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Re: *Docket No. 34677 — REPORTS OF THE INDEPENDENT MARKET MONITOR FOR THE ERCOT REGION*

Ms. Trevino:

Potomac Economics, the Independent Market Monitor for ERCOT, submits the enclosed 2019 State of the Market Report as requested, filed May 29, 2020 in Docket No. 34677, *REPORTS OF THE INDEPENDENT MARKET MONITOR FOR THE ERCOT REGION.*

Thank you for your prompt assistance with this matter.

Sincerely,

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2019 State of the Market Report for the ERCOT Electricity Markets

POTOMAC ECONOMICS

Independent Market Monitor
for ERCOT

May 2020

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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.

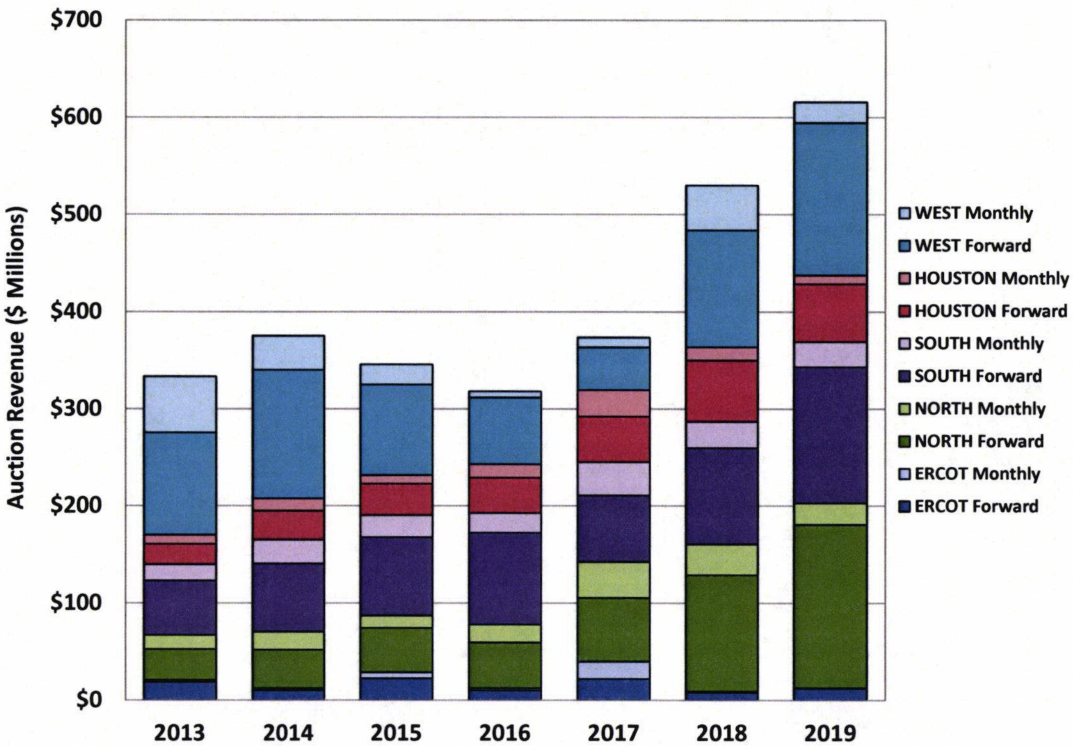
The congestion costs in ERCOT's day-ahead and real-time markets in 2019 totaled $1.1 and $1.26 billion, respectively. These values were comparable to congestion in 2018, the largest share of which was in the West zone in both years. Congestion fell in the North and Houston zones, but increased in the 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.

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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

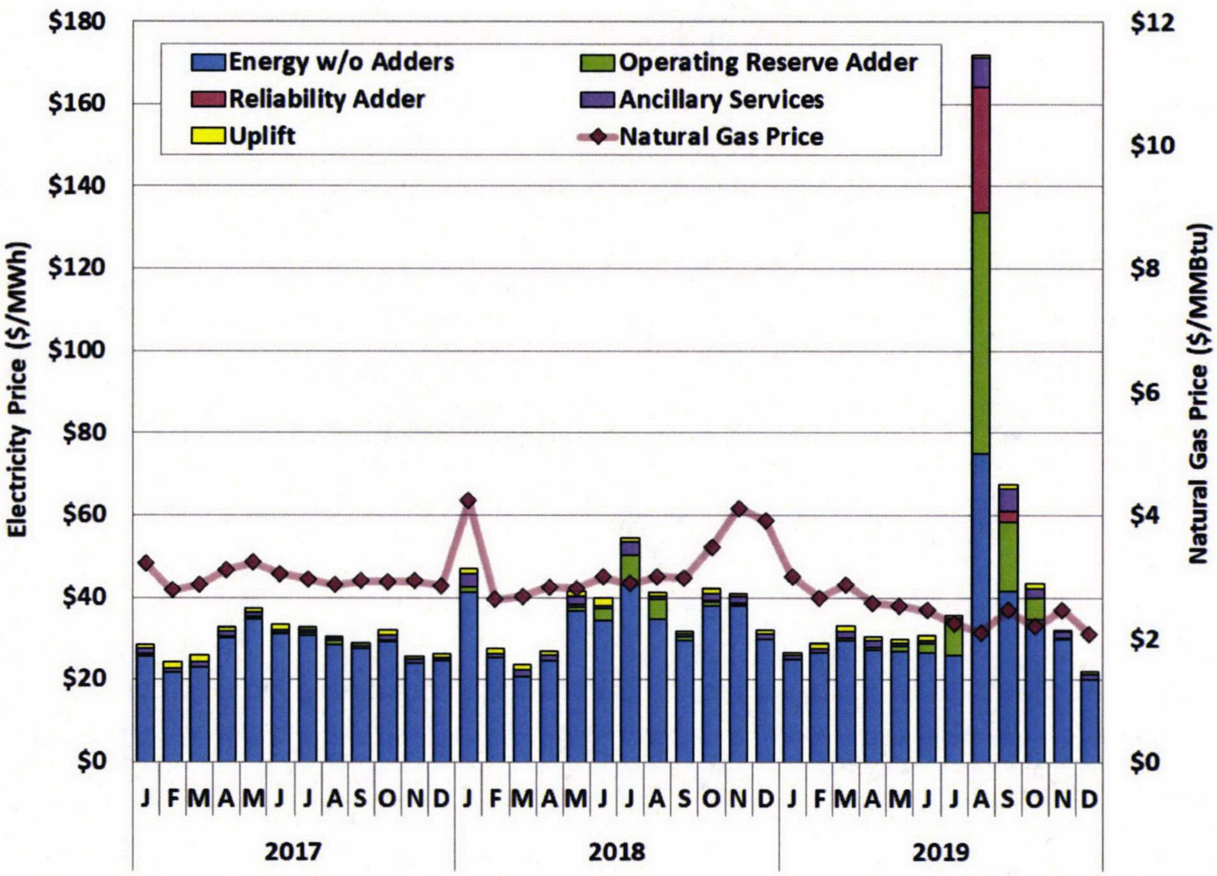
The first analysis of the real-time market evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market-based expenses referred to as "uplift." Figure 1 shows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

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.

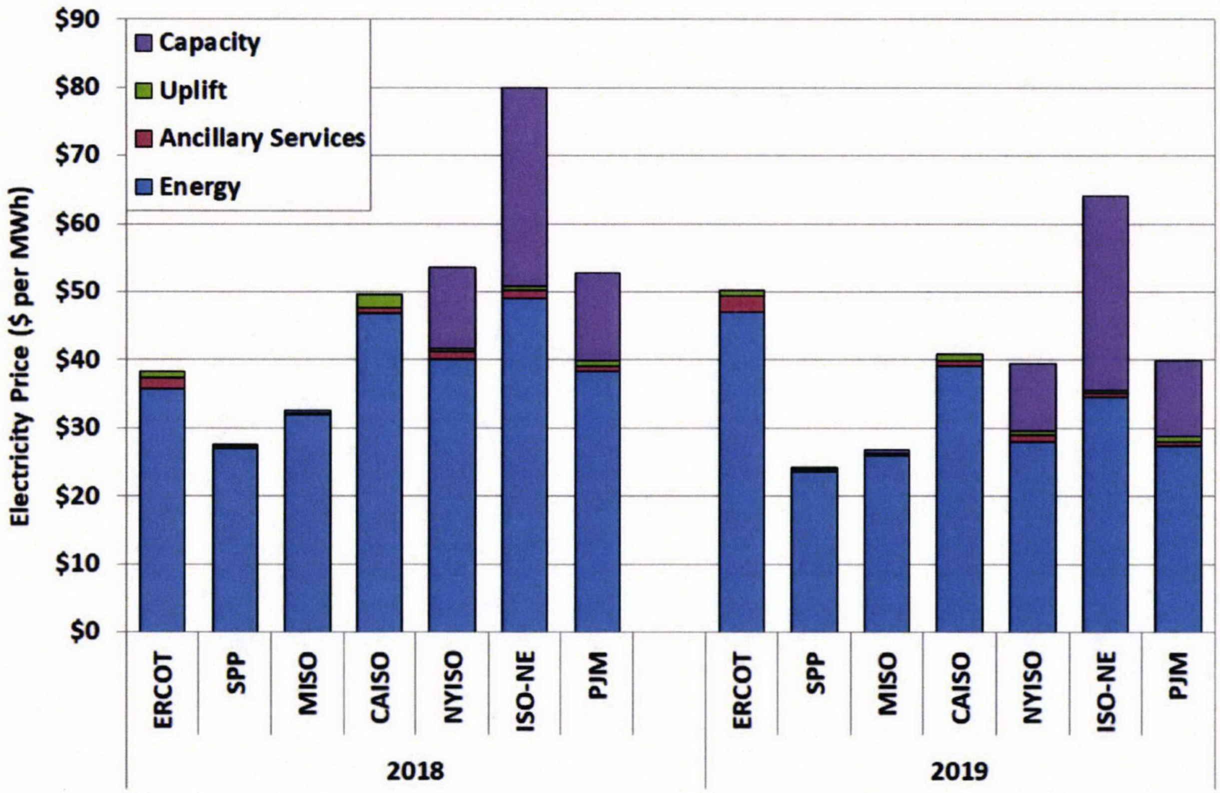
The increase in shortage pricing was partly reflected in the higher contributions from ERCOT's energy price adders: $9.76 per MWh from the operating reserve adder and $3.55 per MWh from the reliability adder. Both of these values are significantly higher than the comparable values in 2018: $1.97 per 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

