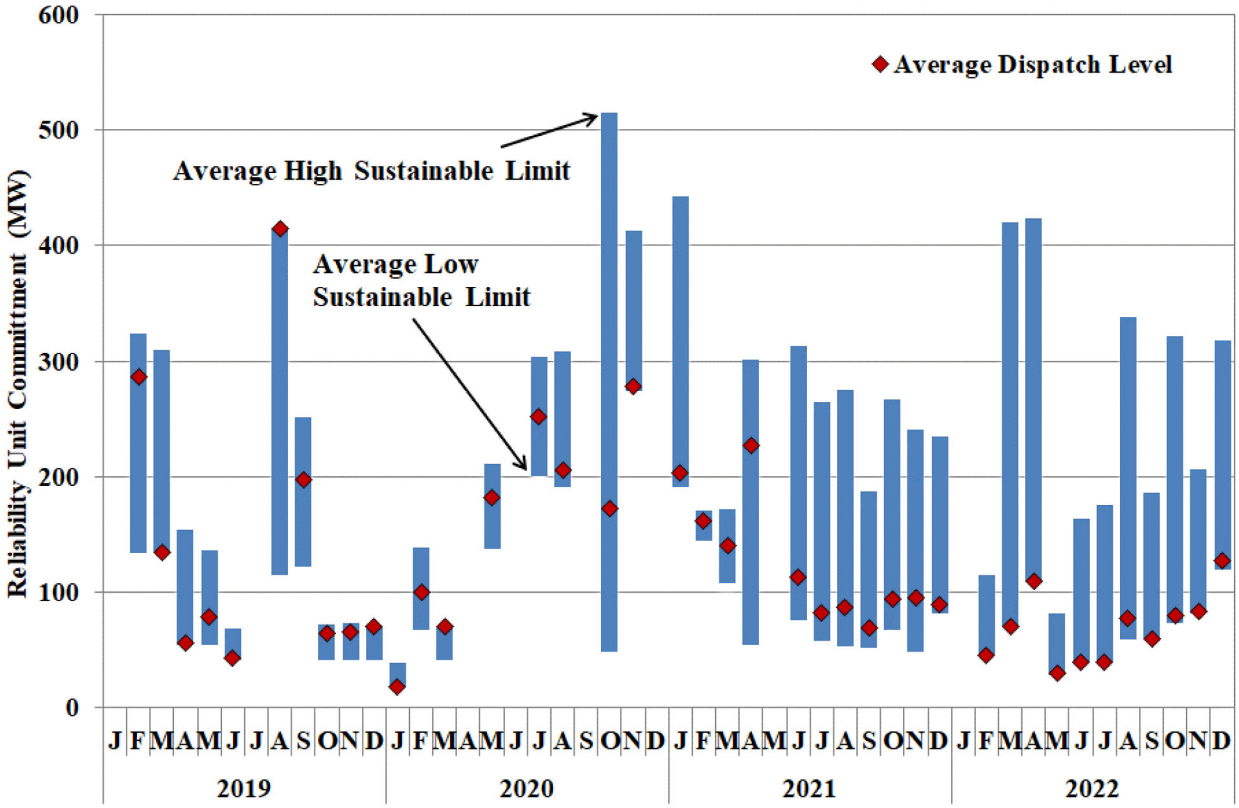
Figure 42: Average Reliability Unit Commitment Capacity and Dispatch Level



2. RUC Settlements and Incentives

Table 6 shows the total annual make-whole payments and claw-back charges for RUCs since 2012. There are two sources of funding for RUC make-whole payments. The first is from QSEs that do not provide enough capacity to meet their short real-time position, rendering them "capacity short." The remaining amount is uplifted to all QSEs on a load-ratio share basis.

Table 6 shows that both claw-back and make-whole payments rose sharply in 2022, up to roughly $24 million and $43 million respectively. This is substantially higher than any year since the early period of the nodal market in 2011. This increase was due in part to ERCOT's desire to have at least 6,500 MW in reserve in all hours in 2022. The claw-back amount was lower than the make-whole payment in 2022. In theory, the claw-back amount should be low because economic units would generally benefit by opting out of the RUC instruction if such profitability is foreseeable. In 2022, roughly 20% of RUC resources opted out.

However, economic resources frequently do not opt out and submit day-ahead offers. Generators that participate in the day-ahead market forfeit only 50% of markets revenues above cost through the claw-back, rather than 100%. Receiving full operational cost recovery via RUC make-whole while also getting the opportunity to keep half or all of any revenues above cost can undermine the incentive to self-commit generators when they would likely be economic.[73] For example, our analysis indicates that as much as 25% and 30% of the RUC-committed hours of combined-cycle and simple-cycle generators, respectively, would have been economic.

Table 6: RUC Settlement Quantities

	Claw-Back from Generator in millions	Make-Whole to Generator in millions
2012	$0.34	$0.44
2013	$1.15	$2.88
2014	$2.81	$3.83
2015	$0.34	$0.48
2016	$1.41	$1.24
2017	$1.20	$0.54
2018	$3.07	$0.61
2019	$0.90	$0.05
2020	$0.48	$0.40
2021	$3.09	$5.38
2022	$23.74	$42.78

We note that forecasting profitability can be difficult, particularly if ERCOT relies on more conservative forecasts than the market participants. Nonetheless, the ability to receive a guarantee of cost recovery plus market revenues clearly undermines the incentive to self-commit resources, which is fundamental to the ERCOT market design. This incentive effect grows as the frequency of RUC activity has grown. Hence, we recommend that ERCOT eliminate the 50% claw-back for day-ahead offers and implement a 100% claw-back for economic RUC resources (see Recommendation 2022-2). This would discipline self-commitment decisions by generators that are likely to be economic and lower costs for ERCOT's consumers.

3. RUC Effects on Price Adders

Committing economic resources through the RUC process leads to artificial increases in ORDC revenues for the rest of a portfolio because of the RUC adjustment to online reserves, as well as additional revenues from the deployment price adder. We estimated the changes in these price adders that would have occurred if the economic RUC resources had instead been self-committed. We found that the total energy revenue from the deployment price adder and the

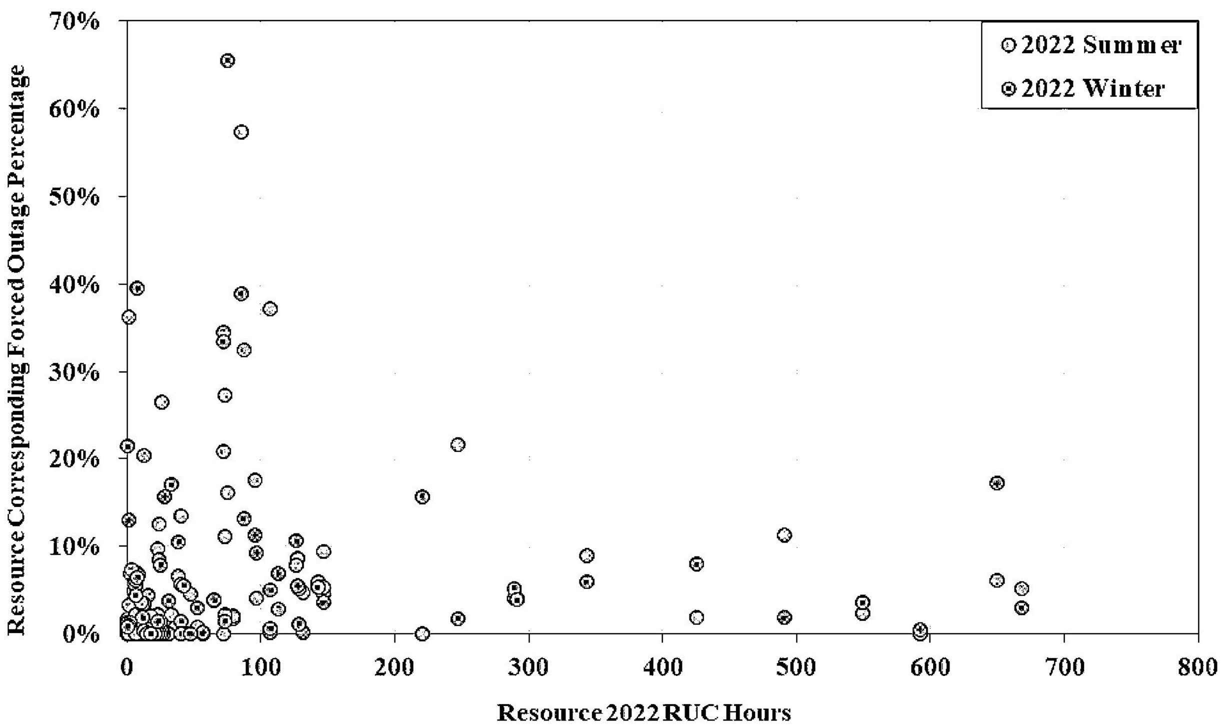
[73] It is notable that there is no requirement that the day-ahead market energy offer that triggers the reduced claw-back percentage be feasible, i.e., able to be awarded by the day-ahead market engine based on resource temporal constraints.

online ORDC adder would have fallen by $41 million and $839 million, respectfully. The latter reduction is 30% of all ORDC revenue.

4. Seasonal Statistics for RUC Resources and Forced Outages

Figure 48 shows our analysis to determine if there is a correlation between instances of running as a RUC resource and forced outage percentages during both summer and winter. Some have argued that RUC frequency might decrease the performance of a unit because it is running more often when it wouldn't otherwise. This may still be true in the long-term, but in the short-term (the first complete year of "conservative operations") this analysis does not show that correlation. We computed the individual resource forced outage percentage for the season and plotted that against the number of hours the resource ran as RUC-committed. Winter is defined as January, February, and December of 2022, while summer is June through August.

Figure 43: RUC Hours and Seasonal Forced Outage Percentages



B. Operational Reserves Compared to Market Reserves

The IMM performed an analysis comparing the operational reserves to the market reserves (Physical Responsive Capability[74] or PRC vs Real-Time On-Line Reserve Capacity[75] or RTOLCAP) for 2019 through 2022. The two reserve calculations (PRC and RTOLCAP) can

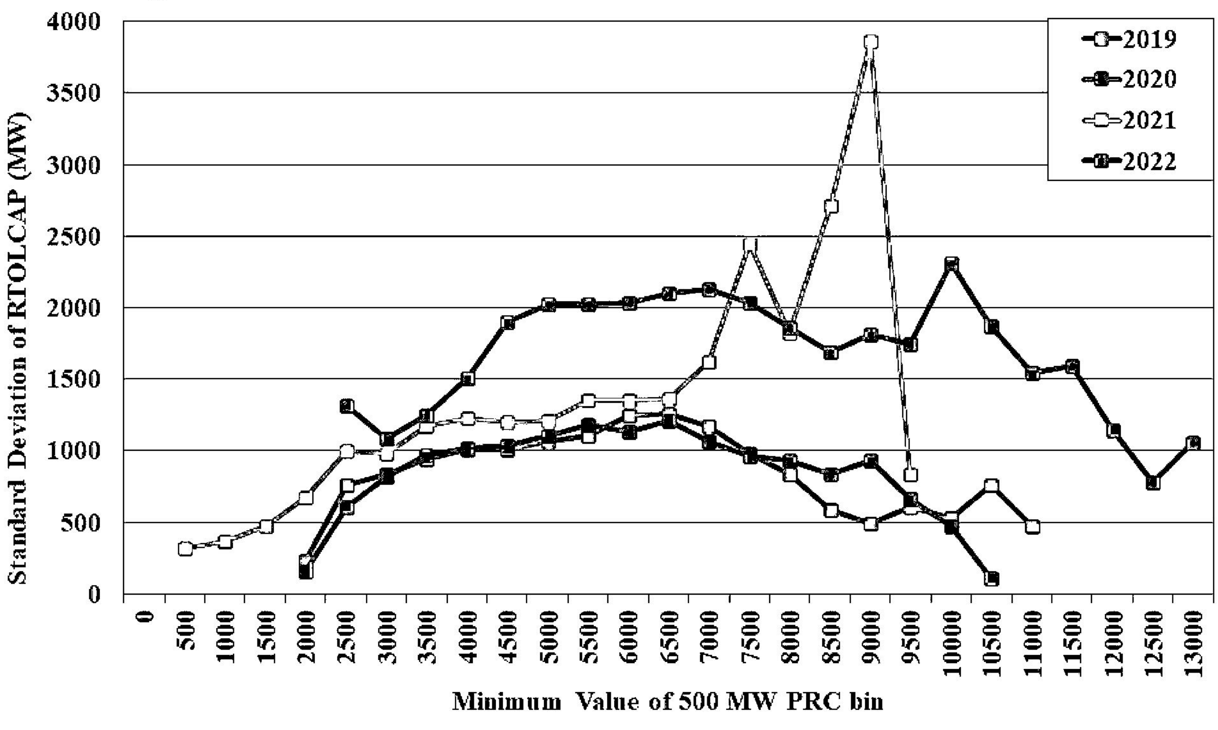
74 A representation of the total amount of frequency responsive online reserve capacity.

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

diverge because different types of capacity are counted in the two metrics. Additionally, when units with RUC instructions are online, the capacity provided by those units is excluded from the ORDC capacity calculation. The additional non-spinning reserve procurement and increased RUC activity have contributed to both higher PRC and a more marked divergence in the two measures of reserve since the second half of 2021. It is important for the real-time market prices to reflect the underlying reliability conditions such as loss of load probability.

Figure 44 shows standard deviation of RTOLCAP at different levels of PRC for the last four years. The increase in the standard deviation in the last two years is attributable to increased variability in the relationship between PRC and RTOLCAP in the months following ERCOT's change in operational posture. During this time there are periods where there are large amounts of capacity that was under RUC instruction and therefore contributing to PRC but not to RTOLCAP. RUC activity can cause operational reserves and market reserves to diverge from their historical relationship and therefore prices to diverge from the historical relationship with grid reliability conditions.

Figure 44: Standard Deviation of RTOLCAP at different levels of PRC



C. QSE Operation Planning

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

The accuracy of COP information greatly influences ERCOT's ability to effectively perform supplemental commitment using the RUC process. COPs are updated on an ongoing basis by QSEs, providing multiple views of their expectations for a particular operating hour. Presumably, QSE expectations about which units will be online in a particular hour are most accurate for the COP submitted just before the operating hour. Figure 45 evaluates the accuracy of the COPs by showing the average difference between the actual online unit capacity and the capacity represented in the COPs in the peak hours (hour ending 12-20) in July and August, as submitted each of the 24 hours leading up to the close of the adjustment period. We show these differences for each of the past four years.

Figure 45: Capacity Commitment Timing – July and August Hour Ending 12 through 20

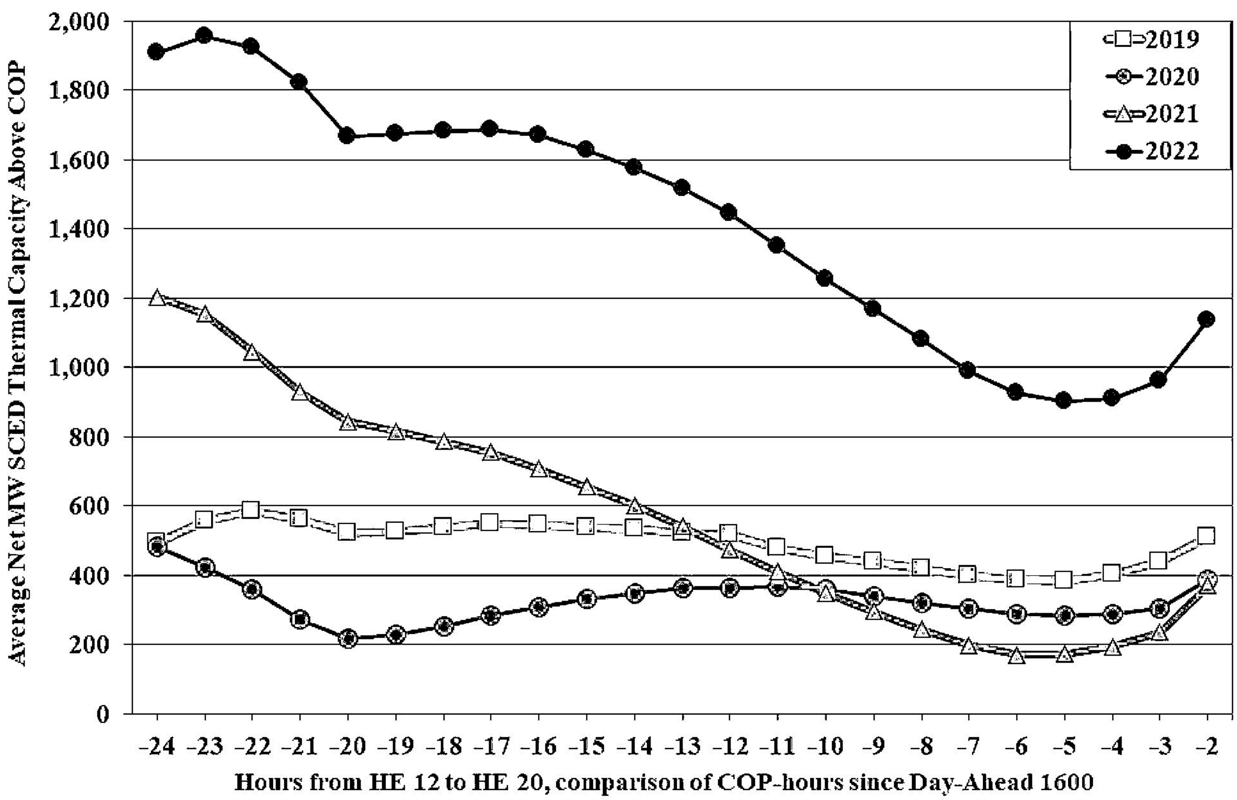


Figure 45 shows that the amount of online capacity in real-time exceeded the thermal capacity represented in COPs at the end of the adjustment period, signifying that generators either did not reflect their commitment decisions in their COPs or changed their commitment decisions within the operating period. Commitment of resources for hours ending 12 to 20 show that much later commitments occurred on average in 2022 than in previous three years. In evaluating this increase in COP inaccuracy, we find that it is caused by two factors:

- Many of the increased commitments in COP leading to the operating hours can be explained by the increase in RUC commitments, particularly of gas steam units committed after the DRUC execution.
- A number of simple-cycle generators that were running did not reflect their online status in the COP. The frequency of this conduct increased in 2022 as new generators entered the market.

Accurate COP statuses are important for many reasons, but most importantly for accurate representation of reserve levels that are analyzed by RUC. There are currently no penalties or other consequences for submitting inaccurate COPs or failing to update COPs as generator commitments change. As ERCOT has transitioned to a much more conservative operating posture, increased COP inaccuracies will predictably lead to more RUC commitments and higher costs for ERCOT's customers. Hence, we encourage ERCOT to actively review COP inaccuracies and work with suppliers to improve their performance. In the longer-term, it may be beneficial to consider new provisions that would provide meaningful economic incentives for suppliers to submit accurate COPs.

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

D. Firm Fuel Supply Service

A new Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of dual-fuel generators to purchase fuel to be stored on site (with a possible expansion to offsite gas storage). The PUCT directed ERCOT to develop and procure this product as part of the Commission's Phase I Market Design effort and in response to Texas Senate Bill 3.[76] Approved on March 31, 2022, NPRR1120 – Create Firm Fuel Supply Service, created this new reliability service.[77] On June 30, 2022, ERCOT issued a Request for Proposals (RFP) to provide FFSS during the November 15, 2022, through March 15, 2023, obligation period. Proposals were due by September 1, 2022.[78]

FFSS was deployed for the first time during Winter Storm Elliott in late December 2022 for four days, which are shown on Table 7.

76 https://www.ercot.com/services/programs/firmfuelsupply

77 https://www.ercot.com/mktrules/issues/NPRR1120

78 https://interchange.puc.texas.gov/Documents/53298_18_1241979.PDF

Table 7: Firm Fuel Supply Service Deployments

Day	Firm Fuel Supply Service MWs	Average RT Price	Operating Day Online Reserves Minimum
12/22/2022	757.5	$18.03	15,492
12/23/2022	948.5	$557.53	4,247
12/24/2022	948.5	$63.19	7,956
12/25/2022	38.5	$31.99	6,878

Table 7 indicates that while there were shortage conditions on December 23, 2022, expected reserve levels and pricing outcomes do not reflect the need for the FFSS on the other three days. Since utilizing Fuel Supply Resources (FFSRs) is costly, we encourage ERCOT to develop clear procedures for deploying FFSS capacity, including a forecasted shortage of capacity or unresolvable transmission constraint.

Currently, the High Sustained Limits of FFSSRs are removed from reserves when calculating operating reserve adders, and FFSSRs have their fuel costs covered by the FFSS payment. This causes them to have the incentives of zero marginal cost resources when they are actually burning expensive fuel oil that consumers must reimburse. This is inefficient and raises the costs of the FFSS unnecessarily, as well as potentially reducing the amount of firm fuel that may be available after the deployment. It would be better if these resources had offer costs that more accurately reflected the fuel they are burning. Once the procedures and criteria are better established, a price formation recommendation to address the deployment of these resources can be developed. Such a recommendation would include whether an offer floor should be established, and whether the reliability adder should consider the effect of the LSL MWs of the deployed resources. These changes would address some of the concerns described above and will be essential if larger quantities are procured in 2023.

VII. RESOURCE ADEQUACY

One of the primary functions of the organized wholesale electricity market is to provide economic signals that will facilitate investment needed to maintain a set of resources adequate to satisfy the system's needs. Without revenues from an installed capacity market, energy and reserve prices provide the only funding for compensation to generators. To ensure that revenues will be sufficient to maintain resource adequacy in an energy-only market, prices should rise during shortage conditions to reflect the diminished reliability and increased possibility of involuntary curtailment of service to customers. The sufficiency of revenues is a long-term expectation while actual revenues may vary greatly from year to year.

The ERCOT market has seen many years of excess generation capacity, with revenues less than estimated costs of investing in new generation (known as the "cost of new entry" or CONE). If long-term expectations of revenues sufficient to support resource adequacy are to be met, revenues that far exceed the CONE must occur in some years as well. This principle of cyclical revenue sufficiency to maintain resource adequacy is applied in the evaluation in this section.

This section begins with our evaluation of these economic signals in 2022 by estimating the "net revenue" that resources received from the ERCOT real-time and ancillary services markets and providing comparisons to other markets. Next, we review the effectiveness of the Scarcity Pricing Mechanism.[79] We present the current estimate of planning reserve margins for ERCOT, followed by a description of the factors necessary to ensure resource adequacy in an energy-only market design as also discussed in the Future Needs section. Finally, we conclude with a brief discussion of the Reliability Must Run and Must Run Alternative (MRA) processes in ERCOT.

A. Net Revenue Analysis

We calculate net revenue by determining the total revenue that could have been earned by a generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. In ERCOT's energy-only market, the net revenues from the ancillary services and real-time energy markets alone provide the economic signals that inform suppliers' decisions to invest in new generation or, conversely, to retire existing generation. To the extent that revenues are available through the day-ahead market or other forward bilateral contract markets, these revenues are ultimately derived from the expected ancillary service and real-time energy prices. Although most suppliers are likely to receive the bulk of their revenues through bilateral contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and thus are appropriate to use for this evaluation. It is important to note

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

that this net revenue calculation is a look back at the estimated contribution based on actual market outcomes. Suppliers will typically base investment decisions on expectations of future electricity prices. Although expectations of future prices are informed by history, they also factor in the likelihood of shortage pricing conditions that may or may not actually occur.

In this analysis, we compute the energy net revenues based on the generation-weighted settlement point prices from the real-time energy market.[80] The analysis may over-estimate the net revenues because it does not include: 1) start-up and minimum energy costs; or 2) ramping restrictions that can prevent generators from profiting during brief price spikes. Despite these limitations, the analysis provides a useful summary of signals for investment in ERCOT.

The next figures provide an historical perspective of the net revenues available to support investment in a new natural gas combustion turbine (Figure 46) and combined cycle generation (Figure 47), which we selected to represent the marginal new supply that may enter when new resources are needed. We calculate net revenues for these units by assuming they will produce energy in any hour in which it is profitable to do so. We further assume that when they are not producing energy, that both types of units will be available to sell responsive or non-spinning reserves in other hours, and that combined cycle units can provide regulation.[81] The figures also show the estimated CONE for each technology for comparison purposes.

These figures show that in 2022, the estimated CONE values for both types of resources remained constant from 2021, with the CONE values for natural gas combustion turbines ranging from $80 to $117 per kW-year. Even without the extreme prices experienced during Winter Storm Uri, the ERCOT market did provide net revenues above the CONE level needed to support new investment in 2022. This was primarily due to the ORDC changes implemented at the beginning of the year. For example, net revenues for:

- Combustion turbines ranged from $137 per kW-year to $1193 per kW-year; while
- Combined-cycle units ranged from $173 per kW-year to $234 per kW-year.

In an energy-only market, shortages typically play a key role in delivering the net revenues an investor needs to recover its investment. Such shortages will tend to be clustered in years with unusually high load or poor generator availability. However, the changes to the ORDC in 2022 contributed to higher net revenues that cover the range of covering CONE for combustion turbines and combined-cycle resources across all zones. This allows us to conclude that the Commission's Phase I action has been very effective at promoting investment in and retention of dispatchable generation.

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

81 For purposes of this analysis, we used the following assumptions: heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a gas turbine, and $4 per MWh in variable operating and maintenance costs. A total outage rate (planned and forced) of 10% was assumed for each technology.

Figure 46: Combustion Turbine Net Revenues

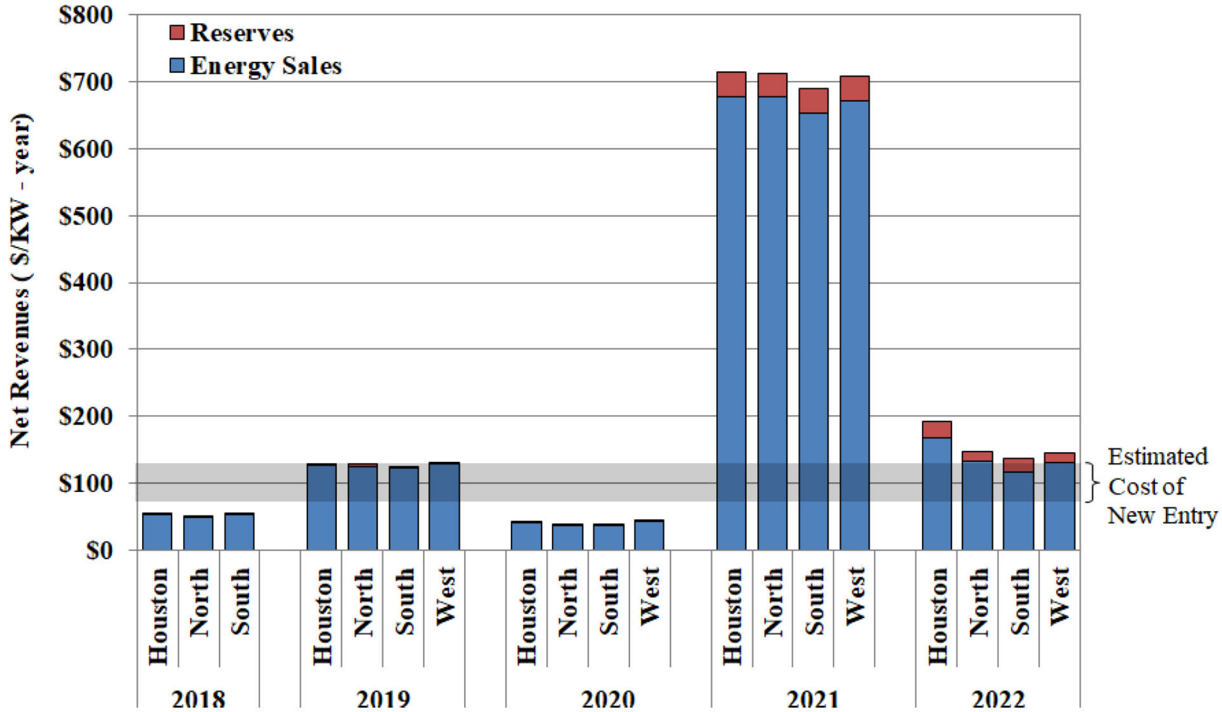
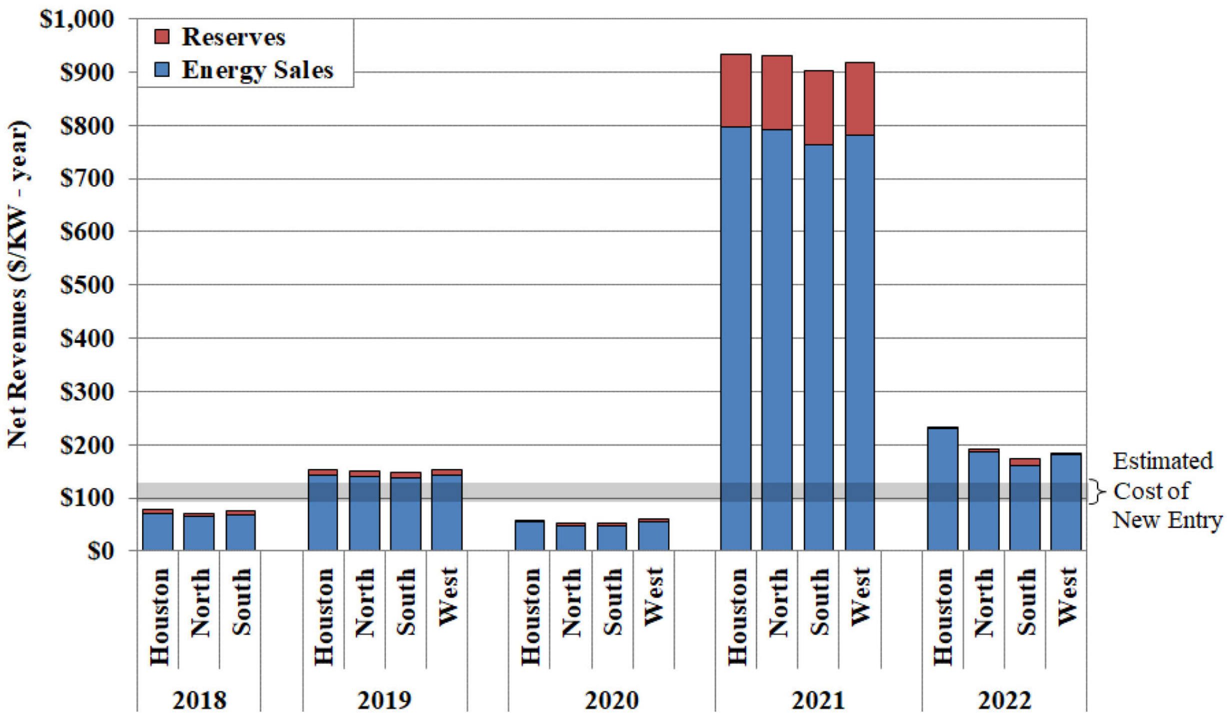


Figure 47: Combined Cycle Net Revenues



The figures above also show that average net revenues were highest in the Houston zone in 2022 as continued congestion led to higher prices in that zone. In 2022, we saw that the separation in natural gas prices return between the Waha and Katy locations, after being less of a factor in 2021.

