2019 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
CAISO	California Independent System Operator
CDR	Capacity, Demand, and Reserves Report
CFE	Comisión Federal de Electricidad
CONE	Cost of New Entry
CRR	Congestion Revenue Rights
DAM	Day-Ahead Market
DC Tie	Direct-Current Tie
EEA	Energy Emergency Alert
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
FIP	Fuel Index Price
GTC	Generic Transmission Constraint
GW	Gigawatt
HCAP	High System-Wide Offer Cap
HE	Hour-ending
Hz	Hertz
ISO-NE	ISO New England
LDF	Load Distribution Factor
LDL	Low Dispatch Limit
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
LSL	Low Sustained Limit
MISO	Midcontinent Independent System Operator
MMBtu	One million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NCGRD	Notification of Change of Generation Resource Designation
NOIE	Non Opt-In Entity
NPRR	Nodal Protocol Revision Request
NSO	Notification of Suspension of Operations
NYISO	New York Independent System Operator
OBD	Other Binding Document
ORDC	Operating Reserve Demand Curve
PCRR	Pre-Assigned Congestion Revenue Rights
PTP	Point-to-Point
PTPLO	Point-to-Point Obligation with links to an Option
PUC	Public Utility Commission
PURA	Public Utility Regulatory Act
QSE	Qualified Scheduling Entity
RDI	Residual Demand Index
RENA	Real-Time Revenue Neutrality Allocation
RTCA	Real-Time Contingency Analysis
RDPA	Real-Time Reliability Deployment Price Adder
RUC	Reliability Unit Commitment
SASM	Supplemental Ancillary Service Market

SCED	Security-Constrained Economic Dispatch
SCR	System Change Request
SPP	Southwest Power Pool
SWOC	System-Wide Offer Cap
VMP	Voluntary Mitigation Plans
VOLL	Value of Lost Load

EXECUTIVE SUMMARY

As the Independent Market Monitor (IMM) for the Public Utility Commission of Texas (Commission), Potomac Economics provides this State of the Market Report (Report), which reviews and evaluates the outcomes of the Electric Reliability Council of Texas (ERCOT) wholesale electricity market in 2019. It is submitted to the Commission and ERCOT pursuant to the requirement in §39.1515(h) of the Public Utility Regulatory Act (PURA). It includes assessments of the incentives provided by current market rules and analyses of the conduct of market participants. The scope of our work in this capacity includes monitoring for attempts to exercise market power or manipulate the markets, identifying market inefficiencies, and recommending improvements to the market design and operating procedures. This Executive Summary provides an overview of our assessment of the performance of the markets and summarizes our recommendations.

ERCOT manages the flow of electric power on the Texas Interconnection that supplies power to more than 26 million Texas customers – representing approximately 90% of the state's electric load. As the independent system operator for the region, ERCOT dispatches more than 680 generating resources to reliably deliver power to customers over more than 46,500 miles of transmission lines. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Commission and the Texas Legislature.

Overall, the ERCOT wholesale market performed competitively in 2019. Key results from 2019 include the following:

- Warm summer temperatures increased both the peak and average loads by roughly 2% from 2018 and set a new record peak hour demand of 74,820 MW on August 12, 2019.
- Average real-time energy prices rose by 32% in 2019, despite a 23% reduction in natural gas prices. This increase is attributable to shortage pricing in August and September, with prices close to the offer cap of $9,000 per MWh for a total of more than two hours.
- The first stage of a change to the shortage pricing mechanism was implemented on March 1, 2019. This change had the effect of increasing the revenue due to shortage pricing by $1.9 to $2.1 billion in 2019, out of a total $3.7 to $5.1 billion. Shortage pricing is key in ERCOT’s energy-only market because it plays a pivotal role in facilitating long-term investment and retirement decisions.
- The supply mix in ERCOT continues to change rapidly.

Although the market performed competitively, we recommend a number of key improvements to ERCOT’s pricing and dispatch. These recommendations are summarized at the end of this Executive Summary.

Market Outcomes and Competitive Performance in 2019

The performance of the markets in ERCOT is essential because those markets coordinate the commitment and dispatch of generating resources, manage flows over the transmission network, and establish prices that guide participants' decisions in the short and long-term. Although natural gas prices fell 23% on average in 2019, causing electricity prices to fall in most of the country's wholesale markets, real-time energy prices rose 32% in ERCOT.

This increase was a competitive outcome, and the result of significant shortages experienced in ERCOT's real-time energy market, which accounted for $23.33 per MWh of the total load-weighted average price of electricity for 2019 of $47.06. Efficient shortage pricing is essential and expected in well-functioning markets experiencing tight reserve margins. Planning reserve margins in ERCOT fell to a historically low 8.6% entering summer of 2019, so shortage pricing was generally expected to occur in some periods.

Periods of hot weather during the summer prompted operating reserve shortages and led to a new all-time record for peak demand on August 12, 2019, of 74,820 MW. The markets performed very well, prompting generators to be highly available and facilitating participation by consumers to reduce demand.[1] Only 4.5% of ERCOT's generation was unavailable during the summer peak conditions, similar to 2018 but lower than the 6% during the summer peaks in 2016 and 2017. We attribute this increased availability to the effectiveness of the shortage price signals in motivating participants to increase maintenance and minimize outages during the summer peak.

On January 17, 2019, the Commission modified ERCOT's shortage pricing by altering the operating reserve demand curve (ORDC). The first stage of these changes was implemented on March 1, 2019 and the effects were significant. The changes accounted for a $6 to $7 per MWh increase in average energy prices and an increase in energy revenue of $1.9 to $2.1 billion in 2019.

The Commission also directed market improvements that will help efficiently transition the wholesale market to a future with a different resource mix. Most importantly, it approved the implementation of real-time co-optimization of energy and ancillary services, which is planned to begin in 2024. This will significantly improve the real-time coordination of ERCOT's resources, lower overall production costs, and improve shortage pricing. These improvements will be increasingly valuable as additional intermittent wind and solar resources enter the ERCOT market.

Finally, ERCOT is working with its stakeholders to plan for the market integration of future technologies, such as Energy Storage Resources (ESRs) and Distribution Generation Resources

1 See ERCOT, 2019 Annual Report of Demand Response in the ERCOT Region (Mar. 2020), available at http://www.ercot.com/services/programs/load.

(DGRs). The lower cost and high value of ESR equipment is accelerating its growth; several hundred additional megawatts are planned in the near future to supplement the 100 MW existing today. DGRs that are connected to ERCOT at the distribution level (<60 kV) are also beginning to enter the ERCOT system.

Review of Real-Time Market Outcomes

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

The significant shortage events in August and September caused the all-in real-time price for electricity in ERCOT to rise significantly in 2019, averaging more than $47 per MWh, the highest since 2011. Prices in non-shortage hours were generally lower in 2019 and highly correlated with natural gas prices, which fell 23%. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. The following table shows the trend in prices in ERCOT overall and in each of the zones.

Average Annual Real-Time Energy Market Prices by Zone

($/MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45
North	$54.24	$27.57	$32.74	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77
South	$54.32	$27.86	$33.88	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44
West	$46.87	$38.24	$37.99	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77
($/MMBtu)									
Natural Gas	$3.94	$2.71	$3.70	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47

Energy prices vary across the ERCOT market because of congestion costs that are incurred as power is delivered over the network. The pattern of zonal prices in 2019 was consistent with the pattern seen in 2018. The West zone again had the highest prices, primarily because of transmission constraints that have arisen as oil and gas development in the Permian Basin have increased load in the West.

ERCOT real-time prices include the effects of two energy price adders designed to improve real-time energy pricing during shortages or when ERCOT takes out-of-market actions for reliability.

- The Operating Reserve Demand Curve adder (operating reserve adder) accounted for $9.76 of the average load-weighted price of electricity in 2019; and
- The Reliability Deployment Price adder (reliability adder) accounted for $3.55.

As an energy-only market, ERCOT relies heavily on high real-time prices that occur during shortage conditions to provide key economic signals that incentivize development of new resources and retention of existing resources. The frequency and impacts of shortage pricing can vary substantially from year-to-year. The hot weather and relatively low planning reserve margin in the summer of 2019 led to prices that exceeded $1,000 per MWh in over 28 cumulative hours and that were at $9,000 per MWh for over two cumulative hours.

Shortage pricing is also reflected in ERCOT's ancillary service prices. Average ancillary service costs per MWh of real-time load were $2.33 per MWh in 2019, up from $1.60 per MWh in 2018. This increase was largely because of the escalation in shortage pricing in August and September.

Demand and Supply

Many of the trends in market outcomes described above are attributable to changes in the supply portfolio and load patterns in 2019. Therefore, we review and analyze these load patterns and the generating capacity available to satisfy the load and operating reserve requirements.

Load in 2019

Total ERCOT load in 2019 increased 2% from 2018, an overall increase of 880 MW per hour on average. The Houston, South and West zones showed an increase in average real-time load in 2019 ranging from 1.9% in Houston to 13% in the West zone. The increase in the West zone is particularly notable in that it comes on top of a 15% increase in 2018. Continuing robust oil and natural gas production activity in the West zone has been the driver for high load growth. Weather impacts on load in 2019 were mixed across the zones. In June, July and August, there was a 6% increase from 2018 in the number of cooling degree days in Houston. Cooling degree days is a metric that is highly correlated with summer loads. In the same timeframe, Dallas had a 2% increase, while Austin had a decrease of 4% in cooling degree days from 2018.

Summer conditions in 2019 produced a new record peak load of 74,820 MW on August 12, 2019, surpassing the previous record of 73,473 MW on July 19, 2018. The South, Houston, and West zones experienced varying increases in peak load ranging from 0.4% in the South zone to more than 11% in the West zone. In contrast, the North Zone consumed 3.4% less at peak than in 2018. The level of peak demand is important because it affects the probability and frequency of shortage conditions, as well as the quantity of resources needed to maintain reliability. However, in recent years, peak net load (demand minus renewable resource output) has become more highly correlated with the probability of a shortage condition.

Generating Resources

Approximately 4.9 gigawatts (GW) of new generation resources came online in 2019, the bulk of which were wind resources with total nameplate capacity level of 4.7 GW, and an effective peak serving capacity of approximately 1,250 MW. The remaining capacity additions were: 80 MW of combustion turbines, 50 MW of solar resources, and 30 MW of storage resources. There were 550 MW of retirements in 2019: 470 MW of coal and 80 MW of wind.

In evaluating generation levels in 2019, we found:

- The generation share from wind has increased every year since 2004, reaching almost 20% of the annual generation in 2019, up from 19% in 2018 and 17% in 2017.
- The share of generation from coal continues to fall, down to just over 20% in 2019.
- The falling coal output was replaced by natural gas generation, which increased from 44% in 2018 to 47% in 2019.

We expect these trends to continue because of historically low natural gas prices, making gas-fired resources increasingly more economic than coal resources, and the continued growth of zero fuel cost resources, like wind and solar.

Wind Output

Investment in wind resources has continued to increase over the past few years in ERCOT. The amount of wind capacity installed in ERCOT approached 27 GW at the end of 2019. ERCOT continued to set new records for peak wind output in 2019. On January 21, wind resources produced a record 19,672 MW instantaneously. On November 26, wind provided nearly 58% of the total load, also a new record.

Increasing levels of wind resources in ERCOT have important implications for the net load served by the non-wind fleet of resources. Net load is defined as the system load less wind and solar production, and the range is getting larger. The difference between highest and lowest net load MWs was even more pronounced in 2019 than 2018. Wind output displaces the total load needed to consume the minimum production from baseload units, particularly at night. The output of wind resources results 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. The importance of net load in ERCOT was illustrated during the week of August 12 when the highest prices did not correspond to the highest loads, but rather to the highest net loads.

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. 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 (with the exception of ancillary service responsibilities). In addition to allowing participants to manage their exposure to real-time prices or congestion or arbitrage the real-time prices, the day-ahead market also helps inform generator commitment decisions. Hence, the effective performance of the day-ahead market is essential.

Convergence Between Day-Ahead and Real-Time Energy Prices

A primary indicator of the performance of any forward market is the extent to which forward prices converge with real-time prices over time. Convergence between the day-ahead and real-time markets leads to improved commitment of resources to satisfy the system's real-time needs. Average price differences reveal whether persistent and predictable differences exist between day-ahead and real-time prices that participants should arbitrage over the long term.

Day-ahead and real-time prices averaged $40 and $38 per MWh in 2019, respectively.[2] This day-ahead premium was consistent with the premium in 2018. Price convergence was evident in all months of 2019 except September, when day-ahead and real-time prices diverged sharply due to significant differences between expected and actual load early in the month. The average absolute difference between day-ahead and real-time prices was $27.63 per MWh in 2019, a sharp increase from $16.21 per MWh in 2018. The largest differences were seen most frequently in August and September, consistent with expectations due to much higher volatility of real-time prices in those months. In the day-ahead market, risk is lower for loads and higher for generators. The higher risk for generators arises from the potential of incurring a forced outage and being left short on energy at real-time prices.

Day-Ahead Market Volumes

Day-ahead market volumes changed little from 2018 to 2019. The volume of day-ahead purchases provided through a combination of three-part generator-specific offers (including start-up, no-load, and energy costs) and virtual energy offers was approximately 59% of real-time load in 2019, a slight reduction from 60% in 2018. Less than half of the cleared day-ahead transactions were from three-part offers by generating resources.

Point-to-point (PTP) obligations are financial transactions purchased in the day-ahead market and provide another way for loads to hedge real-time risk, indicating that the load has secured energy and the only remaining risk going into real-time is congestion. The portion of load that was hedged either through day-ahead energy purchases or PTP obligations dropped slightly to 87% in 2019, similar to the 89% seen in 2018.

Ancillary Services

The table below compares the average annual price for each ancillary service over the last three years, showing that the prices were significantly higher for each product in 2019.

2 These values are simple averages, not load-weighted.

Average Annual Ancillary Service Prices by Service

	2017 ($/MWh)	2018 ($/MWh)	2019 ($/MWh)
Responsive Reserve	**$9.77**	**$17.64**	**$26.61**
Non-spin Reserve	**$3.18**	**$9.20**	**$13.44**
Regulation Up	**$8.76**	**$14.03**	**$23.14**
Regulation Down	**$7.48**	**$5.19**	**$9.06**

The higher prices for all the services seen in 2019 are consistent with the higher clearing prices for energy in the day-ahead market, because ancillary services and energy are co-optimized in the day-ahead market.

Of note, one entity provided 37% of the non-spinning reserves and 43% of the regulation down. The provision of other products was less concentrated by qualified scheduling entity (QSE). These results highlight 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 more efficient prices.

Transmission and Congestion Revenue Rights

Congestion arises when the transmission network lacks sufficient capacity to dispatch the least expensive generators to satisfy demand. When congestion occurs, clearing prices vary by location to reflect the cost of serving load at each location. These nodal prices reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

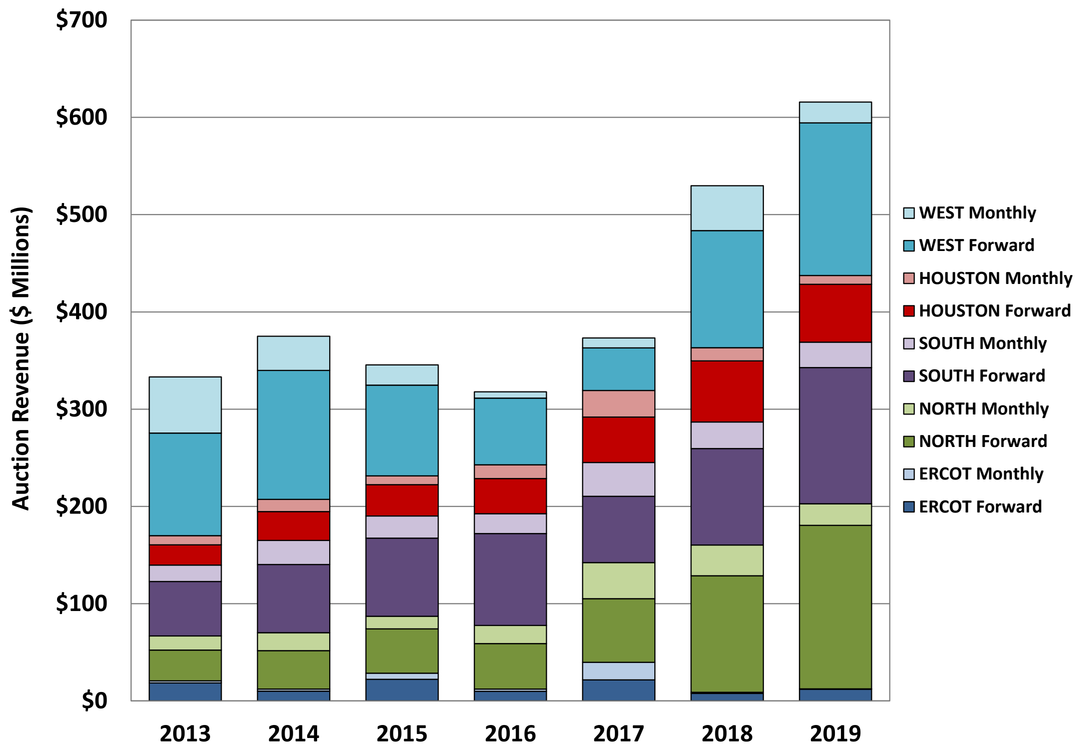
The congestion costs in ERCOT's day-ahead and real-time markets in 2019 totaled $1.1 and $1.26 billion, respectively. These values were comparable to congestion in 2018, the largest share of which was in the West zone in both years. Congestion fell in the North and Houston zones, but increased in the other zones. The months of October, November and December generated the greatest congestion costs, due predominantly to a sharp increase in the West zone.

Operationally, ERCOT's ability to maintain the network flows below the transmission constraint limits improved in 2019. Significant constraint violations fell sharply: constraints violated by more than 20% fell from almost 9% in 2018 to less than 2% in 2019. As noted below, we recommend implementation of well-designed transmission constraint demand curves to more efficiently price conditions when constraints are violated.

Congestion revenue rights (CRRs) are economic property rights which are funded by the congestion revenues 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.

CRRs are sold in monthly and annual auctions that reflect the market's expectation of prices resulting from day-ahead congestion. Revenue from these auctions flow to load. The following figure shows the CRR revenues over the past seven years by zone, whether they were generated by a monthly auction (labeled "monthly") or long-term auctions ("forward").

CRR Revenues by Zone



Aggregate CRR costs have risen steadily since 2016, culminating in CRR auction revenues of $612 million in 2019. Although results for individual participants and specific CRRs varied, the aggregated results for the year and in most months show that participants again paid less for CRRs in 2019 than they received in payment from the day-ahead market. In general, this difference occurred because the substantial increase in congestion that occurred in 2019 was not foreseen by the market, particularly the increase in congestion that occurred late in the year.

Finally, CRRs were fully funded in 2019, with the exception of mandatory deratings of $23 million, with a surplus of day-ahead congestion rent distributed to load of nearly $115 million.

Reliability Commitments

One important characteristic of any electricity market is the extent to which market dynamics result in 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 have a mandatory centralized unit commitment process. The decision to start up or shut down a generator is made by each market participant. The results from the day-ahead market inform these individual decisions, but are only financially binding. Therefore, ERCOT continually assesses the adequacy of market participants' resource commitment decisions using a reliability unit commitment (RUC) process, which executes both on a day-ahead and hour-ahead basis. These additional resources, i.e. RUCs, may be needed for two primary reasons:

- To satisfy the forecasted system-wide demand (14% of RUC commitments in 2019); or
- To make a specific generator available resolve a transmission constraint (86% of RUC commitments in 2019).

The shares of the RUC commitments are consistent with 2018, when most RUC instructions were issued to manage transmission congestion. Overall, however, the number of RUC instructions in 2019 decreased significantly from 2018.

- Unit-hours of RUC instructions issued in 2019 totaled 228, a 64% decrease from the 642 unit-hours in 2018 and the lowest number of instructions since the start of the nodal market in late 2010.
- Of the 2019 instructions, 54% were issued to generators in the West zone as oil and gas load growth has resulted in increased congestion in the region.
- The balance of the RUC instructions were issued as follows: 25% in the North zone, 20% in the South zone, and the remaining 1% were issued in the Houston zone.

The sharp reduction in RUC instructions has led to significant declines in make-whole payments and claw-back revenues. Make-whole payments ensure that generators recover their costs when complying with RUC instructions; at the same time, any profit is subject to being reduced or eliminated. During 2019, less than $1 million was clawed-back from RUC units while only $50,000 in make-whole payments were made to RUC units.

Despite these reductions, certain aspects of the RUC process remain ripe for improvement. First, ERCOT allows generators to "opt out" of RUC settlement, foregoing the make-whole payment to guarantee their costs, but also eliminating the claw-back of market profits. Twenty-six percent of RUC resources opted out of RUC settlement in 2019. This opt-out opportunity can incentivize a resource to provide less accurate information in its Current Operating Plan (COP). Therefore, we recommend removing the opt-out provision, as detailed later in recommendations.

Resource Adequacy

One of the primary functions of the organized 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. These economic signals are best measured with the net revenue metric, which we calculated 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. This net revenue metric varies by fuel type and location.

In ERCOT's energy-only market, the net revenues from the ancillary services and real-time energy markets provide 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 real-time energy prices.

For the first time since 2011, the net revenues in all four zones exceeded the estimated cost of new entry for both natural gas combustion turbines and combined cycle resources. The sharp increases in net revenues were primarily driven by the significant shortages in August and September, in combination with the adjustments to the ORDC in 2019. The increase in the frequency of sustained shortages is consistent with the declining reserve margin in recent years. This existence of operating shortages is not a concern. 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.

The backward-looking net revenue analysis provides insight into the potential profitability of new generation, and therefore the ability of the ERCOT market to attract sufficient new resources to meet growing customer demands for electricity. However, resource investment decisions are generally forward-looking, as opposed to solely relying on past performance, and are driven by many project-specific factors not fully captured in the net revenue analysis. Regardless, there has already been a noticeable and marked improvement in the availability of resources during the high load summer months, as well as significant increases in wind, solar, and energy storage resources under development.

Texas heads into the summer months of 2020 with an improved planning reserve margin of 12.6%, notably higher than the 8.6% reserve margin for 2019. It is worth mentioning that the current methodology of performing the Capacity, Demand and Reserves (CDR) analysis does not consider energy storage resources (e.g., batteries). Including storage resources will 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.

Analysis of Competitive Performance

We evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?).

Structural Market Power

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 potential market power is whether a supplier is "pivotal," i.e., when its resources are necessary to satisfy load or manage a constraint.

At loads greater than 65 GW, there was a pivotal supplier approximately 94% of the time. This observation is not surprising, 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 in 24% of all hours in 2019, which was less frequent than in 2018 when pivotal suppliers existed in 30% of all hours. Even with this reduction, market power continues to be a potential concern in ERCOT, requiring effective mitigation measures to address it.

Our pivotal supplier analysis 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. 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.

Evaluation of Conduct

In addition to the structural market power analyses above, we also evaluated actual participant conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. We draw upon an "output gap" metric to measure potential economic withholding, which occurs when a supplier raises its offer prices to reduce its output and raise clearing prices.

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. Our analysis shows that in 2019, the output gap quantities were very small. Only 22% of the hours in 2019 exhibited an output gap of any magnitude, and virtually all are eliminated when taking voluntary mitigation plans (VMPs) into account.

Likewise, we evaluate potential physical withholding of generating resources to raise prices. Market participants, both large and small, tend to make more capacity available to the market by minimizing planned outages and deratings during high load periods, when the market is most vulnerable to market power. These results taken together with the very low levels of potential economic withholding allow us to conclude that the ERCOT market performed competitively in 2019.

Recommendations

One of the roles of the IMM is to recommend measures to enhance market efficiency. Therefore, although ERCOT markets performed well in 2019, we have identified certain areas that warrant attention, as well as opportunities for improvements that should be considered. We make a total of eight recommendations below: four are corrections to inefficiencies and inappropriate incentives affecting market performance, and four are market improvements. We are also retiring six recommendations from prior years with an explanation for each.

Market Inefficiencies

No. 1 - Remove the "opt out" option for resources receiving RUC instructions.

The ability to opt out of RUC settlement was added in 2014 and provides an unintended incentive for resource owners to show as "off and available" for future hours some resources that they reasonably expect to commit. A resource owner may expect to commit a resource to solve a local congestion problem, but is not sure that that decision will be profitable, perhaps due to the unknown commitment decisions of other resources.

Effectively, a resource owner can gain competitive information from ERCOT simply by showing the status of its resource as "off and available" in the COP. If ERCOT issues a RUC instruction for the resource, the resource owner's assumptions regarding the status of other unit or units are confirmed, and the resource owner can use the opt-out provision to proceed with the commitment as originally planned with no negative consequences.

We have observed instances of the behavior outlined above, and have performed statistical modeling that indicates market-wide behavior changed after the opt-out rule was implemented.[3]

3 See NPRR416, *Creation of the RUC Resource Buyback Provision* (formerly "Removal of the RUC Clawback Charge for Resources Other than RMR Units"), as modified by NPRR575, *Clarification of the RUC Resource Buy-Back Provision for Ancillary Services*, effective January 7, 2014; and NPRR744, *RUC Trigger for the Reliability Deployment Price Adder and Alignment with RUC Settlement*, implemented on June 1, 2017.

Less generation was committed in the COP after this change. By submitting COPs with future statuses that do not fully reflect planned commitments, resource owners are reducing ERCOT's situational awareness and ability to effectively manage the grid. In addition, ERCOT's market design relies on individual resource owners making commitment decisions based on available information, and this COP behavior distorts that information. The minor increase in make-whole payments that may occur with this change is less than the increased reliability for loads and improved market efficiency that would result.

For these reasons, the IMM recommends that the ability to opt out of RUC settlement be eliminated to remove an incentive to submit COPs that do not reflect the actual planned resource status.

No. 2 – Eliminate the "2% rule" and price all congestion regardless of generation impact.

ERCOT only includes a constraint in its real-time pricing and dispatch engine (the Security Constrained Economic Dispatch, or SCED) if at least one resource exists that has a shift factor of greater than 2% or less than negative 2%, which is commonly known as the "2% rule."[4] Shift factors determine a resource's impact on a transmission constraint, and a low shift factor connotes a small impact. The 2% rule was first introduced in the zonal market, and its purpose was to stop congestion prices from rising rapidly and unreasonably when there was no significant generation solution for a constraint. This limitation was due in part to software limitations in constraint management at that time. Those issues have been solved in the nodal market in a more efficient manner by shadow price caps and improved software, so the 2% rule is no longer needed.

It cannot be overstated how important and foundational prices are to an efficient wholesale energy market. By removing congestion pricing signals with the 2% rule, ERCOT has eliminated the only market signal showing prospective resource owners where to place resources to help solve "unsolvable" congestion. It also diminishes reliability by preventing the market dispatch from managing these constraints and compelling ERCOT to take more out-of-market action. Therefore, we recommend that ERCOT eliminate the 2% rule and pricing congestion regardless of resource shift factors.

No. 3 – Modify the allocation of transmission costs by transitioning away from the 4CP method.

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

4 ERCOT's recent analysis of this constraint activation is at http://www.ercot.com/calendar/2020/5/11/192919-CMWG.

The current method of transmission cost allocation assigns costs proportional to load contribution in the highest 15-minute system demand during each of the four months from June through September, or Four Coincident Peak (4CP). This method was first implemented in 1996, as part of a hybrid methodology for wholesale transmission rates, and was intended to allocate transmission costs to the drivers of transmission build. However, as time has passed, peak-coincident summer load is no longer the primary driver of decisions to build transmission in ERCOT.

Rather, as stated in the ERCOT Planning Guide (Section 3.1.3.1), transmission build decisions are "based on whether a simultaneously-feasible, security-constrained generating unit commitment dispatch is expected to be available for all hours of the planning horizon that can resolve the system reliability issue that the proposed project is intended to resolve." In-depth studies of recent and future transmission projects will be needed to assist in constructing the final details of an alternate allocation method. Further, even if the costs were allocated based on the behavior that causes new transmission to be built, the method of distributing the charge through distribution service providers (DSPs) and transmission-level customers only provides a price signal to non-opt-in entities (NOIEs) and transmission-level customers, which represent less than half of the market at 34%.

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

No. 4 – Price Ancillary Services (AS) based on the shadow price of procuring each service.

The current pricing structure for AS creates an incentive for load resources to offer at the lowest allowed offer price, which in turn leads to inefficient rationing of under frequency relay response awards (a service provided by load resources). Prices should reflect the constraints that are used in the ERCOT market to make dispatch or award decisions. However, this is not currently the case with certain ancillary services.

For responsive reserve service, ERCOT's procurement requirements are such that a minimum amount of governor response is needed, which effectively caps the amount of relay response by load resources that can be purchased. These procurement requirements are not factored into the resulting prices. As there is usually a surplus of relay response offered into the market, this mispricing provides an overpricing of relay response. The recurring surplus coupled with the overpricing creates an incentive for relay response to offer at the lowest allowed offer price, which in turn leads to inefficient rationing of relay response awards. Each year the surplus grows, an indicator of economic inefficiency.

In addition, a new ancillary service, ERCOT contingency reserve service, will be implemented before 2024 and will contain a constraint on non-SCED-dispatchable resources. However, a single price is envisioned for that service. The lack of inclusion of the constraint in pricing will also complicate the design of real-time co-optimization, because rules must be put in place on behavior that would otherwise be handled with incentives inherent in correct pricing.

The IMM recommends that the clearing price of ancillary services, both current and future, be based on all the constraints used to procure those services.

Improvements and Enhancements

No. 5 – Modify the reliability deployment adder and operating reserve adder to improve pricing during deployments of Emergency Response Service (ERS).

ERCOT currently calculates the reliability deployment adder (RDPA) during Emergency Response Service (ERS) deployments using contracted ERS amounts rather than an estimate of actual ERS deployment. However, there is a significant difference between the contract and the deployment amounts due to price responsiveness. The ORDC calculation should also account for ERS deployments, for purposes of the ORDC adder.

The RDPA calculation is a "but-for" pricing correction, i.e., what would the price have been "but for" a prescribed set of reliability actions taken by ERCOT. The reliability deployment of ERS resources rightfully belongs in this calculation, but it is inappropriate to assume that all ERS capacity contracted by ERCOT is deployed as a result of an ERCOT deployment instruction. In fact, a large portion of the ERS capacity in the two ERS deployments of 2019 actually deployed prior to the ERCOT reliability instruction. Further, the resources that did deploy per ERCOT's reliability instruction returned to pre-instruction levels in approximately three hours rather than the ten hours assumed in the RDPA calculation. The IMM estimates that these two assumptions in the calculation resulted in an overcharge to load of approximately $400 million in 2019.

Turning to the calculation of the ORDC adder, which accounts for many reliability actions by ERCOT, we note that it does not factor in the deployment of ERS resources. The IMM estimates that modifying the ORDC calculation to factor in the ERS deployment in 2019 (deducting the actual deployed amount from online reserves, and assuming a three-hour restoration time) would have resulted in a $103 million increase in the charge to load.

In sum, the IMM recommends that pricing during ERS deployments be improved in three ways:

1. Include the actual capacity deployed because of an ERCOT instruction (reliability MWs) and not include capacity deployed in response to high prices (market MWs).
2. Use a restoration time based on observed behavior.
3. Include an estimate of reliability MWs of ERS capacity in the ORDC reserve calculation.

The net effect of all three changes we are recommending would have been a decrease of $297 million charged to load in 2019.

No. 6 - Implement a locational reliability deployment price adder (RDPA)

As previously discussed, the reliability deployment adder is intended to be a "but-for" calculation, which is an appropriate adjustment for non-market actions. However, the current RDPA calculation only adjusts the global, ERCOT-wide price for energy, while the vast majority (80%) of RDPAs are triggered by RUCs intended to address local reliability problems. These local reliability RUCs often result in little-to-no adder when calculated on a global basis, but would result in a significant local one. By calculating the RDPA on a global basis, the market is dampening an important market signal.

The IMM recommends changing the reliability deployment adder calculation to reflect local reliability actions.

No. 7 – Improve the mitigated offers for generating resources

Economic theory dictates that suppliers in perfectly competitive markets will offer at prices equal to their marginal costs (i.e., the incremental costs incurred to produce additional output). Importantly, these costs include more than direct financial costs, including risk and opportunity costs. However, mitigated offers are based on the ERCOT's verifiable costs, which does not always reflect resources' full marginal costs. This affects the generators and price formation.

Price formation when RUC Resources are mitigated. When a resource is committed via an ERCOT RUC instruction, its offer is set to a minimum of $1,500 per MWh to ensure that it does not have an inappropriate price-dampening effect on the market. However, should the resource be mitigated, its offer can be lowered significantly below $1,500 per MWh, down to its short run marginal costs. While the short run marginal costs are appropriate mitigated offers for resources for which the owner makes the commitment decision, the commitment costs (startup and no-load) should be factored into the mitigated offer specifically in cases where ERCOT has made the commitment decision.

Issues with verifiable costs. The verifiable cost process that feeds most mitigated offer caps departs from marginal costs in some cases because it does not include the pricing of opportunity costs. For example, when a unit's limitations cause it to forego running in future hours or days to run in the current hour, then it may incur opportunity costs associated with the foregone output. These opportunity costs are short run marginal costs that should be included in verifiable costs. In addition, the verifiable cost calculations should be reviewed to ensure that other marginal costs are included in the verifiable cost, including major maintenance costs and operating risks, and to ensure that no fixed costs are included.

The IMM recommends that mitigated offers be improved by: (a) including commitment costs for RUC-committed intervals by amortizing these costs over the RUC commitment period; (b) including opportunity costs, major maintenance costs, and operating risks that are marginal costs; and (c) removing all fixed costs that are not marginal.

No. 8 – Implement transmission demand curves

As the demand curves for each ancillary service will be evaluated in the co-optimized system in the future, there is an opportunity for ERCOT to also implement transmission demand curves. In the current design, single penalties are applied to limit the cost incurred to resolve a constraint and they set prices when constraints are violated (flows exceed the transmission limit). These penalty values increase with the voltage level of the constraint. Unfortunately, these single values cause the real-time market to price a 0.1% violation of a constraint the same as it prices a 50% violation of a constraint, regardless of the actual risk to the system of such a violation.[5]

Much as the ORDC recognizes that reliability risks increase as operating reserve shortages increase, a well-designed transmission demand curve would recognize that the importance of a post-contingency overload increases as the overload amount increases when a transmission constraint is violated. Implementing such demand curves will improve the nodal prices at all locations that are affected by a violated constraint.

The IMM recommends that ERCOT develop and implement transmission demand curves that reflect the increasing reliability costs of higher overloads.

Retirement of Previous Recommendations

Inclusion of marginal losses in ERCOT locational marginal prices.

In early 2019, the Commission declined to direct ERCOT to implement marginal losses in ERCOT locational marginal prices. The Commission recognized that "assigning marginal transmission losses is common in other markets and an efficient way to account for losses," and the IMM agrees. However, because the Commission reviewed this item and concluded that the incremental benefit of applying marginal losses in the ERCOT market is not worth the implementation cost and market disruption, the IMM retiring this recommendation.

Price congestion at all locations that affect a constraint – generators less than 10MW.

The issue of small generators lacking incentive to follow locational pricing signals was addressed to the IMM's satisfaction in NPRR 917, approved on August 13, 2019 and implemented on September 1, 2019.

5 http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Setting_Maximum_Shadow_Prices_for_Network_and_Power_Balance_Constraints.zip

Evaluate and improve Load Distribution Factors (LDFs) used in the CRR and Day-Ahead Market (DAM) clearing activities.

On February 26, 2020, ERCOT introduced NPRR1004, *Load Distribution Factor Process Update*, which would incorporate load forecasting methods into a daily LDF update. Prior to filing, ERCOT presented details about these proposed methods at multiple sessions of a stakeholder working group, and, based on that information, we foresee that implementing this NPRR will produce more accurate LDFs for the day-ahead market through more frequent updates, load forecasting and error correction. Less clear is the CRR auction impact. The IMM will monitor after implementation of the NPRR, assuming it is approved, to evaluate the effects.

Evaluate policies and programs that create incentives for loads to reduce consumption for reasons unrelated to real-time prices.

Currently, there is rarely a shortage of loads willing to provide ancillary services. Responsive reserve service is oversupplied with load 96% of the time. Moreover, last summer's ERS deployment demonstrated the ERS program does not limit a load's ability to respond to price.

Modify the real-time market software to better commit load and generation resources that can be online within 30 minutes.

The primary option for addressing this recommendation was a multi-interval real-time market. ERCOT's evaluation of the benefits of such a market found that they are insufficient to justify the cost. Additionally, the likely installation of significant amount of utility-scale battery storage in ERCOT over the next few years should ameliorate the issues with the current commitment method for fast-starting resources. Therefore, the priority for this recommendation has decreased and is less important than the other recommendations in this year's Report.

Evaluate the need for a local reserve product.

The IMM is postponing this evaluation to future years because no additional reliability must run (RMR) designation or other indications of the potential need for a local reserve product have occurred in recent years.

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 2019.

A. Real-Time Market Prices

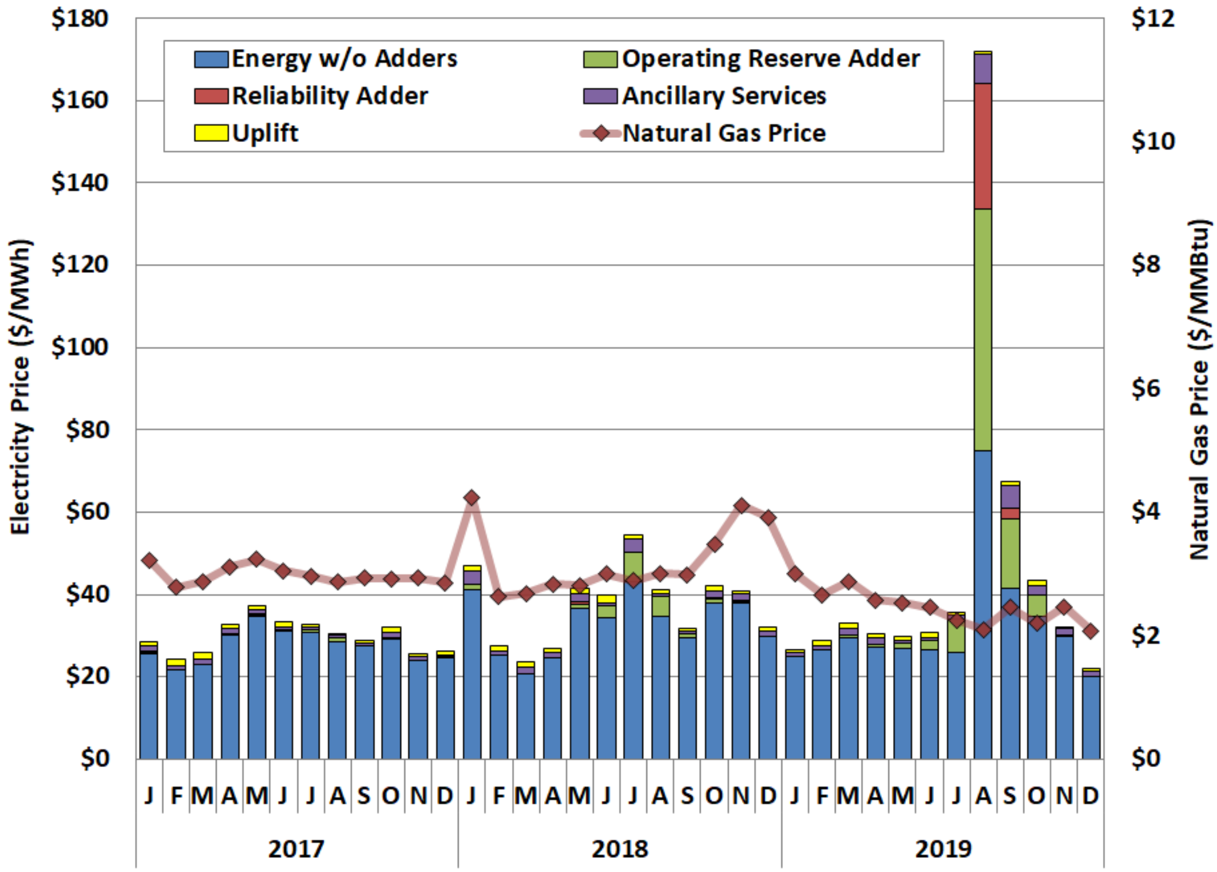
The first analysis of the real-time market evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 1 shows the average "all-in" price of electricity for ERCOT that includes all of 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.[6]

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

6 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.

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 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 is able to 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.[7]

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-

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7 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.

However, in times where there is a shortage of dispatchable capacity, such as in August and September of 2019, shortage pricing mechanisms can drive the price significantly higher. Tight conditions during the summer of 2019 caused shortage pricing in 2019 that raised average real-time prices by 32% (to $47.06 per MWh) compared to 2018. This increase occurred despite the fact that the average natural gas price in 2019 were down approximately 23% from the 2018. As described later, the effects of the shortage pricing in 2019 were enhanced by the changes to the shortage pricing mechanism in ERCOT implemented earlier in the year.

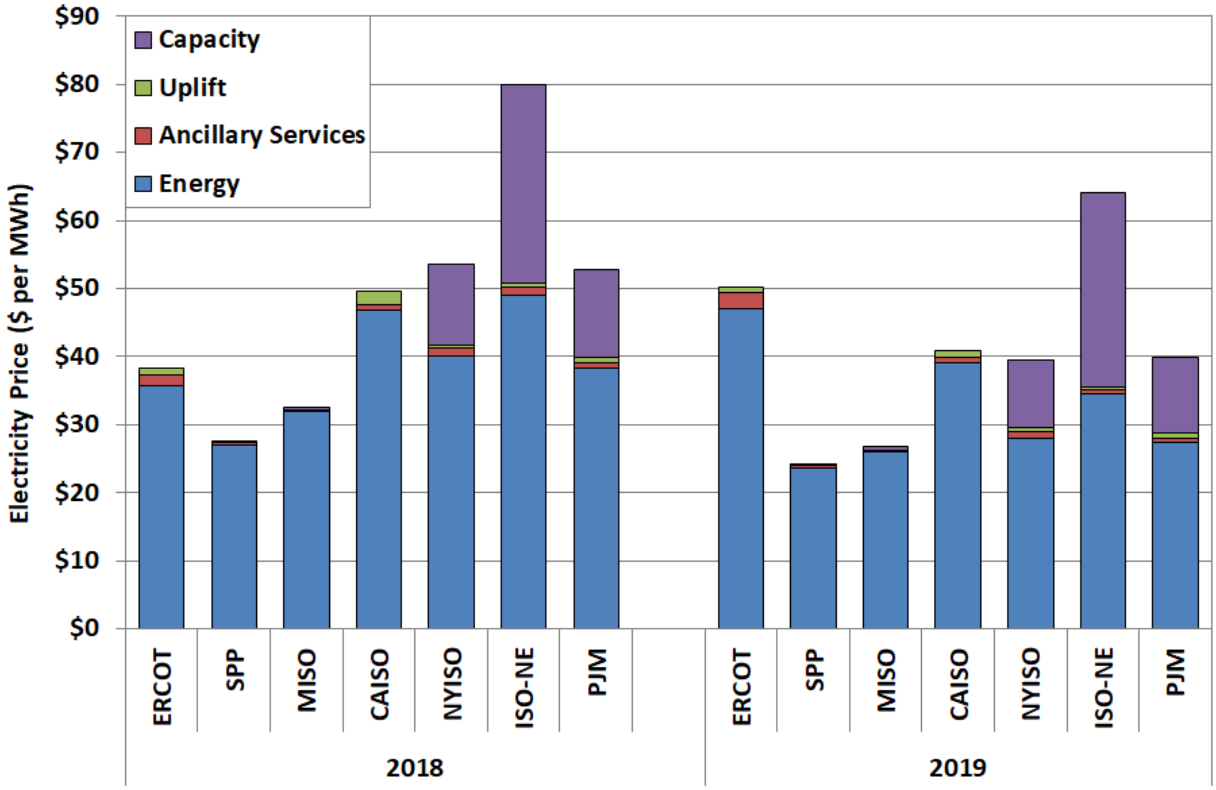
The increase in shortage pricing was partly reflected in the higher contributions from ERCOT's energy price adders: $9.76 per MWh from the operating reserve adder and $3.55 per MWh from the reliability adder. Both of these values are significantly higher than the comparable values in 2018: $1.97 per MWh for the operating reserve adder and $0.08 per MWh for the reliability adder. The adders in 2019 are discussed in greater detail in Subsection F: ORDC Impacts and Prices During Shortage Conditions.

Other cost categories continue to be a relatively small portion of the all-in electricity price. Ancillary services costs were $2.33 per MWh in 2019, up from $1.60 per MWh in 2018 for reasons described in Section III: Day-Ahead Market Performance. Uplift costs accounted for $0.88 per MWh of the all-in electricity price in 2019, down from $1.08 per MWh in 2018. The total amount of uplifted costs in 2019 was approximately $338 million, down from $408 million in 2018. There are many costs included as uplift, but the largest components are the ERCOT system administrative fee ($213 million or $0.55 per MWh), Emergency Response Service (ERS) program costs ($47.6 million or $0.12 per MWh) and the real-time revenue neutrality allocation (RENA), which totaled $49 million or $0.13 per MWh in 2019.

To provide additional perspective on the outcomes in the ERCOT market, Figure 2 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 2 also shows that all-in prices were lower across U.S. markets in 2019, with ERCOT as the exception. The decrease ranged from modest in SPP and MISO to a sizable relative increase in the capacity component in ISO-NE. Prices in ERCOT were second highest across all RTOs. As energy-only markets are inherently more volatile than capacity markets, it is expected that the all-in price in ERCOT will be higher than capacity markets in a shortage dominated year like 2019, unlike years in which there is excess capacity.

Figure 2: Comparison of All-in Prices Across Markets

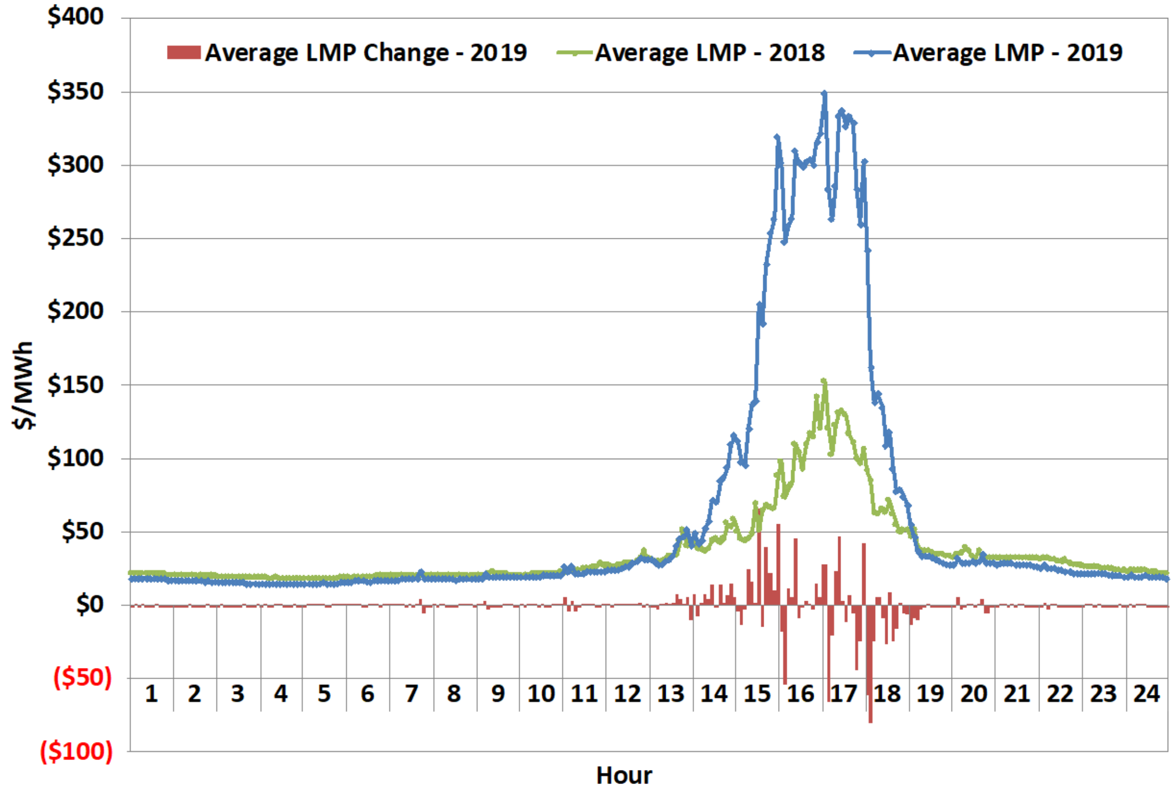


Real-time energy prices vary substantially by time of day. Figure 3 shows the load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices were the highest. It also shows in red the average change in the 5-minute prices in each interval.

The figure shows that the downward changes in five-minute prices were particularly large at the top of each peak hour (hours 16-18). 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.

Regarding overall 5-minute price levels, Figure 3 shows that prices in the peak load hours were much higher in 2019 than in 2018. This was primarily attributable to the shortage conditions that prevailed during the peak hours in the week of August 12. Many intervals during this period were priced at the system-wide offer cap of $9,000 per MWh.

Figure 3: Prices by Time of Day
May-September 2019

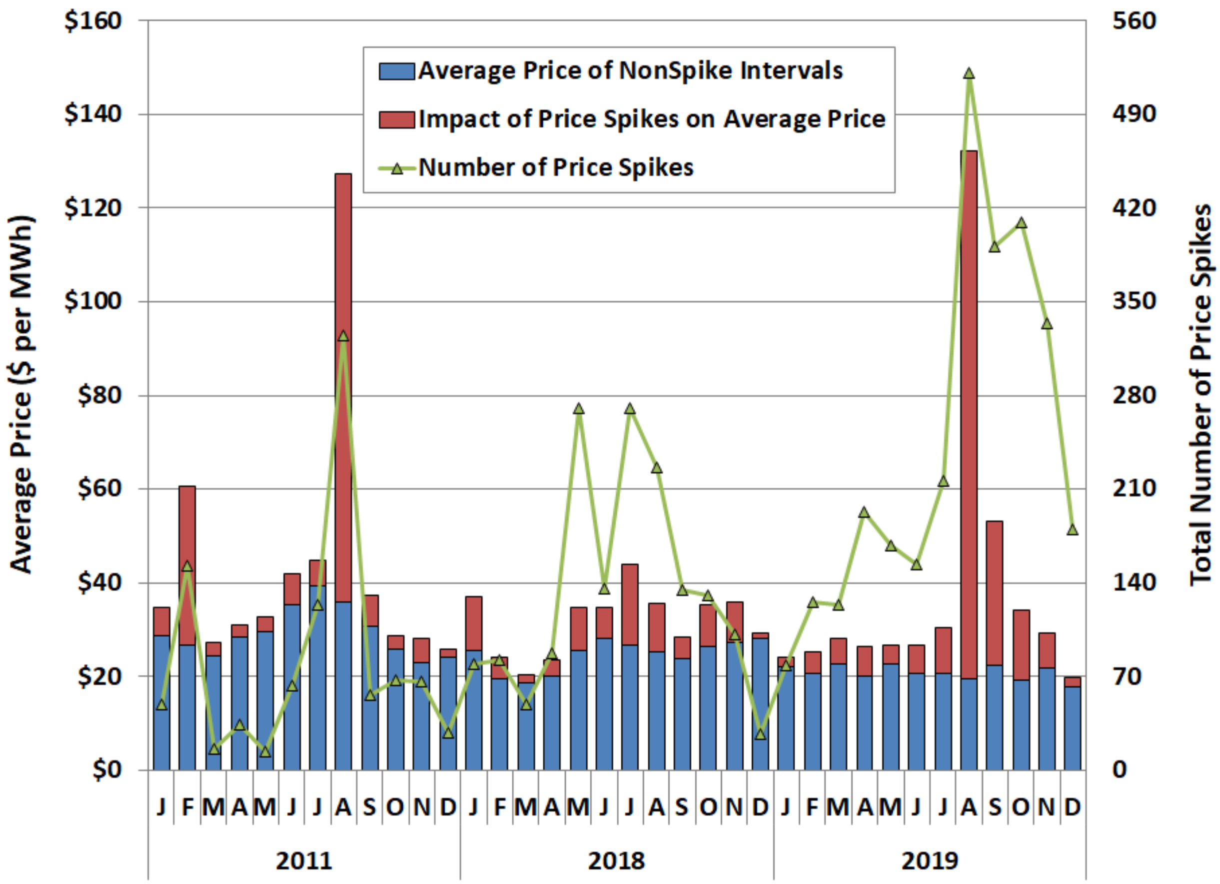


For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2019, see Figure A1 in the Appendix.

Energy prices for the top 100 hours of 2019 were higher than in any other year since the market started, even those in 2011 that exhibited the hottest summer temperatures. The higher prices in 2019 reflect the effects of the falling operating reserve margins in ERCOT together with the changes to the shortage pricing mechanism over the past decade, including the increase of the System Wide Offer Cap (SWOC) to $9,000 per MWh, the implementation of the ORDC, and the implementation of the reliability deployment adder.

To better observe the effect of the highest-priced hours on the average real-time energy price, Figure 4 shows the frequency of price spikes in the real-time energy market. For this analysis, price spikes are defined as intervals when the load-weighted average energy price in ERCOT 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 in ERCOT.

Figure 4: Average Real-Time Energy Price Spikes



Price spikes were even more frequent and important in 2019 compared to 2018 because of larger contributions from the changed operating reserve adder during reduced reserve availability. The overall impact of price spikes in 2019 was $23.33 per MWh, or 50% of the total average price. The pattern of price spikes from 2011 is also shown for comparison, demonstrating the sheer magnitude of the spike in 2019.

