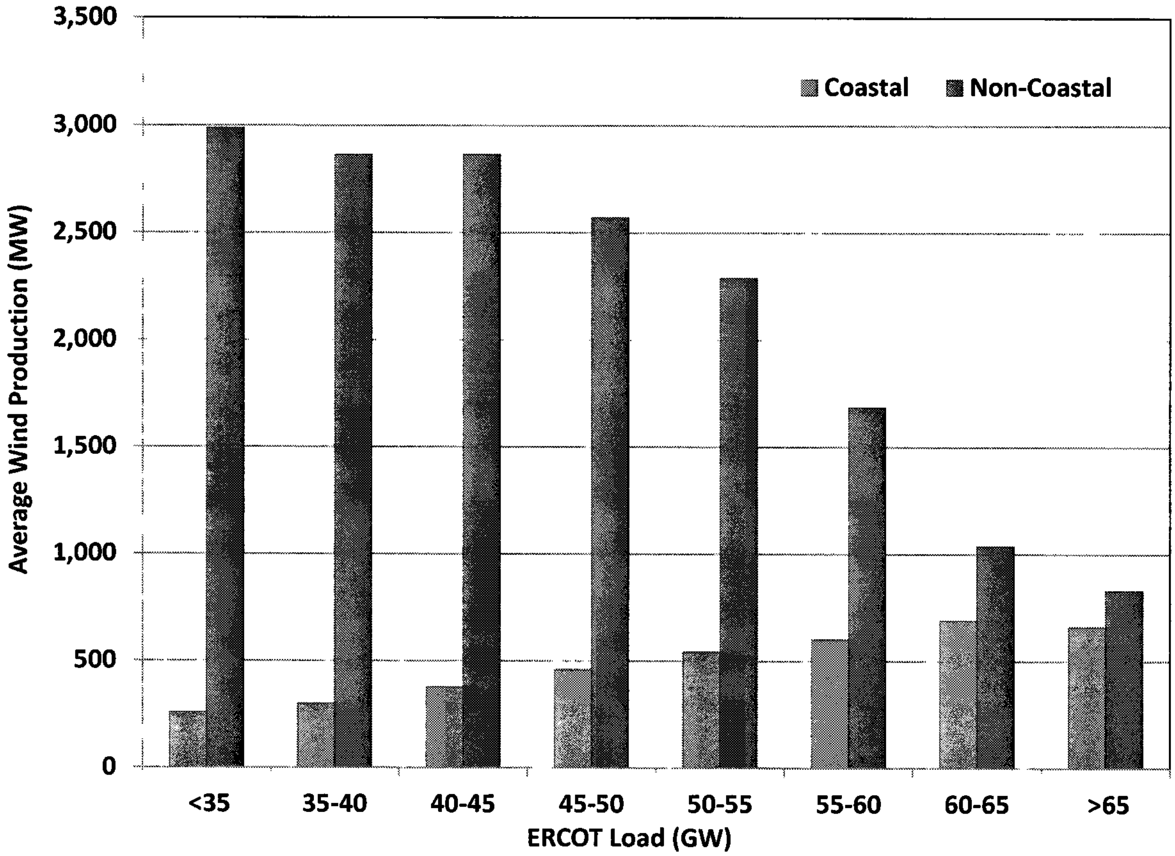
Examining wind generation in total masks the different wind profiles that exist for locations across ERCOT. Wind developers have more recently been attracted to the site facilities along the Gulf coast of Texas due to the higher correlation of winds with electricity demands. Next we compare the differences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

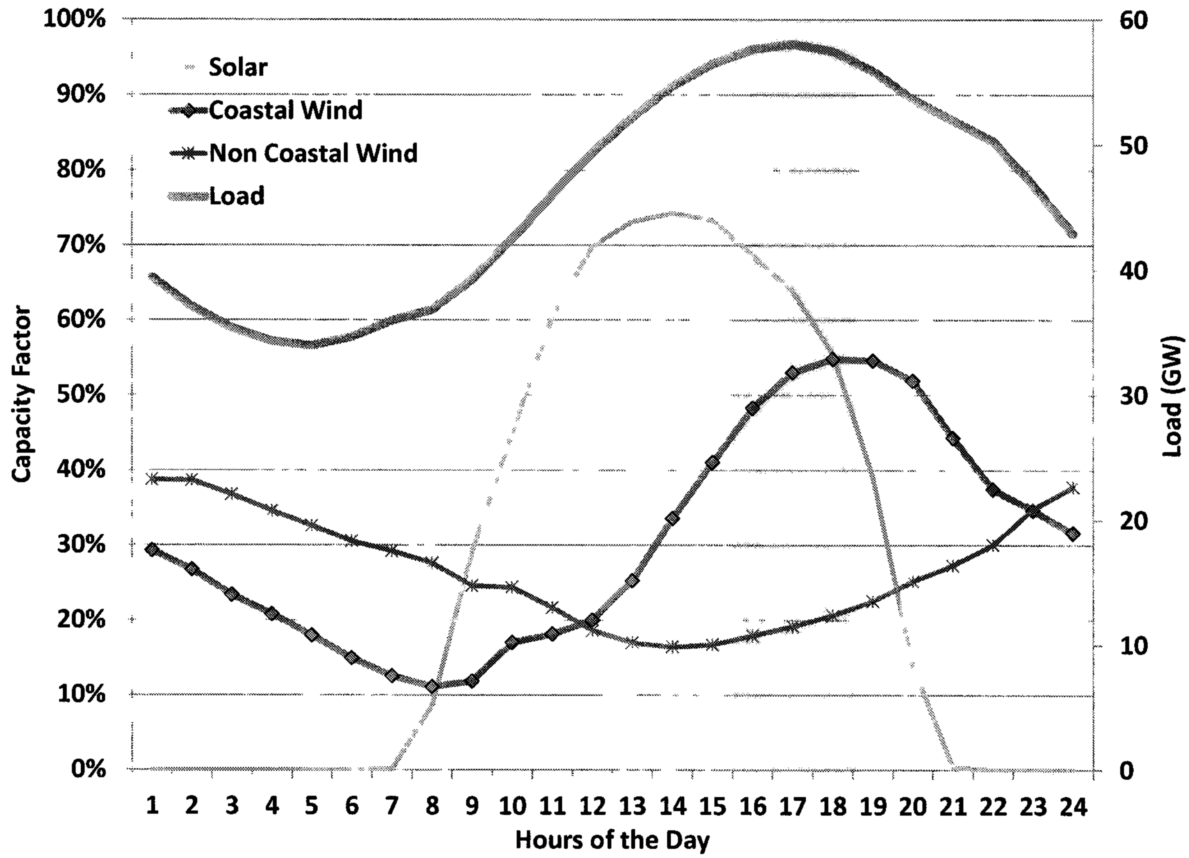
Figure 53: Summer Wind Production vs. Load



In Figure 53 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 54 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 54: Summer Renewable Production



The contrast between coastal wind and non-coastal wind is also clearly displayed in Figure 54. 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 55: Wind Production and Curtailment

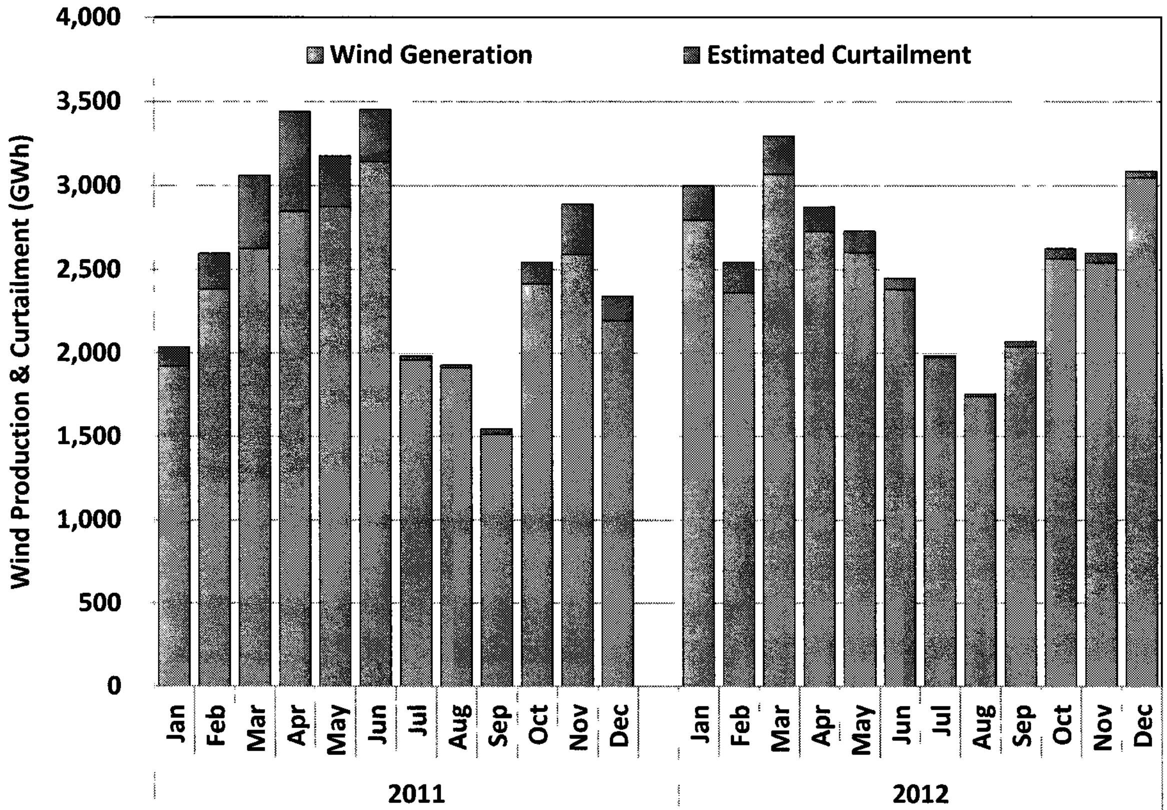
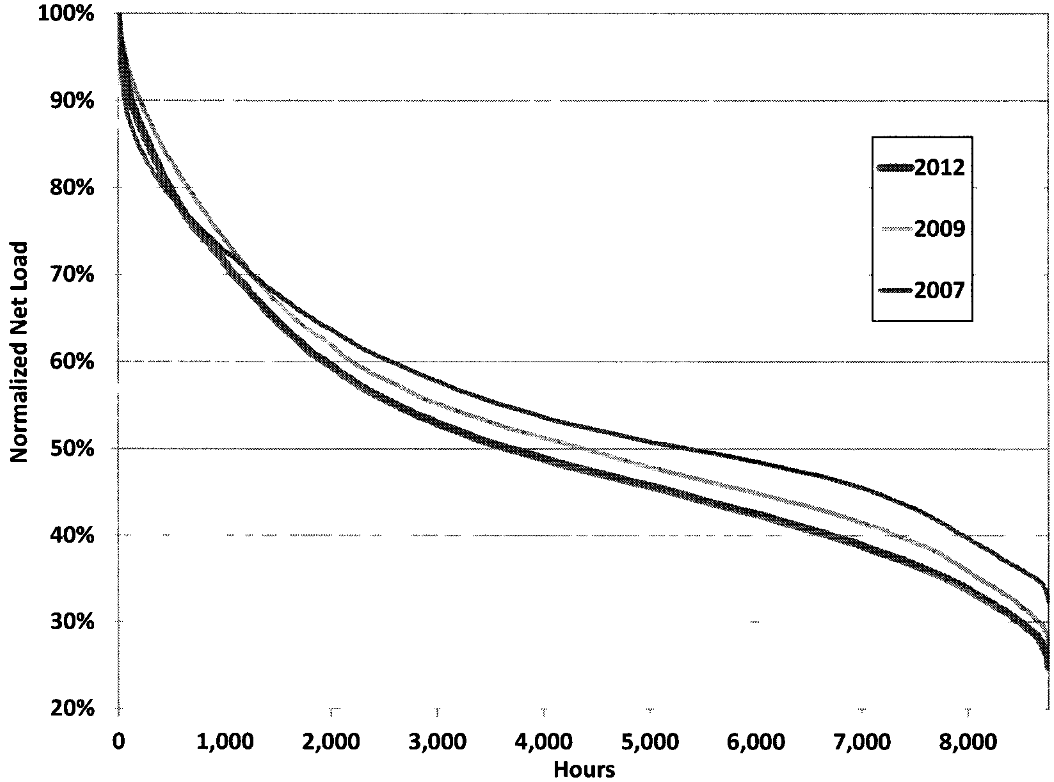


Figure 55 shows the wind production and estimated curtailment quantities for each month of 2011 and 2012. This figure reveals that the total production from wind resources increased again in 2012. More importantly, the quantity of curtailments was lower in 2012 when compared to 2011. The volume of wind actually produced was approximately 96 percent of the total available wind in 2012, up from approximately 92 percent in 2011.

