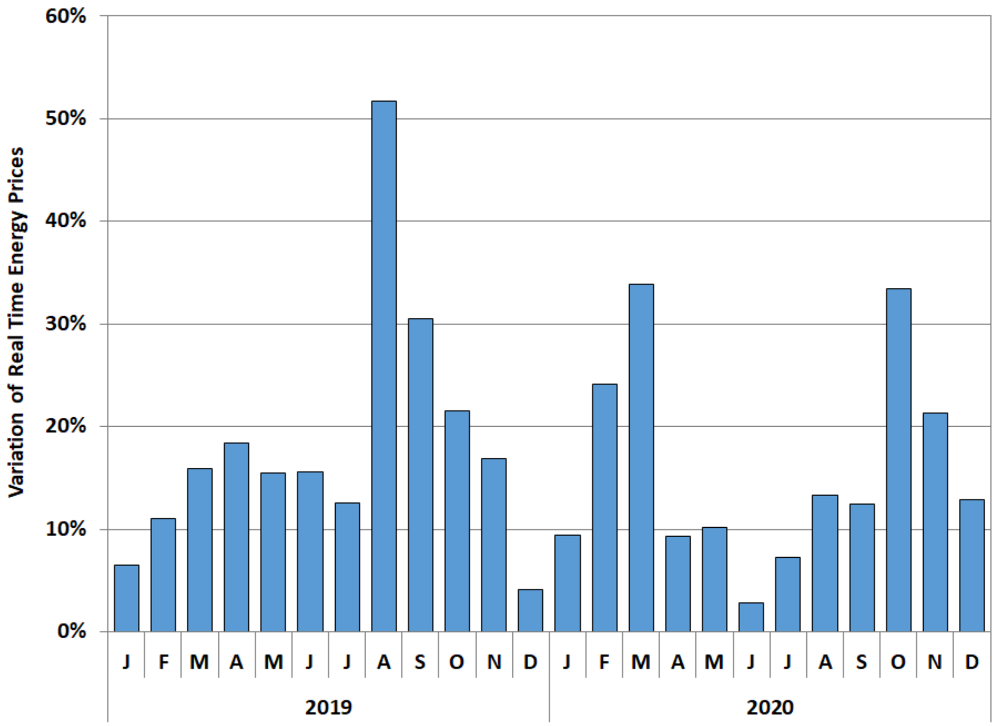
Table A2: Average Implied Heat Rates by Zone

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

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 A9 below shows monthly average changes in five-minute real-time prices by month for 2019 and 2020.

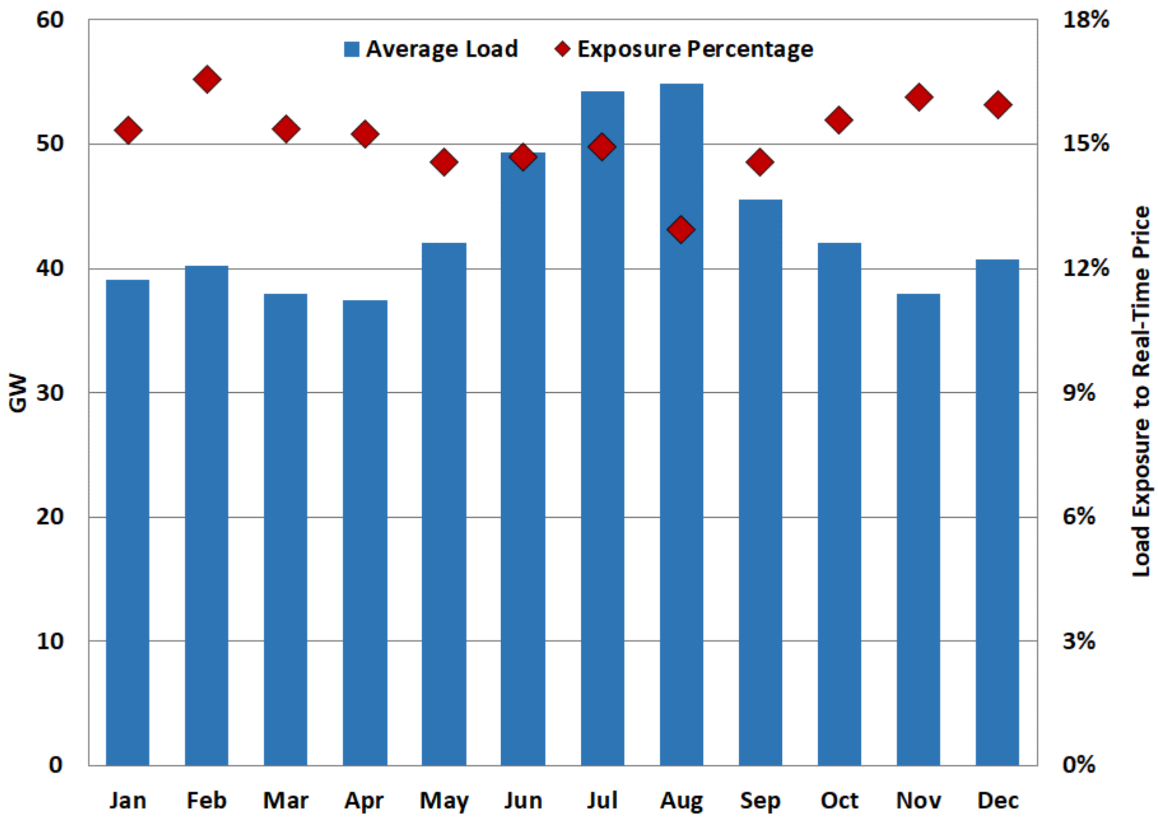
Figure A9: Monthly Price Variation



As expected, the high price variability that occurred during August 2019 when occurrences of shortage pricing were most frequent were not seen in 2020. However, February and March as well as October and November 2020 saw high price variability because of outages reducing available transmission capacity.

Finally, Figure A10 below shows the percentage of load exposed to real-time energy prices.

Figure A10: 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 2020 was lowest in the summer months with the lowest exposure occurring in August. Unhedged loads would be vulnerable to any shortage conditions that may occur during August. The highest portions of load potentially exposed to real-time prices in 2020 occurred at the beginning and end of 2020, in February, March, October and November, respectively. 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.

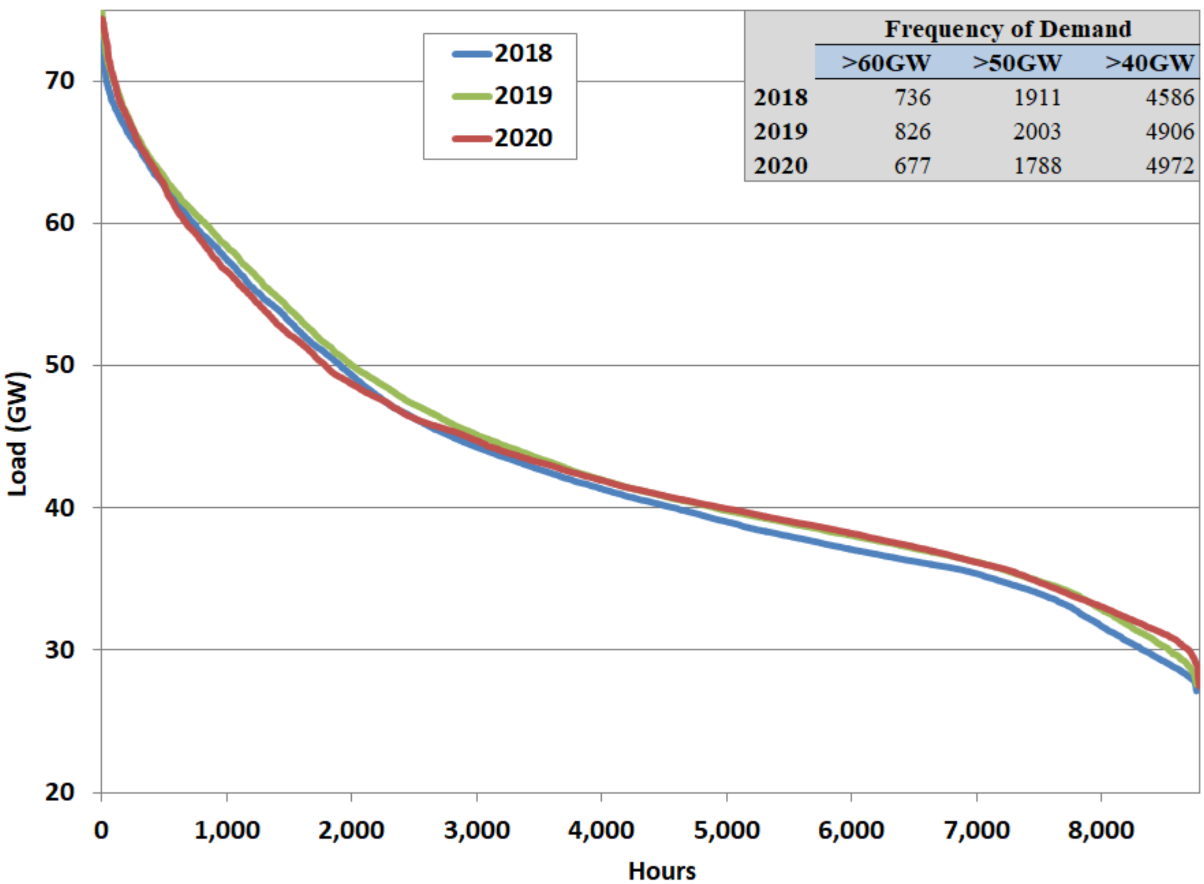
II. Appendix: Demand and Supply in ERCOT

In this section, we provide supplemental analyses of load patterns during 2020 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 A11 compares load duration curves for each year from 2018 through 2020. 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 2020 was similar to both 2018 and 2019, though slightly higher as load growth continues in ERCOT.

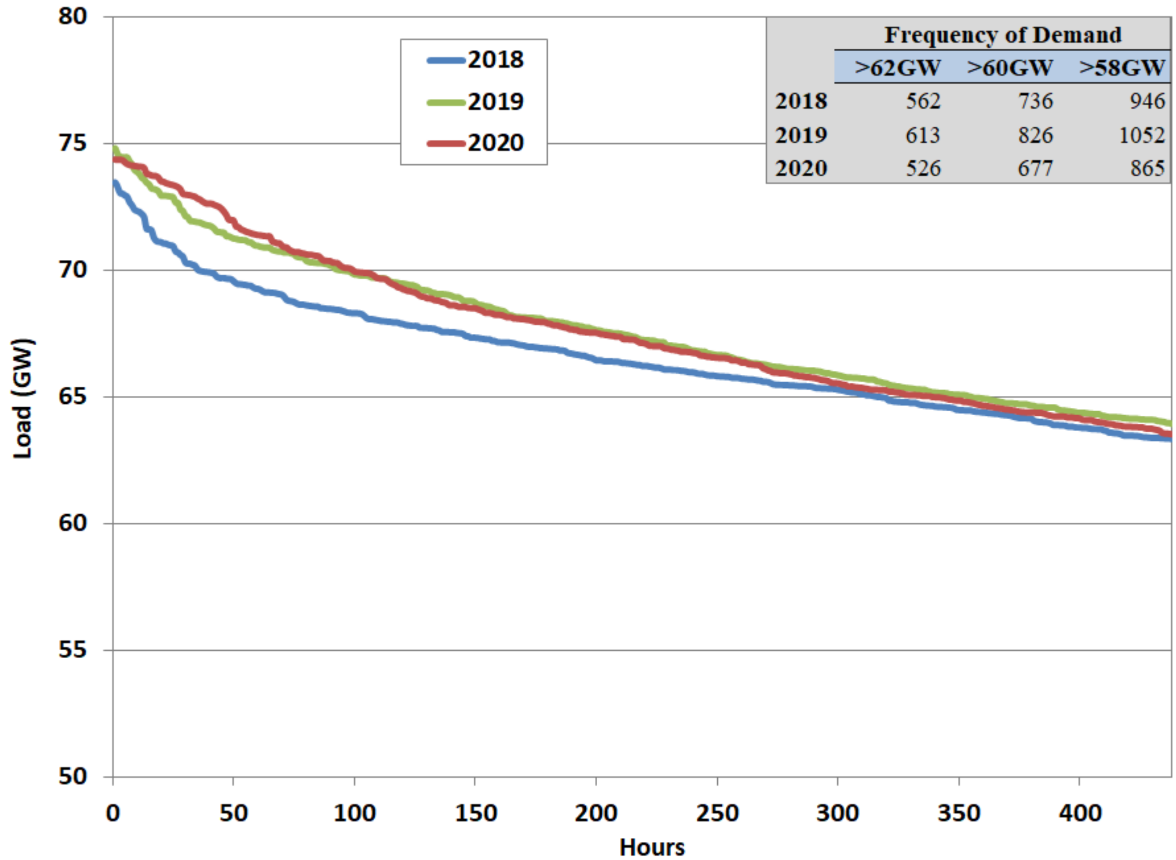
Figure A11: Load Duration Curve – All Hours



	Frequency of Demand		
	>60GW	>50GW	>40GW
2018	736	1911	4586
2019	826	2003	4906
2020	677	1788	4972

To better illustrate the differences in the highest-demand periods between years, Figure A12 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 16% to 19% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than 5% of the hours.

Figure A12: Load Duration Curve – Top 5% of Hours with Highest Load



	Frequency of Demand		
	>62GW	>60GW	>58GW
2018	562	736	946
2019	613	826	1052
2020	526	677	865

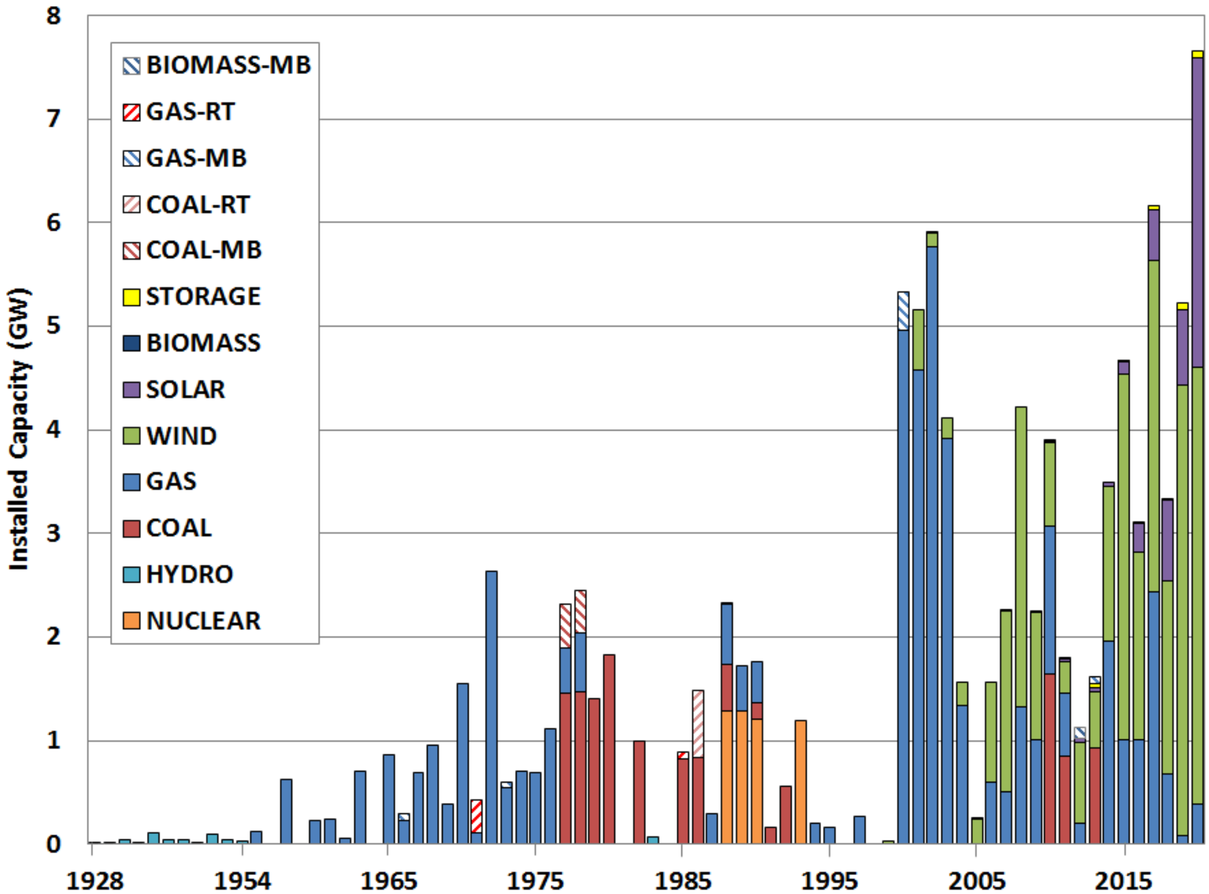
B. Generation Capacity in ERCOT

The generation mix in ERCOT is evaluated in this subsection. Figure A13 shows the vintage of generation resources in ERCOT shown as operational in the December 2020 Capacity, Demand, and Reserves (CDR) report[54] and it also includes resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR. Seventy percent of the total coal capacity in ERCOT was at least thirty years old in 2020.

[54] ERCOT Capacity, Demand, and Reserves Report (Dec. 16, 2020), available at http://www.ercot.com/content/wcm/lists/197379/CapacityDemandandReservesReport_Dec2020.pdf.

