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2015 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

June 2016

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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:

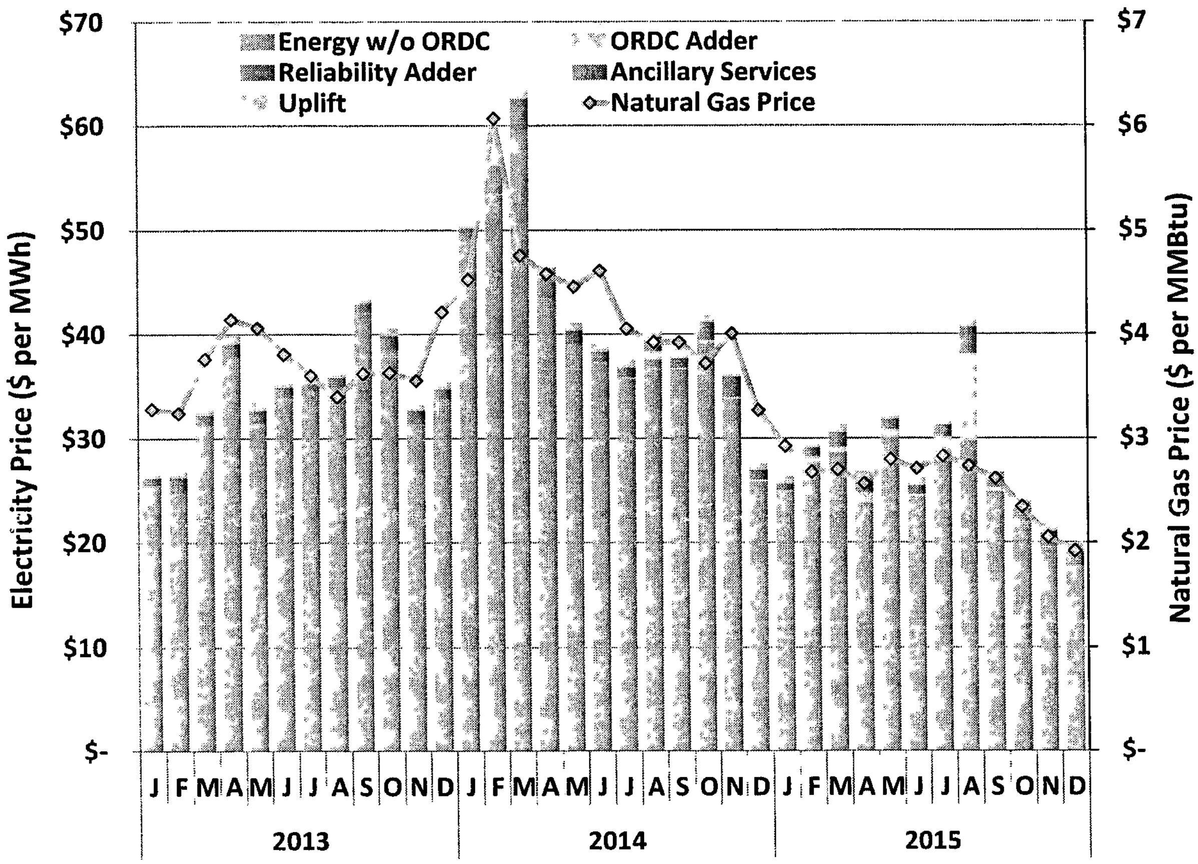
- The ERCOT wholesale market performed competitively in 2015.
- The ERCOT-wide load-weighted average real-time energy price was $26.77 per MWh in 2015, a 34 percent decrease from 2014 primarily driven by lower natural gas prices.
  - The average price for natural gas was 41 percent lower in 2015 than 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

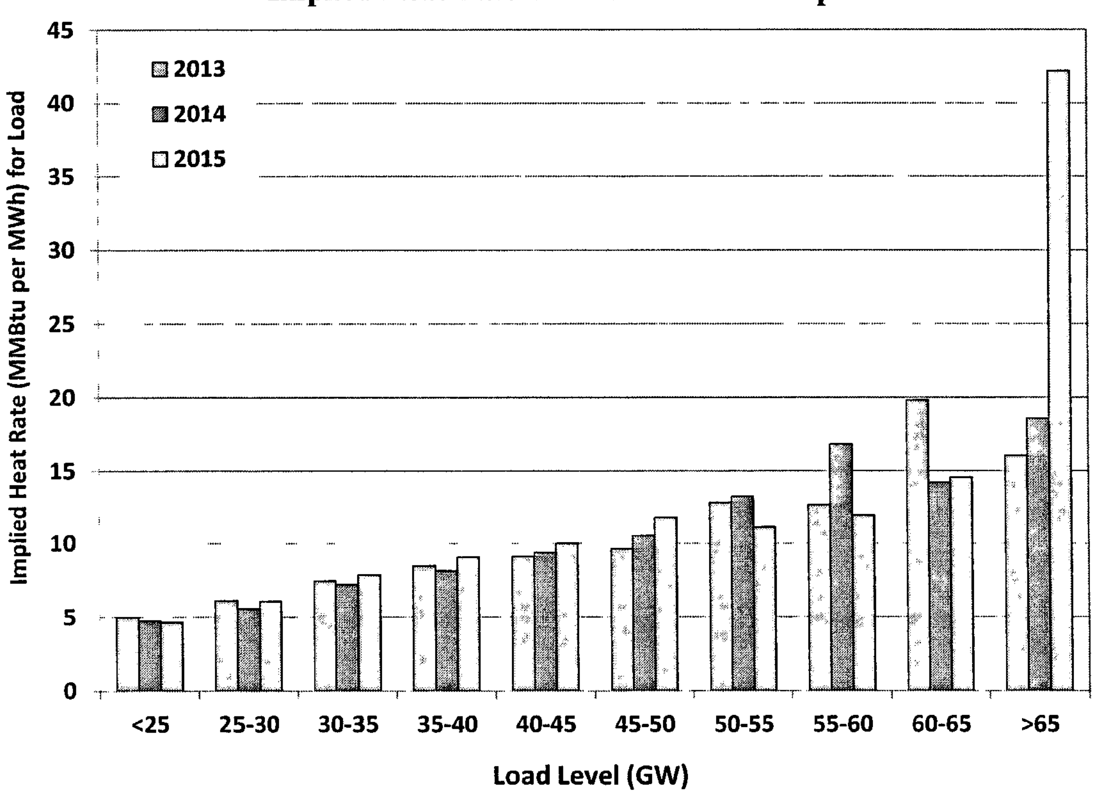
[1] For this analysis uplift includes: Reliability Unit Commitment Settlement, Operating Reserve Demand Curve (ORDC) Settlement, Revenue Neutrality Total, Emergency Energy Charges, Base Point Deviation Payments, Emergency Response Service (ERS) Settlement, Black Start Service Settlement, ERCOT Administrative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

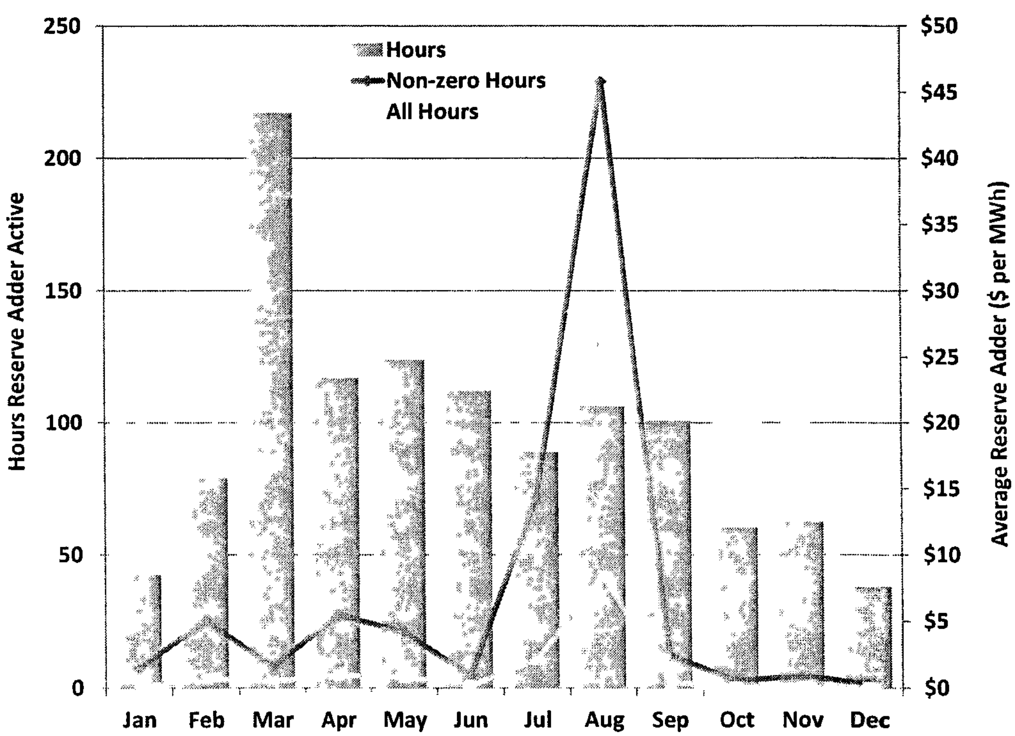
Implied Heat Rate and Load Relationship



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

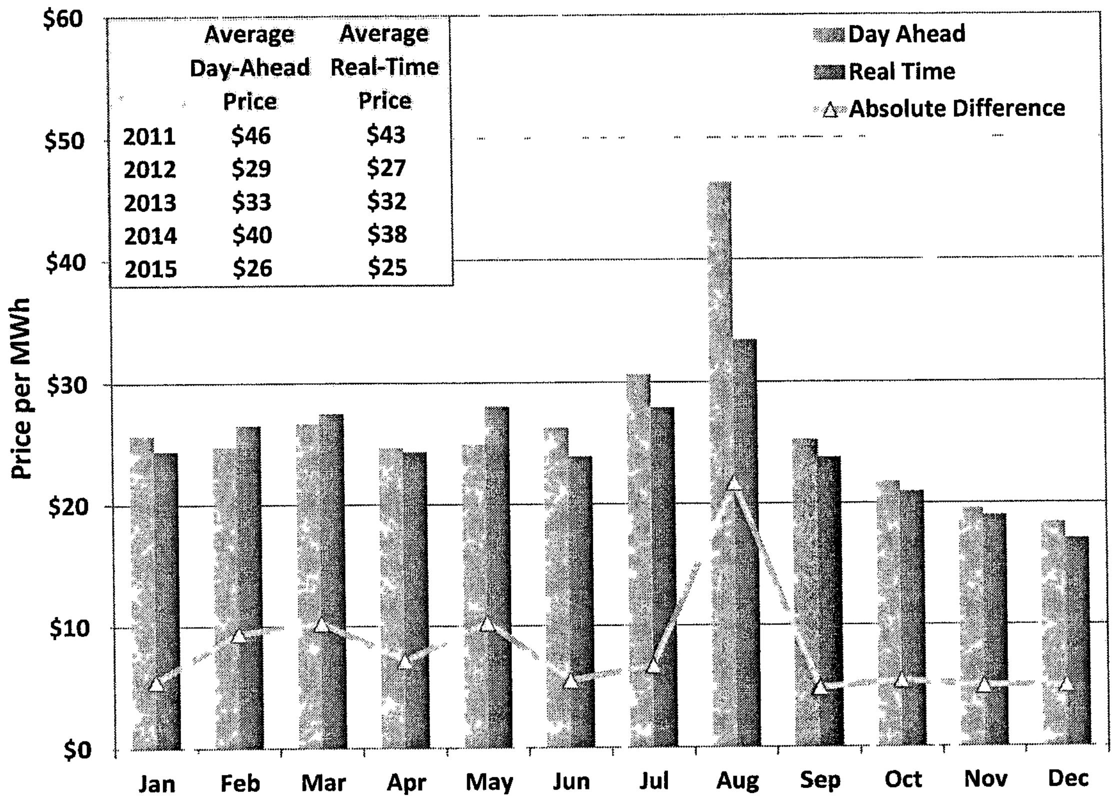
ERCOT's day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Although all bids and offers are evaluated in the context of the ability for them to reliably flow on the transmission network, there are no operational obligations 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

