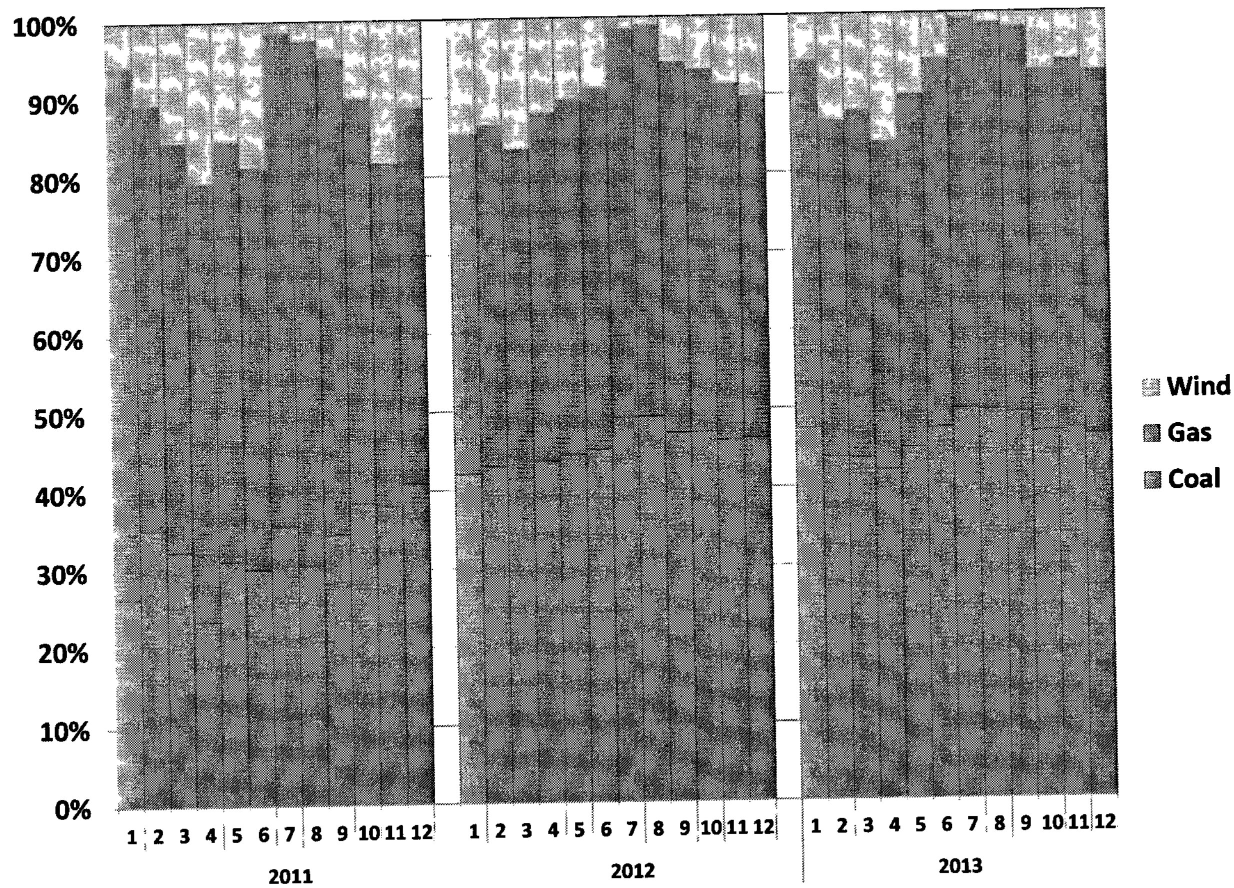
months during 2012, a noticeable increase from 2011. With more coal generation capacity and lower system loads in the first part of the year, this trend continued through 2013.

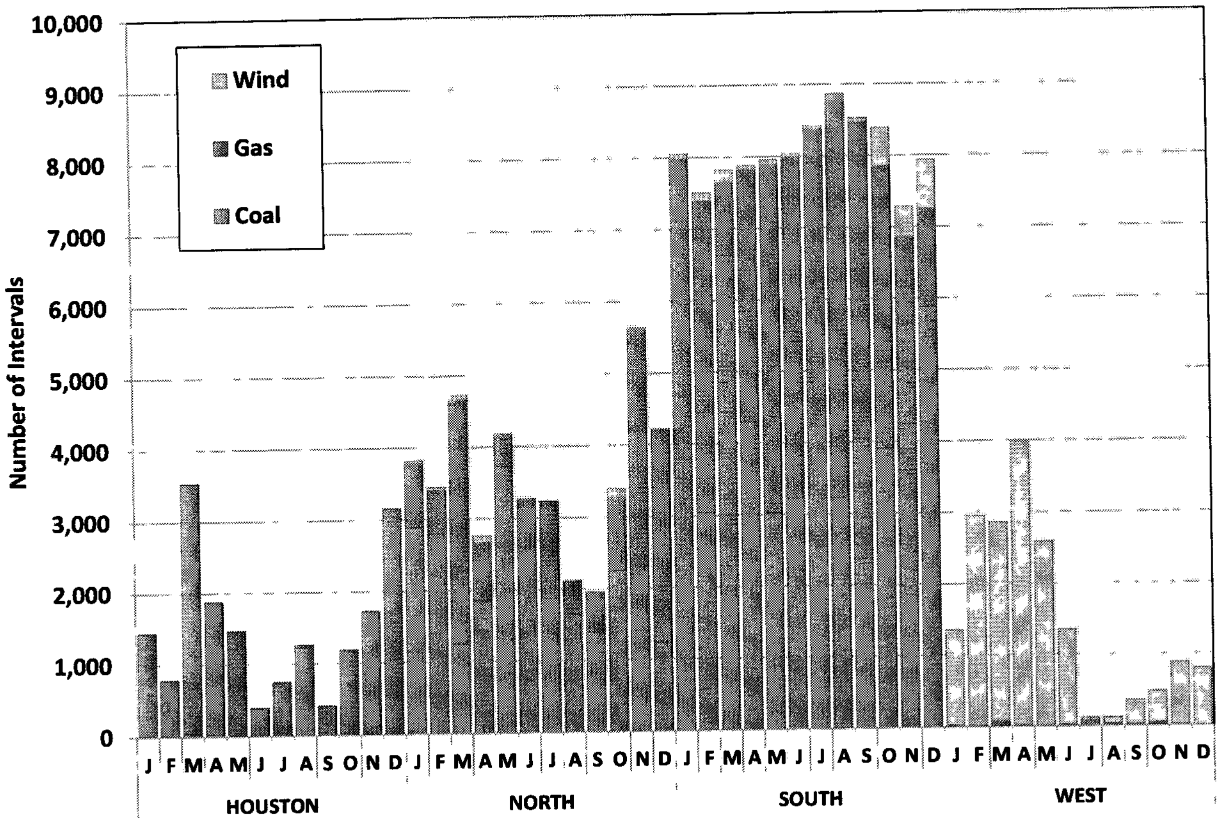
Figure 55: Marginal Unit Frequency by Fuel Type



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 and does not provide much insight into the pricing outcomes.

In the next figure we show the marginal units by location. Using the same methodology previously described we count the occurrences of each fuel type being marginal and aggregate the number of occurrences by zone. From this we can see that the contribution of wind to clearing prices is primarily in the West zone and occurs much less frequently than either coal or gas.

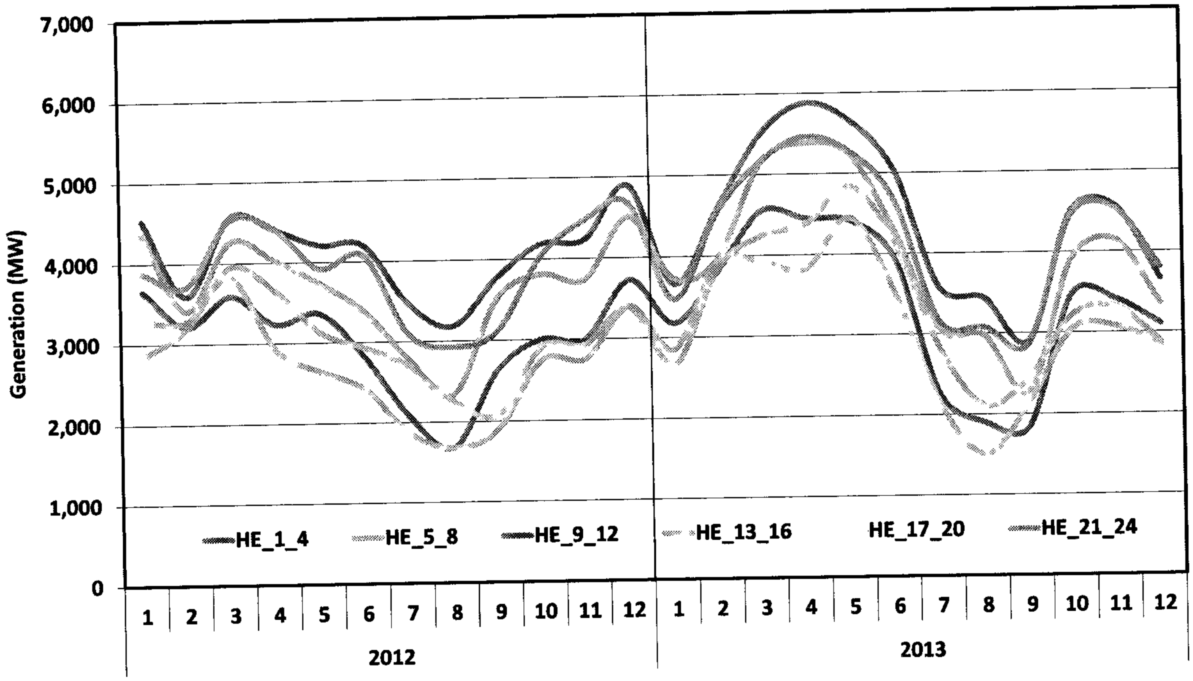
Figure 56: Marginal Units by Zone



1. Wind Generation

The amount of wind generation installed in ERCOT exceeded 11 GW by the end of 2013. Although the large majority of wind generation is located in the West zone, more than 2 GW of wind generation has been located 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 subsection will more fully describe the characteristics of wind generation in ERCOT.

Figure 57: Average Wind Production



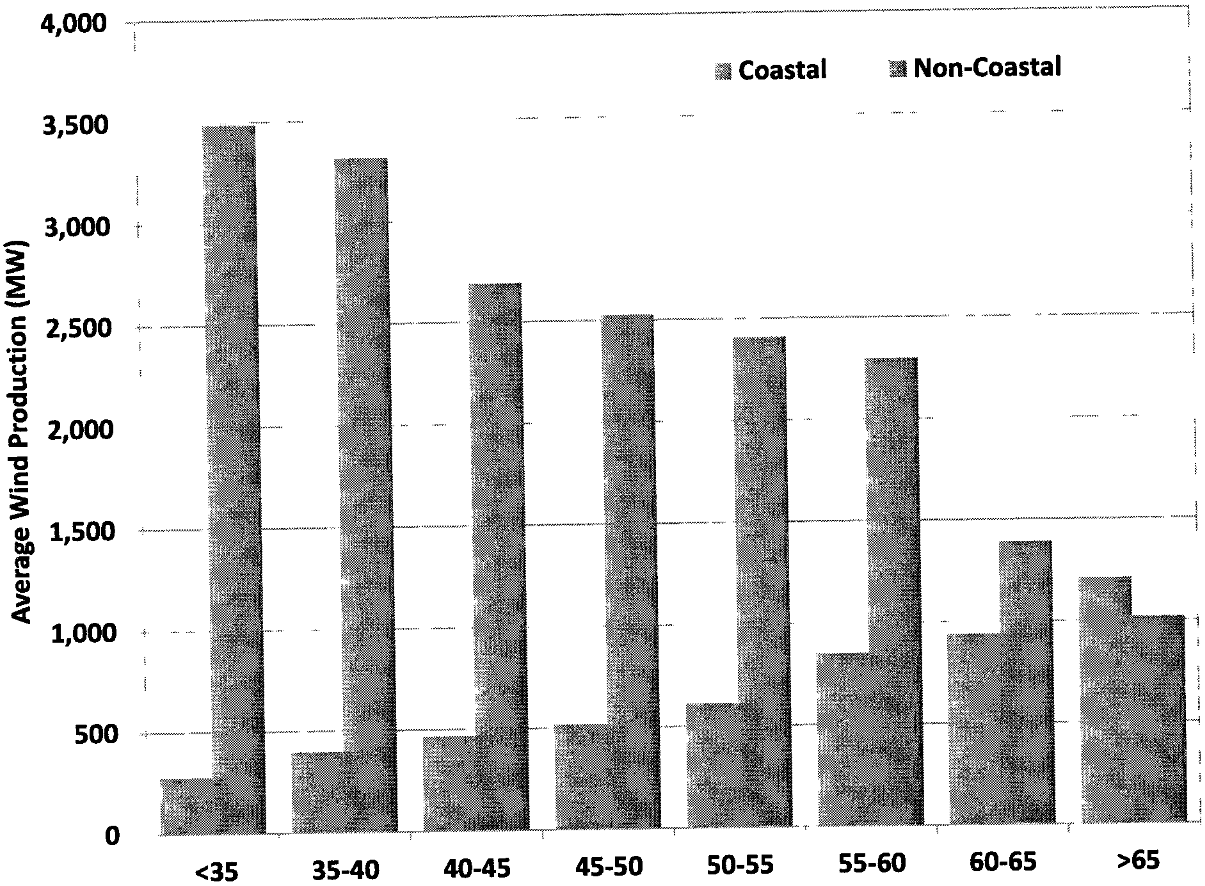
The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure 57 shows average wind production for each month in 2012 and 2013, with the average production in each month shown separately in four hour blocks.[10]

The amount of average wind generation in the spring of 2013 is markedly higher across all hours when compared to 2012. This increase is likely due to the completion of the CREZ transmission lines resulting in reduced curtailments.

Examining wind generation in total masks the different wind profiles that exist for locations across ERCOT. Wind developers have more recently been attracted to site facilities along the Gulf coast of Texas due to the higher correlation of winds with electricity demands. Next we compare the differences in output for wind units located in the coastal area of the South zone and those located elsewhere in ERCOT.

10 Figure 57 shows actual wind production, which was affected by curtailments at the higher production levels. Thus, the higher levels of actual wind production in Figure 57 are lower than the production levels that would have materialized absent transmission constraints.

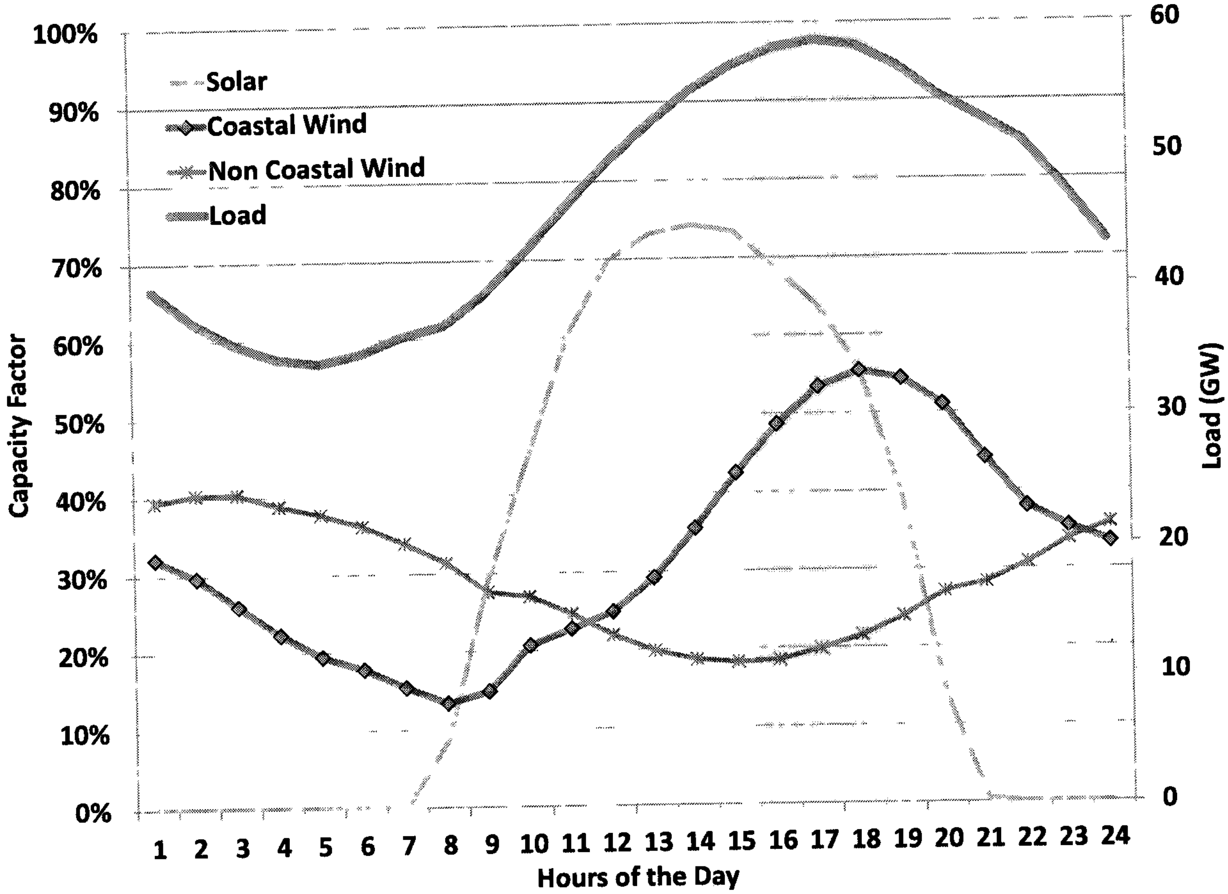
Figure 58: Summer Wind Production vs. Load



In Figure 58 data is presented for the summer months of June through August, comparing the average output for wind generators located in coastal and non-coastal areas in ERCOT across various load levels. It shows a strong negative relationship between non-coastal wind output and increasing load levels. It further shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand.

