

2020 SUMMER RESOURCE ADEQUACY IN THE ERCOT REGION



May 7, 2020

DOE/NETL-2020/2603

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Acknowledgements

The authors would like to recognize and thank Mr. Peter Warnken, Manager of Resource Adequacy at the Electric Reliability Council of Texas, for his careful review and insightful comments on this study.

Suggested Citation:

K. Labarbara, S. Lin, C. E. Logan, J. Brewer, "2020 Summer Reliability in ERCOT," National Energy Technology Laboratory, Pittsburgh, February 18, 2020.

This report was prepared by MESA for the U.S. Department of Energy (DOE) NETL. This work was completed under DOE NETL Contract Number DE-FE0025912. This work was performed under MESA Activity 202.004.004.

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ACRONYMS AND ABBREVIATIONS

| | | | |
|-----------------|---------------------------------------|-----------------|---|
| CDR | Capacity, Demand and Reserves | MESA | Mission Execution and Strategic Analysis |
| CO ₂ | Carbon dioxide | mins | Minutes |
| CONE | Cost of new entry | MMBtu | Million British thermal unit |
| COVID-19 | Coronavirus disease 2019 | MW | Megawatt |
| CREZ | Competitive Renewable Energy Zone(s) | MWh | Megawatt hour |
| DC | Direct current | NERC | North American Electricity Reliability Corporation |
| DOE | Department of Energy | NETL | National Energy Technology Laboratory |
| EEA | Energy Emergency Alert | NG | Natural gas |
| EORM | Economically optimal reserve margin | NOx | Nitrogen oxides |
| ERCOT | Electric Reliability Council of Texas | OPEC+ | Organization of Petroleum Exporting Countries plus Russia |
| ERS | Emergency Response Service | PJM | PJM Interconnection |
| GW | Gigawatt | PRC | Physical responsive capability |
| HSL | High sustained limit | PTC | Production tax credit |
| Hz | Hertz | PUCT | Public Utility Commission of Texas |
| IA | Interconnection agreement | RE | Reliability Entity |
| IMM | Independent market monitor | RTO | Regional transmission organization |
| ISO | Independent system operator | SARA | Seasonal Assessment of Resource Adequacy |
| ITC | Investment Tax Credit | SO ₂ | Sulfur dioxide |
| kV | Kilovolt | SPP | Southwest Power Pool |
| kWh | Kilowatt-hour | TDSP | Transmission and/or Distribution Service Provider |
| LaaR | Loads acting as a Resource | TSP | Transmission Service Provider |
| lbs | Pounds | U.S. | United States |
| LMP | Locational marginal price | VRE | Variable renewable energy resources |
| LOLE | Loss of load expectation | | |
| LOLH | Loss of load hours | | |
| LTRA | Long-Term Reliability Assessment | | |
| Mcf | Million cubic feet | | |
| MERM | Market equilibrium reserve margin | | |

EXECUTIVE SUMMARY

Anticipated reserve margins in the Electric Reliability Council of Texas (ERCOT) have risen from the 8.6 percent reported in ERCOT's Final Seasonal Assessment of Resource Adequacy (SARA) for Summer 2019 to 10.7 percent for Summer 2020 in ERCOT's Capacity, Demand and Reserves [CDR] report published in December 2019 and 2020 Summer Preliminary SARA published in March 2020. [1] [2] [3] This is well below the current minimum target reserve margin of 13.75 percent set by the ERCOT Board of Directors [4], and only slightly above the 10.25 percent market equilibrium reserve margin (MERM), and 9.0 percent economically optimal reserve margin (EORM) levels identified by Brattle in a study done for ERCOT in late 2018. [5] Despite tight operating conditions, ERCOT was able to maintain the system with no load shedding events over 2018 and 2019. [6]

Using data from ERCOT's Preliminary 2020 Summer SARA, CDR, and historical performance data, three economic dispatch scenarios using PROMOD were developed to assess the risk to ERCOT of a load shedding event for Summer 2020.^a The results suggest that ERCOT could make it through the summer season without a loss of load event, as long as the weather remains normal, even though ERCOT will be well below its minimum reserve margin target. However, if demand reaches previous growth adjusted historical peak levels, ERCOT is likely to find itself operating in emergency conditions during the summer peak, which is usually the end of July through mid-August. Under these conditions, on multiple days load would exceed capacity; although ERCOT would call on its operating tools to maintain reliability and continue serving load, those measures alone may not be sufficient to avert a shedding of load. Of course, electricity demand in ERCOT is currently being depressed due to the global Coronavirus disease 2019 (COVID-19) pandemic. Load associated with the oil and gas industry may recover slowly from low oil prices. Whether and how economic activity within Texas rebounds as the state re-opens during its perennially hot summers, along with need for more power generation, remains highly uncertain at the time of this writing.

^a These scenarios were completed prior to the issuance of ERCOT's Final SARA for Summer 2020, which projects a peak load 1,496 MW lower than the preliminary

1 HISTORIC RESOURCE ADEQUACY IN ERCOT

In 2012, Electric Reliability Council of Texas (ERCOT), working with the Public Utility Commission of Texas, commissioned The Brattle Group (“Brattle”) to investigate the question of whether ERCOT’s market design could sufficiently maintain resource adequacy. Unlike other independent system operators (ISOs) and regional transmission organizations (RTOs) that operate capacity, energy, and ancillary service markets, ERCOT operates only energy and ancillary service markets. When Brattle’s study, “ERCOT Investment Incentives and Resource Adequacy,” was published, ERCOT was struggling to attract investment in new generation projects, and reserve margins were predicted to fall below 10 percent. [7]

The Brattle study determined that if ERCOT maintained only a 10 percent reserve margin, this would, on average, “result in approximately one load-shed event per year with an expected duration of two-and-a-half hours, and thirteen such events in a year with a heat wave as severe as the one in 2011.”^b [7] In 2011, Texas experienced both extreme cold weather, with a record winter peak demand in February, and unusually hot weather, with June–August temperatures that were the hottest on record. The average 24-hour statewide temperature from June through August was 86.8 degrees Fahrenheit, the hottest three months on record. [8] Dallas experienced 70 days where temperatures hit 100 degrees Fahrenheit that summer. [9] In August of that year, ERCOT was forced to trigger emergency operating procedures six times. [7]

In another Brattle study, “Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region,” which was completed in 2018 as an update to the 2014 study “Estimating the Economically Optimal Reserve Margin in ERCOT,” the market equilibrium reserve margin (MERM) and the economically optimal reserve margin (EORM) of ERCOT’s wholesale electric market were estimated. [10] [5] The MERM describes the reserve margin that the market can be expected to support in equilibrium, as investment in new supply resources responds to expected market conditions, where a marginal unit’s revenue and cost of a new entry (CONE) intersect. The EORM represents a balance between increased capital costs and decreased reliability-related operating costs and provides a gauge for evaluating the expected MERM. Under projected 2022 market conditions, the suggested EORM is 9.0 percent, and the MERM is 10.25 percent. At the given MERM value, the system could expect to experience 0.5 events per year loss of load expectation (LOLE),^c and 0.8 events per year LOLE at the EORM value. [5]

To address the absence of the capacity market to attract new resources for the market, ERCOT implemented the Operating Reserve Demand Curve (ORDC) on June 1, 2014. The ORDC is used to create a real-time reserve price adder, to reflect the value of reserves in the real-time market, based on the probability that reserves for the ERCOT system fall below a minimum level of

^b For reference, the traditional 1 day-in-10 years reliability planning criteria used by industry equates to 2.4 hours per year.

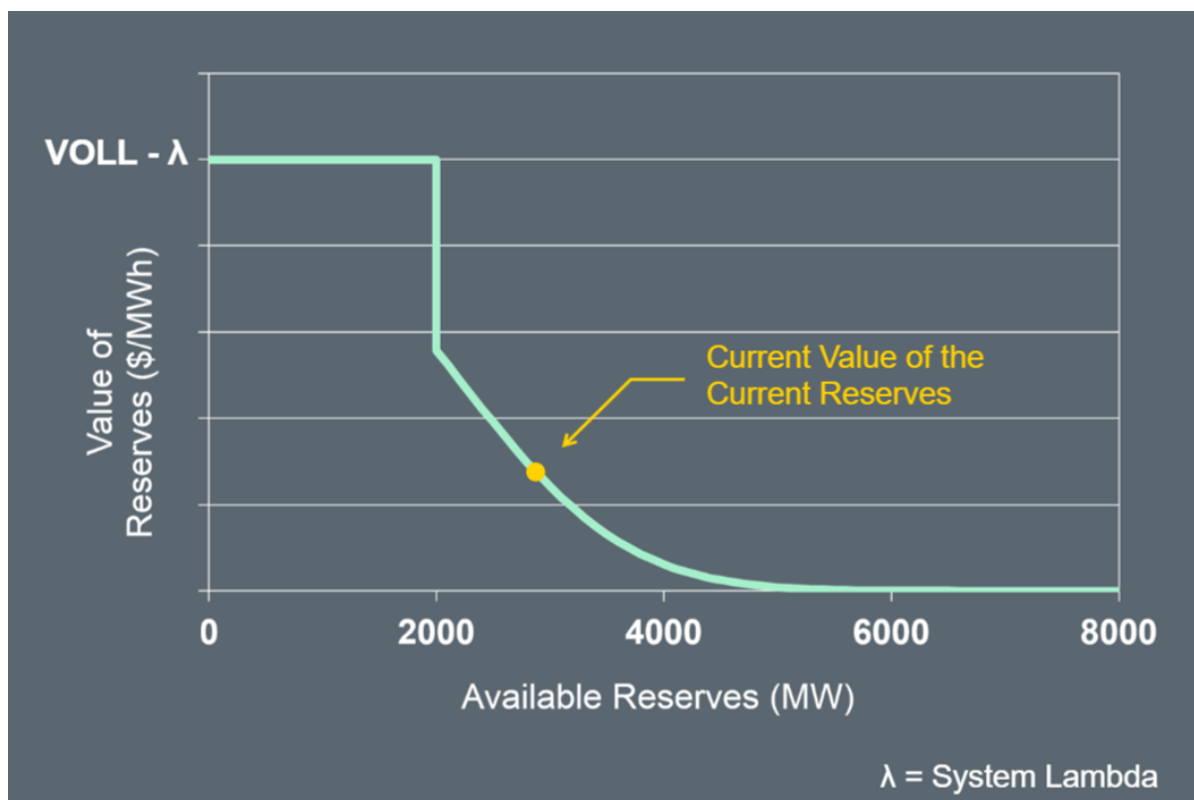
^c LOLE is defined as the expected number of days in which the available generation capacity is insufficient to serve the demand at least once per day. LOLE counts the days meeting this criterion, regardless of the number of consecutive or nonconsecutive hours in the day. [41] For reference, the traditional 1 day-in-10-years reliability planning criteria used in industry is reflected on an LOLE basis. On loss of load hours (LOLH) basis; this is equivalent to 2.4 hours per year. Both are unconcerned with the magnitude or number of outages. [42]

2,000 MW. The ORDC curve is constructed by Value of Lost Load (VOLL), System Lambda (λ), and Loss of Load Probability (LOLP), as shown in the following equation:

$$ORDC = (VOLL - \lambda) \times LOLP$$

Where VOLL is set to be equal to the system wide offer cap, which is currently 9,000 \$/MWh; λ is the price of matching generation and demand at the reference bus; and LOLP is calculated by a normal distribution built from the historical difference between hour ahead reserve and real-time reserve.^d A typical ORDC graph is shown in Exhibit 1-1. Roughly speaking, the ORDC makes nearly zero impact when the reserve is above 6,000 MW. Value increases as reserves tighten, reaching the maximum when reserves drop below 2,000 MW.

