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# 2011 STATE OF THE MARKET REPORT
## FOR THE
# ERCOT WHOLESALE ELECTRICITY MARKETS

POTOMAC ECONOMICS, LTD.

Independent Market Monitor for the
ERCOT Wholesale Market

July 2012

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# EXECUTIVE SUMMARY

## A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2011, 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 pursuant to the provisions of PUCT Substantive Rule 25.505(g).

ERCOT transitioned from the zonal market design that had been in place since 2001 and implemented the nodal market design on December 1, 2010. Thus, this is the first annual report that contains an entire year of nodal market operations. Key findings and statistics from 2011 include the following:

★ The ERCOT wholesale market performed competitively in 2011.

★ The ERCOT-wide load-weighted average real-time energy price was $53.23 per MWh in 2011, a 35 percent increase from $39.40 per MWh in 2010. The increase was primarily driven by extreme weather in February and August which led to operating reserve deficiencies that resulted in real time energy prices reaching $3,000 per MWh for sustained periods of time.

★ The average price for natural gas was 9.2% lower in 2011 than in 2010, decreasing from $4.34 per MMBtu in 2010 to $3.94 per MMBtu in 2011.

★ Total ERCOT load in 2011 was 5.0 percent higher than 2010. Peak load increased by 4.0 percent, setting a new all time system hourly peak of 68,379 MW on August 3rd.

★ The West to North interface constraint was the most frequently occurring transmission constraint in 2011. It was active at some point during every month and was binding more than 20 percent of the time.

★ More reliable and efficient shortage pricing mechanisms than existed in the zonal market allowed energy prices to rise automatically up to the system-wide offer cap during periods of operating reserve shortages. Prices at the system-wide offer cap were experienced in dispatch intervals which totaled 28.5 hours in 2011, or 0.33 percent of the total hours.

★ Net revenues provided by the market in 2011 were sufficient to support investment in either new simple-cycle natural gas-fired turbines or natural gas-fired combined-cycle generation. This was largely the result of the increase in shortage pricing in 2011.

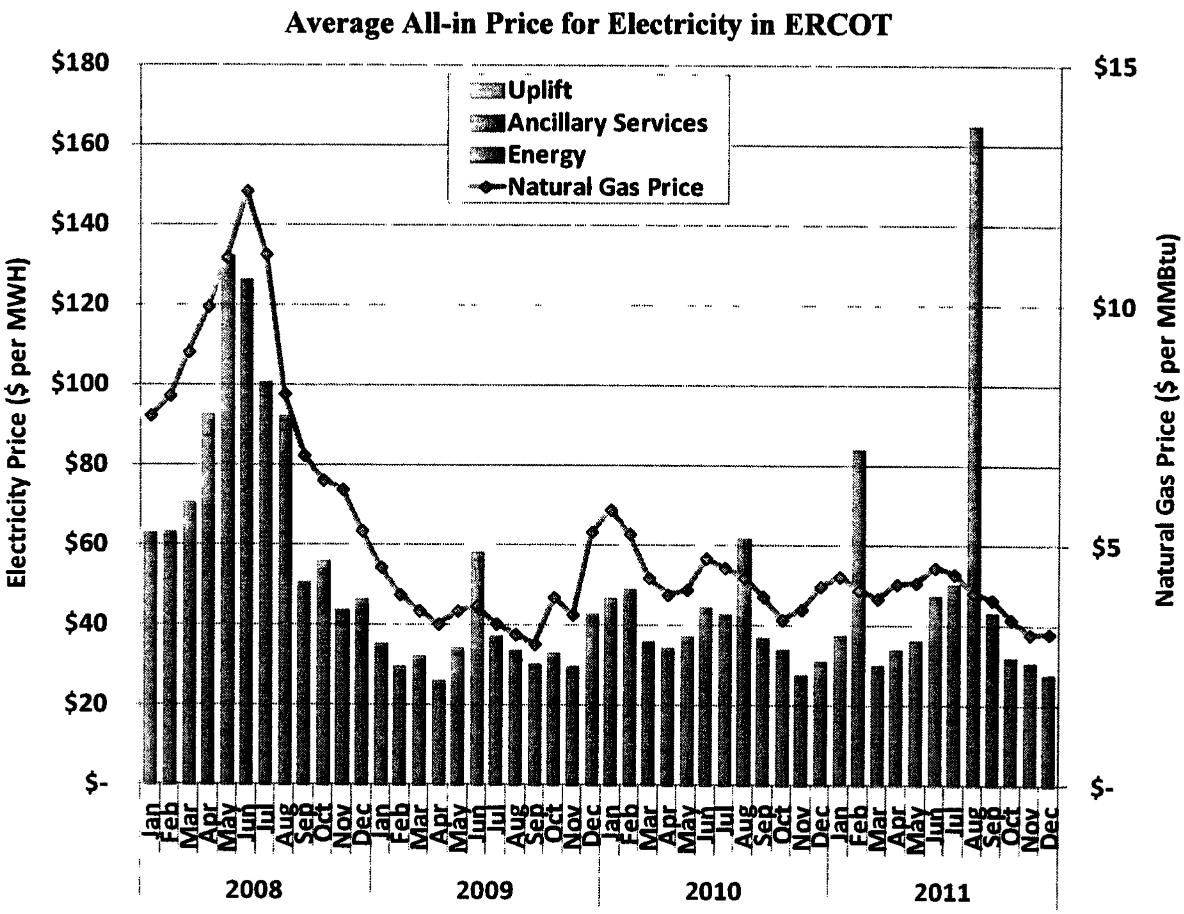
## B. Review of Real-Time Market Outcomes

As is typical in other wholesale markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, the pricing outcomes in the real time energy market are very important because they set the expectations for prices in the 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 2008 through 2011 are shown below:

| | Average Real-Time Electricity Price | | | |
|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 |
| **ERCOT** | **$77.19** | **$34.03** | **$39.40** | **$53.23** |
| **Houston** | $82.95 | $34.76 | $39.98 | $52.40 |
| **North** | $71.19 | $32.28 | $40.72 | $54.24 |
| **South** | $85.31 | $37.13 | $40.56 | $54.32 |
| **West** | $57.76 | $27.18 | $33.76 | $46.87 |
| **Natural Gas** | $8.50 | $3.74 | $4.34 | $3.94 |

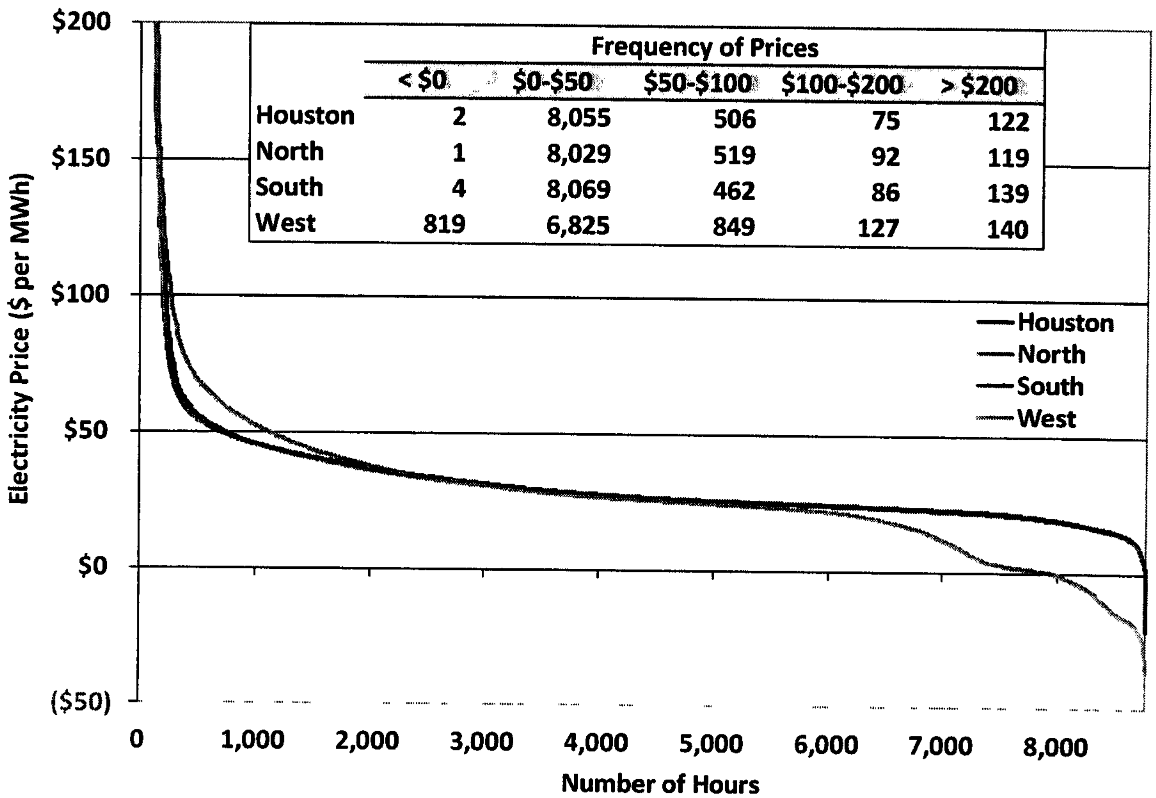
The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices determined in the real-time energy market. ERCOT average real-time market prices were 35 percent higher in 2011 than in 2010. The ERCOT-wide load-weighted average price was $53.23 per MWh in 2011 compared to $39.40 per MWh in 2010. February and August experienced the largest increases to real-time energy prices in 2011, averaging 67 and 160 percent higher than the prices in the same months in 2010. Price increases in both months were driven by extreme weather conditions which led to operating reserve deficiencies resulting in real-time energy prices reaching $3,000 per MWh for sustained periods of time.




The increase in real-time energy prices was partially offset by lower fuel prices in 2011. Natural gas price decreased 9 percent in 2011, averaging $3.94 per MMBtu in 2011 compared to $4.34 per MMBtu in 2010. Although lower natural gas prices contributed to lower real-time energy prices in many hours, these reductions were smaller than the price effects of the shortages in February and August.

To depict how real-time energy prices vary by hour in each zone, the next figure shows the hourly average price duration curve in 2011 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 over 800 hours (9 percent of the time) when the average hourly price was less than zero. The occurrences of relatively low prices in the West zone are generally caused by high wind output in the West that frequently results in severe congestion on transmission interfaces from the West zone to the other zones in ERCOT. The occurrences of relatively higher prices in the West zone are caused by local transmission constraints that typically occur under low wind and high load conditions. Specifics about these transmission constraints are provided in Section III, Transmission and Congestion.

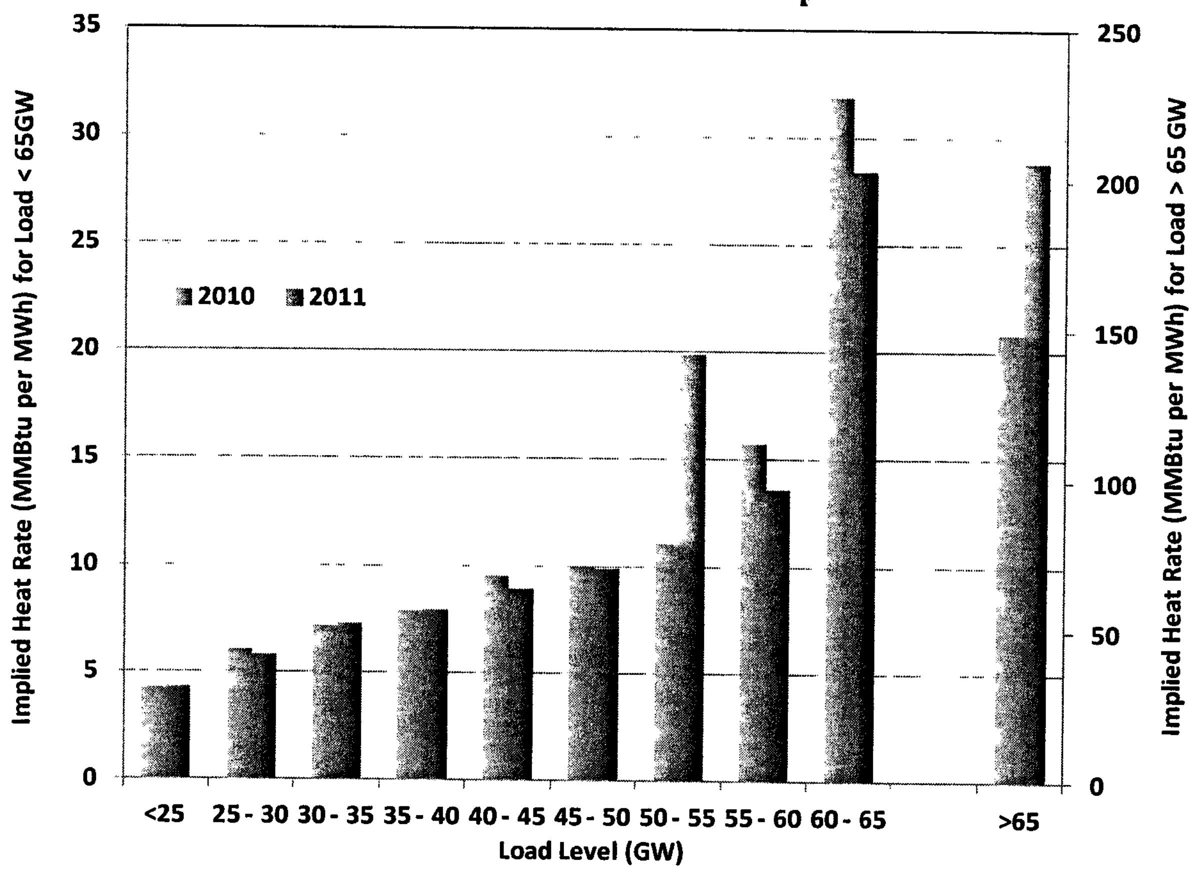
**Zonal Price Duration Curves**




The examination of the real-time energy market continues with an evaluation of implied heat rates at various load levels. The implied heat rate is a metric that shows changes in energy prices that are not due to changes in fuel prices. It is calculated by dividing the real-time energy price by the natural gas price. The figure below provides the average heat rate at various system load levels for 2011 and 2010. 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 there is generally a positive relationship, a noticeable disparity for loads between 50 and 55 GW can be observed. During the extreme cold weather event in early

February, loads were at this level while prices reached $3,000 per MWh for a sustained period of time. Small reductions in heat rates for most load levels during 2011 compared to 2010 were observed and may be attributed to the enhanced efficiency of the nodal market.

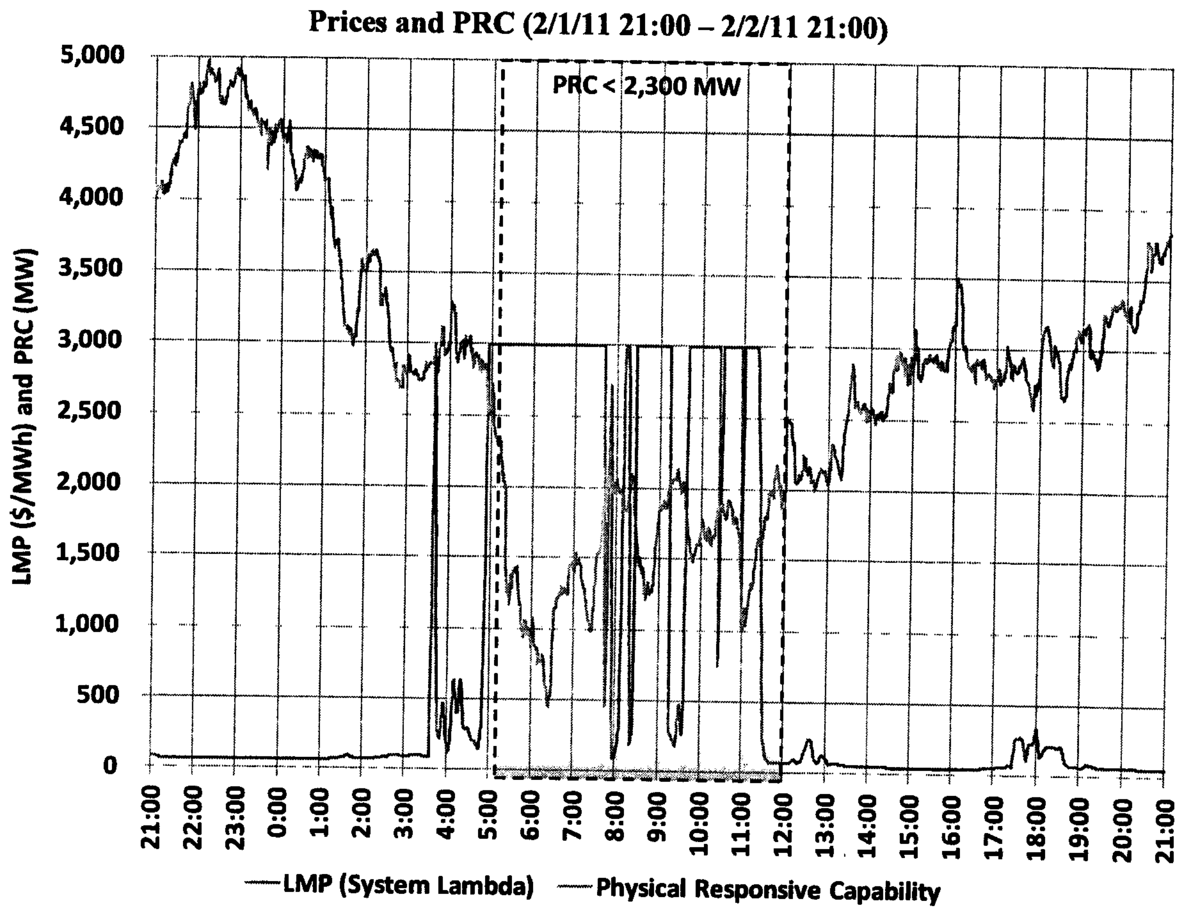
**Heat Rate and Load Relationship**




***February Cold Weather Event***

A significant operational challenge greeted the nascent nodal market in the early morning of February 2, 2011, when the ERCOT region experienced extreme cold weather conditions, record electricity demand levels, and the loss of numerous electric generating facilities across the ERCOT region. These events combined to result in the deployment of load resources contracted to provide responsive reserve service and Emergency Interruptible Load Service ("EILS") and culminated with 4,000 MW of firm load being shed for several hours. The resulting market outcomes had a sizable effect on the overall annual results.

