2015 State of the Market Report
for the
ERCOT Wholesale Electricity Markets

Potomac Economics, Ltd.

Independent Market Monitor for the
ERCOT Wholesale Market

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EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2015 and is submitted to the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT) pursuant to the requirement in Section 39.1515(h) of the Public Utility Regulatory Act (PURA). It includes assessments of the incentives provided by the current market rules and procedures and analyses of the conduct of market participants. This report also assesses the effectiveness of the Scarcity Pricing Mechanism (SPM) pursuant to the provisions of 16 TEX. ADMIN. CODE § 25.505(g).

Key findings and statistics from 2015 include the following:

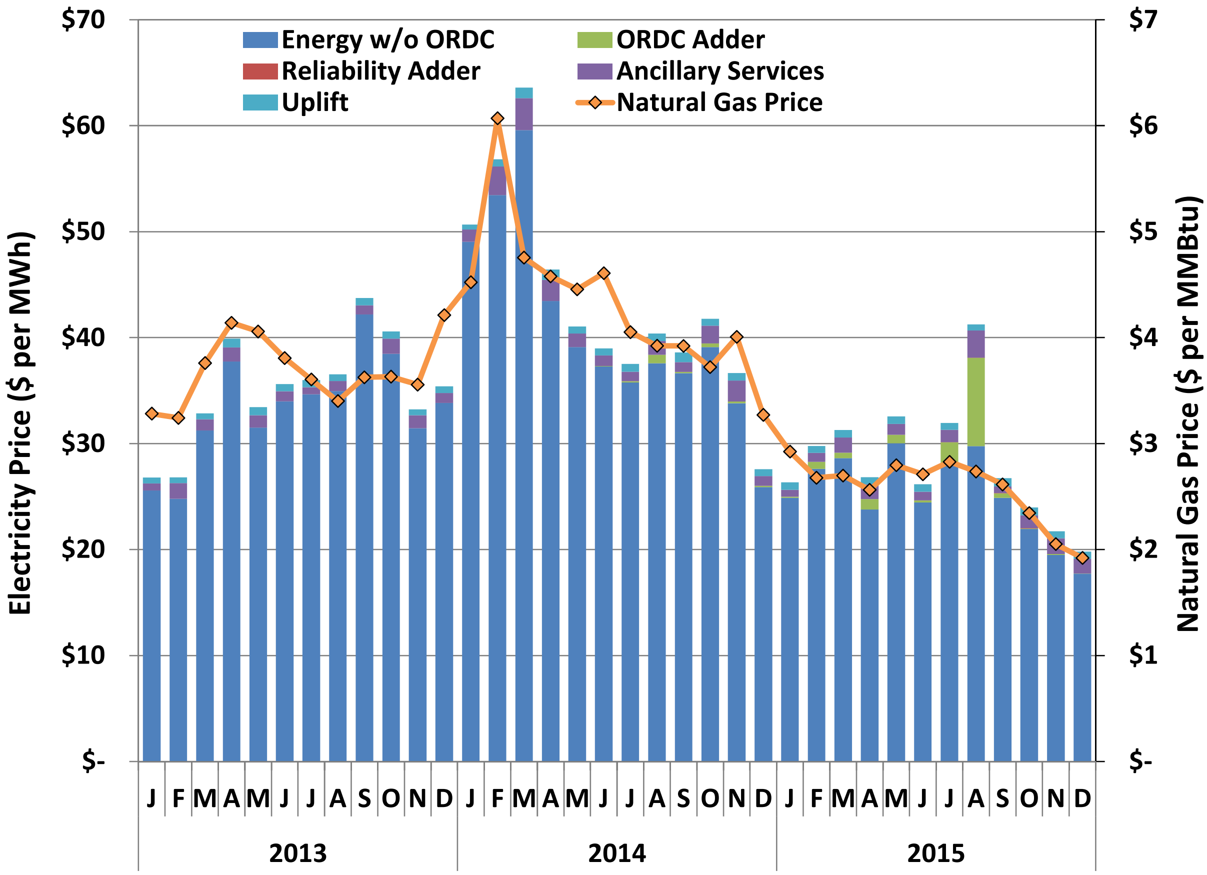
- The ERCOT wholesale market performed competitively in 2015.
- The ERCOT-wide load-weighted average real-time energy price was $26.77 per MWh in 2015, a 34 percent decrease from 2014 primarily driven by lower natural gas prices.
  - The average price for natural gas was 41 percent lower in 2015 than in 2014, decreasing from $4.32 per MMBtu in 2014 to $2.57 per MMBtu in 2015.
  - There were no instances of energy prices rising to the system-wide offer cap in 2015. Prices exceeded $3,000 per MWh in less than one hour, cumulatively.
- A new coincident peak hourly demand record of 69,877 MW was set on August 10. Average real-time load was also up 2.4 percent from 2014.
- The total congestion revenue generated by the ERCOT real-time market in 2015 was $352 million, a decrease of 50 percent from 2014.
  - Lower natural gas prices was the primary contributor to this decrease because natural gas fueled units are typically re-dispatched to manage network flows.
  - The frequency of real-time congestion was similar to that experienced in 2014.
- Net revenues provided by the market during 2015 were less than the amount estimated to be needed to support new greenfield generation, which is not a surprise given that planning reserves are above the minimum target and shortages were rare in 2015.
  - The implementation of Operating Reserve Demand Curve (ORDC) and the increased offer cap will increase net revenues when shortages become more frequent.

B. Review of Real-Time Market Outcomes

As in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the day-ahead and other forward markets where most transactions take place. Unless there are barriers preventing arbitrage of the prices between the spot and forward markets, the prices in the forward market should be directly related to the prices in the spot market.

The figure below summarizes changes in energy prices and other market costs by showing the all-in price of electricity, which is a measure of the total cost of serving load in ERCOT.

Average All-in Price for Electricity in ERCOT



The ERCOT-wide price in this figure is the load-weighted average of the real-time market prices from all load zones. Ancillary services costs and uplift costs are divided by real-time load to show them on a per MWh basis.[1]

The operating reserve adder and the reliability adder are shown separate from the energy price. The Operating Reserve Demand Curve was implemented in mid-2014; thus 2015 provides the first full-year to review the performance of the operating reserve adder. The reliability adder was implemented on June 25, 2015 as a mechanism to capture the impact of reliability deployments on energy prices.

This figure indicates that natural gas prices continued to be a primary driver of electricity prices during this period. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal costs and natural gas is the most widely-used fuel in ERCOT, changes in natural gas prices should translate to comparable changes in offer prices. The average gas price in 2015 was $2.57 per MMBtu, down roughly 40 percent from the 2014 average price of $4.32 per MMBtu.

The largest component of the all-in cost of wholesale electricity is the energy cost. ERCOT average real-time energy prices were 34 percent lower in 2015 than in 2014, equaling $26.77 per MWh in 2015. This price includes the operating reserve adder of $1.41 per MWh and the reliability adder of $0.01 per MWh. The operating reserve adder was highest in August when summer weather led to the tightest market conditions of the year.

Energy prices vary across the ERCOT market because of congestion costs that are incurred as power is delivered over the network. The table below provides the annual average load-weighted average prices in the four geographic ERCOT load zones for the past five years. Price

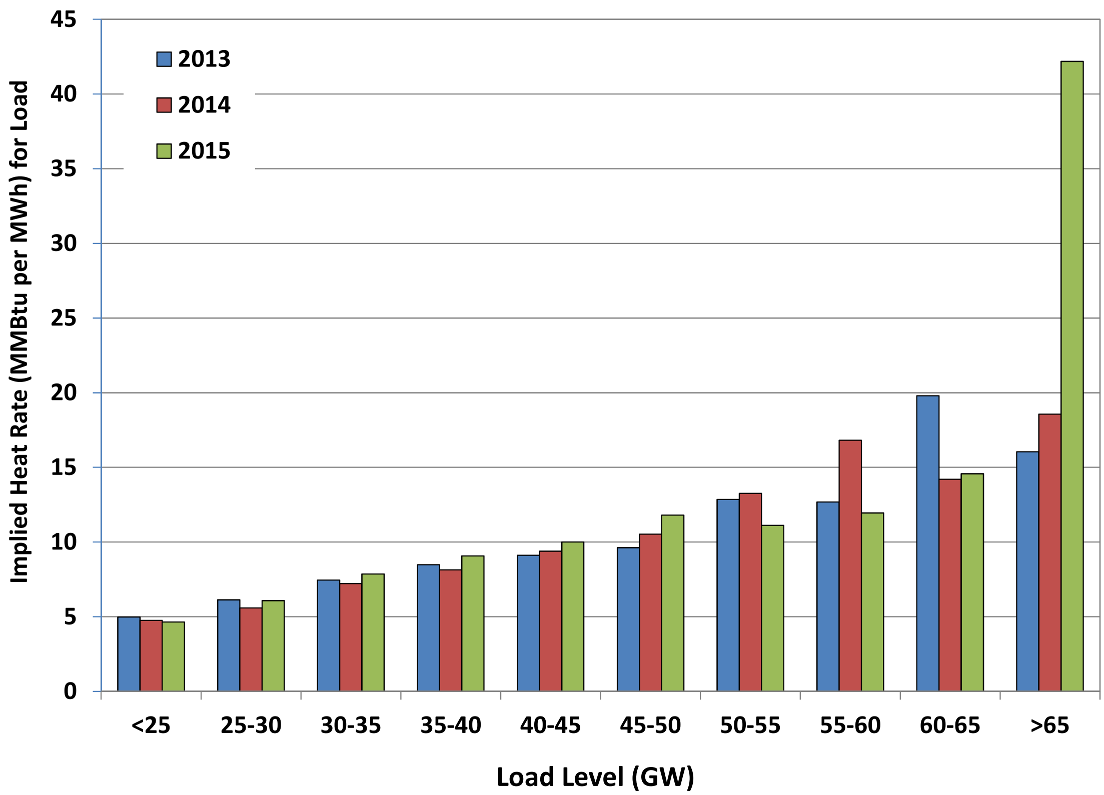
1 For this analysis uplift includes: Reliability Unit Commitment Settlement, Operating Reserve Demand Curve (ORDC) Settlement, Revenue Neutrality Total, Emergency Energy Charges, Base Point Deviation Payments, Emergency Response Service (ERS) Settlement, Black Start Service Settlement, ERCOT Administrative Fee Settlement, and Block Load Transfer Settlement.

differences between zones were much smaller in 2015 than in previous years due to much lower prices in general driven by lower natural gas prices.

	Average Real-Time Electricity Price ($ per MWh)				
	2011	**2012**	**2013**	**2014**	**2015**
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91
North	$54.24	$27.57	$32.74	$40.05	$26.36
South	$54.32	$27.86	$33.88	$41.52	$27.18
West	$46.87	$38.24	$37.99	$43.58	$26.83
Natural Gas ($/MMBtu)	$3.94	$2.71	$3.70	$4.32	$2.57

To summarize the changes in energy prices that were related to other factors, an "implied heat rate" is calculated by dividing the real-time energy price by the natural gas price. The following figure shows the average implied heat rate at various system load levels from 2013 through 2015. In a well-performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs are dispatched to serve higher loads.

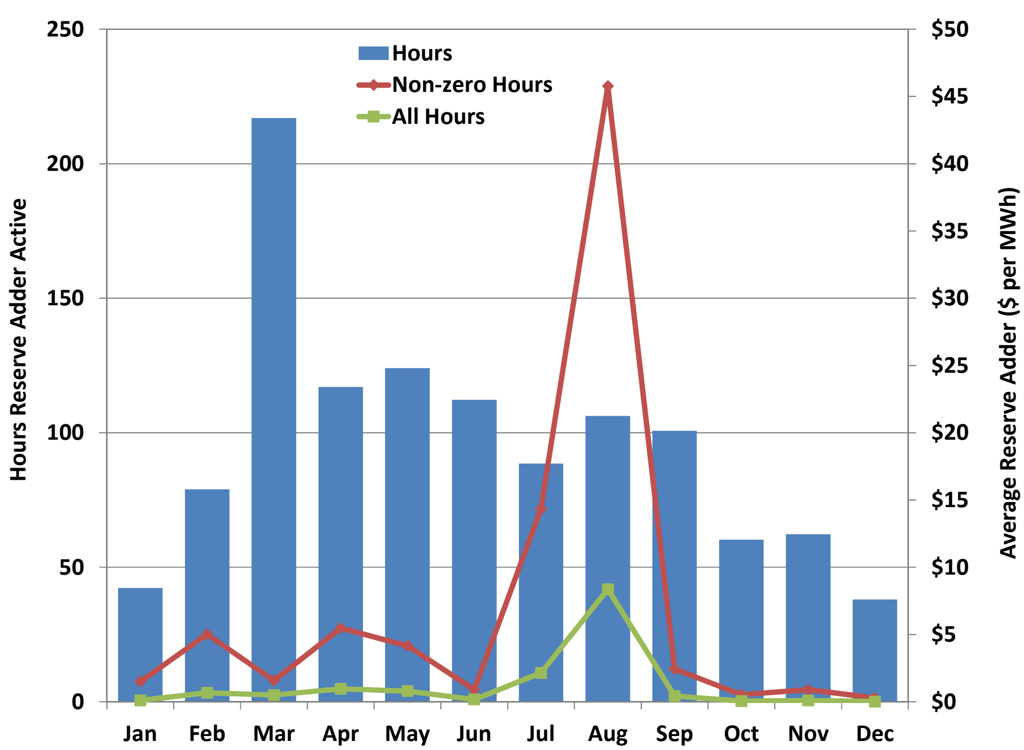
Implied Heat Rate and Load Relationship



There are two noticeable differences in the implied heat rates in 2015. The first is the higher implied marginal heat rate at load levels greater than 65 GW. This increase was due to shortage pricing that occurred when load was in that range during August 2015. The second difference is the lower implied marginal heat rate at load levels between 50 and 60 GW. This is due to the relative lack of shortage pricing at those load levels during the winter months of 2015.

The following analysis illustrates the contributions of the operating reserve adder to energy pricing during the first full year of its implementation. The figure below shows that the operating reserve adder had a relatively modest impact on prices in 2015, with the largest impact during the summer months. The operating reserve adder contributed $1.41 per MWh or 5 percent to the annual average real time price of $26.77 per MWh. While the largest number of hours with the operating reserve adder occurred in the spring months, the average price impacts of the adder in those months were minimal. These results do not indicate that ORDC has been ineffective or that it should be modified. The effects of the operating reserve adder are expected to vary substantially from year to year, and to have the largest effects when poor supply conditions and unusually high load conditions occur together and result in sustained shortages.

Average Operating Reserve Adder



C. Review of Day-Ahead Market Outcomes

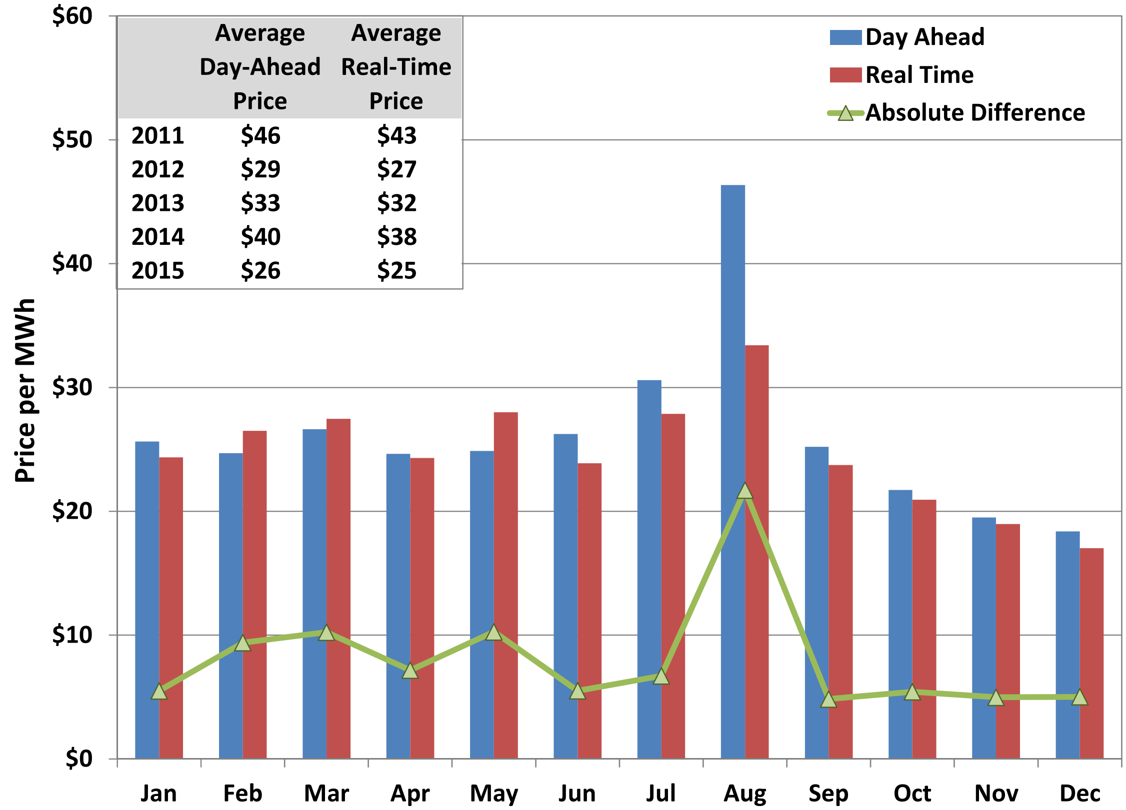
ERCOT's day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Although all bids and offers are evaluated in the context of the ability for them to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market. These transactions are made for a variety of reasons, including satisfying the participant's own demand, managing risk by hedging the participant's exposure to real-time prices, or arbitraging the real-time prices. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all these reasons, the performance of the day-ahead market is essential.

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. In a well-functioning market, participants should eliminate sustained price differences on a risk-adjusted basis by making day-ahead purchases or sales to arbitrage the price differences away over the long term.

The next figure shows the price convergence between the day-ahead and real-time market, summarized by month. Day-ahead prices averaged $26 per MWh in 2015 compared to an average of $25 per MWh for real-time prices.[2] The average absolute difference between day-ahead and real-time prices fell by more than a third to $8.08 per MWh in 2015, which was attributable to lower real-time price volatility and low fuel prices in 2015.

[2] These values are simple averages, rather than load-weighted averages.

Convergence Between Day-Ahead and Real-Time Energy Prices

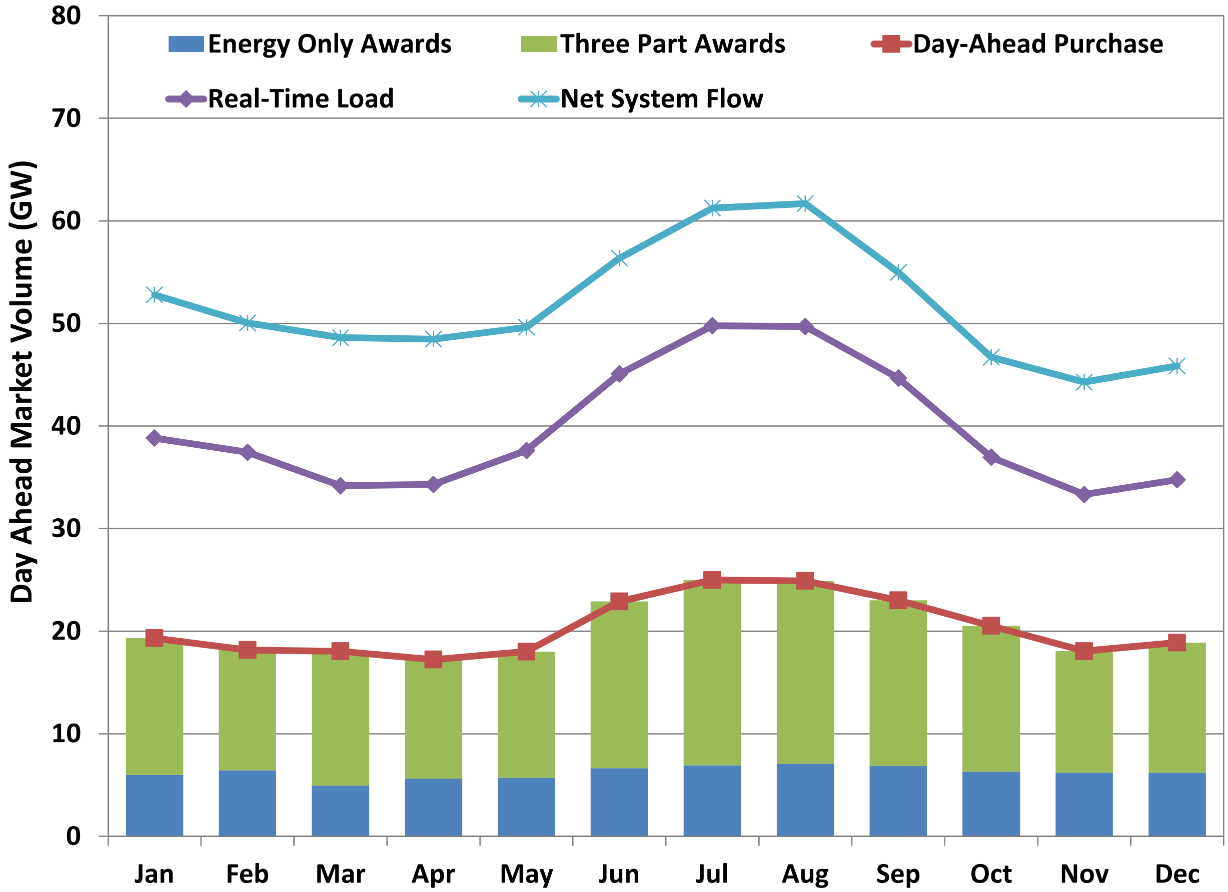


This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead market and higher for generators selling day ahead. The higher risk for generators is associated with the potential of incurring a forced outage and, as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest relative demand and highest prices, as was seen in August 2015. The overall day-ahead premium decreased in 2015 compared to 2014 due to low natural gas prices resulting in overall lower electricity prices and few occurrences of shortage pricing in 2015.

The next analysis summarizes the volume of day-ahead market activity by month. The figure below shows that the volume of day-ahead purchases provided through a combination of generator-specific and virtual energy offers was approximately 51 percent of real-time load in 2015, which was a slight increase compared to 2014 activity.

PTP Obligations are financial transactions purchased in the day-ahead market. Although PTP Obligations do not themselves involve the direct supply of energy, they allow the purchaser to buy the network flow from one location to another.[3] In doing so, the purchaser can avoid the real-time congestion costs between the locations. To provide a volume comparison, all of these "transfers" are aggregated with other energy purchases and sales, netting location-specific injections against withdrawals to arrive at a net system flow. The net system flow in 2015 was almost 8 percent higher than in 2014.

Volume of Day-Ahead Market Activity by Month

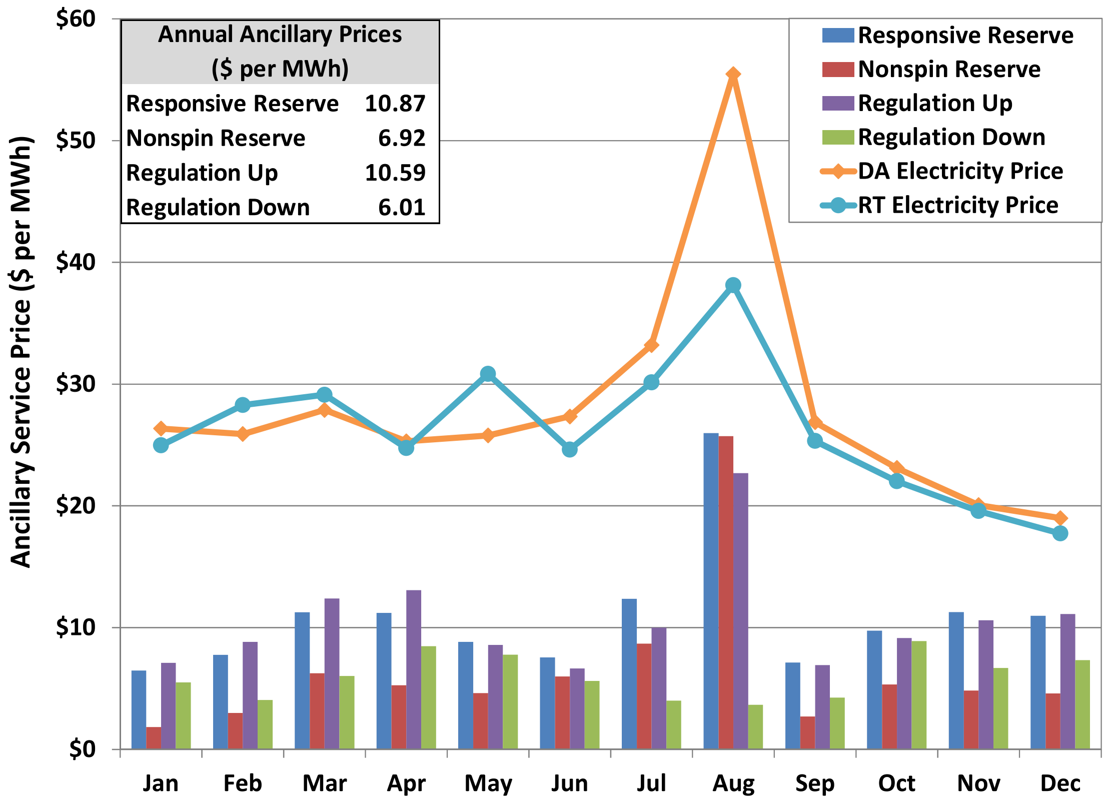


Adding the aggregated transfer capacity associated with purchases of PTP Obligations to the other injections and withdrawals demonstrates that net system flow volume transacted in the day-ahead market exceeds real-time load by approximately 30 percent. The volume in excess of real-time load increased in 2015 compared to 2014, when the monthly net system flow averaged 23 percent more than real-time load.

[3] PTP Obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

Under the nodal market, ancillary services and energy are co-optimized in the day-ahead market. This means that market participants do not have to include their expectations of forgone energy sales in their ancillary service capacity offers. Because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the day-ahead market, ancillary service prices are highly correlated with day-ahead energy prices and, by extension, with real-time energy prices. The next figure presents the average clearing prices of capacity for the four ancillary services, along with day-ahead and real-time prices for energy.

Ancillary Service Prices

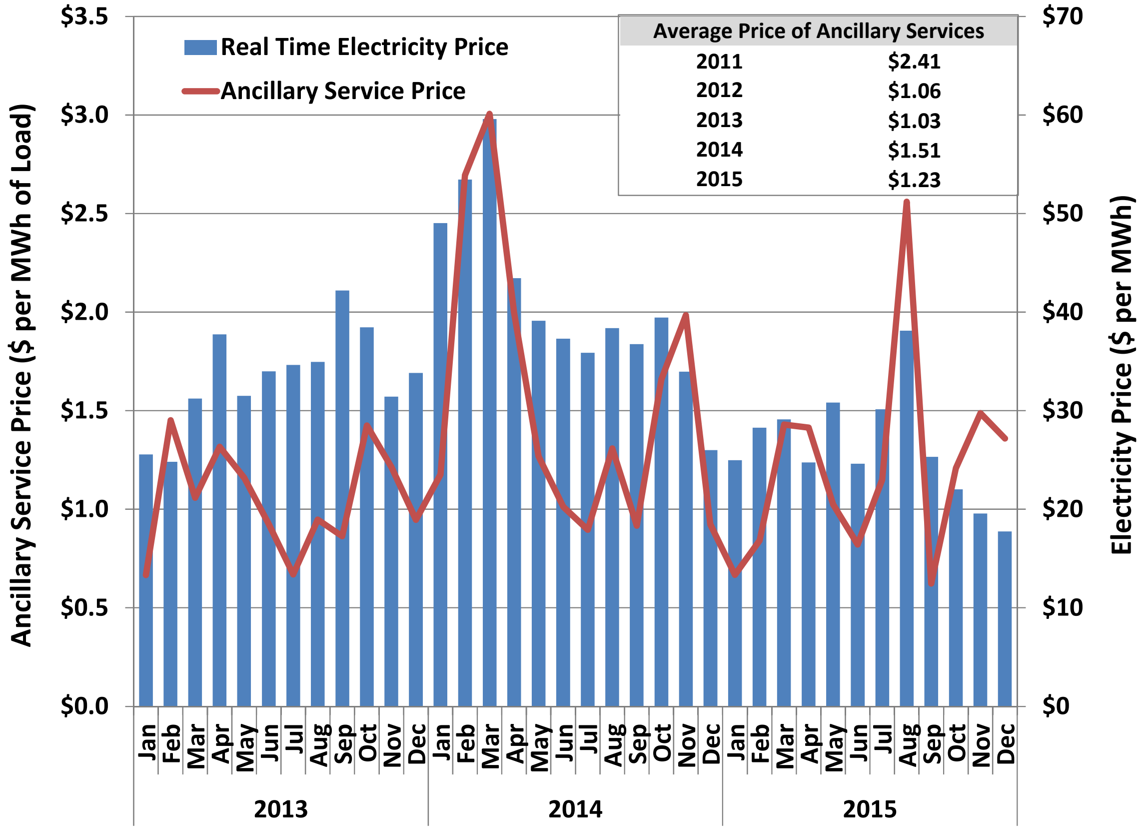


Total ancillary service costs are generally correlated with day-ahead and real-time energy price movements, which occur for two primary reasons. First, higher energy prices increase the opportunity costs of providing reserves and therefore can contribute to higher ancillary service prices. Second, shortages cause both ancillary service prices and energy prices to rise sharply so increases or decreases in the frequency of shortages will contribute to this observed correlation.

With average energy prices varying between $18 and $55 per MWh, the prices of ancillary services remained fairly stable throughout the year, with the exception of August. The price for ancillary services spiked in August, corresponding to the higher real-time electricity prices caused by ERCOT's shortage pricing and the associated increase in day-ahead price. Higher energy and ancillary service prices in August are not unexpected given higher loads and the associated increased potential for shortages.

In contrast to the previous figure that showed the individual ancillary service prices, the following figure shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2013 through 2015.

Ancillary Service Costs per MWh of Load

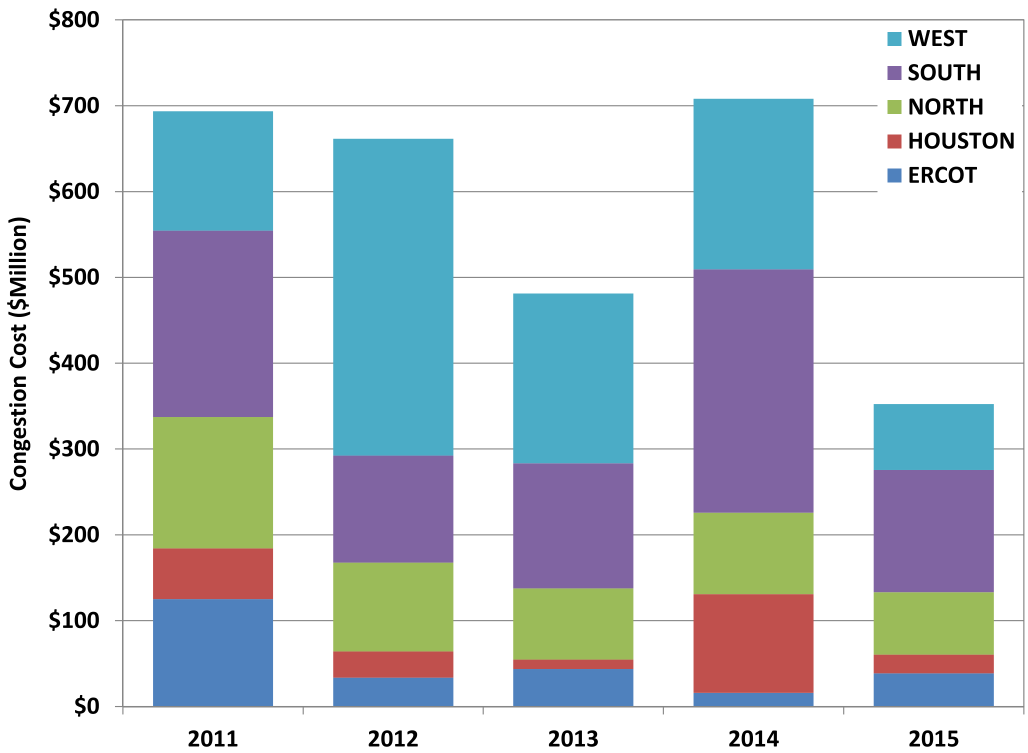


In absolute terms, the average ancillary service cost per MWh of load decreased to $1.23 per MWh in 2015 compared to $1.51 per MWh in 2014. Although the reduction in ancillary service prices and energy prices were both primarily caused by lower natural gas prices, the reduction in ancillary service prices was smaller than the decrease in ERCOT's energy prices. As a result, as a percent of the load-weighted average, total ancillary service costs increased from 3.7 percent of the load-weighted average energy price in 2014 to 4.6 percent in 2015 ($1.23 of $26.77).

D. Transmission and Congestion

Although, the frequency of binding transmission constraints remained similar to 2014 at 44 percent, the congestion costs in 2015 were much lower. The lower congestion costs were a direct result of the low natural gas prices in 2015 because natural gas resources are generally the resources re-dispatched to manage network flows. The figure below displays the amount of real-time congestion costs attributed to each geographic zone. Costs associated with constraints that cross zonal boundaries, i.e. North to Houston, are shown in the ERCOT category.

Real-Time Congestion Costs

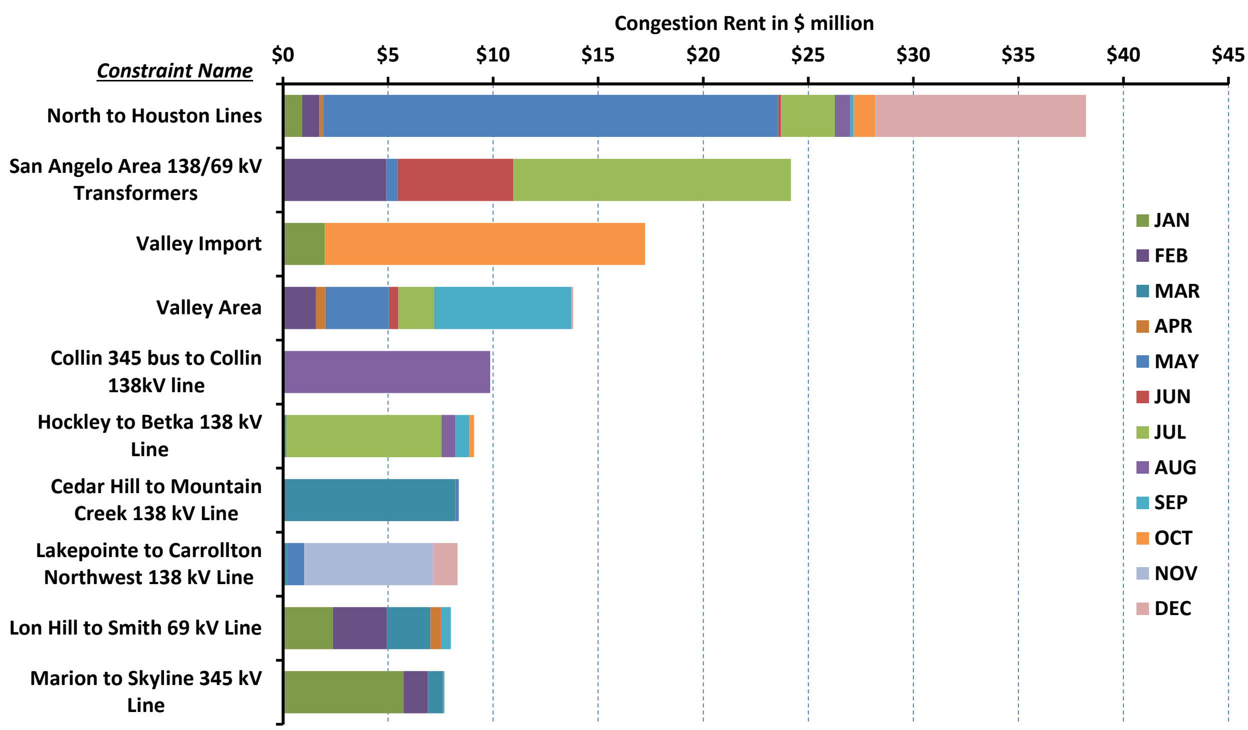


While cross zonal congestion is higher in 2015 than 2014, all other intra-zonal congestion costs have decreased. Annual congestion costs in 2015 were the lowest since the start of the nodal market. This is largely due the significant reduction in natural gas prices and the cumulative benefits of large investments in transmission facilities.

To better understand the main drivers of congestion in 2015, the next analysis describes the congested areas with the highest financial impact as measured by congestion rent. For this discussion a congested area is determined by consolidating multiple real-time transmission constraints that are defined as similar due to their geographical proximity and constraint direction.

The figure below displays the ten most highly valued real-time congested areas as measured by congestion rent. The North to Houston interface and lines, which includes the double circuit Singleton to Zenith 345 kV lines, double circuit Gibbons Creek to Singleton 345 kV lines and double circuit Jewett to Singleton 345 kV lines, were the most congested location in 2015 at $38 million. In contrast, the most congested area in 2014 was the Heights TNP 138/69 kV autotransformers at cost of $74 million which was due to a few months of outage-related congestion.

Top Ten Real-Time Constraints



The second-highest valued congested element was the San Angelo area 138/69 kV auto-transformer with impacts of $24 million. All of the impacts occurred from February through

July, and were related to a planned transformer outage that serves the San Angelo area and for the installation of a new station. This constraint is the only West zone constraint remaining in the top ten constraints following significant transmission upgrades in the West.

In aggregate, congestion related to serving load in the lower Rio Grande Valley was almost as large as the most costly single constraint, totaling $31 million. However, the impacts of the Valley Import constraint and constraints within the Valley are shown separately. The Valley Import constraint is sensitive to the amount of generation available within the Valley. It was active at times when local generating units were on unplanned or forced outage. The two constraints located within the Valley are the La Palma to Villa Cavazos 138 kV line ($12 million) and Rio Hondo to East Rio Hondo 138 kV line ($2 million). These constraints were often in effect during the time that other transmission facilities in the area were taken out of service to accommodate the construction of transmission upgrades in the area.

E. Demand and Supply

Total ERCOT load over the calendar year increased from 340 terawatt-hours (TWh) in 2014 to 348 TWh in 2015, an increase of 2.4 percent or an average of 866 MW every hour. This increase was largely driven by hotter summer temperatures in 2015. Cooling degree days, a metric that is highly correlated with weather-related summer load, increased 6 percent on average from 2014 to 2015 in Houston and Dallas.

Summer conditions in 2015 also led to a new ERCOT coincident peak hourly demand record of 69,877 MW on August 10, 2015. This broke the pre-existing record of 68,311 MW that occurred during August of 2011. In fact, the 2011 demand record was broken five subsequent times during August of 2015. The 2015 peak represents a 5.2 percent increase from the peak hourly demand of 66,451 MW in 2014.

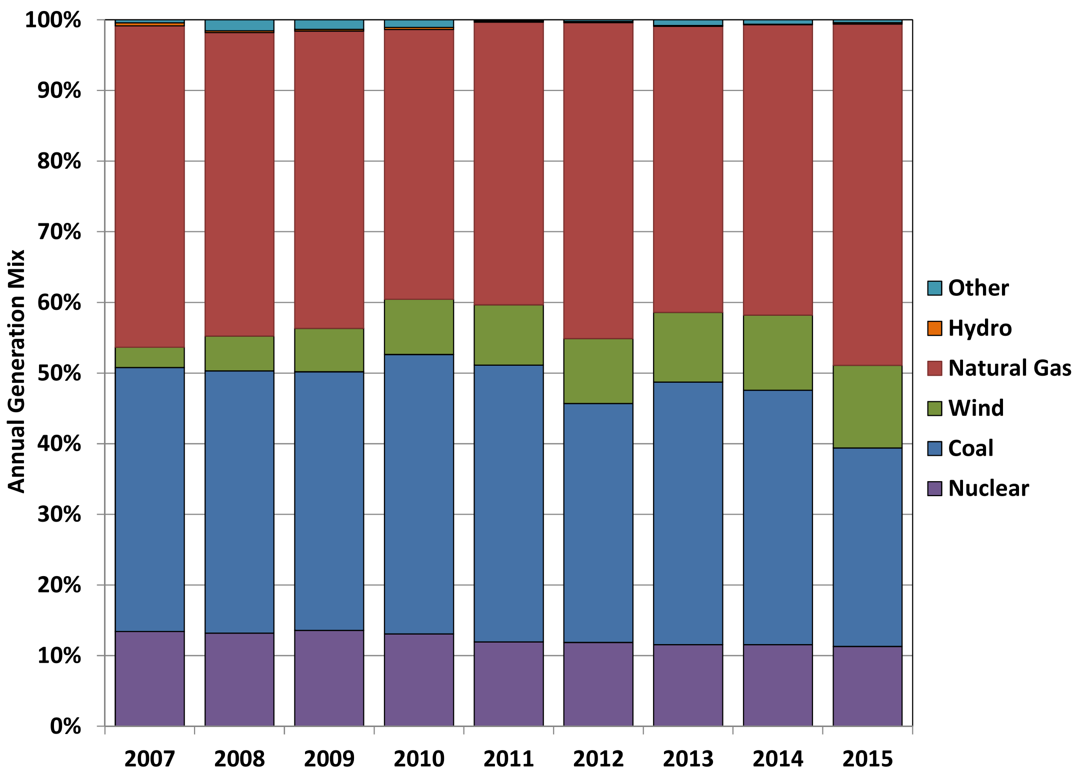
The changes in load at the zonal level are not the same as the ERCOT-wide changes. The growth rate of West zone average load was once again much higher, on a percentage basis, than the other zones because of increased oil and gas production activity in this area. While all zones saw an increase in the peak demand, the increase in the Houston zone was significantly higher than others at 7.3 percent over the 2014 peak.

Approximately 4.8 GW of new generation resources came online in 2015, but it only provided roughly 1.7 GW of net effective capacity. The overwhelming majority of new capacity was from wind generation. The 3.7 GW of newly installed wind capacity only effectively provides approximately 600 MW of peak capacity. The remaining 1.1 GW of new capacity consisted of 100 MW of solar resources and approximately 1 GW of new natural gas combined cycle units.

With these additions, natural gas generation continues to account for approximately 48 percent of total ERCOT installed capacity while the share of coal generation remains at 20 percent in 2015.

The shifting contribution of coal and wind generation is evident in the figure below, which shows the percentage of annual generation from each fuel type for the years 2007 through 2015.

Annual Generation Mix

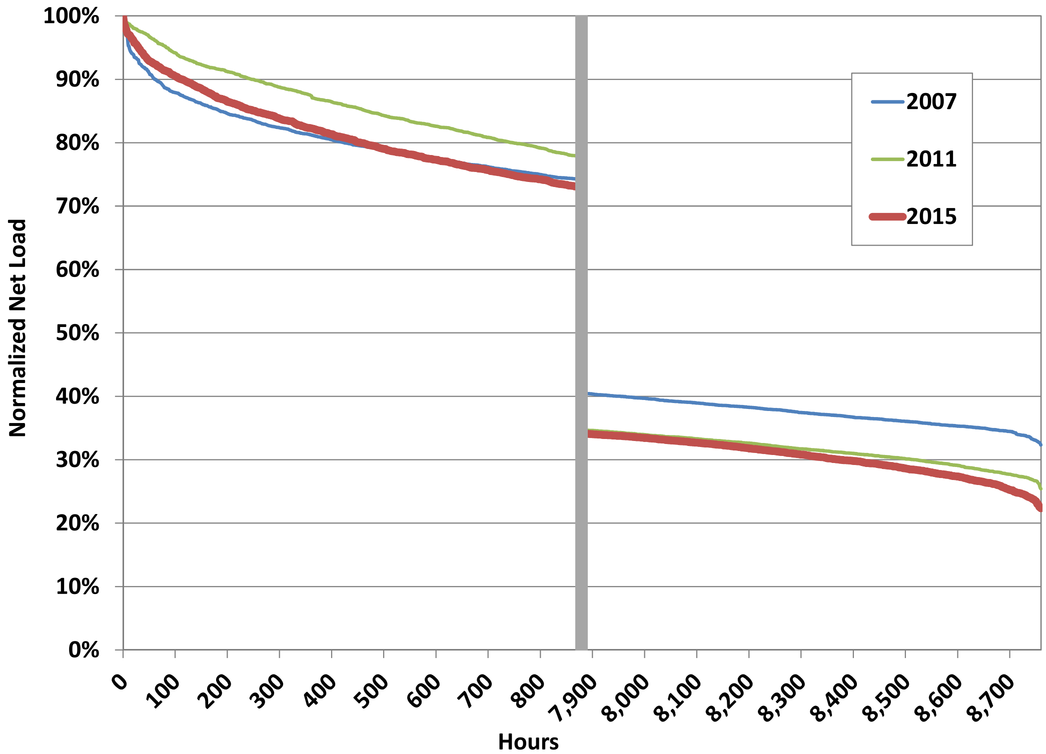


The generation share from wind has increased every year, reaching 12 percent of the annual generation requirement in 2015, up from 3 percent in 2007. The 2015 generation share saw a record high for natural gas and a record low for coal. In 2015 the percentage of generation from natural gas was 48 percent, a significant increase from the 2014 level and the highest share during this time period of 2007-2015. Corresponding with the increase in natural gas share was a significant decrease in the coal share from 36 percent in 2014 to its lowest observed level of 28 percent in 2015.

Wind Output and Net Load

ERCOT continued to set new records for peak wind output in 2015. On December 20, wind output exceeded 13 GW, setting the record for maximum output and providing nearly 45 percent of hourly generation. The amount of wind generation installed in ERCOT was approximately 16 GW by the end of 2015. Although the large majority of wind generation is located in the West zone, more than 3 GW of wind generation has been located in the South zone where the output more closely correlates with peak demand.

Top and Bottom Ten Percent of Net Load



Increasing levels of wind resources in ERCOT has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. The figure above shows net load in the highest and lowest hours.

Even with the increased development activity in the coastal area of the South zone, 74 percent 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 relatively low system demand. This profile results in only modest reductions of the net load relative to the actual load during the hours of highest demand, but much more significant reductions in the net load relative to the actual load in the other hours of the year. Thus, wind generation erodes the amount of energy available to be served by baseload 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 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.

In the hours with the lowest net load (right side of figure) the minimum net load has dropped from approximately 20 GW in 2007 to below 15.4 GW last year, even with sizable growth in total annual load. This continues to put operational pressure on the 23.5 GW of nuclear and coal generation currently installed in ERCOT.

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 meet net load and 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 within the context of the ERCOT energy-only market design.

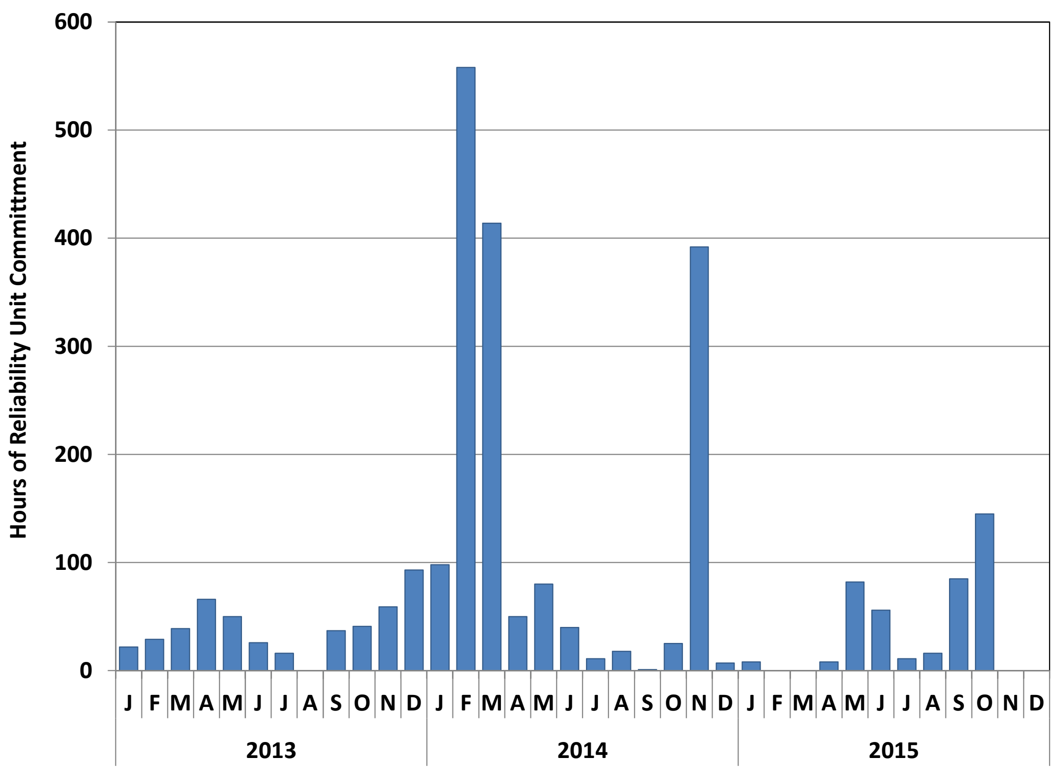
Resource Commitments for Reliability

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 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 outcomes help to inform these decisions, but it is important to note that ERCOT's day-ahead market 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.

Once ERCOT assesses the unit commitments resulting from the day-ahead market, additional capacity commitments are made, if needed, using a reliability unit commitment (RUC) process that executes both on a day-ahead and hour-ahead basis. These additional unit commitments may be made for one of two reasons. Either additional capacity is required to ensure forecasted total demand will be met, or a specific generator is required to resolve a transmission constraint. The constraint may be either a thermal limit or to support a voltage concern. The next figure shows how frequently these reliability commitments have occurred over the past three years, measured in unit-hours.

Frequency of Reliability Unit Commitments



There was a significant decrease in the frequency of reliability unit commitments in 2015. During 2015, 5 percent of hours had at least one unit receiving a reliability unit commitment instruction. This is down from 19 percent in 2014, but roughly the same as 2013. Most of the unusually high reliability unit commitment activity in 2014 occurred during cold winter weather.

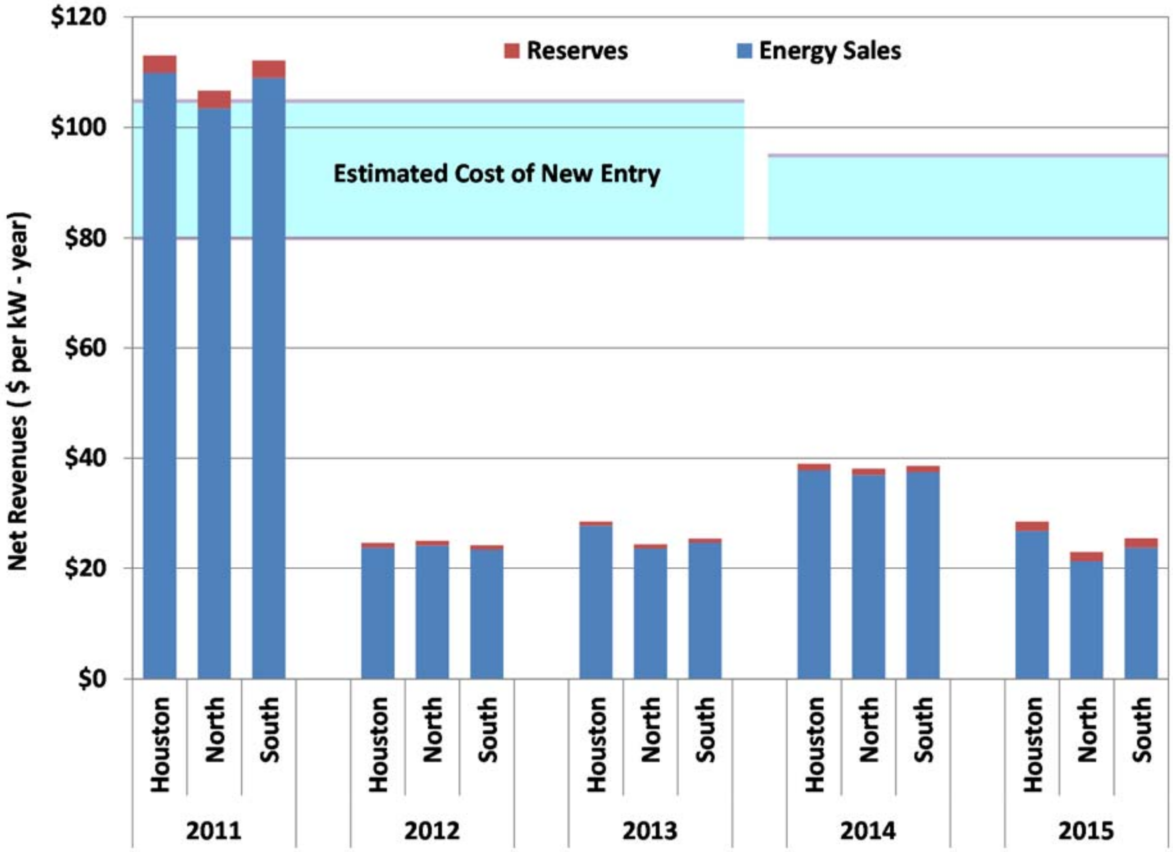
In 2015, such commitments were most frequent in the fall due to congestion in Dallas and the Rio Grande Valley.

