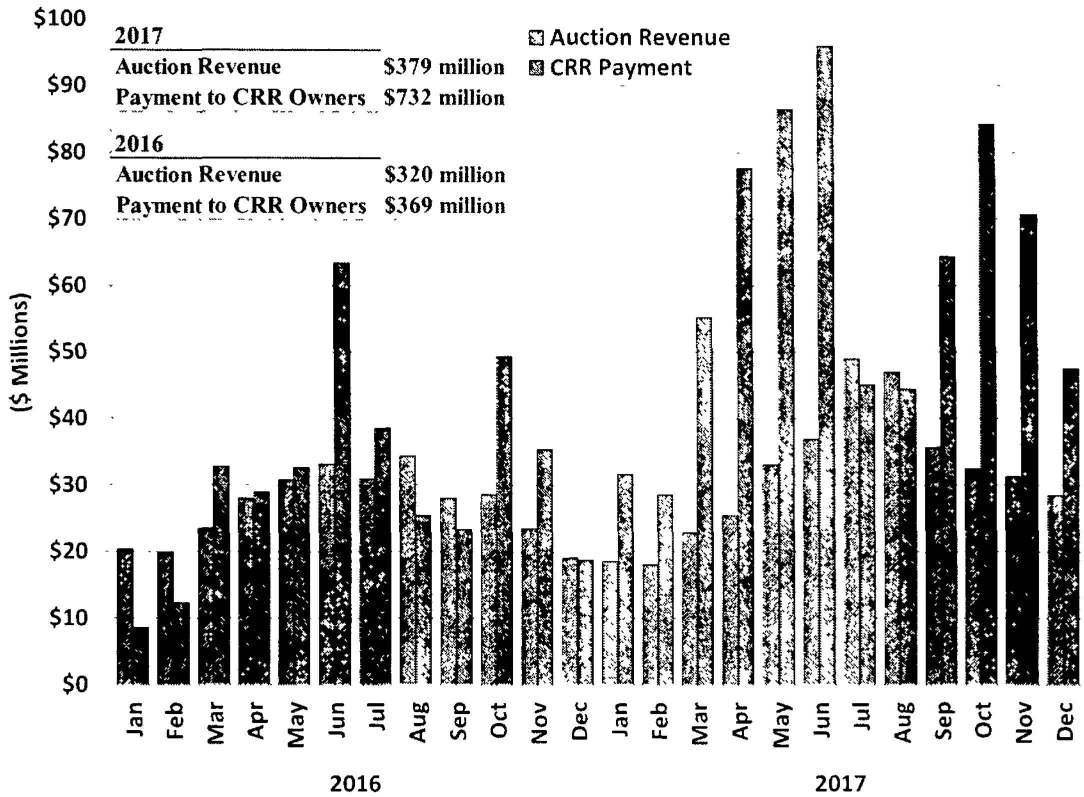
$397 million in 2017 from $320 million in 2016, the total PCRR discount decreased from $70 million in 2016 to $50 million in 2017, similar to the PCRR discount in 2015.

CRR Profitability

Next, Figure 51 compares the value received by CRR owners (in aggregate) to the price paid to acquire the CRRs.

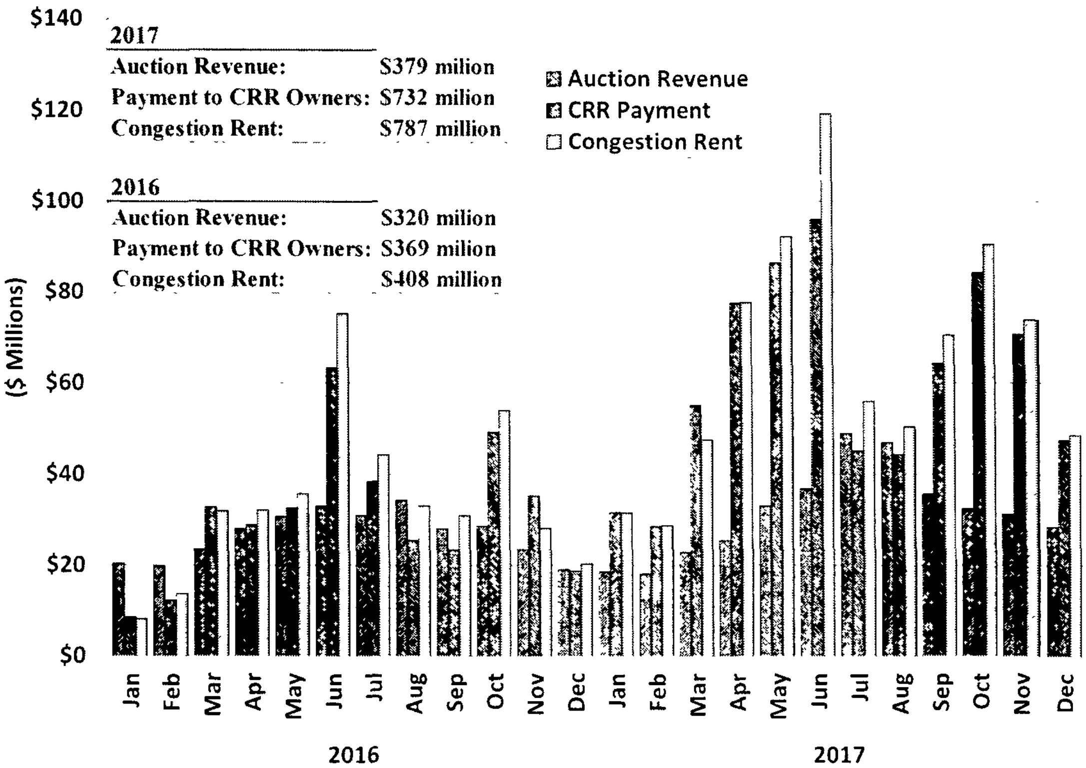
Figure 51: CRR Auction Revenue and Payment Received



Although results for individual participants and specific CRRs varied, the aggregated results for the year and in most months show that participants paid much less for CRRs in 2017 than they received in payment from the day-ahead market. For the entire year of 2017, participants spent $379 million to procure CRRs and received almost twice as much at $732 million. In general, this difference occurred because the substantial increase in congestion that occurred in 2017 was not foreseen by the market. There were two significant periods of congestion that account for this difference: March through June and September through December. In both cases, transmission outages related to construction of new facilities contributed to the substantial unforeseen increases in congestion.

The next analysis of aggregated CRR positions adds day-ahead congestion rent to the picture. Day-ahead congestion rent is the difference between payments and charges of three-part offers, energy only offers, energy only bids, PTP obligation bids, and PTP obligation bids linked to options in day-ahead market.[30] Day-ahead congestion rent creates the source of funds used to make payments to CRR owners. Figure 52 presents CRR auction revenues, payment to CRR owners, and congestion rent in 2016 and 2017, by month. Congestion rent for the year 2017 totaled $787 million and payment to CRR owners was $732 million.

Figure 52: CRR Auction Revenue, Payments and Congestion Rent



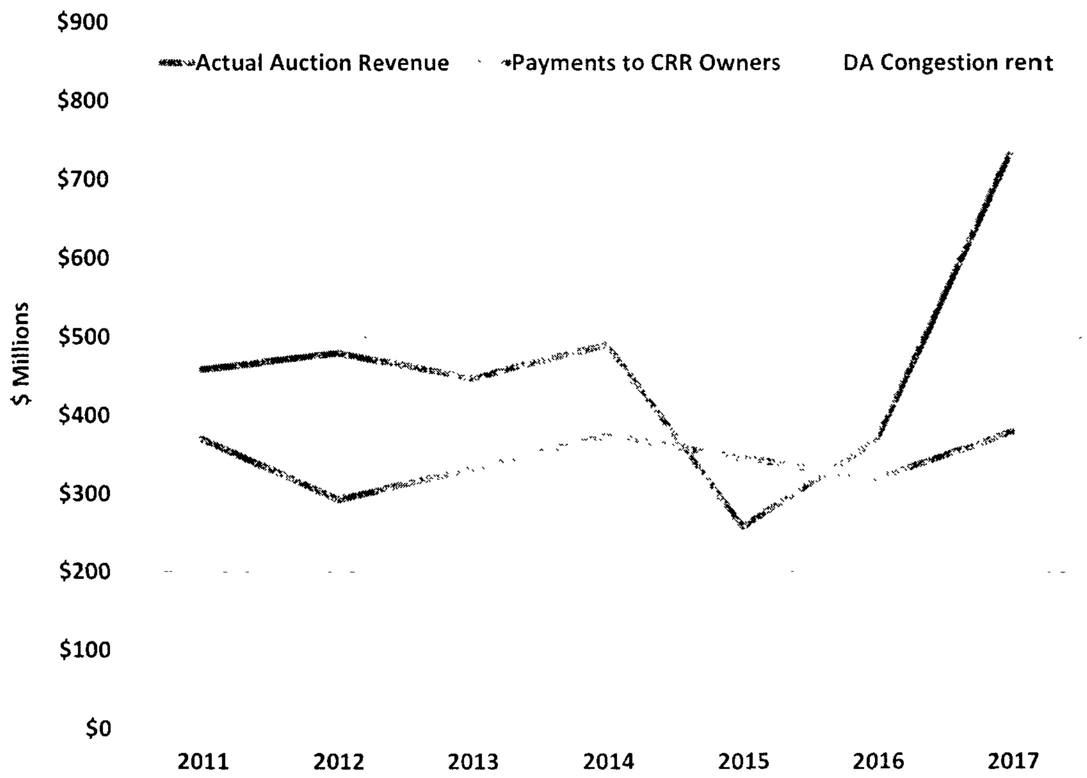
It is worth noting that because the CRR network model uses line ratings that are 90% of the expected lowest line ratings for the month, it is expected that CRRs would be somewhat undersold and that day-ahead congestion rent would be higher than the payment to CRR owners. This indeed was the case in 2017, where payments to CRR owners was 93% of day-ahead congestion rent. In 2016, this ratio was 90%.

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

Figure 53 provides the annual history of these three CRR related values: auction revenues, reflecting the costs paid by owners to obtain the CRRs; Payments to CRR Owners, reflecting the payments received by CRR Owners; and Day-Ahead Congestion rent, which is the funding source for most CRR payments. In 2017, owners of CRRs in aggregate made a substantial profit on their CRR holdings. Payments to CRR owners in 2017 were almost double the total cost paid to acquire the CRRs. As we discuss above, this was primarily due to unanticipated factors that led to significantly higher congestion in 2017. The figure shows that this was not the case in recent years. In 2015, CRR Owners were paid less than the total cost paid to obtain them. In 2016, it appears that CRR Owners made a small profit, but the cost to obtain the CRRs reflects the discounted amounts that NOIEs paid to obtain PCRRs. Adding the NOIE discount to the auction revenue in 2016 would show CRRs, in aggregate, to be unprofitable.

Another item to note from these historical values is the relatively flat auction revenue. The costs paid to acquire CRRs varied in a narrow range between $300 and $400 million per year since the start of the nodal market. This may imply that aggregate CRR profitability is less dependent on CRR Owners making acquisition decisions based on sophisticated analysis, and more likely driven by the vagaries of annual transmission congestion patterns.

Figure 53: CRR History



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CRR Funding Levels

The target value of a CRR is the megawatt amount of the CRR multiplied by the locational marginal price (LMP) of the sink of the CRR less the LMP of the source of the CRR. While the target value is paid to CRR account holders most of the time, there are two circumstances that cause ERCOT to pay less than the target value (i.e., CRRs are not fully funded). The first circumstance happens when the CRR is modeled on the day-ahead network and causes a flow on a transmission line that exceeds the line's limit. In other words, the transmission capability assumed in the CRR market is ultimately higher than in the day-ahead market, which can occur because of outages or other factors that reduce transfer capability. In this case, CRRs with a positive value that have a source or a sink located at a resource node settlement point are paid a lower amount than the target value.

The second circumstance occurs when there is not enough day-ahead congestion rent to pay all the CRRs at target (or derated, if applicable) value. In this case, all holders of positively valued CRRs receive a prorated shortfall charge such that the congestion revenue plus the shortfall charge can pay all CRRs at target or derated value. This shortfall charge has the effect of lowering the net amount paid to CRR account holders; however, if at the end of the month there is excess day-ahead congestion rent that has not been paid out to CRR account holders, the excess congestion rent can be used to make whole the CRR account holders that received shortfall charges. If there is not enough excess congestion rent from the month, the rolling CRR balancing fund can be drawn upon to make whole CRR account holders that received shortfall charges.

Figure 54 shows the CRR balancing fund since the beginning of 2015. Even though the amount of the fund was under $10 million in five months of 2015 and two months of 2016, it started 2017 at its capped value of $10 million and was not drawn upon during the year. While there were monthly shortfalls in day-ahead market settlement in 2015 and 2016, a surplus occurred for each month in 2017, and the total day-ahead surplus was $94.45 million. In comparison, the total annual day-ahead market surplus was only $30.85 million and $34.59 million in 2015 and 2016 respectively. Because there was enough day–ahead market surplus after paying out to the CRR owners for each month in 2017, those CRR owners who received a shortfall charge, at the total annual amount of $12.11 million, were fully refunded at the end of each month. From the perspective of the load, the monthly CRR balancing account allocation to load was always positive in 2017 and resulted in a total amount of $90.10 million at the end of the year, which almost offset the real-time revenue neutrality charge to load at the amount of $96.32 million.

Figure 54: CRR Balancing Fund

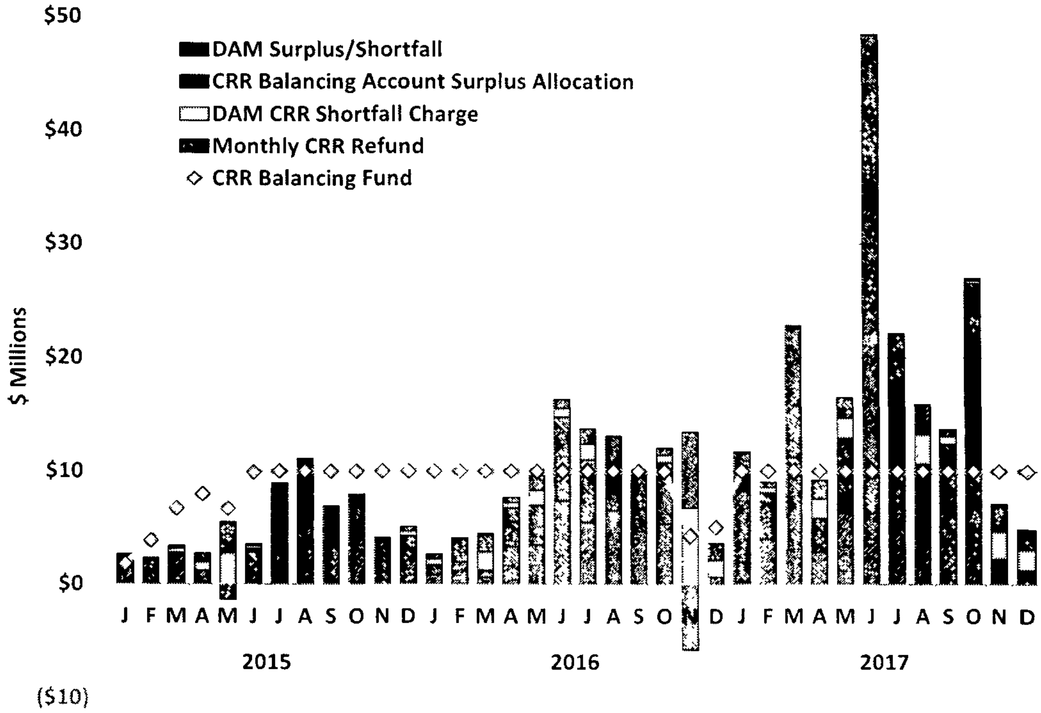
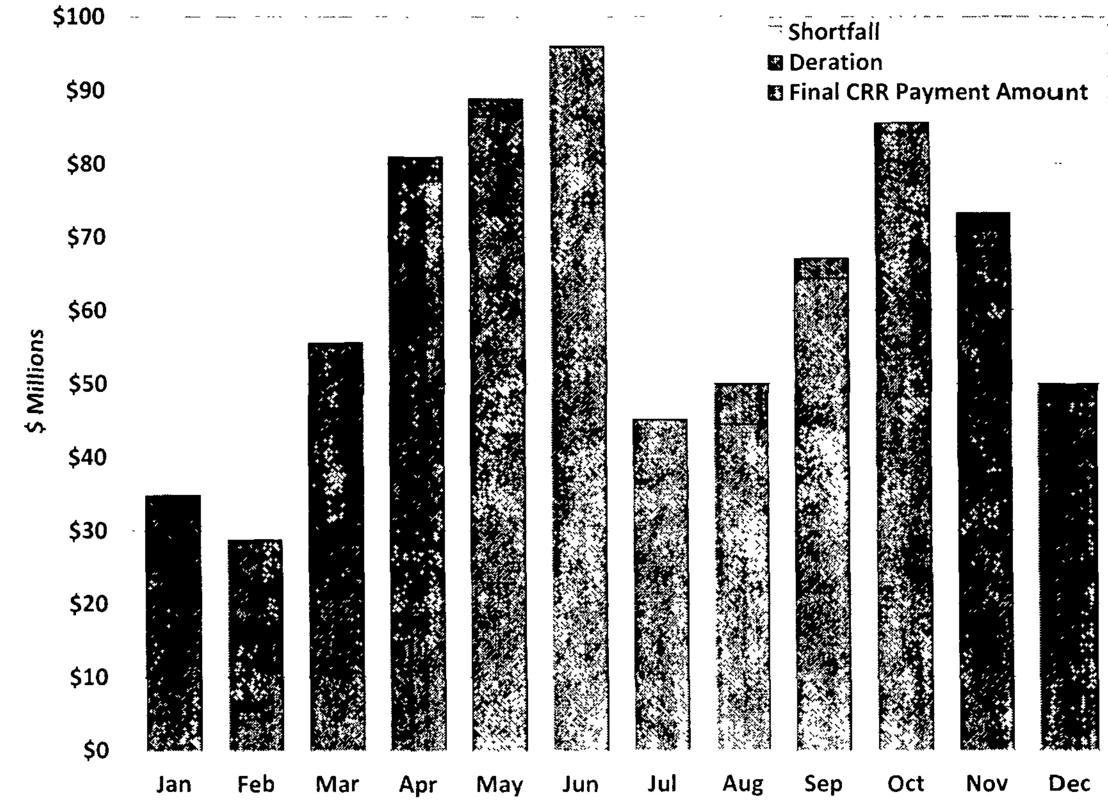


Figure 55 shows the amount of target payment, deration amount, and net shortfall charges (after make whole payments) for 2017. In 2017, the total target payment to CRRs was $756 million; however, there were $24 million of derations and no shortfall charges resulting in a final payment to CRR account holders of $732 million. This final payment amount corresponds to a CRR funding percentage of 97%.

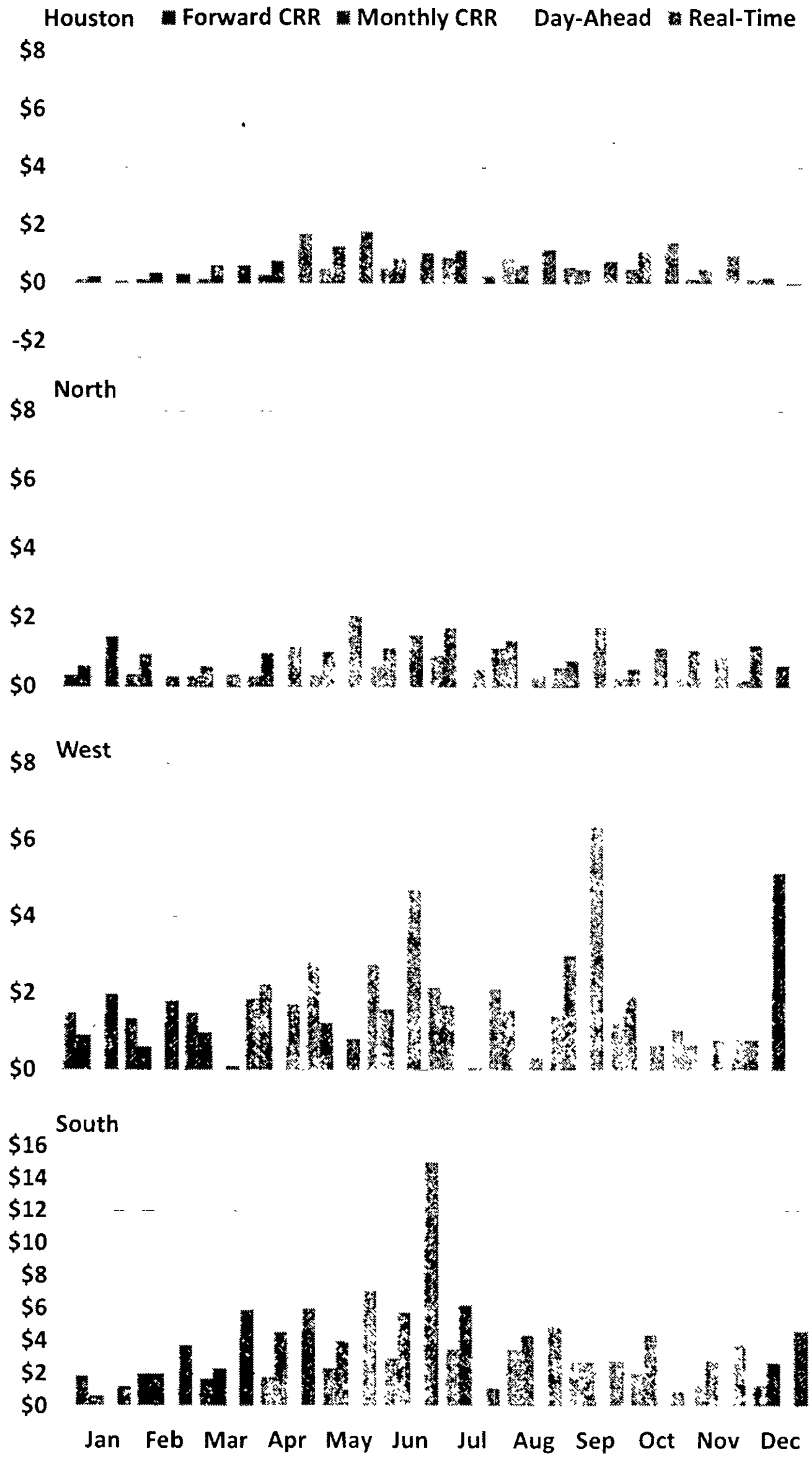
Figure 55: CRR Shortfalls and Derations



The last look at congestion examines the price spreads for each pair of hub and Load Zones in more detail. These price spreads are interesting as many loads may have contracts that hedge to the hub price and are thus exposed to the price differential between the hub and its corresponding Load Zone. Figure 56 presents the price spreads between all Hub and Load Zones as valued at four separate points in time – at the average of the four semi-annual CRR auctions, monthly CRR auction, day-ahead and real-time.

Of note is the relatively poor convergence between the forward CRR price spreads for the West Load Zone and the actual price spreads. This may have been because of the difficulty forecasting the price impacts of variable wind output, or the added uncertainty of whether or not outages associated with ETT's structural maintenance are viable in such wind conditions. The South Load Zone still had the highest hub to zone price spread for the second year in a row, having overtaken the West Load Zone in 2016, likely because of the effects of congestion in the Valley area.

Figure 56: Hub to Load Zone Price Spreads

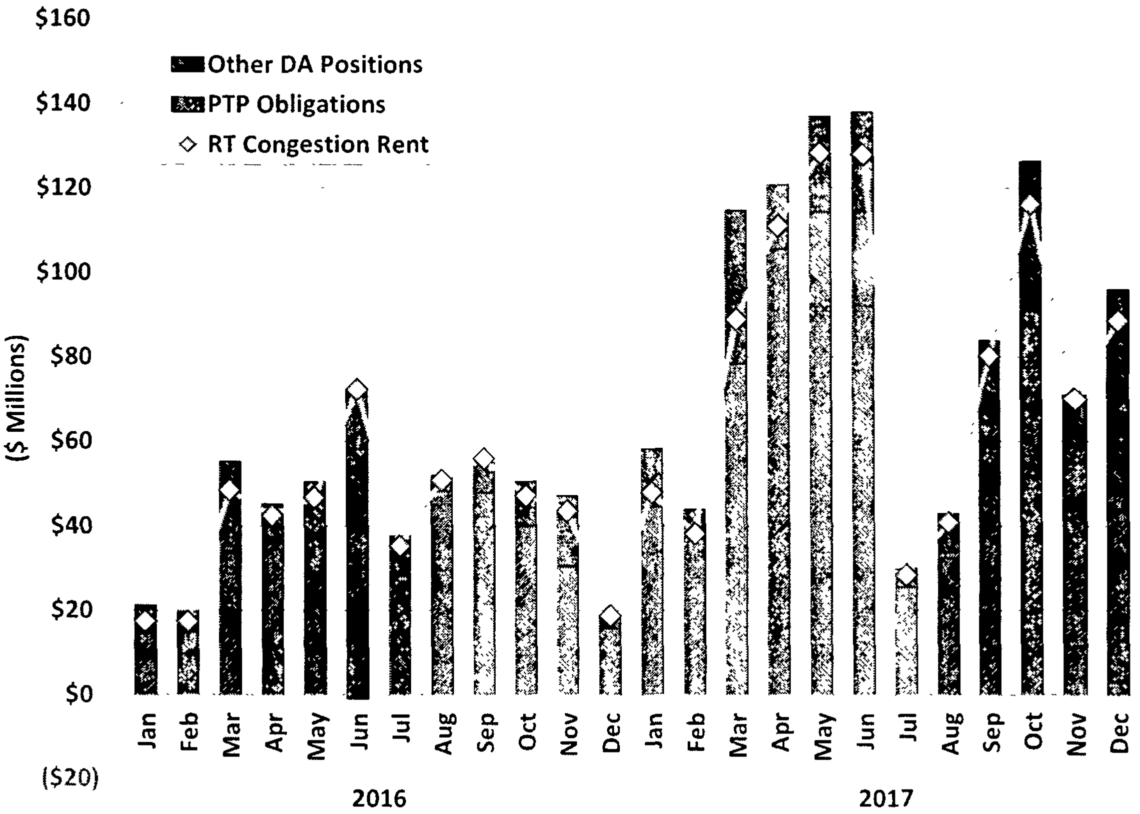


E. Revenue Sufficiency

In Figure 57, the combined payments to Point-to-Point (PTP) obligation owners and effective payments to other day-ahead positions are compared to the total real-time congestion rent. For 2017, real-time congestion rent was $967 million, payments for PTP obligations (including those with links to CRR options) were $812 million and payments for other day-ahead positions were $251 million, resulting in a shortfall of approximately $96 million for the year.