Exhibit 1-1. Graph of ORDC



Used with permission from ERCOT [11]

Then, ERCOT uses the ORDC to calculate two price adders: Real-Time On-Line Reserve Price Adder for all resources that could be available to dispatch within 30 minutes, and Real-Time Off-Line Reserve Price Adder for all other resources that could be available to dispatch within an hour. These two price adders are then incorporated into the ERCOT real-time energy market to pay resources for their value of reserves and energy. Note that ORDC and its associate price adders are only used in the ERCOT real-time energy market; they are not included in the ERCOT day-ahead energy market.

^d More detailed mathematical discussion for the ORDC and LOLP can be found in an ERCOT online course and training. [45]

In response to low reserve margins in recent years, the Public Utilities Commission of Texas (PUCT) directed ERCOT to adjust the ORDC in 2019, particular in the calculation of LOLP to make energy prices rise faster when reserve is low. Generation groups like Vistra Energy support this change; they believe ERCOT should have proper price signals to support generation investment for maintaining resource adequacy during periods of peak demand. [12]

After adjusting its market design to attract new generation investment and maintaining higher reserve margins for several years, ERCOT began to realize the problem predicted by Brattle for 2014, with a projected reserve margin of 10.62 percent back in Summer 2018 and 8.36 percent in Summer 2019. The predicted reserve margin increases slightly to 10.7 percent going into Summer 2020.

The ERCOT Board of Directors has set the region's planning reference margin level at 13.75 percent. [13] The North American Electricity Reliability Corporation (NERC) 2019 Long-Term Reliability Assessment (LTRA) projected an anticipated reserve margin of 10.24 percent for ERCOT in 2020. [6] In the early fall of 2017, ERCOT was notified of the retirements of 9 coal-fired generating units between 2018 and 2020, which constitute the bulk of the retiring 5,622 megawatts (MW), which is around 6 percent of the total current system generation resource capacity. In December 2019, ERCOT published its Capacity, Demand and Reserves (CDR) report, which forecasts a reserve margin of 10.7 percent for Summer 2020. [2] Compared to the 13.75 percent reference reserve margin, the capacity shortfall is due to strong load growth in West Texas, cancellation of gas-fired plants for 1,277 MW, and the delay of some new solar projects for 1,056 MW. [2]

Comparing the forecast in the CDR and Summer 2020 Preliminary Seasonal Assessment of Resource Adequacy (SARA) to Summer 2019 Final Seasonal Assessment of Resource Adequacy, the adjusted peak demand increased from 74,853 MW to 76,696 MW.^e This comes from robust growth of oil and gas exploration activity in West Texas. [1] However, these values were published prior to the domestic impact of Coronavirus disease 2019 (COVID-19) and the severe collapse in oil prices driven by the destruction of fuel demand. While the total impact on these factors on summer electricity supply and demand remain uncertain, ERCOT is proceeding with the preparation of a revised summer peak demand forecast based on the latest county-level economic forecasts provided by Moody's Analytics. The revised peak demand forecast will be included in ERCOT's final summer SARA report to be released May 13, 2020. With current demand profiles that ERCOT is reporting due to COVID-19, where daily peaks have been 2 percent lower and overall energy demand has been 4–5 percent below normal, the region may not see peak summer demand at levels that require emergency actions to be taken. [14]

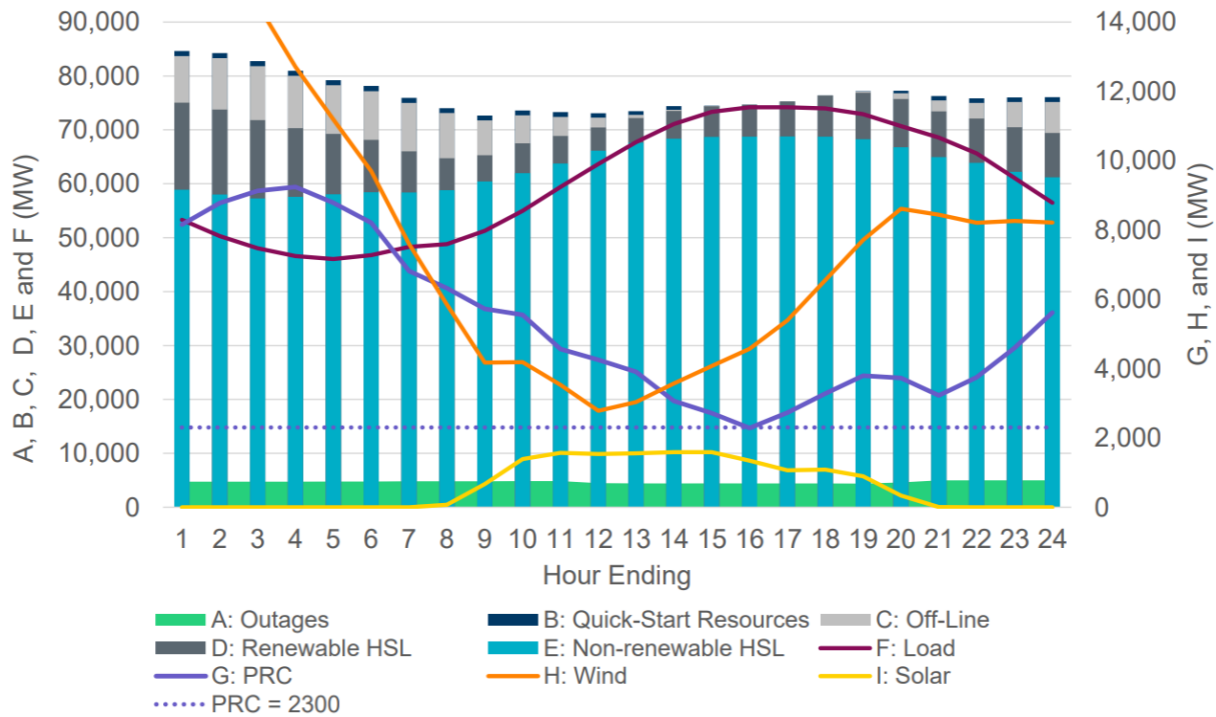
Total resource capacity increased from 78,929 MW to 82,430 MW. The majority of this capacity increase comes from wind, followed by solar and natural gas-fired generation. Note that the final 10.7 percent reserve margin from the CDR considers demand response programs under ERCOT's control, which include registered Load Resources that provide operating reserves in the day-ahead Ancillary Service market, Energy Response Service (discussed in detail later in this

^e Note that the peak demand in Summer 2019 was 74,820 MW, which was very close to the 2019 SARA forecast value.

section), and utility-offered load management programs triggered during summer-season Energy Emergency Alerts (EEAs) declared by ERCOT. These programs account for 2,216 MW.

For Summer 2019, there were multiple days with tight resource adequacy and low operating reserves; ERCOT announced EEA Level-1 events twice.^f However, on the peak demand day August 12, no EEA was announced due to greater wind generation than occurred on the days with EEA-1 events (2,549 MW more than predicted in the 2019 Final SARA; lower than SARA projected wind presented when reserves reached their lowest levels on the days with EEA-1). For both EEA Level-1 (EEA1) days, August 13 and August 15, Emergency Response Service was deployed, and more than 900 MW of load reduction responded. This prevented the need for escalation to EEA Level-2 (EEA2) or EEA Level-3 (EEA3) and an LOLE event due to rotating outages. Detailed generation, reserve, and demand variation for these two days are shown in Exhibit 1-2 and Exhibit 1-3. [15]

Exhibit 1-2. Hourly capacity, demand, and reserve for ERCOT on August 13 2019^g

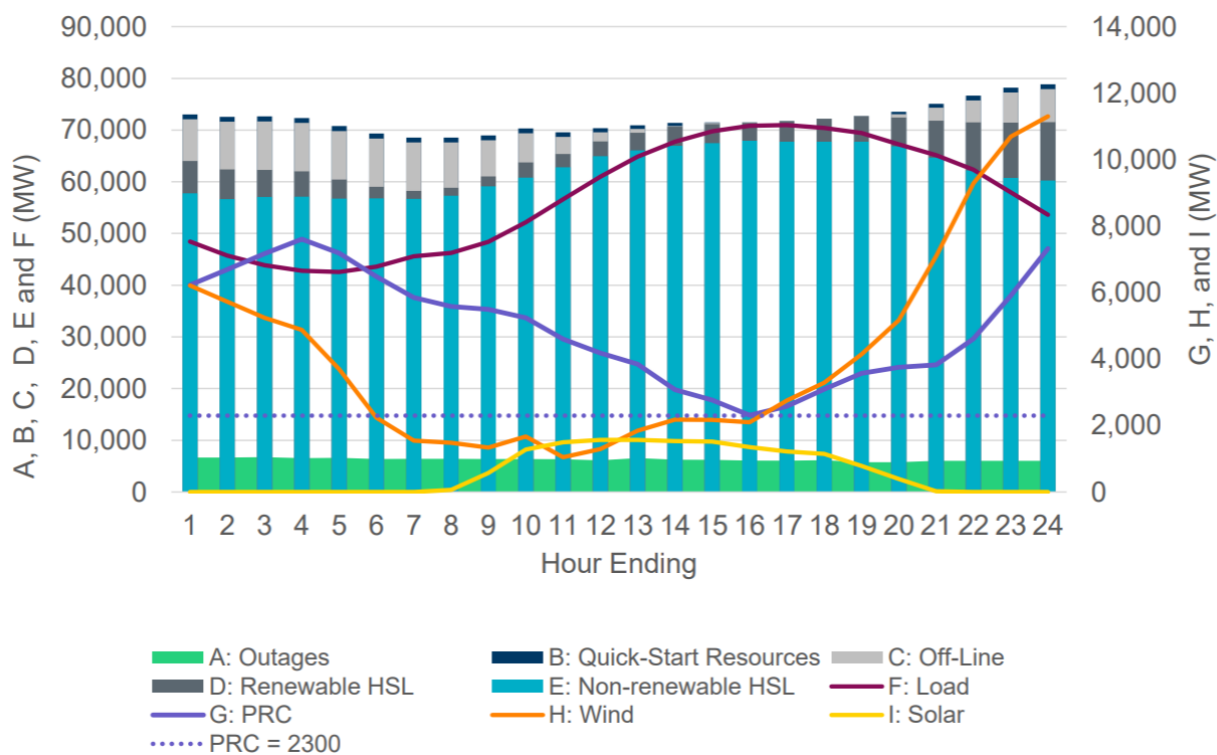


Used with permission from ERCOT [15]

^f More detail about ERCOT EEA definition can be found in Exhibit 1-12 later in this section.

