Control Number: 34677

Item Number: 9

Addendum StartPage: 0

POTOMAC ECONOMICS

RECEIVED
2014 SEP 29 PM 3:54
PUBLIC UTILITY COMMISSION
FILING CLERK

2013 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

September 2014

9

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2013, 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. 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 PUCT Substantive Rule 25.505(g).

Key findings and statistics from 2013 include the following:

- The ERCOT wholesale market performed competitively in 2013.
- The ERCOT-wide load-weighted average real-time energy price was $33.71 per MWh in 2013, a 19 percent increase from $28.33 per MWh in 2012. The increase was primarily driven by higher natural gas prices in 2013.
  - The average price for natural gas was 37 percent higher in 2013 than in 2012, increasing from $2.71 per MMBtu in 2012 to $3.70 per MMBtu in 2013.
  - Loads in 2013 were slightly higher than 2012, but the frequency of shortage conditions decreased. Total ERCOT load in 2013 was 2.1 percent higher than 2012, while the peak load increased by 1.0 percent.
  - Prices at the system-wide offer cap were experienced in dispatch intervals which totaled less than 15 minutes in 2013.
- The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. Given the increase in natural gas prices, a decrease in congestion revenue is a testament to the benefits accrued from investment in transmission facilities.

- The Odessa area continued to be the most highly congested area in 2013. This and other constraints in west Texas had significant financial impacts, causing the West zone average price to be higher than the ERCOT average for the second year in a row.

- Even with the increased system-wide offer cap implemented in 2013, net revenues provided by the market were once again not sufficient to support new generation entry despite the fact planning reserve margins have fallen to levels that are close to the minimum planning reserve targets.

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.

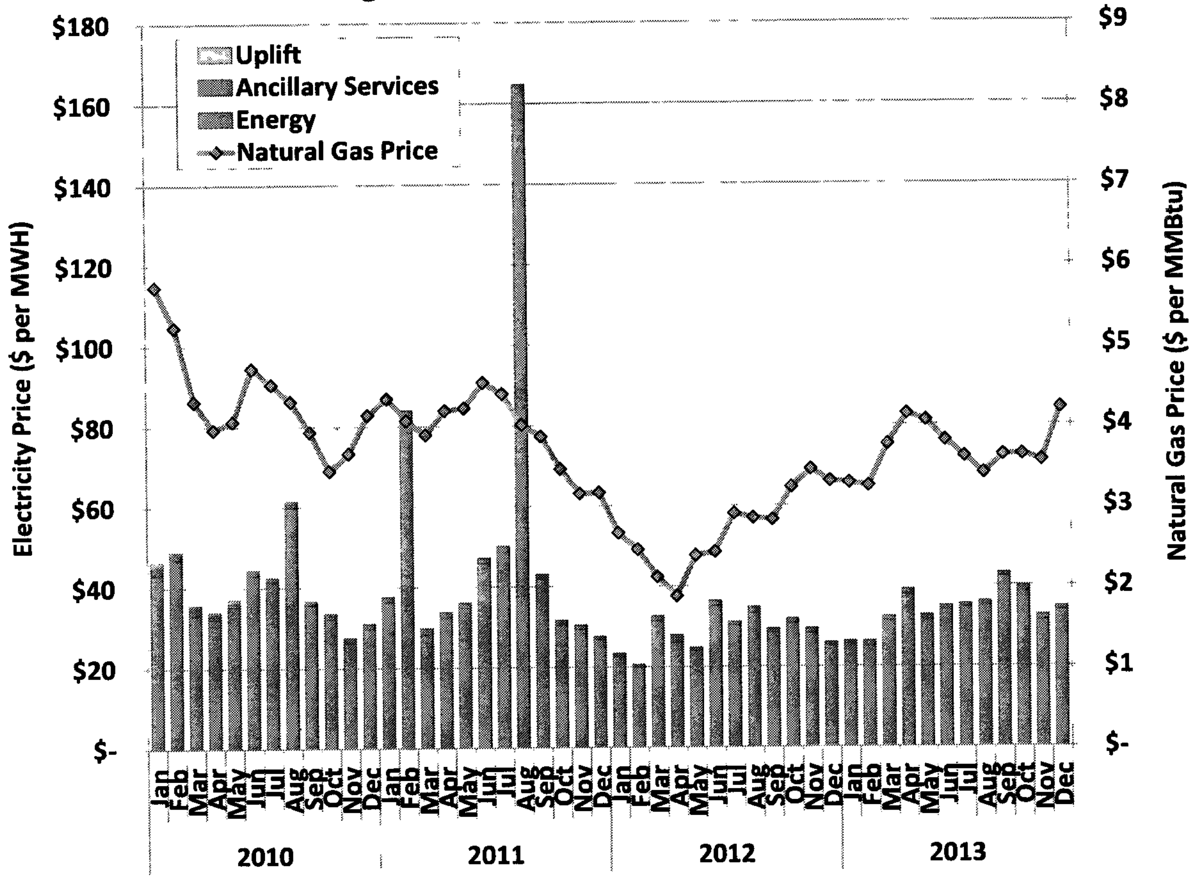
The average real-time energy prices by zone in 2010 through 2013 are shown below:

Average Real-Time Electricity Price ($ per MWh)

	2010	2011	2012	2013
ERCOT	**$39.40**	**$53.23**	**$28.33**	**$33.71**
Houston	$39.98	$52.40	$27.04	$33.63
North	$40.72	$54.24	$27.57	$32.74
South	$40.56	$54.32	$27.86	$33.88
West	$33.76	$46.87	$38.24	$37.99
Natural Gas ($/MMBtu)	$4.34	$3.94	$2.71	$3.70

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 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, which is reflected in the real-time locational marginal prices. ERCOT average real-time market prices were 19 percent higher in 2013 than in 2012. The ERCOT-wide load-weighted average price was $33.71 per MWh in 2013 compared to $28.33 per MWh in 2012.

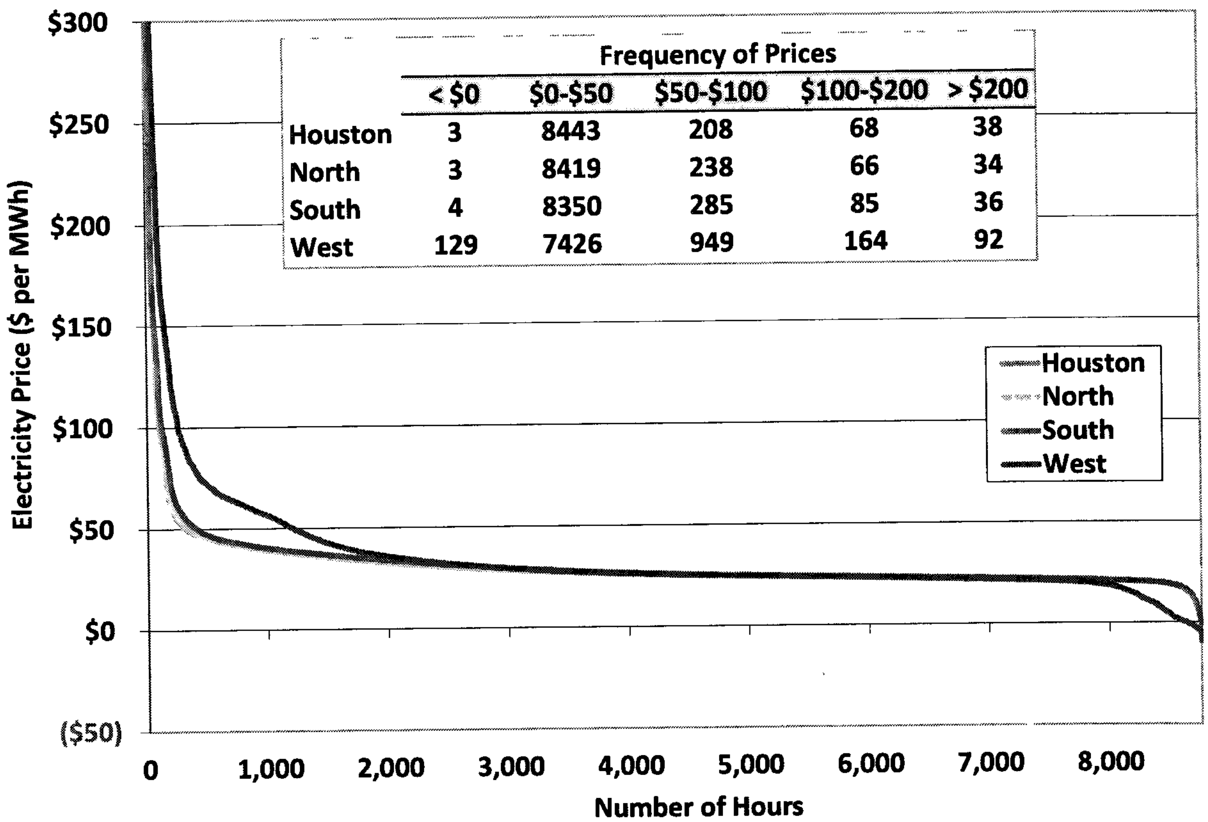
Average All-in Price for Electricity in ERCOT



The increase in real-time energy prices was correlated with higher fuel prices in 2013. The average natural gas price in 2013 was $3.70 per MMBtu, a 37 percent increase compared to $2.71 per MMBtu in 2012. Ancillary service prices represent a relatively small portion of the all-in price of electricity and decreased slightly from 2012 to 2013.

To depict how real-time energy prices vary by hour in each zone, the next figure shows the hourly average price duration curve in 2013 for four ERCOT load zones. 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 with prices greater than $50 per MWh and 129 hours when the average hourly price was less than zero.

Zonal Price Duration Curves



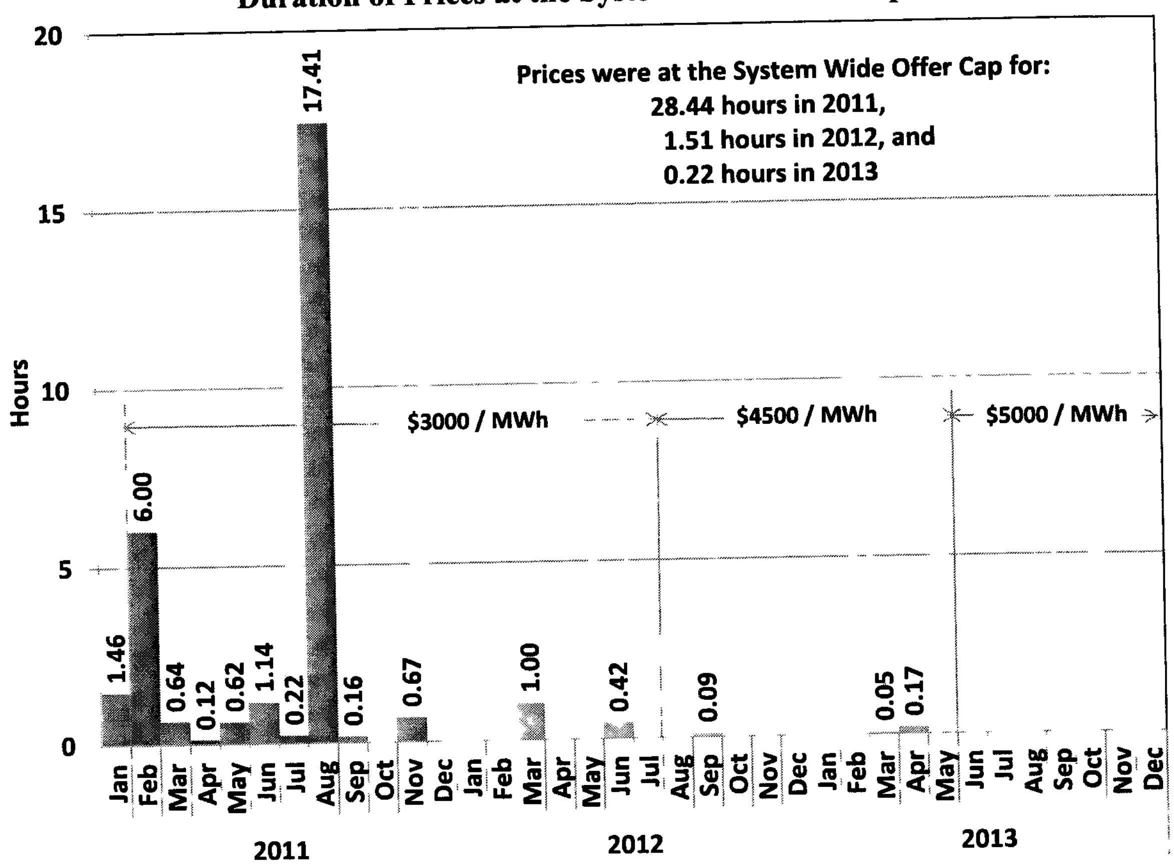
	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	3	8443	208	68	38
North	3	8419	238	66	34
South	4	8350	285	85	36
West	129	7426	949	164	92

As observed over the past few years, West zone prices are lower than the rest of ERCOT when high wind output in the west results in congested transmission interfaces from the West zone to the other zones in ERCOT. Recently, prices higher than the rest of ERCOT have occurred in the West zone due to local transmission constraints that typically occur under low wind and high load, or outage conditions. Specifics about these transmission constraints are provided in Section III, Transmission and Congestion.

As discussed in Section IV, Load and Generation, overall demand for electricity was slightly higher in 2013 than in 2012. However, there were fewer occasions when the available supply of generation resources was insufficient to satisfy the system's demands and, thus, less frequent instances of shortage pricing.

The figure below shows the aggregated amount of time where the real-time energy price was at the system-wide offer cap, displayed by month. Prices during 2013 were at the system-wide offer cap for only 0.22 hours (less than 15 minutes), a reduction from 1.51 hours in 2012 and a significant reduction from the 28.44 hours in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R.25.505 raised the system-wide offer cap to $5,000 per MWh effective June 1, 2013. As shown in the figure below, there was only a brief period when energy prices rose to the cap after these changes were implemented.

Duration of Prices at the System-Wide Offer Cap



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. Although the shortages in 2011 seemed relatively severe, adequate long-term incentives will only exist in ERCOT if the total value of shortages exceeds the value exhibited in 2011 every few years.

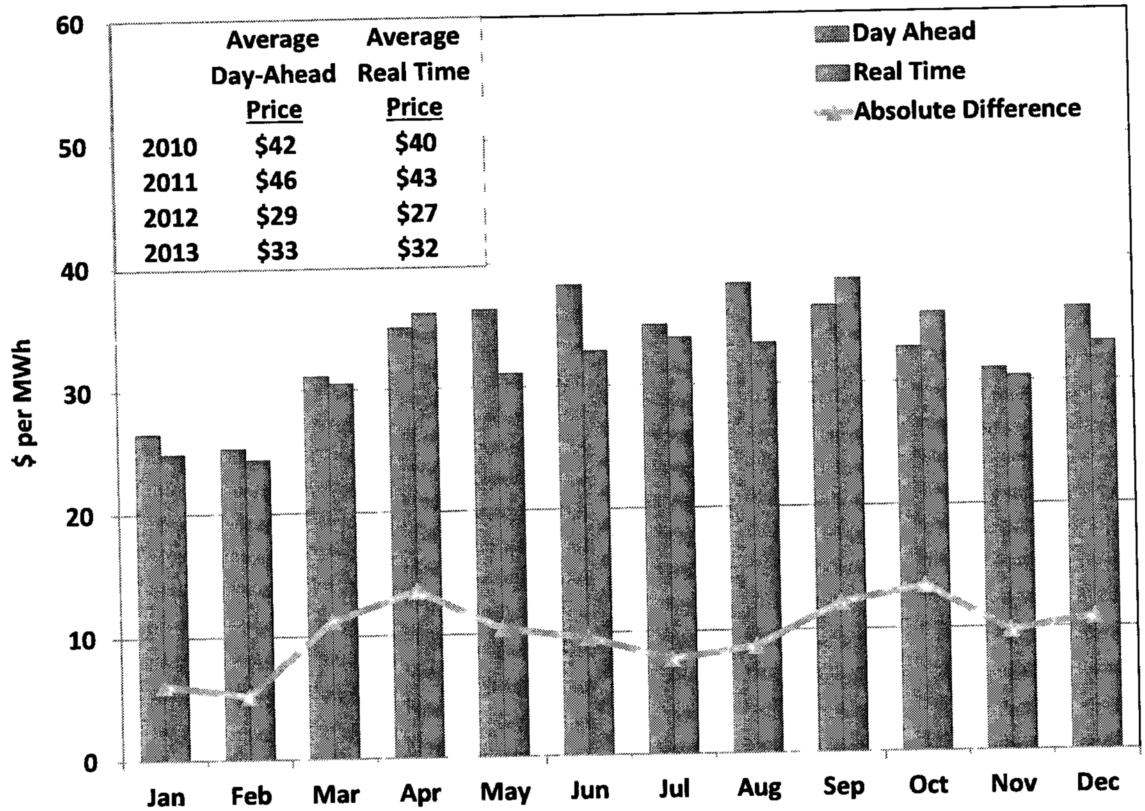
C. Review of Day-Ahead Market Outcomes

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 their ability 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 them over the long-term.