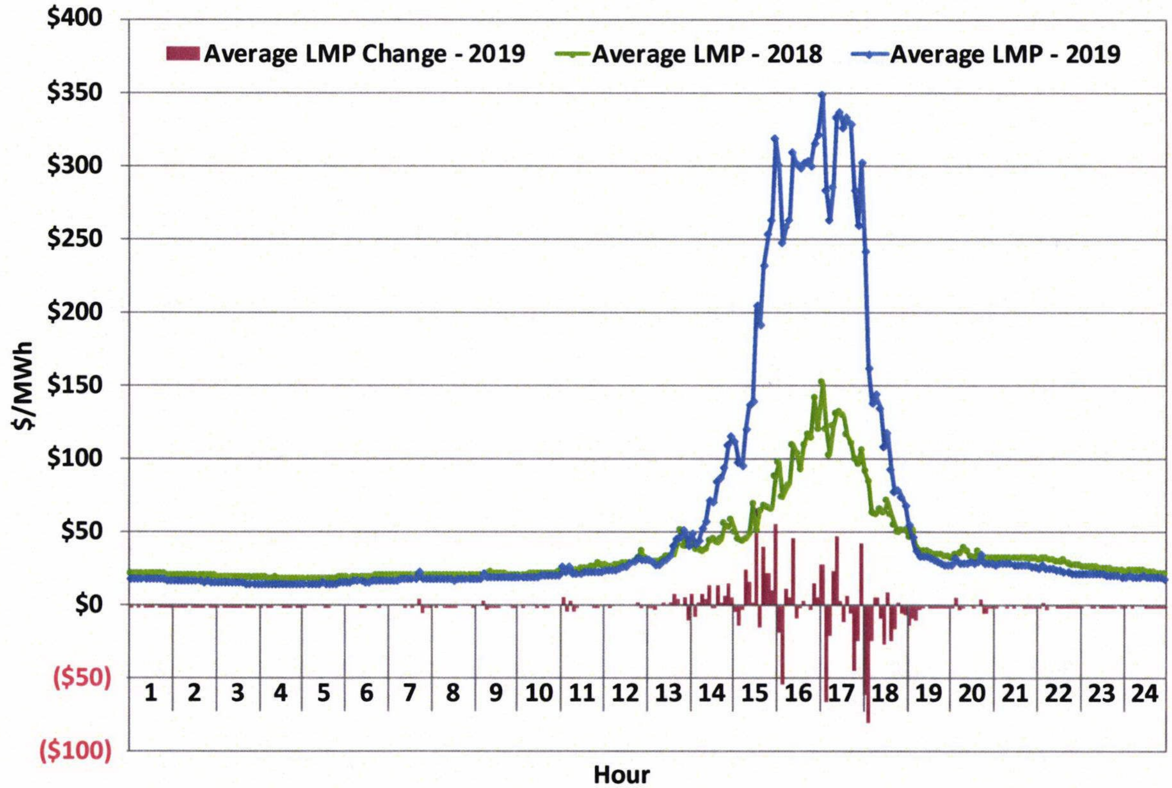


Real-time energy prices vary substantially by time of day. Figure 3 shows the load-weighted average real-time prices in ERCOT in each 5-minute interval during the summer months from May through September, when prices were the highest. It also shows in red the average change in the 5-minute prices in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

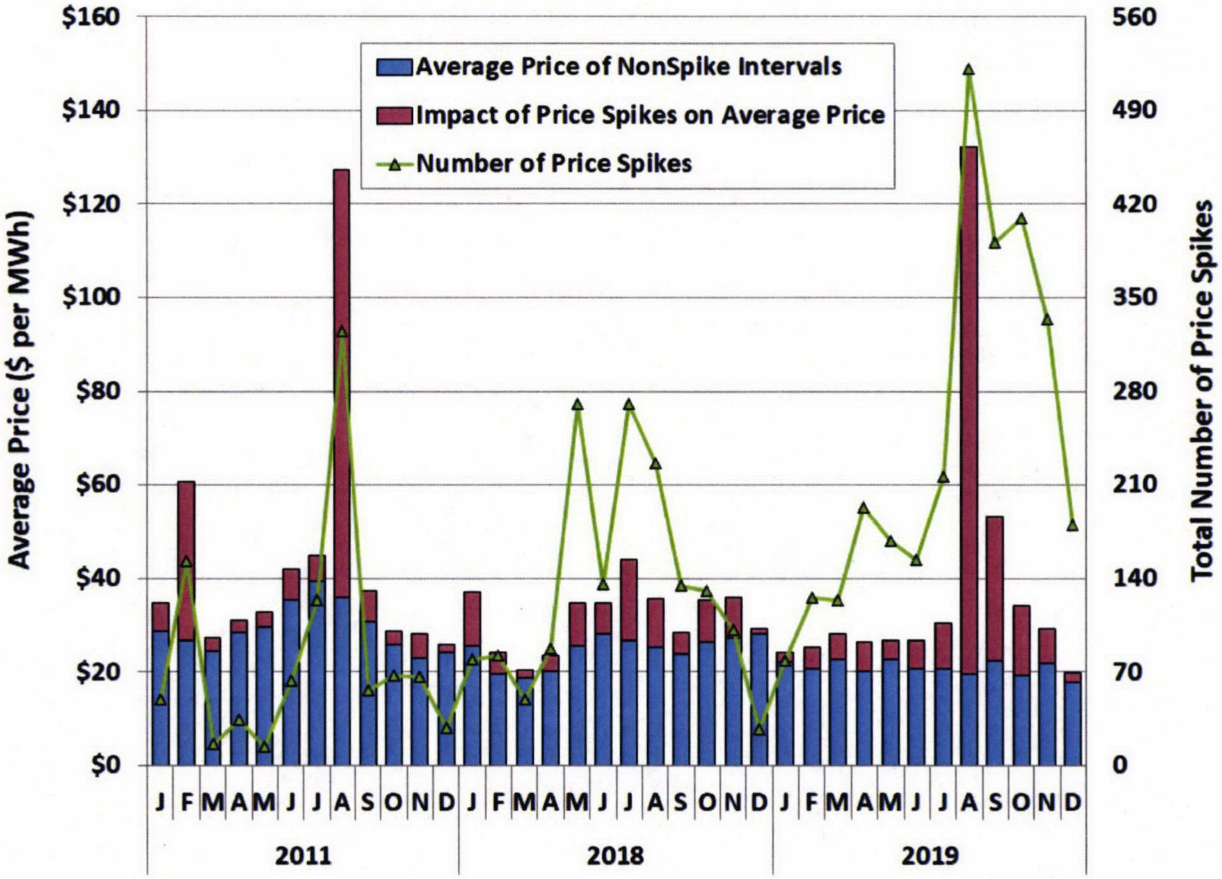


For additional analysis of load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2019, see Figure A1 in the Appendix.

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

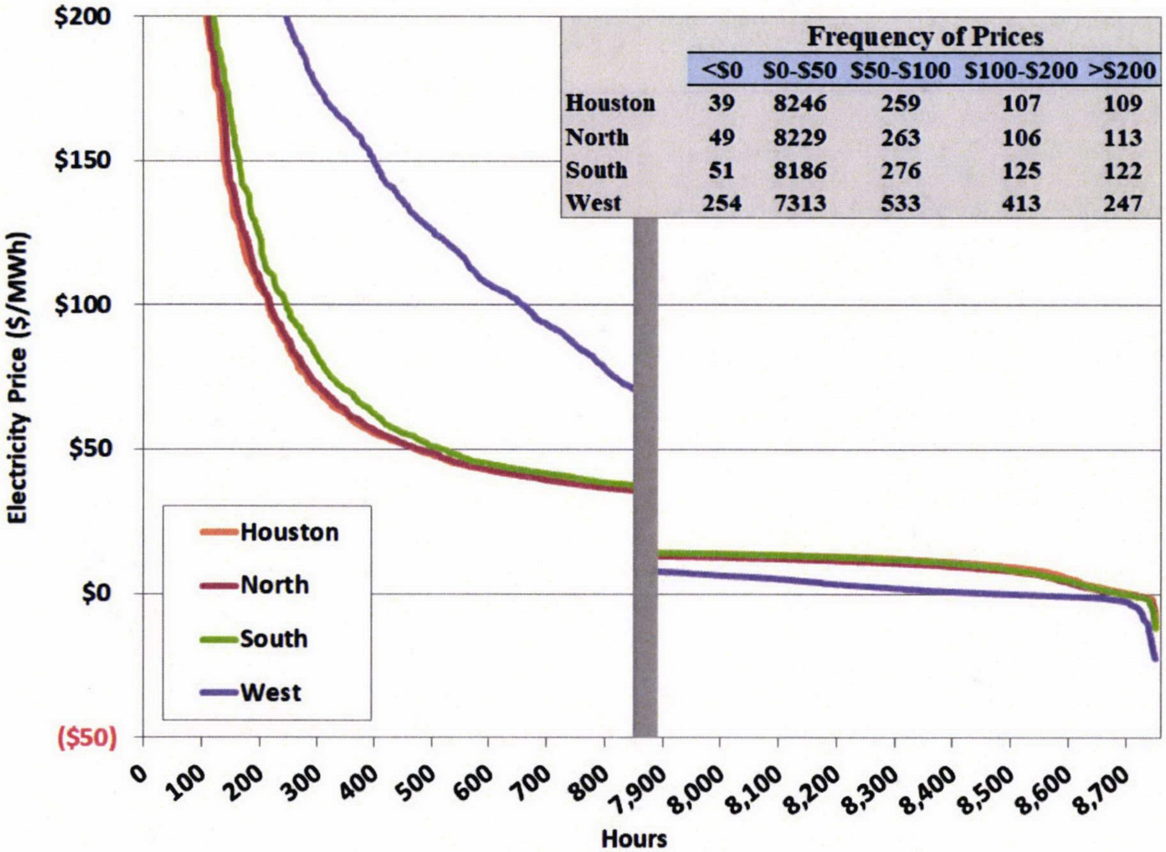
($/MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**	**$24.62**	**$28.25**	**$35.63**	**$47.06**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91	$26.33	$31.81	$34.40	$45.45
North	$54.24	$27.57	$32.74	$40.05	$26.36	$23.84	$25.67	$34.96	$46.77
South	$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



	<$0	$0-$50	$50-$100	$100-$200	>$200
Houston	39	8246	259	107	109
North	49	8229	263	106	113
South	51	8186	276	125	122
West	254	7313	533	413	247