Because of lower fuel cost at Waha, generators served by the Waha location would tend to have higher net revenues than those procuring gas at Katy. In Section VII of the Appendix, we show the fuel price trends at these locations and the differences in net revenues that they would produce for the two new resources. This analysis shows that the new resources would produce net revenue ranging from $150 to $200 per KW-year at the Waha location, compared to net revenues of $130 to $180 per KW-year at Katy, based on 2022 revenues.

B. Net Revenues of Existing Units

Given the high correlation of natural gas prices on energy prices, we evaluate the economic viability of existing coal and nuclear units that have experienced fluctuations in net revenues in recent years. Non-shortage prices, which are substantially affected by the prevailing natural gas prices, are the primary determinant of the net revenues received by these baseload units. Natural gas prices tend to drive system-wide average prices, but it is the prices at resources' specific locations that matter. In addition, resources that can generate during shortage conditions are more likely to realize higher net revenues. As previously described, the load-weighted ERCOT-wide average energy price in 2022 was $74.92 per MWh. Table 8 shows the output-weighted average price by generation type based on the generators' specific locational prices in 2022.

Table 8: Settlement Point Price by Fuel Type

	Output-Weighted Price		
Generation Type	**2020**	**2021**	**2022**
Coal	$24.84	$148.06	$70.00
Combined Cycle	$24.60	$207.84	$80.71
Gas Peakers	$60.26	$1,023.09	$189.86
Gas Steam	$41.90	$405.10	$140.51
Hydro	$23.88	$305.15	$87.76
Nuclear	$20.31	$137.71	$60.78
Power Storage	$80.50	$109.29	$92.64
Private Network	$24.08	$176.76	$74.46
Renewable	$35.23	$43.54	$83.00
Solar	$25.49	$75.97	$73.09
Wind	$11.45	$60.53	$34.09

Table 8 shows that the prices and associated net revenues in 2022 were significantly higher at all resources' locations than in the prior year before Uri (2020). These higher prices and revenues are driven by a combination of higher natural gas prices, weather patterns, load growth, and the shift of the ORDC.

Nuclear Profitability. According to data published by the Nuclear Energy Institute at the end of 2022, the average total generating cost for nuclear energy was $29.13 per MWh in 2021. The 2021 total generating costs were nearly identical to those in 2020 ($29.37 per MWh).[82] Assuming that operating costs in ERCOT are similar to the U.S. average, and that nuclear operating costs have either continued to be stable or declining, ERCOT's 5 GW of nuclear capacity should have costs less than $30 per MWh. The table above shows an average price for the nuclear units of approximately $61 per MWh so it is likely that the nuclear units in ERCOT were profitable in 2022.

Coal Profitability. The generation-weighted price of all coal and lignite units in ERCOT during 2022 was $70.00 per MWh, an increase from $24.84 per MWh in 2020. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $3.10 per MMBtu in 2022, higher than in 2021. At these average fuel prices, coal units in ERCOT that were able to stay online during shortage conditions in the summer are likely receiving sufficient revenue to cover operating costs.

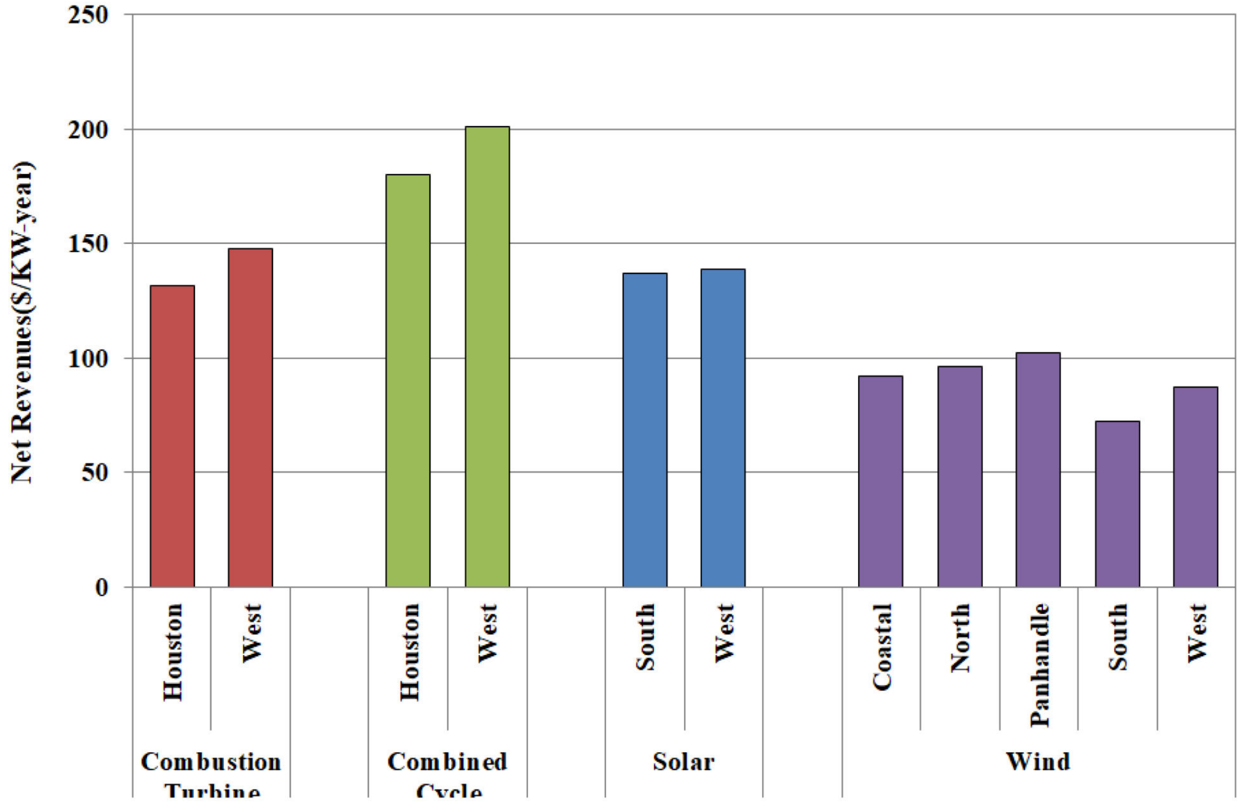
Natural Gas-Fired Resource Profitability. In 2022, revenues were higher than they had been in 2020 though lower than 2021, when they were affected by the shortage pricing during Winter Storm Uri. The pricing for energy and ancillary services produced a spike in net revenues for natural gas resources when compared to a mild year like 2020, which had lower natural gas prices and was prior to the latest ORDC shift.

Net Revenues by Technology and Location. Figure 48 shows the net revenues at different locations for a variety of technologies. Because natural gas prices can vary widely, the revenues for natural gas units are shown for the Houston zone (reflecting Katy hub prices) and the West zone (for Waha). Historically, the high natural gas production in the Permian Basin and limited export capability has resulted in low gas prices at the Waha location and much higher net revenues for gas resources in this area. That basis difference in natural gas prices decreased in 2021 but has rebounded in 2022.

Figure 48 also shows the net revenues for wind and solar generation at multiple locations. The profitability of those resources is chiefly determined by the available natural resource and the prevailing price to be received. Net revenues for wind were again lower than gas technologies in 2022 in all areas. This is partly because wind resources tend to produce less output during hot summer conditions.

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

Figure 48: Net Revenues by Generation Resource Type



Interpreting Single-Year Net Revenues. These results indicate that on a stand-alone basis during 2022, the ERCOT markets did provide sufficient revenues to support profitable investment in combustion turbine and combined cycle technologies. Net revenues were unusually high for a year without shortage conditions because of the ORDC changes that went into effect in January 2022, together with a prolonged, hot summer. Natural gas resource investors' response to these prices will depend on their future revenue expectations over a number of years. The prevailing capacity surplus and the changes in how policymakers and ERCOT will be managing the system going forward are likely to limit these expectations. However, it is also important to recognize that investors may invest instead in new technologies, such as battery energy storage or load-flexible renewables, which have different value propositions than traditional generation.

For all these reasons, it is important to be cautious in interpreting single-year net revenues and projecting their long-term effects. However, net revenues in three of the last four years have exceeded CONE for new gas resources. The shift to the ORDC makes this trend likely to continue, though we expect continued year-to-year variability. Please see Section VII of the Appendix for additional detail and discussion of the net revenue results presented in this subsection.

C. Planning Reserve Margin

Ultimately, the importance of the market signals discussed above is that they facilitate the long-term investment and retirement decisions by market participants that will maintain an adequate resource base. This subsection discusses the trends in the planning reserve margin, which is one measure of the adequacy of the resource base.

The market responds in many ways to high prices, which all raise planning reserve margins:

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

In 2022, there were no significant expected or actual shortages based on the planning reserve margin calculation. Similar to the analysis of net revenues year over year above, it is important to be cautious in interpreting single-year lack of shortage pricing and projecting the long-term based on planning reserves, as shortages can occur in peak net load intervals that may be different than those studied in the planning horizon. Planning reserves take a more holistic and long-term view of market conditions and may not indicate the frequency of shortage conditions in any given year. However, we note that the trend is in the direction of high net revenues, particularly given the ORDC change.

In 2022, ERCOT continued to see significant increases in utility-scale solar resources. Based on ERCOT's interconnection queue, this trend is expected to continue over the next several years and increase the forecasted planning reserve margin for 2023 through 2025 up to 44%.[83] Figure 49 shows ERCOT's previous and forecasted planning reserve margins over the next five years, including the new generators that account the changes in the reserve margin.

Figure 49 indicates that Texas heads into the summer months of 2023 with a healthy planning reserve margin of 22.2%, roughly on par with the reserve margin for 2022. We note that the current CDR does not consider storage resources (the Spring 2023 SARA does, however). Including an expected contribution to peak demand by the growing quantity of storage resources would increase the reserve margin. On the other hand, the CDR relies solely on hour-ending 5 p.m. (the peak hour). The peak net load hour is likely a more accurate predictor of shortage conditions, particularly as solar generation continues to be added to the ERCOT system.[84]

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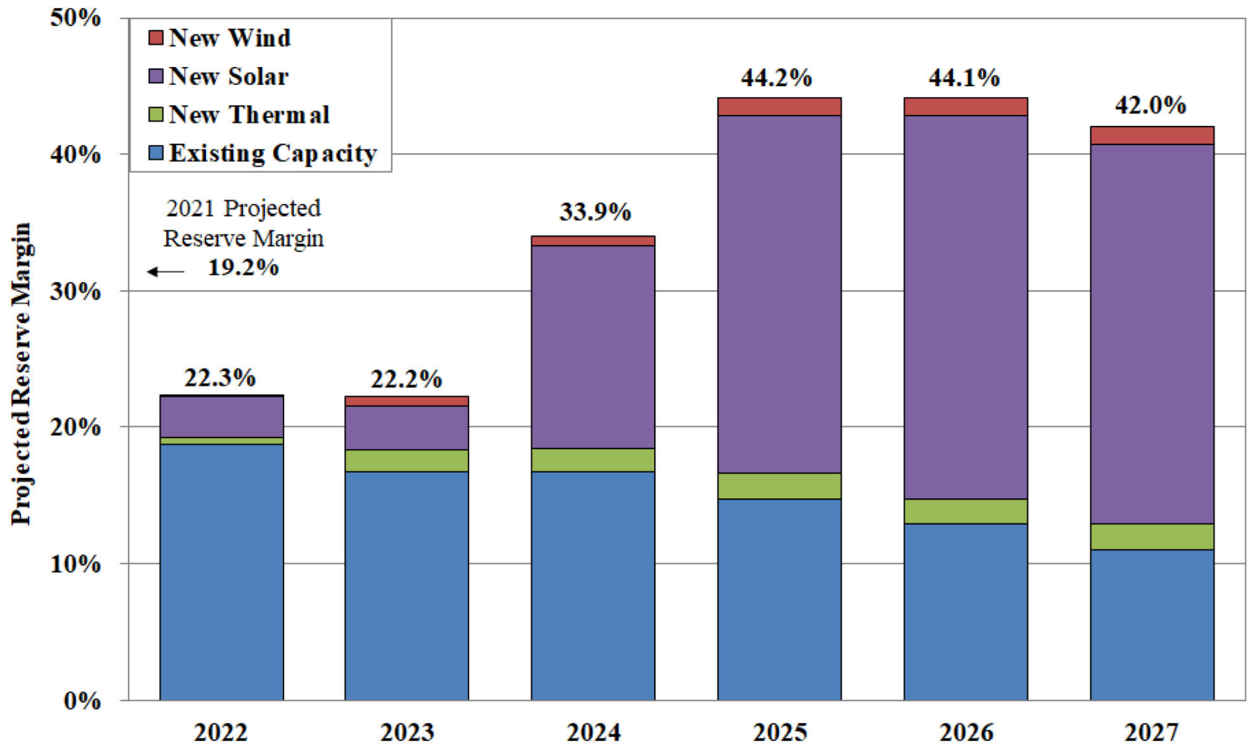
83 *See* Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2023-2032 (May 5, 2023), https://www.ercot.com/files/docs/2023/05/05/CapacityDemandandReservesReport_May2023_Revised.pdf.

84 The May 2023 version of the CDR includes a scenario using 9 p.m. instead and presents an option with energy storage resources. Together, those bring the 2024 summer reserve margin to 27.7%, from 36.3%.

Figure 49: Projected Planning Reserve Margins



Source: ERCOT Capacity, Demand and Reserves Report, May 2023

D. Effectiveness of the Shortage Pricing Mechanism

One of the primary goals of an efficient electricity market is to ensure that in the long term, there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. Generators earn revenues from three sources: energy prices during non-shortage, energy prices during shortage and capacity payments. Without a capacity market in ERCOT, suppliers' revenues are derived solely from energy prices under shortage and non-shortage conditions. Revenues during non-shortage conditions tend to be more stable as planning margins fluctuate, but shortage revenues are the primary means to provide investment incentives when planning margins fall (or incentives to keep existing units in operation). Therefore, the performance of shortage pricing in the ERCOT market is essential.

1. Background on Shortage Pricing in ERCOT

Shortage pricing refers to the price escalation that occurs when supply is not sufficient to satisfy all the system's energy and operating reserve requirements. In these cases, prices should reflect the reliability risks borne by the system as the shortage deepens. Ideally, the value of the shortage should be priced based on the loss of load probability at varying levels of operating reserves multiplied by VOLL.

Shortage pricing in ERCOT occurs through the ORDC that was implemented in 2014, which automatically increases the prices as reserves levels drop. The ORDC is described in more detail in Section I. Since it has been in effect, ORDC has had a growing impact on real-time prices, especially since 2019 when lower installed reserves led to higher expected shortage pricing, and the ORDC calculation was systematically changed over time. The ORDC adder reflects VOLL, which was set to $9,000 per MWh in June 2014 and changed to $5,000 per MWh in January 2022. The real-time prices are increased by the Real-Time Reserve Price, which is determined based on the value of the remaining reserves in the system as specified by the predefined ORDC.

The Scarcity Pricing Mechanism includes a provision termed the Peaker Net Margin (PNM) threshold that is designed to provide a pricing “fail-safe” measure. If the PNM threshold is exceeded, the system-wide offer cap is reduced. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[85] Section I contains several summaries and discussions of the shortage pricing that occurred in 2022. The next subsection compares 2022 pricing to prior years, including 2021, the only year that the PNM threshold was ever reached.

2. Peaker Net Margin in 2022

Figure 50 shows the cumulative PNM results for a selection of years chosen to represent the noteworthy PNM results and patterns seen since the creation of the Scarcity Pricing Mechanism. When administering the scarcity-pricing mechanism in ERCOT under 16 TAC § 25.505, the system-wide offer cap is set equal to the high system-wide offer cap (HCAP) at the beginning of each calendar year and maintained at this level until the PNM during a calendar year exceeds a threshold of three times the annual cost of new entry of new generation plants ($315,000). This figure shows that PNM results in 2022 were higher than any other year except 2021, but still nowhere near reaching the $315,000 PNM threshold. That threshold was exceeded for the first and only time in ERCOT’s history during the ERCOT operating day of February 16, 2021.[86]

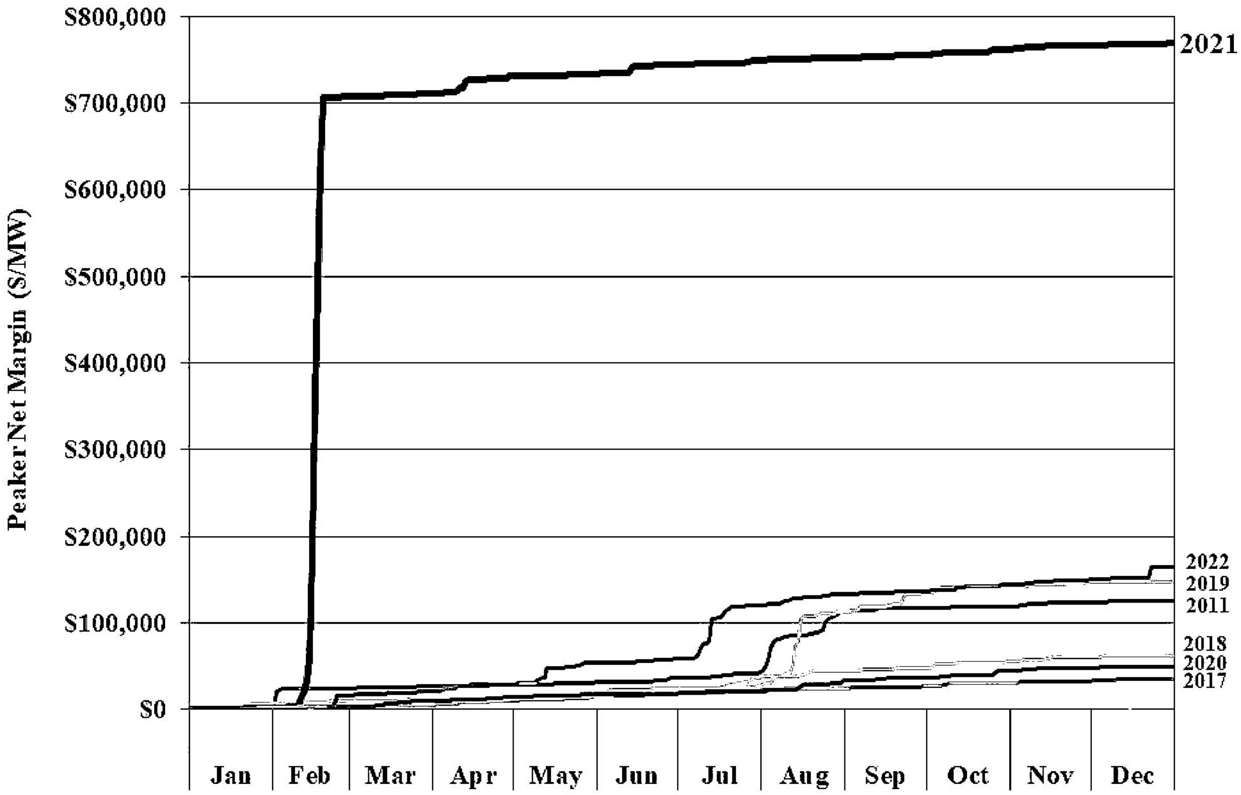
The relatively high PNM results in 2022 were likely due to a combination of hotter temperatures that increased summer loads and changes to the ORDC. Also of note was the PNM accumulation of $32k/MW-yr in the winter months (includes January, February, and December) of 2022. Aside from the winter of 2021, this is the highest recorded winter PNM total and is almost one third of the current CONE. A large portion of this high winter PNM accumulation was due to record winter demand during Winter Storm Elliot on December 23, 2022, and tight system conditions on February 24, 2022, when net load was high. High winter prices were a reflection of those conditions combined with high forced outages of thermal resources and low day-ahead prices (resulting in high RUC activity on February 24).

85 The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

86 Once the peaker net margin threshold is achieved, the system-wide offer cap is set at the low system-wide offer (LCAP) of $2,000 per MWh.

ERCOT's continued reliance on conservative operations to manage grid conditions impacts the efficiency and accuracy of the price signals provided by the energy-only market because it can inflate the price adders as discussed earlier in this Report. Hence, a re-evaluation of the reserve level targets is warranted.

Figure 50: Peaker Net Margin



3. Changes to the ORDC

The Commission directed notable changes to the ORDC in 2021 to be implemented in 2022, and we analyze the effects of those changes in this section. In previous years, the Commission considered proposals modifying various defining aspects of the ORDC, including shifting the LOLP portion of the curve.[87] The LOLP portion of the curves used to determine the ORDC price adder has typically been constructed using normal probability distributions defined by two factors: a) the mean of historical differences between expected and actual operating reserves ("mu"), and b) the standard deviation in those values ("sigma"). On January 17, 2019, the Commission approved a two-part process to modify the ORDC in two steps:

1. Transitioning to a single blended ORDC curve and implementing a 0.25 standard deviation shift in the LOLP calculation in the spring of 2019, and

[87] *Review of Summer 2018 ERCOT Market Performance*, Project No. 48551, Memo from Chairman Deann T. Walker (Jan. 17, 2019).

2. Implementing a second 0.25 standard deviation shift in the spring of 2020. The second step of the ORDC change was implemented on March 1, 2020.

Following Winter Storm Uri, the Commission worked with participants to develop a blueprint for reforms to the design of the wholesale electric market.[88] The blueprint compiled directives and reforms to be implemented in two phases. Phase I of the blueprint focuses on enhancements to current wholesale markets to improve price signals and operational reliability. Part of Phase I of the blueprint included significant changes to the ORDC.

Aimed at rewarding generation assets that self-commit at lower reserve levels, the modified ORDC is designed to cause prices to rise more quickly at those lower reserve levels. This provides incentives to bring generation units online and prompt consumer demand response earlier to help enhance regular market operations and avoid conservation appeals. Changes to the ORDC were made effective January 1, 2022, to set the MCL at 3,000 MW and set the high system-wide offer cap and VOLL to $5,000 per MWh.[89]

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

In 2022, the effect of changes to the ORDC were predictably significant. ORDC revenues in 2022 more than doubled to $3B, increasing by $1.7B from where they would have been absent the change. Even though the offer cap was lowered, operating reserve adders were more frequently non-zero throughout the year.

ORDC naturally accrues to generators that are running during tight conditions, which are often but not always times in which renewable generation is low. Table 9 shows the ORDC revenue in 2022 by generation type, compared to that generator type's contribution to the total energy production for the year. This table shows that gas resources produced 43% of the total generation but received 61% of the ORDC revenues.

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

[89] *Id.*

Table 9: ORDC Revenue by Fuel Type

	Thermal	Wind & Solar	Batteries	Hydro	Biomass
ORDC Revenue ($ millions)	$2,524.0	$423.1	$18.3	$4.3	$11.7
% of ORDC Revenue	*85%*	*14%*	*0.6%*	*0.1%*	*0.6%*
ORDC Revenue per MWh	$8.49	$3.22	$40.19	$14.65	$27.16
Total Generation (GWh)	297,142	131,252	455	294	431
% of Generation (%)	*69%*	*31%*	*0.1%*	*0.1%*	*0.1%*

Table 9 also shows Solar and wind together received 14% of the ORDC revenues while representing 31% of total generation. Without having to perform an effective load carrying capability (ELCC) study and apportion capacity revenues appropriately, the ORDC is an effective mechanism to reward generators that are producing during tight conditions. Moreover, it is by nature self-correcting, since it incorporates uncertainty probabilities in the shape of the curve. Recommendation 2022-5 is intended to ensure this self-correcting mechanism works effectively.

4. Reliability Must Run and Must Run Alternatives

Reliability-Must-Run procedures are essential for determining and addressing the need for generation units to support grid reliability. A Reliability Must Run (RMR) Unit is a resource operated under the terms of an agreement with ERCOT that would not otherwise be operated except that it is necessary to provide voltage support, stability or management of localized transmission constraints under credible single contingency criteria where market solutions do not exist. If ERCOT determines a resource is needed to maintain electric stability, it can enter into an RMR agreement to pay the plant an "out-of-market" payment to continue operating. ERCOT also has a process to consider other resources, known as Must-Run Alternatives (MRA). In lieu of paying an uneconomic to stay open to ensure grid reliability, ERCOT may issue a Request for Proposals for alternative solutions that can address the specific reliability concern.

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 2022.[90] 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 2022.[91]

90 Wharton County Generation LLC: TGF_TGFGT_1; OCI Alamo 1 LLC: OCI_ALM1_ASTRO1; GEUS: STEAM1A_STEAM_1; City of Garland: SPNCER_SPNCE_4 and SPNCER_SPNCE_5; Mountain Creek Power LLC: MCSES_UNIT8.

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

VIII. ANALYSIS OF COMPETITIVE PERFORMANCE

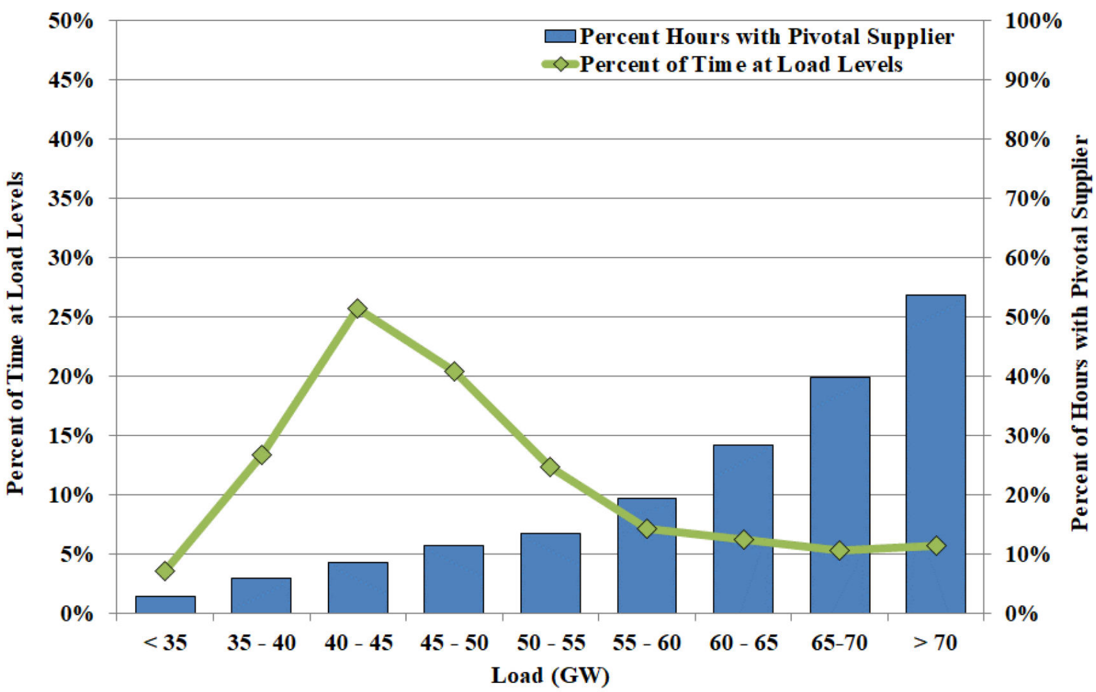
In this section, we evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). This section begins by evaluating a structural indicator of potential market power, then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, this section includes a summary of the Voluntary Mitigation Plans in effect during 2022.

Based on these analyses, we find that the ERCOT wholesale markets performed competitively in 2022, with the exception of the non-spinning reserve market. This market became much less competitive as ERCOT substantially increased its procurement of these reserves. We raised concerns regarding the non-spinning reserve market outcomes and the Commission addressed them by requiring changes to the Voluntary Mitigation Plans (VMPs) of the large suppliers.

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 large supplier is "pivotal", i.e., when its resources are required to meet demand or manage a constraint. Figure 51 shows the results of our 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 51: Pivotal Supplier Frequency by Load Level



At loads greater than 70 GW, there was a pivotal supplier approximately 50% of the time in 2022, down from 71% in 2021. A relatively high pivotal supplier percentage is expected at high load levels because the largest suppliers' resources are more likely to be needed as other suppliers' resources are more fully utilized serving the load. Pivotal suppliers existed in 15% of all hours in 2022, lower than the 18% of all hours in 2021.

We cannot make inferences regarding market power solely from pivotal supplier data because it does not consider the contractual position of the supplier. Bilateral and other financial contract obligations can affect whether a supplier has the incentive to raise prices. For example, a small supplier selling energy solely in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. We recommend that the "small fish" rule be eliminated because these suppliers and sometimes pivotal, and because high offer prices are not necessary to ensure efficient pricing under tight conditions (see SOM Recommendation 2021-1).

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

B. Evaluation of Supplier Conduct

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

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

1. Generation Outages and Deratings

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

Figure 52 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2022. 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; € short-term forced outages; and € long-term outages and deratings greater than 30 days. What remains is the available capacity.

Figure 52: Reductions in Installed Capacity

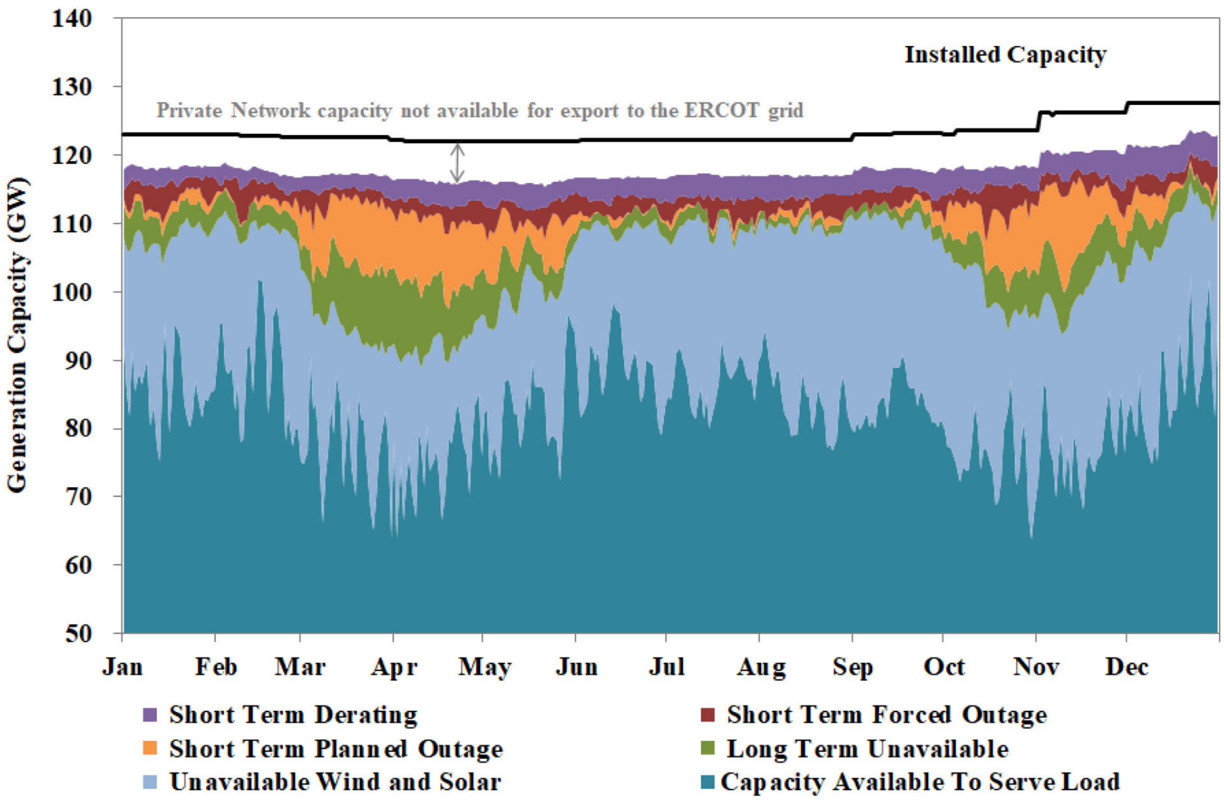


Figure 53 shows that short-term outages and deratings of non-wind generators fluctuated between 3.8 to 20.4 GW, while wind and solar unavailability varied between 7 and 33 GW. Short-term planned outages were largest in the shoulder months of March, April and November, while smallest during the summer months, consistent with our expectations. The quantity of short- and long-term (> 30 days) unavailable capacity peaked in April at more than 24 GW.

