A Notice of Suspension of Operations (NSO) is required of any generator suspension that lasts greater than 180 days. A number of NSOs were submitted in 2020.[47] ERCOT determined that none of the units were necessary to support ERCOT transmission system reliability, therefore no Reliability Must-Run (RMR) contracts were awarded in 2020.[48] However, review of the RMR and MRA evaluation processes continued in 2020, resulting in the approval of Nodal Protocols Revision Request (NPRR) 964, which removed the term Synchronous Condenser Unit from the Protocols, and clarified the ERCOT evaluation process related to reliability analysis and aligns the review process of a seasonal mothball unit with non-seasonal mothball unit.[49]

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

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

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

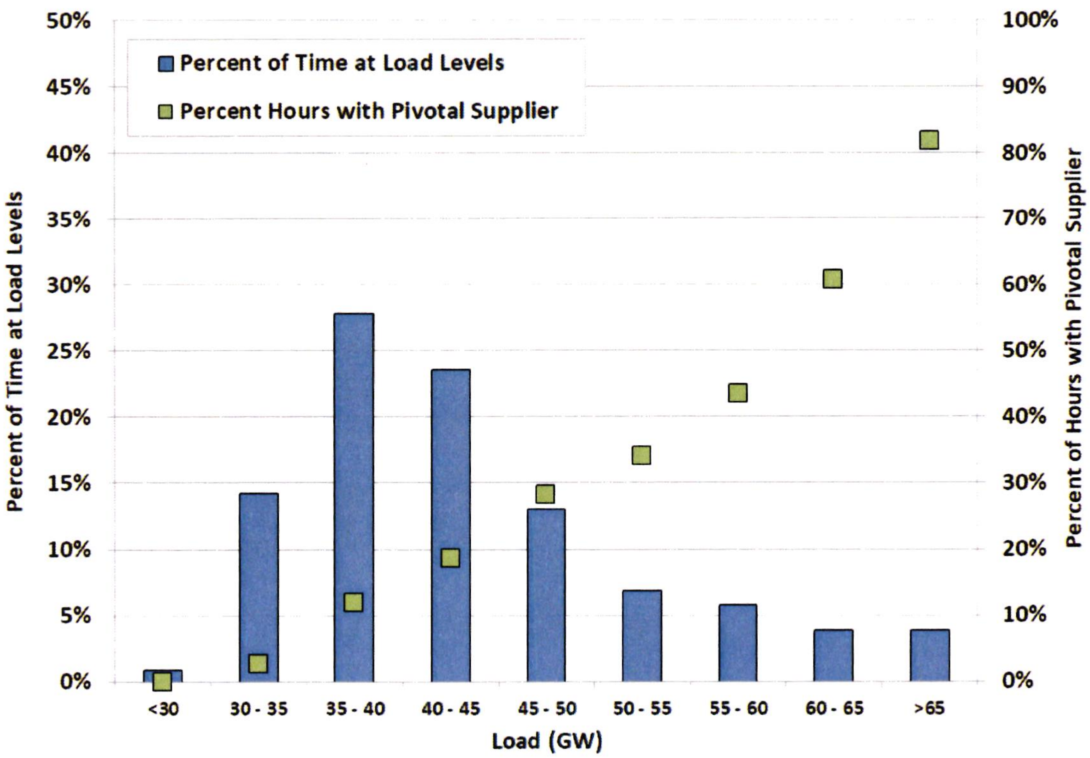
VII. ANALYSIS OF COMPETITIVE PERFORMANCE

In this section, we evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). This section begins by evaluating a structural indicator of potential market power, then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, this section also includes a summary of the Voluntary Mitigation Plans in effect during 2020. Based on these analyses, we find that the ERCOT wholesale market performed competitively in 2020.

A. Structural Market Power Indicators

Traditional market concentration measures are not reliable market power indicators in electricity markets. They do not include the impacts of load obligations that affect suppliers' incentives to raise prices. They also do not account for excess supply, which affects the competitiveness of the market. A more reliable indicator of market power is whether a supplier is "pivotal", i.e., when its resources are necessary to satisfy load or manage a constraint. Figure 49 summarizes the results of the pivotal supplier analysis by showing the portion of time at each load level there was a pivotal supplier. The figure also displays the portion of time each load level occurred.

Figure 49: Pivotal Supplier Frequency by Load Level



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

We cannot make inferences regarding market power solely from pivotal supplier data. Bilateral and other financial contract obligations can affect whether a supplier has the incentive to raise prices. For example, a small supplier selling energy only in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. The pivotal supplier results shown in the previous figure does not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

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

B. Evaluation of Supplier Conduct

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

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

1. Generation Outages and Deratings

At any given time, some portion of the generation is unavailable because of outages and deratings. Due to limitations in outage data, we infer the outage type by cross-referencing unit status information provided to ERCOT with outage submissions, assuming that all scheduled outages are planned outages. Derated capacity is the difference between the summer maximum capacity of a resource as registered with ERCOT and its actual capability. It is common for generating capacity to be partially derated because the resource cannot achieve its installed capacity level due to technical or environmental factors (e.g., equipment failures or ambient temperatures). Wind generators rarely produce at the installed capacity rating because of variations in wind speed. Due to the high numbers, we show wind separately in our evaluation of deratings. As discussed in Section V above, summer availability has been increasing since 2017 in ERCOT because of the incentives provided by the recent increase in shortage pricing as well as a decline in summer outages.

Figure 50 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2020. This analysis includes all in-service and switchable capacity. From the total installed capacity, we subtract the following: (a) capacity from private networks not available for export to the ERCOT grid; (b) wind capacity not available because of the lack of wind input; (c) short-term deratings; (d) short-term planned outages; (e) short-term forced outages; and (e) long-term outages and deratings greater than 30 days. What remains is the available capacity.

Figure 50: Reductions in Installed Capacity

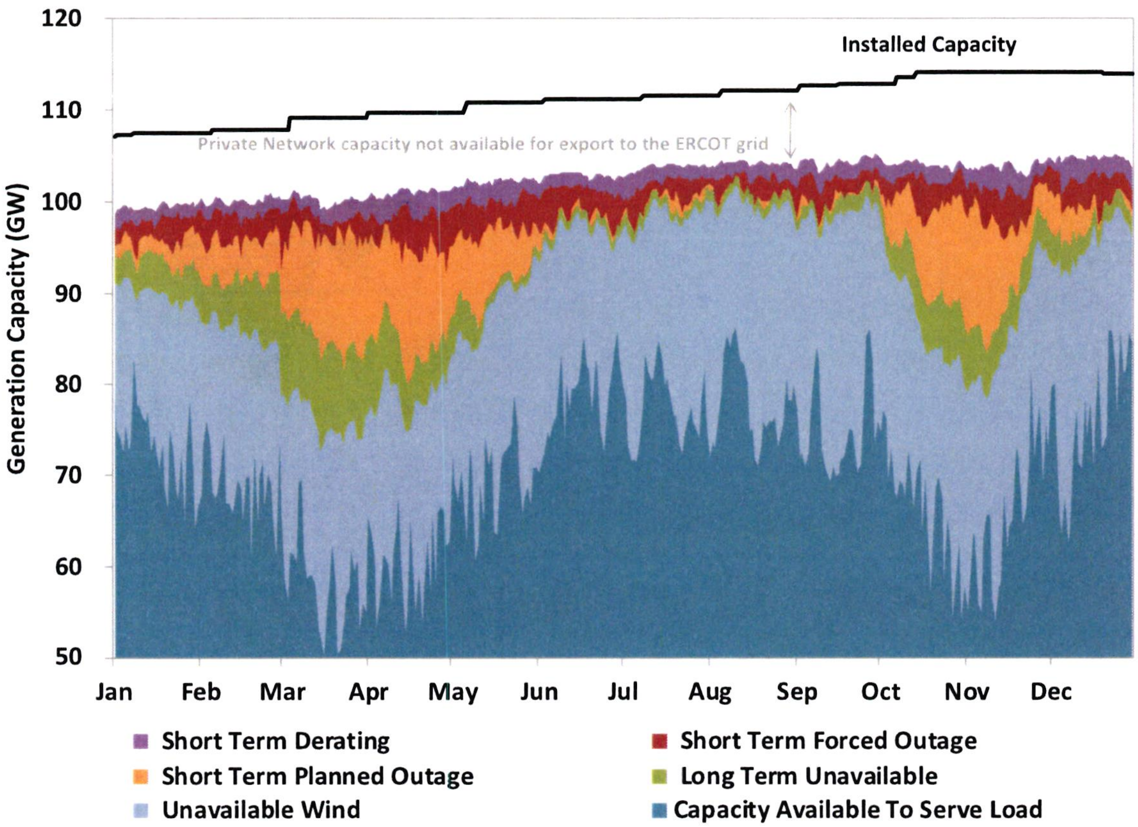


Figure 50 shows that short-term outages and deratings of non-wind generators fluctuated between 1.4 to 21.4 GW, while wind unavailability varied between 7.5 and 30 GW. Short-term planned outages were largest in the shoulder months of April and November, while smallest during the summer months, consistent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

In the next analysis, we focus specifically on short-term planned outages and forced outages and deratings of non-wind units because these classes of outages and deratings are the most likely to be used to physically withhold units in attempts to raise prices. The following Figure 51 provides a comparison of the monthly outage and derating values for 2019 and 2020.

Figure 51: Derating, Planned Outages and Forced Outages

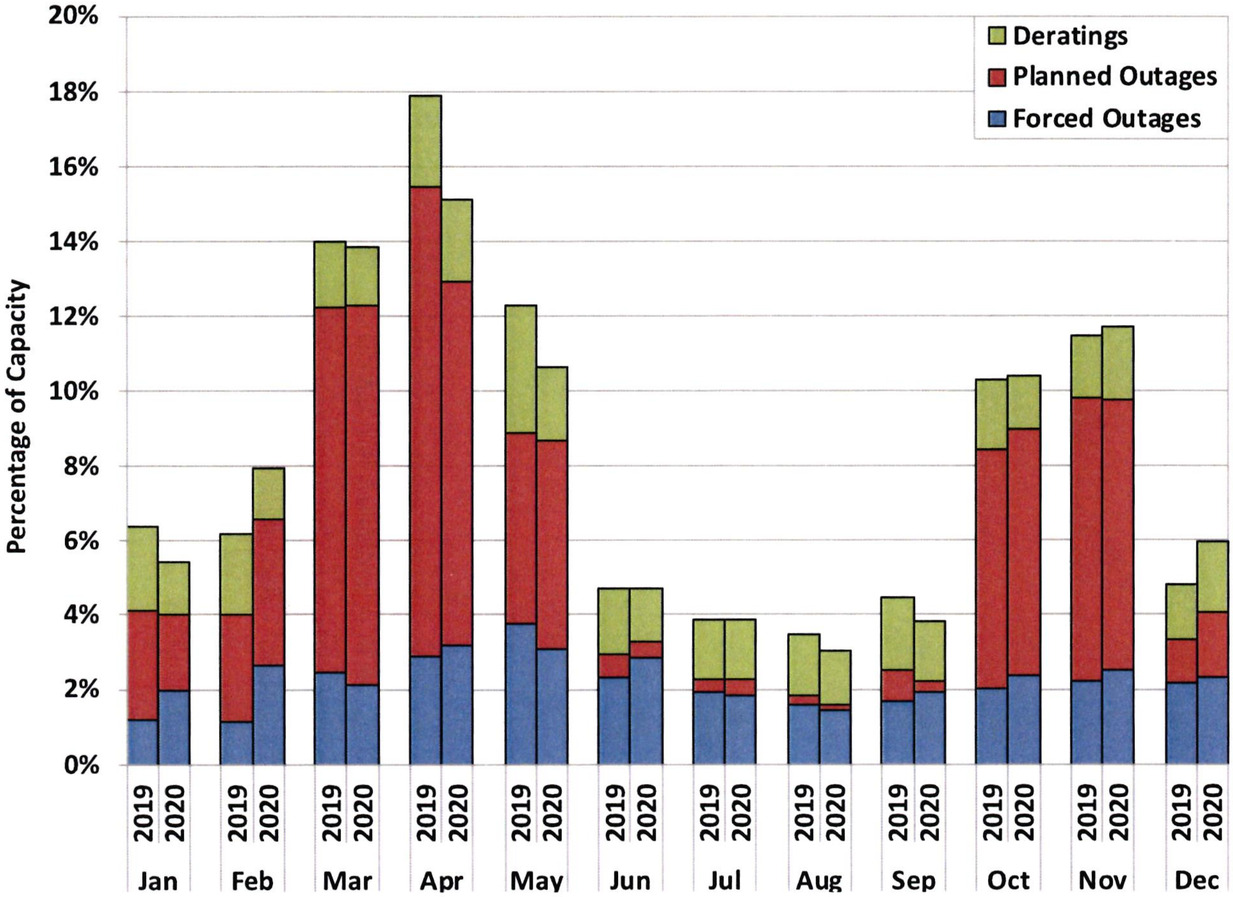


Figure 51 shows a general consistency of forced outages from last year, implying that expectations for 2020 were similar to those in 2019, and that generator operators were again able to defer the impacts of unexpected equipment limitations through September. However, those actions likely were at the cost of higher outage rates in October and November both years. The significant increase in planned outages scheduled during spring and fall in both years is an indicator of preparation for summers in which the ability to capture scarcity pricing is the highest. The consistently small number of deratings across all months of 2020 indicates that generators were intent on maximizing generator availability. The low outage rates during August 2020, even lower than those in August 2019, and the low level of derations overall are likely a result of increased planned maintenance activities. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours.

Figure A47 in the Appendix shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2020.

2. Evaluation of Potential Physical Withholding

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

The pivotal supplier results shown in Figure 49 indicate that the potential for market power abuse rises at higher load levels as the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources because their output is generally most profitable in peak periods.

Figure 52 shows the average short-term deratings and forced outages as a percentage of total installed capacity for large and small suppliers during summer months, as well as the relationship to different real-time load levels. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, we look at the patterns of outages and deratings of large suppliers and compare them to the small suppliers' patterns.

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

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

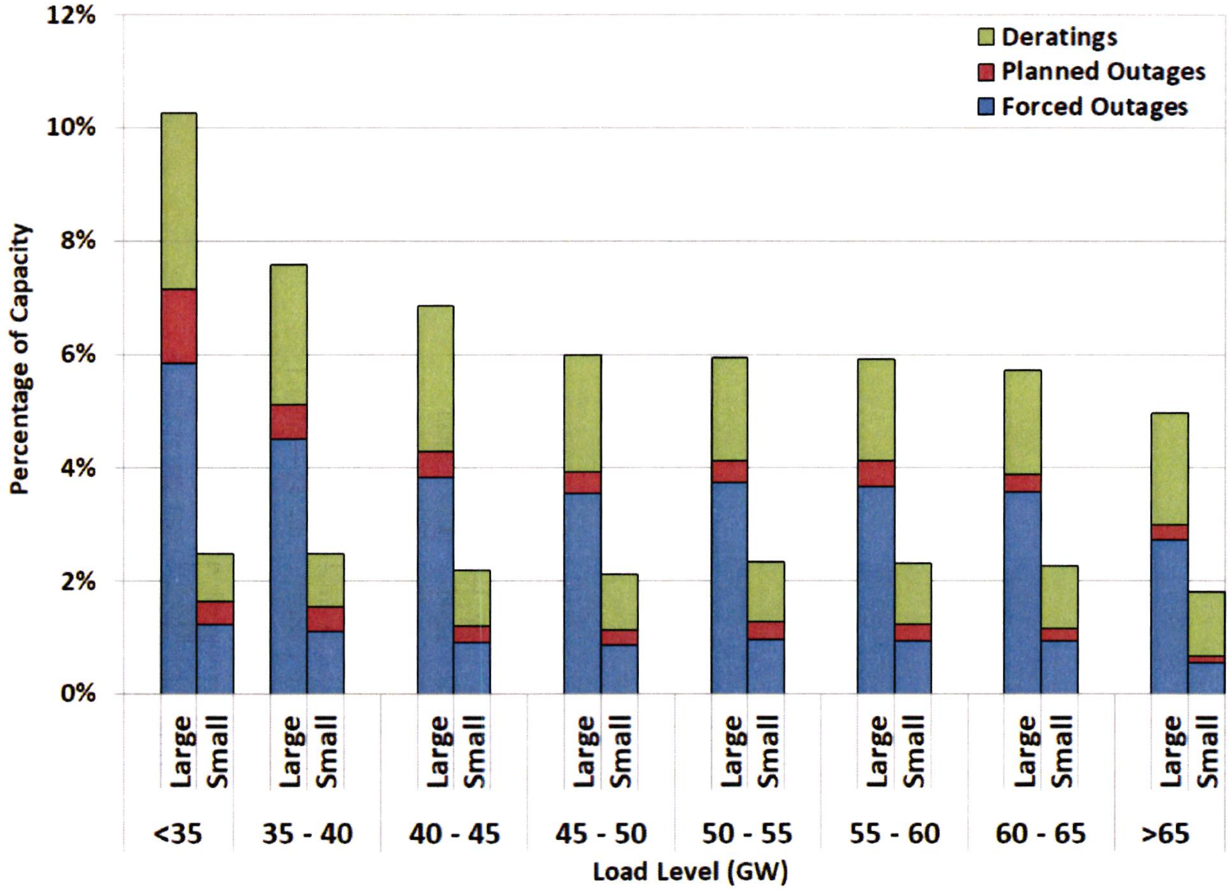


Figure 52 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the outage rates for small suppliers serves as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels exceeded those for small suppliers, but remain at levels that are small enough to raise no competitiveness concerns. Outages rates for small suppliers were historically low in 2020, while large suppliers were up minimally from 2019. Small suppliers have the most incentive to ensure generator availability because each unit in their fleet makes up a larger percentage of the total, which means that any outage has the potential for larger financial impacts.

3. Evaluation of Potential Economic Withholding

To complement the prior analysis of physical withholding, in this subsection we evaluate potential economic withholding by calculating an "output gap." The output gap is the quantity of energy that is not being produced by online resources even though the output is economic to produce by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers so as not to be dispatched.

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

Figure 53: Incremental Output Gap by Load Level and Participant Size – Step 2

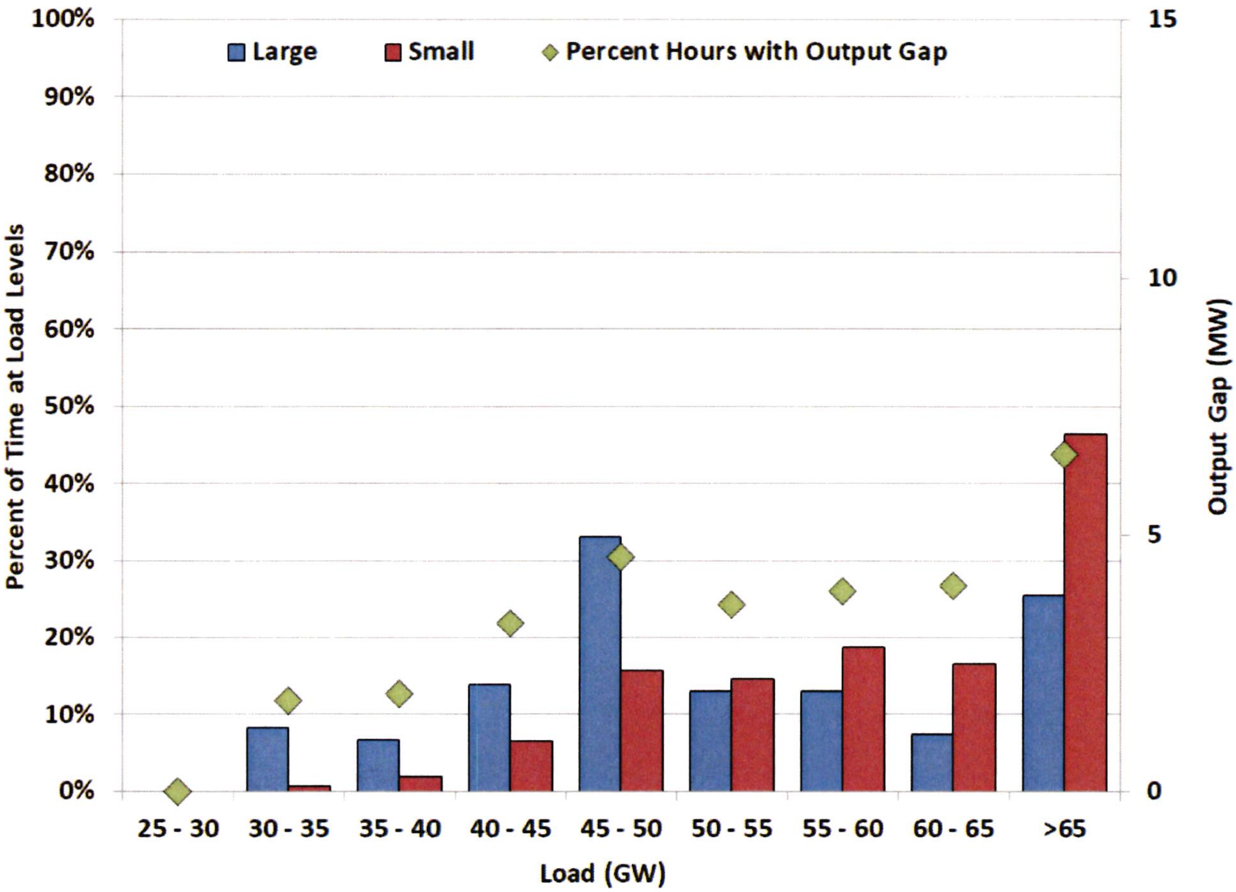


Figure 53 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer, i.e., the mitigated offers, but with a few changes. We use generic costs instead of verifiable for quick-start units since verifiable costs may contain startup costs inappropriate for comparison here. In addition, fuel adders are removed since they represent fixed costs. Finally, we do not count quick-start units if they have zero output. Relatively small quantities of capacity are considered part of this output gap, although 22% of the hours in 2020 exhibited an output gap. Taken together, these results show that potential economic withholding levels were low in 2020, and considering all of our evaluation of the market outcomes presented in this Report, allow us to conclude that the ERCOT market performed competitively in 2020.

C. Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) can be filed and if subsequently approved by the Commission, adherence to such plans constitute an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. VMPs existed for three market participants in 2020. By the end of 2019, Calpine, NRG and Luminant had active and approved VMPs that remained unchanged in 2020.[50] Further details of all three VMPs can be found in Section VII of the Appendix. Generator owners are motivated to enter into VMPs, and the increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market must be balanced by appropriate protections against a potential abuse of market power in violation of PURA §39.157(a) and 16 TAC §25.503(g)(7).

VMPs should promote competitive outcomes and prevent abuse of market power through economic withholding in the ERCOT real-time energy market. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market) because the prices in forward energy markets are derived from expectations for real-time energy prices. Forward energy markets are voluntary, and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market. Therefore, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

Key elements in the three existing VMPs are the termination provisions. The approved VMPs may be terminated by the Executive Director of the Commission with three business days' notice, subject to ratification by the Commission.[51] PURA defines market power abuses as "practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition."[52] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of competition would typically involve profitably raising prices materially above the competitive level for a significant period of time. Thus,

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50 See PUCT Docket No. 40545, Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan, Order (Mar. 28, 2013); PUCT Docket No. 40488, Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e), Order (Jul. 13, 2012); PUCT Docket No. 42611, Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies, Order (Jul. 11, 2014); and PUCT Docket No. 49858, Commission Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e) (Dec. 13, 2019).

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

52 PURA § 39.157(a).

although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner.