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-

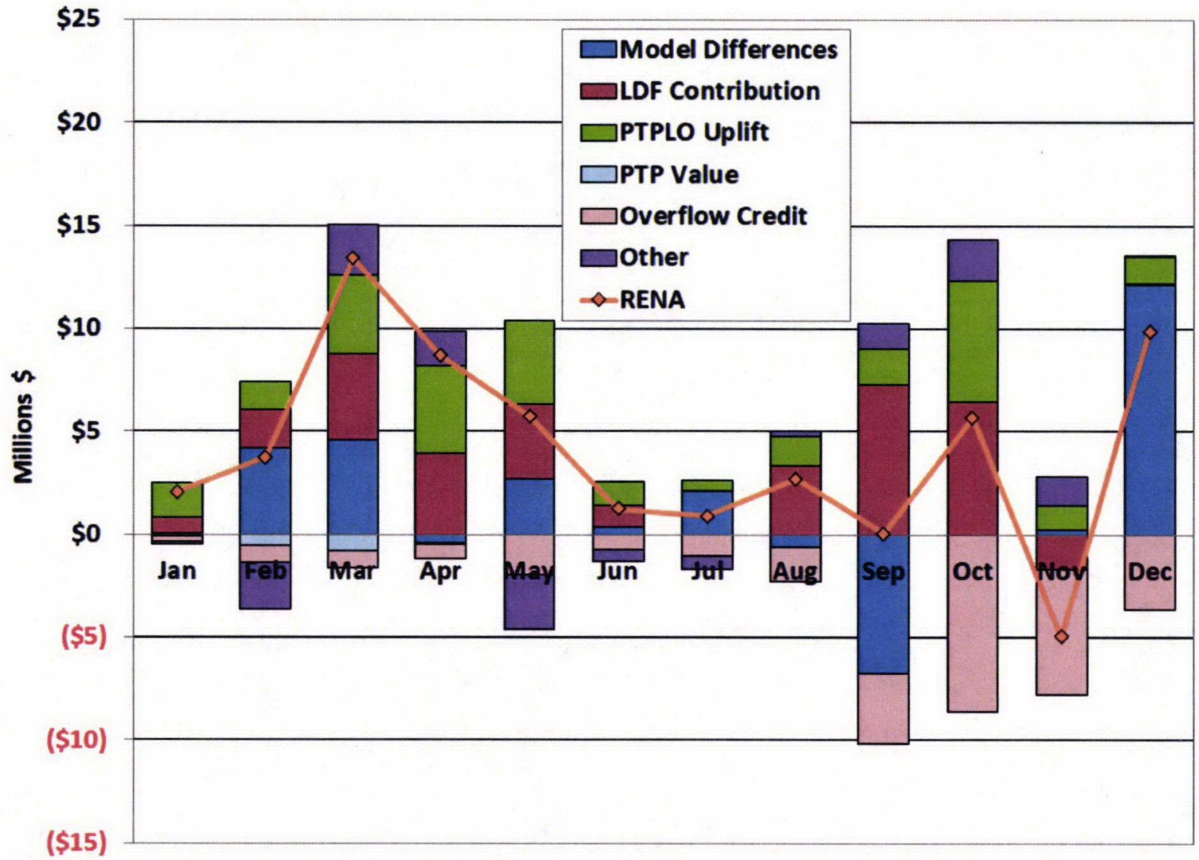
8 A Point-to-Point obligation with links to an option (PTPLO) is a type of CRR that entitles a Non-Opt-In Entity's (NOIE's) PTP Obligation bought in the DAM to be reflective of the NOIE's PTP Option that it acquired in the CRR auction or allocation. Qualified PTP Obligations with Links to an Option shall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

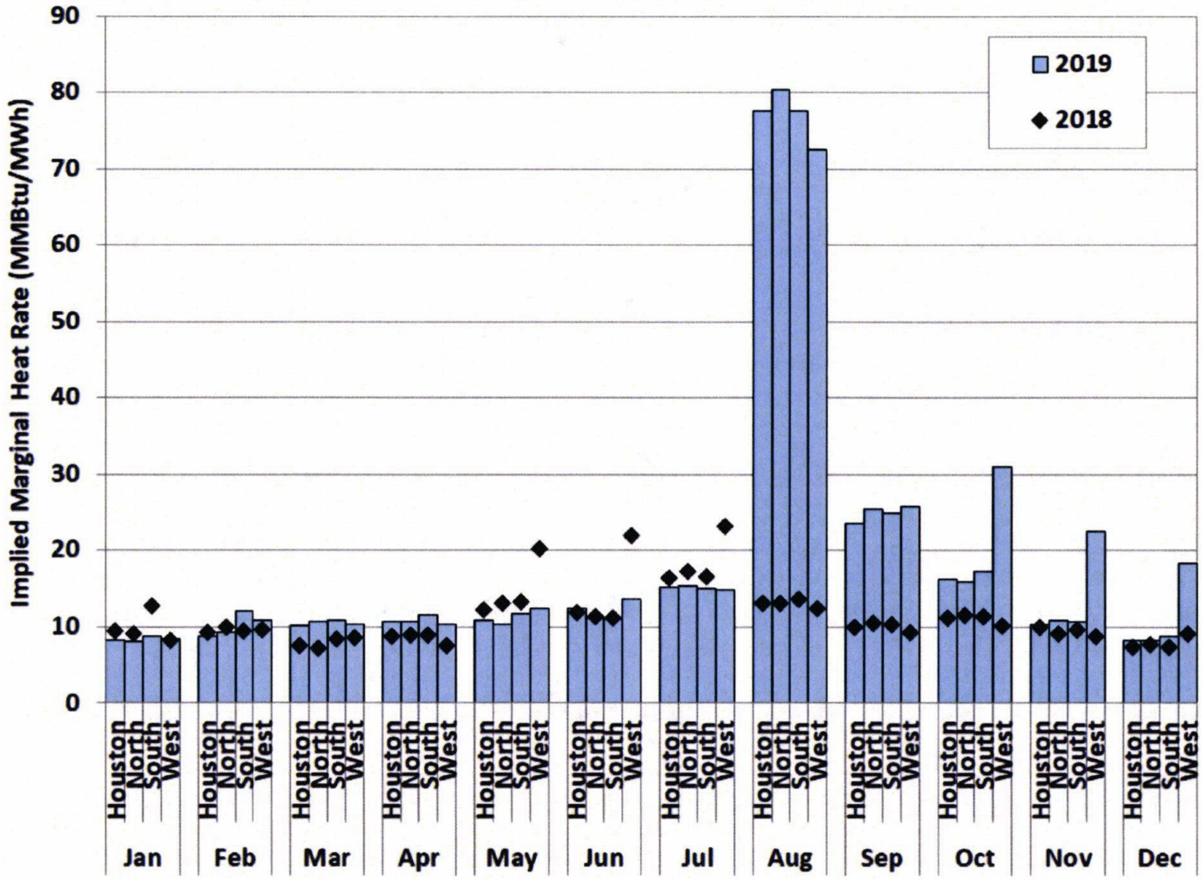


The task of maintaining accurate and consistent load distribution factors across all markets is a difficult one, made more so in areas with large amounts of localized load growth. These are exactly the types of areas that draw higher levels of market interest. To the extent ERCOT is unable to predict 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.

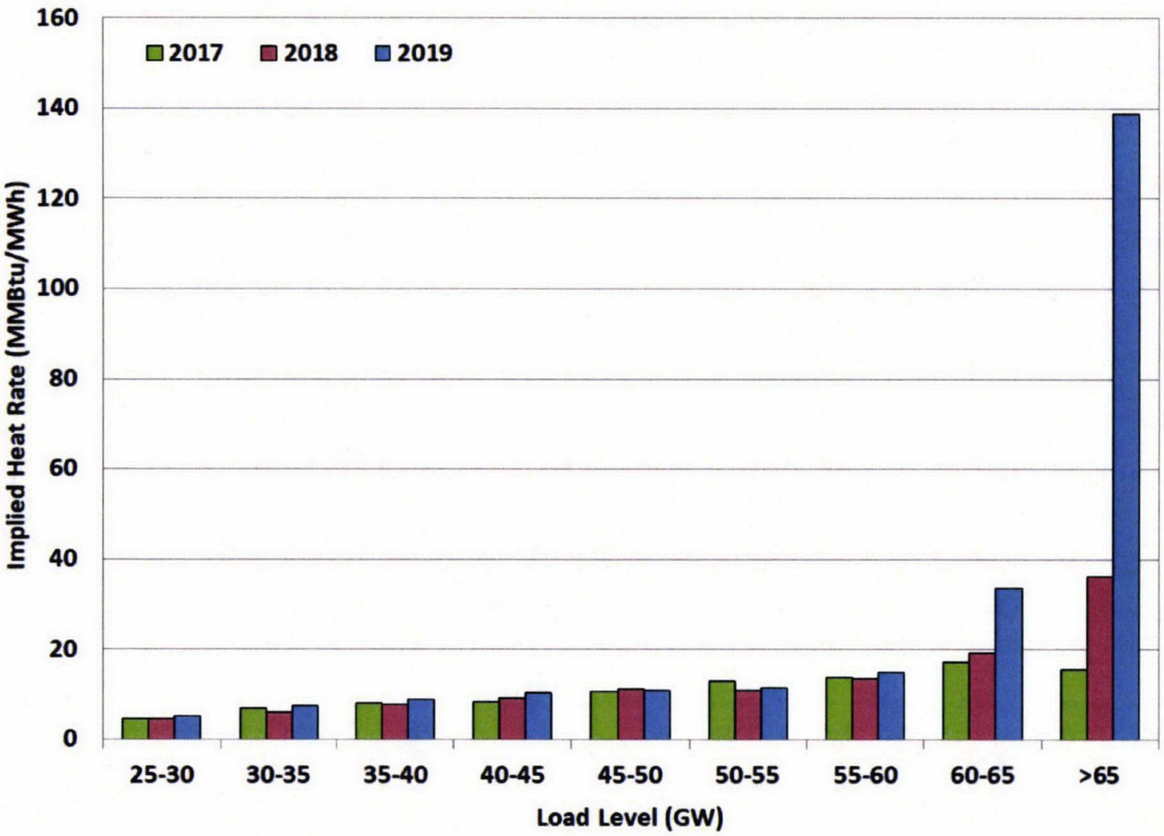
Figure 7: Monthly Average Implied Heat Rates



