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2014 STATE OF THE MARKET REPORT
FOR THE
ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

July 2015

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Executive Summary

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2014, 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 2014 include the following:

- The ERCOT wholesale market performed competitively in 2014.
- The ERCOT-wide load-weighted average real-time energy price was $40.64 per MWh in 2014, a 21 percent increase from $33.71 per MWh in 2013. The increase was primarily driven by higher natural gas prices in 2014.
  - The average price for natural gas was 17 percent higher in 2014 than in 2013, increasing from $3.70 per MMBtu in 2013 to $4.32 per MMBtu in 2014. The highest prices occurred early in the year when unusually cold weather throughout the U.S. resulted in much higher and more volatile natural gas prices.
  - Loads in 2014 were slightly higher than 2013, and the frequency of shortage conditions increased. Total ERCOT load in 2014 was 2.5 percent higher than 2013, although the peak load decreased by 1.2 percent.
  - Prices at the system-wide offer cap were experienced in dispatch intervals which totaled 1.56 hours in 2014.
- The total congestion revenue generated by the ERCOT real-time market in 2014 was $708 million, an increase of 52 percent from 2013. This increase was due the combination of higher gas prices, which generally increases the costs of re-dispatching generation to manage network flows, and more frequent congestion in the South and Houston zones.
  - The two most costly constraints were transformer limitations. They were the Heights TNP 138/69 kV autotransformers in the Houston area and the Lytton Springs 345/138 kV autotransformer in the Austin area. Although in different parts of the state and occurring at different times, both were the result of outages of other nearby transmission facilities.

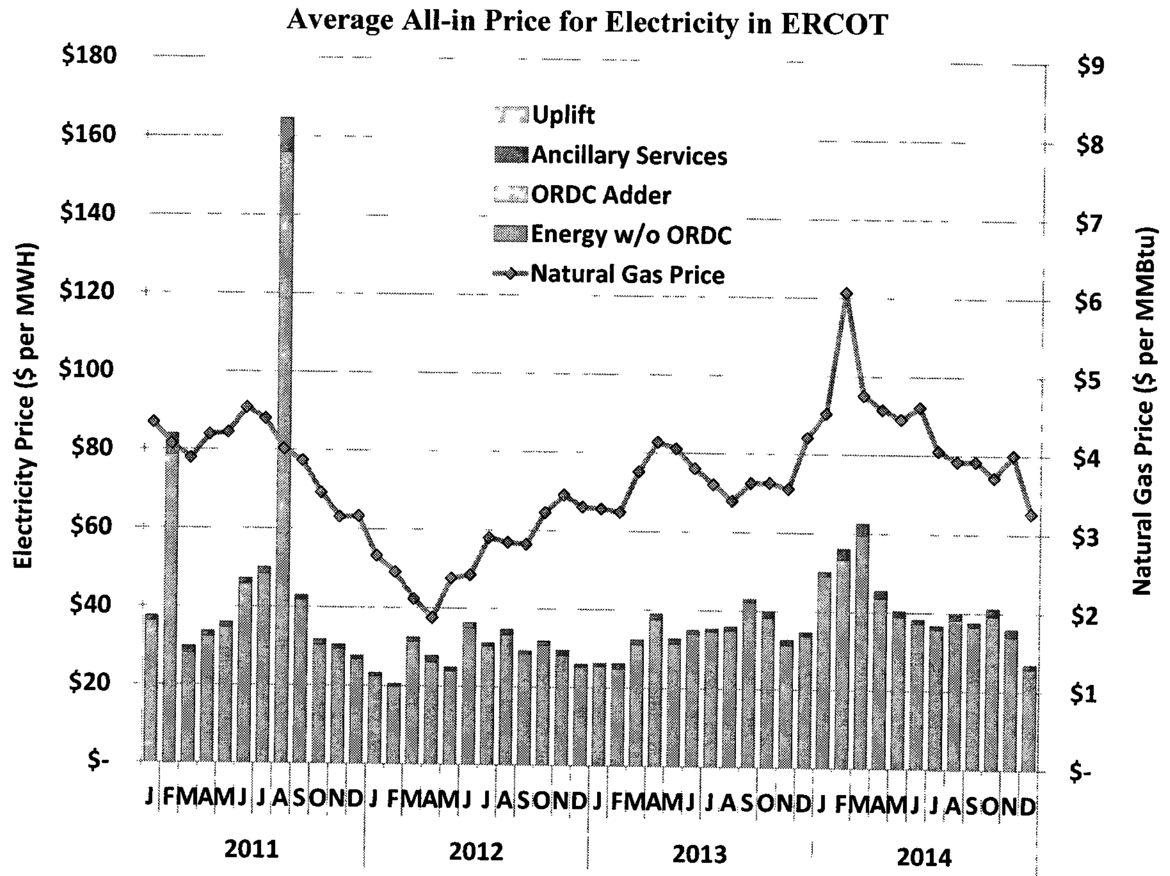
- The Rio Grande Valley was the most congested area in 2014 because of transmission outages scheduled to accommodate the construction of transmission upgrades in the area. A large contribution to total cost occurred in October, when a combination of generation and transmission outages led to a significant congestion. Ultimately, on October 8th the situation in the Valley required that firm load be curtailed.

- Net revenues provided by the market during 2014 were less than the amount estimated to be needed to support new greenfield generation. The increased shortage pricing levels did not substantially increase net revenues in 2014 because shortages were less frequent than average over the long term. Nonetheless, reserve margins in ERCOT are expected to exceed the minimum target for the next several years.

B. Review of Real-Time Market Outcomes

As is typical 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 next figure 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. The ERCOT-wide price is the load-weighted average of the real-time market prices from all load zones. Ancillary services costs are estimated based on total system demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves. Uplift costs are assigned market-wide on a load-ratio share basis to pay for costs associated with reliability unit commitments and reliability must run contracts. Starting June 1, 2014, with the implementation of the Operating Reserve Demand Curve, the real-time energy price includes the online reserve adder. In the figure below this adder is shown separated out from the energy price.



The largest component of the all-in cost of wholesale electricity is the energy cost. ERCOT average real-time all-in prices were 21 percent higher in 2014 than in 2013. The ERCOT-wide load-weighted average price was $40.64 per MWh in 2014 compared to $33.71 per MWh in 2013. The Online Reserve adder was $0.26 per MWh for the last half of the year.

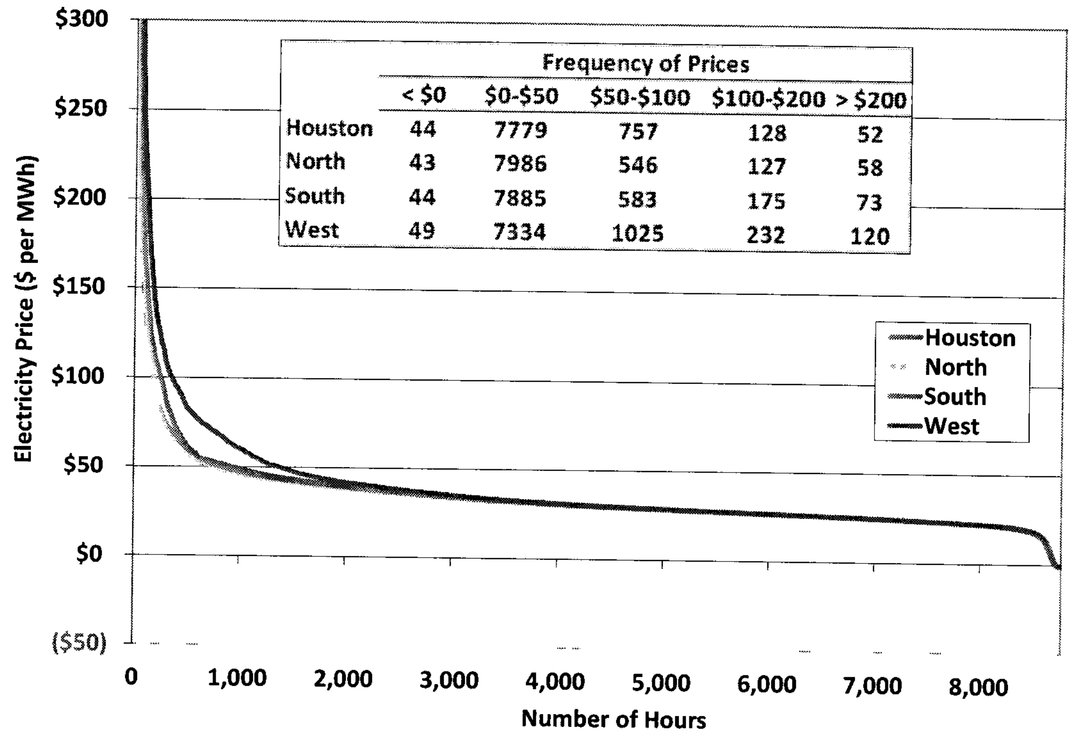
The increase in real-time energy prices was correlated with much higher fuel prices in 2014. The high correlation of natural gas prices and energy prices shown in the figure is consistent with expectations in a well-functioning market. Fuel costs constitute most of the marginal production costs for generating resources in ERCOT and competitive markets provide incentives for suppliers to submit offers consistent with marginal costs. The average natural gas price in 2014 was $4.32 per MMBtu, a 17 percent increase compared to $3.70 per MMBtu in 2013. Gas prices were highest in the first quarter when unusually cold weather throughout the U.S. resulted in much higher and more volatile natural gas prices. Ancillary services are a small portion of the all-in price of energy and increased from $1.03 in 2013 to $1.51 in 2014. Uplift costs continue to be minimal in ERCOT.

The average real-time all-in electricity prices by zone from 2011 through 2014 are shown below:

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

To depict how real-time energy prices vary by hour in each zone, the next figure shows the hourly average price duration curve in 2014 for four ERCOT load zones. The Houston, North and South load zones had similar prices over the majority of hours.

Zonal Price Duration Curves

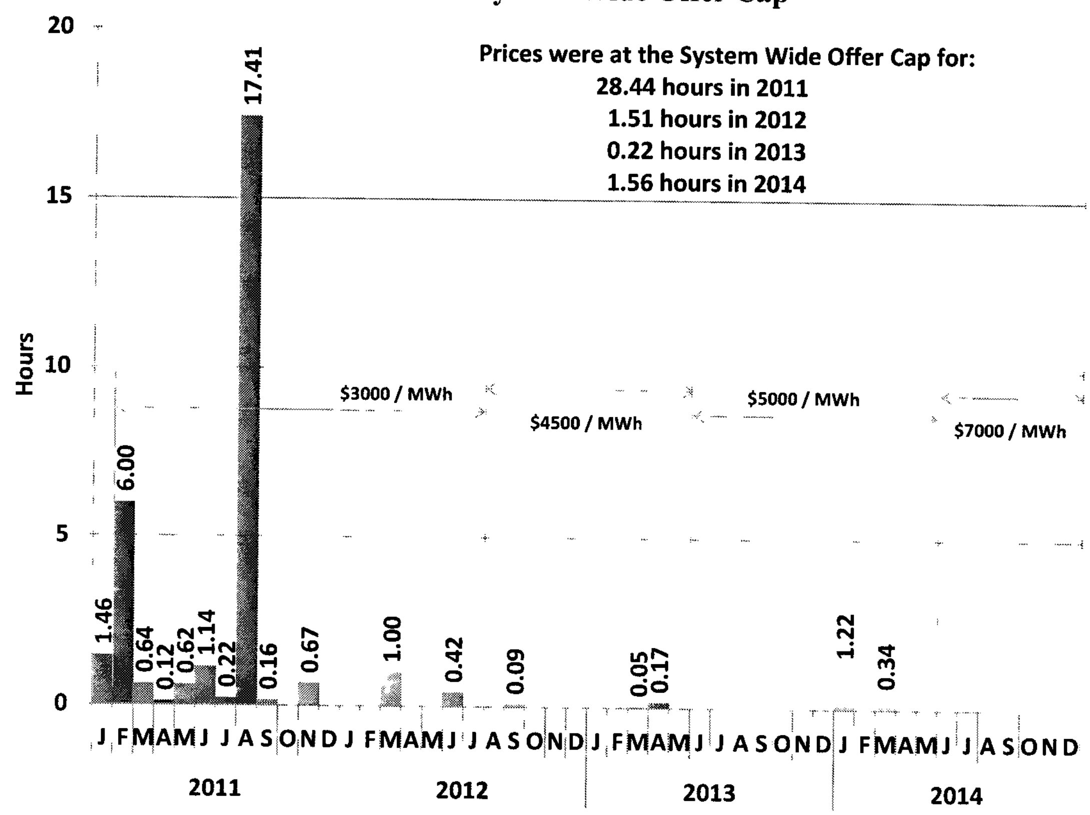


	Frequency of Prices				
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	44	7779	757	128	52
North	43	7986	546	127	58
South	44	7885	583	175	73
West	49	7334	1025	232	120

The price duration curve for the West zone is noticeably different than the other zones, with more hours when prices exceeded $50 per MWh. The number of hours with prices less than $0 per MWh was very similar for all zones in 2014. This is notable since for the past several years the West zone has consistently had much more frequent occurrences of negative prices than the other zones. Significant transmission additions have lowered the frequency of depressed West zone prices due to 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 discussed in Section IV. Demand and Supply, overall demand for electricity was slightly higher in 2014 than in 2013. There were also more occasions when the available supply of generation resources was insufficient to satisfy system demand while maintaining required levels of operating reserves and, thus, more frequent instances of shortage pricing. Significant shortages result in energy prices being set at the system-wide offer cap. The frequency of this shortage pricing is shown in the following figure.

Prices at the System-Wide Offer Cap



The figure above shows the aggregate amount of time where the real-time energy price was set at the system-wide offer cap, displayed by month. There were no instances in 2014 of energy prices rising to the cap after the system-wide offer cap was increased to $7,000 per MWh on June 1. Prices during 2014 were at the system-wide offer cap for only 1.56 hours, an increase from 0.22 hours in 2013 and a slight increase from the 1.51 hours experienced in 2012. All years were much lower than the 28.44 hours at the cap experienced in 2011 and the average amount expected of the long term in an energy-only market.