D. Market Power Mitigation

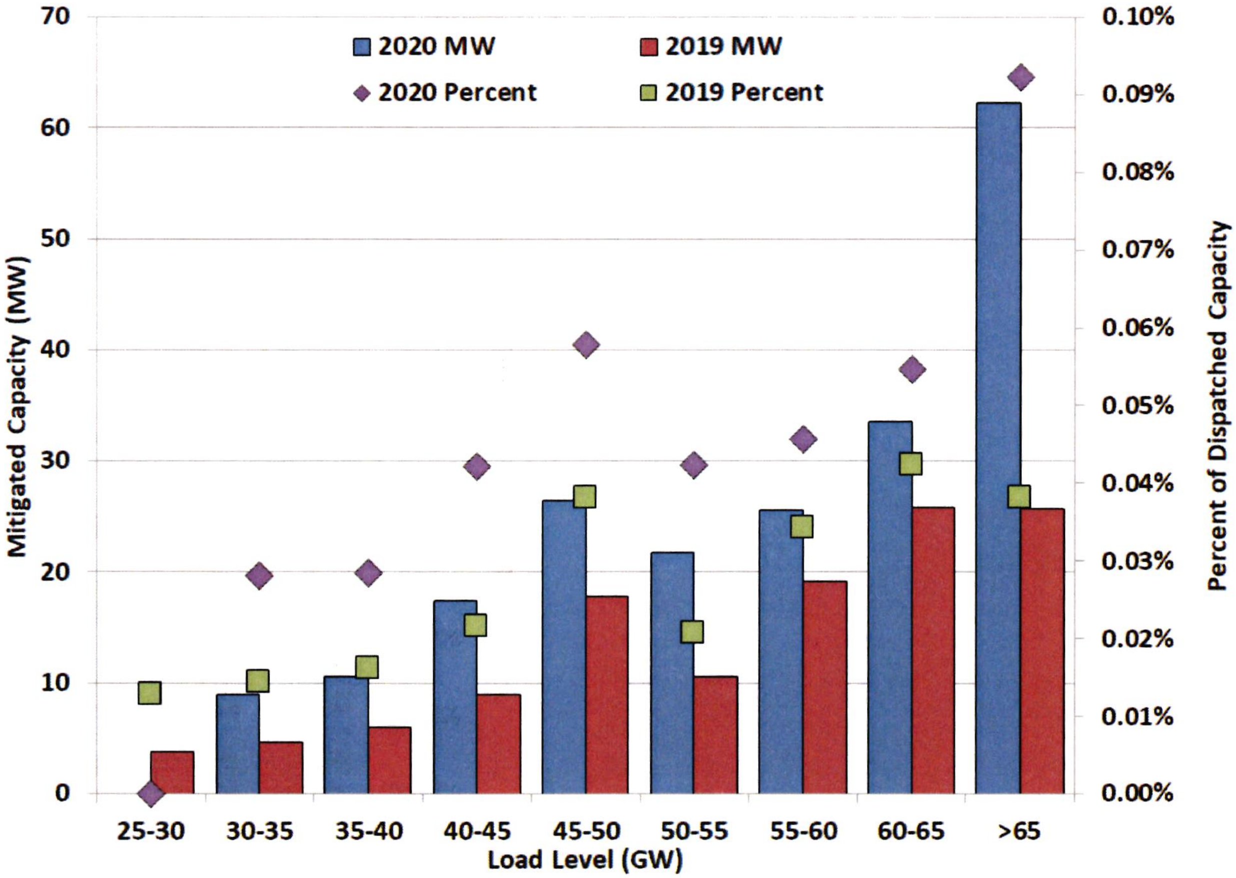
In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to a level that approximates competitive offers. ERCOT's real-time market includes a mechanism to mitigate offers for resources that are required to resolve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

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

This approach is intended to limit the ability of a generator to exercise market power, i.e., to limit its ability use its offer to raise prices in the event of a transmission constraint that requires its output to resolve. In this subsection, we analyze the quantity of mitigated capacity in 2020. Although executing at all times, the automatic price mitigation aspect of the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active and binding in SCED.

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

Figure 54: Mitigated Capacity by Load Level



The amount of mitigation in 2020 was mostly higher than in 2019. This is somewhat expected given the increase in transmission congestion in 2020. If particular resources are necessary to resolve a local constraint, that constraint is more likely to be deemed noncompetitive, resulting in mitigation. Only the amount of capacity that could be dispatched within one interval is counted as mitigated for the purpose of this analysis. More analysis of mitigation is presented and discussed in Section V in the Appendix.

CONCLUSION

As the IMM for the Commission, Potomac Economics is providing this Report to review and evaluate the outcomes of the ERCOT wholesale electricity market in 2020. The year contained high peak demand but more robust reserve margins, culminating in lower shortage pricing than the previous year. Our evaluation of a number of factors suggests that the market performed competitively in 2020. We recommend several corrections and improvements to continue the evolution of the market design.

APPENDIX

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INTRODUCTION

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

Key changes or improvements implemented or proposed in 2020 included:

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

- On March 1, 2020, Phase 1 of NPRR 863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve* became effective, implementing Fast Frequency Response (FFR), the automatic self-deployment and provision by a resource of their obligated response within 15 cycles after frequency meets or drops below a preset threshold, or a deployment in response to an ERCOT Verbal Dispatch Instruction (VDI) within 10 minutes.[53]

- On March 1, 2020, ERCOT implemented certain changes to the Other Binding Document titled, "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder" described in OBDRR011. Specifically, ERCOT implemented the second of two rightward shifts of 0.25 standard deviations to the

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

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

- Effective April 3, 2020, NPRR929, *PTP Obligations with Links to an Option DAM Award Eligibility*, provided a new criteria for determining whether a Point-to-Point (PTP) Obligation with Links to an Option bid is eligible to be awarded based on the Current Operating Plan (COP) Resource Status of the Resource at the Resource Node where the bid sources. Such a bid will no longer be eligible for award if it sources at a Resource with a COP Resource Status of OUT, or a COP Resource Status of OFF and the Resource is not offered into the Day-Ahead Market (DAM).

- Effective on May 29, 2020, NPRR856, *Treatment of OFFQS Status in Day-Ahead Make Whole and RUC Settlements*, provided language for accurate Reliability Unit Commitment (RUC) and Day-Ahead make-whole Settlement of Quick Start Generation Resources (QSGRs).

- Also effective on May 29, 2020, NPRR884, *Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources*, introduced into the ERCOT Nodal Protocols various changes needed for ERCOT systems to effectively manage cases where ERCOT issues a Reliability Unit Commitment (RUC) instruction to a Combined Cycle Generation Resource that is already Qualified Scheduling Entity (QSE)-committed for an hour, with the instruction being that the Resource operate in a configuration with greater capacity for that same hour.

- On June 9, 2020, NPRR1006, *Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data* was approved, returning the ERS resources in a linear curve over a four and a half-hour period following recall, rather than ten hours, to account for the data seen from summer 2019 as well as winter 2014 with the recognition that three days' data does not provide definitive information for further reduction. The NPRR also changed the process for updating this parameter in the future so that it can be updated by the ERCOT Technical Advisory Committee each year as appropriate, without the need to file a new NPRR.

- On June 9, 2020, NPRR1019, *Pricing and Settlement Changes for Switchable Generation Resources (SWGRs) Instructed to Switch to ERCOT*, was approved, which provided that ERCOT systems automatically create a proxy Energy Offer Curve with a price floor of $4,500/MWh for each Reliability Unit Commitment (RUC)-committed SWGR as opposed to requiring Qualified Scheduling Entities (QSEs) to submit Energy Offer Curves reflecting the $4,500/MWh floor, and included a lost revenue cost component to the Switchable Generation Cost Guarantee (SWCG) to ensure that Combined-Cycle Generation Resource SWGRs are made whole to their costs when switching from a non-ERCOT Control Area to the ERCOT Control Area.

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

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

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

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

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

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

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

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

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

Retirement of Previous IMM Recommendations

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

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

Implement transmission demand curves

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

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

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

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

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

Improve the mitigated offers for generating resources

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

Implement a locational reliability deployment price adder (RDPA)

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

I. APPENDIX: REVIEW OF REAL-TIME MARKET OUTCOMES

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

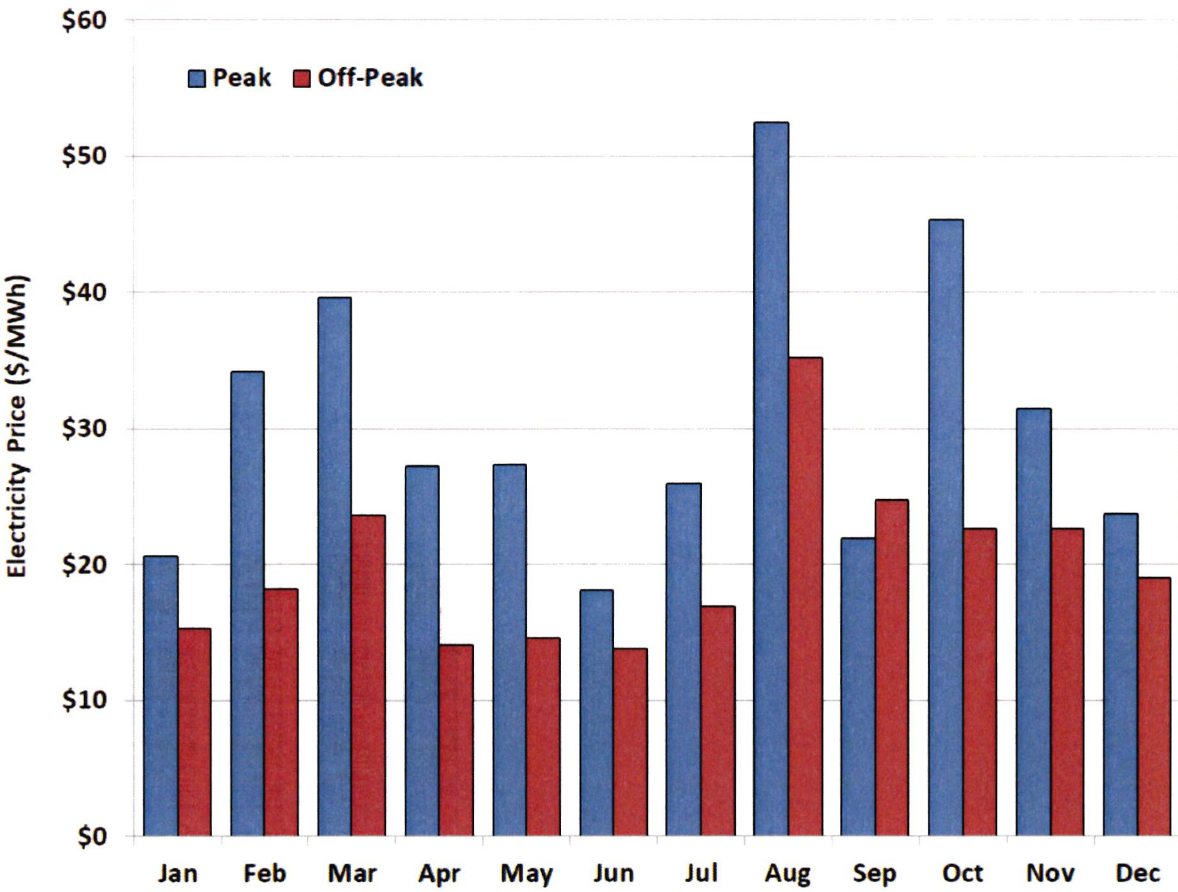
Table A1: ERCOT 2020 Year at a Glance (Annual)

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

A. Real-Time Market Prices

Real-time energy prices vary substantially by time of day. Figure A1 shows the load-weighted average real-time prices in ERCOT for the categories of Peak and Off-Peak for each month in 2020. The Peak block includes hour ending (HE) 7 to HE 22 on weekdays; the Off-Peak block includes all other hours. These pricing blocks align with the categories traded in forward markets.

Figure A1: Peak and Off-Peak Pricing

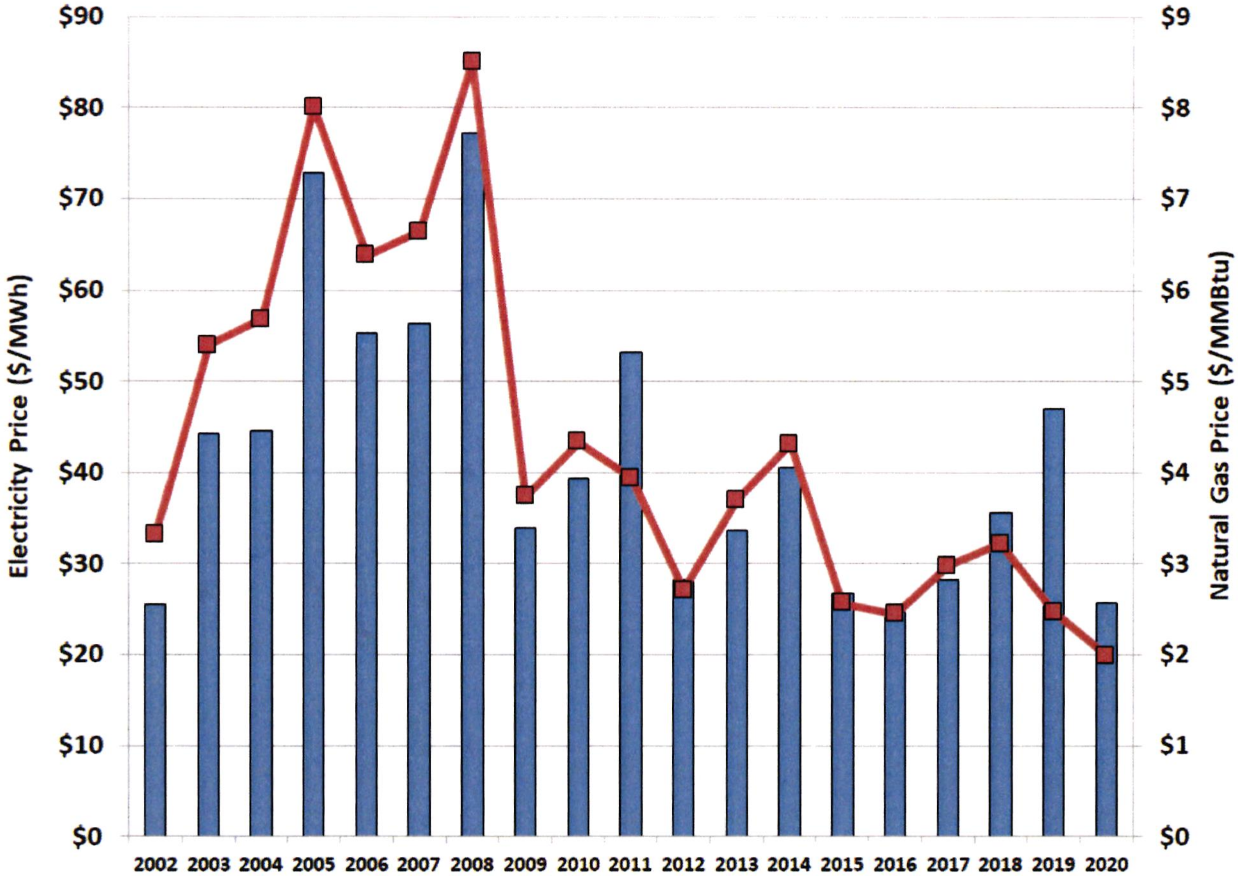


As expected, Peak hours were higher priced than Off-Peak hours for every month in 2020, with the exception of September, when Off-Peak hour prices were $2.84 per MWh higher than peak hour prices. The September Off-Peak price average was impacted by a weekend of high prices on Saturday, September 12 due to exceptionally low wind output over the load peak. For all other months, the difference ranged from a minimum of $4.30 per MWh in June to a maximum of $22.71 per MWh in October. Because of the relative absence of severe shortage conditions during the summer of 2020, no months in 2020 were comparable to August 2019, when the difference was $275.00 per MWh due primarily to shortage conditions and the resulting high prices (multiple intervals at the high system-wide offer cap (HCAP) of $9,000 per MWh) seen during peak hours in the week of August 12, 2019. The average difference between monthly Peak and Off-Peak pricing in 2020 was $10.61 per MWh.

B. Zonal Average Energy Prices in 2020

Figure A2 below provides additional historic perspective on the ERCOT average real-time energy prices as compared to the average natural gas prices in each year from 2002 through 2020.

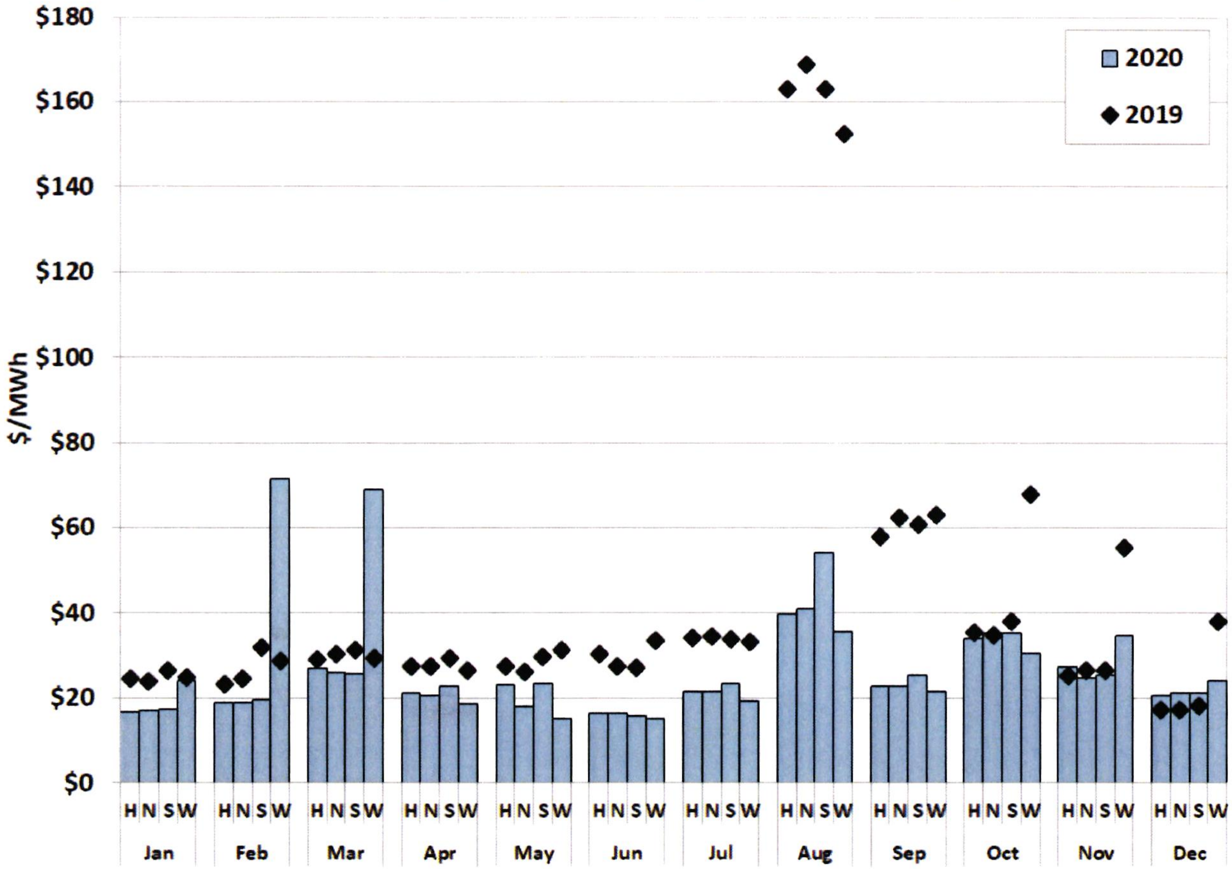
Figure A2: ERCOT Historic Real-Time Energy and Natural Gas Prices



Like Figure 1 in the body of the report, Figure A2 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price. Such relationship is consistent with expectations in ERCOT where natural gas generators predominate and tend to set the marginal price; this is an indication that the price of electricity is reflective of the cost of production. Only in 2011 and 2019 did those trends diverge; in both those years there was significant shortage pricing; that is, the cost of electricity reflected both the cost of production and shortage conditions. This outcome is expected in years with low reserve margins or extreme weather. Neither of those factors were prevalent in 2020.

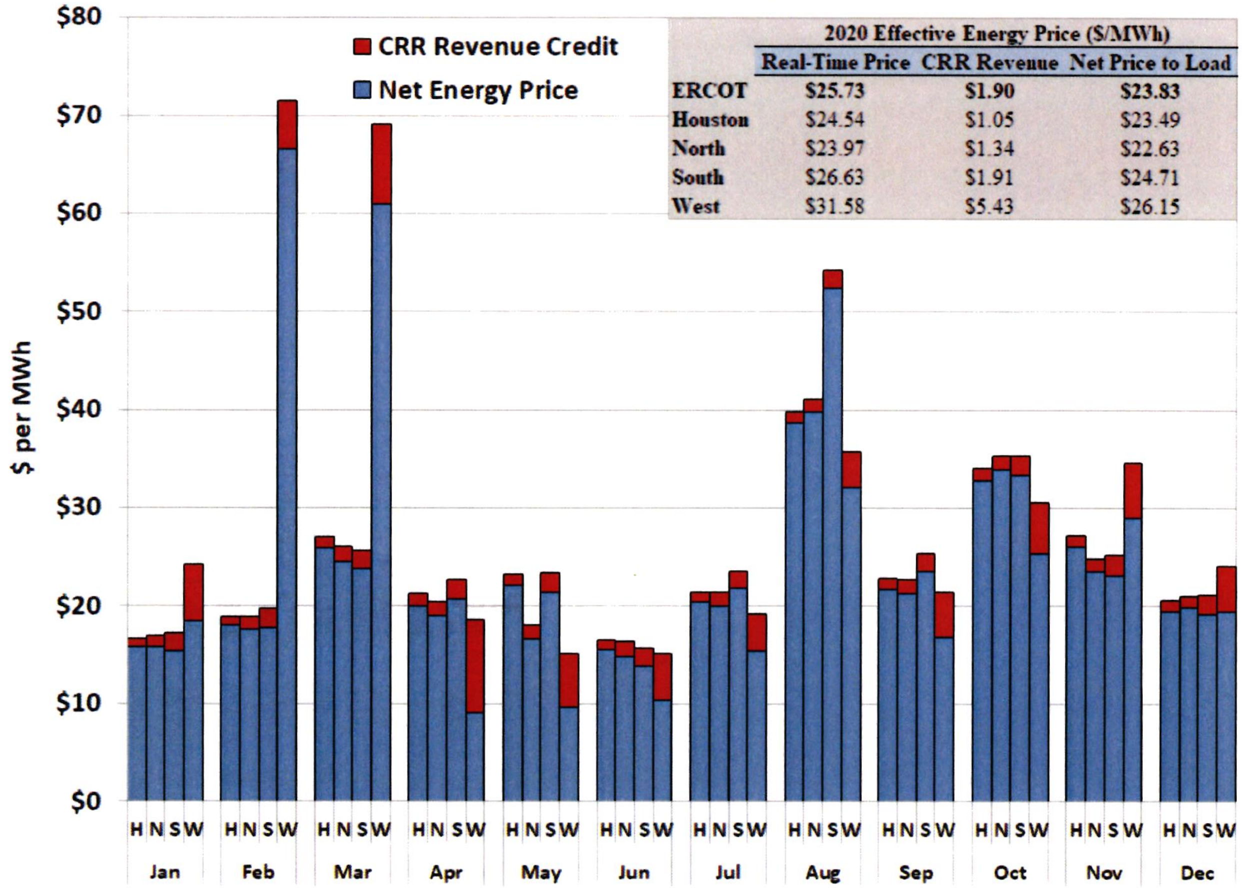
Figure A3 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2019 and 2020. These prices are calculated by weighting the real-time energy price for each interval and each zone by the total load in that interval. Load-weighted average prices are most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral or other forward contract prices. These prices in 2020 were not particularly volatile month-to-month, especially in comparison to 2019.

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



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

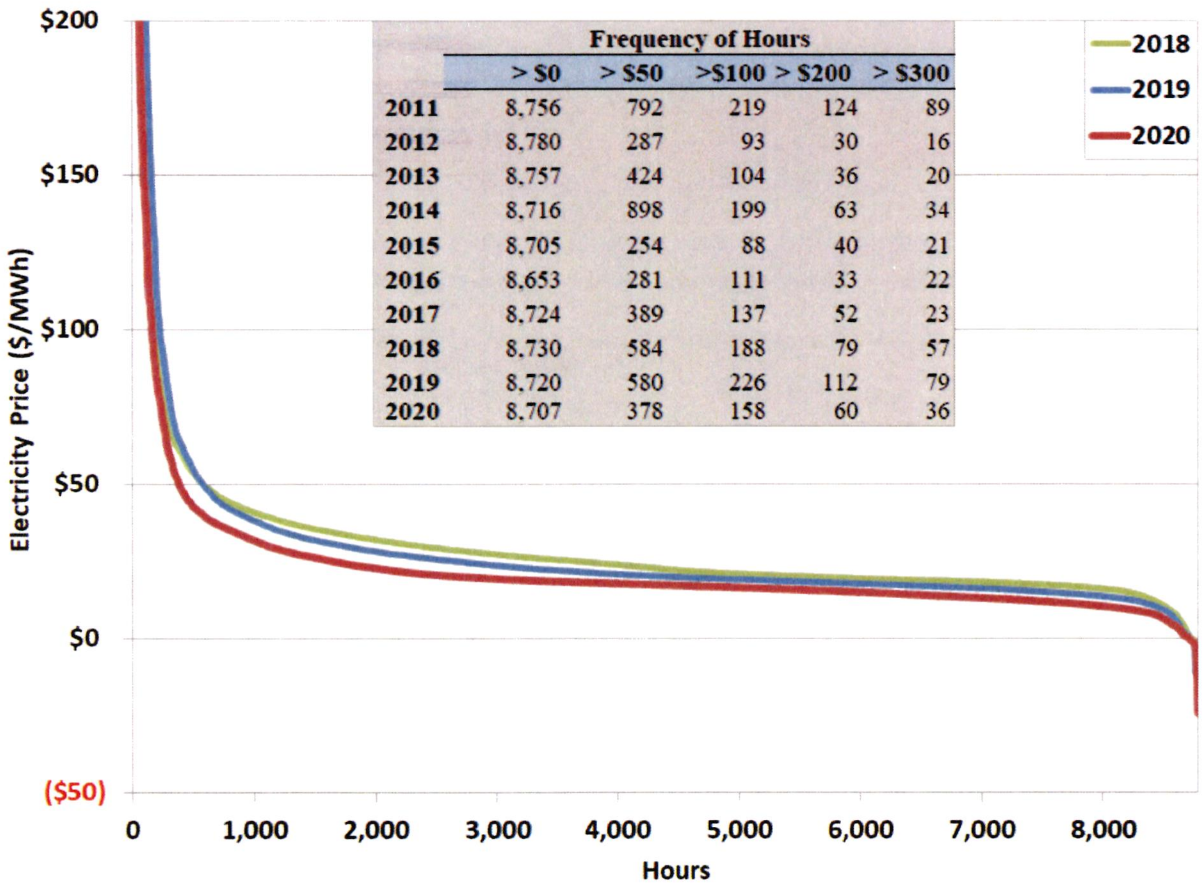
Figure A4: Effective Real-Time Energy Market Prices



2020 Effective Energy Price ($/MWh)	Real-Time Price	CRR Revenue	Net Price to Load
ERCOT	$25.73	$1.90	$23.83
Houston	$24.54	$1.05	$23.49
North	$23.97	$1.34	$22.63
South	$26.63	$1.91	$24.71
West	$31.58	$5.43	$26.15

A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). Figure A5 shows price duration curves for the ERCOT energy market for 2018 through 2020, with 2019 showing the most shortage pricing hours since the nodal market implementation. The prices in this figure are the hourly ERCOT average prices derived by load weighting the zonal settlement point prices.