F. 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 system demands and reliability needs. These economic signals are best measured with the net revenue metric, which 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. Net revenues from the real-time energy and ancillary services markets provide economic signals that help inform suppliers' decisions to invest in new generation or retire existing generation.

The next figure provides an historical perspective of the net revenues available to support new natural gas combustion turbine generation.

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 gas turbine unit ranges from $80 to $95 per kW-year. These estimates reflect Texas-specific construction costs. The net revenue in 2015 for a new gas turbine was calculated to be approximately $23 to 29 per kW-year, depending on the zone location. These values are well below the estimated cost of new gas turbine generation.

These results are consistent with the current surplus capacity that exists over the minimum target level, which contributed to infrequent shortages in 2015. In an energy only market, shortages play a key role in delivering the net revenues an investor would need to recover its investment. Such shortages will tend to be clustered in years with unusually high load and/or poor generator availability. Hence, these results alone do not raise substantial concern regarding design or operation of ERCOT's ORDC mechanism for pricing shortages.

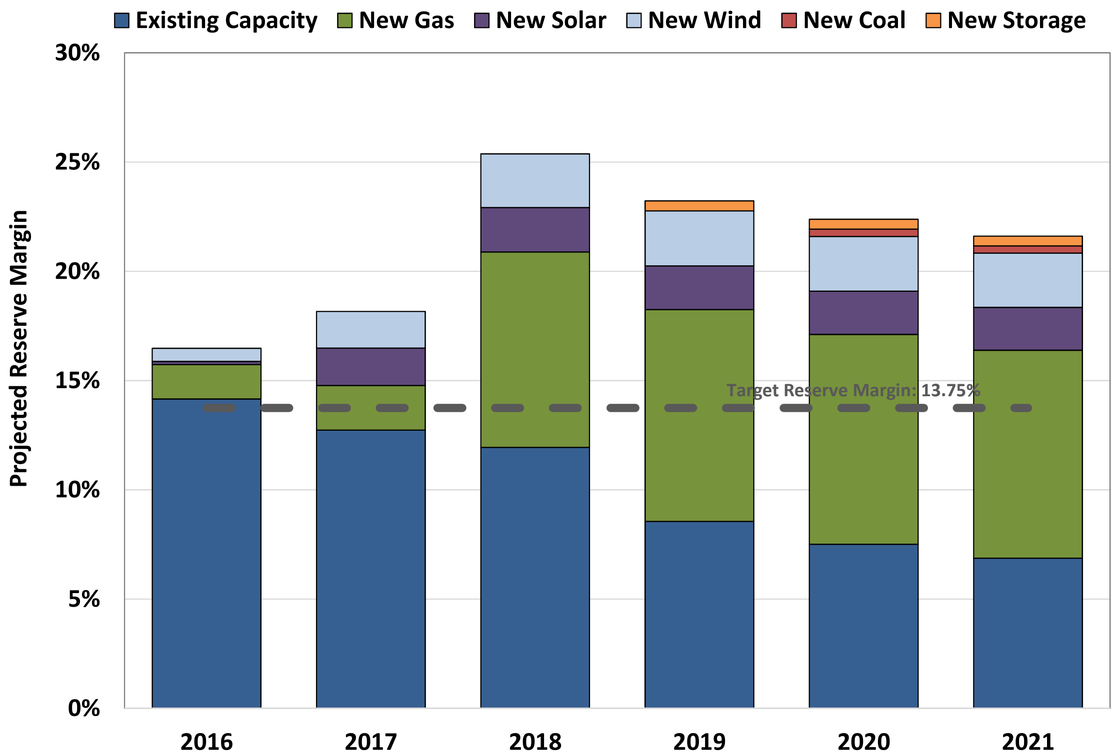
Given the very low energy prices during 2015 in non-shortage hours, the economic viability of existing coal and nuclear units was evaluated. The prices in these hours, which have been substantially affected by the prevailing natural gas prices, determine the vast majority of the net revenues received by these baseload units. The generation-weighted average price for the four nuclear units - approximately 5GW of capacity - was $24.56 per MWh in 2015. According to the Nuclear Energy Institute (NEI), total operating costs for all nuclear units across the U.S. averaged $27.53 per MWh in 2015.[4] Assuming that operating costs in ERCOT are similar to the U.S. average, considering only fuel and operating and maintenance costs indicates that nuclear generation was not profitable in ERCOT during 2015. To the extent nuclear units in ERCOT had any associated capital costs, it is likely those costs were not recovered.

The generation-weighted price of all coal and lignite units in ERCOT during 2015 was $25.94 per MWh. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $3 per MMBtu in 2015. With a typical heat rate of 10 MMBtu per MWh, the fuel-only operating costs for coal units in 2015 may be inferred to be approximately $30 per MWh. As with nuclear units, it appears that coal units were likely not profitable in ERCOT during 2015. This is significant because the retirement or suspended operation of some of these units could cause ERCOT's capacity margin to fall below the minimum target more quickly than anticipated.

The next figure shows ERCOT's current projection of reserve margins and indicates that the region will have a 16.5 percent reserve margin heading into the summer of 2016. Reserve margins are now expected to exceed the target level of 13.75 percent for the next several years. These projections are higher than those developed last year, which were higher than in 2013. These increases are due to more new generation capacity expected to be constructed in ERCOT. The current outlook is very different than it was in 2013, when reserve margins were expected to be below the target level of 13.75 percent for the foreseeable future.

4 NEI Whitepaper, "Nuclear Costs in Context", April 2016, available at http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf.

Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Reports / 2016 from December 2015 and 2017-2021 from May 2016

This current projection of reserve margins combined with relatively infrequent shortage pricing may raise doubts regarding the likelihood of all announced generation actually coming on line as currently planned. Given the projections of continued low prices, investors in some of the new generation included in the report on the Capacity, Demand, and Reserves in the ERCOT Region (CDR) may choose to delay or even cancel their project. Additionally, the profitability analysis of existing baseload resources casts doubt on whether all existing generation will continue to operate.

G. Analysis of Competitive Performance

The report evaluates market power from two perspectives, structural (does market power exist) and behavioral (have attempts been made to exercise it).

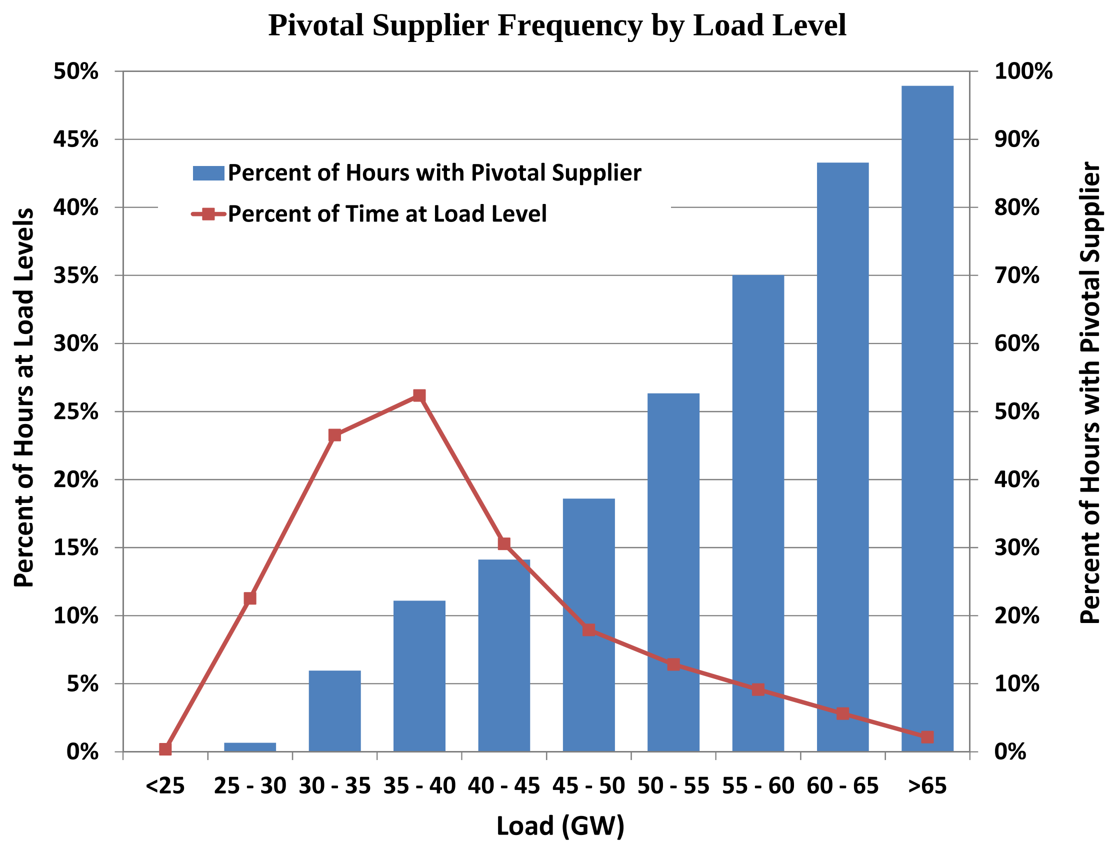
1. Structural Market Power

The market structure is analyzed by using the Residual Demand Index (RDI), a statistic that measures the percentage of load that could not be satisfied without the resources of the largest supplier. 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. 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 as long as 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. The RDI also does not indicate whether it would have been profitable for a pivotal supplier to exercise market power. However, it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

The figure 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.

At loads greater than 65 GW there was a pivotal supplier 98 percent of the time. The occurrences of higher loads were more frequent in 2015 resulting in a pivotal supplier in approximately 26 percent of all hours of 2015, up from 23 percent of hours in 2014. This indicates that market power continues to be a potential concern in ERCOT and underscores the need for effective mitigation measures to address it.



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. 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.

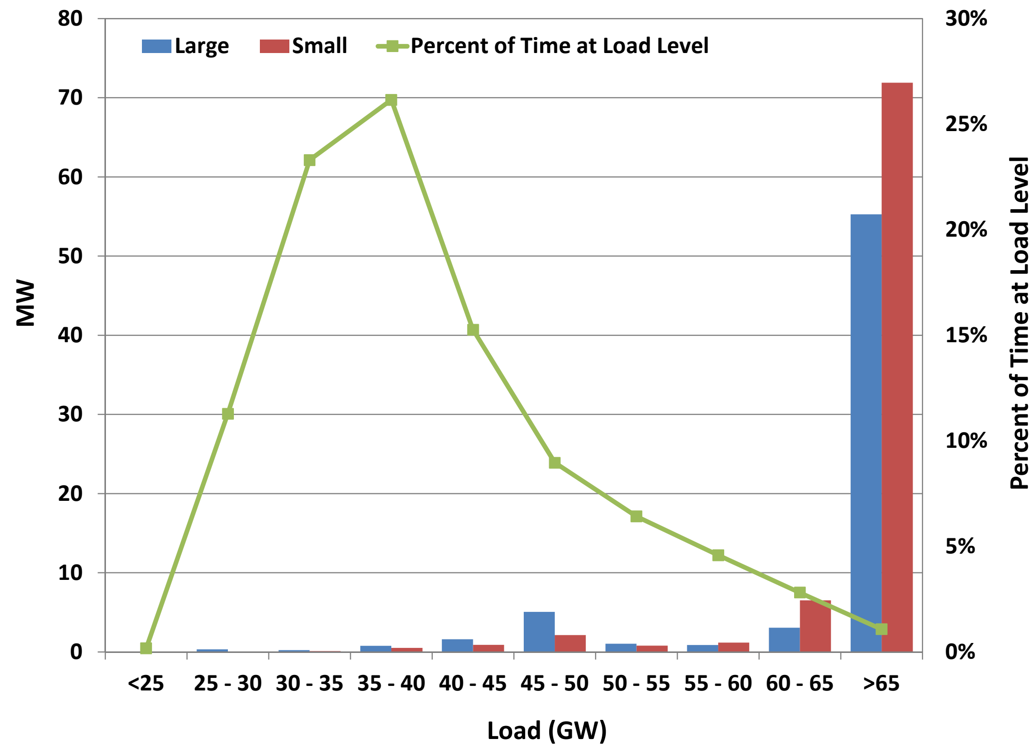
2. Evaluation of Conduct

Next, actual participant conduct is evaluated to assess whether market participants have attempted to exercise market power through physical or economic withholding. An "output gap" metric is used to measure potential economic withholding, which occurs when a supplier raises its offer prices to reduce its output. The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic by a substantial margin given the real-time energy price.

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

The next figure shows the output gap, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. The results are aggregated for the five largest suppliers (those with greater than 5 percent of ERCOT installed capacity) and all other suppliers are aggregated into the small category. In the second step of the dispatch, the after-mitigation offer curve is used to determine dispatch instructions and locational prices. The output gap at Step 2 showed very small quantities of capacity that would be considered part of this output gap.

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



The output gap of several of the largest suppliers were also examined for 2015, and unlike the findings in 2013, found to be consistently low for the largest suppliers 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 2015.

H. Recommendations

Overall, we find that the ERCOT market performed well in 2015. However, we have identified and recommended a number of potential improvements. Some improvements were made in 2015 to address our prior recommendations. One of our prior recommendations was to implement changes to ensure all load deployments are reflected in the real-time energy and reserve prices. The implementation of NPRR626 was a step in that direction. It introduced a second execution of ERCOT's dispatch software (SCED) in situations when loads are deployed. This second execution determines the higher LMPs that would have occurred if the load had continued to be served. The price increment (reliability adder) is added to settlement point prices. As described in Section I.D, the effects of the reliability adder on prices has been small to date.

Other recommendations have not yet been addressed, including the following three recommendations that were provided last year.

1. Implement real-time co-optimization of energy and ancillary services.

   The Operating Reserve Demand Curve (ORDC) provides a mechanism for setting real-time energy prices that reflect the expected value of lost load. However, additional benefits can be achieved by implementing real-time co-optimization of energy and ancillary services. These benefits are twofold. First, jointly optimizing all products in each interval allows ancillary service responsibilities to be continually adjusted in response to changing market conditions. The efficiencies of this continual adjustment would flow to all market participants and would be greater than what can be achieved by QSEs acting individually. The second benefit comes from opening up the supply of ancillary services to all providers. Currently, QSEs without large resource portfolios are effectively precluded from participating in ancillary service markets due to the replacement risk they face having to rely on a supplemental ancillary services market (SASM). For these reasons we continue to recommend ERCOT implement real-time co-optimization of energy and ancillary services.

2. Modify the real-time market software to better commit load and generation resources that can be online within 30 minutes.

   ERCOT has been producing non-binding generation dispatch and price projections for more than three years. It is unclear what, if any, effect this indicative information has had on the operational actions of ERCOT or market participants. This indicative information highlighted weaknesses in ERCOT's short-term load forecasting process. ERCOT has identified improvements to its short-term forecasting process and is currently evaluating the benefits of implementing a multi-interval real-time market. We support these changes because there is a sizable opportunity to improve the commitment and dispatch of both load and generation resources that require longer than 5 minutes to come on line, but are available within 30 minutes. Therefore, we recommend that ERCOT evaluate improvements that would allow it to facilitate better real-time generator and load commitments.

3. Price future ancillary services based on the shadow price of procuring the service.

   In the context of stakeholder discussions about Future Ancillary Services, we re-introduced our recommendation that the clearing price of a service be based on the shadow price of any constraint used in the procurement of that service. At this point we are not recommending any changes to the current ancillary services procurement or pricing practices. However, inefficiencies exist in the current pricing of responsive reserves. As changes are made to ancillary services, we believe it is appropriate to include this change to improve pricing efficiency and supplier incentives.

In addition to these prior recommendations, we offer the following new recommendation.

4. <u>The PUCT should evaluate policies and programs that create incentives for loads to reduce consumption for reasons unrelated to real-time energy prices, including: (a) the need for and structure of ERS and (b) the allocation of transmission costs.</u>

A load that wishes to actively participate in the ERCOT market can participate in ERS, provide ancillary services, or simply choose to curtail in response to high prices. Participating in ERS greatly limits a load's ability to provide ancillary services or curtail in response to high prices. Given the high budget allotted and the low risk of deployment, ERS is a very attractive program for loads. Because the ERS program is so lucrative, there is concern that it is limiting the motivation for loads to actively participate and contribute to price formation in the real-time energy market.[5]

Transmission costs in ERCOT are allocated on the basis of load contribution in 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. Over the last three years, transmission costs have risen by more than 60 percent, significantly increasing an already substantial incentive to reduce load during probable peak intervals in the summer.

Both of these mechanisms provide strong incentives for load to act in ways that are not aligned with the most efficient electricity market outcomes which are to ensure that the price continually reflects both the cost to provide (supply) and the value to consume (demand). For example, loads' preference for ERS may lead many to not provide ancillary services or not respond to high wholesale energy prices. High real-time prices are generally correlated with high loads, but they are more specifically correlated with low operating reserves. Loads that are focused on not consuming during an expectation of high load, and its associated contribution to transmission cost allocation, may be skewing shortage pricing outcomes in ERCOT's real-time energy market.

[5] On May 4, 2016, the PUCT opened Docket 45927, *Rulemaking Regarding Emergency Response Service*.

I. REVIEW OF REAL-TIME MARKET OUTCOMES

As in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the real-time energy market are very important because they set the expectations for prices in the day-ahead and bilateral forward markets where most transactions take place. Unless there are barriers preventing arbitrage of the prices between the spot and forward markets, the prices in the forward market should be directly related to the prices in the spot market (i.e., the spot prices and forward prices should converge over the long-run). Hence, low prices in the real-time energy market will translate to low forward prices. Likewise, price spikes in the real-time energy market will increase prices in the forward markets. This section evaluates and summarizes electricity prices in the real-time market during 2015.

A. Real-Time Market Prices

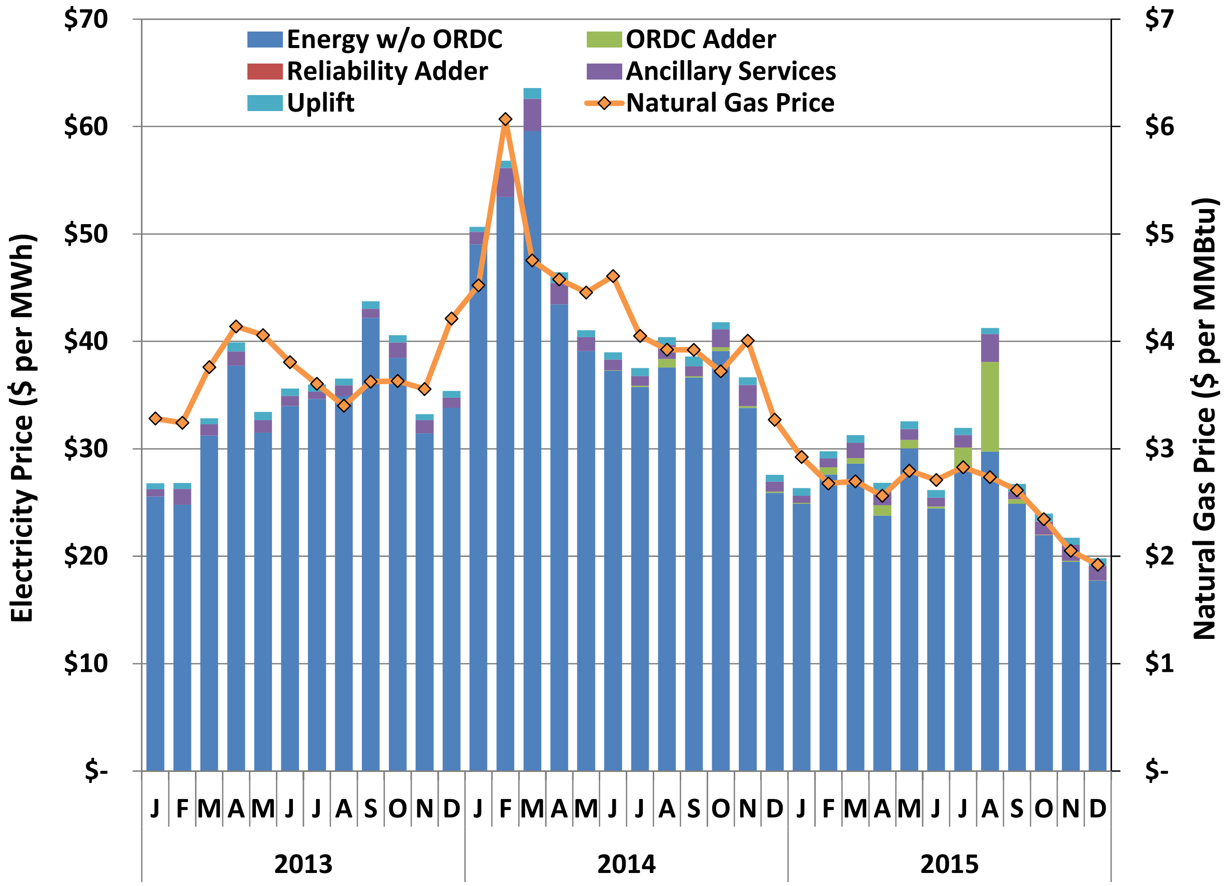
The first analysis evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market based expenses referred to as “uplift.” An average “all-in” price of electricity has been calculated for ERCOT that is intended to reflect wholesale energy costs as well as these additional costs.

Figure 1 summarizes changes in energy prices and other market costs by showing the all-in price of electricity, which is a measure of the total cost of serving load in ERCOT for 2013 through 2015. The ERCOT-wide price in this figure is the load-weighted average of the real-time market prices from all load zones. Ancillary services costs and uplift costs are divided by real-time load to show them on a per MWh basis.[6] The Operating Reserve Demand Curve Adder (”operating reserve adder”) and the Reliability Deployment Price Adder (“reliability adder”) are shown separate from the energy price. The Operating Reserve Demand Curve (ORDC) was implemented in mid-2014; thus 2015 provides the first full-year to review the performance of the

[6] For this analysis Uplift includes: Reliability Unit Commitment Settlement, Operating Reserve Demand Curve (ORDC) Settlement, Revenue Neutrality Total, Emergency Energy Charges, Base Point Deviation Payments, ERS Settlement, Black Start Service Settlement, ERCOT Administrative Fee Settlement, and Block Load Transfer Settlement.

operating reserve adder. The reliability adder was implemented on June 25, 2015 as a mechanism to capture the impact of reliability deployments on energy prices. The reliability adder is calculated using a separate price run of SCED, removing any RUC commitments or deployed load capacity and recalculating prices. When the recalculated price is higher than the initial price, the increment is the adder.

Figure 1: Average All-in Price for Electricity in ERCOT

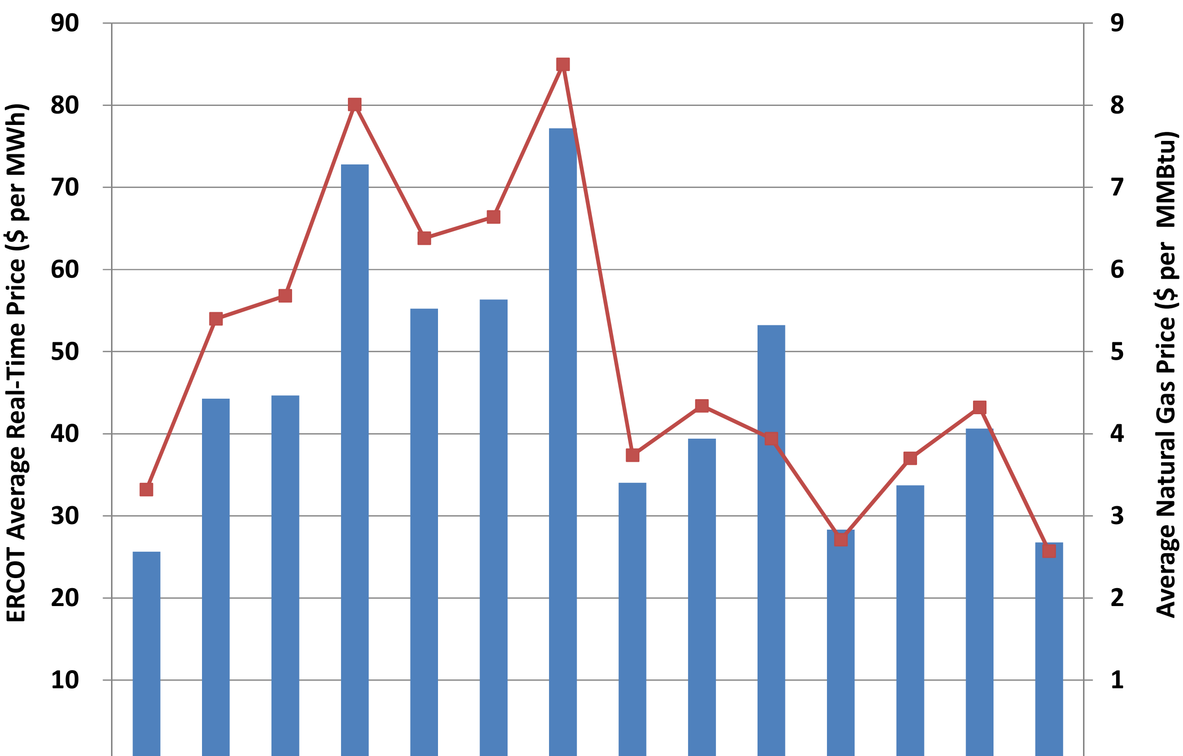


This figure indicates that natural gas prices continued to be a primary driver of electricity prices during this period. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal costs and natural gas is the most widely-used fuel in ERCOT, changes in natural gas prices should translate to comparable changes in offer prices. The average gas price in 2015 was $2.57 per MMBtu, down roughly 40 percent from the 2014 average price of $4.32 per MMBtu. The largest component of the all-in cost of wholesale electricity is the energy cost. ERCOT average real-time energy prices were 34 percent lower in 2015 than in 2014, equaling $26.77 per MWh in 2015. This price includes the operating reserve adder of $1.41 per MWh and the reliability adder of $0.01 per MWh. The operating reserve adder was highest in August when summer weather led to the tightest market conditions of the year.

The decrease in real-time energy prices was correlated with much lower fuel prices in 2015. The high correlation of natural gas prices and energy prices shown in the figure is consistent with expectations in a well-functioning competitive market. Fuel costs constitute most of the marginal production costs for generators in ERCOT and competitive markets provide incentives for suppliers to submit offers consistent with marginal costs. The average natural gas price in 2015 was $2.57, down approximately 40 percent from $4.32 per MMBtu in 2014.

Figure 2 below provides additional historic perspective on the ERCOT average real-time energy prices as compared to the average natural gas price in each year from 2002 through 2015.

Figure 2: ERCOT Historic Real-Time Energy and Natural Gas Prices

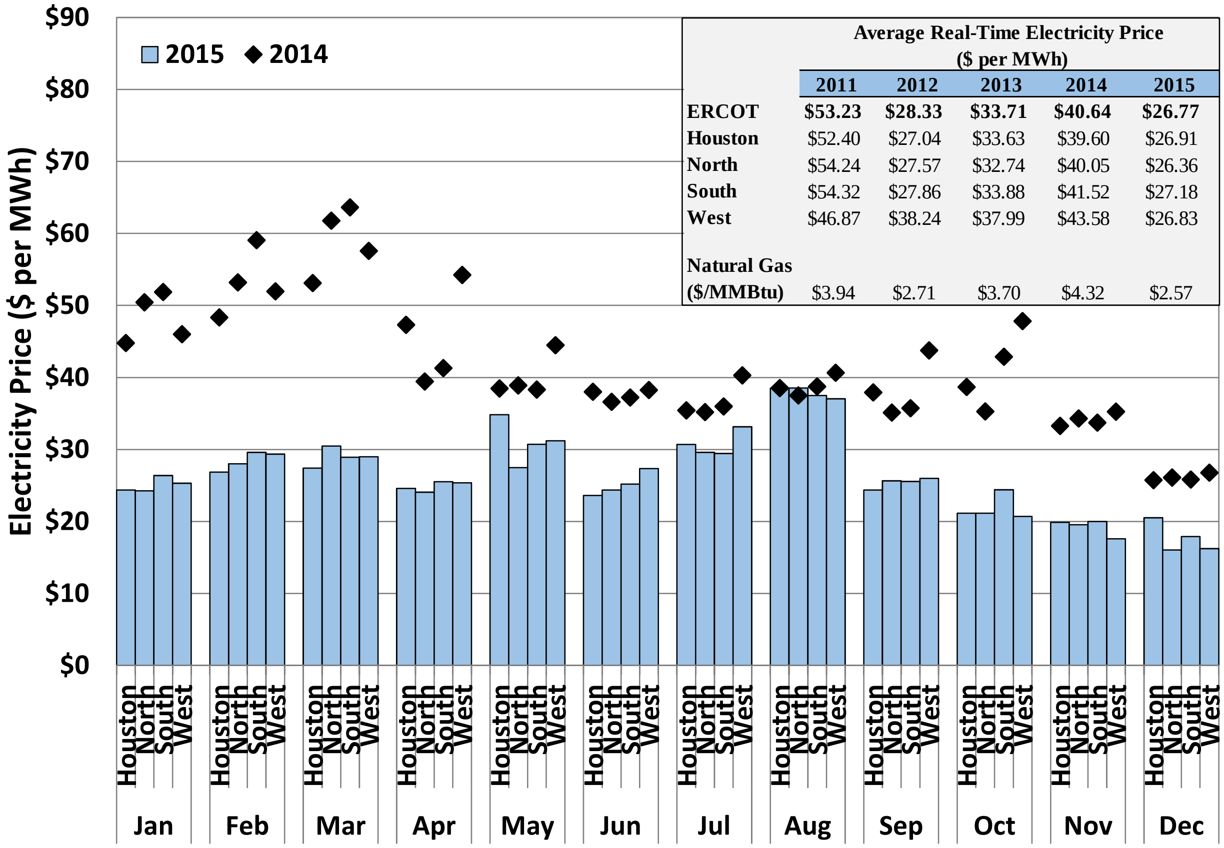


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57

Like Figure 1, Figure 2 shows the close correlation between the average real-time energy price in ERCOT and the average natural gas price. Such relationship is consistent with expectations in ERCOT where natural-gas generators predominate and tend to set the marginal price.

Energy prices vary across the ERCOT market because of congestion costs that are incurred as power is delivered over the network. Figure 3 shows the monthly load-weighted average prices in the four geographic ERCOT load zones during 2015, with the annual average for each zone provided for the past five years on the inset chart. Price differences between zones were much smaller in 2015 than in previous years due to much lower prices in general driven by lower natural gas prices.

Figure 3: Average Real-Time Energy Market Prices



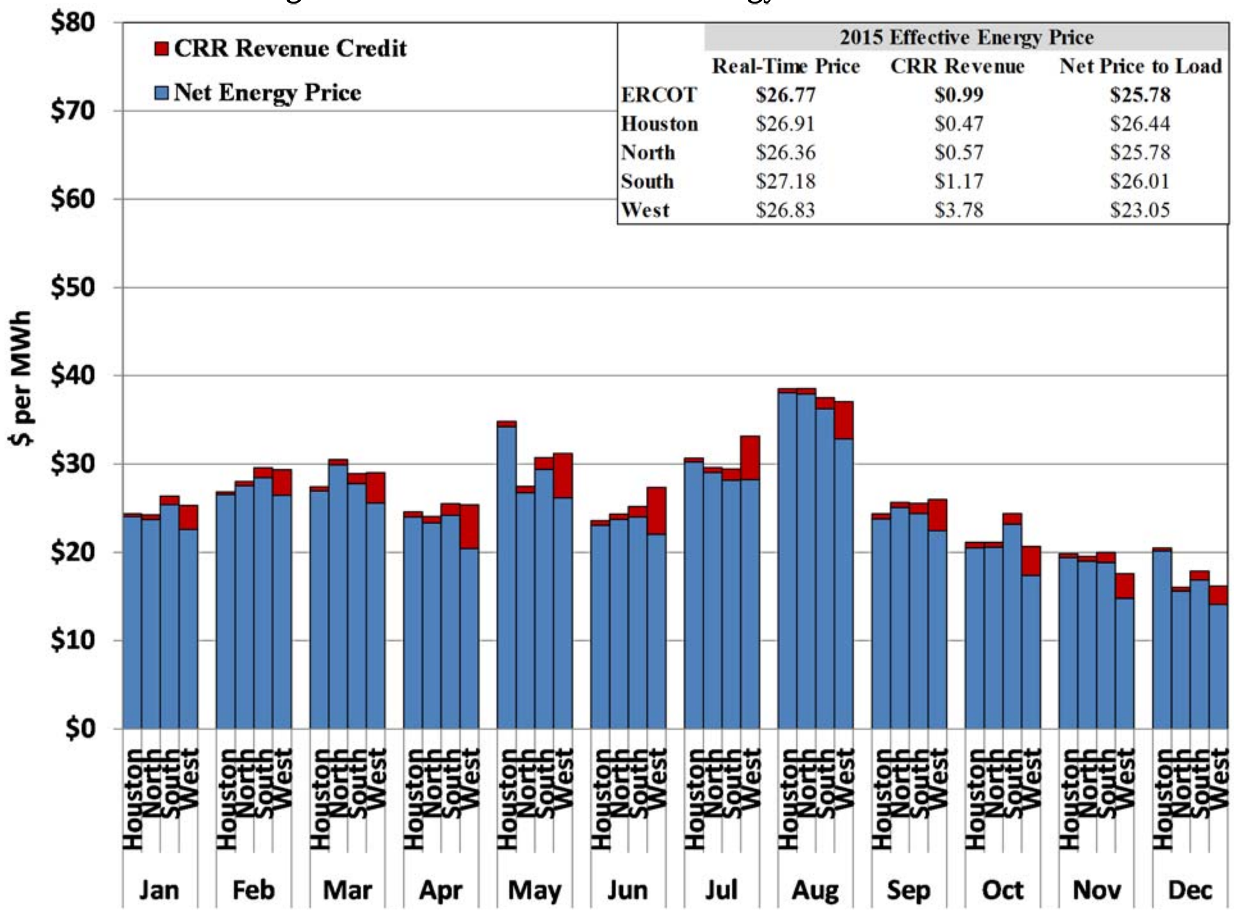
Average Real-Time Electricity Price ($ per MWh)

	2011	2012	2013	2014	2015
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**
Houston	$52.40	$27.04	$33.63	$39.60	$26.91
North	$54.24	$27.57	$32.74	$40.05	$26.36
South	$54.32	$27.86	$33.88	$41.52	$27.18
West	$46.87	$38.24	$37.99	$43.58	$26.83
Natural Gas ($/MMBtu)	$3.94	$2.71	$3.70	$4.32	$2.57

These prices are calculated by weighting the real-time energy price for each interval and each zone by the total zonal load in that interval. Load-weighted average prices are the most representative of what loads are likely to pay, assuming that real-time energy prices are, on average, generally consistent with bilateral or other forward contract prices.

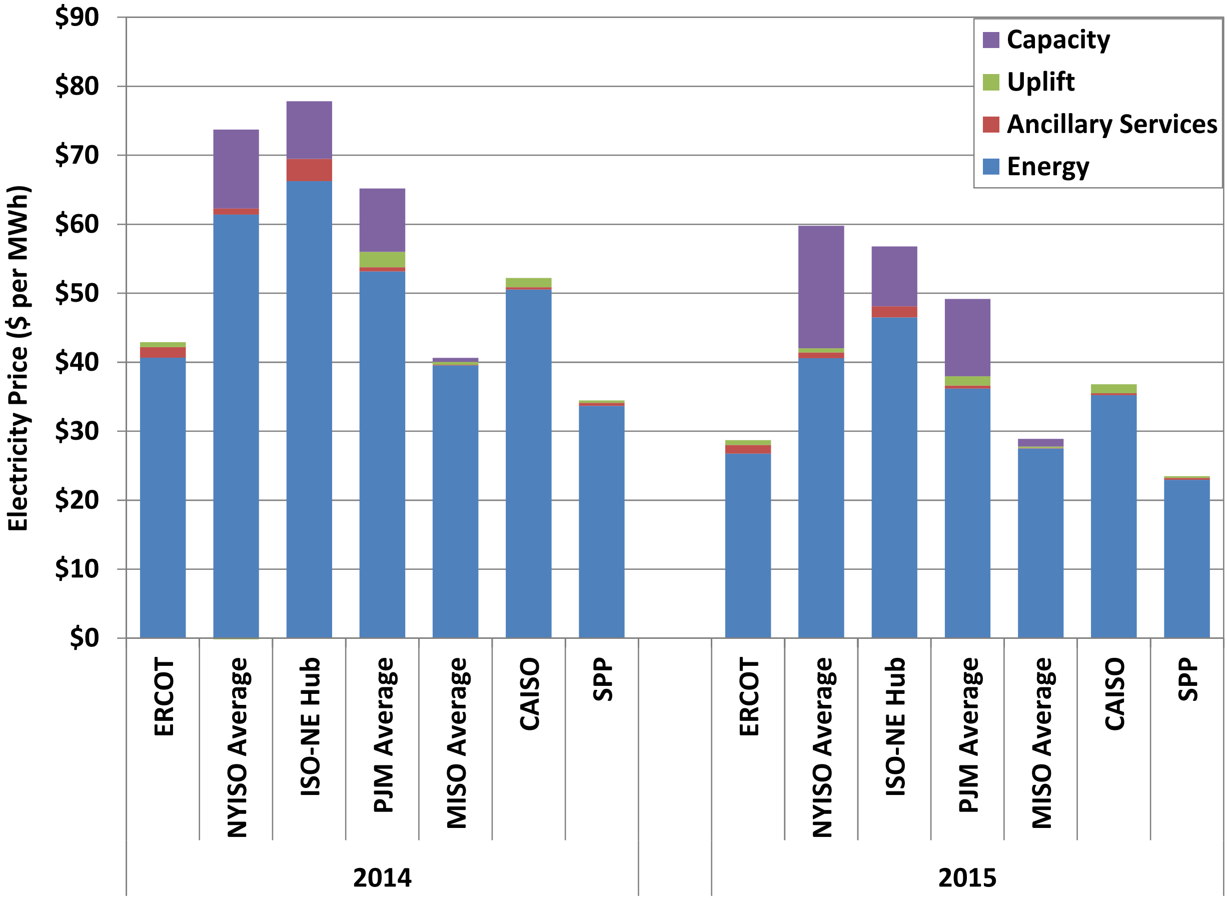
Congestion Revenue Right (CRR) Auction Revenues are distributed to Qualified Scheduling Entities (QSEs) representing load based on a zonal and ERCOT-wide monthly load-ratio share. The CRR Auction Revenues have the effect of reducing the total cost to serve load borne by a QSE. Figure 4 below shows the effect that this reduction has on a monthly basis, by zone. With the CRR Auction Revenue offset included, the ERCOT-wide load-weighted average price was reduced by $0.99 per MWh to $25.78 per MWh in 2015.

Figure 4: Effective Real-Time Energy Market Prices



To provide additional perspective on the outcomes in the ERCOT market, the figure below compares the all-in prices in ERCOT with other organized electricity markets in the United States: New York ISO, ISO New England, Pennsylvania-New Jersey-Maryland (PJM) Interconnection, Midcontinent ISO, California ISO, and the Southwest Power Pool (SPP).

Figure 5: Comparison of All-in Prices Across Markets

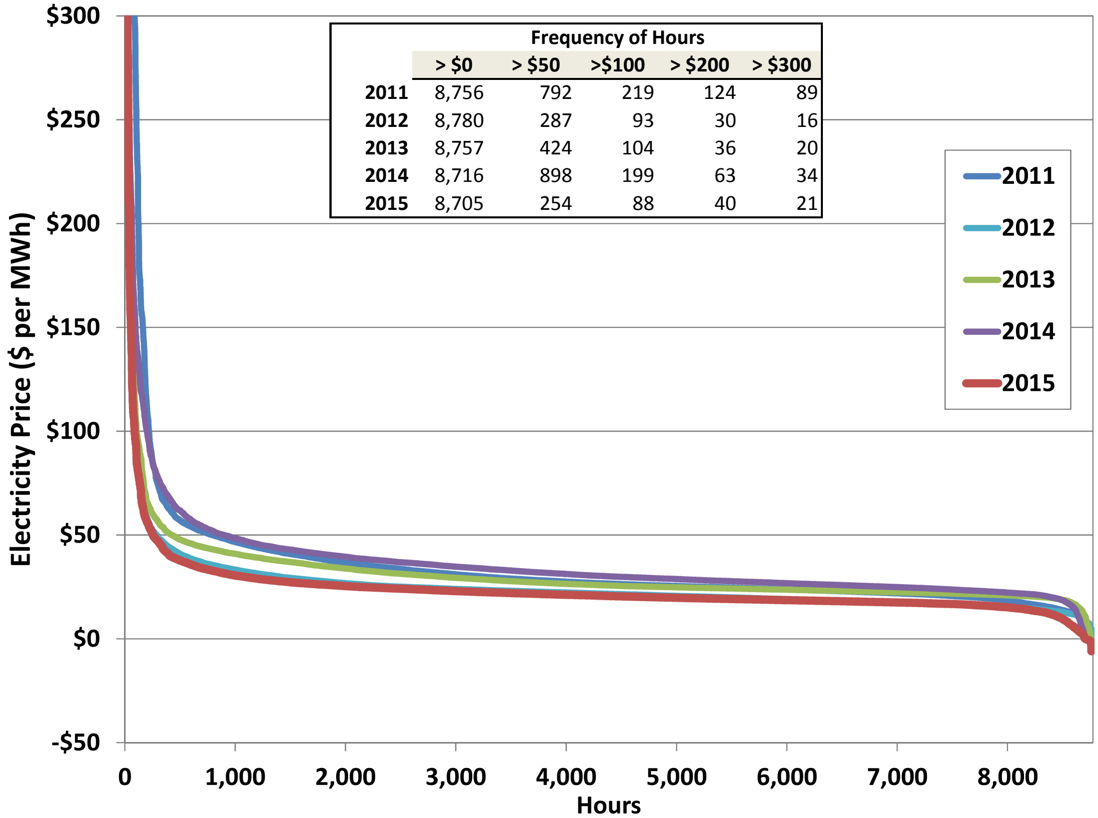


The figure reports each market's average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift. Figure 5 shows that 2015 all-in prices were lower across all U.S. markets, highlighting the pervasive effects of much lower natural gas prices across the nation.

Figure 6 below shows price duration curves for ERCOT energy markets in each year from 2011 to 2015. A price duration curve indicates the number of hours (shown on the horizontal axis) that the price is at or above a certain level (shown on the vertical axis). The prices in this figure are the hourly load-weighted nodal settlement point prices.

Price levels during 2015 were most similar to the prices seen in 2012 with relatively few hours exceeding $50 per MWh. As described later in this section, these lower prices correspond with the lower natural gas prices in 2015, as was the case in 2012.

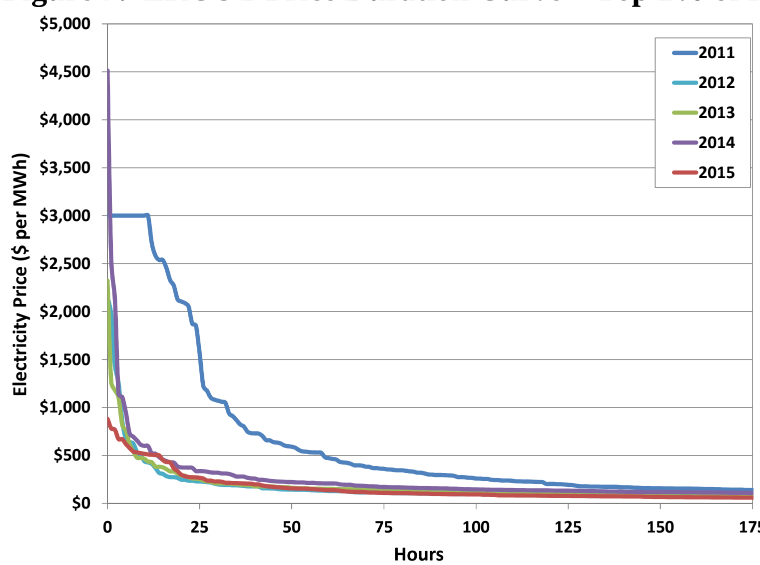
Figure 6: ERCOT Price Duration Curve



	> $0	> $50	>$100	> $200	> $300
2011	8,756	792	219	124	89
2012	8,780	287	93	30	16
2013	8,757	424	104	36	20
2014	8,716	898	199	63	34
2015	8,705	254	88	40	21

To see where the prices during 2015 diverged from prior years, Figure 7 presents a comparison of prices for the highest two percent of hours in each year. In 2011, energy prices for the top 100 hours were significantly higher. These higher prices were due to higher loads leading to more shortage conditions. In the other four years the price duration curves for the top two percent of hours are very similar and reflect few occasions of shortage conditions.

Figure 7: ERCOT Price Duration Curve – Top 2% of Hours



To better observe the effect of the highest-priced hours, the following analysis focuses on the frequency of price spikes in the real-time energy market. For this analysis, price spikes are defined as intervals when the load-weighted average energy price in ERCOT is greater than 18 MMBtu per MWh multiplied by the prevailing natural gas price. Prices at this level typically exceed the marginal costs of virtually all on-line generators in ERCOT.

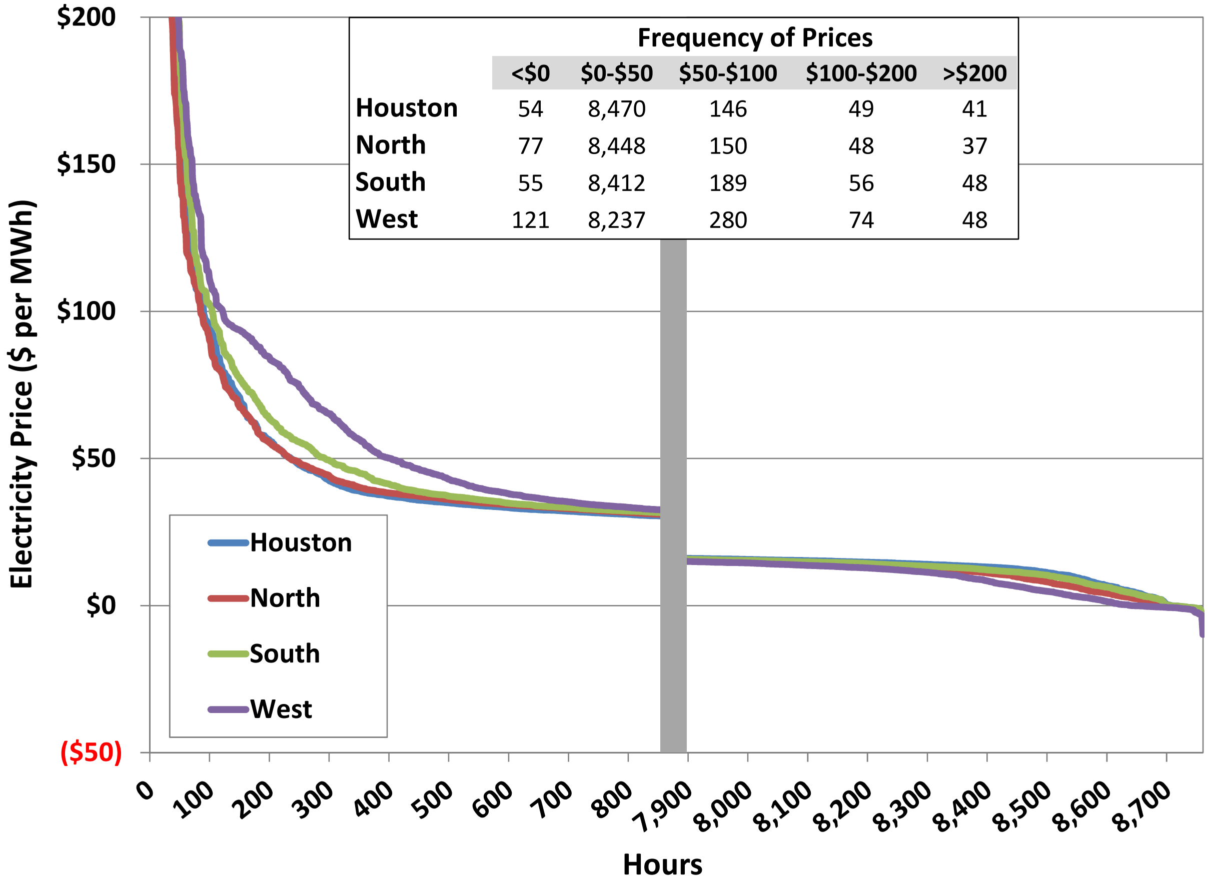
Table 1: Number and Impacts of Price Spikes on Average Real-Time Energy Prices

	Spikes Per Month	Magnitude (per MWh)	Price Impact
2012	94	$3.63	16%
2013	54	$3.43	12%
2014	74	$5.28	16%
2015	89	$3.35	16%

The overall impact of price spikes in 2015 was $3.35 per MWh. This result is generally consistent with the pricing impact of price spikes in past years. Of this price spike impact, $1.33 per MWh was due to the effects of the operating reserve adder.

To depict how real-time energy prices vary by hour in each zone, Figure 8 shows the top and bottom 10 percent of the hourly average price duration curve in 2015 for the four ERCOT load zones.

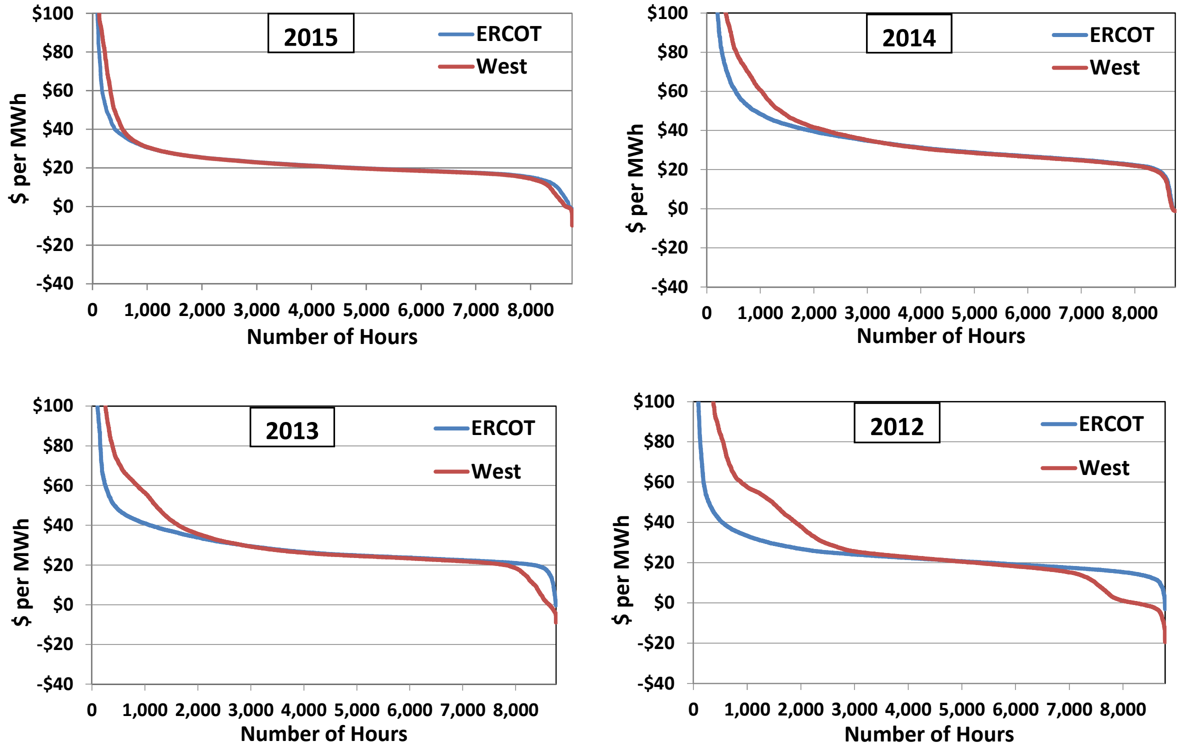
Figure 8: Zonal Price Duration Curves



The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours when prices exceeded $50 per MWh. There were more negatively priced hours in all zones during 2015 compared to 2014. The increase was greatest in the West zone. Since 2012 there has been a general trend toward fewer negative price intervals in the West zone, but such intervals continued to occur more frequently in the West zone than anywhere else. Significant transmission additions have reduced the frequency of negative West zone prices caused by transmission congestion during times of high wind output. However, the trend of local transmission constraints during low wind and high load conditions has continued and causes West prices to be higher than the rest of ERCOT. As shown above in Figure 4, these congestion-related higher prices are largely offset by the CRR Auction Revenues allocated to QSEs representing load.