By comparison, the real-time congestion rent was $497 million in 2016. Payments for PTP obligations and real-time CRRs were $437 million and payments for other day-ahead positions were $88 million, resulting in a shortfall of approximately $28 million for the year. This shortfall is paid for by charges to load.

Figure 57: Real-Time Congestion Rent and Payments



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IV. Demand and Supply

This section reviews and analyzes the load patterns during 2017 and the existing generating capacity available to satisfy the load and operating reserve requirements. Specific analysis of the large quantity of installed wind generation is included, along with a discussion of the daily generation commitment characteristics. This section concludes with a review of the contributions from demand response resources.

A. ERCOT Load in 2017

The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric tends to capture changes in load over a large portion of the hours during the year. Separately evaluating the changes in the load during the highest-demand hours of the year is also important. Significant changes in peak demand levels play a major role in assessing the need for new resources. The level of peak demand also affects the probability and frequency of shortage conditions (i.e., conditions where firm load is served but minimum operating reserves are not maintained). The expectation of resource adequacy is based on the value of electric service to customers and the harm or inconvenience to customers that can result from interruptions to that service. Hence, both of these dimensions of load during 2017 are examined in this subsection and summarized in Figure 58.

This figure shows peak load and average load in each of the ERCOT geographic zones from 2015 to 2017.[31] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 36% of the total ERCOT load); the South and Houston zones are comparable (27%) while the West zone is the smallest (10% of the total ERCOT load).

Figure 58 also shows the annual non-coincident peak load for each zone. This is the highest load that occurred in a particular zone for one hour during the year; however, the peak can occur in different hours for different zones. As a result, the sum of the non-coincident peaks for the zones is greater than the annual ERCOT peak load.

31 For purposes of this analysis, Non-Opt In Entity (NOIE) Load Zones have been included with the proximate geographic zone.

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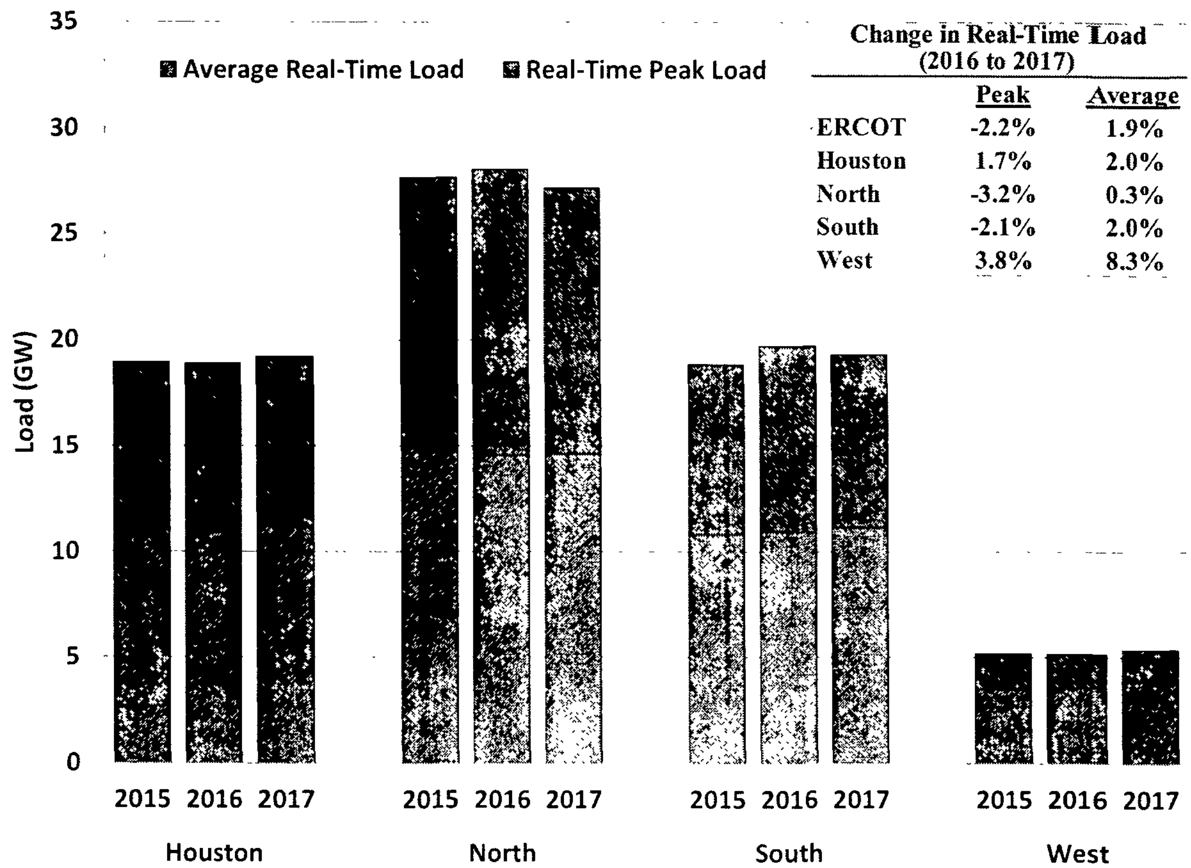
Figure 58: Annual Load Statistics by Zone

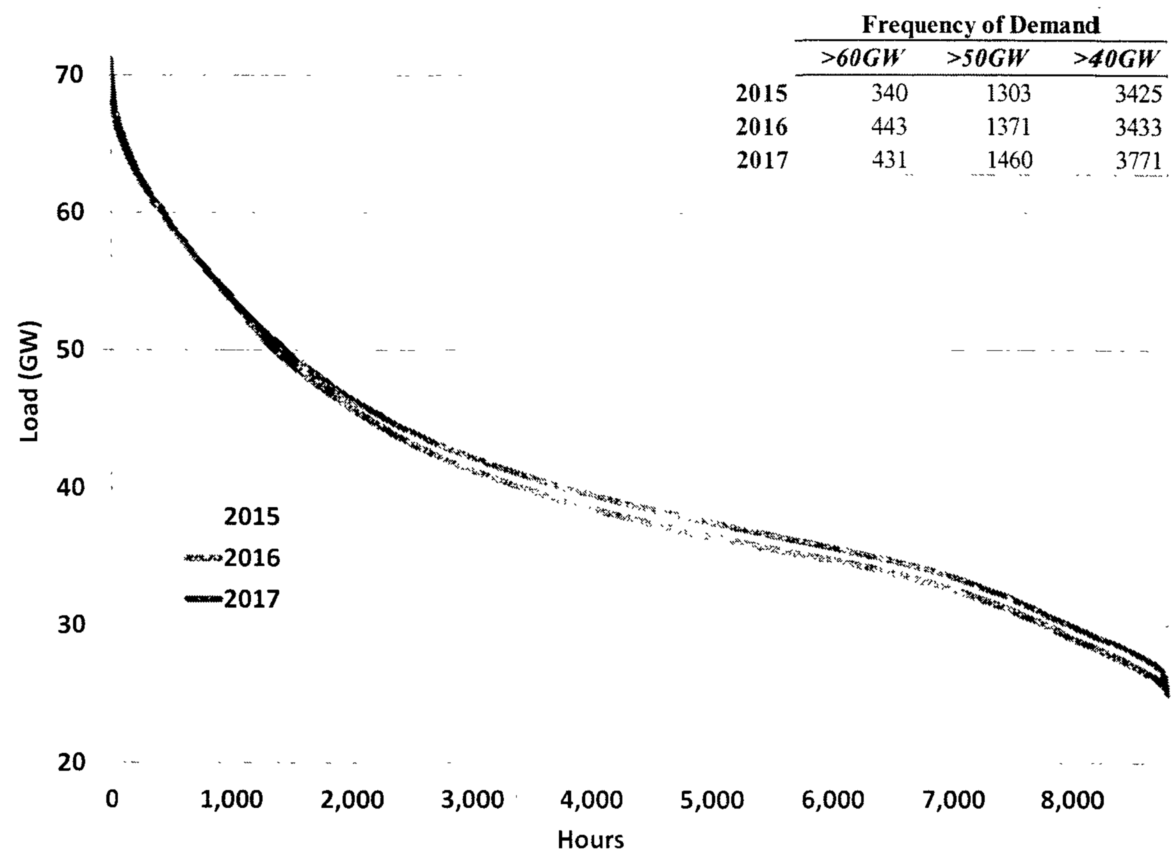


Total ERCOT load in 2017 increased 1.9% (approximately 780 MW per hour on average) to total 357.4 TWh in 2017. All zones showed an increase in average real-time load in 2017. The West zone saw the largest average load increase at 8.3%, which was likely due to continuing robust oil and natural gas production activity. Weather impacts on load in 2017 were mixed. Cooling degree days, a metric that is highly correlated with weather-related summer load, exhibited no change in Houston, decreased in Dallas and increased in Austin as compared to 2016.

Summer conditions in 2017 produced a peak load of 69,512 MW on July 28, 2017, short of the ERCOT-wide coincident peak hourly demand record of 71,110 MW set on August 11, 2016. Further, demand did not ever exceed 70,000 MW in 2017, compared to five separate hours in 2016. The zones experienced varying changes in peak load. The West zone continued to experience the highest percentage growth in peak load, which was likely driven by continuing growth in oil and natural gas production.

To provide a more detailed analysis of load at the hourly level, Figure 59 compares load duration curves for each year from 2015 to 2017. 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 2017 is very similar to 2016 and 2015.

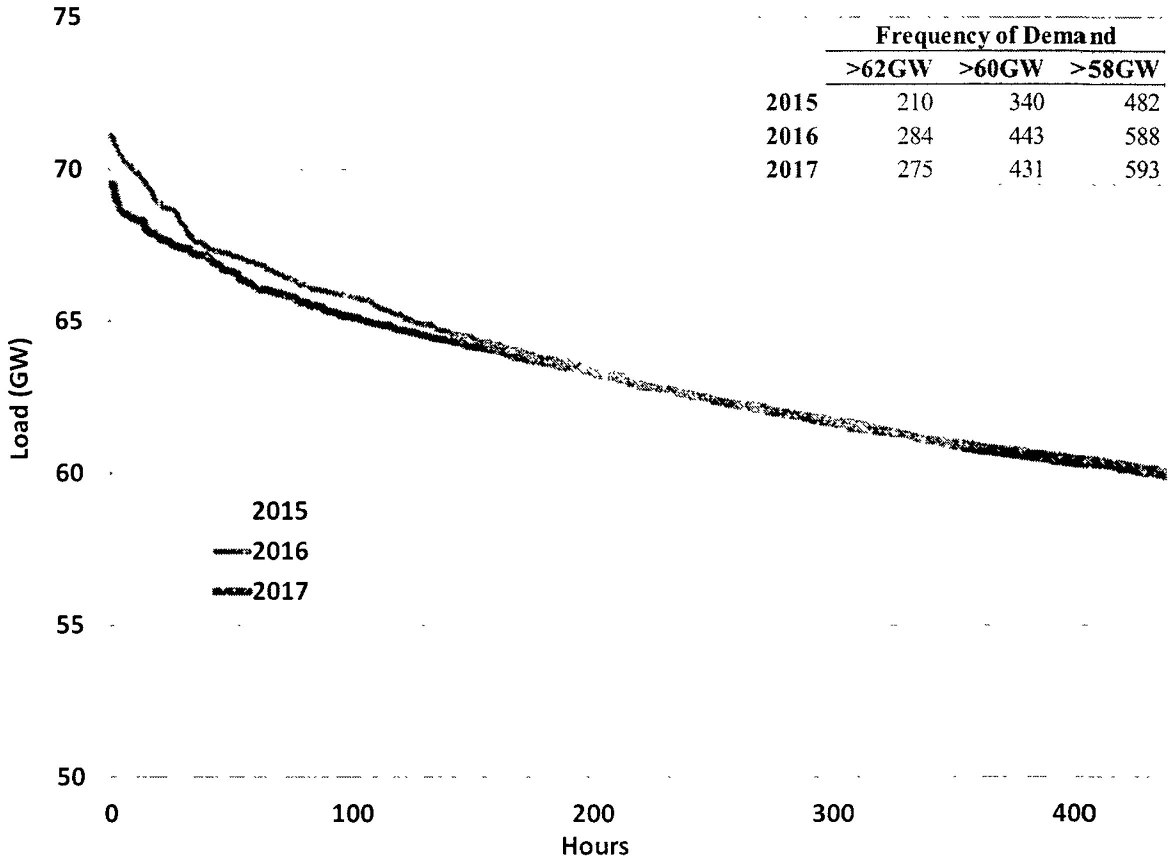
Figure 59: Load Duration Curve – All Hours



	Frequency of Demand		
	>60GW	*>50GW*	*>40GW*
2015	340	1303	3425
2016	443	1371	3433
2017	431	1460	3771

To better illustrate the differences in the highest-demand periods between years, Figure 60 below shows the load duration curve for the five percent of hours with the highest loads. This figure also shows that the peak load in each year is significantly greater than the load at the 95th percentile of hourly load. From 2011 to 2017, the peak load averaged 16% to 18% greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than five percent of the hours.

Figure 60: Load Duration Curve – Top Five Percent of Hours with Highest Load



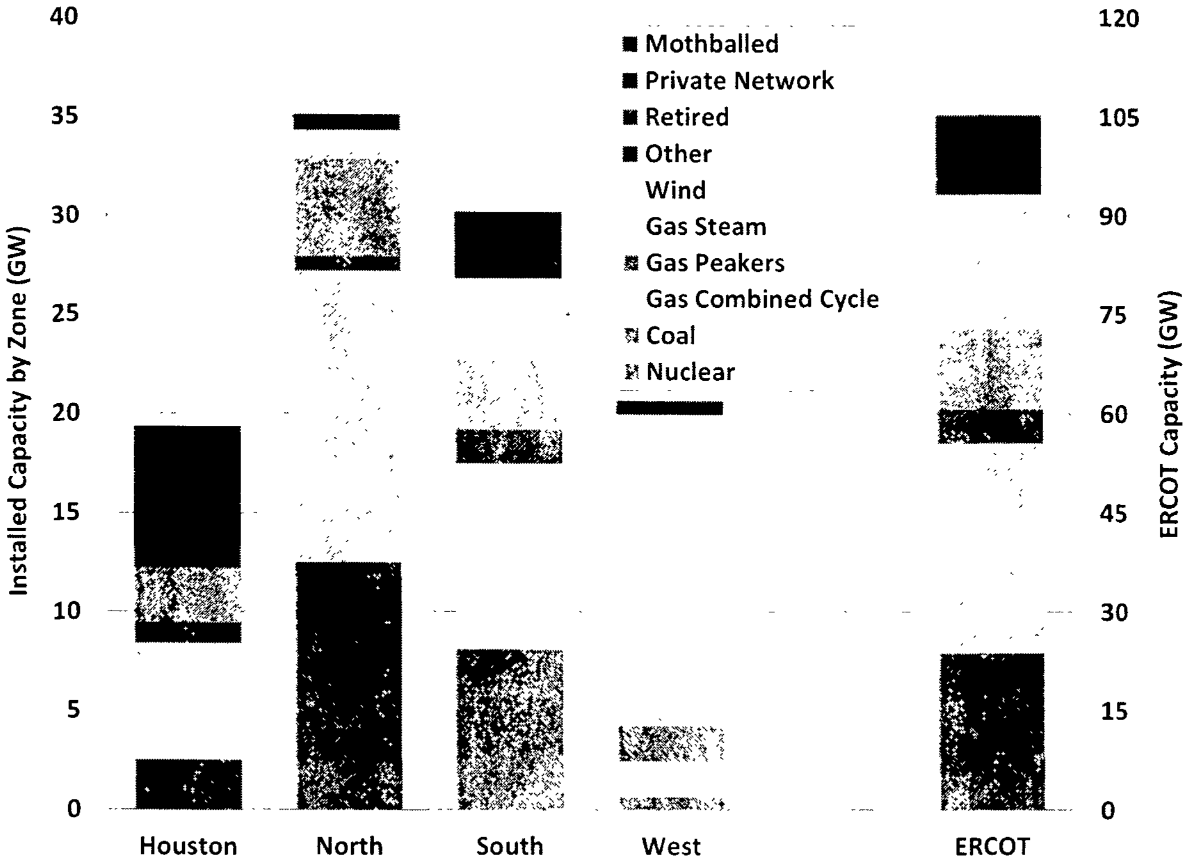
	Frequency of Demand		
	>62GW	>60GW	>58GW
2015	210	340	482
2016	284	443	588
2017	275	431	593

B. Generation Capacity in ERCOT

The generation mix in ERCOT is evaluated in this subsection. The distribution of capacity among the four ERCOT geographic zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West. In 2017, the North zone accounted for approximately 33% of capacity, the South zone 29%, the Houston zone 18%, and the West zone 20%. Excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand,[32] the North zone accounted for approximately 38% of capacity, the South zone 33%, the Houston zone 20%, and the West zone 9% in 2017. Figure 61 shows the installed generating capacity by type in each zone.

[32] The percentages of installed capacity to serve peak demand assume wind availability of 14% for non-coastal wind and 59% for coastal wind.

Figure 61: Installed Capacity by Technology for Each Zone



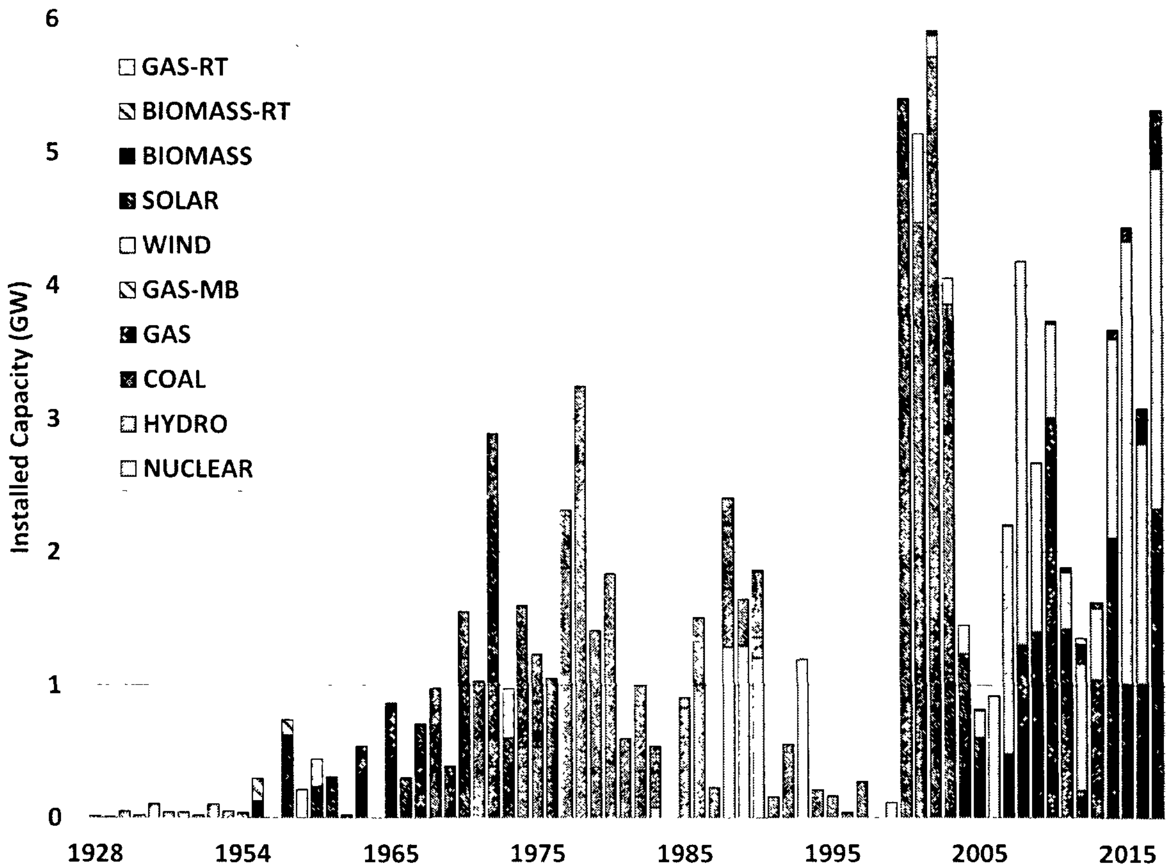
Approximately 3.6 GW of new generation resources came online in 2017; the bulk of which was two new combined cycle natural gas units with total capacity of 2.2 GW. Wind additions totaled 1.1 GW with an effective peak serving capacity of less than 300 MW. The remaining capacity additions were 180 MW of new combustion turbines and 160 MW of solar.

Fourteen generation resources totaling 1,222 MW, consisting primarily of aging natural gas generation, were retired in 2017. Five natural gas units at Calpine's Clear Lake location, totaling 280 MW, were decommissioned and retired on February 1, 2017. Aspen LLC's 45 MW LFBIO_UNIT1 biomass unit was decommissioned and retired as of February 6, 2017. South Texas Electric Cooperative, Inc.'s Pearsall Units 1, 2, and 3, totaling 61 MW of natural gas generation, were decommissioned and retired on August 1, 2017. Union Carbide Corp.'s 30 MW UCC_COGN_UCC_C1 natural gas unit was retired on September 29, 2017. NRG Energy Inc.'s previously mothballed S.R. Bertron natural gas units, totaling 435 MW, were permanently retired and decommissioned on December 31, 2017, as was the 371 MW Greens Bayou 5 natural gas unit, which had previously been deemed necessary for RMR services.

Given these additions and retirements, shares of natural gas and coal capacity did not change significantly in 2017, representing 46% and 18% of installed capacity, respectively.

Figure 62 shows the age of generation resources in ERCOT that were operational in the December 2017 Capacity, Demand, and Reserves Report.[33] The bulk of the coal fleet in ERCOT was built before 1990 and is approaching the end of useful life for this vintage of coal power plants. There was quite a large investment in combined cycle natural gas units in conjunction with deregulation of the ERCOT market. The amount of new combined cycle capacity installed in 2017 was greater than in any year since 2003. A few new coal units were added around 2010. However, wind capacity has been the dominant technology for newly installed capacity since 2006.

Figure 62: Vintage of ERCOT Installed Capacity



The shifting contribution of coal and wind generation is evident in Figure 63, which shows the percentage of annual generation from each fuel type for the years 2011 through 2017.

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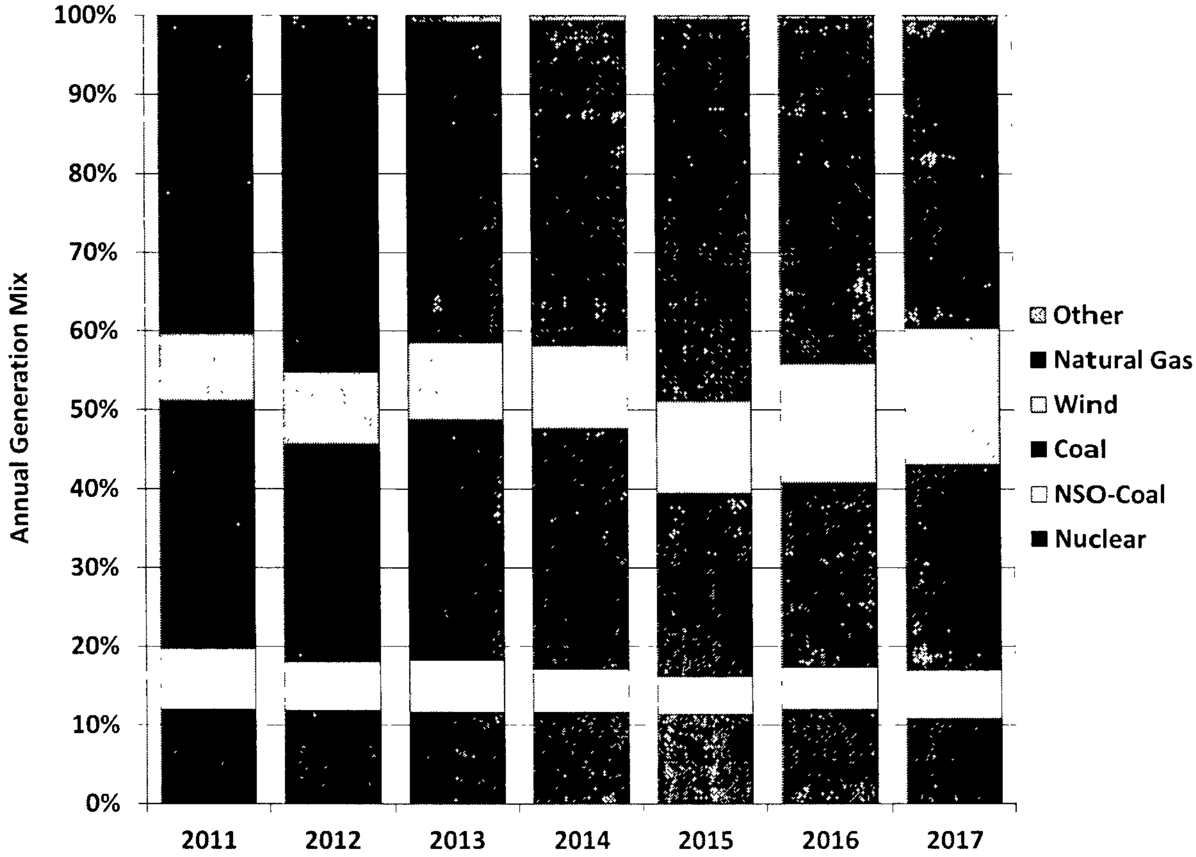
33 ERCOT Capacity, Demand, and Reserves Report (Dec. 2017), available at http://www.ercot.com/gridinfo/resource.