Figure A5: ERCOT Price Duration Curve

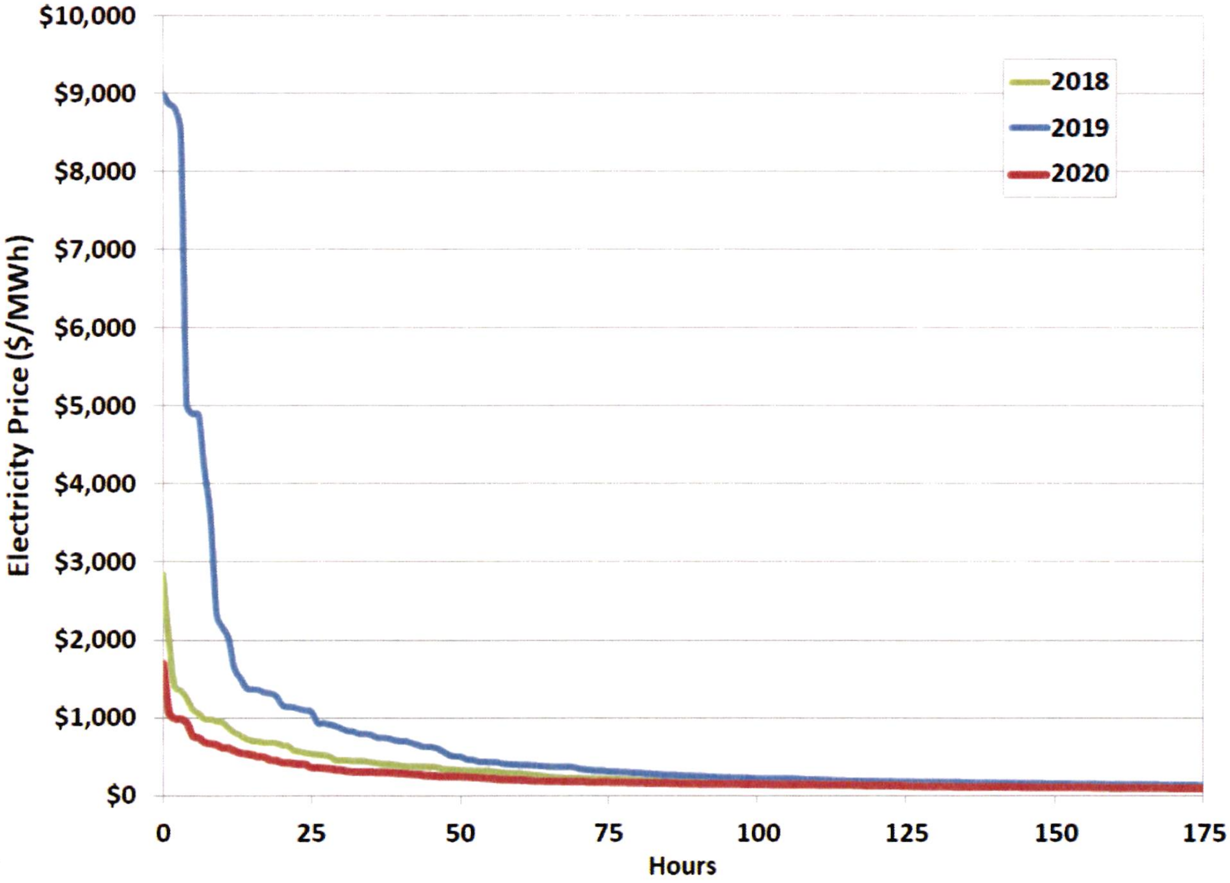


Frequency of Hours	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21
2016	8,653	281	111	33	22
2017	8,724	389	137	52	23
2018	8,730	584	188	79	57
2019	8,720	580	226	112	79
2020	8,707	378	158	60	36

Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure led to increased occurrences of negative prices over the past few years, reaching a high of 131 hours in 2016. That trend reversed in 2017, when there were 36 hours with ERCOT-wide prices at or below zero. In 2020, there were 77 hours with ERCOT-wide prices at or below zero, an increase from the 40 hours in 2019.

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

Figure A6: ERCOT Price Duration Curve – Top 2% of Hours



C. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven largely by changes in natural gas prices, they are also influenced by other factors. To summarize the changes in energy price that were related to these other factors, an "implied heat rate" is calculated by dividing the real-time energy price by the natural gas price.

Figure A7 and Figure A8 show the load-weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart displays the number of hours (shown on the horizontal axis) that the implied heat rate is at or above a certain level (shown on the vertical axis).

Figure A7: Implied Heat Rate Duration Curve – All Hours

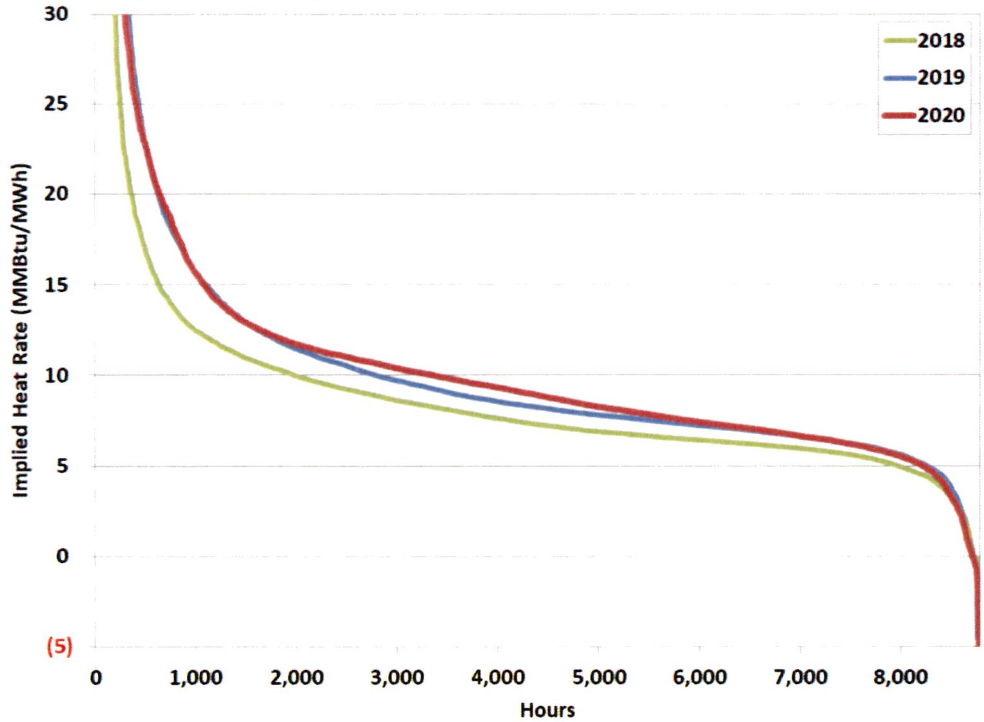


Figure A8 shows the implied marginal heat rates for the top 2% of hours from 2018 to 2020. The implied heat rate duration curve for the top 2% of hours in 2020 was much lower than 2019, and more similar to 2018, because of the lack of significant contributions from shortage pricing.

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

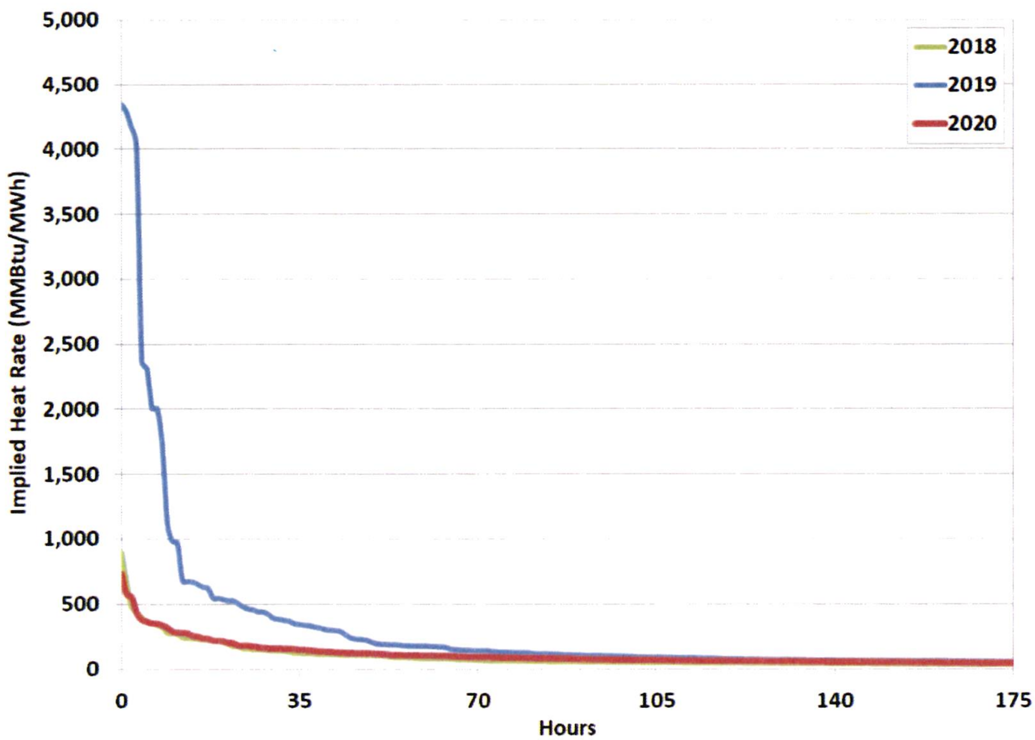


Table A2 displays the annual average implied heat rates by zone for 2014 through 2020. Adjusting for natural gas price influence, Figure A8 shows that the annual, system-wide average implied heat rate decreased significantly in 2020 compared to 2019. Zonal variations in the implied heat rate were greater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

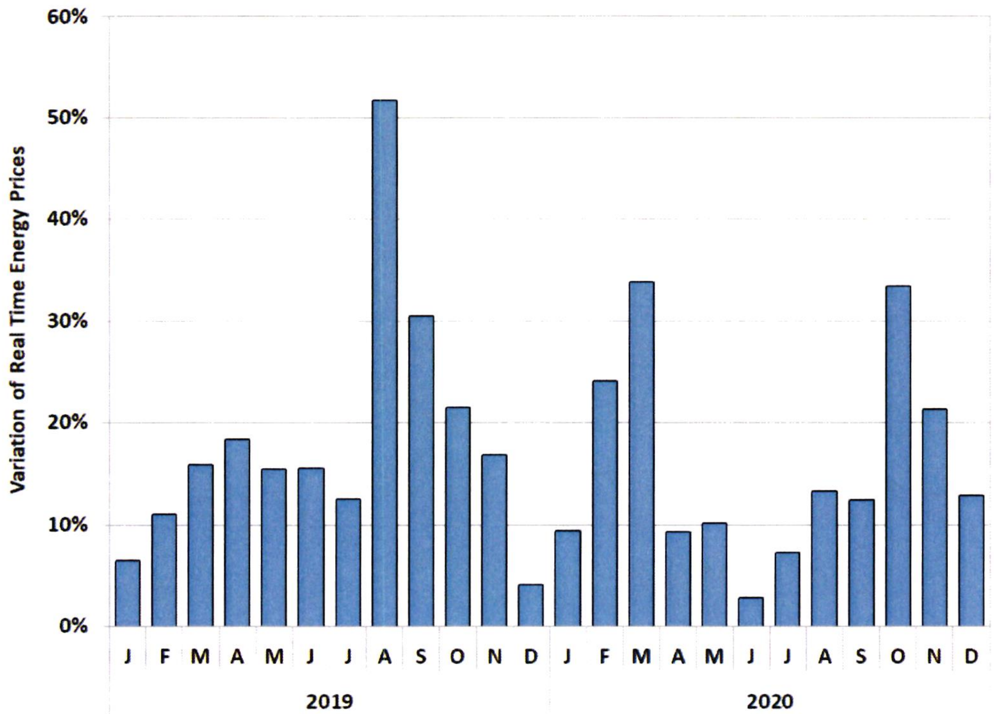
Table A2: Average Implied Heat Rates by Zone

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

D. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. Expanding the view of price volatility, Figure A9 below shows monthly average changes in five-minute real-time prices by month for 2019 and 2020.

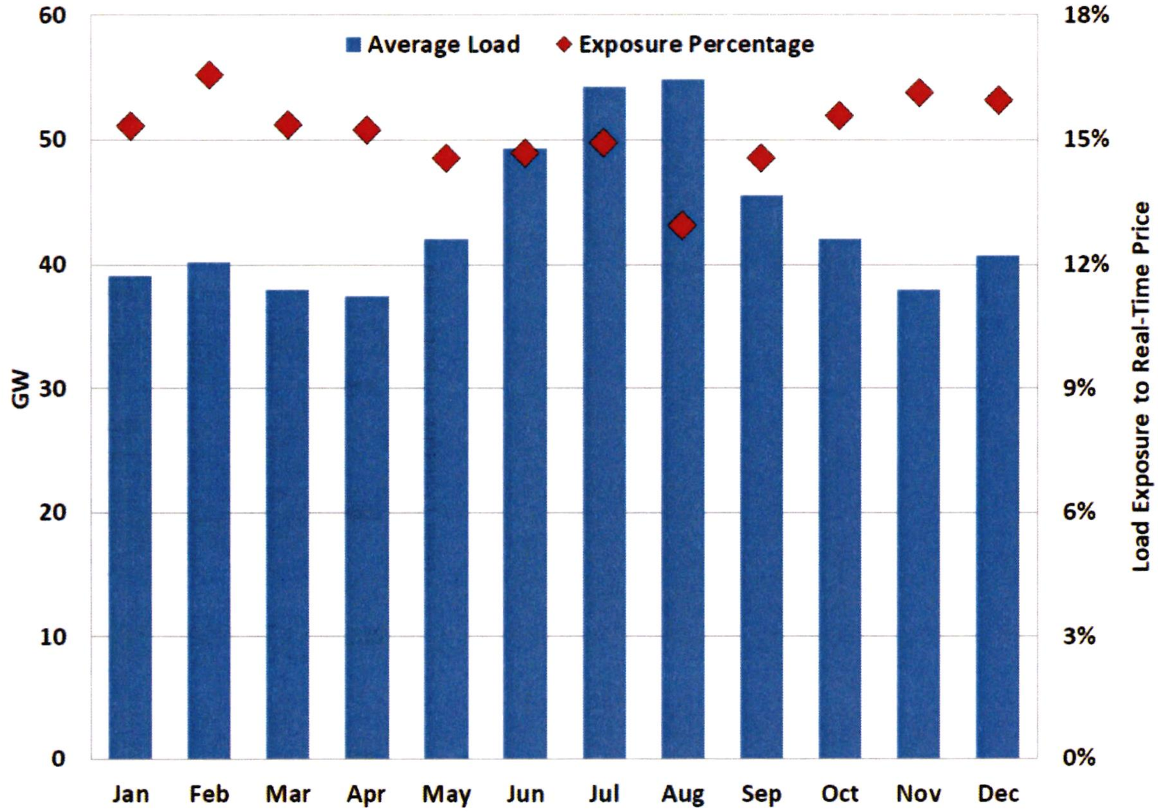
Figure A9: Monthly Price Variation



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

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

Figure A10: Monthly Load Exposure



This determination of exposure is based solely on ERCOT-administered markets and does not include any bilateral or over-the-counter (OTC) index purchases. The smallest portions of load potentially exposed to real-time prices in 2020 was lowest in the summer months with the lowest exposure occurring in August. Unhedged loads would be vulnerable to any shortage conditions that may occur during August. The highest portions of load potentially exposed to real-time prices in 2020 occurred at the beginning and end of 2020, in February, March, October and November, respectively. Although the overwhelming majority of load is not exposed to real-time prices, these prices do form the foundation for all pricing expectations, which inform both supplier and consumer contracting decisions.

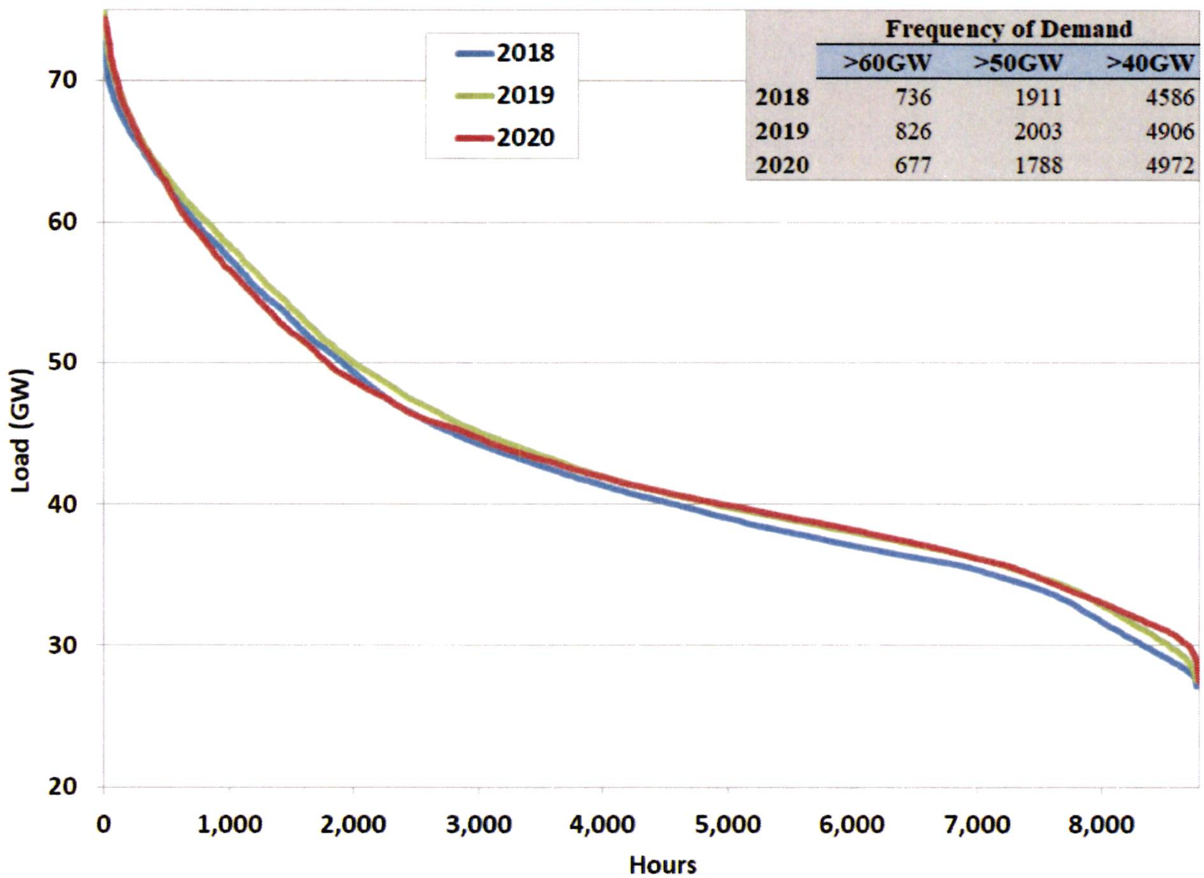
II. APPENDIX: DEMAND AND SUPPLY IN ERCOT

In this section, we provide supplemental analyses of load patterns during 2020 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2020

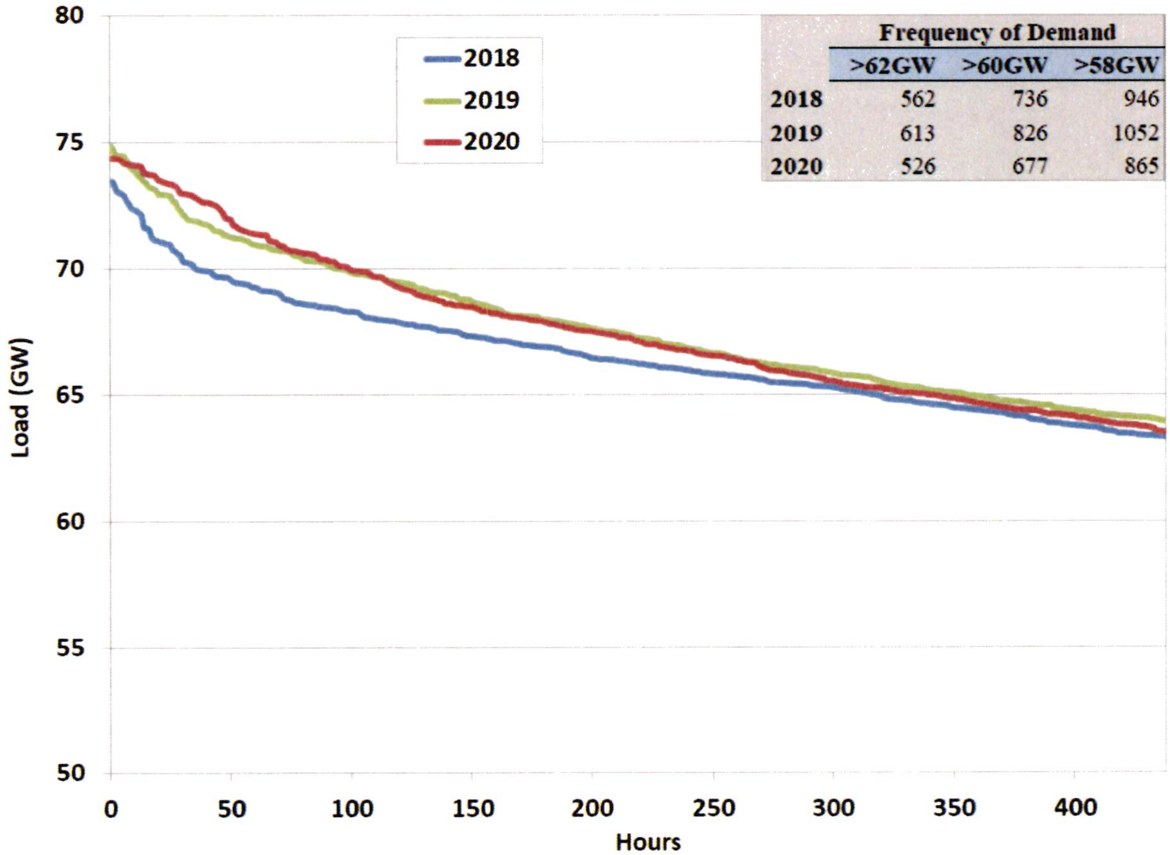
To provide a more detailed analysis of load at the hourly level, Figure A11 compares load duration curves for each year from 2018 through 2020. A load duration curve illustrates the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT has a fairly smooth load duration curve, typical of most electricity markets, with low to moderate electricity demand in most hours, and peak demand usually occurring during the late afternoon and early evening hours of days with exceptionally high temperatures. The load duration curve in 2020 was similar to both 2018 and 2019, though slightly higher as load growth continues in ERCOT.

Figure A11: Load Duration Curve – All Hours



To better illustrate the differences in the highest-demand periods between years, Figure A12 below shows the load duration curve for the 5% of hours with the highest loads for the last three years. This figure also shows that the peak load in each year was significantly greater than the load at the 95th percentile of hourly load. Since 2011, the peak load has averaged 16% to 19% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than 5% of the hours.