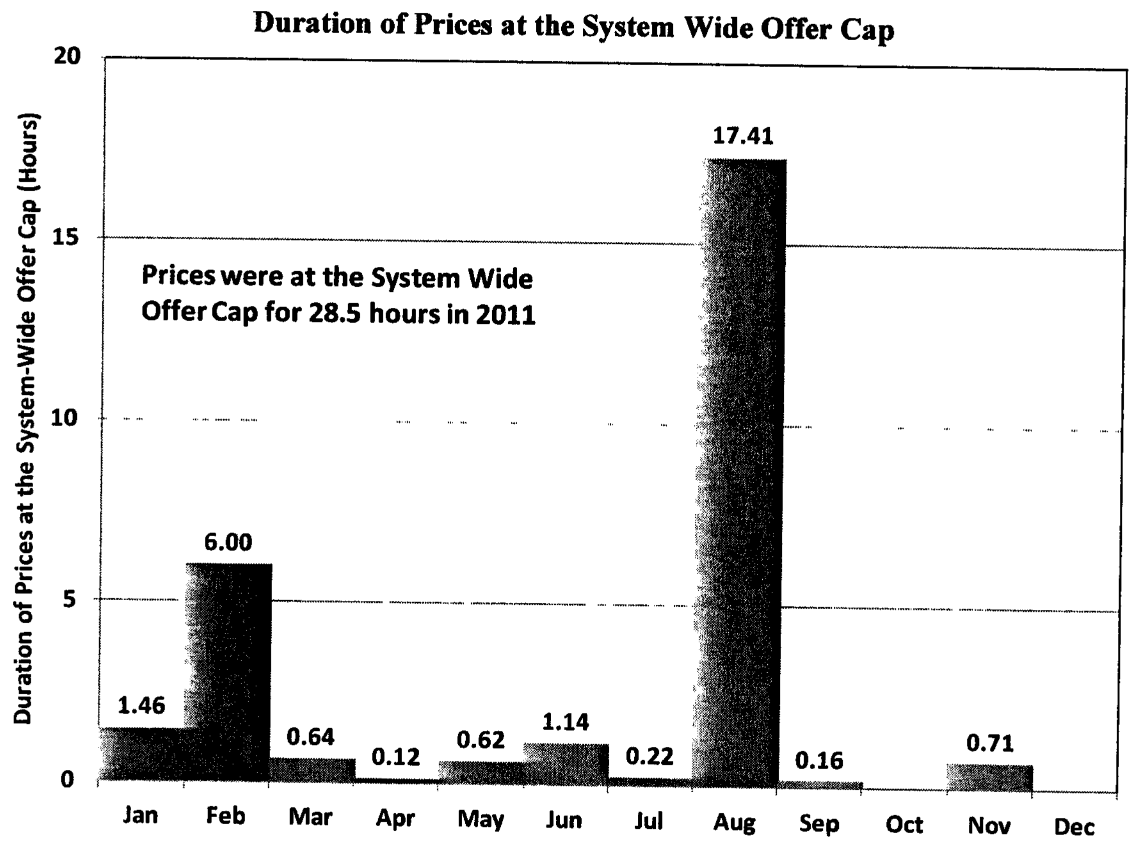
During the morning of February 2nd, ERCOT operating reserve levels were reduced to perilously low levels for a sustained period of time. ERCOT's primary measure of overall operating reserves is Physical Responsive Reserve ("PRC"), and ERCOT will remain in various levels of EEA once PRC drops below 2,300 MW. The figure below shows the wholesale market prices and PRC from 21:00 on February 1 through 21:00 on February 2, 2011.




These wholesale market pricing outcomes were consistent with the ERCOT energy-only market design. The wholesale market prices began communicating the degradation in system reliability as early as 3:30 a.m. By 4:55 a.m. – 15 minutes prior to the reduction of PRC below the minimum acceptable level of 2,300 MW and 50 minutes prior to the first stage of firm load shedding – prices were consistently communicating the rapidly deteriorating system reliability conditions. Finally, as load levels naturally reduced and reserve levels were restored, prices dropped back to levels typical of non-shortage conditions.

### *August Weather Conditions and Shortages*

The summer of 2011 will be remembered as the hottest and driest on record in ERCOT. These extreme weather conditions led to record high demand for electricity during August. There were 50 hours in 2011 with electricity demands that exceeded the highest hourly demand that occurred in 2010.



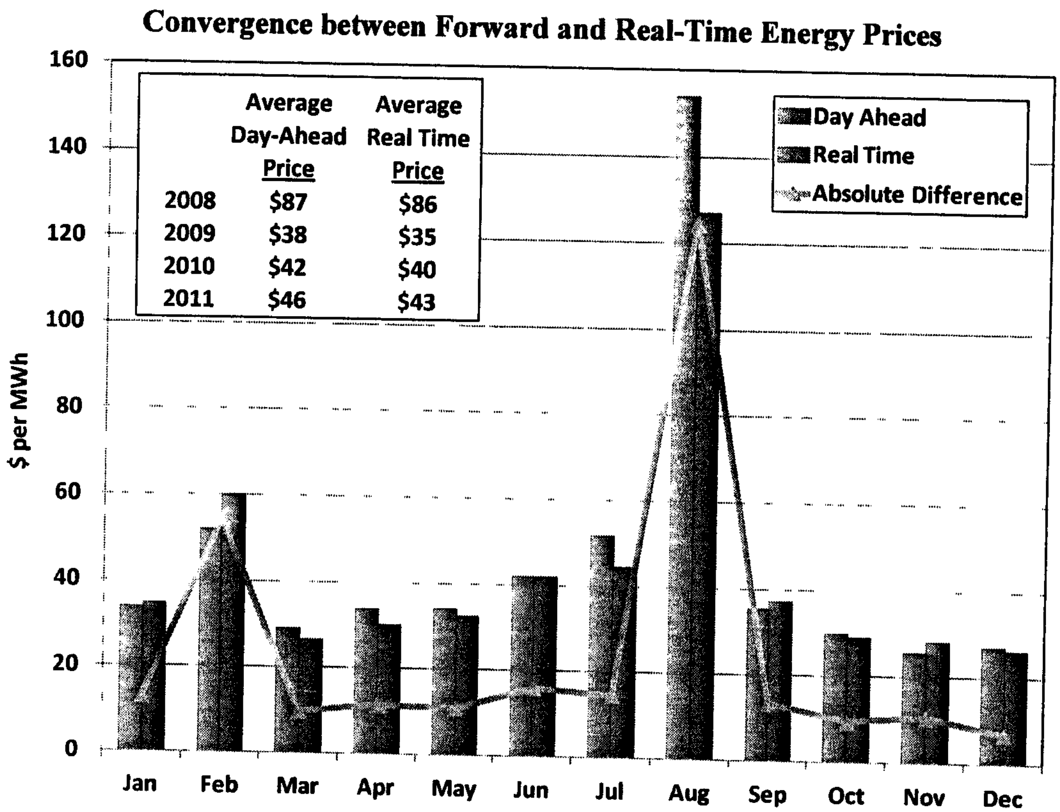

During these high demand conditions there is an increased likelihood that the available generation capacity is not sufficient to meet customer demands for electricity and maintain the required reliability reserves. The nodal market causes energy prices to rise toward the system-wide offer cap as available operating reserves approach minimum required levels to reflect the degradation in system reliability. Presented in the figure above is the aggregated amount of time represented by all dispatch intervals where the real-time energy price was at the system-wide offer cap, displayed by month. Of the 28.5 hours of the annual total time at the system-wide offer cap, more than 17 hours (60 percent) occurred during August.

## C. Review of Day-Ahead Market Outcomes

The performance of the day-ahead market is important because it coordinates the commitments of the ERCOT generation and most wholesale energy bought or sold through the ERCOT markets is settled in the day-ahead market. 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 by making day-ahead purchases or sales to arbitrage them over the long-term.

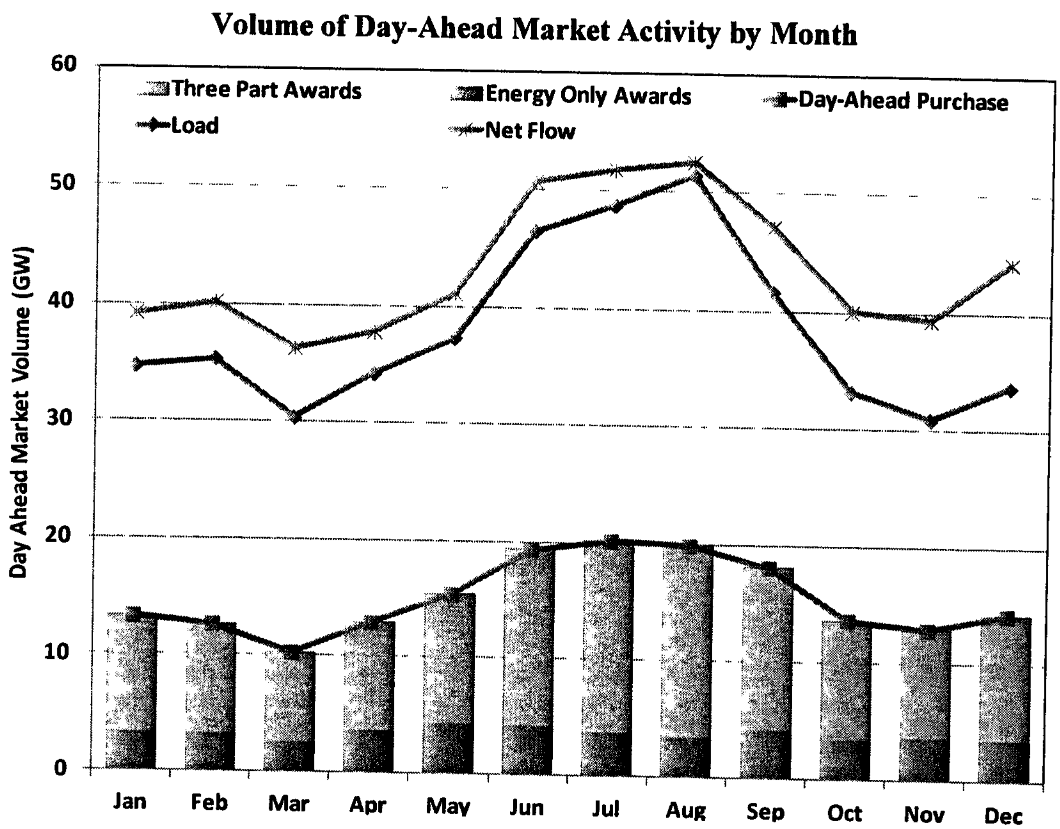
To measure the short-term deviations between real-time and day-ahead prices, the average of the absolute value of the difference between the day-ahead and real-time price on a daily basis is also calculated.

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 2011 was $46 per MWh, compared to the simple average of $43 per MWh for real-time prices. This slight 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 having a forced outage and buying back energy at real-time prices. This may explain why the highest premiums occurred during the highest priced months. Overall, the day-ahead premiums were very similar to the differences observed in 2009 and 2010.

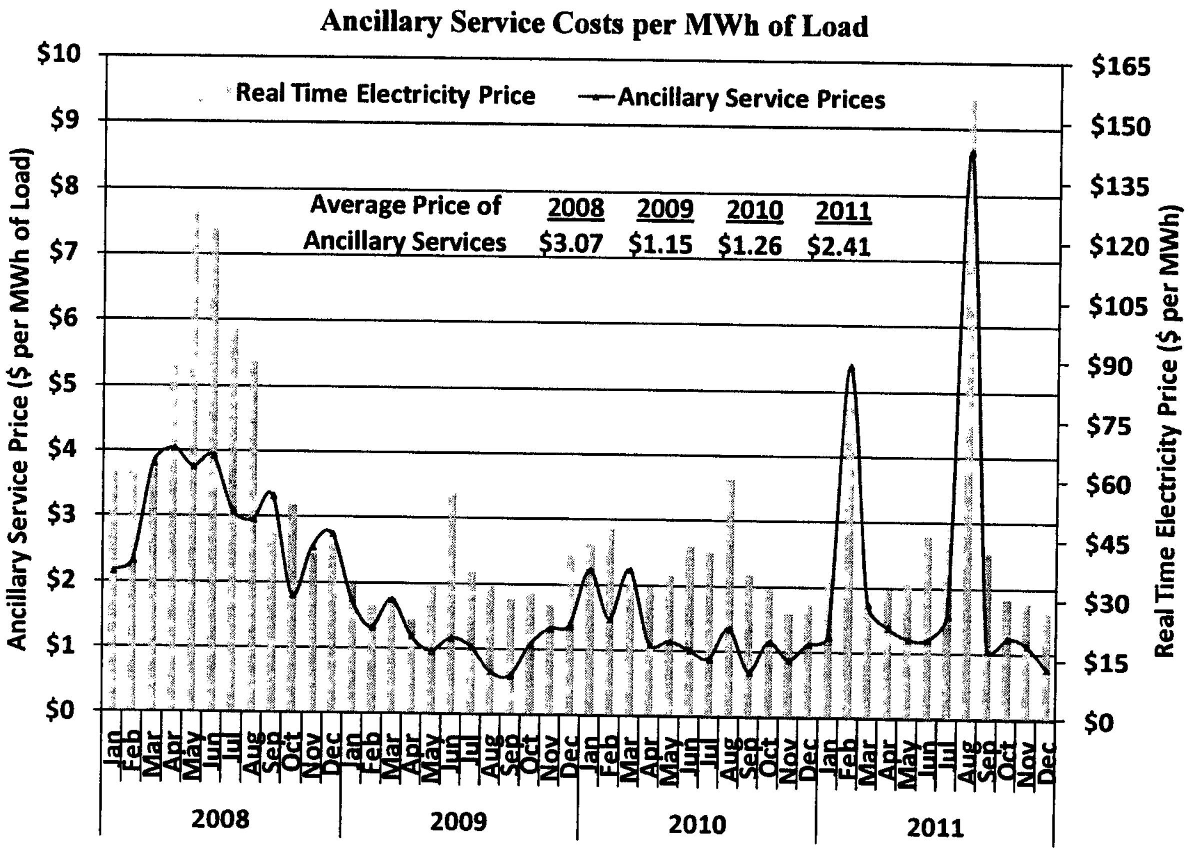



The average absolute difference between day-ahead and real-time prices was $24.50 per MWh in 2011; much higher than in the previous two years where the average absolute difference was $12.25 and $12.37 in 2010 and 2009, respectively. This large increase was the result of the significant periods of very high real-time prices during February and August. Removing the contribution from these two months reduces the average absolute difference to $11.49 per MWh in 2011.