Figure 63: Annual Generation Mix

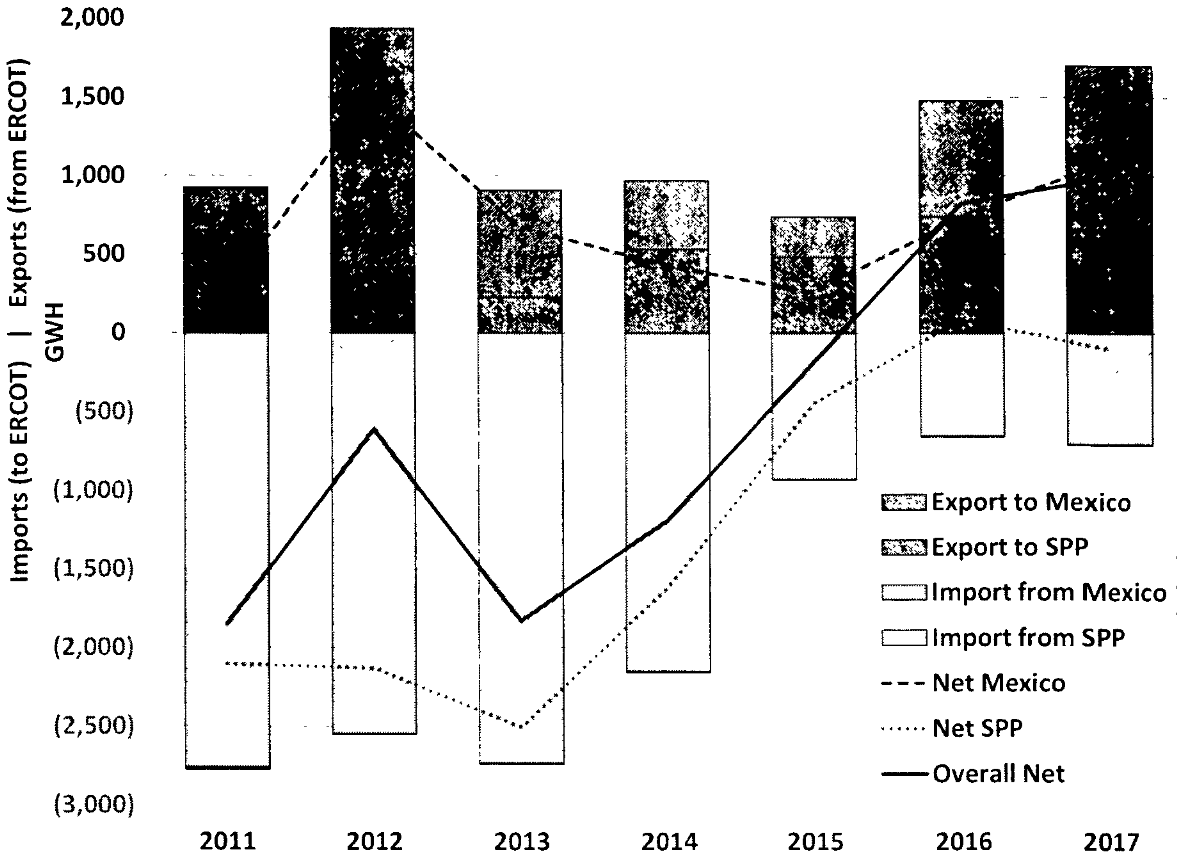


The generation share from wind has increased every year, reaching 17% of the annual generation requirement in 2017, up from 9% in 2011 and 15% in 2016. While the share of generation from coal had declined significantly between 2014 and 2015, its share has increased the last two years, up to 32% in 2017. This figure separately shows the amount of energy provided from coal units that are scheduled to be retired in 2018 (i.e., those that have submitted a Notification of Suspension of Operations or NSO). These seven units have provided an average of 6% of the total annual generation requirements over the past 7 years. Natural gas declined from its high point of 48% in 2015 down to 39% in 2017. This trend should reverse, however, once the coal resources mentioned above retire.

While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There were approximately 24 GW of coal and nuclear generation in ERCOT in 2017. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price.

The ERCOT region is connected to other regions in North America via multiple asynchronous ties. Two ties, totaling 820 MW, connect ERCOT with the Southwest Power Pool (SPP) and three ties, totaling 430 MW, connect ERCOT with Comisión Federal de Electricidad (CFE) in Mexico. Transactions across the DC tie can be in either direction, into or out of ERCOT. These transactions can have the effect of increasing demand (exports) or increasing supply (imports). Figure 64 below shows the total energy transacted across the ties for each of the past several years.

Figure 64: Energy Transacted Across DC Ties in August



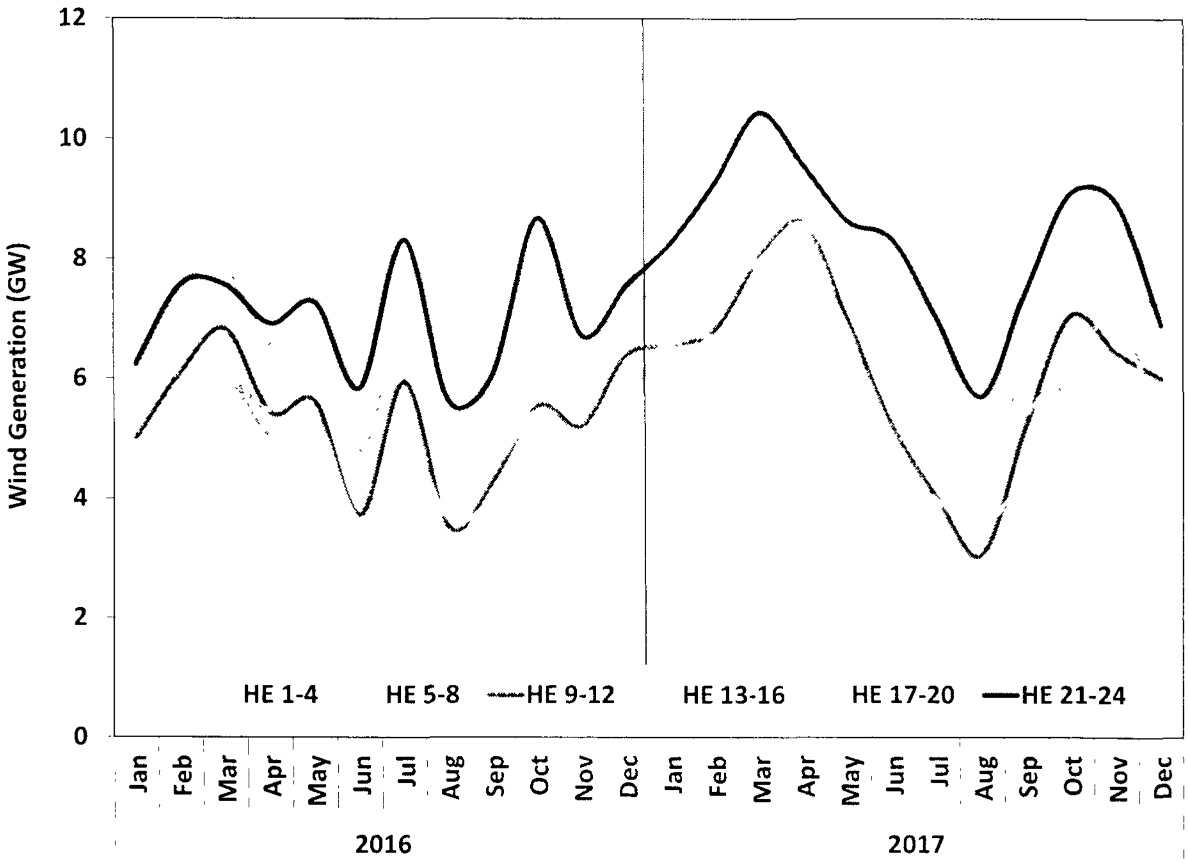
Between 2011 and 2014, ERCOT imported far more energy into its market than it exported into Mexico and SPP combined. In 2011, ERCOT was a net importer by 1,848 GWh, largely because of the high loads and tight conditions in ERCOT. Increased exports to Mexico led to decreased net imports in 2012, but return to previous levels in 2013. Since then there has been a trend of reduced imports from SPP and increased exports to Mexico because prices in ERCOT have remained relatively low. With the tightening supply in ERCOT and the potential for higher prices in 2018, it is likely that this trend will reverse.

C. Wind Output in ERCOT

The amount of wind generation installed in ERCOT was approximately 21.5 GW by the end of 2017. Although the large majority of wind generation is located in the West zone, more than 4.5 GW of wind generation has been located in the South zone. Additionally, a private transmission line that went into service in late 2010 allows another nearly 1 GW of West zone wind to be delivered directly to the South zone. In 2007, wind generation in ERCOT was located in 14 counties; by 2017, there were 55 counties with wind generators serving 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 65 shows average wind production for each month in 2016 and 2017, with the average production in each month divided into four-hour blocks. Though the lowest wind output generally occurs during summer afternoons, there has been such a large amount of wind generation added in ERCOT that the average wind output during summer peak period now averages in excess of 5 GW. This may be a small fraction of the total installed capacity but is now a non-trivial portion of generation supply, even at its lowest outputs.

Figure 65: Average Wind Production

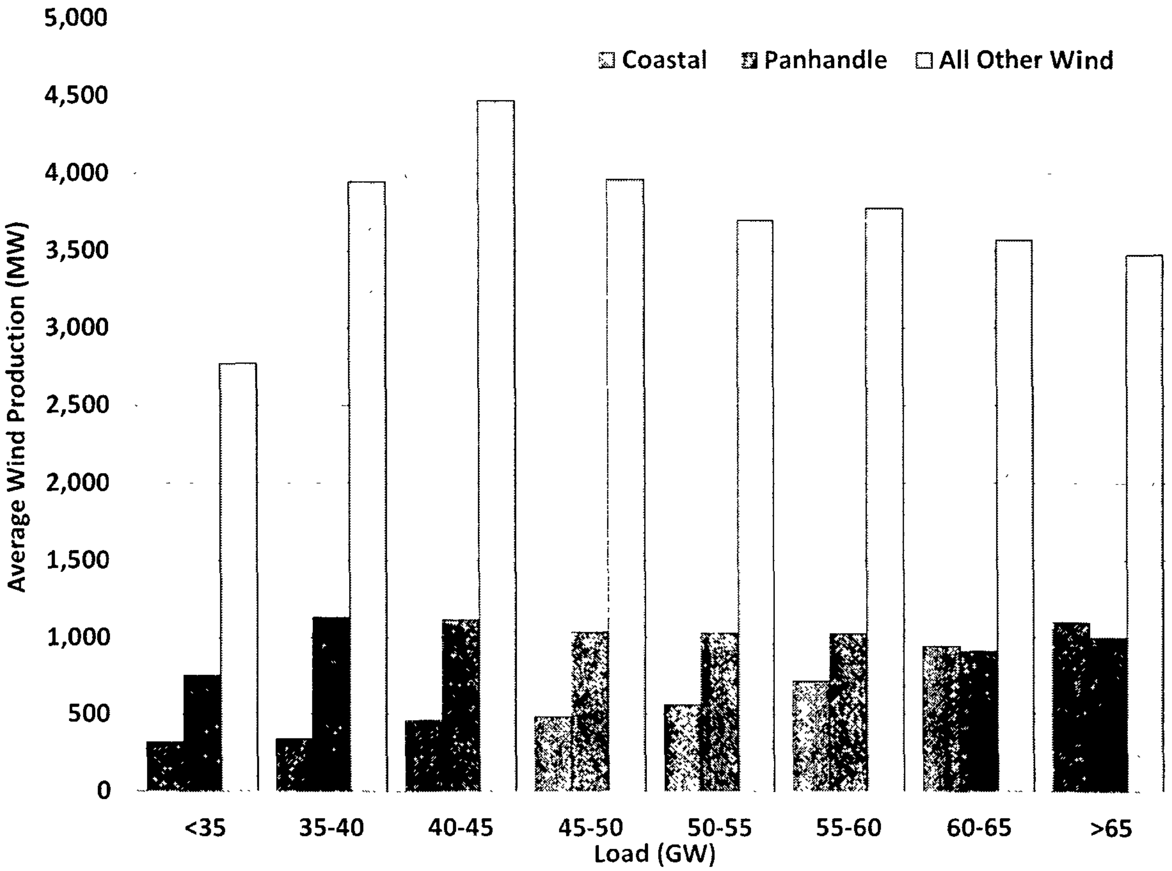


ERCOT continued to set new records for peak wind output in 2017. On November 17, 2017, wind output exceeded 16 GW, setting the record for maximum output and providing nearly 42% of the total load.[34]

Examining wind generation in total masks the different wind profiles that exist for locations across ERCOT. The attraction to sites along the Gulf Coast of Texas is due to the higher correlation of the wind resource in that location with electricity demand. More recently, the Texas Panhandle has attracted wind developer interest because of its abundant wind resources. The differences in output for wind units located in the coastal area of the South zone and those located elsewhere in ERCOT are compared below.

Figure 66 shows data for the summer months of June through August, comparing the average output for wind generators located in the coastal region, the Panhandle and all other areas in ERCOT across various load levels.

Figure 66: Summer Wind Production vs. Load

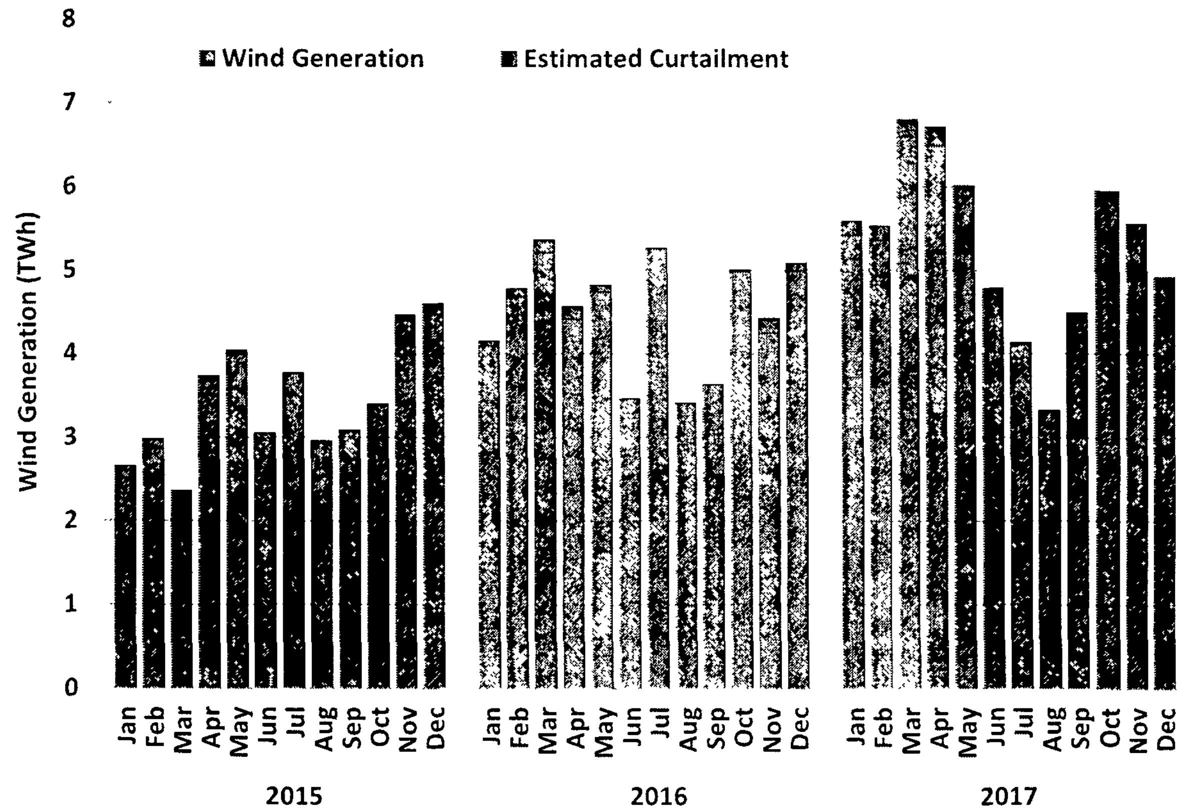


[34] Peak hourly wind generation was 16,035 MW on November 17, 2017 at 10:00 p.m

The typical profile for wind units not located along the coast or in the Panhandle is negatively correlated with peak electricity demand. However, output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand. Panhandle wind shows a more stable output across the load levels.

Figure 67 shows the wind production and estimated curtailment quantities for each month of 2015 through 2017.

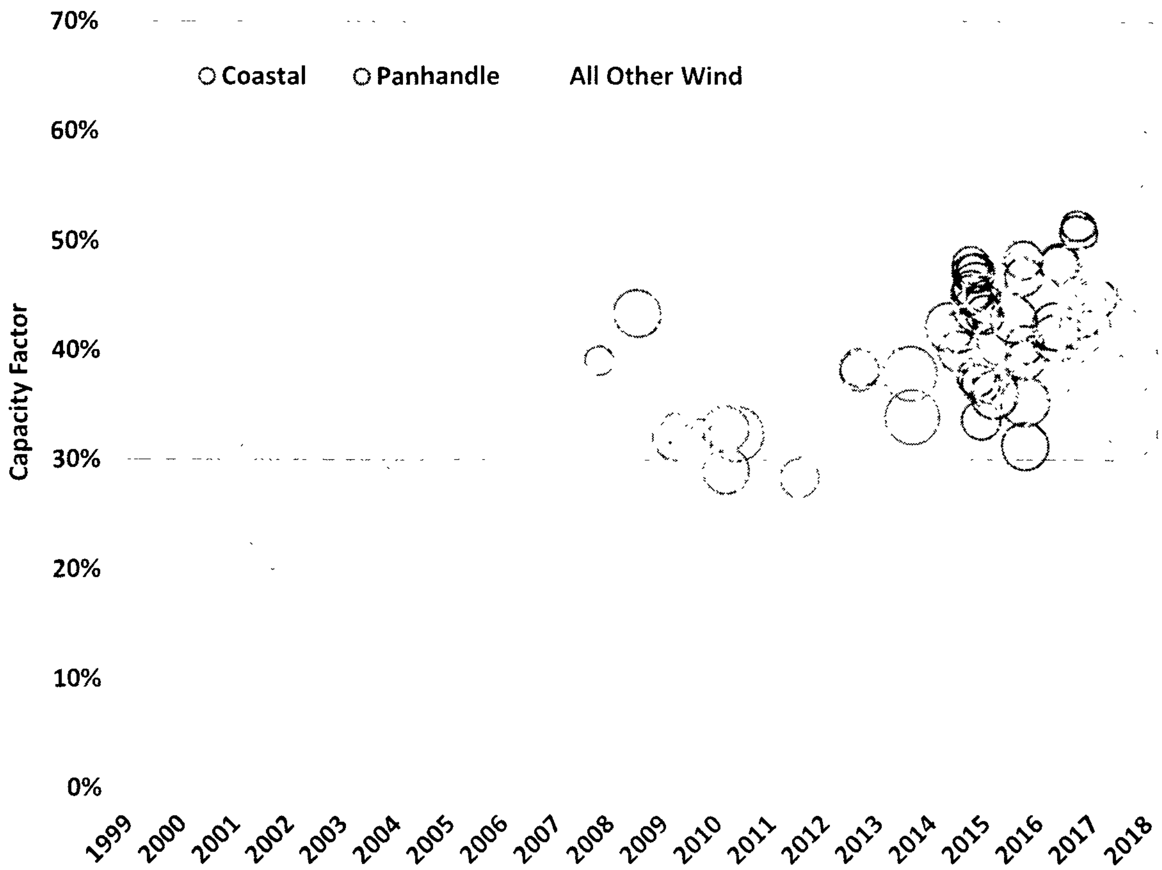
Figure 67: Wind Production and Curtailment



This figure reveals that the total production from wind resources continued to increase, while the quantity of curtailments also increased. The volume of wind actually produced in 2017 was estimated at 98% of the total available wind, continuing the small, but steady decline from 99.5% in 2014. As a comparison, in 2009, the year with the most wind curtailment, the amount of wind delivered was only 83%.

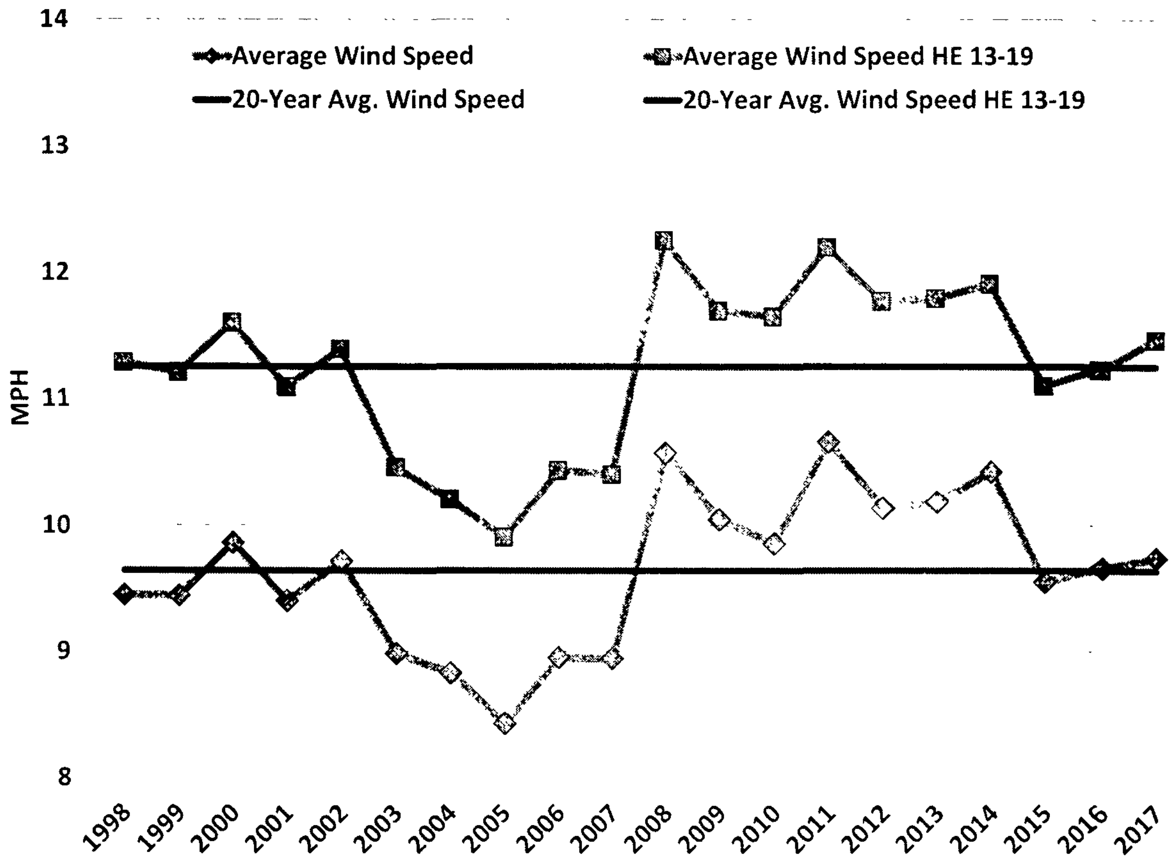
Figure 68 shows the capacity factor and relative size for wind generators by year installed. The chart also distinguishes wind generation units by location, with coastal units in blue and Panhandle resources in red, because of the different wind profiles for these regions. Coastal wind generally has a lower annual capacity factor, but as previously described its output is generally more coincident with summer peak loads. Completion of CREZ transmission lines has enabled more wind units to locate in the windier Panhandle area. The figure also shows a trend toward greater capacity factors for newer units.

Figure 68: Wind Generator Capacity Factor by Year Installed



The next figure shows average wind speeds in ERCOT, weighted by the current installed wind generation locations. Figure 69 provides a picture of the wind supply in 2017, averaged across the year and the average during peak hours, compared to the previous 19 years. The wind supply in 2017 was similar to the average over the past 20 years for all hours and for the peak hours of 13-19. With 2017 being close to an average wind supply year, if the existing fleet of wind generation had existed in prior years, total wind production could have been much greater. Notably, one of the years with higher than average wind speeds was 2011.

Figure 69: Historic Average Wind Speed



Increasing wind output also has important implications for the net load served by non-wind resources. Net load is the system load minus wind production. Figure 70 shows the net load duration curves for the years 2007, 2015, and 2017.

Figure 70 shows the reduction of remaining energy available for non-wind units to serve during most hours of the year, even after factoring in several years of load growth. The impact of wind on the highest net load values is much smaller.