The growing numbers of solar generation facilities in ERCOT also have an expected generation profile highly correlated with peak summer loads. Figure 59 below compares average summertime (June through August) hourly loads with observed output from solar and wind resources. Generation output is expressed as a ratio of actual output divided by installed capacity. The solar output shown is from relatively small central station photovoltaic facilities totaling approximately 50 MW. However, its production as a percentage of installed capacity is the highest, exceeding 70 percent in the early afternoon, and producing more than 50 percent of its installed capacity during peak.

Figure 59: Summer Renewable Production



The contrast between coastal wind and non-coastal wind is also clearly displayed in Figure 59. Coastal wind produced greater than 50 percent of its installed capacity during summer peak hours while output from non-coastal wind was approximately 20 percent.

Figure 60: Wind Production and Curtailment

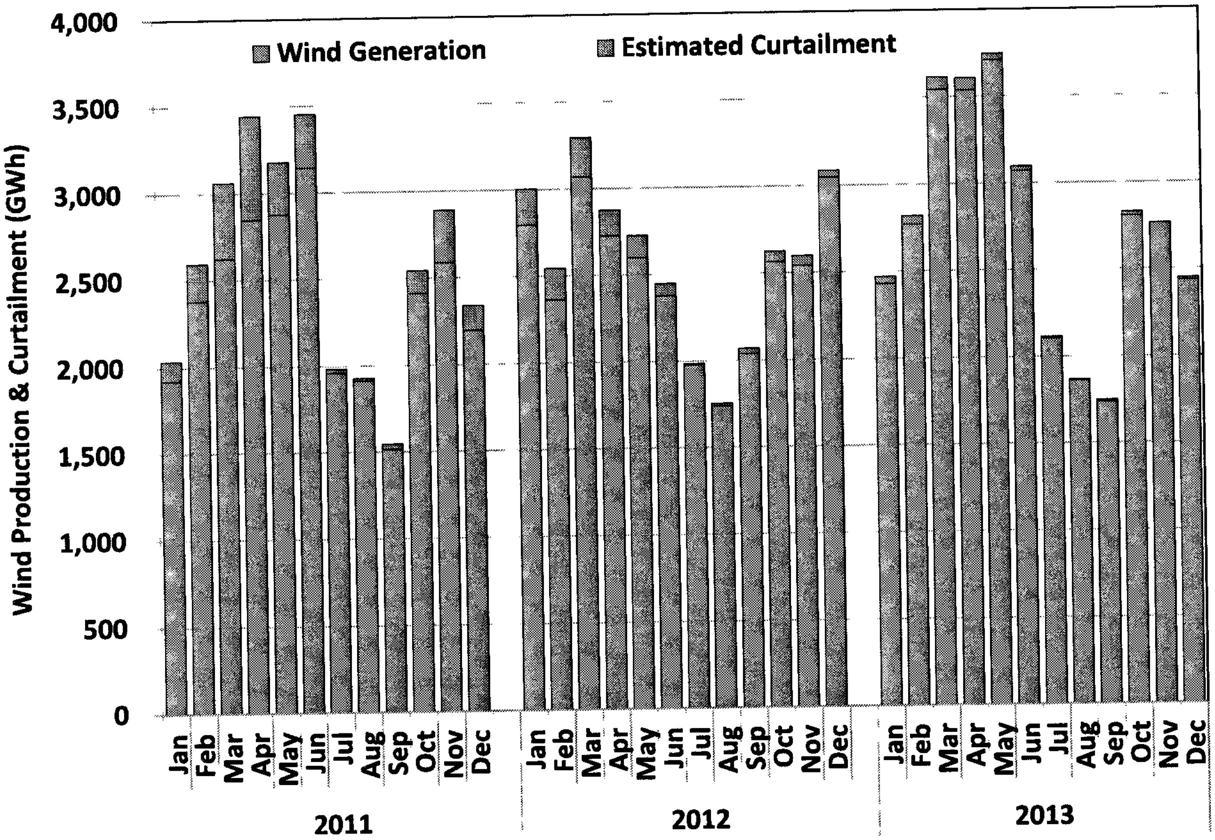
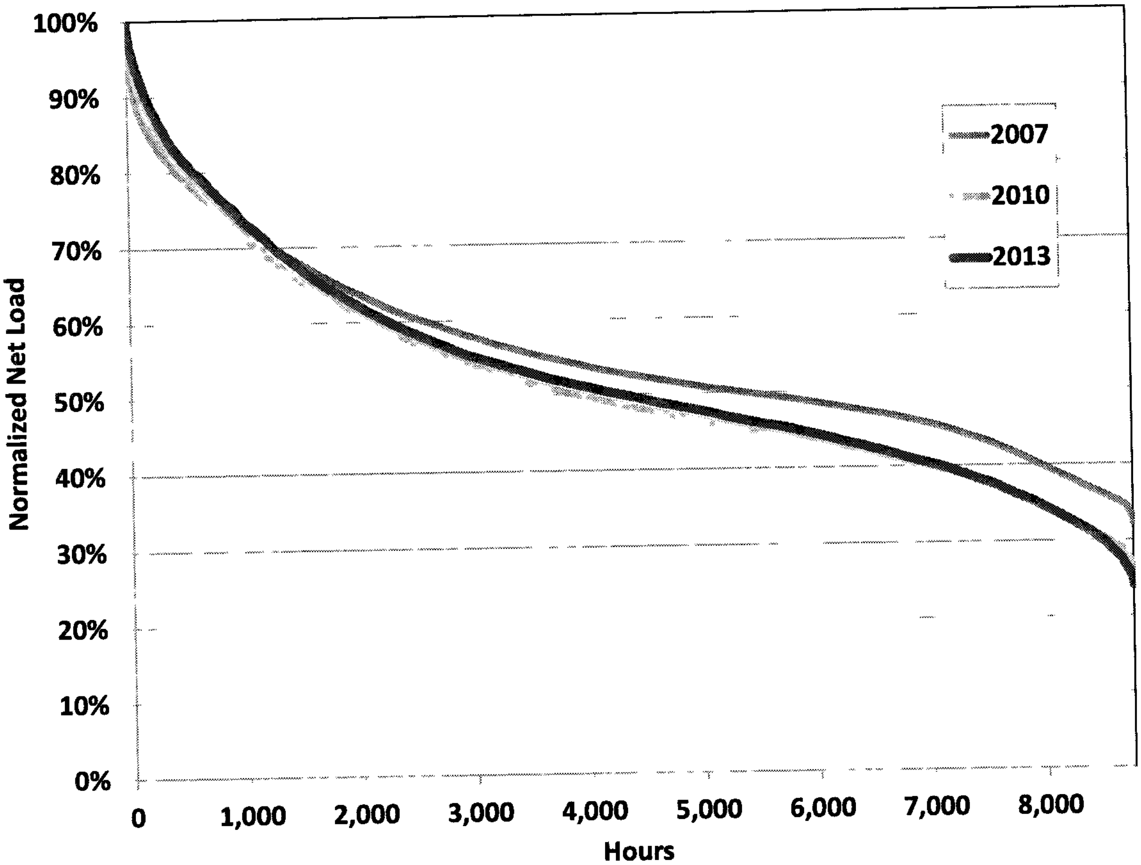


Figure 60 shows the wind production and estimated curtailment quantities for each month of 2011, 2012 and 2013. This figure reveals that the total production from wind resources increased significantly in 2013. More importantly, the quantity of curtailments continues to shrink. The volume of wind actually produced was almost 99 percent of the total available wind in 2013, up from approximately 96 percent in 2012 and 92 percent in 2011.

Increasing levels of wind resources in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. Figure 61 shows the net load duration curves for selected years since 2007, normalized as a percentage of peak load.

Figure 61: Net Load Duration Curves

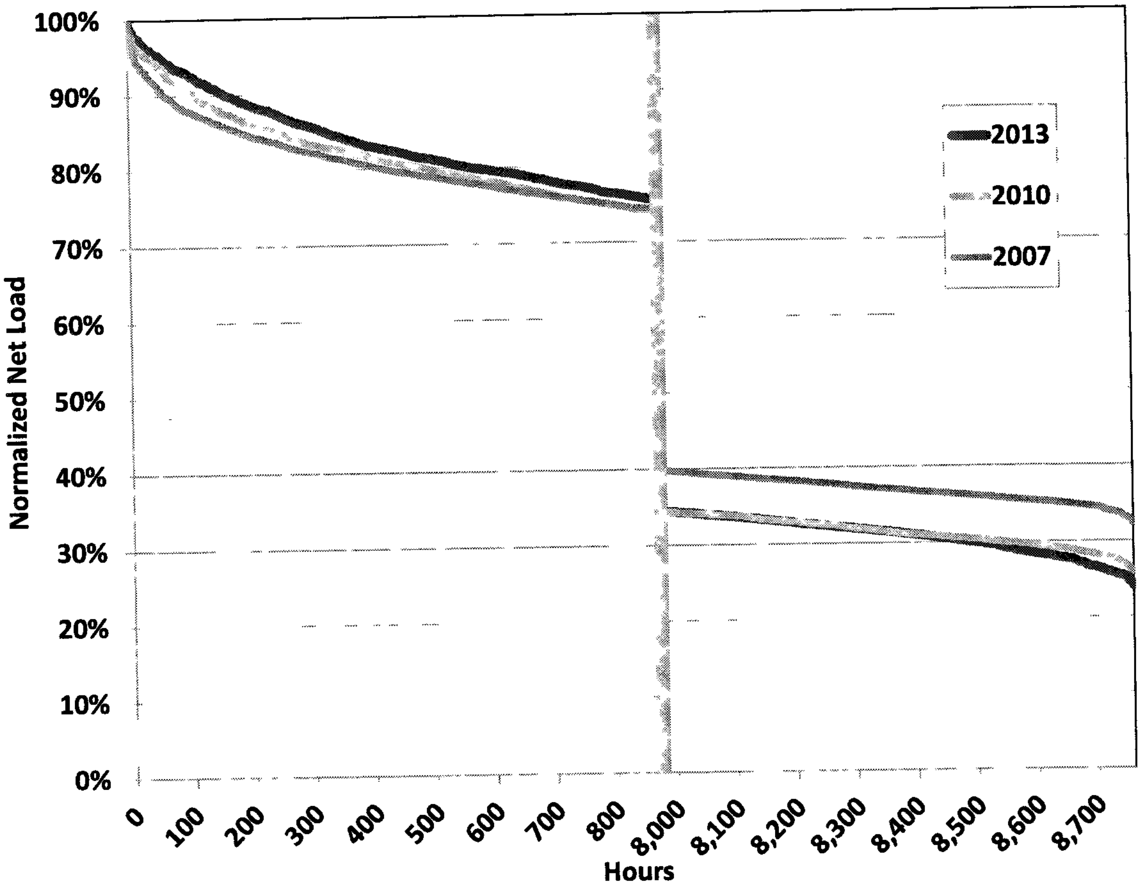


This figure shows the continued erosion of remaining energy available for non-wind units to serve during most hours of the year, with much less impact during the highest loads.

Even with the increased development activity in the coastal area of the South zone, nearly 80 percent of the wind resources in the ERCOT region are located in west Texas. 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.

Focusing on the left side of the net load duration curve shown in Figure 62, the difference between peak net load and the 95th percentile of net load has been between 9.5 and 12.5 GW for the previous seven years.

Figure 62: Top and Bottom Ten Percent of Net Load



On the right side of the net load duration curve, the minimum net load has dropped from approximately 20 GW in 2007 to below 16 GW last year, even with sizable growth in total annual load. This continues to put operational pressure on the 23.5 GW of nuclear and coal-fired generation currently installed in ERCOT.

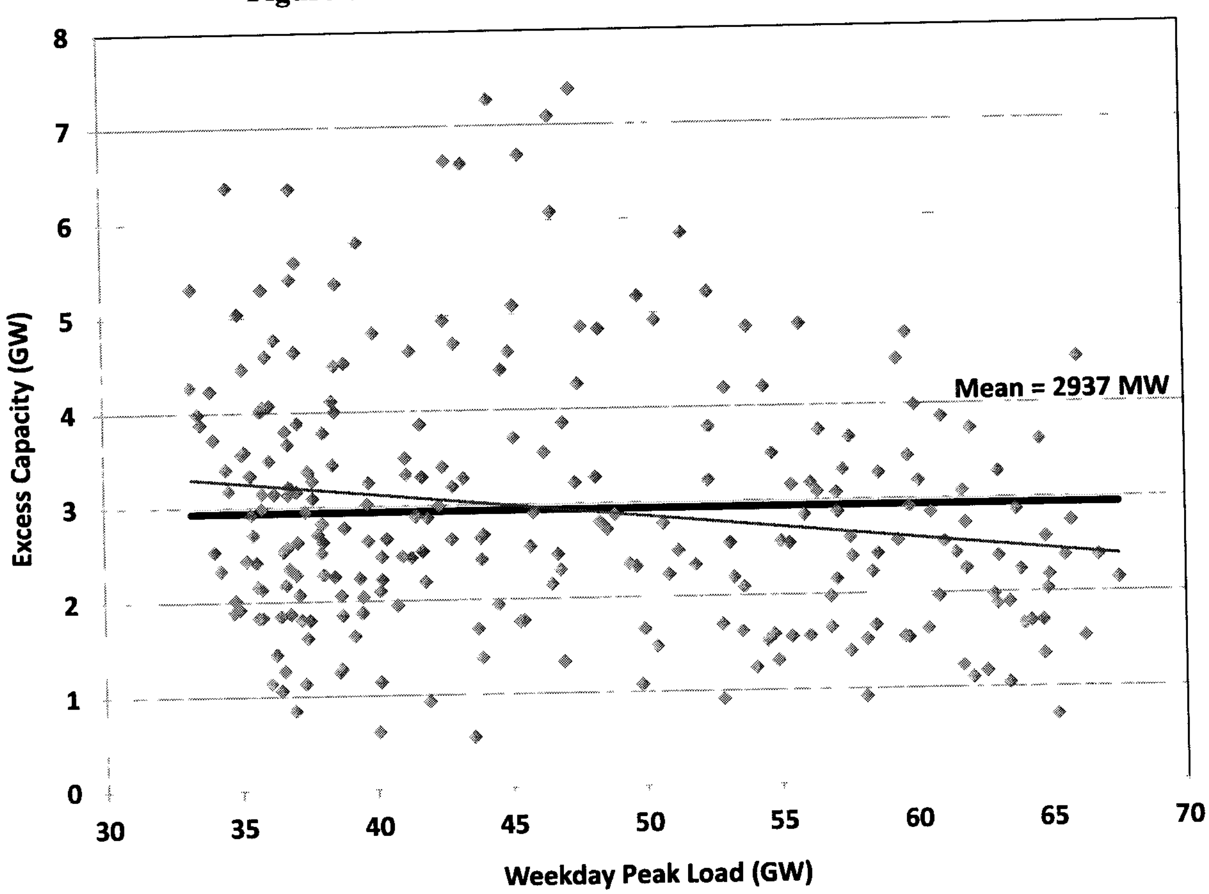
Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet is expected to operate for fewer hours as wind penetration continues to increase.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

2. Daily Generator Commitments

One of the important characteristics of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause apparent shortages in real-time and inefficiently high energy prices while over-commitment can result in excessive start-up costs, uplift charges, and inefficiently low energy prices.

This subsection evaluates the commitment patterns in ERCOT by examining the levels of excess capacity. Excess capacity is defined as the total capacity of online plus quick-start generators minus the demand for energy, responsive reserve, up regulation and non-spinning reserve provided from online capacity or quick-start units. To evaluate the commitment of resources in ERCOT, Figure 63 plots the excess capacity compared to peak load during 2013.