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 53 provides a comparison of the monthly outage and derating values for 2021 and 2022.

Figure 53: Short-Term Deratings and Outages

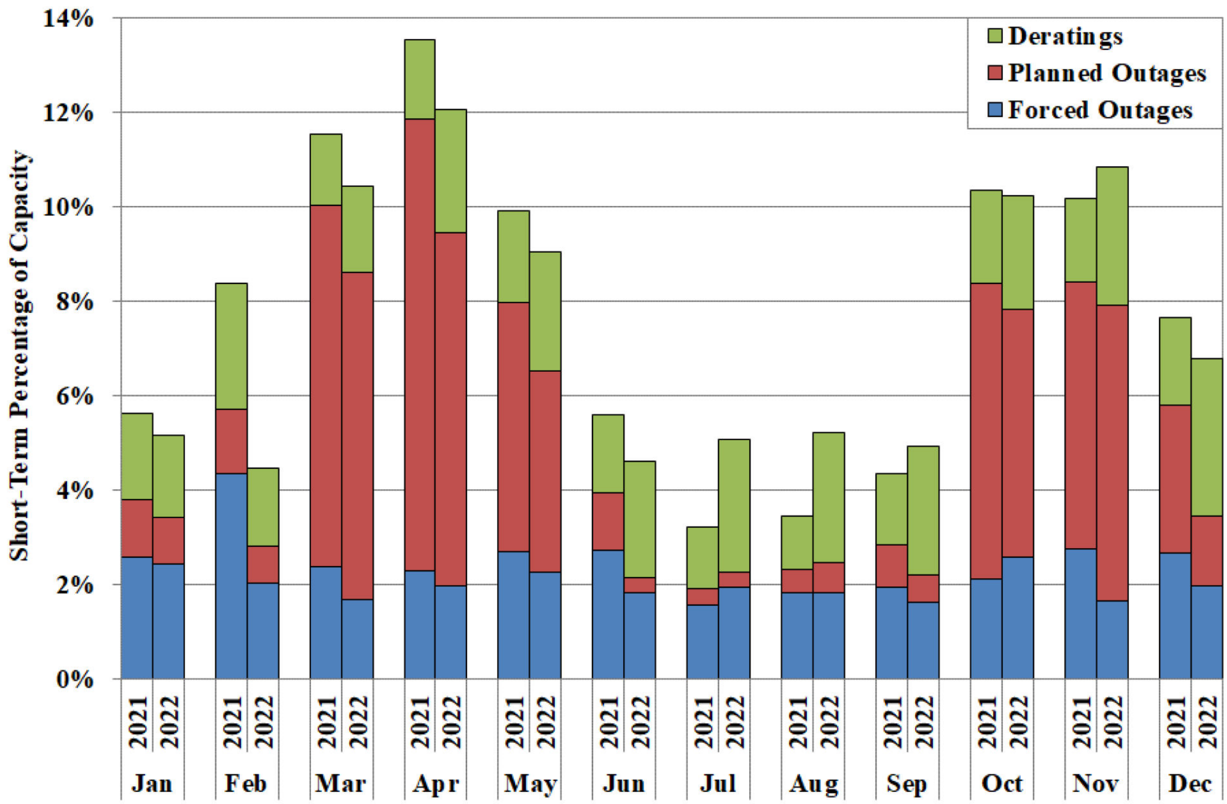


Figure 53 shows generally forced outages in 2022 were generally lower than 2021, with the exception of July and October. The prolonged, hot summer put stress on some generators, leading to high forced outage rates compared to previous years. Planned outages were low in February 2022 again, indicating that there was deferral of some outages in anticipation of another winter event, however, those actions likely were at the cost of higher outage rates in March/April and October/November. Finally, the significant increase in planned outages scheduled during spring and fall in both years is an indicator of preparation for and recovery from the summer months in which the ability to capture shortage pricing is the highest.

Deratings were up in all months in 2022 except February. The uptick in deratings in 2022 indicates that generators were intent on maximizing generator availability by keeping the plants online. Overall, these results show that suppliers behaved competitively, maximizing availability in the highest load hours. Figure A33 in the Appendix shows the average amount of short-term outages and deratings lasting less than 30 days for the year and for each month during 2021. Figure A48 in the Appendix includes long-term outages, which were lower than in prior years.

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.

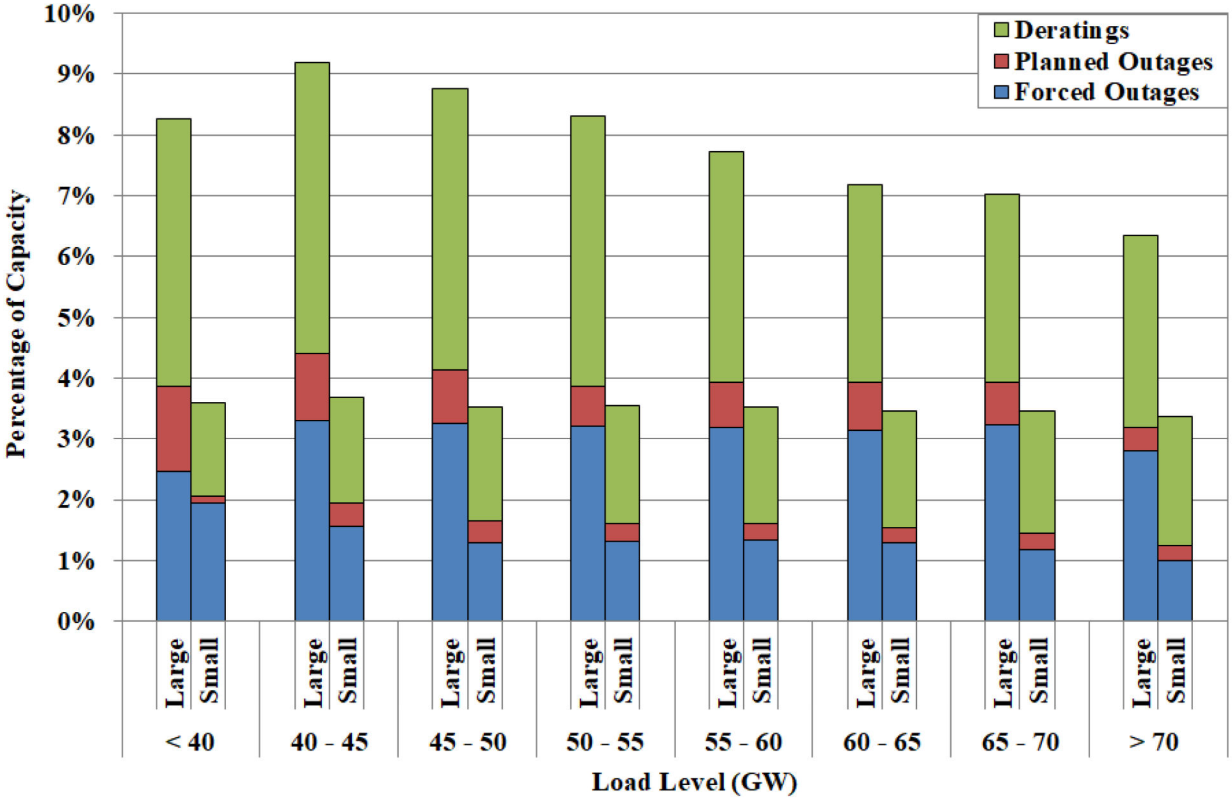
The pivotal supplier results shown in Figure 51 indicate that the potential for market power abuse rises at higher load levels as the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at 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 54 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 54 confirms the pattern we have seen since 2018 that, in general, 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 serve as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels exceeded those for small suppliers but remain at levels that are small enough to raise no competitiveness concerns. Small suppliers have the most incentive to ensure generator availability because each unit in their fleet makes up a larger percentage of their total market share, which means that any outage has the potential for larger financial impacts.

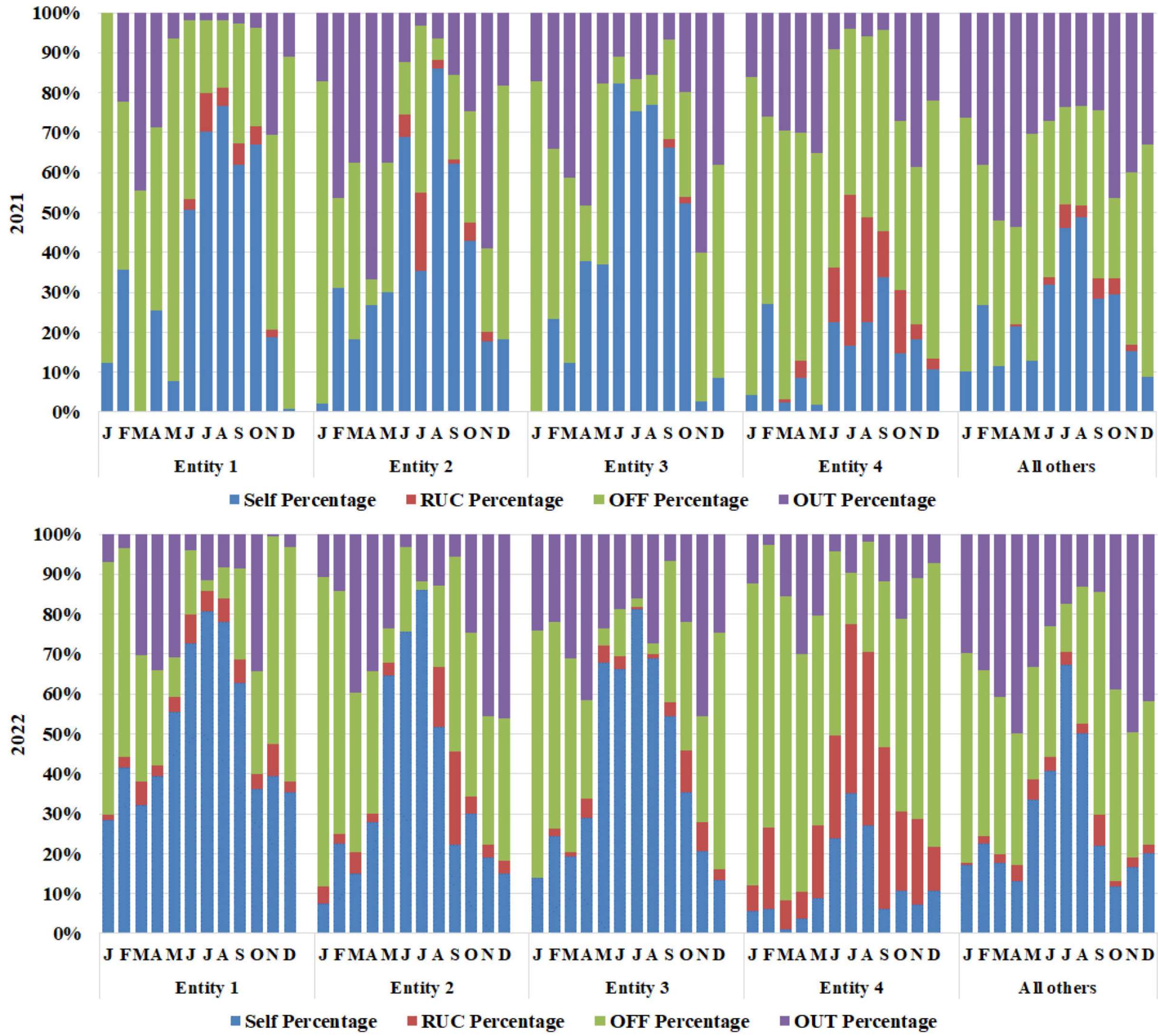
Figure 54: Outages and Deratings by Load Level and Participant Size, June-August



We remain concerned regarding the incentives to self-commit generation resources in light of ERCOT's increased commitment of resources through Reliability Unit Commitment (RUC). Recommendation 2022-2 above is intended to address this concern. This withholding strategy arose out of the frequent use of the RUC tool in the latter half of 2021. Given the predictability of the RUC instructions, the ability to opt out of RUC settlement during the operating hour if conditions changed, and the high RUC offer floor which economically withheld MWs under a RUC instruction, a disincentive to self-commit existed for large suppliers.

One large supplier continued to adjust its self-commitment behavior and was far more likely to run under RUC commitment than was seen in prior years. Figure 55 below depicts the difference in behavior of entities between 2021 and 2022 for resource-daily decisions for gas steam resources. Entity 4 exhibited a marked reduction in self-commitment for these resources, a pattern that occurred from 2020 to 2021 as well and largely did not exist for other entities.

Figure 55: Monthly Commitment Percentages of Gas-Steam Units



To address this incentive issue with the frequent use of RUCs and the high RUC offer floor, we filed NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.* This rule changed the RUC offer floor to $250 per MWh and made the RUC opt-out provision limited in its applicability. The rule change was approved by the Board on April 27, 2022, and partially implemented on May 13, 2022. This year, we add recommendation 2022-2 to address incentive issues with regard to claw-back percentages in combination with the frequent use of RUCs and the RUC settlement guarantee.

3. Evaluation of Potential Economic Withholding

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

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

Figure 56: Incremental Output Gap by Load Level and Participant Size – Step 2

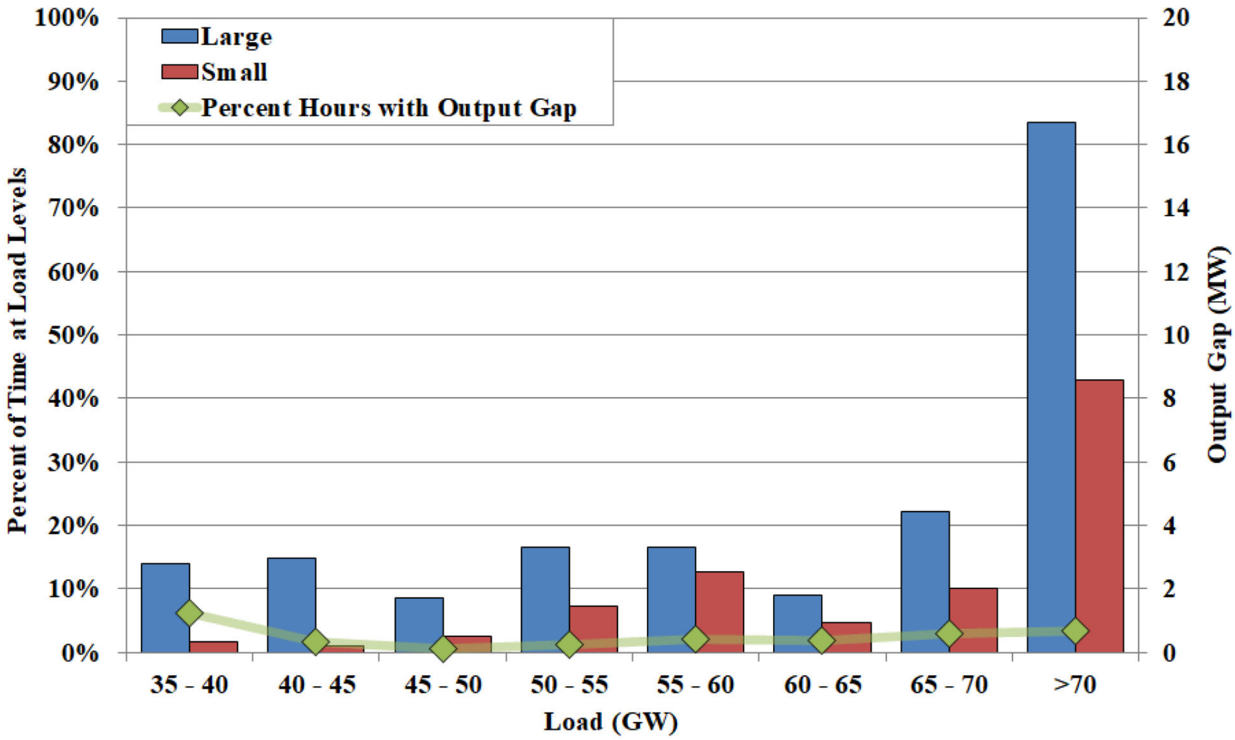


Figure 56 shows the average output gap levels, measured by the difference between a unit's operating level and the output level had the unit been offered to the market based on a proxy for a competitive offer, i.e., the mitigated offers, but with a few changes. We use generic costs instead of verifiable 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, and only roughly 2% of the hours in 2022 exhibited an output gap. Taken together, these results show that potential economic withholding levels were low in 2022. Based on all of our evaluations of the market outcomes presented in this Report, we conclude that the ERCOT energy market performed competitively in 2022.

C. Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) can be filed and if subsequently approved by the Commission, adherence to such plans constitutes an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. In 2022, Calpine, NRG and Luminant had active and approved VMPs filed with the Commission.[92] 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.[93] 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."[94] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of competition would typically involve profitably raising prices materially above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended

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

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

94 PURA § 39.157(a).

consequences associated with the potential exercise of market power can be addressed in a timely manner.

In 2022, competitiveness concerns arose in the non-spin market because of ERCOT's greatly increased procurement of the service based on a more conservative operational posture. The VMPs existing at the time protect the conduct of suppliers in this market from potential enforcement actions. The increase in non-spin procurements in the day-ahead market has fundamentally affected the competitiveness of the non-spin market by reducing the excess supply that used to exist. As reported earlier in the Report, we estimate that this decrease in competitiveness raised non-spinning reserve costs to loads by between $385 million and $480 million between August 2021 through 2022. The Commission addressed this issue by modifying the three active VMPs on March 23, 2023.[95]

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 an amount that approximates competitive offers. ERCOT's real-time market includes a mechanism to mitigate offers for resources that are required to resolve a transmission constraint. Mitigation applies whether the unit is self-committed or receives a RUC instruction. RUC instructions were typically given to resolve transmission constraints in previous years, though in 2022 RUC for system-wide capacity was common. When units that receive RUC instructions are required to resolve a non-competitive transmission constraint, they often are dispatched with mitigated offers in real-time.

ERCOT's dispatch software includes an automatic, two-step mitigation process. In the first step, the dispatch software calculates output levels (base points) and associated locational marginal prices using the participants' offer curves and considering 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.

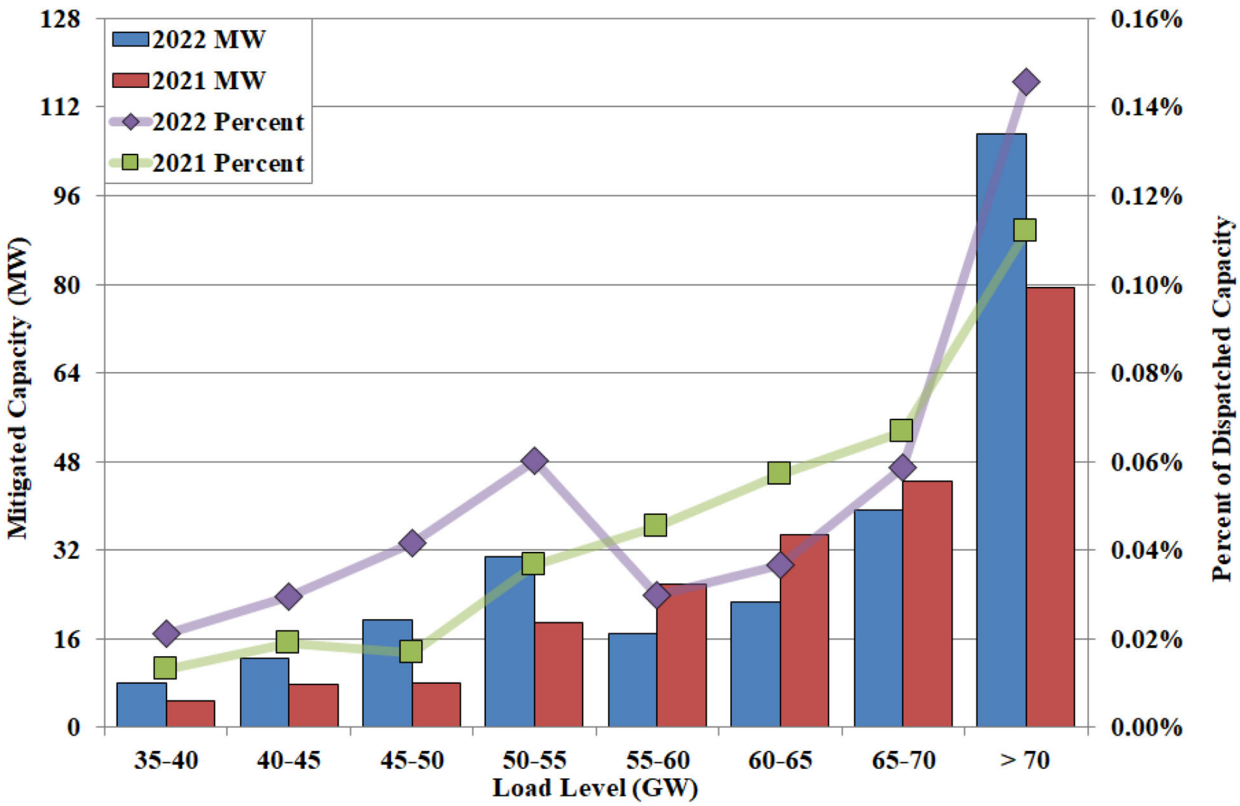
This approach is intended to limit the ability of a generator to exercise market power, i.e., to limit its ability to use its offer to raise prices in the event of a transmission constraint that

95 See *Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 54739 (Mar. 23, 2023); *Request for Ratification of Commission Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket 54740, Order (Mar. 23, 2023); and *Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket 54741, Order (Mar. 23, 2023).

requires its output to resolve. In this subsection, we analyze the quantity of mitigated capacity in 2022. The automatic price mitigation aspect of the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active and binding in SCED.

Figure 57 shows the percentage of capacity, on average, which was actually mitigated during each dispatch interval. The results are provided by load level. The amount of mitigation in 2022 was generally higher than in 2021, due to more non-competitive constraints binding in 2022 than in 2021. In particular, when resources are necessary to resolve a local constraint, it is more likely to be deemed non-competitive and result in mitigation. Only the amount of capacity that could be dispatched within one interval is counted as mitigated for the purpose of this analysis. More analysis of mitigation is presented and discussed in Section VI in the Appendix.

Figure 57: Mitigated Capacity by Load Level



CONCLUSION

As the IMM for the Commission, Potomac Economics is providing this Report to review and evaluate the outcomes of the ERCOT wholesale electricity market in 2022. The ripple effects of the Winter Storm Uri in 2021 continued to reverberate in all corners of the market and system throughout 2022. The results of that extreme event prompted much more conservative operations of the system by ERCOT, as well as the development of a number of market reforms. We will provide support to the Commission and ERCOT as they develop and implement these reforms, as well as continuing to evaluate the performance of the markets in future reports.

Overall, our evaluation of a number of factors suggests that the market performed competitively in 2022, with the exception of the non-spinning reserve market (an issued addressed by the PUCT in 2023 via modification of the three existing Voluntary Mitigation Plans). We remain concerned about the incentives to self-commit in light of the RUC rules and the frequency of these commitments. In the longer term, we continue to look to the implementation of RTC as the most significant change to improve the reliability and competitive performance of the ERCOT markets. We also recommend a number of other improvements to the design and operations of the ERCOT market that will be key in the future as the system transitions to much heavier reliance on intermittent renewable resources.

APPENDIX

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INTRODUCTION

This Appendix provides supplemental analysis of certain topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, our conclusions from these analyses and how they relate to the 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.

I. APPENDIX: KEY CHANGES AND IMPROVEMENTS IN 2022

Key changes or improvements implemented or proposed by the PUCT and ERCOT in 2022 are outlined below. In the aftermath of Winter Storm Uri, the Texas Legislature, during 87th session, approved several measures to address market outcomes and reliability concerns, and addressing those concerns continued throughout 2022 including several PUCT dockets and projects and ERCOT protocol changes as a result of these reforms and initiatives.

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

After a series of rigorous public work sessions and review of comments filed by market participants, the Commission directed ERCOT to enact major reforms in PUCT Project No. 52373, *Review of Wholesale Electric Market Design* at its December 16, 2021, open meeting.[96] Specifically, the Commission approved the blueprint for the design of the wholesale electric market filed in the Project on December 6, 2021. The blueprint compiled directives and concepts designed to reform the ERCOT wholesale electricity market presented in two phases. Phase I of the blueprint, implemented throughout 2022, provided enhancements to current wholesale market mechanisms to enhance ancillary services and improve price signals and operational reliability. Phase II of the blueprint incorporates long-term market design reforms to promote the supply of dispatchable generation and develop a backstop reliability service, and extends beyond 2022, as outlined below.

ERCOT adopted a more conservative posture with regard to operating the grid in July 2021. ERCOT began requiring additional operational reserves and bringing additional generation online outside of the market, and that trend continued in 2022. In addition to ERCOT's more conservative operating posture, the Commission approved and implemented the following directives as part of Phase I of the Review of Wholesale Electric Market Design by the end of 2022:

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

Modifications to the Operating Reserve Demand Curve (ORDC)

In PUCT Project No. 52631, *Review of 25.505*, changes were made to the scarcity pricing mechanism.[97] Effective January 1st, 2022, ERCOT implemented modifications to the Operating Reserve Demand Curve (ORDC) as directed by the PUCT, that set the Minimum Contingency Level (MCL) to 3,000 MW and set both the high system-wide offer cap (HCAP) and value of lost load (VOLL) to $5,000 per MWh. By moving the Minimum Contingency Level (MCL) from 2,000 MW to 3,000 MW, the ORDC will now print higher prices at much higher reserve levels to more appropriately value this increased level of reliability.

The Phase € changes to ERCOT's shortage pricing mechanism via the ORDC have increased real-time market energy revenues by $1.7 billion in 2022. This substantial increase in energy revenues alone greatly enhances the incentives for existing resources to remain in operation and for entities to build new dispatchable resources. This statement does not account for the much higher ancillary service revenues arising from increased requirements put in place in July 2021.

Demand Response & Emergency Response Service (ERS) Reform

For the 2021 ERS program year, two notable changes occurred affecting ERS service. First, as directed by the Public Utility Commission of Texas (PUCT) in October 2021 and codified in the Protocols through NPRR 1106, Deployment of Emergency Response Service (ERS) Prior to *Declaration of Energy Emergency Alert (EEA)*, the deployment of ERS process was revised to allow for the deployment of ERS prior to the declaration of an EEA when Physical Responsive Capability (PRC) falls below 3,000 MW and is not expected to be recovered above that threshold within 30 minutes. The second change through NPRR 984, *Change ERS Standard Contract Terms*, modified the ERS program year, to begin in December of each year and end in November of the following year.

During the 2022 program year the PUCT approved amendments to its Substantive Rule 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS) rule that increases the annual budget for ERS and allows ERCOT the flexibility to procure ERS for up to 24 hours in a contract term to better address seasonal needs.[98] The adopted rule increased the annual budget for ERS to $75 million and allows ERCOT to exceed this amount by up to $25 million for ERS contract term renewals. The adopted rule also provides ERCOT greater

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97 *See also*, *Reorganization of § 25.505,* PUCT Project No. 53191 (Apr. 29, 2022). The adopted rules in this project separated the provisions of repealed §25.505 into three new rules. Specifically, new §25.505 prescribes resource adequacy reporting requirements in the Electric Reliability Council of Texas (ERCOT) region and requires ERCOT to submit to the commission a biennial report on the operating reserve demand curve, new §25.506 sets forth the requirements for the publication of resource and load information in ERCOT, and new §25.509 establishes a scarcity pricing mechanism for the ERCOT market.

98 *Emergency Response Service*, PUCT Project No. 53493, Order Adopting New 16 TAC §25.507 as Approved at the August 4,2022, Open Meeting (Aug. 4, 2022).

flexibility to procure ERS for longer amounts of time with a contract term from individual ERS resources to better address seasonal needs and make other administrative changes to the program.

The changes went into effect at the start of the program year beginning December 1, 2022. The procurement of ERS is administered in accordance with the ERS Procurement Methodology document. The $50 million per year maximum spend limit for ERS was still in effect for the entirety of the 2022 program year.[99]

Firm Fuel Supply Service (FFSS)

A new Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of gas generators to purchase fuel to be stored on site (with a possible expansion to offsite gas storage at a later date). The PUCT directed ERCOT to develop and procure this product as part of the Commission's Phase I Market Design efforts and in response to Texas Senate Bill 3.[100] Approved on March 31, 2022, NPRR1120, Create Firm Fuel Supply Service, created this new reliability service, to be procured via request for proposal (RFP).[101] On June 30, 2022, ERCOT issued a Request for Proposals (RFP) to provide FFSS during the November 15, 2022 through March 15, 2023 obligation period. Proposals were due by September 1, 2022.[102]

ERCOT received proposals from 5 different Qualified Scheduling Entities (QSEs), offering 19 Generation Resources to act as FFSS Resources during the obligation period. ERCOT confirmed that the offered Generation Resources qualified to provide FFSS and determined that the offered Generation Resources could be procured within the budget cap established by the Commission. The following are the FFSS procurement results for the November 15, 2022, through March 15, 2023, obligation period:

- All 19 Generation Resources were awarded at a clearing price of $6.19/MW/hr ($18,000/MW);
- 18 of the 19 Generation Resources offered fuel oil as the reserve fuel type;
- 1 Generation Resource offered natural gas storage;
- A total of 2940.5 MW of FFSS capacity was procured; and
- The total cost of procurement was $52,857,722.28.