Figure 70: Net Load Duration Curves

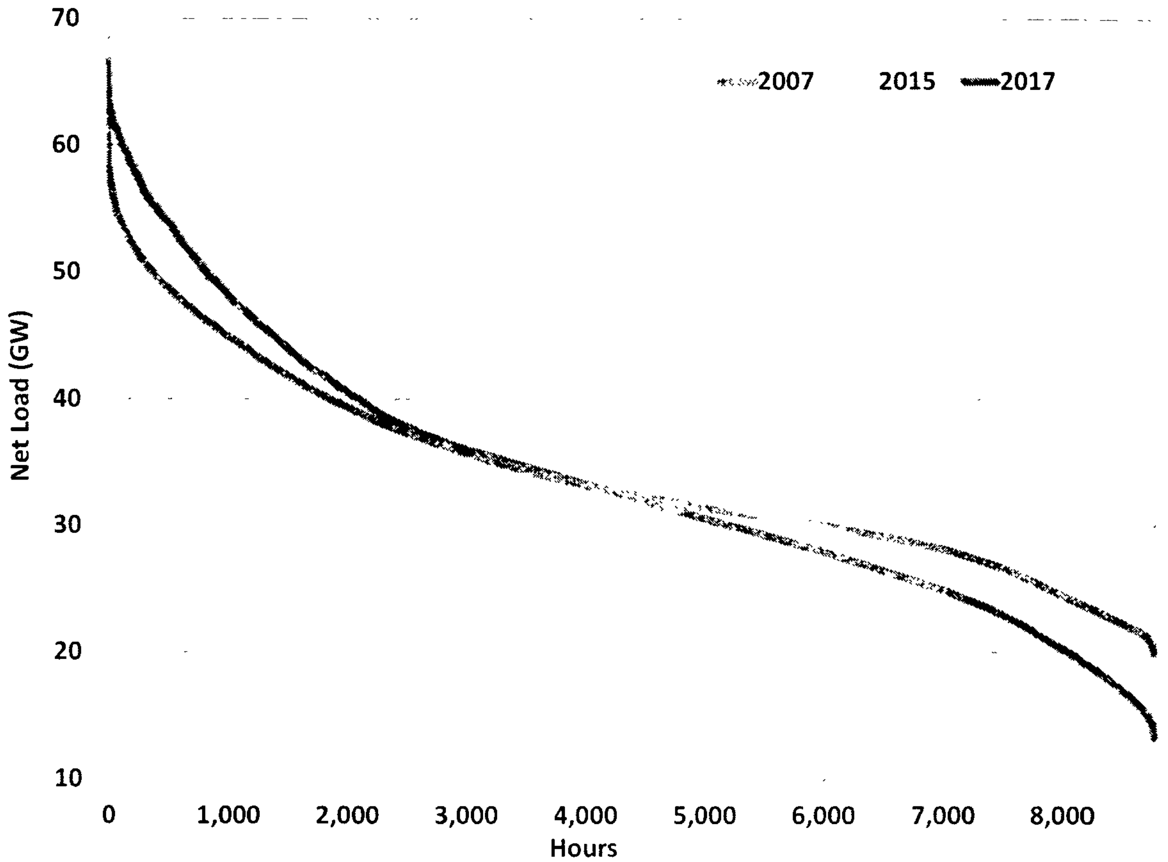
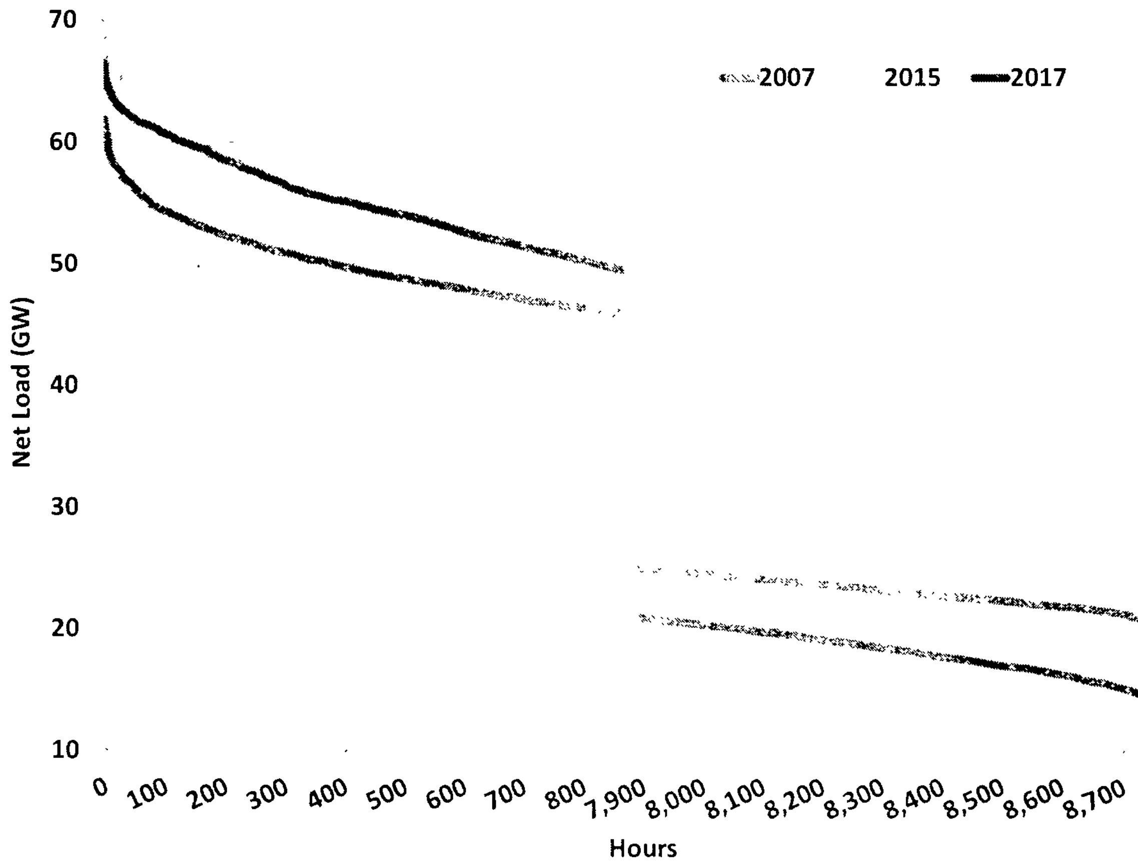


Figure 71 shows net load in the highest and lowest hours. Even with the increased development activity in the coastal area of the South zone, 73% of the wind resources in the ERCOT region are located in West Texas. The wind profiles in this area are such that most of the wind production occurs during off-peak hours or other times of low system demand. This profile results in only modest reductions of the net load relative to the actual load during the highest demand hours, but much larger reductions in the net load in the other hours of the year. Wind generation erodes the total load available to be served by base load coal units, while doing very little to reduce the amount of capacity necessary to reliably serve peak load.

In the hours with the highest net load (left side of the figure above), the difference between peak net load and the 95th percentile of net load has averaged 12.3 GW the past three years. This means that 12.3 GW of non-wind capacity is needed to serve load less than 440 hours per year.

Figure 71: Top and Bottom Deciles (Hours) of Net Load

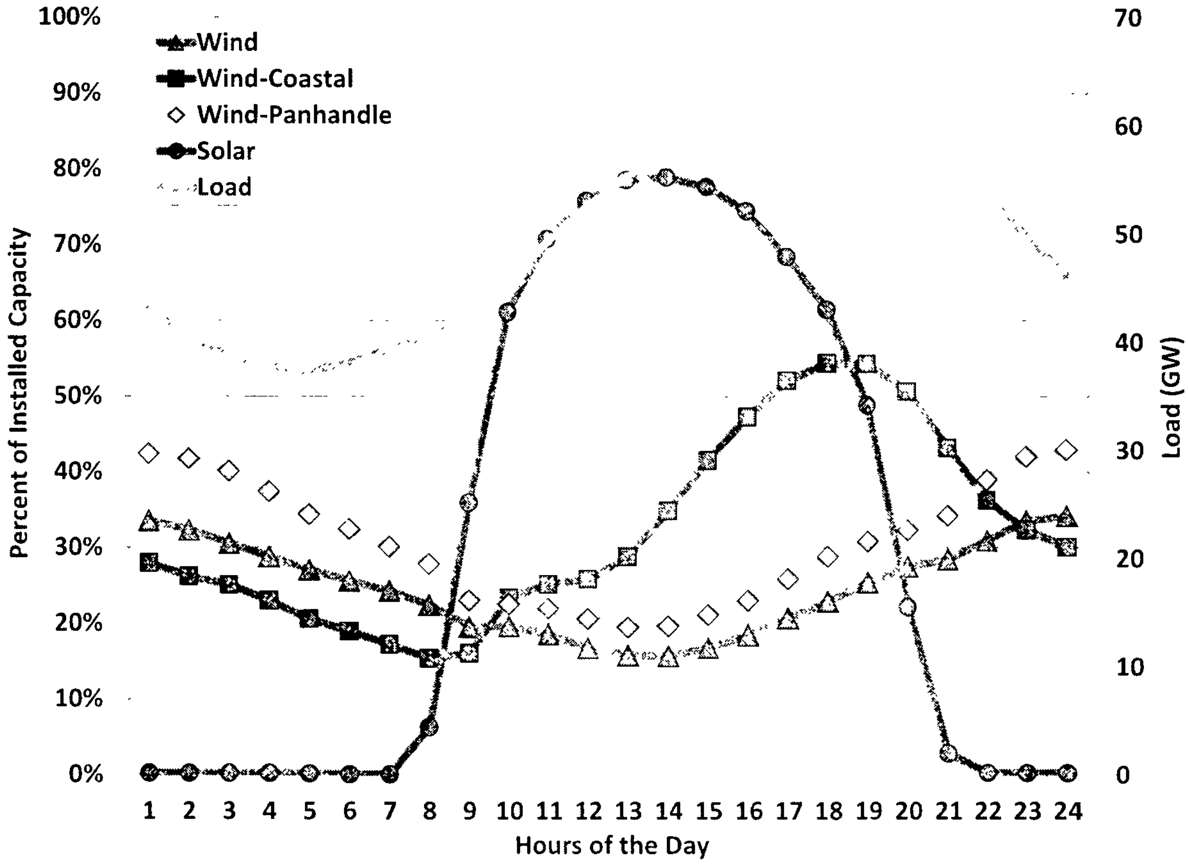


In the hours with the lowest net load (right side of the figure), the minimum net load has dropped from approximately 20 GW in 2007 to below 13.3 GW in 2017, even with the sizable growth in annual load that has occurred. This trend has put operational pressure on the almost 25 GW of nuclear and coal generation that were in-service in 2017. This operational pressure was certainly one of the contributors to the recent retirement of more than 4 GW of coal.

Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to satisfy ERCOT's reliability requirements, the non-wind fleet can expect to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly in the context of the ERCOT energy-only market design.

The growing numbers of solar generation facilities in ERCOT have an expected generation profile highly correlated with peak summer loads. Figure 72 compares average summertime (June through August) hourly loads with observed output from solar and wind resources. Generation output is expressed as a ratio of actual output divided by installed capacity.

Figure 72: Summer Renewable Production



This figure shows that while the total installed capacity of solar generation is much smaller than that of wind generation, its production as a percentage of installed capacity is the highest in the early afternoon, approaching 70%, and producing almost 70% of its installed capacity during peak load hours.

The contrast between coastal wind and all other wind is also clearly displayed in Figure 72. Coastal wind produced over 50% of its installed capacity during summer peak hours. Output from Panhandle wind and all other wind (primarily West zone) was less than 30% during summer peak hours.

D. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to certain market or system conditions. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to a generating resource. The ERCOT Protocols allow for loads to actively participate in the ERCOT-administered markets as load resources. A second way that loads may participate is through ERCOT-dispatched reliability programs, including Emergency Response Service and legislatively-mandated demand response programs administered by the transmission and distribution utilities in their energy efficiency programs. Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges.

Reserve Markets

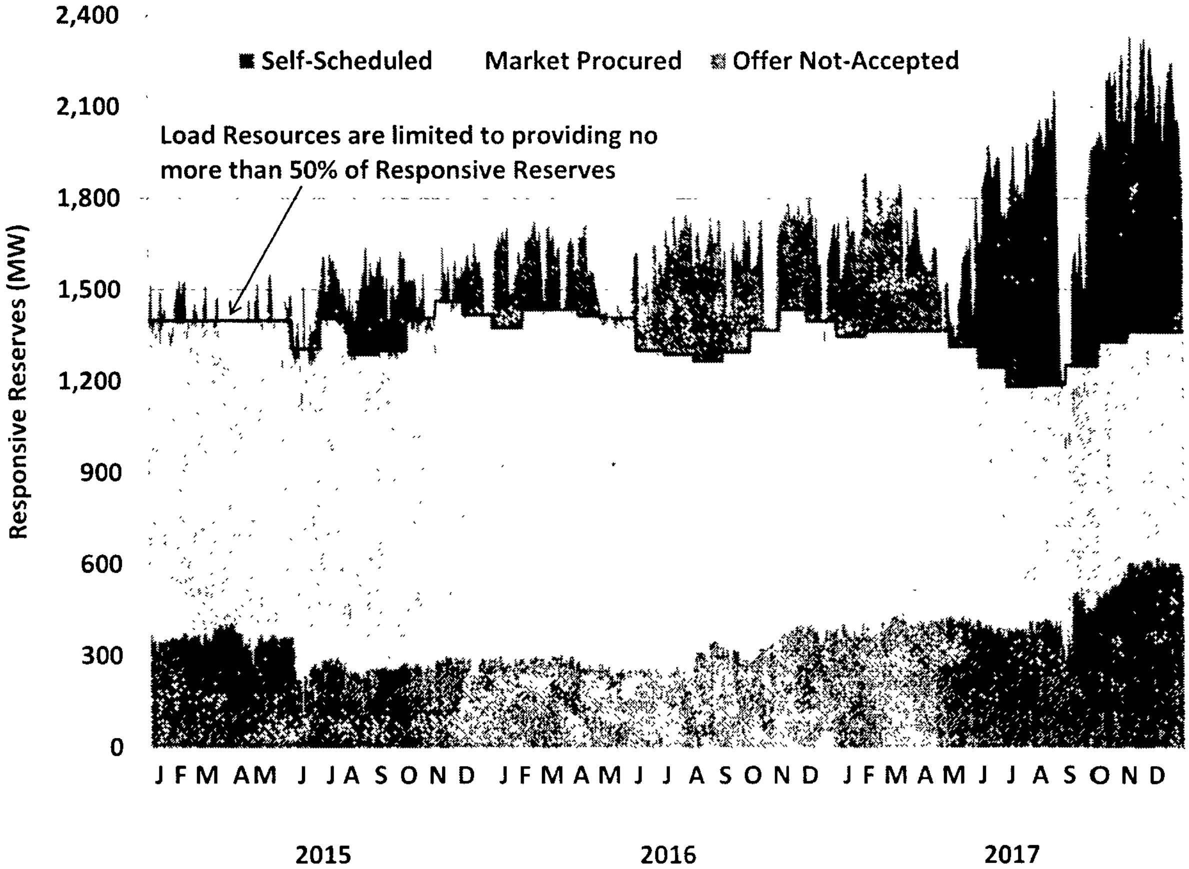
ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Tripping load has the effect of increasing system frequency and can be a very effective mechanism for maintaining system frequency at 60Hz. Load resources providing responsive reserves have high set under-frequency relay equipment, which enables the load to be automatically tripped when the system frequency falls below 59.7 Hz. These events typically occur only a few times each year. As of December 2017, approximately 4,715 MW of qualified Load resources were capable of providing responsive reserve service, an increase of approximately 890 MW during 2017.

On June 1, 2015, ERCOT began procuring a variable amount of responsive reserve service based on season and time of day. ERCOT established equivalency ratios at this time, to better ascertain the amount of primary frequency response expected from the procurement of responsive reserves. In 2016, the first full year with variable procurement, the quantity of megawatts offered but not accepted by load resources increased. During 2016, there were no system-wide manual deployments of load resources providing responsive reserves. There was, however, one automatic deployment of 927 MW of frequency responsive load on May 1, 2016.

In 2017, the total amount of responsive reserves procured by ERCOT varied between 2,300 MW and 2,808 MW per hour. During 2017, there were no system-wide manual or automatic deployments of load resources providing responsive reserve service.

Figure 73 below shows the average amount of responsive reserves provided from load resources on a daily basis for the past three years.

Figure 73: Daily Average of Responsive Reserves Provided by Load Resources



Load resources are limited to providing a maximum of 50% of responsive reserves and the quantity of offers submitted by load resources exceeded the limit most of the time in 2017. One exception is when real-time prices are expected to be high. Because load resources provide capacity by reducing consumption, they have to be consuming energy to be eligible to provide the service. During periods of expected high prices the price paid for energy can exceed the value received from providing responsive reserves. Reduced offer quantities observed during the spring and fall months may reflect the lack of availability of load resources due to annual maintenance at some of the larger load resource facilities. The significant reduction in offers from load resources observed in late August and early September is caused by the effects of Hurricane Harvey interrupting industrial processes along the Gulf Coast.

ERCOT Protocols also permit load resources to provide non-spinning reserves and regulation services, but for a variety of reasons, load resources have participated only minimally in providing these services.

Reliability Programs

There are two main reliability programs in which demand can participate in ERCOT – Emergency Response Service (ERS) and load management programs offered by the transmission and distribution utilities. The ERS program is defined by a PUCT rule enacted in March 2012 setting a program budget of $50 million.[35] The program was modified from a pay-as-bid auction to a clearing price auction in 2014, providing a clearer incentive to load to submit offers based on the costs to curtail, including opportunity cost. In 2016, the procurement for ERS shifted from four time periods per contract term to six time periods per contract term. The additional time periods were created to separate the higher risk times of early morning and early evening from the overnight and weekend hours. The time and capacity-weighted average price for ERS over the contract periods from February 2017 through January 2018 was $6.86 per MWh, exactly the same outcome as the previous program year. This price is significantly higher than the average price of $3.18 and $3.91 per MWh paid for non-spinning reserves in 2016 and 2017. ERS was not deployed in either year.

On March 30, 2017, the Public Utility Commission of Texas adopted an amendment to 16 TAC §25.507, permitting ERS resources to participate in Must Run Alternative (MRA) arrangements to replace the need for Reliability Must Run (RMR) generation resources.[36]

Beyond ERS there were slightly more than 200 MW of load participating in load management programs administered by transmission and distribution utilities in 2017.[37] Energy efficiency and peak load reduction programs are required under state law and PUCT rule and most commonly take the form of load management, where participants allow electricity to selected appliances (typically air conditioners) to be curtailed. These programs administered by transmission and distribution utilities may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

Self-dispatch

In addition to active participation in the ERCOT market and ERCOT-dispatched reliability programs, loads in ERCOT can observe system conditions and reduce consumption accordingly. This response comes in two main forms. The first is by participating in programs administered by competitive retailers or third parties to provide shared benefits of load reduction with end-use customers. The second is through actions taken to avoid the allocation of transmission costs. Of these two methods, the more significant impacts are related to actions taken to avoid the allocation of transmission costs.

35 *See* 16 TAC § 25.507.

36 *See* Project No. 45927, *Rulemaking Regarding Emergency Response Service*.

37 *See* ERCOT 2017 Annual Report of Demand Response in the ERCOT Region (Mar. 2018) at 6, available at http://www.ercot.com/services/programs/load/.

For decades, transmission costs have been allocated on the basis of load contribution to the highest 15-minute system demand during each of the four months from June through September. This allocation mechanism is routinely referred to as four coincident peak, or 4CP. By reducing demand during peak periods, load entities seek to reduce their share of transmission charges. Transmission costs have doubled since 2012, increasing an already substantial incentive to reduce load during probable peak intervals in the summer.[38] ERCOT estimates that as much as 1500 MW of load were actively pursuing reduction during the 4CP intervals in 2016 and 2017.[39]

Load curtailment to avoid transmission charges may be distorting prices during peak demand periods because the response is targeting peak demand rather than responding to wholesale prices. This was readily apparent in 2016 as there were significant load curtailments corresponding to peak load days in June, July and September when real-time prices on those days were in the range of $25 to $40 per MWh. The trend continued in 2017, with significant load curtailments on peak load days in June, August and September when real-time prices were less than $100 per MWh.

Two recent changes in the ERCOT market continue to advance appropriate pricing actions taken by load in the real-time energy market. First, the initial phase of "Loads in SCED" was implemented in 2014, allowing controllable loads that can respond to 5-minute dispatch instructions to specify the price at which they no longer wish to consume. Although an important first step, there are currently no loads qualified to participate in SCED. Second, the reliability adder, discussed in more detail in Section I: Review of Real-Time Market Outcomes, performs a second pricing run of SCED to account for the amount of load deployed, including ERS.

38 *See* PUCT Docket No. 45382, *Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Mar. 25, 2016) and PUCT Docket No. 46604, *Commission Staff's Application to Set 2017 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Final Order (Mar. 30, 2017).

39 *See* ERCOT, 2017 Annual Report of Demand Response in the ERCOT Region (Mar. 2018) at 7, available at http://www.ercot.com/services/programs/load/

V. Reliability Commitments

One of the important characteristics of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause apparent shortages in the real-time market and inefficiently high energy prices, while over-commitment can result in excessive start-up costs, uplift charges, and inefficiently low energy prices.

The ERCOT market does not include a mandatory centralized unit commitment process. The decision to start-up or shut-down a generator is made by the market participant. ERCOT's day-ahead market informs these decisions, but is only financially binding. That is, when a generator's offer to sell is selected (cleared) in the day-ahead market there is no corresponding requirement to actually start that unit. The generator will be financially responsible for providing the amount of capacity and energy cleared in the day-ahead market whether or not the unit operates. This decentralized commitment depends on clear price signals to ensure an efficient combination of units are online and available for dispatch. ERCOT, in its role as reliability coordinator, has the responsibility to commit units it deems necessary to ensure the reliable operation of the grid. Gaps exist between what individual resources, in aggregate, view as economic commitment and what ERCOT views as necessary to ensure the reliability of the region. In the event of these gaps, ERCOT uses its discretion to commit additional units to ensure reliability.

This section describes the evolution of rules and procedures regarding Reliability Unit Commitments (RUC), the outcomes of RUCs, and the price mitigation that occurs during RUC and local congestion. The section concludes with a discussion of the Reliability Must Run (RMR) process revisions in ERCOT in 2017.

A. History of RUC-Related Protocol Changes

The RUC process has undergone several modifications since the nodal market began in 2010. The following changes were implemented in an effort to improve the commitment process and market outcomes associated with RUC. In March 2012, an offer floor was put in place for energy above the Low-Sustained Limit (LSL) for units committed through RUC.[40] Initially, the RUC offer floor was set at the system-wide offer cap. The RUC offer floor was subsequently

40 NPRR435, Requirements for Energy Offer Curves in the Real Time SCED for Generation Resources Committed in RUC, implemented on March 1, 2012.

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adjusted to $1,000 per MWh[41] and then to the current offer floor of $1,500 per MWh.[42] Resources committed through the RUC process receive a make-whole payment and forfeit market revenues through a "clawback" provision. Beginning on January 7, 2014, resources committed through the RUC process could forfeit the make-whole payments and waive the clawback charges, effectively self-committing and accepting the market risks associated with that decision.[43] This buyback or "opt-out" mechanism for RUC requires a resource to update its Current Operating Plan (COP) before the close of the adjustment period for the first hour of a RUC.[44]

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).[45] ERCOT systems now automatically set the energy offer floor at $1,500 per MWh when a resource properly telemeters a status indicating it has received a RUC instruction. The reliability adder, as discussed more in Section I: Review of Real-Time Market Outcomes, captures the impact of reliability deployments such as RUC on energy prices.

The RUC process was modified again in 2017. On June 1, 2017, ERCOT began using a telemetered snapshot at the start of each RUC instruction block as the trigger to calculate the reliability adder. This was an improvement over the previous calculation trigger, which required the Qualified Scheduling Entity (QSE) to accurately telemeter an ONRUC status.[46] To provide even greater flexibility, resources now have the ability to opt-out of RUC instructions given after the close of the adjustment period.

Resources are also now permitted to opt out of RUC instructions via real-time telemetry; opting out of a RUC instruction is available for resources that telemeter ONOPTOUT during the first SCED-dispatchable interval within the first RUC-hour of the commitment block instruction. During 2017, approximately 28% of RUC instructions were given after the close of the

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41 NPRR568, Real-Time Reserve Price Adder Based on Operating Reserve Demand Curve, implemented on June 1, 2014.

42 NPRR626, Reliability Deployment Price Adder, partially-implemented to update the RUC offer floor on October 1, 2014.

43 NPRR416, Creation of the RUC Resource Buyback Provision (formerly "Removal of the RUC Clawback Charge for Resources Other than RMR Units"), as modified by NPRR575, Clarification of the RUC Resource Buy-Back Provision for Ancillary Services

44 Note that the process for electing to opt-out of a RUC will be based on real-time telemetry when NPRR744, RUC Trigger for the Reliability Deployment Price Adder and Alignment with RUC Settlement, goes into effect in mid-2017.

45 *See* NPRR626, Reliability Deployment Price Adder (Formerly "ORDC Price Reversal Mitigation Enhancements").

46 NPRR744, RUC Trigger for the Reliability Deployment Price Adder and Alignment with RUC Settlement, implemented on June 1, 2017.

adjustment period. By comparison, 40% of RUC instructions were issued after the close of the adjustment period in 2016.