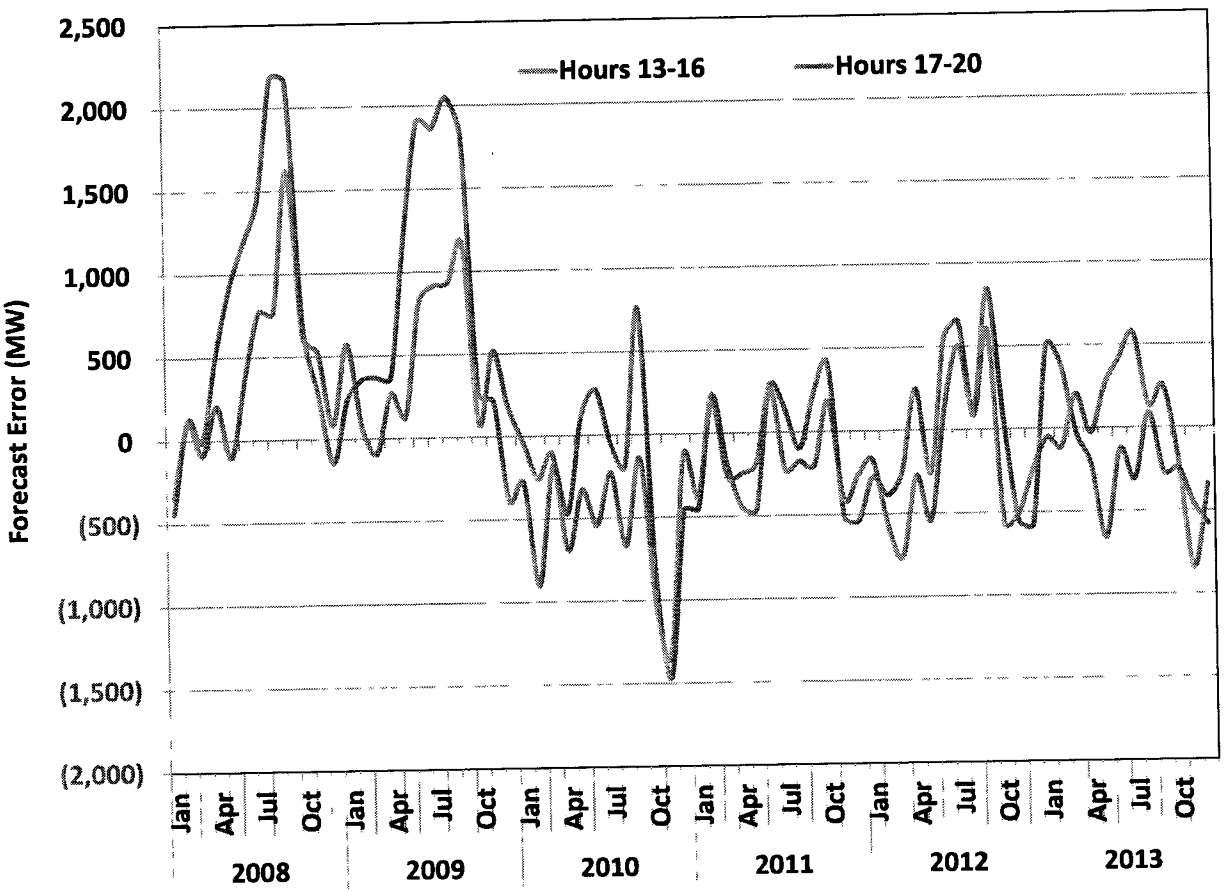
Figure 63: Excess On-Line and Quick Start Capacity



The figure shows the excess capacity in only the peak hour of each weekday because the largest generation commitment usually occurs at the peak hour. Hence, one would expect larger quantities of excess capacity in other hours. The excess on-line capacity during daily peak hours on weekdays, as shown in Figure 63, averaged 2,937 MW in 2013 which was approximately 7.7 percent of the average load in ERCOT. These values have remained consistent for the past three years. In 2012 the average excess on-line capacity was 2,880 MW, or 7.8 percent of average load and in 2011 the average was 2,901 MW, or 7.6 percent.

Even with improved unit commitment coming from having a day-ahead market, if ERCOT's day-ahead load forecast continued to show significant bias toward over-forecasting peak load hours,[11] we would expect to see over commitment of generation using non-market means.

Figure 64: Load Forecast Error



From Figure 64 we can see the noticeable reduction in ERCOT's load forecast bias since 2009. This was due to a procedure change implemented four years ago under which ERCOT identifies

11 See 2010 ERCOT SOM report at pages 49-51 and 2009 ERCOT SOM report at pages 68-70.

and subtracts out the bias from their load forecast and procures additional non-spin capacity in an equal amount. After being in place for four years this procedure has effectively reduced the amount of load forecast bias previously seen, and the corresponding adder to the amount of non-spin procure was minimal. As part of the "Methodologies for Determining Ancillary Service Requirements" document approved in December 2013, ERCOT will stop explicitly calculating the amount of load forecast bias as part of their calculation of the quantity of Non-Spin to procure.

Once ERCOT assesses the unit commitments resulting from the day-ahead market, additional capacity commitments are made, if needed, using a reliability unit commitment process that executes both on a day-ahead and hour-ahead basis. These additional unit commitments may be made for one of two reasons. Either additional capacity is required to ensure forecasted total demand will be met, or a specific generator is required to resolve transmission congestion.

Figure 65: Frequency of Reliability Unit Commitments

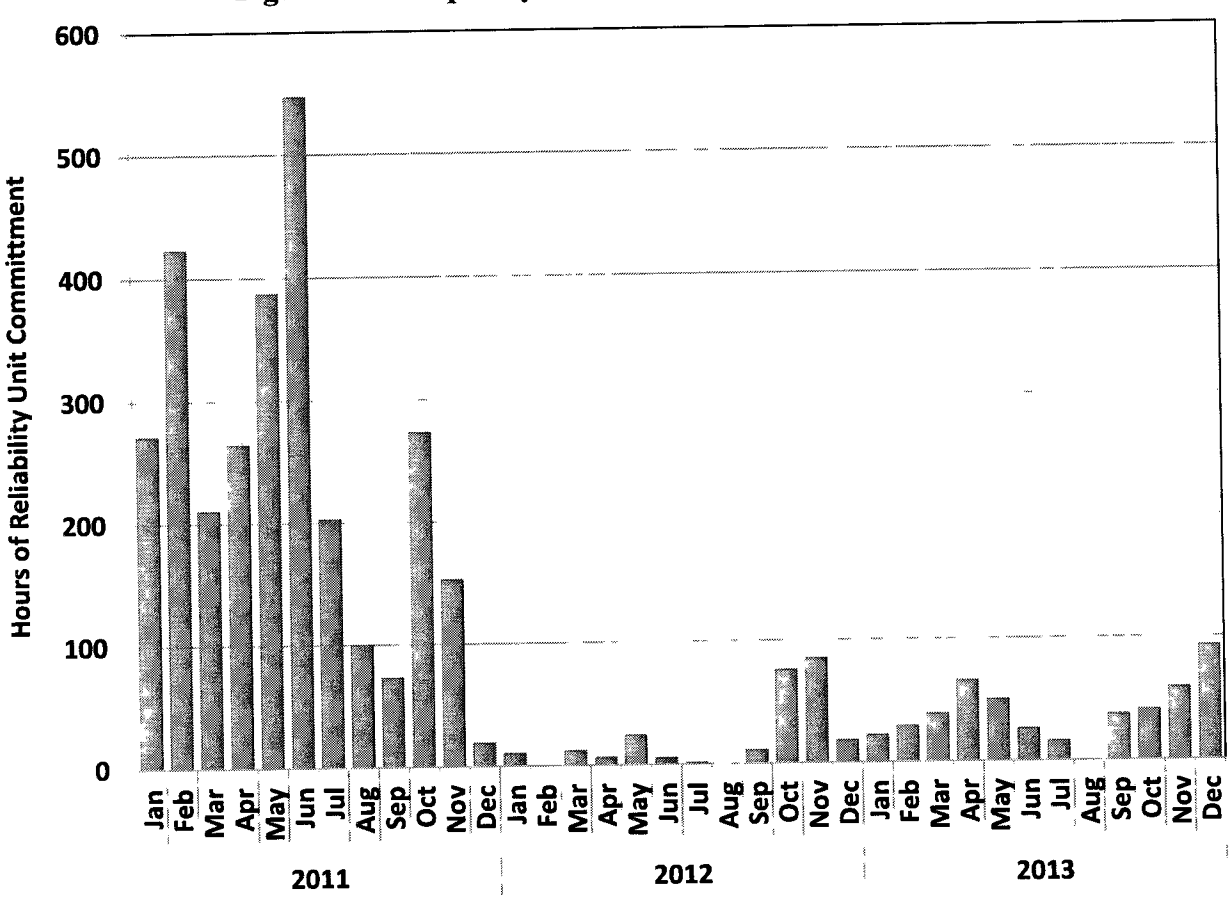


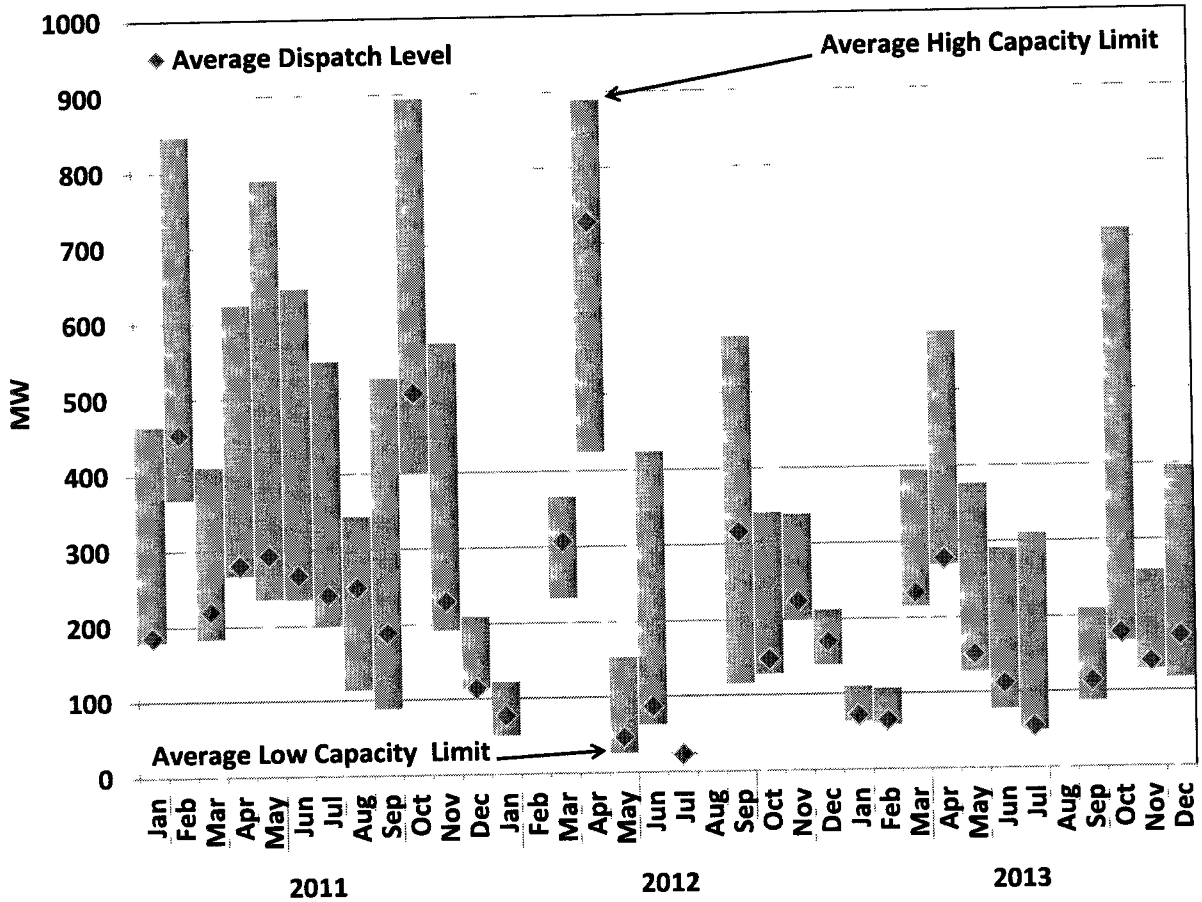
Figure 65 summarizes, by month, the number of hours with units committed via the reliability unit commitment process. We observe a significant reduction in the reliance upon the reliability unit commitment process in 2012 and 2013 as compared to 2011. Approximately one third of the hours during 2011 had at least one unit committed by ERCOT through the reliability unit commitment process. During 2013 the number of hours with at least one unit receiving a reliability unit commitment instruction was 5 percent, a slight increase from 2012 when the value was 3 percent.

The reduction can in part be attributed to the less extreme weather and resulting lower load levels experienced during 2012 and 2013. There also was an operational change midway through 2011 which also contributed to the reduced frequency of reliability unit commitments. During the initial months of operating the nodal market it was common for ERCOT to commit units that were providing non-spin reserves if they were needed to resolve congestion. This practice was greatly reduced starting in July 2011.

The majority of reliability unit commitment instructions are to resolve localized transmission constraints. Less than 15 percent of the unit hours of RUC instructions in 2013 were for system-wide capacity requirements.

The next analysis compares the average dispatched output of the reliability committed units with their operational limits. Figure 66 below shows that the quantity of reliability unit commitment generation in 2013 was similar to the 2012 quantities and both years were lower than 2011 quantities.

Figure 66: Reliability Unit Commitment Capacity



The largest amount of reliability unit commitment capacity typically occurs during off-peak months. Factors contributing to the high average capacity in October 2013 included an unseasonably warm day leading to system-wide capacity deficiency and localized generation requirements because of North to Houston and Valley import transmission constraints. April 2013 capacity needs were primarily in the DFW area for voltage support. The large amounts of reliability unit committed capacity in April 2012 were related to brief generator outages resulting in reactive power deficiencies in the Dallas-Fort Worth area. This was similar to the situation that existed during October 2011. The larger quantity of committed capacity in February 2011 was a result of ERCOT operator action taken to attempt to ensure overall capacity adequacy during both the extreme cold weather event that occurred early in the month, and a subsequent bout of cold weather that occurred one week later.

V. RESOURCE ADEQUACY

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. We begin this section with an evaluation of these economic signals by estimating the "net revenue" new resources would receive from the markets. Next, we review of the effectiveness of the Public Utility Commission's Scarcity Pricing Mechanism and ERCOT's planning reserve margin. We then describe the factors to necessary to ensure resource adequacy in an energy-only market design. We conclude this section with a review of the contributions from demand response toward meeting resource adequacy objectives in ERCOT.

A. Net Revenue Analysis

Net revenue is the total revenue that can be earned by a new generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the energy and ancillary services markets together provide the economic signals that inform suppliers' decisions to invest in new generation or retire existing generation. In long-run equilibrium, markets should provide sufficient net revenue to allow an investor to receive a return of, and on an investment in a new generating unit when that unit is needed. In the short-run, if the net short-run revenues produced by the market are not sufficient to justify entry, then one or more of these conditions exist:

- New capacity is not needed because there is sufficient generation already available;
- Load levels, and thus energy prices, are temporarily low due to mild weather or economic conditions;
- Market rules or operational practices are causing revenues to be reduced inefficiently; or
- Market rules are not sufficiently linked in short-term operations to ensure long-term resource adequacy objectives are met.

Likewise, the opposite would be true if the markets provide excessive net revenues in the short-run. The persistence of excessive net revenues in the presence of a capacity surplus is an indication of competitive issues or market design flaws. In this subsection, we analyze the net revenues that would have been received by various types of generators in each zone.

Although most suppliers are likely to receive the bulk of their revenues through bilateral contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and are appropriate to use for this evaluation. For purposes of this analysis, heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a combustion turbine, and 9.5 MMBtu per MWh for a new coal unit were assumed. Variable operating and maintenance costs of $4 per MWh for the natural gas units and $5 per MWh for the coal unit and fuel and variable operating and maintenance costs of $8 per MWh for the nuclear unit were assumed. For purposes of this analysis, a total outage rate (planned and forced) of 10 percent was assumed for each technology.

The energy net revenues are computed based on the generation weighted settlement point prices from the real-time energy market. Weighting the energy values in this way masks what may be very high locational values for a specific generator location. Some generators may also receive uplift payments because of their specific reliability contributions, either as a reliability must run unit, or through reliability unit commitment actions. 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 ramping restrictions, which can prevent 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.

Figure 67 shows the results of the net revenue analysis for four types of hypothetical new units in 2012 and 2013. These are: (a) natural gas-fired combined-cycle, (b) natural gas-fired combustion turbine, (c) coal-fired generator, and (d) a nuclear unit. For the natural gas units, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in other hours that it is available (*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.