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



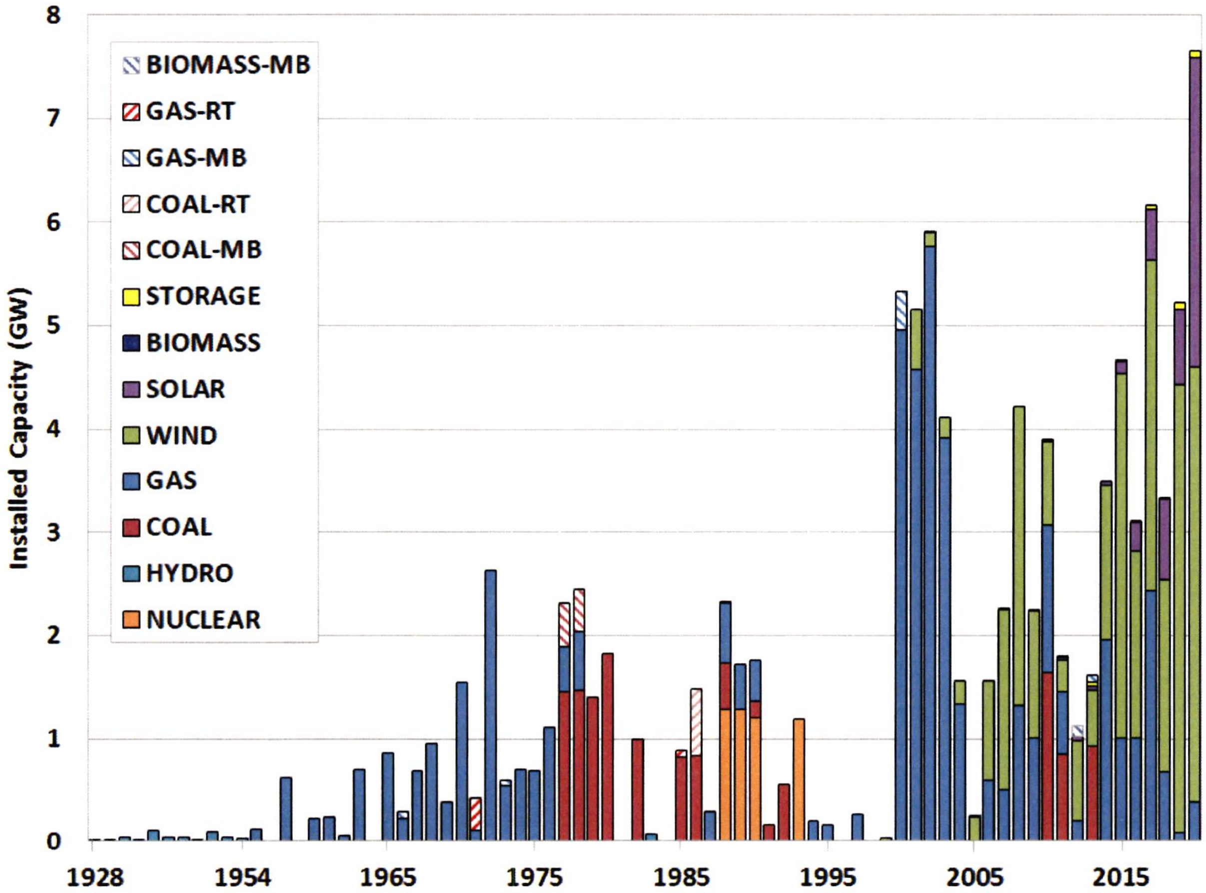
B. Generation Capacity in ERCOT

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

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

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

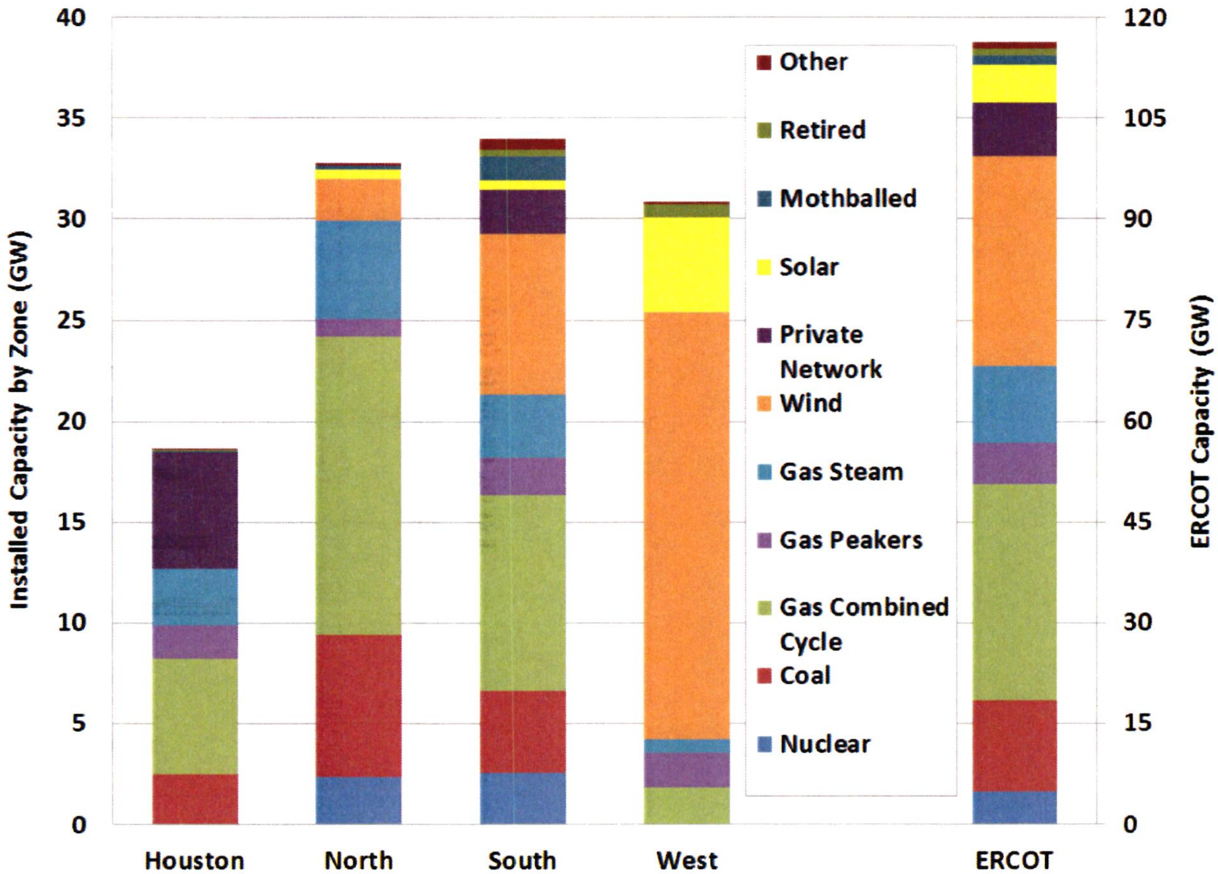
Figure A13: Vintage of ERCOT Installed Capacity



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

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

Figure A14: Installed Capacity by Technology for Each Zone



Approximately 7.7 GW of new generation resources came online in 2020; 4.2 GW of wind resources with an effective peak serving capacity of about 1 GW, 3 GW of solar resources with an ELCC of 2.4 GW. The remaining capacity was 390 MW from combustion turbines and 70 MW of power storage. The majority of the new wind and solar resources were located in the South and West Load Zones. Three resources retired permanently, representing a total summer Seasonal Net Max Sustainable Rating of 1,030 MW.

C. Wind and Solar Output in ERCOT

The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure A15 shows average wind production for each month in 2019 and 2020, with the average production in each month divided into four-hour blocks. Though the lowest wind output generally occurs during summer afternoons, the average wind output during summer peak period increased to 7 GW, due to increases in the amount of wind capacity in ERCOT along with increased geographic diversity of those resources. This may be a small fraction of the total installed capacity, but wind generation is a significant contributor to generation supply, even at its lowest outputs.

Figure A15: Average Wind Production

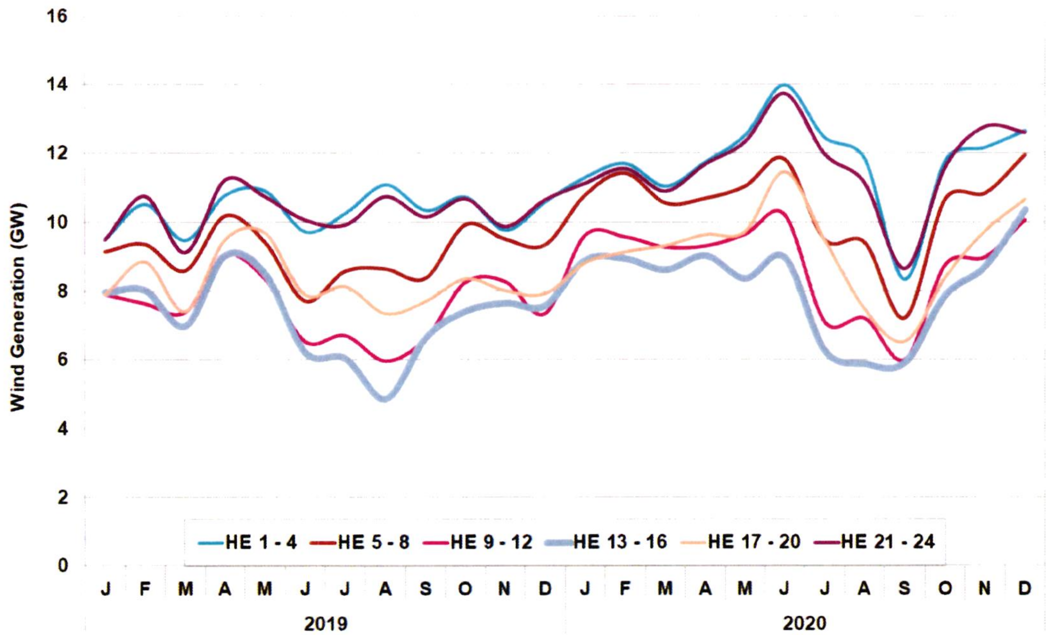
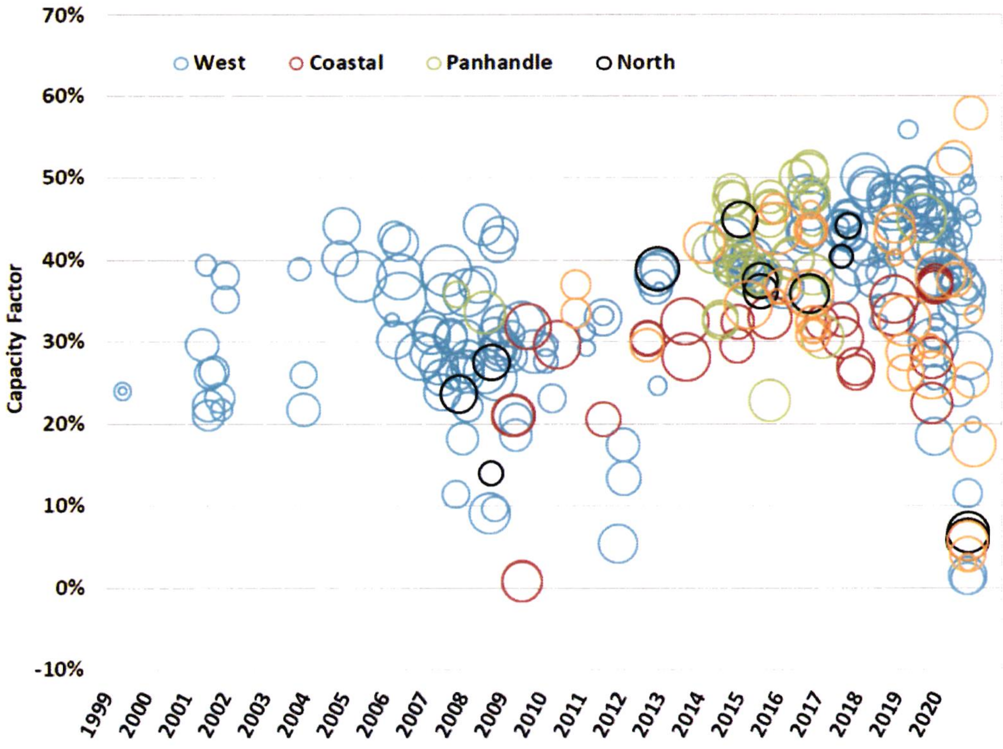


Figure A16 shows the capacity factor (the ratio of actual energy produced by a resource to the hypothetical maximum possible at is full rating) and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location because of the different wind profiles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

Figure A16: Wind Generator Capacity Factor by Year Installed



As more wind generation capacity is installed in ERCOT, more energy from that capacity will be produced. However, the amount of energy produced will vary depending on actual wind speeds, which can vary from year to year. The next figure shows the average wind speed in ERCOT, as weighted by the locations of current installed wind generation. Figure A17 provides a means to compare wind speeds on an annual basis and indicates that the average wind speed in 2020 increased dramatically from 2019, higher than the average over the past 10 years, and by far the highest it has been.

Figure A17: Historic Average Wind Speed

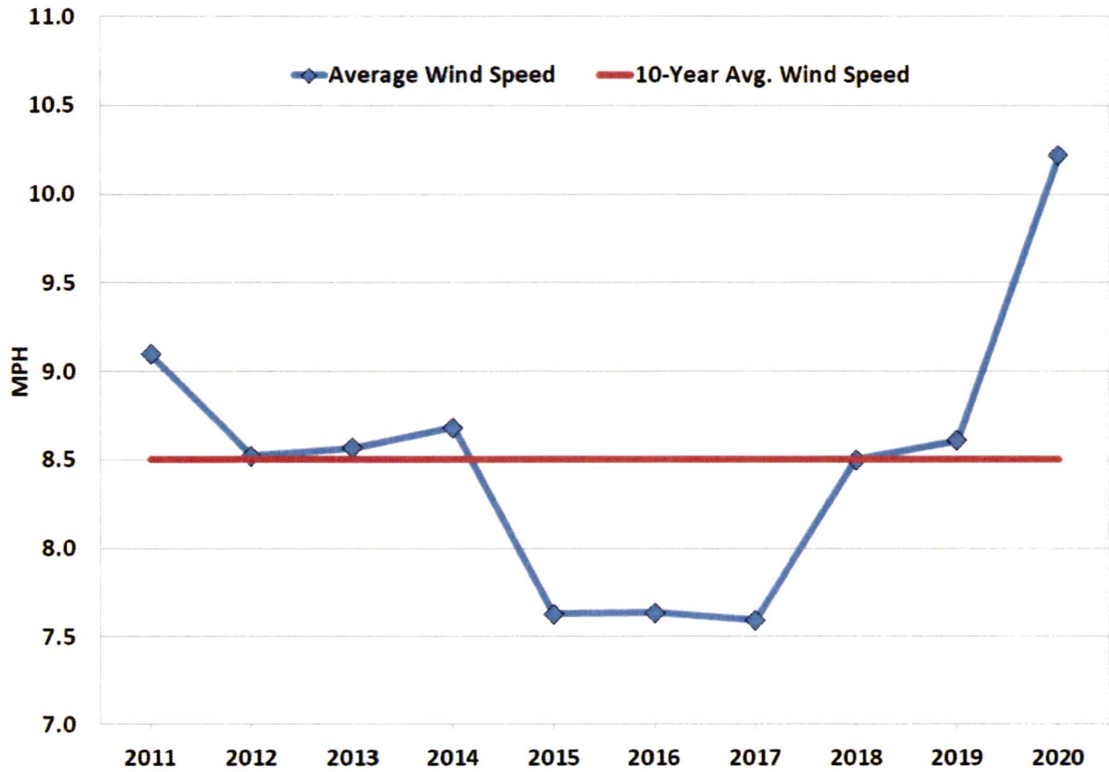
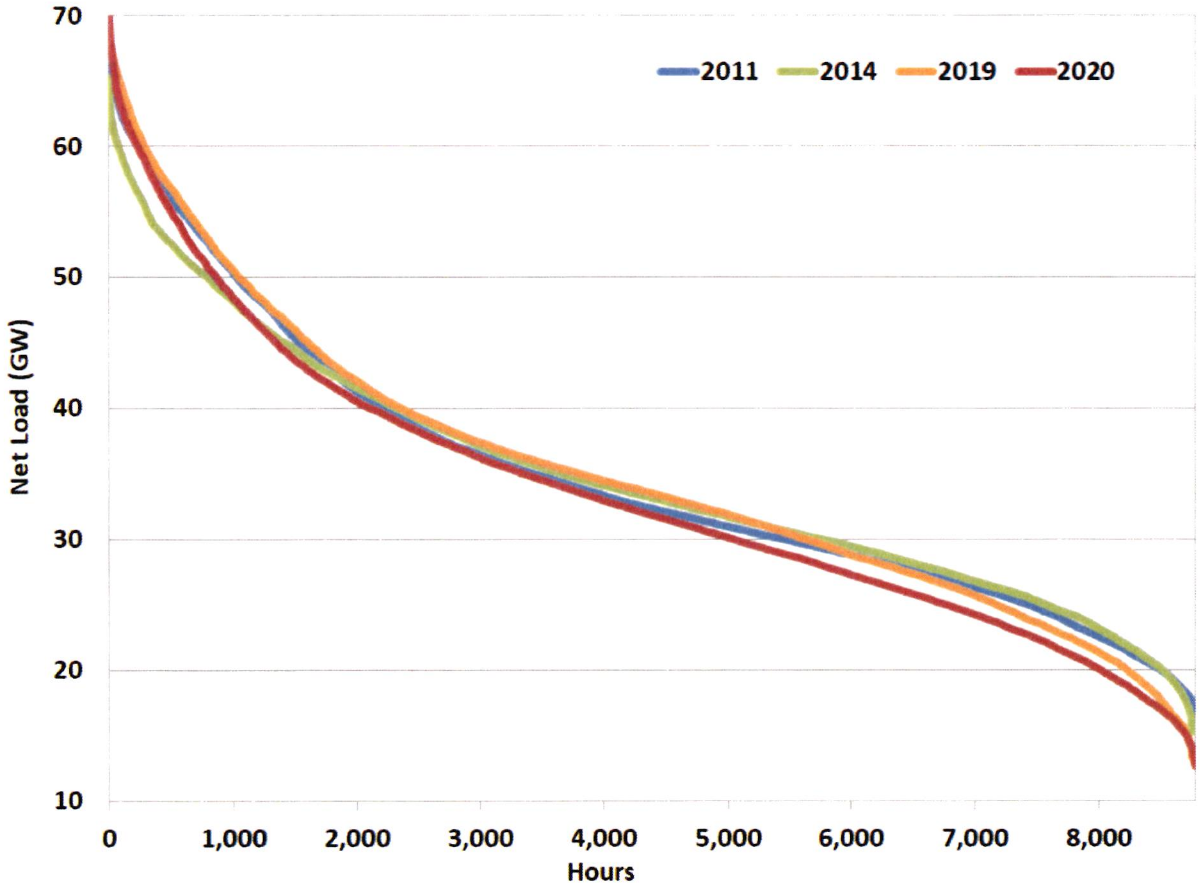


Figure A18 shows the net load duration curves for the years 2011, 2014, 2019 and 2020. Years 2011 and 2014 are included for historical context. Volatility in the net load amounts continues to increase. Increasing wind output has important implications for non-wind resources and for resource adequacy in the ERCOT region as growth in peak demand requires additional resources to be added, but the energy available to be served by non-wind resources overall is reduced.

Figure A18: Net Load Duration Curves



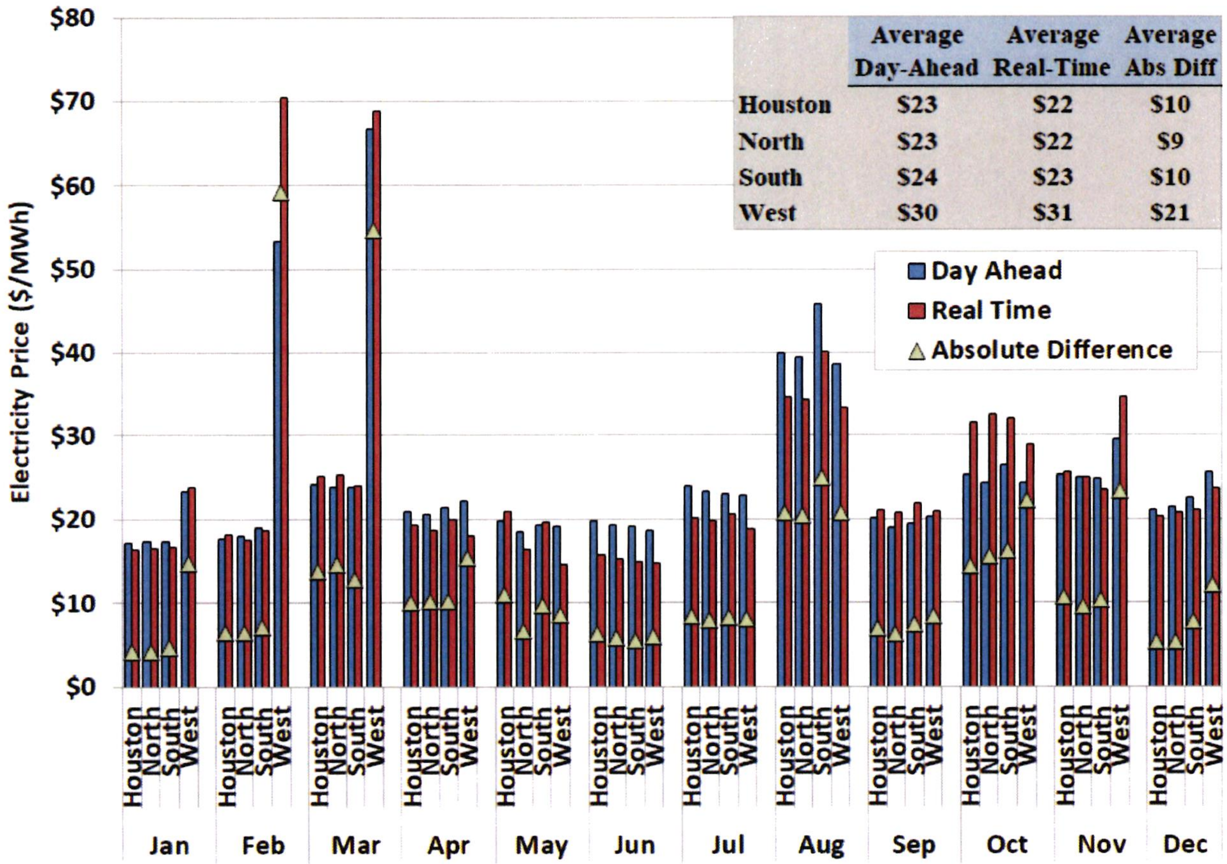
III. Appendix: Day-Ahead Market Performance

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

A. Day-Ahead Market Prices

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

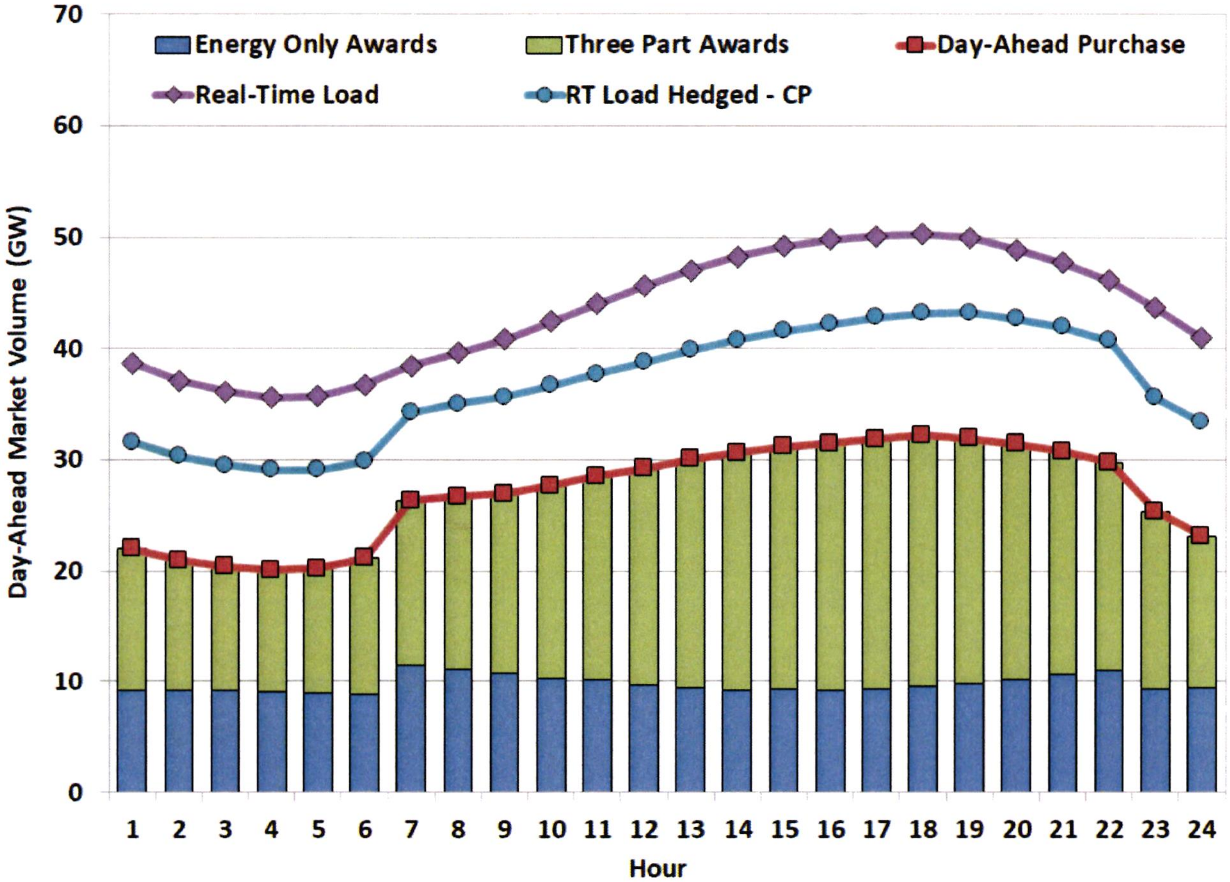
Figure A19: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Figure A20 below presents the same day-ahead market activity data in 2020 summarized by hour of the day. In this figure, the volume of day-ahead market transactions is disproportionate with load levels between HE 7 and HE 22. Because these times align with common bilateral and financial market transaction terms, the results in this figure are consistent with market participants using the day-ahead market to trade around those positions.