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



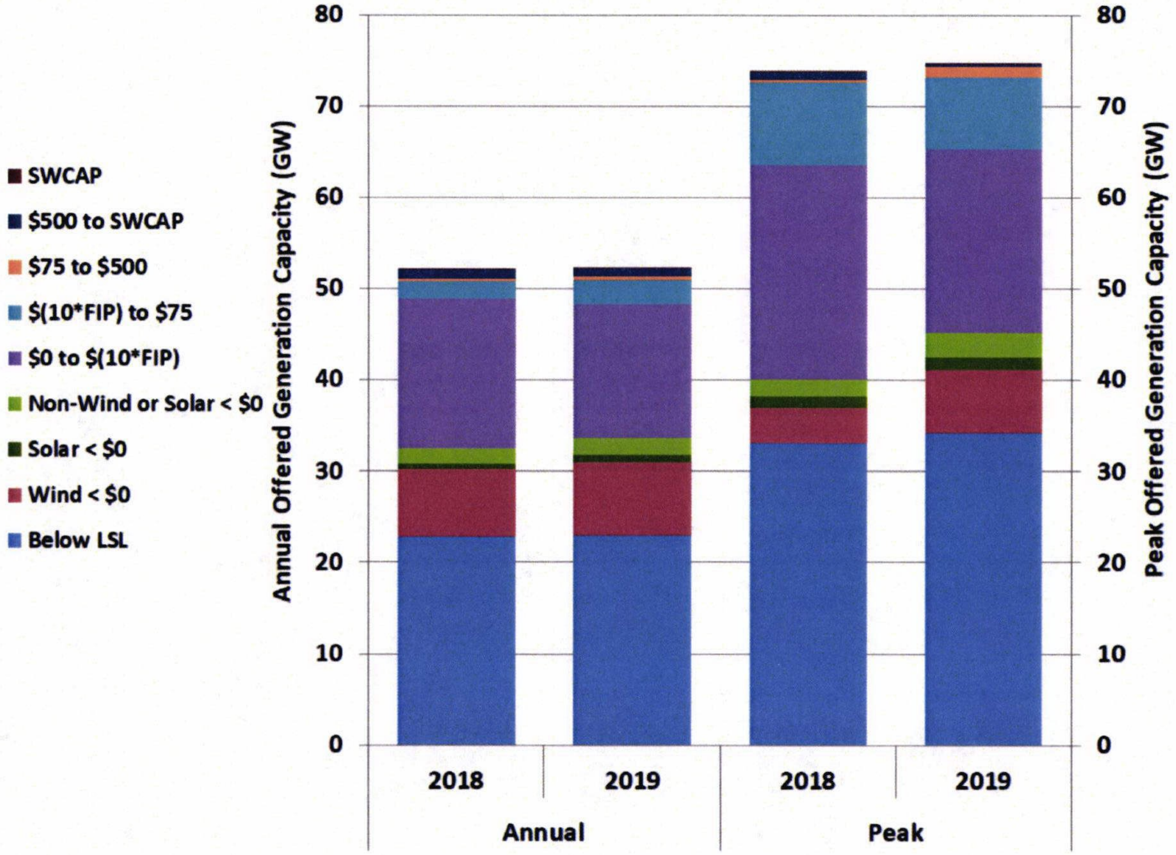
In a well-performing market, a positive relationship between implied heat rate and load level is expected because resources with higher marginal costs are dispatched to serve higher loads. This relationship continued and the magnified effects of increased shortage conditions in 2019 can be seen at the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

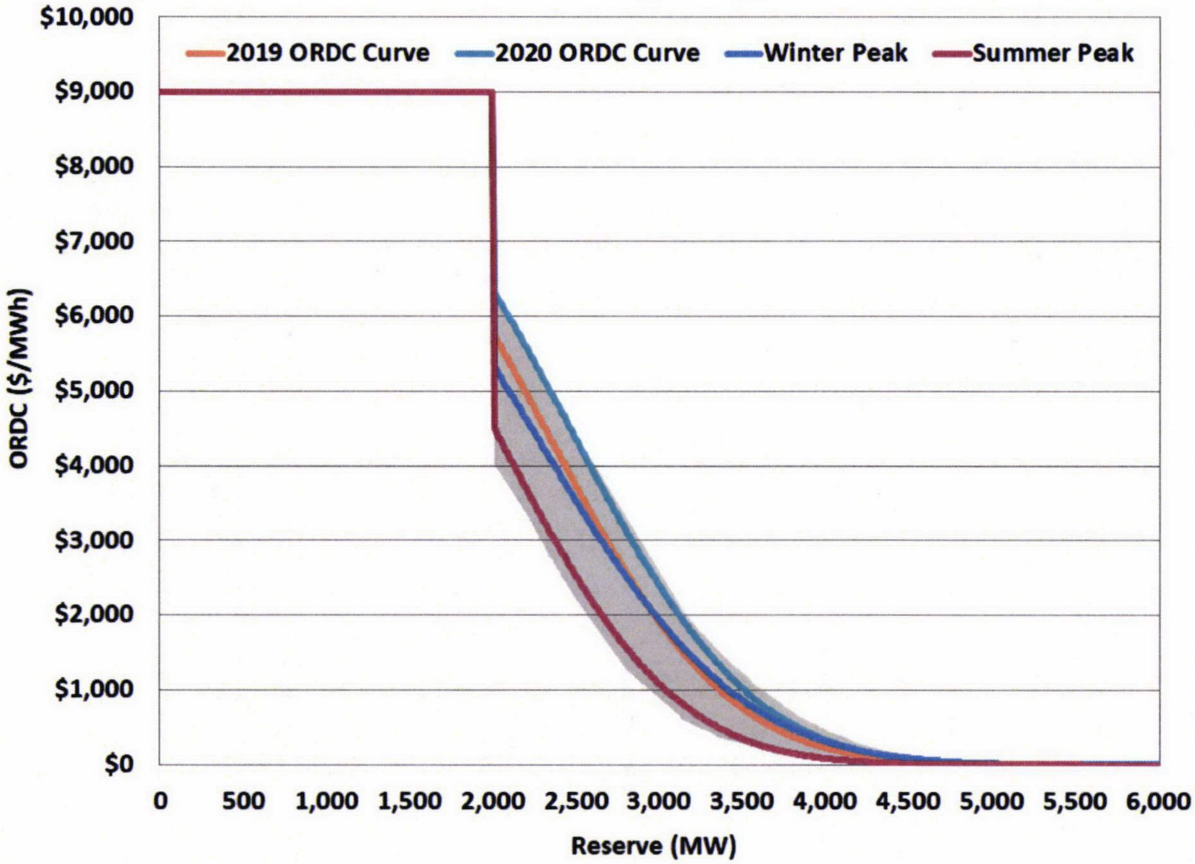
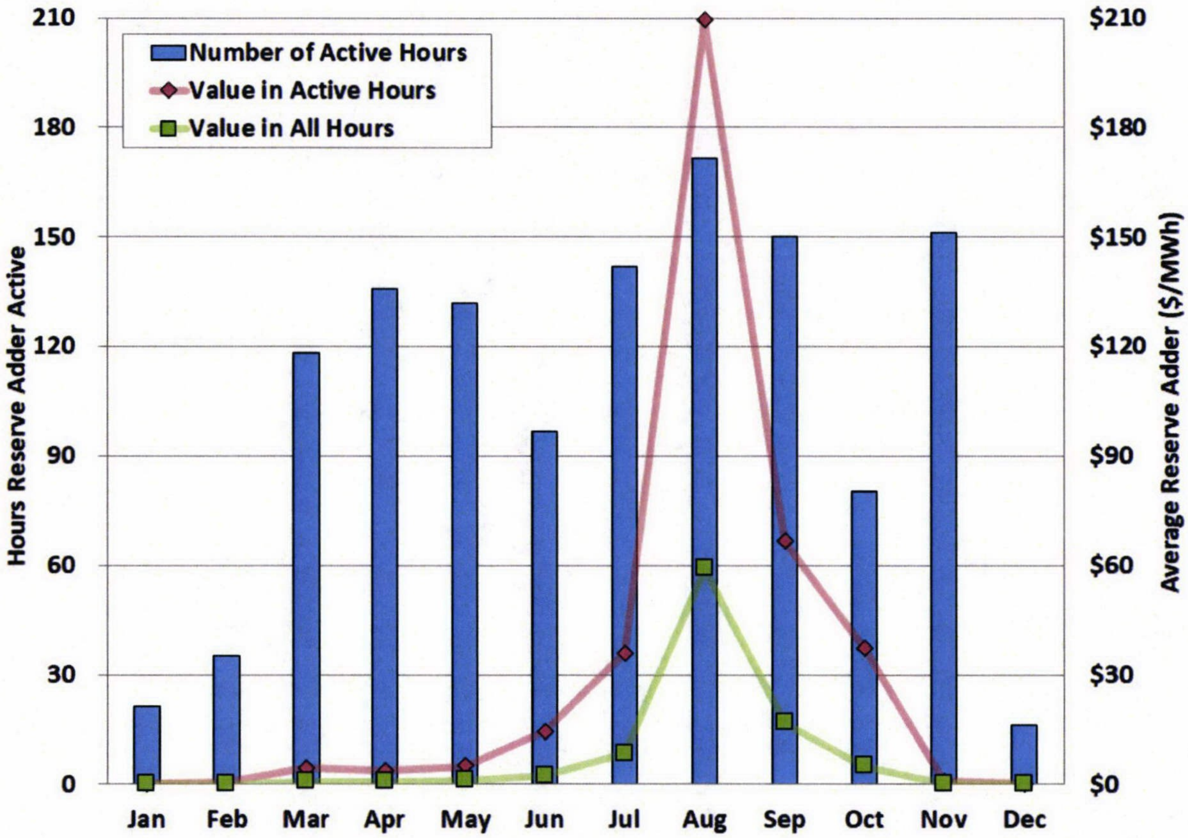


Figure 10 shows that blending the curves increases the level of ORDC contributions to price as reserve capacity drops. For example, the price at 3000 MW reserve level rises from roughly $1100 per MWh on the Summer Peak curve that existed previously to approximately $2400 per MWh on the blended 2020 curve. 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