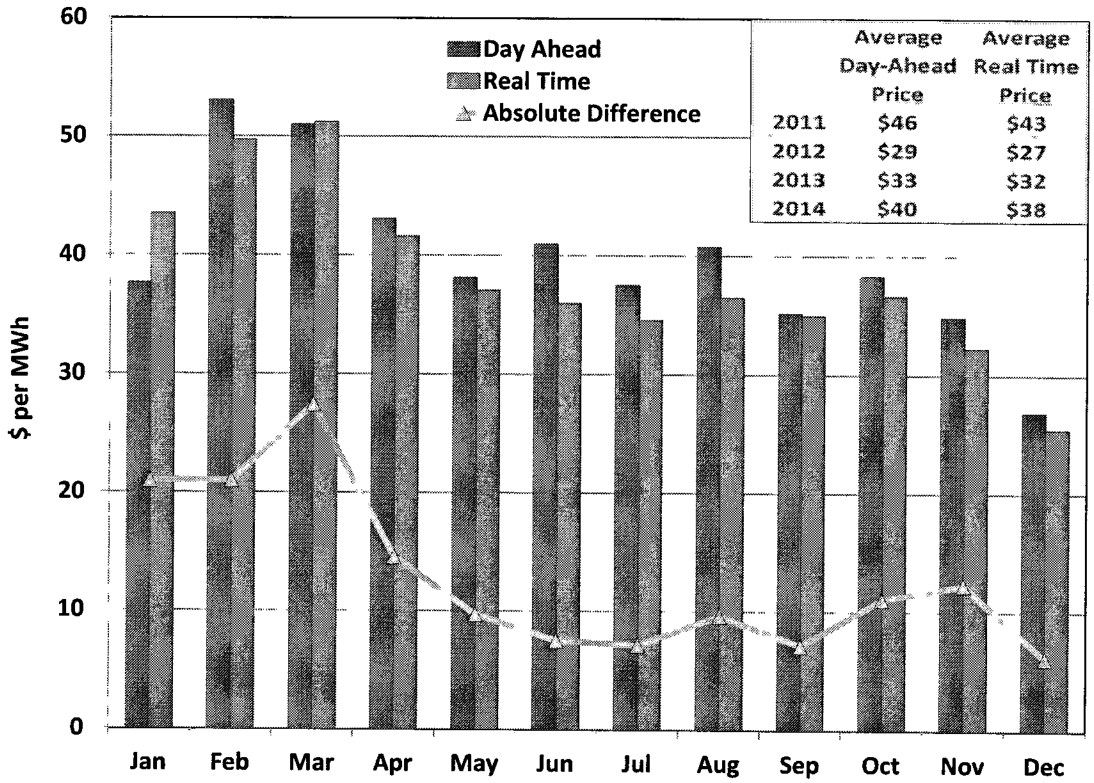
These results are not surprising because shortage pricing is highly variable year-to-year. When temperatures lead to weather-dependent loads that are significantly higher than normal or supply is less available than normal, the frequency of shortages tend to increase exponentially. Hence, one should expect that shortages will be very infrequent in normal or mild years, such as in 2012 and 2013. The occasions when prices reached the system-wide offer cap in 2014 were during colder than typical winter weather. Although the shortages in 2011 seemed relatively severe, adequate long-term incentives in the ERCOT market require shortages in excess of the value exhibited in 2011 every few years.

C. Review of Day-Ahead Market Outcomes

ERCOT's centralized 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 clearing. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. 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.

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.

Convergence Between Forward and Real-Time Energy Prices



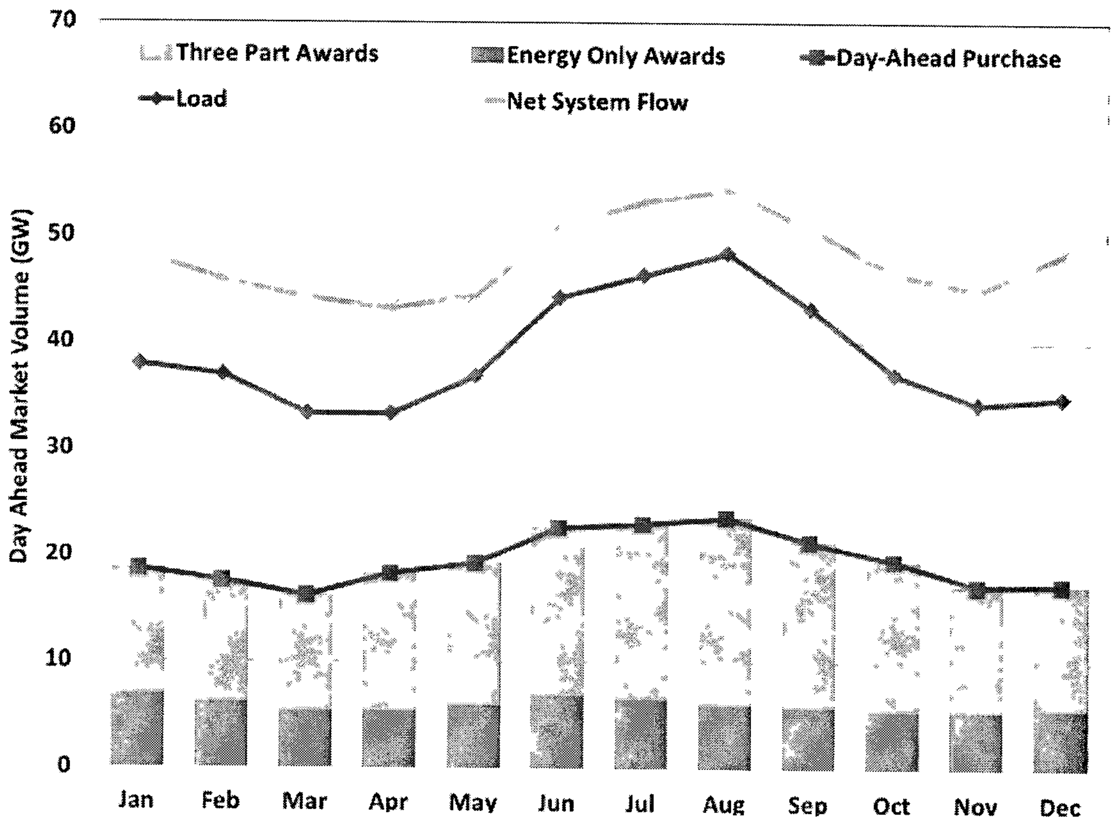
The figure above shows the price convergence between the day-ahead and real-time market, summarized by month. The simple average of day-ahead prices in 2014 was $40 per MWh, compared to the simple average of $38 per MWh for real-time prices. The average absolute difference between day-ahead and real-time prices was $12.87 per MWh in 2014; higher than in 2013 when average of the absolute difference was $9.86 per MWh.

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.

The overall day-ahead premium increased in 2014 compared to 2013, as a result of the much higher premiums in January through March. Although peak loads during the winter are somewhat lower than those in the summer, loads during the first months of 2014 set record highs for that time of the year. Day-ahead premiums 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 2014, it should not be expected over time that every month will always produce a day-ahead premium as 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 January and March).

Summarized in the figure below is the volume of day-ahead market activity by month. It shows that day-ahead purchases are approximately 50 percent of real-time load.

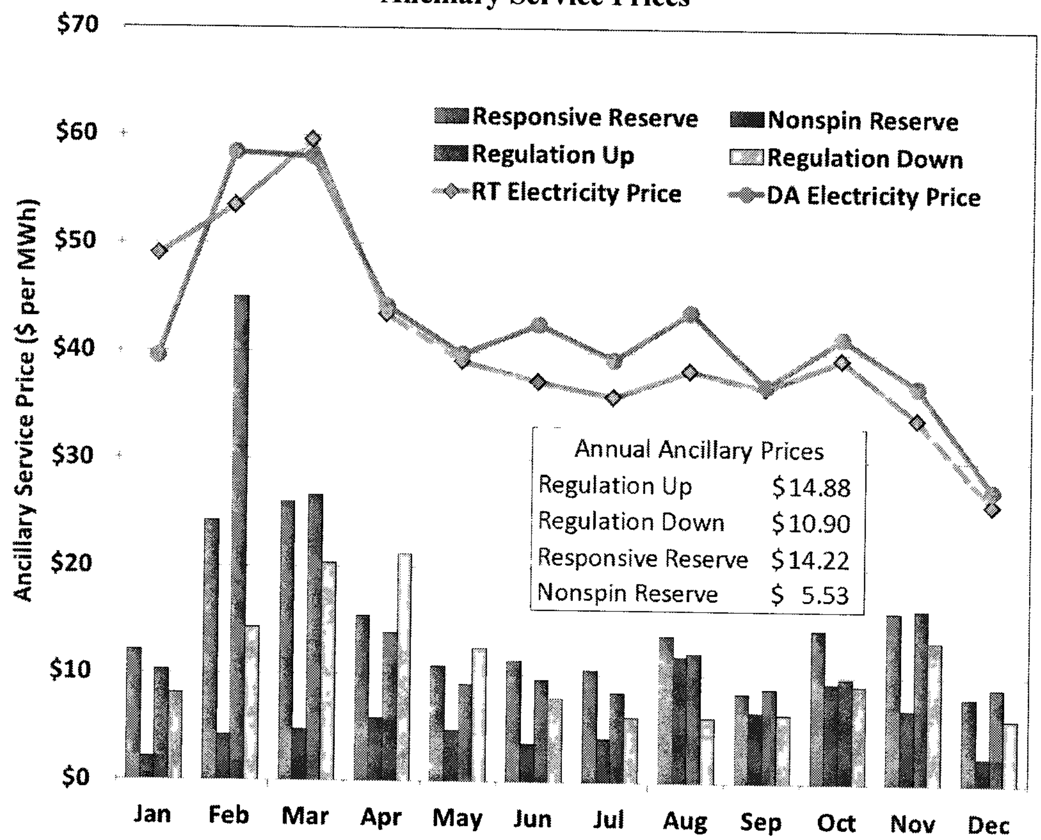
Volume of Day-Ahead Market Activity by Month



This figure also shows the volume of Point-to Point (PTP) Obligations, which are financial instruments purchased in the day-ahead market. Although these instruments do not themselves involve the direct supply of energy, they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. 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 2014 was almost 5 percent higher than in 2013.

Under the nodal market, ancillary service offers are co-optimized as part of the day-ahead market clearing. This means that market participants do not have to include expectations of forgone energy sales in ancillary services capacity offers. As a result of ancillary services clearing prices explicitly accounting for the value of energy in the day-ahead market, ancillary services prices are highly correlated with day-ahead energy prices and, by extension, with real-time energy prices.

Ancillary Service Prices

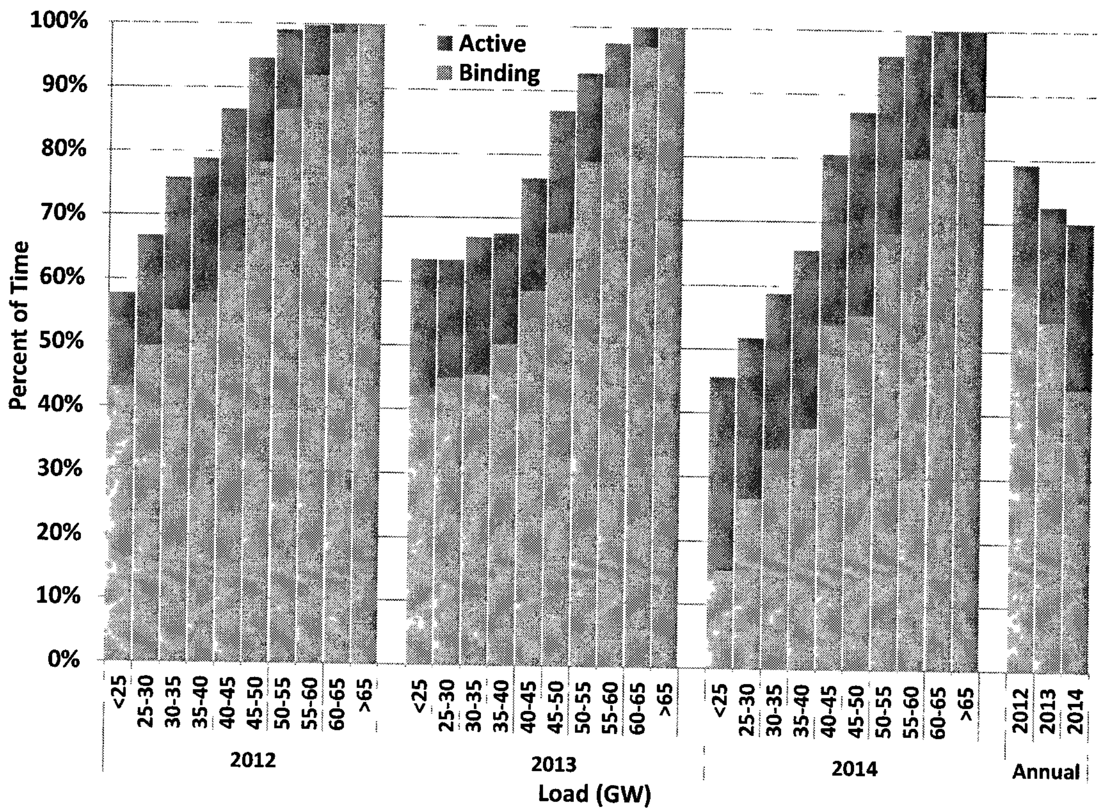


The figure above presents the average clearing prices of capacity for the four ancillary services, along with day-ahead and real-time energy prices. With average energy prices varying between $25 and $60 per MWh, the prices of ancillary services remained fairly stable throughout the year. Considering these costs on a per MWh of ERCOT load, total ancillary services costs increased 47 percent to $1.51 per MWh.

D. Transmission and Congestion

The total congestion revenue generated by the ERCOT real-time market in 2014 was $708 million, an increase of 52 percent from 2013. This increase was due the combination of higher gas prices, which generally increases the costs of re-dispatching generation to manage network flows, and more frequent congestion in the South and Houston zones. The next figure provides a comparison of the amount of time transmission constraints were binding or active at various load levels in 2012 through 2014.

Frequency of Binding and Active Constraints



Binding transmission constraints are those for which the dispatch levels of generating resources are being 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 priced in its Locational Marginal Prices (LMPs). Active transmission constraints are those that did not require a re-dispatch of generation.

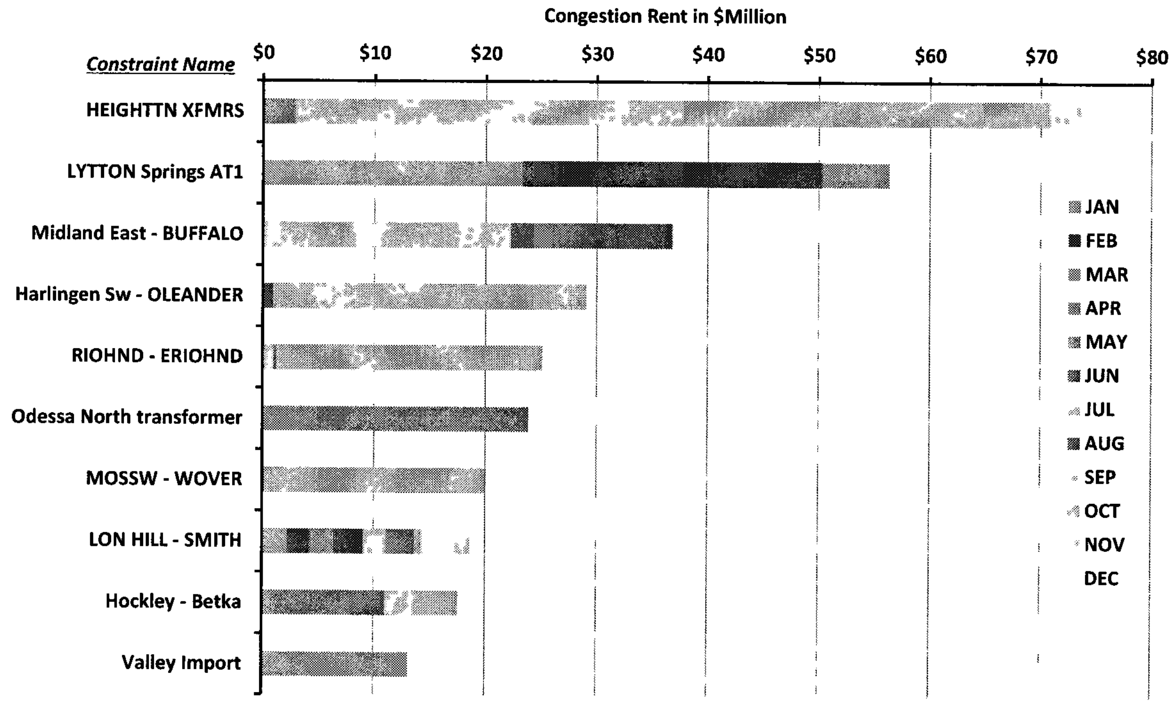
The frequency of binding transmission constraints decreased again in 2014. There was a binding constraint only 44 percent of time in 2014, down from 55 percent of the time in 2013 and 60 percent in 2012. The likelihood of binding constraints increases at higher load levels, which is consistent with the results in ERCOT shown in the figure. However, it is noteworthy that there were binding constraints less than 90 percent of time during the very highest load levels in 2014, much lower than in prior years.