Increasing levels of wind resource in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. Figure 56 shows the net load duration curves for selected years since 2007, normalized as a percent of peak load.

Figure 56: Net Load Duration Curves

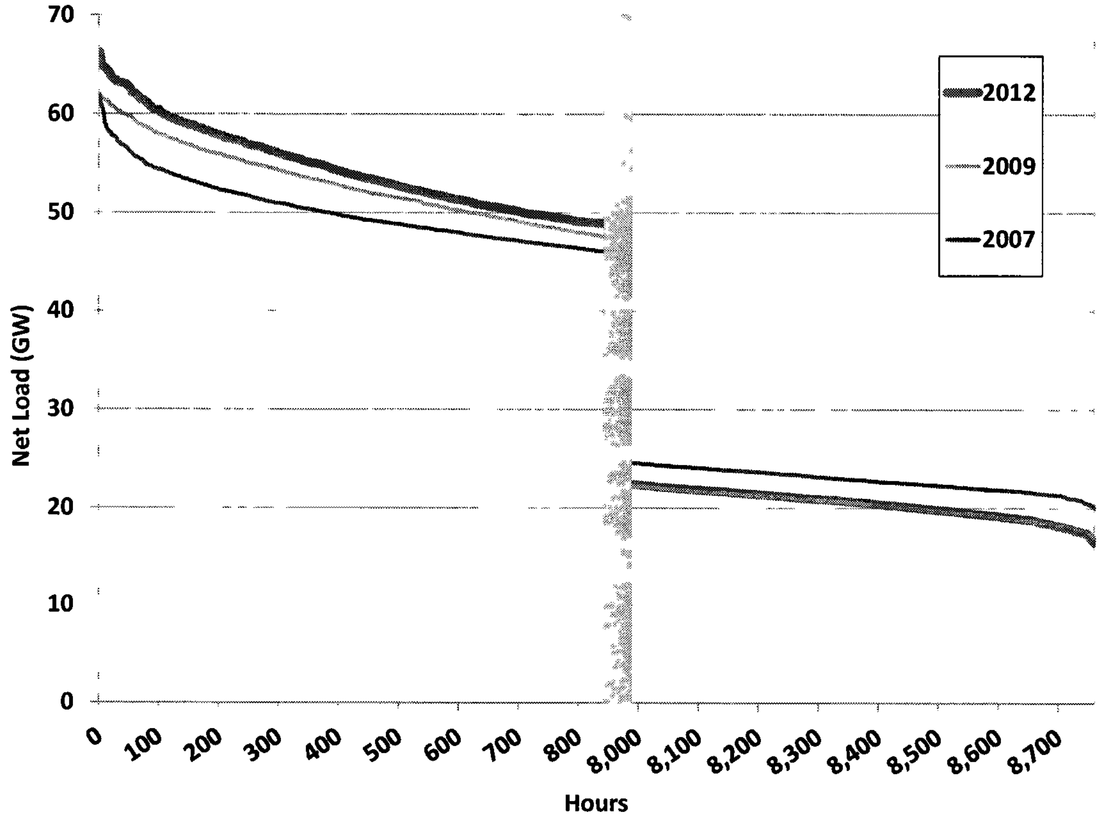


This figure shows the continued erosion of remaining energy available for non-wind units to serve during most hours of the year, with much less impact during the highest loads.

Even with the increased development activity in the coastal area of the South zone, more than 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. The trend shown from 2007 in Figure 56 may continue with the addition of new wind resources and the reduction in the curtailment of existing wind resources after completion of new transmission facilities.

Focusing on the left side of the net load duration curve shown in Figure 57, 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 six years.

Figure 57: Top and Bottom Ten Percent of Net Load



On the right side of the net load duration curve, the minimum net load has remained approximately 17 GW for the past four years, even with sizable growth in total annual load. This continues to put operational pressure on the nearly 25 GW of nuclear and coal-fired generation currently installed in ERCOT.

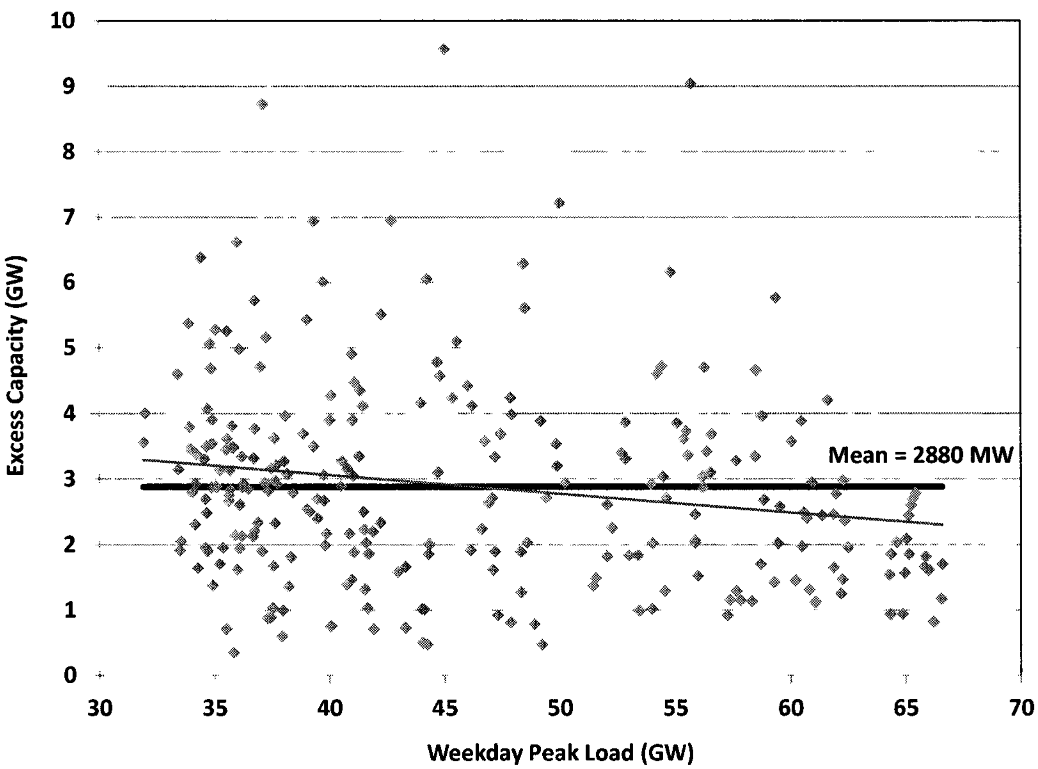
Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet is expected to operate for fewer hours as wind penetration continues to increase. 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.

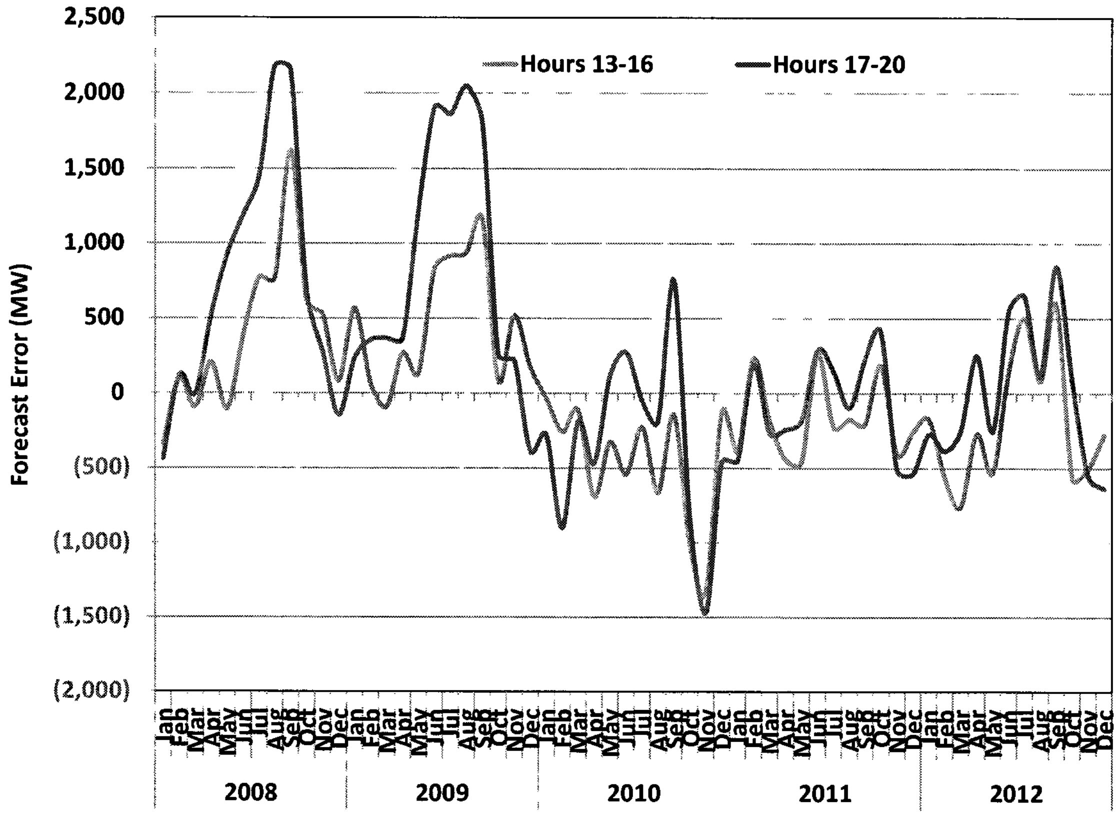
This subsection evaluates the commitment patterns in ERCOT by examining the levels of excess capacity. Excess capacity is defined as the total capacity of online plus quick-start generators minus the demand for energy, responsive reserve, up regulation and non-spinning reserve provided from online capacity or quick-start units. To evaluate the commitment of resources in ERCOT, Figure 58 plots the excess capacity compared to peak load during 2012.

Figure 58: 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. Figure 58 shows that the excess on-line capacity during daily peak hours on weekdays averaged 2,880 MW in 2012 which is approximately 7.8 percent of the average load in ERCOT. These values did not change significantly from 2011, when the average excess on-line capacity was 2,901 MW, or 7.6 percent of the average load. Even with the expected improvements in 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,[16] we would expect to see over commitment of generation using non-market means.

Figure 59: Load Forecast Error



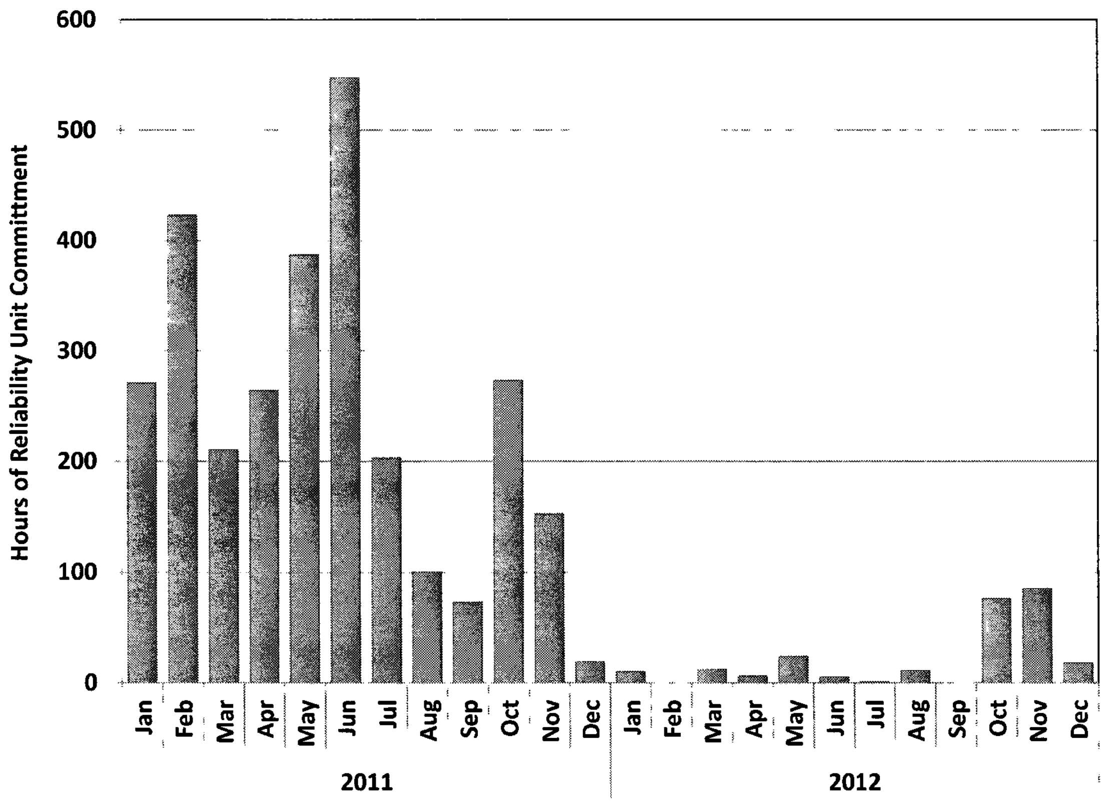
From Figure 59 we can see the noticeable reduction in ERCOT's load forecast bias since 2009. This was due to a procedure change implemented three years ago. ERCOT now specifically identifies and subtracts out the forecast bias and procures additional non-spin capacity in an equal amount.

