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2010 State of the Market Report for the ERCOT Wholesale Electricity Markets

Potomac Economics, Ltd.

Independent Market Monitor for the
ERCOT Wholesale Market

August 2011

6

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EXECUTIVE SUMMARY

A. Introduction

This report reviews and evaluates the outcomes of the ERCOT wholesale electricity markets in 2010, 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).

The market outcomes during the eleven months of zonal market operation in 2010 were generally similar to those in 2009. The highlight of 2010 was the much anticipated implementation of ERCOT's nodal market on December 1, 2010. Some of the analysis contained in this report is for the eleven months of zonal market operation, while others cover the entire year, including the one month of nodal operation.

- ★ The ERCOT-wide load-weighted average balancing energy price was $39.40 per MWh in 2010 compared to $34.03 per MWh in 2009, a 16 percent increase. The natural gas price also increased 16 percent in 2010, averaging $4.34 per MMBtu in 2010 compared to $3.74 per MMBtu in 2009.

- ★ The ERCOT total load in 2010 was 3.5 percent higher than 2009. Peak load requirements increased by 3.7 percent, setting a new all time system hourly peak of 65,776 MW on August 23.

- ★ Even with coal and wind units being added and additional less efficient gas units retired, approximately one-half of the installed generation capacity is natural gas fueled. Despite this continued large contribution to the overall capacity portfolio, natural gas contribution to total energy production is declining, as shown in Figure 24.

- ★ Slight improvement in scarcity pricing results was observed due to tradeoffs made between the day-ahead load forecast error and the quantity of non-spinning reserves procured and the appropriate pricing of energy at times when non-spinning reserves are deployed. However, we still find the reliance upon high-priced offers submitted by participants to be insufficient to ensure appropriate pricing during shortage intervals.

★ Continued low natural gas prices and scarcity pricing deficiencies contributed to net revenues, as shown in Figure 33, that were insufficient to support new generation investment for any generation technology in any region of the ERCOT market.

★ Occurrences of congestion between the west and north zones increased in 2010 due to more installed wind generation exporting from the west zone. There were fewer occurrences of congestion across the south to north and north to south interfaces in 2010 due to reduced transmission outages and some additional transmission capacity. Congestion across the north to Houston interface was comparable to 2009.

★ As summarized in Figure 49, payments for local congestion management during 2010 were the lowest in the past four years.

★ The ERCOT zonal wholesale market performed competitively in 2010, with the competitive performance measures, summarized in Figure 54 and Figure 58, continuing a trend of improved competitiveness over the past several years.

In addition to these key findings, the report generally confirms prior findings that ERCOT's zonal market design resulted in systemic inefficiencies. We are optimistic that the nodal market will bring about much anticipated and expected improvements.

Two of the expected benefits from the nodal market have been immediately observed:

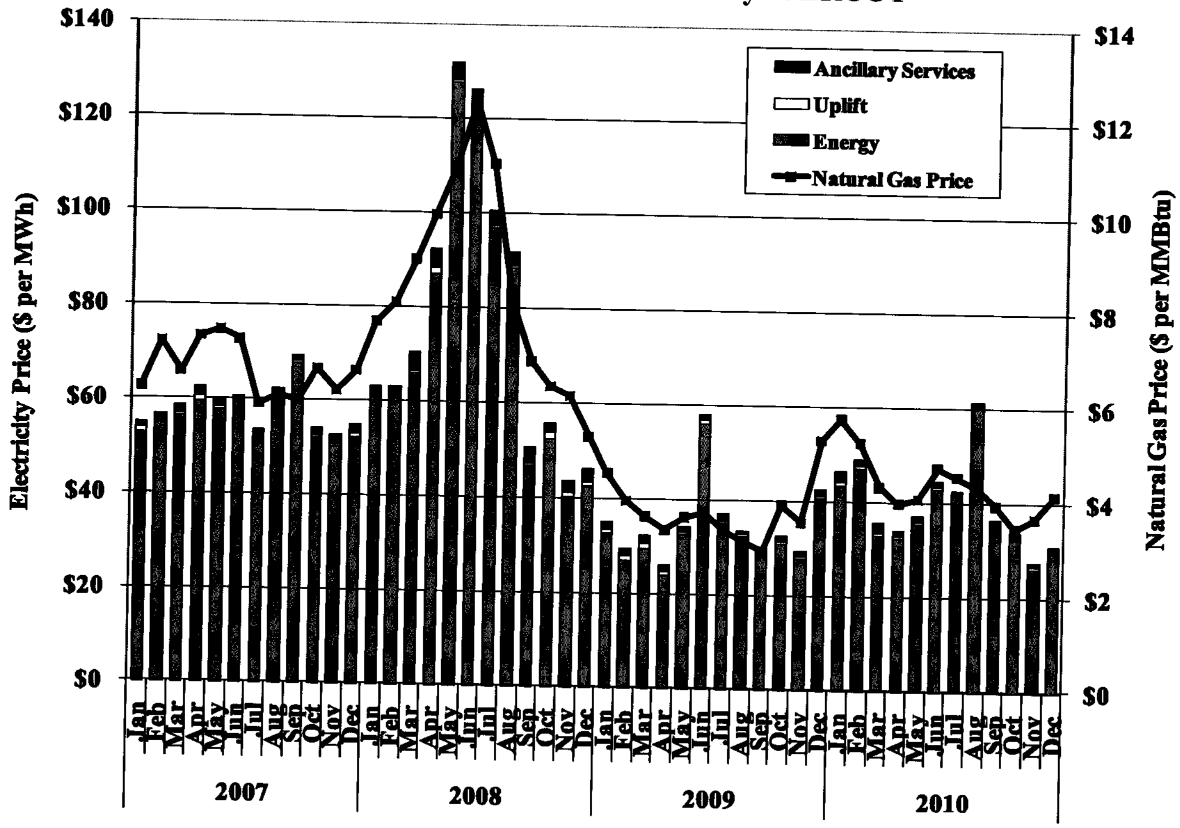
★ Improved management of transmission congestion was evident from even prior to full nodal market implementation. Figure 43 demonstrates the improved utilization of the West to North interface observed during market trials; an increase from 64 percent to 83 percent.

★ More frequent energy deployment instructions and reduced quantities of regulation capacity procured resulted in regulation capacity costs being reduced by $8.5 million during the first month of operation of the nodal market.

B. Review of Market Outcomes

ERCOT average balancing energy market prices were 16 percent higher in 2010 than in 2009, with an ERCOT-wide load-weighted average price of $39.40 per MWh in 2010 compared to $34.03 per MWh in 2009. February and August experienced the highest balancing energy market price increases in 2010, averaging 83 percent higher than the prices in the same months in 2009. Natural gas price increased 16 percent in 2010, averaging $4.34 per MMBtu in 2010 compared to $3.74 per MMBtu in 2009. Hence, the changes in energy prices from 2009 to 2010 were largely a function of natural gas price movements.

Average All-in Price for Electricity in ERCOT

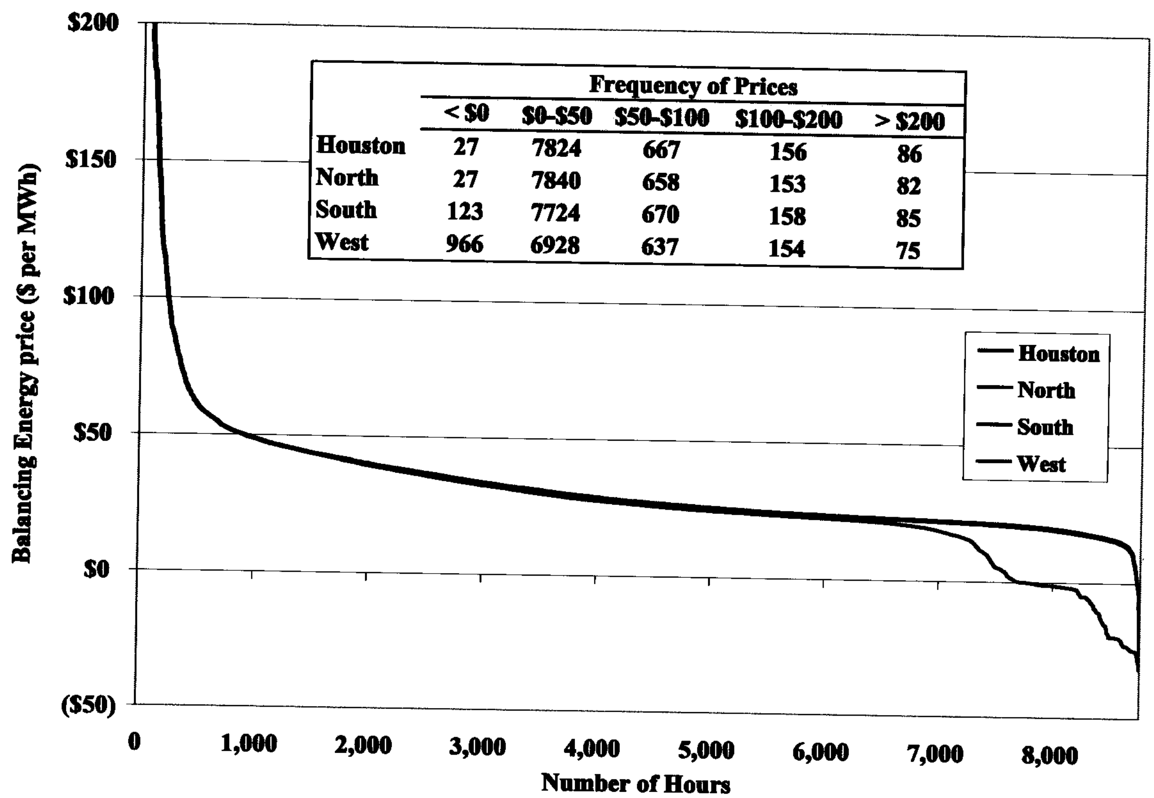


The figure above indicates that natural gas prices were a primary driver of the trends in electricity prices from 2007 to 2010. Again, this is not surprising given that natural gas is a widely-used fuel for the production of electricity in ERCOT, especially among generating units that most frequently set the balancing energy market prices in the zonal market or locational marginal prices in the nodal market.

The largest component of the all-in costs is the energy costs, which are reflected by the prices in the balancing energy market (or locational marginal prices). Under the zonal market design, the balancing energy market is the spot market for electricity in ERCOT. As is typical in other wholesale markets, only a small share of the power produced in ERCOT is transacted in the spot market, although at times such transactions can exceed 10 percent of total demand. Although most power is purchased through bilateral forward contracts, outcomes in the balancing energy market are very important because of the expected pricing relationship between spot and forward markets (including bilateral markets).

The following figure shows the hourly average price duration curve for each of the four ERCOT zones in 2010 and that the Houston, North, and South Zones had similar prices over the majority of hours.

Zonal Price Duration Curves



The price duration curve for the West Zone is generally lower than all other zones, with over 900 hours when the average hourly price was less than zero. These zonal price differences are caused by transmission congestion, as discussed in more detail in Section III.

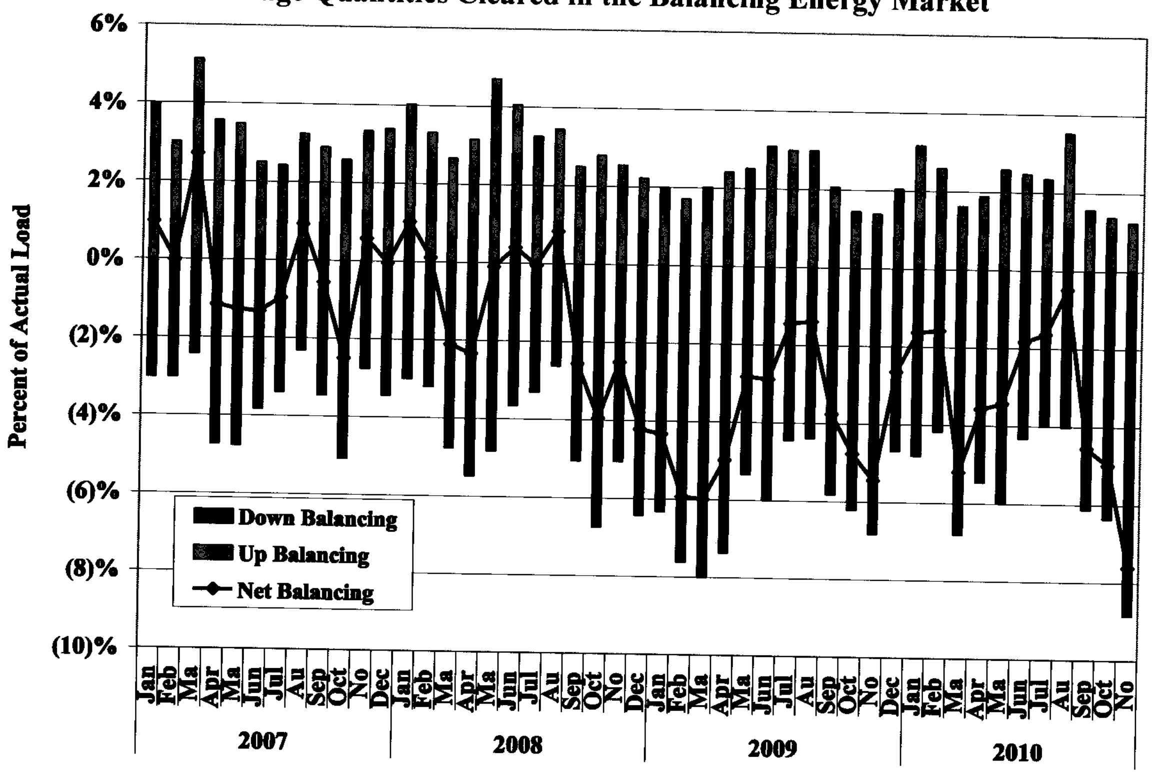
Average zonal prices for balancing energy for 2007 through 2010 are shown below:

Average Balancing Market Prices

	2007	2008	2009	2010
ERCOT	**$56.35**	**$77.19**	**$34.03**	**$39.40**
Houston	$57.05	$82.95	$34.76	$39.98
North	$56.21	$71.19	$32.28	$40.72
South	$56.38	$85.31	$37.13	$40.56
West	$54.27	$57.76	$27.18	$33.76

The following figure shows the average quantities of up balancing and down balancing energy sold by suppliers in each month, along with the net purchases or sales (*i.e.*, up balancing energy minus down balancing energy).

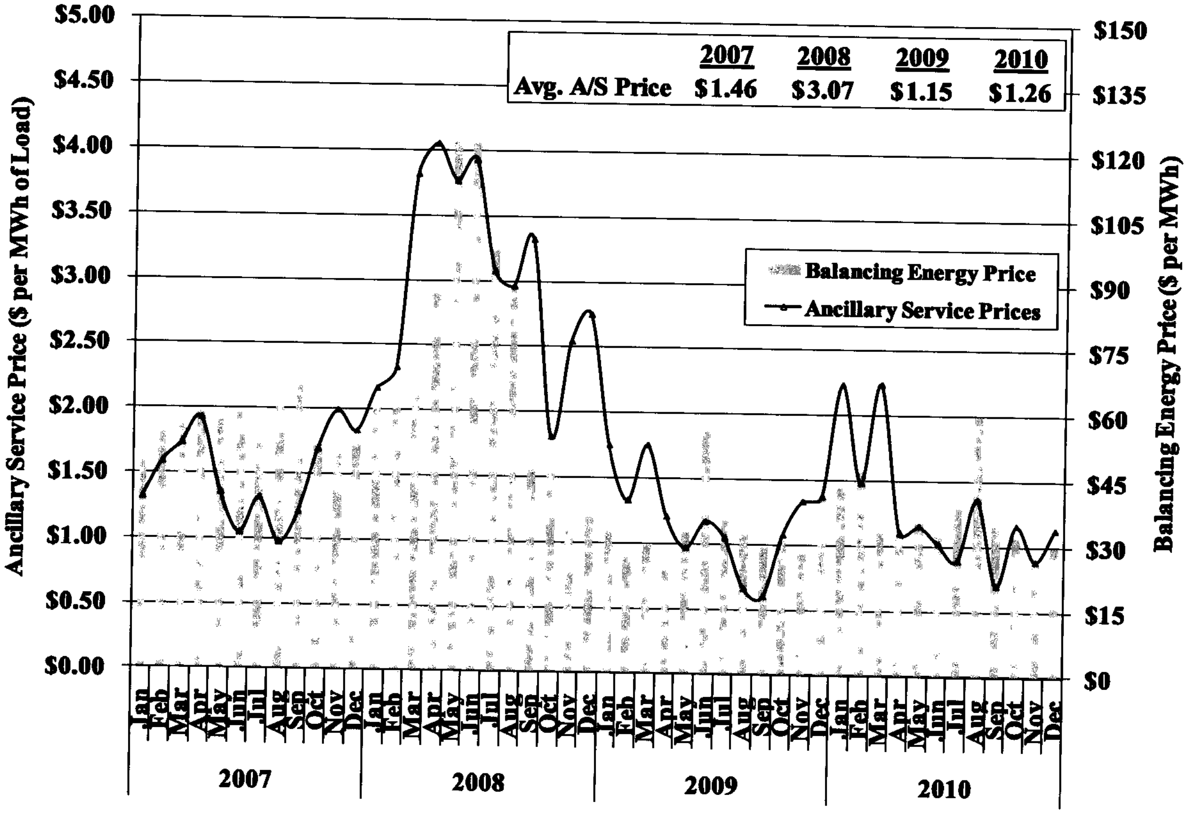
Average Quantities Cleared in the Balancing Energy Market



The net quantity of balancing energy for every month in 2010 was negative, meaning that the average quantity of down balancing energy was greater than the quantity of up balancing energy. As discussed in Section II, this trend is related to the large increase in wind generation capacity added to the ERCOT region since the fall of 2008 and the associated scheduling patterns of these resources.