Because the overall frequency of binding constraints decreased in 2014, their effect on LMPs also decreased in 2014. Congestion in the West zone remained about the same as it was in 2013. Completion of the CREZ transmission projects has eliminated the longstanding limitations on the export of power from the west. However, binding constraints that limit transfers of power into the West continue, particularly under high load and low wind conditions. Constraints associated with oil and gas activity in the Eagle Ford Shale area and limitations serving the lower Rio Grande Valley had a larger impact in 2014. The figure below displays the ten constraints that generated the most real-time congestion.

The two most costly constraints were related to transformer overloads. Specifically, they were the Heights TNP 138/69 kV autotransformers in the Houston area and the Lytton Springs 345/138 kV autotransformer in the Austin area. Both were also the result of outages of other nearby transmission facilities.

The Rio Grande Valley was the most congested area in 2014 as a result of constraints occurring when other transmission facilities in the area were taken out of service to accommodate construction of transmission upgrades in the area. A large contribution to total cost occurred in October when a combination of generation and transmission outages led to a significant congestion. Ultimately, on October 8th the situation in the Valley required that firm load be curtailed.

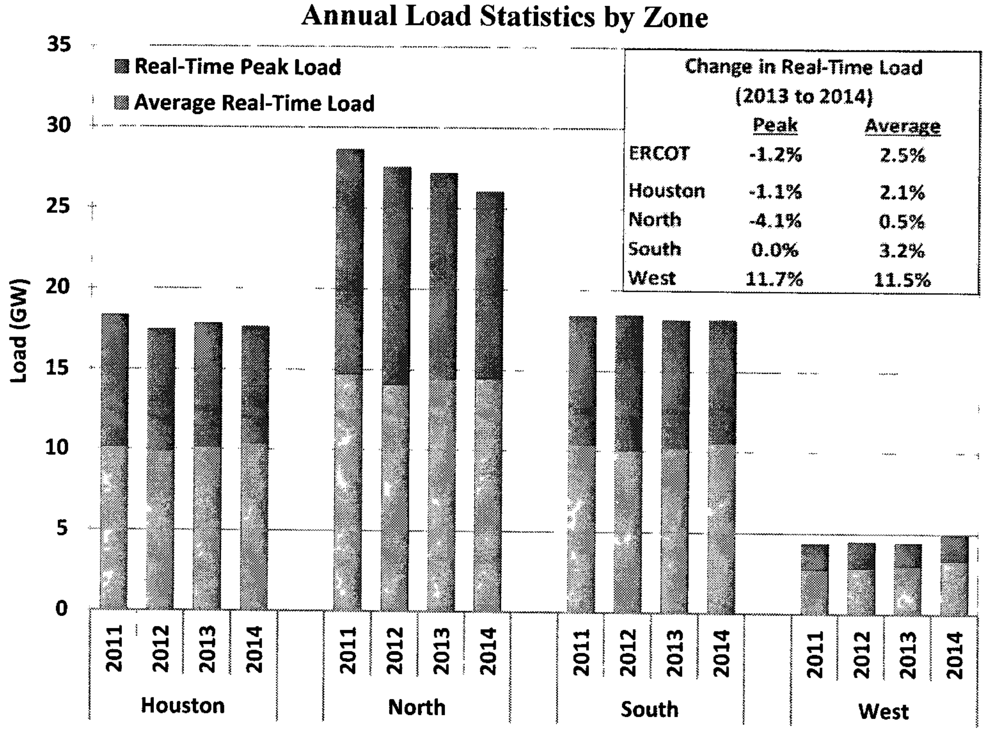
Top Ten Real-Time Constraints



E. Demand and Supply

This figure shows peak load and average load in each of the ERCOT zones from 2011 to 2014.

Annual Load Statistics by Zone



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

Total ERCOT load over the calendar year increased from 332 terawatt-hours (TWh) in 2013 to 340 TWh in 2014, an increase of 2.5 percent or an average of 960 MW every hour. Much of this increase occurred in the first quarter as extremely cold weather contributed to record levels of winter load.

Despite this increase in average load, the ERCOT coincident peak hourly demand decreased from 67,247 MW to 66,451 MW in 2014, a decrease of 795 MW, or 1.2 percent. The highest peak demand experienced in ERCOT remains 68,311 MW that occurred during August of 2011.

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. Peak load in the West zone increased nearly 500 MW in 2014. Peak load did not increase in any other zone.

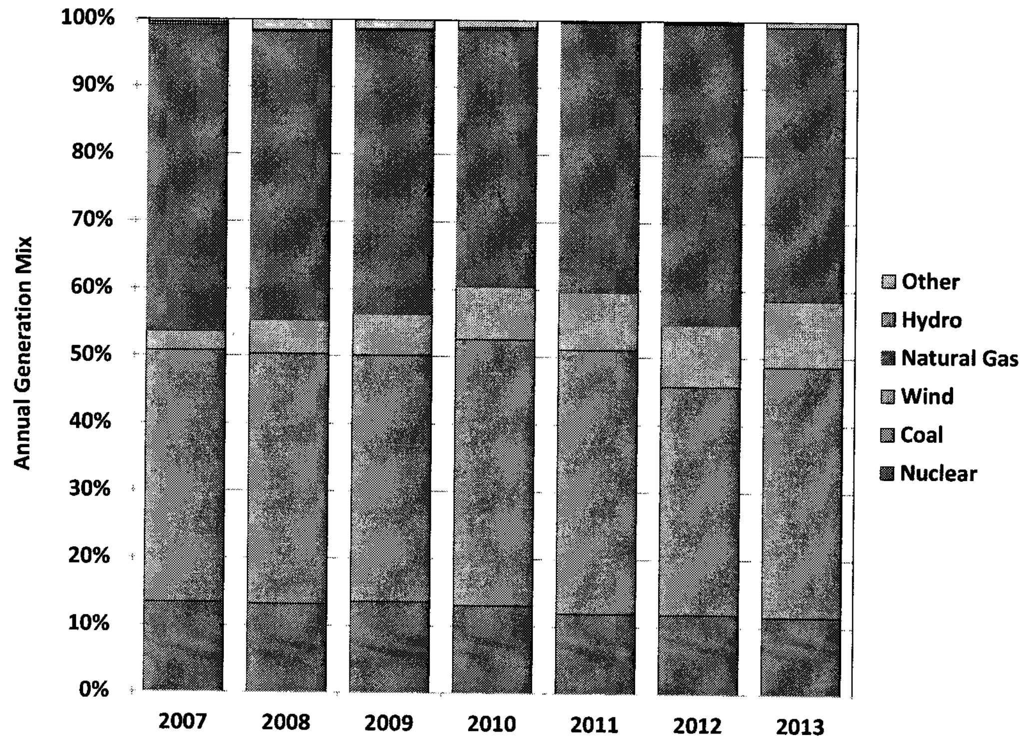
Approximately 2.8 GW of new generation resources came online in 2014. Gas-fueled units accounted for 2.1 GW of the total additions, primarily from two new combined cycle units. The remaining gas additions were a new combined cycle unit built on an existing site of a retired gas steam unit, and the addition of a gas turbine at an existing generator location. The remaining resource additions were wind (0.7 GW) and small solar units. When unit retirements are included, the net capacity addition in 2014 was 1.6 GW. Natural gas generation continues to account for approximately 48 percent of total ERCOT installed capacity while the share of coal generation dropped slightly from 21 percent in 2013 to 20 percent in 2014.

Over the seven years from 2007 to 2014, more new wind and coal generation has been added than any other type of capacity. The sizable additions in these two categories have been more than offset by retirements of old natural gas-fired steam units. Nonetheless, the resulting installed capacity in 2014 was 1 GW more than in 2007. Comparatively, peak load in 2014 was greater than the 2007 peak load by more than 4 GW.

The figure below shows the percentage of annual generation from each fuel type for the years 2007 through 2014. The generation share from wind has increased every year, reaching 11 percent of the annual generation requirement in 2014, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to a low of 38 percent in 2010. In 2014 the percentage of generation from natural gas was 41 percent, which was a very slight increase from the 2013 level.

Similarly, the percentage of generation produced by coal units was 36 percent in 2014, a small decrease from 37 percent in 2013.

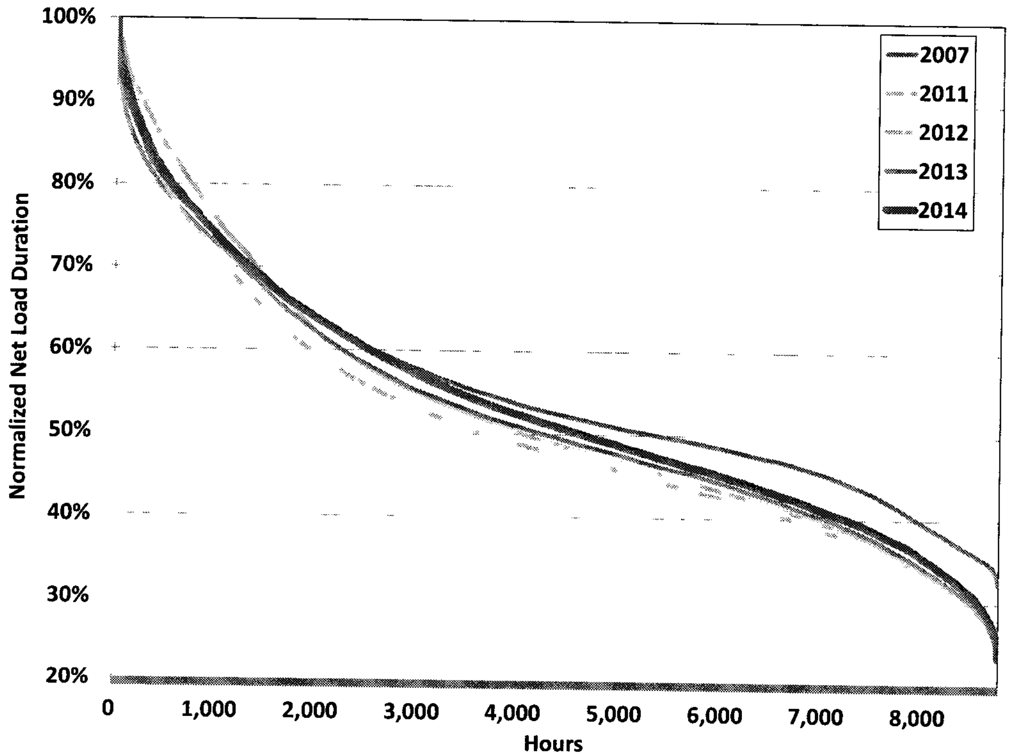
Annual Generation Mix



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 23.4 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.

Increasing levels of wind resources in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. For the following analysis, net load is defined as the system load minus wind production. The figure below shows the net load duration curves for the years 2011 through 2014, normalized as a percentage of peak load, and including 2007 as a point of reference. This figure shows the reduction of remaining energy demand 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. 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.

Net Load Duration Curve



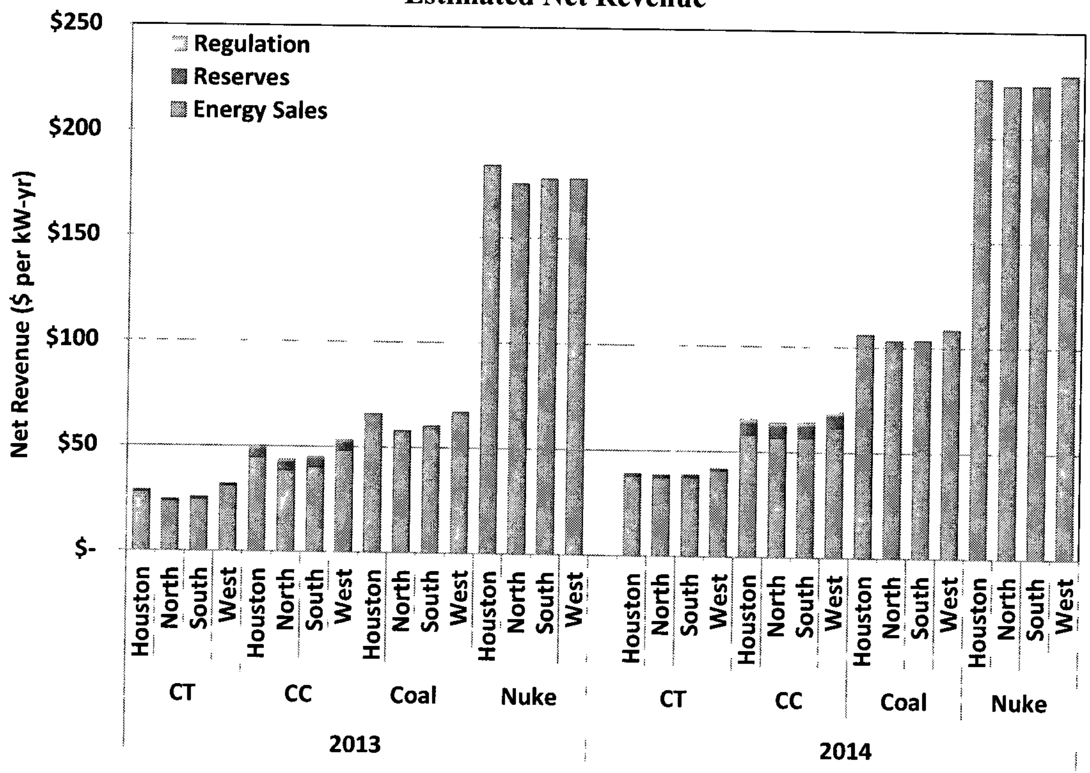
Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet can expect to operate for fewer hours as wind penetration continues to increase. 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.

F. Resource Adequacy

1. Long-Term Incentives: Net Revenue

One of the primary functions of the wholesale electricity market is to provide economic signals that will encourage the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. These economic signals are evaluated by estimating the "net revenue" new resources would receive from the markets. Net revenue 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.

Estimated Net Revenue



The figure above shows the results of the net revenue analysis for four types of hypothetical new units in 2013 and 2014. These are: (a) natural gas-fired combustion turbine, (b) natural gas-fired combined-cycle, (c) coal-fired generator, and (d) a nuclear unit. For the natural gas units, 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 in all other hours. For coal and nuclear technologies, net revenue is calculated solely from producing energy.