Figure 9 shows the relationship between West zone and ERCOT average prices for 2012 through 2015.

Figure 9: West Zone and ERCOT Price Duration Curves

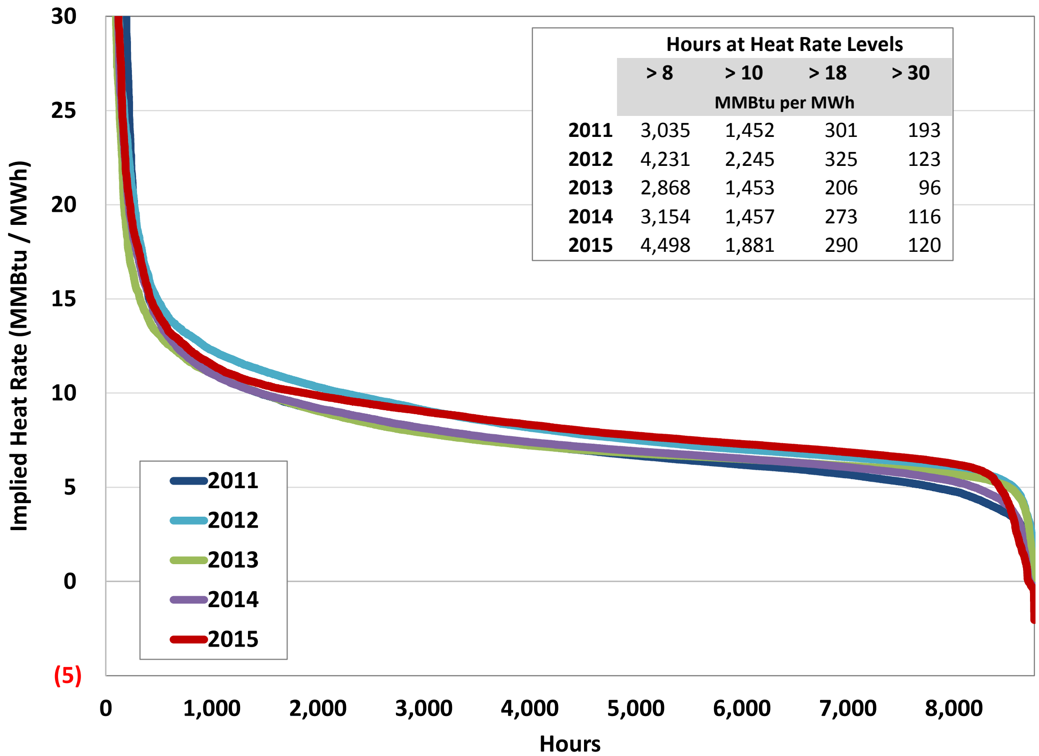


West zone prices remained higher than the ERCOT average for a significant number of hours in 2015, although the difference between West zone and ERCOT prices has steadily declined each year from 2012 to 2015. The combination of more hours with higher prices, and fewer hours with less negative prices resulted in the average real-time energy price in the West zone in 2015 being greater than the ERCOT average. However, unlike the past three years the West zone was not the highest priced zone in ERCOT. That distinction in 2015 went to the Houston zone. As noted previously, the offset provided by CRR Auction Revenue actually brings the effective average real-time energy price in the West zone lower than the ERCOT average. The same cannot be said for the Houston zone. More details about the transmission constraints influencing zonal energy prices are provided in Section III. Transmission Congestion.

B. Real-Time Prices Adjusted for Fuel Price Changes

Although real-time electricity prices are driven to a large extent by changes in fuel prices, natural gas prices in particular, they are also influenced by other factors. To summarize the changes in energy price that were related to other factors, an "implied heat rate" is calculated by dividing the real-time energy price by the natural gas price. Figure 10 and Figure 11 show the load-weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the real-time energy price is replaced by the marginal heat rate that would be implied if natural gas was always on the margin.[7]

Figure 10: Implied Heat Rate Duration Curve – All Hours



Implied heat rates in 2015 were similar to those in 2012 and were noticeably higher for the majority of hours, as compared to the other three years. This can be explained by the very low natural gas prices experienced in 2012 and 2015, and resulting pricing outcomes which were influenced by coal, not natural gas, being the marginal fuel.[8] For most hours, there are no discernable differences between 2011, 2013, and 2014.

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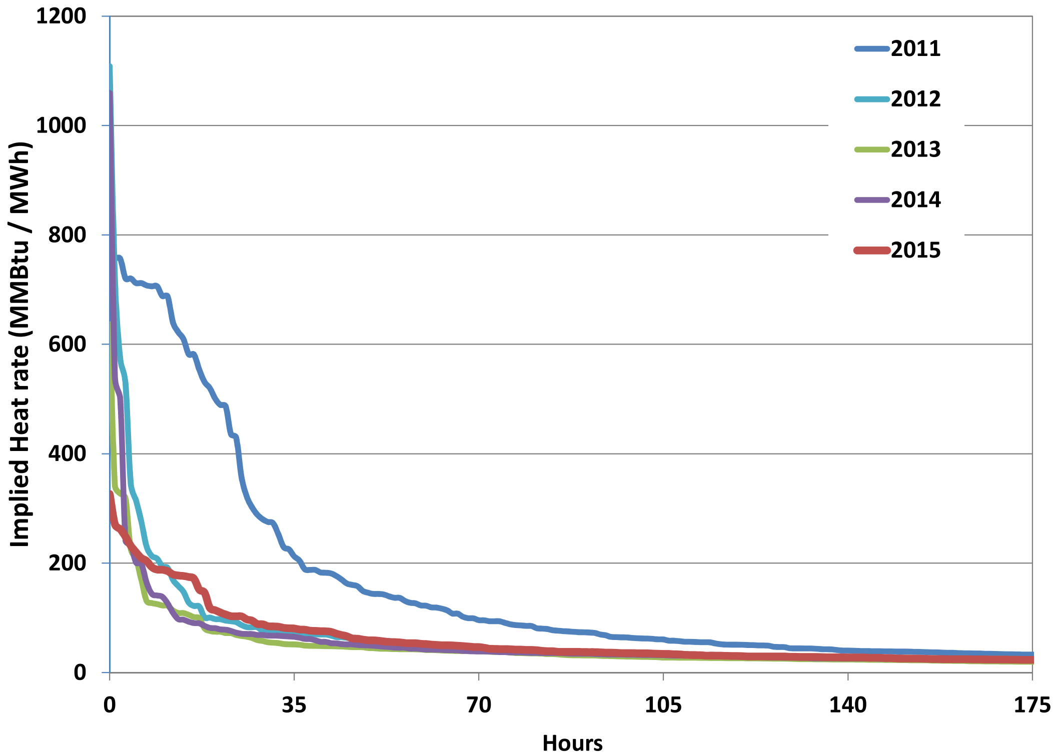
7 The *Implied Marginal Heat Rate* equals the *Real-Time Energy Price* divided by the *Natural Gas Price*. This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

8 *See* the 2012 State of the Market Report at pages 12-13.

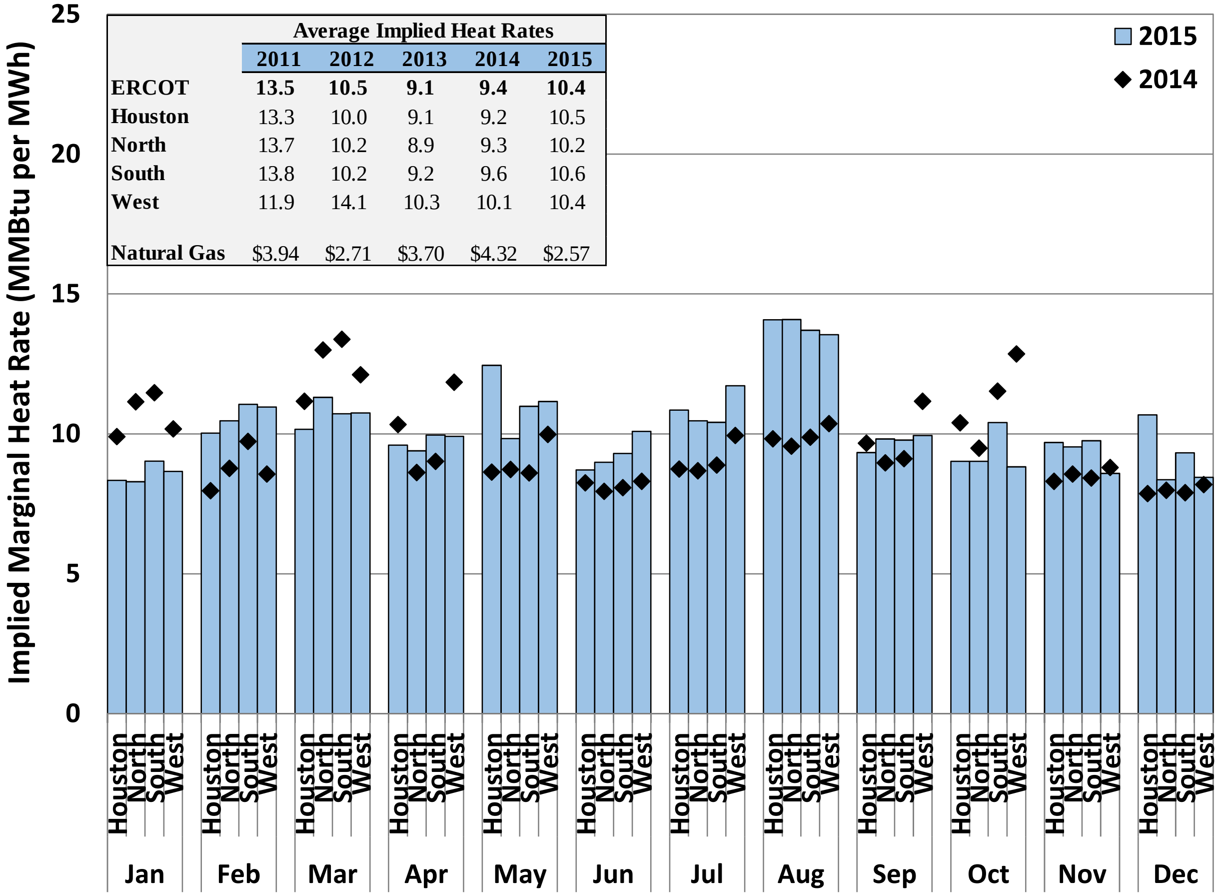
Figure 11 shows the implied marginal heat rates for the top two percent of hours for years 2011 through 2015. The implied heat rates in 2012, 2013, 2014 and 2015 are very similar, while 2011 remains an outlier.

Figure 11: Implied Heat Rate Duration Curve – Top 2 Percent of Hours



To further illustrate these differences, the next figure shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones in 2014 and 2015, with annual average heat rate data for 2011 through 2015. This figure is the fuel price-adjusted version of Figure 3 in the prior subsection. Adjusting for natural gas price influence, Figure 12 shows that the annual, system-wide average implied heat rate increased in 2015 compared to 2014.

Figure 12: Monthly Average Implied Heat Rates

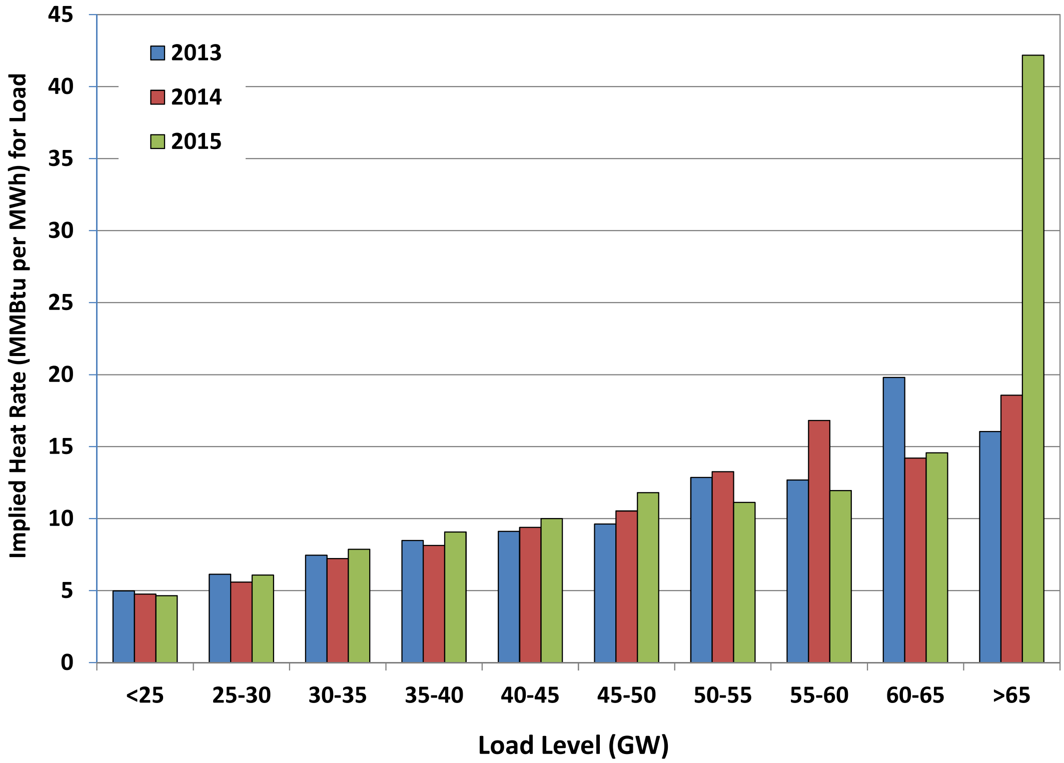


Average Implied Heat Rates	2011	2012	2013	2014	2015
ERCOT	**13.5**	**10.5**	**9.1**	**9.4**	**10.4**
Houston	13.3	10.0	9.1	9.2	10.5
North	13.7	10.2	8.9	9.3	10.2
South	13.8	10.2	9.2	9.6	10.6
West	11.9	14.1	10.3	10.1	10.4
Natural Gas	\$3.94	\$2.71	\$3.70	\$4.32	\$2.57

The monthly average implied heat rates in 2015 are generally higher than those in 2014, with the exception of January, March, and October. High loads associated with colder weather explain the higher implied heat rates in January and March of 2014. The higher implied heat rate in October 2014 reflects the impacts of significant Valley Import congestion. With the exception of the West Load Zone, the annual average implied heat rate across ERCOT in 2015 closely resembles the average implied heat rate in 2012 which is consistent with the low natural gas prices in both years.

The examination of implied heat rates from the real-time energy market concludes by evaluating them at various load levels. Figure 13 below provides the average implied heat rate at various system load levels from 2013 through 2015.

Figure 13: Implied Heat Rate and Load Relationship



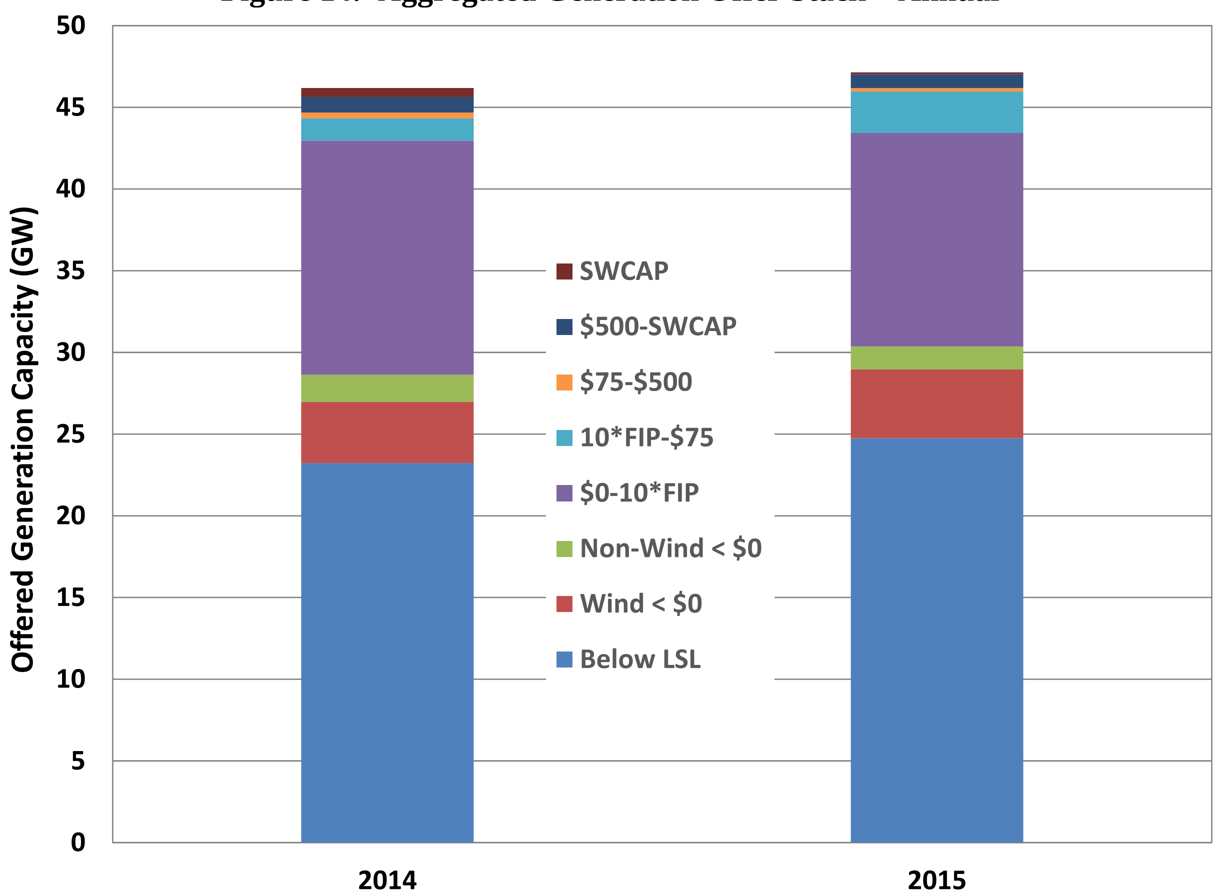
In a well-performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs are dispatched to serve higher loads. There are two noticeable differences in the implied heat rates in 2015. The first is the higher implied marginal heat rate at load levels greater than 65 GW. This increase was due to shortage pricing that occurred when load was in that range during August 2015. The second difference is the lower implied marginal heat rate at load levels between 50 and 60 GW. This is due to the relative lack of shortage pricing at those load levels during the winter months of 2015.

C. Aggregated Offer Curves

The next analysis compares the quantity and price of generation offered in 2015 to that of 2014. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 14 provides the aggregated generator offer stacks for the entire year. Comparing 2015 to 2014, more capacity was offered at lower prices. Specifically, continuing a trend from 2013, there was approximately 1,700 MW of additional capacity offered at prices less than zero. This was split between more capacity offered from wind generators (500 MW) and capacity from below generators' low operating limits (1,500 MW) with a small decrease

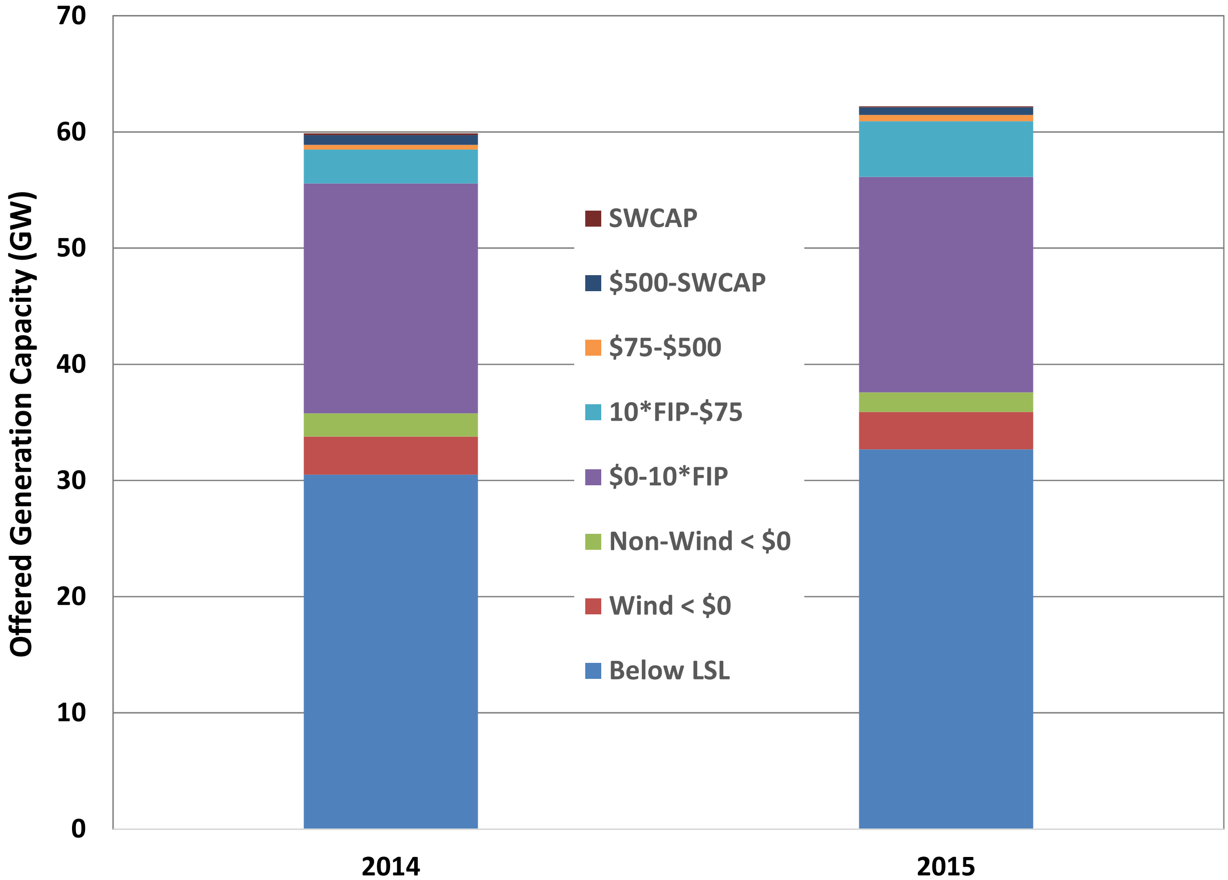
(300 MW) in capacity offered at prices less than zero from non-wind units. There was a decrease of approximately 1,300 MW of additional capacity offered in 2015 at prices between zero and ten multiplied by the daily natural gas price. The amount of capacity offered at prices between 10 multiplied by the daily natural gas price and $75 per MWh increased by 1,200 MW from 2014 to 2015. With a small, net decrease (700 MW) to the quantities of generation offered at prices above $75 per MWh, the resulting average aggregated generation offer stack was roughly 1,000 MW greater in 2015 than in 2014.

Figure 14: Aggregated Generation Offer Stack – Annual



The next analysis provides a similar comparison focused on the summer season. As shown below in Figure 15, the changes in the aggregated offer stacks between the summer of 2014 and 2015 were similar to those just described. Comparing 2015 to 2014, there were approximately 1,800 MW additional capacity offered at prices less than zero, with an increase of 2,200 MW of capacity below generators' low sustained limits (LSLs) and a decrease of 400 MW in energy offered at prices less than zero but above the generators' LSLs. There was 1,200 MW less energy offered at prices between zero and ten multiplied by the daily natural gas price, but 1,900 MW more energy offered at prices between ten multiplied by the daily natural gas price and $75. With small reductions to the quantities of generation offered at prices above $75 per MWh, the resulting average aggregated generation offer stack for the summer season was approximately 2,300 MW greater than in 2014.

Figure 15: Aggregated Generation Offer Stack – Summer



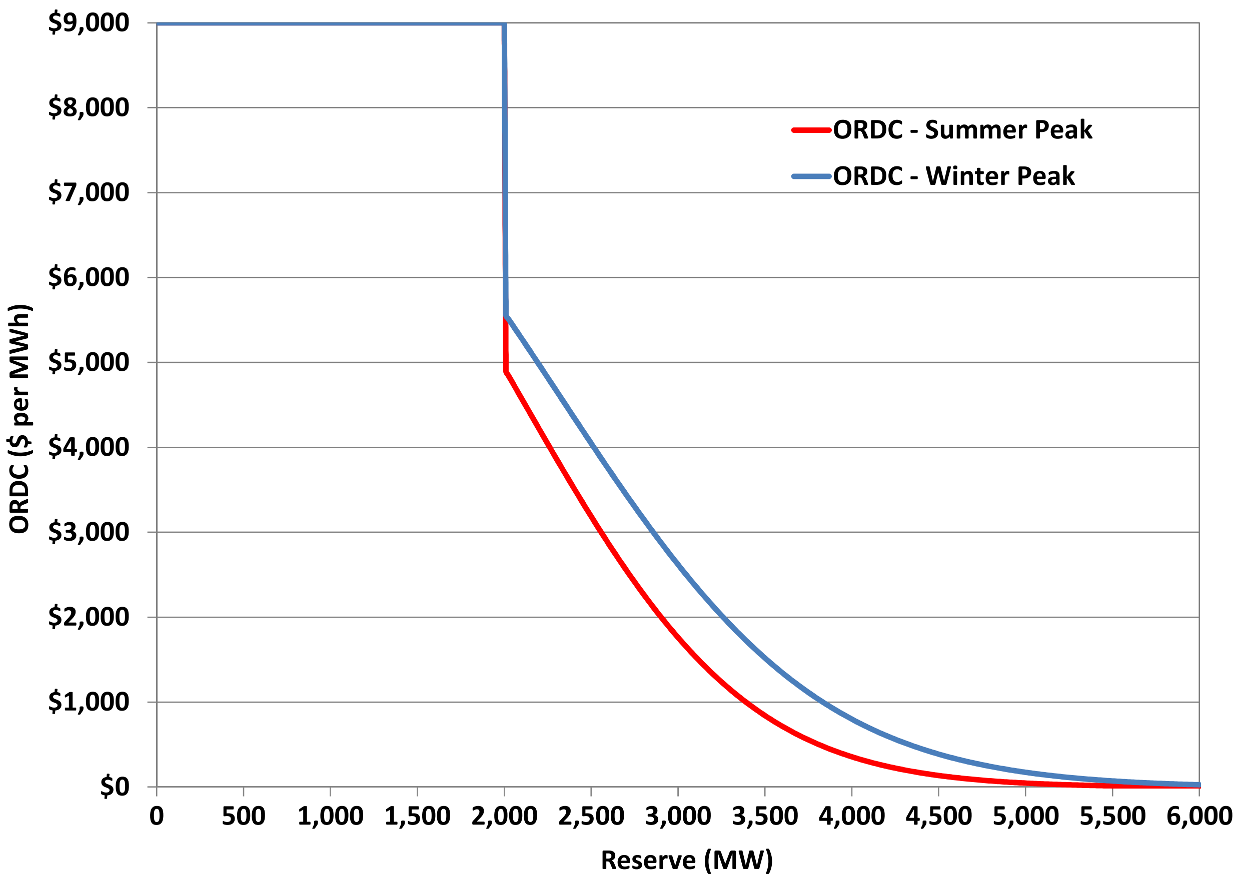
D. ORDC Impacts and Prices During Shortage Conditions

The ORDC is a shortage pricing mechanism that reflects the loss of load probability (LOLP) at varying levels of operating reserves multiplied by the deemed value of lost load (VOLL).[9] Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC places an economic value on the reserves being provided, with

9 At the September 12, 2013 Open Meeting, the PUCT Commissioners directed ERCOT to move forward with implementing ORDC, including setting the Value of Lost Load at $9,000

separate pricing for online and offline reserves. As the quantity of reserves decreases, payments for reserves will increase. As shown below in Figure 16, once available reserve capacity drops to 2,000 MW, payment for reserve capacity will rise to $9,000 per MWh.

Figure 16: Operating Reserve Demand Curves

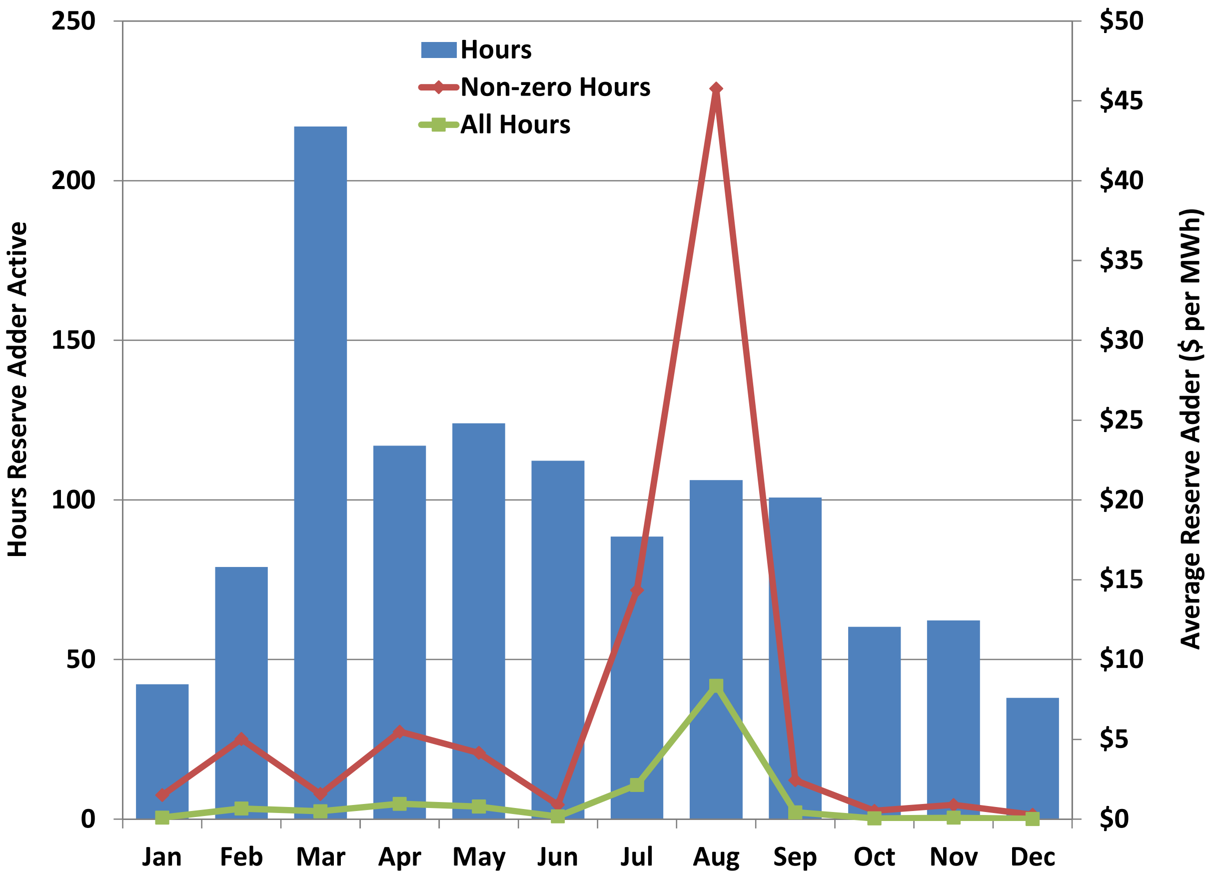


The following two analyses illustrate the contributions of the operating reserve adder and the newly-implemented reliability adder to shortage pricing. Since the operating reserve adder was implemented mid-year in 2014, 2015 provides the first full calendar year for reviewing the operating reserve adder performance.

Figure 17 shows the number of hours in which the adder affected prices, and the average price effect in these hours and all hours. This figure shows that the operating reserve adder had a relatively modest impact on prices in 2015, with the largest impact during the summer months. The operating reserve adder contributed $1.41 per MWh or 5 percent to the annual average real time price of $26.77 per MWh. While the largest number of hours with the operating reserve adder occurred in the spring months, the average price impacts in those months were minimal.

These results do not indicate that ORDC has been ineffective or that it should be modified. The effects of the operating reserve adder are expected to vary substantially from year to year, and to have the largest effects when poor supply conditions and unusually high load conditions occur together and result in sustained shortages.

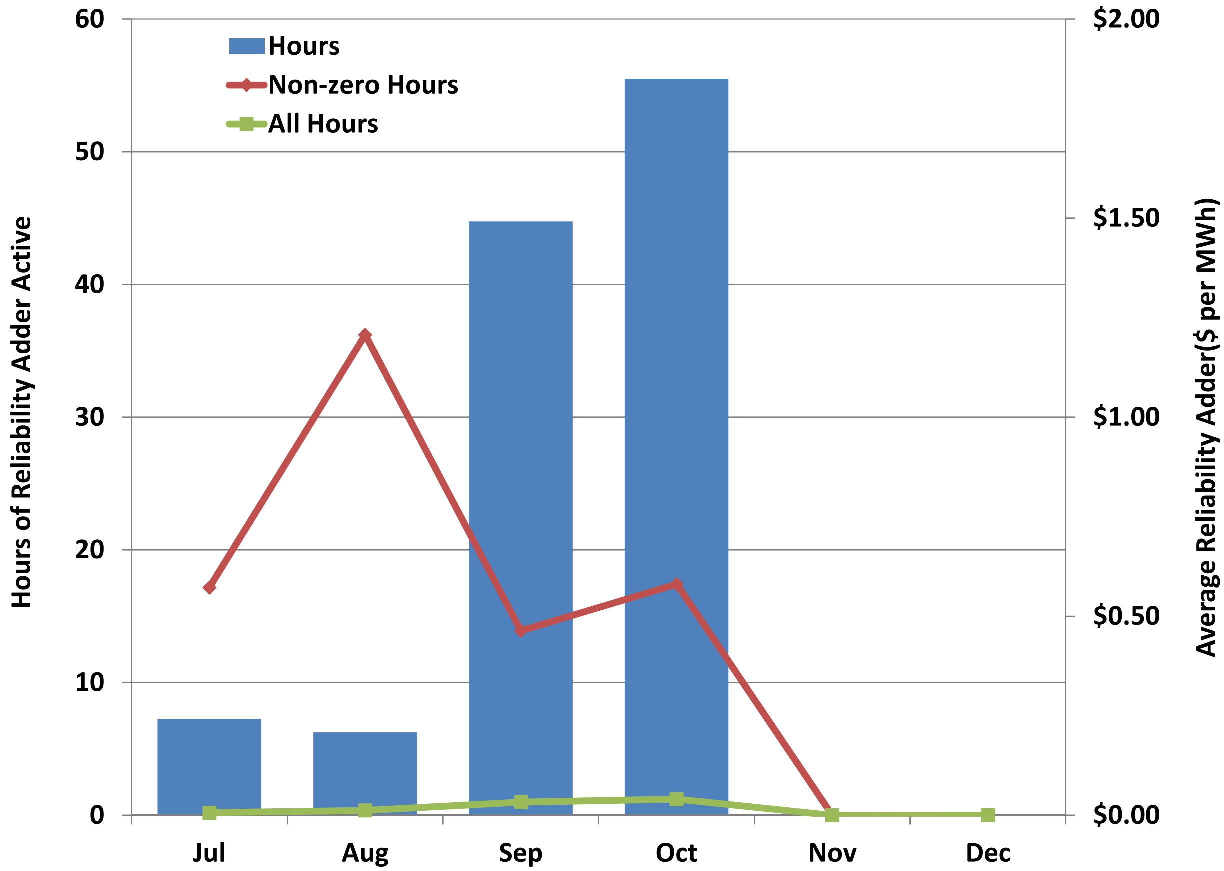
Figure 17: Average Operating Reserve Adder



In addition to the operating reserve adder, a reliability adder was implemented at the end of June 2015. The reliability adder is intended to allow prices to reflect the costs of reliability actions taken by ERCOT, including RUC commitments and deployed load capacity. Absent this adder, prices will generally fall when these actions are taken.

Figure 18 below shows the impacts of the reliability adder. When averaged across the active hours, the largest price impact of the reliability adder occurred in August. The contribution from the reliability adder to the annual average real-time energy price was $0.01 per MWh.

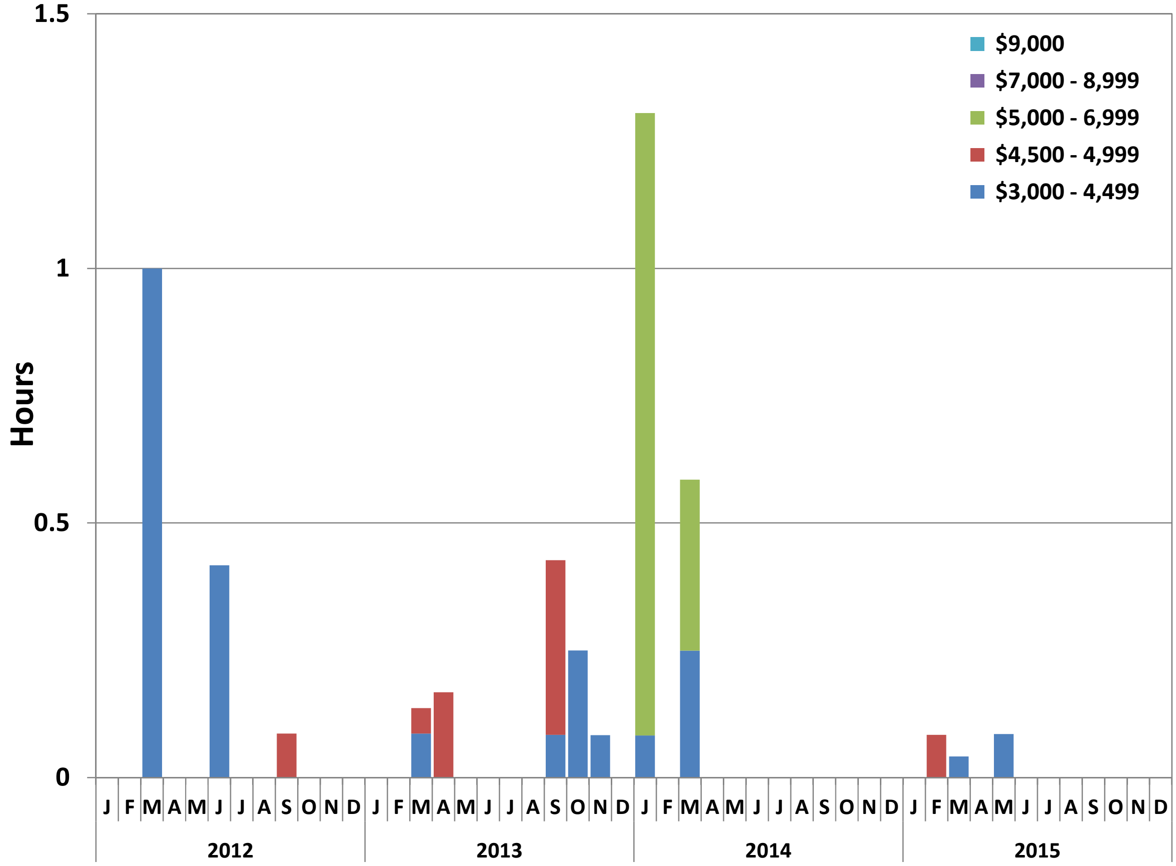
Figure 18: Average Reliability Adder



As an energy-only market, the ERCOT market relies heavily on high real-time prices that occur during shortage conditions. These prices provide key economic signals that provide incentives to build new resources and retain existing resources. However, the frequency and impacts of shortage pricing can vary substantially from year-to-year.

To summarize the shortage pricing that occurred from 2012 to 2015, Figure 19 below shows the aggregate amount of time when the real-time energy price was at the system-wide offer cap, by month. This figure shows that there were no instances in 2015 of energy prices rising to the system-wide offer cap, which was $7,000 per MWh through May 31 and $9,000 per MWh for the remainder of the year. Prices did exceed $3,000 per MWh for a total of 0.21 hours, or less than 15 minutes. Prices during 2014 exceeded $3,000 per MWh for a total of 1.89 hours and were at the system-wide offer cap for only 1.56 hours, an increase from 0.22 hours and 1.51 hours in 2013 and 2012, respectively.

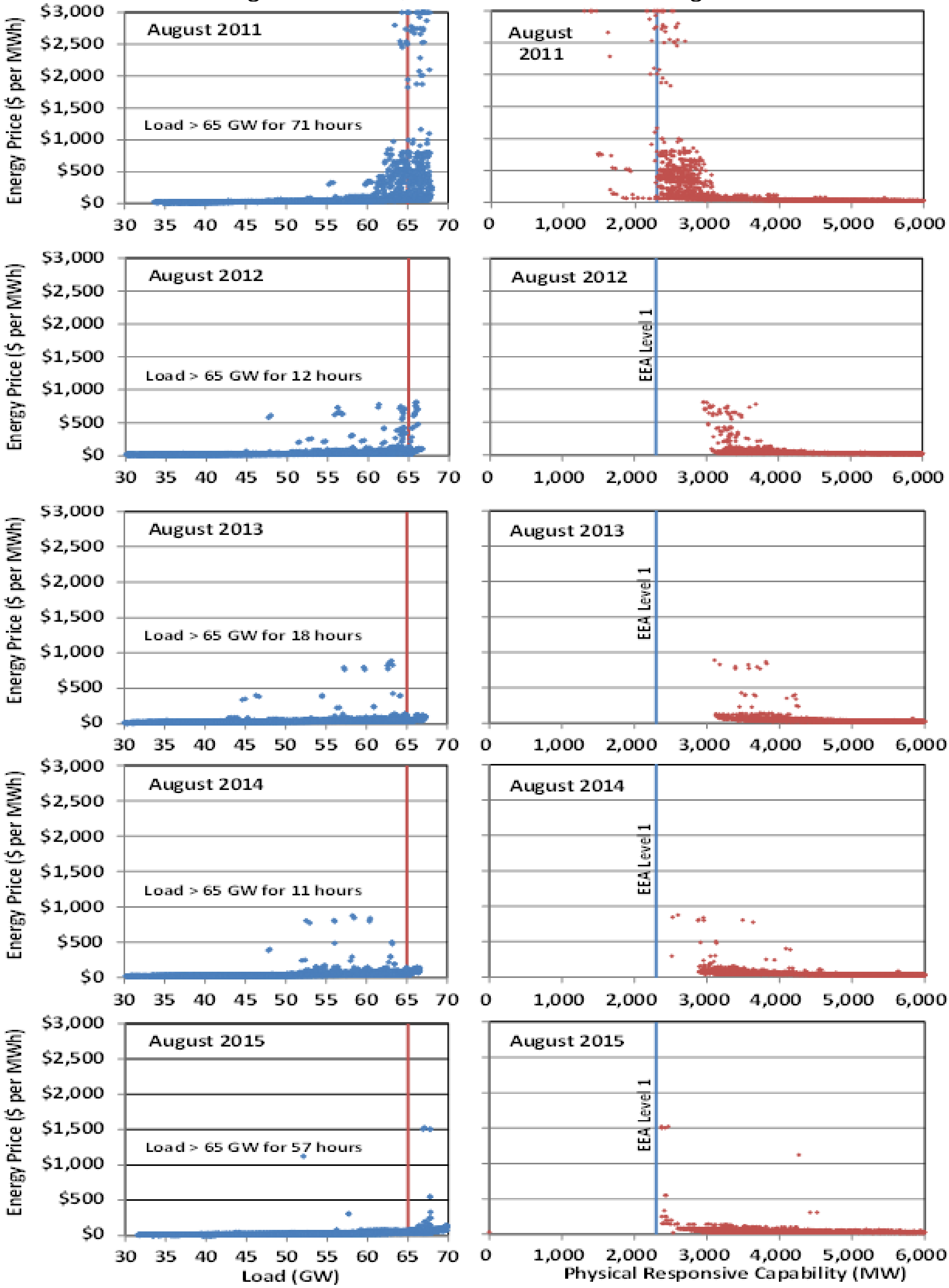
Figure 19: Prices at the System-Wide Offer Cap



The frequency of the market clearing at the cap in all of these years was much lower than the 28.44 hours experienced in 2011, which was caused by unusually hot and sustained summer temperatures. This is the type of year when one should expect much more frequent shortages. Shortages in years with normal weather should be infrequent. As capacity margins fall, the frequency of shartages is likely to increase but will still vary substantially year-to-year.

Figure 20 provides a detailed comparison for 2011 through 2015 of each August's load, required reserve levels, and prices for 2011 through 2015. There were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012, 2013, 2014, and 2015 compared to the relatively high frequency it occurred in 2011. Although the weather may have been similar, there were significant differences in load and available operating reserve levels, resulting in much higher prices in August 2011.

Figure 20: Load, Reserves and Prices in August



The left side of Figure 20 shows the relationship between real-time energy price and load level for each dispatch interval for the months of August in the years 2011 to 2015. ERCOT loads in August were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for 12 hours, 18 hours, and 11 hours in 2012, 2013, and 2014, respectively.

Because temperatures were relatively hot in August of 2015, ERCOT load exceeded 65 GW for 57 hours. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market, and this analysis shows such a relationship. However, this relationship appears to be weaker in years 2012 to 2014 with more instances of higher prices occurring at lower loads. These instances are generally due to high-priced, fast ramping generation being dispatched at times when changing system conditions exceed the capabilities of other available generation to respond.

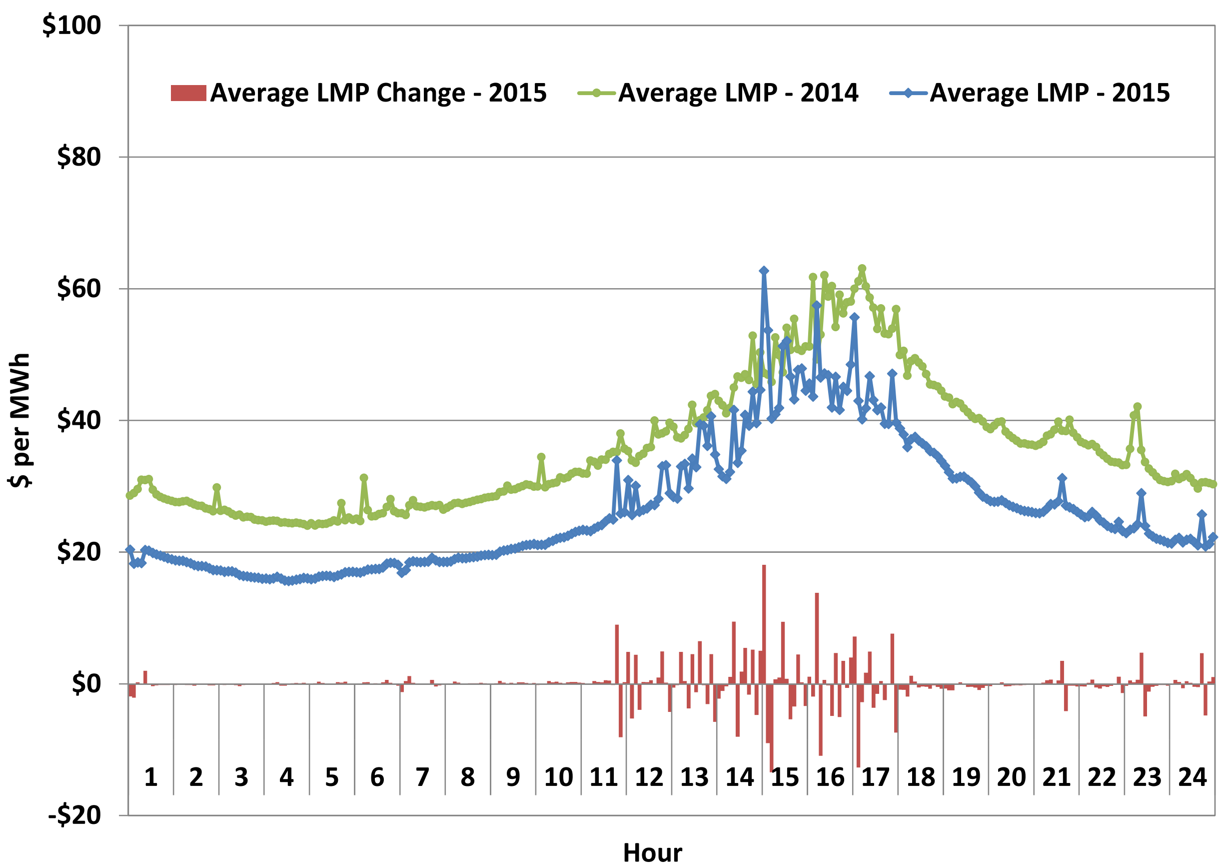
Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity of operating capacity, the amount of operating reserves diminishes. The minimum required operating reserves prior to ERCOT declaring Energy Emergency Alert (EEA) Level 1 is 2,300 MW. As the available operating reserves approach the minimum required amount, energy prices should rise toward the system-wide offer cap to reflect the degradation in system reliability and the associated value of loss of load.

The right side of Figure 20 shows the relationship between real-time energy prices and the quantity of available operating reserves for each dispatch interval during August of 2011, 2012, 2013, 2014, and 2015. This figure shows a strong correlation between diminishing operating reserves and rising prices. Operating reserves did get very close to the minimum required level on one day in August 2015, but remained just above the level at which ERCOT would declare EEA Level 1. Concerns have been expressed that real-time prices were not higher in this situation. As discussed in Section V.B, in response to those concerns a review of the ORDC parameters is ongoing. Lower loads in August 2012, 2013, and 2014, resulted in available operating reserves remaining well above minimum levels for the entire month, and there were no occurrences when the energy price reached the system-wide offer cap. In contrast, there were numerous dispatch intervals in August 2011 when the minimum operating reserve level was approached or breached, and prices reached the system-wide offer cap in 17.4 hours.

E. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability of supply to adjust can be restricted by physical limitations of the resources and the transmission network. Figure 21 below presents a view of the price volatility experienced in ERCOT's real-time energy market during the summer months of May through August. Average five-minute real-time energy prices are presented along with the magnitude of change in price for each five-minute interval. Average real-time energy prices from the same period in 2014 are also presented. Comparing average real-time energy prices for 2015 with those from 2014, the effects of lower natural gas prices on average prices may be observed. Although prices were lower in 2015, there was more price volatility (variability) in 2015.

