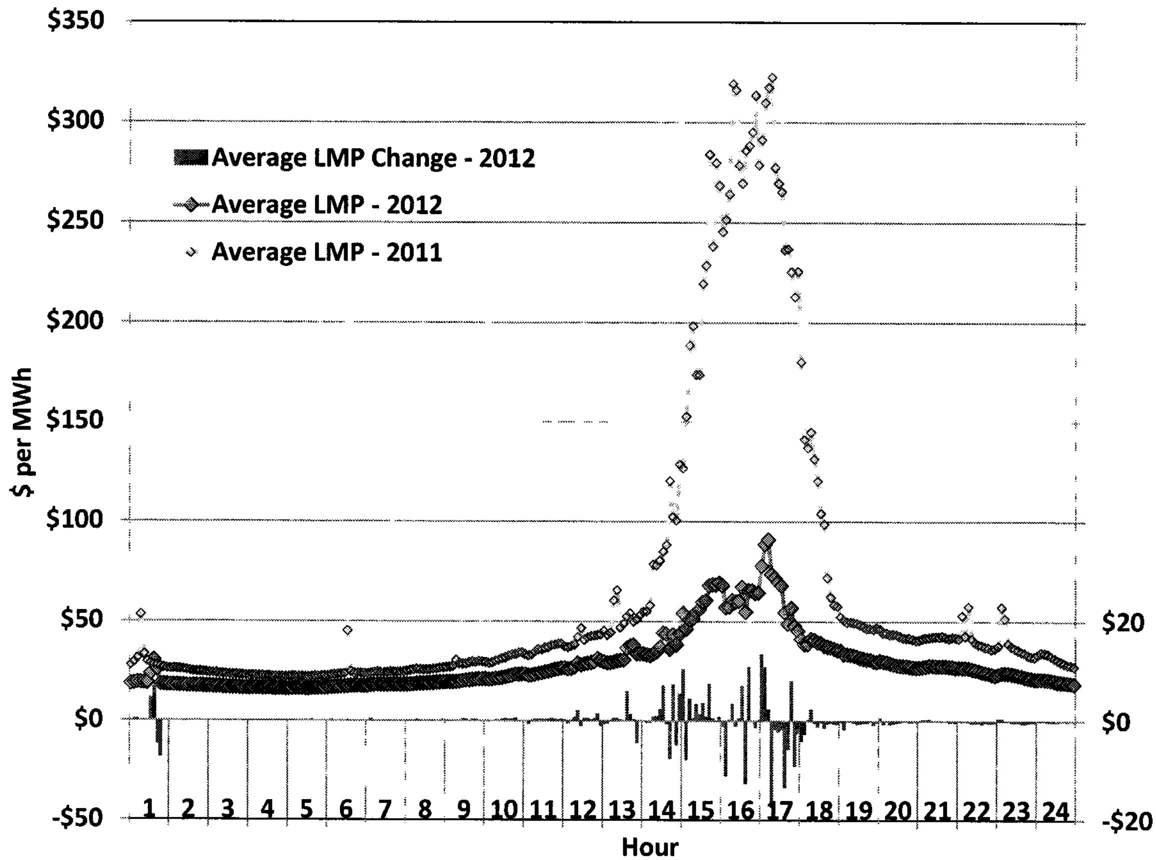
shutdown may have led to the reduced the effects of this type of ramp rate limitation on price spikes during 2012. The average of the absolute value of changes in five-minute real-time energy prices, expressed as a percentage of average price was less than 4 percent in 2012 compared to approximately 6 percent for the same period in 2011.

Figure 14: Real-Time Energy Price Volatility (May – August)



Reduced price volatility in 2012 is also observed in 15 minute settlement point prices for the four geographic load zones, as shown below in Table 1.

Table 1: 15 Minute Price Changes as a Percent of Annual Average Price

Load Zone	*2011*	*2012*
Houston	21.4%	13.0%
South	19.9	13.1
North	22.5	13.9
West	26.2	19.4

The table shows that the price volatility fell substantially from 2011 to 2012. This was primarily due to the sharply reduction in shortages that occurred in 2012, which exhibit relatively normal summer weather conditions. In contrast, 2011 exhibited the hottest summer temperatures in more than 100 years, leading to frequent shortages and associated higher price volatility. The table also shows that 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.

D. Prices at the System-Wide Offer Cap

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

As more fully described later in Section V, Resource Adequacy, 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.

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

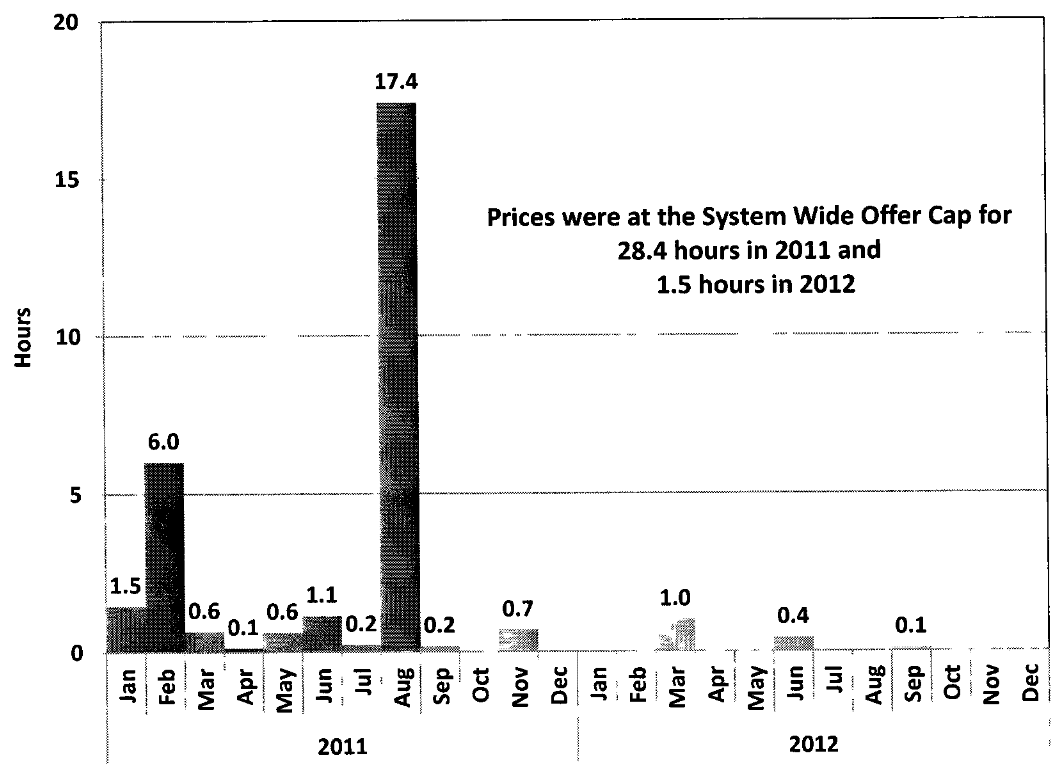
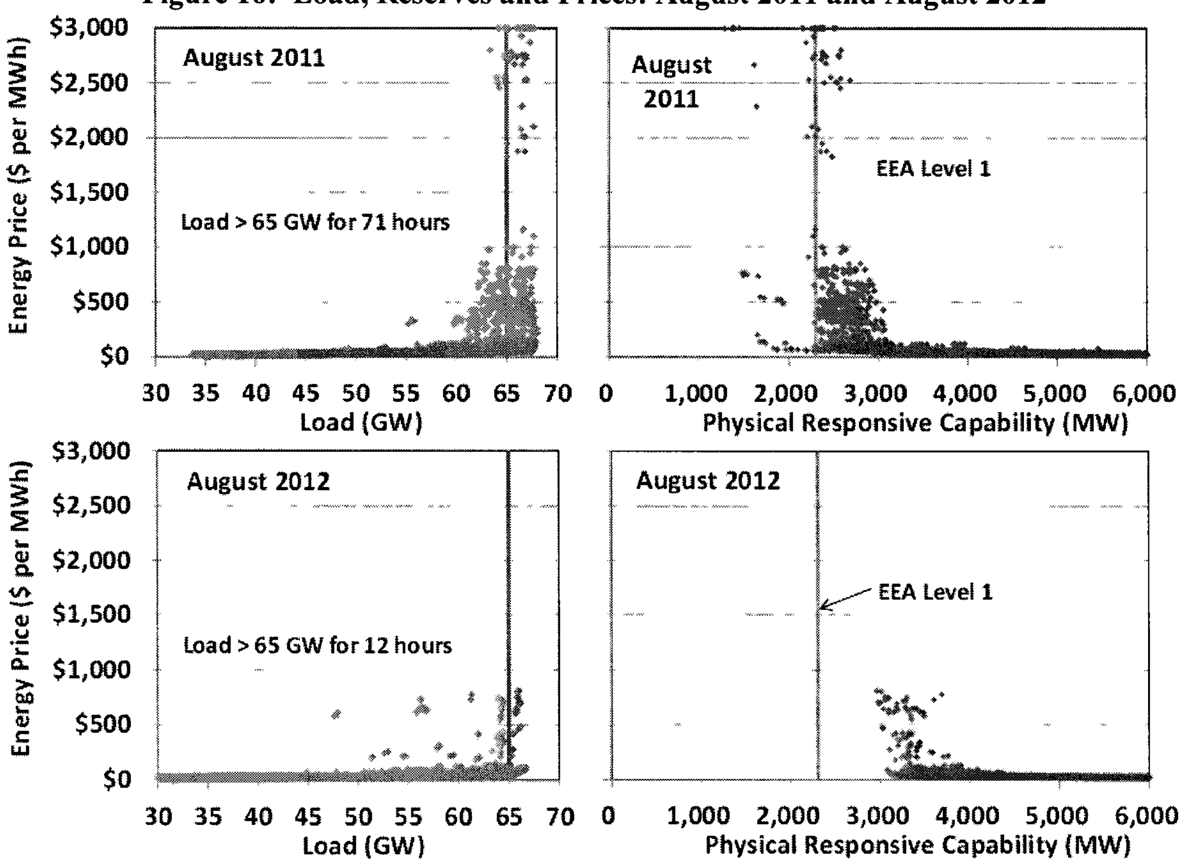


Figure 15 above shows the aggregated amount of time represented by all five-minute dispatch intervals where the real-time energy price was at the system-wide offer cap, displayed by month. Prices during 2012 prices were at the system-wide offer cap for only 1.5 hours, a significant reduction from the 28.4 hours experienced in 2011. Approved during 2012, PUCT SUBST. R.25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. As shown in Figure 15 above, there was only a brief period when energy prices rose to the cap after this change was implemented

The next figure provides a detailed comparison of August's load, required reserve levels, and prices for 2011 and 2012. As expected, the weather in ERCOT was extremely hot and dry during both months, but there were very few dispatch intervals when real-time energy prices reached the system-wide offer cap in 2012 compared to the relatively high frequency it occurred in 2011. Although the weather may have been similar, there were significant differences in load and available operating reserve levels, resulting in much higher prices in August 2011.

Figure 16: Load, Reserves and Prices: August 2011 and August 2012



Shown on the left side of Figure 16 is the relationship between real-time energy price and load level for each dispatch interval for the month of August in 2011 (top) and 2012 (bottom). ERCOT loads were greater than 65 GW for 71 hours in 2011, whereas loads reached that level for less than 12 hours during August 2012. As previously discussed, a strong positive correlation between higher load and higher prices is expected in a well-functioning energy market. We observe such a relationship between higher prices and higher loads in both months.

Although load levels are strong predictors of energy prices, an even more important predictor is the level of operating reserves. Simply put, operating reserves are the difference between the total capacity of operating resources and the current load level. As load level increases against a fixed quantity of operating capacity, the amount of operating reserves diminishes. The minimum required operating reserves prior to the declaration of Energy Emergency Alert ("EEA") Level 1 by ERCOT is 2,300 MW. As the available operating reserves approach the minimum required amount, energy prices should rise toward the system-wide offer cap to reflect the degradation in system reliability.

On the right side of Figure 16 are data showing the relationship between real-time energy prices and the quantity of available operating reserves for each dispatch interval during August of 2011 (top) and 2012 (bottom). This figure shows a strong correlation between diminishing operating reserves and rising prices. With the lower loads in August 2012, available operating reserves were well above minimum levels for the entire month, and there were no occurrences where the energy price reached the system-wide offer cap. In contrast, there were numerous dispatch intervals in August 2011 when the minimum operating reserve level was approached or breached, with 17.4 hours where prices reached $3,000 per MWh.[9] It should be noted that during August 2011 there were a number of dispatch intervals where operating reserves were below minimum requirements with prices well below the level that would be reflective of the reduced state of reliability. In Section IV, Load and Generation at page 93, we provide an example explaining why this can occur and offer a recommendation for improvement.

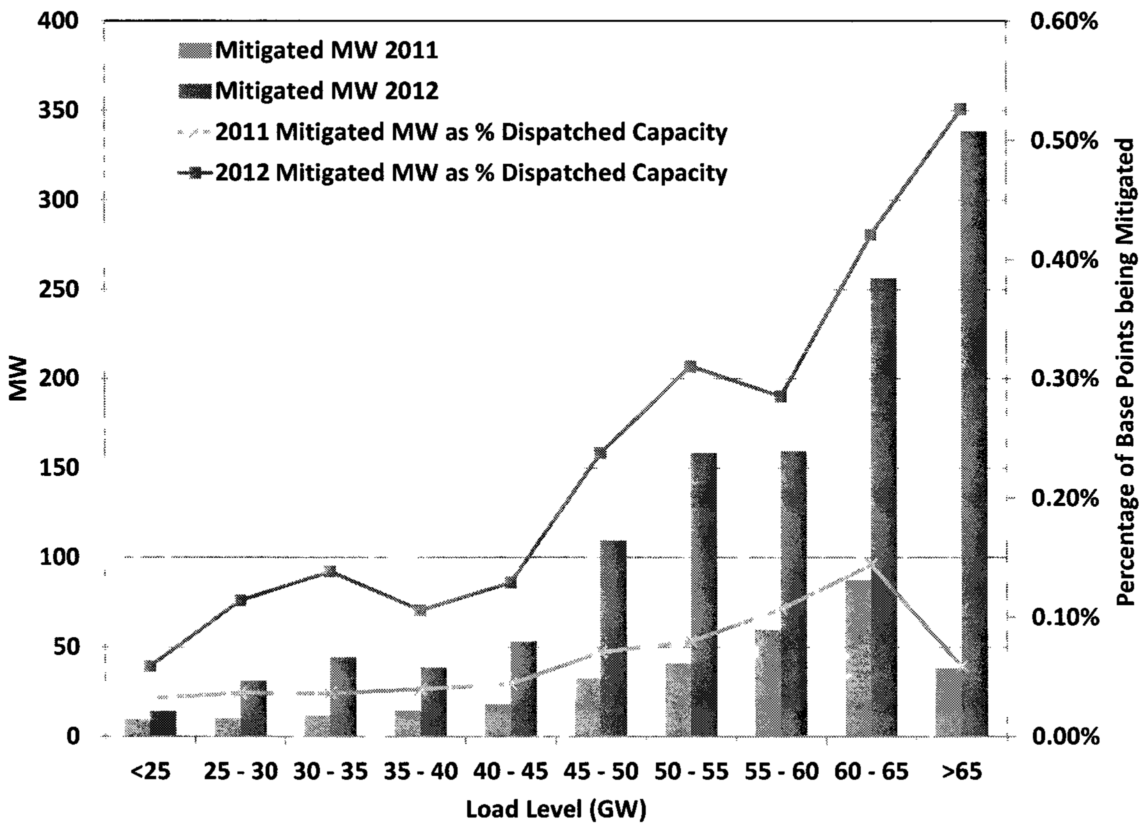
[9] The system-wide offer cap during August 2011 was set at $3,000 per MWh. It was increased to $4,500 per MWh effective August 1, 2012.

E. Mitigation

The dispatch software includes an automatic, two step price mitigation process. In the first step, the dispatch software calculates output levels (Base Points) and associated locational marginal prices 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. This approach is intended to limit the ability of a specific generator to raise prices in the event of a transmission constraint that requires their output to resolve. In this section we analyze the quantity of capacity affected by this mitigation process.

Our first analysis computes how much capacity, on average, is actually mitigated during each dispatch interval. The results, shown in Figure 17, are provided by load level.

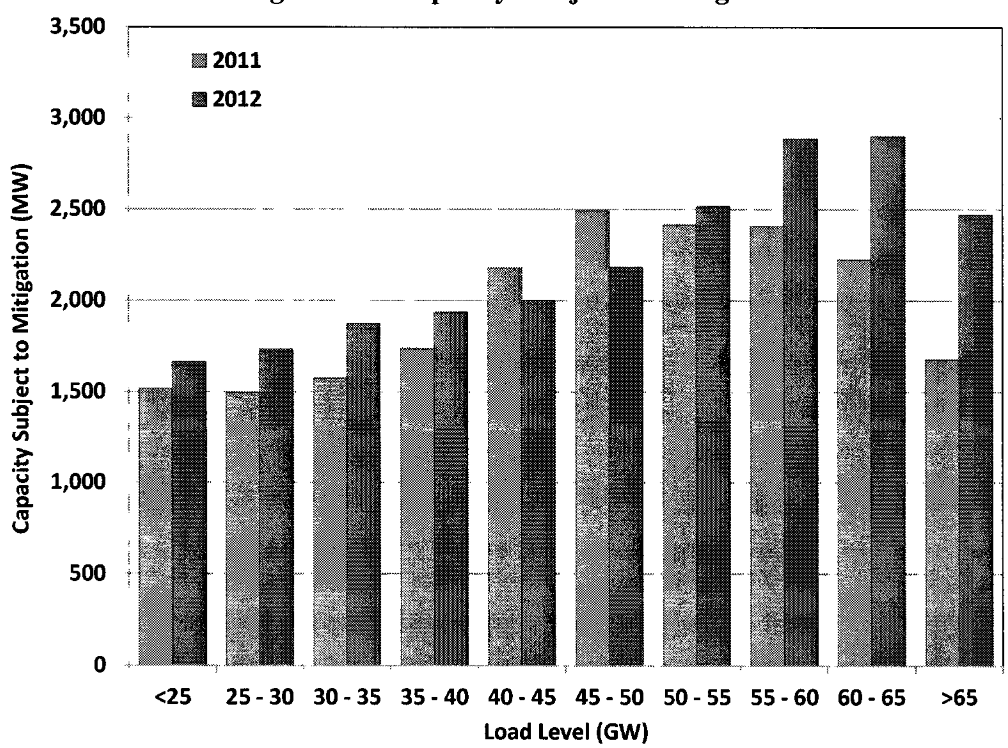
Figure 17: Mitigated Capacity by Load Level



The quantities of capacity actually mitigated in 2012 were much larger than during 2011, averaging 14 MW at low loads and increasing to 338 MW at loads above 65 GW. Although the quantities of mitigated capacity were greater in 2012, they were less than one-half of one percent of the total dispatched capacity at all but the very highest load levels. The decrease in mitigated capacity at high loads observed in 2011 due to the reluctance by ERCOT operators to activate certain transmission constraints during very high system load conditions is not present in 2012.

In the previous figure only the amount of capacity that can be dispatched within one interval is counted as mitigated. In our next analysis we compute the total capacity subject to mitigation. These values are determined by comparing a generator's mitigated and unmitigated (as submitted) offer curves and determining the point at which they diverge. We then take the difference between the total unit capacity and the capacity at the point the curves diverge. This calculation is performed for all units and aggregated by load level, as shown in Figure 18. From this figure we observe that at most 7 percent of capacity necessary to serve load is subject to mitigation. An important note about this capacity measure is that it includes all capacity above the point at which a unit's offers become mitigated, without regard for whether that capacity is actually required to serve load.