Figure 67: Estimated Net Revenue by Zone and Unit Type

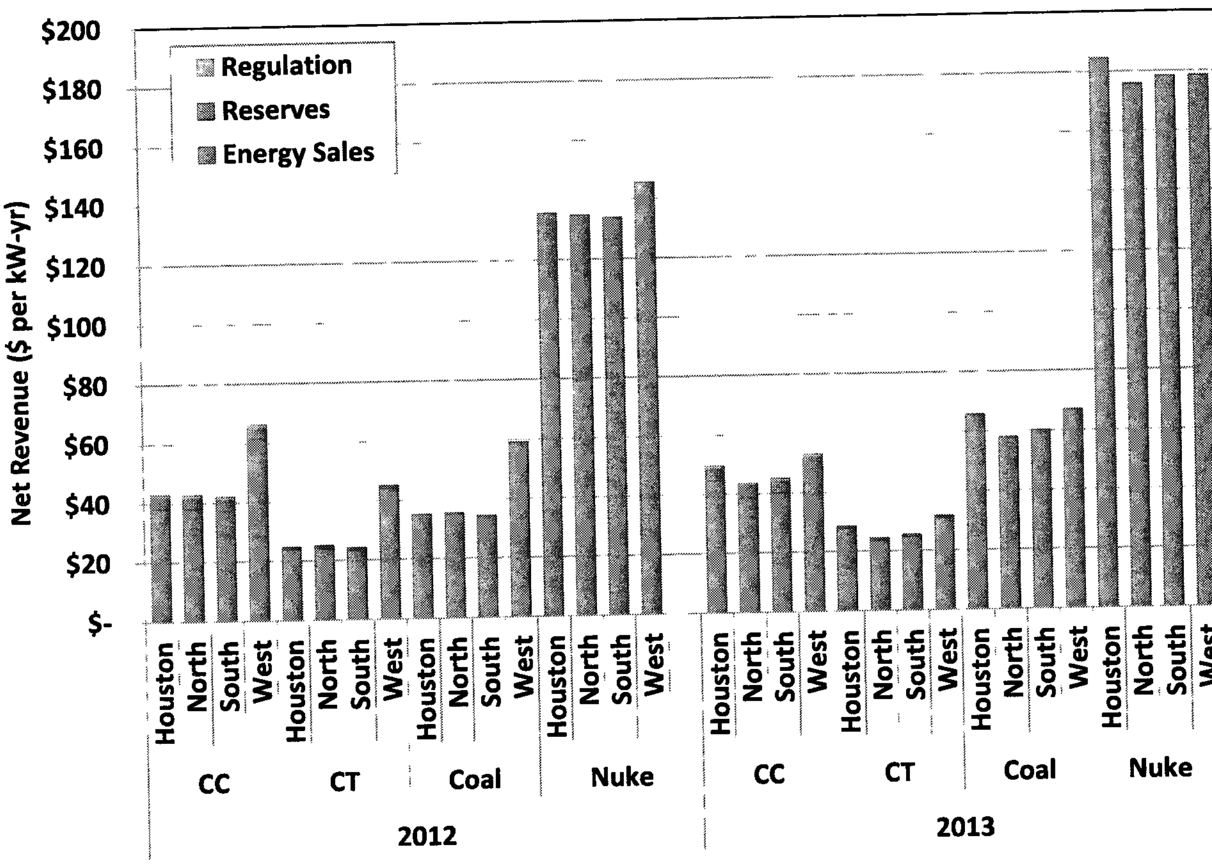


Figure 67 shows that the 2013 net revenue for the natural gas-fired technologies was similar to 2012 levels, with the notable exception of in the West zone. The decrease in net revenues in the West zone was due to reduced transmission congestion resulting in lower prices in the West zone. Net revenues for coal and nuclear technologies were higher in 2013 than in 2012 because of higher natural gas prices, but still not close to being sufficient to support new entry for either of these technologies.

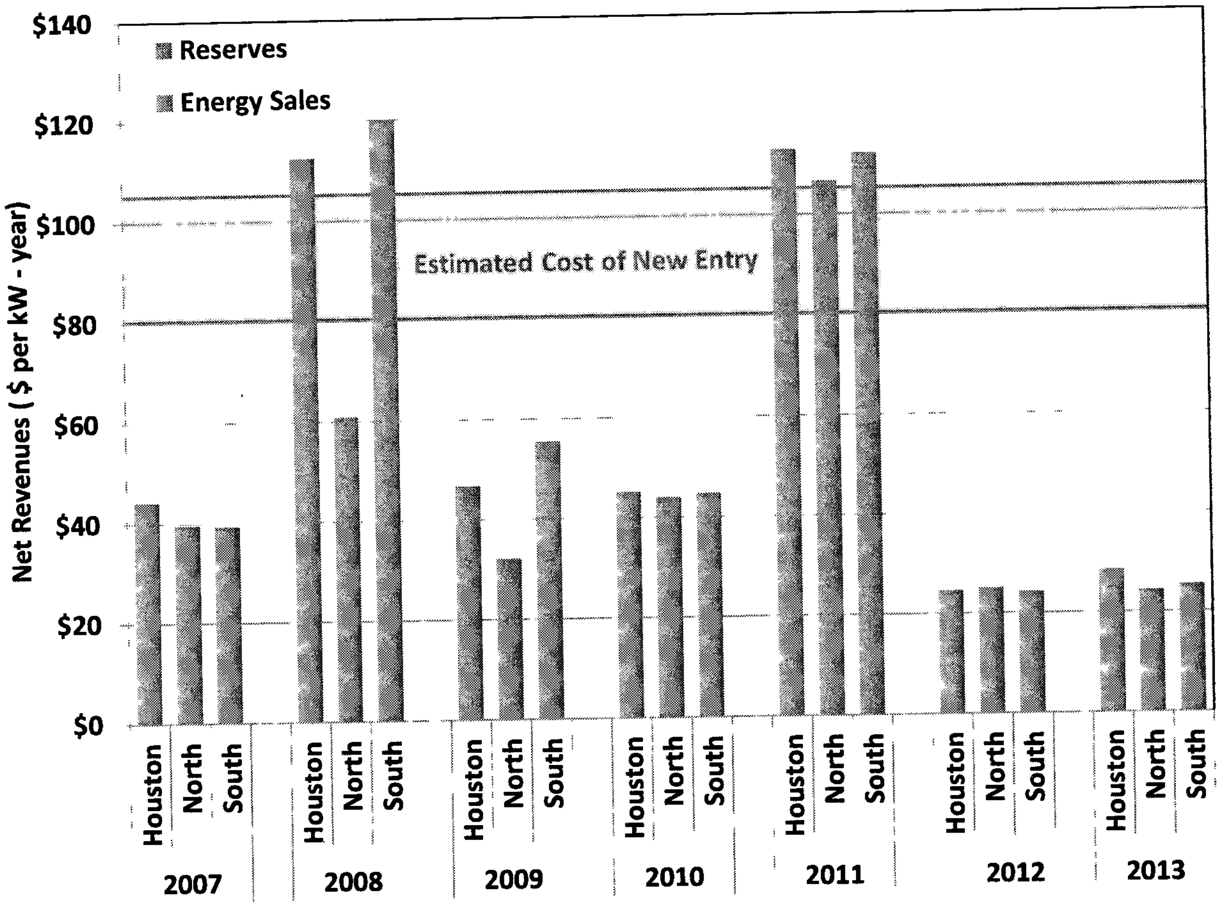
- For a new coal unit, the estimated net revenue requirement is approximately $275 to $350 per kW-year. The estimated net revenue in 2013 for a new coal unit ranged from $58 to $67 per kW-year.

- For a new nuclear unit, the estimated net revenue requirement is approximately $415 to $540 per kW-year. The estimated net revenue in 2013 for a new nuclear unit was approximately $180 per kW-year.

Prior to 2005, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. Higher natural gas prices through 2008 resulted in sustained energy prices 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. However, natural gas prices have been on the decline since 2008, resulting in reduced net revenues for coal and nuclear technologies. Even with the higher energy prices experienced in 2011, net revenues for these technologies were insufficient to support new entry. Very low natural gas prices and few occurrences of shortage pricing during 2012 resulted in 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. Although natural gas prices increased in 2013, the net revenue for coal and nuclear technologies continues to be insufficient to support new entry.

The next two figures provide an historical perspective of the net revenues available to support new gas turbine (Figure 68) and combined cycle generation (Figure 69).

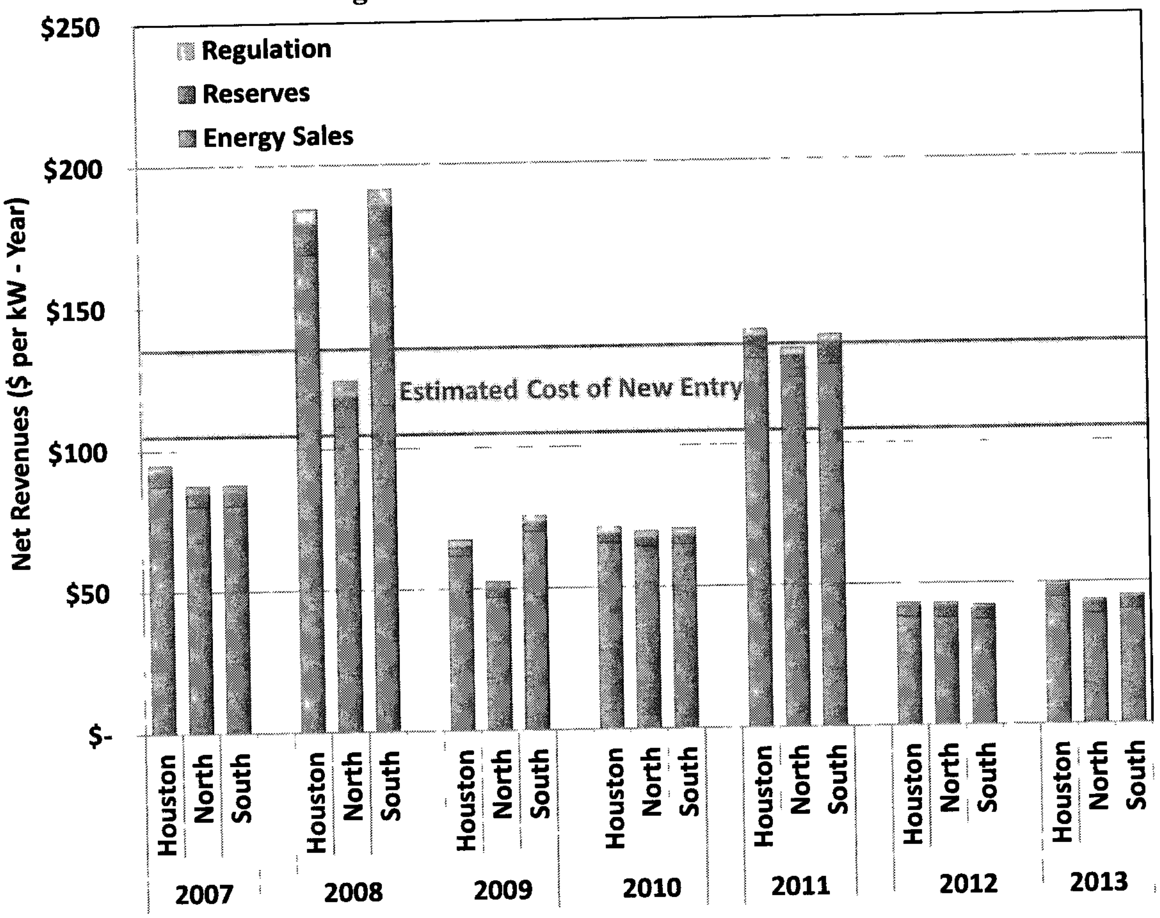
Figure 68: Gas Turbine Net Revenues



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 2013 for a new gas turbine was approximately $26 per kW-year, far below the levels required to support new gas turbine generation.

For a new combined cycle unit, the estimated net revenue requirement is approximately $105 to $135 per kW-year. The estimated net revenue in 2013 for a new combined cycle unit was approximately $45 per kW-year, also far below the levels to support new combined cycle generation in ERCOT.

Figure 69: Combined Cycle Net Revenues



Even though net revenues for the Houston and South zones in 2008 may have appeared to be sufficient to support new natural gas-fired generation, it was actually extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves which led to high prices and resulting higher than warranted net revenues. Discounting the effect that the 2008 results would have had on forward price signals, we find that 2011 has been the only year during our tenure monitoring the ERCOT market that net revenues have been sufficient to support either new gas turbine or combined cycle generation.

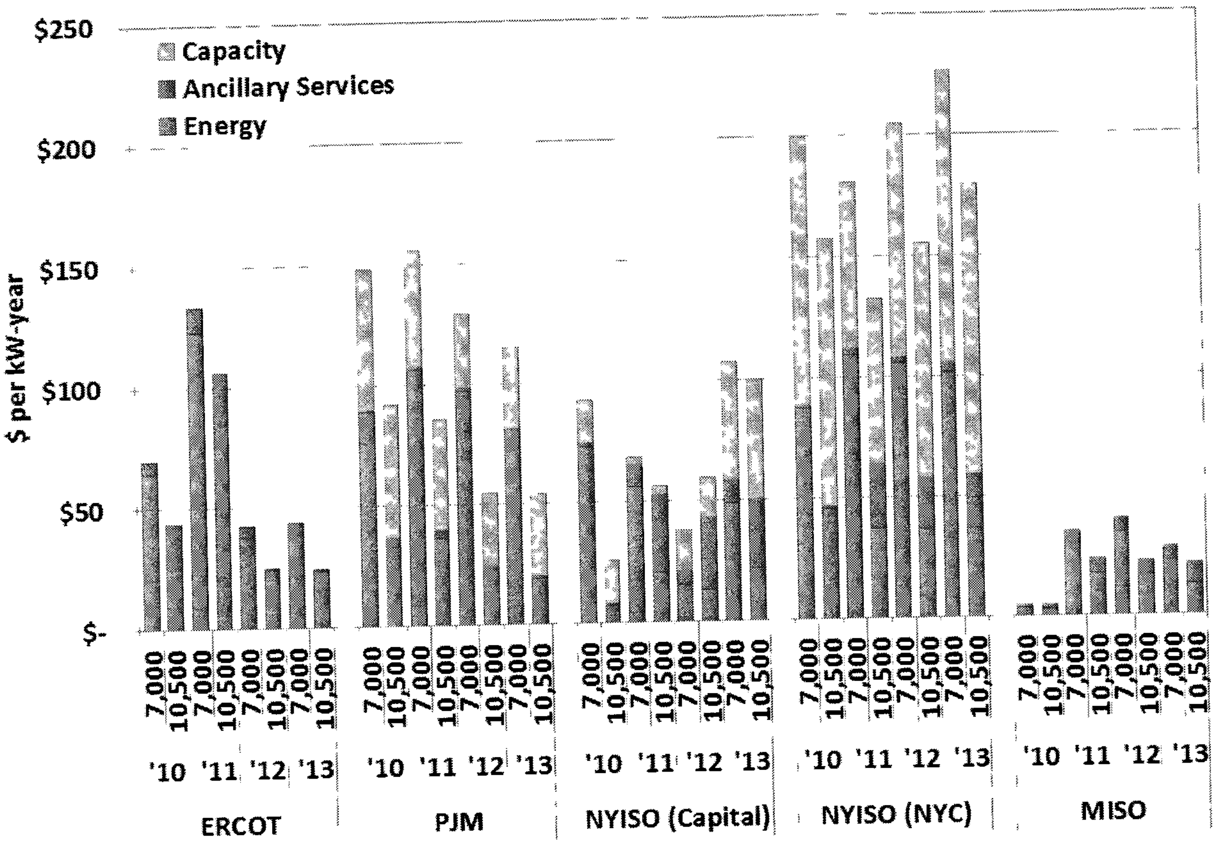
These results indicate that during 2013 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. The net revenues in 2013 were very similar to those in 2012, and both years were much lower than in 2011. This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

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

To provide additional context for the net revenue results presented in this subsection, we also compared the net revenue in the ERCOT market for two types of natural gas-fired technologies with the net revenue that those technologies could expect in other wholesale markets with centrally cleared capacity markets. The technologies are differentiated by their assumed heat rate; 7,000 MMBtu per MWh for combined cycle and 10,500 MMBtu per MWh for simple-cycle combustion turbine.

Figure 70 compares estimates of net revenue for the ERCOT North zone, PJM, two locations within the New York ISO, and the Midcontinent ISO. Most of these locations are central locations with the exception of New York City, which is significantly affected by congestion.

Figure 70: Comparison of Net Revenue of Gas-Fired Generation between Markets



The figure includes estimates of net revenue from energy, reserves and regulation, and capacity. ERCOT does not have a capacity market, and thus, does not have any net revenue from capacity sales. For that reason, the net revenues in ERCOT and MISO, which also lacks a functional capacity market, are the lowest among these markets. This is notable because ERCOT's reserve margin is also the lowest among these markets, which should contribute to higher net revenues.

Figure 70 shows net revenues in ERCOT for both technologies did not change much in 2013 when compared to 2012. Net revenues for both technologies decreased in PJM and Midcontinent ISO, while they increased for both technologies at both locations in NY ISO. In the figure net revenues are calculated for central locations. However, there are load pockets within each market where net revenue and the cost of new investment may be higher. Thus, even if new investment is not generally profitable in a market, it may be economic in certain areas. Finally, resource investments are driven primarily by forward price expectations, so historical net revenue analyses do not provide a complete picture of the future pricing expectations that will spur new investment. In an energy only market, we would expect net revenues to be less than required to support new investment. However, in the small number years that are much worse than normal, the sharp increase in the frequency of shortage pricing should cause the net revenues in that year to be multiples of the annual level required to support investment. This pattern over the long run must create an expectation that net revenues, on average, will support the new investments.

B. Effectiveness of the Scarcity Pricing Mechanism

The Public Utility Commission of Texas ("PUCT") adopted rules in 2006 that define the parameters of an energy-only market. These rules include a Scarcity Pricing Mechanism ("SPM") that increased the system-wide offer cap in multiple steps until it reached $3,000 per MWh shortly after the implementation of the nodal market. PUCT SUBST. R. 25.505 provides that the IMM may conduct an annual review of the effectiveness of the SPM. This subsection provides an assessment of the effectiveness of the SPM in 2013 under ERCOT's energy-only market structure.