Combined cycle gas capacity had been the predominant addition for years; however, wind has been the primary technology for new capacity since 2006. In 2020, almost 39% of new capacity was solar.

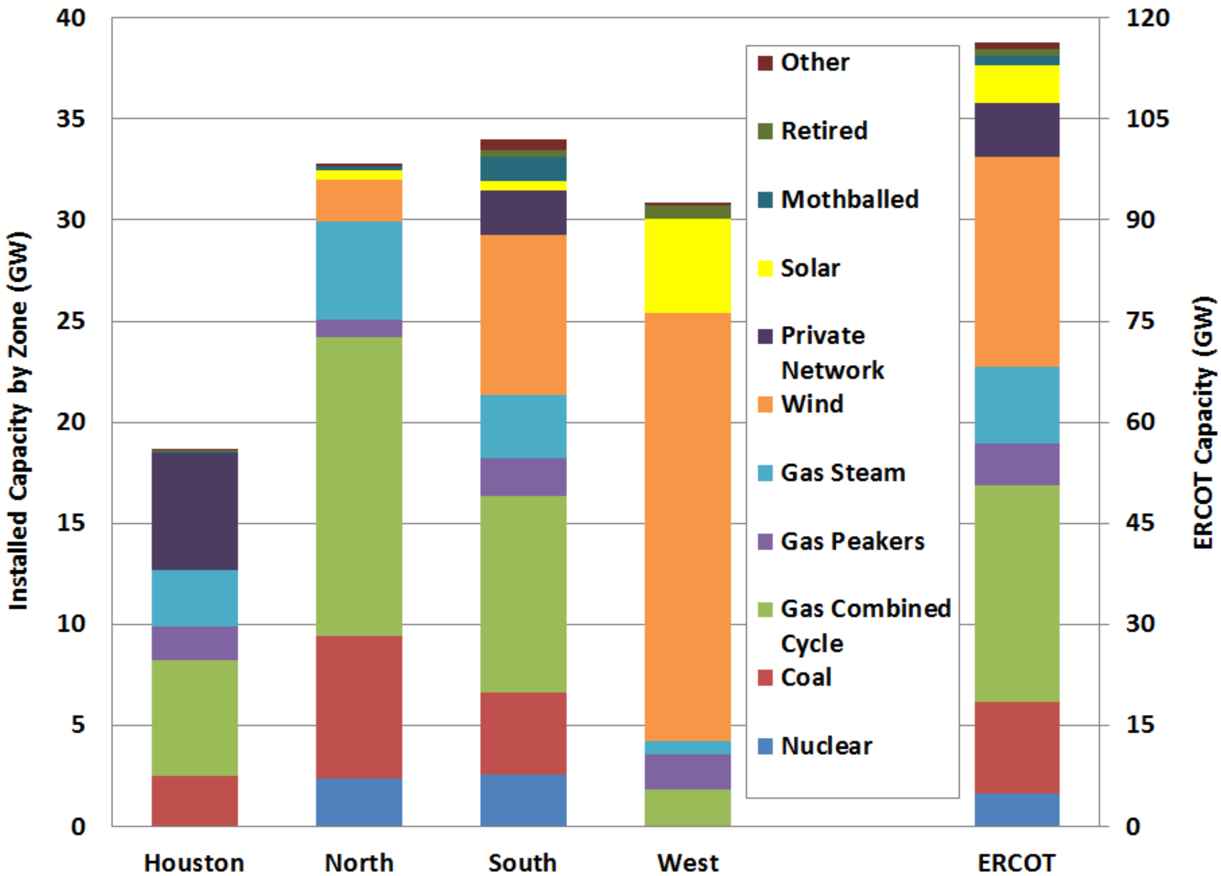
Figure A13: Vintage of ERCOT Installed Capacity



When excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand, the distribution of capacity among the four ERCOT geographic zones in 2020 was similar to the distribution of demand in those same zones, with the exception of the Houston zone.[55] Based on that metric, the North zone accounted for approximately 29% of capacity, the South zone 29%, the Houston zone 16%, and the West zone 26% in 2020. The installed generating capacity by type in each zone is shown in Figure A14.

55 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.

Figure A14: Installed Capacity by Technology for Each Zone



Approximately 7.7 GW of new generation resources came online in 2020; 4.2 GW of wind resources with an effective peak serving capacity of about 1 GW, 3 GW of solar resources with an ELCC of 2.4 GW. The remaining capacity was 390 MW from combustion turbines and 70 MW of power storage. The majority of the new wind and solar resources were located in the South and West Load Zones. Three resources retired permanently, representing a total summer Seasonal Net Max Sustainable Rating of 1,030 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 A15 shows average wind production for each month in 2019 and 2020, with the average production in each month divided into four-hour blocks. Though the lowest wind output generally occurs during summer afternoons, the average wind output during summer peak period increased to 7 GW, due to increases in the amount 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 wind generation is a significant contributor to generation supply, even at its lowest outputs.

Figure A15: Average Wind Production

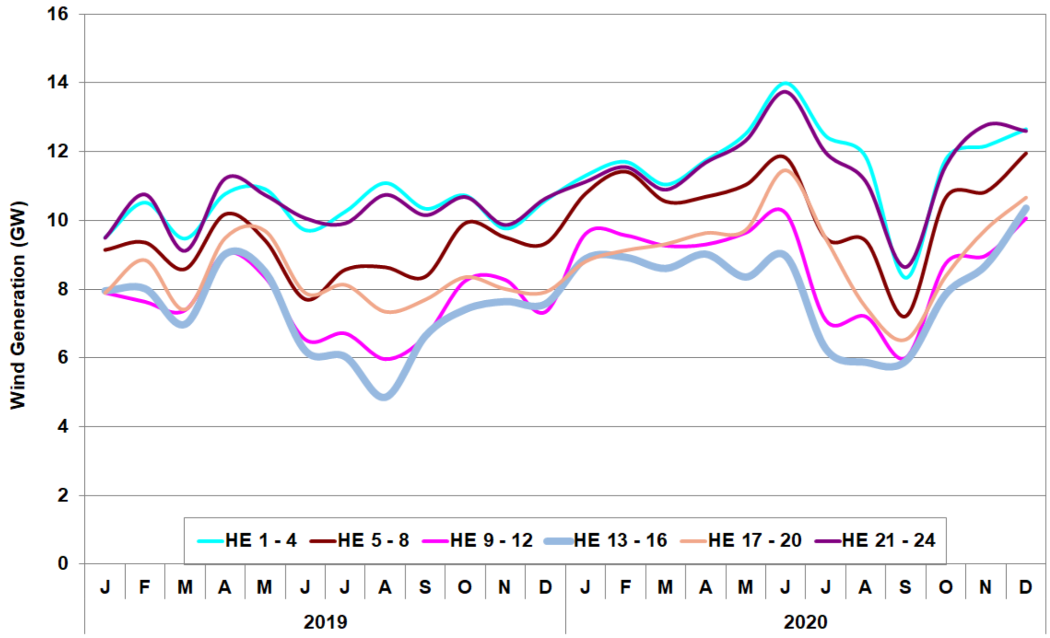
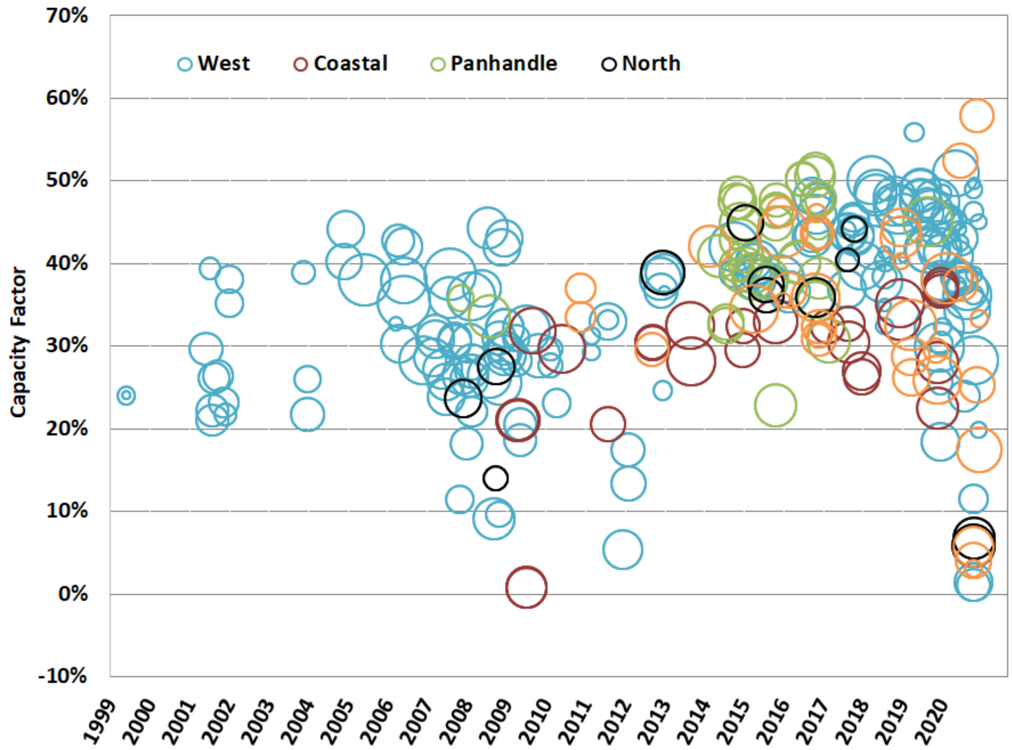


Figure A16 shows the capacity factor (the ratio of actual energy produced by a resource to the hypothetical maximum possible at is full rating) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles for each. Transmission maintenance for some 345 kV transmission lines limited output from some of the resources in the Panhandle, reducing their capacity factors.

Figure A16: 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 average wind speed in ERCOT, as weighted by the locations of current installed wind generation. Figure A17 provides a means to compare wind speeds on an annual basis and indicates that the average wind speed in 2020 increased dramatically from 2019, higher than the average over the past 10 years, and by far the highest it has been.

Figure A17: Historic Average Wind Speed

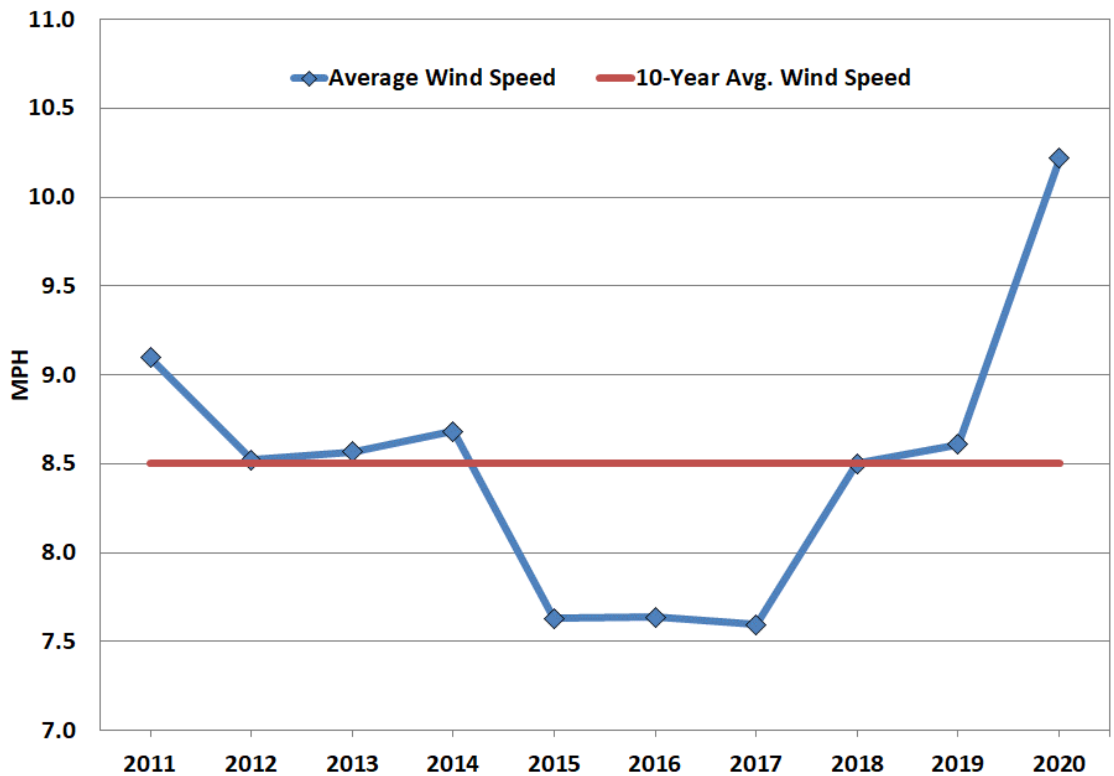
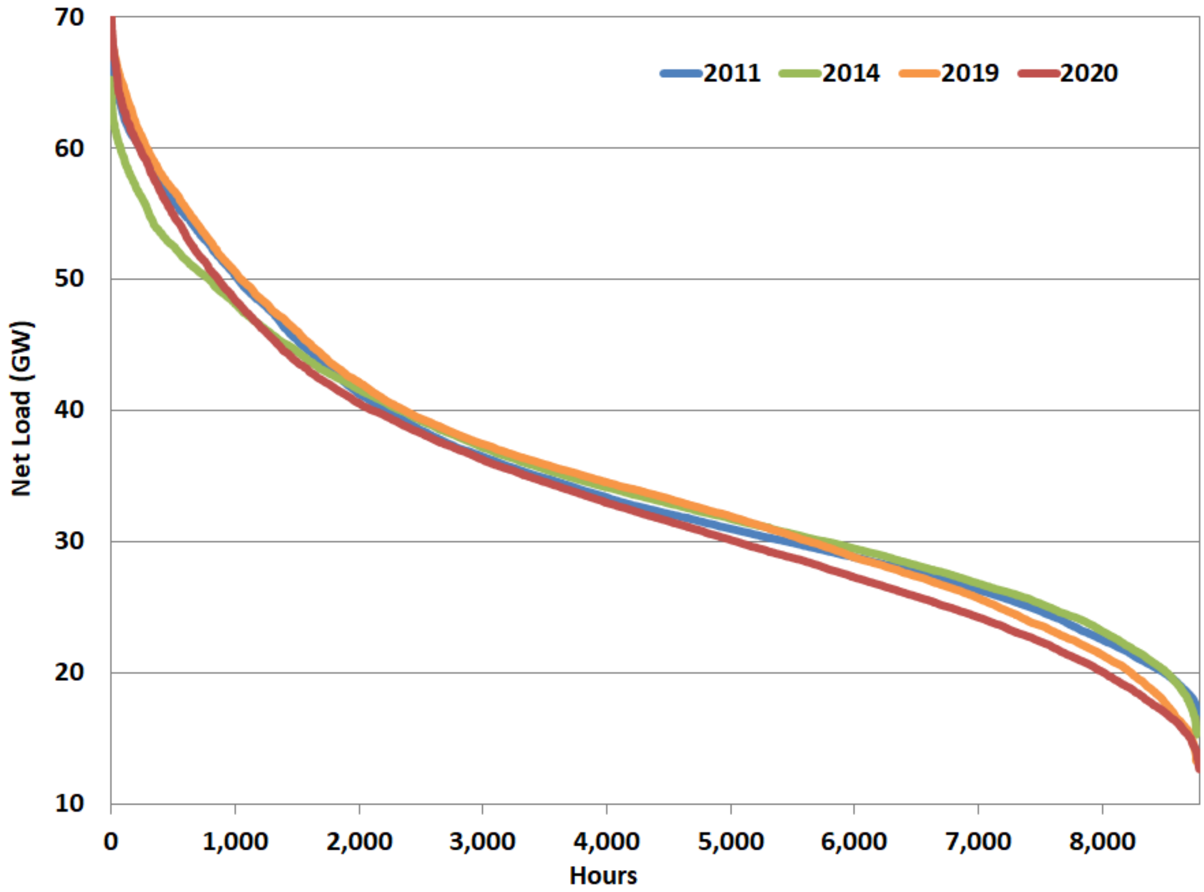


Figure A18 shows the net load duration curves for the years 2011, 2014, 2019 and 2020. Years 2011 and 2014 are included for historical context. Volatility in the net load amounts continues to increase. Increasing wind output has important implications for non-wind resources and for resource adequacy 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 A18: Net Load Duration Curves