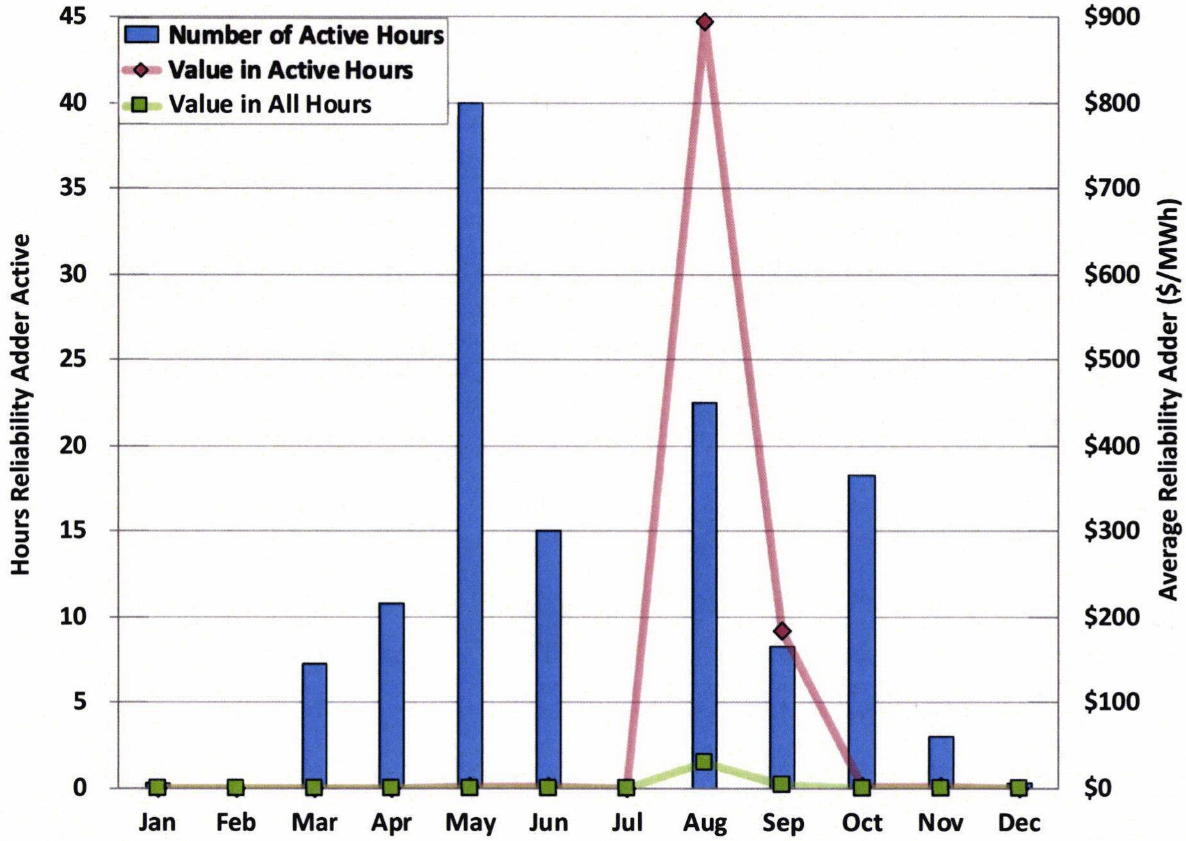


Overall, the operating reserve adder contributed $9.76 per MWh, or approximately 21% of the annual average real-time energy price of $47.06 per MWh in 2019. The effects of the operating reserve adder are expected to vary substantially from year to year. It will have the largest effects when low supply 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

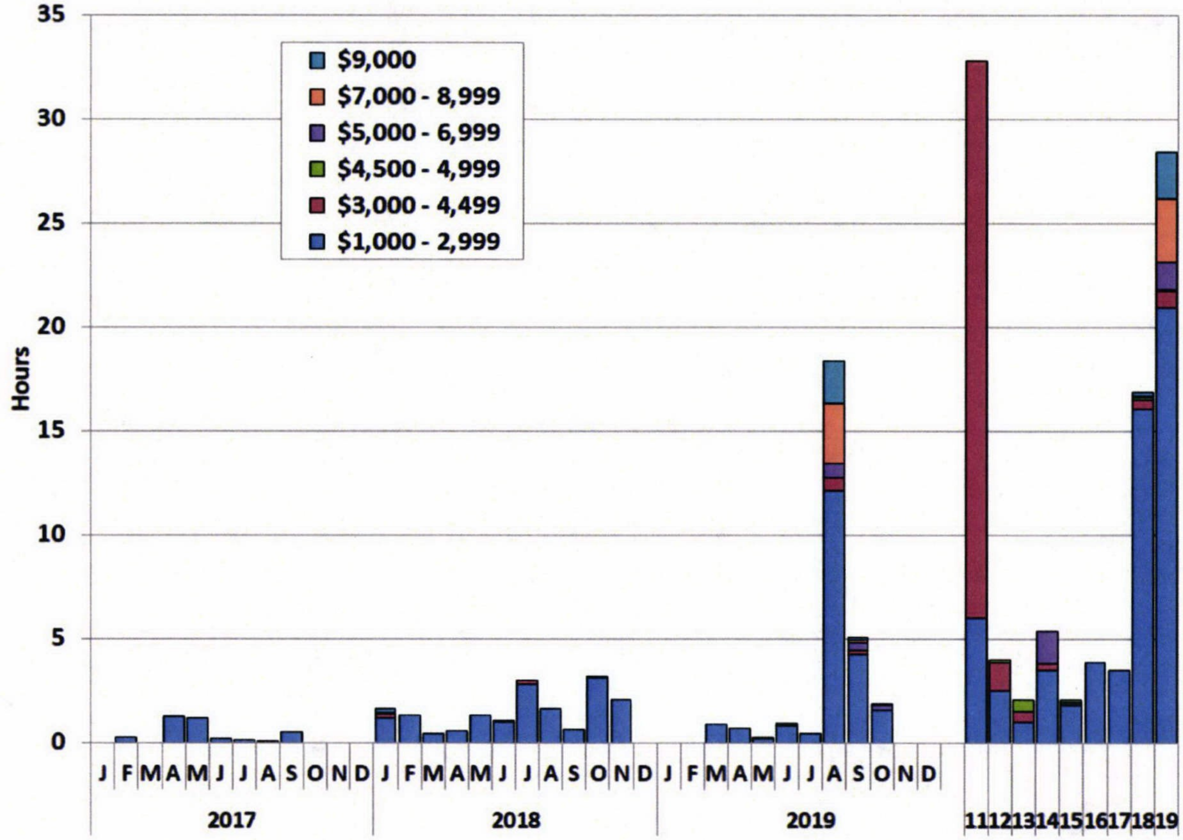


Weaknesses in the implementation of the reliability deployment adder were identified in 2018 and addressed in 2019. The primary flaw identified in the calculation method used to determine the reliability adder was that relaxing the low dispatch limit of all resources could make the price adders higher, 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.