99 2022 Annual Report of Demand Response In the ERCOT Region (December 2022); https://www.ercot.com/mp/data-products/data-product-details?id=NP3-110

100 https://www.ercot.com/services/programs/firmfuelsupply

101 https://www.ercot.com/mktrules/issues/NPRR1120

102 https://interchange.puc.texas.gov/Documents/53298_18_1241979.PDF

At noon on December 21, 2022, a Public Notice was issued instructing Qualified Scheduling Entities (QSEs) to prepare for potential FFSS deployments. Later that same day, the first FFSS deployment instructions were issued. Between approximately noon on December 22, 2022, and noon on December 25, 8 Resources had active FFSS deployments. Due to the timing of the FFSS deployments within the obligation period and the on-going potential for extreme cold weather and natural gas supply disruptions, QSEs for FFSS Resources that were deployed were given instructions and approval to restock fuel reserves for FFSS.[103] We have identified potential price formation issues with FFSS. More rigorous deployment criteria should be considered; once that is done and the Commission has finalized the expansion of the FFSS details, those price formation issues should be addressed.

ERCOT Contingency Reserve Service (ECRS)

At the end of 2021, during Phase I of the market redesign effort, the PUCT instructed ERCOT to accelerate the implementation of a new ramping ancillary service product called ERCOT Contingency Reserve Service (ECRS). ERCOT started the ECRS project in January 2022 with a go-live target prior to the EMS freeze. Within this new framework, RRS (old) will be unbundled into two products: RRS (new) and ECRS. ECRS is a new AS product introduced to restore RRS (new) responsibility once RRS resources are depleted or to mitigate a reliability concern if there is a deficiency in the ramping capacity. By design, ECRS can be dispatched by SCED and should respond within 10 minutes to the deployment instructions

Weatherization of Generation Resources

At the September 29, 2022, open meeting, the PUCT approved a new version of 16 Tex. Admin. Code (TAC) § 25.55, the Weather Emergency Preparedness rule.[104] The new 16 TAC §25.55 represents the second phase of the two phases in the commission's development of robust weather emergency preparedness reliability standards to ensure that the electric industry is prepared to provide continuously reliable electric service. Specifically, it requires generation entities and transmission service providers (TSPs) in the ERCOT power region to maintain weatherization preparation standards for both winter and summer seasons. The new rule requires ERCOT to conduct on-site inspections of every generation resource and transmission facility in the ERCOT region. Additionally, the new rule requires utilities who do not comply with weatherization preparedness standards to undergo an independent assessment by a qualified professional engineer.[105]

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103 https://www.ercot.com/calendar/01242023-TAC-Meeting

104 https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.55/25.55.pdf

105 *Electric Weather Preparedness Standards – Phase II*, Project No. 53401, Order Repealing 16 TAC 25.55 and Adopting New 16 TAC 25.55, as Approved at the September 29, 2022 Open Meeting (Sept. 29, 2022).

Critical natural gas facility mapping

In June 2021, the 87th Texas Legislature enacted House Bill (HB) 3648, requiring the Public Utility Commission and Railroad Commission of Texas to collaborate on rules regarding critical natural gas facilities and entities. Specifically, the agencies were tasked with establishing a process to designate certain natural gas facilities in Texas as critical customers during an energy emergency. On November 30, 2021, the Public Utility Commission and Railroad Commission separately adopted rules to codify HB 3648 and establish new regulations for electric utilities and natural gas entities to ensure that critical natural gas facilities are appropriately identified.[106]

On April 29, 2022, the Texas Electricity Supply Chain Security and Mapping Committee (comprised of comprised of the PUCT, the Railroad Commission, ERCOT, and the Texas Division of Emergency Management) adopted an Electricity Supply Chain Map of critical infrastructure – the first of its kind in the state of Texas – for use during disaster and emergency preparedness and response. The map identifies critical infrastructure facilities that make up the state's electricity supply chain, including electric generation plants and the natural gas facilities that supply fuel to power the plants. State emergency management officials will use the map during weather emergencies and disasters to pinpoint the location of critical electric and natural gas facilities and emergency contact information for those facilities. The current map has more than 65,000 facilities including electricity generation plants powered by natural gas, electrical substations, natural gas processing plants, underground gas storage facilities, oil and gas well leases, saltwater disposal wells, as well as more than 21,000 miles of gas transmission pipelines and approximately 60,000 miles of power transmission lines. In addition to infrastructure layers, the Electricity Supply Chain Map includes elements such as Texas Division of Emergency Management regions, emergency contact information for facilities, as well as visualization of weather watches and warnings as they occur in any part of the state. The map is a living document and will be updated twice a year, or more often if necessary.[107]

Phase II: The Performance Credit Mechanism (2023)

Finally, Phase II of the market design blueprint, adopted by the PUCT on December 6, 2021, called for a study of specific long-term market design principles, including novel hybrid design that maintain the unique ERCOT energy-only market. To that end, the PUCT commissioned a report from Energy and Environmental Economics, Inc. (E3) titled Assessment of Market Reform Options to Enhance Reliability of the ERCOT System, released on November 10, 2022. E3 performed a quantitative and qualitative review on a range of proposed market designs that were initially discussed in Project No. 52373, *Review of Wholesale Electric Market Design* in producing the report. One design proposal that emerged from the report is the Performance

[106] https://www.puc.texas.gov/industry/electric/cng/default.aspx

[107] https://www.puc.texas.gov/agency/resources/pubs/news/2022/042922-joint-rrc-puc-map-press-release.pdf

Credit Mechanism (PCM). The PCM, as described by E3, establishes a requirement for LSEs to purchase "performance credits" (PCs) – earned by generators based on their availability to the system during the top 30 hours of highest risk – at a centrally determined clearing price. The PC requirement is a fixed quantity that is determined in advance of the compliance period, while the settlement process occurs retroactively based on the quantity of PCs that were actually produced.[108]

On January 19, 2023, the PUCT adopted the PCM as their preferred market design concept and directed PUCT Staff and ERCOT to delay implementation of the PCM until such time as the 88th Legislature has had an opportunity to render judgment on the merits of the PCM or establish an alternate solution. Additionally, the PUCT directed ERCOT to evaluate bridging options to retain existing assets and build new dispatchable generation until the PCM can be fully implemented.[109]

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

Others Key Changes and Improvements in 2022

In addition to the Phase I changes to wholesale market, other key changes and improvements were implemented in 2022, including the implementation of securitization and financing, as well as resolution of the Brazos Adversary Proceeding, outlined below.

PUCT Implementation of Securitization and Financing

In Subchapter M of PURA Chapter 39, the Legislature approved a process by which ERCOT could seek approval of a Debt Obligation Order authorizing financing of the Default Balance, which is defined by PURA to include: (1) amounts owed to ERCOT by competitive wholesale market participants from the Period of Emergency that otherwise would be or have been uplifted to other wholesale market participants; (2) financial revenue auction receipts used by ERCOT to temporarily reduce amounts short-paid to wholesale market participants related to the Period of Emergency; and (3) reasonable costs incurred by a state agency or ERCOT to implement a debt obligation order, including the cost of retiring or refunding existing debt. PURA § 39.602(1).[110]

108 *Review of Market Reform Assessment Produced by Energy and Environmental Economics, Inc. (E3)*, Project No. 54335, E3 Report, staff memo and updated questions (Nov. 10, 2022).

109 *Id.*, Order and Modified Memorandum (Jan. 19, 2023).

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

In Subchapter N of PURA Chapter 39, the Legislature authorized ERCOT to seek approval of a Debt Obligation Order to finance the Uplift Balance, including Reliability Deployment Price Adder ("RDPA") charges and Ancillary Service costs above the Commission' s system-wide offer cap as that term is defined in PURA § 39.652.[111]

Accordingly, ERCOT filed applications for Debt Obligation Orders pursuant to Subchapter M and N of Chapter 39 of the Public Utility Regulatory Act (PURA), to finance the Winter Storm Uri Default and Uplift Balances in July 2021. The Debt Obligation Orders were issued on October 13, 2021. The PUCT authorized ERCOT to finance a "default balance," which is an amount not greater than $800 million that includes the following: certain unpaid amounts owed to ERCOT by competitive market participants; Congestion Revenue Right (CRR) auction funds used by ERCOT to reduce short payments related to Winter Storm Uri; and costs associated with implementing the debt obligation order. The PUCT authorized ERCOT to assess a monthly "default charge" on Qualified Scheduling Entitles (QSEs) and CRR Account Holders to repay the default balance.

The Subchapter M Default Balance Securitization financing closed, and proceeds were disbursed, in November 2021. ERCOT began collecting default charges to repay the default balance in January 2022. A compliance docket was opened in accordance with ordering paragraph 45C of the Debt Obligation Order for all filings required by the Debt Obligation Order.[112] Approved on December 16, 2021, NPRR1103, *Securitization – PURA Subchapter M Default Charges*, established processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRRAHs pursuant to the Debt Obligation Order (DOO) issued in PUCT Docket No. 52321, *Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of PURA*.[113]

Further, the PUCT authorized ERCOT to finance an "uplift balance," which is an amount not greater than $2.1 billion for certain extraordinary costs incurred by Load Serving Entities (LSEs) related to Winter Storm Uri. The PUCT authorized ERCOT to assess a daily "uplift charge" on QSEs that represent LSEs that are not opted out of the uplift charge to repay the uplift balance and costs associated with implementing the debt obligation order. The Subchapter N Uplift Balance Securitization financing closed on June 15, 2022. Posted on December 29, 2021, and approved on March 31, 2022, NPRR1114, *Securitization – PURA Subchapter N Uplift Charges*,

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

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

113 https://www.ercot.com/about/hb4492securitization/subchapterm

established processes to assess and collect Uplift Charges to QSEs representing LSEs pursuant to the DOO issued in PUCT Docket No. 52322.[114]

Resolution of the Brazos Adversary Proceeding

On March 1, 2021, Brazos Electric Power Cooperative, Inc. (Brazos) filed its bankruptcy petition under Chapter 11 of the United States Bankruptcy Code (Bankruptcy Code) after failing to pay invoices due to ERCOT in the amount of approximately $1.9 billion for electricity and Ancillary Services purchased during Winter Storm Uri. ERCOT subsequently filed a proof of claim in the amount of approximately $1.9 billion based on Brazos' failure to pay ERCOT as required, which became the subject of the Brazos Adversary Proceeding. Brazos sought to substantially reduce ERCOT's approximately $1.9 billion proof of claim and have the entire amount of the reduced claim classified as an unsecured claim.[115]

In the Brazos Adversary Proceeding, Brazos sought to reduce ERCOT's proof of claim by more than $1.1 billion—the amount of ERCOT's claim attributable to ERCOT's administrative adjustment to wholesale market prices based on the Commission's Emergency Orders entered February 15 and 16, 2021, directing ERCOT to set prices at their highest to reflect the scarcity in the market during Winter Storm Uri. Trial in the Brazos Adversary Proceeding began on February 22, 2022. It was suspended on March 3, 2022, at the urging of the Bankruptcy Court, in order for the parties to engage in mediation. The ERCOT Settlement included the following critical economic terms:

- ERCOT will be promptly reimbursed (on the Effective Date of the Plan) $599,709,609.22, which represents the amount of Congestion Revenue Rights (CRRs) temporarily used by ERCOT to reduce the amount of the market shortfall immediately following Winter Storm Uri that was attributable to Brazos's short pay; and
- Impacted Market Participants having at least two payment options to address their short-pays: (1) an earlier discounted payment on the condition they release ERCOT of any obligation to pay the remaining balance or (2) full payment over 30 years.

On October 28, 2022, the ERCOT Board of Directors voted to approve Brazos' Amended Chapter 11 Plan of Reorganization, dated October 27, 2022, which memorialized and incorporated the terms of the ERCOT Settlement, subject to final approval by the bankruptcy court. On November 9, 2022, the Commission approved and supported ERCOT's authority to resolve the Brazos Adversary Proceeding and did not oppose the settlement approved by ERCOT.[116]

114 https://www.ercot.com/about/hb4492securitization/subchaptern

115 Brazos Settlement Overview

116 Brazos Bankruptcy Settlement

ERCOT Market Rule Revisions

ERCOT approved or introduced a number of Nodal Protocol Revision Requests (NPRRs), Other Binding Document Revision Requests (OBDRRs), and Verifiable Cost Manual Revision Requests (VCMRRs) in 2022 to reflect and implement the changes authorized by the Texas Legislature and PUCT, as well as a suite of general market improvements, outlined below.

Nodal Protocol Revision Requests (NPRRs)

- NPRR1058, Resource Offer Modernization.
  - Status: Approved on November 3, 2022.
  - Description: This NPRR allows all Resources to update their offers in Real-Time to reflect their current costs.
- NPRR1085, Ensuring Continuous Validity of Physical Responsive Capability (PRC) and Dispatch through Timely Changes to Resource Telemetry and Current Operating Plans (COPs).
  - Status: Approved on September 15, 2022.
  - Description: This NPRR improves the validity of the Physical Responsive Capability (PRC) calculation and dispatch by requiring quicker updates by Qualified Scheduling Entities (QSEs) to the telemetered Resource Status, High Sustained Limit (HSL), and other relevant information.
- NPRR1092, Reduce RUC Offer Floor and Limit RUC Opt-Out Provision.
  - Status: Approved by the Board on April 28, 2022; effective date of May 13, 2022, for Section 6.5.7.3, Security Constrained Economic Dispatch, and upon system implementation for the remainder.
  - Description: Posted on August 11, 2021, by the IMM, this NPRR as filed would have reduced the value of the offer floor on Resources that have the status of ONRUC to $75/MWh and removed the ONOPTOUT status. This NPRR was still pending at the end of 2021, but a modified version was approved in 2022. That version sets a $250/MWh RUC offer floor and allows ONOPTOUT status in more limited circumstances.
- NPRR1096, Require Sustained Two-Hour Capability for ECRS and Four-Hour Capability for Non-Spin.
  - Status: Approved on May 12, 2022.
  - Description: This NPRR requires Resources that provide ERCOT Contingency Reserve Service (ECRS) to limit their responsibility to a quantity of capacity that is capable of being sustained for two consecutive hours and/or Non-Spinning

Reserve (Non-Spin) to limit their responsibility to a quantity of capacity that is capable of being sustained for four consecutive hours. Additionally, this NPRR also requires ERCOT to conduct unannounced tests on Energy Storage Resources (ESRs) that are providing ECRS and/or Non-Spin in Real-Time.

- NPRR1100, Allow Generation Resources and Energy Storage Resources to Serve Customer Load When the Customer and the Resource are Disconnected from the ERCOT System.
  - Status: Approved on July 14, 2022, effective July 15, 2022.
  - Description: This NPRR clarifies that a Generation Resource or Energy Storage Resource (ESR) may serve Customer Load in any circumstance in which the Customer and the Resource are both disconnected from the ERCOT System due to an Outage of the transmission or distribution system. It is limited to configurations where the Resource and Customer Load are using privately owned transmission and distribution infrastructure during the Private Microgrid Island (PMI) operation. This is not a Private Use Network and the Load and Resource do not net during normal circumstances. For PMIs with an ESR, after the initial Settlement of an Operating Day in which the private microgrid operated as a PMI, this NPRR proposes an adjustment to ensure that consumption by the ESR prior to the PMI operation period and subsequently used to serve the Customer during private microgrid operation is no longer treated as Wholesale Storage Load (WSL). This adjustment will recharacterize the Load from WSL to Non-WSL on an Operating Day basis for as many Operating Days as necessary to ensure that ESR Load not eligible for WSL treatment is not provided WSL treatment.
- NPRR1120, Create Firm Fuel Supply Service.
  - Status: Approved on March 31, 2022, effective August 1, 2022 (Sections 1.3.1.2(1)(g), 2.1, 3.1.4.3(3), 3.9(7), and 3.14.5) and October 14, 2022 (Sections 2.1, 4.3, and 8.1.1.2.1.7).
  - Description: This NPRR creates a new reliability service, Firm Fuel Supply Service (FFSS). This new reliability service is developed consistent with directives from the Legislature (provided in Section 18 of Senate Bill 3, 87I that are now found in PURA 39.159€(2), requiring ancillary or reliability services to address reliability during extreme cold weather conditions) and the PUCT (see e.g. PUCT Project No. 52373, *Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT*, ordering ERCOT to develop a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard). By necessity this NPRR focuses on components that require accommodation in the Settlement and Billing system, since those components

require the longest lead time to design. Additional requirements were reflected in the RFP.

- See OBDRR039, ORDC Changes Related to NPRR1120, Create Firm Fuel Supply Service.

- NPRR1124, Recovering Actual Fuel Costs through RUC Guarantee.
  - Status: Approved on May 12, 2022, effective May 13, 2022.
  - Description: This NPRR proposes a change to ensure Generation Resources recover their actual fuel costs when instructed to start due to a RUC. Specifically, this NPRR recommends that the Startup Price per start (SUPR) and the Minimum-Energy Price (MEPR), as defined in paragraph (6) of Section 5.7.1.1, RUC Guarantee, will be set to the Startup Cap (SUCAP) and the Minimum-Energy Cap (MECAP), respectively, utilizing the actual approved fuel price paid.
- NPRR1131, Controllable Load Resource Participation in Non-Spin.
  - Status: Approved on September 15, 2022.
  - Description: This NPRR changes Controllable Load Resource participation in Non-Spinning Reserve (Non-Spin) from Off-Line to On-Line Non-Spin. Consistent with On-Line treatment, this NPRR also sets a bid floor of $75 per MWh for Controllable Load Resource capacity providing Non-Spin, equivalent to the offer floor for a Generation Resource providing On-Line Non-Spin and adds the requirement that if the Qualified Scheduling Entity (QSE) also assigns Responsive Reserve (RRS) and/or Regulation Up Service (Reg-Up) to a Controllable Load Resource that has been assigned Non-Spin, there will be a bid floor for the sum of the RRS, Reg-Up, and Non-Spin Ancillary Service Resource Responsibilities of $75 per MWh. ERCOT notes that the cap on a Real-Time Market (RTM) Energy Bid addressed in paragraph (2) of Section 6.4.3.1, RTM Energy Bids, remains unchanged.
  - See OBDRR040, ORDC Changes Related to NPRR1131, Controllable Load Participation in Non-Spin.

- NPRR1135, Add On-Line Status Check for Resources Telemetering OFFNS for Ancillary Service Imbalance Settlements.
  - Status: Approved on September 15, 2022.
  - Description: This NPRR modifies the definition of the Real-Time Generation Resources with an Off-Line Non-Spin Schedule (RTOFFNSHSL) to allow non-zero values for this billing determinant only if the Resource was Off-Line when it telemetered OFFNS. This is to ensure accurate Settlement in the scenario where an On-Line Resource erroneously telemetered OFFNS.
- NPRR1136, Updates to Language Regarding a QSE Moving Ancillary Service Responsibility Between Resources.
  - Status: Approved on September 15, 2022.
  - Description: This NPRR makes changes to reflect the logic that will be in place after the implementation of Fast Frequency Response (FFR) Advancement project, the next phase of implementation for NPRR863, Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve. Specifically, the NPRR adds new paragraph (5) of Section 4.4.7.3 to align with language in Section 6.4.7. These changes are for clarity only, and do not modify the system design. The new paragraph (6) of Section 4.4.7.3 is an additional check that needs to be in place to ensure a QSE does not replace a Regulation Service with Fast Responding Regulation Service (FRRS). This section does not need to be addressed in the FFR Advancement implementation, and it is ERCOT's intent to implement this logic change in a future project.
- NPRR1140, Recovering Fuel Costs for Generation Above LSL During RUC-Committed Hours.
  - Status: Approved on November 3, 2022, effective November 4, 2022 (Section 9.14.7).
  - Description: This NPRR proposes changes to permit Generation Resources to recover their fuel costs when instructed to start due to a Reliability Unit Commitment (RUC) and operate above the Generation Resource's Low Sustained Limit (LSL). Specifically, this NPRR makes the following changes: • Remove the Max (0) function from the Revenue Less Cost Above LSL During RUC-Committed Hours (RUCEXRR) equation for Resources that have been granted a fuel dispute; • Add a Reliability Unit Commitment Fuel Cost Adder (RUCFCA) to the Real-Time Energy Offer Curve Cost Cap (RTEOCOST) to represent the incremental cost of fuel for generation above LSL; and • Provide clarification to Protocol Section 9.14.7 to allow for the recovery of such fuel costs via RUC Settlements.

- NPRR1142, ERS Changes to Reflect Updated PUCT Rule Changes re SUBST. R. 25.507.
  - Status: Approved on August 25, 2022, effective August 26, 2022.
  - Description: This NPRR increases the annual budget for the Emergency Response Service (ERS), allows ERCOT the flexibility to contract ERS for up to 24 hours in an ERS Standard Contract Term, and makes other administrative changes to the ERS program.
  - See OBDRR042, Related to NPRR1142, ERS Changes to Reflect Updated PUCT Rule Changes re SUBST. R. 25.507.
- NPRR1148, Language Cleanup Related to ERCOT Contingency Reserve Service (ECRS).
  - Status: Posted on August 30, 2022, approved on January 26, 2023.
  - Description: This NPRR addresses Protocol gaps found during the creation of the ECRS system change requirements. Specific changes include: Language was added to Section 4.4.7.2.1 to align NPRR863, Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve, implementation to a pre-Real-Time Co-Optimization (RTC) system design. Clarification was added about simultaneous awarding and Real-Time provision of Responsive Reserve (RRS), ECRS, and Non-Spinning Reserve (Non-Spin) by Load Resources that are not Controllable Load Resources; Language was added to paragraph (1) of Section 6.5.7.6.2.4 to clarify that ECRS will also be deployed to provide energy upon detection of insufficient available capacity for net load ramps. (Such use is in addition to the uses already included in the Protocols: use for frequency restoration, energy during an Energy Emergency Alert (EEA), or as a backup to Regulation Up Service (Reg-Up)); and Language was added to paragraph (2)€ of Section 6.5.7.3.1 to clarify that ECRS deployments from Load Resources that are not Controllable Load Resources will be considered at a ten-minute linear ramp for the calculation of the Real-Time On-Line Reliability Deployment Price Adder. This is similar to the approach taken with RRS deployments from Load Resources that are not Controllable Load Resources.
  - See OBDRR043, Related to NPRR1148, Language Cleanup Related to ERCOT Contingency Reserve Service (ECRS).
- NPRR1149, Implementation of Systematic Ancillary Service Failed Quantity Charges.
  - Status: Posted on May 12, 2022, approved on March 23, 2023.
  - Description: This NPRR charges a Qualified Scheduling Entity (QSE) an Ancillary Service failed quantity if the Ancillary Service Supply Responsibility held by the QSE is not met by Resources in their portfolio in Real-Time, based on

a comparison of their Real-Time telemetry. The charges will be done systematically without ERCOT control room operators having to take additional action.

- NPRR1154, Include Alternate Resource in the Availability Plan for the Firm Fuel Supply Service.
  - Status: Posted on November 3, 2022, approved on January 26, 2023.
  - Description: This NPRR updates language to allow for a qualified alternate Resource to be considered in the calculation of the availability reduction factor for the Firm Fuel Supply Service Resource (FFSSR). Additionally, this NPRR provides a new Settlement billing determinant that will provide the Firm Fuel Supply Service Award Amount per Qualified Scheduling Entity (QSE) per FFSSR by hour.

Other Binding Document Revision Requests (OBDRRs)

- OBDRR039, ORDC Changes Related to NPRR1120, Create Firm Fuel Supply Service.
  - Status: Approved on March 31, 2022.
  - Description: This OBDRR removes the High Sustained Limits (HSLs) of Resources deployed for Firm Fuel Supply Service (FFSS) from the Operating Reserve Demand Curve (ORDC) reserve calculation, as proposed in the 2/7/22 IMM comments to NPRR1120. The 2/7/22 IMM comments were discussed at the NPRR1120 workshop held on February 9, 2022.
- OBDRR040, ORDC Changes Related to NPRR1131, Controllable Load Participation in Non-Spin.
  - Status: Approved on September 15, 2022.
  - Description: This OBDRR removes the Controllable Load Resource providing Non-Spinning Reserve (Non-Spin) schedules and Regulation Service schedules from the capacity calculations in alignment with NPRR1131 as a standing deployment.
- OBDRR042, Related to NPRR1142, ERS Changes to Reflect Updated PUCT Rule Changes re SUBST. R. 25.507.
  - Status: Approved on August 25, 2022, effective August 26, 2022.
  - Description: This OBDRR increases the annual budget for the Emergency Response Service (ERS) and makes other administrative changes to the ERS program.

- OBDRR043, Related to NPRR1148, Language Cleanup Related to ERCOT Contingency Reserve Service (ECRS).
  - Status: Posted on August 30, 2022, approved on January 26, 2023.
  - Description: This OBDRR aligns the ORDC methodology with the Protocol revisions of NPRR1148.

Verifiable Cost Manual Revision Requests (VCMRRs)

- VCMRR033, Excluding Exceptional Fuel Costs from Fuel Adders.
  - Status: Posted on June 21, 2022, and still pending at the end of 2022.
  - Description: This VCMRR provides that the actual fuel purchases used in Exceptional Fuel Costs that were already included in the Mitigated Offer Cap (MOC), as described in paragraph (1)(f) of Protocol Section 4.4.9.4, Mitigated Offer Cap and Mitigated Offer Floor, will not also be included when calculating fuel adders.
- VCMRR034, Excluding RUC Approved Fuel Costs from Fuel Adders.
  - Status: Posted on June 21, 2022, and still pending at the end of 2022.
  - Description: This VCMRR provides that actual fuel purchases that were used to determine the Reliability Unit Commitment (RUC) Guarantee, as described in Protocol Section 9.14.7, Disputes for RUC Make-Whole Payment for Fuel Costs, shall not also be included when calculating fuel adders.
- VCMRR035, Allow Verified Contractual Costs in Fuel Adder Calculation.
  - Status: Posted on July 8, 2022, and still pending at the end of 2022.
  - Description: This VCMRR enables generators to include pipeline-mandated costs and penalties in the fuel adder of the verified cost filings.

II. Appendix: Review of Real-Time Market Outcomes

In this section of the Appendix, we provide supplemental analyses of 2022 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2022, including AS charges by type. This does not reflect the total cost of each AS because it is the net charges after self-arrangement. Also, for energy we calculated the real-time energy value based on MWs generated rather than settlement data since energy imbalance charges net out (plus RENA).

Table A1: ERCOT 2022 Year at a Glance (Annual)

Cost Type	Annual Total ($M)
Energy	$32,225
Regulation Up	$78
Regulation Down	$28
Responsive Reserve	$383
Non-Spin	$743
Balancing Account Surplus	$299
CRR Auction Distribution	$1,098
CRR Day-Ahead Market Payment	$2,066
PTP Day-Ahead Market Charge	$1,798
PTP RT Payment	$2,162
Emergency Response Service	$36
Revenue Neutrality Uplift	$43
AS Imbalance Uplift	$6
ERCOT Fee	$239
ERO Passthrough Fee	$22
Other Load Allocation	$1

Table A2 is the monthly aggregate costs of various ERCOT market settlement totals in 2022, including AS costs by type.

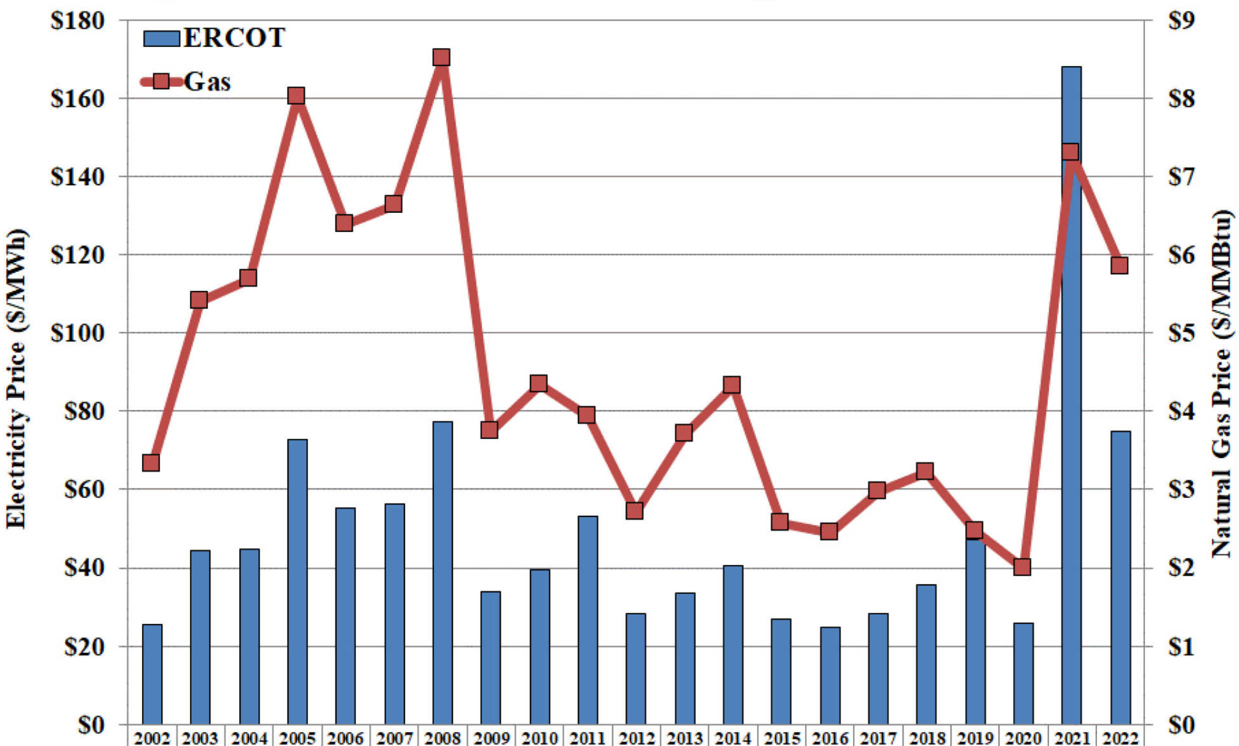
Table A2: Market at a Glance Monthly

	Monthly Totals (Millions)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Energy	$1,053	$1,765	$1,112	$1,747	$4,050	$2,972	$7,561	$4,029	$2,540	$1,713	$1,361	$2,321
Regulation Up	$3	$4	$6	$5	$11	$6	$18	$5	$3	$2	$2	$11
Regulation Down	$1	$2	$5	$4	$5	$2	$2	$2	$2	$1	$1	$2
Responsive Reserve	$14	$19	$32	$29	$49	$33	$91	$21	$11	$9	$7	$70
Non-Spin	$14	$42	$33	$53	$165	$65	$141	$44	$22	$45	$22	$98
CRR Auction Distribution	$70	$65	$78	$77	$92	$114	$111	$101	$91	$103	$98	$98
Balancing Account Surplus	$7	$10	$14	$27	$72	$43	$41	$19	$8	$15	$12	$32
CRR DAM Payment	$92	$132	$205	$300	$430	$213	$143	$90	$57	$109	$153	$144
PTP DAM Charge	$66	$105	$157	$258	$390	$224	$121	$67	$50	$100	$131	$130
PTP RT Payment	$71	$106	$184	$274	$574	$219	$163	$53	$52	$95	$139	$233
Emergency Response Service	$6	$6	$6	$1	$1	$4	$4	$4	$4	$0	$0	$0
Revenue Neutrality Uplift	$3	$5	$13	($3)	$1	$0	($6)	$2	$6	$8	$11	$4
AS Imbalance Uplift	$1	$5	$2	$13	($10)	$1	($19)	$5	$4	($1)	$2	$3
ERCOT Fee	$19	$17	$17	$17	$22	$23	$26	$24	$21	$18	$17	$19
ERO Passthrough Fee	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Firm Fuel	-	-	-	-	-	-	-	-	-	-	$7	$14
Other Load Allocation	$0.6	$0.1	$0.5	$0.5	$0.0	$0.1	($0.4)	($0.1)	($0.4)	$0.2	$0.4	($0.1)

A. Zonal Average Energy Prices in 2022

Figure A1 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 2022.