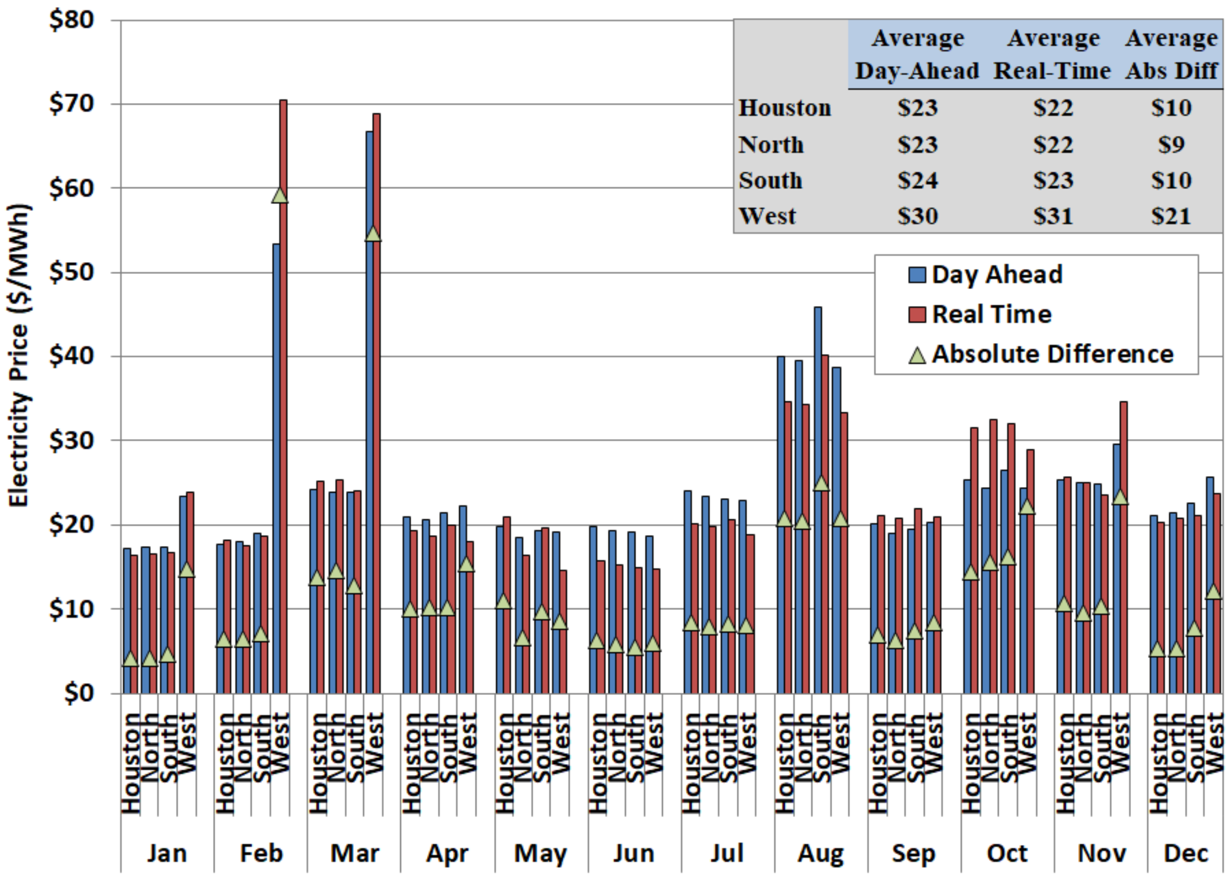
III. Appendix: Day-Ahead Market Performance

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 A19 below, monthly day-ahead and real-time prices for 2020 are shown for each of the geographic zones. Overall volatility was relatively low in 2020 across all zones. October 2020 witnessed the most pronounced price differences, with an average difference between day-ahead and real-time prices of $6.20 per MWh. Although the average day-ahead and real-time prices were similar in all zones, the average absolute difference in the West zone was the largest. This trend is explained by wide swings in West zone prices, the result of different kinds of transmission congestion constraints in the area related to outages and high load.

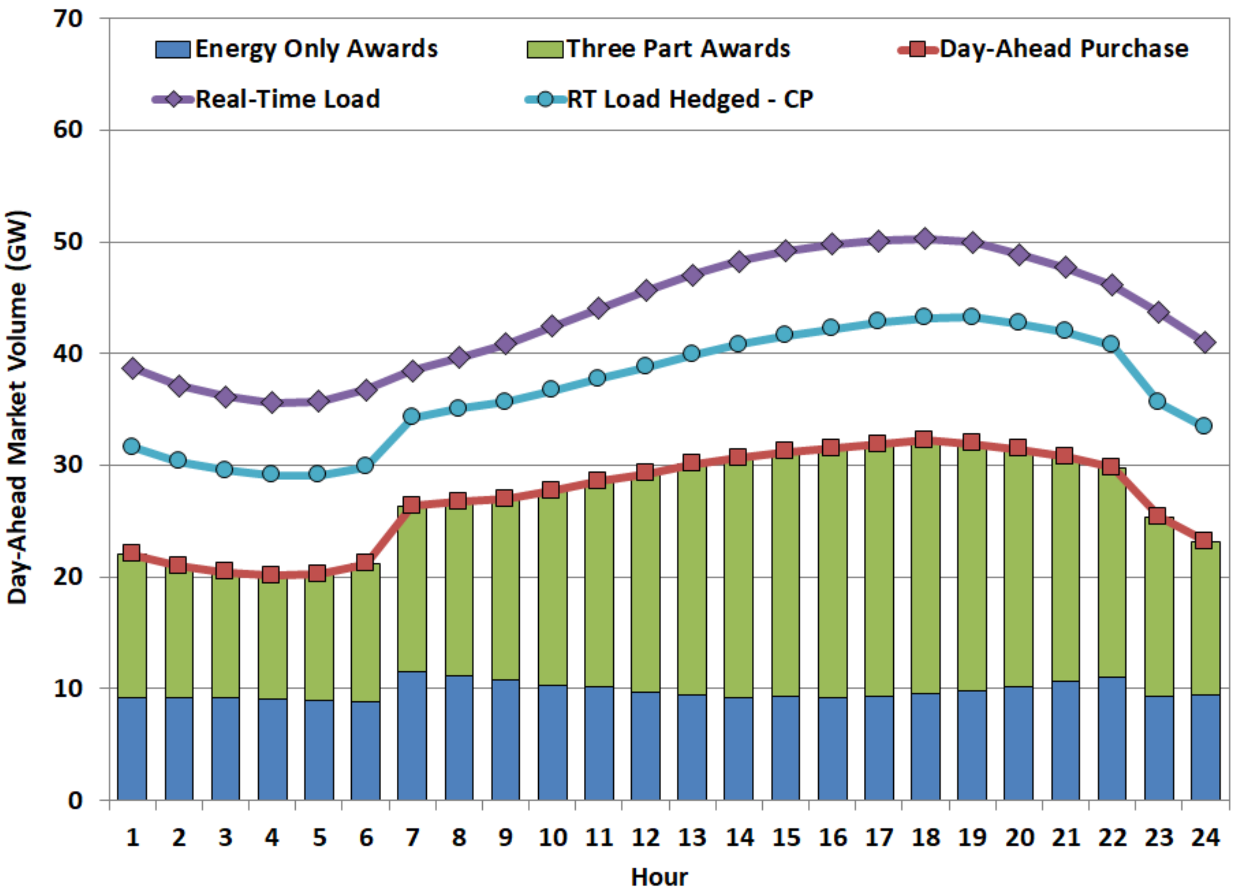
Figure A19: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Figure A20 below presents the same day-ahead market activity data in 2020 summarized by hour of the day. In this figure, the volume of day-ahead market transactions is disproportionate with load levels between HE 7 and HE 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 day-ahead market to trade around those positions.

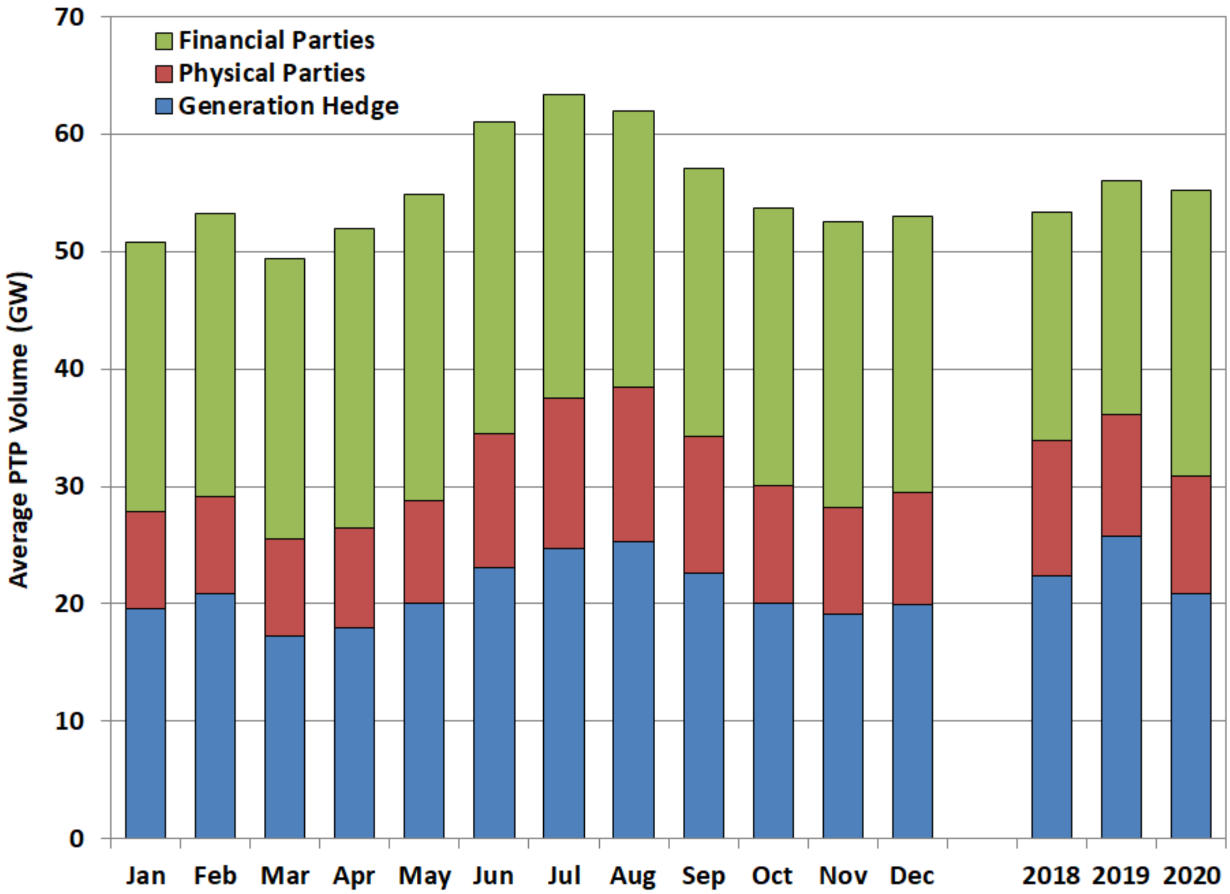
Figure A20: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A21 below presents the total volume of PTP obligation purchases in 2020 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 for the past three years, with 2020 falling in between 2018 and 2019.

Figure A21: 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 generation hedging comprised most of the volume of PTP obligations purchased in 2018 and 2019, but that in 2020, financial parties actually comprised most of the volume of PTP obligations purchased. 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 organized 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 again purchased 42% of the total volume of PTP obligations in 2020, higher than the 36% in 2018 and 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 A22 below displays the hourly average quantities of ancillary services procured for each month in 2020.

Figure A22: Hourly Average Ancillary Service Capacity by Month

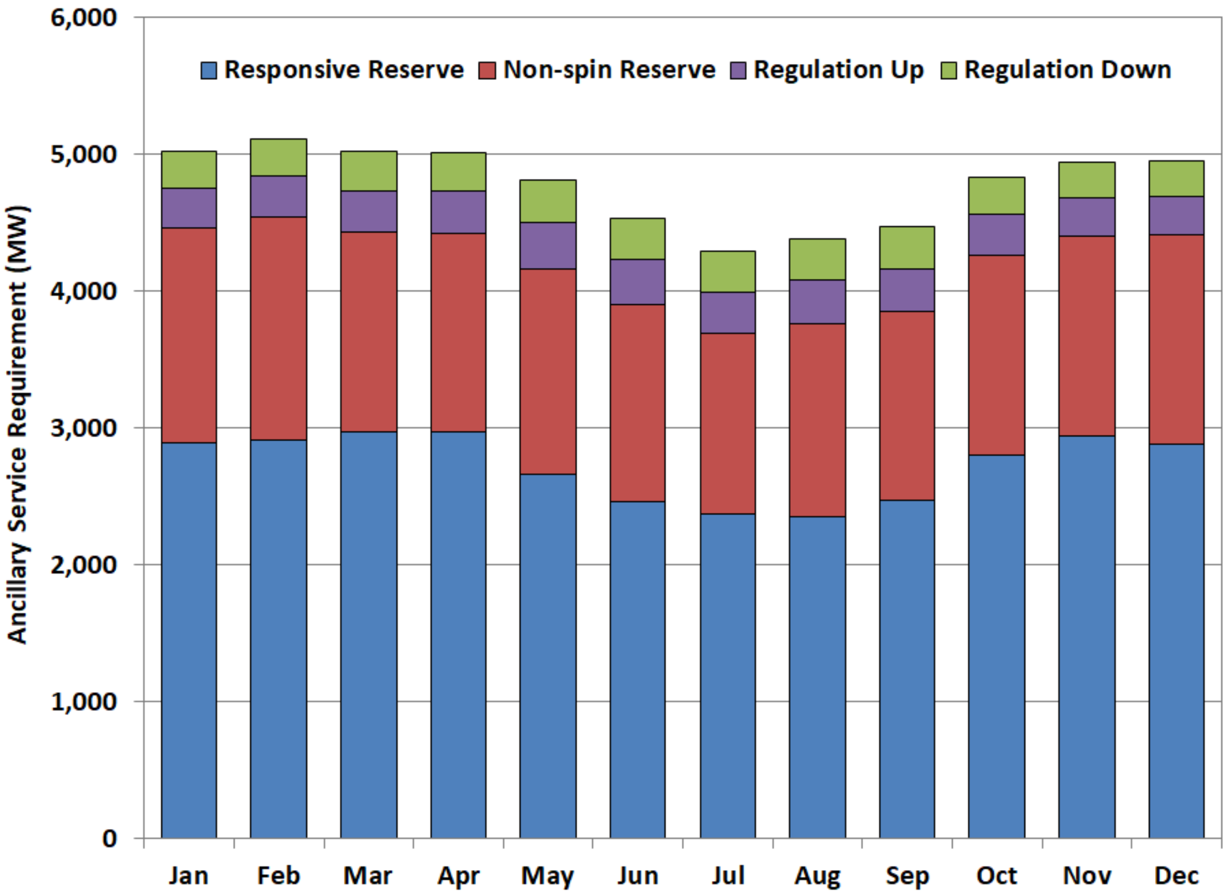


Figure A23 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the large variation in quantities between some adjacent hours was readily apparent. This pattern was a result of the methodology that, broadly speaking, sets quantities that change throughout the day, with regulation reserve quantities set based on net load variability, responsive reserve based on inertia conditions, and non-spinning reserve based on forecast errors.

Figure A23: Yearly Average Ancillary Service Capacity by Hour

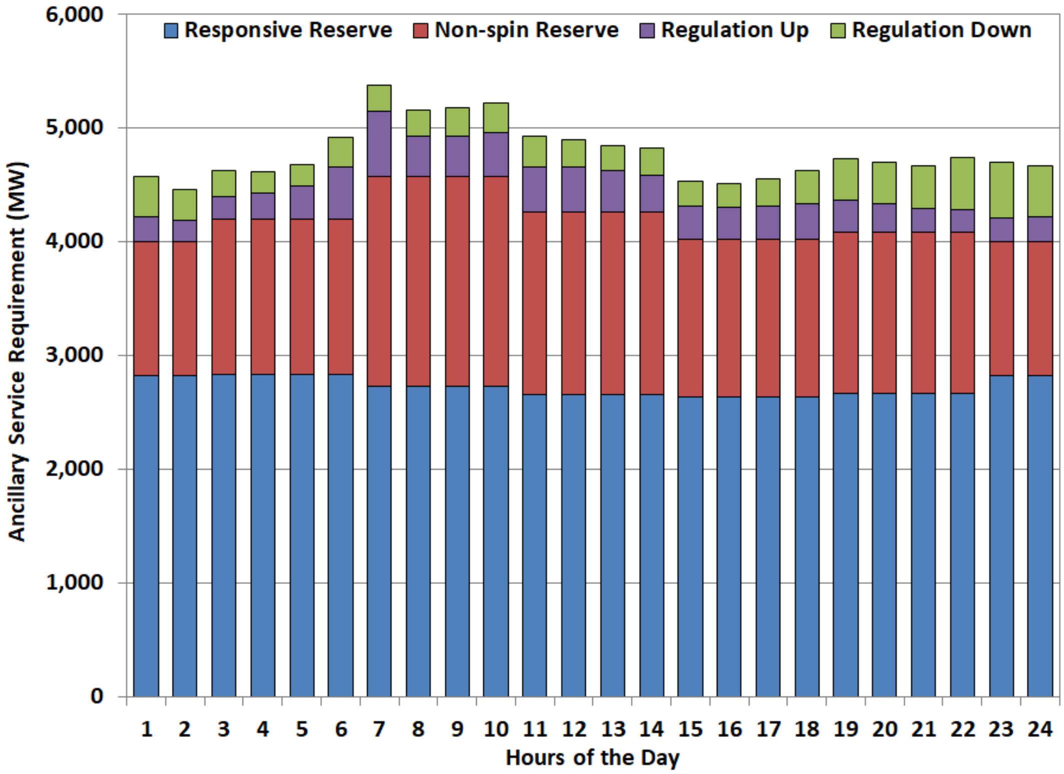
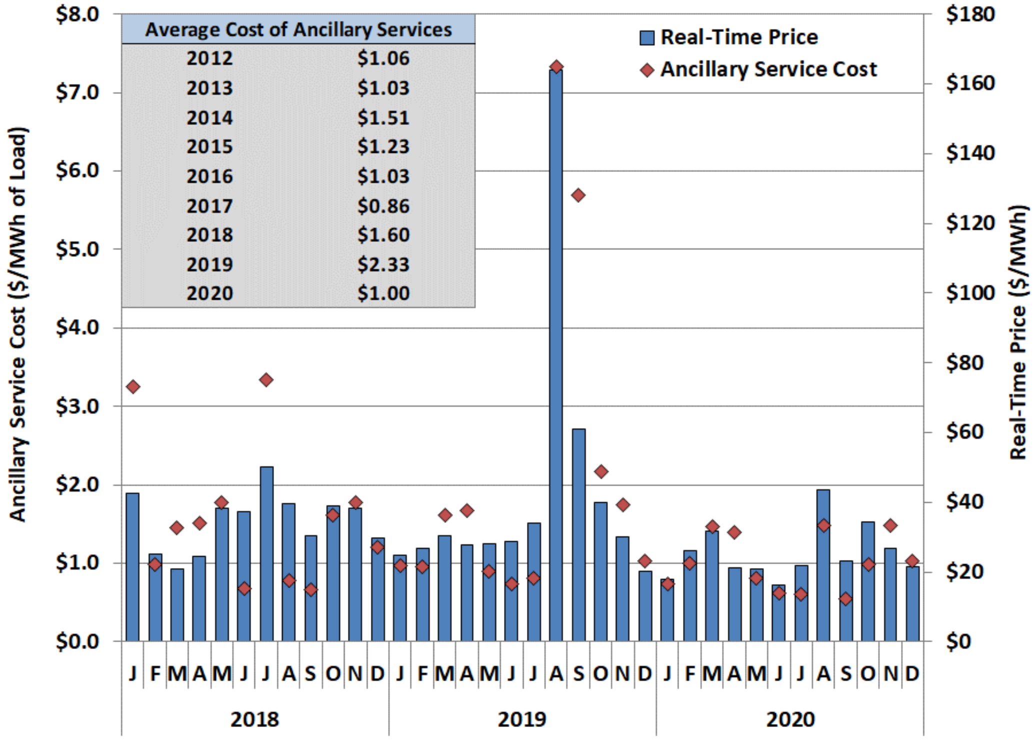


Figure A24 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2018 through 2020.