B. RUC Outcomes

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

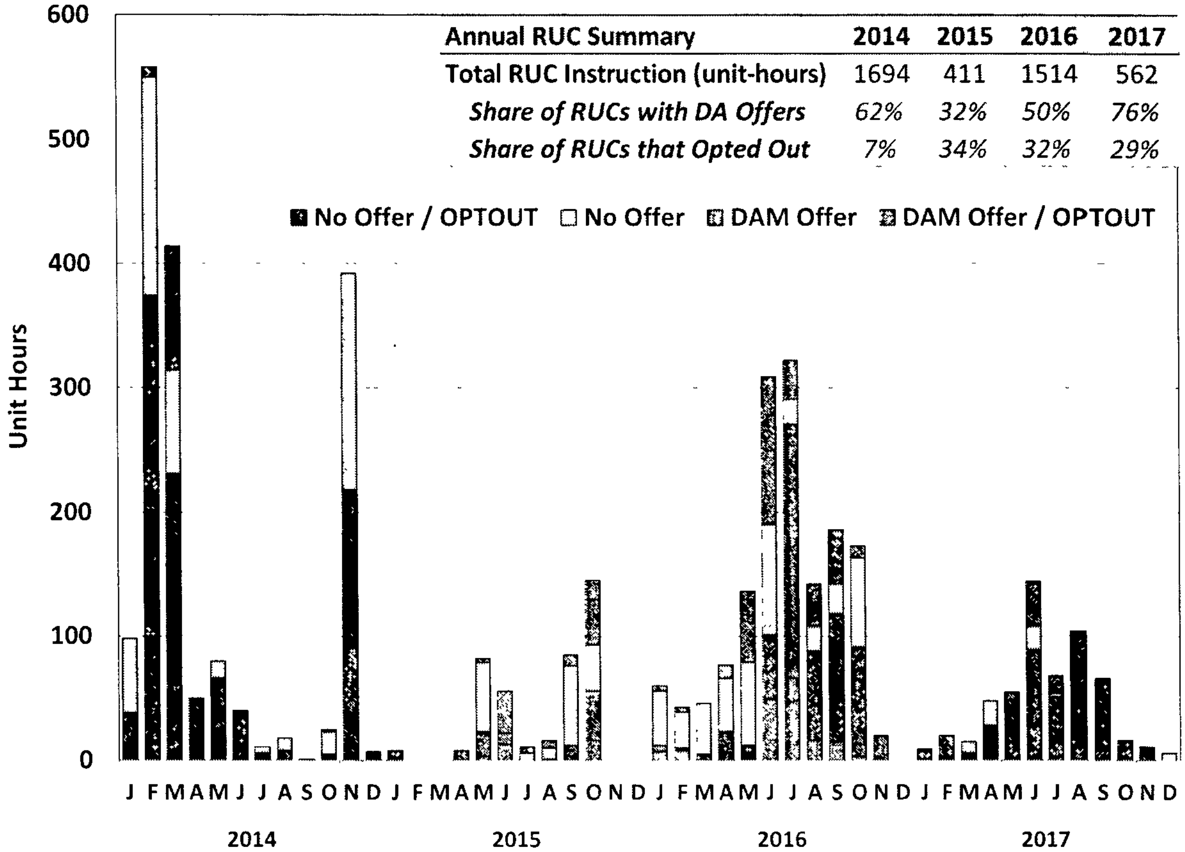
The number of RUC instructions in 2017 dropped considerably from 2016. The 562 unit-hours of RUC instructions in 2017 represent a 63% decrease from 1514 unit-hours in 2016. These 2017 RUC instructions were geographically diverse as well, with 41% to generators in the South zone in a variety of locations: San Antonio, Corpus Christi and the Rio Grande Valley (the Valley), 33% were to generators in the Houston zone, 24% were to generators in the North zone, and the remaining 2% were to generators in the West zone.

Like 2016, most reliability commitments in 2017 were made primarily to manage transmission constraints in 2017 (84% of unit-hours), including 7% to manage congestion in the aftermath of Hurricane Harvey. Only 13% of RUC instructions were made to ensure sufficient system-wide capacity and 2% for voltage support. The RUC activity in previous years was driven by a variety of other factors: in 2014, RUC activity was concentrated during cold weather events in February and March and in response to transmission outages in March and November. In 2015, RUCs were most frequent in the fall because of congestion in Dallas and the Valley. The high amount of RUC activity in 2016 was primarily for localized transmission congestion mainly to units located in Houston and the Valley.

Although the total volume of RUC instructions was much lower in 2017 compared to 2016, the amount of RUC instructions for system-wide capacity was greater in 2017. There were 73 unit-hours of RUC instructions to ensure system-wide adequacy, which represents 13% of the total in 2017. In 2016, there were 33 unit-hours, representing 2% of the total.

Figure 74 below shows RUC activity by month, indicating the volume of generators receiving a RUC instruction that had offers in the day-ahead market or chose to opt-out of the RUC instruction.

Figure 74: Day-Ahead Market Activity of Generators Receiving a RUC



A unit that receives a RUC instruction is guaranteed payment of its start-up and minimum energy costs (RUC make-whole payment). However, if the energy payments received by a unit operating under a RUC instruction exceed its operating costs, payment to that generator is reduced (RUC clawback charge). Generators without offers submitted to the day-ahead market forfeit all excess revenues, whereas generators with day-ahead offers forfeit only 50% of excess revenues. Given this incentive to have offers submitted into the day-ahead market, it is somewhat surprising that all units do not submit day-ahead offers. In 2017, only 76% of the generators receiving RUC instructions had day-ahead offers, a relatively low percentage considering the incentive to provide day-ahead offers inherent in the RUC claw-back rules. This low percentage was still an increase from 2016 when the ratio was 50%. This may indicate that some reduction in the RUC activity in 2017 was due to a larger share of the units needed for reliability being committed through the day-ahead market.

Since January 2014, a generator receiving a RUC instruction has had the choice to "opt out," meaning it forgoes all RUC make-whole payments in return for not being subject to RUC clawback charges. The percentage of generators receiving RUC instructions in 2017 that chose to opt-out was 29%, similar to the 32% of generators that chose to opt-out in 2016.

During the first half of 2017, QSE telemetry of a generator's RUC status served as the trigger for calculating a reliability adder. There were 397 hours in which units were settled as RUC in 2017 and 201.6 hours of pricing intervals with non-zero reliability adders that occurred coincident with a settled RUC hour.

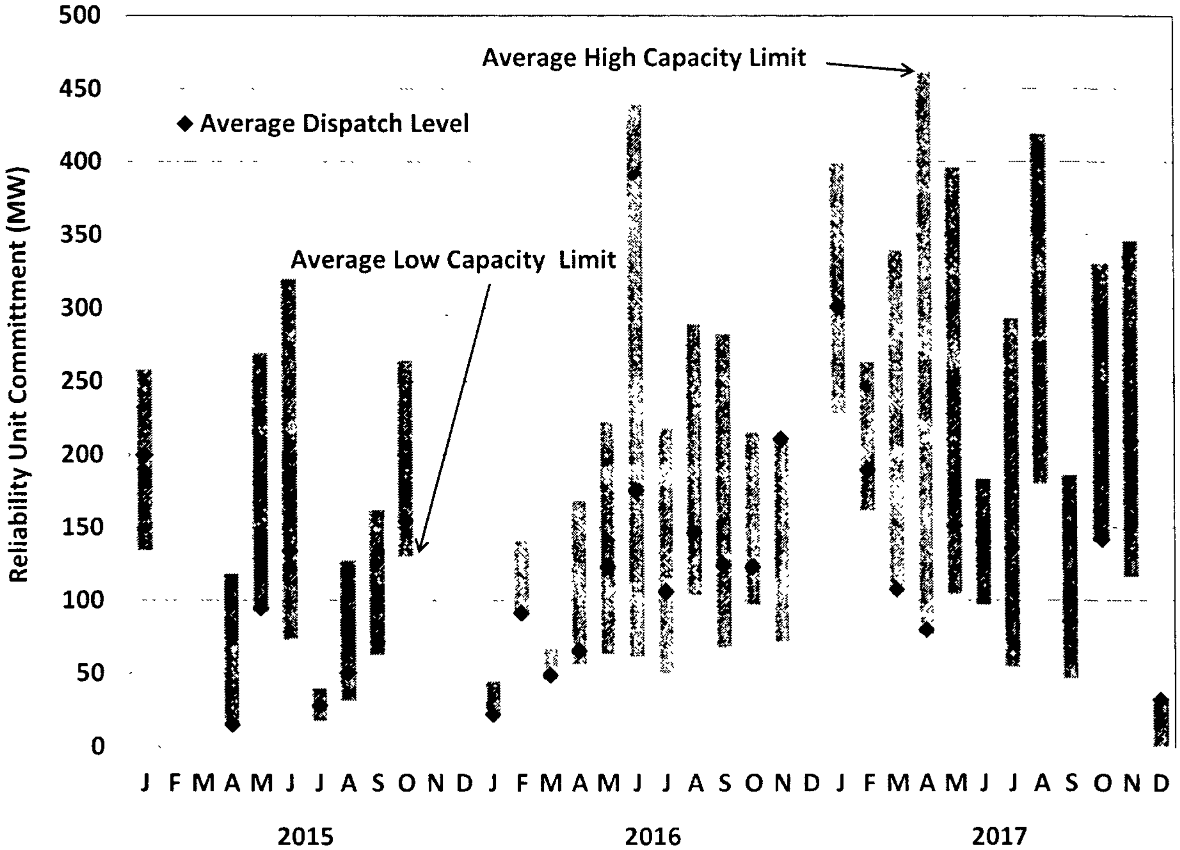
Table 9 lists the generators receiving the most RUC instructions in 2017. Also provided in the table are the total hours of RUC instruction, the number of hours in which the unit opted-out, and the average LSL for the unit. The units highlighted in gray in Table 9 are generators that most frequently received RUC instructions in 2016.

Table 9: Most Frequent Reliability Unit Commitments

Resource	Location	Unit RUC Hours	Unit OPTOUT Hours	Average LSL during RUC Hours
WA Parish G4	Houston	40	24	138
Duke CC1	Valley	31	21	177
Mountain Creek Unit 6	DFW	32	8	15
Silas Ray 10	Valley	2	36	24
WA Parish G3	Houston	12	24	90
Silas Ray CC1	Valley	21	12	47
WA Parish G2	Houston	19	8	27
Handley Unit 5	DFW	26	-	120
Coleto G1	Victoria	24	-	300
Handley Unit 4	DFW	21	1	120
Barney Davis G1	Corpus Christi	21	-	58
Cedar Bayou G2	Houston	16	-	94
Ennis Tractebel CC1	DFW	16	-	140
Barney Davis CC1	Corpus Christi	13	-	244
WA Parish G1	Houston	5	6	25

The next analysis compares the average dispatched output of the reliability-committed units, including those that opted-out, with the operational limits of the units. Figure 75 shows that the monthly average magnitude of RUC generation increased in 2017 compared to the prior two years. This figure shows that the average quantity dispatched during most months of 2017 exceeded 100 MW. In January, the average dispatch level was 300 MW because of a number of large generators receiving RUC instructions for a brief period.

Figure 75: Reliability Unit Commitment Capacity

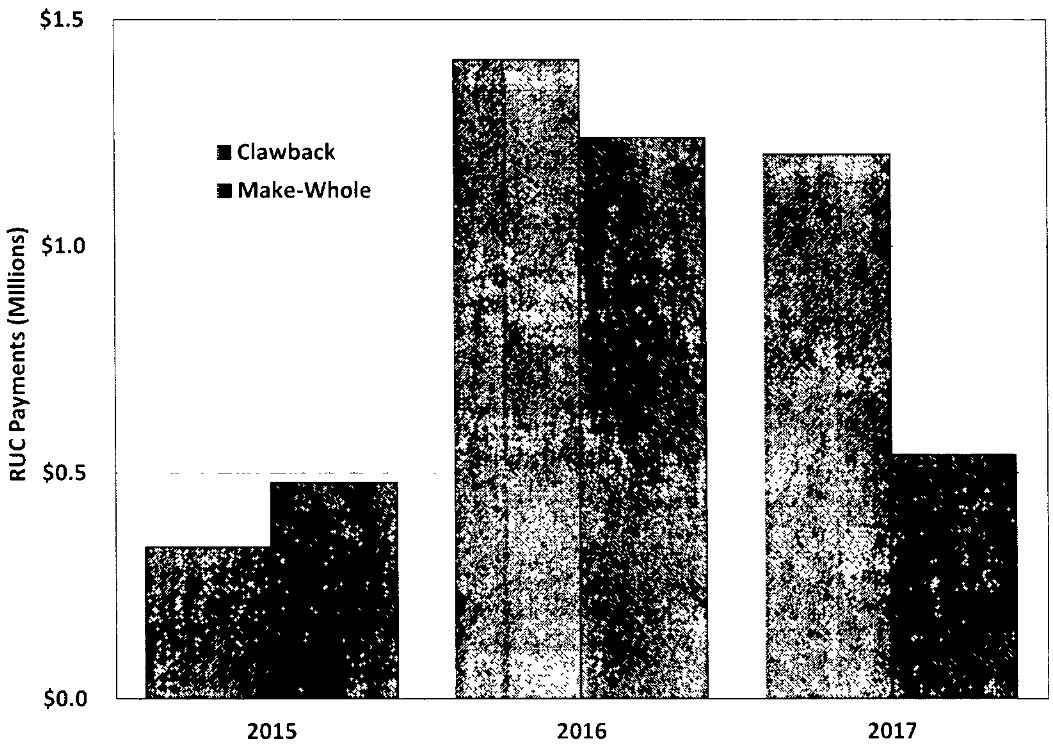


Units committed for RUC in 2017 showed a significant increase in the dispatch level compared to prior years. In 21% of intervals with RUC resources, one or more resources were dispatched above their Low Dispatchable Limit (LDL), whereas in prior years, resources receiving a RUC were infrequently dispatched above LDL. This higher dispatch level indicates that most units receive RUC instructions to resolve local constraints, and that these local constraints are non-competitive. As a result, units receive payment based on their mitigated offer caps. It is rare for a generator receiving a RUC instruction to be dispatched above LDL with their offer above the $1,500 per MWh offer floor and it did not occur during 2017.

When a unit is committed for RUC, the unit will receive a make-whole payment if the real-time revenues are less than the costs incurred to commit the unit. These costs can be based on generic values or unit-specific verifiable costs. Of the 43 different resources that received a RUC instruction in 2017, 34 resources had approved unit-specific verifiable costs for start-up costs and minimum load costs. Those 34 resources represent 80% of total RUC-instructed megawatt-hours in 2017.

Figure 76 displays the total annual amount of make-whole payments and clawback charges attributable to RUCs for 2015-2017. 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 obligations. If there are remaining RUC make-whole funds required after contributions from any capacity short QSEs, any remaining RUC make-whole funding will be uplifted to all QSEs on a load-ratio share.

Figure 76: RUC Make-Whole and Clawback



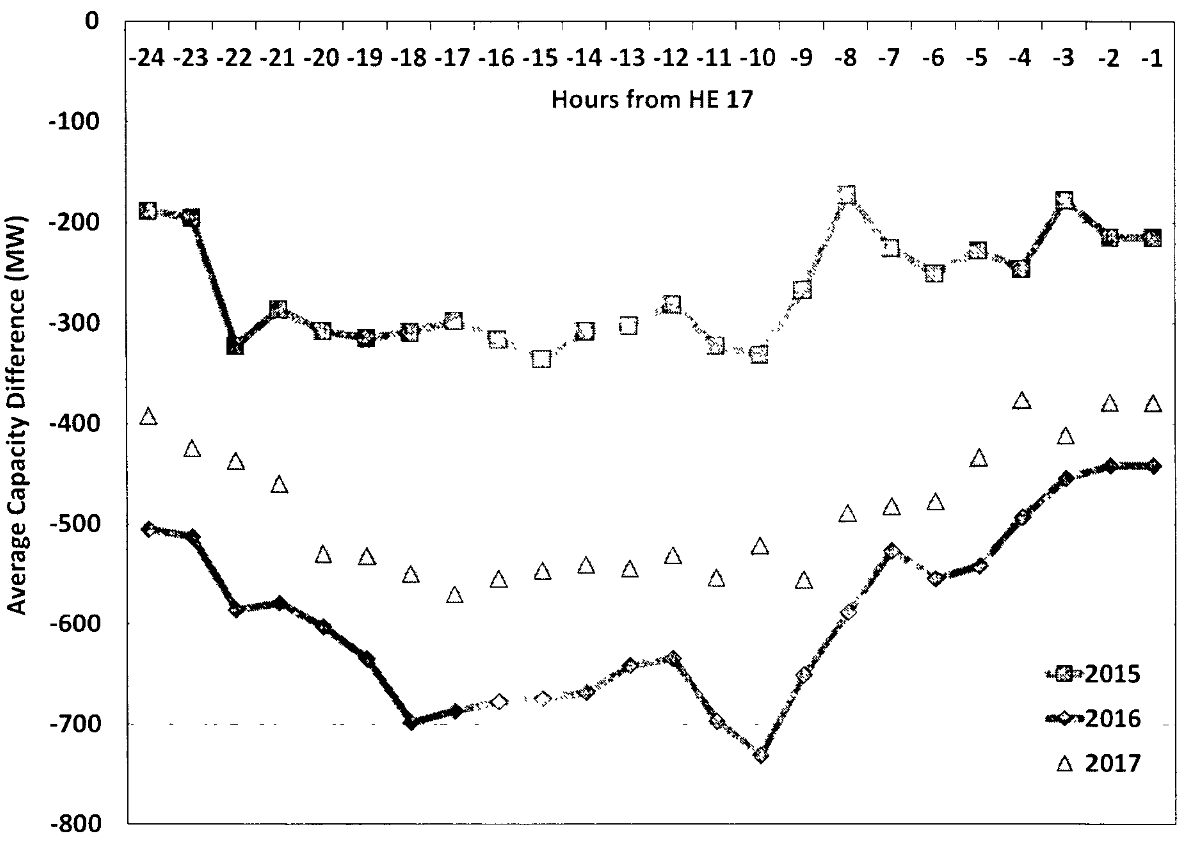
As stated above, if real-time revenues received by a RUC resource exceed the operating costs incurred by the unit, then excess revenues are clawed-back and returned to QSEs representing load. During 2017, $1.2 million was clawed back from RUC units while only $0.5 million in make-whole payments were made to RUC units. All RUC make-whole payments in 2017 were collected from QSEs that were capacity short. The magnitude of both the clawback and make-whole amounts are very small compared to the size of the ERCOT real-time energy market.

One of the important characteristics of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause apparent shortages in the real-time market and inefficiently high energy prices; while over-commitment can result in excessive start-up costs, uplift charges, and inefficiently low energy prices.

Figure 77 shows the average difference between the actual online unit capacity in the peak hour and the amount of capacity planned to be online in the peak hour for each of the 24 hours leading up to the close of the adjustment period. This data is derived from current operating plan submissions and averaged for hour ending 17 in the months of July and August, for each year 2015 through 2017. As shown in the figure below, the amount of capacity committed in advance of the operating hour for 2017 was greater than in 2016, but much less than in 2015. In 2015, on average, about 200 MW of capacity was committed in the last hour before real time. In 2016, the amount increased to over 420 MW, with even larger deficiencies seen in the last hours leading up to real time. The increase in self-committed capacity seen for summer 2017 may have been a reaction to the increased RUC activity observed in 2016.

As previously described, only a small portion of total RUC instructions were issued to ensure system-wide capacity sufficiency. This is testament to the restraint exhibited by ERCOT operators to allow market participants make their own commitment decisions with regard to the nearly 400 MW of close-to real-time capacity commitments. The fact that there is nearly 5,000 MW of fast starting generators controlled by multiple market participants highlights the complexity of these decisions and suggests that improvements to these close-to-real-time commitments may be warranted.

Figure 77: Capacity Commitment Timing – July and August Hour 17



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C. Mitigation

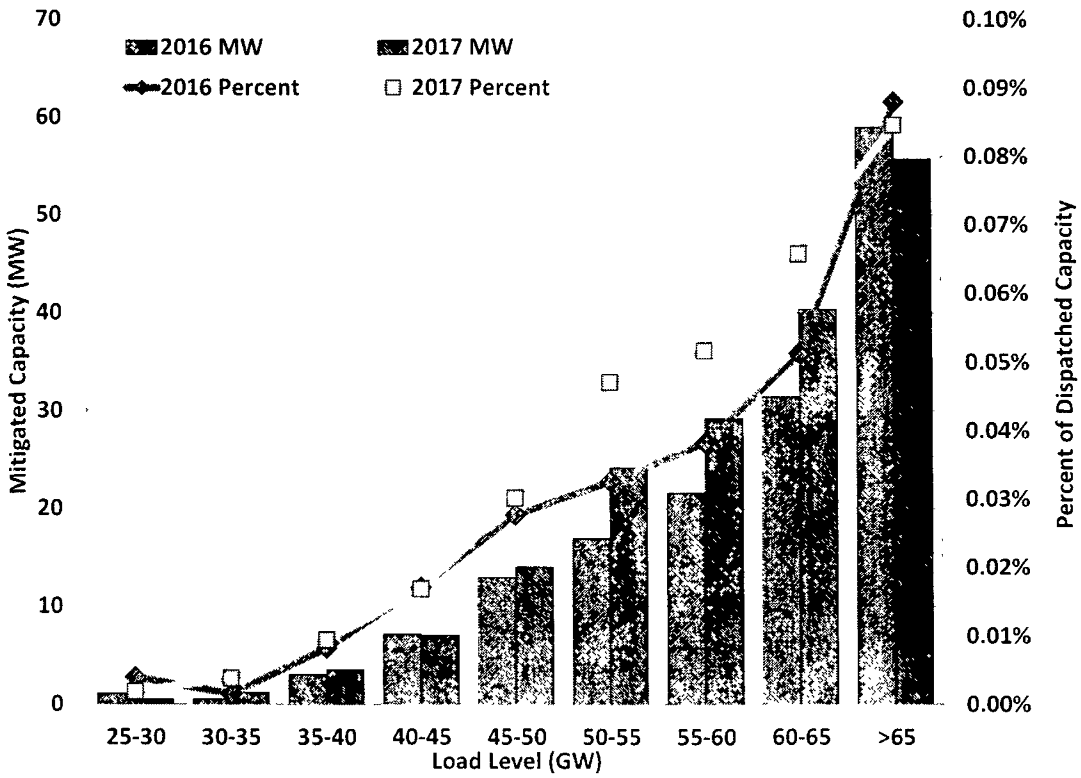
In situations where competitive forces are not sufficient, it can be necessary to mitigate prices to a level that approximates competitive outcomes. ERCOT's real-time market includes a mechanism to mitigate prices for resources that are required to resolve a transmission constraint. Mitigation applies whether the unit is self-committed or receives a RUC instruction. Units typically received a RUC instruction to resolve transmission constraints and as such they are typically required to resolve a transmission constraint, and therefore mitigated. As shown previously in Figure 75, units that received a RUC instruction were frequently dispatched above their low operating limits in 2017. This higher dispatch was due to the RUC units being dispatched based on their mitigated price, not the RUC offer floor of $1,500 per MWh.

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

This approach is intended to limit the ability of a generator to raise prices in the event of a transmission constraint that requires its output to resolve. In this subsection the quantity of mitigated capacity in 2017 is analyzed. Although executing at all times, the automatic price mitigation aspect of the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active. With the introduction of an impact test in 2013 to determine whether units are relieving or contributing to a transmission constraint, only the relieving units are now subject to mitigation. This change has significantly reduced the amount of capacity subject to mitigation.

The analysis shown in Figure 78 computes the percentage of capacity, on average, that is actually mitigated during each dispatch interval. The results are provided by load level.

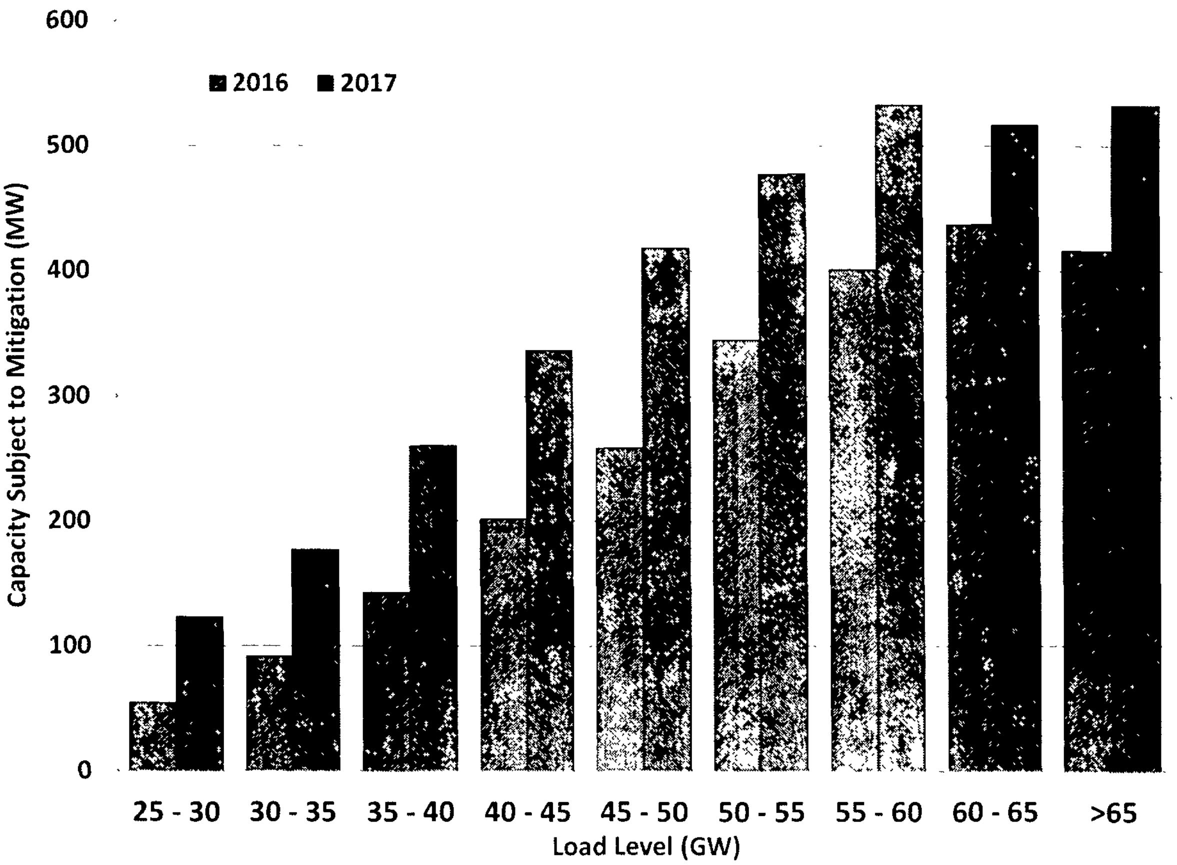
Figure 78: Mitigated Capacity by Load Level



The level of mitigation in 2017 was very similar to 2016. The average amount of mitigated capacity averaged almost 60 MW at loads greater than 65 GW in both 2017 and 2016.