Figure A1: ERCOT Historic Real-Time Energy and Natural Gas Prices

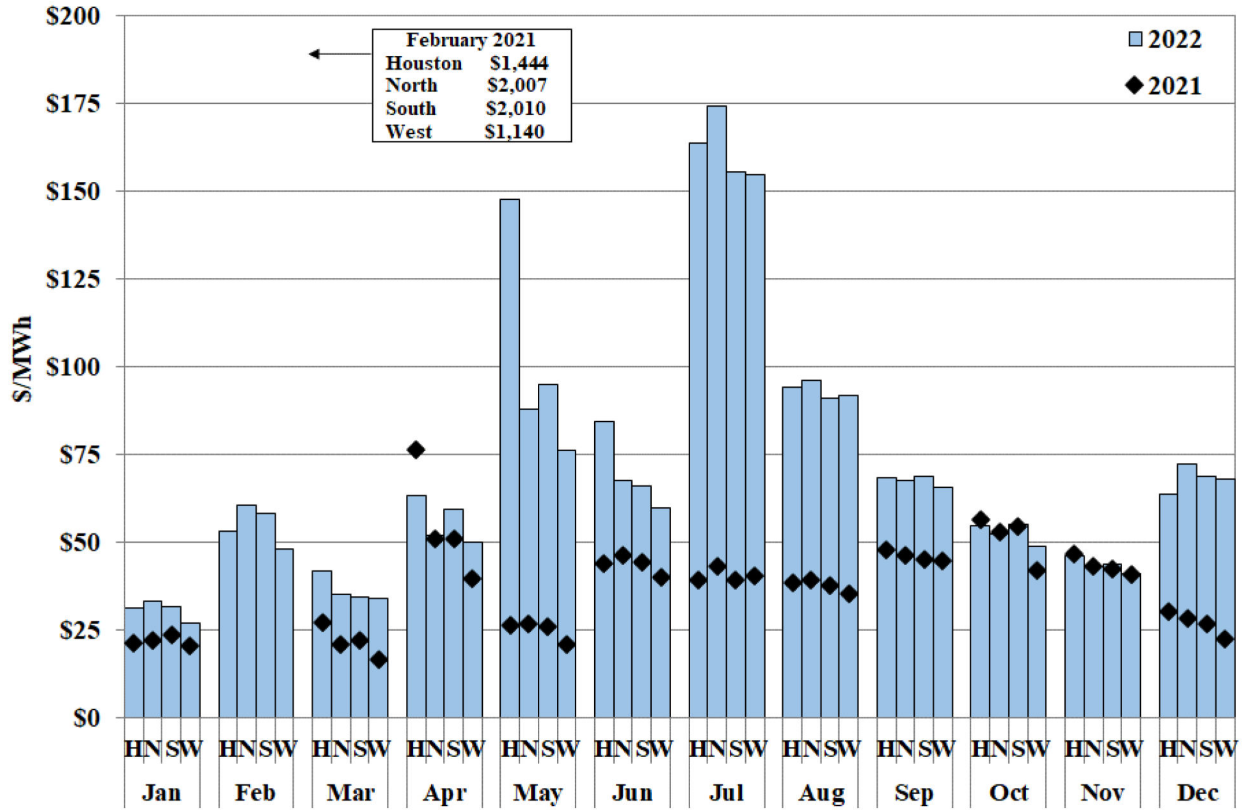


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77	24.62	28.25	35.63	47.06	25.73	167.8	74.92
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57	2.45	2.98	3.22	2.47	1.99	7.30	5.84

Like Figure 2 in the body of the report, Figure A1 shows the historically close correlation between the average real-time energy price in ERCOT and the average natural gas price. Such relationship is consistent with expectations in ERCOT where natural gas generators predominate and tend to set the marginal price; this is an indication that the price of electricity is reflective of the cost of production.

Figure A2 shows the monthly load-weighted average prices in the four geographic ERCOT zones during 2021 and 2022. 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 were volatile month-to-month in 2022, particularly in May and July, due to planned outages in May limiting imports into Houston and July having forced outages in Central Texas and Houston.

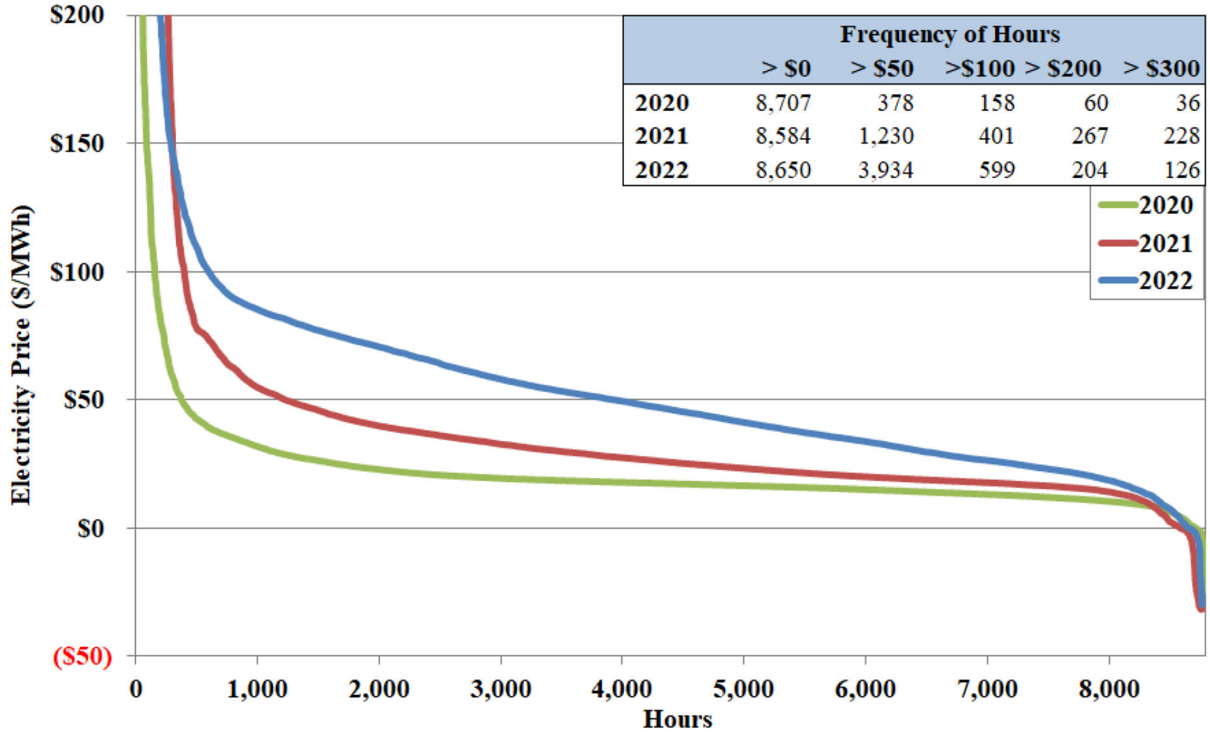
Figure A2: Average Real-Time Energy Market Prices by Zone



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.

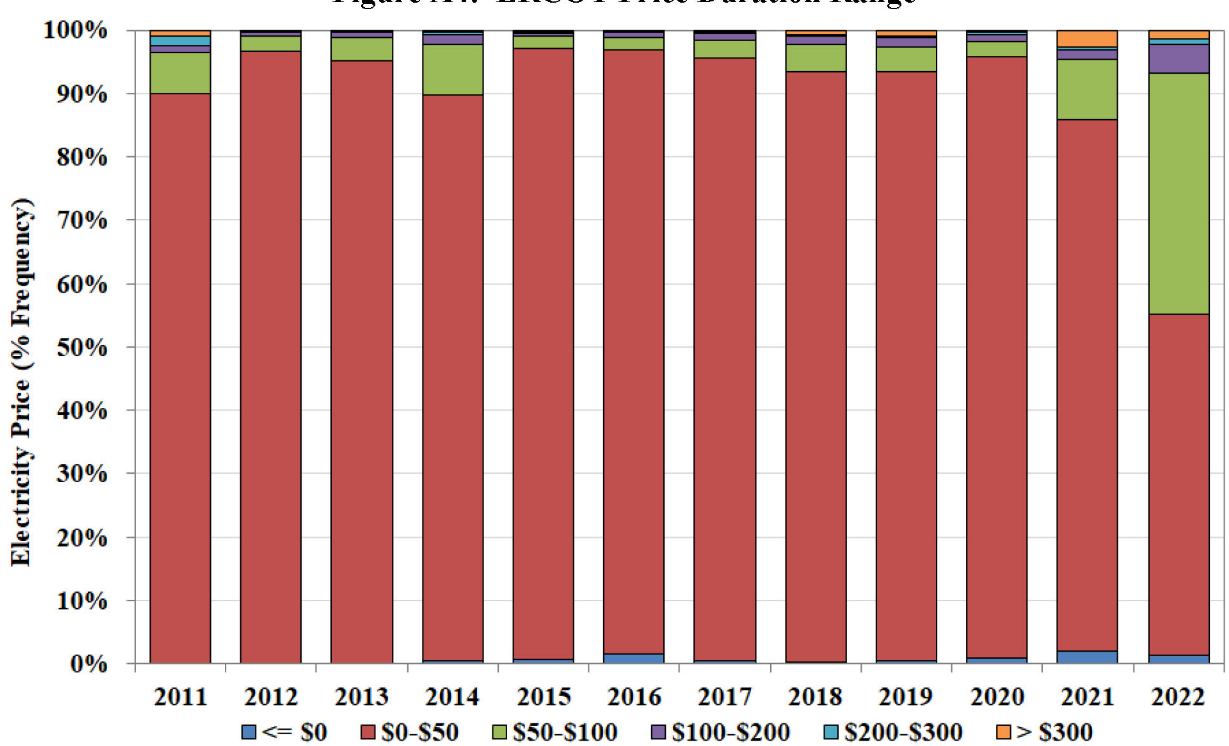
Negative ERCOT-wide prices may occur when wind is the marginal generation. More installed wind generation and additional transmission infrastructure led to increased occurrences of negative prices over the past few years. In 2022, there were 110 hours with ERCOT-wide prices at or below zero, a decrease from the 176 hours in 2021. Figure A3 and Figure A4 present price duration curve and range data to demonstrate this effect. In 2022, there was a clear increase in the duration of prices in the middle range from the previous two years ($50 - $100).

Figure A3: ERCOT Price Duration Curve



Frequency of Hours	> $0	> $50	>$100	> $200	> $300
2020	8,707	378	158	60	36
2021	8,584	1,230	401	267	228
2022	8,650	3,934	599	204	126

Figure A4: ERCOT Price Duration Range



B. 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 A5 shows the load-weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The 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 A5: Implied Heat Rate Duration Curve – All Hours

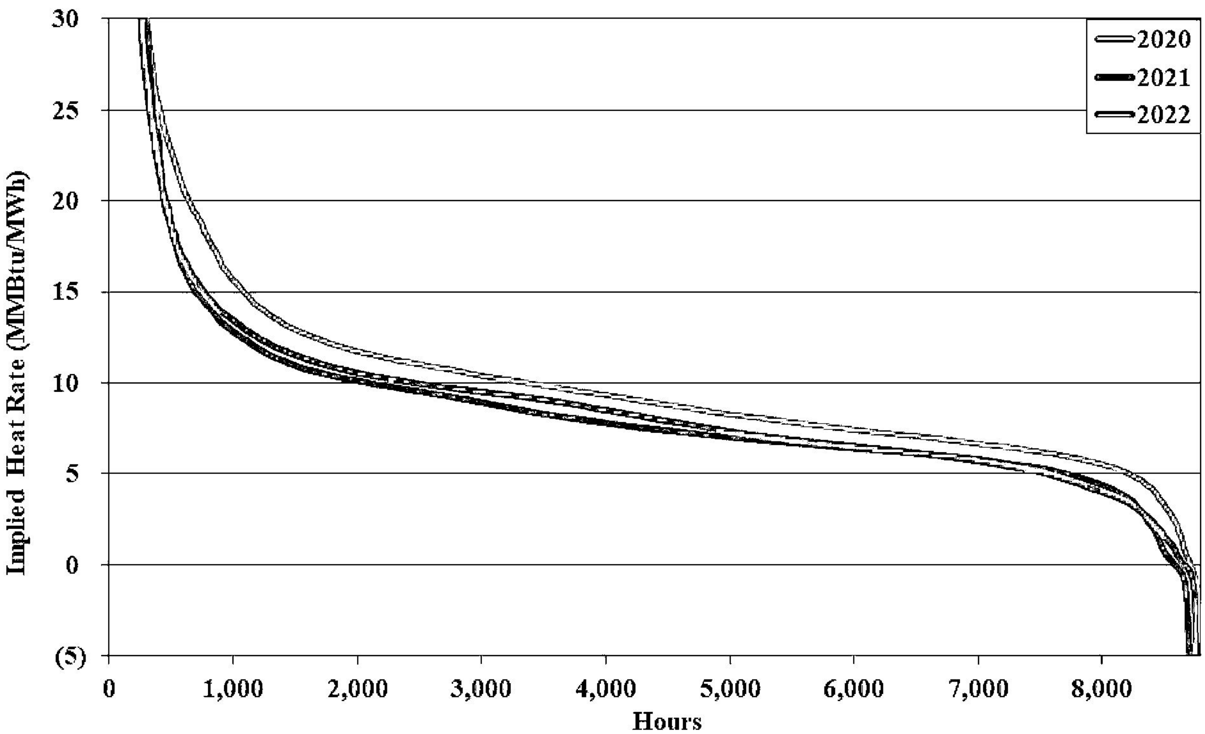


Table A3 displays the annual average implied heat rates by zone for 2014 through 2022. Adjusting for natural gas price influence, Figure A5 above shows that the annual, system-wide average implied heat rate was relatively consistent from 2020 to 2022.

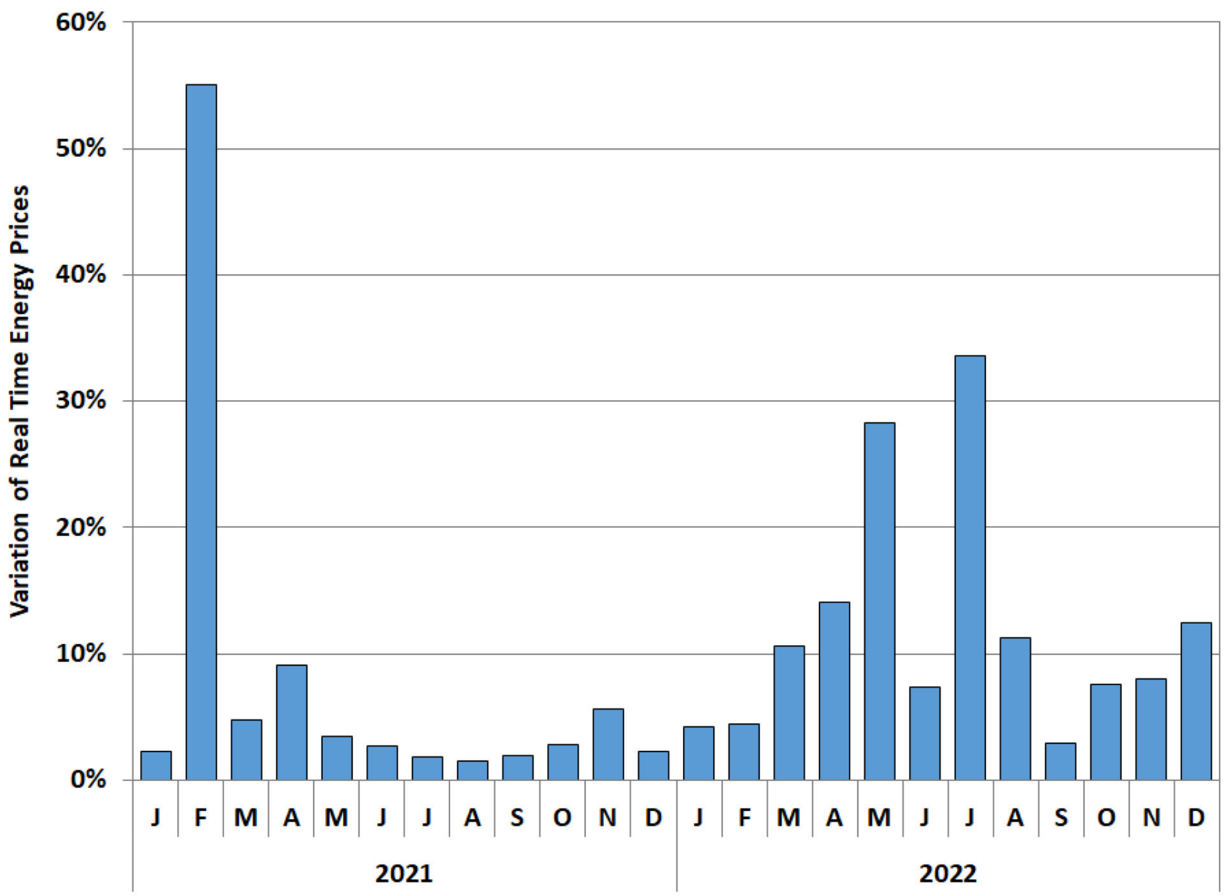
Table A3: Average Implied Heat Rates by Zone

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Natural Gas (MMBtu/MWh)									
ERCOT	**9.4**	**10.4**	**10.1**	**9.5**	**11.1**	**19.0**	**12.9**	**23.0**	**12.8**
Houston	9.2	10.5	10.8	10.7	10.7	18.4	12.3	17.7	13.9
North	9.3	10.2	9.7	8.6	10.9	18.9	12.0	28.3	12.9
South	9.6	10.6	10.1	9.9	11.2	19.2	13.4	25.7	12.5
West	10.1	10.4	9.0	8.2	12.3	20.5	15.9	14.4	11.2
Natural Gas Price ($/MMBtu)									
	$4.32	$2.57	$2.45	$2.98	$3.22	$2.47	$1.99	$7.30	$5.84

C. 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 A6 below shows monthly average changes in five-minute real-time prices by month for 2021 and 2022.

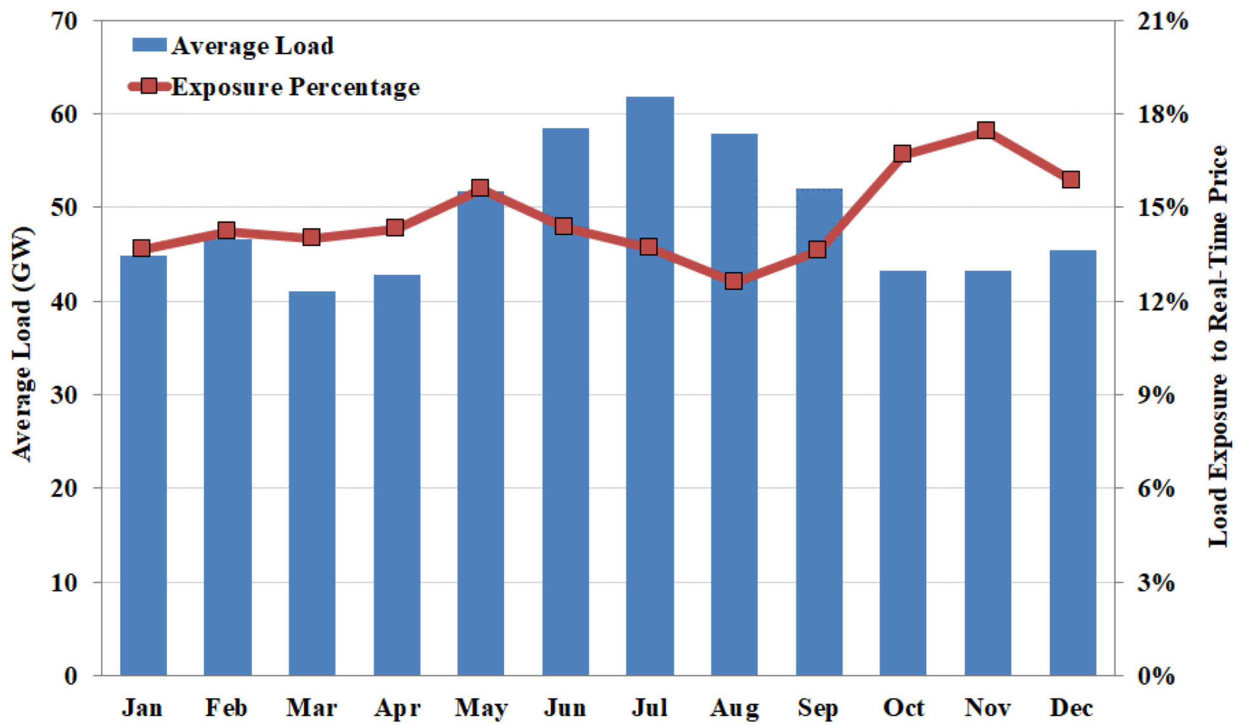
Figure A6: Monthly Price Variation



Although much smaller than the high price variability that occurred during February 2021 when unprecedented occurrences of shortage pricing occurred during Winter Storm Uri, price variability was higher overall in 2022. In particular, May and July 2022 saw significantly higher than normal price variability because of outages reducing available transmission capacity as well as variability in renewable output due to weather.

Finally, Figure A7 below shows the percentage of load exposed to real-time energy prices in 2022.

Figure A7: 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 2022 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 the year, and it is therefore expected that hedging activity would increase during months with the highest likelihood of extreme weather and shortage conditions (typically, though not exclusively, summer in Texas).

The highest portions of load potentially exposed to real-time prices in 2022 occurred at the end of the year in October, November, and December, likely due to higher real-time price expectations for January and February for potential cold weather. Although the overwhelming majority of load is not exposed to real-time prices, these prices do form the foundation for all pricing expectations, which inform both supplier and consumer contracting decisions.

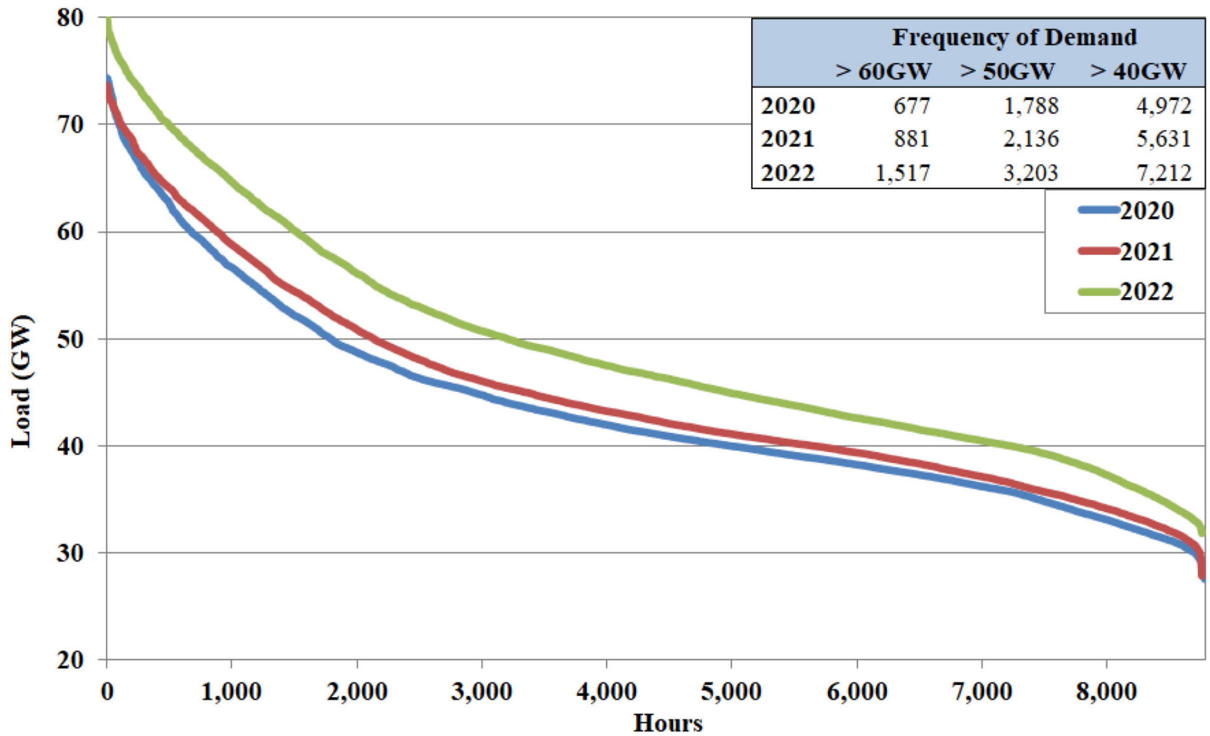
III. APPENDIX: DEMAND AND SUPPLY IN ERCOT

In this section, we provide supplemental analyses of load patterns during 2022 and the existing generating capacity available to satisfy the load and operating reserve requirements.

A. ERCOT Load in 2022

To provide a more detailed analysis of load at the hourly level, Figure A8 compares load duration curves for each year from 2020 through 2022. 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 2022 was similar to both 2020 and 2021, though higher as load growth continues in ERCOT.

Figure A8: Load Duration Curve – All Hours

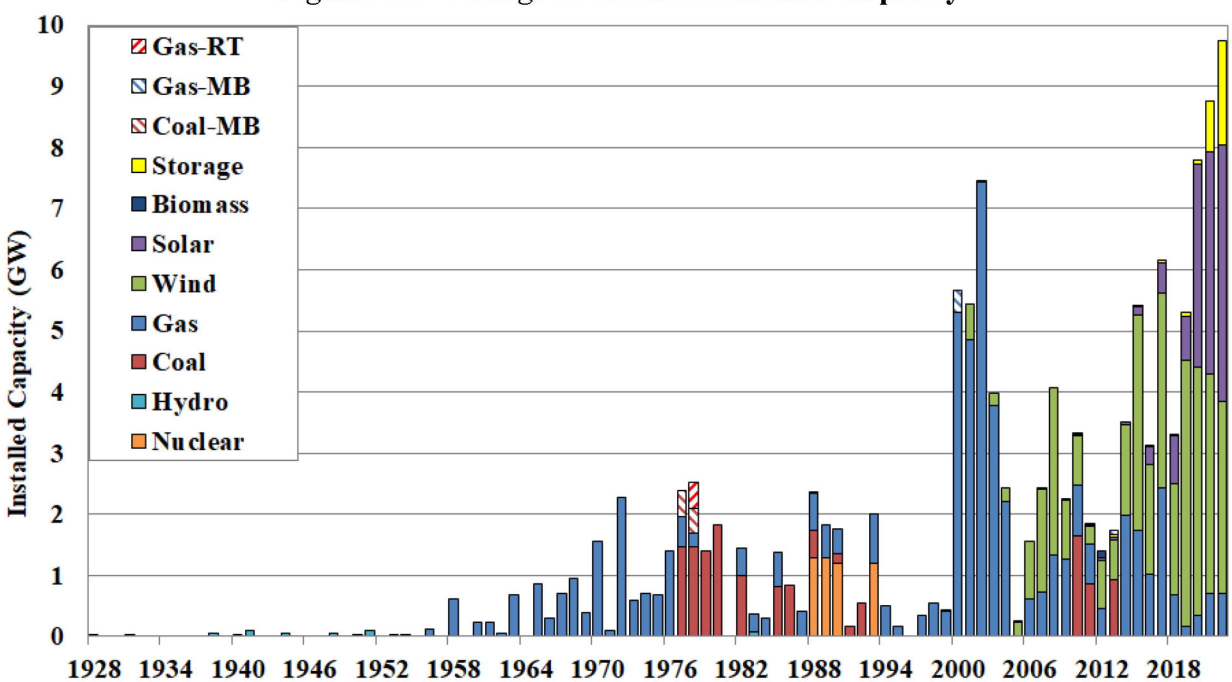


B. Generation Capacity in ERCOT

The generation mix in ERCOT is presented in this subsection. Figure A9 shows the vintage of generation resources in ERCOT shown as operational in the December 2022 Capacity, Demand, and Reserves (CDR) report[117] and it also includes resources that came online but were not yet commercial. The evaluation excludes Private Use Network capacity contributions to the CDR. The “Gas-RT” label applies to gas-fired units that were retired in 2022, and the “Gas-MB” and “Coal-MB” label applies to gas- or coal-fired units that were mothballed in 2022.

The figure shows several distinct periods of time where different technologies were added. The period prior to 1954 is entirely hydro generation additions. Between 1955 and 1977, the majority of additions were gas-fired boiler units. Additions during the period of 1978 to 1985 were primarily nuclear capacity. Between 1986 and 2006 the additions were primarily gas-fired combined cycle generators. Between 2006 and 2019 the additions were primarily wind and beginning in 2020 a substantial amount of solar and some storage were added. Since 2020, the addition of solar has gradually increased with almost 39% of new capacity as solar in 2020, 41% in 2021, and 43% in 2022. In 2021 and 2022, additions of storage capacity were pronounced (9% of new capacity in 2021, and almost 18% in 2022).