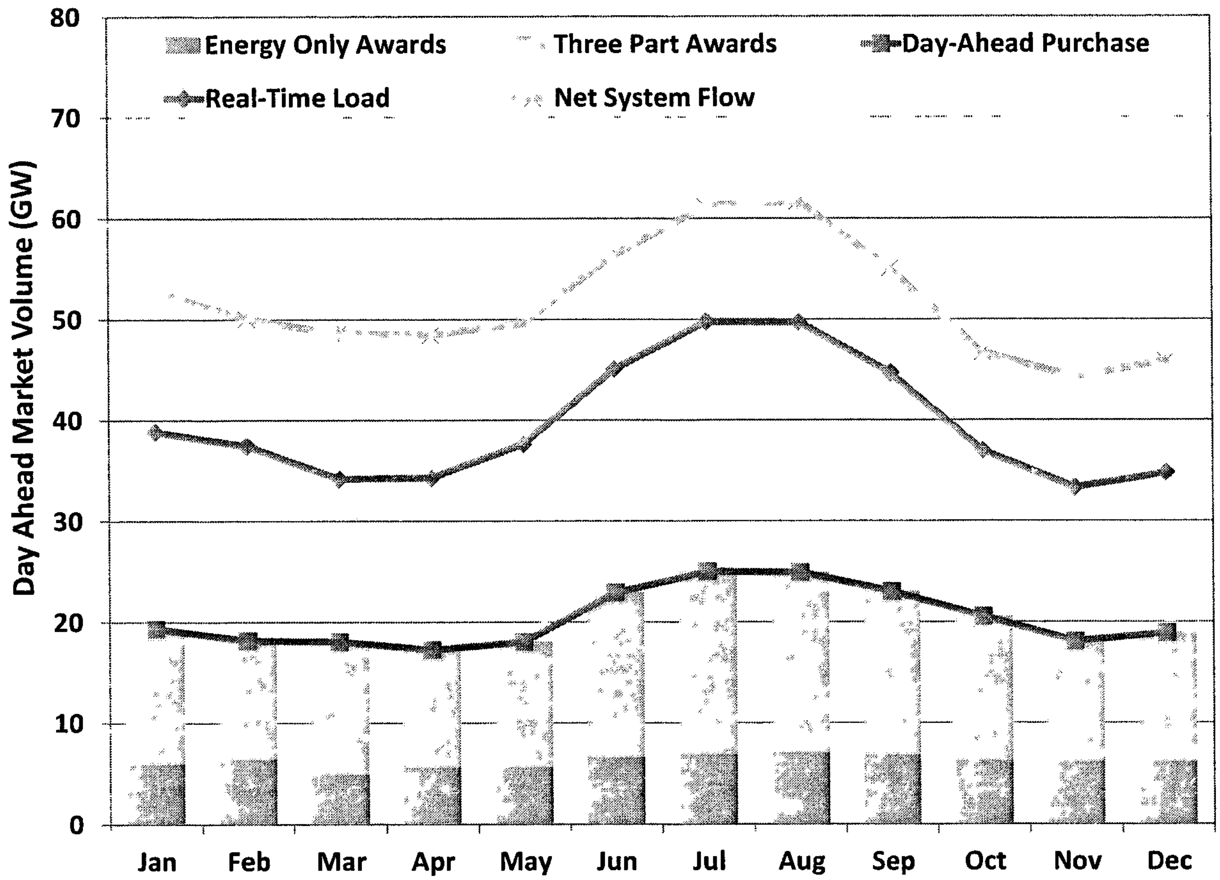


This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead market and higher for generators selling day ahead. The higher risk for generators is associated with the potential of incurring a forced outage 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

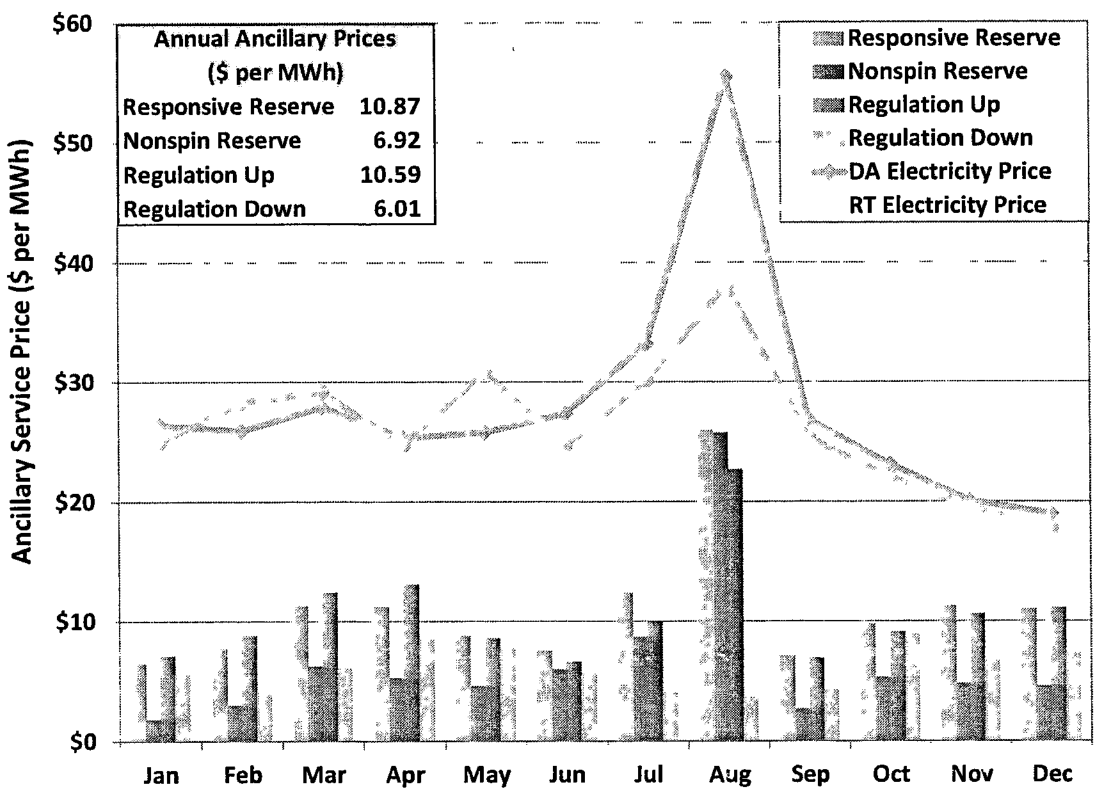


Adding the aggregated transfer capacity associated with purchases of PTP Obligations to the other injections and withdrawals demonstrates that net system flow volume transacted in the day-ahead market exceeds real-time load by approximately 30 percent. The volume in excess of real-time load increased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

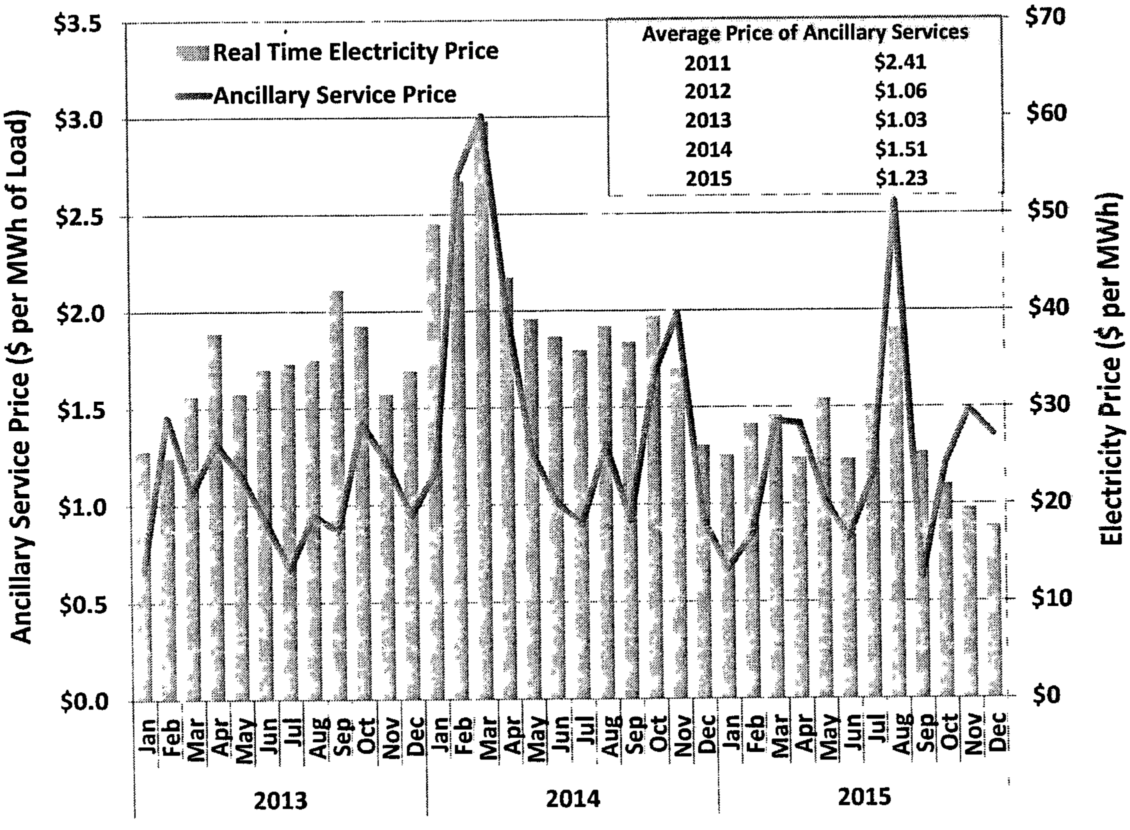


Total ancillary service costs are generally correlated with day-ahead and real-time energy price movements, which occur for two primary reasons. First, higher energy prices increase the opportunity costs of providing reserves and therefore can contribute to higher ancillary service prices. Second, shortages 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

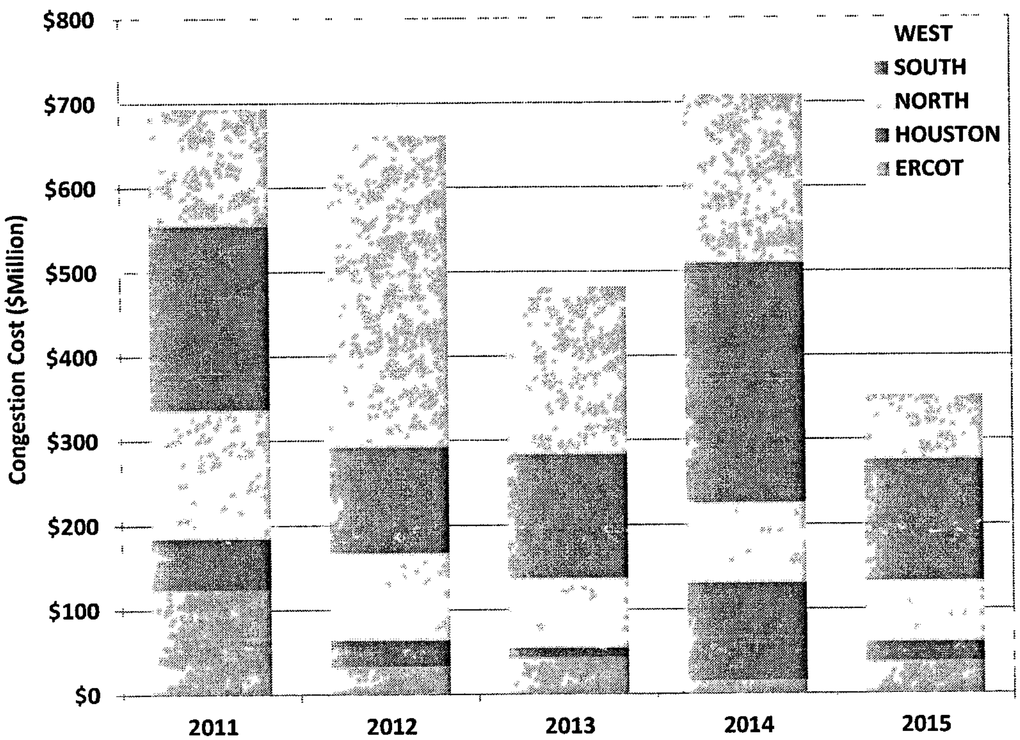


In absolute terms, the average ancillary service cost per MWh of load decreased to $1.23 per MWh in 2015 compared to $1.51 per MWh in 2014. Although the reduction in ancillary service prices and energy prices were both primarily caused by lower natural gas prices, the reduction in ancillary service prices 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