Approved during 2012, new PUCT SUBST. R. 25.508 increased the system-wide offer cap to $4,500 per MWh effective August 1, 2012. Revisions to PUCT SUBST. R. 25.505 were also adopted that specified the following increases to the system-wide offer cap:

- $5,000 per MWh beginning on June 1, 2013,
- $7,000 per MWh beginning on June 1, 2014, and
- $9,000 per MWh beginning on June 1, 2015.

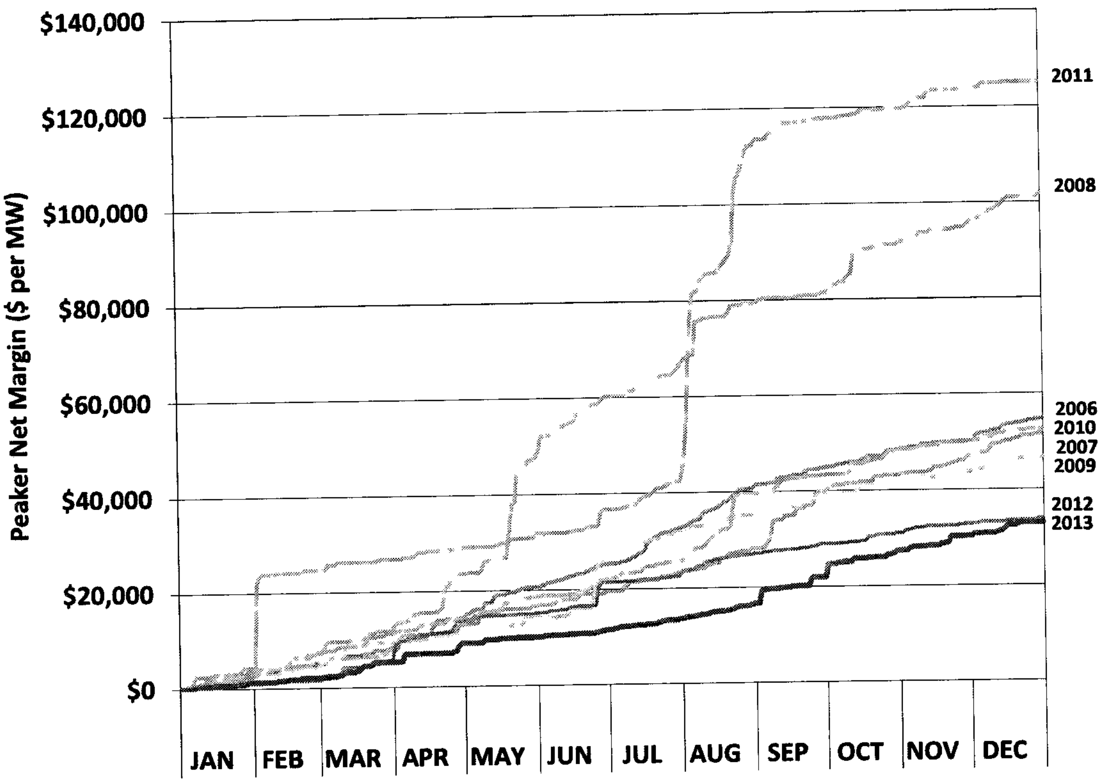
As shown in Figure 15 on page 15 there have been very brief periods when energy prices rose to the cap since the system-wide offer cap was increased to greater than $3,000 per MWh.

The SPM includes a provision termed the Peaker Net Margin ("PNM") that is designed to provide a fail-safe pricing measure, which if exceeded would result in reducing the system-wide offer cap. PNM also serves as a simplified measure of the annual net revenue of a hypothetical peaking unit.[12] This aspect of the rule was also amended in 2012. Under the current rule, if the PNM for a year reaches a cumulative total of $300,000 per MW, the system-wide offer cap is

[12] The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[13] Figure 71 shows the cumulative PNM results for each year from 2006 through 2013 and shows that PNM in 2013 was the lowest it has been since its implementation.

Figure 71: Peaker Net Margin



As previously described, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80,000 to $105,000 per MW-year. Thus, as shown in Figure 71 and consistent with the previous findings in this section relating to net revenue, the PNM was again nowhere near sufficient to support new entry in 2013. Only in two of the seven years since the rule was implemented has the PNM been sufficient – 2008 and 2011. A significant portion of the net revenue increase in 2008 was associated with extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves.[14] With these issues addressed in the zonal

13 For 2014 and each subsequent year, ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants. The PNM threshold for 2014 and each subsequent year will be set to $315,000 per MW-yr based on the analysis prepared by Brattle dated June 1, 2012, unless there is a change identified in the cost of new entry of new generation plants.

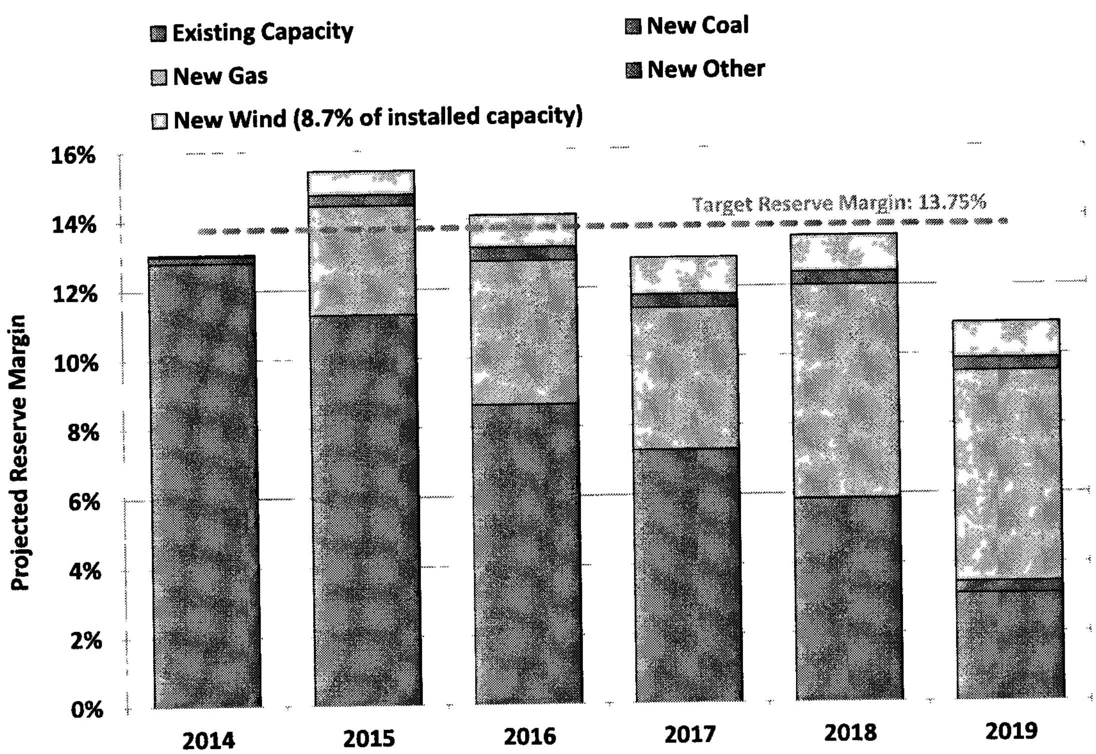
14 See 2008 ERCOT SOM Report at pages 81-87.

market, the PNM dropped substantially in 2009 and 2010. The extreme weather experienced in 2011 was highly anomalous. Hence, although the PNM may have been sufficient to cover the costs of a new combustion turbine in 2011, we would not expect this to be true on a continuous basis into the future.

C. Planning Reserve Margin

The prior subsection discusses and evaluates the economic signals produced by the ERCOT markets to facilitate efficient decisions by suppliers to maintain an adequate base of resources. This subsection summarizes and discusses the current level of capacity in ERCOT, as well as the long-term need for capacity in ERCOT. The figure below shows ERCOT's projection of reserve margins developed prior to the summer of 2014.

Figure 72: Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Report issued February 2014

Figure 72 above indicates that the region would have a 13.0 percent reserve margin heading into the summer of 2014. After completion of announced generation additions, the reserve margin is expected to reach 15.4 percent in 2015. This increase in expected reserve margin is partially a result of ERCOT's revised load forecasting methodology, which has reduced historical forecasts of load growth. The total quantity of expected future generation additions has also decreased. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which is expansions at existing facilities.

To compare the situation in ERCOT with other regions, Figure 73 provides the anticipated reserve margins for all the American NERC regions for the summer of 2014.[15]

Figure 73: Reserve Margins in Other Regions

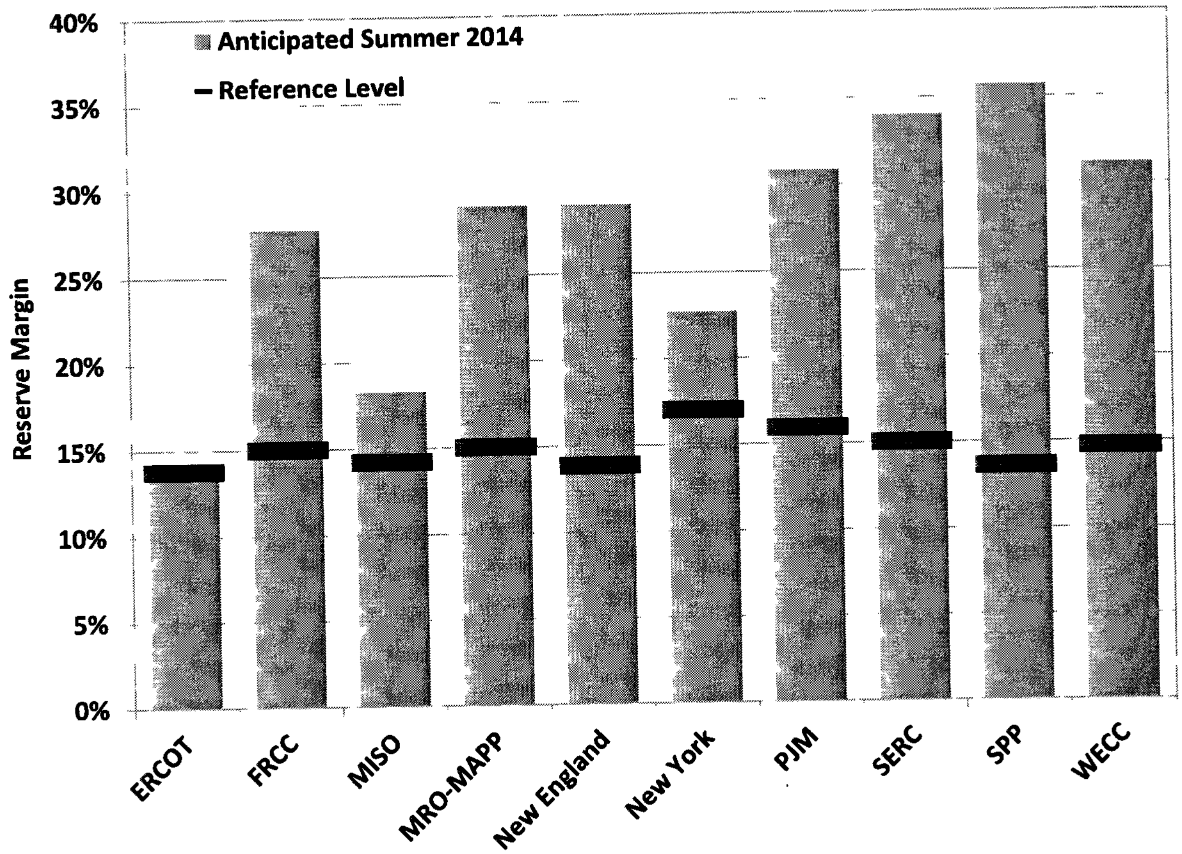


Figure 73 shows that required, or reference level reserve margins center around 15 percent across other regions. These regions run the gamut from traditional bundled, regulated utility service territories to fully competitive, centrally operated wholesale markets. There are large differences in the level of planning reserves expected for the summer of 2014. ERCOT is unique in that its

[15] Data from NERC 2013 Long-Term Reliability Assessment (December 2013) available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

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

D. Ensuring Resource Adequacy

One of the primary goals of an efficient and effective electricity market is to ensure that over the long term there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. In a region like ERCOT, where customer requirements for electricity are continually increasing, even with growing demand response efforts, maintaining adequate supply requires capacity additions. To incent these additions the market design must provide revenues such that the marginal resource receives revenues sufficient to make that resource economic. In this context, 'economic' includes both a return of, and on capital investment.

Generators earn revenues from three sources: energy prices during non-scarcity, energy prices during scarcity and capacity payments. The capacity payments generators receive in ERCOT are related to the provision of ancillary services. As we described in the discussion of net revenue in a previous subsection, ancillary service payments are a small contributor: $5 - $10 per kW-year. Setting them aside, generator revenue in ERCOT is overwhelmingly derived from energy prices under both scarcity and non-scarcity conditions.

Expectations for energy pricing under non-scarcity conditions are the same regardless of whether payments for capacity exist, or not. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under scarcity conditions must be large enough to provide the necessary incentives for new capacity additions. This will occur when energy prices are allowed to rise substantially at times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements.

Ideally, energy and reserve prices during shortages should reflect the diminished system reliability under these conditions, which is equal to the increased probability of "losing" load times the value of the lost load. Allowing energy prices to rise during shortages mirrors the outcome expected if loads were able to actively specify the quantity of electricity they wanted and the price they would be willing to pay. The energy-only market design relies exclusively on these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment when required. In this way, energy-only markets can provide price signals that will sustain a portfolio of resources to be used in real time to satisfy the needs of the system. However, this portfolio may produce a planning reserve margin that is less than the planning reserve target.

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 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 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 there is a shortage of supply in the market, the marginal action first 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.

Faced with reduced levels of generation development activity coupled with higher than expected loads resulting in diminishing planning reserve margins, the PUCT has devoted considerable effort recently deliberating issues related to resource adequacy. In addition to increasing the system-wide offer cap and adjusting the Peaker Net Margin threshold, as previously described, these deliberations have included the question of whether the planning reserve margin is a target or a minimum requirement. Further, if it is a minimum requirement, whether the energy-only market design can ensure the desired reliability level or whether an alternate market design mechanism may be required. To date, the PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to introduce an additional pricing mechanism based on the quantity of available operating reserves.

Regardless of the means by which revenues are produced in a wholesale electricity market, it is fundamental that investment will only occur when the total net revenues expected by the investor are greater than its entry costs, which include profit on its investment. Additionally, these sources of revenue must be available to all resources, both new and existing, in order to facilitate efficient investment, maintenance, and retirement decisions by all suppliers.

In an energy only market, the primary source of such revenue is the net revenues received during periods of shortage. Expectations about both the magnitude of the energy price during shortage conditions and the frequency of shortage conditions are the primary means to attract new investment in an energy-only market. If the expected revenues are not high enough to facilitate enough investment to satisfy the planning reserve target, one option is to increase the shortage pricing levels to levels that substantially exceed the expected value of lost load. As the planning reserve levels grow, however, the frequency of shortages will tend to drop sharply, which can make it difficult to use this means to meet planning reserve requirements.

Most other competitive electricity markets do not rely solely on shortage pricing to generate sufficient revenue to support the capacity additions necessary to satisfy their planning reserve requirements. They employ capacity markets to competitively generate capacity payments over the year that are made to suppliers in return for meeting defined capacity obligations. Capacity prices and associated payments vary monthly or annually based on long-term planning reserve levels, independent of the real-time supply and demand conditions. These capacity markets are designed to ensure that a specified planning reserve margin is achieved.

With the implementation of the nodal market, more reliable and efficient shortage pricing has been achieved by establishing pricing rules that recognize when operating reserve shortages exist and allowing energy prices to rise automatically. Figure 16 on page 16 clearly shows this relationship between increasing prices as operating reserve levels decline. This approach is more reliable than what existed in the previous zonal market because it is not dependent upon the submission of high-priced offers by small market participants to be effective. It is also more efficient during the vast majority of time in which shortage conditions do not exist because it is not necessary for market participants to effectively withhold lower cost resources by offering relatively small quantities at prices dramatically higher than their marginal cost. 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.

In conjunction with the offer floors for non-spinning reserves, the Power Balance Penalty Curve ("PBPC") and the offer floors for up regulation and responsive reserve provided from generation resources defines the relationship between the quantity of operating reserve deficiency and the resulting energy price. The PBPC was modified during 2013 in conjunction with the increase in the system-wide offer cap to $5,000 per MWh. This curve is shown below in Table 4.