B. Zonal Average Energy Prices in 2019

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 eight years and also 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. 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 2011 and 2019, this trend diverges as substantial shortage pricing led to higher energy prices as expected in periods with low reserve margins or extreme weather. 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

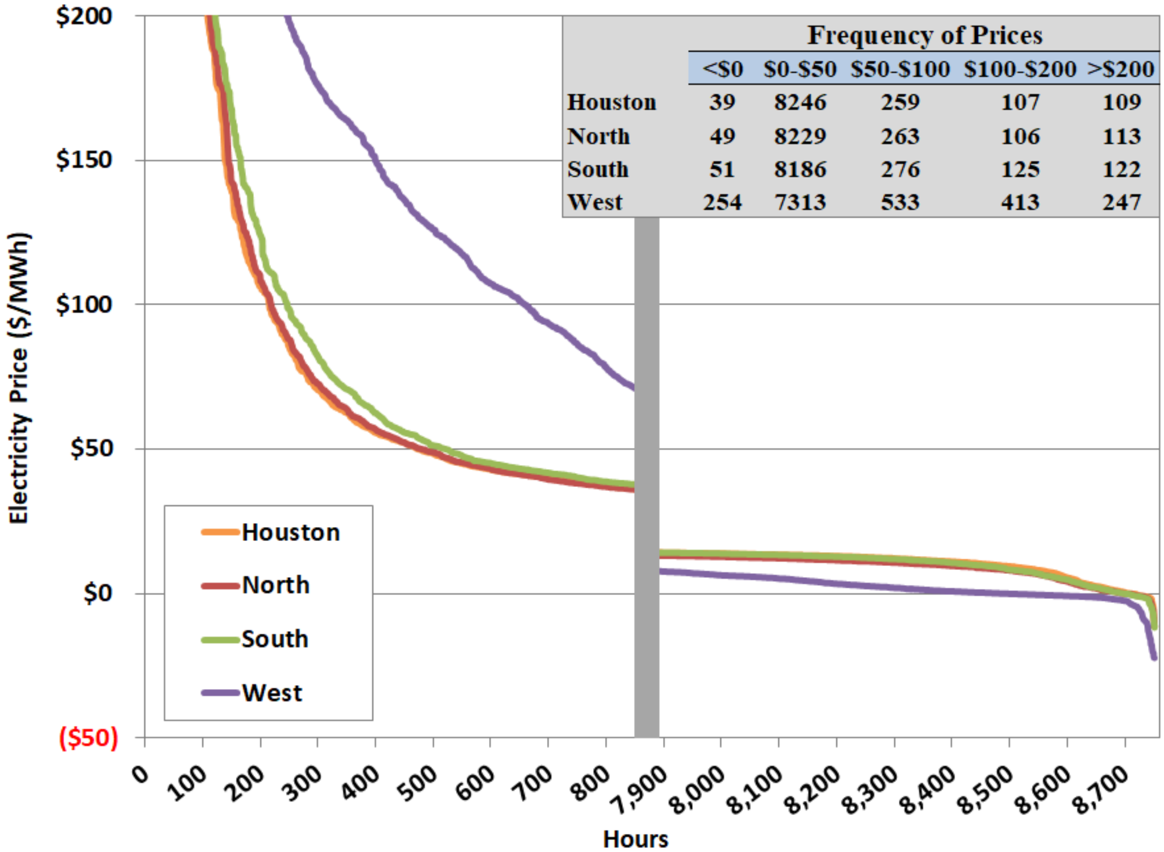
($/MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45
North	$54.24	$27.57	$32.74	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77
South	$54.32	$27.86	$33.88	$41.52	$27.18	$24.78	$29.38	$36.15	$47.44
West	$46.87	$38.24	$37.99	$43.58	$26.83	$22.05	$24.52	$39.72	$50.77
($/MMBtu)									
Natural Gas	$3.94	$2.71	$3.70	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47

Table 1 also shows that the pattern of zonal prices in 2019 was consistent with the pattern seen in 2018. 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 2019, 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 2018 and 2019, see Figure A3 in the Appendix.

The South zone was again the second highest-priced zone in 2019 because of congestion associated with planned bus outages in the central Texas. 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 5 shows the top 10% and bottom 10% of the duration curves of hourly average prices in 2019 for the four zones. Compared to the other zones, both low and high prices in the West zone were noticeably different in 2019. 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 5: 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 decreased substantially. Much of this decrease was due to lower RENA, which decreased 63%, from $134 million ($0.35 per MWh) in 2018 to $49 million ($0.13 per MWh) in 2019. 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 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);

- Settlement of day-ahead Point-to-Point (PTP) obligations linked to options[8] (PTPLO Uplift);
- Manual corrections that occurred when the settling price of PTP obligations in the day-ahead market was higher than the submitted bid price (PTP Value)[9];
- Extra congestion rent that accrued when real-time transmission constraints were violated (Overflow Credit); and
- Other factors, including setting a price floor in the real-time market at (-$251) per MWh (Other).

Figure 6 provides an analysis of RENA uplift in 2019, separately showing the components of RENA on a monthly basis. Net negative uplift represents an overall payment to load.

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 2019 were LDF inconsistencies and NOIE PTP obligations settled as options, contributing $31 million and $28 million, respectively. These uplifted values were offset by $30 million in negative uplift related to the overflow credit when the shadow price reached the shadow price cap for a given transmission constraint.

Figure 6 below also shows that RENA uplift from the settlement of day-ahead PTP obligations linked to options, described as PTPLO Uplift, was relatively high in March, April, May and October, and the uplift from transmission modelling differences was significant in February, March and December. It is worth noting that while the manual corrections of those PTP obligation awards in the day-ahead market generated a negative uplift for the first four months in 2019, this negative uplift dissipated beginning in May 2019, after a system change was implemented to automatically address the related PTP pricing issue in day-ahead market.[10] Uplift from the contributions of load distribution factor differences between day-ahead and real-

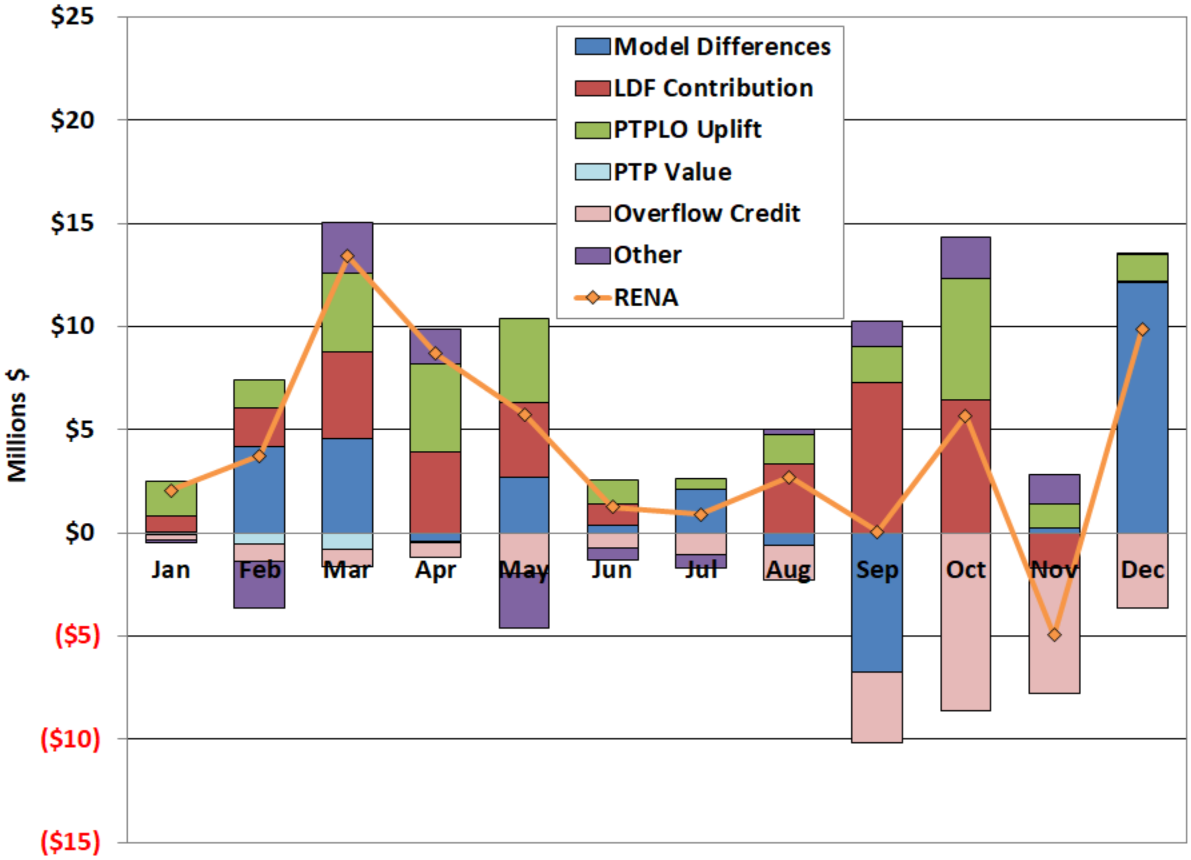
[8] A Point-to-Point obligation with links to an option (PTPLO) is a type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation bought in the DAM to be reflective of the NOIE's PTP Option that it acquired in the CRR auction or allocation. Qualified PTP Obligations with Links to an Option shall be settled as if they were a PTP Option.

[9] See NPRR 827: *Disallow PTP Obligation Bid Award where Clearing Price exceeds Bid Price by $0.25/MW per hour*. Implemented on June 29, 2017, NPRR 827 disallowed ERCOT from settling PTP Obligations in the DAM where the corresponding clearing price is greater than the bid price for the PTP Obligation by $0.25/MW per hour.

[10] See NPRR 833: *Modify PTP Obligation Bid Clearing Change*. Approved on August 8, 2017 and implemented on April 5, 2019, NPRR 833 allowed ERCOT to update the DAM optimization engine to address the situation where a contingency disconnects a Resource Node. Instead of ignoring the PTP obligation MWs in contingency analysis if that PTP sources or sinks at the disconnected point, the engine will "pick up" those MWs and distribute them to other nodes. The Settlement Point Price now includes that "pick up" shift factor in the price calculation. With implementation of NPRR 833, the optimization price and the settlement price are equal (within one cent for rounding).

time, described as LDF Contribution, was mostly positive in 2019, with the most notable contributions in September and October.

Figure 6: ERCOT RENA Analysis

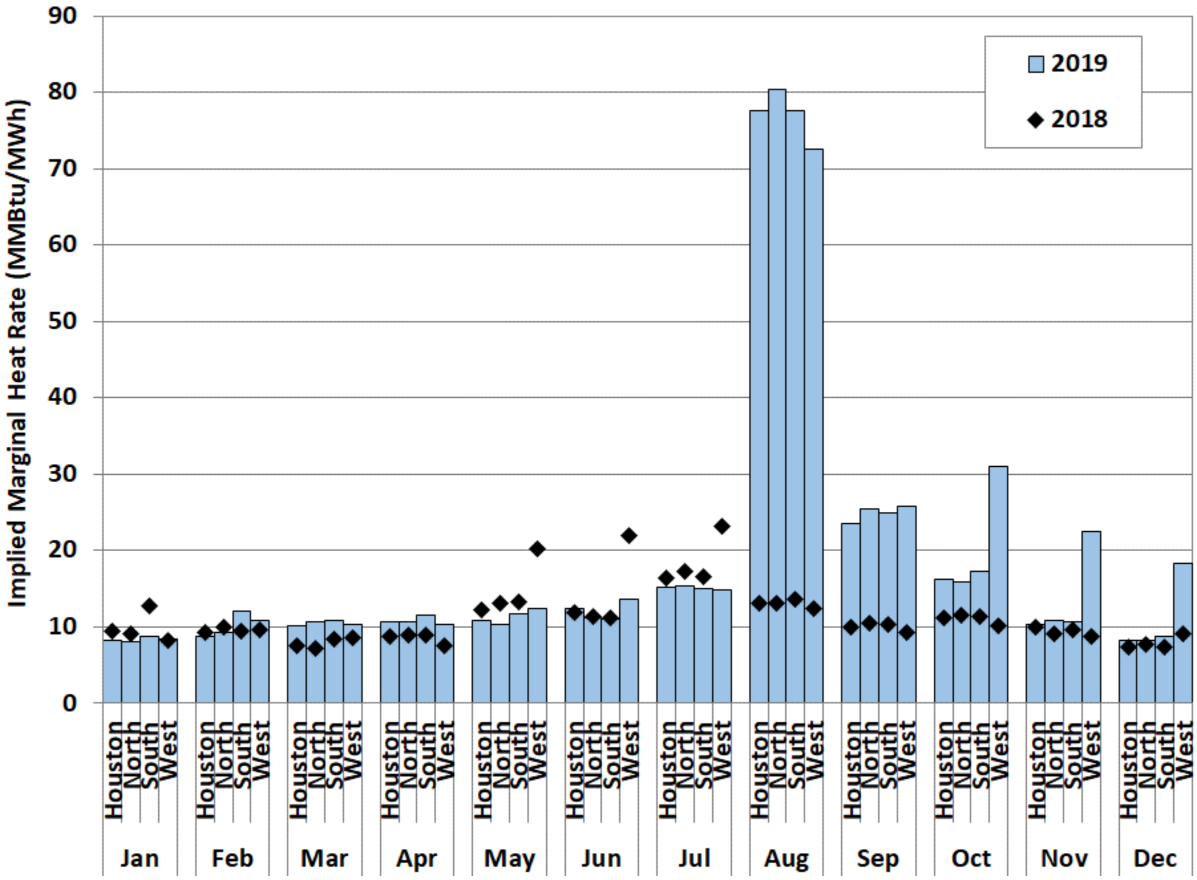


The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict accurate load distribution factors across all markets, RENA impacts will persist. ERCOT has a proposal to improve load distribution factors pending in the stakeholder process (NPRR1004, *Load Distribution Factor Process Update*, posted on February 26, 2020).

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 7 shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones for 2018 and 2019. This figure is the fuel price-adjusted version of Figure A3 in the Appendix.

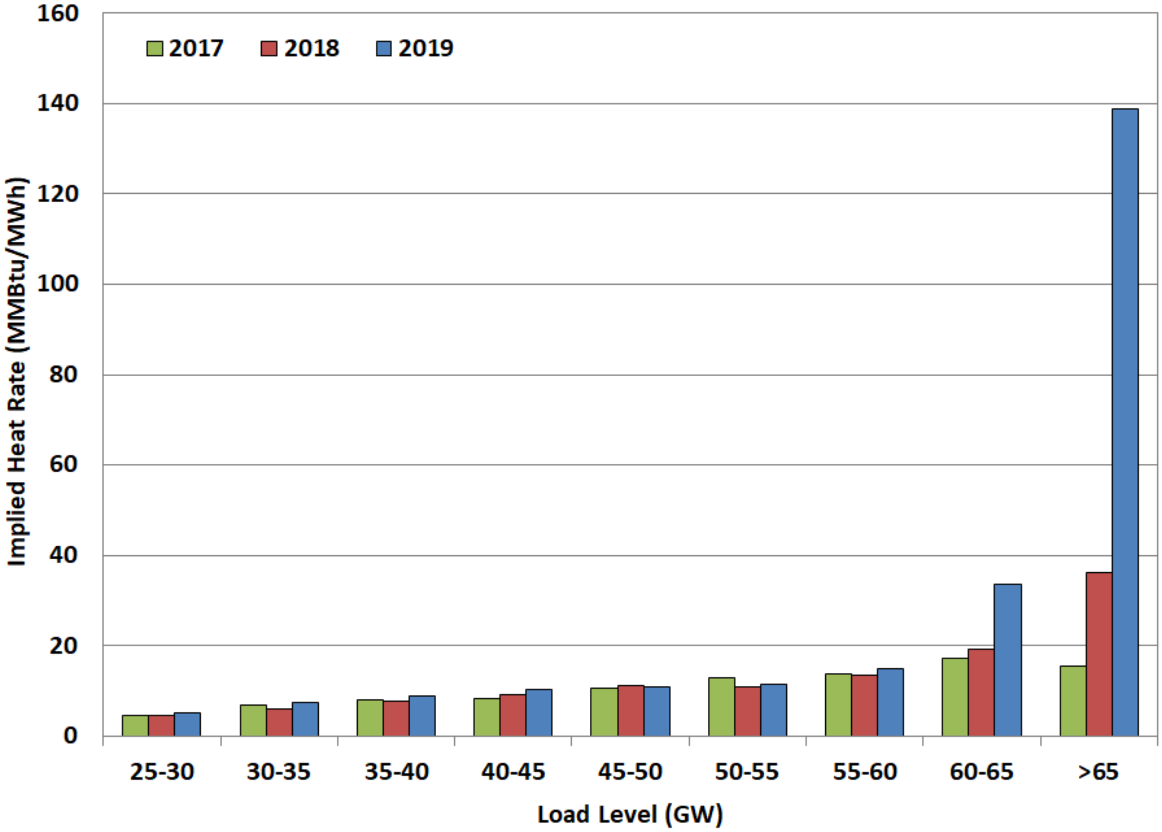
Figure 7: Monthly Average Implied Heat Rates



This figure shows that the implied heat rate varied substantially over the year and among zones. The most significant increases occurred in August and September as hot weather led to high load levels and prices. In August, in particular, frequent operating reserve shortages and associated shortage pricing explain the sharp increase in implied heat rates in that month. A second factor driving zonal differences in implied heat rates is transmission congestion, which was most notable in the West zone in May to July 2018 and in October to December 2019. Overall, average implied heat rates were higher in 2019 than in any year since 2011, which also exhibited frequent operating reserve shortages because of hot summer weather.

Our review of implied heat rates from the real-time energy market concludes with an evaluation at various load levels. Figure 8 below provides the average implied heat rate at various system load levels for years 2017 through 2019.

Figure 8: Implied Heat Rate and Load Relationship



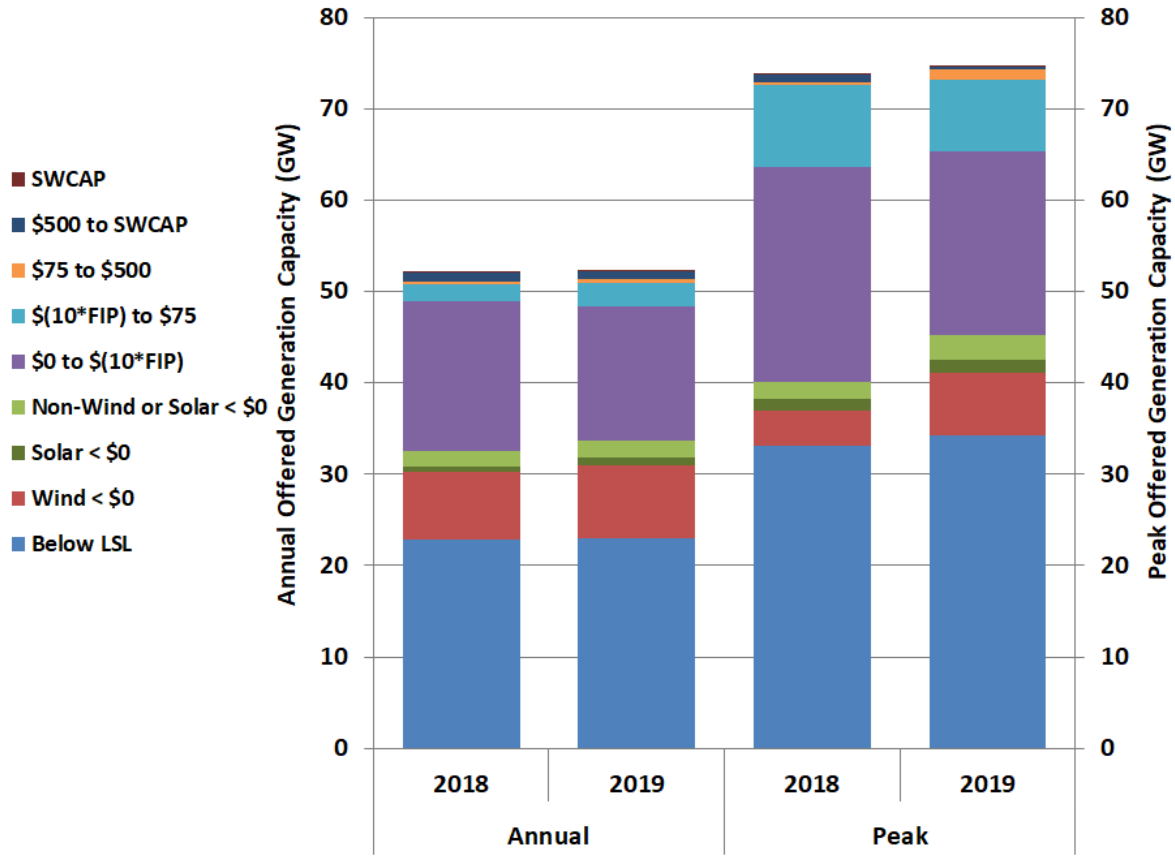
In a well-performing market, a positive relationship between implied heat rate and load level is expected because resources with higher marginal costs are dispatched to serve higher loads. This relationship continued and the magnified effects of increased shortage conditions in 2019 can be seen at the highest load levels.

For additional analysis of real-time energy prices adjusted for fuel price changes, see Figure A7, Figure A8, and Table A1 in the Appendix.

E. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2019 to that offered in 2018. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 9 provides the average aggregated generator offer stacks for the entire year, as well as the offers in the summer.

Figure 9: Aggregated Generation Offer Stack - Annual and Peak



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.

The average annual offer patterns shown in Figure 9 reveal that in 2019:

- The amount of capacity offered at prices less than zero increased by more than 1,000 MW, with more than half coming from wind generators;
- Approximately 1800 MW less capacity was offered between $0 and $(10*FIP). This was likely related to the higher volatility in real-time prices and shortage conditions, which created higher operating risks and opportunity costs to be priced.
- The amount of capacity offered at prices between $(10*FIP) and $75 per MWh increased by 750 MW from 2018 to 2019.
- The aggregate amount of generation capacity offered into ERCOT's real-time market increased by nearly 250 MW in 2019.

Figure 9 also shows that the changes in the aggregated offer stacks between the summers of 2018 and 2019 were somewhat different than those in the annual aggregated offer stacks for those years. The changes that occurred in 2019 during the summer included:

- The aggregate offer stack increased by approximately 850 MW from the previous summer as generators responded to the incentives provided by shortage pricing.
- The amount of additional capacity offered at negative prices increased by approximately 3,900 MW, of which 3,000 MW came from wind units.
- This increase was offset by reductions of nearly 3,300 MW capacity offered at prices between $0 and $(10*FIP), and of 1,300 MW of capacity offered at $(10*FIP) and $75 per MWh.

When natural gas prices are very low, as they were in 2019, the price range between $0 and $(10*FIP) will be smaller. This likely caused a smaller amount of energy offers in this range in 2019. Meanwhile, there was a noticeable increase for the offers between $75 and $500, as well as the negatively priced offers.

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).[11] 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, with a second step of 0.25 to be implemented in the spring of 2020.[12]

The effects of these changes are shown in Figure 10. This figure shows the Summer and Winter Peak curves that existed prior to the blending of the curves in 2019. It also depicts the new single blended ORDC curves for 2019 and 2020. The curves within the range are determined in

[11] 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.

[12] The ORDC changes were approved by the ERCOT Board of Directors at its February 12, 2019 meeting and implemented on March 1, 2019 via OBDRR011, ORDC OBD Revisions for PUCT Project 48551.

advance for four-hour blocks that vary across seasons. This shaded area depicts the breadth of distribution of the ORDC values across the year.

Figure 10: Winter and Summer Peak Operating Reserve Demand Curves

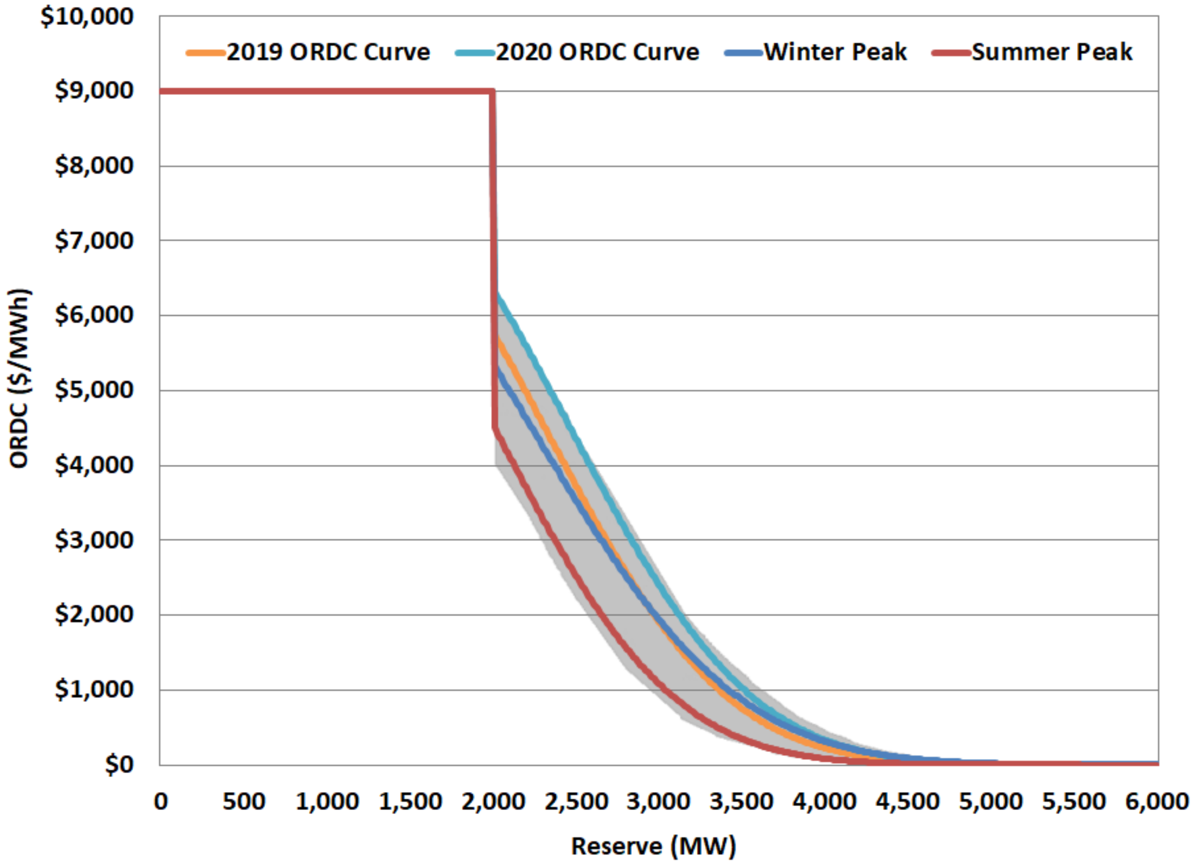
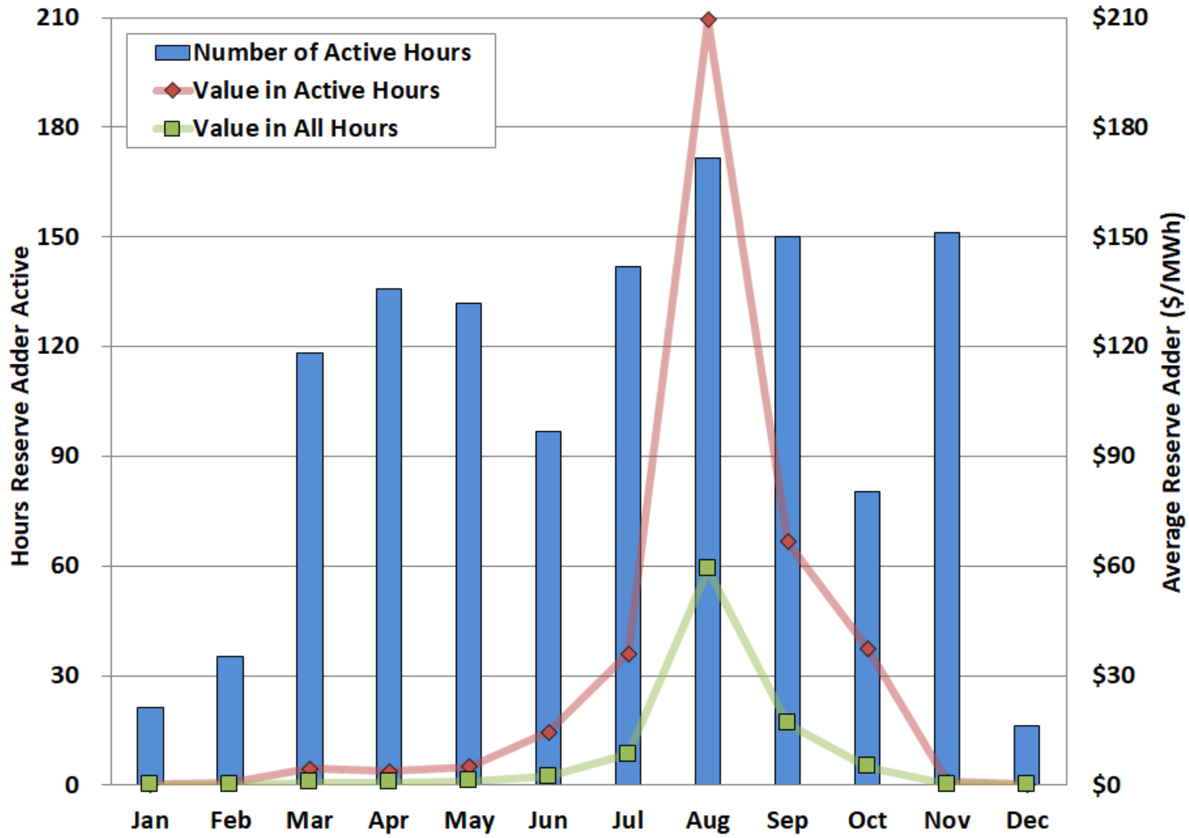


Figure 10 shows that blending the curves increases the level of ORDC contributions to price as reserve capacity drops. For example, the price at 3000 MW reserve level rises from roughly $1100 per MWh on the Summer Peak curve that existed previously to approximately $2400 per MWh on the blended 2020 curve. Once available operating reserve levels decrease to 2,000 MW, prices will rise to $9,000 per MWh for all the curves.

The following two analyses illustrate the contributions of the operating reserve adder and the reliability adder to real-time prices. As described above in Figure 1, the contributions of the energy price adders increased in 2019. The first of the two adders, the operating reserve adder, is a shortage value intended to reflect the expected value of lost load given online and offline reserve levels.

Figure 11 shows the number of hours in which the adder affected prices, and the average price effect in these hours and all hours. This figure shows that in 2019, the operating reserve adder had the largest price impacts in August because of the shortage conditions that occurred during the peak week of August 12. The contribution from the operating reserve adder in 2019 was much greater than in recent years because of the increase in shortage conditions, as well as the modifications to the ORDC described above.

Figure 11: Average Operating Reserve Adder

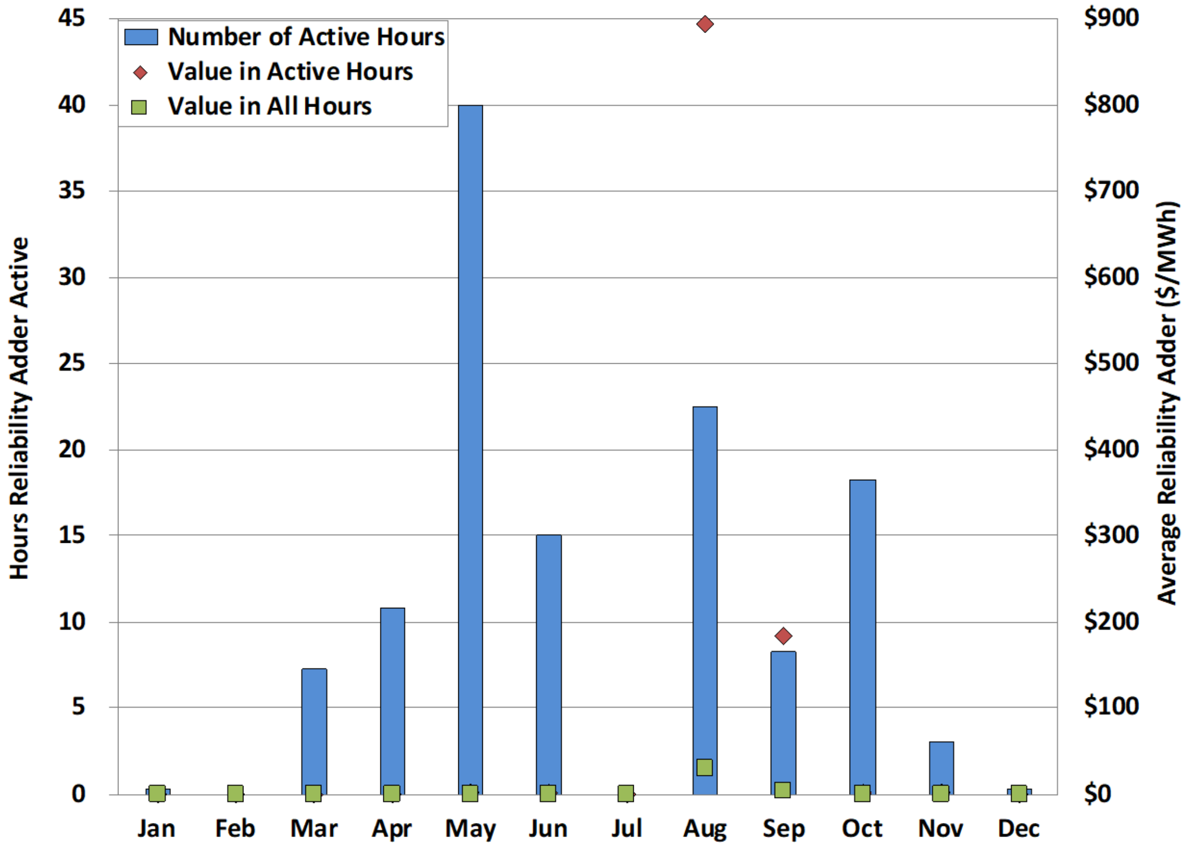


Overall, the operating reserve adder contributed $9.76 per MWh, or approximately 21% of the annual average real-time energy price of $47.06 per MWh in 2019. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply conditions and high load conditions occur together and result in sustained shortages, like the market experienced in 2019.

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 12 below shows the impacts of the reliability adder in 2019. When averaged across only the hours when the reliability adder was non-zero, the largest price impacts of the reliability adder occurred during the week of August 12. RUC instructions for August and September, encompassing the shortage intervals of 2019, resulted in a positive reliability adder for 31 hours, with a contribution to real-time price of $16 per MWh. The reliability adder was non-zero for 1.4% of the hours in 2019, most of which occurred in May, but the contribution to the real-time energy price was small outside of August and September. The contribution from the reliability adder to the annual average load-weighted real-time energy price was $3.55 per MWh.

Figure 12: Average Reliability Adder

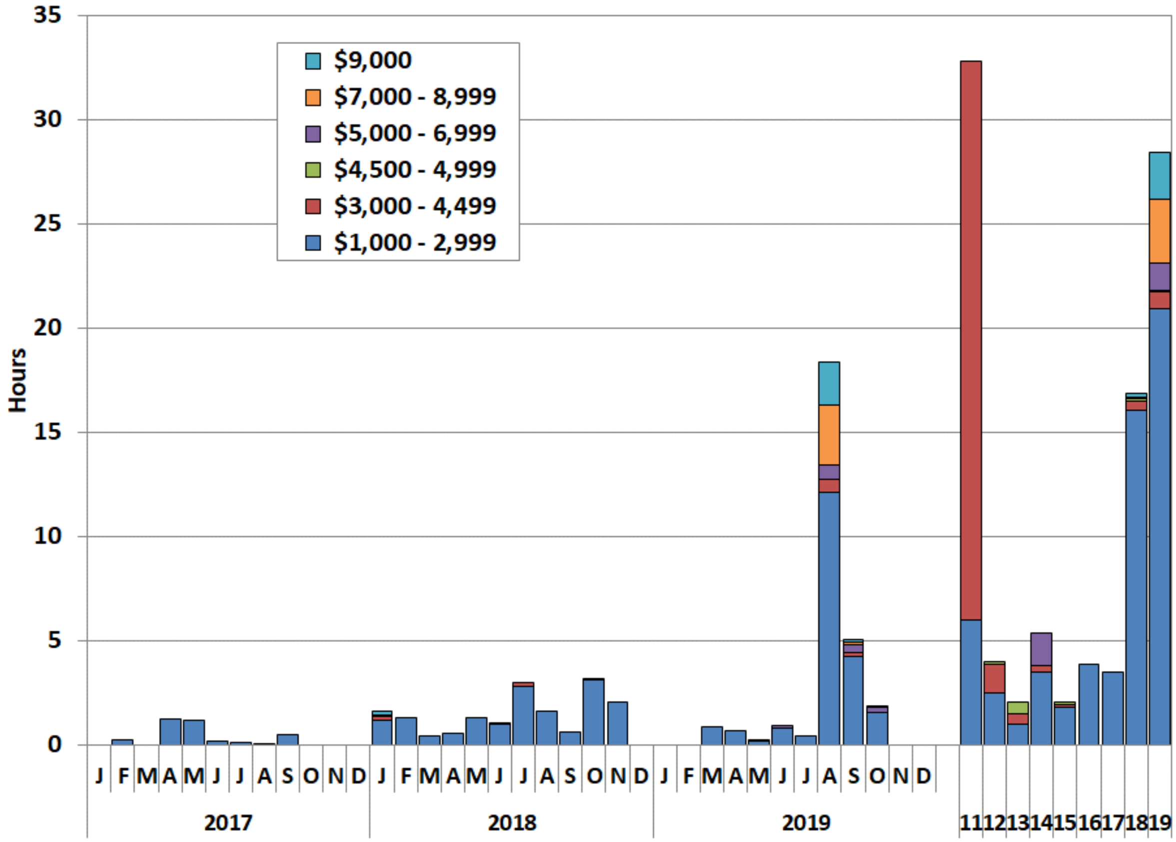


Weaknesses in the implementation of the reliability deployment adder were identified in 2018 and addressed in 2019. The primary flaw identified in the calculation method used to determine the reliability adder was that relaxing the low dispatch limit of all resources could make the price adders higher, even when all RUC-instructed resources were dispatched above their low dispatch limits and thus there was no artificial suppression of prices. In August 2019, NPRR904, *Revisions to Real-Time On-Line Reliability Deployment Price Adder for ERCOT-Directed Actions Related to DC Ties* was approved, which revised the categories of ERCOT-directed actions that trigger the Real-Time On-Line Reliability Deployment Price Adder (RDPA) pricing run to include Direct Current Tie (DC Tie) related actions in order for prices to reflect current system conditions and corrected the previously identified flaw with the adder.

As an energy-only market, the ERCOT market relies heavily on high real-time prices that occur during shortage conditions to provide key economic signals to build new resources and retain existing resources. However, the frequency and impacts of shortage pricing can vary substantially from year-to-year, as shown in the figure below.

To summarize the shortage pricing that has occurred since 2011, Figure 13 below shows the aggregate amount of time when the real-time system-wide energy price exceeded $1,000 per MWh, by month for 2017 through 2019, as well as annual summaries for 2011 through 2019.

Figure 13: Duration of High Prices



This figure shows that high prices occurred more frequently in 2019 than in any previous year since 2011. 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. Prices previously reached the $9,000 system-wide offer cap for the first time in ERCOT's history in January 2018. In 2019, the cap was reached for intervals totaling more than two full hours during the peak week of August 12.

In comparison, market prices cleared at the then-effective cap of $3,000 per MWh for 28.44 hours in 2011. Extreme cold in February 2011 paired with unusually hot and sustained summer temperatures led to much more frequent shortages in that year, even though capacity levels were higher..

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 2013-2019. Larger values represent higher deviation from the mean.

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

Load Zone	2013	2014	2015	2016	2017	2018	2019
Houston	14.8%	14.7%	13.4%	20.8%	24.9%	21.5%	22.7%
South	15.4%	15.2%	14.6%	19.9%	26.2%	23.5%	23.5%
North	13.7%	14.1%	11.9%	15.5%	14.8%	20.7%	22.6%
West	17.2%	15.4%	12.9%	16.8%	17.5%	21.8%	24.7%

These results show overall volatility has been rising modestly over the past two years. This overall increase is consistent with the falling operating reserve margins that have led to more frequent instances of tight supply conditions.

Congestion explains most of the interzonal differences in price volatility. Volatility was highest in the West zone in 2019 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.

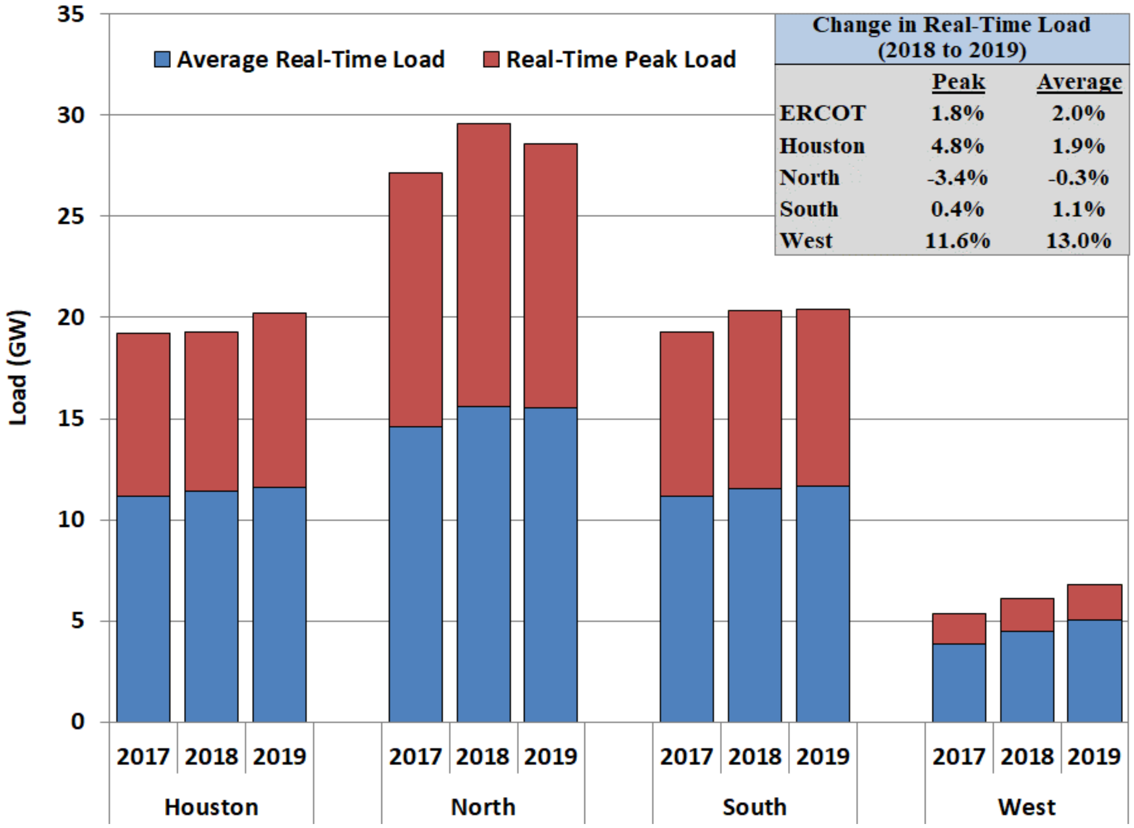
II. Demand and Supply in ERCOT

Many of the trends in market outcomes described in Section I are attributable to changes in the supply portfolio or load patterns in 2019. 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 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 2019

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.[13] Figure 14 shows peak load and average load by geographic zone from 2017 through 2019.[14]

Figure 14: Annual Load Statistics by Zone



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

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

Figure 14 shows that the total ERCOT load in 2019 increased 2% from 2018, an increase of approximately 880 MW per hour on average. Most of this increase occurred in the West zone. The West zone experienced double-digit growth in both peak and average load since 2018, driven by continuing expansion of oil and natural gas production activity. The other zone that experienced material increases in both average and peak loads was Houston, whereas the North zone experienced decreases in both load metrics.

Summer conditions in 2019 produced a new record hourly peak load of 74,820 MW on August 12, 2019, surpassing the previous ERCOT coincident peak hourly load record of 73,473 MW set on July 19, 2018. These changes 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 loads. For the three summer months of June through August 2019, ERCOT experienced a 2% increase from 2018 in the number of cooling degree days in Dallas, a 6% increase in Houston and 4% decrease in Austin. These results indicate that the summer of 2019 was slightly warmer than in 2018. 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

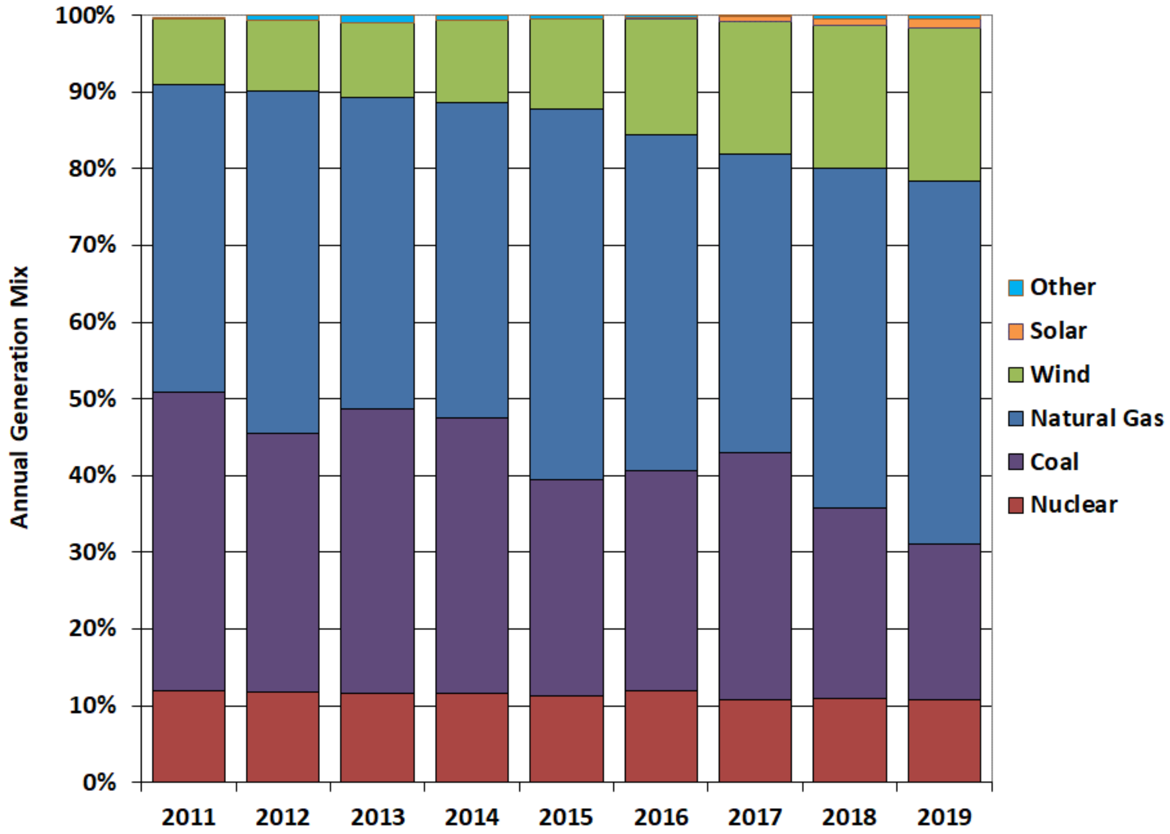
We evaluate the generation portfolio in ERCOT in this subsection. The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand with the exception of Houston. The Houston zone has increasingly relied on imports from the rest of the state as resources have been mothballed and the reliance on wind capacity that is only fractionally available to meet peak demand has increased.[15]

Approximately 4.9 GW of new generation resources came online in 2019, the bulk of which was wind resources with total nameplate capacity level of 4.7 GW, and an effective peak serving capacity of approximately 1,250 MW. The remaining capacity additions were: 80 MW of combustion turbines, 50 MW of solar resources, and 30 MW of storage resources. There were only 550 MW of retirements in 2019, 470 MW coal and 80 MW wind. These changes are detailed in Section IV of the Appendix, along with a review of the vintage of the ERCOT fleet.

Figure 15 shows the annual composition of the generating output in ERCOT from the first full year of the nodal market in 2011 to 2019. 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 2019. 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.

15 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 63% for coastal wind, 16% for other wind, and 76% for solar.

Figure 15: Annual Generation Mix in ERCOT



This figure shows that:

- The generation share from wind has increased every year, reaching almost 20% of the annual generation in 2019.
- The share of generation from coal continues to fall, down to just over 20% in 2019.
- The falling coal output was replaced by natural gas generation, which increased from 44% in 2018 to 47% in 2019.

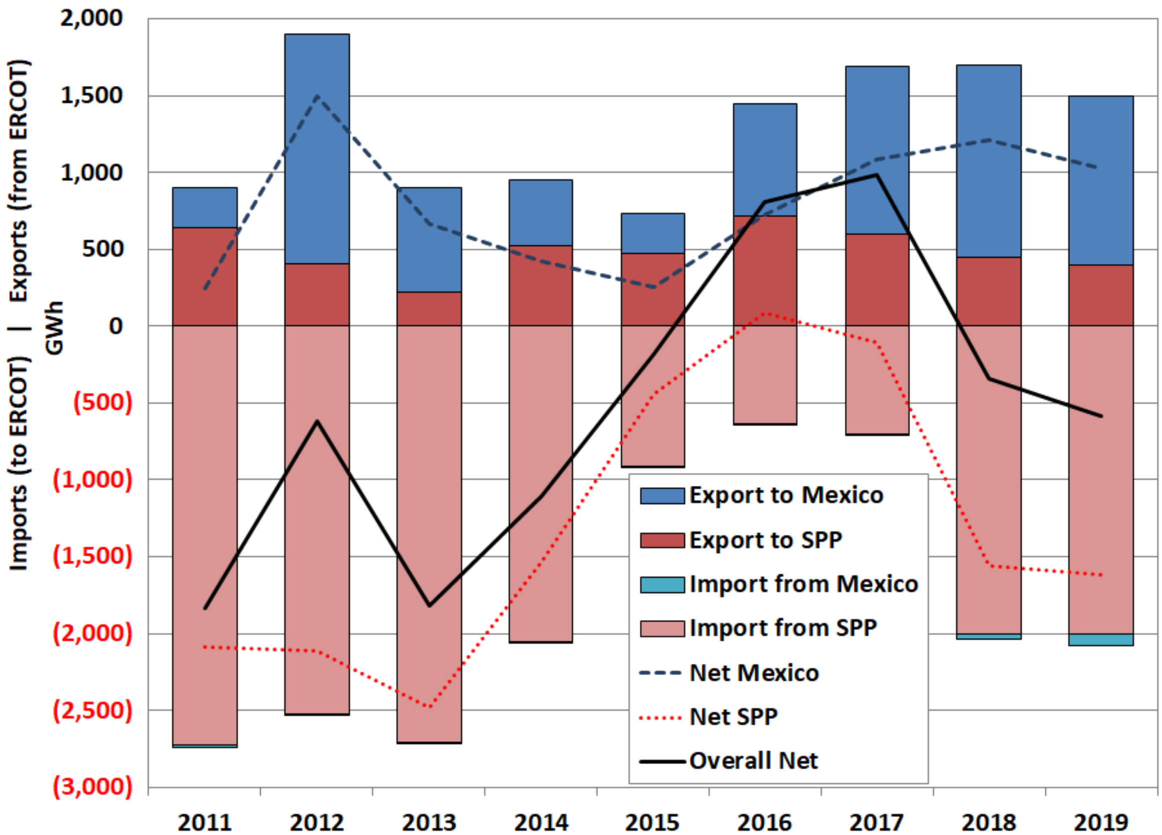
We expect these trends to continue because of the ongoing decline in natural gas prices, making gas-fired resources increasingly more economic than coal resources, and the continued growth of wind resources.

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) tie 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 16 shows the total energy transacted across the ties for each of the past several years.

Figure 16: Annual Energy Transacted Across DC Ties



The figure shows that after 2013, there was a trend of reduced imports from SPP and increased exports to Mexico because prices in ERCOT remained relatively low. This trend caused ERCOT to be a net exporter in 2016 and 2017. However, the tightening supply in ERCOT and the resulting higher prices in 2018 and 2019 have caused this trend to reverse. ERCOT became a net importer again as imports from SPP increased sharply.