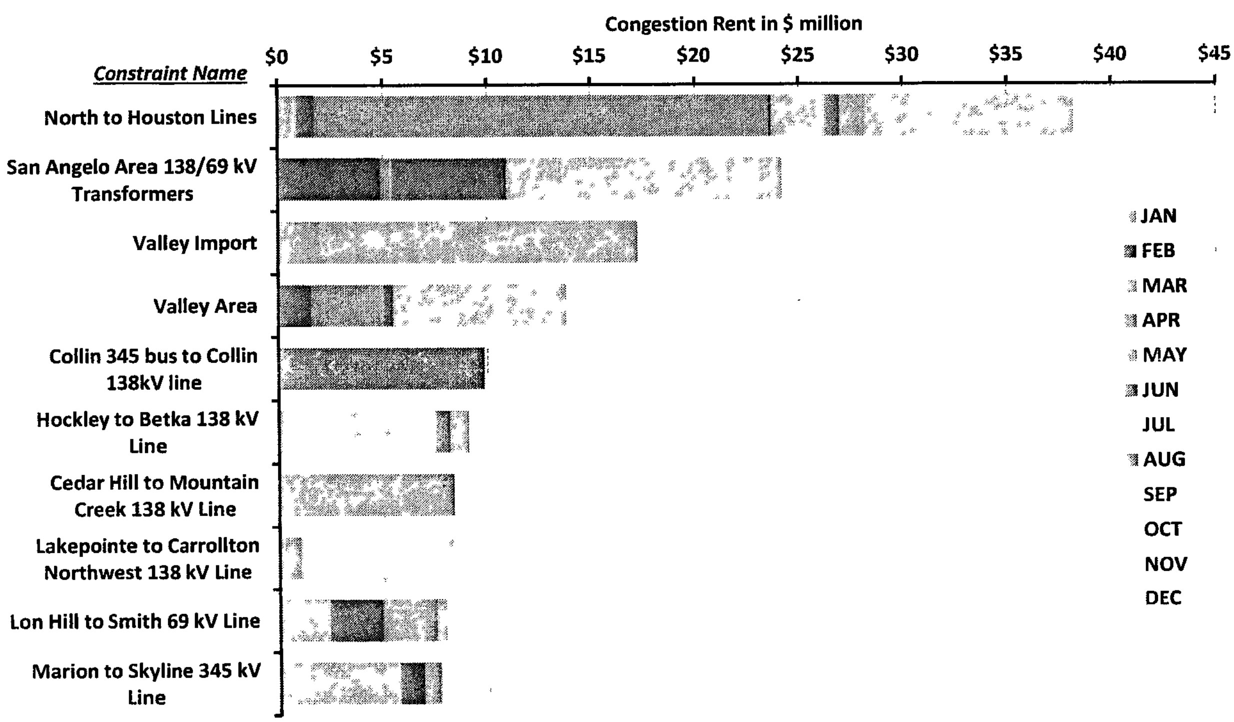


While cross zonal congestion is higher in 2015 than 2014, all other intra-zonal congestion costs have decreased. Annual congestion costs in 2015 were the lowest since the start of the nodal market. This is largely due the significant reduction in natural gas prices and the cumulative benefits of large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

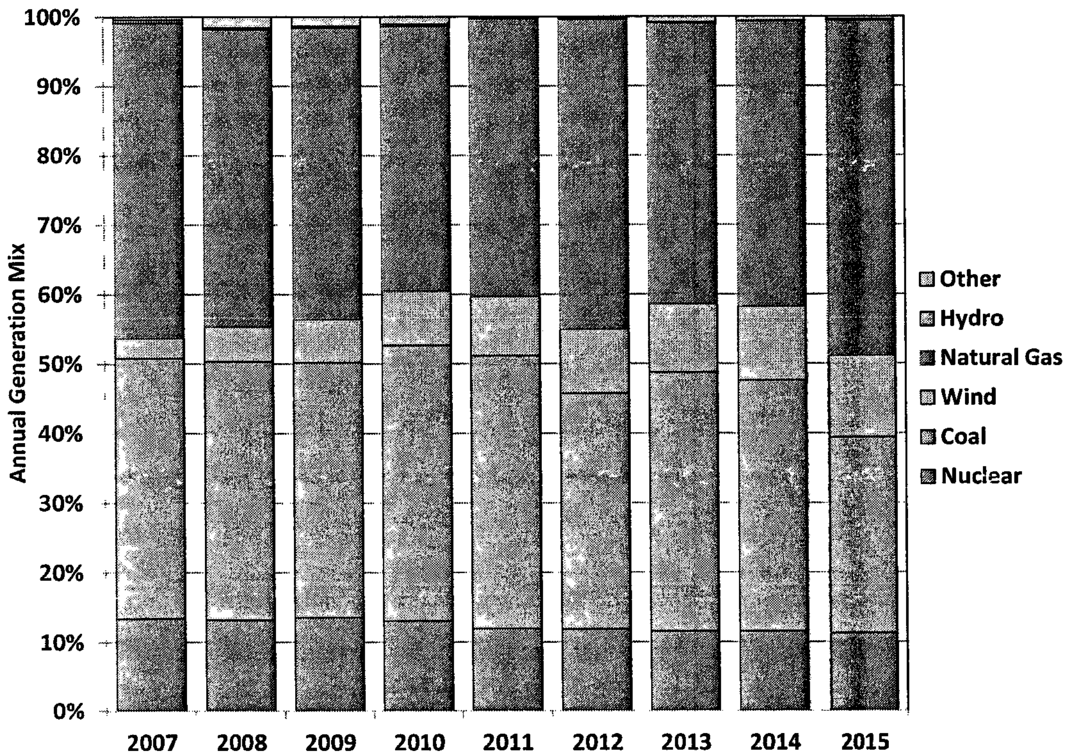
The changes in load at the zonal level are not the same as the ERCOT-wide changes. The growth rate of West zone average load was once again much higher, on a percentage basis, than the other zones because of increased oil and gas production activity in this area. While all zones saw an increase in the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

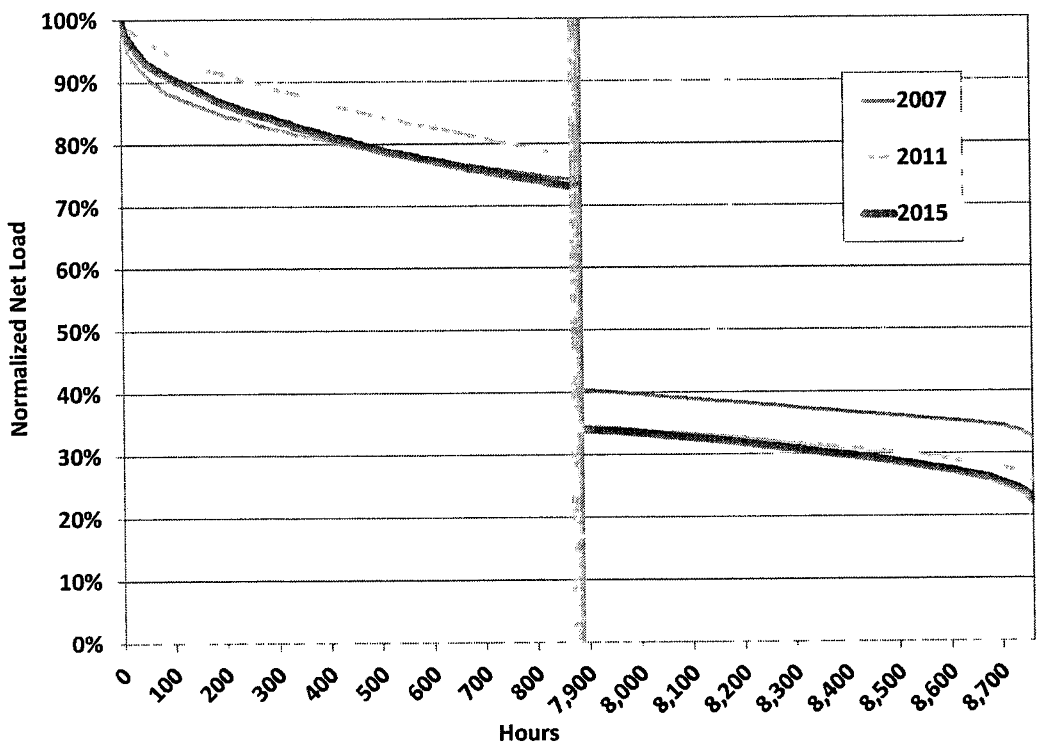


The generation share from wind has increased every year, reaching 12 percent of the annual generation requirement in 2015, up from 3 percent in 2007. The 2015 generation share saw a record high for natural gas and a record low for coal. In 2015 the percentage of generation from natural gas was 48 percent, 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.

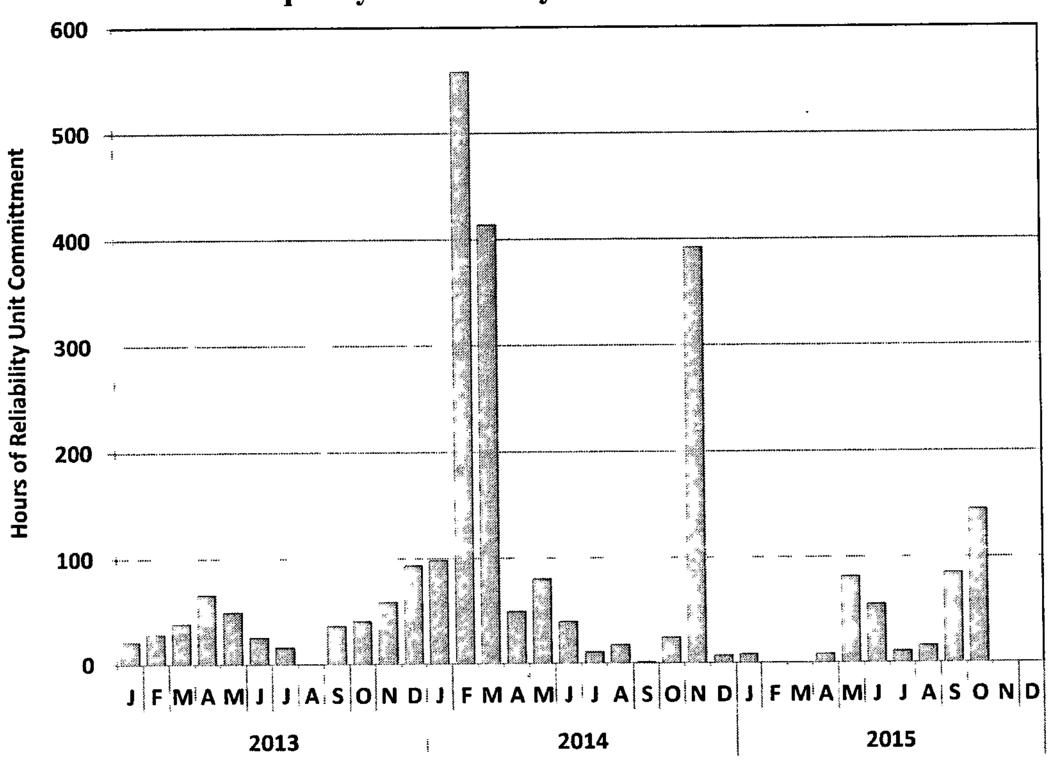
Resource Commitments for Reliability

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.