Overall, the net revenues in 2014 were higher than those in 2013 and 2012, and all three years were much lower than in 2011. This is not surprising given shortages have been very infrequent over the past three years. Shortage pricing plays a pivotal role in providing investment incentives in an energy-only market like ERCOT. In order to provide adequate incentives, some years must exhibit an extraordinary number of shortages and net revenues that are multiples of annual net revenues needed to support investment.

The figure above also shows that the 2014 net revenue for new natural gas-fired units was somewhat higher than 2013 levels, primarily because of higher gas prices during the first quarter of 2014. Net revenues for coal and nuclear technologies increased by larger amounts from 2013 to 2014 because they benefit from the increase in natural gas prices.

Despite these increases, the net revenues produced by the ERCOT markets in 2014 were lower than the estimated annualized cost of investing in any of these new technologies.

- For a new natural gas-fired combustion turbine, the estimated net revenue requirement is approximately $80 to $95 per kW-year. The net revenue in 2014 for a new gas turbine was calculated to be approximately $37 per kW-year.
- For a new combined cycle unit, the estimated net revenue requirement is approximately $110 to $125 per kW-year. The net revenue in 2014 for a new combined cycle unit was calculated to be approximately $57 per kW-year.
- For a new coal-fired unit, the estimated net revenue requirement is approximately $265 to $310 per kW-year. The net revenue in 2014 for a new coal unit was calculated to be approximately $105 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $450 to $585 per kW-year. The net revenue in 2014 for a new nuclear unit was calculated to be approximately $227 per kW-year.

These results indicate that during 2014 the ERCOT markets would not have provided revenues greater than the estimated costs of any of the types of generation technology evaluated.

Therefore, it may seem inconsistent with these results that new generation continues to be added in the ERCOT market. This can be explained by the following factors:

First, the net revenues in any one year may be higher or lower than an investor would require over the long term. In 2014, the net revenues were substantially lower than the estimated cost of entry because shortages were much less frequent than would be expected in the long-term on average. 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 other years it will be less frequent and net revenue will be less than the cost of entry.

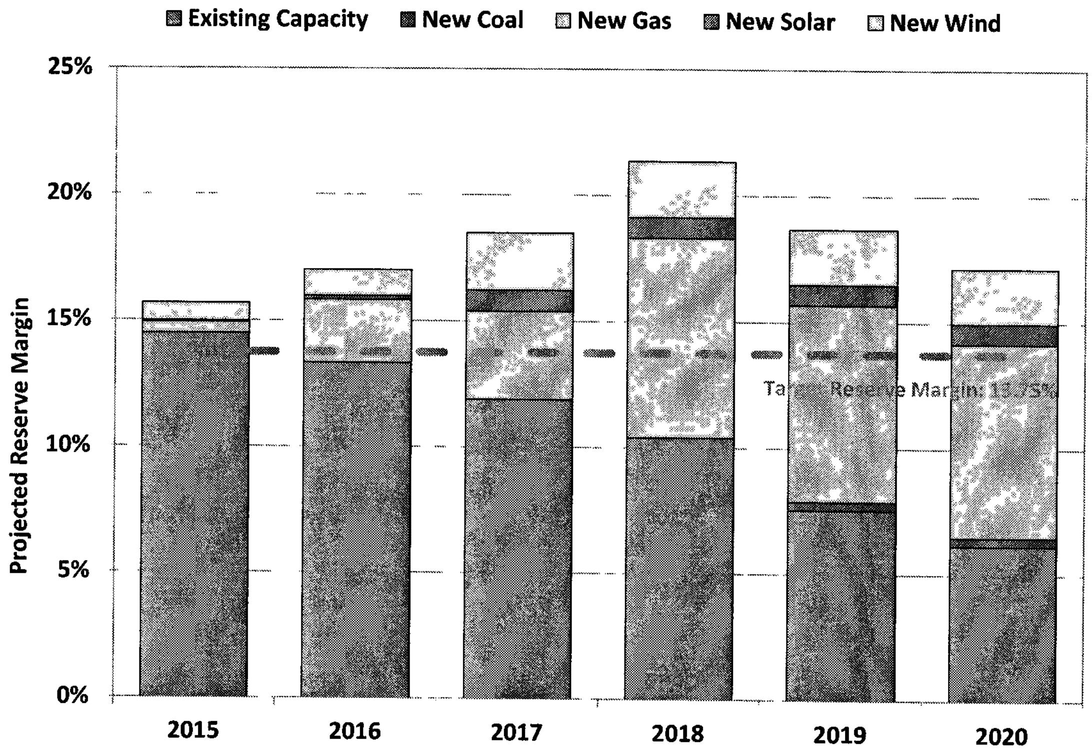
Second, the costs of new entry used in this report are generic and reflective of the costs of new resources on a new, undeveloped, greenfield site. They have been reduced somewhat to reflect the lower costs of construction in Texas. However, companies may have opportunities to build generation at much lower cost than these estimates; either by having access to lower equipment costs, possibly though large, long-term supply agreements, or by adding generation to existing sites, or through some combination of both.

Third, in addition to the equipment cost, financing structures and costs can vary greatly between suppliers. Again, the net revenue analysis assumes generic financing costs that a specific supplier may be able to improve on. 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. Suppliers will develop their own view of future expected revenue which may include a power sales contract for some amount of the output. A power sales contract could provide them with more revenue certainly than is available by relying solely on the ERCOT wholesale market. 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.

2. 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 projection of reserve margins developed prior to the summer of 2015.

Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Reports / 2015 from December 2014 and 2016-2020 from May 2015

This figure indicates that the region will have a 15.7 percent reserve margin heading into the summer of 2015. 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. Further, this outlook is very different than in 2013 when reserve margins were expected to be below the target level of 13.75 percent for the foreseeable future.

In 2013 the expected reserve margin for 2016 was 10.4 percent, much lower than the current expectation for 2016 of 17 percent. This increase in expected reserve margin is not due to an increase in available generating resources, but rather to ERCOT's revised long-term load forecasting methodology and resulting reduction in the forecasted peak demand. The quantity of available resources expected in 2016 as shown in the May 2013 Capacity Demand Report (CDR) is nearly identical to the quantity of resources shown in the May 2015 CDR. Although the total expected capacity of resources has not changed between the two CDRs, the mix has changed. Almost 1,700 MW of increased wind capacity expected in 2016 has been offset by reductions in the total capacity expected from natural gas and coal.

Looking beyond 2016, several new additions have been announced and meet the requirements for being included in the CDR. The bulk of this new capacity is from new gas units (greater than 5 GW) sited at locations across the ERCOT region. Wind additions also are projected to continue, with 1.5 GW of capacity shown in the CDR representing nearly 10 GW of installed wind capacity. Rounding out the additions is more than 500 MW of solar capacity.

3. 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. To incent generation additions the market design must provide revenues such that the marginal resource receives revenues sufficient to make that resource economic. Generators earn revenues from three sources: energy prices during non-scarcity, energy prices during scarcity, and capacity payments. Generator revenue in ERCOT is overwhelmingly derived from energy prices under both scarcity and non-scarcity conditions.

Expectations for energy pricing under non-scarcity 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 and to maintain existing resources. This will occur when energy prices are allowed to rise substantially at 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 for 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 result in falling planning reserve margins, the PUCT has devoted considerable effort since 2012 deliberating issues related to resource adequacy. To date, the PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to improve ERCOT's shortage pricing based on the demand for operating reserves.

The Operating Reserve Demand Curve (ORDC) is a shortage pricing mechanism that reflects the loss of load probability (LOLP) at varying levels of operating reserves multiplied by the value of lost load (VOLL). Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC provides a new form of shortage pricing for online and offline reserves, as well as energy. As available reserve capacity drops to 2,000 MW, payment for reserve capacity will rise to VOLL, or $9,000 per MWh.

The initial implemetation of ORDC went into effect on June 1, 2014 and included the introduction of real-time reserve on-line and off-line adders. The load-weighted real-time energy price for the period of 2014 after ORDC implementation (i.e. after June 1st) was $35.68 per MWh. Of that total, $0.26 per MWh (less than 1 percent) was the on-line reserve adder. The on-line reserve adder includes the off-line adder, which was $0.09 per MWh for this time period.

G. Analysis of Competitive Performance

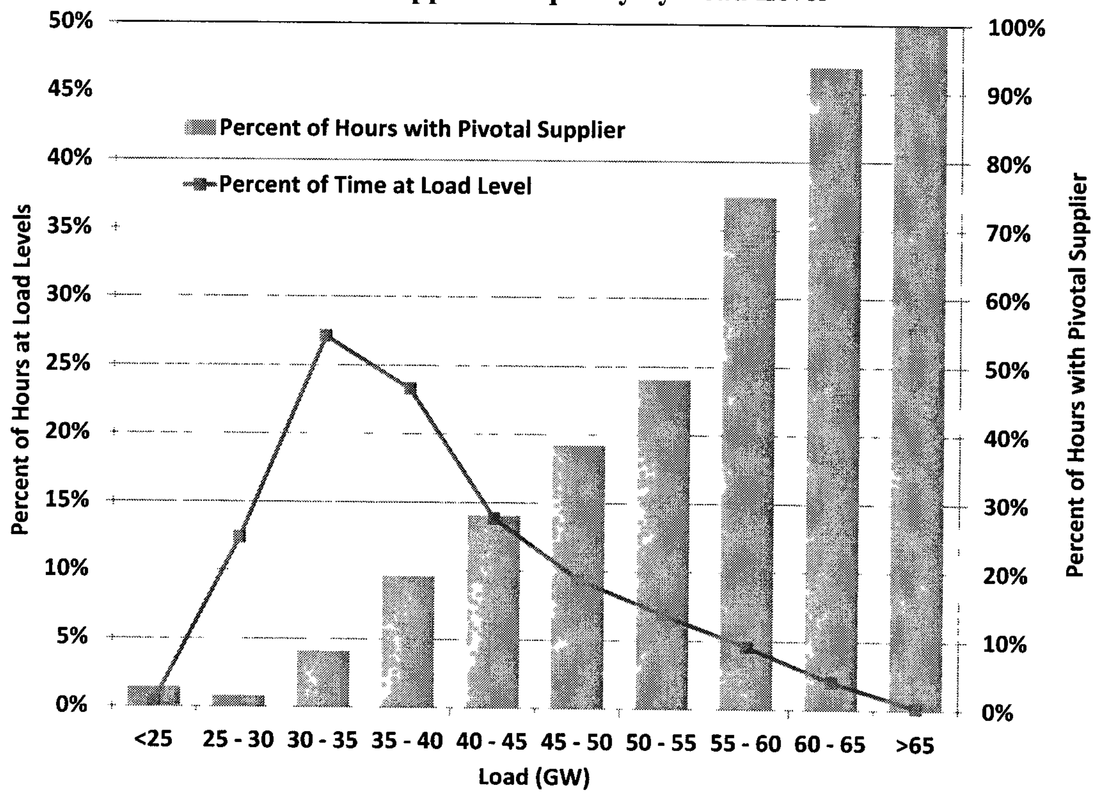
The report evaluates market power from two perspectives, structural (does market power exist) and behavioral (have attempts been made to exercise it).

1. Structural Market Power

The Residual Demand Index (RDI) is used as the primary indicator of potential structural market power. The RDI measures 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; that is, 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.

Pivotal Supplier Frequency by Load Level



The figure above summarizes the results of the RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 100 percent of the time. The figure also displays the percentage of time each load level occurs. By combining these values it can be determined that there was a pivotal supplier in approximately 23 percent of all hours of 2014, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that 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

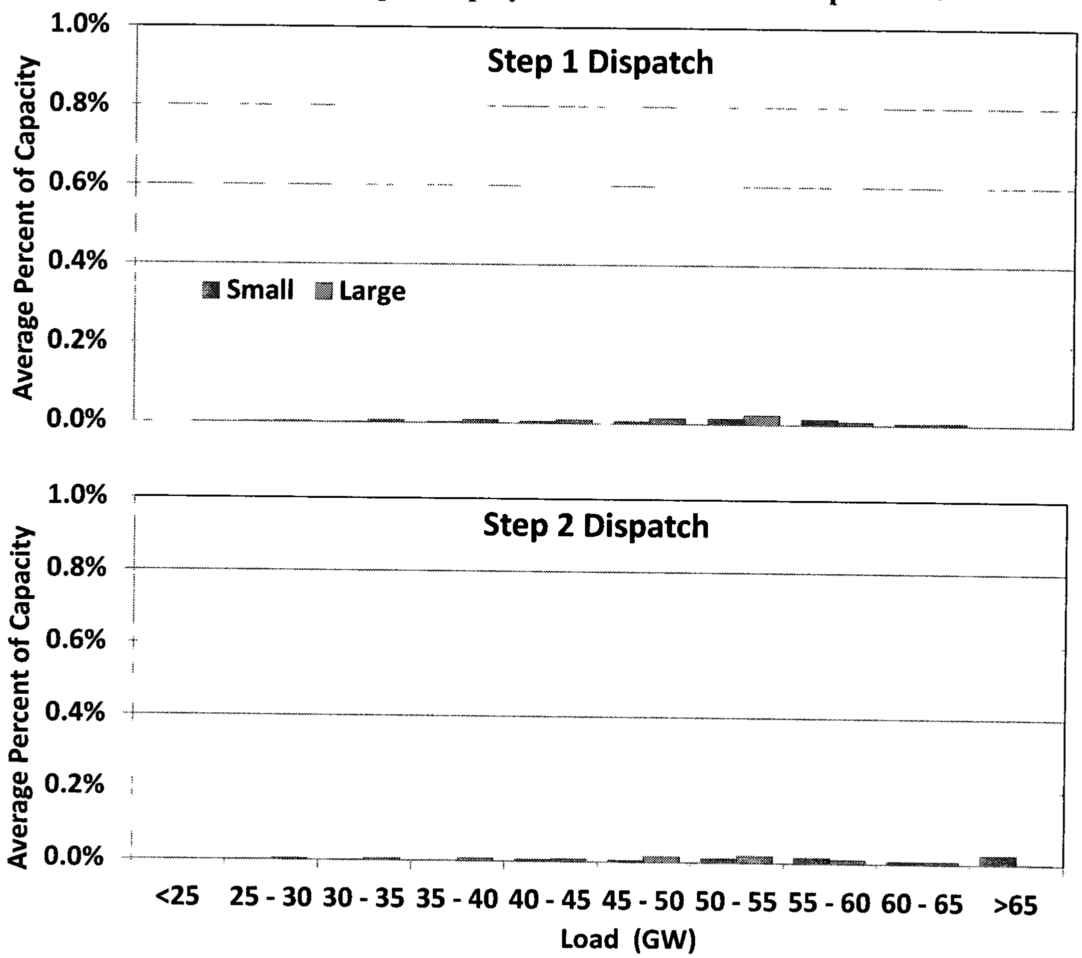
This subsection assesses potential physical withholding and economic withholding using a variety of metrics; starting with an evaluation of potential economic withholding, which is conducted by calculating an "output gap." The output gap is defined as the quantity of energy that is not being produced 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.

Resources are considered for inclusion in the output gap when they are committed and producing at less than full output. Energy not produced from committed resources is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $50 per MWh, which serves as an estimate of the marginal production cost of energy from that resource.