The following figure shows the monthly total ancillary service costs per MWh of ERCOT load and the average balancing energy price for 2007 through 2010.

Ancillary Service Costs per MWh of Load

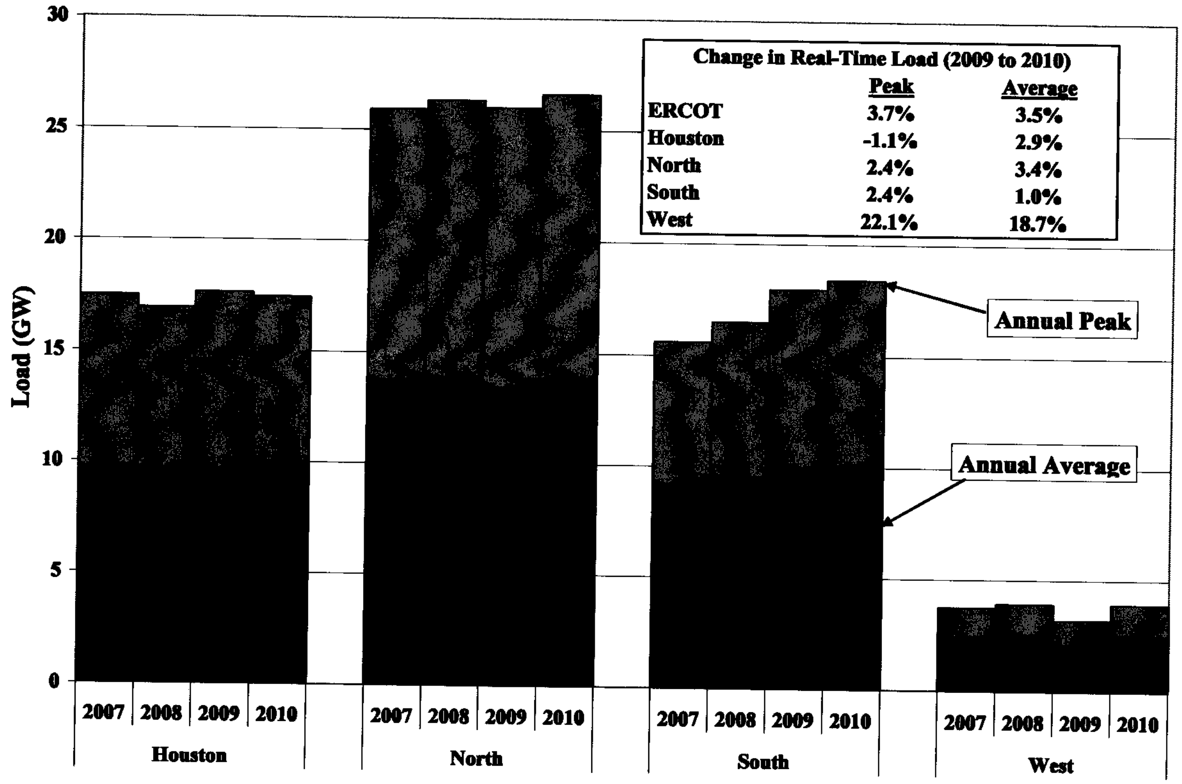


This figure shows that total ancillary service costs are generally correlated with balancing energy price movements, which, as previously discussed, are highly correlated with natural gas price movements. The average ancillary service cost per MWh of load increased to $1.26 per MWh in 2010 compared to $1.15 per MWh in 2009, an increase of 10 percent. Total ancillary service costs were equal to 3.3 and 3.2 percent of the load-weighted average energy price in 2009 and 2010, respectively.

C. Demand and Resource Adequacy

The figure below shows peak load and average load in each of the ERCOT zones from 2007 to 2010. The North Zone is the largest zone (about 38 percent of the total ERCOT load); the South and Houston Zones are comparable (with about 27 percent) while the West Zone is the smallest (with about 7 percent of the total ERCOT load).

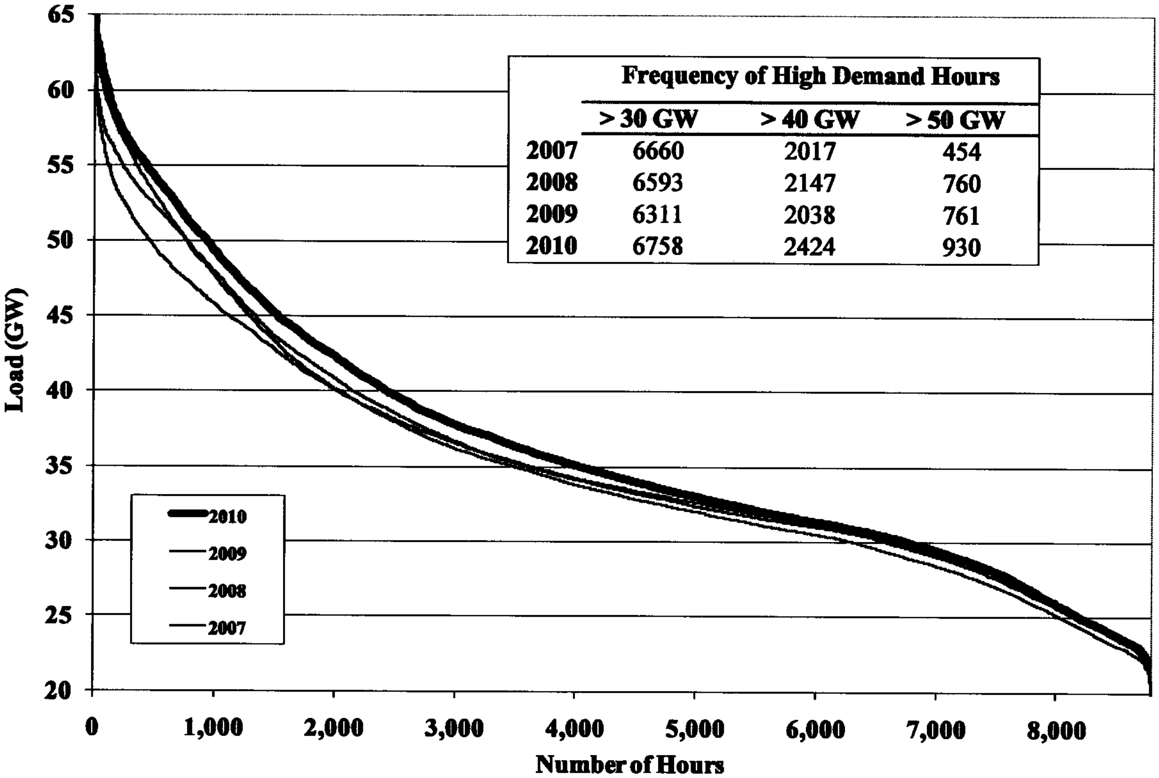
Annual Load Statistics by Zone



Overall, the ERCOT total load increased from 308,278 GWh in 2009 to 319,239 GWh, an increase of 3.5 percent, or an average of 1250 MW every hour. The ERCOT coincident peak demand increased from 63,400 MW in 2009 to 65,782 MW in 2010 (2382 MW), an increase of 3.7 percent.

To provide a more detailed analysis of load at the hourly level, the following figure compares load duration curves for each year from 2007 to 2010. 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.

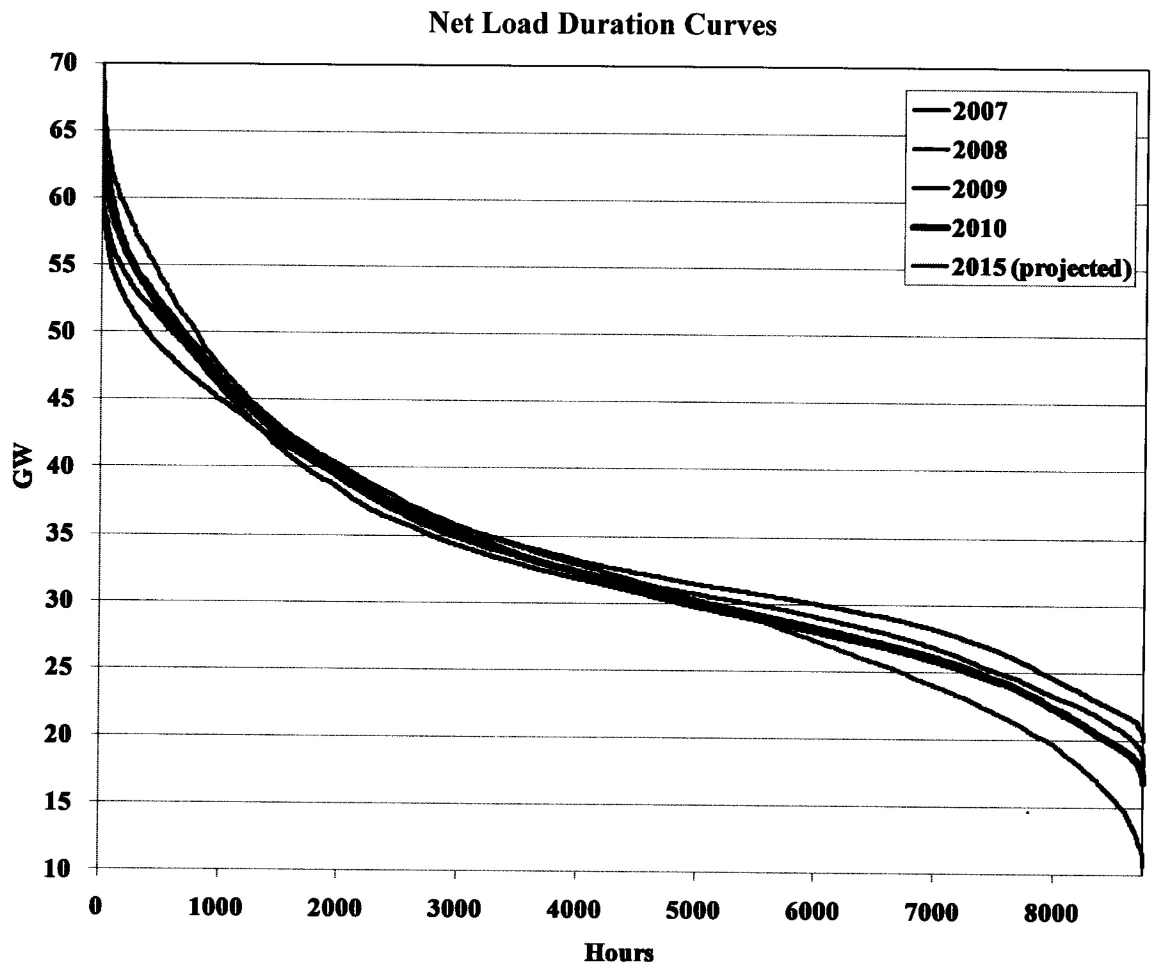
ERCOT Load Duration Curve – All Hours



	> 30 GW	> 40 GW	> 50 GW
2007	6660	2017	454
2008	6593	2147	760
2009	6311	2038	761
2010	6758	2424	930

As shown above, the load duration curve for 2010 is higher than in 2009 and is consistent with the load increase of 3.5 percent from 2009 to 2010.

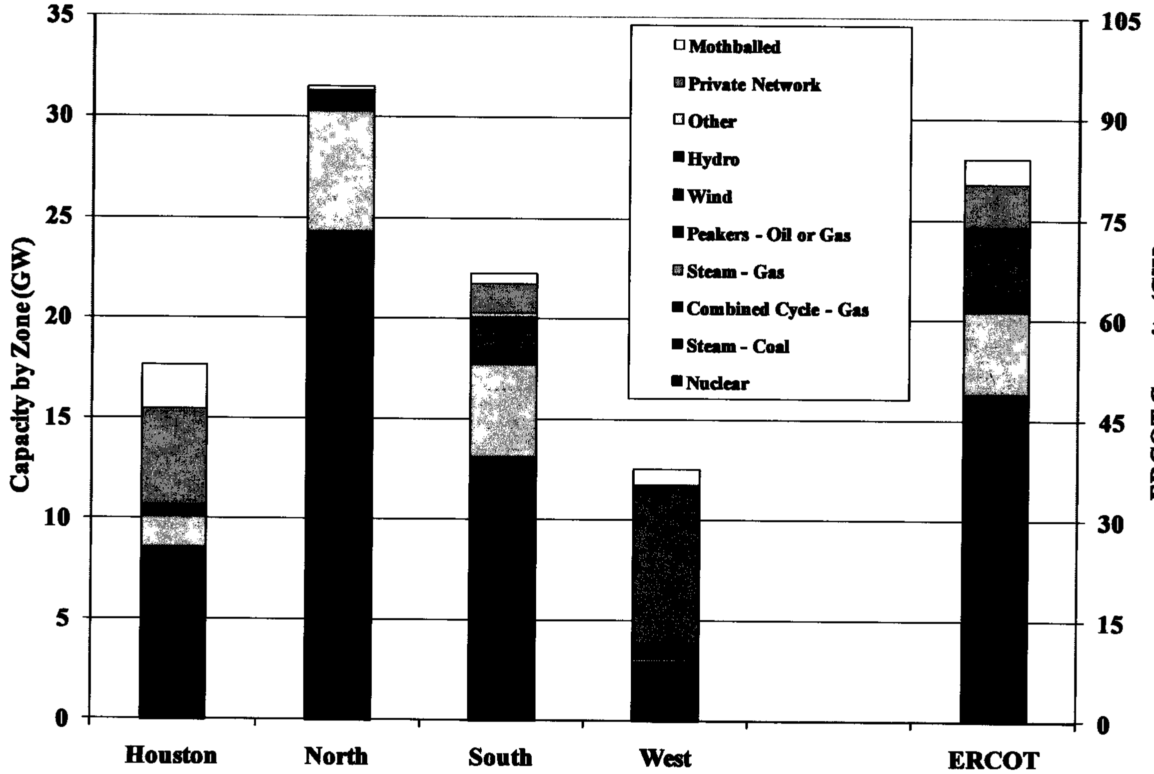
Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. The following figure shows the net load duration curves for 2007 through 2010, with projected values for 2015 based on ERCOT data from its Competitive Renewable Energy Zones assessment.



Over 90 percent of the wind resources in the ERCOT region are located in West Texas, and the wind profiles in this area are such that most of the wind production occurs during off-peak hours or other times of relatively low system demand. This profile results in only modest reductions of the net load relative to the actual load during the hours of highest demand, but much more significant reductions in the net load relative to the actual load in the other hours of the year. The projection for 2015 indicates that the trend shown from 2007 to 2010 is expected to continue and amplify with the addition of significant new wind resources and the reduction in the curtailment of existing wind resources after completion of new transmission facilities.