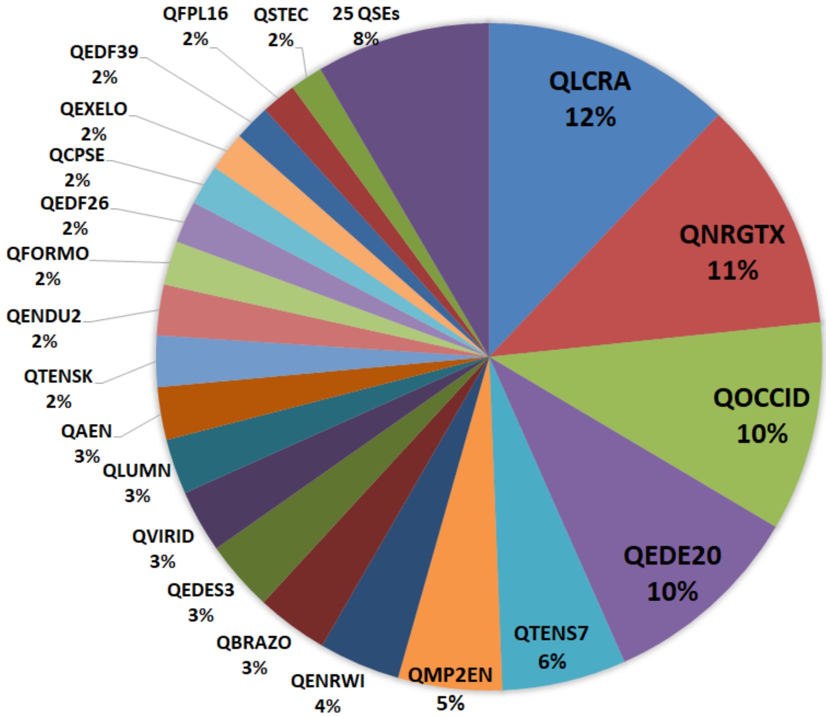
Figure A24: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load decreased from $2.33 per MWh in 2019 to $1.00 in 2020, but still above the all-time low of $0.86 per MWh in 2017. Similar to years past, the total ancillary service costs in 2020 were approximately 4% of the load-weighted average energy price, compared to 5% in 2019 and 4.5% in 2018.

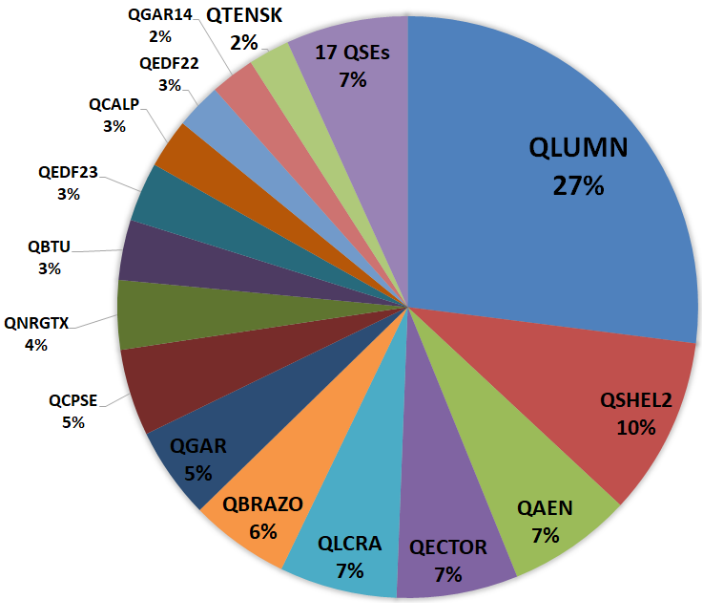
Figure A25 below shows the share of the 2020 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2020, 46 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market. The number of providers has been roughly the same for the past five years (43 in 2018 and 2019, 45 in 2017, 42 in 2016, and 46 in 2015). LCRA (QLCRA) was the largest provider of responsive reserves in 2020, but generally there were no significant changes from 2019 in the largest providers or in the share of responsive reserve provided.

Figure A25: Responsive Reserve Providers



In contrast, Figure A26 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 27% share of non-spin responsibility was a decrease from the 37% share it held in 2019, 41% in 2018, and 56% in 2017. The change in composition of Luminant's generation fleet likely explains the continued reduction. As Luminant's non-spin responsibility decreased again in 2020, many other suppliers such as Austin Energy (QAEN) and LCRA (QLCRA) increased their share slightly.

Figure A26: 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 real-time co-optimization of energy and ancillary services. 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), perhaps distributing the responsibility to provide among even more entities.

Figure A27: Regulation Up Reserve Providers

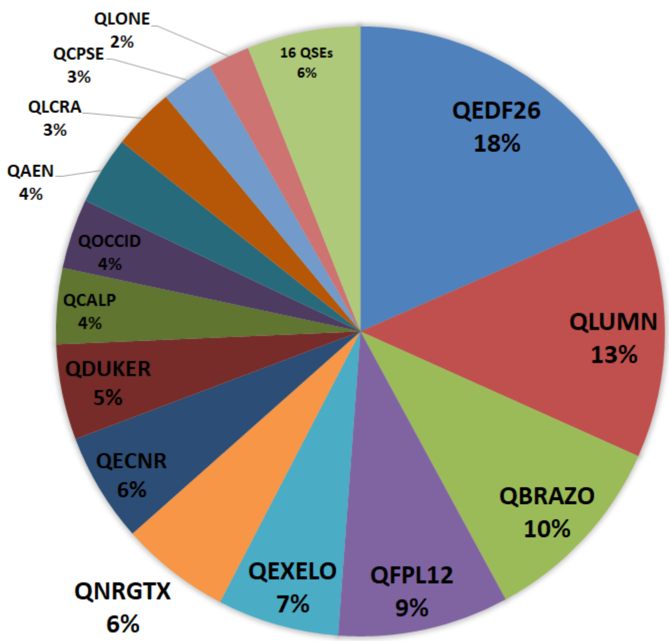
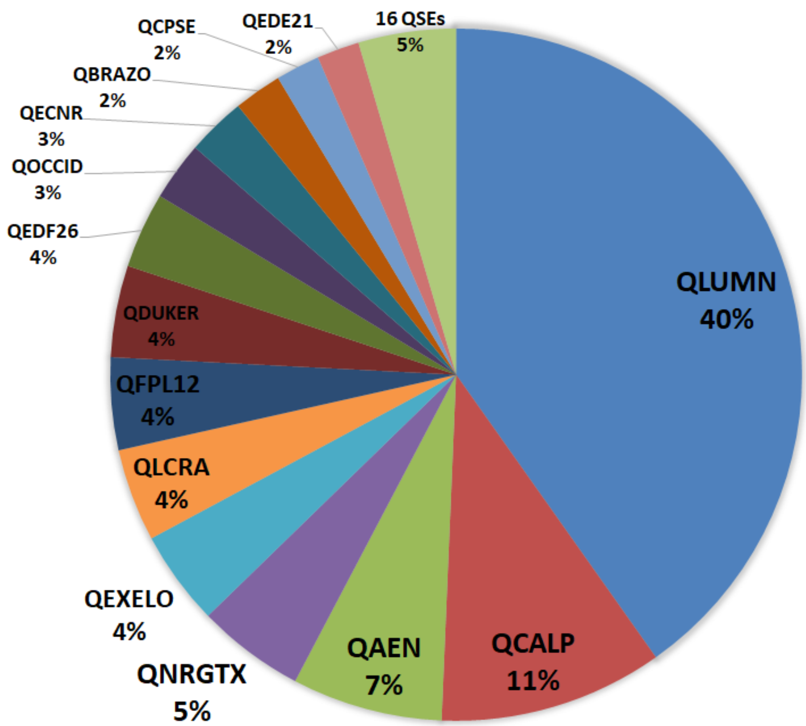


Figure A27 above shows the distribution for regulation up reserve service providers and Figure A28 shows the distribution for regulation down reserve providers in 2020. Figure A27 shows that regulation was spread more evenly, similar to responsive reserve providers, while EDF North America (QEDF26) more than doubled its share from 2019 and provided 18% of regulation up. Figure A28 shows that that regulation down had similar concentration to non-spinning reserves in 2020. Again, Luminant had a dominant position in the provision of regulation down. Its 40% share of the regulation down responsibility in 2020 was on par with the 43% it provided in 2019, and the 41% in 2018.

Figure A28: Regulation Down Reserve Providers



Ancillary service capacity is procured as part of the day-ahead market 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 day-ahead market. 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 are still effectively precluded from participating in ancillary service markets 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 typically three to 40 times greater than annual average clearing prices from the day-ahead market.

A SASM may also be opened if ERCOT changes its ancillary service plan, although this did not occur during 2020. A SASM was executed 28 times in 2020, with SASM awards providing 490 service-hours. SASMs were more frequent in 2020 than 2019; 2019 awarded only 168 service-hours. In addition to more frequent shortages, it appears that ERCOT operators were more sensitive to AS shortages in 2020 than in previous years and took the step to procure replacement MWs more often. Figure A29 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years.

Figure A29: Ancillary Service Quantities Procured in SASM

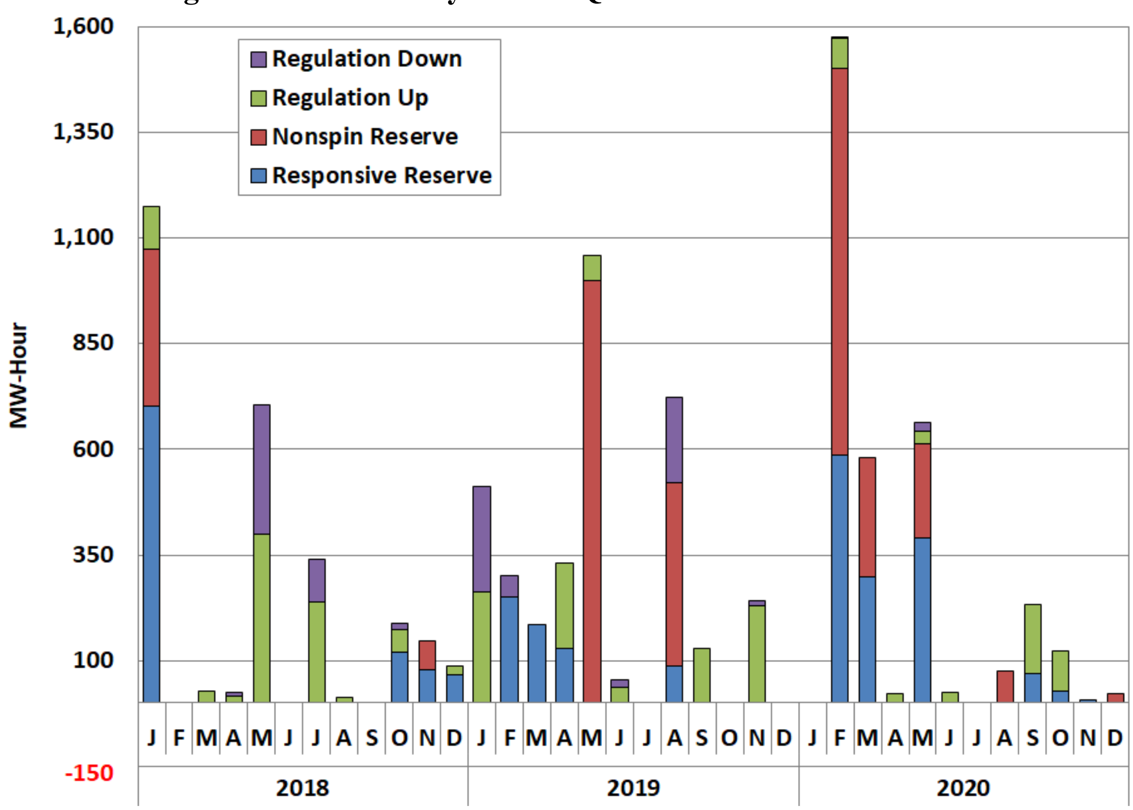
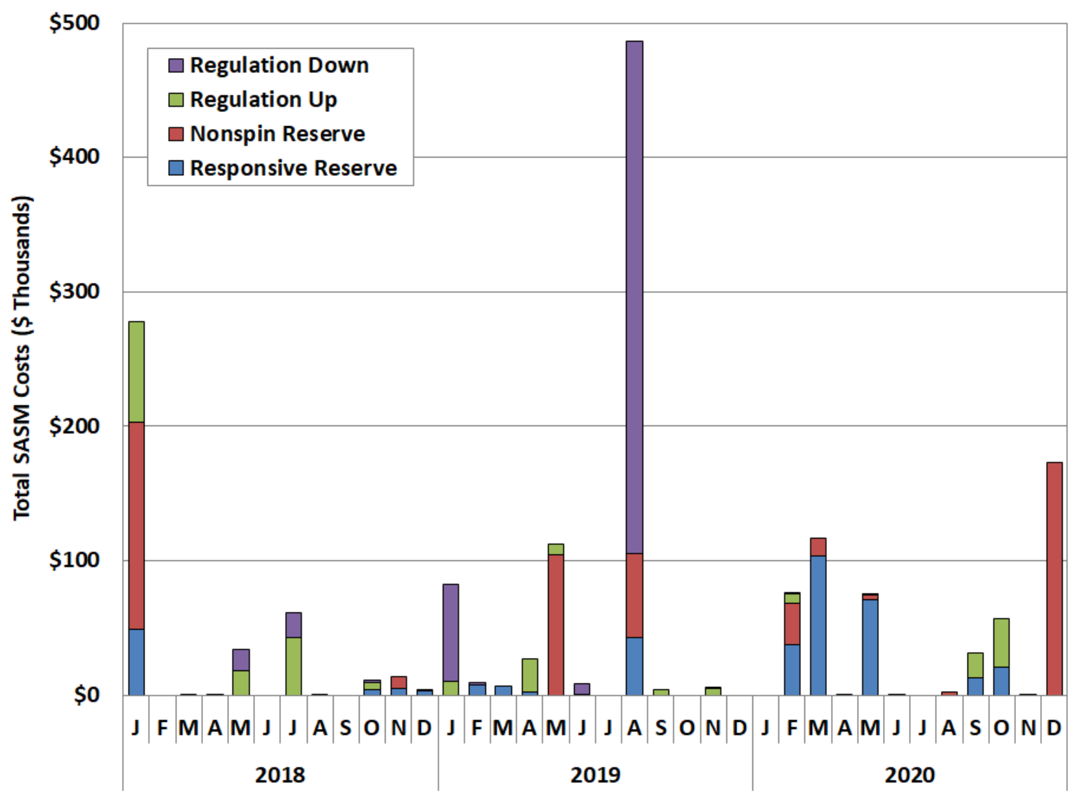


Figure A29 shows that the volume of service-hours procured via SASM over the year (more than 3,300 MWs of service-hours in 2020) is still infinitesimal when compared to the total ancillary service requirement of nearly 42 million MWs of service-hours.

Figure A30 shows the average cost of the replacement ancillary services procured by SASM in 2020. Nothing in 2020 approached the total SASM costs seen in August of 2019, by far the highest SASM costs seen since the beginning of 2018. 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 relative absence of shortage conditions, resources were less likely to be diverted to provide energy rather than reserves, thus lowering the cost of ancillary services in 2020.