Summarized in the figure below is the volume of day-ahead market activity by month. It shows that day-ahead purchases are approximately 40 percent of real-time load. These energy purchases are met through a combination of generator specific and virtual offers. Once the effects of net energy flows associated with purchases of PTP Obligations are included, total volumes transacted in the day-ahead market are, on average, greater than real-time load.



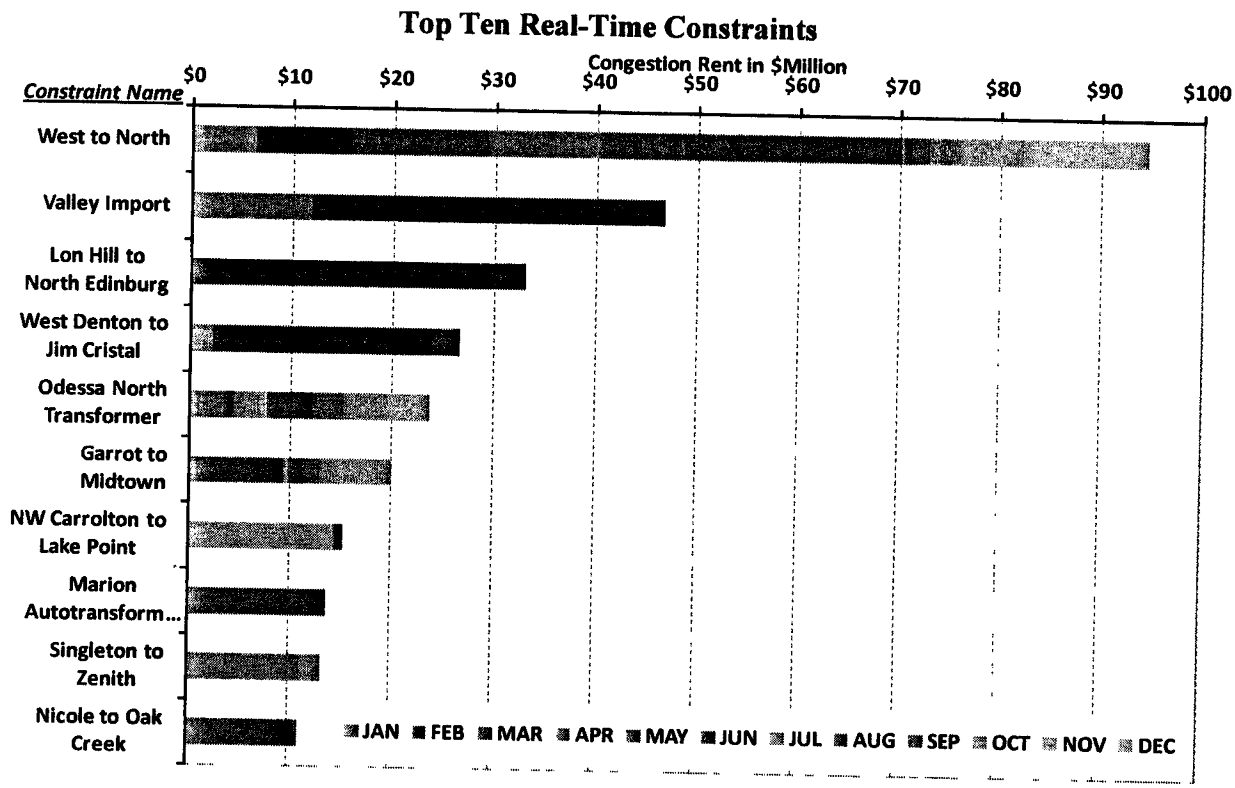

Ancillary Service capacity is procured as part of the day-ahead market clearing. The figure below shows the monthly total ancillary service costs per MWh of ERCOT load and the average real time energy price for 2008 through 2011. Total ancillary service costs are generally correlated with real-time energy price movements, which are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load increased to $2.41 per MWh in 2011 compared to $1.26 per MWh in 2010, an increase of 91 percent. Total ancillary service costs increased from 3.2 percent of the load-weighted average energy price in 2010 to 4.5 percent in 2011.




## D. Transmission and Congestion

There were more than 300 different transmission constraints active at some point during real-time operations in 2011. The median financial impact of all these constraints, as measured by congestion rent, was approximately $300,000.

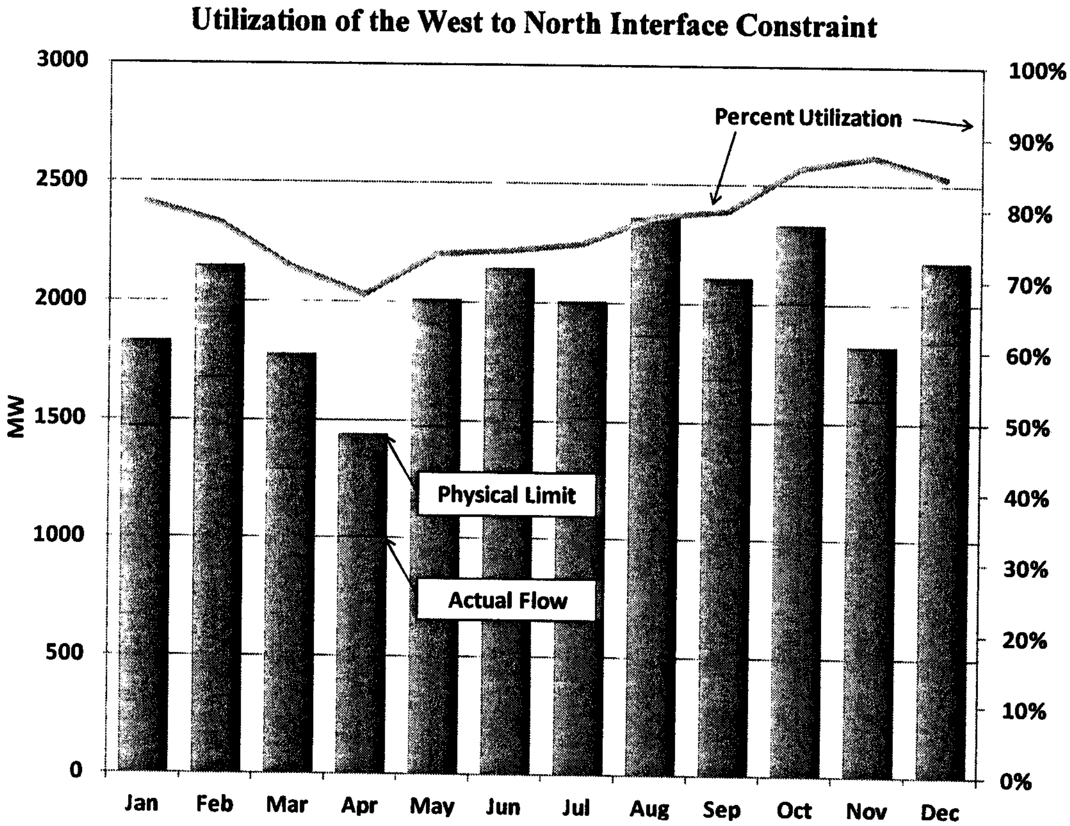
The figure below displays the ten most costly real-time constraints and indicates that the West to North interface constraint had the highest financial impact during 2011. The West to North interface constraint is very similar to the competitively significant constraint that existed since the inception of ERCOT's zonal market. Through the years it has been a major impediment to delivering all the wind generation located and produced in the western reaches of ERCOT to the load centers. The West to North interface constraint was the most frequently occurring constraint in 2011. It was active at some point during every month of 2011 and was binding more than 20 percent of the time in 2011.




Two additional constraints on the list are also related to west zone wind generation, although in different directions. The Nicole to Oak Creek constraint is a small capacity 69 kV transmission line that typically overloads under high wind conditions, while due to its load serving nature, the Odessa North 138/69 kV transformer typically overloads under low wind conditions.

The second and third constraints shown in the figure are similar and reflect limitations on the amount of electricity that can be reliably imported into the Rio Grande Valley. This was most notable during the cold weather event of early February. Whereas system wide generation shortages were limited to February 2$^{nd}$, extremely high customer demands for electricity coupled with the extended planned outage of local generation led to shortages and resulting load curtailments in the Valley over the next two days. Constraints limiting imports to the Valley were active and not able to be resolved for a total of 13 hours during January and February.

To maximize the economic use of scarce transmission capacity, the ideal outcome would be for the actual transmission line flows to reach, but to not exceed the physical limits required to maintain reliable operations.



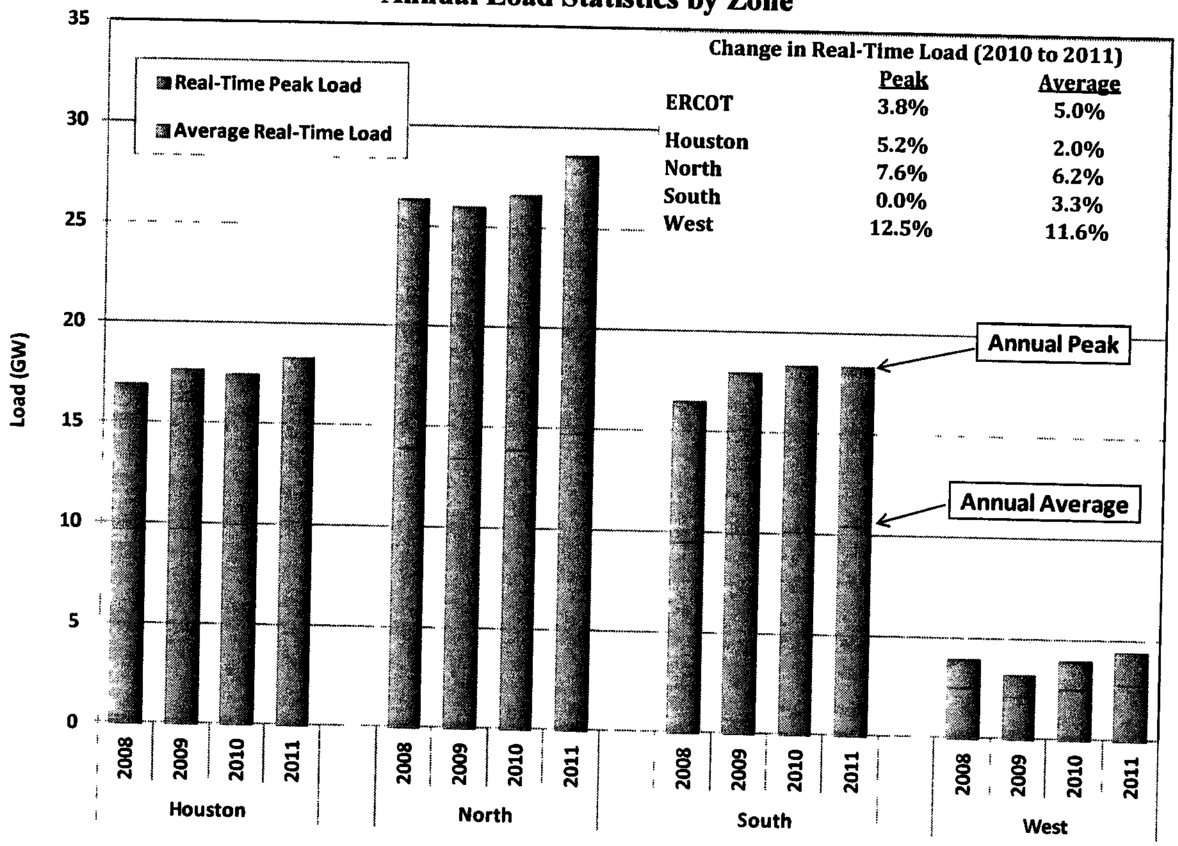

The figure above presents a summary of the utilization of the most active transmission constraint during 2011, the West to North interface. Its average utilization is determined by comparing the actual flow with the physical limit of the constraint for each real-time dispatch interval it was binding. Although there was significant variation throughout the year, the average physical limit was slightly less than 2,000 MW and the average actual flow during constrained intervals was approximately 1,500 MW. The average annual utilization of 76 percent compares favorably to 64 percent utilization experienced during the final months of the zonal market. Even more encouraging is the upward trend in utilization observed in the latter part of the year. This increase may be attributed to increased operator confidence that generators, specifically wind generators in this case, will reduce their output as expected when the constraint is active.

There should be opportunity for increased limits in the short term and even higher utilization of this constraint as ERCOT implements more sophisticated real-time analysis of this constraint, rather than relying on off-line studies. Over the long term, the physical limit will increase as CREZ transmission projects are completed.

## E. Load and Generation

This figure below shows peak load and average load in each of the ERCOT zones from 2008 to 2011. In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North Zone is the largest zone (with about 39 percent of the total ERCOT load); the South and Houston Zones are comparable (27 percent) while the West Zone is the smallest (7 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 was greater than the annual ERCOT peak load.

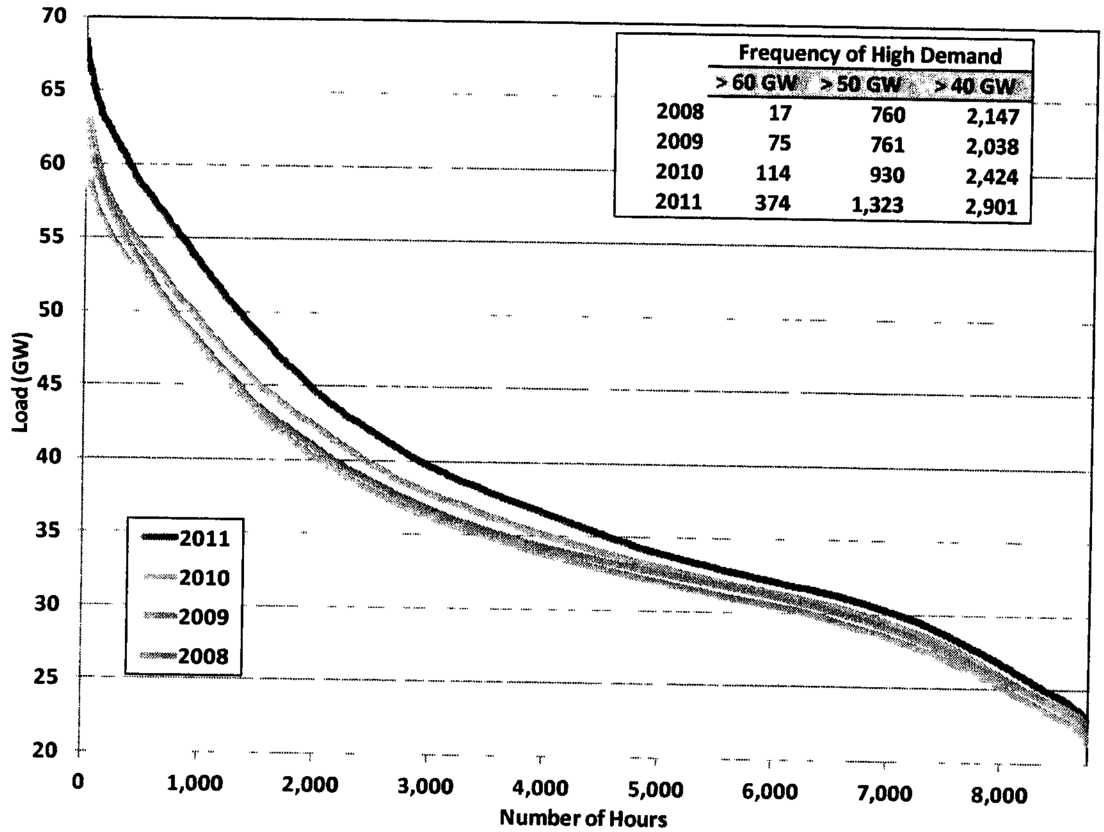
**Annual Load Statistics by Zone**




Total ERCOT load increased from 319 TWh in 2010 to 335 TWh in 2011, an increase of 5.0 percent or an average of approximately 1,800 MW every hour. Similarly, the ERCOT coincident peak hourly demand increased from 65,776 MW in 2010 to 68,379 MW, an increase of roughly 2,600 MW, or 4.0 percent.