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

[16] See 2010 ERCOT SOM report at pages 49-51 and 2009 ERCOT SOM report at pages 68-70.

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 60 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 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. The amount of time during 2012 reduced to three percent. The primary reason for the reduction is likely the less extreme weather and resulting lower load levels experienced during 2012. Lower loads resulted in reduced congestion and therefore reduced need for specific units to be brought online to resolve.

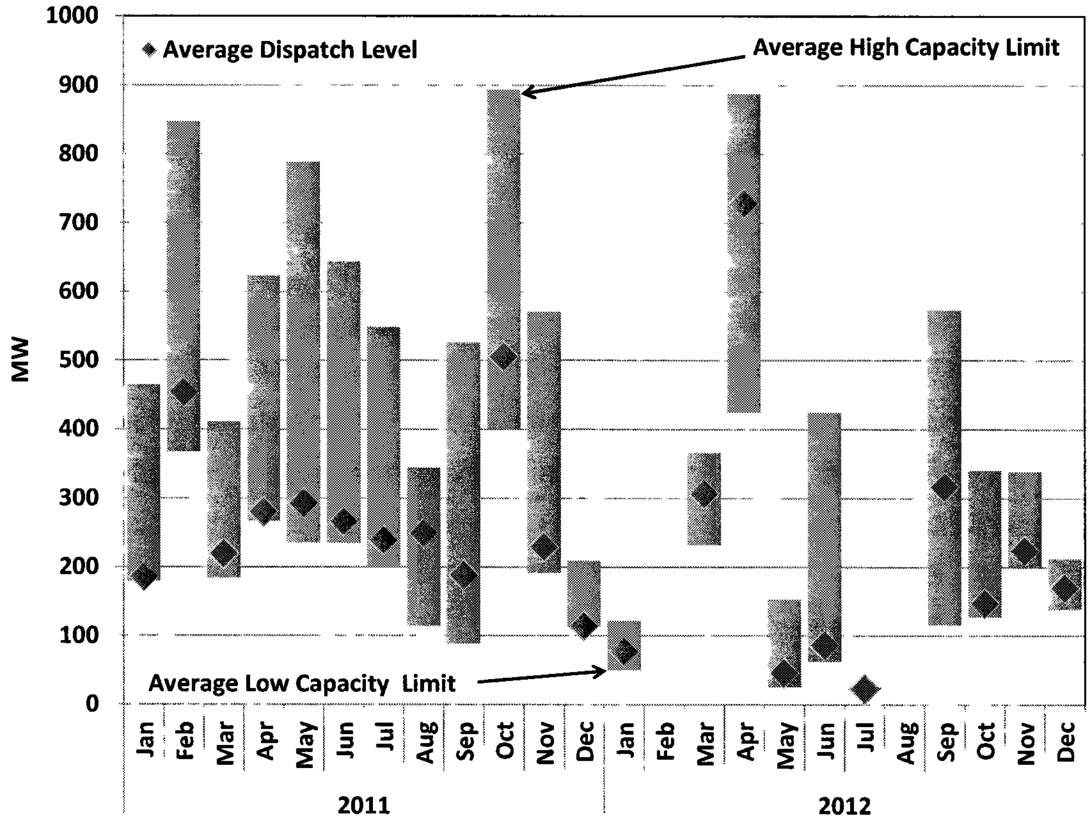
Figure 60: Frequency of Reliability Unit Commitments



There 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 next analysis compares the average dispatched output of the reliability committed units with their operational limits. Figure 61 shows that for most months of 2012 the amount of capacity actually dispatched from units brought on line via the reliability unit commitment process was less than the 200 to 300 MW that was typical for 2011.

Figure 61: Reliability Unit Commitment Capacity



The notable exception was in April 2012, when the large amounts of reliability unit committed capacity 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, our review of the effectiveness of the Public Utility Commission's Scarcity Pricing Mechanism includes two recommendations for market design improvements. We conclude this section with a review of the contributions from demand response toward meeting resource adequacy objectives in ERCOT and our third recommended improvement.

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 that 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 section, 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 the 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, or through the reliability unit commitment. This source of revenue is not considered in this analysis. The analysis also includes simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. The following factors are not explicitly accounted for in the net revenue analysis: (i) start-up costs, which can be significant; and (ii) minimum running times and ramp restriction, which can prevent the natural gas generators from profiting during brief price spikes. Despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

Figure 62 shows the results of the net revenue analysis for four types of hypothetical new units in 2011 and 2012. 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-fired technologies, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in other hours that it is available (*i.e.*, when it is not experiencing a planned or forced outage). For coal and nuclear technologies, net revenue is calculated by assuming that the unit will produce at full output.

Figure 62: Estimated Net Revenue by Zone and Unit Type

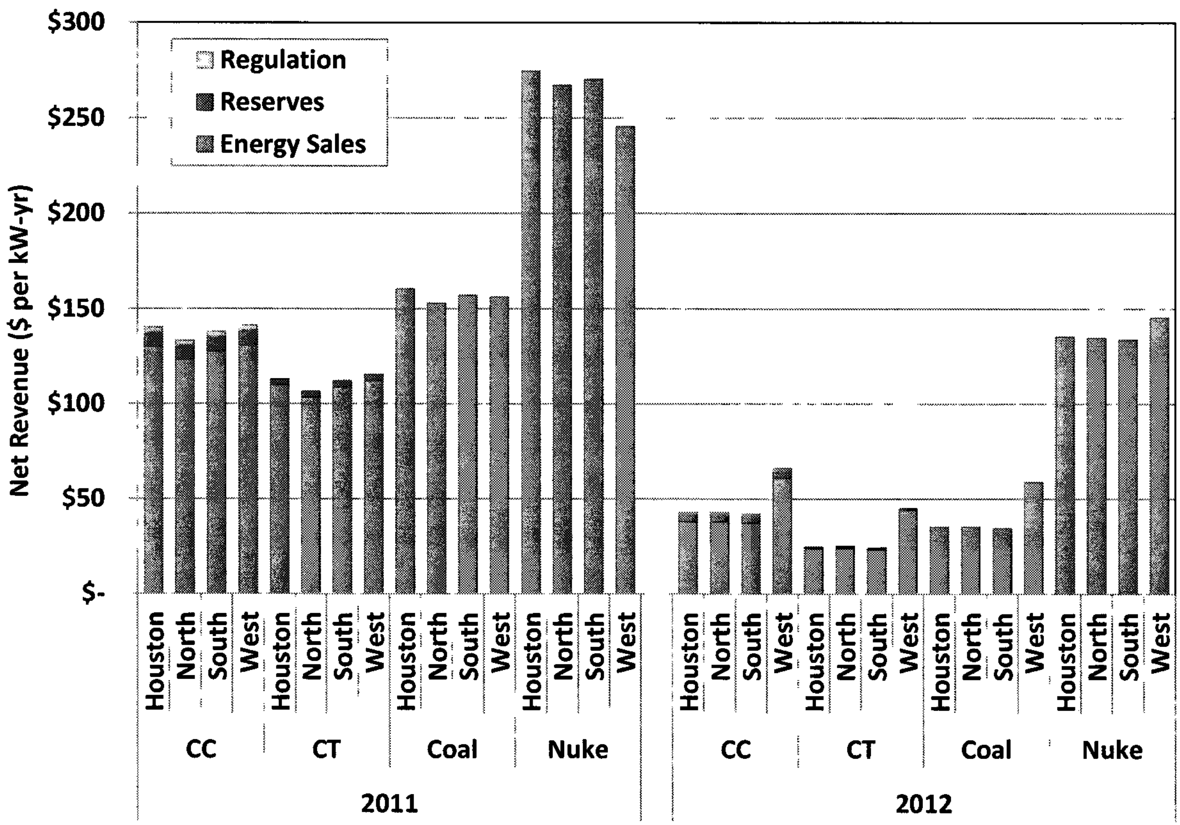


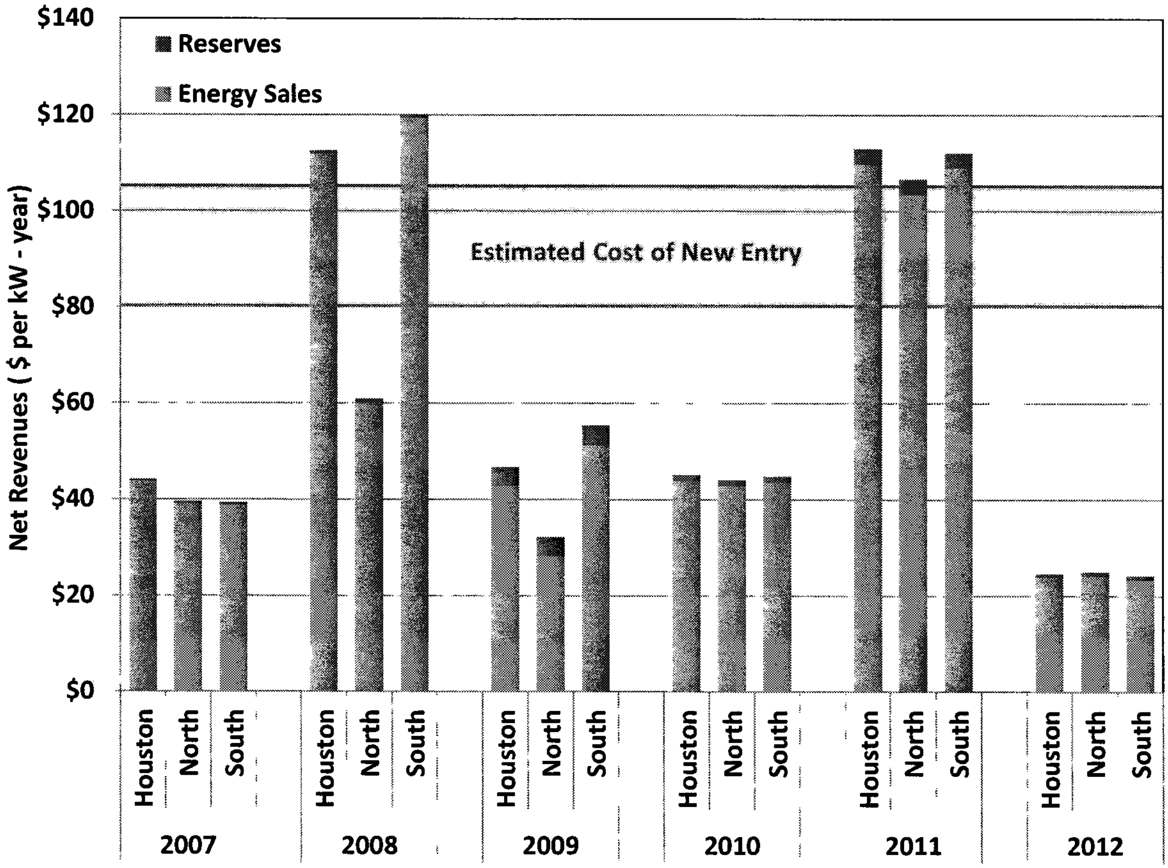
Figure 62 shows that the net revenue for every generation technology type decreased substantially in 2012 compared to each zone in 2011.

- For a new coal unit, the estimated net revenue requirement is approximately $210 to $270 per kW-year. The estimated net revenue in 2012 for a new coal unit was approximately $35 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $280 to $390 per kW-year. The estimated net revenue in 2012 for a new nuclear unit was approximately $134 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 allowed energy prices to remain at levels high enough to support new entry for these technologies. The production costs of coal and nuclear units did not change significantly over this period, leading to a dramatic rise in net revenues. However, since 2008 natural gas prices have been on the decline, 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. With the further decline in natural gas prices and few occurrences of shortage pricing, the estimated net revenue for either a new coal or a nuclear unit in ERCOT was well below the levels required to support new entry in 2012.

The next two figures provide an historical perspective of the net revenues available to support new gas turbine (Figure 63) and combined cycle generation (Figure 64).