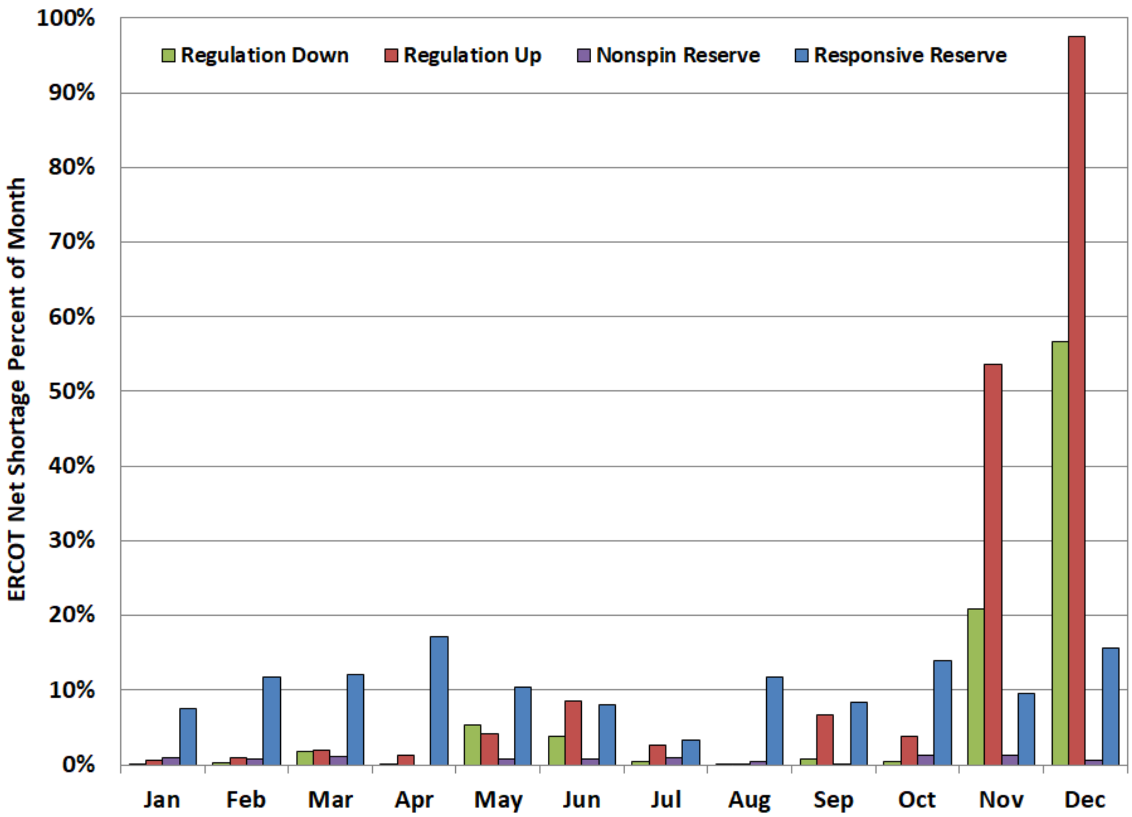
Figure A30: Average Costs of Procured SASM Ancillary Services



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 real-time co-optimization 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 A31 depicts the percentage of hours in each month of 2020 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 A31: ERCOT-Wide Net Ancillary Service Shortages



This analysis shows that ERCOT-wide shortages for all ancillary services were relatively low in 2020, generally at or below 10% in all months for all services, although regulation up and down experienced slightly higher shortages during the fall months, occurring in more than 50% of hours in November and December. These were primarily due to one entity and have been addressed. 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 2020, 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	$522	$732	$899	$568	$648	$573	$878	$1,786	$764	$1,075	$734	$648
Regulation Up	$1.88	$2.12	$2.88	$2.74	$2.28	$1.84	$2.25	$5.18	$1.53	$2.41	$3.09	$1.92
Regulation Down	$1.42	$1.24	$1.39	$2.20	$2.69	$1.65	$1.47	$1.64	$2.22	$2.11	$1.33	$1.92
Responsive Reserve	$15.6	$20.4	$32.2	$27.4	$16.6	$13.6	$16.9	$41.9	$11.8	$20.4	$32.2	$23.7
Non-Spin	$2.38	$4.30	$4.99	$5.36	$3.72	$4.88	$4.05	$11.58	$2.55	$5.94	$4.05	$3.61
CRR Auction Distribution	$54.9	$51.4	$65.8	$68.3	$60.3	$64.3	$65.2	$66.5	$59.2	$60.7	$53.9	$55.0
Balancing Account Surplus	$6.7	$11.0	$11.6	$12.5	$11.6	$0	$0	$0	$0	$0	$0	$0
CRR DAM Payment	$75	$155	$200	$55	$43	$57	$60	$197	$53	$137	$143	$100
PTP DAM Charge	$63	$135	$172	$50	$40	$44	$46	$153	$44	$106	$107	$79
PTP RT Payment	$68	$180	$192	$37	$71	$36	$50	$147	$45	$94	$127	$78
Emergency Response Service	$0	$16.3	$0	$0	$0	$11.7	$0	$0	$0	$16.8	$0	$0
Revenue Neutrality	$6.40	$7.59	$26.98	$2.78	$14.20	($0.30)	$1.37	($13.3)	$5.28	($2.87)	$22.35	$5.15
ERCOT Fee	$16.1	$15.6	$15.7	$15.0	$17.4	$19.7	$22.4	$22.7	$18.2	$17.4	$15.2	$16.8
Other Load Allocation	$0.58	$0.67	$1.08	$1.71	$1.46	$0.48	$2.49	$10.61	$1.92	$4.21	$0.89	$0.54

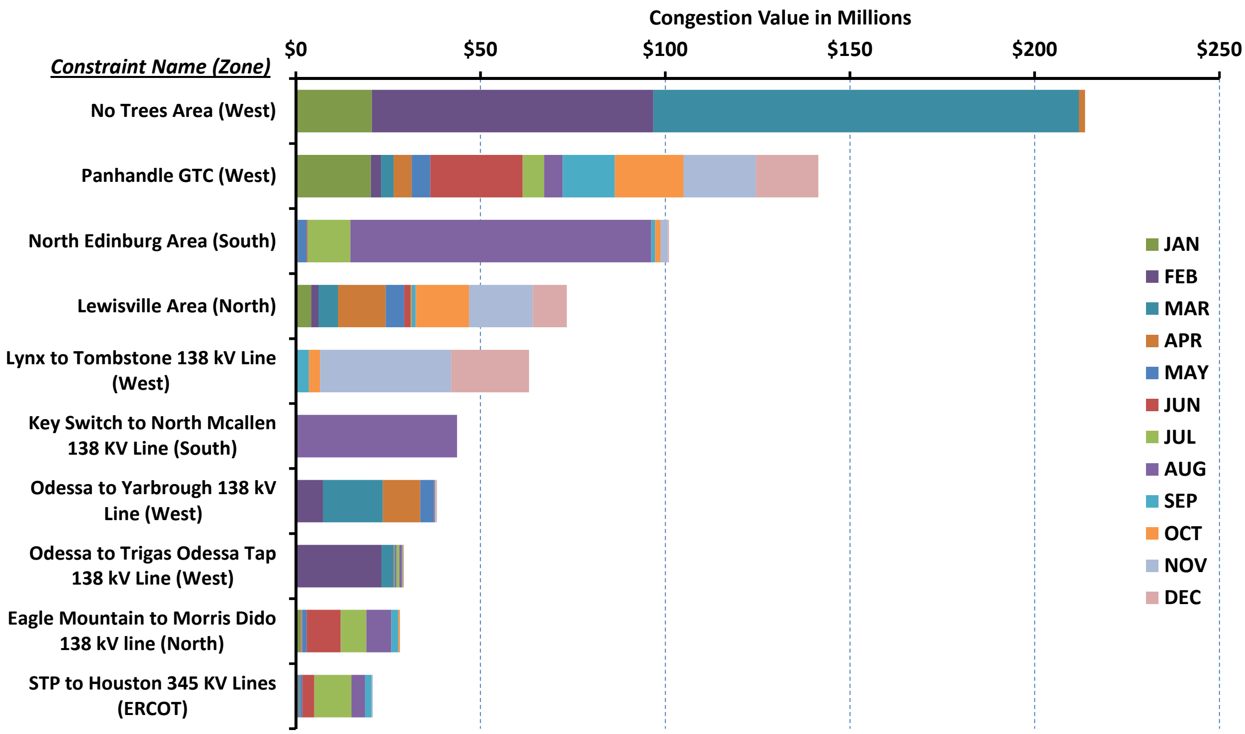
IV. Appendix: Transmission Congestion and Congestion Revenue Rights

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 day-ahead market in 2020. Figure A32 presents the ten most congested areas from the day-ahead market, ranked by their value. Eight of the constraints listed here were described in Figure 34: Most Costly Real-Time Congested Areas. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the day-ahead market similar to how energy flows in real-time, the same transmission constraints are expected to appear in both markets.

Figure A32: 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 2020 were also costly real-time constraints. Aside from the Eagle Mountain to Morris Dido, the rest of the constraints that exist in both the top 10 real-time and the top 10 day-ahead incurred less congestion value in the day-ahead market than the real-time market. This is a result of less wind generation participating in the day-ahead market, likely because of the uncertainty associated with predicting its output.

The two remaining top 10 day-ahead constraints, Odessa to Yarborough 138 kV line and STP to Houston 345 kV lines (which include the 345 kV lines STP to WA Parish and STP to Jones Creek) only ranked in the top 20 of real-time congestion costs.

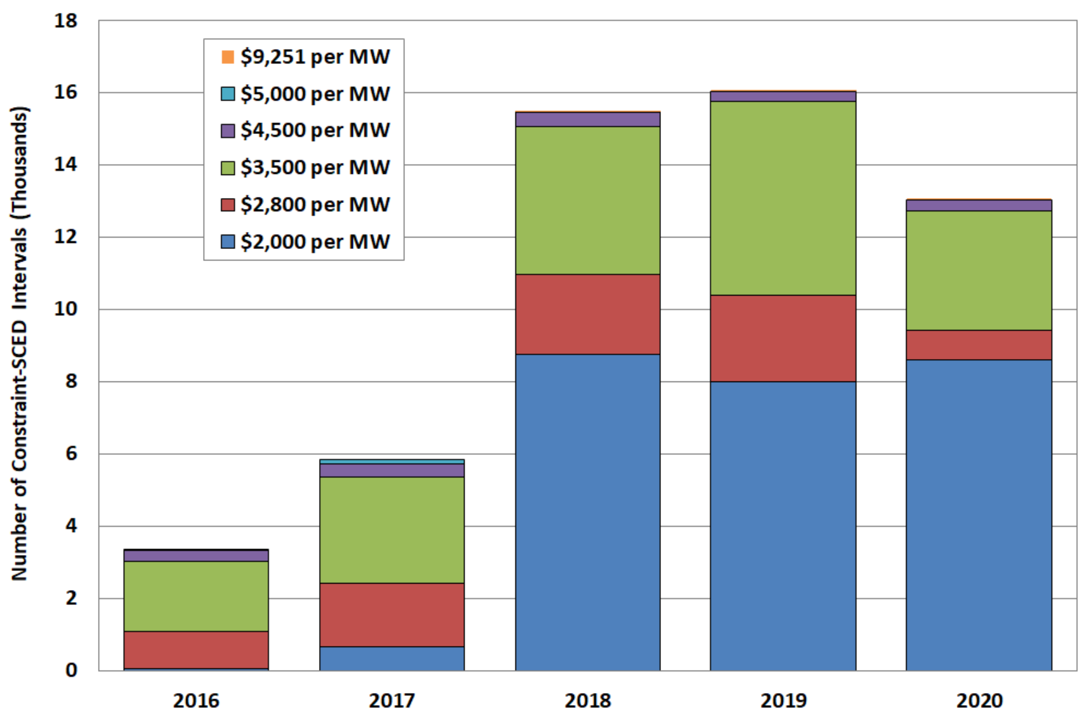
B. Real-Time Congestion

All actual physical congestion occurs in real-time and the real-time market and ERCOT operators manage power flows across the network. The expected costs of this congestion are reflected in the day-ahead market, but the ultimate source of the congestion is the physical constraints binding in real time.

1. Types and Frequency of Constraints in 2020

Figure A33 below depicts constraints were violated (i.e., at maximum shadow prices) less frequently in 2020 than they were in 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. Violated constraints continued to occur in only a small fraction of all the constraint-intervals, 5% in 2020, down from 7% in 2019 and 8% in 2018.

Figure A33: Frequency of Violated Constraints

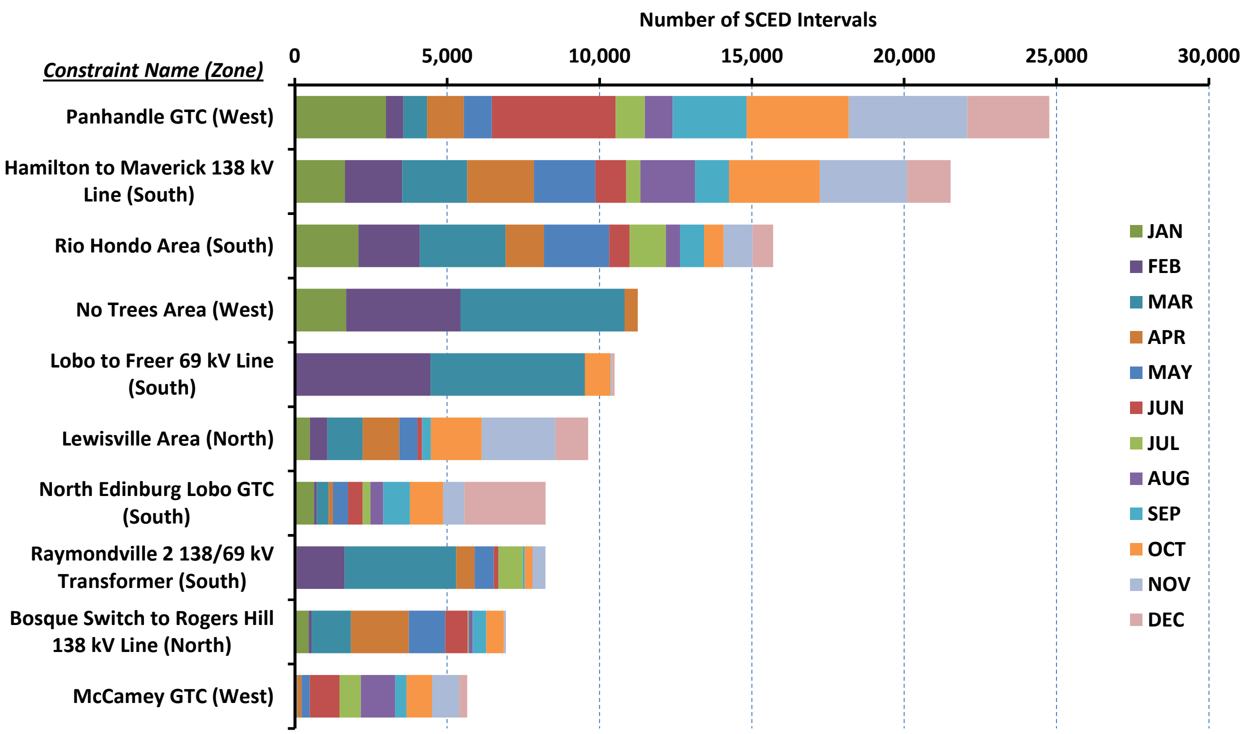


2. Real-time Constraints and Congested Areas

The Panhandle export contributes to the congestion in the Lewisville area and Eagle Mountain to Morris Dido 138 kV line, which is near Dallas-Fort Worth. The components of the Lewisville area include the West TNP to TI TNP, and the Lewisville to Jones Street TNP 138 kV lines. The congestion values for these constraints almost doubled from $51 million in 2019 to $80 million in 2020. The Eagle Mountain to Morris Dido 138 kV line was the eighth most costly at $27 million, the same value from 2019. The activation of constraints in the Panhandle GTC, Lewisville area, Lynx to Tombstone 138 kV line, and the Eagle Mountain to Morris Dido 138 kV line all had the effect of dispatching wind output down and increasing the generation in the North. While there are transmission upgrades in the Lewisville and Eagle Mountain area, congestion continues due to the abundance of renewable generation in the West zone.

All constraints, except those located in the South zone, listed in Figure A34 were frequently constrained in 2020 due to variable renewable output. The constraints in the South zone were frequent in August and September due to the damage caused by Hurricane Hanna. Four of the ten most frequently occurring constraints in 2020 were also among the ten most costly constraints, consisting of Panhandle GTC, No Trees Area, Lewisville Area, and North Edinburg Lobo GTC. The other six of the most frequent constraints aggregated more than $74 million in congestion value.

Figure A34: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

As shown in Table A4, 16 element combinations were deemed irresolvable in 2020 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[56] 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	2020 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2020
Base Case	Valley Import	$9,251	$2,000	1/1/12	-	South	-
SSOLFTS8	Fort Stoctkon to Barilla 69 kV Line	$2,800	$2,000	5/13/19	-	West	-
DCASTXR8	Moore to Hondo Creek Switching Station 138 kV Line	$3,500	$2,549	1/2/18	1/30/20	West	-
SWINYUC8	Wickett TNP to Winkler County 6 TNP 69 kV Line	$2,800	$2,000	4/9/18	1/30/20	West	-
SJUNYEL9	Yellow Jacket to Hext LCRA 69 kV line	$2,800	$2,000	5/18/18	1/30/20	West	-
XFRI89	Sonora 138/69 kV Transformer	$2,800	$2,000	5/24/19	-	West	7
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	$2,800	$2,000	9/23/19	-	West	745
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	10/15/19	-	West	6,471
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	10/23/19	-	West	3,049
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	11/29/19	-	West	62
SHACPB38	Rio Pecos to Woodward 2	$3,500	$2,000	1/1/20	-	West	50
DWINDUN8	Andrews County South to Amoco Three Bar Tap 138 kV Line	$3,500	$2,000	3/24/20	-	West	831
DNEDWED8	Hidalgo Energy Center to Azteca Sub 138 kV Line	$3,500	$2,000	8/5/20	-	South	313
SMV_ALT8	Weslaco Switch to North Alamo 138 kV Line	$3,500	$2,000	8/7/20	-	West	78
SPHAWES8	Key Switch to North McAllen 138 kV Line	$3,500	$2,000	8/10/20	-	West	8
SHACPB38	Lynx to Tombstone 138 kV Line	$3,500	$2,000	11/30/20	-	West	865

56 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.