Figure 18: Capacity Subject to Mitigation



Although executing all the time, the automatic price mitigation aspect of the two step dispatch process only has an effect when a non-competitive transmission constraint is active. This can result in mitigating certain units inappropriately. The mitigation process is intended to limit the ability of a generator to affect price when their output is required to manage congestion. The process does not currently identify a situation where there are a competitively sufficient number of generators on the other side of the constraint and mitigates all their offers. This unnecessary mitigation will be addressed with the implementation of changes described in NPRR520. This change will introduce an impact test to determine whether units are relieving or contributing to a transmission constraint, and only subject the relieving units to mitigation.

II. Review of Day-Ahead Market Outcomes

ERCOT's centralized day-ahead market allows participants to make financially binding forward purchases and sales of power for delivery in real-time. Offers to sell can take the form of either a three-part supply offer, which allow sellers to reflect the unique financial and operational characteristics of a specific generation resource, or an energy only offer, which is location specific but is not associated with a generation resource. Bids to buy are also location specific. Ancillary services are also procured as part of the day-ahead market clearing. The third type of transaction included in the day-ahead market is bids to buy Point to Point ("PTP") Obligations, which allow parties to hedge the incremental cost of congestion between day-ahead and real-time operations.

With the exception of the acquisition of ancillary service capacity, the day-ahead market is a financial market. Although all bids and offers are evaluated in the context of their ability to reliably flow on the transmission network, there are no operational obligations resulting from the day-ahead market clearing. These transactions are made for a variety of reasons, including satisfying the participant's own supply, managing risk by hedging the participant's exposure to the real-time market, or arbitraging with the real-time markets. For example, load serving entities can insure against volatility in the real-time market by purchasing in the day-ahead market. Finally, the day-ahead market plays a critical role in coordinating generator commitments. For all of these reasons, the performance of the day-ahead market is essential.

In this section we review energy pricing outcomes from the day-ahead market and compare their convergence with real-time energy prices. We will also review the volume of activity in the day-ahead market, including a discussion of PTP Obligations. We conclude this section with a review of the ancillary service markets.

A. Day-Ahead Market Prices

One indicator of market performance is the extent to which forward and real-time spot prices converge over time. 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.

In this section, we evaluate the price convergence between the day-ahead and real-time markets. This analysis reveals whether persistent and predictable differences exist between day-ahead and real-time prices, which participants should arbitrage over the long-term. To measure the short-term deviations between real-time and day-ahead prices, we also calculate the average of the absolute value of the difference between the day-ahead and real-time price on a daily basis.

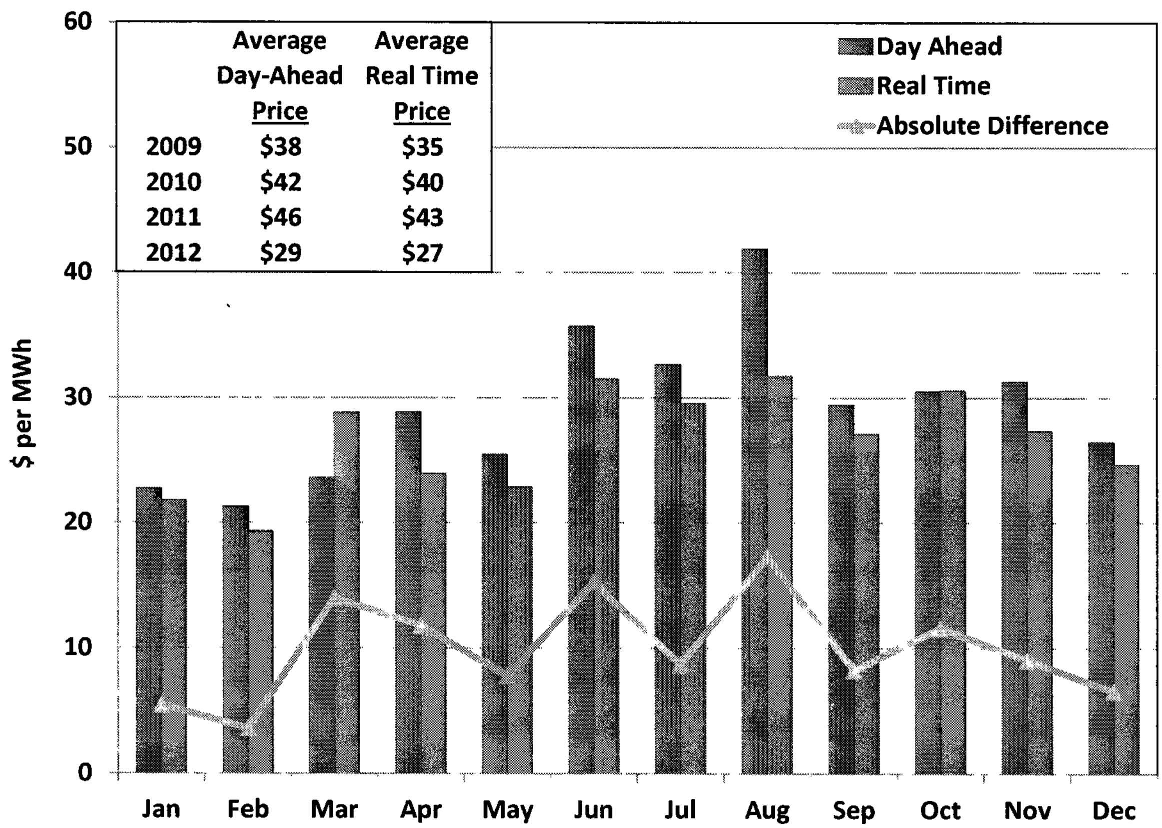
This measure captures the volatility of the daily price differences, which may be large even if the day-ahead and real-time energy prices are the same on average. For instance, if day-ahead prices are $70 per MWh on two consecutive days while real-time prices are $40 per MWh and $100 per MWh on the two days, the absolute price difference between the day-ahead 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.

Figure 19 shows the price convergence between the day-ahead and real-time market, summarized by month. Day-ahead prices averaged $29 per MWh in 2012 compared to an average of $27 per MWh for real-time prices.[10] The average absolute difference between day-ahead and real-time prices was $9.96 per MWh in 2012; much lower than in 2011 when average of the absolute difference was $24.50 per MWh. This reduction was due to fewer occurrences of shortage intervals and associated high prices in 2012. This day-ahead premium is consistent with expectations due to the much higher volatility of real-time prices. Risk is lower for loads purchasing in the day-ahead and higher for generators selling day-ahead. The higher risk for generators is associated with the potential of incurring a forced outage and as a result, having to buy back energy at real-time prices. This explains why the highest premiums tend to occur during the months with the highest demand and highest prices. Overall, the day-ahead premiums

[10] These values are simple averages, rather than load-weighted averages presented in Figure 1and Figure 2.

were very similar to the differences observed in 2010 and 2011, but remain higher than observed in other organized electricity markets.[11] Real-time energy prices in ERCOT are allowed to rise to levels that are much higher than what is allowed in other organized electricity markets, which increases risk and helps to explain the higher day ahead premiums regularly observed in ERCOT Although most months experienced a day-ahead premium (*e.g.,* $10 per MWh in August), it should not be expected over time that every month will always produce a day-ahead premium as the real-time risks that lead to the premiums will materialize unexpectedly on occasion, resulting in real-time prices that exceed day-ahead prices (*e.g.*, in March).

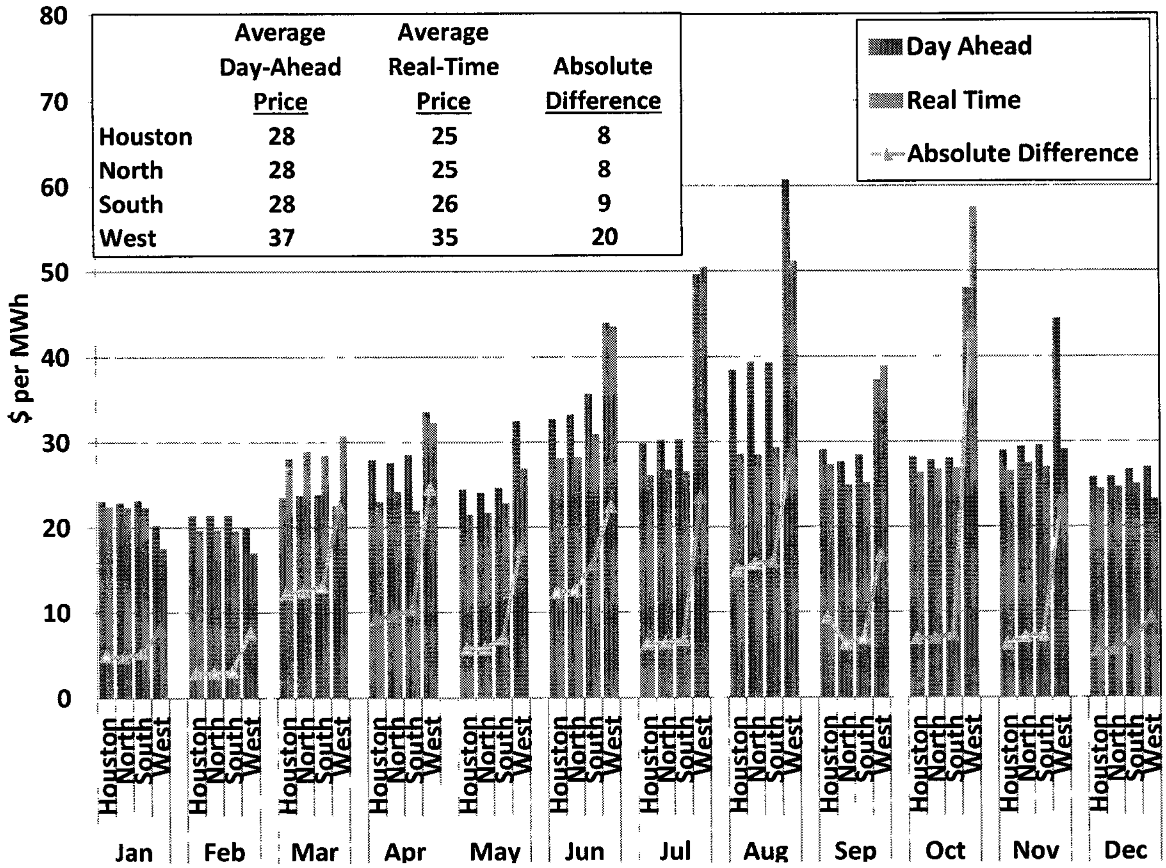
Figure 19: Convergence between Forward and Real-Time Energy Prices



[11] In 2009 and 2010 under the zonal market the comparison was made between on-peak forward prices and prices for the same on-peak period in the balancing energy market.

In Figure 20 below, monthly day-ahead and real-time prices are shown for each of the geographic load zones. Of note is the difference in the West zone data compared to the other regions. The higher volatility in West zone pricing is likely associated with the uncertainty of forecasting wind generation output and the resulting price differences between day-ahead and real-time.

Figure 20: Day-Ahead and Real-Time Prices by Zone



B. Day-Ahead Market Volumes

Our next analysis summarizes the volume of day-ahead market activity by month. In Figure 21 below, we find that day-ahead purchases are approximately 45 percent of real-time load. These energy purchases are met through a combination of generator specific and virtual offers.

As discussed in more detail in the next sub-section, Point to Point Obligations are financial instruments purchased in the day-ahead market. They do not provide any energy supply themselves, but they do provide the ability to avoid the congestion costs associated with transferring the delivery of energy from one location to another. To provide a volume comparison we aggregate all of these "transfers", netting location specific injections against withdrawals. By adding the aggregated transfer capacity associated with purchases of PTP Obligations, we find that on average, total volumes transacted in the day-ahead market are greater than real-time load.

Figure 21: Volume of Day-Ahead Market Activity by Month

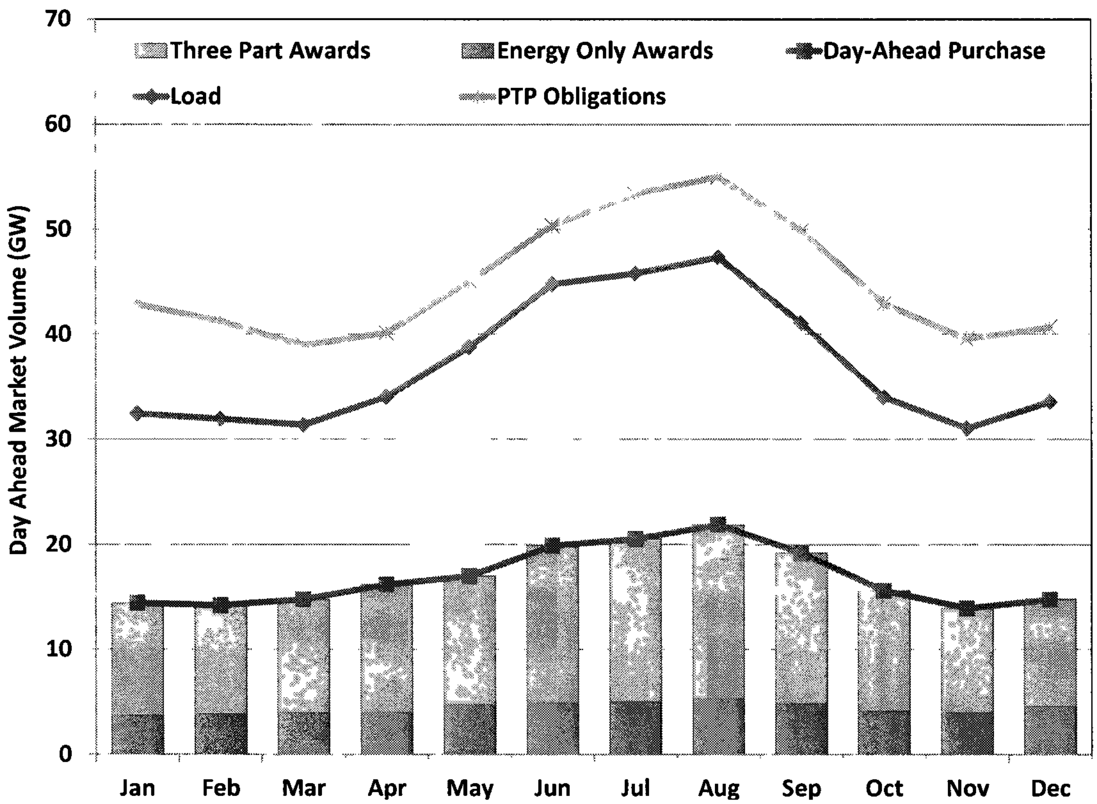
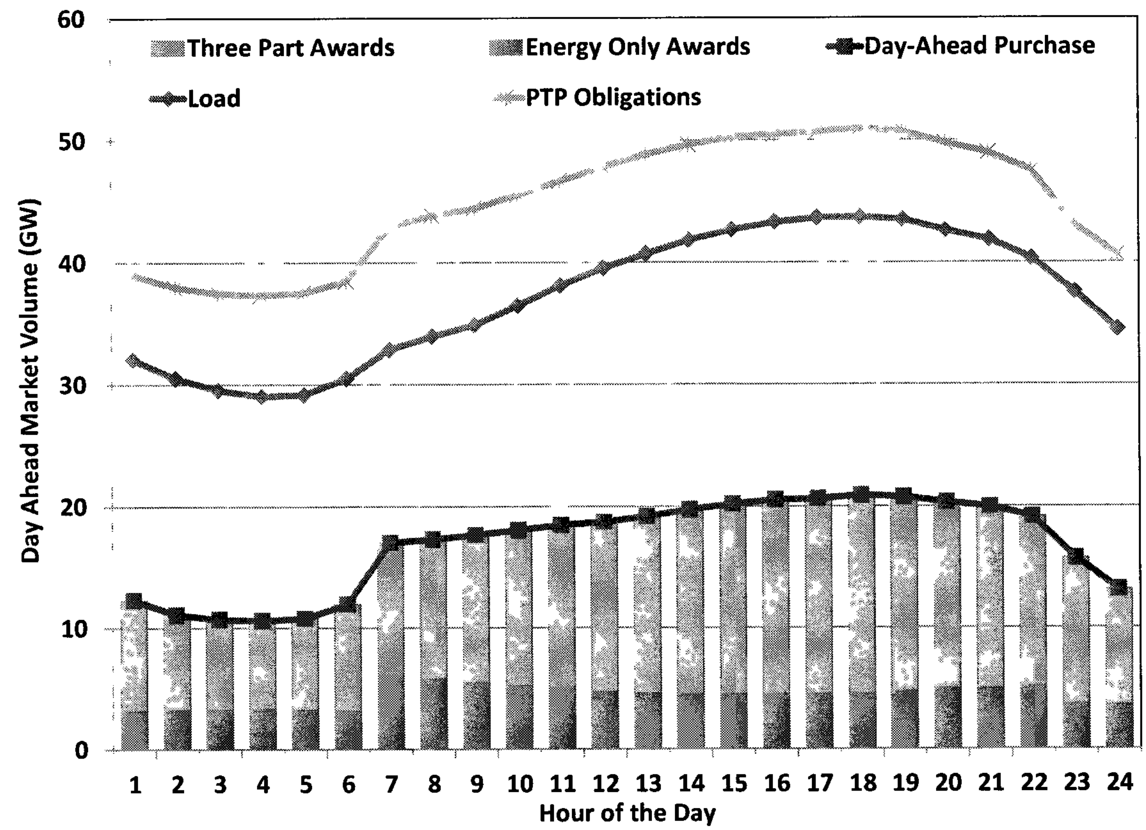


Figure 22 below, presents the same day-ahead market activity data summarized by hour of the day. In this figure the volume of day-ahead market transactions is disproportionate with load levels between the hours of 6 and 22. Since these times align with common bilateral transaction terms, it appears that market participants are using the day-ahead market to trade around those positions.

Figure 22: Volume of Day-Ahead Market Activity by Hour



C. Point to Point Obligations

Purchases of Point to Point ("PTP) Obligations comprise a significant portion of day-ahead market activity. These instruments are similar to, and can be used to complement Congestion Revenue Rights (CRRs). CRRs, as more fully described in Section III, are acquired via monthly and annual auctions and allocations. CRRs accrue value to their owner based on locational price differences as determined by the day-ahead market. PTP Obligations are instruments that are purchased as part of the day-ahead market and accrue value to their owner based on real-time locational price differences. By acquiring a PTP Obligation using the proceeds due to them from their CRR holding, a market participant may be described as rolling their hedge to real-time.

In this subsection we provide additional details about the volume and profitability of these PTP Obligations.