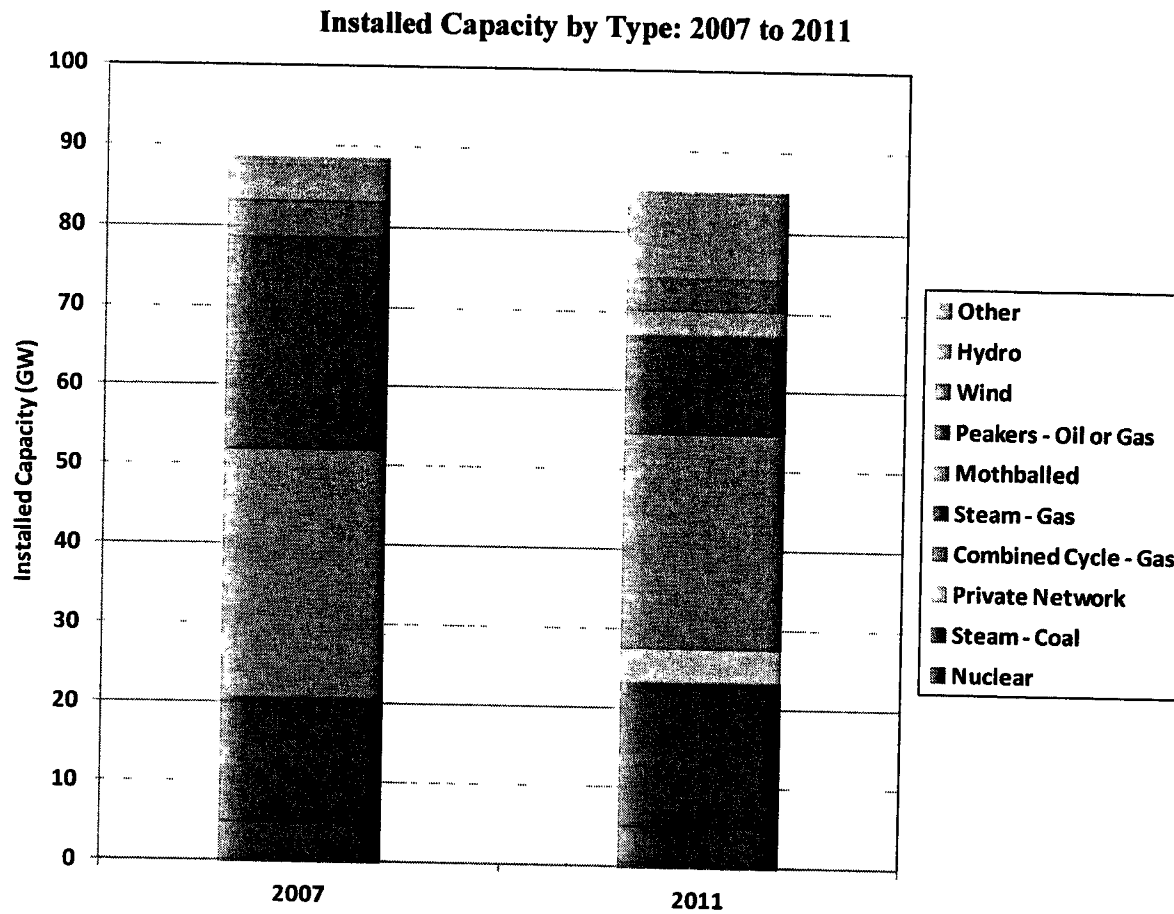
To provide a more detailed analysis of load at the hourly level, the next figure compares load duration curves for each year from 2008 to 2011. A load duration curve shows the number of hours (shown on the horizontal axis) that load exceeds a particular level (shown on the vertical axis). ERCOT has a fairly smooth load duration curve, typical of most electricity markets, with low to moderate electricity demand in most hours, and peak demand usually occurring during the late afternoon and early evening hours of days with exceptionally high temperatures.

**Load Duration Curve – All hours**



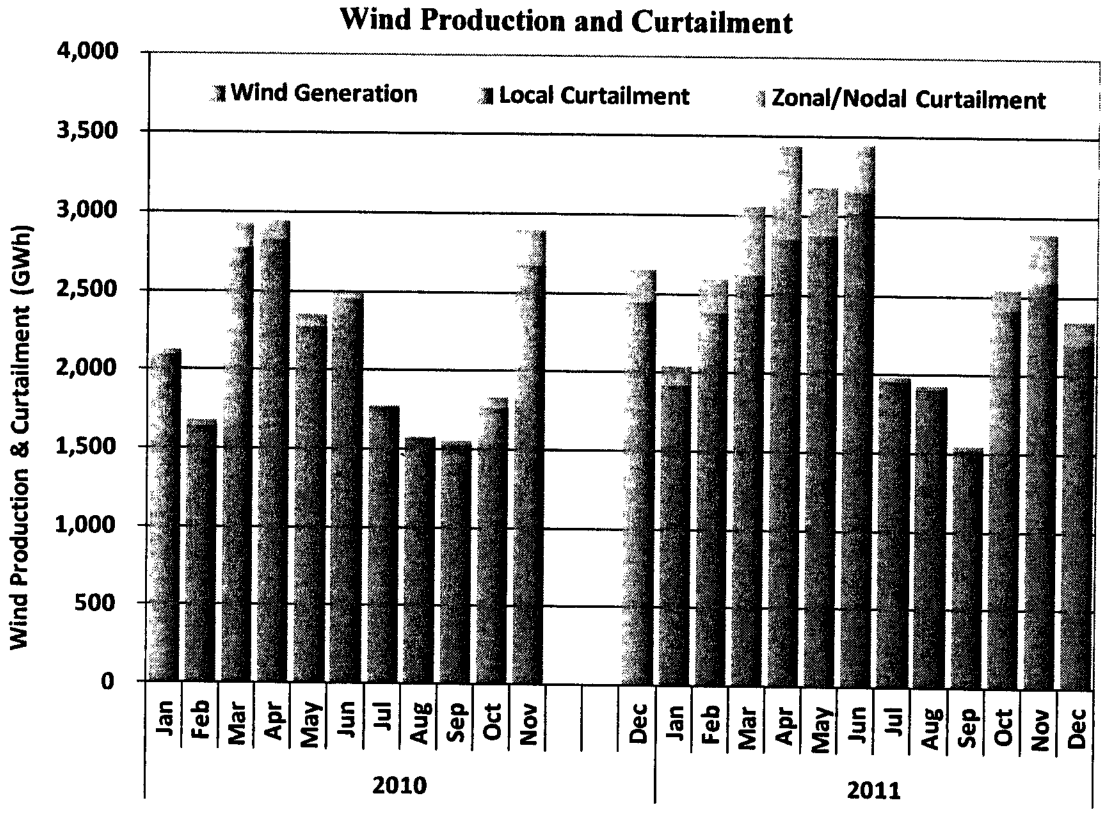

As shown in the figure above, the load duration curve for 2011 is significantly higher than in 2010 across all hours of the year. This is consistent with the aforementioned 5.0 percent load increase from 2010 to 2011.

Although there were very few new units placed in service during 2011, by comparing the current mix of installed generation capacity to that in 2007, as shown in the figure below, the effects of longer term trends may be observed.

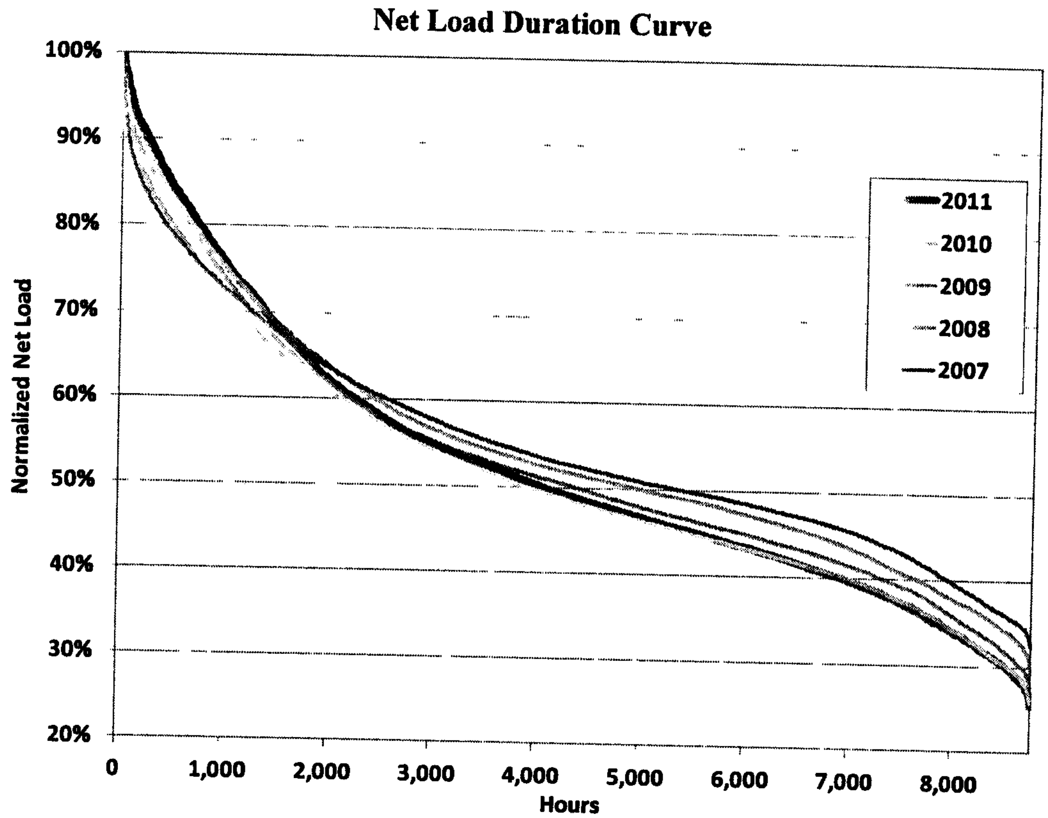



Over these five years wind and coal generation are the only two categories with increased capacity. However, the sizable additions in these two categories have been more than offset by retirements of natural gas fueled steam units, resulting in less installed capacity in 2011 than there was in 2007.

The next figure shows the wind production and local and zonal curtailment quantities for each month of 2010 and 2011. This figure reveals that the total quantity of curtailments for wind resources once again increased in 2011 when compared to 2010, even as actual production increased.



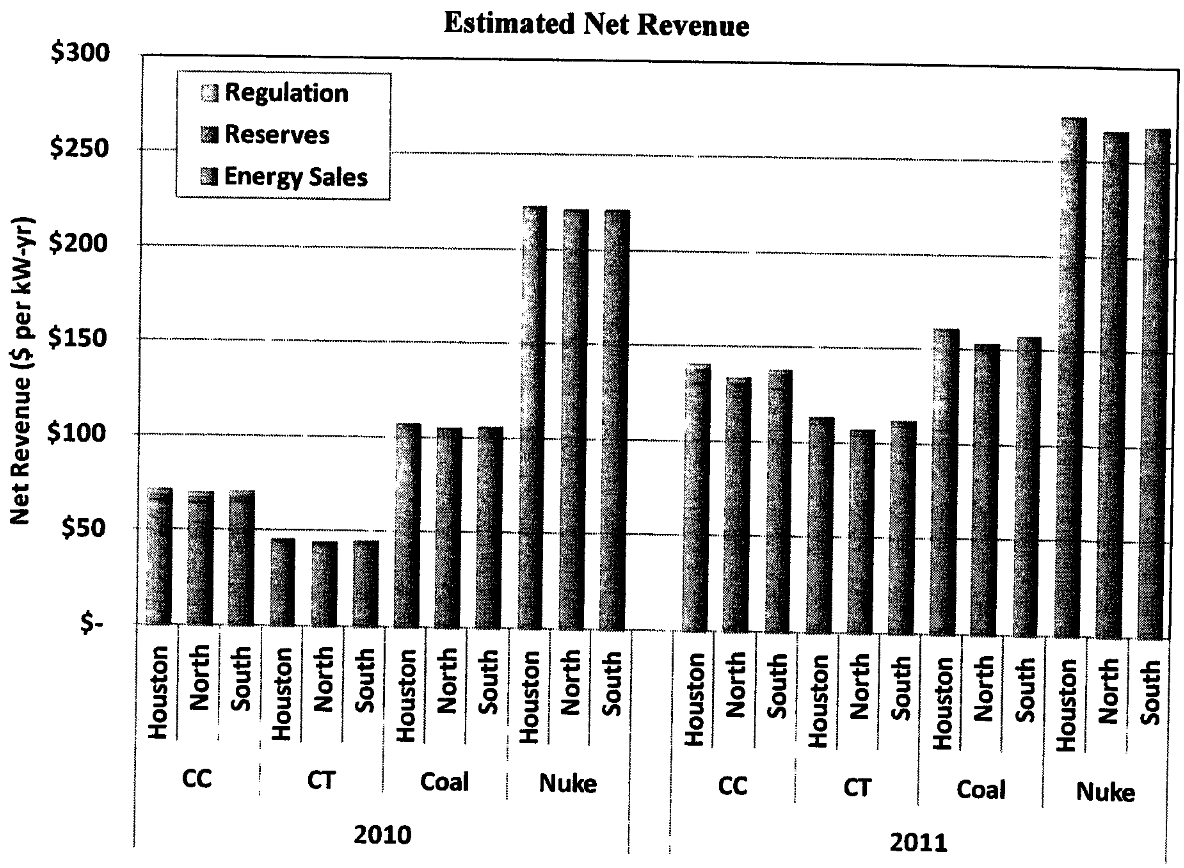

Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. The figure below shows the net load duration curves for 2008 through 2011, normalized as a percent of peak load. This figure shows the continued erosion of remaining energy available for non-wind units to serve during most hours of the year, with much less impact during the highest loads.




## F. Resource Adequacy

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. We evaluate these economic signals by estimating the "net revenue" new resources would receive from the markets. Net revenue is the total revenue that can be earned by a new generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the energy and ancillary services markets together provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. In a 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.

The figure below shows the results of the net revenue analysis for four types of hypothetical new units in 2010 and 2011. These are: (a) natural gas fueled combined-cycle, (b) natural gas fueled combustion turbine, (c) coal fueled generator, and (d) a nuclear unit. For the gas-fired technologies, 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 energy net revenues are computed based on the generation weighted settlement point prices from the real-time energy market. Weighting the energy values in this way masks what may be very high locational values for a specific generator location. Some generators may also receive uplift payments because of their specific reliability contributions, either as a reliability must run, or through the reliability unit commitment. This source of revenue is not considered in this analysis. The analysis also includes simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. Start-up costs and minimum running times and ramp restrictions, which can prevent the natural gas generators from profiting during brief price spikes, are not explicitly accounted for in the net revenue analysis. Despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

The figure above shows that the net revenue for every generation technology type increased in 2011 compared to each zone in 2010. Prior to 2005, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. However, high natural gas prices through 2008 allowed energy prices to remain at levels high enough to support new entry for these technologies. The production costs of coal and nuclear units did not change significantly over this period, leading to a dramatic rise in net revenues. Conditions have now changed with the much lower natural gas prices experienced through 2011. The estimated net revenue for both a new coal or a nuclear unit in ERCOT were well below the levels required to support new entry, despite the relatively frequent shortages in 2011.

- For a new coal unit, the estimated net revenue requirement is approximately $210 to $270 per kW-year. The estimated net revenue in 2011 for a new coal unit was less than $160 per kW-year.

- For a new nuclear unit, the estimated net revenue requirement is approximately $280 to $390 per kW-year. The estimated net revenue in 2011 for a new nuclear unit was approximately $270 per kW-year.

- For a new natural gas fueled combustion turbine, the estimated net revenue requirement is approximately $80 to $105 per kW-year. The estimated net revenue in 2011 for a new gas turbine ranged from $107 per kW-year in the North zone to $113 per kW-year in the Houston zone, indicating that for the first time since 2008 that net revenues were sufficient to support new gas turbine generation.

- For a new natural gas fueled combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2011 for a new combined cycle unit ranged from $133 per kW-year in the North to $140 per kW-year in Houston, again indicating that 2011 was the first time since 2008 that net revenues have been sufficient to support new combined cycle generation in ERCOT.