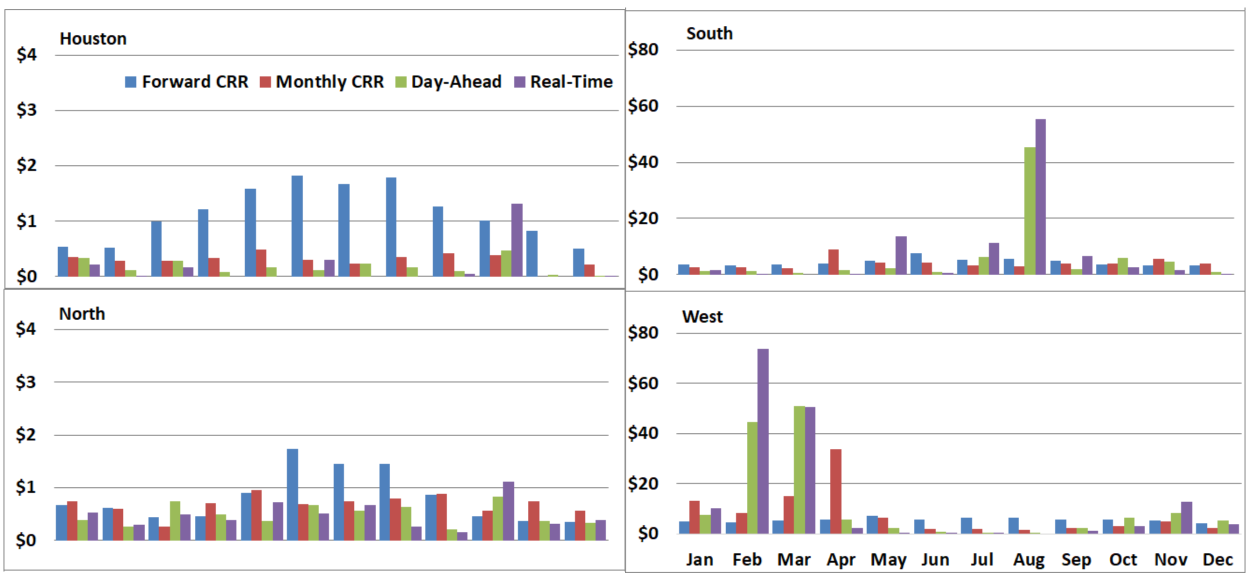
Three constraints, the Moore to Hondo Creek 138 kV line, Wickett to Winkler County 69 kV line, and Yellow Jacket to Hext 69 kV line, were deemed resolvable during ERCOT's annual review and were removed from the list. All irresolvable constraints are located in the West zone with the exception of the Valley Import GTC and Hidalgo Energy Center to Azteca 138 kV line, which is located in the South zone. The Dollarhide to No Trees 138 kV line was deemed irresolvable at the end of 2019 for three different contingency conditions. However, an upgrade for the element was completed in spring 2020 and did not experience congestion after April.

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A35 below shows the price spreads between all hub and load zones 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.

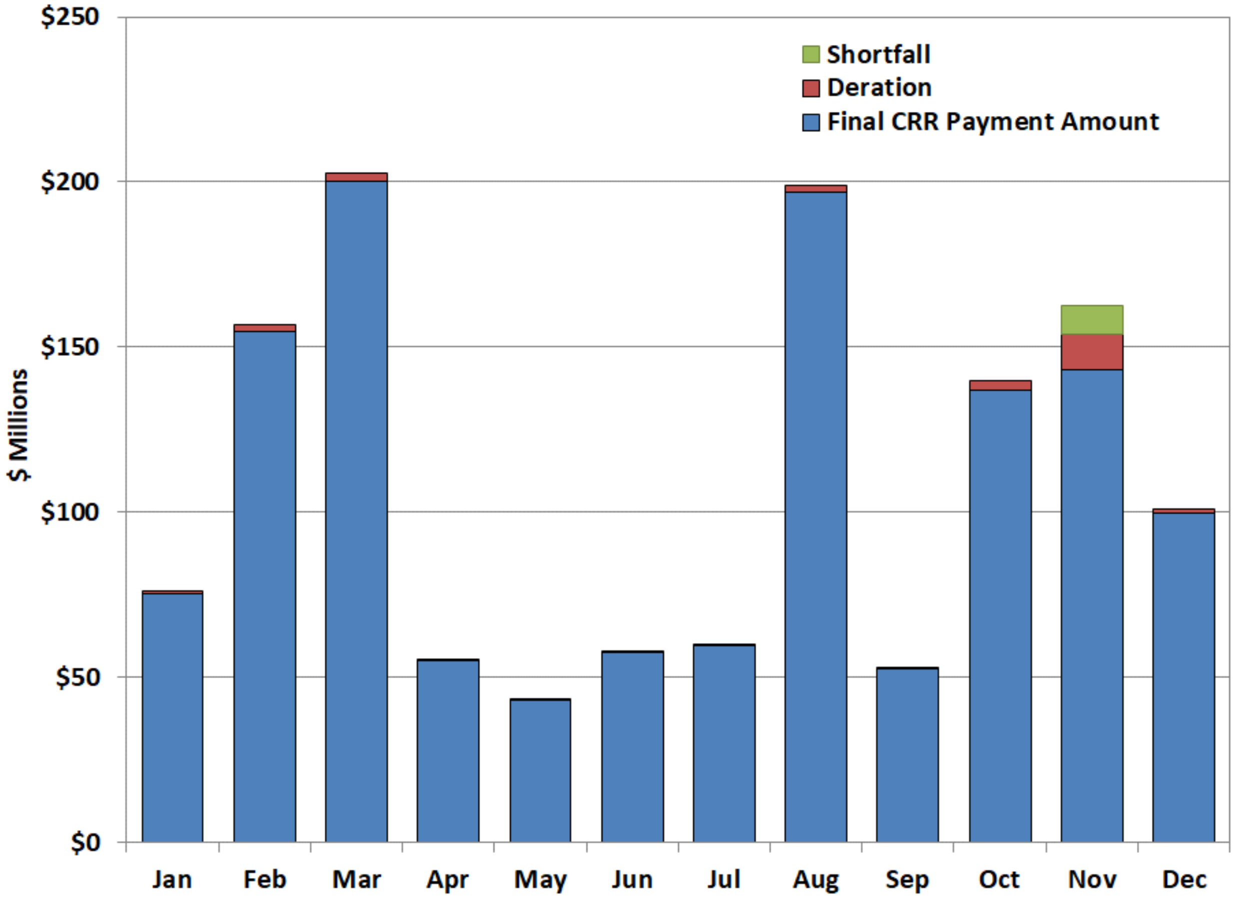
Figure A35: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A36 shows the amount of target payment, deration amount, and final shortfall for 2020. In 2020, the total target payment to CRRs was $1.3 billion; however, there were approximately $24 million of derations and almost $9 million in shortfall charges (all of which occurred in November) resulting in a final payment to CRR account holders of $1.28 billion. This final payment amount corresponds to a CRR funding percentage of 98%, roughly the same as the funding percentage of 97.6% in 2019.

Figure A36: CRR Shortfall and Derations



V. Appendix: Reliability Unit Commitments

In this section, we provide supplemental analyses of RUC activity in 2020 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 I: 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 day-ahead market. A new settlement structure for SWGRs that receive a RUC instruction was approved and implemented in 2019 to address concerns of inadequate compensation for SWGRs that were instructed to switch from a non-ERCOT control area to the ERCOT Control Area.

RUC-related improvements in 2020 included updates to ERCOT systems to effectively manage cases where ERCOT issues a RUC instruction to a combined cycle resource that is already QSE-committed for an hour, with the instruction being that the resource operate in a configuration with greater capacity for that same hour. Further, the maximum amount that may now be recovered for fuel oil disputes is the difference between the RUC Guarantee based on the actual price paid and the adjusted Fuel Oil Price (FOP). And finally, ERCOT systems now automatically create a proxy Energy Offer Curve with a price floor of $4,500/MWh for each RUC-committed SWGR as opposed to requiring QSEs to submit Energy Offer Curves reflecting the $4,500/MWh floor.[57]

B. 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 hour-ahead basis. Additional resources may be needed for two primary reasons – to satisfy the total forecasted demand, or to make a specific generator available resolve a transmission constraint. The transmission constraint may be either a thermal limit or voltage concern.

Figure A37 below shows RUC activity by month for 2018 through 2020, indicating the volume of generators receiving a RUC instruction that had offers in the day-ahead market or chose to opt-out of the RUC instruction. The monthly data shows no consistent pattern of RUC activity over the past three years. For comparison, annual summaries are also provided in the table going back to 2014, the year with the highest amount of RUC activity.

57 See NPRR856, Treatment of OFFQS Status is 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).

Figure A37: Day-Ahead Market Activity of Generators Receiving a RUC

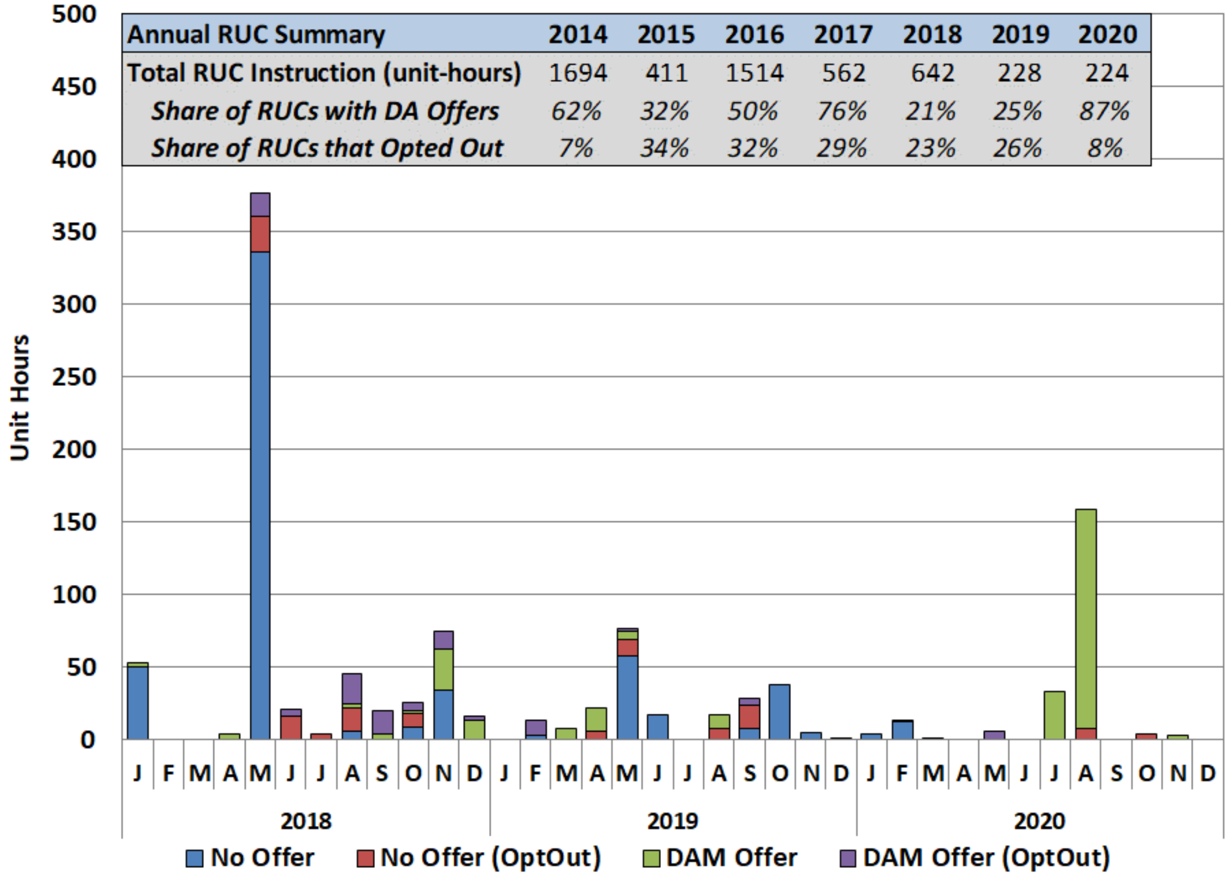


Table A5 below lists the generation resources that received the most RUC instruction in 2020 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. The units highlighted in gray are the ones that similarly received RUC instructions in 2019. ERCOT issued frequent RUC instructions to the North Edinburg combined cycle unit due to localized transmission congestion related to forced outages caused by Hurricane Hanna.

Table A5: 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
North Edinburg CC1	Valley	182	0	316	211	201	220
Duke CC1	Valley	5	6	269	182	177	202
Ector Energy G1	Far West	8	0	171	83	80	119
Mountain Creek Unit 6	DFW	0	8	122	87	15	92
Lake Hubbard Unit 2A	DFW	0	4	515	142	48	172
Silas Ray 10	Valley	4	0	39	17	18	18
Permian CT 5	Far West	3	0	75	41	41	49
Permian CT 1	Far West	2	0	73	42	41	73
Ector Energy G2	Far West	1	0	171	95	80	168
Permian CT 4	Far West	1	0	70	41	41	70

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) six months in 2020.
- No RUC activity occurred in April, June, September, or December.
- In February, March, May, June, August and October 2020, the average dispatch level was more than the average low limit because of mitigation of the resource.
- Also, in May, August, and October, the average dispatch level was higher due to RUC resources choosing to opt out and thus not being subject to the $1,500/MWh offer floor.

Figure A38: Reliability Unit Commitment Capacity

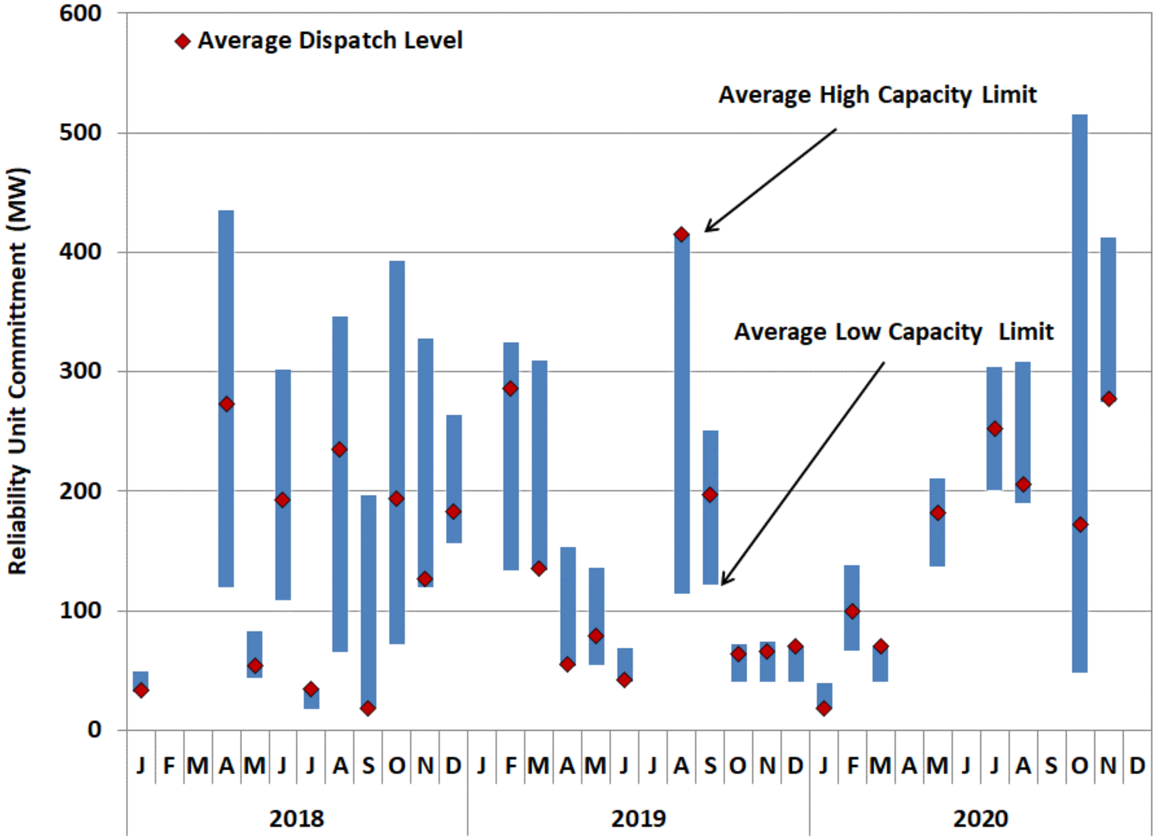


Figure A38 shows in 30% of intervals with RUC resources, one or more resources were dispatched above their low dispatch limit (LDL), a decrease from 40% of the intervals in 2019. This higher dispatch level in 2019 indicates that most units receive RUC instructions to resolve local constraints and scarcity intervals, and that these local constraints are non-competitive. Because all RUC instructions in 2020 were given to relieve congestion, units were dispatched based on their mitigated offers. It is rare for a generator receiving a RUC instruction to be dispatched above LDL with its offer at or above the $1,500 per MWh offer floor. In 2020, this occurred in less than 1% of the intervals with a RUC-settled resource.