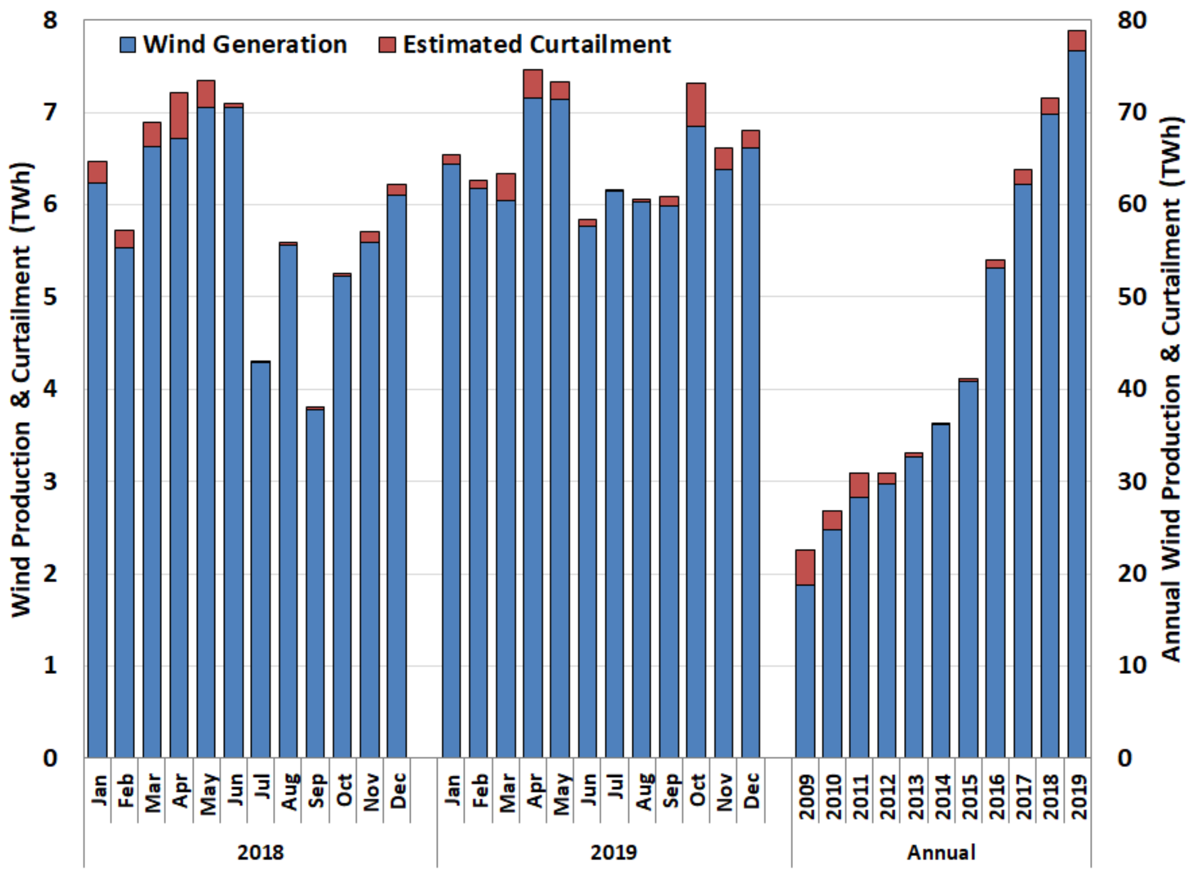
D. Wind Output in ERCOT

Investment in wind resources has continued to increase over the past few years in ERCOT. The amount of wind capacity installed in ERCOT approached 27 GW at the end of 2019. Although the large majority of wind generation is located in the West zone, more than 6.1 GW of wind generation is located in the South zone.

Although wind output has grown rapidly, its value in satisfying ERCOT's peak summer demands is limited by its negative correlation with load.[16] The highest wind production occurs during non-summer months, and predominately during off-peak hours. This negative correlation can contribute to shortage conditions, which is why it has been useful to track "net load." As noted previously, net load is defined as the system load less wind and solar production. During the peak week of August 2019, peak prices ($9,000 per MWh) coincided not with peak load, but with peak *net* load, when wind generation during peak hours was low and increased the demand on other generation units. The importance of wind generation output during times of shortage will continue to rise if reserve margins remain low.

Figure 17 shows the average wind production and estimated curtailment quantities for each month from 2017 through 2019.

Figure 17: Wind Production and Curtailment



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

ERCOT continued to set new records for peak wind output in 2019. New wind output records were set:

- On January 21, when wind resources produced 19,672 MW instantaneously; and
- On November 26 when wind served nearly 58% of load.

Figure 17 reveals that the total production from wind resources continued to increase, while the quantity of curtailments implemented to manage congestion caused by the wind resources also increased. These curtailments reduced wind output by less than 3%, 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 18: Top and Bottom Deciles (Hours) of Net Load

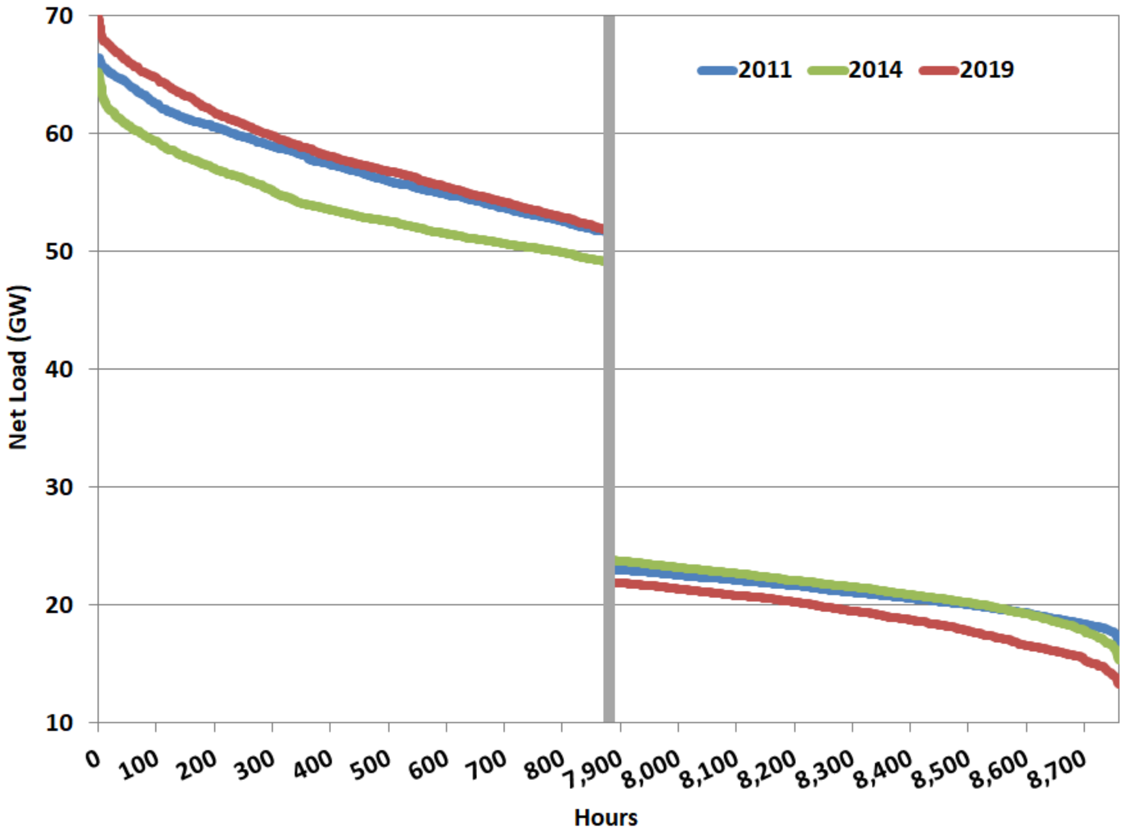


Figure 18 shows net load in the highest and lowest hours. Even with the increased development activity in the coastal area of the South zone, 71% of the wind resources in ERCOT are located in West Texas (including the Panhandle). The wind profiles in this area result in only modest reductions of the 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 18 shows that:

- In the hours with the highest net load (the left panel), the difference between the peak and the 95th percentile of net load has averaged 12.3 GW the past three years. This means that 12.3 GW of non-wind capacity is needed to serve load in less than 440 hours per year.
- 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 13.3 GW in 2019, 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 very 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 75% for facilities located in the west and 68% for those in central Texas. Hence, these resources provide a larger resource adequacy benefit than wind resources.

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; or
- Legislatively-mandated demand response programs administered by the transmission and distribution utilities in their energy efficiency programs.

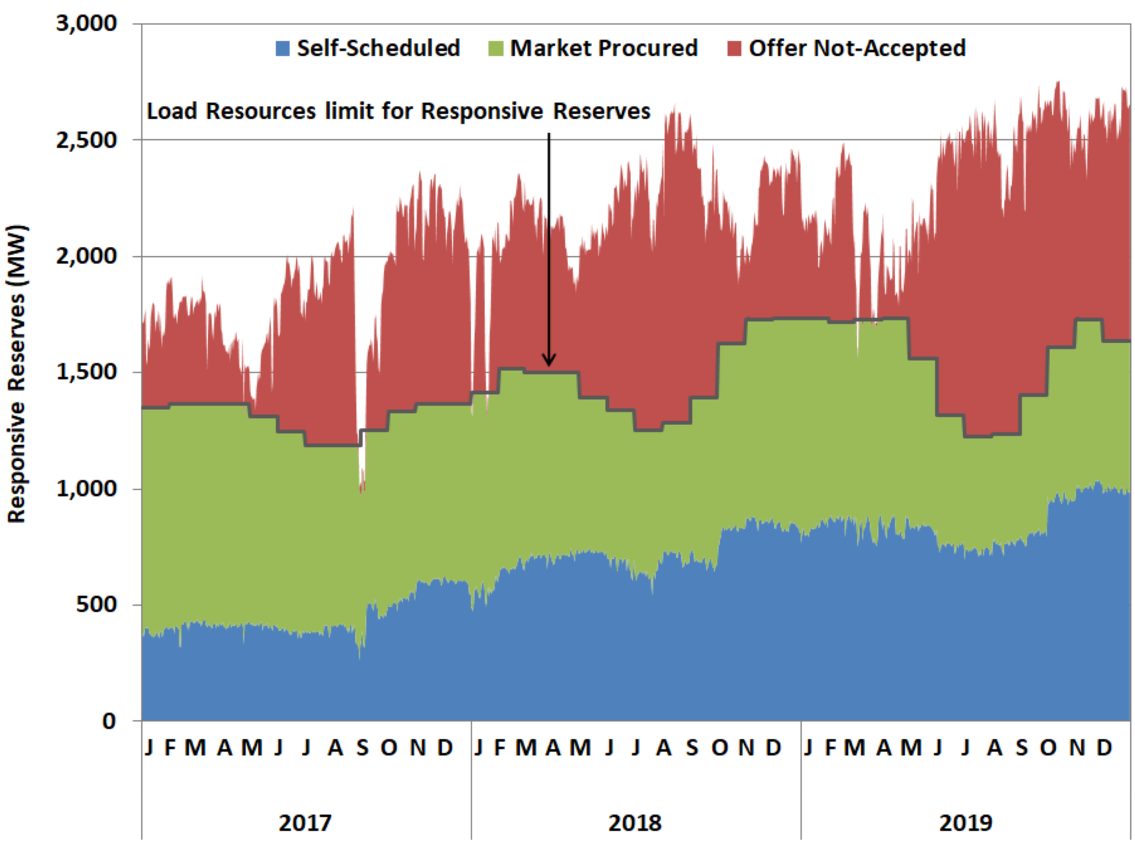
Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges.

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. A load relay response has the effect of increasing system frequency and can be a very effective mechanism for maintaining system frequency at 60Hz. Load resources providing responsive reserves have high set under-frequency relay equipment, which 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 2019, approximately 5,506 MW of qualified load resources were capable of providing responsive reserve service, an increase of approximately 440 MW during 2019. However, the total amount of responsive reserves procured by ERCOT was a maximum of 3,200 MW per hour. During 2019, there were no deployments of load resources providing responsive reserve service. Figure 19 below shows the average amount of responsive reserves provided from load resources on a daily basis for the past three years.

Figure 19: Daily Average of Responsive Reserves Provided by Load Resources



Prior to June 1, 2018, load resources were limited to providing a maximum of 50% of responsive reserves. The implementation of NPRR815: *Revise the Limitation of Load Resources Providing Responsive Reserve (RRS) Service* in June 2018 allowed load resources to now provide up to 60% of the responsive reserve obligation, while also requiring that at least 1,150 MW of responsive reserves be provided from generation resources.[17] The quantity of load providing responsive reserve offers exceeded the limit for almost all of 2019, 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. 4 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.[18] The time- and capacity-weighted average price for ERS over the contract periods from February 2019 through January 2020 was $6.59 per MWh, down slightly from $6.72 per MWh the previous program year. This price was lower than the average price paid to non-spinning reserves ($13.44 on average) and responsive reserves ($26.61 on average) in 2019.[19]

There were slightly more than 285 MW of load participating in load management programs administered by the TDUs in 2019.[20] 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.[21] 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.

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

18 *See* 16 TAC § 25.507.

19 *Id.*, *ERCOT's Updated Total System Demand Response/Price Response Results for Summer 2019 Peak Week August 12—August 16, 2019* (Feb. 6, 2020). http://www.ercot.com/content/wcm/lists/200201/49852_ERCOT_Update_Demand_Response_Summer_2019_Assessment.pdf

20 *See* ERCOT 2019 Annual Report of Demand Response in the ERCOT Region (Mar. 2020) at 9, available at http://www.ercot.com/services/programs/load.

21 *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).

- 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 on the basis of 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.[22] ERCOT estimates that as much as 2,200 MW of load were actively pursuing reduction during the 4CP intervals in 2019, much higher than the 2018 estimate.[23]

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 2017 when significant reductions were observed on peak load days in June, August and September when real-time prices were less than $100 per MWh. Likewise, reductions were observed during June, July, and August of 2018 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. To address these distortions, we continue to recommend that modifications to ERCOT's transmission cost allocation methodology be explored (see recommendation No. 3 above).

4. Demand Response and Market Pricing

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 5-minute dispatch instructions to specify the price at which they no longer wish to consume. However, in 2019 there were no loads qualified to participate in real-time dispatch.

22 See PUCT Docket No. 48928, *Commission Staff's Petition to Set 2019 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Apr. 4, 2019); PUCT Docket No. 47777, *Commission Staff's Application to Set 2018 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Mar. 29, 2018); PUCT Docket No. 46604, *Commission Staff's Application to Set 2017 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Mar. 30, 2017); PUCT Docket No. 45382, *Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Mar. 25, 2016).

23 See ERCOT, 2019 Annual Report of Demand Response in the ERCOT Region (Mar. 2020) at 7, available at http://www.ercot.com/services/programs/load.

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. Unfortunately, the RDPA does not accurately account for ERS deployments. To address these concerns, we recommend improvements for pricing during ERS deployments in the following three areas:

- The adder is calculated using the amount of ERS MWs that have been contracted for rather than an estimate of actual deployment at any given SCED interval. A significant portion of the ERS capacity in the two ERS deployments of 2019 was actually deployed prior to the ERCOT ERS instruction, presumably to avoid paying the high real-time energy prices. This is a market-driven response and therefore is not appropriate to include in the reliability adder.
- The adder calculation contains an assumption that ERS resources ramping back to pre-instruction levels over ten hours. However, in 2019 the resources that did deploy in response to ERCOT reliability instruction returned to pre-instruction levels in roughly three hours.[24] Assuming ten hours, therefore, artificially exaggerates the adder.
- The ORDC adder accounts for many ERCOT actions, but does not account for ERS deployment. This adder should be reduced by removing the ERS deployment amount from the reserve calculation.

Based on IMM estimates, the first two improvements would have resulted in a reduction in charges to load of approximately $400 million in 2019, while the third would have resulted in an increase of about $100 million. Given the importance of shortage and near-shortage pricing in ERCOT's energy only market, addressing these concerns with the RDPA and ORDC adders should be a high priority.

24 See NPRR 1006: *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data*. Posted on March 3, 2020, this NPRR proposes to return 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 changes the process for updating this parameter in the future so that it can be updated by TAC each year as appropriate, without the need to file an NPRR.

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 a 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.

With the exception of 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 2019 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.

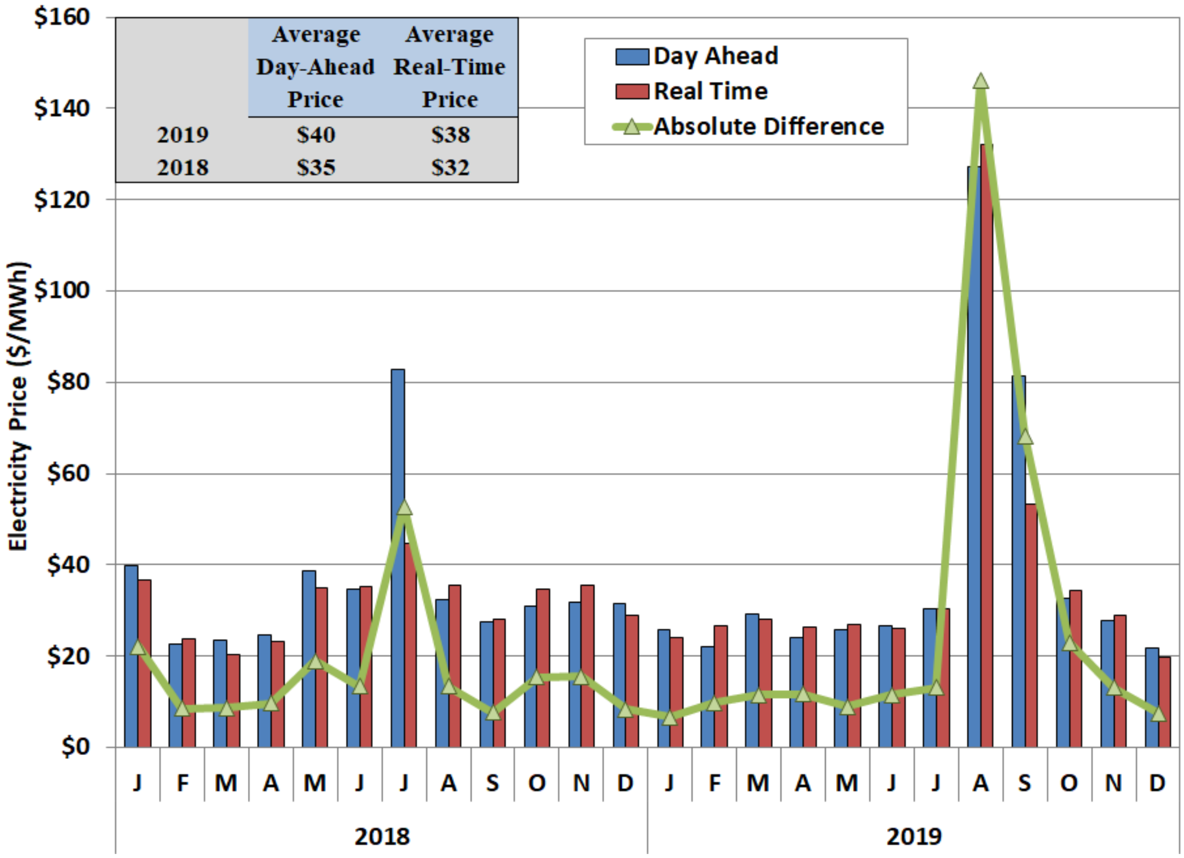
Overall, 2019 day-ahead prices were higher for both energy and ancillary services, as expected given the lower reserve margin. Liquidity in the day-ahead market was similar to previous years, which included active trading of congestion products in the day-ahead market.

A. Day-Ahead Market Prices

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 will occur when: (1) there are low barriers to shifting purchases and sales between the forward and real-time markets; 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 convergence. Convergence between the day-ahead and real-time markets leads to improved 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 reveals whether persistent and predictable differences exist between day-ahead and real-time prices that participants should arbitrage over the long term. Figure 20 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.[25]

Figure 20: Convergence Between Day-Ahead and Real-Time Energy Prices



Day-ahead and real-time prices averaged $40 and $38 per MWh in 2019, respectively.[26] This day-ahead premium was consistent with the premium in 2018. Most of the premium in both years occurred in the summer months and likely reflects the value of day-ahead energy purchases as a hedge against the volatility of real-time prices under tight conditions. Price convergence was evident in all months of 2019 except September, when day-ahead and real-time prices diverged sharply due to significant differences between expected and actual load early in the

25 For example, if day-ahead prices are $30 per MWh on two consecutive days while real-time prices are $20 and $40 per MWh respectively, the absolute price difference between the day-ahead market and the real-time market would be $10 per MWh on both days, while the difference in average prices would be $0 per MWh.

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

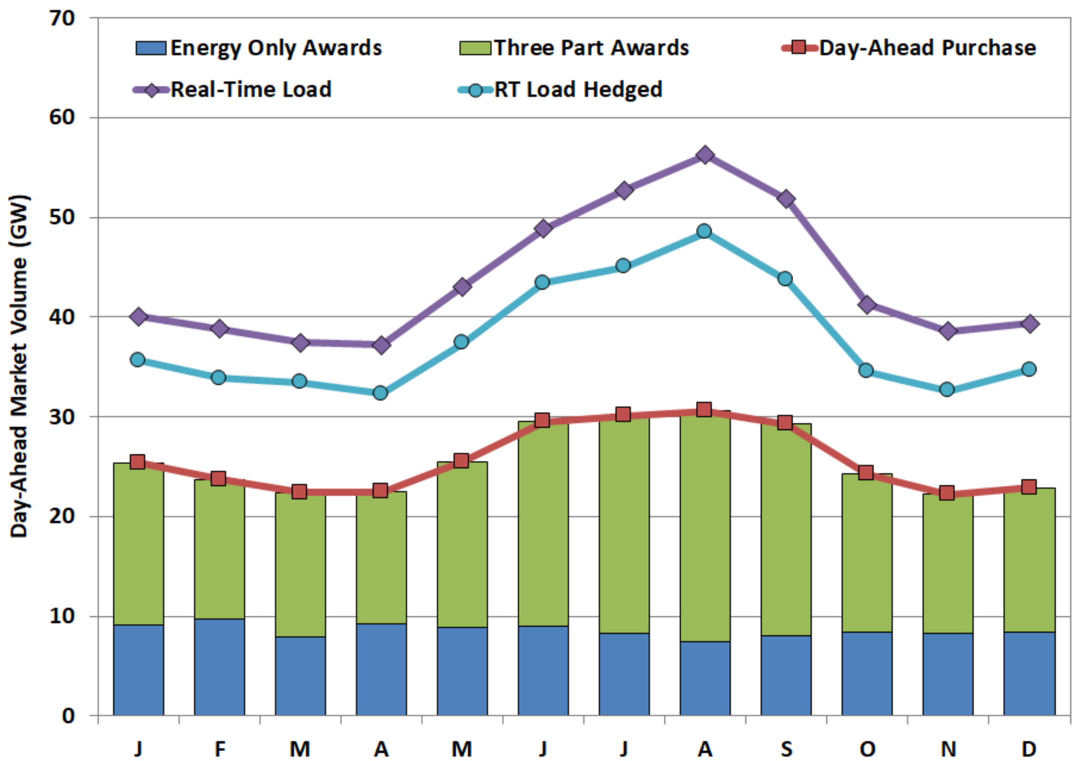
month.[27] Smaller quantities of installed reserves for the summer of 2019, coupled with the ORDC changes, led to expectations of more frequent shortage conditions and higher associated prices in real-time. This led to very high day-ahead prices in August and September.

The average absolute difference between day-ahead and real-time prices was $27.63 per MWh in 2019, a sharp increase from $16.21 and $8.60 per MWh in 2018 and 2017, respectively. The large absolute difference primarily occurred in August and September as expectations of shortages in the day-ahead market and actual reserve shortages in the real-time market led to large 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 2019, see Figure A9, Figure A10, and Figure A19 in the Appendix.

B. Day-Ahead Market Volumes

Figure 21 summarizes the volume of day-ahead market activity by month, which includes both purchases and sales of energy. 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 21: Volume of Day-Ahead Market Activity by Month



[27] ERCOT recently identified a software error in the reserve calculation that affected prices, particular on Sept. 6, 2019. Day-ahead and real-time price convergence for September would have been improved if the real-time price had been correctly calculated. *See* http://www.ercot.com/services/comm/mkt_notices/archives/4542.

Figure 21 shows that the volume of day-ahead purchases provided through a combination of three-part generator-specific offers (including start-up, no-load, and energy costs) and virtual energy offers was 59% of real-time load in 2019, a slight reduction from 60% in 2018. Although it may appear that many loads are still subjecting themselves to greater risk by not locking in a day-ahead price, other transactions or arrangements outside the organized market are used to hedge real-time prices and often PTP obligations are scheduled to hedge real-time congestion costs.

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.[28] 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.

Figure 21 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).[29] 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 87% in 2019, similar to the 89% seen in 2018.

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 22 shows the total capacity from three-part offers submitted in the day-ahead market for 2019.

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.

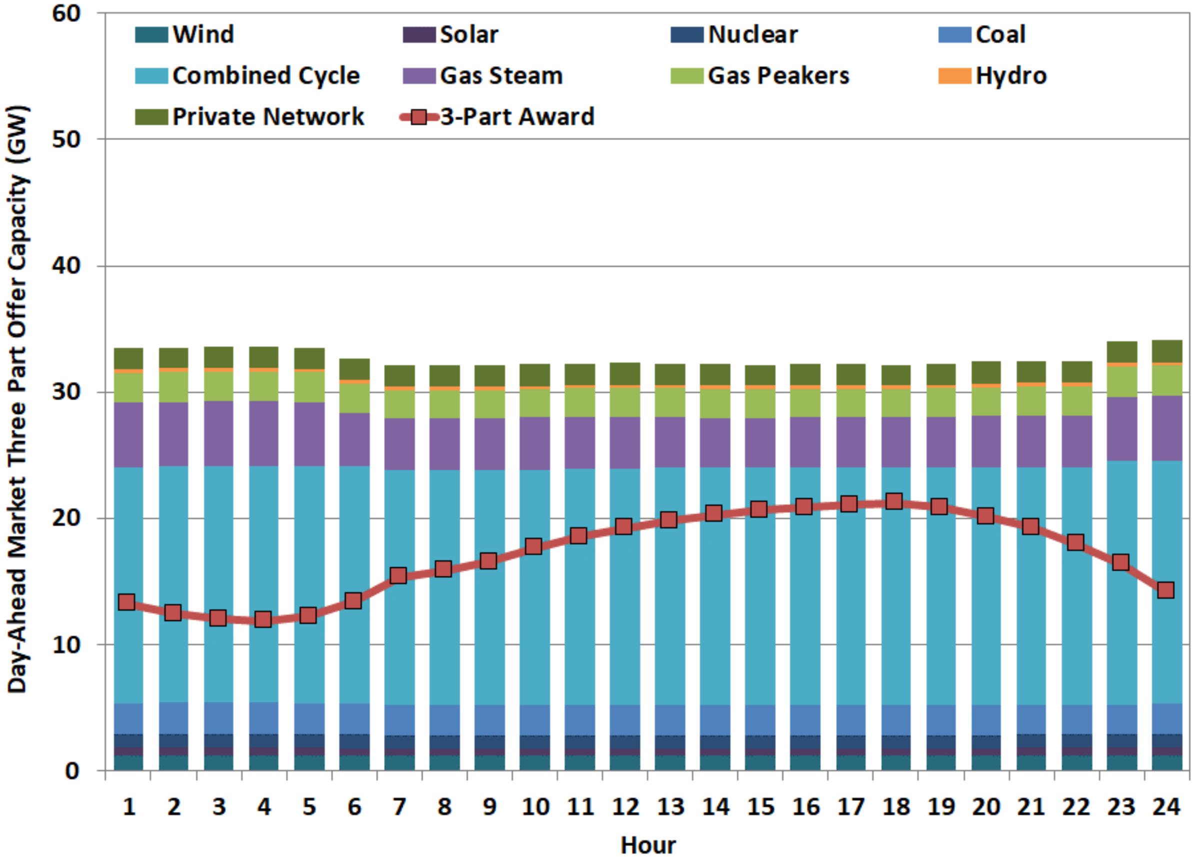
With the largest share of installed capacity, it follows that combined cycle units are the predominant type of generation submitting offers in the day-ahead market. More importantly, because combined cycle units are most typically marginal units, offering that capacity into the day-ahead market allows 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

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

29 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.

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.

Figure 22: Day-Ahead Market Three-Part Offer Capacity

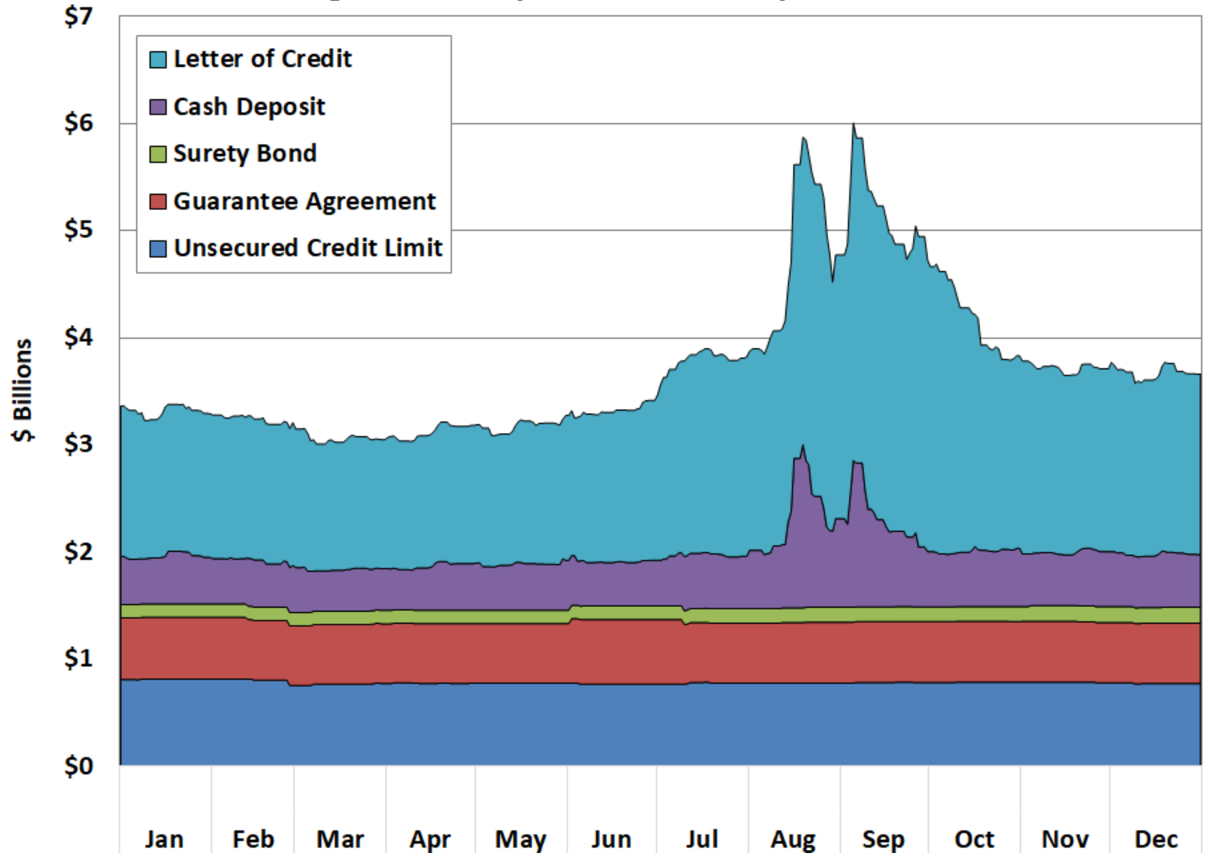


Parties that wish to participate in ERCOT's day-ahead market are required to have sufficient collateral with ERCOT. In 2018, ERCOT introduced forward prices as a determinant in calculating collateral requirements.[30] With even smaller installed reserves in 2019, forward prices were especially high for the summer months of 2019. The effect that forward prices had on the total collateral held by ERCOT throughout the year was quite significant, particularly in August and September, as shown below in Figure 23.

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 2019.

30 NPRR800: *Revisions to Credit Exposure Calculations to Use Electricity Futures Market Prices*

Figure 23: Daily Collateral Held by ERCOT

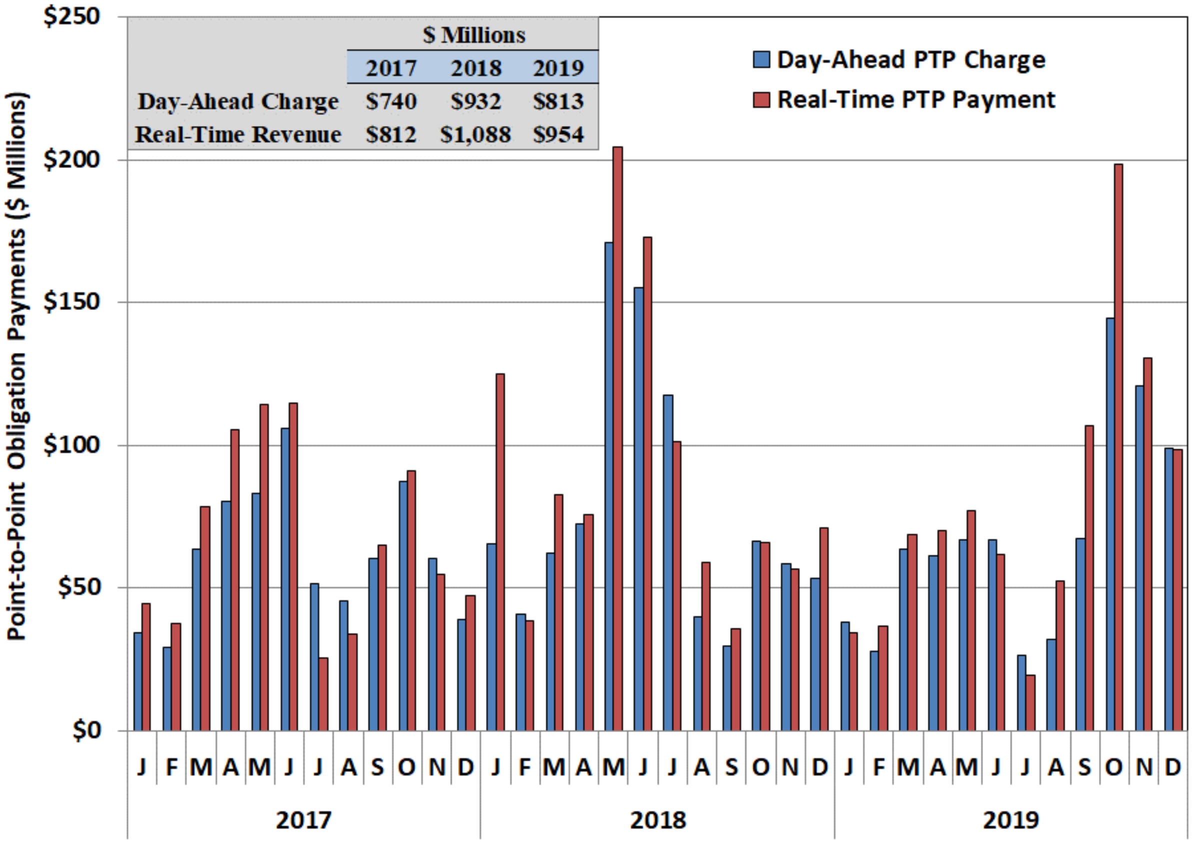


C. Point-to-Point Obligations

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 24, 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 24: Point-to-Point Obligation Charges and Revenues



As prices and total congestion costs have increased substantially in recent years, so have the costs and revenues associated with PTP obligations, although this trend was reversed in 2019. The average volume of PTP obligations has been fairly stable for the past three years.

Figure 24 shows that the aggregated total revenue received by PTP obligation owners in 2019 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. This occurs when real-time congestion costs are greater than day-ahead market congestion costs. Most of profits accrued in August through October when congestion priced in the day-ahead market was much lower than the congestion that actually occurred in real time.

To provide additional insight on the profits that have accrued to PTP obligations, Figure 25 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". These are instruments available only to Non-Opt-In Entities, shown below as "PTP Options," because that is how they are settled.

Figure 25: Average Profitability of Point-to-Point Obligations

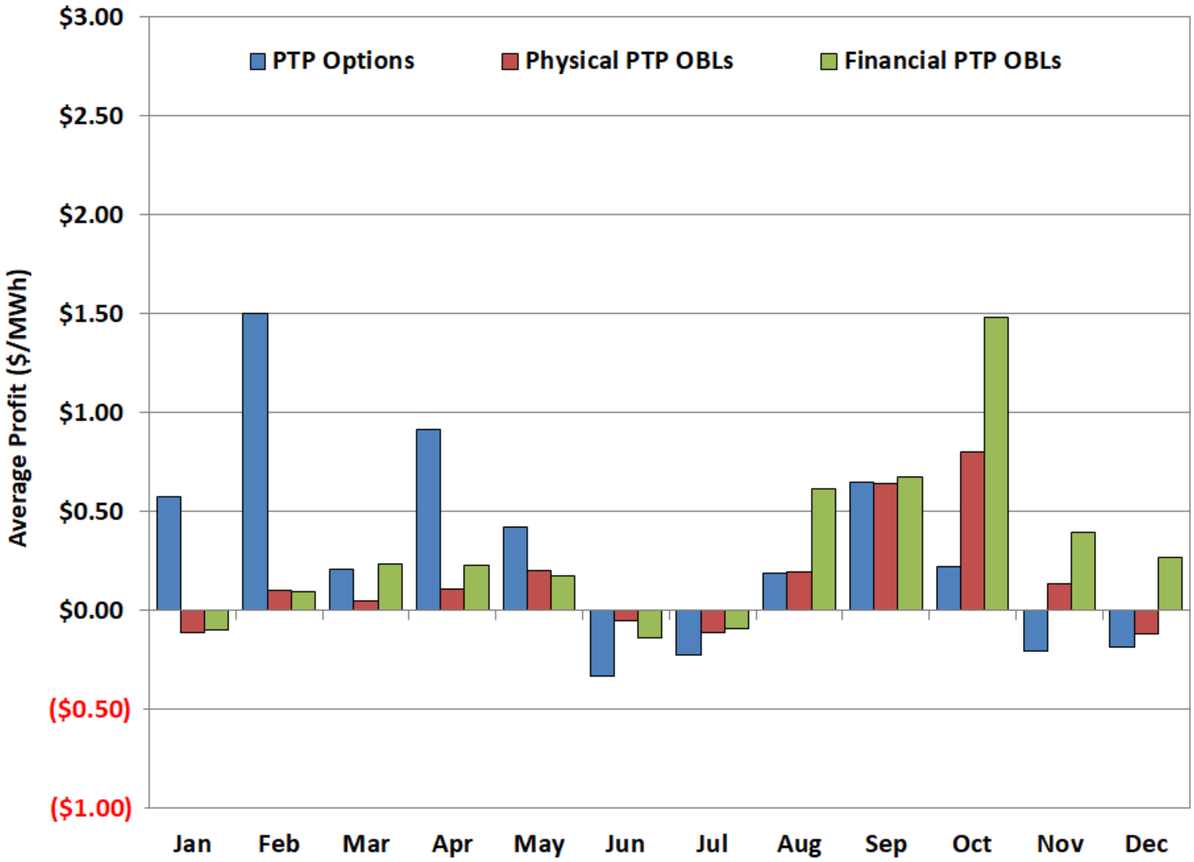


Figure 25 shows that in aggregate, PTP obligation transactions in 2019 were profitable for the year, yielding an average profit of $0.22 per MWh. This is slightly less than the average profit of $0.24 per MWh in 2018. PTP obligations were profitable during 2019 for all types of parties, with average profits of $0.16 per MWh for physical parties, $0.35 per MWh for financial parties, and $0.28 per MWh for PTP obligations settled as options. For analysis of the total volume of PTP obligation purchases in 2019, 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 2019. At the end of 2018, with the implementation of System Change Request (SCR) 795, *Addition of Intra-Hour Wind Forecast to GTBD Calculation*, ERCOT began including a new factor in the determination of generation to be dispatched in the 5-minute dispatch by improving 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.

1. Ancillary Services Requirements

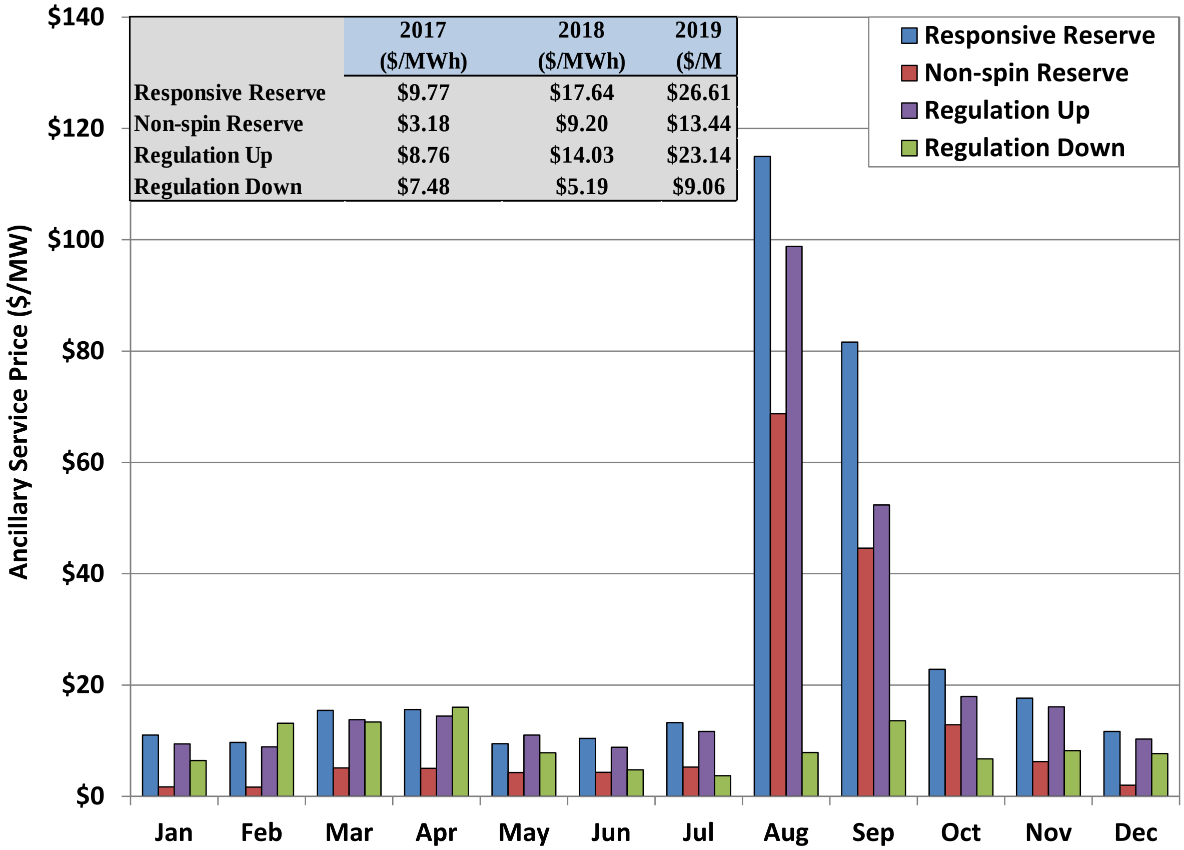
Since June 2015, ERCOT has calculated responsive reserves requirements based on a variable hourly need. This requirement is posted in advance for the year. ERCOT procures non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95% of the calculated net load 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.

The average total ancillary services requirement in 2019 was just shy of 4,900 MW, although the quantity of reserves held varies hour to hour. For example, on average ERCOT held roughly 5,500 MW of total reserves in the hour ending at 7 am, while it held roughly 4,500 MW of reserves in hour ending 3 pm. 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 2019.

2. Ancillary Services Prices

Figure 26 below presents the monthly average clearing prices of capacity for the four ancillary services, while the inset table shows the average annual prices over the last three years. The prices for ancillary service were noticeable higher in the months of August and September. These outcomes are consistent with the higher clearing prices for energy in the day-ahead market for those two months 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 26: 2019 Ancillary Service Prices



The inset table compares the average annual price for each ancillary service from 2017 through 2019. In 2019, higher prices for all ancillary services are explained by high day-ahead energy prices. This was largely the result of more frequent real-time shortage conditions that were also reflected in day-ahead prices. Responsive reserve service is the largest quantity purchased and is typically the highest-priced ancillary service product.

The increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase to $2.33 per MWh in 2019 from $1.60 per MWh in 2018. 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 3 shows the share of the 2019 ancillary services that are procured from the top ten QSE providers of ancillary services, in terms of volumes. 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 3: Share of Reserves Provided by the Top QSEs in 2018-2019

	2018				2019			
	Responsive	Non-Spin	Reg Up	Reg Down	Responsive	Non-Spin	Reg Up	Reg Down
# of Suppliers	**43**	**34**	**32**	**33**	**43**	**30**	**32**	**39**
QLUMN	2%	41%	14%	41%	2%	37%	14%	43%
QBRAZO	3%	6%	9%	3%	4%	6%	13%	3%
QLCRA	11%	7%	2%	5%	11%	6%	4%	3%
QEXELO	4%	0%	9%	4%	4%	0%	13%	5%
QAEN	3%	5%	4%	6%	2%	7%	3%	7%
QOCCID	12%	0%	1%	2%	12%	0%	2%	5%
QCPSE	6%	4%	8%	9%	3%	3%	5%	6%
QFPL12	0%	0%	9%	4%	0%	0%	9%	4%
QNRGTX	7%	2%	1%	0%	8%	2%	1%	0%
QEDE26	2%	1%	14%	2%	1%	0%	7%	2%

During 2019, 43 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. 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.

With regard to the concentration of the supply for each product, Table 3 shows that:

- The supply of responsive reserves has not been highly concentrated, with the largest QSE providing only 12% of ERCOT's responsive reserves.
- The provision of non-spinning reserves is much more concentrated, with a single QSE (Luminant, shown above as "QLUMN") bearing almost 40% of the requirements. Luminant's 37% share has been falling from as high as 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 exhibited similar concentration to non-spinning reserves in 2019. Luminant was a dominant supplier, selling 43% of all regulation down in 2019.

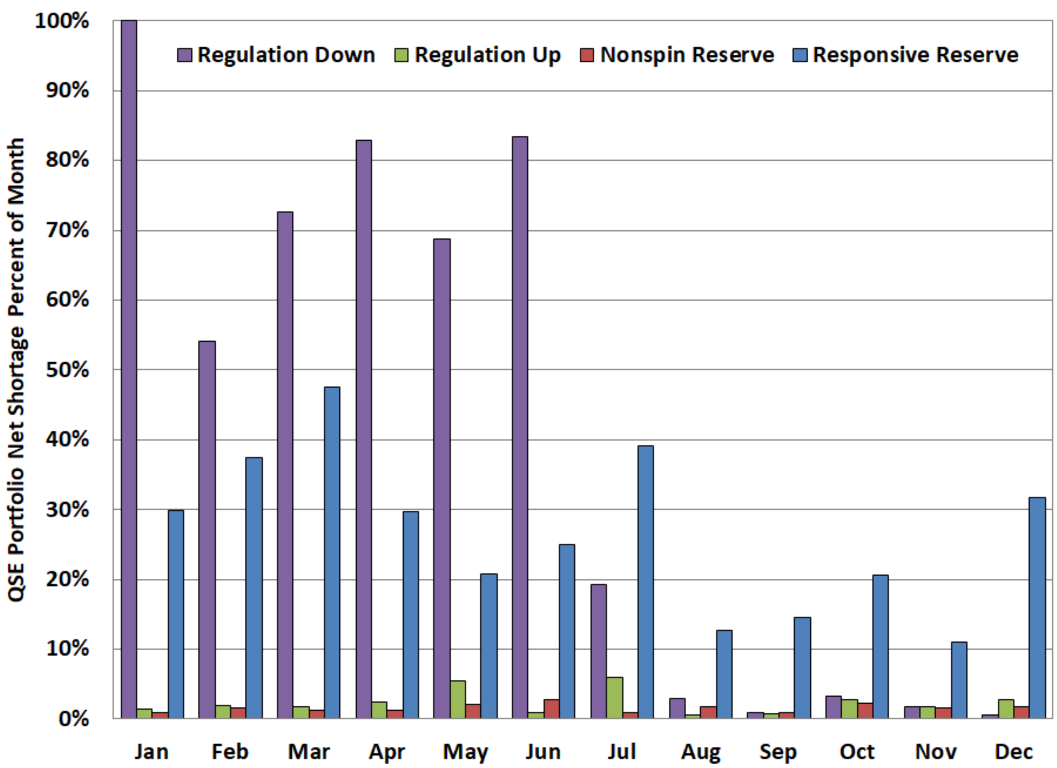
The ongoing concentration in the supply of non-spinning reserves and regulation down highlights the importance of modifying the ERCOT ancillary service market design and implementing real-time co-optimization. Jointly optimizing all products in each interval will allow the market to substitute its procurements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

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 their 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). This 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. Replacement can be necessary if the resource is unexpectedly unavailable or a transmission constraint prevents its delivery. Real-time co-optimization will address these issues. Because real-time co-optimization it is on the horizon, 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 2019.

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 27 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 27: 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. This reversal was due primarily to ERCOT's publicly-stated altered approach to ancillary service shortages starting in May 2019 at various stakeholder meetings (and codified in in NPRR947). This was positive from both a market and reliability perspective as ancillary services were more accurately accounted for and appropriately compensated. The NPRR refines 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.[31]

31 See NPRR 947: Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities, still pending at the close of 2019.

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 2019.

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 2019. We first discuss the congestion costs in the day-ahead and real-time markets, which totaled $1.1 billion and $1.26 billion respectively, in 2019. We then discuss the CRR markets and funding in 2019.

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 28 and Figure 29 summarize the monthly and annual congestion costs in the day-ahead and real-time markets. The values are aggregated by geographic zone.

Figure 28 shows that the total day-ahead congestion costs in 2019 were roughly 6% lower than costs in 2018 even though congestion costs were virtually unchanged in real-time. Most of the differences in congestion costs between day-ahead and real-time were in the West zone, which constituted approximately half of all of 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 last quarter of 2019.

Figure 28: Day-Ahead Congestion Costs by Zone

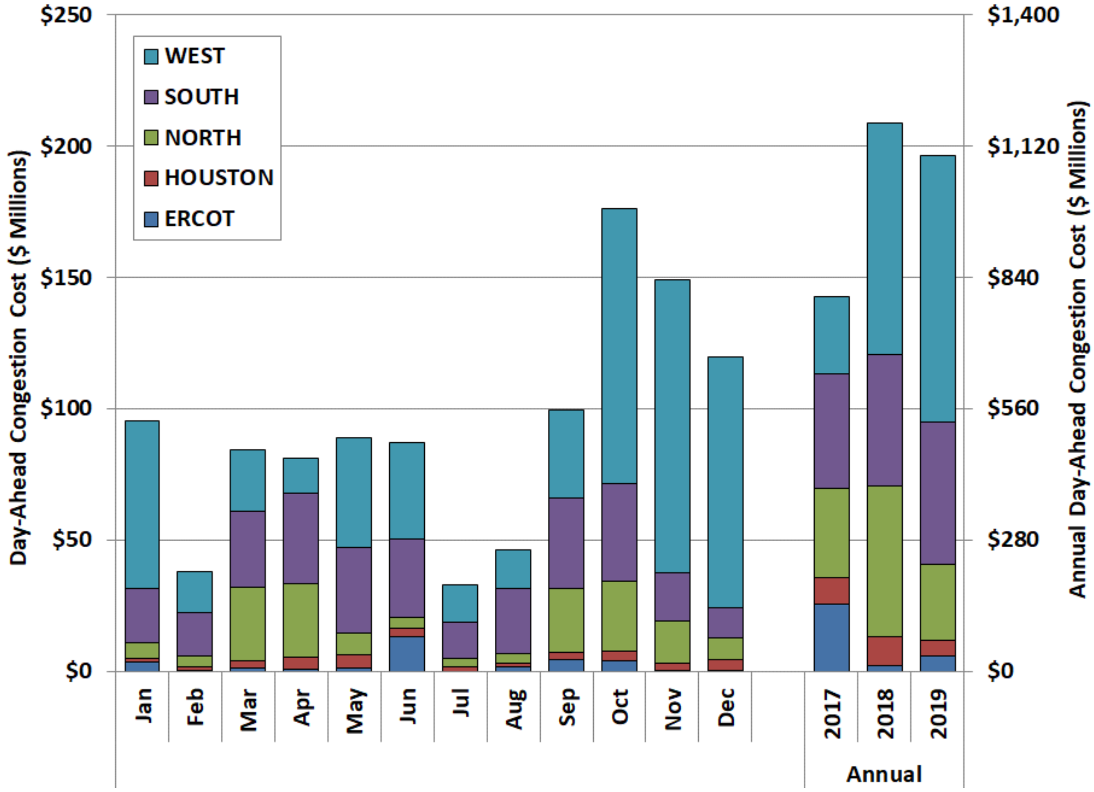
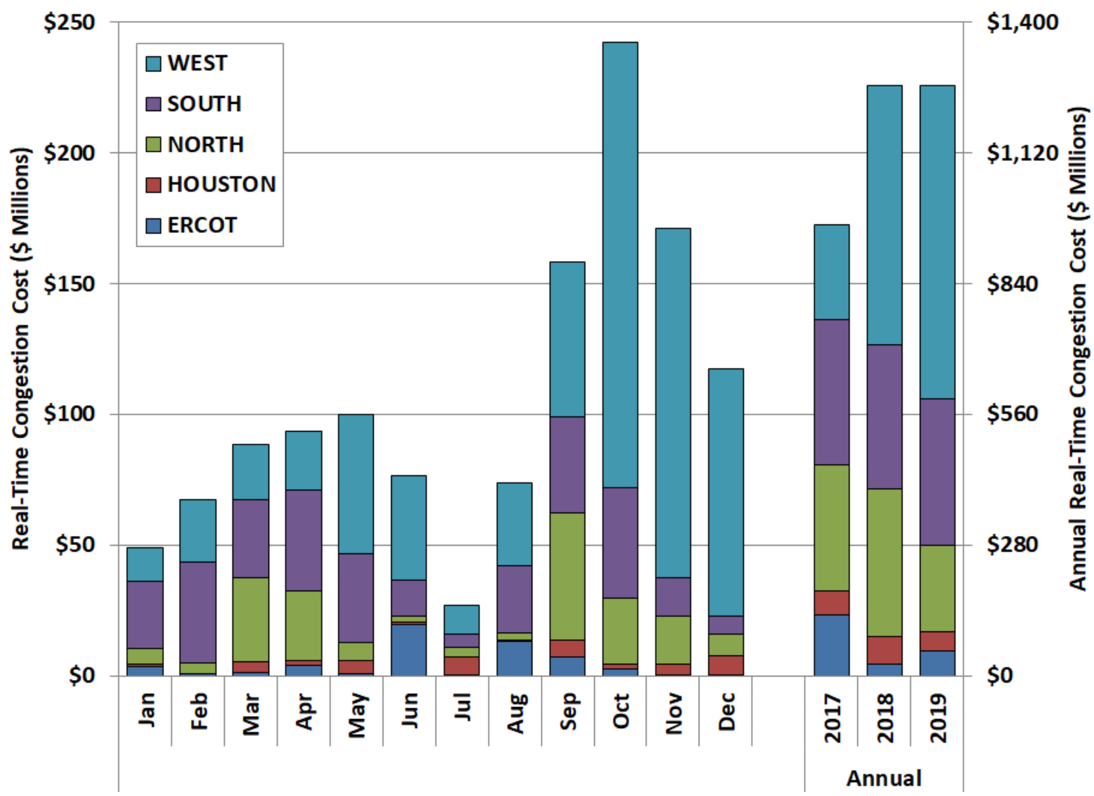


Figure 29: Real-Time Congestion Costs by Zone



The 2019 monthly congestion profile shows that congestion was highest in the spring 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 September through December was likely due to an increase in significant transmission and generation outages, some of which were postponed to increase resource availability in the summer of 2019.