^g HSL: High Sustained Limit; PRC: Physically Responsive Capacity

Exhibit 1-3. Hourly capacity, demand, and reserve for ERCOT on August 15, 2019

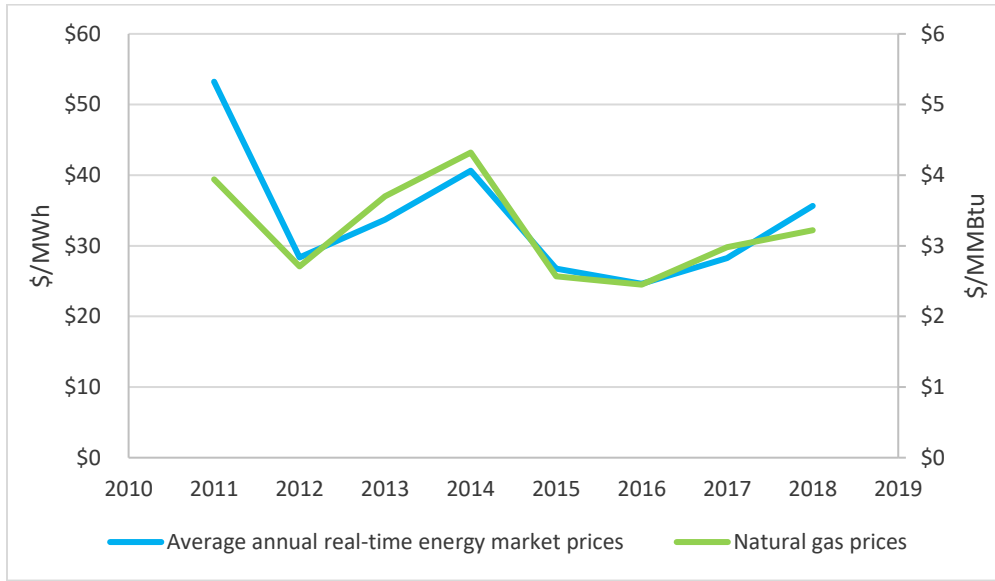


Used with permission from ERCOT [15]

An October 2017 article in *Power* magazine points to a roughly 50 percent drop in wholesale power prices in ERCOT’s energy market since 2011 as the primary driver of the recent plant retirements. [16] In 2016, average annual real-time energy market prices in ERCOT were \$24.62, down from \$53.23 in 2011, although they increased slightly in 2017 to \$28.25, as seen in Exhibit 1-4. [17] The *Power* article posits that coal and nuclear units in ERCOT are becoming unprofitable, and the retirements announced in the fall of 2017 were economic decisions by generator owners who determined that the plants were unable to earn a profit under existing market conditions. [16] In 2018, AEP Texas also scheduled to retire Oklaunion, a 650-MW coal-fired power plant in 2020 due to unfavorable market condition. AEP Texas stated that the cost to generate energy from Oklaunion is no longer competitive in ERCOT. [18] Note that in Exhibit 1-4, the ERCOT real-time energy market price in 2018 jumped to \$35.63 per megawatt-hour (MWh), a 26 percent increase from 2017.^h This was due to the combination of increased natural gas prices and decreased capacity reserve margins. [17]

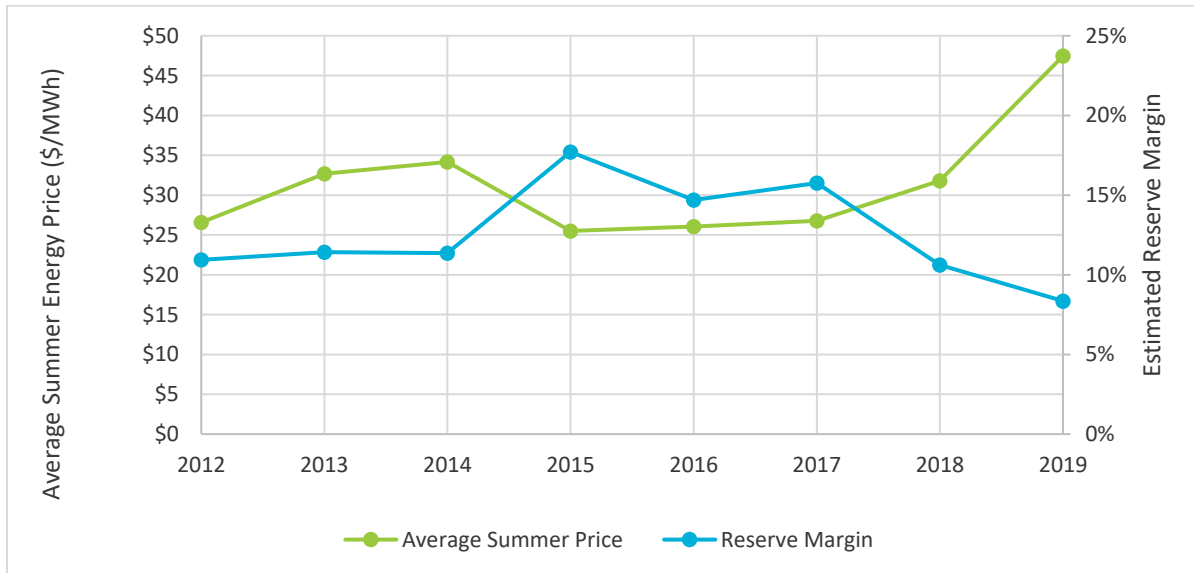
^h The ERCOT 2019 State of the Market Report has not yet been released as of the date of this publication.

Exhibit 1-4. Average annual real-time energy market and natural gas prices [17]



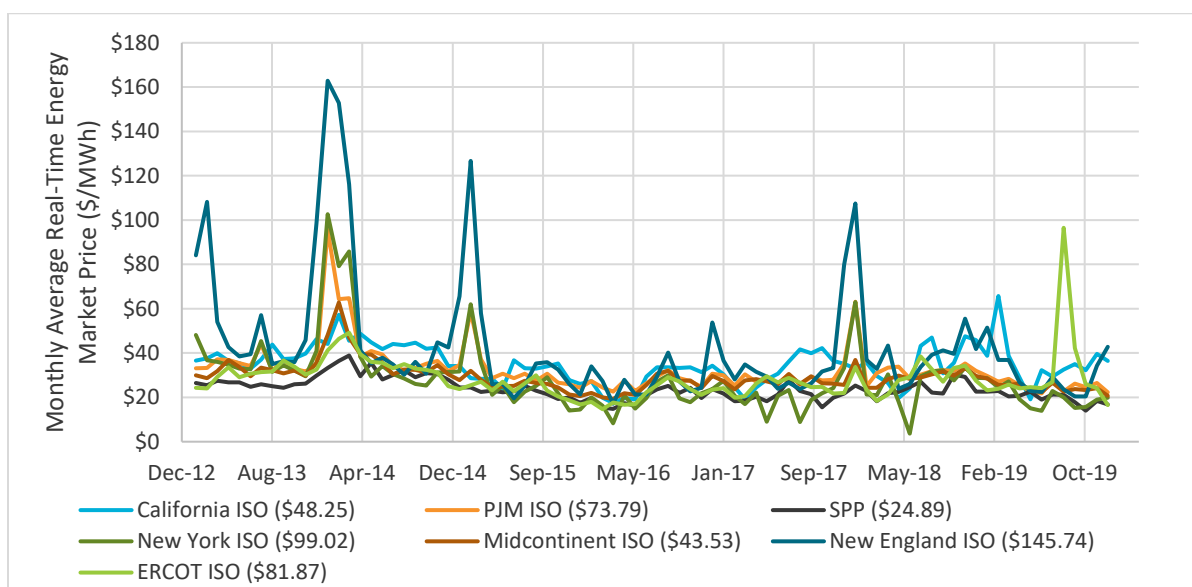
The recent thermal plant retirements result in a lower summer reserve margin for these years. The lower reserve margin is a major factor causing higher summer energy prices, as shown in Exhibit 1-5. The reserve margins are the estimated values from SARA and CDR reports published by ERCOT each year, not the operating reserves from summer peak days. As seen in Exhibit 1-5, the reserve margin has dropped nearly half from 17.71 percent to 8.36 percent from 2015 to 2019, while the average summer energy price increased from \$25.50/MWh to \$47.45/MWh from 2015 to 2019. The energy prices are from ERCOT’s real time energy market average hub prices in June, July, August, and September. [19]

Exhibit 1-5. ERCOT Estimate Summer Reserve Margin and Average Energy Market Price from 2012 to 2019 [19]



A lower reserve margin not only helps cause higher average energy market price in summer, but also results in higher price fluctuations. Exhibit 1-6 shows the monthly hub average real-time energy prices in ERCOT compared with those for other ISOs/RTOs in the United States (U.S.) over the last seven years. While the overall energy price is relatively low in ERCOT, energy price spikes occur in winter and summer, when demands are highest and wind resources reach their lowest seasonal output levels. Energy price ranges from \$15 to \$97 per MWh in ERCOT, which is the 5th largest swing among market regions; only ISO New England and ISO New York experienced wider swings of \$145 and \$99, respectively. Price spikes in ERCOT are significantly higher in Summer 2019 than previous years. On August 13, 2019, real-time energy price even reached the market price cap of \$9,000/MWh, [20] showing the resource adequacy problem ERCOT is facing as a result of low reserves.