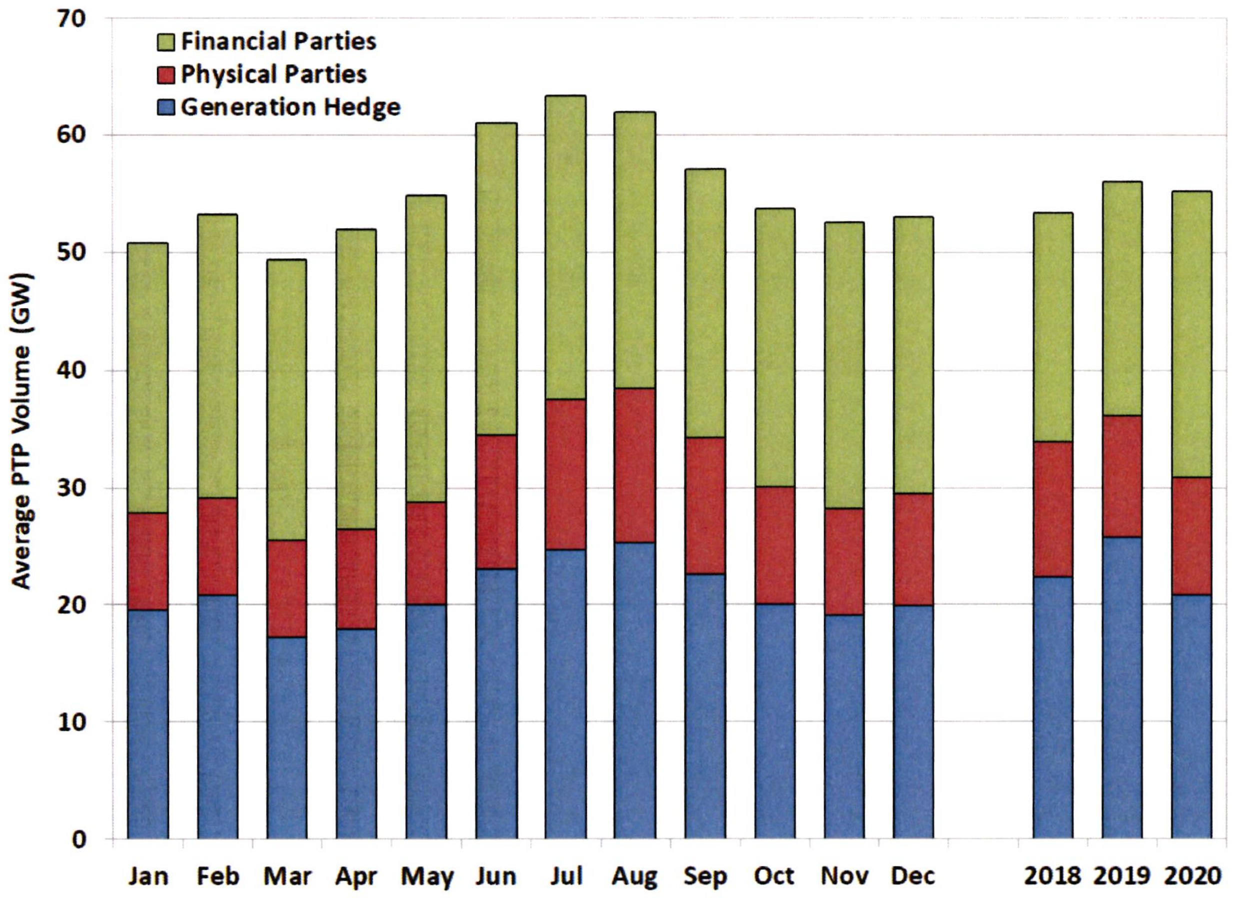
Figure A20: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Figure A21 below presents the total volume of PTP obligation purchases in 2020 divided into three categories. There can be multiple PTP obligations sourcing and sinking at the same settlement point, however the volumes in this figure do not net out those injections and withdrawals. Average purchase volumes are presented on both a monthly and annual basis. The total volume of PTP obligation cleared purchases has been fairly stable for the past three years, with 2020 falling in between 2018 and 2019.

Figure A21: Point-to-Point Obligation Volume



For all PTP obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that generation hedging comprised most of the volume of PTP obligations purchased in 2018 and 2019, but that in 2020, financial parties actually comprised most of the volume of PTP obligations purchased. Other than generation hedging, the volumes of PTP obligations are not directly linked to a physical position. They are assumed to be purchased primarily to arbitrage anticipated price differences between two locations or to hedge trading activities occurring outside of the organized market. This arbitrage activity is further separated by type of market participant.

Physical parties are those that have actual real-time load or generation, whereas financial parties have neither. Financial parties again purchased 42% of the total volume of PTP obligations in 2020, higher than the 36% in 2018 and 2019. Financial parties increasing volumes can have liquidity benefits but also strains the software, particularly those bids that are unlikely to be awarded. As discussed in our recommendation No. 2020-4, a bid fee would better allocate the scarce labor and hardware resources in the DAM, especially since these parties do not contribute otherwise to the administration of ERCOT.

D. Ancillary Services Market

Figure A22 below displays the hourly average quantities of ancillary services procured for each month in 2020.

Figure A22: Hourly Average Ancillary Service Capacity by Month

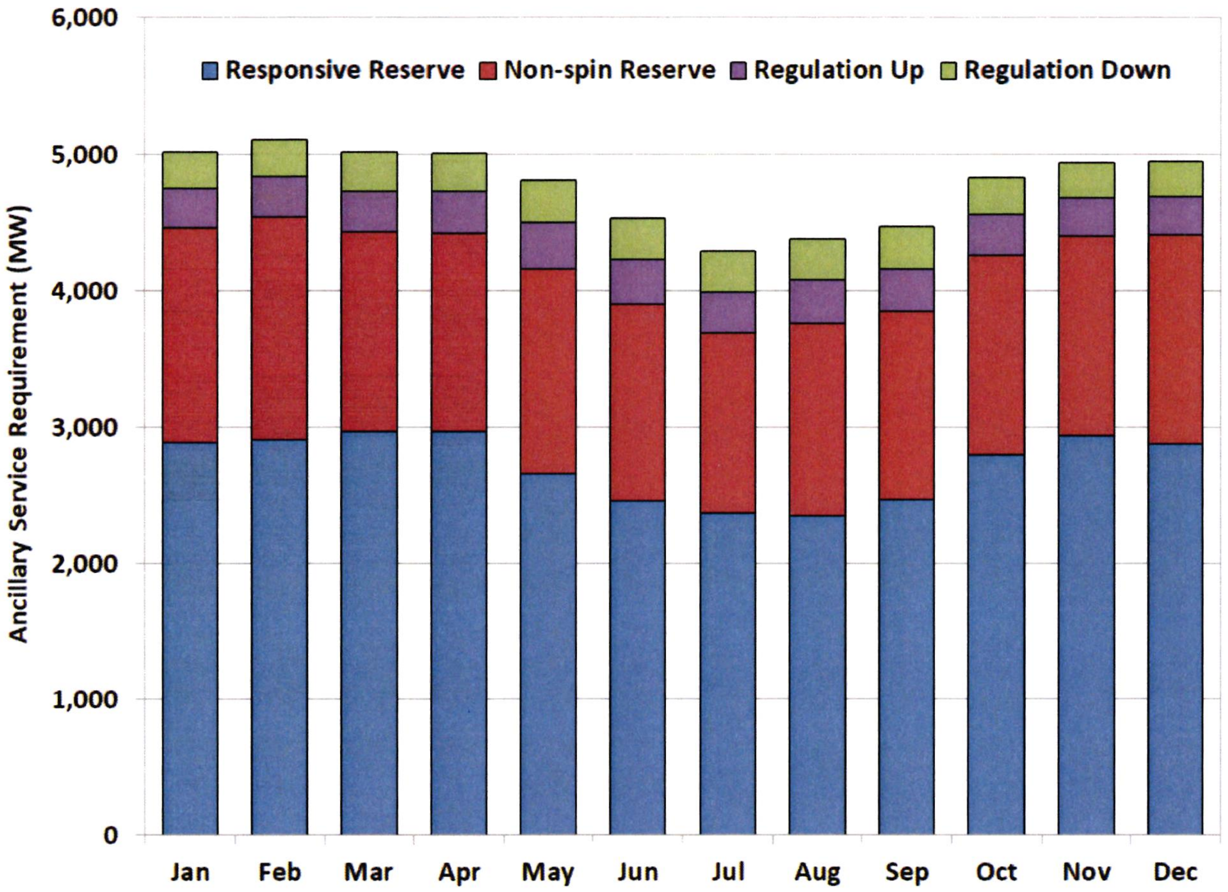


Figure A23 presents an alternate view of ancillary service requirements, displaying them by hour, averaged over the year. In this view the large variation in quantities between some adjacent hours was readily apparent. This pattern was a result of the methodology that, broadly speaking, sets quantities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

Figure A23: Yearly Average Ancillary Service Capacity by Hour

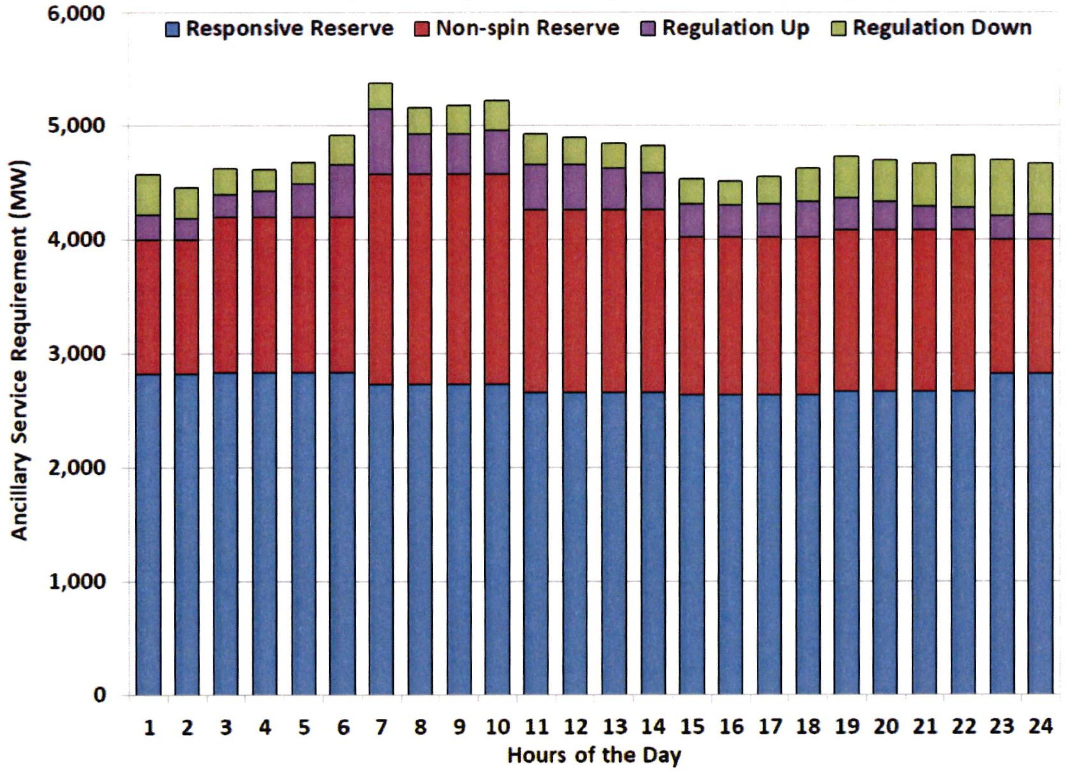
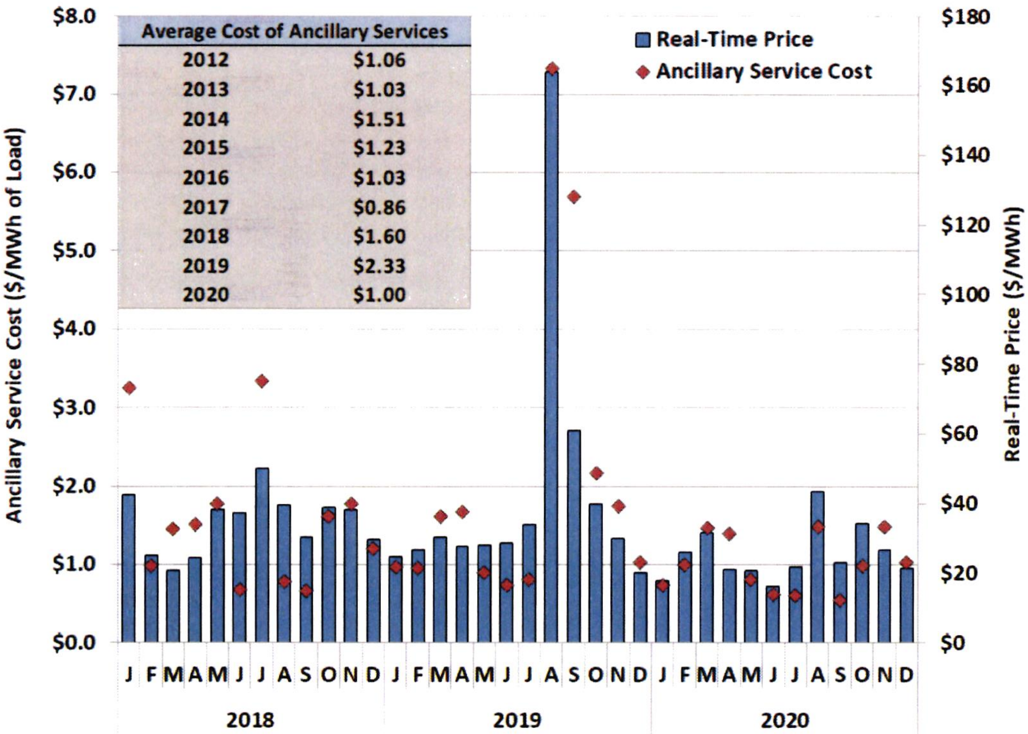


Figure A24 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2018 through 2020.

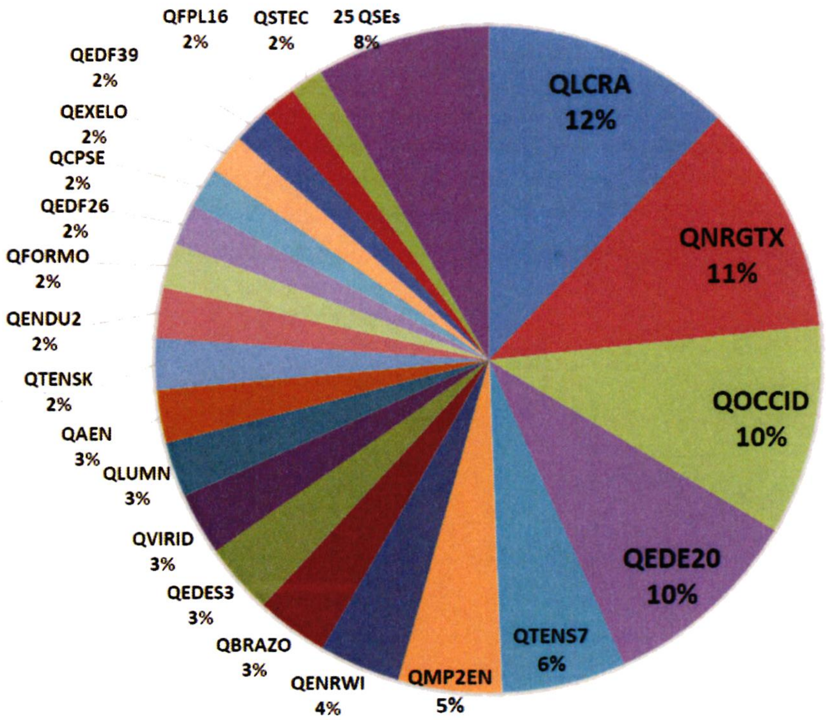
Figure A24: Ancillary Service Costs per MWh of Load



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

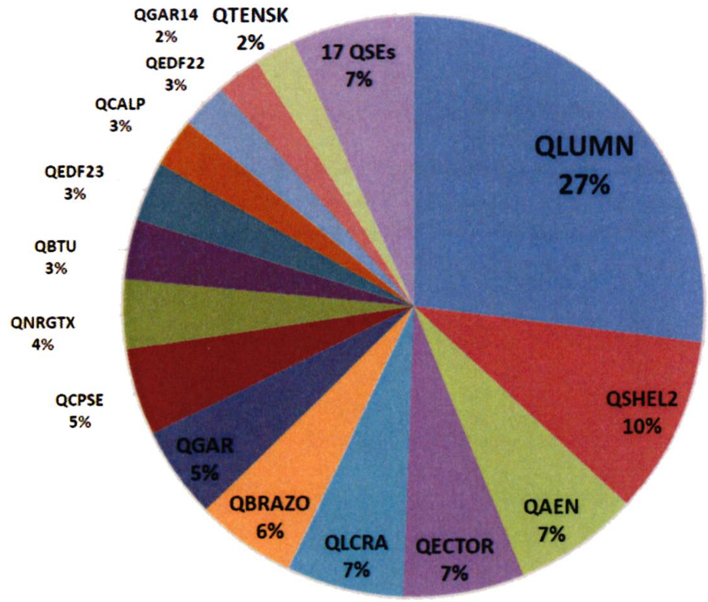
Figure A25 below shows the share of the 2020 annual responsive reserve responsibility including both load and generation, displayed by QSE. During 2020, 46 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market. The number of providers has been roughly the same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

Figure A25: Responsive Reserve Providers



In contrast, Figure A26 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE (Luminant, QLUMN) still bearing are large share of the total responsibility, but a smaller share than in years past. Luminant's 27% share of non-spin responsibility was a decrease from the 37% share it held in 2019, 41% in 2018, and 56% in 2017. The change in composition of Luminant's generation fleet likely explains the continued reduction. As Luminant's non-spin responsibility decreased again in 2020, many other suppliers such as Austin Energy (QAEN) and LCRA (QLCRA) increased their share slightly.

Figure A26: Non-Spinning Reserve Providers



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

Figure A27: Regulation Up Reserve Providers

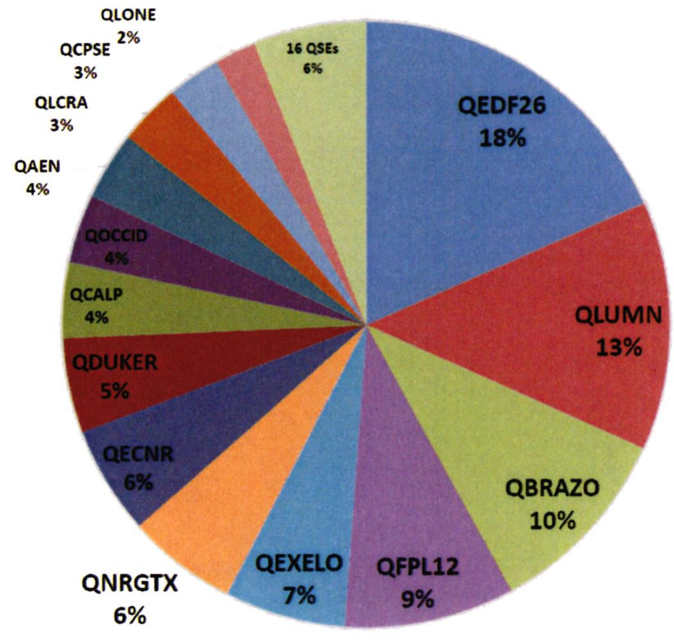
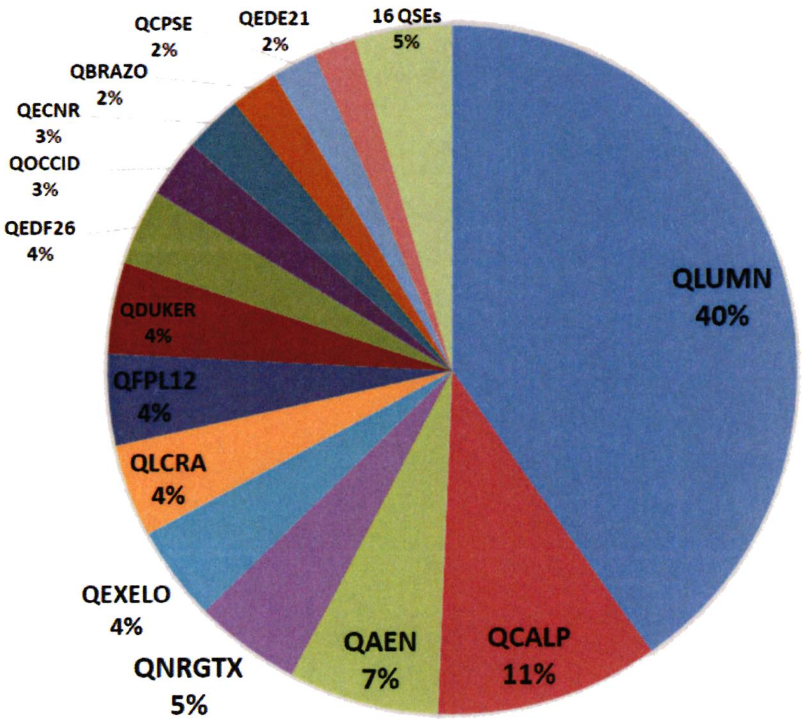


Figure A27 above shows the distribution for regulation up reserve service providers and Figure A28 shows the distribution for regulation down reserve providers in 2020. Figure A27 shows that regulation was spread more evenly, similar to responsive reserve providers, while EDF North America (QEDF26) more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

Figure A28: Regulation Down Reserve Providers



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

1. Supplemental Ancillary Services Market (SASM)

The ERCOT market appropriately reflects the tradeoff between providing capacity for ancillary services versus providing energy in its co-optimized day-ahead market. Those same tradeoffs exist in real-time. Until comprehensive, market-wide co-optimization is implemented, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest, and therefore are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios are still effectively precluded from participating in ancillary service markets because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in SASM are typically three to 40 times greater than annual average clearing prices from the day-ahead market.