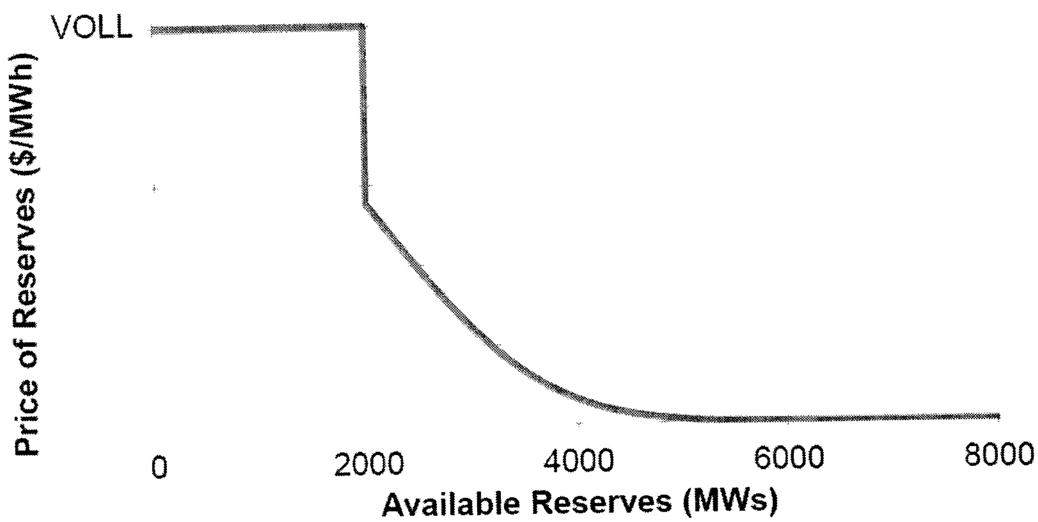
Under the current curve, if operating reserves are deficient by 5 MW or less, the energy price will be $250 per MWh. If the deficiency is greater than 150 MW but less than 200 MW, the energy price would be set at $4,000 per MWh. Once the 200 MW from the PBPC is exhausted, the only remaining energy available is from generator provided responsive reserves and up regulation reserves. Since energy provided by these services is required to be offered at the system-wide offer cap, real-time energy prices will be set at that level.

Table 4: Power Balance Penalty Curve

Maximum Operating Reserve Deficiency (MW)	Energy Price ($ per MWh) Current Curve
5	$250
10	$300
20	$400
30	$500
40	$1,000
50	$2,250
100	$3,000
150	$3,500
200	$4,000
>200	$5,001

The current relationship between operating reserve deficiency and energy prices defined by the PBPC and the operating reserve offer floors has no real analytic basis other than having its end anchored by the system-wide offer cap. As directed by the PUCT, a more analytically rigorous approach will be introduced to complement the PBPC. The Operating Reserve Demand Curve ("ORDC") is an operating reserve pricing mechanism that reflects the loss of load probability ("LOLP") at varying levels of operating reserves multiplied by the value of lost load ("VOLL"). Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC will create a new payment mechanism for online and offline reserves. As the quantity of reserves decreases, payments will increase. As conceptualized below in Figure 74, once available reserve capacity drops to 2000MW, payment for reserve capacity will rise to VOLL, or $9000 per MWh.

Figure 74: Operating Reserve Demand Curve



These changes will likely increase the net revenues a new investor would expect during shortage conditions. Whether they will be sufficient to maintain capacity margins near the target reserve margin is unknown, which will require continued monitoring and evaluation. If it does not, the reliability implications of allowing the planning reserve margin to fall will need to be assessed and other changes in the ERCOT markets to improve long-run economic signals may need to be considered.

With regard to the ORDC, we are also concerned that prices resulting from ORDC will rise to levels approaching the VOLL when the available reserves are at levels where the LOLP is less than 1.0 and involuntary load curtailment is not imminent, which may facilitate inefficient actions by participants when these conditions are probable. We will evaluate this concern going forward as the ORDC is fully implemented.

Finally, we continue to recommend that ERCOT implement a system to co-optimize energy and ancillary services because this would improve the efficiency of ERCOT's dispatch, more fully utilize its resources, and allow for improvements in its shortage pricing.

E. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to certain market or system conditions. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to a generating resource. The ERCOT Protocols allow for loads to actively participate in the ERCOT administered markets as Load Resources. Additionally, loads may participate passively in the market by simply adjusting consumption in response to observed prices. Unlike active participation in ERCOT administered markets, passive demand response is not directly tracked by ERCOT.

ERCOT allows qualified load resources to offer responsive reserves and non-spinning reserves into the day-ahead ancillary services markets. Those providing responsive reserves must have high set under-frequency relay equipment, which enables the load to be automatically tripped when the frequency falls below 59.7 Hz, which will typically occur only a few times in each year. Deployments of non-spinning reserves occur much more frequently. To date, load resources have shown a clear preference for providing responsive reserve service.

As of December 2013, approximately 2,950 MW of capability were qualified as Load Resources. Figure 75 shows the amount of responsive reserves provided from load resources on a daily basis in 2013. The high level of participation by demand response in the ancillary service markets sets ERCOT apart from other operating electricity markets. For reliability reasons the maximum amount of responsive reserves that can be provided by load resources was limited to 1,150 MW until April 2012. At that time, the limitation on load resources providing responsive reserve increased to 1,400 MW, corresponding with the increase in total responsive reserve requirements.

Figure 75: Daily Average of Responsive Reserves provided by Load Resources

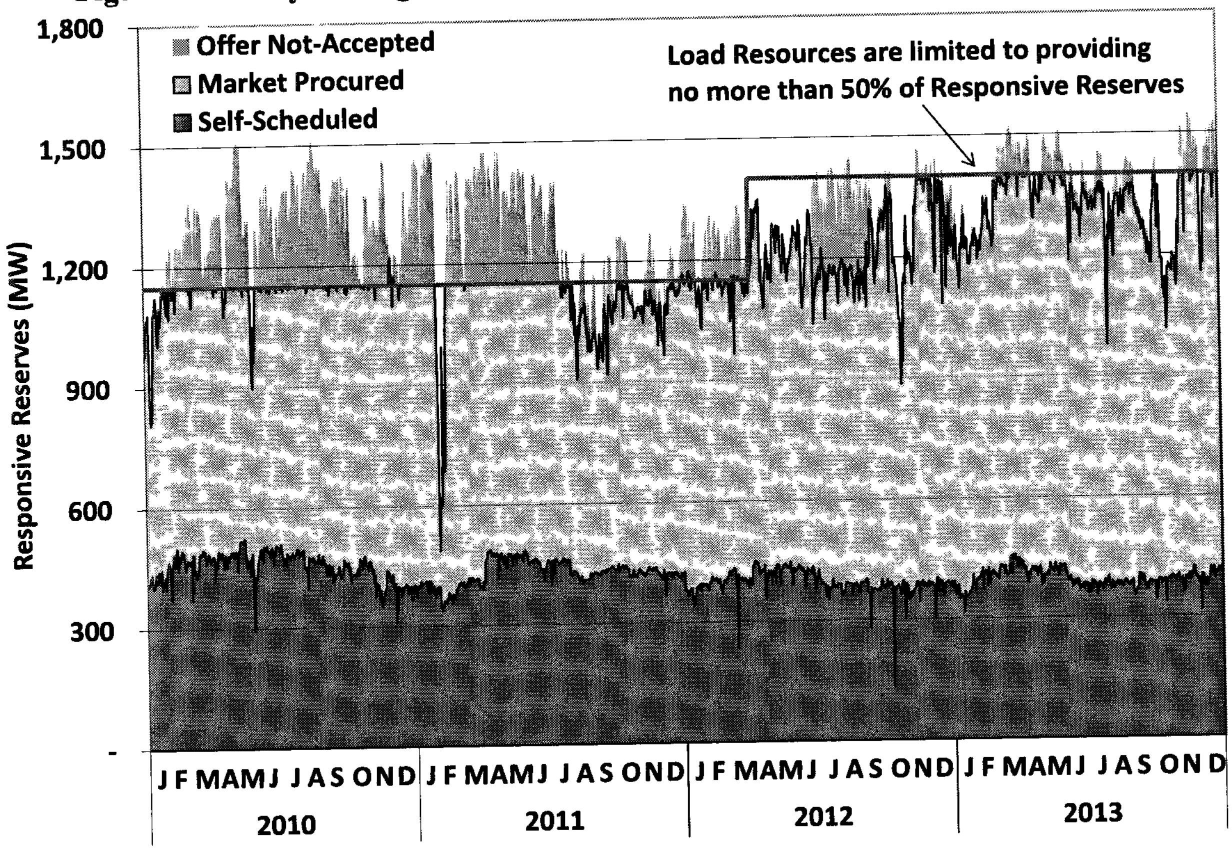


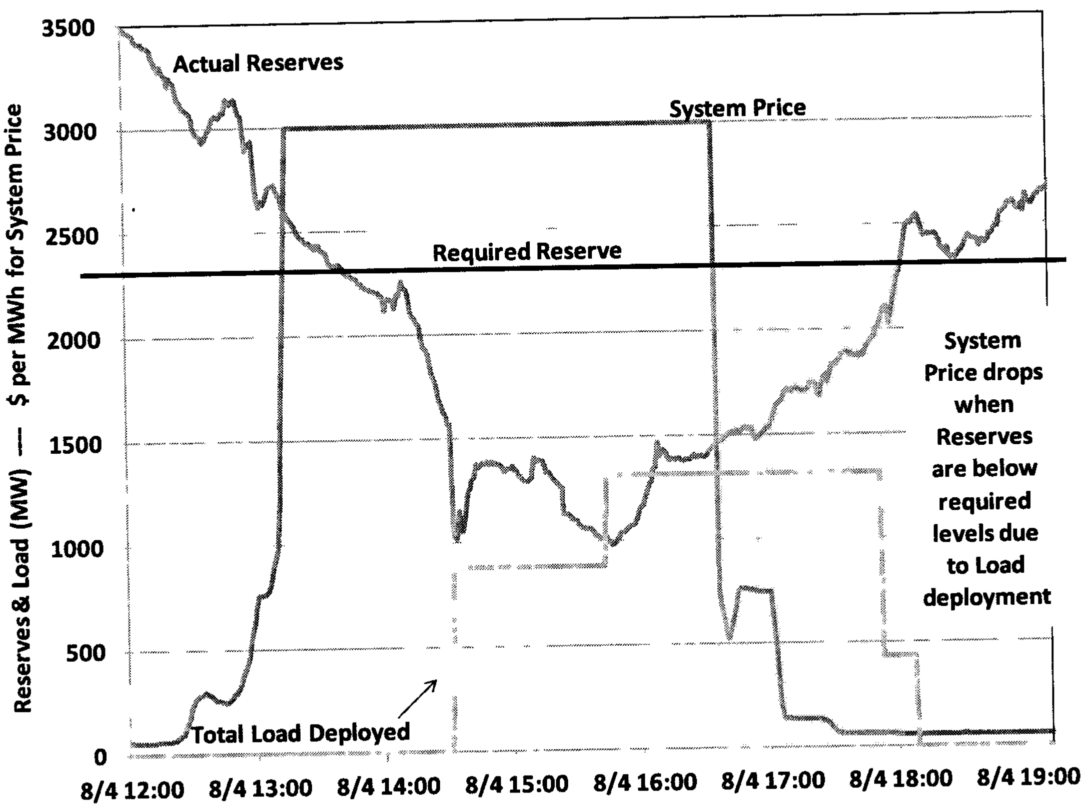
Figure 75 shows that it took a few months after implementing the increased requirement for the amount of offers by load resources to routinely reach this level. During 2011 there was a significant reduction in loads offering to provide responsive reserve during early February and again starting in mid-July. Both of these times corresponded with expected high real-time prices. Since load resources provide capacity by reducing their consumption, they have to actually be consuming energy to be eligible to provide the capacity service. During periods of expected high prices the price paid for the energy can exceed the value received from providing responsive reserves.

Pricing During Load Deployments

During times when there are shortages of supply offers available for dispatch and Responsive Reserves are deployed, that is, converted to energy as one of the last steps taken before shedding firm load, 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.

Unfortunately, ERCOT's dispatch software does not recognize that load has been curtailed, and computes prices based on supplying only the remaining load. A good example of this situation occurred on August 4, 2011. Figure 76 displays available reserves and the system price for that afternoon and shows that even though reserves were below required levels, system price dropped to $60 per MWh. At this level prices are being set based on supply offers and do not reflect the value of the load that is being curtailed to reliably serve the remaining system demand.

Figure 76: Pricing During Load Deployments



In 2014 ERCOT will take the first step toward including the actions taken by load during the real-time energy market. The first phase of "Loads in SCED" will allow those controllable loads that can respond to 5 minute dispatch instructions to specify the price at which they no longer wish to consume. Although an important first step, there are very few loads that can respond to price in this manner.

We recommend that ERCOT implement system changes that will ensure that ***all*** demand response that is actively deployed by ERCOT be able to set the price at the value of load at times when such deployments are necessary to reliably serve the remaining system demand. This includes load resources and Emergency Response Service (ERS) providers being deployed for the services they contracted to provide or when firm load is involuntarily curtailed. It may be possible to integrate load bids and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal. Alternatively, it may be adequate to address this concern through administrative shortage pricing rules.

VI. Analysis of Competitive Performance

In this section we evaluate market power from two perspectives, structural (does market power exist) and behavioral (have attempts been made to exercise it). We examine market structure by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal increased at higher levels of demand. This is consistent with observations in prior years. This section also includes a summary of the Voluntary Mitigation Plans in effect during 2013. To evaluate participant conduct we estimate measures of physical and economic withholding. We examine withholding patterns relative to the level of demand and the size of each supplier's portfolio. In this discussion we single out the conduct of one participant that was noticeable for being outside the bounds of competitive expectations. However, the behavior is allowed under current PUCT Rules and its impact on prices was minimal.

Based on these analyses, we find the overall performance of the ERCOT wholesale market to be competitive in 2013.

A. Structural Market Power Indicators

We analyze market structure by using the Residual Demand Index ("RDI"), a statistic that measures the percentage of load that could not be satisfied without the resources of the largest supplier. The RDI is used to measure the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers.[16] When the RDI is greater than zero, the largest supplier is pivotal (i.e., its resources are needed to satisfy the market demand). When the RDI is less than zero, no single supplier's resources are required to serve the load as long as the resources of its competitors are available.

The RDI is a useful structural indicator of potential market power, although it is important to recognize its limitations. As a structural indicator, it does not illuminate actual supplier behavior to indicate whether a supplier may have exercised market power. The RDI also does not indicate

[16] For the purpose of this analysis, "quick-start" includes off-line simple cycle gas turbines that are flagged as on-line in the current operating plan with a planned generation level of 0 MW that ERCOT has identified as capable of starting-up and reaching full output after receiving a dispatch instruction from the real-time energy market.

whether it would have been profitable for a pivotal supplier to exercise market power. However, it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

Figure 77 shows the RDI relative to load for all hours in 2013. The trend line indicates a strong positive relationship between load and the RDI. This analysis shown below is done at the QSE level because the largest suppliers that determine the RDI values own a large majority of the resources they are offering. It is possible that they also control other capacity through bilateral arrangements, although we do not know whether this is the case. To the extent that the resources scheduled by the largest QSEs are not controlled by or provide revenue to the QSE, the RDIs will tend to be slightly overstated.