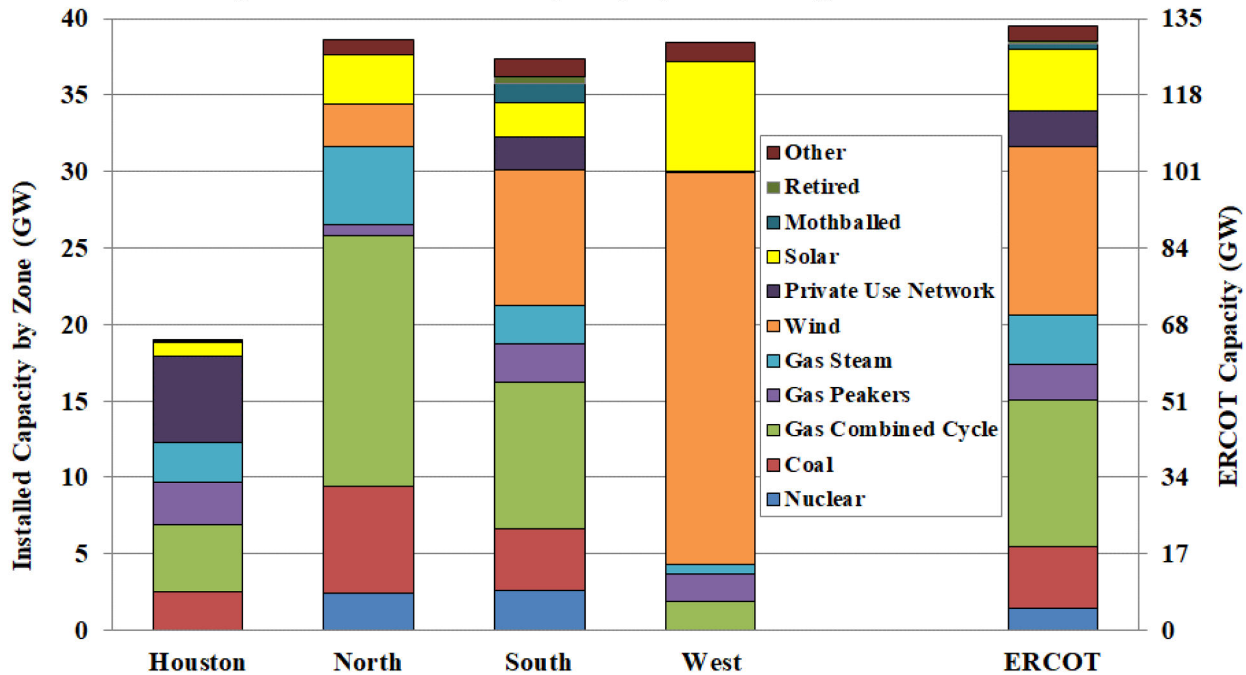
Figure A9: Vintage of ERCOT Installed Capacity



117 ERCOT Capacity, Demand, and Reserves Report (Nov. 29, 2022), available at https://www.ercot.com/files/docs/2022/11/29/CapacityDemandandReservesReport_Nov2022.pdf.

When excluding mothballed resources and including only the fraction of wind capacity deemed available to reliably meet peak demand, the distribution of capacity among the North, South, and West zones was nearly the same.[118] Based on that metric, the North zone accounted for approximately 35% of capacity, the South zone 29%, the Houston zone 18%, and the West zone 18% in 2022. The installed generating capacity by type in each zone is shown in Figure A10.

Figure A10: Installed Capacity by Technology for Each Zone



Approximately 9.7 GW of new generation resources came online in 2022; the 3.1 GW of wind resources has a deemed effective peak serving capacity of about 0.7 GW and the 4.2 GW of solar resources has a deemed effective peak serving capacity of 3.3 GW. The remaining new capacity is from 707 MW of combustion turbines and 1.7 GW of ESRs. Approximately 34% of the new resources were located in the West, 27% in the North, and 13% in the South. In addition, one 420 MW resource retired permanently.

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 A11 shows average wind production for each month in 2021 and 2022, with the average production in each month divided into four-hour blocks. The lowest wind output generally occurs during summer afternoons, and the average wind output during summer peak period increased from about 7 GW in 2021 to 8 GW in 2022, due to a strong presence of wind

118 The percentages of installed capacity to serve peak demand assume availability of 30% for panhandle wind, 60% for coastal wind, 20% for other wind, and 80% for solar.

capacity in ERCOT along with increased geographic diversity of those resources. This may be a small fraction of the total installed capacity, but it indicates that wind generation is a significant contributor to generation supply.

Figure A11: Average Wind Production

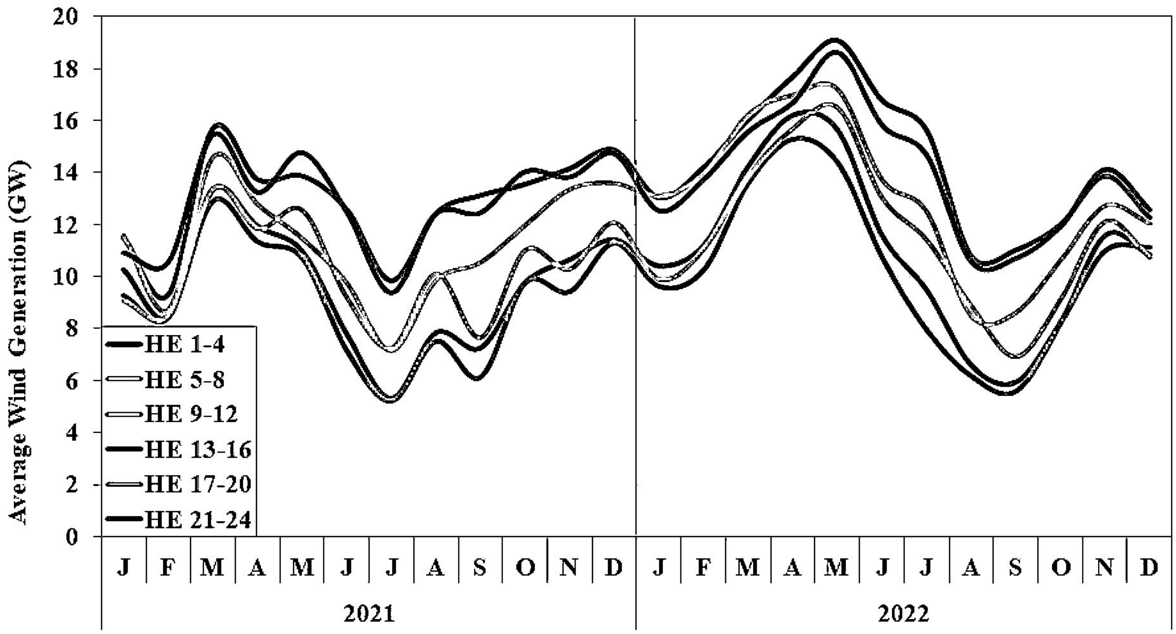
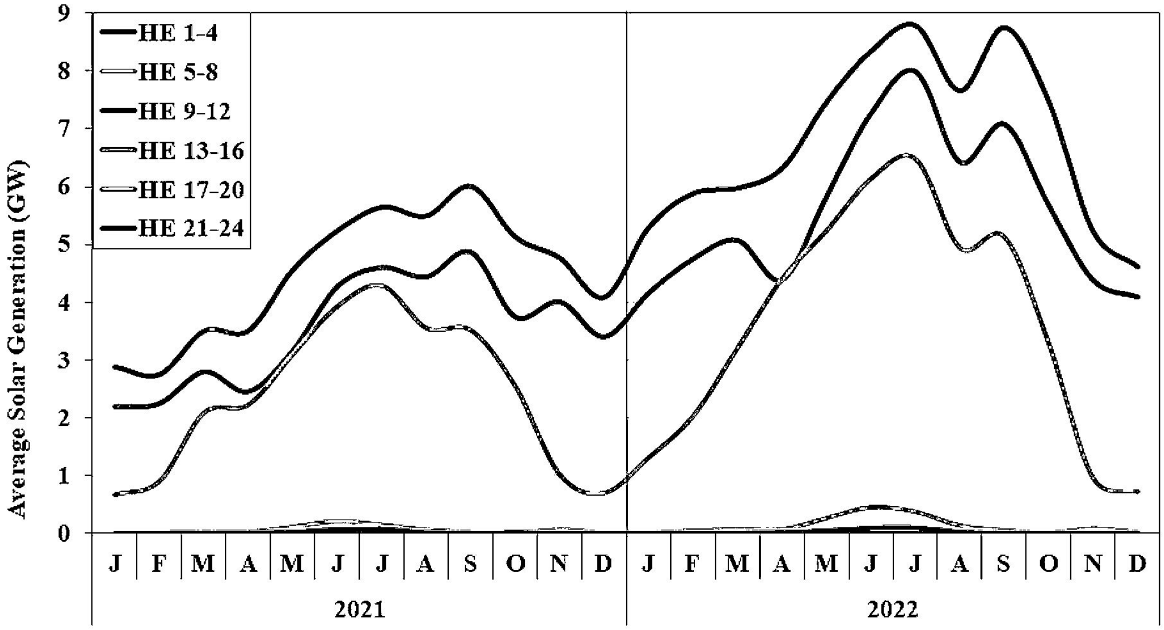


Figure A12 below shows average solar production for each month in 2021 and 2022, with the average production in each month divided into four-hour blocks. The average solar output nearly doubled from 2021 to 2022 due to a significant increase in solar capacity of 4,200 MW along with increased geographic diversity of those resources.

Figure A12: Average Solar Production



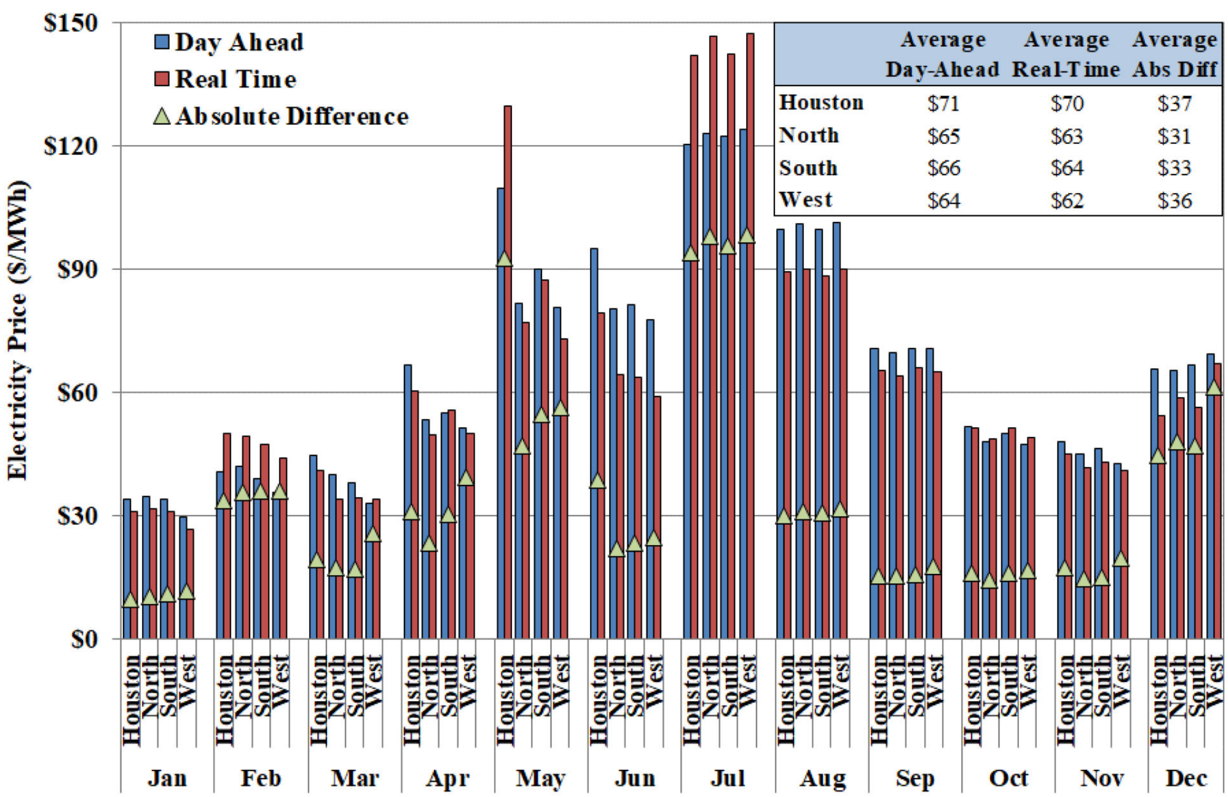
IV. APPENDIX: DAY-AHEAD MARKET PERFORMANCE

In this section, we provide supplemental analyses of 2022 prices and outcomes in ERCOT's day-ahead energy market.

A. Day-Ahead Market Prices and Convergence

In Figure A13, monthly day-ahead and real-time prices for 2022 are shown for each of the geographic zones. Overall volatility was relatively high in 2022 across all zones. July saw the highest prices overall, with real-time prices diverging higher than day-ahead prices because of the exceptionally high and sustained temperatures throughout the month and some instances of under-forecasting demand day-ahead. This under-forecasting increases uncertainty and high load level increase divergence caused by load distribution factors. Although the average day-ahead and real-time prices were similar in all zones, the average absolute difference in the Houston zone was the largest. This trend is explained by wide swings in Houston zone prices, the result of transmission congestion in the area related to high load in real-time.

Figure A13: Day-Ahead and Real-Time Prices by Zone

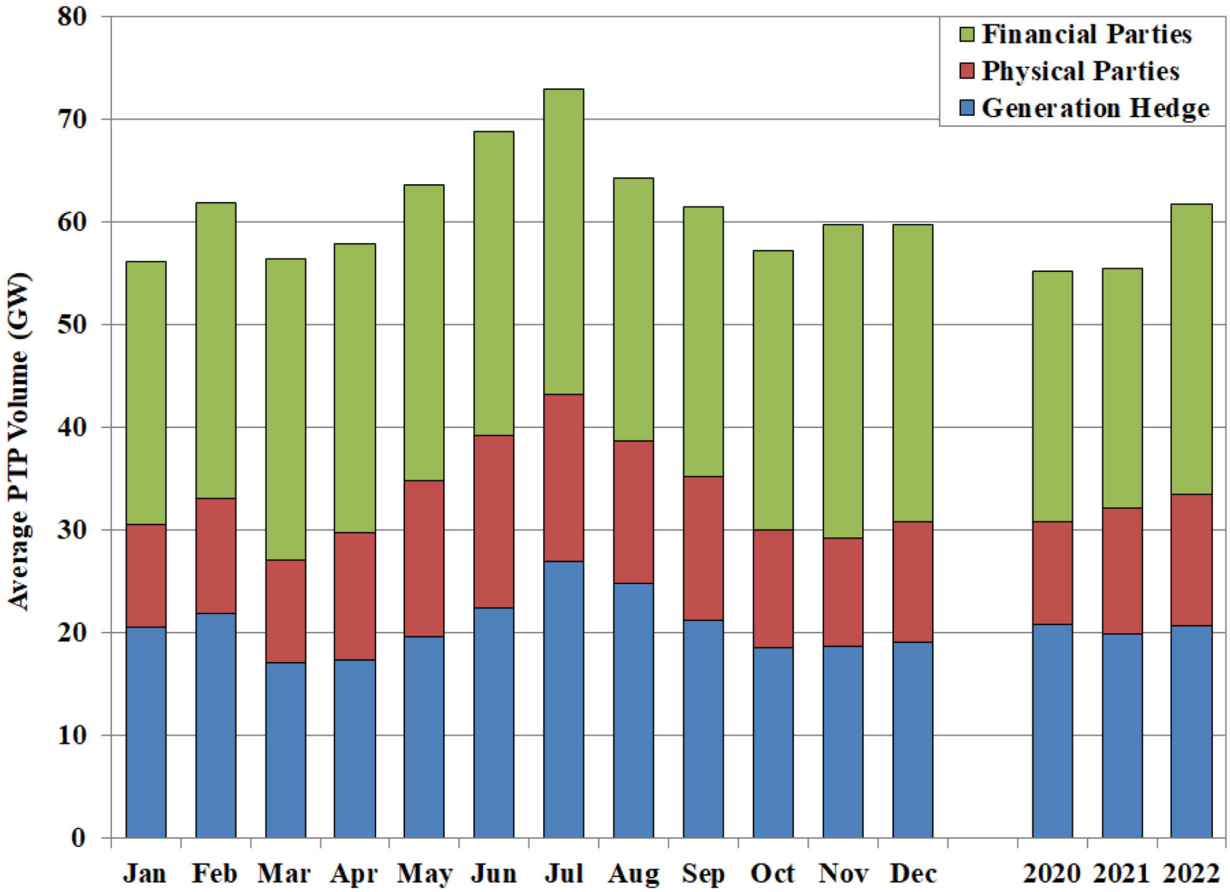


	Average Day-Ahead	Average Real-Time	Average Abs Diff
Houston	$71	$70	$37
North	$65	$63	$31
South	$66	$64	$33
West	$64	$62	$36

B. Point-to-Point Obligations

Figure A14 below presents the total volume of PTP obligation purchases in 2022 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 and so could be overcounting. Average purchase volumes are presented on both a monthly and annual basis. The total volume of PTP obligation purchases has been fairly stable in recent years, with the volume in 2022 slightly higher than previous years because of high congestion rent attracting more hedging activity.

Figure A14: Point-to-Point Obligation Volume



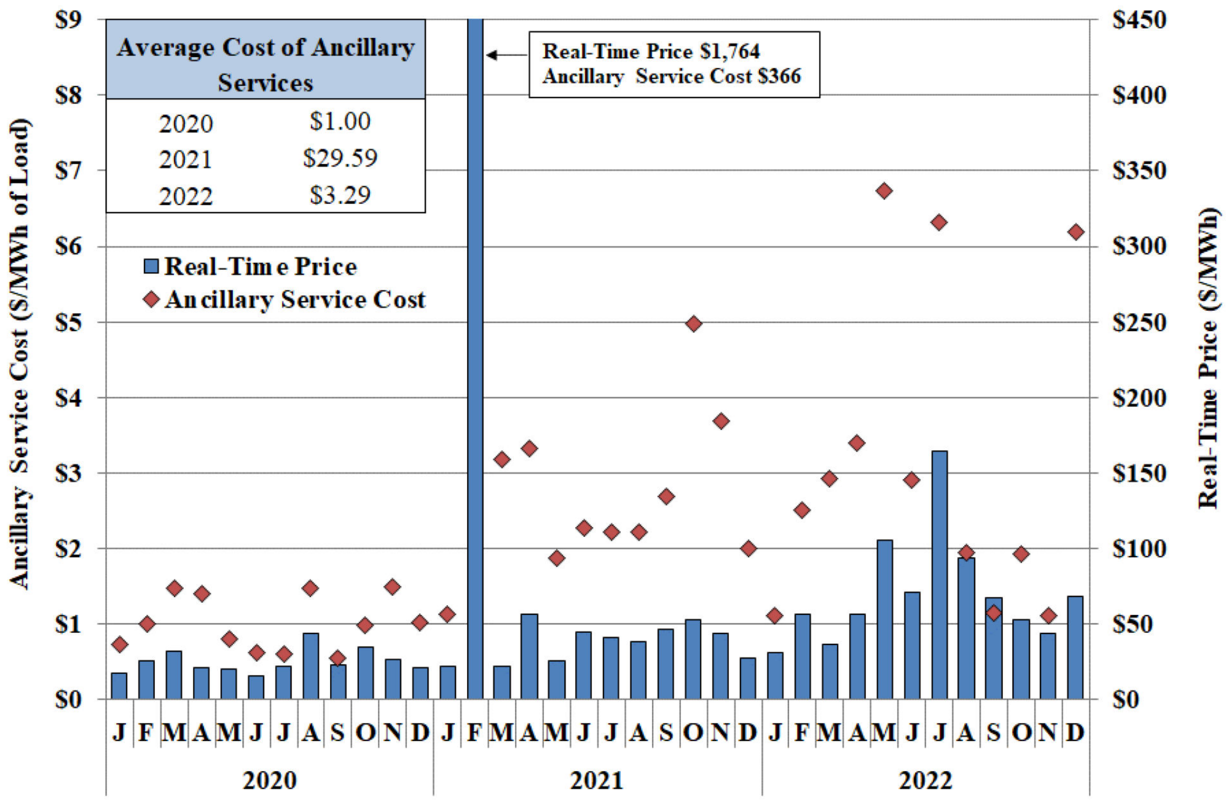
For all PTP obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that in 2022, like in 2020 and 2021, financial parties comprised the plurality of the volume of PTP obligations purchased (44%), with generation hedging comprising a somewhat smaller volume of PTP obligations purchased for the year (34%). Other than generation hedging and load hedging, the volumes of PTP obligations are not directly linked to a physical position. They are assumed to be purchased primarily to arbitrage anticipated price differences between two locations or to hedge trading activities occurring outside of the ERCOT market. This arbitrage activity is further separated by type of market participant.

Physical parties are those that have actual real-time load or generation, whereas financial parties have neither. Financial parties purchased 44% of the total volume of PTP obligations in 2022, consistent with the 41% share in 2021 and 42% in 2020. Financial parties increasing volumes can have liquidity benefits but also strain the software due to large amounts of bids being submitted, 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 day-ahead market, especially since these parties do not contribute otherwise to the administration costs of ERCOT.

C. Ancillary Services Market

Figure A15 below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2020 through 2022.

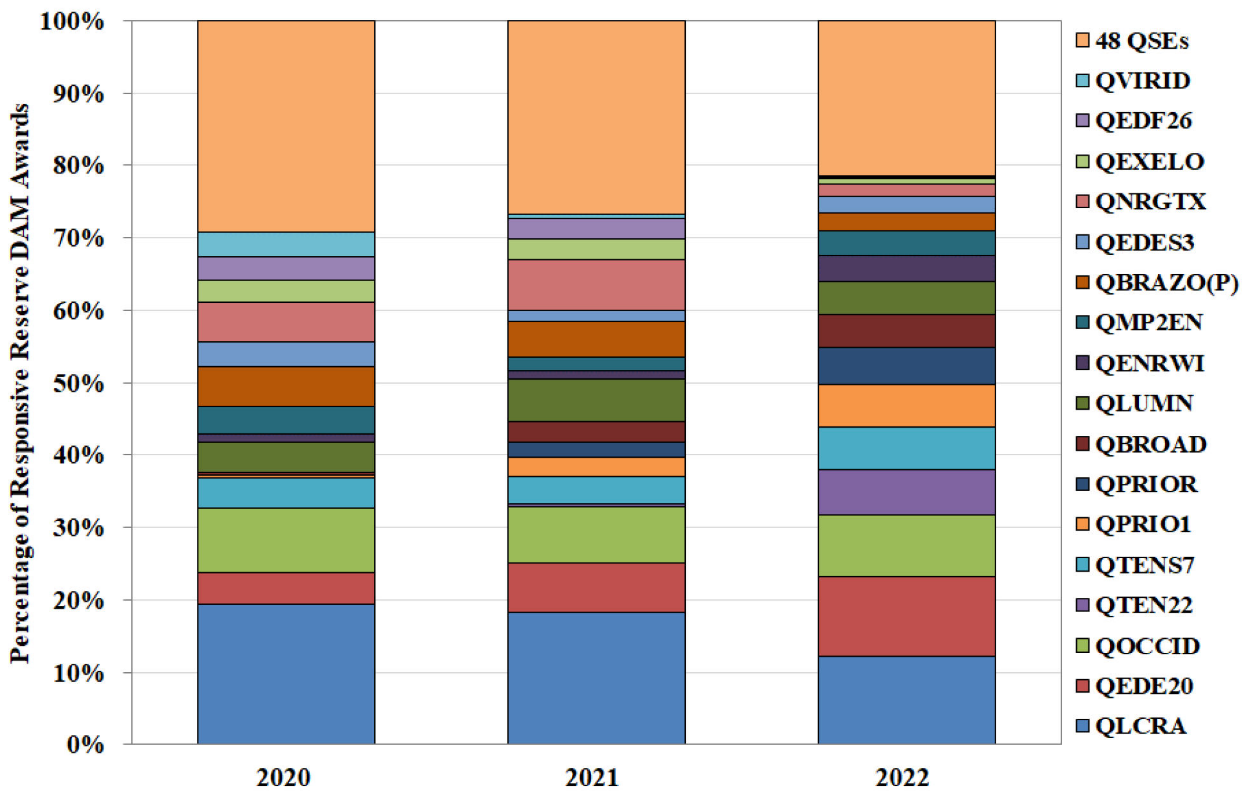
Figure A15: Ancillary Service Costs per MWh of Load



The average ancillary service cost per MWh of load increased from $1.00 per MWh in 2020 to $29.59 per MWh in 2021, mostly due to the effects of Winter Storm Uri, and back again down to $3.29 in 2022. The 2022 average ancillary service cost per MWh of load was still significantly higher than any other non-Uri year. Part of this increase is due to sustained high natural gas prices throughout the year, and part is due to the higher AS procurement volumes.

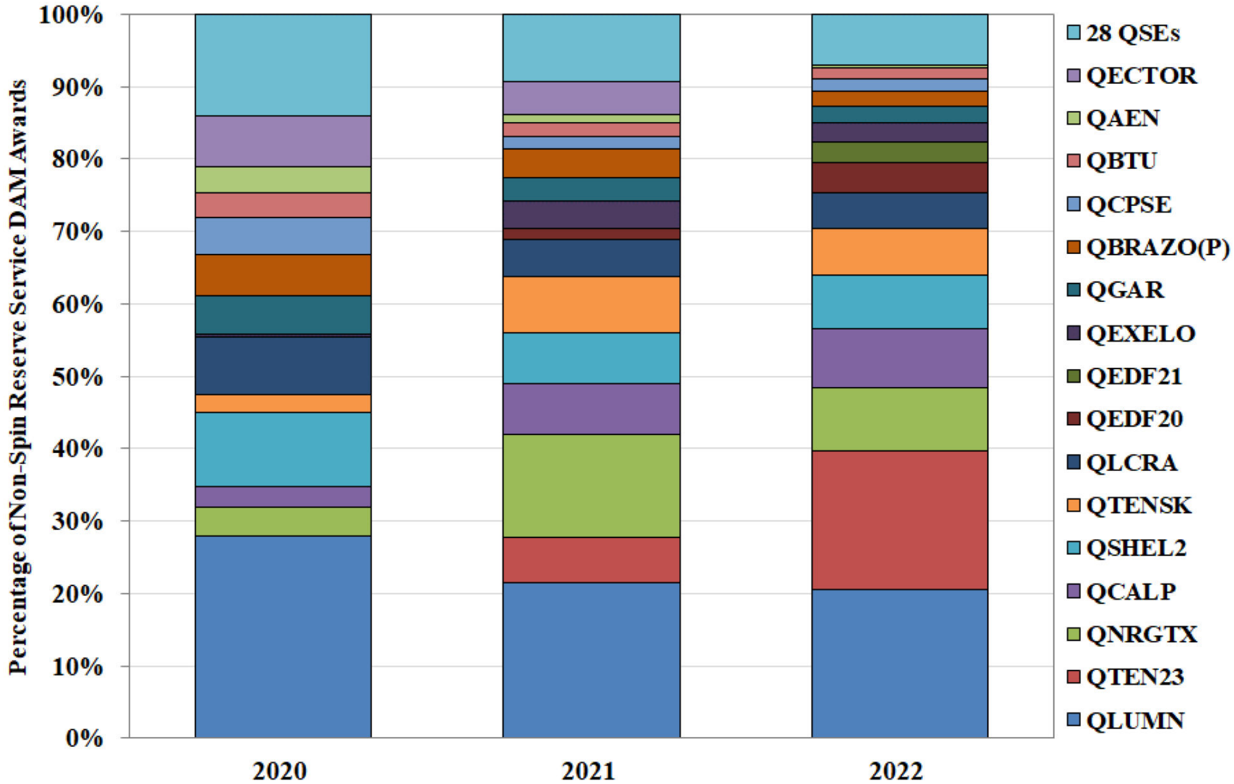
Figure A16 below shows the share of the 2022 annual responsive reserve responsibility including all types of resources, displayed by QSE. In the past, we have reported this information including self-arranged amounts. This year, we are only including QSEs with resource-specific awards in the day-ahead market. During 2022, 49 different QSEs were awarded responsive reserves as part of the day-ahead market. The number of QSEs awarded in day-ahead market was similar to 2020 at 45, whereas 2021 had 55 different QSEs awarded responsive reserve service. The top three providers of responsive reserve service (LCRA (QLCRA), EDF (QEDE20), and Occidental (QOCCID)), remained the same for the third year in a row.

Figure A16: Responsive Reserve Providers



In contrast, Figure A17 below shows that the provision of non-spinning reserves is much more concentrated, with Luminant (QLUMN) bearing a large share of the total responsibility (21%) followed closely by Tenaska (QTEN23) with a 19% share, which significantly increased its share from 2021 (only 6%). Luminant's share in 2022 was similar to its share in 2021 (20%) but Tenaska's more than doubled year-over-year. NRG (QNRGTX) lost about a third of its share from 2021 while Calpine (QCALP) maintained their shares in 2022 from 2021.

Figure A17: Non-Spinning Reserve Providers



The concentration in the supply of non-spinning reserve highlights the importance of modifying the ERCOT ancillary service market design and implementing RTC. Jointly optimizing all products in each interval will allow the market to substitute its procurements among all resources 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) in the day-ahead market (for resources that qualify), potentially distributing the provision of ancillary services among even more entities.