The figure below shows the price convergence between the day-ahead and real-time market, summarized by month. The simple average of day-ahead prices in 2013 was $33 per MWh, compared to the simple average of $32 per MWh for real-time prices. The average absolute difference between day-ahead and real-time prices was $9.86 per MWh in 2013; slightly lower than in 2012 when average of the absolute difference was $9.96 per MWh.

Convergence between Forward and Real-Time Energy Prices

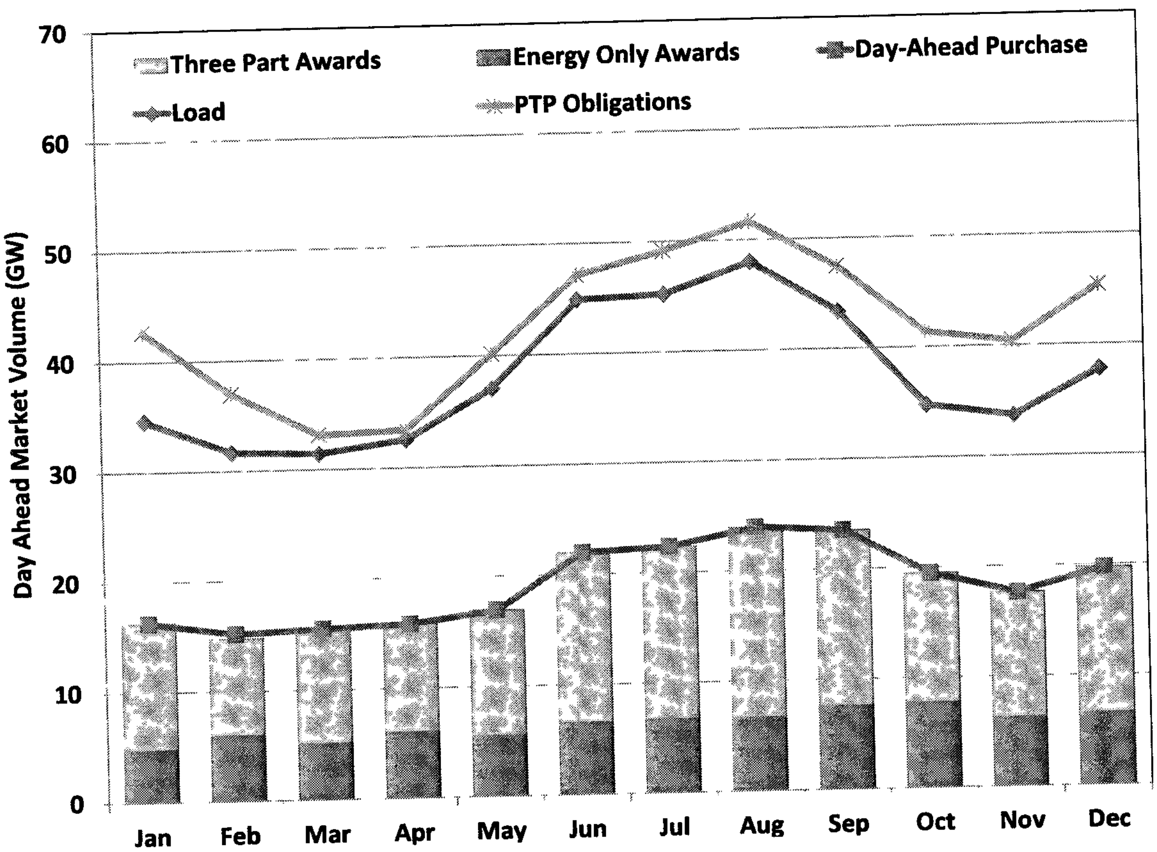


This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and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

Overall, the day-ahead premiums were very similar to the differences observed in 2012, but 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 what is allowed 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 (*e.g.*, $5 per MWh in May, June and August), 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 April, September and October).

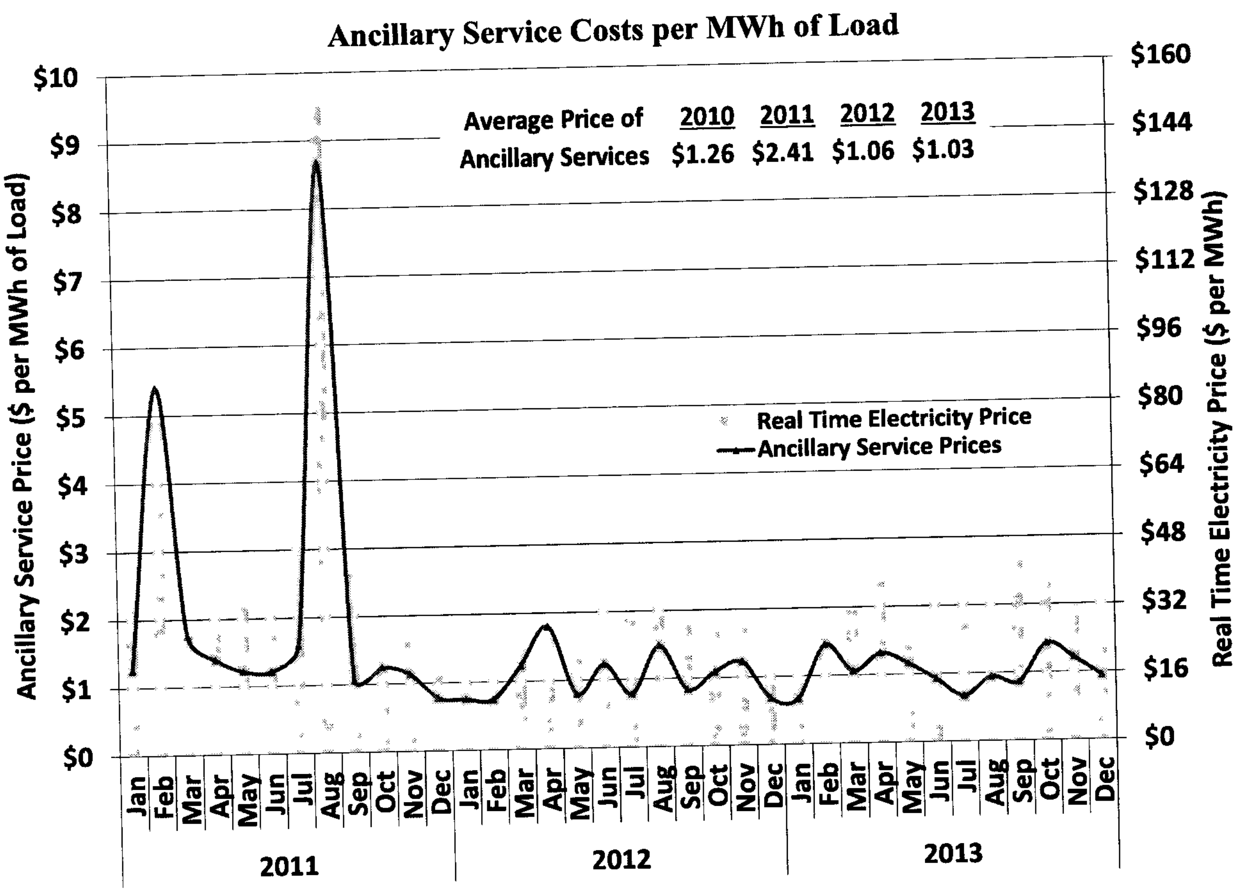
Summarized in the figure below is the volume of day-ahead market activity by month. It shows that day-ahead purchases are approximately 50 percent of real-time load, which is an increase from 2012 when they averaged 45 percent.

Volume of Day-Ahead Market Activity by Month



This figure also shows the volume of Point to Point 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 show the volume of these transactions, we aggregate all of these "transfers", netting location specific injections against withdrawals. To provide a sense of the magnitude of the PTP transactions, the figure shows that by adding the aggregated transfer capacity associated with purchases of PTP Obligations, total volumes transacted in the day-ahead market on average are greater than real-time load in each month.

Ancillary Service capacity is procured through the day-ahead market. The figure below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2011 through 2013. Total ancillary service costs are generally correlated with real-time energy price movements, which in turn are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load decreased to $1.03 per MWh in 2013 compared to $1.06 per MWh in 2012, a decrease of 3 percent. Total ancillary service costs decreased from 3.7 percent of the load-weighted average energy price in 2012 to 3.0 percent in 2013.



D. Transmission and Congestion

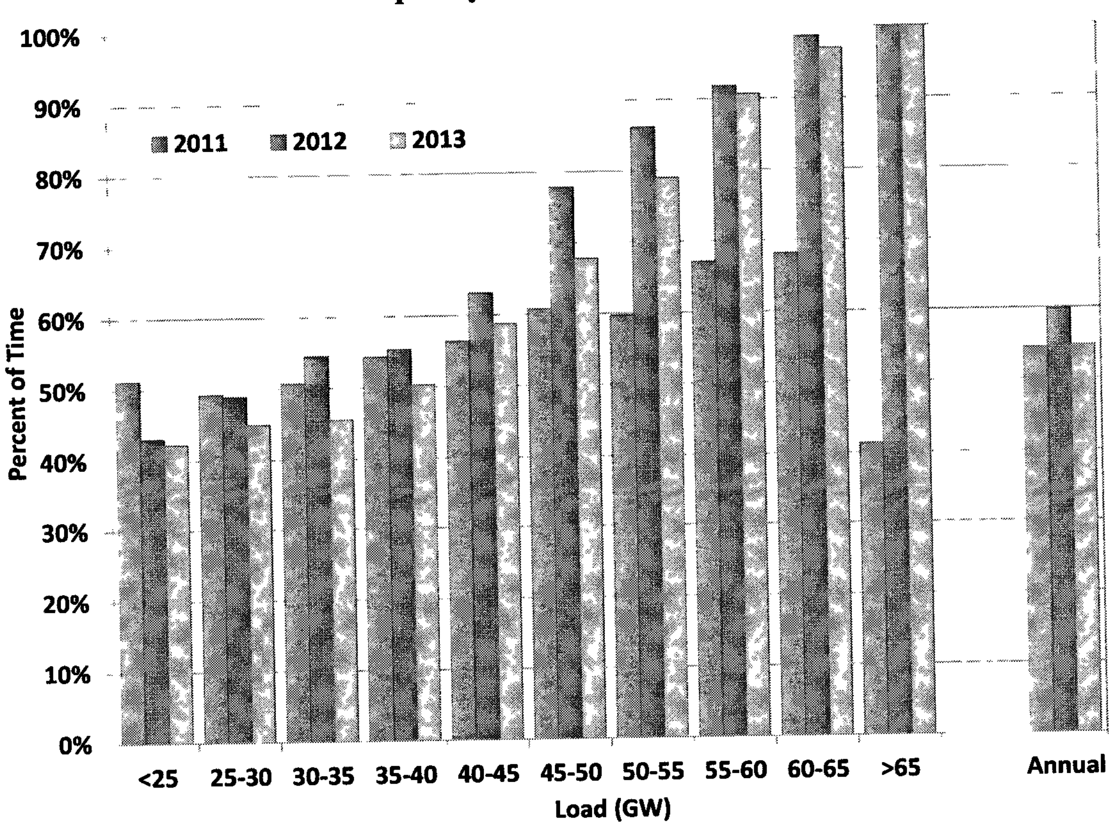
The total congestion revenue generated by the ERCOT real-time market in 2013 was $466 million, a decrease of 3 percent from 2012. This decrease is mostly attributed to transmission improvements in west Texas, specifically in the Odessa area and the completion of CREZ transmission projects. The largest contributors to the overall costs of congestion in 2013 were several localized transmission constraints in far west and south Texas.

Real-time transmission congestion during 2013 continued the trend seen since 2012 of localized higher load due to increased oil and natural gas production activity as the cause of most significant constraints. There was an increase in congestion within the South zone related to higher loads associated with increased activity in the Eagle Ford shale during 2013 and transmission equipment outages within the South zone.

Given increases in local loads and the increase in fuel prices, it is noteworthy that transmission congestion decreased in 2013. This reduction was due in large part to transmission improvements that decreased the congestion levels in the West zone. Annual prices for loads located in the West zone were $11 per MWh higher than ERCOT average in 2012. In 2013, West zone prices were $5 per MWh higher. By the end of 2013, the completion of the CREZ transmission lines virtually eliminated longstanding limitations affecting wind exports from the West zone.

The next figure shows the amount of time transmission constraints were active at various load levels in 2013, 2012 and 2011.

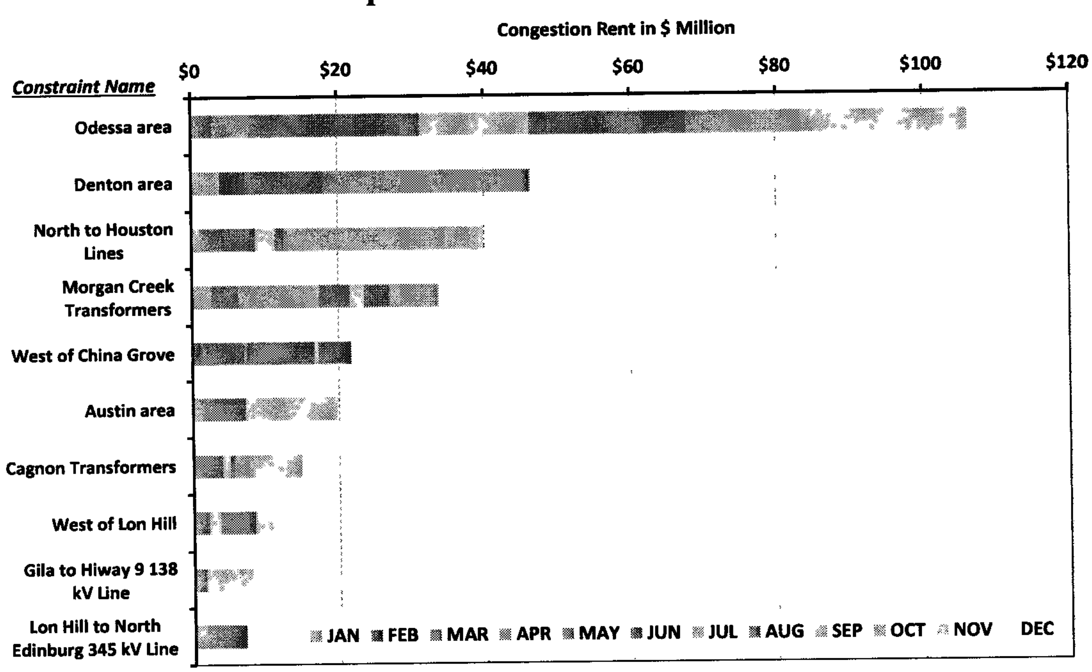
Frequency of Active Constraints



This figure shows that constraints were active slightly less frequently in 2013 than in 2012, but still more frequently than 2011. We previously observed that during 2011, ERCOT operators did not always activate (or sometimes de-activated) transmission constraints during periods of higher system loads. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified this practice in 2012 to retain active transmission constraints even during periods of high demand. Further, NERC standards support the continued management of transmission constraints under higher loads and potential scarcity conditions.

The figure below displays the ten areas that generated the most real-time congestion and indicates that the Odessa area was again the most congested location in 2013. The primary constraint in the area is the Odessa to Odessa North 138 kV line, representing 54 percent of the total cost for the area. Congestion in this area became more pronounced in 2012 and is mainly attributed to load growth in far west Texas driven by increased oil and natural gas activity.