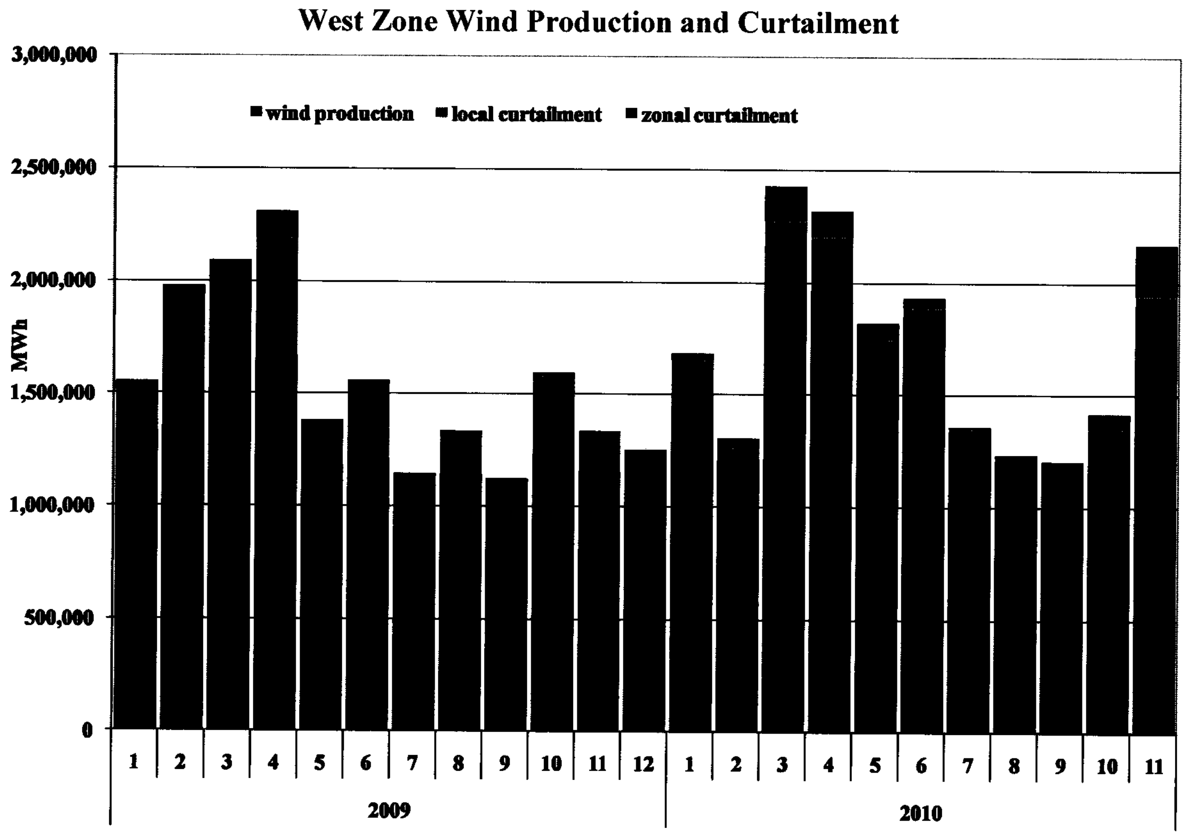
The figure below shows the installed generating capacity by type in each of the ERCOT zones. With the exception of the wind resources in the West Zone and the nuclear resources in the North and Houston Zones, the mix of generating capacity is relatively uniform in ERCOT.

Installed Capacity by Technology for each Zone



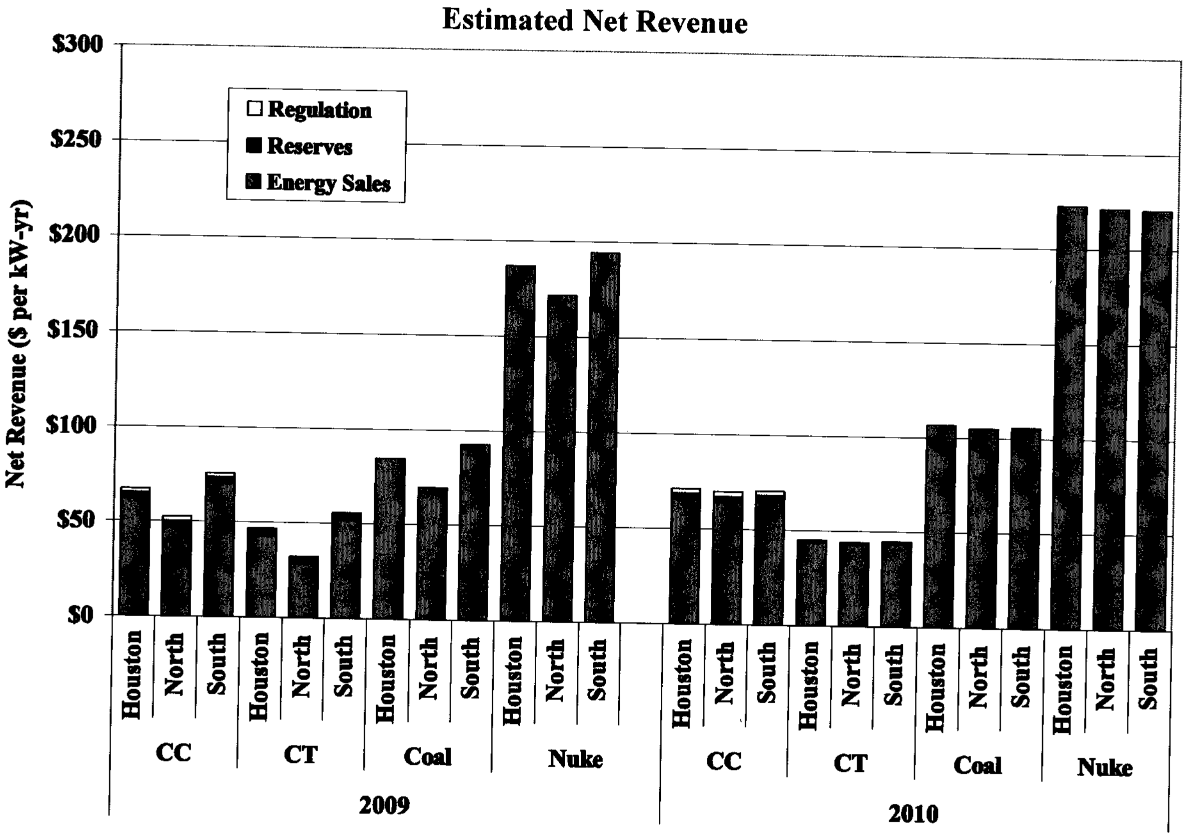
Notable changes to ERCOT's installed generation during 2010 included new coal units and wind units increasing their percentage shares, while several less efficient natural gas fueled units were mothballed or retired. Even after these changes natural gas generation accounts for approximately 50 percent of the installed capacity in ERCOT.

The figure below shows the wind production and local and zonal curtailment quantities for the West Zone for each month of 2009 and 2010. This figure reveals that the quantity of zonal curtailments for wind resources in the West Zone was increased from 442 GWh in 2009 to over 785 GWh in 2010, while the quantity of local curtailments decreased from over 3,400 GWh in 2009 to 1,068 GWh in 2010.



The following figure shows the results of the net revenue analysis for four types of units in 2009 and 2010. These are: (a) a gas combined-cycle, (b) a combustion turbine, (c) a coal unit, 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 (*i.e.*, when it is not experiencing a planned or forced outage). 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 balancing energy price in each hour. Although most suppliers would receive the bulk of their revenues through bilateral contracts, the spot prices produced in the balancing energy market should drive the bilateral energy prices over time and are appropriate to use for this evaluation.

Although some units will also receive a substantial amount of revenue through uplift payments (*i.e.*, Out-of-Merit Energy, Out-of-Merit Capacity, and Reliability Must Run payments), 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. The following factors are not explicitly accounted for in the net revenue analysis: (i) start-up costs, which can be significant; and (ii) minimum running times and ramp restriction, which can prevent the natural gas generators from profiting during brief price spikes. Despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

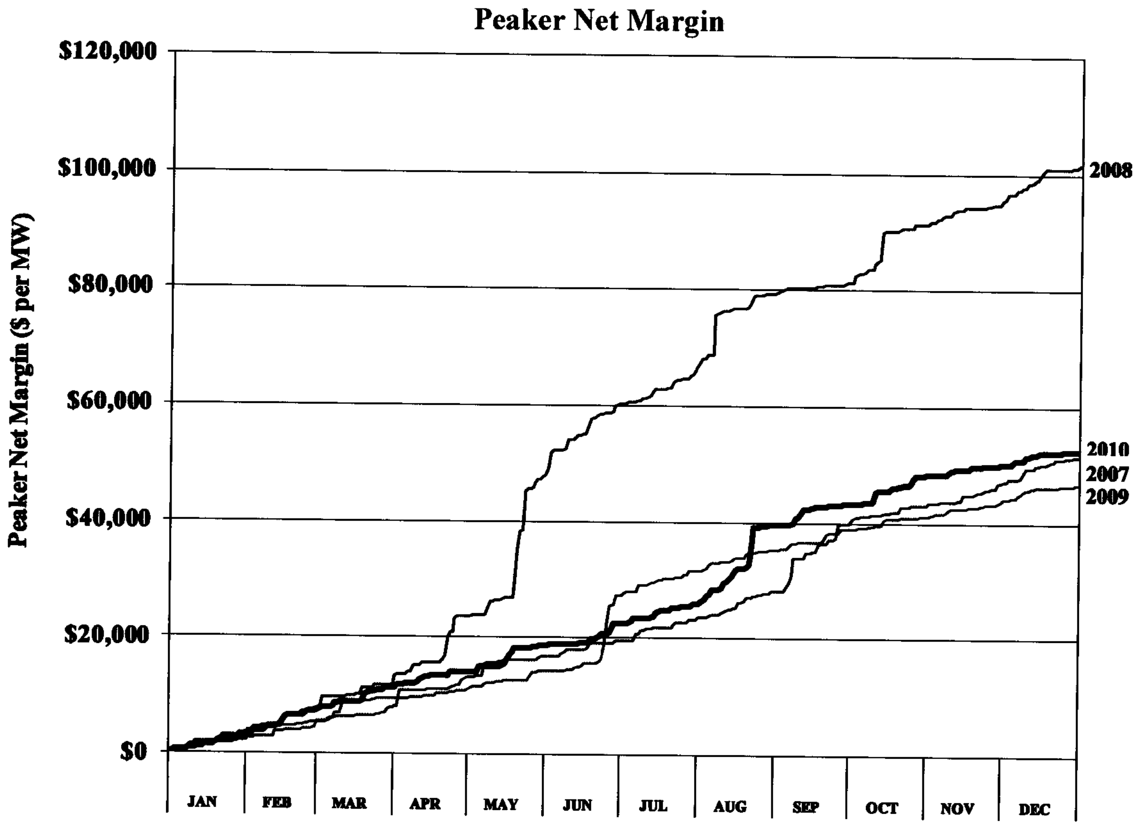


The analysis shows that the net revenue generally increased in 2010 compared to each zone in 2009. Based on our estimates of investment costs for new units, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80 to $105 per kW-year. The estimated net revenue in 2010 for a new gas turbine was approximately $45 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 2010 for a new combined cycle unit was approximately $70 per kW-year. These values indicate that the estimated net revenue in 2010 was well below the levels required to support new entry for a new gas turbine or a combined cycle unit in the ERCOT region.

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. That view has now changed with the relatively lower natural gas prices experienced in 2009 and 2010. For a new coal unit, the estimated net revenue requirement is approximately $210 to $270 per kW-year. The estimated net revenue in 2010 for a new coal unit was approximately $105 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 2010 for a new nuclear unit was approximately $221 per kW-year. These values indicate that the estimated net revenue for either a new coal or a nuclear unit in ERCOT was well below the levels required to support new entry in 2010.

Although estimated net revenue once again is below levels to support new investment, the nodal market design will have an effect on the profitability of new resources. In a particular location, nodal prices could be higher or lower than the prices in the current market depending on the pattern of congestion.

The Scarcity Pricing Mechanism ("SPM") defined in Public Utility Commission of Texas ("PUCT") SUBST. R. 25.505 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 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 following figure shows the cumulative PNM results for each year from 2007 through 2010. As previously noted, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit is approximately $80 to $105 per kW-year (i.e., $80,000 to $105,000 per MW-year).



Thus, as shown above and consistent with the previous findings in this section relating to net revenue, the PNM reached the level sufficient for new entry in only one of the last four years. In 2008, the peaker net margin and net revenue values rose substantially, surpassing the level required to support new peaker entry. However, a significant portion of the net revenue increase in 2008 was associated with a specific circumstance of extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves. Both of these issues were corrected in the zonal market and were further improved with the implementation of the nodal market in late 2010. With these issues addressed, the peaker net margin dropped substantially in 2009 and 2010.

In our review of the effectiveness of the SPM in 2010 we note improvement in two areas of concern raised last year: (1) bias in ERCOT's day-ahead load forecast and (2) appropriate energy pricing during the deployment of non-spinning reserves. However, we found the dependence upon market participants to submit offers at or near the offer cap to not be a reliable means of producing scarcity pricing during shortage conditions under the zonal market design.

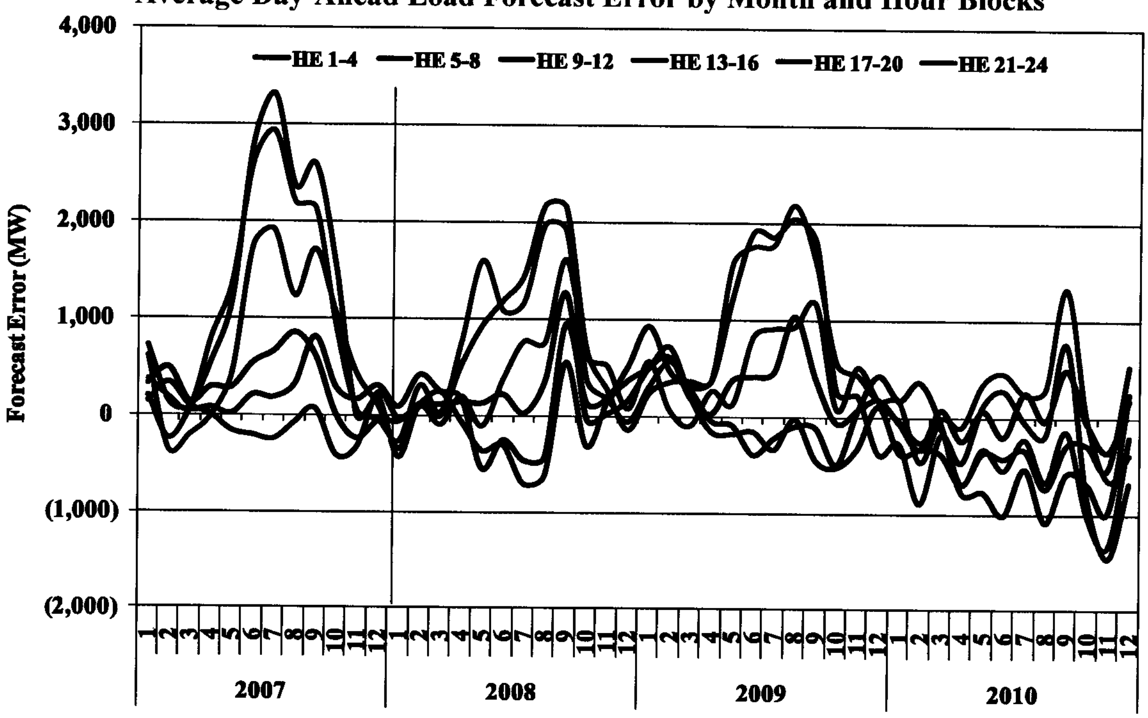
1. ERCOT Day-Ahead Load Forecast Error

ERCOT's zonal market includes the operation of a day-ahead Replacement Reserve Service ("RPRS") market that is designed to ensure that adequate capacity is available on the system to meet reliability criteria for each hour of the following operating day. This includes an assessment of the capacity necessary to meet forecast demand and operating reserve requirements, as well as capacity required to resolve transmission constraints.

A key input to the RPRS market is the day-ahead load forecast developed by ERCOT. If the day-ahead load forecast is significantly below actual load and no subsequent actions are taken, ERCOT may run the risk of there not being enough generating capacity online to meet reliability criteria in real-time. In contrast, if the day-ahead load forecast is significantly higher than actual load, the outcome may be an inefficient commitment of excess online capacity in real-time.

The figure below shows the day-ahead load forecast error data for 2007 through 2010 with the average megawatt error displayed for each month in four hour blocks (hours ending). This figure shows a change of pattern from significant over-forecasting during peak load hours to much smaller errors in 2010.

Average Day-Ahead Load Forecast Error by Month and Hour Blocks



The 2010 ERCOT ancillary service procurement methodologies was modified to adjust the ERCOT day-ahead load forecast to account for the historically measured net load forecast bias, and to compensate for this adjustment by increasing the quantity of non-spinning reserves procured. The revised procedures went into effect in January 2010 and the effect is clearly observable in the data shown in the figure above when compared 2010 to the three prior years.

2. Appropriate energy pricing during deployment of Non-Spin

The following improvements related to the deployment and pricing of non-spinning reserves were implemented in May 2009:

- Eliminate the previous *ex post* re-pricing provisions to provide for *ex ante* pricing during non-spinning reserve deployments, thereby providing more pricing certainty for resources and loads and significantly reducing the probability of *ex post* scarcity level prices during non-scarcity conditions;
- Allow quick start units providing non-spinning reserves to offer in the balancing energy market at a market-based price reflecting the cost and risks of starting and deploying these resources; and
- Reduce the probability of transitional shortages by providing more timely access to these reserves through the balancing energy market instead of manual operator deployments.

With the increased quantity of non-spinning reserves being procured in 2010, the increased efficiencies in market operations and pricing during the deployment of non-spinning reserves became even more important.

Although the implementation of the nodal market has significantly increased market efficiencies in a number of areas, including the move to a five-minute rather than fifteen-minute energy dispatch, the initial implementation lacked an efficient economic commitment mechanism for resources such as offline gas turbines and other resources that are not immediately dispatchable in the five-minute energy dispatch. The current mechanisms result in prices that are inefficiently low because they are not representative of the costs associated with starting and running the gas turbines that are being deployed to meet demand.