The output gap is measured at both steps in ERCOT's two-step dispatch because if a market participant has sufficient market power, it might raise its offer in such a way as to increase the reference price in the first step of ERCOT's dispatch process. 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 out whether a market participant is withholding in a manner that may influence the reference price.

The ultimate output gap is 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. 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 due to a market participant exerting market power. The following figure shows the output gap after each step.

Incremental Output Gap by Load Level and Participant Size



In addition to this analysis of potential economic withholding, outages, deratings, and economic units that were not committed were also evaluated to identify other means suppliers may have used to withhold resources. Very little evidence of potential physical withholding was found. Based on the analyses described above and the results of our ongoing monitoring, we find the overall performance of the ERCOT market to be competitive in 2014.

H. Recommendations

Overall, we find that the ERCOT market performed well in 2014. Nonetheless, we have identified and recommended a number of potential improvements. We describe these recommendations in this section.

Our recommendation to modify the Protocols related to proxy energy offer curve provisions has been addressed in NPRR 662. With this modification, available capacity without an associated energy offer will be priced at the same price as the last megawatt associated with a submitted offer, rather than being priced at the system-wide offer cap. We assert that the more appropriate price to assume for this available, but un-offered capacity is the highest price that the resource has actually submitted. This is particularly true given the recent changes raising the system-wide offer cap to $9000 per MWh and the implementation of ORDC, under which available capacity will receive a reserve adder payment, whether it has a submitted offer or not.

1. <u>Implement real-time co-optimization of energy and ancillary services</u>

   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 the market to substitute its procurements between units on an interval-by-interval basis to minimize costs and set efficient prices. The second benefit, more fully described in Section II.D, Ancillary Services Market at page 38, would be the improved handling of situations when an entity that was selected to provide ancillary services becomes unable to fulfill that commitment, e.g. due to a generator forced outage. For these reasons we continue to recommend ERCOT implement real-time co-optimization of energy and ancillary services.

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

   ERCOT has been producing non-binding generation dispatch and price projections for more than two years, but it is unclear what, if any, effect this indicative information has had on the operational actions of ERCOT or market participants. This indicative information has highlighted weaknesses in ERCOT's short term load forecasting process.

ERCOT has identified improvements to its forecasting process and once those improvements have been implemented, ERCOT and stakeholders will undertake an evaluation of the benefits of implementing a multi-interval real-time market. We continue to believe there is 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 to this process that would allow it to facilitate better real-time generator and load commitments.

3. <u>Implement changes to ensure all load deployments are reflected in the real-time dispatch energy and reserve prices.</u>

   When load is not being served – either because the price is higher than the load's willingness to pay, or the load has been curtailed due to emergency conditions – the energy price should reflect the value to load of not being served. Currently, when load is curtailed, the energy price reflects the cost of supply to serve the reduced amount of load. While Phase 1 of Loads in SCED made some progress in this direction, the implementation of NPRR626 will go further, by introducing a second execution of SCED in situations when loads are deployed. This second execution will determine the higher LMPs that would have occurred if the load had continued to be served. The price increment (reliability adder) will be added to settlement point prices. We will evaluate the effects of NPRR626 implementation in 2015. A further step would be to integrate bids from load resources and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal.

4. <u>Price future ancillary services based on the shadow price of procuring the service.</u>

   In the context of ongoing stakeholder discussions about Future Ancillary Services, we re-introduce 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. Although we are not recommending any changes to the current ancillary services procurement or pricing practices, inefficiencies exist in the current practices for responsive reserves. As the services and requirements for those services are re-defined, we believe it is appropriate to include this change to improve pricing efficiency and supplier incentives.

I. REVIEW OF REAL-TIME MARKET OUTCOMES

As is typical 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 forward markets (including bilateral 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, artificially low prices in the real-time energy market will translate to artificially-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 2014.

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.

The ERCOT-wide price is the load-weighted average of the real-time market prices from all load zones. Ancillary services costs are estimated based on total system demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves. Uplift costs are assigned market-wide on a load-ratio share basis to pay for costs associated with reliability unit commitments and reliability must run contracts. Starting June 1, 2014, with the implementation of the Operating Reserve Demand Curve, the real-time energy price includes the Online Reserve Adder. In the figure below this adder has been separated out from the energy price.

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

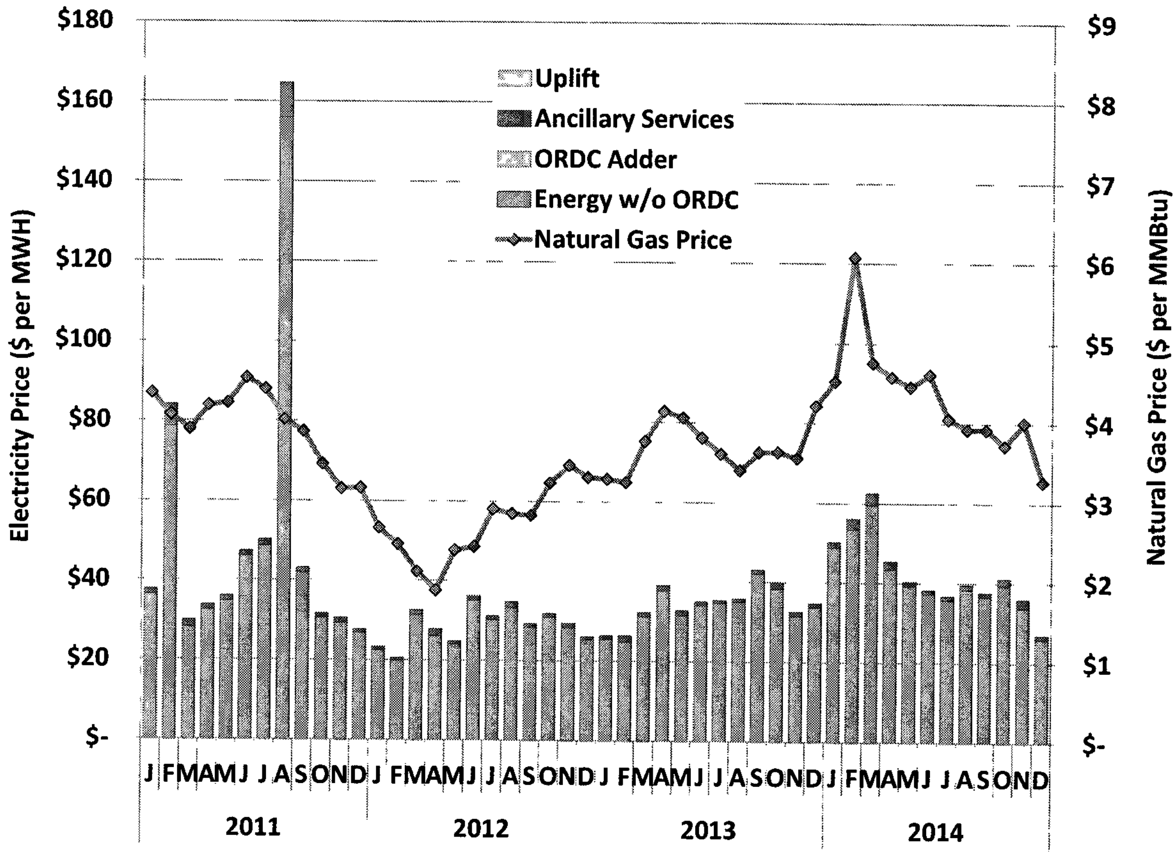


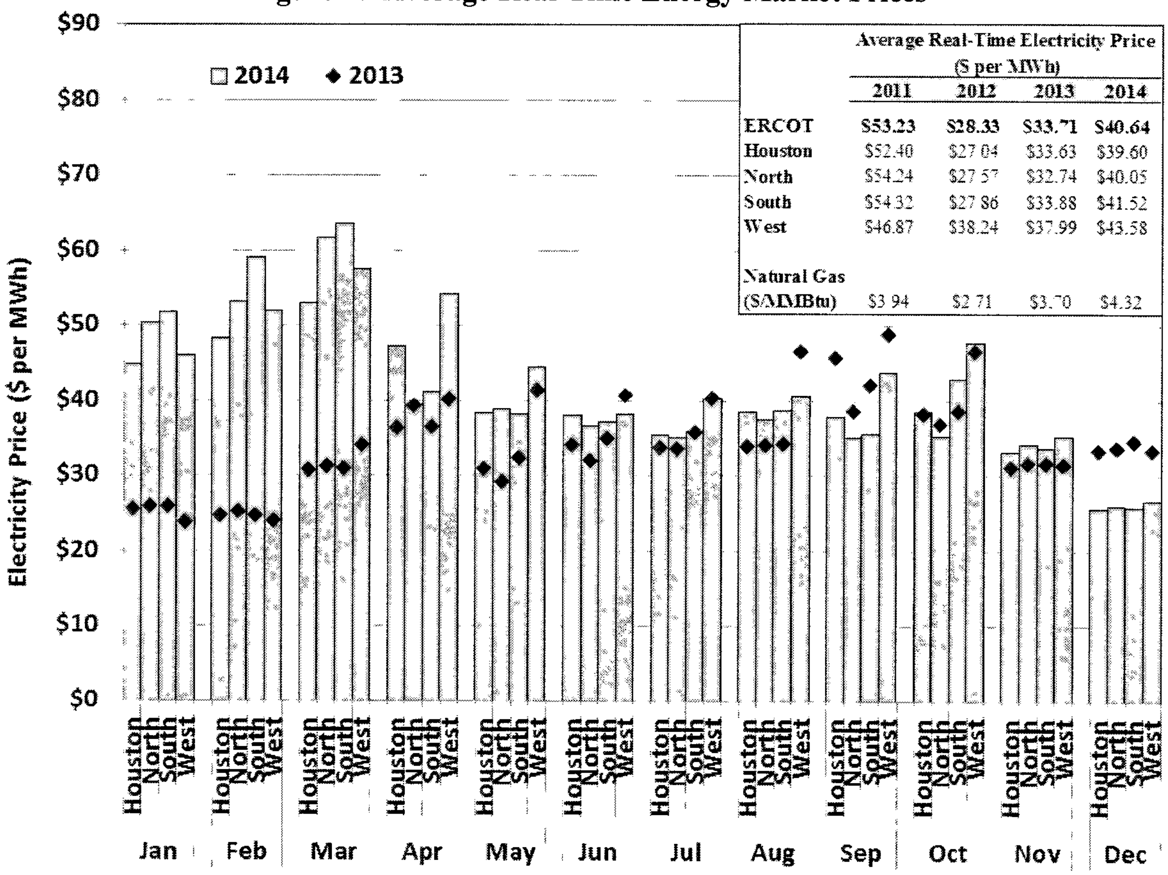
Figure 1 shows the monthly average all-in price for all of ERCOT from 2011 to 2014 and the associated natural gas price. This figure indicates that natural gas prices were a primary driver of the trends in electricity prices from 2011 to 2014. Again, this is not surprising given that natural gas is a widely-used fuel for the production of electricity in ERCOT, especially among generating units that most frequently set locational marginal prices in the nodal market.

The all-in price of electricity is equal to the load-weighted average real-time energy price, plus ancillary services, and real-time uplift costs per MWh of real-time load. The largest component of the all-in cost of wholesale electricity is the energy cost. ERCOT average real-time all-in prices were 21 percent higher in 2014 than in 2013. The ERCOT-wide load-weighted average price was $40.64 per MWh in 2014 compared to $33.71 per MWh in 2013. The Online Reserve adder was $0.26 per MWh for the last half of the year.

The increase in real-time energy prices was correlated with much higher fuel prices in 2014. The high correlation of natural gas prices and energy prices shown in the figure is consistent with expectations in a well-functioning market. Fuel costs constitute most of the marginal production costs for generating resources in ERCOT and competitive markets provide incentives for suppliers to submit offers consistent with marginal costs. The average natural gas price in 2014 was $4.32 per MMBtu, a 17 percent increase compared to $3.70 per MMBtu in 2013. Gas prices were highest in the first quarter when unusually cold weather throughout the U.S. resulted in much higher and more volatile natural gas prices.

Figure 2 shows the monthly load-weighted average prices in the four geographic ERCOT load zones during the past four years.

Figure 2: Average Real-Time Energy Market Prices

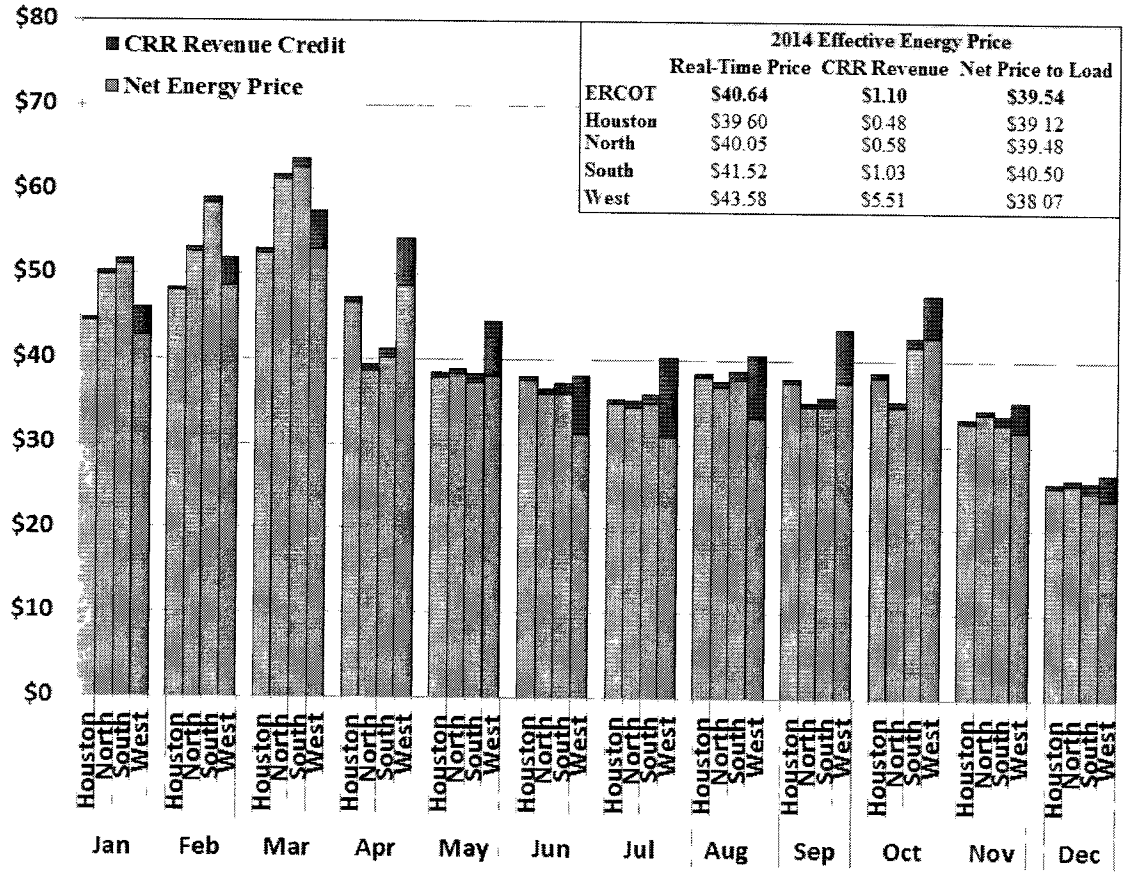


	Average Real-Time Electricity Price ($ per MWh)			
	2011	2012	2013	2014
ERCOT	**$53.23**	**$28.33**	**$33.71**	**$40.64**
Houston	$52.40	$27.04	$33.63	$39.60
North	$54.24	$27.57	$32.74	$40.05
South	$54.32	$27.86	$33.88	$41.52
West	$46.87	$38.24	$37.99	$43.58
Natural Gas ($/MMBtu)	$3.94	$2.71	$3.70	$4.32

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 contract prices.