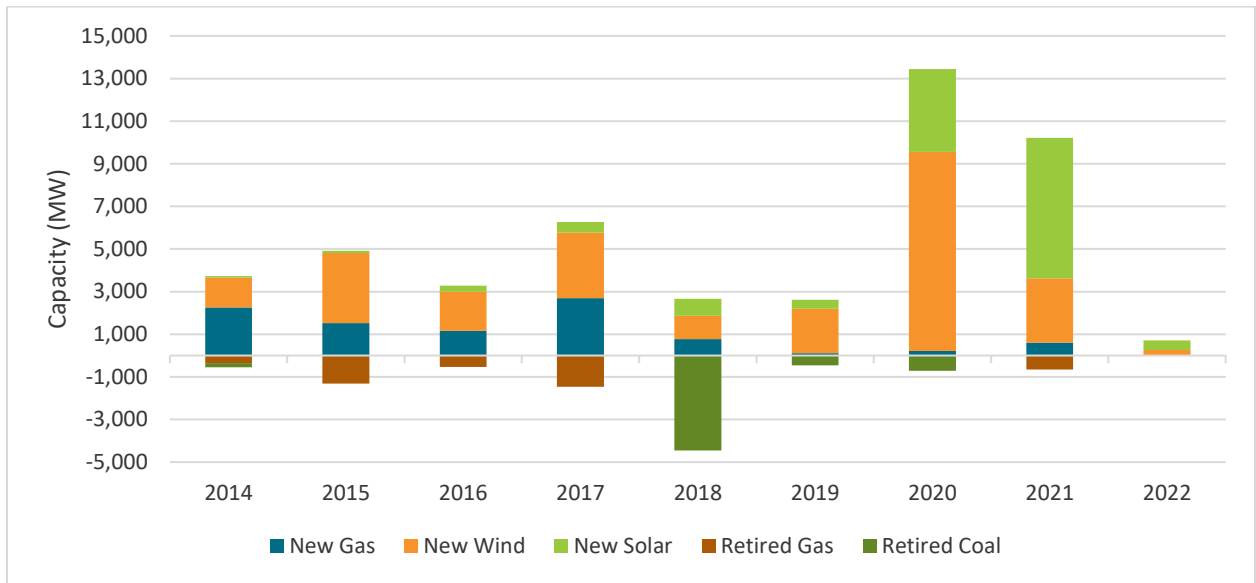
Exhibit 1-6. ISO/RTO averaged monthly average real-time energy market price (\$/MWh) [21]



Values in legend indicate the range between the lowest and highest prices in each respective region.

The generation capacity changes to date and projected changes within ERCOT from 2014 to 2022, are shown in Exhibit 1-7. Wind and natural gas capacity compose the majority of new generating capacity in ERCOT, while solar generation saw steady relative growth. In 2017, ERCOT added more than five gigawatts (GWs) of new capacity, with 57 percent coming from variable renewable energy (VRE) sources. In 2020, more than 13 GW of new capacity will be added with more than 98 percent being VRE. Coal has been the largest capacity on a fuel type basis that has been retired to date with an additional 650 MW of coal-fired capacity scheduled to be retired on October 1, 2020. Apart from coal, about 3.7 GW of natural gas has also retired from 2014 to 2019 with 804 MW of natural gas-fired capacity currently scheduled to be retired by late 2021.

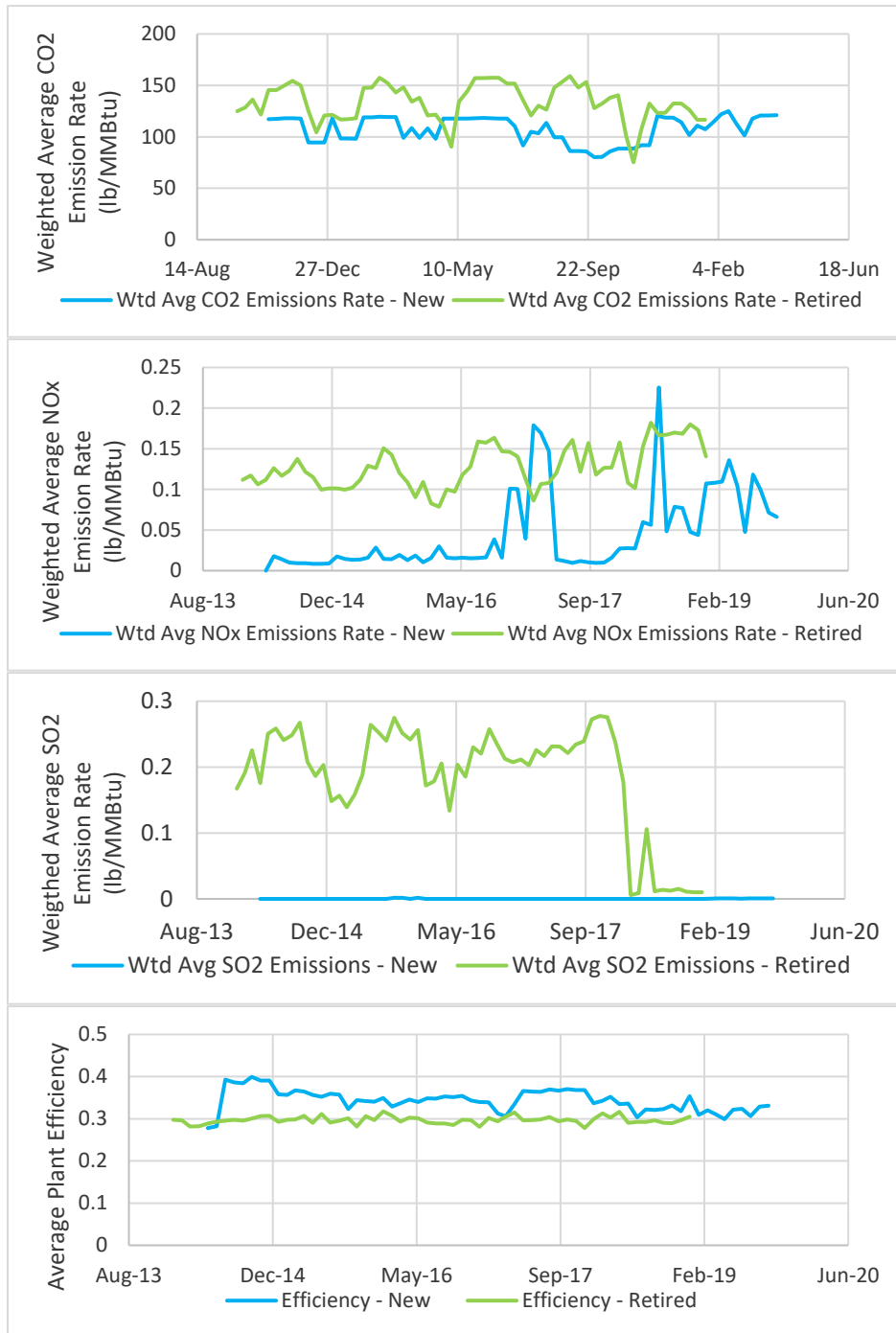
Exhibit 1-7. ERCOT generation capacity changes and projection changes from 2014 to 2022 [22]



Note: Negative capacity indicates retirement, while positive capacity indicates addition

The following plots further compare the fossil fired generation fleet between the new generation on-line and retired generation within the last five years. The top three plots of Exhibit 1-8 show that newly added natural gas capacity emission rates are much less than that of the retired capacity. The newly added generators have a zero-emission rate for sulfur dioxide (SO₂) for most months since 2014. With higher emission rate capacity retiring and lower emission rate natural gas capacity and VRE coming on-line, overall emissions in ERCOT are declining. The very bottom plot of Exhibit 1-8 shows the efficiency comparison between newly added and retired generation in ERCOT. Newly added generators have a higher average efficiency than retired generators from July 2014 to December 2018. Note that the retired plants (red curve) stops at December 2018 because all retired power plants had ceased generation by December 2018.

Exhibit 1-8. ERCOT new vs retired (retired before 2019) thermal generation plant emission performance and efficiency [21]



There are other factors behind the retirement of at least one of these plants, the Big Brown plant owned by Vistra Energy Corp. As part of a planned merger with Dynegy, Inc., Vistra was directed by PUCT in PUCT Control No. 47801 to divest itself of at least 1,281 MW of generation to avoid market power concerns. In order to comply, Vistra chose to market three natural gas

plants and to market, or retire, in the absence of a buyer, the two units, total 1.2 GW, coal-fired Big Brown plant. [23] [24]

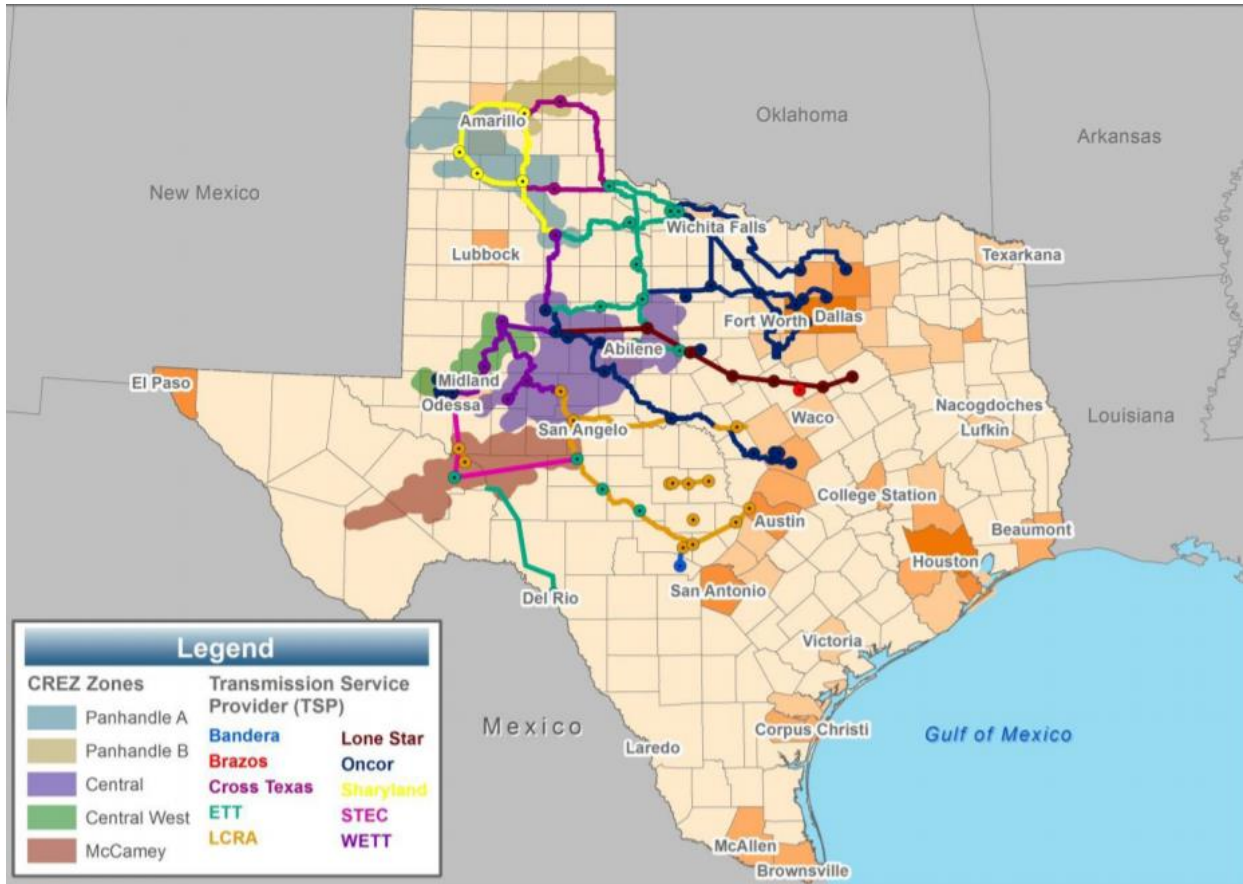
Since the majority of new generation in ERCOT's queue is either natural gas, wind, or solar, as discussed above, the decline in wholesale power prices is being driven by the dynamics of increased natural gas-fired generating capacity, low natural gas prices, and subsidized wind power. [16] In the view of ERCOT's independent market monitor (IMM), Potomac Economics, lower wholesale power prices are proof that market competition is working, and that less efficient, higher-cost generation is being driven out of the market in favor of lower-cost generation. [16] [17]