In the previous figure, only the amount of capacity that could be dispatched within one interval was counted as mitigated. The next analysis computes the total capacity subject to mitigation, by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. The difference between the total unit capacity and the capacity at the point the curves diverge is calculated for all units and aggregated by load level. The results are shown in Figure 79.

Figure 79: Capacity Subject to Mitigation



The amount of capacity subject to mitigation in 2017 was higher than 2016 in all load levels. In 2015 and 2014, the largest amount of capacity subject to mitigation did not exceeded 300 MW. 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.

D. Reliability Must Run

A total of eight generation resources provided Notifications of Suspension of Operations (NSOs) with suspension dates in 2017, accounting for approximately 2,000 MW of the capacity being retired or mothballed during the year.[47] ERCOT determined that the units were not necessary to support ERCOT transmission system reliability, and as a result no new reliability must run (RMR) contracts were awarded in 2017. However, review of the RMR process remained active

[47] Calpine Corp (RE), Aspen LLC, Pearsall Units 1, 2, and 3, Union Carbide Corp (RE), Gibbons Creek and Barney Davis.

throughout the year, including continued scrutiny of the RMR contract for Greens Bayou 5 executed in 2016.

Greens Bayou 5 is a 371 MW natural gas steam unit built in 1973 and located in Houston. On March 29, 2016, NRG submitted an NSO indicating that Greens Bayou 5 would be mothballed indefinitely beginning June 27, 2016. On May 27, 2016, ERCOT made a final determination that Greens Bayou 5 was necessary for RMR service. The Greens Bayou 5 RMR agreement was effective June 2, 2016 for a term of 25 months and a budgeted cost of $58.1 million, plus the opportunity for up to 10% more as an availability incentive. ERCOT initially determined that Greens Bayou 5 was needed for transmission system stability in the Houston region during the summers of 2016 and 2017 until the Houston Import Project transmission upgrade was completed. However, following changes to the RMR study parameters[48] and an earlier than expected completion of new generation in Houston, ERCOT provided NRG, the owner of Greens Bayou 5, with notice of termination of the RMR Agreement on February 27, 2017. The RMR contract was cancelled effective May 29, 2017. The total cost paid to the NRG for the Greens Bayou RMR contract was approximately $22 million, and the unit was never operated during the term of the contract. On December 5, 2017, NRG submitted a Notification of Change of Generation Resource Designation for Greens Bayou 5, declaring the unit permanently decommissioned as of December 31, 2017.

As a result of the ongoing review of the RMR process, several protocols changes were implemented in 2017. Effective May 1, 2017, NPRR810 removed the applicability of the RMR Incentive Factor to reservation and transportation costs associated with firm fuel supplies, which will now be considered fuel costs.[49] The protocols were also changed to separate costs in the RMR Standby Payment equation based on Incentive Factor applicability.[50]

In addition to the protocol revisions contemplated in the stakeholder process, the Commission-directed rulemaking proceeding to evaluate certain aspects of RMR service in ERCOT concluded in 2017.[51] The amendments to 16 TAC §25.502 adopted by the Commission[52] adjust the notice requirements and complaint timeline applicable to suspending a resource's operation. They also gives ERCOT the discretion to decline to enter into an RMR agreement based on the economic value of lost load, requires ERCOT approval of RMR and MRA agreements and requires refunds

48 *See* NPRR788, RMR Study Modifications.

49 NPRR810, Applicability of RMR Incentive Factor on Reservation and Transportation Costs Associated with Firm Fuel Supplies.

50 *Id.*

51 *See* Project No. 46369, *Rulemaking Relating to Reliability Must-Run Service.*

52 The amendments to §25.502 relating to pricing safeguards in markets operated by ERCOT became effective on January 1, 2018.

in some instances for capital expenditures related to those agreements. An NPRR to incorporate these rule changes into the ERCOT Protocols is currently in progress.[53]

Further, several new proposed Protocol revisions were initiated in 2017, including reevaluation of the process for determining the Mitigated Offer Cap for RMR resources, previously contemplated in NPRR784.[54] The proposal would allow the RMR resource to be dispatched but be priced above other resources that solve the same constraint. Another proposed revision would clarify that operations and maintenance (O&M) costs are to be updated and submitted to ERCOT every three months, consistent with the schedule for provision of updated budgets for RMR resources, and would clarify the requirement for variable O&M costs submissions to include all variable costs incurred by the RMR resource for up to a ten year historical period.[55] And finally, a proposal was submitted that would allow third-party evaluation of submitted budget items, changes to the standby payment as cost information changes, and a final reconciliation intended to ensure that RMR payments are as accurate as possible.[56] This protocol change would include a requirement for ERCOT to issue a miscellaneous Invoice to reconcile final RMR costs no later than 30 days after the Real-Time Market True-Up Statement is issued for the termination date of the RMR agreement.

53 *See* NPRR862, Updates to Address Revisions under PUCT Project No. 46369.

54 NPRR826, Mitigated Offer Caps for RMR Resources.

55 NPRR838, Updated O&M Cost for RMR Resources.

56 NPRR845, RMR Process and Agreement Revisions.

VI. RESOURCE ADEQUACY

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's needs. This section begins with an evaluation of these economic signals by estimating the "net revenue" resources received from ERCOT real-time and ancillary services markets and providing comparisons to other markets. Next, the effectiveness of the Scarcity Pricing Mechanism is reviewed. The current estimate of planning reserve margins for ERCOT and other regions are presented, followed by a description of the factors necessary to ensure resource adequacy in an energy-only market design.

A. Net Revenue Analysis

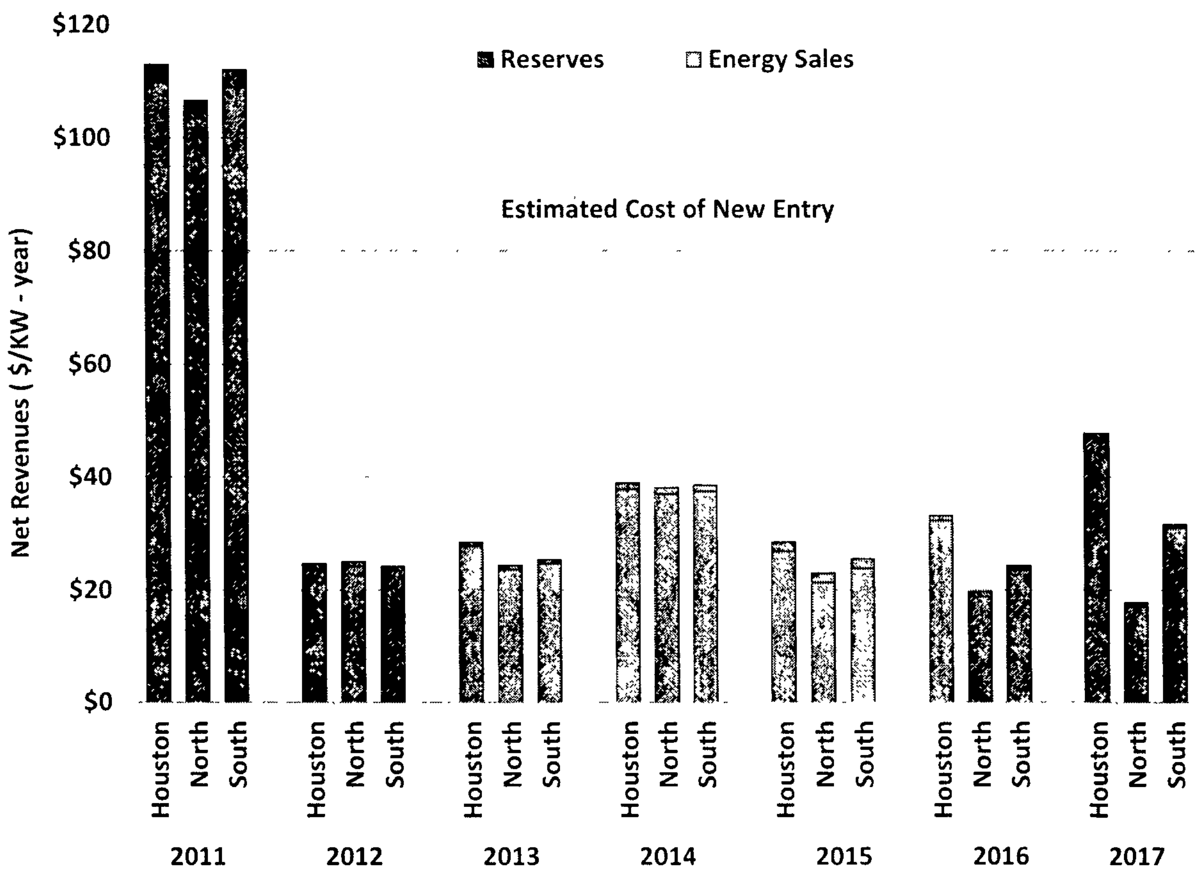
Net revenue is calculated by determining the total revenue that could have been earned by a generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. In ERCOT's energy-only market, the net revenues from the real-time energy and ancillary services markets alone provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. To the extent that revenues are available through the day-ahead market or other forward bilateral contract markets, these revenues are ultimately derived from the expected real-time energy and ancillary service 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 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 should be informed by history, they will also factor in the likelihood of shortage pricing conditions that could be very different than what actually occurred.

The energy net revenues are computed based on the generation-weighted settlement point prices from the real-time energy market. Weighting the energy values in this way facilitates comparisons between geographic zones, but will mask what could be very high values for a specific generator location. This analysis does not consider any payments for potential RUC actions. The analysis necessitates reliance on simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. Start-up costs and minimum running times are not accounted for in the net revenue analysis. Ramping restrictions, which can prevent generators from profiting during brief price spikes, are also excluded. But despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

For purposes of this analysis, the following assumptions were used for natural gas units: heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a combustion 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. Net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation (combined cycle units only) in all other hours.

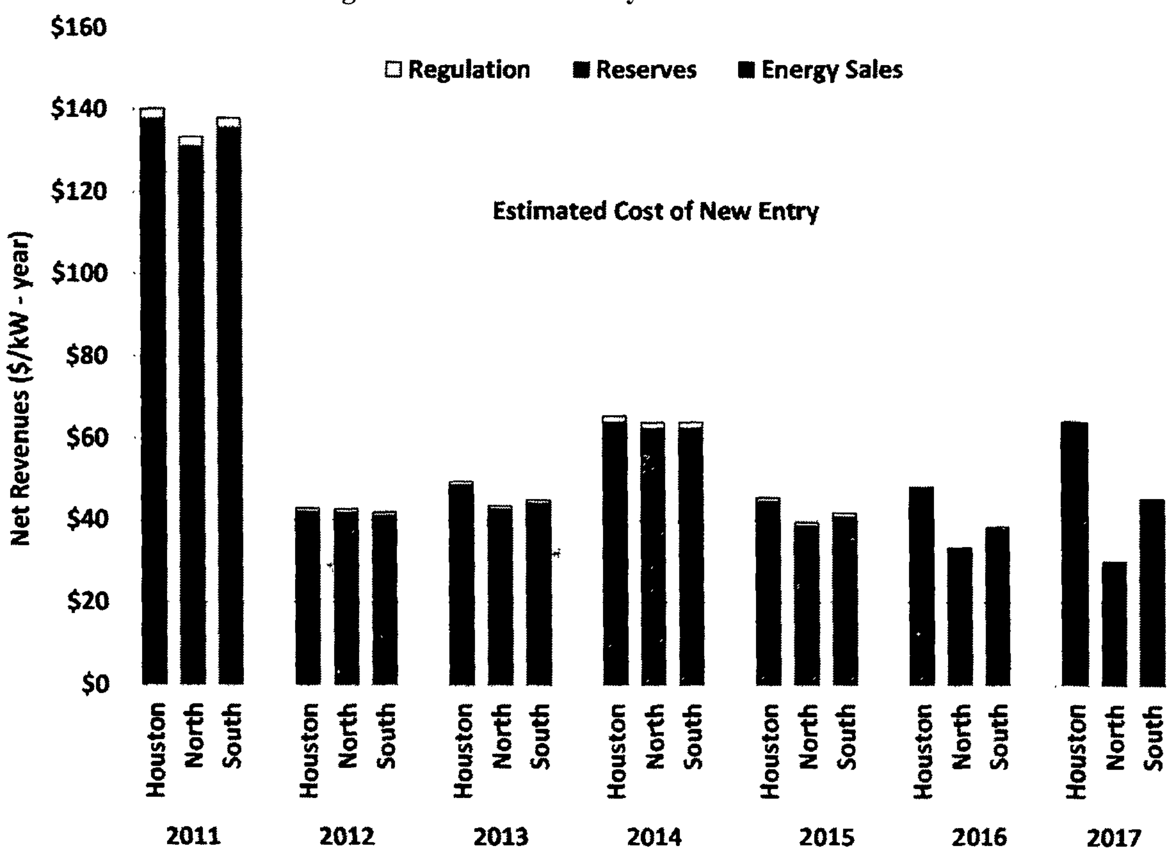
The next two figures provide an historical perspective of the net revenues available to support investment in a new natural gas combustion turbine (Figure 80) and combined cycle generation (Figure 81), selected to represent the marginal new supply that may enter when new resources are needed. Values for the West zone are excluded because historically lower energy prices make it a less attractive location to site natural gas generation. The figure also shows the estimated "cost of new entry," which represents the revenues needed to break even on the investment.

Figure 80: Combustion Turbine Net Revenues



Based on estimates of investment costs for new units, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new combustion turbine unit ranges from $80 to $95 per kW-year. The ERCOT market continued to provide net revenues well below the level needed to support new investment, ranging from below $20 per kW-year in the North Zone to almost $48 per kW-year in Houston.

Figure 81: Combined Cycle Net Revenues



For a new combined cycle natural gas unit, the estimate of net revenue requirement is approximately $110 to $125 per kW-year. The net revenue in 2017 for a new combined cycle unit was calculated to be approximately $30 to $64 per kW-year, depending on the zone. These values are well below the estimated cost of new combined cycle generation.

These results are consistent with continued surplus of capacity, which contributed to infrequent shortages over the past three years. In an energy-only market, shortages play a key role in delivering the net revenues an investor needs to recover its investment. Such shortages will tend to be clustered in years with unusually high load or poor generator availability. Hence, these results alone do not raise substantial concern regarding design or operation of ERCOT's Operating Reserve Demand Curve (ORDC) mechanism for pricing shortages. Given the recent generation retirements and continued load growth, 2018 may well be a year with significantly more occurrences of shortage pricing.

Given the low natural gas and resulting energy prices in 2017, the economic viability of existing coal and nuclear units was evaluated. Non-shortage prices, which have been substantially affected by the prevailing natural gas prices, determine the vast majority of net revenues received by these base load units. As previously described, the load-weighted ERCOT-wide average energy price in 2017 was $28.25 per MWh. The generation-weighted average price for the four nuclear units in ERCOT (approximately 5 GW of capacity) was lower at $24.73 per MWh. This is similar to nuclear prices in 2016 and 2015, which were also lower than the ERCOT-wide prices in those years. Nuclear prices were $21.46 per MWh in 2016, down from $24.56 per MWh in 2015.

Table 10 displays the calculated output-weighted price by generation type.

Table 10: Settlement Point Price by Fuel Type

Generation Type	Output-Weighted Price
Coal	$26.32
Combined Cycle	$28.45
Gas Peakers	$50.22
Gas Steam	$43.34
Hydro	$27.48
Nuclear	$24.73
Power Storage	$47.66
Private Network	$30.07
Renewable	$23.91
Solar	$24.34
Wind	$16.57

Assuming that operating costs in ERCOT are similar to the U.S. average, it is likely that these units were not profitable in 2017 based on the fuel and operating and maintenance costs alone. Hence, it is unlikely that these nuclear units covered any capital costs that may have been incurred. However, unlike other regions with large amounts of nuclear generation, the four nuclear units in ERCOT are relatively new and owned by four entities with sizable load obligations. Although not profitable on a stand-alone basis, the nuclear units have substantial option value for the owners because they ensure that their cost of serving their load will not rise substantially if natural gas prices increase. Nonetheless, the economic pressure on these units does potentially raise a resource adequacy issue that will need to continue to be monitored.

The generation-weighted price of all coal and lignite units in ERCOT during 2017 was $26.32 per MWh, an increase from $23.98 per MWh in 2016. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $2.59 per MMBtu in 2017; returning to 2015 levels after decreasing to $2.51 per MMBtu in 2016. During 2015 and 2016, delivered coal costs in ERCOT were higher than natural gas prices at the Houston Ship Channel, resulting in reduced market share for coal generation. With the increased natural gas prices in 2017, the spread between coal and natural gas increased to nearly $0.40 per MMBtu. However, given coal units generally have higher heat rates and more expensive non-fuel operations and maintenance costs, economic pressure remain. During 2017 one coal unit was seasonally mothballed and Luminant declared its intention to retire seven other coal units in early 2018. The IMM reviewed each of these actions and found them to be supported by the unit specific financials.

These results indicate that during 2017 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. As detailed in Figure 62, 2017 saw the highest level of non-renewable capacity additions since 2010, which may seem inconsistent with the low levels of scarcity pricing present in the ERCOT market in recent years. However, the fact that new generation continues to be added in the ERCOT market can be explained by a number of factors.

First, resource investments are driven primarily by forward price expectations. Historical net revenue analyses do not provide a view of the future pricing expectations that will spur new investment. Suppliers will develop their own view of future expected revenue and given the level to which prices will rise under shortage conditions, small differences in expectations about the frequency of shortage pricing can greatly influence revenue expectations.

Second, this analysis does not account for bilateral contracts. The only revenues considered in the net revenue calculation are those that came directly from the ERCOT real-time energy and ancillary services markets in a specific year. Some developers may have bilateral contracts for unit output that would provide more revenue than the ERCOT market did in 2017. Given the level to which prices will rise under shortage conditions, buyers may enter bilateral contracts to hedge against high shortage pricing.

Third, net revenues in any one year may be higher or lower than an investor would require over the long term. In 2017, shortages were again much less frequent than would be expected over the long term. Shortage revenues play a pivotal role in motivating investment in an energy-only market like ERCOT. Hence, in some years shortage pricing will be frequent and net revenues may substantially exceed the cost of entry, while in most others it will be less frequent and net revenue will be less than the cost of entry.

Finally, the costs of new entry used in this report are generic and reflective of the costs of a new unit on an undeveloped greenfield site. They have been reduced somewhat to reflect the lower costs of construction in Texas. However, companies may have opportunities to build generation at much lower cost than these estimates; either by having access to lower cost equipment, or by adding the new unit to an existing site, or some combination of both. Financing structures and costs can vary greatly between suppliers and may be improved to be lower than the generic financing costs assumed in the net revenue analysis.

To provide additional context for the net revenue results presented in this subsection, the net revenue in the ERCOT market for two types of natural gas generation technologies are compared with the net revenue that those technologies could expect in other wholesale markets.

Figure 82 provides a comparison of net revenues for a hypothetical combustion turbine with an assumed heat rate of 10,500 MMBtu per MWh installed in ERCOT, MISO, NYISO, and PJM. Net revenues for two locations in both ERCOT and NYISO are provided to highlight the variation in value that can exist even within the same market.

Figure 82: Combustion Turbine Net Revenue Comparison Between Markets

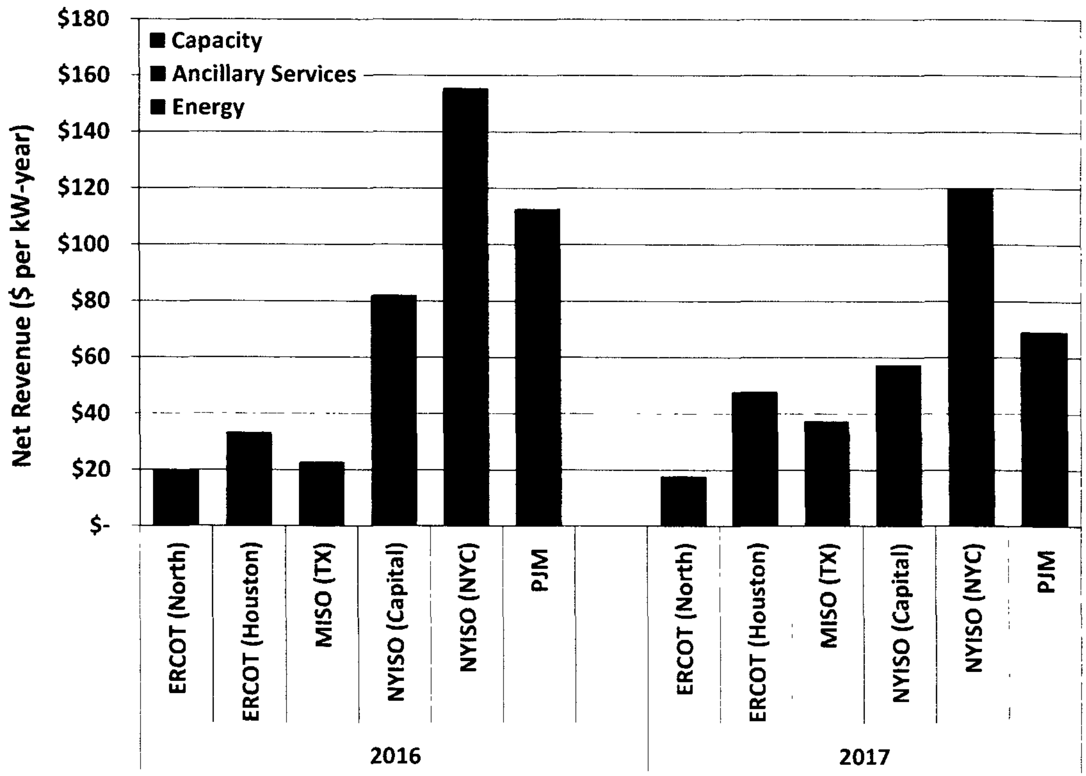


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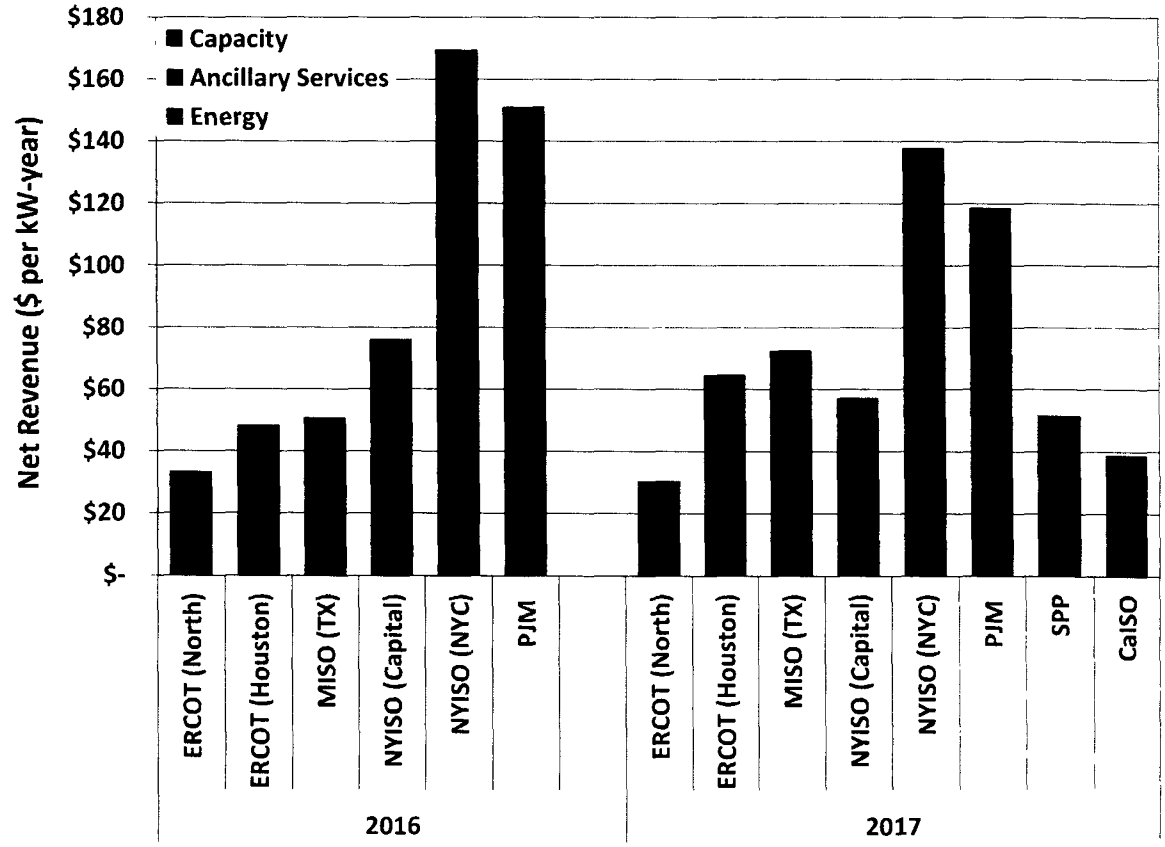
Figure 83 provides the net revenues for a hypothetical combined cycle unit with an assumed heat rate of 7,000 MMBtu per MWh installed in ERCOT, MISO, NYISO, and PJM. Both figures display estimates of net revenue from energy, reserves and regulation, and capacity. ERCOT does not have a capacity market, and thus, does not have any net revenue from capacity sales. Additionally, Figure 83 includes estimated total net revenues for a combined cycle generator located in SPP and CalSO, shown without the component values.