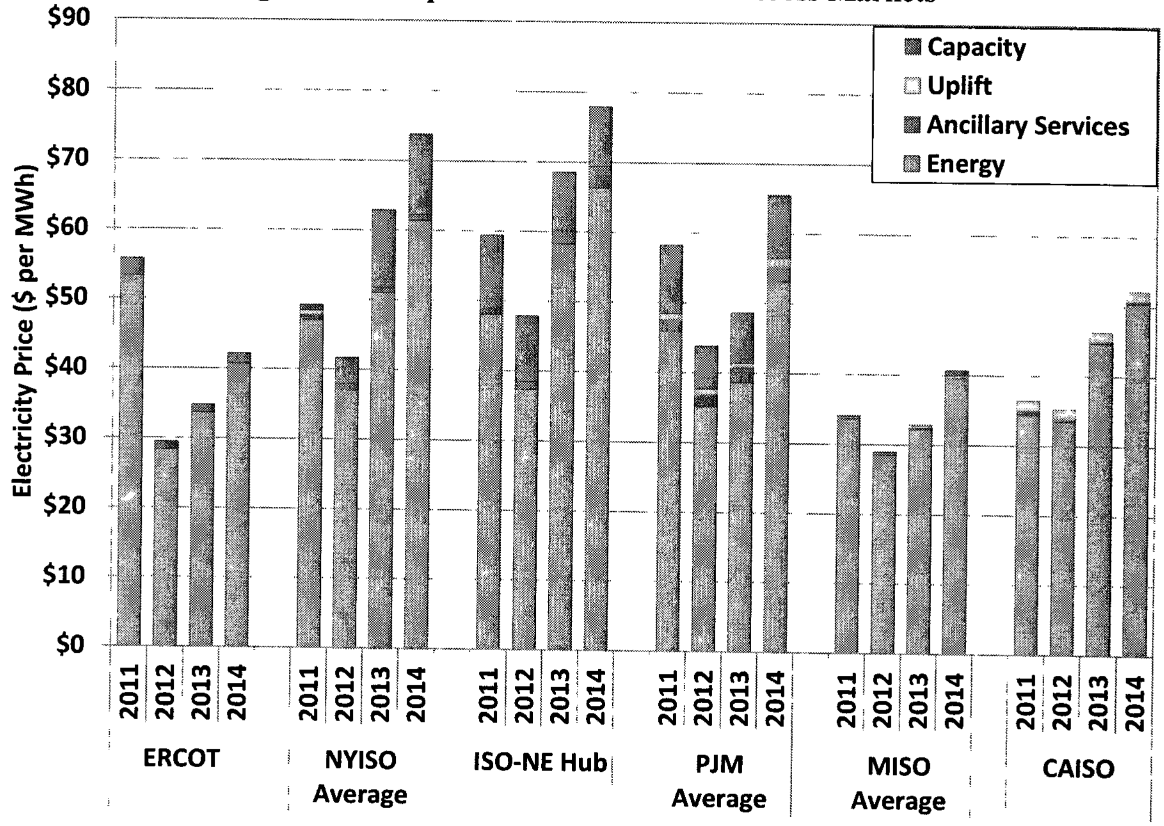
Congestion Revenue Right (CRR) Auction Revenues are distributed to Qualified Scheduling Entities (QSEs) representing load based on a zonal and ERCOT-wide monthly load ratio share. The CRR Auction Revenues have the effect of reducing the total cost to serve load borne by a QSE. Figure 3 below shows the 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 $1.10 per MWh to $39.54 per MWh in 2014.

Figure 3: Effective Real-Time Energy Market Prices



To provide additional perspective on the outcomes in the ERCOT market, the following figure 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, and California ISO.

Figure 4: Comparison of All-in Prices Across Markets

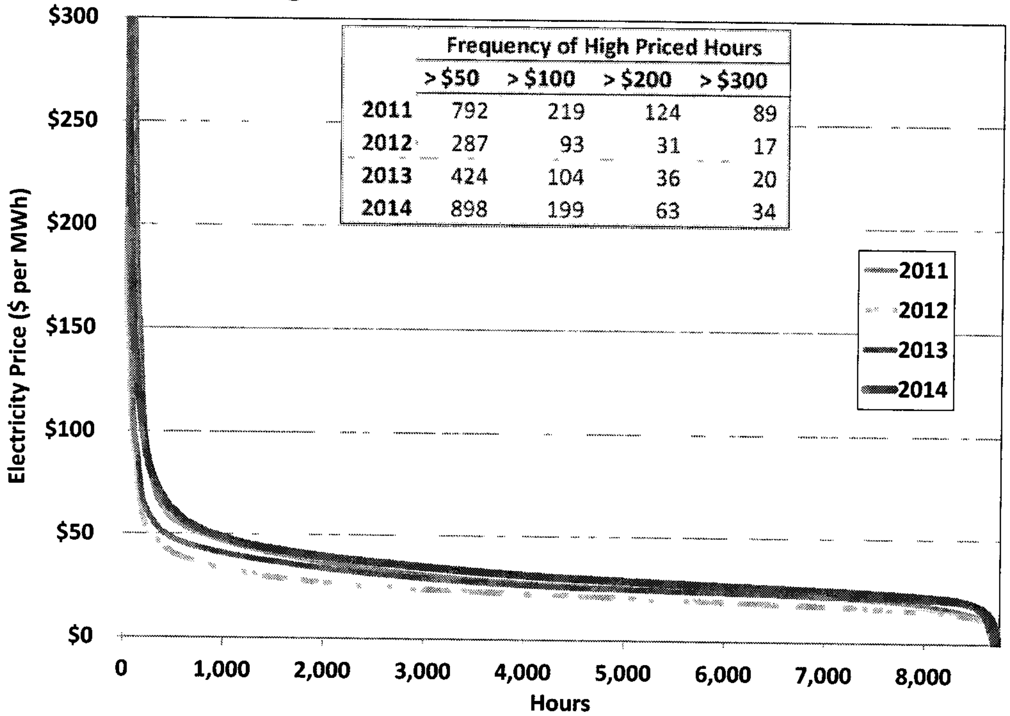


The figure reports each market's average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift for economically out-of-merit resources. Figure 4 shows that ERCOT all-in prices in 2014 were lower than CaISO and the eastern markets of New York, New England and PJM, and on par with MISO.

Figure 5 below presents price duration curves for ERCOT energy markets in each year from 2011 to 2014. 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.

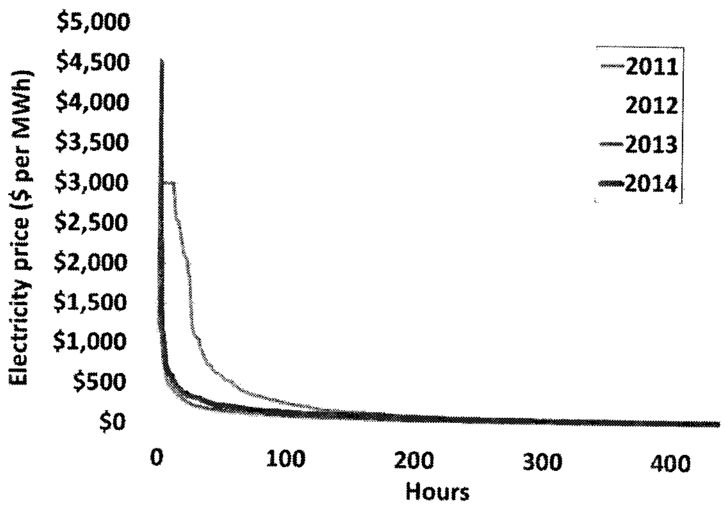
Price levels during 2014 were similar to those in 2011 for most of the year, with both years having 700 to 800 hours with prices exceeding $50 per MWh. Prices in 2012 and 2013 exceeded $50 per MWh much less often. As described later in this section, these lower prices were a result of lower natural gas prices in those two years.

Figure 5: ERCOT Price Duration Curve



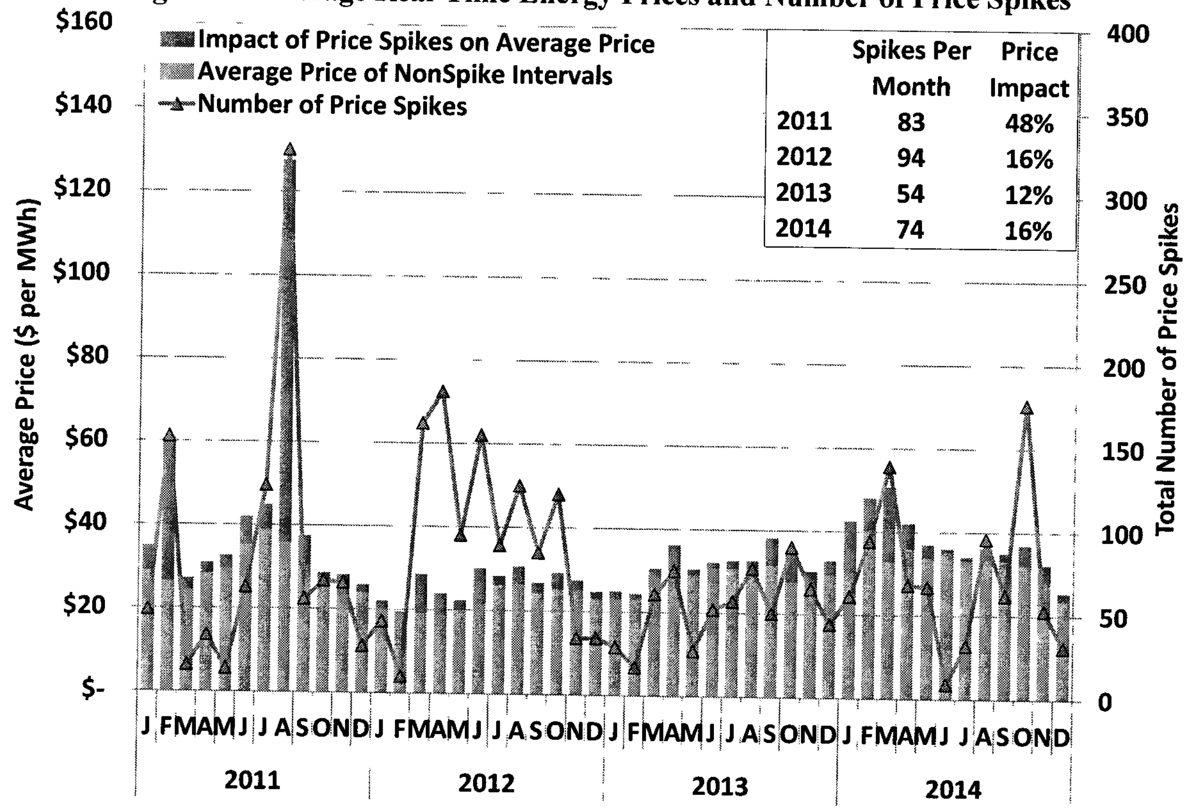
To see where the prices during 2014 diverged from the previous three years, a comparison of prices for the highest 5 percent of hours in each year is presented. In 2011, energy prices for the top 100 hours were significantly higher. These higher prices were due to higher loads leading to more shortage conditions coupled with a more effective shortage pricing mechanism implemented as part of the nodal market design. In 2012, 2013, and 2014, the price duration curves for the top 5 percent of hours are very similar and reflect fewer occasions of shortage conditions.

Figure 6: ERCOT Price Duration Curve – Top 5% 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. Figure 7 shows the average price and the number of price spikes in each month. 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.

Figure 7: Average Real-Time Energy Prices and Number of Price Spikes

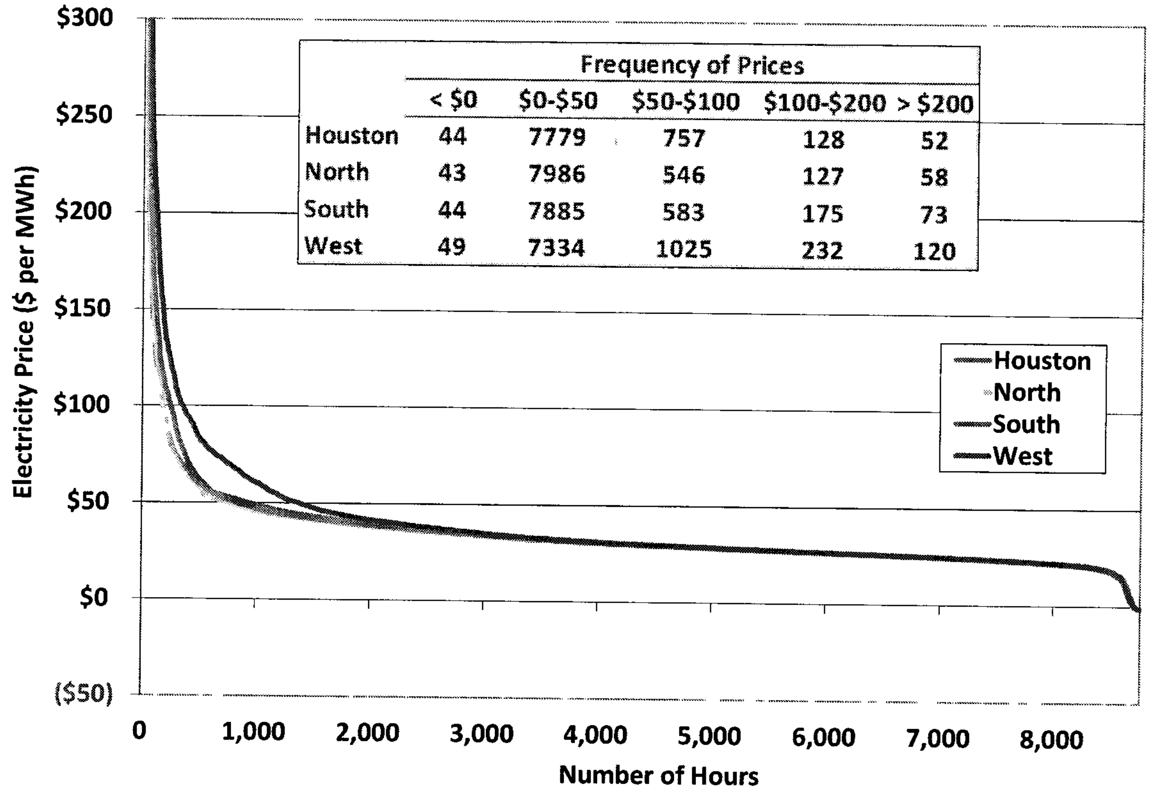


The number of price spike intervals during 2014 averaged 74 per month, an increase from the average of 54 price spike intervals per month during 2013.