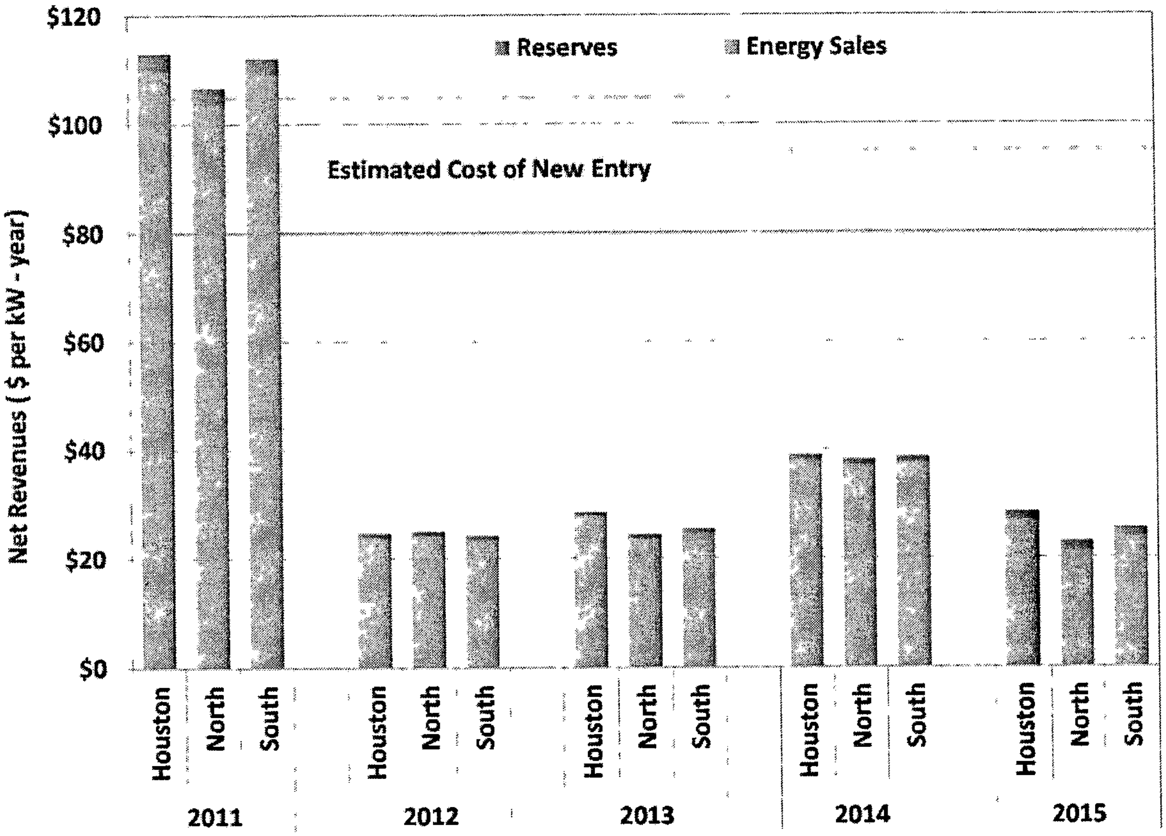
In 2015, such commitments were most frequent in the fall due to congestion in Dallas and the Rio Grande Valley.

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.

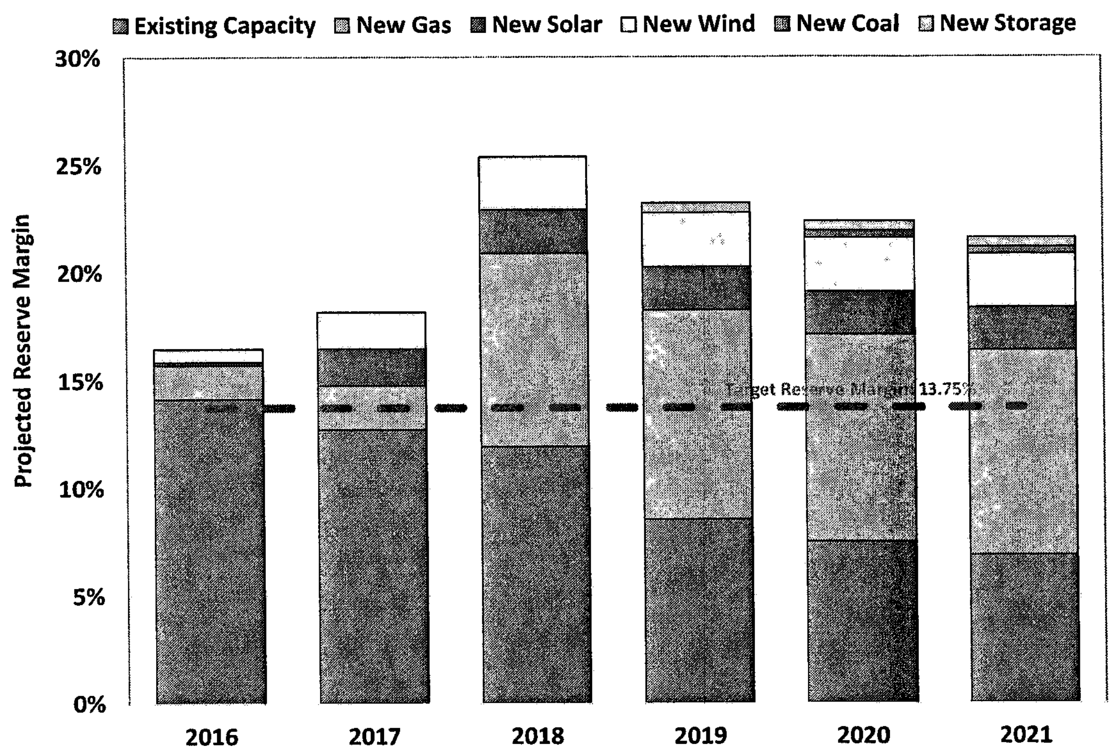
Given the very low energy prices during 2015 in non-shortage hours, the economic viability of existing coal and nuclear units was evaluated. The prices in these hours, which have been substantially affected by the prevailing natural gas prices, determine the vast majority of the net revenues received 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).

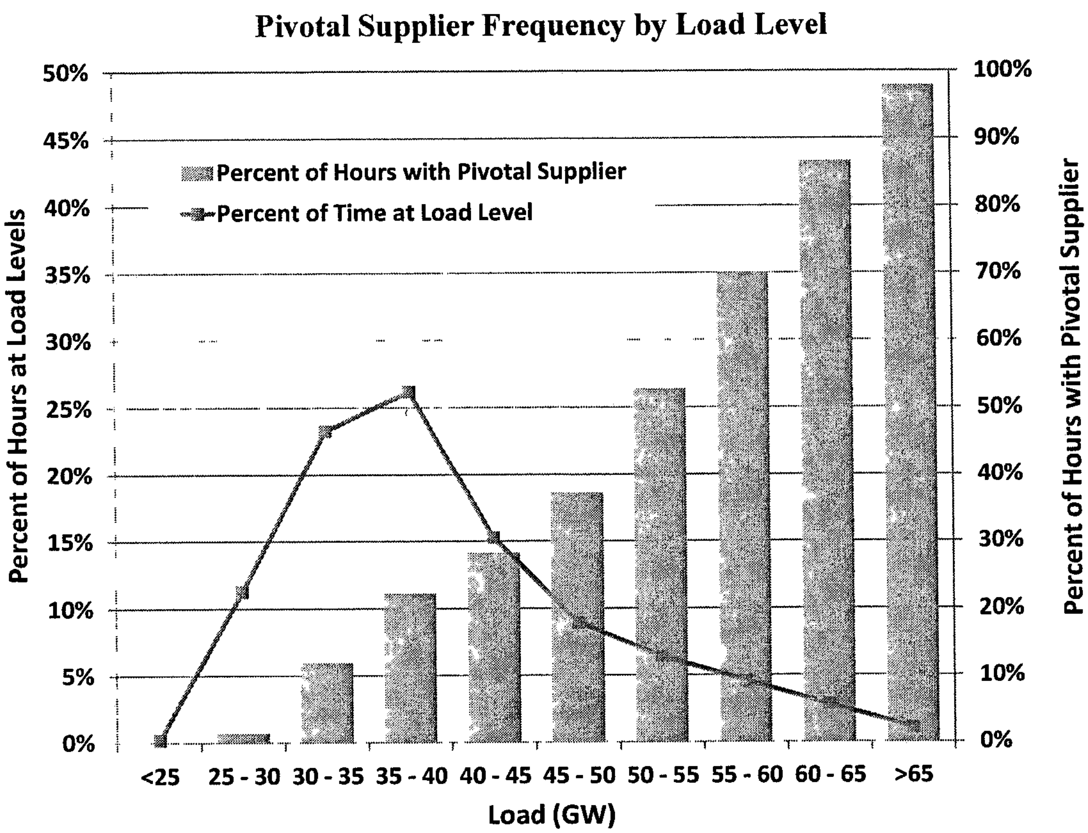
1. Structural Market Power

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.

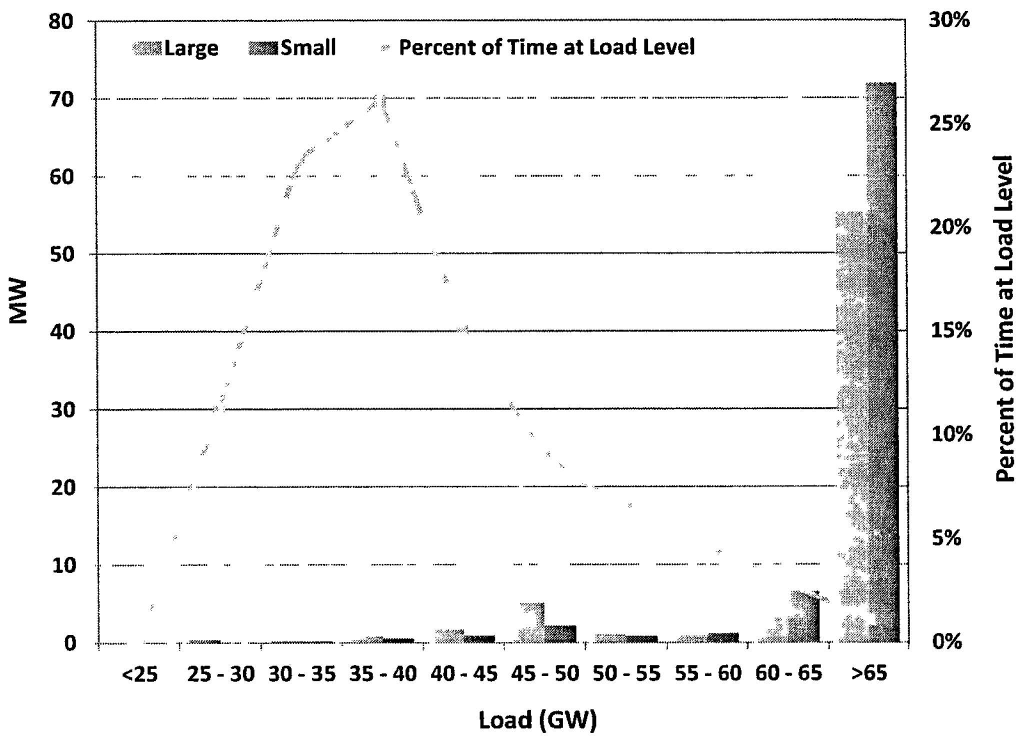
2. Evaluation of Conduct

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. 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.