Figure 63: Gas Turbine Net Revenues

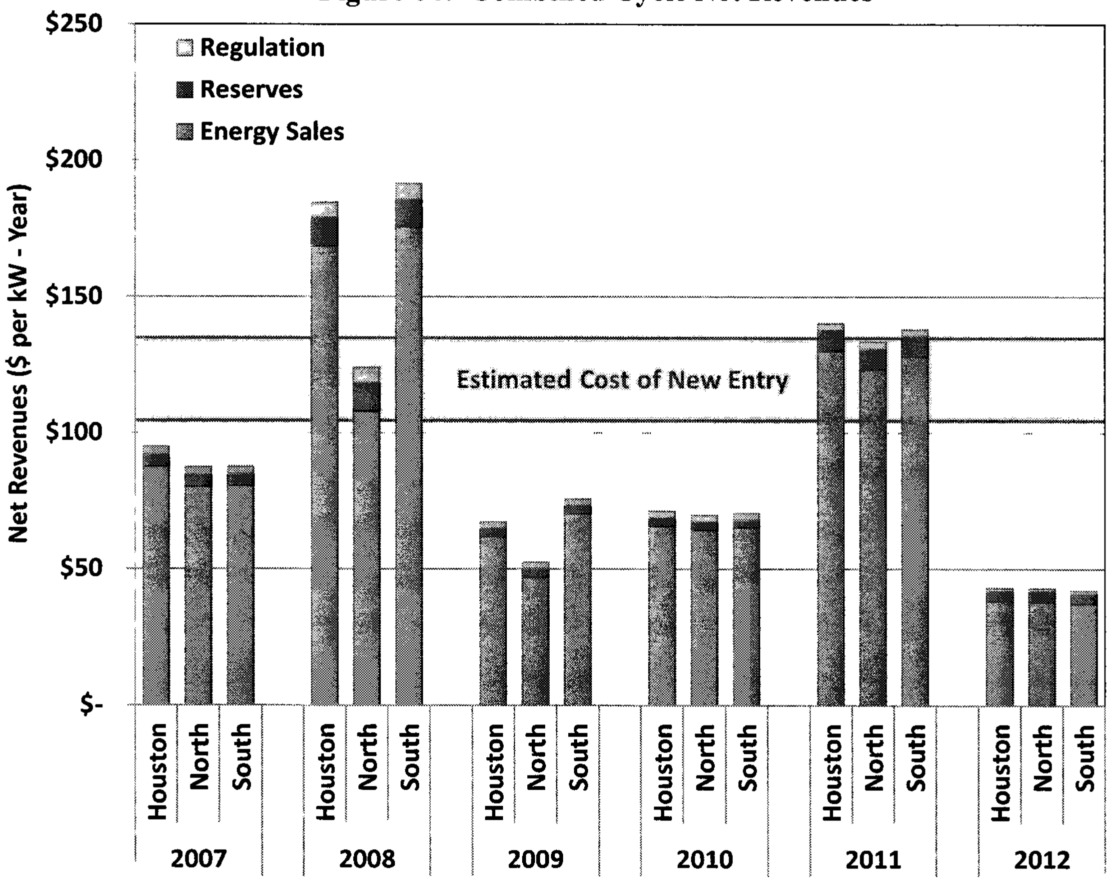


Based on our estimates of investment costs for new units, the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80 to

$105 per kW-year. The estimated net revenue in 2012 for a new gas turbine was approximately $25 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 2012 for a new combined cycle unit was approximately $42 per kW-year, also far below the levels to support new combined cycle generation in ERCOT.

Figure 64: Combined Cycle Net Revenues



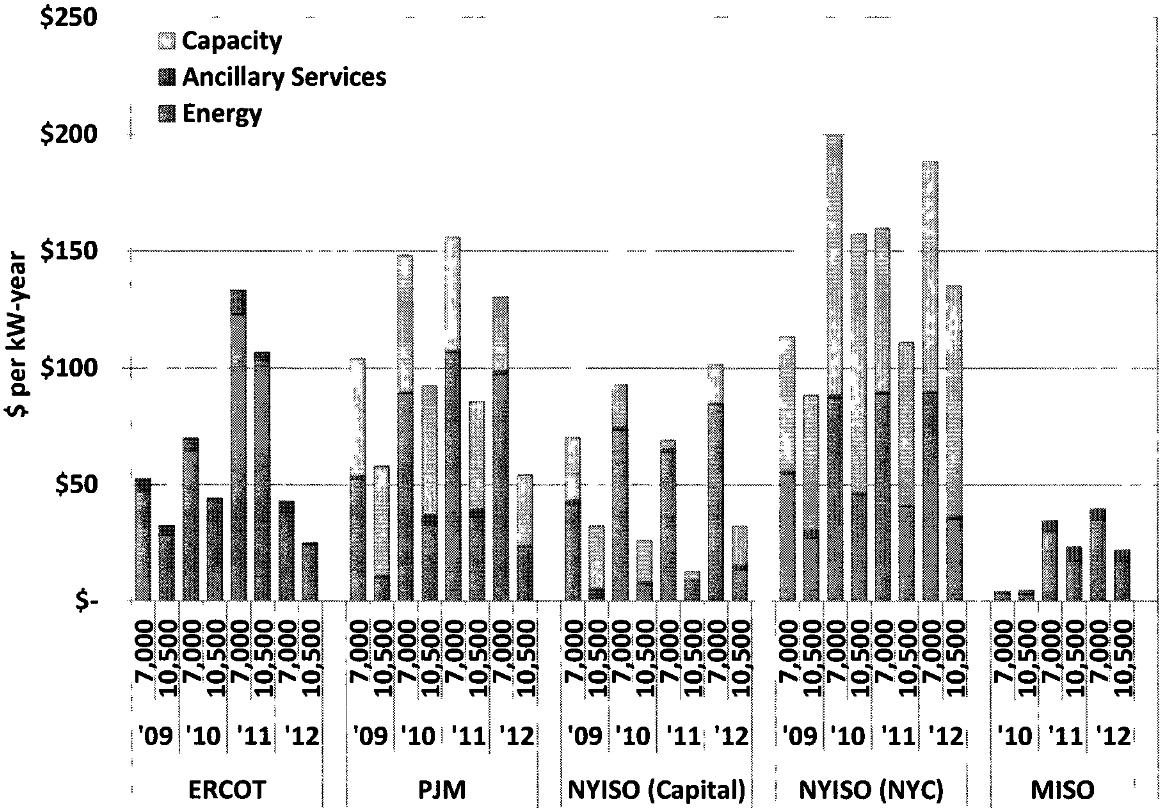
Even though net revenues for the Houston and South zones in 2008 may have appeared to be sufficient to support new natural gas-fired generation, it was actually extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves 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 was the first time in five years that net revenues have been sufficient to support either new gas turbine or combined cycle generation.

These results indicate that the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. Higher energy prices in the West zone during 2012 resulted in higher net revenues in that zone, but they were still not high enough to support new entry there. The net revenues in 2012 were much lower than in 2011. However, it is important to recognize that 2011 was highly anomalous, with some of the hottest summer temperatures on record. Net revenues may have been sufficient to cover the costs of a new combined cycle or new combustion turbine in 2011, however, we would not expect this to be consistently true in years with comparable reserve margins absent the extreme weather conditions, as evidenced by the 2012 net revenue results.

To provide additional context for the net revenue results presented in this section, 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 65 compares estimates of net revenue for the ERCOT North zone, PJM, two locations within the New York ISO, and the Midwest ISO. 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. Figure 65 shows that net revenues increased from 2011 to 2012 for both technologies in NY ISO. In PJM net revenue decreased and in Midwest ISO net revenues remained flat. In the figure below, 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.

Figure 65: Comparison of Net Revenue of Gas-Fired Generation between Markets



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 relaxed the existing system-wide offer cap by increasing it 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 2012 under ERCOT's energy-only market structure.

Experiencing reduced levels of generation development activity coupled with higher than expected loads resulting in diminishing planning reserve margins, the PUCT has devoted considerable effort over the past two years deliberating issues related to resource adequacy. These deliberations have included the question of whether that 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 has taken no action to change the fundamental energy-only nature of the ERCOT market or the designation of the planning reserve margin as a target. However, there have been changes to the rules governing the system-wide offer cap and peaker net margin mechanism.

Approved during 2012, new 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 on page 15, there was only a brief period when energy prices rose to the cap after this change was implemented. Revisions were also adopted to PUCT SUBST. R. 25.505 which specified future increases to the system-wide offer cap as follows:

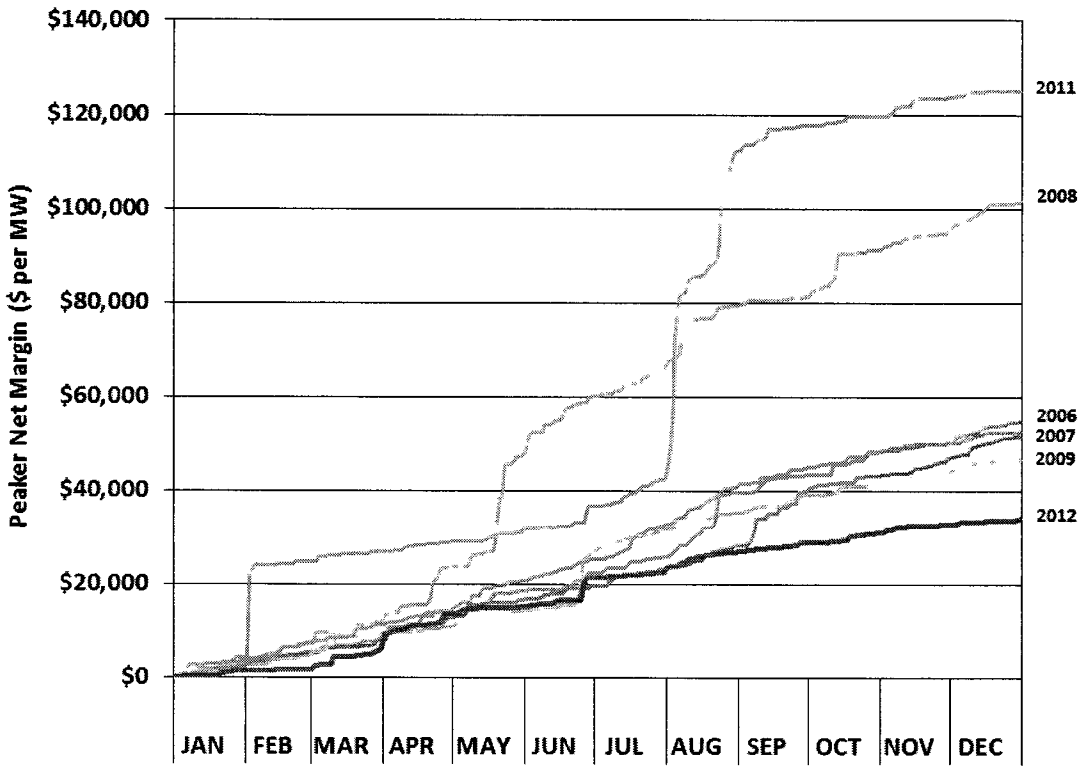
- $5,000 per MWh beginning on June 1, 2013,
- $7,000 per MWh beginning on June 1, 2014, and
- $9,000 per MWh beginning on June 1, 2015.

The SPM includes a provision termed the Peaker Net Margin ("PNM") that is designed to measure the annual net revenue of a hypothetical peaking unit. 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,[17] the system-wide offer cap is then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[18] Figure 66 shows the cumulative PNM results for each year from 2006 through 2012 and shows that PNM in 2012 was the lowest it has been since its implementation.

[17] 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.

[18] These values were increased from a previous threshold of $175,000 per MW and an LCAP of $500 per MWh.

Figure 66: 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 66 and consistent with the previous findings in this section relating to net revenue, the PNM was nowhere near sufficient to support new entry in 2012. 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.[19] With these issues addressed in the zonal 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.

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

Shortage Pricing and Resource Adequacy

Efficient electricity markets allow energy prices 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, which is discussed in the next subsection.

The expectation of competitive energy market outcomes is no different in energy-only than in markets that include a capacity market. However, capacity markets are designed to ensure a specified planning reserve margin, which may be higher than what an energy-only market would achieve. Under this condition the higher planning reserve margin will serve to reduce the frequency of shortages in the energy market.

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.

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.

Although the nodal market implementation brought about more reliable and efficient shortage pricing, there remain aspects of the ERCOT real-time energy pricing that can be improved. As discussed later in this section, prices during the deployment of load resources do not reflect the value of reduced reliability which occurs when responsive reserves have been converted to energy.

Similarly, during the first year of nodal market operation when non-spinning reserves were deployed (converted to energy), prices rarely reflected the marginal cost of the action being taken. Non-spinning reserves are provided primarily by off-line natural gas-fired combustion turbines capable of starting in 30 minutes or less. The implementation of the nodal market significantly increased market efficiencies in a number of areas, including the move to a five minute rather than 15 minute energy dispatch. However, it lacked an efficient economic commitment mechanism for resources such as offline gas turbines and other resources that are not immediately dispatchable in the five minute energy dispatch. This led to prices that were inefficiently low because they did not represent the costs associated with starting and running the gas turbines that were being deployed to meet demand.