As previously recommended, this deficiency in ERCOT's nodal market design should be addressed by implementing an additional energy market "look ahead" functionality to produce a projected unit dispatch with energy and ancillary services co-optimized. This additional functionality represents a major change to ERCOT systems, which may not be able to be implemented for several years. However, because the market inefficiencies associated with the current mechanisms are significant, we recommend that an interim solution be pursued that can be implemented in the near term that will more reasonably reflect the marginal costs of the actions being taken when non-spinning reserves are deployed and necessary to meet demand.

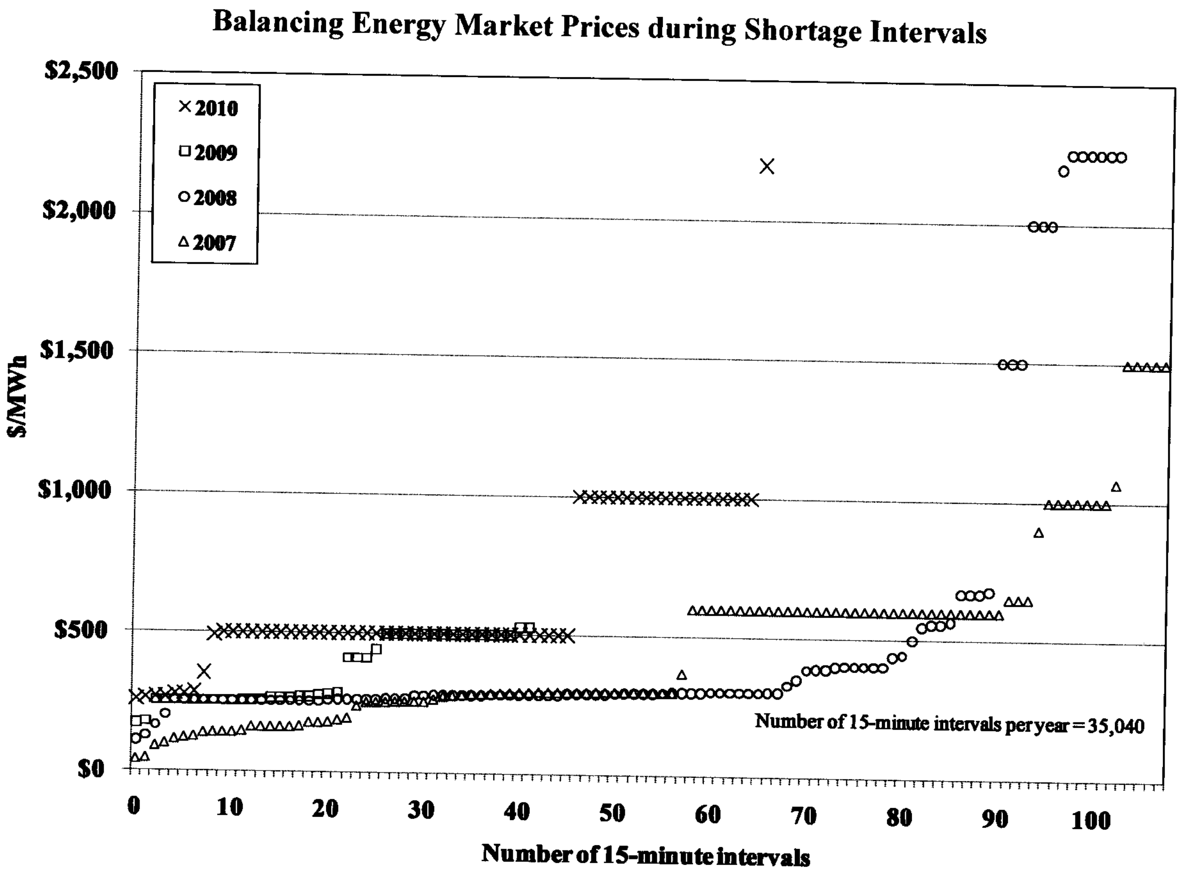
3. Dependence on High-Priced Offers by Market Participants

As a general principle, competitive and efficient market prices should be consistent with the marginal cost of the marginal action taken to satisfy the market's demand. In the vast majority of hours, the marginal cost of the marginal action is that associated with the dispatch of the last generator required to meet demand. It is appropriate and efficient in these hours for this generator to "set the price." However, this is not true under shortage conditions. When the system is in shortage, the demand for energy and minimum operating reserves cannot be satisfied with the available resources, which will cause the system operator to take one or more of the following actions:

- Sacrifice a portion of the operating reserves by dispatching them for energy;
- Voluntarily curtail load through emergency demand response programs;
- Curtail exports or make emergency imports; or
- Involuntarily curtail load.

A market design that adheres to the pricing principles stated above will set prices that reflect each of these actions. When the market is in shortage, the marginal action taken by the system operator is generally to not satisfy operating reserves requirements (*i.e.*, dispatching reserves for energy). Diminished operating reserves results in diminished reliability, which has a real cost to electricity consumers. In this case, the value of the foregone reserves – which is much higher than the marginal cost of the most expensive online generator – should be reflected in energy prices to achieve efficient economic signals governing investment in generation, demand response, and transmission.

Under the PUCT rules governing the energy-only market, the mechanism that allows for such pricing during shortage conditions relies upon the submission of high-priced offers by small market participants.



The figure above shows the balancing market clearing prices during the 15-minute shortage intervals from 2007 through November 2010. The 66 shortage intervals for the first eleven months of 2010 are significantly fewer than the 108 and 103 shortage intervals that occurred in 2007 and 2008, respectively, but more than the 42 intervals that occurred in 2009. Although each of the data points in the figure above represents system conditions in which the market was in shortage, the pricing outcomes are widely varied, with the majority of prices reflecting the marginal offer of the most expensive generation resource dispatched as opposed to the value of foregone operating reserves. Had an offer been submitted that established the MCPE at the system-wide offer cap in each of the 66 shortage intervals of zonal market operations, the 2010 annual peaker net margin would have increased from $52,491 to $79,009 per MW-year, an increase of over 50 percent. The associated increase in the annual load-weighted average balancing energy price would have been less significant, increasing from $39.40 to $43.27 per MWh, a 9.8 percent increase.

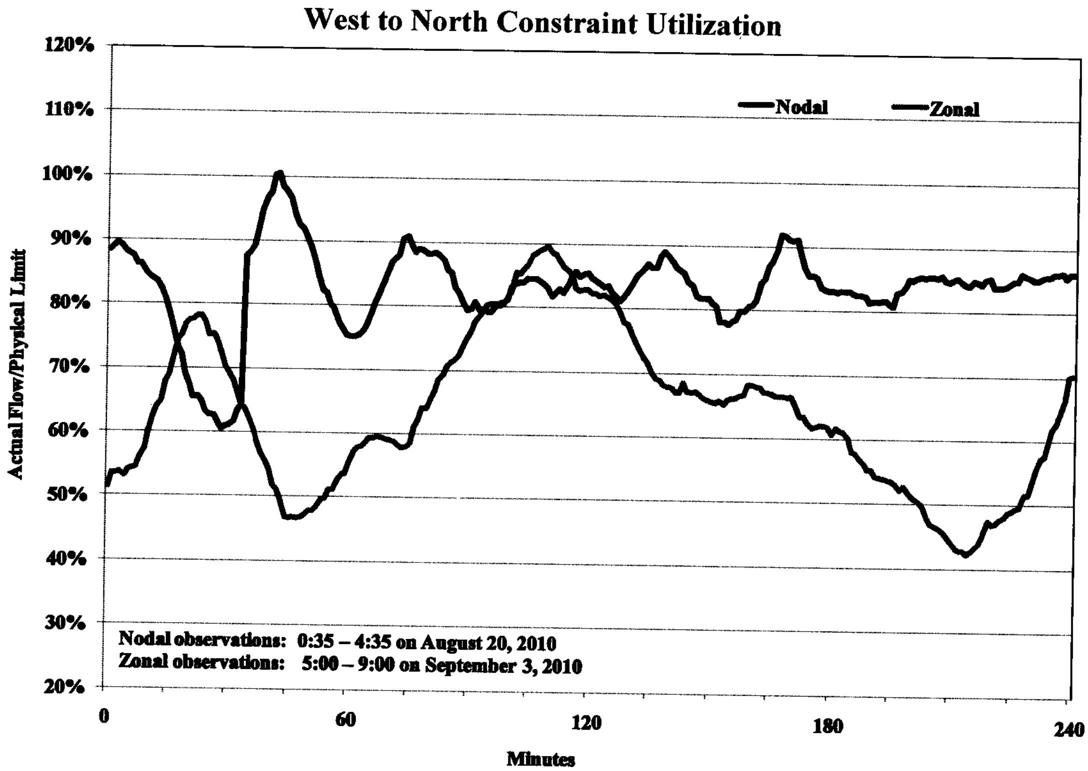
These results indicate that relying exclusively upon the submission of high-priced offers by market participants was generally not a reliable means of producing efficient scarcity prices during shortage conditions under ERCOT's zonal market. In fact, although the system-wide offer cap was $2,250 per MWh, there was only one interval in 2010 when an offer submitted by a market participant set the clearing price at greater than $1000 per MWh. There were only 451 hours (5.6 percent) with an offer that exceeded $1,000 per MWh, and the average of the highest offers submitted by any market participant across all hours in 2010 was $520 per MWh.

More reliable and efficient shortage pricing could be achieved by establishing pricing rules that automatically produce scarcity level prices when operating reserve shortages exist. Such an approach would be more reliable because it would not be dependent upon the submission of high-priced offers by small market participants to be effective. It would also be more efficient during the greater than 99 percent of time in which shortage conditions do not exist because it would not be necessary for market participants to effectively withhold lower cost resources by offering relatively small quantities at prices dramatically higher than their marginal cost.

This type of mechanism is part of the nodal market design. At times when there is insufficient capacity available to meet both energy and minimum operating reserve requirements, all available capacity will be dispatched and the clearing price will rise in a predetermined manner to a maximum of the system-wide offer cap. During December 2010 there were15 executions of the security constrained economic dispatch (SCED) algorithm that resulted in the system-wide energy clearing price being set at the system-wide offer cap. These 15 SCED intervals represented 32 minutes spread over 5 settlement intervals.

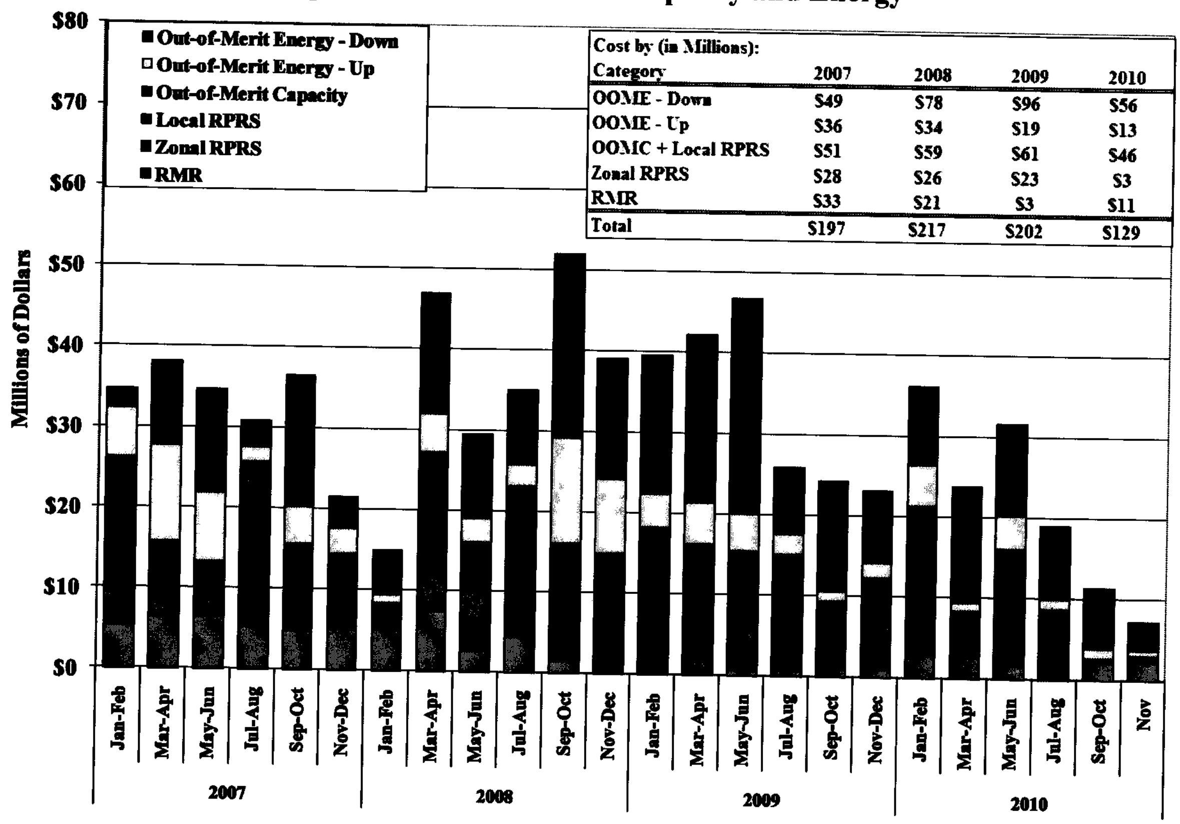
D. Transmission and Congestion

The nodal market provides many improvements, including unit-specific offers and shift factors, simultaneous resolution of all transmission congestion, actual output instead of schedule-based dispatch, and 5-minute instead of 15-minute dispatch, among others. These changes should help to increase the economic and reliable utilization of scarce transmission resources well beyond that experienced in the zonal market, and in so doing, also dispatch the most efficient resources available to reliably serve demand. Early indications of the improvement in constraint utilization expected under the nodal market are evident in the figure below, which compares the utilization of the West to North constraint under the zonal and nodal markets. The difference in utilization across similar four hour periods is obvious. Using zonal market congestion management techniques the average utilization was 64 percent compared to 83 percent under the nodal market. Although this is much too small a sample to draw definitive conclusions, the improvement demonstrated bodes well for the improved transmission system utilization expected to occur under the nodal market design.



ERCOT manages local (intrazonal) congestion by using out-of-merit dispatch ("OOME up" and "OOME down"), which causes units to depart from their scheduled output levels. When insufficient capacity is committed to meet local or system reliability requirements, ERCOT commits additional resources to provide the necessary capacity in either the day-ahead market or in the adjustment period (the adjustment period includes the hours after the close of the day-ahead market up to one hour prior to real-time). Capacity required for local reliability constraints is procured through either the Replacement Reserve Service market ("Local RPRS") or as out-of-merit capacity ("OOMC"). Capacity required for system reliability requirements (*i.e.*, the requirement that the total system-wide online capacity be greater than or equal to the sum of the ERCOT load forecast plus operating reserves in each hour) is procured through either the RPRS market ("Zonal RPRS") or as OOMC. ERCOT also enters into RMR agreements with certain generators needed for local reliability that may otherwise be mothballed or retired. When RMR units are called out-of-merit, they receive revenues specified in the agreements rather than standard OOME or OOMC payments. The following figure shows the out-of-merit energy and capacity costs, including RMR costs, from 2007 to 2010.