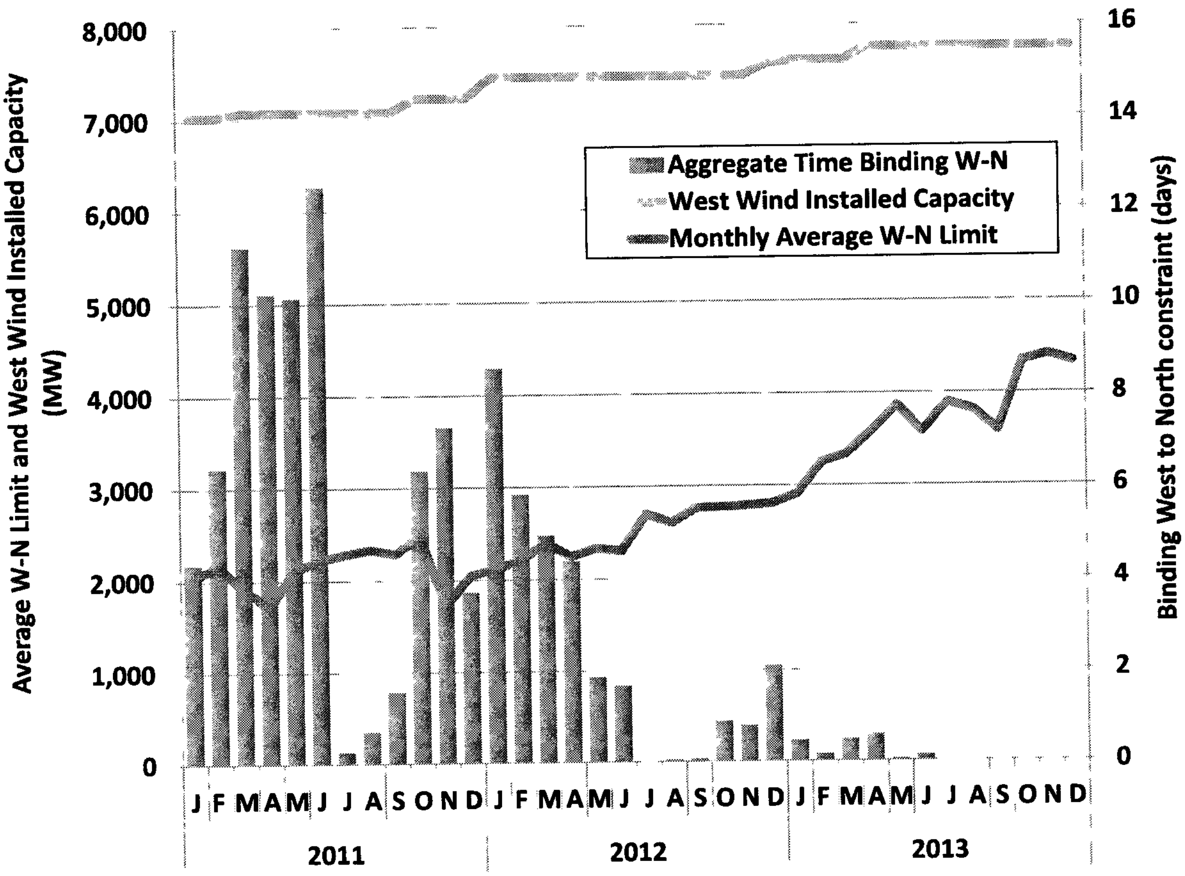
Top Ten Real-Time Constraints



The most significant constraint in 2012, the Odessa North 138/69 kV transformer, was no longer binding in 2013 because the transformer was upgraded in late 2012. Even with the elimination of the most significant constraint in 2012, the Odessa area continues to have the most real-time congestion in ERCOT, with more than twice the financial impact of the second most congested area.

The figure below shows the number of 24-hour periods that the West to North interface transmission constraint was binding each month from 2011 through 2013. Even with continued increases in wind resources in the West zone, binding constraints affecting exports from the West zone fell sharply as the completion of CREZ lines resulted in higher limits on the West to North constraint.

Utilization of the West to North Interface Constraint

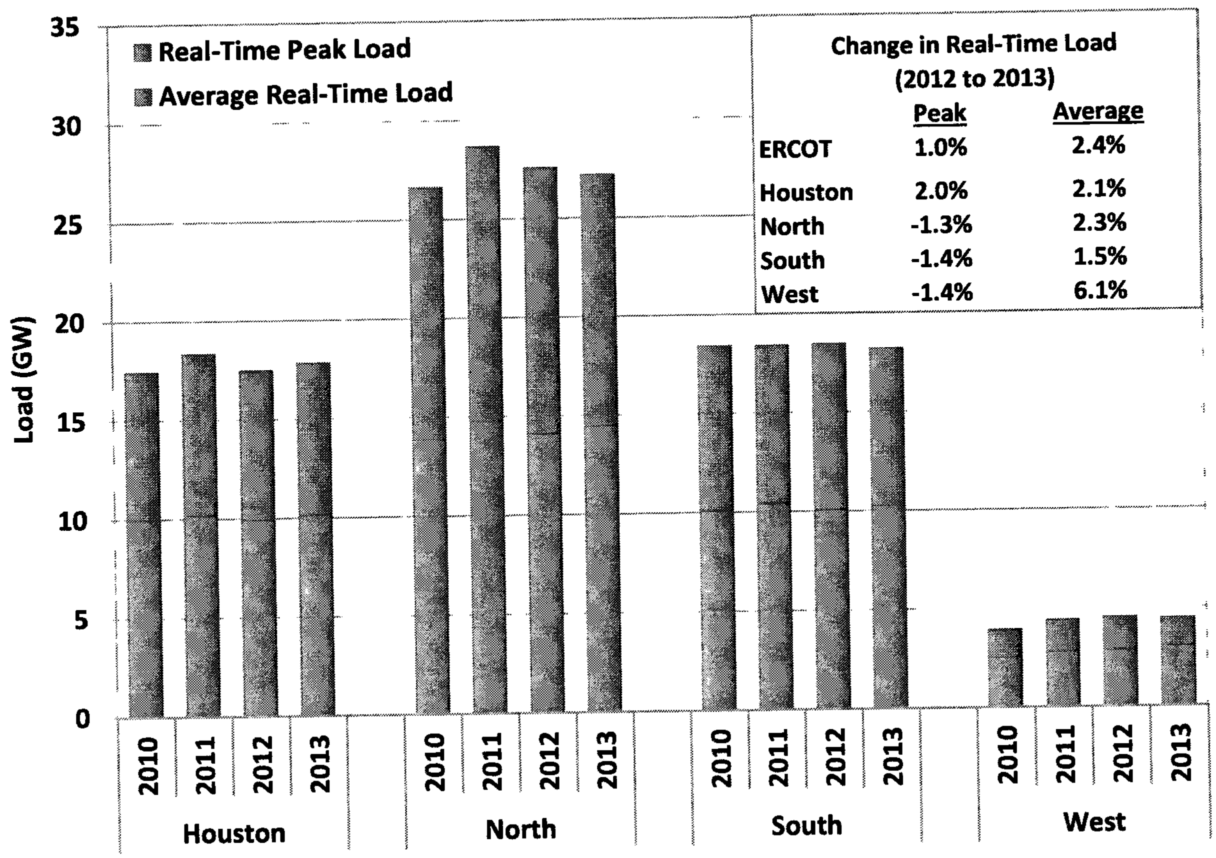


Prior to 2013, the West to North transmission constraint was perennially a top 10 real-time constraint. However, with the completion of the CREZ transmission lines at the end of 2013, the West to North constraint is no longer a significant factor.

E. Load and Generation

The figure below shows peak load and average load in each of the ERCOT zones from 2010 to 2013. In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (8 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.

Annual Load Statistics by Zone



Total ERCOT load increased from 325 TWh in 2012 to 332 TWh in 2013, an increase of 2.1 percent or an average of 870 MW every hour. Similarly, the ERCOT coincident peak hourly demand increased from 66,559 MW to 67,245 MW in 2013, an increase of 686 MW, or 1.0 percent.

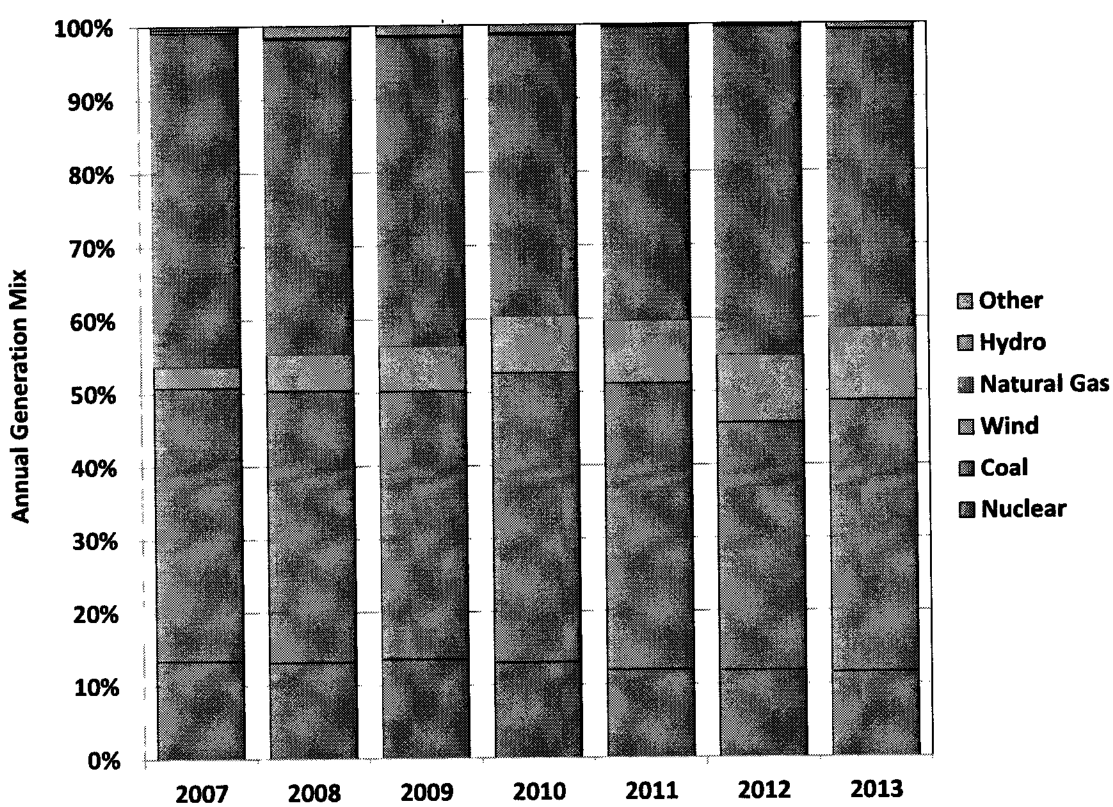
The changes in load at the zonal level are not the same. Peak load in the Houston zone increased, while it decreased in the other zones. The average growth rate of load in the West zone once again was much higher than in the other zones.

Approximately 1.6 GW of new generation resources came online in 2013, the bulk of which was a single large (970 MW) coal unit. The other additions were wind, gas and solar units. When unit retirements are included, the net capacity addition in 2013 was 1 GW. After the capacity changes in 2013 the mix between natural gas and coal generation remains stable. Natural gas generation accounts for approximately 48 percent of total ERCOT installed capacity and coal for approximately 21 percent.

Over the seven years from 2007 to 2013, wind and coal generation capacity increased the most. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2013 than there was in 2007.

The figure below shows the percentage of annual generation from each fuel type for the years 2007 through 2013.

Annual Generation Mix

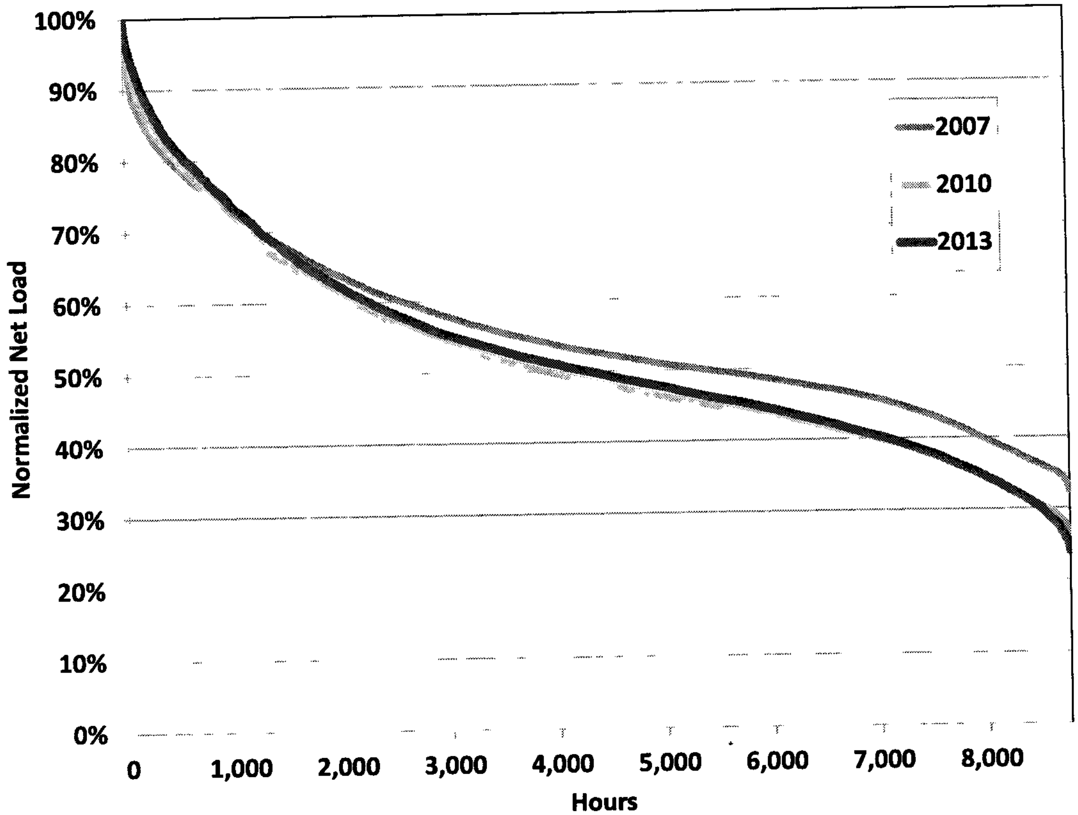


The generation share from wind has increased every year, reaching 10 percent of the annual generation requirement in 2013, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to a low of 38 percent in 2010. In 2013 the percentage of generation from natural gas decreased slightly from 2012 to 41 percent. Correspondingly, the percentage of generation produced by coal units ranged from a high of 40 percent in 2010 to a low of 34 percent in 2012. The percentage of generation from coal increased to 37 percent in 2013. The rebound in the share of generation produced by coal in 2013 was due to the increase in natural gas prices from the historical low levels experienced in 2012.

While coal/lignite and nuclear plants produce a large share of the energy in ERCOT because they operate primarily as base load units, natural gas resources are most frequently on the margin setting the real-time energy prices. This accounts for the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23.5 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.