   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

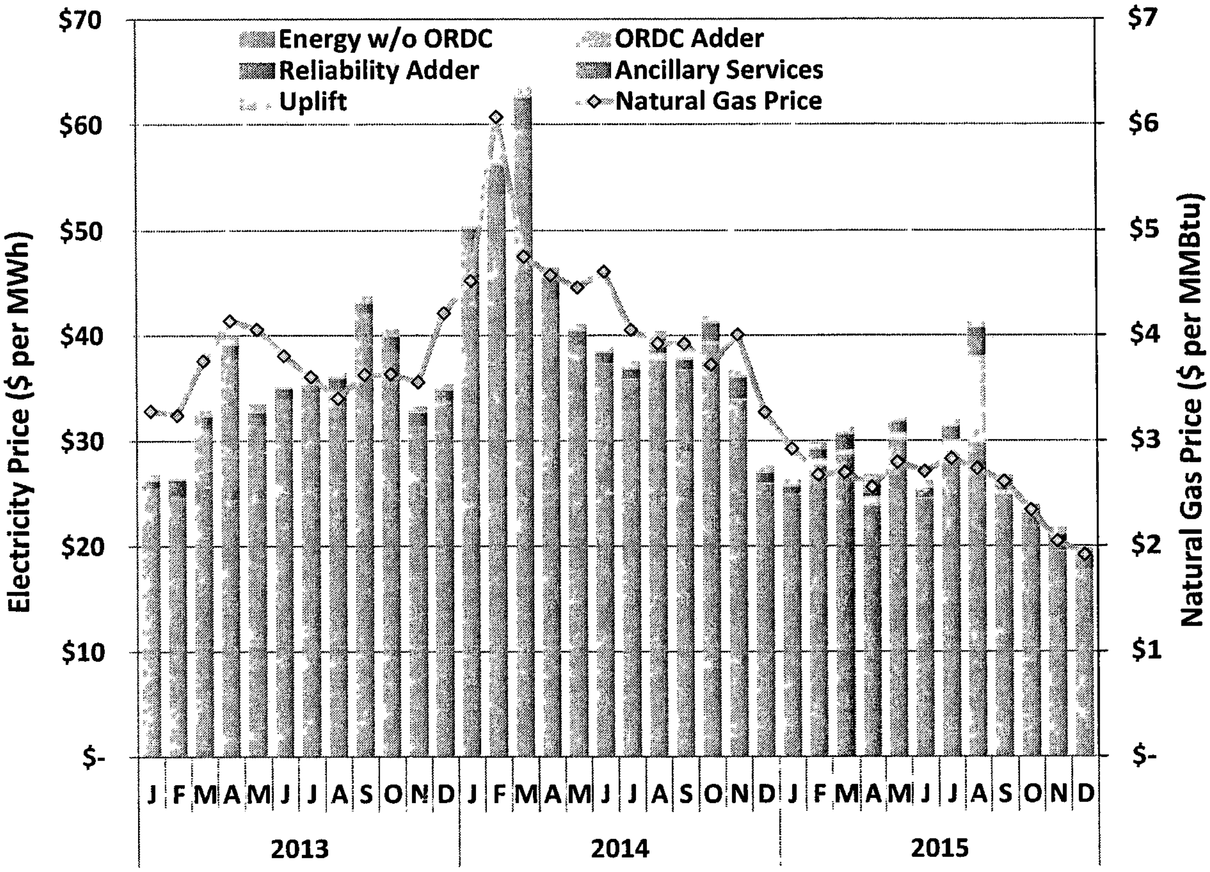
The first analysis evaluates the total cost of supplying energy to serve load in the ERCOT wholesale market. In addition to the costs of energy, loads incur costs associated with ancillary services and a variety of non-market based expenses referred to as "uplift." An average "all-in" price of electricity 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

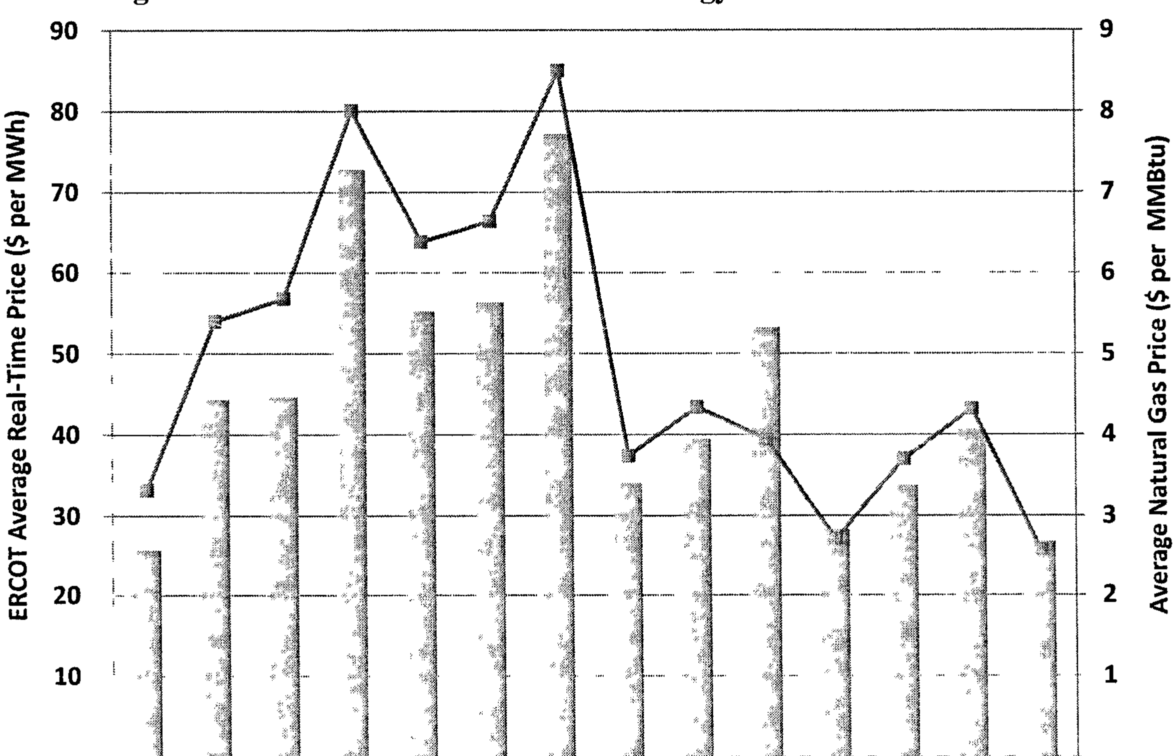


This figure indicates that natural gas prices continued to be a primary driver of electricity prices during this period. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a 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

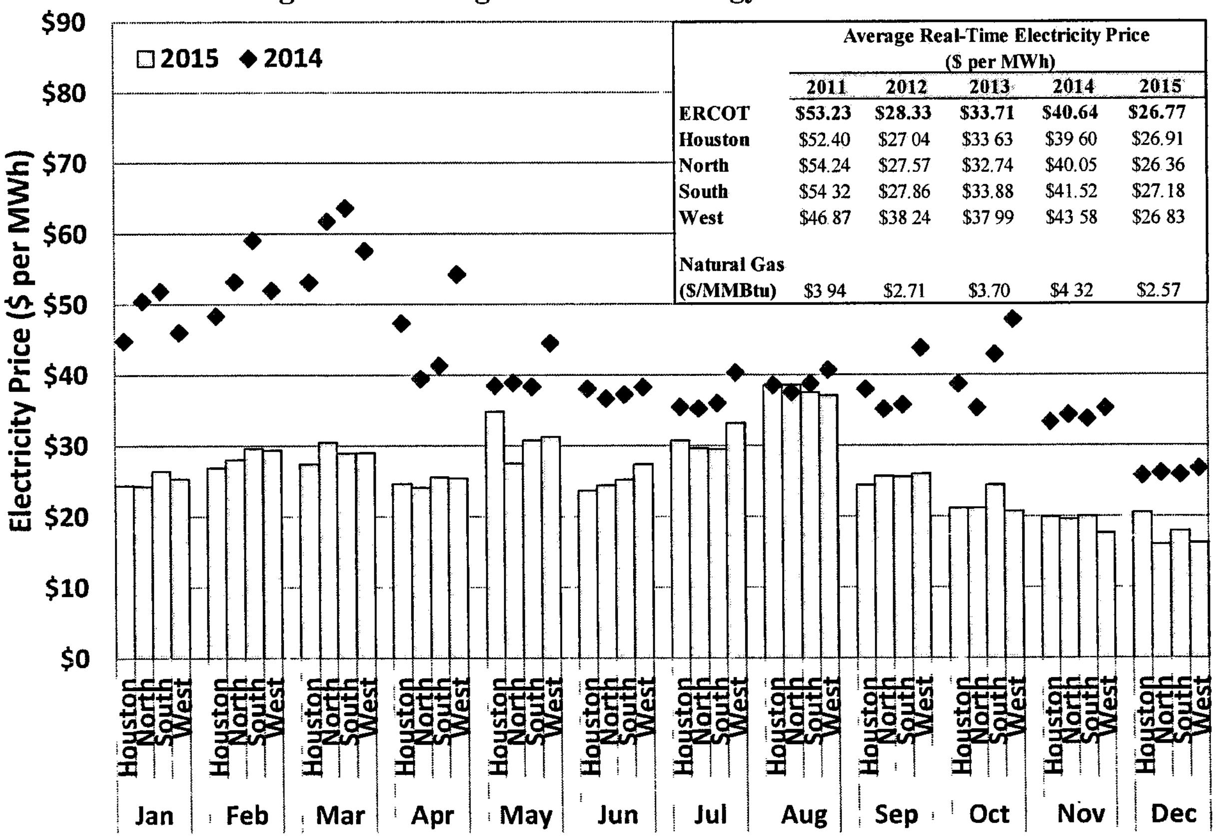


	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ERCOT	25.64	44.26	44.64	72.79	55.22	56.35	77.19	34.03	39.40	53.23	28.33	33.71	40.64	26.77
Gas	3.32	5.40	5.68	8.01	6.38	6.64	8.50	3.74	4.34	3.94	2.71	3.70	4.32	2.57