Expenses for Out-of-Merit Capacity and Energy



Cost by (in Millions): Category	2007	2008	2009	2010
OOME - Down	$49	$78	$96	$56
OOME - Up	$36	$34	$19	$13
OOMC + Local RPRS	$51	$59	$61	$46
Zonal RPRS	$28	$26	$23	$3
RMR	$33	$21	$3	$11
Total	$197	$217	$202	$129

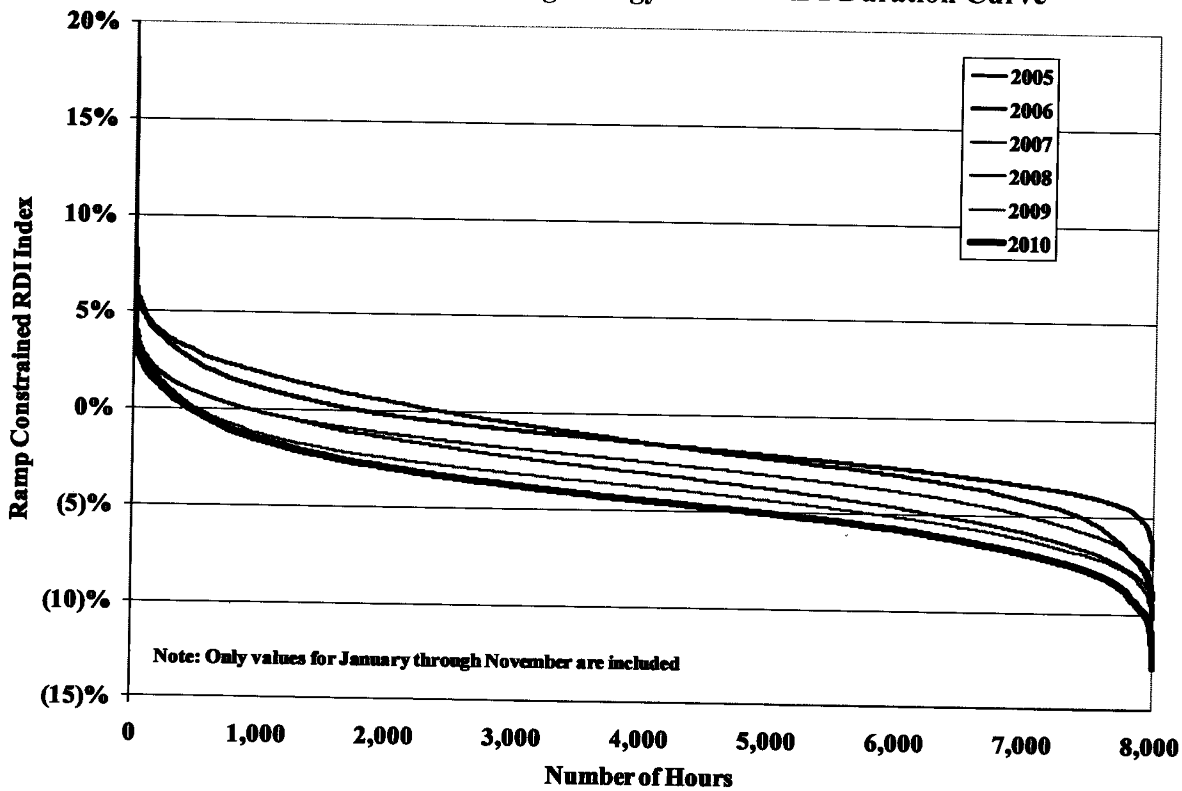
The results in the figure above show that overall uplift costs for RMR units, OOME units, OOMC/ Local RPRS and Zonal RPRS units were $129 million in 2010, which is a $73 million decrease over $202 million in 2009. Even taking into account that there were only eleven months, 2010 had the lowest zonal market uplift costs of the past four years. OOME Down and RPRS costs accounted for the most significant portion of the reduction in 2010. OOME down decreased from $96 million in 2009 to $56 million in 2010. This is primarily attributable to decreases in OOME Down instructions for wind resources in the West Zone.

E. Analysis of Competitive Performance

The report evaluates two aspects of market power: (1) structural indicators of market power and (2) behavioral indicators that would signal attempts to exercise market power. The structural analysis in this report focuses on identifying circumstances when a supplier is "pivotal," *i.e.*, when its generation is essential to serve the ERCOT load and satisfy the ancillary services requirements.

The pivotal supplier analysis indicates that the frequency with which a supplier was pivotal in the balancing energy market decreased in 2010 compared to 2009. The following figure shows the ramp-constrained balancing energy market Residual Demand Index ("RDI") duration curves for 2005 through 2010. When the RDI is greater than zero, the largest supplier's balancing energy offers are necessary to prevent a shortage of offers in the balancing energy market.

Ramp-Constrained Balancing Energy Market RDI Duration Curve

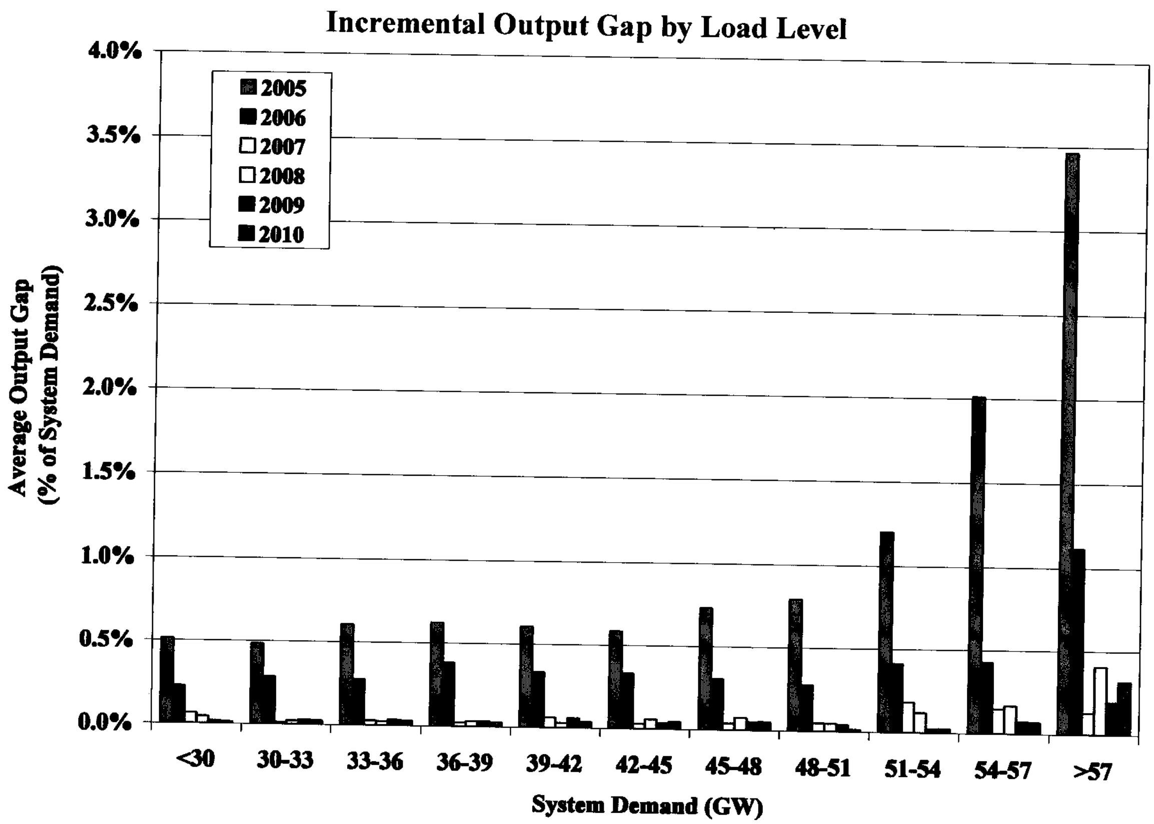


The frequency with which at least one supplier was pivotal in the balancing energy market (*i.e.*, an RDI greater than zero) has fallen consistently; from 29 and 21 percent of the hours in 2005 and 2006, respectively, to less than 11 percent of the hours in 2007 and 2008, to less than

6 percent of the hours in 2009 and 2010. These results highlight the trend of continued improvement in the structural competitiveness of the balancing energy market over the last six years.

A behavioral indicator that evaluates potential economic withholding is measured 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 balancing energy price. A participant can economically withhold resources, as measured by the output gap, by raising its balancing energy offers so as not to be dispatched or by not offering unscheduled energy in the balancing energy market.

The figure below compares the real-time load to the average incremental output gap for all market participants as a percentage of the real-time system demand from 2005 through November 2010.



The figure shows that the competitiveness of supplier offers improved considerably in 2006 compared to 2005, followed by even more substantial improvement in 2007 through 2010.

Overall, the output gap measures during the first eleven months of 2010 were comparable with the levels in 2009, with all the years showing significant improvement over 2005 and 2006.

In summary, we find that the ERCOT zonal wholesale market performed competitively in 2010.

I. REVIEW OF MARKET OUTCOMES

A. Balancing Energy Market

1. Balancing Energy Prices During 2010

Although ERCOT implemented its highly anticipated nodal market design on December 1, 2010, the bulk of our analysis reviews the performance and efficiency of the zonal market for the first eleven months of 2010. Where appropriate we include comparable data for December 2010. 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 we refer 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.

The components of the all-in price of electricity include:

- Energy costs: Balancing energy market prices are used to estimate energy costs, under the assumption that the price of bilateral energy purchases converges with balancing energy market prices over the long-term, as more fully discussed below.
- Ancillary services costs: These costs are estimated based on total system demand and prices in the ERCOT markets for regulation, responsive reserves, and non-spinning reserves.
- Uplift costs: Uplift costs are assigned market-wide on a load-ratio share basis to pay for out-of-merit energy dispatch, out-of-merit commitment, replacement reserve services and Reliability Must Run contracts.[1]

Figure 1 shows the monthly average all-in price for all of ERCOT from 2007 to 2010 and the associated natural gas price.

[1] Nodal market uplift costs only include the charges associated with additional Reliability Unit Commitment and any Reliability Must Run contracts.

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

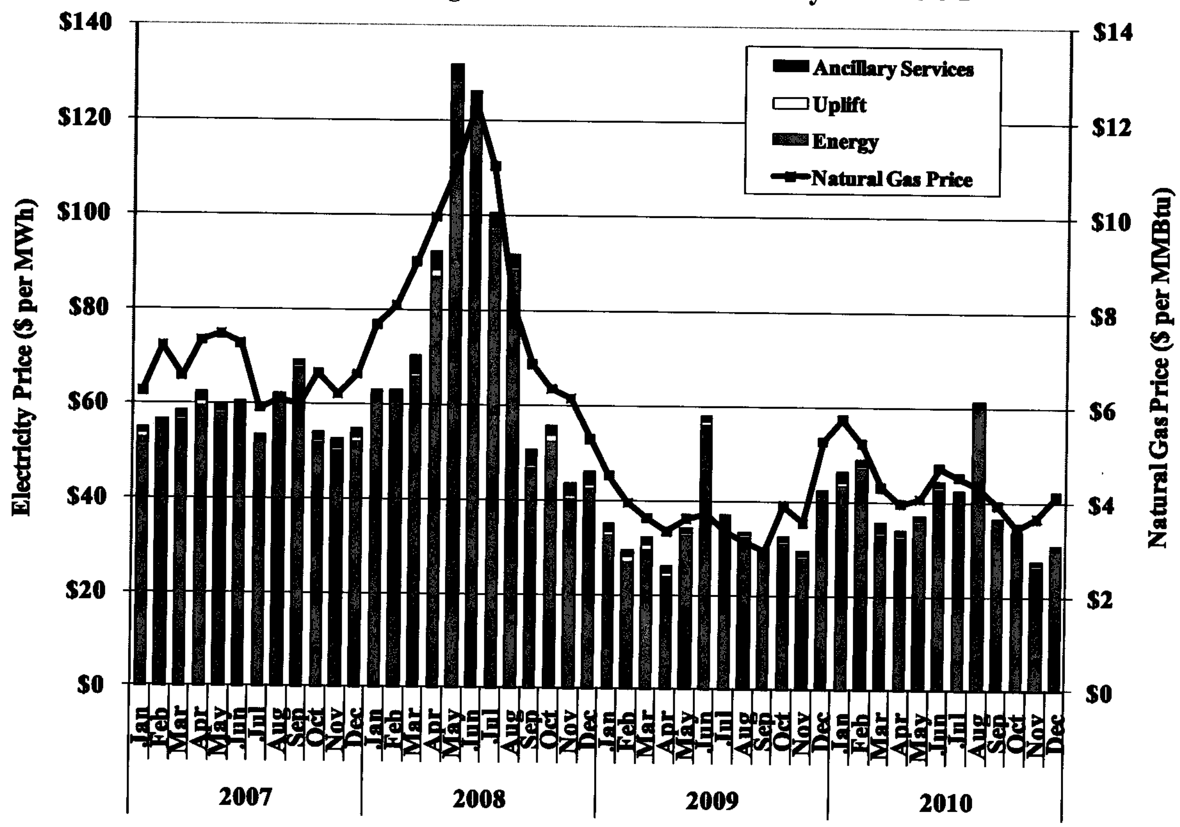


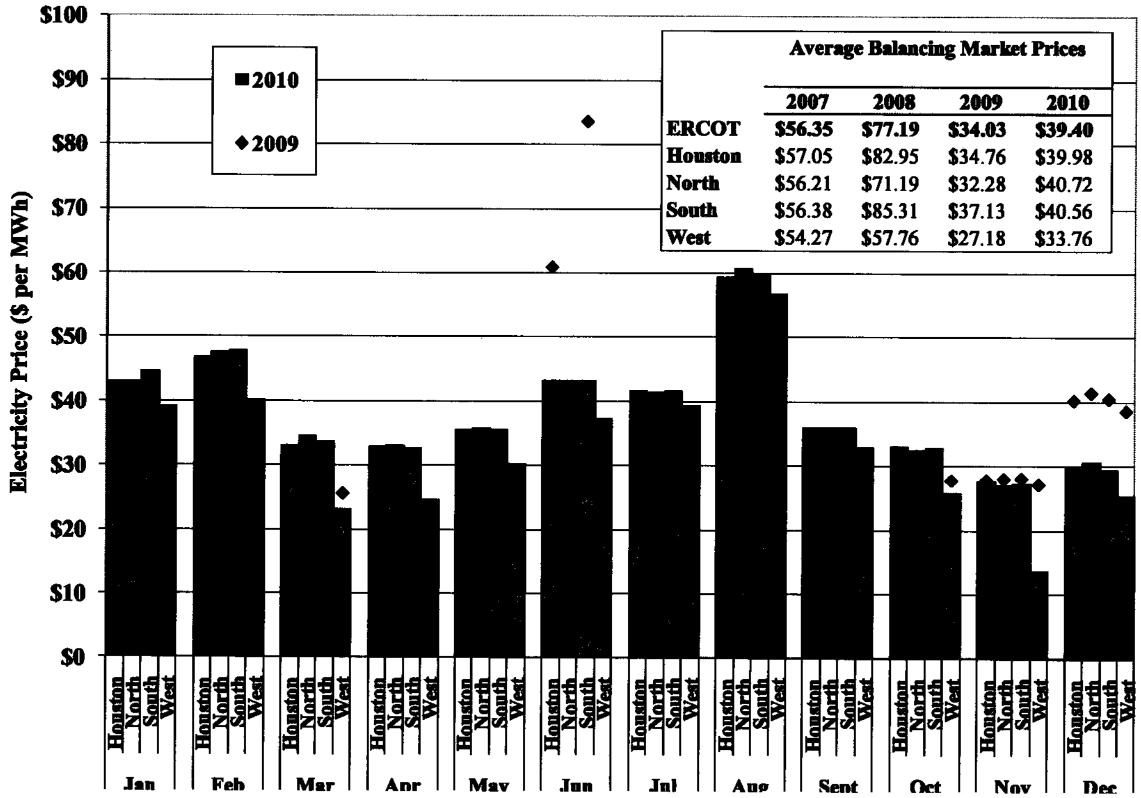
Figure 1 indicates that natural gas prices were a primary driver of the trends in electricity prices from 2007 to 2010. Again, this is not surprising given that natural gas is a widely-used fuel for the production of electricity in ERCOT, especially among generating units that most frequently set the balancing energy market prices in the zonal market or locational marginal prices in the nodal market.

The largest component of the all-in costs is the energy costs, which are reflected by the prices in the balancing energy market (or locational marginal prices). Under the zonal market design, the balancing energy market is the spot market for electricity in ERCOT. As is typical in other wholesale markets, only a small share of the power produced in ERCOT is transacted in the spot market, although at times such transactions can exceed 10 percent of total demand. Although most power is purchased through bilateral forward contracts, outcomes in the balancing energy market are very important because of the expected pricing relationship between spot and forward markets (including bilateral markets).

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 balancing energy market will translate to artificially-low forward prices. Likewise, price spikes in the balancing energy market will increase prices in the forward markets. This section evaluates and summarizes balancing energy market prices during 2010.