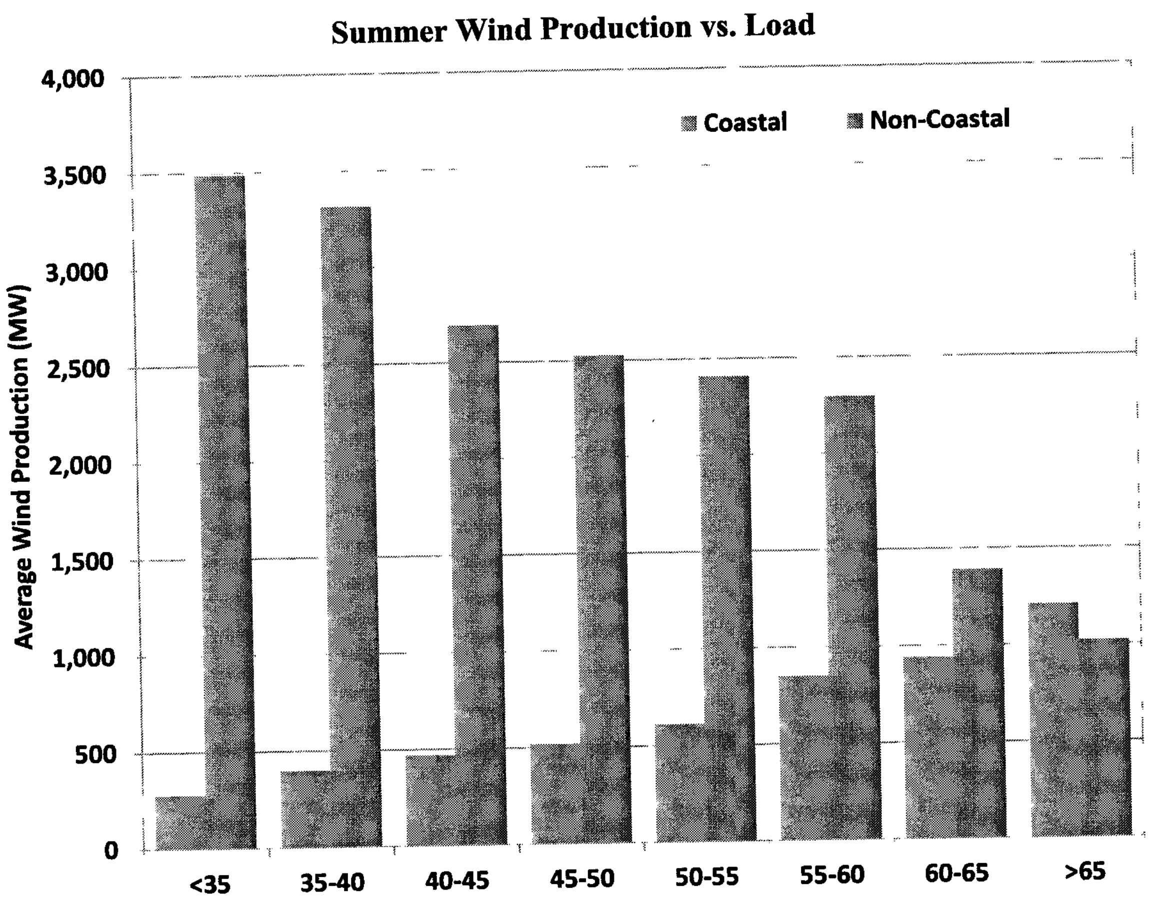
Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. For the following analysis, we define net load as the system load minus wind production. The figure below shows the net load duration curves for selected years since 2007, normalized as a percent of peak load. This figure shows the continued erosion of residual load for non-wind units to serve during most hours of the year. These results show that these impacts were much less during the highest load periods because wind tends to produce much less during peak load conditions.

Net Load Duration Curve



Thus, although the peak net load and reserve margin requirements are projected to continue to increase, the non-wind fleet is expected to operate for fewer hours as wind penetration increases. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly within the context of the ERCOT energy-only market design.

The next figure compares the output during the summer months of June through August from wind units located in the coastal area of the South zone with those located elsewhere in ERCOT.



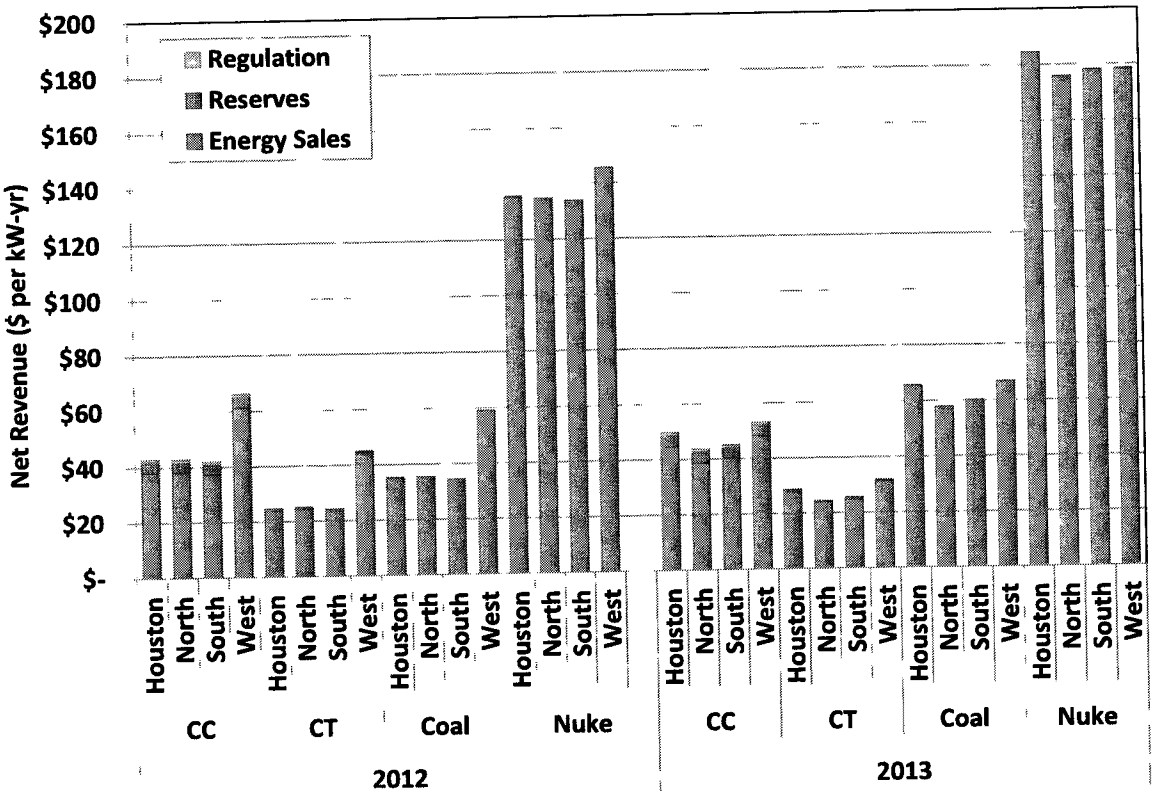
It shows a strong negative relationship between non-coastal wind output and increasing load levels. This pattern limits the value of wind resources in satisfying ERCOT's resource adequacy needs described in the next subsection. It also shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand than is non-coastal wind.

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. Net revenues from the energy and ancillary services markets together provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. In long-run equilibrium, markets should provide sufficient net revenue to allow an investor to receive a return of, and on an investment in a new generating unit.

Estimated Net Revenue



The figure above shows the results of the net revenue analysis for four types of hypothetical new units in 2012 and 2013. These are: (a) natural gas-fired combined-cycle, (b) natural gas-fired combustion turbine, (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 other hours that it is available. For coal and nuclear technologies, net revenue is calculated by assuming that the unit will produce at full output.

The figure above shows that the 2013 net revenue for new natural gas-fired units was similar to 2012 levels, with the notable exception of in the West zone. The decrease in net revenues in the West zone was due to reduced transmission congestion resulting in lower prices in the West zone. Net revenues for coal and nuclear technologies were higher in 2013 than in 2012 because of higher natural gas prices, but still not close to being sufficient to support new entry for either of these technologies.

- For a new coal-fired unit, the estimated net revenue requirement is approximately $275 to $350 per kW-year. The estimated net revenue in 2013 for a new coal unit ranged from $58 to $67 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $415 to $540 per kW-year. The estimated net revenue in 2013 for a new nuclear unit was approximately $180 per kW-year.
- For a new natural gas-fired combustion turbine, the estimated net revenue requirement is approximately $80 to $105 per kW-year. The estimated net revenue in 2013 for a new gas turbine was approximately $26 per kW-year.
- For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2013 for a new combined cycle unit was approximately $45 per kW-year.

These results indicate that during 2013 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. The net revenues in 2013 were very similar to those in 2012, and both years were much lower than in 2011. This is not surprising because shortages were very infrequent over the past two years. Shortage pricing plays a pivotal role in providing investment incentives in an energy-only market like ERCOT's. 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.

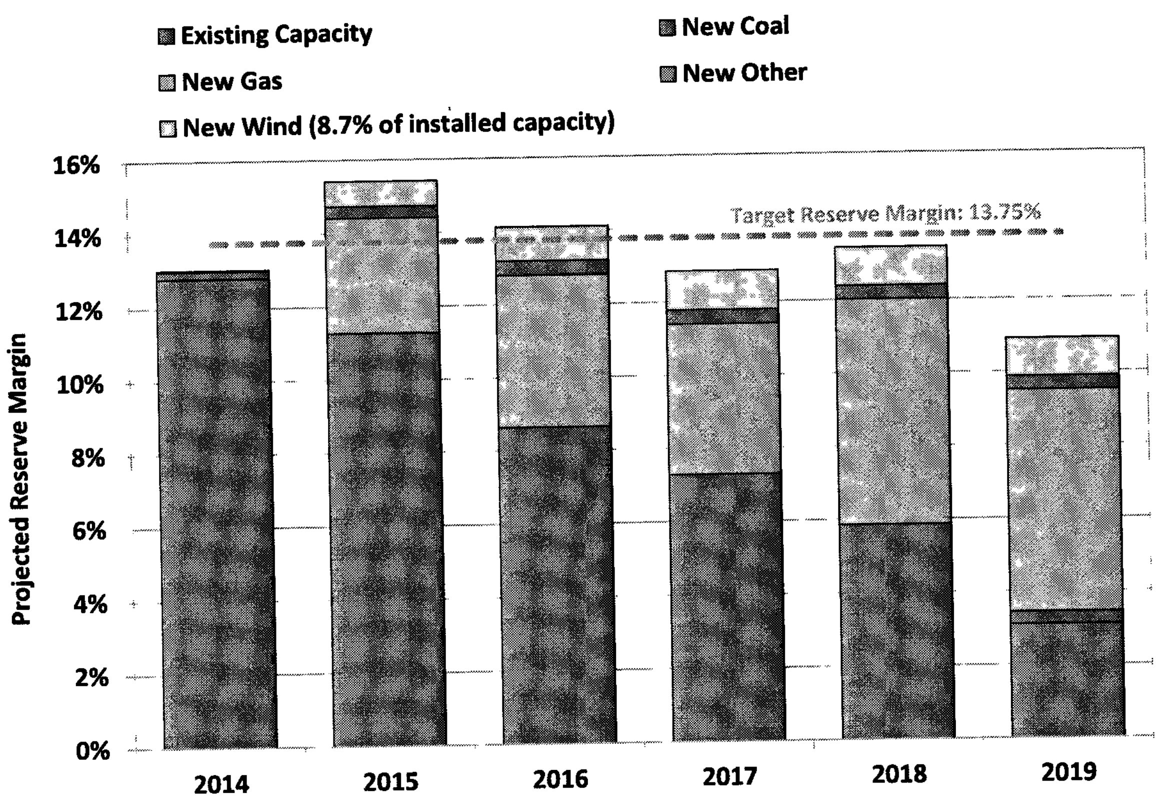
While 2011 exhibited much more frequent shortages than in the years prior or since, it is important to recognize that 2011 was highly anomalous with some of the hottest summer temperatures on record. Notwithstanding these conditions, net revenues may have been narrowly sufficient to cover the annual costs of a new combined cycle or new combustion turbine. This indicates that higher shortage prices are likely necessary to provide adequate long-term economic signals to invest in and maintain generating resources in ERCOT. As more fully described in

Section V, Resource Adequacy, the PUC has taken actions over the past year to increase energy and ancillary prices during shortage and near-shortage conditions.

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 2014.

Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Report issued February 2014

It indicates that the region would have a 13.0 percent reserve margin heading into the summer of 2014. After completion of announced generation additions, the reserve margin is expected to reach 15.4 percent in 2015. This increase in expected reserve margin is partially a result of ERCOT's revised load forecasting methodology, which has reduced historical forecasts of load growth. The total quantity of expected future generation additions has also decreased. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which is expansions at existing facilities.

Even with the forecasted additions, ERCOT is projected to sustain lower reserve margins than all other RTOs, and less than its target reserve margin after 2016. This is not necessarily a problem since the 13.75 percent level is just a target. However, it is nonetheless important to ensure that the ERCOT market is designed to provide adequate economic signals to remain near this target, which is discussed below.

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, or not. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under scarcity 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 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 higher than expected loads resulting in diminishing planning reserve margins, the PUCT has devoted considerable effort recently deliberating issues related to resource adequacy. These deliberations have resulted in changes to the rules governing the system-wide offer cap and the Peaker Net Margin mechanism. The PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to introduce an additional pricing mechanism based on the quantity of available operating reserves.

As directed by the PUCT, a more analytically rigorous approach will be introduced to complement the Power Balance Penalty Curve. The Operating Reserve Demand Curve ("ORDC") is an operating reserve pricing mechanism that reflects the loss of load probability 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 will create a new payment mechanism for online and offline reserves. As the quantity of reserves decreases, payments will increase. As conceptualized, once available reserve capacity drops to 2000MW, payment for reserve capacity will rise to VOLL, or $9000 per MWh.

These changes will likely increase the net revenues a new investor would expect during shortage conditions. Whether they will be sufficient to maintain capacity margins near the target reserve margin is unknown, which will require continued monitoring and evaluation. Additionally, we continue to recommend that ERCOT implement a system to co-optimize energy and ancillary services because this would improve the efficiency of ERCOT's dispatch, more fully utilize its resources, and allow for improvements in its shortage pricing.

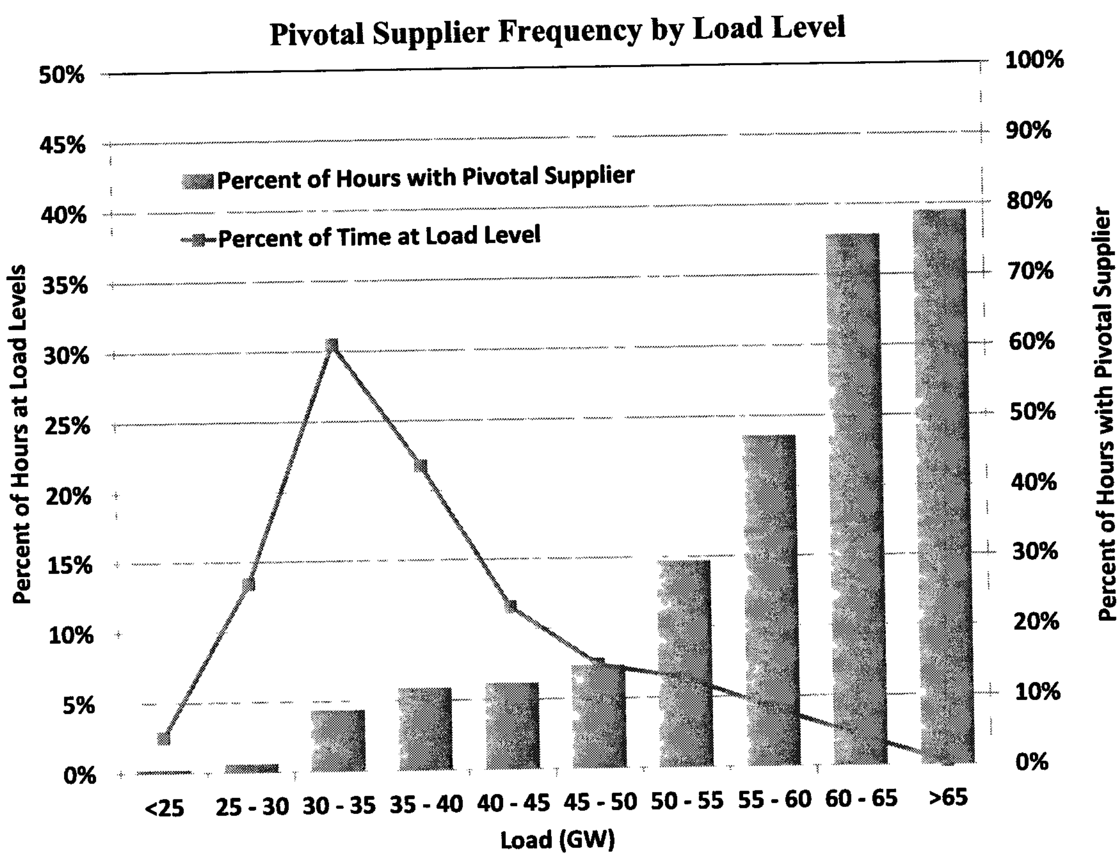
G. Analysis of Competitive Performance

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.



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 79 percent of the time. The figure also displays the percentage of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 14 percent of all hours of 2013, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that address it.

Additionally, we note 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, b) the application of limits on offer prices in these areas.