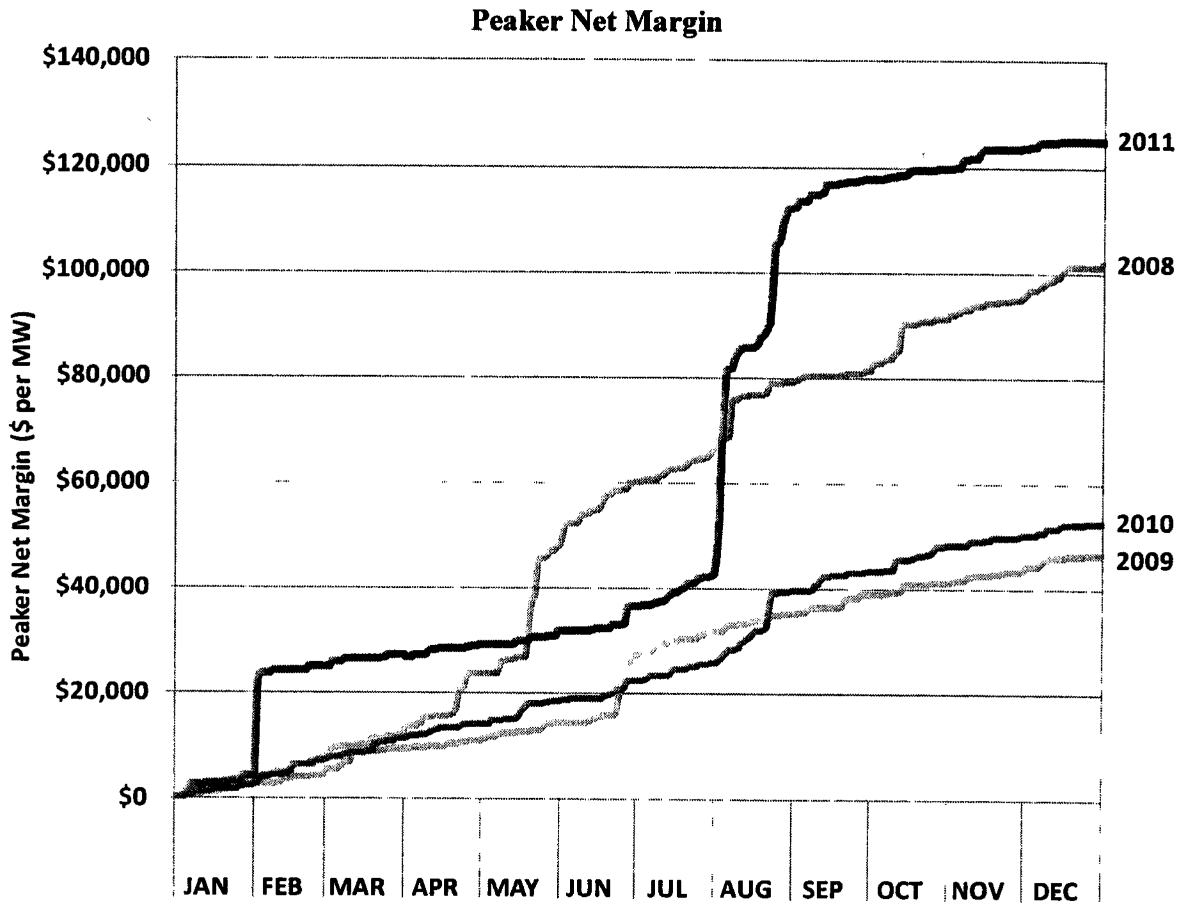
Even though net revenues for the Houston and South zone in 2008 may have appeared to be sufficient to support new gas fueled generation, it was actually extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves which led to high prices and resulting higher than warranted net revenues. Discounting the effect that the 2008 results would have had on forward price signals, we find that 2011 is the first time in five years that net revenues have been sufficient to support either new gas turbine or combined cycle generation.

***Scarcity Pricing Effectiveness***

PUCT SUBST. R. 25.505 provides that the IMM may conduct an annual review of the effectiveness of the SPM. This subsection provides an assessment of the effectiveness of the SPM in 2011 under ERCOT's energy-only market structure. In markets with a long-term capacity market, fixed capacity payments are made to resources across the entire year independent of the relationship between real-time supply and demand. The objective of the energy-only market design is to allow energy prices to rise significantly higher at times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements. 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 upon these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment when required. The expectation of competitive energy market outcomes is no different in energy-only than in markets that include a capacity market. However, capacity markets are designed to ensure a specified planning reserve margin, which may be higher than an energy-only market would achieve. Under this condition the higher planning reserve margin will serve to reduce the frequency of shortages in the energy market.

The SPM includes a provision termed the Peaker Net Margin ("PNM") that is designed to measure the annual net revenue of a hypothetical peaking unit. Under the current rule, if the PNM for a year reaches a cumulative total of $175,000 per MW, the system-wide offer cap is then reduced to the higher of $500 per MWh or 50 times the daily gas price index.

The next figure shows the cumulative PNM results for each year from 2008 through 2011 and shows that PNM in 2011 was higher than it has ever been. As previously described, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80,000 to $105,000 per MW-year. Thus, as shown below and consistent with the previous findings in this section relating to net revenue, the PNM reached the level sufficient for new entry in 2011.



Although the nodal market implementation brought about more reliable and efficient shortage pricing there remain aspects of the ERCOT real-time energy pricing that can be improved. These improvements would address conditions that cause energy prices to understate the marginal costs of satisfying the real-time demand. In particular, real time energy prices do not fully reflect:

- The value of curtailed load when load resources are deployed;
- The value of reduced reliability when responsive reserves or non-spinning reserves have been converted to energy;
- The costs associated with starting and running the gas turbines (or other resources not dispatchable in the 5-minute energy dispatch) that were being deployed to meet demand.

After multiple protocol revisions are implemented in 2012, real-time energy price formation will be improved, but the non-spinning reserve deployment process remains sub-optimal from a reliability and efficiency perspective. We continue to recommend that ERCOT develop a mechanism that will rationally commit generation and load resources that can start or curtail within 30 minutes.

This deficiency in ERCOT's nodal market design should be addressed by implementing a "look ahead" dispatch functionality for the real-time market to produce an energy and ancillary services commitment and dispatch results that are co-optimized and recognize anticipated changes in system demands. This additional functionality represents a major change to ERCOT systems; one we recommend together with improved pricing provisions that will allow offers from load resources to set prices if they are required to meet system demand.

An effective look ahead dispatch functionality should also reduce the price dampening effects of energy produced by units operating below their low sustainable operating limit. Although alternatives have been suggested to address this issue in a standalone manner, we believe the better approach will be to develop a comprehensive look ahead dispatch solution.

Expectations about both the magnitude of the energy price during shortage conditions and the frequency of shortage conditions are what will attract new investment in an energy-only market. In other words, the higher the price during shortage conditions, the fewer shortage conditions that are required to provide the investment signal, and vice versa. As we have continually observed since the SPM was first put in place in late 2006, the magnitude of price expectations is determined by the market rules established by the PUCT, and it is yet to be seen whether the frequency of shortage conditions over time will be sufficient to produce market equilibrium that satisfies the current reliability requirement of maintaining a 13.75 percent planning reserve.

Proceedings are currently underway at the PUCT to review both the magnitudes of prices during operating reserve shortage conditions and the current reliability requirement; specifically whether the assumptions relating to the planning reserve margin calculation are appropriate for the ERCOT energy-only market, and whether the resulting value is to be treated as a target or a minimum requirement. Upon clarification of these issues, policy options will be considered to ensure that the market design elements are properly linked to the chosen resource adequacy objectives.

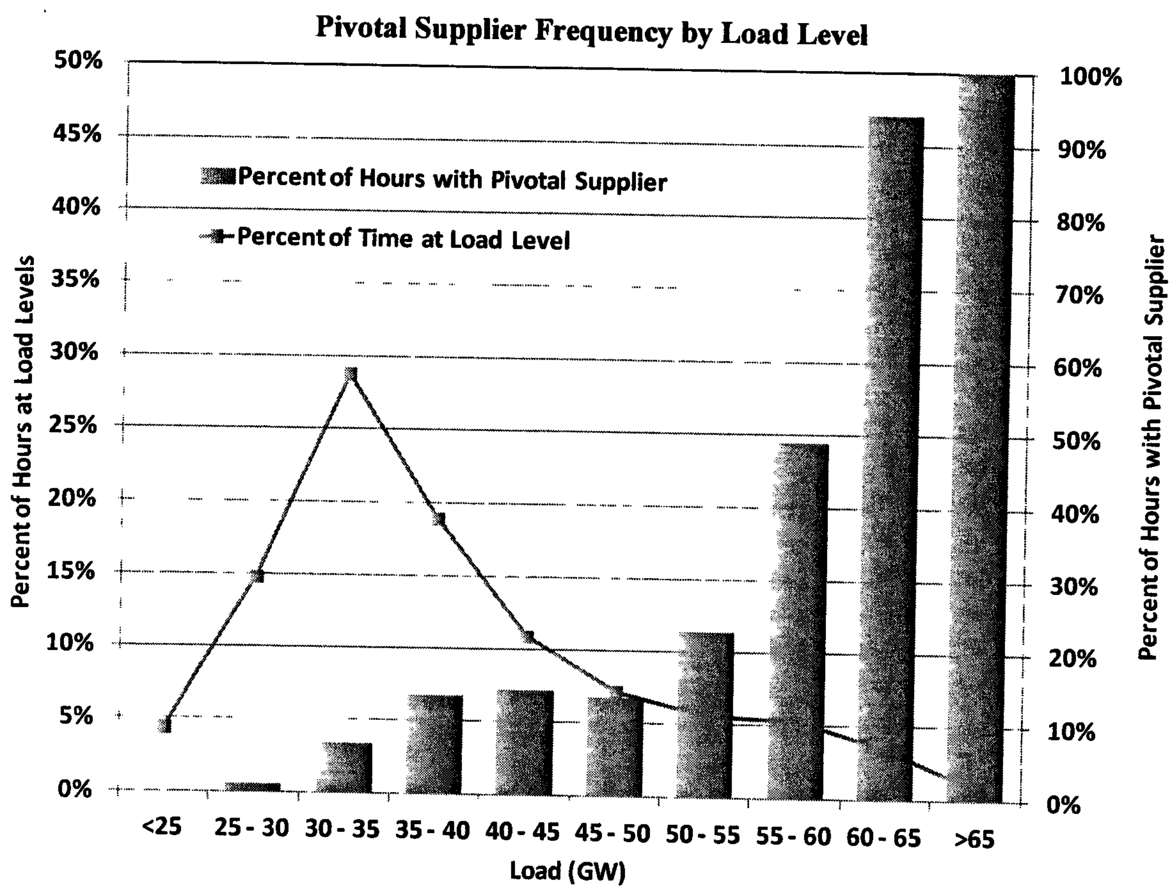
As extreme as the weather and resulting load was in 2011, the total number of dispatch intervals with system-wide energy prices at the offer cap amounted to 28.5 hours. Although net revenues were sufficient for new gas generation, they were not overly so. Even with the improvements discussed, pricing during shortage intervals may need to be even higher to ensure that investments in new supply and/or demand resources result in maintaining the minimum required installed reserve margin.

## G. Analysis of Competitive Performance

The report evaluates market power from two perspectives, structural and behavioral. The Residual Demand Index ("RDI") is used to analyze market structure. The RDI is used to measure the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers. When the RDI is greater than zero the largest supplier is pivotal; 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 below summarizes the results of our RDI analysis by displaying the percent of time at each load level there as a pivotal supplier. At loads greater than 65 GW there is a pivotal supplier 100 percent of the time. The figure also displays the percent of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 15 percent of all hours of 2011. As a comparison, the same system-wide measure for the Midwest ISO resulted in zero hours with a pivotal supplier.



It is important to recognize that inferences regarding market power cannot be made solely from this data. Bilateral contract obligations can affect a supplier's potential market power. For example, a smaller supplier selling energy in the real-time energy market and through short-term bilateral contracts may have a much greater incentive to exercise market power than a larger supplier with substantial long-term sales contracts. The RDI measure shown in the previous figure does not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

The behavioral aspects of market power abuse are evaluated 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.

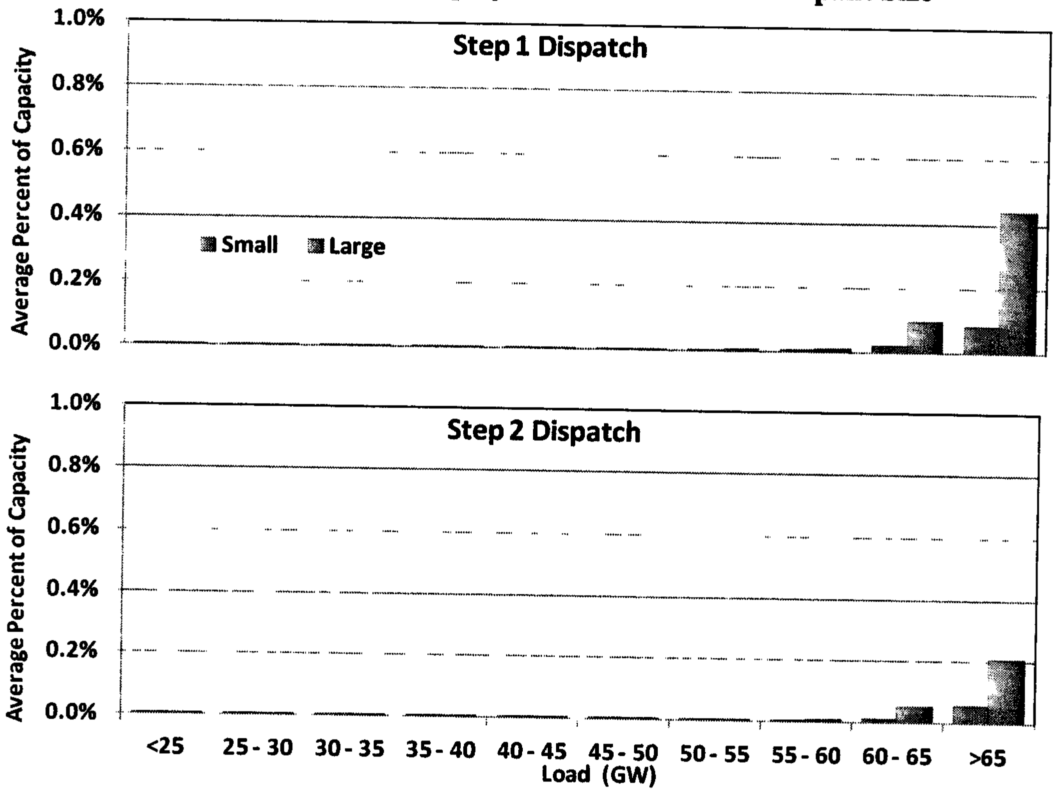
Resources are considered for inclusion in the output gap when they are committed and producing at less than full output. Energy not produced from committed resources is included in the output gap if the real-time energy price exceeds by at least $50 per MWh that unit's mitigated offer cap which serves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

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

If a market participant has sufficient market power, it might raise its offer in such a way to increase the reference price in the first step. Although in the second step, the offer appears to be mitigated, the market participant has still influenced the market price. This output gap is measured by the difference between the capacity level on a generator's original offer curve at the first step reference price and the capacity level on the generator's cost curve at the first step reference price. However, this output gap is only indicative because no output instructions are sent based on the first step. It is only used to screen 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. As previously illustrated, even though the offer curve is mitigated there is still the potential for the mitigated offer curve to be increased as a result of a high first step reference price due to a market participant exerting market power.

**Incremental Output Gap by Load Level and Participant Size**




The figure above shows the magnitude of the output gap to be very small, even at the highest load levels, for both steps in the dispatch process. These small quantities raise no competitive concerns. In summary, we find that the ERCOT nodal wholesale market performed competitively in 2011.

## H. Nodal Market Performance and Recommendations

As discussed in prior ERCOT State of the Market Reports, implementation of the nodal market was expected to provide the following improvements:

- Fundamental improvements in ERCOT's ability to efficiently manage transmission congestion, which is one of the most important functions in electricity markets.
- The nodal market will enable all transmission congestion to be managed through market-based mechanisms
- The nodal market will provide better incentives to market participants, facilitate more efficient commitment and dispatch of generation, and improve ERCOT's operational control of the system.
- The use of unit-specific dispatch in the nodal market will allow ERCOT to more fully utilize generating resources than the zonal market, which frequently exhibited price spikes even when generating capacity was not fully utilized.
- The nodal market will allow ERCOT to increase the economic and reliable utilization of scarce transmission resources well beyond that attainable in the zonal market.
- The nodal market will significantly improve the ability to efficiently and reliably integrate the ever-growing quantities of intermittent resources, such as wind and solar generating facilities.
- The nodal market will produce price signals that better indicate where new generation is most needed (and where it is not) for managing congestion and maintaining reliability.

In the long-term, these enhancements to overall market efficiency should translate into substantial savings for consumers. This report reviews the first year of nodal market operations, highlights the areas of expected improvements that have been observed in the first year, documents areas of unanticipated outcomes during the nodal transition, and provides recommendations for future improvements to the nodal market.