The changes described in NPRRs 426 and 428 were implemented in early 2012, and added requirements for providers of non-spinning reserve to make that capacity available to ERCOT's dispatch software, subject to certain offer floors.[20] Providers are now able to specify the price at which they are willing to convert their non-spinning reserve capacity to energy. Further, ERCOT uses this price information to determine which non-spin units to deploy. Real-time energy price formation has been improved, but the current mechanism is sub-optimal from a reliability and efficiency perspective. We continue to recommend that ERCOT develop a mechanism that will rationally commit generation that can start or load resources that can curtail within 30 minutes.

This deficiency in ERCOT's nodal market design should be addressed by implementing "look ahead" dispatch functionality for the real-time energy market to produce energy and ancillary services commitment and dispatch results that are co-optimized and recognize anticipated changes in system demands.[21] This additional functionality represents a major change to ERCOT systems; one we recommend together with improved pricing provisions that will allow offers from load resources to set prices if they are required to meet system demand.

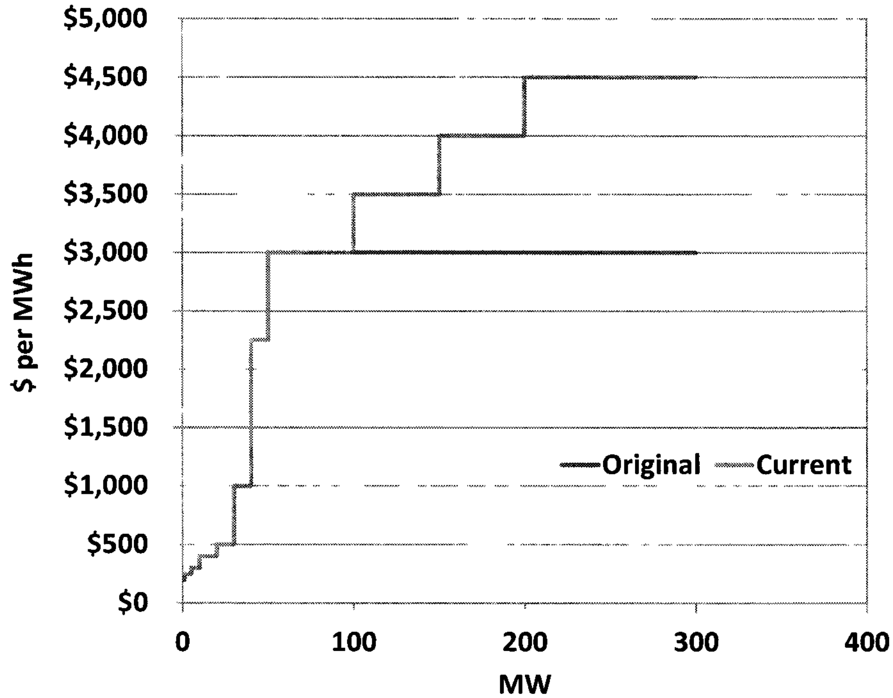
Effective look ahead dispatch functionality should also reduce the price dampening effects of energy produced by units operating below their low sustainable operating limit. Although alternatives have been suggested to address this issue in a standalone manner, we believe the better approach will be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

[20] The offer floors for online and offline non-spinning reserves are $120 and $180 per MWh, respectively. NPRR427 requires that energy offers from generation resources providing responsive reserve and up regulation reserves be priced at the system-wide offer cap.

[21] See Direct Testimony of David B. Patton, PUCT Docket No. 31540, (Nov. 10, 2005), at pages 35-41.

Aside from 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 2012 in conjunction with the increase in the system-wide offer cap to $4,500 per MWh. Figure 67 compares the original PBPC in place at the start of the nodal market and the current curve, as modified in 2012.

Figure 67: Power Balance Penalty Curves



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) Original Curve	Energy Price ($ per MWh) Current Curve
1	$200	
5	$250	$250
10	$300	$300
20	$400	$400
30	$500	$500
40	$1,000	$1,000
50	$2,250	$2,250
>50	$3,001	
100		$3,000
150		$3,500
200		$4,000
>200		$4,501

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. The intermediate values are set at values acceptable to the collective agreement of stakeholders. A more analytically rigorous approach would be to introduce an operating reserve pricing mechanism that reflects the operational loss of load probability ("LOLP") at varying levels of operating reserves multiplied by the value of lost load ("VOLL"). The LOLP would be equal to 1.0 when operating reserves fall to the level where involuntary load shedding is directed by ERCOT. The LOLP would decline exponentially from 1.0 as the level of operating reserves increased.

The implementation of such a curve is currently being evaluated under different approaches. The most complex approach would be to implement real-time co-optimization of energy and reserves with an operating reserve demand curve. The approach named "Solution B+" is likely to be easier to implement and would introduce the operating reserve demand curve but not include real-time co-optimization.[22] And yet another approach would be to adjust the current

[22] See ERCOT Presentation Regarding Potential Implementation of Scarcity Pricing Proposal Offered by Professor Hogan, PUCT Docket No. 40000, (Jan. 22, 2013).

operating reserve offer floors to better reflect LOLP * VOLL at various levels of operating reserves. Each of these approaches could result in more efficient pricing of operating reserve shortages. However, for any of these approaches to result in planning reserve margins over the long-term that meet the historical standard of one loss of load event in ten years would likely require an increase to the level of minimum operating reserves significantly beyond what is required to maintain reliable system operations, or by establishing shortage pricing that is substantially higher than the system-wide offer cap rising to $9,000 per MWh or most reasonable estimates of VOLL. As discussed below, each of these changes can introduce costly operational inefficiencies into the ERCOT energy markets.

As the system-wide offer cap increases to $5,000 per MWh and beyond, it is likely under the current market mechanisms that prices will rise to levels approaching the VOLL when the available reserves are at levels where the LOLP is much less than 1.0 and involuntary load curtailment is not imminent. We have two recommendations to address this concern. The first is to modify the slope of the existing PBPC and the offer floor for responsive reserve service to provide a more gradual slope up to the system-wide offer cap. This could be accomplished by any of three approaches discussed above. We also recommend modifying the automatic pricing of unoffered capacity such that it is not all priced at the system-wide offer cap to avoid the inefficiencies associated with the automated economic withholding of such capacity.

Shortage Pricing, Capacity Markets, and Resource Adequacy

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 (including 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 targets.[23] Additionally, as discussed below, such approaches introduce costly operational inefficiencies in to the ERCOT energy markets.

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.

In 2012, ERCOT engaged The Brattle Group to assess its resource adequacy outlook by evaluating a number of market design scenarios.[24] Brattle also supplemented its report with the following table that presents a comparison of costs and reliability for the energy-only market and two capacity market scenarios with 10% and 14% reserve margin requirements.[25] The results of this analysis are summarized in the table below.

Brattle estimates that even with $9,000 per MWh system-wide offer caps, economic equilibrium for the ERCOT energy-only market is achieved at an 8 percent planning reserve margin, although the actual reserve margin outcomes will be uncertain. Brattle further estimates that in the energy-only market at annual equilibrium, wholesale generation costs will be $18.3 billion. In contrast, Brattle's assessment of a capacity market with a more certain 14 percent reserve margin expectation, estimates generation costs at annual equilibrium to be $18.7 billion.

---

23 The difficulty of relying primarily on shortage pricing will depend on how high the planning reserve target is relative to the planning reserve levels any energy-only market priced at the expected value of lost load would provide. See the discussion of the Brattle Report below.

24 *ERCOT Investment Incentives and Resource Adequacy,* The Brattle Group, PUCT Docket No. 37987 (June 1, 2012).

25 *Customer Cost Comparison,* The Brattle Group, PUCT Docket No. 40000 (Sept. 4, 2012).

It is important to recognize that this increase in cost is not due to the introduction of the capacity market, it is due to the requirement to sustain a planning reserve margin greater than 8 percent. In fact, the Brattle analysis indicates that a capacity market would deliver the higher planning reserve margin at a relatively low incremental cost with much more certainty.

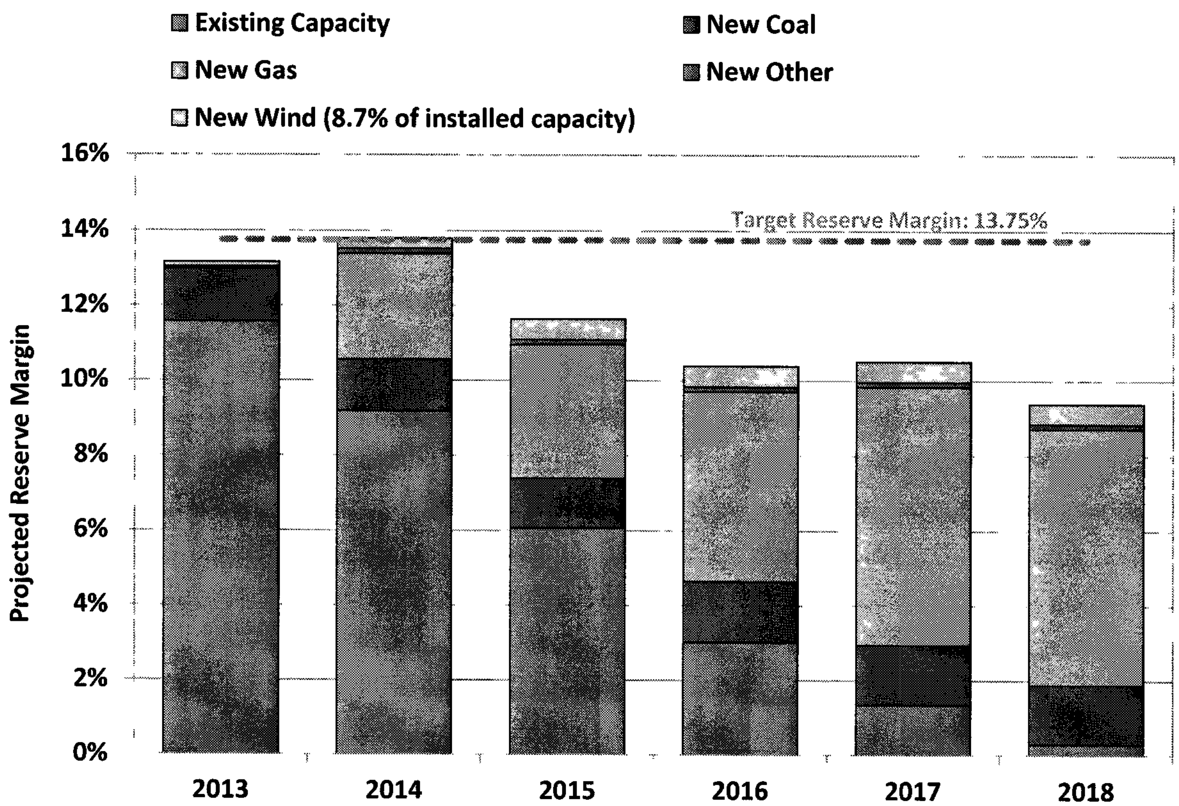
COMPARISON OF COSTS AND RELIABILITY

	Energy-Only Equilibrium	10% Reserve Margin Requirement	14% Reserve Margin Requirement
Reliability			
Reserve Margin	8%	10%	14%
Reserve Margin Certainty	Uncertain	More Certain	More Certain
Annual Avg. Loss of Load Hours	4.1	2.2	0.3
Customer Costs			
Energy Costs ($billions)	$18.3	$16.3	$14.0
Capacity Costs ($billions)	$0	$2.1	$4.7
Total Costs ($billions)	$18.3	$18.4	$18.7
Cost Increase over Energy-Only Equilibrium (%)	NA	0.7%	2.4%
Rate Increase over Energy-Only Equilibrium (%)	NA	0.4%	1.4%
Combustion Turbine Energy Margins and Capacity Revenues			
Energy Margins ($/kW-y)	$105	$75	$41
Capacity Revenues ($/kW-y)	$0	$30	$64
Total Margins ($/kW-y)	$105	$105	$105

Notes: 8% energy-only equilibrium reserve margin based on The Brattle Group's simulations with a $9,000 price cap and gradually sloping scarcity pricing function. Rate impacts assume generation costs comprise 60% of total retail rates.

Recent studies have indicated that to maintain the same small level of risk of having an involuntary curtailment of firm load, the planning reserve target should be increased from 13.75 percent to approximately 16 percent. Hence, the difficulty of satisfying ERCOT's planning needs with shortage pricing alone will grow if this recommendation is adopted. Shown below in Figure 68 is ERCOT's most current projection of reserve margins. It indicates that the region will have a 13.2 percent reserve margin heading into the summer of 2013. With the addition of recently announced generation additions, in 2014 the reserve margin is expected to reach 13.8 percent -- just barely above the current target. The bulk of the new capacity being added is natural gas-fired generation, approximately a quarter of which is expansions at existing facilities.