A 2017 report by IHS Markit offers a different assessment of the state of ERCOT's energy market. IHS Markit asserts that subsidizing the cost of renewable generation is distorting the market, causing the share of wind generation to exceed its cost-effective level. [25] The study argues that wind output is disproportional to the ERCOT demand curve, which means wind generates more power while demand and market clearing prices are lower. With subsidies, it distorts the wholesale energy prices and even causes negative prices in ERCOT.ⁱ On the other hand, major transmission projects have been built to transmit renewable-generated power, and the cost of those projects is not accounted for in wholesale energy prices.

One of the largest transmission investment projects in Texas was the establishment of Competitive Renewable Energy Zones (CREZ). In 2005, Texas Senate Bill 20 was passed requiring the design of a transmission plan to deliver wind generation from windy, but less populated CREZ in West Texas, to end-users in Texas demand centers (Exhibit 1-9). The CREZ transmission projects were completed in 2014 and are able to accommodate 18.5 GW of electricity flow with approximately 3,600 circuit miles of 345-kilovolt (kV) transmission lines. The total project cost was around \$6.9 billion. [26] After the completion of the CREZ transmission projects in January 2014, wind curtailment dropped to 0.5 percent from 17 percent back in 2009, but with more and more proposed wind and solar generation projects in the queue, congestion could possibly return as these projects enter service if transmission constraints return. Benefitting from federal and state subsidies, including the wind production tax credit (PTC), an additional total of about 23.1 GW of wind capacity has been proposed, with more than 8 GW of wind generation having signed interconnection agreements (IAs) with posted financial security and slated to come online in 2020, as shown in Exhibit 1-10; however, only 3.5 GW is approved for synchronization, as of the time of writing. [27] Because of the intermittent nature of wind generation, ERCOT optimistically expects to receive a 63% contribution from coastal projects, 29% from projects in the Texas panhandle, and 16% from projects elsewhere in the state, based on the historical performance of existing projects during average weather conditions. [3] This means that ERCOT only plans for 637 MW from this 3.5 GW (18%) and potentially less, if conditions approach those projected in the SARA low wind scenario.

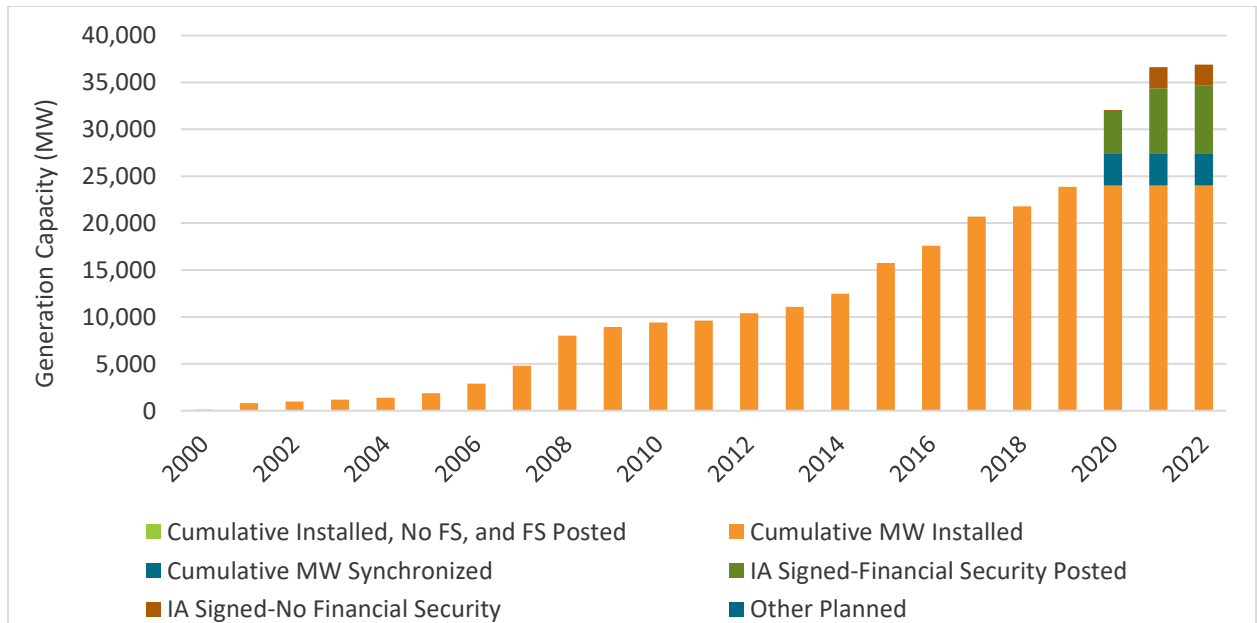
ⁱ A November 2019 study by authors from Lawrence Berkeley National Lab concluded that the frequency of negative prices in the ERCOT West region has ranged from below 2% to nearly 10% across the period covering 2011 to 2017. [44]

Exhibit 1-9. CREZ and projects (2014)



Used with permission from ERCOT [28] [26]

Exhibit 1-10. ERCOT wind generation cumulative and proposed capacity (MW) with IA signed (as of April 13, 2020) [29]



PTC is a production-based credit for the first 10 years of a wind generation project's operation. It was set at 1.5 cents per kilowatt-hour (kWh) in 1992 and is indexed to inflation so it is now worth 2.5 cents per kWh pre-tax in 2019. [30] This is close to some wholesale electricity prices in the United States. [31] The Department of the Treasury has estimated PTC to be the most expensive energy-related tax credit, and 47th most expensive overall, under the U.S. tax code, with \$1 to 4 billion in credits forecast annually from 2020 to 2029, for a total of nearly \$34 billion.^j [32] Wind capacity beginning construction after December 31, 2019, no longer qualifies for the credit under the phase-out and sunset provisions set by Congress in late 2015.

While traditional generation resources receive some federal subsidies, they are not as substantial as the PTC. With the PTC, wind generation is able to bid into the market at prices lower than its true cost, thereby undercutting other forms of generation. IHS Markit estimates that without subsidized wind, the market clearing price in ERCOT during peak periods would have been about one-third higher in 2014. Although IHS Markit does not state that wind subsidies are the cause of plant retirements in ERCOT, this price change would be large enough to change the economic calculation for recently retired coal- and gas-fired generating units. [25]

For solar energy, the Solar Investment Tax Credit (ITC) is a significant subsidy to support the growth of solar energy in the United States. The ITC was created and enacted in 2006 with the passage of the Energy Policy Act of 2005. Since then, solar energy has grown rapidly, with average annual growth of 50 percent over last decade. After the multi-year extension passed by Congress in 2015, ITC provides a 30 percent tax credit for investment in an eligible solar residential or commercial property that began construction by 2019. Commercial solar projects that begin construction in 2020, 2021, or 2022 will get a 26, 22, or 10 percent tax credit, respectively. For residential solar projects, the same tax credits apply for projects that begin construction in 2020 or 2021. [33] The Department of the Treasury has estimated that the ITC will provide a total of almost \$27 billion in credit from 2020 to 2029.^k [32]

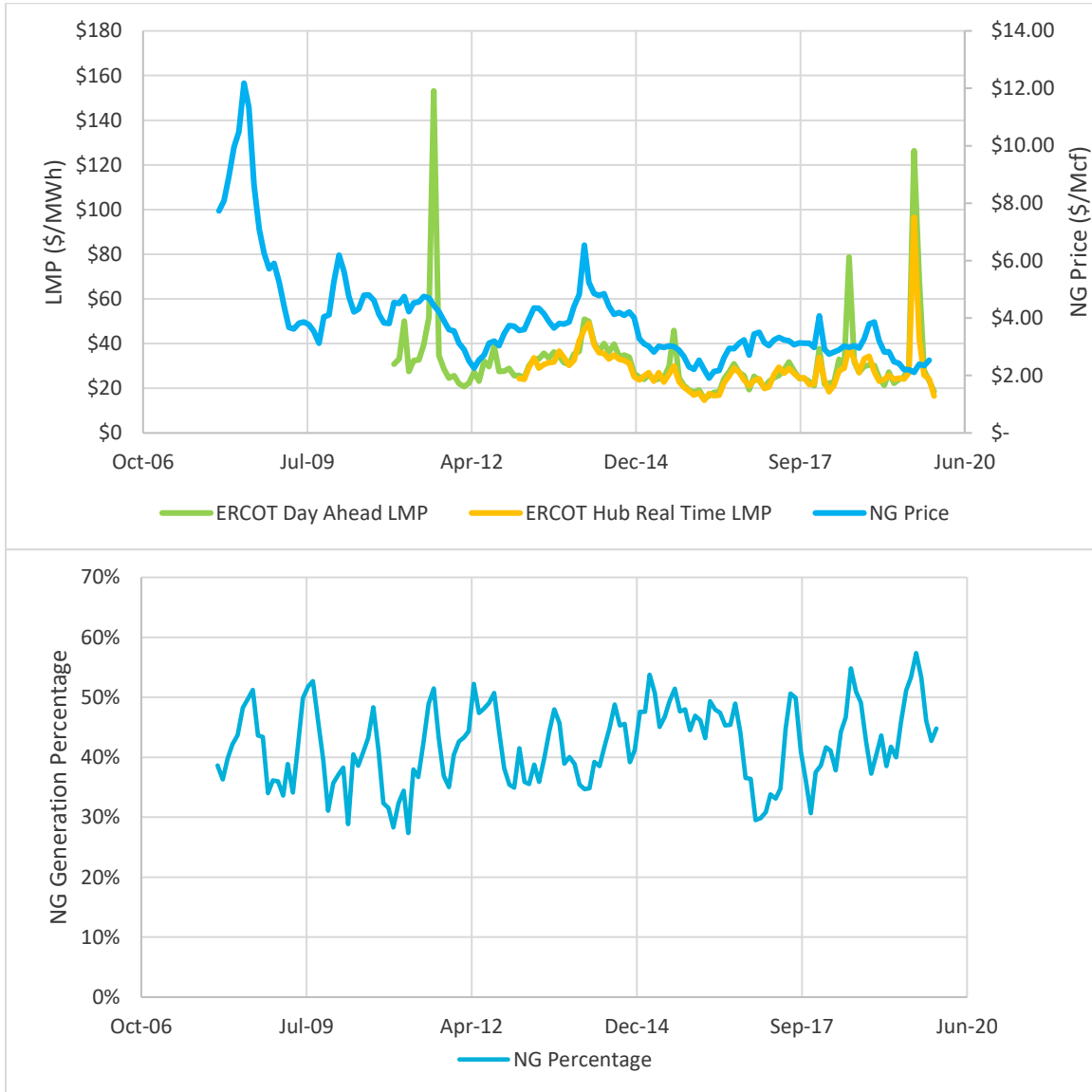
Low natural gas price is also a major driver for the decreasing wholesale power price ERCOT. The top plot of Exhibit 1-11 shows the correlation between natural gas price, day ahead, and real-time LMP in ERCOT. The natural gas price curves and LMP curves have similar trends and fluctuations except for a few LMP summer spikes. The bottom plot of Exhibit 1-11 shows the monthly natural gas generation percentage, on a MWh basis as a percentage of all energy generated in ERCOT in each month. As seen in the plot, ERCOT relies heavily on natural gas-fired electricity generation, with more than 50 percent of natural gas in summer. ERCOT's IMM, Potomac Economics, also points out that natural gas prices have and will continue to be a primary driver for the electricity prices. [17] With coal plants retirement and new natural gas plants added in the ERCOT power grid, the electricity price in ERCOT might become more volatile and experience larger price fluctuation. This is because coal prices are historically more stable than natural gas, and natural gas price fluctuations can lead to unstable LMP prices. Unlike other regions of the nation where natural gas price volatility often drives the highest