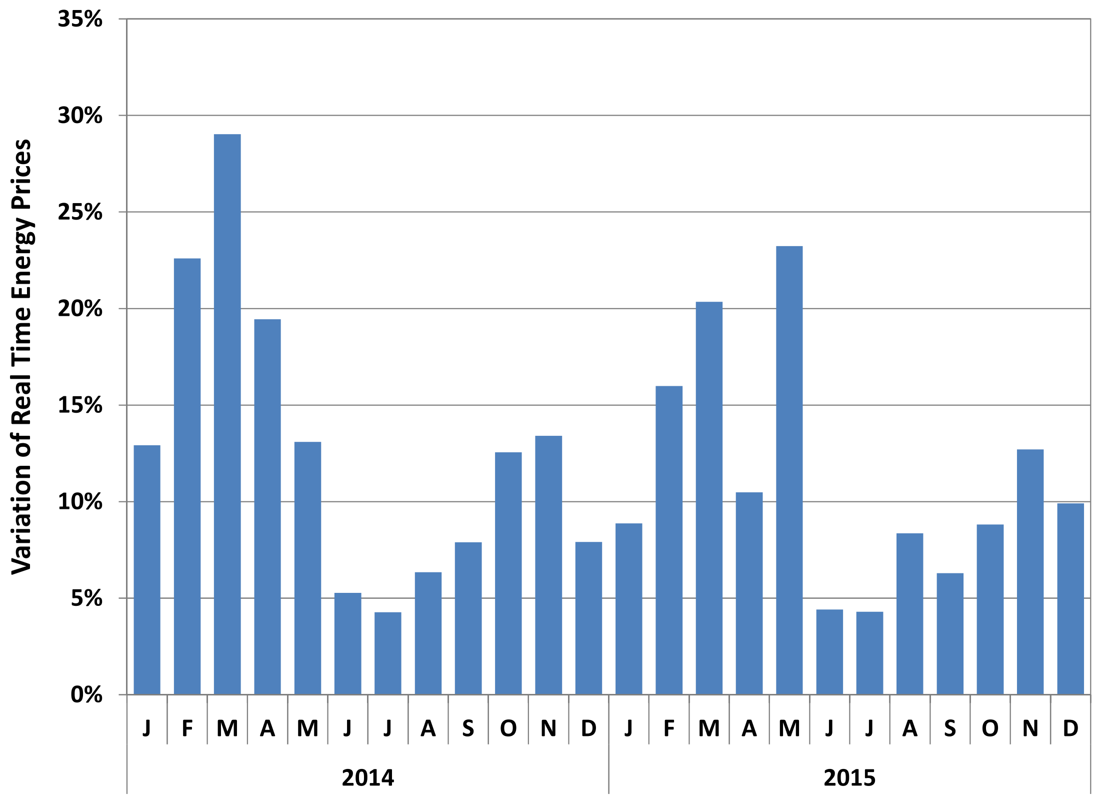
Figure 21: Real-Time Energy Price Volatility (May – August)



The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percent of average price, was 4.9 percent in 2015, compared to a range of 3.0 percent to 3.6 percent in the prior three years. In 2011, the absolute value of five-minute price changes was 6.2 percent.

Expanding the view of price volatility, Figure 22 below shows monthly average changes in five-minute real-time prices. Without any prices at, or close to the system-wide offer cap, the highest price variability occurs during spring and fall months when wind generation variations and load and wind generation forecast errors are the highest.

Figure 22: Monthly Price Variation



To show how the price volatility has varied by location, Table 2 below, shows the volatility of 15-minute settlement point prices for the four geographic load zones in 2015.

Table 2: 15-Minute Price Changes as a Percentage of Annual Average Prices

Load Zone	2012	2013	2014	2015
Houston	13.0	14.8	14.7	13.4
South	13.1	15.4	15.2	14.6
North	13.9	13.7	14.1	11.9
West	19.4	17.2	15.4	12.9

These results show that price volatility is generally lower in 2015 than in the prior three years. The table also shows that price volatility in the West Load Zone has continued to decrease, likely as a result of transmission investment in the region. In fact, price volatility in the West zone in 2015 was lower than price volatility in the South Load Zone.

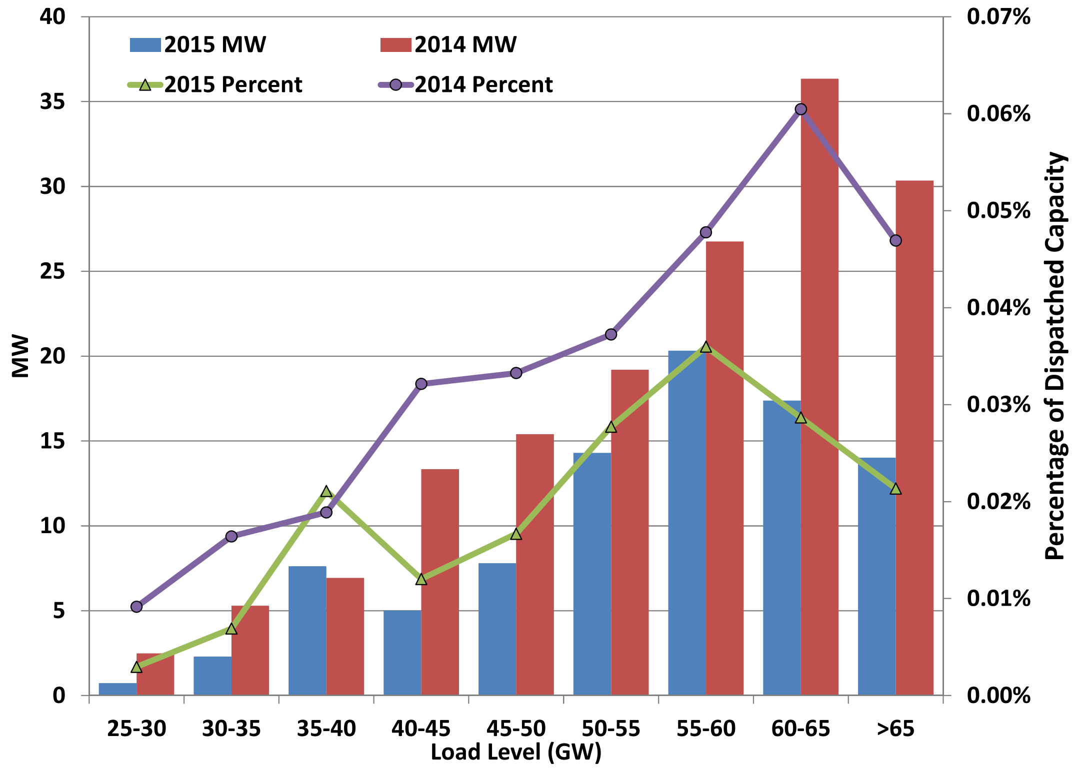
F. Mitigation

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 2015 is analyzed. Although executing all the time, 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 in 2013 of an impact test 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 23 computes how much capacity, on average, is actually mitigated during each dispatch interval. The results are provided by load level.

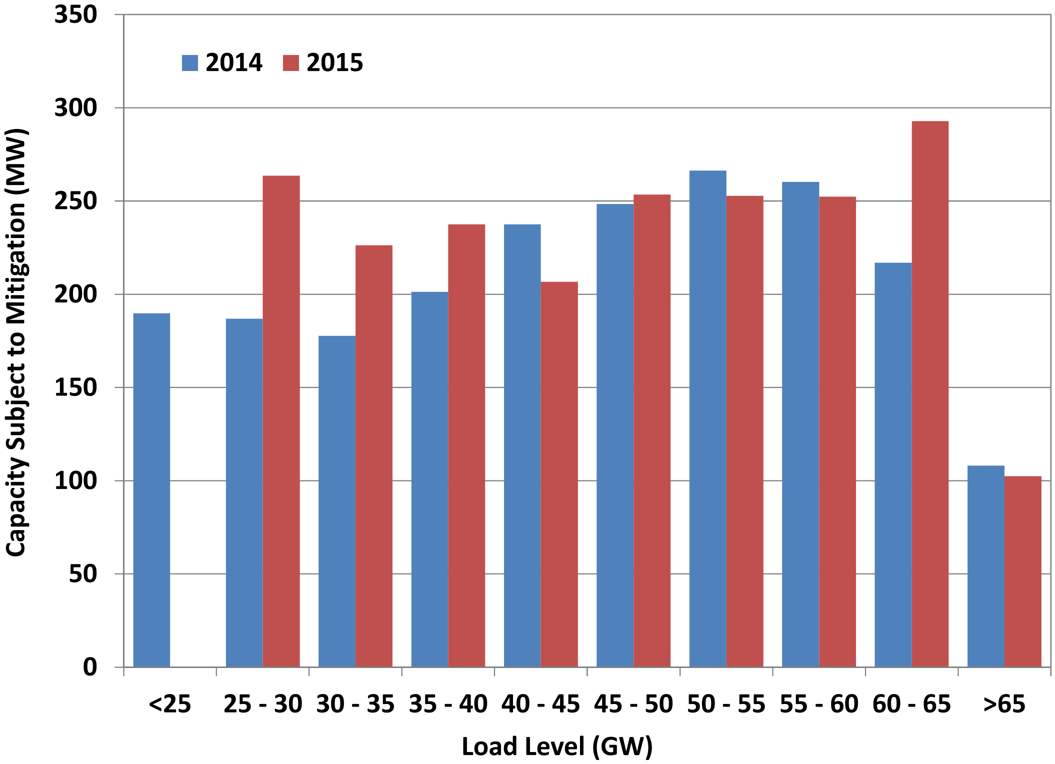
Figure 23: Mitigated Capacity by Load Level



The level of mitigation in 2015 was lower than in 2014. The average amount of mitigated capacity was less than 20 MW for all load levels in 2015, slightly lower than in 2014 when the greatest quantity of mitigated capacity being dispatched was just over 35 MW at high load levels. The similar frequency of congestion that occurred in 2015 and 2014, as described later in Section III, supports the similar mitigation levels experienced in the two years.

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 24.

Figure 24: Capacity Subject to Mitigation



As in the previous analysis, the amount of capacity subject to mitigation in 2015 was similar to the amounts in 2014. The largest amount of capacity subject to mitigation has not exceeded 300 MW for the past two years. This is in contrast to the situation prior to mid-2013 when the mitigation rules were modified to only apply to generators that can relieve non-competitive constraints.

By comparison, in 2012, prior to the change, up to 7 percent of capacity required to serve load was subject to mitigation. In 2015, this percentage was less than 1 percent. 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.

II. Review of Day-Ahead Market Outcomes

ERCOT's day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Offers to sell can take the form of either a three-part supply offer, which allows sellers to reflect the unique financial and operational characteristics of a specific generation resource, or an energy-only offer, which is location specific but is not associated with a generation resource. Bids to buy are also location specific. In addition to power, the day-ahead market also includes ancillary services and Point-to-Point (PTP) Obligations. PTP Obligations allow parties to hedge the incremental cost of congestion between day-ahead and real-time operations.

With the exception of the acquisition of ancillary service capacity, the day-ahead market is a financial market. Although all bids and offers are evaluated for the ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market. These transactions are made for a variety of reasons, including satisfying the participant's own demand, managing risk by hedging the participant's exposure to real-time prices, or arbitraging with the real-time prices. For example, load-serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

In this section energy pricing outcomes from the day-ahead market are reviewed and convergence with real-time energy prices is examined. The volume of activity in the day-ahead market, including a discussion of PTP Obligations is also reviewed. This section concludes with a review of the ancillary service markets.

A. Day-Ahead Market Prices

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. Forward prices will converge with real-time prices when: (1) there are low barriers to shifting purchases and sales between the forward and real-time markets; and (2) sufficient information is available to market participants to allow them to develop accurate expectations of future real-time prices. When these conditions are met, market participants can be expected to arbitrage predictable differences between forward prices and real-time spot prices by increasing net purchases in the lower priced market and increasing net sales in the higher priced market. This improves the convergence of forward and real-time prices, which generally improves the commitment of resources needed to satisfy the system's real-time needs.

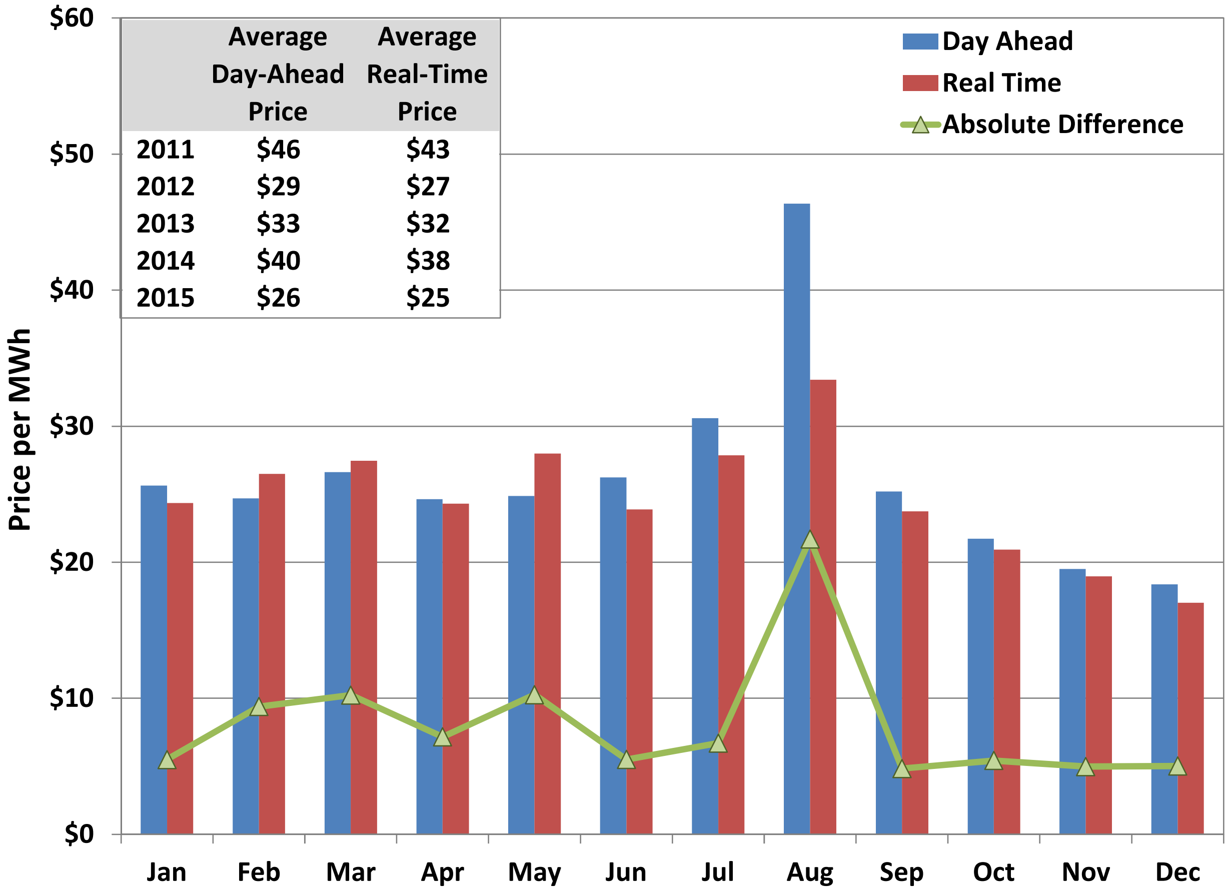
In this subsection, price convergence between the day-ahead and real-time markets is evaluated. This average price difference reveals whether persistent and predictable differences exist between day-ahead and real-time prices, which participants should arbitrage over the long term. To measure the short-term deviations between real-time and day-ahead prices, the average of the absolute value of the difference between the day-ahead and real-time price are calculated on a daily basis. This measure captures the volatility of the daily price differences, which may be large even if the day-ahead and real-time energy prices are the same on average.[10]

Figure 25 summarizes the price convergence between the day-ahead and real-time market, by month. Day-ahead prices averaged $26 per MWh in 2015 compared to an average of $25 per MWh for real-time prices.[11] This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead market and higher for generators selling day ahead. The higher risk for generators is associated with the potential of incurring a forced outage and, as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest relative demand and highest prices, as was seen in August 2015. The overall day-ahead premium decreased in 2015 compared to 2014, due to low natural gas prices resulting in overall lower electricity prices and few occurrences of shortage pricing in 2015. The average absolute difference between day-ahead and real-time prices fell by more than a third to $8.08 per MWh in 2015 which was attributable to lower real-time price volatility and low fuel prices in 2015.

10 For instance, if day-ahead prices are $30 per MWh on two consecutive days while real-time prices are $20 per MWh and $40 per MWh respectively, the absolute price difference between the day-ahead market and the real-time market would be $10 per MWh on both days, while the difference in average prices would be $0 per MWh.

11 These values are simple averages, rather than load-weighted averages as presented in Figures 1 and 2.

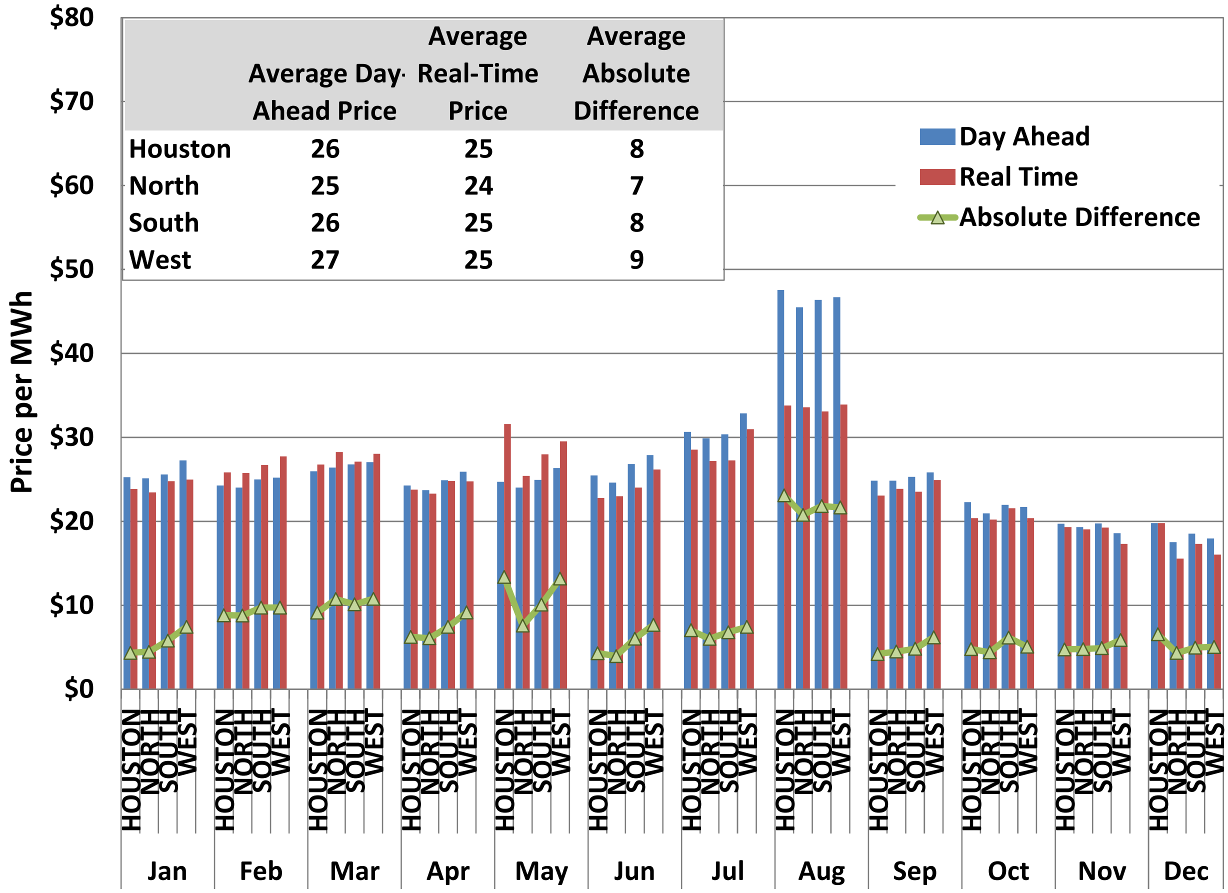
Figure 25: Convergence Between Day-Ahead and Real-Time Energy Prices



Day-ahead premiums in high-load months in ERCOT remain higher than observed in other organized electricity markets. Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than the shortage pricing in other organized electricity markets, which increases risk and helps to explain the higher day-ahead premiums regularly observed in ERCOT. Although most months experienced a day-ahead premium in 2015, it should not be expected that every month will produce a day-ahead premium. The real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.*, in February, March and May).

In Figure 26 below, monthly day-ahead and real-time prices are shown for each of the geographic load zones. Of note is that the volatility in the West zone has decreased and more closely resembles the relative stability of the other load zones. The larger difference between day-ahead and real-time prices previously observed in the West zone was likely associated with the uncertainty of forecasting wind generation output and associated transmission congestion.

Figure 26: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

The next analysis summarizes the volume of day-ahead market activity by month. Figure 27 below shows that the volume of day-ahead purchases provided through a combination of generator-specific and virtual energy offers was approximately 51 percent of real-time load in 2015, which was a slight increase compared to 2014 activity.

As discussed in more detail in the next subsection, PTP Obligations are financial transactions purchased in the day-ahead market. Although PTP Obligations do not themselves involve the direct supply of energy, allow a participant to buy the network flow from one location to another.[12] In doing so, the participant can avoid the associated real-time congestion costs between the locations. To provide a volume comparison, all of these “transfers” are aggregated

12 PTP Obligations are equivalent to scheduling virtual supply at one location and virtual load at another.

with other energy purchases and sales, netting location-specific injections against withdrawals to arrive at a net system flow. The net system flow in 2015 was almost 8 percent higher than in 2014.

Adding the aggregated transfer capacity associated with purchases of PTP Obligations to the other injections and withdrawals demonstrates that net system flow volume transacted in the day-ahead market exceeds real-time load by approximately 30 percent. The volume in excess of real-time load increased in 2015 compared to 2014, when the monthly net system flow averaged 23 percent more than real-time load.

Figure 27: Volume of Day-Ahead Market Activity by Month

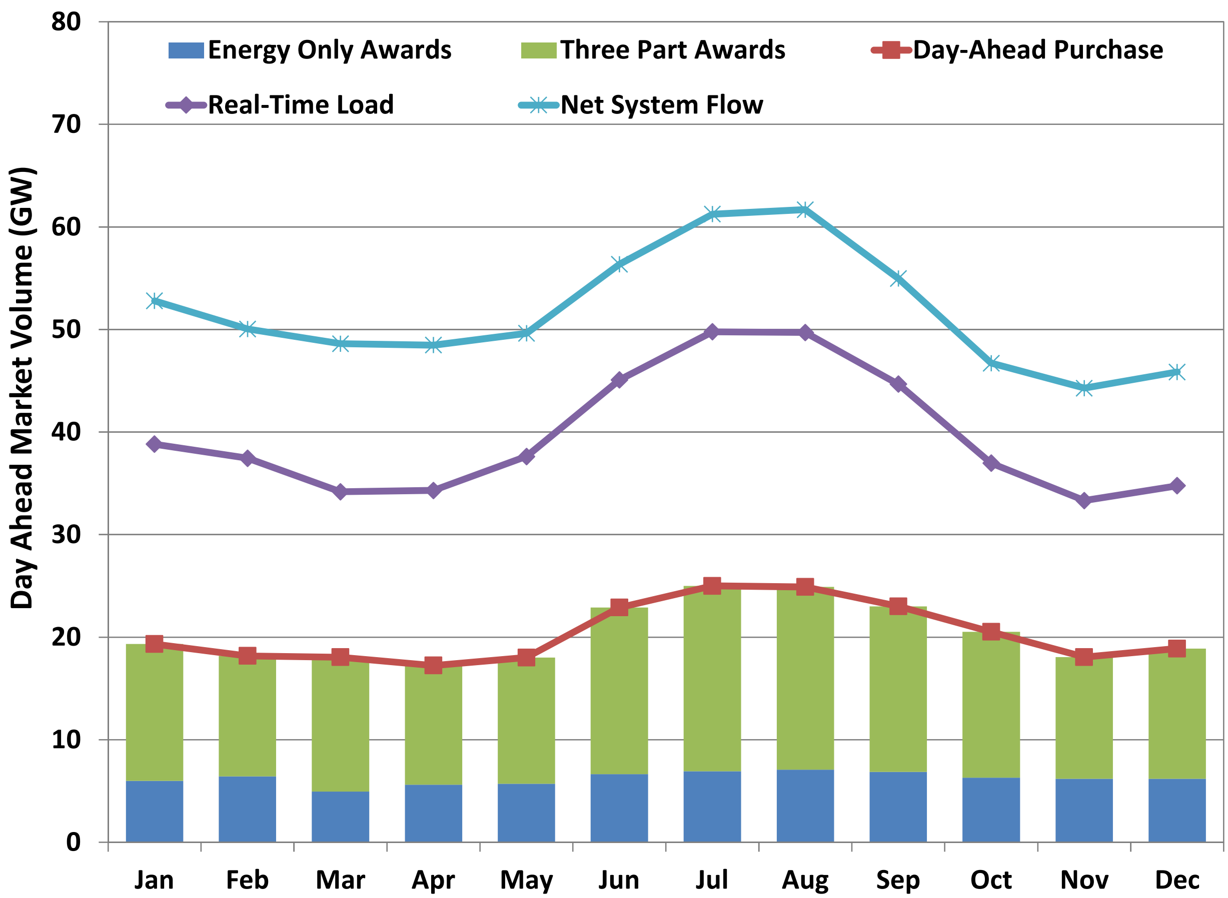
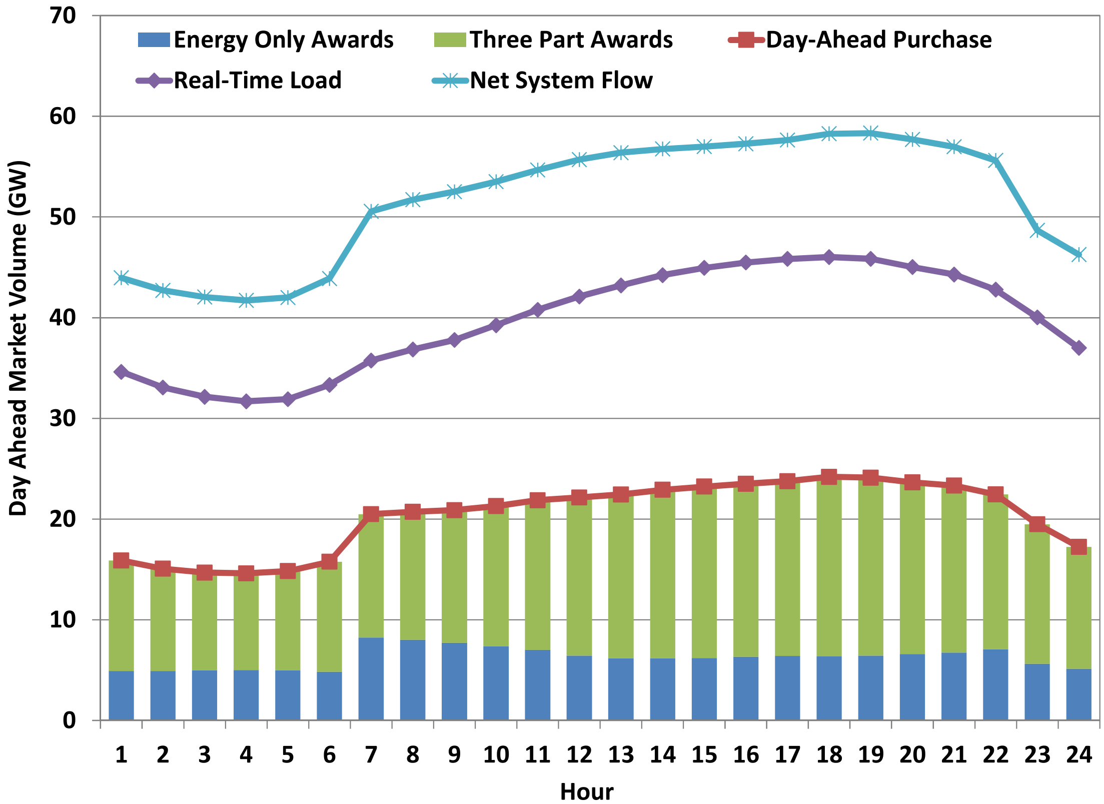


Figure 28 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, the results in this figure are consistent with market participants using the day-ahead market to trade around those positions.

Figure 28: Volume of Day-Ahead Market Activity by Hour



C. Point-to-Point Obligations

Purchases of PTP Obligations comprise a significant portion of day-ahead market activity. They are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III.D, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the day-ahead market.

Participants buy PTP Obligations by paying the difference in prices between two locations in the day-ahead market. They receive the difference in prices between the same two locations in the real-time market. Hence, a participant that owns a CRR can use its CRR proceeds from the day-ahead market to buy the PTP Obligation in order to transfer its hedge to real-time. Because PTP Obligations represent such a substantial portion of the transactions in the day-ahead market, additional details about the volume and profitability of these PTP Obligations are provided in this subsection.

Figure 29: Point-to-Point Obligation Volume

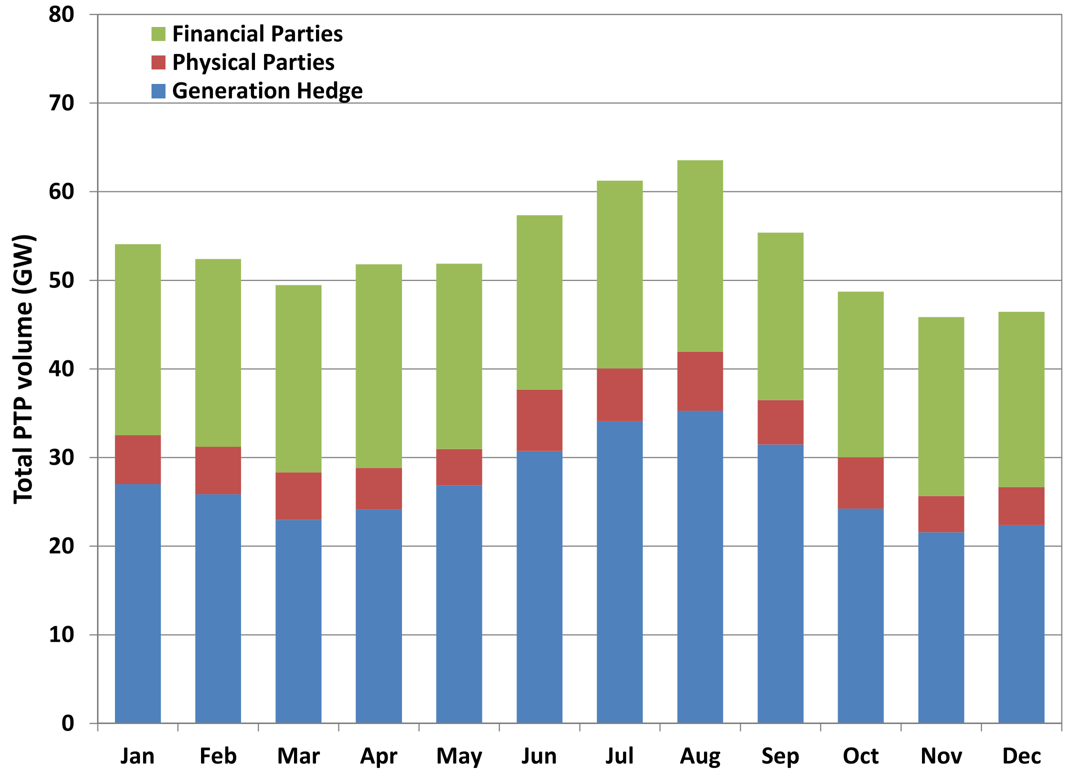


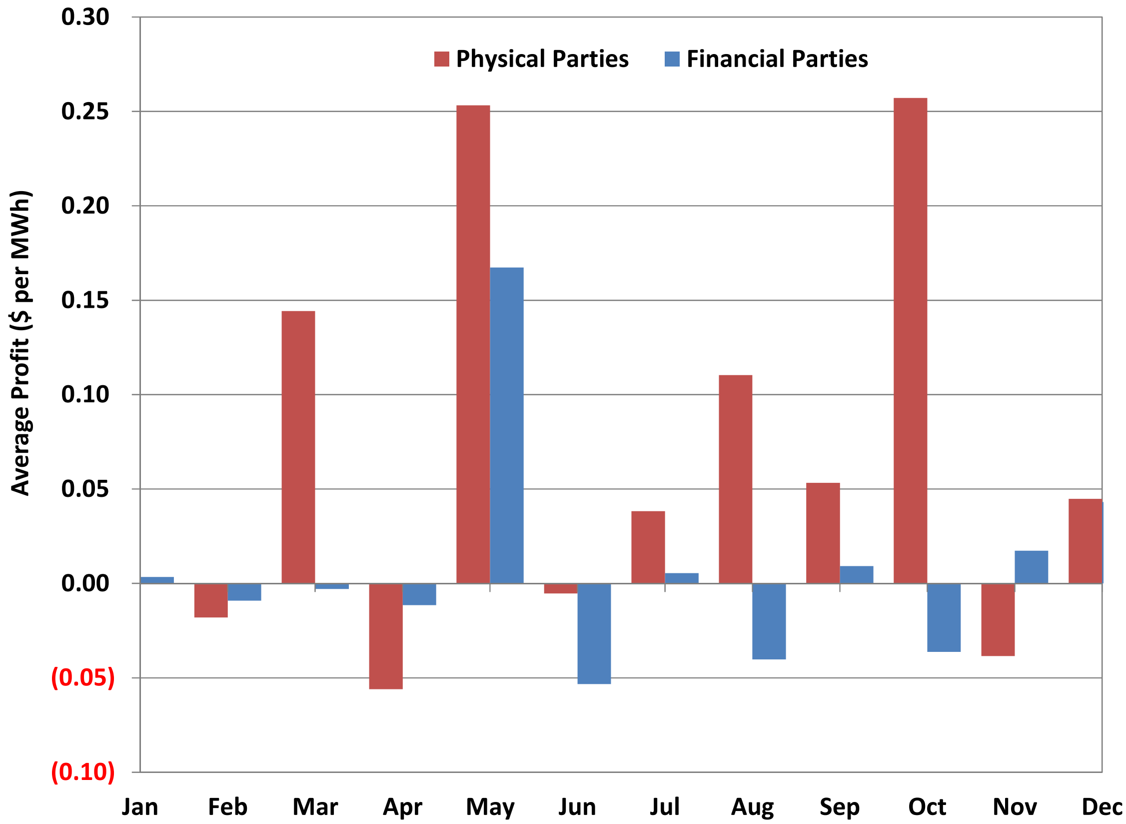
Figure 29 presents the total volume of PTP Obligation purchases divided into three categories. This figure presents total volume, compared to the previous two figures that showed net flows associated with PTP Obligations. The volumes in this figure do not net out the injections and withdrawals occurring at the same location, as is done to calculate the net flows.

For all PTP Obligations that source at a generator location, the capacity up to the actual generator output is considered to be hedging the real-time congestion associated with generating at that location. The figure above shows that this comprised most of the volume of PTP Obligations purchased. The remaining volumes of PTP Obligations are not directly linked to a physical position and are assumed to be purchased primarily to arbitrage anticipated price differences between two locations. This arbitrage activity is further separated by type of market participant. Physical parties are those that have actual real-time load or generation, whereas financial parties have neither.

To the extent the price difference between the source and sink of a PTP Obligation is greater in real-time than it was for the day-ahead price, the owner will profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be unprofitable.

The profitability of PTP Obligation holdings by the two types of participants are compared in Figure 30.

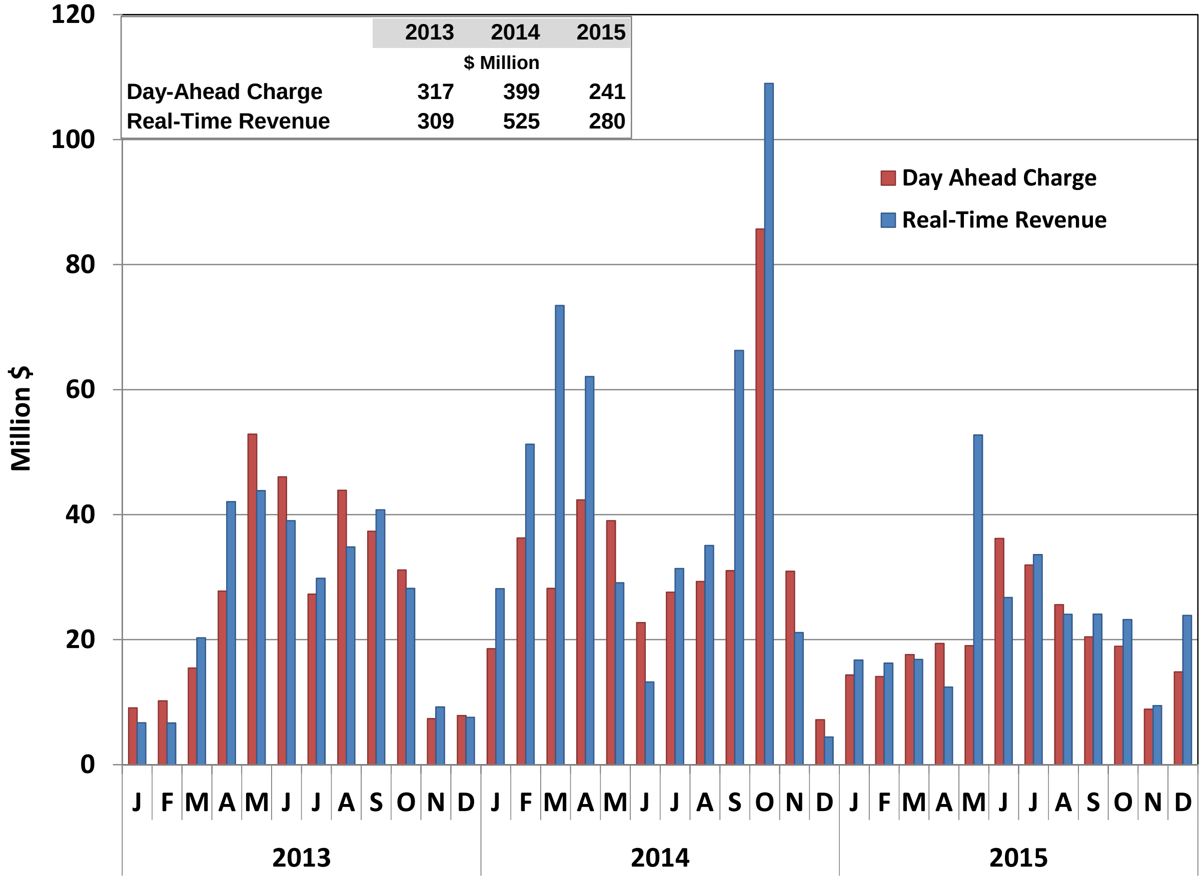
Figure 30: Average Profitability of Point-to-Point Obligations



This analysis shows that in aggregate PTP Obligation transactions were profitable overall in 2015 for both classes of participants. However, transactions of physical participants were more consistently profitable than those of financial participants. The profits and losses shown in this figure are relatively small and the profitability of the PTP Obligation transactions were slightly lower in 2015 than 2014 in aggregate. This is due in part to the fact that the day-ahead and real-time prices were relatively well arbitraged.

To conclude the analysis of PTP Obligations, Figure 31 compares the total day-ahead payments for these transactions with the total amount of revenue they received in the real-time market.

Figure 31: Point-to-Point Obligation Charges and Revenues



	2013	2014	2015
	$ Million		
Day-Ahead Charge	317	399	241
Real-Time Revenue	309	525	280

As in prior years, with the exception of 2013, the aggregated total revenues received by PTP Obligation owners was greater than the amount charged to the owners to acquire them. This indicates that, in aggregate, buyers of PTP Obligation profited from the transactions. This occurs when real-time congestion is greater than day-ahead market congestion. Across the year, and in eight of twelve months, the acquisition charges were less than the revenues received, implying that expectations of congestion as evidenced by day-ahead purchases were less than the actual congestion that occurred in real-time. The largest net revenues paid to PTP Obligation owners was $30 Million in May when unexpected North to Houston real-time congestion occurred.

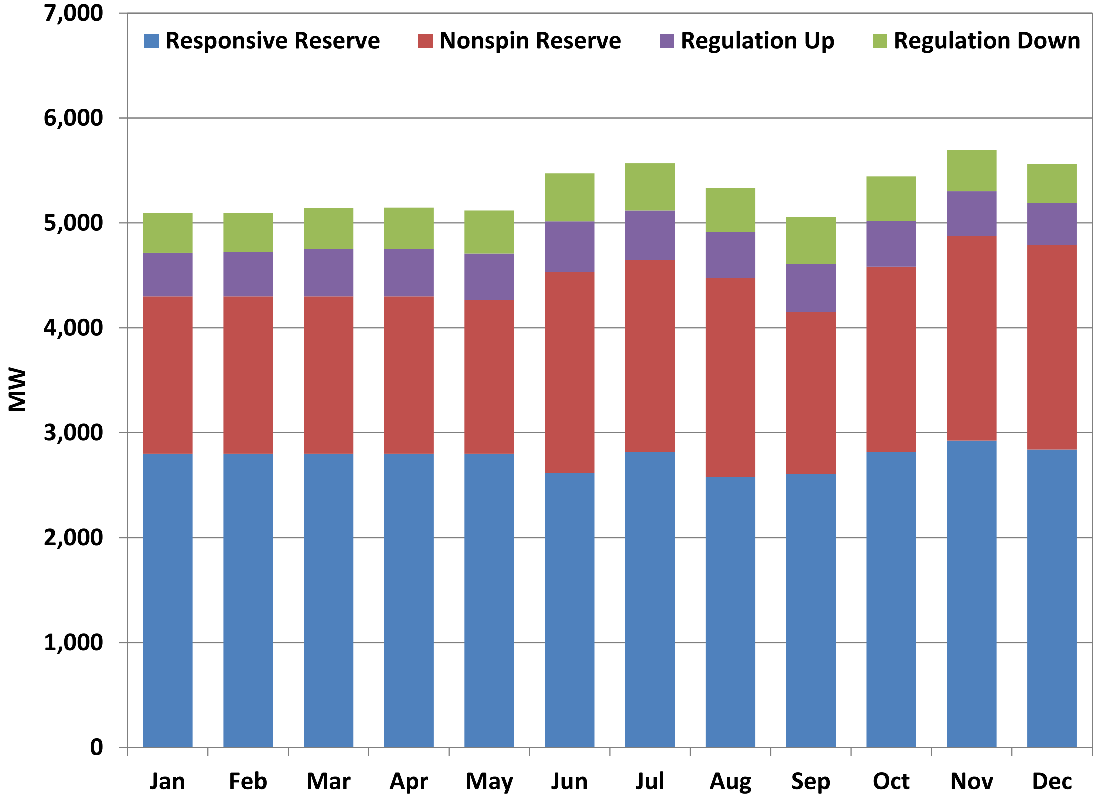
The payments made to PTP Obligation owners come from real-time congestion rent. The sufficiency of real-time congestion rent to cover both PTP Obligations and payments to owners of CRRs who elect to receive payment based on real-time prices are assessed in Section III.E.

D. Ancillary Services Market

The primary ancillary services are up regulation, down regulation, responsive reserves, and non-spinning reserves. Market participants may self-schedule ancillary services or purchase them through the ERCOT markets. In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (*e.g.*, unplanned generator outages, load forecast error, wind forecast error), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from slower responding generation capacity, and can be deployed alone, or to restore responsive reserve capacity. Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to fill the gap between energy deployments and actual system load.

ERCOT's procurement methodology for responsive and non-spinning reserves was adjusted effective June 1, 2015. For responsive reserves, ERCOT now calculates the requirement based on a variable hourly need; this requirement is determined and posted in advance for the year. ERCOT procures non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95 percent of the calculated Net Load forecast error. ERCOT will always procure a minimum quantity of non-spinning reserves greater than or equal to the largest generation unit. Figure 32 displays the hourly average quantities of ancillary services procured for each month in 2015.

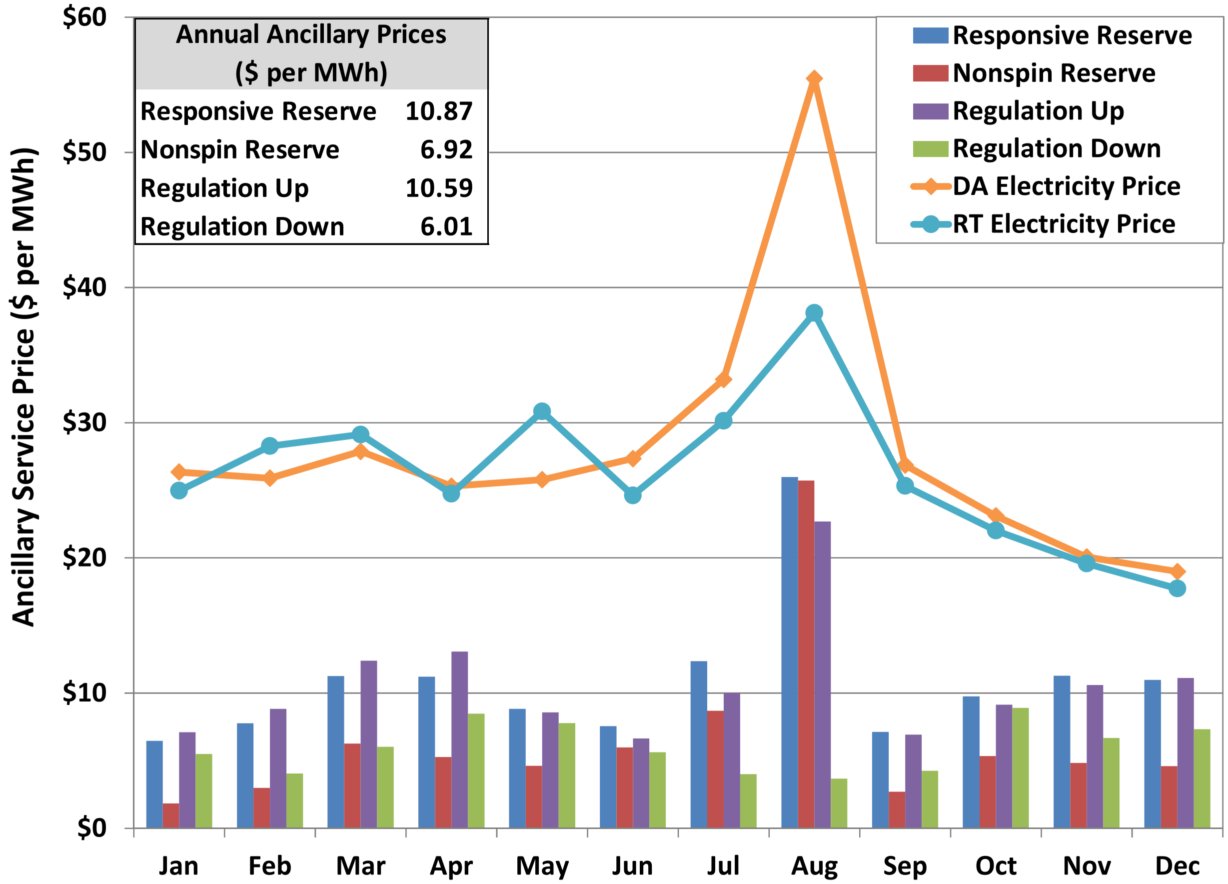
Figure 32: Hourly Average Ancillary Service Capacity



Under the nodal market, ancillary services and energy are co-optimized in the day-ahead market. This means that market participants do not have to include their expectations of forgone energy sales in their ancillary service capacity offers. Because ancillary service clearing prices explicitly account for the opportunity costs of selling energy in the day-ahead market, ancillary service prices are highly correlated with day-ahead energy prices and, by extension, with real-time energy prices.

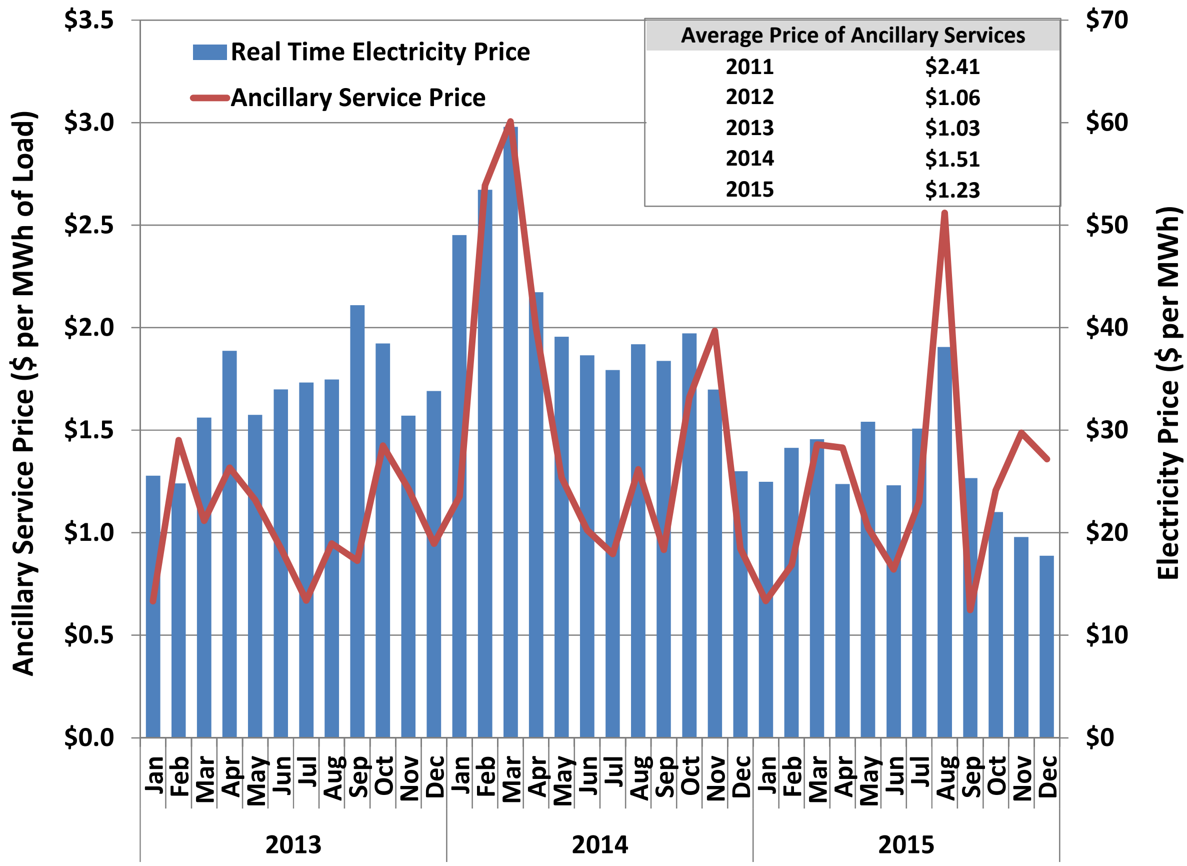
Figure 33 below presents the average clearing prices of capacity for the four ancillary services, along with day-ahead and real-time prices for energy. With average energy prices varying between $18 and $55 per MWh, the prices of ancillary services remained fairly stable throughout the year, with the exception of August. The price for ancillary services spiked in August, corresponding to the higher real-time electricity prices caused by ERCOT's shortage pricing and the associated increase in day-ahead price.

Figure 33: Ancillary Service Prices



In contrast to the previous figure that showed the individual ancillary service prices, Figure 34 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2013 through 2015. This figure shows that total ancillary service costs are generally correlated with day-ahead and real-time energy price movements, which occurs for two primary reasons. First, higher energy prices increase the opportunity costs of providing reserves and, therefore, can contribute to higher ancillary service prices. Second, shortages cause both ancillary service prices and energy prices to rise sharply so increases or decreases in the frequency of shortages will contribute to this observed correlation.

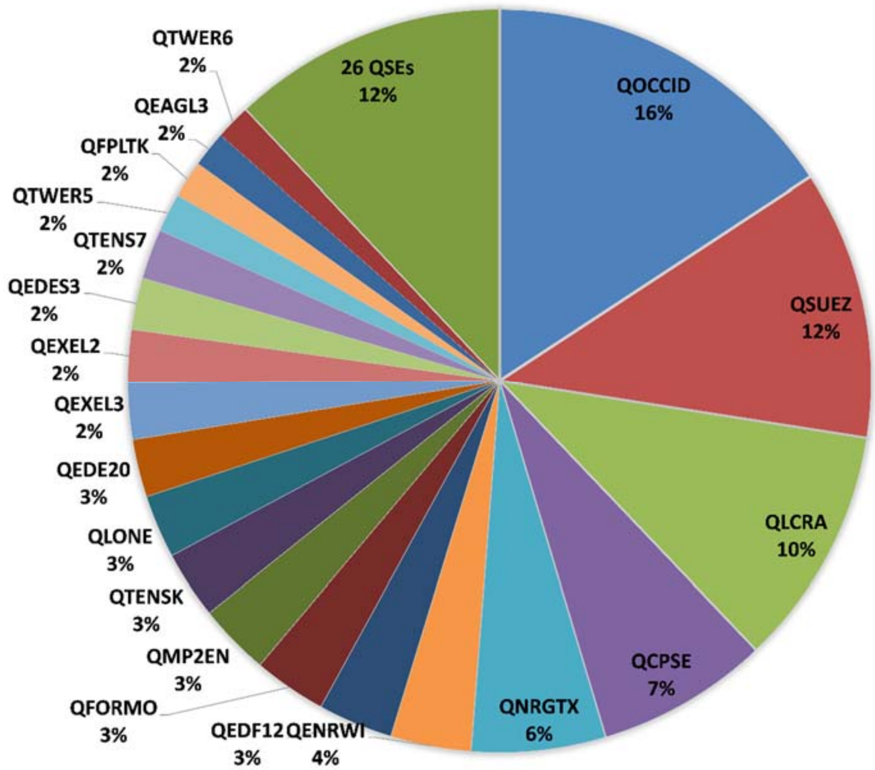
Figure 34: Ancillary Service Costs per MWh of Load



In absolute terms, the average ancillary service cost per MWh of load decreased to $1.23 per MWh in 2015 compared to $1.51 per MWh in 2014. Although the reduction in ancillary service prices and energy prices were both primarily caused by lower natural gas prices, the reduction in ancillary service prices was smaller than the decrease in ERCOT's energy prices. As a result, as a percent of the load-weighted average, total ancillary service costs increased from 3.7 percent of the load-weighted average energy price in 2014 to 4.6 percent in 2015 ($1.23 of $26.77).