Overall pricing outcomes from the nodal real-time market have met expectations for improved efficiency. The discussion of Figure 11, Figure 13, and Figure 14 on pages 12 and 14-15 describes how prices are much more appropriately correlated with load level in the nodal market than they were in the zonal market. Section V.B, Effectiveness of the Scarcity Pricing Mechanism , specifically at page 84, provides more details about the improved pricing during shortage conditions, now that scarcity pricing is no longer dependent upon the offers from participants with small generator fleets. The nodal market has also enabled the higher utilization of transmission facilities as described in the discussion of Figure 36, on page 45.

Three areas where the nodal market implementation led to unanticipated outcomes were identified and quickly resolved in 2011. The calculation of real-time settlement point prices every 15 minutes at resource node locations originally included weighting the price from each dispatch interval by the dispatch level (base point) of the resource. This led to price differences between locations when there was no transmission congestion. These price differences would have resulted in payments and charges to owners of Point-to-Point Obligations and Congestion Revenue Rights settled in real-time which were not supported by real-time congestion rent and would have required uplifted payments to support. The base point weighting factor was removed with the implementation of NPRR 326.

As described in Section III.A, Real-Time Constraints at page 46, transmission constraint and base point oscillations were observed during the spring of 2011. After ERCOT modified their constraint management software and started providing the curtailment flag to wind generators, as required under NPRR 285, there have been no more occurrences of constraint oscillation.

The last area of unanticipated outcomes has to do with the modeling of the transmission system and the impact that de-energized elements had on locational prices. Shortly after the implementation of the nodal market, it was determined that when particular generation resources were offline, according to the established pricing rules the real-time price at that location was set using a system-wide value. This created inconsistent pricing between the day-ahead and real-time markets, allowing participants to acquire certain Point-to-Point Obligations for low, or no cost in the day-ahead market and receive payment because there were real-time price differences. In February 2011, ERCOT improved their network model by adding hundreds of transmission system elements at 140 locations. This model improvement, combined with NPRR343 which precludes parties from buying Point-to-Point Obligations between electrically similar locations, has greatly reduced the potential for this type of inefficient trading activity. However, under certain combinations of transmission equipment outages similar price discrepancies can occur.

In conjunction with any market design changes that may result from the current PUCT proceedings related to resource adequacy, we recommend improvements to two aspects of the nodal market design.

1. We recommend a change 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 VI.C, Mitigation at page 107, we support introducing a test to determine whether a unit is either contributing to, or helping to resolve a transmission constraint and only subject the relieving units to mitigation.

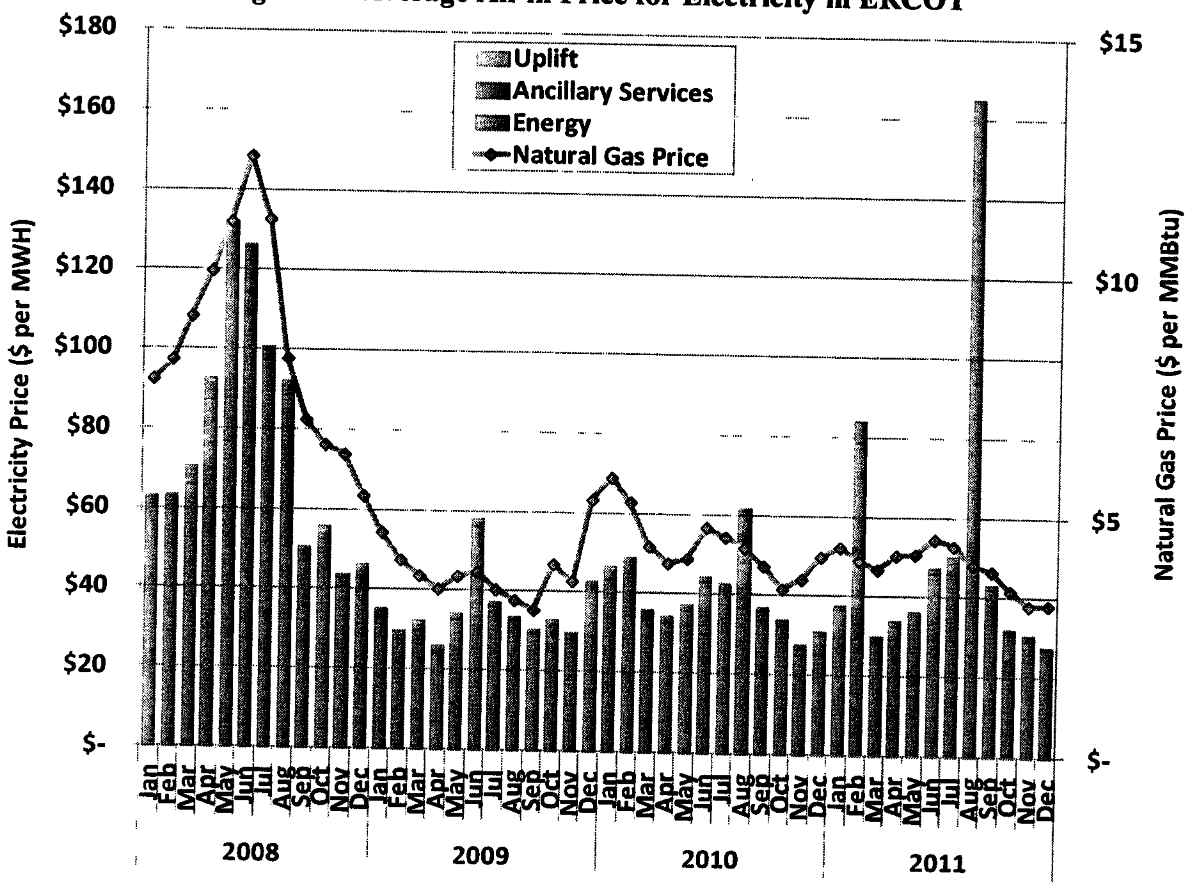
2. We recommend a change to the real-time market software to allow it to"look ahead" a sufficient amount of time to better commit load and generation resources that can be online within 30 minutes. More discussion of this topic can be found starting on page 86 in Section V.B, Effectiveness of the Scarcity Pricing Mechanism.

# 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 2008 to 2011 and the associated natural gas price. With the noticeable exception of February and August last year, Figure 1 indicates that natural gas prices were a primary driver of the trends in electricity prices from 2008 to 2011. 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. As discussed later, the high prices in February and August were the result of extreme weather conditions leading to generation scarcity.

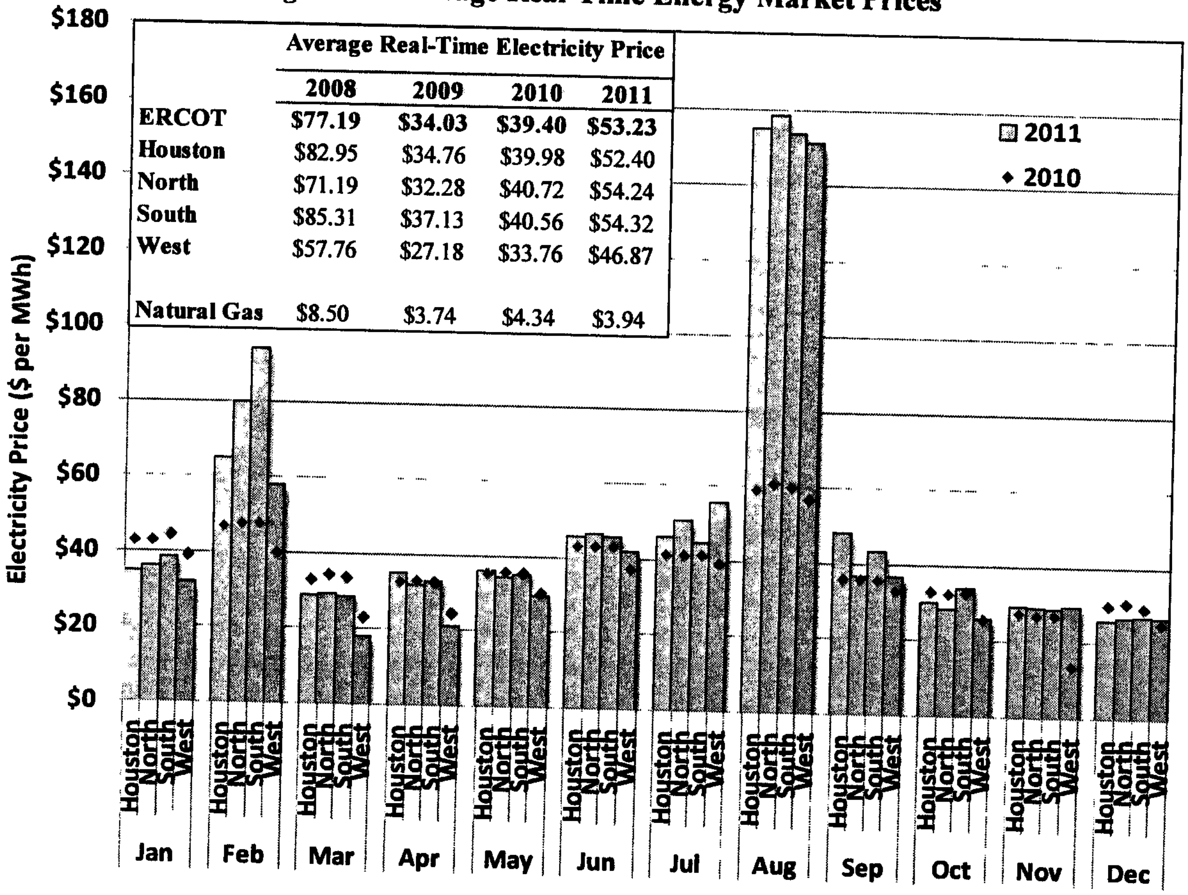
The largest component of the all-in cost of wholesale electricity is the energy cost, which is reflected by the locational marginal prices. As is typical in other wholesale markets, only a small share of the power produced in ERCOT is transacted in the spot market. However, the pricing outcomes in the 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 2011.

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

[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.

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**



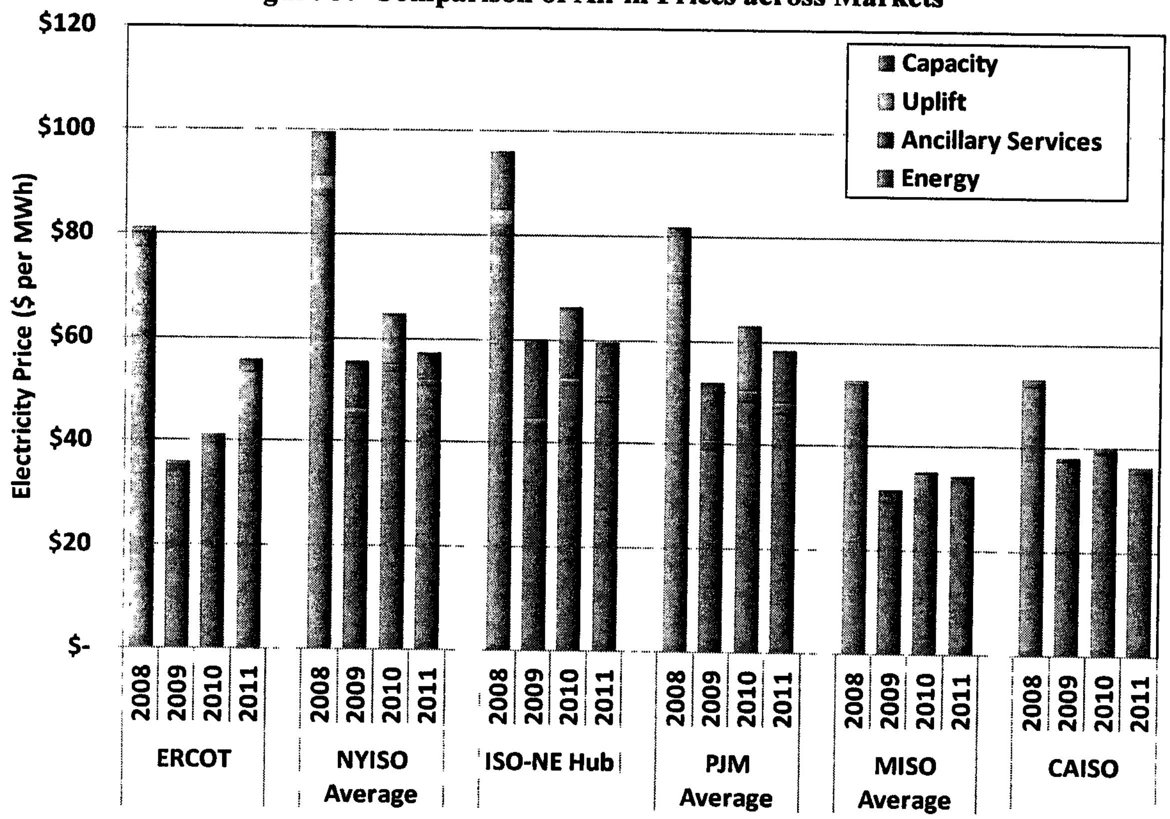

| | Average Real-Time Electricity Price | | | |
|---|---|---|---|---|
| | **2008** | **2009** | **2010** | **2011** |
| **ERCOT** | **$77.19** | **$34.03** | **$39.40** | **$53.23** |
| **Houston** | $82.95 | $34.76 | $39.98 | $52.40 |
| **North** | $71.19 | $32.28 | $40.72 | $54.24 |
| **South** | $85.31 | $37.13 | $40.56 | $54.32 |
| **West** | $57.76 | $27.18 | $33.76 | $46.87 |
| **Natural Gas** | $8.50 | $3.74 | $4.34 | $3.94 |

ERCOT average real-time market prices were 35 percent higher in 2011 than in 2010. The ERCOT-wide load-weighted average price was $53.23 per MWh in 2011 compared to $39.40 per MWh in 2010. February and August experienced the largest increases to real-time energy prices in 2011, averaging 67 and 160 percent higher than the prices in the same months in 2010. Price increases in both months were driven by extreme weather conditions which led to operating reserve deficiencies resulting in real-time energy prices reaching $3,000 per MWh for sustained periods of time.

The increase in real-time energy prices was partially offset by lower fuel prices in 2011. Natural gas prices decreased 9 percent in 2011, averaging $3.94 per MMBtu in 2011 compared to $4.34 per MMBtu in 2010. Although lower natural gas prices contributed to lower real-time energy prices in many hours, these reductions were smaller than the price effects of the shortages in February and August.

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 U.S.: New York ISO, ISO New England, PJM, Midwest ISO, and California ISO.

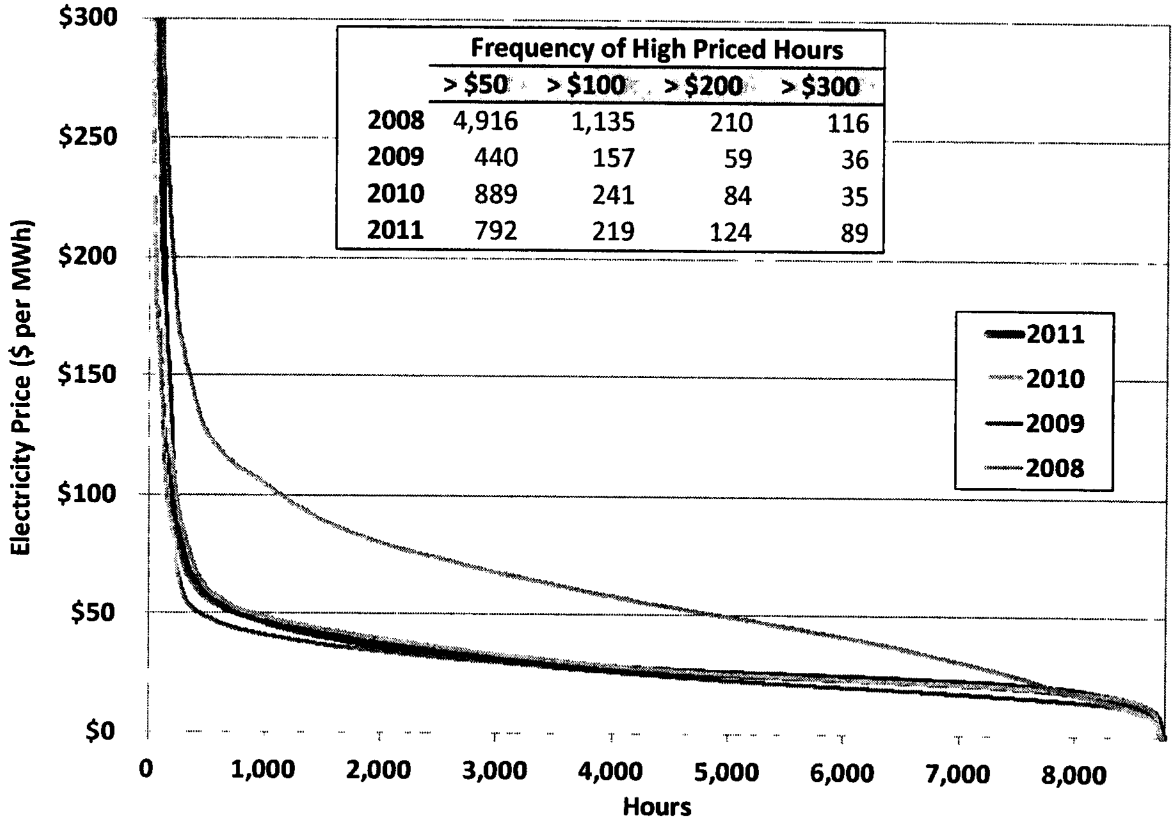
**Figure 3: Comparison of All-in Prices across Markets**




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 2011 were on par with the all-in prices from the other markets with centralized capacity markets. As discussed in more detail in Section V.A, Net Revenue Analysis, after two years of inadequate prices signals, ERCOT energy prices in 2011 rose to levels to support much needed new supply.