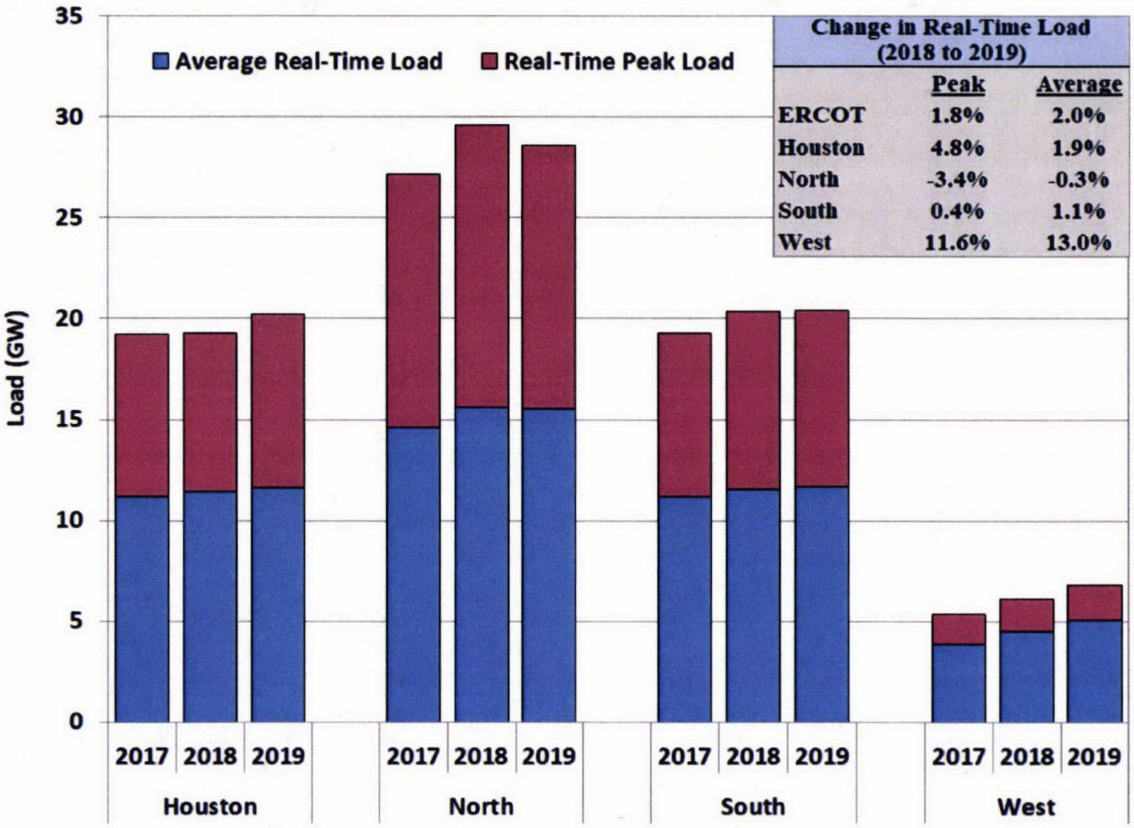
II. Demand and Supply in ERCOT

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

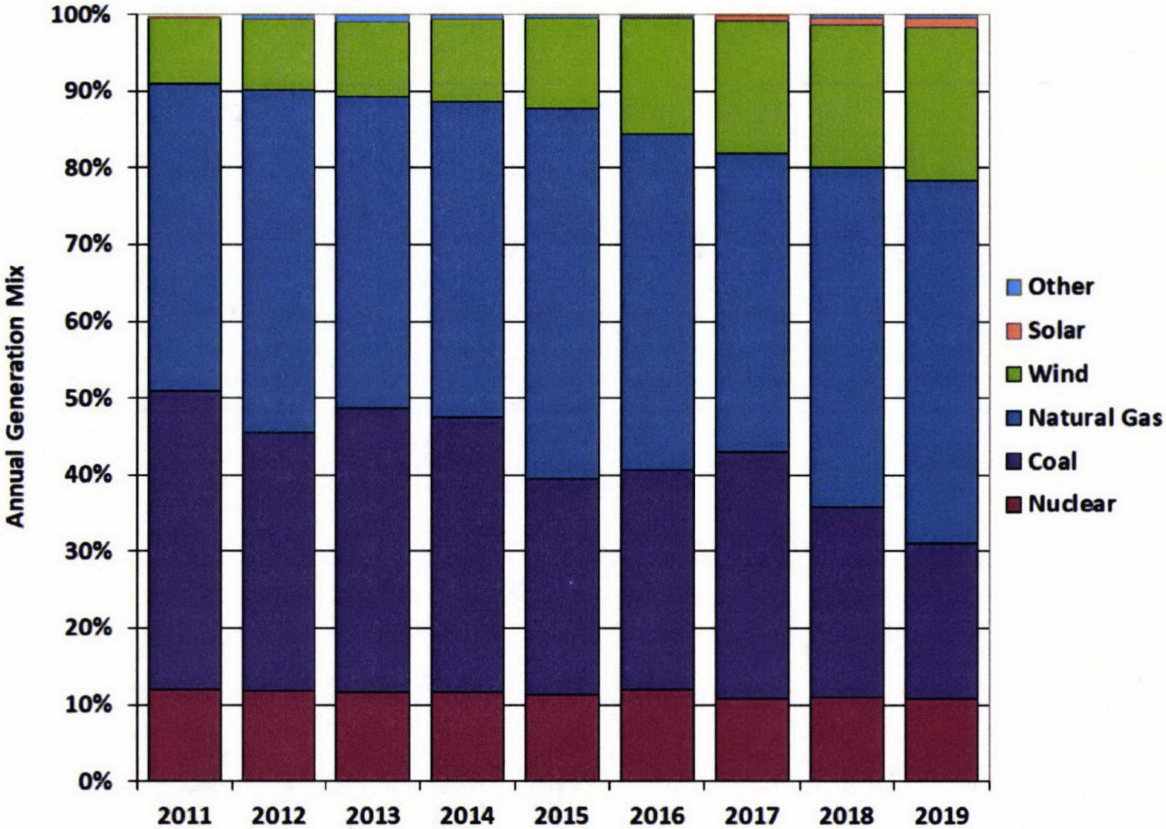
We evaluate the generation portfolio in ERCOT in this subsection. The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand with the exception of Houston. The Houston zone has increasingly relied on imports from the rest of the state as resources have 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.

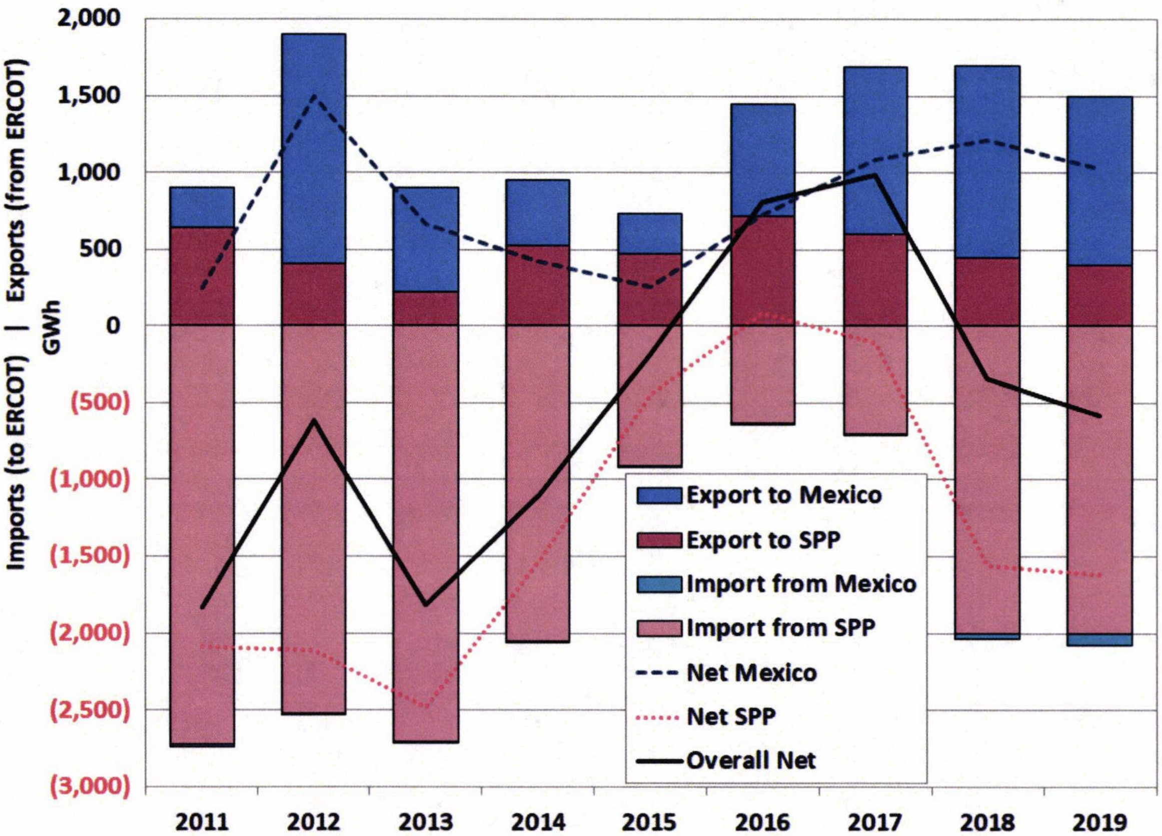
We expect these trends to continue because of the ongoing decline in natural gas prices, making gas-fired resources increasingly more economic than coal resources, and the continued growth of wind resources.

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.

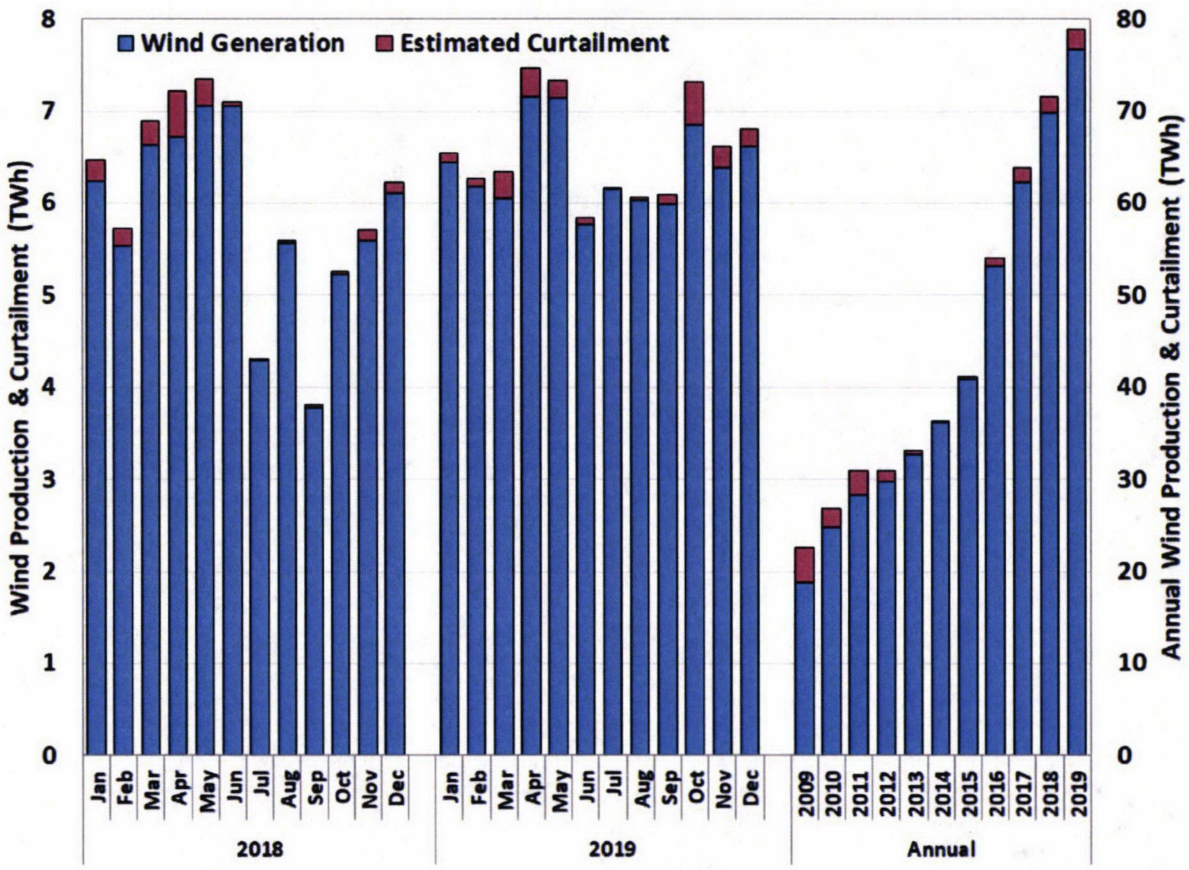
D. Wind Output in ERCOT

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

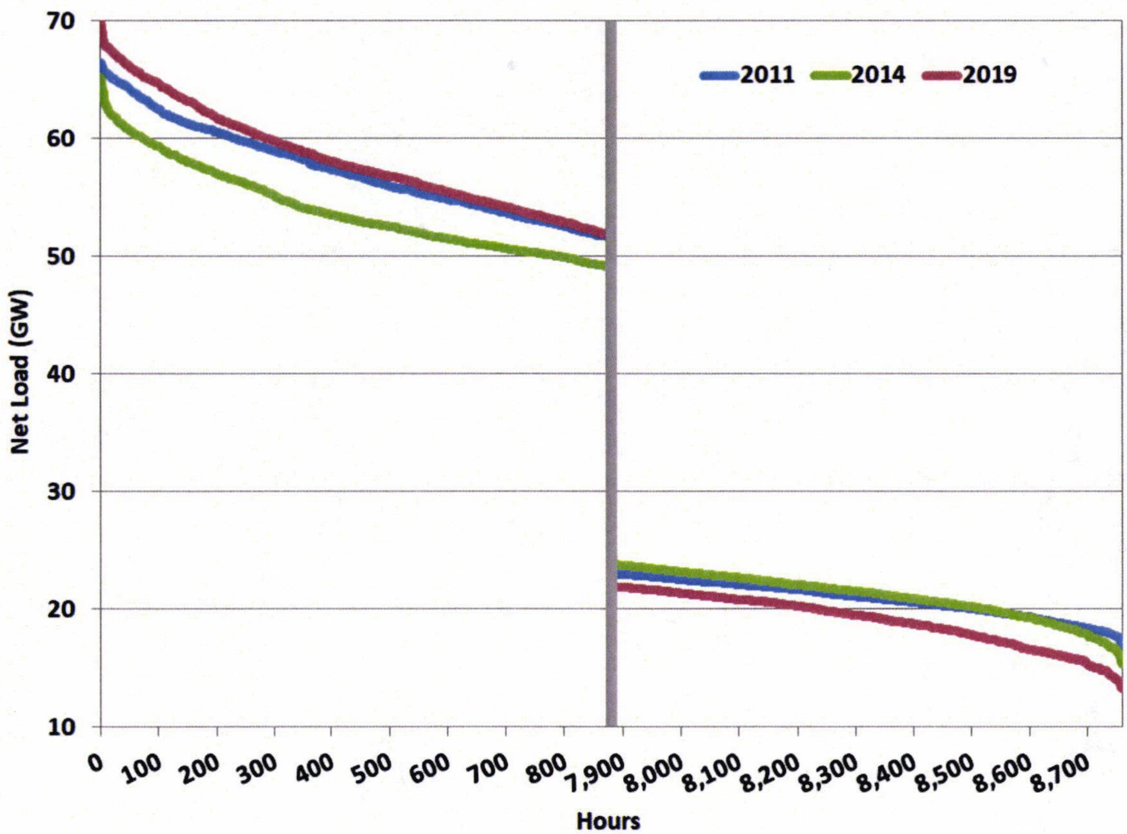


Figure 18 shows net load in the highest and lowest hours. Even with the increased development activity in the coastal area of the South zone, 71% of the wind resources in ERCOT are located in West Texas (including the Panhandle). The wind profiles in this area result in only modest reductions of the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