^j For comparison, the much more politicized and publicly visible Earned Income Tax Credit and Student Loan Interest deductions are projected at \$52 billion and \$24 billion, respectively, over the same period.

^k For an additional comparison the nearly \$61 billion value of the combined ITC and PTC exceeds the combined total of all other energy-related tax credits and deductions by more nearly \$16 billion. [32]

spikes in LMP seen throughout the year, spikes in ERCOT are primarily driven by increased demand during the summer cooling season. [34]

Exhibit 1-11. ERCOT monthly natural gas price compares to monthly hub average real-time and day ahead market LMP (top) and ERCOT monthly natural gas generation percentage (bottom) [21]



Source: ABB Velocity Suite and EIA

Not everyone shares IHS Markit’s perspective on the impact these price distortions have on ERCOT’s market. A Greentech Media article published in June 2018 argues that ERCOT has saved customers billions by not developing a capacity market, while also maintaining resource adequacy and transitioning to cheaper sources of electricity. [35] The article acknowledged that ERCOT would be operating with tight reserves in Summer 2018, but maintained that ERCOT had enough operating tools to manage a situation where peak load might come close to exceeding

available capacity. In fact, Texas did not suffer from any energy emergency events during Summer 2018, and in 2019, only two EEA1 events occurred on August 13 and 15.

ERCOT has defined EEA levels and procedures to utilize operational tools and send out alert communications when reserve is low to maintain system reliability. ERCOT uses physical responsive capability (PRC) as a trigger for EEA. [36] [37] PRC represents the grid’s response time to disturbances from online generating and load resources. The real-time PRC is published on the ERCOT System Ancillary Service Capacity Monitor page.¹ The EEA trigger criteria and corresponding operation for each level are shown in Exhibit 1-12. In Summer 2011, with the severe heat wave, ERCOT issued EEA1 six times and EEA2 twice. As stated in the previous section, ERCOT issued EEA1 twice in Summer 2019.

Exhibit 1-12. ERCOT EEA matrix

| Emergency Level | Trigger Criteria | Grid Operation | Other Operation |
|------------------------|--|--|---|
| Control Room Watch | PRC < 2,500 MW with no expectation to recover within 30 minutes (mins) | <ul style="list-style-type: none"> Issue “Watch” to ERCOT Market Participants Release non-spinning reserves | <ul style="list-style-type: none"> Notify PUCT and Texas RE Provide update to ERCOT board |
| EEA1 – Power Watch | PRC < 2,300 MW with no expectation to recover within 30 mins | <ul style="list-style-type: none"> Issue EEA 1 to ERCOT Market Participants Import energy from DC tie Implement 30-minute ERS Deploy responsive reserve Launch TDSP load management program | <ul style="list-style-type: none"> Contact utility Update grid condition on social media and update app status Release news if appropriate |
| EEA2 – Power Warning | PRC < 1,750 MW with no expectation to recover within 30 mins or frequency below 59.91 Hz for more than 15 mins | <ul style="list-style-type: none"> Issue EEA 2 to ERCOT Market Participants Deploy demand response resource Deploy remaining ERS Instruct transmission service provider to use voltage reduction Begin block load transfer to other grids | Same as above |
| EEA3 – Power Emergency | PRC < 1,000 MW with no expectation to recover within 30 mins or frequency below 59.91 Hz for more than 15 mins | <ul style="list-style-type: none"> Issue EEA 3 “Rotating Outages” to ERCOT Market Participants Instruct transmission operators for load shedding | Same as above |

In addition to internal generation resources, ERCOT can utilize direct current (DC) ties to import energy from neighboring systems. There are two DC ties between ERCOT and the Southwest Power Pool (SPP) and three DC ties between ERCOT and Mexico’s state-owned electric utility, Comisión Federal de Electricidad. The combined DC ties allow the import of up to 1,250 MW to help ERCOT manage tight reserves. [38] There are also switchable generation units on the

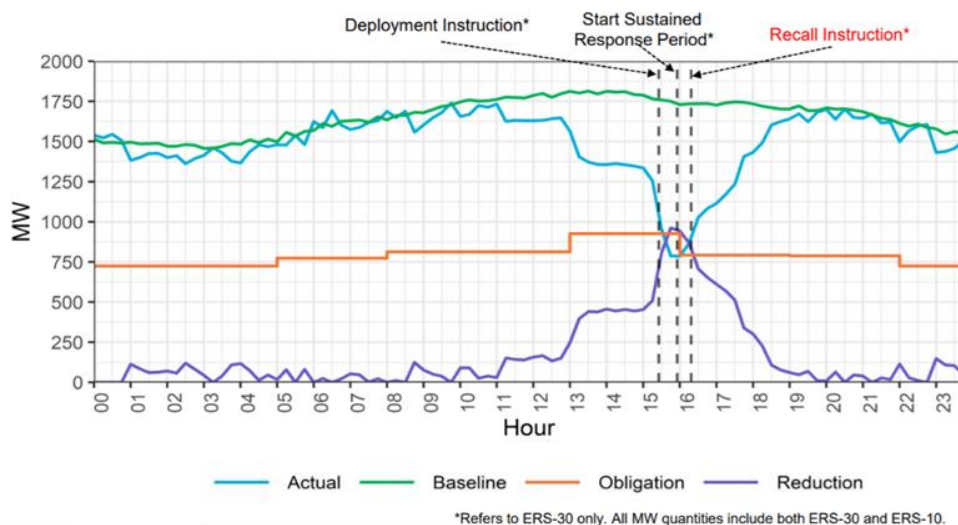
¹ http://www.ercot.com/content/cdr/html/as_capacity_monitor.html

border of the ERCOT grid that can provide electricity to ERCOT, if needed. These switchable units serve customers in SPP or the Midcontinent ISO but maintain an operating agreement with ERCOT allowing ERCOT to request assistance from these units during an energy emergency.

ERCOT procures Emergency Response Services (ERS) three times annually (for four-month service) to help avoid load shedding during a grid emergency. Qualified loads and generators can offer to provide ERS to ERCOT through their qualified scheduling entities. ERCOT publishes the procurement results on their website.^m As an example, for Time Period 4 (17:00 to 19:00) from February 1 to May 31, 2019, ERCOT procured 825 MW of non-weather sensitive 30-minutes response time ERS from 361 load resources and 26 generation resources. [39]. These generation and demand response resources can help ERCOT avoid a load shedding event during energy emergency situations.

Demand response is an ability from the load side to reduce or shift electricity consumption when the price is high or when the reliability of the grid is endangered. Customers who are capable of demand response can participate in ERCOT's market in three ways. The first is to become an ERCOT Load Resource to participate in ERCOT's day-ahead energy market, real-time energy market, or ancillary service market. The second is to participate in ERCOT ERS (as described above). The last method is to opt into the transmission or distribution utility's demand response program. On August 13, 2019, the ERCOT EEA 1 announcement day, ERS were deployed as shown in Exhibit 1-13 to ease the emergency condition.

Exhibit 1-13. ERCOT ERS deployment on August 13, 2019



Used with permission from ERCOT [15]

In ERCOT, price responsive load may not receive proper price benefit of their load shifting action because the load zone settlement point prices are the average of 5-minute bus locational marginal prices (LMP) during the 15-minute period. The payment of retail load is to multiply 15-minute energy by the 15-minute settlement point price. This calculation will cause disconnection when load demand's response action is based on 5-minute price. For example,

^m <http://www.ercot.com/services/programs/load/eils/>

Exhibit 1-14 lays out a theoretical example of price responsive and non-price responsive load scenarios with identical total electricity usage. With the current ERCOT settlement calculation, the options result in the exact same amount of electricity cost during this 15-minute period, indicating there is no benefit for demand response. In the demand response scenario, load should be paying only \$15,000 (300 kWh times \$50/kWh), which is half of the cost shown in Exhibit 1-14.