Figure 23: Point to Point Obligation Volume

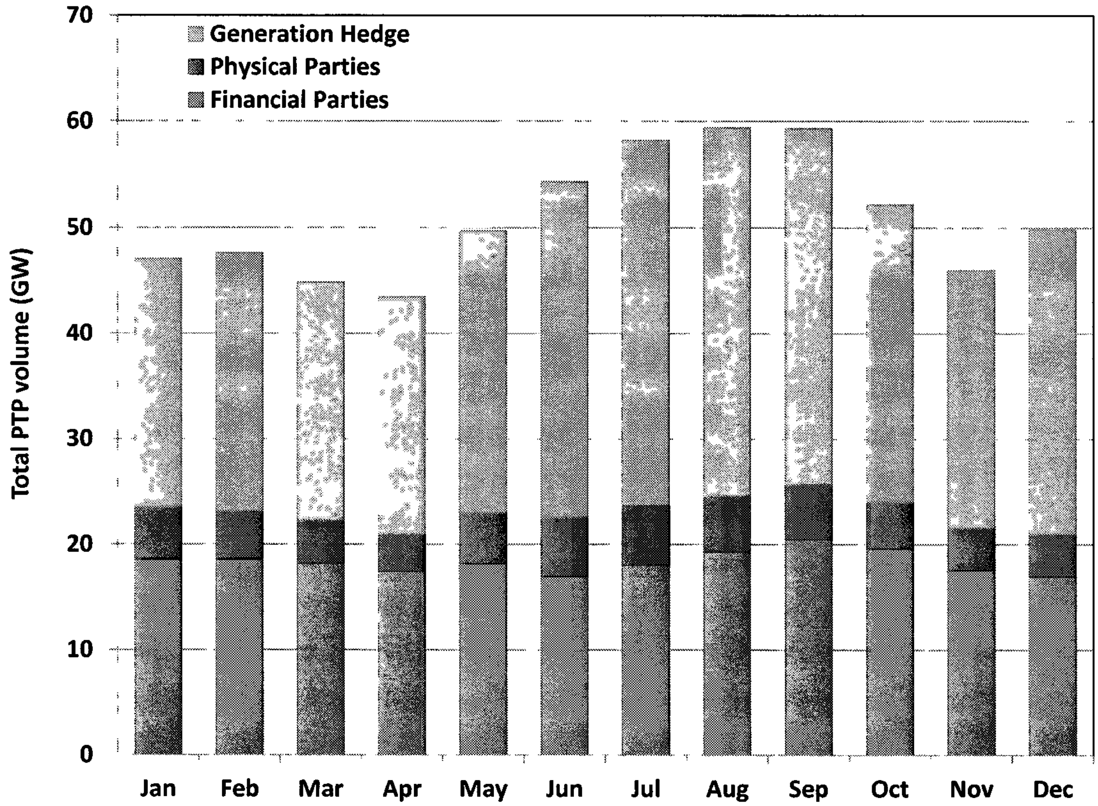
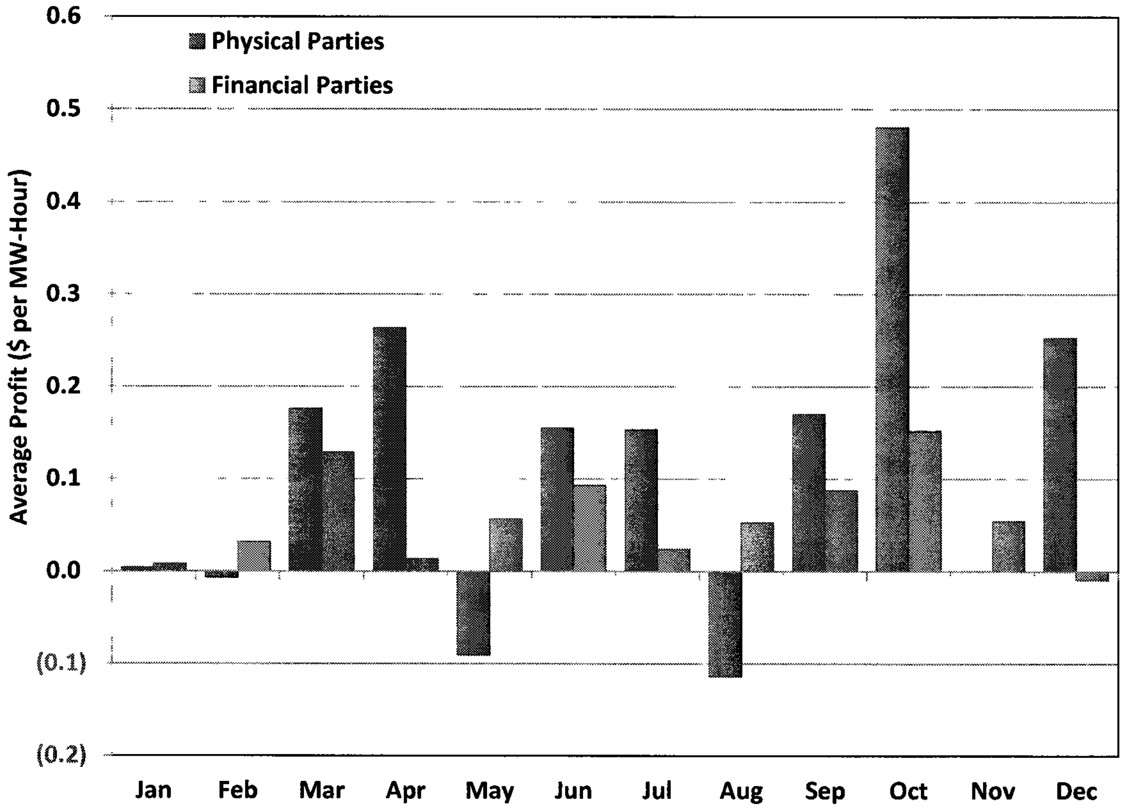


Figure 23 presents the total volume of PTP Obligation purchases divided into three categories. Compared to the previous two figures which showed net flows associated with PTP Obligations, in this figure we examine the total volume. For all PTP Obligations that source at a generator location, we attribute capacity up to the actual generator output as a generator hedge. From the figure above we see that this comprised most of the volume of PTP Obligations purchased. The remaining volumes of PTP Obligations are not directly linked to a physical position and are assumed to be purchased primarily to profit from anticipated price differences between two locations. We further separate this arbitrage activity by type of market participant. Physical parties are those that have actual real-time load or generation, whereas financial parties have neither.

To the extent the price difference between the source and sink of a PTP Obligation is greater in real-time than it was for the day-ahead price, the owner will have made a profit. Conversely, if the price difference does not materialize in real-time, the PTP Obligation may be unprofitable.

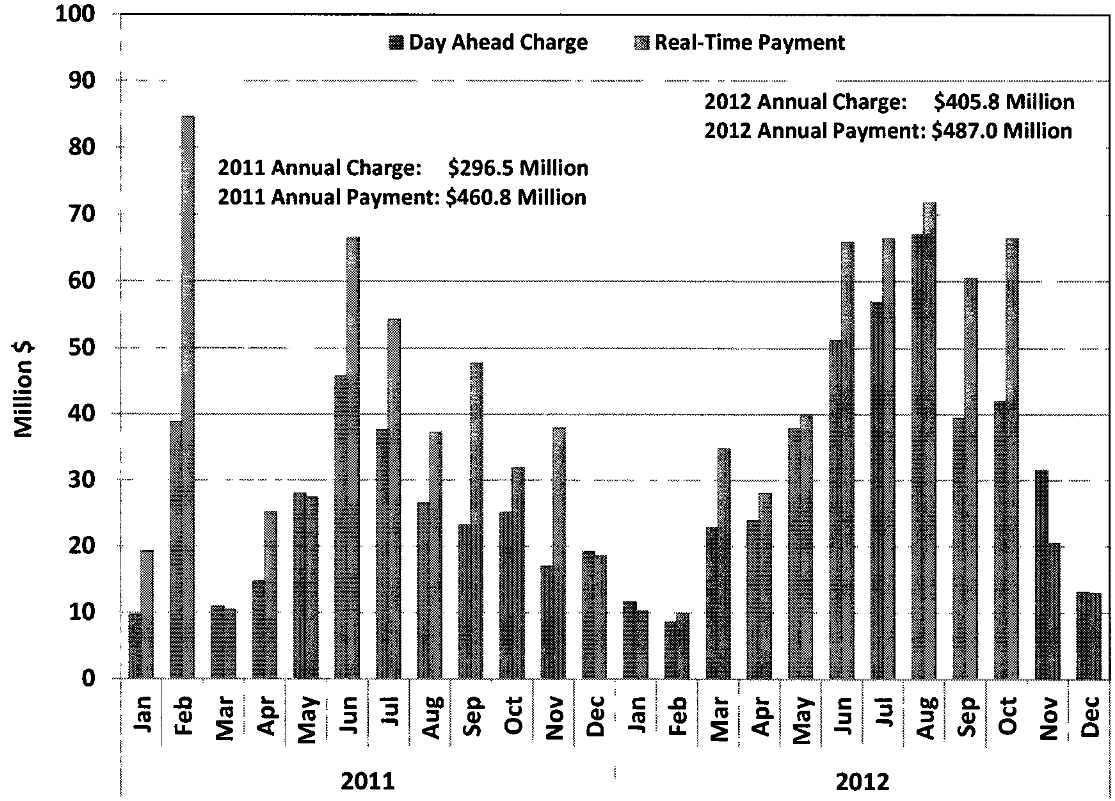
We compare the profitability of PTP Obligation holdings by the two types of participants in Figure 24.

Figure 24: Average Profitability of Point to Point Obligations



From the figure above we can infer different motivations between the two types of participants. Because financial participants have no real-time load or generation they have no other exposure to real-time prices. If a financial participant is not making a profit on their PTP Obligations there is no reason for them to buy any. In fact, their profit seeking action of buying PTP Obligations between points where congestion is expected helps make the day-ahead market converge with real-time market outcomes. On the other hand, physical participants do have exposure to real-time prices. It is reasonable to expect that this type of participant is most interested in limiting that exposure by using PTP Obligations as a hedge.

Figure 25: Point to Point Obligation Charges and Payments

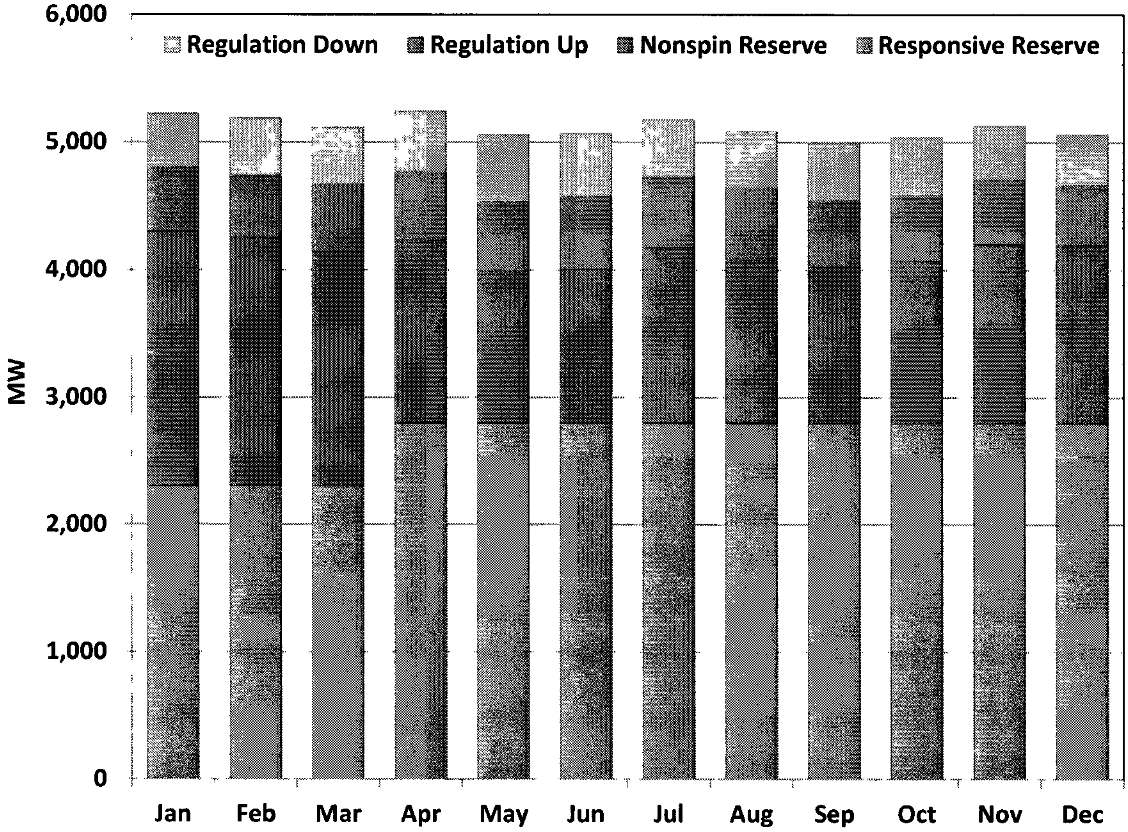


To conclude our analysis of PTP Obligations, in Figure 25 we compare the total amount paid for these instruments day-ahead, with the total amount received by their holders in real-time. In most months owners received, in aggregate, more in payments for their PTP Obligations than they paid to acquire them. This occurs when real-time congestion is greater than what occurred in the day-ahead. The payments made to PTP Obligation owners come from real-time congestion rent. We assess the sufficiency of real-time congestion rent to cover both PTP Obligations and payments to owners of CRRs who elect to receive payment based on real-time prices in Section III, Transmission and Congestion at page 52.

D. Ancillary Services Market

The primary ancillary services are up regulation, down regulation, responsive reserves, and non-spinning reserves. Market participants may self-schedule ancillary services or purchase their required ancillary services through the ERCOT markets. This section reviews the results of the ancillary services markets in 2012. We start with a display of the quantities of each ancillary service procured each month shown in Figure 26.

Figure 26: Ancillary Service Capacity

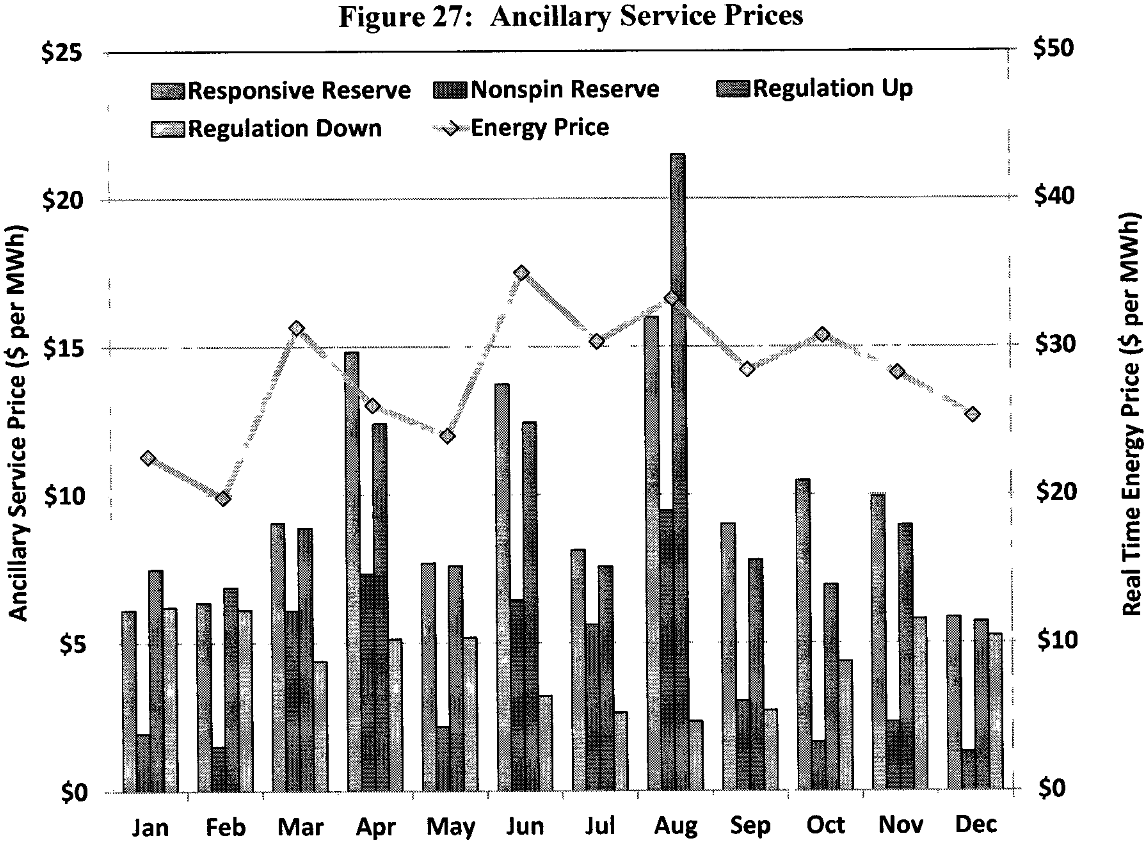


In general, the purpose of responsive and non-spinning reserves is to protect the system against unforeseen contingencies (*e.g.*, unplanned generator outages, load forecast error, wind forecast error), rather than for meeting normal load fluctuations. ERCOT procures responsive reserves to ensure that the system frequency can quickly be restored to appropriate levels after a sudden, unplanned outage of generation capacity. Non-spinning reserves are provided from slower responding generation capacity, and can be deployed alone, or to restore responsive reserve capacity. Regulation reserves are capacity that responds every four seconds, either increasing or decreasing as necessary to fill the gap between energy deployments and actual system load.

One notable change made to ancillary service procurements during 2012 was the increased amount of responsive reserve procured beginning in April. This 500 MW increase was balanced with the same amount of decrease in the amount of non-spinning reserves procured. Although the minimum level of required responsive reserve remains at 2,300 MW, having the additional 500 MW of responsive reserve provides a higher quality – that is, faster responding capacity available to react to sudden changes in system conditions. As the amount of wind generation in ERCOT continue to increase, this additional responsive reserve should contribute to improved system reliability.

Under the nodal market, ancillary service offers are co-optimized as part of the day-ahead market clearing. This means that market participants no longer have to include their expectations of forgone energy sales in their ancillary services capacity offers. However, because clearing prices for ancillary services capacity will explicitly account for the value of energy, there is a much higher correlation between ancillary services prices and real-time energy prices.

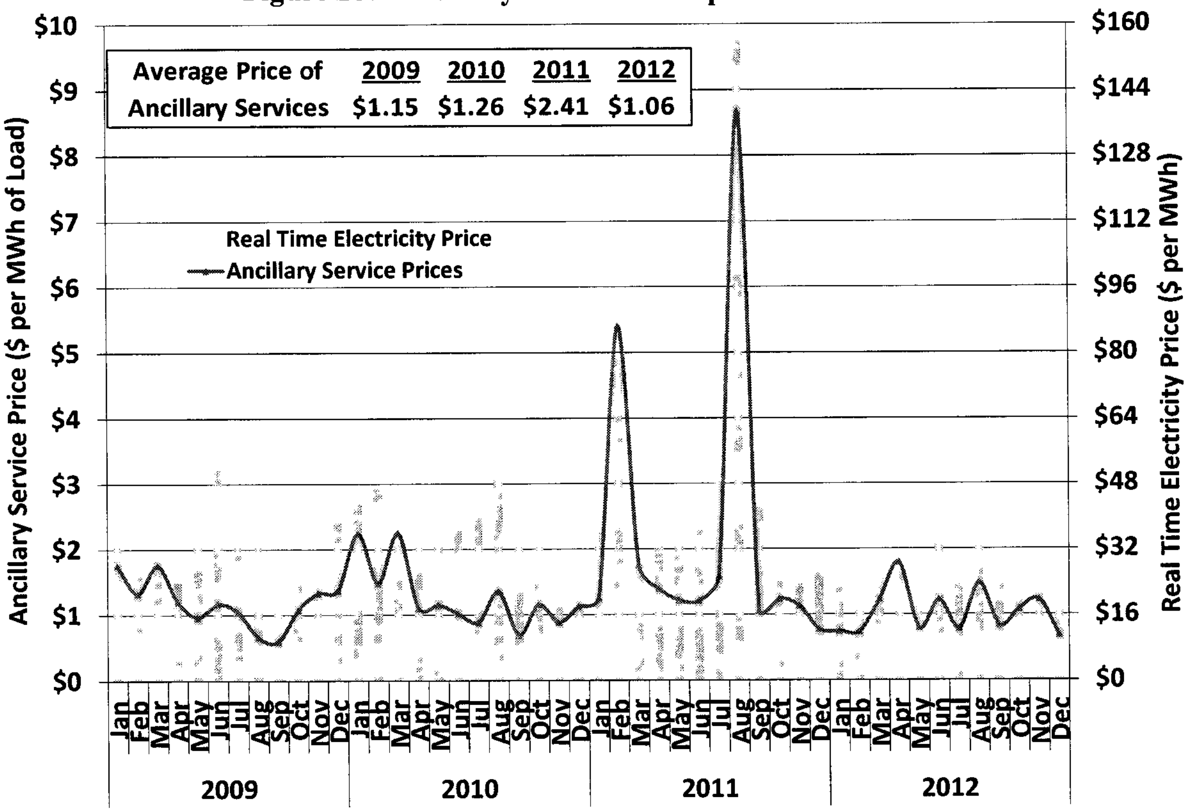
Figure 27: Ancillary Service Prices



With average energy prices varying only between $20 and $35 per MWh, we observe the prices of ancillary services remaining fairly stable throughout the year. However, the average price of responsive reserve was higher in April than in March, even though average energy price declined for the same period. We attribute this pricing outcome to the increased responsive reserve requirement being implemented in April.