Responsive reserve service is the largest quantity and typically the highest priced ancillary service product. Figure 35 below shows the share of the 2015 annual responsive reserve responsibility including both load and generation, displayed by Qualified Scheduling Entity (QSE). During 2015, 46 different QSEs self-arranged or were awarded responsive reserves as part of the day-ahead market; an increase from 38 different providers in 2014.

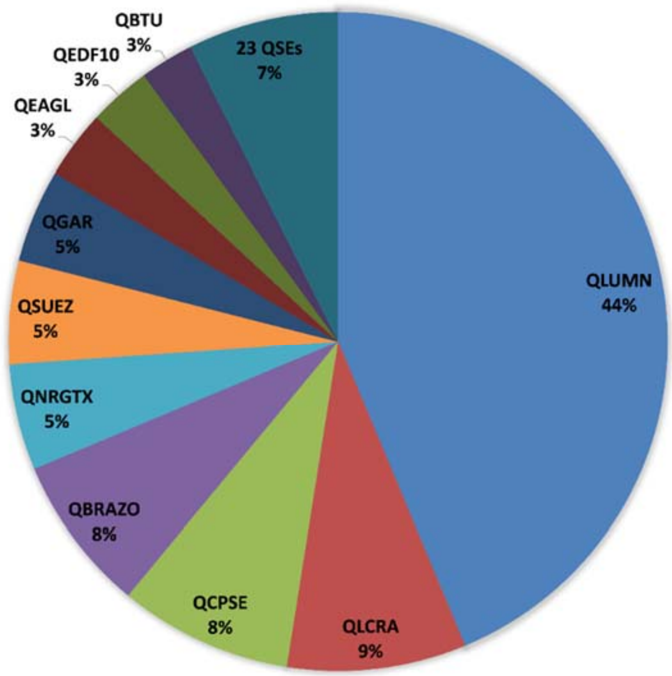
Figure 35: Responsive Reserve Providers



In contrast, Figure 36 below shows that the provision of non-spinning reserves is much more concentrated, with a single QSE having nearly half the responsibility to provide non-spinning reserves. Notably, this concentration decreased from 55 percent of the total in 2014 to 44 percent of the total in 2015. While this is an improvement, the fact that one party is consistently providing the preponderance of this service should be considered in the ongoing efforts to redefine ERCOT ancillary services.

It also highlights the importance of modifying the ERCOT ancillary service market design to include real-time co-optimization of energy and ancillary services. Jointly optimizing all products in each interval would allow the market to substitute its procurements between units on an interval-by-interval basis to minimize costs and set efficient prices. Additionally, it would allow higher quality reserves (e.g., responsive reserves) to be substituted for lower quality reserves (e.g., non-spinning reserves), reducing the reliance upon a single entity to provide this type of lower quality reserves.

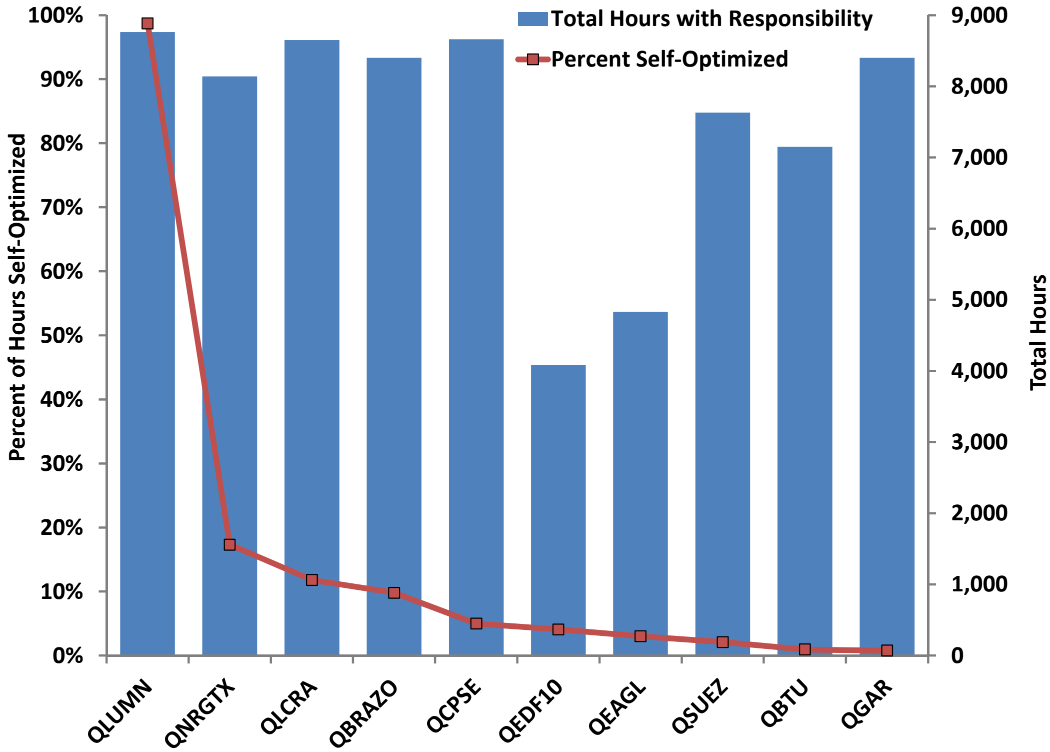
Figure 36: Non-Spinning Reserve Providers



Ancillary Service capacity is procured as part of the day-ahead market clearing. Between the time it is procured and the time that it is needed, changes often occur that prompt a QSE to move all or part of its ancillary service responsibility from one unit to another. These changes may be due to a unit outage or to other changes in market conditions affecting unit commitment and dispatch. In short, QSEs with multiple units are continually reviewing and moving ancillary service requirements, presumably to improve the efficiency of ancillary service provision, at least from the QSE's perspective.

The charts below shows the percentage of time in which each QSE with a unit-specific ancillary service responsibility at 16:00 day-ahead, moved any portion of its ancillary service responsibility to a different unit in its portfolio for real-time operations. Figure 37 shows the total hours of non-spinning reserve responsibility by QSE along with the percent of hours when the non-spinning reserve responsibility was moved to a different unit within the QSE portfolio before real-time operations.

Figure 37: Internal Management of Non-Spinning Reserve Portfolio by QSE



The QSEs are listed in descending order based on the frequency of self-optimization. This figure, taken in conjunction with Figure 36, shows that the provider with the largest share of non-spinning reserve responsibility also most frequently moved the responsibility between its units. Furthermore, a comparison of NRG (QNRGTX) and the City of Garland (QGAR) reveals that QSEs with larger fleets may have more opportunity to self-optimize. As shown in Figure 36, both QSEs provided 5 percent of ERCOT's non-spinning reserve requirements in 2015. NRG, with its much larger generation fleet, self-optimized more than 17 percent of the time, while Garland self-optimized less than 1 percent of the time.

Figure 38 below provides a similar analysis for the percent of time when responsive reserve service was self-optimized by a QSE, that is, moving the day-ahead responsibility to a different unit before real-time.

Figure 38: Internal Management of Responsive Reserve Portfolio by QSE

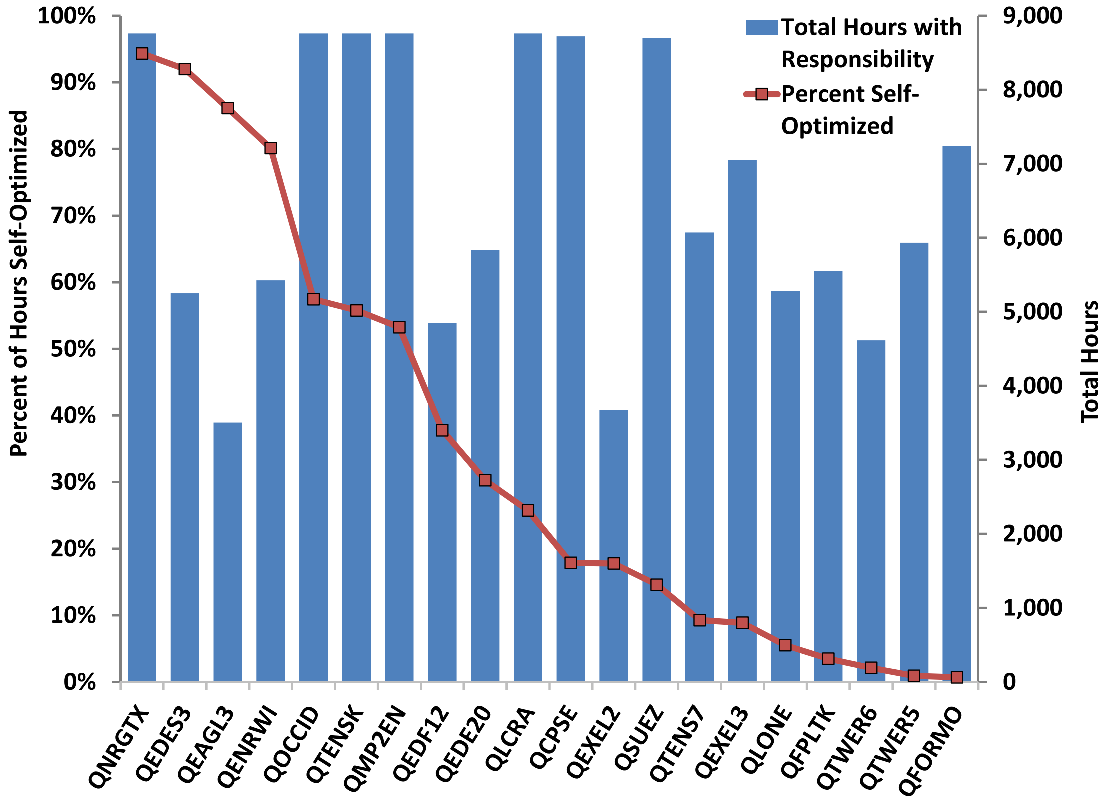


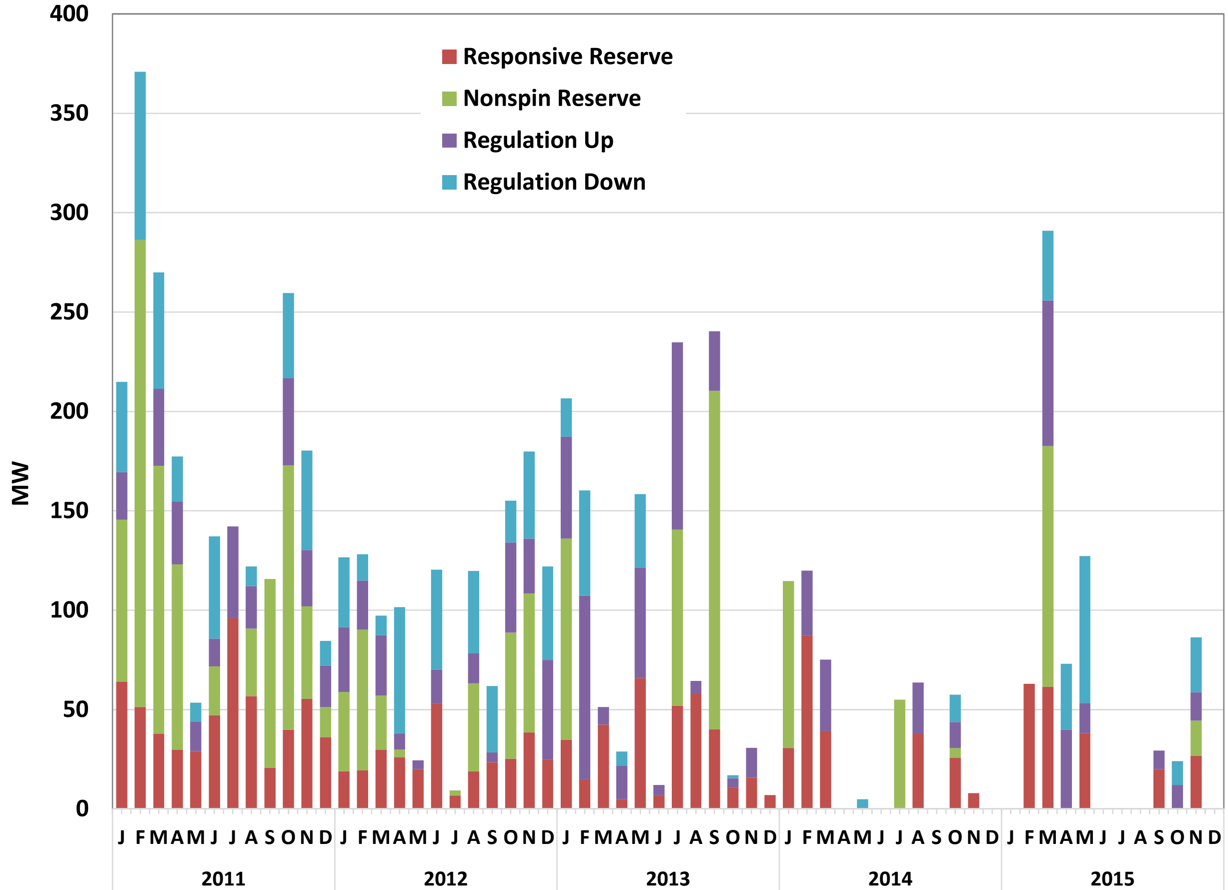
Figure 38 demonstrates that QSEs moved responsive reserve responsibilities between units more routinely than QSEs providing non-spinning reserve service. For responsive reserve service, seven QSEs moved the responsibility more than 50% of the time; whereas only one QSE moved non-spinning reserve responsibility more than 50% of the time.

If all ancillary services could be continually reviewed and adjusted in response to changing market conditions, the efficiencies would flow to all market participants and would be greater than what can be achieved by QSEs acting individually. This improved efficiency is why the IMM has been recommending, since the initial consideration of ERCOT's nodal market design, that ERCOT implement real-time co-optimization of energy and ancillary services.

Without comprehensive, market-wide co-optimization, the ERCOT market will continue to be subject to the choices of individual QSEs. These choices are likely to be in the QSE's best interest. They are not likely to lead to the most economic provision of energy and ancillary services for the market as a whole. Further, QSEs without large resource portfolios are effectively precluded from participating in ancillary service markets due to the replacement risk they face having to rely on a supplemental ancillary services market (SASM). This replacement risk is substantial. Clearing prices for ancillary services procured in SASM are thirty to fifty times greater than annual average clearing prices from the day-ahead market.

SASMs are used to procure replacement ancillary service capacity when transmission constraints arise which make the capacity undeliverable, or when outages or limitations at a generating unit lead to failure to provide. A SASM may also be opened if ERCOT changes its ancillary service plan; this did not occur during 2015. ERCOT executed a SASM for 67 hours, or less than one percent of the time in 2015. The frequency of SASMs continues to decline, from seven percent in 2012, three percent in 2013, to two percent in 2014. The final analysis in this section, shown in Figure 39, summarizes the average quantity of each service that was procured via SASM. As previously discussed, SASM was rarey used to replace deficiencies in ancillary services in 2015.

Figure 39: Ancillary Service Quantities Procured in SASM



The primary reason that SASMs were infrequent was the dearth of ancillary service offers typically available throughout the operating day, limiting the opportunity to replace ancillary service deficiencies via a market mechanism. Without sufficient ancillary service offers available, ERCOT must resort to using reliability unit commitment (RUC) procedures to bring additional capacity online.

The SASM procurement method, while offer based, is inefficient and problematic. Because ancillary services are not co-optimized with energy in the SASM, potential suppliers are required to estimate their opportunity cost rather than have the auction engine calculate it directly, which leads to resources that underestimate their opportunity costs being inefficiently preferred over resources that overestimate their opportunity costs. Further, the need to estimate the opportunity costs, which change constantly and significantly over time as the energy price changes, provides a strong disincentive to SASM participation, contributing to the observed lack of SASM offers. The paucity of SASM offers frequently leaves ERCOT with two choices: (1) use an out-of - market ancillary service procurement action with its inherent inefficiencies; or (2) operate with a deficiency of ancillary services with its inherent increased reliability risk.

Real-time co-optimization of energy and ancillary services does not require resources to estimate opportunity costs, would eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider. Because co-optimization allows the real-time market far more flexibility to procure energy and ancillary services from online resources, it would also reduce ERCOT's need to use RUC procedures to acquire ancillary services. Its biggest benefit would be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g. due to a generator forced outage. Thus, implementation of real-time co-optimization would provide benefits across the market.

III. Transmission Congestion and CRRs

One of the most important functions of any electricity market is to manage the flows of power over the transmission network by limiting additional power flows over transmission facilities when they reach their operating limits. The action taken to ensure operating limits are not violated is called congestion management. The effect of congestion management is to change the output level of one or more generators so as to reduce the amount of electricity flowing on the transmission line nearing its operating limit.[13] Congestion leads to higher costs because higher cost resources must sometimes produce more and lower cost resources must produce less in order to manage flows over the network. These trade-offs result in different prices at different nodes. The decision about which generator(s) will vary its output is based on the generator's energy offer curve and how much of its output will flow across the overloaded transmission element. This leads to a dispatch of the most efficient resources available to reliably serve demand.

This section of the report summarizes transmission congestion in 2015, provides a review of the costs and frequency of transmission congestion in both the day-ahead and real-time markets, and concludes with a review of the activity in the congestion rights market.

A. Summary of Congestion

The total congestion costs generated by the ERCOT real-time market in 2015 was $352 million, a 50 percent reduction from 2014 values. Although the price impacts of congestion were greatly reduced, the frequency of congestion was similar to 2014. Congestion between the North and Houston zones increased, while congestion within all zones decreased in 2015.

Figure 40 provides a comparison of the amount of time transmission constraints were binding or active at various load levels in 2013 through 2015. This figure also indicates the average number of constraints in a Real-Time Contingency Analysis (RTCA) execution for each load level.

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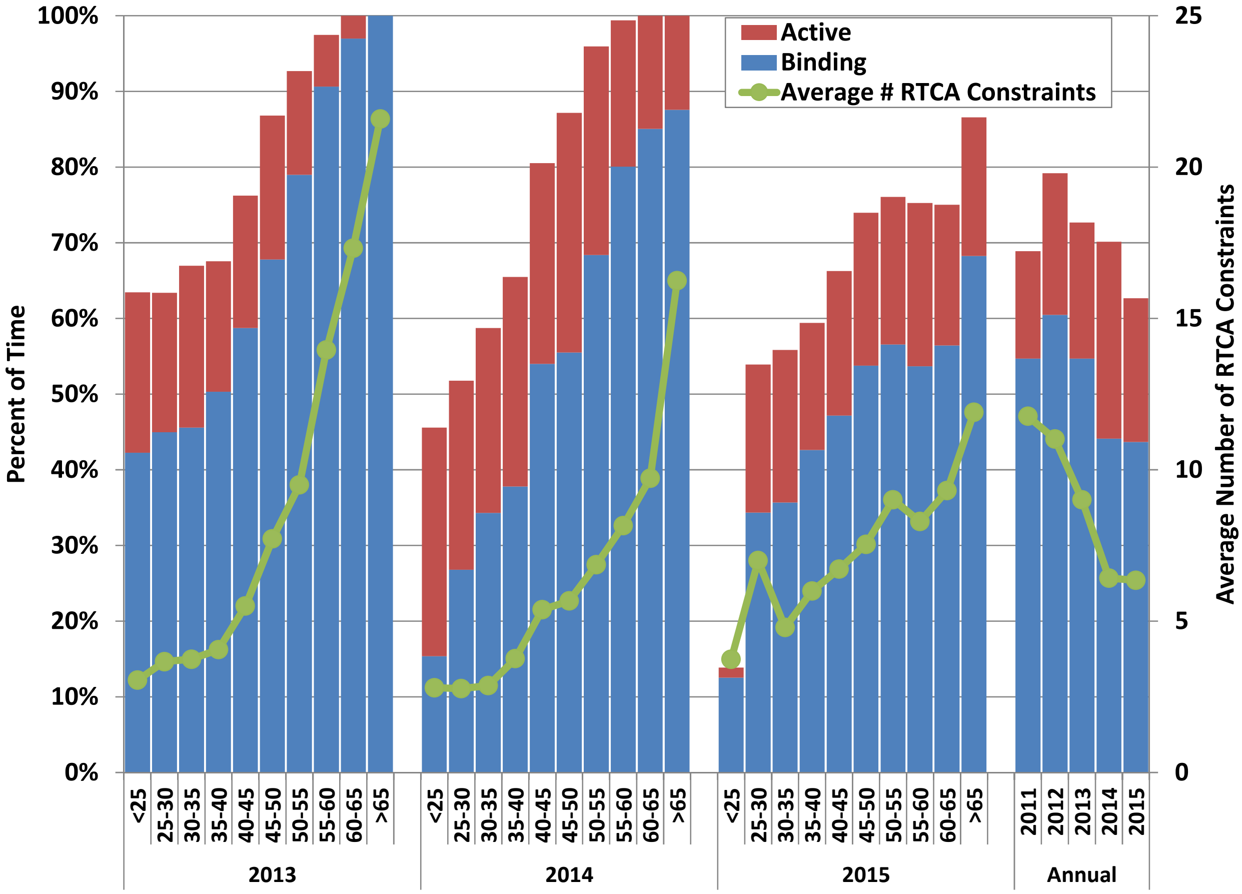
[13] Because the transmission system is operated such that it can withstand the unexpected outage of any element at any time, congestion management actions most often occur when a transmission element is expected to be overloaded if a particular unexpected outage (contingency) were to occur.

Binding transmission constraints are those for which the dispatch levels of generating resources are actually altered in order to maintain transmission flows at reliable levels. The costs associated with this re-dispatch are the system's congestion costs and are included in nodal prices. Active transmission constraints are those which the dispatch software evaluated, but did not require a re-dispatch of generation.

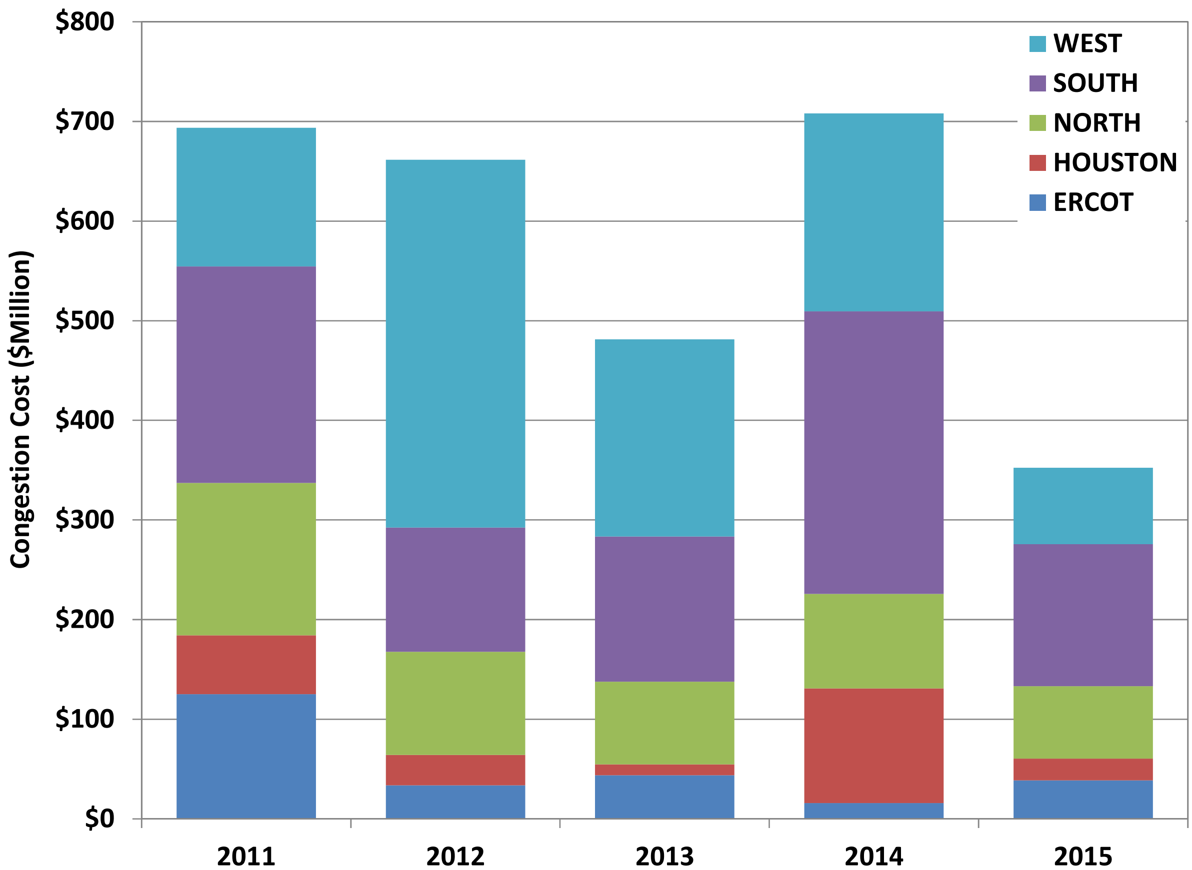
Figure 40: Frequency of Binding and Active Constraints



Constraints were activated much less frequently in 2015, only 63 percent of the time compared to 70 percent of the time in 2014. The reduction in frequency of binding transmission constraints is most notable at the very highest load levels. There was a binding transmission constraint 68 percent of the time when load exceeded 65 GW in 2015. This compares to 88 percent of the time at the same load levels in 2014 and 100 percent of the time in 2013. These reductions in frequency are likely attributed to transmission construction, most notably completion of Competitive Renewable Energy Zone (CREZ) lines reducing congestion in lower load (high wind) periods. Other transmission projects to improve the high load growth areas associated with increased oil and gas development in the Permian Basin and Eagle Ford Shale have likely contributed to reduced congestion frequency during high load periods.

Although the frequency of binding transmission constraints remained similar to 2014 at 44 percent, the congestion costs in 2015 were much lower. The much lower congestion costs were a direct result of the low natural gas prices in 2015 because natural gas resources are generally the resources re-dispatched to manage network flows. Figure 41 displays the amount of real-time congestion costs attributed to each geographic zone. Costs associated with constraints that cross zonal boundaries, i.e. North to Houston, are shown in the ERCOT category.

Figure 41: Real-Time Congestion Costs



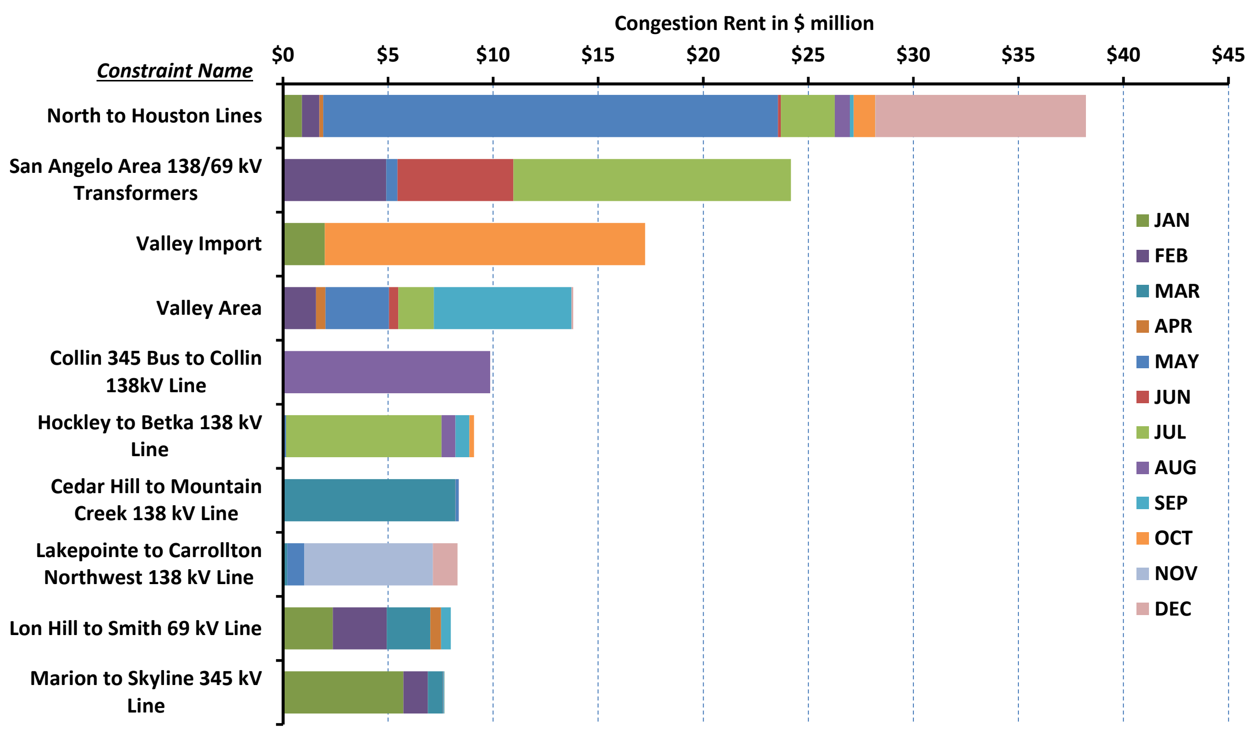
While cross zonal congestion was higher in 2015 versus 2014, all other intra-zonal congestion has decreased. Annual congestion costs in 2015 were the lowest since the start of the nodal market. This is largely due the significant reduction in natural gas prices and the cumulative benefits of large investments in transmission facilities.

B. Real-Time Constraints

The review of real-time congestion begins with describing the congested areas with the highest financial impact as measured by congestion rent. For this discussion a congested area is determined by consolidating multiple real-time transmission constraints that are defined as similar due to their geographic proximity and constraint direction. There were 350 unique constraints that were binding at some point during 2015, about the same number of constraints that were binding in 2014 and 2013. The median financial impact of the 2015 constraints was approximately $162,000. This was a 49 percent decrease from the median impact in 2014.

Figure 42 below displays the ten most highly valued real-time congested areas as measured by congestion rent. The North to Houston interface and lines, which includes the double circuit Singleton to Zenith 345 kV lines, double circuit Gibbons Creek to Singleton 345 kV lines and double circuit Jewett to Singleton 345 kV lines, were the most congested location in 2015 at $38 million. In contrast, the most congested area in 2014 was the Heights TNP 138/69 kV autotransformers at a cost of $74 million which was due to a few months of outage-related congestion.

Figure 42: Top Ten Real-Time Constraints



The second-highest valued congested element was the San Angelo area 138/69 kV auto-transformer with impacts of $24 million. All of the impacts occurred from February through July, and were related to a planned transformer outage that serves the San Angelo area and for the installation of a new station. This constraint is the only West zone constraint remaining in the top ten constraints following significant transmission upgrades in the West.

In aggregate, congestion related to serving load in the lower Rio Grande Valley was almost as large as the most costly single constraint, totaling $31 million. However, the impacts of the Valley Import constraint and constraints within the Valley are shown separately. The Valley Import constraint is sensitive to the amount of generation available within the Valley. It was active at times when local generating units were on unplanned or forced outage. There has been a generation change in the Rio Grande Valley of note, due to its potential impact on the congestion in the area.

In April 2015, Frontera disconnected one of the gas turbines at its combined cycle plant from the ERCOT grid and connected it to the Comisión Federal de Electricidad (CFE) grid. This switchable capability was part of the unit’s original design more than fifteen years ago, but it has rarely been exercised. With the announcement that the entire Frontera combined cycle unit will disconnect from ERCOT and connect to CFE in 2016, there is an increased likelihood of congestion in the Valley, especially during construction of the 345kV lines from Lobo to North Edinburg and North Edinburg to Loma Alta. These lines are scheduled for completion in June 2016. The two constraints located within the Valley are the La Palma to Villa Cavazos 138 kV line ($12 million) and Rio Hondo to East Rio Hondo 138 kV line ($2 million). These constraints were often in effect during the time that other transmission facilities in the area were taken out of service to accommodate the construction of transmission upgrades in the area.

The next four constraints were due to planned outages and/or high loads in the area. The Collin constraint is located north of Dallas with congestion occurring solely in August. Located northwest of Houston, the Hockley to Betka constraint was the 9th most costly constraint in 2014. In July 2015 the line was congested due to a planned outage nearby. Both Cedar Hill to Mountain Creek 138 kV and Lakepoint to Carrollton Northwest 138 kV are located near the Dallas area.

Congestion on the Lon Hill to Smith 69kV line west of Corpus Christi totaled $8 million, a $10 million reduction from the cost in 2014. Congestion on this line was due to the increased loads related to oil and natural gas development in the Eagle Ford Shale. It was not an active constraint after May due to completed transmission upgrades in the area.

The last element on the list, the Marion to Skyline 345 kV line, is located north and east of San Antonio and was affected by transmission outages in the area.

Irresolvable Constraints

When a constraint becomes irresolvable, ERCOT's dispatch software can find no combination of generators to dispatch in a manner such that the flows on the transmission element(s) of concern are below where needed to operate reliably. In these situations, offers from generators do not set locational prices since there are no supply options for resolving the constraint. Prices are set based on predefined rules, intended to reflect the value of reduced reliability for demand. To address the situation more generally, a regional peaker net margin mechanism was introduced such that once local price increases accumulate to a predefined threshold due to an irresolvable constraint, the shadow price of that constraint would drop.

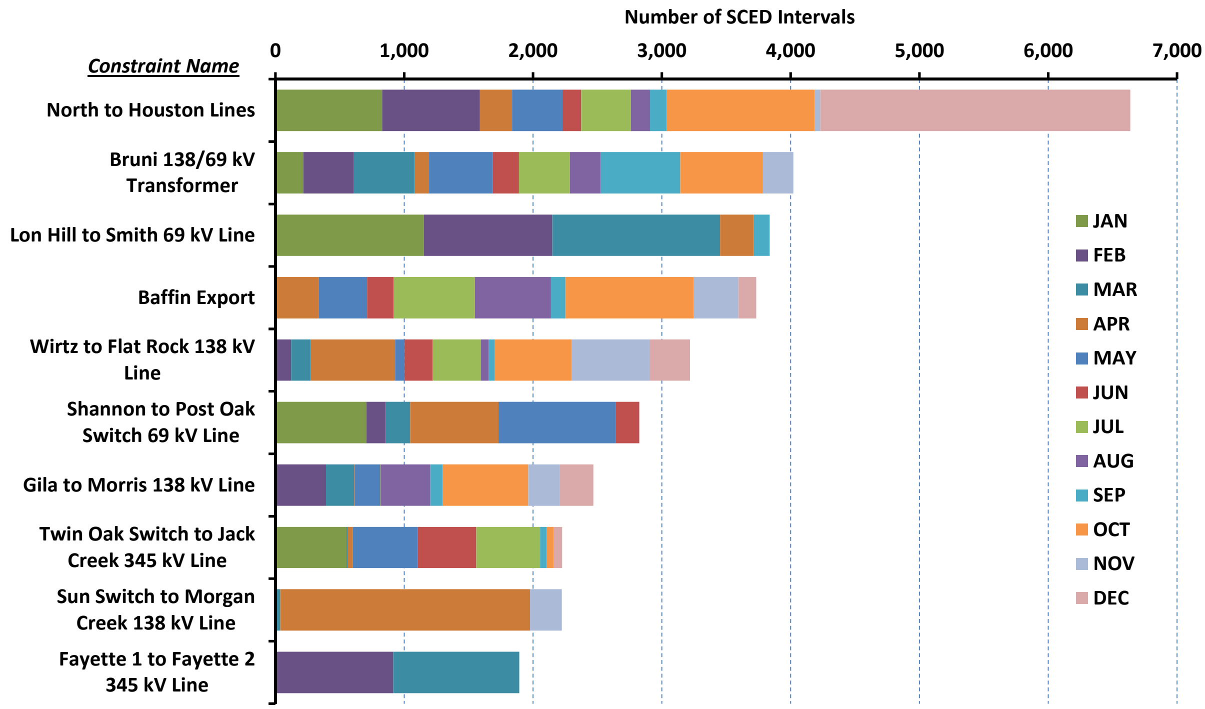
As shown below in Table 3, twelve elements were deemed irresolvable in 2015 and had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. The two highlighted irresolvable elements were previously discussed as costly real-time constraints. Three elements were deemed resolvable during ERCOT's annual review and were removed from the list. In ERCOT's ongoing analysis, one more element was deemed resolvable in February. All three irresolvable constraints located in the South Load Zone are located in the Valley.

Table 3: Irresolvable Elements

Irresolvable Element:	Original Max Shadow Price	2015 Adjusted Max Shadow Price	Irresolvable Effective Date	Termination Date	Load Zone
Valley Import	$5,000	$2,000.00	1/1/12	-	South
Odessa Basin to Odessa North 69 kV line	$2,800	$2,800.00	1/1/12	1/30/15	West
China Grove to Bluff Creek 138 kV line	$3,500	$2,000.00	5/3/12	1/30/15	West
Morgan Creek #1 345/138 kV autotransformer	$4,500	$2,000.00	11/2/12	1/30/15	West
Midland East to Buffalo 138 kV line	$3,500	$2,377.57	7/24/14	2/11/15	West
Heights TNP #1 138/69 kV transformer	$3,500	$2,000.00	9/23/14	-	Houston
Abilene Northwest to Ely Rea Tap 69 kV line	$2,800	$2,780.38	9/26/14	-	West
Harlingen to Oleander 69 kV line	$2,800	$2,000.00	10/9/14	-	South
Rio Hondo to East Rio Hondo 138 kV line	$3,500	$2,000.00	10/10/14	-	South
Emma to Holt Switch 69 kV line	$2,800	$2,800.00	10/27/14	-	West
Heights TNP #2 138/69 kV transformer	$3,500	$2,000.00	10/28/14	-	Houston
San Angelo College Hills 138/69 kV autotransformer	$3,500	$2,000.00	7/22/15	-	West

Figure 43 presents a slightly different set of real-time congested areas. These are the most frequently occurring.

Figure 43: Most Frequent Real-Time Constraints



Of the ten most frequently occurring constraints, two have already been described as costly. They are the North to Houston Lines and Lon Hill to Smith 69kV line. The rest of the constraints, although frequently occurring, had very small financial impacts. This can result if the generation to be re-dispatched is similarly priced. The Bruni 138/69 kV transformer constraint frequently limits the output from two wind generators located east of Laredo. Similarly, the Baffin Export is also a limitation on multiple wind generators near Ajo. The Shannon to Post Oak Switch 69 kV line is located between Fort Worth and Wichita Falls. The Gila to Morris 138 kV line is located in the Corpus Christi area. Twin Oak Switch to Jack Creek 345 kV line is located between North and Houston and feeds into College Station. Sun Switch to

Morgan Creek 138 kV line is in the West and Fayette 1 to Fayette 2 345 kV line is located between Austin and Houston.

C. Day-Ahead Constraints

This subsection provides a review of the transmission constraints from the day-ahead market. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the day-ahead market similarly to how they transact in real-time, the same transmission constraints are expected to appear in both markets.

Figure 44: Top Ten Day-Ahead Congested Areas

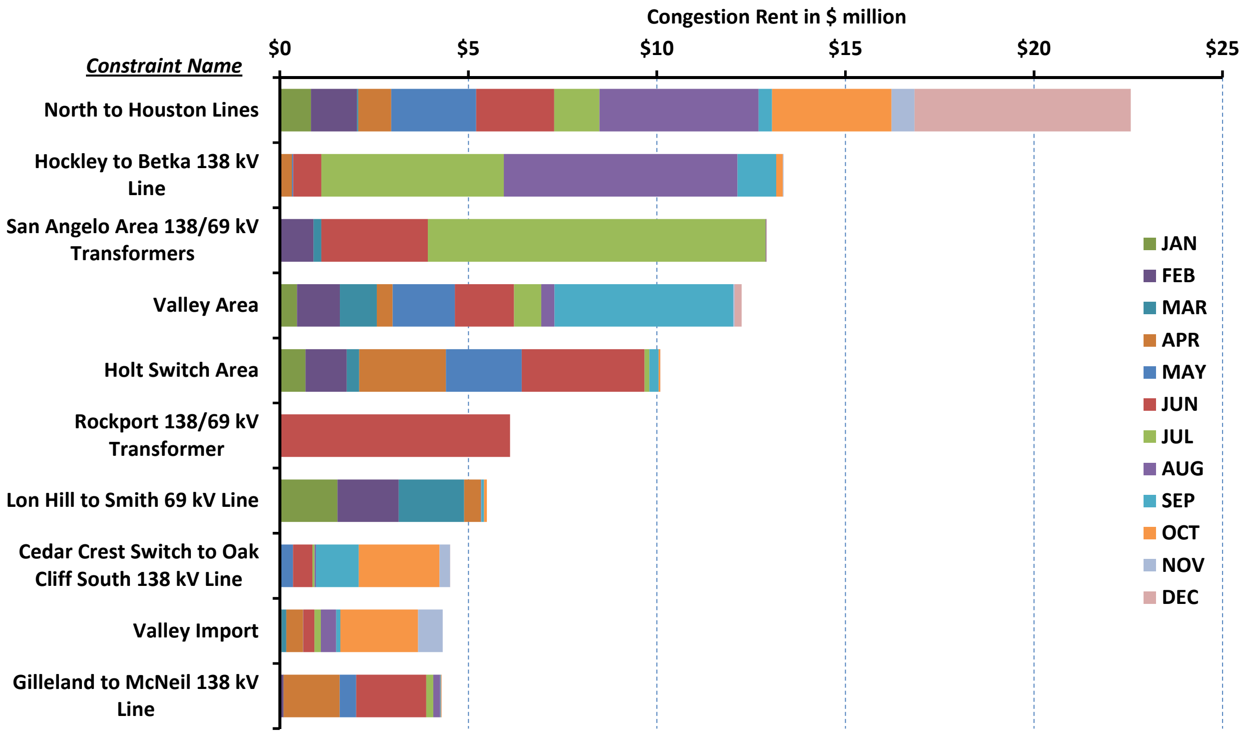
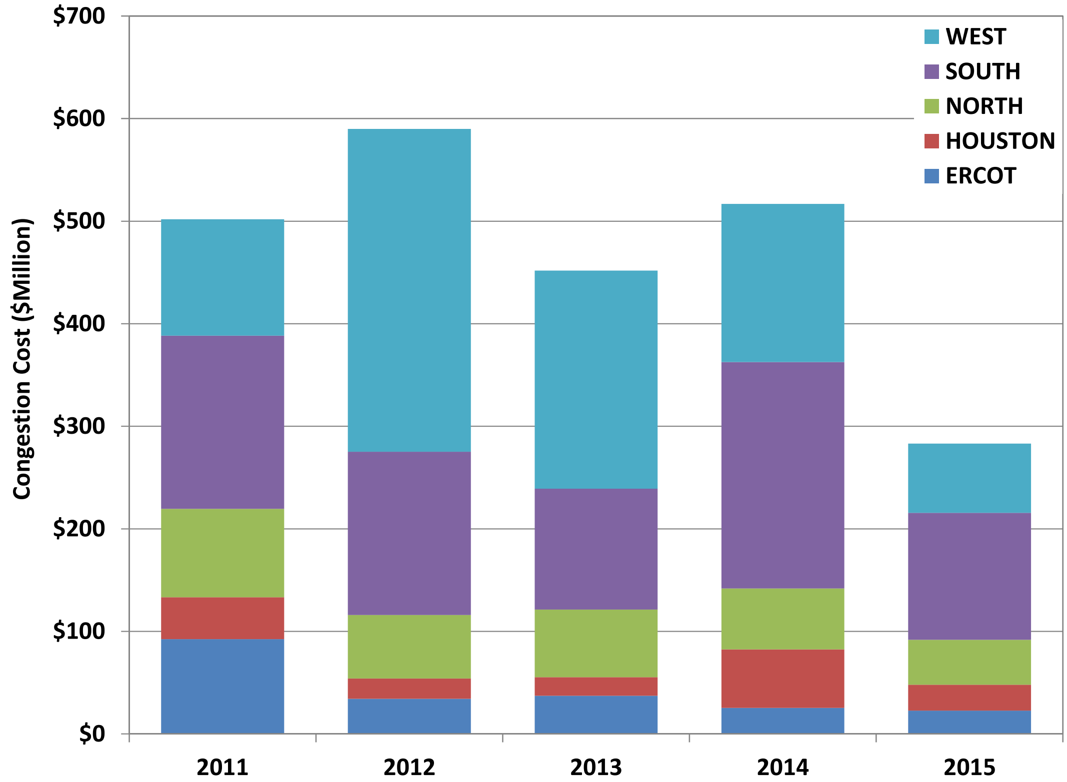


Figure 44 presents the top ten congested areas from the day-ahead market, ranked by the financial impact as measured by congestion rent. Five of the constraints listed here were previously described in the real-time subsection. Holt Switch to Amoco Midland Farms 138 kV ($6.4 million) line and the Holt Switch to Emma Tap 69 kV line ($3.7 million) comprise Holt Switch Area in the Far West. The Rockport 138/69 kV transformer is located in Corpus Christi and its congestion was likely related to expected impacts from a planned outage in the area. The last two constraints are Cedar Crest Switch to Oak Cliff South 138 kV line located in Dallas and Gilleland to McNeil 138 kV line is in Austin.

Figure 45: Day-Ahead Congestion Costs by Zone



As they were in real-time, day-ahead congestion in all zones was lower in 2015 than 2014. The total reduction in day-ahead congestion costs was 45 percent. The Houston zone experienced the greatest decrease between 2014 and 2015 with an 81 percent reduction in both day-ahead and real-time congestion costs. This is primarily because the Heights TNP transformers, located in Houston, were the subject of significant congestion in 2014.

D. Congestion Revenue Rights Market

Congestion can be significant from an economic perspective, compelling the dispatch of higher-cost resources because power produced by lower-cost resources cannot be delivered due to transmission constraints. Under the nodal market design, one means by which ERCOT market participants can hedge these price differences is by acquiring Congestion Revenue Rights (CRRs) between any two settlement points.

CRRs are acquired by semi-annual and monthly auctions while Pre-Assigned Congestion Revenue Rights (PCRRs) are allocated to certain participants based on their historical patterns of transmission usage. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same source and sink. Both CRRs and PCRRs entitle the holder to payments corresponding to the difference in day-ahead locational prices of the source and sink.

Figure 46: CRR Costs by Zone

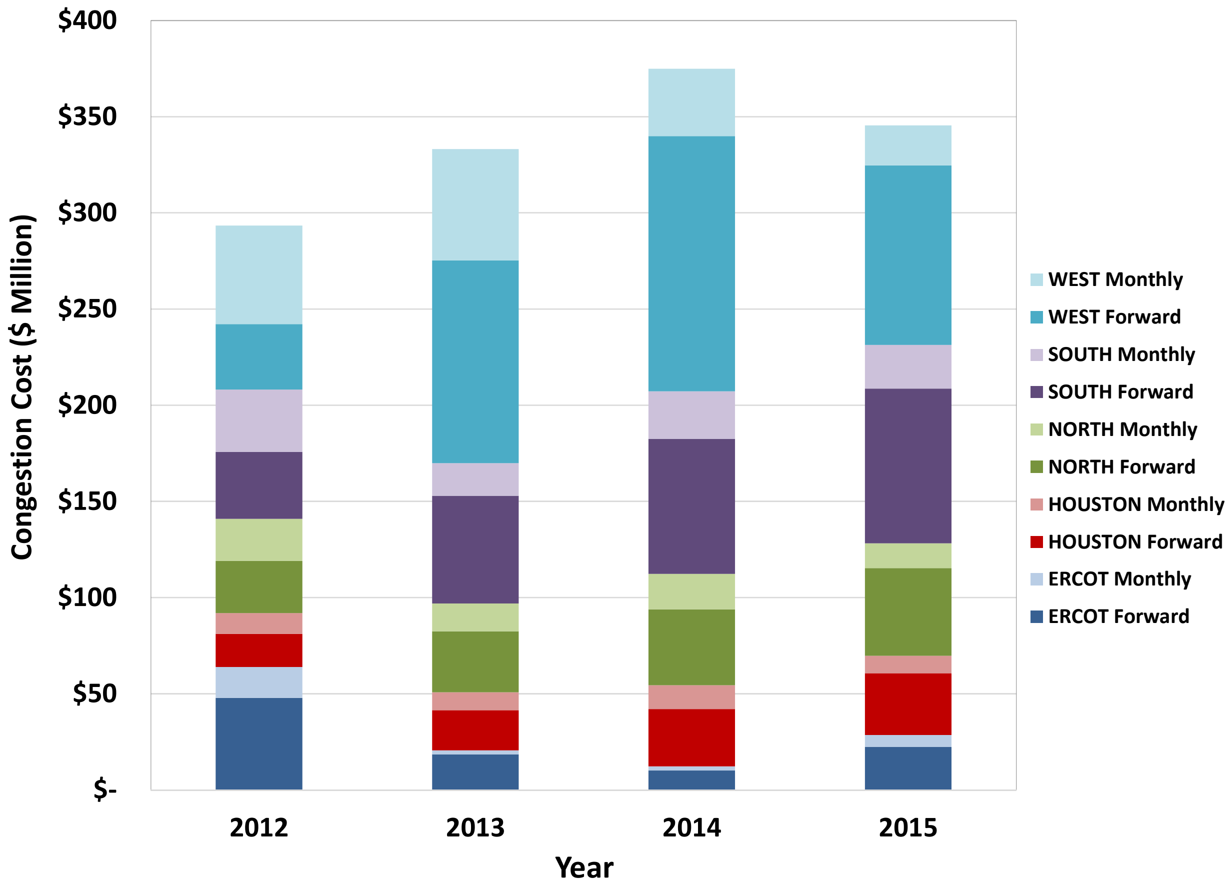
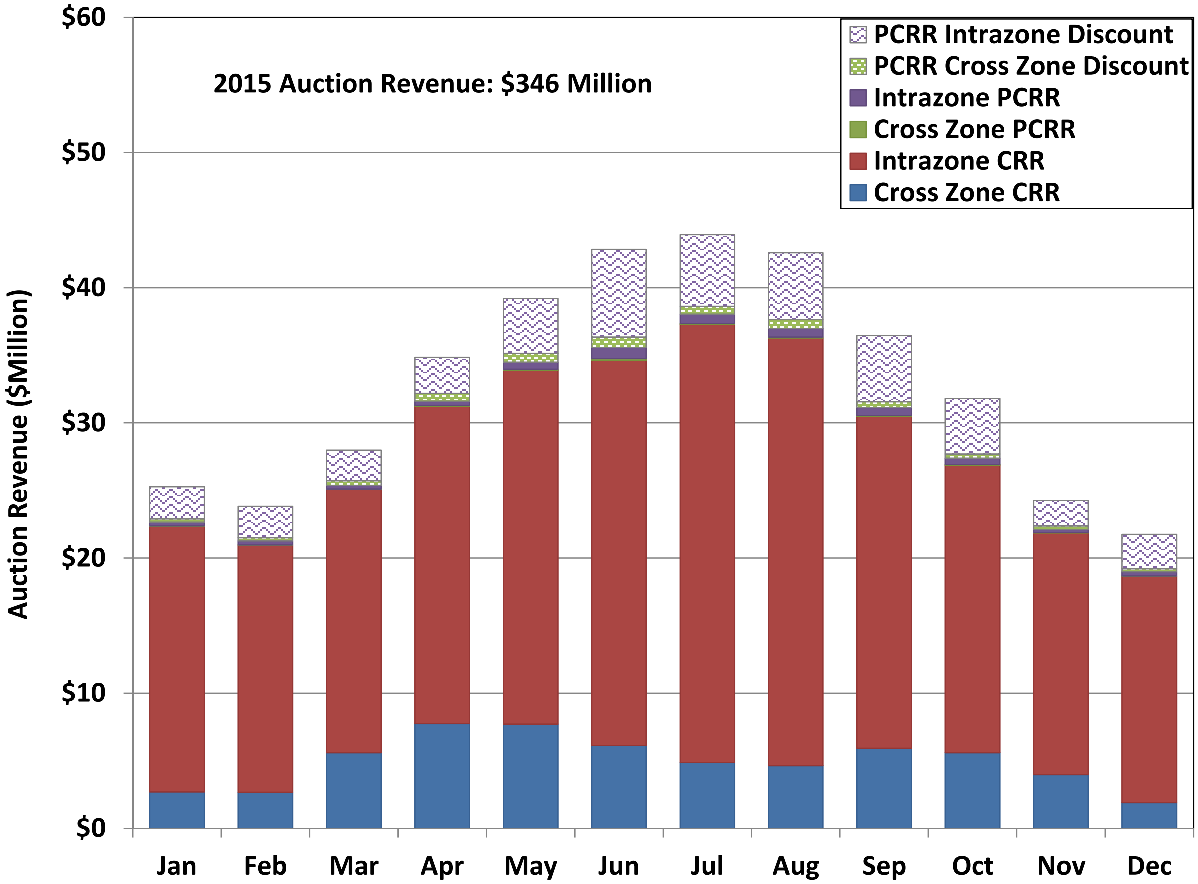


Figure 46 above details the congestion cost as calculated by shadow price and flow on binding constraints in the CRR auctions. The costs are broken down by zone and whether they were incurred in a monthly auction (Monthly) or a seasonal or annual auction (Forward). The CRR congestion shown in Figure 46 indicates different trends than the day-ahead and real-time congestion. Namely the forward congestion costs (with the exception of those in the West) increased rather than decreased. The monthly costs decreased (except for the inter-zonal "ERCOT" congestion) but did not decrease as much as the day-ahead and real-time congestion.