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

Figure A29: Ancillary Service Quantities Procured in SASM

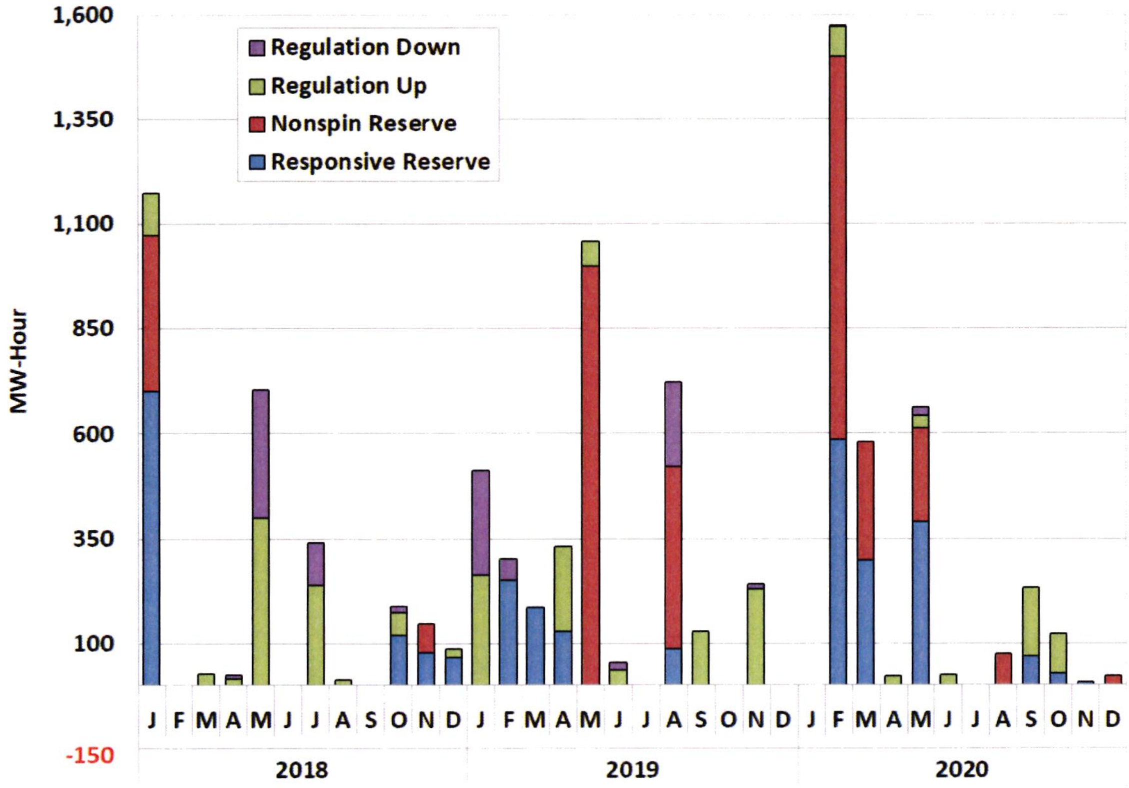
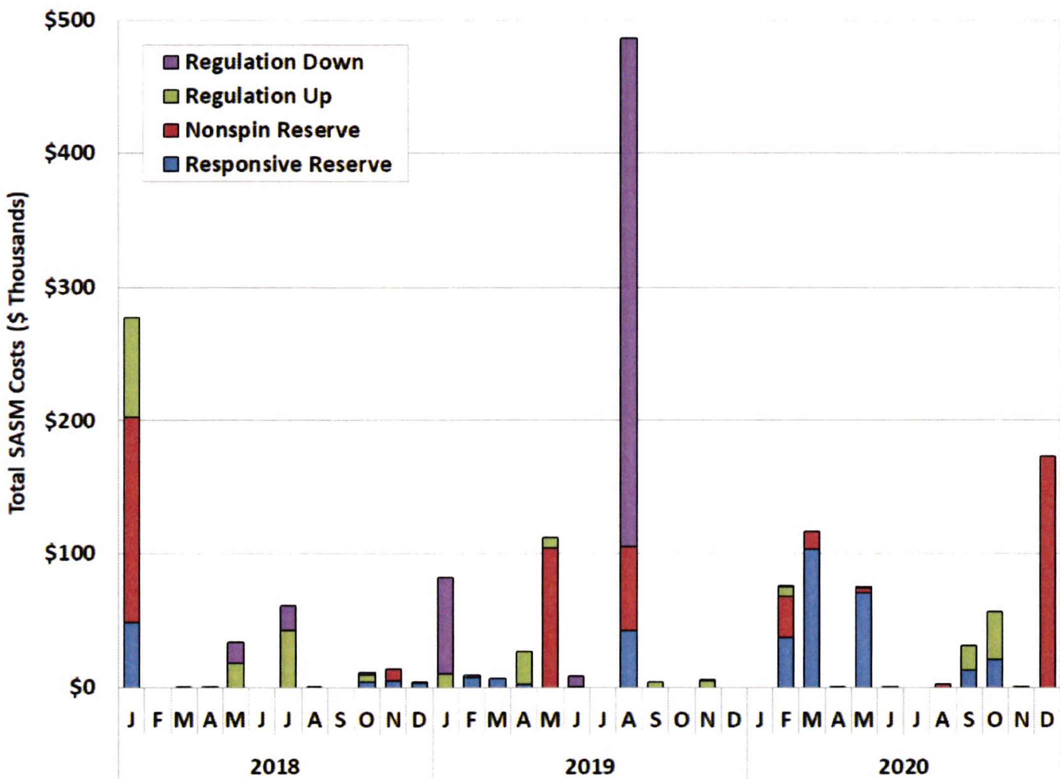


Figure A29 shows that the volume of service-hours procured via SASM over the year (more than 3,300 MWs of service-hours in 2020) is still infinitesimal when compared to the total ancillary service requirement of nearly 42 million MWs of service-hours.

Figure A30 shows the average cost of the replacement ancillary services procured by SASM in 2020. Nothing in 2020 approached the total SASM costs seen in August of 2019, by far the highest SASM costs seen since the beginning of 2018. If a resource has reserve responsibilities under tight shortage conditions, the QSE would factor in the risk of covering responsibilities for those who could not provide ancillary services when they themselves might need to provide energy, so they have high reserve costs to cover their energy requirements if they end up providing reserves. However, because of the relative absence of shortage conditions, resources were less likely to be diverted to provide energy rather than reserves, thus lowering the cost of ancillary services in 2020.

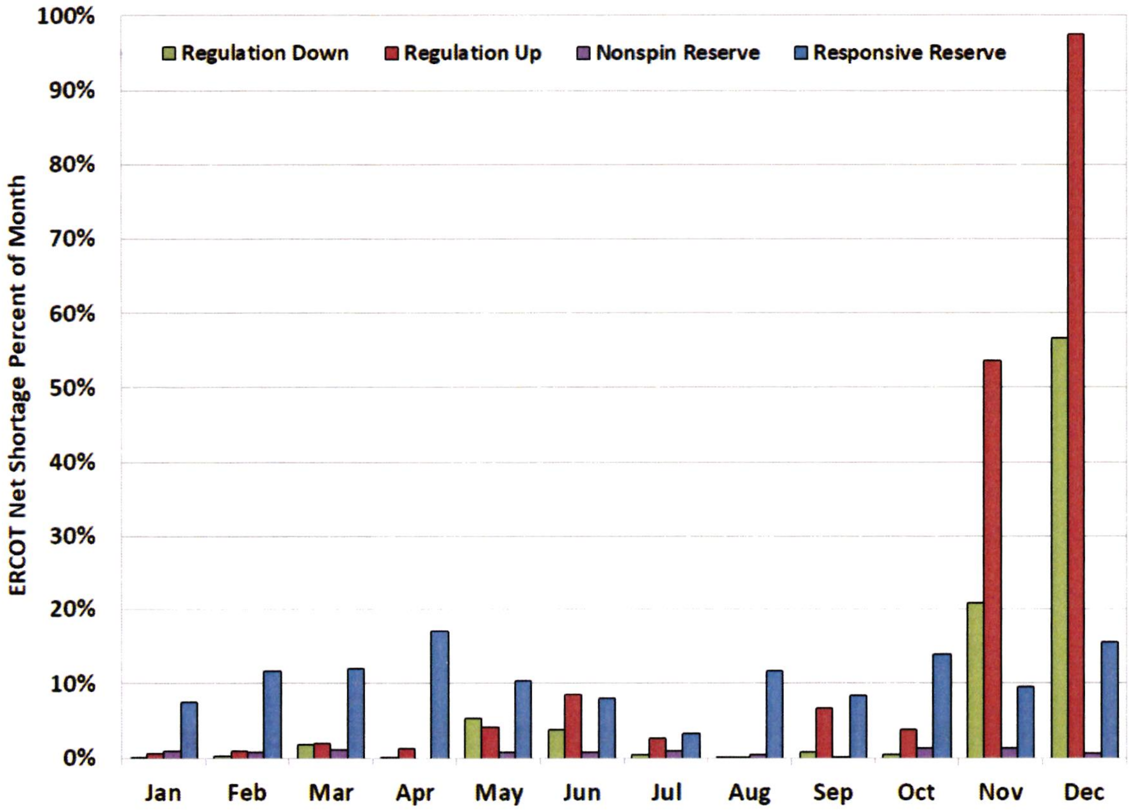
Figure A30: Average Costs of Procured SASM Ancillary Services



Real-time co-optimization of energy and ancillary services will not require resources to estimate opportunity costs between providing energy or reserves, will eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider. The greatest benefit will be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g., because of a generator forced outage. Thus, implementation of real-time co-optimization will provide benefits across the market in future years.

In addition to its other weaknesses, a SASM is only useful for replacing ancillary services as part of a forward-looking view of the grid conditions. However, there are instances where the system is short ancillary services in real-time as per the resource details telemetered to ERCOT. Figure A31 depicts the percentage of hours in each month of 2020 where there was an ERCOT-wide shortage in the respective ancillary service. For this analysis, a shortage is defined as greater than 0.1 MW of obligation not being provided for at least 15 minutes out of an hour.

Figure A31: ERCOT-Wide Net Ancillary Service Shortages



This analysis shows that ERCOT-wide shortages for all ancillary services were relatively low in 2020, generally at or below 10% in all months for all services, although regulation up and down experienced slightly higher shortages during the fall months, occurring in more than 50% of hours in November and December. These were primarily due to one entity and have been addressed. Again, this analysis is based on the telemetered status provided by the parties with the responsibility.

Table A3 is the monthly aggregate costs of various ERCOT market settlement totals in 2020, including AS costs by type.

Table A3: Market at a Glance Monthly

	Monthly Totals (Millions)											
	Jan	Feb	May	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Energy	$522	$732	$899	$568	$648	$573	$878	$1,786	$764	$1,075	$734	$648
Regulation Up	$1.88	$2.12	$2.88	$2.74	$2.28	$1.84	$2.25	$5.18	$1.53	$2.41	$3.09	$1.92
Regulation Down	$1.42	$1.24	$1.39	$2.20	$2.69	$1.65	$1.47	$1.64	$2.22	$2.11	$1.33	$1.92
Responsive Reserve	$15.6	$20.4	$32.2	$27.4	$16.6	$13.6	$16.9	$41.9	$11.8	$20.4	$32.2	$23.7
Non-Spin	$2.38	$4.30	$4.99	$5.36	$3.72	$4.88	$4.05	$11.58	$2.55	$5.94	$4.05	$3.61
CRR Auction Distribution	$54.9	$51.4	$65.8	$68.3	$60.3	$64.3	$65.2	$66.5	$59.2	$60.7	$53.9	$55.0
Balancing Account Surplus	$6.7	$11.0	$11.6	$12.5	$11.6	$0	$0	$0	$0	$0	$0	$0
CRR DAM Payment	$75	$155	$200	$55	$43	$57	$60	$197	$53	$137	$143	$100
PTP DAM Charge	$63	$135	$172	$50	$40	$44	$46	$153	$44	$106	$107	$79
PTP RT Payment	$68	$180	$192	$37	$71	$36	$50	$147	$45	$94	$127	$78
Emergency Response Service	$0	$16.3	$0	$0	$0	$11.7	$0	$0	$0	$16.8	$0	$0
Revenue Neutrality	$6.40	$7.59	$26.98	$2.78	$14.20	($0.30)	$1.37	($13.3)	$5.28	($2.87)	$22.35	$5.15
ERCOT Fee	$16.1	$15.6	$15.7	$15.0	$17.4	$19.7	$22.4	$22.7	$18.2	$17.4	$15.2	$16.8
Other Load Allocation	$0.58	$0.67	$1.08	$1.71	$1.46	$0.48	$2.49	$10.61	$1.92	$4.21	$0.89	$0.54

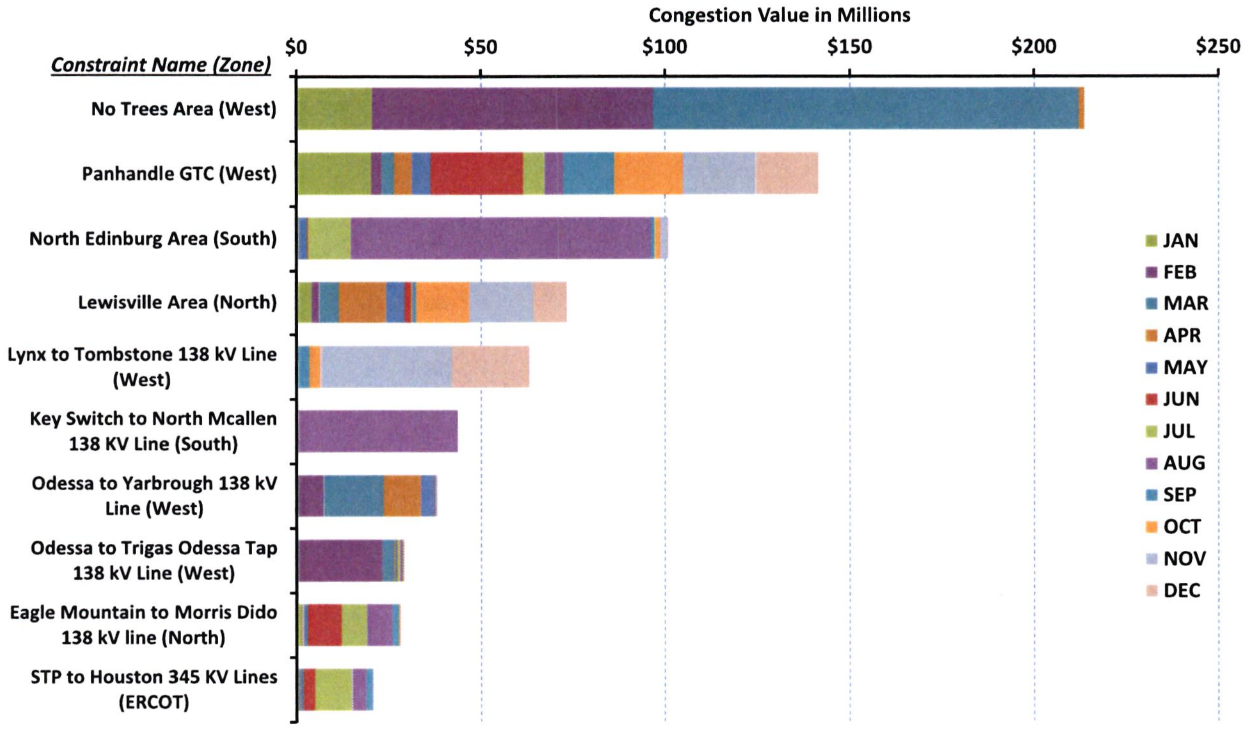
IV. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2020, review the costs and frequency of transmission congestion in both the day-ahead and real-time markets, as well as review the activity in the CRR market.

A. Day-Ahead and Real-Time Congestion

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

Figure A32: Most Costly Day-Ahead Congested Areas



Since the start of the nodal market, it had been common for the day-ahead constraint list to contain many constraints that were unlikely to occur in real-time. However, for the fourth year in a row, the majority of the costliest day-ahead constraints in 2020 were also costly real-time constraints. Aside from the Eagle Mountain to Morris Dido, the rest of the constraints that exist in both the top 10 real-time and the top 10 day-ahead incurred less congestion value in the day-ahead market than the real-time market. This is a result of less wind generation participating in the day-ahead market, likely because of the uncertainty associated with predicting its output.

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

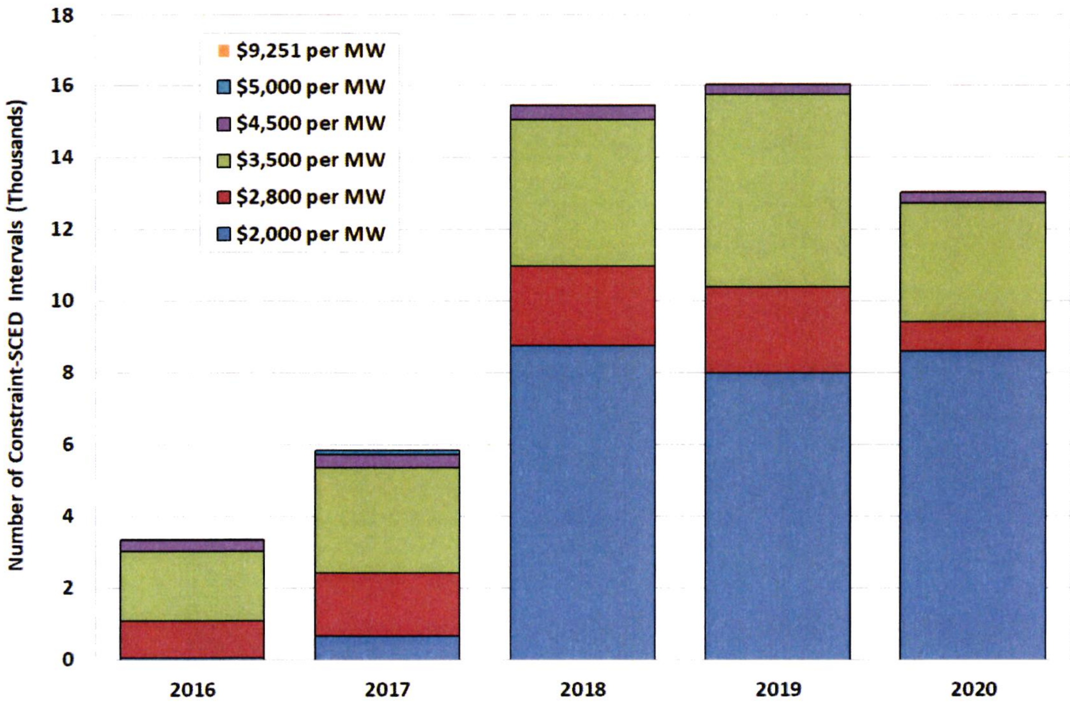
B. Real-Time Congestion

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

1. Types and Frequency of Constraints in 2020

Figure A33 below depicts constraints were violated (i.e., at maximum shadow prices) less frequently in 2020 than they were in 2019. In 2019, the majority of the violated constraints occurring at the $2,000 per MW value were related to the Dollarhide to No Trees 138 kV line irresolvable element, but dropped to 30% in 2020 due to the upgrades addressing the irresolvable element completed in spring 2020. Violated constraints continued to occur in only a small fraction of all the constraint-intervals, 5% in 2020, down from 7% in 2019 and 8% in 2018.

Figure A33: Frequency of Violated Constraints

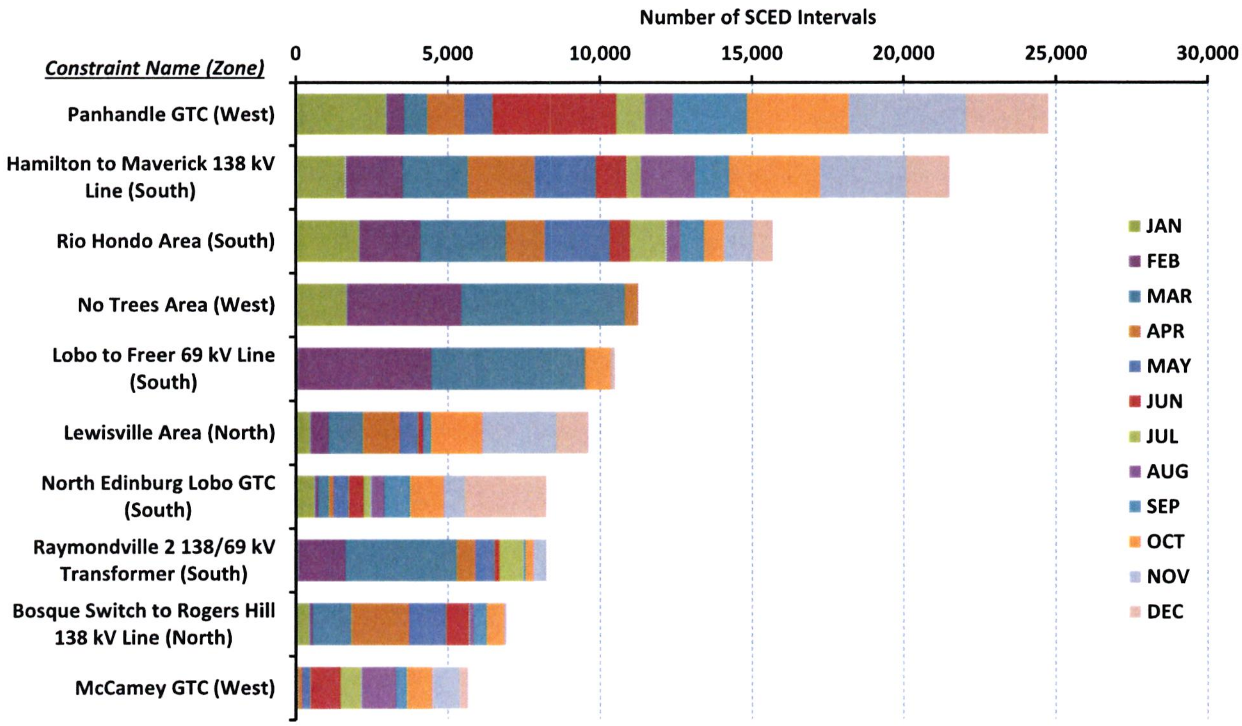


2. Real-time Constraints and Congested Areas

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

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

Figure A34: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

As shown in Table A4, 16 element combinations were deemed irresolvable in 2020 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[56] and are intended to reflect the level of reduced reliability that occurs when a constraint is irresolvable. The shadow price caps are $9,251 per MW for base-case (non-contingency) or voltage violations, $4,500 per MW for 345 kV constraints, $3,500 per MW for 138 kV, and $2,800 per MW for 69 kV thermal violations. GTCs are considered stability constraints either for voltage or transient conditions with a shadow price cap of $9,251 per MW.

Table A4: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price	2020 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2020
Base Case	Valley Import	$9,251	$2,000	1/1/12	-	South	-
SSOLFTS8	Fort Stoctkon to Barilla 69 kV Line	$2,800	$2,000	5/13/19	-	West	-
DCASTXR8	Moore to Hondo Creek Switching Station 138 kV Line	$3,500	$2,549	1/2/18	1/30/20	West	-
SWINYUC8	Wickett TNP to Winkler County 6 TNP 69 kV Line	$2,800	$2,000	4/9/18	1/30/20	West	-
SJUNYEL9	Yellow Jacket to Hext LCRA 69 kV line	$2,800	$2,000	5/18/18	1/30/20	West	-
XFRI89	Sonora 138/69 kV Transformer	$2,800	$2,000	5/24/19	-	West	7
SECNMO28	Andrews County South to Amoco Three Bar Tap 138 kV Line	$2,800	$2,000	9/23/19	-	West	745
SECNMO28	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	10/15/19	-	West	6,471
DWINDUN8	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	10/23/19	-	West	3,049
DYKNWIN8	Dollarhide to No Trees Switch 138 kV Line	$3,500	$2,000	11/29/19	-	West	62
SHACPB38	Rio Pecos to Woodward 2	$3,500	$2,000	1/1/20	-	West	50
DWINDUN8	Andrews County South to Amoco Three Bar Tap 138 kV Line	$3,500	$2,000	3/24/20	-	West	831
DNEDWED8	Hidalgo Energy Center to Azteca Sub 138 kV Line	$3,500	$2,000	8/5/20	-	South	313
SMV_ALT8	Weslaco Switch to North Alamo 138 kV Line	$3,500	$2,000	8/7/20	-	West	78
SPHAWES8	Key Switch to North McAllen 138 kV Line	$3,500	$2,000	8/10/20	-	West	8
SHACPB38	Lynx to Tombstone 138 kV Line	$3,500	$2,000	11/30/20	-	West	865

56 Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints (ERCOT Board Approved December 8, 2020, effective December 10, 2020), available at http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Setting_Maximum_Shadow_Prices_for_Network_and_Power_Balance_Constraints.zip.

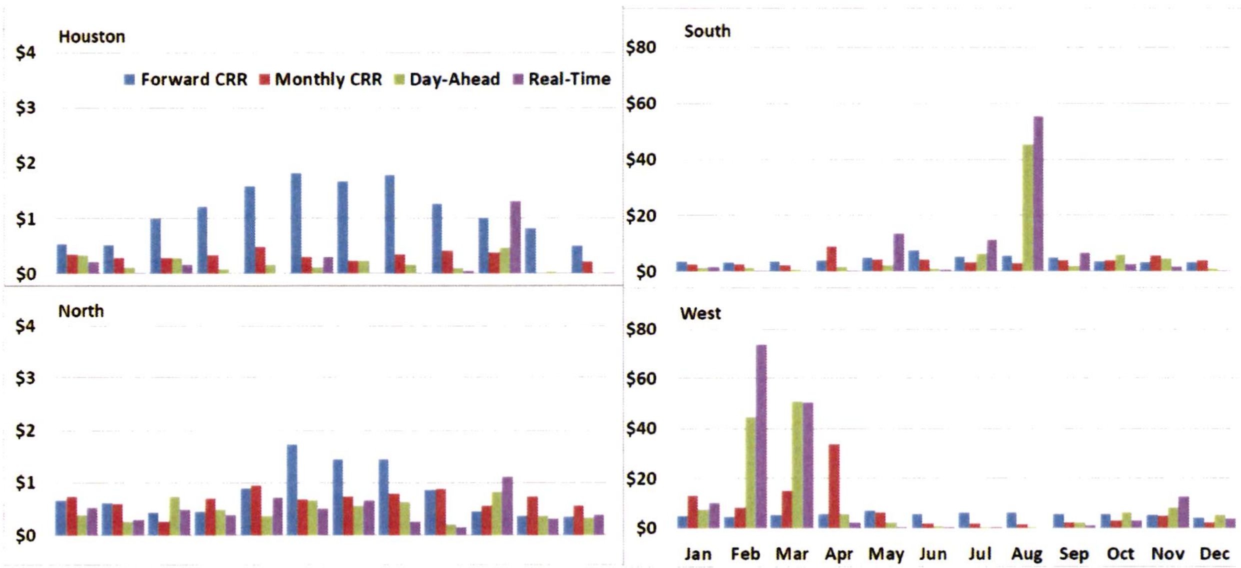
Three constraints, the Moore to Hondo Creek 138 kV line, Wickett to Winkler County 69 kV line, and Yellow Jacket to Hext 69 kV line, were deemed resolvable during ERCOT's annual review and were removed from the list. All irresolvable constraints are located in the West zone with the exception of the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

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Profitability

Figure A35 below shows the price spreads between all hub and load zones as valued at four separate points in time – at the average of the four semi-annual CRR auctions, monthly CRR auction, day-ahead, and real-time.