Figure 83: Combined Cycle Net Revenue Comparison Between Markets



Both figures indicate a general decline in net revenues across all markets. The exceptions to this trend were ERCOT's Houston zone and MISO's TX zone. Most other markets also have sufficient installed reserves, typically a result of flat or no load growth. The increase in Houston was related to transmission congestion limiting imports to the area. The two figures also show that capacity revenues in NYISO and PJM provide a meaningful portion of the net revenues for new resources. In ERCOT, these revenues will be provided through its shortage pricing, which is evaluated in the next section.

B. Effectiveness of the Scarcity Pricing Mechanism

The PUCT adopted rules in 2006 that define the parameters of an energy-only market. In accordance with the IMM's charge to conduct an annual review,[57] this subsection assesses the Scarcity Pricing Mechanism (SPM) in 2017 under ERCOT's energy-only market structure.

Revisions to 16 TAC § 25.505 were adopted in 2012 that specified a series of increases to the ERCOT system-wide offer cap. The last step went into effect on June 1, 2015, increasing the system-wide offer cap to $9,000 per MWh. As shown in Figure 20: Duration of High Prices on page 23, there have been very brief periods when energy prices rose to the cap since the system-wide offer cap was increased to greater than $3,000 per MWh, and none since 2015.

The SPM includes a provision termed the Peaker Net Margin (PNM) that is designed to provide a fail-safe pricing measure, which if exceeded would cause the system-wide offer cap to be reduced. If the PNM for a year reaches a cumulative total of $315,000 per MW, the system-wide offer cap is then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[58] PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[59]

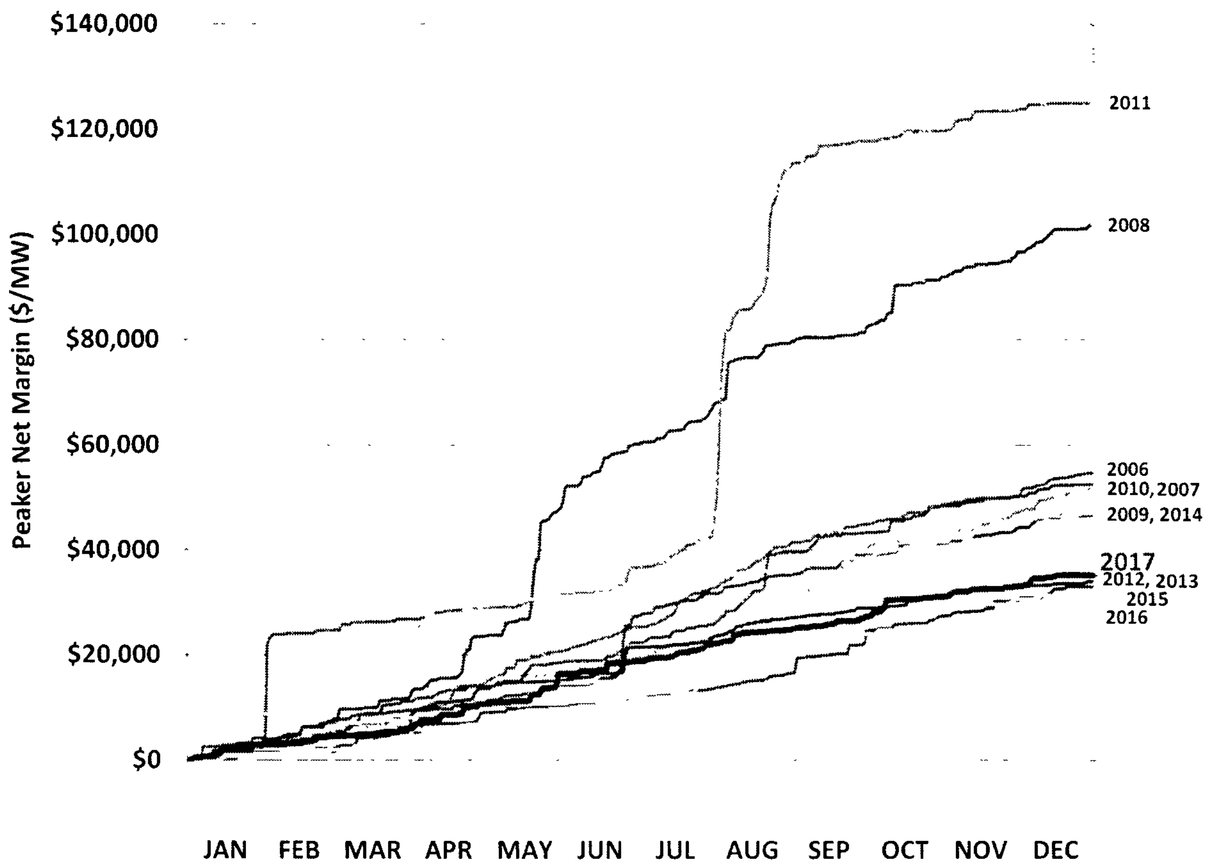
Figure 84 shows the cumulative PNM results for each year from 2006 through 2017 and shows that PNM in 2017 increased slightly from 2015 and 2016 levels. Considering the purpose for which the PNM was initially defined, that is to provide a "circuit breaker" trigger for lowering the system-wide offer cap, it has not approached levels that would dictate a needed reduction in the system wide offer cap.

57 *See* 16 TAC § 25.505(g)(6)(D).

58 The threshold established in the initial Rule was $300,000 per MW-year. For 2014 and each subsequent year, ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants. The current threshold is based on the most recent version of an Other Binding Document entitled "System-Wide Offer Cap and Scarcity Pricing Mechanism Methodology."

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

Figure 84: Peaker Net Margin



As with net revenues, the PNM is expected to be less than the cost of new entry in most years. Concerns with the SPM under the zonal market design were addressed in every State of the Market Report produced during that period.[60] The implementation of the nodal market design, which included a power balance penalty curve, created the opportunity for real-time energy prices to systematically reflect the value of reduced reliability imposed under shortage conditions, regardless of submitted offers.

In 2013, the PUCT took another step toward improving resource adequacy signals by directing ERCOT to implement the ORDC. As discussed in Section I: Review of Real-Time Market Outcomes, ORDC is a shortage pricing mechanism that reflects the loss of load probability at varying levels of operating reserves multiplied by the value of lost load. In the short time it has been in effect, ORDC has had a small impact on real-time prices.

60 The zonal market design was not the problem per se, rather its reliance on high-priced offers to set high prices during periods of shortage was of concern.

In October 2015, the PUCT signaled its interest in reviewing ORDC "in order to examine how it has functioned and whether there is a need for minor adjustments to improve its efficiency."[61] Given the short time period with ORDC in effect, it is difficult to evaluate whether adjustments are warranted. As previously discussed, shortages are generally clustered in periods when weather-dependent load is unusually high or generation availability is poor; neither of which has occurred since the ORDC was implemented.

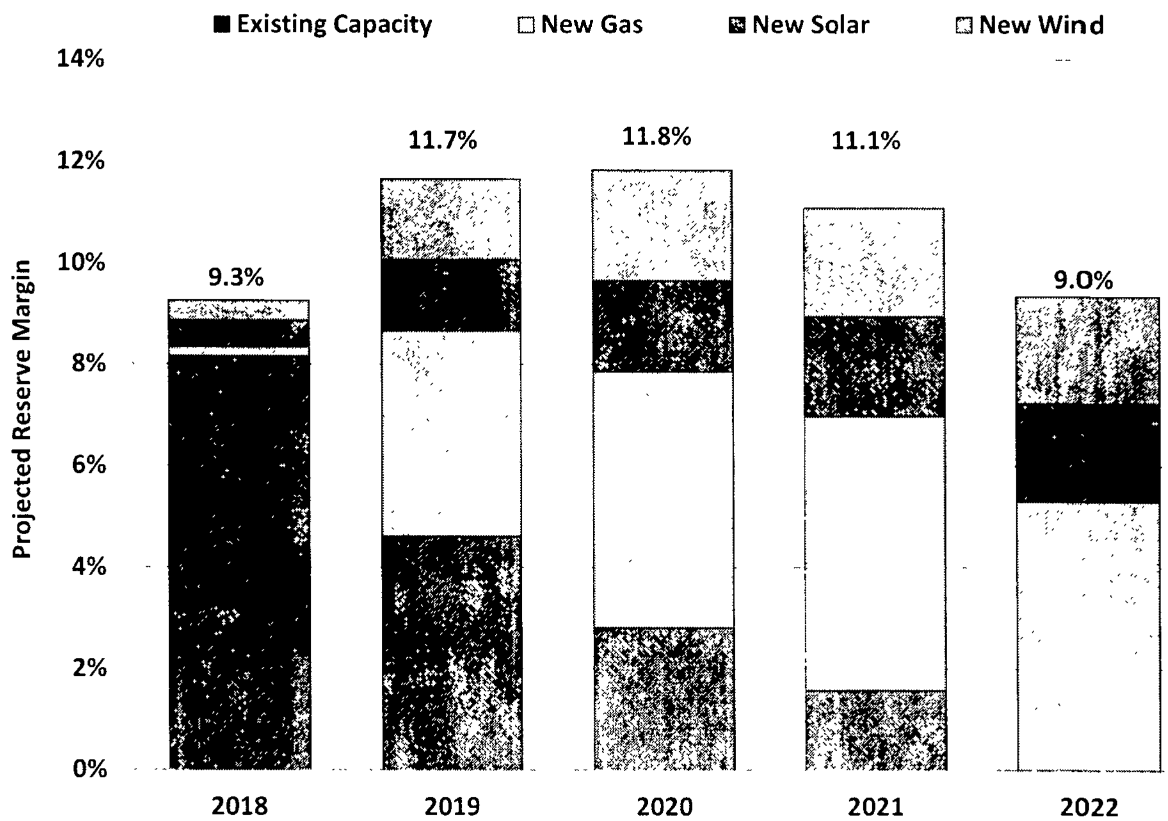
The fact that responsive and regulating reserves are forced to be maintained (held behind the High Ancillary Service Limit (HASL)) under the current market design will continue to be problematic, regardless of the ORDC parameters that are selected. Jointly optimizing all products would improve the utilization of ERCOT resources, ensure that shortage pricing only occurs when the system is actually short after fully utilizing its resources, and establish prices for each product that efficiently reflect its reliability value without the use of administrative caps and adders. Hence, the IMM continues to recommend that ERCOT make the investment necessary to achieve the full benefits of real-time co-optimization across all resources.

C. Planning Reserve Margin

The prior subsection discusses and evaluates the economic signals produced by the ERCOT markets to facilitate efficient decisions by suppliers to maintain an adequate base of resources. This subsection summarizes and discusses the current level of capacity in ERCOT, as well as the long-term need for capacity in ERCOT. Figure 85 below shows ERCOT's current projection of planning reserve margins.

61 PUCT Project No. 40000, *Commission Proceeding to Ensure Resource Adequacy in Texas*, Memorandum from Commissioner Kenneth W. Anderson, Jr. (Oct. 7, 2015).

Figure 85: Projected Planning Reserve Margins



Source: ERCOT Capacity, Demand and Reserves Report - December 2017

Figure 85 indicates that the region will have a 9.3% reserve margin heading into the summer of 2018. These projections are noticeably lower than those developed since May of last year,[62] which is due in large part to the approximately 5 GW of capacity taken offline by early 2018, with an expectation that the reserve margin will continue to be below the existing target level of 13.75% for the foreseeable future.[63]

This current projection of planning reserve margins is consistent with the economic signals produced by the market in recent years, which are themselves the product of the sustained

62 See Report on the Capacity, Demand and Reserves in the ERCOT Region (May 2, 2017); http://www.ercot.com/content/wcm/lists/114798/CapacityDemandandReserveReport-May2017.pdf

63 The target planning reserve margin of 13.75% was approved by the ERCOT Board of Directors in November 2010, based on a one in ten loss of load expectation (LOLE). The PUCT directed ERCOT to evaluate planning reserve margins based on an assessment of the Economically Optimal Reserve Margin (EORM) and the Market Equilibrium Reserve Margin (MERM). *See* PUCT Project No. 42303, ERCOT Letter to Commissioners (Oct. 24, 2016). On December 12, 2017, ERCOT published its "Study Process and Methodology Manual: Estimating Economically Optimum and Market Equilibrium Reserve Margins" as part of its ongoing reporting initiative.

capacity surpluses that have existed in ERCOT. Hence these results demonstrate that the market is functioning properly. Less efficient, uneconomic units are retiring in times of relatively low prices. Of the eleven generation units scheduled to retire or mothball since the May 2017 CDR, eight of those units (totaling approximately 4,500 MW) were coal units.[64] The IMM views the decisions to retire the coal units to be justified based on the operating history and estimated costs of continued operations. Similar to the forces that have led to the retirement of less efficient natural gas fueled steam units, the retirement of older, less efficient coal units is an expected market outcome. With expectations for future natural gas prices to remain relatively low, the economic pressure on coal units in ERCOT is not expected to subside any time soon. This economic pressure will exist regardless of the future of environmental regulations that could require additional capital investment for existing coal units.

The retirement of uneconomic generation should not be viewed as failure to provide resource adequacy. In fact, facilitating efficient decisions by generators to retire uneconomic units is nearly as important as facilitating efficient decisions to invest in new resources. The market will achieve both objectives by establishing good economic price signals.

Even with low prices, there continues to be high interest in the ERCOT market from generation developers as evidenced by the amount of capacity under consideration for interconnection. At the end of 2017 there was more capacity in the various stages of interconnection evaluation than at the beginning of the year. However, the composition of that capacity had changed with much more solar generation and reduced amounts of natural gas generation.

Because the surplus has now disappeared and shortages are likely to be more frequent in 2018, the economic signals could change rapidly. These short-term market outcomes and price signals, as well as investors' response to these economic signals, will be monitored. This response could cause the planning reserve margins to exceed the forecast shown in Figure 85 above.

D. Ensuring Resource Adequacy

One of the primary goals of an efficient and effective electricity market is to ensure that, over the long term, there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. In a region like ERCOT, where customer requirements for electricity have been and are expected to continue to increase, even with growing demand response efforts, maintaining adequate supply requires capacity additions. To incent these additions the market design must provide revenues such that the marginal resource receives

64 Monticello Units 1, 2, and 3, totaling 1,865 MW, to be retired on January 4, 2018; Sandow Units 4 and 5, totaling approximately 1,200 MW, to be retired on January 11, 2018; Big Brown Units 1 and 2, totaling 1,208 MW, to be retired on February 12, 2018; Gibbons Creek, a 470 MW unit seasonally mothballed in October 2017.

revenues sufficient to make that resource economic. In this context, "economic" includes both a return of and on capital investment.

Generators earn revenues from three sources: energy prices during non-shortage, energy prices during shortage and capacity payments. The capacity payments generators receive in ERCOT are related to the provision of ancillary services. Ancillary service payments are a small contributor, approximately $5 per kW-year. Setting ancillary service payments aside, generator revenue in ERCOT is overwhelmingly derived from energy prices under both shortage and non-shortage conditions.

Expectations for energy pricing under non-shortage conditions are the same regardless of whether payments for capacity exist. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under shortage conditions must be large enough to provide the necessary incentives for new capacity additions. This will occur when energy prices are allowed to rise substantially during times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements.

Ideally, energy and reserve prices during shortages should reflect the diminished system reliability under these conditions, which is equal to the increased probability of "losing" (not serving) load times the value of the lost load. Allowing energy prices to rise during shortages mirrors the outcome expected if loads were able to actively specify the quantity of electricity they wanted and the price they would be willing to pay. The energy-only market design relies exclusively on these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment, when required. In this way, energy-only markets can provide price signals that will sustain a portfolio of resources to be used in real-time to satisfy the needs of the system. However, this portfolio may not include enough capacity to meet a specified target quantity of planning reserves.

Faced with reduced levels of generation development activity coupled with increasing loads that resulted in falling planning reserve margins, in 2012 and 2013 the PUCT devoted considerable effort deliberating issues related to resource adequacy. In September 2013, the PUCT Commissioners directed ERCOT to move forward with implementing ORDC, a mechanism designed to ensure effective shortage pricing when operating reserve levels decrease. Over the long term, a co-optimized energy and operating reserve market will provide more accurate shortage pricing. Planning reserves should continue to be monitored to determine whether shortage pricing alone is leading to the desired level of planning reserves.

VII. Analysis of Competitive Performance

In this section, market power is evaluated 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. This section also includes a summary of the Voluntary Mitigation Plans in effect during 2017. Market participant conduct is evaluated by reviewing measures of physical and economic withholding. These withholding patterns are further examined relative to the level of demand and the size of each supplier's portfolio. Based on these analyses, we find the overall performance of the ERCOT wholesale market to be competitive in 2017.

A. Structural Market Power Indicators

The market structure is analyzed by using the Residual Demand Index (RDI). The RDI is used to measure the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers.[65] When the 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 required to serve the load if the resources of its competitors are available.

The RDI is a useful structural indicator of potential market power, although it is important to recognize its limitations. As a structural indicator, it does not illuminate actual supplier behavior to indicate whether a supplier may have exercised market power, or whether it would have been profitable for a pivotal supplier to exercise market power. Nonetheless, it does identify conditions under which a supplier could raise prices significantly by withholding resources.

Figure 86 shows the ramp-constrained RDI, calculated at the QSE level, relative to load for all hours in 2017. The trend line indicates a strong positive relationship between load and the RDI.

65 For the purpose of this analysis, "quick-start" includes off-line combustion turbines that are flagged as on-line in the current operating plan with a planned generation level of 0 MW that ERCOT has identified as capable of starting-up and reaching full output after receiving a dispatch instruction from the real-time energy market.

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Figure 86: Residual Demand Index

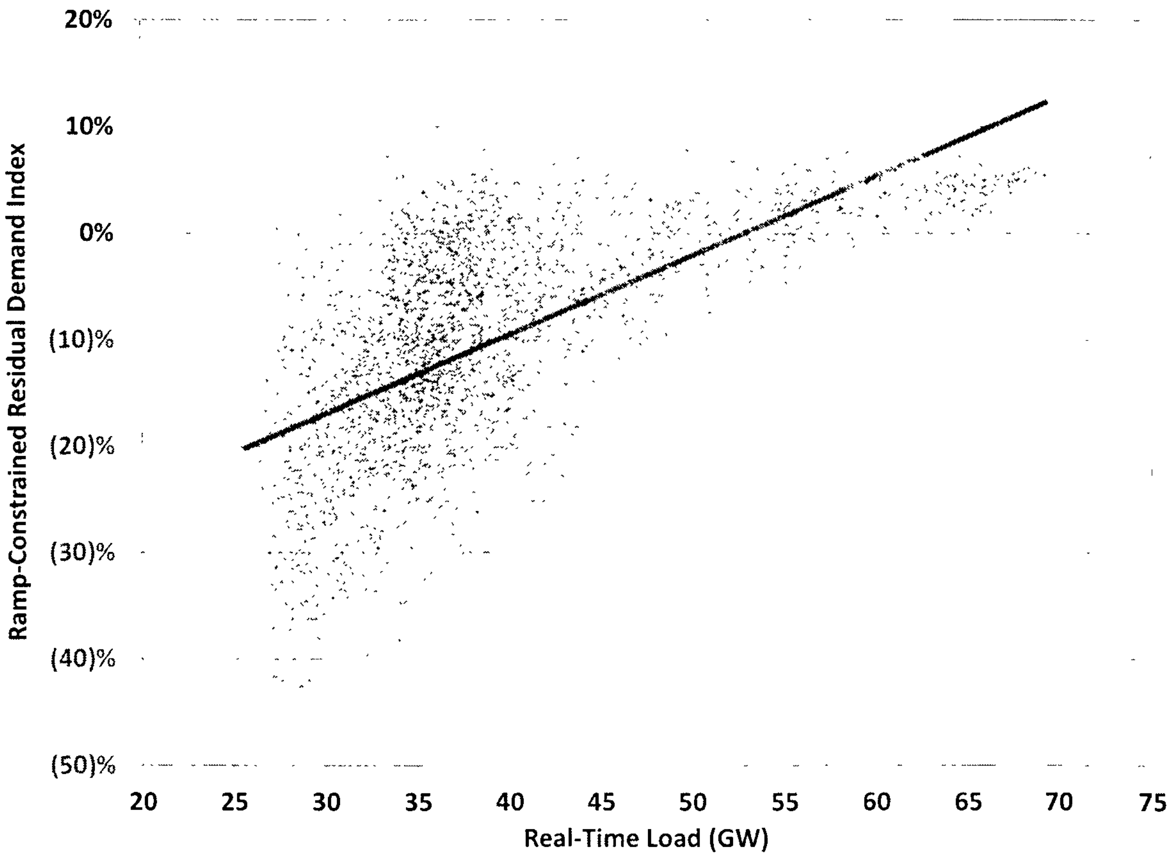
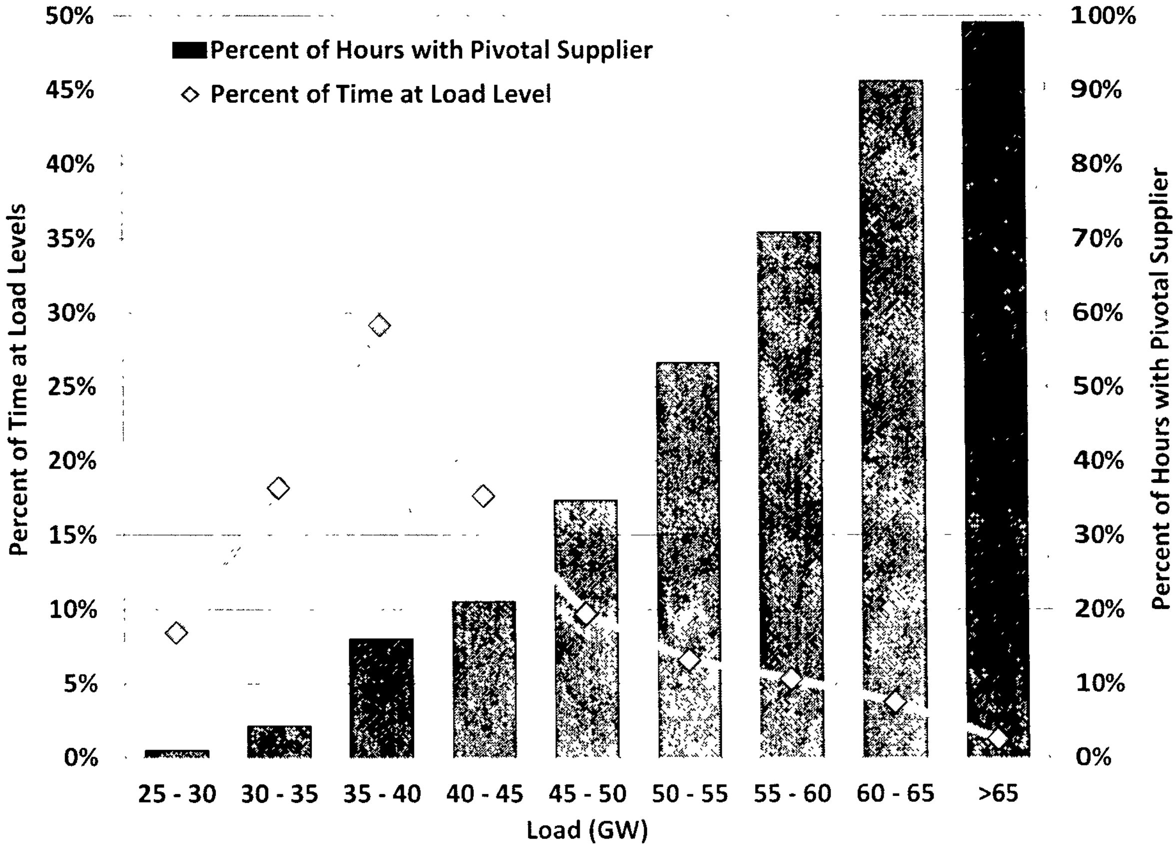


Figure 87 below summarizes the results of the RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. The figure also displays the percentage of time each load level occurs.

Figure 87: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW there was a pivotal supplier 99% of the time. This is expected because at high load levels, the largest suppliers are more likely to be pivotal as other suppliers' resources are more fully utilized serving the load. There was a noticeable decrease in the percentage of time with a pivotal supplier at loads below 50GW in 2017. This led to a decrease in the pivotal supplier frequency to 24.5% of the time in 2017, down from 28.5% and 26% of all hours in 2016 and 2015, respectively. Even with the slight decrease, market power continues to be a potential concern in ERCOT and underscores the need for effective mitigation measures to address it.

Inferences regarding market power cannot be made solely from pivotal supplier data. Bilateral and other financial contract obligations can affect a supplier's potential market power. For example, a small supplier selling energy only in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. The RDI measure shown in the previous figures do not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

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

Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) existed for four market participants in 2017. Generation owners are motivated to enter into VMPs because adherence to a plan approved by the PUCT constitutes an absolute defense against an allegation of market power abuse through economic withholding with respect to behaviors addressed by the plan. This 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 the real-time energy prices. Because forward energy markets are voluntary and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

By the end of 2017, the four market participants with approved VMPs were Calpine, NRG, Luminant and Exelon. Calpine's VMP was approved in March of 2013.[66] 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 recent additions to Calpine's generation fleet its current amount of offer flexibility has increased to approximately 700 MW. Calpine's VMP shall remain in effect from the date it was approved by the Commission until terminated by the Executive Director of the Commission or Calpine.