Figure 68: Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Reports / 2013 data from Winter 2012, 2014 - 2018 from May 2013

In response to these observations, proposals have been put forth that would introduce significant operational inefficiencies into the ERCOT energy markets, such as a requirement to substantially increase the quantity of operating reserves ERCOT procures and to, by rule, economically withhold these surplus reserves from the market. Such approaches would introduce significant inefficiencies into ERCOT day ahead and real time operations in an effort to manufacture more frequent shortage pricing and a higher planning reserve margin than would be achieved in a pure energy-only market framework. However, such approaches will not guarantee that the planning reserve targets will be satisfied and, because of the resulting inefficiencies, will be more costly for ERCOT's consumers. Hence, consistent with Brattle's findings, it is our view that, if the planning reserve margin is viewed as a minimum requirement, implementation of a capacity market is the most efficient mechanism to achieve this objective. As observed by Brattle, a well-designed capacity market can efficiently meet a planning reserve requirement without impairing the efficiency of energy market operations. However, there are many determinations required in the design, implementation and maintenance of a capacity market construct.[26]

C. 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 2012, approximately 2,500 MW of capability were qualified as Load Resources. Figure 69 shows the amount of responsive reserves provided from load resources on a daily basis in 2012. 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.

[26] *ERCOT Investment Incentives and Resource Adequacy,* The Brattle Group, at 115-119, PUCT Docket No. 37987 (June 1, 2012).

Figure 69: Daily Average of Responsive Reserves provided by Load Resources

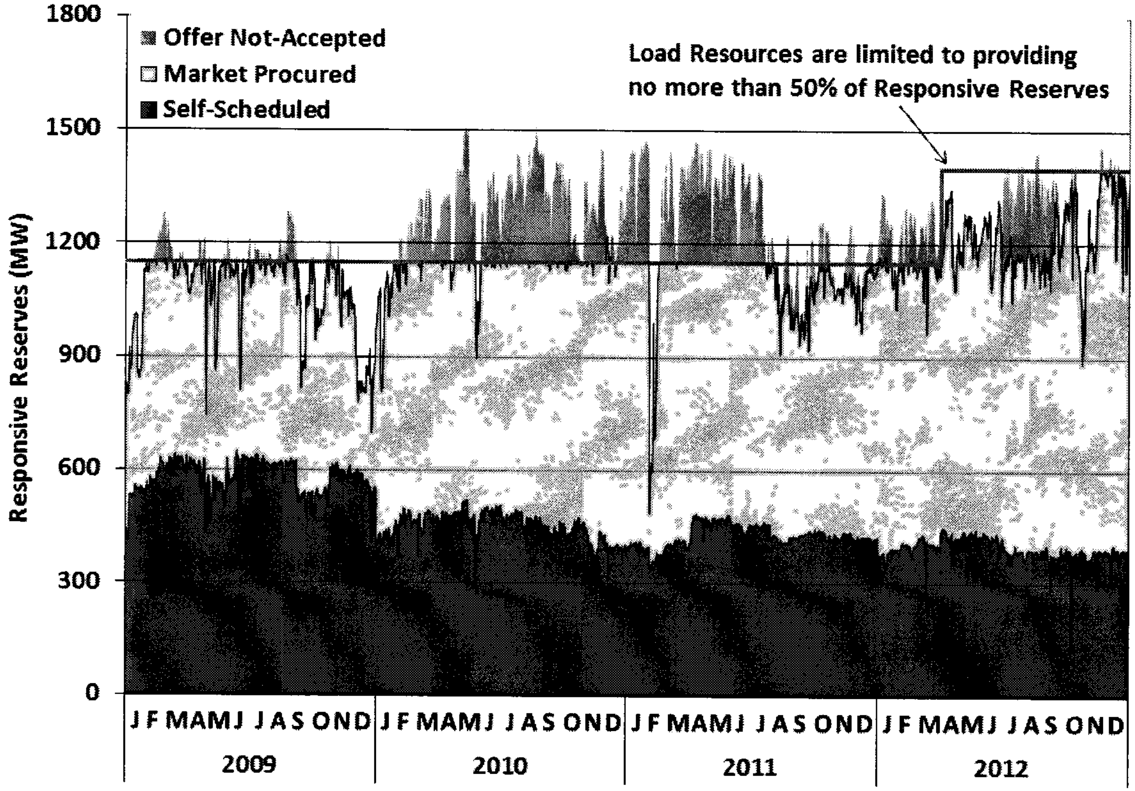


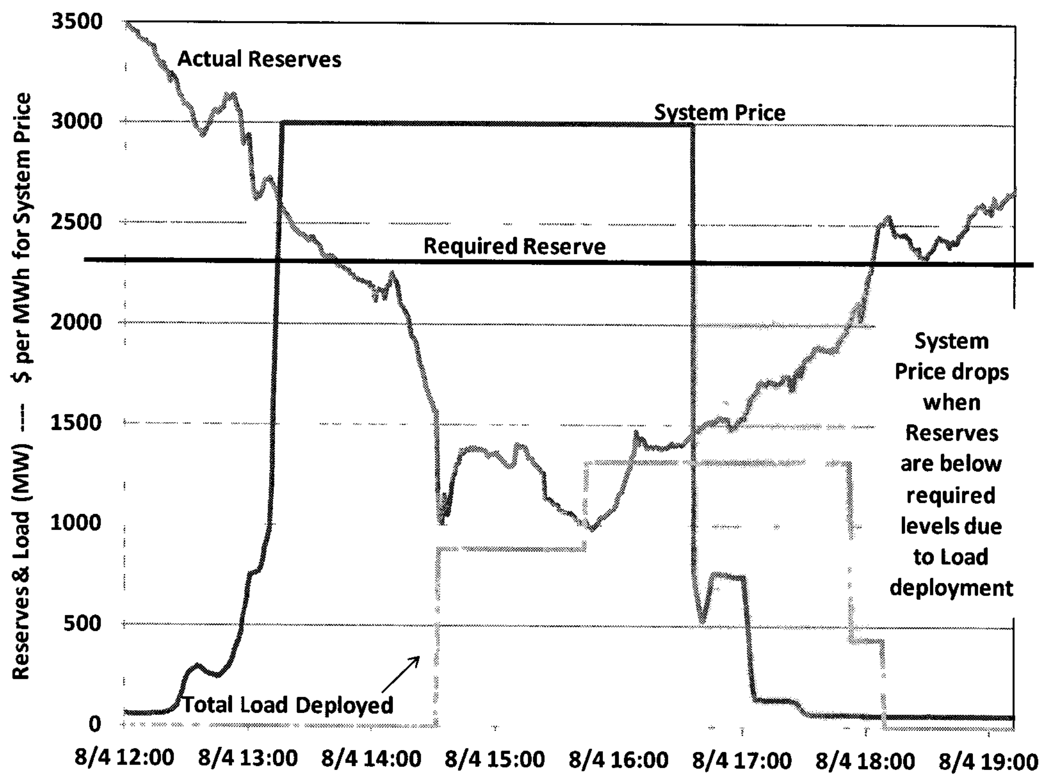
Figure 69 shows that it took a few months after implementing the increased requirement for the amount of offers by load resources to routinely reach this level. Notable exceptions include a prolonged reduction from November 2008 through January 2009 that was likely a product of the economic downturn and its effect on industrial operations. Seasonal reductions were also observed during late 2009 and 2012.

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 70 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 70: Pricing During Load Deployments



We recommend that ERCOT implement system changes that will ensure that ***all*** demand response that is actively deployed by ERCOT be incorporated into the dispatch software so that such deployments will 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.

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. 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.

Based on these analyses, we find the overall performance of the ERCOT wholesale market to be competitive in 2012.

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.[27] 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 whether it would have been profitable for a pivotal supplier to exercise market power. However,

[27] 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.

it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

Figure 71 shows the RDI relative to load for all hours in 2012. 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 or providing revenue to the QSE, the RDIs will tend to be slightly overstated.

Figure 71: Residual Demand Index

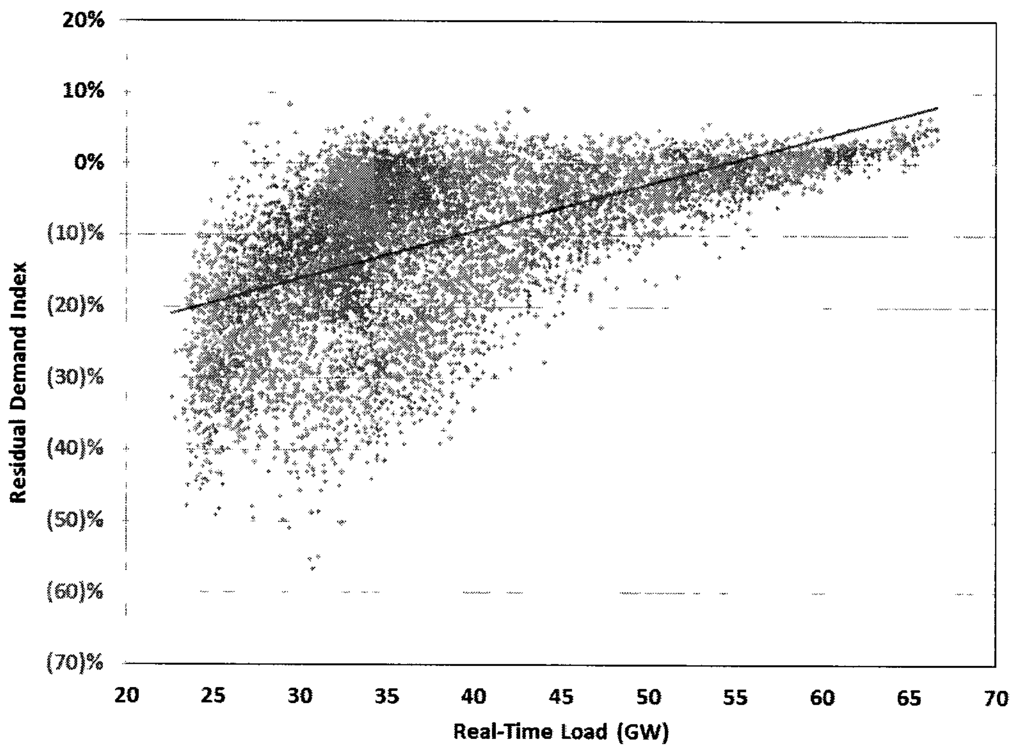
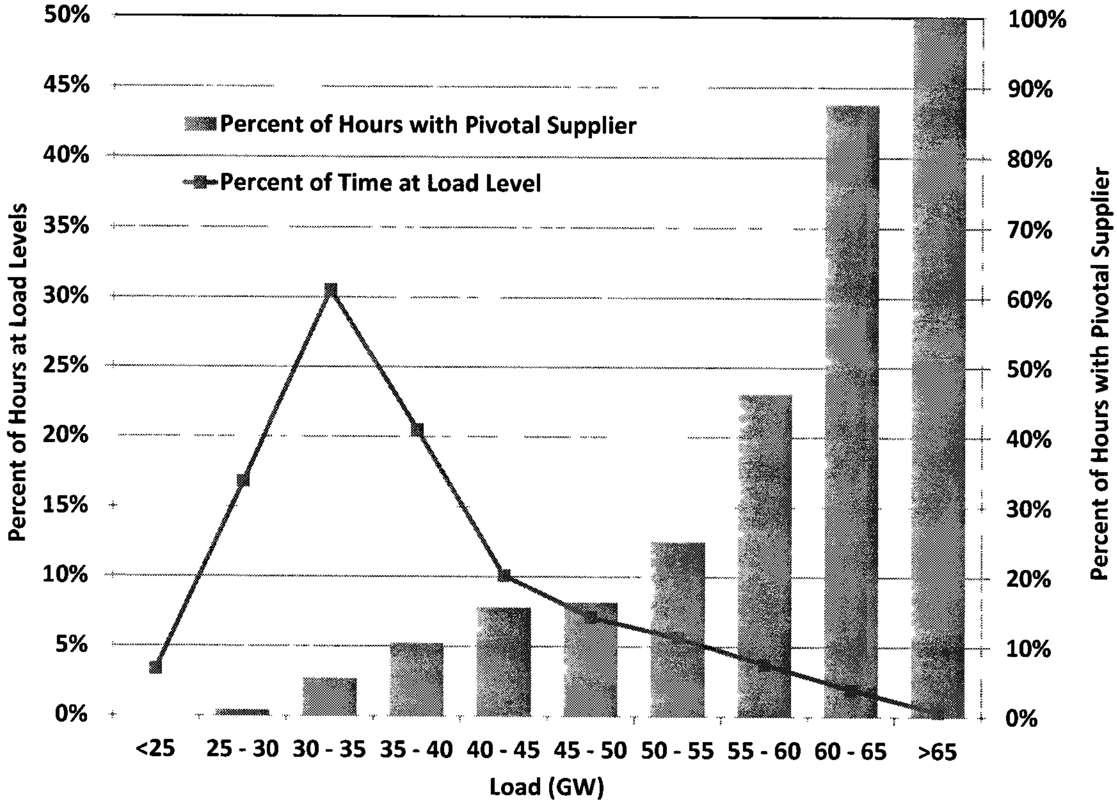


Figure 72 below summarizes the results of our RDI analysis by displaying the percent of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 100 percent of the time. The figure also displays the percent of time each load level occurs. Combining these values we find that there was a pivotal supplier in approximately

12 percent of all hours of 2012. As a comparison, the same system-wide measure for the Midwest ISO resulted in less than 1 percent of all hours with a pivotal supplier.