Figure 4 presents price duration curves for ERCOT energy markets in each year from 2008 to 2011. 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]

**Figure 4: ERCOT Price Duration Curve**



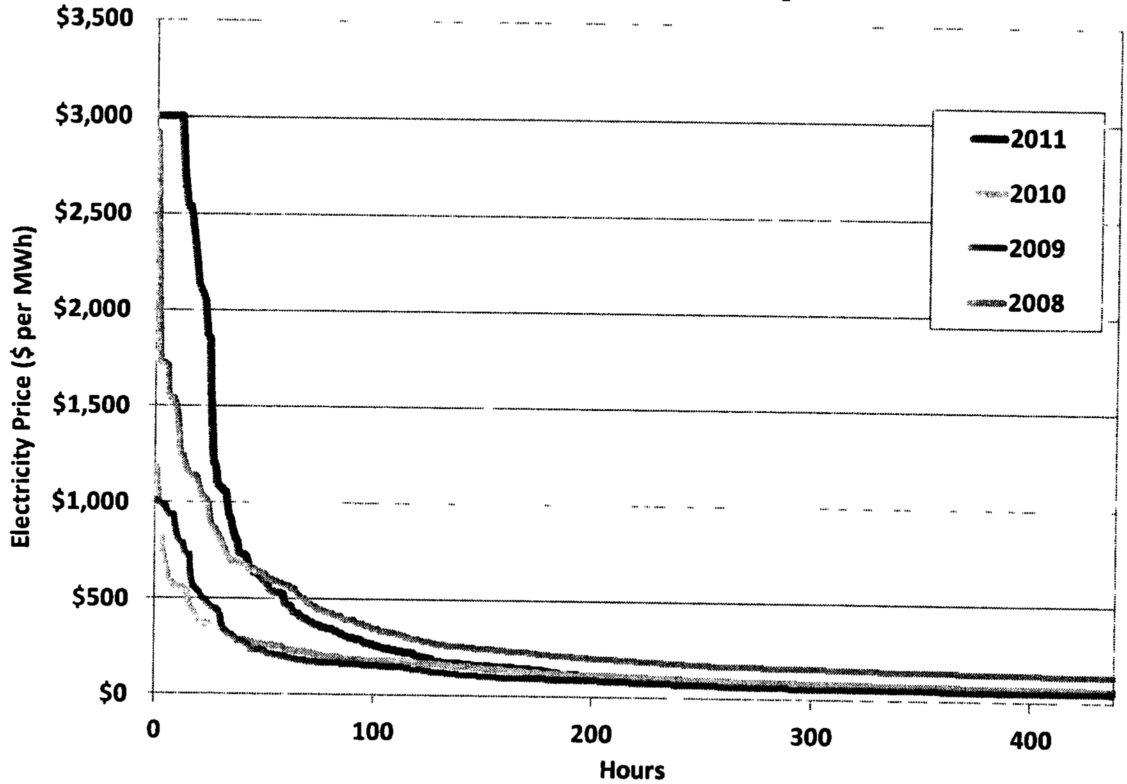

In Figure 4 we can see the impact of much higher natural gas prices experienced in 2008, leading to higher energy prices across the vast majority of hours in that year. In contrast, with similar levels of natural gas prices for the past three years, the price duration curves for 2009 – 2011 are remarkably close for most of the year.

To see the where the prices during 2011 were much different than in the previous two years, we present Figure 5, which compares prices for the highest five percent of hours. In 2011, energy prices for the top 100 hours were significantly higher than in the past two years. It is this small

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

number of very high priced hours which is the primary driver of higher average energy prices in 2011.

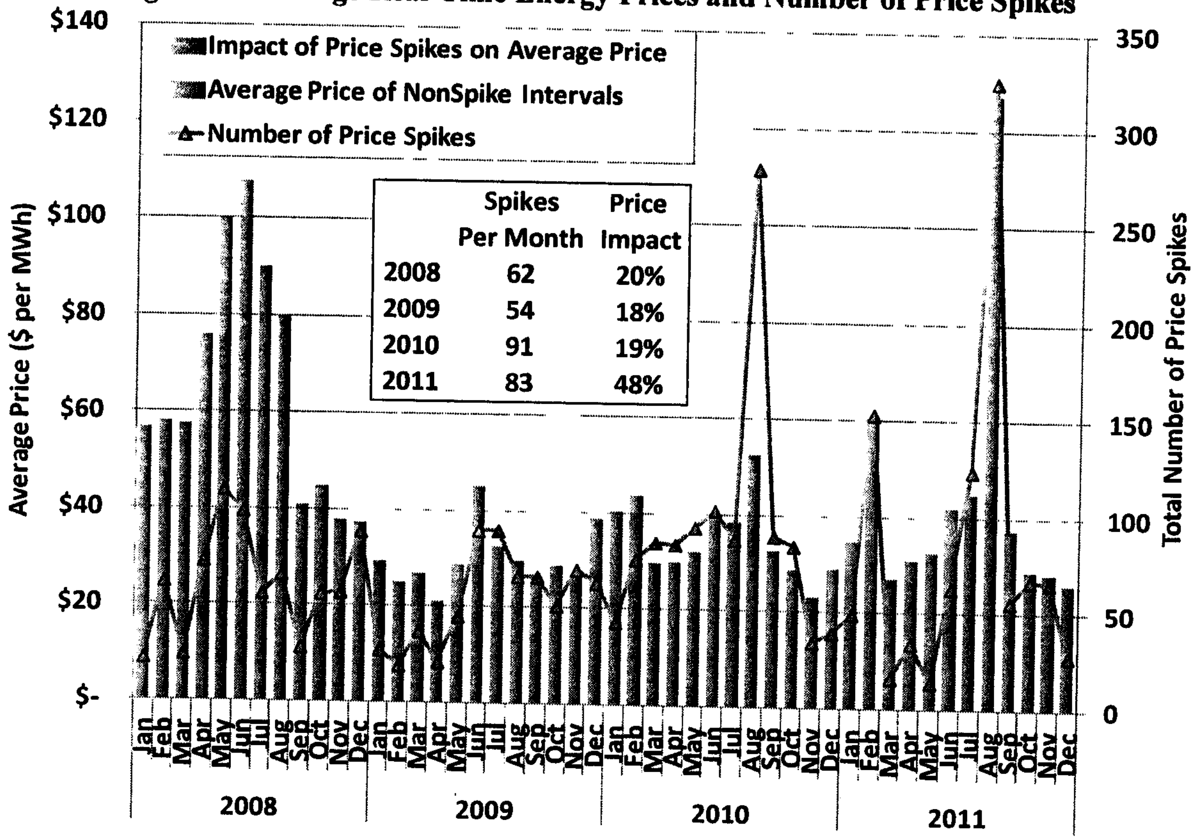
**Figure 5: ERCOT Price Duration Curve – Top 5% of Hours**




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 since December 2010. Prior information was 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 should exceed the marginal costs of virtually all of the on-line generators in ERCOT.

The number of price spike intervals during 2011 was 83 per month, a decrease from the 91 per month in 2010. However, just looking at the average can be misleading. Comparing the monthly details of 2011 with 2010 we see that for most months there were much fewer price spike intervals in 2011, likely due to the improved efficiencies of the nodal market. The noticeable exceptions were the months of February and August.

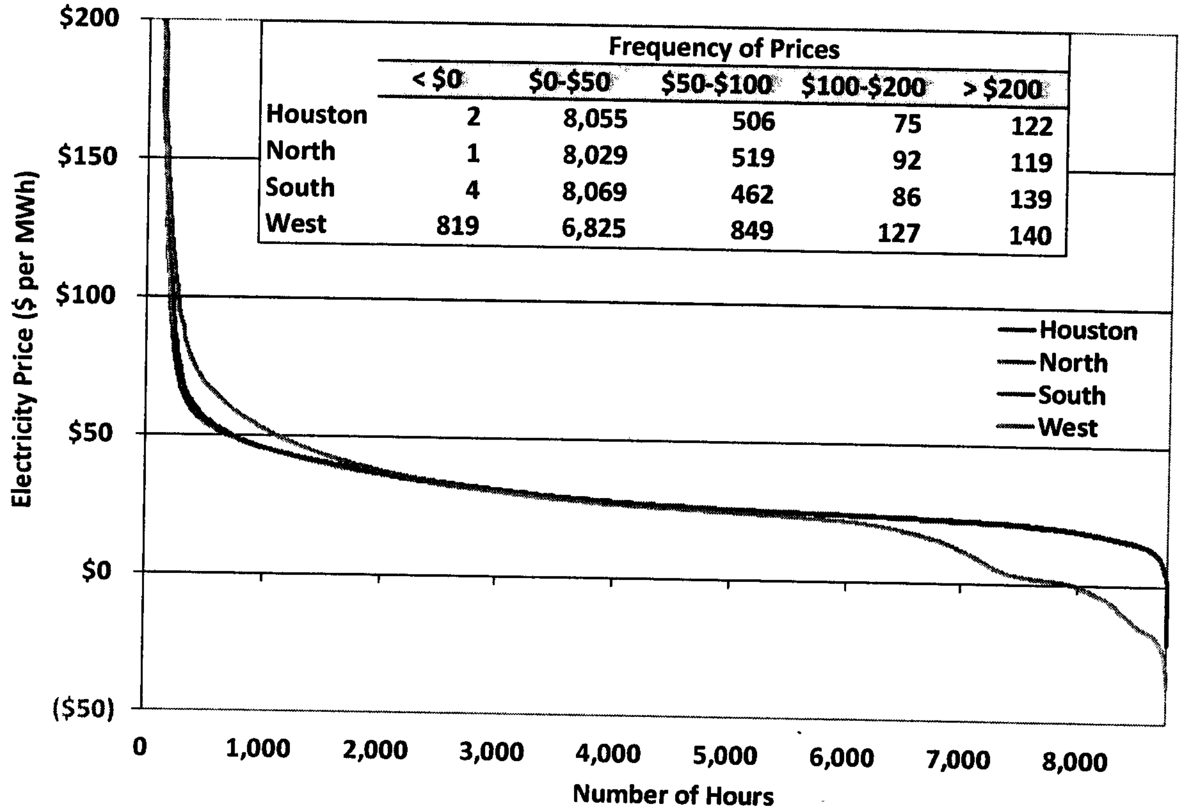
Figure 6: Average Real-Time Energy Prices and Number of Price Spikes




To measure the impact of these price spikes on average price levels, the figure also shows the 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 2011, the impact grew with the frequency of the price spikes, averaging $10.71, $4.67 and $5.53 per MWh during 2008, 2009 and 2010, respectively. However, in 2011 the impact on average energy price was $14.09 per MWh, or 48 percent of the annual average price. This increased impact of the price spikes is a direct result of the improved mechanism for pricing real-time energy during scarcity, as discussed in more detail in Section V.B, Effectiveness of the Scarcity Pricing Mechanism.

To depict how real-time energy prices vary by hour in each zone, Figure 7 shows the hourly average price duration curve in 2011 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 over 800 hours (9 percent of the time) when the average hourly price was less than zero. The relatively low prices in the West zone are generally caused by high wind output in the West that frequently results in severe congestion on transmission interfaces from the West zone to the other zones in ERCOT. The relatively higher prices in the West zone are caused by local transmission constraints that typically occur under low wind and high load conditions. Specifics about these transmission constraints are provided in Section III, Transmission and Congestion.

**Figure 7: Zonal Price Duration Curves**




| | Frequency of Prices | | | | |
|---|---|---|---|---|---|
| | < $0 | $0-$50 | $50-$100 | $100-$200 | > $200 |
| Houston | 2 | 8,055 | 506 | 75 | 122 |
| North | 1 | 8,029 | 519 | 92 | 119 |
| South | 4 | 8,069 | 462 | 86 | 139 |
| West | 819 | 6,825 | 849 | 127 | 140 |

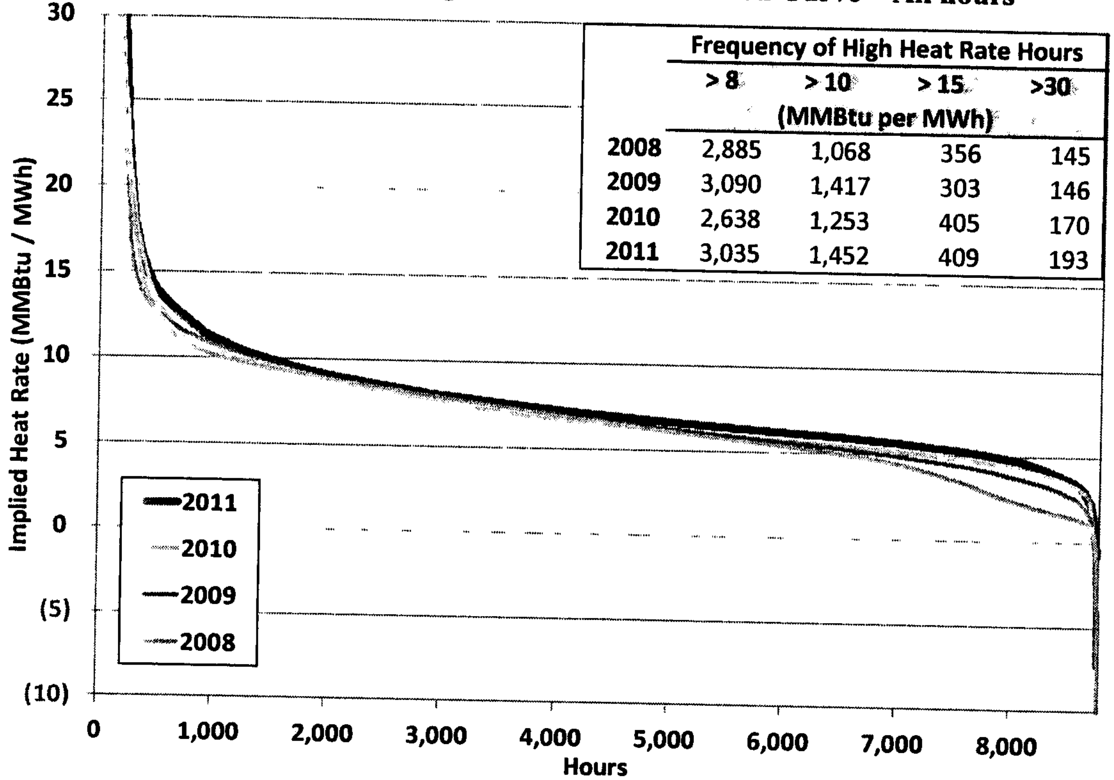
## B. Real-Time Prices Adjusted for Fuel Price Changes

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 8 and Figure 9 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]