To measure the impact of these price spikes on average price levels, the figure also shows average prices with and without the price spike intervals. The top portions of the stacked bars show the impact of price spikes on monthly average price levels. At $14.09 per MWh, the impact of price spikes was the greatest in 2011. In 2012 the frequency of price spikes increased but the magnitude of their price impact decreased to $3.63 per MWh. The magnitude decreased again in 2013 to $3.43 per MWh. The magnitude increased in 2014, with an impact on the average energy price of $5.28 per MWh. Of this price spike impact, $0.20 was due to the effects of the Operating Reserve Demand Curve (ORDC) adder.

To depict how real-time energy prices vary by hour in each zone, Figure 8 shows the hourly average price duration curve in 2014 for the four ERCOT load zones.

Figure 8: Zonal Price Duration Curves

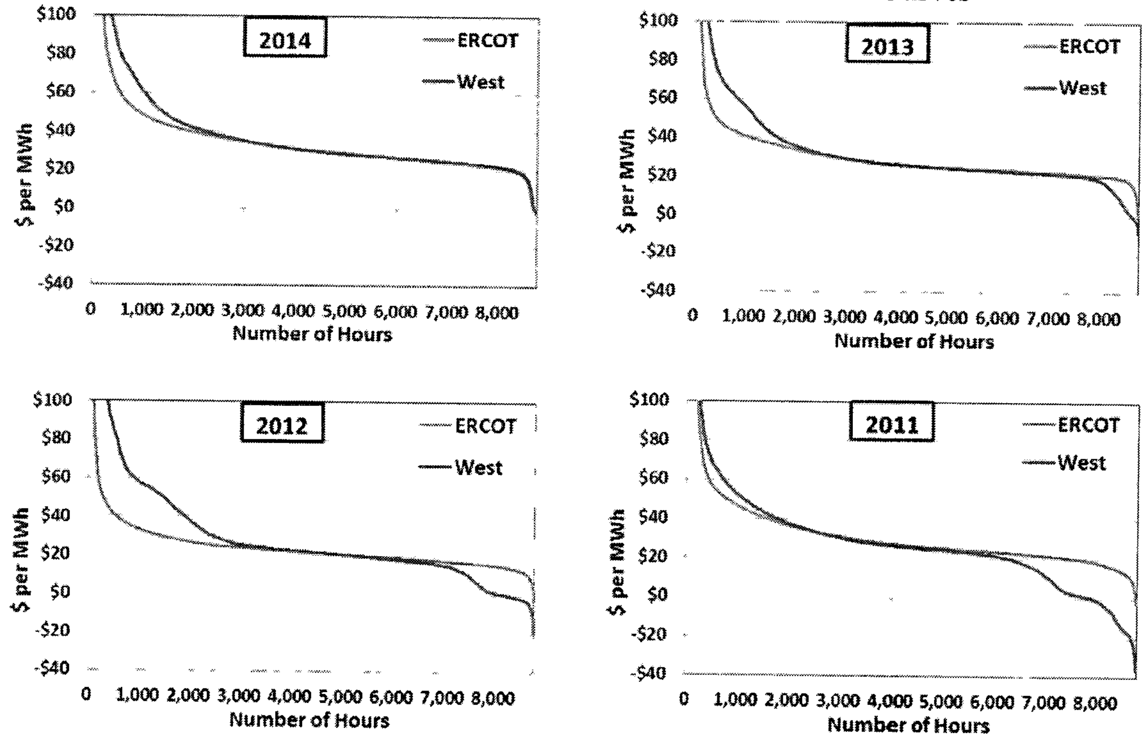


	Frequency of Prices				
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	44	7779	757	128	52
North	43	7986	546	127	58
South	44	7885	583	175	73
West	49	7334	1025	232	120

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. The number of hours with prices less than $0 per MWh was very similar for all zones in 2014. This is notable since for the past several years the West zone has consistently had much more frequent occurrences of negative prices than the other zones. Significant transmission additions have lowered the frequency of depressed West zone prices due to 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 discussed above in Figure 3, these 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 2011 through 2014.

Figure 9: West Zone and ERCOT Price Duration Curves



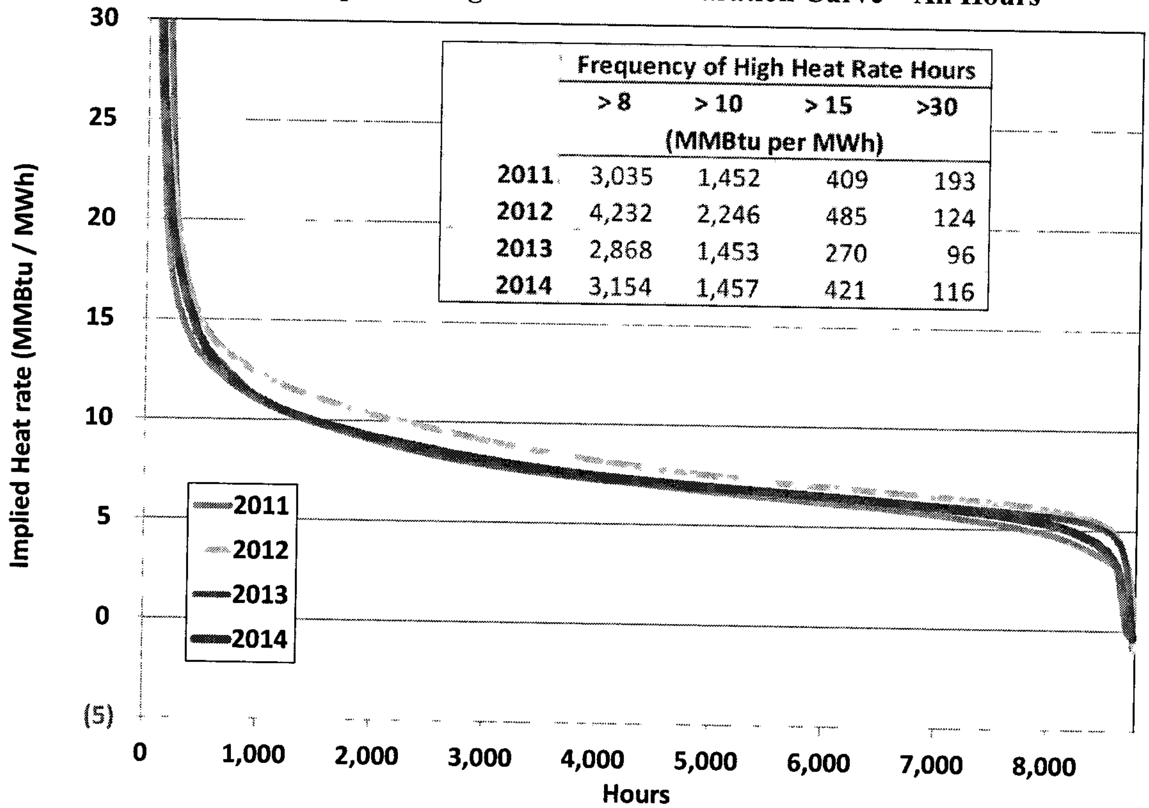
On the low price end, the near elimination in the number of hours when West zone prices were below the ERCOT average can be observed. Note that the minimum West zone prices have increased; that is, become "less negative." West zone prices were noticeably higher than the ERCOT average for a significant number of hours in 2014, although not to the same magnitude as they were in 2013 (which was itself a reduction from 2012). But like 2013 and 2012, 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 being greater than the ERCOT average. As noted previously, however, 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.

More details about the transmission constraints influencing energy prices in the West zone are provided in Section III. Transmission and 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 clearly identify changes in electricity prices that are not driven by changes in natural gas prices, 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.[1]

Figure 10: Implied Marginal Heat Rate Duration Curve – All Hours



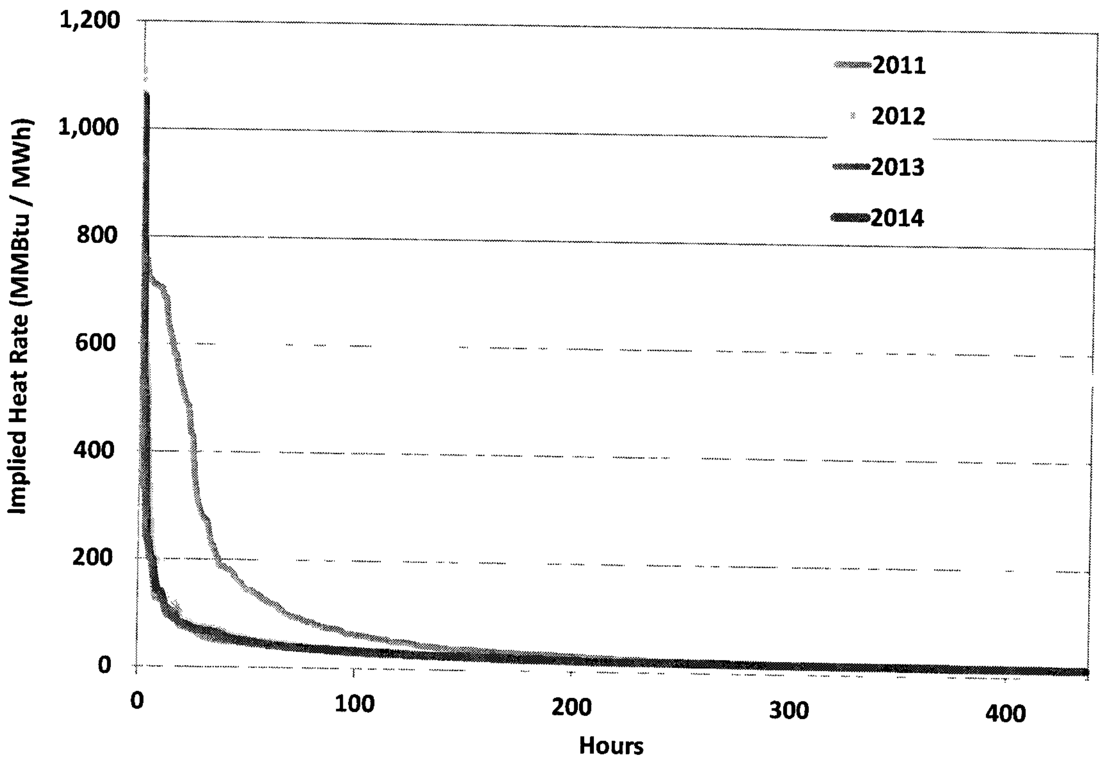
Implied heat rates in 2012 were noticeably higher for the majority of hours, as compared to the other three years. This can be explained by the very low natural gas prices experienced in 2012, and resulting pricing outcomes which were influenced by coal, not natural gas, being the

[1] 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.

marginal fuel.[2] For most hours, there are no discernable differences between 2011, 2013, and 2014.

Taking a closer look at the implied marginal heat rates for the top five percent of hours for years 2011 through 2014 in Figure 11 also shows that the implied heat rates in 2012, 2013, and 2014 are also very similar; 2011 remains an outlier.

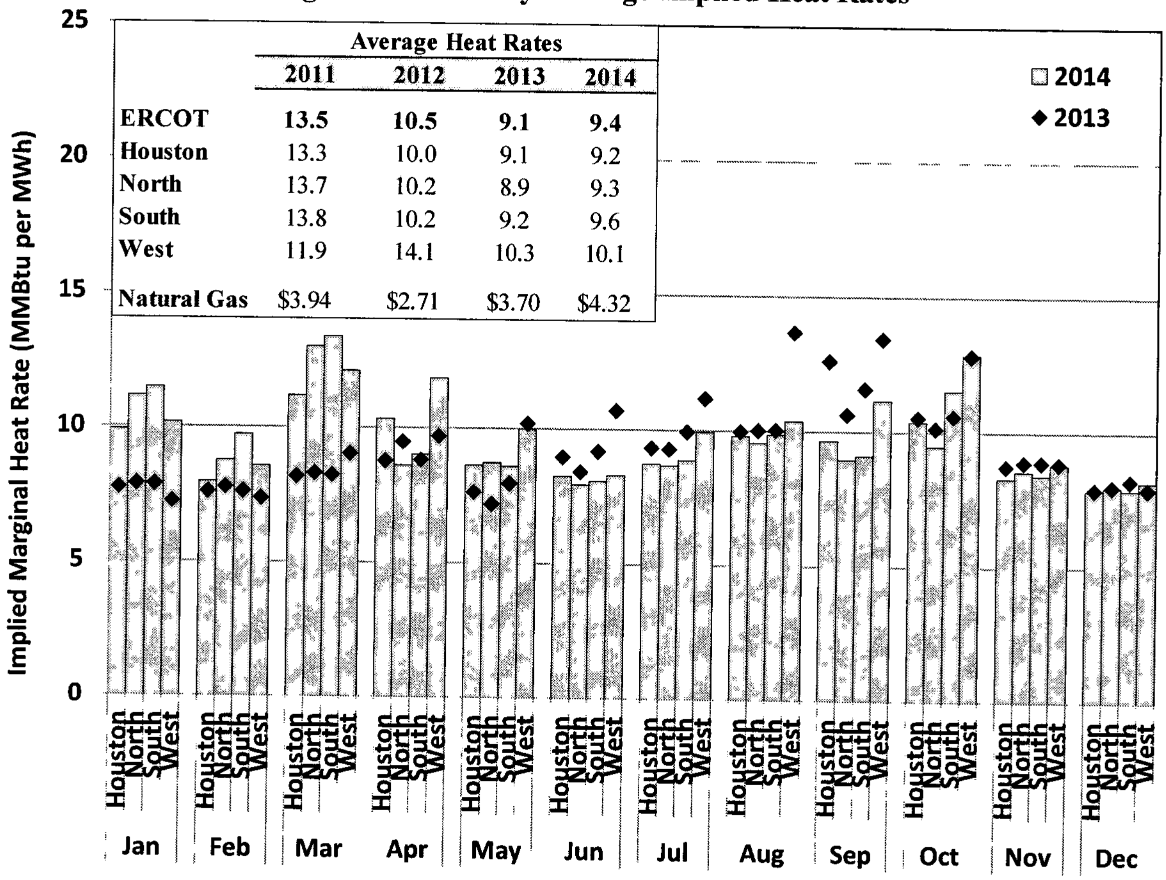
Figure 11: Implied Marginal Heat Rate Duration Curve – Top Five Percent of Hours



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 2013 and 2014, with annual average heat rate data for 2011 through 2014. This figure is the fuel price-adjusted version of Figure 2 in the prior subsection. Adjusting for natural gas price influence, Figure 12 shows that the annual, system-wide average implied heat rate increased in 2014 compared to 2013.

[2] *See* the 2012 ERCOT SOM report at pages 12-13.