Figure 47 summarizes the revenues collected by ERCOT in each month for all CRRs, both auctioned and allocated.

Figure 47: CRR Auction Revenue

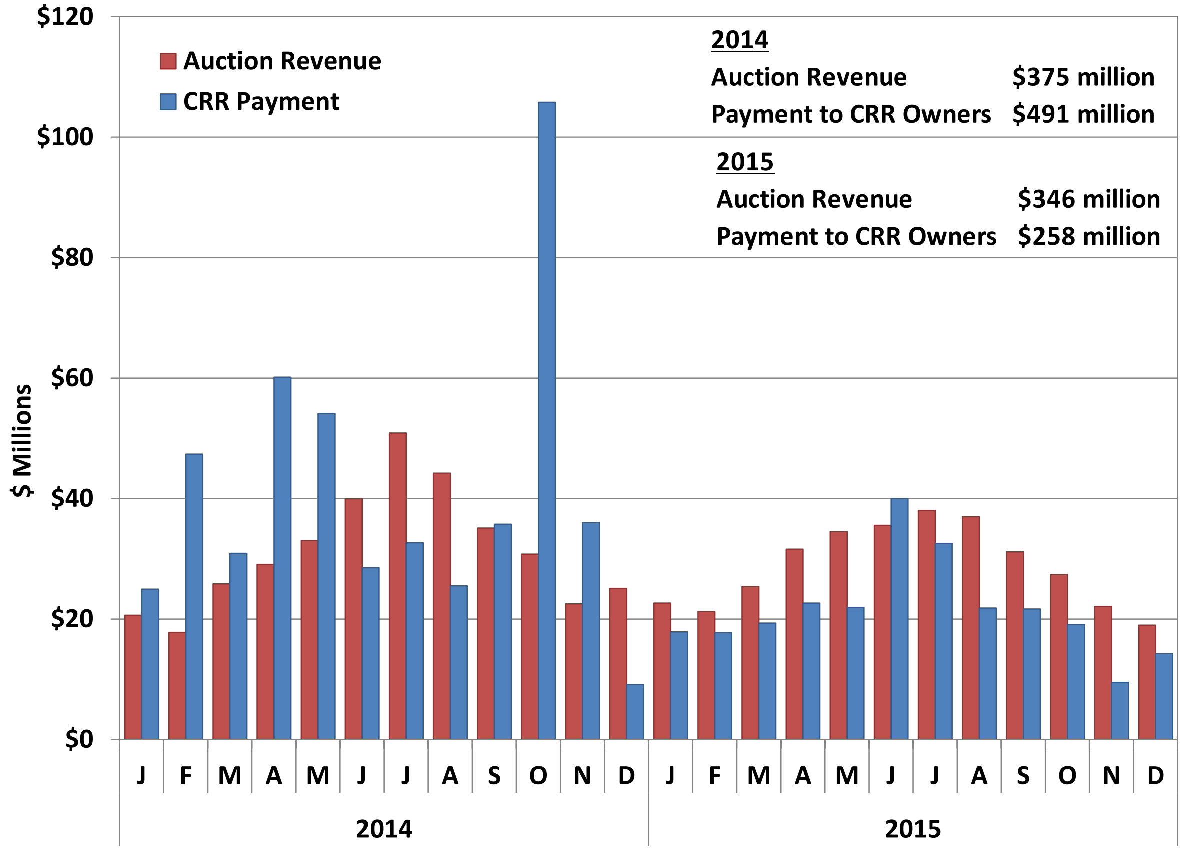


ERCOT distributes these revenues to loads in one of two ways. Revenues from cross-zone CRRs are allocated to loads ERCOT wide. Revenues from CRRs that have the source and sink in the same geographic zone are allocated to loads within that zone. This method of revenue allocation provides a disproportionate share of CRR Auction revenues to loads located in the West zone. In 2015, CRRs with both the source and sink in the West zone accounted for 32 percent of CRR Auction revenues. This revenue was allocated to West zone loads, which accounted for only 9 percent of the ERCOT total. By comparison, in 2014, 42 percent of CRR Auction revenues were allocated to the West zone load, which accounted for 9 percent of the ERCOT total. Allocating CRR Auction revenues in this manner helps reduce the impact of the higher congestion on West zone prices. As shown in Figure 3, the annual average real-time energy price for the West zone was $26.83 per MWh, 6 cents per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to $2.79 per MWh higher than the ERCOT-wide average distribution of CRR Auction revenues. In 2015, like 2014, the effective load zone price for the West zone, $23.05 per MWh, was the lowest in ERCOT.

As previously mentioned in this section, purchasers of PCRRs are only charged a fraction of the PCRR auction value. The difference between the auction value and the value charged to the purchaser is shown in Figure 47 as the PCRR Discount. The total PCRR discount for 2015 was $49 million.

Next, Figure 48 compares the value received by CRR owners (in aggregate) to the price paid to acquire the CRRs.

Figure 48: CRR Auction Revenue and Payment Received

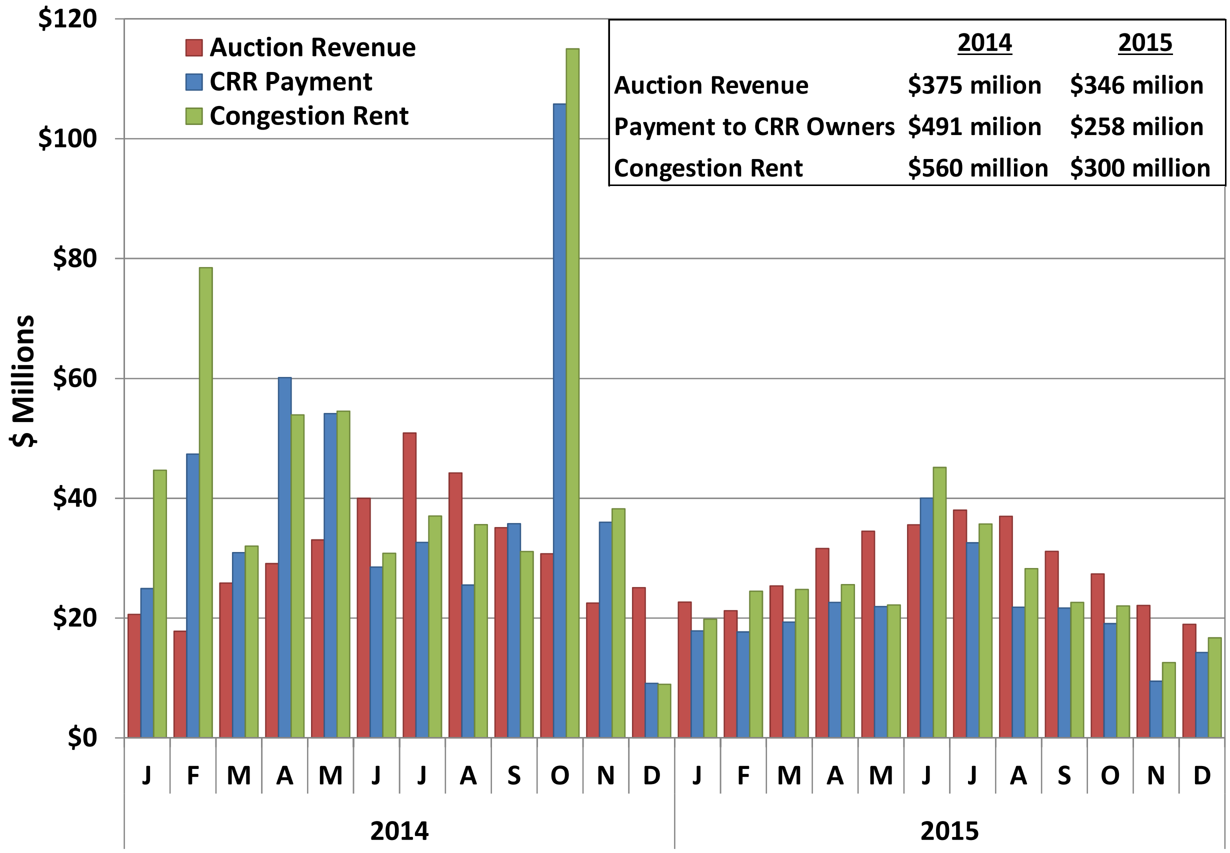


Although results for individual participants and specific source/sink combinations varied, the aggregated results for the year and in most months show that participants overpaid to acquire

CRRs in 2015. This is the first time since the implementation of the Nodal market that is the case. For the entire year of 2015 participants spent $346 million to procure CRRs and received $258 million.

The next analysis of aggregated CRR positions adds day-ahead congestion rent to the picture. Day-ahead congestion rent is the difference between the total costs that loads pay and the total revenue that generators receive in the day-ahead market. Day-ahead congestion rent creates the source of funds used to make payments to CRR owners. Figure 49 presents CRR Auction revenues, payment to CRR owners, and day-ahead congestion rent in 2014 and 2015, by month. Congestion rent for the year 2015 totaled $300 million and payment to CRR owners was $258 million.

Figure 49: CRR Auction Revenue, Payments and Congestion Rent



The target value of a CRR is the MW amount of the CRR multiplied by the 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 where an amount less than the target value is paid. 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 this case, CRRs with a positive value that have a source and/or a sink located at a resource node settlement point are often derated, that is, 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.

2015 was the first full year with a rolling CRR balancing fund.[14] The CRR balancing fund grew from $20 thousand to its capped present value of $10 million and was only drawn upon once to cover a shortfall of $1.3M for the month of May.

[14] The CRR Balancing Fund was implemented with NPRR580.

Figure 50: CRR Shortfalls and Derations

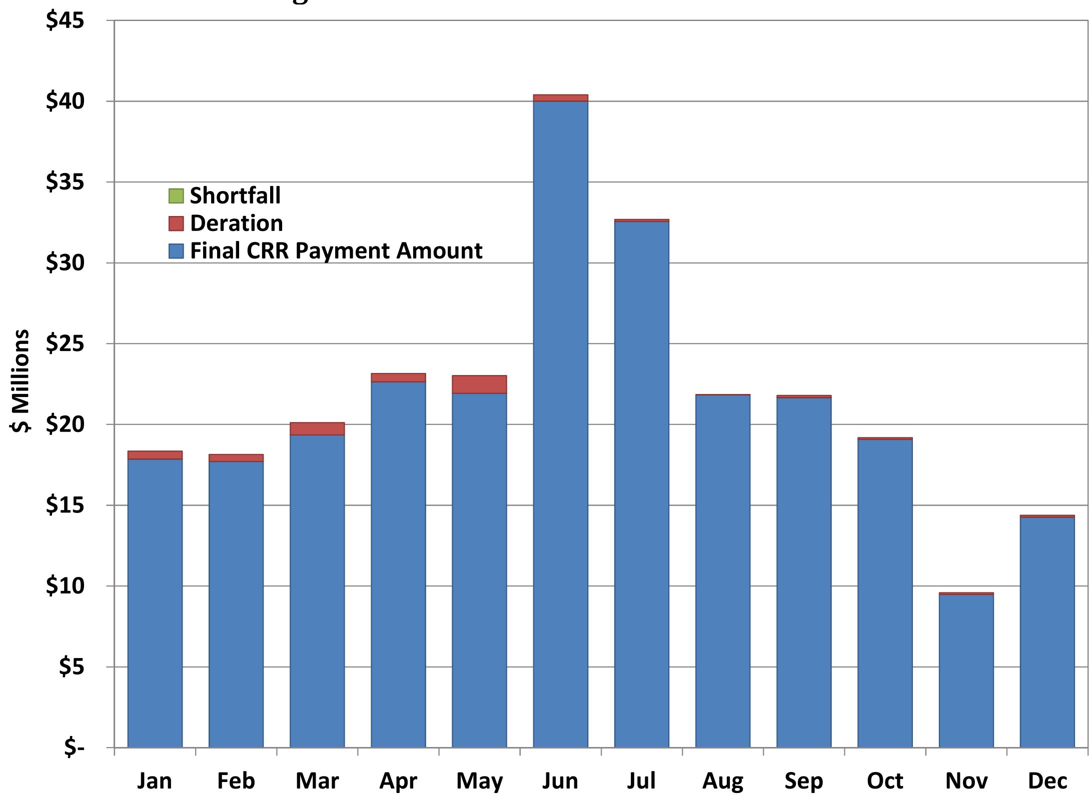


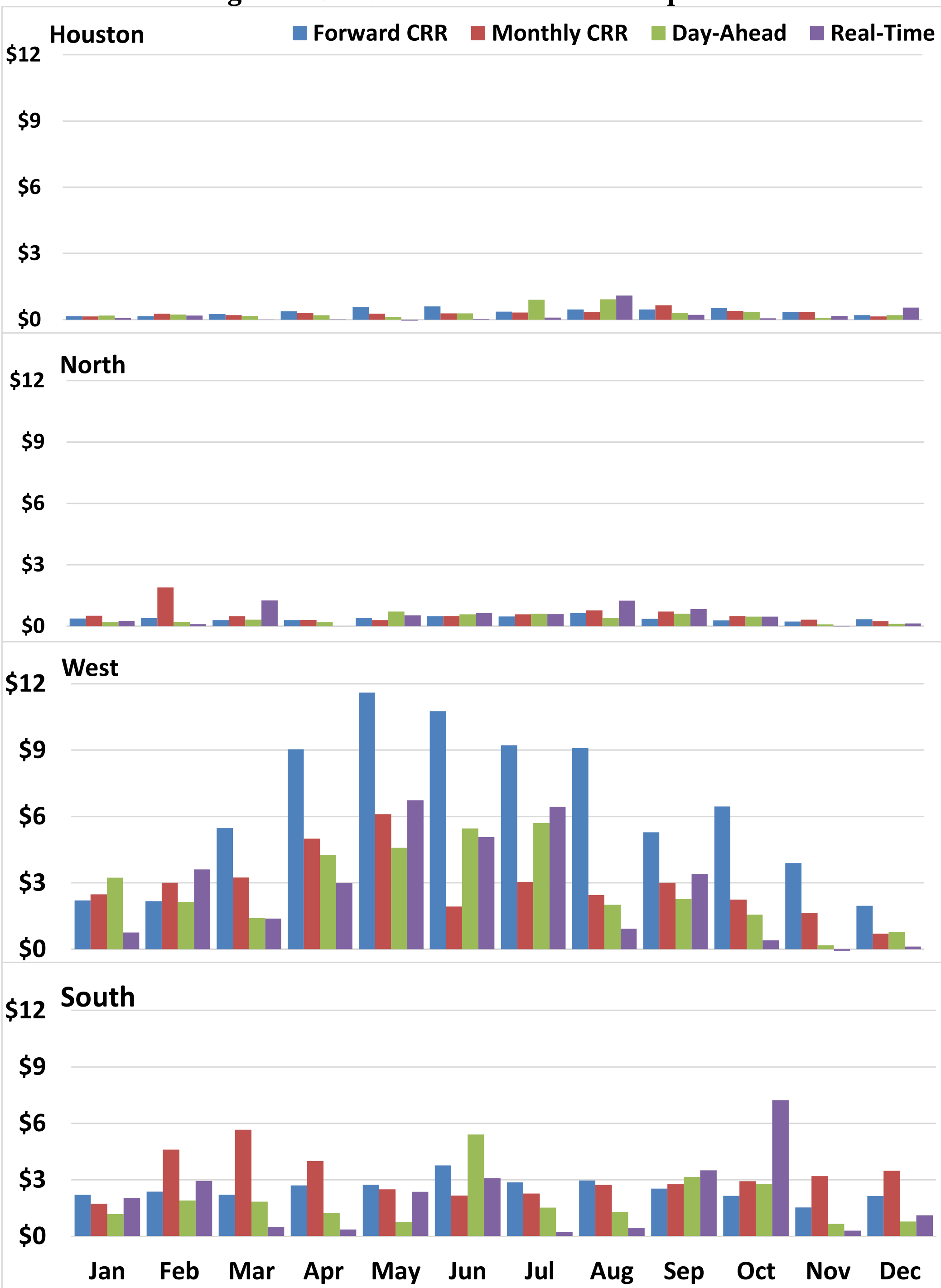
Figure 50 shows the amount of target payment, deration amount, and net shortfall charges (after make whole payments) for 2015. In 2015 the total target payment to CRRs was $262 million; however, there were $4.3 million of derations and no shortfall charges leaving a final payment to CRR account holders of $258 million. This corresponds to a CRR funding percentage of 98 percent.

The last look at congestion examines the price spreads for each pair of hub and load zone in more detail. These price spreads are interesting as many loads may have contracts that hedge them to the hub price and are thus exposed to the price differential between the hub and its corresponding load zone. Figure 51 presents the price spreads between all Hub and load zones as valued at four separate points in time – at the semi-annual CRR Auction, monthly CRR auction, day-ahead and in real-time.

Of note is that the same intra-zone congestion that drives the relatively high CRR auction revenue amounts for the West zone also drives high price spreads between the West hub and the

West load zone. Of the other zones only the South has an average price spread over a dollar per MWh.

Figure 51: Hub to Load Zone Price Spreads

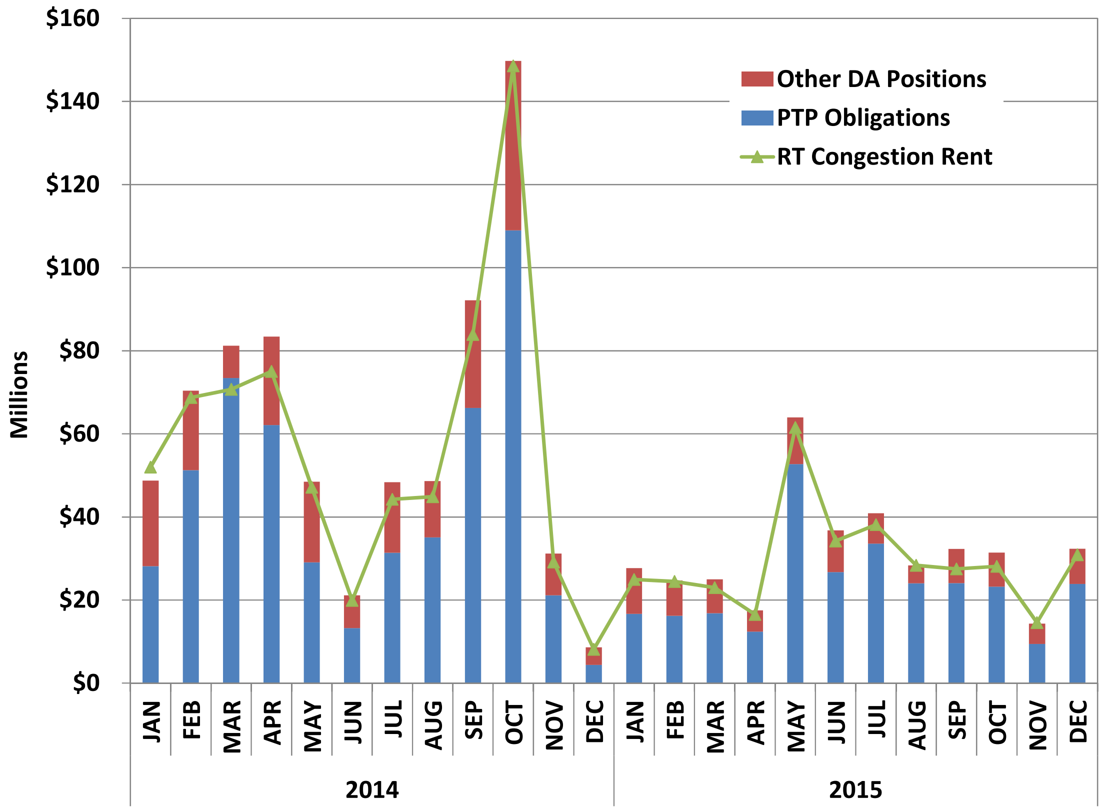


E. Revenue Sufficiency

In Figure 52 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 2015, real-time congestion rent was $352.3 million, payments for PTP Obligations (including those with links to CRR Options) were $279.8 million and payments for other day-ahead positions were $95.3.3 million, resulting in a shortfall of approximately $23 million for the year.

By comparison, the real-time congestion rent was $692.5 million in 2014. Payments for PTP Obligations and real-time CRRs were $524.5 million and payments for other day-ahead positions were $207.5 million, resulting in a shortfall of approximately $39.5 million for the year.

Figure 52: Real-Time Congestion Rent and Payments



Most of the 2015 shortfall, $16.5 million, was the result of settling PTP Obligations with links to CRR Options as options. The remainder is the result of discrepancies between transmission topology assumptions used when clearing the day-ahead market and the actual transmission topology that occurs during real-time. The total shortfall is effectively paid by all loads, allocated on a load-ratio share.

IV. DEMAND AND SUPPLY

This section reviews and analyzes the load patterns during 2015 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 discussion of demand response resources.

A. ERCOT Load in 2015

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 2015 are examined in this subsection and summarized in Figure 53.

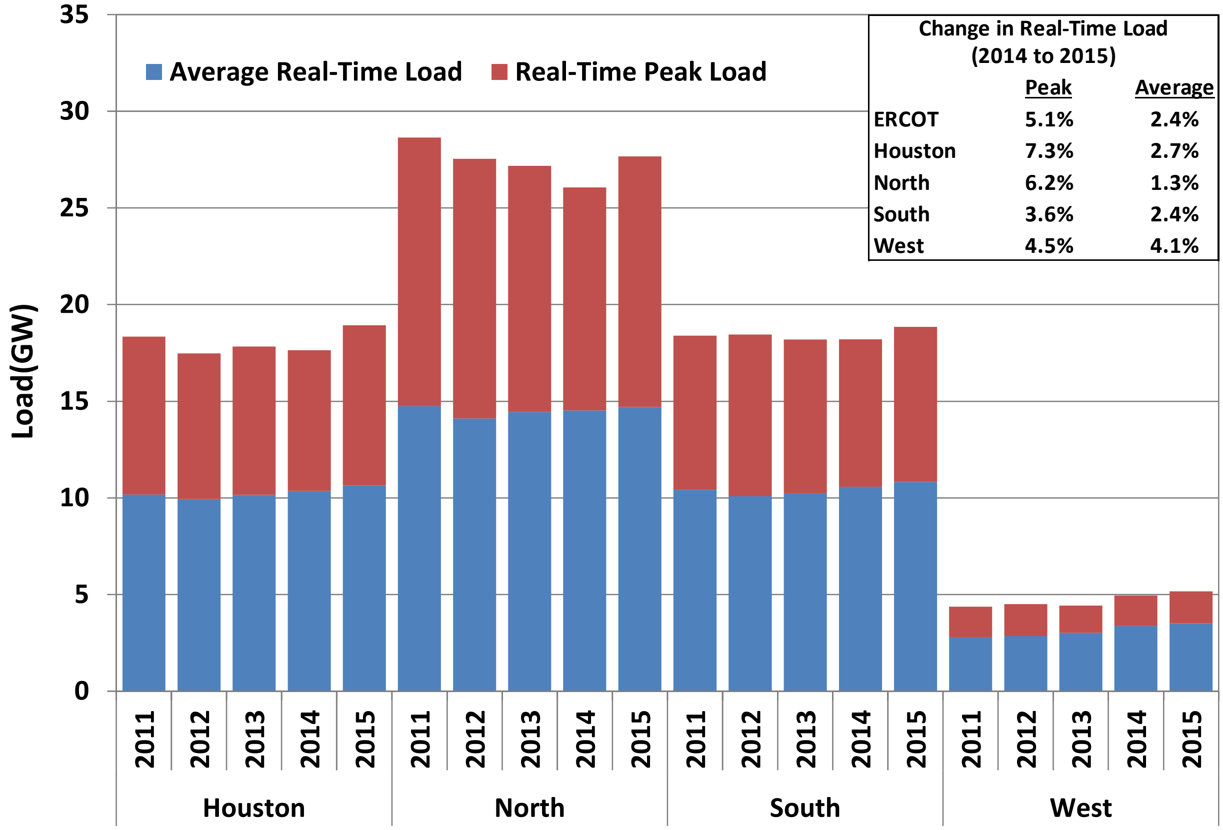
This figure shows peak load and average load in each of the ERCOT zones from 2011 to 2015.[15] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 37 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (9 percent of the total ERCOT load).

Figure 53 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

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

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.

Figure 53: Annual Load Statistics by Zone



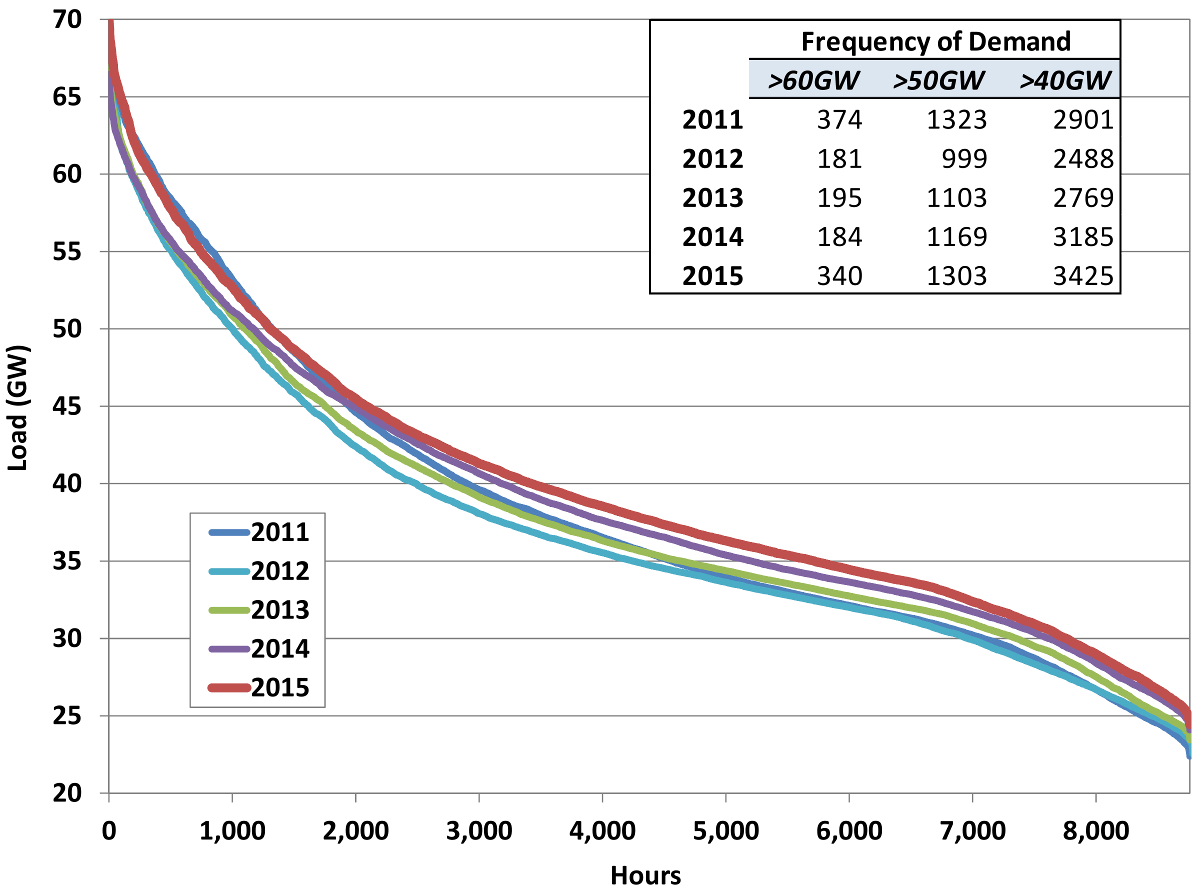
Total ERCOT load over the calendar year increased from 340 terawatt-hours (TWh) in 2014 to 348 TWh in 2015, an increase of 2.4 percent or an average of 866 MW every hour. This increase was largely driven by hotter summer temperatures in 2015. Cooling degree days, a metric that is highly correlated with weather-related summer load, increased 6 percent on average from 2014 to 2015 in Houston and Dallas. However, cooling degree days in 2015 were still 16 percent lower than ERCOT's hottest recent summer in 2011 in these locations.

Summer conditions in 2015 also led to a new ERCOT coincident peak hourly demand record of 69,877 MW on August 10, 2015. This broke the pre-existing peak demand record of 68,311 MW that occurred during August of 2011. In fact, the 2011 demand record was broken five subsequent times during August 2015. The 2015 peak represents a 5.2 percent increase from the peak hourly demand of 66,451 MW in 2014.

The changes in load at the zonal level are not the same as the ERCOT-wide changes. The growth rate of West zone average load was once again much higher, on a percentage basis, than the other zones because of increased oil and gas production activity in this area. While all zones saw an increase in the peak demand, the increase in the Houston zone was significantly higher than others at 7.3 percent over the 2014 peak.

To provide a more detailed analysis of load at the hourly level, Figure 54 compares load duration curves for each year from 2011 to 2015. 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.

Figure 54: Load Duration Curve – All Hours

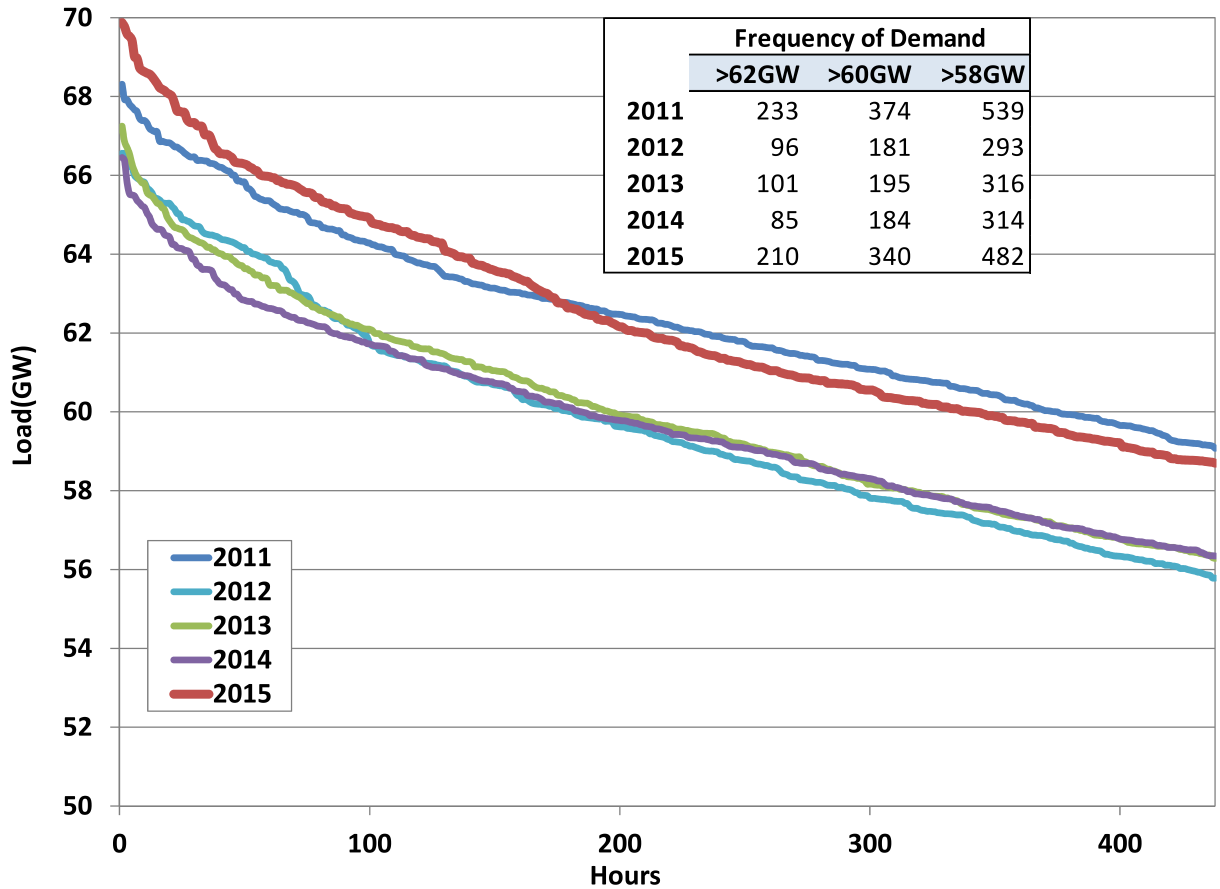


	Frequency of Demand		
	>60GW	*>50GW*	*>40GW*
2011	374	1323	2901
2012	181	999	2488
2013	195	1103	2769
2014	184	1169	3185
2015	340	1303	3425

As shown in Figure 54, the load duration curve for 2015 is generally higher than the four previous years. However, the 2011 load duration curve remained slightly higher than 2015 for hours 500 to 1,500.

To better illustrate the differences in the highest-demand periods between years, Figure 55 shows the load duration curve for the 5 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 2015, the peak load value averaged 18 percent greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – more than 10 GW – is needed to supply energy in less than 5 percent of the hours.

Figure 55: Load Duration Curve – Top Five Percent of Hours

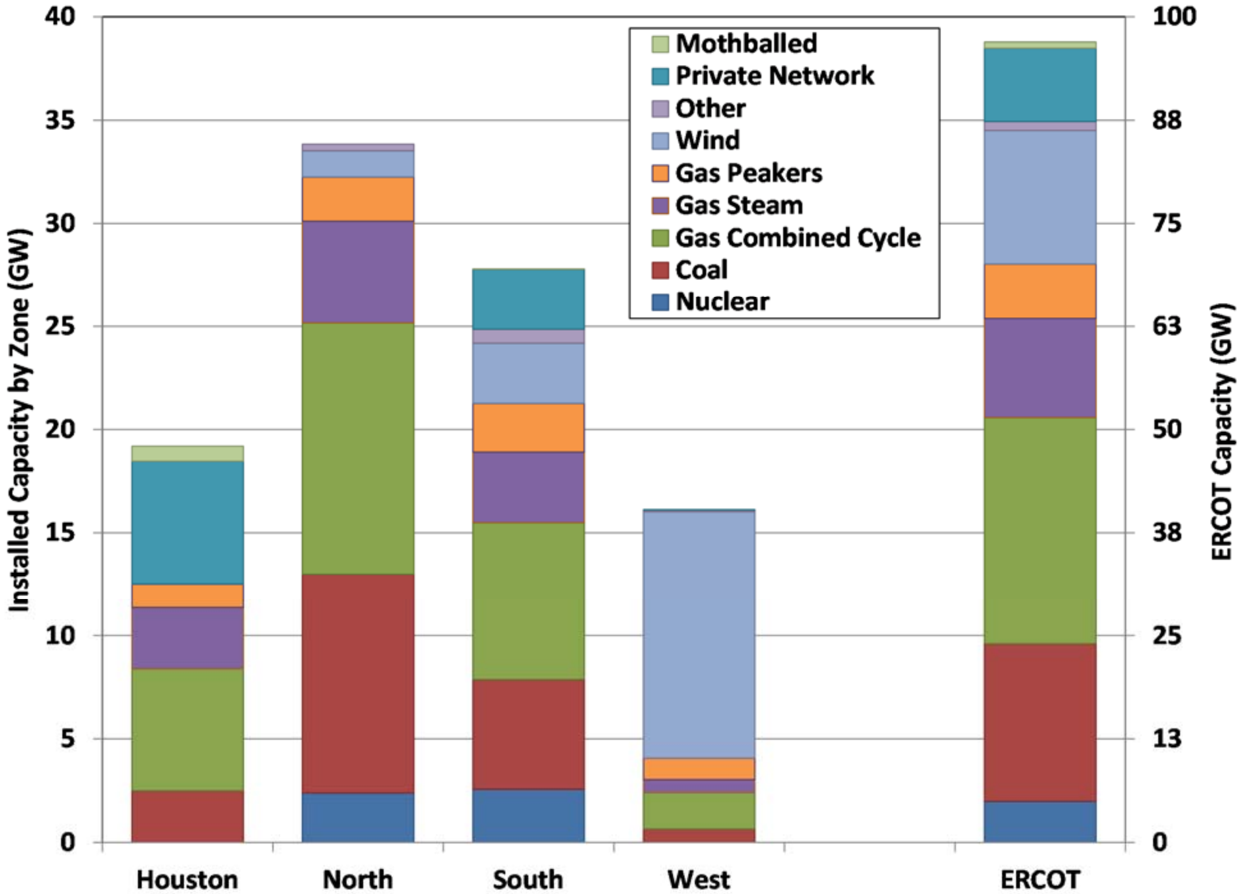


Frequency of Demand	>62GW	>60GW	>58GW
2011	233	374	539
2012	96	181	293
2013	101	195	316
2014	85	184	314
2015	210	340	482

B. Generation Capacity in ERCOT

The generation mix in ERCOT is evaluated in this subsection. The distribution of capacity among the ERCOT zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West zone. The North zone accounts for approximately 35 percent of capacity, the South zone 29 percent, the Houston zone 20 percent, and the West zone 17 percent. Excluding mothballed resources and including only the fraction of wind capacity available to reliably meet peak demand,[16] the North zone accounts for approximately 39 percent of capacity, the South zone 32 percent, the Houston zone 22 percent, and the West zone 7 percent. Figure 56 shows the installed generating capacity by type in each zone.[17]

Figure 56: Installed Capacity by Technology for Each Zone



Approximately 4.8 GW of new generation resources came online in 2015, but it only provided roughly 1.7 GW of net effective capacity. The overwhelming majority of new capacity was from wind generation. The 3.7 GW of newly installed wind capacity is approximately 600 MW of

16 The percentages of installed capacity to serve peak demand assume wind availability of 12 percent for non-coastal wind and 55 percent for coastal wind.

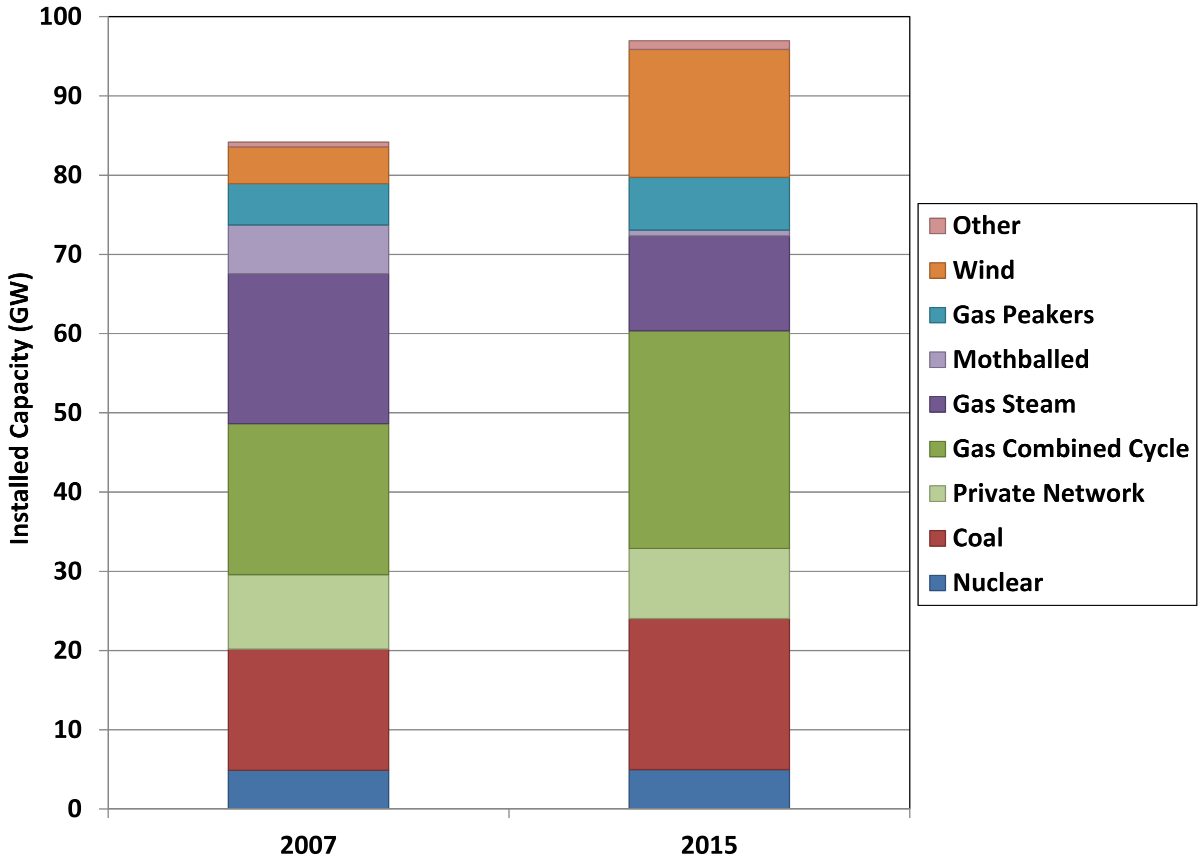
17 For purposes of this analysis, generation located in a NOIE Load Zone has been included with the proximate geographic Load Zone.

peak capacity. The remaining 1.1 GW of new capacity consisted of 100 MW of solar resources and approximately 1 GW of new natural gas combined cycle units.

With these additions, natural gas generation continued to account for approximately 48 percent of total ERCOT installed capacity while the share of coal generation remained at 20 percent in 2015.

By comparing the current mix of installed generation capacity to that in 2007, as shown in Figure 57,[18] the effects of longer term trends can be seen.

Figure 57: Installed Capacity by Type: 2007 Compared to 2015



Over these eight years, additions of wind, gas combined cycle, and coal generation have been offset by retirements of older, presumably less efficient natural gas steam units. Between 2007 and 2015, twelve new combined cycle gas units were added. Four combined-cycle units totaling

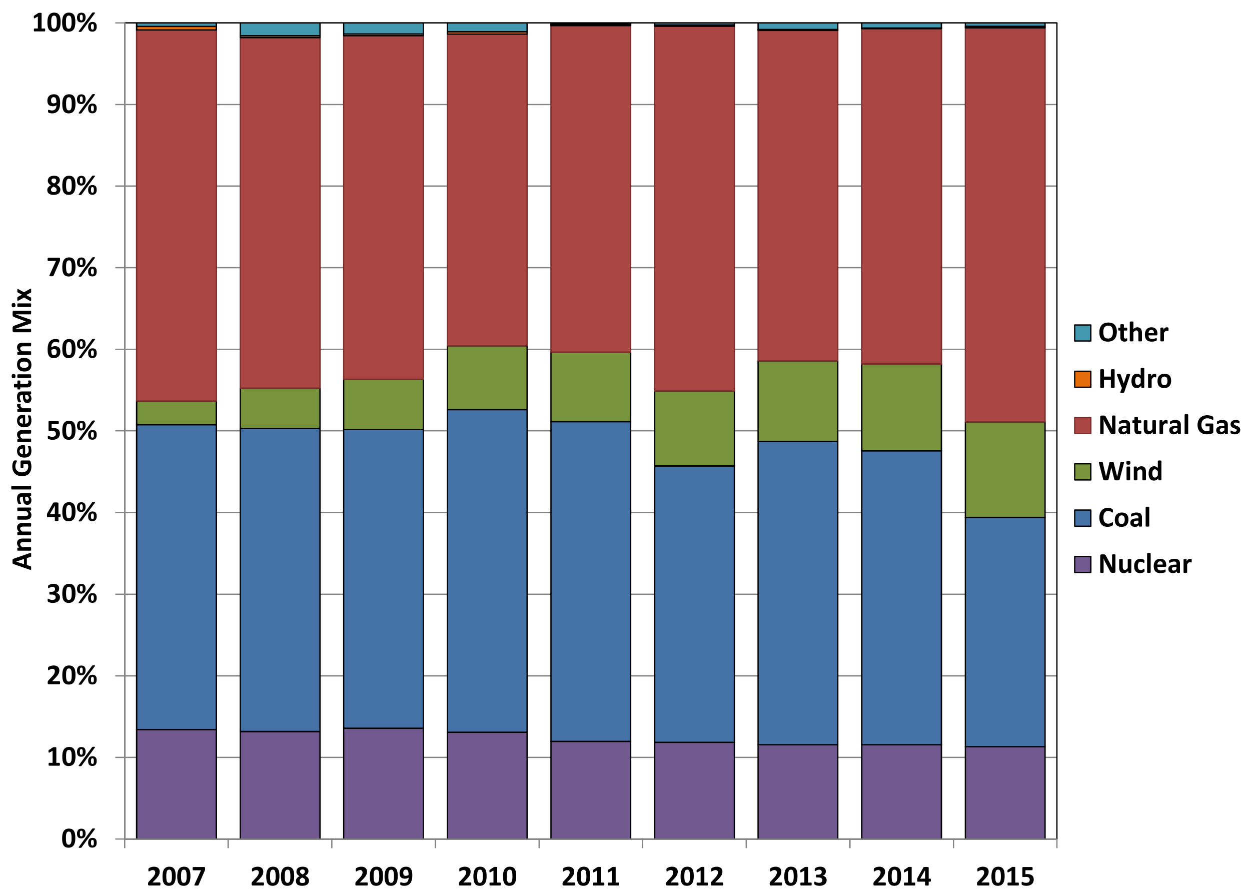
18 Wind and Private Network capacity is shown at its full installed capacity in this chart.

2.6 GW of capacity have been added in just the past two years. The amount of new wind generation installed since 2007 is 11.5 GW. The effective peak load serving capability of this new wind generation is calculated to be 2.1 GW.

These new additions and the return from mothball of 5.4 GW of resources, less the 6.9 GW of natural gas steam unit retirements has resulted in the installed capacity in 2015 growing by 12.8 GW compared to 2007. However, the increase in peak load serving capability of all net changes to installed capacity is 3.4 GW from 2007 to 2015, whole peak load was 7.7 GW higher in 2015 than in 2007. Hence, although ERCOT's generation base is growing, installed reserve margins have decreased.

The shifting contribution of coal and wind generation is evident in Figure 58, which shows the percentage of annual generation from each fuel type for the years 2007 through 2015.

Figure 58: Annual Generation Mix



The generation share from wind has increased every year, reaching 12 percent of the annual generation requirement in 2015, up from 3 percent in 2007. The 2015 generation share saw a record high for natural gas and a record low for coal. In 2015 the percentage of generation from natural gas was 48 percent, a significant increase from the 2014 level and the highest share during this time period of 2007-2015.[19] Corresponding with the increase in natural gas share was a significant decrease in the coal share from 36 percent in 2014 to its lowest observed level of 28 percent in 2015.

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 is approximately 24 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price.

1. Wind and Solar Generation

The amount of wind generation installed in ERCOT was approximately 16 GW by the end of 2015. Although the large majority of wind generation is located in the West zone, more than 3 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. This subsection will more fully describe the characteristics of wind generation in ERCOT.

The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure 59 shows average wind production for each month in 2014 and 2015, 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 approximately 3 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.

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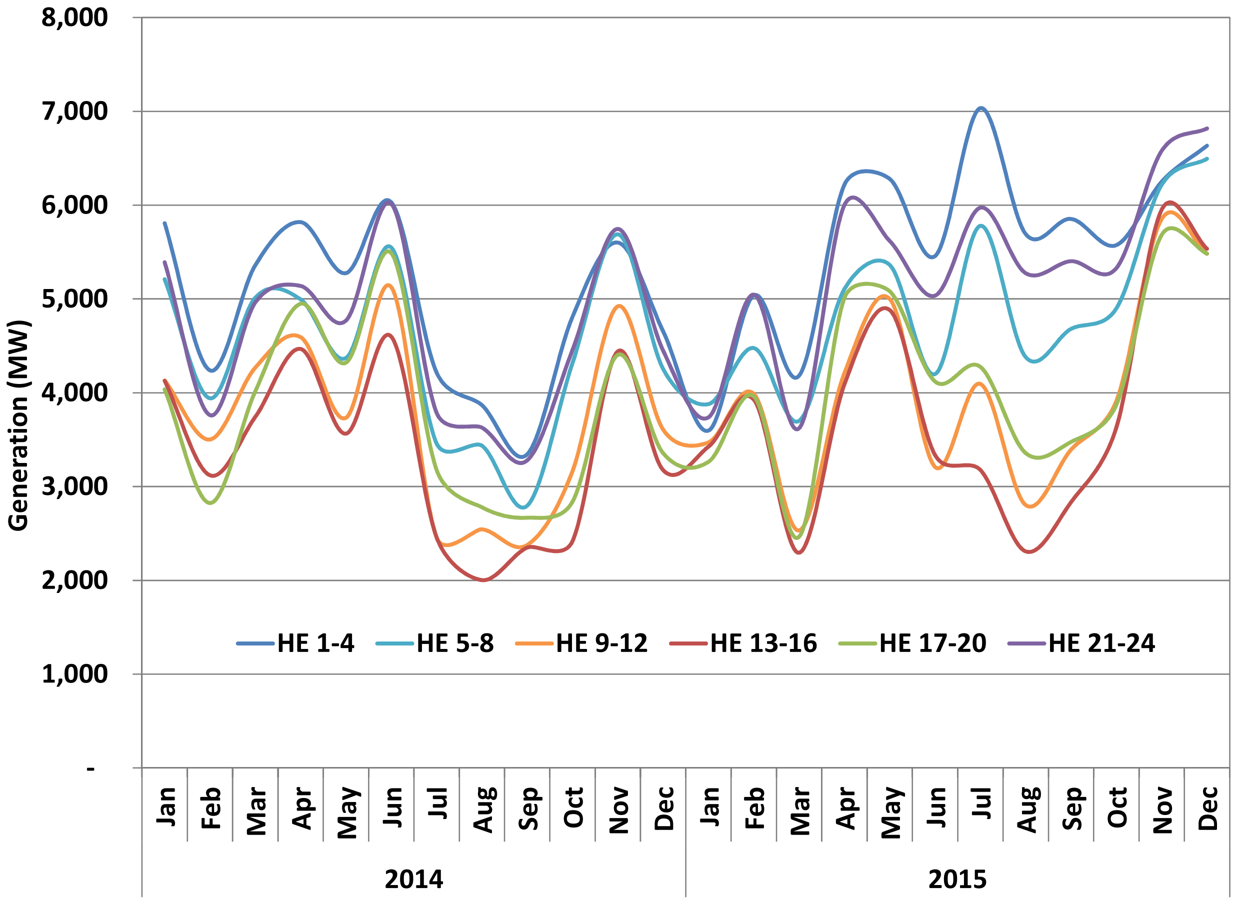
[19] Natural gas provided 40.5 percent of total generation in 2013, and 41.1 percent in 2014.

Figure 59: Average Wind Production



ERCOT continued to set new records for peak wind output in 2015. On December 20, wind output exceeded 13 GW, setting the record for maximum output and providing nearly 45 percent of hourly generation.