The North and Houston zones saw a decrease in congestion in 2019 because of completed transmission projects. While congestion in all other zones increased, including ERCOT cross-zonal congestion. The North to Houston constraint was a significant contributor to ERCOT congestion in recent years, but the completion of the Houston import transmission project in April 2018 reduced congestion in 2018 and this reduction continued into 2019. Import constraints to Houston have instead shifted to the south. The largest contributor to congestion costs in 2019 was again the congestion in the West zone; however, there was a move from the most constrained location from south of Odessa in 2018 to north of Odessa in 2019. The congestion north of Odessa in 2019 was the result of the high load caused by oil and gas development in the Permian Basin. 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 2019

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.

RTCA is the process that evaluates the resulting flows on the transmission system under a large number of different contingency scenarios. A base-case constraint exists if the flow on a transmission element exceeds its normal rating. A thermal contingency constraint exists if the outage of a transmission element (i.e., a contingency) would result in a flow higher than the rating of an in-service element.[32] Active transmission constraints are those that the dispatch

[32] 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.

software evaluated, as some constraints are identified but not activated by the operator for various reasons. The 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.

Our review of the active and binding constraints during 2019 is shown in Figure A33 and Table A2 in the Appendix, and shows the following:

- The ERCOT system had at least one binding constraint 76% of the time in 2019, a slight increase from 73% in 2018.
- On average, slightly more than five constraints were active in each interval, down from approximately six in 2018.
- Constraint numbers were relatively consistent across the load levels, although the average number of active constraints were highest when load was above 65 GW and lowest when load was less than 30 GW.

GTCs were binding 16% of the time in 2019, compared to 15% in 2018. GTCs are used to ensure that the generation dispatch does not violate a transient or voltage stability condition. Certain GTC limits are determined in real-time using the Voltage Stability Assessment Tool (VSAT) or the Transient Stability Assessment Tool (TSAT). These tools are used continuously to evaluate the North to Houston and the Rio Grande Valley Import limits, which provides a more accurate real-time limit than could be achieved through offline studies. ERCOT has a goal of getting better data for the full range of inverter technology, which will over time allow all GTC limits to be calculated in real-time rather than using offline studies. As more renewable generation comes online in ERCOT, the benefits of these dynamic models will grow. Table A2 in the Appendix shows the GTCs that were binding in real-time, and shows that:

- Panhandle, initiated in July 2015, represented 88% of all binding GTCs, at 15,352 binding intervals, while 8.6% were related to Treadwell, initiated in May 2018.
- With the exception of the North to Houston, Rio Grande Valley Import, and East Texas constraints, all GTCs resulted from issues identified during the generation interconnection process.

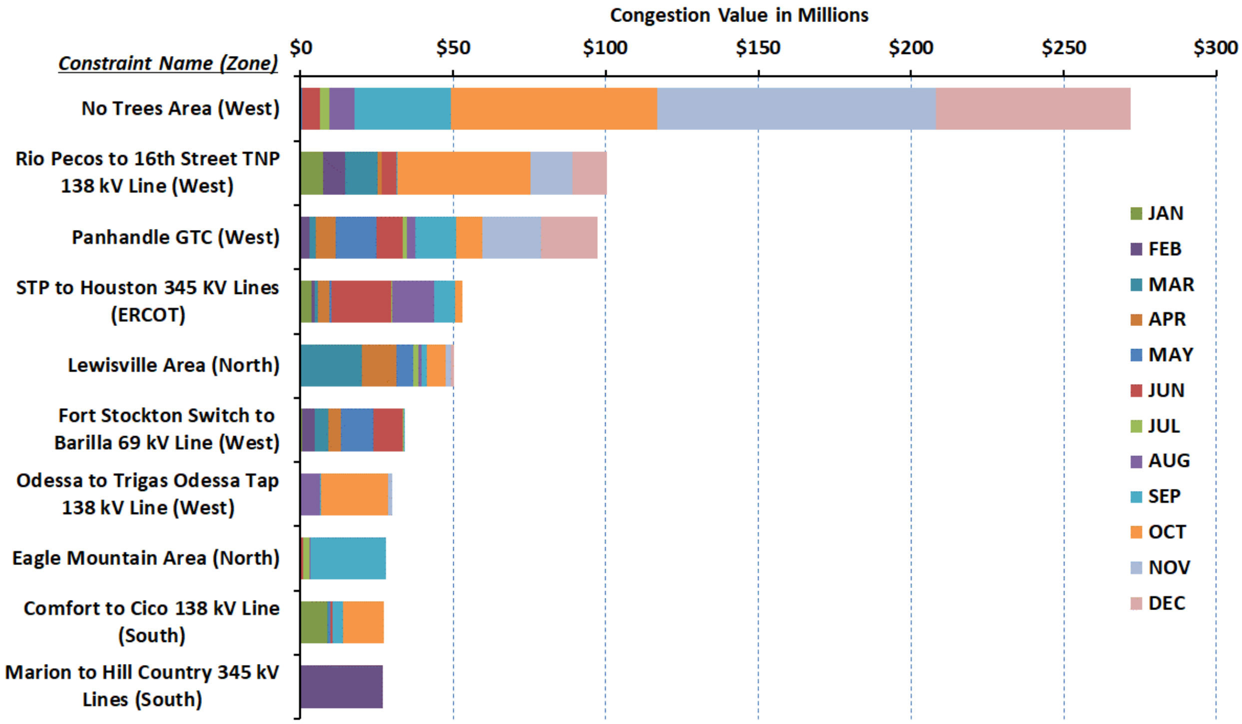
The next subsection describes where and some reasons why these constraints occurred.

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. The shadow price represents the per-MW redispatch cost, defined as the marginal cost of the constraint (i.e., the dollar amount that would be avoided if the transmission element limit was 1 MW larger). To get the total cost of the constraint, this value must be multiplied by the flow over the transmission element itself, which is 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 binding or violated at some point during 2019, with a median financial impact of approximately $197,000. In 2018, there were 443 unique constraints with a median financial impact of $177,000. Figure 30 displays the ten most costly real-time constraints with their respective zone measured by congestion value.

Figure 30: Most Costly Real-Time Congested Areas



The constraint with the highest congestion value in 2019 ($272 million) was the No Trees Area, consisting of the 138 kV line series starting at Amoco Three Bar Tap and ending at Cheyenne Tap. The majority of the congestion value was generated on the line between Dollar Hide and No Trees Switch, which accounted for $197 million of real-time congestion. The congestion value associated with the No Trees Area in 2019 was $20 million more than the Yucca Switch to Basin 138 kV line segments in in 2018, and represents a shift in congestion from south of the Odessa to north of Odessa. Most of this congestion occurred in October through December, with the shift in congestion occurring due to upgrades of the Yucca to Basin 138 kV line segments and the oil and gas development in Permian Basin.[33]

The second most costly constraint in 2019 was the Rio Pecos to 16th Street TNP 138 kV line constraint, which was mostly caused by planned outages in the area. The Panhandle GTC constraint remained the third most costly constraint in 2019 as it was in 2018. The Panhandle constraint caused $97 million of congestion in 2019, a modest 5% decrease from 2018. By the end of 2019, there was almost 5.1 GW of generation capacity in the Panhandle area, about 90% of which was wind generation. The GTC limit average was 3,200 MW, down by 300 MW from 3,500 MW in 2018. This decrease 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.

Finally, the fourth most congested path was the STP to Houston 345 kV lines, which is a trio of three segments starting from South Texas Project and going to a) Jones Creek ($25 million), b) WA Parish ($15 million), and c) Dow 345 kV ($11 million) substations. A major reason for the higher congestion value for these constraints is the higher allowance for the maximum shadow price due to the 345 kV voltage because these lines were frequently in violation. As discussed below, shadow price caps for contingency constraints increase as the voltage increases. Another consideration is the high cost to maintain reliability when serving Houston loads especially during system-wide shortage conditions.

Day-ahead congestion costs were highest on the top three paths discussed above, with day-ahead congestion costs totaling roughly $388 million, somewhat less than the $470 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 A35 in the Appendix presents additional detail on real-time congested areas with their respective zones in 2019.

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

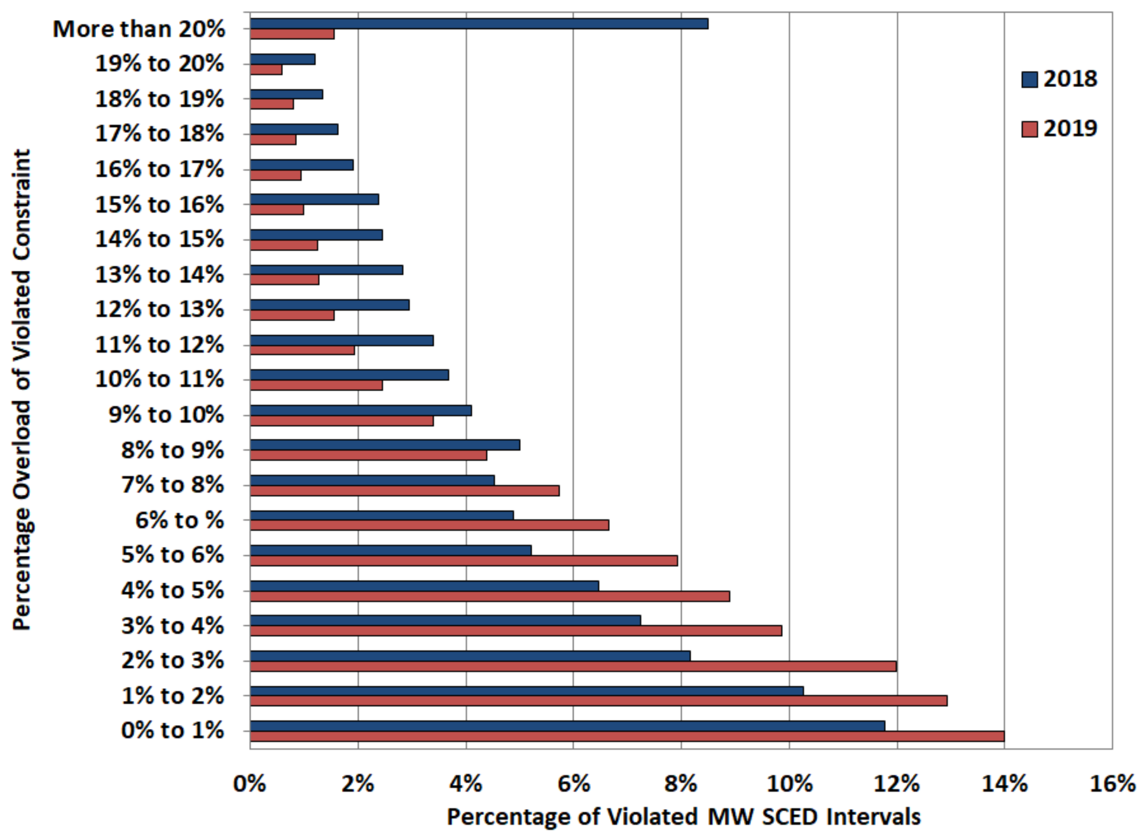
33 The load growth, variable renewable output, and transmission upgrades in the far west also caused the shifts onto the constraints Rio Pecos to 16th Street 138 kV line, Fort Stockton to Barilla 69 kV line, Odessa to Trigas Odessa Tap 138 kV line.

model cannot find a solution to manage the constraint at a marginal cost less than the shadow price cap, the constraint will be "irresolvable" or "in violation" in that interval, and the shadow price will be set at the cap.[34] 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 31 presents the distribution of the percentage overload of violated constraints between 2018 and 2019. Violated constraints continued to occur in a small fraction of all of the constraint intervals, 10% in 2019, up from 8% in 2018.

Figure 31: Percentage Overload of Violated Constraints



34 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 31 shows that although the share of constraints that were violated was higher in 2019, the severity of the violation was much lower. For example, constraints violated by more than 20% fell from almost 9% to less than 2%, while the frequency of less severe violations increased in 2019. This suggests a significant improvement in ERCOTs ability to manage the flows in 2019.

Finally, 14% 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. Implementing a well-designed transmission demand curve would recognize that the reliability risk of a post-contingency overload increases as the overload amount increases. Hence, we recommend ERCOT work to implement transmission constraint demand curves (see recommendation No. 3 above).

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.[35] Table A3 in the Appendix shows that 12 elements were deemed irresolvable in 2019 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

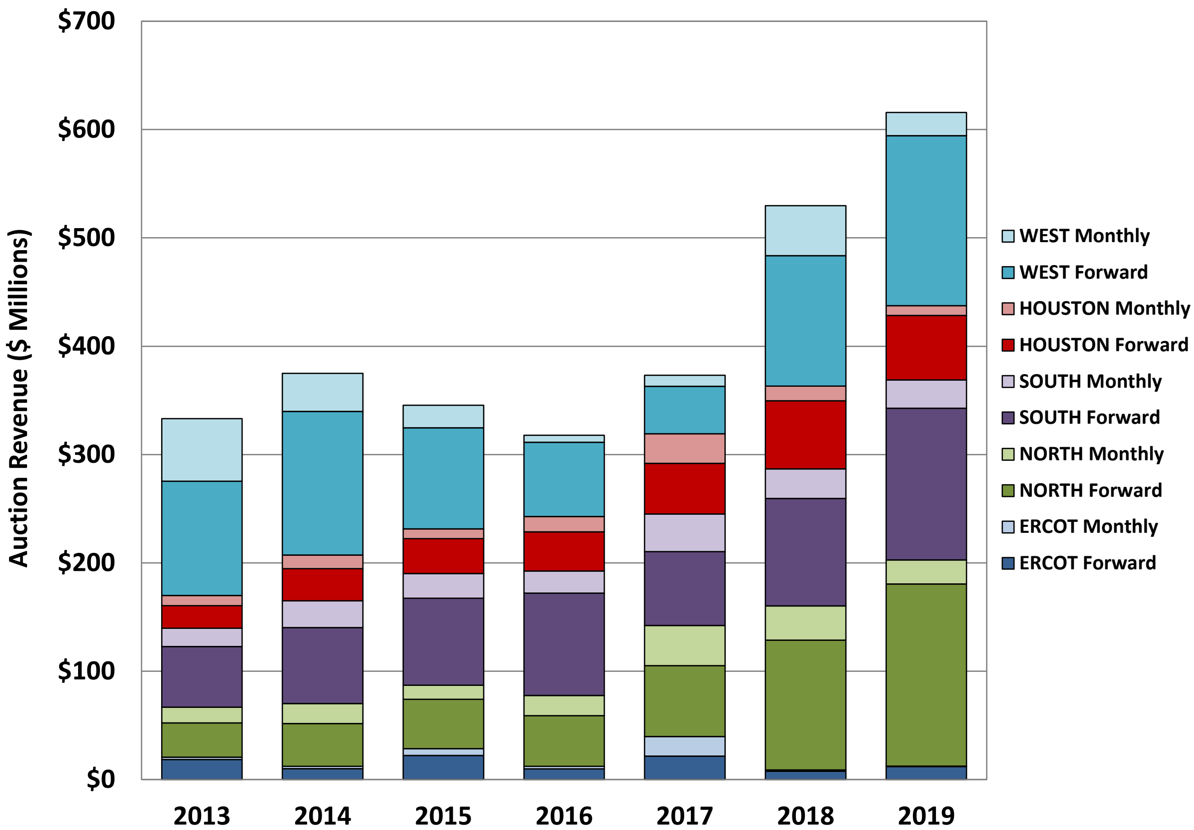
CRRs may be acquired in semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to certain participants (Non Opt-In Entities or "NOIEs") based on generation units owned or contracted for prior to the start of retail competition in Texas. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same source and sink. To summarize the results of the CRR market, Figure 32 shows the congestion as calculated by the shadow price times the flow on binding constraints in the CRR auctions.

35 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.

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

Figure 32 shows that aggregate CRR revenues have risen steadily since 2016. We note that all forwards for each of the categories increased between 2018 and 2019, whereas the monthly auction revenues decreased. In general, monthly auctions will produce prices that reflect the most accurate expectations of actual congestion because they are closest to the operating horizon.

Figure 32: CRR Revenues by Zone



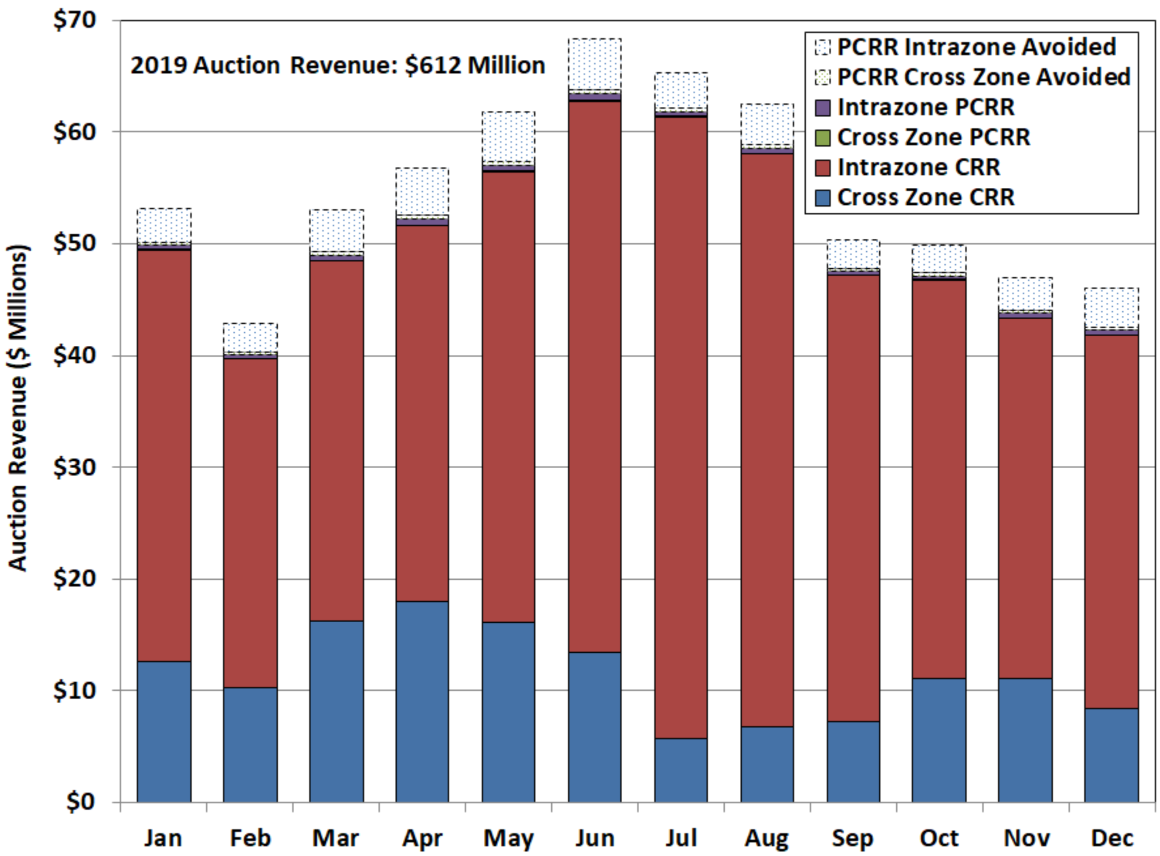
From early 2018 to early 2020, ERCOT was implementing third year CRR auctions for the first time.[36] These new auctions caused more of the transmission capacity to be sold in advance of the monthly auctions. Opportunities to purchase CRRs earlier improve forward hedging and add

[36] 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.

liquidity. However, earlier purchases can also increase differences between CRR auction revenue and day-ahead payouts because more of the CRRs are sold when there is higher uncertainty regarding the status of transmission elements, generator availability, and load levels.

ERCOT distributes CRR auction revenues to loads in one of two ways. First, revenues from cross-zone CRRs are allocated to loads ERCOT-wide. Second, revenues from CRRs that have the source and sink in the same geographic zone are allocated to loads within that zone. Figure 33 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 33: 2019 CRR Auction Revenue

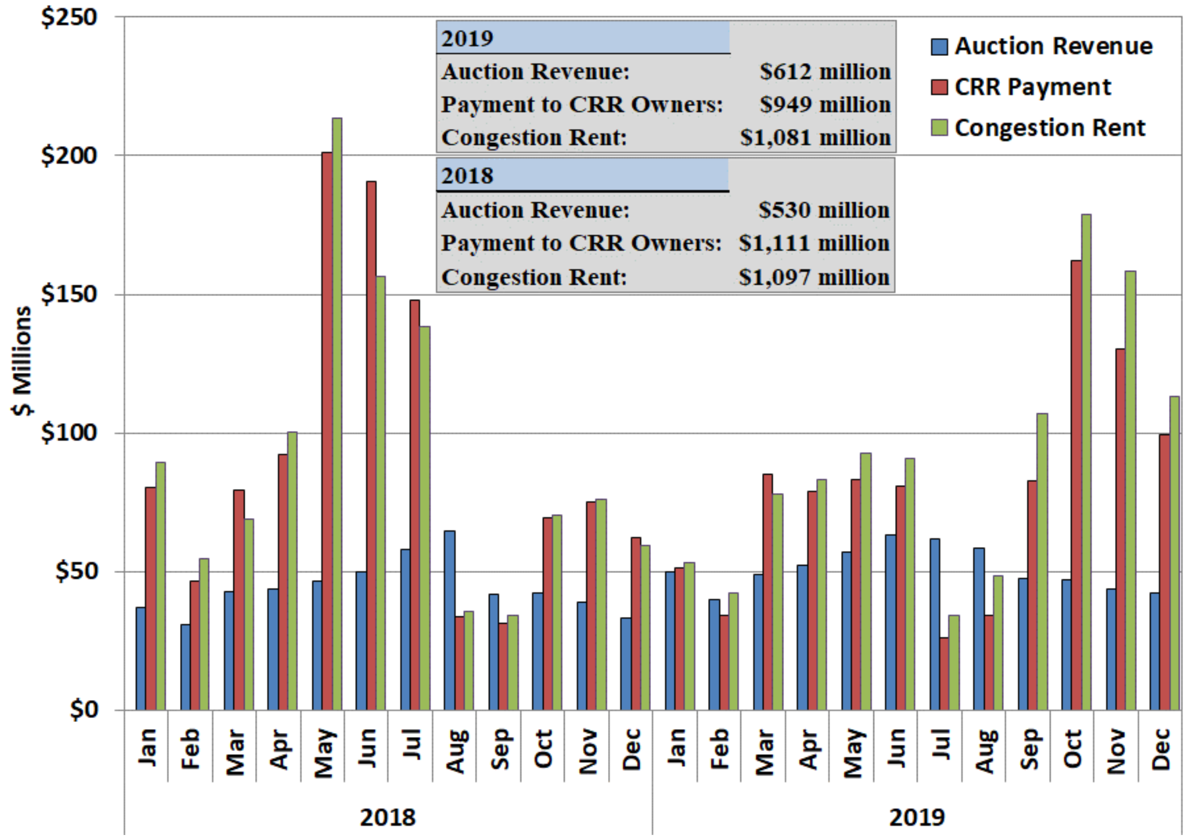


The total amount of CRR auction revenue increased to $612 million in 2019 from $530 million in 2018, while the total PCRR discount increased from $31 million in 2018 to $45 million in 2019. These increases reflect an increased expectation of congestion in 2019.

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 2019 with participants again paying much less for CRRs they procured than their ultimate value. To present and evaluate these results, Figure 34 shows the monthly CRR auction revenue, the day-ahead congestion rent collected to fund the CRRs, and the ultimate payout to the CRR owners.[37]

Figure 34: CRR Auction Revenue, Payments and Congestion Rent



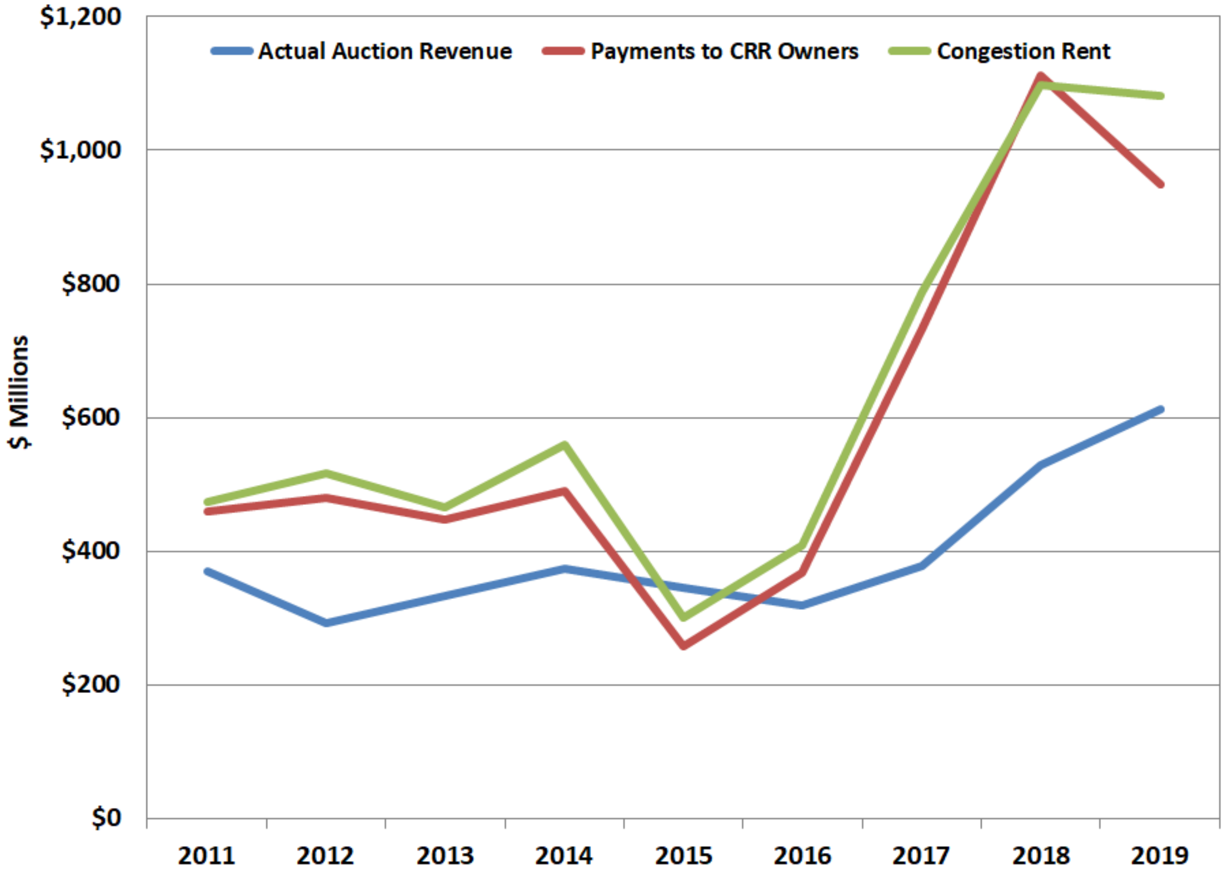
37 Under Protocol Section 7.9.3.1, Day-Ahead congestion rent is calculated as the sum of: (a) The total of payments to all QSEs for cleared DA energy offers, whether through Three-Part Supply Offers or through DA Energy-Only Offer Curves, calculated under Section 4.6.2.1, DA Energy Payment; (b) The total of charges to all QSEs for cleared DA Energy Bids, calculated under Section 4.6.2.2, DA Energy Charge; and (c) The total of charges or payments to all QSEs for PTP Obligation bids cleared in the DA Market, calculated under Section 4.6.3, Settlement for PTP Obligations Bought in DA Market. (d) The total of charges to all QSEs for PTP Obligation with Links to an Option bids cleared in the DA Market, calculated under Section 4.6.3.

Figure 34 shows that for the entire year, participants spent $612 million to procure CRRs and in aggregate received $949 million, as shown in above. In general, this difference occurred because of the substantial increase in congestion that occurred in 2019 was not foreseen by the market. The period of congestion that accounted for most of this difference was October, November and December in the West zone, which resulted in CRR payments that were $258 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 during the summer months of July and August in 2019.

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 2019, when the payout in aggregate was $132 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 35 provides the annual CRR auction revenues, payments to CRR owners and day-ahead congestion rent.

Figure 35: CRR History



In 2019, like the two prior years, owners of CRRs in aggregate made a substantial profit on their CRR holdings because of unanticipated factors that led to significantly higher congestion. Note that this "profit" does not take into account the time value of money, which is notable because a CRR is paid for at the time of the auction.

Figure 35 shows that actual congestion has been rising 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 A36 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

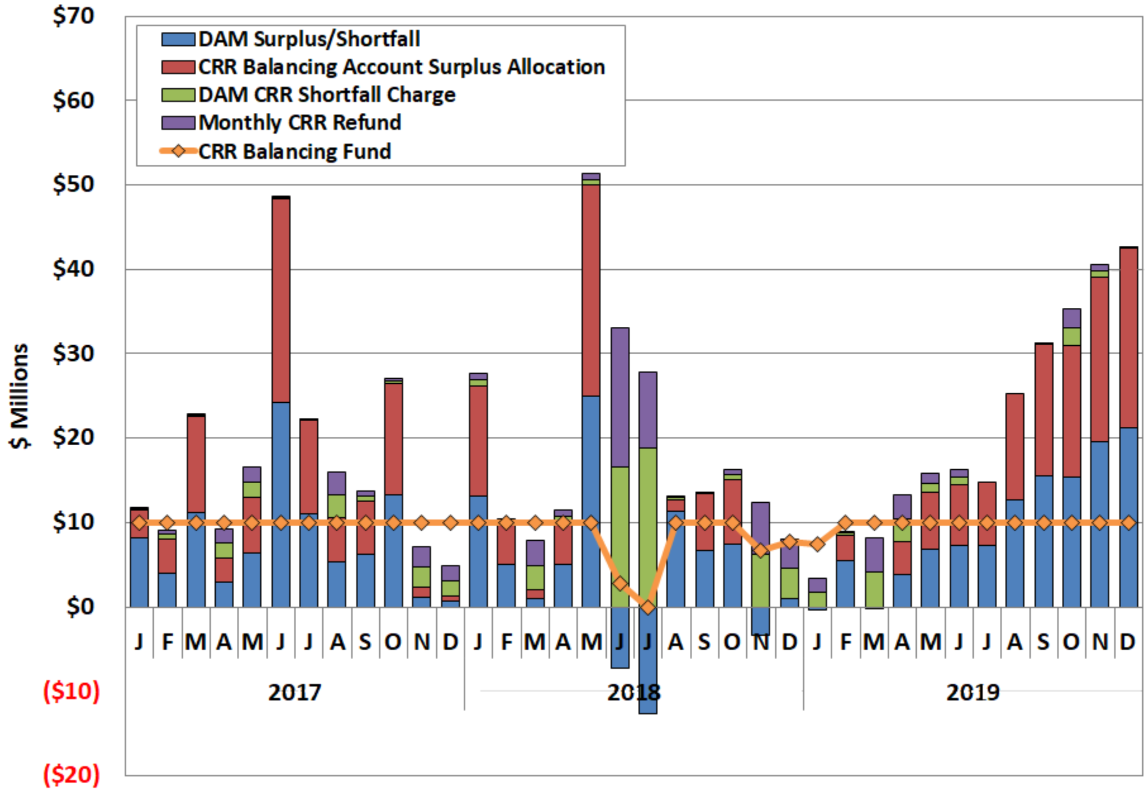
The target value of a CRR is the quantity of the CRR multiplied by the price difference between sink and source. It is desirable for the payout to fully equal the target value because it makes the

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.

However, if there is excess day-ahead congestion rent that has not been paid out to CRR account holders at the end of the month, that 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. If there is not enough excess congestion rent from the current month to refund all shortfall charges, the rolling CRR balancing fund from previous months can be drawn upon to fully pay CRR account holders that received shortfall charges. Figure 36 shows the CRR balancing fund since the beginning of 2017.

Figure 36: CRR Balancing Fund



The fact that ERCOT's processes are designed to only sell 90% of the forecasted transmission capability makes funding shortfalls less likely. Figure 36 shows that in 2019, CRR holders experienced no shortfalls as the CRR balancing fund remained steady at its capped value of $10 million throughout the year. The total day-ahead surplus was nearly $115 million, significantly higher than the surplus of $52 million in 2018. From the perspective of the load, the monthly CRR balancing account allocation to load totaled amount of $113 million at the end of the year.

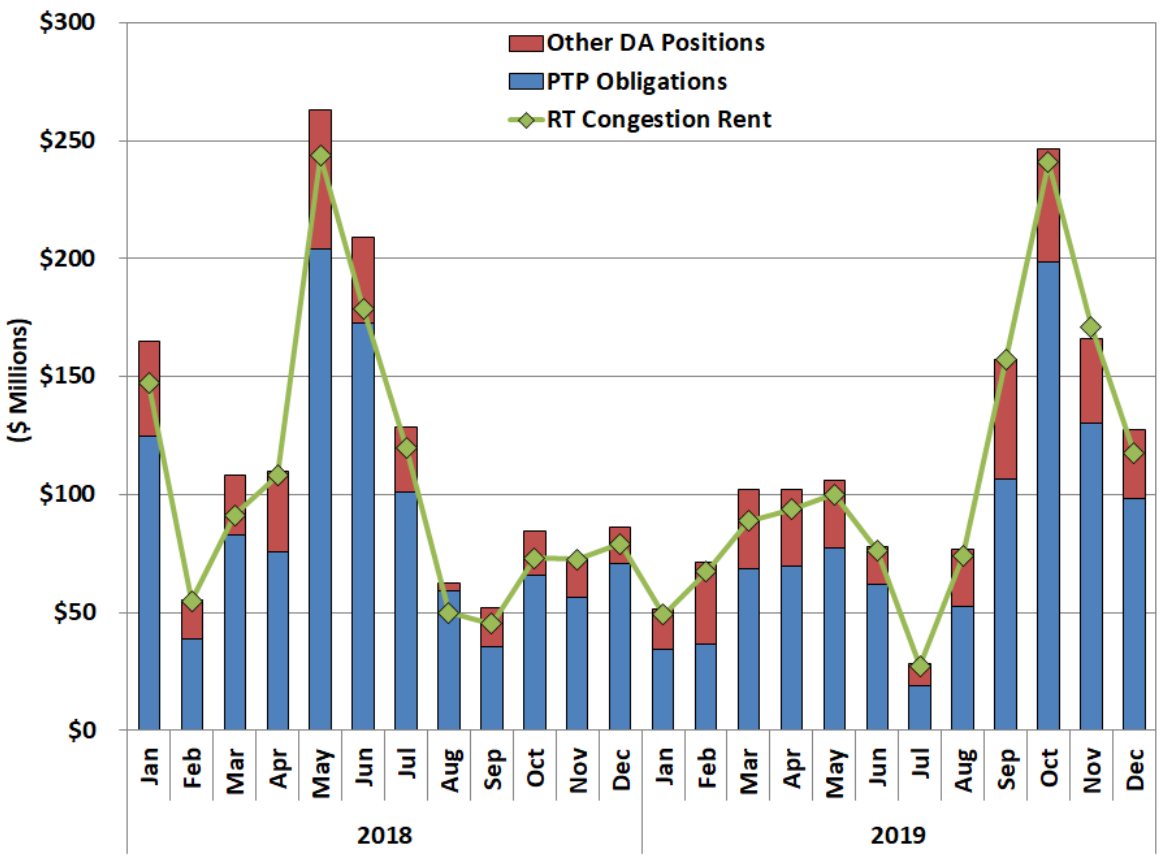
Importantly, despite the fact that the day-ahead market produced more than enough revenues to fully fund the CRRs, many CRRs were derated in 2019 and not paid the full target value due to the mandatory deration process. In total, CRR deratings resulted in a $23 million reduction in payments to CRR holders. These deratings reduced ERCOT's overall funding percentage to 97.6%, slightly higher than the funding percentage of 95% in 2018. ERCOT's deratings and shortfalls are shown on a monthly basis in Figure A37 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 37 shows the combined payments to all of these day-ahead positions compared to the total real-time congestion rent.

Figure 37: Real-Time Congestion Rent and Payments



In 2019, real-time congestion rent was $1,263 million, while payments for PTP obligations (including those with links to CRR options) were $954 million and payments for other day-ahead positions were $359 million. This resulted in a shortfall of $49 million for the year.

By comparison, payments for PTP obligations and real-time CRRs were $1,088 million in 2018 and payments for other day-ahead positions were $310 million, resulting in a shortfall of approximately $134 million for the year. This substantial reduction in real-time shortfalls indicates that 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 "claw-back" 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 claw-back 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 two years, ERCOT has made a number of improvements to the RUC process relating to fast-starting generators and switchable generators that are dually connected to other control areas. 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 evolution of rules and procedures regarding RUCs and the outcomes of RUC activity in 2019. 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. Finally, we conclude with a discussion of the Reliability Must-Run (RMR) process revisions in ERCOT in 2019.

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 (14% of RUC commitments in 2019); or
- To make a specific generator available resolve a transmission constraint (86% of RUC commitments in 2019).

The proportions of the RUC commitment reasons are consistent with 2018, when most RUC instructions were issued to manage transmission congestion. Overall, however, the number of RUC instructions in 2019 decreased significantly from 2018:

- The 228 unit-hours of RUC instructions were issued in 2019, a 64% decrease from the 642 unit-hours in 2018 and the lowest number of instructions since the start of the nodal market.
- 54% were issued to generators in the West zone as oil and gas load has grown and resulted in increased congestion in the region.
- The balance of the RUC instructions were issued as follows: 25% in the North zone, 20% in the South zone, and the remaining 1% were issued in the Houston zone.

The sharp reduction in RUC instructions has led to significant declines in make-whole payments and claw-back revenues. Table 4 displays the total annual amounts of make-whole payments and claw-back 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 4: 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

Table 4 shows that the make-whole payments fell to roughly $50,000 in 2019, by far the lowest level since the start of the market. This reduction was likely due to: the decline in RUC activity, the lower natural gas prices (which lowers the costs of most of the RUC units), and the increase in prices in 2019 due to lower capacity margins. Likewise, less than $1 million was clawed-back from RUC units in 2019. In theory, the claw-back amount should be low because units that are economic (and therefore subject to the claw-back provision) would generally benefit by opting out of the RUC instruction. In 2019, slightly more than one-quarter of RUC units opted out, which is consistent with the shares that have opted-out over the past few years.

RUC Generators with Day-Ahead Offers. Generators that participate in the day-ahead market forfeit only 50% of markets revenues above cost through the claw-back, rather than 100%. Given this incentive to offer in the day-ahead market, it is surprising that all units do not submit day-ahead offers. In 2019, only 25% of the total RUC unit-hours had day-ahead offers, similar to the 21% in 2018, but much lower than the 76% in 2017. The very low values in 2018 and 2019 may be explained by the large number of fast starting generators receiving RUC instructions because it is not unusual for the decision to commit fast starting units to be made in real-time.

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 2019 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 2019 more frequently because of shortage conditions in August and September and due to the mitigation of some of the resources committed to resolve non-competitive constraints in the shoulder months. 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 38 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 five years.

Figure 38: Capacity Commitment Timing – July and August Hour Ending 12 through 20

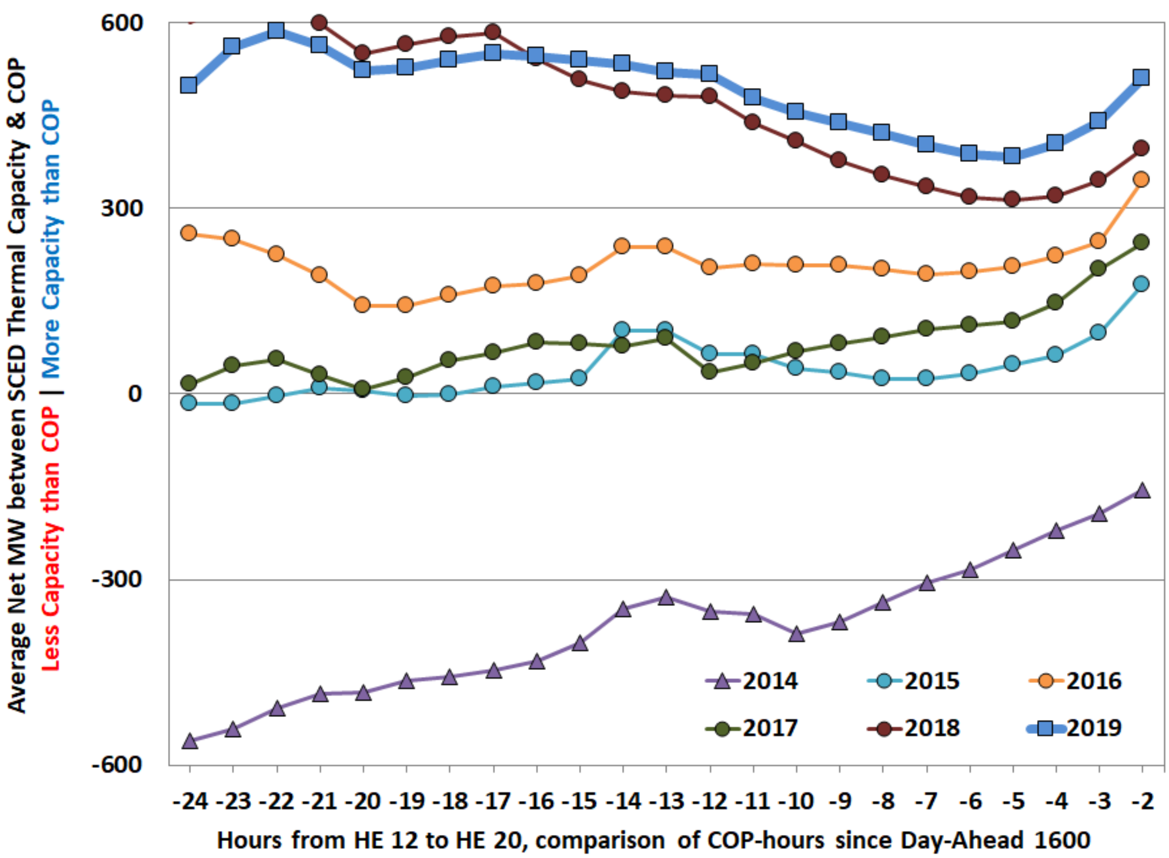


Figure 38 shows that the amount of online capacity needed exceeded the thermal capacity represented in COPs at the end of the adjustment period, signifying that generators changed their commitment decisions within the operating period. This difference has been increasing, from 175 MW in 2015 to more than 500 MW in 2019.

An average of the hours from hour-ending (HE) 12 through HE 20 masks the changes market participants may make closer to real-time. 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 to allow market participants to make their own commitment decisions, including the nearly 500 MW of near real-time thermal capacity commitments.

However, the current mechanism allowing resources to opt-out of RUC settlements may provide incentives for resources to defer their own commitment decision to the last possible moment with no negative consequences. If the unit is required, ERCOT will issue a RUC instruction, following which the resource can chose to opt out of RUC settlement. Having the ability to convert an ERCOT-issued commitment instruction into a self-commitment is expected to become more problematic with smaller reserve margins and less system flexibility. Additionally, the ability to opt-out of the RUC instruction provides no discernable benefit to the market. Therefore, the IMM recommends that the option to opt out of RUC settlement be eliminated (see recommendation No. 1 above).

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 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.[38] Finally, 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.

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 energy prices over time and thus are appropriate to use for this evaluation.

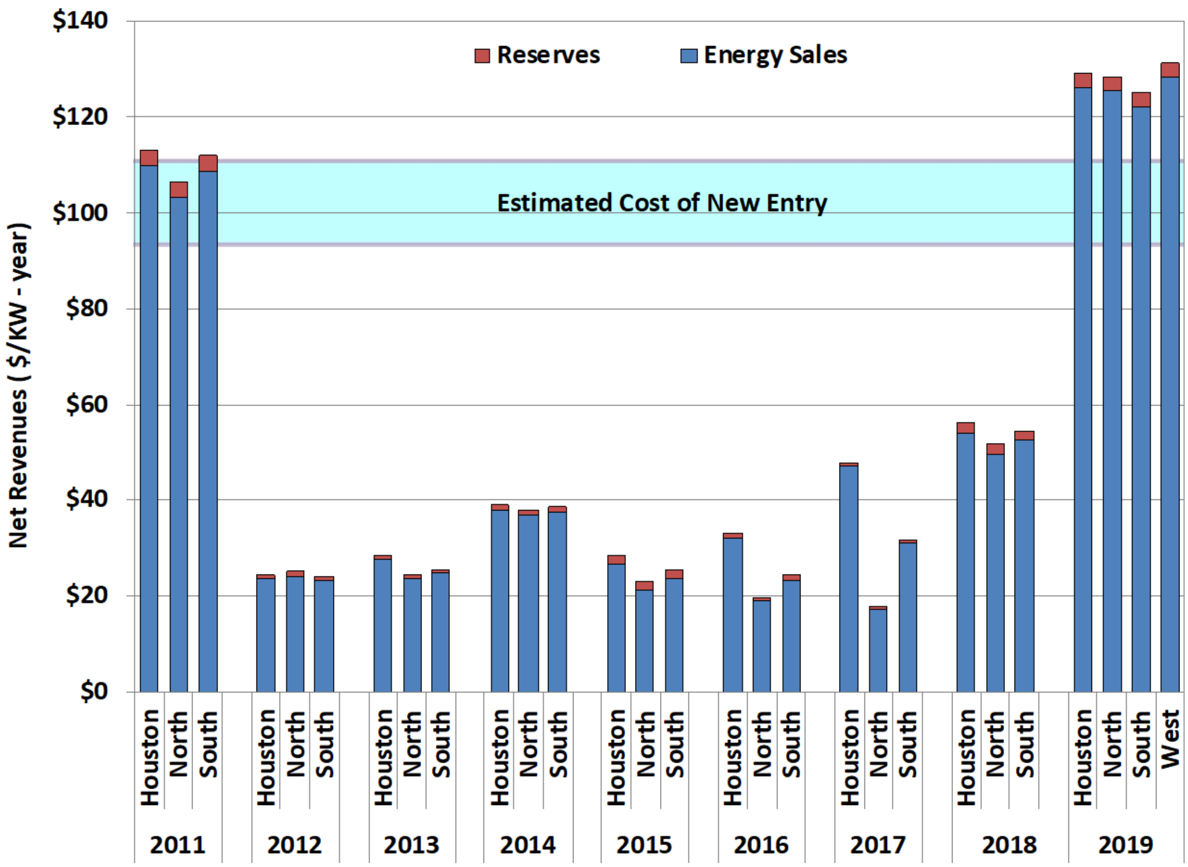
[38] See 16 TAC §25.505(g). This report generally employs the more accurate "shortage pricing" terminology in place of "scarcity pricing", except in cases where Scarcity is part of a name.

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.[39] 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 39) and combined cycle generation (Figure 40), which we selected to represent the marginal new supply that may enter when new resources are needed.

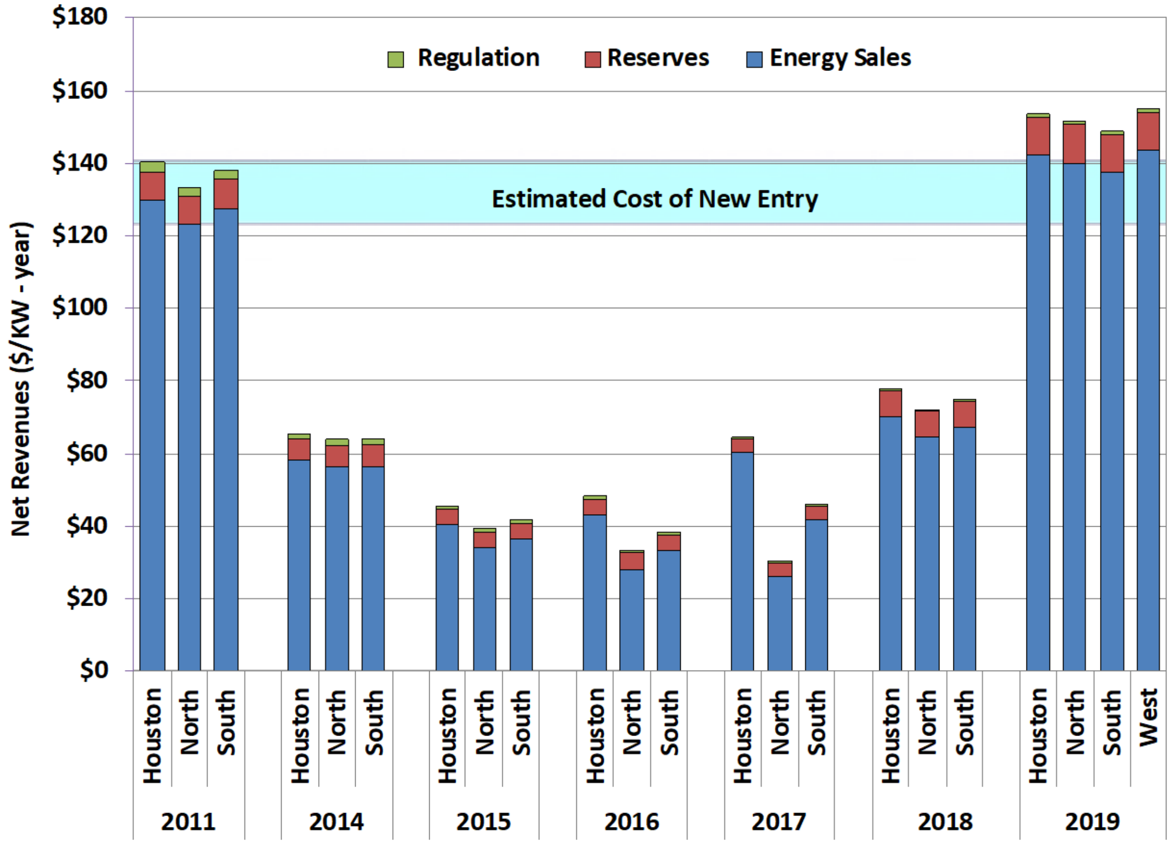
Figure 39: Combustion Turbine Net Revenues



39 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 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.[40] The figures also show the estimated CONE for each technology for comparison purposes.

Figure 40: Combined Cycle Net Revenues



In 2019, the estimated CONE values for both types of resources increased, with the CONE values for natural gas combustion turbines ranging from $95 to $110 per kW-year, and the CONE values for natural gas-fired combined cycle units ranging from roughly $120 to $140 per kW-year. Even with these higher CONE values, however, the ERCOT market provided net revenues above the CONE level needed to support new investment in 2019:

- Net revenues for combustion turbines ranged from $125 per kW-year in the South zone to more than $129 per kW-year in Houston; while
- Net revenues for combined-cycle units ranged from approximately $149 to $154 per kW-year, depending on the zone.

40 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 increases in net revenues were primarily caused by the significant shortages in August and September, in combination with the adjustments to the ORDC in 2019. The increases in the frequency of sustained shortages is consistent with the declining reserve margin in recent years. This existence of operating shortages is not a concern. 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.

The figures above also show that average net revenues were highest in the West zone in 2019 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 2019, we saw a continuing trend of the growing separation in natural gas prices between the Waha and Katy locations in the West.[41] Increased drilling activity in the Permian Basin has produced a glut of natural gas and consequently, much lower prices at the Waha location. Waha prices dipped below $0 multiple times throughout 2019 and were much more volatile than prices at Katy.

Hence, 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 $190 to more than $200 per KW-year at the Waha location, compared to net revenues of $130 to $145 per KW-year at Katy.

B. Net Revenues of Existing Units

Given the continuing effects of relatively 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 2019 was $47.06 per MWh. Table 5 shows the output-weighted average price by generation type based on the generator's specific locational price in 2019.

41 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).

Table 5: Settlement Point Price by Fuel Type

Generation Type	Output-Weighted Price		
	2017	2018	2019
Coal	$26.32	$33.31	$43.92
Combined Cycle	$28.45	$35.53	$47.06
Gas Peakers	$50.21	$71.64	$126.16
Gas Steam	$43.34	$66.09	$135.16
Hydro	$27.47	$34.40	$42.90
Nuclear	$24.73	$29.00	$35.38
Power Storage	$47.71	$103.19	$154.80
Private Network	$30.05	$34.41	$46.16
Renewable	$23.91	$39.84	$141.09
Solar	$24.34	$35.37	$61.45
Wind	$16.57	$19.26	$20.54

Table 5 shows that the prices and associated net revenues were substantially higher at almost all resources' locations in 2019. This is explained by the sizable effects of the shortage pricing that occurred in ERCOT in August and September.

Nuclear Profitability. According to data published by the Nuclear Energy Institute, the total generating cost for nuclear energy in the U.S. was $31.88 per MWh in 2018.[42] The 2018 total generating costs were 7.1% lower than in 2017, and nearly 25% 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 in excess of $35 per MWh making it likely that the nuclear units in ERCOT are profitable.

Coal Profitability. The generation-weighted price of all coal and lignite units in ERCOT during 2019 was $43.92 per MWh, an increase from $33.31 per MWh in 2018. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.66 per MMBtu in 2019, very similar to 2018. 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 41 shows the net revenues at different locations for a variety of technologies. Because natural gas prices can vary widely, the revenues

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

for natural gas units are shown only for the Houston zone to reflect Katy hub prices and the West zone for Waha. These results would likely fully cover the costs of all but the very oldest natural gas-fired resources. 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.