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

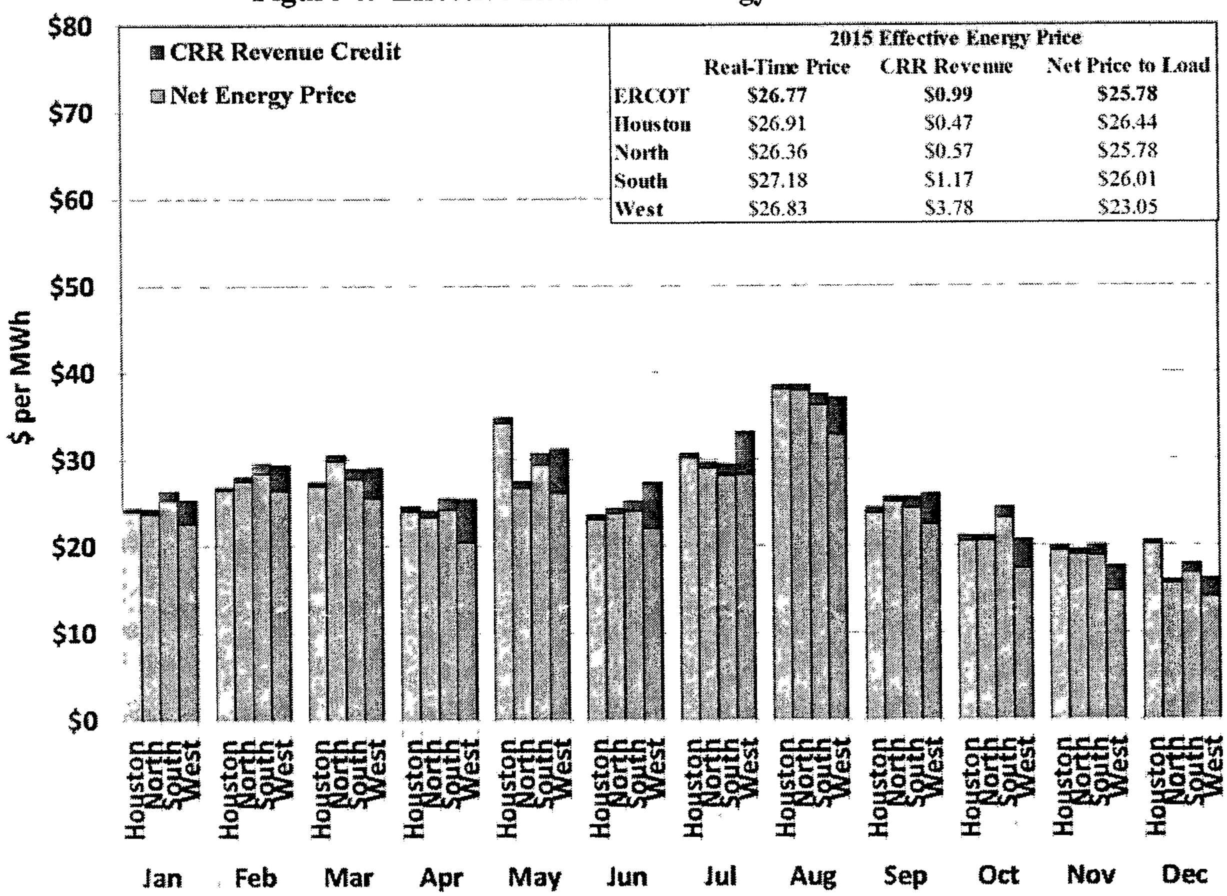


	Average Real-Time Electricity Price ($ per MWh)				
	2011	2012	2013	2014	2015
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**	**$26.77**
Houston	$52.40	$27 04	$33 63	$39 60	$26.91
North	$54.24	$27.57	$32.74	$40.05	$26 36
South	$54 32	$27.86	$33.88	$41.52	$27.18
West	$46 87	$38 24	$37 99	$43 58	$26 83
Natural Gas ($/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.

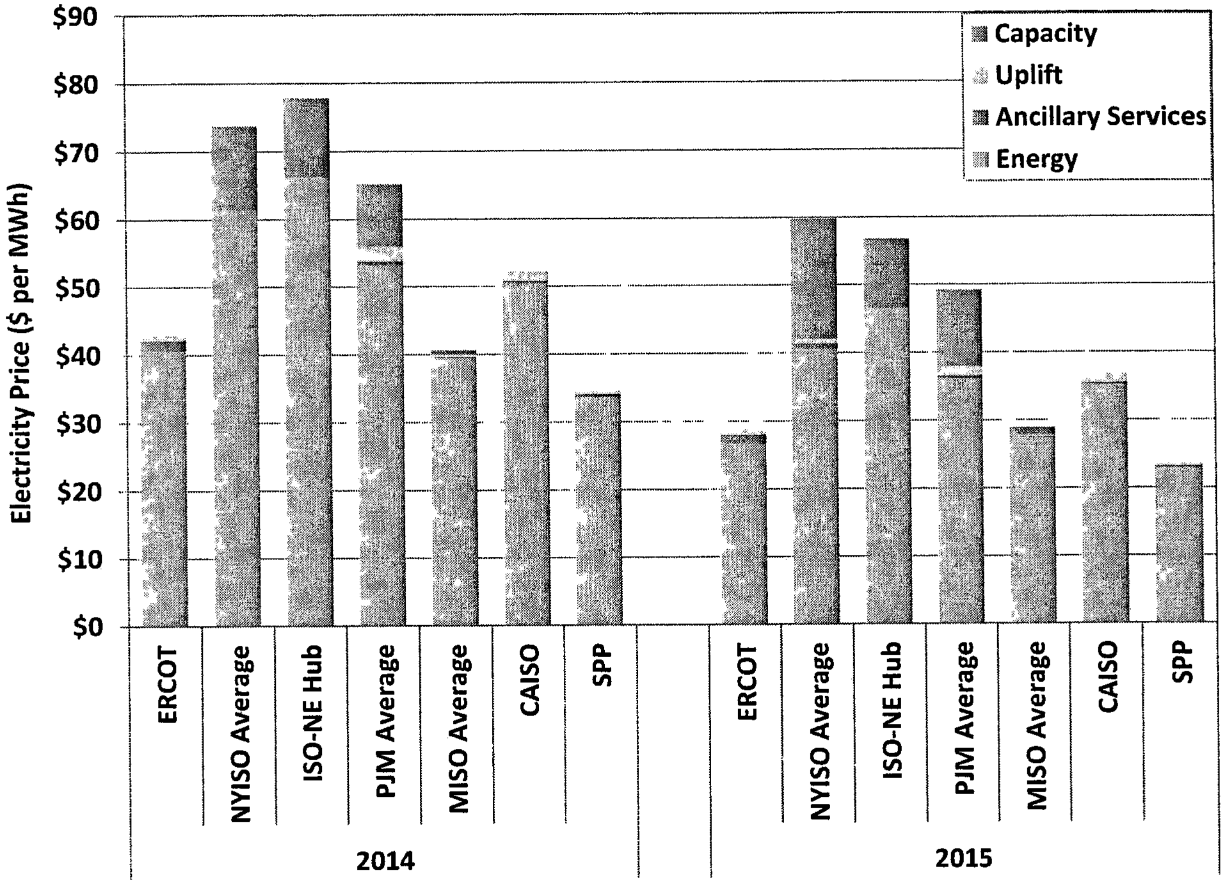
Figure 4: Effective Real-Time Energy Market Prices



2015 Effective Energy Price	Real-Time Price	CRR Revenue	Net Price to Load
ERCOT	$26.77	$0.99	$25.78
Houston	$26.91	$0.47	$26.44
North	$26.36	$0.57	$25.78
South	$27.18	$1.17	$26.01
West	$26.83	$3.78	$23.05

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

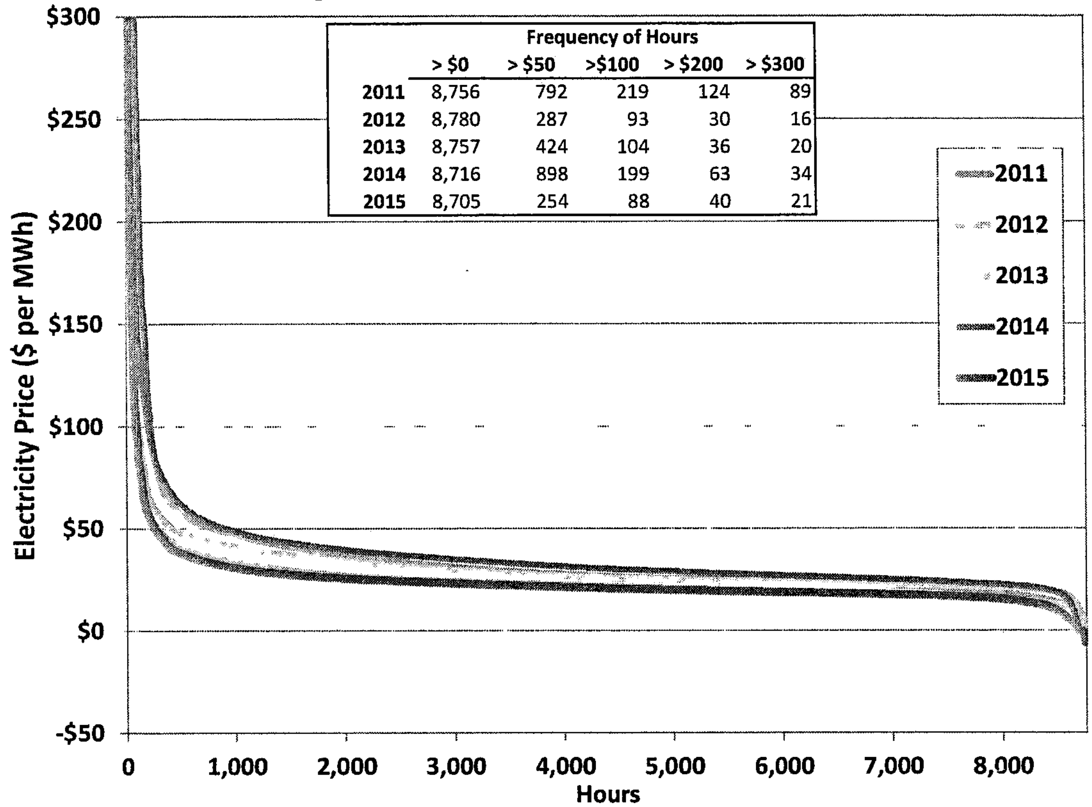


The figure reports each market's average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift. Figure 5 shows that 2015 all-in prices were lower across all U.S. markets, highlighting the pervasive effects of much lower natural gas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

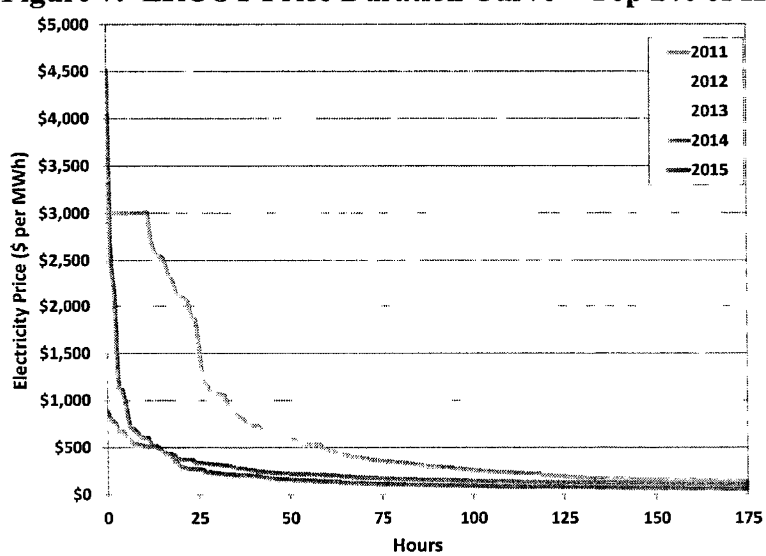
Figure 6: ERCOT Price Duration Curve



	> $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.

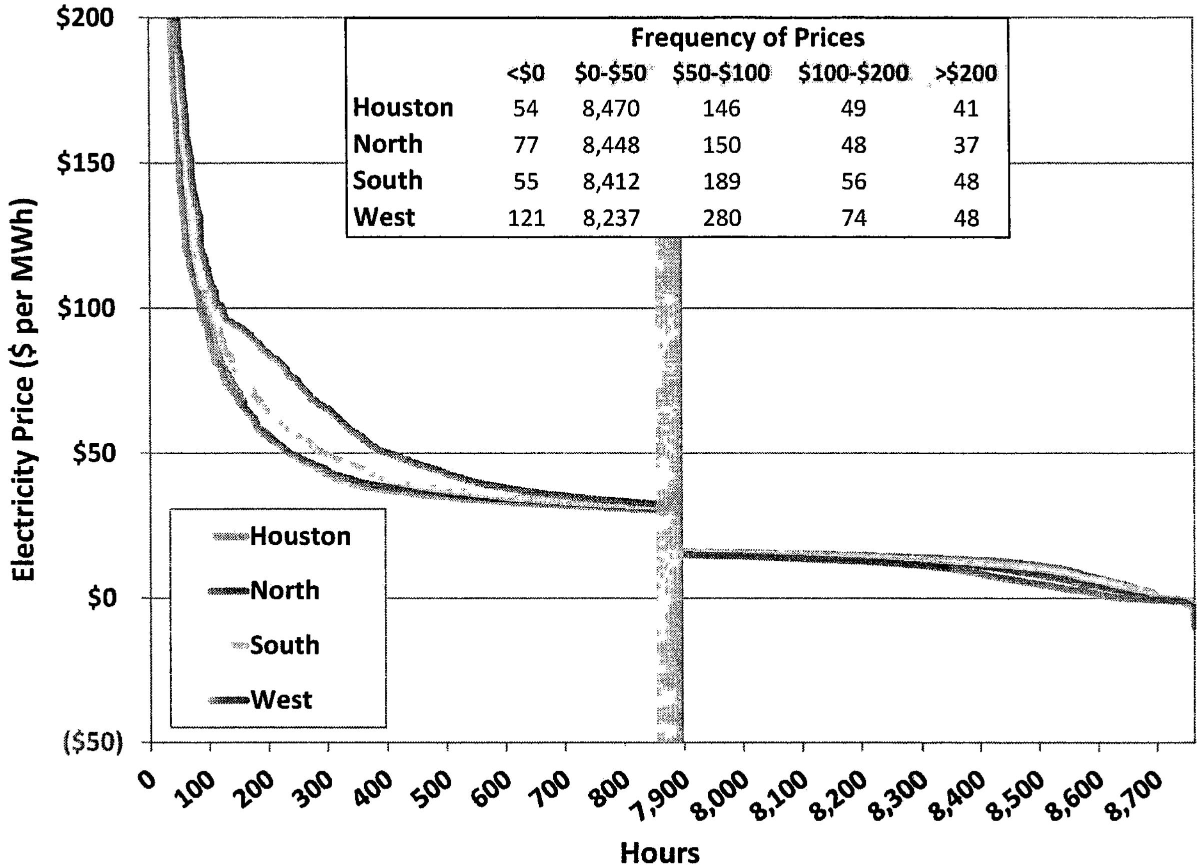
Table 1: Number and Impacts of Price Spikes on Average Real-Time Energy Prices