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 due to 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 60 presents data for the summer months of June through August, comparing the average output for wind generators located in the coastal region, the Panhandle and other areas in ERCOT across various load levels. The "Others" category is primarily composed of wind generators in West Texas and some in the northern part of the state. There is a strong negative relationship between wind output in the "Others" category and increasing load levels. It further shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand. Other than at loads greater than 65 GW, Panhandle wind shows a more stable output across the load levels.

Figure 60: Summer Wind Production vs. Load

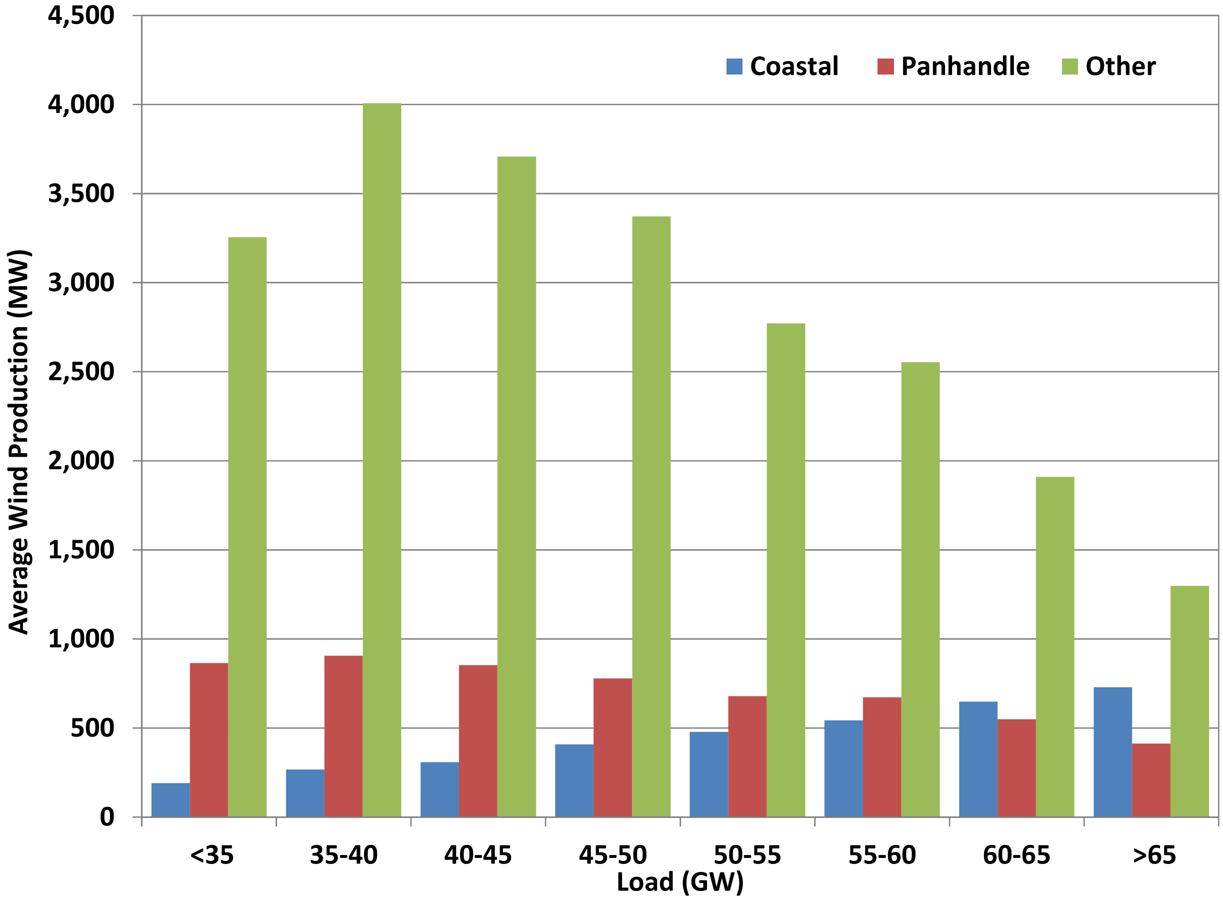


Figure 61 shows the wind production and estimated curtailment quantities for each month of 2012 through 2015. This figure reveals that the total production from wind resources continued to increase, while the quantity of curtailments was up slightly from 2014. The volume of wind actually produced in 2015 was estimated as 99 percent of the total available wind, compared with 99.5 percent in 2014, 98.9 percent in 2013 and 96 percent in 2012.

Figure 61: Wind Production and Curtailment

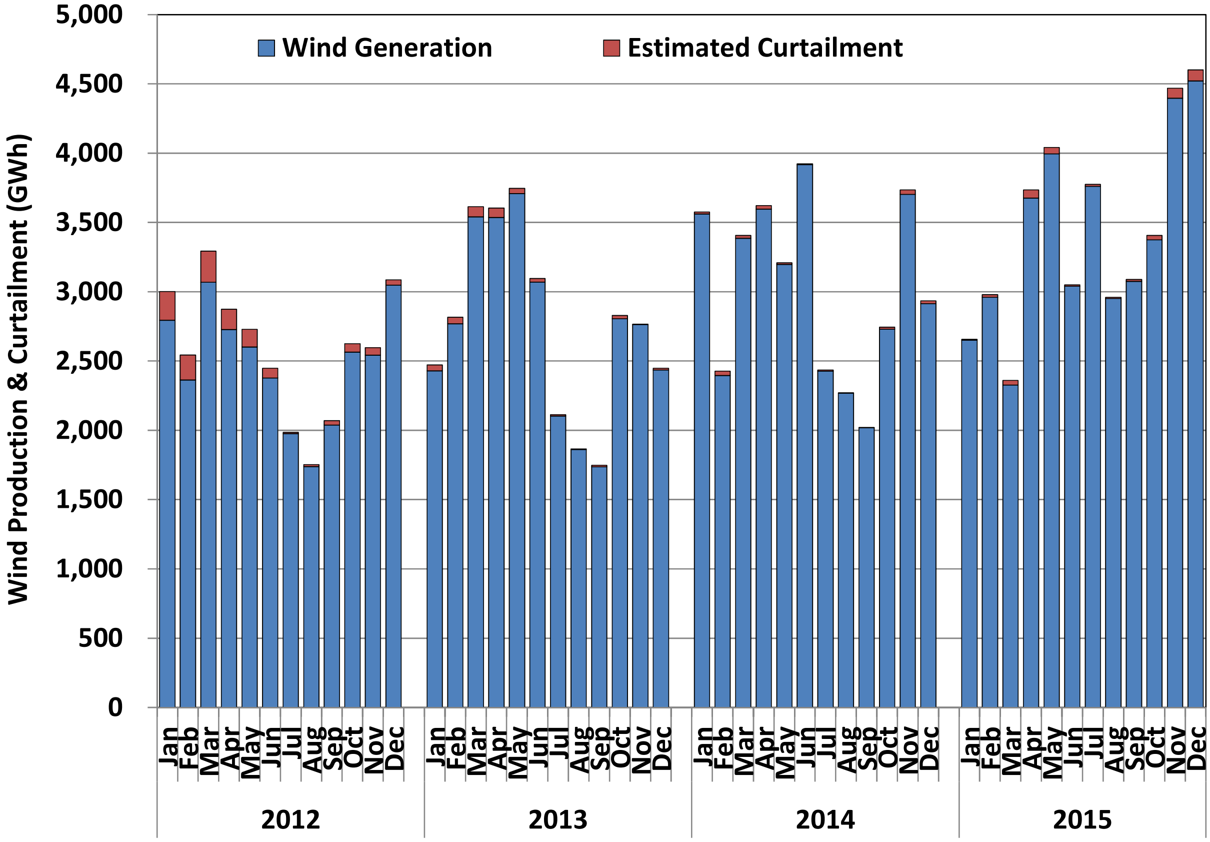
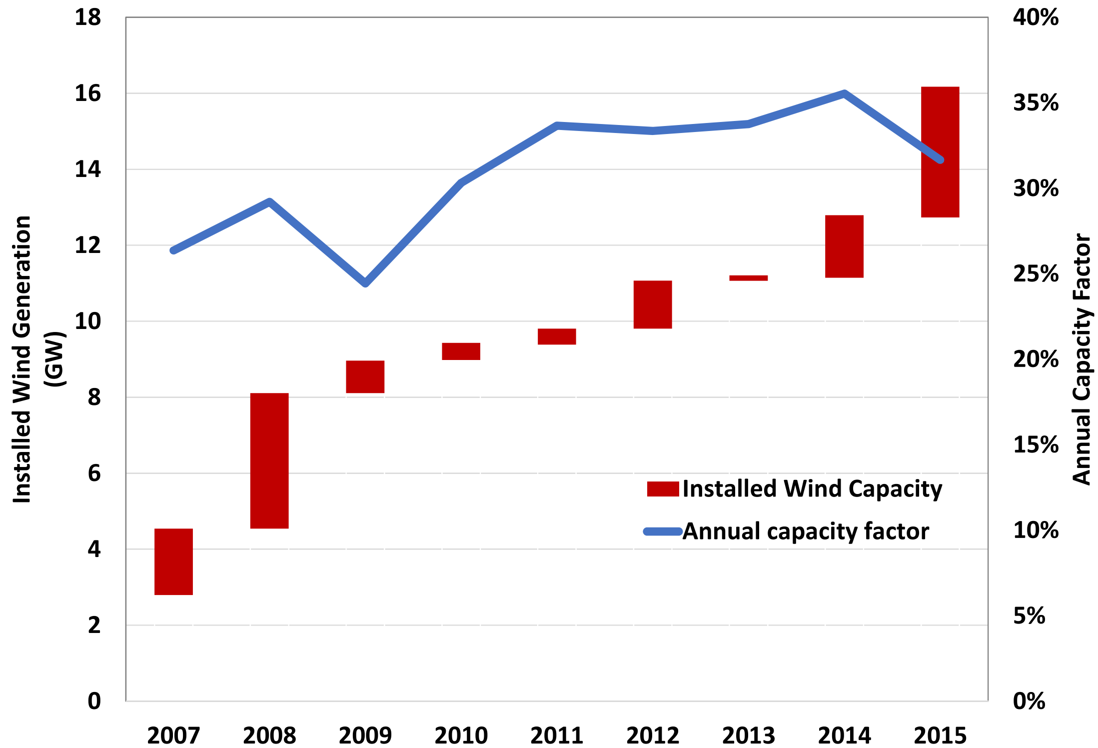


Figure 62 below, shows the quantities of wind generation installed every year from 2007 and the annual capacity factor of the wind output for each year. The amount of wind generation installed in 2015 was almost as large as in 2008. This was likely driven by two factors, the completion of the CREZ transmission lines and the scheduled expiration of the federal production tax credits at the end of 2015. The federal production tax credits have been extended for another four years, which should reduce the pressure on developers to quickly complete all future projects.

Figure 62 also provides the annual wind generation capacity factor. Prior to 2011, annual capacity factors were less than 30 percent, which reflected the large amounts of curtailments incurred due to transmission limitations. As completed CREZ lines allowed more wind to be produced, curtailments were reduced to approximately 1 percent. Capacity factors were 34, 36, and 32 percent in 2013, 2014, and 2015, respectively. These differences are now the result of natural variations in wind availability. So even though wind generation provided 12 percent of annual generation requirements, which was a new record, it occurred in a relatively low wind year.

Figure 62: Wind Generation Capacity Factor



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 63 shows the net load duration curves for the years 2015, 2011, and 2007, normalized as a percentage of peak load.

Figure 63: Net Load Duration Curves

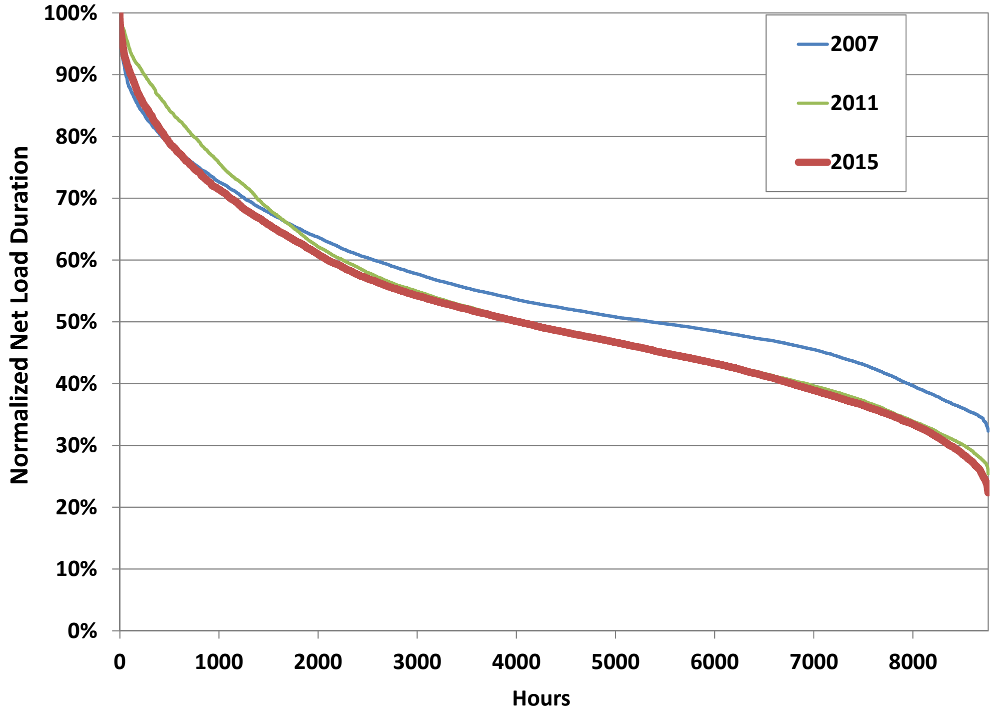
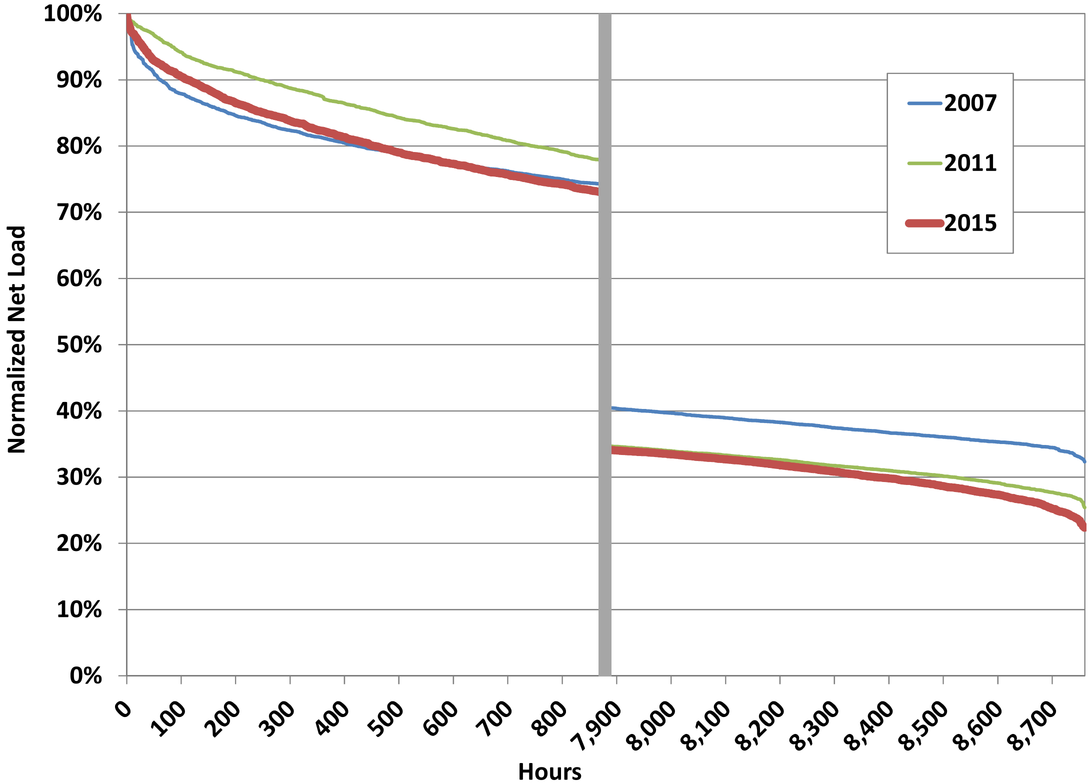


Figure 63 shows the reduction of remaining energy available for non-wind units to serve during most hours of the year, even after factoring in several years of load growth. The impact of wind on the highest net load values is much smaller.

Figure 64 shows net load in the highest and lowest hours. Even with the increased development activity in the coastal area of the South zone, 74 percent 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 hours of highest demand, 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 baseload coal units, while doing very little to reduce the amount of capacity necessary to reliably serve peak load.

Figure 64: Top and Bottom Ten Percent of Net Load



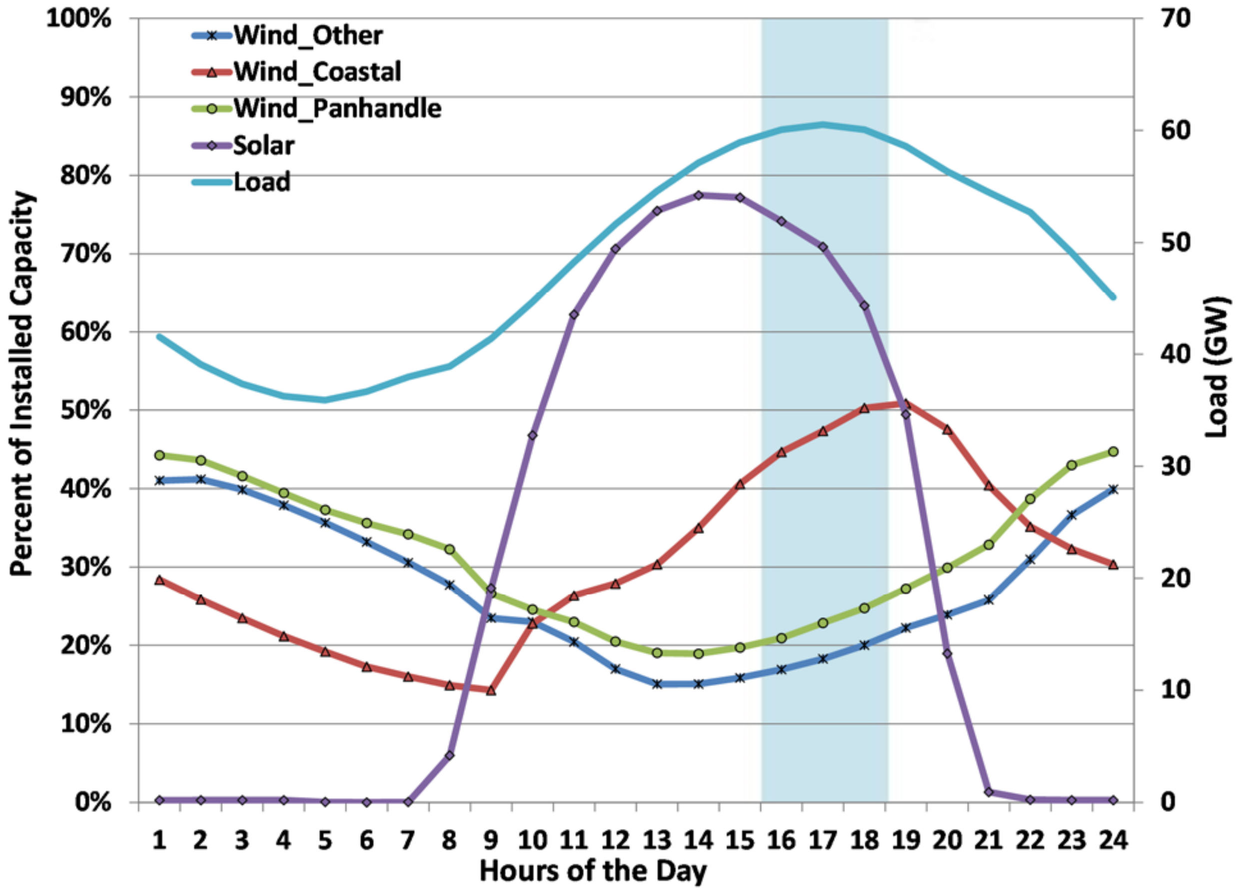
In the hours with the highest net load (left side of the figure above), the difference between peak net load and the 95th percentile of net load has averaged 12.3 GW the past three years. This means that 12.3 GW of non-wind capacity is needed to serve load less than 440 hours per year.

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 15.4 GW last year, even with sizable growth in total annual load. This continues to put operational pressure on the 23.5 GW of nuclear and coal generation currently installed in ERCOT.

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 meet net load and 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 within 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 65 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 65: Summer Renewable Production



This figure shows that the total installed capacity of solar generation is much smaller than that of wind generation. However, its production as a percentage of installed capacity is the highest in the early afternoon, nearing 80 percent, and producing more than 60 percent of its installed capacity during peak load hours.

The contrast between coastal wind and non-coastal wind is also clearly displayed in Figure 65. Coastal wind produced nearly 50 percent of its installed capacity during summer peak hours. Output from Panhandle wind exceeded 20 percent, while output from non-coastal wind (primarily West Zone) was less than 20 percent during summer peak hours.

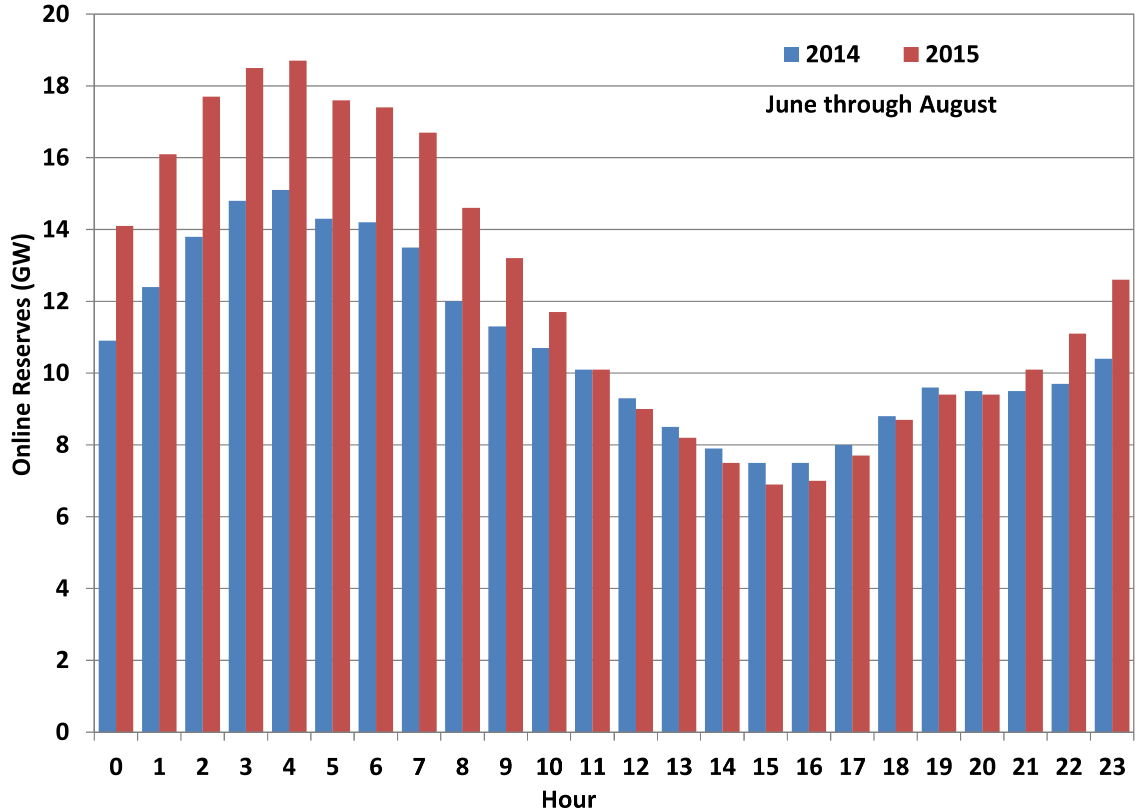
2. Resource Commitments for Reliability

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 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 outcomes help to inform these decisions, but it is important to note that ERCOT's day-ahead market 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.

The following figure compares the amount of on-line reserves, by hour, for the summer months of June through August in 2015 and 2014. The amount of on-line reserves is equal to the amount of capacity committed in excess of expected demand. Figure 66 displays available online reserves by operating hour and shows the expected pattern of declining reserves as system load increases during peak demand hours. Two interesting patterns emerge from this data. First, there were significantly more online reserves during overnight hours in 2015. Second, the online reserves during peak operating hours in summer 2015 were generally lower than in 2014.

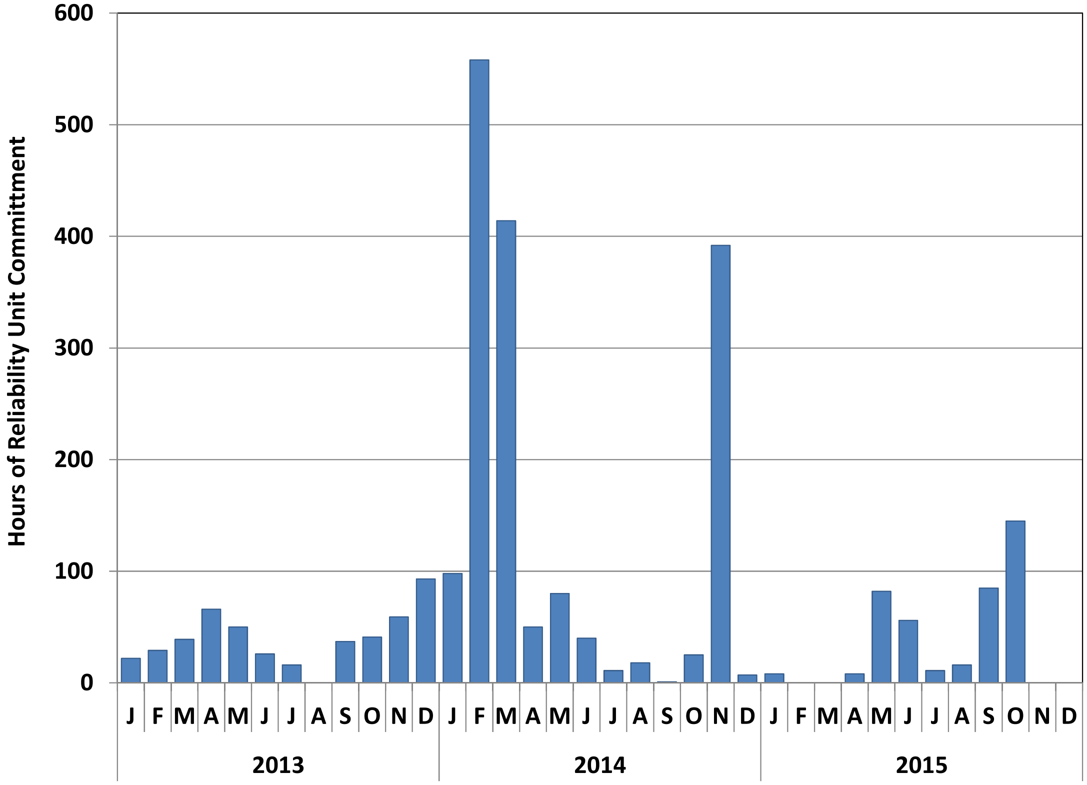
Figure 66: Average On-line Summer Reserves



One possible explanation for the increased off-peak capacity commitments in 2015 is that the low natural gas prices reduced minimum load operating costs, leading many generators to keep their units online overnight rather than incurring the risk and cost of shutting down and starting the unit every day. The small (500-600 MW) reductions to online reserves during peak hours in 2015 are explained by much higher (2500-2600 MW) average loads in those hours.

Once ERCOT assesses the unit commitments resulting from the day-ahead market, additional capacity commitments are made, if needed, using a reliability unit commitment (RUC) process that executes both on a day-ahead and hour-ahead basis. These additional unit commitments may be made for one of two reasons. Either additional capacity is required to ensure forecasted total demand will be met, or a specific generator is required to resolve a transmission constraint. The constraint may be either a thermal limit or to support a voltage concern. Figure 67 shows how frequently these reliability unit commitments have occurred over the past three years, measured in unit-hours.

Figure 67: Frequency of Reliability Unit Commitments



There was a significant decrease in the frequency of reliability unit commitments in 2015. During 2015, five percent of hours had at least one unit receiving a reliability unit commitment instruction. This is the same as the percent of hours in 2013 and down from 2014 when 19 percent of hours had RUC instructions. Most of the unusually high RUC activity in 2014 occurred during cold winter weather. In 2015, RUC commitments were most frequent in the fall due to congestion in Dallas and the Rio Grande Valley.

Table 4 provides the units most frequently called upon for RUC. Also provided are the hours of RUC instruction and the number of hours in which the unit opted out. A unit that receives a RUC instruction is guaranteed payment of its start-up and minimum energy costs (RUC Make-Whole). However, if the energy payments received by a unit operating under a RUC instruction exceed that unit's costs, payment to that unit is reduced (RUC Claw-Back). Beginning in January 2014, a unit receiving a RUC instructions had the choice to "Opt Out," meaning it would forgo all RUC Make-Whole in return for not being subject to RUC Claw-Back. In 2015, units receiving RUC instructions elected to opt out 34 percent of unit-hours.

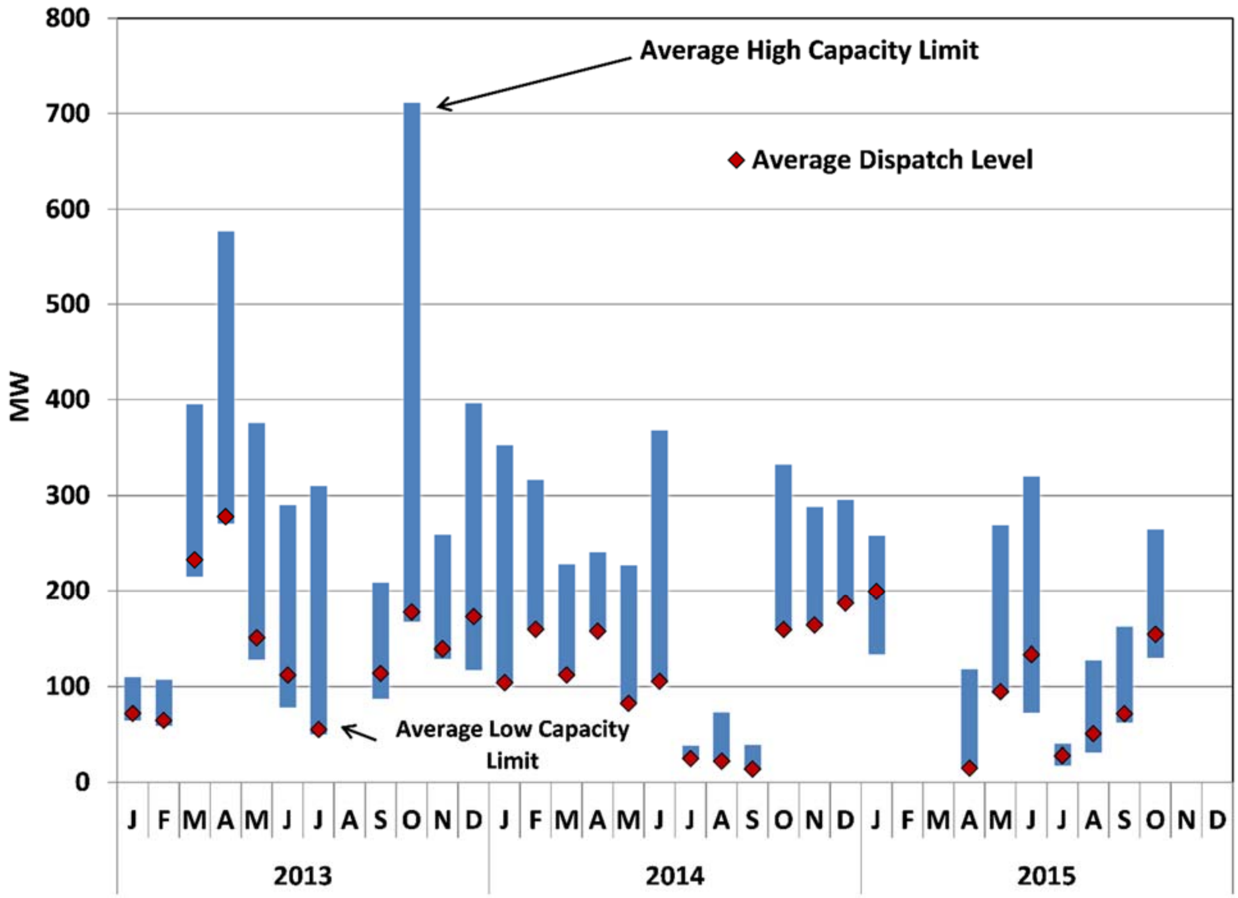
Table 4: Most Frequent Reliability Unit Commitments

Resource	Location	Reason	Unit RUC Hours	Unit OPTOUT Hours
Silas Ray CC1	Valley	Congestion	54	44
Morgan Creek Unit 8	Dallas	Congestion	58	-
Silas Ray 10	Valley	Congestion	15	23
Morgan Creek Unit 7	Dallas	Congestion	30	-
Decker DPG2	Austin	Congestion	-	22
Barney Davis CC1	Corpus Christi	Congestion	-	16
Decker DPG1	Austin	Congestion	-	16
Nueces Bay CC1	Corpus Christi	Congestion	16	-
North Edinburg CC1	Valley	Congestion & Voltage	14	-
Frontera CC1	Valley	Congestion	9	-
Lake Hubbard Unit 1	Dallas	Congestion	3	6
Mountain Creek Unit 6	Dallas	Congestion	8	-
Midlothian CT 4	Dallas	Capacity	-	8
Forney CC1	Dallas	Voltage	7	-
Midlothian CT 5	Dallas	Voltage	7	-

The vast majority of the 411 unit-hours with RUC instructions during 2015 were to resolve localized thermal transmission constraints (93 percent), and of those the majority were to units located in the Rio Grande Valley (37 percent) and in Dallas (27 percent). A small number of commitments, 20 unit-hours or 5 percent, were made due to voltage concerns in the Rio Grande Valley and in Dallas during the off-peak hours during a planned outage of one of the Comanche Peak units. There were eight unit-hour commitments (2 percent) given to a Midlothian Combustion Turbine for system-wide capacity requirements. This compares to 2014 when 18 percent of the unit hours of RUC instructions were for system-wide capacity requirements, primarily during the period from January through March.

The next analysis compares the average dispatched output of the reliability committed units with the operational limits of the units. Figure 68 below shows that the quantity of reliability unit commitment generation also decreased in 2015 compared to 2014. This figure shows that the average quantity dispatched during any month in 2015 was always less than 200 MW, and less than 100 MW in five of the eight months with reliability unit commitments. Therefore, the energy produced from reliability committed units does not generally displace a large quantity of energy from market committed units.

Figure 68: Reliability Unit Commitment Capacity



Additionally, this figure shows a decreasing trend in reliability unit commitments since 2013, which is good because such commitments and undermine real-time pricing.

C. Demand Response Capability

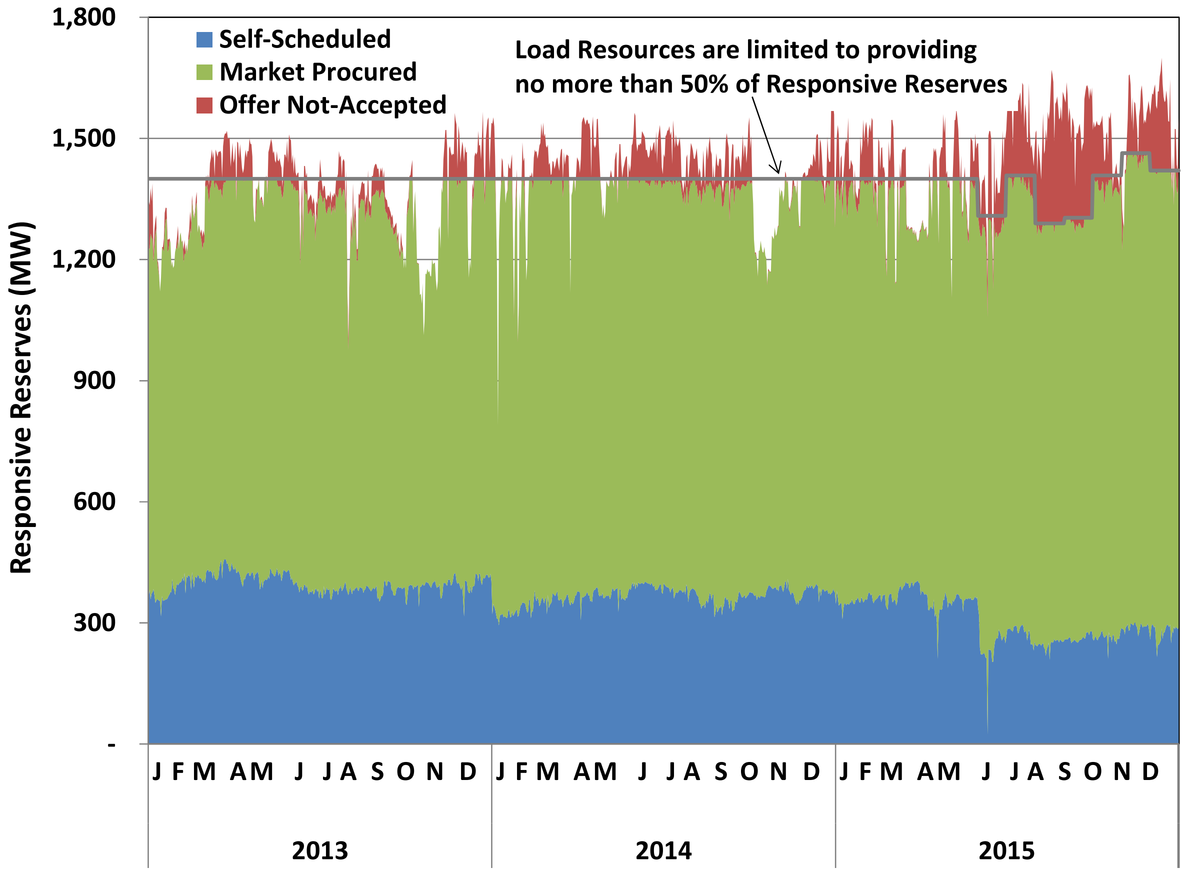
Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to certain market or system conditions. The ERCOT market allows participants with demand-response capability to provide energy and 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 transmission providers. Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges. Unlike active participation in ERCOT-administered markets, self-dispatch by demand is not directly tracked by ERCOT.

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Those providing responsive reserves have high set under-frequency relay equipment. This equipment enables the load to be automatically tripped when the frequency falls below 59.7 Hz, which will typically occur only a few times each year. As of December 2015, approximately 3,413 MW were qualified as Load Resources.

Figure 69 shows the amount of responsive reserves provided from load resources on a daily basis for the past three years. For reliability reasons the maximum amount of responsive reserves that can be provided by load resources is limited to 50 percent of the total.

Figure 69: Daily Average of Responsive Reserves Provided by Load Resources



For the first five months of 2015, the RRS procurement amount was constant at 2,800 MW, of which 1,400 MW could be provided by load. On June 1, 2015, ERCOT began procuring a variable amount of RRS based on season and time of day. The total amount of RRS varies between 2,300 to 3,000 MW. During 2015, there were no system-wide manual deployments of load resources providing RRS and only one automatic deployment of a small portion of frequency responsive load.

Figure 69 shows amounts of responsive reserves that were either self-scheduled or offered by load resources. The quantity of offers submitted by load resources exceeds the 50 percent limit most of the time. This is only generally not the case when real-time prices are expected to be high. Since 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 the 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.

ERCOT Protocols permit load resources to provide non-spinning reserves and regulation services, but for a variety of reasons there has been minimal participation by load resources.

2. Reliability Programs

There are two main reliability programs in which demand can participate in ERCOT – Emergency Response Service and transmission provider load management programs. The Emergency Response Service (ERS) product is defined by a PUCT Rule enacted in March of 2012 setting a program budget of $50 million.[20] The amount of ERS procured ranged from 783 MW to 1018 MW across the various periods in the 2015 program year. 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. The time and capacity-weighted average price paid for ERS over the contract periods from February

[20] *See* 16 TEX. ADMIN. CODE § 25.507.

2015 through January 2016 was $6.45 per MWh, just below the average price of $6.92 per MWh paid for non-spinning reserves in 2015. ERS was not deployed in 2015.

A load has to make a choice between participating in ERS, providing Ancillary Services, or simply choosing to curtail in response to high wholesale energy prices. A specific load cannot provide more than one of these functions at the same time. Given the high budget allotted and the low risk of deployment, ERS is a very attractive program for loads. Because the ERS program is so lucrative, there is concern that it is limiting the motivation for loads to actively participate in SCED and contribute to price formation. We suggest that the PUCT evaluate the need for and structure of this program.[21]

Beyond ERS there are slightly less than 200 MW of load participating in load management programs administered by transmission providers. 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 providers may be deployed by ERCOT during a Level 2 Energy Emergency Alert (EEA).

3. 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 and/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.

For decades, transmission costs have been allocated to all loads in ERCOT 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. Over the last three years, transmission costs have risen by more than 60 percent, thus

[21] On May 4, 2016, the PUCT opened Docket 45927, *Rulemaking Regarding Emergency Response Service.*

significantly increasing an already substantial incentive to reduce load during probable peak intervals in the summer. ERCOT estimates that over 800MW of load is actively pursuing reduction during these intervals.[22]

Two recent changes in the ERCOT market have made advances in appropriately pricing actions taken by load during 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, performs a second pricing run of SCED to account for the amount of load deployed, including ERS.

[22] *See* ERCOT, *2015 Annual Report of Demand Response in the ERCOT Region* (Mar. 2016) at 6, available at http://www.ercot.com/services/programs/load.

V. 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 system demands and reliability 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

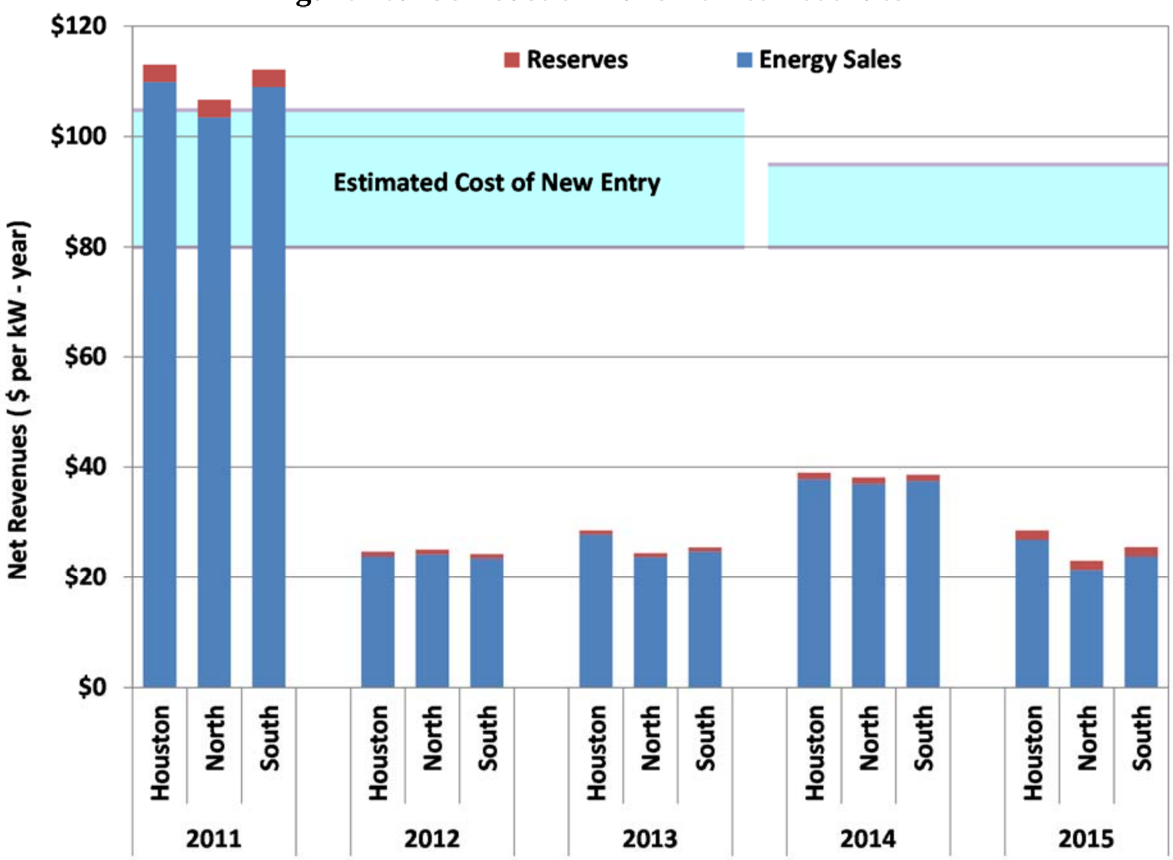
Net revenue is calculated by determining the total revenue that could have been earned by a generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the real-time energy and ancillary services markets provide economic signals that help inform suppliers' decisions to invest in new generation or retire existing generation. 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 reliability unit commitment 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 percent 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.

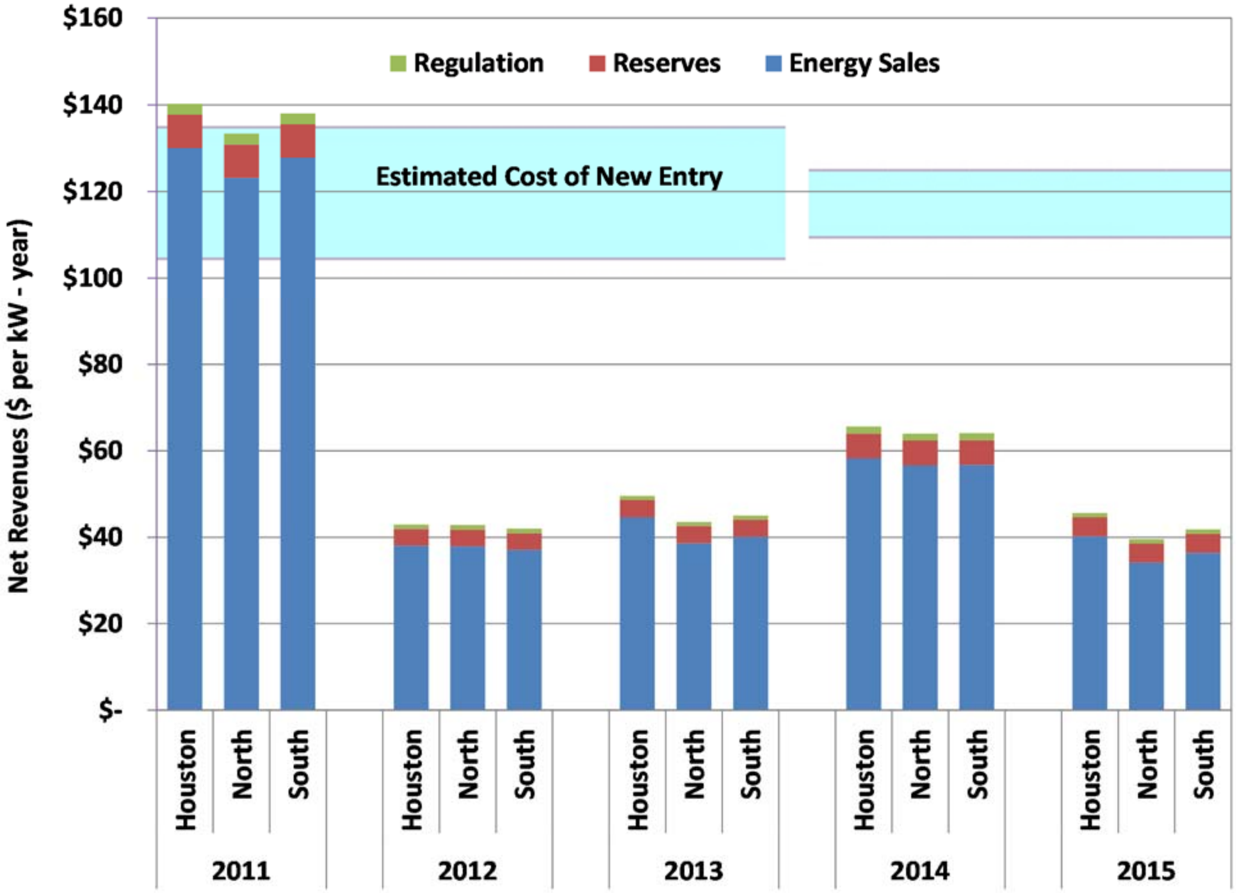
The next two figures provide an historical perspective of the net revenues available to support new natural gas combustion turbine (Figure 70) and combined cycle generation (Figure 71).

Figure 70: 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 gas turbine unit ranges from $80 to $95 per kW-year. The net revenue in 2015 for a new gas turbine was calculated to be approximately $23 to 29 per kW-year, depending on the zone. These values are well below the estimated cost of new gas turbine generation.

Figure 71: Combined Cycle Net Revenues



For a new combined cycle gas unit, the estimate of net revenue requirement is approximately $110 to $125 per kW-year. The net revenue in 2015 for a new combined cycle unit was calculated to be approximately $40 to 46 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 the current surplus capacity that exists over the minimum target level, which contributed to infrequent shortages in 2015. In an energy only market, shortages play a key role in delivering the net revenues an investor would need to recover its investment.

Such shortages will tend to be clustered in years with unusually high load and/or poor generator availability. Hence, these results alone do not raise substantial concern regarding design or operation of ERCOTs ORDC mechanism for pricing shortages.

Given the very low energy prices during 2015 in non-shortage hours, the economic viability of existing coal and nuclear units was evaluated. The prices in these hours, which have been substantially affected by the prevailing natural gas prices, determine the vast majority of net revenues received by these baseload units. As previously described, the load-weighted ERCOT-wide average energy price in 2015 was $26.76 per MWh. The generation-weighted average price for the four nuclear units - approximately 5GW of capacity - was $24.56 per MWh in 2015. According to the Nuclear Energy Institute (NEI), total operating costs for all nuclear units across the U.S. averaged $27.53 per MWh in 2015.[23] Assuming that operating costs in ERCOT are similar to the U.S. average, considering only fuel and operating and maintenance costs indicates that nuclear generation was not profitable in ERCOT during 2015. To the extent nuclear units in ERCOT had any associated capital costs, it is likely those costs were not recovered.

The generation-weighted price of all coal and lignite units in ERCOT during 2015 was $25.94 per MWh. Although specific unit costs may vary, index prices for Powder River Basin coal delivered to ERCOT were approximately $3 per MMBtu in 2015. With a typical heat rate of 10 MMBtu per MWh, the fuel-only operating costs for coal units in 2015 may be inferred to be approximately $30 per MWh. As with nuclear units, it appears that coal units were likely not profitable in ERCOT during 2015. This is significant because the retirement or suspended operation of some of these units could cause ERCOT's capacity margin to fall below the minimum target more quickly than anticipated.

These results indicate that during 2015 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated, which may seem inconsistent with the fact that new generation continues to be added in the ERCOT market. This can be explained by a number of factors.

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23 NEI Whitepaper, "Nuclear Costs in Context", April 2016, available at http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf.

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 2015. 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 2015, shortages were 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 the 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.