In contrast to the previous data that showed the individual ancillary service capacity prices, Figure 28 shows the monthly total ancillary service costs per MWh of ERCOT load and the average real-time energy price for 2009 through 2012. This figure shows that total ancillary service costs are generally correlated with real-time energy price movements, which, as previously discussed, are highly correlated with natural gas price movements.

Figure 28: Ancillary Service Costs per MWh of Load

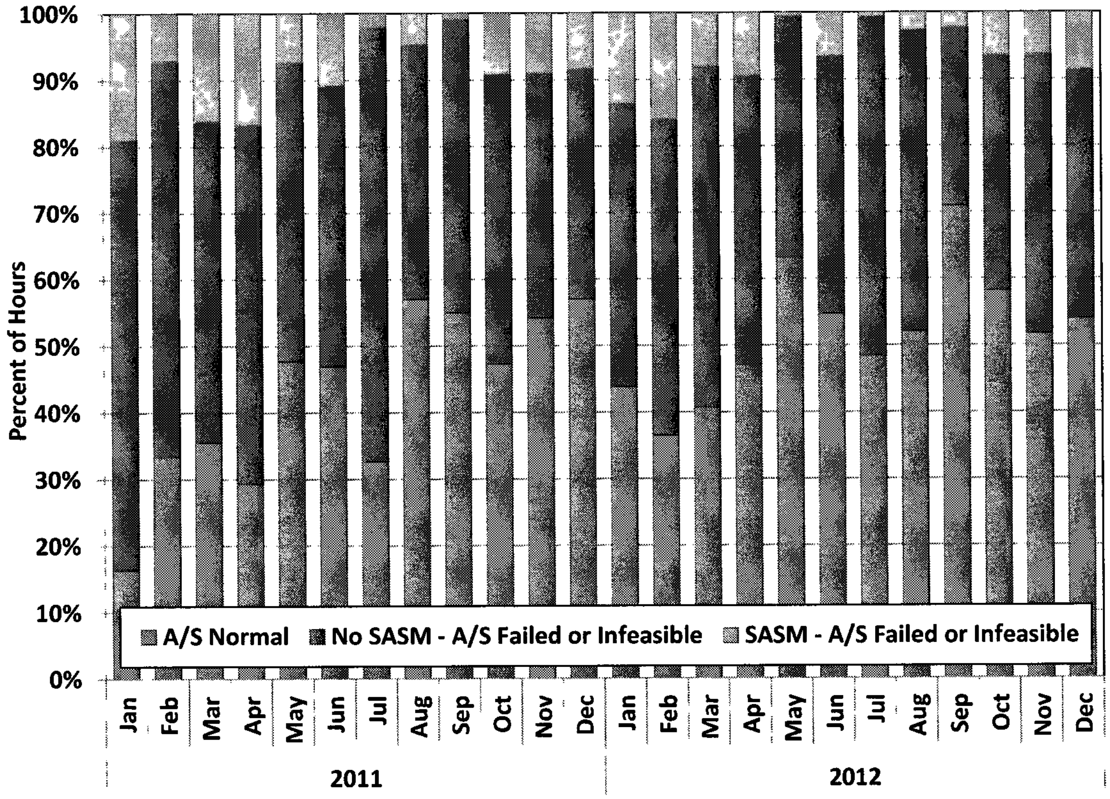


The average ancillary service cost per MWh of load decreased to $1.06 per MWh in 2012 compared to $2.41 per MWh in 2011, a decrease of 56 percent. Total ancillary service costs decreased from 4.5 percent of the load-weighted average energy price in 2011 to 3.7 percent in 2012.

Ancillary Service capacity is procured as part of the day-ahead market clearing. Between the time it is procured and the time that it is required to be provided events can occur which make this capacity unavailable to the system. Transmission constraints can arise which make the capacity undeliverable. Outages or limitations at a generating unit can lead to failures to provide. When either of these situations occurs, ERCOT may open a supplemental ancillary services market ("SASM") to procure replacement capacity.[12]

Figure 29 presents a summary of the frequency with which ancillary service capacity was not able to be provided and the number of times that a SASM was opened.

Figure 29: Frequency of SASM Clearing



The percent of time that capacity procured in the day-ahead was actually able to provide the service in the hour it was procured for continued to increase in 2012. This percentage was 52 percent in 2012 compared to 43 percent in 2011. Even though in more than 40 percent of the hours there were deficiencies in ancillary service deliveries, SASMs were opened to procure replacement capacity only 7 percent of the time, down from 9 percent of the hours in 2011.

[12] ERCOT may also open a SASM if they change their ancillary service plan. This did not occur during 2012.

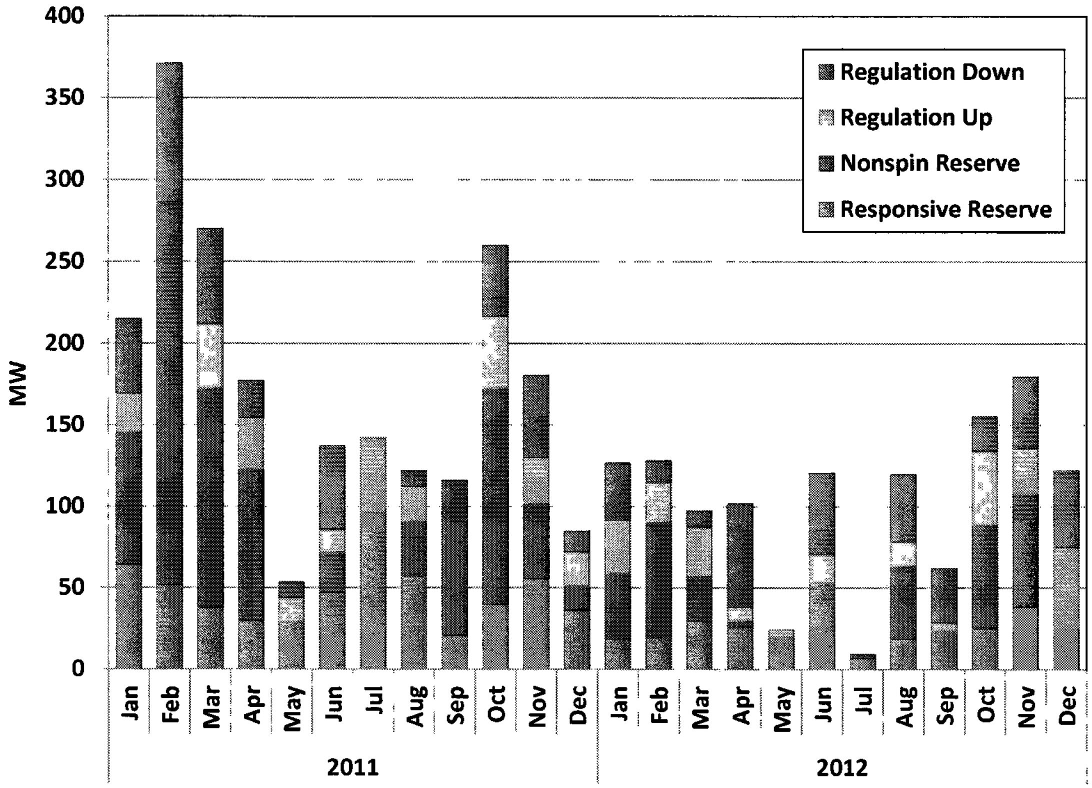
In Table 2 below, we provide an annual summary of the frequency and quantity of ancillary service deficiency, which is defined as either failure-to-provide or as undeliverable.

Table 2: Ancillary Service Deficiency

2012 *Service*	*Hours Deficient*	*Mean Deficiency (MW)*	*Median Deficiency (MW)*
Responsive Reserve	3756	34	15
Non-Spin Reserve	664	36	8
Up Regulation	750	41	25
Down Regulation	522	48	39
2011			
Responsive Reserve	4053	39	20
Non-Spin Reserve	1254	90	39
Up Regulation	1222	27	20
Down Regulation	1235	22	11

The number of hours with deficiency decreased for all types of ancillary services when compared to 2011. Responsive Reserve service was deficient most frequently. Well over 90 percent of the deficiency occurrences were caused by failure to provide by the resource rather than undeliverability related to a transmission constraint. We also note that the average magnitude of non-spin reserve deficiency reduced from 90 MW in 2011 to 36 MW in 2012. On the other hand, the amount of deficiency in regulation services (up and down) increased slightly in 2012 when compared to 2011.

Figure 30: Ancillary Service Quantities Procured in SASM



Our final analysis in this section, shown in Figure 30, summarizes the average quantity of each service that was procured via SASM. Along with reduced occurrences of ancillary service deficiency, the quantity of services procured via SASM also declined in 2012. The average quantities of responsive and non-spin reserves procured via SASM in 2012 were roughly half what they were the previous year.

III. TRANSMISSION AND CONGESTION

One of the most important functions of any electricity market is to manage the flows of power over the transmission network by limiting additional power flows over transmission facilities when they reach their operating limits. The action taken to ensure operating limits are not violated is called congestion management. The effect of congestion management is to change generator(s) output level so as to reduce the amount of electricity flowing on the transmission line nearing its operating limit. Because the transmission system is operated such that it can withstand the unexpected outage of any element at any time, congestion management actions most often occur when a transmission element is expected to be overloaded if a particular unexpected outage (contingency) were to occur. Congestion leads to higher costs due to lower cost generation being reduced and higher priced generation increased. Different prices at different nodes are the result. The decision about which generator(s) will vary their output is based on generating unit specific offer curves and the relative shift factors to the contingency and constraint pair. This leads to a dispatch of the most efficient resources available to reliably serve demand.

After summarizing congestion activity in 2012, this section of the report provides a review of the costs and frequency of transmission congestion in both the day-ahead and real-time markets. We will then provide a review the activity in the congestion rights market.

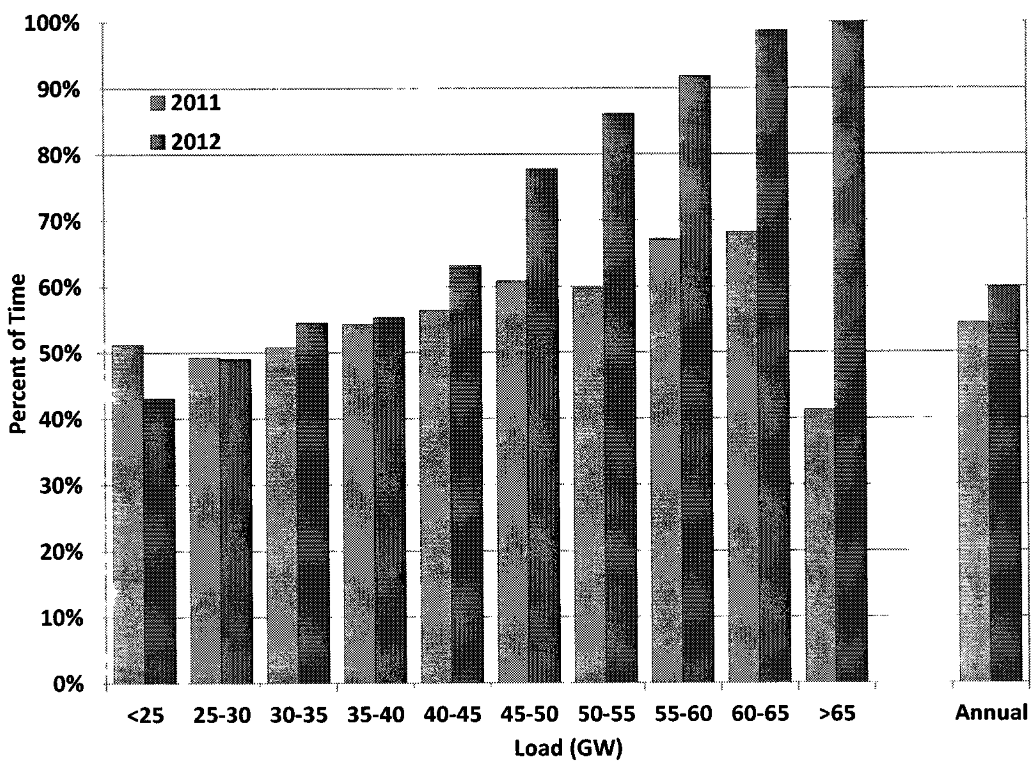
A. Summary of Congestion

There was a marked change in the nature of real-time transmission congestion during 2012 when compared to previous years. For the past several years a significant portion of real-time transmission congestion could be described as limiting the export of wind generation ***from*** the West zone to the load centers across the rest of ERCOT. Transmission congestion in 2012 was more significantly the result of limitations on the ability to get generation ***to*** loads in the West zone. Some portion of the limitation can be attributed to transmission outages taken to enable the construction of new CREZ transmission lines. Another factor is that loads in far west Texas have experienced much greater growth than the system-wide average.

The total congestion revenue generated by the ERCOT real-time market in 2012 was $480 million, a decrease of 9 percent from 2011. This decrease was not as large as might be expected given the much larger decreases in average natural gas prices real-time energy prices. Two factors influencing the overall costs of congestion in 2012 were the significant financial impact of several localized transmission constraints in far west Texas and the higher frequency of active transmission constraints.

Figure 31 provides a comparison of the amount of time transmission constraints were active at various load levels in 2012 and 2011. Active transmission constraints are those for which generators are being dispatched to a less efficient output level in order to maintain transmission flows at reliable levels.

Figure 31: Frequency of Active Constraints



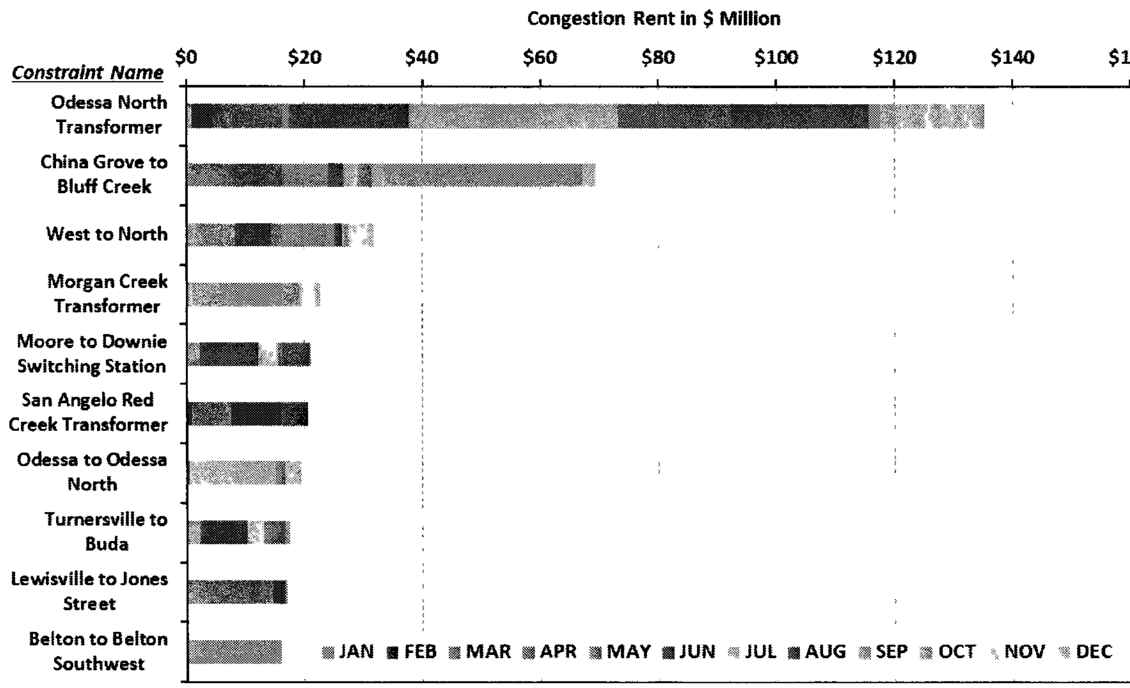
We observe that in 2012 the likelihood of having an active transmission constraint was higher than it was in 2011 and that for loads above 45 GW the frequency was much higher. During 2011, we observed that at higher system loads ERCOT operators did not always activate (or sometimes de-activated) transmission constraints. This was due to a concern that by having a constraint active during periods of high demand the total capacity available to serve load may be limited. However, ERCOT's dispatch software contains parameters that allow it to automatically make the correct decision about when to violate transmission constraints when necessary to serve total system load. Therefore, ERCOT modified their practice in 2012 to retain active transmission constraints even during periods of high demand.

B. Real-Time Constraints

We begin our review by examining the real-time transmission constraints with the highest financial impact as measured by congestion rent. There were more than 350 different constraints active at some point during 2012, a slight increase from 2011. The median financial impact, as measured by congestion rent, was approximately $200,000 during 2012. This is a significant decrease from 2011, when the median impact was approximately $300,000. Given the significant reduction in average energy costs from 2011 to 2012, reduced financial impact of congestion is expected.

Figure 32 below displays the ten most highly valued real-time constraints as measured by congestion rent and indicates that the Odessa North 138/69 kV transformer constraint was by far

Figure 32: Top Ten Real-Time Constraints



the most highly valued during 2012. This constraint became more pronounced from 2011 to 2012 and is mainly attributed to load growth in far west Texas driven by increased oil and natural gas activity.

The Odessa North 138/69 kV transformer typically overloads under low wind conditions. The characteristics that load the Odessa North 138/69 kV transformer are the same conditions that also affect the Odessa to Odessa North 138 kV line, which is shown as the seventh constraint on the list. Not only did this constraint have nearly twice the financial impact of the second constraint on the list, its impact was more than 40 percent greater than the top constraint from 2011. Its magnitude is even more significant given the overall lower costs of energy in 2012. Not surprisingly, much public attention was focused on this constraint; much of it questioning its causes and the potential for short-term remedies. ERCOT and the local transmission provider were able to identify two transmission lines, which when opened greatly reduced congestion around the Odessa North station without causing other reliability concerns. After the lines were opened in mid-September, congestion around Odessa North was almost eliminated for the rest of the year.

The second constraint on the list is the overload of the 138 kV transmission line between China Grove and Bluff Creek. Also located in west Texas, west of Abilene, this constraint was new to the top ten list in 2012. Most of the time this line was constrained in the China Grove to Bluff Creek direction, typically under low wind conditions but also when there were other lines out of service. Depending on the level of wind and outages, the direction of the constraint would be reversed. That is, under high wind conditions flow on the line would be limited in the Bluff Creek to China Grove direction (from the west).