Figure 41: Net Revenues by Generation Resource Type

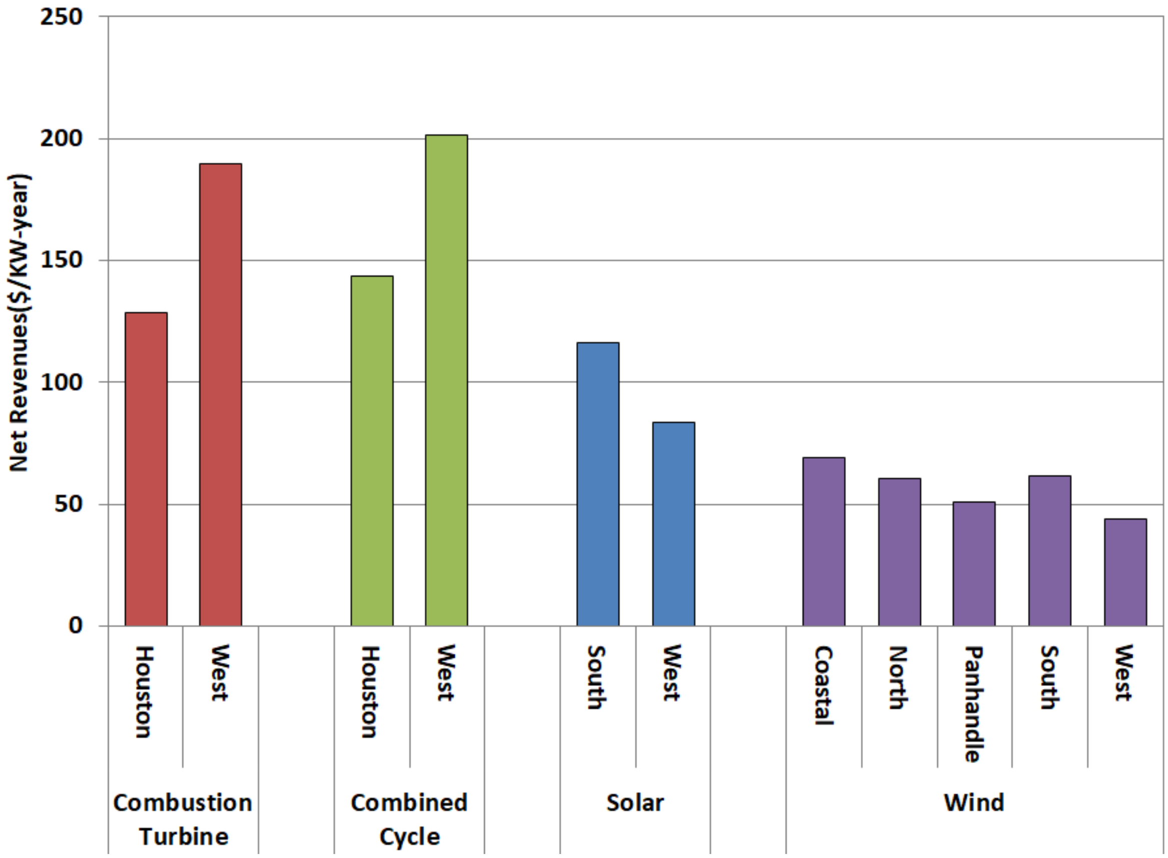


Figure 41 also shows the net revenues for wind and solar generation at multiple locations. As the cost to install wind or solar does not vary much by location, the profitability of those resources is chiefly determined by the available natural resource and the prevailing price to be received. Net revenues for wind and solar were less than gas technologies in 2019 in all areas. This is partly because intermittent technologies cannot maximize its output and associated revenues during the shortages that occurred in 2019. This is particularly true for wind resources that tend to produce less output during hot summer conditions.

We did not include battery energy storage in the net revenue analysis for 2019 because of the relatively low installed capacity. However, based on our profitability analysis considering a wide range of business models, battery energy storage would have been highly profitable in 2019, primarily but not exclusively if co-located with solar.

Interpreting Single-Year Net Revenues. These results indicate that on a stand-alone basis during 2019, the ERCOT markets did provide sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Much of the net revenue increase was the result of shortage pricing. Therefore, 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 very different than the net revenues in any one year.
- The CONE for any particular project may be very 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 of 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.

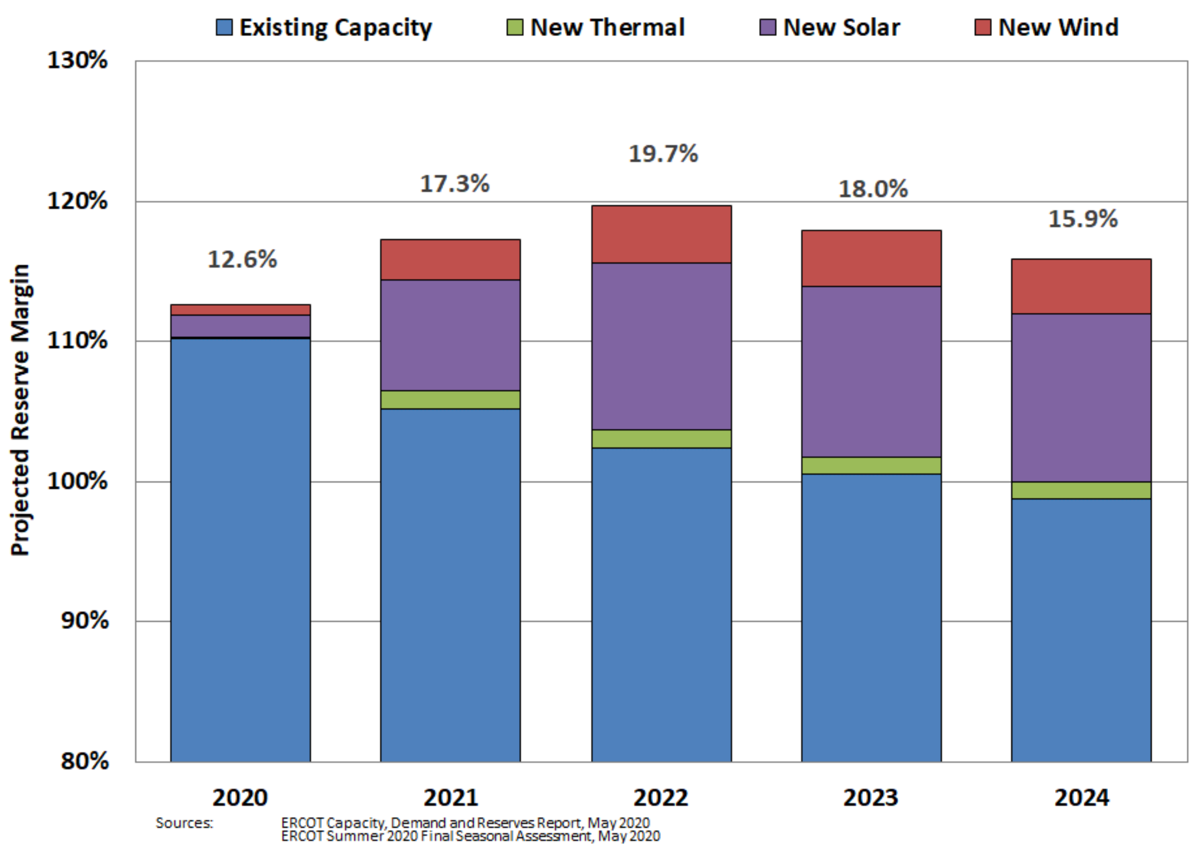
Prior to the summer of 2018, there were expectations by many market participants of shortage driven prices in the ERCOT market that mainly went unrealized. In 2019, however, there were significant shortages. The impact of the ORDC was significant. There are many ways that the market can respond to high prices, all of which result in rising planning reserve margins:

- Building new generation facilities;

- Increasing investment in existing resources, including heightened 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 the December 2018 Capacity, Demand, and Reserves (CDR) report, the 2019 summer reserve margin was projected to be 8.1%, a reduction of 2.9 percentage points from the May 2018 CDR report.[43] The planning reserve margin for summer 2019 ultimately increased to 8.6% based on the resource updates in the final summer 2019 SARA report.[44] Recent market outcomes and pre-existing investment plans are causing expected increases in the planning margins. Figure 42 shows ERCOT's current projection of planning reserve margins.

Figure 42: Projected Planning Reserve Margins



43 See Report on the Capacity, Demand and Reserves in the ERCOT Region, 2019-2028 (December 4, 2018), http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReservesReport-Dec2018.pdf.

44 See Seasonal Assessment of Resource Adequacy (SARA) (May 8, 2019), http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx.

Figure 42 indicates that Texas heads into the summer months of 2020 with an improved reserve margin of 12.6%, notably higher than the 8.6% reserved margin for 2019. 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.

The range of planning reserve margins from 2018 to 2020, although historically low, is likely consistent with expectations for ERCOT's energy-only market. On February 21, 2019, ERCOT filed a revised and final report with the Commission titled "*Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region: 2018 Update*."[45] 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 2022. ERCOT retained The Brattle Group (Brattle) to perform a study, and Brattle calculated a MERM of 10.25% and an EORM of 9%, estimating that societal costs vary only modestly between reserve margins of 7% and 11%.

Finally, despite historically low installed reserve margins for summer of 2019, the retirement of uneconomic generation should not be viewed as failure to provide resource adequacy. In fact, 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 (AEP) publicly announced in September 2018 that the 650 MW Oklaunion coal unit will retire in the third quarter of 2020, which accounts for 4% 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.

45 See *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region: Update 2018* (December 20, 2018); http://www.ercot.com/content/wcm/lists/167026/2018_12_20_ERCOT_MERM_Report_Final.pdf http.

1. Background on Shortage Pricing in ERCOT

Shortage pricing refers to the price escalation that occurs when supply is not sufficient to satisfy all of 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.

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.

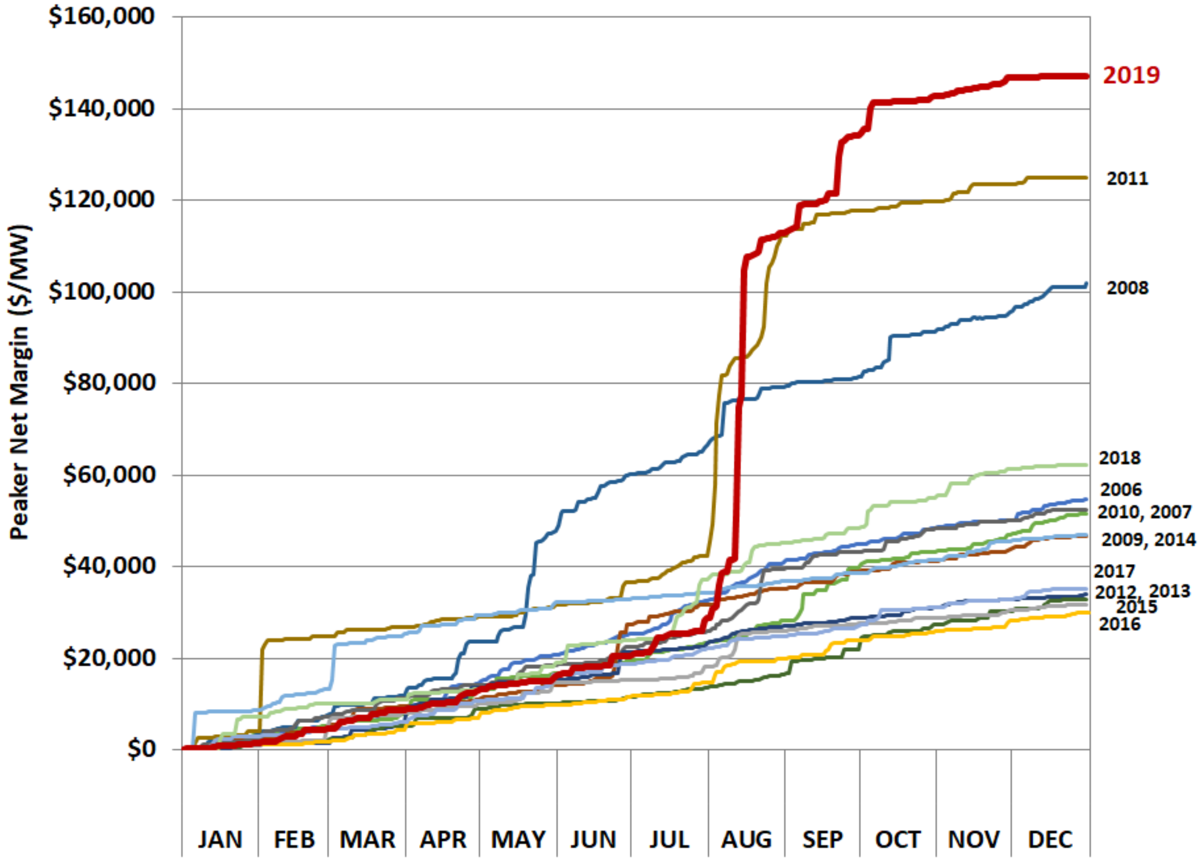
The Scarcity Pricing Mechanism includes a provision termed the Peaker Net Margin (PNM) that is designed to provide a pricing "fail-safe" measure. If the PNM is exceeded, the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[46] Section I contains a number of summaries and discussions of the shortage pricing that occurred in 2019. The next section, however, reviews pricing in 2019 showing the PNM in 2019 compared to prior years.

2. Peaker Net Margin in 2019

Figure 43 shows the cumulative PNM results for each year since the creation of the Scarcity Pricing Mechanism. This figure shows that PNM in 2019 was highest on record. PNM was initially defined to provide a "circuit breaker" trigger for lowering the system-wide offer cap. However, PNM still has 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.

[46] 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 43: 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.[47] 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").[48] 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, with a second step of .25 in the spring of 2020. The initial ORDC changes were implemented on March 1, 2019 and we have estimated their effects in 2019. These results are shown below in Table 6.

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

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

Table 6: 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
March	30	<1	<0.1	<1	838	0
April	28	<1	1	2	751	14
May	28	1	1	3	907	25
June	29	2	2	6	1,010	58
July	34	8	6	17	1,329	221
August	162	52	25-31	15-19	6,772	1,035-1,274
September	60	17	12	19	2,237	429
October	39	5	3	0	1,198	106
November	29	0	0	0	812	4
December	20	0	0	0	581	0
Total	50	11	6-7	12-13	16,433	1,890-2,130

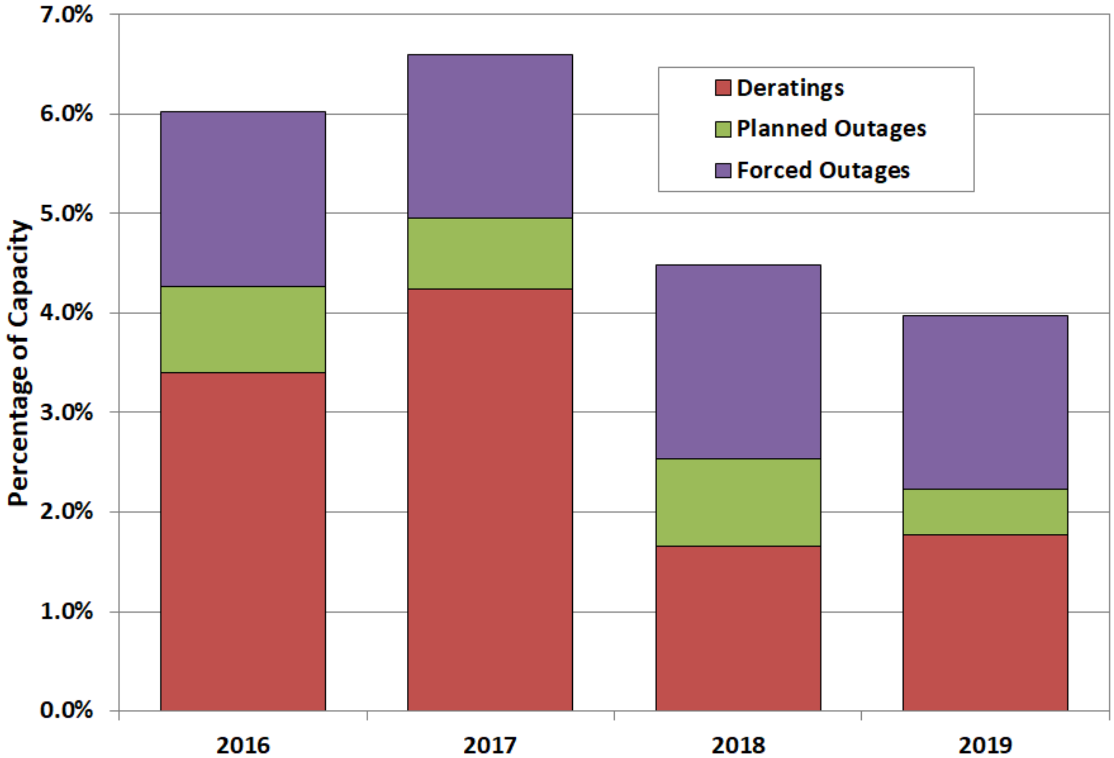
Table 6 above shows that the ORDC change increased the effects of shortage pricing by an estimated 12 to 13% -- increasing the total impact of the ORDC on average prices from $6 to $7 per MWh. This led to increased market costs and revenues to generators of roughly $2 billion in 2019. Although further changes are being implemented for 2020, shortage pricing will not likely exceed 2019 levels if planning reserve margins rise as projected.

4. Short-Term Effects of Shortage Pricing in 2019

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 very strong incentive for generators to be available at the times when they are expected to be needed most. Figure 44 shows the level of outages and deratings that have occurred during summer peak conditions over the past four years.

This figure shows that as the planning reserve margin has declined and expectations of shortages have increase, outages have decreased substantially. Most of these 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 44: Summer Month Outage Percentages



E. Reliability Must Run and Must Run Alternative

A Notice of Suspension of Operations (NSO) is required of any generator suspension that lasts greater than 180 days. ERCOT received a number of NSOs in 2019, and determined that none of the units were necessary to support ERCOT transmission system reliability, therefore no new Reliability Must-Run (RMR) contracts were awarded in 2019.[49] However, review of the RMR and Must-Run Alternative (MRA) evaluation processes remained active throughout the 2019, culminating in the approval of several changes to ERCOT protocols discussed below. In addition, multiple other Nodal Protocols Revision Requests (NPRRs) regarding this topic remained pending at the end of 2019.

Two NPRRs were approved on June 11, 2019 (NPRR885 and NPRR896) that in tandem provide an appropriate Protocol framework for MRA evaluation, contracting, processes and settlement. NPRR885 proposed new Protocol language to address numerous issues related to the solicitation and operation of MRA service.[50] Taken in conjunction with NPRR885, NPRR896 outlines the process ERCOT will use to evaluate the cost-effectiveness of procuring RMR or MRA service.[51]

49 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.

50 NPRR885, *Must-Run Alternative (MRA) Details and Revisions Resulting from PUCT Project No. 46369, Rulemaking Relating to Reliability Must-Run Service*

51 NPRR896, *RMR and MRA Alternative Evaluation Process*.

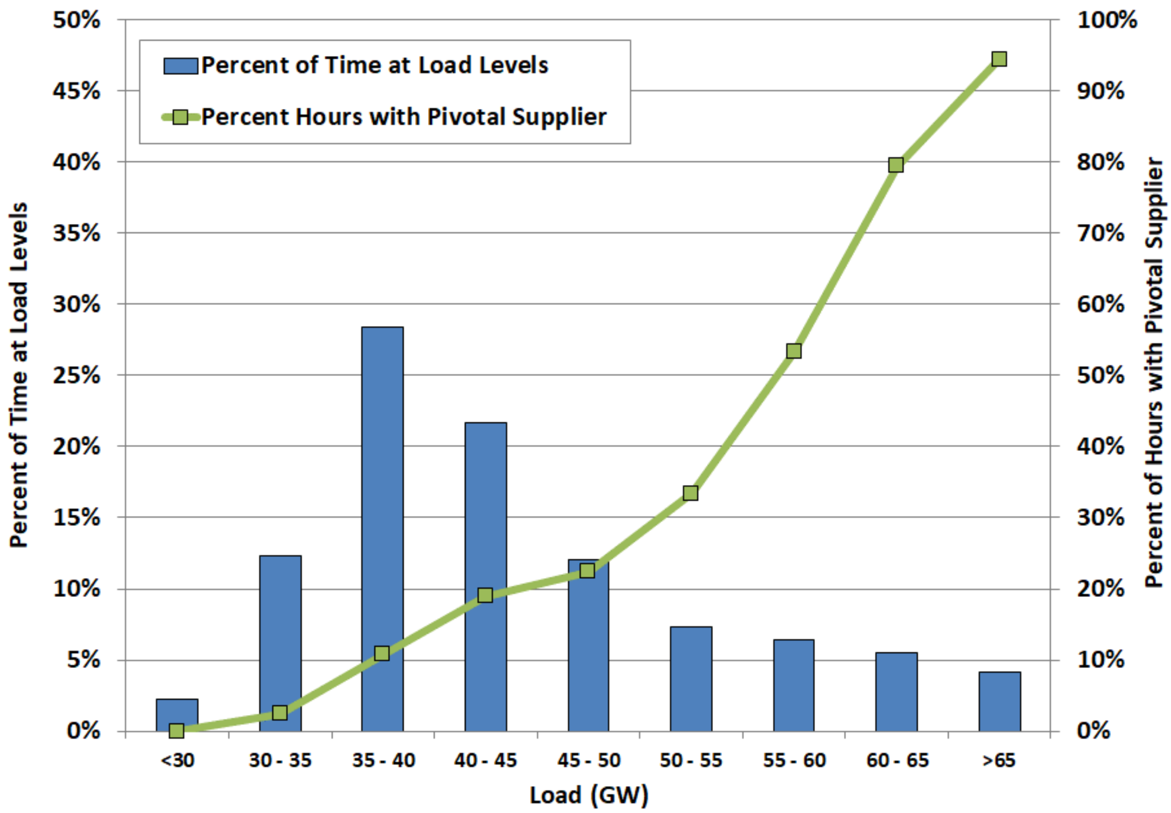
VII. Analysis of Competitive Performance

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 2019. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2019.

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 45 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 45: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW, there was a pivotal supplier approximately 94% of the time. This is 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 24% of all hours in 2019, which was less frequent than in 2018 when pivotal suppliers existed in 30% of all hours. Even with this reduction, market power continues to be a potential concern in ERCOT, requiring effective mitigation measures to address it. More detailed analysis of the pivotal supplier analysis is presented in Figure A47 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 very 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.

Figure 46 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2019. 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 46: Reductions in Installed Capacity

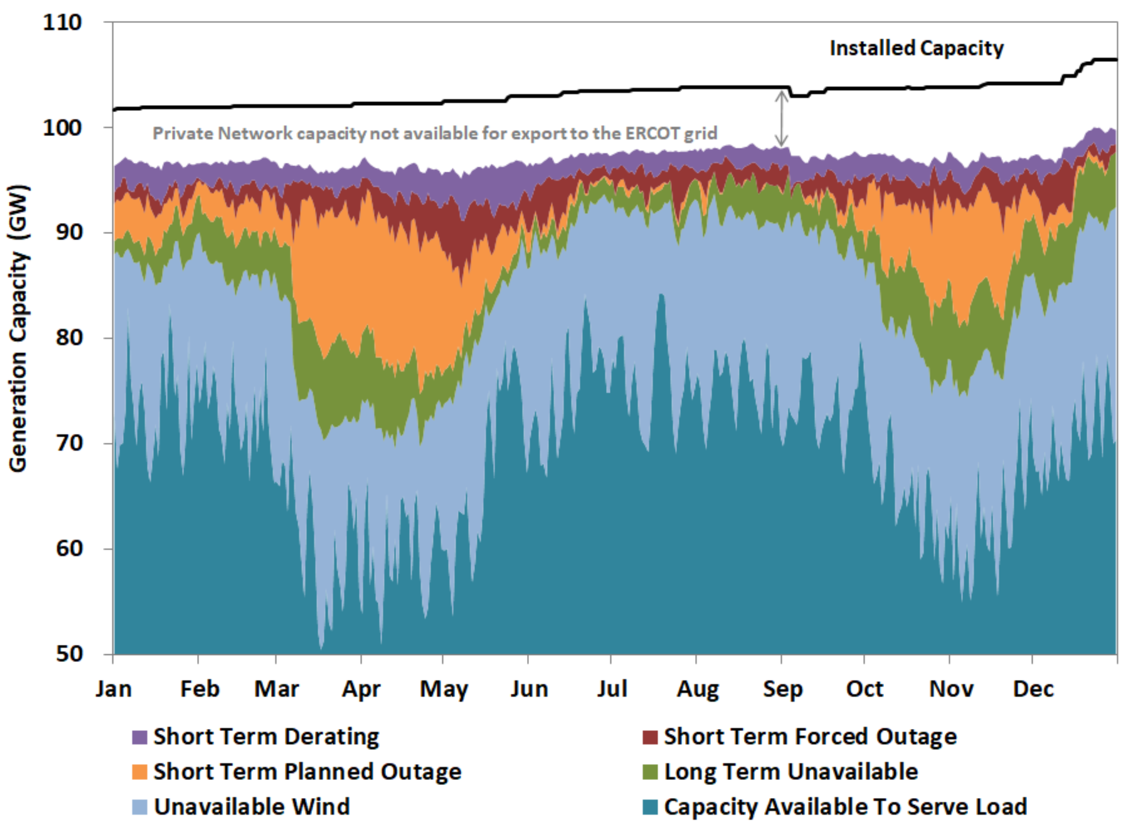


Figure 46 shows that short-term outages and deratings of non-wind generators fluctuated between two and 21 GW, while wind unavailability varied between four and 23 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent 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 8 GW, with almost all capacity returned to service in anticipation of tighter conditions during the summer of 2019.

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 47 provides a comparison of the monthly outage and derating values for 2018 and 2019.

Figure 47: Derating, Planned Outages and Forced Outages

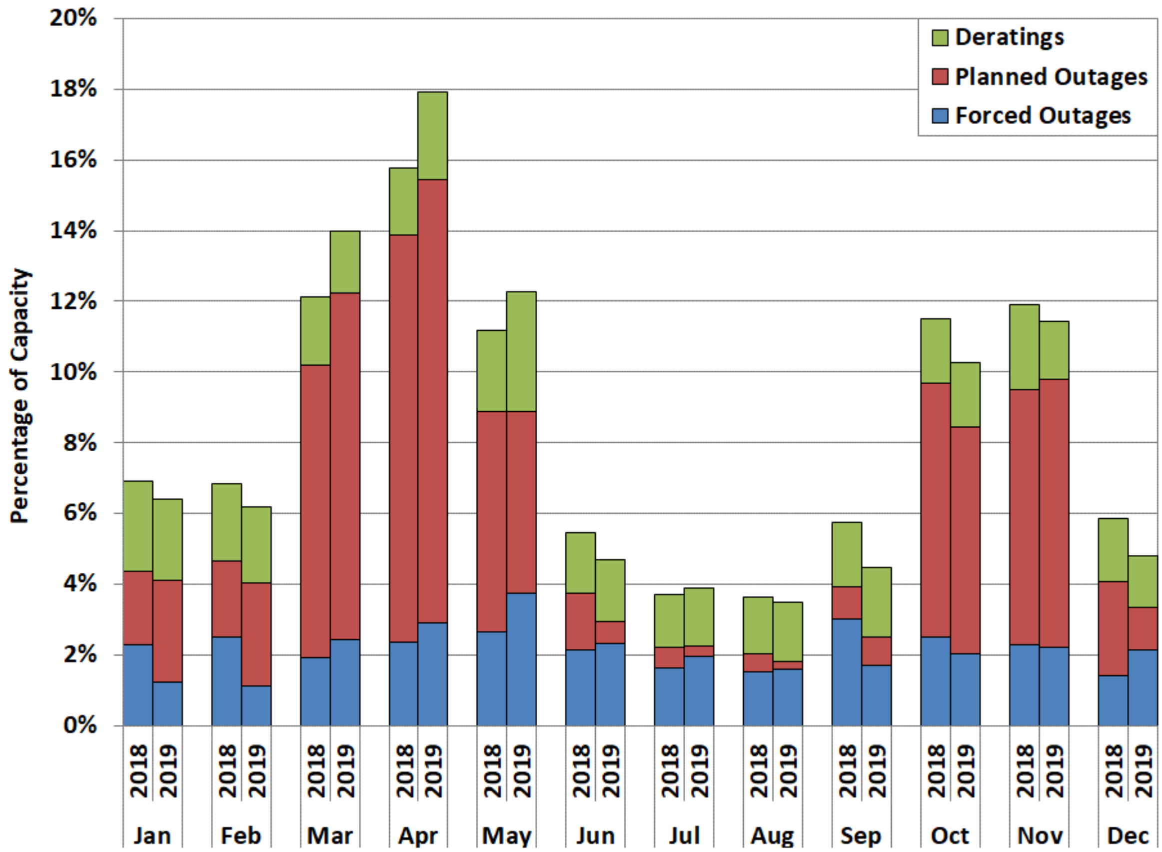


Figure 47 shows a general consistency of forced outages from last year, implying that expectations for 2019 were similar to those in 2018, and that generator operators were again able to defer the impacts of unexpected equipment limitations through September. However, those actions likely were at the 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 intense preparation for what was expected by many to be a summer with very tight operating conditions. The consistently small number of deratings across all months of 2019 indicates that generators were intent on maximizing generator availability. The low outage rates during August and the low level of derations overall may have been partly a result of increased planned maintenance activities. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours.

Figure A48 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 2019.

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 45 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 48 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 48: Outages and Deratings by Load Level and Participant Size, June-August

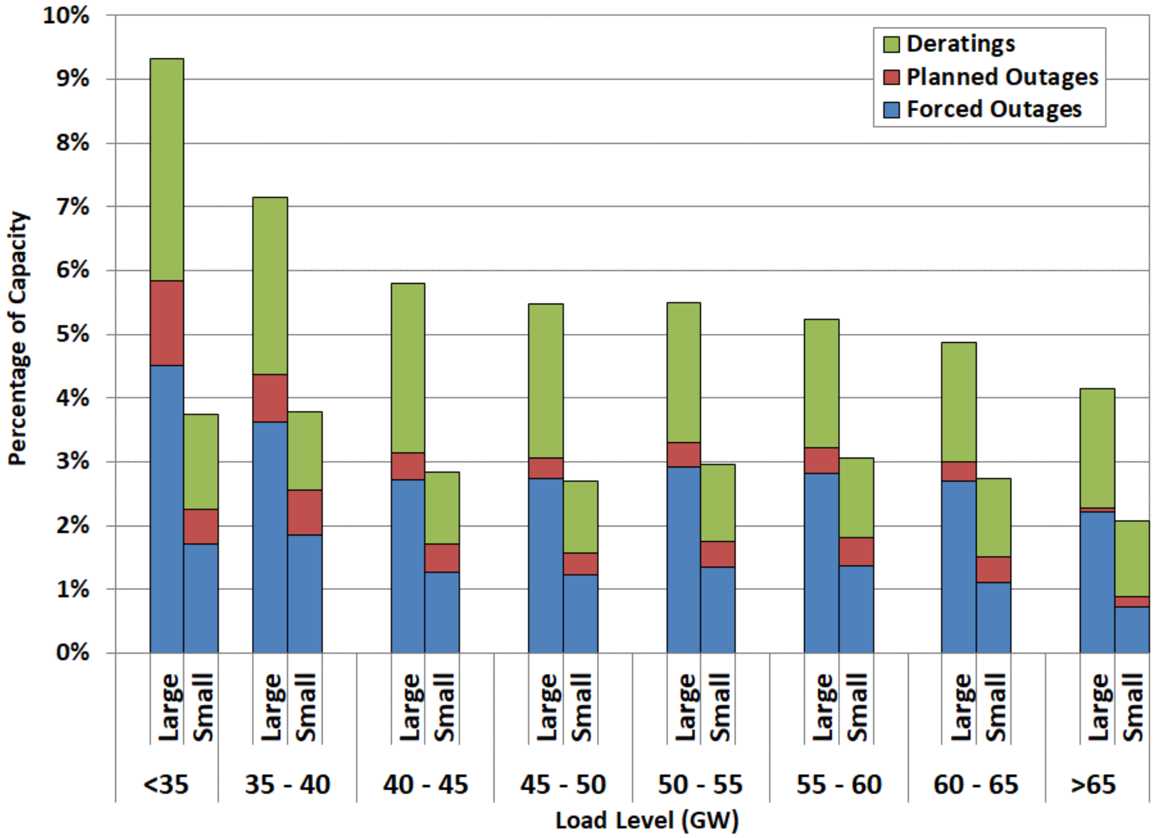


Figure 48 confirms the pattern we saw in 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the 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 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 $50 per MWh. The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

Figure 49: Incremental Output Gap by Load Level and Participant Size – Step 2

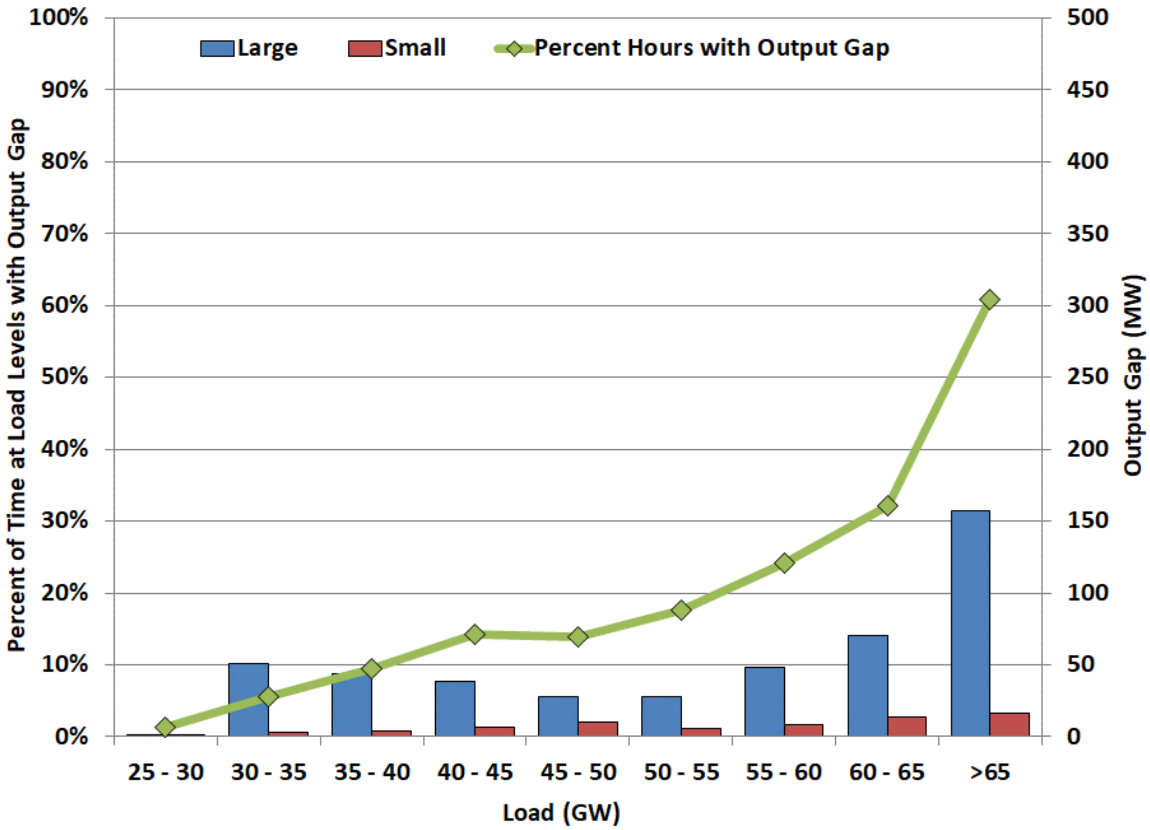


Figure 49 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. Relatively small quantities of capacity are considered part of this output gap, although 22% of the hours in 2019 exhibited an output gap. If the three entities that are under a VMP are removed from the analysis, the capacity and number of hours exhibiting output gaps are de minimis. Taken together, these results show that potential economic withholding levels were low in 2019, 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 2019.

Notwithstanding the findings above, the existence of some of these output gaps is the result of shortcomings in the mitigated offer caps. Specifically, the verifiable cost process that feeds most mitigated offer caps should allow for the pricing of:

- Opportunity costs that result from operating limitations that cause it to forego future output when it runs in the current hour;
- The costs of major maintenance; and
- Operating risks.

We recommend that ERCOT pursue these improvements to ensure that mitigation is reasonable and effective. See recommendation No. 7 above.

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 at various times in 2019. By the end of 2019, Calpine, NRG and Luminant had active and approved VMPs. 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.

There were no changes to Calpine or NRG's VMPs in 2019, and details can be found in Section VII of the Appendix. Luminant received approval from the Commission for a new VMP in December 2019.[52] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[53] The new VMP provides for small amounts of

52 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).

53 *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).

capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable capacity for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the 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 has historically been deemed allowable.

The final 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.[54] 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."[55] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of competition would typically involve profitably raising prices materially above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner.

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 frequently dispatched above their low sustained limits in 2018. 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

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54 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.

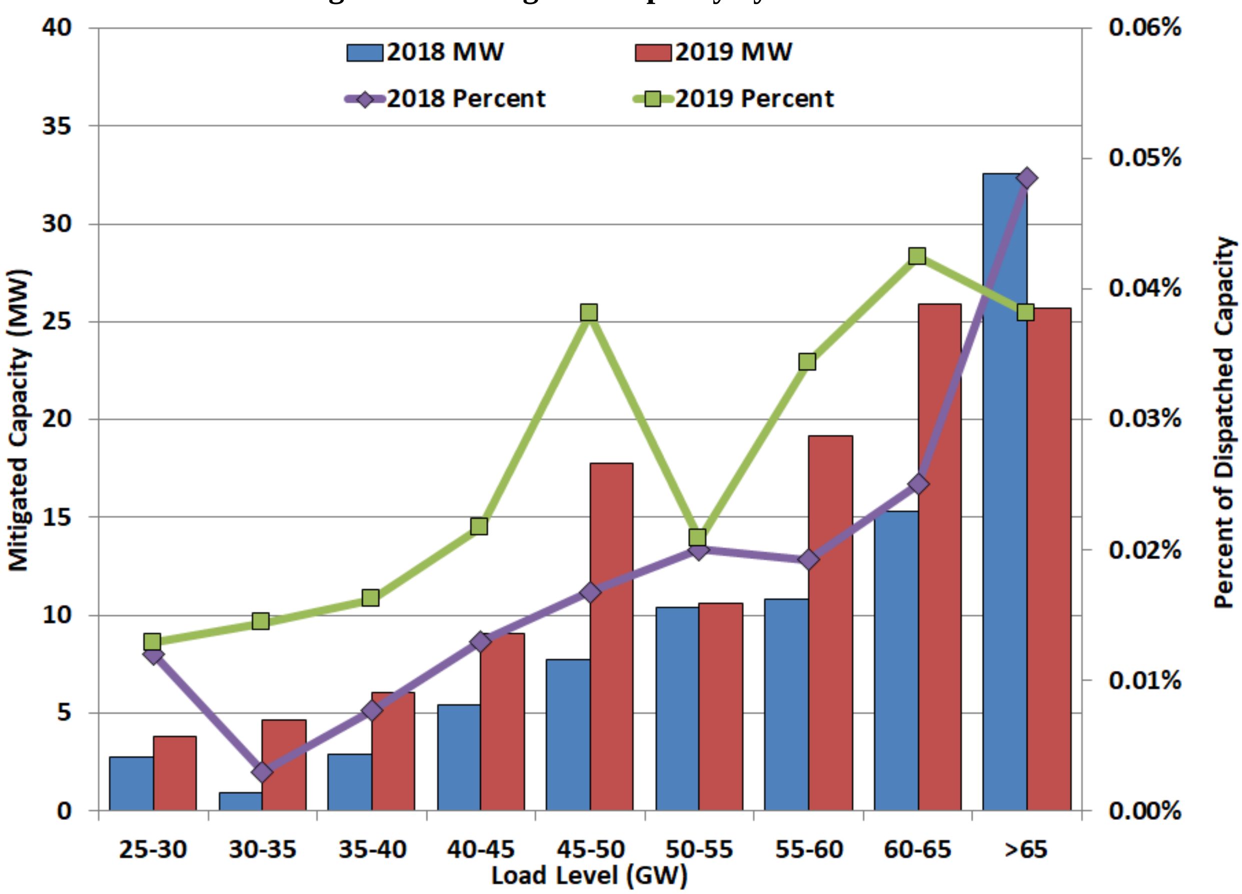
55 PURA § 39.157(a).

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 2019. 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 50 computes the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level.

Figure 50: Mitigated Capacity by Load Level



The amount of mitigation in 2019 was generally higher than in 2018. This is somewhat expected given the RUC instructions given to the combustion turbines in the Permian Basin, even with similar congestion costs between 2018 and 2019. If RUC instructions are necessary to resolve a local constraint, that constraint is more likely to be deemed noncompetitive, resulting in mitigation. Another factor for most of 2019 may be the separation in natural gas prices between the ERCOT Fuel Index Price and Waha fuel price indices.[56] To the extent some generator offers (and costs) were based on very low Waha gas prices, there would be no need to mitigate them based on Fuel Index Price prices. 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.

56 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*. his change is consistent with recent amendments to P.U.C. SUBST. R. 25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, adopted by the Public Utility Commission of Texas (PUCT) in Project No. 48721, which give ERCOT 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).

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 2019. The year contained record peak demand and low reserve margins, culminating in significant shortage pricing. Our evaluation of a number of factors suggests that the market performed competitively in 2019. We recommend several corrections and improvements to continue the evolution of the market design.

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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 in 2019 included:

- On February 8, 2019, ERCOT implemented SCR 794, Updated SCED Limit Calculation, which adjusted the methodology for converting Megavolt Ampere (MVA) limits for transmission elements into Megawatt (MW) limits that can be used by SCED. This improved the calculation in cases when the MW flow approached zero, when the previous methodology for MVA limit conversion was not as accurate.
- On March 1, 2019, the ORDC was changed to shift the Loss of Load Probability (LOLP) curve to the right in the positive direction by 0.25 standard deviations and to replace the seasonal and time-of-day blocks with a blended curve.
- On April 5, 2019, ERCOT implemented NPRR833, Modify PTP Obligation Bid Clearing Change, which modified pricing outcomes to be consistent with bid prices in cases where a contingency disconnects a source or sink Settlement Point.
- On April 5, 2019, ERCOT also implemented NPRR847, Exceptional Fuel Cost Included in the Mitigated Offer Cap, to allow Qualified Scheduling Entities (QSEs) to incorporate intraday weighted average fuel prices in mitigated offers to accommodate high fuel price events.
- Regarding improvements to the RMR process, on April 5, 2019, ERCOT implemented NPRR845, making a number of changes to the RMR agreement and settlement.
- On April 10, 2019, ERCOT lowered the mitigated offer floor for natural gas resources to $0/MWh, due to the very low-to-negative fuel costs in West Texas (NPRR916, Mitigated Offer Floor Revisions). On May 31, 2019, ERCOT lowered it further to (-$20)/MWh.
- On May 31, 2019, ERCOT implemented NPRR901, Switchable Generation Resource Status Code, which created a separate status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area. In addition, a new settlement mechanism was added to address RUC instructions to these SWGRs (NPRR912).
- On May 31, 2019, ERCOT also implemented new logic to prevent the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource has previously been awarded a Three-Part Supply offer (NPRR910).

- On July 1, 2019, NPRR821, Elimination of the Congestion Revenue Right (CRR) Deration Process for Resource Node to Hub or Load Zone CRRs, was made effective, leaving only CRRs that sink at Resource Nodes to remain subject to deration when paths are oversold.
- On August 9, 2019, ERCOT implemented restrictions on financial transactions in the Day-Ahead Market at certain Private Use Network settlement points, eliminating a source of RENA uplift (SCR796).
- On December 12, 2019, ERCOT switched the Fuel Index Price to use Katy Hub rather than Houston Ship Channel as the delivery point, due to its superior liquidity (NPRR952).
- On December 16, 2019, NPRR920, Change to Ramp Rate Calculation in Resource Limit Calculator, was implemented to dynamically adjust the amount of ramp rate reserved for Regulation Service in real-time to optimize ramp sharing between Regulation and SCED.

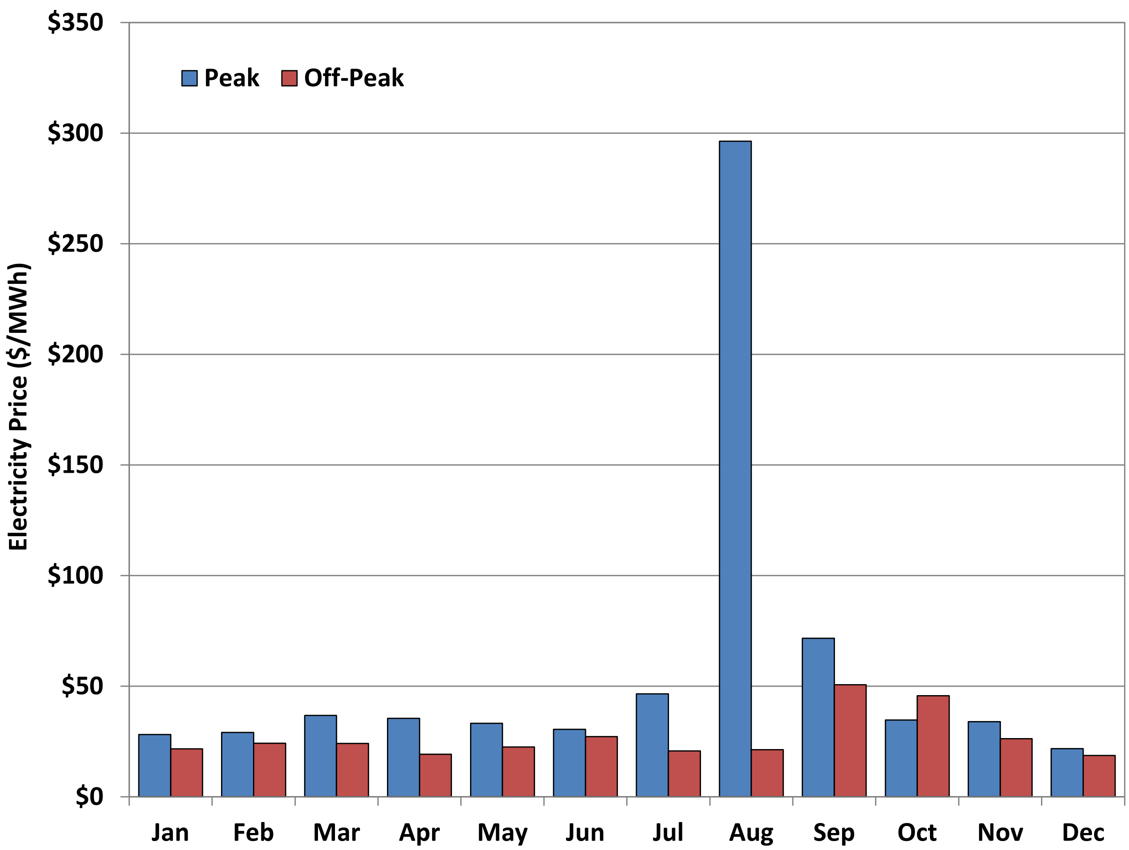
I. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of the prices and outcomes in ERCOT's real-time energy market.

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 2019. 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



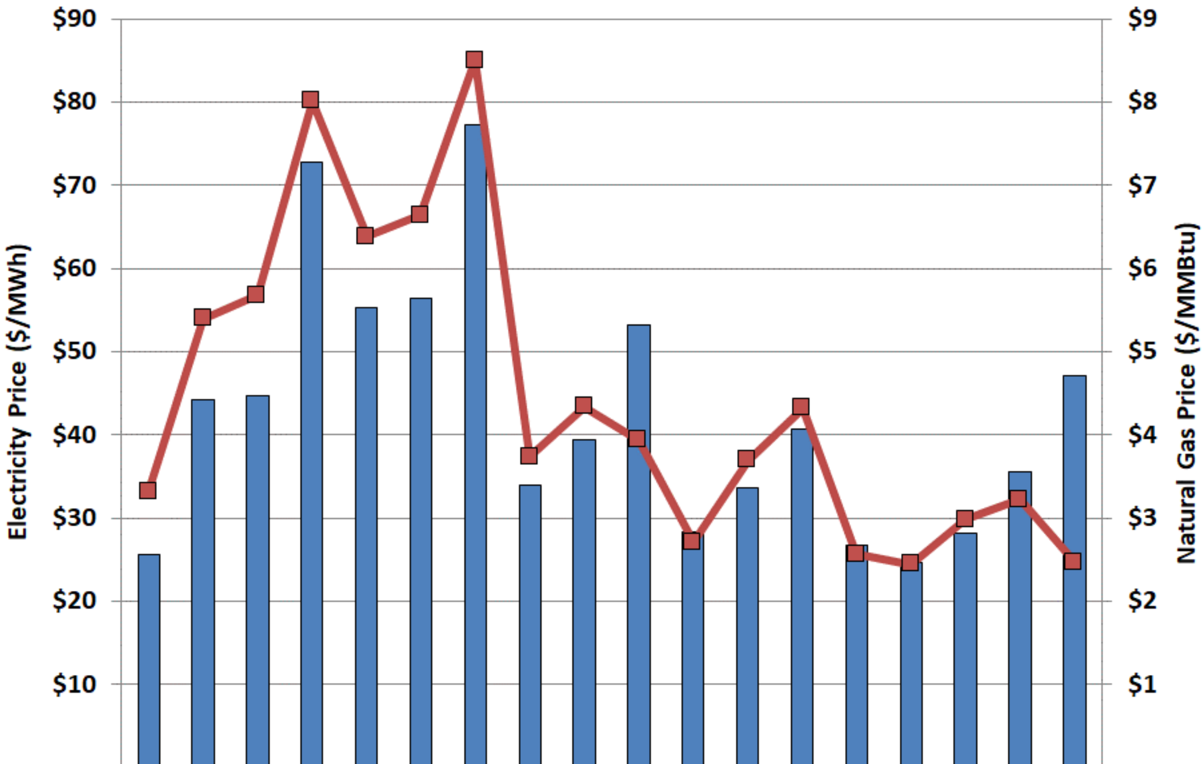
As expected, Peak hours were higher priced than Off-Peak hours for every month in 2019, with the exception of October, when Off-Peak hour prices were $10.96 per MWh higher than peak hour prices, due to transmission emergency conditions in the far side of the West zone during planned outages in the evening. For all other months, the difference ranged from a minimum of $3.14 per MWh in December to a maximum of $275.00 per MWh in August. The difference in

August was 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 12th. Excluding the effects of those intervals reduces the difference to $26.55. The average difference between monthly Peak and Off-Peak pricing was $13.63 per MWh.

B. Zonal Average Energy Prices in 2019

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 2019.

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

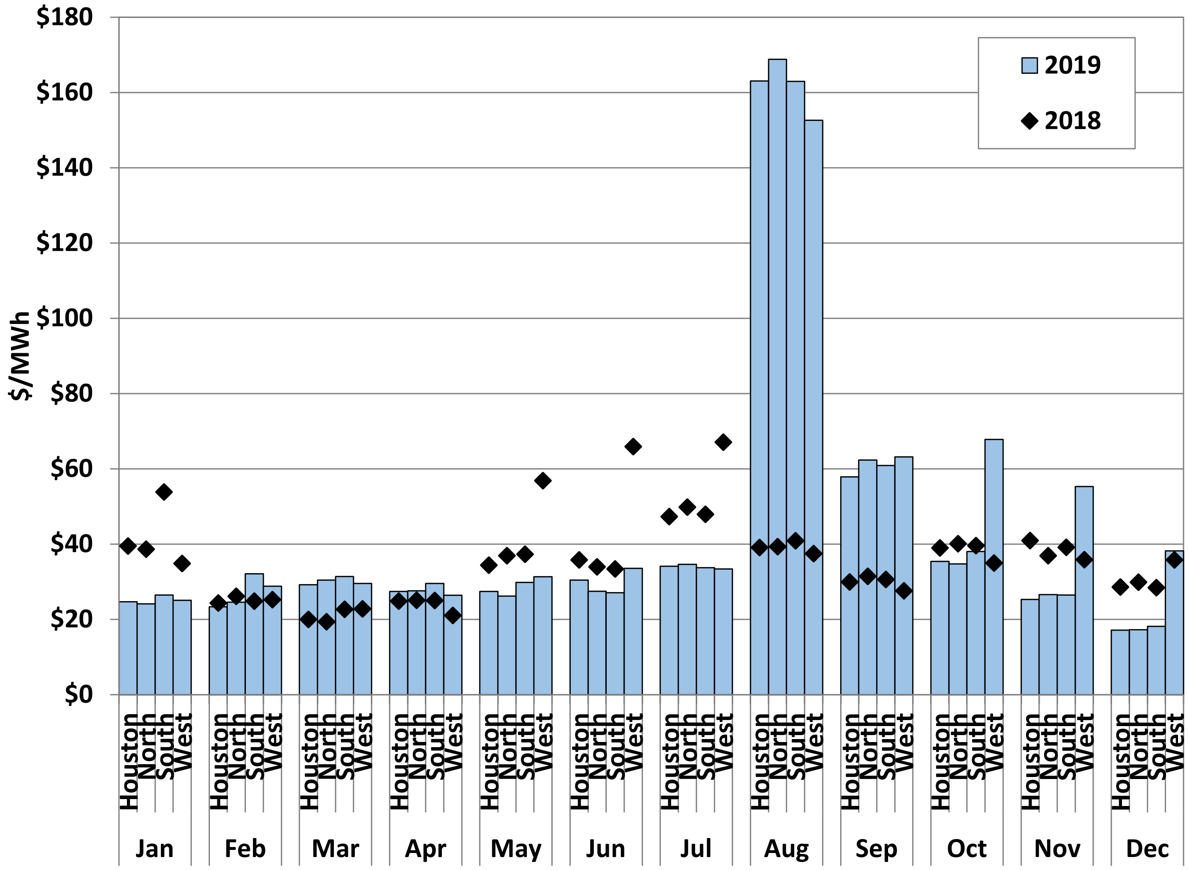


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77	24.62	28.25	35.63	47.06
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57	2.45	2.98	3.22	2.47

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. However, in 2011 and 2019 the 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.