Figure 77: Residual Demand Index

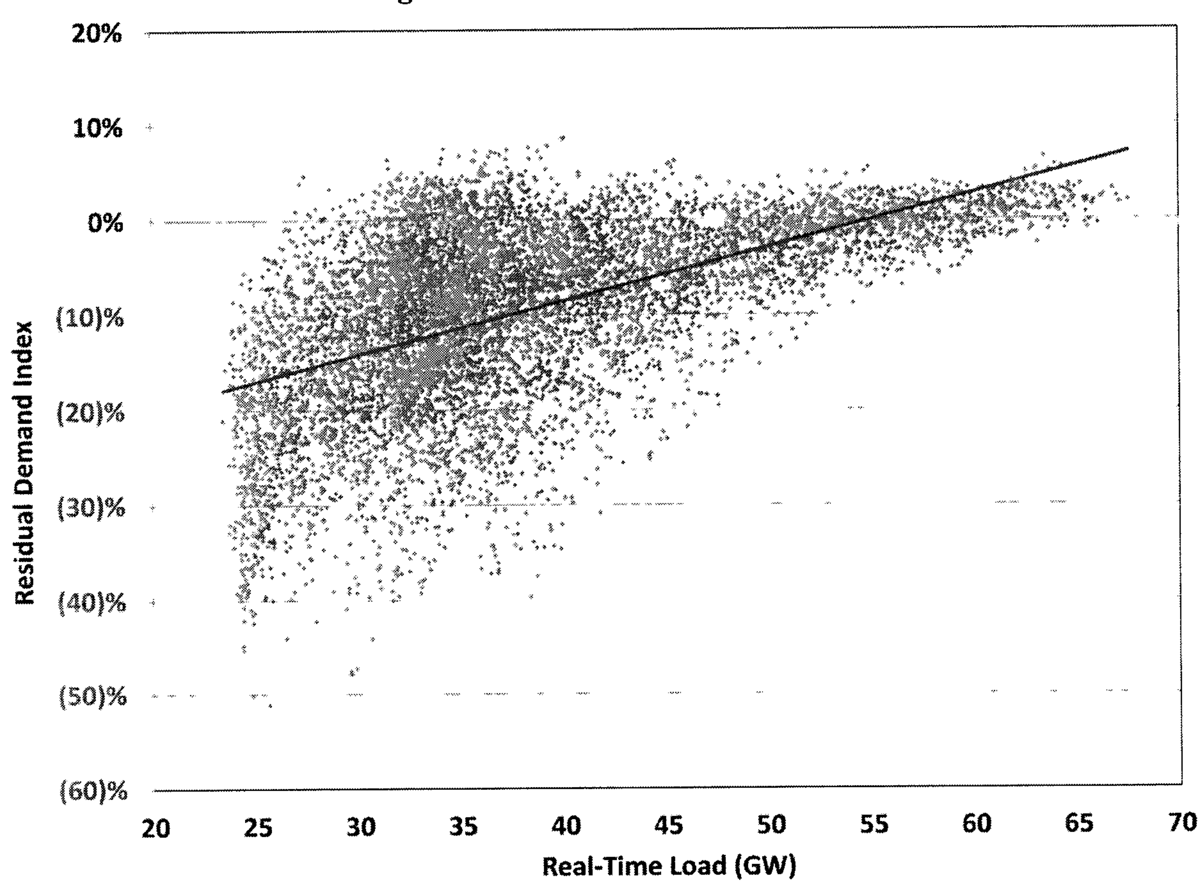
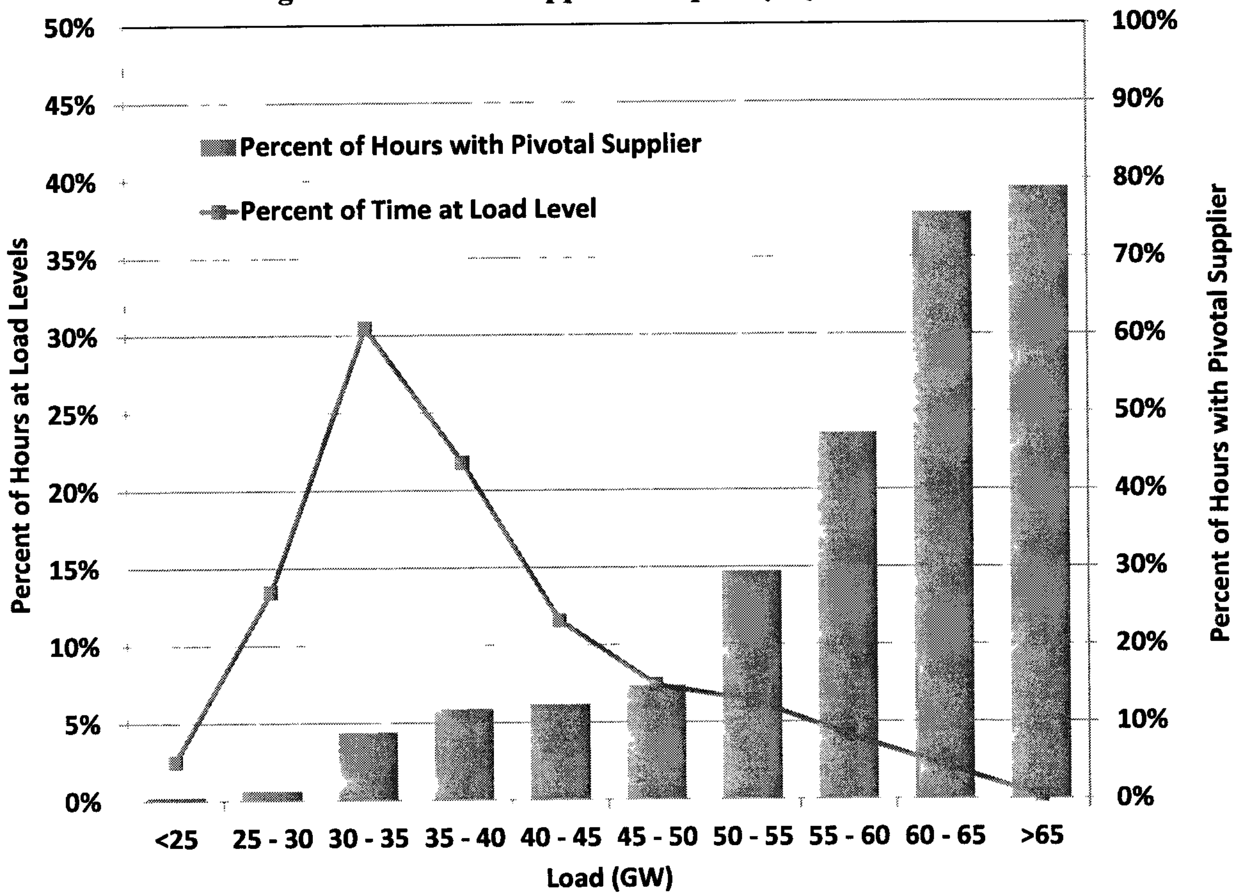


Figure 78 below summarizes the results of our RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 79 percent of the time. The figure also displays the percentage of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately 14 percent of all hours of 2013, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that address it.

Figure 78: Pivotal Supplier Frequency by Load Level



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

Voluntary Mitigation Plans

Voluntary Mitigation Plans ("VMP") existed for three market participants – NRG, Calpine and GDF SUEZ – during 2013. Generation owners are motivated to enter into VMPs because adherence to a plan approved by the commission constitutes an absolute defense against an allegation of market power abuse through economic withholding with respect to behaviors addressed by the plan. This increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market, must be balanced by appropriate protections against a potential abuse of market power in violation of PURA §39.157(a) and PUCT SUBST. R. 25.503(g)(7).

It is our position that VMPs should promote competitive outcomes and prevent abuse of market power in the ERCOT real-time energy market through economic withholding. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market) because the price in forward energy markets is derived from the real-time energy prices. Because the forward energy markets are voluntary and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

The plan approved for NRG in June 2012 allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit (5 percent for each coal/lignite unit) may be offered no higher than the higher of $500 per MWh or 50 times the natural gas price. Additionally, up to 3 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions would be less than 500 MW.

Calpine's VMP was approved in March of 2013. Because their generation fleet is entirely fueled by natural gas, the details of Calpine's plan are somewhat different that NRG's. Calpine may offer up to 10 percent of their portfolio's dispatchable capacity at prices up to $500 per MWh. Additionally, Calpine may offer up to 5 percent of their portfolio's dispatchable capacity at prices no higher than the system-wide offer cap. The amount of capacity covered by these provisions would also be less than 500 MW.

Allowing offers up to these high levels is intended to accommodate potential legitimate fluctuations in marginal cost that may exceed the base offer caps, such as operational risks, short-term fluctuations in fuel costs or availability, or other factors. However, both NRG's and Calpine's VMPs contains a requirement that these offers, if offered in any hour of an operating day, must be offered in the same price/quantity pair for all hours of the operating day. This provision, along with the quantity limitations, significantly reduces the potential that the VMPs will allow market power to be exercised.

The final key element in these two VMPs is the timing of termination. The approved VMPs for NRG and Calpine may each be terminated after three business days' notice. PURA §39.157(a) defines market power abuses as "practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition..." The exercise of market power may not rise to the level of an abuse of market power if it does not unreasonably impair competition, which would involve profitably raising prices significantly above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMP are designed based on experience to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner rather than persisting and rising to the level of an abuse of market power.

The VMP for GDF SUEZ was approved in March 2013 and confirmed that the amount of capacity in their portfolio does not exceed 5 percent of installed capacity in ERCOT. Given that their generation portfolio does not exceed the threshold set in P.U.C Subst. R. 25.504 (c), GDF SUEZ is deemed not to have ERCOT-wide market power, and therefore has "an absolute defense against an allegation of an abuse of market power through economic withholding with respect to real-time energy offers up to and including the system-wide offer cap."[17]

Although 5 percent of total ERCOT capacity may seem like a small amount, the potential market impacts of a market participant whose size is just under the 5 percent threshold choosing to exercise flexibility and offering a significant portion of their fleet at very high prices could be large.

The figure below shows the amount of surplus capacity available in each hour of every day during 2011, 2012 and 2013. For this analysis, surplus capacity is defined as online generation plus any offline capacity that was available day ahead, plus DC Tie imports (minus exports), minus responsive reserves provided by generation and regulation up capacity, minus load. Over the past three years there were 13 hours with no surplus capacity, the large majority occurring in 2011. These correspond to times when ERCOT was unable to meet load and maintain all operating reserve obligations.

Currently, the 5 percent "small fish" threshold is roughly 4,000 MW, as indicated by the red line in Figure 79. There were 465 hours over the past three years with less than 4,000 MW of surplus capacity. During these times a large "small fish" would have been pivotal and able through their offers to increase the market clearing price, potentially as high as the system-wide offer cap.

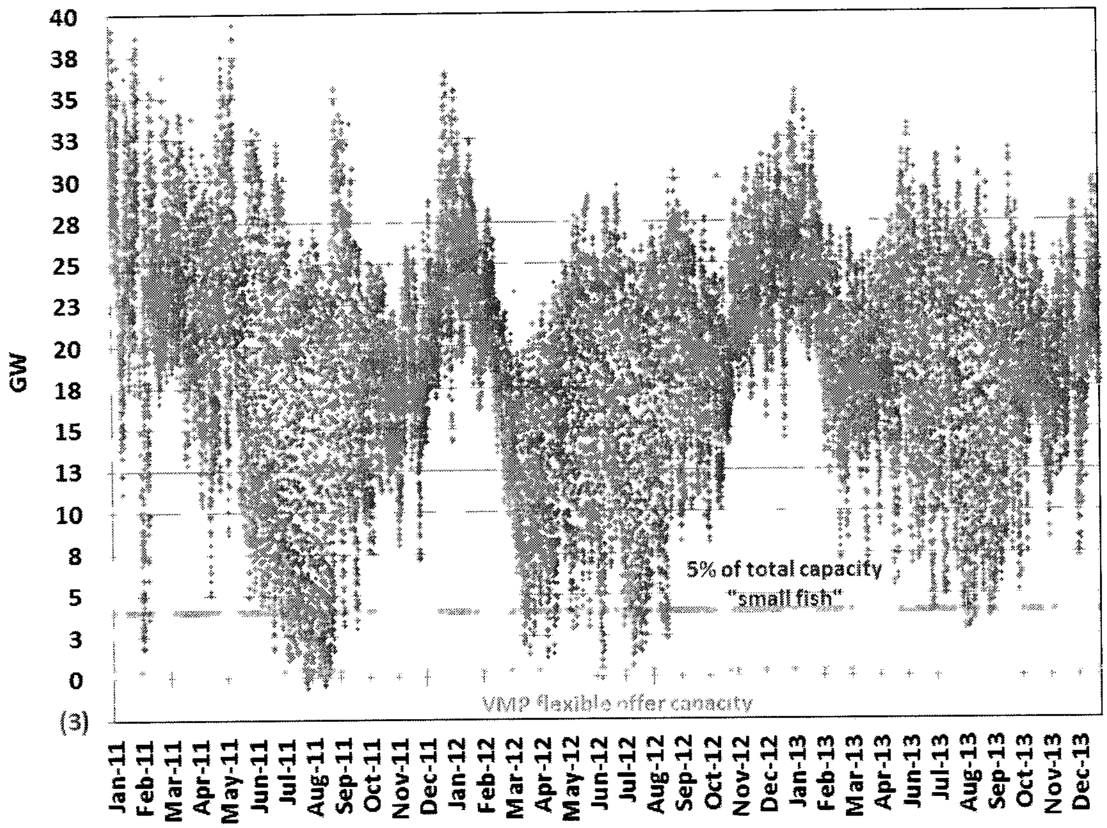
The effects of such actions became much more pronounced after June 21, 2013 when changes to real-time mitigation measures went into effect. These changes narrowed the scope of mitigation addressing the previously discussed issue where mitigation measures were being applied much more broadly than intended or necessary in the ERCOT real-time energy market.[18] Although "small fish" market participants have always been allowed to offer all of their capacity at prices up to the system-wide offer cap, the effect on market outcomes of a large "small fish" offering

17 Order & Settlement Agreement and Voluntary Mitigation Plan Pursuant to PURA §15.023(f) and P.U.C. SUBST. R. 25.504(e), page 10, filed March 28, 2013, in Docket 41276

18 Refer to Section I.F, Mitigation at page 20.

substantial quantities at high prices became more noticeable after the scope of mitigation was narrowed.

Figure 79: Surplus Capacity



The next subsection evaluates the competitive conduct of all suppliers in ERCOT, including the small fish.

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. In this subsection we evaluate actual participant conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. First, we examine unit deratings and forced outages to detect physical withholding and then we evaluate the "output gap" to detect economic withholding.

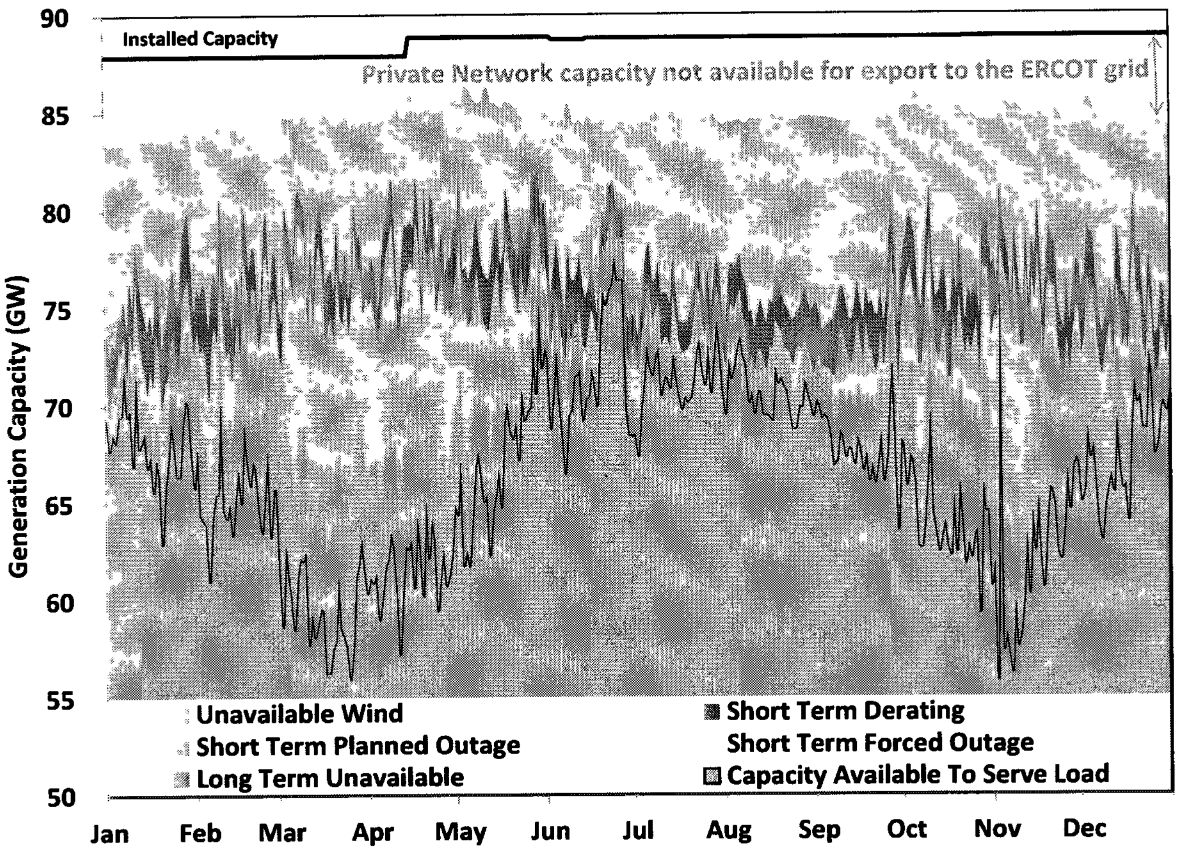
In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher market clearing prices, allowing the supplier to profit on its other sales in the real-time energy market. Because forward prices will generally be highly correlated with spot prices, price increases in the real-time energy market can also increase a supplier's profits in the bilateral energy market. The strategy is profitable only if the withholding firm's incremental profit due to higher price is greater than the lost profit from the foregone sales of its withheld capacity.

1. Generation Outages and Deratings

A substantial portion of the installed capability is frequently unavailable due to generator outages and deratings. Due to data limitations on outages, we must infer what type of outage is occurring. To do this, we start with the unit status information communicated to ERCOT on a continuous basis. For those units with a status of OUT, meaning they are unavailable, we then cross check to see if an outage had been scheduled. If there is a corresponding scheduled outage, we consider the unit on planned outage. If not, it is considered to be a forced outage. We further define derated capacity as the difference between the summertime maximum capability of a generating resource and its actual capability as communicated to ERCOT on a continuous basis. It is very common for generating capacity to be partially derated (e.g., by 5 to 10 percent) because the resource cannot achieve its installed capability level due to technical or environmental factors (e.g., component equipment failures or ambient temperature conditions). It is rare for wind generators to produce at their installed capacity rating due to variations in available wind input. Because such a large portion of derated capacity is related to wind generation we show it separately. In this subsection, we evaluate long-term and short-term deratings to inform our evaluation of ERCOT capacity levels.

Figure 80 shows a breakdown of total installed capability for ERCOT on a daily basis during 2013. This analysis includes all in-service and switchable capacity. From the total installed capacity we subtract: (a) capacity from private networks not available for export to the ERCOT grid, (b) wind capacity not available due to the lack of wind input, (c) short-term deratings, (d) short-term planned outages, (e) short-term forced outages, and (e) long-term outages and deratings – greater than 30 days. What remains is the capacity available to serve load.

Figure 80: Reductions in Installed Capability



Outages and deratings of non-wind generators fluctuated between 3 and 21 GW, as shown in Figure 80, while wind unavailability varied between 3 and 11 GW. Short term planned outages were largest in March, April, October and November and small during the summer, which are consistent with expectations. Short term forced outages also declined during the summer. Short term deratings peaked during October.