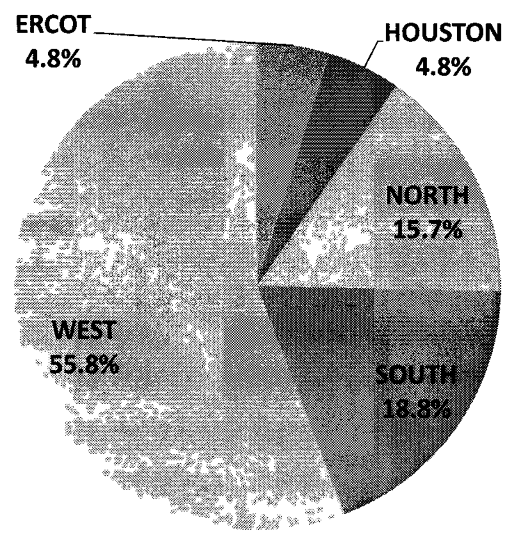
The West to North constraint continued to be active at some point during every month of 2012 but with far less impact than in 2011. Through the years this constraint has been a major impediment to delivering all the wind generation located and produced in the western reaches of ERCOT to the load centers. This constraint had the highest financial impact of all real-time transmission constraints during 2011, but in 2012 its impact dropped to one third that level. The reduction was a result of the combined impact of higher loads in the West and increased transfer capability due to the first CREZ transmission lines being placed in service. We will review the utilization of this constraint in more detail later in this section.

In all, eight of the top ten real-time constraints during 2012 were due to load and wind conditions within the West. In addition to the four constraints previously discussed, the Morgan Creek and San Angelo Red Creek transformer constraints were typically active under high load and low wind conditions. Unlike the previous constraints the Moore to Downie 138 kV line and the Turnersville to Buda 138 kV line are not located in the West, but became constrained during low wind and high load conditions in the West that occurred while other, larger capacity transmission lines were out of service.

The remaining two constraints on the list were of fairly short duration; their high impact reflecting limitations on the ability to import power to a major load center. The Lewisville to Jones Street 138 kV constraint was related to serving load in the DFW area. Belton to Belton Southwest was due to outage conditions that limited the flow to Central Texas.

To further highlight the significance of West zone congestion, Figure 33 depicts that more than half of the costs of real-time congestion that occurred in 2012 were associated with facilities located in the West zone. Further, the cost of congestion on facilities that spanned zonal boundaries, labeled ERCOT in the figure, primarily comprised costs associated with West to North congestion.

Figure 33: Real-Time Congestion Costs



Irresolvable Constraints

When a constraint becomes irresolvable, ERCOT's dispatch software can find no combination of generators to dispatch in a manner such that the flows on the transmission line(s) of concern are below where needed to operate reliably. In these situations, offers from generators are not setting locational prices. Prices are set based on predefined rules, which since there are no supply options for clearing, should reflect the value of reduced reliability for demand. To address the situation more generally, a regional peaker net margin mechanism was introduced such that once local price increases accumulate to a predefined threshold due to an irresolvable constraint; the shadow price of that constraint would drop.

As shown below in Table 3, thirteen contingency and constraint pairs were deemed irresolvable in 2012 and as such, had a maximum shadow price cap imposed according to the Irresolvable Constraint Methodology. Three of the top ten real-time constraints, Odessa North 138/69 kV transformer, China Grove to Bluff Creek 138 kV line, and Morgan Creek #1 345/138 kV Autotransformer were designated as irresolvable in 2012. One of these constraints, the Odessa North 138/69 kV transformer, reached the second level trigger in the procedure and had its maximum shadow price lowered to $2,000 per MW in August 2012.

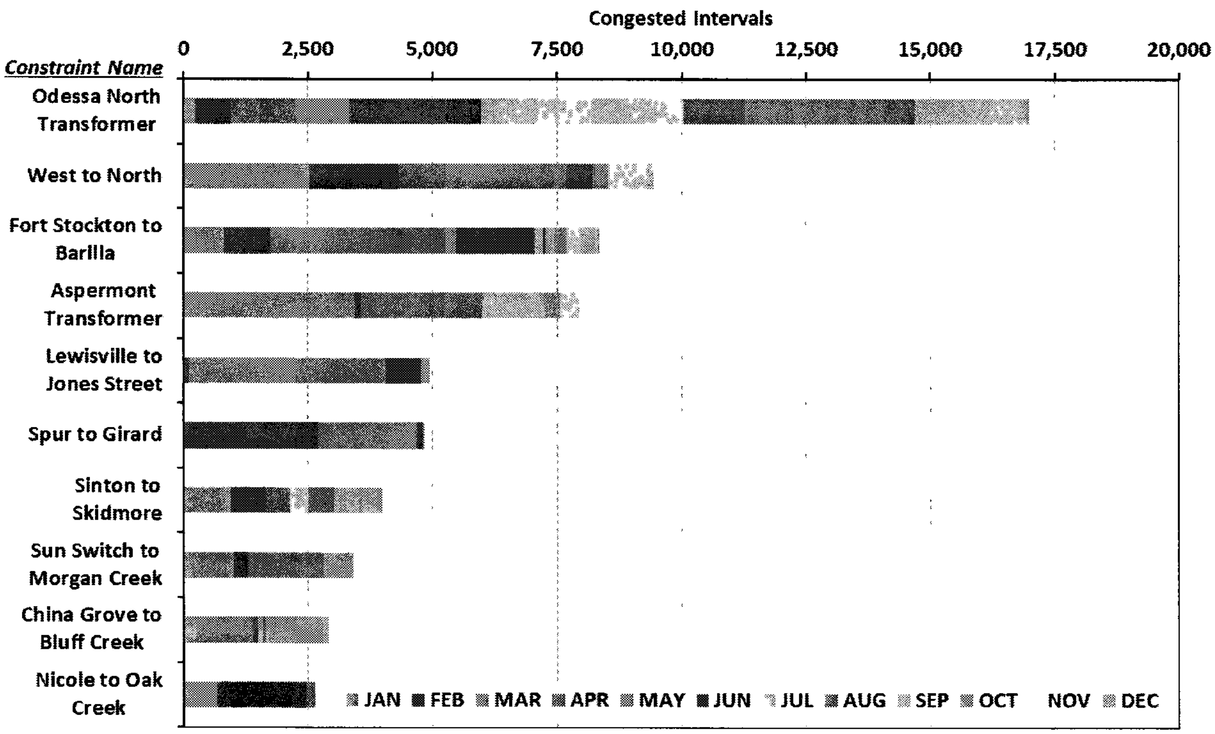
Table 3: Irresolvable Constraints

Loss of:	Overloads:	Maximum Shadow Price	Effective Date
Base case	Valley Import	$2,000.00	Jan 1, 2012
Graham to Long Creek 345 kV line	Bomarton to Seymour 69 kV line	$2,000.00	Jan 1, 2012
Odessa to Morgan Creek / Quail 345 kV lines	Ackerly Vealmoor to Ackerly 69 kV line	$2,000.00	Jan 1, 2012
Denton to Argyle / West Denton 138 kV lines	Jim Crystal to West Denton 69 kV line	$2,000.00	Jan 1, 2012
Cabaniss to Westside 138 kV line	Naval to North Padre 69 kV line	$2,000.00	Jan 1, 2012
Key to Willow Valley 138 kV line	Ackerly Vealmoor to Ackerly 69 kV line	$2,554.65	Jan 1, 2012
Key to Willow Valley 138 kV line	Ackerly to Lyntegar 69 kV line	$2,800.00	Jan 1, 2012
Odessa North to Holt 69 kV line	Odessa Basin to Odessa North 69 kV line	$2,800.00	Jan 1, 2012
Holt to Moss 138 kV line	Odessa North 138/69 kV transformer	$2,274.65 $2000.00	Jan 1, 2012 Aug 6, 2012
Odessa Basin to Odessa North 69 kV line	Holt to Ector Shell Tap 69 kV line	$2,000.00	Jan 1, 2012
Odessa to Morgan Creek / Quail 345 kV lines	China Grove to Bluff Creek 138 kV line	$2,000.00	May 3, 2012
Sun Switch to Morgan Creek 138 kV line	China Grove to Bluff Creek 138 kV line	$2,000.00	Oct 11, 2012
Morgan Creek #4 345 kV/138 kV Autotransformer	Morgan Creek #1 345 kV/138 kV Autotransformer	$2,000.00	Nov 2, 2012

Figure 34 presents a slightly different set of real-time constraints. These are the most frequently occurring. Other than the Lewisville to Jones Street constraint described previously, all constraints in this ranking are related to wind generation. With the exception of the Odessa North 138/69 kV transformer, which typically overloads under low wind and high local load conditions, the other frequently occurring constraints are all related to high West zone wind. Not only was the Odessa North 138/69 kV transformer constraint the most costly real-time constraint, it tops the list as the most frequently occurring constraint in 2012. It was binding more than 15 percent of the time in 2012.

As the second most frequently occurring real-time constraint, West to North was binding less than 10 percent of the time in 2012. During 2011 this constraint was the most frequently occurring real-time constraint; active more than 20 percent of the time.

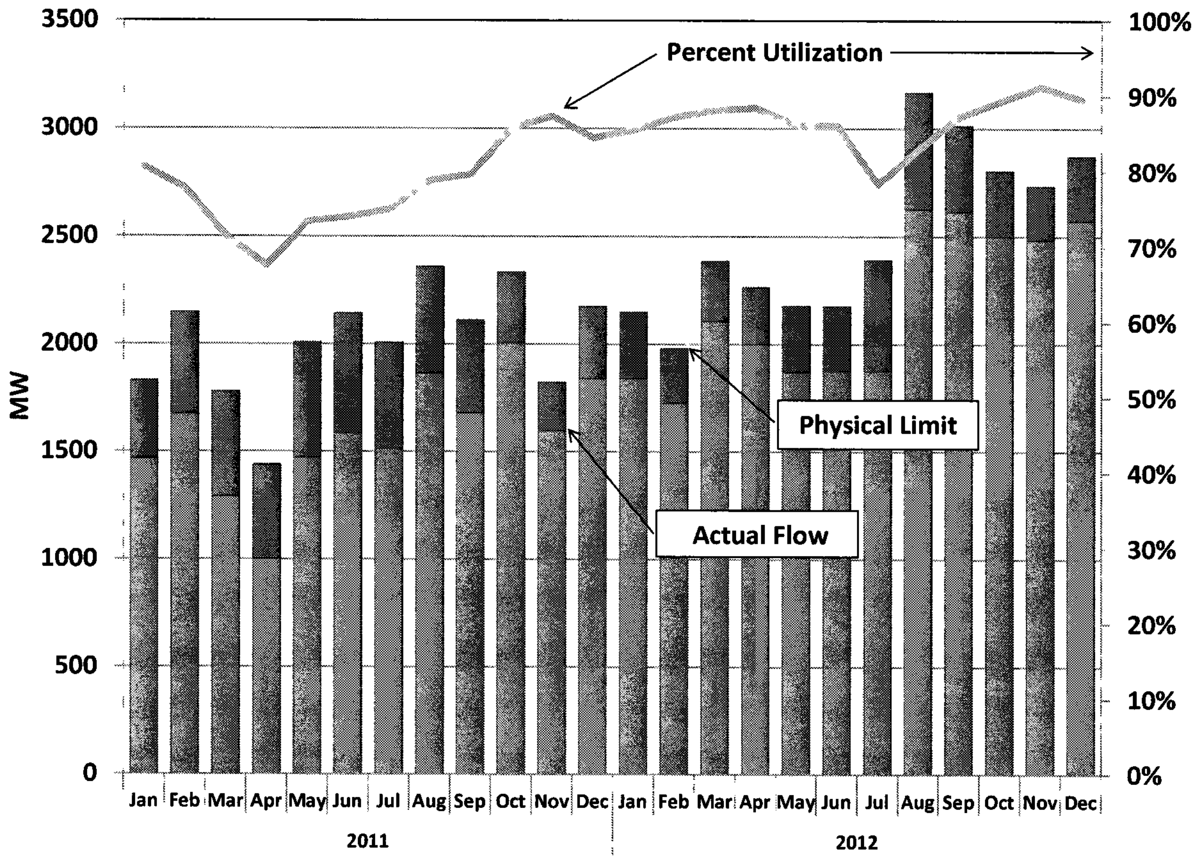
Figure 34: Most Frequent Real-Time Constraints



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. Figure 35 presents a summary of the utilization of the West to

North interface transmission constraint during 2011 and 2012. By comparing the actual flow with the physical limit of the constraint for each dispatch interval it was binding, we can compute its average utilization.

Figure 35: Utilization of the West to North Interface Constraint



Through July 2012, the average physical limit was approximately 2,200 MW and the average actual flow during constrained intervals was approximately 1,900 MW. After July 2012, the physical limit increased to an average of 2,900 MW and the actual flow increased to approximately 2,500 MW. In March 2012, a new real-time analysis tool was implemented to better track the dynamic nature of the transient stability limit of the West to North interface. However, there was not a noticeable increase to the transfer limit corresponding to its implementation due to the effects of transmission outages occurring to accommodate maintenance activities and the installation of CREZ lines. Many of these outages were complete by July 2012 which accounts for the increase in the West to North limit. The average annual utilization of the West to North constraint was 87 percent in 2012, which compares favorably to

78 percent utilization experienced in 2011. Over the long term, the physical limit will continue to increase as CREZ transmission projects are completed.

C. Day-Ahead Constraints

In this section we review transmission constraints from the day-ahead market. To the extent the model of the transmission system used for the day-ahead market matches the real-time transmission system, and assuming market participants transact in the DAM similarly to how they transact in real-time, we would expect to see the same transmission constraints appear in the day-ahead market as actually occurred during real-time.

Figure 36: Top Ten Day-Ahead Constraints

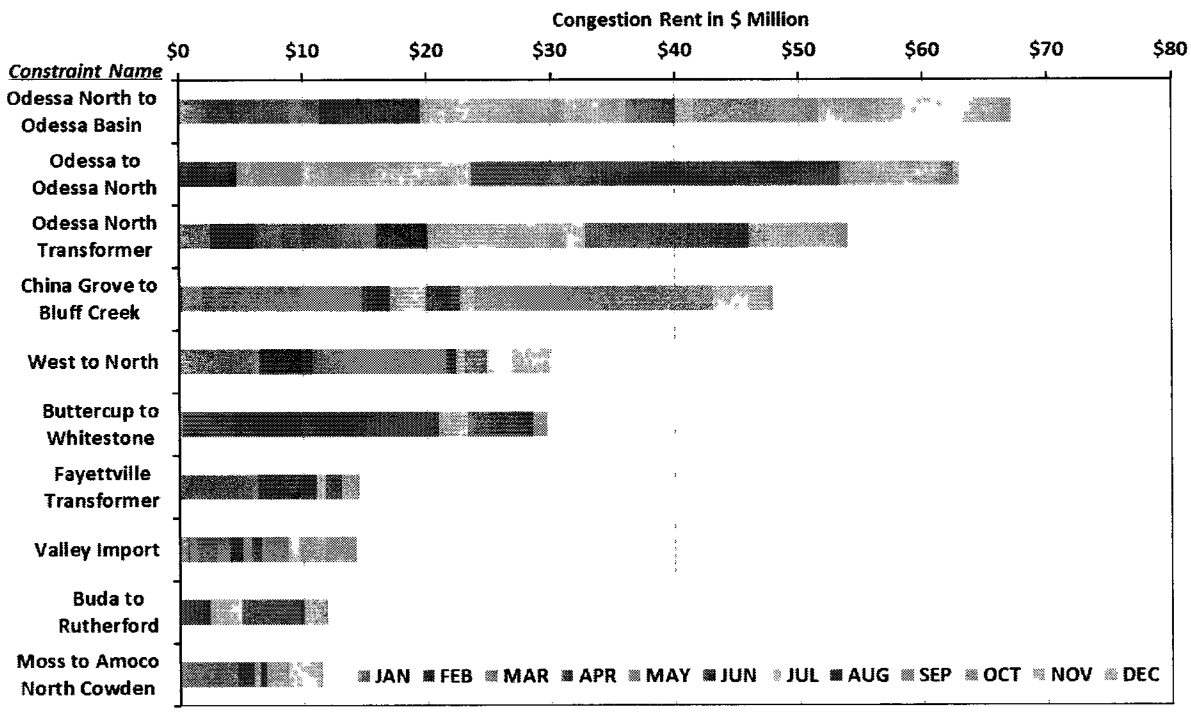


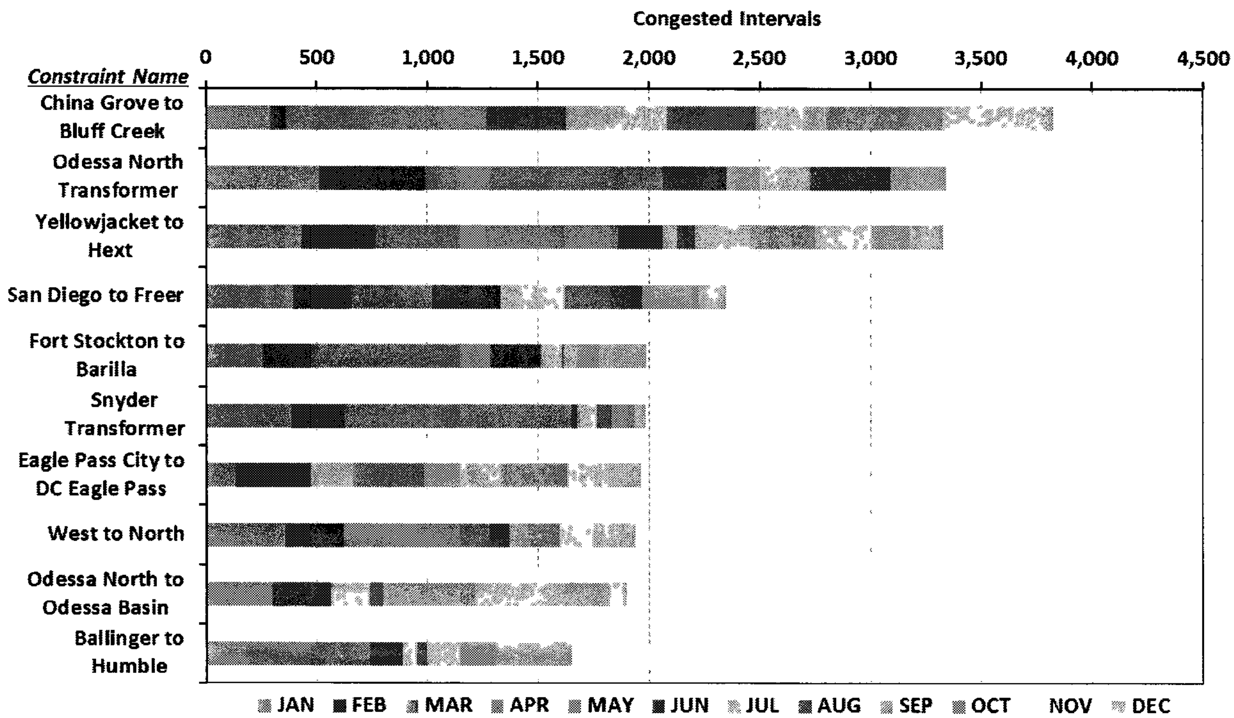
Figure 36 presents the top ten constraints from the day-ahead market, ranked by their financial impact as measured by congestion rent. As was the case with the real-time constraints, the Odessa North transformer constraint had a significant financial impact, although it was not the first on the list. However, the top three constraints are all associated with the Odessa North substation, which further demonstrates the limiting nature of the area. The final constraint on the list, the Moss to Amoco North Cowden 138 kV line, is similar to these Odessa North constraints.

Only the Odessa North transformer, China Grove to Bluff Creek and West to North constraints were previously shown in the real-time list of constraints.