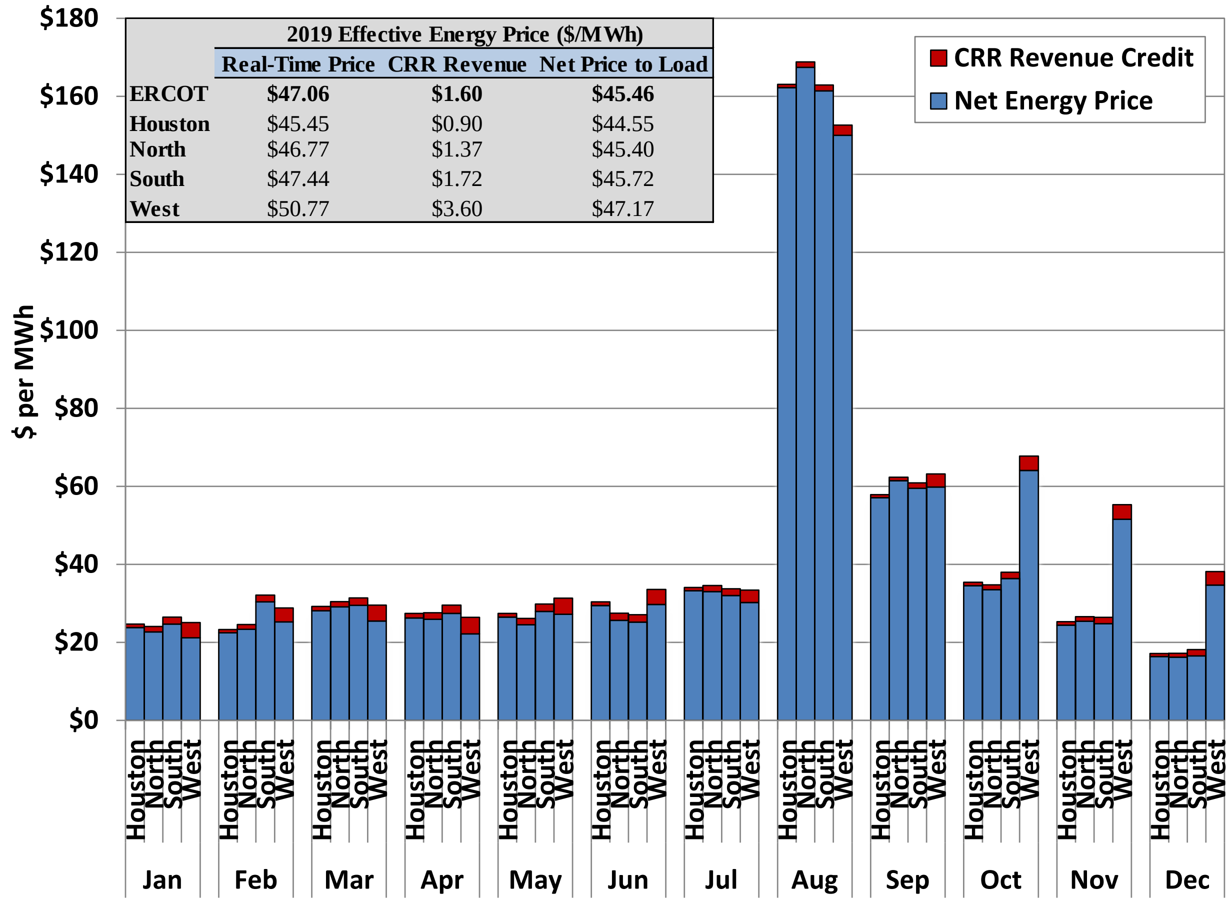
Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2018 and 2019. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral or other forward contract prices.

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



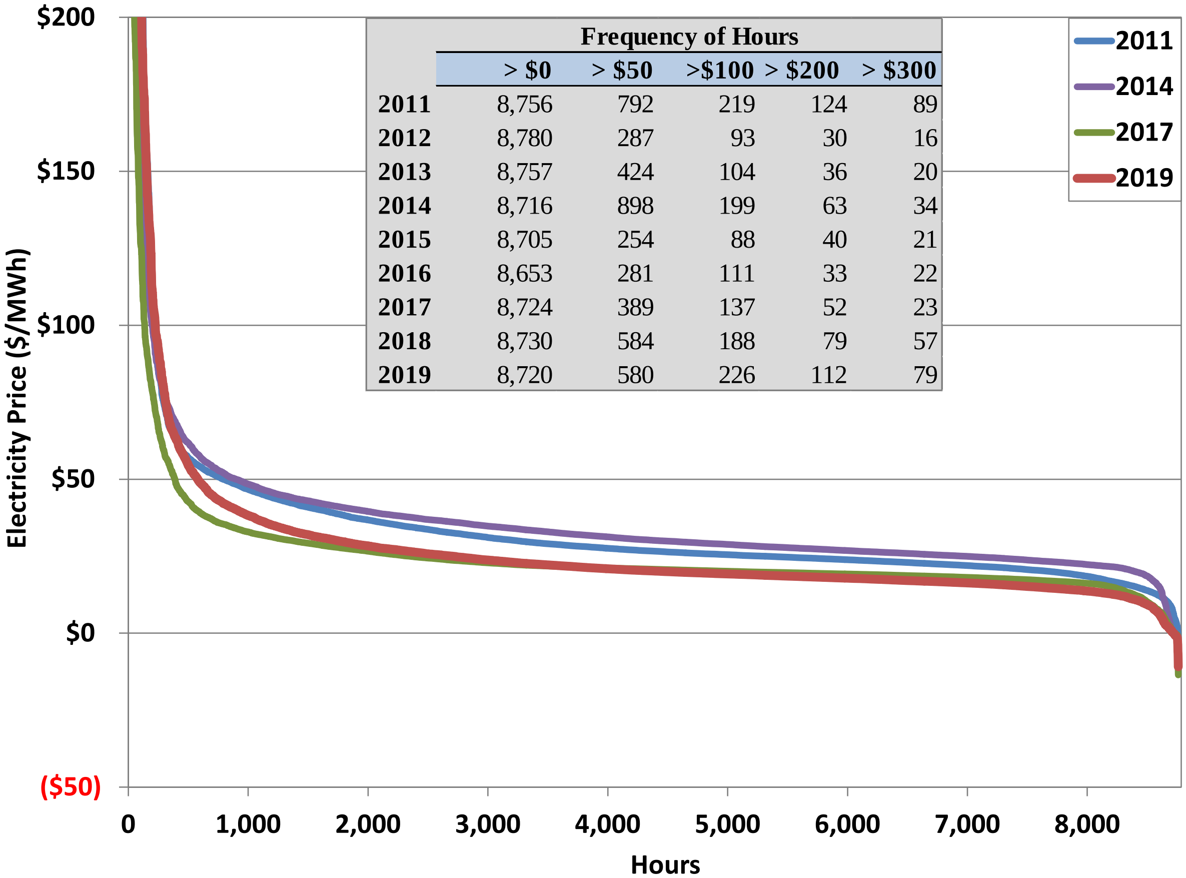
Another factor influencing zonal price differences is CRR auction revenue distributions. These are allocated to Qualified Scheduling Entities (QSEs) representing load, based on both zonal and ERCOT-wide monthly load-ratio shares. The CRR auction revenues have the effect of reducing the total cost to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

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 A shows price duration curves for the ERCOT energy market for 2017 and 2019, and includes 2011 and 2014 for historical context, because those years show the second and third most shortage pricing hours (2019 is the first) 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

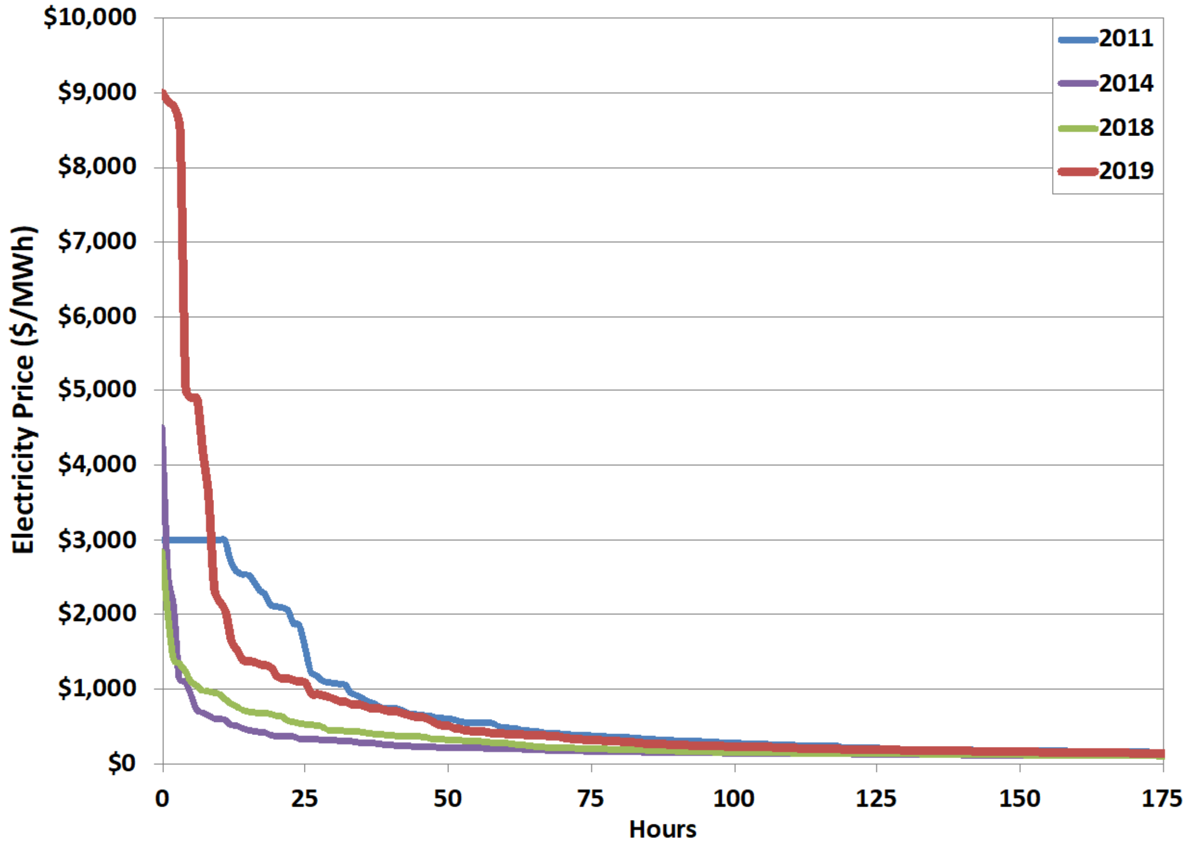


Frequency of Hours	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79

Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure has 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 2019, there were 40 hours with ERCOT-wide prices at or below zero, an increase from the 30 hours in 2018.

Figure A6 compares prices for the highest-priced 2% of hours in 2018 with 2019. Years 2014 and 2011 are also included for historical context. Energy prices for the highest 100 hours of 2019 were significantly higher than even those in 2011, the previous peak year. 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 (SWOC) to $9000/MWh, the implementation of the Operating Reserve Demand Curve and subsequent changes to its parameters, and the implementation of the Reliability Deployment Adder.

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

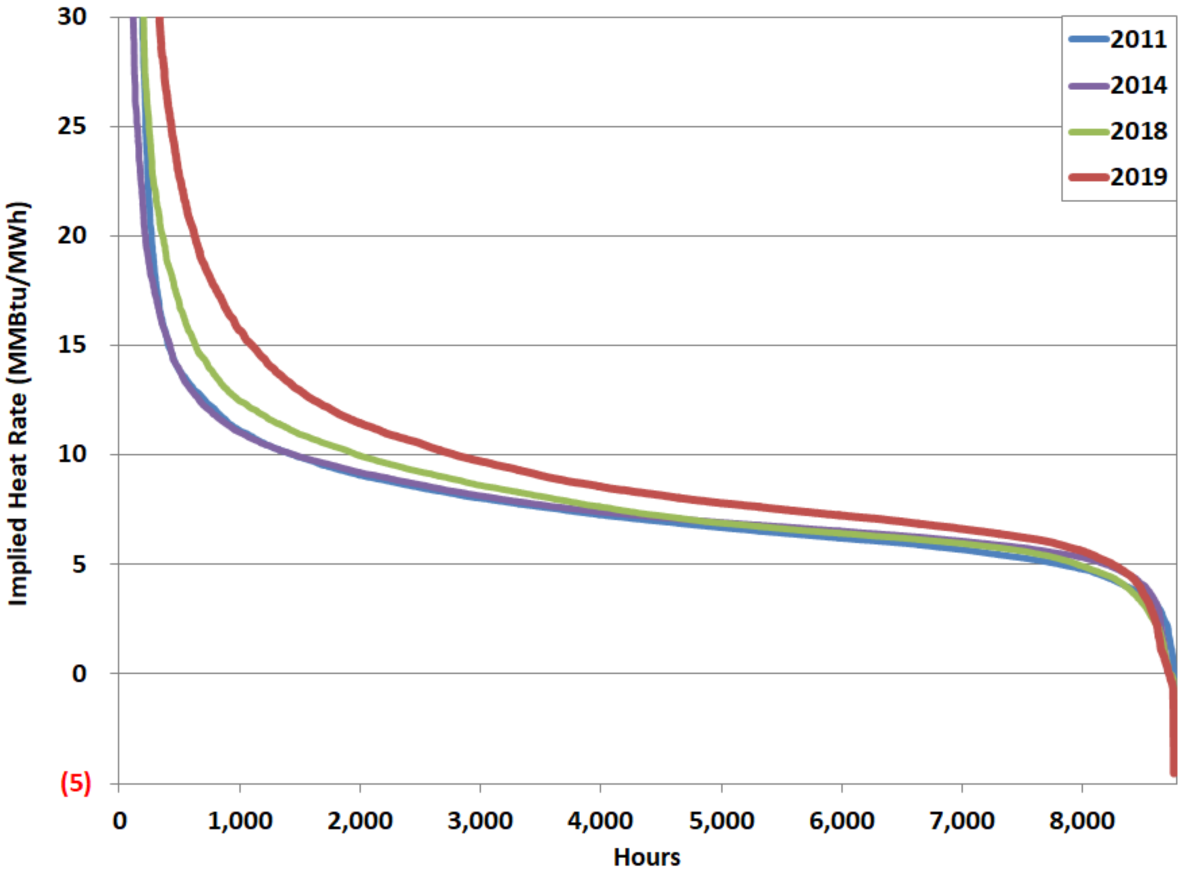


Figure A8 shows the implied marginal heat rates for the top 2% of hours in 2018 and 2019, with years 2014 and 2011 included for historical context. The implied heat rate duration curve for the top 2% of hours in 2019 was higher than 2018 because of the significant increased contribution of shortage pricing. Because of the increased contribution from shortage pricing in 2019, the implied heat rates in 2019 rose above even the levels seen in 2011, a year with extreme and record-breaking heat and drought.

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

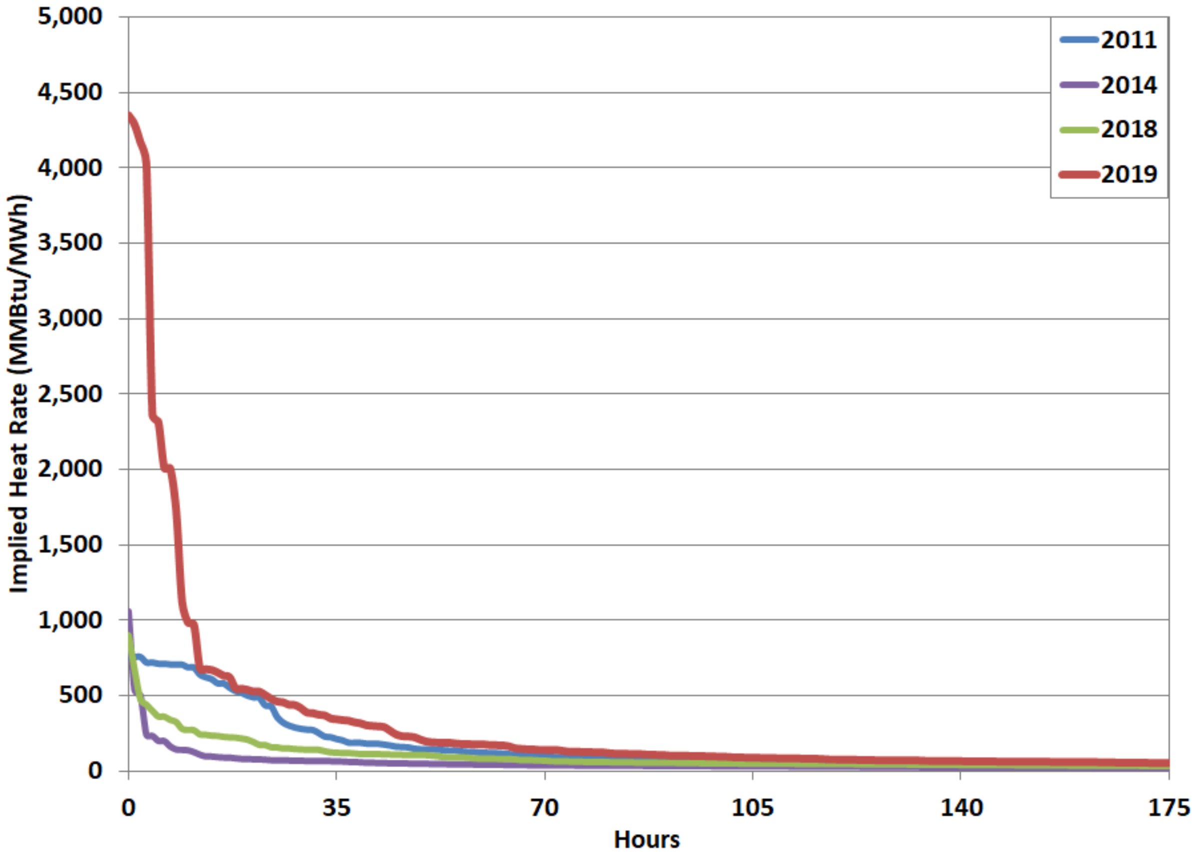


Table A1 displays the annual average implied heat rates by zone for 2011 through 2019. Adjusting for natural gas price influence, Figure A8 shows that the annual, system-wide average implied heat rate increased significantly in 2019 compared to 2018. Further, zonal implied heat rates in 2019 were the highest experienced in the nodal market, higher even than 2011.[57] Zonal variations in the implied heat rate were greater in 2017 because of the increased influence of transmission congestion. The zonal variations in 2018 and 2019 were not as pronounced.

[57] The implied heat rate for the West zone was highest in 2012 due to extreme transmission congestion.

Table A1: Average Implied Heat Rates by Zone

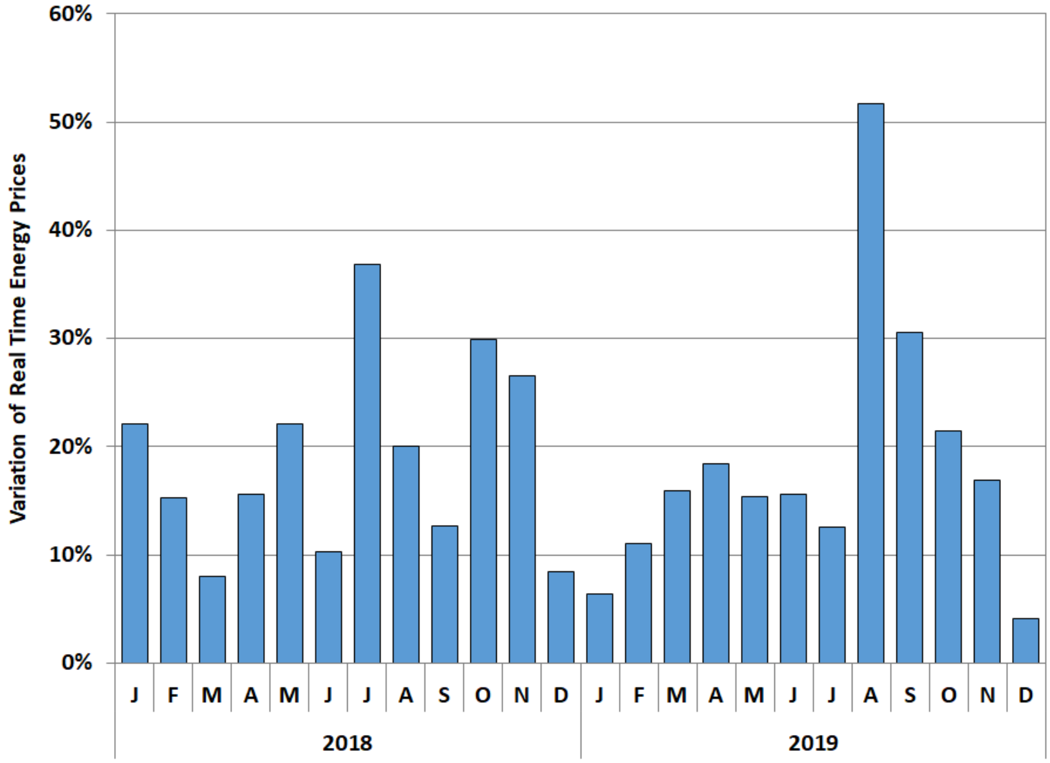
(MMBtu/MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	**13.5**	**10.5**	**9.1**	**9.4**	**10.4**	**10.1**	**9.5**	**11.1**	**19.0**
Houston	13.3	10.0	9.1	9.2	10.5	10.8	10.7	10.7	18.4
North	13.7	10.2	8.9	9.3	10.2	9.7	8.6	10.9	18.9
South	13.8	10.2	9.2	9.6	10.6	10.1	9.9	11.2	19.2
West	11.9	14.1	10.3	10.1	10.4	9.0	8.2	12.3	20.5
($/MMBtu)									
Natural Gas	$3.94	$2.71	$3.70	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47

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.

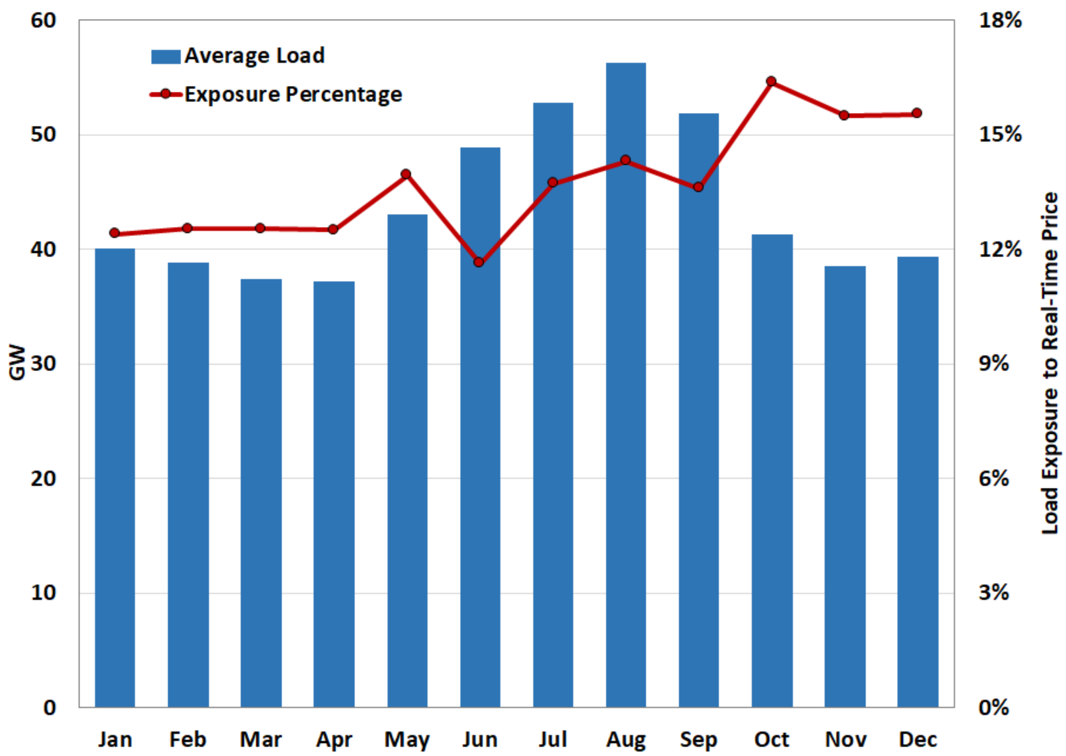
Expressed as a percentage of average price, the average absolute value of changes in five-minute real-time energy prices during the months of May through August was 6.4% in both 2018 and 2019. Expanding the view of price volatility, Figure A9 below shows monthly average changes in five-minute real-time prices by month for 2018 and 2019. As expected, the highest price variability occurred during August when occurrences of shortage pricing were most frequent in 2019.

Figure A9: Monthly Price Variation



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. While the smallest portion of load potentially exposed to real-time prices was lowest in June, that portion rose again during the high-load summer months of July, August, and September, when even hedged loads were more vulnerable to the shortage conditions and high prices (multiple intervals at the high system-wide offer cap (HCAP) of $9,000 per MWh) seen during those months. 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.

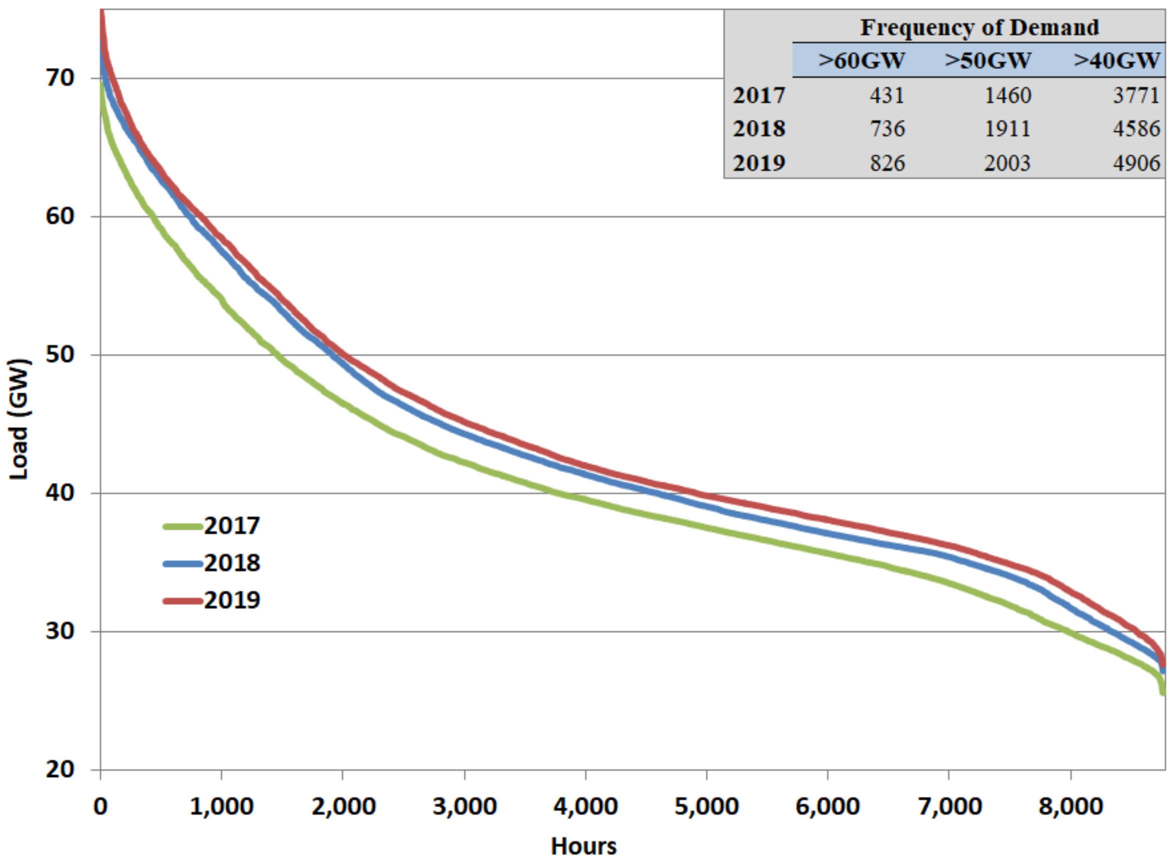
II. APPENDIX: DEMAND AND SUPPLY IN ERCOT

In this section, we provide supplemental analyses of load patterns during 2019 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2019

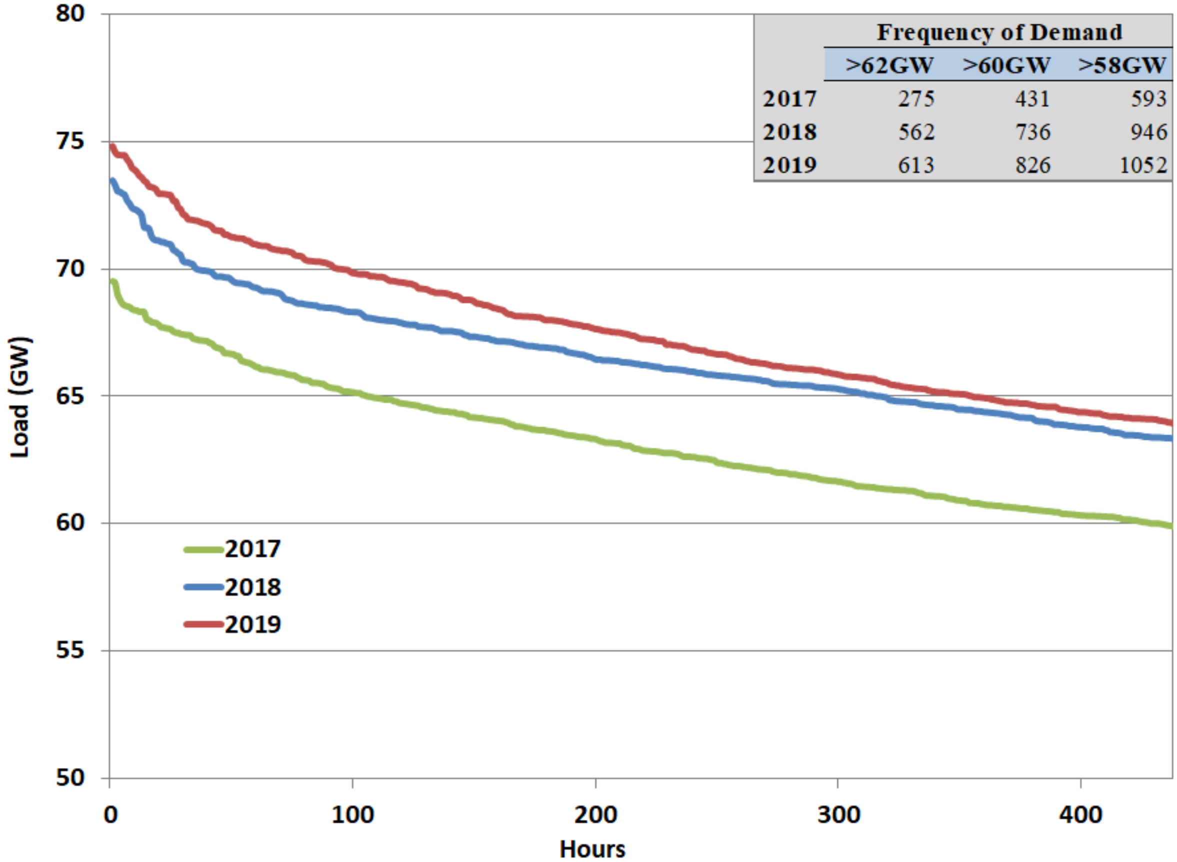
To provide a more detailed analysis of load at the hourly level, Figure A11 compares load duration curves for each year from 2017 through 2019. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT 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 2019 was similar to 2018 and 2017, though slightly higher as load continues to increase in ERCOT.

Figure A11: Load Duration Curve – All Hours



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



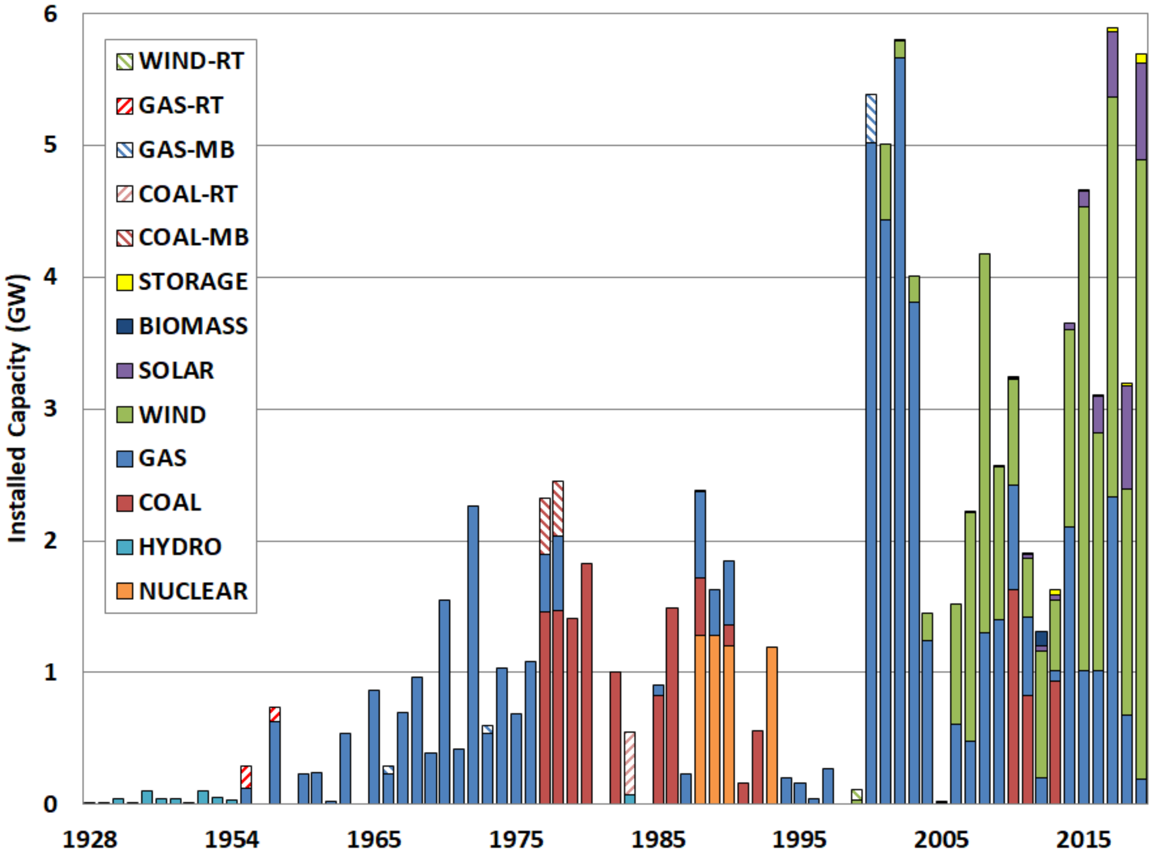
B. Generation Capacity in ERCOT

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 2019 Capacity, Demand, and Reserves (CDR) report[58] and 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 2019. Combined cycle gas capacity had been the predominant addition for years; however, wind has been the primary technology for new capacity since 2006.

58 ERCOT Capacity, Demand, and Reserves Report (Dec. 5, 2019), available at http://www.ercot.com/content/wcm/lists/167023/CapacityDemandandReserveReport-Dec2019.xlsx.

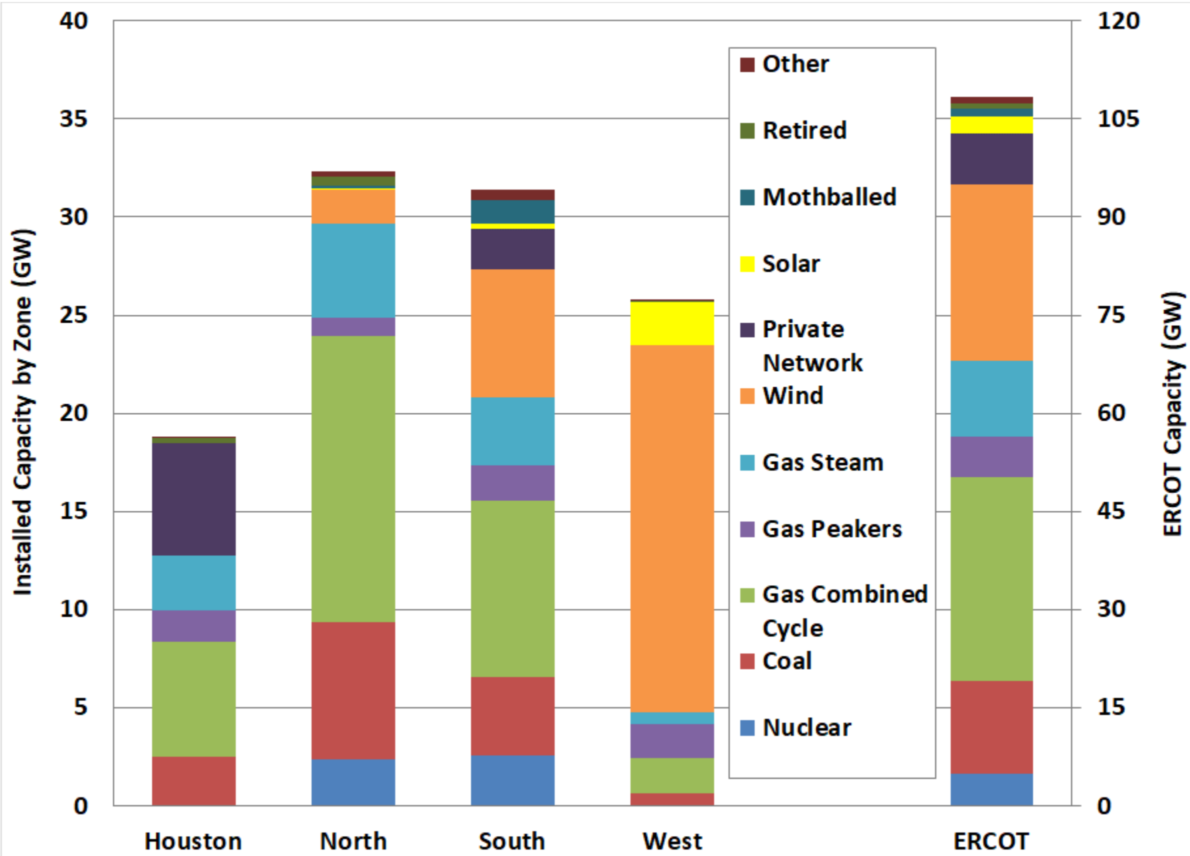
Figure A13: Vintage of ERCOT Installed Capacity



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 2019 is similar to the distribution of demand in those same zones, with the exception of the Houston zone.[59] Based on that metric, the North zone accounted for approximately 35% of capacity, the South zone 31%, the Houston zone 22%, and the West zone 12% in 2019. The installed generating capacity by type in each zone is shown in Figure A14.

[59] The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 63% for coastal wind, 16% for other wind, and 76% for solar.

Figure A14: Installed Capacity by Technology for Each Zone



Approximately 4.9 GW of new generation resources came online in 2019, the bulk of which were wind resources with total capacity of 4.7 GW.

On May 23, 2019, ERCOT received a Notification of Suspension of Operations (NSO) for West Texas Wind Energy Partners, LP's Southwest Mesa (SW_MESA_SW_MESA) Generation Resource. The NSO indicated that the Resource Entity would decommission and retire the resource permanently on November 15, 2019. The NSO further indicated that Southwest Mesa (SW_MESA_SW_MESA) has a summer Seasonal Net Max Sustainable Rating of 80 MW, and a summer Seasonal Net Minimum Sustainable Rating of 0 MW.

On June 28, 2019, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for the City of Garland's Gibbons Creek Generating Station (GIBCRK_GIB_CRG1) indicating the resource would be decommissioned and retired permanently as of October 23, 2019. Gibbons Creek is a 470 MW coal unit located in Grimes County (20 miles southeast of College Station) and owned by the Texas Municipal Power Agency (TMPA), which is an organization jointly owned by four municipalities: the cities of Garland, Denton, Bryan and Greenville.

C. Wind 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 2018 and 2019, 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 5.5 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

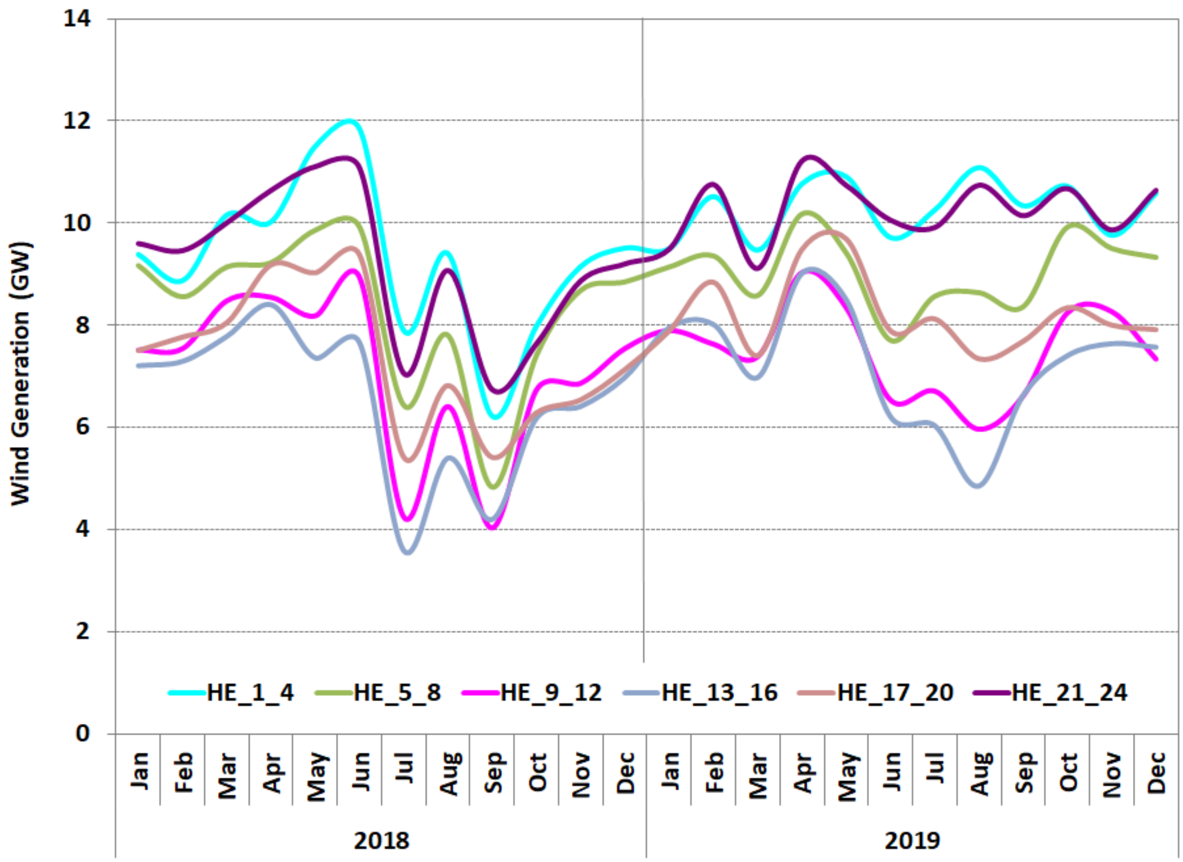
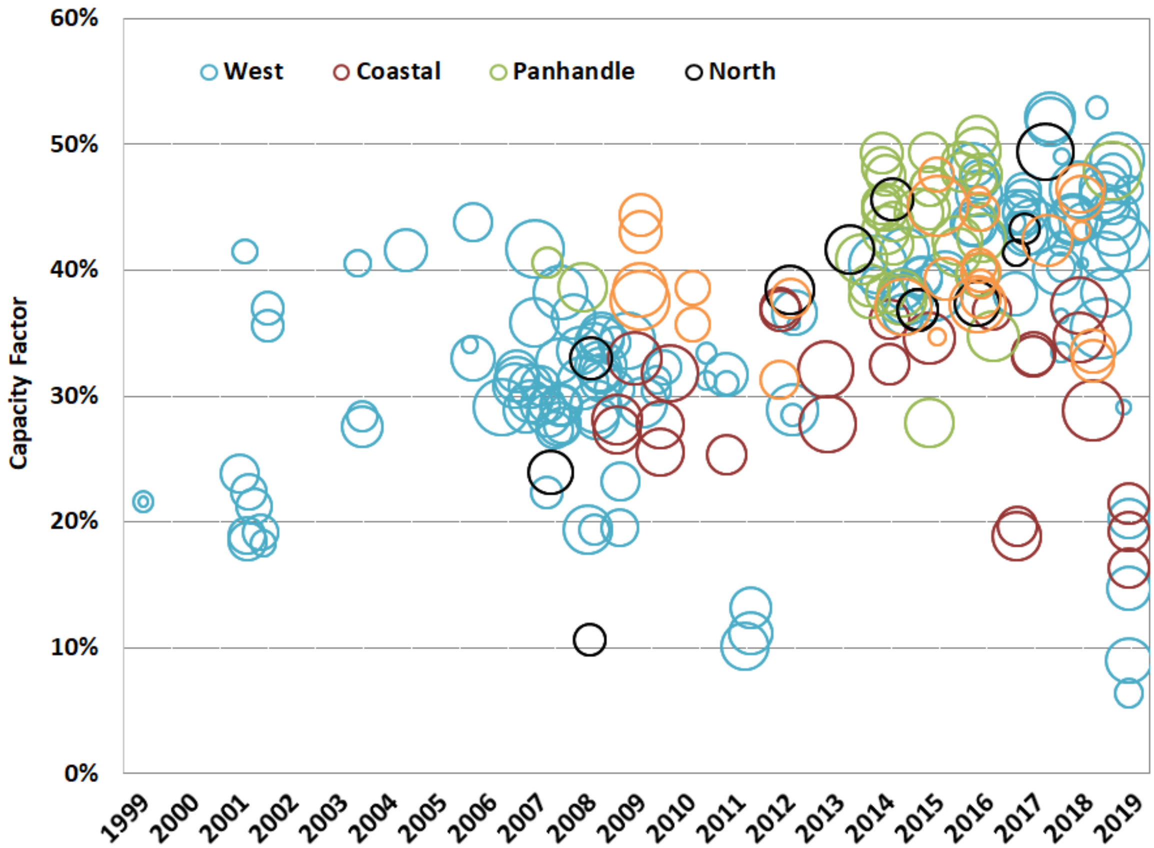


Figure A16 shows the capacity factor (the ratio of actual energy produced by an energy generating unit or system in a given period, to the hypothetical maximum possible, i.e. energy produced from continuous operation at full rated power) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles for each. Transmission maintenance for some 345 kV transmission lines had the effect of limiting 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 2019 increased slightly from 2018 and was higher than the average over the past 10 years.

Figure A17: Historic Average Wind Speed

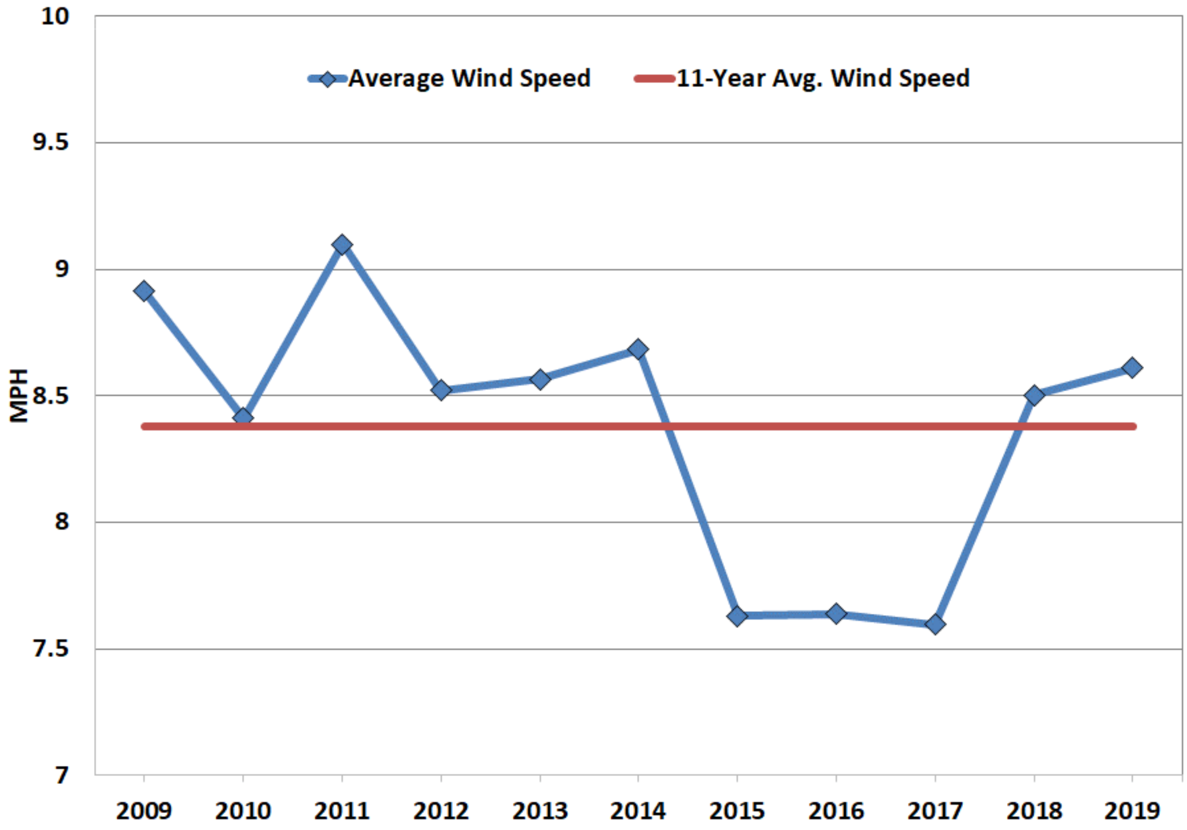
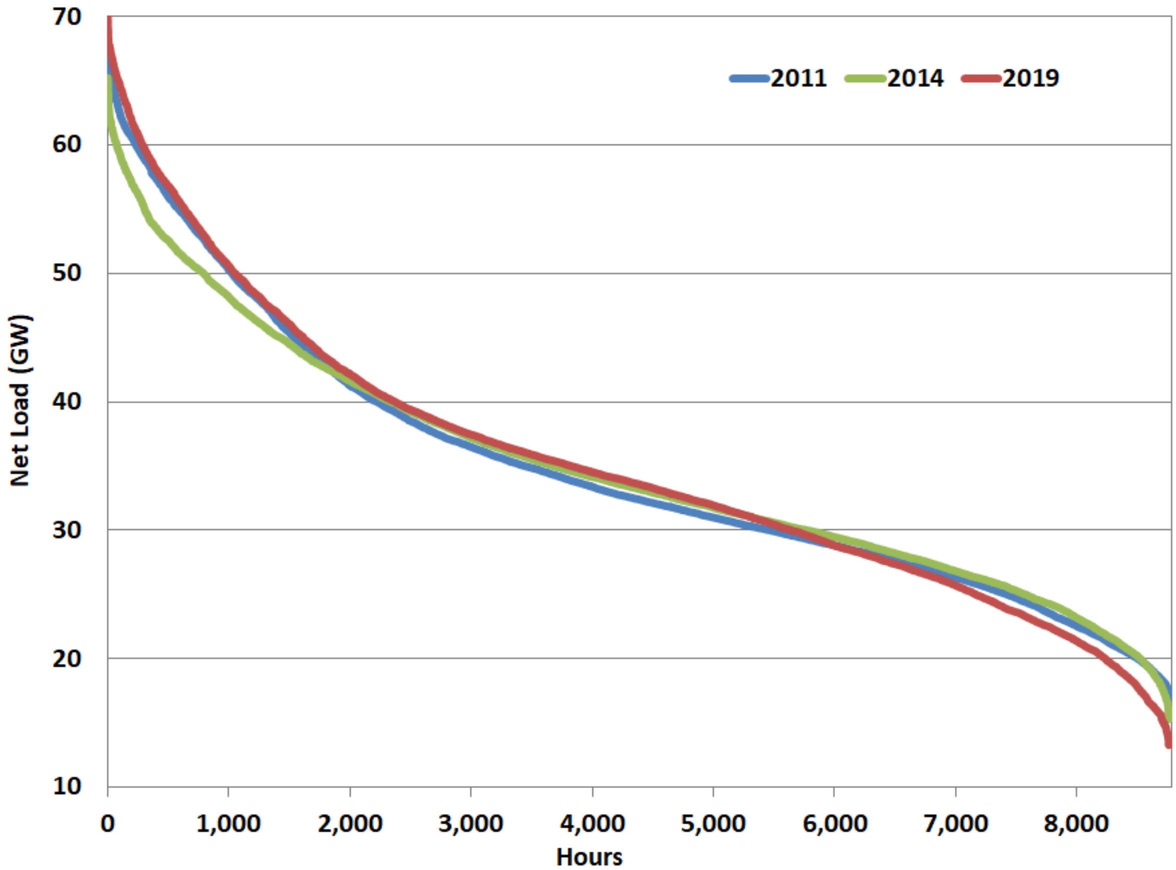


Figure A18 shows the net load duration curves for the years 2011, 2014, and 2019. Increasing wind output has important implications for non-wind resources and for resource adequacy in the ERCOT region as growth in peak demand requires additional resources to be added, but the energy available to be served overall is reduced.