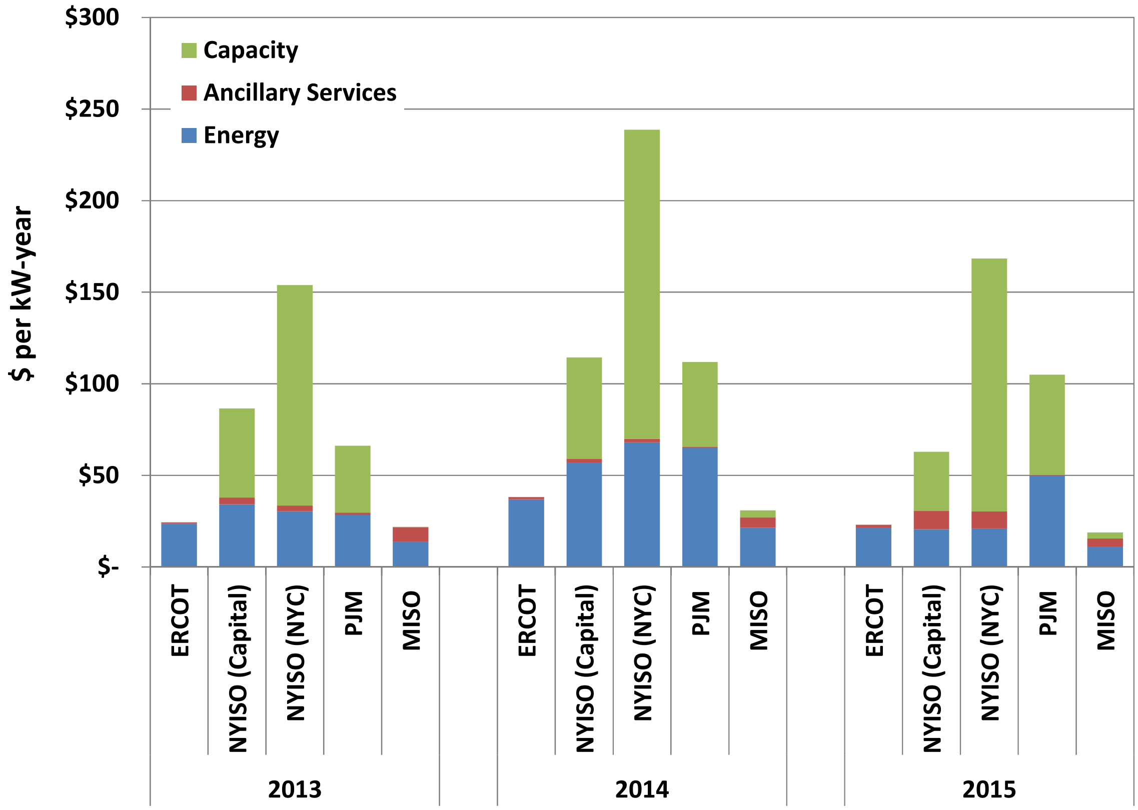
Finally, the costs of new entry used in this report are generic and reflective of the costs of a new unit on an undeveloped greenfield site. They have been reduced somewhat to reflect the lower costs of construction in Texas. However, companies may have opportunities to build generation at much lower 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 lower than 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 with centrally-cleared capacity markets. The technologies are differentiated by assumed heat rate;

7,000 MMBtu per MWh for combined cycle and 10,500 MMBtu per MWh for simple-cycle combustion turbine.

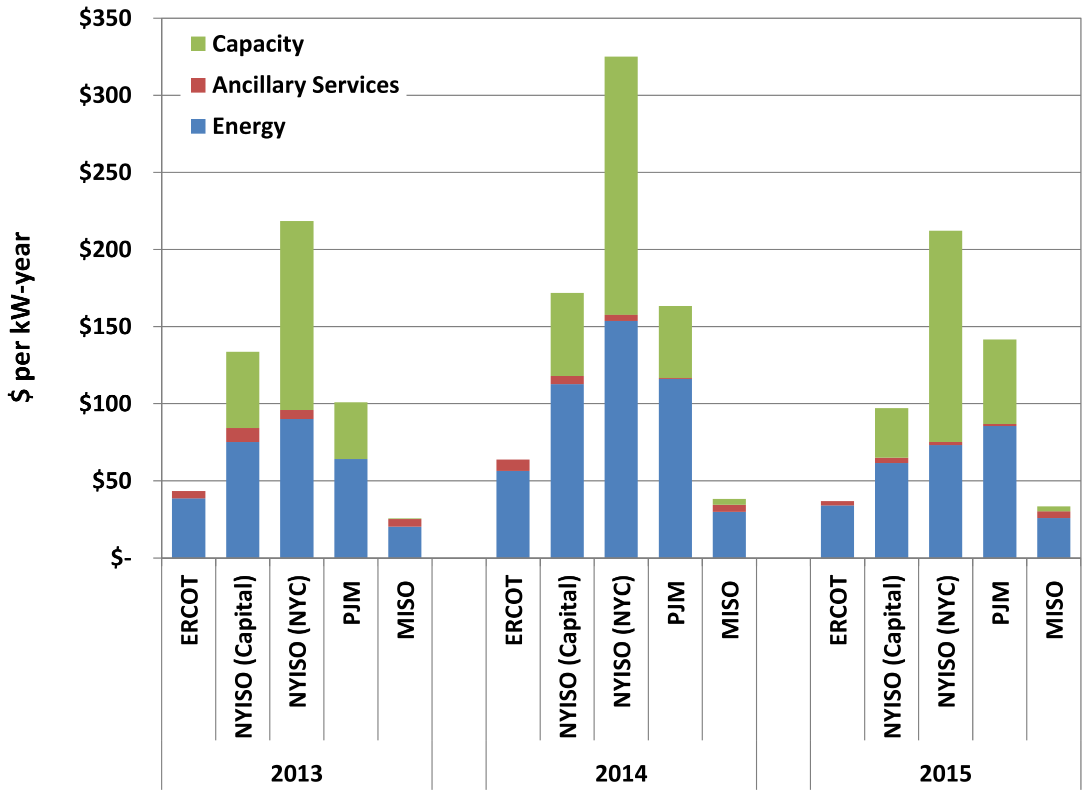
The next two figures compare estimates of net revenue for these two types of natural gas generators for the ERCOT North zone, PJM, two locations within the New York ISO, and the Midcontinent ISO. Figure 72 provides a comparison of net revenues for a combustion turbine and Figure 73 provides the same comparison for a combined cycle unit.

Figure 72: Combustion Turbine Net Revenue Comparison Between Markets



The figures include 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. Most of the locations shown are central locations, but there are load pockets within each market where net revenue and the cost of new entry may be higher. The NYC zone of NYISO is an example of much higher value in a load pocket. Thus, even if new investment is not generally profitable in a market, it may be economic in certain areas.

Figure 73: Combined Cycle Net Revenue Comparison Between Markets



Both figures indicate that across all markets net revenues decreased substantially in 2015 because of low natural gas prices across the country and sufficient installed reserves, typically a result of flat or no load growth. With the exception of MISO, capacity revenues 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 Public Utility Commission of Texas (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,[24] this subsection assesses the Scarcity Pricing Mechanism (SPM) in 2015 under ERCOT's energy-only market structure.

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[24] *See* 16 TEX. ADMIN. CODE § 25.505(g)(6)(D).

Revisions to 16 TEX. ADMIN. CODE § 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 19 on page 20, 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. There have been no instances of prices rising above $5,000 per MWh.

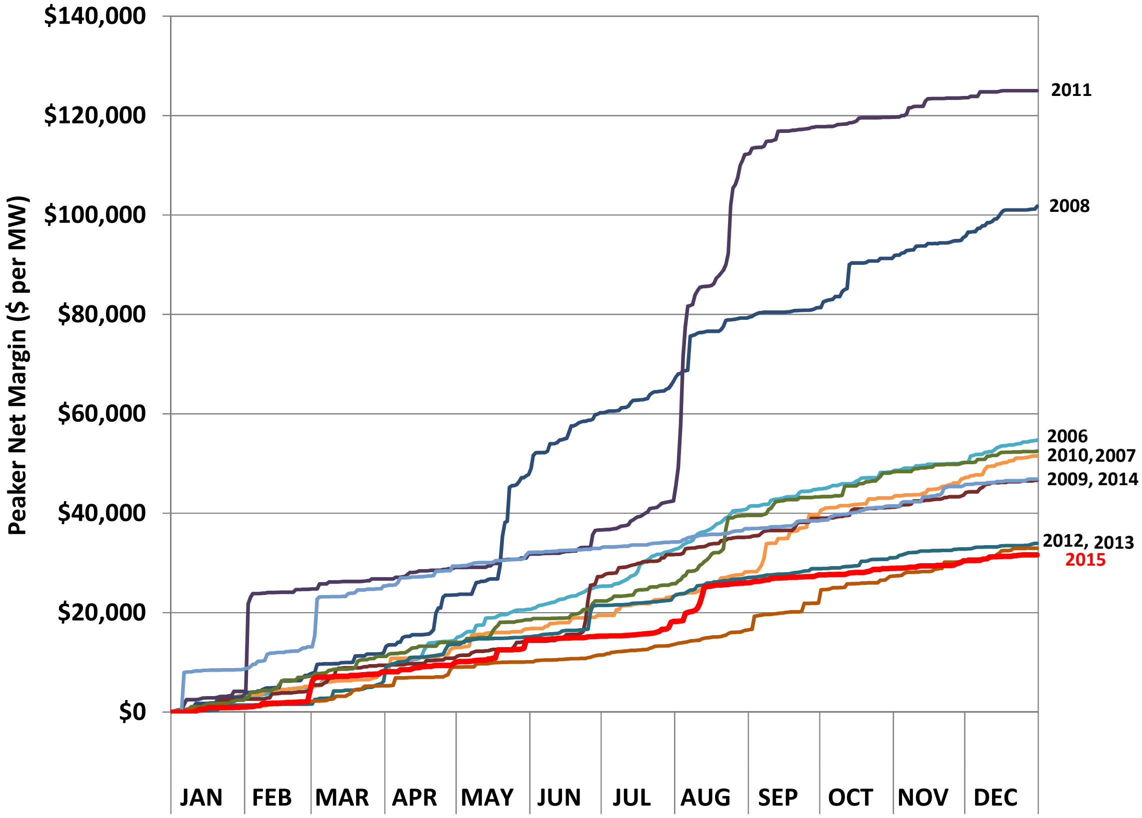
The SPM includes a provision termed the Peaker Net Margin (PNM) that is designed to provide a fail-safe pricing measure, which if exceeded would cause the system-wide offer cap to be reduced. If the PNM for a year reaches a cumulative total of $315,000 per MW, the system-wide offer cap is then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[25] PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[26]

Figure 74 shows the cumulative PNM results for each year from 2006 through 2015 and shows that PNM in 2015 was the lowest it has been since it became effective in 2006. 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.

[25] 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 analysis prepared by Brattle dated June 1, 2012, and will remain in place until there is a change identified in the cost of new entry of new generation plants.

[26] 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 74: 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.[27] 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 improve resource adequacy signals, by directing ERCOT to implement the Operating Reserve Demand Curve (ORDC). As discussed in Section I.D, 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.

27 Not that the zonal market design was the problem per se, but rather its reliance on high-priced offers to set high prices during periods of shortage.

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."[28] Given how long it has been in place, 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 and/or generation availability is poor; neither of which was the case in 2015.

Nonetheless, whatever the outcome of this ongoing review, 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. The figure below shows ERCOT's current projection of reserve margins.

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

Figure 75: Projected Reserve Margins

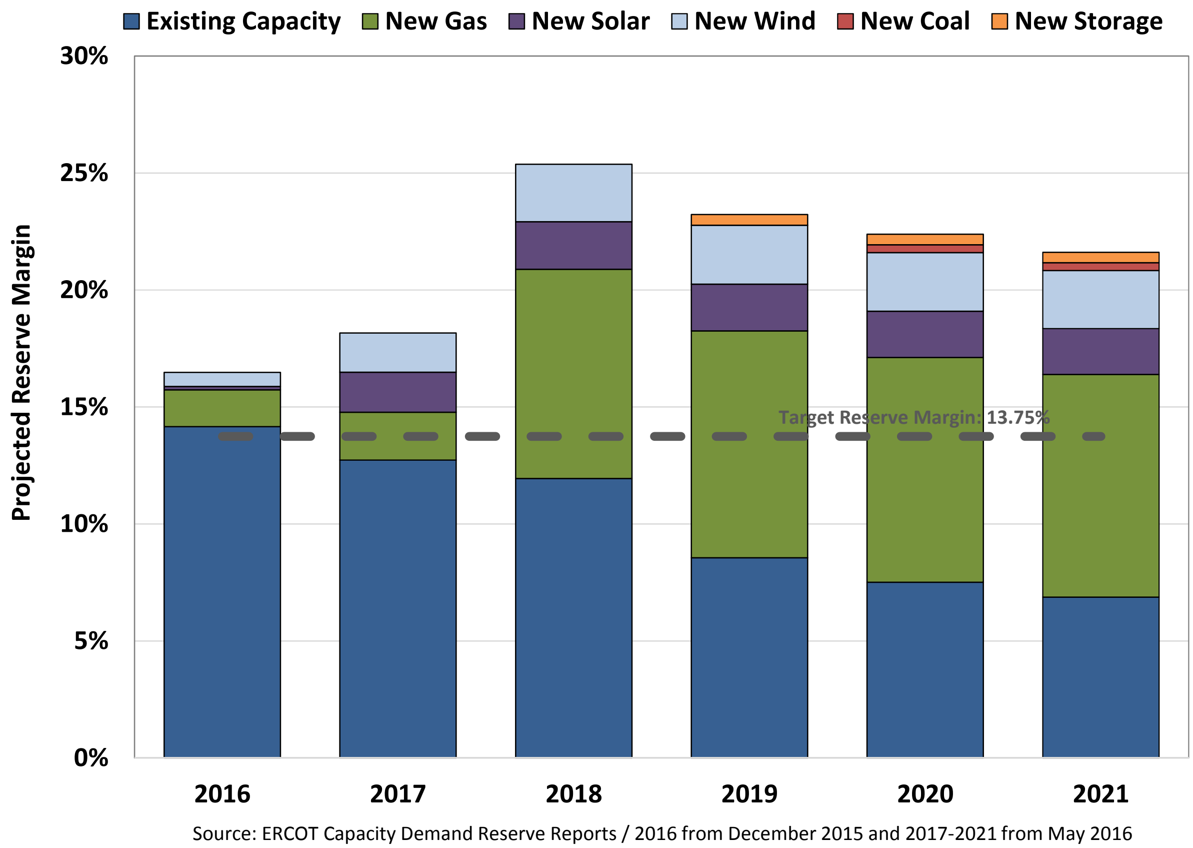


Figure 75 above indicates that the region will have a 16.5 percent reserve margin heading into the summer of 2016. Reserve margins are now expected to exceed the target level of 13.75 percent for the next several years. These projections are higher than those developed last year, which were higher than in 2013. These increases are due to more new generation capacity expected to be constructed in ERCOT. The current outlook is very different than it was in 2013, when reserve margins were expected to be below the target level of 13.75 percent for the foreseeable future.

This current projection of reserve margins combined with relatively infrequent shortage pricing may raise doubts regarding the likelihood of all announced generation actually coming on line as currently planned. Given the projections of continued low prices, investors of some of the new generation included in the Report on the Capacity, Demand, and Reserves in the ERCOT Region (CDR) may choose to delay or even cancel their project. Additionally, the profitability analysis of existing baseload resources casts doubt on the assumption embedded in the CDR that all existing generation will continue to operate.

As previously discussed, the decreased share of total generation provided by coal is evidence of the economic strain that coal units were under in 2015. The share of coal in the overall generation mix has historically dropped whenever natural gas prices have fallen below $3 per MMBtu.[29] This was true again in 2015. With expectations for future natural gas prices to remain relatively low, the pressure on the ability of coal units in the ERCOT market to economically operate is not expected to subside any time soon. In the face of these challenging fuel market economics, increased environmental requirements are also coming to the fore. Although currently under litigation, the interplay of multiple environmental regulations would require additional investment in pollution control technology at many existing coal units, thus further increasing the challenge to economic operations.

The retirement of uneconomic generation should not in any way be viewed as failure to provide resource adequacy. Having the right pricing signals to encourage sufficient and efficient generation signals is the goal. Most of the coal units facing the greatest price and environmental pressure have been operating for more than thirty-five years. 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.

ERCOT's installed reserve margin is compared that of other regions below. Figure 76 provides the anticipated reserve margins for the North American Electric Reliability Council (NERC) regions in the United States for the summer of 2016, as of NERC 2015 Long-Term Reliability Assessment.[30] Figure 76 shows that required, or reference level reserve margins center around 15 percent across other regions. These regions run the gamut from traditional bundled, regulated utility service territories to fully competitive, centrally operated wholesale markets. There are differences in the level of planning reserves expected for the summer of 2016. However, reserve margins are lower in nearly every region this year compared to last. ERCOT continues to stand out with its anticipated reserve margin remaining very close to its target level. Even with the

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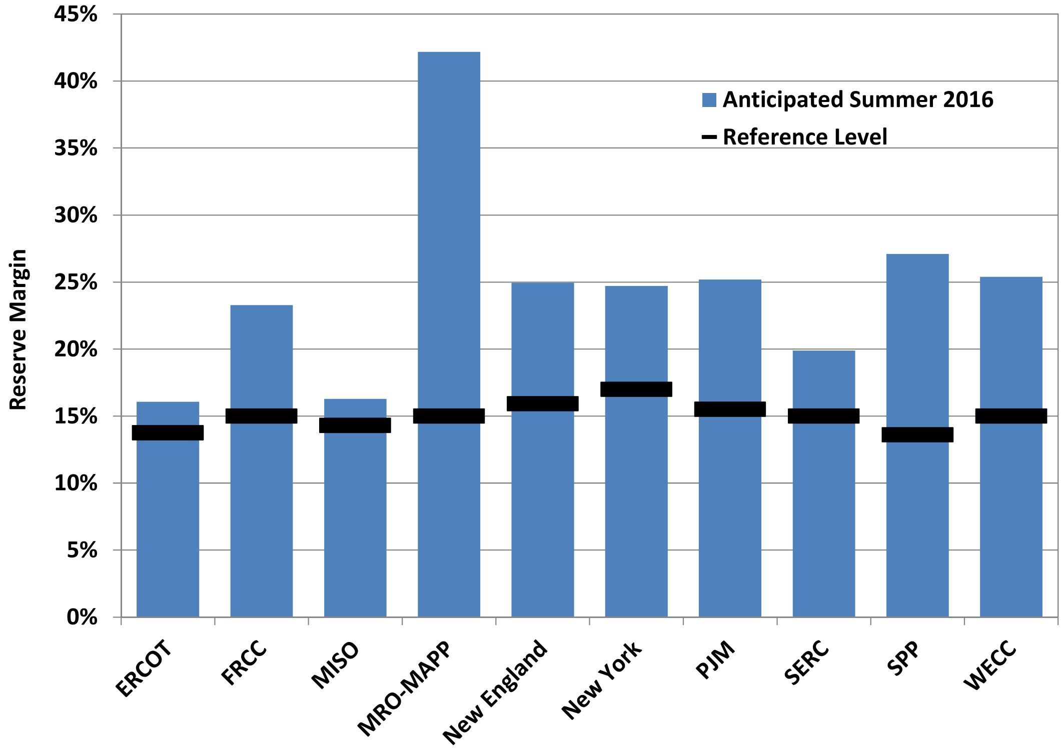
29 *See* 2012 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd.

30 Data from NERC 2015 Long-Term Reliability Assessment (January 2016) available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf For the most recent projected reserve margins for ERCOT, please see Figure 75 and the associated discussion

forecasted additions, ERCOT is projected to sustain lower reserve margins than many other regions. This makes it important to ensure that the ERCOT market is designed to provide adequate economic signals to remain near this target, which is discussed below.

Figure 76: Reserve Margins in Other Regions



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 are continually increasing, 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 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. As discussed in the net revenue subsection, ancillary service payments are a small contributor: $5 - $10 per kW-year. Setting them 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” 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 produce a planning reserve margin that is less than the planning reserve target.

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 reserve margins should be closely monitored to determine whether shortage pricing alone is leading to the desired level of planning reserves.

VI. 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 2015. 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 2015.

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.[31] 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 as long as 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. The RDI also does not indicate whether it would have been profitable for a pivotal supplier to exercise market power. However,

[31] For the purpose of this analysis, "quick-start" includes off-line simple cycle gas 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.

it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

Figure 77 shows the ramp-constrained RDI relative to load for all hours in 2015. The trend line indicates a strong positive relationship between load and the RDI. The analysis shown below is done at the QSE level because the largest suppliers that determine the RDI values own a large majority of the resources they are offering. To the extent that the resources scheduled by the largest QSEs are not controlled by or provide revenue to the QSE, the RDIs will tend to be slightly overstated.

Figure 77: Residual Demand Index

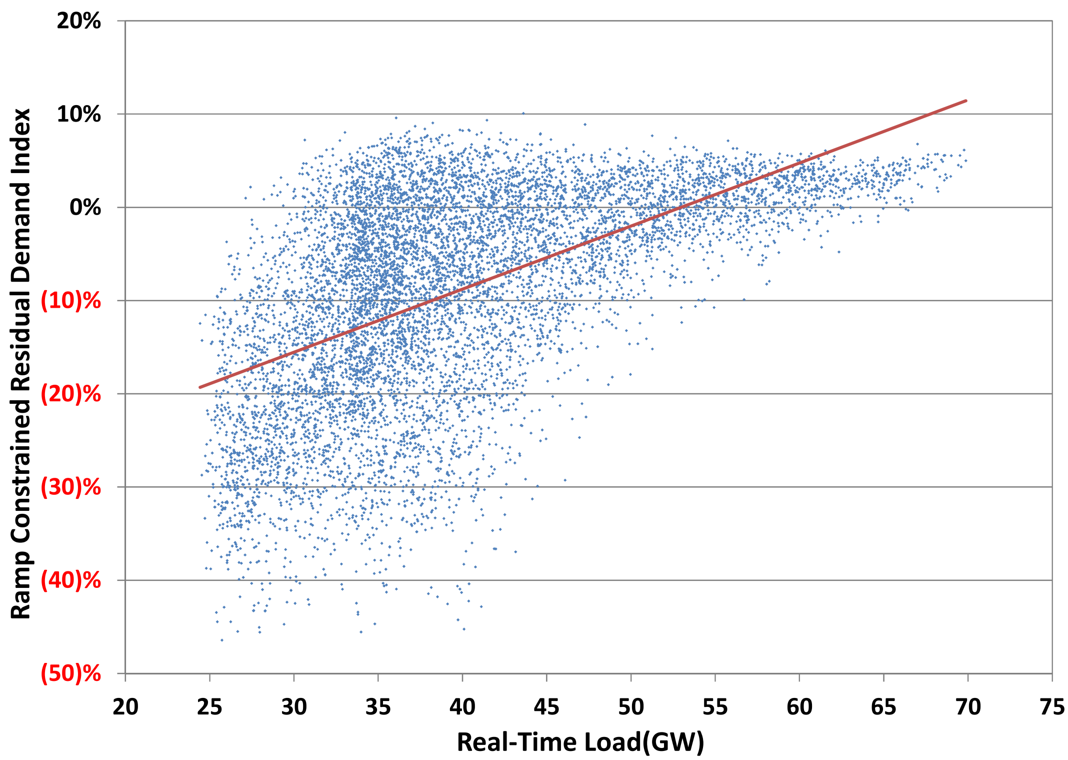
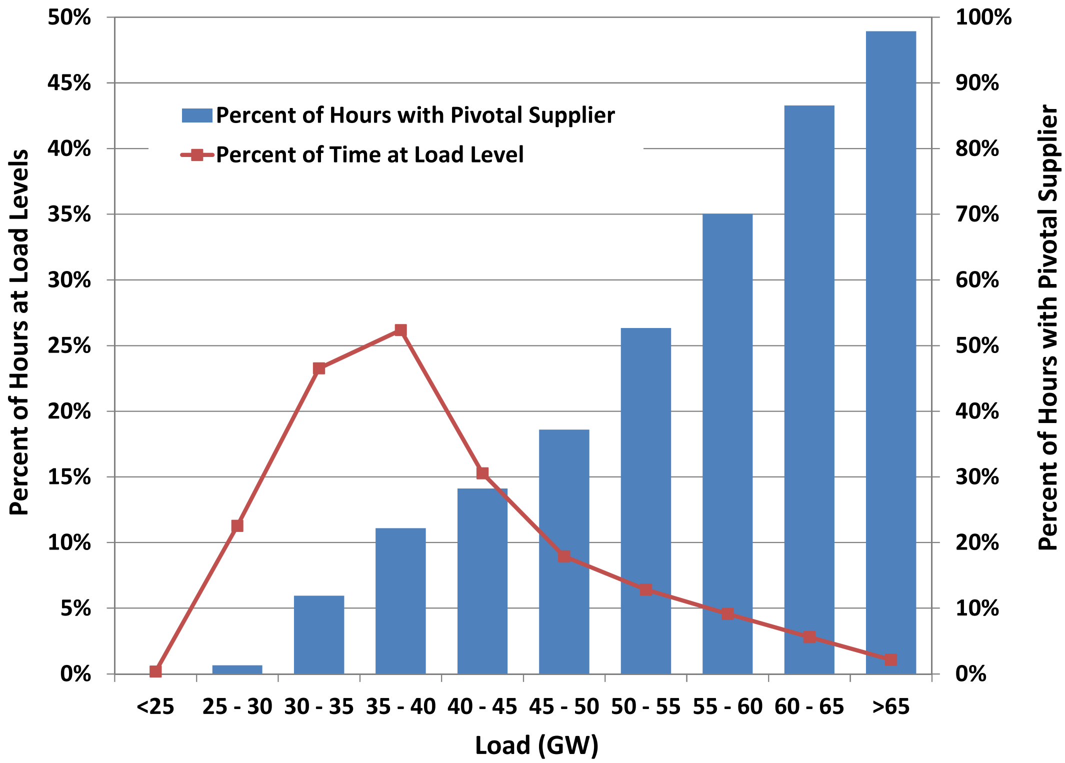


Figure 78 below summarizes the results of the RDI analysis by displaying the percent of time at each load level there was a pivotal supplier. The figure also displays the percentage of time each load level occurs.

Figure 78: Pivotal Supplier Frequency by Load Level



At loads greater than 65 GW there was a pivotal supplier 98 percent of the time. The occurrences of higher loads were more frequent in 2015 resulting in a pivotal supplier in approximately 26 percent of all hours of 2015, up from 23 percent of hours in 2014. This indicates that 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.

Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) existed for two market participants – NRG and Calpine – for the full year in 2015. In addition, the PUCT approved a VMP for Luminant in May 2015.[32] 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 TEX. ADMIN. CODE § 25.503(g)(7).

VMPs should promote competitive outcomes and prevent abuse of market power in the ERCOT real-time energy market through economic withholding. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market) because the price in forward energy markets is 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.

NRG's plan, initially approved in June 2012 and modified in May 2014,[33] allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12 percent of the difference between the high sustained limit and the low sustained limit – the dispatchable capacity – for each natural gas unit (5 percent for each coal/lignite unit) may be offered no higher than the higher of $500 per MWh or 50 times the natural gas price. Additionally, up to 3 percent 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.

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[32] 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).

[33] 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).

Calpine's VMP was approved in March of 2013.[34] Because its generation fleet consists entirely of natural-gas fueled combined cycle units, the details of the Calpine plan are somewhat different than NRG. Calpine may offer up to 10 percent of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5 percent 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.

The most recently approved VMP for Luminant is similar in many respects to the NRG plan. Under the VMP, Luminant is permitted to offer a maximum of 12 percent of the dispatchable capacity for natural gas units (5 percent for coal/lignite units) at prices up to $500 per MWh and offer a maximum of 3 percent of the dispatchable capacity for natural gas units up to the system-wide offer cap. The amount of capacity covered by these provisions is slightly more than 500 MW. In addition, the plan contains a maximum offer for Luminant's approximately 1000 MW of quick-start qualified combustion turbines based on unit-specific verifiable costs and index prices for fuel and emissions.

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 three VMPs contain a requirement that these offers, if offered in any hour of an operating day, must be offered in the same price/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 element in the VMPs is 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

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

possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition."[35] 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 percent of total ERCOT capacity, are granted under 16 TEX. ADMIN. CODE § 25.504(c). Although 5 percent of total ERCOT capacity may seem like a small amount, the potential market impacts of a market participant whose size is just under the 5 percent threshold choosing to exercise flexibility and offering a significant portion of their fleet at very high prices can be large.

The figure below shows the amount of surplus capacity available in each hour of every day from 2011 to 2015. For this analysis, surplus capacity is defined as online generation plus any offline capacity that was available day ahead, plus DC Tie imports (minus exports), minus responsive reserves provided by generation, regulation up capacity, and load. Over the past five years, there were 13 hours with no surplus capacity, with all but one hour occurring in 2011. These correspond to times when ERCOT was unable to meet load and maintain all operating reserve obligations.

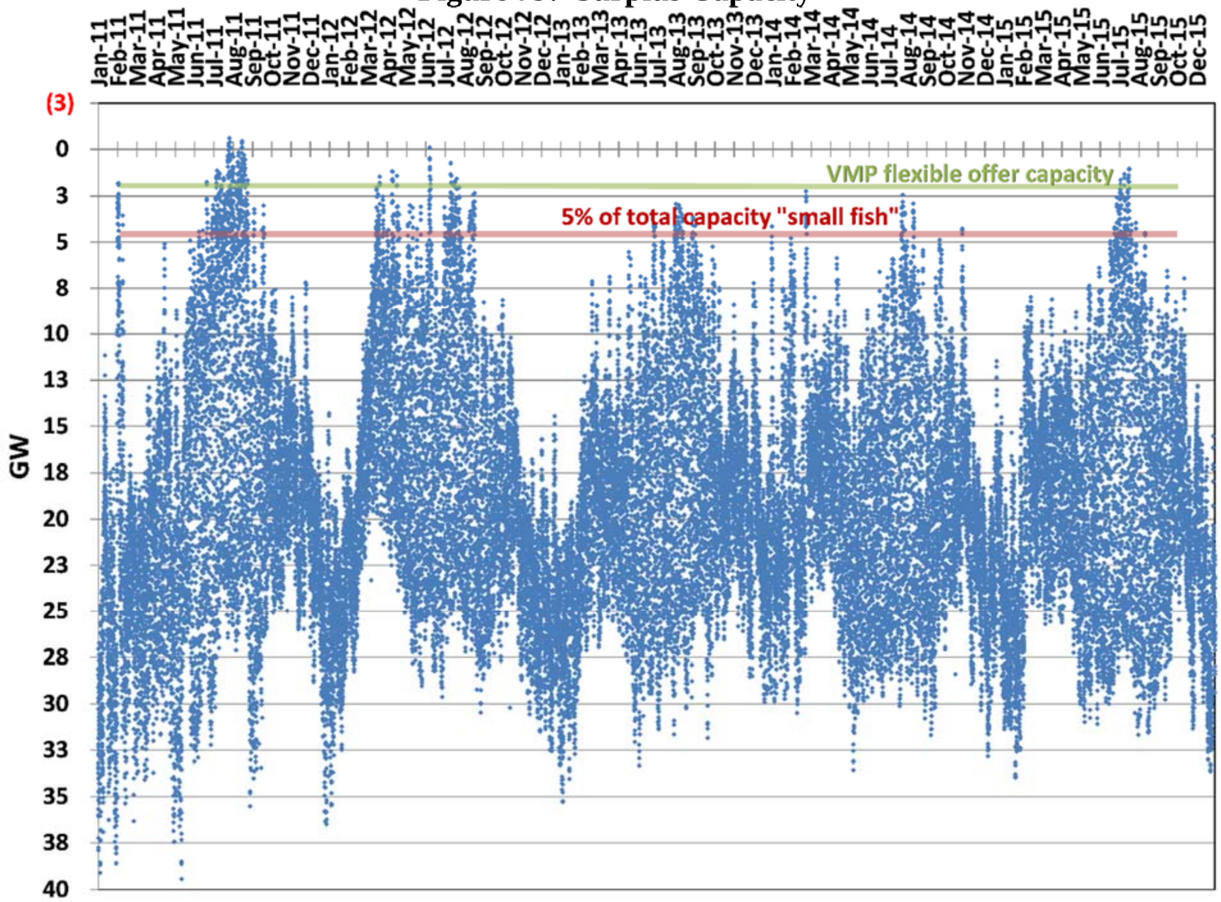
Currently, the 5 percent "small fish" threshold is roughly 4,000 MW, as indicated by the red line in Figure 79. There were 547 hours over the past five years with less than 4,000 MW of surplus capacity.[36] During these times a large "small fish" would have been pivotal and able to increase the market clearing price through its offer, potentially as high as the system-wide offer cap. In

35 PURA § 39.157(a).

36 Surplus capacity was less than 4,000 MW for 296 hours in 2011, 154 hours in 2012, 15 hours in 2013, 26 hours in 2014, and 56 hours in 2015.

contrast, the combined amount of capacity afforded offer flexibility under the VMPs granted to NRG, Calpine, and Luminant totals less than 1,800 MW of capacity. This amount of capacity would have been pivotal for a total of 120 hours across the past five years.

Figure 79: Surplus Capacity



The effects of such actions became much more pronounced after June 21, 2013 when changes to real-time mitigation measures went into effect. These changes narrowed the scope of mitigation addressing the concern that mitigation measures were being applied much more broadly than intended or necessary in the ERCOT real-time energy market.[37] Although "small fish" market participants have always been allowed to offer all capacity at prices up to the system-wide offer cap, the effect on market outcomes of a large "small fish" offering substantial quantities at high prices became more noticeable after the scope of mitigation was narrowed.

[37] Refer to Section I.F. Mitigation.

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. In this subsection actual participant conduct is evaluated 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.

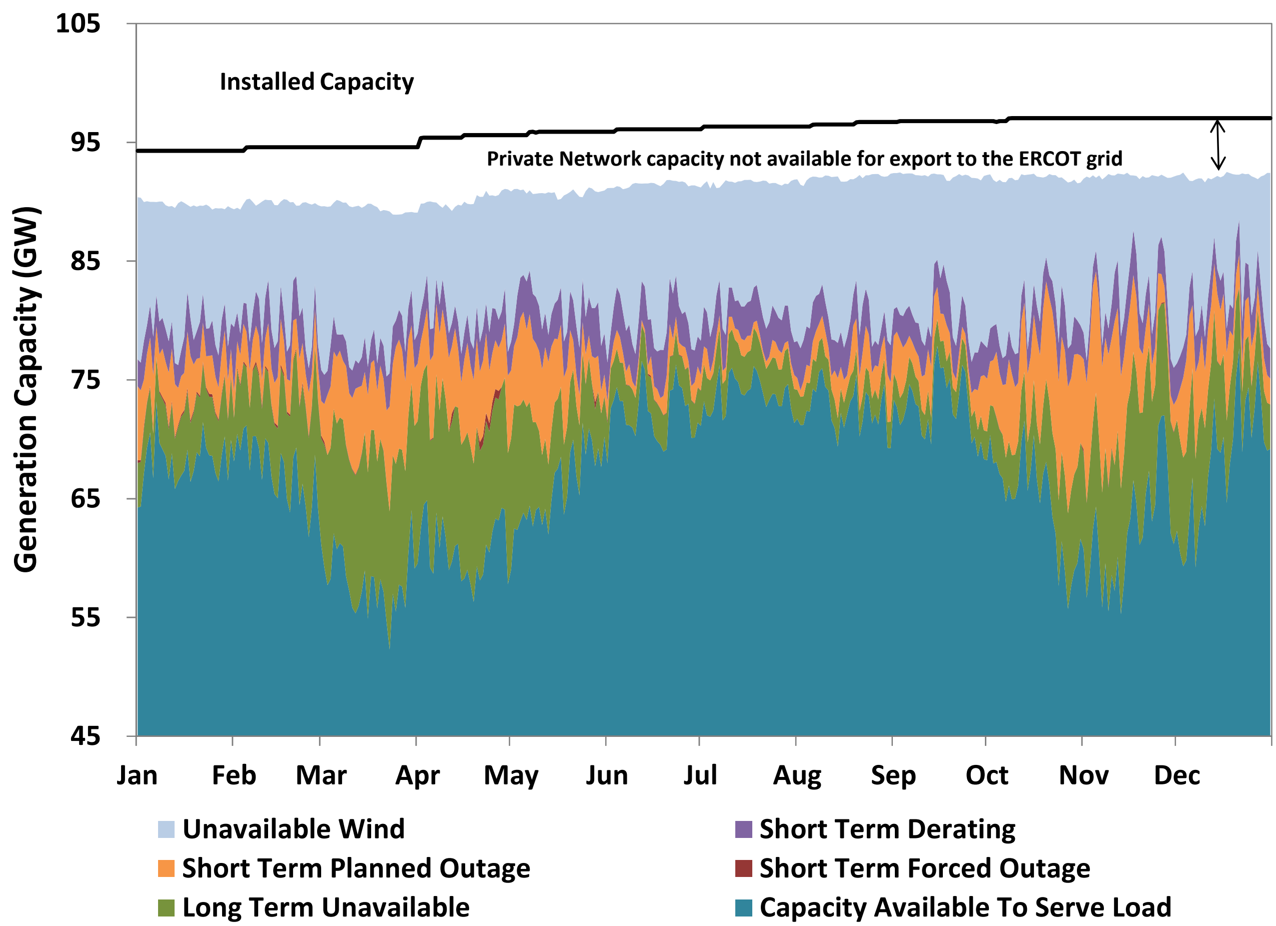
In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher market clearing prices, allowing the supplier to profit on its other sales in the real-time 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 due to higher price is greater than the lost profit from the foregone sales of its withheld capacity.

1. Generation Outages and Deratings

Some portion of installed capacity is commonly unavailable because of generator outages and deratings. Due to 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 outages. 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 (e.g., by 5 to 10 percent) because the resource cannot achieve its installed capacity level due to technical or environmental factors (e.g., component equipment failures or ambient temperature conditions). Wind generators rarely produce at the installed capacity rating due to 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 80 shows a breakdown of total installed capacity for ERCOT on a daily basis during 2015. 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 due to 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 80: Reductions in Installed Capacity



Outages and deratings of non-wind generators fluctuated between 5 and 26 GW, as shown in Figure 80, while wind unavailability varied between 4 and 16 GW. Short-term planned outages were largest between mid-October and mid-November, and smallest during the summer months, which is consistent with expectations. Short-term forced outages also declined during the summer months. Short-term deratings peaked during October.

The quantity of long-term (greater than 30 days) unavailable capacity, peaked in March at 11.2 GW, reduced to less than 1.5 GW during the summer months, and increased to almost 9.2 GW in November. This pattern reflects the choice by some owners to mothball certain units on a seasonal basis, maintaining the units' operational status only during the high load summer season when more costly units have a higher likelihood of operating.

The next analysis focuses specifically on short-term planned and forced outages and deratings 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 81 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2015.

Figure 81: Short-Term Outages and Deratings

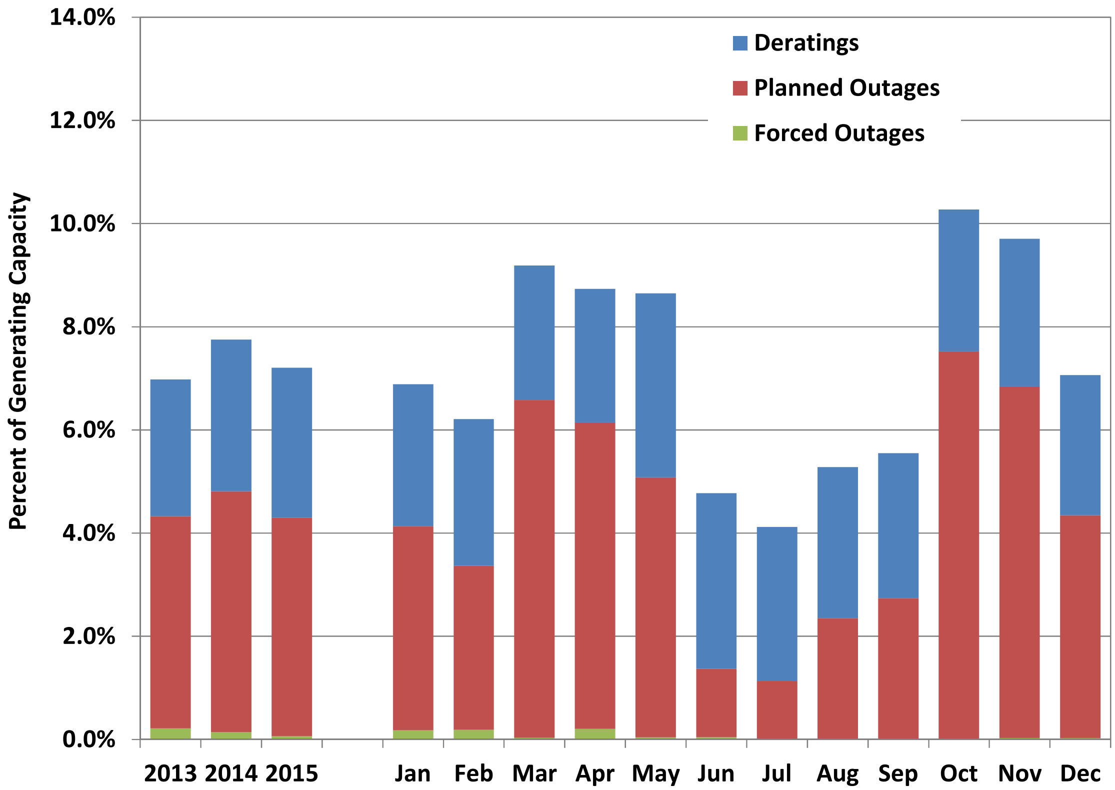


Figure 81 shows that total short-term deratings and outages were as large as 10.3 percent of installed capacity in October, and averaged less than 5 percent during the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2015 averaged 7.2 percent of installed capacity. This is a slight decline from 7.8 experienced in 2014 and an increase from the 7.0 percent experienced in 2013. Overall, the fact that outages and deratings are lowest during the summer when load is expected to be highest is consistent with expectations in a competitive market.

2. 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 77 and Figure 78 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 since their output is generally most profitable in peak periods.

Figure 82 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load level for large and small suppliers. 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 82: Outages and Deratings by Load Level and Participant Size June to August, 2015

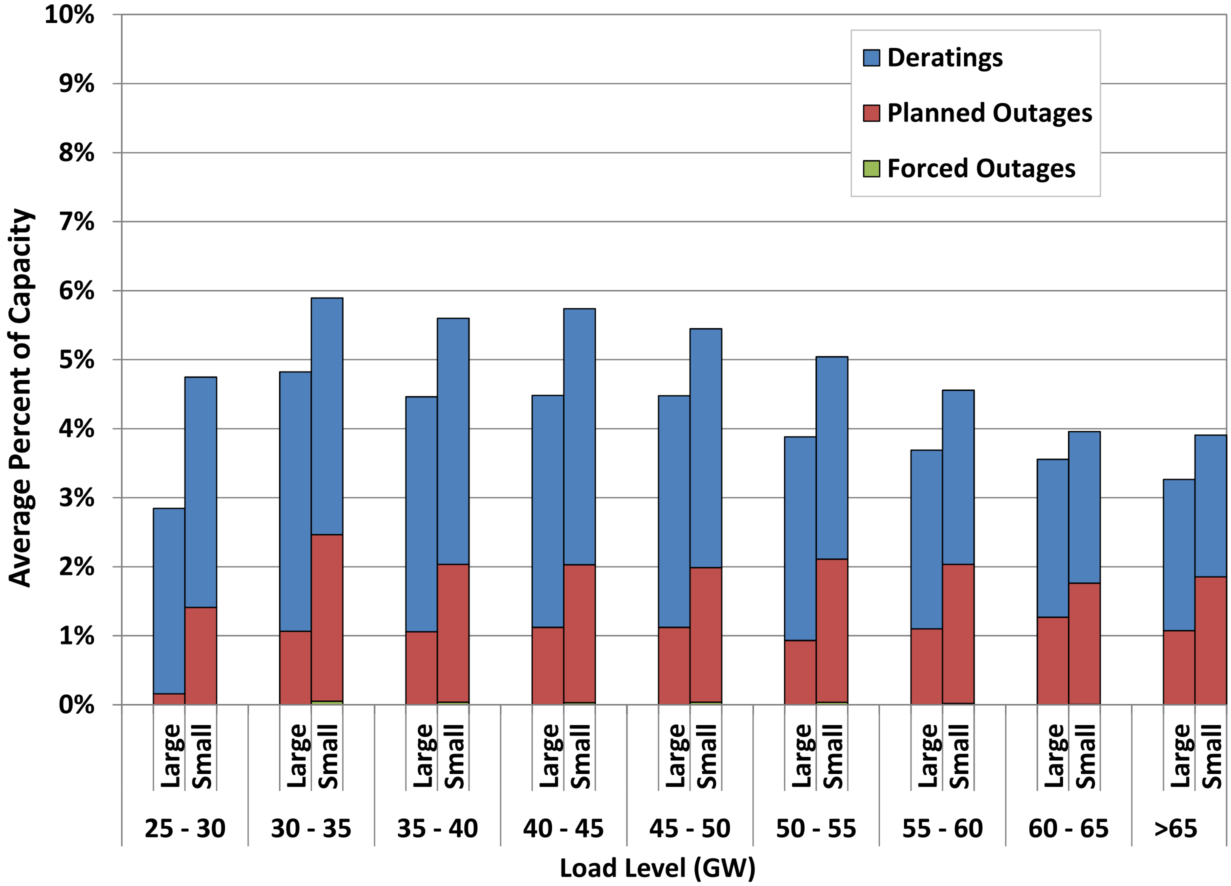


Figure 82 suggests that as demand for electricity increases, all market participants tend to make more capacity available to the market. For large suppliers, the combined short-term derating and forced outage rates decreased from 5 percent at low demand levels to approximately 3.5 percent at load levels above 65 GW. Rates for small participants also declined at higher loads. Outage rates for large participants were lower than those of small participants across all load levels. Since 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. Hence, these results do not raise potential competitive concerns.

3. 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 defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic 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.

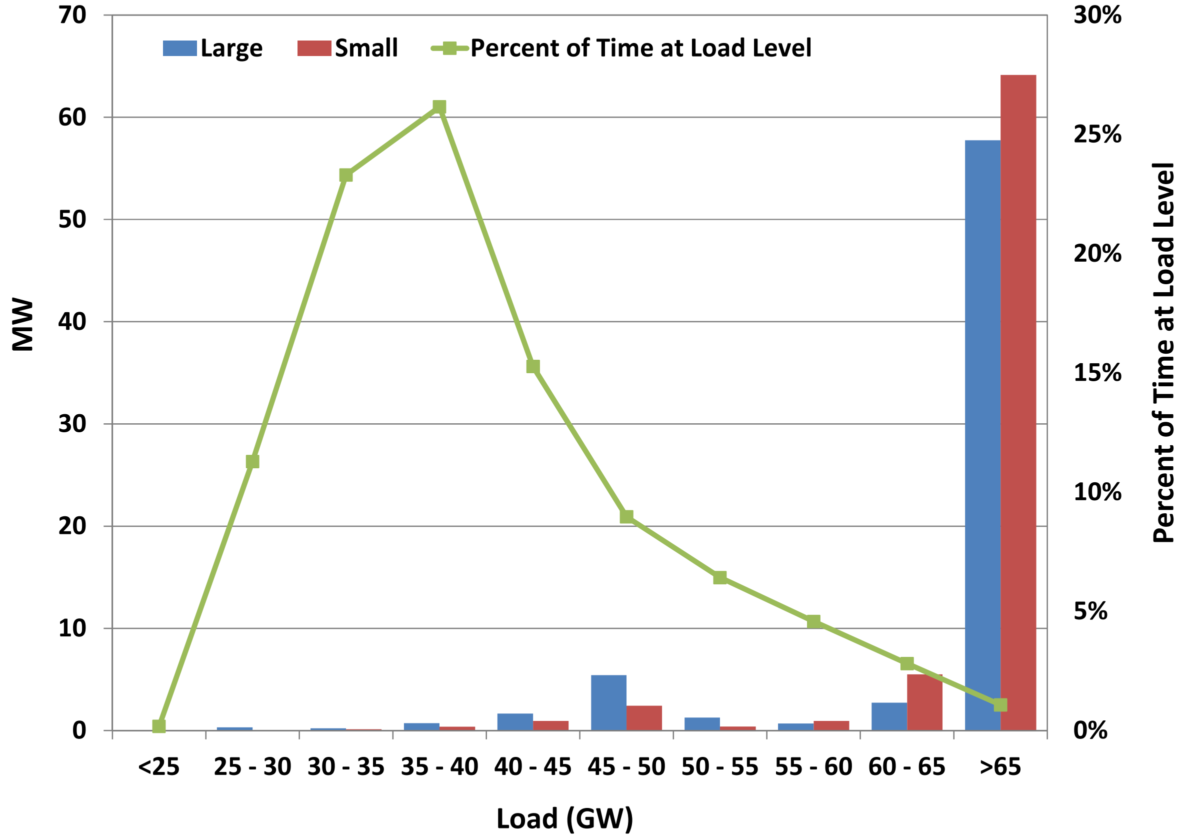
A resource is evaluated for inclusion in the output gap when it is committed and producing at less than full output. Energy not produced from a committed resource is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $30 per MWh.[38] The mitigated 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.

[38] Given the low energy prices during 2015, the output gap margin was reduced to $30 for purposes of this analysis. In past years, the State of the Market report used $50 for the output gap margin.

Figure 83: Incremental Output Gap by Load Level and Participant Size – Step 1

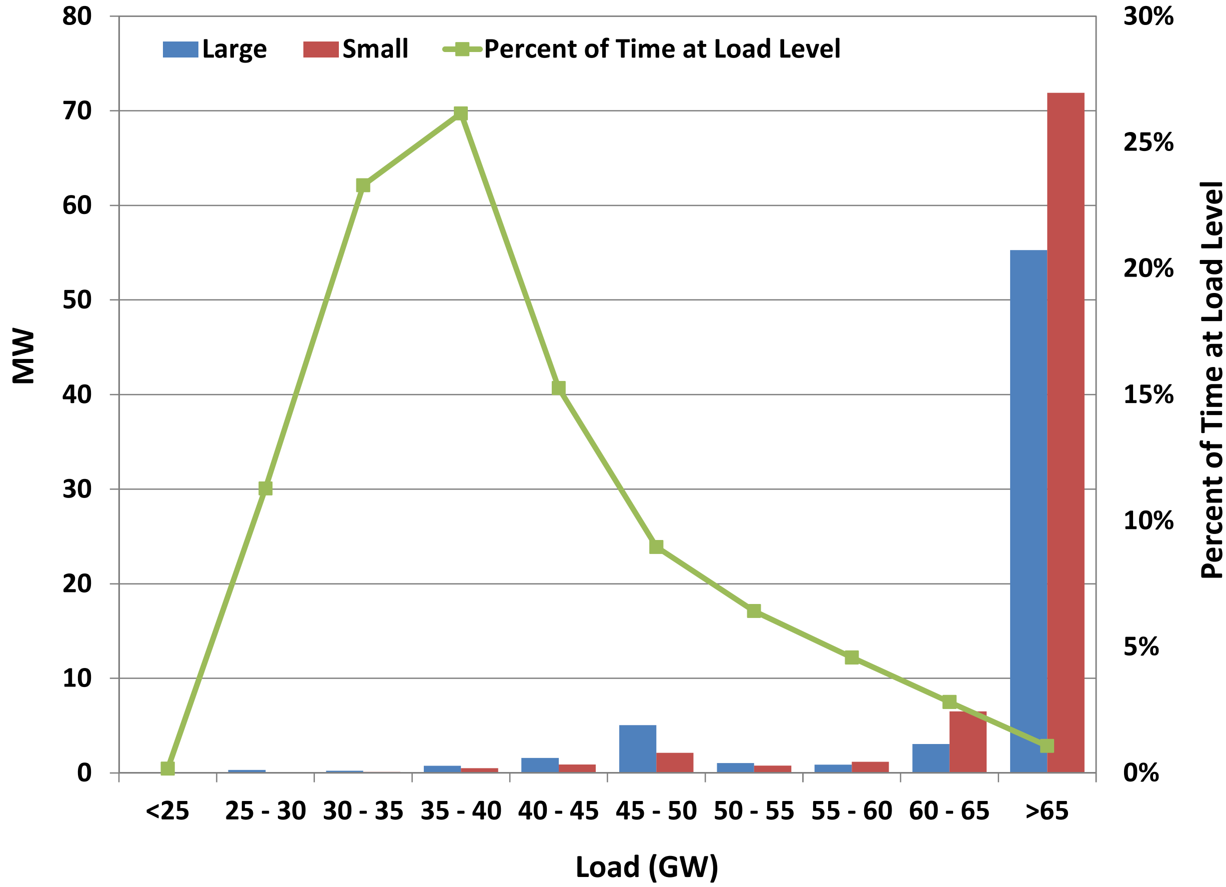


The results of the analysis shown in Figure 83 indicate that only very small amounts of capacity would be considered part of the first step output gap.

Figure 84 shows the ultimate output gap, 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 84 also shows very small quantities of capacity that would be considered part of this output gap.

Figure 84: Incremental Output Gap by Load Level and Participant Size – Step 2



The output gap of several of the largest suppliers were also examined for 2015, and unlike the findings in 2013, found to be consistently low for the largest suppliers 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 2015.