Figure 72: 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.

In the next analysis of RDI, we impose ramp rate limitations on the capacity available to meet load. As shown in Figure 73, the ramp constrained RDI shows the same pattern of becoming increasingly positive at higher load levels, but is much more likely to be positive as the total capacity available to the market is smaller than in the previous analysis. We observe that the ramp rate constrained RDI was usually positive, indicating the presence of a pivotal supplier, except when load was below 25 GW.

Figure 73: Ramp-Constrained Residual Demand Index

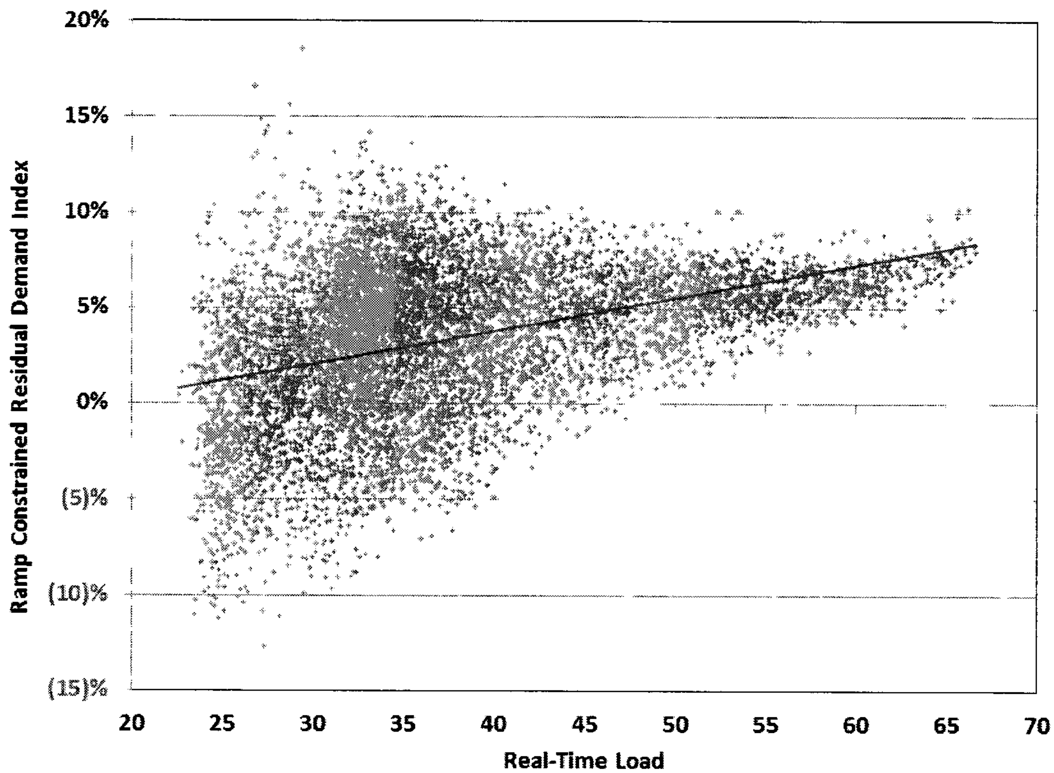
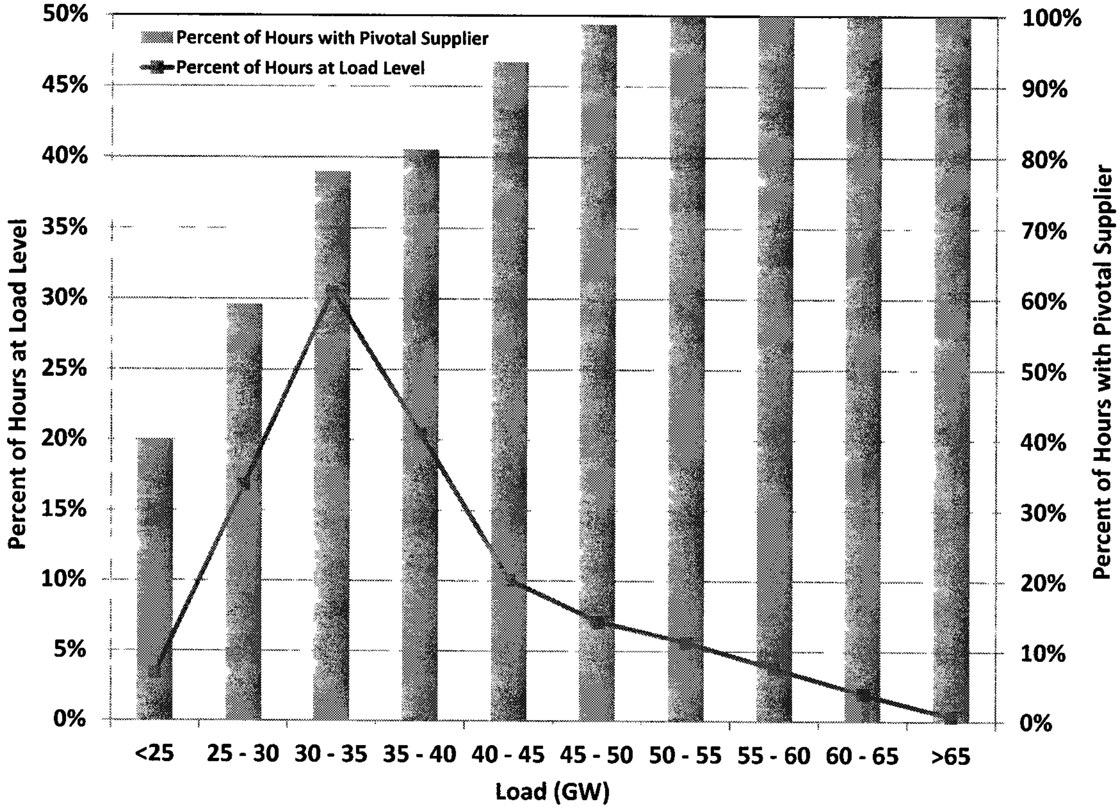


Figure 74 displays the percent of time at each load level there was a pivotal supplier when ramp rate constraints are considered. At loads greater than approximately 50 GW there is a pivotal supplier 100 percent of the time. Ramp rate constrained RDI indicates that there was a pivotal supplier in approximately 80 percent of all hours in 2012. It is important to note that this ramp rate constraint is being imposed for every dispatch interval, or approximately every 5 minutes.

Figure 74: Frequency of Ramp Constrained Pivotal Supplier by Load Level



Voluntary Mitigation Plans

The PUCT approved Voluntary Mitigation Plans ("VMP") for two market participants – NRG and GDF SUEZ – during 2012. Action on the request to approve a VMP for a third participant, Calpine, was pending at the end of the year. 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.

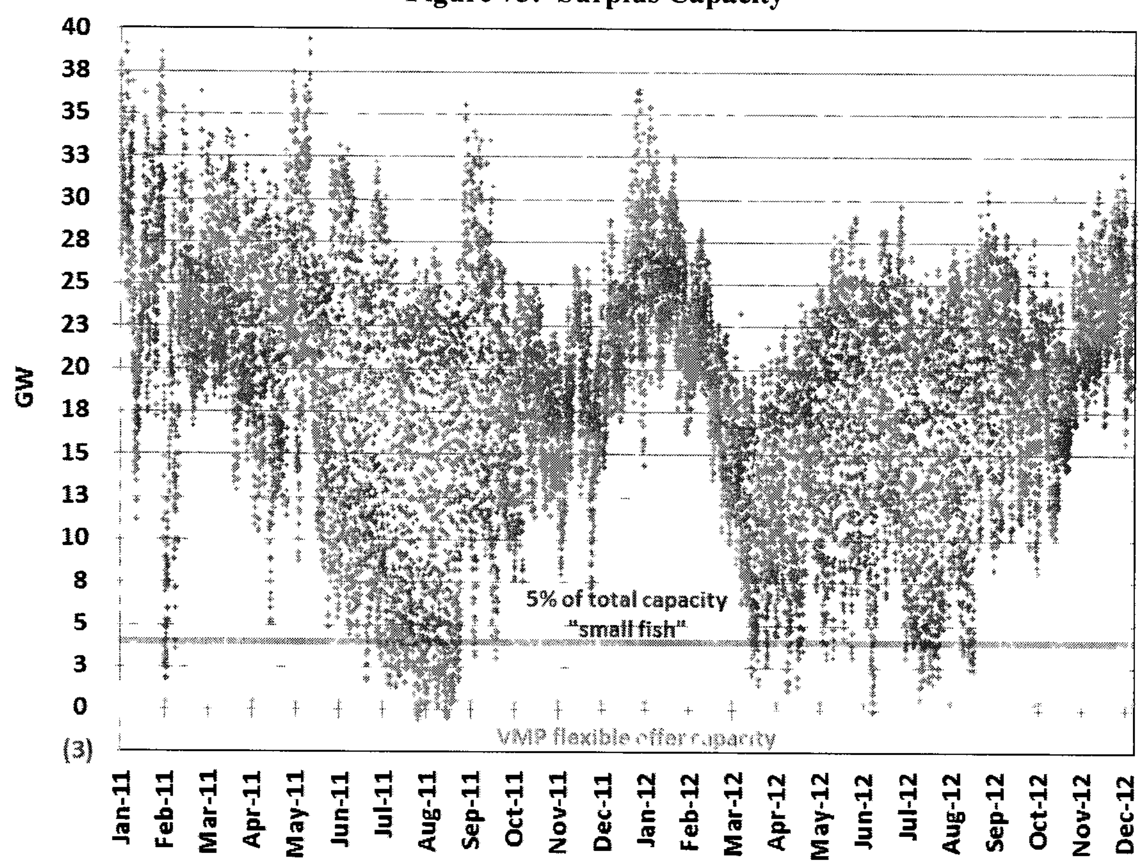
The plan approved for NRG allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit (5 percent for each coal/lignite unit) may 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 could be as much as 400 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, NRG's VMP 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 for tuning these offers in response to particular market conditions and significantly increases the likelihood that such offers, if offered, are based on legitimate marginal cost considerations.

Under P.U.C. Subst. R. §25.505(d), market participants controlling less than five percent of the capacity in ERCOT by definition do not possess ERCOT-wide market power under the PUCT rules. Hence, these participants can submit very high-priced offers that, per the PUCT rule, will not be deemed to be an exercise of market power. 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 and 2012. 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 two years there were 13 hours with no surplus capacity. 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 75. There were 450 hours over the past two years with less than 4,000 MW of surplus capacity. During these times a large "small fish" would be pivotal and able through their offers to increase the market clearing price, potentially as high as the system-wide offer cap.

Figure 75: Surplus Capacity



To date, the over-mitigation issue discussed in Section I.E, Mitigation at page 20 has meant that mitigation measures have been applied much more broadly than intended or necessary in the ERCOT real-time energy market. Market system changes to narrow the scope of mitigation are scheduled to be implemented in June 2013 to address this issue. Although "small fish" market participants have always been allowed to offer up to all their capacity at prices up to the system-wide offer cap, the effect on market outcomes of a large "small fish" offering substantial quantities at high prices will become more noticeable after the scope of mitigation is narrowed.

The approved NRG VMP affords the company offer flexibility for up to approximately 400 MW.[28] As indicated by the green line in Figure 75, the ability for NRG to raise the clearing price as a result of its offers would have occurred in less than 30 hours over the past two years.

The final key element in a VMP is the timing of termination. The approved VMP for NRG may 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.

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. In this section 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.

[28] Under the terms of their VMP, NRG may offer a certain portion of their dispatchable capacity from online units at prices up to \$500 per MWH – 5 percent of coal units and 12 percent of gas units. Additionally, NRG may offer up to 3 percent of their dispatchable capacity from online gas units at prices up to the system-wide offer cap. Any capacity offered under either of these terms must be offered in the same price/quantity pairs for all hours of the operating day.

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.