Figure A18: Net Load Duration Curves



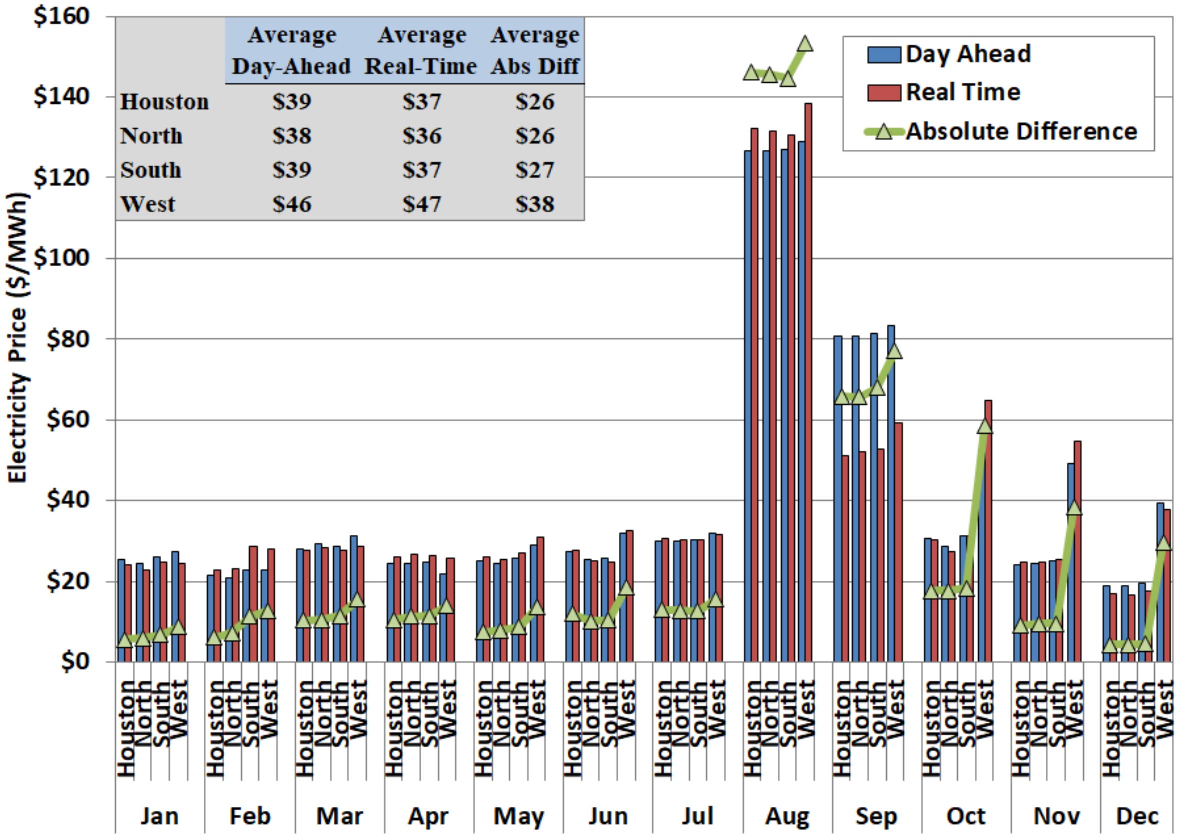
III. APPENDIX: DAY-AHEAD MARKET PERFORMANCE

In this section, we provide supplemental analyses of the 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 are shown for each of the geographic zones. Overall volatility was relatively low in 2019 across all zones. September 2019 witnessed the most pronounced price differences, with an average difference between day-ahead and real-time prices of $27.84 per MWh. Finally, although the average day-ahead and real-time prices were the most similar in the West zone, 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.

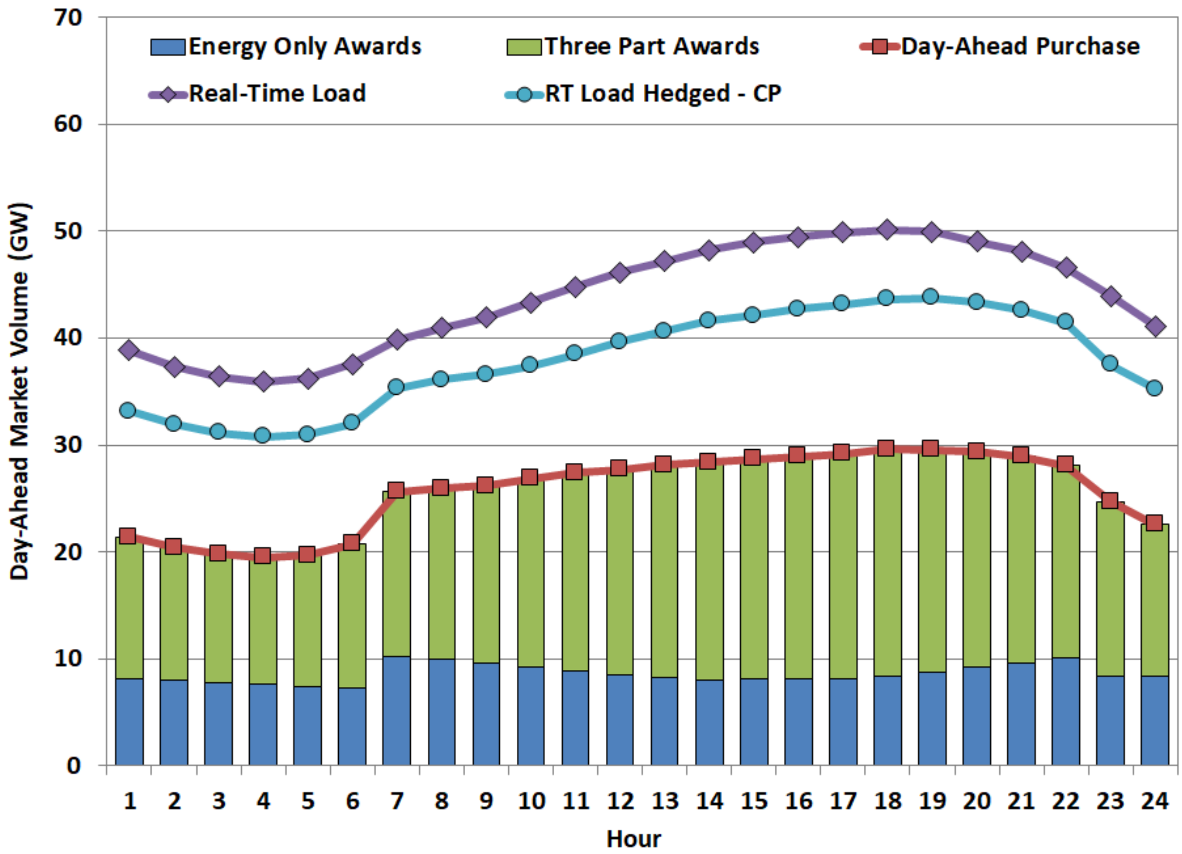
Figure A19: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Figure A20 below presents the same day-ahead market activity data 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.

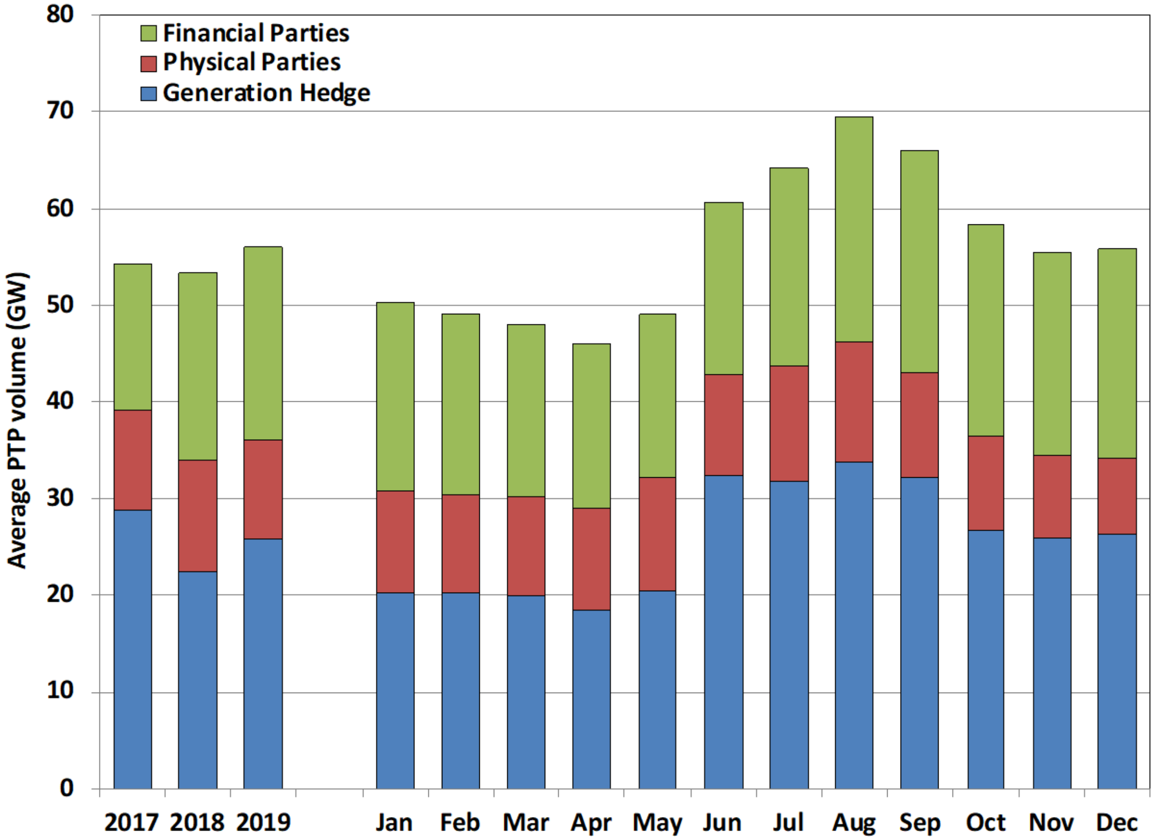
Figure A20: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A21 below presents the total volume of PTP obligation purchases in 2019 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 purchases has been fairly stable for the past three years.

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. The remaining 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 36% of the total volume of PTP obligations in 2019, the same as in 2018, and an increase from 28% in 2017.

D. Ancillary Services Market

Figure A22 below displays the hourly average quantities of ancillary services procured for each month in 2019.

Figure A22: Hourly Average Ancillary Service Capacity by Month

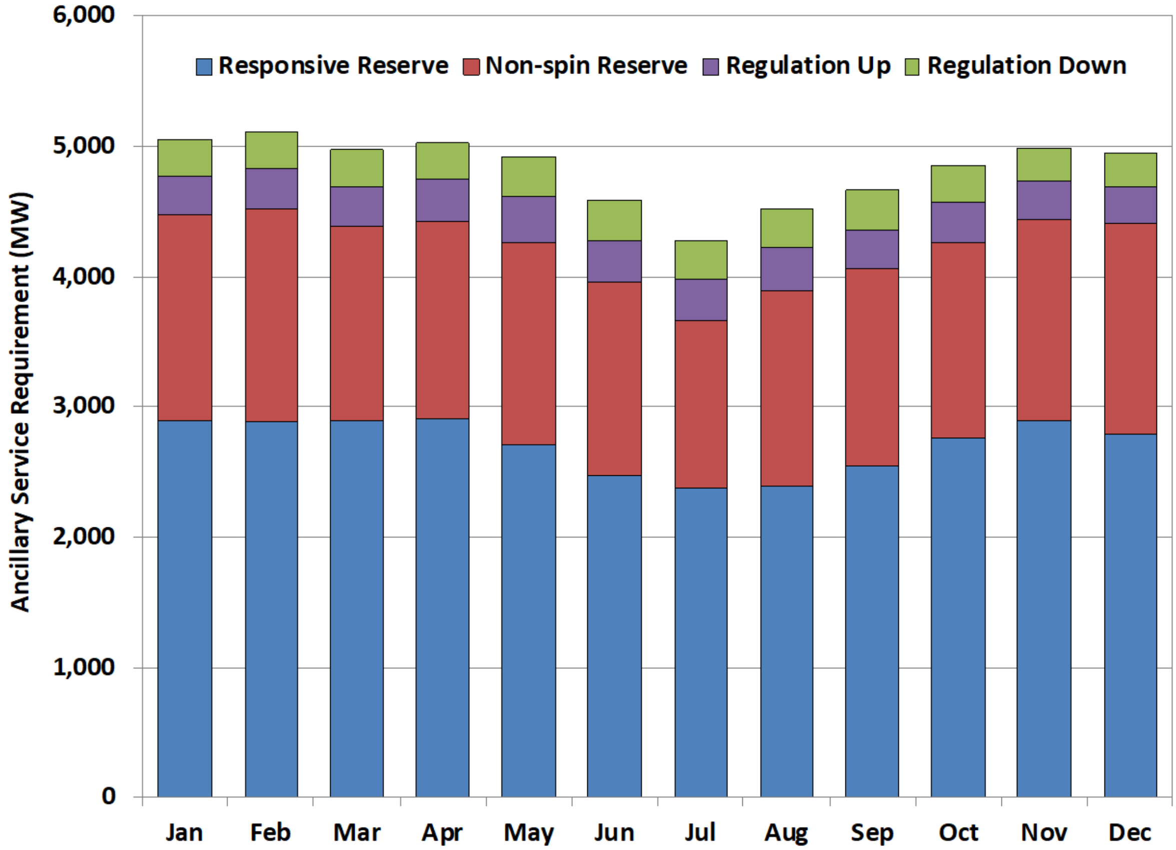


Figure A23 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the large variation in quantities between some adjacent hours was readily apparent. For example, capacity requirements increased almost 400 MW in HE 7, decreased 237 MW in HE 8 and gradually increased for the next two hours. Hour 23 provided another example of an increase in requirements in the hour prior to a decrease. This pattern was a result of the methodology that sets responsive and non-spinning reserve quantities in four-hour blocks, while regulation reserve quantities are set hourly.

Figure A23: Yearly Average Ancillary Service Capacity by Hour

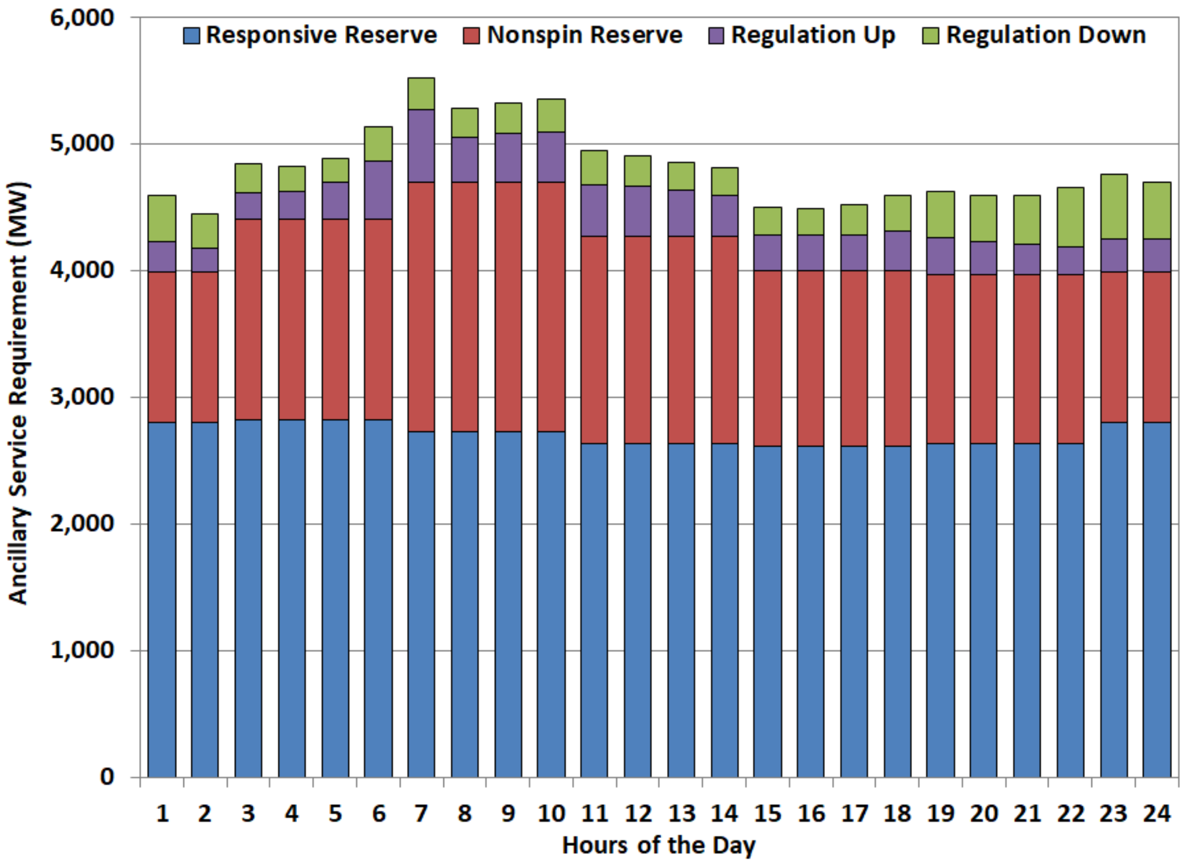
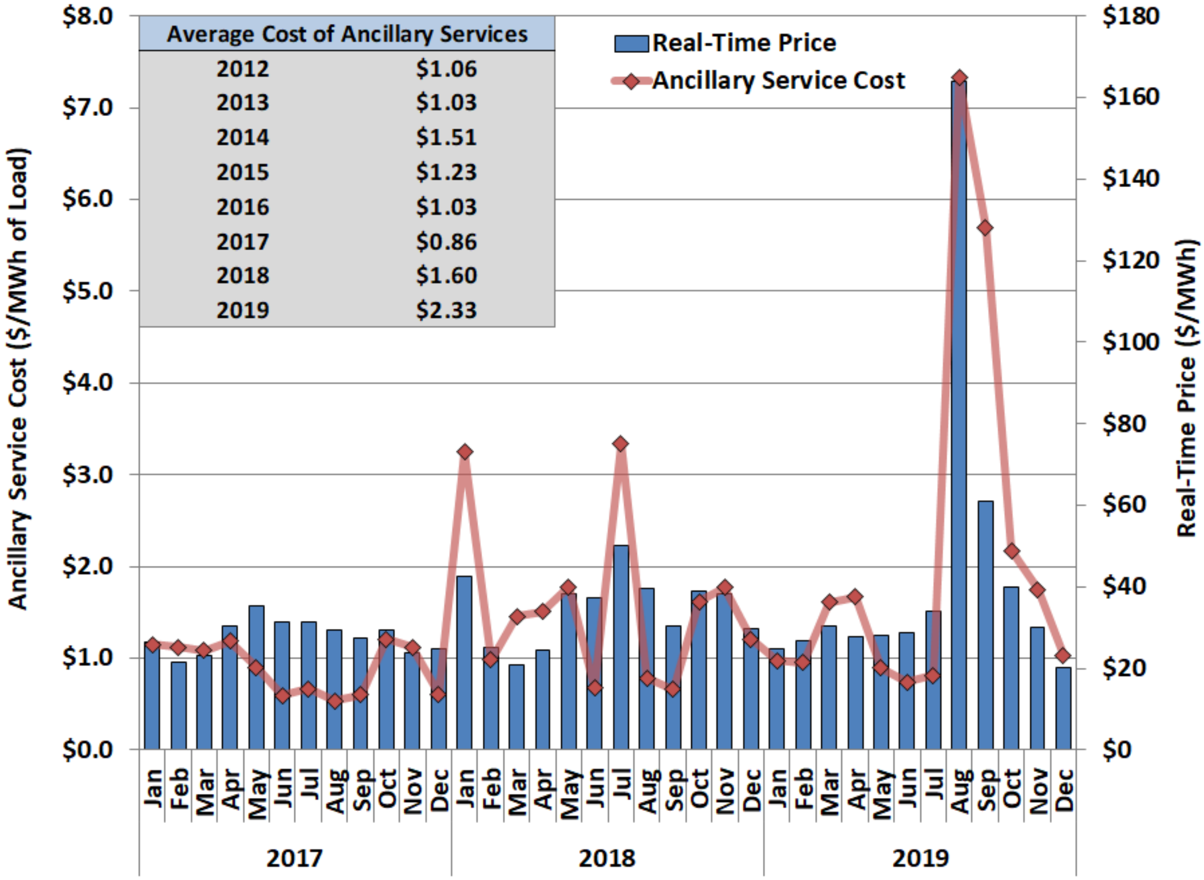


Figure A24 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2017 through 2019.

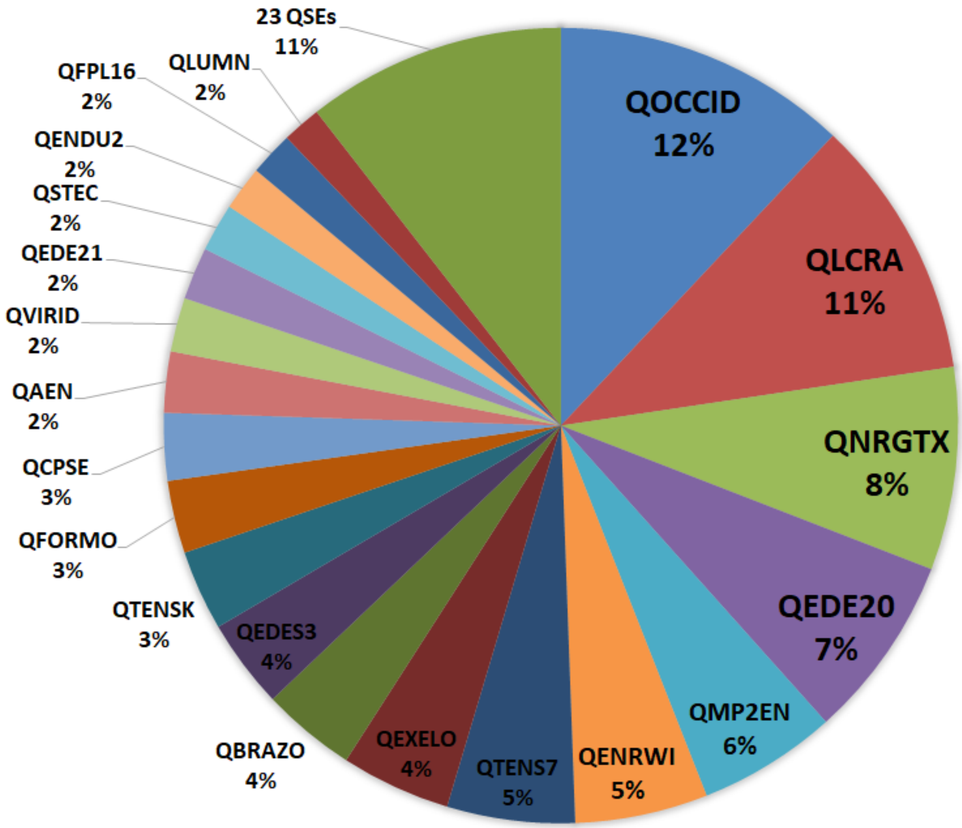
Figure A24: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load increased to $2.33 per MWh in 2019 from $1.60 per MWh in 2018 and the all-time low of $0.86 per MWh in 2017. Total ancillary service costs were approximately 5% of the load-weighted average energy price in 2019, compared to 4.5% in 2018 and 3.0 % in 2017, continuing the upward trend started a year ago.

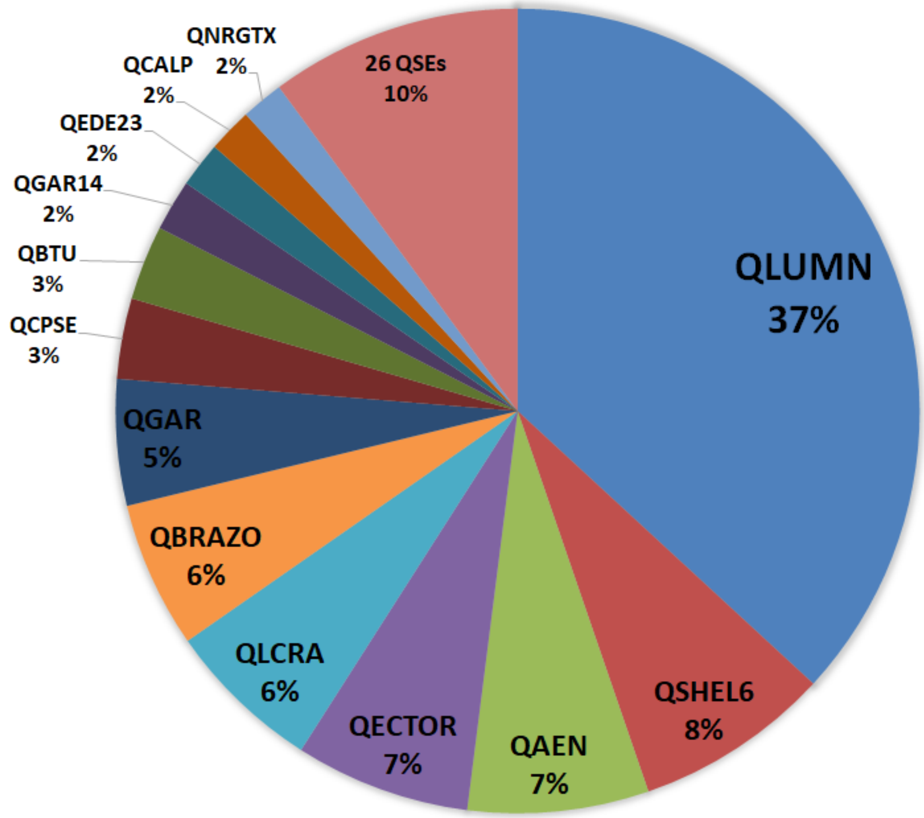
Figure A25 below shows the share of the 2019 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2019, 43 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market. The number of providers has been roughly the same for the past five years (43 in 2018, 45 in 2017, 42 in 2016, and 46 in 2015). There were no significant changes from 2018 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) still bearing almost 40% the total responsibility. Luminant's 37% share of non-spin responsibility however was a decrease from the 41% share it held in 2018 and 56% in 2017. The change in composition of Luminant's generation fleet, due to merger and retirements, likely explains the continued reduction. As Luminant's non-spin responsibility decreased again in 2019, many other suppliers such as Austin Energy (QAEN) and Ector County Energy Center (QECTOR) 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 more entities.

Figure A27: Regulation Up Reserve Providers

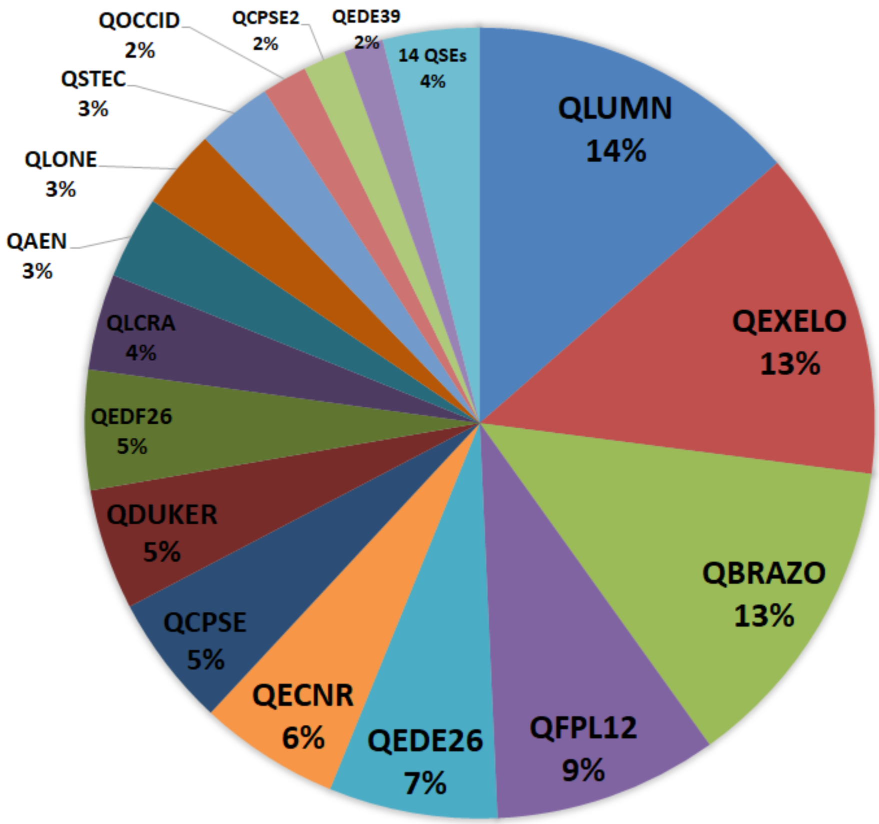
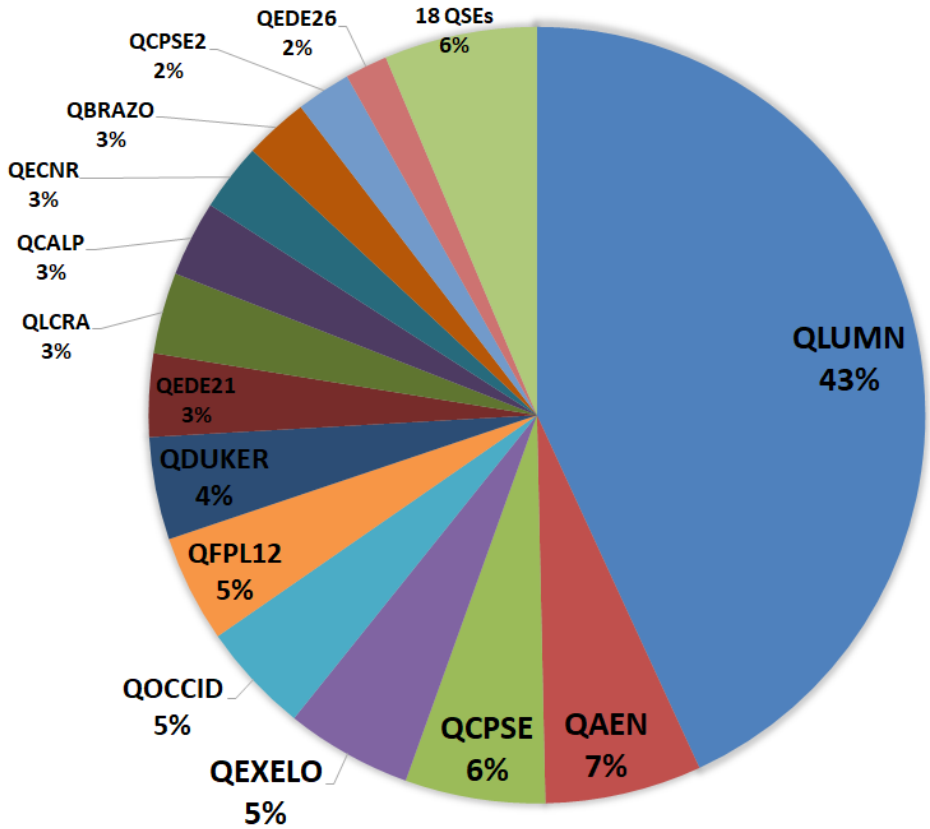


Figure A27 above shows the distribution for regulation up reserve service providers and Figure A28 shows the distribution for regulation down reserve providers in 2019. Figure A27 shows that regulation up was spread fairly evenly, similar to responsive reserve providers, while Figure A28 shows that that regulation down had similar concentration to non-spinning reserves in 2019. Again, Luminant had a dominant position in the provision of regulation down. Its 43% share of the regulation down responsibility in 2018 was higher than in preceding years (41% in 2018, 25% in 2017 and 10% in 2016).

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, 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 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 2019. A SASM was executed 22 times in 2019, with SASM awards providing 168 service-hours. SASMs were almost equally frequent in 2019 and 2018, where 2018 awarded 245 service-hours.

Figure A29 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years. The volume of service-hours procured via SASM over the year (more 3,500 MWs of service-hours in 2019) is still infinitesimal when compared to the total ancillary service requirement of nearly 43 million MWs of service-hours.

Figure A29: Ancillary Service Quantities Procured in SASM

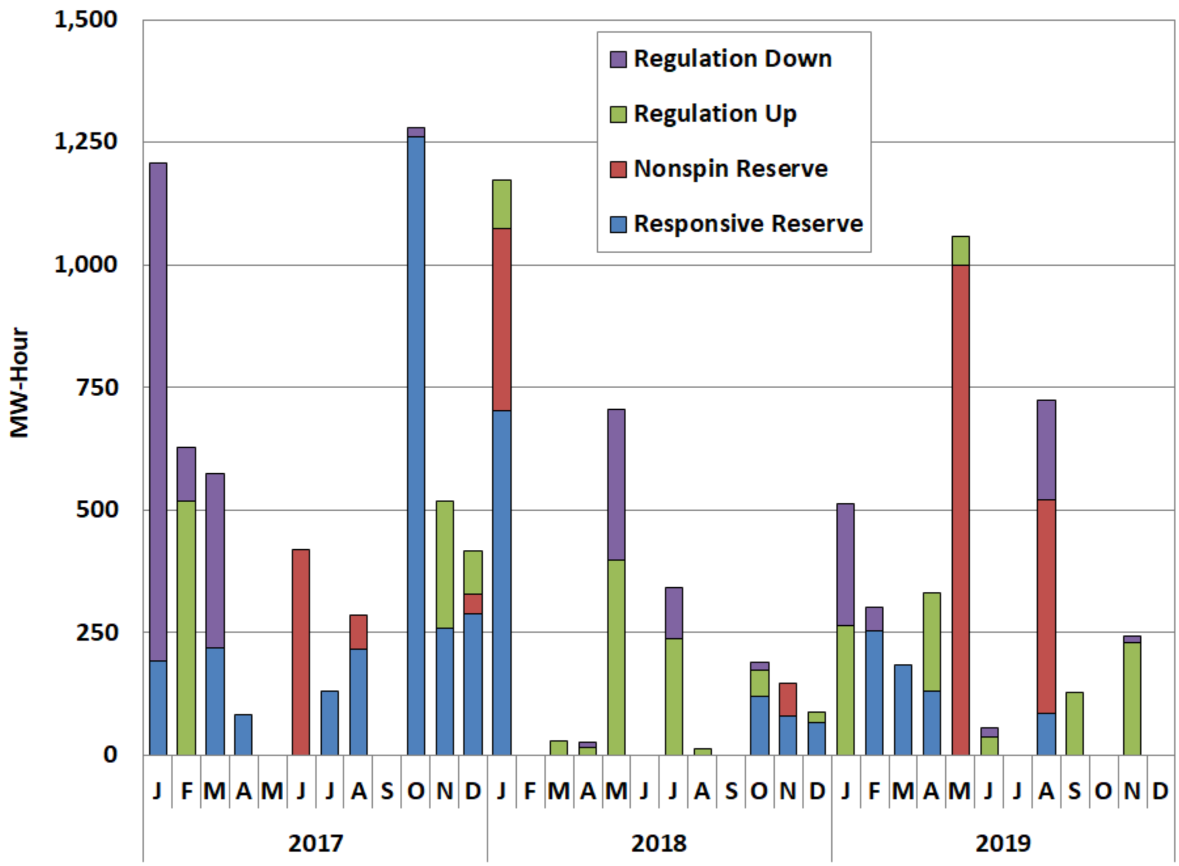
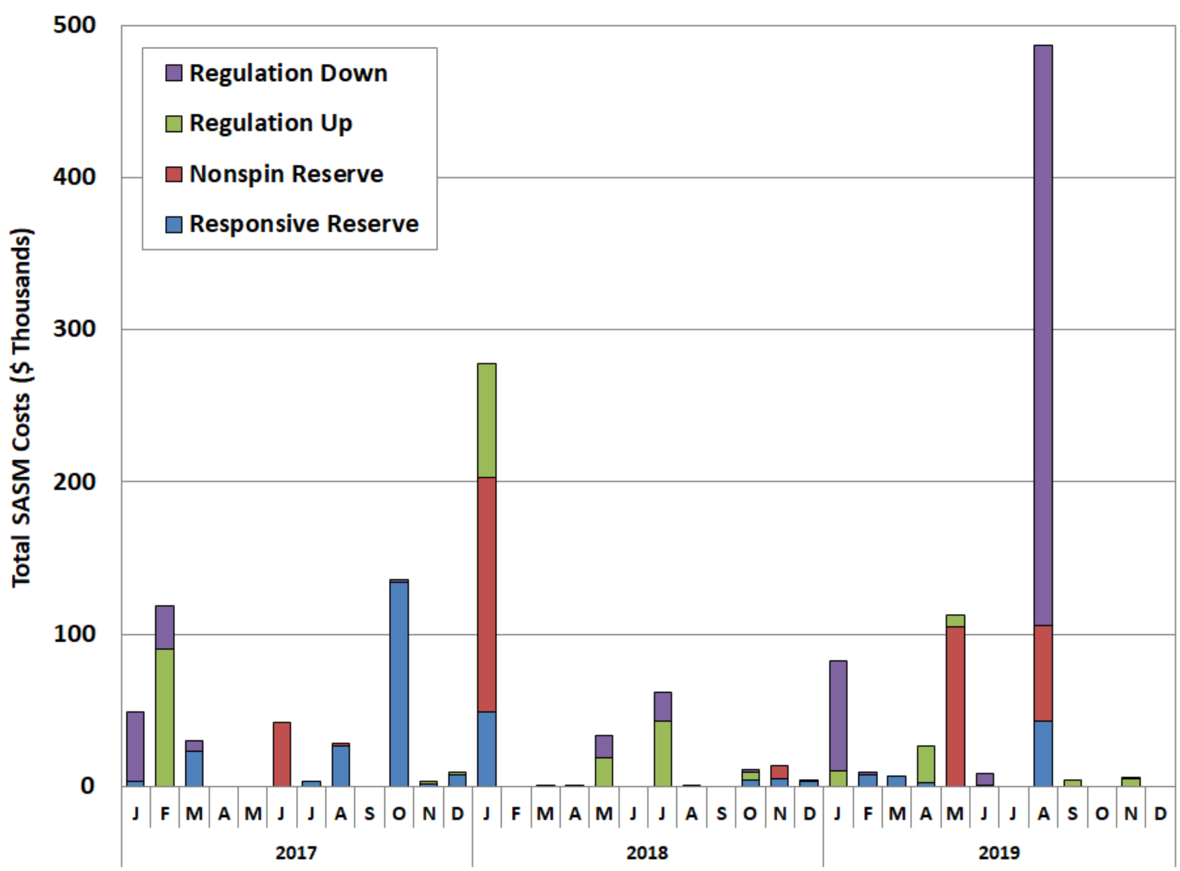


Figure A30 shows the average cost of the replacement ancillary services procured by SASM in 2019. Total SASM costs in August of 2019 were by far the highest SASM costs seen since the beginning of 2017. August 2019 saw high temperatures and very high energy prices, particularly during the week of August 12. Under such conditions, resources might be diverted to provide energy rather than reserves, thus raising the cost of ancillary services. If a resource had reserve responsibilities under those tight 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.

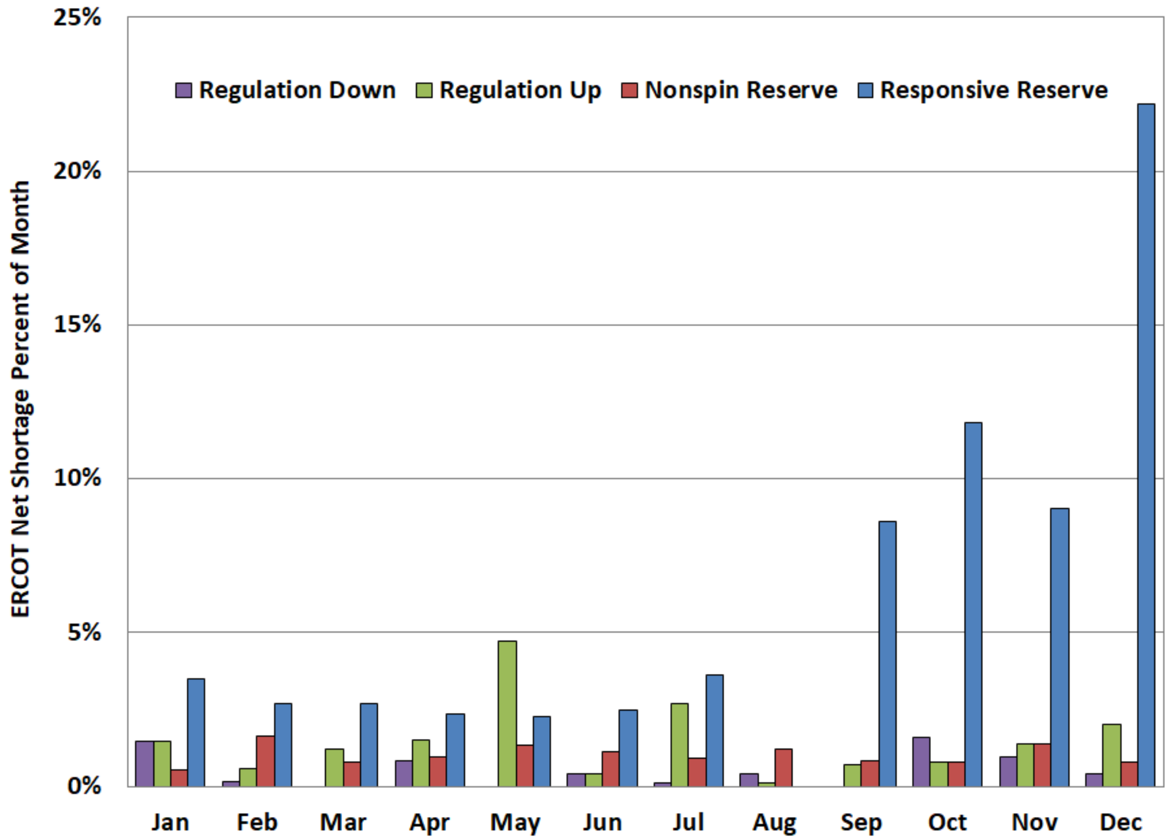
Figure A30: Average Costs of Procured SASM Ancillary Services



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 2019 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 considerably lower in 2019 compared to 2018, generally below 5% in all months for all services, although responsive reserve experienced slightly higher shortages during the fall months, occurring in more than 10% of hours in October and December. Again, this analysis is based on the telemetered status provided by the parties with the responsibility.

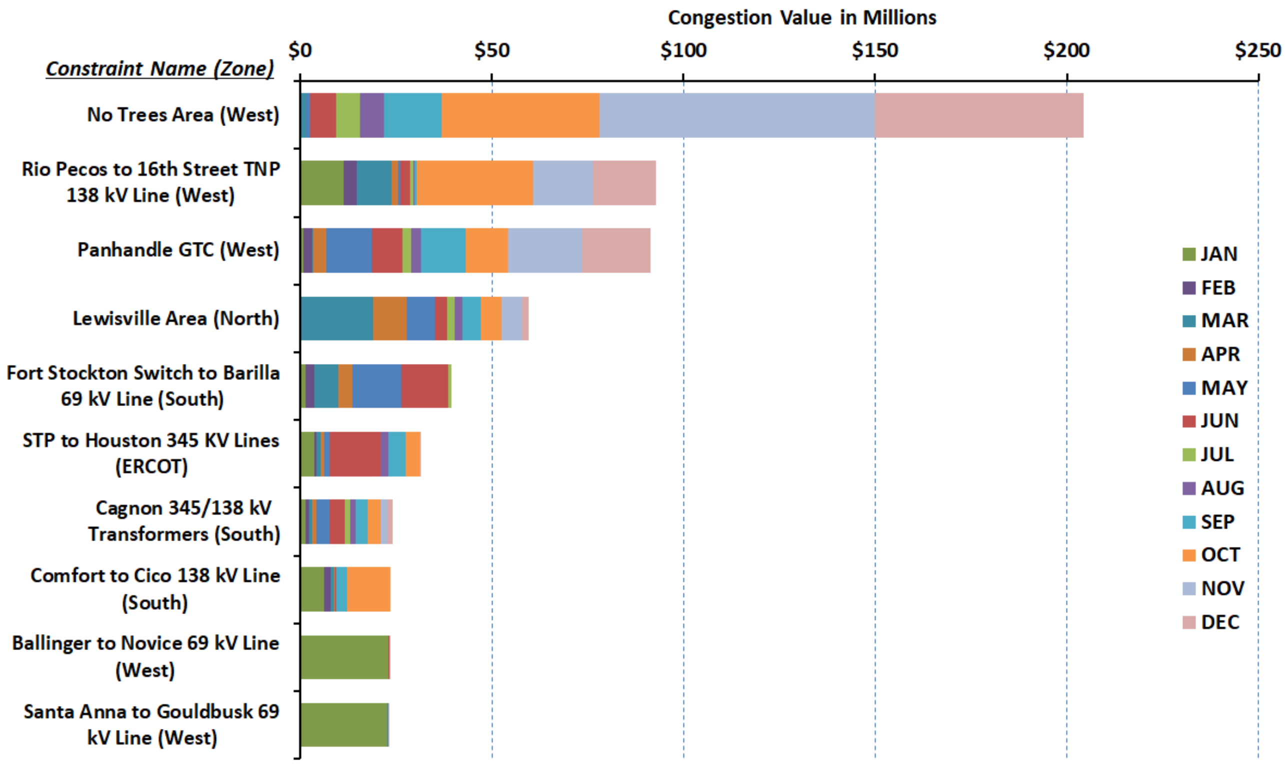
IV. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2019, 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 2019. Figure A32 presents the ten most congested areas from the day-ahead market, ranked by their value. Seven of the constraints listed here were described in Figure 30: 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 third year in a row, the majority of the costliest day-ahead constraints in 2019 were also costly real-time constraints. Aside from the Lewisville area and Fort Stockton Switch to Barilla, 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 three other constraints are prime examples that would not have incurred similar real-time congestion costs seen from the day-ahead: Cagnon 345/138 kV transformers, Ballinger to Novice, and Santa Anna to Gouldbusk 69 kV lines. The Cagnon constraint is a combination of the high and low side of the transformer. The other two are a representation of a series of two lines: Ballinger to Humble to Novice and Santa Anna to Coleman Junction to Gouldbusk. Only one of the pairs of contingency and overloaded element would be active in real-time at a time for each group due to constraint filtering procedures in place.

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 2019

Our review of the active and binding constraints in 2019 is shown in Figure A33 and Figure A34.

Figure A33: Frequency of Binding and Active Constraints

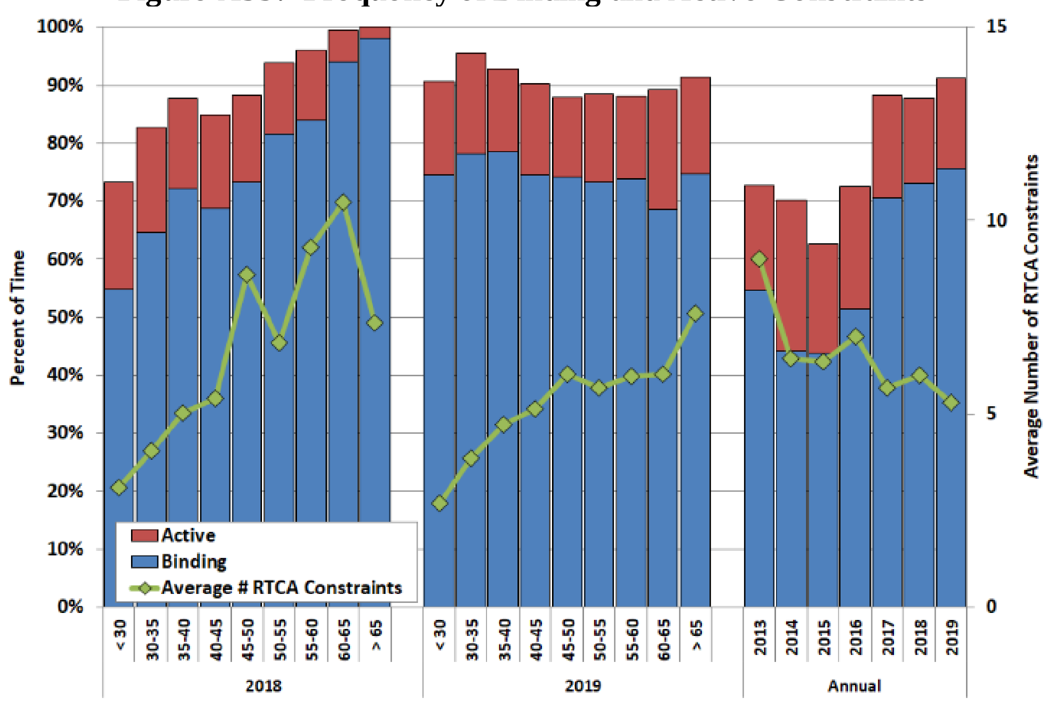
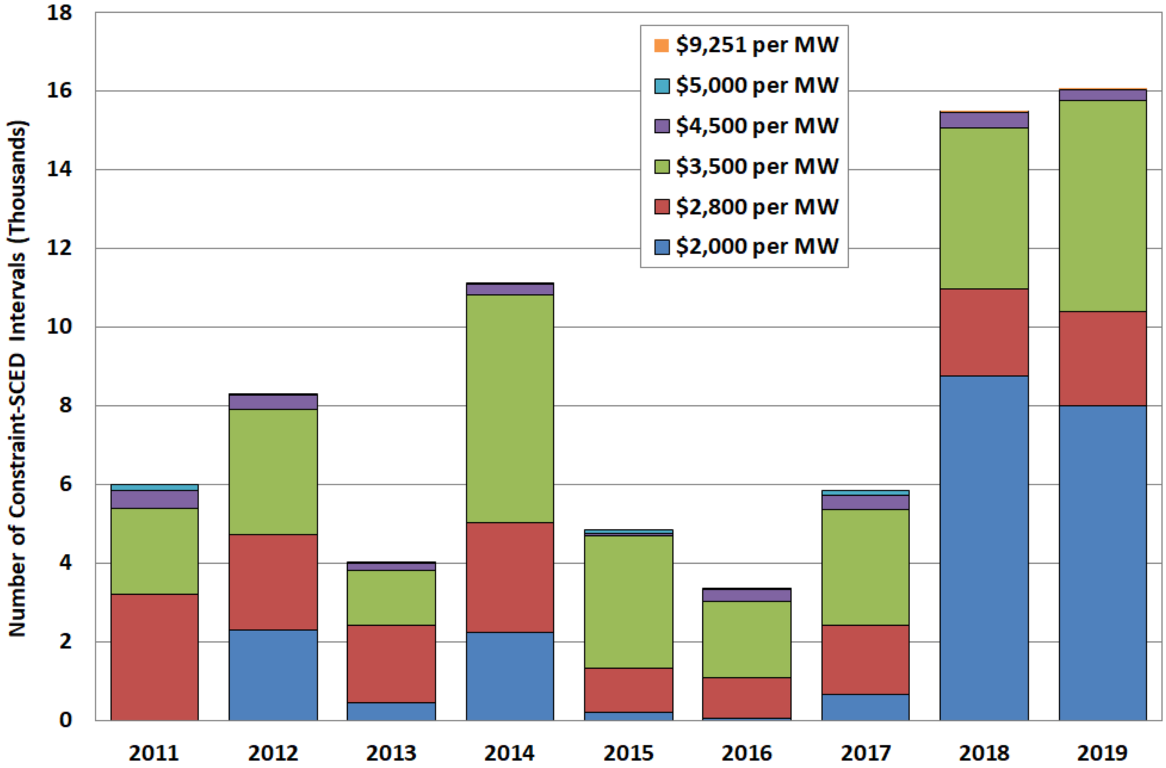


Figure A34 below depicts constraints were violated (i.e., at maximum shadow prices) slightly more frequently in 2019 than they were in 2018. The majority of the violated constraints occurring at the $2,000 per MW value were related to the Dollarhide to No Trees 138 kV line irresolvable element. Violated constraints continued to occur in only a small fraction of all of the constraint-intervals, 8% in 2018, up from 3% in 2017.

Figure A34: Frequency of Violated Constraints



A GTC was binding in 16% of the time in 2019 compared to 15% in 2018. GTCs are used to ensure that the generation dispatch does not violate a transient or voltage stability condition. Table A2 below shows the GTCs that were binding in real-time.