Exhibit 1-14. Demand response scenarios and calculations

| Scenario | 0-5 minute (\$125/kWh) | 5-15 minute (\$125/kWh) | 10-15 minute (\$50/kWh) | 15-minute (kWh) | Price | Cost |
|-----------------|------------------------|-------------------------|-------------------------|-----------------|-----------|----------|
| Demand Response | 0 kWh | 0 kWh | 300 kWh | 300 kWh | \$100/kWh | \$30,000 |
| Flat Demand | 100 kWh | 100 kWh | 100 kWh | 300 kWh | \$100/kWh | \$30,000 |

ERCOT realized that demand response load is not receiving proper benefits and planned to address it by integrating telemetry signals for 5-minute energy usage data. An extra credit or charge would be created by multiplying 5-minute energy by 5-minute LMP. This credit or charge would be applied to an ERCOT Balancing Account. By fixing this problem, it helps to attract more responsive loads and the current responsive loads to respond better to real-time market price. [40]

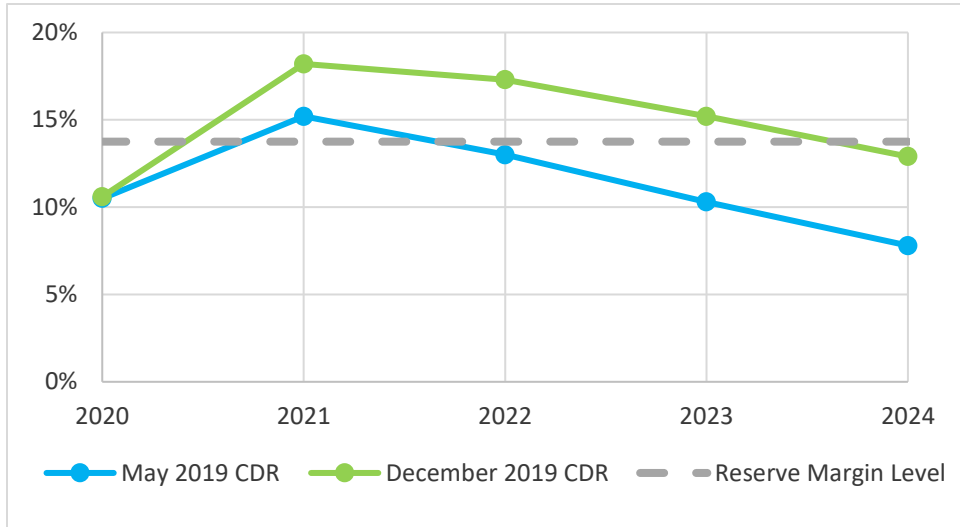
Another point made by the Greentech Media article is that there is uncertainty around the correct reserve margin. [35] Utility standard for decades has been to plan to a one day in ten years’ LOLE. However, LOLE events are rare enough that it is difficult to determine what level of reserves are necessary to prevent such an event. This is especially true now that transmission operators have increasingly sophisticated tools at their disposal for managing load, including demand response and interruptible load. A 2014 paper by Brattle suggested that to plan for the 1-in-10 LOLE standard, ERCOT needed a reserve margin of 14.1 percent, although in its consideration, the economically optimal reserve margin was 10.2 percent. [10] Under the 10.2 percent reserve margin scenario, ERCOT could still meet a 24-hours in 10 years loss of load hours (LOLH) standard (e.g., 2.4 hours in a given year). Under such a standard, an LOLE event is unlikely to be a sustained system-wide blackout, but controlled rolling outages that leave individual customers without power for several minutes. [10]

There is potential for several EEA events in ERCOT during Summer 2020 due to the low capacity reserve. ERCOT plans to utilize its operational tools and ask consumers for voluntary conservation to manage the operation during these EEA events. Once all resources are deployed, ERCOT can instruct transmission or distribution providers to initiate rotating outages to protect the entire grid. However, it is not clear whether these tools will be sufficient.

Exhibit 1-15 shows the summer reserve margin forecast beyond 2020 based on ERCOT CDR. The reserve margins will have a sudden increase in 2021 (around 5 percent and 8 percent for the May and December 2019 CDR respectively), and then steadily decrease under both curves. The increase in 2021 is caused by new planned resources. The majority of those resources are

renewable—about 5 GW of solar and 2 GW of wind. After the generation surge in 2021, there are few generation increases but steady load growth, which results in reserve margin decline. Even though the reserve margin is decreasing after 2021, it will stay above the NERC reserve margin level of 13.75 percent until 2024 according to the latest CDR forecast. Note that it is typical for generation developers to submit interconnection requests up to two to four years before the plan in-service dates. Therefore, CDRs will report little planned capacity beyond four years, and planning reserve margin will always decrease as long as load growth is positive.

Exhibit 1-15. Reserve margin estimation by ERCOT CDR from 2020 to 2024 [13]



2 ERCOT SUMMER SCENARIOS

ERCOT releases several resource adequacy assessments throughout the year, with the primary assessments being the SARA and the CDR. SARA releases are seasonal, with the Preliminary Summer 2020 SARA released in March prior to the domestic impacts of COVID-19 and collapse of oil prices due to the breakdown of OPEC+. [3]ⁿ The summer SARA includes scenarios with a range of potential risks, including typical maintenance and forced thermal outages, extreme forced outages, low wind output, and a peak load adjustment accounting for extreme weather. In order to evaluate these scenarios, data was evaluated from a variety of sources, including the preliminary summer SARA, the most recent CDR, and ERCOT performance data from 2019. The SARA predicts a peak demand of 76,696 MW. This prediction is based on normal weather conditions and does not account for higher-than-average temperatures. [13] Data from ERCOT performance during Summer 2019 was used to develop wind generation profiles.

Using this data, four scenarios were developed using ABB’s PROMOD IV to assess the LOLE event risk to ERCOT for Summer 2020, as shown in Exhibit 2-1. Generation in the model was updated using the generation available in the December 2019 CDR.^o Model peak loads were updated to match information in the SARA. The Base scenario uses the SARA Summer 2020 peak load estimate. The Thermal Forced Outages (“Outages”) scenario adds the thermal forced outages in the SARA to peak load, under the assumption that typical thermal forced outages are outages that should be expected on a typical summer weekday.^p Unlike maintenance outages, forced outages are not planned and cannot be postponed under an emergency situation. This scenario gives a picture of the expected change between available capacity (shown in Exhibit 2-2) and peak load under normal weather conditions. The Extreme Weather Seasonal Load (“Extreme Weather”) scenario assumes an extreme weather event similar to what happened in 2011 in the ERCOT region. The Past Wind scenario substituted 2019 ERCOT summer hourly wind generation for the wind generation profiles in PROMOD and uses the same peak load from the extreme weather scenario. These new wind generation profiles were used when calculating dispatch using the Extreme Weather scenario peak loads, to provide a picture of generation performance with wind generation experienced in 2019. The use of the 2019 ERCOT summer hourly wind profile, in place of the existing wind profiles in PROMOD results in wind generation on the same scale, with different periods of high and low production. The result is the frequency of these shifts from high to low is slightly lower in the 2019 ERCOT data, compared to the existing wind profiles. The lower frequency of shifts results in slightly longer periods of high and low production, with some of those low points being lower than the output using the existing profiles by 100–300 MW, while the average hourly output for the study period remains

ⁿ While this text was in review, ERCOT issued its final SARA for the 2020 Summer which projects a peak load 1,496 MW less than the preliminary SARA. [45]

^o PROMOD model data is created using provided ABB interconnection model and updated using available information from regulatory filings and other sources. Model thermal and renewable generation was updated to match summer as closely as possible using available information.

^p Since specific generator forced outages cannot be predicted and a random selection would impact the network congestion component of the dispatch, the outage totals were added to the demand side, since a shift in the overall supply curve or a shift in the demand curve have the same net effect toward obtaining the marginal generation cost.

within 55 MW in each scenario. These four scenarios are used in PROMOD to provide a simulation of generation and load for the summer season.⁹ PROMOD uses the updated peak loads, along with past hourly demand, to generate future hourly demand estimates. Historic renewable production data and data from National Renewable Energy Laboratory is used by ABB to provide the profiles used to estimate wind and solar generation on an hourly basis. These factors combine to create an hourly estimate of available capacity in the model.

Exhibit 2-1. Peak load under scenarios

| Scenario | Peak Load (MW) |
|-----------------|----------------|
| Base | 76,696 |
| Outages | 80,727 |
| Extreme Weather | 83,979 |
| Past Wind | 83,979 |

Exhibit 2-2. Available generating capacity

| Category | Capacity (MW) |
|---------------------|---------------|
| Thermal* | 71,300 |
| Hydro (Derated) | 460 |
| Wind (Derated) | 7,043 |
| Solar (Derated) | 2,842 |
| DC Ties (Derated) | 854 |
| Interruptible Loads | 2,160 |
| Total Capacity | 84,657 |

*Includes switchable units

As seen in Exhibit 2-1 and Exhibit 2-2, available on-peak reserve generating capacity, including DC ties and interruptible loads called in emergency situations, exceeds load in the Extreme Weather scenario by only 678 MW. The exhibits below show the on-peak reserve capacity of each day compared against the minimum target reserve margin of 13.75 percent. The reserve capacity is the available capacity at each hour, minus the total load at that hour. Exhibit 2-3 through Exhibit 2-6 show the results of the PROMOD runs. Exhibit 2-7 shows the number of days on-peak reserve capacity fell below Reference margins, EEA event thresholds, and zero, in each scenario. In only the first two scenarios, ERCOT is expected to have sufficient reserves capacity to meet peak load. In the Extreme Weather scenario, on-peak reserve capacity dips below zero for five days. In the Past Wind scenario, on-peak reserve capacity dips below zero for three days during the end of July and beginning of August. The magnitude of the shortfall in August is over 5 GW. ERCOT considers any period where reserves fall below 1,000 MW and an EEA Level 3 is triggered to be a loss of load event, regardless of whether reserves remain above zero. By this metric, the simulations indicate a predicted LOLE of eight days in the Extreme Weather scenario, and three days in the Past Wind scenario. Exhibit 2-7 summarizes the EEA events that result in each scenario.

⁹ June 1 through September 30.