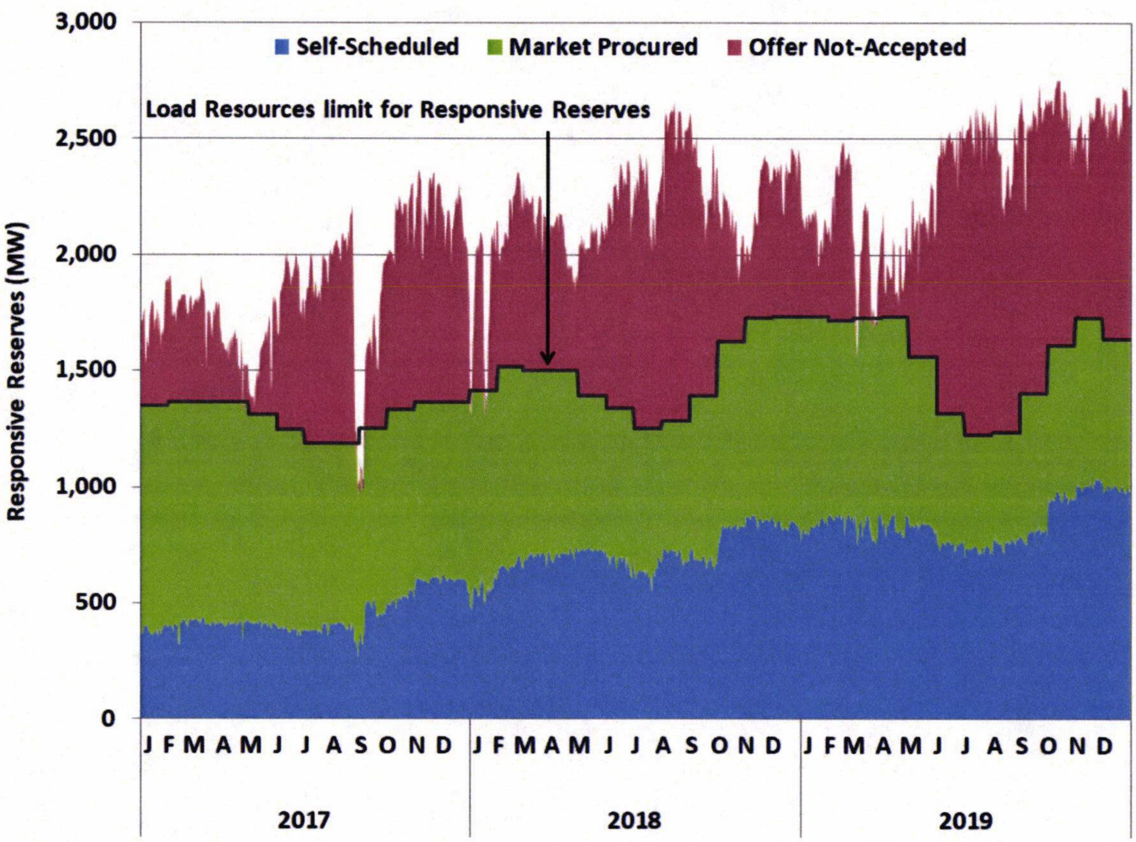
Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges.

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.
- Through voluntary actions taken to avoid the allocation of transmission costs.

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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).

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.

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

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.

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.

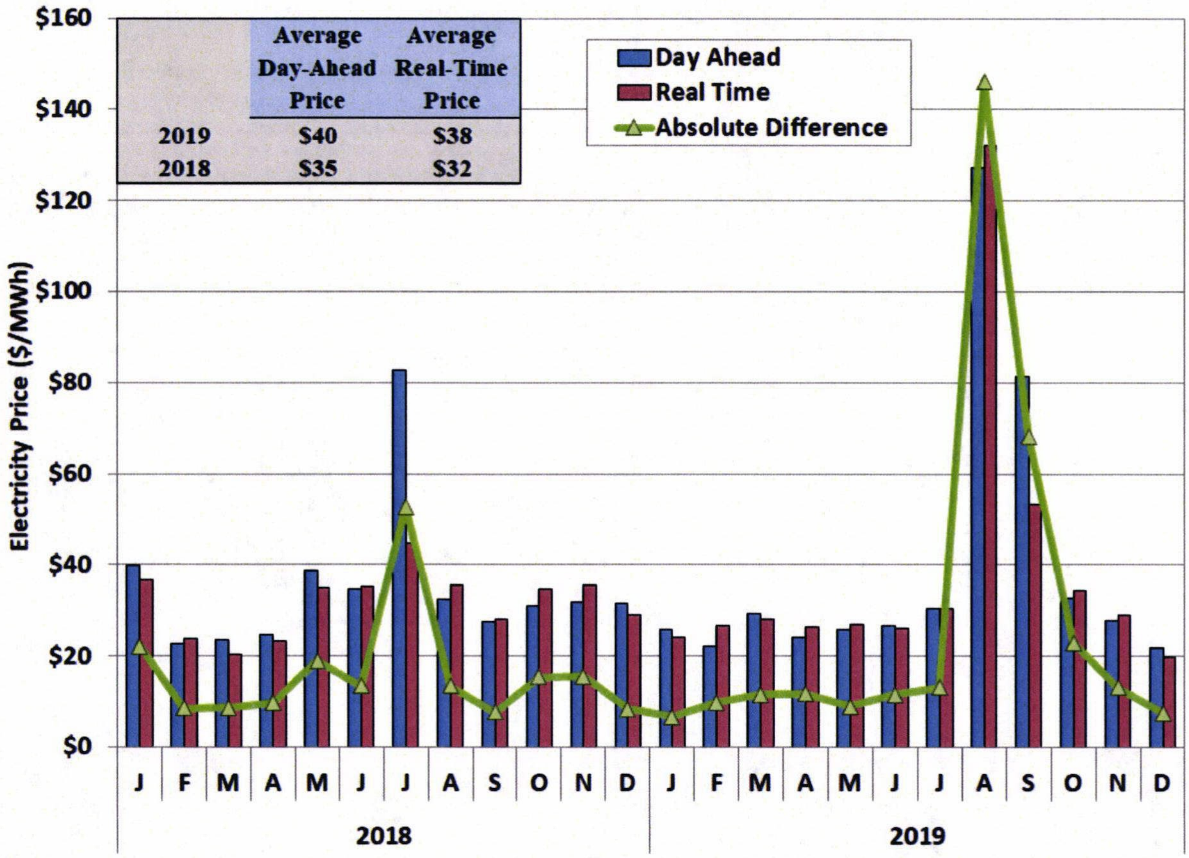
Overall, 2019 day-ahead prices were higher for both energy and ancillary services, as expected given the lower reserve margin. Liquidity in the day-ahead market was similar to previous years, which included active trading of congestion products in the day-ahead market.

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



	Average Day-Ahead Price	Average Real-Time Price
2019	$40	$38
2018	$35	$32

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.

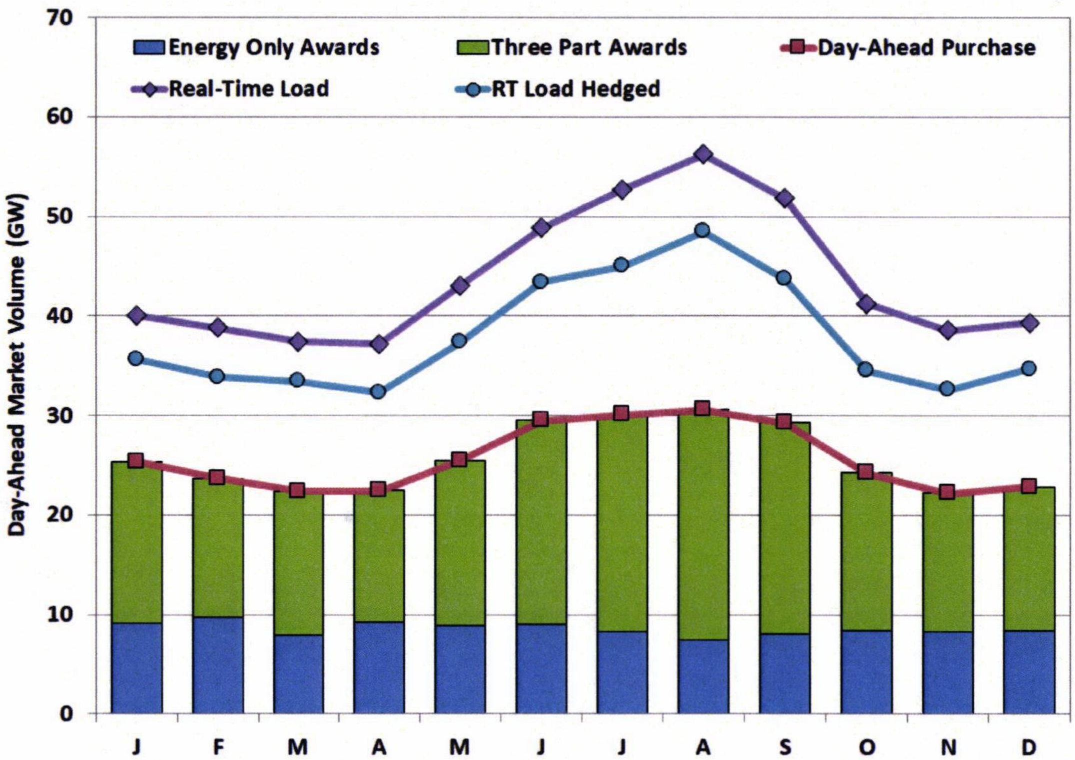
month.[27] Smaller quantities of installed reserves for the summer of 2019, coupled with the ORDC changes, led to expectations of more frequent shortage conditions and higher associated prices in real-time. This led to very high day-ahead prices in August and September.