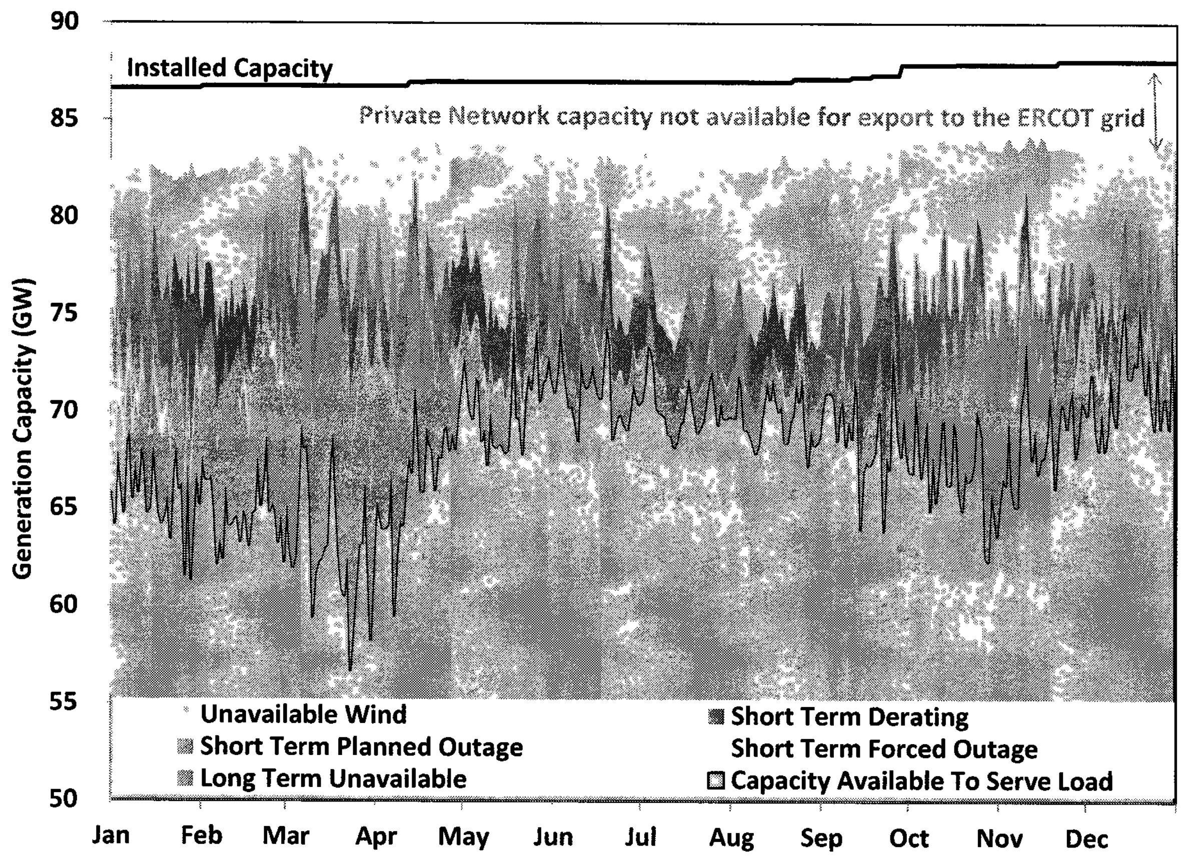
1. Generation Outages and Deratings

A substantial portion of the installed capability is frequently unavailable due to generator outages and deratings. For this analysis 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 76 shows a breakdown of total installed capability for ERCOT on a daily basis during 2012. This analysis includes all in-service and switchable capacity. From the total installed capacity we subtract away (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 – greater than 30 day -- outages and deratings. What remains is the capacity available to serve load.

Outages and deratings of non-wind generators fluctuated between 3 and 18 GW, as shown in Figure 76, while wind unavailability varied between 1 and 10 GW. Short term planned outages were largest in March, April and October and small during the summer, which are consistent with expectations. Short term forced outages also declined during the summer. Short term deratings peaked during September.

Figure 76: Reductions in Installed Capability



The quantity of long term (greater than 30 days) unavailable capacity, peaked in March at nearly 10GW, reduced to 2 GW during the summer months and increased to almost 6GW in October. 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. Figure 77 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2012.

Figure 77: Short-Term Outages and Deratings

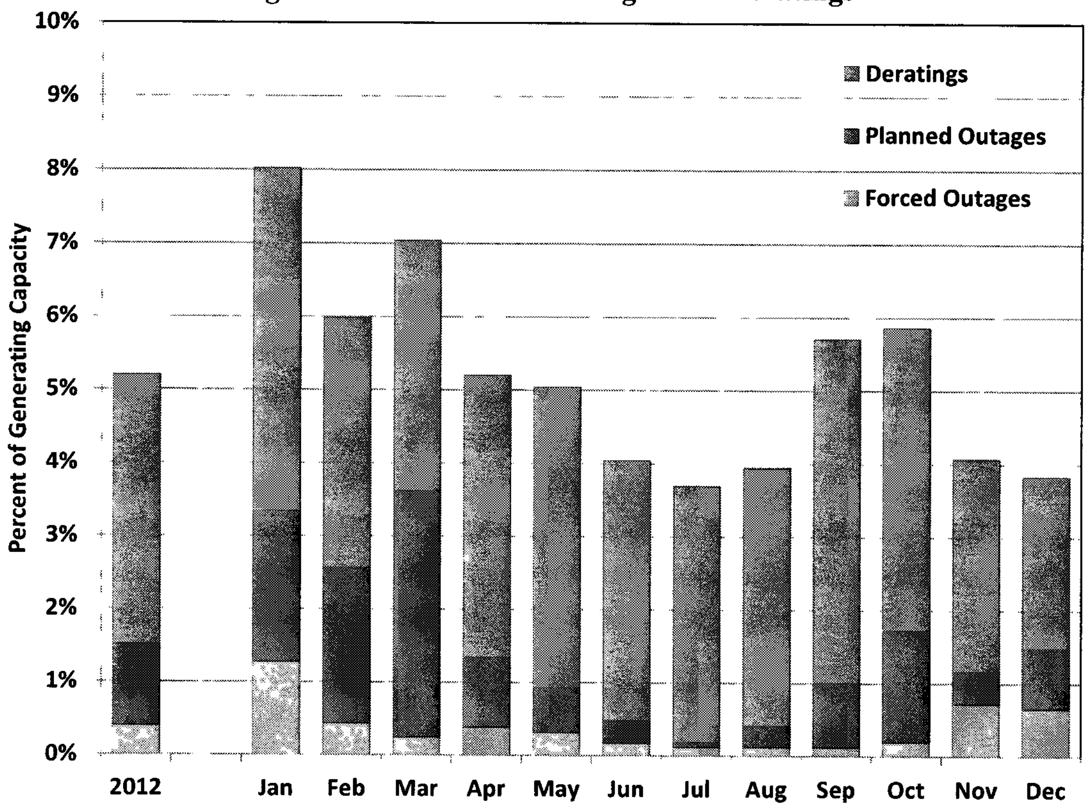


Figure 77 shows that total short-term deratings and outages were as large as 8 percent of installed capacity in January, dropping to below 4 percent for the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2012 averaged slightly above 5 percent of installed capacity. This is a decrease from 2011, when the amount 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.

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 section 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 71 through Figure 74 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 a problem in ERCOT, 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 these peak periods.

Figure 78: Outages and Deratings by Load Level and Participant Size
June to August, 2012

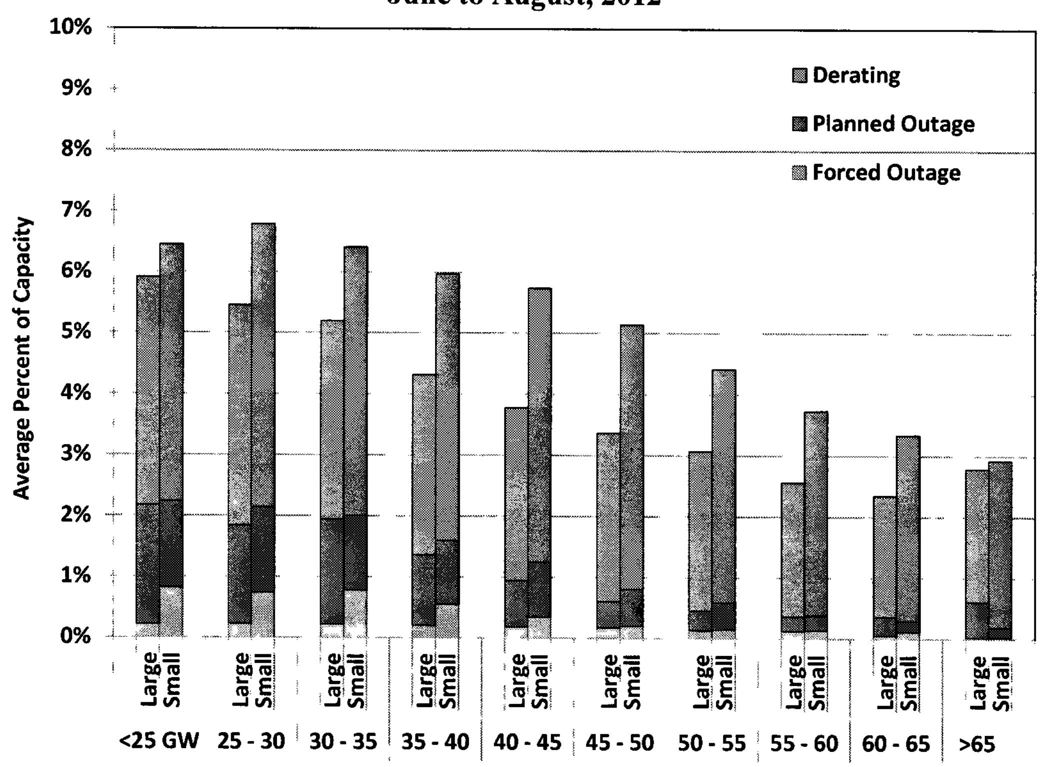


Figure 78 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load level for large and small suppliers.

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 four largest suppliers in ERCOT. The small supplier category includes the remaining suppliers.

Figure 78 suggests that as demand for electricity increases, all market participants tend to make more capacity available to the market. For both small and large suppliers, the combined short-term derating and forced outage rates decreased from 6 to 7 percent at low demand levels to less than 3 percent at load levels above 65 GW. We observe that at all load levels the percent of unavailable capacity from large suppliers is less than that from small suppliers.

3. Evaluation of Potential Economic Withholding

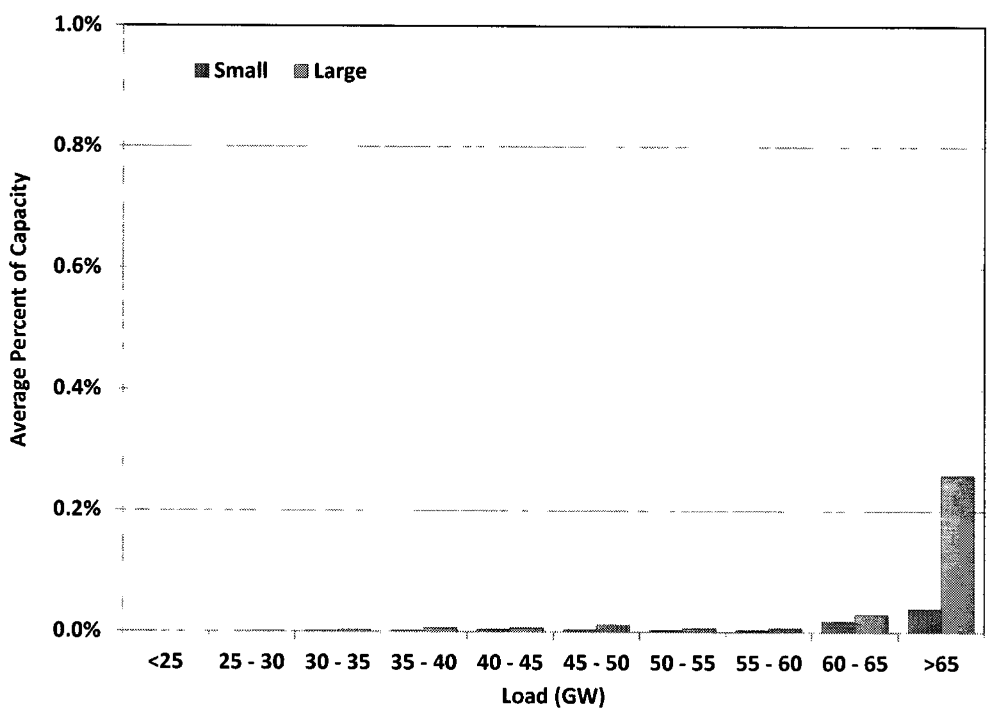
To complement the prior analysis of physical withholding, this subsection evaluates potential economic withholding by calculating an "output gap". The output gap is defined as the quantity of energy that is not being produced by in-service capacity even though the in-service capacity is economic by a 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 79: Incremental Output Gap by Load Level and Participant Size – Step 1



From the results of this analysis, shown in Figure 79, we observe only very small amounts of capacity at only the very highest loads that would be considered part of this output gap. These small quantities raise no competitive concerns.

Figure 80 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 due to a market participant exerting market power.

Similar to the previous analysis, Figure 80 shows the magnitude of the output gap to be very small, even at the highest load levels. These small quantities raise no competitive concerns.

Figure 80: Incremental Output Gap by Load Level and Participant Size – Step 2