To summarize the price levels during the past four years, Figure 2 shows the monthly load-weighted average balancing energy market prices in each of the ERCOT zones during 2009 and 2010, with annual summary data for 2007 through 2010.[2]

Figure 2: Average Balancing Energy Market Prices



ERCOT average balancing energy market prices were 16 percent higher in 2010 than in 2009, with an ERCOT-wide load-weighted average price of $39.40 per MWh in 2010 compared to

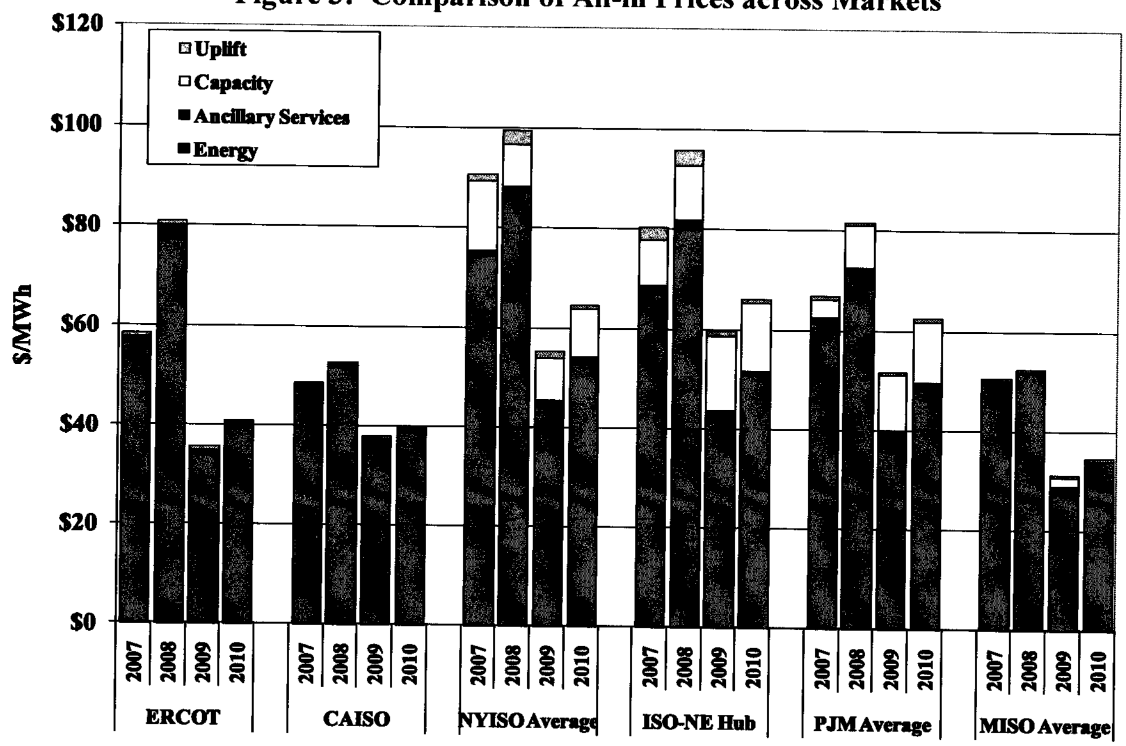
2 The load-weighted average prices are calculated by weighting the balancing energy price for each interval and each zone by the total zonal load in that interval. For this evaluation, balancing energy prices are load-weighted since this is the most representative of what loads are likely to pay (assuming that balancing energy prices are, on average, generally consistent with bilateral contract prices).

$34.03 per MWh in 2009. February and August experienced the highest balancing energy market price increases in 2010, averaging 83 percent higher than the prices in the same months in 2009. Higher prices in February can be explained by colder weather in 2010 compared to 2009, leading to a 19 percent increase in energy consumption. Weather also explains the increase in prices during August, when extended hot, dry weather resulted in record system peak demands. The change evident in June is due to there not being the extended period of North to South zonal congestion experienced in 2009.

Natural gas price increased 16 percent in 2010, averaging $4.34 per MMBtu in 2010 compared to $3.74 per MMBtu in 2009. Hence, the changes in energy prices from 2009 to 2010 were largely a function of natural gas price movements.

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

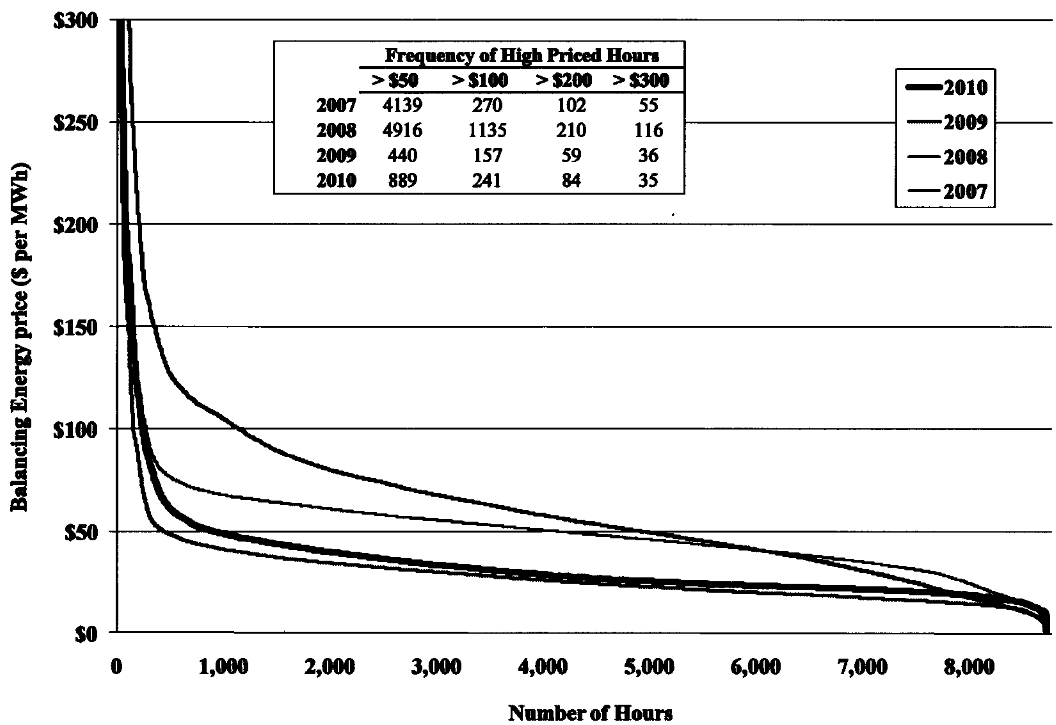
Figure 3: Comparison of All-in Prices across Markets



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 energy prices increased slightly in wholesale electricity markets across the U.S. in 2010. Although there are regional differences in prices across the country, the annual pattern of change in price is consistent across all markets.

Figure 4 presents price duration curves for the ERCOT balancing energy market in each year from 2007 to 2010. 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 hourly load-weighted average prices for the ERCOT balancing energy market.[3]

Figure 4: ERCOT Price Duration Curve



Balancing energy prices exceeded $50 per MWh for 889 hours in 2010. In both 2007 and 2008, the balancing energy prices exceeded $50 per MWh in more than 4,000 hours. These year-to-

3 ERCOT switched to a nodal market on December 1, 2010. The December nodal prices are also included in the price duration curve. The report uses hourly load-weighted zonal price for the zonal market and nodal hourly load-weighted settlement point price for the nodal market.

year changes reflect lower natural gas prices in 2009 and 2010 that affected electricity prices across a broad range of hours.

Figure 5: Zonal Price Duration Curves

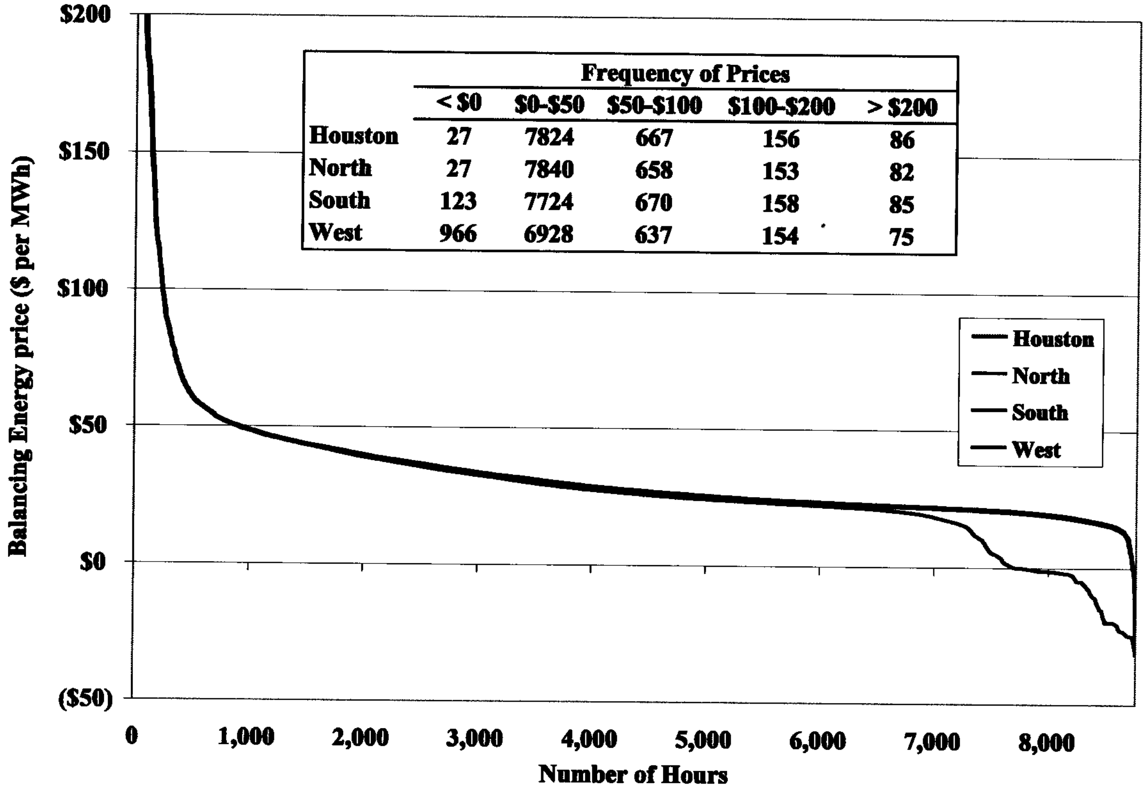
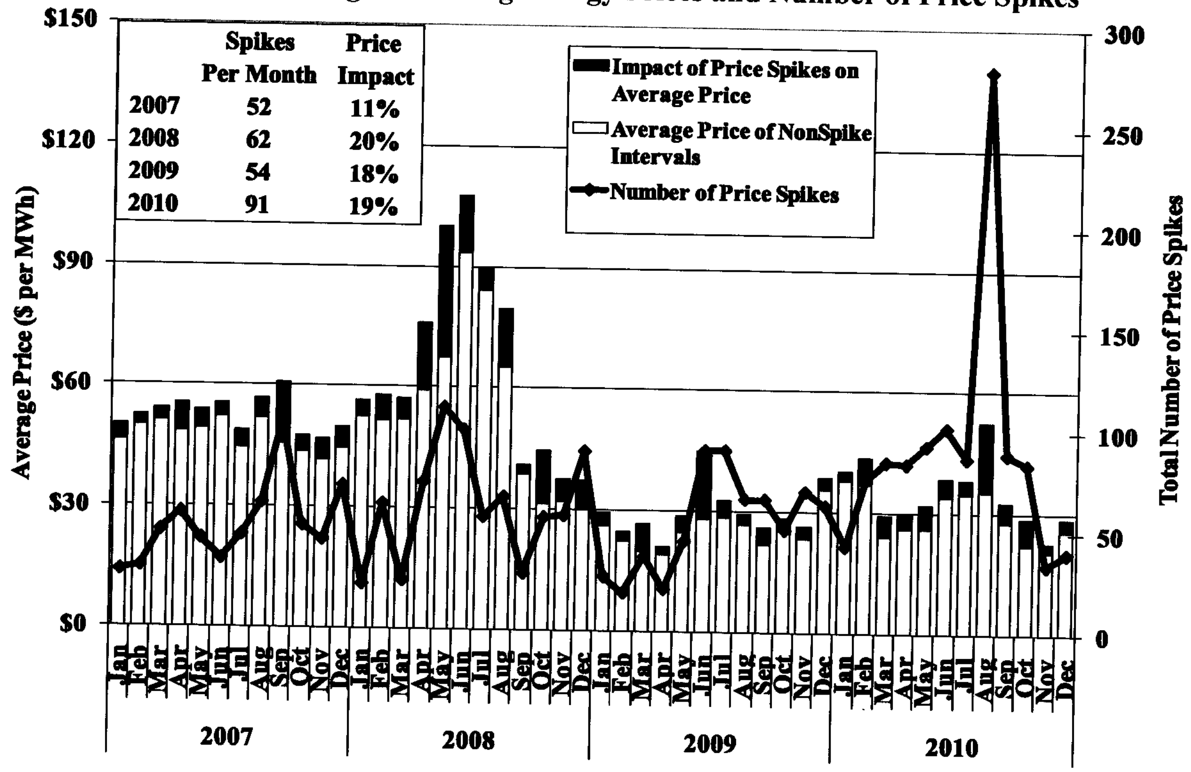


Figure 5 shows the hourly average price duration curve for each of the four ERCOT zones in 2010 and that the Houston, North and South Zones had similar prices over the majority of hours. The price duration curve for the West Zone is generally lower than all other zones, with over 900 hours when the average hourly price was less than zero. These zonal price differences are caused by transmission congestion, as discussed in more detail in Section III.

Other market factors that affect balancing energy prices occur in a subset of intervals, such as the extreme demand conditions that occur during the summer or when there is significant transmission congestion. Figure 4 shows that there were differences in balancing energy market prices between 2007 and 2010 at the highest price levels. For example, 2008 experienced considerably more occasions when prices exceeded $300 per MWh. To better observe the effect of the highest-priced hours, the following analysis focuses on the frequency of price spikes in the balancing energy market from 2007 to 2010. 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 Market Clearing Price of Energy ("MCPE") 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.

Figure 6: Average Balancing Energy Prices and Number of Price Spikes



The number of price spike intervals during 2010 was 91 per month, an increase from the 54 per month in 2009. Previously, high frequency of price spikes occurred when there was significant zonal transmission congestion.[4] In 2010, the high frequency of price spikes during August can be explained by the record high peak load conditions in that month. 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. The impact grows with the frequency of the price spikes, averaging $5.30, $10.71, $4.67 and $5.53 per MWh during 2007, 2008, 2009 and 2010, respectively. Even though price spikes account for a small portion of the total intervals, they

4 *See* 2009 ERCOT SOM Report, Section III and 2008 ERCOT SOM Report at 81-87.

have a significant impact on overall price levels.

Although fuel price fluctuations are the dominant factor driving electricity prices in the ERCOT wholesale market, fuel prices alone do not explain all of the price outcomes. Several other factors provided a meaningful contribution to price outcomes in 2010. These factors include (1) changes in peak demand and average energy consumption levels, as discussed in Section II; (2) the increased penetration of wind resources, as discussed in Sections II; (3) the effectiveness of the scarcity pricing mechanism, as discussed in Section II; and (4) the competitive performance of the wholesale market, as discussed in Section IV. Analyses in the next subsection adjust for natural gas price fluctuations to better highlight variations in electricity prices not related to fuel costs.

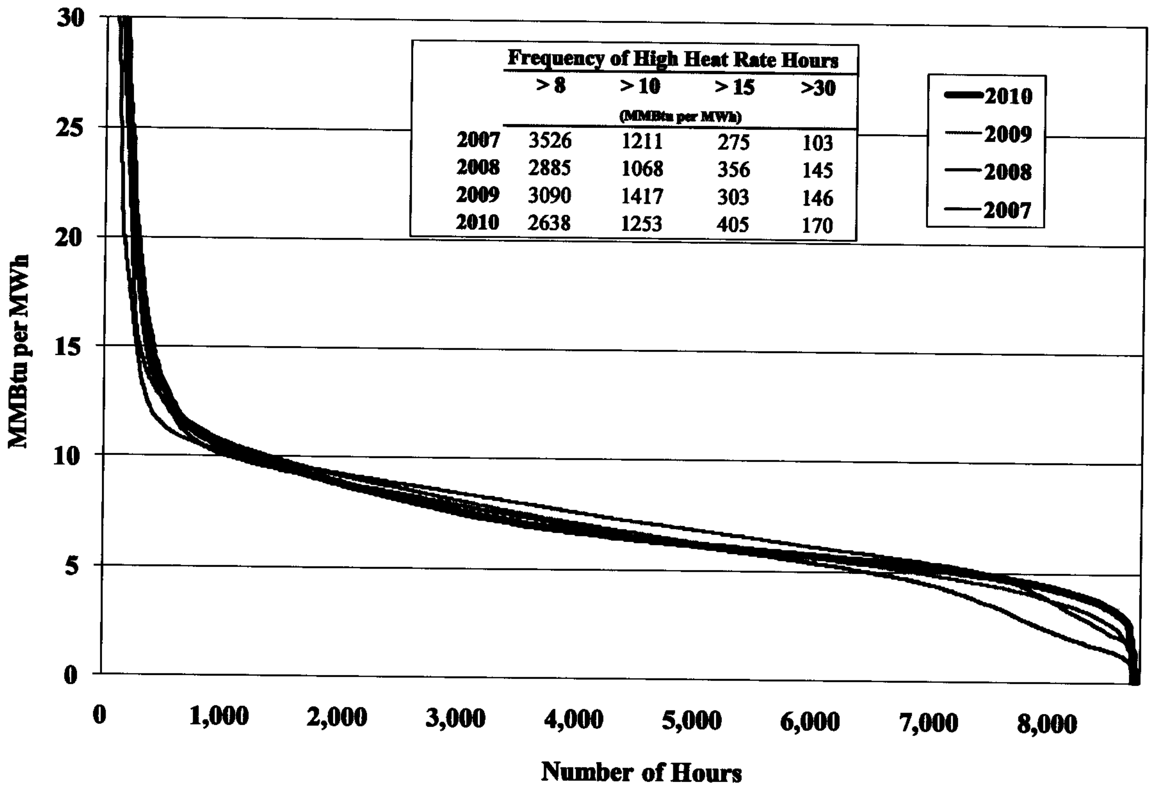
2. Balancing Energy Prices Adjusted for Fuel Price Changes

The pricing patterns shown in the prior subsection are driven to a large extent by changes in fuel prices, natural gas prices in particular. However, prices are influenced by a number of other factors as well. To clearly identify changes in electricity prices that are not driven by changes in natural gas prices, Figure 7 and Figure 8 show balancing energy prices adjusted to remove the effect of natural gas price fluctuations. The first chart shows a duration curve where the balancing energy price is replaced by the marginal heat rate that would be implied if natural gas was always on the margin.[5] 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 2007 to 2010.