Table A2: Generic Transmission Constraints

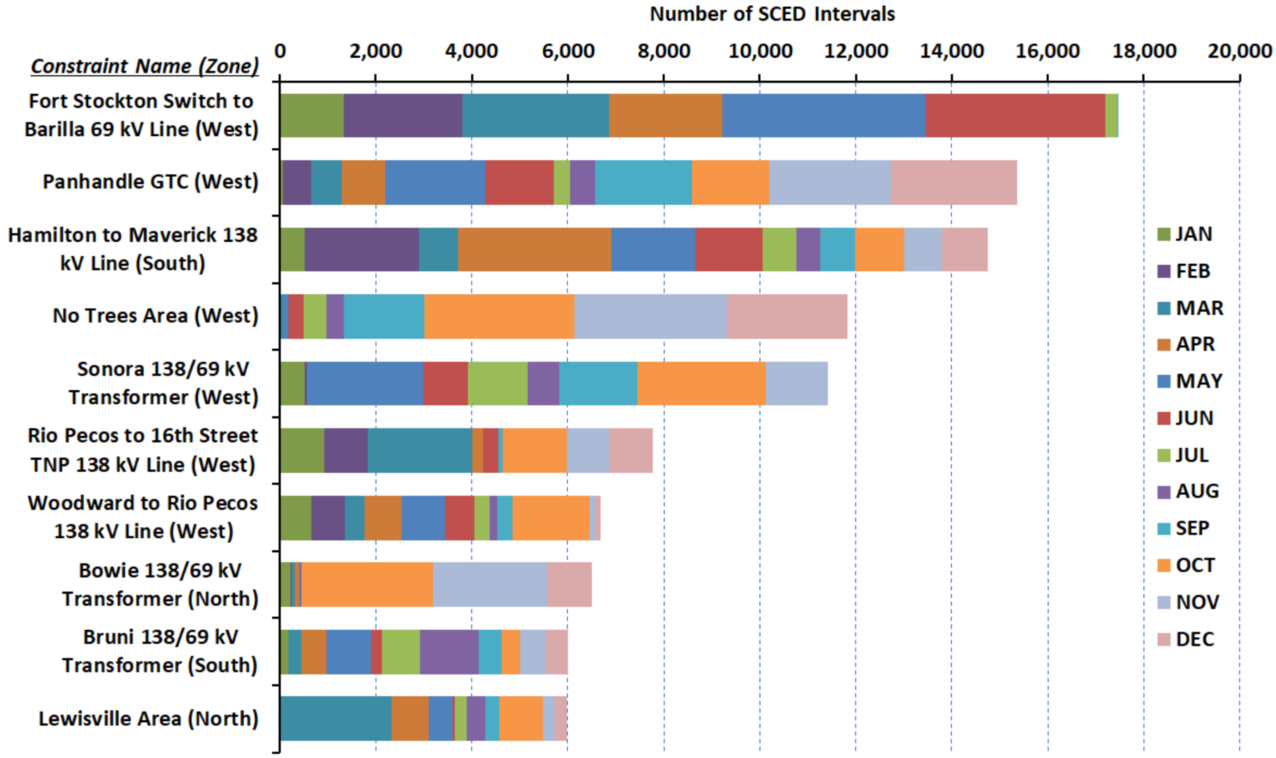
Generic Transmission Constraint	Effective Date	# of Binding Intervals in 2019
Panhandle	July 31, 2015	15,352
Treadwell	May 18, 2018	1,539
Raymondville - Rio Hondo	May 2, 2019	385
East Texas	November 2, 2017	155
North Edinburg - Lobo	August 24, 2017	59
Bearkat	November 20, 2019	14
McCamey	March 26, 2018	3
North to Houston	December 1, 2010	-
Rio Grande Valley Import	December 1, 2010	-
Red Tap	August 29, 2016	-
Nelson Sharpe - Rio Hondo	October 30, 2017	-

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 Lakepoint to Carrollton Northwest, the West TNP to TI TNP, and the Lewisville to Jones Street TNP 138 kV lines. The congestion values for these constraints reduced by 50% since 2018 at $51 million. Eagle Mountain to Morris Dido 138 kV line is one-line segment of the Eagle Mountain congested area in 2018, which was the fourth most costly, a 50% reduction in value at $28 million. The activation of constraints in the Panhandle GTC, Lewisville area, 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, the congestion appears to be shifting from one local area to the next when upgrades are completed.

All constraints listed in Figure A35 were frequently constrained due to variable renewable output. Five of the ten most frequently occurring constraints in 2019 were also among the ten most costly constraints, consisting of Fort Stockton to Barilla 69 kV line, Panhandle GTC, No Trees Area, Rio Pecos to 16th Street 138 kV line, and Lewisville Area. The other half of the most frequent constraints aggregated more than $50 million in congestion value.

Figure A35: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

Shadow price caps are based on a reviewed methodology,[60] 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.

As shown in Table A3, 12 elements were deemed irresolvable in 2019 and had a shadow price cap imposed according to the irresolvable constraint methodology. Two constraints, the Emma to Holt Switch 69 kV line and Yucca Drive Switch to Gas Pad 138 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, which is located in the South zone. The Fort Stockton Switch to Barilla 69 kV line constraint, located in far west Texas, was deemed irresolvable in January 2018. The area was also impacted by solar

60 Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (ERCOT Board Approved June 11, 2019, effective June 12, 2019), 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.

installations and Permian Basin load development. While the constraint was deemed irresolvable, the shadow price cap was not lowered for 2018, so its status as irresolvable had no impact. However, in 2019, the constraint reached the threshold in which the maximum shadow price was reduced to 2,000 per MWh in May. This constraint was also the most frequently activated in SCED for 2019. There is a future project planned to upgrade the 69-kV line to 138 kV identified in ERCOT's *2018 Constraints and Needs Report.*[61]

Table A3: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price	2019 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2019
Base Case	Valley Import	$9,251	$2,000	1/1/12	-	South	-
SMDFHLT8/ SBAKHL48	Emma to Holt Switch 69 kV Line	$2,800	$2,000	10/27/14	1/30/19	West	-
SSOLFTS8	Barilla to Fort Stockton Switch 69 kV Line	$2,800	$2,800	1/1/18	5/12/19	West	2,950
		$2,800	$2,000	5/13/19	-	West	6,302
DCASTXR8	Moore to Hondo Creek Switching Station 138 kV Line	$3,500	$2,549	1/2/18	-	West	-
SWINYUC8	Wickett TNP to Winkler County 6 TNP 69 kV Line	$2,800	$2,000	4/9/18	-	West	-
SWCSBOO8	Yucca Drive Switch – Gas Pad 138 kV line	$3,500	$2,000	5/4/18	1/30/19	West	-
SJUNYEL9	Yellow Jacket to Hext LCRA 69 kV line	$2,800	$2,000	5/18/18	-	West	-
XFRI89	Sonora 138/69 kV Transformer	$2,800	$2,000	5/24/19	-	West	2,970
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	$2,800	$2,000	9/23/19	-	West	996
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	10/15/19	-	West	5,317
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	10/23/19	-	West	2,107
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	$2,800	$2,000	11/29/19	-	West	391

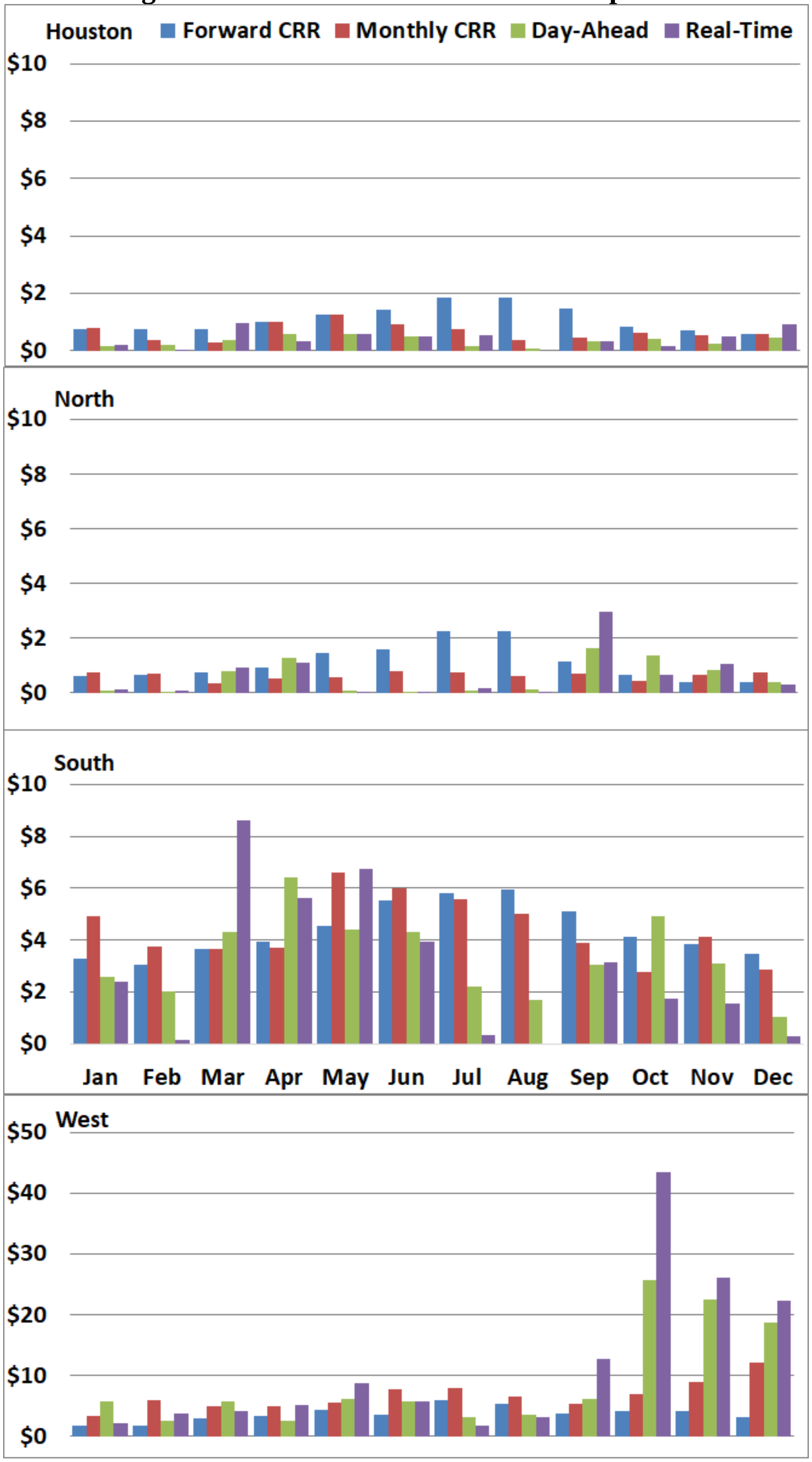
C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A36 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.

61 The percentages of installed capacity to serve peak demand assume availability of 29% for panhandle wind, 63% for coastal wind, 16% for other wind, and 76% for solar.

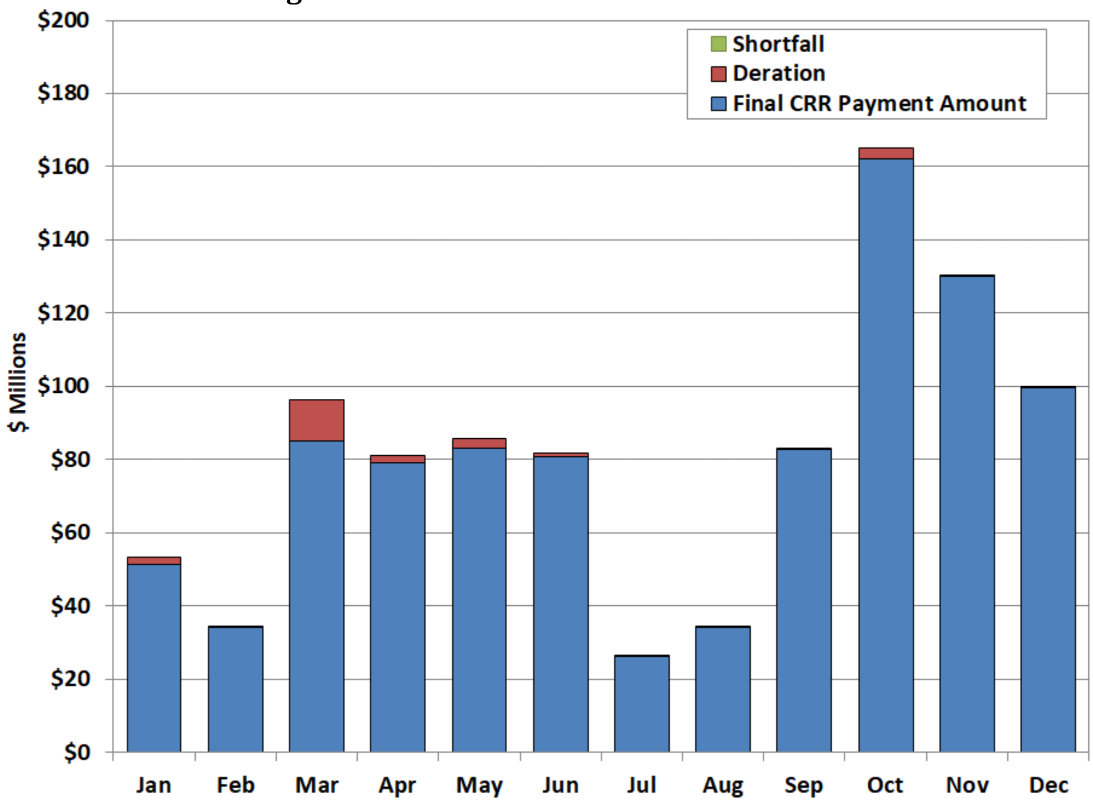
Figure A36: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A37 shows the amount of target payment, deration amount, and final shortfall for 2019. In 2019, the total target payment to CRRs was $972 million; however, there were $23 million of derations and no non-refunded shortfall charges resulting in a final payment to CRR account holders of $949 million. This final payment amount corresponds to a CRR funding percentage of 97.6%, slightly higher than the funding percentage of 95% in 2018.

Figure A37: CRR Shortfall and Derations



V. APPENDIX: RELIABILITY UNIT COMMITMENTS

In this section, we provide supplemental analyses of RUC activity in 2019 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 "claw-back" provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the claw-back charges, effectively self-committing and accepting the market risks associated with that decision. This buyback or "opt-out" mechanism for RUC initially required a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.

On June 25, 2015, ERCOT automated the RUC offer floor of $1,500 per MWh and implemented the Real-Time On-Line Reliability Deployment Adder (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.

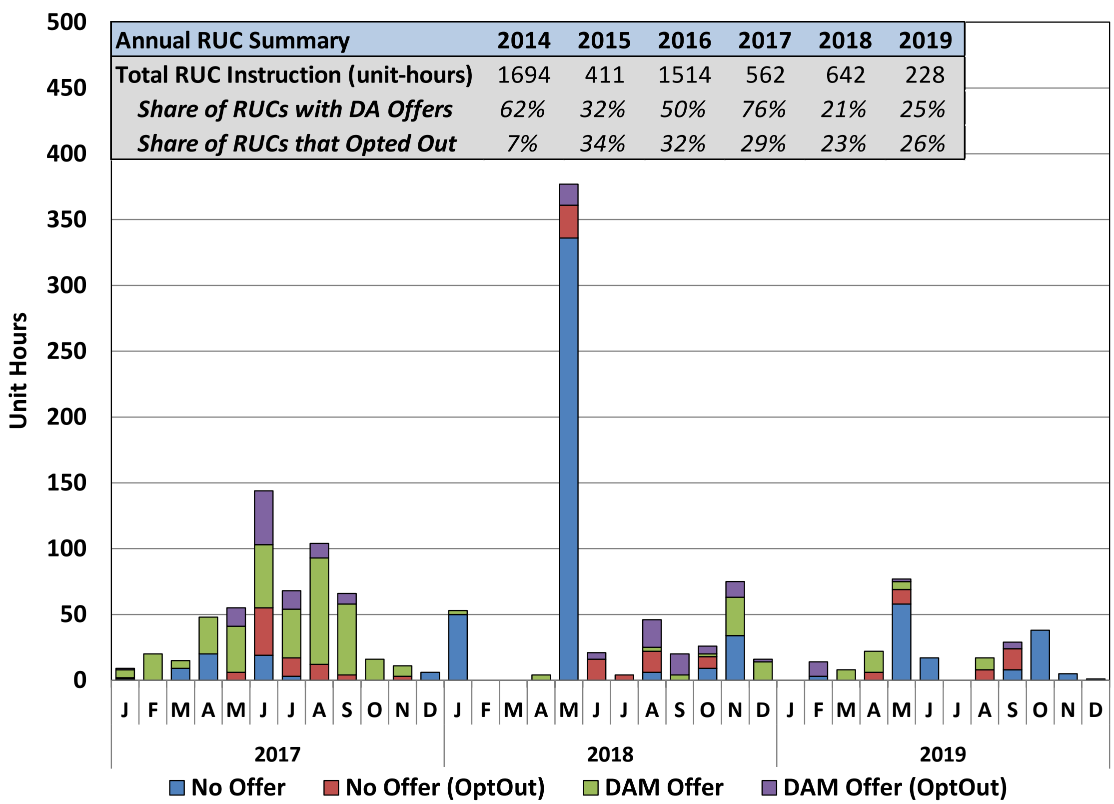
In 2018, the RUC engine was modified to consider fast-start generators (those with a start time of one hour or less) as self-committed for future hours, allowing ERCOT to defer supplementary commitment decisions, and allowing market participants full opportunity to make their own unit commitment decisions. 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. And finally, 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.

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 A38 below shows RUC activity by month for 2017 through 2019, 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.

Figure A38: Day-Ahead Market Activity of Generators Receiving a RUC



Annual RUC Summary	2014	2015	2016	2017	2018	2019
Total RUC Instruction (unit-hours)	1694	411	1514	562	642	228
Share of RUCs with DA Offers	*62%*	*32%*	*50%*	*76%*	*21%*	*25%*
Share of RUCs that Opted Out	*7%*	*34%*	*32%*	*29%*	*23%*	*26%*

Table A4 below lists the generation resources that received the most RUC instruction in 2019 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 2018. ERCOT issued frequent RUC instructions to the Permian Basin units due to localized transmission congestion related to high area loads, intermittent generation, and line outages.

Table A4: 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
Permian CT 1	Far West	53	0	41	41	48	70
Permian CT 2	Far West	46	0	41	41	55	70
Nueces Bay CC1	Corpus	8	11	134	216	222	318
Mountain Creek Unit 7	DFW	16	0	15	15	15	118
Permian CT 4	Far West	14	0	41	41	45	66
Tenaska CC1	North	3	9	116	123	191	200
Lake Hubbard Unit 2A	DFW	0	12	110	288	324	518
Stryker Unit 2	DFW	3	4	35	317	409	468
Jack County CC1	DFW	6	0	165	172	180	264
Permian CT 5	Far West	6	0	41	44	70	75
Braunig VHB1	San Antonio	0	6	62	106	134	217
Duke CC1	Valley	0	6	157	155	162	248
Silas Ray 10	Valley	0	3	20	20	36	38
Frontier CC1	Bryan	3	0	365	500	504	629
Laredo Unit G5	Laredo	0	2	35	35	90	90

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) seven months in 2019.
- No RUC activity occurred in January or July.
- In May, October, November, and December 2019, the average dispatch level was more than the average low limit because of mitigation of the resource.
- Also, in both May and September, the average dispatch level was higher due to RUC resources choosing to opt out and thus not being subject to the $1,500 per MWh offer floor.

- Real-time system-wide scarcity in August and September caused RUC resources that did not opt out to have an average dispatch above average LSL.

Figure A39: Reliability Unit Commitment Capacity

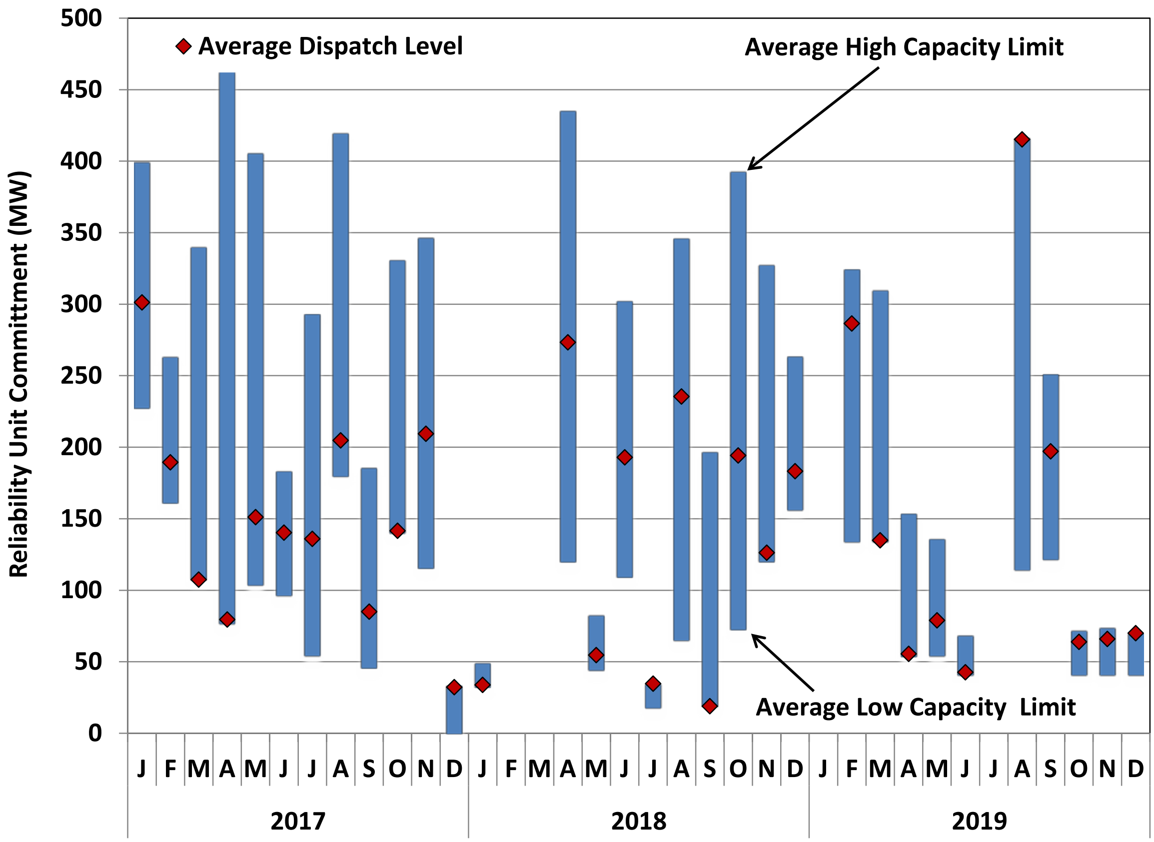


Figure A39 shows in 40% of intervals with RUC resources, one or more resources were dispatched above their low dispatch limit (LDL), whereas in prior years, resources receiving a RUC were infrequently dispatched above LDL, an increase from 27% of the intervals in 2018. This higher dispatch level indicates that most units receive RUC instructions to resolve local constraints, and that these local constraints are non-competitive. As a result, units are 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 2019, this occurred in only 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 A40: Large Supplier Capacity Commitment Timing – July and August Hour Ending 17

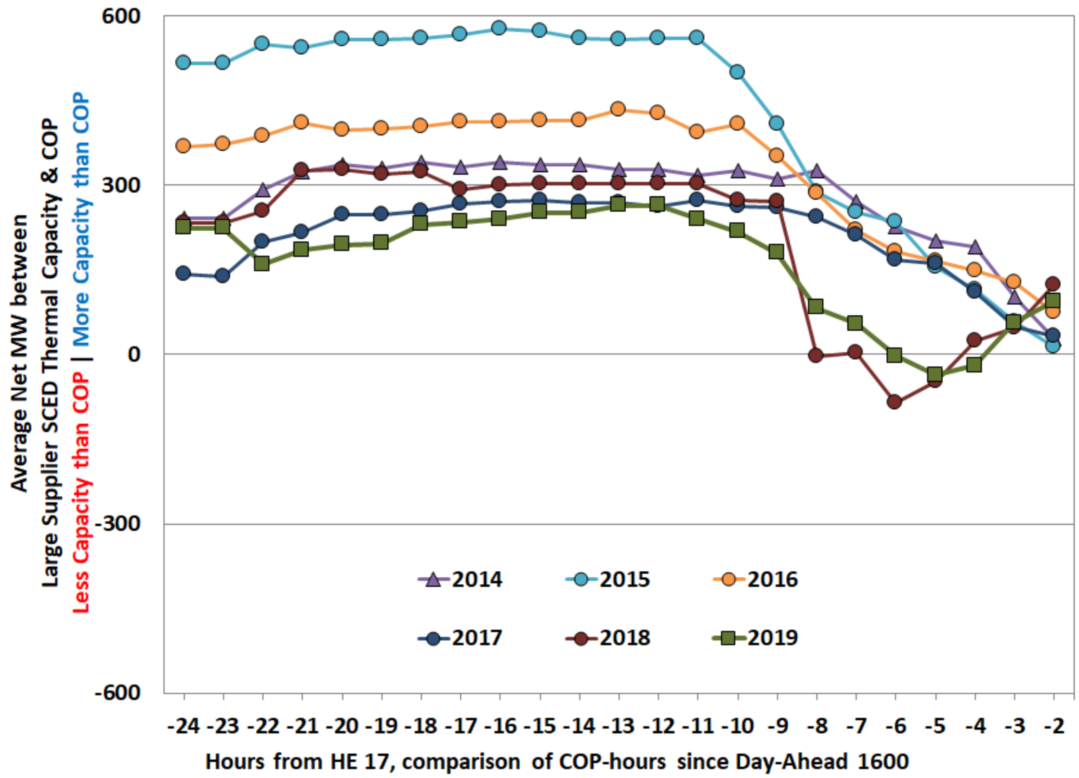
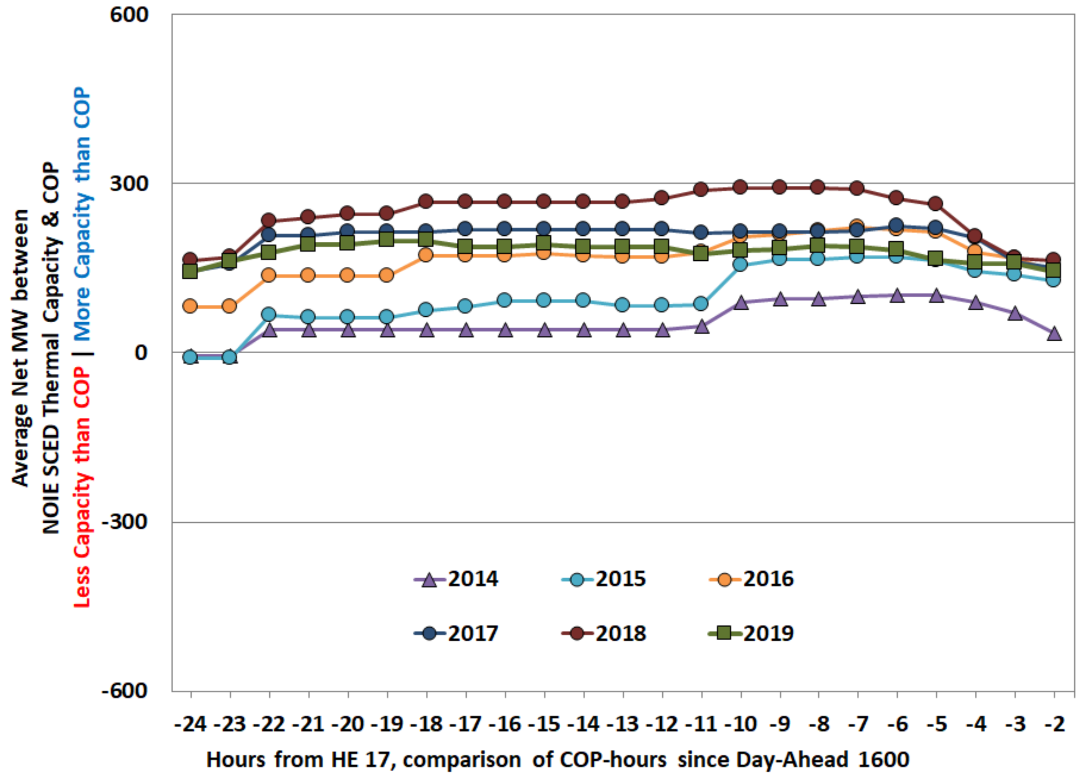


Figure A41: NOIE Capacity Commitment Timing – July and August Hour Ending 17

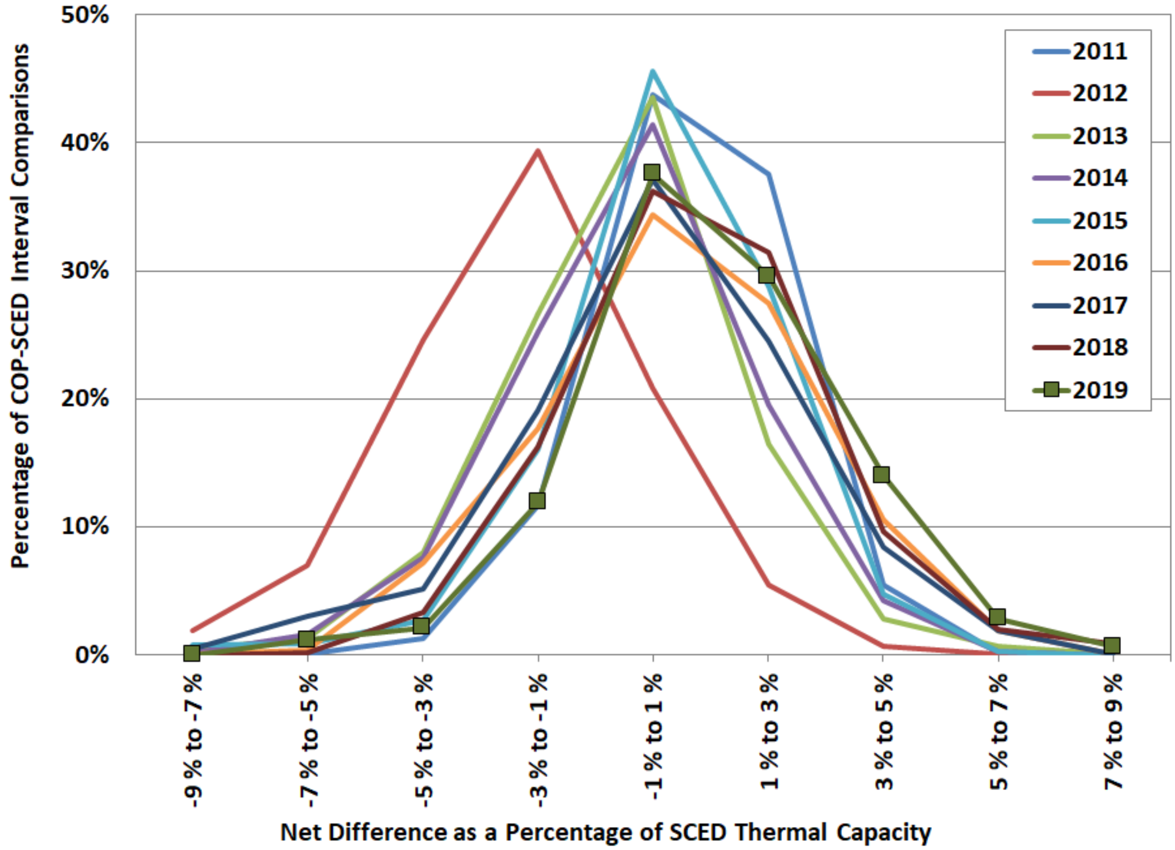


The next set of analyses quantify the difference between the aggregated capacity commitments as described by all the COP submissions, and the actual capacity commitments as a percentage of the actual capacity observed in real-time. These analyses are limited to the peak hours of 12 through 20 for the 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 A42 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. A trend of having less thermal SCED capacity materialize than expected via the COP below -1% percentage error continued through 2014, but the frequency peaks are within the 1% percentage error. In 2015, 45.6% of the COP-SCED interval comparisons were within 1% of the SCED thermal capacity, the highest since 2011, and shifted to seeing more thermal SCED capacity materialize than what was shown in the COP. 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 21.2% were greater than 3%.

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 curves from 2018 and 2019 are similar, with 2019 exhibiting a slightly bigger contrast.

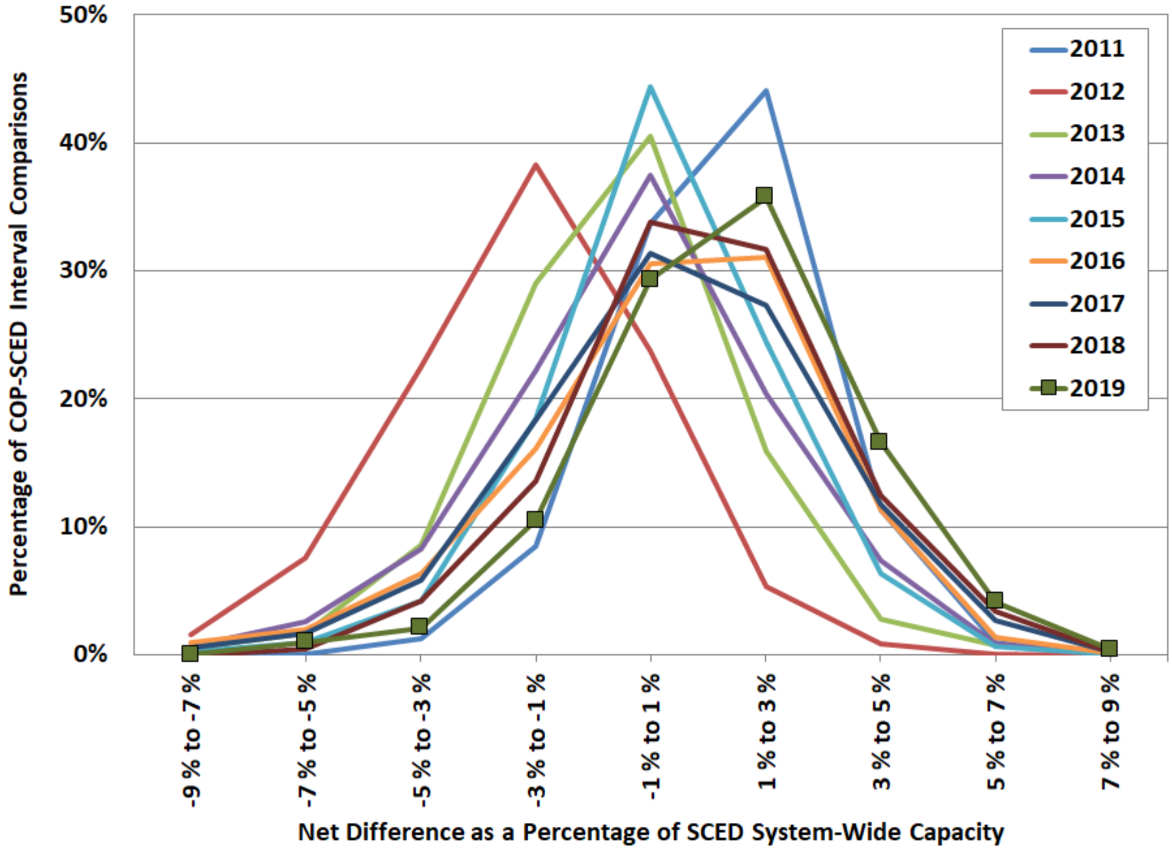
Figure A42: Real-Time to COP Comparisons for Thermal Capacity



One explanation for this trend is the accuracy of the load forecast improving and the changes in market behavior resulting in representing less capacity from the day ahead 1600 COP to the end of the adjustment period. Another explanation for COP under-reporting includes resources that were currently on startup or shutdown before and after their operating periods, additional capacity available from power augmentation not being shown in the COP value, offline non-spin resources deploying, resources coming online responding to market activity, or combined cycle resources increasing their configuration size.

Figure A43 summarizes the same analysis as above, but for system-wide capacity. The most interesting difference between Figure A42 and Figure A43 is the shift in the peak for years 2011 and 2019, where more than 30% of the COP-SCED intervals analyzed were in the 1% to 3% error category. In 2011, the shift was the result of the combination of the wind contribution and the increase in thermal capacity coming online to meet the higher expected load in July and August. In 2019, the shift is more largely attributed to the increase in renewables, both wind and solar, in HE 12 through HE 20. In 2011, the difference was due to installed capacity of about 9 GW of wind to about 30 GW in 2019 for wind and solar.

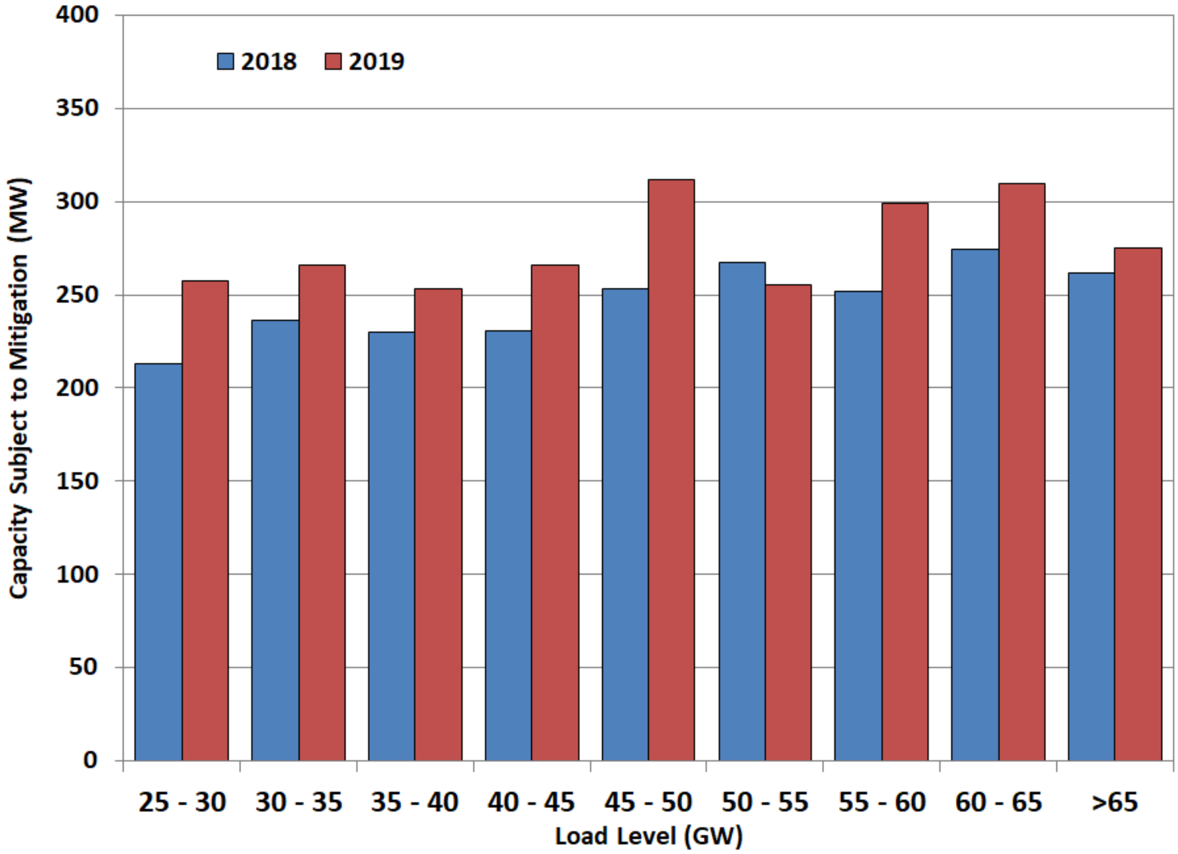
Figure A43: Real-Time to COP Comparisons for System-Wide Capacity



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 A44.

Figure A44: Capacity Subject to Mitigation



As in the prior analysis, the amount of capacity subject to mitigation in 2019 was higher than 2018 in all but the 50 to 55 GW load level. As described previously, the reduction may be explained by the overall higher costs in 2019 and the separation in natural gas prices between Fuel Index Price and Waha. 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.

E. Reliability Must Run and Must Run Alternative

On May 23, 2019, ERCOT received a Notification of Suspension of Operations (NSO) for West Texas Wind Energy Partners, LP's Southwest Mesa (SW_MESA_SW_MESA) Generation Resource. The NSO indicated that the Resource Entity would decommission and retire the generation resource permanently on November 15, 2019. The NSO further indicated that Southwest Mesa (SW_MESA_SW_MESA) has a summer Seasonal Net Max Sustainable Rating of 80 MW, and a summer Seasonal Net Minimum Sustainable Rating of 0 MW.

On June 28, 2019, ERCOT received a Notification of Change of Generation Resource Designation (NCGRD) for the City of Garland's Gibbons Creek Generating Station

(GIBCRK_GIB_CRG1). The NCGRD stated that this resource, which was under a mothballed status, would change to a status of decommissioned and retired permanently as of October 23, 2019. Gibbons Creek is a 470 MW coal unit located in Grimes County (20 miles southeast of College Station) and owned by the Texas Municipal Power Agency (TMPA), which is an organization jointly owned by four municipalities – the cities of Garland, Denton, Bryan and Greenville.

Finally, on July 29, 2019, ERCOT received an NSO for Gregory Power Partners, LLC's LGE Generation Resources.[62] The NSO indicated that these Resources would suspend operations on a year-round basis (i.e., mothball) beginning October 17, 2019, with a Seasonal Operation Period of June 1 through September 30. The NSO further indicated that these Resources have a summer Seasonal Net Max Sustainable Rating of 365 MW, and a summer Seasonal Net Minimum Sustainable Rating of 195 MW.

62 LGE_LGE_GT1, LGE_LGE_GT2 and LGE_LGE_STG.

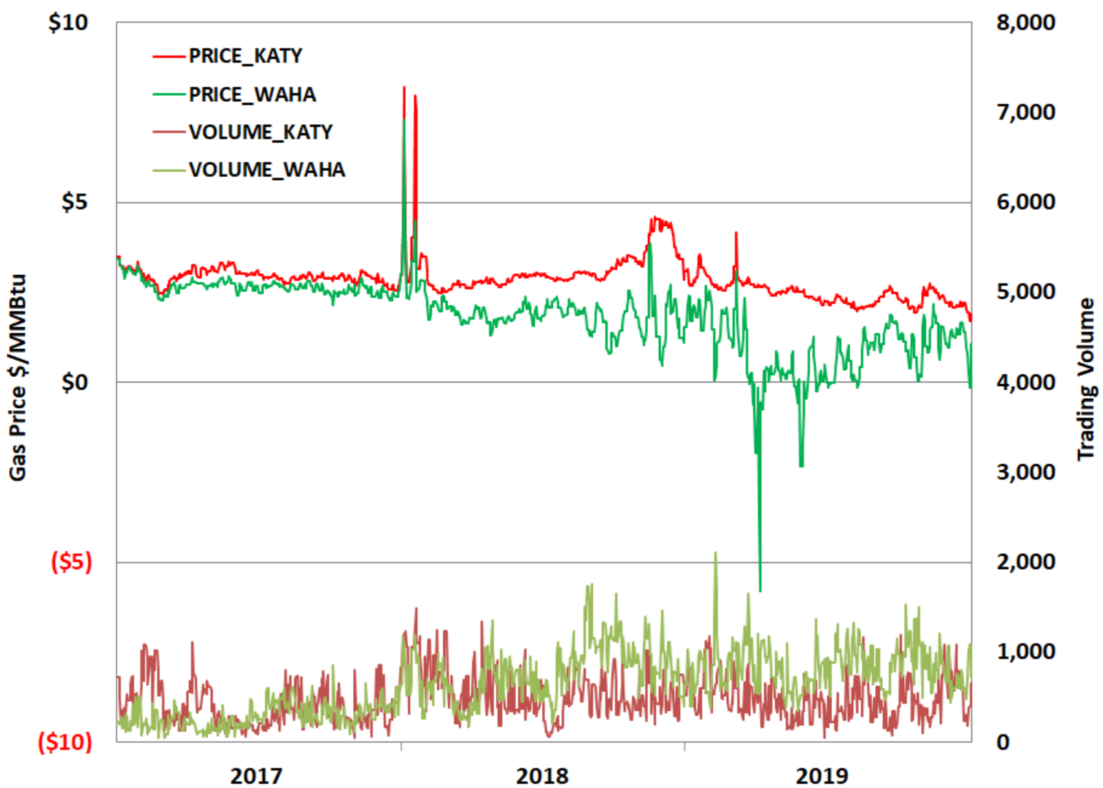
VI. Appendix: Resource Adequacy

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 2019, we saw a continuing trend evident of the growing separation in natural gas prices between the Waha and Katy locations in the West.[63] Increased 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 A45 below, Waha prices dipped below $0 multiple times throughout 2019, and were more volatile than Katy.

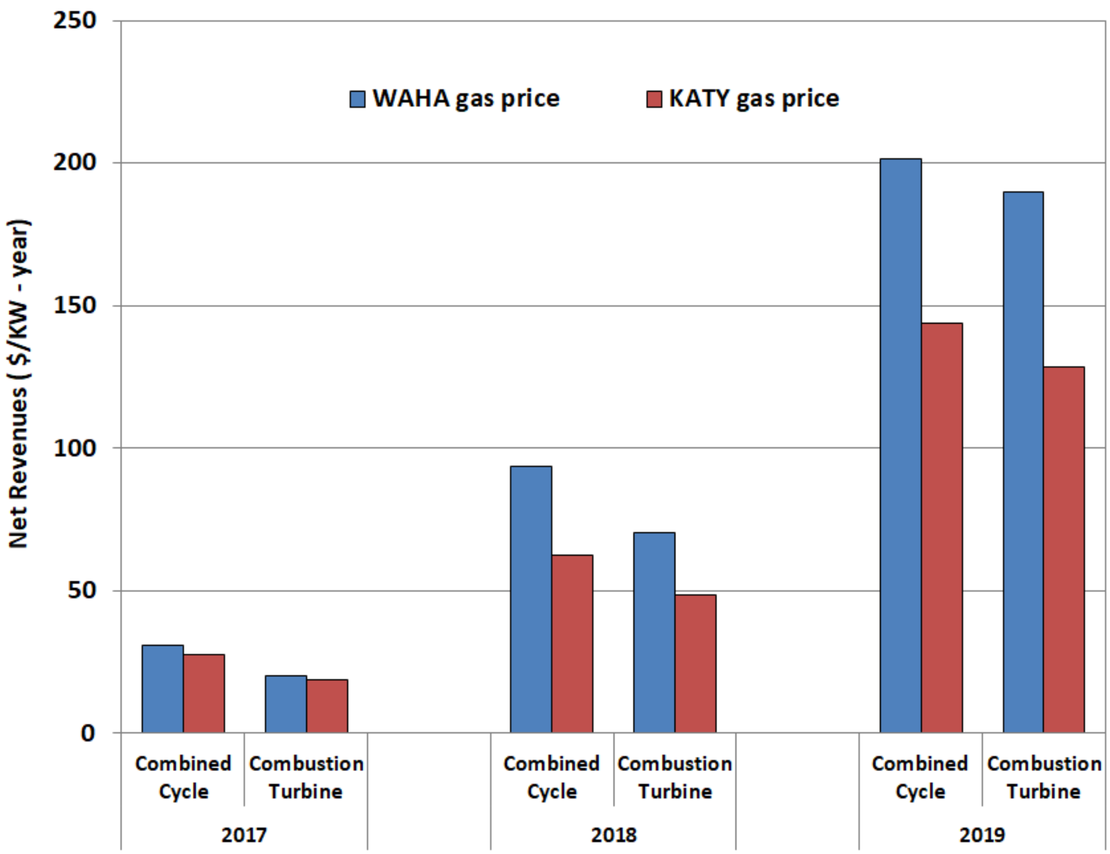
Figure A45: Gas Price and Volume by Index



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

Historically, resources in the West zone have had lower net revenues that resources in the other zones, but that was not the case in 2019. Additionally, the divergence between Waha and Katy gas prices contributed to even greater net revenues for West Texas gas-fired generators. Figure A46 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 significantly higher than in the other three zones.

Figure A46: West Zone Net Revenues



VII. Appendix: Analysis of Competitive Performance

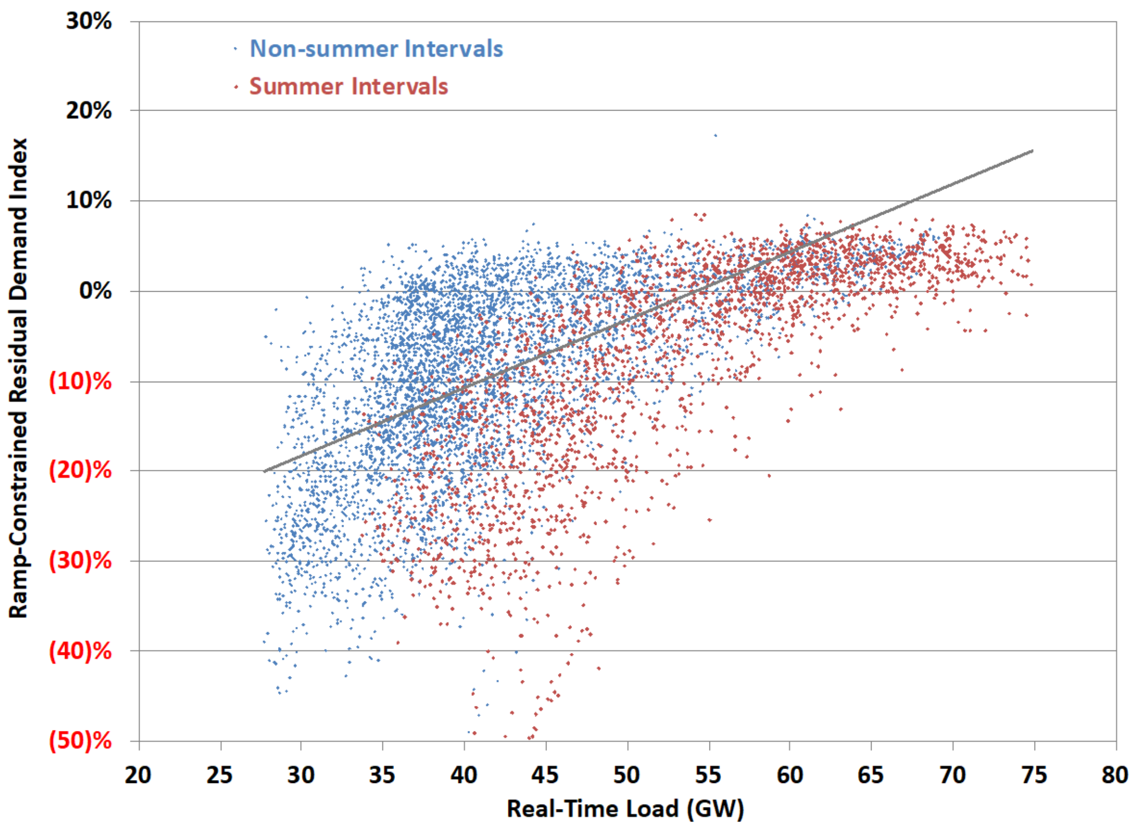
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a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

Figure A47 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2019. 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 35 GW. The trend line indicates a strong positive relationship between load and the RDI.

Figure A47: Residual Demand Index



1. Voluntary Mitigation Plans

Calpine's VMP was approved in March of 2013.[64] 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,[65] 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.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A48 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2019.

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

65 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).

Figure A48: Short-Term Outages and Deratings

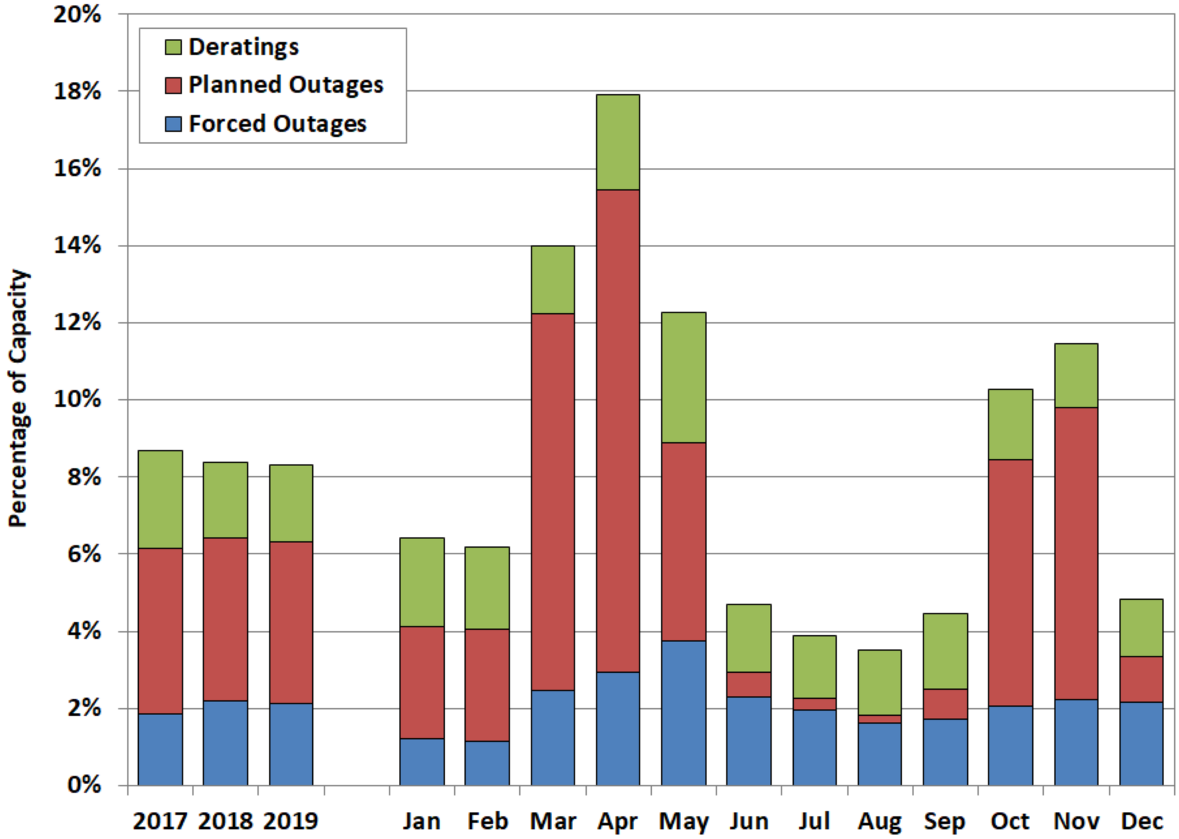


Figure A48 shows that short-term outages and deratings in 2019 followed a pattern similar to what occurred in 2018, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2019 were almost 18% of installed capacity in April (up from 14% in 2018) and dropped to less than 4% during July and August (the same as in 2018).

Most of this fluctuation was due to planned outages. The amount of capacity unavailable during 2019 averaged 8.3% of installed capacity, a modest decrease from the 8.4% experienced in 2018, and 8.7% experienced in 2017. The numbers of planned outages remained steady in 2019, 4.2% on average for both 2018 and 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.