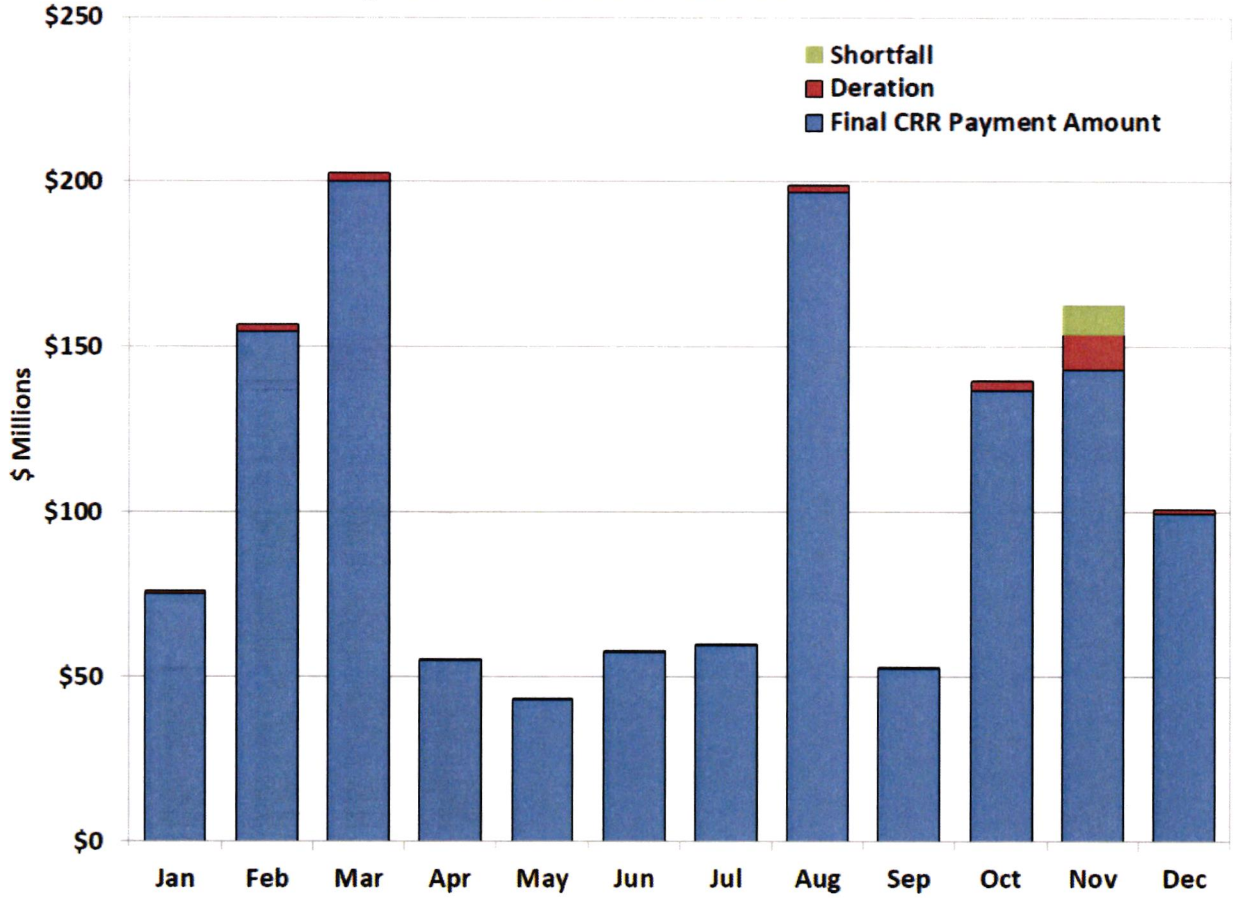
Figure A35: Hub to Load Zone Price Spreads



2. CRR Funding Levels

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

Figure A36: CRR Shortfall and Derations



V. Appendix: Reliability Unit Commitments

In this section, we provide supplemental analyses of RUC activity in 2020 as well as the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC.

A. History of RUC-Related Protocol Changes

The RUC process has undergone several modifications since the nodal market began in 2010. Changes have been implemented in an effort to improve the commitment process and market outcomes associated with RUC. In March 2012, an offer floor was put in place for energy above the Low-Sustained Limit (LSL) for units committed through RUC, and it is currently set at $1,500 per MWh. Resources committed through the RUC process are eligible for a make-whole payment but also forfeit any profit through a clawback provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the clawback charges, effectively self-committing and accepting the market risks associated with that decision. This buyback or "opt-out" mechanism for RUC initially required a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.

On June 25, 2015, ERCOT automated the RUC offer floor of $1,500 per MWh and implemented the Real-Time On-Line Reliability Deployment Adder (reliability adder). ERCOT systems now automatically set the energy offer floor at $1,500 per MWh when a resource properly telemeters a status indicating it has received a RUC instruction. The reliability adder, as discussed more in Section I: Review of Real-Time Market Outcomes, captures the impact of reliability deployments such as RUC on energy prices.

The RUC process was modified again in 2017. On June 1, 2017, ERCOT began using a telemetered snapshot at the start of each RUC instruction block as the trigger to calculate the reliability adder. This was an improvement over the previous calculation trigger, which required the QSE to telemeter the correct resource status. Another impact of the change is that resources could opt-out of RUC settlement after the close of the adjustment period, because the opt-out decision is no longer communicated via the COP.

In 2018, the RUC engine was modified to consider fast-start generators (those with a start time of one hour or less) as self-committed for future hours, allowing ERCOT to defer supplementary commitment decisions, and allowing market participants full opportunity to make their own unit commitment decisions. RUC-related improvements in 2019 included approval and implementation of NPRR901, *Switchable Generation Resource Status Code*, which created a new resource status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area to provide additional transparency for operations and reporting. New logic was implemented that now prevents the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource was awarded a resource-specific offer in the day-ahead market. A new settlement structure for SWGRs that receive a RUC instruction was approved and implemented in 2019 to address concerns of inadequate compensation for SWGRs that were instructed to switch from a non-ERCOT control area to the ERCOT Control Area.

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

B. RUC Outcomes

ERCOT continually assesses the adequacy of market participants' resource commitment decisions using the RUC process, which executes both on a day-ahead and hour-ahead basis. Additional resources may be needed for two primary reasons – to satisfy the total forecasted demand, or to make a specific generator available resolve a transmission constraint. The transmission constraint may be either a thermal limit or voltage concern.

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

57 See NPRR856, Treatment of OFFQS Status is Day-Ahead Make Whole and RUC Settlements (implemented May 2020); NPRR884, Adjustments to Pricing and Settlement for Reliability Unit Commitments (RUCs) of On-Line Combined Cycle Generation Resources (implemented May 2020); NPRR970, Reliability Unit Commitment (RUC) Fuel Dispute Process Clarification (implemented March 2020); NPRR977, Create MIS Posting for RUC Cancellations (implemented May 2020); NPRR1019 Pricing and Settlement Changes for Switchable Generation Resources (SWGRs) Instructed to Switch to ERCOT (partially implemented June 2020; automation of offers will be delivered separately as part of a future project); NPRR1028, RUC Process Alignment with Resource Limitations Not Modeled in the RUC Software (approved December 2020); and NPRR1032, Consideration of Physical Limits of DC Ties in RUC Optimization and Settlements (approved December 2020).

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

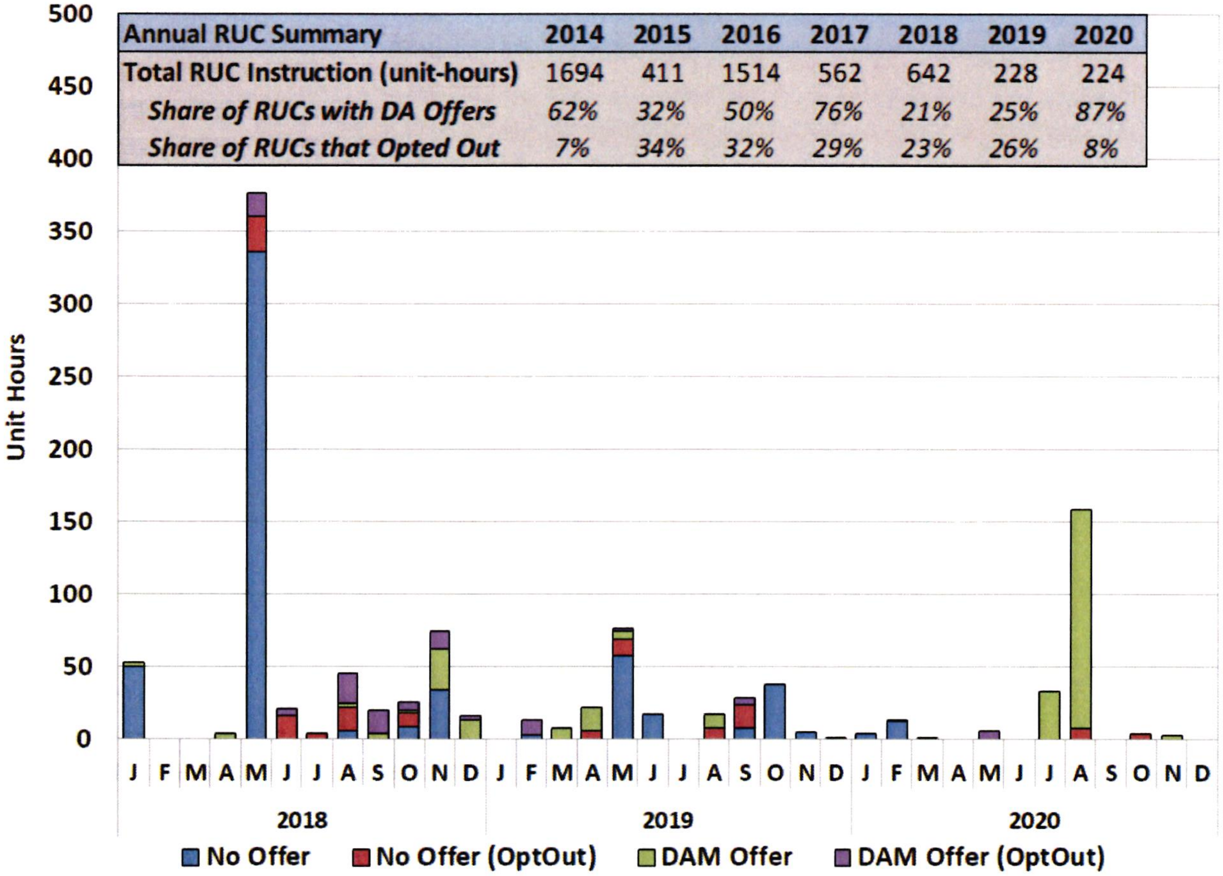


Table A5 below lists the generation resources that received the most RUC instruction in 2020 and includes the total hours each unit was settled as a RUC and the number of hours in which the unit opted out of RUC settlement. The units highlighted in gray are the ones that similarly received RUC instructions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

Table A5: Most Frequent Reliability Unit Commitments

Resource	Location	Unit-RUC Hours	Unit OPTOUT Hours	Average LSL during Dispatchable Hours	Average LDL during Dispatchable Hours	Average Dispatch during Dispatchable Hours	Average HSL during Dispatchable Hours
North Edinburg CC1	Valley	182	0	316	211	201	220
Duke CC1	Valley	5	6	269	182	177	202
Ector Energy G1	Far West	8	0	171	83	80	119
Mountain Creek Unit 6	DFW	0	8	122	87	15	92
Lake Hubbard Unit 2A	DFW	0	4	515	142	48	172
Silas Ray 10	Valley	4	0	39	17	18	18
Permian CT 5	Far West	3	0	75	41	41	49
Permian CT 1	Far West	2	0	73	42	41	73
Ector Energy G2	Far West	1	0	171	95	80	168
Permian CT 4	Far West	1	0	70	41	41	70

Our next analysis compares the average real-time dispatched output of the reliability-committed units, including those that opted out, with the average operational limits of the units. It shows that the monthly average SCED dispatch of units receiving RUC instructions has rarely been close to the average high capacity limit.

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

Figure A38: Reliability Unit Commitment Capacity

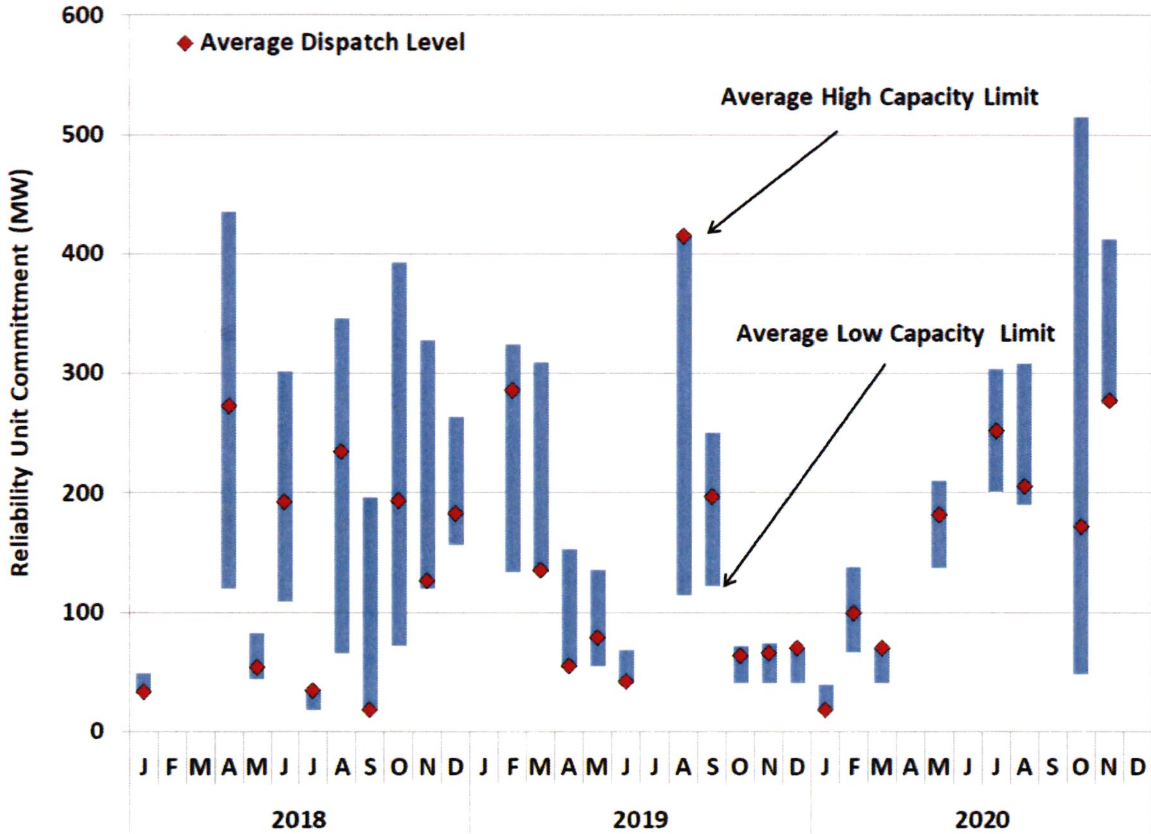


Figure A38 shows in 30% of intervals with RUC resources, one or more resources were dispatched above their low dispatch limit (LDL), a decrease from 40% of the intervals in 2019. This higher dispatch level in 2019 indicates that most units receive RUC instructions to resolve local constraints and scarcity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

C. QSE Operation Planning

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

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

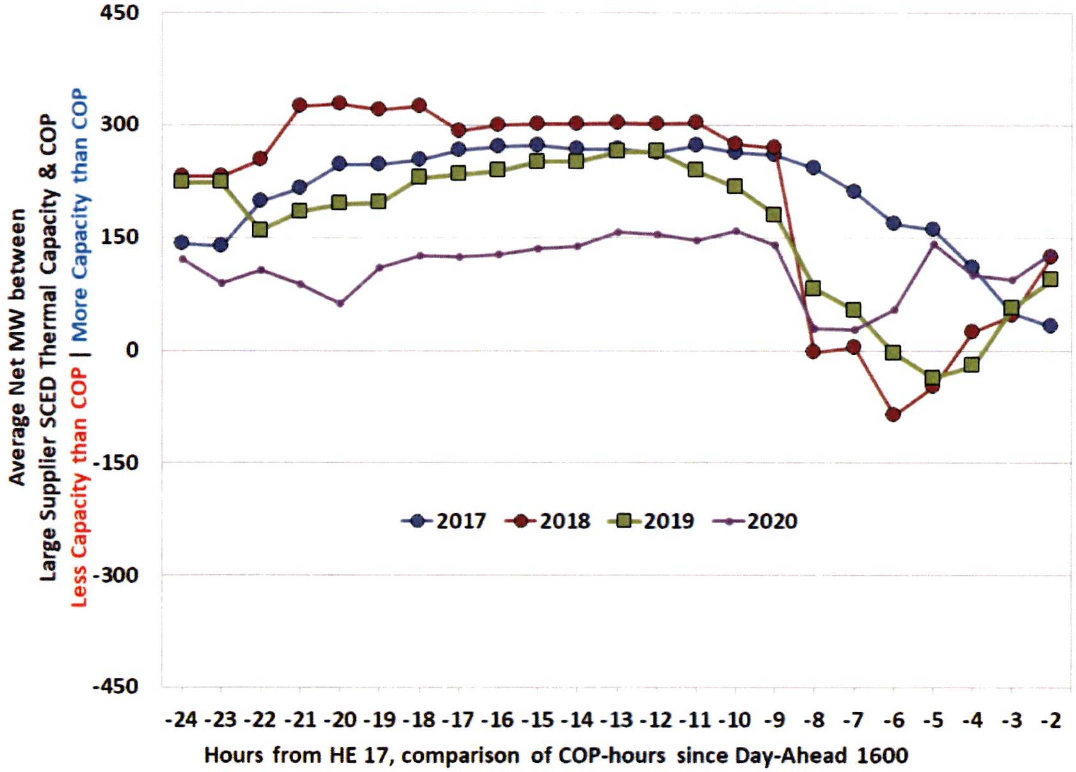
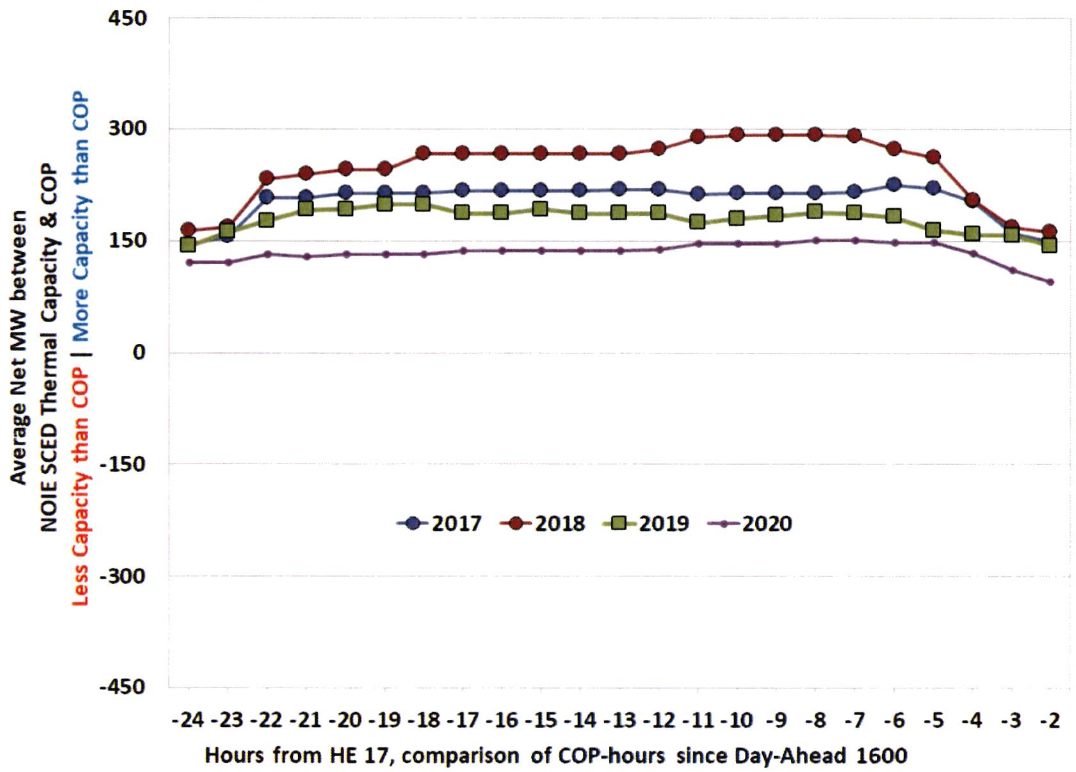


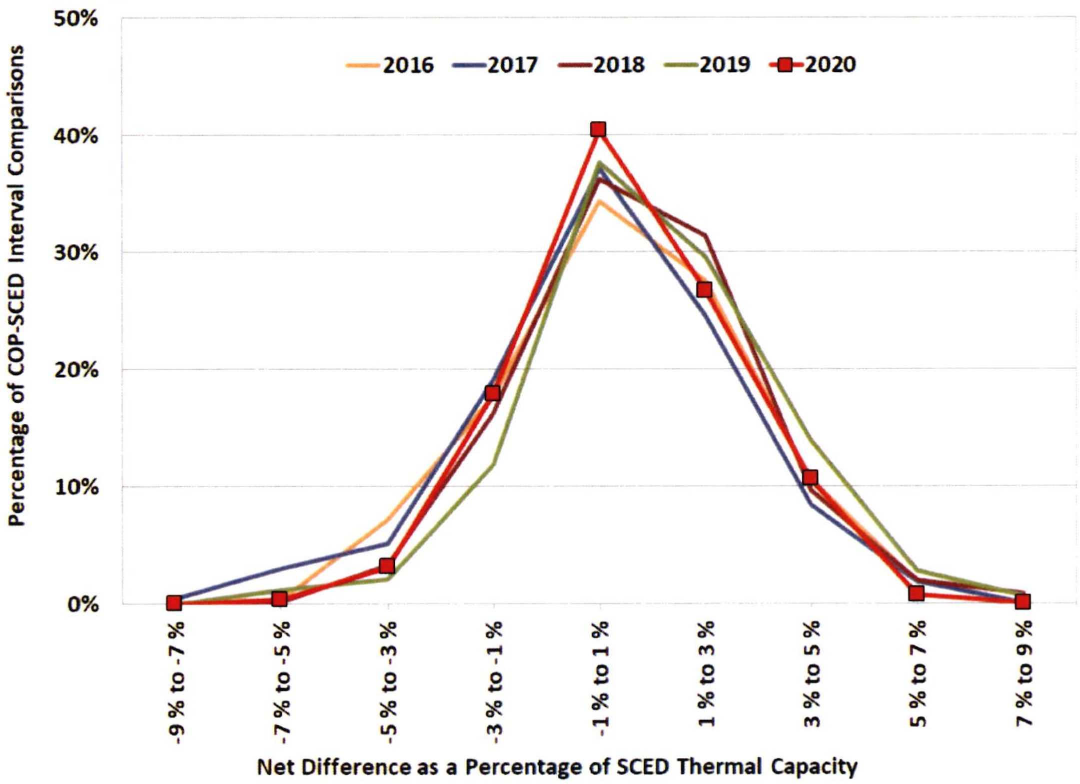
Figure A40: NOIE Capacity Commitment Timing – July and August Hour Ending 17



The next set of analyses quantify the difference between the aggregated capacity commitments as described by all the COP submissions, and the actual capacity commitments as a percentage of the actual capacity observed in real-time. These analyses are limited to the peak hours of 12 through 20 for the summer months of July and August. Multiple COP submissions as of day-ahead 1600 provide data for each of the hours being evaluated, and there can be large variations in unit commitment expectations reflected in those multiple COPs, even for the same operating hour. Because unit commitment decisions for renewable resources are influenced by the solar and wind forecasts, which are discussed in Section II: Appendix: Demand and Supply in ERCOT, the differences will not be highlighted here.

Figure A41 summarizes the frequency of percentage error between SCED thermal capacity and its respective COP. The comparisons include relevant COPs since day-ahead 1600 - 24 hours prior to HE 12 through HE 20, to the COP at the end of the adjustment period. The analysis focuses on the net difference as a percentage of the SCED thermal capacity due to load fluctuations between years. The last five years have shown a tendency towards an error greater than 1%. In 2019, 15.3% of the COP-SCED interval comparisons were below -1% error, 37.6% occurring within 1%, 47.1% had a percentage error greater than 1%, and 17.5% were greater than 3%. In 2020, 21.4% of the COP-SCED interval comparisons were below -1% error, 40.4% occurring within 1%, 38.2% had a percentage error greater than 1%, and 11.5% were greater than 3%.