The next two constraints, Buttercup to Whitestone and Buda to Rutherford, are located in Central Texas and were binding in the westward direction. They are both examples of constraints limiting more remote generation reaching the increasing load in west Texas, especially with certain transmission lines out of service. The Fayetteville 345/138 kV transformer constraint limited transfers feeding 138 kV loads in Houston. The Valley import constraint had less of an impact in 2012 than 2011 although it was active during every month.

In our final analysis of this section we review the most frequently occurring day-ahead constraints shown in Figure 37.

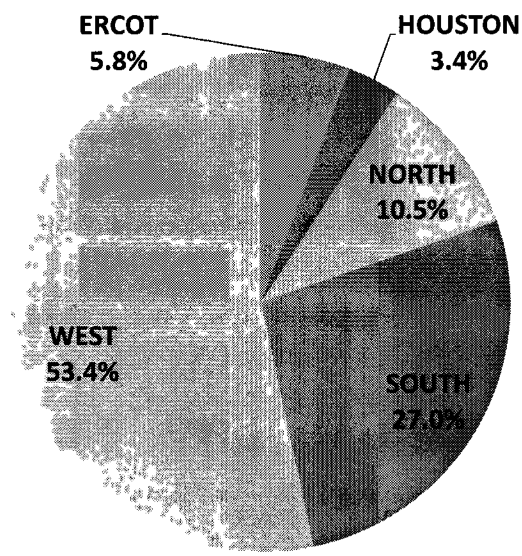
Figure 37: Most Frequent Day-Ahead Constraints



Three of the constraints appearing on the list would not occur in real-time. The Eagle Pass City to Eagle Pass DC Tie constraint appears frequently as a day-ahead constraint, but in real-time operations all transactions with Mexico using this DC Tie are scheduled using a separate process. The process would strictly limit the volume of transactions and not allow a constraint to occur.

The Yellowjacket to Hext and Ballinger to Humble constraints are both affected by nearby phase shifters that depending on the tap setting of the element will have different impedances through the phase shifter. In the day-ahead market, the phase shifters are set at one value throughout the day, typically a mid-setting of the full range. The constraint seen in the day-ahead would likely not bind in real-time due to the fact that the tap settings can be changed to alter the flow over the elements.

Figure 38: Day-Ahead Congestion Costs



With the exception of the San Diego to Freer 69 kV line located in a sparse transmission area of South Texas all of the constraints listed in Figure 37 are associated with West zone conditions.

To further emphasize the effects of West zone congestion in 2012, Figure 38 highlights that, like real-time, day-ahead West zone congestion accounted for more than half the congestion in 2012.

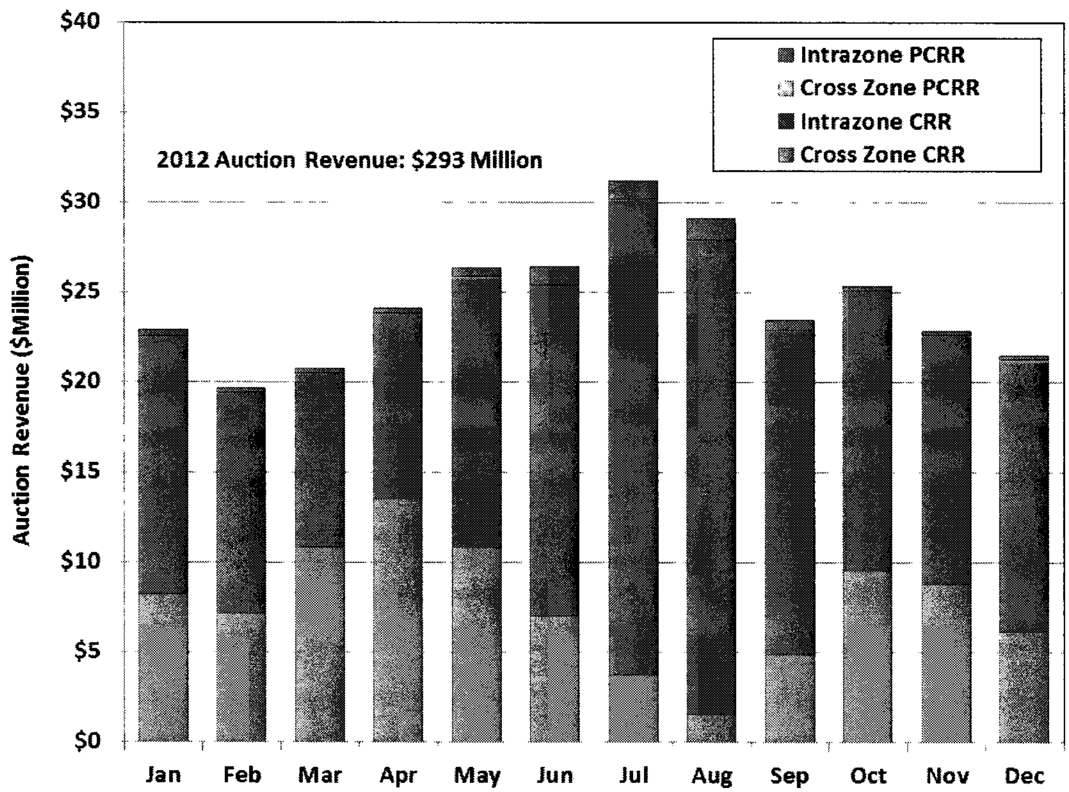
D. Congestion Rights Market

Congestion can be significant from an economic perspective, compelling the dispatch of higher-cost resources because power produced by lower-cost resources cannot be delivered due to transmission constraint(s). Under the nodal market design, one means by which ERCOT market participants can hedge these price differences is by acquiring Congestion Revenue Rights ("CRRs") between any two settlement points.

CRRs are acquired by annual and monthly auctions while Pre-assigned Congestion Revenue Rights ("PCRRs") are allocated to certain participants based on their historical patterns of transmission usage. Parties receiving PCRRs pay only a fraction of the auction value of a CRR between the same source and sink. Both CRRs and PCRRs entitle the holder to payments corresponding to the difference in locational prices of the source and sink.

Figure 39 summarizes the revenues collected by ERCOT in each month for all CRRs, both auctioned and allocated. These revenues are distributed to loads in one of two ways. Revenues from cross zone CRRs are allocated to loads ERCOT wide. Revenues from CRRs that have their source and sink in the same geographic zone are allocated to loads within that zone. This method of revenue allocation provides a disproportionate share of CRR auction revenues to loads located in the West zone. In 2012, CRRs with both their source and sink in the West zone accounted for 27 percent of CRR Auction revenues. This share of revenue was allocated to West zone loads, which accounted for only 7 percent of the ERCOT total. Allocating CRR Auction revenues in this manner helps reduce the impact of the higher congestion on West zone prices.

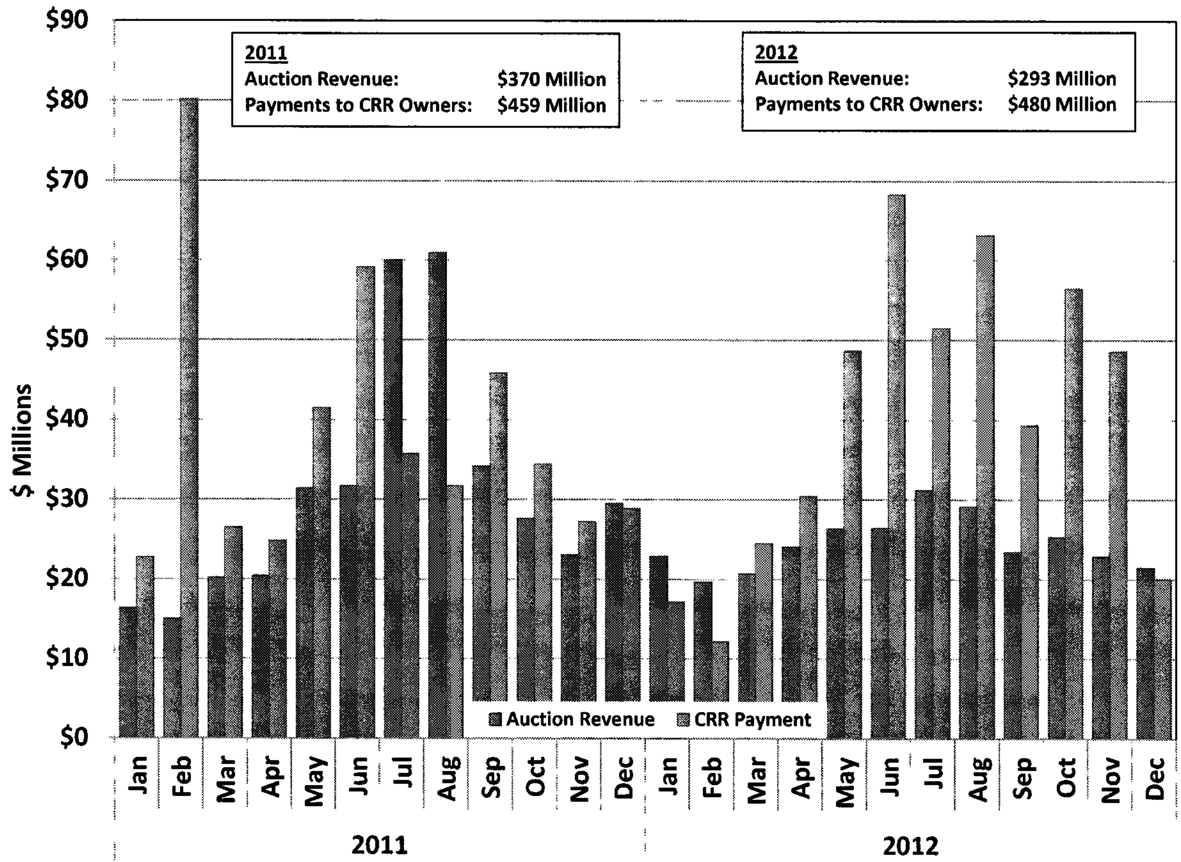
Figure 39: CRR Auction Revenue



As we showed in Section I.A, Real-Time Market Prices, the annual average price for the West zone was $38.24 per MWh, nearly $10 per MWh higher than the ERCOT-wide average. The value of CRR Auction revenues distributed only to the West zone equated to almost $3 per MWh more than the amounts distributed to other zones.

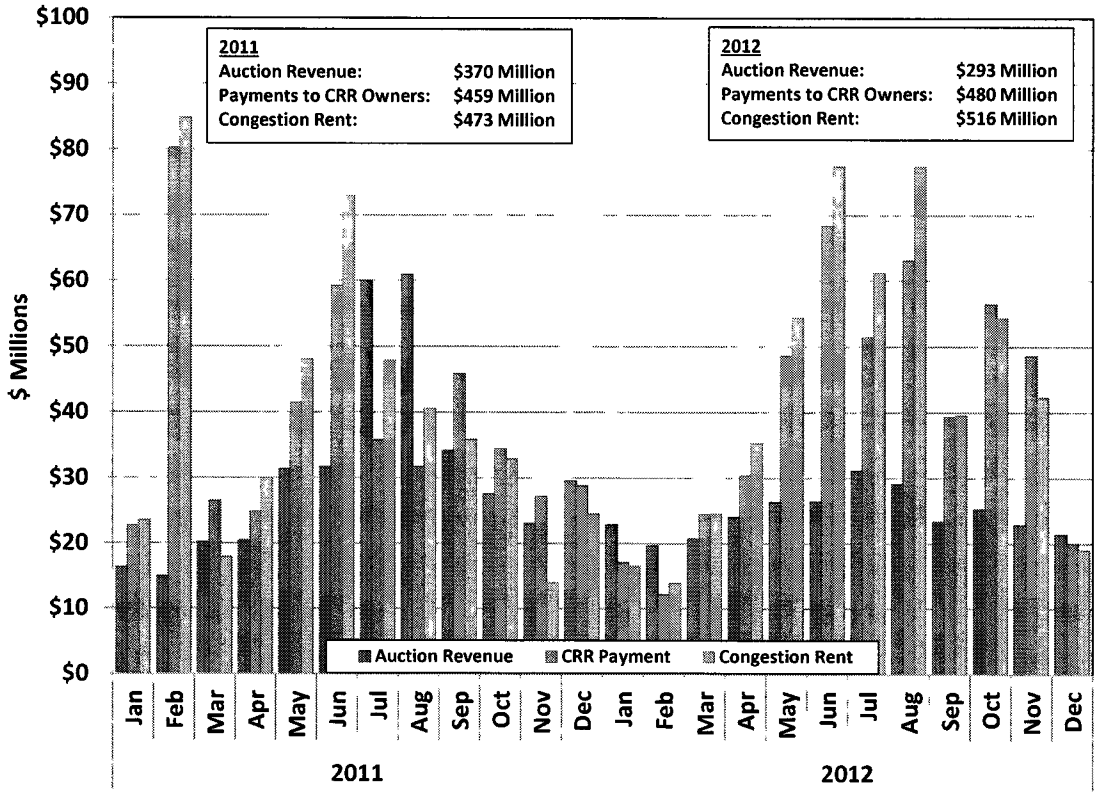
Next, in Figure 40 we examine the value CRR owners (in aggregate) received compared to the price they paid to acquire the CRRs. Although results for individual participants and specific source/sink combinations varied, we find that in most months participants did not over pay in the auction. Across the entire year of 2012, participants spent $293 million to procure CRRs and received $480 million.

Figure 40: CRR Auction Revenue and Payment Received



In our next look at aggregated CRR positions, we add congestion rent to the picture. Simply put, congestion rent is the difference between the total costs that loads pay and the total revenue that generators receive. Congestion rent creates the source of funds used to make payments to CRR owners. Figure 41 presents all three values for each month of 2011 and 2012. Congestion rent for the year 2012, totaled $516 million and payments to CRR owners were $480 million. The only months in 2012 when congestion rent was less than payments to CRR owners were January and October through December.

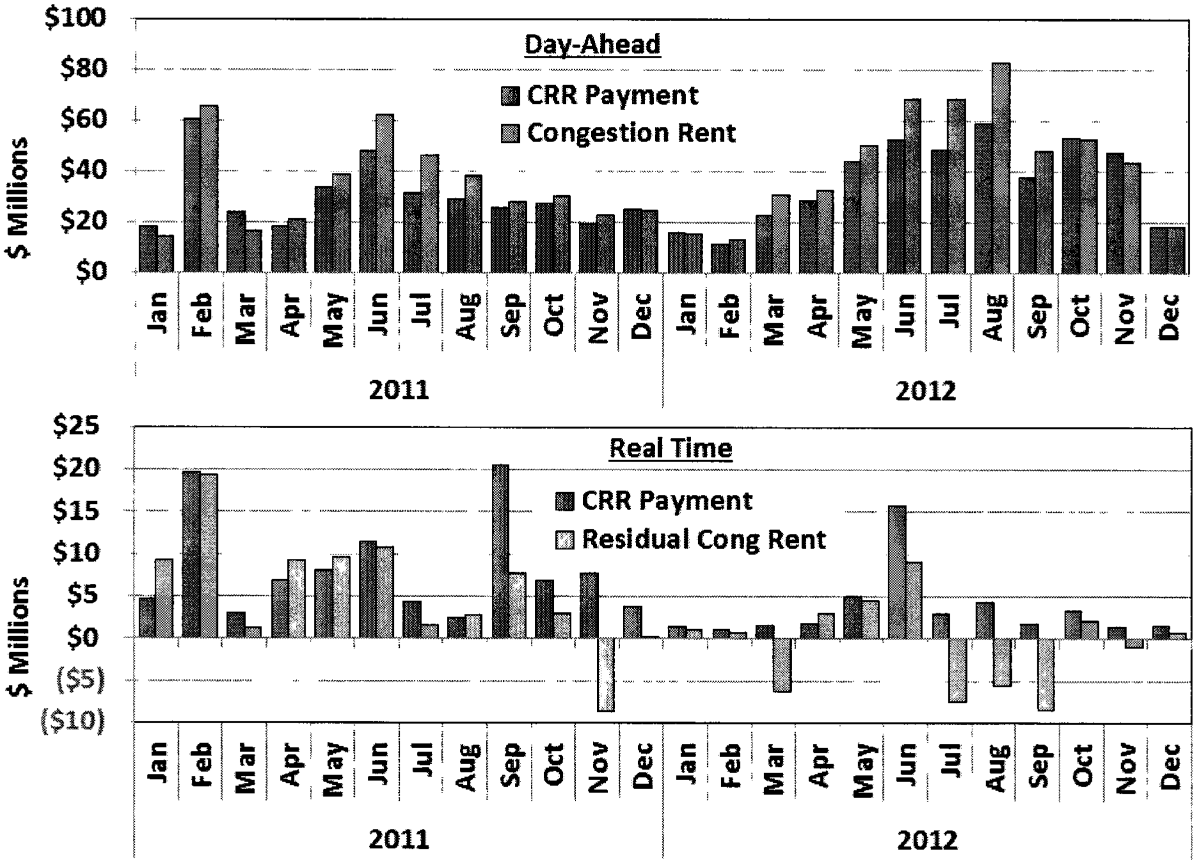
Figure 41: CRR Auction Revenue, Payments and Congestion Rent



We further analyze the relationship between congestion rent and payments to CRR owners by separating the impacts of CRRs that are settled based on day-ahead prices from the subset of CRRs that are paid based on real-time prices.

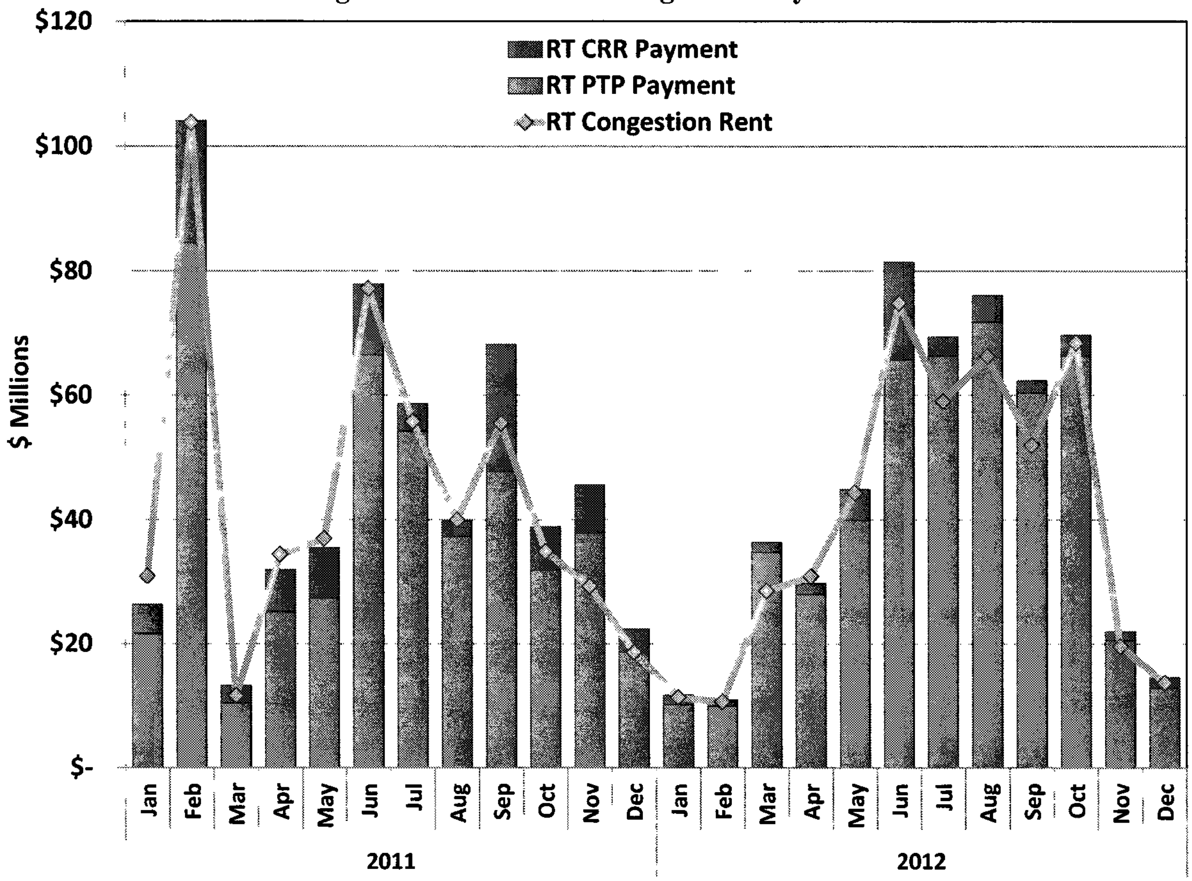
The top portion of Figure 42, shown below, displays the comparison of day-ahead congestion rent to payments received by CRR owners. Congestion rent was larger than payments in most months of 2012 and for the year congestion rent was $523 million compared to $438 million that was paid to CRR owners.