2. Evaluation of Conduct

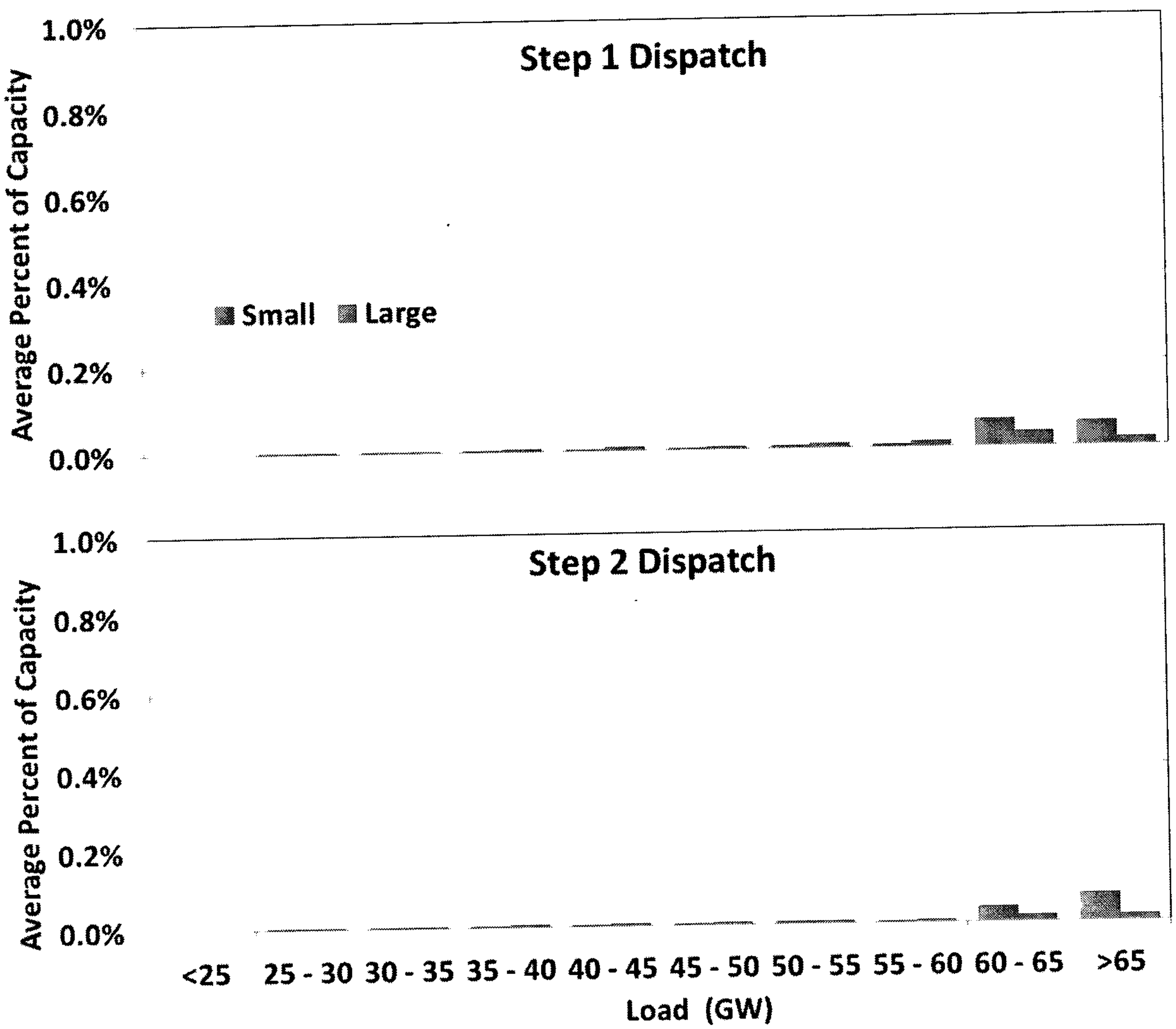
This report assesses potential physical withholding and economic withholding using a variety of metrics. In this subsection, we describe our evaluation of potential economic withholding, which is conducted by calculating an "output gap". The output gap is defined as the quantity of energy that is not 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 by at least $50 per MWh that unit's mitigated offer cap, 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 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



The results of the analysis shown in the figure above indicate small quantities of capacity at the highest loads that were potentially economically withheld by small suppliers. Almost all of these quantities reflect the conduct of GDF SUEZ. GDF SUEZ is deemed not to have ERCOT-wide market power under P.U.C Subst. R. 25.504 (c) because they control less than 5 percent of the capacity in ERCOT and, therefore, are able to offer its resources at any price up to the system-wide offer cap. In evaluating this conduct, we estimated that the aggregate effect of its conduct was less than $1 per MWh and, therefore, does not raise substantial competitive concerns.

In addition to this analysis of potential economic withholding, we also evaluate outages, deratings, and economic units that were not committed to identify other means suppliers may have used to withhold resources. We found very little evidence of potential physical withholding. Based on our analyses above and the results of our ongoing monitoring, we find the overall performance of the ERCOT market to be competitive in 2013.

H. Recommendations

Overall, we find that the ERCOT market performed well in 2013. Nonetheless, we have identified and recommended a number of potential improvements over the past few years. We describe these recommendations in this section.

In the 2012 ERCOT State of the Market report we recommended changes to the automated mitigation procedures that are part of the real-time dispatch to eliminate the occurrences of over-mitigation we have observed. As more fully described in Section I.F, Mitigation, we supported the changes described in NPRR520, which introduced a test to determine whether a unit is either contributing to, or helping to resolve a transmission constraint. Only the units providing relief are mitigated because only these suppliers may have local market power. These changes were implemented on June 21, 2013 and substantially reduced inappropriate mitigation of resources that are not in a position to exercise local market power.

1. In the 2012 ERCOT State of the Market report we also recommended a change to the real-time market software to allow it to "look ahead" a sufficient amount of time to better commit load and generation resources that can be online within 30 minutes. ERCOT started producing non-binding generation dispatch and price projections on June 28, 2012. It is unclear what, if any effect this indicative information has had on the operational actions of ERCOT or its market participants. 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, but are responsive within 30 minutes. Therefore, we recommend that ERCOT evaluate improvements to this process that would allow it to facilitate better real-time generator commitments.

2. Last year's recommendation to improve reserve shortage pricing has been superseded by the Commission's direction to implement an Operating Reserve Demand Curve (ORDC). The ORDC provides a more analytically rigorous mechanism for settling 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. In addition to improving the shortage pricing in ERCOT, co-optimization

would improve the efficiency of ERCOT's dispatch in all intervals. Therefore, we continue to recommend ERCOT implement co-optimization.

3. We continue to recommend modifying the Protocols related to proxy offer curve provisions such that all unoffered capacity is not automatically priced at the system-wide offer cap. Currently, if available capacity does not have an associated energy offer, ERCOT's dispatch software "fills in" with an offer that is priced at the system-wide offer cap. During 2013, the average amount of capacity priced in this manner exceeded 180 MW.

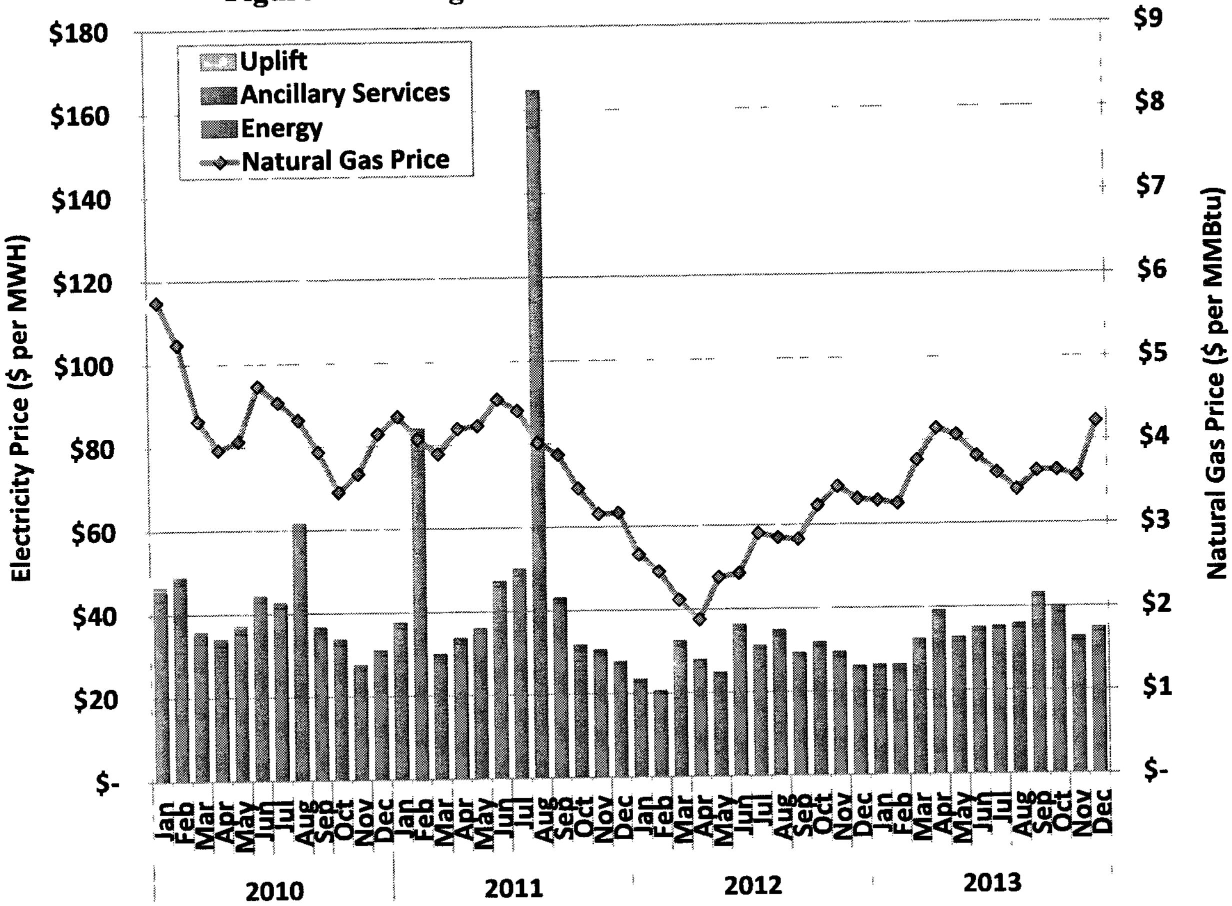
4. We continue to recommend that changes be implemented to ensure ERCOT deployments of load resources, Emergency Response Service (ERS), or the involuntary curtailment of firm load are reflected in the real-time dispatch energy and reserve prices. Building on the Phase 1 efforts of Loads in SCED, this recommendation could be addressed in various ways. It may be possible to integrate load bids and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal. Alternatively, it may be adequate to address this concern through administrative shortage pricing rules.

I. Review of Real-Time Market Outcomes

A. Real-Time Market Prices

Our 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". We have calculated an average "all-in" price of electricity for ERCOT that is intended to reflect wholesale energy costs as well as these additional costs.

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



Energy, ancillary services and uplift costs are the three components in the all-in price of electricity. The ERCOT wide price is the load weighted average of the real-time market prices from all load zones. Prior to ERCOT's conversion to the nodal market in December 2010, energy costs were determined from the zonal balancing energy market. 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 charges associated with additional reliability unit commitment and any reliability must run contracts.[1]

Figure 1 shows the monthly average all-in price for all of ERCOT from 2010 to 2013 and the associated natural gas price. This figure indicates that natural gas prices were a primary driver of the trends in electricity prices from 2010 to 2013. 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.

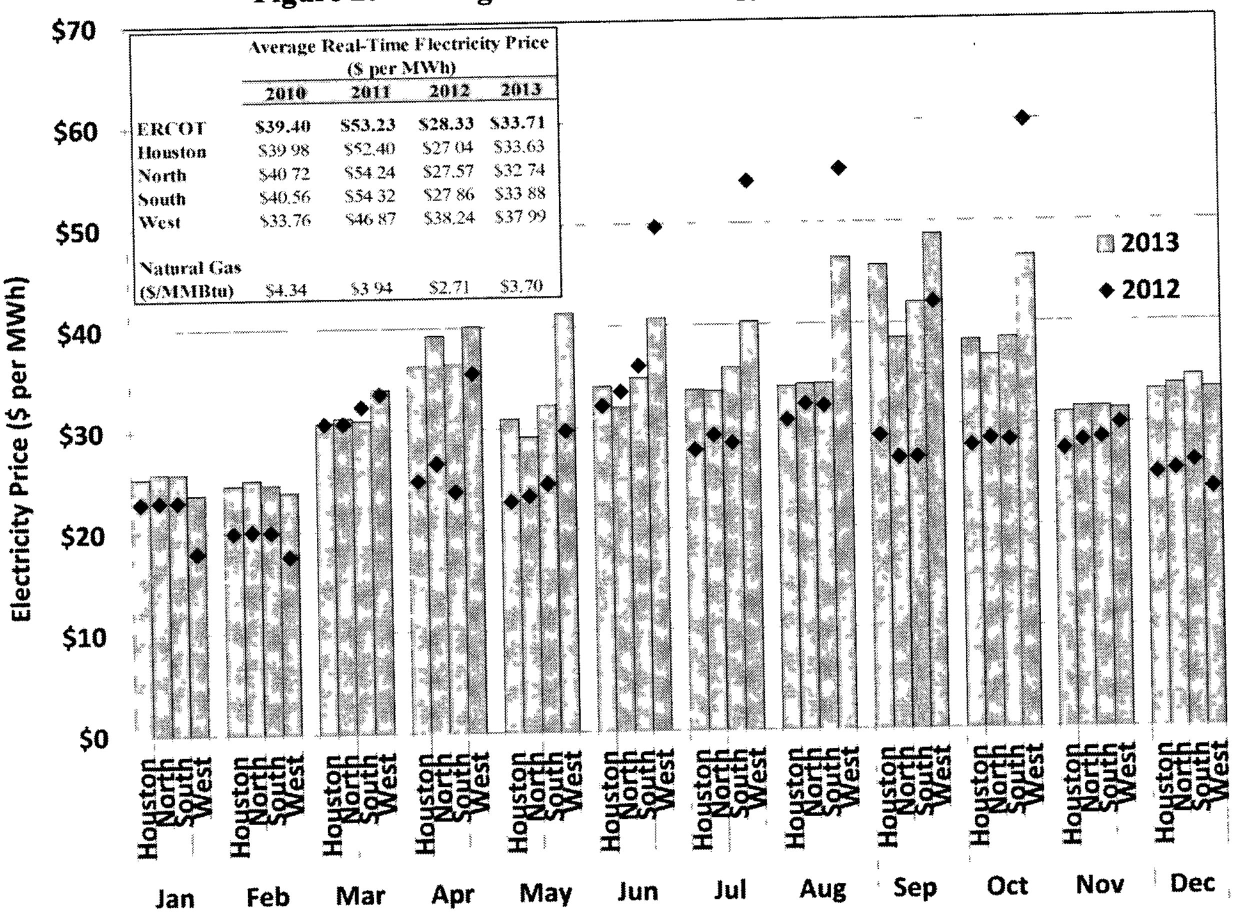
The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices. As is typical in other wholesale electricity markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, prices in the 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 2013.

ERCOT average real-time market prices were 19 percent higher in 2013 than in 2012. The ERCOT-wide load-weighted average price was $33.71 per MW in 2013 compared to $28.33 per MWh in 2012. The increase in real-time energy prices was correlated with much higher fuel prices in 2013. The steady increase in natural gas prices from May 2012 to 2013 resulted in the 2013 average natural gas price of $3.70 per MMBtu, a 37 percent increase compared to $2.71 per MMBtu in 2012.

1 Prior to December 2010 uplift costs included charges for out-of-merit energy and capacity, replacement reserve services and any reliability must run contracts.