C. QSE Operation Planning

The two figures below are related to the discussion in the Report surrounding the accuracy of COP submissions and how the accuracy changes as time approaches the operating hour. An example of large changes or trends of changes are relayed in the graphs, one regarding a large supplier and the other a NOIE.

Figure A39: Large Supplier Capacity Commitment Timing – July and August Hour Ending 17

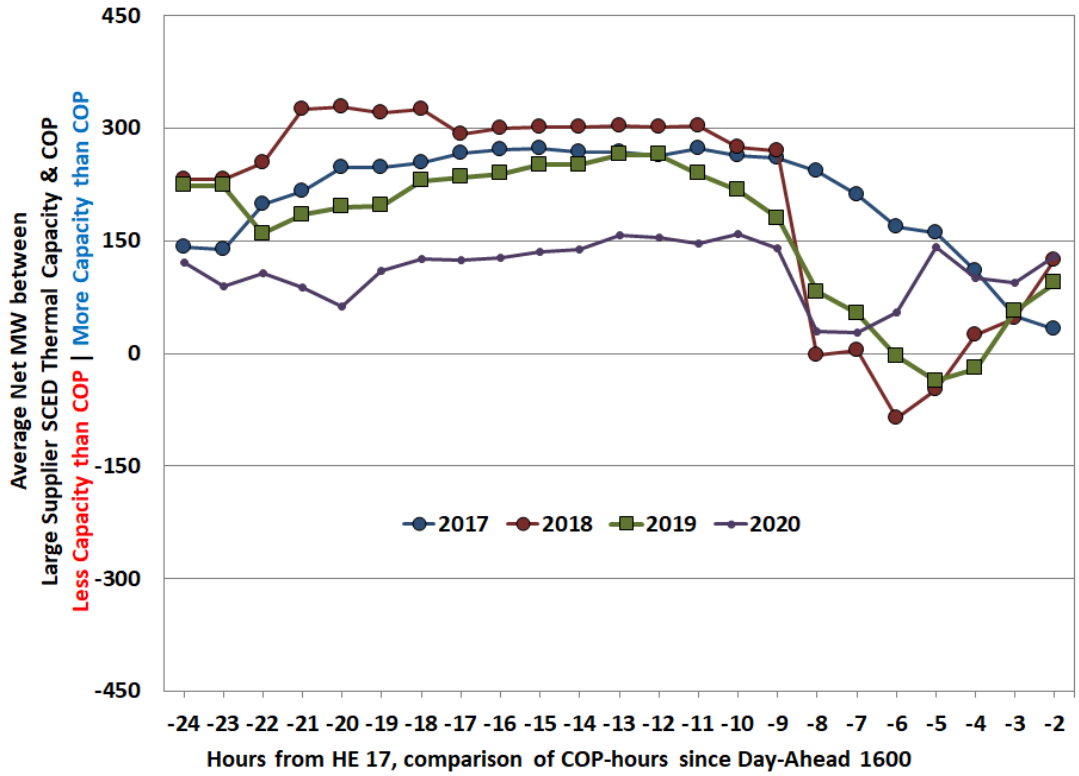
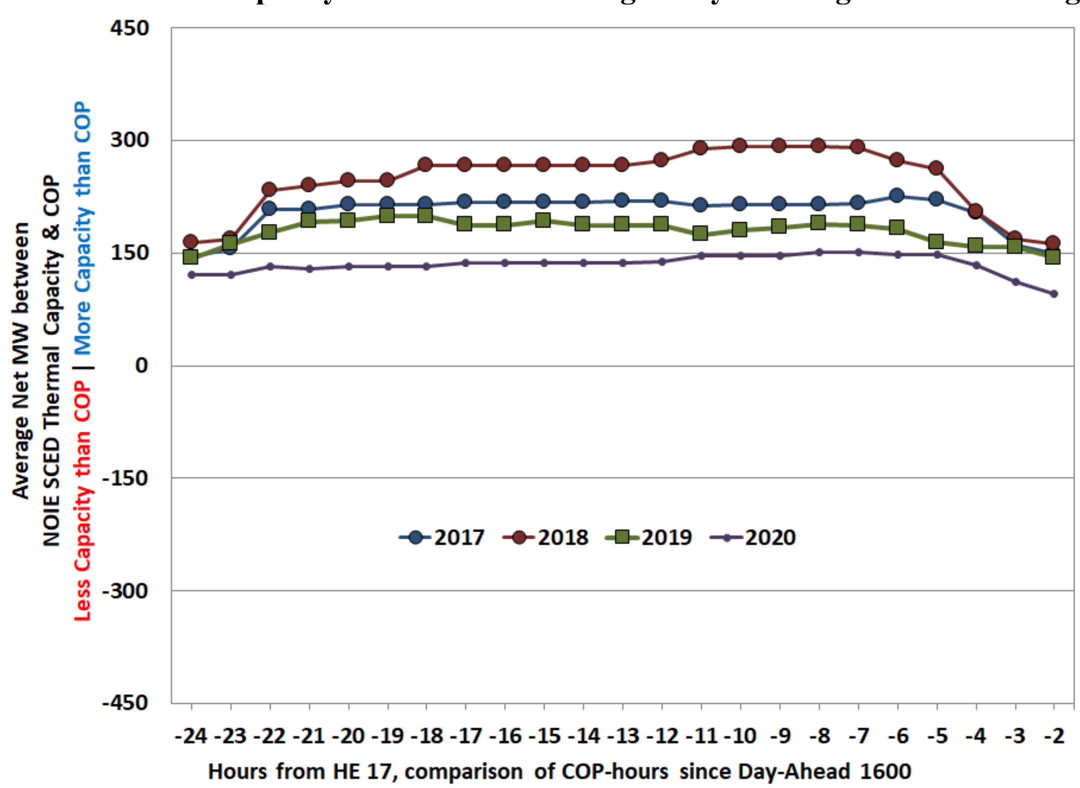


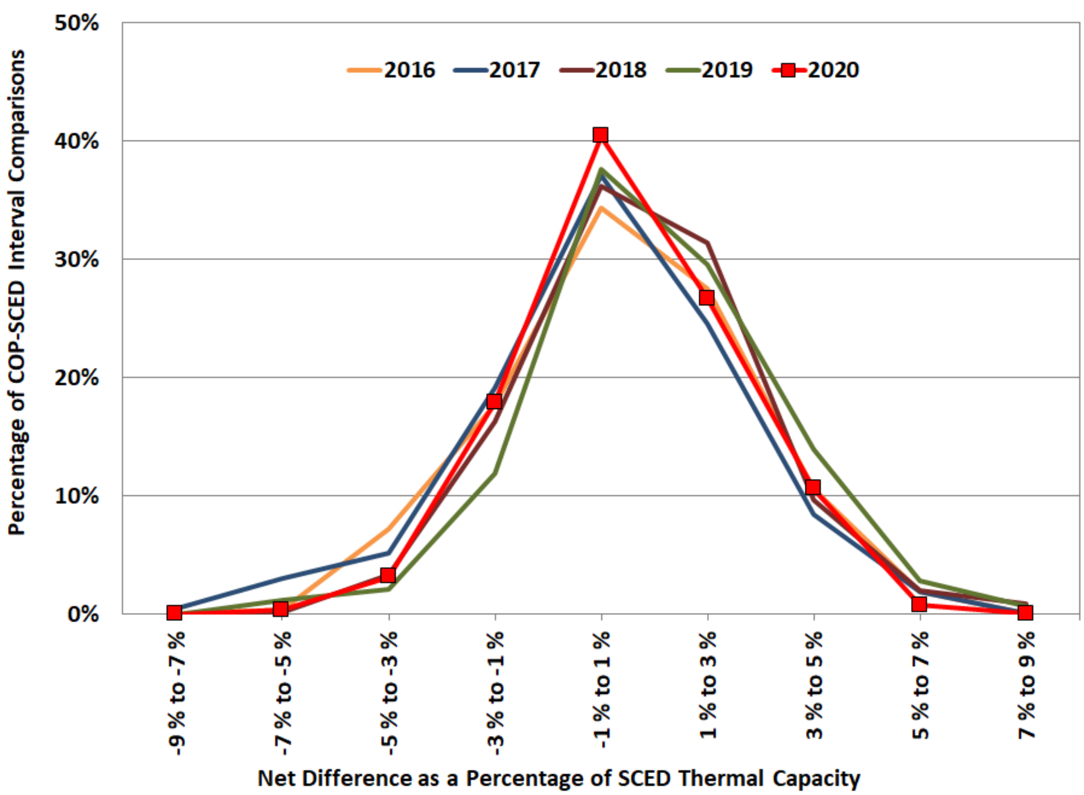
Figure A40: NOIE Capacity Commitment Timing – July and August Hour Ending 17



The next 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 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 II: 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 five 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%.

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

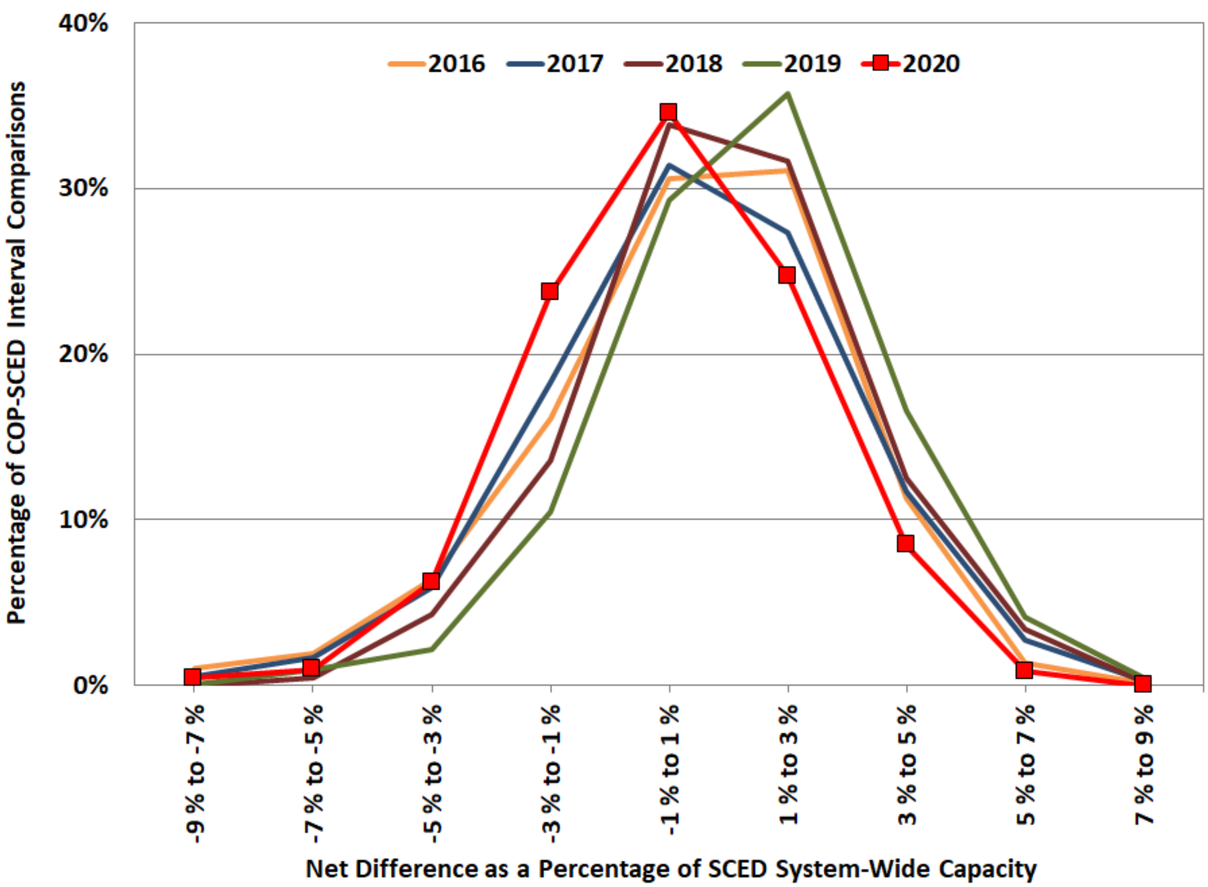


When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then under-report the COP at the end of the adjustment period a small percentage of the time. The curve from 2020 is similar to the curves from the last five years, with 2020 exhibiting a slightly bigger contrast.

In 2019, there was a bias towards under-representing the amount of capacity that would materialize in real-time. In 2020, 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. The most interesting difference between Figure A41 and Figure A42 is the shift towards having less capacity occur in real-time at the system-wide level, including intermittent renewable resources. A possible explanation for this is a higher than expected forecast for the renewables leading up to the operating hour.

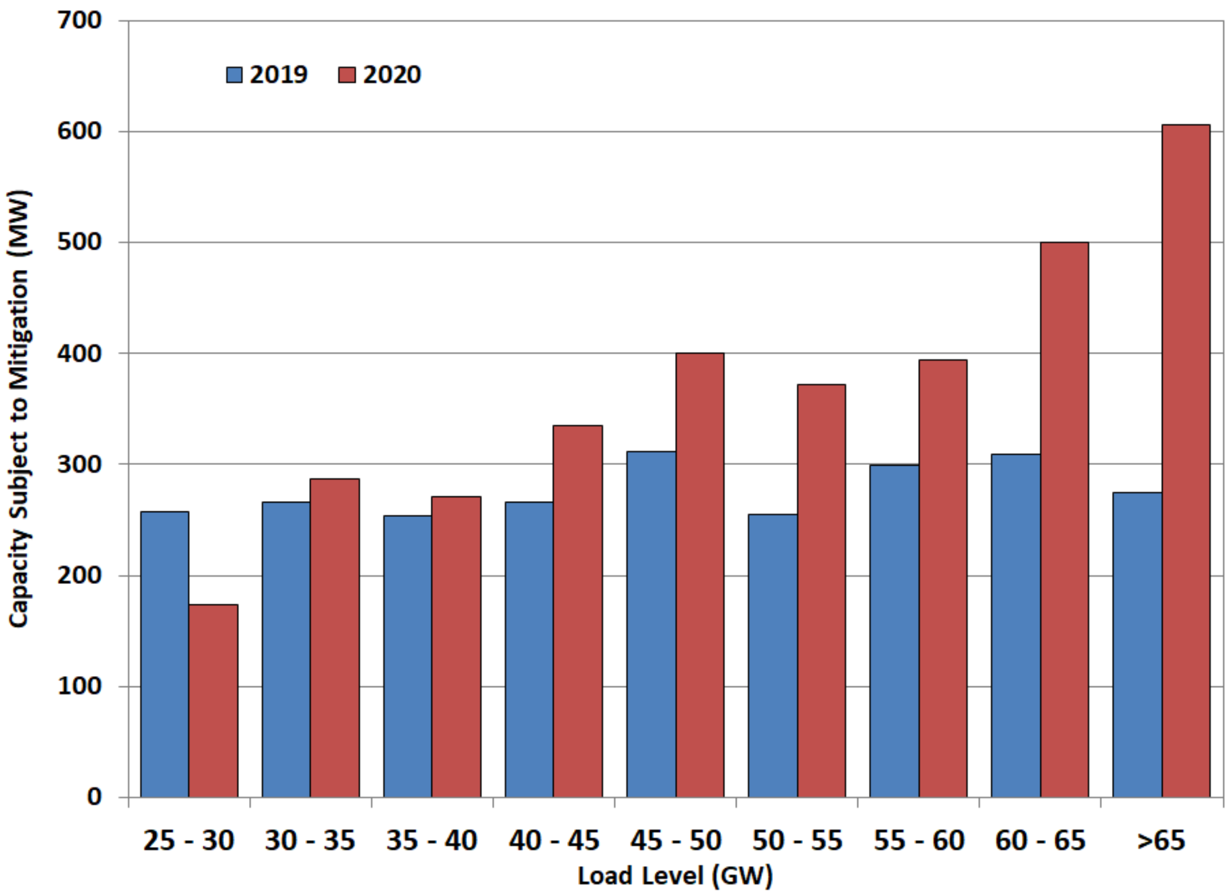
Figure A42: Real-Time to COP Comparisons for System-Wide Capacity



D. Mitigation

The next analysis computes the total capacity 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: Capacity Subject to Mitigation



The amount of capacity subject to mitigation in 2020 was higher than 2019 in all but the 25 to 30 GW load level. Mitigation was historically low in 2019 and so this increase represents a return to a more typical value. 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.