The quantity of long term (greater than 30 days) unavailable capacity, peaked in March at nearly 8.4 GW, reduced to 1.5 GW during the summer months and increased to almost 7.7 GW in November. This pattern reflects the choice by some owners to mothball certain generators on a seasonal basis, maintaining the units' operational status only during the high load summer season when more costly units have a higher likelihood of operating.

The next analysis focuses specifically on short-term planned and forced outages and deratings because these classes of outages and deratings are the most likely to be used to physically withhold units in an attempt to raise prices. Figure 81 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2013.

Figure 81: Short-Term Outages and Deratings

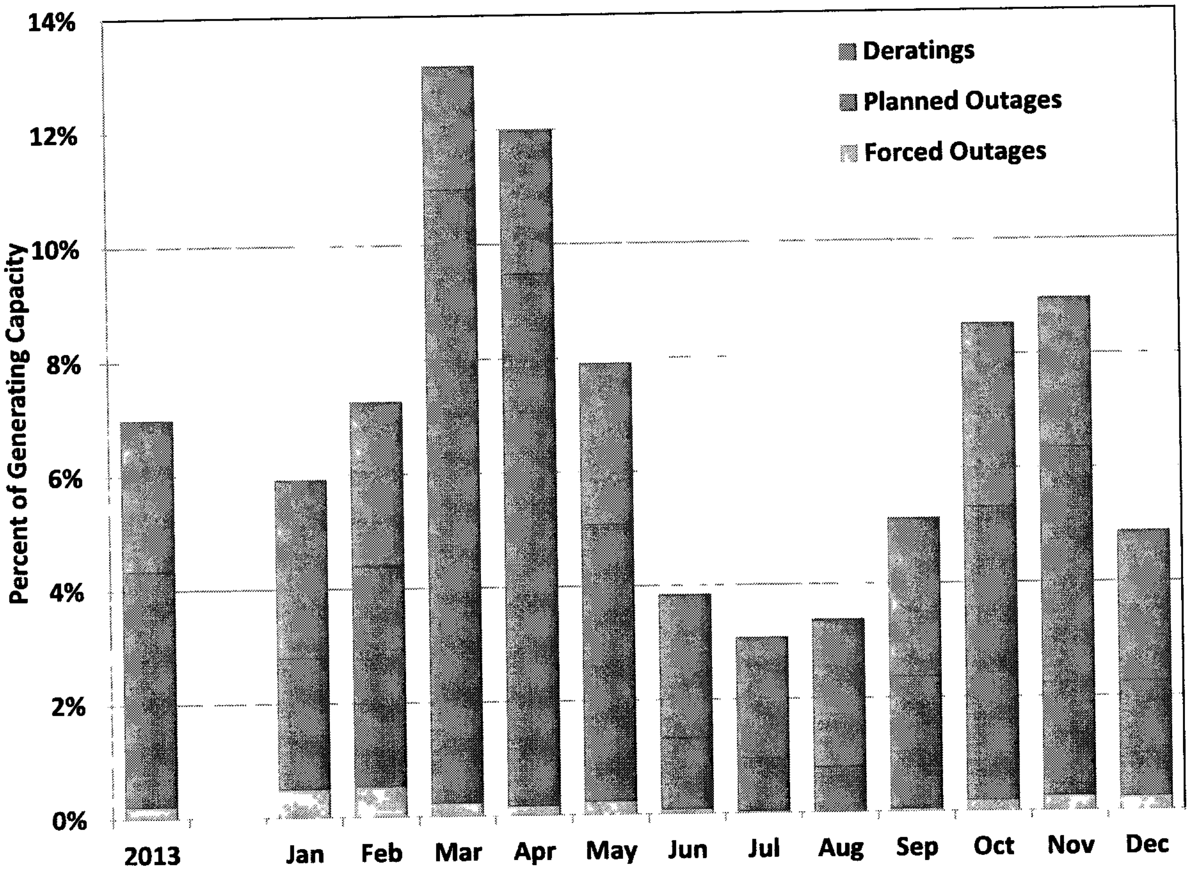


Figure 81 shows that total short-term deratings and outages were as large as 13.1 percent of installed capacity in October, and averaged a little above 3 percent during the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2013 averaged slightly more than 7 percent of installed capacity. This is an increase from 2012, when the amount was greater than 5 percent and 2011 when the value was greater than 6 percent. Similar metrics from the zonal market were consistently above 15 percent. The large disparity between values from the zonal and nodal markets is likely due to combined effects of improved incentives in the nodal market and the lack of unit specific data available from zonal market systems. Overall, the fact that outages and deratings are lowest during the summer when load is expected to be highest is consistent with expectations in a competitive market.

2. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and that are economic at prevailing market prices. This can be done either by derating a unit or declaring it as forced out of service. Because generator deratings and forced outages are unavoidable, the goal of the analysis in this subsection is to differentiate justifiable deratings and outages from physical withholding. We test for physical withholding by examining deratings and outage data to ascertain whether the data are correlated with conditions under which physical withholding would likely be most profitable.

The RDI results shown in Figure 77 and Figure 78 indicate that the potential for market power abuse rises at higher load levels as the frequency of positive RDI values increases. Hence, if physical withholding is occurring, we would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources since their output is generally most profitable in peak periods.

Figure 82 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load level for large and small suppliers. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, the patterns of outages and deratings of large suppliers can be usefully evaluated by comparing them to the small suppliers' patterns.

Long-term deratings are not included in this analysis because they are unlikely to constitute physical withholding given the cost of such withholding. Wind and private network resources are also excluded from this analysis because of the high variation in the availability of these classes of resources. The large supplier category includes the five largest suppliers in ERCOT. The small supplier category includes the remaining suppliers.

**Figure 82: Outages and Deratings by Load Level and Participant Size
June to August, 2013**

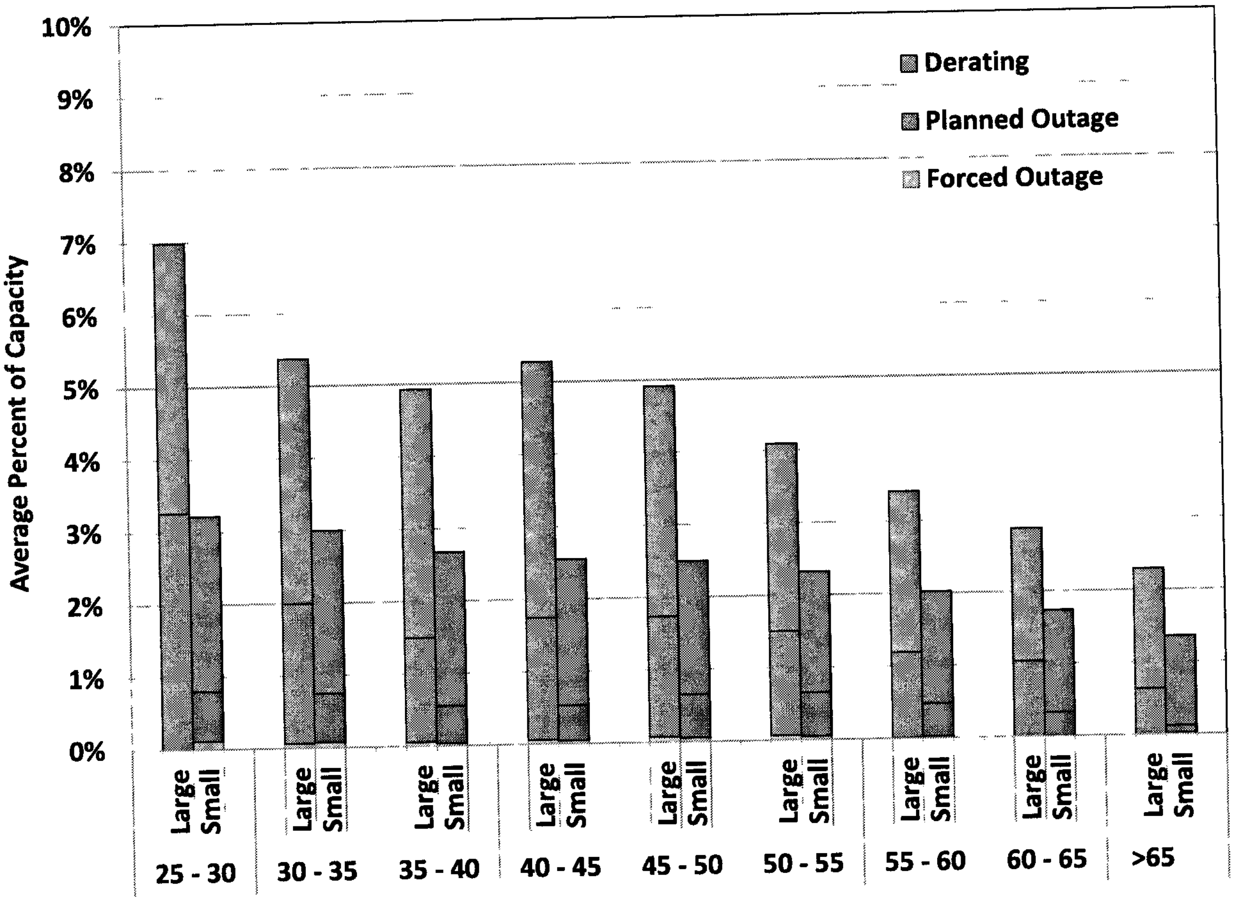


Figure 82 suggests that as demand for electricity increases, all market participants tend to make more capacity available to the market. For large suppliers, the combined short-term derating and forced outage rates decreased from 7 percent at low demand levels to approximately 2 percent at load levels above 65 GW. These are larger than for small suppliers at all load levels, which at first look may be seen as a competitive concern. However, large supplier outage rates are roughly the same as they were in 2012, whereas small supplier outage rates reduced nearly 50 percent. We attribute this greater reduction in small supplier outage rates to the heightened impact that competitive forces exert on small suppliers. Given the overall low magnitude of outage rates for all suppliers, these results raise no competitiveness concerns.

3. Evaluation of Potential Economic Withholding

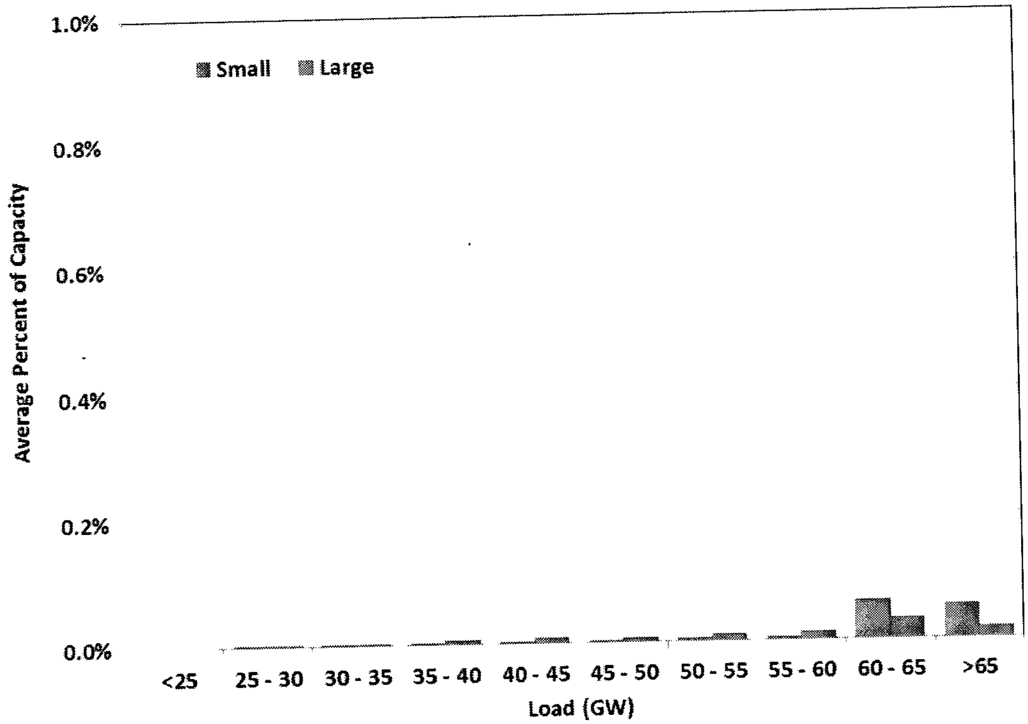
To complement the prior analysis of physical withholding, this subsection evaluates potential economic withholding by calculating an "output gap". The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers so as not to be dispatched.

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

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

If a market participant has sufficient market power, it might raise its offer in such a way to increase the reference price in the first step. Although in the second step the offer appears to be mitigated, the market participant has still influenced the market price. This output gap is measured by the difference between the capacity level on a generator's original offer curve at the first step reference price and the capacity level on the generator's cost curve at the first step reference price. However, this output gap is only indicative because no output instructions are sent based on the first step. It is only used to screen out whether a market participant is withholding in a manner that may influence the reference price.

Figure 83: Incremental Output Gap by Load Level and Participant Size – Step 1

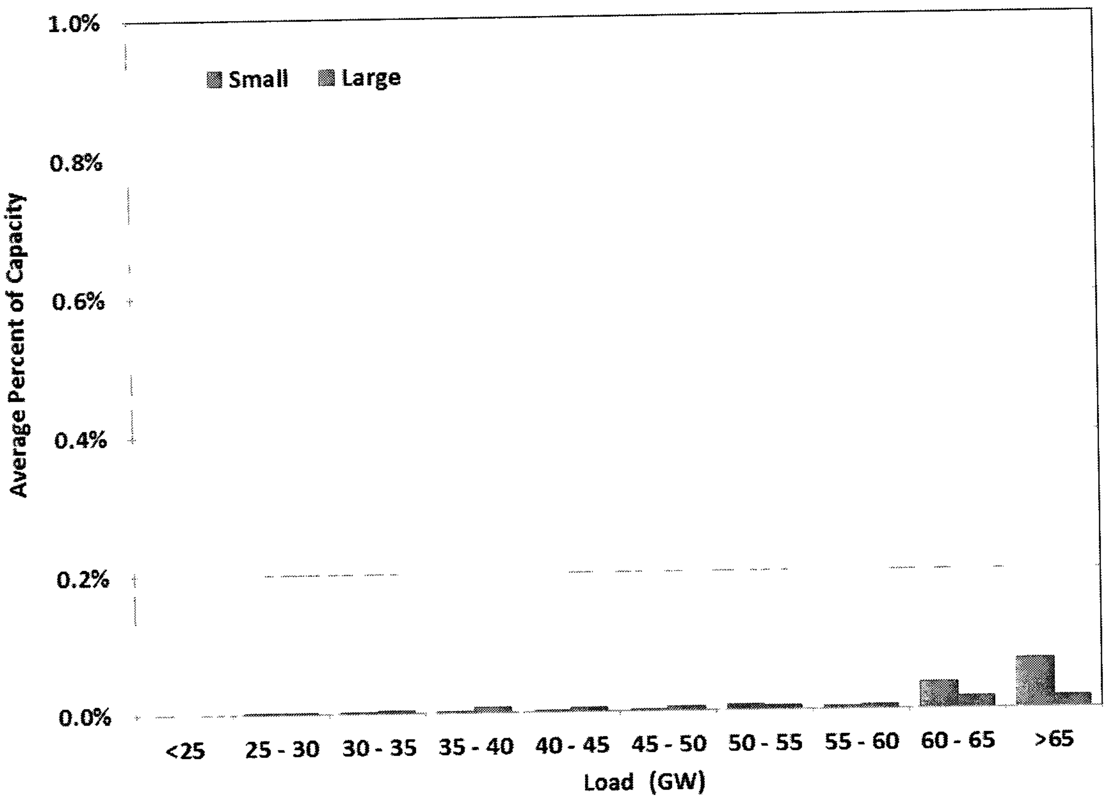


The results of the analysis shown in Figure 83 indicate small quantities of capacity at the highest loads that were potentially economically withheld by small suppliers.

Figure 84 shows the ultimate output gap, measured by the difference between a unit's operating level and the output level had the unit been competitively offered to the market. In the second step of the dispatch, the after-mitigation offer curve is used to determine dispatch instructions and locational prices. As previously illustrated, even though the offer curve is mitigated there is still the potential for the mitigated offer curve to be increased as a result of a high first step reference price being influenced by a market participant raising prices.

Similar to the previous analysis, Figure 84 shows small, but noticeable quantities of capacity at the highest loads that would be considered part of this output gap from small suppliers.

Figure 84: Incremental Output Gap by Load Level and Participant Size – Step 2



To evaluate these quantities in more detail, we provide a comparison of the output gap of several of the largest suppliers in ERCOT in Figure 85. This figure shows that the offering conduct of GDF SUEZ stands apart from the others. At the very highest load levels, up to 400 MW of GDF SUEZ's resources were not producing even though real-time energy prices were at least $50 per MWh greater than assumed short run marginal costs. We observed many instances during 2013 where GDF SUEZ changed their offer curves intraday, increasing the offer price for hundreds of MWs of their capacity during the highest load hours, then reducing the price of their offered generation after the peak load period. The effects on real time energy prices of GDF SUEZ's offer patterns were mixed and were only material after the changes to real-time mitigation went into effect on June 21, 2013. We estimate the overall impact that GDF SUEZ's offer patterns on the ERCOT average real-time energy prices was less than $1.00 per MWh.