[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

**Figure 8: Implied Marginal Heat Rate Duration Curve – All hours**

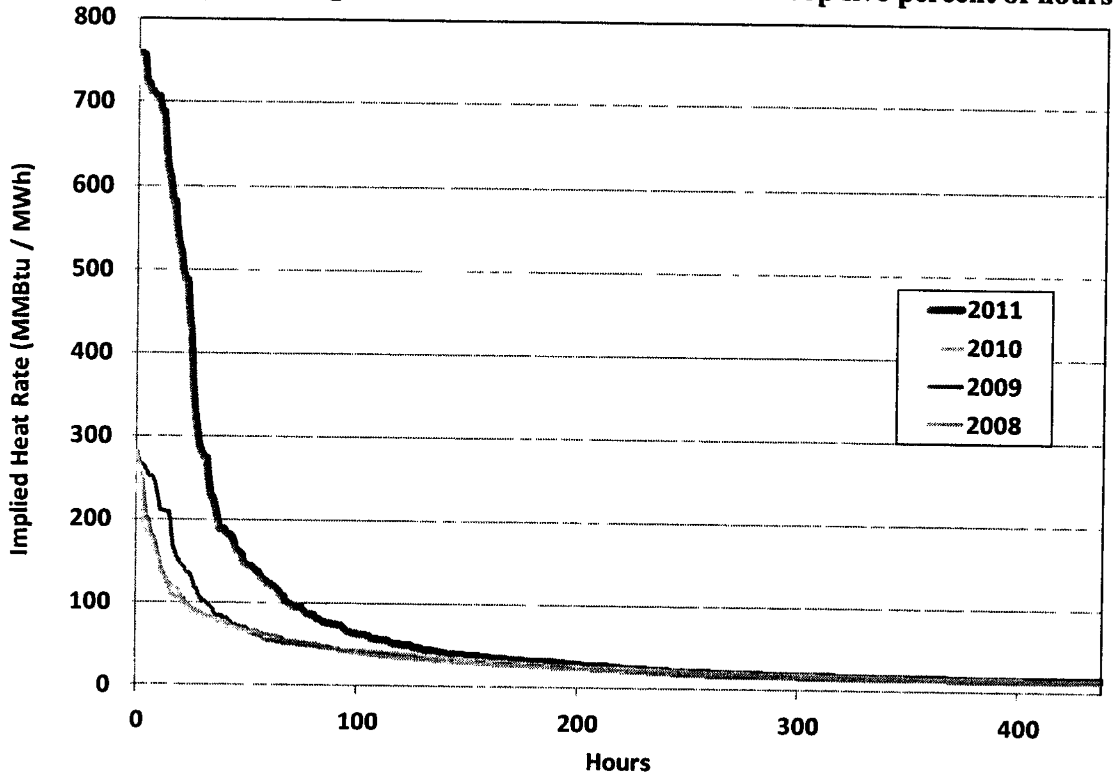



| | Frequency of High Heat Rate Hours | | | |
|---|---|---|---|---|
| | > 8 | > 10 | > 15 | >30 |
| | (MMBtu per MWh) | | | |
| 2008 | 2,885 | 1,068 | 356 | 145 |
| 2009 | 3,090 | 1,417 | 303 | 146 |
| 2010 | 2,638 | 1,253 | 405 | 170 |
| 2011 | 3,035 | 1,452 | 409 | 193 |

The second chart shows the same duration curves for the five percent of hours in each year with the highest implied heat rate. Both figures show duration curves for the implied marginal heat rate for 2008 to 2011. Similar to Figure 4, Figure 8 shows that the implied marginal heat rates were relatively consistent across the majority of hours from 2008 to 2011. The implied heat rate during 2011 was somewhat higher for most hours, when compared to 2010. This can be explained by the much higher loads experienced throughout 2011. There were 193 hours during 2011 when the implied heat rate was greater than 30 MMBtu per MWh, compared to 145, 146, and 170 hours in 2008, 2009, and 2010, respectively. This indicates that there are price differences that are due to factors other than changes in natural gas prices.

move in direct proportion to changes in natural gas prices.

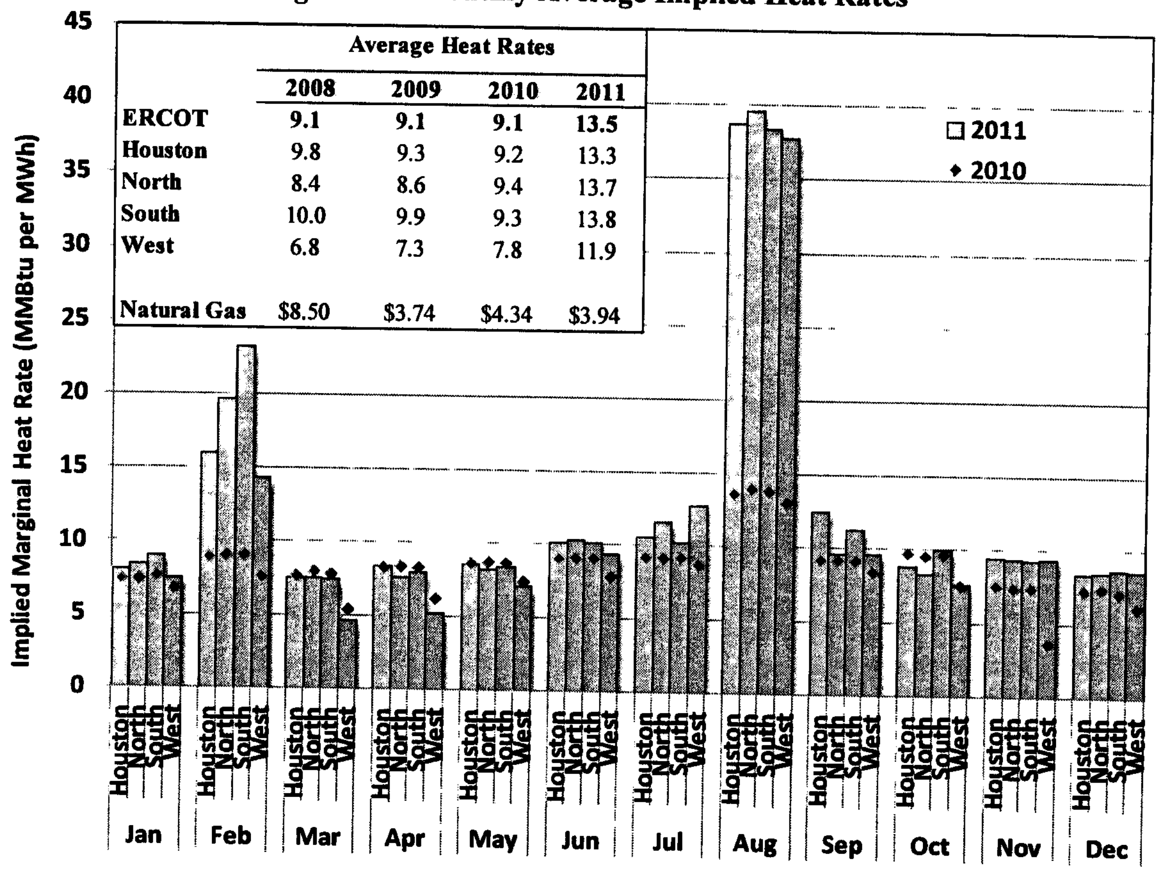
**Figure 9: Implied Marginal Heat Rate Duration Curve – Top five percent of hours**




The price differences that were apparent from Figure 4 in the highest-priced hours persist even after adjusting for natural gas prices. Figure 9 shows the implied marginal heat rates for the top five percent of hours in 2008 through 2011 and highlights that although the number of hours with high (greater than 30 MMBtu per MWh) implied heat rates did increase in 2011, the larger effect was due to the heights at which scarcity prices were set.

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 2010 and 2011, with annual average heat rate data for 2008 through 2011. This figure is the fuel price-adjusted version of Figure 2 in the prior sub-section. Adjusting for gas price influence, Figure 10 shows that the annual, system-wide average implied heat rate increased significantly after remaining constant for the previous three years.

**Figure 10: Monthly Average Implied Heat Rates**



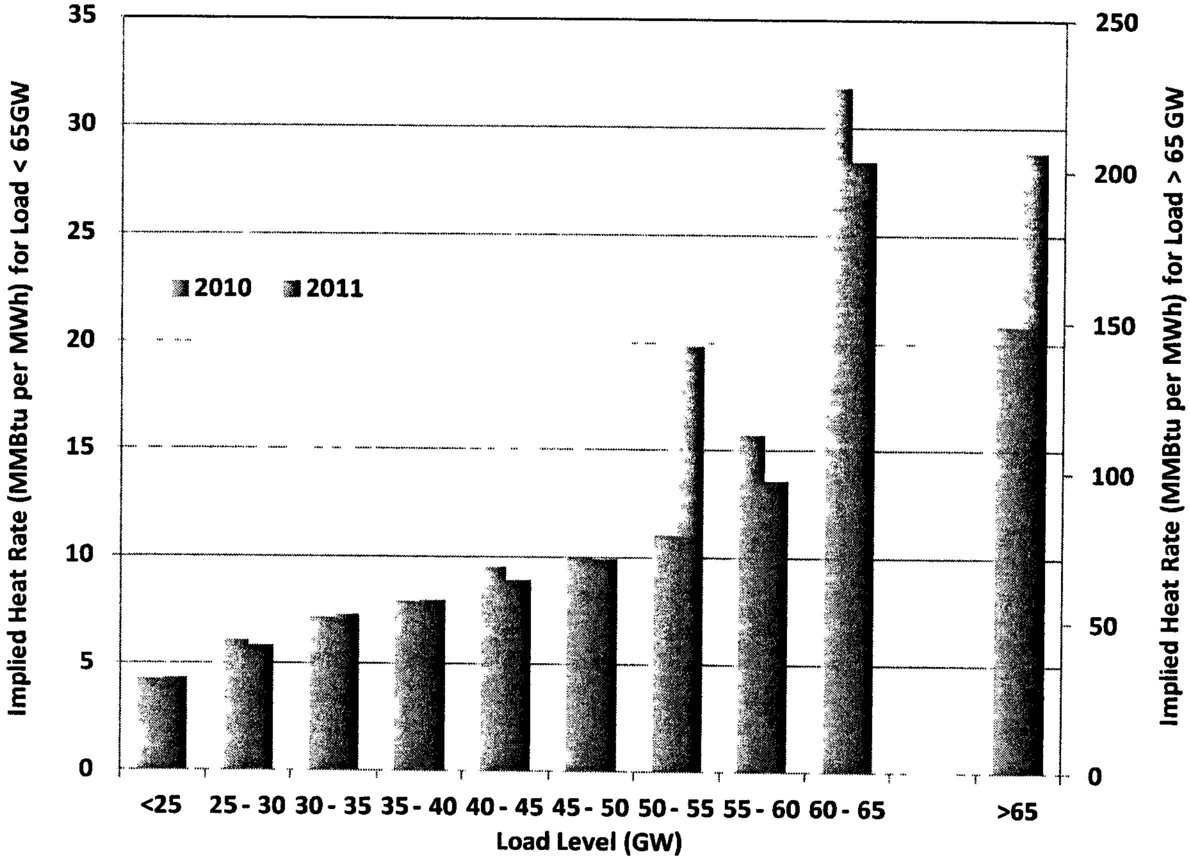

| Average Heat Rates | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| ERCOT | 9.1 | 9.1 | 9.1 | 13.5 |
| Houston | 9.8 | 9.3 | 9.2 | 13.3 |
| North | 8.4 | 8.6 | 9.4 | 13.7 |
| South | 10.0 | 9.9 | 9.3 | 13.8 |
| West | 6.8 | 7.3 | 7.8 | 11.9 |
| Natural Gas | $8.50 | $3.74 | $4.34 | $3.94 |

The monthly average implied heat rates in 2011 are generally consistent with 2010, with notable exceptions in February and August. Higher heat rates in February can be explained by the extended period when real-time prices were $3,000 per MWh due to extreme cold weather and the resulting unplanned outages of numerous generators. Extended hot, dry weather resulted in record system peak demands in August, and another extended period of energy prices reflecting scarcity conditions. The differences in the average annual implied heat rates observed at the zonal level can be attributed to the continued significant congestion related to wind generation exports from the West zone.

We conclude our examination of implied heat rates from the real-time energy market by evaluating them at various load levels. Figure 11 provides the average heat rate at various system load levels for 2011 and 2010.[4]

4 To appropriately compare twelve months of data under each market design, data labeled as 2010 in Figure 11 is from December 1, 2009 through November 30, 2010.

**Figure 11: Heat Rate and Load Relationship**



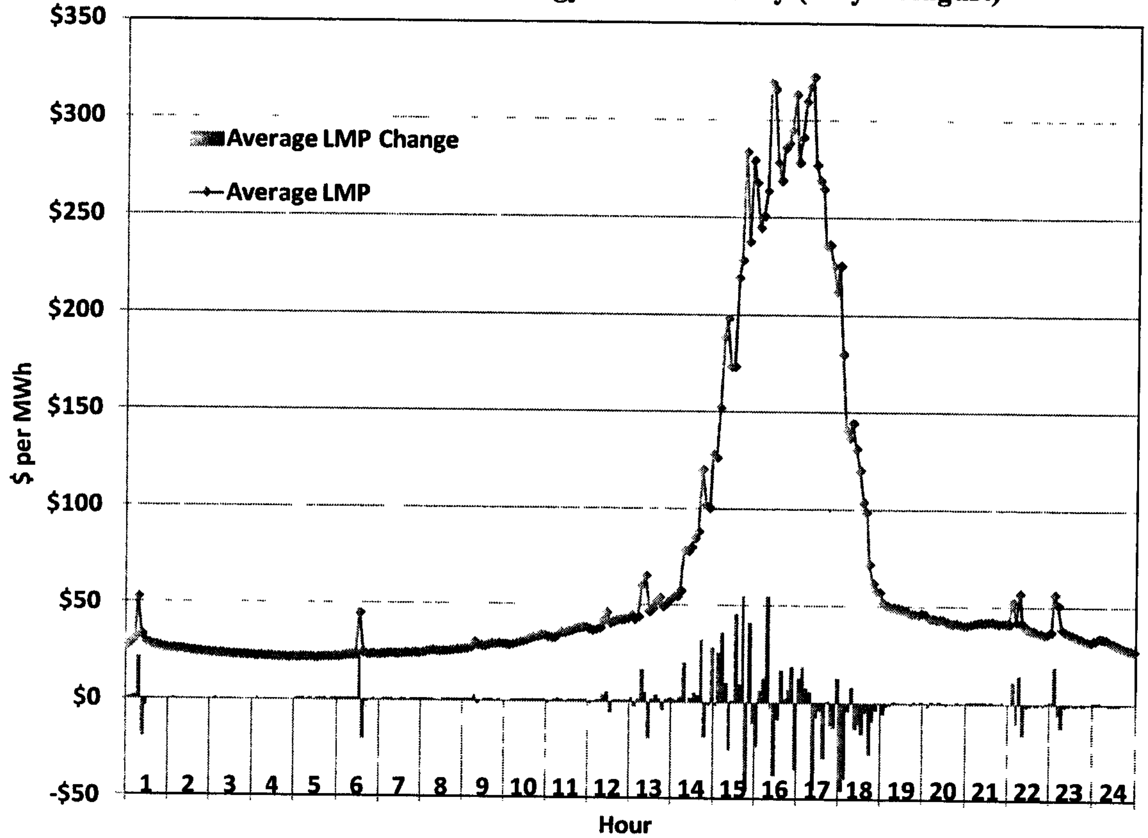

In a well performing market, a clear positive relationship between these two variables is expected since resources with higher marginal costs must be dispatched to serve higher loads. Although we do see a generally positive relationship, there is a noticeable disparity for loads between 50 and 55 GW. During the extreme cold weather event in early February, loads were at this level while prices reached $3,000 per MWh for a sustained period of time.

We also observe small reductions in heat rates for most load levels during 2011 compared to 2010, which we attribute to the enhanced efficiency of the nodal market.

## C. Real-Time Price Volatility

Volatility in real-time wholesale electricity markets is expected because system load can change rapidly and the ability for supply to adjust can be restricted by physical limitations of the resources and the transmission network. Figure 12 presents a view of the price volatility experienced in ERCOT's real-time energy market during the summer months of May through August. Average five-minute LMPs are presented along with the magnitude of change in LMP for each five-minute interval. Outside of the hours from 15 to 18 (2:00 pm to 6:00 pm), short-term increases in average LMPs are typically caused by singular occurrences of high prices resulting from generator ramp rate limitations.

**Figure 12: Real-Time Energy Price Volatility (May – August)**




The average of the absolute value of changes in five-minute LMPs, expressed as a percentage of average LMP was approximately 6 percent for this period. To be able to compare with zonal market results, a similar percentage was calculated using 15 minute settlement point prices for the four geographic Load Zones.

From the comparisons shown below in Table 1, implementation of the nodal market has resulted in less price volatility than experienced in the zonal market. Price volatility in the West zone has continued to be higher than in the other zones, which is expected given the very high penetration of variable output wind generation located in that area.