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.

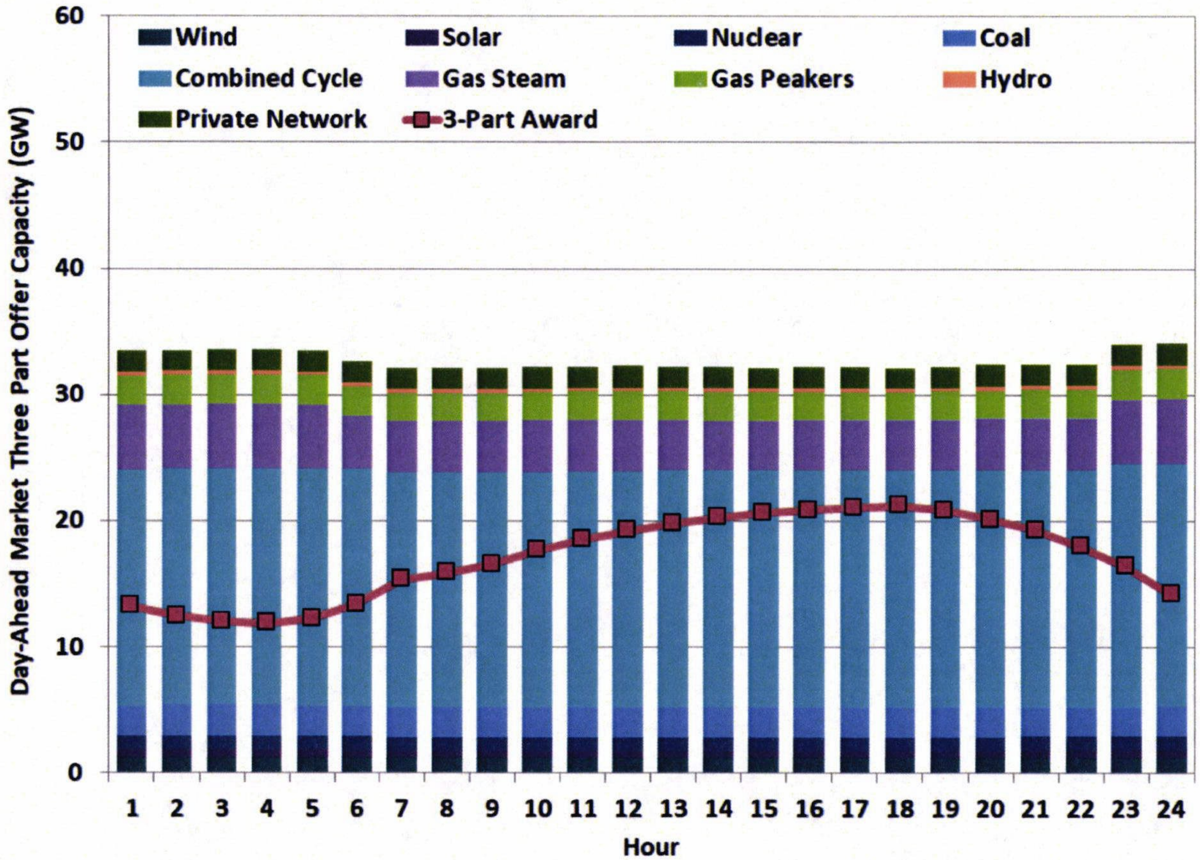
With the largest share of installed capacity, it follows that combined cycle units are the predominant type of generation submitting offers in the day-ahead market. More importantly, because combined cycle units are most typically marginal units, offering that capacity into the day-ahead market allows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

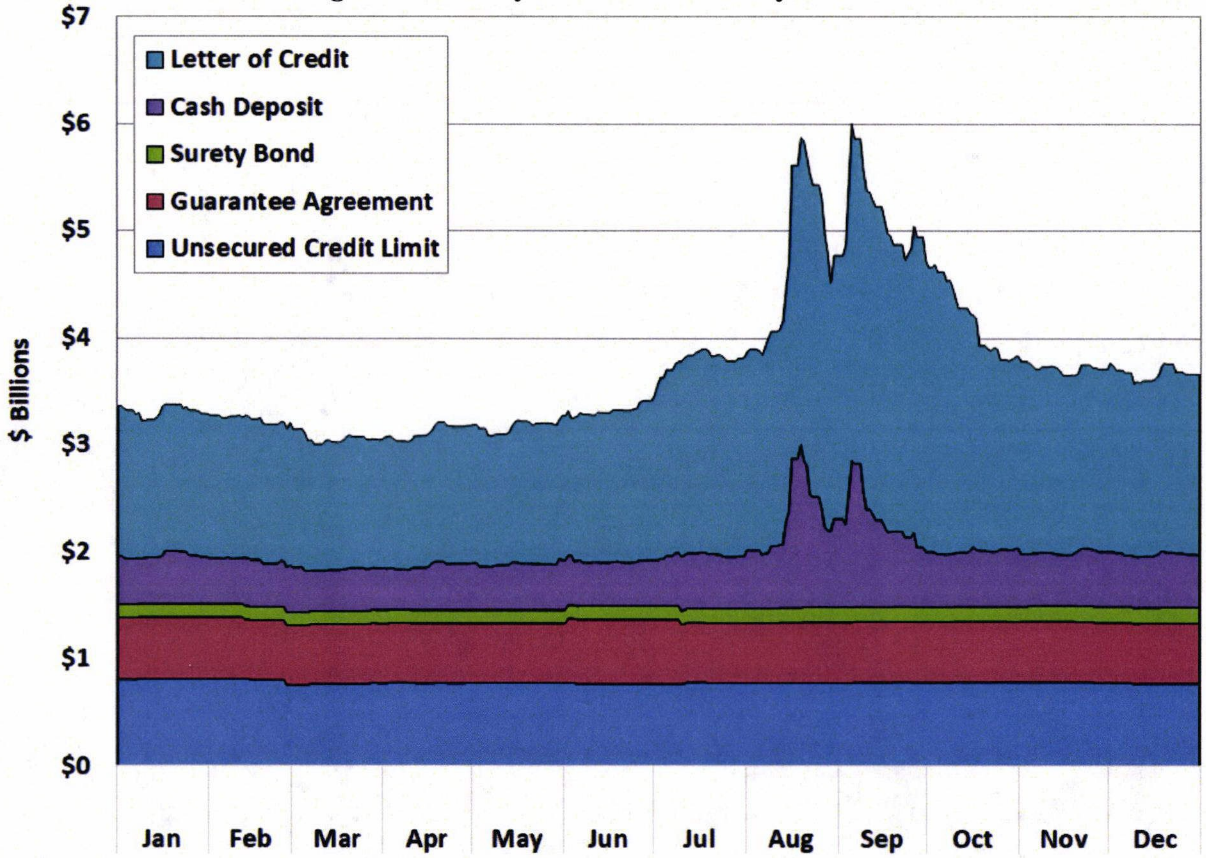


Parties that wish to participate in ERCOT's day-ahead market are required to have sufficient collateral with ERCOT. In 2018, ERCOT introduced forward prices as a determinant in calculating collateral requirements.[30] With even smaller installed reserves in 2019, forward prices were especially high for 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

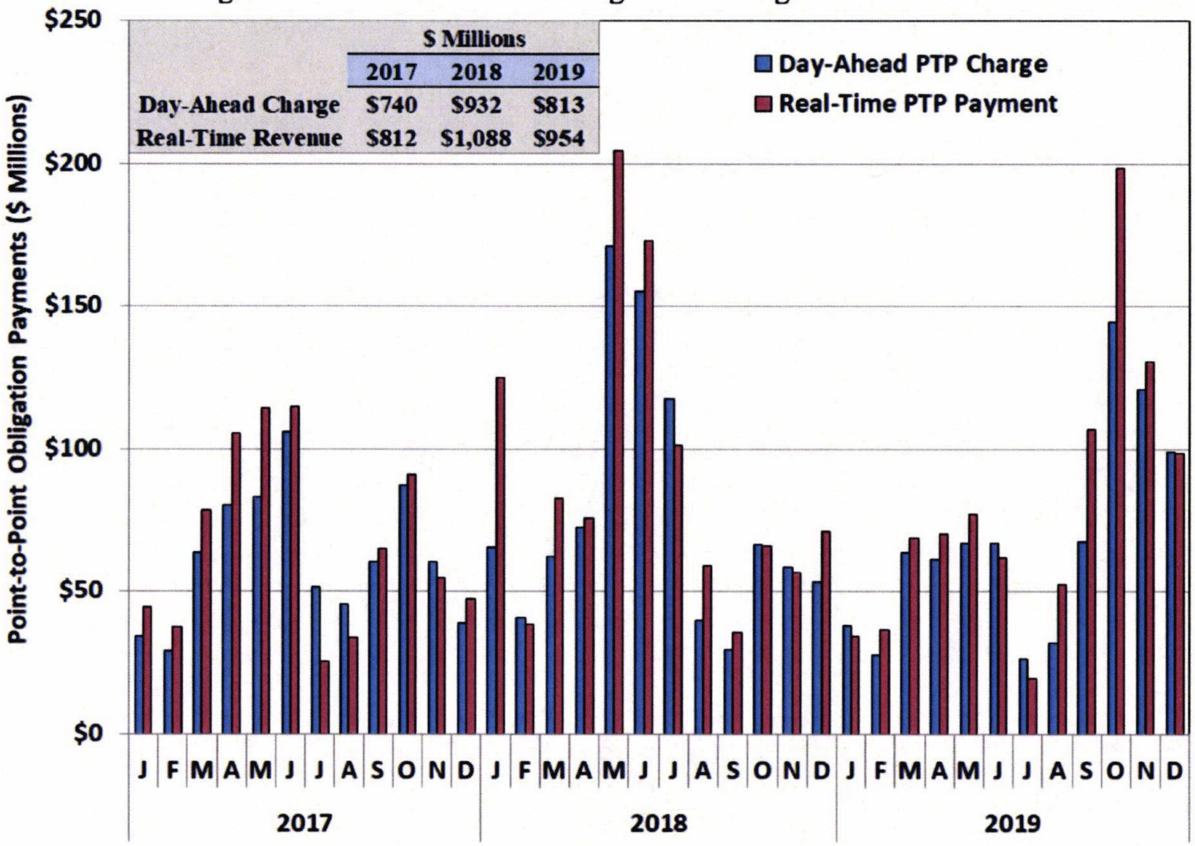


C. Point-to-Point Obligations

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.