Figure 42: Day-Ahead and Real-Time Congestion Payments and Rent



The bottom portion of Figure 42 presents a different view. For this analysis we have assumed that all PTP Obligations have been fully funded from real-time congestion rent and any residual real-time congestion rent is available to fund payments to the subset of CRR owners that elected to have their CRRs be settled based on real-time prices. In 2012 there was less real-time congestion rent than the payments to holders of PTP Obligations, resulting in a $7 million shortfall. Further, there were real-time CRR payments of $42 Million. Hence, real-time congestion rent was insufficient to fund all PTP Obligations and CRRs being settled in real-time in the amount of $49 million. The next figure shows this explicitly.

Figure 43: Real-Time Congestion Payments



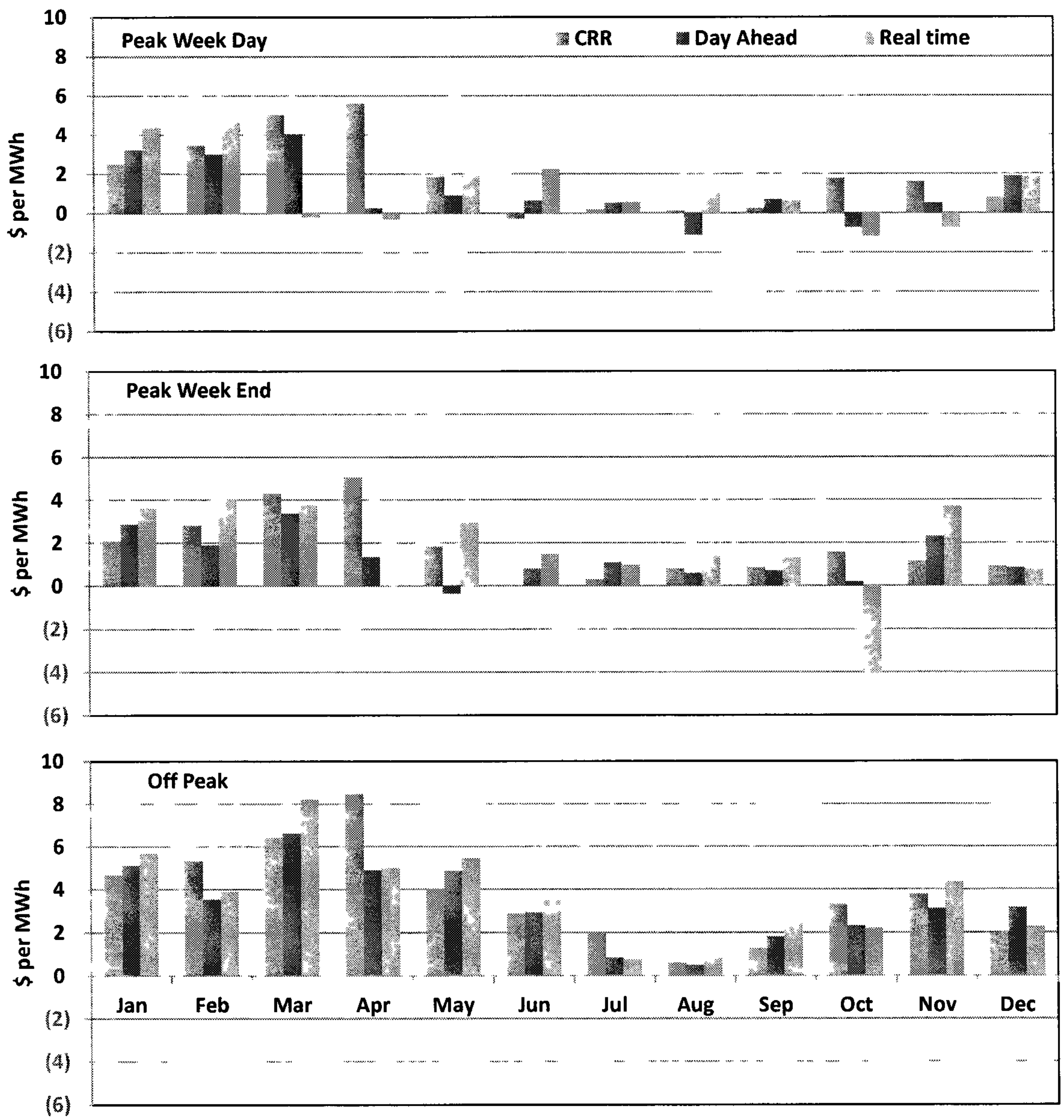
In Figure 43 the combined payments to PTP Obligation owners and CRR owners that have elected to receive real-time payments are compared to the total real-time congestion rent. For the year of 2012, real-time congestion rent was $480 million, payments for PTP Obligations were $487 million and payments for real-time CRRs were $42 million, resulting in a shortfall of approximately $49 million for the year.

This type of shortfall typically results from discrepancies between transmission topology assumptions used when clearing the day-ahead market and the actual transmission topology that exists during real-time. Specifically, if the day-ahead topology assumptions allow too many real-time congestion instruments (PTP Obligations and CRRs settled at real-time prices) with impacts on a certain path, and that path constrains at a lower limit in real-time, there will be insufficient rent generated to pay all of the congestion instruments.

From Figure 43 we can see that March and June through September were the months with the most noticeable deficiencies. A detailed examination of the daily congestion pattern during these months shows that outages of transmission facilities did occur on days with large insufficiency.

For our last look at congestion we examine the impacts of the West to North constraint in more detail. Figure 44 presents the price spreads between the West Hub and North load zone as valued at three separate points in time – at the monthly CRR auction, day-ahead and in real-time.

Figure 44: West Hub to North Load Zone Price Spreads



Since CRRs are sold for one of three defined time periods, weekday on peak, weekend on peak, and off peak, Figure 44 includes a separate comparison for each.

As expected, most real-time congestion, as evidenced by the largest price spread, occurred in the off peak period, for the months of January through June and November. The day-ahead price spreads were very similar for this period, while the prices paid for CRRs in April were more than the value received. Conversely, during the summer months of July and August, there was very little congestion. In October day-ahead and real-time prices were higher at the West Hub at the peak hours, which the results of the CRR auction did not anticipate.

IV. LOAD AND GENERATION

This section reviews and analyzes the load patterns during 2012 and the existing generating capacity available to satisfy the load and operating reserve requirements. We provide specific analysis of the large quantity of installed wind generation and conclude this section with a discussion of the daily generation commitment process.

A. ERCOT Loads in 2012

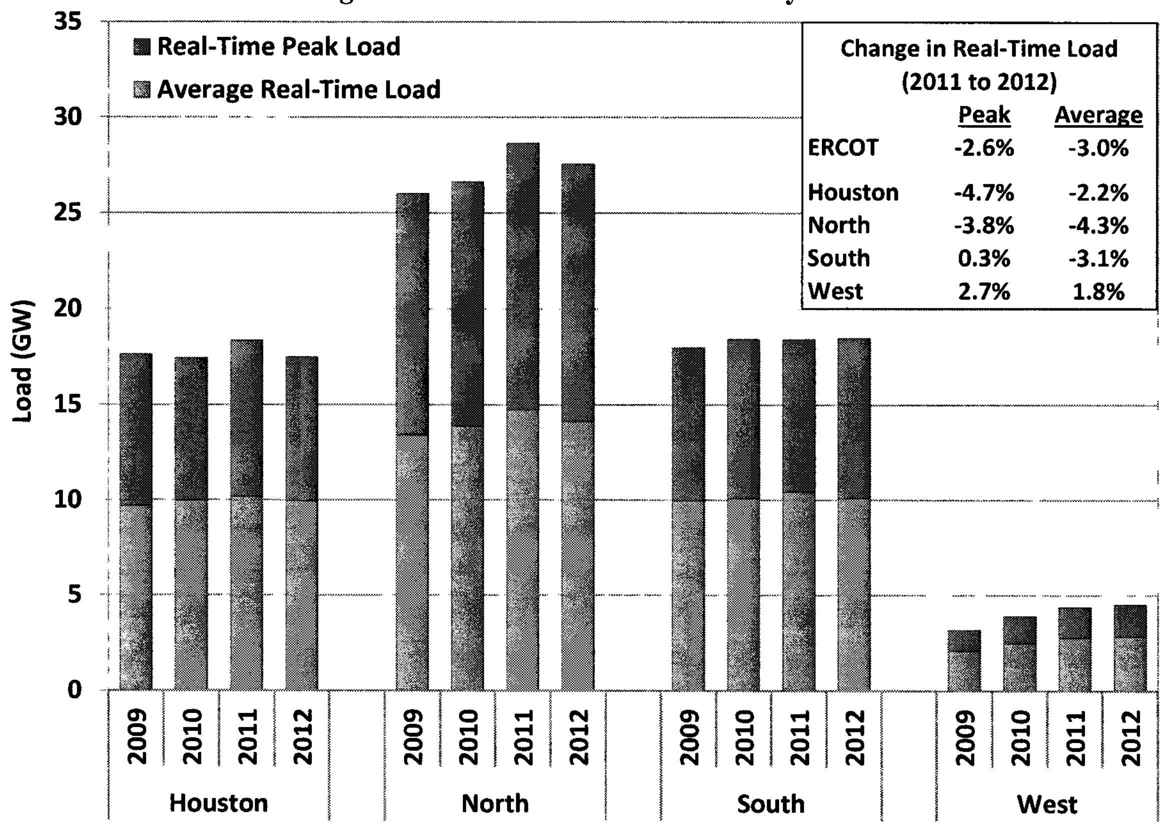
The changes in overall load levels from year to year can be shown by tracking the changes in average load levels. This metric will tend to capture changes in load over a large portion of the hours during the year. It is also important to separately evaluate the changes in the load during the highest-demand hours of the year. Significant changes in peak demand levels play a major role in assessing the need for new resources. They also affect the probability and frequency of shortage conditions (*i.e.*, conditions where firm load is served but minimum operating reserves are not maintained). The expectation of resource adequacy is based on the value of electric service to customers and the harm and inconvenience to customers that can result from interruptions to that service. Hence, both of these dimensions of load during 2012 are examined in this subsection and summarized in Figure 45.

This figure shows peak load and average load in each of the ERCOT zones from 2009 to 2012.[13] In each zone, as in most electrical systems, peak demand significantly exceeds average demand. The North zone is the largest zone (with about 38 percent of the total ERCOT load); the South and Houston zones are comparable (27 percent) while the West zone is the smallest (8 percent of the total ERCOT load).

Figure 45 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.

13 For purposes of this analysis NOIE Load Zones have been included with the proximate geographic Load Zone.

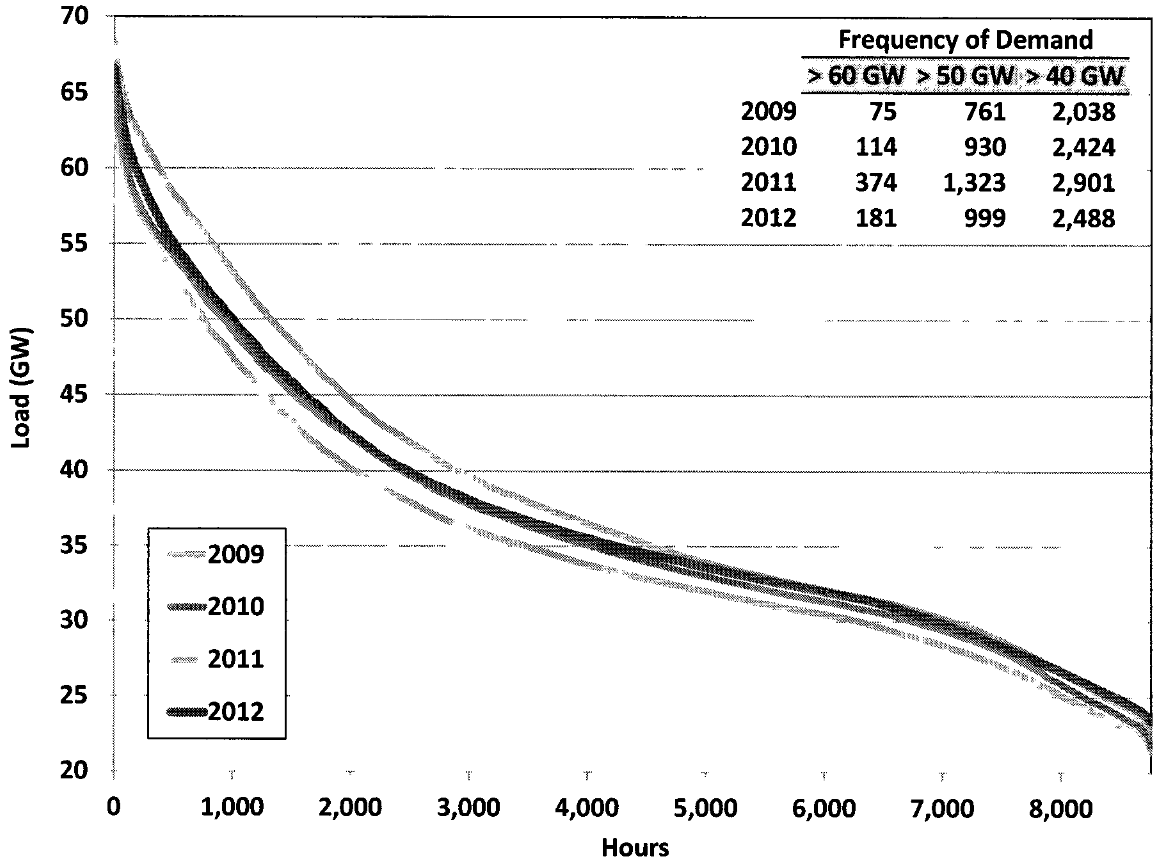
Figure 45: Annual Load Statistics by Zone



Total ERCOT load decreased from 334 TWh in 2011 to 325 TWh in 2012, a decrease of 2.7 percent or an average of 1,130 MW every hour. Similarly, the ERCOT coincident peak hourly demand decreased from 68,311 MW in 2011 to 66,559 MW, a decrease of 1,752 MW, or 2.6 percent. The results at the zonal level are not consistent. Average load decreased in three of the four zones, but grew by 1.8 percent in the West zone.

To provide a more detailed analysis of load at the hourly level, Figure 46 compares load duration curves for each year from 2009 to 2012. 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.

Figure 46: Load Duration Curve – All hours

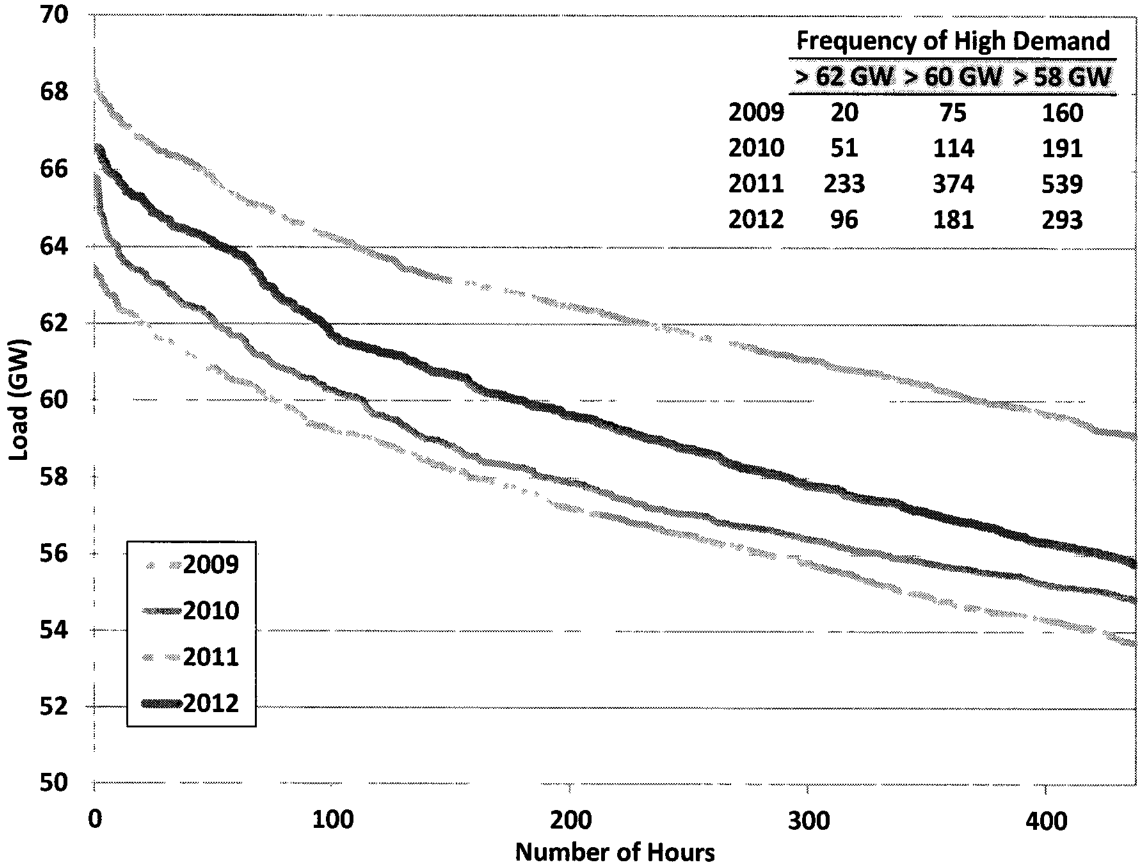


	Frequency of Demand		
	> 60 GW	> 50 GW	> 40 GW
2009	75	761	2,038
2010	114	930	2,424
2011	374	1,323	2,901
2012	181	999	2,488

As shown in Figure 46, the load duration curve for 2012 is significantly lower than in 2011 for approximately half of the hours in the year. This is consistent with the aforementioned 2.7 percent load decrease from 2011 to 2012.

To better illustrate the differences in the highest-demand periods between years, Figure 47 shows the load duration curve for the five percent of hours with the highest loads. This figure also shows that the peak load in each year is significantly greater than the load at the 95th percentile of hourly load. From 2009 to 2012, the peak load value averaged 18 percent greater than the load at the 95th percentile. These load characteristics imply that a substantial amount of capacity – almost 10 GW – is needed to supply energy in less than 5 percent of the hours.