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

NRG's plan, initially approved in June 2012 and modified in May 2014,[67] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12% of the difference between the high sustained limit and the low sustained limit – the dispatchable capacity – for 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 shall remain 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 PUCT for a VMP in May 2015.[68] The Luminant plan is similar in many respects to the NRG plan. Under the VMP, Luminant is permitted to offer a maximum of 12% of the dispatchable capacity for its natural gas units (5% for coal/lignite units) at prices up to $500 per MWh and offer a maximum of 3% of the dispatchable capacity for natural gas units up to the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW. With the acquisition of three combined cycle units, the amount of offer flexibility had increased to approximately 900 MW. In addition, the plan contains a maximum offer for the approximately 1,000 MW of quick-start qualified combustion turbines owned by Luminant based on unit-specific verifiable costs and index prices for fuel and emissions. Luminant's VMP was in effect for all of 2017, with a termination clause requiring that it would stay in effect until terminated by the Executive Director of the Commission or by Luminant.[69]

Approved on August 31, 2017,[70] Exelon's VMP provides for up to 12% but no more than 40 MW of dispatchable capacity from non-quick start natural gas units to be offered no higher than $500 per MWh or fifty times the fuel index price defined in the VMP. Up to 3% of the difference between the high sustained limit and the low sustained limit may be offered at prices up to and including the high system-wide offer cap (HCAP). The amount of capacity covered by these provisions is slightly less than 600 MW. Exelon's VMP shall remain in effect from the

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

68 PUCT Docket No. 44635, *Request for Approval of a Voluntary Mitigation Plan for Luminant Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e)*, Order Approving VMP Settlement (May 22, 2015).

69 Luminant terminated its VMP on April 9, 2018, upon closing of the proposed transaction approved by the Commission in the Order in PUCT Docket No. 47801.

70 PUCT Docket No. 47378, *Request for Approval of a Voluntary Mitigation Plan for Exelon Generation Company, LLC*, Order (Aug. 31, 2017).

date it is approved by the Commission until terminated by the Executive Director of the Commission or Exelon, or terminated automatically upon the earlier of: (a) three years from the date of the Commission's August 31, 2017 Order, or (b) the day Exelon's Installed Generation Capacity drops below 5% of the total ERCOT Installed Generation Capacity.

Allowing small amounts of high-priced offers is intended to accommodate potential legitimate fluctuations in marginal cost that may exceed the base offer caps, such as operational risks, short-term fluctuations in fuel costs or availability, or other factors. However, all four VMPs contain a requirement that these offers, if offered in any hour of an operating day, must be offered in the same price and quantity pair for all hours of the operating day. This provision, along with the quantity limitations, significantly reduces the potential that the VMPs will allow market power to be exercised.

The final key elements in the VMPs are the termination provisions. The approved VMPs may be terminated by the Executive Director of the PUCT with three business days' notice, subject to ratification by the Commission. 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."[71] The exercise of market power may not rise to the level of an abuse of market power if it does not unreasonably impair competition, which would typically involve profitably raising prices significantly above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner rather than persisting and rising to the level of an abuse of market power.

The amount of offer flexibility afforded by the VMPs is small when compared to the offer flexibility that small participants – those with less than 5% of total ERCOT capacity – are granted under 16 TAC § 25.504(c). Although 5% of total ERCOT capacity may seem relatively trivial, the potential market impacts of a market participant whose size is just under the 5% threshold choosing to exercise flexibility and offering a significant portion of their fleet at very high prices can be large.

Currently, the 5% "small fish" threshold is roughly 4,000 MW.[72] The combined amount of capacity afforded offer flexibility under the VMPs granted to Calpine, NRG, Luminant and Exelon totals less than 2,800 MW of capacity.

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71 PURA § 39.157(a).

72 For purposes of the 5% exemption, the estimated total installed generation capacity is currently 80,423 MW; see Project No. 39870, *Estimate of Installed Generation Capacity in ERCOT*, PUC Competitive Markets' Estimate of Installed Generation Capacity in ERCOT at 1 (May 25, 2018).

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. This subsection provides the results of evaluating actual participant conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. First, unit deratings and forced outages are examined to detect physical withholding. This is followed by an evaluation of the "output gap," used to detect economic withholding.

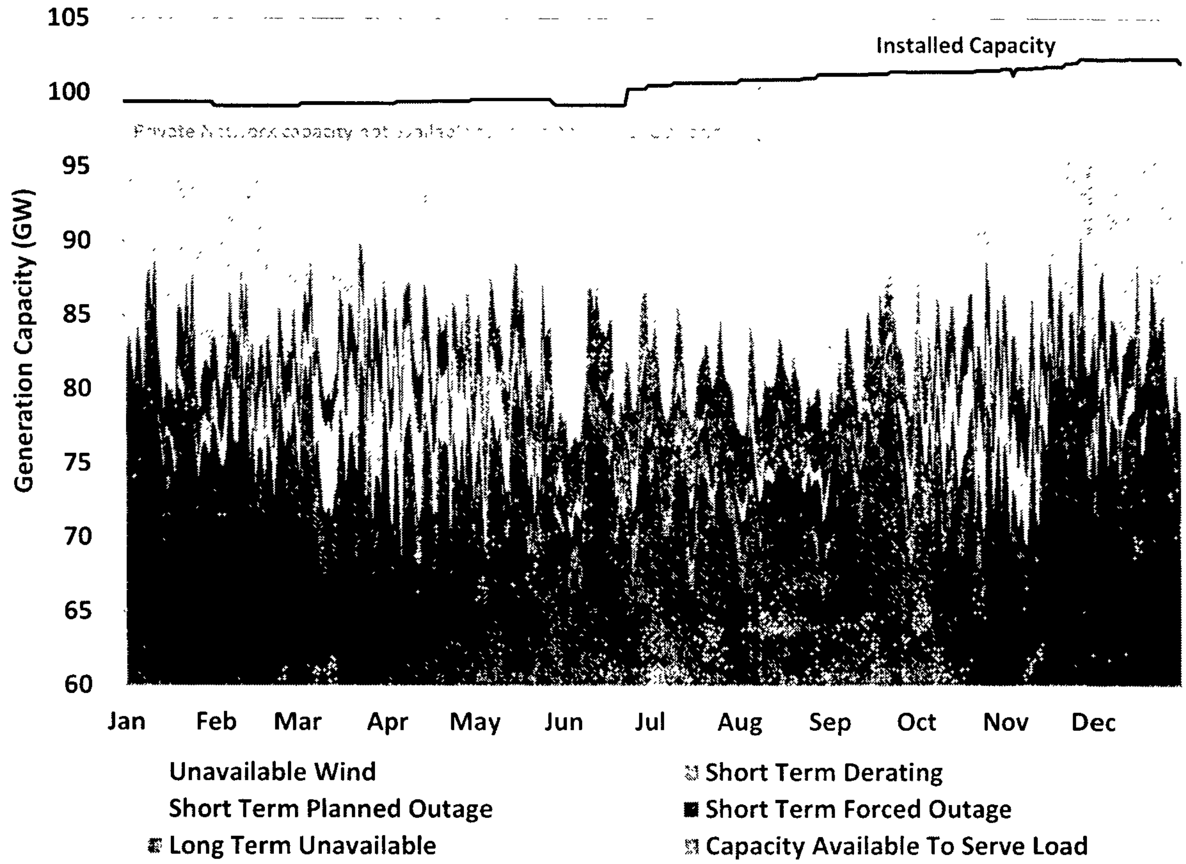
In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher market clearing prices, allowing the supplier to profit on its other sales in the real-time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

Generation Outages and Deratings

Some portion of installed capacity is commonly unavailable because of generator outages and deratings. Because of limitations in outage data, the outage type must be inferred. The outage type can be inferred by cross-referencing unit status information communicated to ERCOT with scheduled outage submissions. If there is a corresponding scheduled outage, the unit is considered to be on a planned outage. If not, it is considered to be a forced outage. The derated capacity is defined as the difference between the summertime maximum capacity of a generating resource and its actual capability as communicated to ERCOT on a continuous basis. It is very common for generating capacity to be partially derated because the resource cannot achieve its installed capacity level because of technical or environmental factors (e.g., component equipment failures or ambient temperature conditions). Wind generators rarely produce at the installed capacity rating because of variations in available wind input. Because such a large portion of derated capacity is related to wind generation it is shown separately in the following evaluation of long-term and short-term deratings.

Figure 88 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2017. This analysis includes all in-service and switchable capacity. From the total installed capacity the following are subtracted: (a) capacity from private networks not available for export to the ERCOT grid; (b) wind capacity not available because of the lack of wind input; (c) short-term deratings; (d) short-term planned outages; (e) short-term forced outages; and (e) long-term outages and deratings greater than 30 days. What remains is the capacity available to serve load.

Figure 88: Reductions in Installed Capacity



Outages and deratings of non-wind generators fluctuated between 5 and 17 GW, as shown in Figure 88, while wind unavailability varied between 4 and 20 GW. Short-term planned outages were largest in the shoulder months of March, April and October, while smallest during the summer months, consistent with expectations. Short-term forced outages and deratings had no discernable seasonal pattern, occurring throughout the year.

The quantity of long-term (greater than 30 days) unavailable capacity, peaked in March at 4.7 GW and dropped to below 1 GW in late May. In early June, one of the Comanche Peak nuclear units experienced a long term forced outage lasting until early August, driving the long-term unavailable capacity to just over 2 GW. Unavailable capacity reduced to 1 GW with the return to service of Comanche Peak unit 2 before increasing to 3.3 GW in October. With the exception of the impacts of the Comanche Peak outage, this pattern reflects the continued choice by generation owners to schedule long duration outages during the spring and fall so as to ensure the units are available during the high load summer season when the units have a higher likelihood of operating.

The next analysis focuses 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 an attempt to raise prices. Figure 89 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2017.

Figure 89: Short-Term Outages and Deratings

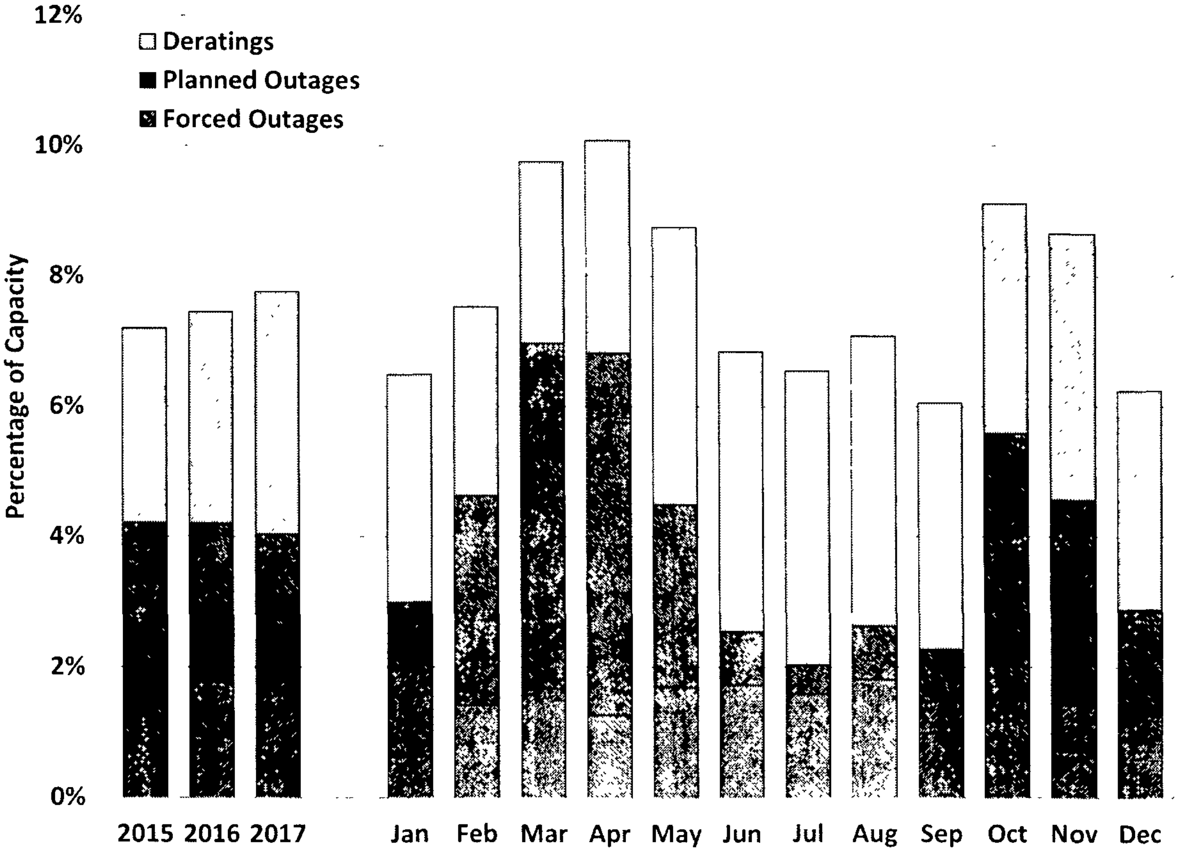


Figure 89 shows that total short-term deratings and outages were as large as 10% of installed capacity in April, and averaged around 6.5% during the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2017 averaged 7.7% of installed capacity. This is a slight increase from 7.5% experienced in 2016 and 7.2% experienced in 2015. Excluded from this analysis was a lengthy forced outage of Comanche Peak unit 2, which occurred from early June to mid-August. Including the effects of this long-term forced outage of this large unit increases the monthly forced outage rates in June through August to almost 3%, and raises the annual forced outage rate from 1.6% to approximately 1.8%. Even with including the Comanche Peak outage, outages and deratings are lowest during the summer when load is expected to be highest is consistent with expectations in a competitive market.

Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and that are economic at prevailing market prices. This can be done either by derating a unit or declaring it 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. Physical withholding is tested for 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 RDI results shown in Figure 86 and Figure 87 indicate that the potential for market power abuse rises at higher load levels as the frequency of positive RDI values 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 90 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load levels for large and small suppliers during summer months. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, the patterns of outages and deratings of large suppliers can be usefully evaluated by comparing them to the small suppliers' patterns.

Long-term deratings are not included in this analysis because they are unlikely to constitute physical withholding given the cost of such withholding. 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 90: Outages and Deratings by Load Level and Participant Size, June-August

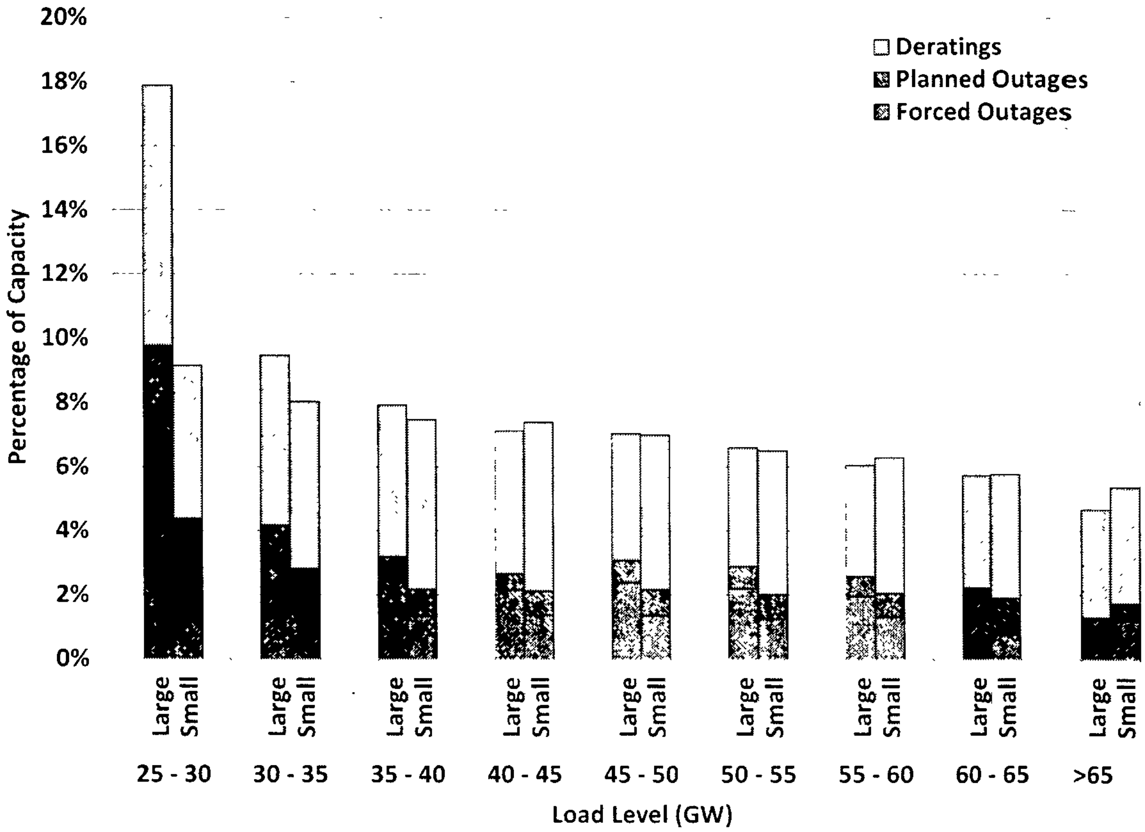


Figure 90 suggests that as demand for electricity increases, all market participants tend to make more capacity available to the market by scheduling planned outages during low load periods. Because small participants have less incentive to physically withhold capacity, the outage rates for small suppliers serves as a good benchmark for competitive behavior expected from the larger suppliers.

As in the previous analyses, the lengthy forced outage of Luminant's Comanche Peak nuclear unit is excluded from the analysis shown in Figure 90. If included, the effects of that outage would have approximately doubled the forced outage rates for large parties during the higher load periods. The higher forced outage rate for large parties at the lowest load levels reflects the impacts of Hurricane Harvey. Setting these two issues aside because they raise no competitive concerns, outage and deration rates for large suppliers were less than those of the smaller suppliers in 2017.

Evaluation of Potential Economic Withholding

To complement the prior analysis of physical withholding, this subsection evaluates 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.

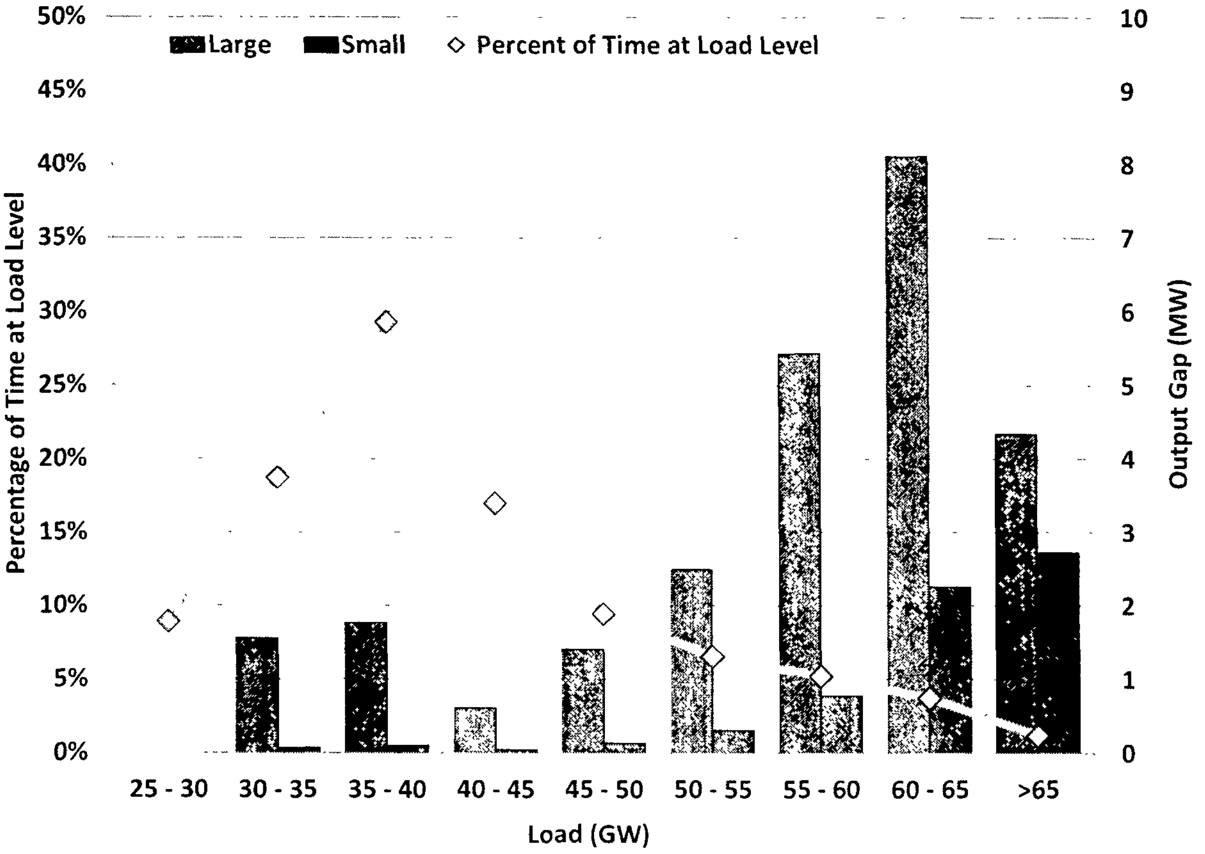
A resource is evaluated for inclusion in the output gap when it is committed and producing at less than full output. Energy not produced from a committed resource is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $30 per MWh.[73] The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

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

If a market participant has sufficient market power, it might raise its offer in such a way to increase the reference price in the first step. Although in the second step the offer appears to be mitigated, the market participant has still influenced the market price. This output gap is measured by the difference between the capacity level on a generator's original offer curve at the first step reference price and the capacity level on the generator's cost curve at the first step reference price. However, this output gap is only indicative because no output instructions are sent based on the first step. It is only used to screen whether a market participant is withholding in a manner that may influence the reference price.

73 Given the low energy prices since 2016, the output gap margin has been reduced to $30 for purposes of this analysis. Prior to 2015, the State of the Market report used $50 for the output gap margin.

Figure 91: Incremental Output Gap by Load Level and Participant Size – Step 1

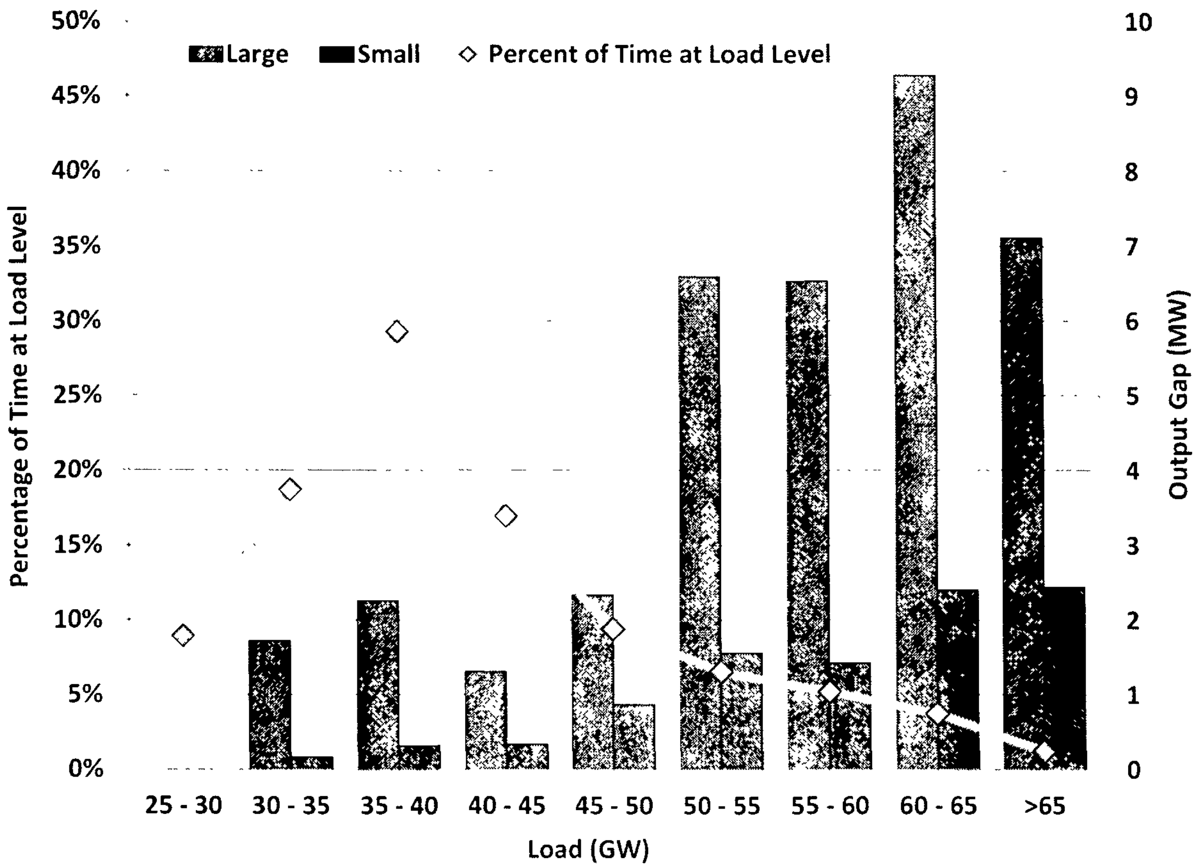


The results of the analysis shown in Figure 91 indicate that only very small amounts of capacity would be considered part of the first step output gap.

Figure 92 below shows the ultimate output gap levels, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. In the second step of the dispatch, the after-mitigation offer curve is used to determine dispatch instructions and locational prices. As previously illustrated, even though the offer curve is mitigated there is still the potential for the mitigated offer curve to be increased as a result of a high first-step reference price being influenced by a market participant raising prices.

Similar to the previous analysis, Figure 92 also shows very small quantities of capacity that would be considered part of this output gap.

Figure 92: Incremental Output Gap by Load Level and Participant Size – Step 2



These results show that potential economic withholding levels were extremely low for the largest suppliers and small suppliers alike in 2017. Output gaps of the largest suppliers are routinely monitored individually and were found to be consistently low across all load levels. These results, together with our evaluation of the market outcomes presented in this report, allow us to conclude that the ERCOT market performed competitively in 2017.