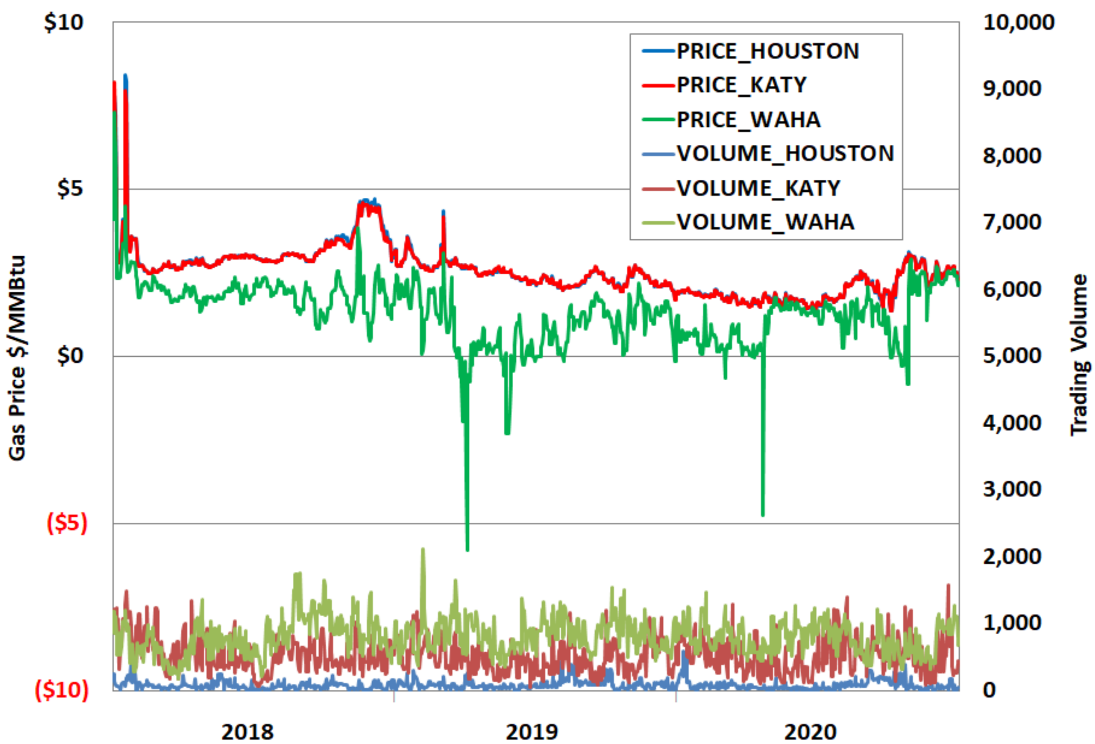
VI. Appendix: Resource Adequacy

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.[58] 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. As seen in Figure A44 below, Waha prices dipped below $0 multiple times throughout 2020, and were more volatile than Katy.

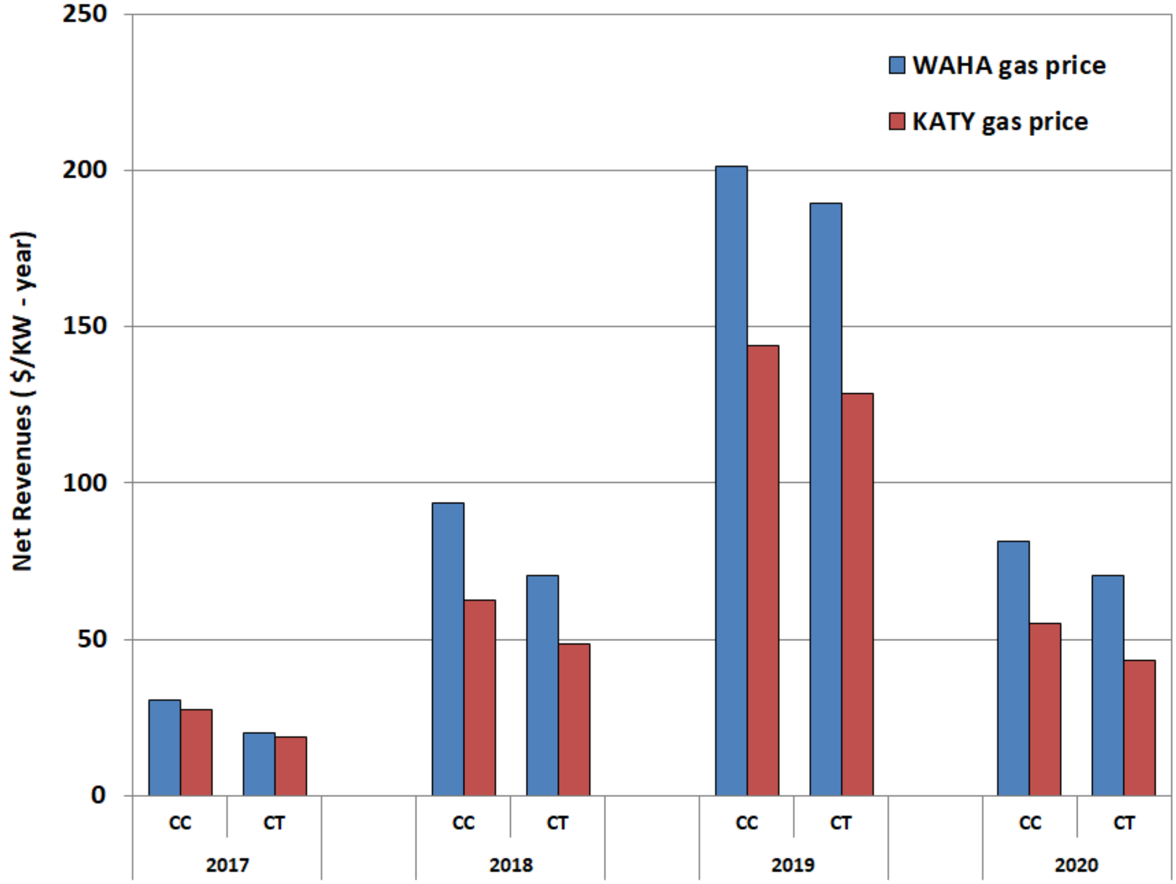
Figure A44: Gas Price and Volume by Index



58 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 either 2019 or 2020. Additionally, the divergence between Waha and Katy gas prices contributed to even 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.[59] ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

On March 23, 2020, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for Gregory Power Partners, LLC's LGE_LGE_GT1, LGE_LGE_GT2, and LGE_LGE_STG resources. The NCGRD stated that as of May 1, 2020, the resources, which were currently under a seasonal mothball status with a Seasonal Operation Period of June 1st through September 30th, would change the start date of their Seasonal Operation Period to May 1st.

On May 5, 2020, ERCOT received a NCGRD for the City of Garland's SPNCER_SPNCE_4 and SPNCER_SPNCE_5 resources. The NCGRD stated that as of May 5, 2020, the resources, which were under a seasonal mothball status with a Seasonal Operation Period of June 1st through September 30th, would change the start date of their Seasonal Operation Period to May 20th, and changed the end date of their Seasonal Operation Period to October 10th.

On May 29, 2020, ERCOT received a Notification of Suspension of Operations (NSO) for Nacogdoches Power LLC's NACPW_UNIT1 resource. The NSO indicated that this resource would suspend operations on a year-round basis (i.e., mothball) beginning October 16, 2020, with a Seasonal Operation Period of May 15 through October 15. The NSO further indicated that this Resource had a summer Seasonal Net Max Sustainable Rating of 105 MW, and a summer Seasonal Net Minimum Sustainable Rating of 70 MW.

On June 1, 2020, ERCOT received an NSO for the City of Austin dba Austin Energy's DECKER_DPG1 resource. The NSO indicated that the resource will be decommissioned and retired permanently as of October 31, 2020. The NSO further indicated that the resource has a summer Seasonal Net Max Sustainable Rating of 315 MW, and a summer Seasonal Net Minimum Sustainable Rating of 50 MW.

On September 21, 2020, ERCOT received an NSO for Petra Nova Power I LLC's PNPI_GT2 resource indicating that the resource would suspend operations (i.e., mothball) beginning December 20, 2020, with a Seasonal Operation Period of June 1 through September 30. The NSO further indicated that this resource has a summer Seasonal Net Max Sustainable Rating of 71 MW, and a summer Seasonal Net Minimum Sustainable Rating of 65 MW.

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59 Petra Nova Power I LLC - PNPI_GT2; South Texas Electric Cooperative Inc. - RAYBURN_RAYBURG1 and RAYBURN_RAYBURG2; Luminant Generation Company LLC - TRSES_UNIT6; Wharton County Generation, LLC - TGF_TGFGT_1; City of Austin dba Austin Energy - DECKER_DPG1; Nacogdoches Power LLC - NACPW_UNIT1; City of Garland (RE) - SPNCER_SPNCE_4 and SPNCER_SPNCE_5; and Gregory Power Partners, LLC (RE) - LGE_LGE_GT1, LGE_LGE_GT2, and LGE_LGE_STG.

On October 1, 2020, ERCOT received an NSO for South Texas Electric Cooperative Inc.'s RAYBURN_RAYBURG1 and RAYBURN_RAYBURG2 resources. The NSO indicated that the resources will be decommissioned and retired permanently as of February 28, 2021. The NSO further indicated that each resource has a summer Seasonal Net Max Sustainable Rating of 11 MW, and a summer Seasonal Net Minimum Sustainable Rating of 5 MW.

On November 30, 2020, ERCOT received an NSO for Luminant Generation Company LLC's TRSES_UNIT6 resource. The NSO indicated that the resource will be decommissioned and retired permanently as of April 29, 2021. The NSO further indicated that the resource has a summer Seasonal Net Max Sustainable Rating of 235 MW, and a summer Seasonal Net Minimum Sustainable Rating of 70 MW. Note that this NSO was withdrawn, however, on April 1, 2021.

On November 30, 2020, ERCOT received an NSO for Wharton County Generation, LLC's TGF_TGFGT_1 resource. The Resource Entity indicated in the NSO that the resource ceased operations due to a Forced Outage and was decommissioned and retired permanently as of November 30, 2020. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 69 MW, and a summer Seasonal Net Minimum Sustainable Rating of 59 MW.

VII. APPENDIX: ANALYSIS OF COMPETITIVE PERFORMANCE

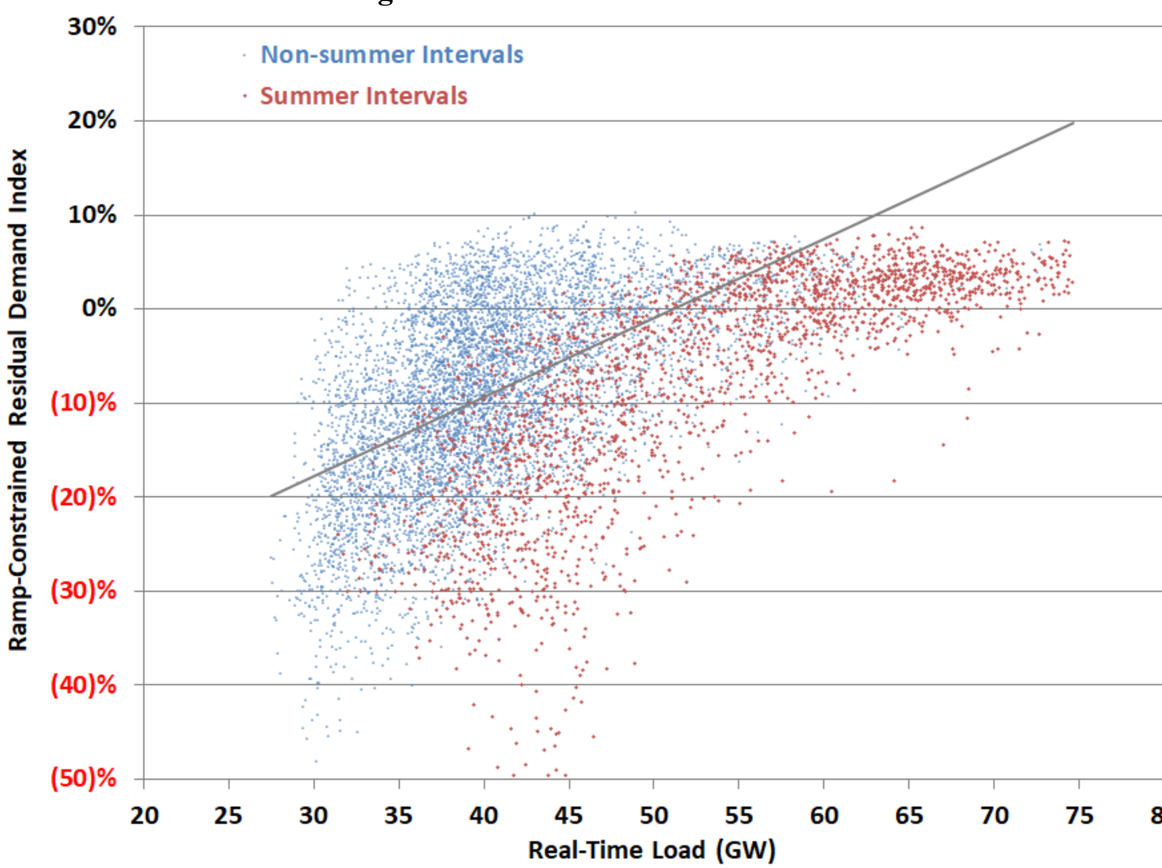
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a 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 2020. 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

Calpine's VMP was approved in March of 2013.[60] 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,[61] 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.[62] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[63] The new VMP provides for small amounts of capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable capacity

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

61 PUCT Docket No. 40488, *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)*, Order (Jul. 13, 2012); PUCT Docket No. 42611, *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Order (Jul. 11, 2014).

62 PUCT Docket No. 49858, 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)* (Dec. 13, 2019).

63 *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 PUCT Docket No. 44635, *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)*, Order Approving VMP Settlement (May 22, 2015).

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. These limits are defined by a simplified formula, which is expected to produce prices lower than what had historically been deemed allowable.

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 2020.

Figure A47: Short-Term Outages and Deratings

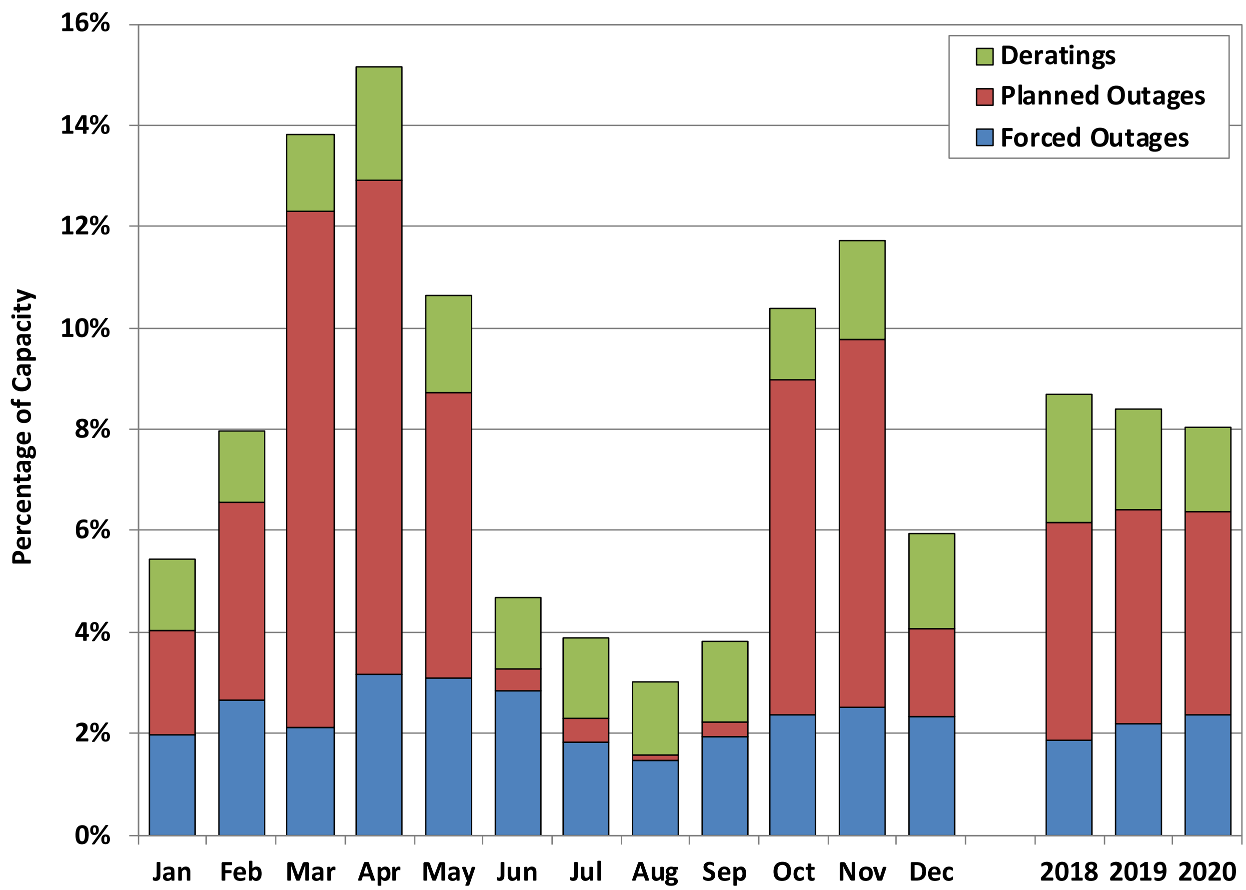


Figure A47 shows that short-term outages and deratings in 2020 followed a pattern similar to what occurred in 2018 and 2019, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2020 were approximately 15.2% of installed capacity in April (down from almost

18% in 2019) and dropped to less than 4% during July and August (the same as in 2018 and 2019).

Most of this fluctuation was due to planned outages. The amount of capacity unavailable during 2020 averaged 8.0% of installed capacity, a modest decrease from the 8.3% experienced in 2019 and 8.4% in 2018. The numbers of planned outages remained steady in 2020, 4.0% on average, down slightly from 4.3% in 2018 and 4.2% in 2019. This 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 two years may be similarly explained by generators operating in modes that would allow them to maximize generation.