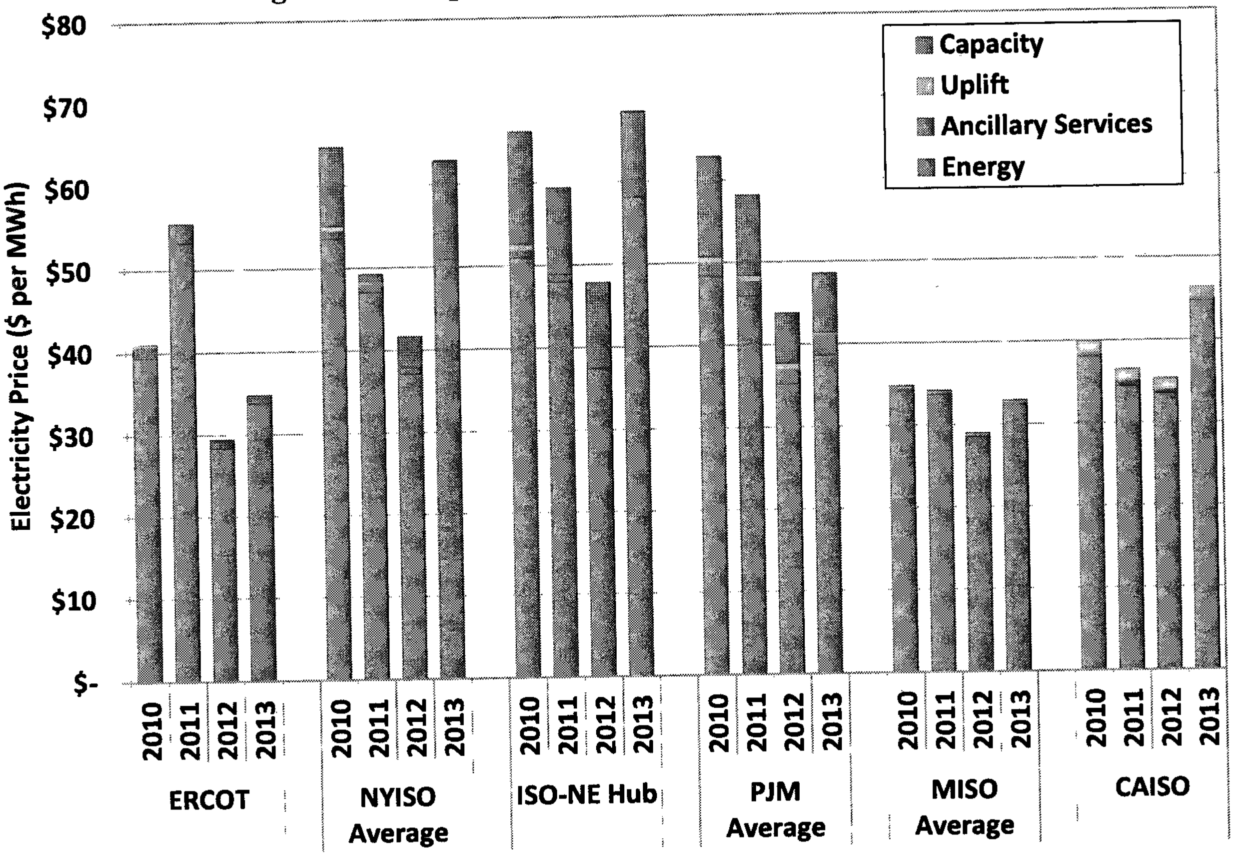
To summarize the price levels during the past four years, Figure 2 shows the monthly load-weighted average prices in the four geographic ERCOT load zones. These prices are calculated by weighting the energy price for each interval and each zone by the total zonal load in that interval. Since December 2010 these prices were determined by the nodal real-time energy market. Prior prices were derived from the zonal balancing energy market. 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.

Figure 2: Average Real-Time Energy Market Prices



To provide additional perspective on the outcomes in the ERCOT market, our next analysis compares the all-in price metrics for ERCOT and other electricity markets. 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, PJM, Midcontinent ISO, and California ISO.

Figure 3: Comparison of All-in Prices across Markets



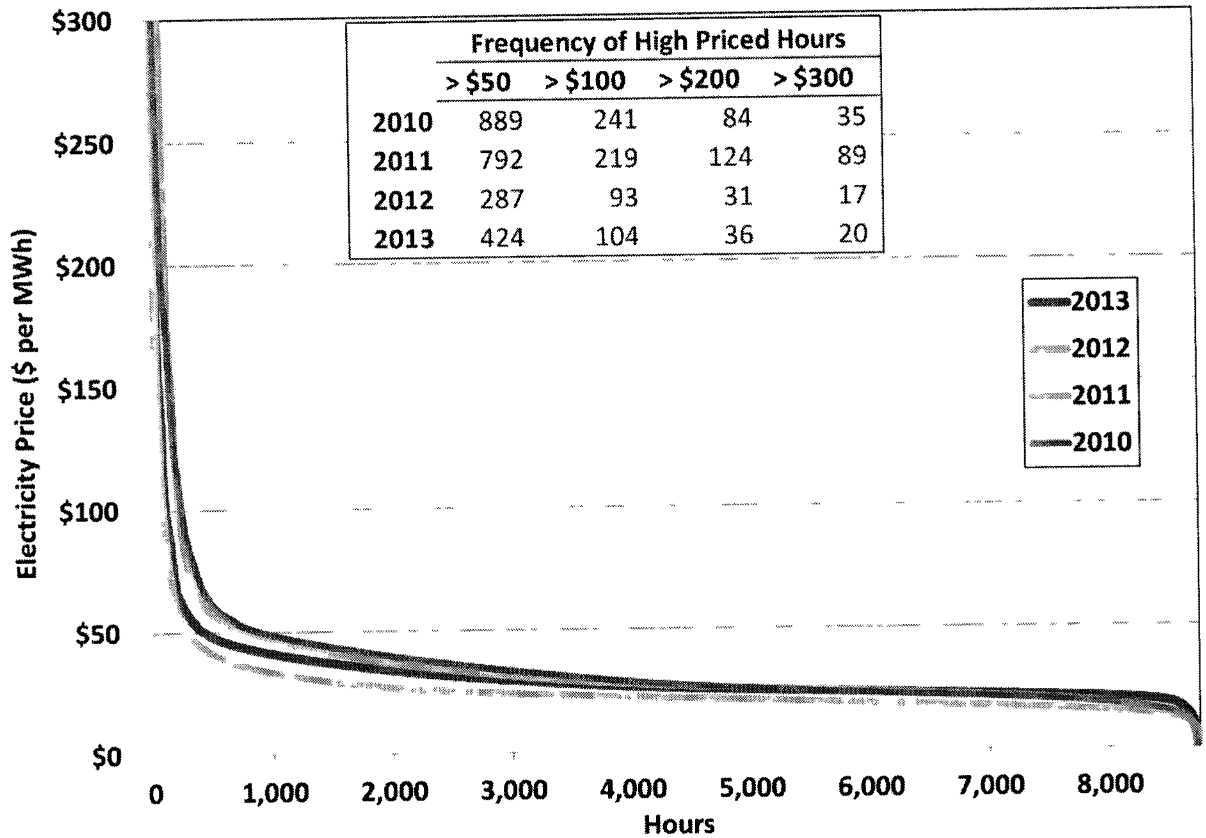
For each region, the figure reports the average cost (per MWh of load) for energy, ancillary services (reserves and regulation), capacity markets (if applicable), and uplift for economically out-of-merit resources. Figure 3 shows that ERCOT all-in prices in 2013 were slightly higher than in the Midcontinent ISO and significantly lower than all other regions. Prices in all markets increased from 2012 to 2013.

Figure 4 presents price duration curves for ERCOT energy markets in each year from 2010 to 2013. 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 zonal balancing energy price for the zonal market and hourly load-weighted nodal settlement point price for the nodal market.[2]

---

2 ERCOT switched to a nodal market on December 1, 2010. The December nodal prices are included in the 2010 price duration curve.

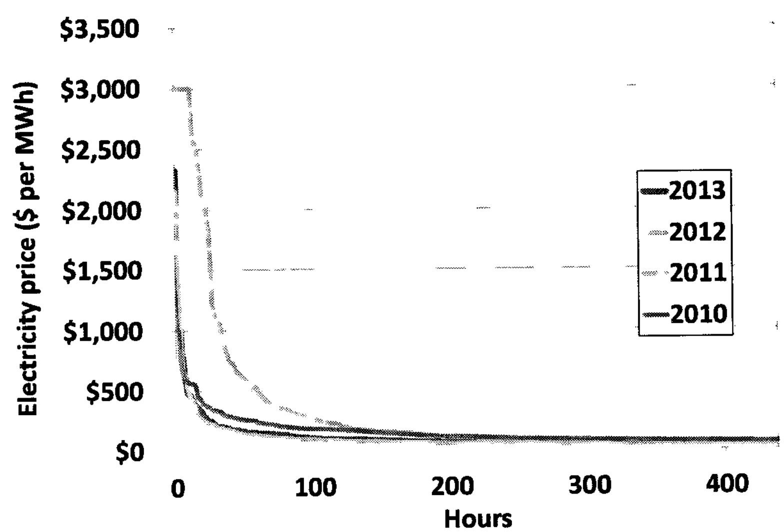
Figure 4: ERCOT Price Duration Curve



Frequency of High Priced Hours	> $50	> $100	> $200	> $300
2010	889	241	84	35
2011	792	219	124	89
2012	287	93	31	17
2013	424	104	36	20

Due to the lowest natural gas prices seen in ten years, the 2012 price duration curve is below the duration curve of other years in most hours.

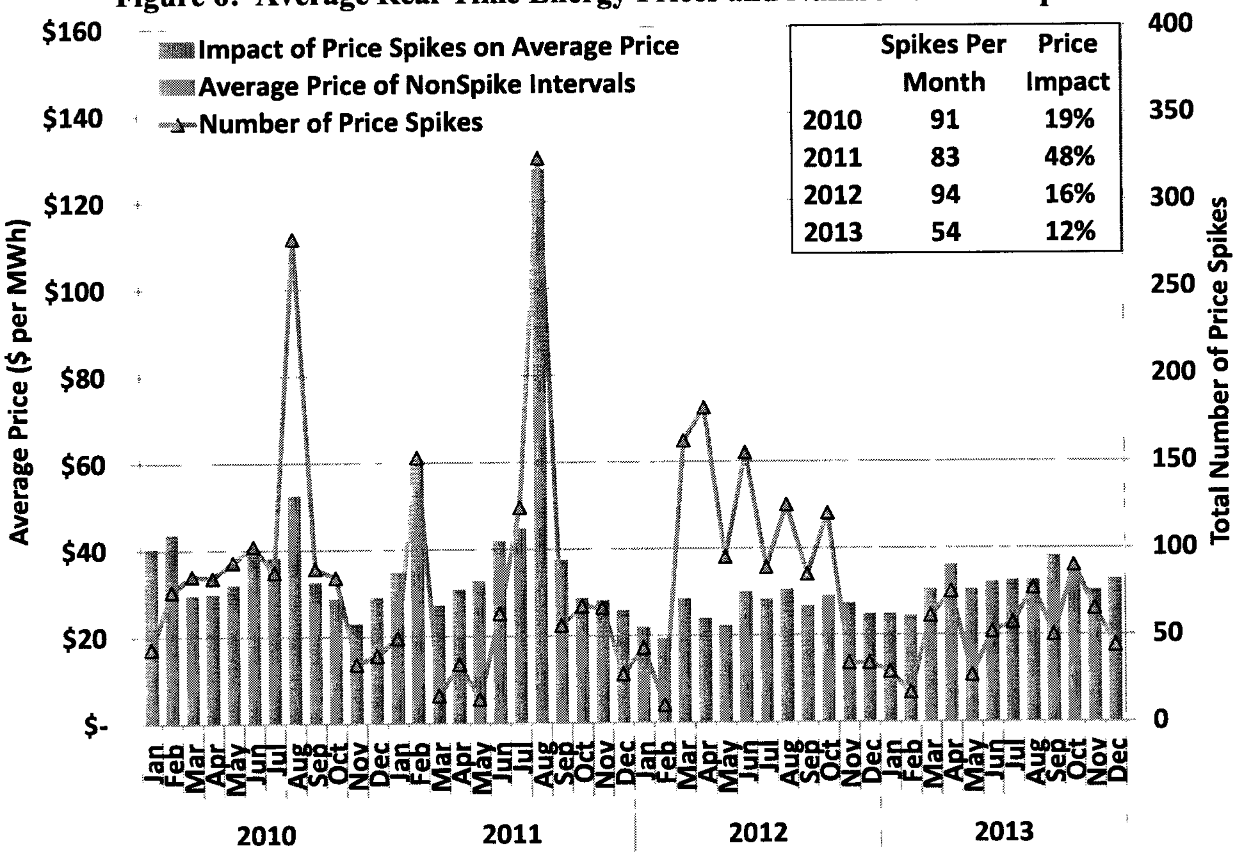
Figure 5: ERCOT Price Duration Curve – Top 5% of Hours



To see where the prices during 2013 were much different than in the previous three years, we present a comparison of prices for the highest 5 percent of hours. In 2011, energy prices for the top 100 hours were significantly higher 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 and 2013, the energy duration curves for the top 5 percent of hours are very similar and reflect fewer occassions of shortage conditions resulting from lower loads.

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. Data prior to December 2010 is from the zonal balancing energy market. Figure 6 shows the average price and the number of price spikes in each month. For this analysis, price spikes are defined as intervals where the load-weighted average energy price in ERCOT is greater than 18 MMBtu per MWh times the prevailing natural gas price. Prices at this level have historically exceeded the marginal costs of virtually all of the on-line generators in ERCOT.

Figure 6: Average Real-Time Energy Prices and Number of Price Spikes



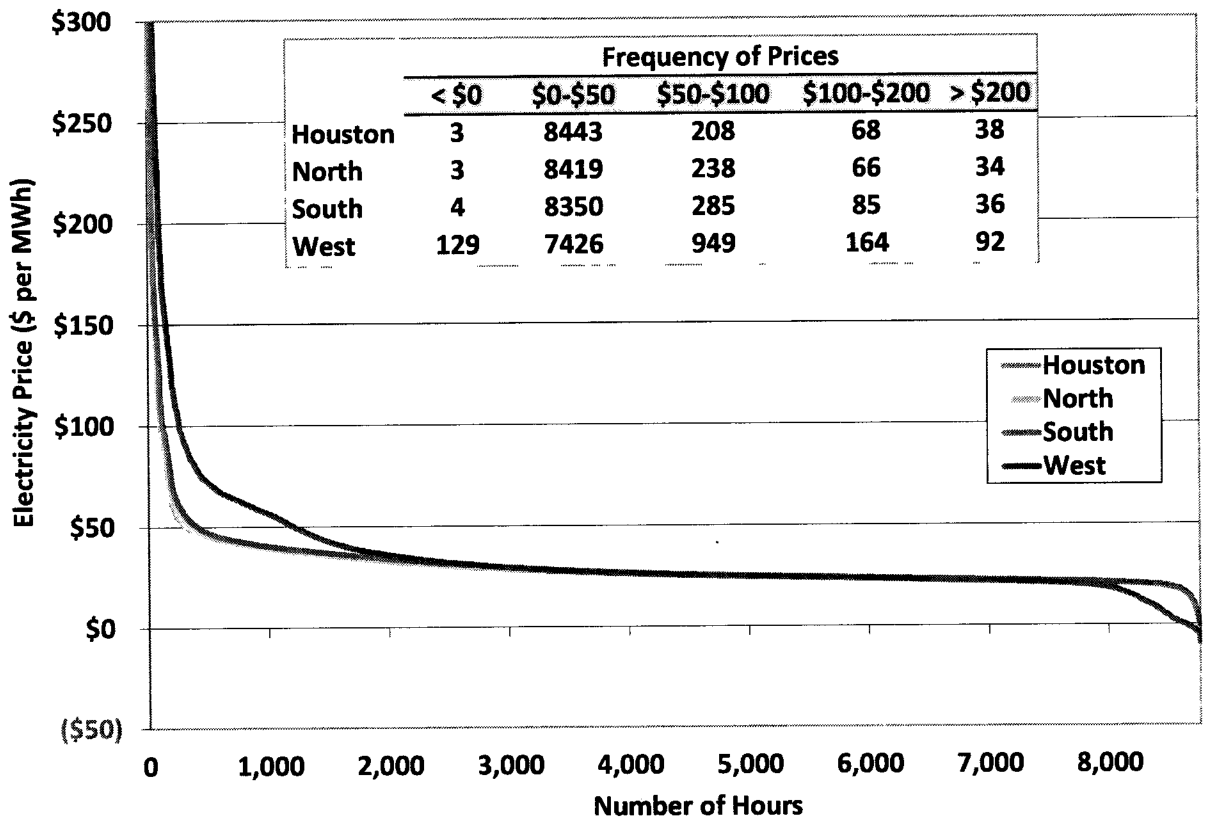
	Spikes Per Month	Price Impact
2010	91	19%
2011	83	48%
2012	94	16%
2013	54	12%

The number of price spike intervals during 2013 was 54 per month, a large decrease from the number of price spike intervals during 2012, which totaled 94 per month. However, as described in the 2012 SOM, the high number of price spikes in 2012 was related to the very low price of natural gas and the resulting 'overlap' of offers from natural gas and coal.

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. Prior to 2012, the impact grew with the frequency of the price spikes, averaging $5.53 and $14.09 per MWh during 2010 and 2011, respectively. Although the frequency of price spikes increased in 2012, the magnitude of their price impact decreased. The magnitude decreased again in 2013, with an average $3.43 per MWh impact on the average energy price in 2013.