	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

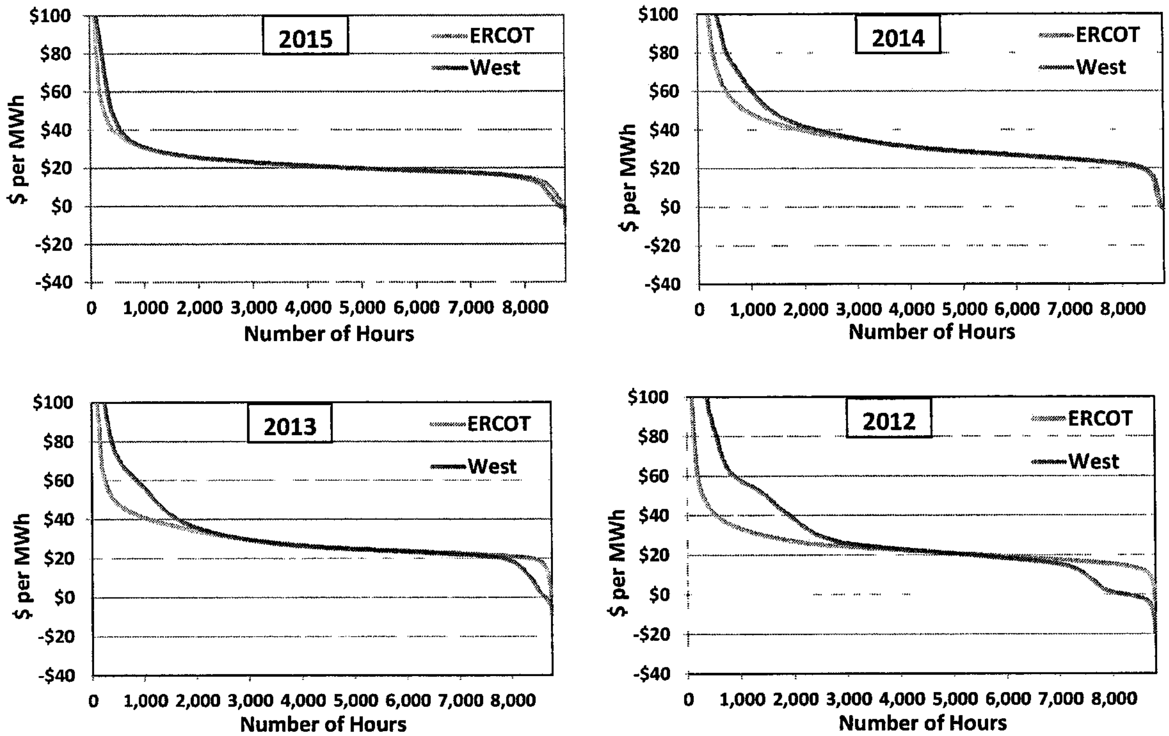


Frequency of Prices	<$0	$0-$50	$50-$100	$100-$200	>$200
Houston	54	8,470	146	49	41
North	77	8,448	150	48	37
South	55	8,412	189	56	48
West	121	8,237	280	74	48

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

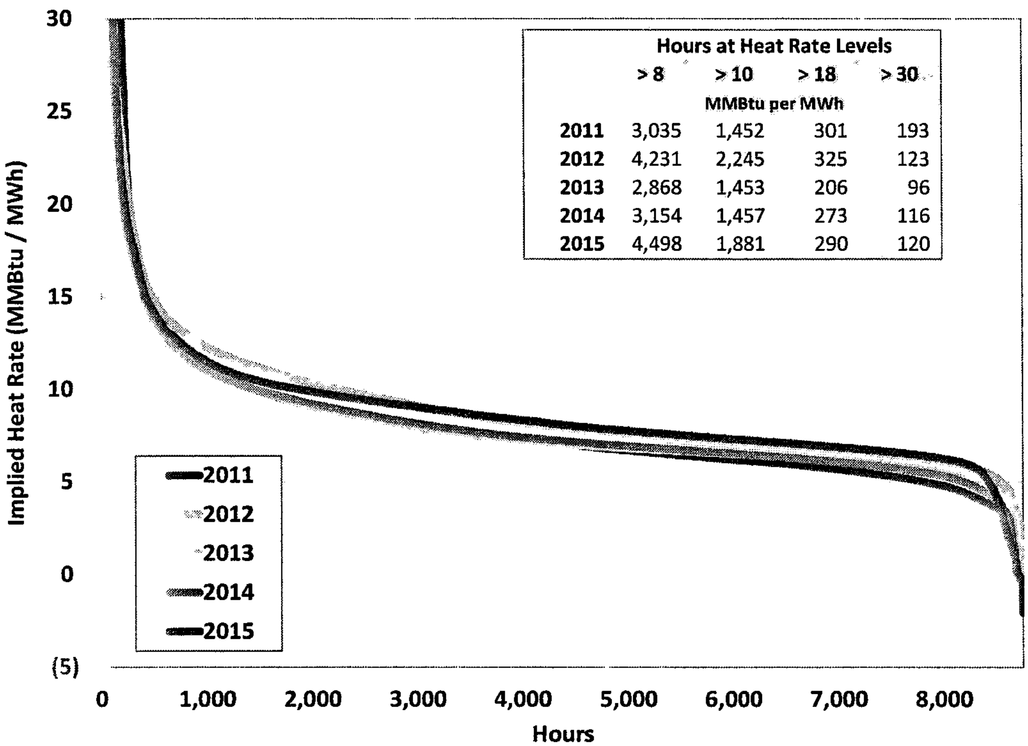


West zone prices remained higher than the ERCOT average for a significant number of hours in 2015, although the difference between West zone and ERCOT prices has steadily declined each year from 2012 to 2015. The combination of more hours with higher prices, and fewer hours with less negative prices 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



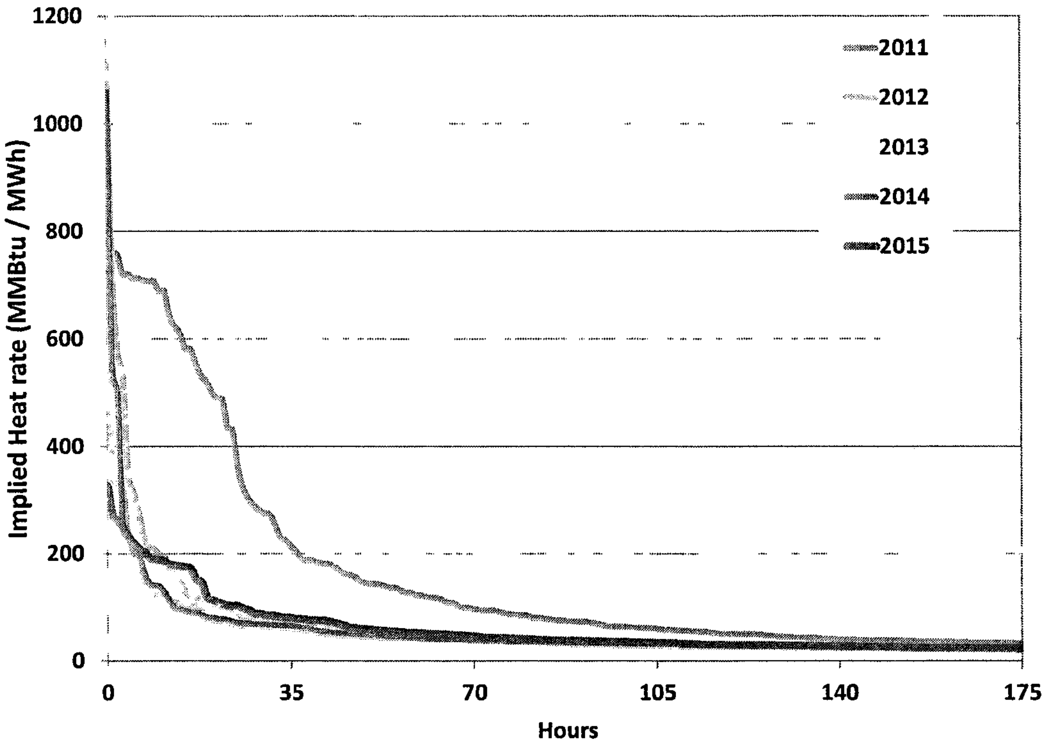
Implied heat rates in 2015 were similar to those in 2012 and were noticeably higher for the majority of hours, as compared to the other three years. This can be explained by the very low natural gas prices experienced in 2012 and 2015, and resulting pricing outcomes which were influenced by coal, not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

[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.

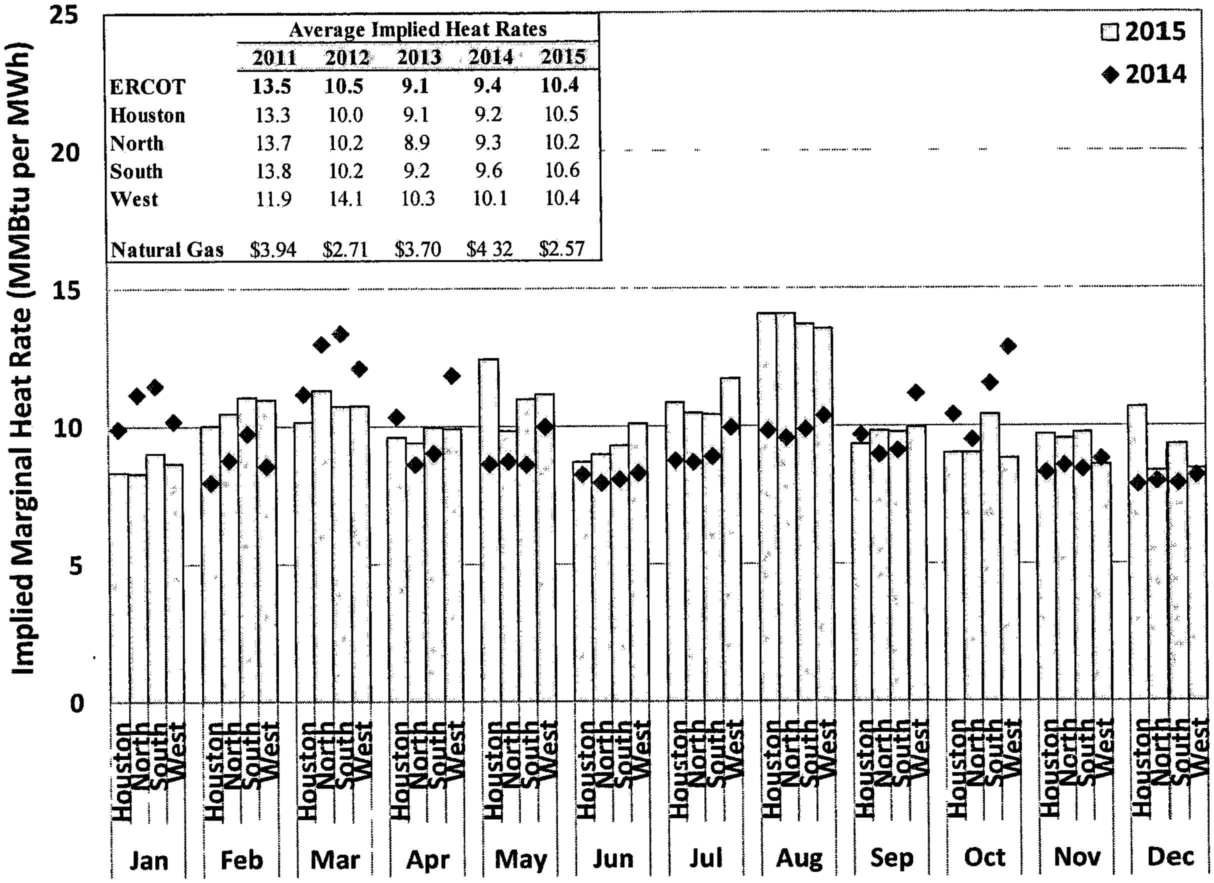
Figure 11 shows the implied marginal heat rates for the top two percent of hours for years 2011 through 2015. The implied heat rates in 2012, 2013, 2014 and 2015 are very similar, while 2011 remains an outlier.