Figure A18: Regulation Up Reserve Providers

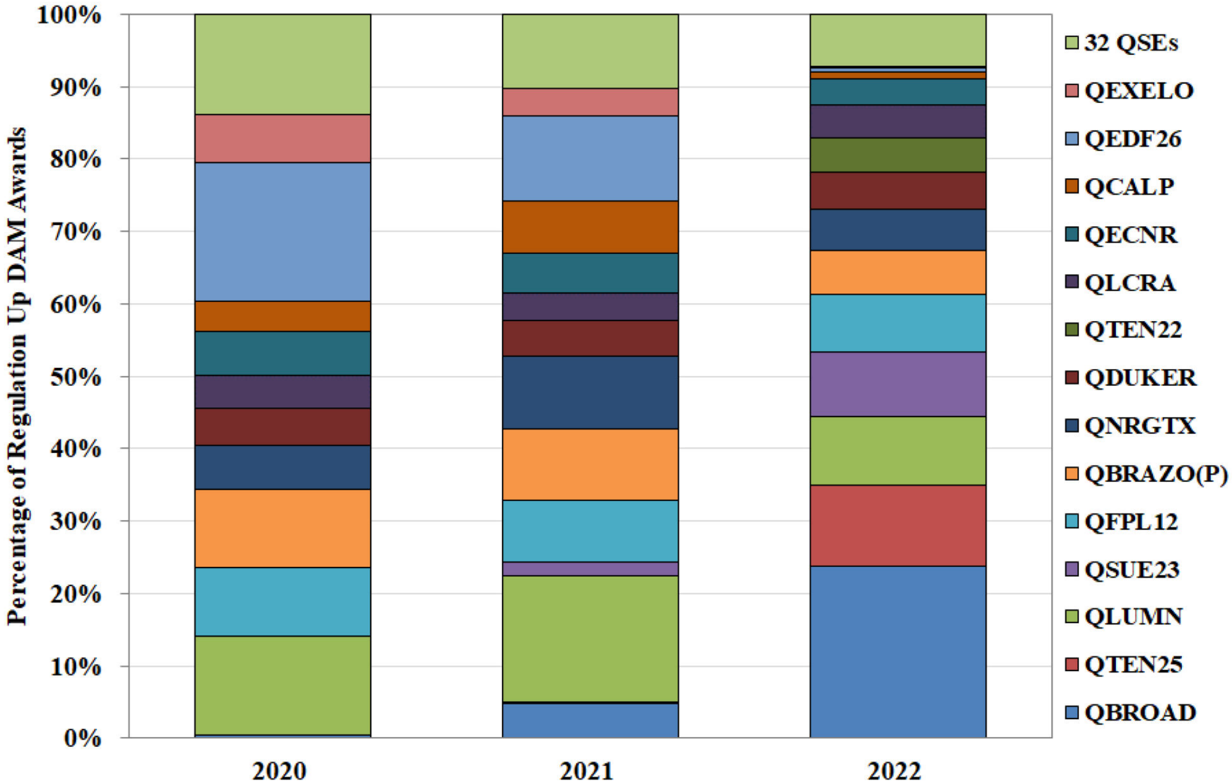
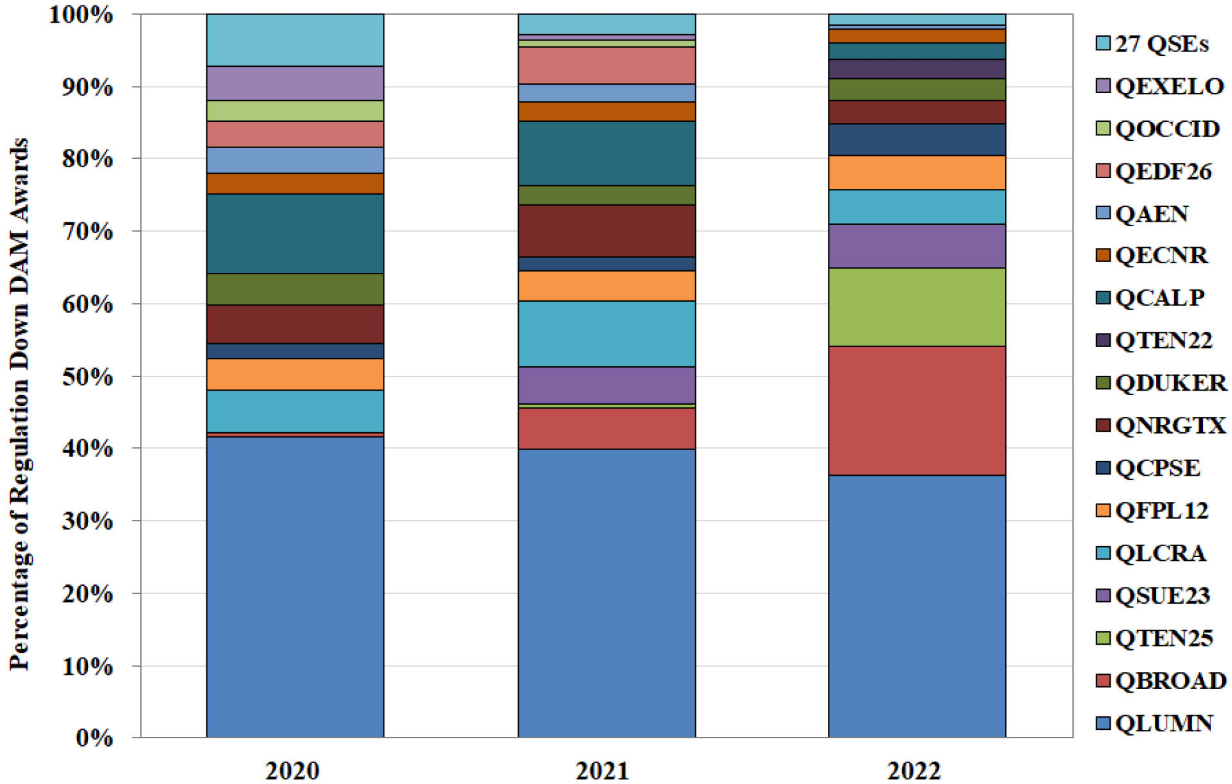


Figure A18 above shows the distribution for regulation up reserve service providers and Figure A19 shows the distribution for regulation down reserve providers in 2022. Despite regulation being spread more evenly, Figure A18 shows the emergence of energy storage resources (ESRs) as a major player in the regulation market. Broad Reach Power (QBROAD), who primarily represents Energy Storage Resources, more than quadrupled its market share to become the largest supplier of regulation up reserve service, up from 5% in 2021 to 24% in 2022.

Figure A19 shows that that while Luminant retained a dominant position in the provision of regulation down, Broad Reach Power increased its market share from 6% in 2021 to 18% in 2022, easily making it the second largest provider. The emergence of ESRs in the regulation markets is a significant change and is expected to continue as ESRs become more prevalent in ERCOT.

Figure A19: Regulation Down Reserve Providers



Ancillary service capacity is procured in the day-ahead market. 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 resource outage or to other changes in market conditions affecting unit commitment and dispatch. In short, QSEs with multiple resources 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 RTC is implemented and all ancillary services are continually reviewed and adjusted in response to changing market conditions, then 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 real-time co-optimization is implemented, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest, and therefore are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios still face larger risks than QSEs with small portfolios because of the replacement risk faced in having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in a SASM are often three to four times greater than 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 2021. A SASM was executed 64 times in 2022, double the amount from 2021, with SASM awards providing 448 service-hours. SASMs were more frequent and for more total hours in 2022; in 2021, a SASM was executed 37 times, and 340 service-hours were awarded. In addition to more frequent shortages, it appears that ERCOT operators were more proactive regarding AS shortages in 2022 than in previous years and took the step to procure replacement MWs more often. Figure A20 below provides the aggregate quantity of each service-hour that was procured via SASM over the last three years.

Figure A20: Ancillary Service Quantities Procured in SASM

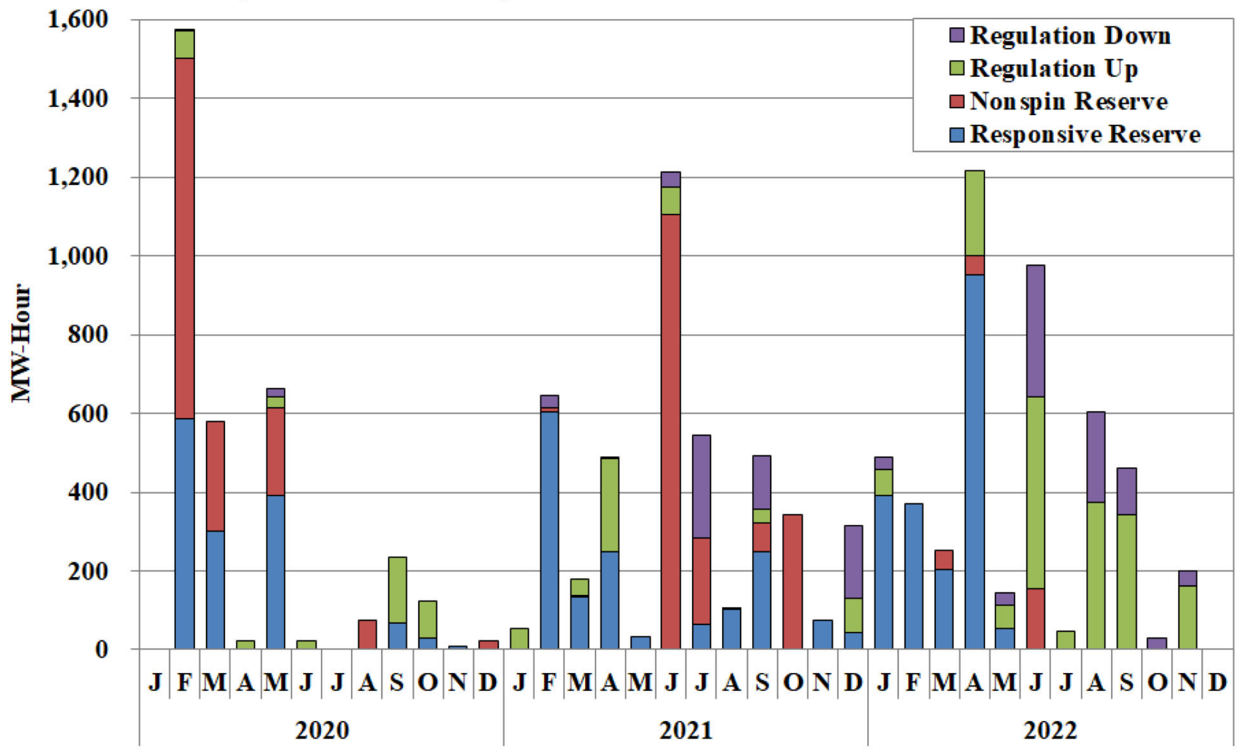
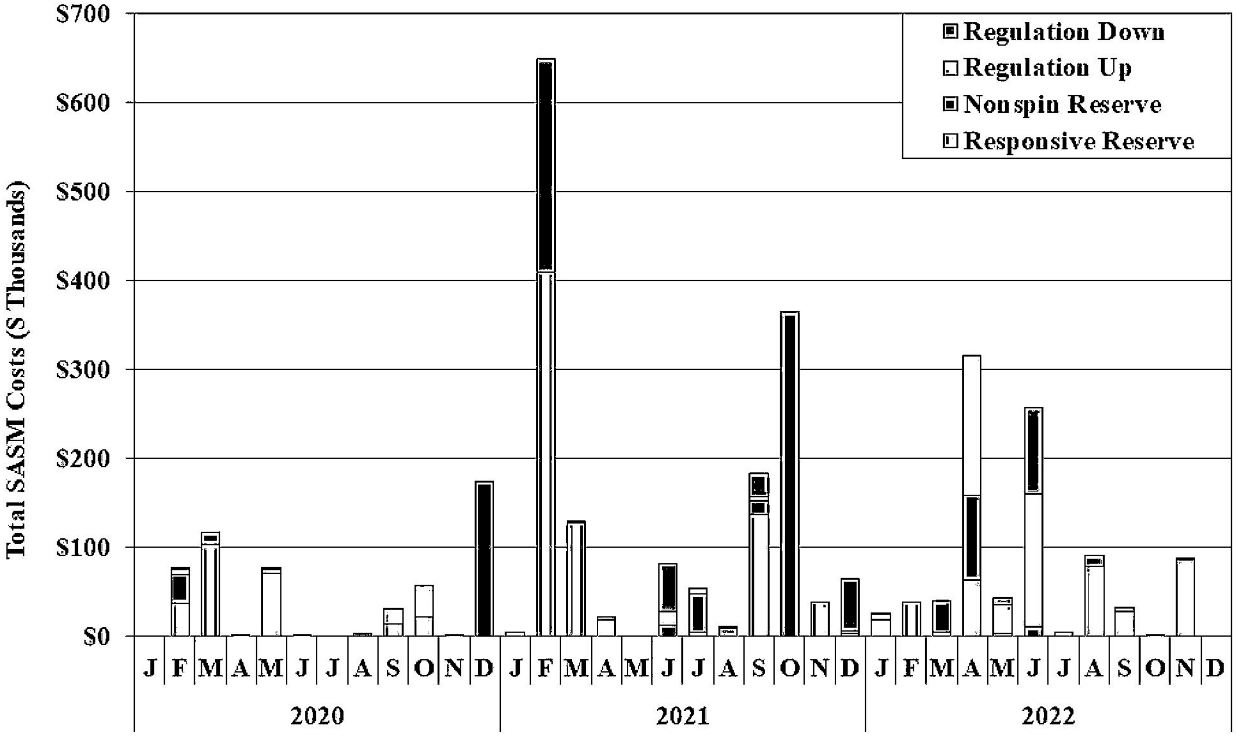


Figure A20 shows the volume of service-hours procured via SASM. Over the year it was 4,782 MW of service-hours in 2022, which is very small when compared to the total ancillary service requirement of nearly 42 million MW of service-hours.

Figure A21 shows the average cost of the replacement ancillary services procured by SASM over the last three years. The total SASM costs seen in February 2021 exceeded the previous high SASM costs in August of 2019. The total SASM costs throughout 2022 did not approach that level set in February 2021.

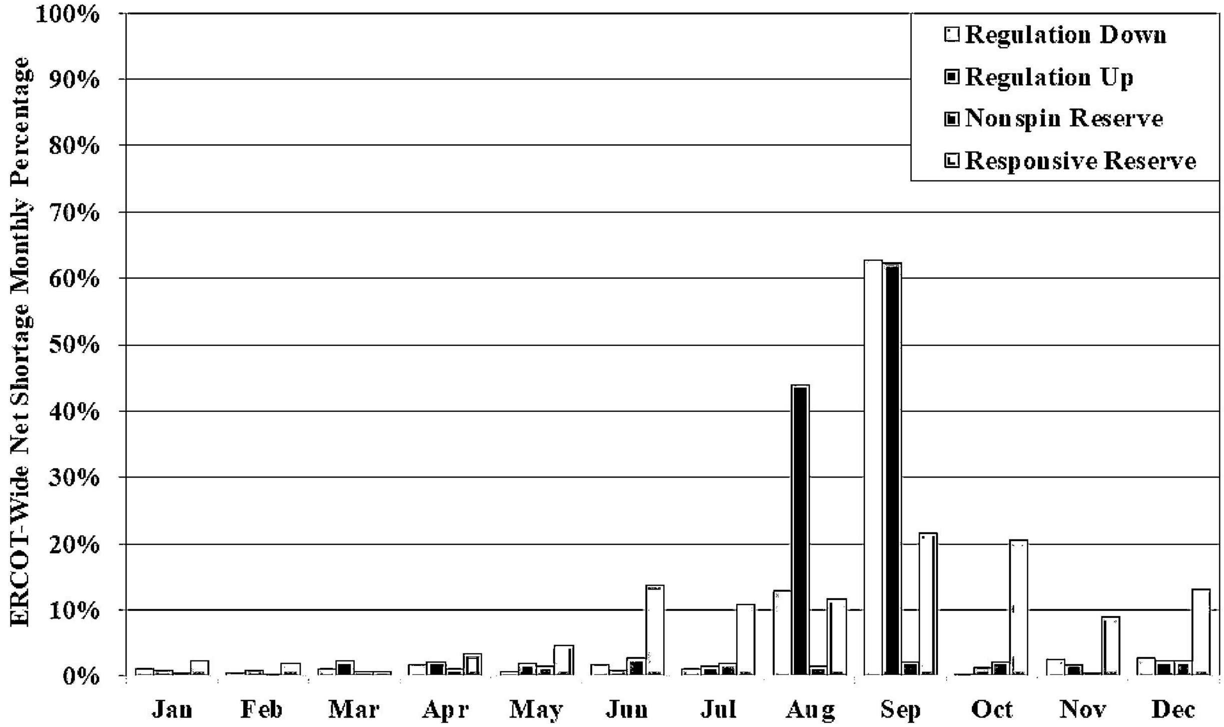
Figure A21: Average Costs of Procured SASM Ancillary Services



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

In addition to its other weaknesses, a SASM is only useful for replacing ancillary services as part of a forward-looking view of the grid conditions. However, there are instances where the system is short ancillary services in real-time. Figure A22 depicts the percentage of hours in each month of 2022 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. It does not identify whether or not the QSE was charged for the shortage.

Figure A22: ERCOT-Wide Net Ancillary Service Shortages



This analysis, based on the telemetered status provided by the parties with the responsibility, shows that ERCOT-wide shortages for all ancillary services returned to normal levels, after the extraordinarily high level of shortages last year due to Winter Storm Uri. Shortages of regulation up and down were particularly pronounced in August and September.

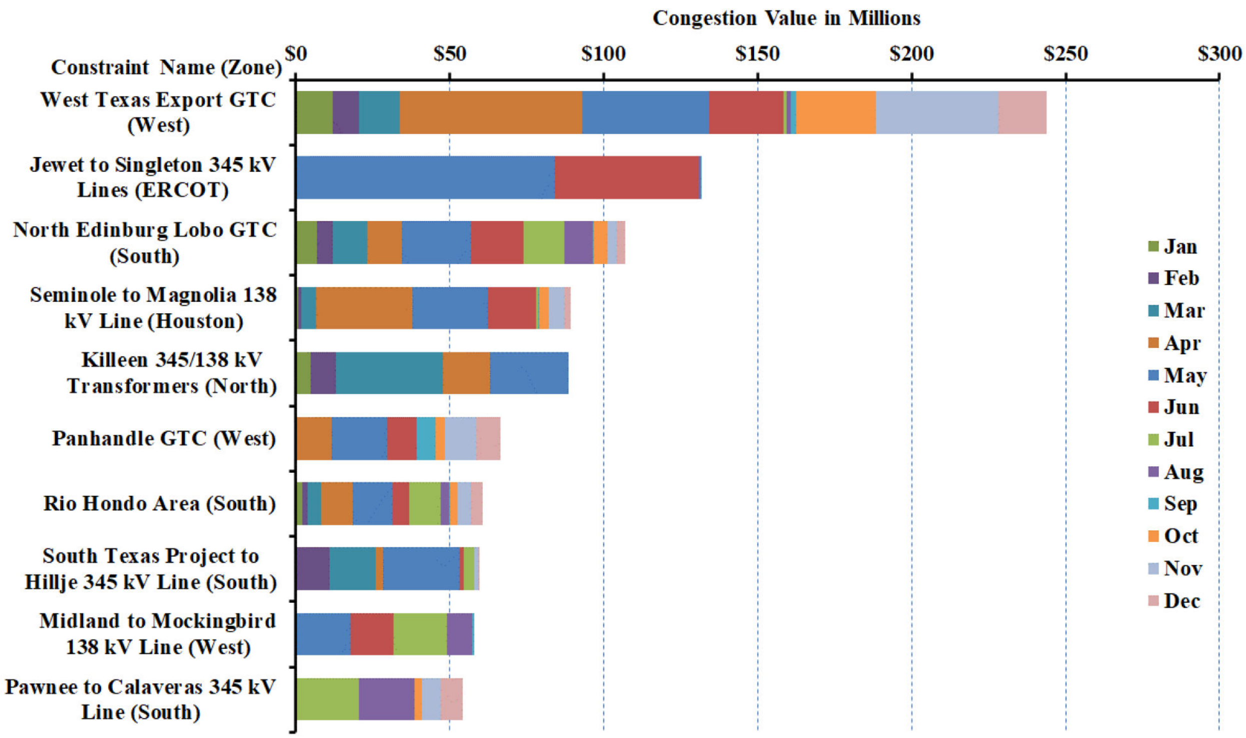
V. Appendix: Transmission Congestion and Congestion Revenue Rights

In this section, we provide supplemental analyses of transmission congestion in 2022, 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 2022. Figure A23 presents the ten most congested areas from the day-ahead market, ranked by their value. Nine 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 A23: 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 fifth year in a row, the majority of the costliest day-ahead constraints in 2022 were also costly real-time constraints. All of the constraints that exist in both the top ten real-time market and the top ten day-ahead market 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.

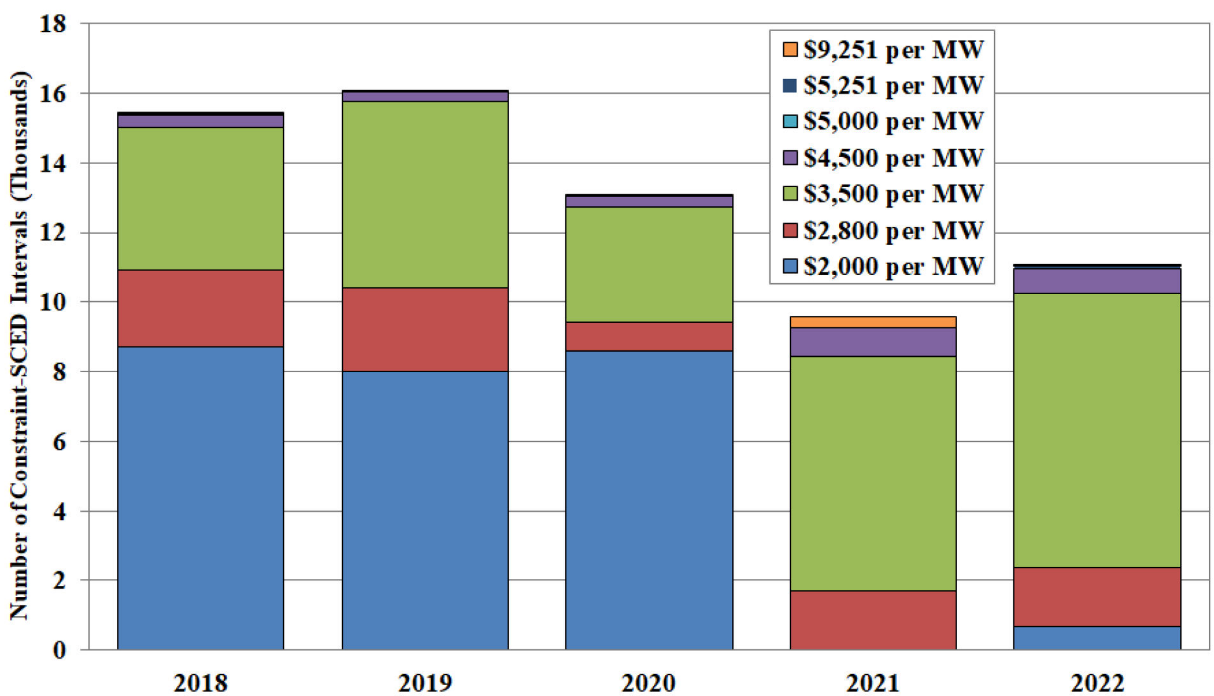
B. Real-Time Congestion

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 2022

Figure A24 below depicts constraints were violated (i.e., at maximum shadow prices) more frequently in 2022 than they were in 2021, reversing the downward trends beginning in 2019. While upgrades have resolved many of the concerns in the West zone in spring 2020, thus eliminating previously irresolvable constraints, planned outages in other regions to accommodate new transmission or transmission maintenance temporarily cause constraints to be unable to be solved by SCED dispatch. In 2022, the majority of the violated constraints occurred at the $3,500 per MW value, the 138 kv level, because of the increased congestion from Port Lavaca to Houston and congestion within the Rio Grande Valley. Violated constraints continued to occur in a small share of all the constraint-intervals, 3% in 2022, down from 4% in 2021, 5% in 2020 and 7% in 2019.

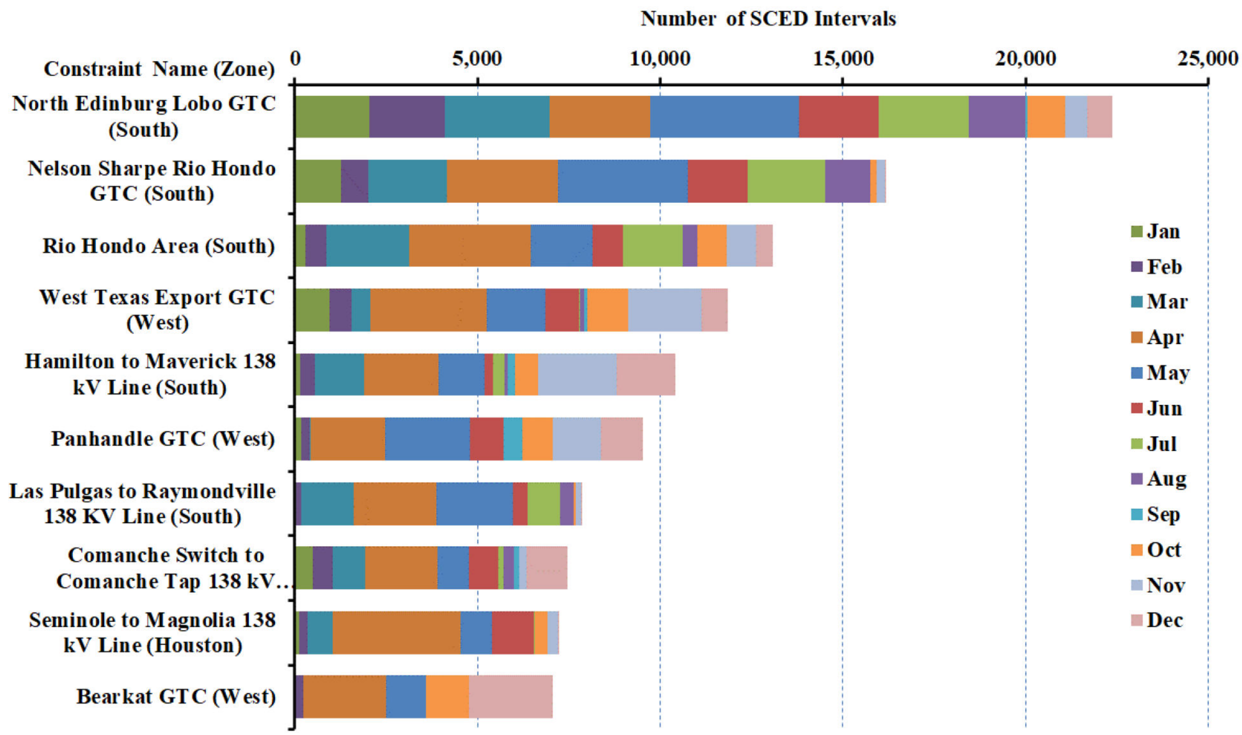
Figure A24: Frequency of Violated Constraints



2. Real-time Constraints and Congested Areas

Four GTCs (Panhandle, West Texas Export, North Edinburg Lobo and North to Houston GTC) were in the top ten congested valued areas in 2022, up from 3 in 2021. GTC constraints increase by half in congestion value to approximately $640 million from $410 million in 2021. ERCOT continues to conduct workshops and create taskforces to study and analyze models and future needs, as congestion continues to persist. All constraints listed in Figure A25 were frequently constrained in 2022 due to variable renewable output. The top ten most congested valued real-time constraints totaled $1,158 million, whereas the top ten most frequently constrained constraints totaled $739 million.

Figure A25: Most Frequent Real-Time Constraints



3. Irresolvable Constraints

As shown in Table A4, 10 element combinations were deemed irresolvable in 2022 and had a shadow price cap imposed according to the irresolvable constraint methodology. Shadow price caps are based on a reviewed methodology,[119] and are intended to reflect the level of reduced reliability that occurs when a constraint is irresolvable. The shadow price caps are

119 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.

$5,251 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 $5,251 per MW.

Table A4: Irresolvable Elements

Contingency Code	Irresolvable Element	Equivalent Element Max Shadow Price ($ per MWh)	2022 Adjusted Max Shadow Price ($ per MWh)	Irresolvable Effective Date	Termination Date	Load Zone	# of Binding Intervals in 2022
Base Case	Valley Import GTC	9,251	2,000	1/1/12	3/31/22	South	-
		5,251	2,000	4/1/22	-	South	-
DNEDWED8	Hidalgo Energy Center to Azteca Sub 138 kV Line	3,500	2,000	8/5/20	1/30/22	South	-
SMV_ALT8	Weslaco Switch to North Alamo 138 kV Line	3,500	2,000	8/7/20	1/30/22	West	-
SPHAWES8	Key Switch to North McAllen 138 kV Line	3,500	2,000	8/10/20	1/30/22	West	-
SHACPB38	Lynx to Tombstone 138 kV Line	3,500	2,000	11/30/20	1/30/22	West	-
SBEVASH8	Hamilton to Maverick 138 kV Line	3,500	2,000	2/18/21	12/27/22	South	435
		3,500	3,500	12/28/22	-	South	
SCRDJON5	Decordova Dam to Carmichael Bend Switch 138 kV Line	3,500	2,000	2/20/21	-	West	425
XFRE89	Gillespie 138/69 kV Transformer	3,500	3,117	2/5/22	-	South	-
SBE2ASH8	Hamilton to Maverick 138 kV Line	3,500	3,500	12/28/22	-	South	-
MCOMPR28	Royse Switch 138/69 kV Transformer	3,500	3,500	12/28/22	-	North	-

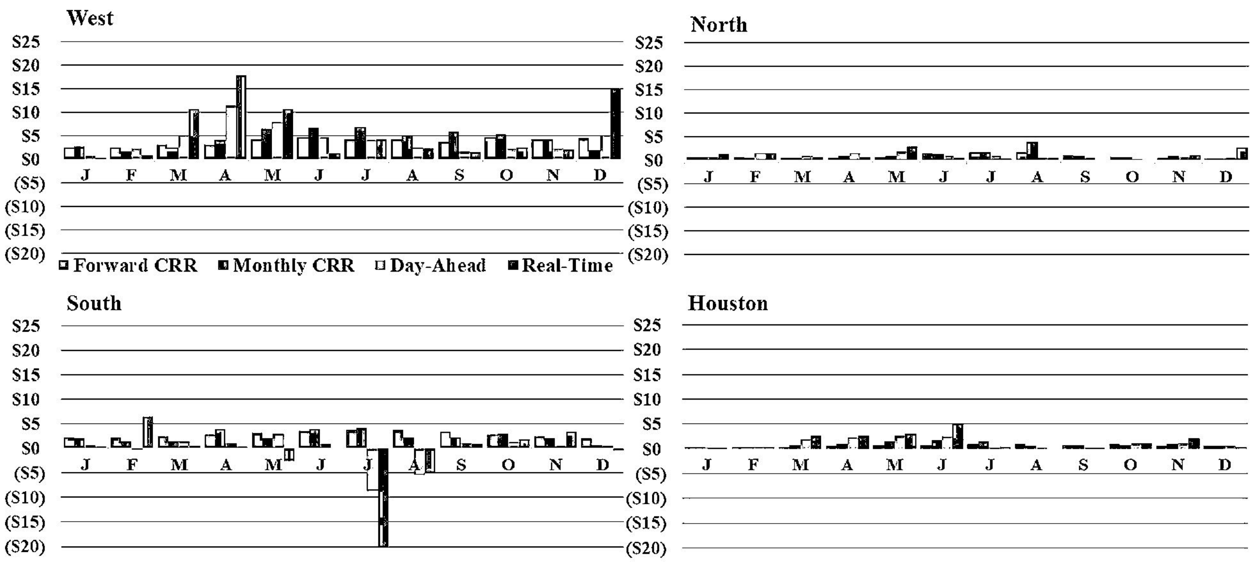
Four constraints identified with a termination date of January 30, 2022, and one with a termination date of December 27, 2022, were deemed resolvable during ERCOT's annual review and were removed from the list. Only one West zone irresolvable constraint remained in 2022 after the termination of the other four West zone constraints. An alternative contingency code for Hamilton to Maverick 138 kV Line was added, and one additional South zone irresolvable constraint was found in 2022 at the Gillespie 138/69 kV Transformer. Royse Switch 138/69 kV was the one addition from the North zone.

C. CRR Market Outcomes and Revenue Sufficiency

1. CRR Prices

Figure A26 below shows the price spreads between all hub and load zones in 2022 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.