Figure 12: Monthly Average Implied Heat Rates

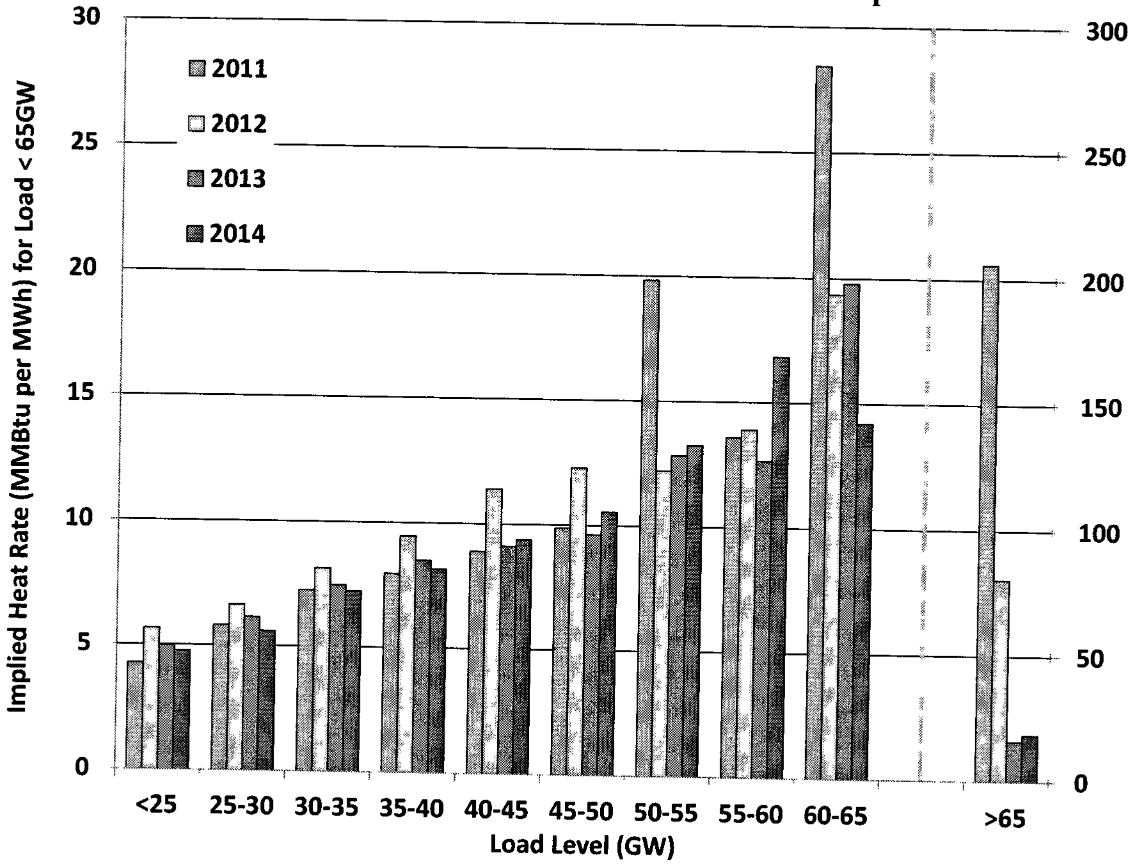


	Average Heat Rates			
	2011	2012	2013	2014
ERCOT	**13.5**	**10.5**	**9.1**	**9.4**
Houston	13.3	10.0	9.1	9.2
North	13.7	10.2	8.9	9.3
South	13.8	10.2	9.2	9.6
West	11.9	14.1	10.3	10.1
Natural Gas	$3.94	$2.71	$3.70	$4.32

The monthly average implied heat rates in 2014 are generally higher than those in 2013 through May, after which they drop below the 2013 heat rates. This trend is generally consistent with rising gas prices and higher loads in early 2014 compared to the same months of 2013.

The examination of implied heat rates from the real-time energy market concluded by evaluating them at various load levels. Figure 13 below provides the average heat rate at various system load levels from 2011 through 2014.

Figure 13: 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. Although a generally positive relationship exists, there is a noticeable disparity for loads between 50 and 55 GW. During the extreme cold weather event in early February 2011, loads were at this level while prices reached $3,000 per MWh for a sustained period of time. The higher heat rates observed at lower loads in 2012 are likely due to the displacement of generation from coal units by generation from natural gas units when low natural gas prices were experienced during that year.[3]

There are two noticeable differences in 2014 relative to the other years. The first is the higher implied marginal heat rate at load levels between 55 and 60 GW. This is due to scarcity pricing that occurred when load was in that range during January. The second is the lower implied

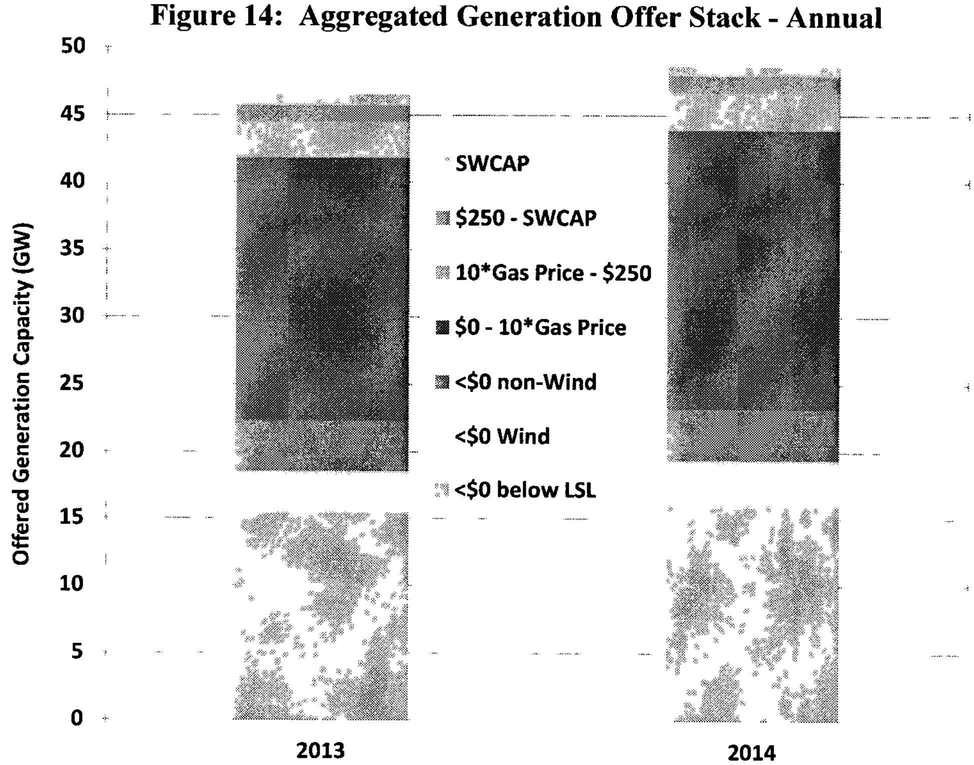
[3] For additional explanation see the 2012 ERCOT SOM report at pages 12-13.

marginal heat rate at load levels between 60 and 65 GW. This is due to the relative lack of scarcity pricing at those load levels during the summer.

C. Aggregated Offer Curves

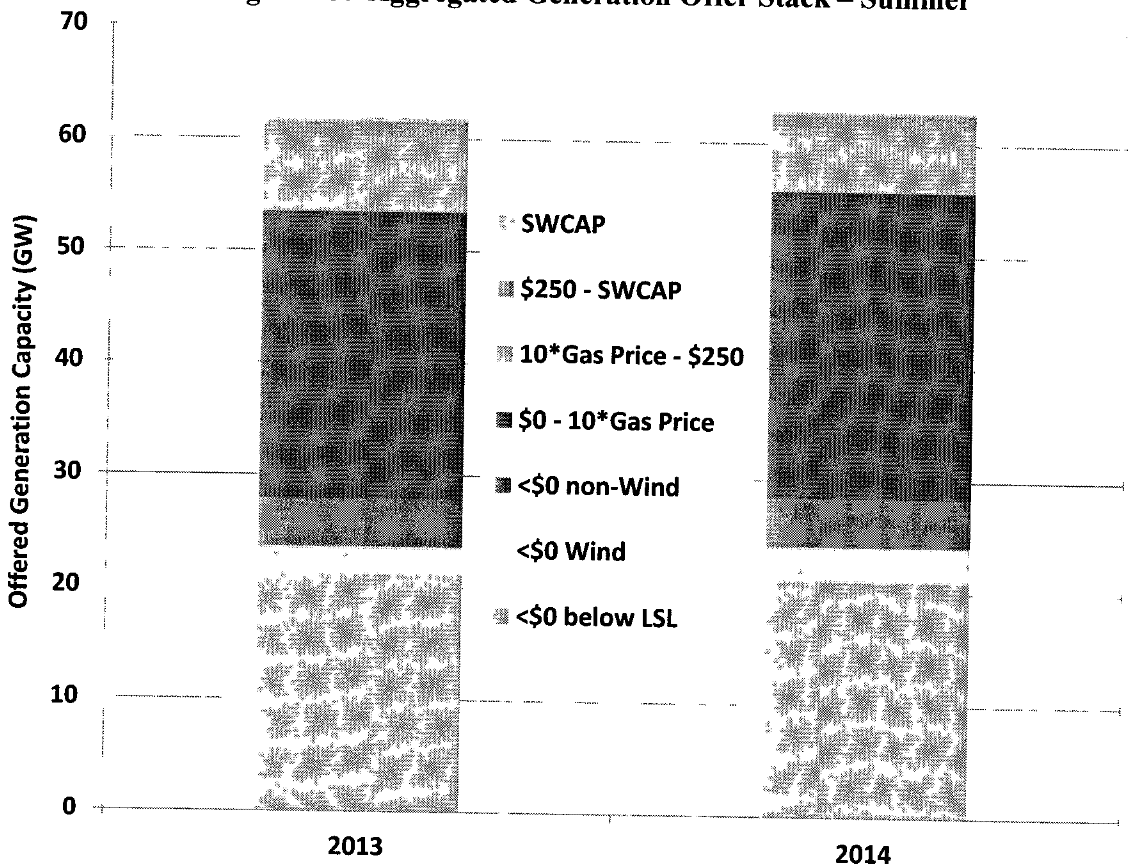
The next analysis compares the quantity and price of generation offered in 2014 to that of 2013. By averaging the amount of capacity offered at selected price levels, an aggregated offer stack can be assembled. Figure 14 provides the aggregated generator offer stacks for the entire year. Comparing 2014 to 2013, more capacity was offered at lower prices. Specifically, there was approximately 900 MW of additional capacity offered at prices less than zero. This was split between offers from wind generators (400 MW) and capacity below generators' low operating limits (500 MW). There was approximately 1,200 MW of additional capacity offered in 2014 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 $250 per MWh was similar in the both years. With smaller changes to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack was roughly 2,100 MW greater in 2014 than in 2013.

Figure 14: Aggregated Generation Offer Stack - Annual



The next analysis provides a similar comparison for only the summer season. As shown below in Figure 15, the changes in the aggregated offer stacks between the summer of 2013 and 2014 were similar to those just described. Comparing 2013 to 2014, there were approximately 2,300 MW additional capacity offered at prices less than 10 multiplied times the daily natural gas price; 600 MW at prices less than zero; and 1,700 MW at prices greater than zero. There was approximately 1,000 MW less capacity offered at prices between 10 multiplied by the daily natural gas price and $250 per MWh. With smaller reductions to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack for the summer season was approximately 1,000 MW greater than in 2013.

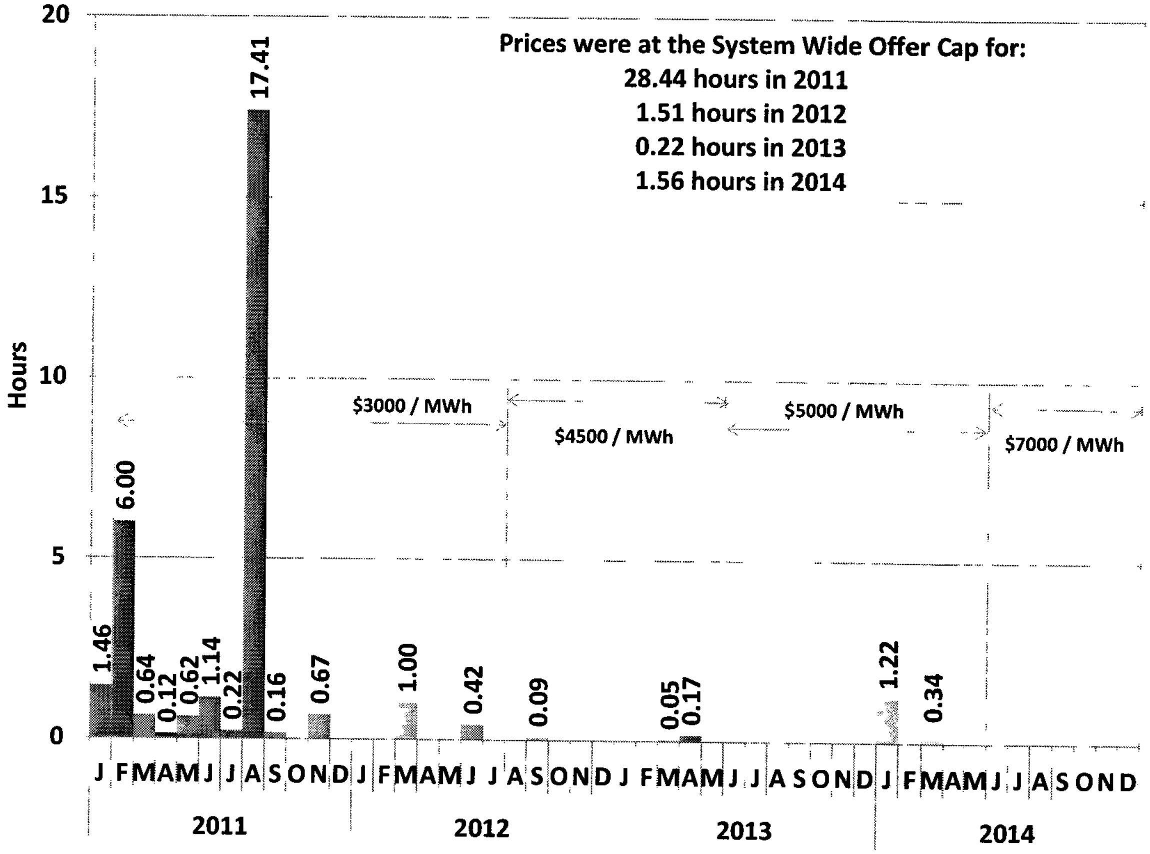
Figure 15: Aggregated Generation Offer Stack – Summer



D. Prices at the System-Wide Offer Cap

Revisions to 16 TEX. ADMIN. CODE § 25.505 raised the system-wide offer cap to $5,000 per MWh effective June 1, 2013; $7,000 per MWh effective June 1, 2014; and $9,000 per MWh effective June 1, 2015. As more fully described later in Section V. Resource Adequacy, independent of the energy offers by generators, energy prices rise toward the system-wide offer cap as available operating reserves approach minimum required levels to reflect the degradation in system reliability. Given the ERCOT market's reliance on these high real-time prices, Figure 16 below shows the aggregate amount of time when the real-time energy price was at the system-wide offer cap, displayed by month.

Figure 16: Prices at the System-Wide Offer Cap



There were no instances in 2014 of energy prices rising to the cap after the system-wide offer cap was increased to $7,000 per MWh on June 1. Prices during 2014 were at the system-wide offer cap for only 1.56 hours, an increase from 0.22 hours in 2013 and a slight increase from the 1.51 hours experienced in 2012. All years were much lower than the 28.44 hours at the cap experienced in 2011 and the average amount expected over the long term in an energy-only market.

The next figure provides a detailed comparison of each August's load, required reserve levels, and prices for 2011 through 2014. There were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012, 2013, and 2014 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 17: Load, Reserves and Prices in August