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

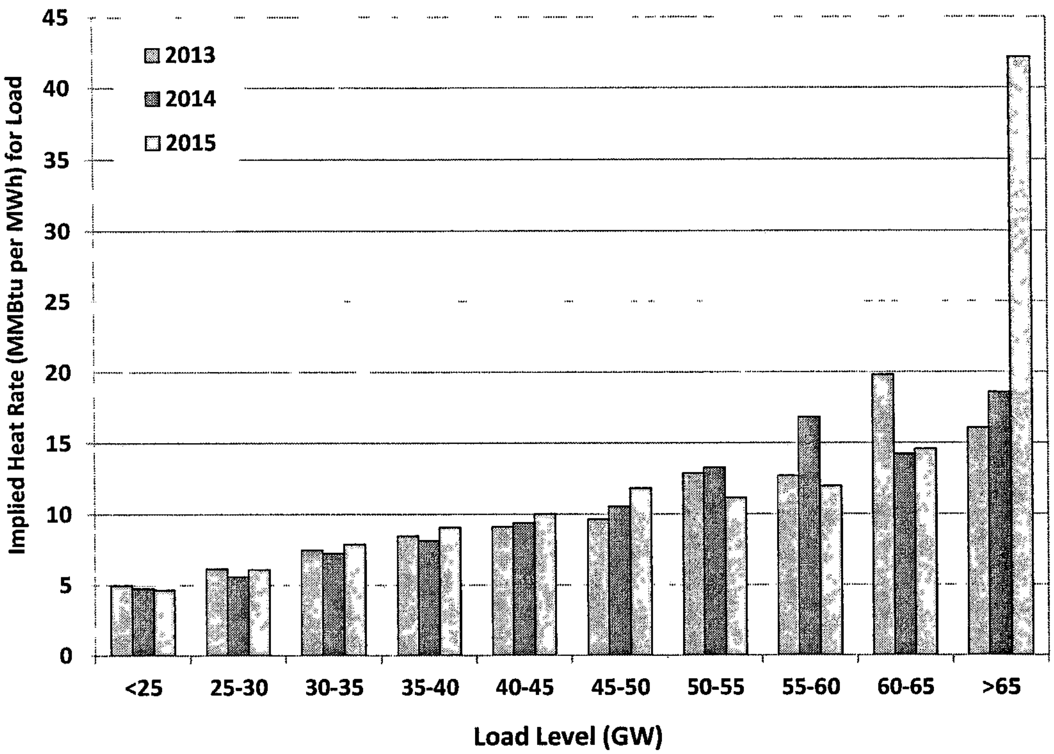


	Average Implied Heat Rates				
	2011	2012	2013	2014	2015
ERCOT	**13.5**	**10.5**	**9.1**	**9.4**	**10.4**
Houston	13.3	10.0	9.1	9.2	10.5
North	13.7	10.2	8.9	9.3	10.2
South	13.8	10.2	9.2	9.6	10.6
West	11.9	14.1	10.3	10.1	10.4
Natural Gas	$3.94	$2.71	$3.70	$4 32	$2.57

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



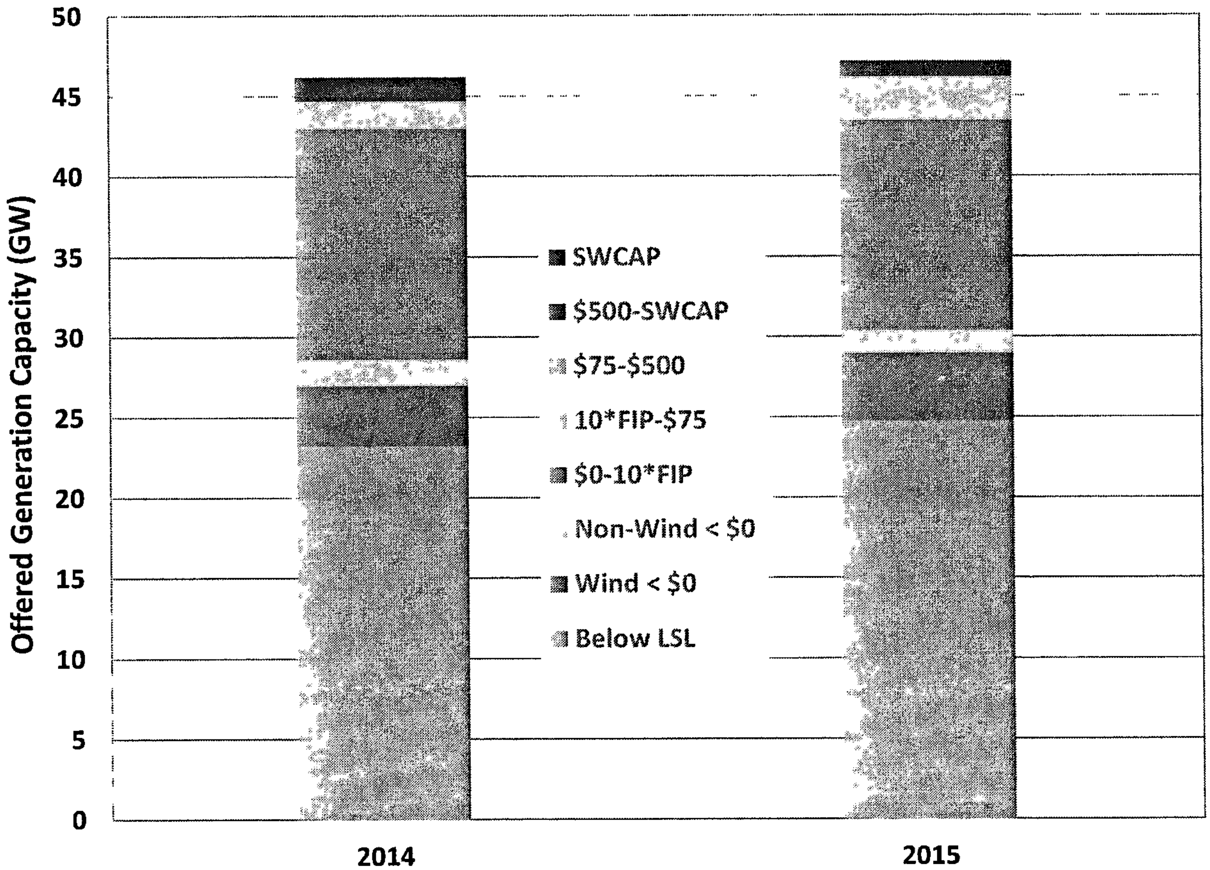
In a well-performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs are dispatched to serve higher loads. There are two noticeable differences in the implied heat rates in 2015. The first is the higher implied marginal heat rate 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

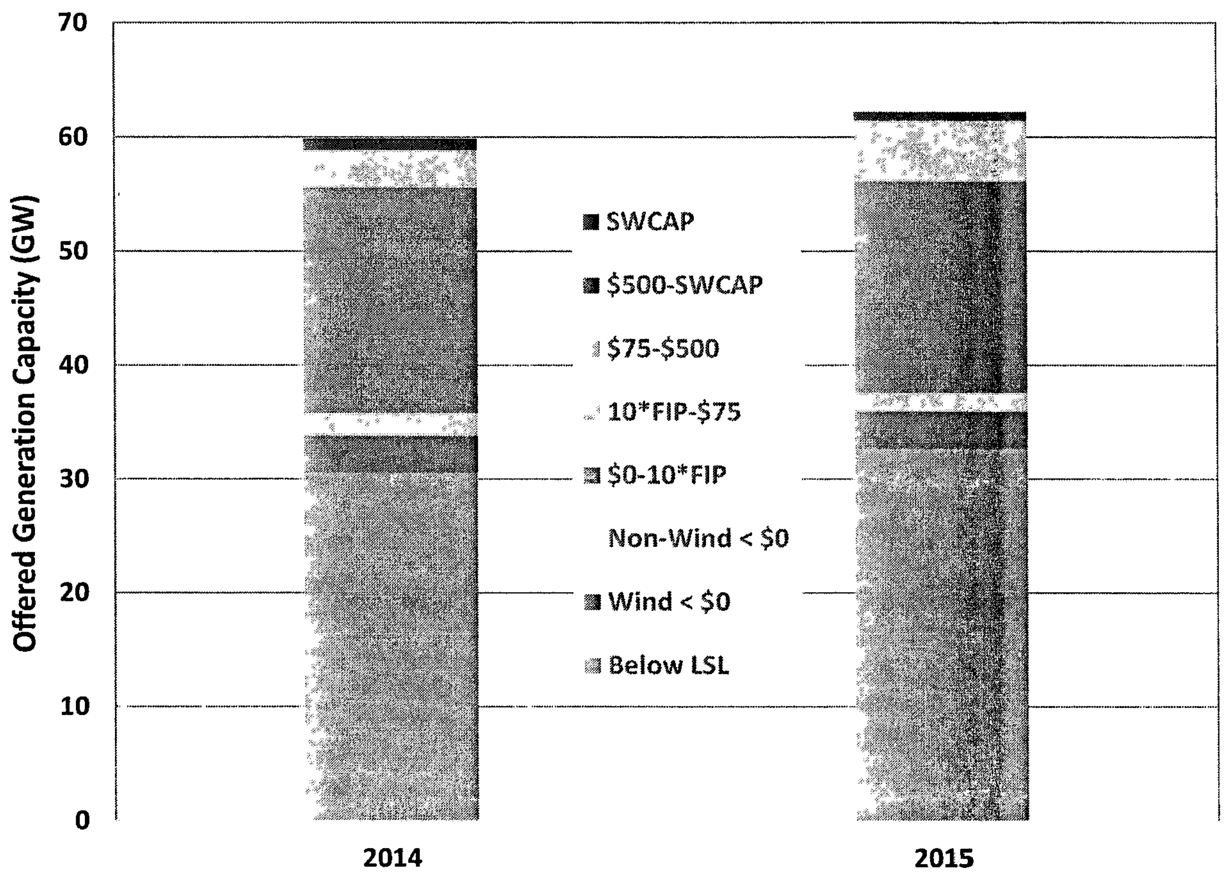
(300 MW) in capacity offered at prices less than zero from non-wind units. There was a decrease of approximately 1,300 MW of additional capacity offered in 2015 at prices between zero and ten multiplied by the daily natural gas price. The amount of capacity offered at prices between 10 multiplied by 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