To depict how real-time energy prices vary by hour in each zone, Figure 7 below shows the hourly average price duration curve in 2013 for four ERCOT load zones.

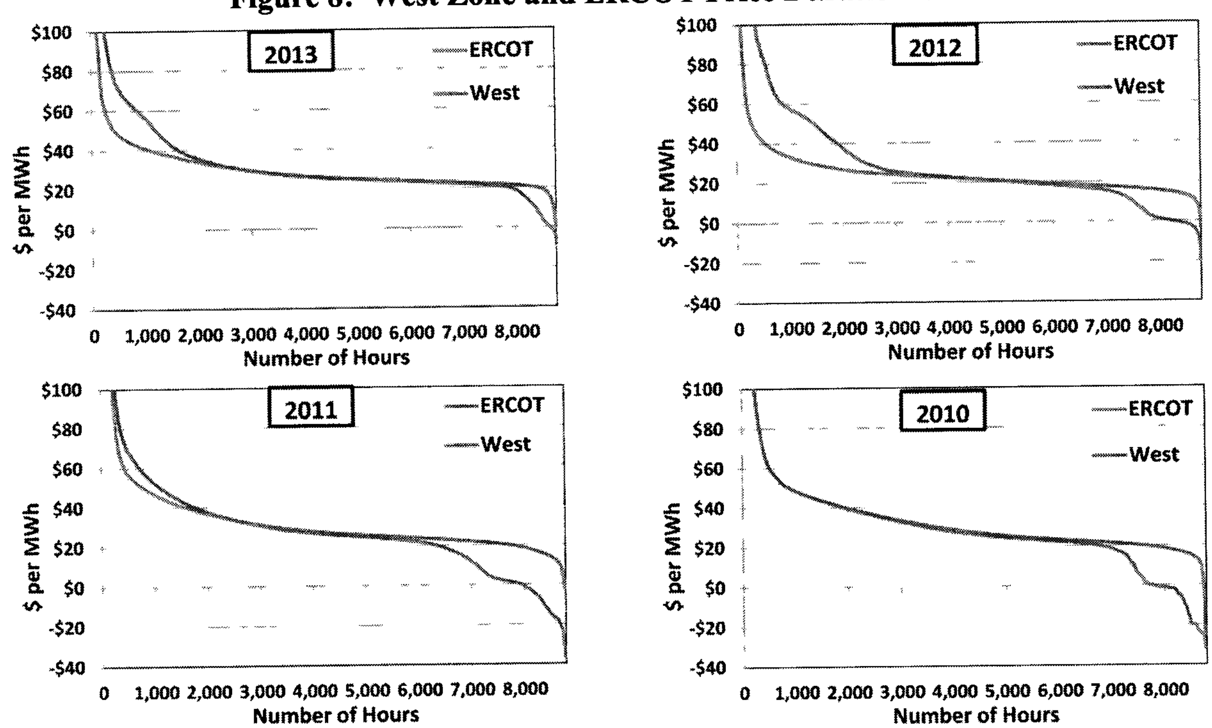
Figure 7: Zonal Price Duration Curves



The Houston, North and South load zones had similar prices over the majority of hours. The price duration curve for the West zone is noticeably different than the other zones, with more hours with prices greater than $50 per MWh and 129 hours when the average hourly price was less than zero. As observed over the past few years, West zone prices are lower than the rest of ERCOT when high wind output in the West results in congested transmission interfaces from the West zone to the other zones in ERCOT. Recently, prices higher than the rest of ERCOT have occurred in the West zone due to local transmission constraints that typically occur under low wind and high load, or outage conditions.

Figure 8 below shows the relationship between West zone and ERCOT average prices for the 2010 through 2013.

Figure 8: West Zone and ERCOT Price Duration Curves



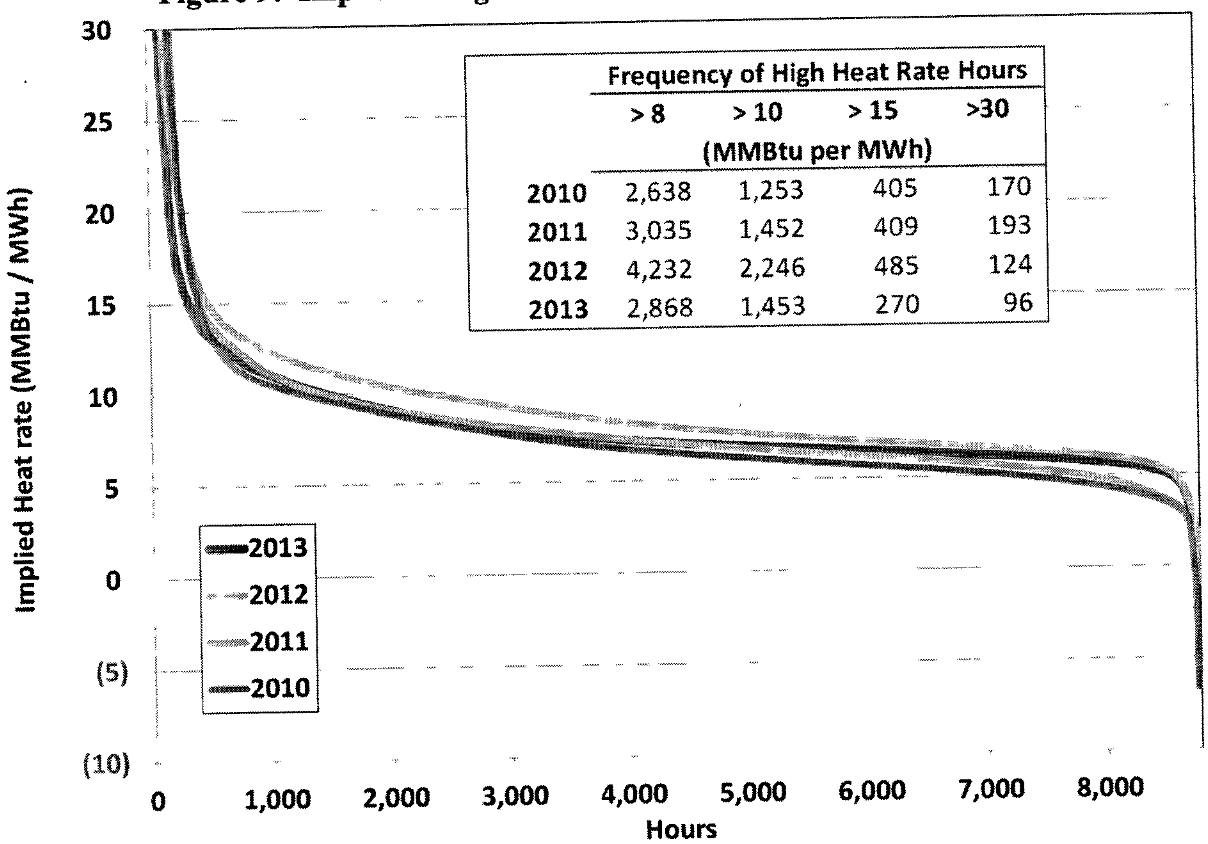
On the low price end, we observe a reduction in the number of hours when West zone prices were below the ERCOT average. We also note that minimum West zone prices have increased; that is, become "less negative". West zone prices were noticeably higher than the ERCOT average for a significant number of hours in 2013, although not to the same magnitude as they were in 2012. But like 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.

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.

Figure 9: Implied Marginal Heat Rate Duration Curve – All hours



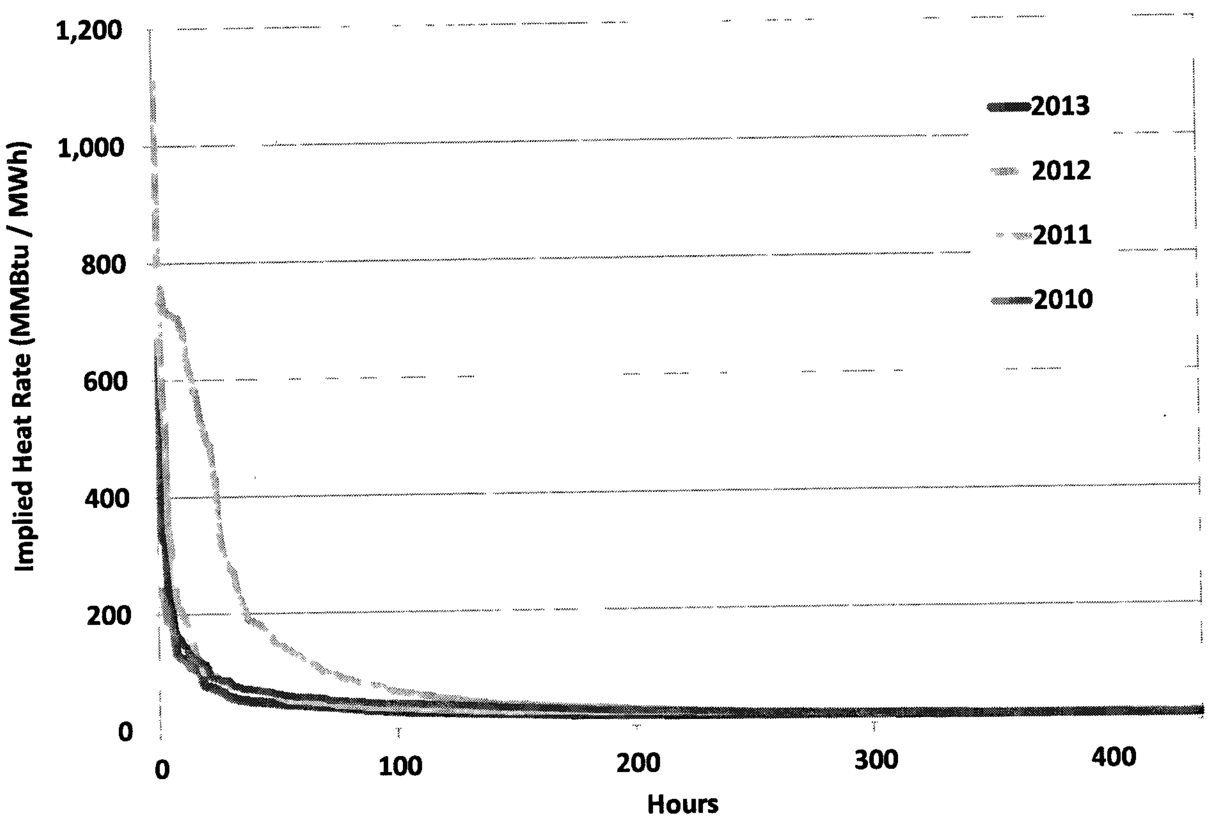
To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 9 and Figure 10 show the load weighted, hourly average real-time energy price adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the real-time energy price is replaced by the marginal heat rate that would be implied if natural gas was always on the margin.[3] Implied heat rates in 2012 were noticeably

[3] The *Implied Marginal Heat Rate* equals either the *Balancing Energy Price* (zonal) or the *Real-Time Energy Price* (nodal) divided by the *Natural Gas Price*. This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

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 marginal fuel.[4]

Figure 10 shows the implied marginal heat rates for the top 5 percent of hours in 2010 through 2013 and highlights that the implied heat rate in 2013 at the top 5 percent of hours is consistent with other years, except for 2011, where the heat rates were higher at top hours.

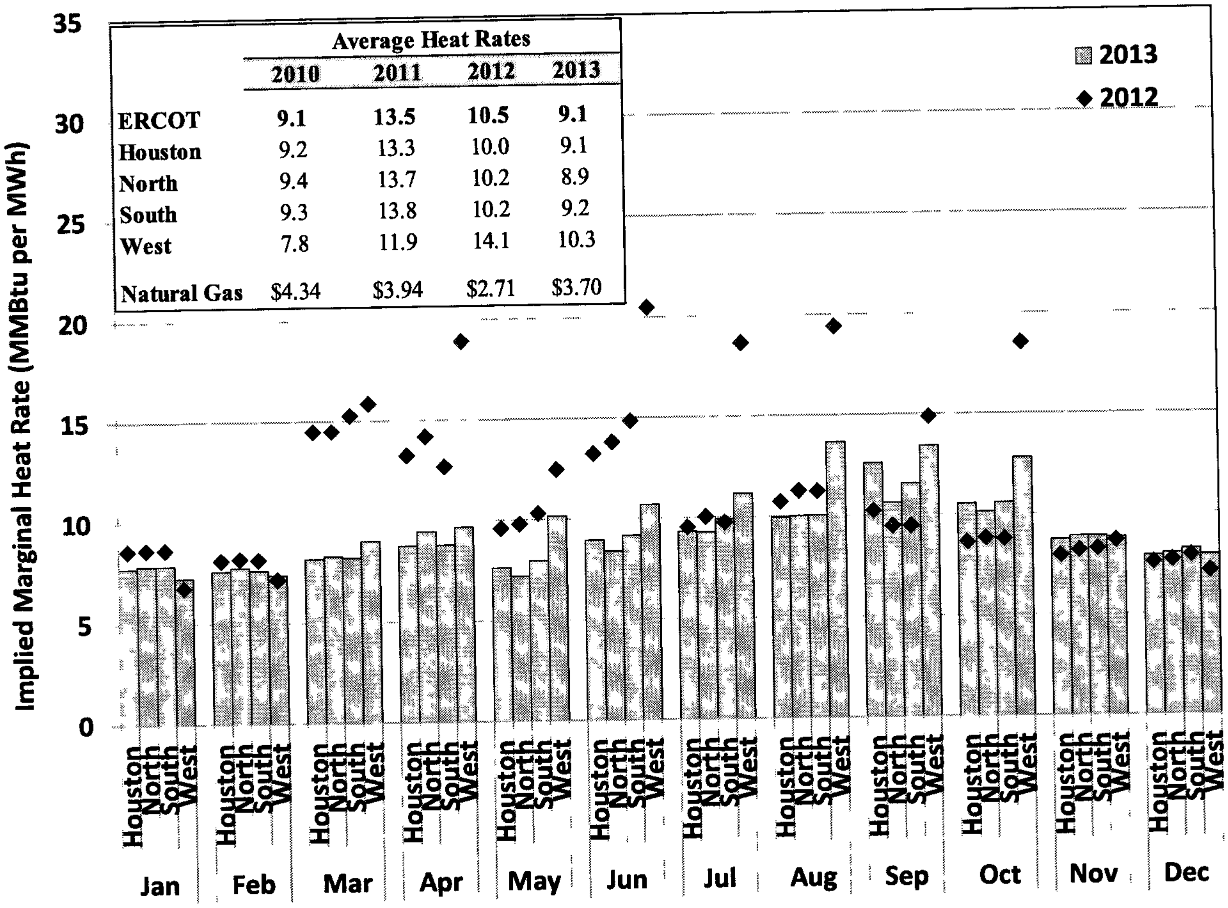
Figure 10: Implied Marginal Heat Rate Duration Curve – Top Five Percent of Hours



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 2012 and 2013, with annual average heat rate data for 2010 through 2013. This figure is the fuel price-adjusted version of Figure 2 in the prior subsection. Adjusting for natural gas price influence, Figure 11 shows that the annual, system-wide average implied heat rate decreased in 2013 compared to 2012.