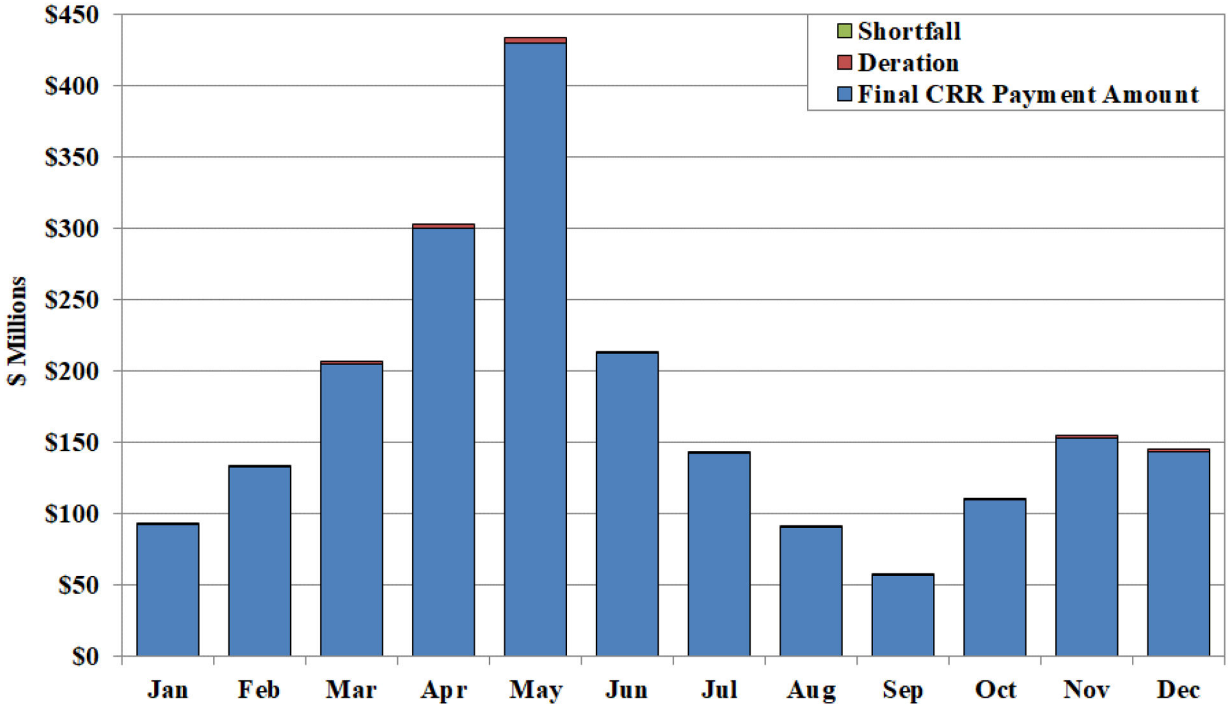
Figure A26: Hub to Load Zone Price Spreads



2. CRR Funding Levels

Figure A27 shows the amount of target payment, deration amount, and final shortfall for 2022. In 2022, the total target payment to CRRs was approximately $2.1 billion, a significant increase over the $1.3 billion in 2021; there were approximately $15 million of derations in 2022, down from $32 million in 2021, but no shortfall charges resulting in a final payment to CRR account holders of approximately $2 billion. This final payment amount corresponds to a CRR funding percentage of 99%, roughly the same as the funding percentage in 2021 (98%).

Figure A27: CRR Shortfall and Derations



VI. APPENDIX: RELIABILITY UNIT COMMITMENTS

In this section, we provide supplemental information about RUC activity in 2022, the Current Operating Plan data submitted by Qualified Scheduling Entities (QSEs) and used by ERCOT to determine the need for a RUC, as well as mitigation.

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 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 $250 per MWh. Resources committed through the RUC process are eligible for a make-whole payment but also forfeit any profit through a claw-back provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the claw-back charges, effectively self-committing and accepting the market risks associated with that decision. This buyback or "opt-out" mechanism for RUC initially required a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.

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

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

In 2018, the RUC engine was modified to consider fast-start generators (those with a start time of one hour or less) as self-committed for future hours, allowing ERCOT to defer supplementary commitment decisions, and allowing market participants full opportunity to make their own unit commitment decisions. RUC-related improvements in 2019 included approval and implementation of NPRR901, *Switchable Generation Resource Status Code*, which created a new resource status code of Switchable Generation Resources (SWGRs) operating in a non-ERCOT Control Area to provide additional transparency for operations and reporting. New logic was implemented that now prevents the triggering of the Real-Time Reliability Deployment Price Adder and the application of a RUC offer floor when a RUC Resource was awarded a resource-specific offer in the 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 per MWh for each RUC-committed SWGR as opposed to requiring QSEs to submit Energy Offer Curves reflecting the $4,500 per MWh floor.[120]

In 2021, RUC activity picked up significantly after Winter Storm Uri in February. ERCOT committed to taking a more conservative approach to operating the grid. According to ERCOT, their grid management is at its most aggressive since the market was created two decades ago. ERCOT is increasing operational reserves to ensure adequate generation is available to Texas homes and businesses and is bringing more generation online sooner if it is needed to balance supply and demand. ERCOT is also purchasing more reserve power, especially on days when the weather forecast is uncertain.[121]

In May of 2022, NPRR1092, *Reduce RUC Offer Floor and Limit RUC Opt-Out Provision* was approved. This NPRR as filed by the IMM on August 11, 2021, would have reduced the value of the offer floor to $75/MWh on Resources with the status of ONRUC and removed the ONOPTOUT status. The approved version sets a $250/MWh RUC offer floor and allows ONOPTOUT status in more limited circumstances.

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

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

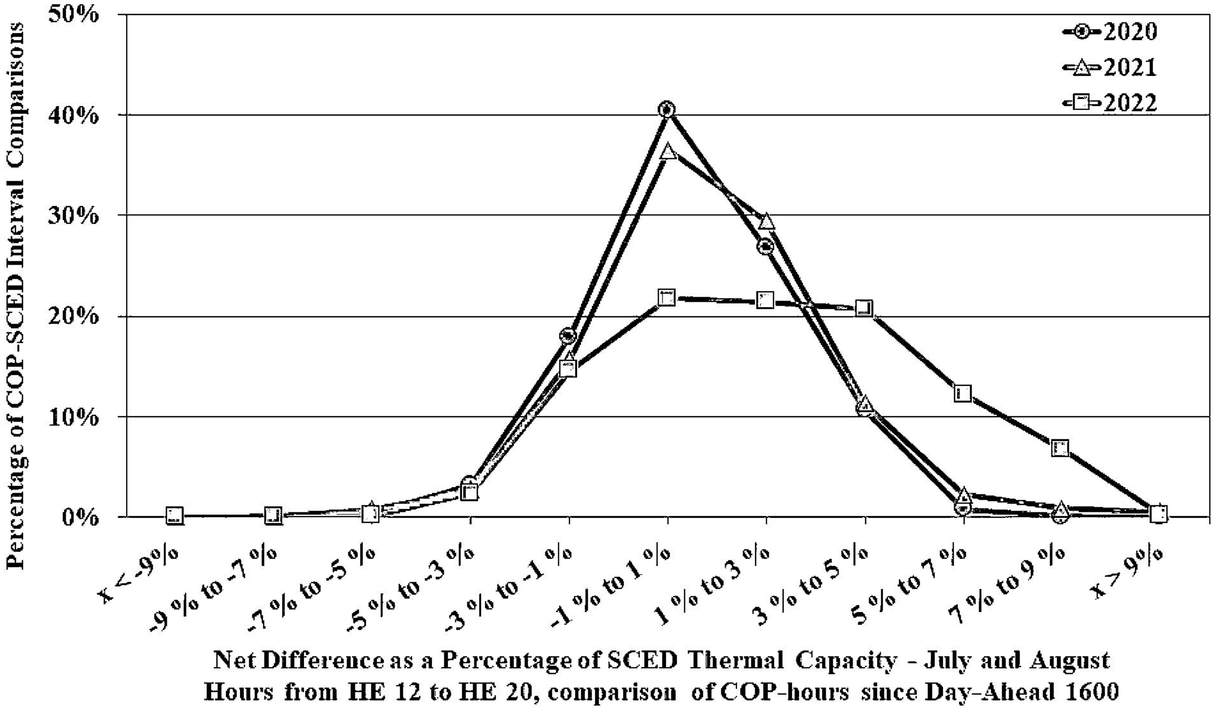
NPRR1124, *Recovering Actual Fuel Costs through RUC Guarantee*, also approved in May, ensures Generation Resources recover their actual fuel costs when instructed to start due to a RUC. Specifically, this NPRR establishes that the Startup Price per start (SUPR) and the Minimum-Energy Price (MEPR), as defined in paragraph (6) of Section 5.7.1.1, RUC Guarantee, will be set to the Startup Cap (SUCAP) and the Minimum-Energy Cap (MECAP), respectively, utilizing the actual approved fuel price paid.

B. QSE Operation Planning

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

Figure A28 shows the frequency of percentage error between SCED thermal capacity and its respective COP in months July and August of each year. The comparisons include relevant COPs from HE 12 through HE 20 at the end of the adjustment period. The analysis focuses on the net difference as a percentage of the SCED thermal capacity to control for load fluctuations between years. The last three years have shown a trend towards an error greater than 1%.

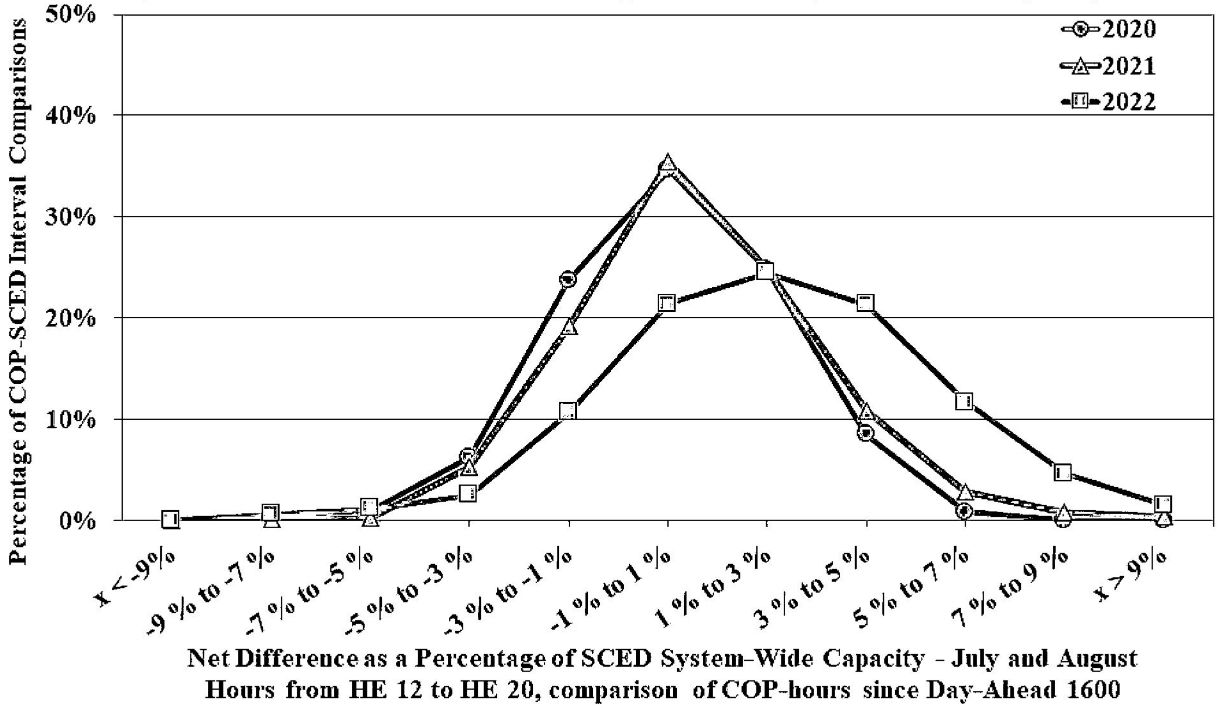
Figure A28: Real-Time to COP Comparisons for Thermal Capacity



When analyzing the average net between SCED thermal capacity and the respective COP reported from 24 hours to the last valid COP, there appears to be a tendency to under-report COP capacity 24 hours ahead, commit some capacity, and then under-report the COP at the end of the adjustment period a small percentage of the time. The curve from 2021 is generally similar to the curves from the previous two years, but 2022 is notably more depressed, exhibiting a much smaller contrast. This is due to the fact that there were more instances of COP errors than in previous years. The shape of the curves in 2020 and 2021 indicates a more evenly distributed representation of capacity in real-time versus the COP capacities. The curve in 2022 shows an increased bias towards under-representing the amount of available real-time capacity.

Figure A29 summarizes the same analysis as above, but for system-wide capacity in months July and August of each year. The curve in 2022 shows a smaller amount of capacity occurring in real-time at the system-wide level, including intermittent renewable resources, as opposed to 2020 and 2021. A possible explanation for this is the lack of incentives for accurate COP statuses. This is a significant issue because the failure to submit accurate COPs can cause excessive amounts of resources to be committed by ERCOT out-of-market. We would not expect thermal resources to exhibit this level of inaccuracy. These figures show the amount of MW from the day-ahead at 1600 leading up to operating hours 12 through 20 not being self-committed and being selected in other ways. There are also many MWs from gas peakers that are materializing in real-time that otherwise did not show operation in the COP.

Figure A29: Real-Time to COP Comparisons for System-Wide Capacity

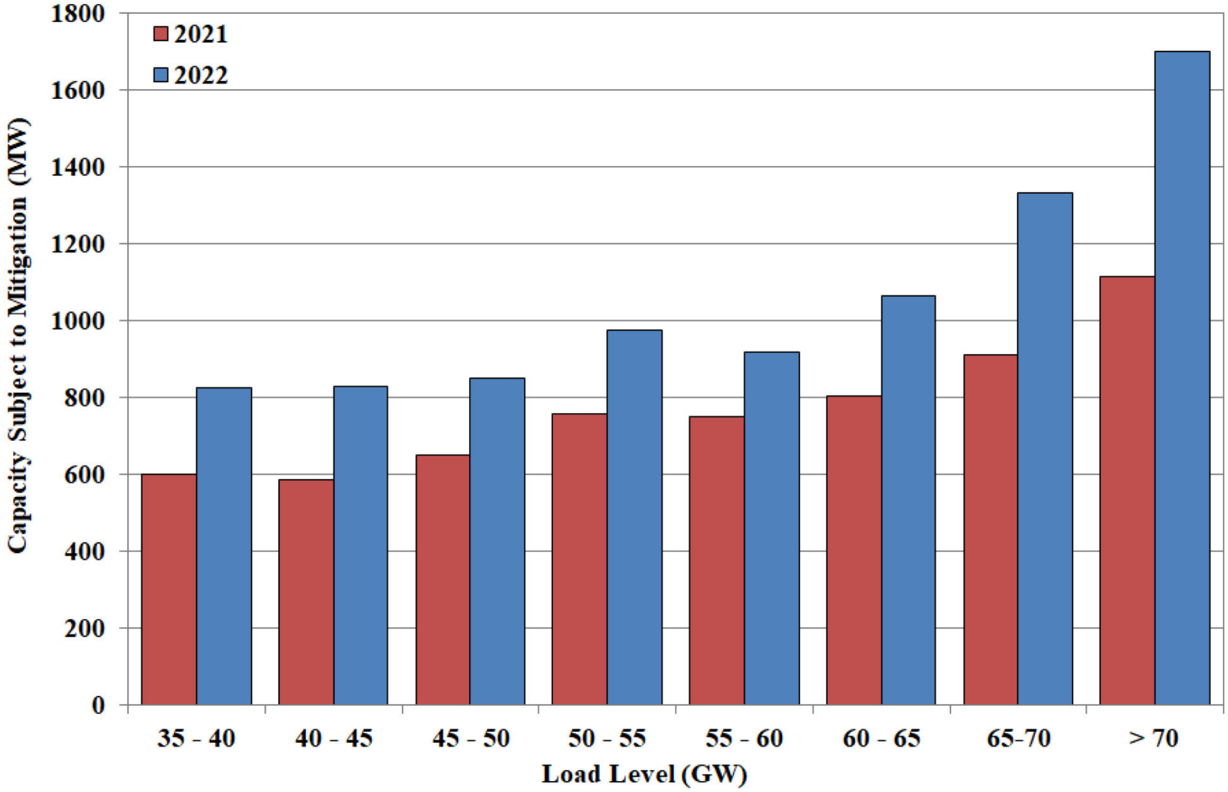


C. Mitigation

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

Figure A30.

Figure A30: Average Capacity Subject to Mitigation



The average amount of capacity subject to mitigation in 2022 was higher than 2021 in all load levels. It is important to note that this measure includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity was actually required to serve load.

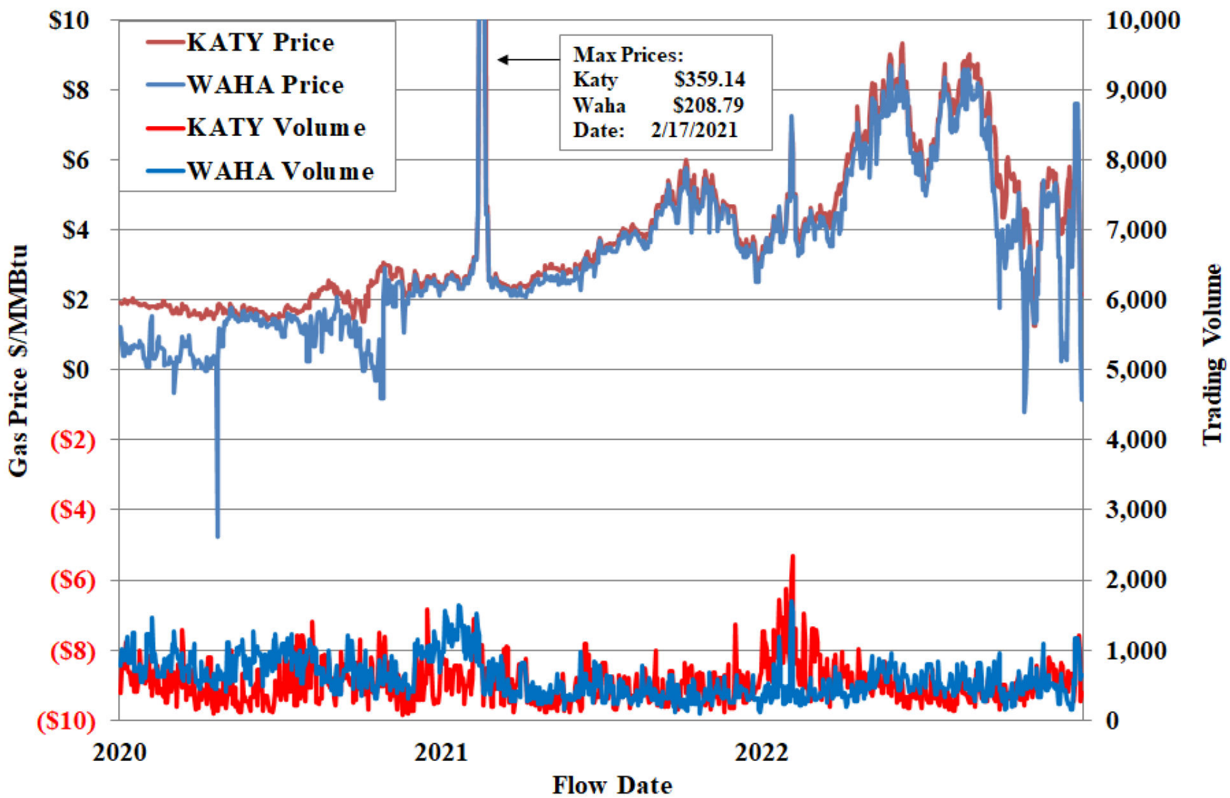
VII. Appendix: Resource Adequacy

In this section, we provide a supplemental analysis of the economic signals present in 2022 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

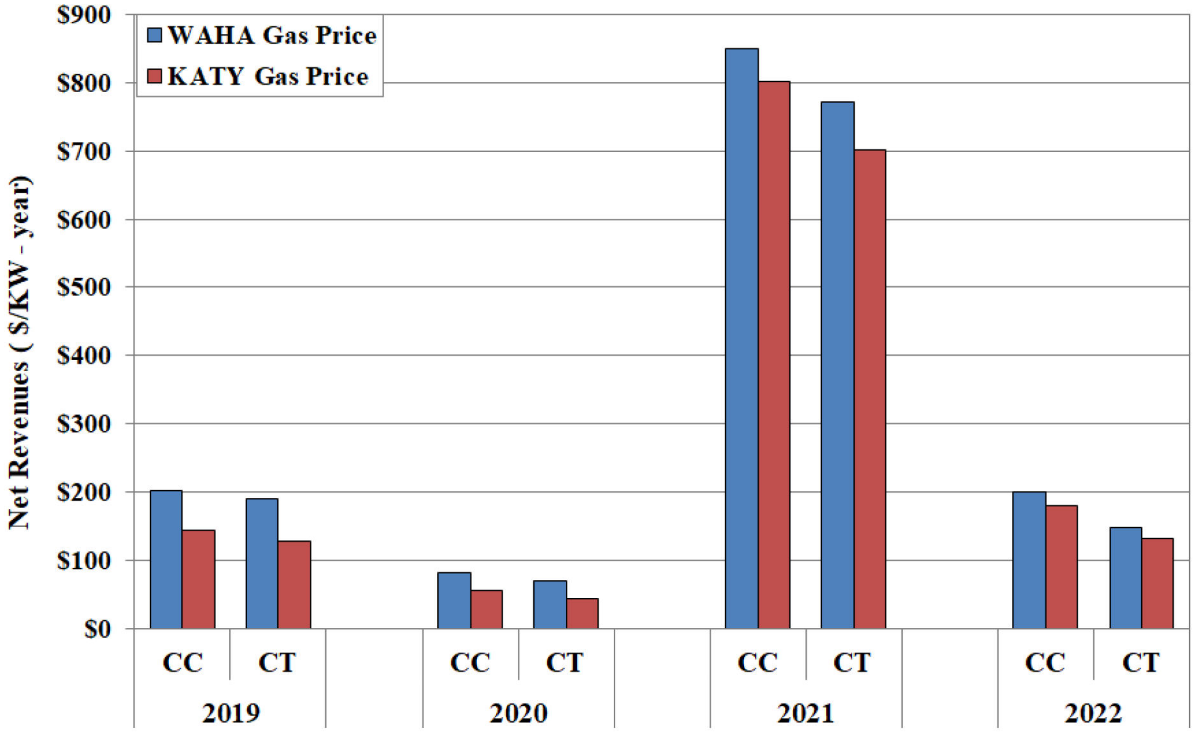
Fuel prices are a substantial determinant of net revenues because they are the primary offset from market revenues when calculating net revenues. In 2020, we noted the growing separation in natural gas prices between the Waha location in the west and Katy locations in the east. Drilling activity in the Permian Basin of far west Texas has produced a glut of natural gas and consequently, relatively much lower prices at the Waha location. As seen in Figure A31 below, prices were up overall in 2022. Waha prices in 2022 dipped below $0 multiple times and were again more volatile than Katy.

Figure A31: Gas Price and Volume by Index



Historically, resources in the West zone have had lower net revenues than resources in the other zones, but that was not the case in 2020 through 2022. Additionally, the divergence between Waha and Katy gas prices contributed to greater net revenues for West Texas gas-fired generators. Figure A32 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 contribute to higher West zone revenues.

Figure A32: 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 2022, a number of Notice of Suspension of Operations (NSO) were submitted in 2022.[122] ERCOT determined that none of the resources listed below were necessary to support ERCOT transmission system reliability.

On January 19, 2022, ERCOT received an updated Notification of Change of Generation Resource Designation (NCGRD) for Wharton County Generation LLC's TGF_TGFGT_1 resource. The updated NCGRD, originally received by ERCOT on December 17, 2021, indicated that the Resource Entity intended to change the resource's designation to operational as of February 4, 2022. Based on this notification, ERCOT initiated discussions with the interconnecting Transmission Service Provider (TSP) to determine the required studies and

122 Wharton County Generation LLC: TGF_TGFGT_1; OCI Alamo 1 LLC: OCI_ALM1_ASTRO1; GEUS: STEAM1A_STEAM_1; City of Garland: SPNCER_SPNCE_4 and SPNCER_SPNCE_5; Mountain Creek Power LLC: MCSES_UNIT8.

facility upgrades for this Resource to return to service. ERCOT determined that studies and facility upgrades required by the TSP to return the Resource to service would delay the Resource's return to service beyond February 4, 2022.

On June 20, 2022, ERCOT received an NSO for OCI Alamo 1 LLC's OCI_ALM1_ASTRO1 resource. The NSO indicated that the resource would be decommissioned and retired permanently as of November 17, 2022. The NSO further indicated that the resource had a summer Seasonal Net Max Sustainable Rating of 1 MW and a summer Seasonal Net Minimum Sustainable Rating of 0 MW.

On July 1, 2022, ERCOT received an NSO for GEUS's STEAM1A_STEAM_1 resource. The NSO indicated that beginning October 1, 2022, the resource would suspend operation on a year-round basis and begin operation on a seasonal basis with a Seasonal Operation Period that begins June 1 and ends on September 30. The NSO further indicated that the resource has a summer Seasonal Net Max Sustainable Rating of 17.50 MW and a summer Seasonal Net Minimum Sustainable Rating of 10 MW.

On July 15, 2022, ERCOT received NSOs for the City of Garland's SPNCER_SPNCE_4 and SPNCER_SPNCE_5 resources. The NSOs indicated that the resources would suspend operation on a year-round basis and begin operation on a seasonal basis with a Seasonal Operation Period that begins on March 1 and ends on November 30. The NSO for SPNCER_SPNCE_4 indicated that the Generation Resource has a summer Seasonal Net Max Sustainable Rating of 57 MW and a summer Seasonal Net Minimum Sustainable Rating of 15 MW. The NSO for SPNCER_SPNCE_5 indicated that the Generation Resource has a summer Seasonal Net Max Sustainable Rating of 61 MW and a summer Seasonal Net Minimum Sustainable Rating of 15 MW.

On October 26, 2022, ERCOT received a NCGRD for the City of Garland's SPNCER_SPNCE_4 and SPNCER_SPNCE_5 resources. The NCGRD indicated that as of October 24, 2022, the Mothballed Generation Resources operating under a Seasonal Operation Period would change its start date of Seasonal Operation Period from March 1 to April 2.

On November 30, 2022, ERCOT received an NSO for Mountain Creek Power LLC's MCSES_UNIT8 resource. The NSO indicated that beginning March 1, 2023, the Generation Resource will suspend operation on a year-round basis and begin operation on a seasonal basis with a Seasonal Operation Period that begins June 1 and ends on September 30. The NSO further indicated that the Generation Resource has a summer Seasonal Net Max Sustainable Rating of 568 MW.

VIII. Appendix: Analysis of Competitive Performance

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

A. Structural Market Power Indicators

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

1. Voluntary Mitigation Plans

In 2022, three market participants had active Voluntary Mitigation Plans (VMPs) that remain unchanged throughout the year, though a significant modification regarding non-spinning reserve was made in March 2023. In those modifications, NRG's ancillary services offers are no longer covered by their VMP; Luminant has a $20/MW non-spinning reserve offer cap; and Calpine has a dynamic formula based on their offers for other ancillary services.

Calpine's VMP was approved in March of 2013.[123] 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,[124] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12% of

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

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

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.[125] The Commission terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy, Inc.[126] 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 for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the high system-wide offer cap (HCAP). When approved in late 2019, the amount of capacity covered by these provisions was less than 900 MW. In addition, the plan defines allowable limits for energy offers from Luminant's quick start combustion turbines.

B. Evaluation of Supplier Conduct

1. Generation Outages and Deratings

Figure A33 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2022.

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

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

Figure A33: Short-Term Outages and Deratings

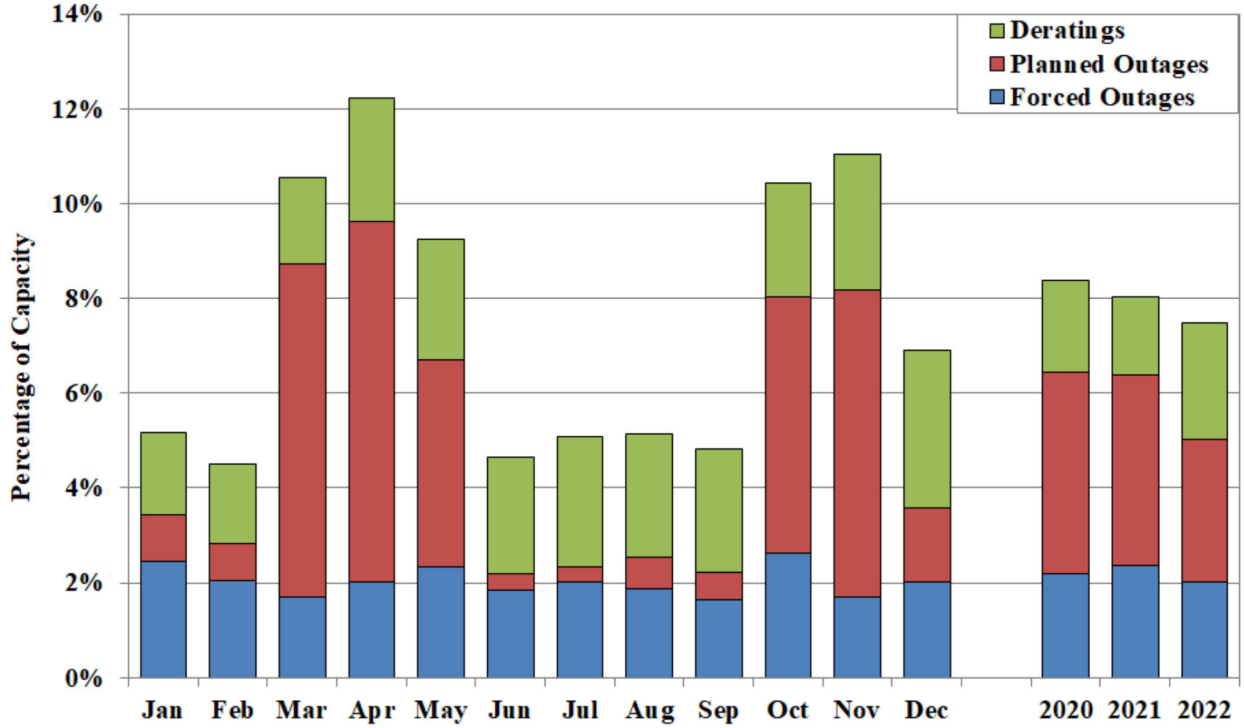


Figure A33 shows that short-term outages and deratings in 2022 followed a pattern similar to what occurred in 2020 and 2021, as the expectations for summer shortage in both years prompted short-term outage and derating spikes in shoulder months. The total short-term deratings and outages in 2022 were approximately 12.2% of installed capacity in April (down from 1352% in 2021) and dropped to around 5% during June, July, August and September (only marginally higher than the same months in 2020 and 2021.

The amount of capacity unavailable during 2022 averaged 7.5% of installed capacity, a modest decrease from the 7.8% in 2021 and 8.0% experienced in 2020. The numbers of planned outages dropped again in 2022, 2.0% on average, down from 3.6% in 2021 and 4.0% in 2020. This slight downward trend can be explained by the heightened expectations for shortages during the summer and generators taking outage time to ensure higher availability. The low levels of deratings the last three years may be similarly explained by generators operating in modes that would allow them to maximize generation.

Figure A34 below includes both short and long-term outages, and there was consistency across all months except for February through April. In those months in 2021, because of the effects of Winter Storm Uri, the rate of planned and forced outages were almost double what they were in those months of 2022.

Figure A34: Short- and Long-Term Deratings and Outages