In contrast to Figure 4, Figure 7 shows that the implied marginal heat rates were relatively consistent across the majority of hours from 2007 to 2010. The increase in energy prices from 2009 to 2010 is not evident in the vast majority of hours when the effect of fuel price changes is removed, which confirms that the increase in prices in most hours is primarily due to the rise in natural gas prices.

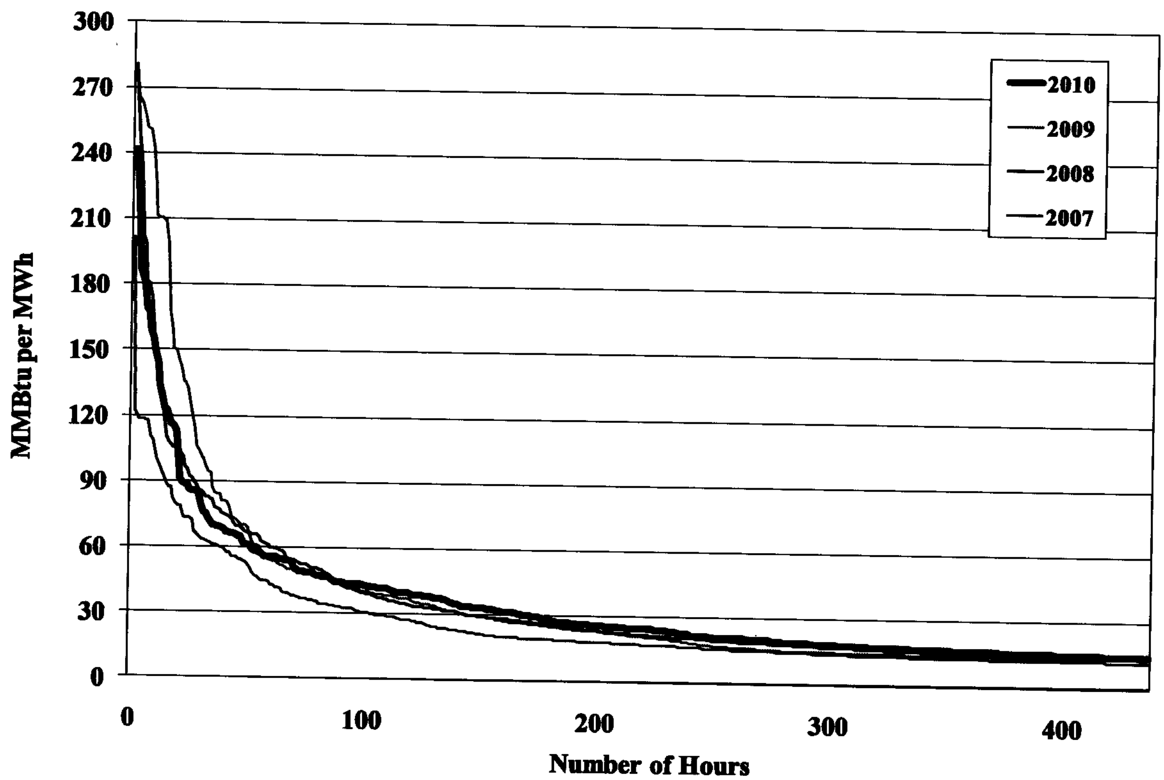
5 The *Implied Marginal Heat Rate* equals the *Balancing Energy Price* divided by the *Natural Gas Price*. This methodology implicitly assumes that electricity prices move in direct proportion to changes in natural gas prices.

Figure 7: Implied Marginal Heat Rate Duration Curve – All hours



However, the price differences that were apparent from Figure 4 in the highest-priced hours persist even after the adjustment for natural gas prices. Figure 8 shows the implied marginal heat rates for the top five percent of hours in 2007 through 2010 and highlights the small increase in the number of hours with an implied marginal heat rate greater than 30 MMBtu per MWh in 2010 compared to the other years. There were 170 hours during 2010 when the implied heat rate was greater than 30 MMBtu per MWh, compared to 103, 145, and 146 in 2007, 2008, and 2009 respectively. This indicates that there are price differences that are due to factors other than changes in natural gas prices.

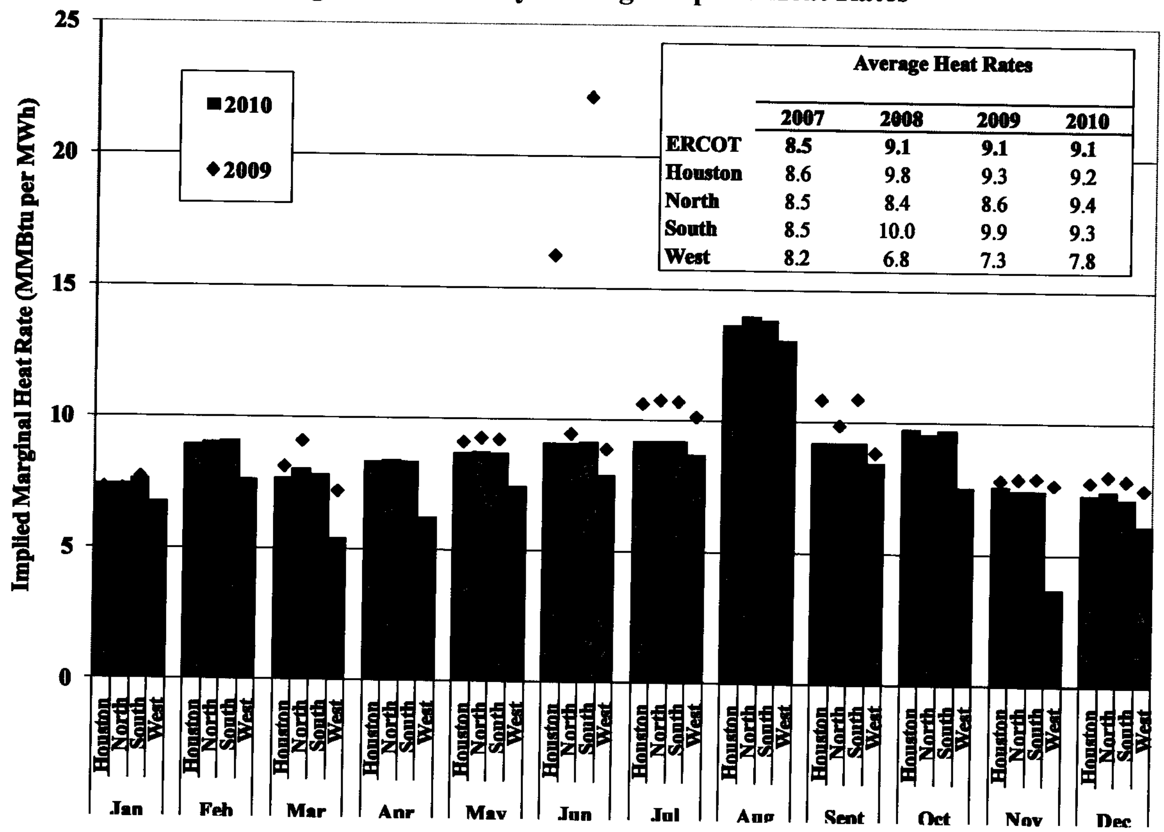
Figure 8: Implied Marginal Heat Rate Duration Curve – Top five percent of hours



The number of hours when the implied heat rate was greater than 30 MMBtu per MWh in 2008 is primarily attributable to chronic and severe congestion on the North to Houston and North to South constraints in April through June 2008. In contrast, although a portion of the 146 hours with an implied heat rate greater than 30 MMBtu per MWh in 2009 is associated with significant congestion on the North to South constraint in late June 2009, many of these hours in 2009 are associated with the implementation of PRR 776 that increased the frequency of the deployment of off-line, quick start gas turbines in the balancing energy market, as discussed in Section II. The changes brought about by PRR 776 continued under the zonal market in 2010, and were combined with increased procurements of off-line, quick start capacity.

To better illustrate these differences, the next figure shows the implied marginal heat rates on a monthly basis in each of the ERCOT zones in 2009 and 2010, with annual average heat rate data for 2007 through 2010. This figure is the fuel price-adjusted version of Figure 2 in the prior sub-section. Adjusting for gas price influence, Figure 9 shows that the annual, system-wide average implied heat rate has remained constant for the past three years. 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.

Figure 9: Monthly Average Implied Heat Rates



The monthly average implied heat rates in 2010 are generally consistent with 2009, with notable exceptions in February, June, July and August. As described previously, higher heat rates in February can be explained by colder weather in 2010 compared to 2009. Extended hot, dry weather resulted in record system peak demands in August, leading to higher implied heat rates. The change evident in June is due to there not being the extended period of North to South zonal congestion experienced in 2009.

3. Price Convergence

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. Under ERCOT's zonal market design, there was no centralized day-ahead market so prices are formed in the day-ahead bilateral contract market. The real-time spot prices are formed in the balancing energy market. Forward prices will converge with real-time prices when two main conditions are in place: a) there are low barriers to shifting purchases and sales between the forward and real-time markets; and b) sufficient information is available to market participants to allow them to develop accurate expectations of future real-time prices. When these conditions are met, market participants can be expected to arbitrage predictable differences between forward prices and real-time spot prices by increasing net purchases in the lower-priced market and increasing net sales in the higher-priced market. These actions will tend to improve the convergence of forward and real-time prices.

These two conditions are largely satisfied in ERCOT's zonal market. Relaxed balanced schedules allowed QSEs to increase and decrease their purchases in the balancing energy market, enabling them to arbitrage forward and real-time energy prices. While this should result in better price convergence, it should also reduce QSEs' total energy costs by allowing them to increase their energy purchases in the lower-priced market. However, volatility in balancing energy prices can create risks that affect convergence between forward prices and balancing energy prices. For example, risk-averse buyers are willing to pay a premium to purchase energy in the bilateral market thereby locking in their energy costs and avoiding the more volatile costs of the balancing energy market.

In this section, we evaluate the price convergence between forward and real-time markets. To determine whether there are significant differences between forward and real-time prices, we examine the difference between the average forward price and the average balancing energy price in each month between 2007 and 2010.[6] This analysis reveals whether persistent and predictable differences exist between forward and real-time prices, which participants should arbitrage over the long-term.

To measure the short-term deviations between real-time and forward prices, we also calculate the average of the absolute value of the difference between the forward and real-time price on a daily basis during peak hours. It is calculated by taking the absolute value of the difference between a) the average daily peak period price from the balancing energy market (*i.e.*, the average of the 16

6 Day-ahead bilateral prices as reported by Megawatt Daily are used to represent forward prices. For 2007, we use the ERCOT Seller's Choice product. For 2008 to 2010, we use the average of the North, South and Houston Zone products.

peak hours during weekdays) and b) the day-ahead peak hour bilateral price. This measure captures the volatility of the daily price differences, which may be large even if the forward and balancing energy prices are the same on average. For instance, if forward prices are $70 per MWh on two consecutive days while real-time prices are $40 per MWh and $100 per MWh on the two days, the price difference between the forward market and the real-time market would be $30 per MWh on both days, while the difference in average prices would be $0 per MWh. These two statistics are shown in Figure 10 for each month between 2007 and 2010.

Figure 10: Convergence between Forward and Real-Time Energy Prices

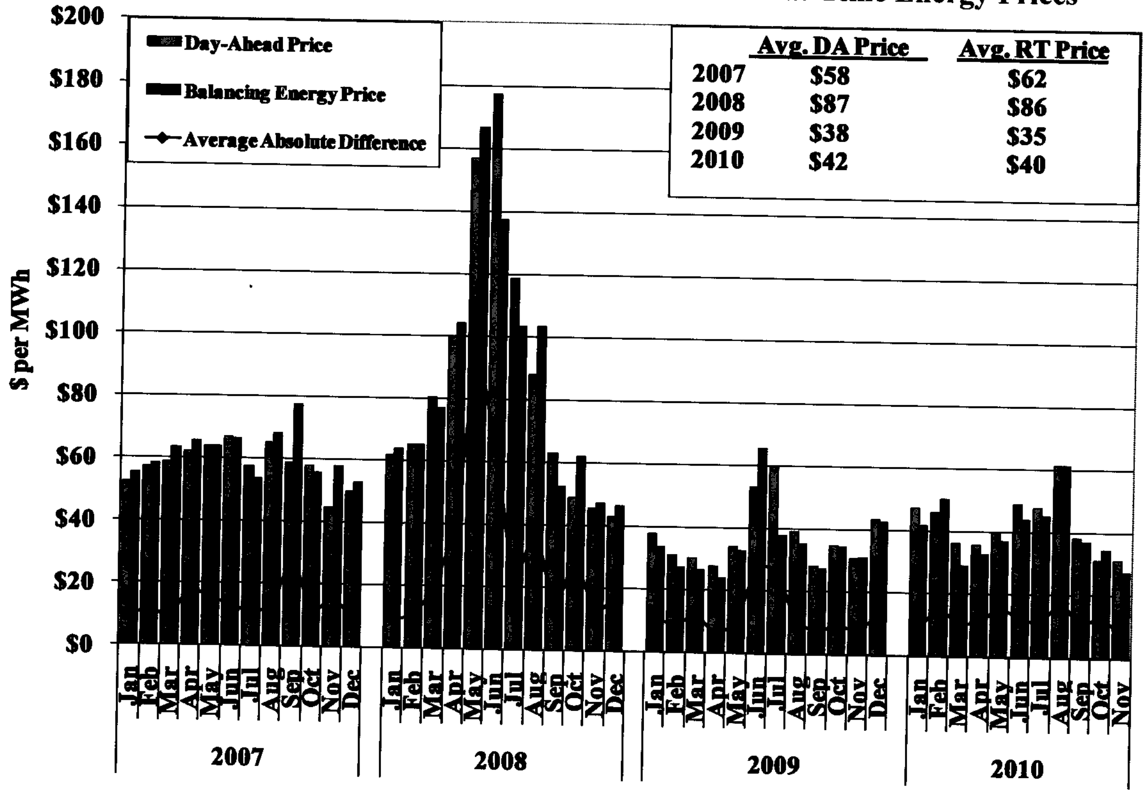
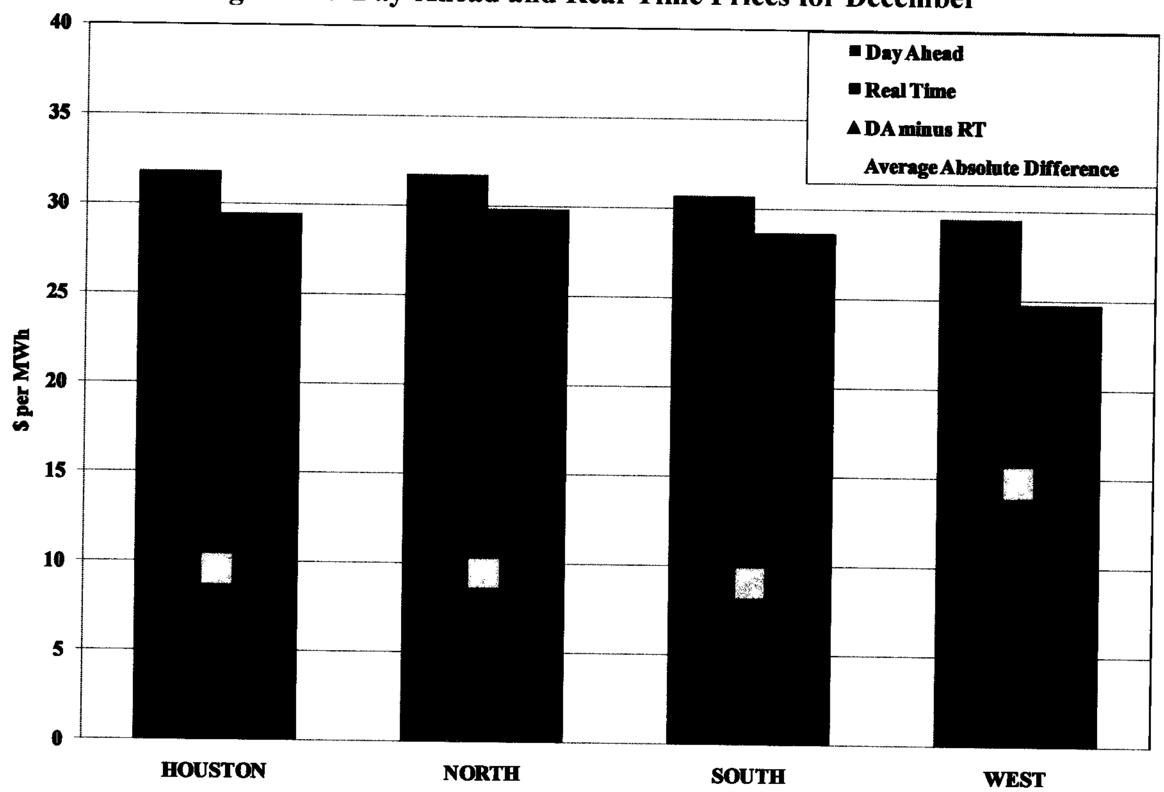


Figure 10 shows price convergence during peak periods (*i.e.*, weekdays between 6 AM and 10 PM). Day-ahead prices averaged $42 per MWh in 2010 compared to an average of $40 per MWh for real-time prices. The day-ahead and real-time prices exhibit relatively good average convergence in 2010 with an average absolute difference being $12.25, almost the same as the level in 2009, where the average absolute difference was $12.37.