Figure 47: Load Duration Curve – Top five percent of hours

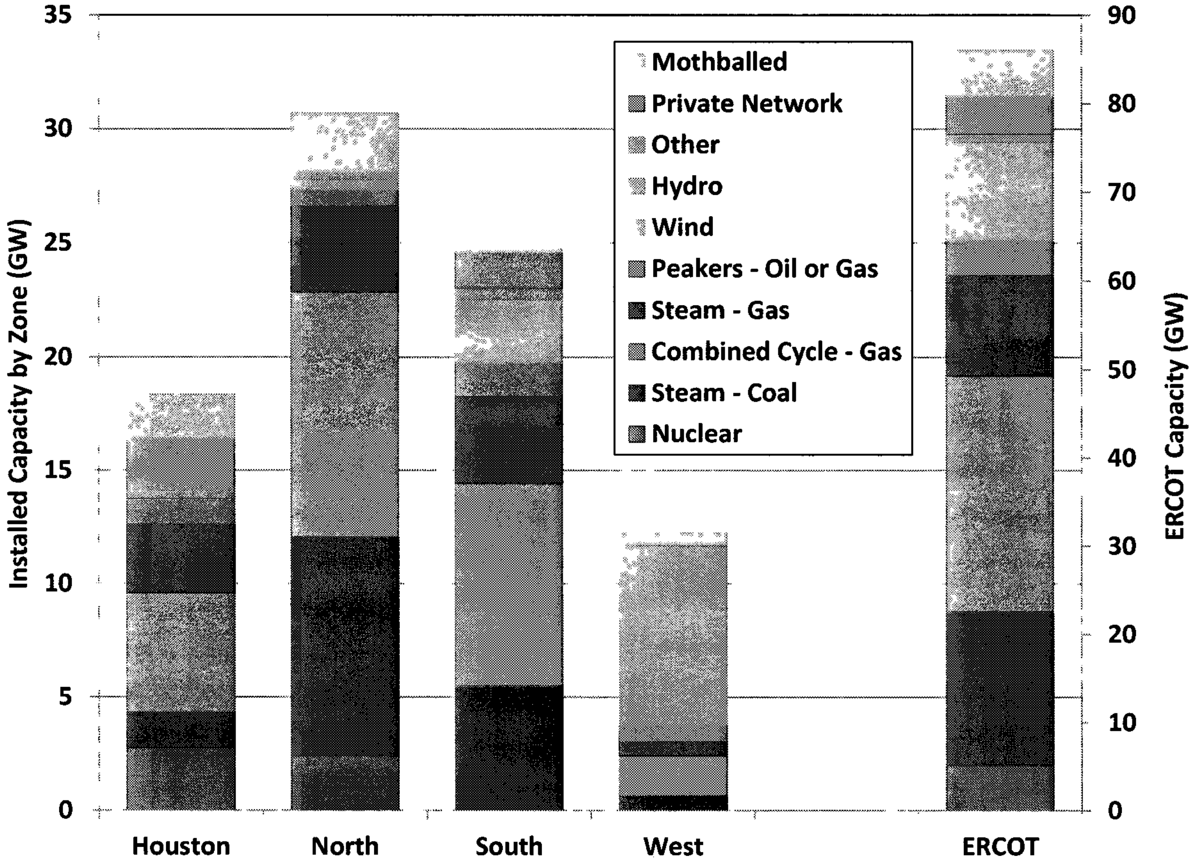


B. Generation Capacity in ERCOT

In this section we evaluate the generation mix in ERCOT. The distribution of capacity among the ERCOT zones is similar to the distribution of demand with the exception of the large amount of wind capacity in the West zone. The North zone accounts for approximately 36 percent of capacity, the South zone 29 percent, the Houston zone 21 percent, and the West zone 14 percent. The Houston zone typically imports power, while the West zone typically exports power. Excluding mothballed resources and including only 8.7 percent of wind capacity as capacity available to reliably meet peak demand, the North zone accounts for approximately 39 percent of capacity, the South zone 31 percent, the Houston zone 23 percent, and the West zone 6 percent. Figure 48 shows the installed generating capacity by type in each of the ERCOT zones.[14]

[14] For purposes of this analysis, generation located in a NOIE Load Zone has been included with the proximate geographic Load Zone

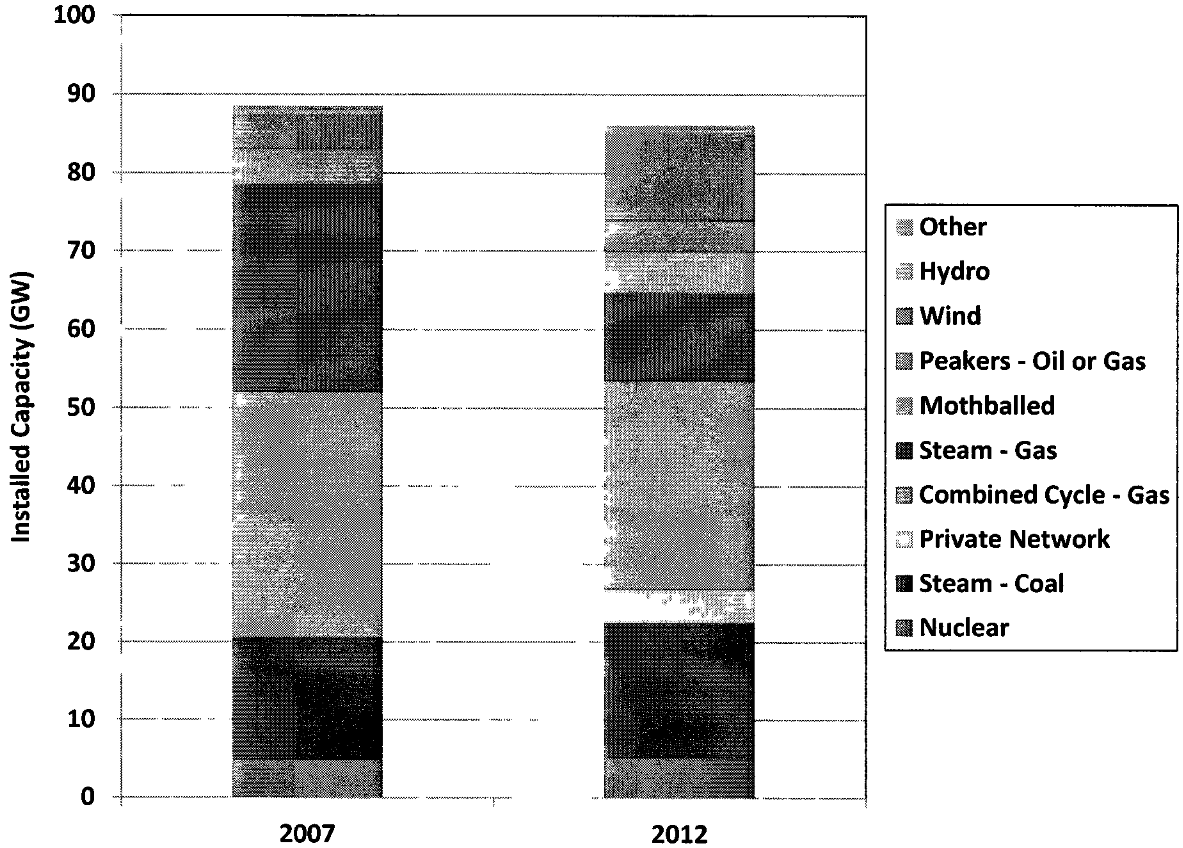
Figure 48: Installed Capacity by Technology for each Zone



Approximately 1 GW of generation resources came online in 2012; most of which were wind units and the remainder were solar and biomass. Even with no new natural gas units added during 2012, natural gas generation accounts for approximately 49 percent of total ERCOT installed capacity, and coal generation accounts for approximate 20 percent.

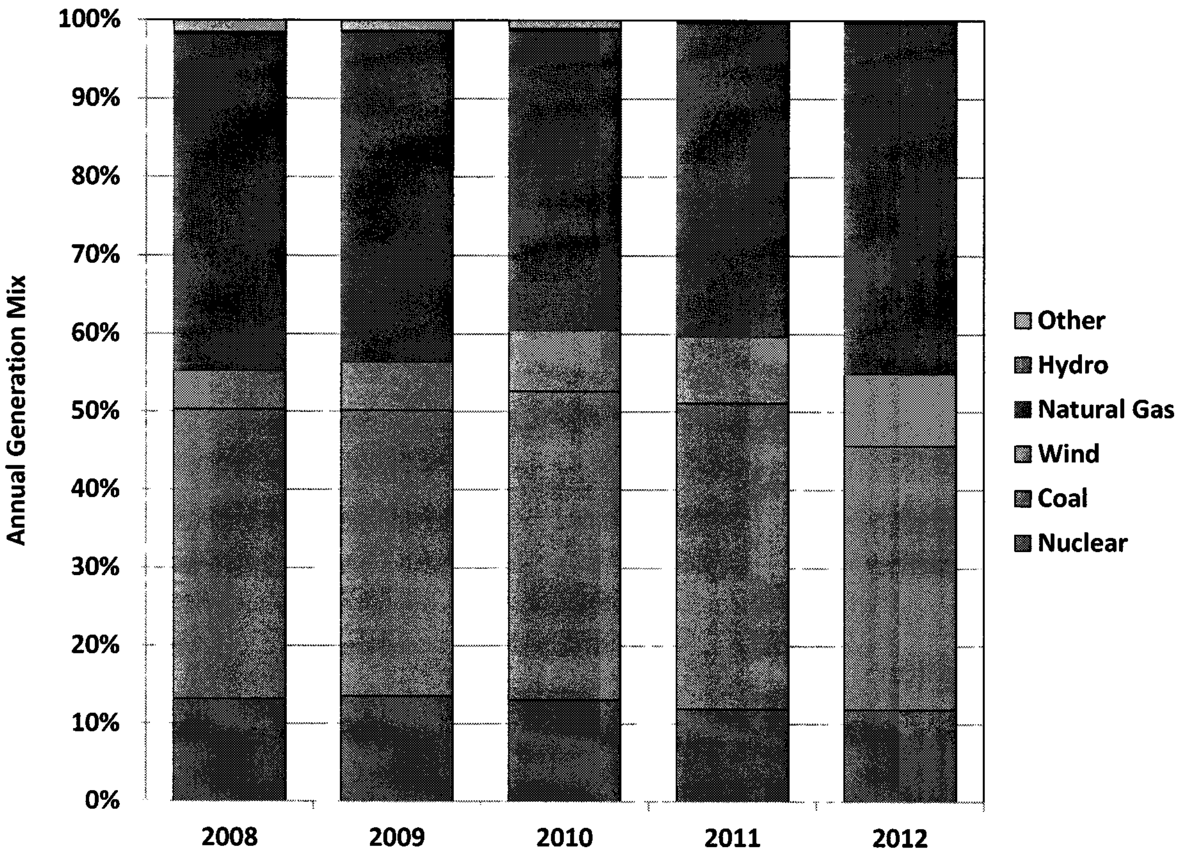
By comparing the current mix of installed generation capacity to that in 2007, as shown in Figure 49, we can see the effects of longer term trends. Over these six years, wind and coal generation are the two categories with the most increased capacity. The sizable additions in these two categories have been more than offset by retirements of natural gas-fired steam units, resulting in less installed capacity in 2012 than there was in 2007.

Figure 49: Installed Capacity by Type: 2007 to 2012



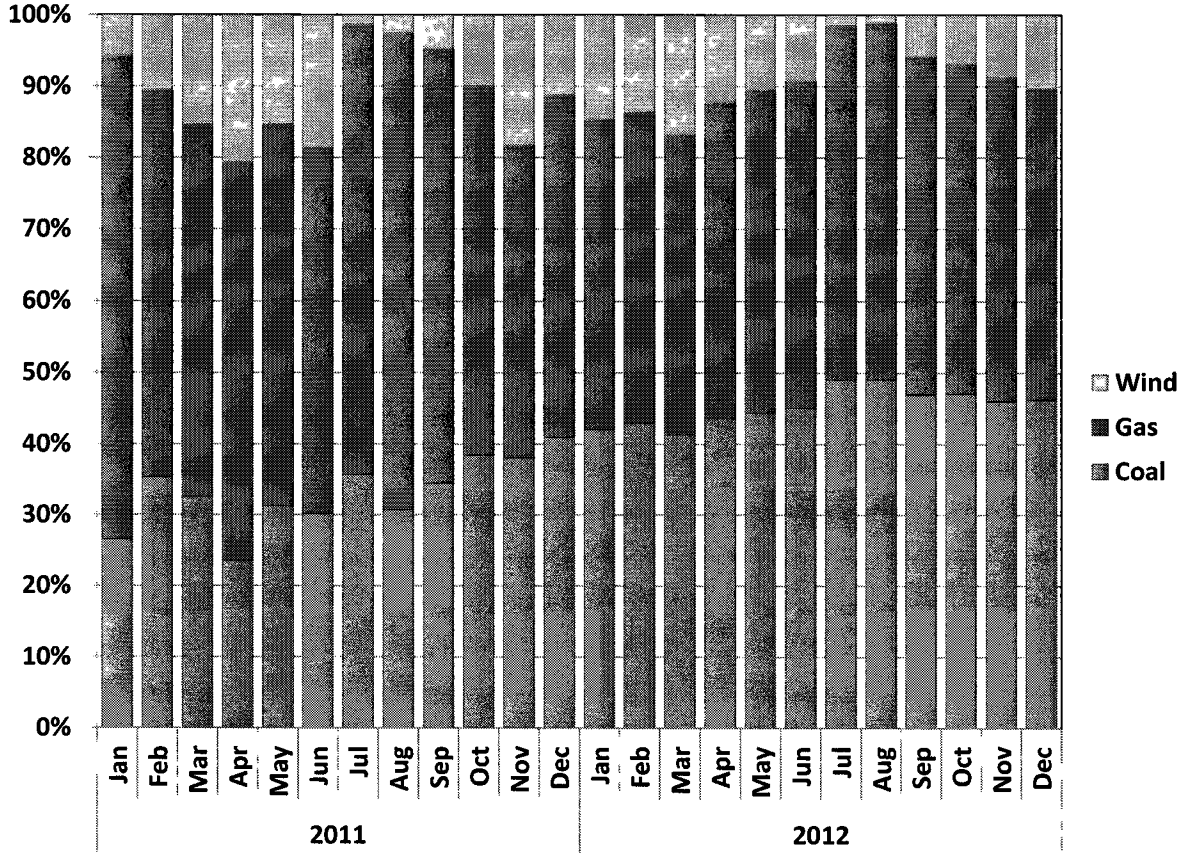
The shifting contribution of coal and wind generation is evident in Figure 50, which shows the percent of annual generation from each fuel type for the years 2008 through 2012. The generation share from wind has increased every year, reaching 9 percent of the annual generation requirement in 2012, up from 5 percent in 2008. During the same period the percentage of generation provided by natural gas decreased from 43 percent in 2008 to 38 percent in 2010, before increasing to 45 percent in 2012. Correspondingly, the percentage of generation produced by coal units increased from 37 percent to 40 percent in 2010 before decreasing to 34 percent in 2012. The increase in the share of generation produced by natural gas, and corresponding reduction in coal generation is due to historically low price of natural gas in 2012.

Figure 50: Annual Generation Mix



While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price. However, due to the low price of natural gas in 2012, we observe that the share of generation produced from coal-fired and nuclear units decreased to less than half of the energy in ERCOT, with the reduction coming from decreased coal generation. This reduction in the share of coal generation results in an increase in the occurrences when coal units were setting the price. This happens because the decrease in natural gas price results in those units becoming infra-marginal; that is, less costly than the last unit needed to satisfy total demand. As natural gas units are marginal less frequently, coal units increasingly become marginal. We can see the results of this tradeoff in Figure 51 which shows that the frequency with which coal was the marginal fuel was greater than 40 percent in all months during 2012, a noticeable increase from 2011.

Figure 51: Marginal Unit Frequency by Fuel Type



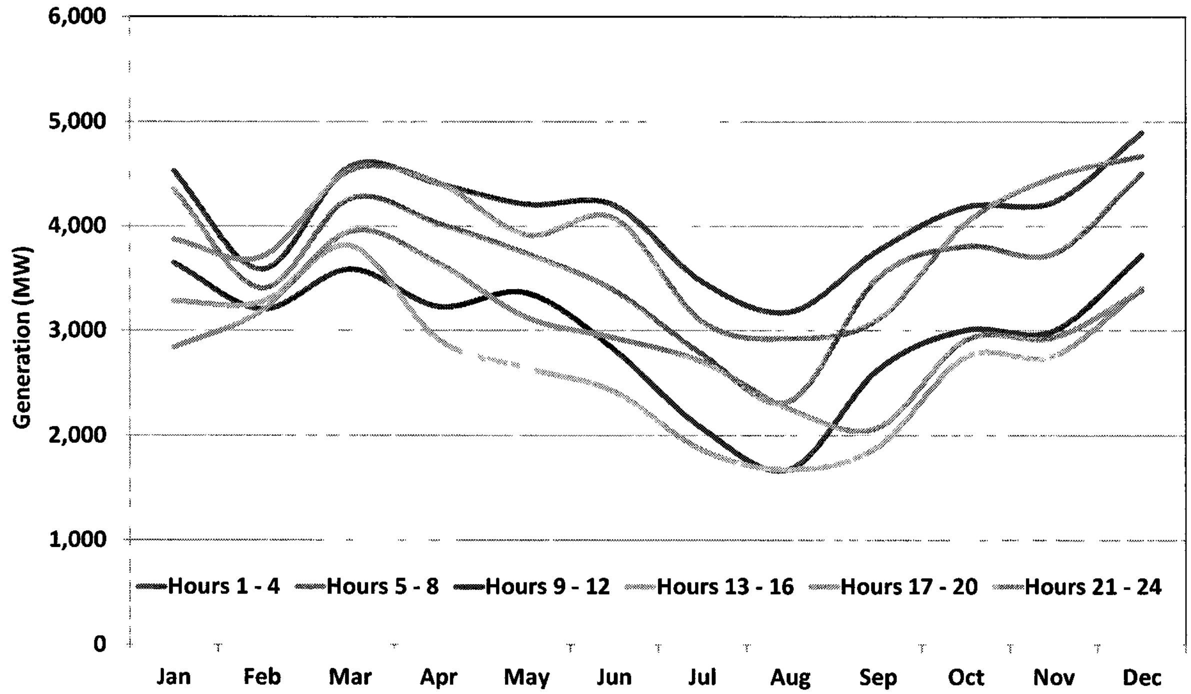
The methodology used in this analysis reflects the details of the unit specific dispatch that are available under the nodal market design. For every five-minute interval we determine which units are marginal, that is they are being dispatched and their offer price is contributing to the locational marginal price. When there is congestion, units with different prices can be marginal at the same time. With all the marginal units identified, we aggregate by their fuel type to compute monthly percentages. This aggregation ignores all locational price differences.

Although natural gas units continue to be marginal most of the time, the frequency at which coal units were marginal has steadily increased since late 2011. As previously discussed this can be attributed to the decline in natural gas prices. The frequency of wind units being marginal also declined in 2012. This can be attributed to the reduced necessity for wind curtailments due to transmission constraints.

1. Wind Generation

The amount of wind generation installed in ERCOT exceeded 10 GW by the end of 2012. Although the large majority of wind generation is located in the West zone, there has been more than 2 GW of wind generation recently installed in the South zone. Additionally, a private transmission line went into service in late 2010 allowing nearly another 1 GW of West zone wind to be delivered directly to the South zone. This section will more fully describe the characteristics of wind generation in ERCOT.

Figure 52: Average Wind Production



The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure 52 shows average wind production for each month in 2012, with the average production in each month shown separately in four hour blocks.[15]

15 Figure 52 shows actual wind production, which was affected by curtailments at the higher production levels. Thus, the higher levels of actual wind production in Figure 52 are lower than the production levels that would have materialized absent transmission constraints.