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

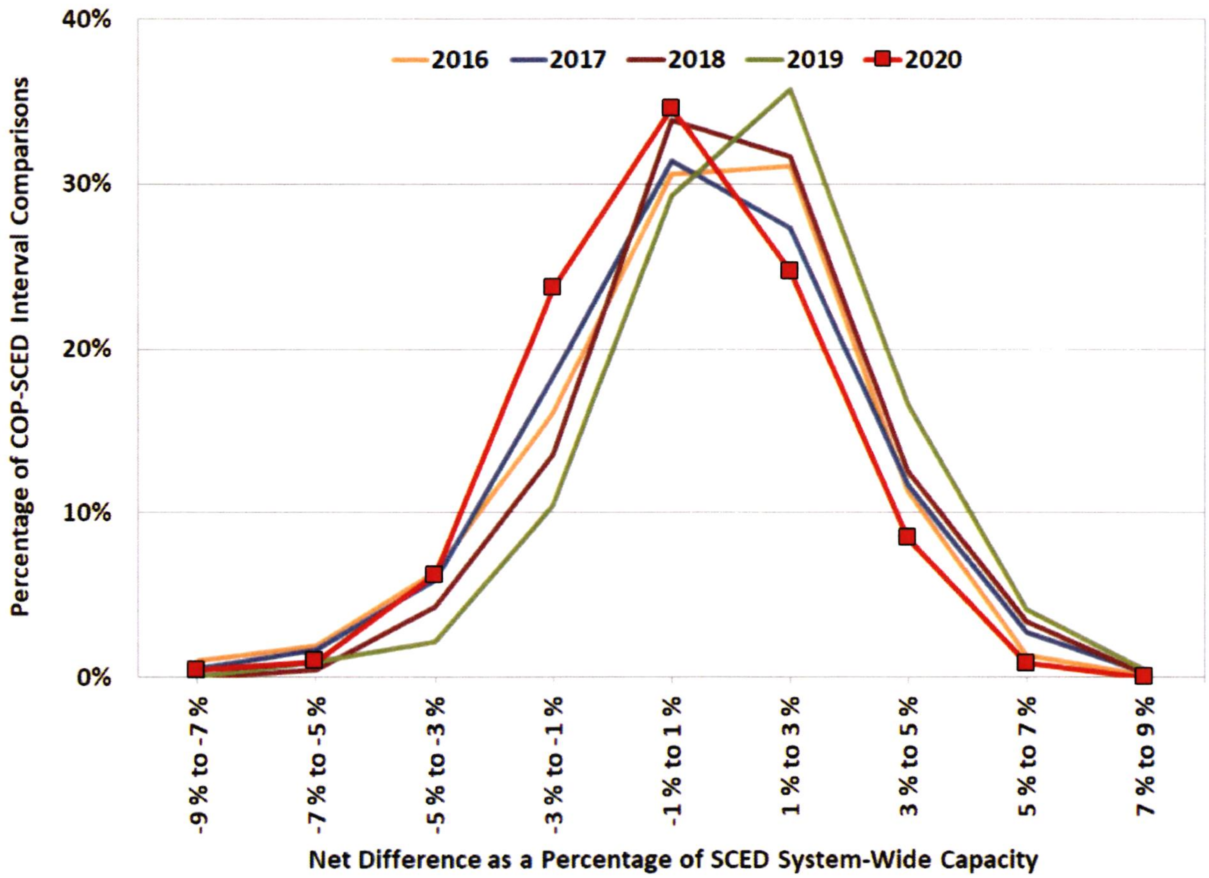


When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then under-report the COP at the end of the adjustment period a small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

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

Figure A42 summarizes the same analysis as above, but for system-wide capacity. The most interesting difference between Figure A41 and Figure A42 is the shift towards having less capacity occur in real-time at the system-wide level, including intermittent renewable resources. A possible explanation for this is a higher than expected forecast for the renewables leading up to the operating hour.

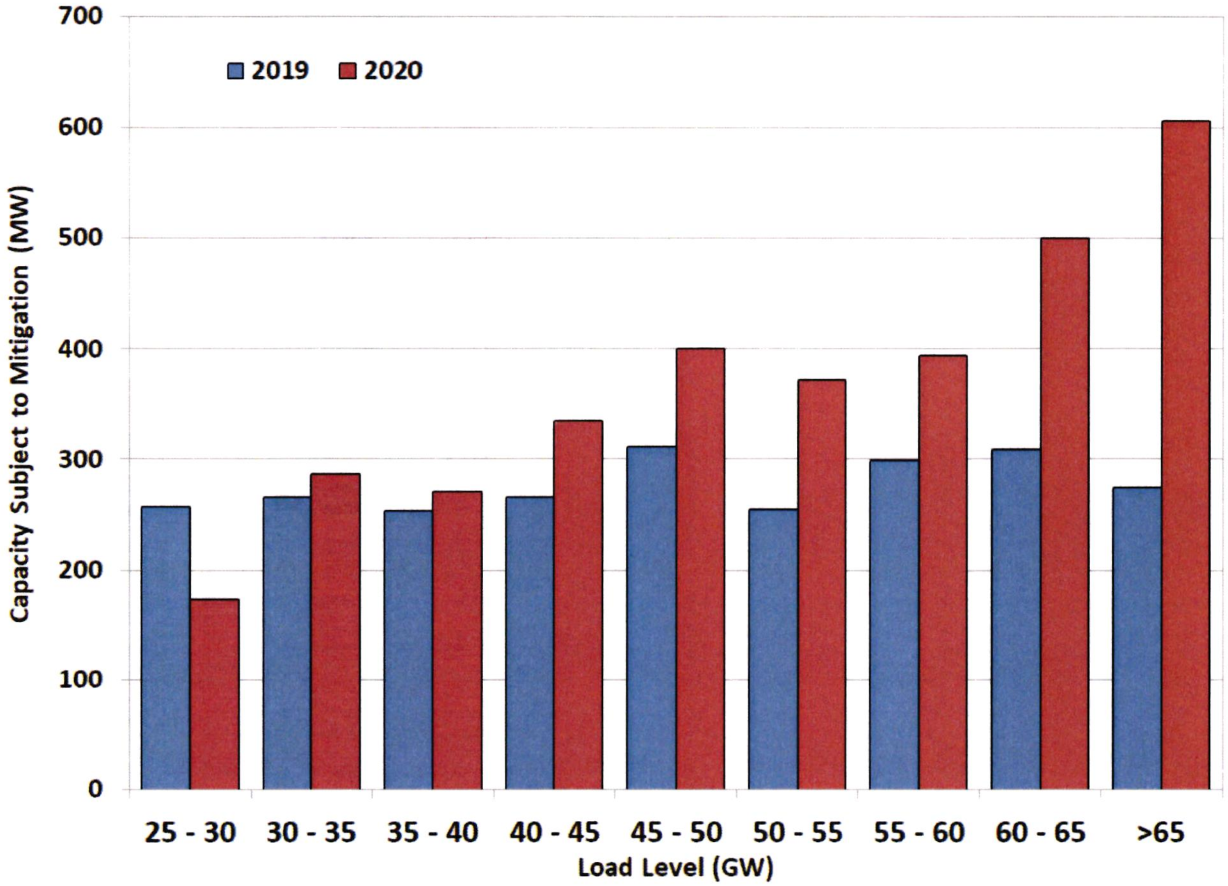
Figure A42: Real-Time to COP Comparisons for System-Wide Capacity



D. Mitigation

The next analysis computes the total capacity subject to mitigation, by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. The difference between the total unit capacity and the capacity at the point the curves diverge is calculated for all units and aggregated by load level. The results are shown in Figure A43.

Figure A43: Capacity Subject to Mitigation



The amount of capacity subject to mitigation in 2020 was higher than 2019 in all but the 25 to 30 GW load level. Mitigation was historically low in 2019 and so this increase represents a return to a more typical value. It is important to note that this measure includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

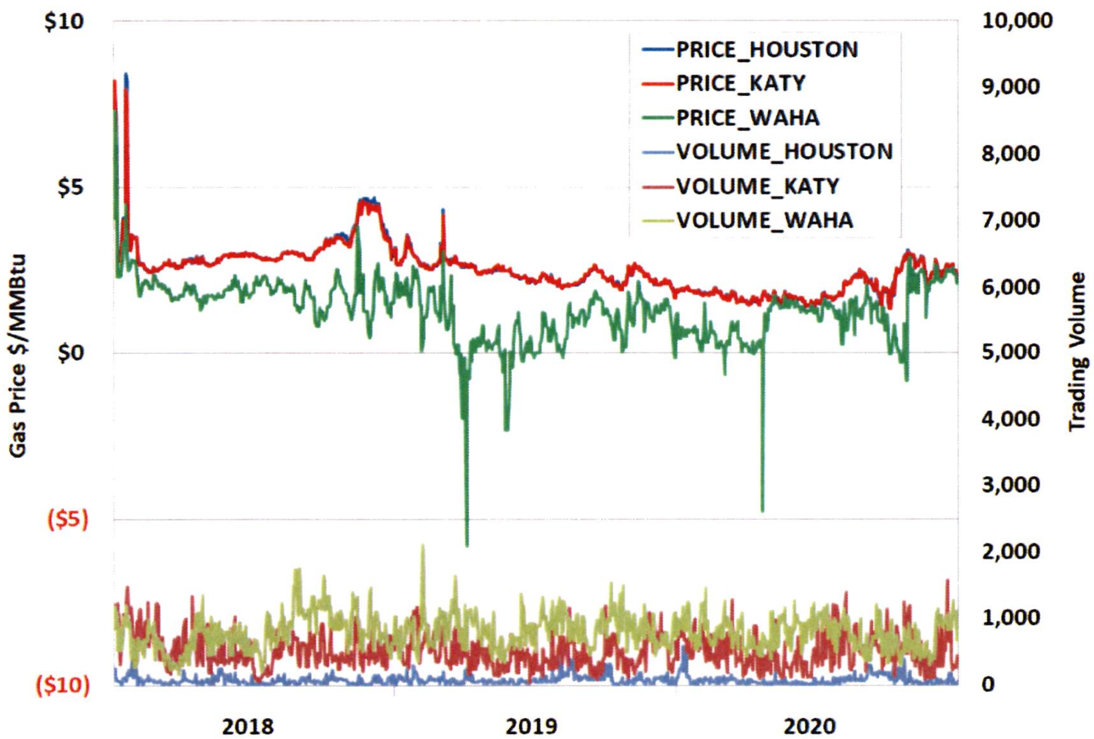
VI. Appendix: Resource Adequacy

In this section, we provide a supplemental analysis of the economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's needs by estimating the "net revenue" resources received from ERCOT real-time and ancillary services markets and providing comparisons to other markets.

A. Locational Variations in Net Revenues in the West Zone

Fuel prices are a substantial determinant of net revenues because they are the primary offset from market revenues when calculating net revenues. In 2020, we saw a continuing trend evident of the growing separation in natural gas prices between the Waha and Katy locations in the West.[58] Drilling activity in the Permian Basin of far west Texas has produced a glut of natural gas and consequently, much lower prices at the Waha location. As seen in Figure A44 below, Waha prices dipped below $0 multiple times throughout 2020, and were more volatile than Katy.

Figure A44: Gas Price and Volume by Index



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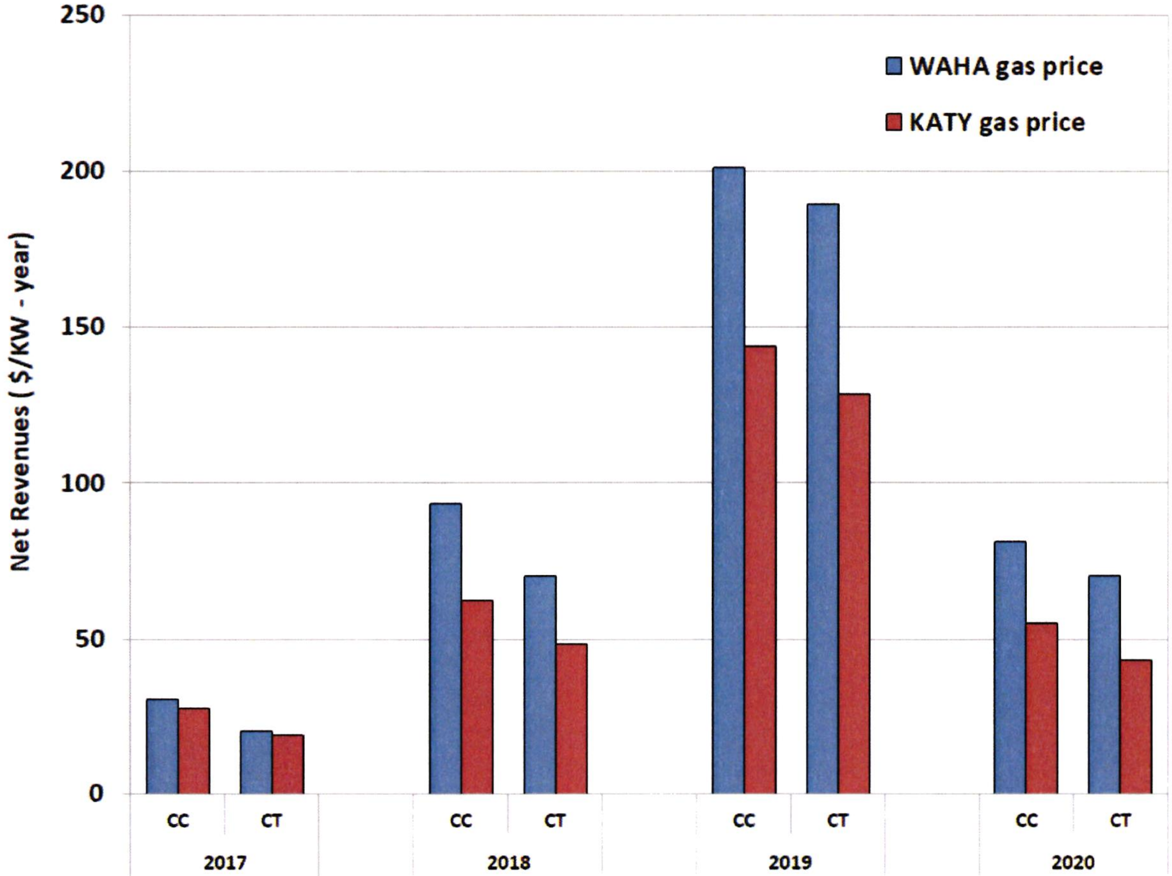
58 Effective December 12, 2019, the Katy Hub replaced Houston Ship Channel as the reference for the Fuel Index Price (FIP) for natural gas in ERCOT's systems. See NPRR952: *Use of Katy Hub for the Fuel Index Price*. ERCOT has the flexibility to select an appropriate natural gas price index for the purposes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

Historically, resources in the West zone have had lower net revenues that resources in the other zones, but that was not the case in either 2019 or 2020. Additionally, the divergence between Waha and Katy gas prices contributed to even greater net revenues for West Texas gas-fired generators. Figure A45 provides a comparison of net revenue for both types of natural gas units assuming Katy and Waha gas prices. Net revenues based on Waha gas prices are higher than in the other three zones.

Figure A45: West Zone Net Revenues



B. Reliability Must Run and Must Run Alternative

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability. Although no new Reliability Must-Run (RMR) contracts were awarded in 2020, a number of Notice of Suspension of Operations (NSO) were submitted in 2020.[59] ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

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

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

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

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

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

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

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

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

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

VII. Appendix: Analysis of Competitive Performance

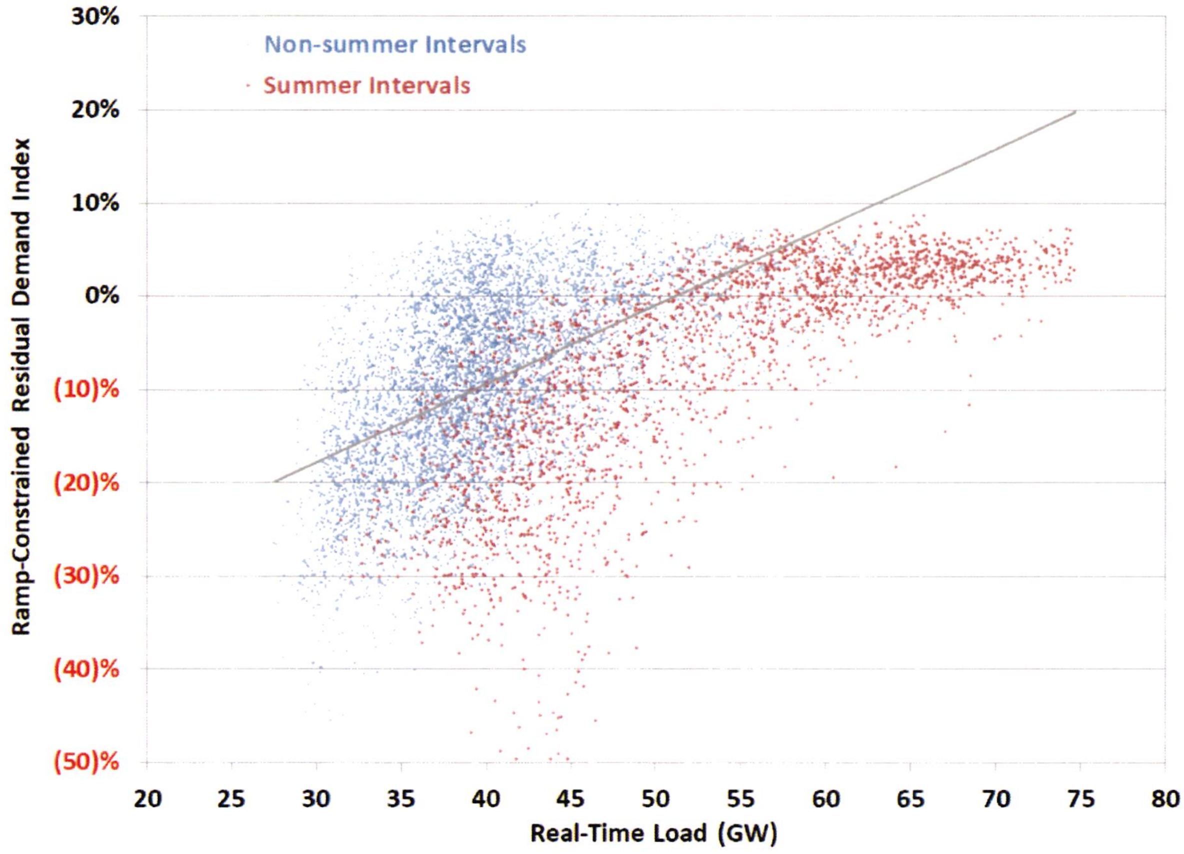
In this section, we provide supplemental analyses to evaluate market power from two perspectives: structural (does market power exist?) and behavioral (have attempts been made to exercise it?). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal at higher load levels. Market participant conduct is evaluated by reviewing measures of physical and economic withholding. These withholding patterns are examined relative to the level of demand and the size of each supplier's portfolio.

A. Structural Market Power Indicators

When the Residual Demand Index (RDI) is greater than zero, the largest supplier is pivotal (i.e., its resources are needed to satisfy the market demand). When the RDI is less than zero, no single supplier's resources are needed to serve the load if the resources of its competitors are available.

Figure A46 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2020. The occurrences of a pivotal supplier are not limited to just the high load summer period. This analysis indicated the existence of a pivotal supplier for some fraction of time at load levels as low as 30 GW. The trend line indicates a strong positive relationship between load and the RDI.

Figure A46: Residual Demand Index



1. Voluntary Mitigation Plans

Calpine's VMP was approved in March of 2013.[60] Because its generation fleet consists entirely of natural gas fueled combined cycle units, the details of the Calpine plan are somewhat different than the others. Calpine may offer up to 10% of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5% of the dispatchable capacity of its portfolio at prices no higher than the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW. With additions to Calpine's generation fleet made since the VMP was approved, its current amount of offer flexibility has increased to approximately 700 MW. Calpine's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or Calpine.

NRG's plan, initially approved in June 2012 and modified in May 2014,[61] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12% of the difference between the high sustained limit and the low sustained limit – the dispatchable capacity – each natural gas unit (5% for each coal or lignite unit) may be offered no higher than the greater of $500 per MWh or 50 times the natural gas price. Additionally, up to 3% of the dispatchable capacity for each natural gas unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions is approximately 500 MW. NRG's VMP remains in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or by NRG.

Luminant received approval from the Commission for a new VMP in December 2019.[62] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[63] The new VMP provides for small amounts of capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable capacity

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

61 PUCT Docket No. 40488, *Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Order (Jul. 13, 2012); PUCT Docket No. 42611, *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies*, Order (Jul. 11, 2014).

62 PUCT Docket No. 49858, Commission Staff *Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e)* (Dec. 13, 2019).

63 *See Application of Luminant Power Generation LLC, Big Brown Power Company LLC, Comanche Peak Power Company LLC, La Frontera Holdings LLC, Oak Grove Management Company LLC, and Sandow Power Company Under Section § 39.158 of the Public Utility Regulatory Act*, Docket No. 47801 (Nov. 22, 2017); on April 9, 2018, Luminant filed a letter with the Commission terminating its VMP upon closing of the proposed transaction approved by the Commission in Finding of Fact No. 36 of the Order in Docket No. 47801, see also PUCT Docket No. 44635, *Request for Approval of a Voluntary Mitigation Plan for Luminant Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Order Approving VMP Settlement (May 22, 2015).

for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the high system-wide offer cap (HCAP). When approved in late 2019, the amount of capacity covered by these provisions was less than 900 MW. In addition, the plan defines allowable limits for energy offers from Luminant's quick start combustion turbines. These limits are defined by a simplified formula, which is expected to produce prices lower than what had historically been deemed allowable.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A47 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2020.

Figure A47: Short-Term Outages and Deratings

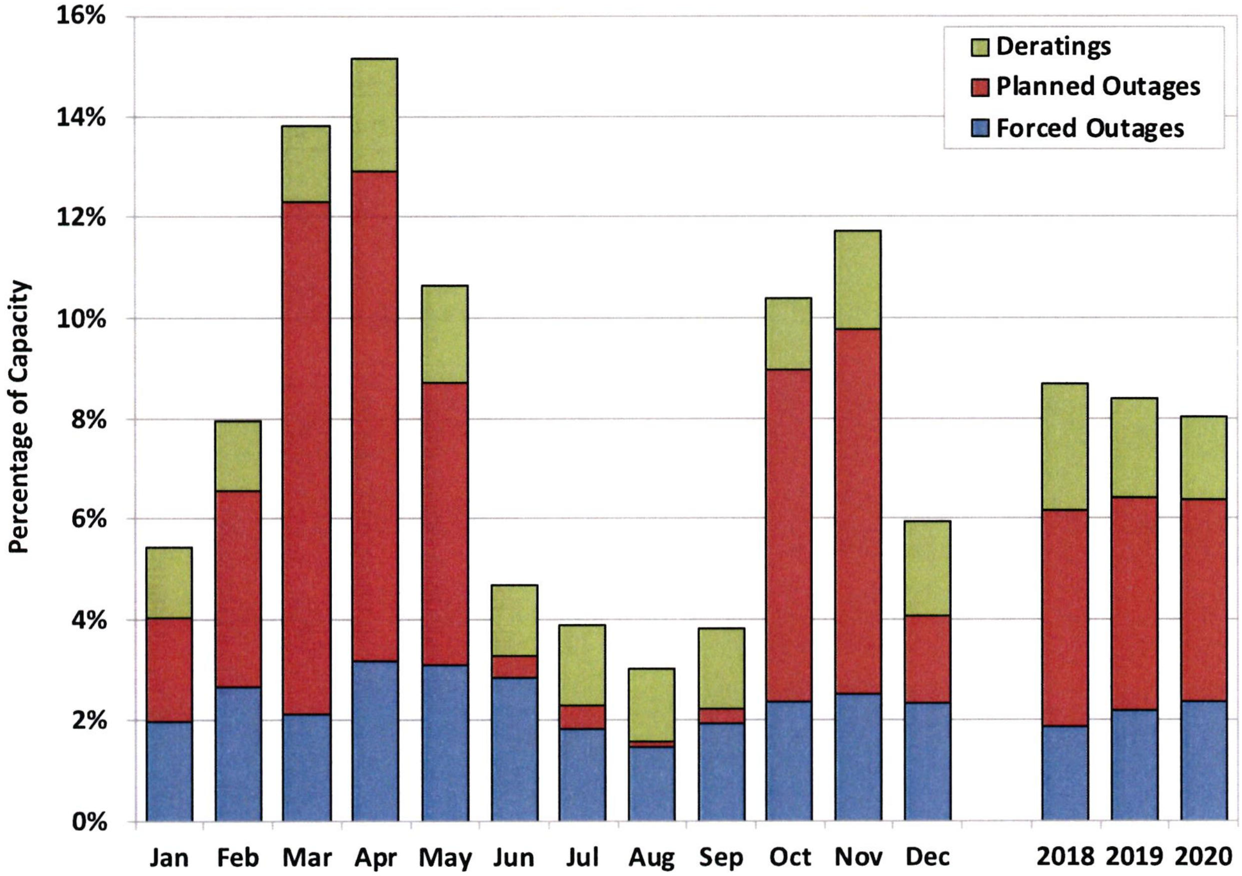


Figure A47 shows that short-term outages and deratings in 2020 followed a pattern similar to what occurred in 2018 and 2019, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2020 were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

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

Most of this fluctuation was due to planned outages. The amount of capacity unavailable during 2020 averaged 8.0% of installed capacity, a modest decrease from the 8.3% experienced in 2019 and 8.4% in 2018. The numbers of planned outages remained steady in 2020, 4.0% on average, down slightly from 4.3% in 2018 and 4.2% in 2019. This can be explained by the heightened expectations for shortages during the summer and generators taking outage time to ensure higher availability. The low levels of deratings the last two years may be similarly explained by generators operating in modes that would allow them to maximize generation.