One of the fundamental improvements brought about by the implementation of ERCOT's nodal market design is the establishment of a centralized day-ahead market. As a preliminary review of the performance of ERCOT's new day-ahead market, we evaluate the price differences between day-ahead and real-time for the month of December 2010. Figure 11 shows the both the average and absolute price differences between the two markets for the four geographic load zones. Although one month of data is insufficient to reach conclusions on the long-term performance, these data indicate a positive outlook regarding the convergence of day-ahead and real-time energy prices in the nodal market, with the day-ahead prices indicating a slight premium over real-time prices, on average, which is consistent with expectations. Also notable is the difference in the west zone data compared to the other regions, which is likely associated with the uncertainty in forecasting wind generation output and resulting price levels between day-ahead and real-time.

Figure 11: Day-Ahead and Real-Time Prices for December



4. Volume of Energy Traded in the Balancing Energy Market

The primary purpose of the balancing energy market is to match supply and demand in real-time and to manage zonal congestion. In addition to fulfilling this purpose, the balancing energy market signals the value of power for market participants entering into forward contracts and plays a role in governing real-time dispatch. This section examines the volume of activity in the balancing energy market.

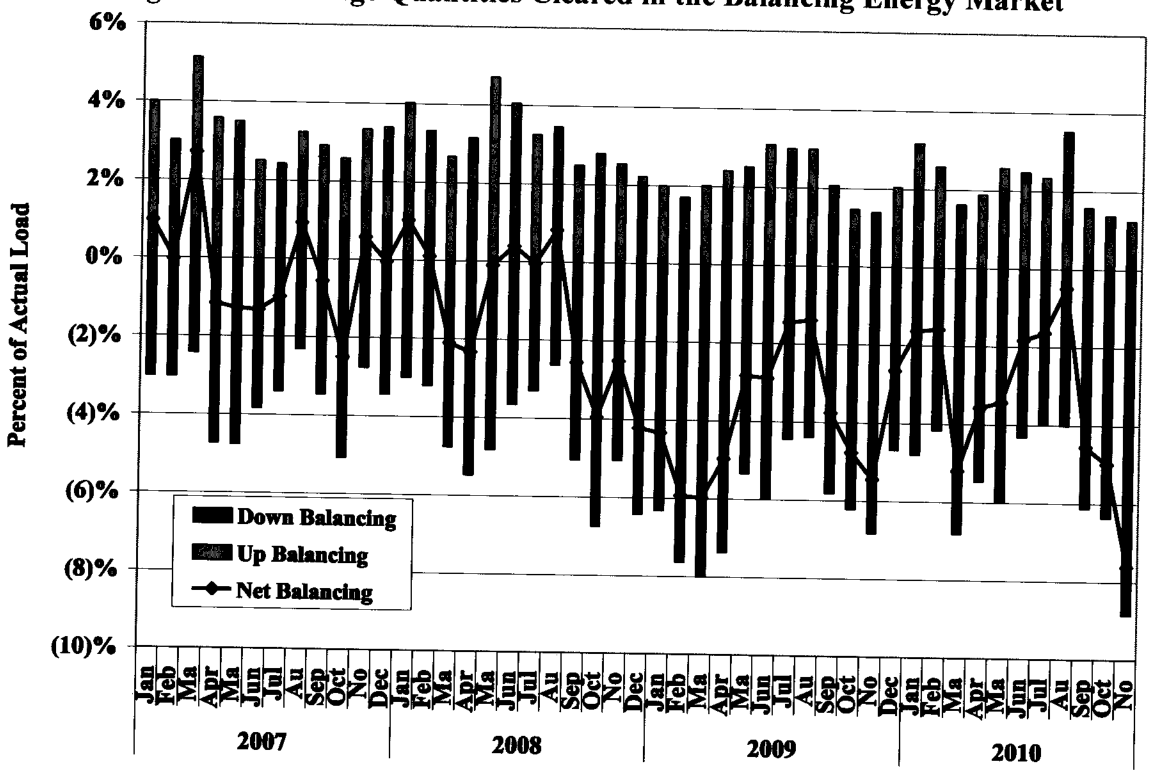
The average amount of energy traded in ERCOT's balancing energy market is small relative to overall energy consumption, although the balancing energy market can at times represent well over ten percent of total demand. Most energy is purchased and sold through forward contracts that insulate participants from volatile spot prices. Because forward contracting does not precisely match generation with real-time load, there will be residual amounts of energy bought and sold in the balancing energy market. Moreover, the balancing energy market enables market participants to make efficient changes from their forward positions, such as replacing relatively expensive generation with lower-priced energy from the balancing energy market.

Hence, the balancing energy market will improve the economic efficiency of the dispatch of generation to the extent that market participants make their resources available in the balancing energy market. In the limit, if all available resources were offered competitively in the balancing energy market (to balance up or down), prices in ERCOT's current market would be identical to prices obtained by clearing all power through a centralized spot market, even though most of the commodity currently settles bilaterally. It is rational for suppliers to offer resources in the balancing energy market even when they are fully contracted bilaterally because they may be able to increase their profit by reducing the output from their resources and support the bilateral sale with balancing energy purchases. Therefore the balancing energy market should govern the output of all resources, even though only a small portion of the energy is settled through the balancing energy market.

In addition to their role in governing real-time dispatch, balancing energy prices also provide a vital signal of the value of power for market participants entering into forward contracts. As discussed above, the spot prices emerging from the balancing energy market should directly affect forward contract prices, assuming that the market conditions and market rules allow the two markets to converge efficiently.

This section summarizes the volume of activity in the balancing energy market. Figure 12 shows the average quantities of up balancing and down balancing energy sold by suppliers in each month, along with the net purchases or sales (*i.e.*, up balancing energy minus down balancing energy).

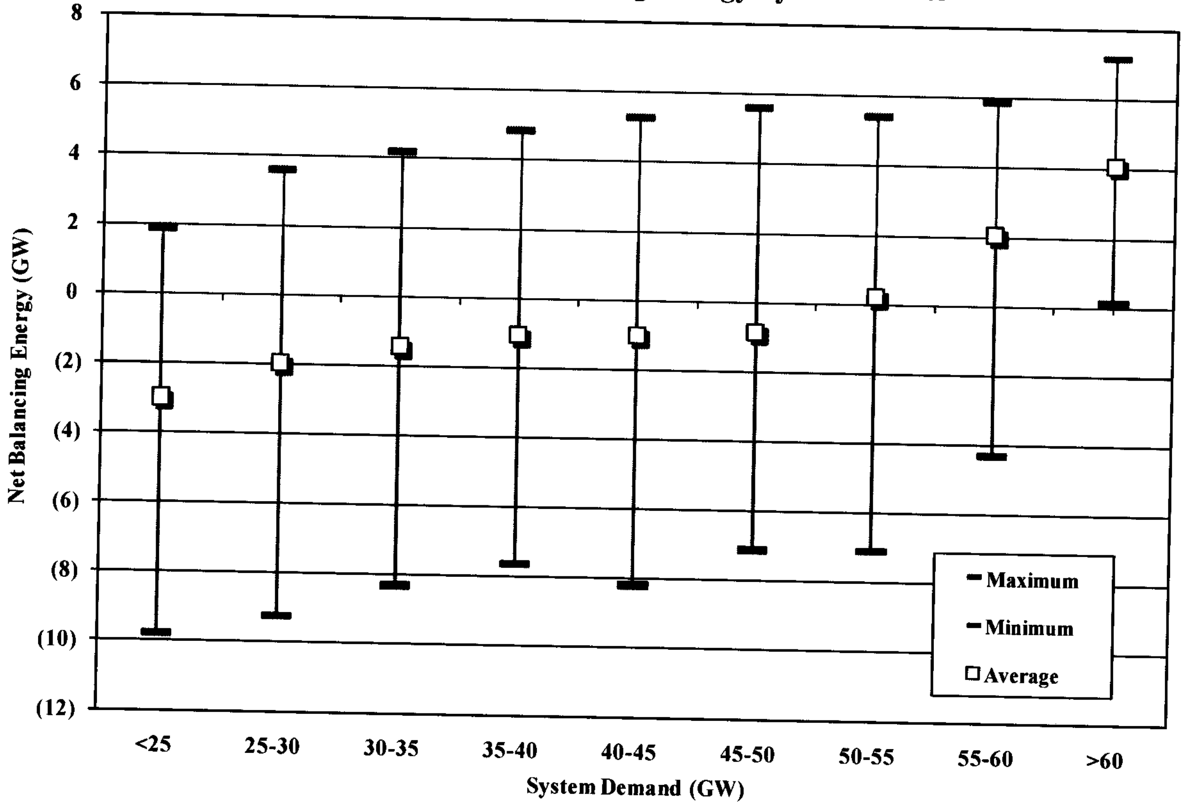
Figure 12: Average Quantities Cleared in the Balancing Energy Market



The total volume of up balancing and down balancing energy as a share of actual load decreased from an average of 8.3 percent in 2009 to 7.7 percent in 2010. Starting in August 2006, the average volume of down balancing energy began to increase. In 2008, for the first time the average amount of down balancing energy was greater than up balancing energy. This trend continued through 2010. The net quantity of balancing energy for every month in 2010 was negative, meaning that the average quantity of down balancing energy was greater than the quantity of up balancing energy. As discussed in Section II, this trend is related to the large increase in wind generation capacity added to the ERCOT region since the fall of 2008 and the associated scheduling patterns of these resources.

Figure 13 provides additional perspective to the monthly average net balancing energy deployments shown in Figure 12 by showing the net balancing energy deployments by load level for all intervals in 2010.

Figure 13: 2010 Net Balancing Energy by Load Level



While Figure 12 shows average net down balancing energy deployments in 2010, Figure 13 shows that this relationship is quite different when viewed as a function of the ERCOT system demand. Figure 13 shows average net down balancing deployments at load levels less than 50 GW, and average net up balancing deployments for load levels greater than 50 GW. Relaxed balanced schedules allow market participants to intentionally schedule more or less than their anticipated load, buying or selling in the balancing energy market to satisfy their actual load obligations. This scheduling flexibility allows the balancing energy market to operate as a centralized energy spot market. Although convergence between forward prices and spot prices has not been good on a consistent basis, the centralized nature of the balancing energy market facilitates participation in the spot market and improves the efficiency of the market results.

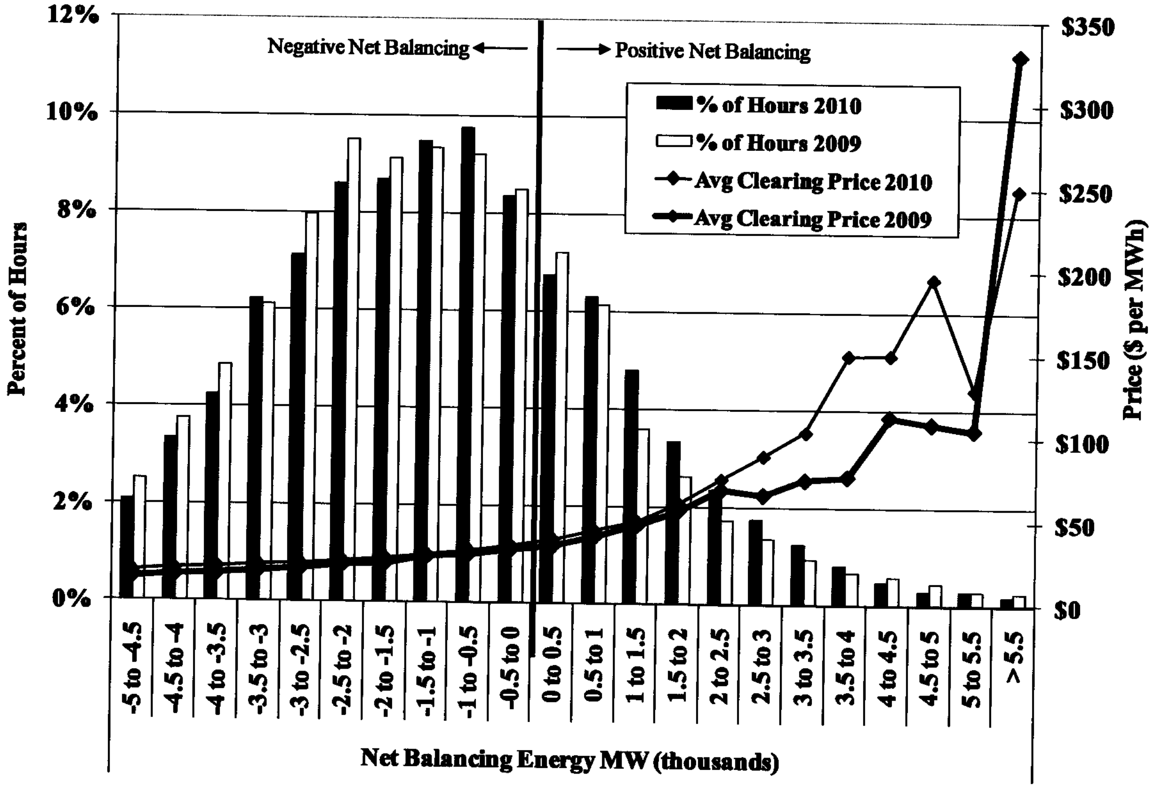
Aside from the introduction of relaxed balanced schedules, another reason for significant balancing energy quantities is that large quantities of up balancing and down balancing energy are often deployed simultaneously to clear "overlapping" balancing energy offers. Deployment of overlapping offers improves efficiency because it displaces higher-cost energy with lower-cost energy, lowering the overall costs of serving load and allowing the balancing energy price to more accurately reflect the marginal value of energy.

Large quantities of net up balancing or net down balancing energy indicates that Qualified Scheduling Entities (QSEs) are systematically under-scheduling or over-scheduling load relative to real-time needs. If large hourly under-scheduling or over-scheduling occurs suddenly, the balancing energy market can lack the ramping capability (*i.e.*, how quickly on-line generation can increase or decrease its output) and sometimes the volume of energy offers necessary to achieve an efficient outcome. In these cases, large net balancing energy purchases can lead to transient price spikes. These occur when capacity exists to supply the need, but is not available within the 15-minute timeframe of the balancing energy market. The remainder of this sub-section and the next section will examine in detail the patterns of over-scheduling and under-scheduling that has occurred in the ERCOT market, and the effects that these scheduling patterns have had on balancing energy prices.

To provide a better indication of the frequency with which net purchases and sales of varying quantities are made from the balancing energy market, Figure 14 presents a distribution of the hourly net balancing energy. The distribution is shown on an hourly basis rather than by interval to minimize the effect of short-term ramp constraints and to highlight the market impact of persistent under- and over-scheduling. Each of the bars in Figure 14 shows the portion of the hours during the year when balancing energy purchases or sales were in the range shown on the x-axis. For example, the figure shows that the quantity of net balancing energy traded was between zero and positive 0.5 gigawatts (*i.e.*, loads were under-scheduled on average) in approximately 7 percent of the hours in 2010.

Figure 14 shows that the distribution of net balancing energy deployments in 2010 is very similar to the distribution in 2009. The distribution is shifted well to the left of zero, meaning that more down balancing energy was deployed than up balancing energy. This observation is consistent with the data shown in Figure 12, and is discussed in more detail in Section II.

Figure 14: Magnitude of Net Balancing Energy and Corresponding Price



The lines plotted in Figure 14 show the average balancing energy prices corresponding to each level of balancing energy volumes for 2009 and 2010. In an efficiently functioning spot market, there should be little relationship between the balancing energy prices and the net purchases or sales. Instead, one should expect that prices would be primarily determined by more fundamental factors, such as actual load levels and fuel prices. However, this figure clearly indicates that balancing energy prices increase as net balancing energy volumes increase. This relationship is explained in part by the fact that net balancing energy deployments tend to be positively correlated with the level of demand as shown in Figure 13. However, as discussed in our previous reports, scheduling practices and ramping issues unique to the zonal market contribute significantly to the observed pattern.[7]

[7] See 2009 ERCOT SOM Report at 20 – 28 for the most recent discussion.