Exhibit 2-3. Base scenario (76,696 MW peak)

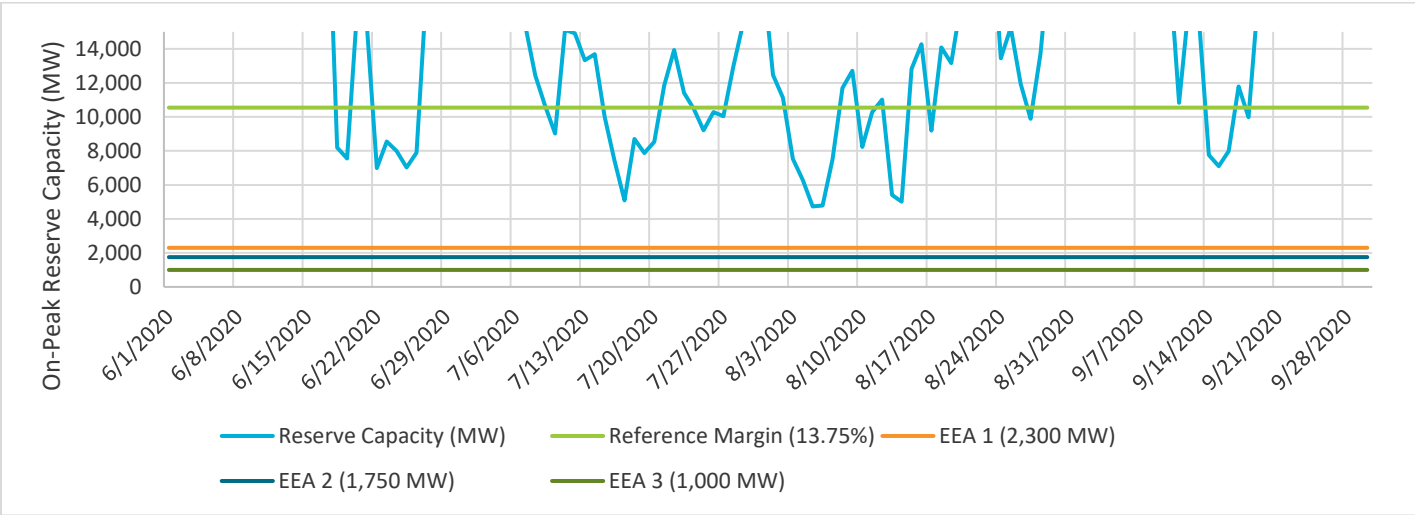


Exhibit 2-4. Base + Outages (80,727 MW peak)

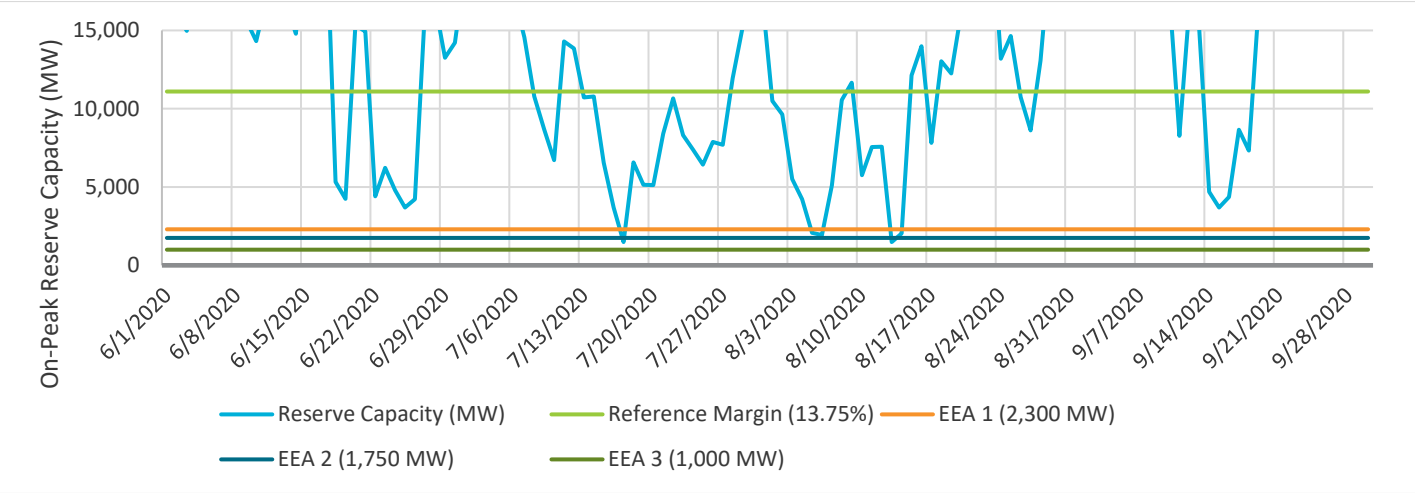


Exhibit 2-5. Base + Outages + Extreme Weather (83,979 MW peak)

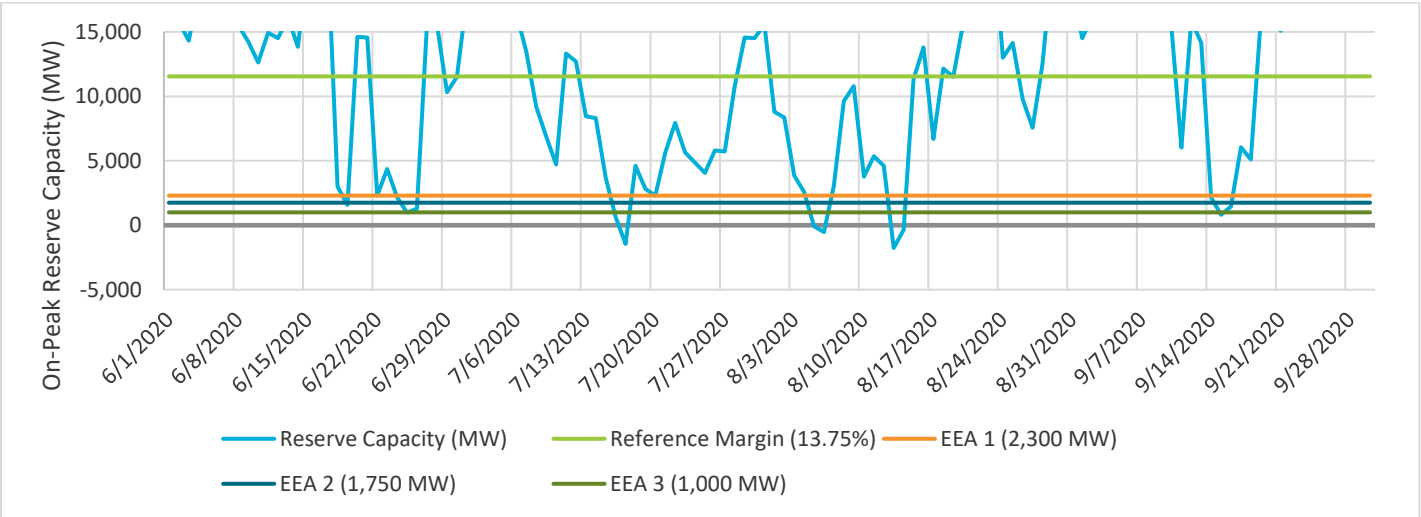


Exhibit 2-6. Base + Outages + Extreme Weather + Past Wind (83,979 MW peak)

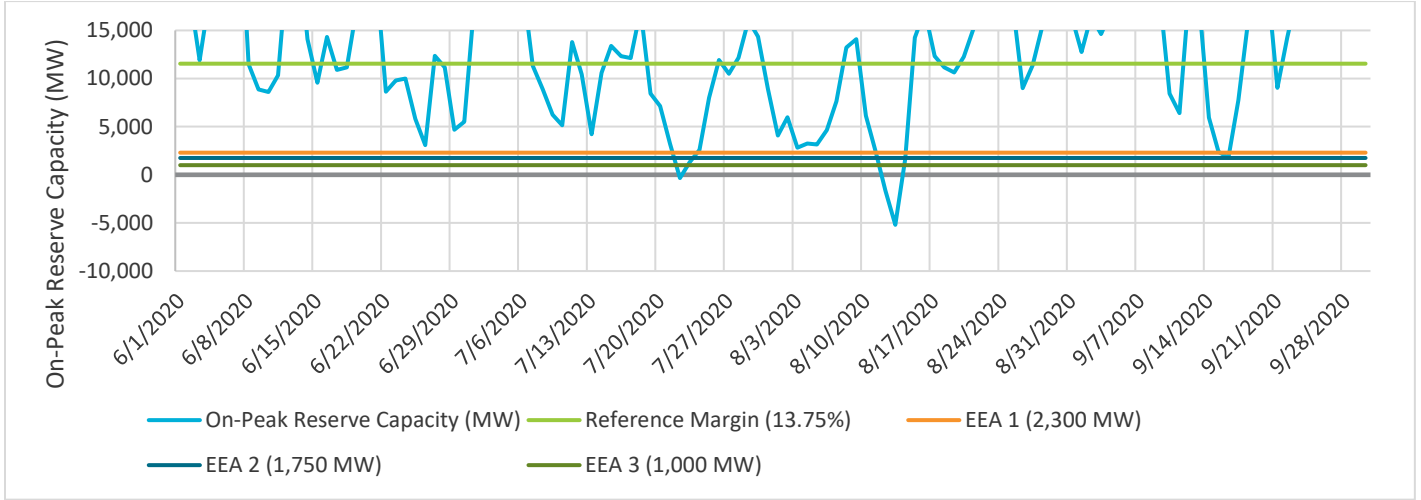


Exhibit 2-7. Number of days with reserve shortfall under four modeled scenarios

| Scenario | Reference Margin | EEA 1 | EEA 2 | EEA 3 |
|-----------------|------------------|-------|-------|-------|
| Base | 33 | 0 | 0 | 0 |
| Outages | 47 | 5 | 2 | 0 |
| Extreme Weather | 53 | 15 | 11 | 8 |
| Past Wind | 54 | 6 | 5 | 3 |

3 SUMMARY

ERCOT is continuing to face a test of both its operating system and its energy-only market. As discussed in Section 1, the ERCOT market has successfully functioned to date. While annualized wholesale prices have declined and emissions have decreased, summer seasonal prices have increased and with higher price spikes. Going into Summer 2020, however, the energy-only market is contending with a low reserve margin, caused by a number of generating capacity retirements in 2017, delays in new capacity projects coming online since 2018, and continued strong load growth in West Texas and other areas in the ERCOT region. ERCOT will have to rely on other tools until the reserve margin returns to levels where there is less risk of EEA. Even with those tools, the market construct implemented by ERCOT runs the risk of higher energy prices and situations that trigger EEAs in the Summer of 2020.

The PROMOD scenarios described in Section 2 suggest that ERCOT could make it through the summer season without an LOLE event, as long as the weather remains normal, even though ERCOT will be well below its minimum target reserve margin. If demand in the region reaches potential peak levels, escalated for extreme weather, problems could arise on the system. ERCOT could then find itself operating in emergency conditions during the height of the summer peak demand season, which is usually the end of July through mid-August. Should these conditions occur, ERCOT will need to call on its operating tools to maintain reliability and continue serving load, and those measures alone may not be sufficient to avert a shedding of load. However, if the demand profiles that ERCOT is currently seeing due to COVID-19 continue, where daily peaks have been 2 percent lower and overall energy demand has been 4–5 percent below normal, the region may not see peak summer demand at levels that require emergency actions to be taken. The energy-only market, combined with subsidized renewables and cheap natural gas prices driving out other forms of generation, may result in lower wholesale energy prices than other market models that pay for capacity, but it may also be taking greater reliability risks.

Post-Script (5/29/2020): Without reconducting the simulations and simply applying the changes between ERCOT's preliminary and final SARAs as a post-process adjustment, indicates that the results may change slightly with some days changing their EEA severity. It does not, however, indicate that events may not occur this summer, only that their frequency and level of severity may be reduced, with EEA 3 events still projected to occur in the Extreme Weather and Past Wind Scenarios.

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