4 See 2012 ERCOT SOM report at pages 12-13.

Figure 11: Monthly Average Implied Heat Rates



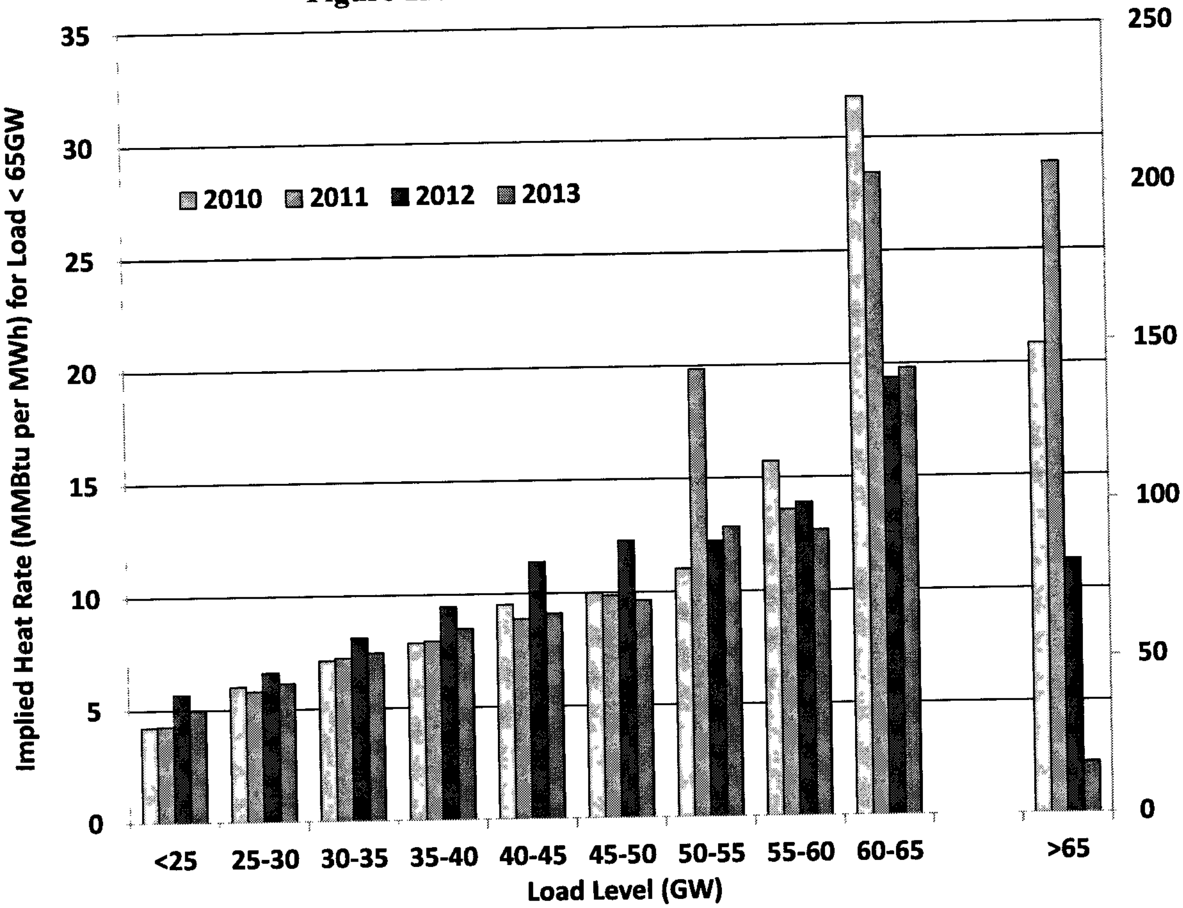
	2010	2011	2012	2013
ERCOT	9.1	13.5	10.5	9.1
Houston	9.2	13.3	10.0	9.1
North	9.4	13.7	10.2	8.9
South	9.3	13.8	10.2	9.2
West	7.8	11.9	14.1	10.3
Natural Gas	\$4.34	\$3.94	\$2.71	\$3.70

The monthly average implied heat rates in 2013 are generally lower than those in 2012 up until September, when 2013 monthly heat rates started to exceed those in 2012. This trend is generally consistent with rising gas prices and higher loads in late 2013 compared to the same months of 2012. The largest differences in the average annual implied heat rates observed at the zonal level are for the West zone. The differences can be attributed to congestion related to wind generation exports resulting in lower implied heat rates in 2010 and 2011, and congestion related to serving higher loads related to oil and gas production resulting in higher implied heat rates in 2012 and 2013.

We conclude our examination of implied heat rates from the real-time energy market by evaluating them at various load levels. Figure 12 below, provides the average heat rate at various system load levels from 2010 through 2013.[5]

5 To appropriately compare twelve months of data under each market design, data labeled as 2010 in Figure 12

Figure 12: 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 must be dispatched to serve higher loads. Although we do see a generally positive relationship, 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 interplay between coal and natural gas prices because of the low natural gas prices experienced in 2012.

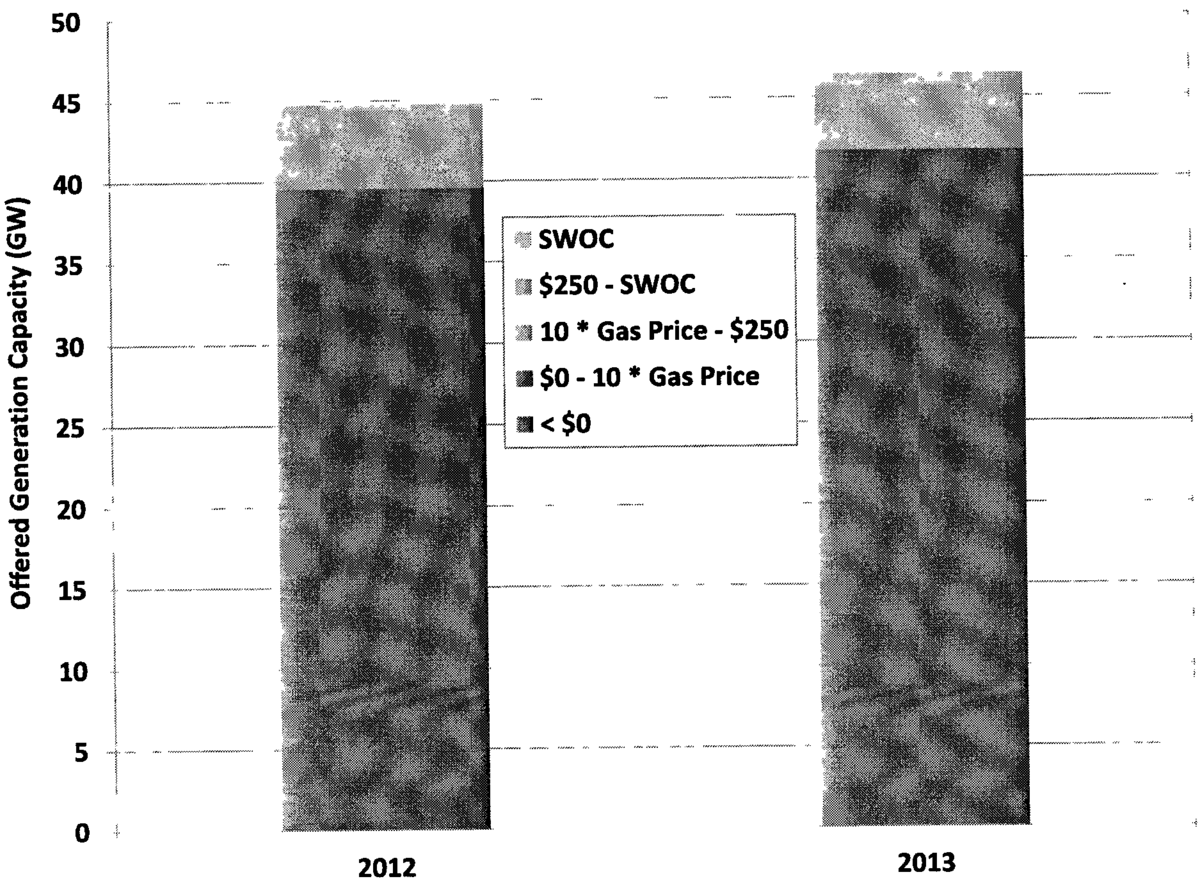
A noticeable difference in 2013 relative to the other years is the lower implied marginal heat rate at highest loads. At loads greater than 65GW, the implied heat rate was approximately 16 MMBtu per MWh in 2013 compared to 80 MMBtu per MWh in 2012.

are from December 1, 2009 through November 30, 2010.

C. Aggregated Offer Curves

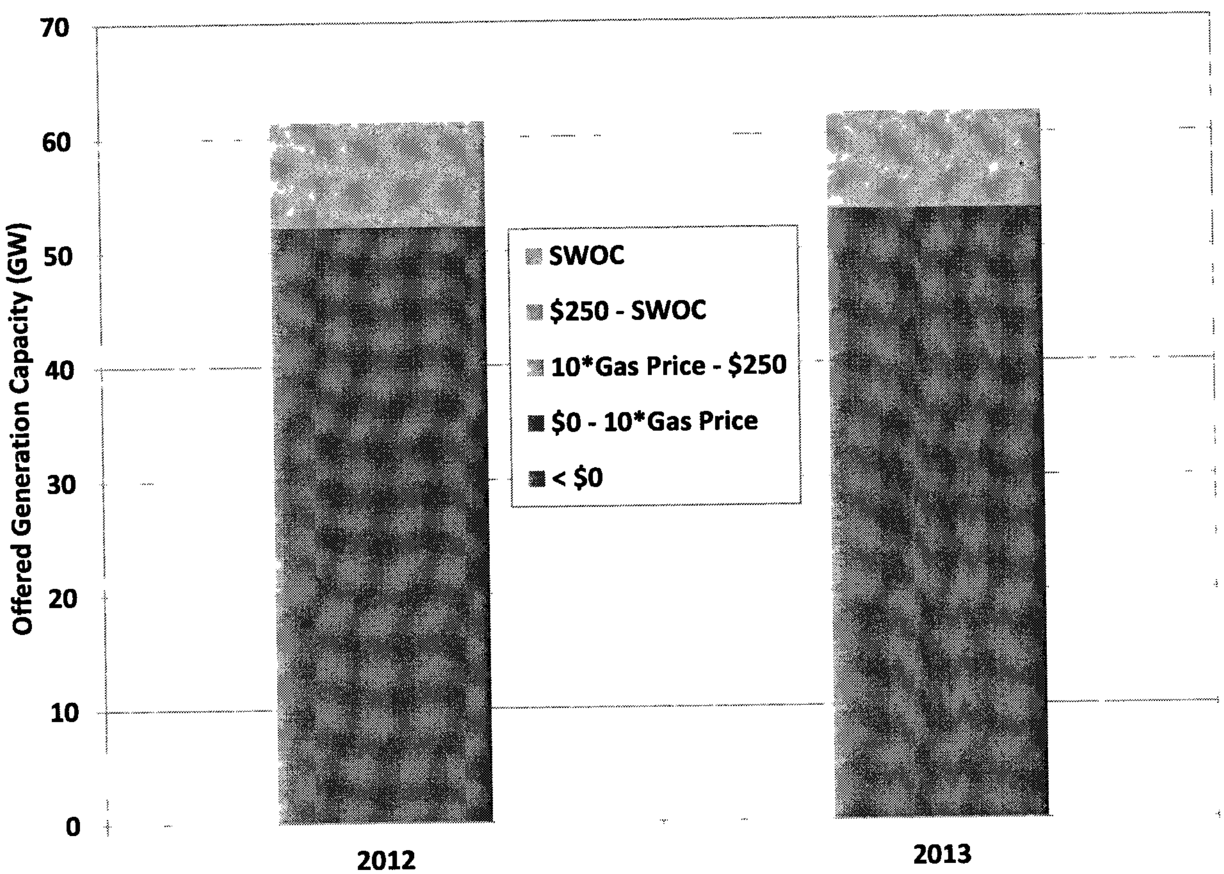
The next analysis provides the quantity and price of generation offered in 2013 compared to 2012. By averaging the amount of capacity offered at selected price levels we can assemble an aggregated offer stack. Figure 13 provides the aggregated generator offer stacks for the entire year. Comparing 2013 to 2012, we observe more capacity offered at lower prices. Specifically, there was more than 1000 MW of additional capacity offered both at prices less than zero, and at prices between zero and ten multiplied times the daily natural gas price. There was approximately 1,000 MW less capacity offered at prices between 10 multiplied times the daily natural gas price and $250 per MWh. With smaller changes to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack was roughly 1,600 MW greater in 2013 than in 2012.

Figure 13: Aggregated Generation Offer Stack - Annual



The next analysis provides a similar comparison for only the summer season. As shown in Figure 14, the changes in the aggregated offer stacks between the summer of 2013 and 2012 were similar to those just described. Comparing 2013 to 2012, there was 1,270 MW additional capacity offered at prices less than 10 multiplied times the daily natural gas price; 389 MW additional at prices less than zero, and 881 MW additional at prices greater than zero. There was approximately 1,100 MW less capacity offered at prices between 10 multiplied times the daily natural gas price and $250 per MWh. With smaller changes to the quantities of generation offered at prices above $250 per MWh, the resulting average aggregated generation offer stack for the summer season was 480 MW greater in 2013 than in 2012.

Figure 14: Aggregated Generation Offer Stack - Summer

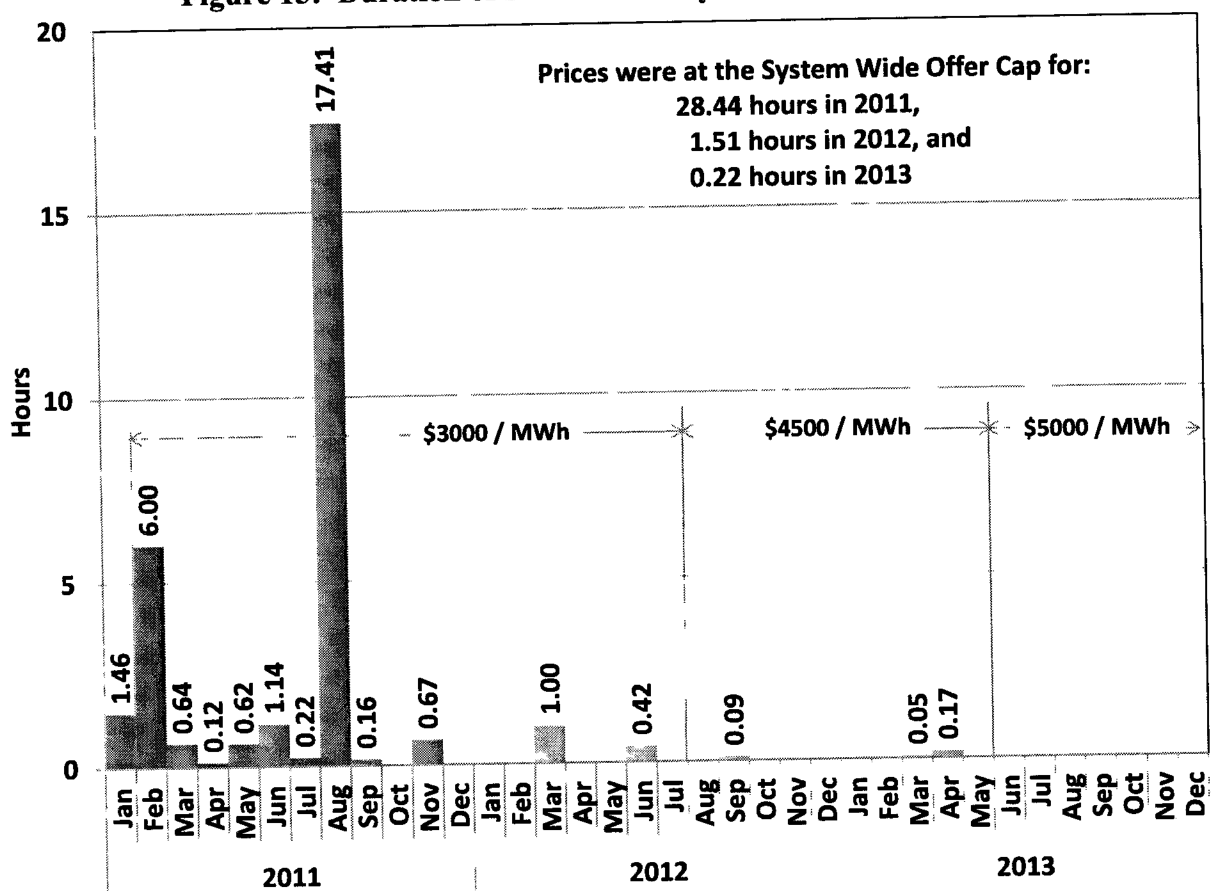


D. Prices at the System-Wide Offer Cap

After the extremes of 2011, weather conditions in Texas returned to closer to normal in 2012 and 2013. As more fully discussed in Section IV, Load and Generation, overall demand for electricity was higher in 2013 than in 2012 but lower than in 2011, resulting in few occasions when the available supply generation capacity was unable to meet customer demands. This resulted in a decreased likelihood that the available generation capacity was not sufficient to meet customer demands for electricity and maintain the required reliability reserves. 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.

Figure 15 below shows the aggregated amount of time where the real-time energy price was at the system-wide offer cap, displayed by month.

Figure 15: Duration of Prices at the System-Wide Offer Cap



Prices during 2013 were at the system-wide offer cap for only 0.22 hours, a reduction from 1.51 hours in 2012 and a significant reduction from the 28.4 hours experienced in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R.25.505 raised the system-wide offer cap to $5,000 per MWh effective June 1, 2013. As shown in Figure 15 above, there was only a brief period when energy prices rose to the cap after this change was implemented.